

**INVESTIGATION OF THE EFFECT OF WELL
DIAMETER AND FLUID SATURATION ON WELL
PERFORMANCE**

**A THESIS SUBMITTED TO THE INSTITUTE OF
GRADUATE STUDIES
OF
NEAR EAST UNIVERSITY**

**By
SARKAWT KARIM KAKA HAMA KAKA HAMA**

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

NICOSIA, 2021

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SarkawtKarim Kaka Hama KAKA HAMA: INVESTIGATION OF THE EFFECT OF WELL DIAMETER AND FLUID SATURATION ON WELL PERFORMANCE

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Graduate Studies**

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To my family...

ABSTRACT

Three of the most critical challenges in the petroleum production sector are nodal analysis and vertical lift performance and inflow performance relationship (IPR). This is directly connected to well efficiency since it helps estimate pressure loss in the production system by detecting the pressure drop in each section as well as the total pressure in input and outflow. The IPR represents fluid flow from the reservoir to the wellbore, while the vertical lift performance (VLP) represents fluid flow from the wellbore to the surface. Each part in the production system has a different effect on well efficiency, so several considerations must be considered when examining well performance, such as well design, reservoir parameters, PVT data, tubing diameter, and so on. As a consequence, deciding which parameter is the root of a particular problem necessitates significant effort.

One of the parameters having a significant impact on the efficiency of an oil well is tubing diameter. Inappropriate tubing size selection results in a decrease in output volume or other serious problems. In this circumstance, a smaller diameter of the tubing represents more problems, such as higher friction and a pipe flow problem, which results in a reduction of the output rate, hence a non-economic rate, although larger tubes negatively affect production, the loss of liquid phase owing to slippage may also occur.

The aim of this project is to investigate the influence of the size of tubing and oil saturation on well efficiency by performing a sensitivity study for essential water to oil saturation critical water in oil saturation (SOWCR) and different tubing sizes using simulation tools and predicting the optimum size for the tubing section. Well diameters of 0.3ft, 0.5ft, and 0.8ft were examined, with the 0.5ft well tubing size yielding the most oil. Various SOWCR values were used, including (0.05, 0.3, 0.6, and 0.7), and the lowest, SOWCR provided the most amount of oil.

Keywords: Nodal analysis; vertical lift performance (VLP); inflow performance relationship (IPR); pressure loss; tubing size; SOWCR

ÖZET

Düğüm analizi, akış performansı ilişkisi (IPR) ve dikey kaldırma performansı, petrol üretimi endüstrisindeki en önemli konulardan üçüdür. Bu konu, her bir parçadaki basınç düşüşünün yanı sıra giriş ve çıkıştaki genel basıncı belirleyerek üretim sistemindeki basınç kaybını tahmin etmeye yardımcı olduğundan, kuyu verimliliği ile yakından ilgilidir. IPR, rezervuardan kuyu deliğine sıvı akışını temsil ederken, VLP, kuyudan yüzeye sıvı akışını temsil eder. Üretim sistemindeki her bir parçanın kuyu verimliliği üzerinde farklı bir etkisi vardır, bu nedenle kuyu performansını incelerken, tasarım, rezervuar parametreleri, PVT verileri, boru çapı vb gibi birkaç husus dikkate alınmalıdır. Sonuç olarak, hangi parametrenin belirli bir problemin kök kaynağı olduğuna karar vermek önemli bir çaba gerektirir.

Bir petrol kuyusunun verimliliği üzerinde önemli bir etkiye sahip olan parametrelerden biri de boru çapıdır. Uygun olmayan üretim borusu boyutu seçimi, çıktı hacminde bir azalmaya veya diğer ciddi sorunlara neden olur. Daha küçük boru çapları durumunda, daha yüksek sürtünme direnci ortaya çıkar, bu da çıktı oranını daha düşük bir seviyeye düşürür, dolayısıyla ekonomik değildir. Daha büyük boru boyutları üretim üzerinde olumsuz bir etkiye sahip olsa da, kayma nedeniyle sıvı faz kaybına da neden olabilirler.

Bu projenin amacı, simülasyon araçlarını kullanarak temel su-petrol doygunluğu (SOWCR) ve farklı boru boyutları için bir duyarlılık çalışması yaparak ve boru bölümü için optimum boyutu tahmin ederek boru boyutunun ve petrol doygunluğunun kuyu verimliliği üzerindeki etkisini araştırmaktır. 0.3ft, 0.5ft ve 0.8ft'lik kuyu çapları incelendi ve 0.5ft kuyu tüp boyutu en fazla petrolü verdi. 0.05, 0.3, 0.6 ve 0.7 dahil olmak üzere çeşitli SOWCR değerleri kullanıldı ve en düşük SOWCR en fazla miktarda petrolü sağladı.

Anahtar Kelimeler:Düğüm analizi; akış performansı ilişkisi (IPR); dikey kaldırma performansı (VLP); basınç kaybı; boru boyutu; SOWCR

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LIST OF SYMBOLS AND ABBREVIATIONS

Ø:	Porosity
K_x:	Permeability in x direction
K_y:	Permeability in y direction
K_z:	Permeability in z direction
FOPR:	Field oil production rate
FOPT:	Field oil production total
GOC:	Gas-oil contact
WOC	Water-Oil Contact
SOWCR	Reduced critical oil-in-water saturation

CHAPTER 1

INTRODUCTION

1.1. Background

Tubing size is a major, critical part of the production system due to the place where the fluid is lifted up to the surface. The process of determining and selecting the production casing size should be proposed by production engineers based on the tubing design that has been selected before drilling the well. The selection of ideal tubing size depends on the production mode, certain production scenario, largest and minimum tubing sizes. Tubing size can be changed, but the production and tubing casing cannot be changed, so it is important to consider the type of well, production mode, stimulation, and oil properties in case of selecting production casing size.

Pressure loss is one of the factors causing reduction in oil production rate and it happens due to different sections of pipe connections in the production system. Figure 1.1 shows the flow of oil and gas from reservoir to the separator at the surface. There is direct correlation between pipe diameter and pressure loss. In a study made by Newton et al. (1992) on the impact of pipe diameter on pressure drop in horizontal two-phase flow. The study shows that the smaller diameter size results greater pressure drops, while the pressure drop reduces with increasing the diameter of the pipe. According to the result of their study, smaller diameter pipe size has greater effect on pressure drop compared to larger diameter pipe size.

The production system can be simplified into two main systems: inflow and outflow. For instance, when the node is selected at P_{wf} of the bottom hole of the well, then the inflow covers the flow of fluids through the porous media, and flowing fluid through the completion part. The outflow covers two different sections, which are the flow of fluids through tubing string and the flow of fluids through the surface facility. Therefore, nodal analysis is crucial for optimizing the production and predicting future scenarios with numerical simulation (Renpu, 2011). The inflow system can be observed through inflow performance relationship (IPR), while the outflow system can be observed through vertical lift performance (VLP). Through inflow and outflow, the diameter size and flow rate can be described in IPR diagrams and the best diameter can be selected depending on the production rate.

Not considering tubing size or inappropriate selection of tubing diameter can result in unpredictable outcomes, which may result in loss in liquid phase production, and limiting the production. For instance, smaller tubing size results in higher friction factor and those will limit the production rate. But in case of larger tubing size, extra loss of liquid phase occurs due to slippage effect in vertical flow in pipes.

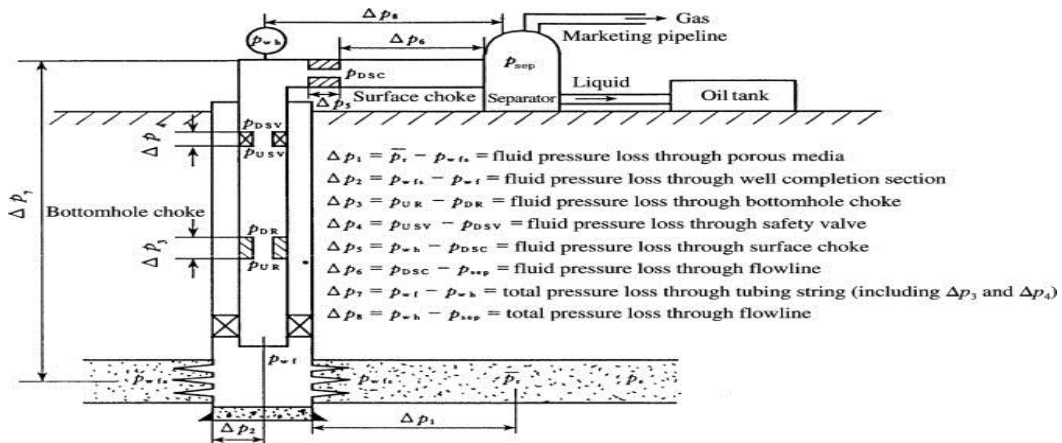


Figure 1.1: Schematic of nodal analysis for flow of fluids through the production system(Renpu, 2011).

1.2. Research Objective

The main purposes of this project are to:

1. Conduct a sensitivity analysis of the parameters that influence the tubing size and overall well performance.
2. Investigate the critical water to oil saturation on well performance.
3. Selecting optimum tubing size for an oil well in an example field.

1.3. Problem Statement

One of the most important parts of a flowing well production system is the tubing as it is the main channel for the development of an oil and gas field. The rate of pressure drop increases to 80% in case of lifting fluid from bottom of the hole to the surface through the tubing

section (Renpu, 2011). Therefore, tubing is a sensitive part of any oil or gas well and should have optimum tubing sizes. When the tubing diameter is small, it results increasing in the friction between the produced fluid and inner wall of the tubing string, which results in minimizing the production. Additionally, large diameters result in losses in the liquid phase due to the excessive downhole liquid and the impact of gravity which affects the loading of liquids. Thus, the selection criteria are critical to defining the optimum tubing diameter size in order to prevent any problems or risks associated with inappropriate tubing size such as limiting production rate due to high friction resistance or loss of liquid phase due to slippage impact.

1.4. Scope of Study

The result and procedure of this project could help all the petroleum engineers, including reservoir and production engineers by providing the required information regarding the impact of different tubing sizes and fluid saturation on oil well reservoir performance. Therefore, this paper helps to investigate the fluid flow and completion design impact on the production by observing its impact on well reservoir performance.

1.5. Relevance of Work

Any oil company's aim is to increase earnings by efficiently producing its wells. The aim of this project is to find the best tubing size for achieving the best production rate while maximizing reservoir energy use. The following are some of the reasons why this work is important:

- Optimum tubing size for optimal performance.
- Keeping the pressure decrease in the tubing to a minimum.
- The least amount of energy is used to raise the hydrocarbon.
- Frictional flow resistance is kept to a minimum.
- Flowing time is the longest.
- Maximum energy efficiency is achieved.

1.6. Organization of the Study

Chapter 1 (Introduction): This chapter discusses the background, objective and problem of this study.

Chapter 2 (Literature Review): This chapter provides all the previous studies related to this topic.

Chapter 3 (Research Methodology): In this chapter, the methodology (procedure) of this study is discussed in detail which includes reservoir fluid and rock data, and simulation procedure.

Chapter 4 (Results& Discussion): This chapter discusses the result of the simulation.

Chapter 5 (Conclusion & Recommendations): All the conclusion and recommendation remarks are mentioned here.

CHAPTER 2

LITERATURE REVIEW

2.1. Inflow Performance Relationship (IPR)

By plotting the inflow performance relationship, the well's flow potential or rate can be resolved at different flow sand face pressures. This procedure, called IPR analysis, can be utilized to decide deliverability for a well producing oil or water (Fekete, 2018). Figure 2.1 demonstrates the inflow performance relationship (TOAG, 2018). For oil wells, it is assumed that liquid inflow rate is relative to the distinction between reservoir pressure and well-bore pressure. This suspicion prompts a straight-line relationship that can be received from Darcy's law for relentless state flow of an incompressible, single phase Newtonian liquid and is known as the Productivity Index (PI). In any case, this presumption is substantial just over the bubble point pressure (P_b).

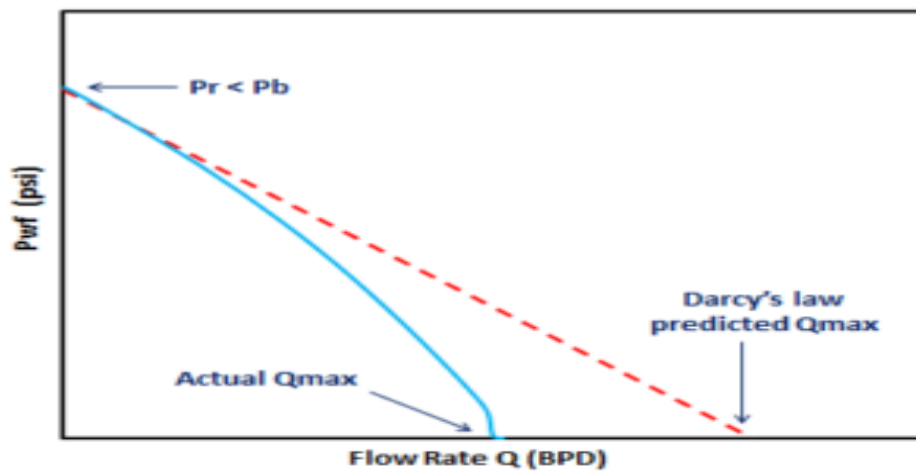


Figure 2.1: Inflow performance relationships (TOAG, 2018)

In the presence of multi-stage stream circumstances, Evinger and Muskat (1942) proved that a curved connection exists between flow rate and pressure when two phase flow occurred in the reservoir. There are numerous utilizations of inflow performance relationship and one of them is identifying the maximum flow rate (Q_{max}) that a well can produce. Estimating maximum

flow rate is helpful in the plan of exploitation, and to fix the reference value from which it can recognize the decrease in the well production. The inflow curves are connected by their dimensionless relations, which use the factors of flow rate and pressure in a well test production (Aragón et al., 2007). In this way, IPR enhances the understanding of the reservoir. Since the IPR gives an indication of how much oil can flow into the well, this information can be utilized in structuring right tubing size through which liquids will flow to the surface. Inflow performance relationship can likewise be extrapolated to get a perspective for future performance from a well under a specific production procedure. The straight line IPR under single stage flow is otherwise called productivity index. For two-stage flow conditions, the IPR can be acquired from Vogel (1968) inflow performance relationship or that of Fetkovich (1973).

2.1.1. Vogel's inflow performance relationship

Vogel was the first to exhibit a simple to-utilize strategy for anticipating the performance of oil wells (Vogel, 1968). His observational inflow performance relationship (IPR) depends on simulation results and is given by

$$\frac{q_o}{q_o(max)} = 1 - 0.2 \left(\frac{P_{wf}}{P_r} \right) - 0.8 \left(\frac{P_{wf}}{P_r} \right)^2 \quad (2.1)$$

For this connection, oil engineers need to estimate the rate of production of oil and the flowing low pressure from the production well test and at the time of the test acquire an average reservoir pressure. The maximum oil production rate for other fluid lower-hole pressure at the reservoir pressure may be measured and used to estimate production rates (Vogel, 1968).

2.1.2. Single- and two-phase flow

Under some situations, a one-phase and a two-phase flow in the tank can occur when the average tank pressure exceeds the oil tank bubble-point pressure but the fluid pressure of the bottom hole is not exactly the pressure of the bubble-point. Neely (1967) established a composite IPR to cope with this situation, which is shown by Brown (1984). The composite IPR pairs Vogel IPR with single flow efficiency index for 2-phase flow. The relationship that yields the maximum oil production rate is

$$q_o(max) = J(Pr - Pb + \frac{Pb}{1.8}) \quad (2.2)$$

At various bottom-hole pressure and when the Pwf is greater than the Pb, the production rate can be estimated using the following equation:

$$q_o = J(Pr - Pwf) \quad (2.3)$$

When the Pwf is less than the Pb, then the following equation can be used:

$$q_o = q_o(max) - qb) = \left[1 - 0.2 \left(\frac{Pwf}{Pb} \right) - 0.8 \left(\frac{Pwf}{Pb} \right)^2 \right] + qb \quad pwf \leq pb \quad (2.4)$$

For the prediction of the output of a horizontal well, the reservoir influx behaviour on the side can be employed. Modelling approaches can also be utilized for analysis or reservoir simulation to achieve this objective. Both approaches anticipate the flow rate in the lateral due to the pressure drop. Whereas reservoir simulation models are more efficient in predicting good outcomes, analytical modelling is a more attractive choice in the field, since less data, effort and time are needed, in particular when planning and optimizing a single well output. The horizontal wells are calculated using input performance (IPR) equations. In horizontal wells, IPR equations are separated between static flow circumstances, under which the pressure at the limit is constant and pseudo steady flow situations, where the flow at the limit does not exist, but the pressure at the limit depends on the limit conditions (Kamkom and Zhu 2006).

Depending on the boundary situation, the flow rate of a somewhat compressible single-phase fluid, like oil, can be described using either stable or pseudo-state condition. For a horizontal well with no flow barriers and pressures gradient, Babu and Odeh (1989) have suggested a pseudo-state IPR model.

A horizontal well was turned to resemble a vertical well, and a geometry element was included to account for the change in drainage area. Babu and Odeh's model assumes a box-shaped drainage region with reservoir length in the x-direction and width in the horizontal y-direction perpendicular to the wellbore, as shown in Figure 2.2 (Hill et al., 2008).

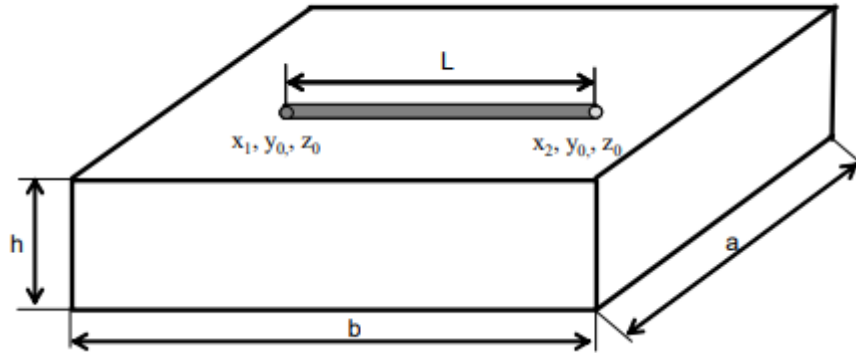


Figure 2.2: Schematic of Babu and Odeh's model (Hill et al., 2008)

The horizontal wellbore is situated anywhere in the reservoir and travels parallel to the x-axis. The model, on the other hand, imposes certain constraints on the wellbore not being too close to any of the reservoir borders. This is governed by conditional equations in the model, as will be demonstrated. The model utilizes a partial penetration skin factor to account for input from the reservoir beyond the wellbore's ends in the x-direction (Hill et al. 2008). The inflow equation is presented in the most typical form for a vertical well in this model. As a result, for a horizontal well, the Babu and Odeh inflow equation is represented by the following equation:

$$Q = \frac{\sqrt{KyKzb}(P-p_{wf})}{141.2B_o\mu \left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H - 0.75 + S_R + S \right]} \quad (2.5)$$

The form factor is CH, while the partial penetration skin factor is SR. The skin factor represents other skins, such as creation or completion skin influence(s). Babu and Odeh devised simplified formulae for computing the form factor, CH, and partial penetration skin, sR, both of which are required for solving the horizontal well inflow equation.

The partial penetration skin component accounts for any input that extends beyond the wellbore's ends. As a consequence, sR is equal to zero if the horizontal well completely enters the reservoir, i.e., when the wellbore length, L, matches the reservoir drainage length,

b. When the wellbore is partially penetrated, that is, when the length of the wellbore is smaller than the length of the drainage, SR is assessed in two ways.

2.1.3. Single- and two-phase flow

a. Two-phase friction factor determination

Poettmann and Carpenter's charts can be used to quantify the two-phase friction factor, f_{2F} (1952). However, since Guo and Ghalambor (2002)'s correlation approximates the values of the Poettmann and Carpenter (1952) two-phase friction factor chart as given by equations below, it was used in the machine for ease of coding (19). The two-phase friction effect is constant over all tubing segments for a given flow rate and size since it is a combination of flow rate and tubing scale.

$$D_{pv} = (1.4737 \times 10^{-5} M_{qo})/D \quad (2.6)$$

$$F_{2F} = 10^{1.444 - 2.5 \log(D_{pv})} \quad (2.7)$$

b. Average density determination

The gas–oil–water three-phase combination in the tube is generally handled as a homogenous mixture according to the Poettmann and Carpenter (1952) approach. To reproduce this homogenous combination, the mixture density at the top and bottom of each tubing segment had to be calculated, as well as the average mixture density of each tubing segment.

The mass flow rate, M , and volume flow rate at the top, $V_{mt}(k)$, and bottom, $V_{mb}(k)$, of the k th tubing segment is used to measure the density at the top and bottom of the k th tubing segment (Guo, 2019; Nind, 1964). The overall mass associated with one storage tank barrel of oil, M (Guo, 2019), is used to be determined using the equation below:

$$M = 350.17 (y_o + \text{WOR} (y_w)) + ((\text{GOR}) (p_{air})(y_g)) \quad (2.8)$$

Where y_w is water specific gravity

y_o is oil specific gravity

yg is gas specific gravity

2.1.4. Multiphase flow

Multi-phase fluid flow has been written a lot in the literature regarding pipes. Since liquid (oil or condensate and water) and vapor flow simultaneously are present, this issue is significantly more difficult than the single-phase flow problem (gas). The techniques for measuring pressure decrease in multi-phase flow are based on the mechanical energy equation; nevertheless, the issue is to decide the appropriate velocity, friction factor and density to be used in the multi-phase mixture estimates. Moreover, the problem is worsened by the rise in speeds, fluid charges and fractional vapor to liquid as fluid flows to the surface as a result of pressure.

Several researchers have suggested methods for calculating pressure drops in multiphase flow. Some researchers have linked pressure-drop calculations to flow patterns because each method is based on a combination of theoretical, experimental, and field observations. The distribution of each fluid phase within the pipe is defined by flow patterns or flow regimes. This means that calculating pressure is reliant on the expected flow pattern. In the most basic description of flow systems, there are four flow patterns (Orkiszewski, 1967):

- Bubble flow
- Slug flow
- Transition flow
- Mist flow, with a continually increasing fraction of vapor to liquid from bubble to mist flow

One of the first studies of the construction a multiphase flow correlation for oil wells, was Poetman and Carpenter (1952), while an early multiphase correlation was presented for gas wells by Gray (1974). A considerable number of experiments have been conducted using multiphase pipe flow. Many of these similarities are reviewed in Brill and Mukerjee (1999) and Brown and Beggs (1977). To allow for variations in flow parameters as a result of strain, the multiphase-flow correlations must be applied in an iterative, trial-and-error manner. This requires a lot of calculations and is better done with computer programs. Pressure equations

are frequently expressed in the form of pressurized cross curves, such as the one seen in Figure 2.3, for a particular tube diameter, output rate and fluid characteristics. Pressure-transverse curves are generated for a range of gas/liquid ratios, offering pressure estimations based on the depth. Simple computations by man can be made using these curves.

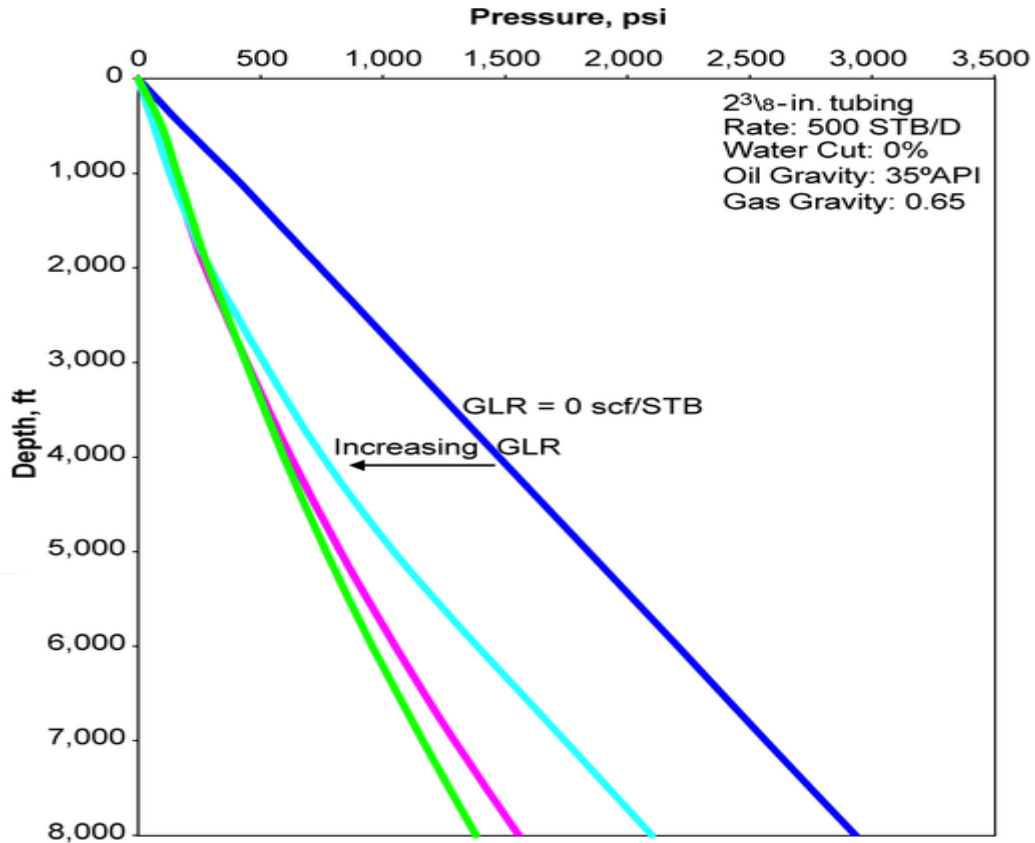


Figure 2.3: Pressure traverse curves(Petrowiki, 2020)

2.2. Vertical Lift Performance (VLP)

The production of a well depends on several factors, including: wellbore mechanical configuration, rock and fluid properties, and reservoir condition. There are several ways to estimate the performance of a well, such as inflow performance relationship and vertical lift performance(Gromotka, 2015). Figure 2.4 shows the vertical lift performance for an oil well(Hatton and Potter, 2011).

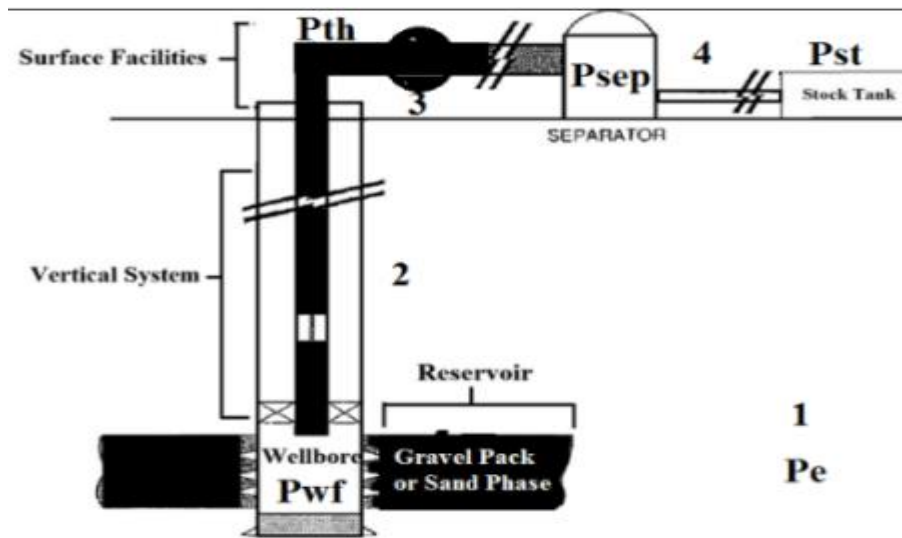


Figure 2.4: Typical production system with pressure components parameters (Hatton and Potter, 2011)

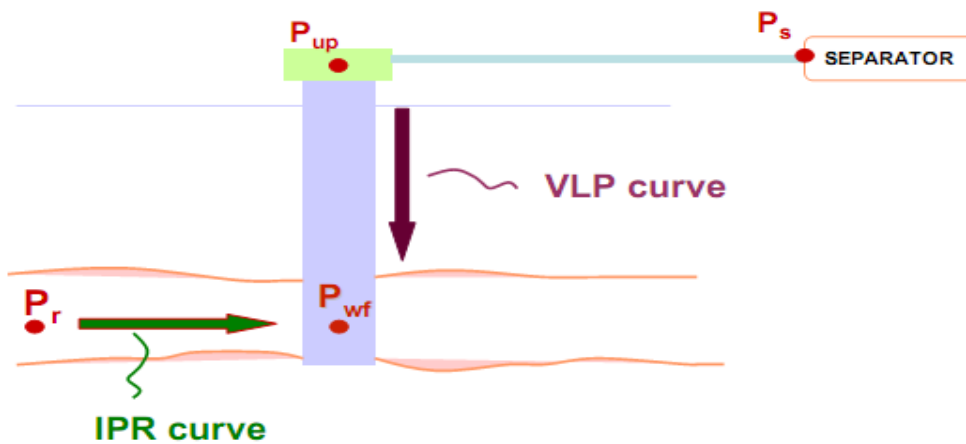


Figure 2.5: IPR vs. VLP (Fetoui, 2017).

The vertical lift performance curve consists of two main parts: the first part is a relationship between flow rate and the pressure drop of the well at wellhead, while the second curve relates between bottom-hole pressure and flow rate at the top section of the well, which here the wellhead pressure is added to the pressure drop to provide the actual pressure at the bottom of the well.

Simply, the vertical lift performance is bottom-hole pressure as a function of flow rate. The main factors that the vertical lift performance depends on fluid PVT properties, well depth, surface pressure, gas-oil ratio (GOR), water-cut (Wct), and tubing size. Figure 2.5 illustrates both well performances relationships: IPR and VLP(Fetoui, 2017).The IPR provides information of reservoir deliverability from the bottom-hole of the well, while the VLP provides what the well will provide to the surface. The Figure 2.6 shows the IPR and VLP curves in which the intersection between the IPR and VLP is called operating points(Fetoui, 2017).

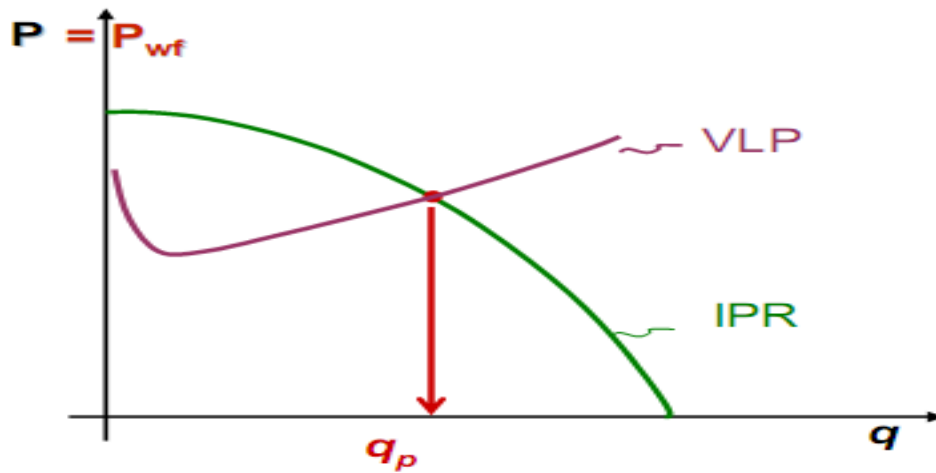


Figure 2.6: IPR and VLP curves (Fetoui, 2017)

2.3. Relative Permeability

The fluids which flow in reservoir commonly include multiphase flow, which implies that the general capacity of one fluid to flow is influenced by the other of different fluid in the reservoir. Relative permeability is a concept used to describe the decrease in flow ability because of the presence of multi-phase flow. It depends on pore geometry, wettability, distribution of fluids, and saturation history. Subsequently, relative permeability estimations are frequently asked for ventures where secondary as well as tertiary recovery is being considered (Fekete, 2018). Figure 2.7 shows typical relative permeability curve illustrating the wetting and non-wetting phases (Von Gonten et al., 1992). Figure 2.8 shows the drainage

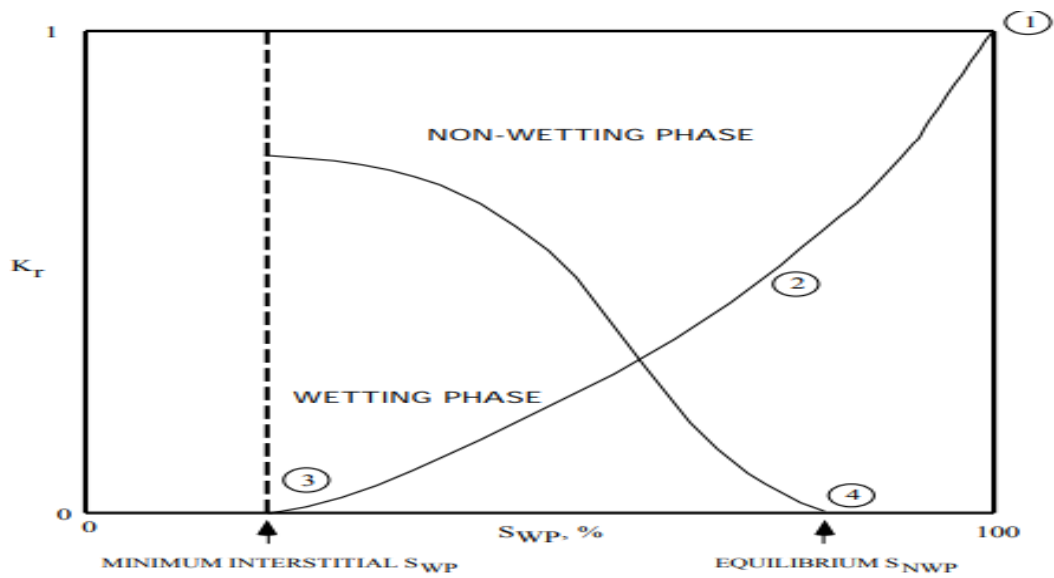


Figure 2.7: Typical relative permeability curve for wetting and non-wetting phases (Von Gonten et al., 1992)

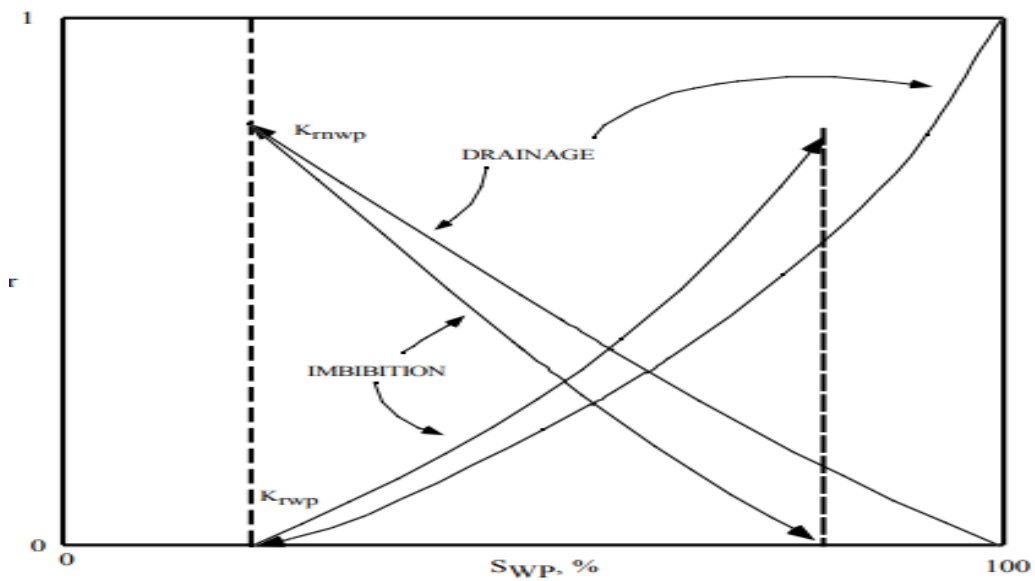


Figure 2.8: Relative permeability curve (Drainage and imbibition curves) (Von Gonten et al., 1992)

and imbibition curves where wetting phase is displaced by non-wetting phase and imbibition process where non-wetting phase is displaced by wetting phase (Von Gonten et al., 1992).

2.4. Capillary Pressure

In the study of porous media containing two or more immiscible fluids, capillary pressure is an essential quantity. The capillary force of a porous media regulates the distribution and the flow of the non-mixable phases together with viscous and gravitational forces. The presence of capillary pressure is based on interface tension or interfacial free energy between two uncompromising fluids. In the narrower radius of the capillary tube (or pore) the capillary pressure is higher (Bognø, 2008). The capillary pressure curve shows how the pressure fluctuates with the saturation of the fluid. A porous media has a continuous pore size distribution and hence a constant function of fluid saturation is provided by a capillary pressure curve. Figure 2.9 shows a typical curve of capillary pressures (Bera and Belhaj, 2016).

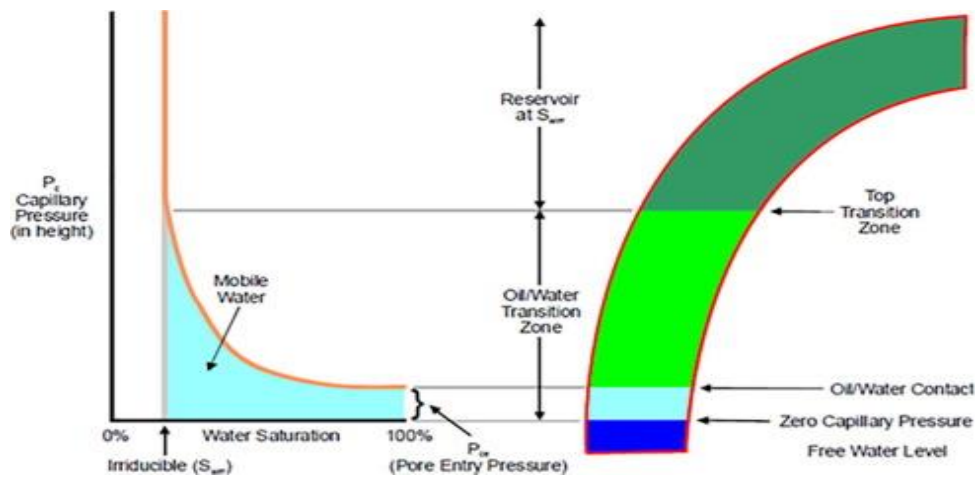


Figure 2.9: Capillary pressure vs water saturation (Bera and Belhaj, 2016)

2.5. Nodal Analysis

When the well is drilled and completed, a great energy is required to transport the fluid through the reservoir into the piping system and up to the separator. The required energy is for overcoming the friction loss and to lift the produced fluids up to the surface. The total pressure drop at any time is equal to the initial fluid pressure minus existing fluid pressure (PetroBlogger, 2012). The sum of the pressure drop is basically the sum of all pressure drop in all the components of the system. Production rate is the variable which the selection and

sizing of each component depends on. Each component of the production system in nodal analysis has its own relationship between flow rate and pressure drop (PetroBlogger, 2012). When the node is selected, the pressure is calculated. The pressure for inflow to the node is calculated by the following equation:

$$P_{\text{node}} = P_r - \Delta P \quad (\text{Upstream component}) \quad (2.9)$$

Where P_r is the reservoir pressure, and ΔP is the change in pressure.

Figure 2.10 shows the effect of changing the tubing size on flow capacity. According to the figure, inflow and outflow performance curves are described and it shows the operating conditions at the intersect section.

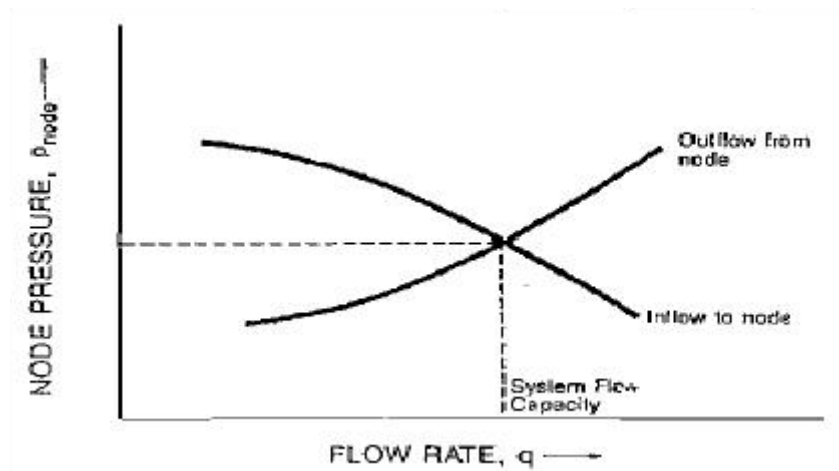


Figure 2.10: Effect of tubing size on inflow and outflow(Petroblogger, 2012)

2.6. Selection of the Optimum Tubing Size and Flow-line

The selection of tubing size and deviation are key elements in the well completion process. The drilling engineer plans the hole configuration and calculates the output casing size using standard techniques. The production engineer chooses and decides on the tubing size and method of production based on the production casing that has been selected after a well has been drilled and completion is to be finished. As a result of this practice, manufacturing

processes are constrained by the scale of the production casing. Casing size, for example, would become a dependent factor if output volume is increased by increasing tubing size. This project would demonstrate the logical determination and specification of the optimal tubing size for output wells in order to avoid this conventional procedure. In accordance with criteria of energy tanking and production engineering, the rational tube dimension should first be computed in a separate production mode and then an allowable minimum production casing size is identified and chosen. The logical tubing size can be calculated and chosen during the flowing development stage using a sensitivity study of tubing size based on nodal analysis.

Pressure drop is understood to occur from the reservoir to the surface separator, and output cannot take place without this pressure difference. As a result, an oil and gas well's output mechanism can be broken down into two major components: inflow and outflow. As a result, establishing a relationship between the inflow and outflow in terms of tubing size is crucial for deciding the best tubing size for the best production volume. The project would also take into account the importance of flow line scaling in a well's optimum efficiency (Al-Jawad and Sadeq, 2006).

The determination of tubing size and flow line is essential in the oil field development plan. In oil wells, the pressure misfortune through the tubing can comprise the greater part of pressure loss through the whole system.

In the event that the tubing size is undersized in well, friction loss will end up too problematic as it is too high. When the tubing size is too large, extra pressure losses will be experienced because of fluid stacking. Expect that the accessible flow line sizes are in the scope of (2.5 to 7 inch) inside distances across and the tubing sizes are in scope of (2.5 to 7 in). The extensive measurement of tubing size is taken when the production is from the packaging. Figure 2.11 demonstrates the tubing and the flow line mixes for a specific oil field. The convergence of the flow line curve and the tubing curve to the conceivable flow rate for the given blend. For instance, to deliver the well at 4000 STB/D as appeared in Figure 2.11 and Figure 2.12, all crossing points of flow line and tubing plots to one side of the vertical line through 4000 STB/D will create the well palatable. The most prudent blend or the ideal mix is 4-inch tubing and 5inch flow line (Al-Jawad and Sadeq, 2006).

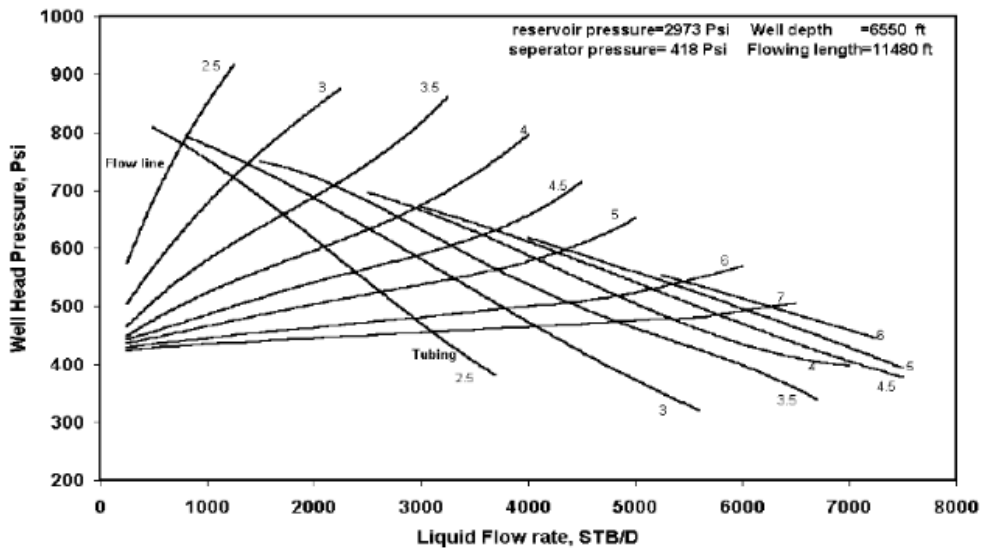


Figure 2.11: Analysis chart of tubing and flow line combinations (Al-Jawad and Sadeq, 2006)

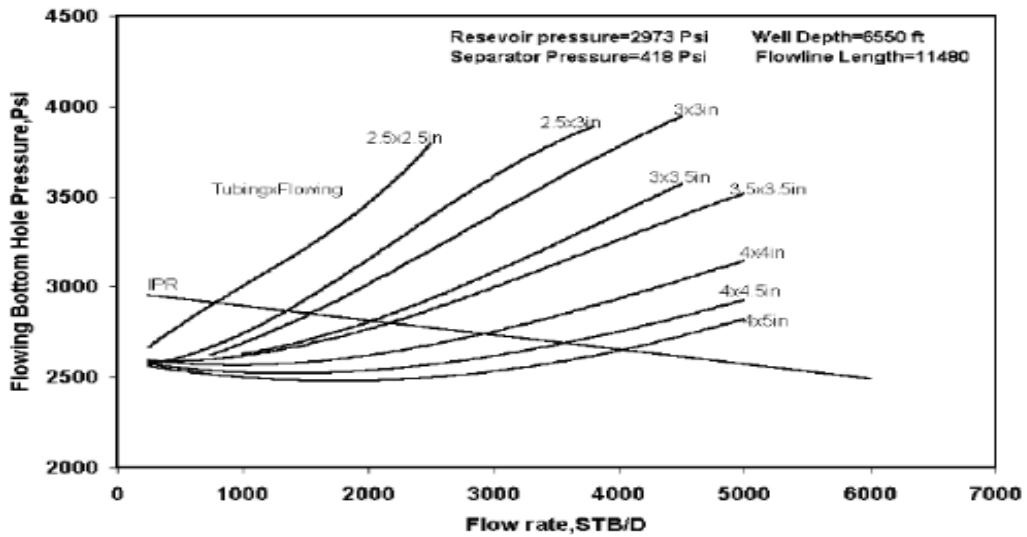


Figure 2.12: Effect of various tubing and flow line sizes combinations (Al-Jawad and Sadeq, 2006)

2.7. Liquid Loading

Liquid that reaches the wellbore at the bottom of the hole will only flow to the surface if the pressure differential between the bottom and top of the well is greater than the fluid column's hydrostatic pressure, plus any friction caused by flow up the tubing. The fluid will remain stagnant in the wellbore if the pressure is insufficient. Water loading is the term for this. If the primary source of energy is coal, Water escaping from the formation or concentrated within the tubing will even build up in the wellbore if the gas isn't moving fast enough to lift the water out. The structure can be subjected to increased backpressure as a result of the accumulation of this stagnant fluid column, which may greatly decrease the well's efficiency or even "destruct" the well and prevent it from flowing at all.

It could be appropriate to adjust the wellbore structure or add artificial lift equipment if liquid loading occurs. The velocity of the fluid running up the well, for example, is affected by the tubing size. Because of the narrower cross-sectional area, the fluid velocity would be higher when smaller tubing is used. Turner et al. (1969) established a valuable correlation based on an analysis of over 100 fluid gas wells to calculate the minimum flow rate (and thus velocity) needed to lift liquids continuously from a gas well. Turner's correlation can be used to calculate the amount of tubing needed to continually drain water from a well that is running at a certain rate.

It may be appropriate to mount artificial lift equipment to pump liquids to the surface of oil or gas wells that produce huge quantities of water or condensate. Rod motors, submersible pumps, and gas lift valves are the most popular artificial lift methods (see Artificial lift).

2.8. Impact of Different Variables on Production Performance

2.8.1. Effect of liquid flow rate on pressure loss

Friction equation shows that the loss of friction increases as the liquid rate increases (v increases). With increased liquid demand, the hydrostatic gradient also rises (Knut, 2009).

2.8.2. Effect of gas-to-liquid ratio on pressure loss

As the gas-to-liquid ratio (GLR) is raised, the hydrostation gradient is lowered. Increased GLR, however, increases friction forces and affects the contrary pressure at the bottom hole. As the

friction contribution surpasses the hydrostatic strength, the true lower hole pressure starts increasing. This indicates that the extent of the gas pushed benefitfully is limited in terms of gas boost (Knut, 2009).

2.8.3. Effect of water cut on pressure loss

Increased water reductions induce an increase in the mass of liquids, increasing hydrostatic forces and friction in the bottomhole.

2.8.4. Effect of tubing size on pressure loss

Increasing the tube size reduces the friction-caused pressure gradient. However, only a specific point in the diameter of the pipe may be expanded. The combination is too wider to increase the fluid and the well begins to fill with liquid and hydrostatically growing pressure (components: $v=q/A$, pipe cross section) (Knut, 2009).

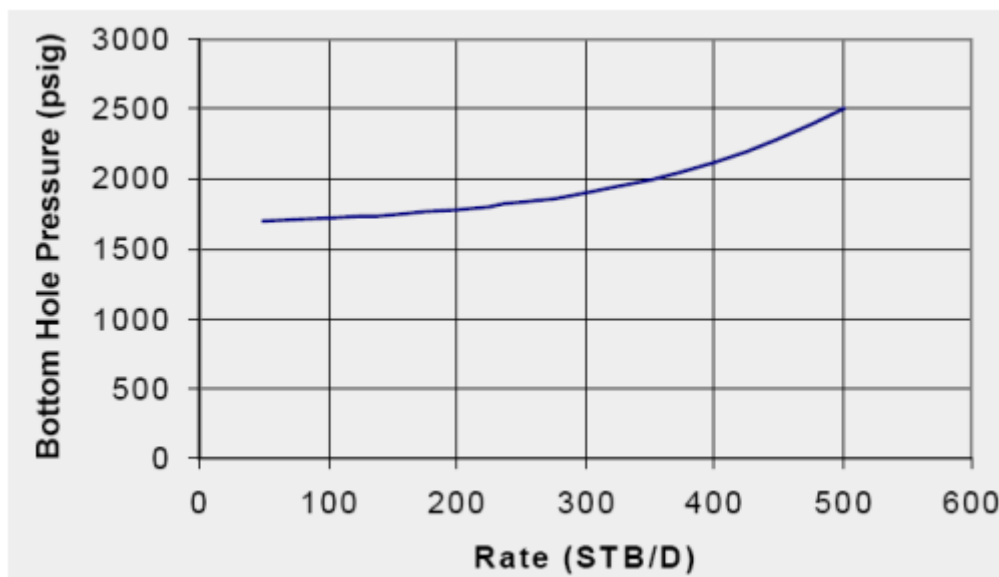


Figure 2.13: VLP curve (Knut, 2009)

CHAPTER 3

METHODOLOGY

In this chapter, the entire procedure used in this project is discussed and explained. The data that are obtained from conducting simulation studies have been analyzed and discussed in brief.

3.1. Reservoir Simulation Description

Reveal compositional reservoir simulation software was used by this project. A synthetic reservoir model has been created from the available reservoir data. In this simulation run the optimum well diameter was investigated. The simulator runs for 1000 days of production. Three different diameters are investigated; 0.3, 0.5, and 0.8 ft the results are analyzed and compared through FGOR (fields gas oil ratio), FOPT (total field oil production), FPR (reservoir pressure), and FWCT (water cut).

The reservoir dimensions are 10 x 15 x 4 (x, y, and z) include a production well located in cell (5, 6) and completed in the layers 2-4. Figure 3.1 illustrates the reservoir model that has been used in the simulation study.

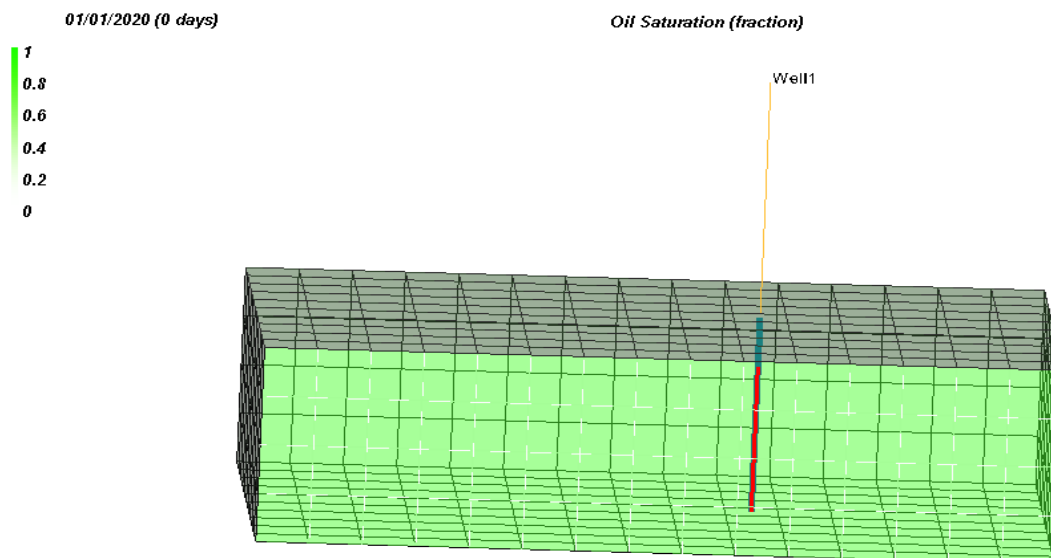


Figure 3.1: Reservoir model

Relative permeability curves of oil-water and gas-oil are shown in Figures 3.2 and 3.3 respectively.

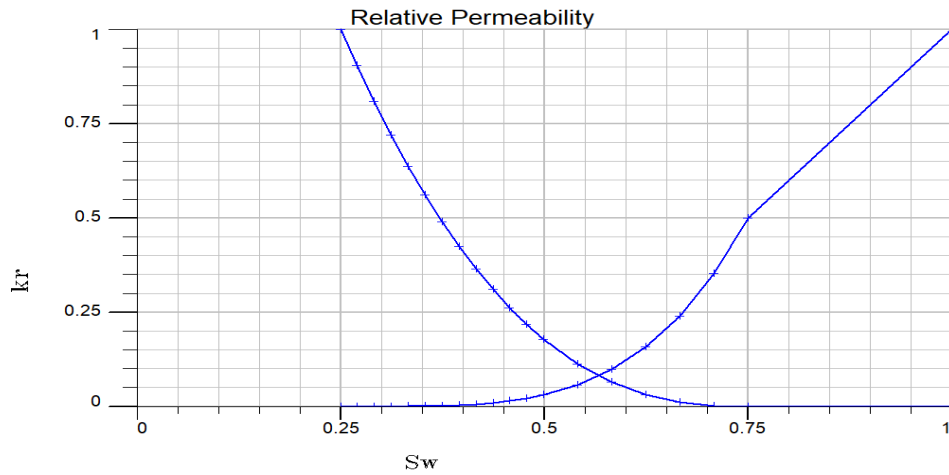


Figure 3.2: Relative permeability of water and oil

Figure 3.2 shows the relative permeability curve, which the relative permeability of water increasing with increasing water saturation, and relative permeability of oil is reducing with reduction in oil saturation due to production of oil.

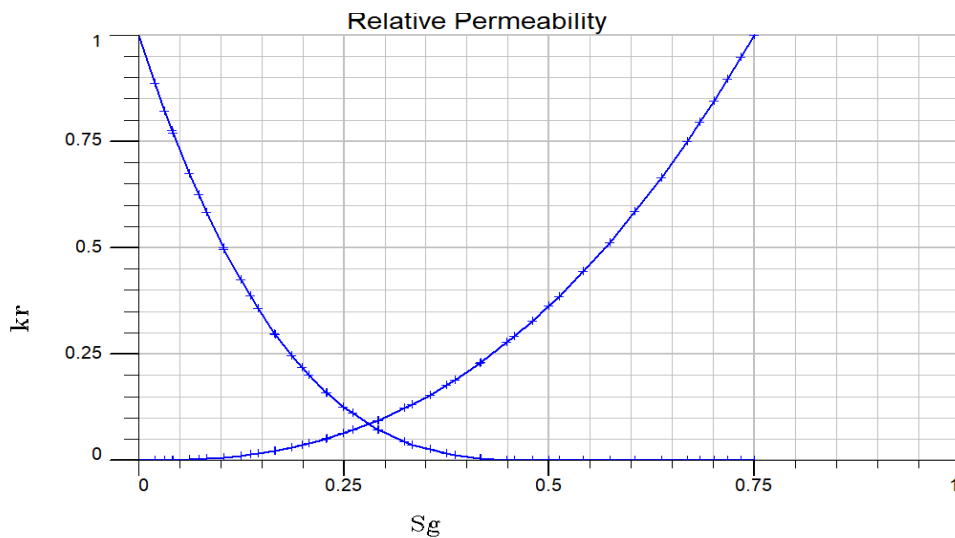


Figure 3.3: Relative permeability of gas and oil

Figure 3.3 provide the plot of gas relative permeability versus its saturation with considering oil relative permeability and saturation as well. Gas relative permeability is increasing from the beginning while oil relative permeability is reducing.

Figure 3.4 shows relative permeability to water (K_{rw}) vs. water saturation (S_w) curve and relative permeability to oil (K_{ro}) and oil saturation (S_o) curve respectively.

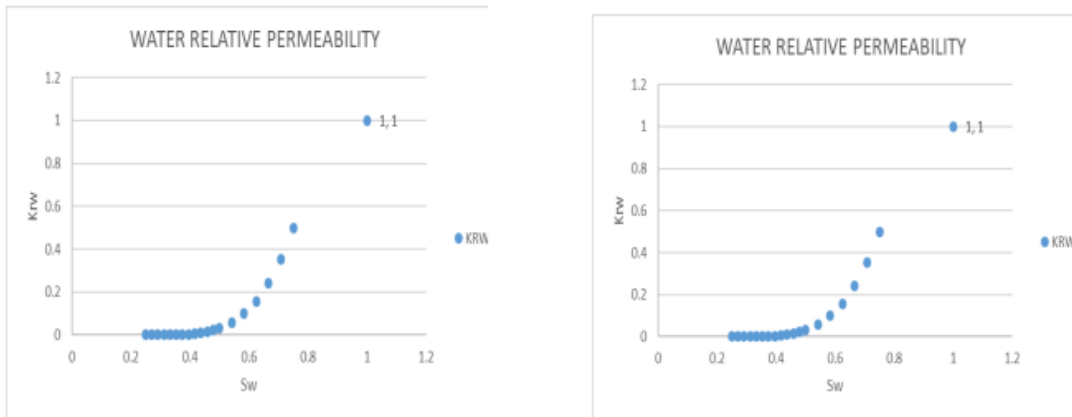


Figure 3.4: K_{rw} vs. S_w on the left and K_{ro} vs. S_o on the right

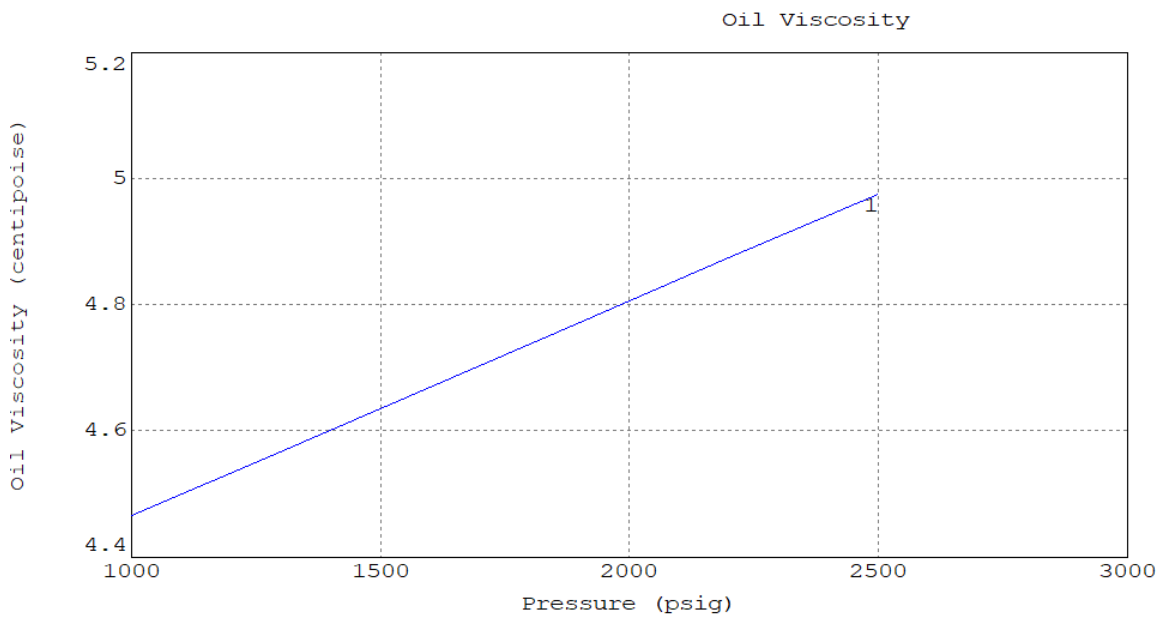


Figure 3.5: Oil viscosity vs. pressure

Figure 3.5 illustrates the plot of viscosity vs pressure. The oil viscosity reduces from 4.95 to 4.43 cP with respect to reduction in pressure.

3.2. Simulation Procedure

The following steps represent the simulation procedure:

1. Data deck preparation, running the model with well having a diameter of 0.3 ft.
2. Investigating three more different diameters (0.3, 0.5, and 0.8) ft.
3. Compare the results between each case and select the optimum case that provides the greater oil recovery and less water cut.
4. Modify the data again with a constant diameter for investigating the impact of critical water to oil saturation.
5. Use different reduced critical water to oil saturation (SOWCR) and compare the results to determine its influence on production performance.

3.3. Sensitivity Analysis

Three different well diameters (0.3, 0.5, and 0.8 ft) are used as parameters of sensitivity analysis

The results are evaluated and analyzed according to the production outputs, including: (FOPT, FPR, and FWCT). Additionally, a sensitivity run for critical water to oil saturation is also investigated and been discussed in chapter 4 which involving four different, SOWCR values to see how it impacts well performance.

CHAPTER 4

RESULTS AND DISCUSSIONS

This section discusses and analyzes the results were obtained investigating the impact of well diameter and fluid saturation in and around the produced wells using the reservoir simulator. The effect of tubing diameter and critical oil saturation are explained in terms of well performance, oil volume recovery, gas-oil ratio, total oil production, and water cut. A vertical production well is used and produced for 1000 days, and the results are shown in the following sections.

4.1. Effect of Tubing Diameter on Production Performance

4.1.1. Effect of liquid flow rate on pressure loss

a. Effect of tubing diameter of 0.8 ft. on GOR and WCT

A sensitivity analysis is conducted through investigating four different tubing diameters (0.3, 0.5, and 0.8 ft).and critical oil saturations around the producing wells, using Reveal oil compositional simulator. Figure 4.1 shows the effect of tubing size on field gas oil ratio and water-cut for tubing size 0.8 ft. According to the obtained result, it is clear from Figure 4.1 that higher tubing diameter size results in increasing GOR from 100 SCF/STB to 600 SCF/STB is being produced daily. Also, water-cut has increased from 0.0005% to 0.0022 % due to reservoir properties.

b. Effect of tubing diameter of 0.52 ft. on GOR and WCT

Additionally, the impact of well diameter of 0.52 ft. on well performance has been investigated and Figure 4.2 shows the effect of tubing size on field gas oil ratio and water-cut for tubing size 0.52 ft. Based on the obtained result, it is clear from Figure 4.2 that reducing tubing diameter size results in increasing GOR from 100 SCF/STB to 680 SCF/STB. The water-cut has increased from 0.0005% to 0.0022 % due to reservoir properties which contain less water.

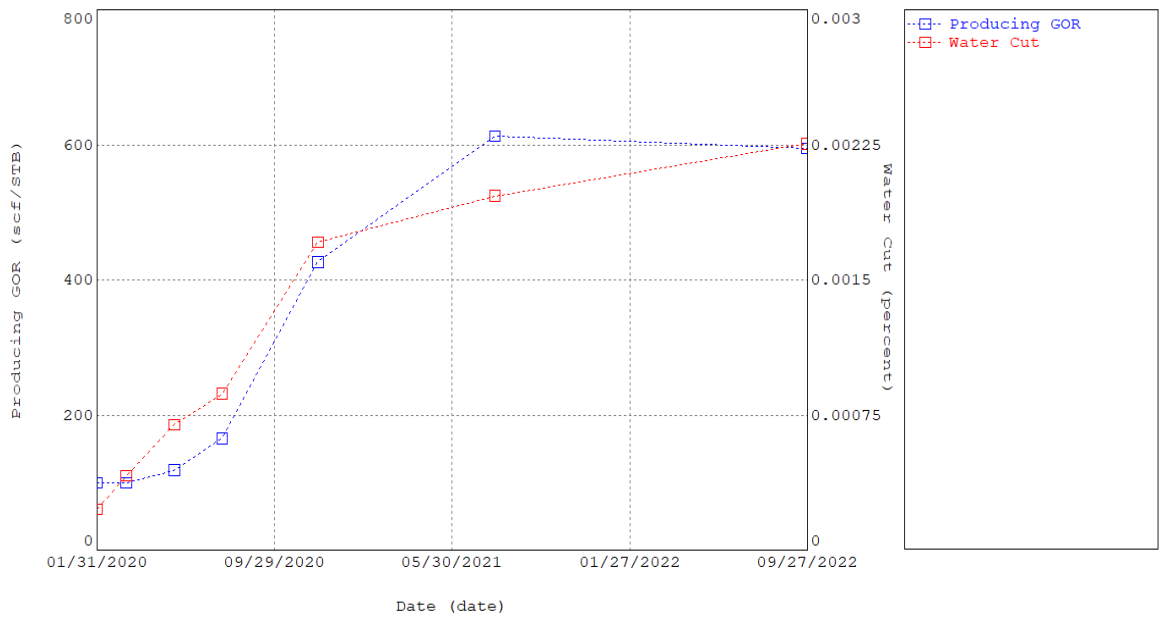


Figure 4.1: 0.8 ft. Tubing size effect on GOR and WCT

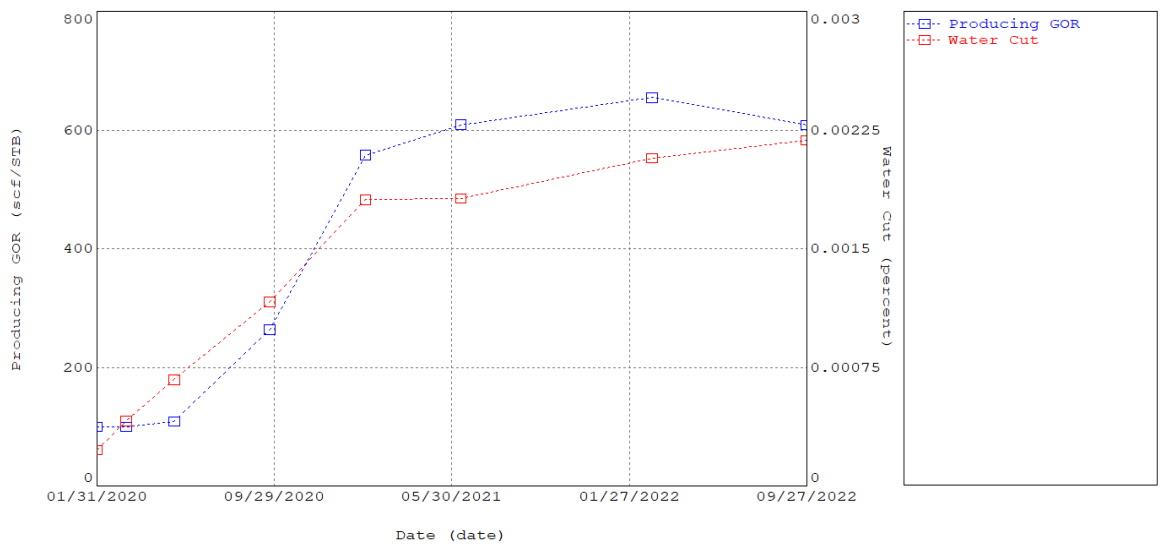


Figure 4.2: 0.52 ft. Tubing size effect on GOR and WCT

c. Effect of tubing diameter of 0.2 ft. on GOR and WCT

Furthermore, the effect of 0.2 ft. well diameter on well production has also been examined, and Figure 4.3 illustrates the effect of tubing size on field gas oil ratio and water-cut for

tubing size 0.2 ft. Figure 4.3 shows that minimizing the tubing diameter size results in GOR of 640 SCF/STB. Due to reservoir properties that hold less water, the water-cut has risen from 0.0005% to 0.00223%.

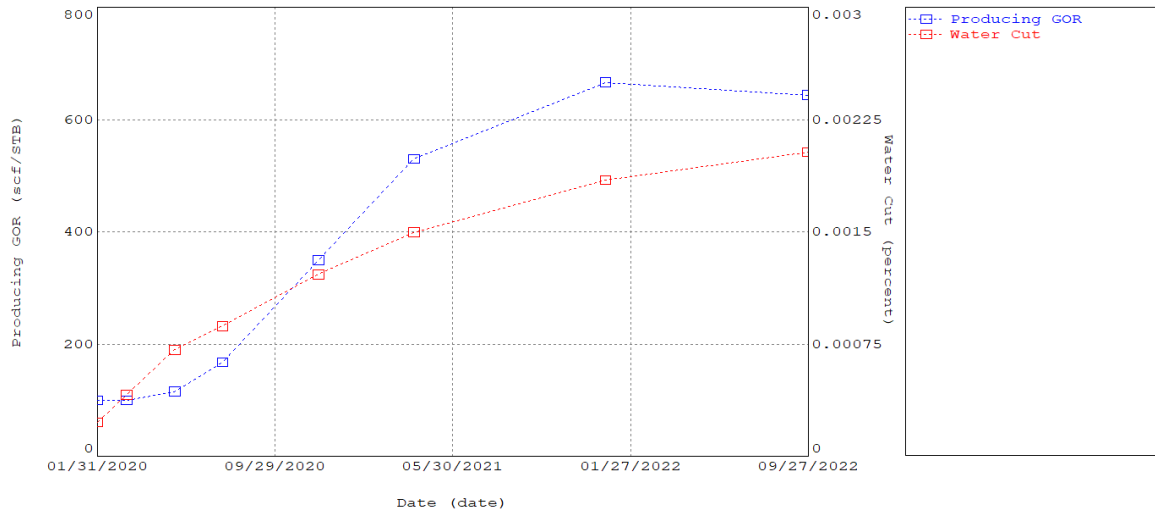


Figure 4.3: 0.2 ft. Tubing size effect on GOR and WCT

4.1.2. Impact of tubing size on overall oil production

The overall objective of petroleum engineers is to maximize oil production and reduce the associated cost. Here overall oil production is investigated and observed through analyzing the effect of different tubing sizes in total oil production and daily oil production for X-well. Figures 4.4, 4.5 and 4.6 shows the result of the sensitivity analysis in terms of overall oil production after 1000 days of production for well diameters 0.8 ft., 0.52 ft., and 0.2 ft. respectively. The higher diameter of 0.8ft produced an amount of oil which is about 891,000 barrels of oil while the smaller diameter of 0.2 ft produced about 915,000 barrels of oil and the other tubing diameter of 0.52 ft. produced 1.0104 million barrels of oil. So, it is apparent that the greater diameter size doesn't mean higher overall oil production, but a suitable selection of neither smaller and not the largest diameter size produces the highest amount of oil. The oil production rate for well diameter 0.8 ft. is around 470 bpd, while for well

diameter size of 0.2 ft. starts from 2000 bpd to 350 bpd. Finally, the daily oil production for well diameter size of 0.52 ft. produce around 400 bpd.

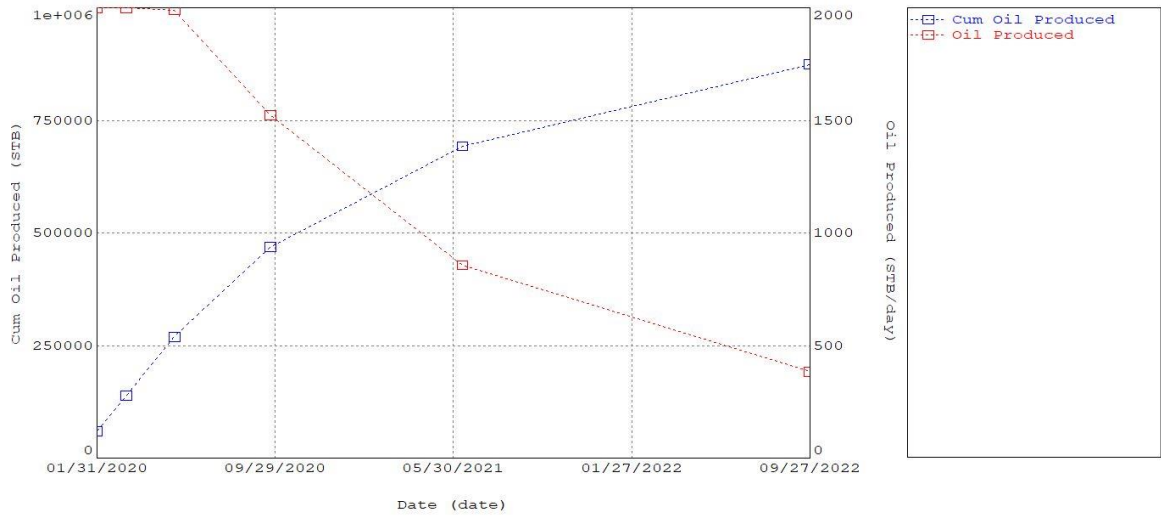


Figure 4.4: 0.8 ft. Tubing size effect on FOPR & FOPT

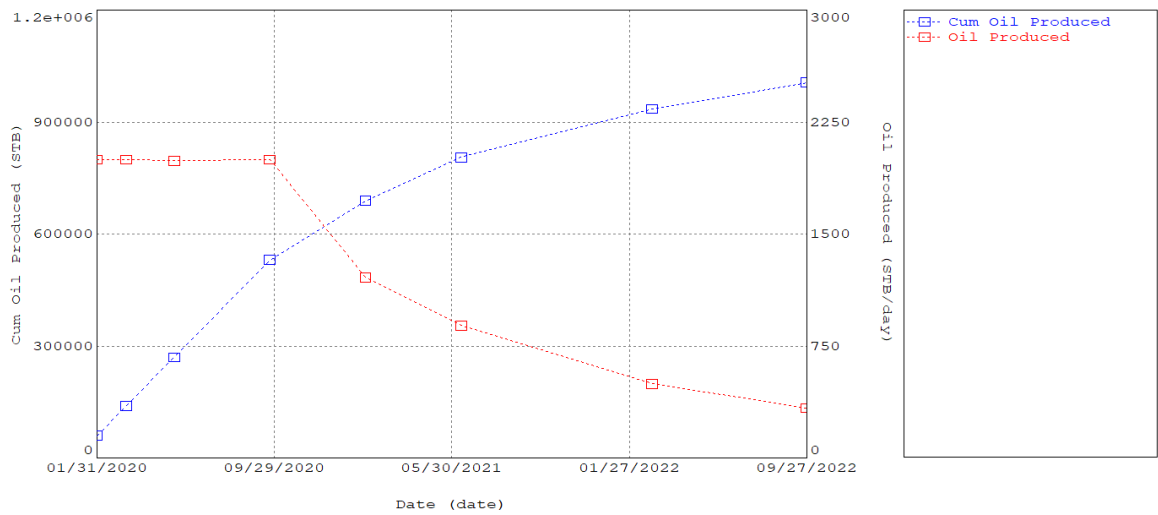


Figure 4.5: 0.52 ft. Tubing size effect on FOPT & FOPR

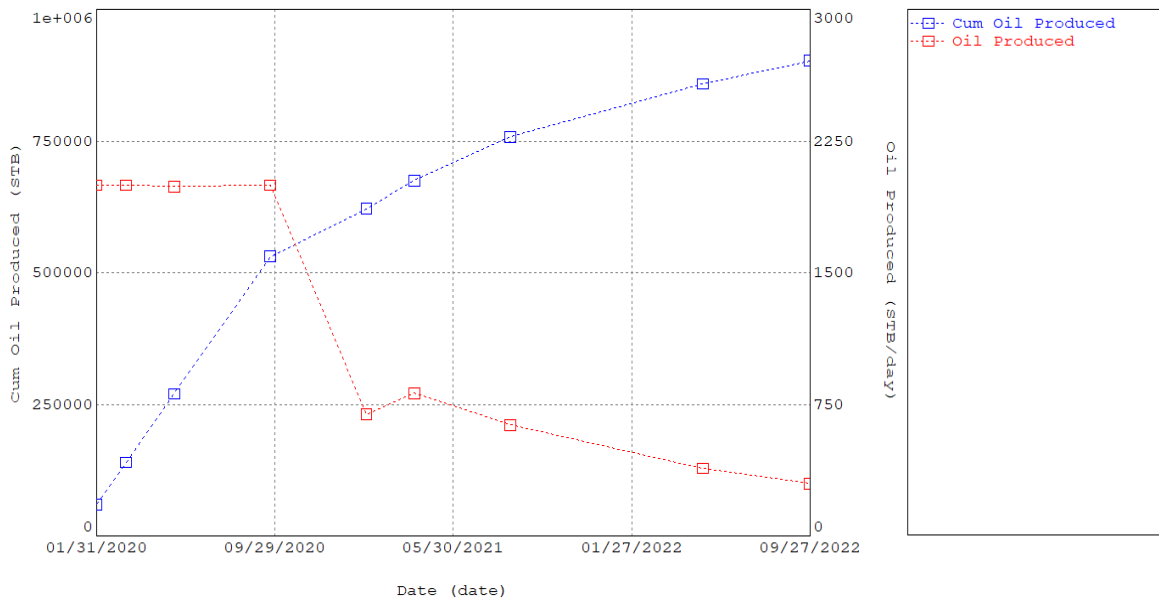


Figure 4.6: 0.2 ft. Tubing size effect on FOPT & FOPR

4.2. Effect of SOWCR On Production Performance

4.2.1. Impact of SOWCR on GOR and WCT

Different SOWCR values are used including 0.05, 0.3, 0.6, and 0.7 ft which have been run through a sensitivity analysis using Reveal compositional simulation software to observe their effect of on production performance. Figure 4.7, 4.8, 4.9 and 4.10 illustrate the influence of different SOWCR values of 0.7, 0.6, 0.3, and 0.05 on GOR and WCT respectively. SOWCR has a great impact on gas-oil ratio, which is clear from the Figures as the greater the SOWCR, the greater the GOR we get. The 0.7 SOWCR produced 850 SCF/STB which is too much compared to the smaller SOWCR with a value of 0.05 as it produced about 580 SCF/STB of GOR. While the other two values of (0.3 and 0.6) produces few more than the smallest value. So, the greater the SOWCR, the more GOR is produced. Additionally, the same effect goes for water-cut, as the highest SOWCR of 0.7 produces 0.0348% water-cut as seen in Figure 4.7, while the smallest SOWCR of 0.05 produces around 0.0022% of water-cut based on Figure 4.10.

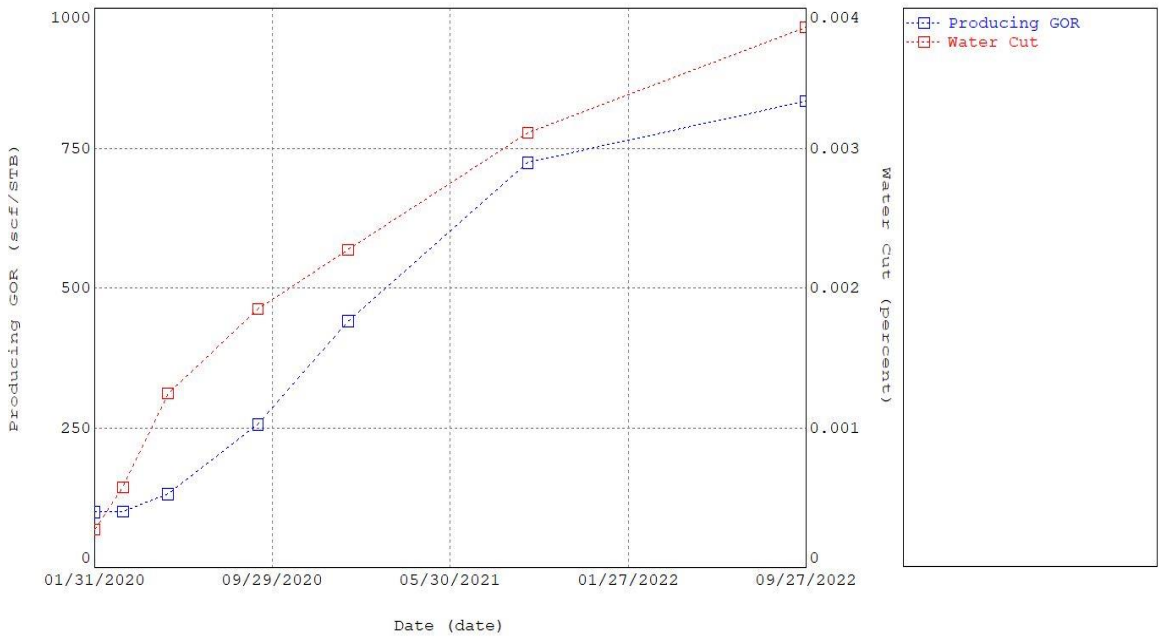


Figure 4.7: Effect of 0.7 SOWCR on GOR and WCT

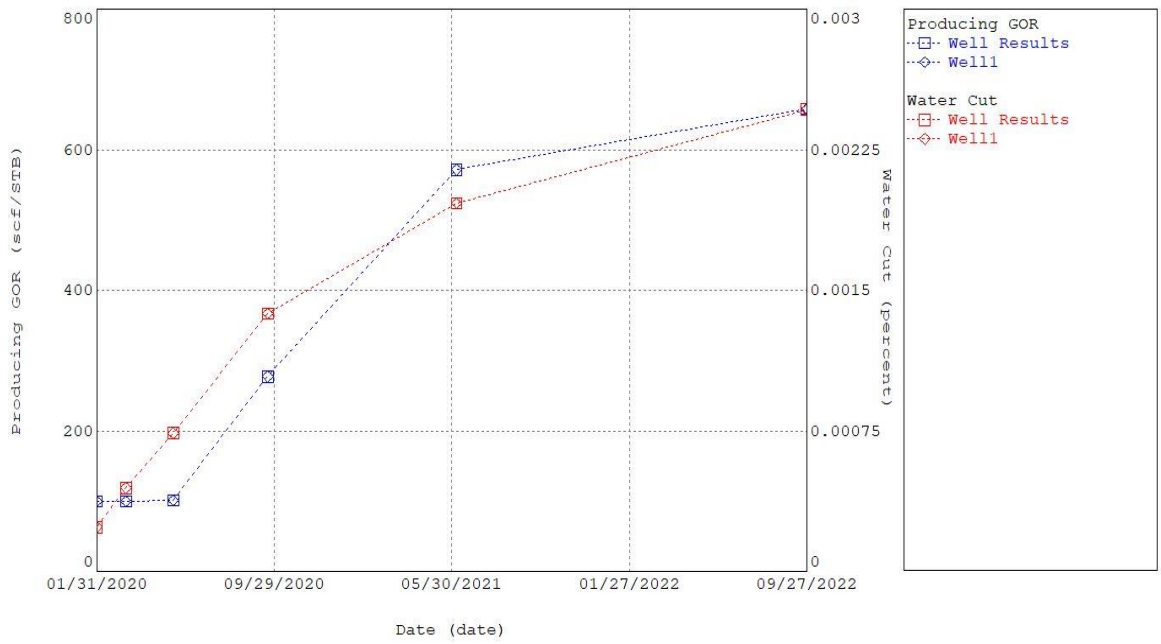


Figure 4.8: Effect of 0.6 SOWCR on GOR and WCT

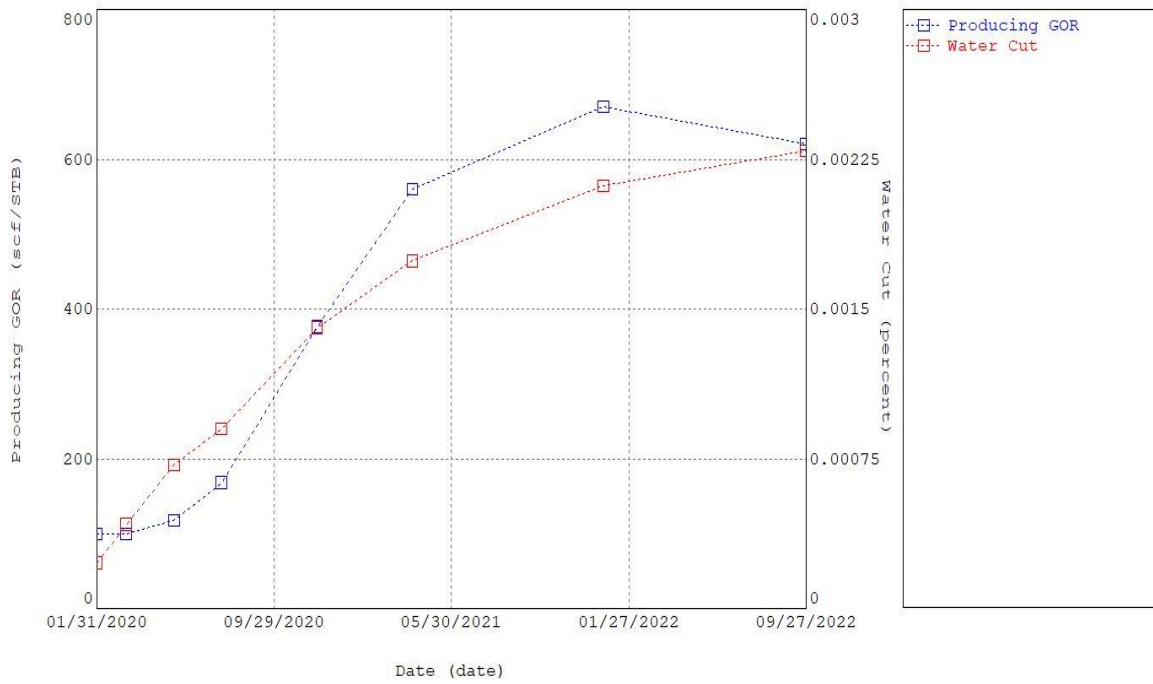


Figure 4.9: Effect of 0.3 SOWCR on GOR and WCT

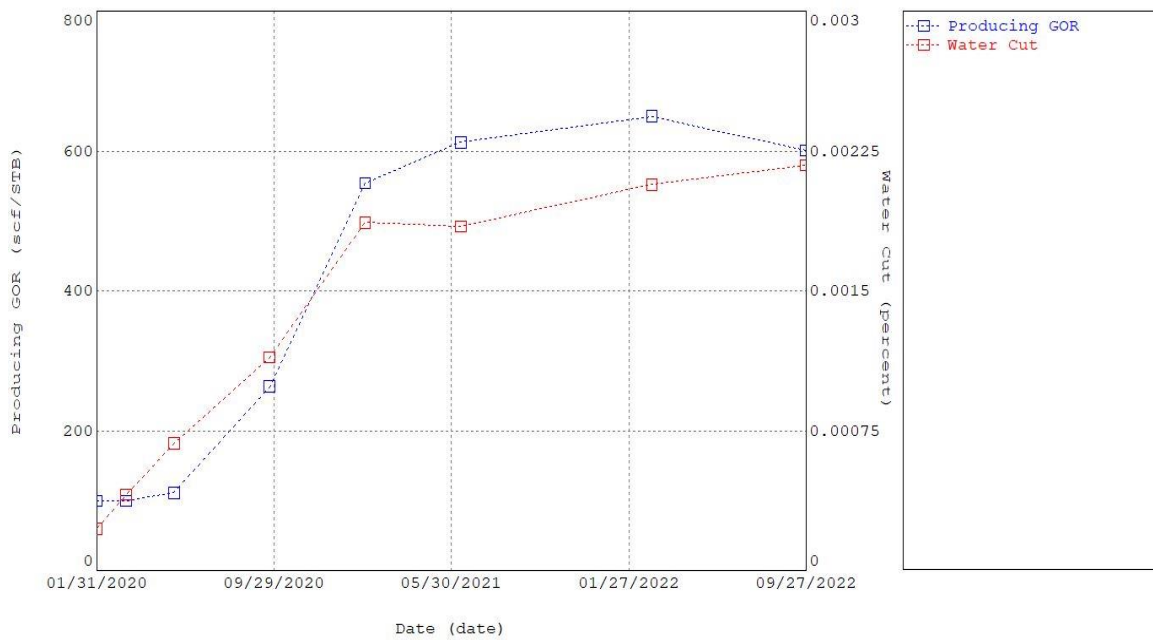


Figure 4.10: Effect of 0.05 SOWCR on GOR and WCT

4.2.2. Impact of SOWCR on overall oil production

Saturation impact is indeed immensely important to be considered, the effect of it has been observed mainly through comparing different SOWCR on overall oil production and daily oil production. Figure 4.11, 4.12, 4.13, and 4.14 show the effect of SOWCR on total oil production and daily oil production. Which according to simulation results, the greater SOWCR, the less oil is recovered as in 0.7 SOWCR case, which produced less oil compared to other cases, as it produces around 810,000 barrels. The 0.6 SOWCR produced 914,000 barrels, while 0.3 SOWCR produced 994,000 barrels of oil. On the other hand, the smaller SOWCR with a value of 0.05 produced a great quantity of oil, which recovered about 1.0099 million barrels of oil. In terms of oil production rate, it's clear that the highest SOWCR starts with a production rate of 2000 bpd and reduces after 4 months until it reaches around 350 bpd at the end of the simulation. On the other hand, the simulation result shows that the lowest SOWCR of 0.05 starts with a production rate of 2000 bpd and reduced after 10 months of production and reaches 500 bpd at the end of the simulation.

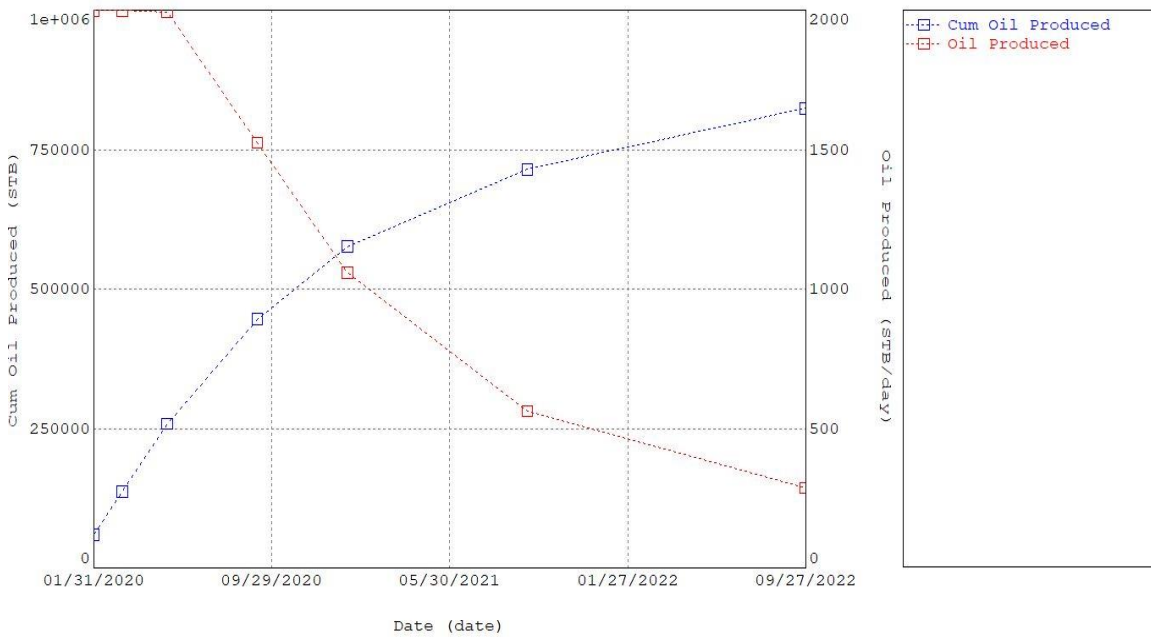


Figure 4.11: Effect of 0.7 SOWCR on FOPT and FOPR

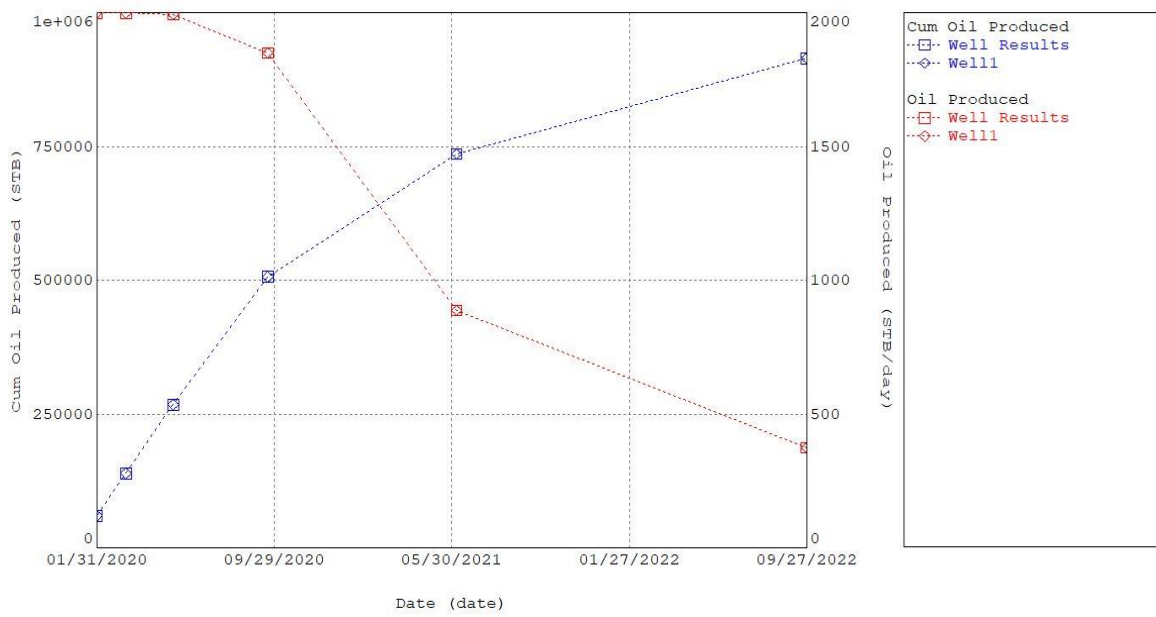


Figure 4.12: Effect of 0.6 SOWCR on FOPT and FOPR

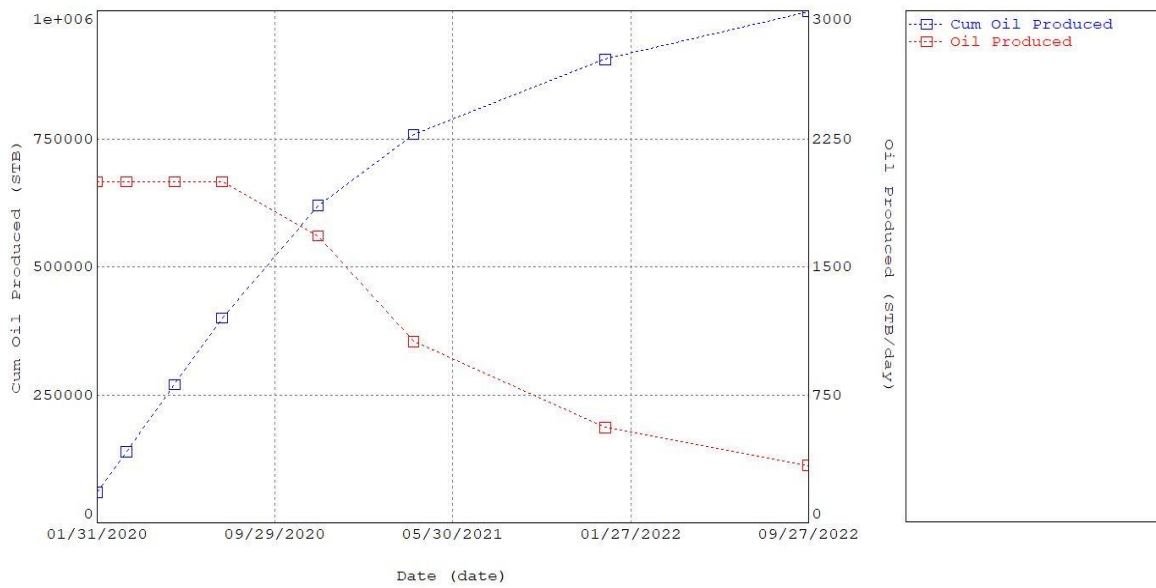


Figure 4.13: Effect of 0.3 SOWCR on FOPT and FOPR

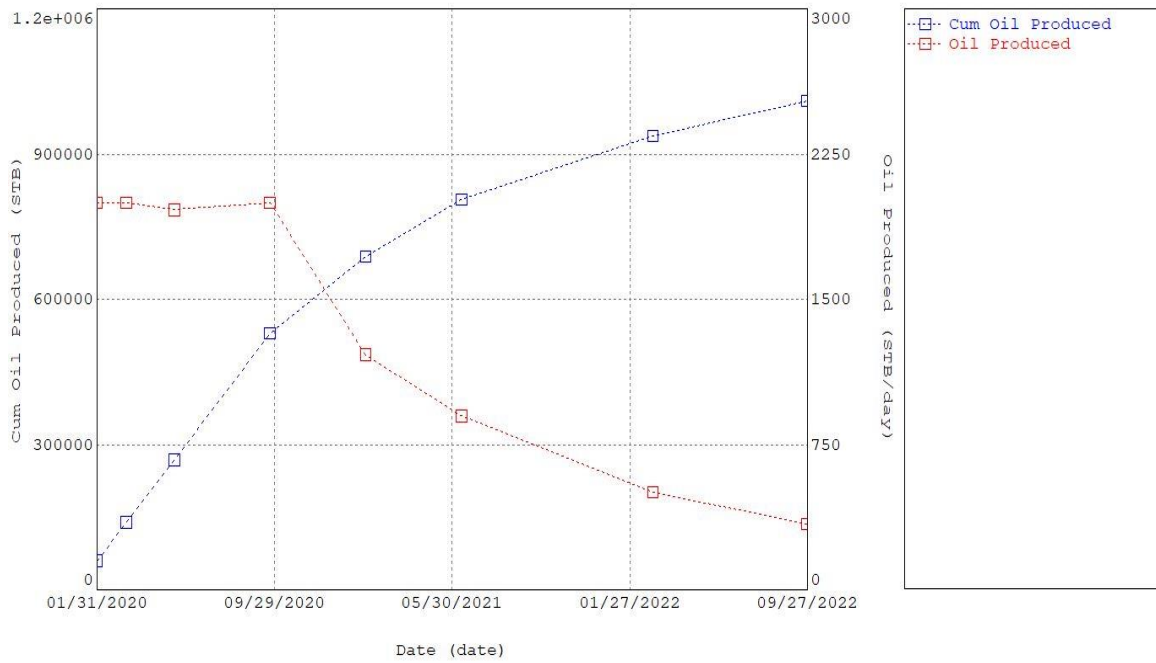


Figure 4.14: Effect of 0.05 SOWCR on FOPT and FOPR

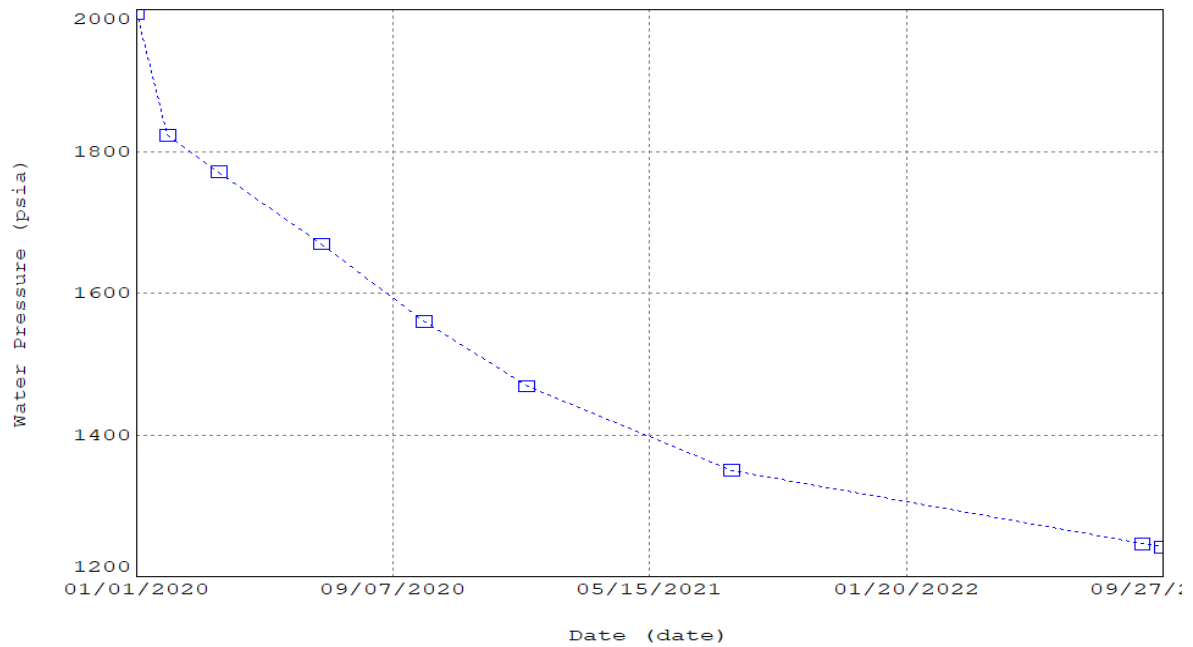


Figure 4.15: Effect of 0.52 tubing size on pressure

4.3. Pressure Profile

The effect of both tubing size and SOWCR on pressure has been investigated through a sensitivity run, which has been shown in Figure 4.15 and 4.16 respectively. In case of tubing diameter, the tubing size of 0.52 ft. is selected, and SOWCR of 0.05 is selected. The pressure drop for tubing size of 0.5 ft. reaches around 1246 psi at the end of the simulation from 2000 psi at the start of production.

Figure 4.16 shows the impact of 0.05 SOWCR on pressure profile. The simulation starts at a pressure of 2000 psi and reaches 1074 psi at the end of the simulation.

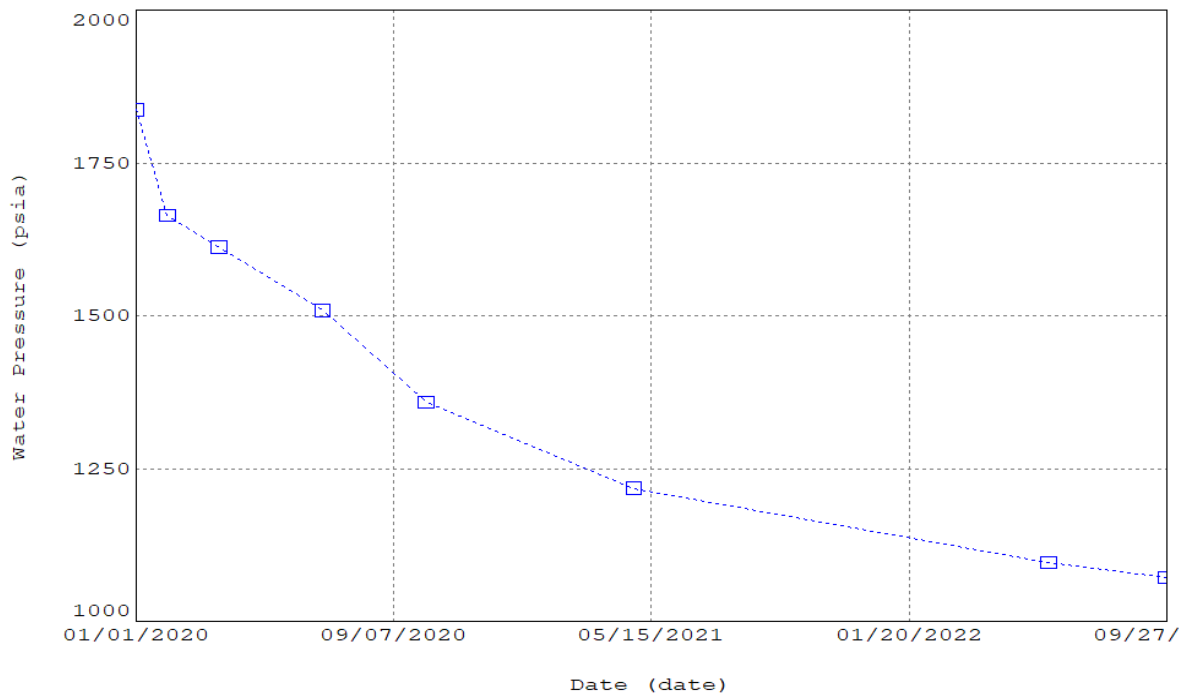


Figure 4.16: Effect of 0.05 SOWCR on pressure

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1. Conclusions

Based on the results, the following points can be concluded:

1. Pressure loss is one of the main problems related to tubing size.
2. IPR and VLP as well as nodal analysis are methods used for determining reservoir performance in addition to detecting the source of pressure loss by nodal analysis.
3. Smaller tubing size has a negative impact on well performance as it results in friction loss and impacts well performance negatively.
4. Intermediate diameter size (suitable selection as in 0.5 ft) results in highest oil recovery.
5. SOWCR has a critical, high effect on production performance, the greater the, SOWCR, the less oil is produced.
6. The greater the SOWCR, the more GOR is produced.
7. A smaller diameter of the tubing represents more problems, such as higher friction and a pipe flow problem, which results in a reduction of the output rate, hence a non-economic rate, although larger tubes negatively affect production

5.2. Recommendations

More research is needed to determine the effect of tubing size on well performance in various scenarios, for example. The influence of tubing size on well output in geothermal reservoirs, or the influence of tubing sizes in injection wells. Furthermore, it is advised to avoid using smaller tubing diameters than the optimum which mitigate friction loss and optimize the production rate. Furthermore, further research on the effect of saturation on well output is needed, as discussed in this study. Moreover, more analysis is needed to improve awareness of the discussed problems.

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APPENDICES

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APPENDIX 2
ETHICAL APPROVAL LETTER



YAKIN DOĞU ÜNİVERSİTESİ
ETHICAL APPROVAL DOCUMENT

Date: 06/10/2021

To the **Institute of Graduate Studies**

The research project titled “**INVESTIGATION OF THE EFFECT OF WELL DIAMETER AND FLUID SATURATION ON WELL PERFORMANCE**” 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

APPENDIX 3

SIMILARITY REPORT

Cavit Atalar | User Info | Messages | Instructor | English | Community | Help | Logout



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Prof. Dr. Cavit ATALAR