EVALUATION AND OPTIMIZATION OF GAS ASSISTED GRAVITY DRAINAGE PROCESS

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การประเมินและการหาค่าที่เหมาะสมของกระบวนการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊ส

นาย ธีรวัฒน์ วัชรศิริธรรม

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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ธีรวัฒน์ วัชรศิริธรรม : การประเมินและการหาค่าที่เหมาะสมของกระบวนการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊ส. (EVALUATION AND OPTIMIZATION OF GAS ASSISTED GRAVITY DRAINAGE PROCESS) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 125 หน้า.

กระบวนการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊สกระทำโดยการกับการอัดแก๊สที่ด้านบนของแหล่งกักเก็บผ่านหลุมแนวตั้งและการผลิตน้ำมันจากหลุมแนวนอนที่วางอยู่ด้านล่างของแหล่งกักเก็บ แก๊สจะสะสมตัวด้านบนและผลักดันน้ำมันไปยังหลุมผลิต วัตถุประสงค์ของการศึกษานี้คือ การตรวจสอบผลกระทบของอัตราการผลิตน้ำมัน อัตราการอัดแก๊สและรูปแบบของหลุมต่อประสิทธิภาพของกระบวนการนี้ พร้อมทั้งศึกษาผลกระทบของวิธีการหาค่าความสัมพันธ์ของค่าความซึมผ่านสัมพัทธ์ สัดส่วนของค่าความซึมผ่านในแนวตั้งและแนวนอน และค่าความอิ่มตัวของน้ำมันที่เหลือ

ผลการศึกษาด้วยแบบจำลองแหล่งกักเก็บบ่งบอกว่า สัดส่วนปริมาณน้ำมันที่ผลิตที่ได้จากในแหล่งกักเก็บที่มีความลาดเอียงเพิ่มขึ้นอย่างมีนัยสำคัญเมื่อผลิตโดยการอาศัยแรงโน้มถ่วงและการอัดแก๊ส สัดส่วนปริมาณน้ำมันที่ผลิตได้จากกระบวนการนี้อยู่ในช่วงร้อยละ69ถึง74 เมื่ออัตราการผลิตน้ำมันและการอัดแก๊สมีค่าน้อย สัดส่วนปริมาณน้ำมันที่ได้จะมีค่าสูงที่ระยะเวลาสิ้นสุดการผลิต แต่เมื่อพิจารณาช่วงเวลาการผลิต 30 ปี สัดส่วนปริมาณน้ำมันจะมีค่าสูงเมื่ออัตราการผลิตน้ำมันและการอัดแก๊สมีค่าสูง นอกจากนี้การเพิ่มอัตราการอัดแก๊สขณะที่อัตราการผลิตน้ำมันคงที่ส่งผลให้สัดส่วนปริมาณน้ำมันที่ผลิตได้เพิ่มขึ้น รูปแบบการผลิตที่ให้สัดส่วนปริมาณน้ำมันสูงสุดคือ การวางหลุมผลิตแนวนอนให้มีความลึกมากที่สุด และหลุมอัดแก๊สแนวตั้งที่ตำแหน่งสูงสุด

วิธีการหาค่าความสัมพันธ์ของค่าความซึมผ่านสัมพัทธ์ที่แตกต่างกัน ให้สัดส่วนปริมาณน้ำมันที่ใกล้เคียงกัน และเมื่อสัดส่วนของค่าความซึมผ่านระหว่างแนวตั้งและแนวนอนเพิ่มขึ้นส่งผลให้ปริมาณน้ำมันที่ผลิตได้เพิ่มขึ้น ขณะที่การลดลงของค่าความอิ่มตัวที่เหลือของน้ำมันทำให้สัดส่วนปริมาณน้ำมันที่ผลิตเพิ่มขึ้นและเวลาการผลิตเพิ่มขึ้น ผลการศึกษาแสดงให้เห็นว่าการลดลงของค่าความอิ่มตัวของน้ำมันที่เหลือจาก 0.05 ถึง 0.15 ส่งผลให้สัดส่วนปริมาณน้ำมันที่ผลิตที่ได้เพิ่มขึ้นมากถึงร้อยละ13% ที่ระยะเวลาสิ้นสุดการผลิต

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต..
สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก..............
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KEYWORDS: GAGD / GRAVITY DRAINAGE / DIPPING RESERVOIR

TEERAWAT VACCHARASIRITHAM: EVALUATION AND OPTIMIZATION OF GAS ASSISTED GRAVITY DRAINAGE PROCESS. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 125 pp.

Gas Assisted Gravity Drainage (GAGD) process involves injecting gas at the top of the pay zone through vertical wells and producing oil from a horizontal wells placed near the bottom of reservoirs. Injected gas accumulates at the top and displaces oil to the production well. The objective of this study is to determine the optimal oil production rate, gas injection rate and well pattern on the performance of GAGD applied in dipping reservoirs. Sensitivity analysis of relative permeability correlations, permeability anisotropy ratio and residual oil saturation is also performed.

The results from reservoir simulation in dipping reservoirs indicate that oil recovery is significantly increased when performing GAGD. The oil recovery is in the range of 69% to 74%. At the end of production time, high oil recovery is obtained when very low injection and production rates are used. However, when considering at 30 years, higher oil production rate and gas injection rate results in higher oil recovery for the study reservoirs. In addition, when the production rate is fixed, increasing injection rate provides higher oil recovery. For well pattern, using one horizontal producer located at the deepest depth together with a vertical gas injector at the most updip location yields the highest oil recovery.

For sensitivity analysis, relative permeability correlations provide insignificantly different oil recovery except for the production time, and increasing vertical to horizontal permeability ratio gives higher cumulative oil production. Furthermore, a decrease in residual oil saturation results in higher oil recovery and the extended production time. The result shows that decreasing oil saturation from 0.05 to 0.15 leads to an increase in oil recovery up to 13% at the end of production time.

Department: Mining and Petroleum Engineering Student's Signature……......…...
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Contents

Page

Page

List of Tables

Page

Page

List of Figures

Page

Page

Page

Page

Page

List of Abbreviations

DDP	Double Displacement Process
SSWAG	Simultaneous Selective Water Alternating Gas
SWAG	Simultaneous Water Alternating Gas
WAG	Water Alternating Gas
GAGD	Gas Assisted Gravity Drainage
CGI	Continuous Gas Injection
MMSTB	Million Stock Tank Barrel
STB/D	Stock tank barrel per day
MSCF/D	Thousand standard cubic feet per day
MSCF/STB	Thousand standard cubic feet per stock-tank barrel
mD	Millidarcy
psia	Pounds per square inch absolute
rb/stb	Reservoir barrel per stock tank barrel
cp	Centipoises
lb/cuft	Pound per cubic feet

Nomenclatures

ρ_o	Density of oil
ρ_w	Density of water
ρ_g	Density of gas
g	Gravitational acceleration
L	Length of the reservoir
H	Height of the reservoir
N_g	Dimensionless gravity number
k_h	Horizontal permeability
k_z	Vertical permeability
σ_{gw}	Gas-water interfacial tension
σ_{go}	Gas-oil interfacial tension
σ_{ow}	Oil-water interfacial tension
α	Spreading coefficient
M	Mobility ratio
λ_g	Mobility of gas
λ_o	Mobility of oil
μ_g	Viscosity of gas
μ_o	Viscosity of oil
k	Absolute permeability of the porous media
v_d	Darcy velocity
S_w	Water saturation
S_o	Oil saturation
S_g	Gas saturation
S_{wco}	Connate water saturation
k_{rog}	Oil relative permeability in presence of gas phase
k_{row}	Oil relative permeability in presence of water phase
k_{ro}	Oil relative permeability
t	Time period

CHAPTER I

INTRODUCTION

1.1 Background

The displacement of oil by gas injection in oil reservoirs is an attractive method of improved oil recovery because of its excellent microscopic displacement efficiencies achieved in the gas-swept region. However, one of the main drawbacks of this process is the poor volumetric sweep efficiency due to unfavorable mobility ratio. Viscosity of the commonly injected gases such as CO_2, hydrocarbon and N_2 is generally less than one-tenth of the reservoir fluids viscosity. Consequently, gas overriding and viscous instability of injection front usually occur and cause an early breakthrough. In addition, the high density difference between the injected gas and oil leads to gravity segregation in the reservoir, especially in horizontal reservoirs. As a result, large reservoir areas are ultimately left unswept, resulting in poor volumetric sweep efficiencies.

Many methods have been proposed to solve such problems, such as double displacement process (DDP), simultaneous water alternating gas (SWAG), and gravity assisted gas drainage (GAGD) process. Among these commonly used methods, GAGD process is considered to be one of the most efficient methods for most reservoir conditions, especially reefs and dipping reservoirs. Several field investigations and laboratory studies have confirmed that high oil recovery can be achieved in reefs and dipping or even in horizontal reservoir using GAGD process [1]. Contrary to horizontal gas injection projects, GAGD process takes advantage of the gravity segregation to improve reservoir volumetric sweep efficiencies. This method involves injecting gas at the top of the pay zone through vertical wells and producing oil from horizontal wells placed near the bottom of the reservoir. Due to the high density difference between gas and oil, gravity segregation causes gas to migrate upward and accumulate at the top underlain by oil and water zone. This gravity segregation of reservoir fluids results in pressure maintenance driving oil downward to production wells. As a result, better volumetric sweep efficiency and higher oil recovery can be achieved.

The performance of GAGD process is significantly influenced by both design and system parameter. Thus, it is necessary to understand the effect of these parameters in order to determine the best strategy for GAGD process. In this study, Black oil simulator ECLIPSE100 will be used to determine the effect of three important design parameters which are oil production rate, gas production rate, location of wells. In addition, sensitivity analysis is also performed to investigate the effect of system parameters such as vertical to horizontal permeability ratio, relative permeability correlation and residual oil saturation.

1.2 Objectives

1. To investigate the effects of design parameters in dipping reservoir including oil production rate, gas injection rate and well pattern and choose the best production strategy for GAGD process.
2. To determine the sensitivity of study parameters including relative permeability correlation, vertical to horizontal permeability ratio and residual oil saturation.

1.3 Outline of methodology

1. Study various related literatures and collect required input data for reservoir simulation model
2. Construct reservoir simulation models with three different dip angles which are 15, 30 and 60 degrees
3. For each dip angle, simulate the model with different design parameters in order to study the effect on production performance for GAGD includes
    - Oil production rate
    - Gas injection rate
    - Well pattern
4. Analyze the results from simulation to determine the most appropriate design parameter for each dip angle
5. Simulate the models and determine the effect of system parameters includes
    - Three-phase relative permeability models
    - Vertical permeability or vertical to horizontal permeability ratio
    - Residual oil saturation in the gas-oil system
6. Discuss and summarize effect of the systems parameters on production performance for GAGD

1.4 Thesis outline

This thesis consists of six chapters as outlined below:

Chapter I introduces the background and indicates the objectives and methodology of this study.

Chapter II presents some previous works related to GAGD which include both laboratory experiment and simulation studies.

Chapter III introduces the general concept of GAGD and describes the related theory.

Chapter IV provides detail of reservoir models used in this study including reservoir dimensions, PVT data, and rock and fluid properties.

Chapter V illustrates and discusses the simulation results of GAGD process performed under different operating and reservoir conditions.

Chapter VI provides the conclusions and recommendations obtained from this study.

CHAPTER II

LITERATURE REVIEW

This chapter describes some previous studies, both experimental and simulation study on GAGD. Development of method, advantage, disadvantage and improvement in oil production of each method are discussed.

2.1 Implementation of Gas Injection EOR

The concept of injecting gas to improve oil recovery has been proposed as early as 1920's [2]. According to EOR survey [3], gas injection processes have steadily grown to become the main process for light oil EOR application. Apart from conventional continuous gas injection, various modes of gas injection such as Water Alternative Gas process (WAG), Simultaneous WAG (SWAG), and Selective Simultaneous WAG (SSWAG) have been developed in the past few years. However, viscous fingering and gravity segregation are still the common problem for gas injection process leading to very poor vertical sweep efficiency.

In order to solve these problems, WAG, proposed by Caudle and Dyes [4], was developed to improve oil sweep efficiency during gas injection by utilizing the higher microscopic displacement of gas and the better macroscopic sweep efficiency of water. Although the concept is theoretically sound, the field performance of WAG has been considerably less than expected. Christensen et al. [5] performed a field survey on 59 WAG projects in both miscible and immiscible modes. The results indicated that the majority of these projects resulted in only 5 to 10% additional recovery. This poor WAG performance mainly results from gravity segregation and the increasing water saturation, which reduces relative permeability to oil. Furthermore, some operation problems such as corrosions and reduced injectivity also occur in WAG process.

2.2 Gas Assisted Gravity Drainage (GAGD)

Laboratory experiments and field tests confirm that up-dip gas injection into dipping reservoirs is one of the most efficient oil recovery methods in both secondary and tertiary modes. The commercial applications of gravity stable gas injection have appeared first in Carlson's paper discussing a gas injection project in Hawkins Field [6]. As shown in Figure 2.1, produced gas and inert gas were injected into a dipping reservoir in order to recover additional oil in the water invaded area. The study indicated that gas-drive gravity drainage successfully recovered considerable additional oil and was able to significantly reduce the residual oil saturation in the water-invaded oil column from 35 percent to about 12 percent.

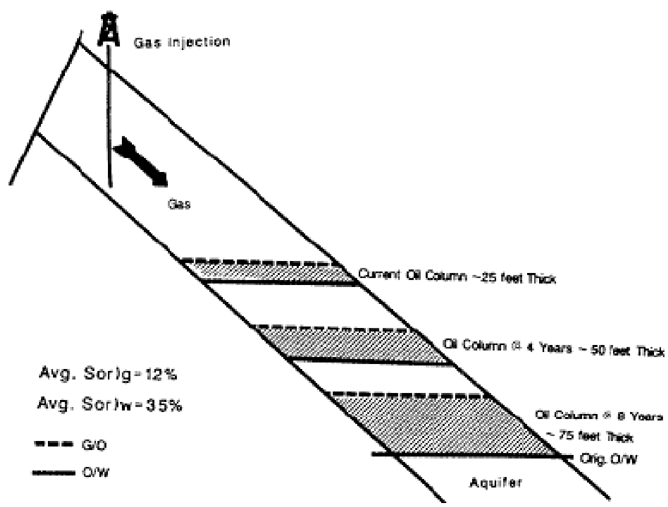


Figure 2.1 Gravity-stable gas injection performed in a dipping reservoir
(after Carlson [6])

The success in field applications of the gravity stable gas injections in dipping reservoirs and pinnacle reefs have also been proven by a field review conducted by Kulkarni [1] on nine gravity drainage field projects. The results indicate that gas injection in all of the nine field projects in various parts of the world was successfully performed. The ultimate oil recovery from these projects has been in the range 64- 95 % of initial oil in place in tertiary mode after secondary waterfloods. The success of these projects proved that gravity drainage can be implemented in a wide variety of geological settings, ranging from sandstones, which are mostly water wet, to carbonates and dolomites, which are mostly oil wet.

Gas assisted gravity drainage (GAGD) process was proposed by Rao et al. [7] from Louisiana State University intending to extend this gravity stable gas floods to horizontal type reservoirs. The newly proposed GAGD process consists of several existing vertical gas injectors to inject gas in the top of the payzone, whereas the horizontal producer was placed at the bottom to produce drained oil. A schematic of the process is shown in Figure 2.2. In GAGD process, the injected gas gathers at the top of the pay zone and displaces oil, which drains to the horizontal producer. As injection continues, the gas-swept area expands downward and sideway. In addition, the gravity segregation helps in delaying, or even eliminating, gas breakthrough to the producer, preventing the competition of gas to flow with oil. As a result, better volumetric sweep efficiency and higher oil recovery can be achieved.

There are several laboratory experiments conducted to determine effects of system parameters both fluid and reservoir properties on the performance of GAGD process. Some of the related studies are discussed as follows:

Kulkarni [8] performed miscible and immiscible coreflood experiments to compare performance of competing processes with GAGD, namely water alternating gas (WAG) and continuous gas injection (CGI). The results indicated that GAGD provides higher oil recovery compared to WAG and CGI in secondary and tertiary immiscible mode. The performance of the immiscible GAGD recovered about 65% of residual oil in place in tertiary mode. While, in miscible flooding which high pressure is applied, the recovery of GAGD process was at or near 100% of residual oil in place in tertiary recovery.

Mahmoud et al. [9] conducted experiments to study the feasibility of GAGD process on various conditions by using a scaled visual model. The scaled visual model consisted of two glass plates with sand packed in the gap, a plastic tube located at the bottom of the model serving as a horizontal well and vertical tubes functioning as gas injectors. From experimental results, they concluded that GAGD process is an effective process for secondary or tertiary oil recovery. Additionally, immiscible GAGD experiment showed that high density difference between injected gas and oil and low gas injection rate are two key parameters which allow gravity domination to take place. When gravity force dominates the flooding process, a near horizontal flood front can be observed in the experiments. However, some viscous fingering possibly occurred due to unfavorable mobility ratio. The study also reported that miscible flooding recovered more oil than immiscible flooding because of its higher microscopic displacement efficiency. The experimental results showed that oil recovery in secondary mode was up to 87% of initial oil in place, while, in tertiary mode, additional oil could be recovered as high as 54% of residual oil saturation.

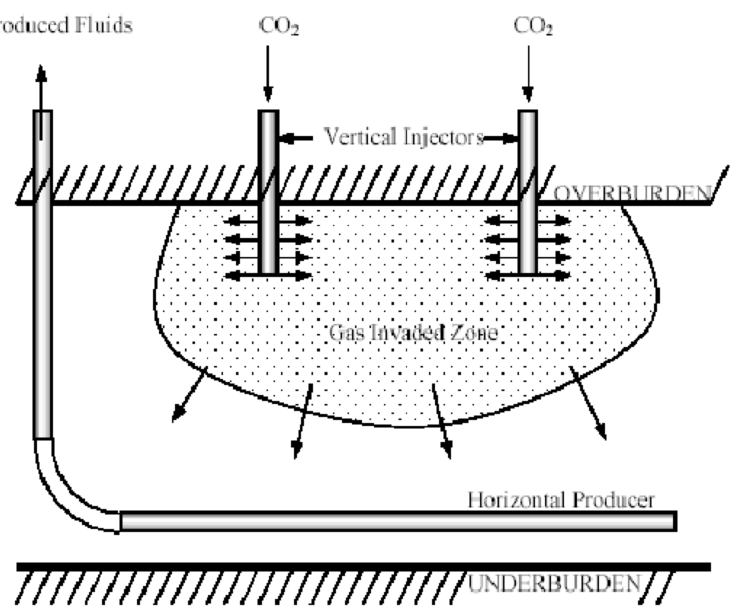


Figure 2.2 Schematic view of GAGD process (after Rao et al. [7])

Another set of laboratory experiments was conducted by Paidin [10]. The author aimed at investigating the effect of wettability and fractures on GAGD performance by using both physical water-wet and oil-wet models, in both secondary and tertiary modes. The experimental results indicated that oil-wet model recoveries were fairly higher than the water-wet ones since continuous thin-oil film formed on the oil-wet surface helps drain oil into the horizontal producer. Furthermore, he reported that increasing grain size which increases porosity and permeability results in higher oil recovery. The study also investigated the effect of vertical fractures on GAGD performance. The results showed incremental oil recovered in fractured cores compared to the same core without a fracture presence because the natural fractures serve as additional exchange ways for oil to flow out of the matrix and gas to flow into the matrix through these fractures.

Ren et al. [11] performed reservoir simulations to investigate the effects of parameters such as production, rate injection, oil wettability and capillary pressure on the performance of gravity stable gas injection in water invaded reservoir. Three reservoir dip angles used in this study are 8, 30 and 60 degrees. The study showed that both injection and production rates are significantly important to control the stability of gas floold front when applying the gravity assisted tertiary gas injection process. The results also indicated that steeply dipping reservoirs are favorable conditions for the gravity assisted tertiary gas injection process.

Another numerical simulation study concerning SSWAG and GAGD was conducted by Oranat [12]. The study indicated that oil recovery factor of SSWAG and GAGD, performed in dipping reservoir, is in range of 50% to 80%, based on design parameters. For SSWAG, oil production is improved by injecting gas at together with water. Horizontal producer is located at downdip. She reported that locations and lengths of injectors have minimal effect on oil recovery efficiency. For GAGD, oil production is enhanced by using high gas injection rate and horizontal producer. Gas injector should be located at shallowest depth whereas oil producer should be at the deepest depth.The results showed that SSWAG provides poorer performance compared to GAGD and DDP and might not be suitable to implement in dipping reservoir.

Although many literatures utilized GAGD techniques in their studies and showed impressive performance, there is little work available concerning GAGD in dipping reservoirs. In this study, GAGD in dipping reservoirs will be analyzed by performing reservoir simulations under various design parameters. In addition, the sensitivity of results due to uncertainty in selected study parameters will also be investigated.

CHAPTER III

THEORY AND CONCEPT

This chapter presents fundamental principles used to describe GAGD process and also important concepts related to this method.

3.1 Gas Assisted Gravity Drainage (GAGD)

The performance of GAGD process in dipping reservoirs is significantly influenced by dip angle and injection rates. First, effect of dip angle on the efficiency of the gas/oil displacement process will be discussed using a fractional flow of gas which is developed by Weldge [13]. The assumptions used in his work are steady-state flow, constant pressure, no compositional effect, no capillary effect and uniform cross-sectional flow. The fractional flow of gas at any gas saturation is calculated as follows:

$$f_g = \frac{1 - \frac{k k_{ro} g \Delta\rho A \sin\alpha}{q_t \mu_o}}{1 + 1/M} \tag{3.1}$$

where

A = area of cross section normal to the bedding plane,

f_g = fraction of flowing gas volume,

k = absolute permeability,

M = Mobility ratio, $\frac{k_{rg}\mu_o}{\mu_g k_{ro}}$,

k_{ro} = relative permeability to oil,

k_{rg} = relative permeability to gas,

μ_o = viscosity of oil,

μ_g = viscosity of gas,

q_t = total volumetric flow rate through area A,

α = angle of dip, positive downdip,

$\Delta\rho$ = density difference, ρ_o- ρ_g,

g = gravitational acceleration

From Equation 3.1, it is clearly observed that the gravity term becomes positive when gas is displacing oil in downdip direction. The effect of gravity term is illustrated in Figure 3.1. Gas saturation at breakthrough of formation with dip angle increases with additional gravity term when performing gas injection at updip. The better displacement efficiency confirms that displacing oil updip (injecting gas at the top) is more favorable in GAGD process. Furthermore, in dipping reservoirs with high permeability, gravity significantly helps to increase the displacement efficiency.

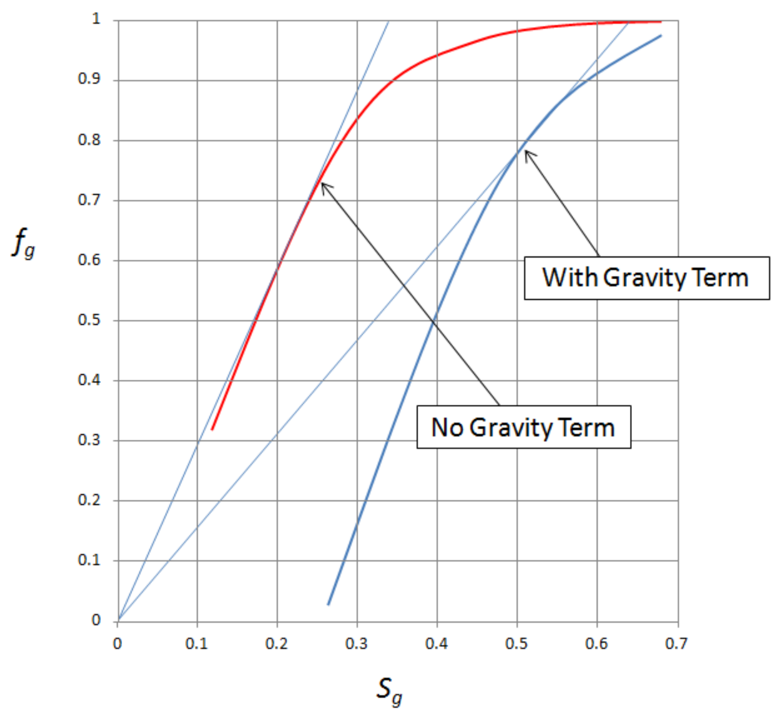


Figure 3.1 Effect of gravity on gas/oil fractional flow for updip gas injection

Injection rate is another important parameter that strongly affects the gas-oil interface. Two phenomena happen when gas is injected at the top, one where the injection rate is so low that the interface is horizontal showing complete gravity stability as illustrated in Figure 3.2 a, and one where the injection rate is so high that the interface is unstable and thus gas advances along the top of the layer bypassing oil at the bottom as illustrated in Figure 3.2 b.

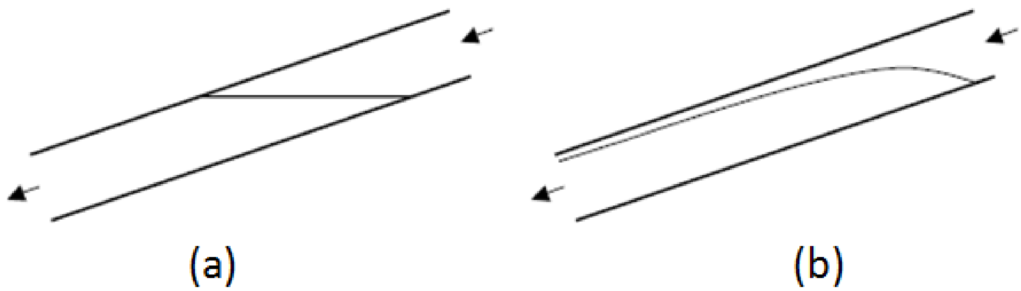


Figure 3.2 Effect of injection rate on gas flooding when displacing oil downdip
(a) Stable flood front with proper rate (b) Unstable flood front with too high rate

3.2 Factors affecting gravity drainage

Gravity drainage process in porous media is characterized by complex interaction between fluids filling in pore space and the contact surface such as wettability, spreading phenomena, viscosity, and permeability anisotropy. The significance of these parameters towards gravity drainage process will be discussed in this section [14].

Wettability

Wettability is used to describe the preference of a solid to contact one liquid or gas. It is an important factor in gravity drainage process since it significantly affects oil spreading behavior and effectiveness of gas injection. Generally, wettability is categorized widely into water-wet, oil-wet, and mixed-wet. In a water-wet formation, for spreading oils, oil exists as a mobile oil film and can be transported by the gas. For non-spreading oils, oil has to be pushed out by the gas as discontinuous ganglia, hence less oil is produced. On the other hand, in an oil-wet system, the oil forms a continuous film on the solid surface. Thus, injected gas effectively expands the oil phase, resulting in higher quantities of oil produced. In mixed wettability systems, smaller pores are occupied by water and are water-wet whereas the larger pores of the rock are oil-wet, and a continuous filament of oil exists on the reservoir rock. Because oil occupies in the larger pores of the system in a continuous path, oil displacement can occur even at very low oil saturation. Consequently, the residual oil saturation of mixed-wettability rocks is very low.

Spreading Coefficient

Spreading coefficient (S) characterizes the preferential spreading of one fluid over the other in porous media. This coefficient along with wettability is used to describe oil filming behavior. These two parameters are very important for gravity drainage since the effectiveness of the process is largely depends on the oil film forming ability. The spreading coefficient of gas, oil and water system is defined as

$$S = \sigma_{gw} - \sigma_{go} - \sigma_{ow} \tag{3.2}$$

where σ_{gw}, σ_{go} and σ_{ow} are the gas-water, gas-oil and oil-water interfacial tension, respectively.

$S > 0$ indicates that oil tends to spread and form thin film spontaneously between gas and water phases, resulting in less residual oil saturation compared to one in a non-spreading system. For $S < 0$, a large quantity of oil is trapped in the reservoir and thus lower oil recovery is obtained.

Viscosity

Viscosity is another important parameter need to be considered in determining efficiency of gas/oil displacement. Two aspects about viscosity are directly related to gasflooding. First, due to low viscosity of gas, unfavorable mobility ratio usually occurs in gas injection and leading to instability of floodfront especially in heterogeneous reservoirs, thus the stability of gas front need to be concerned to prevent poor performance. Gas displacement velocity needs to be effectively controlled in order to reduce impact of viscous force. Second, before implementing gas injection, viscosity of the displaced oil should be in acceptable range in order to obtain good displacement efficiency and prevent viscous fingering.

Permeability anisotropy

Permeability anisotropy is the quality of variation in permeability values in different directions. The term generally used to represent the permeability anisotropy in a reservoir is vertical-to-horizontal permeability ratio (k_v/k_h). High k_v/k_h ratio usually leads to gravity segregation, crossflow and ultimately inefficient oil recovery, especially in horizontal flooding. Several experimental studies have suggested that GAGD process is probably less influenced by permeability anisotropy compared to horizontal flooding process

3.3 Relative permeability

The relative permeability to a fluid is defined as the ratio of effective permeability at a given saturation of that fluid to the absolute permeability when that fluid is fully saturated. Relative permeability characteristics of each porous system are unique must be measured experimentally. However, direct measurements of three-phase relative permeabilities are costly and require complicated process. As a result, three-phase relative permeabilities are typically calculated from two sets of two-phase data. Some common correlations used to determine two-phase and three-phase relative permeability will be discussed as follow:

3.3.1 Two-phase relative permeability

3.3.1.1 Corey's correlation

In ECLIPSE reservoir simulator, two sets of relative permeability are generated using Corey's correlation. The values of relative permeability in oil/water and gas/oil system are determined by the following Equation [15]:

$$k_{ro}(S_w) = k_{ro@S_{wmin}} \left[\frac{S_{wmax}-S_{orw}-S_w}{S_{wmax}-S_{orw}-S_{wi}}\right]^{C_o} \tag{3.3}$$

$$k_{rw}(S_w) = k_{rw@S_{orw}} \left[\frac{S_w - S_{wcr}}{S_{wmax} - S_{orw} - S_{wcr}}\right]^{C_w} \quad (3.4)$$

where

S_w	=	water saturation,
S_{wmin}	=	minimum water saturation,
S_{wmax}	=	maximum water saturation,
S_{orw}	=	residual oil saturation to water,
S_{wi}	=	initial water saturation,
S_{wcr}	=	critical water saturation,
$k_{ro}(S_w)$	=	relative permeability to oil at any water saturation,
$k_{rw}(S_w)$	=	relative permeability to water at any water saturation,
$k_{ro}@S_{wmin}$	=	relative permeability to oil at minimum water saturation,
$k_{rw}(S_w)$	=	relative permeability to water at any water saturation,
C_o	=	Corey oil exponent,
C_w	=	Corey water exponent.

3.3.2 Three-phase relative permeability model

3.3.2.1 ECLIPSE model

The ECLIPSE model is a default model for three-phase relative permeability unless any particular model is selected. This model can be considered as saturation weighted model. The oil saturation is assumed to be constant throughout the cell. The gas and water are assumed to be fully segregated, except that the water saturation in the gas zone is equal to the connate saturation (S_{wco}). The schematic diagram assuming the block average saturations of gas, oil and water is shown in Figure 3.3

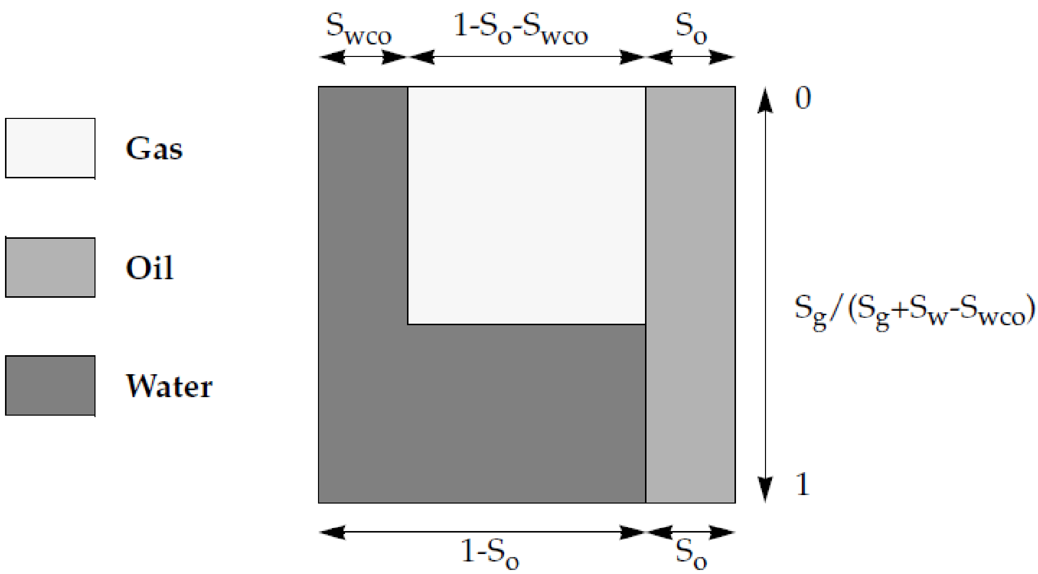


Figure 3.3 Default model of three-phase relative permeability assumed by ECLIPSE (after Schlumberger technical manual [16])

The oil relative permeability is then calculated by

$$k_{ro} = \frac{S_g k_{rog} + (S_w - S_{wco}) k_{row}}{S_g + S_w - S_{wco}} \tag{3.5}$$

Where

k_{rog} = the oil relative permeability for a system with oil, gas and connate water (tabulated as a function of S_o)

k_{row} = the oil relative permeability for a system with oil and water only (tabulated as a function of S_o)

3.3.2.2 Stone 1 Model

An alternative three-phase relative permeability model available in ECLIPSE is Stone 1 model [17]. This model was developed from the theory of channel flow in porous media. He suggested that minimum residual oil saturation (S_{om}) exists when oil is displaced simultaneously by water and gas. However, this minimum oil saturation (S_{om}) is different than the critical oil saturation in the oil-water system (S_{orw}) and the residual oil saturation in the gas-oil system (S_{org}). This model was originally generated from an interpolation technique between two-phase flow conditions. Stone also introduced the following normalized saturations:

$$S_o^* = \frac{S_o - S_{om}}{\left(1 - S_{wc} - S_{om}\right)} \tag{3.6}$$

$$S_w^* = \frac{S_w - S_{wc}}{\left(1 - S_{wc} - S_{om}\right)} \tag{3.7}$$

$$S_g^* = \frac{S_g}{\left(1 - S_{wc} - S_{om}\right)} \tag{3.8}$$

The oil-relative permeability in a three-phase system is then defined as

$$k_{ro} = S_o^* \beta_w \beta_g \tag{3.9}$$

The two multipliers β_w and β_g are calculated from

$$\beta_w = \frac{k_{row}}{1 - S_w^*} \tag{3.10}$$

$$\beta_g = \frac{k_{rog}}{1 - S_w^*} \tag{3.11}$$

where k_{row} = oil relative permeability as determined from the oil-water two-phase relative permeability at S_w

k_{rog} = oil relative permeability as determined from the gas-oil two-phase relative permeability at S_g

In order to determine k_{ro}, value of S_{om} needs to be determined first. Fayers and Matthews [18] presented a relation for determining S_{om} as follows:

$$S_{om} = \alpha S_{orw} + (1 - \alpha) S_{org} \tag{3.12}$$

With $\alpha = 1 - \dfrac{S_g}{(1 - S_{wc} - S_{org})}$

where S_{orw} = the residual oil saturation in the oil-water system

S_{org} = the residual oil saturation in the oil-gas system

3.3.2.3 Stone 2 Model

A modified form of Stone 1 model was suggested by stone [19] in 1973 to avoid the difficulties in choosing S_{om}. The equation of this model is defined as:

$$k_{ro} = (k_{row} + k_{rw})(k_{rog} + k_{rg}) - k_{rw} - k_{rg} \tag{3.13}$$

This equation is rearranged in normalized form as:

$$k_{ro} = k_{rocw}[(\frac{k_{row}}{k_{rocw}} + k_{rw})(\frac{k_{rog}}{k_{rocw}} + k_{rg}) - k_{rw} - k_{rg}] \tag{3.14}$$

3.4 Fracturing pressure

In order to prevent reservoir fracturing during gas injection, the injection pressure needs to be kept lower than a fracturing pressure of the reservoir. The formation fracturing pressure can be determined using the following correlation by Manisa [20] for Gulf of Thailand.

$$\text{Fracturing pressure (bar)} = \frac{FRAC.S.G. \times TVD}{10.2} \tag{3.15}$$

while

$$FRAC.S.G. = 1.22 + (TVD \times 1.6 \times 10^{-4}) \tag{3.16}$$

where

$FRAC.S.G$ = fracturing pressure gradient (bars/meter)

TVD = true vertical depth below rotary table (meters)

3.5 Barrel of oil equivalent

The concept of barrel of oil equivalent (BOE) is used in this study to combine the different types of production into single unit, which is useful for comparison or estimation the net production in a process. The amount of oil, gas production and gas injection can be converted into the net barrel of oil equivalent by Equation 3.17 [21].

Net BOE (STB) = Cumulative oil production (STB) +Cumulative gas production (MMSCF) x 166.7 – Cumulative gas injection (MMSCF) x 166.7 (3.17)

CHAPTER IV

RESERVOIR SIMULATION MODEL

A black oil ECLIPSE 100 reservoir simulator is used as a tool to evaluate and compare the performance of GAGD in various conditions. In this chapter, input keywords used in construction of the reservoir and well models are presented.

4.1 Reservoir model

The homogeneous dipping reservoir models with dip angle of 15, 30 and 60 degrees are constructed using Cartesian coordinate and corner point grid. The dimensions are 6000 x 2000 x 210 ft. with the number of grid block of 73 x 31 x 21 in the x-, y- and z- direction, respectively. The reservoir properties are the same for three dip angles as listed in Table 4.1

The reservoir is initially undersaturated since the initial reservoir pressure is equal to the bubble point pressure. The top depth is set at the depth of 5000 ft.

Table 4.1 Reservoir properties

Parameter	**Value**	**Units**
Porosity	15.09	%
Horizontal permeability	32.529	mD
Vertical permeability	3.2529	mD
Datum depth	5000	ft
Top depth	5000	ft
Bubble point pressure	2242	psia
Initial pressure @ datum depth	2242	psia

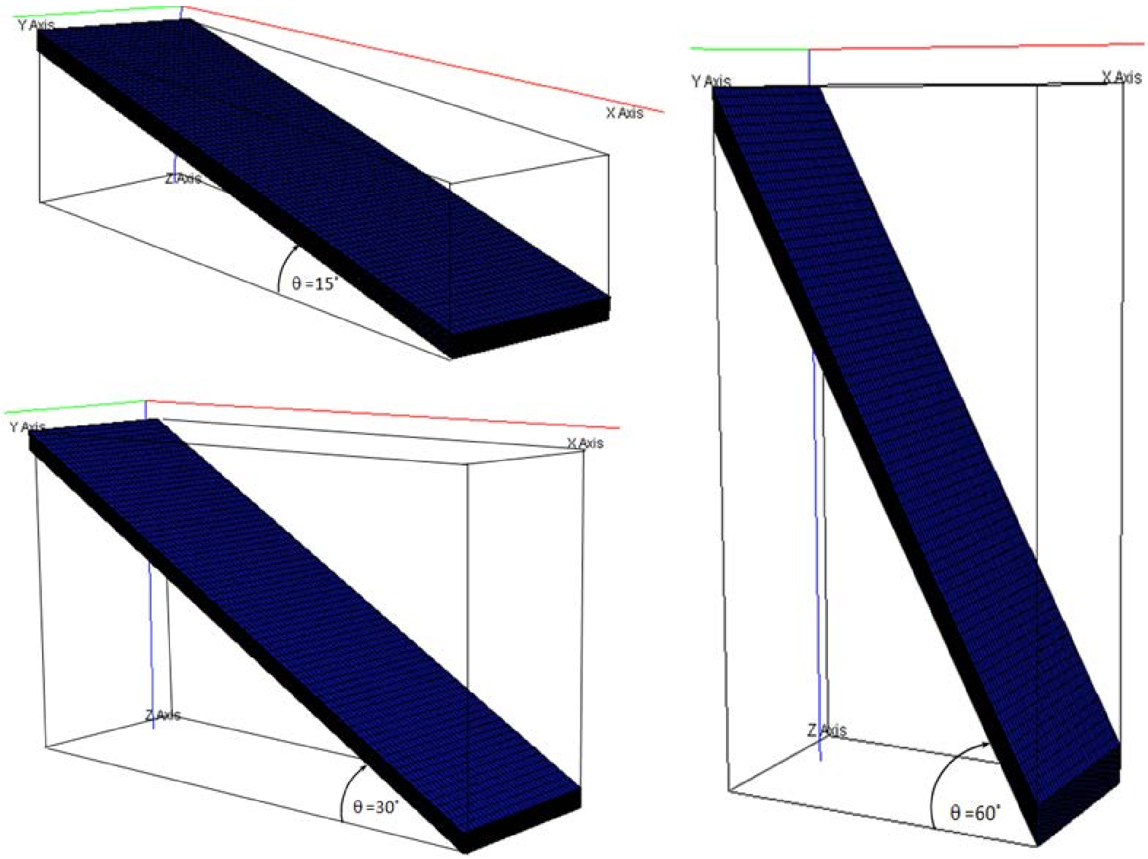


Figure 4.1 Reservoir models with different dip angles

In GAGD base cases, a vertical gas injector is located at the middle of the width on the up-dip side while one horizontal oil producer is located at the bottom as illustrated in Figure 4.2.

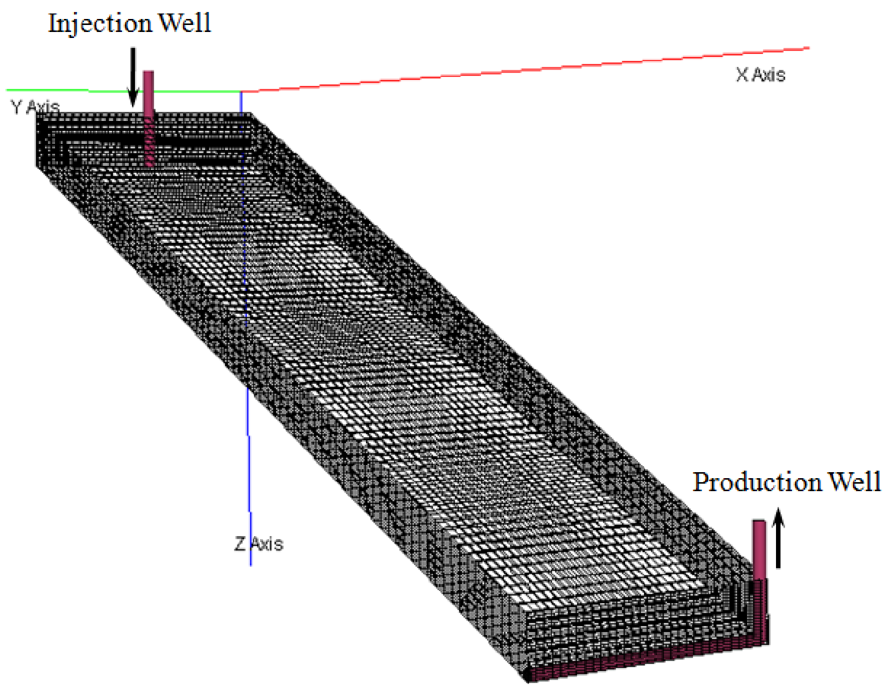


Figure 4.2 Well schematic of GAGD base case

4.2 PVT properties

The PVT properties of reservoir fluids used in this study are generated by using ECLIPSE correlation set 2. Input parameters required for the correlation are listed in Table 4.2. Table 4.3 demonstrates the properties of water, and the density of each fluid is shown in Table 4.4. The properties of dry gas and live oil PVT obtained from the correlation are shown in Figure 4.3 and 4.4, respectively.

Table 4.2 Input data for ECLIPSE correlation

Input parameter	Value	Units
Oil gravity	39	^{o}API
Gas gravity	0.7	
Solution gas	650	scf/stb
Reservoir temperature	200	°F
Reference pressure	3000	psia
Porosity	15.09	%
Rock type	Consolidated Sandstone	

Table 4.3 Water PVT properties

Property	**Value**	**Units**
Reference pressure(Pref)	3000	psia
Water FVF at Pref	1.021734	rb/stb
Water compressibility	3.09988E-6	/psi
Water viscosity at Pref	0.3013289	cp
Water viscosibility	3.292727E-6	/psi

Table 4.4 Fluid densities at surface condition

Property	**Value**	**Units**
Oil density	51.45684	lb/cuft
Water density	62.42797	lb/cuft
Gas density	0.04369958	lb/cuft

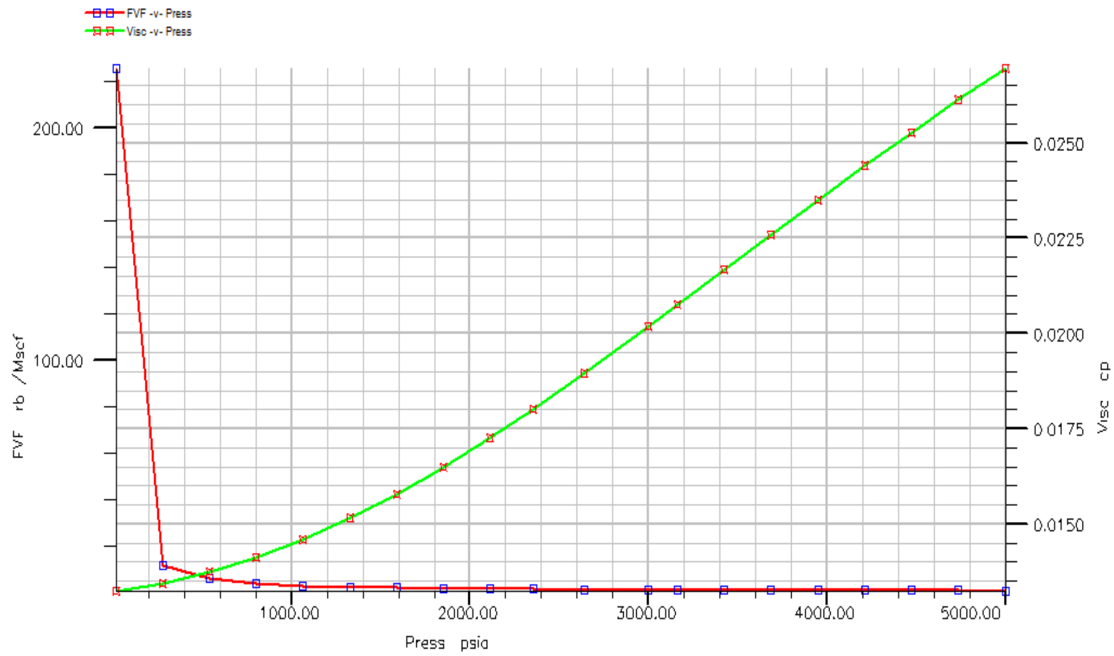


Figure 4.3 Dry gas PVT properties (no vaporized oil)

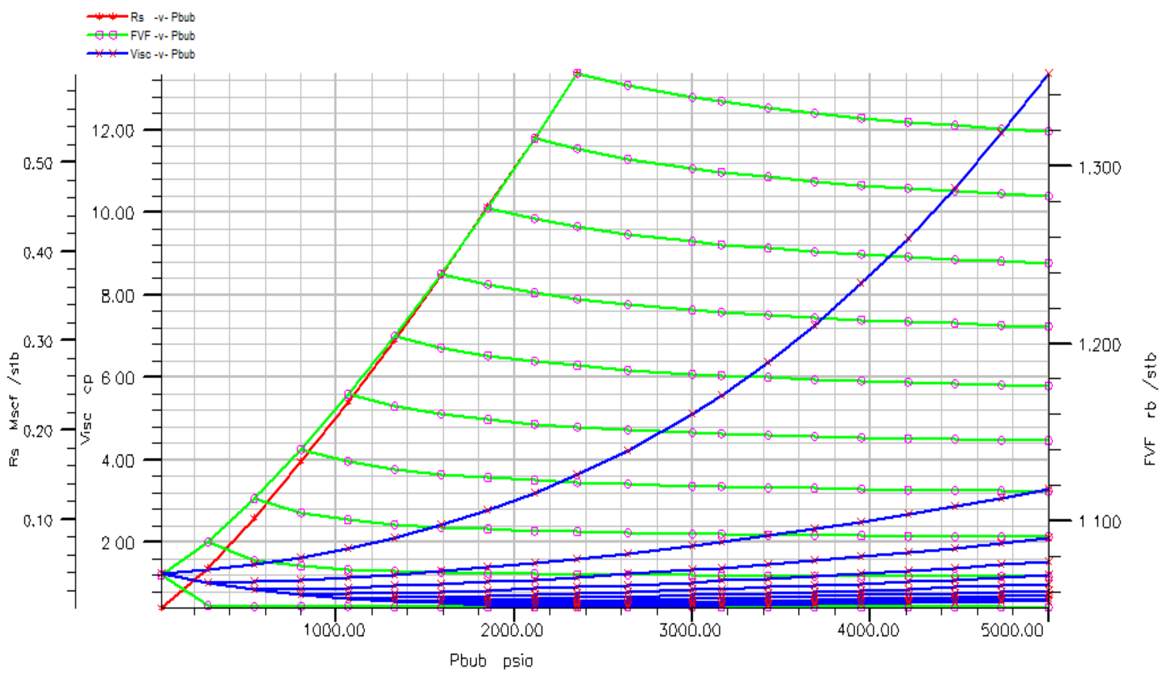


Figure 4.4 Live oil PVT properties (dissolved gas)

4.3 SCAL (Special Core Analysis) Section

In this study, relative permeability curves are calculated by using Corey's correlation. The parameters used in Corey's correlation are listed in Table 4.5. The values of relative permeability curves obtained from this set of inputs are tabulated in Table 4.5 and 4.7 and also plotted in Figures 4.5 and 4.6.

Table 4.5 Input data for Corey's correlation

Corey water	2	Corey Gas/Oil	3	Corey Oil/Water	3
S_{wmin}	0.3	S_{gmin}	0	Corey Oil/Gas	3
S_{wcr}	0.3	S_{gcr}	0.15	S_{org}	0.1
S_{wi}	0.3	S_{gi}	0.15	S_{orw}	0.3
S_{wmax}	1	$k_{rg}(S_{org})$	0.8	$k_{ro}(S_{wmin})$	0.8
$k_{rw}(S_{orw})$	0.8	$k_{rg}(S_{gmax})$	0.8	$k_{ro}(S_{gmin})$	0.8
$k_{rw}(S_{wmax})$	0.8				

Table 4.6 Water and oil relative permeabilities

S_w	k_{rw}	k_{ro}
0.3	0	0.8
0.344444	0.009877	0.561866
0.388889	0.039506	0.376406
0.433333	0.088889	0.237037
0.477778	0.158025	0.137174
0.522222	0.246914	0.070233
0.566667	0.355556	0.02963
0.611111	0.483951	0.008779
0.655556	0.632099	0.001097
0.7	0.8	0
1	0.8	0

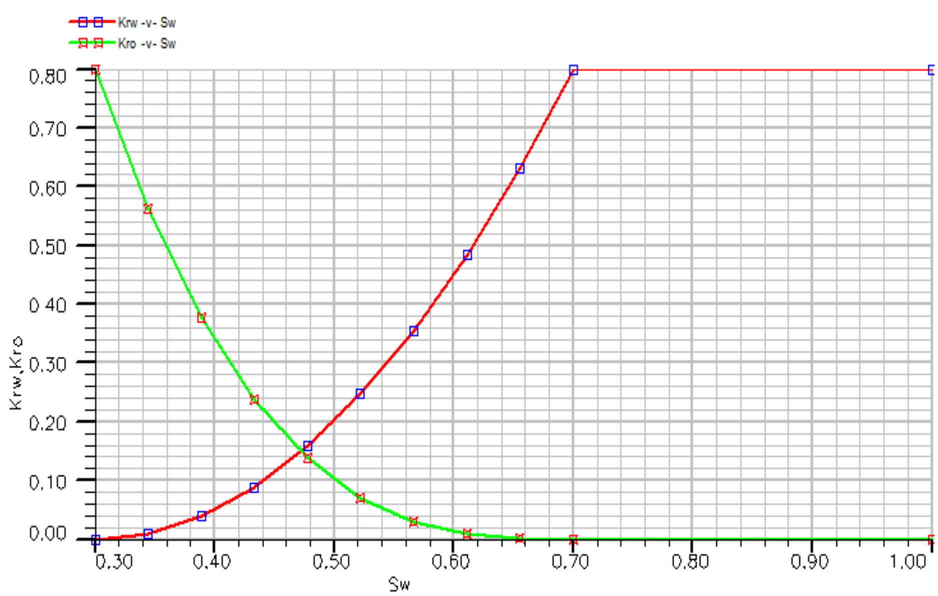


Figure 4.5 Water/oil saturation function

Table 4.7 Gas and oil relative permeabilities

S_g	k_{rg}	k_{ro}
0	0	0.8
0.15	0	0.3375
0.20625	0.001563	0.226099
0.2625	0.0125	0.142383
0.31875	0.042188	0.082397
0.375	0.1	0.042188
0.43125	0.195313	0.017798
0.4875	0.3375	0.005273
0.54375	0.535938	0.000659
0.6	0.8	0
0.7	0.8	0

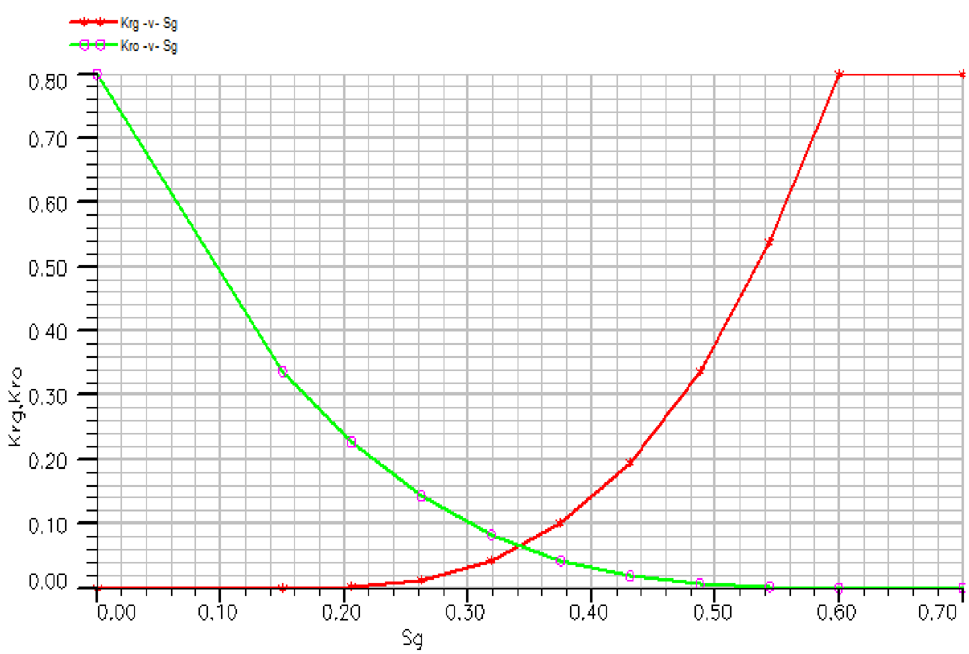


Figure 4.6 Gas/oil saturation function

4.4 Well schedule

In this study, it is assumed that all wellbore diameters are 6-5/8 inches and there is no skin. For production well, the economic oil production rate is 100 STB/D with minimum bottomhole pressure of 500 psia. For injection well, the maximum bottom-hole injection pressure is set equal to fracture pressure at 3300 psia. The production period is set at 100 years while a concession period is 30 years. In this study, two criteria will be used to evaluate oil recovery and performance of the reservoirs. These two criteria are at the end of 30 years and at the end production time, which the production cannot meet the economic limit.

CHAPTER V

SIMULATION RESULTS AND DISCUSSION

In this chapter, the results of all study parameters and sensitivities are illustrated and discussed in order to analyze the effects on GAGD process. Firstly, natural depletion is simulated as a reference case. After that, GAGD process was introduced and simulated under different conditions by varying three design parameters which are oil production rate, gas injection rate and well pattern. The results of all operating conditions are compared and discussed. Lastly, the sensitivity of results due to uncertainty related to relative permeability correlation, vertical to horizontal permeability ratio and relative permeability to oil and gas are investigated.

5.1 Natural depletion scheme

In order to understand the nature of the given reservoirs, natural depletion or primary recovery is firstly simulated. The results from this simulation are used as references for comparison with GAGD cases. Simulations are performed in reservoir models with dip angle of 15, 30 and 60 degrees. One horizontal production wells is placed in the y-direction at the down dip side of the reservoir at the bottommost grid block as shown in Figure 5.1. The maximum liquid production rates are set at 1000, 2000, 3000 and 4000 STB/D with the minimum bottomhole pressure of 500 psia. The production period is set at 100 years with an economic limit oil rate of 100 STB/D while a concession period is 30 years.

A 30-degree dipping reservoir with the maximum liquid rate of 3000 STB/D is chosen for describing the reservoir performance during natural depletion. Figure 5.2 illustrates oil and gas production rates of the reservoir. Oil is produced at the maximum liquid rate of 3000 STB/D for about 5 years until the reservoir pressure depletes and the bottomhole pressure declines to 500 psia as shown in Figure 5.3. Gas production rate decreases slightly during early time and then sharply increases as the reservoir pressure decreases since evolved gas begins to flow into the well. Gas production rate peaks at around 5 years and gradually drops as oil production rate decreases.

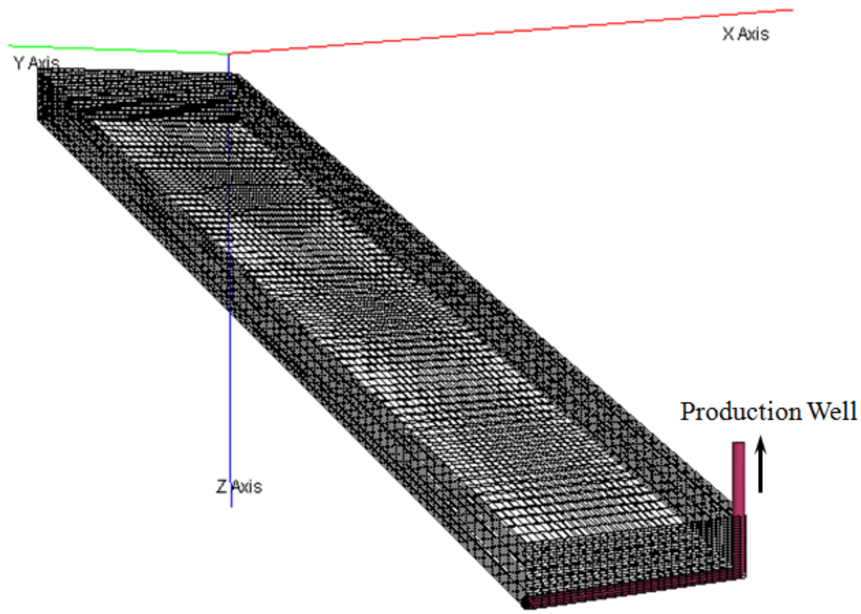


Figure 5.1 Well placement of natural depletion scheme

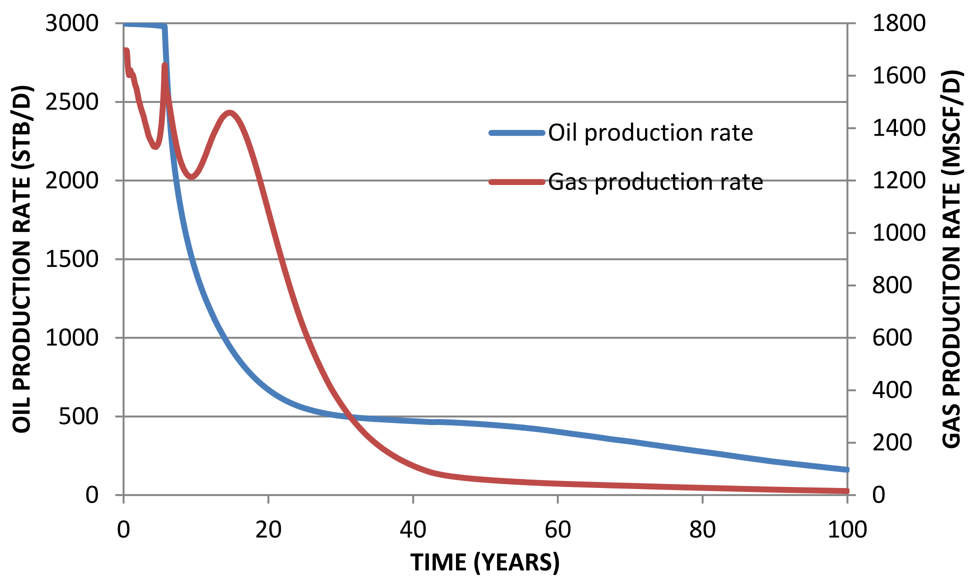


Figure 5.2 Oil and gas production rates of natural depletion scheme

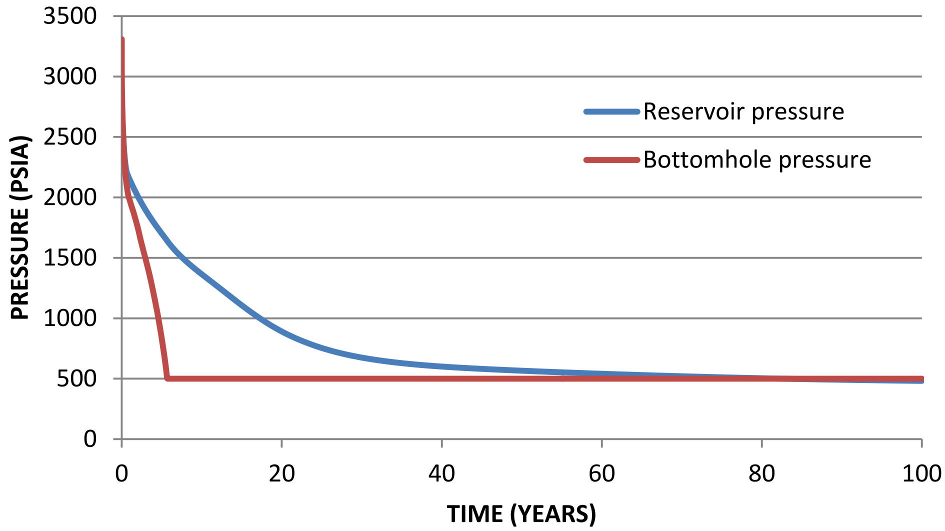


Figure 5.3 Reservoir and bottomhole pressure of natural depletion scheme

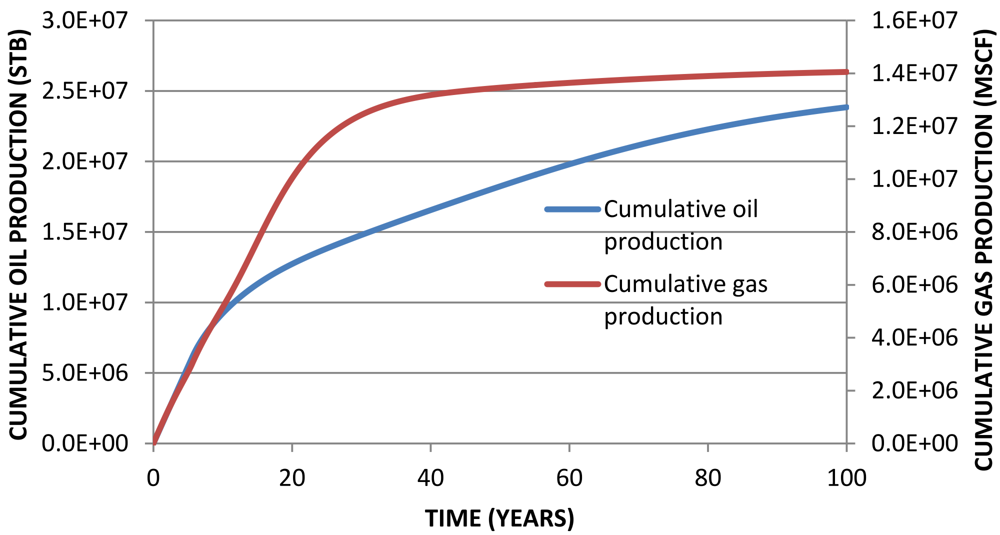


Figure 5.4 Cumulative oil and gas production of natural depletion scheme

The cumulative oil and gas production for the reservoir are illustrated in Figure 5.4. At the end of 30 years of concession period, the cumulative oil and gas productions are 14.78 MMSTB and 12.43 BCF, respectively, yielding oil recovery factor of 41.32%.

While, at the end of production period of 100 years, the cumulative oil is 23.85 MMSTB which is equal to oil recovery factor of 66.64% and the cumulative gas productions is 14.05 BCF.

Simulations are also performed in reservoirs with dip angle of 15 and 60 degrees by using various liquid production rates. The results obtained in these cases have the same trends with the one already discussed. The result summary for every dip angle at 30 years of concession and the end of production is listed in Table 5.1. At the end of 30 years, the maximum recovery is achieved when the production rate is 4000 STB/D for every dip angle. At the end of 100 years, the highest cumulative oil production occurs when the production rate of 4000 STB/D is used for dip angle of 15 and 30 degrees but, for dip angle 60 degrees, oil recovery is the highest when the production rate is 1000 STB/D due to significant gravity effect in a steep dip angle. In general, oil recovery factor becomes higher when the dip angle is increased. This can be explained by considering the effect of gravity in dipping reservoirs. In the steeply inclined reservoirs with a high vertical permeability, gravity encourages gas which comes out of oil during production to migrate upward and form a secondary gas cap. This gas cap provides additional drive energy and thus oil recovery factor is considerably increased in dipping reservoir.

Table 5.1 Summary of results for natural depletion scheme for different dip angles

Dip angle	Qo,prod (STB/D)	ABANDONMENT					30 YEARS			
		Production time (Year)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Net BOE (MMSTB)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Net BOE (MMSTB)
15	1000	100	18.65	52.36	14.23	21.02	10.79	30.28	7.63	12.06
	2000	100	19.07	53.54	14.36	21.46	12.77	35.85	12.72	14.89
	3000	100	19.21	53.92	14.38	21.60	13.06	36.66	13.08	15.24
	4000	100	19.25	54.05	14.38	21.65	13.15	36.91	13.18	15.34
30	1000	100	23.53	65.77	13.67	25.81	10.91	30.50	5.24	11.79
	2000	100	23.80	66.51	13.99	26.13	14.36	40.15	11.88	16.35
	3000	100	23.85	66.64	14.05	26.19	14.78	41.32	12.43	16.86
	4000	100	23.87	66.71	14.07	26.21	14.91	41.68	12.55	17.01
60	1000	98.75	24.25	67.42	13.96	26.58	10.91	30.32	5.87	11.89
	2000	87.75	24.18	67.21	14.01	26.51	17.25	47.96	8.99	18.75
	3000	85.33	24.16	67.18	14.02	26.5	18.12	50.39	9.68	19.74
	4000	84.5	24.16	67.16	14.02	26.5	18.37	51.06	9.86	20.01

5.2 Gas Assisted Gravity Drainage (GAGD)

In this section, GAGD is performed in the same reservoir models as those in section 5.1 in order to study the effect on oil recovery and production profile. Well location of GAGD scheme is illustrated in Figure 5.5. A vertical gas injector is located at middle width on the up-dip side of the reservoir at coordinate (1, 15) with full perforation interval and a horizontal producer is placed downdip in the y-direction in the bottommost grid block. Gas injection starts since the first day of production with the maximum bottomhole injection pressure set at 3300 psia to avoid fracturing the reservoir while the minimum bottomhole pressure for production well is 500 psia. A 30-degree dipping reservoir is selected for describing the reservoir performance during GAGD. The maximum liquid production rate is 3000 STB/D while gas injection rate is set at 3500 MSCF/D.

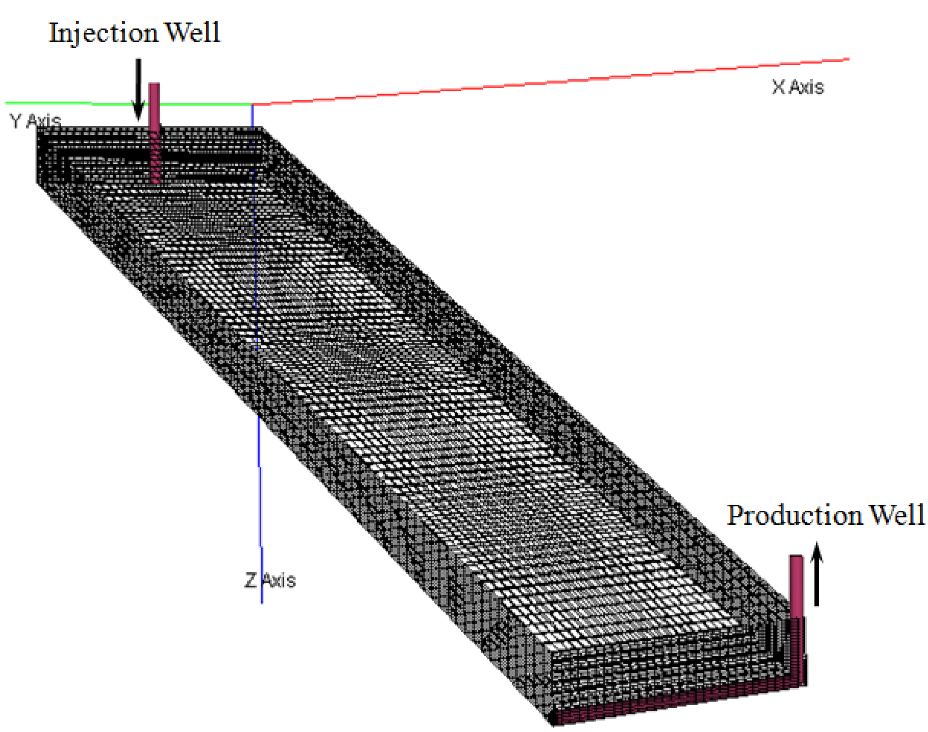


Figure 5.5 Well placement of GAGD base case

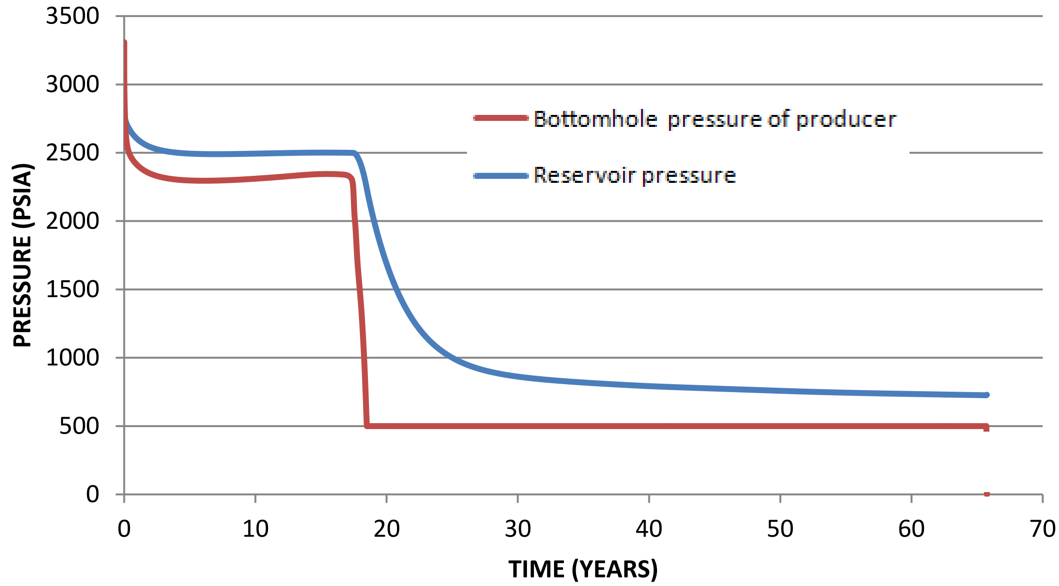


Figure 5.7 Reservoir pressure and bottomhole pressures of GAGD base case

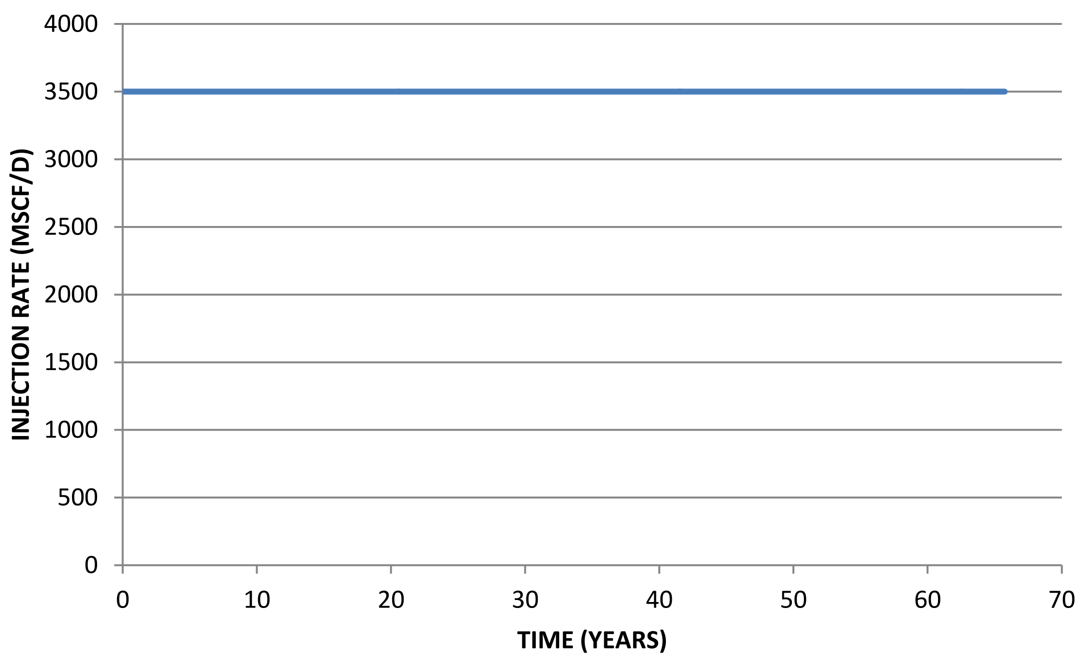


Figure 5.8 Gas injection rate of GAGD base case

Oil and gas production rates are shown in Figure 5.6. Oil is produced at the maximum rate of 3000 STB/D until the injected gas reaches the production well. This causes a drop in oil production rate and reservoir pressure. The bottomhole pressure is kept at 500 psia until the production ends as shown in Figure 5.7. The period that oil is produced at the maximum rate can be extended since the reservoir pressure is maintained by the injected gas. For gas production rate, gas production is quite constant in early stage until gas begins to flow into the producer at 17 years as seen in the sharp increase in gas production rate in Figure 5.6. Once oil production rate decreases, gas production steadily declines and stays at the rate equal to the injection rate. Gas injection rate is constant at 3500 MSCF/D throughout the production as shown in Figure 5.8.

Figure 5.9 shows the cumulative oil and gas production for GAGD base case. At 30 years, the cumulative oil and gas production are 22.91 MMSTB and 47.25 BSCF, respectively, yielding oil recovery factor of 64.02%. At the end of production period of 65 years, the cumulative oil and gas productions are 25.01 MMSTB and 94.54 BCF, respectively, which gives oil recovery factor of 69.89%.

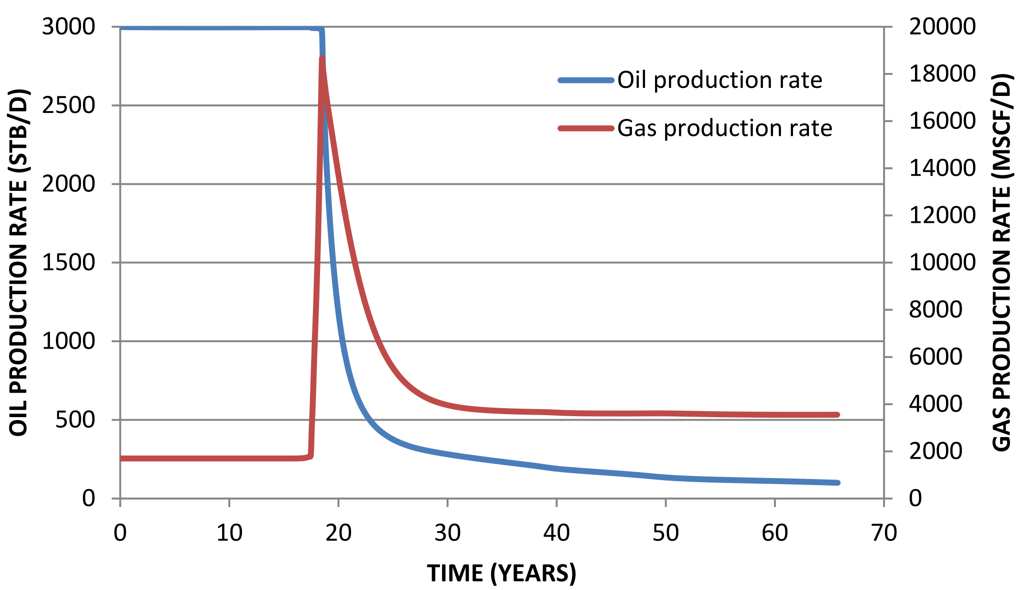


Figure 5.6 Oil and gas production rates of GAGD base case

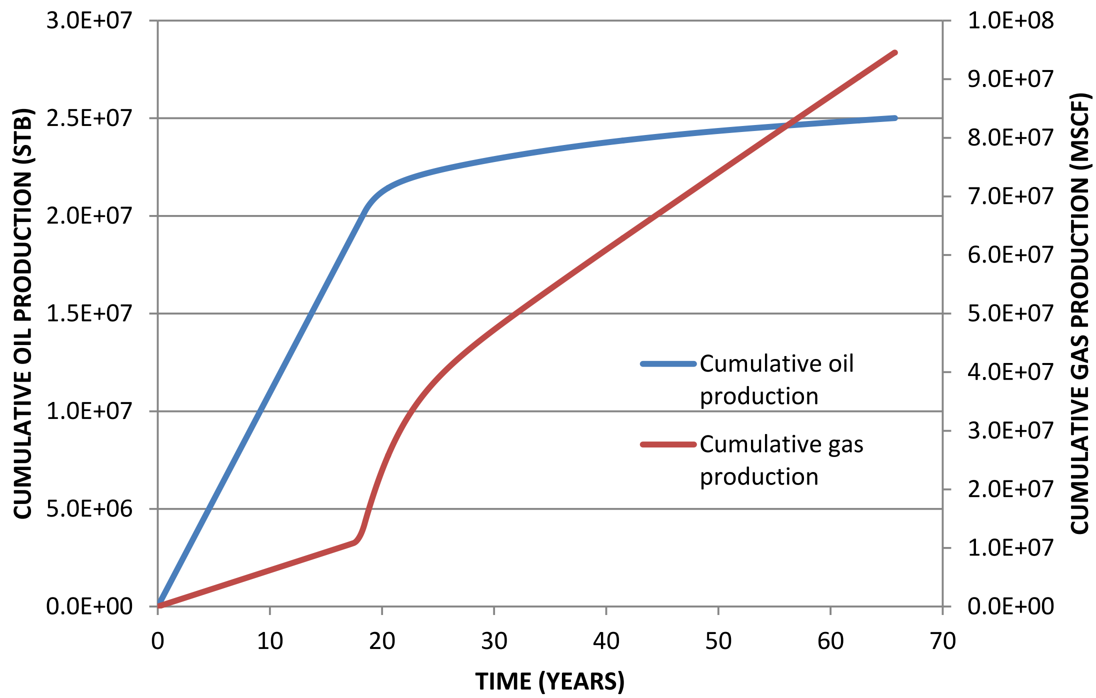


Figure 5.9 Cumulative oil and gas production of GAGD base case

Mechanism of GAGD can be described by considering oil saturation profile in Figure 5.10 (a) to (g). As gas is continuously injected into the reservoir, gas accumulates at the top part of the formation because of its lower density. In Figure 5.10 (b) to (c), gas chamber expands and displaces oil downward towards the horizontal producer and breaks through as illustrated by Figure 5.10 (d). As injection continues, gas chamber grows vertically and diagonally down the reservoir. Thus, more area is swept. Furthermore, in the gas-invaded area, oil saturation still gradually decreases although gas has already broken through. At the end of production as shown in Figure 5.10 (g), most part of the reservoir is swept. There is only a small amount of residual oil left. Thus, higher oil recovery is achieved.

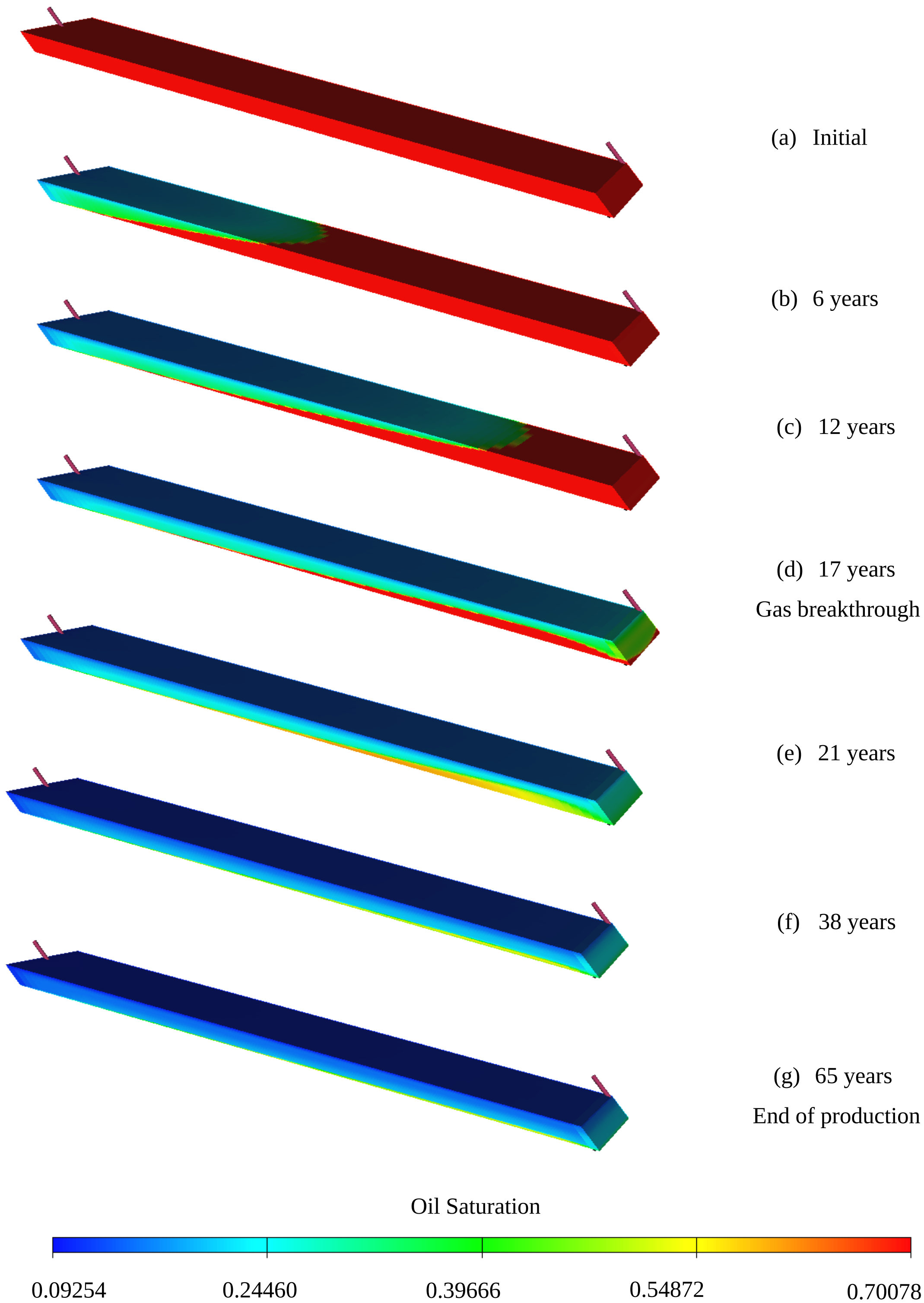


Figure 5.10 Oil saturation profile of GAGD base case

5.3 Effect of production and gas injection rates on GAGD

Production and gas injection rates are parameters that significantly affect GAGD performance. Profitability of a GAGD project considerably changes with different production and gas injection rates. In other words, low production and injection rates allow gravity to dominate the flooding process resulting in high oil recovery but it takes a long production time and thus might not be economically practical. On the other hand, high production and injection rates whose values are beyond the critical rate for gravity drainage causes instabilized flood front and early breakthrough. Therefore, finding the suitable production and injection rates is a critical step in optimizing GAGD process.

Two scenarios will be considered in studying the effects of production and injection rates. In the first scenario, four production rates, i.e., 1000, 2000, 3000 and 4000 STB/D are considered. The injection rate is selected based on the production rate in order to balance the subsurface pressure. In the second scenario, the set of production and injection rates that gives comparatively high BOE at 30 years of concession will be selected and the injection rate will be increased to investigate an increase in BOE.

5.3.1 Dip angle of 15 degrees

In the first scenario, both production rates and gas injection rates are changed. For dip angle of 15 degrees, the injection rates selected are 1100, 2300, 3500 and 4700 MSCF/D, corresponding to the production rates of 1000, 2000, 3000 and 4000 STB/D respectively in order to maintain the reservoir pressure. Oil and gas production rates are illustrated in Figure 5.11 and 5.12, respectively. As illustrated in the Figures, the higher oil production and gas injection rates, the earlier gas breaks through. For high oil production rate, high amount of gas injected is required to maintain the reservoir pressure. Thus, gas breaks through earlier compared to the case of low oil production and gas injection rates. As seen in Figure 5.12, the time required for gas to reach the production well for production rate of 4000, 3000, 2000 and 1000 is around 10, 15, 25 and 67 years, respectively. After gas breakthrough, unswept oil at the bottom of the reservoir can still be displaced by gas until oil production rate reaches the economic rate at 100 STB/D. Furthermore, the reservoir pressure is maintained because gas can be injected at maximum rate for every injection rate as shown in Figure 5.13. This means that the fracture pressure has never been reached.

Cumulative oil and gas productions for the first scenario are illustrated in Figure 5.14 and 5.15, respectively. In addition, the summary of cumulative oil production, cumulative gas production, cumulative gas injection, barrel of oil equivalent (BOE), oil recovery efficiency and production time for different sets of oil production and gas injection rates at the end of production time and 30 years of concession for 15 degree dip angle is listed in Table 5.2. At the end of 30 years, it is obvious that there are three production rates, which are 2000, 3000 and 4000 STB/D, that give comparably high oil recovery and BOE. On the other hand, oil recovery and BOE for the production rate of 1000 STB/D is comparatively lower than other cases because of its very low production rate. As illustrated in Figure 5.16, when oil production rate is 1000 STB/D, there is a large area of the reservoir that oil is not swept by gas at 30 years. Thus, the oil recovery is relatively low. For the gas production and injection, oil production rate of 4000 STB/D yields both the highest gas production and injection, followed by the production rate of 3000, 2000 and 1000 STB/D. At the end of production, a production rate of 1000 STB/D gives the highest oil production at 25.18 MMSTB (70.68% RF). While the production rate of 2000, 3000 and 4000 STB/D give slightly lower oil recovery at around 69%. This is because, when a low production rate is used, gas has enough time to segregate from oil and migrate to the top, forming a secondary gas cap. This gas cap helps to provide drive energy. At the same time, migration of gas also delays gas breakthrough. Consequently, higher oil recovery is achieved. For gas production and injection, the production rate of 4000 STB/D also gives both the highest total amount of gas production and injection.

In addition, Table 5.2 shows the results of natural depletion scheme comparing with those of GAGD. At the end of 30 years, oil recovery of GAGD is higher for all study production rates. About 20% of additional oil recovery is obtained by implementing GAGD except for the production rate of 1000 STB/D that oil recovery is about the same as that of natural depletion. In term of BOE, GAGD provides significantly higher BOE when production rate is 2000, 3000 and 4000 STB/D. However, when production rate of 1000 STB/D is used in GAGD, the BOE is slightly lower. This is because, at the end of 30 years, the injected gas in GAGD process does not break through which means that only dissolved gas is produced. Thus, with the same oil recovery, higher amount of gas produced by natural depletion results in higher BOE. At the end of production, gas production and oil recovery for GAGD are considerably higher than those of natural depletion for every production rate. 15-18% of Additional oil recovery of is achieved with shorter production time.

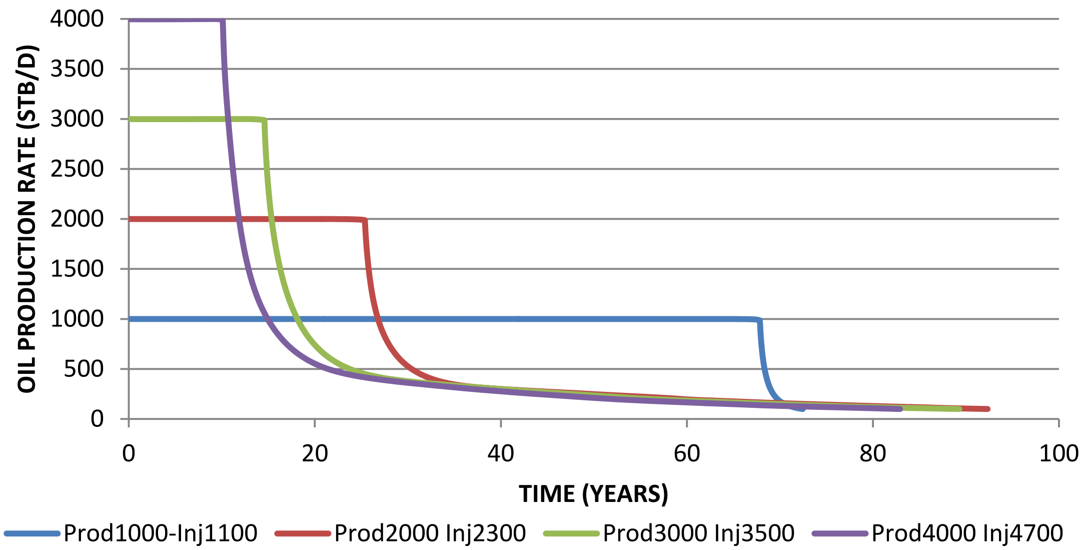


Figure 5.11 Oil production rate for different sets of gas injection and oil production rates (15-degree dip angle)

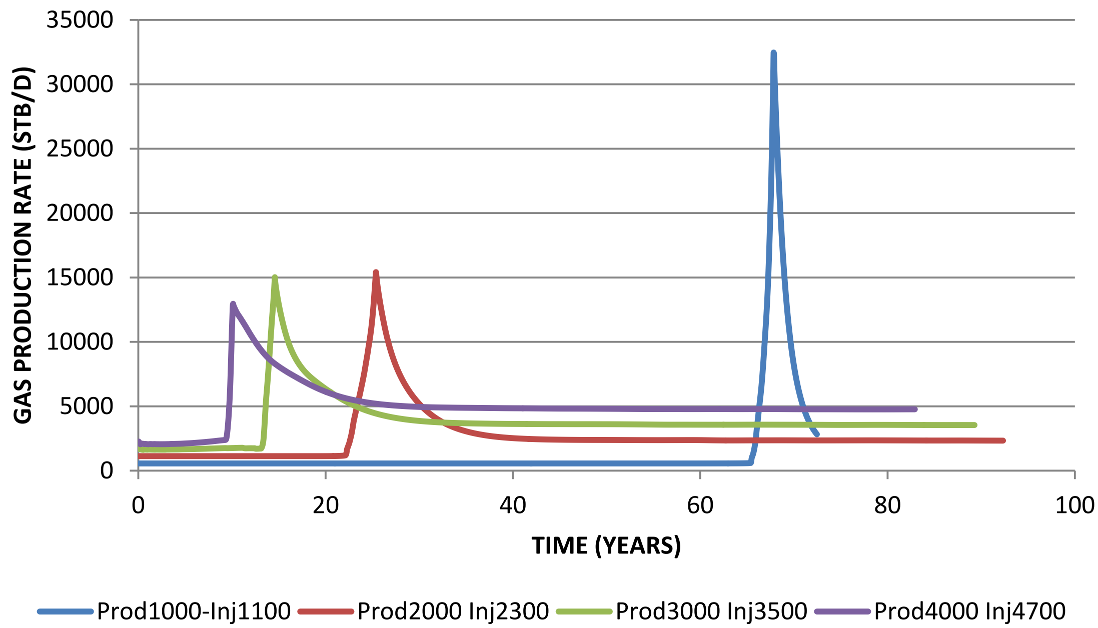


Figure 5.12 Gas production rate for different sets of gas injection and oil production rates (15-degree dip angle)

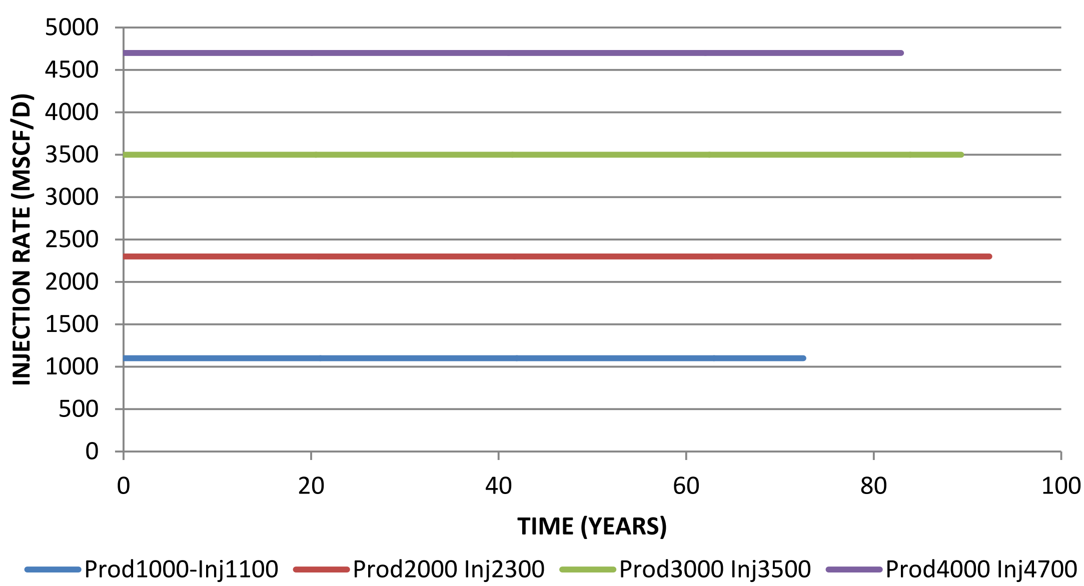


Figure 5.13 Gas injection rate for different sets of gas injection and oil production rates (15-degree dip angle)

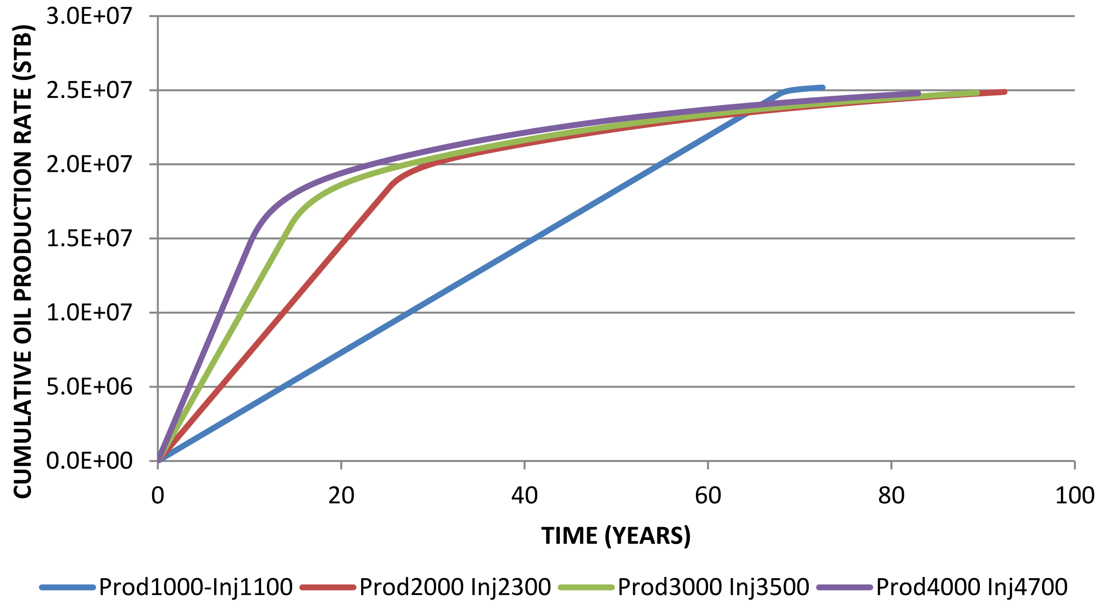


Figure 5.14 Gas injection rate for different sets of gas injection and oil production rates (15-degree dip angle)

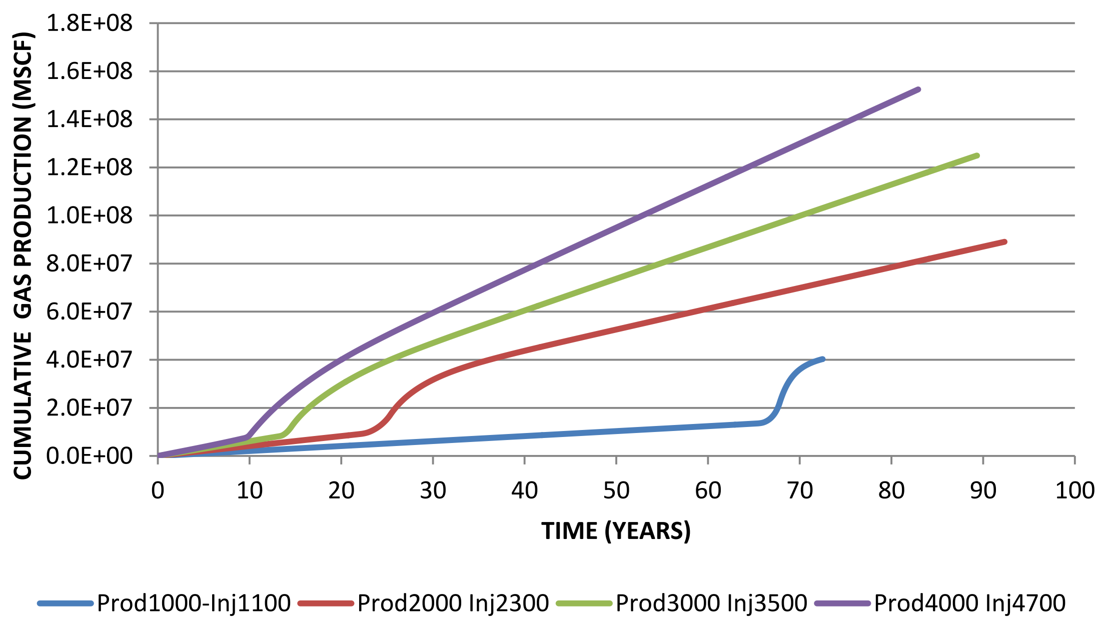
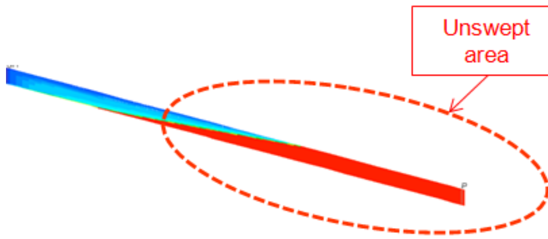
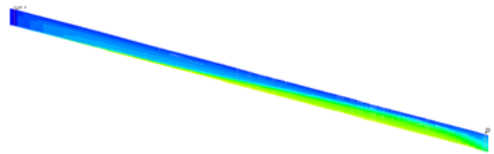


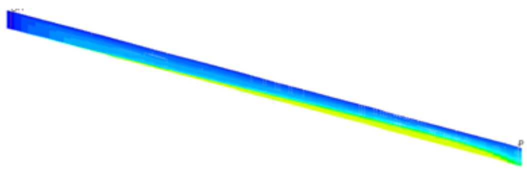
Figure 5.15 Cumulative gas production for different sets of gas injection and oil production rates (15-degree dip angle)

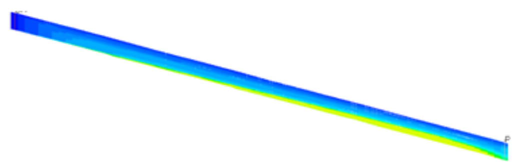




(a) Oil production rate: 1000 STB/D
Gas injection rate: 1100MSCF/D

(b) Oil production rate: 2000 STB/D
Gas injection rate: 2300MSCF/D





(c) Oil production rate: 3000 STB/D
Gas injection rate: 3500MSCF/D

(d) Oil production rate: 4000 STB/D
Gas injection rate: 4700MSCF/D

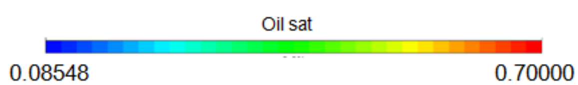


Figure 5.16 Oil saturation profile at 30 years for different sets of oil production and gas injection rates (15-degree dip angle)

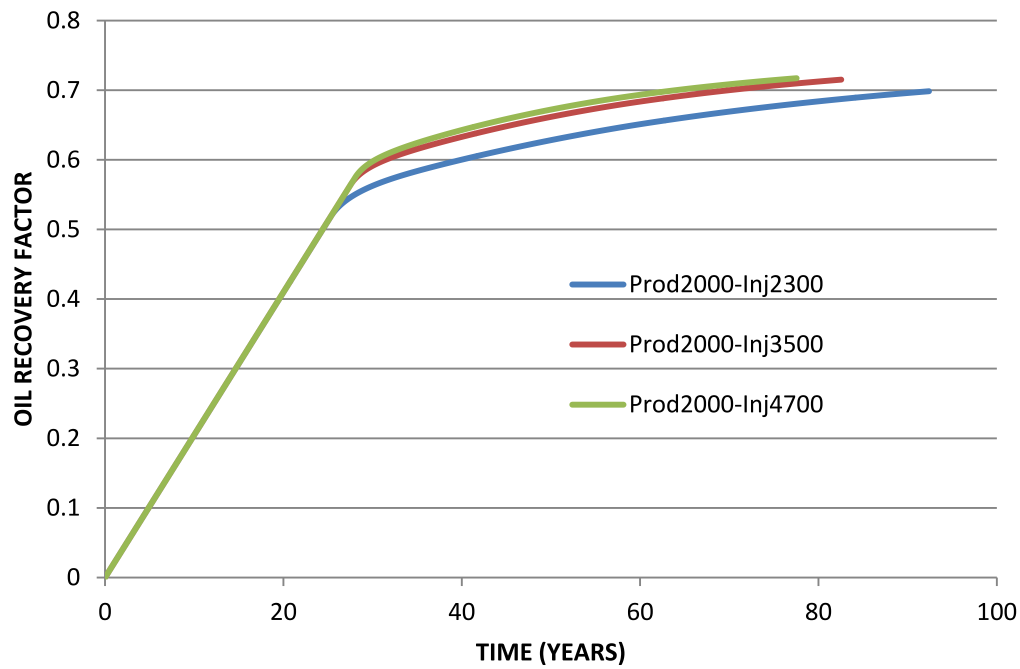
Table 5.2 Summary of results for different sets of oil production and gas injection rates (15-degree dip angle)

	Qo,prod	Qg,inj	ABANDONMENT						30 YEARS				
	(STB/D)	(MSCF/D)	Production time (Year)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
GAGD	1000	1100	72.50	25.18	70.68	40.26	29.13	27.03	10.95	30.75	6.20	12.05	9.98
	2000	2300	92.33	24.88	69.85	89.06	77.56	26.80	20.05	56.28	31.67	25.20	21.12
	3000	3500	89.33	24.83	69.70	124.91	114.20	26.61	20.41	57.29	46.97	38.35	21.84
	4000	4700	82.91	24.79	69.60	152.44	142.34	26.47	20.98	58.89	59.51	51.50	22.31
Natural depletion	1000	-	100	18.65	52.36	14.23	-	21.02	10.79	30.28	7.63	-	12.06
	2000	-	100	19.07	53.54	14.36	-	21.46	12.77	35.85	12.72	-	14.89
	3000	-	100	19.21	53.92	14.38	-	21.60	13.06	36.66	13.08	-	15.24
	4000	-	100	19.25	54.05	14.38	-	21.65	13.15	36.91	13.18	-	15.34

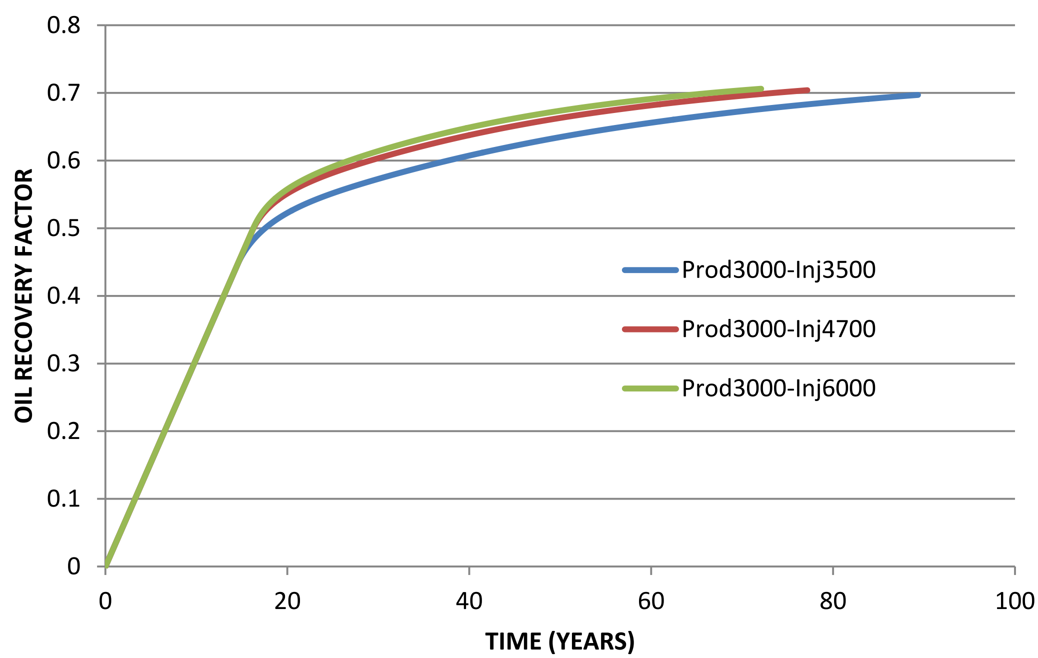
In the second scenario, gas injection rate is increased while the oil production rate is fixed at 2000, 3000 and 4000 STB/D. From the first scenario, it is clearly seen that production rate should be more than 1000 STB/D so that high oil recovery is achieved within 30 years. The combinations of gas injection and oil production rates studied are listed in Table 5.3. The results indicate that increasing gas injection rates results in higher oil recovery. However, when the gas injection rate outweighs the oil production rate, the effect of increasing gas injection rate becomes smaller as seen in a slight increase in oil recovery as illustrated in Table 5.3 and Figure 5.17. This is because the injector bottom-hole pressure reaches the maximum injection pressure at 3,300 psia and thus the intended maximum gas injection rate cannot be achieved as shown Figures 5.18 and 5.19. From Table 5.3, case 8 is probably the most attractive operating condition because it gives comparatively high BOE. Although the BOE of case 8 is slightly lower than the highest BOE of case 9, the gas injection rate, the total amount of gas production and injection are lower. Therefore, case 8 is considered to be the most suitable production strategy for the reservoir.

Table 5.3 Summary of results for different gas injection rates at the end of 30 years (15-degree dip angle)

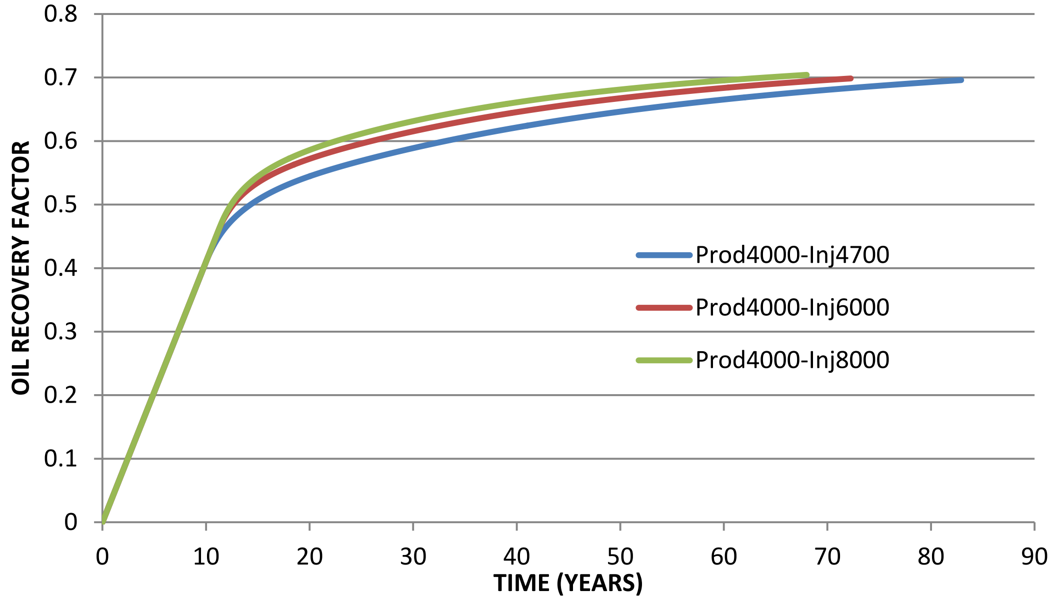
CASE	Qo,prod (STB/D)	Qg,inj (MSCF/D)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
1	2000	2300	20.05	56.28	31.67	25.20	21.12
2		3500	21.07	59.14	38.72	35.42	21.62
3		4700	21.30	59.80	40.09	38.4	21.58
4	3000	3500	20.41	57.29	46.97	38.35	21.84
5		4700	21.50	60.35	59.26	51.48	22.80
6		6000	21.87	61.40	65.81	59.00	23.01
7	4000	4700	20.98	58.89	59.51	51.50	22.31
8		6000	21.92	61.53	73.06	65.75	23.14
9		8000	22.49	63.14	86.83	80.69	23.51



(a) Maximum oil production rate is 2000 STB/D

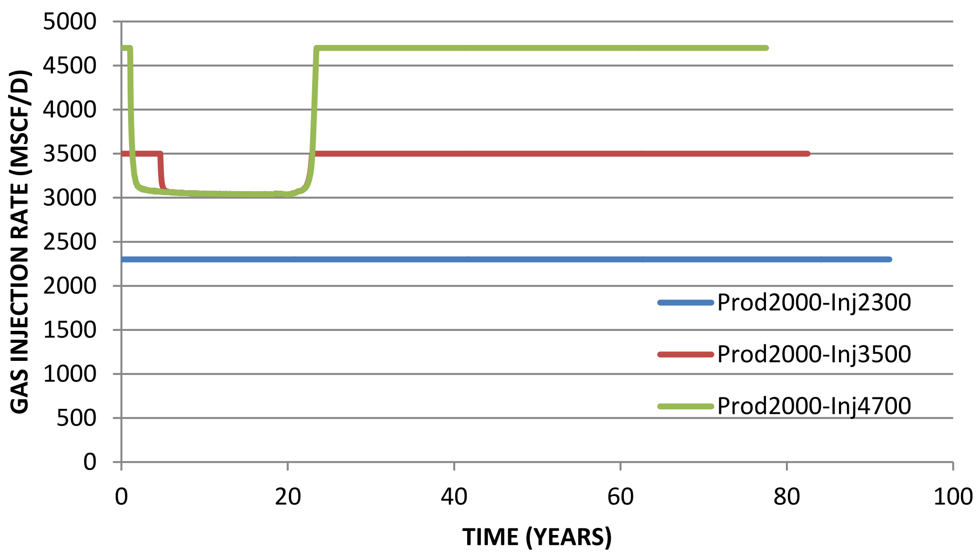


(b) Maximum oil production rate is 3000 STB/D

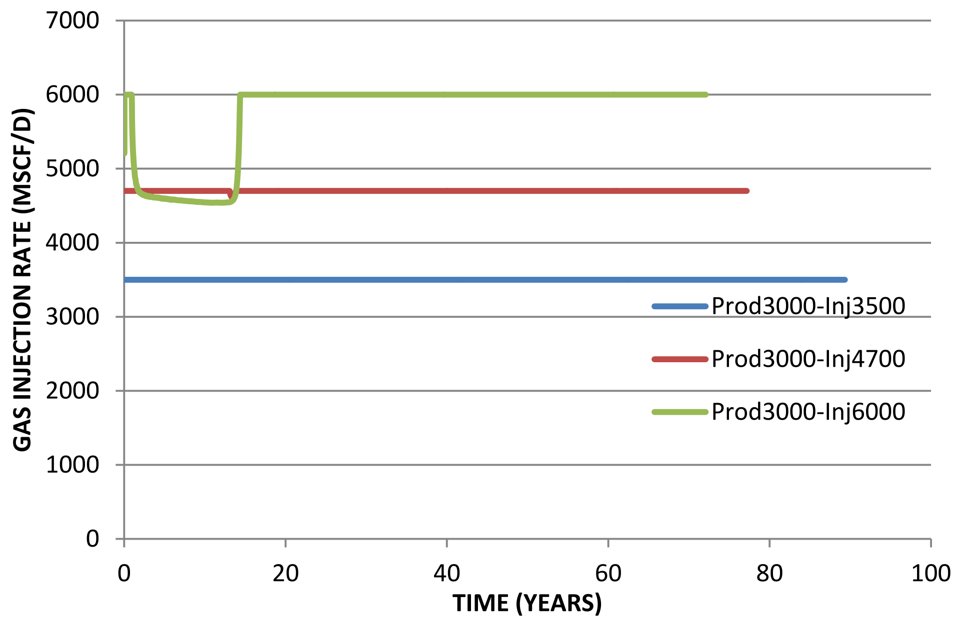


(c) Maximum oil production rate is 4000 STB/D

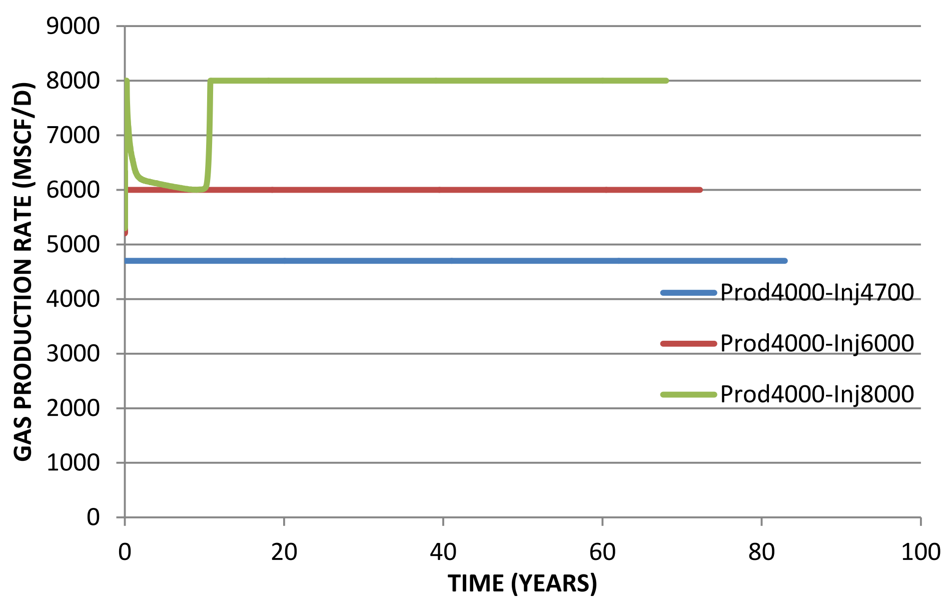
Figure 5.17 Oil recovery efficiency for different gas injection rates when maximum oil production rate is fixed at 2000, 3000 and 4000 STB/D (15-degree dip angle)



(a) Maximum oil production rate is 2000 STB/D

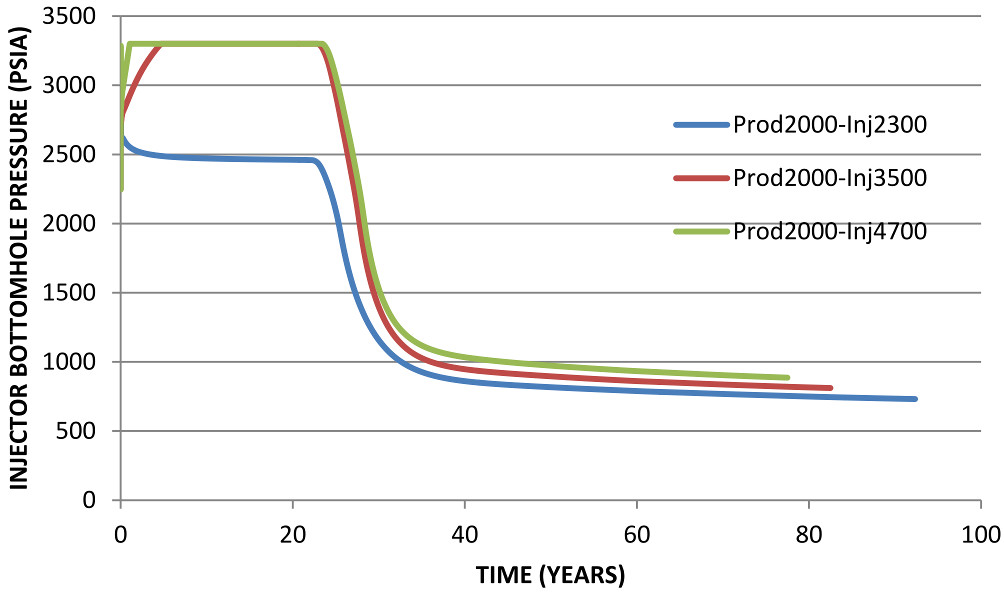


(b) Maximum oil production rate is 3000 STB/D

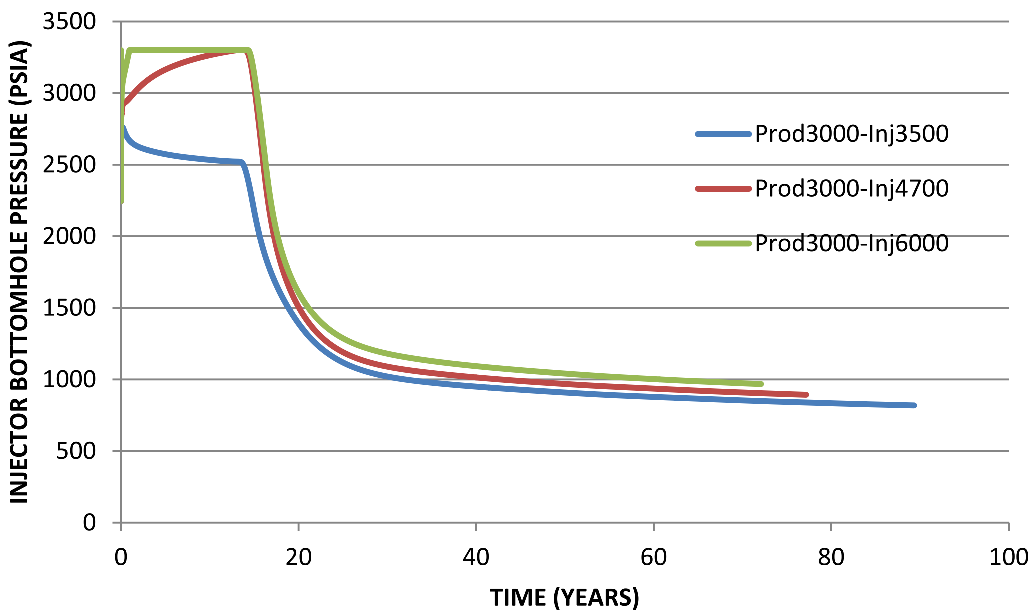


(c) Maximum oil production rate is 4000 STB/D

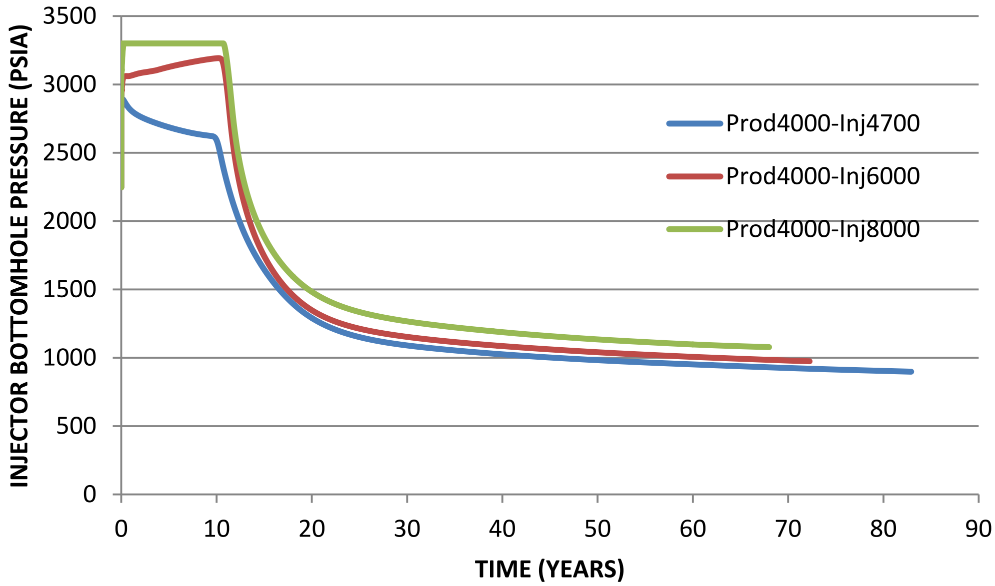
Figure 5.18 Gas injection rate when maximum oil production rate is fixed at 2000, 3000 and 4000 STB/D (15-degree dip angle)



(a) Maximum oil production rate is 2000 STB/D



(b) Maximum oil production rate is 3000 STB/D



(c) Maximum oil production rate is 4000 STB/D

Figure 5.19 Injection well bottomhole pressure when maximum oil production rate is fixed at 2000, 3000 and 4000 STB/D (15-degree dip angle)

5.3.2 Dip angle of 30 degrees

The effects of production and injection rates are also studied in the reservoir with dip angle of 30 degrees. In the first scenario, the injection rates selected for dip angle of 30 degrees are 1200, 2500, 3700 and 4900 MSCF/D, corresponding to production rate 1000, 2000, 3000 and 4000 STB/D, respectively. Higher gas injection rate is required to maintain the reservoir pressure in comparison to the 15-degree case due to the higher reservoir pressure in reservoir higher dip angle.

Production profiles obtained from the 30-degree reservoir are similar to those obtained from the 15-degree dip angle case. Oil production rate and gas injection rate are shown in Figure 5.20 and 5.21, respectively. Oil is produced at the maximum rate until gas arrives at the production well and causes oil production to decline. The time required for gas to reach the production well for oil production rates of 4000, 3000, 2000 and 1000 STB/D is around 12, 18, 31 and 70 years, respectively. It can be noted that time required for gas to break through in the 30-degree dipping reservoir is slightly longer compared to that in the 15-degree dipping reservoir. The later time for gas to break through indicates that gravity effect is increased by the increasing dip angle. For gas production, the results are similar to the ones from dip angle of 15 degrees. Increasing gas injection rate results in earlier gas breakthrough due to the higher amount of gas injected. In addition, the maximum gas injection rates can be achieved throughout the production time as illustrated in Figure 5.22.

Cumulative oil and gas production are illustrated in Figure 5.23 and 5.24, respectively. In addition, the summary of cumulative oil production, cumulative gas production, cumulative gas injection, barrel of oil equivalent (BOE), oil recovery efficiency and production time for different sets of production and gas injection rates at the end of production time and 30 years of concession for 30 degree dip angle is listed in Table 5.4. At the end of 30 years, two oil production rates which are 3000 and 4000 STB/D give relatively high oil recovery and BOE. While, production rate of 1000 and 2000 STB/D yield significantly lower oil recovery because the time required for gas to completely sweep oil and break through for these gas injection rates is much longer than the production time. Thus, only small amount of recoverable oil is produced within 30 years of production. Cumulative gas production and injection are relatively high for the production rate of 3000 and 4000 STB/D due to gas breakthrough occurring within 30 years. At the end of production, like in the 15-degree case, a production rate of 1000 STB/D gives the highest oil production at 26.16 MMSTB (73.10% RF) and also yield lowest gas production. While, the production rate of 2000, 3000 and 4000 STB/D give slightly lower oil recovery at 69.88, 69.95 and 69.94 %, respectively. For gas production and injection, the production rate of 4000 STB/D yields the highest total amount of both gas production and injection.

In addition, Table 5.4 shows the results of natural depletion scheme comparing with those of GAGD. At the end of 30 years, oil recovery is significantly increased when the production rate is 2000, 3000 and 4000 STB/D. Additional oil recovery obtained when these three production rate is used is in the range of 21% to 23%. On the other hand, the oil recovery of GAGD is about the same as that of natural depletion when the production rate is 1000 STB/D because oil can be produced effectively for this production rate at the end of 30 years. In term of BOE, GAGD provides significantly higher BOE for production rate of is 2000, 3000 and 4000 STB/D. However, when production rate is 1000 STB/D, the BOE is slightly lower. This is because the amount of gas injected during GAGD reduces the BOE. At the end of production, GAGD provides higher gas production and oil recovery than those of natural depletion for every production rate. Furthermore, the production time is considerably reduced for every production rate.

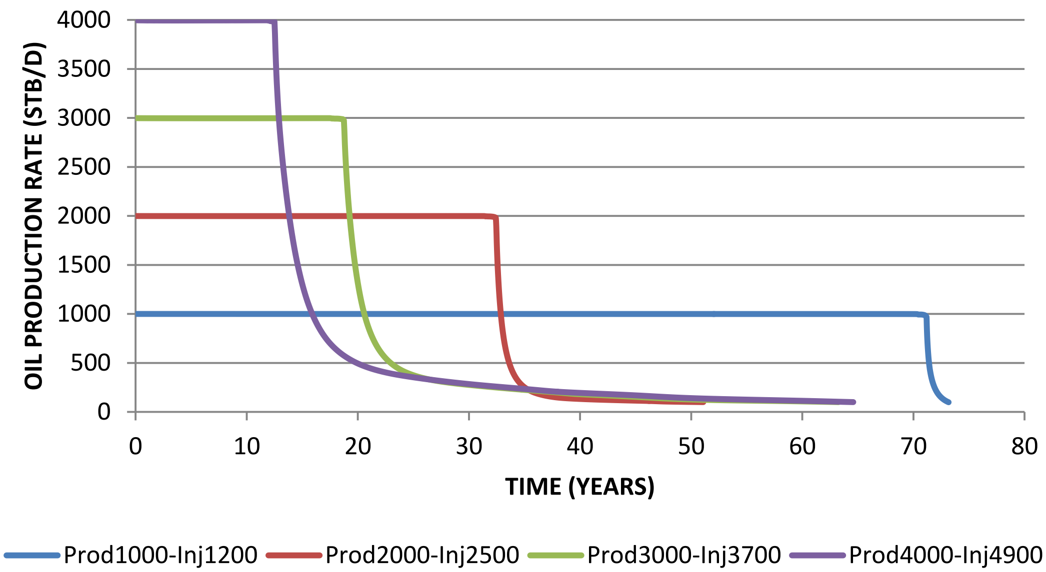


Figure 5.20 Oil production rate for different sets of gas injection and oil production rates (30-degree dip angle)

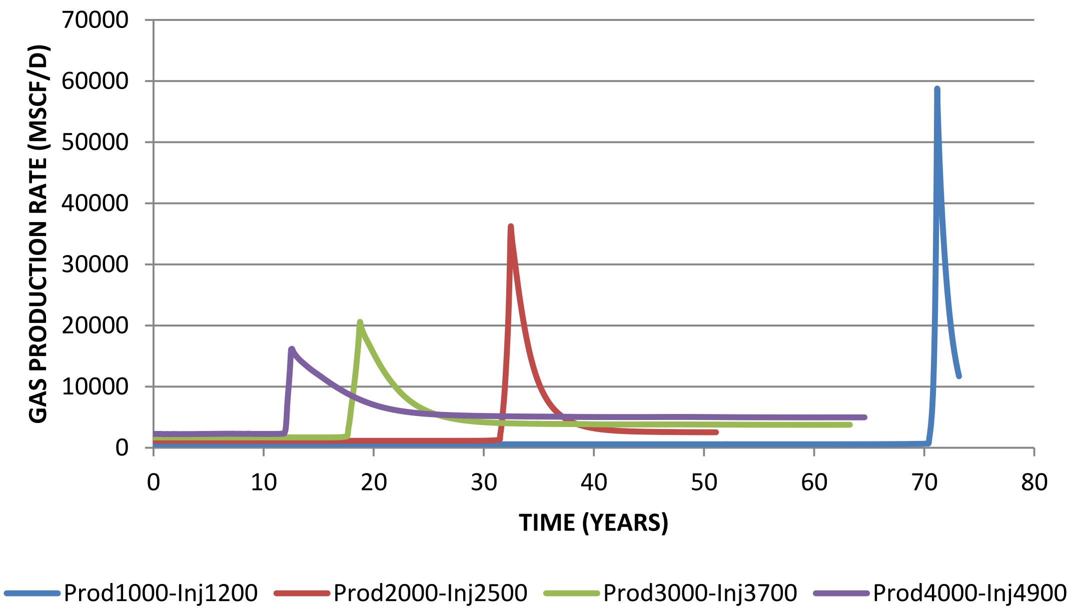


Figure 5.21 Gas production rate for different sets of gas injection and oil production rates (30-degree dip angle)

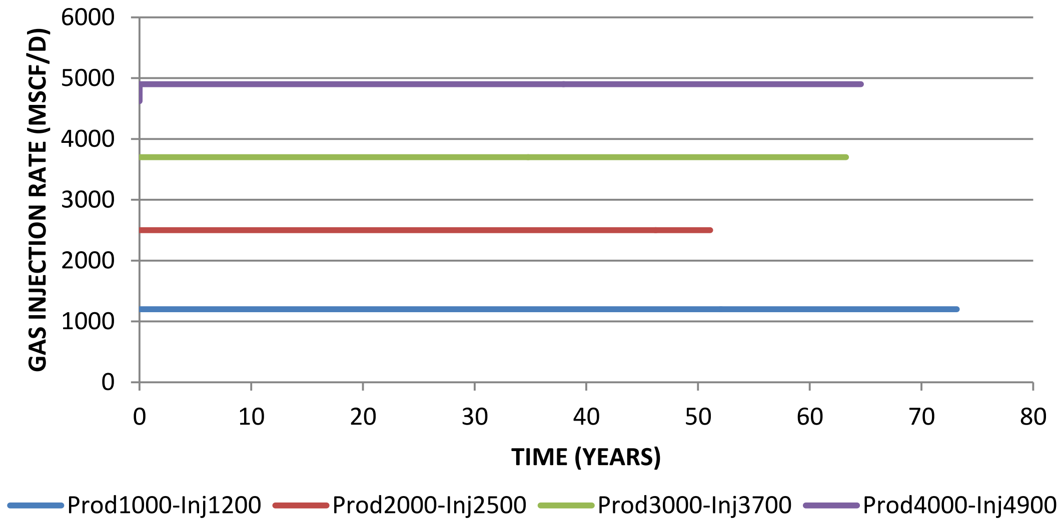


Figure 5.22 Gas injection rate for different sets of gas injection and oil production rates (30-degree dip angle)

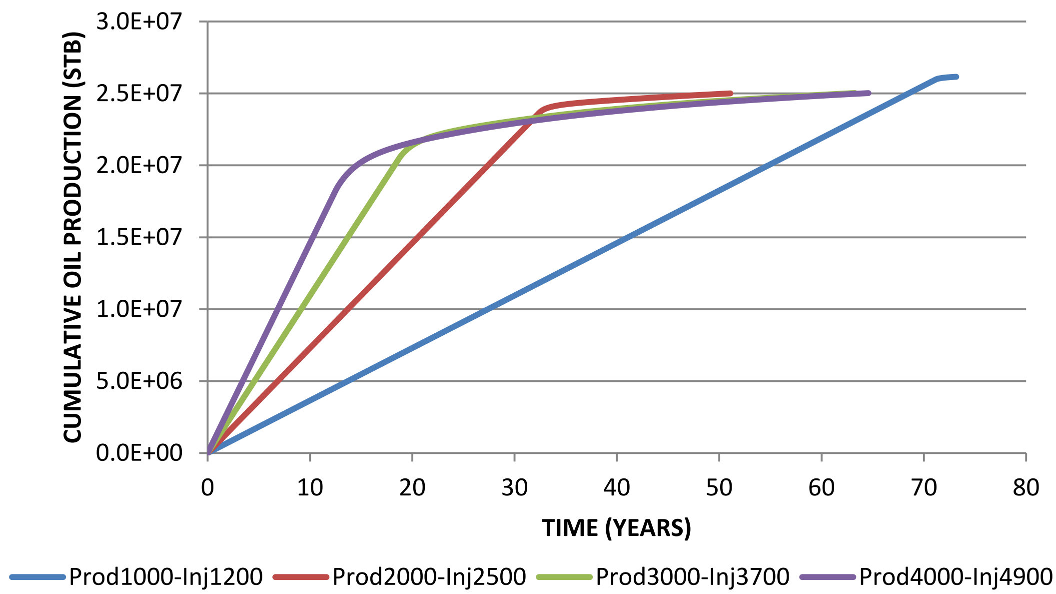


Figure 5.23 Cumulative oil production for different sets of gas injection and oil production rates (30-degree dip angle)

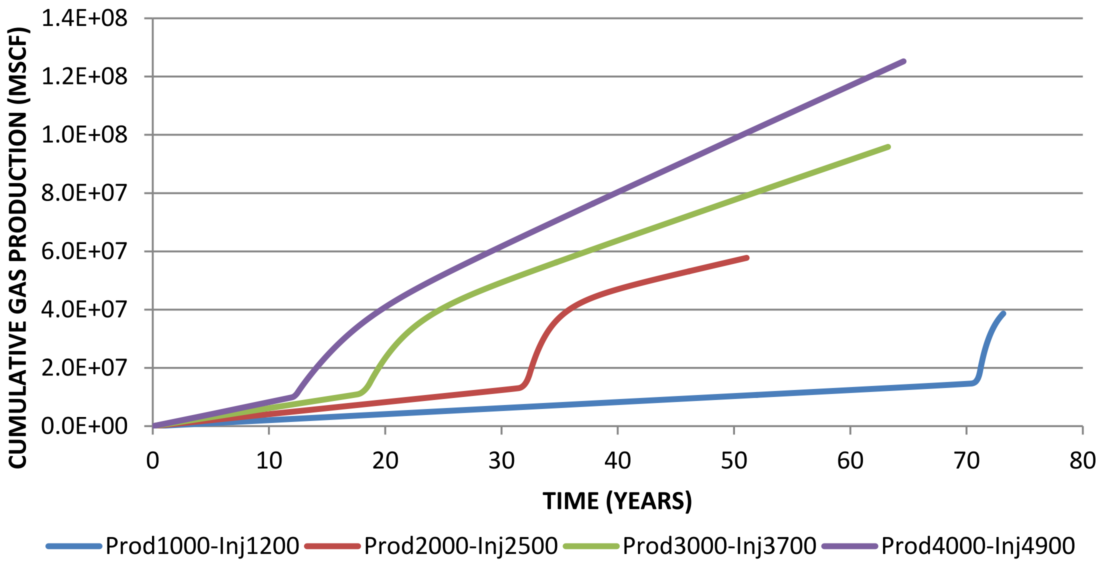


Figure 5.24 Cumulative gas production for different sets of gas injection and oil production rates (30-degree dip angle)

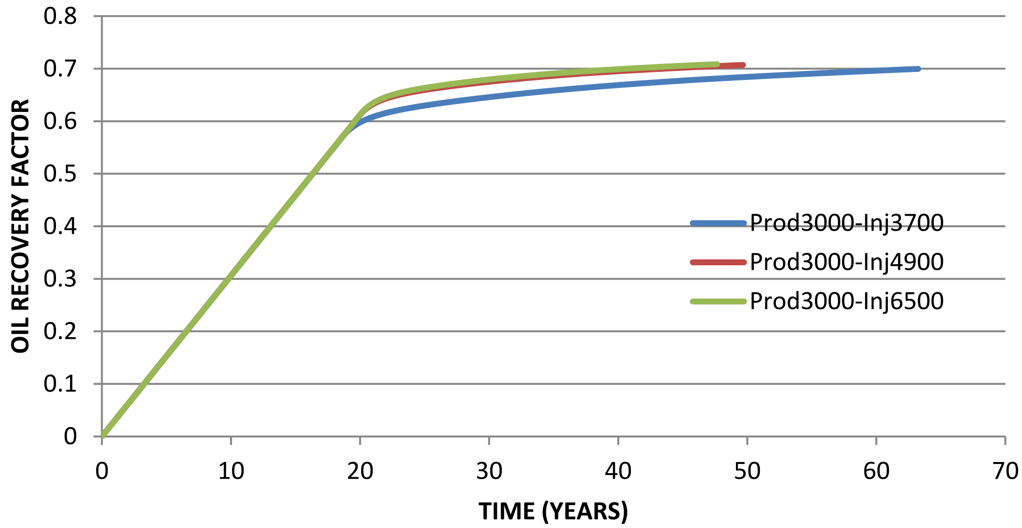
Table 5.4 Summary of results for different sets of oil production and gas injection rates (30-degree dip angle)

	Qo,prod (STB/D)	Qg,inj (MSCF/D)	ABANDONMENT						30 YEARS				
			Production time (Year)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
GAGD	1000	1200	73.16	26.16	73.10	38.66	32.07	27.26	10.95	30.61	6.20	13.15	9.79
	2000	2500	51.09	25.01	69.88	57.78	46.65	26.86	21.90	61.21	12.40	27.40	19.40
	3000	3700	63.25	25.03	69.95	95.87	85.47	26.76	23.10	64.57	49.32	40.54	24.57
	4000	4900	64.58	25.02	69.94	125.23	115.43	26.66	22.92	64.05	61.70	53.69	24.25
Natural depletion	1000	-	100	23.53	65.77	13.67	-	25.81	10.91	30.50	5.24	-	11.79
	2000	-	100	23.80	66.51	13.99	-	26.13	14.36	40.15	11.88	-	16.35
	3000	-	100	23.85	66.64	14.05	-	26.19	14.78	41.32	12.43	-	16.86
	4000	-	100	23.87	66.71	14.07	-	26.21	14.91	41.68	12.55	-	17.01

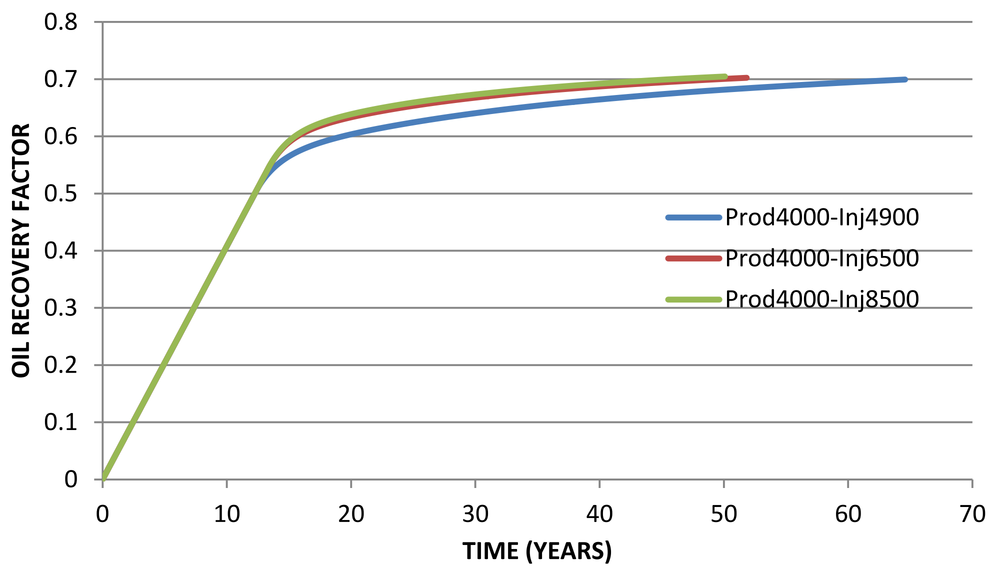
In the second scenario, gas injection rate is increased in order to increase oil production. From the first scenario, it is clearly seen that there are only two production rates which are 3000 and 4000 STB/D that provide relatively high BOE. The combinations of gas injection and oil production rates studied are listed in Table 5.5. The results indicate that increasing gas injection rate results in higher oil recovery. However, when increasing gas injection rate to a very high rate, the bottomhole pressure of the injector reaches the fracture pressure. The injection rate then has to be reduced to control the bottomhole pressure not to exceed the fracture pressure. As a result, the effect of increasing an injection rate is small and BOE becomes similar as shown in Table 5.5 and Figure 5.25. Injection rate and the injection well for each oil production rate is shown in Figure 5.26 and 5.27, respectively. From Table 5.5, case 2 is considered to be the most suitable production strategy for the reservoir since it provides the highest BOE with comparatively small amount of total gas injection.

Table 5.5 Summary of results for different gas injection rates at the end of 30 years (30-degree dip angle)

CASE	Qo,prod (STB/D)	Qg,inj (MSCF/D)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
1	3000	3700	23.1	64.57	49.32	40.54	24.57
2		4900	24.15	67.51	60.22	52.15	25.50
3		6500	24.31	67.93	65.98	58.95	25.48
4	4000	4900	22.92	64.05	61.70	53.69	24.25
5		6500	23.89	66.77	76.95	69.7	25.10
6		8500	24.09	67.32	88.50	82.36	25.11

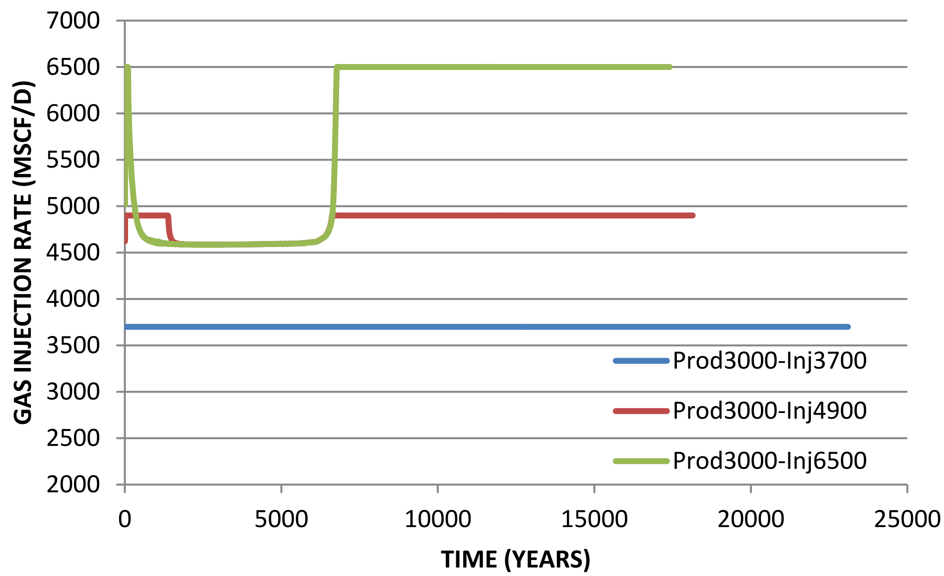


(a) Maximum oil production rate is 3000 STB/D

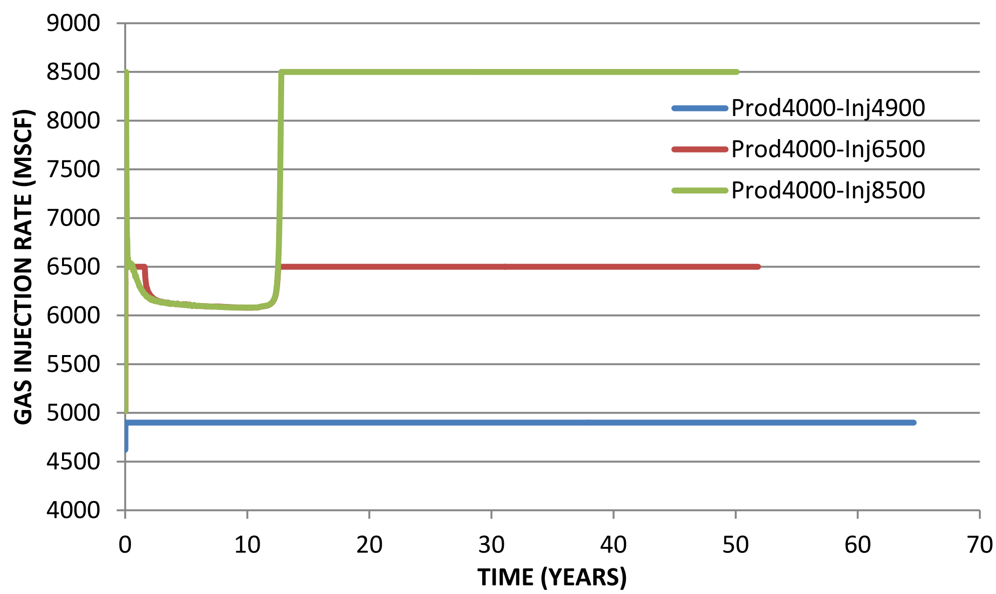


(b) Maximum oil production rate is 4000 STB/D

Figure 5.25 Oil recovery efficiency for different gas injection rates when maximum oil production rate is fixed at 3000 and 4000 STB/D (30-degree dip angle)

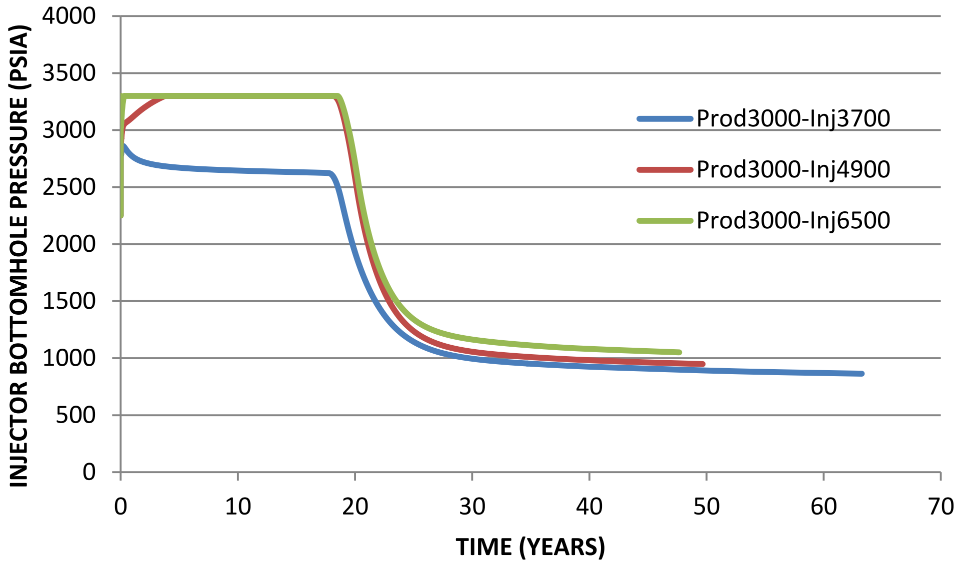


(a) Maximum oil production rate is 3000 STB/D

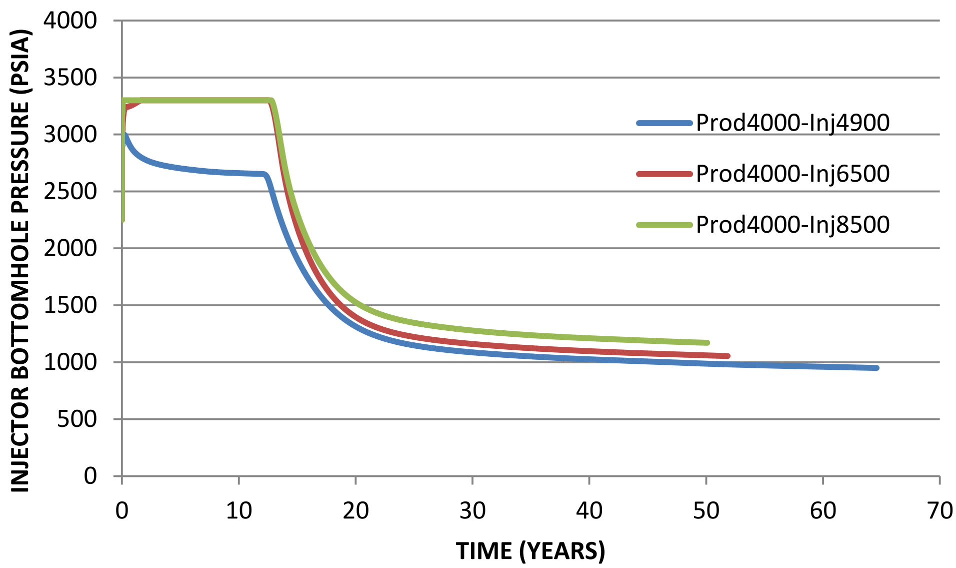


(b) Maximum oil production rate is 4000 STB/D

Figure 5.26 Gas injection rate when maximum oil production rate is fixed at 3000 and 4000 STB/D (30-degree dip angle)



(a) Maximum oil production rate is 3000 STB/D



(b) Maximum oil production rate is 4000 STB/D

Figure 5.27 Injection well bottomhole pressure when maximum oil production rate is fixed at 3000 and 4000 STB/D (30-degree dip angle)

5.3.3 Dip angle of 60 degrees

In the first scenario which production rate is changed as well as gas injection rate, the injection rates selected for dip angle of 60 degrees are 1400, 3100, 4300 and 5400 MSCF/D, corresponding to production rate 1000, 2000, 3000 and 4000 STB/D, respectively.

Oil production rate, gas production are depicted in Figure 5.28 and 5.29, respectively. As shown in Figure 5.28, the oil production rate of 60-degree case is similar to the 15-degree and 30- degree cases. Oil is produced at the maximum rate until gas start to flow into well, reducing oil relative permeability and causing oil production to decline. Figure 5.29 indicates that gas breaks through earlier when increasing production and injection rates. The time that gas arrives at the production well for production rates of 4000, 3000, 2000 and 1000 STB/D are 13, 18, 32 and 71 years, respectively. It can be observed that gas breaks through in the 60-degree case slightly later than in 15- and 30-degree case. The longer time for gas to break through indicates that the effect of gravity becomes significant in steeply dipping reservoir. The maximum gas injection rates can be achieved throughout production time as shown in Figure 5.30.

Cumulative oil and gas production are illustrated in Figure 5.31 and 5.32, respectively, and the summary of cumulative oil production, cumulative gas production, cumulative gas injection, barrel of oil equivalent (BOE), oil recovery efficiency and production time for different gas injection rates at the end of production time and 30 years of concession for 60-degree dip angle are listed in Table 5.6. At 30 years, only production rate of 3000 and 4000 STB/D give comparatively high BOE. This is because gas has swept most of the reservoir area and arrived at the production well within the production time. On the other hand, production rate of 1000 and 200 STB/D provide relatively lower BOE because of the low production rates.

At the end of production, a production rate of 1000 STB/D gives the highest oil production at 26.77 MMSTB (74.43% RF) and also yield the lowest gas production like in the cases of the 15-degree and 30-degree dipping reservoir. The effect of gravity becomes increased with increasing dip angle as seen in an increase in oil recovery factor both in natural depletion and GAGD process.

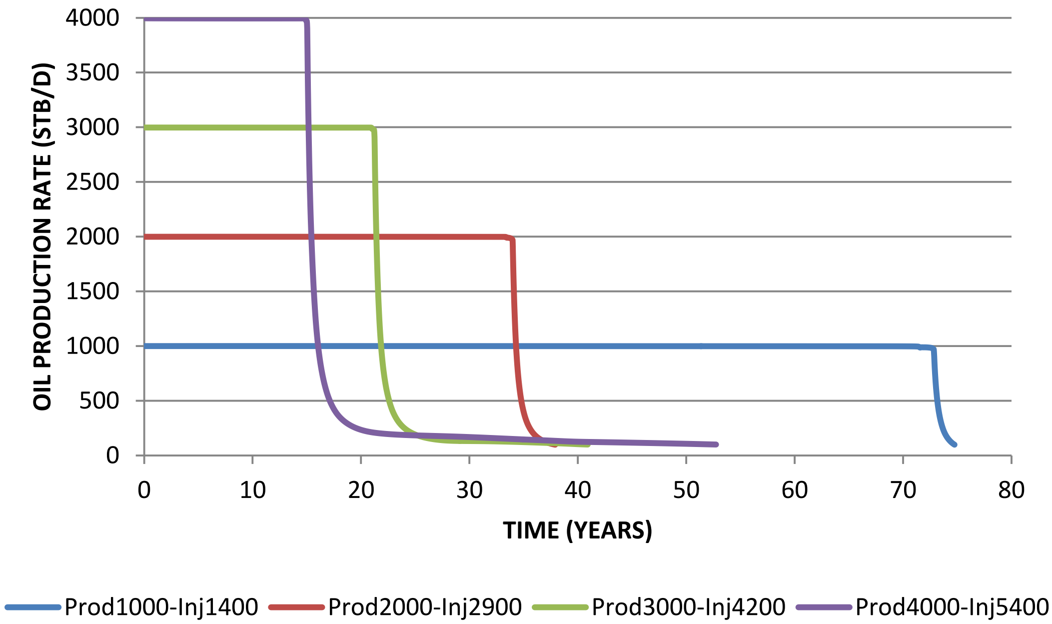


Figure 5.28 Oil production rate for different sets of gas injection and oil production rates (60-degree dip angle)

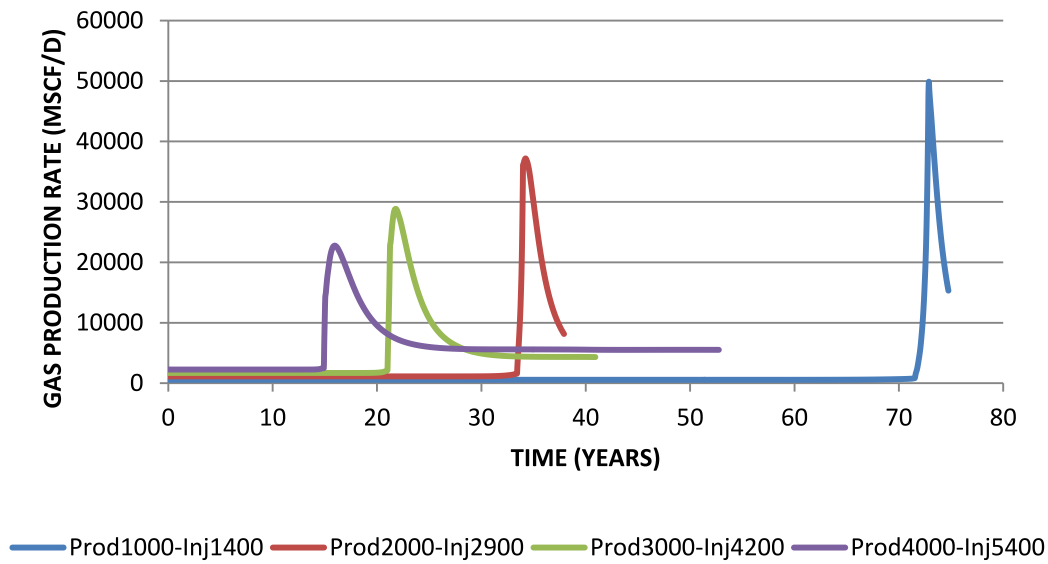


Figure 5.29 Gas production rate for different sets of gas injection and oil production rates (60-degree dip angle)

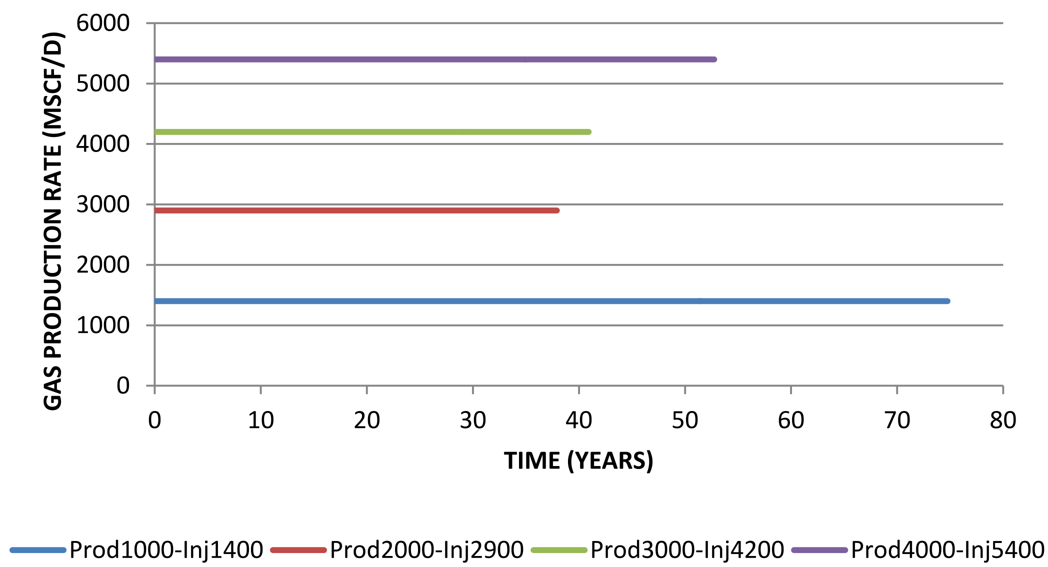


Figure 5.30 Gas injection rate for different sets of gas injection and oil production rates (60-degree dip angle)

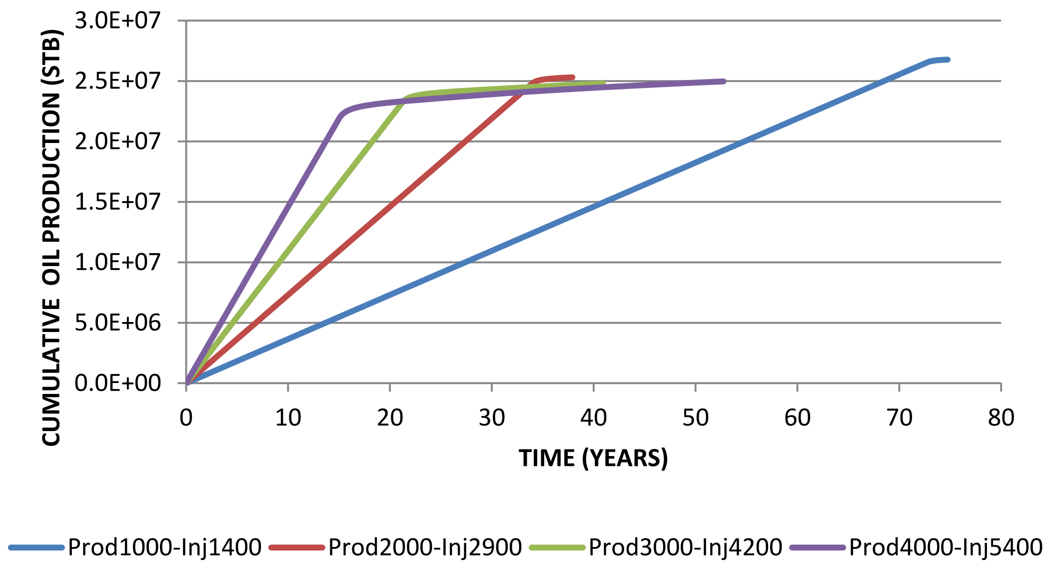


Figure 5.31 Cumulative oil production for different sets of gas injection and oil production rates (60-degree dip angle)

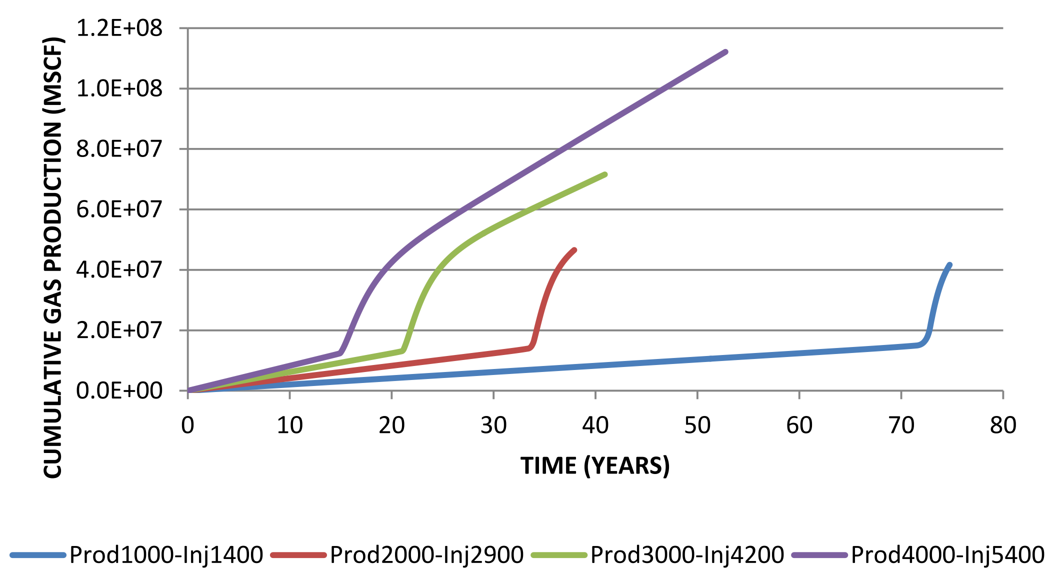


Figure 5.32 Cumulative gas production for different sets of gas injection and oil production rates (60-degree dip angle)

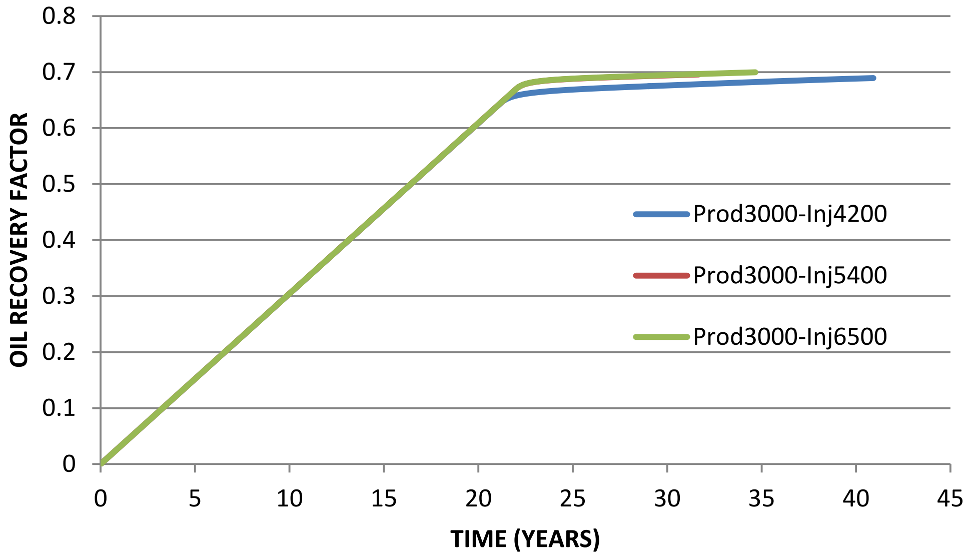
Table 5.6 Summary of results different sets of oil production and gas injection rates (60-degree dip angle)

	Qo,prod (STB/D)	Qg,inj (MSCF/D)	ABANDONMENT						30 YEARS				
			Production time (Year)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
GAGD	1000	1400	74.75	26.77	74.43	41.69	38.22	27.35	10.96	30.46	6.20	15.34	9.43
	2000	2900	37.92	25.31	70.35	46.58	40.16	26.37	21.90	60.89	12.40	31.78	18.67
	3000	4200	40.92	24.80	68.94	71.58	62.77	26.27	24.32	67.62	53.91	46.02	25.64
	4000	5400	52.75	24.97	69.42	112.15	104.04	26.32	23.91	66.46	66.02	59.17	25.05
Natural depletion	1000	-	98.75	24.25	67.42	13.96	-	26.58	10.91	30.32	5.87	-	11.89
	2000	-	87.75	24.18	67.21	14.01	-	26.51	17.25	47.96	8.99	-	18.75
	3000	-	85.33	24.16	67.18	14.02	-	26.50	18.12	50.39	9.68	-	19.74
	4000	-	84.50	24.16	67.16	14.02	-	26.50	18.37	51.06	9.86	-	20.01

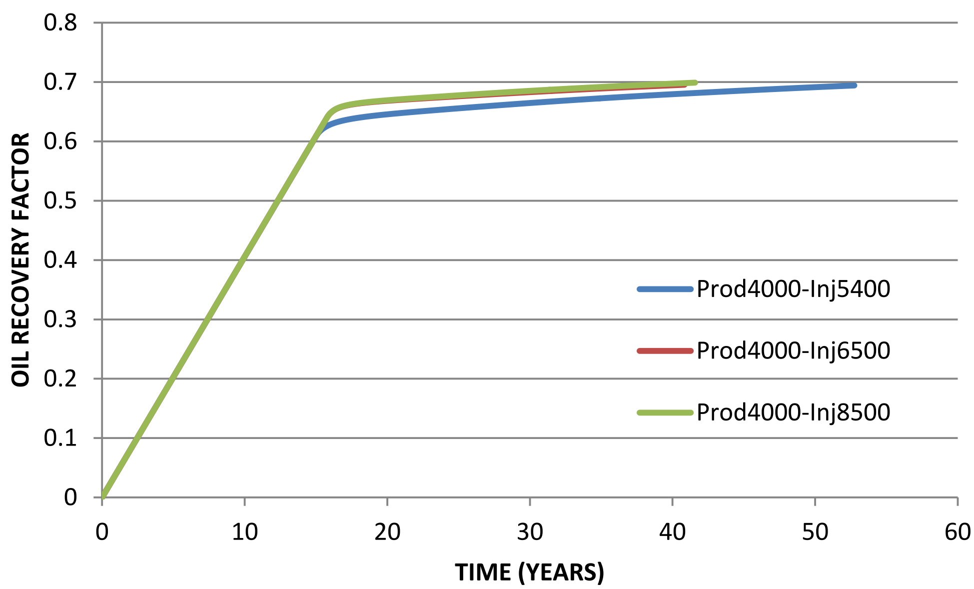
In the second scenario, gas injection rate is increased in order to increase oil production. From the first scenario, it is clearly seen that there are only two production rates which are 3000 and 4000 STB/D which provide relatively high BOE. The combinations of gas injection and oil production rates studied are listed in Table 5.7, the results shows that increasing gas injection significantly improves oil recovery. However, an increase in gas injection rate is limited by the fracture pressure as shown in Figure 5.35. Thus, the injection rate needs to be reduced and oil recovery slowly increases as shown in Figure 5.33 and 5.34. From Table 5.7, case 2 is considered to be the most suitable production strategy for the reservoir since it yields the highest BOE with comparatively small amount of total gas injection.

Table 5.7 Summary of results for different gas injection rates at the end of 30 years (60-degree dip angle)

CASE	Qo,prod (STB/D)	Qg,inj (MSCF/D)	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
1	3000	4200	24.32	67.62	53.91	46.02	25.64
2		5400	24.97	69.41	60.98	53.61	26.20
3		6500	24.99	69.48	63.40	56.86	26.08
4	4000	5400	23.91	66.46	66.02	59.17	25.05
5		6500	24.57	68.29	76.16	69.55	25.67
6		8500	24.64	68.51	85.09	79.96	25.50

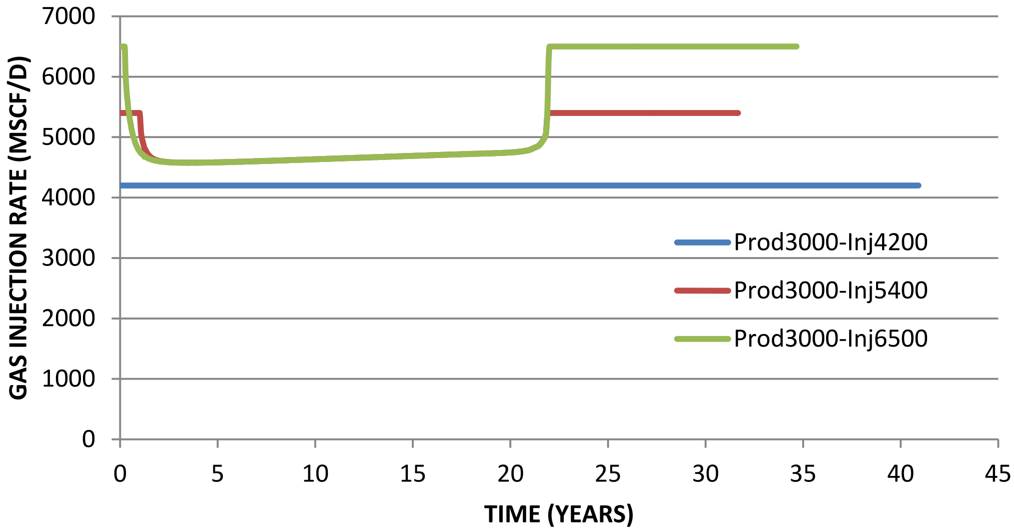


(a) Maximum oil production rate is 3000 STB/D

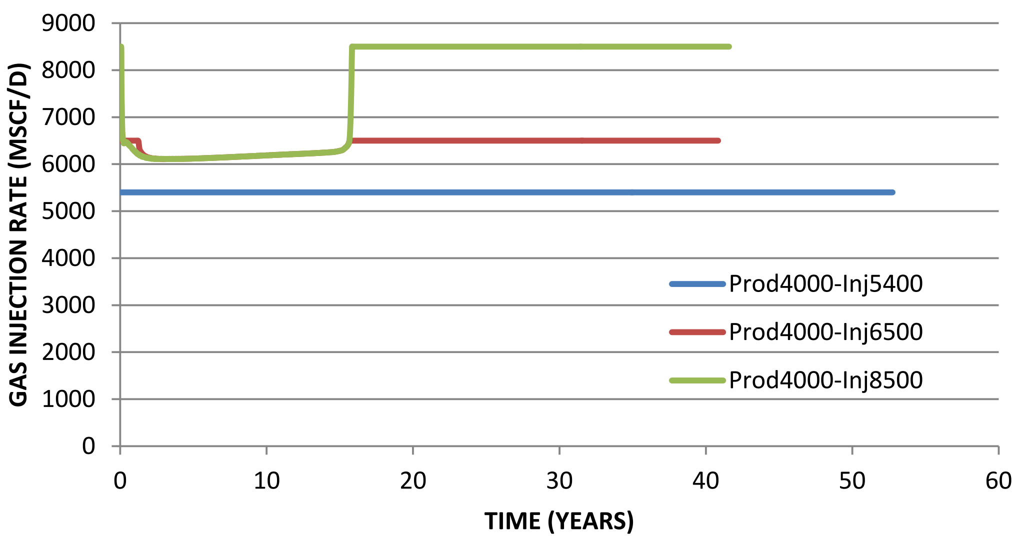


(b) Maximum oil production rate is 4000 STB/D

Figure 5.33 Oil recovery efficiency for different gas injection rates when maximum oil production rate is fixed at 3000 and 4000 STB/D (60-degree dip angle)

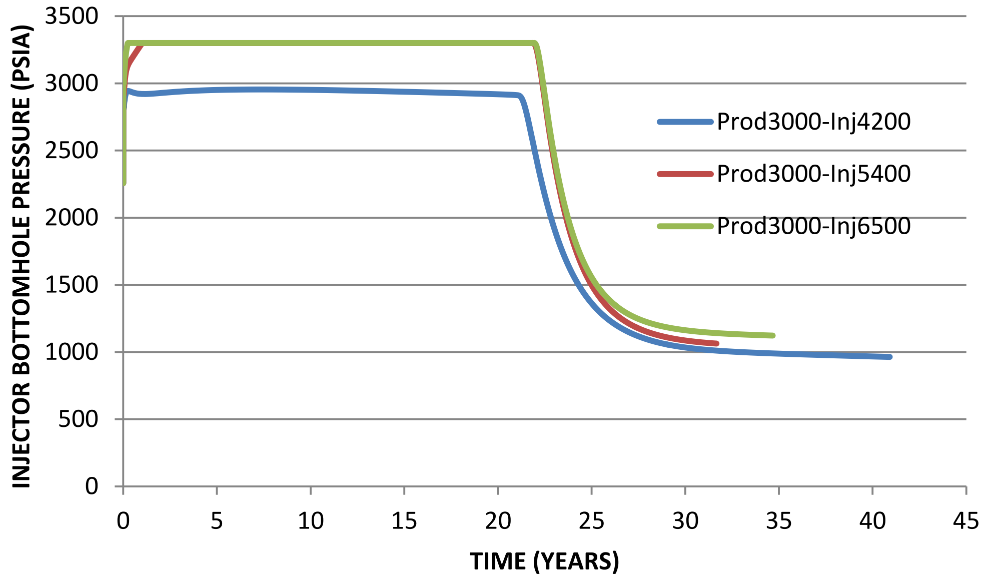


(a) Maximum oil production rate is 3000 STB/D

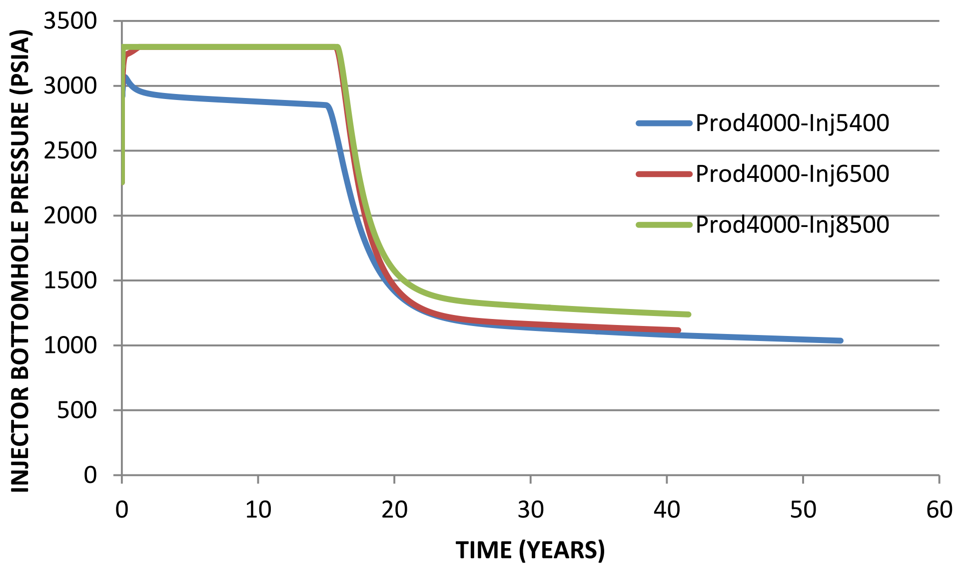


(b) Maximum oil production rate is 4000 STB/D

Figure 5.34 Gas injection rates when maximum oil production rate is fixed at 3000 and 4000 STB/D (60-degree dip angle)



(a) Maximum oil production rate is 3000 STB/D



(b) Maximum oil production rate is 4000 STB/D

Figure 5.35 Injection well bottomhole pressure when maximum oil production rate is fixed at 3000 and 4000 STB/D (60-degree dip angle)

5.4 Effect of well pattern

In this section, different well patterns and numbers are investigated in an attempt to recovery the highest amount of oil during 30-year concession. Various dip angles are studied in order to select the well pattern that is suitable for each dip angle. Four well patterns are used as illustrated in Figures 5.36-5.39. The oil production and gas injection rates selected from the previous section are implemented for each dip angle. For every well pattern, production wells are controlled by group control to achieve a field production rate with minimum bottomhole of 500 psia for each production well. The injection well is still constrained by the fracture pressure.

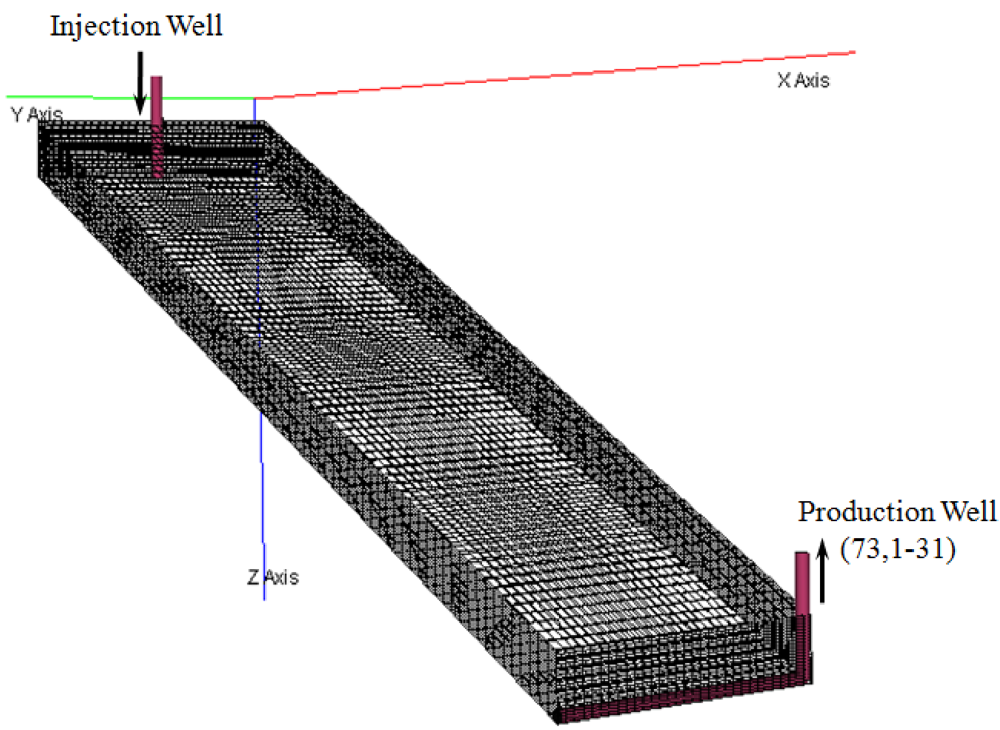


Figure 5.36 Schematic of well pattern 1

For well pattern 1, the system is composed of a vertical gas injector at the updip of the reservoir and a horizontal production well located along the entire width of the reservoir in y-axis direction at the downdip of the reservoir as shown in Figure 5.36. Gas is injected through the injection well on the top with the maximum bottom-hole pressure of 3300 psia while oil is produced by the production well at the bottom with the minimum bottom-hole pressure of 500 psia. The field economic rate used to stop the production is oil production rate of 100 STB/D.

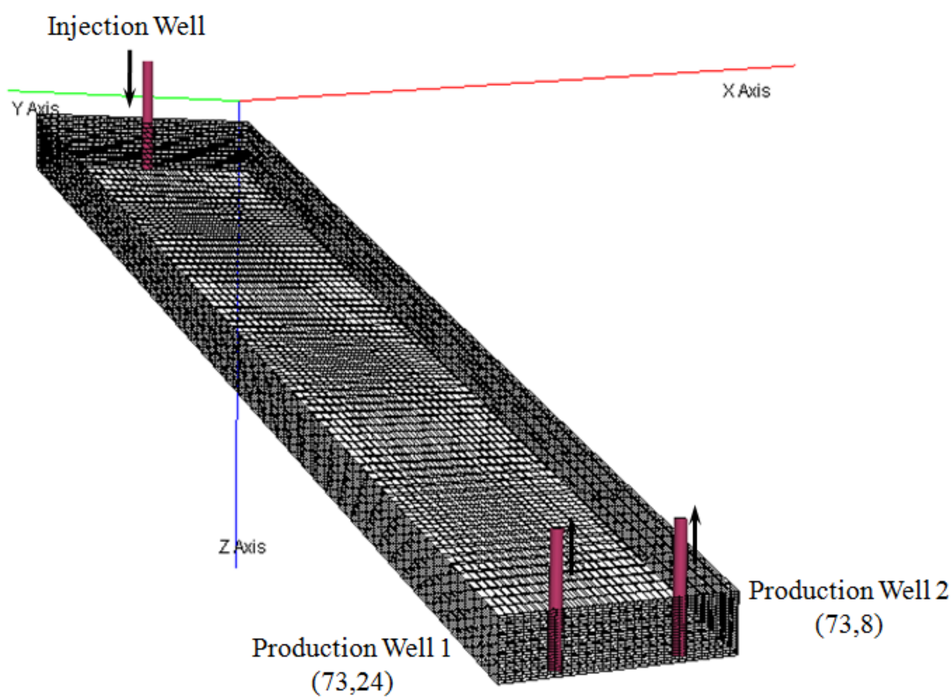


Figure 5.37 Schematic of well pattern 2

For well pattern 2, the system is composed of a vertical gas injector located updip and two vertical production wells located at the bottom of the reservoir at the downdip of the reservoir as shown in Figure 5.37. Gas is injected through the injection well on the top with the maximum bottom-hole pressure of 3300 psia while oil is produced by the production wells at the bottom with the minimum bottom-hole pressure of 500 psia. The field economic rate used to stop the production is minimum oil production rate of 100 STB/D.

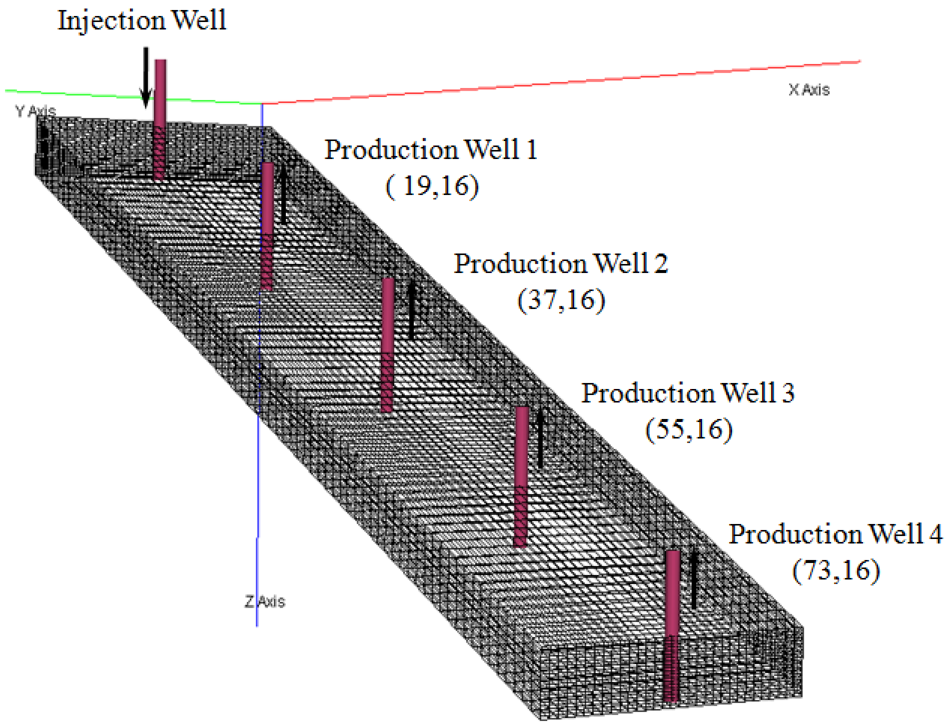


Figure 5.38 Schematic of well pattern 3

For well pattern 3, the system is composed of one vertical gas injector located updip and four vertical production wells located along the length of the reservoir with equal spacing between them as shown in Figure 5.38. Gas is injected through the injection well on the top with the maximum bottom-hole pressure of 3300 psia while oil is produced under a group control to achieve the field production rate with the minimum bottom-hole pressure of 500 psia. The condition used to shut in well 1, 2 and 3 is maximum gas-oil ratio of 30 MSCF/STB whereas the field economic rate used to stop the production is minimum oil production rate of 100 STB/D.

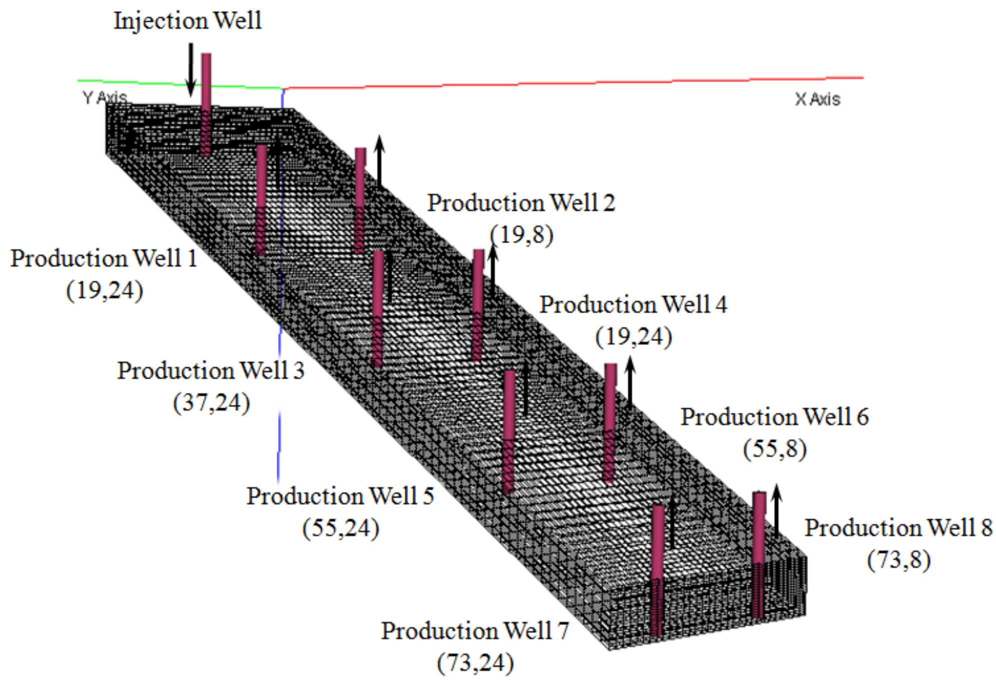


Figure 5.39 Schematic of well pattern 4

For well pattern 4, the system is composed of one vertical gas injector located updip and eight vertical production wells located in pairs along the length of the reservoir with equal spacing between their pairs as shown in Figure 5.39. Well placement of pattern 4 is similar to that of pattern 3 except for a higher number of production wells. Increasing the number of production wells helps reduce a required drawdown and the residual oil bypassed by injected gas. Gas is injected through the injection well on the top with the maximum bottom-hole pressure of 3300 psia while oil is produced under a group control to achieve the field production rate with the minimum bottom-hole pressure of 500 psia. The condition used to shut in well 1, 2, 3, 4, 5 and 6 is maximum gas-oil ratio of 30 MSCF/STB whereas the field economic rate used to stop the production is minimum oil production rate of 100 STB/D.

5.4.1 Dip angle of 15 degrees

Figure 5.40 illustrates gas production rate for each well pattern. Gas production rate for pattern of 1 horizontal producer and pattern of 2 vertical producers is constant at early time and sharply increases when the injected gas starts to flow into the production wells. For pattern of 4 and 8 producers, gas production rate fluctuates because of gas breakthrough occurring in the updip wells. The time required for the injected gas to firstly reach the production wells for pattern of 4 producers, 8 producers, 2 producers and 1 horizontal producer is 1.5, 2, 9 and 10 years, respectively. It is clearly observed that the time for pattern of 4 and 8 producers is considerably shorter than the time for pattern of 1 horizontal producer and 2 producers due to the closer distance between the gas injector and the producers in pattern of 4 and 8 producers. It is also seen that, in spite of the same distance between the producers and the injectors in the pattern of 4 and 8 producers, gas breakthrough starts slightly later in the pattern of 8 producers compared to that for 4 producers. This is because the higher number of production wells in the pattern of 8 producers help to reduce a required drawdown, resulting in a delay in gas breakthrough. In addition, the time for gas to break through for pattern of 1 horizontal producer is slightly longer than that for pattern of 2 producers since the horizon well is located at the bottommost grid block whereas the vertical wells is perforated for the lower half of the entire reservoir thickness of 210 ft.

Oil production rate is illustrated in Figure 5.41. Oil production is kept at the maximum rate for pattern of 1 horizontal producer, 2 producers 4 producers and producers for about 11.5, 11, 9 and 9.5 years respectively. The oil production plateau can be maintained for longer period in pattern of 1 horizontal producer and 2 producers than the one in pattern of 4 and 8 producers. This can be explained by considering the time that the injected gas reaches the production wells. In well patterns 3 and 4, the injected gas breaks through earlier due to a closer distance between the injector and the producers. As a result, high amount of gas is produced at an early time, causing a decline in oil production rate. On the other hand, for patterns 1 and 2, wells are located at the downdip, enabling gas to migrate upward and accumulate at the top. This helps provide the drive energy to the field and delay gas breakthrough. Note that oil production rate, gas production rate and the reservoir pressure of pattern of 1 horizontal producer are comparable to those of pattern of 2 producers while those of pattern of 4 producers are comparable to those of pattern of 8 producers. This is mainly due to similarity in well location between pattern of 1 horizontal producer and 2 producers and also between pattern of 4 and 8 producers.

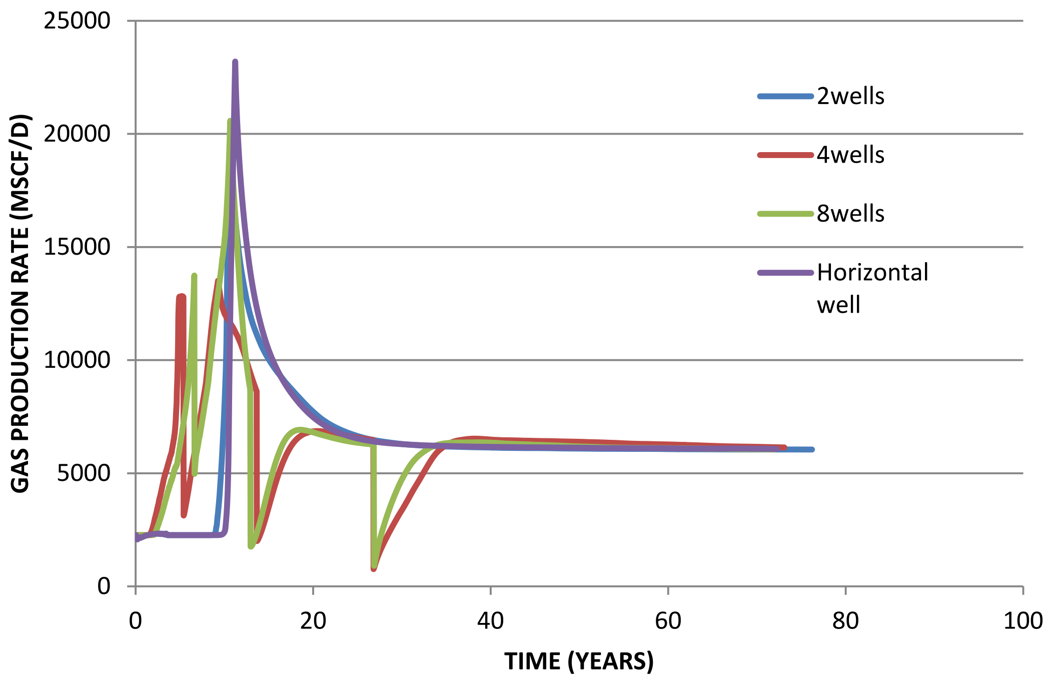


Figure 5.40 Gas production rate for different well patterns (15-degree dip angle)

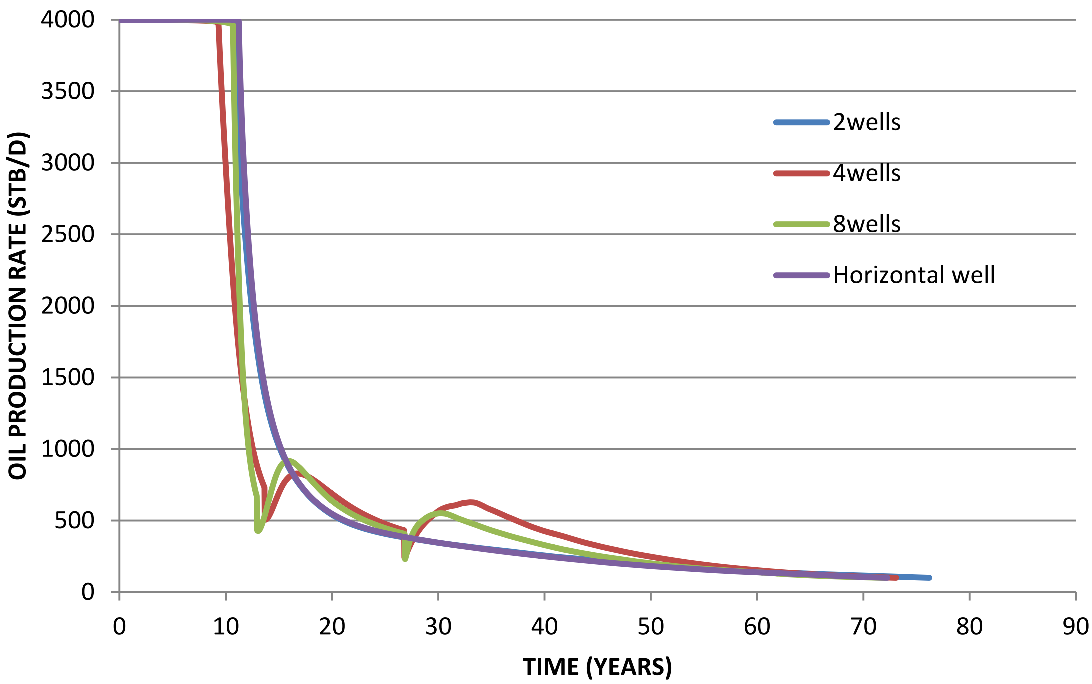


Figure 5.41 Oil production rate for different well patterns (15-degree dip angle)

Cumulative oil and gas production are illustrated in Figure 5.42 and 5.43, respectively. The summary of cumulative oil production, oil recovery factor, cumulative gas production, cumulative gas injection, BOE at the end of 30 years of the reservoir with dip angle 15 degrees for each well pattern are shown in Table 5.8. At the end of 30 years, pattern of 1 horizontal producer gives the highest cumulative oil and BOE of 21.92 and 23.14 MMSTB, respectively, followed by pattern of 2 producers. Due to similar well location, the cumulative oil in pattern of 1 horizontal producer is slightly higher than one in pattern of 2 producers whereas, the cumulative oil and gas production in pattern of 8 producers are slightly higher than those in pattern of 4 producers.

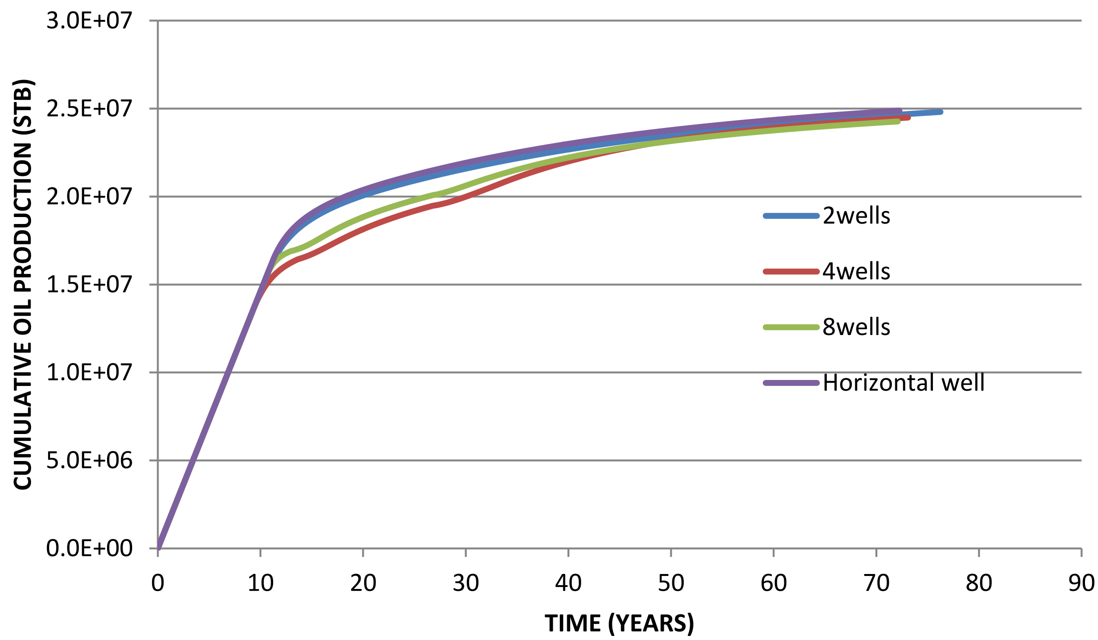


Figure 5.42 Cumulative oil production for different well patterns

(15-degree dip angle)

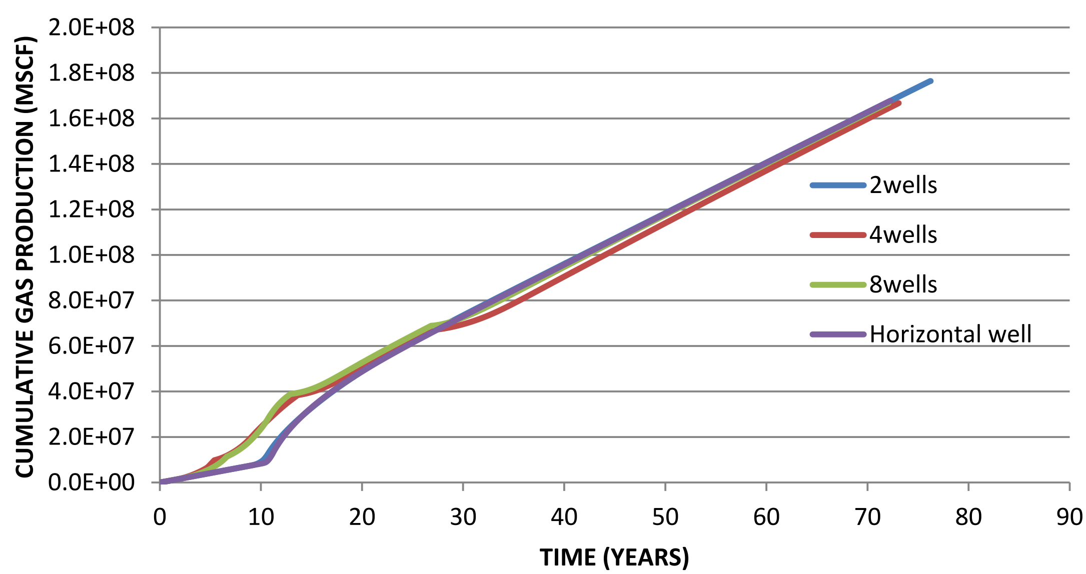


Figure 5.43 Cumulative gas production for different well patterns

(15-degree dip angle)

Table 5.8 Summary of results for different well pattern at the end of 30 years (15-degree dip angle)

CASE	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
Horizontal Well	21.92	61.53	73.06	65.75	23.14
2 Wells	21.59	60.60	73.47	65.75	22.87
4 Wells	19.99	56.11	69.56	65.75	20.62
8 Wells	20.62	57.89	72.48	65.75	21.74

5.4.2 Dip angle of 30 degrees

Gas production rate for each well pattern is illustrated in Figure 5.44. Similar to 15-degree case, gas production rate for pattern of 1 horizontal producer and pattern of 2 vertical producers is constant at early time until the injected gas starts to flow into the production wells and gas production rapidly increases. For pattern of 4 and 8 producers, gas production rate fluctuates because of gas breakthrough occurring in the updip wells. The time required for the injected gas to firstly reach the production wells for pattern of 4 producers, 8 producers, 2 producers and 1 horizontal producer is 3, 3.5, 16 and 18 years, respectively. From the results, it is clearly observed that the time for pattern of 4 and 8 producers is considerably shorter than the time for pattern of 1 horizontal producer and 2 producers due to the closer distance between the gas injector and the producers in pattern of 4 and 8 producers. The higher number of production wells in the pattern 8 producers helps to reduce a required drawdown. As a result, gas breaks through slightly later in the pattern of 8 producers compared to that for 4 producers. In addition, the time for gas to break through for pattern of 1 horizontal producer is slightly longer than that for pattern of 2 producers since the horizon well is located at the bottommost grid block whereas the vertical wells is perforated for the lower half of the entire reservoir thickness of 210 ft.

Figure 5.45 shows oil production rate for different well patterns. Maximum oil production rate can be kept for pattern of 1 horizontal producer, 2 producers 4 producers and 8 producers for about 20, 19.5, 16 and 17.5 years respectively. Like in 15-degree case, the oil production plateau in pattern of 1 horizontal producer and 2 producers are considerably longer than the one in pattern of 4 and 8 producers since the location of the producers for well patterns of 1 horizontal producer and 2 producers is much farther from the injector. Thus, gas is kept in the reservoir and helps provide drive energy for production. Note that oil production rate, gas production rate and the reservoir pressure of pattern of 1 horizontal producer are similar to those of pattern of 2 producers while those of pattern of 4 producers are similar to those of pattern of 8 producers. This is mainly due to similarity in well location between pattern of 1 horizontal producer and pattern of 2 producers and also between pattern of 4 and 8 producers.

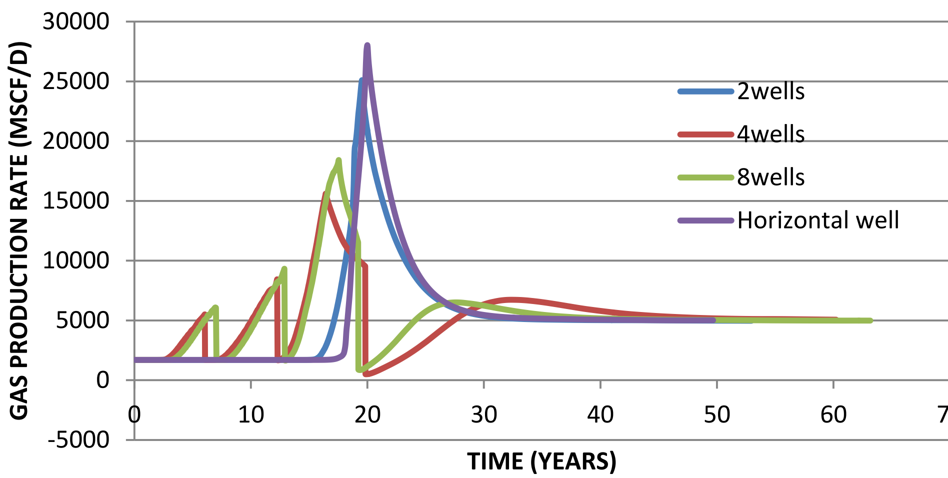


Figure 5.44 Gas production rate for different well patterns (30-degree dip angle)

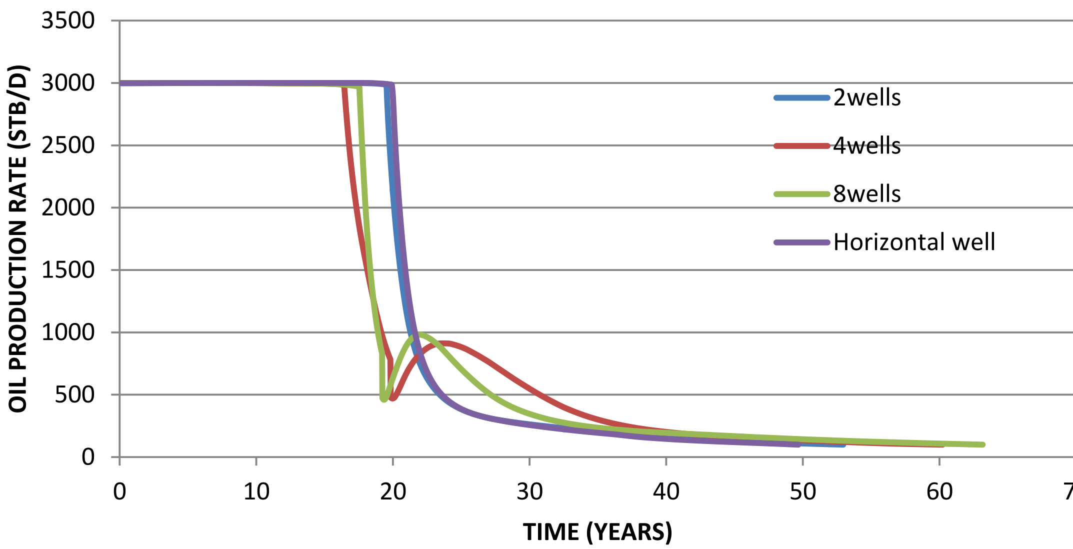


Figure 5.45 Oil production rate for different well patterns (30-degree dip angle)

Cumulative oil and gas production are illustrated in Figure 5.46 and 5.47, respectively. The summary of cumulative oil production, oil recovery factor, cumulative gas production, cumulative gas injection, BOE at the end of 30 years of the reservoir with dip angle 15 degrees for each well pattern are shown in Table 5.9. At the end of 30 years, pattern of 1 horizontal producer gives the highest cumulative oil and BOE of 24.15 and 25.50 MMSTB, respectively, followed by pattern of 2 producers. Due to similar well location, cumulative oil for pattern for 1 horizontal producer are slightly higher than those in pattern 2 producers while cumulative oil and gas production for pattern of 4 and 8 producers are about the same. Note that the total oil and gas production for every well pattern in 30-degree dip angle are higher than those in 15-degree dip angle. This indicates that gravity effect becomes more significant in higher dip angle.

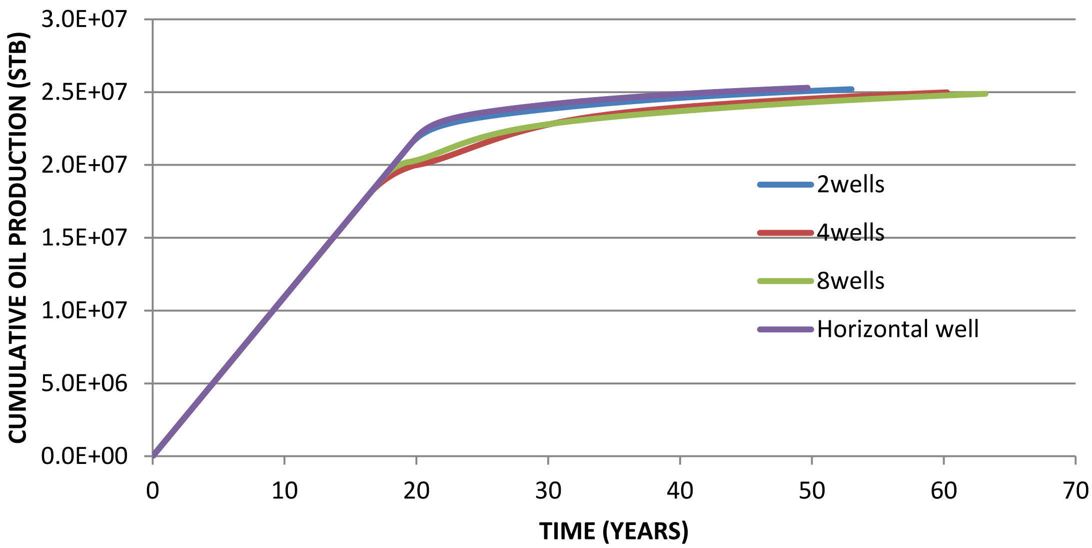


Figure 5.46 Cumulative oil production for different well patterns

(30-degree dip angle)

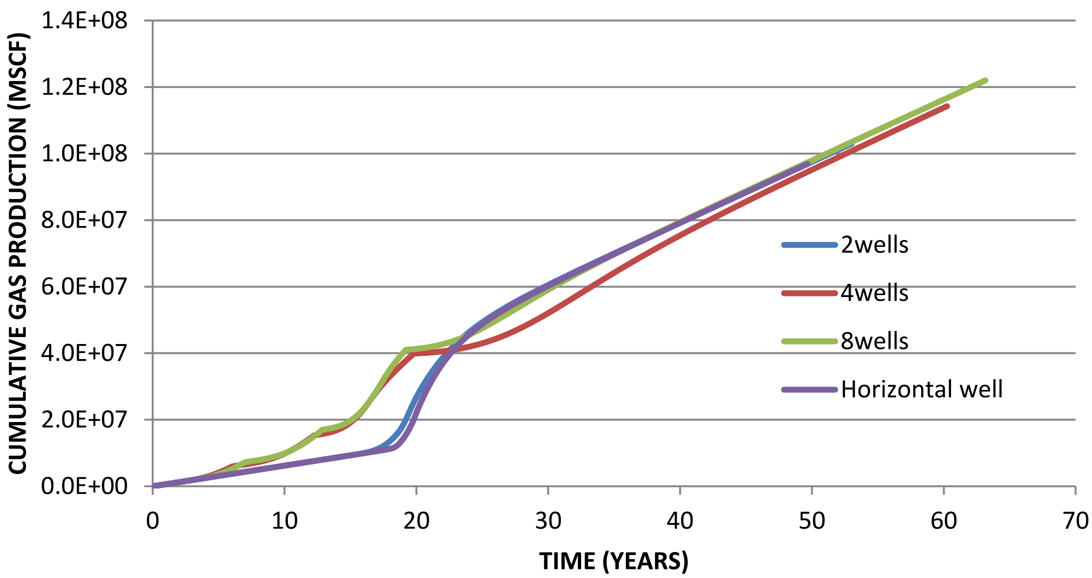


Figure 5.47 Cumulative gas production for different well patterns

(30-degree dip angle)

Table 5.9 Summary of results for different well pattern at the end of 30 years (30-degree dip angle)

CASE	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
Horizontal Well	24.15	67.51	60.22	52.15	25.50
2 Wells	23.85	66.64	60.54	52.33	25.21
4 Wells	22.77	63.64	52.06	53.69	22.50
8 Wells	22.80	63.71	59.08	53.69	23.70

5.4.2 Dip angle of 60 degrees

Gas production rate for each well pattern is illustrated in Figure 5.48. Similar to 15- and 30-degree cases, gas production rate for pattern of 1 horizontal producer and pattern of 2 vertical producers is constant at early time until the injected gas starts to flow into the production wells and gas production rapidly increases. For pattern of 4 and 8 producers, there are small peaks of gas production because of gas breakthrough occurring in the updip wells. The time required for the injected gas to firstly reach the production wells for pattern of 8 producers, 4 producers, 2 producers and 1 horizontal producer is 4, 4.5, 21 and 21.5 years, respectively. From the results, it is noticeable that gas breaks through slightly later than of 15- and 30-degree cases. This indicates that gravity become more significant in higher dip angle and gas tends to segregate to the top. This helps delay gas breakthrough and improves volumetric sweep efficiency. The higher number of production wells in the pattern 8 producers helps to reduce a required drawdown. As a result, gas breaks through slightly later for the pattern of 8 producers compared to that for 4 producers. The time for gas to break through for pattern of 1 horizontal producer and 2 producers is almost the same because of the similar location of producers.

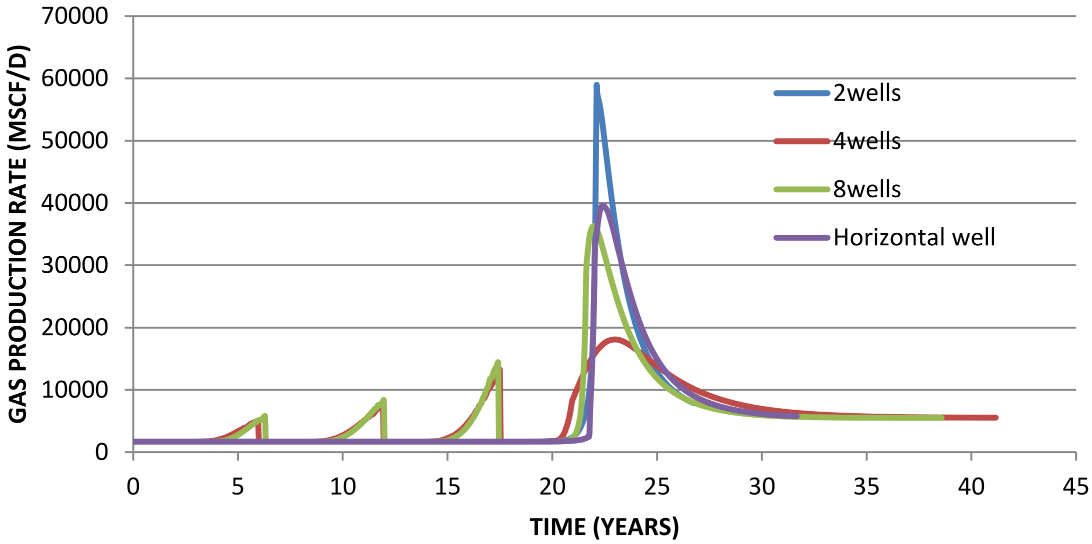


Figure 5.48 Gas production rate for different well patterns (60-degree dip angle)

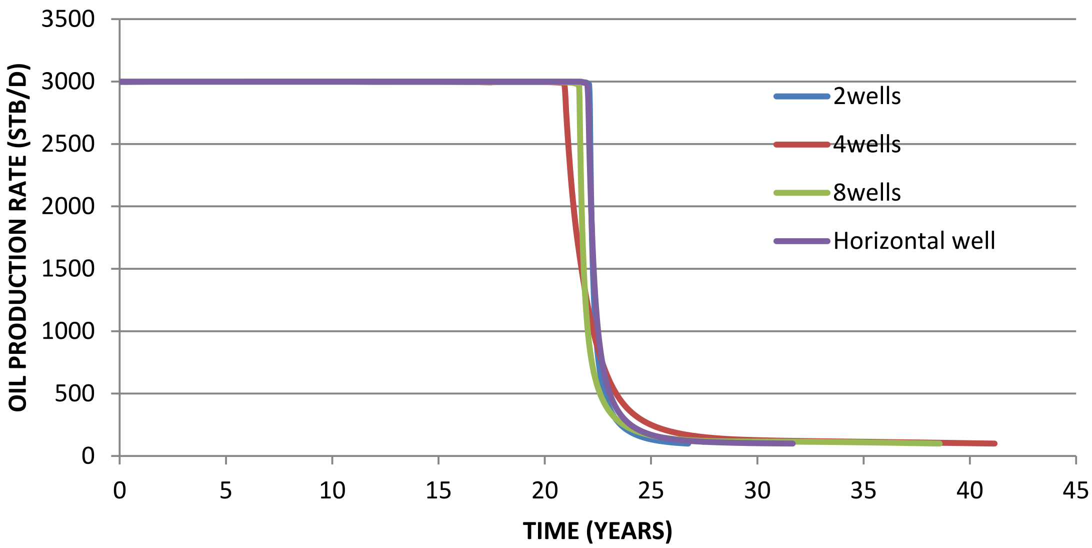


Figure 5.49 Oil production rate for different well patterns (60-degree dip angle)

Figure 5.49 shows oil production rate for different well patterns. Maximum oil production rate can be kept for pattern of 1 horizontal producer, 2 producers 4 producers and 8 producers for about 22, 22, 21 and 21.5 years respectively. It is observed that the maximum oil rate for every well pattern can maintained for longer period compared to the 15- and 30-degree cases. In addition, the plateau period for pattern of 1 horizontal producer and 2 producers are slightly longer than those of pattern of 4 and 8 producers because the producers in pattern of 1 horizontal producer and 2 producers are placed at the most downdip location. With this location, the injected gas is stored in the reservoir for a longer period and help provides drive energy to the reservoir, resulting in longer plateau period.

Cumulative oil and gas production are illustrated in Figure 5.50 and 5.51, respectively. The summary of cumulative oil production, oil recovery factor, cumulative gas production, cumulative gas injection, BOE at the end of 30 years of the reservoir with dip angle 15 degrees for each well pattern are shown in Table 5.10. At the end of 30 years, the oil recovery is significantly among every well pattern. Well pattern of one horizontal producer yield the highest cumulative oil and BOE of 24.97 and 26.20 MMSTB, respectively. The total gas production of 60-degree case is lower than that of 15-degree case. This indicates that, in higher dip angle, gas becomes more effectively displace oil and higher oil recovery is achieved.

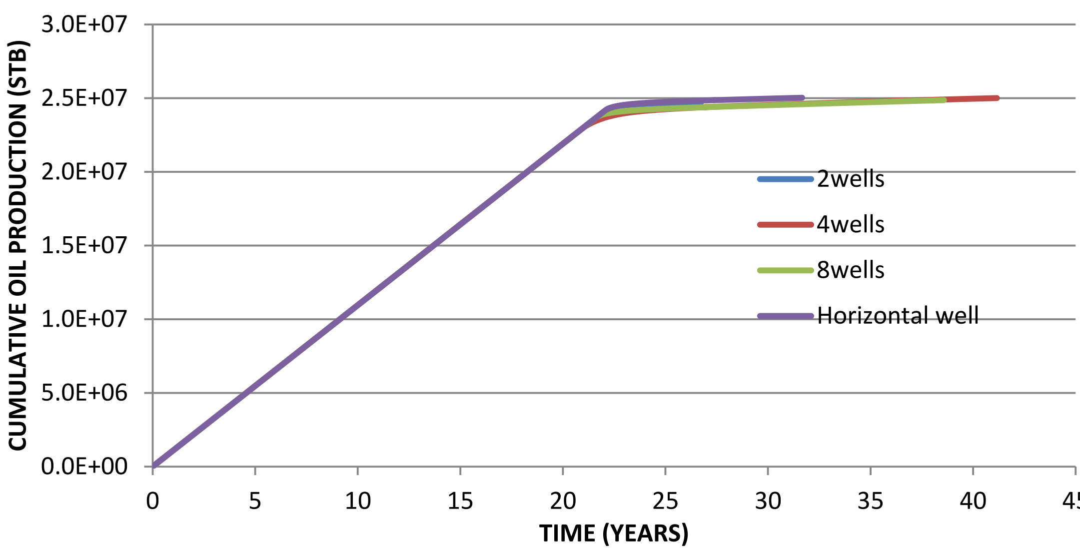


Figure 5.50 Cumulative oil production for different well patterns

(60-degree dip angle)

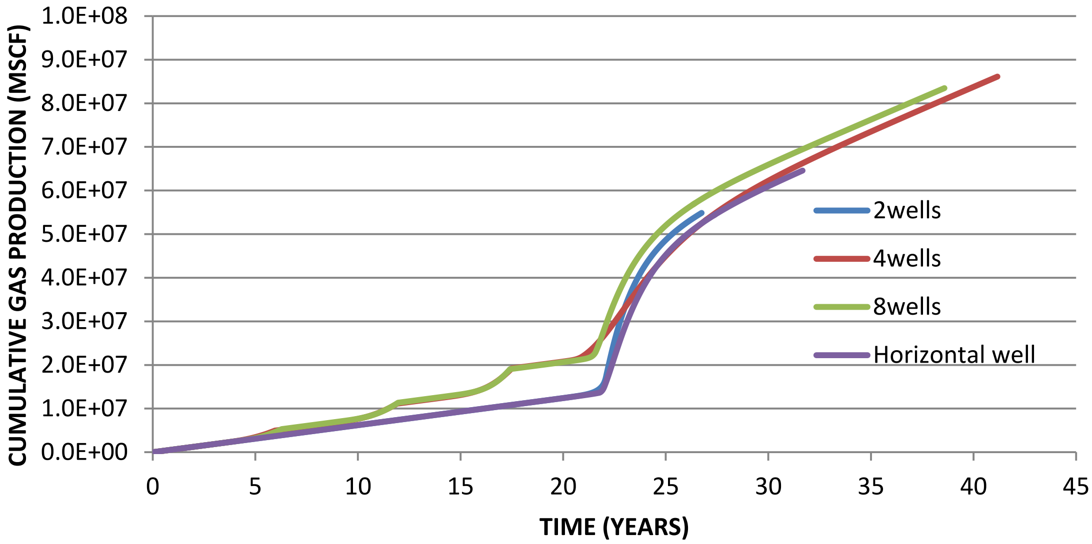


Figure 5.51 Cumulative gas production for different well patterns (60-degree dip angle)

Table 5.10 Summary of results for different well pattern at the end of 30 years (60-degree dip angle)

CASE	Np (MMSTB)	RF (%OOIP)	Gp (BSCF)	Ginj (BSCF)	Net BOE (MMSTB)
Horizontal Well	24.97	69.41	60.98	53.61	26.20
2 Wells	24.74	68.77	54.86	47.36	25.99
4 Wells	24.55	68.24	62.25	58.00	25.26
8 Wells	24.52	68.17	65.94	58.06	25.83

5.5 Sensitivity analysis

After selecting the most suitable operating conditions for each dip angle, the sensitivity analysis is performed in order to investigate effects on the production performance due to uncertainties of some parameters. The following study parameters are selected:

- Relative permeability correlation
- Vertical to horizontal permeability ratio
- Relative permeability to oil and gas

5.5.1 Effect of relative permeability correlation

In this section, the results obtained from simulation by using three different relative permeability correlations which are ECLIPSE default, Stone 1 and Stone 2 will be compared to study the effect on GAGD performance.

Cumulative oil and gas production for every dip angle are illustrated in Figures 5.52-5.54 and gas-oil ratio is depicted in Figures 5.55-5.57. Summary of cumulative oil production, cumulative gas production, and production time for different three-phase relative permeability correlations for dip angle of 15, 30 and 60 degrees is listed in Table 5.11. The figures show insignificant difference in cumulative oil production among these correlations for dip angle of 15, 30 and 60 degrees at 30 years but there is a difference in cumulative oil production in the range of 1.2 to 2.2% at the end of production. Furthermore, Stone 2 model provides slightly lower cumulative gas production and a shorter production time compared to Stone 1 and ECLIPSE default model. Interestingly, the difference in production time in Stone 2 model increases as dip angle increases. In addition, as shown in Figures 5.55-5.57, gas-oil ratios from all correlations are quite the same until gas breakthrough occurs. After gas breakthrough, Stone 2 model tends to yield higher gas-oil ratio which results in less productivity of oil and shorter production time. Moreover, it can be observed that the results obtained from ECLIPSE default model is very much closer to those obtained from Stone 1.

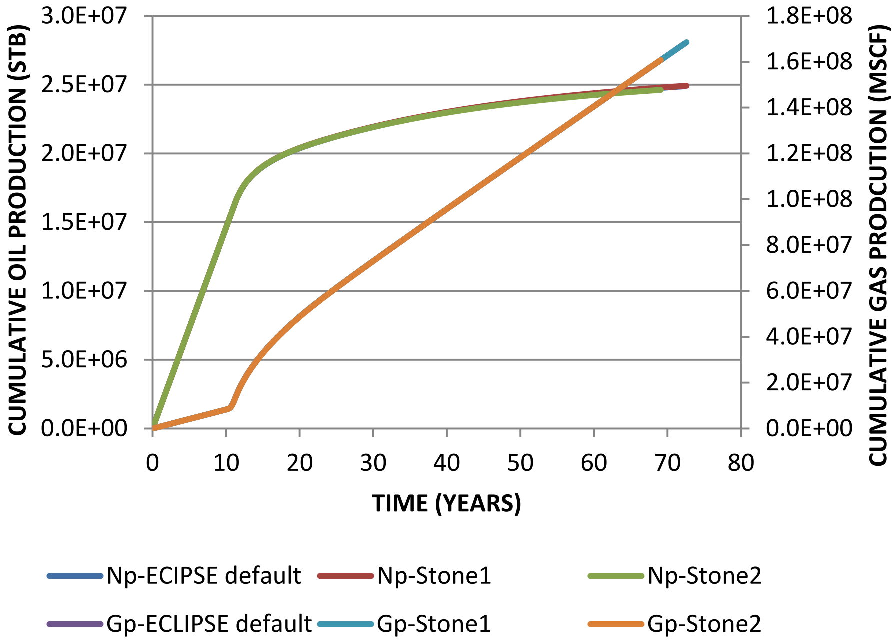


Figure 5.52 Cumulative oil and gas production for different three-phase relative permeability correlations (15-degree dip angle)

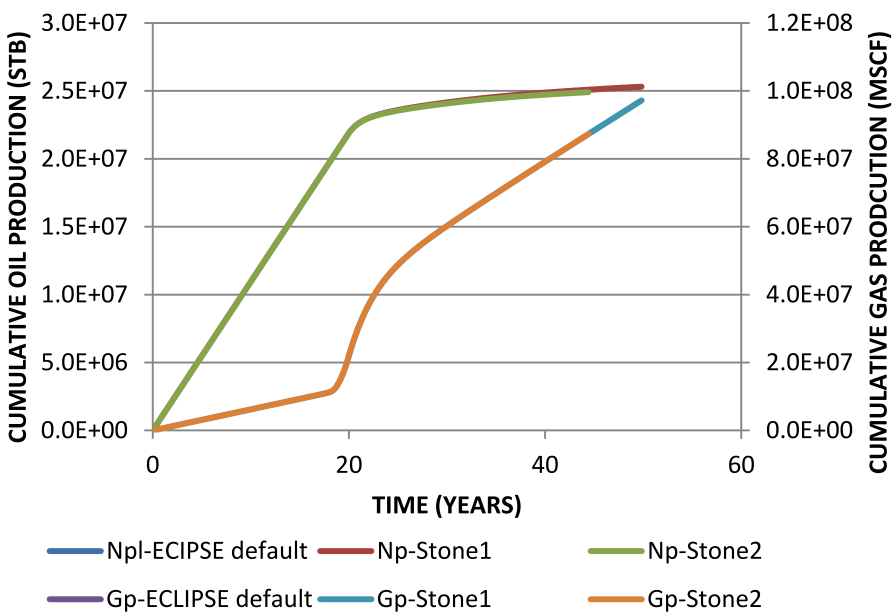


Figure 5.53 Cumulative oil and gas production for different three-phase relative permeability correlations (30-degree dip angle)

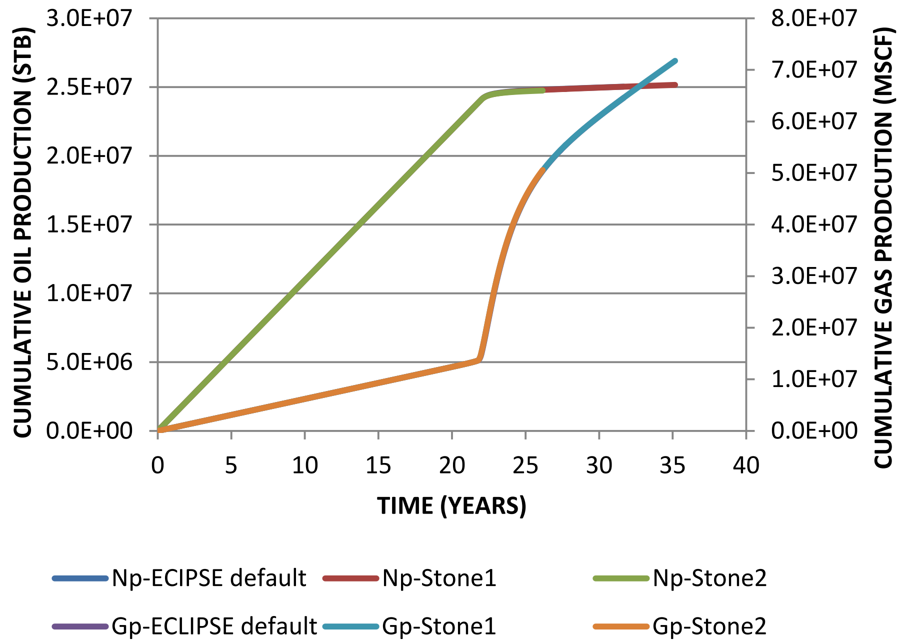


Figure 5.54 Cumulative oil and gas production for different three-phase relative permeability correlations (60-degree dip angle)

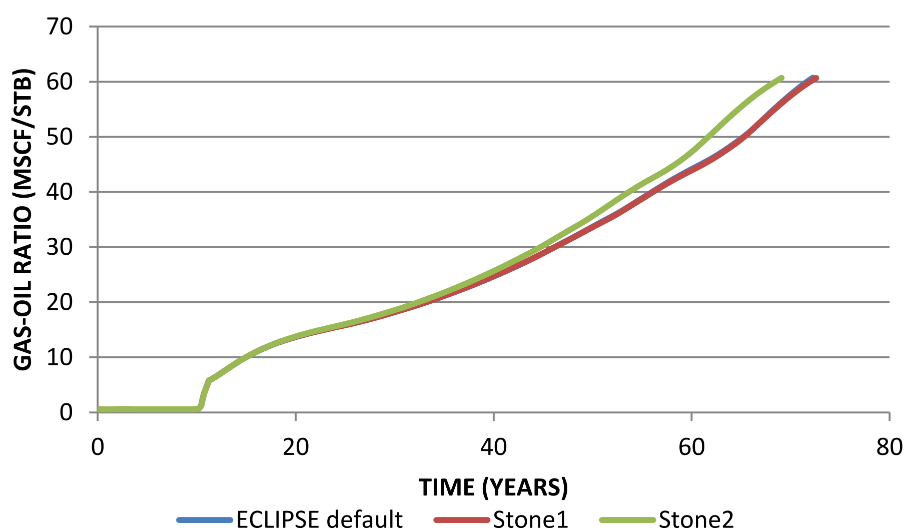


Figure 5.55 Gas-oil ratio and reservoir pressure for different three-phase relative permeability correlations (15-degree dip angle)

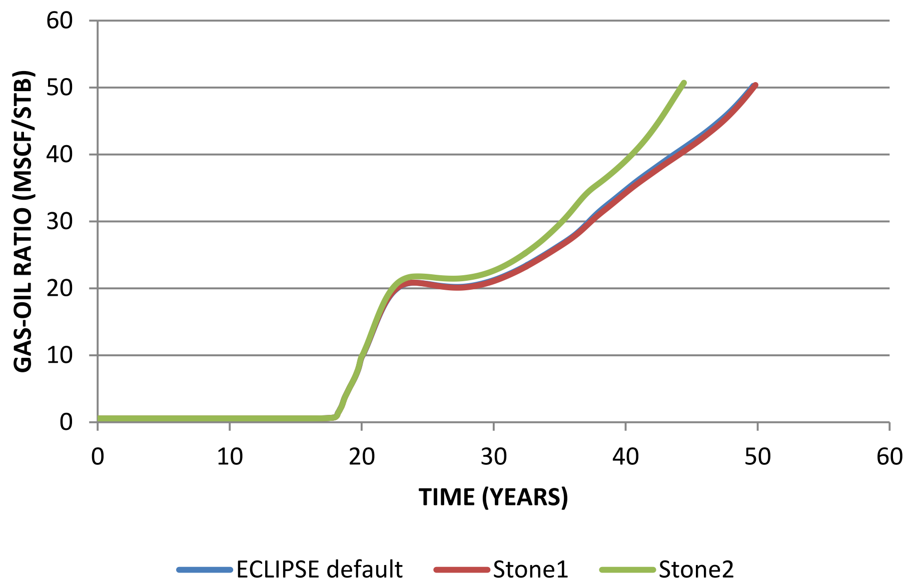


Figure 5.56 Gas-oil ratio and reservoir pressure for different three-phase relative permeability correlations (30-degree dip angle)

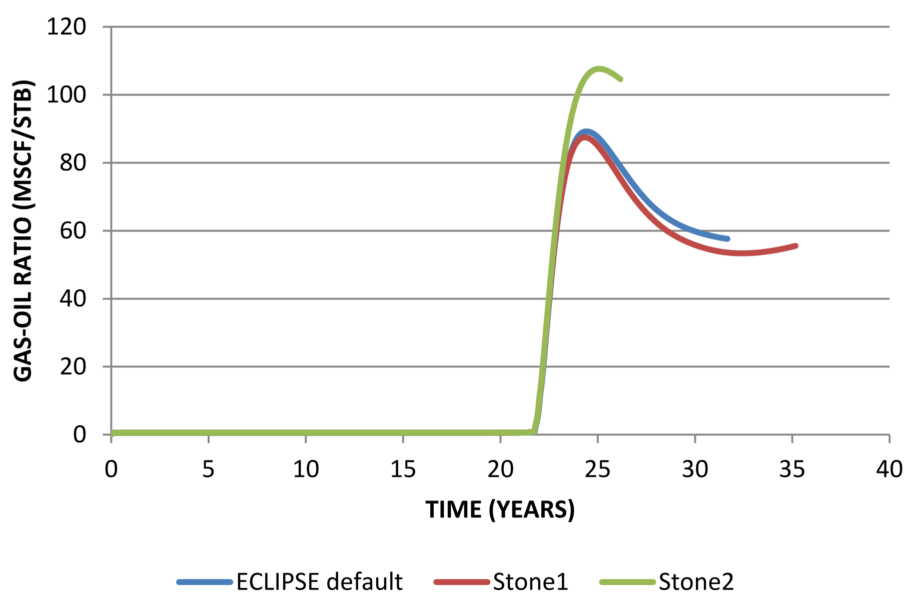


Figure 5.57 Gas-oil ratio and reservoir pressure for different three-phase relative permeability correlations (60-degree dip angle)

Table 5.11 Summary of the results for different three-phase relative permeability correlations

Dip angle	Model	Production time (years)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)
15	ECLIPSE default	72.25	24.88	167.75
	Stone 1	72.58	24.92	168.50
	Stone 2	69.09	24.62	160.76
30	ECLIPSE default	49.67	25.30	96.90
	ECLIPSE	49.83	25.31	97.23
	Stone 2	44.42	24.91	87.30
60	ECLIPSE default	51.25	25.91	101.43
	Stone 1	51.58	25.96	102.12
	Stone 2	42.42	25.41	83.32

5.5.2 Effect of vertical to horizontal permeability ratio

In this section, the results obtained from simulation by using three different values of vertical to horizontal permeability ratios are compared to study the effect on GAGD performance. For all cases, the value of horizontal permeability is fixed while values of vertical permeability are varied as listed in Table 5.12.

Table 5.12 Vertical and horizontal permeabilities for different anisotropy ratio

Case	Vertical to horizontal permeability ratio	Vertical Permeability (md)	Horizontal Permeability (md)
1	0.01	0.32529	32.529
2	0.1	3.2529	32.529
3	1	32.529	32.529

Figures 5.58-5.60 shows gas production rate for different vertical to horizontal ratios for dip angle of 15, 30 and 60 degrees. As illustrated in Figures 5.58 and 5.59, for dip angle of 15 and 30 degrees, in case 3, gas arrives at the production well earlier than

the other cases because increasing vertical permeability allow gas to flows more easily in vertical direction. However, for dip angle of 60 degrees in which the effect of gravity becomes substantial, time required for gas to break through is the longest in case 1 as illustrated in Figure 5.60. This is because gravity segregation effectively migrate gas to the top and drain oil downward, thus very stable gas-oil contact is formed and gas breakthrough occurs quite later compared to other dip angles.

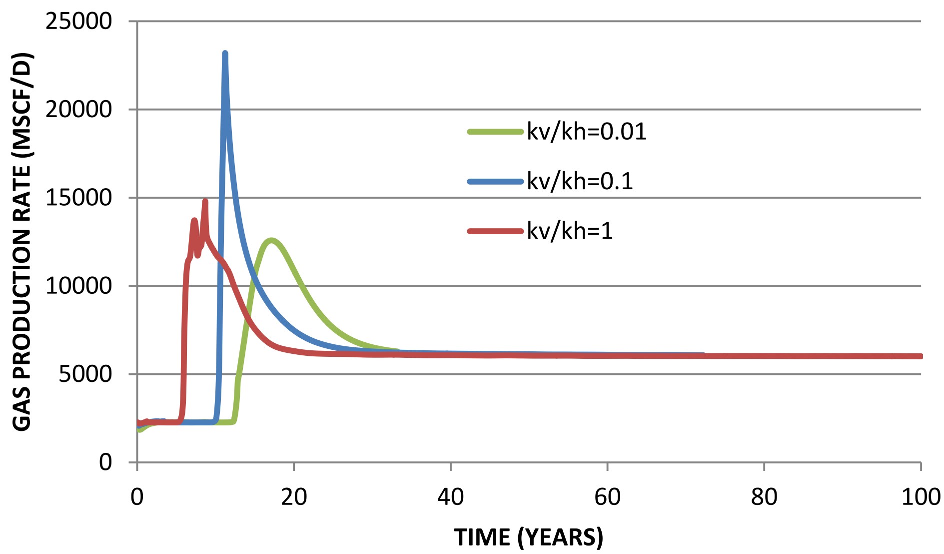


Figure 5.58 Gas production rate for different vertical to horizontal ratios (15-degree dip angle)

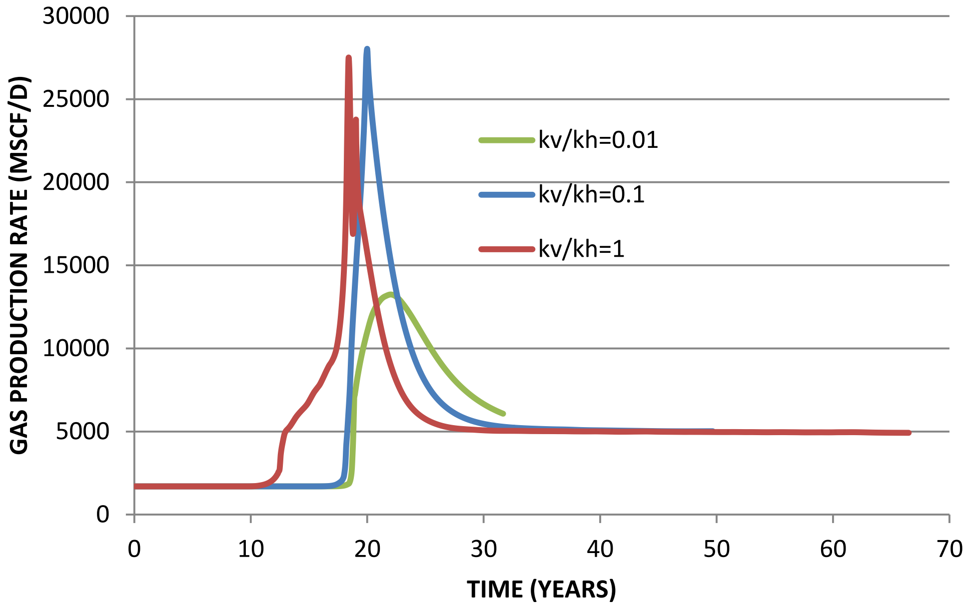


Figure 5.59 Gas production rate for different vertical to horizontal ratios (30-degree dip angle)

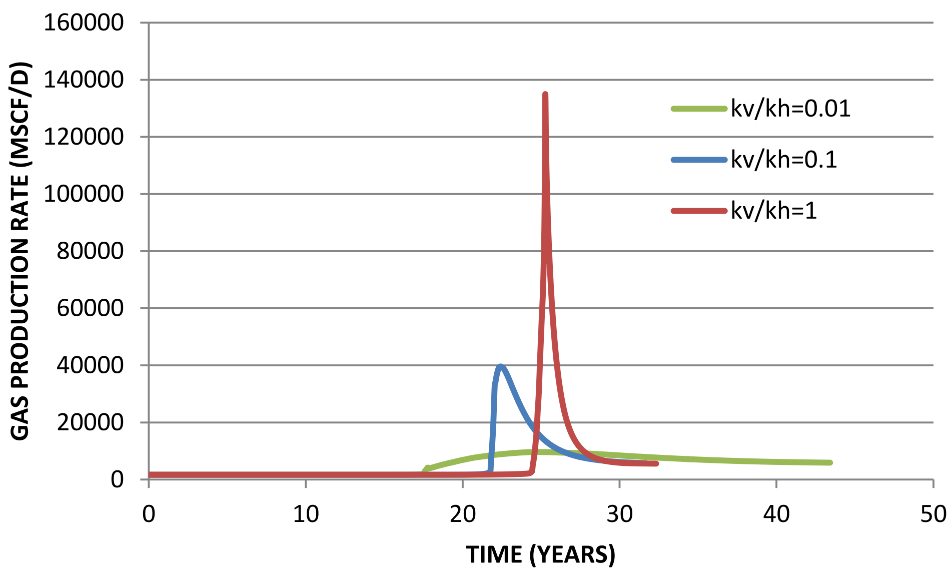


Figure 5.60 Gas production rate for different vertical to horizontal ratios (60-degree dip angle)

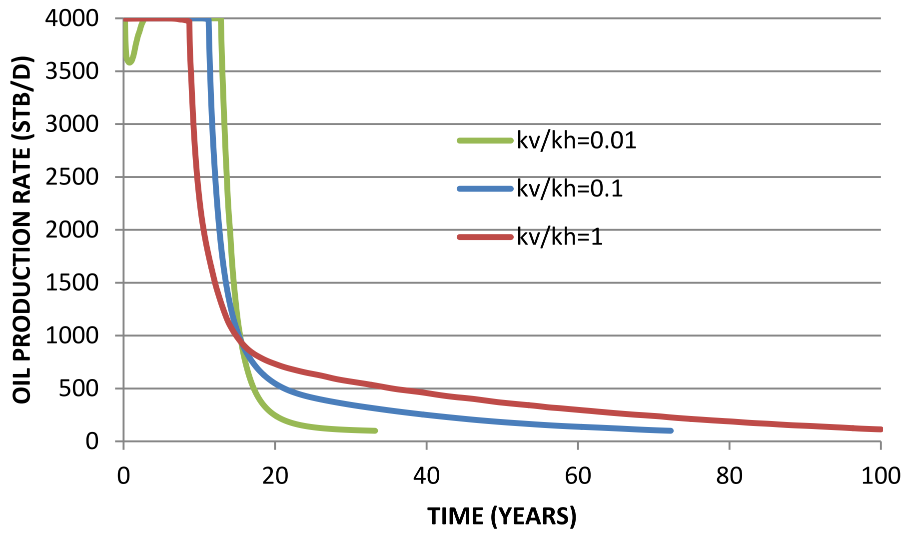


Figure 5.61 Oil production rate for different vertical to horizontal ratios (15-degree dip angle)

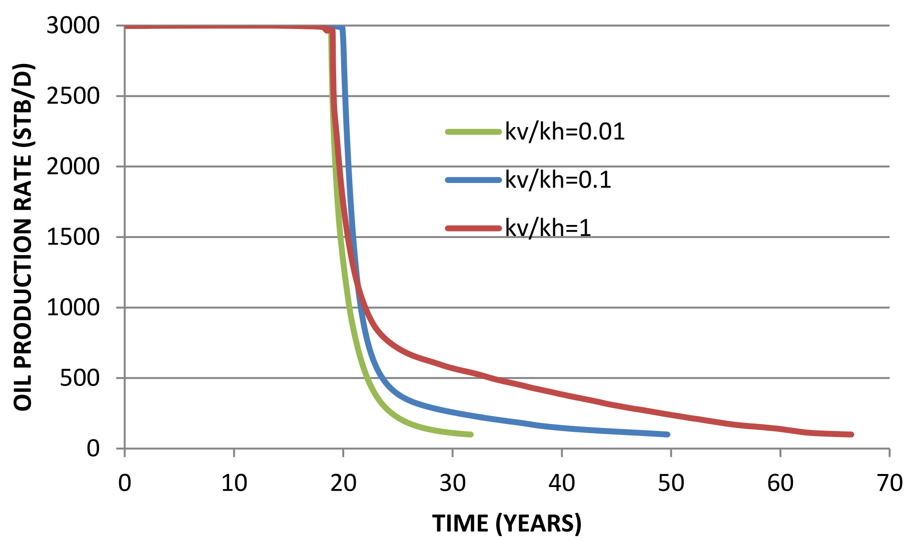


Figure 5.62 Oil production rate for different vertical to horizontal ratios (30-degree dip angle)

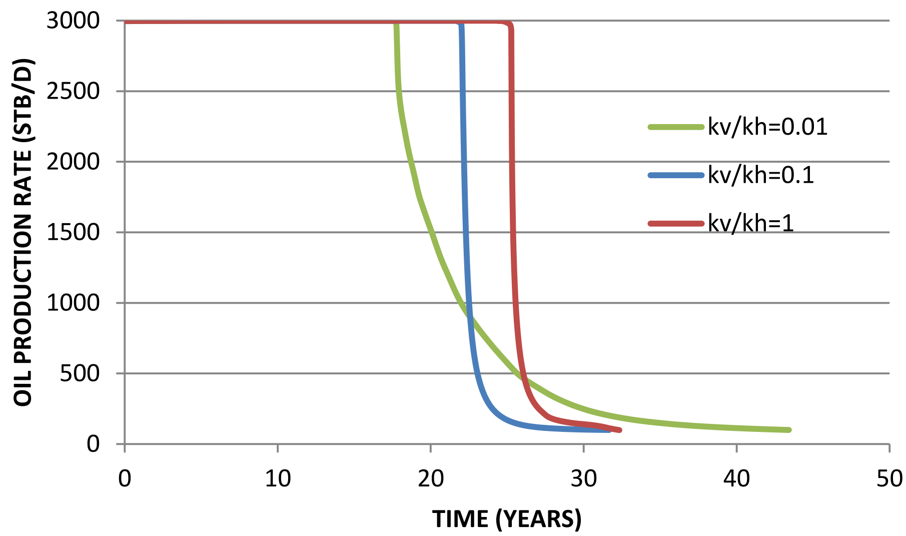
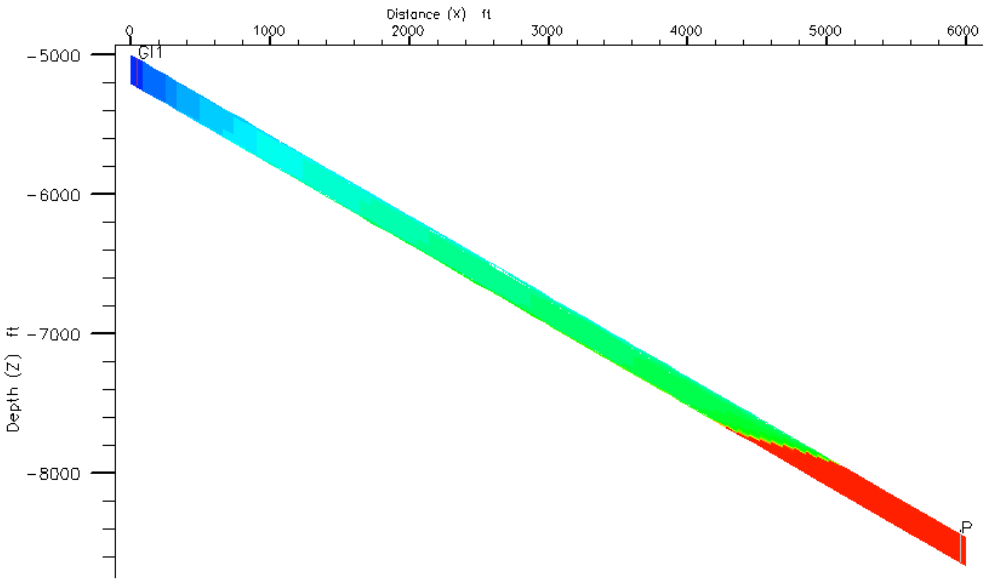
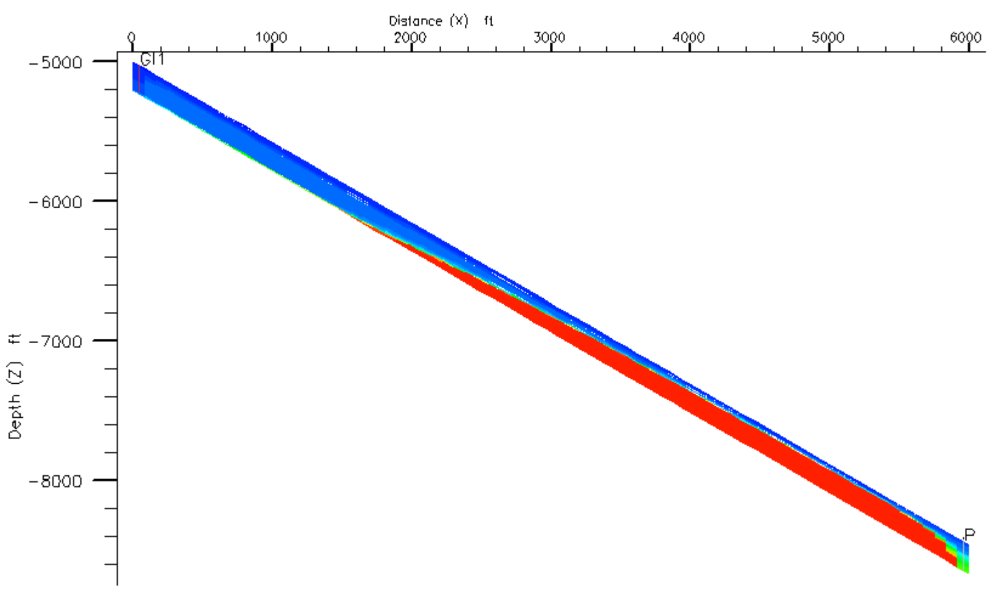


Figure 5.63 Oil production rate for different vertical to horizontal ratios (60-degree dip angle)

Oil production rate for different vertical to horizontal ratios is shown in Figures 5.61-5.63. It is obvious that, for dip angle of 15 and 30 degrees, production time in case 3 is longest whereas oil production declines fastest in case 1. With increasing vertical permeability, not only fluids tend to flow easily toward production well, but gas injection also effectively supports pressure and aids production. Conversely, with the decreasing vertical permeability, fluids flow harder with and the effect of injection is reduced. Furthermore, decreasing ratio of vertical to horizontal permeability results in lower displacement efficiency. As shown in Figure 5.64 (a) and 5.64 (b), in spite of the more stable gas-oil contact, there is higher oil saturation left behind gas flood front in case of lower vertical permeability.

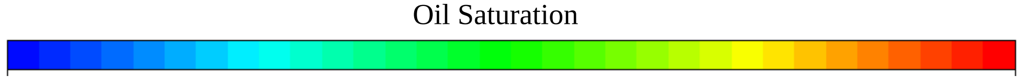


(a) Vertical to horizontal permeability ratio of 0.01



(b) Vertical to horizontal permeability ratio of 1

Oil Saturation



0.07563 0. 70175

Figure 5.64 Oil saturation distribution for vertical to horizontal permeability ratio of 0.01 and 1 for dip angle of 30 degrees at 15 years of production

Summary of production time, oil recovery factor for different vertical to horizontal permeability ratios is listed in Table 5.13. At 30 years, oil recovery factor of case 3 is lower than other cases for dip angle of 15 degrees but, for dip angle of 30 and 60, oil recovery factor is the highest in case 3 because higher vertical permeability together with gravity force improves displacement efficiency and helps drain oil toward the production well. At the end of production, it is clearly seen that case 3 provides the highest oil recovery for every dip angle. This is because high vertical permeability encourages fluids to flow easily toward production well and also enable gas injection to effectively enhance the production via gravity segregation.

Table 5.13 Summary of results for different vertical to horizontal permeability ratios

		At 30 years	At the end of production	
Dip angle	k_v/k_h	Oil recovery factor (%)	Production time (years)	Oil recovery factor (%)
15	0.01	61.20	33.25	61.54
	0.1	61.53	72.25	69.85
	1	57.81	100.00	78.57
30	0.01	63.43	31.67	63.61
	0.1	67.51	49.67	70.70
	1	68.65	66.49	79.22
60	0.01	65.28	43.41	67.23
	0.1	69.41	31.67	69.58
	1	78.53	32.33	78.82

5.5.3 Effect of relative permeability to oil and gas

In this section, residual oil saturation in gas-oil system (S_{org}) is used as a study parameter to determine the effect of different relative permeability to oil and gas. The relative permeability curves are calculated using Corey's correlation. All of the inputs are the same as in base case except for the residual oil saturation which is varied into three values: 0.05, 0.1 and 0.15. The values of relative permeability curves obtained from the sets of inputs are plotted in Figures 5.65.

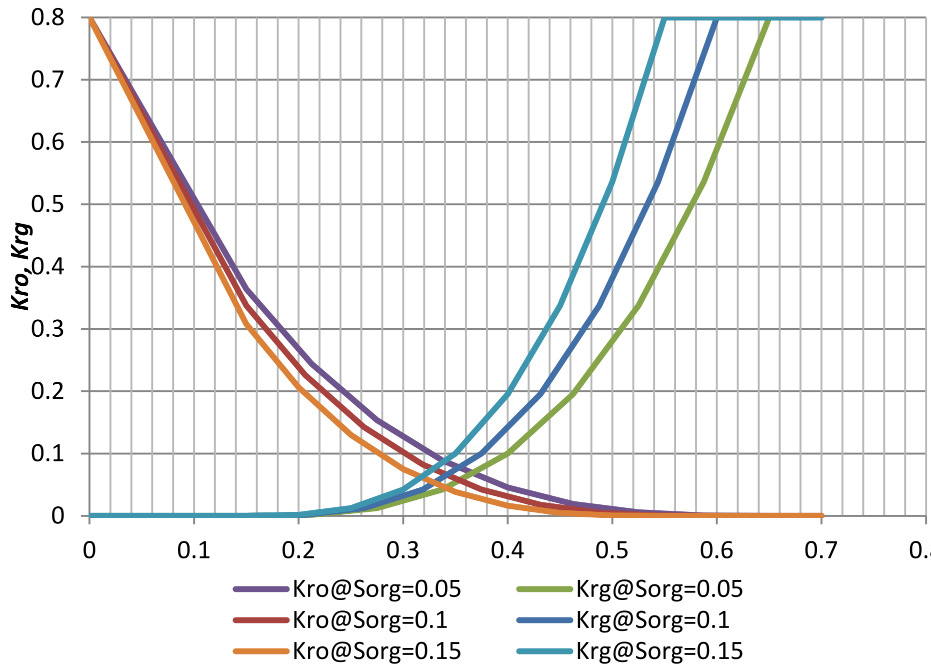


Figure 5.65 Oil/gas saturation function obtained from different residual oil saturation (S_{org})

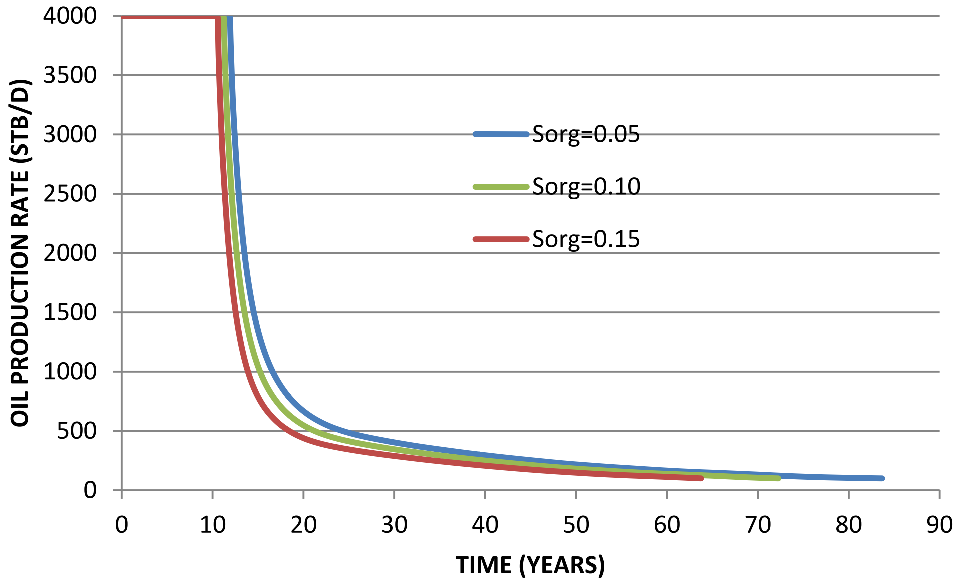


Figure 5.66 Oil production rate for different residual oil saturations (15-degree dip angle)

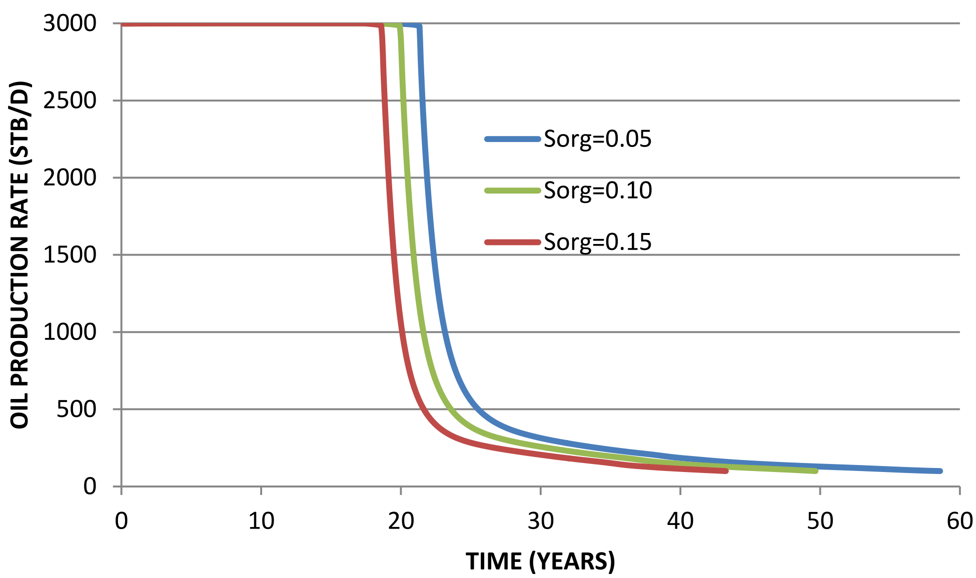


Figure 5.67 Oil production rate for different residual oil saturations (30-degree dip angle)

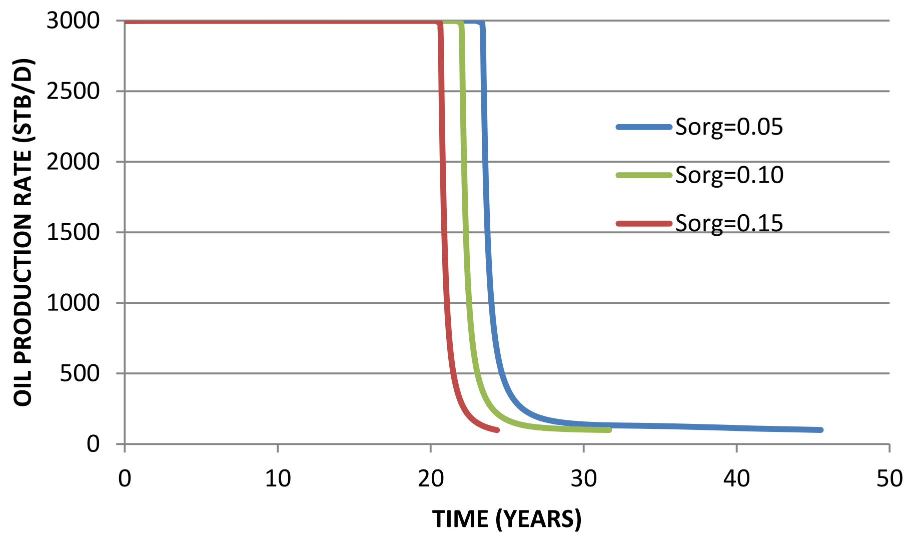


Figure 5.68 Oil production rate for different residual oil saturations (60-degree dip angle)

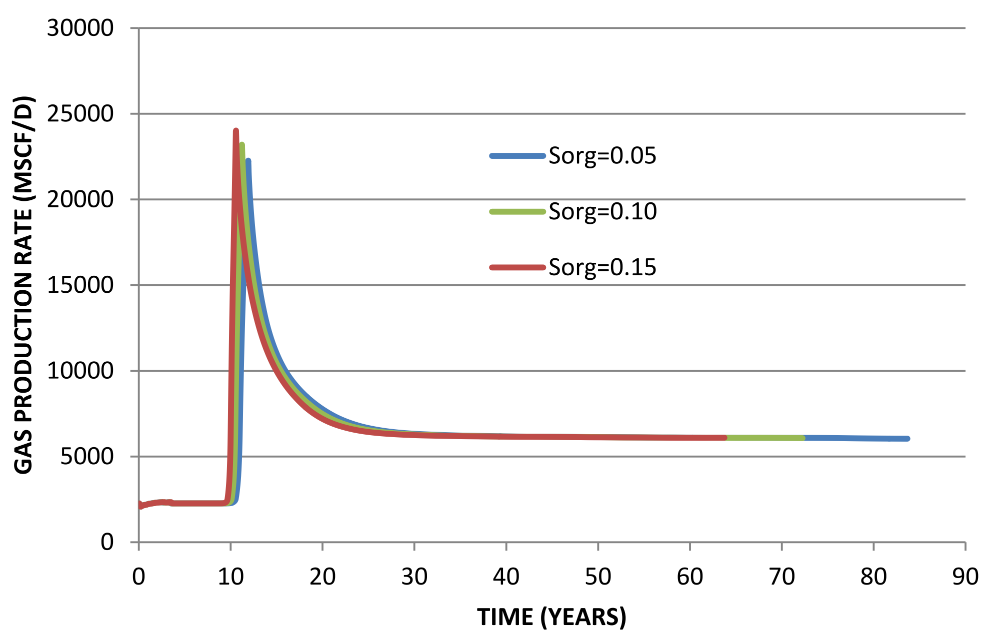


Figure 5.69 Gas production rate for different residual oil saturations (15-degree dip angle)

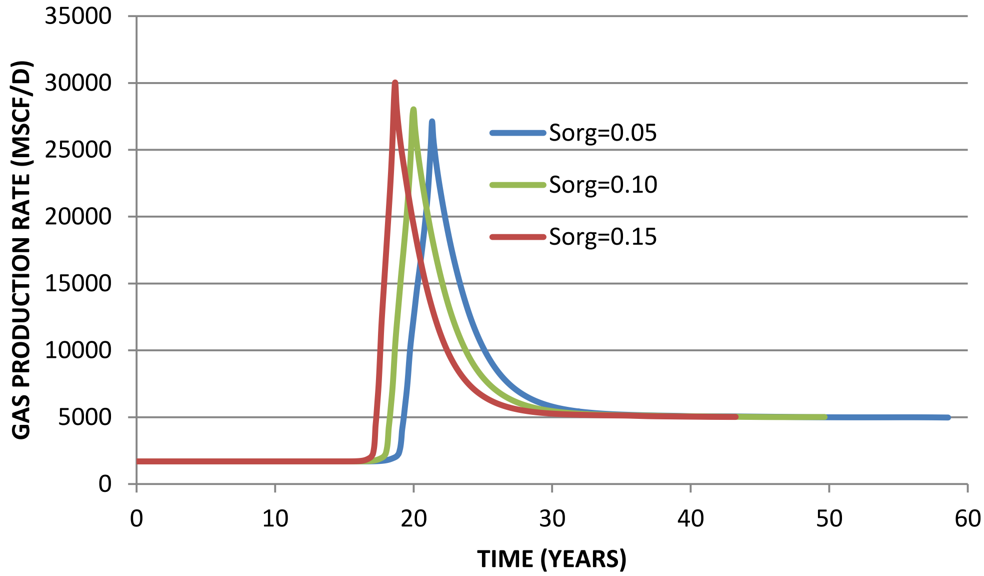


Figure 5.70 Gas production rate for different residual oil saturations (30-degree dip angle)

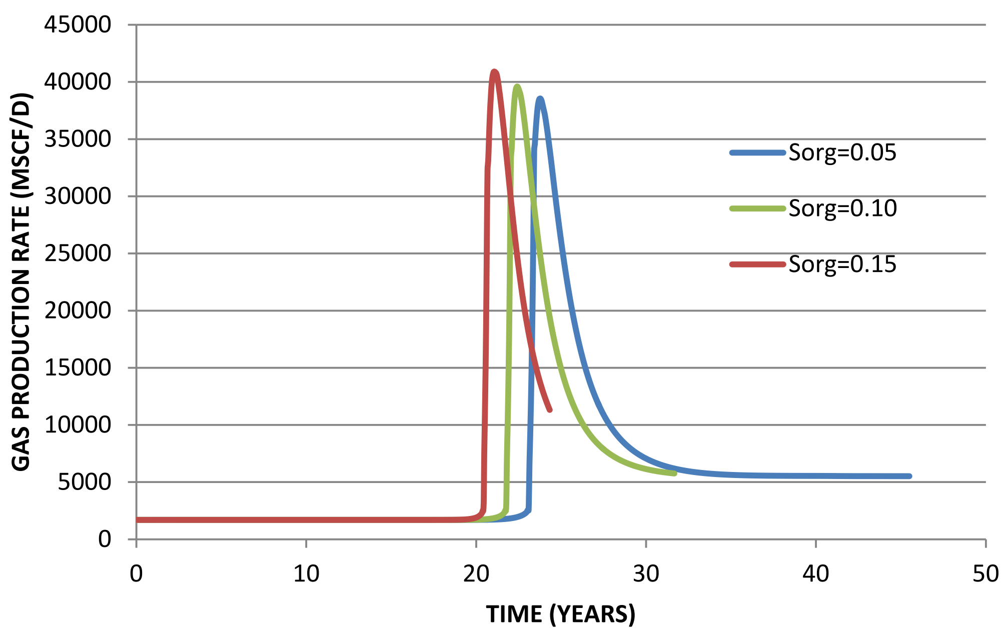


Figure 5.71 Gas production rate for different residual oil saturations (60-degree dip angle)

Oil production rate and gas production for every dip angle is illustrated in Figures 5.66-5.71. Similar trend is observed for every dip angle. It is obvious that decreasing S_{org} extends the production time. For example, in dip angle of 15 degrees, the production time is 83, 72 and 63 years when S_{org} is equal to 0.05, 0.10 and 0.15, respectively. This is because when S_{org} is lower, higher amount of recoverable oil can be produced. Thus, it takes longer production time for the same production rate.

Summary of oil recovery factor for different residual oil saturations for GAGD at 30 years and at the end of production is listed in Table 5.14. The results indicated that the lower S_{org}, the higher oil recovery. At 30 years, oil recovery factor is the highest when S_{org} is 0.05 and difference in oil recovery factor obtained from the sets of Sorg is up to 8.31, 8.67 and 9.41% for dip angle of 15, 30 and 60 degrees, respectively. At the end of production, oil recovery is still the highest when S_{org} is 0.05 and difference in oil recovery factor obtained from the sets of Sorg is up to 13.44, 11.77 and 11.29% for dip angle of 15, 30 and 60 degrees, respectively. An increase in oil recovery factor when decreasing S_{org} can be explained by considering the amount of oil that can be displaced by gas. With low S_{org}, high amount of oil can be recovered after gas flooding process. Thus, high oil recovery is achieved. Furthermore, total amount of gas production and injection is higher when S_{org} is lower because of the longer production time.

Table 5.14 Summary of results for different residual oil saturations

Dip angle	S_{org}	At 30 years: Oil recovery factor (%)	At the end of production: Production time (years)	At the end of production: Oil recovery factor (%)
15	0.05	65.61	83.67	76.79
	0.1	61.53	72.25	69.85
	0.15	57.30	63.75	63.35
30	0.05	71.79	58.58	76.80
	0.1	67.51	49.67	70.70
	0.15	63.12	43.25	65.03
60	0.05	73.84	45.50	75.72
	0.1	69.41	31.67	69.58
	0.15	64.43	24.33	64.43

CHAPTER VI

CONCLUSION AND RECOMMENDATION

In this chapter, effect of all design parameters on GAGD performance and results obtained from sensitivity analysis are concluded. Some comments and recommendations which might be useful for future study are also included.

6.1 Conclusion

The results from this study show that performance of GAGD is significantly influenced by both location of production wells, oil production rate and gas injection rate. In addition, production time is also an important factor to be considered in determining the most suitable set of design parameters for a specific reservoir. The summary of effect from each parameter is listed as follows:

1. GAGD considerably increases oil production comparing to that of natural depletion. In dipping reservoir with enough permeability, the injected gas tends to accumulate at the top and forms a gas cap. The gas cap displaces oil down toward the producer and helps maintain the reservoir pressure. As a result, higher oil recovery is achieved.
2. Reservoir dip angle affects the oil recovery. An increase in dip angle enables gravity effect to improve the stability of flood front and increase gas sweep efficiency. The maximum oil recovery obtained from natural depletion and GAGD process when dip angle is 60 degrees confirms that the effect of gravity is substantial in improving oil recovery for inclined reservoirs.
3. Oil production rate is a key parameter in GAGD process. Very low production rate encourages gravity drainage to occur which can be observed from the stable gas-oil contact. This allows gas to effectively displace oil and delays gas

breakthrough. Nevertheless, it takes impractically long production time which might not be an attractive operating condition. On the other hand, high production and injection rates help accelerate oil production. However, when the oil is produced at the too high rate, injected gas and solution gas likely to be produced earlier. This reduces the benefit of gas injection and leads to higher gas production.

4. For the production time of 30 years, oil production rate used in GAGD should be higher than 1000 STB for 15-degree dip angle and more than 2000 STB/D for 30- and 60-degree dip angle for the reservoirs and fluid properties used in this study in order to obtain comparatively high oil recovery. The lower production rates result in inefficient small amount of oil recovered under the desired production time, although they provide more stable flood front and better displacement efficiency.
5. When production rate is fixed, increasing injection rate increases the oil recovery. This trend continues until injection rate is so high that the maximum injection rate cannot be achieved throughout production life due to the injection well constraint on fracture pressure. When the injection rate rises beyond certain value, the injection rate has less effect on additional production, thus; oil recovery hardly increases.
6. In dipping reservoirs, gas injector should be located at the most updip location whereas production well should be placed at the most downdip location to prevent premature gas breakthrough and maximize volumetric sweep efficiency.
7. In terms of sensitivity study, different three phase correlations yield about the same oil production and reservoir performance. However, production time is slightly different for each correlation.
8. Increasing vertical to horizontal permeability ratio significantly increases oil recovery, improves displacement efficiency and also extends production time since the increased vertical permeability permits fluids to flow easily toward

production well and also enable gas injection to effectively enhance the production via gravity segregation.

9. Decrease in residual oil saturation in gas-oil system results in higher oil recovery. Varying oil saturation from 0.05 to 0.15 leads to difference in oil recovery up to 9% and 13% at 30 years and the end of production time, respectively. This is because higher amount of oil can be recovered after gas flooding process.

6.2 Recommendation

1. The performance of different well patterns is based on the selected set of production and injection rate. Thus, effect of different sets of injection and production rates for each well pattern should be investigated.
2. This study is conducted using ECLIPSE 100 black oil reservoir simulator in which the effect of compositional change is not included. The effect of miscible should be as well determined by using ECLIPSE 300 compositional reservoir simulator.
3. In this study, the reservoir model is a depletion reservoir which is not contact with any water or gas interface. The effect of other drives such as water drive, gas cap drive and combination drives should be studied.
4. The performance of GAGD process may be investigated in heterogeneous reservoirs.

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APPENDIX

Appendix

Reservoir model

A reservoir model is constructed using ECLIPSE 100 reservoir simulator. The model used in this study composes of 73 x 31 x 21 blocks in the x-, y- and z- directions. The following required data are input in each section of the program.

1. Case Definition

Simulator	Black oil
Model dimension	Number of cells in the x-direction73
	Number of cells in the y-direction 31
	Number of cells in the z-direction 21
Grid type	Cartesian
Geometry type	Corner Point
Oil-Gas-Water options	Water, oil, gas and dissolved gas
Solution type	Fully Implicit

2. Reservoir properties

<u>Gird</u>

Active Grid Block X(1-73)	= 1
Y(1-31)	= 1
Z(1-21)	= 1
X Permeability	32.529 md
Y Permeability	32.529 md
Z Permeability	3.2529 md
Porosity	0.1509
Dip angle	30 degrees in base case
Grid block sizes	based on calculation with dip angle

3. PVT

Fluid densities at surface condition	Oil density	51.45684	lb/cu.ft
	Water density	62.42797	lb/cu.ft
	Gas density	0.04369958	lb/cu.ft
Water PVT properties	Reference pressure (Pref)	3000	psia
	Water FVF at Pref	1.021734	rb/stb
	Water compressibility	3.099E-06	/psi
	Water viscosity at Pref	0.3013289	cp
	Water viscosibility	3.3927E-06	/psi
Rock properties	Reference pressure	3000	psia
	Rock compressibility	3.01392E-06	psi-1

Live oil PVT properties (dissolved gas)

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.001325123	14.7	1.069137	1.240277
	277.08421	1.0521431	1.315743
	539.46842	1.0516839	1.449801
	801.85263	1.0515252	1.626163
	1064.2368	1.0514448	1.84373
	1326.6211	1.0513962	2.104802
	1589.0053	1.0513637	2.413226
	1851.3895	1.0513403	2.773787
	2113.7737	1.0513228	3.191926
	2353.4592	1.0513102	3.629233
	2638.5421	1.0512982	4.224983
	3000	1.0512863	5.110913
	3163.3105	1.0512818	5.563312
	3425.6947	1.0512754	6.363454
	3688.0789	1.05127	7.259572
	3950.4632	1.0512653	8.257824
	4212.8474	1.0512612	9.36392
	4475.2316	1.0512575	10.58297
	4737.6158	1.0512543	11.91932
	5000	1.0512514	13.37641
0.045575432	277.08421	1.0879253	1.010324
	539.46842	1.0778477	1.039916

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.045575432	801.85263	1.0743875	1.085731
	1064.2368	1.0726378	1.144382
	1326.6211	1.0715815	1.214381
	1589.0053	1.0708747	1.295021
	1851.3895	1.0703685	1.385986
	2113.7737	1.0699882	1.487169
	2353.4592	1.0697149	1.588539
	2638.5421	1.0694546	1.7203
	3000	1.0691957	1.905033
	3163.3105	1.0690982	1.99504
	3425.6947	1.068961	2.148242
	3688.0789	1.0688433	2.312071
	3950.4632	1.0687413	2.486529
	4212.8474	1.068652	2.671564
	4475.2316	1.0685731	2.867062
	4737.6158	1.068503	3.072842
	5000	1.0684403	3.28865
0.10170558	539.46842	1.1124223	0.840021
	801.85263	1.1044637	0.862883
	1064.2368	1.100452	0.894564
	1326.6211	1.0980343	0.933676
	1589.0053	1.096418	0.979443
	1851.3895	1.0952613	1.031404
	2113.7737	1.0943926	1.089276
	2353.4592	1.0937687	1.147152
	2638.5421	1.0931746	1.222087
	3000	1.092584	1.326458
	3163.3105	1.0923615	1.377
	3425.6947	1.0920485	1.462563
	3688.0789	1.0917802	1.553431
	3950.4632	1.0915475	1.649517
	4212.8474	1.0913438	1.750714
	4475.2316	1.0911641	1.856891
	4737.6158	1.0910043	1.967896
	5000	1.0908613	2.083547
0.16395522	801.85263	1.1403543	0.721582
	1064.2368	1.1333311	0.740749
	1326.6211	1.1291083	0.765549

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.16395522	1589.0053	1.1262889	0.79526
	1851.3895	1.124273	0.829422
	2113.7737	1.1227599	0.86773
	2353.4592	1.1216739	0.906163
	2638.5421	1.12064	0.955981
	3000	1.1196126	1.025323
	3163.3105	1.1192256	1.058853
	3425.6947	1.1186814	1.115517
	3688.0789	1.1182149	1.175545
	3950.4632	1.1178104	1.238841
	4212.8474	1.1174565	1.305308
	4475.2316	1.1171442	1.374834
	4737.6158	1.1168665	1.4473
	5000	1.1166181	1.522572
0.23059392	1064.2368	1.171041	0.635607
	1326.6211	1.1644833	0.652281
	1589.0053	1.1601136	0.67288
	1851.3895	1.1569925	0.696974
	2113.7737	1.1546518	0.724264
	2353.4592	1.1529727	0.751802
	2638.5421	1.151375	0.787624
	3000	1.149788	0.837589
	3163.3105	1.1491905	0.861763
	3425.6947	1.1483504	0.902609
	3688.0789	1.1476303	0.945853
	3950.4632	1.1470062	0.991406
	4212.8474	1.1464601	1.03918
	4475.2316	1.1459783	1.089084
	4737.6158	1.14555	1.141019
	5000	1.1451668	1.194883
0.30071672	1326.6211	1.204112	0.57048
	1589.0053	1.1977854	0.58531
	1851.3895	1.1932748	0.603029
	2113.7737	1.1898952	0.62336
	2353.4592	1.1874724	0.644036
	2638.5421	1.1851685	0.671071
	3000	1.1828813	0.708926
	3163.3105	1.1820205	0.727274

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.30071672	3425.6947	1.1808105	0.758301
	3688.0789	1.1797735	0.791164
	3950.4632	1.1788751	0.825783
	4212.8474	1.1780892	0.862081
	4475.2316	1.1773958	0.899977
	4737.6158	1.1767796	0.939391
	5000	1.1762283	0.980239
0.37375579	1589.0053	1.2393217	0.519385
	1851.3895	1.2330917	0.532773
	2113.7737	1.2284318	0.548372
	2353.4592	1.2250939	0.564391
	2638.5421	1.2219219	0.585475
	3000	1.218775	0.615151
	3163.3105	1.2175912	0.629575
	3425.6947	1.2159274	0.654002
	3688.0789	1.2145023	0.679906
	3950.4632	1.2132677	0.707215
	4212.8474	1.212188	0.735858
	4475.2316	1.2112357	0.765766
	4737.6158	1.2103895	0.796869
	5000	1.2096327	0.829098
0.44931763	1851.3895	1.2764901	0.478153
	2113.7737	1.2702713	0.490372
	2353.4592	1.2658241	0.503058
	2638.5421	1.2616011	0.519891
	3000	1.2574146	0.543737
	3163.3105	1.2558405	0.555368
	3425.6947	1.2536291	0.575105
	3688.0789	1.2517354	0.596074
	3950.4632	1.2500957	0.618208
	4212.8474	1.2486619	0.641444
	4475.2316	1.2473976	0.665718
	4737.6158	1.2462744	0.690972
	5000	1.24527	0.717145
0.52711162	2113.7737	1.3154764	0.444115
	2353.4592	1.3096957	0.454329
	2638.5421	1.304216	0.468002
	3000	1.2987883	0.487519

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.52711162	3163.3105	1.2967486	0.49708
	3425.6947	1.2938843	0.513344
	3688.0789	1.2914326	0.530665
	3950.4632	1.2893103	0.548978
	4212.8474	1.2874552	0.568227
	4475.2316	1.2858199	0.588355
	4737.6158	1.2843675	0.609308
	5000	1.2830689	0.631034
0.59993517	2353.4592	1.3525813	0.417782
	2638.5421	1.3457468	0.429226
	3000	1.3389887	0.445684
	3163.3105	1.3364506	0.453782
	3425.6947	1.3328877	0.467596
	3688.0789	1.3298393	0.482344
	3950.4632	1.3272015	0.497967
	4212.8474	1.3248966	0.514411
	4475.2316	1.3228653	0.531625
	4737.6158	1.3210616	0.54956
	5000	1.3194492	0.568169

Dry gas PVT properties (no vapourised oil)

Press (psia)	FVF (rb /Mscf)	Visc (cp)
14.7	225.77118	0.013253
277.08421	11.684415	0.013439
539.46842	5.8604139	0.013739
801.85263	3.8557057	0.014127
1064.2368	2.8465392	0.014598
1326.6211	2.2432054	0.01515
1589.0053	1.8454849	0.01578
1851.3895	1.5665663	0.016484
2113.7737	1.3625791	0.017254
2353.4592	1.2205693	0.018006
2638.5421	1.0902445	0.018947
3000	0.96700949	0.020188
3163.3105	0.92257588	0.020758
3425.6947	0.86218077	0.021676

Press (psia)	FVF (rb /Mscf)	Visc (cp)
3688.0789	0.81250833	0.022593
3950.4632	0.77111488	0.023499
4212.8474	0.73619385	0.024392
4475.2316	0.70639432	0.025268
4737.6158	0.68069512	0.026126
5000	0.65831597	0.026965

4. SCAL

Water/oil saturation functions

Sw	Krw	Kro	Pc (psia)
0.3	0	0.8	0
0.344444	0.009877	0.561866	0
0.388889	0.039506	0.376406	0
0.433333	0.088889	0.237037	0
0.477778	0.158025	0.137174	0
0.522222	0.246914	0.070233	0
0.566667	0.355556	0.02963	0
0.611111	0.483951	0.008779	0
0.655556	0.632099	0.001097	0
0.7	0.8	0	0
1	0.8	0	0

Gas/oil saturation functions

Sg	Krg	Kro	Pc (psia)
0	0	0.8	0
0.15	0	0.3375	0
0.20625	0.001563	0.226099	0
0.2625	0.0125	0.142383	0
0.31875	0.042188	0.082397	0
0.375	0.1	0.042188	0
0.43125	0.195313	0.017798	0
0.4875	0.3375	0.005273	0
0.54375	0.535938	0.000659	0
0.6	0.8	0	0
0.7	0.8	0	0

5. Initialization

Equilibration data specification

Datum depth	5000 ft
Pressure at datum depth	2242 psia
WOC depth	12000 ft
GOC depth	5000 ft

6. Schedule

In reservoir simulation model, each well setting is described as follows:

6.1 GAGD basecase

Oil horizontal production well

Well specification

Well name	P
Group	G
I location	73
J location	1
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

Well connection data

Well connection data	P
K upper	21
K lower	21
Open/shut flag	OPEN
Well bore ID	0.5522083 ft
Direction	Y

Production well control

Well	P
Open/shut flag	OPEN
Control	LRAT
Liquid rate	3000 stb/day
BHP target	500 psia

Production well economic limits

Well	P
Minimum oil rate	100 stb/day
Workover procedure	WELL
End run	YES
Quantity for economic limit	RATE

The keyword of well connection data is repeated for J Location of 2 through 21 so that the horizontal section of the well can be created.

Gas vertical injection well

Well specification

Well name	GI
Group	G
I location	1
J location	16
Preferred phase	GAS
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

Well connection data

Well connection data	GI
I Location	1
J Location	16

K upper	1
K lower	21
Open/shut flag	OPEN
Well bore ID	0.5522083 ft
Direction	Z

Injection well control

Well	GI
Injector type	GAS
Open/shut flag	OPEN
Control mode	RATE
Liquid surface rate	3500 stb/day
BHP target	3300 psia

In section 5.4 which effect of different well patterns is studied, the keywords used for injection well in every well pattern are the same as GAGD basecase except for gas injection rates that are different depending on each dip angle. While the keywords used for production wells for each well pattern are listed below.

6.2 Well pattern 1

The keywords used for production wells for well pattern 2 are exactly the same as GAGD basecase.

6.3 Well pattern 2

Well specification

Well name	P1
Group	G
I location	73
J location	8
Preferred phase	OIL
Inflow equation	STD

Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

The keyword for well specification is repeated for well P2 except that (I, J) location for well P2 is (73, 24).

<u>Well connection data</u>

Well connection data	P*
K upper	8
K lower	21
Open/shut flag	OPEN
Well bore ID	0.5522083 ft
Direction	Z

<u>Production well control</u>

Well	P*
Open/shut flag	OPEN
Control	GRUP
BHP target	500 psia

<u>Group Production control</u>

Group	G
Control	LRAT
Liquid rate	based on dip angle

<u>Group economic limits</u>

Group	G
Minimum oil rate	100 stb/day
Workover procedure	WELL
End run	YES

6.4 Well pattern 3

<u>Well specification</u>

Well name	P1
Group	G
I location	19
J location	16
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

The keyword for well specification is repeated for well P2 except that (I, J) location for well P2, P3 and P4 are (37, 16), (55, 16) and (73, 16), respectively.

<u>Well connection data</u>

Well connection data	P1
K upper	5
K lower	21
Open/shut flag	OPEN
Well bore ID	0.5522083 ft
Direction	Z

The keyword for well specification is repeated for well P2, P3. While K upper and lower for well P4 are 10 and 21, respectively.

<u>Production well control</u>

Well	P*
Open/shut flag	OPEN
Control	GRUP
BHP target	500 psia

<u>Group Production control</u>

Group	G
Control	LRAT
Liquid rate	based on dip angle

<u>Production well economic limits</u>

Well	P1
Maximum Gas-Oil Ratio	30 Mscf/stb
Workover procedure	WELL
End run	NO

The keyword for Production well economic limits is repeated for well P2 and P3.

<u>Group economic limits</u>

Group	G
Minimum oil rate	100 stb/day
Workover procedure	WELL
End run	YES

6.5 Well pattern 4

<u>Well specification</u>

Well name	P1
Group	G
I location	19
J location	24
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

The keyword for well specification is repeated for well P2, P3, P4, P5, P6, P7 and P8 except that (I, J) location for these wells are (19, 8), (37, 24), (37, 8), (55, 24), (55, 8), (73, 24) and (73, 8), respectively.

<u>Well connection data</u>

Well connection data	P1
K upper	5
K lower	21
Open/shut flag	OPEN
Well bore ID	0.5522083 ft
Direction	Z

The keyword for well specification is repeated for well P2, P3, P4, P5 and P6. While K upper and lower for well P7 and P8 are 10 and 21, respectively.

<u>Production well control</u>

Well	P*
Open/shut flag	OPEN
Control	GRUP
BHP target	500 psia

<u>Group Production control</u>

Group	G
Control	LRAT
Liquid rate	based on dip angle

<u>Production well economic limits</u>

Well	P1
Maximum Gas-Oil Ratio	30 Mscf/stb
Workover procedure	WELL
End run	NO

The keyword for Production well economic limits is repeated for well P2 P2, P3, P4, P5 and P6.

Group economic limits

Group	G
Minimum oil rate	100 stb/day
Workover procedure	WELL
End run	YES

Vitae

Teerawat Vaccharasiritham was born on July 19th, 1988 in Bangkok, Thailand. He completed his Bachelor Degree in Mechanical Engineering from the Faculty of Engineering, Chulalongkorn University in 2011. After graduating, he continued his study in Master's Degree of Petroleum Engineering at Department of Mining and Petroleum Engineering, Chulalongkorn University since 2011.