EVALUATION OF IN-SITU GAS LIFT
USING NUMERICAL RESERVOIR MODELING

Mr. Weerayut Brahmahitadara

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By	Mr. Weerayut Brahmahitadara
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Thesis Advisor	Assistant Professor Suwat Athichanagorn, Ph.D.

Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

…………………………Dean of the Faculty of Engineering
(Associate Professor Boonsom Lerdhirunwong, Dr.Ing.)

THESIS COMMITTEE

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(Assistant Professor Suwat Athichanagorn, Ph.D.)

……………………………………Examiner
(Assistant Professor Jirawat Chewaroungroaj, Ph.D.)

…………………………..………External Examiner
(Witsarut Tungsunthomkhan, Ph.D.)

วีรยุทธ พรหมหิตาทร: การประเมินการใช้ก๊าซจากแหล่งกักเก็บเพื่อช่วยผลิตน้ำมันโดยใช้แบบจำลองเชิงตัวเลขของแหล่งกักเก็บ. **(**EVALUATION OF IN-SITU GAS LIFT USING NUMERICAL RESERVOIR MODELING) อ. ที่ปรึกษาวิทยานิพนธ์หลัก**:** ผศ. ดร. สุวัฒน์ อธิชนากร**,** 80 หน้า

แหล่งกักเก็บขนาดเล็กโดยเฉพาะแหล่งกับเก็บน้ำมันที่อยู่ห่างไกลและนอกชายฝั่งเป็นความท้าทายในการพัฒนาแหล่งผลิตเนื่องจากมีข้อจำกัดในเชิงเศรษฐศาสตร์ ในกรณีนี้เทคนิคการใช้ก๊าซจากแหล่งกักเก็บเพื่อช่วยผลิตน้ำมันสามารถนำมาใช้ได้โดยวิธีนี้จะใช้ผลิตน้ำมันได้ก็ต่อเมื่อมีก๊าซแรงดันสูงจากภายในหลุม วิธีการนี้ไม่จำเป็นต้องสร้างแนวท่อสำหรับก๊าซและเครื่องอัดอากาศรวมทั้งอุปกรณ์อื่นๆ ดังนั้นจึงเป็นการลดการใช้จ่ายอย่างมีประสิทธิภาพ วัตถุประสงค์ของการศึกษานี้คือศึกษาและหาตัวแปรที่มีผลต่อการใช้ก๊าซจากแหล่งกักเก็บเพื่อช่วยผลิตน้ำมัน

การศึกษานี้เริ่มต้นด้วยการสร้างแบบจำลองของแหล่งกักเก็บและใช้ตารางความสามารถในการไหลในแนวตั้ง แบบจำลองเริ่มต้นด้วยการจำลองการไหลแบบธรรมชาติ แล้วตามด้วยการหาผลและประสิทธิภาพของการยกน้ำมันโดยก๊าซโดยปรับสถานการณ์ที่มีการเปลี่ยนแปลงของตัวแปรหลายๆ ตัวแปรต่อไปนี้ (1) ความสามารถในการซึมผ่านของชั้นก๊าซ (2) ระยะการยิงทะลุท่อกรุในชั้นก๊าซ (3) ความลึกของชั้นก๊าซ (4) ความหนาของชั้นก๊าซ และ (5) แหล่งน้ำช่วยรักษาแรงดันในชั้นน้ำมัน

จากผลการจำลองสถานการณ์ต่างๆ ของแหล่งกักเก็บ พบว่า ค่าความสามารถในการซึมผ่านที่ต่ำจะช่วยในการเพิ่มในการผลิตน้ำมันได้ดีขึ้น ในขณะที่กรณีของชั้นก๊าซที่มีความสามารถในการซึมผ่านสูงและมีความหนา การปรับลดระยะการยิงทะลุท่อกรุของชั้นก๊าซสามารถช่วยเพิ่มความสามารถในการผลิตน้ำมันได้ สำหรับกรณีผลกระทบความลึกของชั้นก๊าซ พบว่าเฉพาะกรณีที่มีความสามารถในการซึมผ่านสูง ที่ชั้นก๊าซตื้นๆ จะให้ค่าความสามารถในการผลิตน้ำมันต่ำสุด อย่างไรก็ตามในกรณีของการปรับเปลี่ยนความหนาของชั้นก๊าซ แทบจะไม่มีผลอย่างนัยสำคัญต่อประสิทธิภาพในการผลิตน้ำมันเลย สำหรับในกรณีที่มีแหล่งน้ำใต้ดินจะทำให้ความสามารถในการผลิตน้ำมันลดลงเมื่อเทียบกับกรณีที่ไม่มีแหล่งน้ำใต้ดิน

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต..

สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก....................

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WEERAYUT BRAHMAHITADARA: EVALUATION OF IN-SITU GAS LIFT USING NUMERICAL RESERVOIR MODELING. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 80 pp.

Small oil reserves which are located in remote area or offshore are challenging to develop due to economic reasons. In this case, in-situ gas lift can be used to lift the oil where relatively high pressure gas is available. This method does not need pipeline for lift gas and gas compression facilities. Thus, it is cost effective. The purpose of this study is to determine variables that affect to in-situ gas lift and make guideline for reservoir condition which are suitable for this method.

This study starts with constructing the reservoir model using reservoir simulation and vertical flow performance. The model is simulated with natural depletion case first; then we investigate the effect on gas lift performance of several variables which are: (1) permeability of gas bearing zone (2) perforation interval of gas bearing zone (3) depth of gas bearing zone (4) thickness of gas bearing zone and (5) water aquifer in the oil zone.

From the results of reservoir simulation, low permeability of gas zone results in better recovery factor. For high permeability and high thickness of gas reservoir, reducing perforation interval helps increase the oil recovery factor. Regarding the depth of gas bearing zone, shallow depth provides the lowest oil recovery factor. However, there is no significant difference in oil recovery factor for cases with different of thicknesses of gas zone. Oil reservoir with aquifer has lower oil recovery factor than the one without aquifer.

Department: Mining and Petroleum Engineering Student's Signature……………………
Field of Study: Petroleum Engineering……….. Advisor's Signature……………………
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Also I would like to thank to Chevron Thailand Exploration and Production for financial support for this study and to Schlumberger for providing educational license of ECLIPSE 100 reservoir simulator to the Department of Mining and Petroleum Engineering, Chulalongkorn University. This software is used to construct reservoir model and determine the performance of in-situ gas lift for all scenarios.

Last but not least, I would like to thank my family for their encouragement and always being beside me.

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NOMENCLATURES

D_f	depth of formation, mid perforation
D_{ov}	depth of injection valve
G_{av}	average pressure gradient above injection point
G_{bv}	average pressure gradient of flowing formation fluid below injection point
J	productivity index
k	absolute permeability
k_{rg}	gas relative permeability
k_{rw}	water relative permeability
k_o	oil permeability
k_{ro}	oil relative permeability
p	pressure
p_i	initial pressure
p_b	bubble point pressure
p_e	static average pressure measured at the drainage radius, r_e
p_R	average reservoir pressure
p_{wf}	bottom-hole flowing pressure measured at the wellbore radius, r_w
p_{wh}	wellhead pressure
q	production flow rate
q_o	oil production rate
$(q_o)_{max}$	maximum oil production rate
q_w	water production rate
R_s	solution gas-oil ratio
S_g	gas saturation
S_{gc}	critical gas saturation
S_o	oil saturation
S_{oi}	initial oil saturation
S_{or}	residual oil saturation
S_w	water saturation
S_{wc}	connate water saturation

μ	viscosity, cp
μ_o	viscosity for oil
μ_g	viscosity for gas

CHAPTER I

INTRODUCTION

The oil field life cycle consists of exploration phase, appraisal phase, development phase, production phase and decommissioning phase. After passing the exploration and appraisal phase, the result of feasibility study will indicate that the project will take place or not.

The decision to invest or develop the oil field is based on economic evaluation of the reserve. Therefore, some small reserves which are located in remote area or offshore become more challenging to develop to the production phase. Capital and operation costs which may include cost of artificial lift need to be analyzed. In-situ or natural gas lift will be of interest for these cases.

Most oil reservoirs in Thailand are highly faulted, having small reserves. These reservoirs have limited development option for economic reason. In-situ gas lift can be used to artificially lift the oil from the production zone and generate a significant value such as saving cost of gas compression facilities. Injected gas should come from the deepest gas zone which is better in terms of lowering the bottomhole pressure.

In-situ gas lift is a method of lifting fluid where relatively high pressure gas is used as the lifting medium through a mechanical process without using external source of high pressure gas, and gas compression facilities is not required as well as power supply. Only oil wells which intersect gas zone(s) are suitable for this technique.

The purpose of this study is to determine variables that affect in-situ gas lift and make guideline for reservoir conditions which are suitable for this method and also compare with conventional gas lift in term of oil recovery factor using numerical reservoir model.

1.1 Thesis Objectives

The objectives for this study are as follows:

(i) To compare between natural depletion and in-situ gas lift in term of recovery factor

(ii) To discuss and evaluate below variables that affect in-situ gas lift technique in oil reservoirs including make guideline to determine reservoir conditions which are proper for in-situ gas lift technique. The variables are;

- permeability of gas bearing zone
- perforation interval of gas bearing zone
- depth of gas bearing zone
- thickness of gas bearing zone
- aquifer in oil zone

1.2 Outline of Methodology

This thesis studies variables that affect oil recovery factor in in-situ gas lift technique. The reservoir model to be used in the study is assumed to be homogeneous. Reservoir and fluid properties will be taken from an offshore oilfield in Thailand to generate the model. After the reservoir model is generated, natural depletion will be applied first. Then, in-situ gas lift technique will be applied based on different scenarios. The oil recovery factor of natural depletion will be compared with different cases of in-situ gas lift. Also, effects of variables of in-situ gas lift will be investigated to determine a guideline for this technique.

The approach to conduct the systematic analysis consists of the following steps:

1. Gather and prepare data for reservoir simulation model.
2. Define the natural depletion as the base case for reservoir model and related variables for in-situ gas lift technique.

3. Use ECLIPSE 100 black oil reservoir simulator to construct reservoir model and use PROSPER to find pressure loss from bottom hole to surface.

4. Simulate reservoir model with natural depletion.

5. Simulate the reservoir model with in-situ gas lift technique by creating a gas reservoir between the oil reservoirs and study the effect of the following variables:

- Depth of the gas bearing zone
- Perforation interval of gas bearing zone (to control the gas rate)
- Permeability of the gas bearing zone
- Thickness of gas bearing zone
- Water aquifer

6. Summarize, discuss and conclude the results from simulation to identify variables affecting in-situ gas lift technique.

7. Make conclusion and recommendation

1.3 Thesis Outline

This thesis consists of 6 chapters.

Chapter 2 reviews previous studies that are related to in-situ gas lift technique and commingled production in monobore oil wells.
Chapter 3 describes all principles and basic theories related to this study.
Chapter 4 explains the reservoir construction and input parameters for numerical reservoir modeling.
Chapter 5 analyzes the results of the simulation runs in each scenario and explains what affect the oil recovery factor.
Chapter 6 concludes the results of the study and comes up with recommendations for using the in-situ gas lift technique to optimize oil production.

CHAPTER II
LITERATURE REVIEW

This chapter reviews previous works that are related to the in-situ gas lift technique. Some works are important for using the input parameters for reservoir modeling, some explain the concept of in-situ gas lift which is very useful.

2.1 Previous Works

Betancourt *et al.* [1] explained the natural gas lift method which contains concept and practice in commingled oil production for both continuous and non-continuous gas zone. They presented the result of numerical modeling which has a dual drive mechanism, a gas cap and a bottom aquifer, and a horizontal well. In this study, when the well placement is closer the WOC, production rate is increased and gas breakthrough is delayed. This study also considers gas lift valve size selection with a range of opening and presents field case study of Troll oil field in Norway. They also mentioned the main advantage of in-situ gas lift technique which is the reduction cost of artificial lift such as gas lift facilities especially in remote area and offshore location.

Al-kasim *et al.* [2] discussed the design and installation of remotely controlled in-situ gas lift in a horizontal well in Norne subsea field. The problem of this field is high water cut (>60%). The solution is installation of wireline retrievable gas lift valve size 5-1/2”. As they tried to find the proper design such as size of in-situ gas lift valve in order to control the gas rate from gas bearing zone by varying orifice size, a numerical reservoir model was run for different case scenarios before the installation of gas lift valve. The main benefit of the project is cost saving with an increase in production to 2,000 sm^3/day.

Vasper [3] presented a basic theory of natural or in-situ gas lift and some benefits from this type of artificial lift such as saving capital cost of gas compression facilities. Gas from both gas bearing formation and gas cap is used for the auto or in-situ gas lift technique. The way to control gas flow into tubing is to use a downhole flow control valve. The packer is set to divide gas and oil zones. As the gas lift valve is used to control the gas flow rate, sizing is done based on required gas flow rate. The flow can be controlled by 20, 40, 60, 80, 100% slot open and closed positions. The calculation of setting depth of gas lift valve was discussed as well. The suggestion from the author is in-situ gas lift should be used when there is the right environment as it can provide better financial better than conventional gas lift.

Al-Somali *et al.* [4] discussed the first in-situ gas lift system, gas lift operation including principle of utilizing the gas cap, installation procedure, production and well performance of an offshore, Saudi Aramco field. The completion has a sand screen device and also isolates the two producing intervals by packer. The analyses of water cut, skin and orifice size were conducted to evaluate the production rate. Another advantage is this technique can save the rig time and revive some dead wells.

Nezhad and Darani [5] studied gas zone controlling for natural gas lift in an Iranian offshore oil field and also compared performance with artificial gas lift. They constructed reservoir dynamic model using ECLIPSE^{TM} black oil simulator. This study supported the idea that increasing recovery factor by applying immiscible gas and water injection is not effective. Finally, this reservoir is implemented by natural gas lift to economize the cost related to surface injection facilities.

Warren *et al.* [6] discussed the first three wells in a smart in-situ gas lift system for offshore field in the Arabian Gulf. This paper described gas lift completion including principle, design logic, installation procedure and field test result. This reservoir is laid in an anticline trap, and the drive mechanism is gas cap.

Rodriguez and Schott [7] explained the development of natural gas lift method applied for wellbore with multiple formations by isolating the selected zone with packer, coupled with gas lift mandrels to allow formation gas to lift liquids to the surface. The result showed that this method can deliquify all zones more efficiently and increase well production as well.

Ardthasivanon [8] studied some pre-determined variables that affect the commingled production in monobore oil wells using the in-situ gas lift in term of oil recovery factor and compared with the oil recovery from conventional gas lift. The tool used to set up the model is Integrated Production Model which consists of GAP, PROSPER and MBAL. The result showed that the recovery factor using the in-situ gas lift is very comparable with conventional gas lift and the recovery factor can be increased with deeper or thicker in-situ gas zone.

CHAPTER III

RELATED THEORIES AND CONCEPT

In this chapter, the theories and concepts related to gas lift and production system are presented. In order to understand in-situ gas lift, we need to know the fundamental concept and theory of production system and conventional gas lift as followins:

3.1 Nodal Analysis

Nodal analysis is a specific application used to analyze a production system. A node is set to divide the production system for inflow and outflow. The node can be located at any component in the production system. At the node, only one pressure can exist and the flow to the node shall be equal to the outflow from the node. The production system can include many components as shown in Figure 3.1 [9] such as separator, choke, safety valve, etc. It is necessary to calculate pressure loss in all the components in the production system to determine the performance of the well. A production system can be optimized by using nodal analysis which requires flow rate and pressure drop for each component in the system.

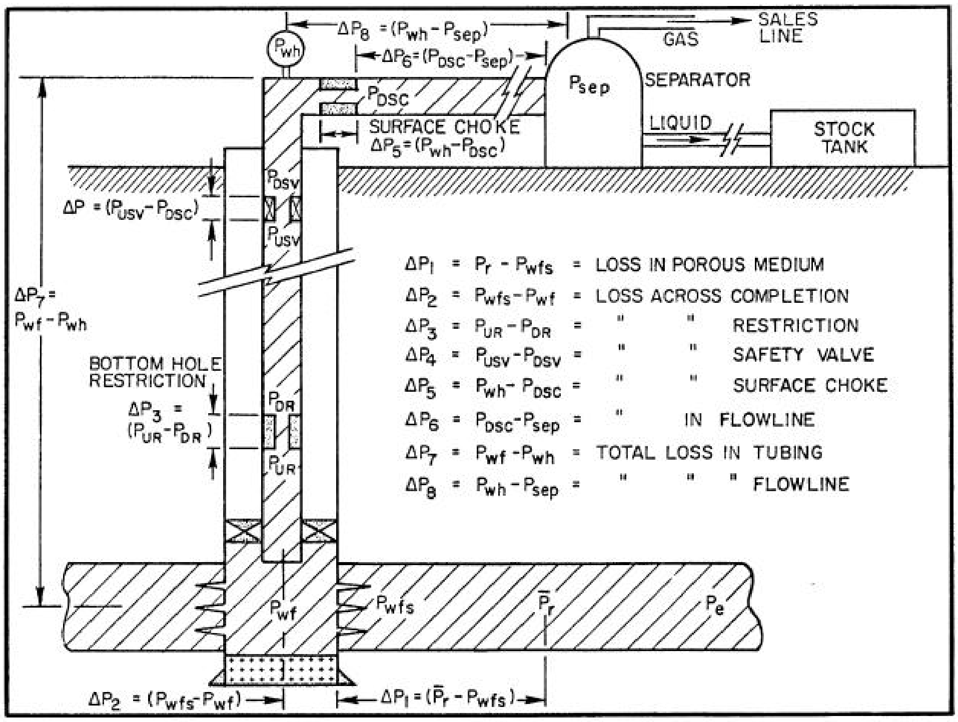


Figure 3.1: A diagram of components in production system [9]

3.1.1 Inflow performance relationship (IPR)

In order to understand the principle of fluid flow through the production system, it is important to determine the performance of a well. Inflow performance relationship (IPR) is used to define the relationship between surface oil production rate and bottomhole well flowing pressure. The simplest form of IPR curve is a straight line relationship as shown in Figure 3.2. But this relationship has an assumption, oil is undersaturated oil and slightly compressible. This relationship can be expressed in term of *production index*, the ratio between oil production rate and pressure drawdown, *J*, defined in the equation below;

$$J = \frac{q_o}{\bar{p}_R - p_{wf}} \tag{3.1}$$

where J = productivity Index

q_0 = liquid production rate

p_R = reservoir pressure

p_{wf} = well flowing pressure

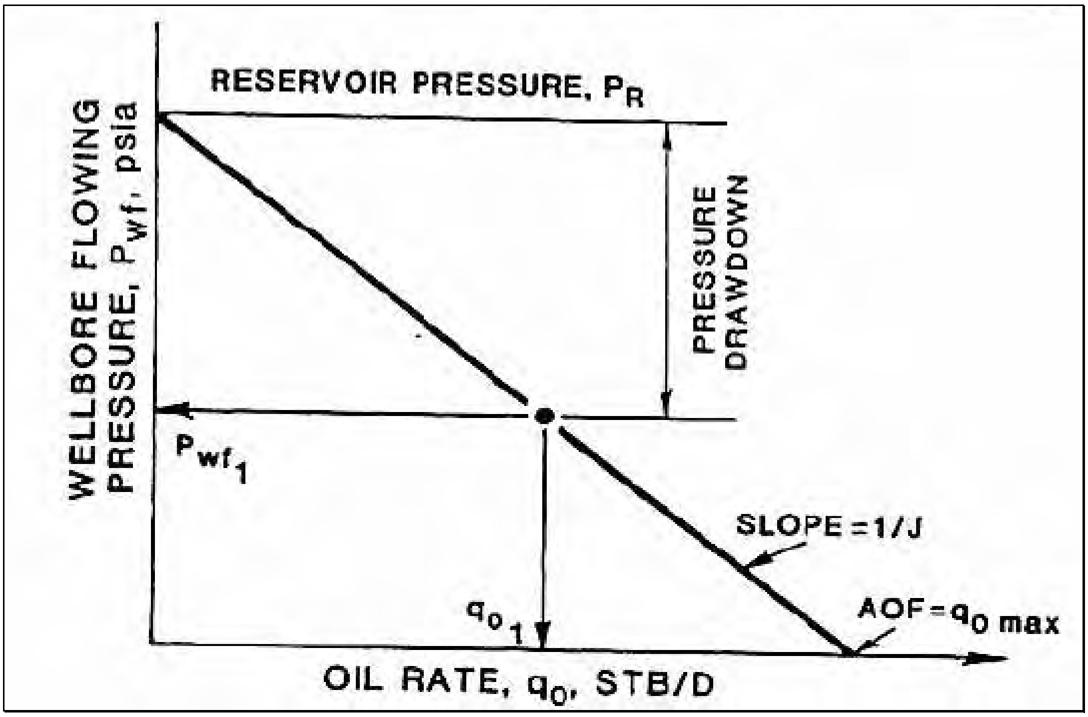


Figure 3.2: A straight-line IPR curve [10]

There are many equations of IPR. Most require at least one stabilized test on a well. The other famous IPR equation is Vogel's equation. Vogel [10] used a mathematical reservoir to find IPR equation for oil well in saturated reservoirs. The following equation is the dimensionless Vogel's equation, Figure 3.3 shows a plot of this IPR 's equation.

$$q_o/q_{omax} = 1- 0.2\,(p_{wf}/p_R) - 0.8(p_{wf}/p_R)^2 \qquad (3.2)$$

where q_{omax} = maximum liquid production rate

q_o = liquid production rate

p_R = reservoir pressure

p_{wf} = well flowing pressure

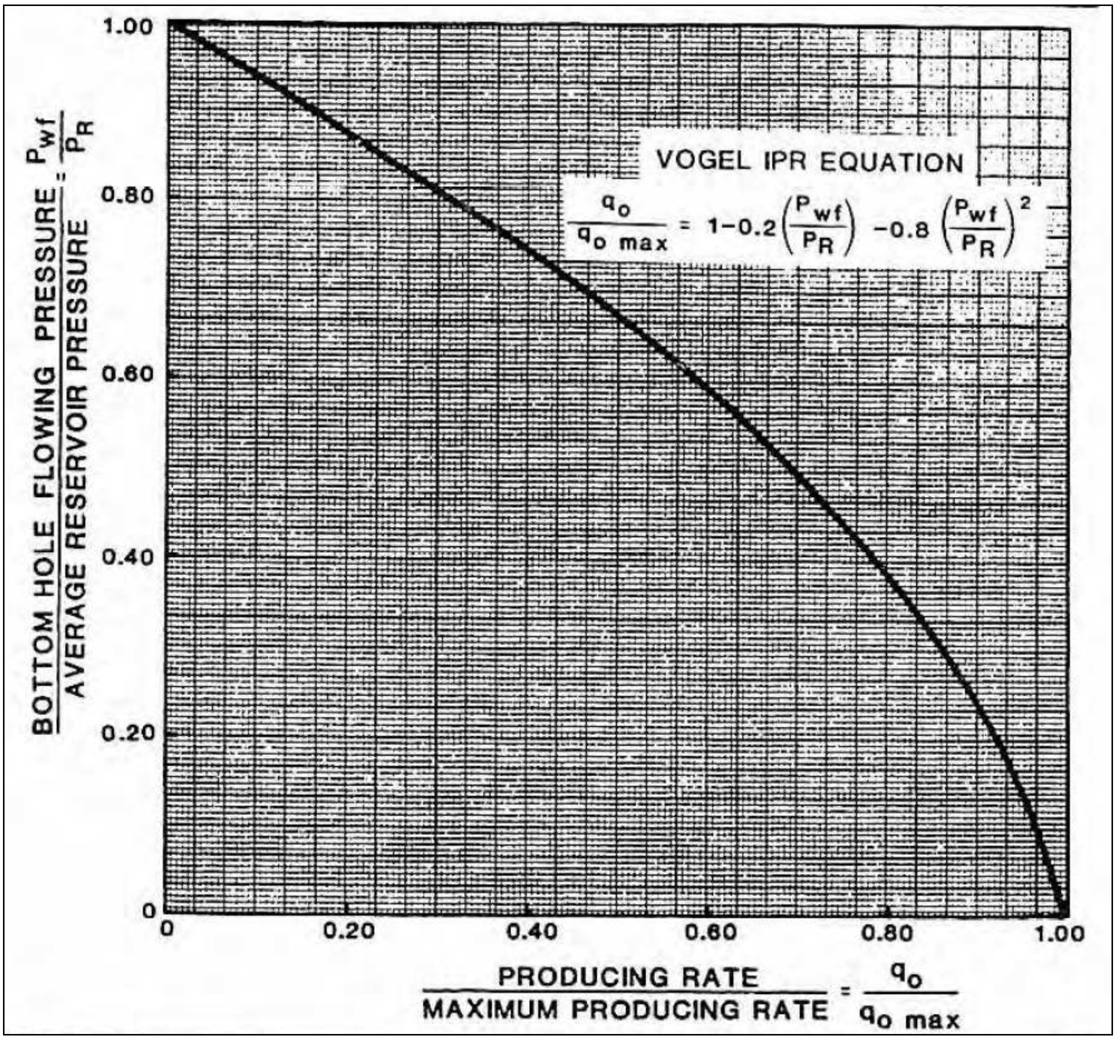


Figure 3.3: Vogel's IPR curve for saturated oil wells [10]

Another method to determine IPR is Fetkovich method [11]. Fetkovich method can be used for analyze both oil and gas wells. He applied multipoint backpressure testing of gas wells to oil wells both above and below a bubblepoint pressure. Fetkovich's IPR equation can be expressed in Equation (3.3)

$$q_0 = C(p_R^2 - p_{wf}^2)^n \tag{3.3}$$

where q_0 = production rate

C = flow coefficient

n = exponent depending on well characteristics

3.1.2 Tubing performance relation (TPR)

Another main factor to determine the well deliverability is pressure loss in production tubing. The pressure loss production tubing is depending on size of tubing, flow rate, bottomhole temperature and well fluid density. It can be determined by chart or correlation. Figure 3.4 shows example of the typical pressure transverse curve. When we know the tubing head pressure, this curve can be used to find friction loss in tubing. The relation between bottomhole pressure and oil rate is called “tubing performance relation (TPR)” or “vertical lift performance (VLP)”

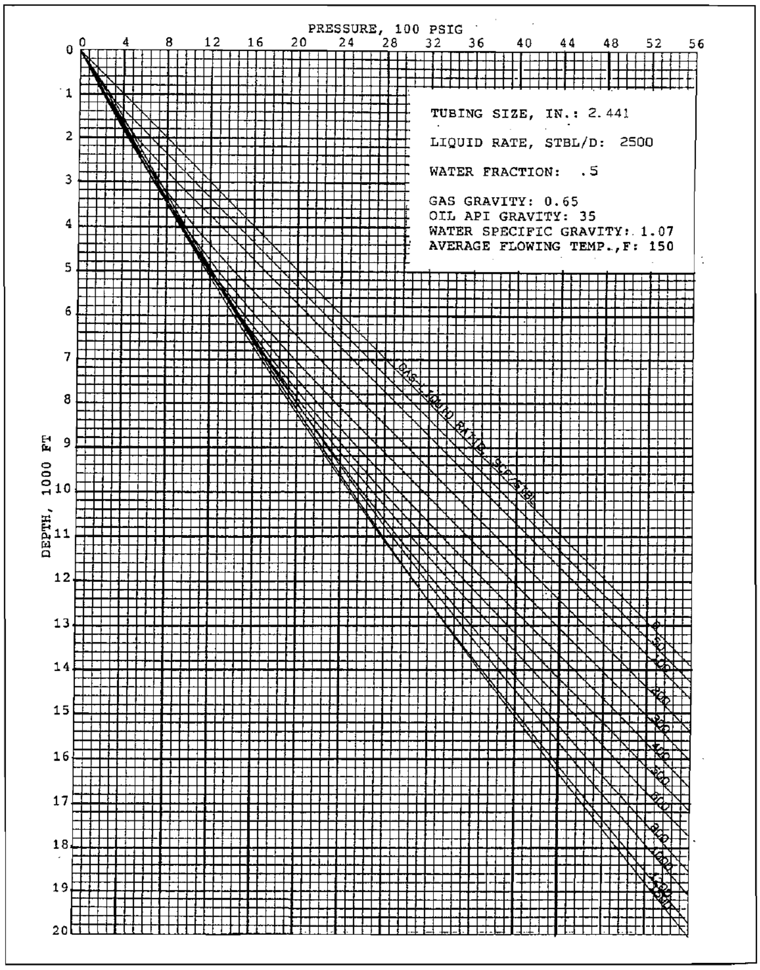


Figure 3.4: Example of typical vertical pressure transverse curve [11]

The pressure at bottom of production tubing consists of 3 components

1) back pressure from surface or “well head pressure”
2) hydrostatic pressure due to gravity and changing in elevation between well head and bottom of production tubing
3) friction losses from bottom of production tubing to well head.

Figure 3.5 illustrates the three component s of pressure in a tubing performance curve; wellhead pressure, hydrostatic pressure and friction losses for liquid, dry gas and mixture of two phases. It can be found that the hydrostatic pressure gradient is a constant in case of single phase liquid because of the density is assumed constant. However, friction loss is depending on flow rate with two flow regimes;

laminar and turbulent flow. This two flow regimes are connected by transition zone. At low flow rates, the flow is laminar flow and the pressure gradient changes linearly with rate or flow velocity. But high flow rates, the flow is turbulent flow and the pressure gradient increases more than linearly with increasing flow rate. Normally, the higher the flow rate, the higher in pressure loss.

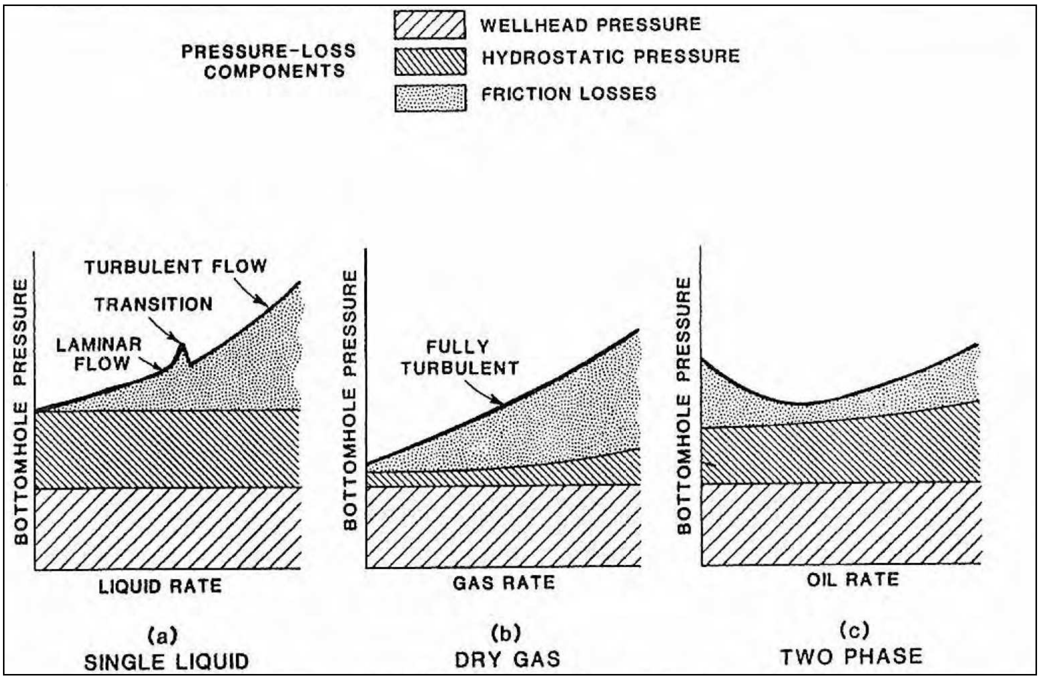


Figure 3.5: Various type of artificial lift system [10]

In case of dry gas, there are some relations between density, flow rate and pressure of gas. Increasing the gas flow rate will cause increasing of friction losses significantly due to the turbulent flow. For hydrostatic pressure is not constant because of changing in gas density.

In case of mixture or two phases, there are some relations between density, flow rate and pressure of mixture more complicated than for gas. The trend of hydrostatic pressure is similar to case of dry gas.

$$\frac{dp}{dZ} = \left(\frac{dp}{dZ}\right)_{elevation} + \left(\frac{dp}{dZ}\right)_{fricion} + \left(\frac{dp}{dZ}\right)_{acceleration} \tag{3.4}$$

Equation 3.4 is used to calculate the pressure losses in wellbore fluid flow. There are three components of which are:

1) $(\Delta P)_{elevation}$ or the elevation component of pressure drop due to gravity and the changing in elevation between wellhead and the intake of the tubing.
2) $(\Delta P)_{friction}$ or the frictional component of pressure drop which includes irreversible pressure losses due to viscous drag and slippage.
3) $(\Delta P)_{acceleration}$ or the acceleration component of pressure drop due to acceleration of an expanding fluid. We can neglect this component due it is usually insignificant value when compared with the other losses.

3.2 Gas Lift Theory

As the well produces, the energy inside the well is consumed as well. After the time passes, the energy is not enough to bring the well fluid to the surface and the well will cease production. At this time, it is necessary to put some type of artificial lift to provide the energy to the well. Figure 3.6 shows various types of artificial lift systems.

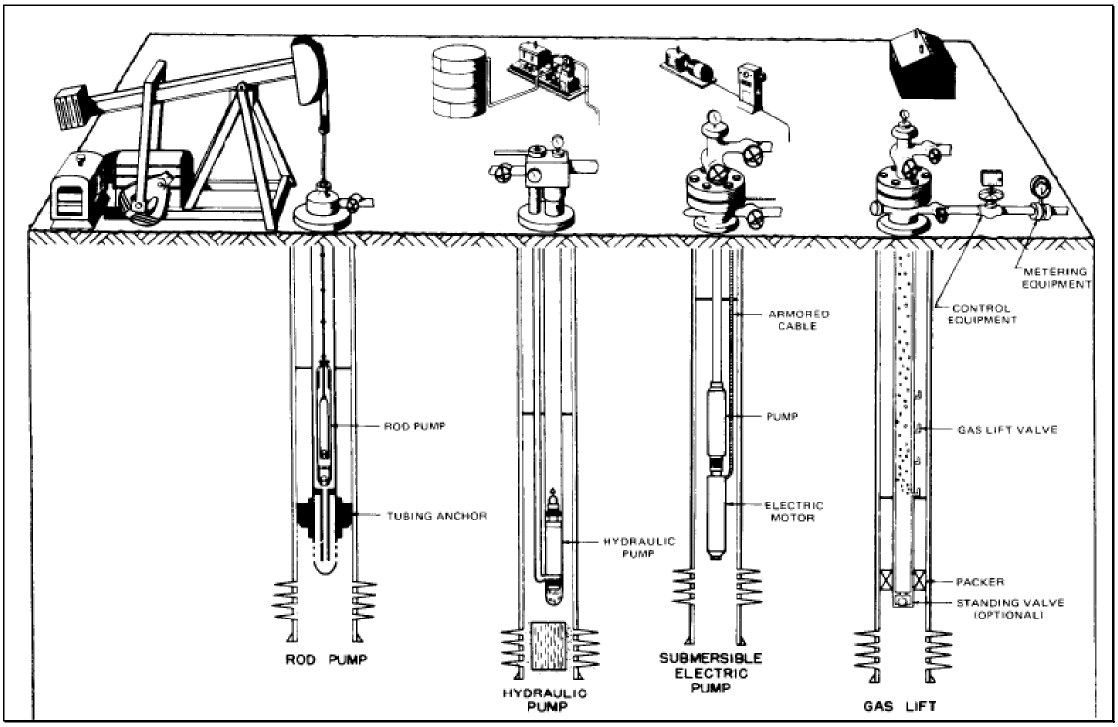


Figure 3.6: Various type of artificial lift system [9]

Gas lift is another type of artificial lift method using external source of high pressure gas by gas compression facilities at surface. Gas lift is particularly applicable when there is a significant amount of gas produced with the crude. Gas compressors are installed and can be designed to supply the high pressure gas for the gas lift system to supplement formation gas to lift the crude. There are 2 types of gas lift: continuous and intermittent gas lift.

3.2.1 Conventional gas lift

Because most wells are produced in continuous flow, gas is injected in the annulus continuously at a maximum possible depth which depends on depth of the well and injected gas pressure. The injected gas will mix with formation fluid, and then the flowing pressure gradient is decreased from the mixing point of fluid to the surface. The bottomhole pressure is subsequently decreased due to reduction in the flowing pressure gradient.

Figure 3.7 shows that the pressure gradient is decreased above gas injection point because when formation fluid in the reservoir is mixed with the injection gas, its causes fluid density to decrease.

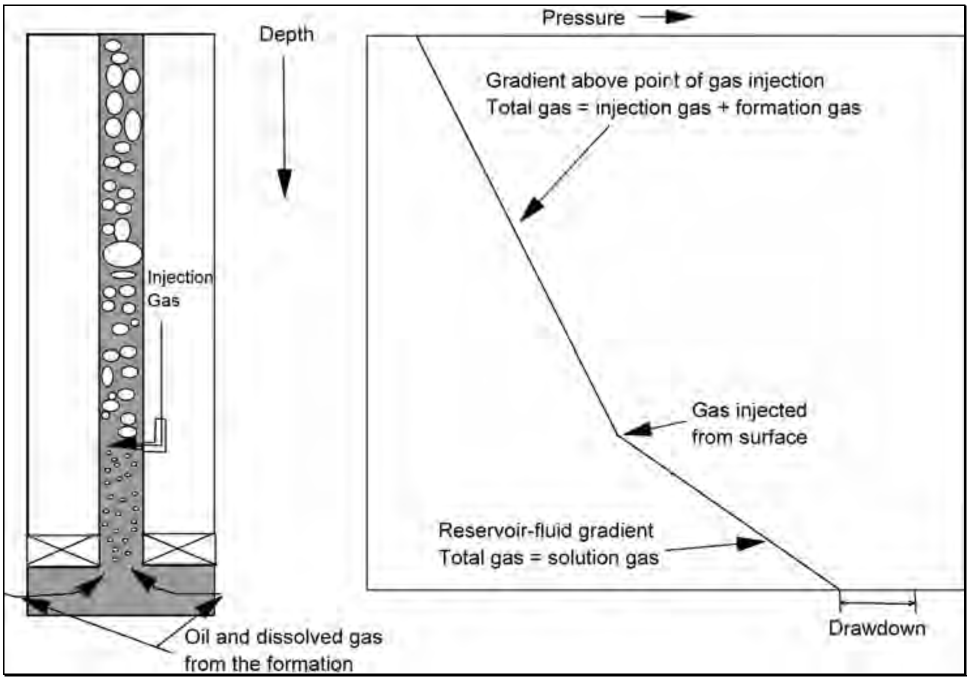


Figure 3.7: Flowing pressure gradient above and below the depth of gas injected point in a continuous gas lift well. [12]

For intermittent gas lift, gas is injected in a periodic or interval time by using time control device. Gas is injected into tubing to make liquid production as a slug. This action force is similar to the way the bullet is fired from a gun. This method cannot produce oil at high rate and should not be considered until the bottom hole pressure is low. Figure 3.8 shows produced oil slug after the bottom gas lift valve is opened.

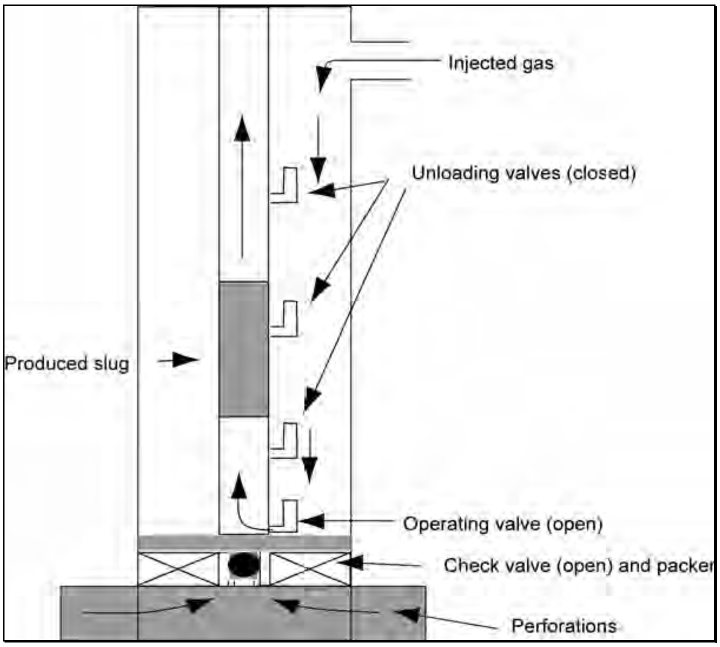


Figure 3.8: Cycle of gas lifting, a liquid slug in an intermittent gas lift well [12]

In order to design a gas lift system, many factors must be considered. First, we need to select whether continuous or intermittent flow is appropriate. The purpose of gas lift valves is mainly for unloading fluid in the well and control gas injection rate for both unloading and operating conditions. The locations of gas lift valves depend on

1) available gas pressure for unloading
2) fluid weight or gradient of the fluid in the well at the time of unloading
3) well performance during the time of unloading
4) surface back pressure at well head against where fluid is unloaded and produced
5) the fluid level in the well
6) the BHP and well producing characteristics

After installation of gas lift valves is finished, the next process is unloading process. This process enables the injection gas to pass gas lift valves into tubing without excessive pressure from the reservoir. Figure 3.9 shows a gas lift system for continuous gas lift [10].

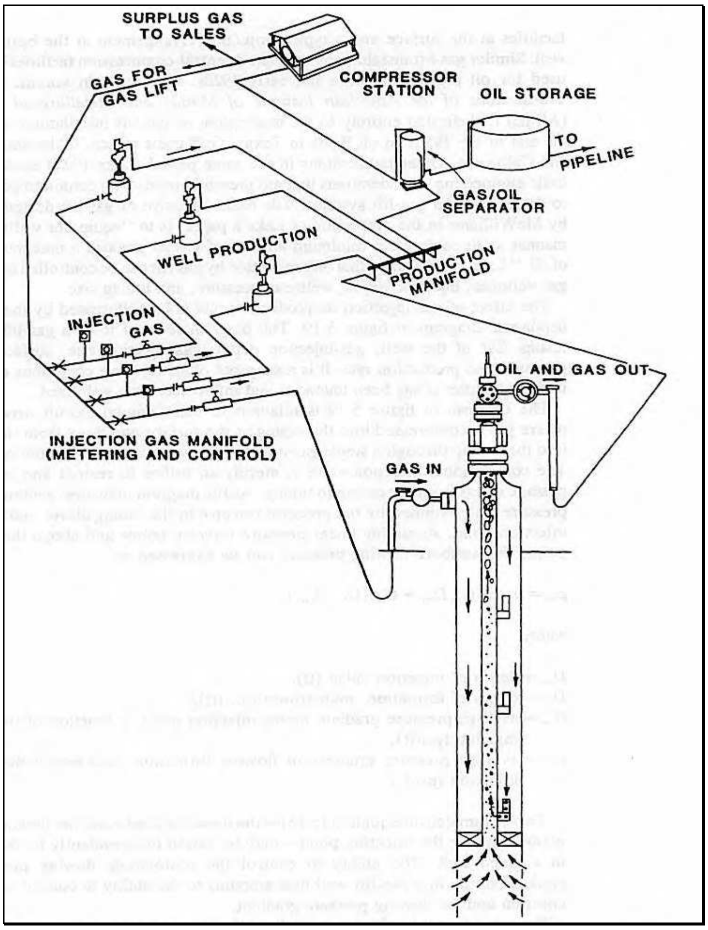


Figure 3.9: A typical gas lift system [10]

The oil production can be controlled by changing flowing pressure gradient and injection depth as shown in the equation below:

$$p_{wf} = p_{wh} + G_{av}D_{av} + G_{bv}(D_f - D_{av}) \quad (3.5)$$

where p_{wf} = well flowing pressure (psi)

p_{wh} = well head pressure (psi)

G_{av} = average pressure gradient above injection point, a function of the gas rate injection (psi/ft)

D_{av} = depth of the gas lift valve (ft)

G_{bv}= average pressure gradient below injection point,
a function of the gas rate injection (psi/ft)

D_f = Depth of the formation (ft)

3.2.2 In-situ gas lift

In-situ gas lift is different from the conventional gas lift because it has been developed without external gas sources, using the gas from formation or gas cap. This method is applied to wells in marginal field in remote or offshore location which a gas zone(s) is available. In many cases, one or more gas zones are perforated with limited or partial perforation interval and produced along with the oil zones for production.

In-situ gas lift can generate significant value by

1) the use of cost effective artificial lift system and eliminating a capital cost of gas compression facilities including gas transfer pipeline.
2) eliminating the replacement or re-sizing of conventional gas lift equipment.
3) reducing the foot print and platform load caused by gas compression facilities.

In some oil fields, In-situ gas lift can be applied by install a downhole auto gas lift valve(s). The auto gas-lift valve is usually sized to control gas flow rate to optimize production across the range of well condition. The gas flow rate flowing through the valve should be controlled by fully open, close and another open positions (20, 40, 60 and 80%). For the setting depth of the auto gas lift valve can be determined in a similar way with conventional gas lift valve. Figure 3.10 illustrates the well schematic of the well that applies auto gas lift system.

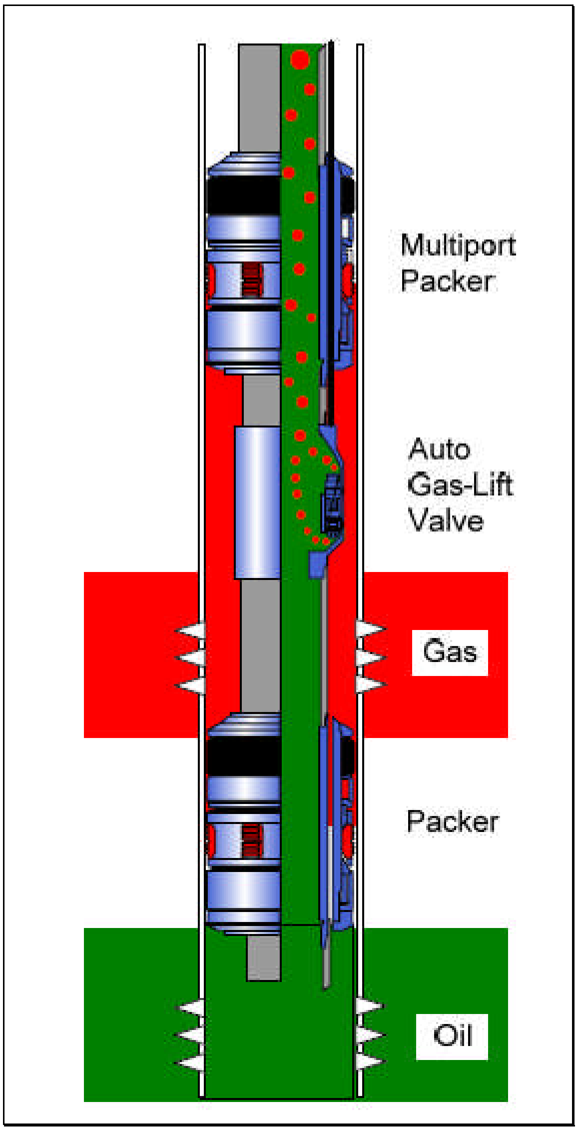


Figure 3.10: An auto gas-lift well schematic [3]

CHAPTER IV

RESERVOIR MODEL CONSTRUCTION

This chapter depicts all input values used in reservoir model construction and describes how to set up model for in-situ gas lift. Moreover, the setting of initial condition in order to get vertical flow performance (VFP) table from PROSPER is explained as well.

In order to study variables that affect oil recovery factor in in-situ gas lift technique in commingled reservoirs, numerical reservoir simulation software called ECLIPSE 100, which is a black oil simulator, is used as a tool to construct reservoir model with multi-segmented well function and VFP tables created by PROSPER. The multi segment function is used in this study because this function can divide the well into segments and calculate pressure loss in the well bore more accurately when there are multiple producing zones.

We can divide the reservoir simulation model in the following:

1. **Grid Section:** Geometry, permeability, porosity, reservoir thickness and top face depth in each zone of reservoir are specified in this section.
2. **PVT Section:** Fluid properties including bubble point pressure, solution gas-oil ratio, viscosity and compressibility are specified in this section.
3. **SCAL Section:** Gas and oil relative permeability, gas saturation and capillary pressure are specified in this section.
4. **Wellbore Section:** Well specification, production constraints and multi-segmented function are specified in this section.

4.1 Grid Section

In this study, a 3D-Cartesian grid model is used to represent hypothetical homogeneous multiple-layer reservoirs. The model consists of 5 pay zones. Four of which are oil zones and one is gas bearing reservoir. The top depth of the oil zone is set at 5,000 ft, 6,000 ft, 7,000 ft and 8,000 ft. The thickness of each oil zone in the base case is 40 ft (4 grid blocks). The top depth of gas zone is varied at 5,500 ft, 6,500 ft and 7,500 ft with thickness of 80 ft each. The thickness of shale separating each of the oil zones is 1,000 ft in the base case. Figure 4.1 depicts the 3D view of the reservoir model. Other properties are illustrated in Table 4.1

Table 4.1: Reservoir dimension and rock properties

Description	**Value**
Reservoir size	1700x1700x3040 ft^3
Grid geometry	
Number of cells	17x17x34
X grid block size	100 feet
Y grid block size	100 feet
Z grid block size	10 feet (oil zone), vary from 2.5, 5 and 20 ft (gas zone)
Properties	
Porosity	0.24
X permeability	200 mD
Y permeability	200 mD
Z permeability	20 mD
Depth of top reservoir	5,000 feet

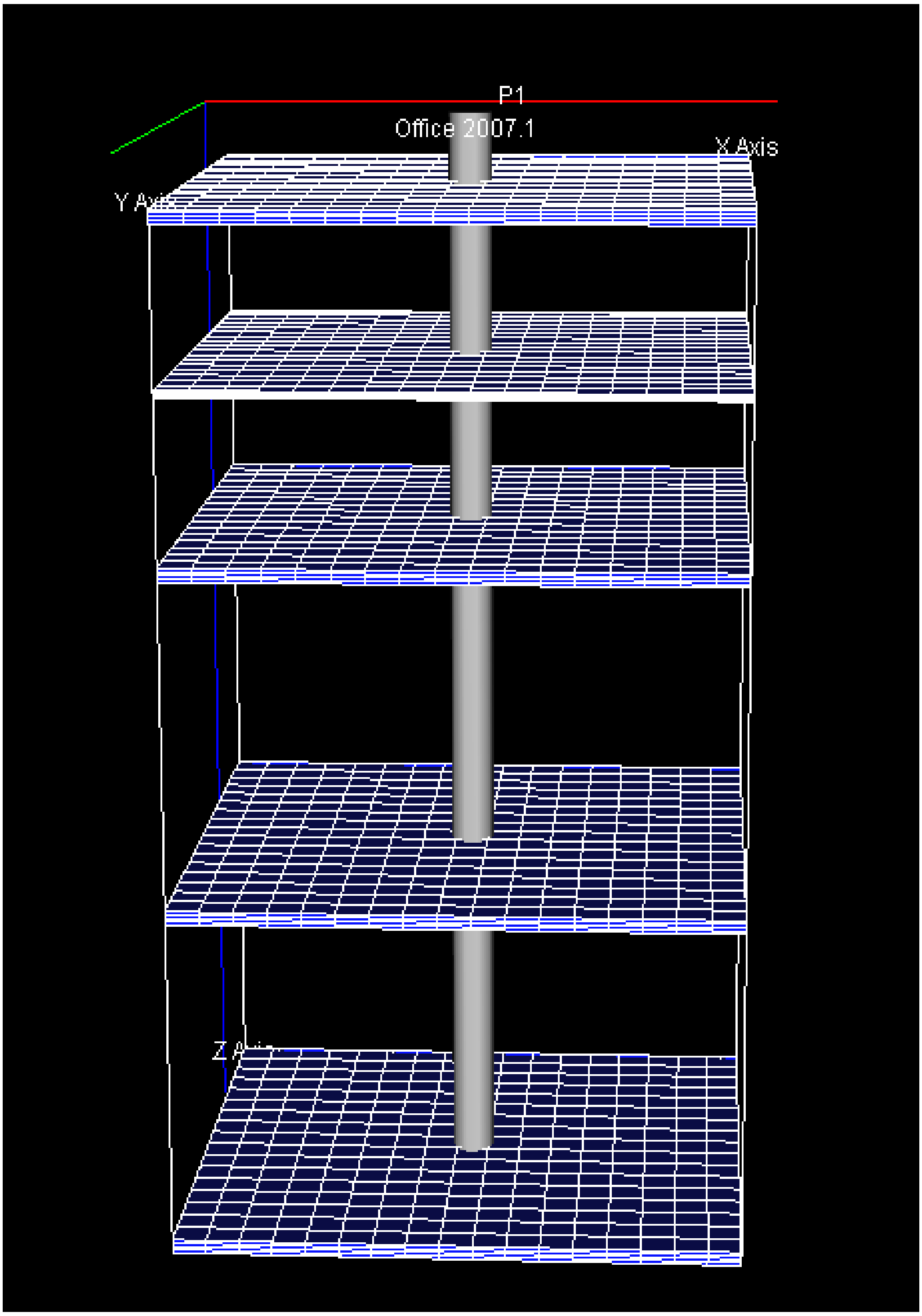


Figure 4.1: Reservoir model in 3D view.

4.2 PVT Section

Table 4.2 and 4.3 summarize the input data in PVT section. At initial reservoir condition, the pay zones have different pressures and temperatures. As each pay zone is located at different depths, reservoir temperature and pressure are computed according to the depth of that zone. The deeper the zone, the higher the temperature and pressure. The live oil and dry gas PVT properties of each pay zone are shown in Figures 4.2- 4.12.

Table 4.2: Input data for PVT Section

Parameter	**Units**	**Value**
Oil gravity	^{o}API	35
Gas gravity	-	0.8
Surface temperature	^{o}F	60
Surface pressure	psia	14.7

Table 4.3: Fluid properties in each pay zone

Depth (ft)	Fluid type	Reservoir temperature (^{o}F)	Reservoir pressure (psia)	Solution gas/oil ratio (scf/sTB)
5,000	Oil	240	2,166	200
5,500	Gas	210	2,451	-
6,000	Oil	270	2,596	250
6,500	Gas	242	2,897	-
7,000	Oil	290	3,031	350
7,500	Gas	275	3,342	-
8,000	Oil	310	3,464	350

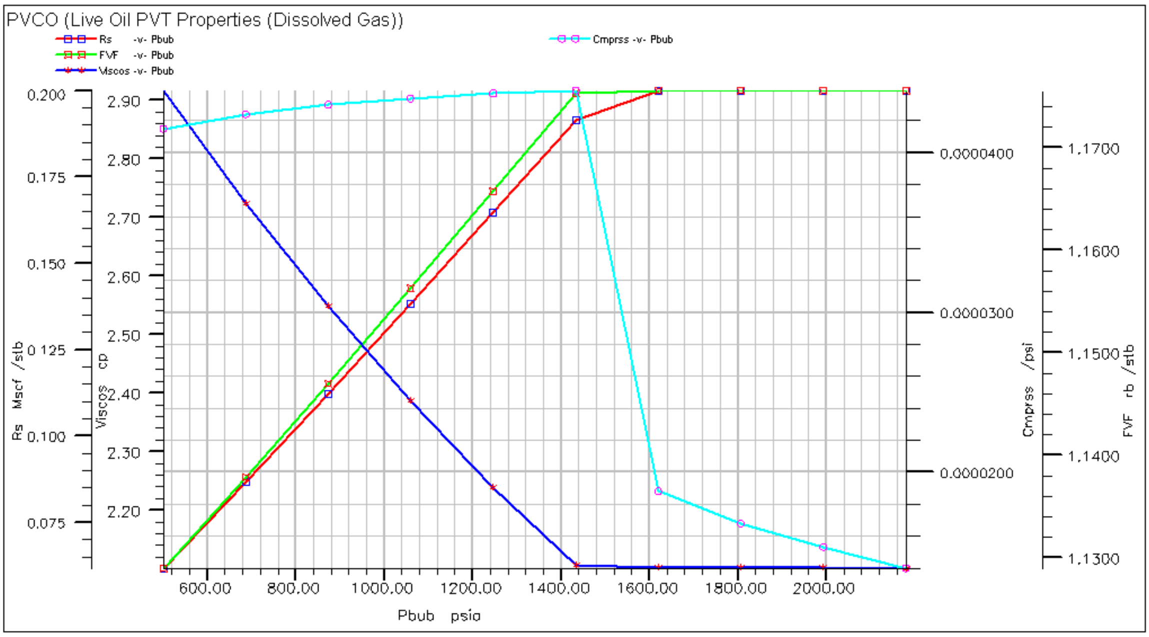


Figure 4.2: Live oil PVT properties used in oil zone at depth 5,000 ft

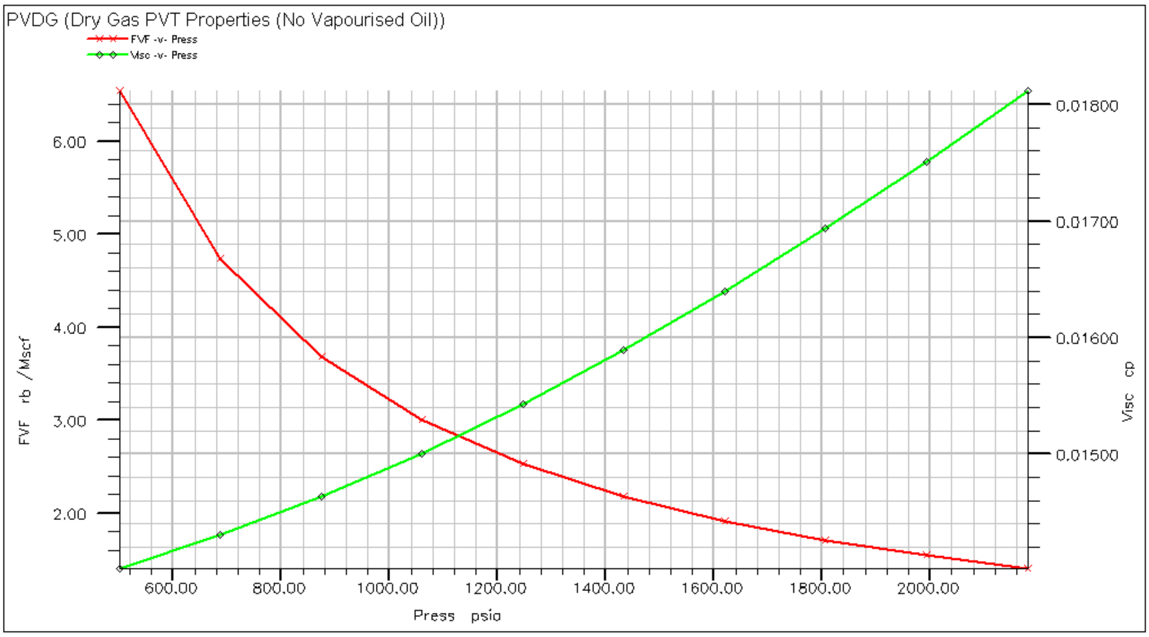


Figure 4.3: Dry gas PVT properties used in oil zone at depth 5,000 ft

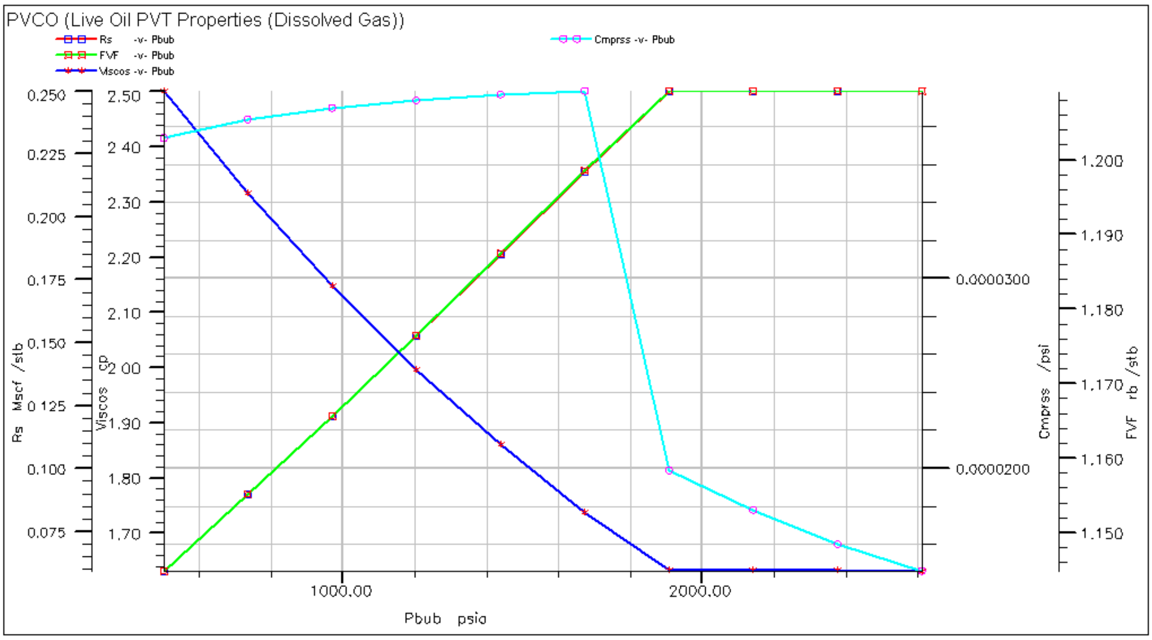


Figure 4.4: Live oil PVT properties used in oil zone at depth 6,000 ft

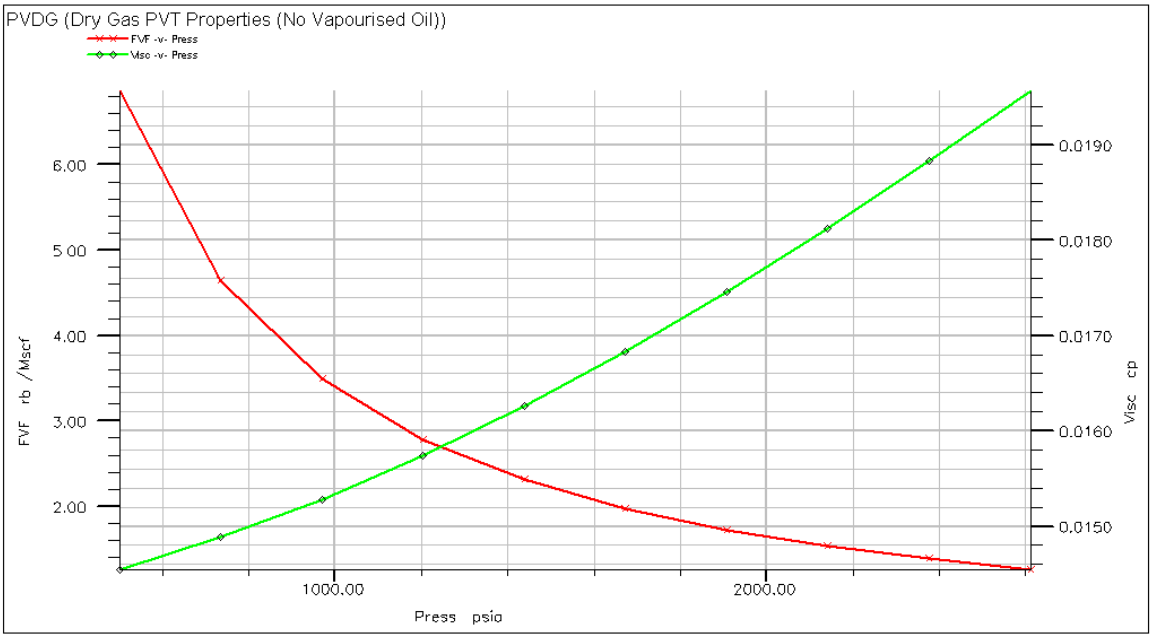


Figure 4. 5: Dry gas PVT properties used in oil zone at depth 6,000 ft

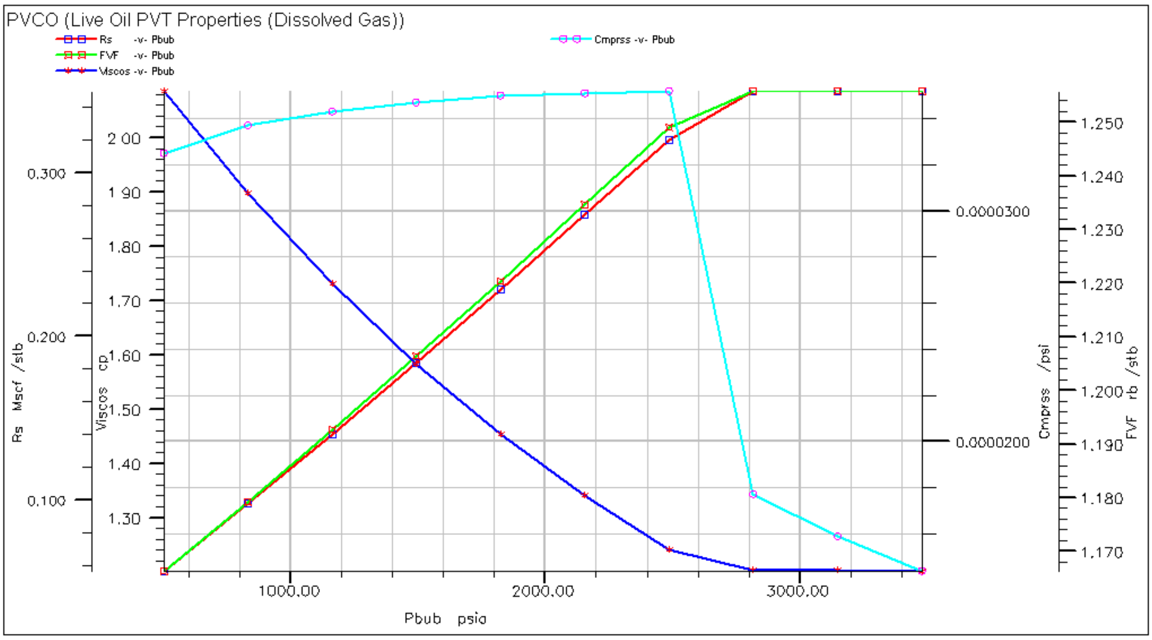


Figure 4.6: Live oil PVT properties used in oil zone at depth 7,000 ft

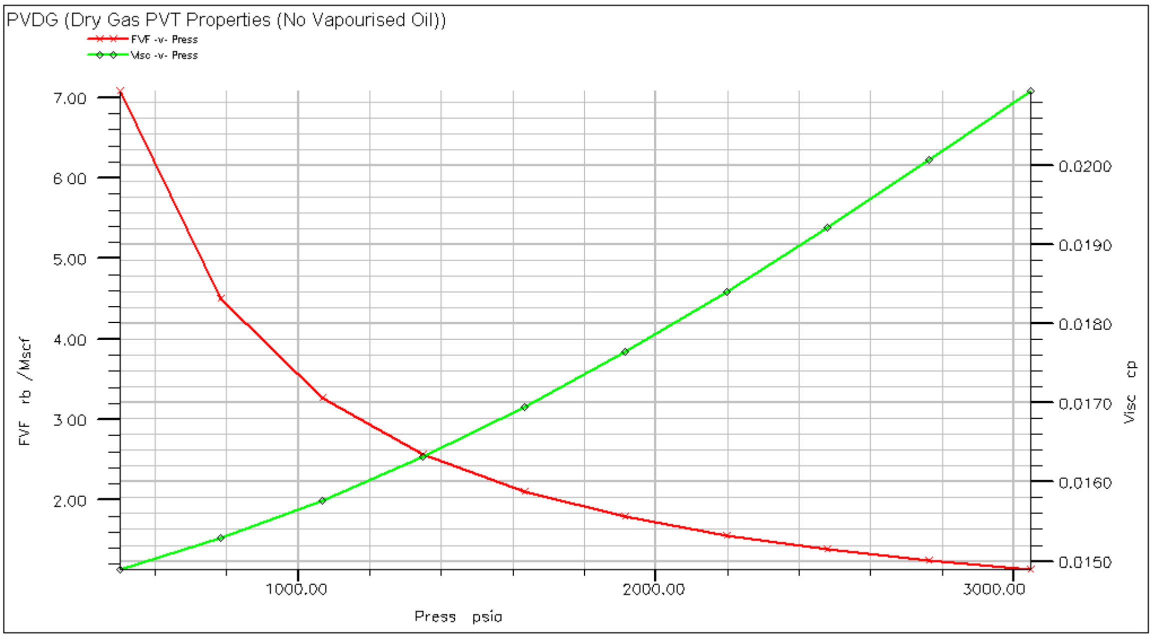


Figure 4.7: Dry gas PVT properties used in oil zone at depth 7,000 ft

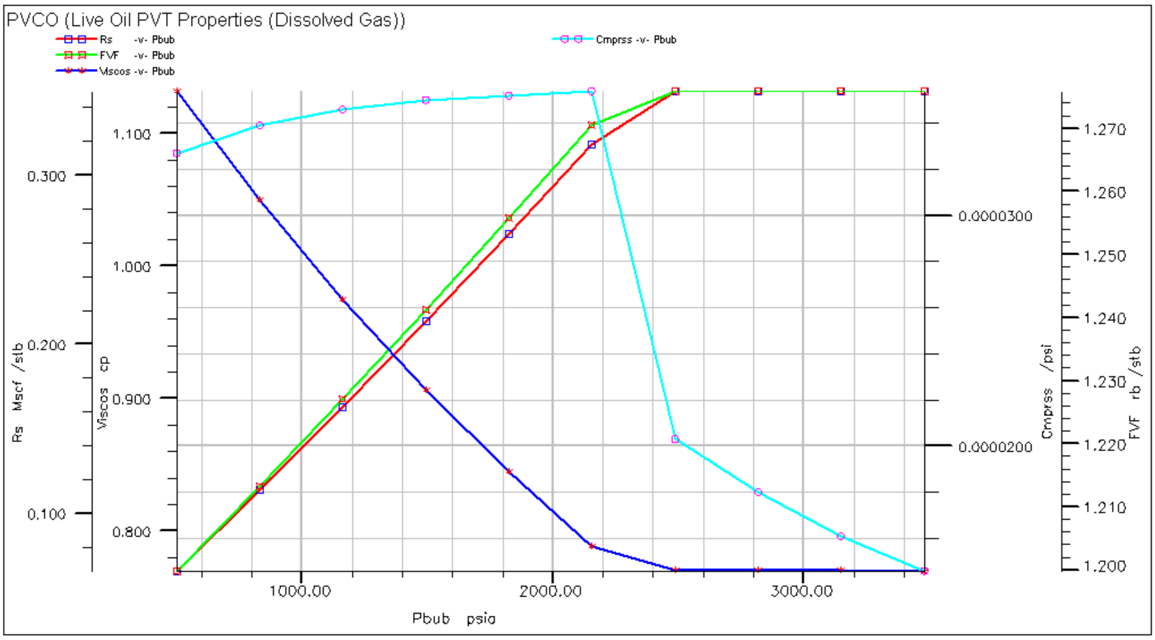


Figure 4.8: Live oil PVT properties used in oil zone at depth 8,000 ft

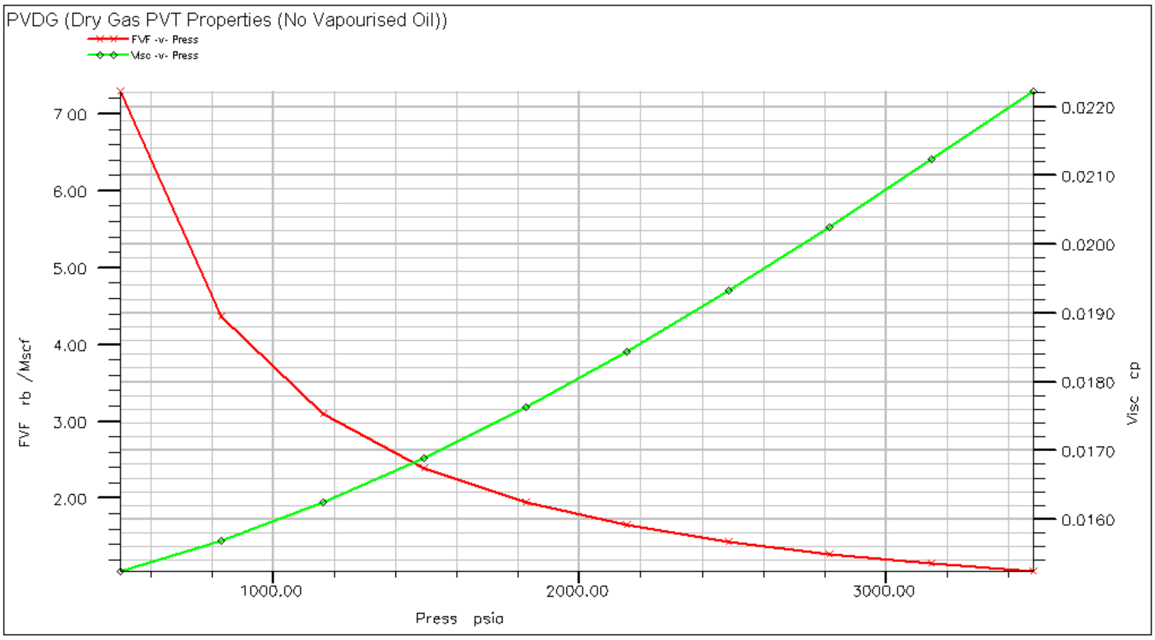


Figure 4.9: Dry gas PVT properties used in oil zone at depth 8,000 ft

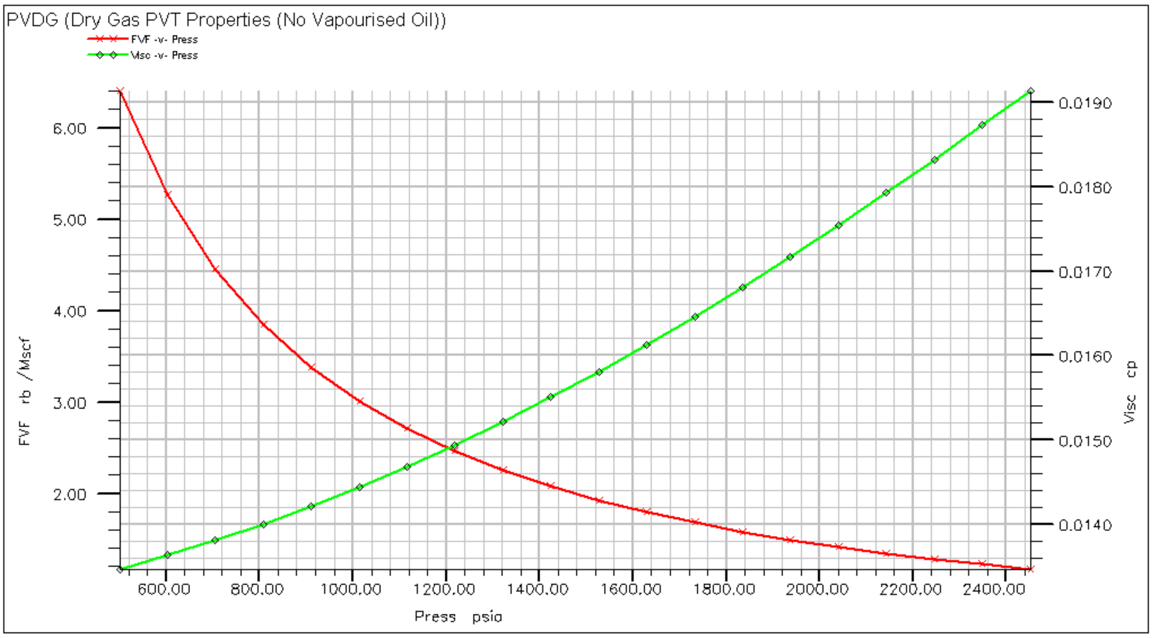


Figure 4.10: Dry gas PVT properties used in gas zone at depth 5,500 ft

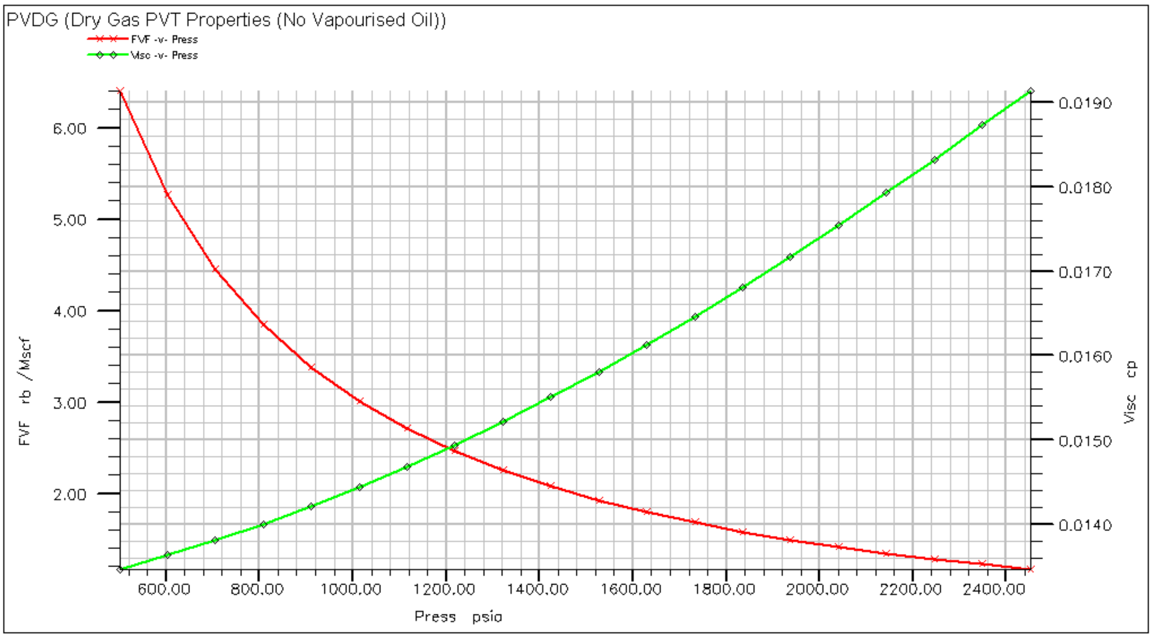


Figure 4.11: Dry gas PVT properties used in gas zone at depth 6,500 ft

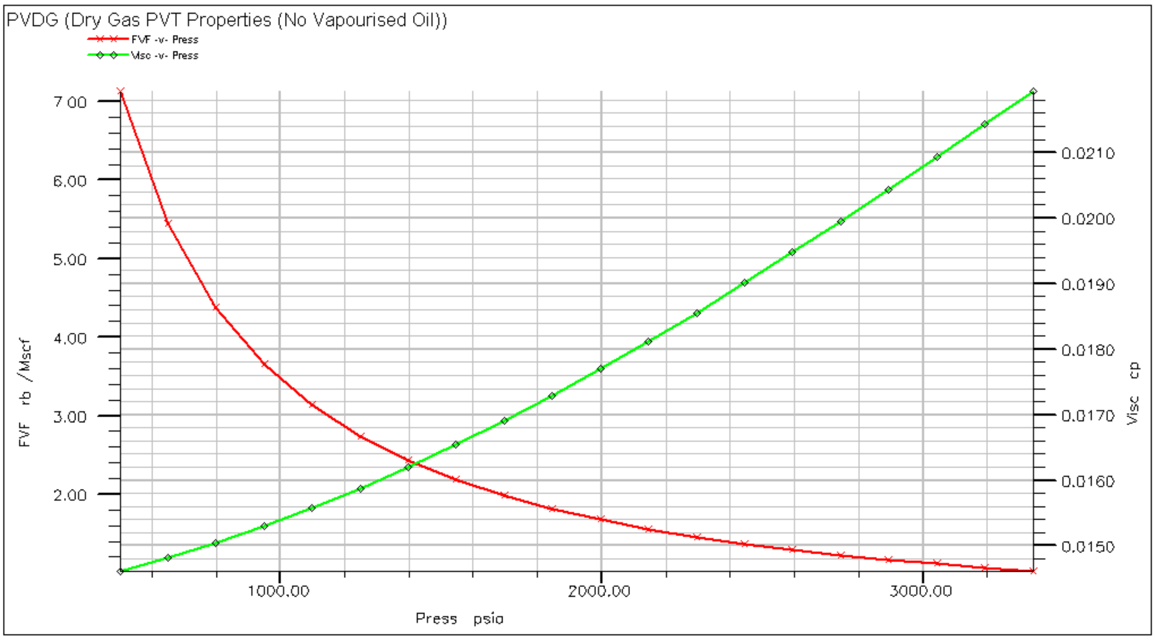


Figure 4.12: Dry gas PVT properties used in gas zone at depth 7,500 ft

4.3 SCAL (Special Core Analysis) Section

In this study, SCAL data are obtained from an offshore oil field, Gulf of Thailand. Figures 4.13 – 4.16 show the plot of relative permeability for both oil and gas zone.

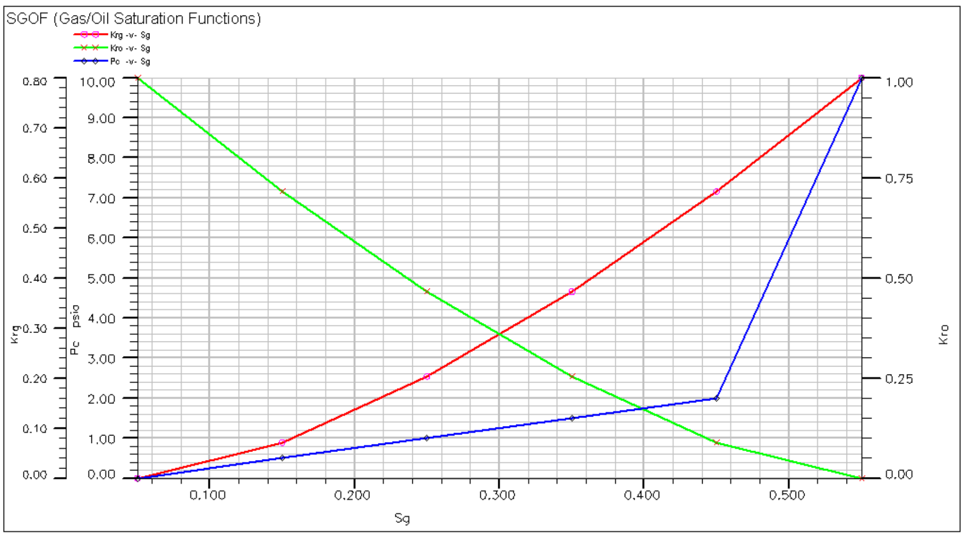


Figure 4.13: Gas-oil relative permeability in oil zone (including p_c)

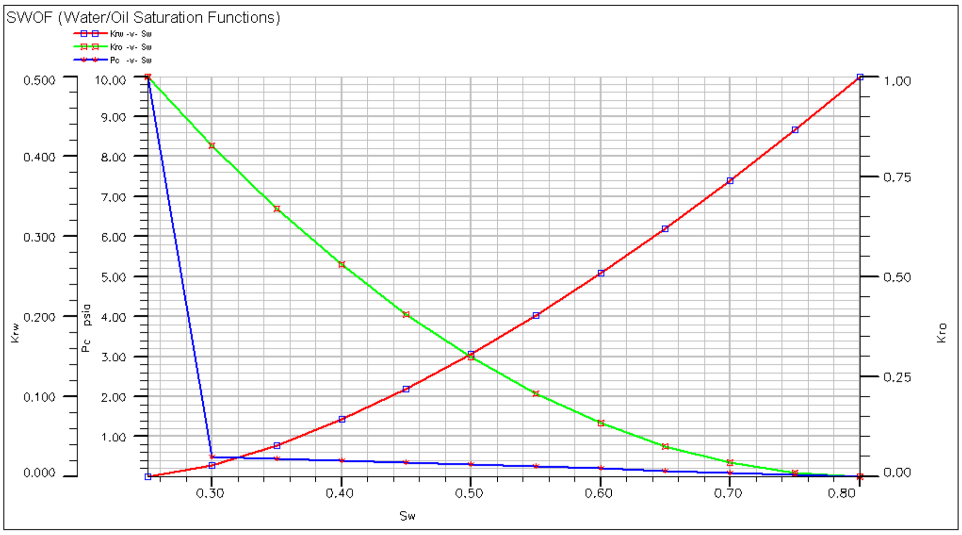


Figure 4.14: Water-oil relative permeability in oil zone (including p_c)

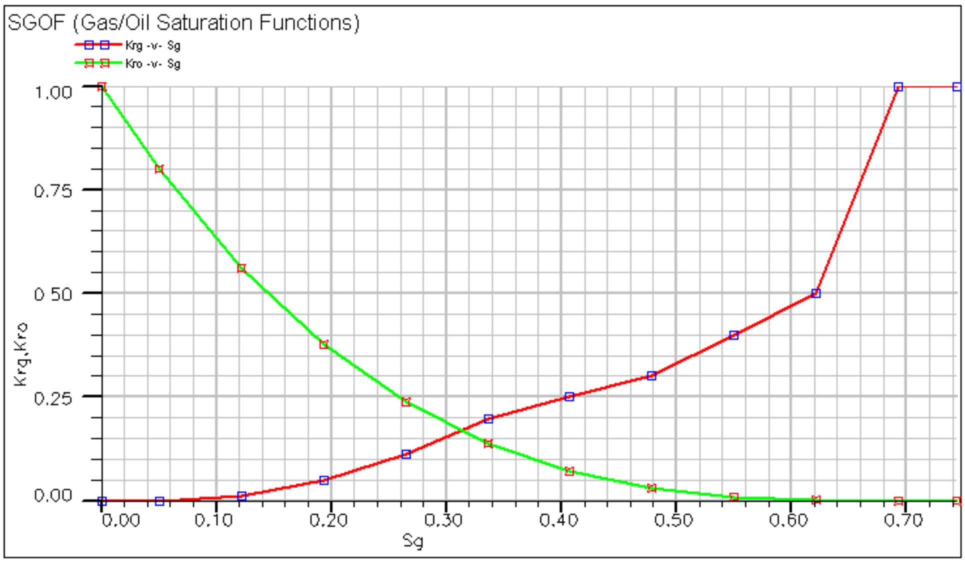


Figure 4.15: Gas-oil relative permeability in gas zone

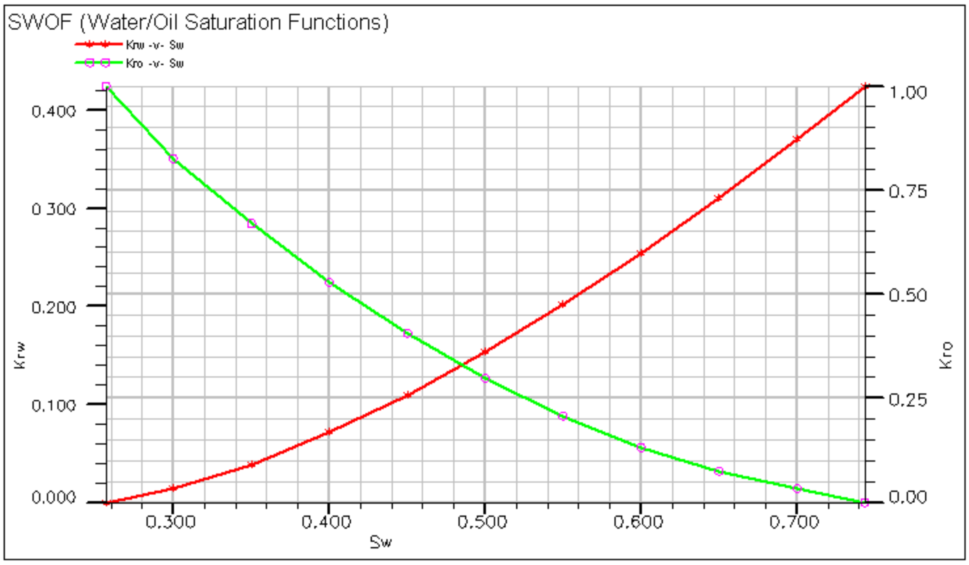


Figure 4.16: Water-oil relative permeability in gas zone

4.4 Wellbore Section

A vertical production well is constructed in the middle of the reservoir (X, Y: 9, 9) with tubing size 2-7/8”. The well is controlled by setting the production rate of liquid to be at most 1,000 BPD. The production well constraints are specified in Table 4.4. The time step is set to 20 years maximum. This length covers all simulation scenarios.

Table 4.4: Production well constraints

Parameters	Unit	Value
Minimum production THP	psia	150
Maximum production rate of liquid	STB/D	1,000
Minimum oil rate	STB/D	100

As there are 5 pay zones, the segmented well function in ECLIPSE 100 is implemented (segmented well definition, segmented well completion, segmented VFP table and iteration parameters for multi segment wells). The most important element in this function is vertical flow performance table. As we know that PROSER is useful in term of calculation of tubing flow performance, it is used to create vertical flow performance table for this study. Input parameters from Table 4.2 and 4.3 in PVT section (including the geothermal gradient) and Table 4.5 are used to generate VFP tables.

Table 4.5: Input parameters for PROSPER

Description	**Value**
Correlations	
- For Pb, Rs, Bo	Standing
- Oil viscosity	Beal et al
-Surface equipment	Beggs and Brill

CHAPTER V
RESULTS AND DISCUSSION

This chapter discusses the performance of oil production from natural depletion and all scenarios of in-situ gas lift technique. In this study, we investigate the effect of the following variables to in-situ gas lift technique:

- permeability of gas bearing zone
- perforation interval of gas bearing zone
- depth of gas bearing zone
- thickness of gas bearing zone
- size of aquifer in oil zone

5.1 Natural Depletion

The chapter starts with natural depletion and its oil recovery factor. All oil zones are fully perforated and made to flow naturally until the tubing head pressure is less than 150 psia as depicted in Figure 5.1. The oil recovery factor for the natural flow is 4.16 % with 515 days of production.

With natural depletion, the bottom hole pressure decreases until it cannot lift the oil up to the surface. The well stops flowing after the tubing head pressure reaches 150 psia. Figure 5.2 shows that oil production rate is maintained at 1,000 STB/day while gas production rate slightly decreases for the entire duration of more than 500 days of production. The gas-oil ratio becomes slightly lower as oil is produced as depicted in Figure 5.3. The lower gas-oil ratio, the higher hydrostatic load of lifting liquid to the surface.

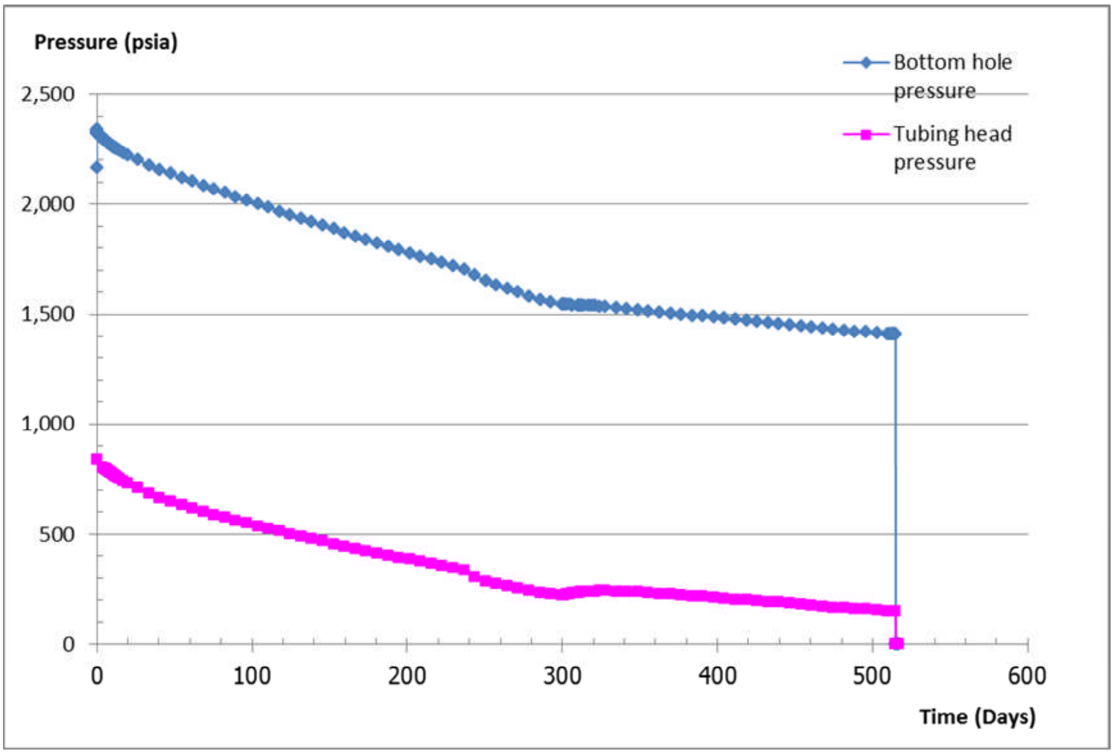


Figure 5.1: Bottom hole pressure and tubing head pressure in natural depletion case.

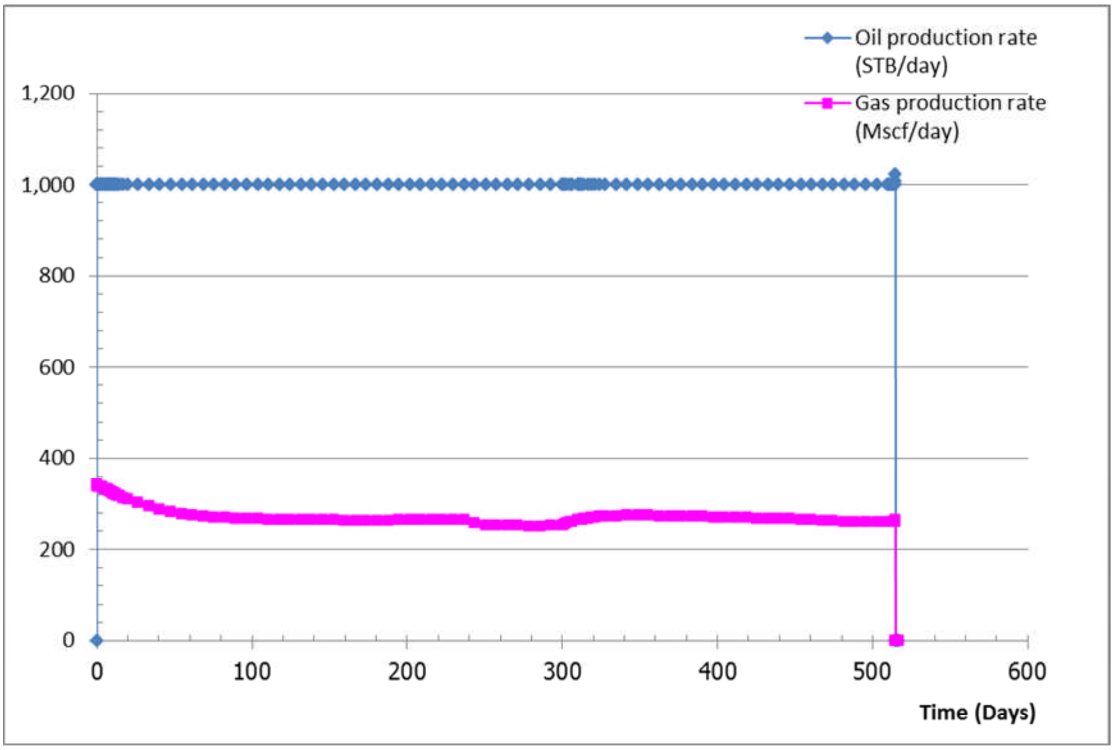


Figure 5.2: Oil and gas production rate in natural depletion case.

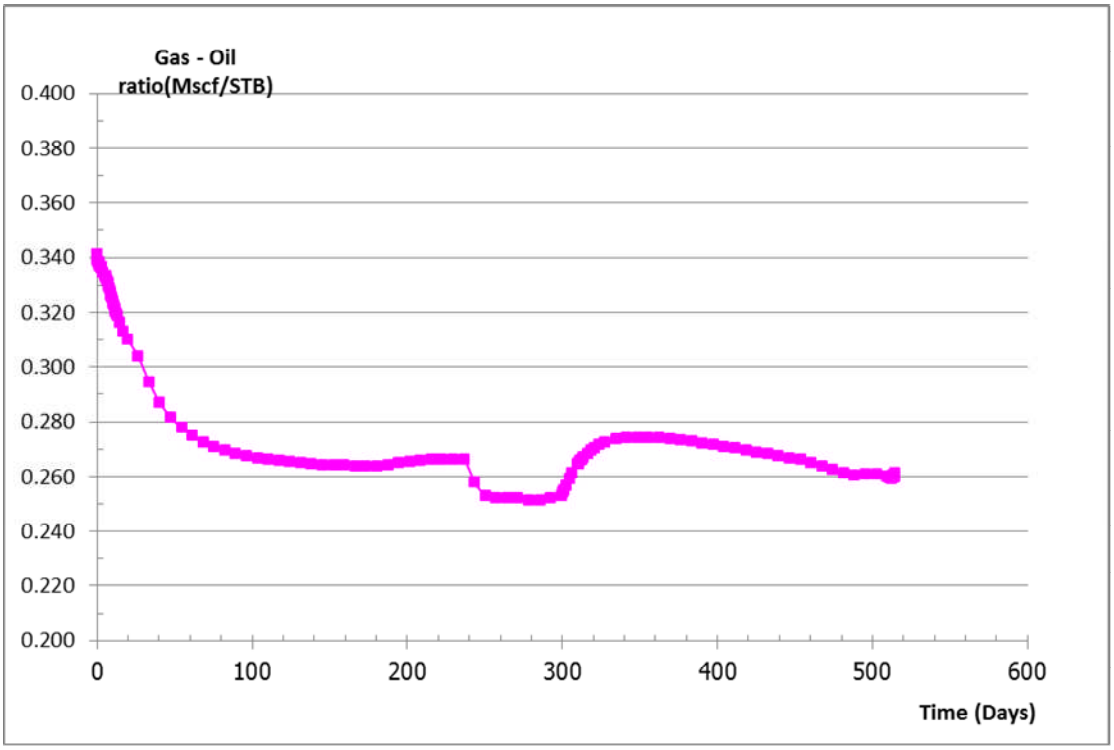


Figure 5.3: Gas-oil ratio in natural depletion case.

5.2 Effect of Permeability of Gas Zone

After we obtain the oil recovery factor of natural depletion, all scenarios of in-situ gas lift were run with its result of oil recovery factor of each scenario. All the results and discussion are presented as follows:

5.2.1 Gas zone at 5,500 ft

In this section, the gas bearing zone is located at depth 5,500 ft. In order to study the effect of permeability of gas zone, we vary the permeability as 1, 10 and 200 md for gas zone thickness of 10, 20 and 80 ft. The oil recovery factors for all cases are plotted in Figure 5.4

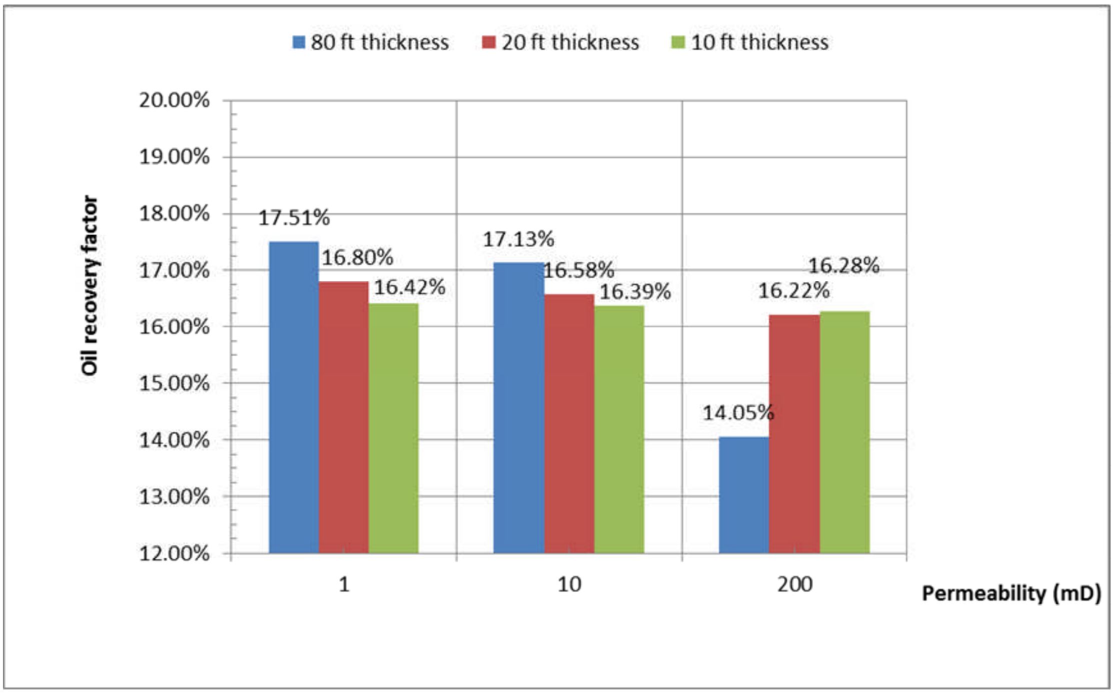


Figure 5.4: Oil recovery factor for in-situ gas lift at 5,500 ft with different permeabilities

From Figure 5.4, it can be observed that when the permeability of the gas zone decreases, the recovery factor generally increases for all cases which have different thicknesses of gas zone (80, 20 and 10 ft), especially the case of 10-ft and 20-ft gas reservoirs. However, the recovery factor is insignificantly increased when permeability decreases. For cases that the thickness of gas zone is 80 ft, there is a moderate difference in recovery factor between permeability of 200 mD (14.05%) and 10 mD (17.13%). This is because the gas-oil ratio in the case of 200-mD gas ratio is too high which adversely affects the friction in tubing.

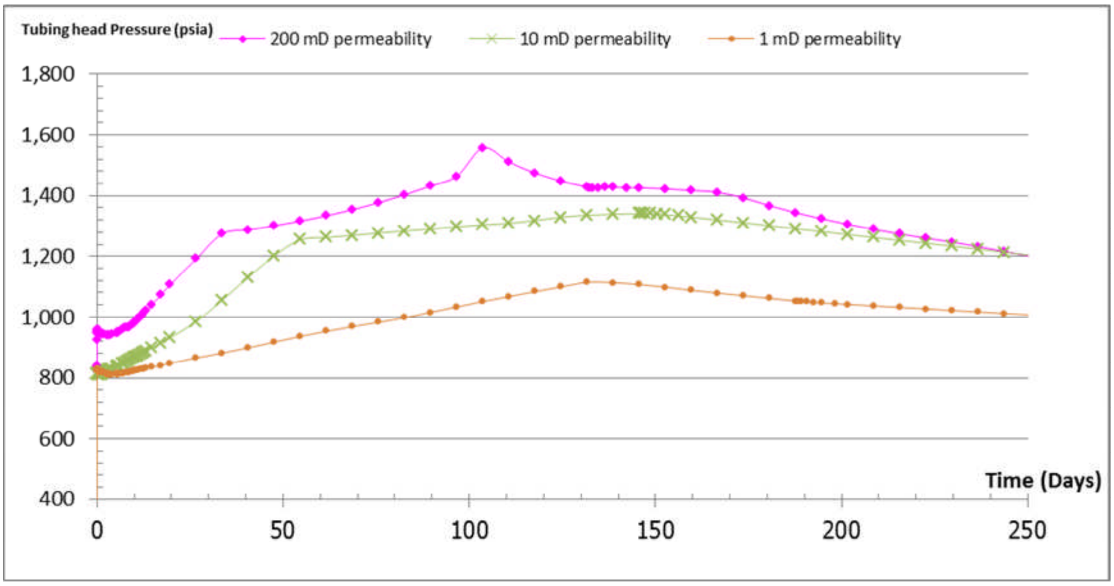


Figure 5.5: Tubing head pressure for in-situ gas lift at 5,500 ft (80 ft thick) with different permeabilities during early period

Figure 5.5 depicts the tubing head pressure for case of 80 ft of gas zone thickness having different permeabilities. It can be observed that the higher the gas zone permeability, the higher the tubing head pressure during early period, similar to the bottom hole pressure (see Figure 5.6). The higher tubing head pressure and bottom hole pressure come with higher gas-oil ratio from a more permeable gas zone. As per Figure 5.6, we also observe the cross flow in the early period as we can compare the initial pressure for the topmost oil zone is less than the bottomhole pressure but this causes no any effect to the performance of oil production as the well fluid will flow out of pay zone in the later period.

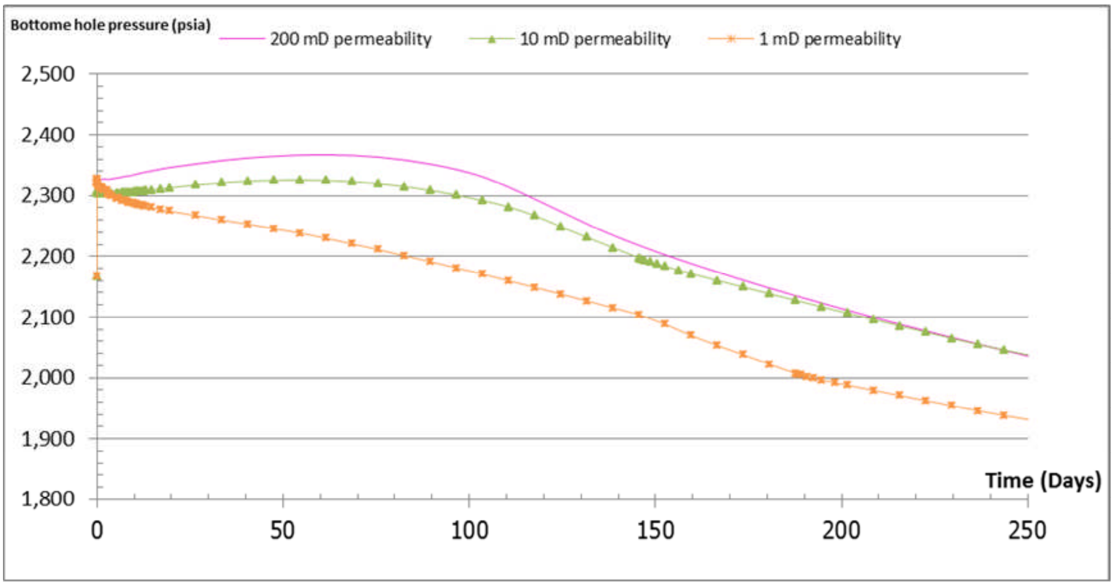


Figure 5.6: Bottom hole pressure for in-situ gas lift at 5,500 ft (80 ft thick) with different permeabilities during early period

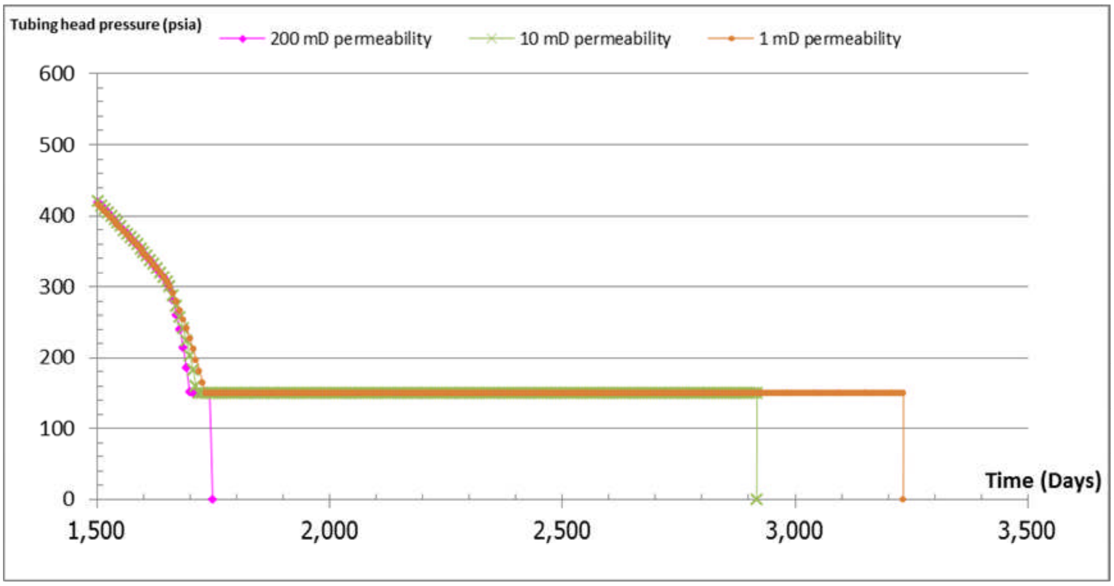


Figure 5.7: Tubing head pressure for in-situ gas lift at 5,500 ft (80 ft thick) with different permeabilities during late times

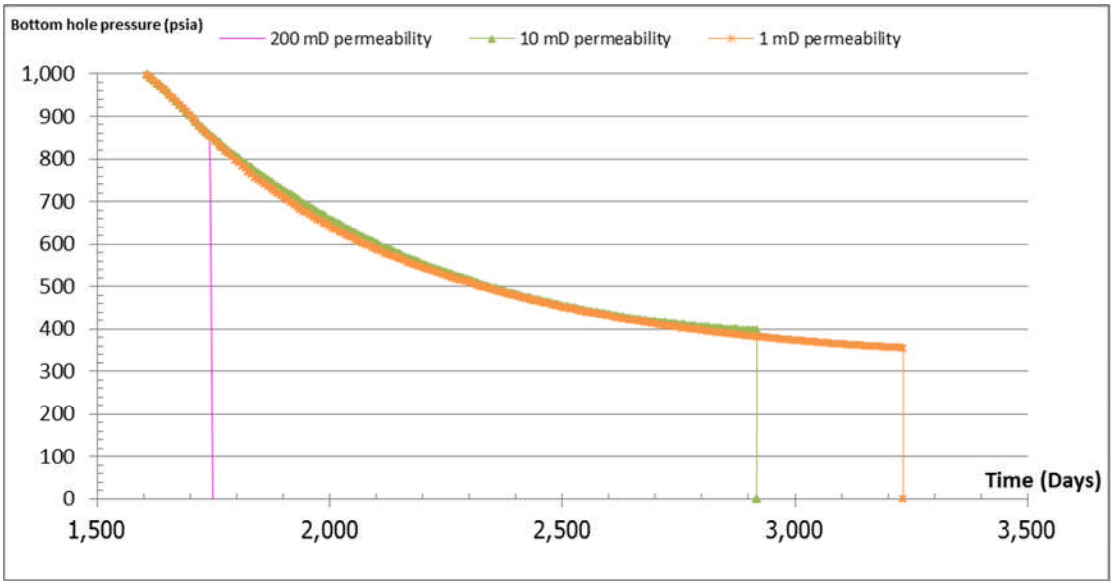


Figure 5.8: Bottom hole pressure for in-situ gas lift at 5,500 ft (80 ft thick) with different permeabilities during late times

At late time, we can see that the tubing head pressure and bottomhole pressure for all cases have similar values as depicted in Figure 5.7 and 5.8, respectively. This is because we are reaching the limiting condition in all cases. In addition, we can see that the lower permeability of the gas zone, the longer the well life. For gas zone permeability of 200, 10 and 1 mD, the well life is 1749, 2918 and 3233 days, respectively. This is because low permeability gas reservoir still has a large amount of gas left in the gas zone at late times. This gas then can help lift the oil at late times.

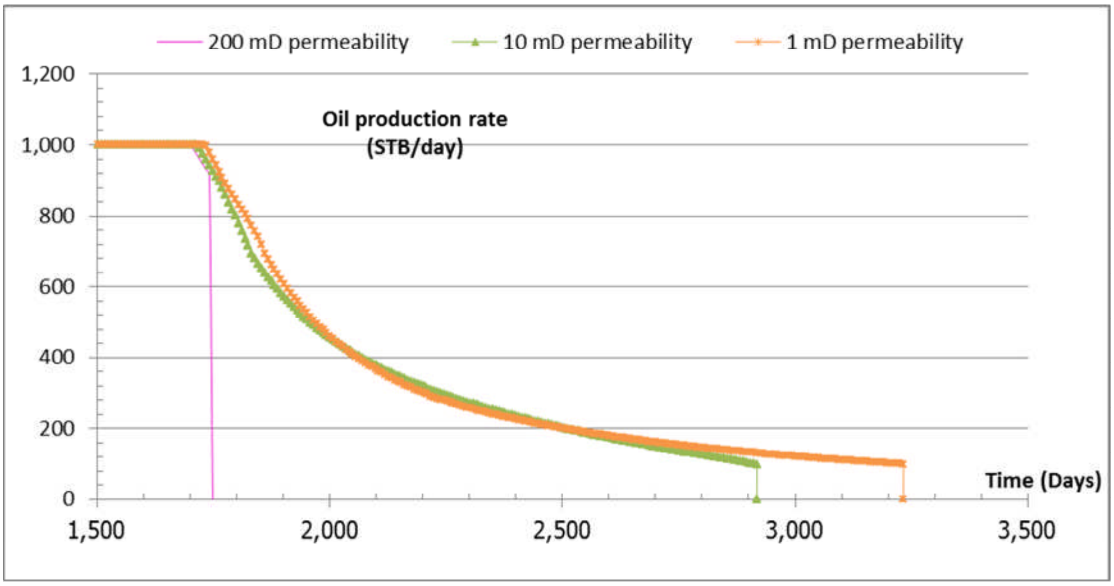


Figure 5.9: Oil production rate for in-situ gas lift at 5,500 ft gas zone (80 ft thick) with different permeabilities

Figure 5.9 depicts oil produciton rate for all cases of different permeabilities. The trend of the oil production rate is the same in all different cases of permeability as we set the maximum of oil production rate at 1,000 BPD. But after the oil cannot be produced at the maximum oil rate anymore, the oil production rate for the case in which the gas zone has low permeability is slightly higher than the one for the case with higher permeability, and the well life is longer as well. This is because the low permeability gas zone yields a smaller amount of gas-oil ratio which is more favorable for tubing performance. As shown in Figure 5.10, gas zone with permeability of 200 mD provides higher gas-liquid ratio compared with gas zone with permeability of 10 mD for the first 2,000 days of production. High gas-liquid ratio is unfavorable at this point as it causes high friction loss. However, at late times (from 2,000 to 2,900 days) the oil production rate in the case of 1 mD gas reservoir is higher than the one in the case of 10 mD gas reservoir. This is because the high GOR of 1 mD case is more favarable for pressure loss in tubing than the low GOR of 10 mD case. Note that favarable GOR is high for small oil rate and low for large oil rate because friction loss in tubing increases very fast in the case of high oil rate.

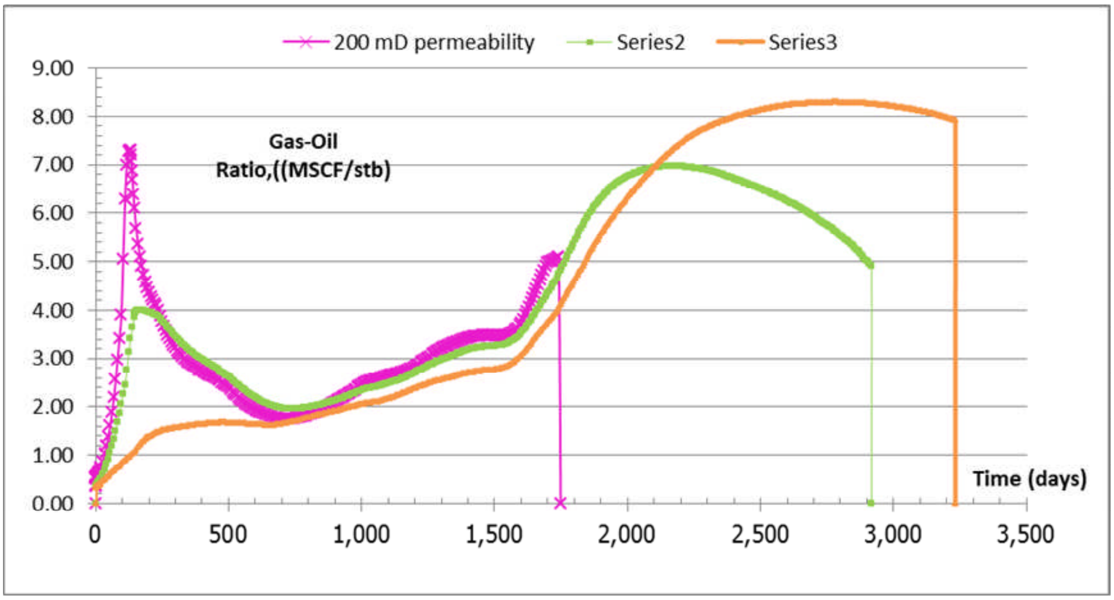


Figure 5.10: Gas-oil ratio for in-situ gas lift at 5,500 ft (80 ft thick) with different permeabilities

5.2.2 Gas zone at 6,500 ft

In this section, the gas bearing zone is located at depth 6,500 ft. We also vary the permeability as 1, 10 and 200 md for gas zone thicknesses of 10, 20 and 80 ft, similar to Section 5.2.1. The oil recovery factors for all cases are plotted in Figure 5.11.

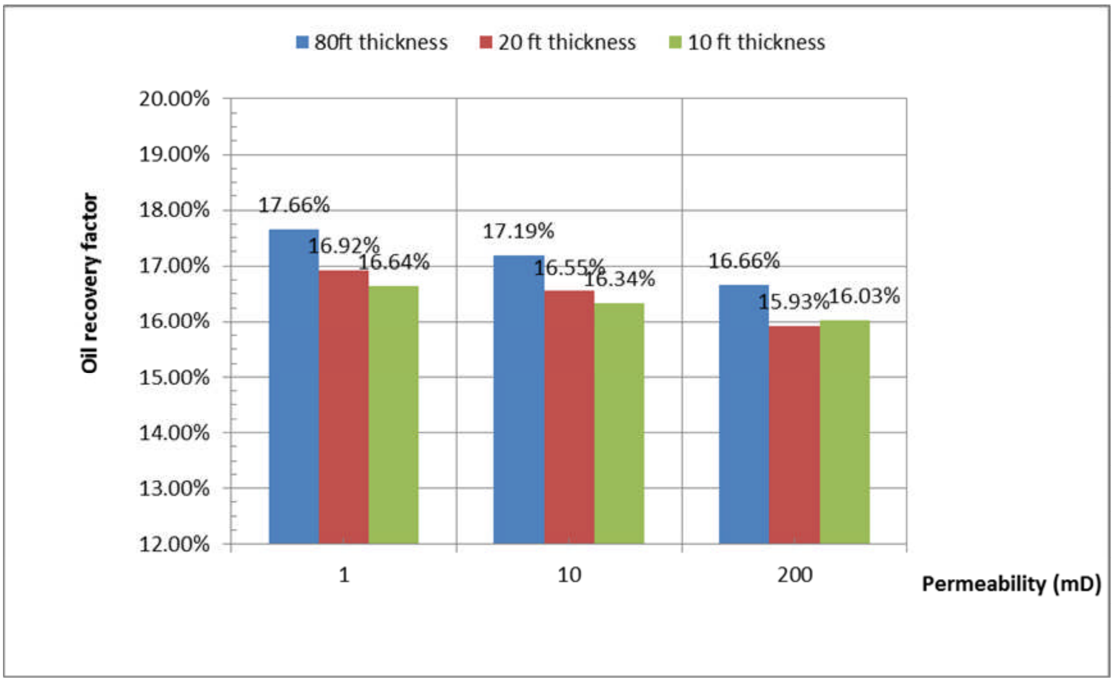


Figure 5.11: Oil recovery factor for in-situ gas lift at 6,500 ft with different permeabilities

From Figure 5.11, it can be observed that when the permeability of the gas zone decreases, the recovery factor increases for cases with gas zone thickness of 80, 20 and 10 ft, respectively. This observation is the same as the one in Section 5.2.1.

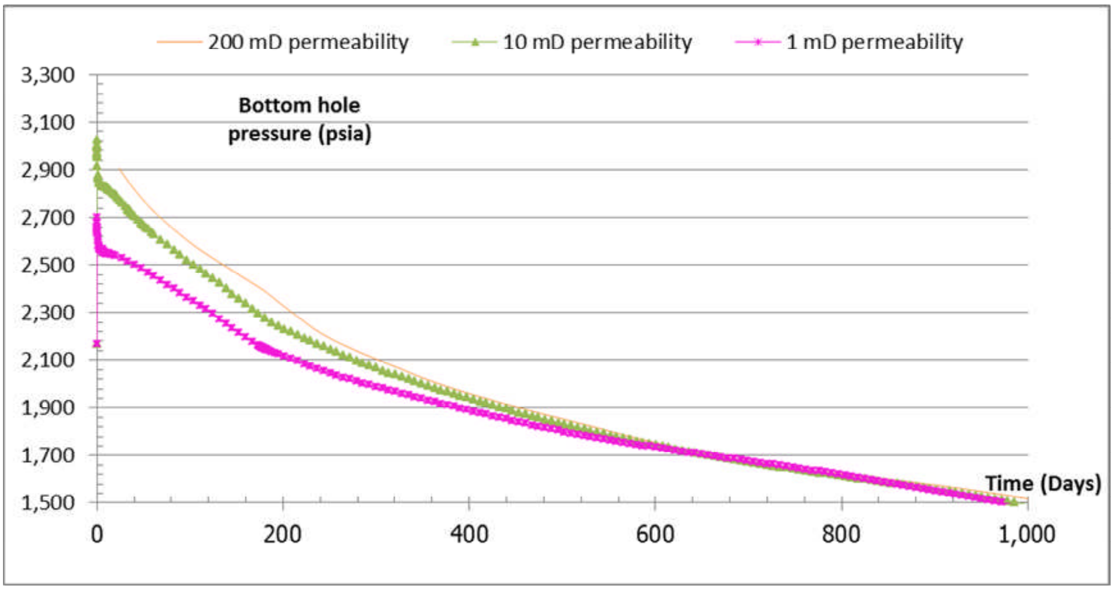


Figure 5.12: Bottomhole pressure for in-situ gas lift at 6,500 ft (80 ft thick) with different permeabilities during early period

Figure 5.12 depicts the bottom hole pressure for case 80 ft of gas zone thickness having different permeabilities. It can be observed that the higher the gas zone permeability, the higher the bottom hole pressure during early period, similar to the tubing head pressure. The higher tubing head pressure and bottom hole pressure come with higher gas-oil ratio from a more permeable gas zone.

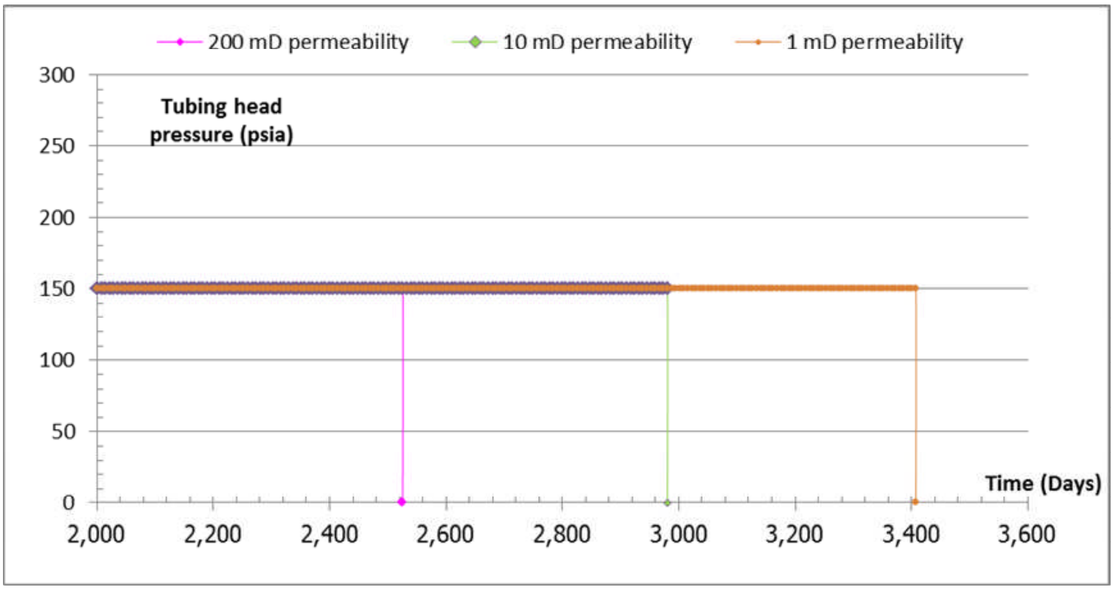


Figure 5.13: Tubing head pressure for in-situ gas lift at 6,500 ft (80 ft thick) with different permeabilities during late times

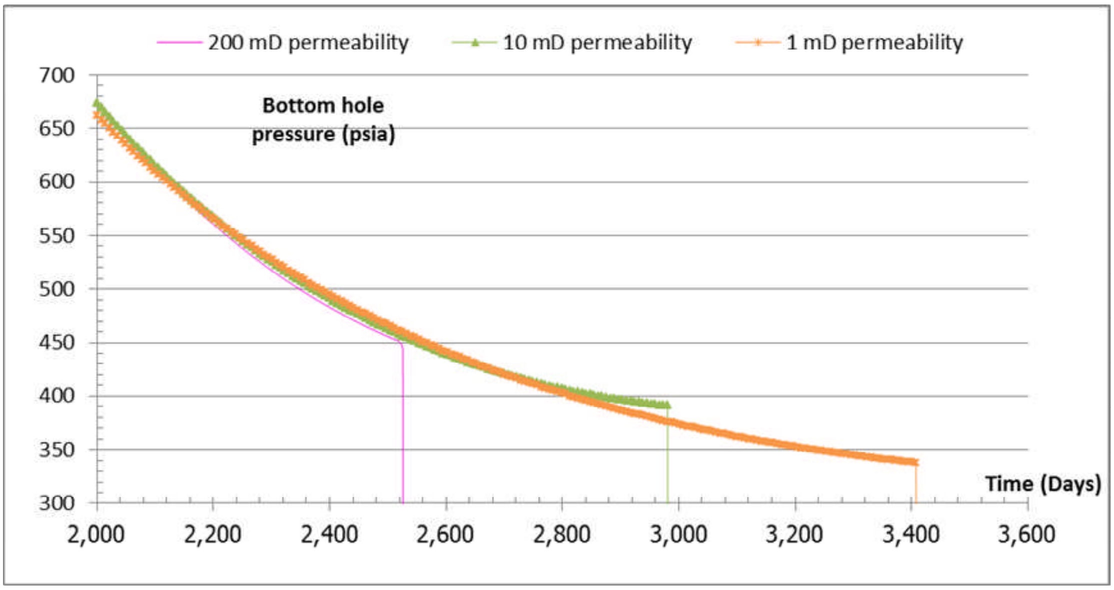


Figure 5.14: Bottom hole pressure for in-situ gas lift at 6,500 ft (80 ft thick) with different permeabilities during late times

At late time, we can see that the tubing head pressure and bottomhole pressure for all cases have similar values as depicted in Figure 5.13 and 5.14, respectively. This is because we are reaching the limiting condition in all cases. In addition, we can see that the lower permeability of the gas zone, the longer the well life. For gas zone permeability of 200, 10 and 1 mD, the well life is 2526, 2981 and 3408 days, respectively.

Figure 5.15 depicts oil produciton rate for all cases of different permeabilities. The trend of the oil production rate is the same in all different cases of permeability as we set the maximum of oil production rate at 1,000 BPD. But after the oil cannot be produced at the maximum oil rate anymore, the oil production rate for the case in which the gas zone has low permeability is slightly higher than the one for the case with higher permeability, and the well life is longer as well. This is because the low permeability gas zone yields a smaller amount of gas-oil ratio which is more favorable for tubing performance. As shown in Figure 5.16, gas zone with permeability of 200 mD provides higher gas-liquid ratio compared with gas zone with permeability of 10 mD for the first 2,400 days of production. High gas-liquid ratio is unfavorable at this point as it causes high friction loss. However, at late times (from 2,400 to 2,900 days) the oil production rate in the case of 1 mD gas reservoir is higher than the one in the case of 10 mD gas reservoir. This is because the high GOR of 1 mD case is more favarable for pressure loss in tubing than the low GOR of 10 mD case. Note that favarable GOR is high for small oil rate and low for large oil rate because friction loss in tubing increases very fast in the case of high oil rate.

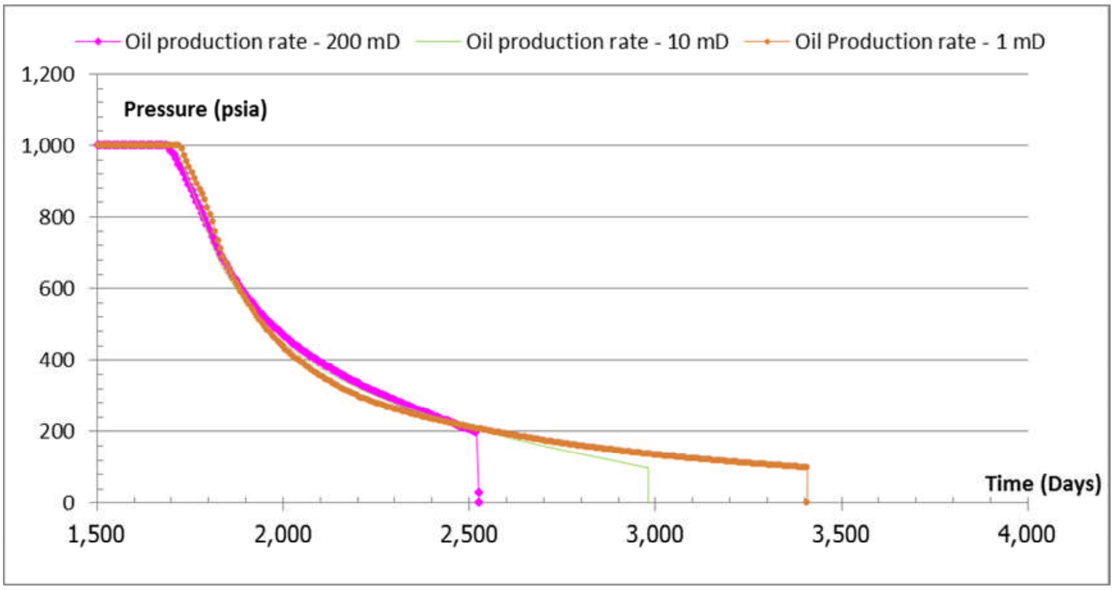


Figure 5.15: Oil production rate for in-situ gas lift at 6,500 ft (80 ft thick) with different permeabilities

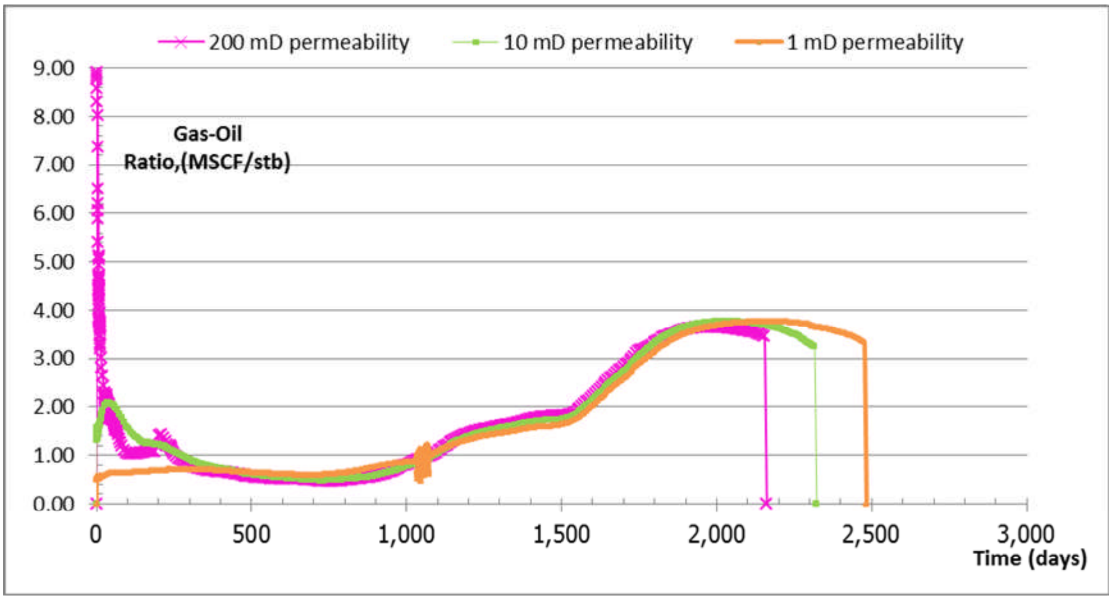


Figure 5.16: Gas-oil ratio for in-situ gas lift at 6,500 ft (10 ft thick) with different permeabilities

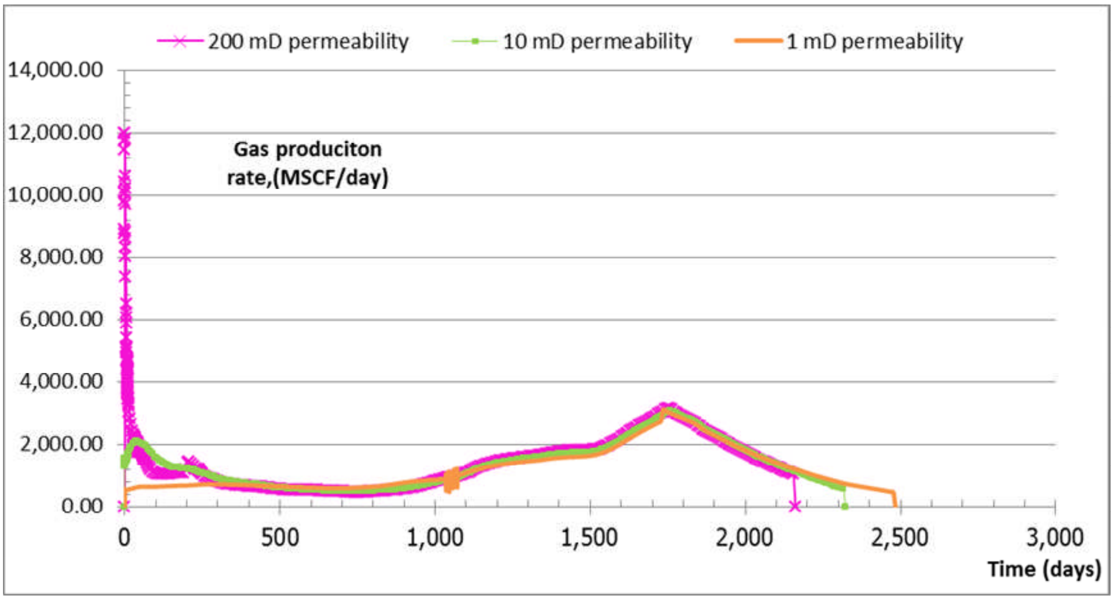
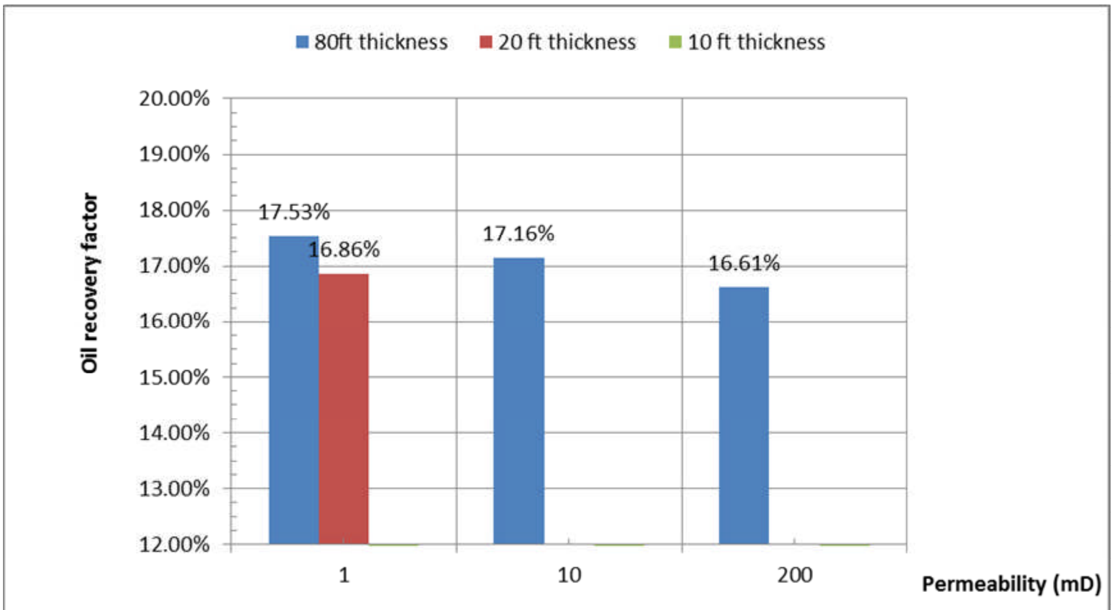


Figure 5.17: Gas production rate for in-situ gas lift at 6,500 ft (10 ft thick) with different permeabilities

5.2.3 Gas zone at 7,500 ft

In this section, the gas bearing zone is located at depth 6,500 ft. We also vary the permeability as 1, 10 and 200 md for gas zone thicknesses of 10, 20 and 80 ft, similar to Section 5.2.1 and 5.2.2. The oil recovery factors for all cases are plotted in Figure 5.18.

From Figure 5.18, it can be observed that when the permeability of the gas zone decreases, the recovery factor increases for cases with gas zone thickness of 80, 20 and 10 ft, respectively. This observation is the same as the one in Section 5.2.1 and 5.2.2.



Note: RF for the cases of 10 ft thick and 20 ft thick (for 10 and 200 mD) gas reservoir cannot be determined due to nonconvergence in the simulation.

Figure 5.18: Oil recovery factor for in-situ gas lift at 7,500 ft with different permeabilities

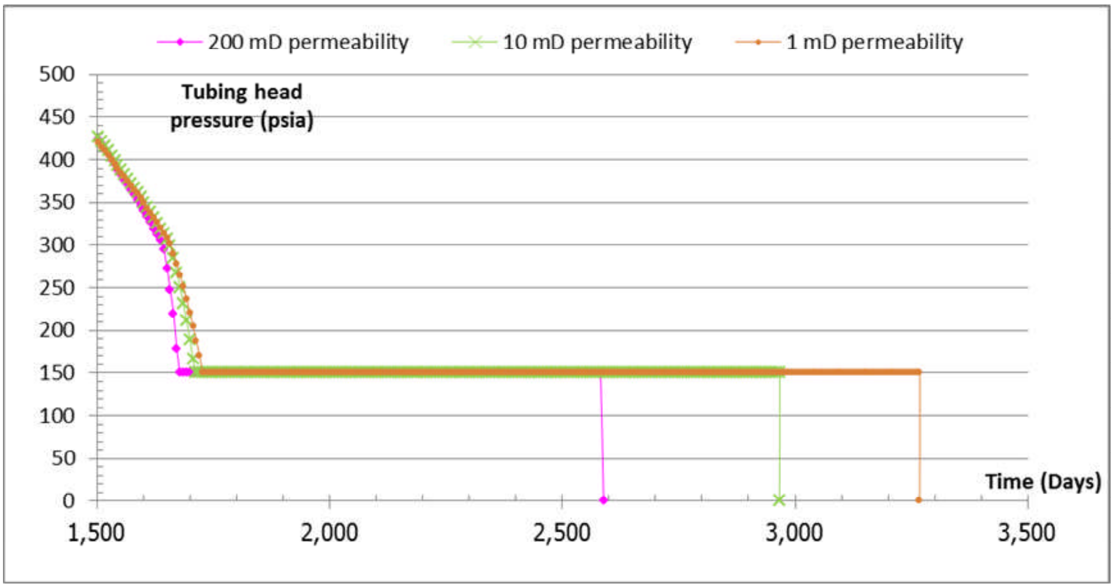


Figure 5.19: Tubing head pressure for in-situ gas lift at 7,500 ft (80 ft thick) with different permeabilities during late times

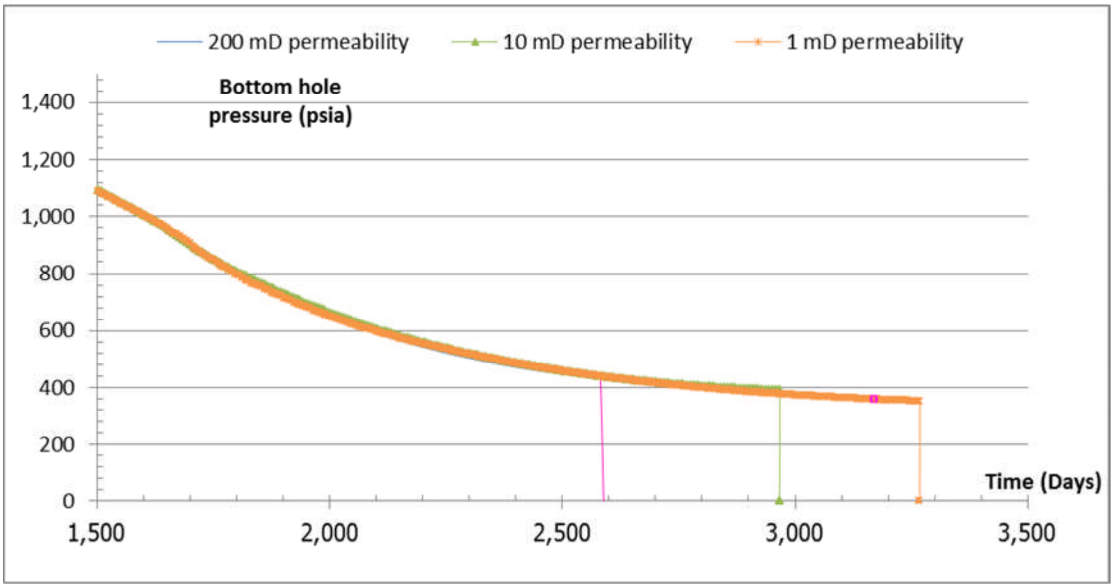


Figure 5.20: Bottom hole pressure for in-situ gas lift at 7,500 ft (80 ft thick) with different permeabilities during late times

At late time, we can see that the tubing head pressure and bottomhole pressure for all cases have similar values as depicted in Figure 5.19 and 5.20, respectively. This is because we are reaching the limiting condition in all cases. In addition, we can see that the lower permeability of the gas zone, the longer the well life. For gas zone permeability of 200, 10 and 1 mD, the well life is 2589, 2967 and 3268 days, respectively.

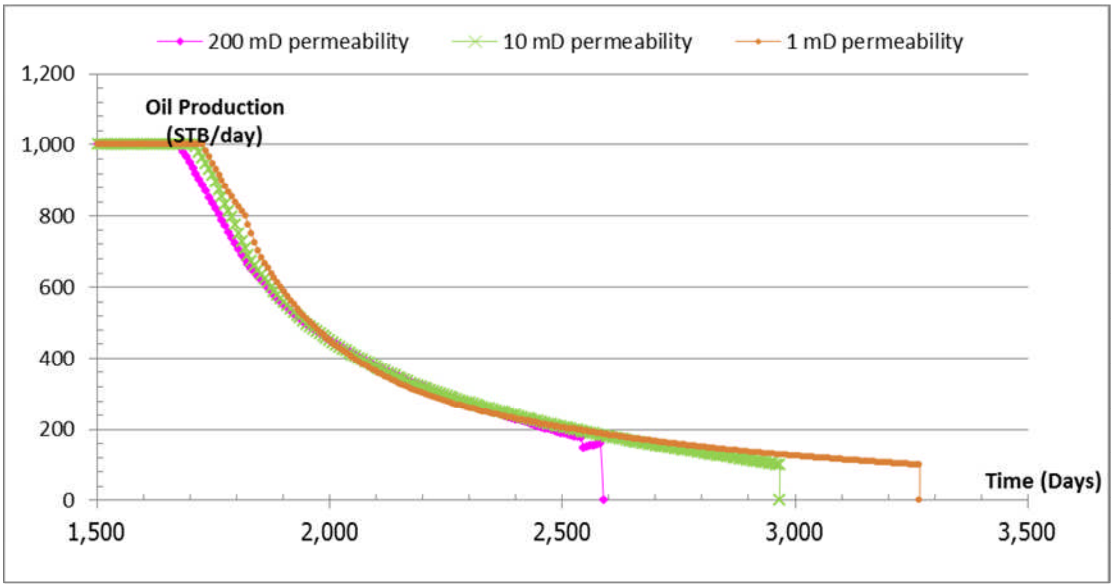


Figure 5.21: Oil production rate for in-situ gas lift at 7,500 ft (80 ft thick) with different permeabilities

5.3 Effect of Perforation Interval of Gas Zone

In order to study the effect of perforation interval of gas zone, we vary the perforation interval for gas zone thickness of 20 (perforation interval is 10 ft) and 80 ft (perforation interval is 20 ft) with permeability 1, 10 and 200 mD.

5.3.1 Gas zone at 5,500 ft

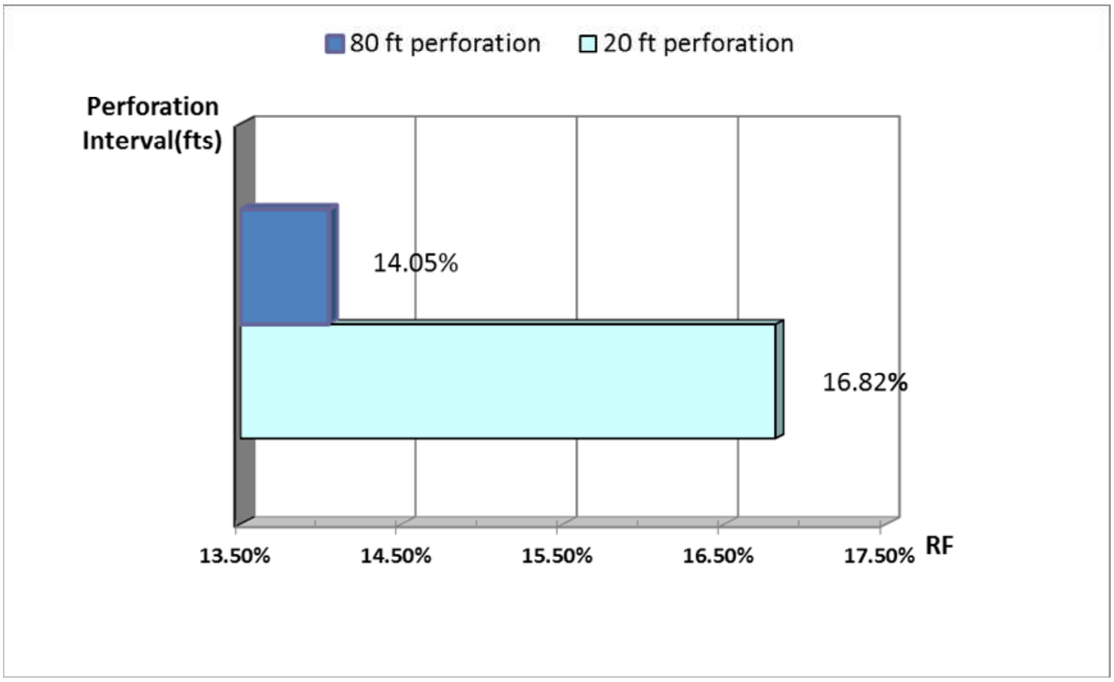


Figure 5.22: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 200 mD, 80 ft thick gas reservoir with full and partial perforation

Figure 5.22 shows the oil recovery factor for 80 ft thick gas reservoir. Note that the permeability of the gas zone is 200 mD. From Figure 5.22, it can be observed that when the perforation inteval of the gas zone decreases, the recovery factor increases. For the the case of gas zone thickness of 80 ft, there is a significant increase in recovery factor when the zone is partially perforated as perfartion 80 ft of high permeability gas reservoir obviously provides excessive GOR for in-situ gas lift.

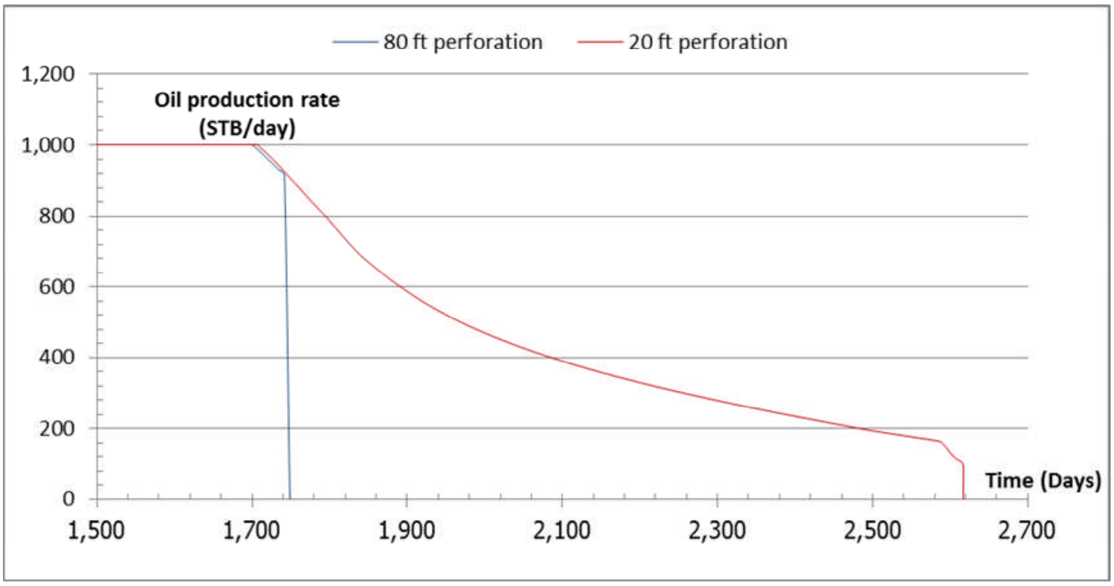


Figure 5.23: Oil production rate for in-situ gas lift by 5,500 ft deep, 200 mD, 80 ft thick gas reservoir with full and partial perforation

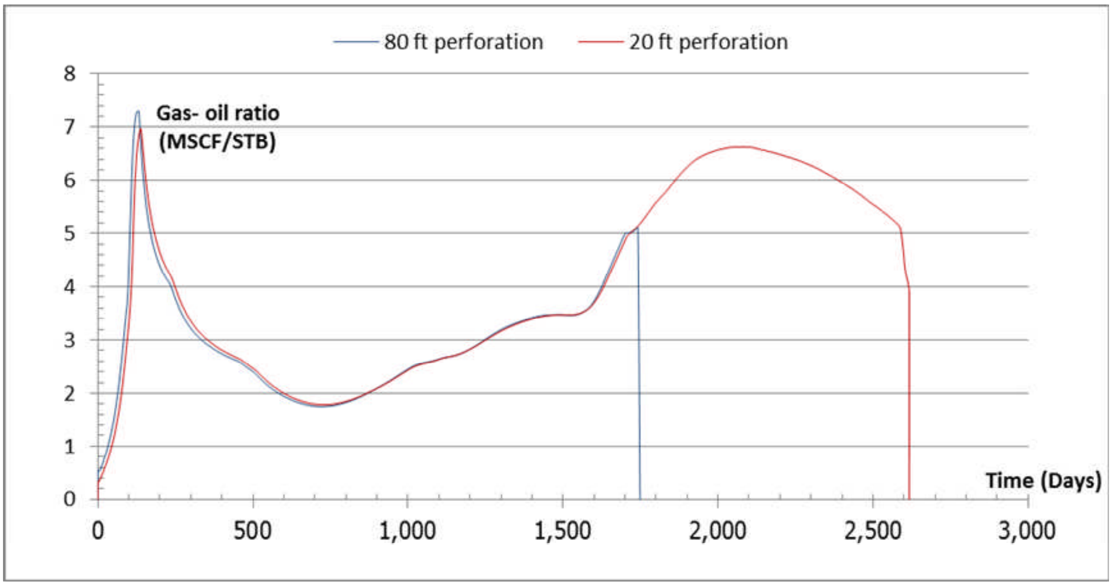


Figure 5.24: Gas-oil ratio for in-situ gas lift by 5,500 ft deep, 200 mD, 80 ft thick reservoir with full and partial perforation

Figure 5.23 depicts oil produciton rate for both case of ful and partial perforation. The oil production rate is initially 1,000 BPD. But after the oil cannot be produced at the maximum oil rate anymore, the oil production rate for the case which partial perforation is slightly higher than the one for the case with full perforation, and the well life is longer as well. This is because the partial perforation case gas zone yields a smaller amount of gas-oil ratio which is more favorable for tubing performance. As shown in Figure 5.24, gas zone with full perforation provides slighly higher gas-liquid ratio compared with partial perforation case for the first 200 days of production. High gas-liquid ratio is unfavorable at this point as it causes high friction loss. Anyway for early period till 1,500 days, GOR for both cases have almost the same trend. But for the partial perforation case, the amout of gas inside the gas zone is still more compared with that for the full perforation case at the late times. This causes the well life to be longer.

For the case of 20 ft thick gas reservoir, full and partial perforations do not yield significant difference in the results as shown in Figure 5.25. This is because the thin reservoir does not provide excessive GOR for in-situ gas lift.

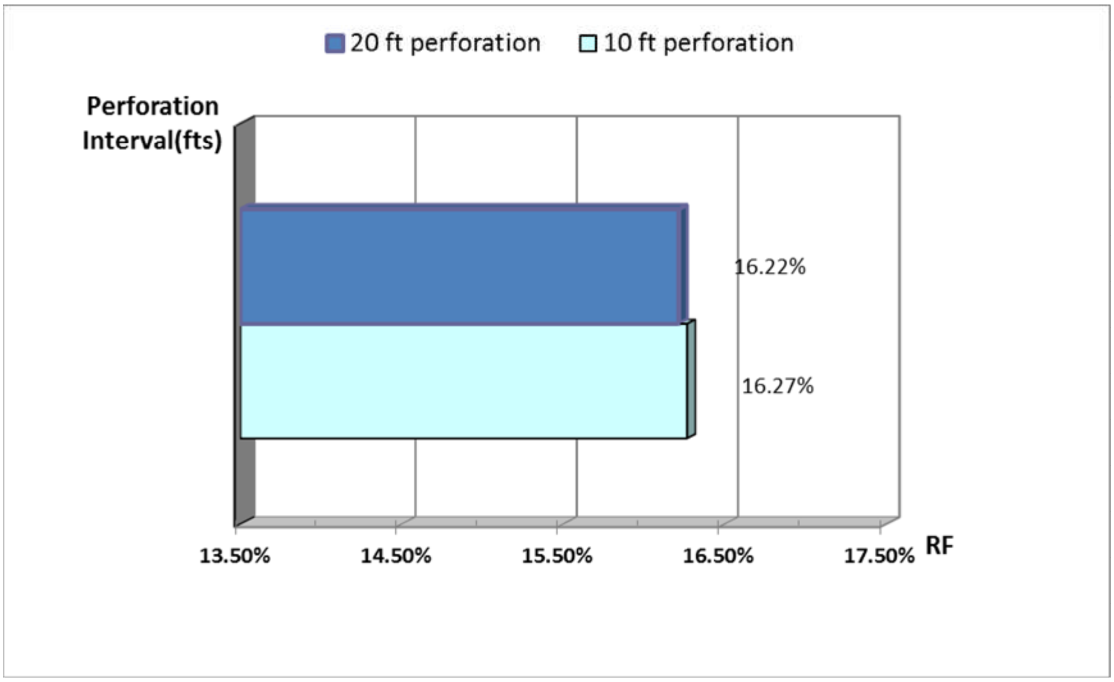


Figure 5.25: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 200 mD, 20 ft thick gas reservoir with full and partial perforation

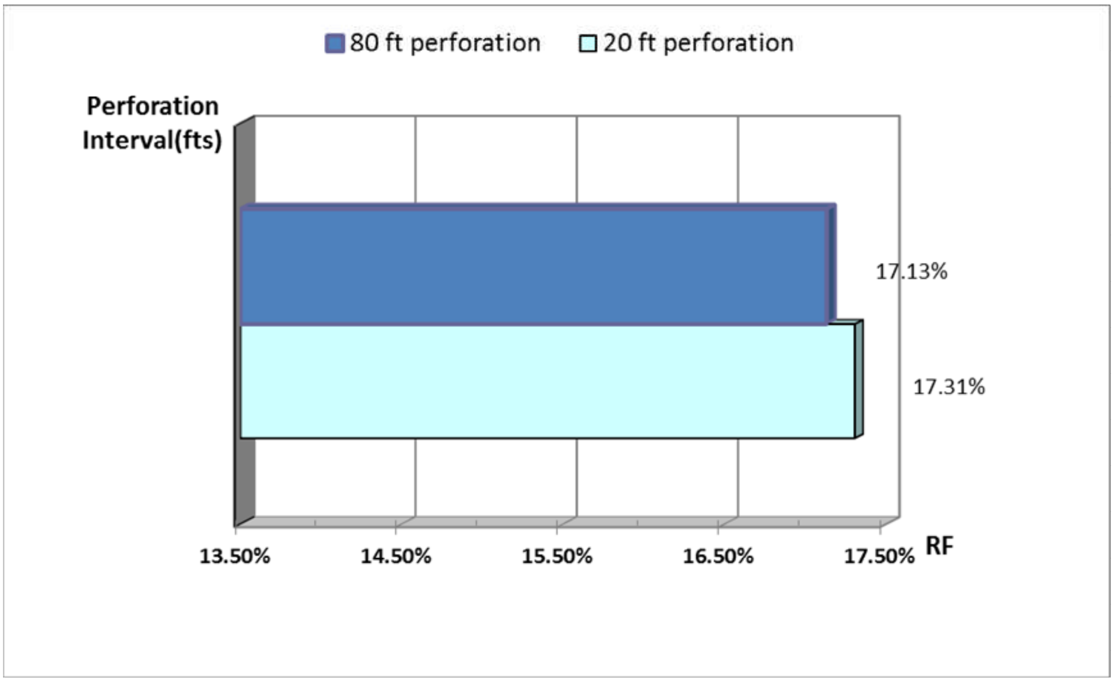


Figure 5.26: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 10 mD, 80 ft thick gas reservoir with full and partial perforation

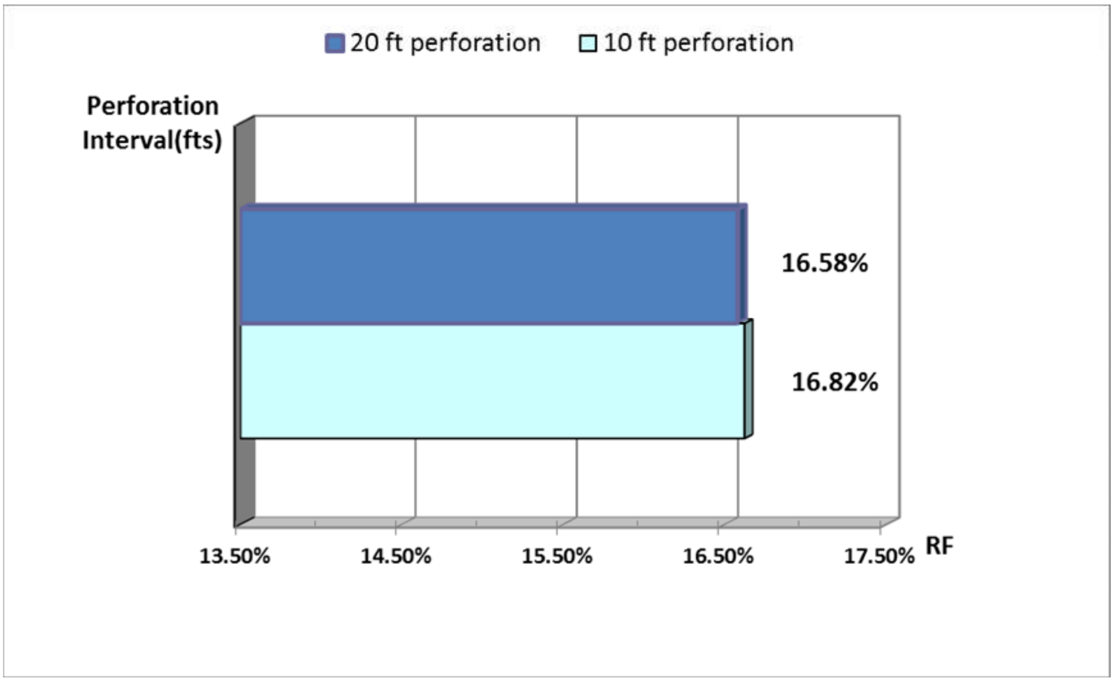


Figure 5.27: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 10 mD, 20 ft thick gas reservoir with full and partial perforation

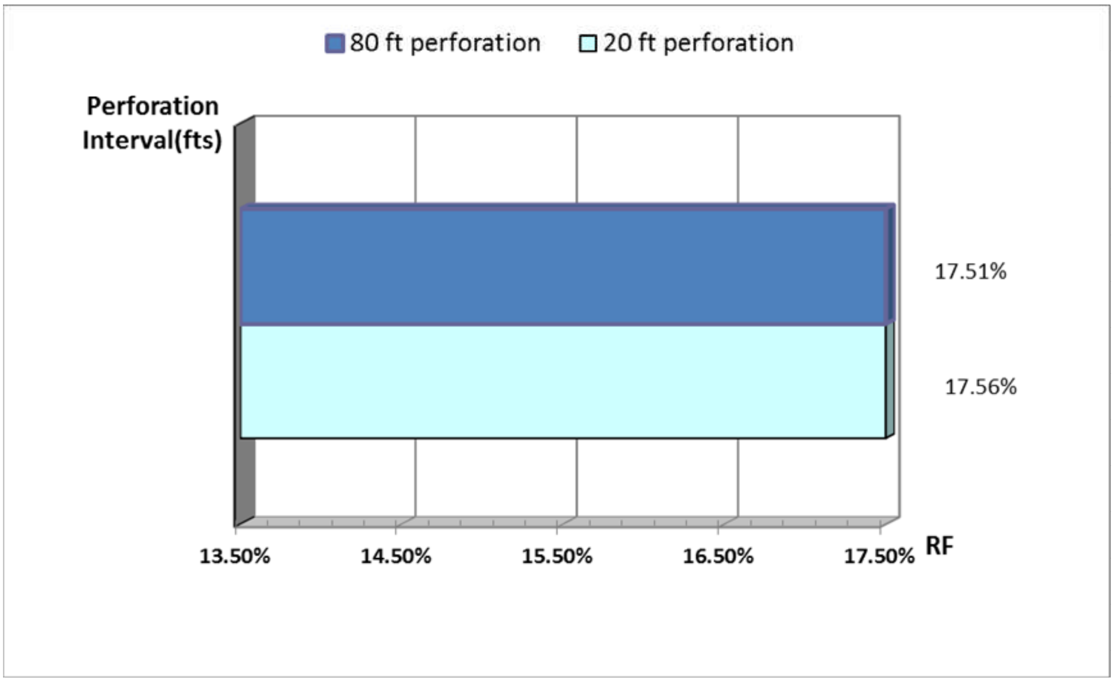


Figure 5.28: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 1 mD, 80 ft thick gas reservoir with full and partial perforation

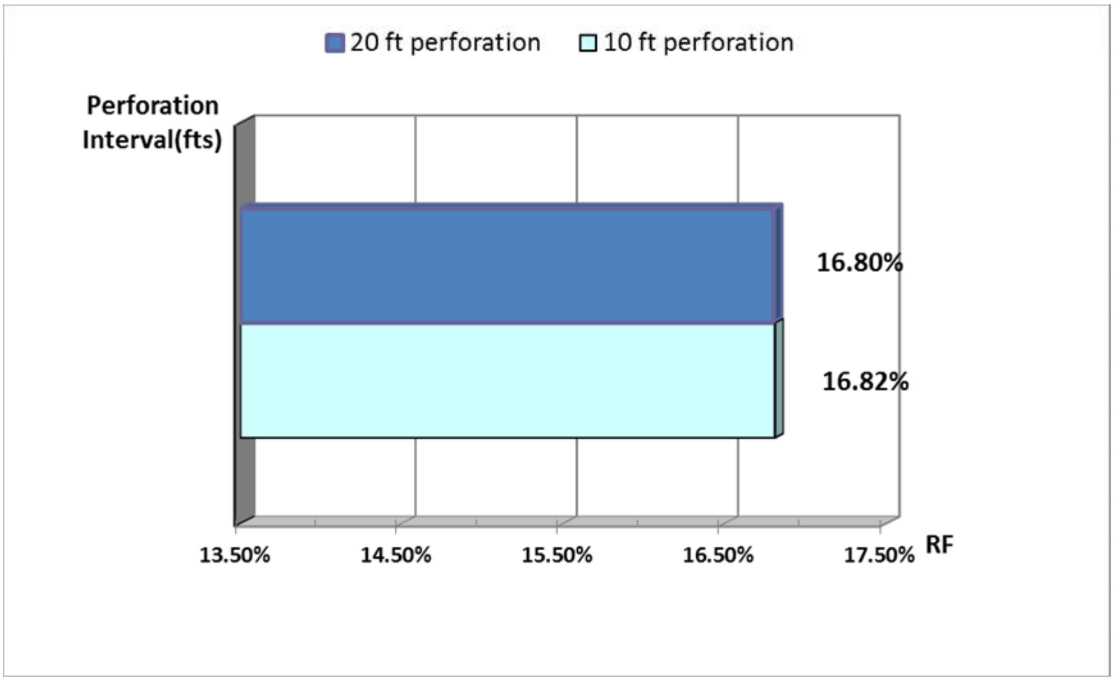


Figure 5.29: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 1 mD, 20 ft thick gas reservoir with full and partial perforation

Figures 5.26 and 5.27 respectively depict the oil recovery factor for 80 ft and 20 ft thick reservoirs having permeability of 10 mD while Figures 5.28 and 5.29 display the recovery factor for 1 mD. From Figures 5.26 to 5.29, it can be observed that when the perforation inteval of the gas zone decreases, the recovery factor increases slightly. This observation is similar with the case of 20 ft thick gas reservoir having permeability of 200 mD. In addition, we can observe that the lower the permeability the lower the difference in oil recovery factor between full and partial perforation. This is because low permeability reservoir does not release a large amount of unnecessary gas at early time even though it is fully perforated for the entire thickness in contrast to permeable resevoir that gives a lot of unnecessary gas at early time when it is fully perforated.

5.3.2 Gas zone at 6,500 ft

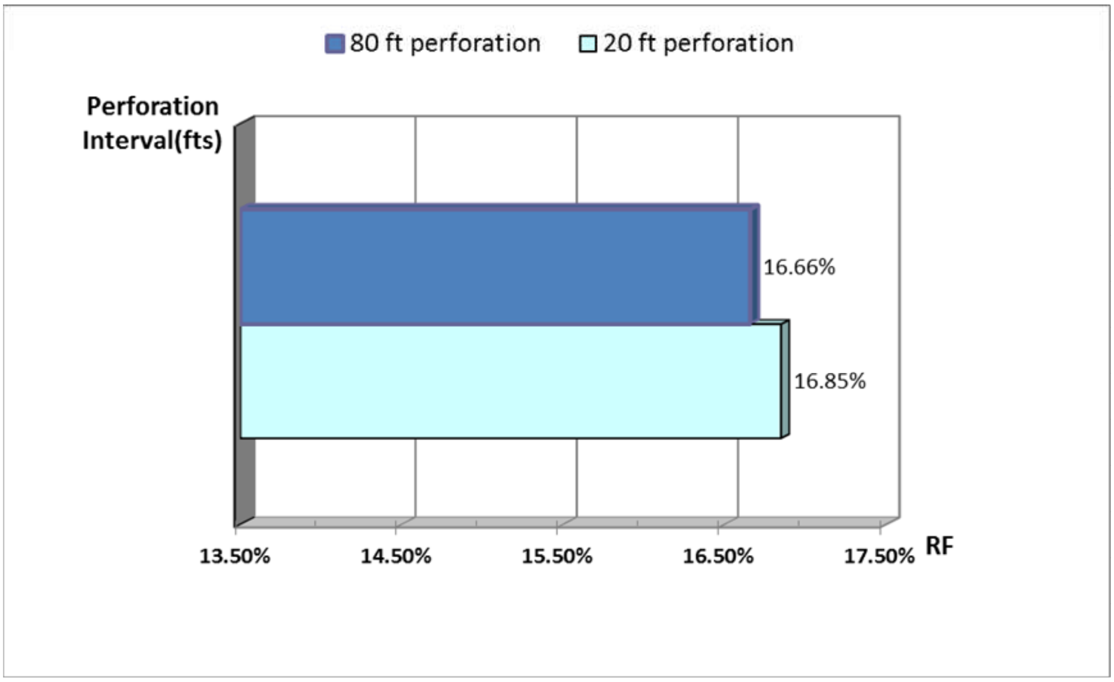


Figure 5.30: Oil recovery factor for in-situ gas lift by 6,500 ft deep, 200 mD, 80 ft thick gas reservoir with full and partial perforation

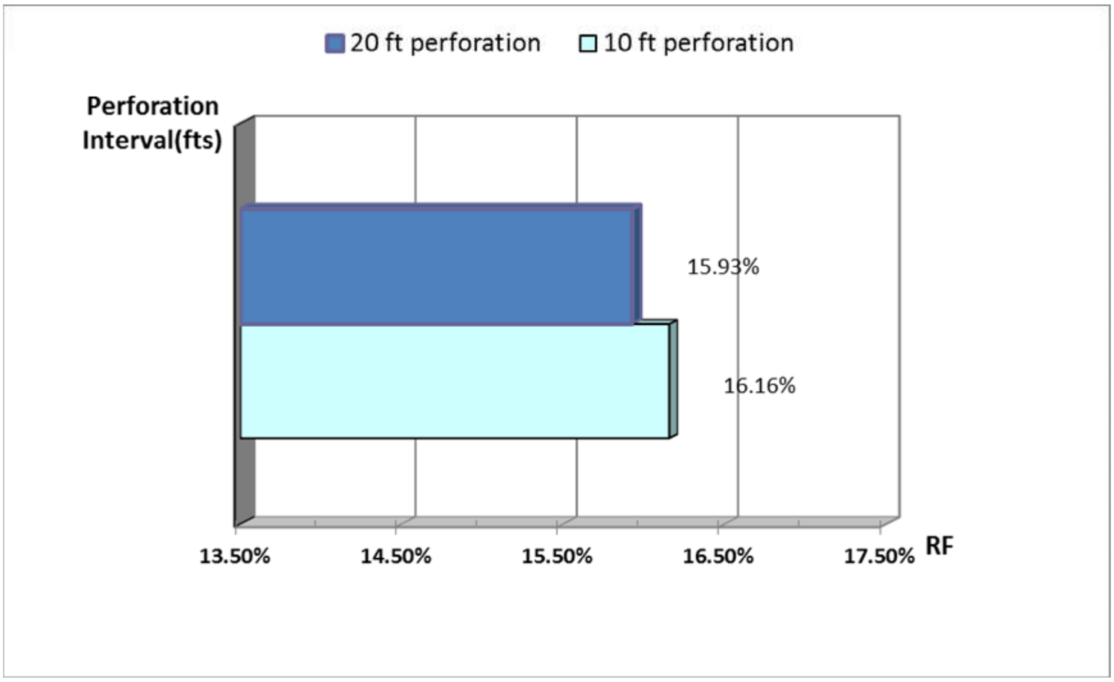


Figure 5.31: Oil recovery factor for in-situ gas lift by 6,500 ft deep, 200 mD, 20 ft thick gas reservoir with full and partial perforation

Figures 5.30 and 5.31 show the oil recovery factor for 80 ft and 20 ft thick gas reservoir, respectively. It can be observed that when the perforation inteval of the gas zone decreases, the recovery factor slightly increases. This is no significant difference in recovery factor for cases with permeability of 200 mD.

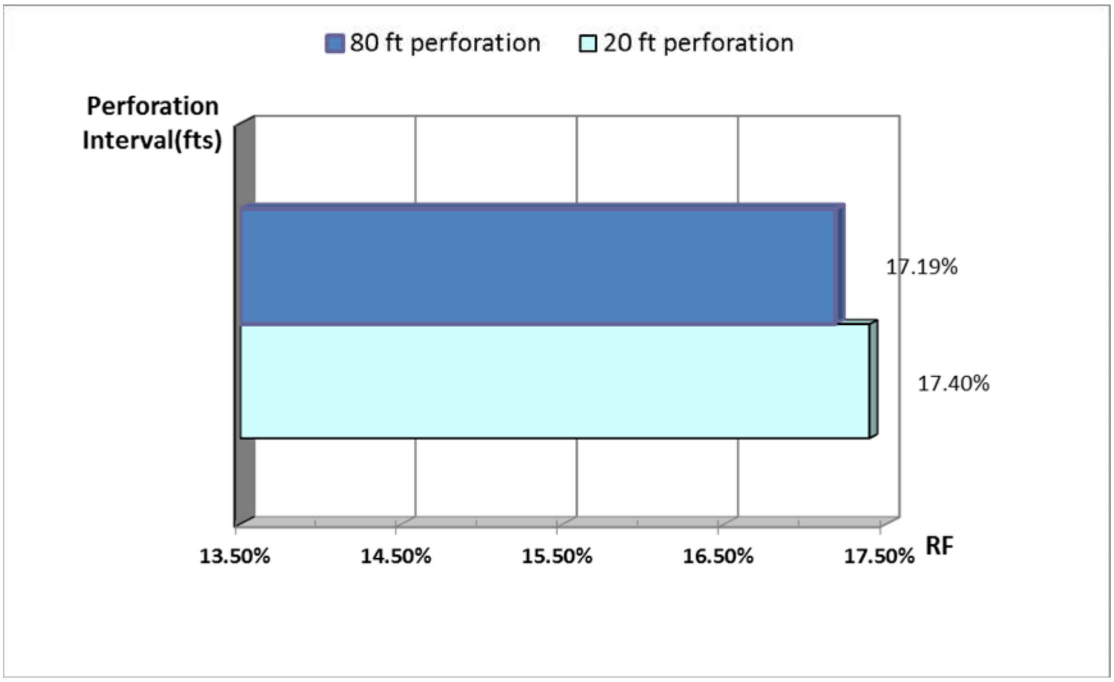


Figure 5.32: Oil recovery factor for in-situ gas lift by 6,500 ft deep, 10 mD, 80 ft thick gas reservoir with full and partial perforation

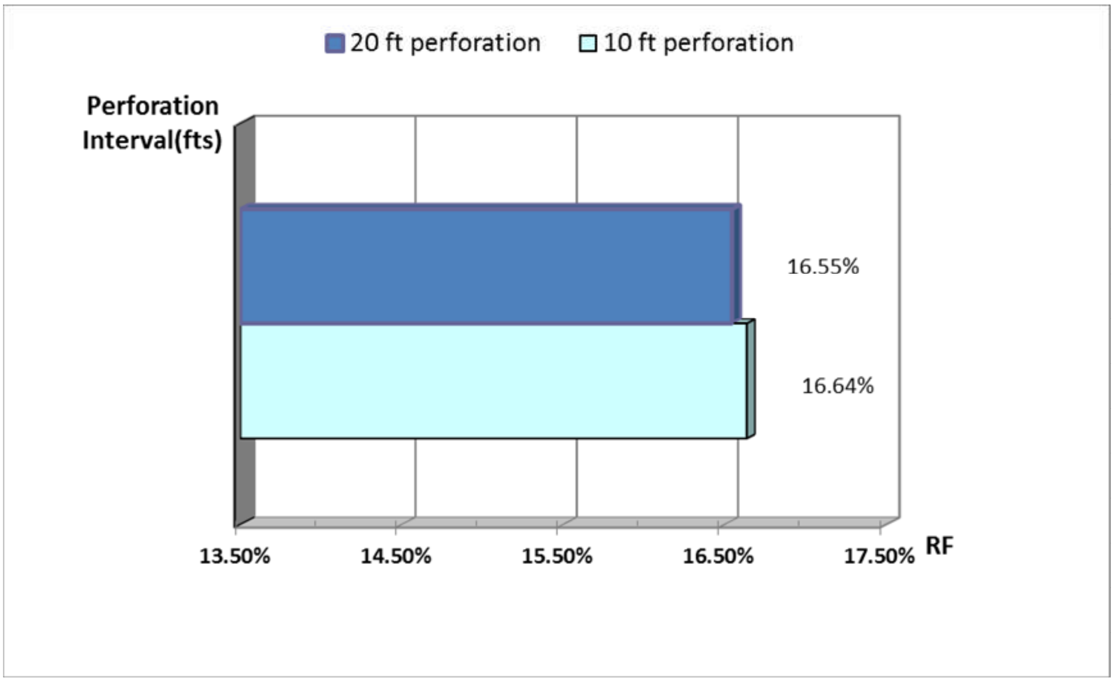


Figure 5.33: Oil recovery factor for in-situ gas lift by 6,500 ft deep, 10 mD, 20 ft thick gas reservoir with full and partial perforation

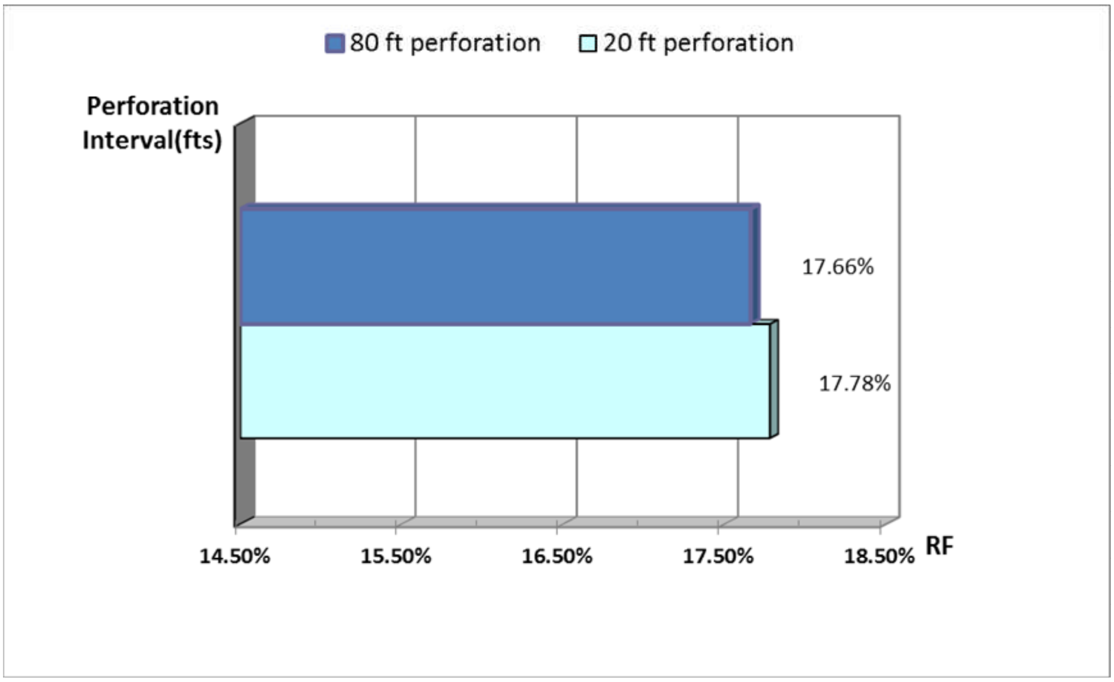


Figure 5.34: Oil recovery factor for in-situ gas lift by 6,500 ft deep, 1 mD, 80 ft thick gas reservoir with full and partial perforation

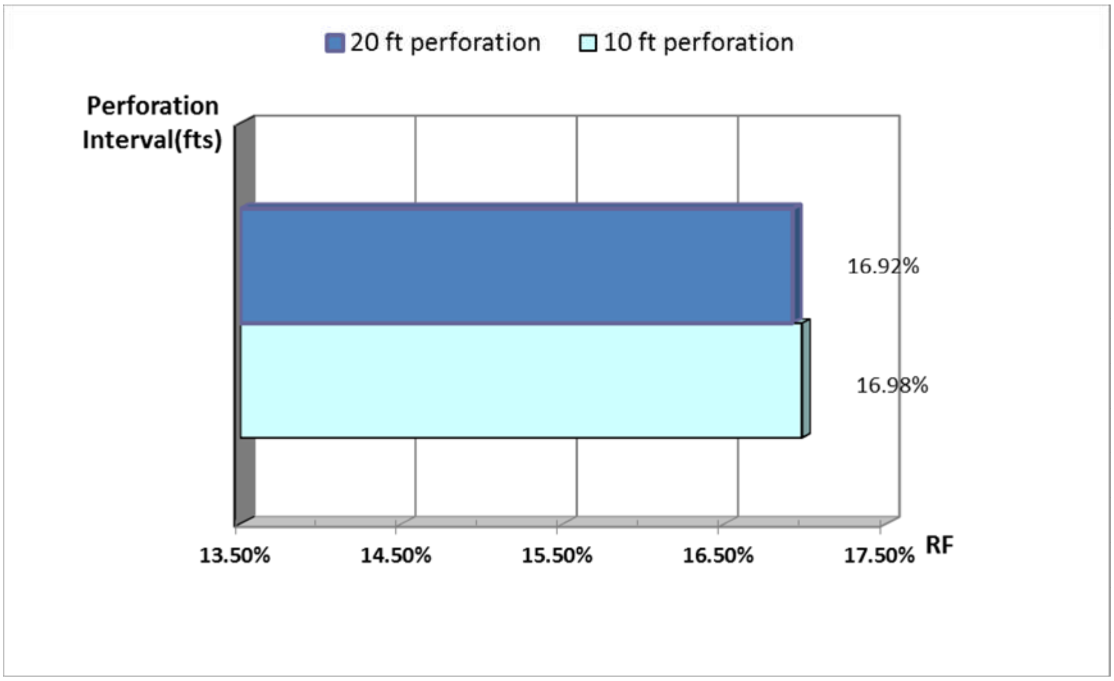


Figure 5.35: Oil recovery factor for in-situ gas lift by 6,500 ft deep, 1 mD, 20 ft thick gas reservoir with full and partial perforation

Figures 5.32 and 5.33 respectively illustrate the oil recovery factor for 80 ft and 20 ft thick reservoirs having permeability of 10 mD while Figures 5.34 and 5.35 show the recovery factor for 1 mD. From Figures 5.32 - 5.33, it can be observed that when the perforation inteval of the gas zone decreases, the recovery factor slightly increases. There is no significant difference in recovery factor for all cases with permeability of 10 and 1 mD. This observation is similar to the case of 200 mD.

5.3.3 Gas zone at 7,500 ft

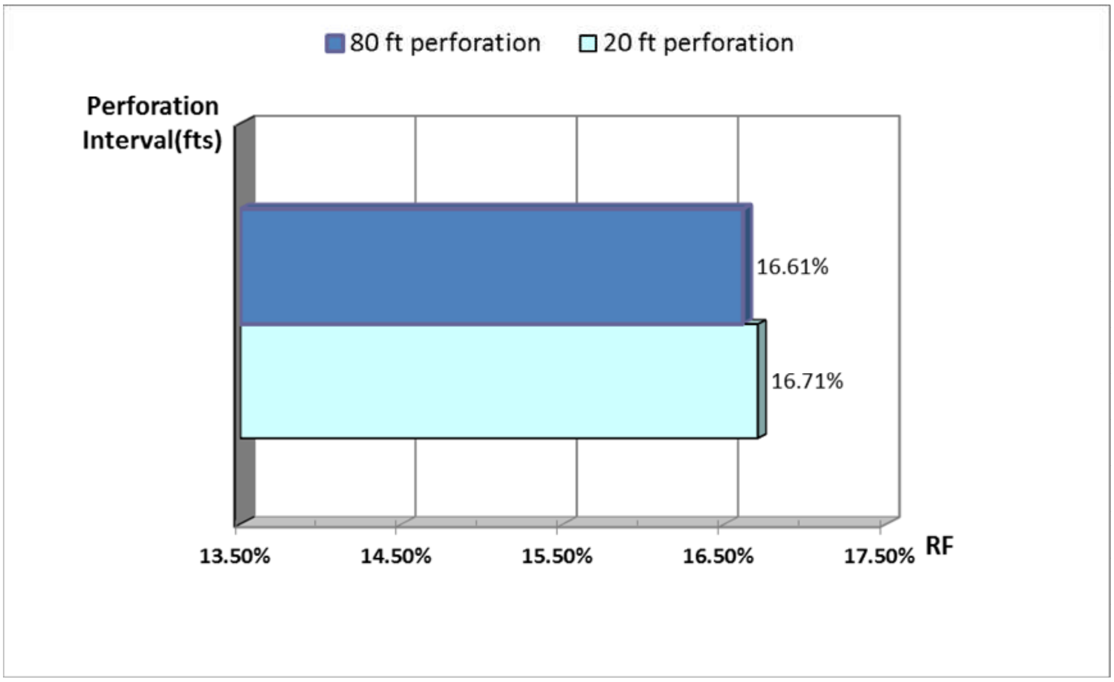


Figure 5.36: Oil recovery factor for in-situ gas lift by 7,500 ft deep, 200 mD, 80 ft thick gas reservoir with full and partial perforation

Figure 5.37 and 5.38 show the oil recovery factor for 80 ft thick gas reservoir of 200 and 10 mD, respectively, it can be observed that when the perforation inteval of the gas zone decreases, the recovery factor slightly increases. This is no significant difference in recovery factor for cases with permeability of 200 and 10 mD. Note that cases for in-situ gas lift by 7,500 ft deep, 200 and 10 mD, 20 ft thick with full and partial perforation cannot be determined due to nonconvergence in the simulation.

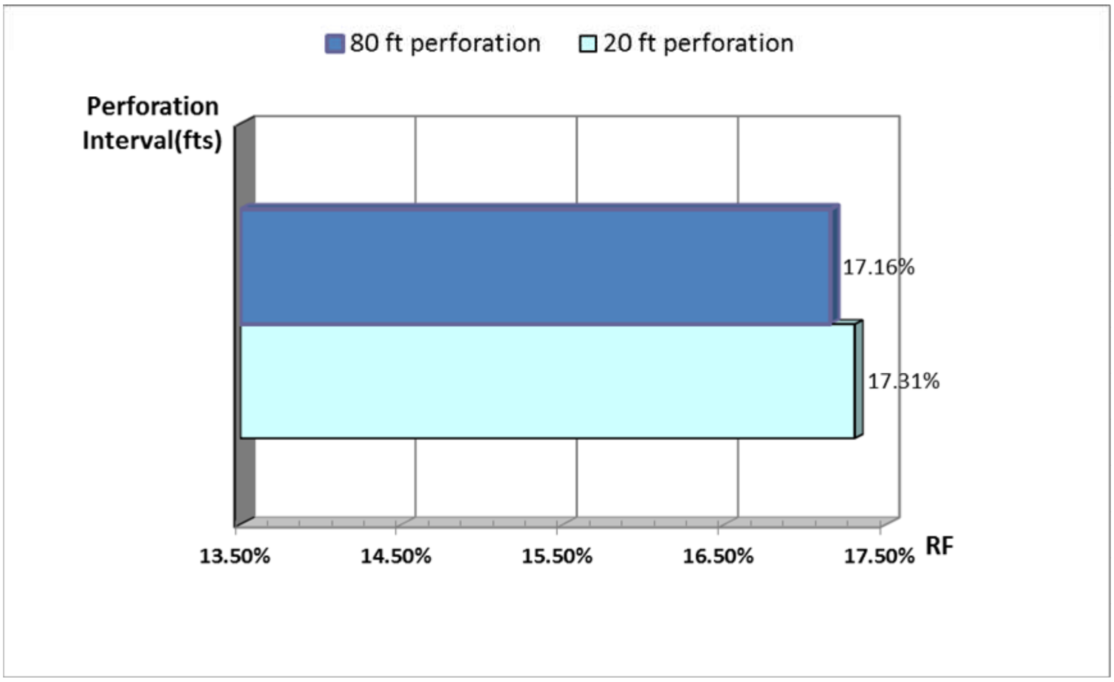


Figure 5.37: Oil recovery factor for in-situ gas lift by 7,500 ft deep, 10 mD, 80 ft thick gas reservoir with full and partial perforation

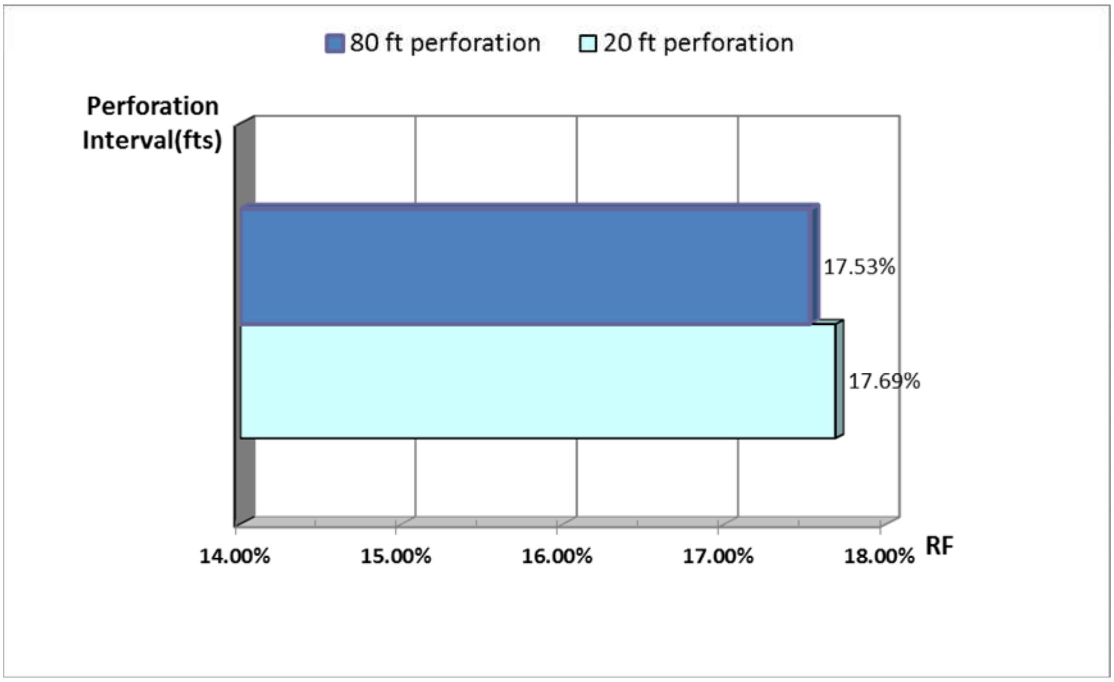


Figure 5.38: Oil recovery factor for in-situ gas lift by 7,500 ft deep, 1 mD, 80 ft thick gas reservoir with full and partial perforation

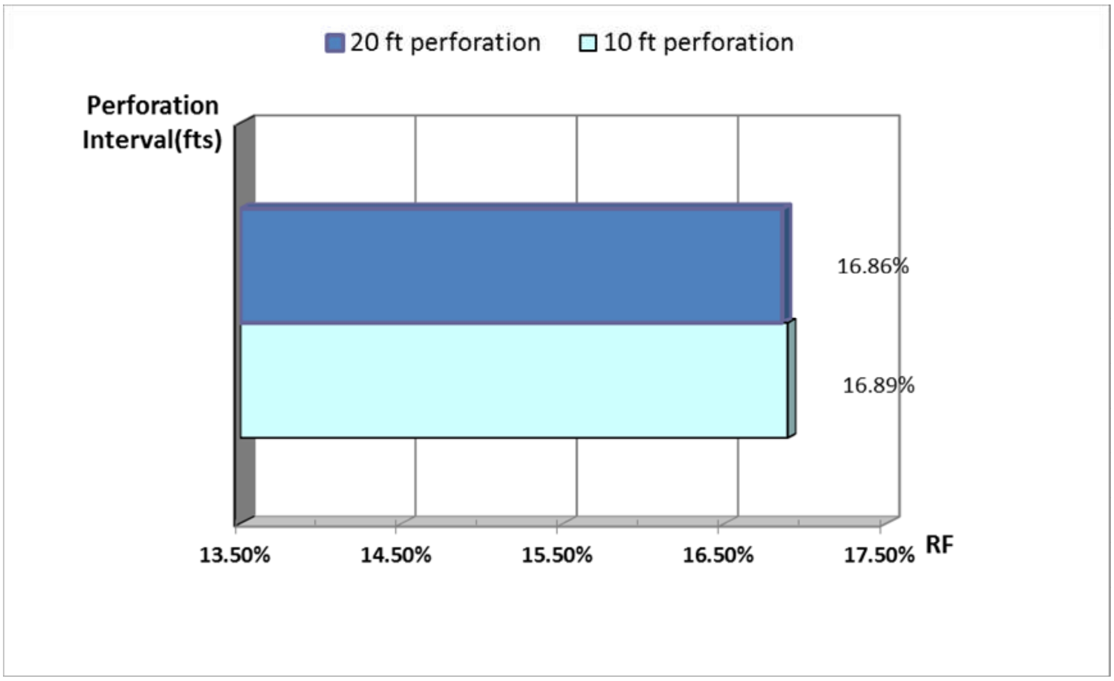
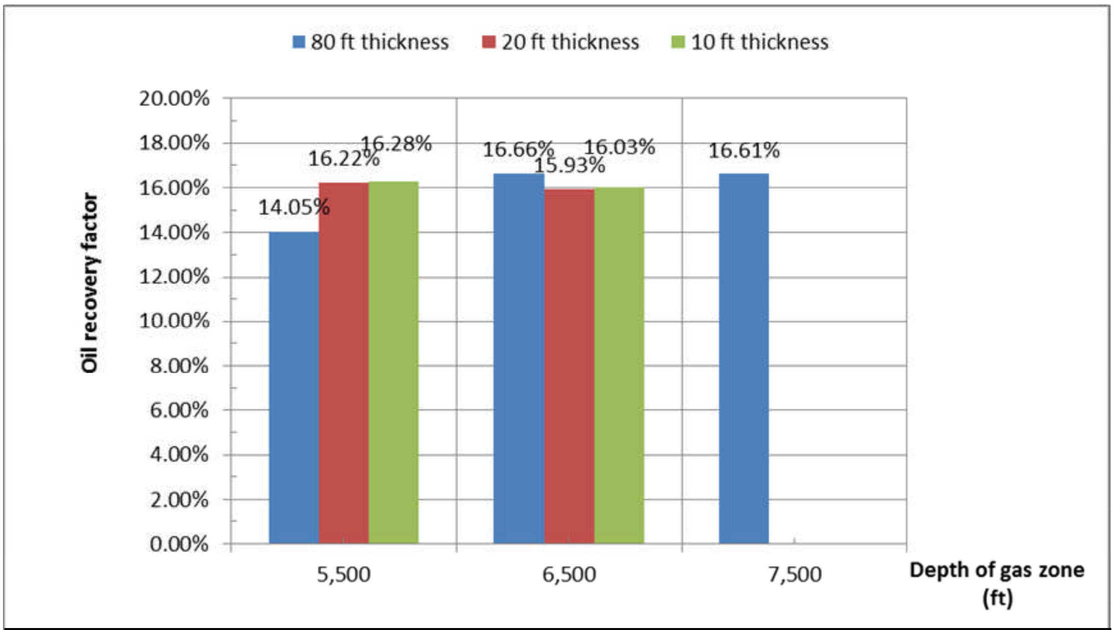


Figure 5.39: Oil recovery factor for in-situ gas lift by 7,500 ft deep, 1 mD, 20 ft thick gas reservoir with full and partial perforation

Figures 5.38 and 5.39 respectively show the oil recovery factor for 80 ft and 20 ft thick reservoirs having permeability of 1 mD. From Figures 5.38 - 5.39, it can be observed that when the perforation inteval of the gas zone decreases, the recovery factor slightly increases. There is no significant difference in recovery factor for all cases with permeability of 1 mD. This observation is similar to the case of 200 mD.

5.4 Effect of Depth of Gas Zone

5.4.1 Gas zone permeability of 200 mD



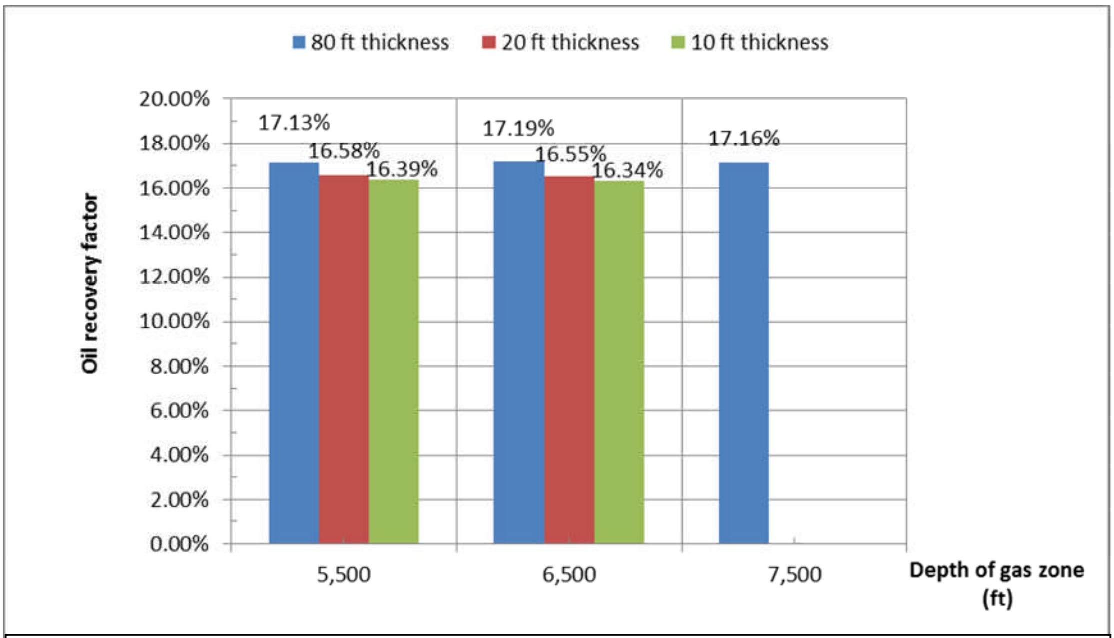
Note: RF for the cases of 20 and 10 ft thick gas reservoir at depth 7,500 ft cannot be determined due to nonconvergence in the simulation.

Figure 5.40: Oil recovery factor for in-situ gas lift by 200 mD permeability with different depths of gas zone

Figure 5.40 shows the oil recovery factor for 80 ft, 20 and 10 ft thick gas reservoirs having permeability of 200 mD with different depths of gas reservoir. As seen in the figure, there is no significant difference in oil recovery factor among the cases except for the case of 80-ft gas reservoir at 5,500 ft. In this case, gas from the gas zone flows into the wellbore at high flow rate due to low bottomhole pressure at 5,500 ft (in comparison to 6,500 and 7,500 ft) and large thickness. This high amount of gas causes the GOR to be too high for gas lift, thus resulting in a lower recovery in comparison to other cases.

5.4.2 Gas zone permeability of 10 mD

Figure 5.41 shows the oil recovery factor for 80 ft, 20 and 10 ft thick gas reservoirs having permeability of 10 mD with different depths of gas reservoir. From Figure 5.41, the recovery oil factor in the deeper gas bearing zone the lower oil recovery factor. This is no significant difference in recovery factor for cases with permeability of 10 mD. The effect of higher thickness of gas zone makes to oil recovery factor more than the effect of deeper gas bearing zone.

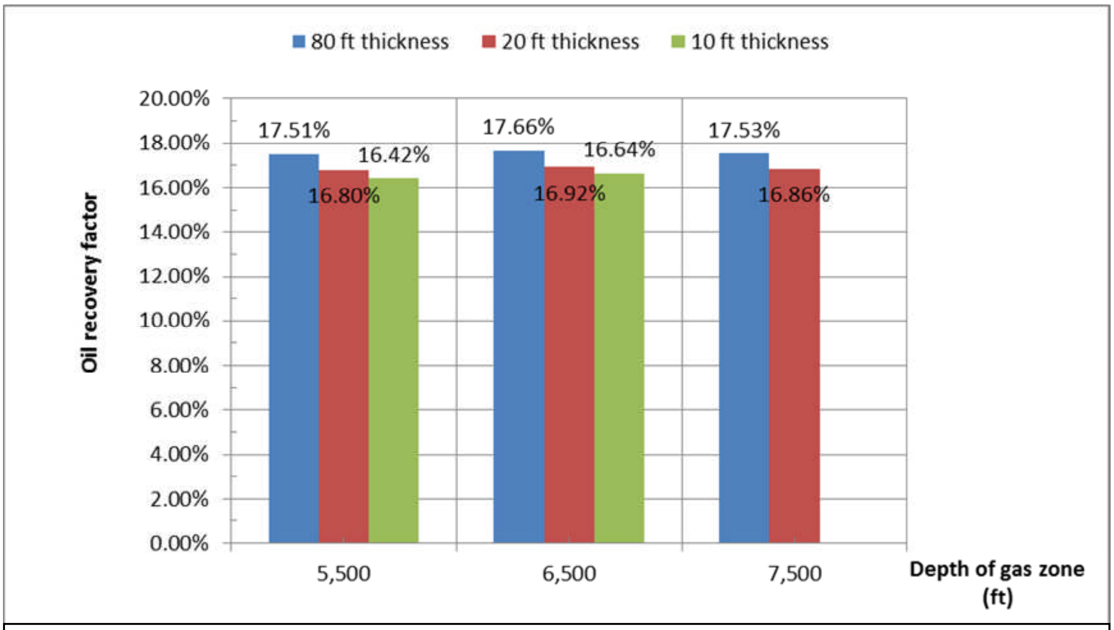


Note: RF for the cases 20 and 10 ft thick gas reservoir at depth 7,500 ft cannot be determined due to nonconverge in the simulation.

Figure 5.41: Oil recovery factor for in-situ gas lift by 10 mD permeability with different depth of gas zone

5.4.3 Gas zone permeability of 1 mD

Figure 5.42 depicts the oil recovery factor for 80 ft, 20 and 10 ft thick gas reservoirs having permeability of 1 mD with different depths of gas reservoir. Again, there is no significant difference in recovery factor for all cases.



Note: RF for the cases of 10 ft thick gas reservoir at depth 7,500 ft cannot be determined due to nonconvergence in the simulation.

Figure 5.42: Oil recovery factor for in-situ gas lift by 1 mD permeability with different depths of gas zone

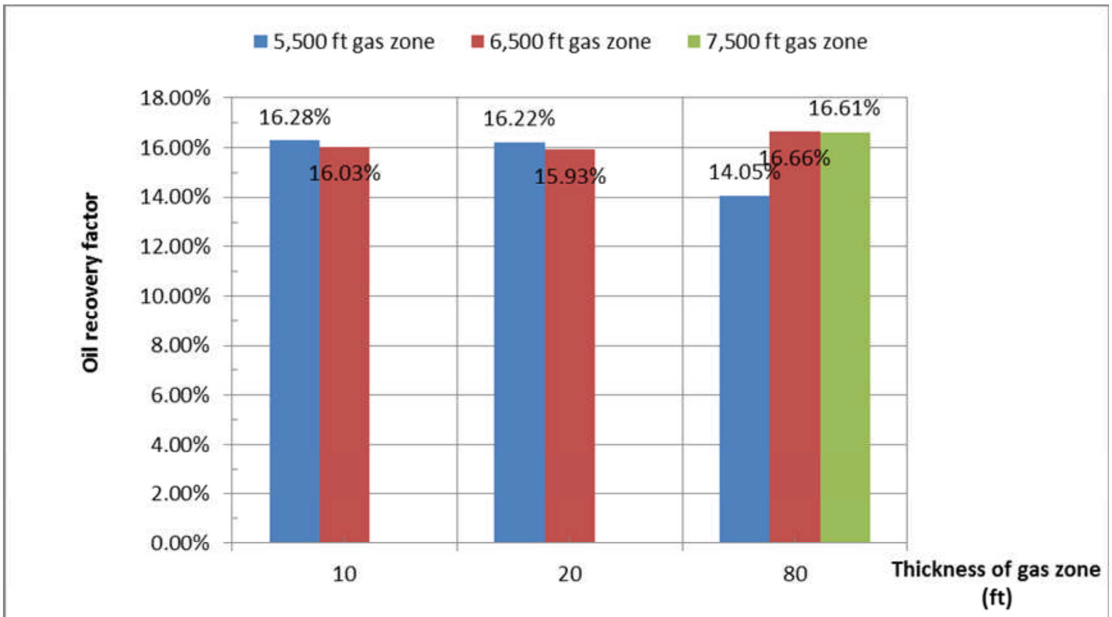
In summary, depth of in-situ gas zone does not affect the recovery factor except for the case of 200 mD, 80-ft gas reservoir. In this case, the deeper the gas zone, the higher the oil recovery.

5.5 Effect of Thickness of Gas Zone

In this section, gas zone thickness of 10, 20 and 80 ft are varied in order to study the effect of thickness of gas zone to oil recovery factor.

5.5.1 Gas zone permeability of 200 mD

Figure 5.43 shows the oil recovery for cases with gas zone permeability 200 mD having different thicknesses of gas zone at depth 5,500, 6,500 and 7,500 ft. As seen in the figure, there is no significant difference in oil recovery factor among the cases except for the case of 80-ft gas reservoir at 5,500 ft. In this case, gas from the gas zone flows into the wellbore at high flow rate due to low bottomhole pressure at 5,500 ft (in comparison to 6,500 and 7,500 ft) and large thickness. This high amount of gas causes the GOR to be too high for gas lift, thus resulting in a lower recovery in comparison to other cases.

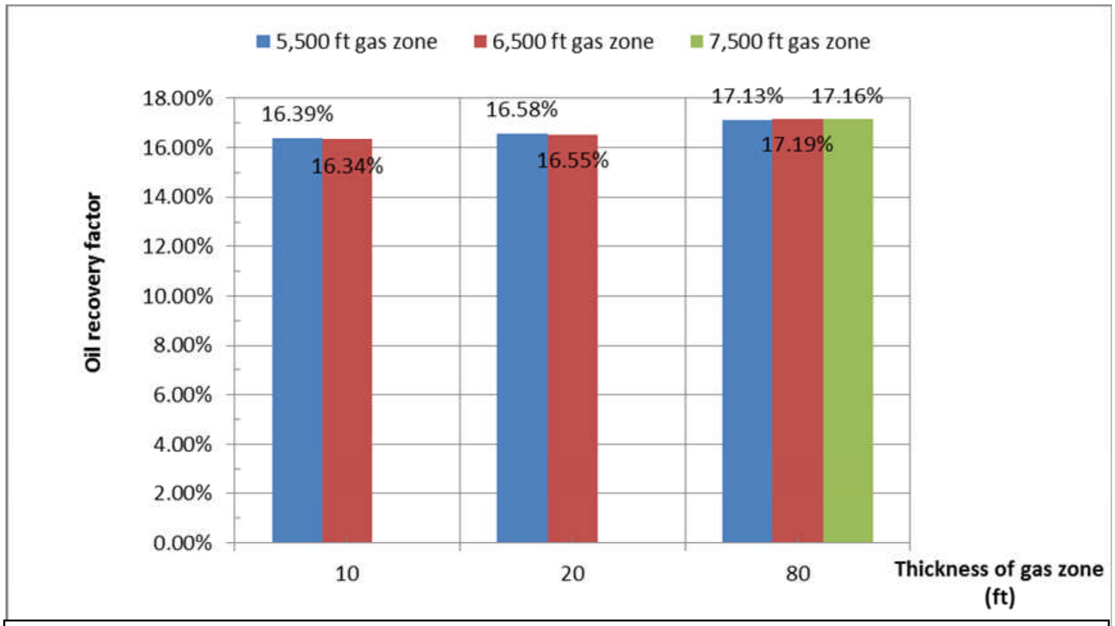


Note: RF for the cases of 20 and 10 ft thick gas reservoir at depth 7,500 ft cannot be determined due to nonconvergence in the simulation.

Figure 5.43: Oil recovery factor for in-situ gas lift at permeability of gas zone 200 mD with different thicknesses of gas zone

5.5.2 Gas zone permeability of 10 mD

Figure 5.44 shows the oil recovery for cases with gas zone permeability 10 mD having different thicknesses of gas zone at depth 5,500, 6,500 and 7,500 ft. There is no significant difference in recovery factor in cases with different depths of gas zone, although there is a slight increase in recovery factor when thickness increases.

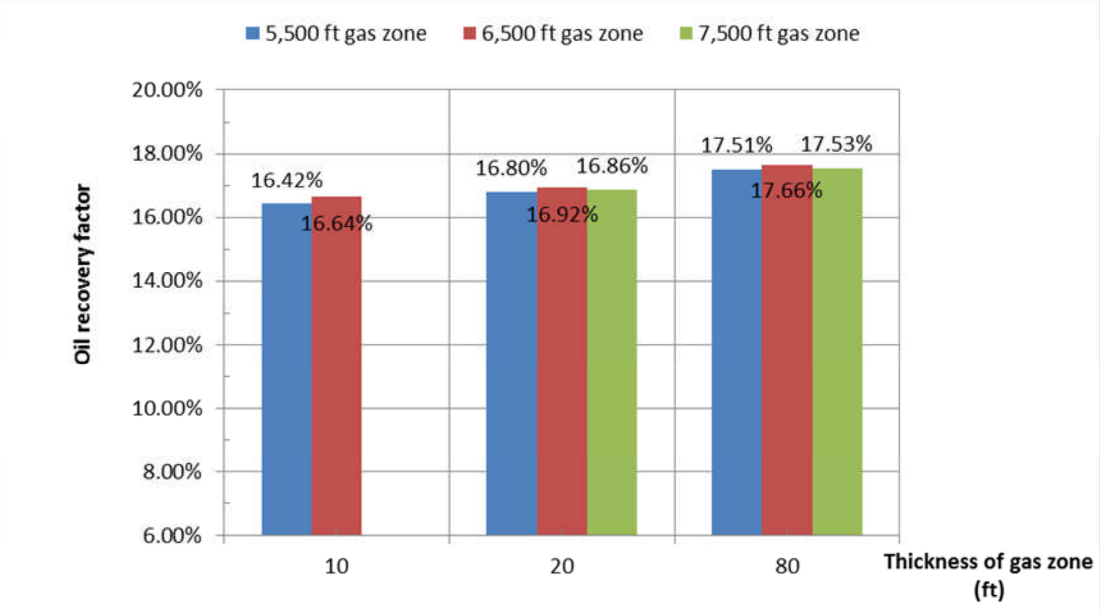


Note: RF for the cases of 20 and 10 ft thick gas reservoir at depth 7,500 ft cannot be determined due to nonconvergence in the simulation.

Figure 5.44: Oil recovery factor for in-situ gas lift at permeability of gas zone 10 mD with different thicknesses of gas zone

5.5.3 Gas zone permeability of 1 mD

Figure 5.45 shows the oil recovery for cases with gas zone permeability 1 mD having different thickness of gas zone at depth 5,500, 6,500 and 7,500 ft. There is no significant difference in recovery factor for cases with different depth of gas zone, although there is a slight increase in recovery factor when thickness increases.



Note: RF for the cases of 10 ft thick gas reservoir at depth 7,500 ft cannot be determined due to nonconvergence in the simulation.

Figure 5.45: Oil recovery factor for in-situ gas lift at permeability of gas zone 1 mD with different thicknesses of gas zone

5.6 Effect of Aquifer

In this section, aquifer, size of 10 time of oil zone is added in to reservoir model for the oil zone at depth 5,000 ft. In order to study the effect of aquifer to oil recovery factor, we vary the gas zone thickness of 10, 20 and 80 ft with the permeability 1, 10 and 200 md.

5.6.1 Gas zone at 5,500 ft and 80 ft thick

Figure 5.46 displays the oil recovery factor for in-situ gas lift by gas bearing zone at depth 5,500 ft, thickness of 80 ft with and without aquifer. From Figure 5.46, it can be observed that with aquifer support the oil recovery factory decreases for all different permeability cases. In addition, when the permeability of the gas zone decreases, the recovery factor increases for all cases including the cases which have thickness of 80 ft. This trend is the same for both cases with and without aquifer support.

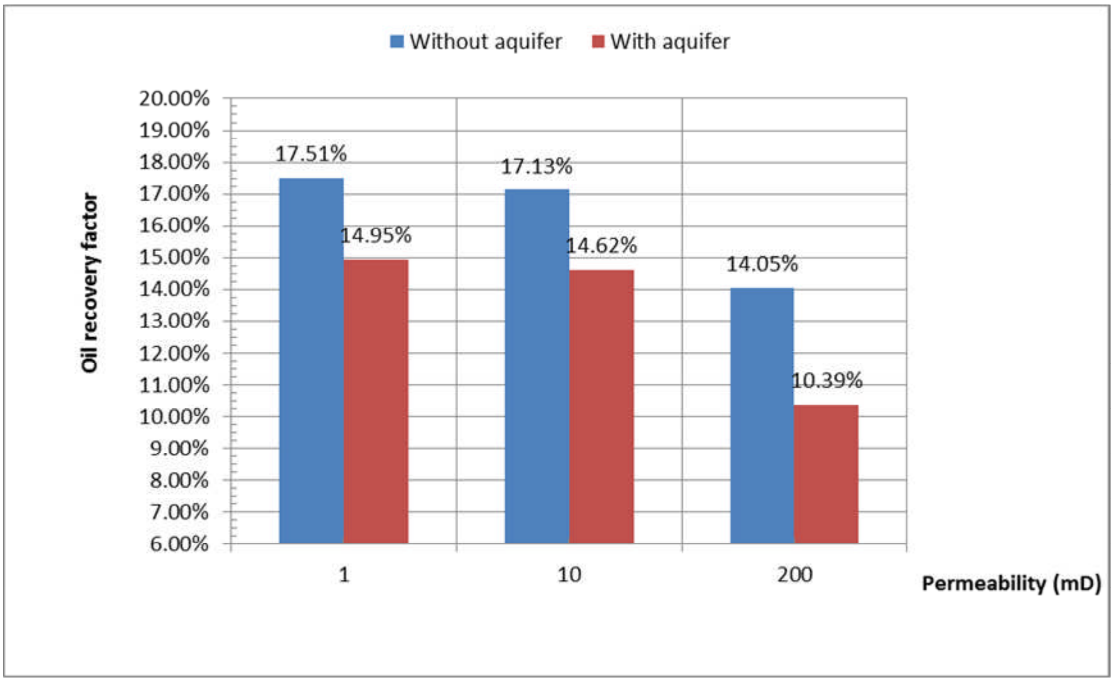


Figure 5. 46: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 80 ft thick gas reservoir

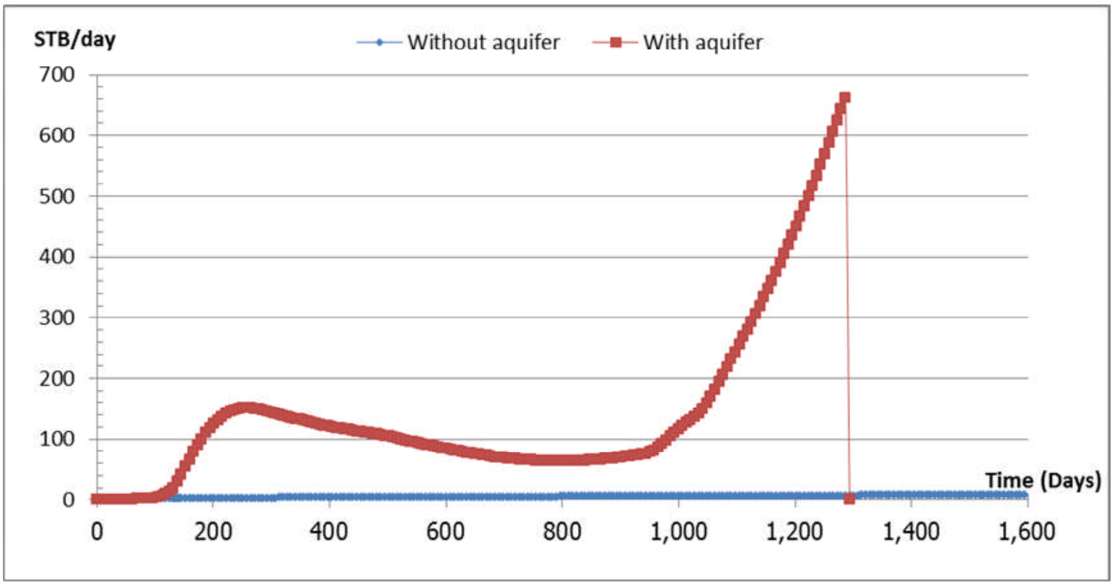
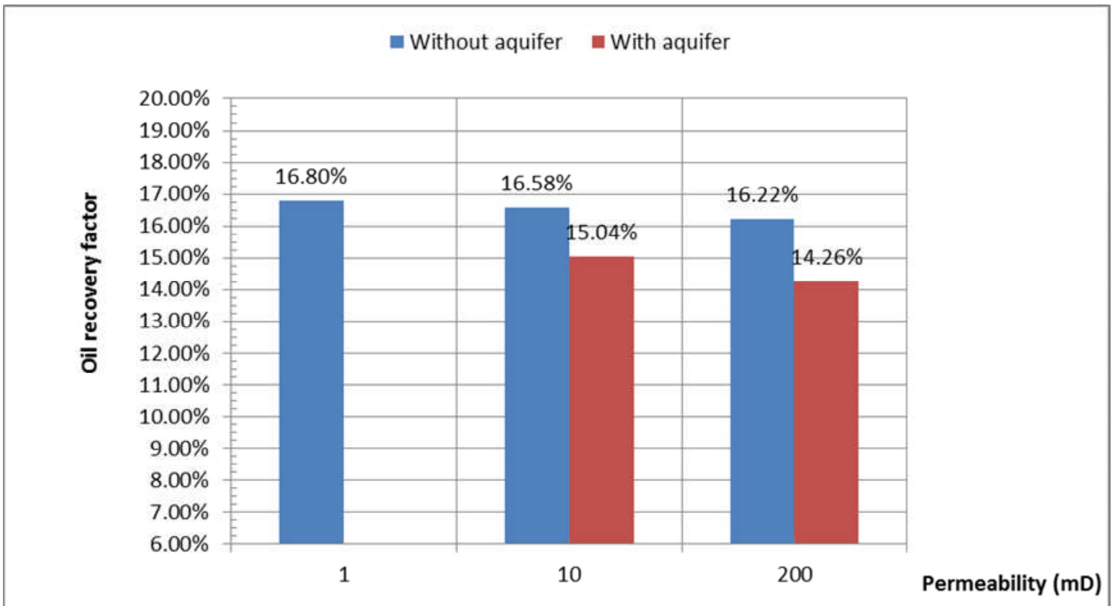


Figure 5.47: Water production rate for in-situ gas lift lift by 5,500 ft deep, 200 mD, 80 ft thick gas reservoir

Figure 5.47 shows the water produciton rate compared between cases with and without aquifer for the same permeability of gas zone, 200 mD. The higher water production rate causes the oil recovery factor to decrease compared with cases without aquifer because of the higher hydrostatic load while the amount of gas in gas bearing zone is the same.

5.6.2 Gas zone at 5,500 ft and 20 ft thick

Figure 5.48 shows the oil recovery factor for in-situ gas lift by gas bearing zone at depth 5,500 ft, thickness of 20 ft with and without aquifer. From Figure 5.48, it can be observed that with aquifer support the oil recovery factory decreases for all different permeability cases. This observation is the same as the one in Section 5.6.1.



Note: RF for the cases of 1 mD, 20 ft thickness with aquifer cannot be determined due to nonconvergence in the simulation.

Figure 5.48: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 20 ft thick gas reservoir

5.6.3 Gas zone at 5,500 ft and 10 ft thick

Figure 5.49 depicts the oil recovery factor for in-situ gas lift by gas bearing zone at depth 5,500 ft, thickness of 10 ft with and without aquifer. From Figure 5.49, it can be observed that with aquifer support the oil recovery factory decreases for all different permeability cases. This observation is the same as in Section 5.6.1 and 5.6.2.

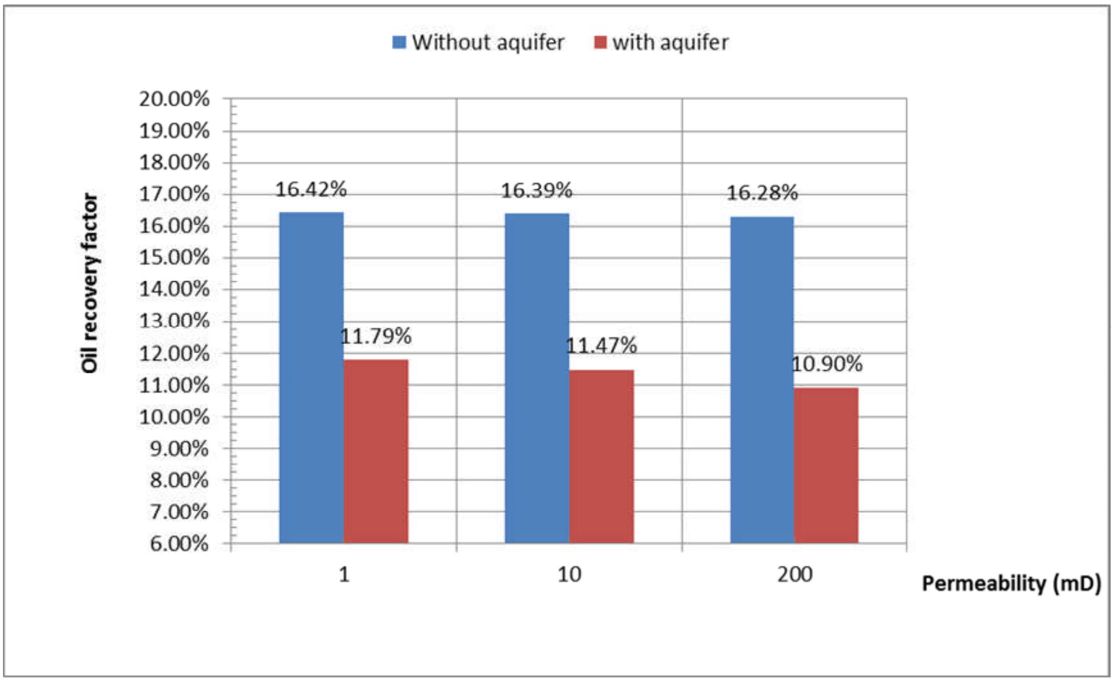


Figure 5.49: Oil recovery factor for in-situ gas lift by 5,500 ft deep, 10 ft thick gas reservoir

Table 5.1: Summary of results from all scenarios except aquifer cases

Gas Depth (ft)	Interval (ft)	K @ gas zone (md)	Time (days)	Total ROE
5500	80	1	3,233	17.51%
5500	80	10	2,918	17.13%
5500	80	200	1,749	14.05%
5500	20 from 80	1	3,261	17.56%
5500	20 from 80	10	3,065	17.31%
5500	20 from 80	200	2,616	16.82%
6500	80	1	3,408	17.66%
6500	80	10	2,981	17.19%
6500	80	200	2,526	16.66%
6500	20 from 80	1	3,485	17.78%
6500	20 from 80	10	3,170	17.40%
6500	20 from 80	200	2,666	16.85%
7500	80	1	3,268	17.53%
7500	80	10	2,967	17.16%
7500	80	200	2,589	16.61%
7500	20 from 80	1	3,394	17.69%
7500	20 from 80	10	3,072	17.31%
7500	20 from 80	200	2,610	16.71%
5500	20	1	2,652	16.80%
5500	20	10	2,484	16.58%
5500	20	200	2,246	16.22%
6500	20	1	2,715	16.92%
6500	20	10	2,428	16.55%
6500	20	200	2,120	15.93%
7500	20	1	2,680	16.86%
7500	20	10	Nonconvergence	
7500	20	200		
5500	10 from 20	1	2,666	16.81%
5500	10 from 20	10	2,498	16.62%
5500	10 from 20	200	2,274	16.27%
6500	10 from 20	1	2,764	16.98%
6500	10 from 20	10	2,498	16.64%
6500	10 from 20	200	2,211	16.16%
7500	10 from 20	1	2,708	16.89%
7500	10 from 20	10	Nonconvergence	
7500	10 from 20	200		
5500	10	1	2,379	16.42%
5500	10	10	2,365	16.39%
5500	10	200	2,309	16.28%
6500	10	1	2,484	16.64%
6500	10	10	2,323	16.34%
6500	10	200	2,162	16.03%
7500	10	1	Nonconvergence	
7500	10	10		
7500	10	200		

Table 5.2: Summary of results from all scenarios with aquifer cases

Gas Depth (ft)	Interval (ft)	K @ gas zone (md)	Time (days)	Total ROE
5500	80	1	3,233	14.95%
5500	80	10	2,932	14.62%
5500	80	200	1,294	10.39%
5500	20	1	Nonconvergence	
5500	20	10	2,274	15.04%
5500	20	200	1,875	14.26%
5500	10	1	1531.675	11.79%
5500	10	10	1447.675	11.47%
5500	10	200	1356.675	10.90%

Tables 5.1 and 5.2 show the results from all scenarios. The case that obtain the highest oil recovery factor is the case that gas bearing zone is located at depth 6,500 ft (80 ft thick) with permeability of 1 mD and partial perforation (17.78 %). This case has the longest well life. From the table, it can be observed again that the effect of depth of gas zone is insignificant for the performance of oil production. For cases with higher thickness of gas zone, perforation interval would help improve oil recovery factor. For other variables, the effect is very small.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

This chapter summarizes the conclusions and observation from previous chapter. Some results show benefit for in-situ gas lift technique while some come up with insignificant results. This chapter also includes recommendations for further study.

6.1 Conclusions

According to all simulation results, the following can be concluded:

(a) For scenarios with different permeabilities of gas zone, lower permeability results in an increase in the oil recovery factor because case with the low permeability gas zone yields a smaller amount of gas-oil ratio which is more favorable for tubing performance while high gas-oil ratio is unfavorable as it causes high friction loss.

(b) For scenarios with an in-situ gas zone with high permeability at shallow depth (5500 ft), there is a need to control the amount of gas produced into the well to prevent excessive gas rate. For this study, reducing perforation interval helps increase the oil recovery factor. This would help the improvement of oil recovery as well in case that we have higher thickness of gas zone.

(c) For scenarios with different gas bearing zone locations, highly permeable gas zone at shallow depth (5,500 ft) provides the lowest oil recovery factor. The recovery factors for other cases are insignificantly different. This is because gas from such gas zone flows into the wellbore at high flow rate due to low bottomhole pressure at 5,500 ft in comparison with deeper gas reservoir (6,500 and 7,500 ft), causing the GOR to be too high for gas lift. Thus, the oil recovery factor is lower compared with other cases.

(d) For scenarios with different thicknesses of gas zone, there is insignificant difference in oil recovery factor although there is a slight increase in recovery factor with thickness of gas zone.

(e) For scenarios comparing between with and without aquifer support, the cases with aquifer support have lower oil recovery factor than cases without aquifer support due to higher hydrostatic pressure. The higher water production rate causes the oil recovery factor to decrease compared with cases without aquifer because of the higher hydrostatic load while the amount of gas in gas bearing zone is the same.

(f) Cross flow can be found in the early period of well life but it does not effect to the oil recovery factor.

6.2 Recommendations

As a result, given similar fluid properties and arrangement of the oil and gas reservoirs in the well model, the recommendations for using the in-situ gas lift are as follows:

(a) A in-situ gas lift would be suitable for below scenarios

- Low permeability of gas zone
- Partial perforation would improve the oil recovery factor in case of high thickness of gas zone and high permeability of gas zone.

(b) In order to better understand, changing in oil zone properties may be applied.

- Changing in initial gas oil ratio
- Changing in permeability in oil zone

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APPENDIX

APPENDIX A

Table A. 1 Input data for option summary in PROSPER

Parameters	Input Data	
	Oil	**Gas**
Fluid	Oil	Dry Gas
PVT Method	Black Oil	
Equation Of State	N/A	
Separator	Single-Stage	
Hydrates	Disable Warning	
Water Viscosity	Use Pressure Corrected Correlation	
Viscosity Model	Newtonian Fluid	
Steam Option	No Steam Calculations	
Flow Type	Tubing	
Well Type	Producer	
Predicting	Pressure and Temperature (offshore)	
Temperature Model	Rough Approximation	
Completion	Cased Hole	
Sand Control	None	
Inflow Type	Single Branch	
Gas Coning	No	

VITAE

Weerayut Brahmahitadara was born on October 24th, 1981 in Surat-thani, Thailand. He graduated his Bachelor degree from Faculty of Engineering in Mechanical engineering, Kasetsart University in 2005. He has been a graduate student in the Master's Degree Program in Petroleum Engineering in the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2009.