EVALUATION OF PRODUCTION PERFORMANCE OF SELECTIVE SIMUTANEOUS WATER ALTERNATING GAS (SSWAG) AND GAS ASSISTED GRAVITY DRAINAGE (GAGD) IN STEEPLY DIPPING RESERVOIR

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
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การประเมินสมรรถนะการผลิตด้วยวิธีอัดน้ำสลับแก๊สพร้อมกันแบบเลือกตำแหน่งและวิธีการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊สในแหล่งกักเก็บที่มีความชัน

นางสาว อรณัฐ สันติธนานนท์

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต

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Thesis Title	EVALUATION OF PRODUCTION PERFORMANCE OF SELECTIVE SIMULTANEOUS WATER ALTERNAITNG GAS (SSWAG) AND GAS ASSISTED GRAVITY DRAINAGE (GAGD) IN STEEPLY DIPPING RESERVOIR
By	Ms. Oranat Santidhananon
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Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

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อรณัฐ สันติธนานนท์ : การประเมินสมรรถนะการผลิตด้วยวิธีอัดน้ำสลับแก๊สพร้อมกันแบบเลือกตำแหน่งและวิธีการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊สในแหล่งกักเก็บที่มีความชัน. (EVALUATION OF PRODUCTION PERFORMANCE OF SELECTIVE SIMUTANEOUS WATER ALTERNATING GAS (SSWAG) AND GAS ASSISTED GRAVITY DRAINAGE (GAGD) IN STEEPLY DIPPING RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 154 หน้า.

วิธีการที่ได้ผสมผสานการอัดน้ำและแก๊สรวมกันคือการอัดน้ำสลับแก๊สพร้อมกันแบบเลือกตำแหน่ง วิธีนี้ต้องการหลุมสองหลุมเพื่ออัดน้ำและแก๊สแยกกัน หลุมอัดแก๊สจะอยู่ลึกกว่าหลุมอัดน้ำและมีหลุมผลิตอยู่อีกด้านของแหล่งกักเก็บ ซึ่งอยู่ตรงข้ามกับหลุมอัดทั้งสองหลุม

วิธีการที่ใช้ผลิตโดยอาศัยแรงโน้มถ่วงคือวิธีการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊ส วิธีนี้ประกอบด้วยหลุมผลิตแบบนอนอยู่ที่ส่วนล่างของแหล่งกักเก็บ และอัดแก๊สผ่านหลุมตั้งที่มีอยู่แล้ว แก๊สที่อัดจะไหลขึ้นข้างบนและขยายออกด้านข้างและด้านล่าง การขยายตัวของแก๊สจะช่วยดันน้ำมันไปยังหลุมผลิต

ผลการศึกษาพบว่าค่าสัดส่วนของน้ำมันที่ผลิตได้จากการอัดน้ำสลับแก๊สพร้อมกันแบบเลือกตำแหน่งและวิธีการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊สที่นำมาใช้ในแหล่งกักเก็บที่มีความชัน มีค่าอยู่ในช่วง 50 ถึง 80 เปอร์เซ็นต์ ประสิทธิภาพการผลิตนั้นขึ้นอยู่กับการออกแบบตัวแปรที่เหมาะสม การอัดน้ำสลับแก๊สพร้อมกันแบบเลือกตำแหน่งสามารถผลิตน้ำมันได้มากขึ้นเมื่ออัดแก๊สในอัตราสูงพร้อมอัดน้ำในอัตราต่ำ หลุมผลิตควรมีส่วนแนวนอนที่สั้นและควรวางในตำแหน่งที่ลึกที่สุดในด้านที่ลาดต่ำกว่า ตำแหน่งและความยาวของหลุมอัดมีผลต่อประสิทธิภาพการผลิตน้ำมันที่น้อย สำหรับวิธีการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊สสามารถผลิตน้ำมันได้มากขึ้นเมื่อใช้อัตราการอัดแก๊สที่สูงและหลุมผลิตที่ยาว หลุมอัดแก๊สควรวางในตำแหน่งที่ตื้นในขณะที่หลุมผลิตควรวางในตำแหน่งที่ลึกที่สุด อย่างไรก็ตามการอัดน้ำสลับแก๊สพร้อมกันแบบเลือกตำแหน่งอาจจะไม่เหมาะที่จะใช้ในแหล่งกักเก็บที่มีความชันถ้าเปรียบเทียบกับวิธีการผลิตโดยอาศัยแรงโน้มถ่วงและการอัดแก๊สและวิธีการแทนที่สองครั้งเพราะประสิทธิภาพการผลิตน้ำมันต่ำกว่า

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม...... ลายมือชื่อนิสิต..

สาขาวิชา วิศวกรรมปิโตรเลียม.................. ลายมือชื่ออ.ที่ปรึกษาวิทยานิพนธ์หลัก.............

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ORANAT SANTIDHANANON EVALUATION OF PRODUCTION PERFORMANCE OF SELECTIVE SIMUTANEOUS WATER ALTERNATING GAS (SSWAG) AND GAS ASSISTED GRAVITY DRAINAGE (GAGD) IN STEEPLY DIPPING RESERVOIR. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 154 pp.

One known process that integrates combined gas and water injection is Selective Simultaneous Water Alternating Gas (SSWAG). SSWAG requires two wells for injecting water and gas separately. A gas injector is usually placed at the bottom of the formation while a water injector is placed at the top with another producer well on the other side of the reservoir opposite these two injectors.

One process that utilizes gravity drainage is Gas Assisted Gravity Drainage (GAGD). GAGD consists of placing a horizontal producer near the bottom of the reservoir and injecting gas through existing vertical wells. Injected gas tends to flow to the top of the pay zone and expand in sideward and downward direction. The expansion of gas helps sweep the oil towards the horizontal producer.

The study showed that recovery factor of SSWAG and GAGD, implemented in dipping reservoir, falls in range of 50% to 80%. The efficiency depends on design parameters. Oil production is enhanced through SSWAG by injecting gas at high rate together with water at low rate with shorter length of horizontal producer and deepest location of horizontal producer in the downdip side. 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 longer producer. Gas injector should be located at shallowest depth while oil producer should be at the deepest depth. However, SSWAG might not be suitable to implement in dipping reservoir when compared with GAGD and DDP as it has poorer performance.

Department Mining and Petroleum Engineering ……… Student's Signature……........…...
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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
CAPEX	Capital Expenditure
OPEX	Operating Expenditure
NPV	Net Present Value
IRR	Internal Rate of Return
PI	Profitability Index
DPI	Discounted Profitability Index
NCF	Net Cash Flow
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
P_v	Present value at time zero of the future amount
F_v	Future value at time t
i	Interest or discount rate
t	Time period

CHAPTER I

INTRODUCTION

1.1 Background

An essential process to increase the production of oil after natural drive mechanism is Improve Oil Recovery (IOR). Waterflooding and gas injection are commonly used to achieve such objectives for most reservoir conditions including steeply dipping reservoirs. One method recognized for dipping reservoirs is Double Displacement Process (DDP) which involves gas injection at up-dip location of the field after implementation of waterflooding. Injection of gas into formation containing residual oil globules helps the oil phase to reconnect and create thin film. This oil film tends to flow downward due to gravity force towards the producing well located at the down-dip side of the reservoir. DDP could give oil recovery of 85 to 95% of original oil in place according to reports from the field test [1]. The simulation study from Suwannakul [2] also showed that DDP can recover oil up to 80% compared to normal waterflood which gives recovery factor in the range of 40–50 %. Even though DDP gives high recovery, it requires a very long period of production time up to 90 years in some cases, and this can make DDP unattractive in economical aspect. This study intends to propose other candidates of production strategies suitable for the same type of reservoir which are Selective Simultaneous Water Alternating Gas (SSWAG) and Gas Assisted Gravity Drainage (GAGD).

Selective Simultaneous Water Alternating Gas (SSWAG) is the modified method from Simultaneous Water Alternating Gas (SWAG). The difference between these two methods is that SWAG process requires injection of mixture of water and gas into one wellbore while SSWAG requires two wells for injecting water and gas separately. The normal practice is to place gas injector at the bottom and water at the top of the reservoir strata with a producer well on the other side of the reservoir opposite those two injectors. Published literatures have shown that SSWAG would increase oil recovery compared to normal WAG process.

Gas Assisted Gravity Drainage (GAGD) has been proposed since 2004 with intention to overcome natural gravity segregation problem in Water Alternating Gas (WAG). Unlike WAG, GAGD method uses the benefit of natural segregation of injected gas into crude oil reservoir. The process consists of placing a horizontal producer near the bottom of the reservoir and injecting gas through existing vertical wells. Injected gas tends to flow to the top of the pay zone and forces oil to flow downward towards the horizontal producer.

In this study, sensitivity analysis will be performed to investigate the effect of various design parameters on performance of SSWAG and GAGD via ECLIPSE100 reservoir simulator. Moreover, simulation results from these two strategies will be compared with DDP process in order to find the most appropriate strategies for dipping reservoir.

1.2 Objectives

1. To determine effects of design parameters such as locations of horizontal injectors, location of vertical producer, length of horizontal injectors, perforation interval of vertical producer, water injection rate, and gas injection on oil recovery and choose the best production strategy for SSWAG.
2. To determine effects of design parameters such as number of vertical gas injectors, locations of vertical gas injectors, completion intervals of vertical injectors, gas injection rate, length of horizontal producer, and location of horizontal producer on oil recovery and choose the best production strategy for GAGD.
3. To conduct comparative study between SSWAG, GAGD, and DDP to determine the most appropriate strategy for dipping reservoir.

1.3 Outline of methodology

1. Study various published literatures and gather required data for reservoir simulation model.
2. Construct the base case for SSWAG and GAGD processes.
3. Simulate the model with different design parameters in order to study the effects on production performance for SSWAG includes
    - Gas and water injection rate
    - Gas and water injection pressure
    - Locations of injectors and producer
    - Length of horizontal injectors
    - Perforation interval of vertical producer
4. Simulate the model and see effect of up-dip injection and down-dip injection in SSWAG mode.
5. Simulate the model with different designing parameters in order to study the effects on production performance for GAGD includes
    - Number and location of gas injectors
    - Gas injection rate
    - Length of horizontal producer
    - Location of horizontal producer
    - Perforation interval of vertical injector
6. Analyze the result from simulation for both SSWAG and GAGD methods and compare with result from DDP methods.
7. Discuss and summarize the most suitable production strategy for dipping reservoir.

1.4 Thesis outline

The rest of this thesis is divided into five chapters as outline below

Chapter II presents previous works on SSWAG and GAGD methods which include laboratory experiment and simulation studies. These studies showed increase in oil recovery after implementing SSWAG and GAGD methods.

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

Chapter IV describes detail of reservoir model used in this study including reservoir dimension, PVT data, and rock and fluid properties.

Chapter V presents and discusses the simulation results of stand-alone water and gas injection as well as SSWAG and GAGD in terms of effect of different design parameters on recovery of oil. These results are also compared with DDP processes.

Chapter VI evaluates SSWAG and GAGD, stand-alone gas and stand-alone water injection in term of monetary value.

Chapter VII provides conclusion and recommendation.

CHAPTER II

LITERATURE REVIEW

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

2.1 Selective Simultaneous Water Alternating Gas (SSWAG)

Water Alternating Gas (WAG) has been recognized since 1957 by the work of Caudle and Dyes [3]. The purpose was initially to improve oil sweep efficiency during gas injection by combining better microscopic displacement of gas injection with improved macroscopic sweep efficiency of water injection. Because gas has very low viscosity which results in higher mobility ratio between injected gas phase and displaced oil bank. This condition will cause early breakthrough and create unfavorable condition or so-called viscous fingering; thus, sweep efficiency is reduced. The WAG process has been developed to overcome this common problem of gas injection with additional injection of water along with gas to control mobility of injected fluid and stabilize the flood front. The combined mobility of both injected phases is less than that of gas alone; therefore, better mobility ratio is achieved and displacement and volumetric sweep efficiency is improved. Also, the WAG process has an advantage over conventional gas or water flooding as it provides more contact of unswept zones, especially of attic or cellar oil by exploiting the segregation of gas to the top and/or the accumulating of water towards the bottom. For these reasons, WAG is one of interesting option for oil recovery enhancement.

The technique was implemented by injecting specific volume of water and gas as alternate slugs in one cycle as shown in Figure 2.1, or injecting both water and gas simultaneously. The simultaneous injection process can be classified into two methods. In the first method referred as Simultaneous WAG (SWAG), water and gas are mixed at the surface and injected together through one injector. In the second method, referred as Selective SWAG (SSWAG), water and gas are not mixed at surface but pumped separately using a dual completion injector and are selectively injected into the formation [4]. Normally, gas is injected at the bottom of the formation and water injected into the upper section of the reservoir.

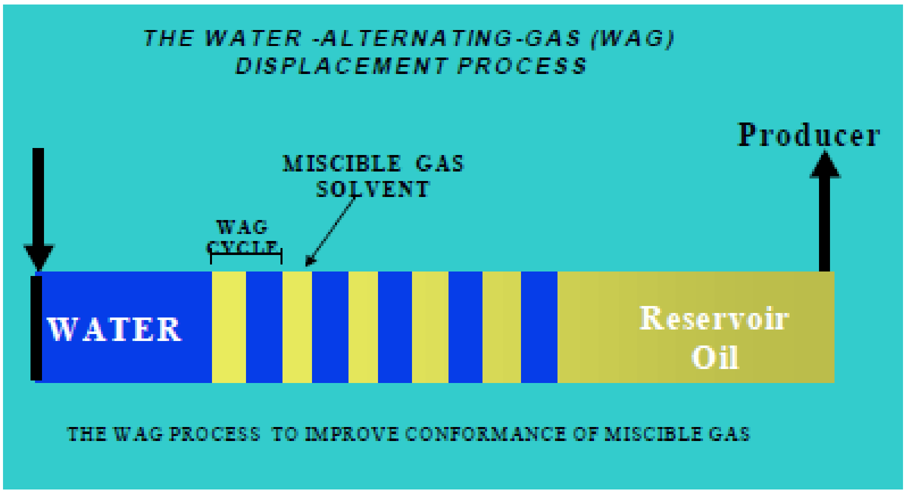


Figure 2.1 Schematic view of WAG process (after Sanchez N.L. [5])

Recently, SSWAG has gained more interest as it has been proved to provide more advantages than normal SWAG. The problem with SWAG is that first of all, SWAG usually encounters loss of injectivity because of injecting two phases of fluid into one injection well. Secondly, the mixed flow zone of gas and water penetrate into formation in short distance as natural gravity segregation normally occurs very close to injection well with gas travelling to the top of reservoir while water underriding at the bottom. The upper portion of gas flow zone is usually thinner than that of the water flow zone due to high mobility of gas. This phenomena leaves more portion of the reservoir untouched by gas, resulting in poor sweep efficiency. In 2003, Gharbi [6] studied different injection techniques to optimize oil recovery in a carbonate reservoir. He introduced a modified method of SSWAG by utilizing two horizontal injectors and one vertical producer on another side of reservoir with horizontal gas injector below horizontal water injector. The author concluded that this modified schematic provides more oil recovery and favorable economic.

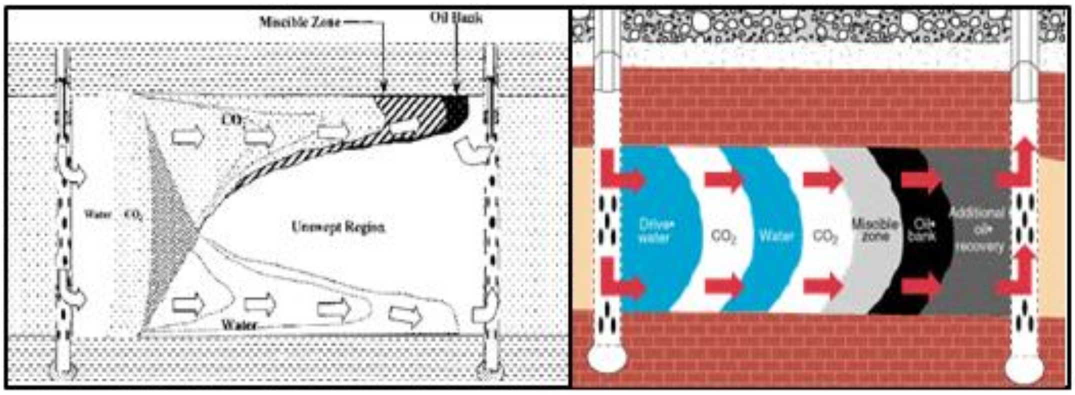
Stone [7] proved that the modified scheme of SSWAG suggested by Gharbi [6] provides better vertical sweep efficiency. The author stated that the vertical sweep in water and gas floods increases in proportion to an increase in total injection rate. However, the fracture pressure of the formation limits the injection rate. As a result, maximum permitted fluid injection rate is proportional to the length of the completion interval. In a vertical well, this length is equal to formation thickness while it is the length of the side of the formation for horizontal well. Thus, horizontal well allows higher injection rate and consequently better vertical sweep. Calculations based on a quasi-steady-state simulator for a two-layered reservoir were performed to investigate vertical sweep of WAG and SWAG with vertical and horizontal wells (later called SSWAG in subsequent papers). The result showed that vertical sweep efficiency of SWAG with horizontal well is highest at 62% because it gives deepest penetration of mixed zone.

Darvishnezhad et al. [4] compared performance of different techniques of WAG such as Immiscible WAG, Miscible WAG, Hybrid WAG, SWAG, SSWAG and water and gas injection using commercial reservoir simulator ECLIPSE. Their result showed that SSWAG yields the highest total oil production with less fluctuation when compared among natural depletion, water and gas injection alone and other types of WAG. SSWAG also has the least amount of residual oil saturation left in the reservoir. Moreover, SSWAG provides highest oil recovery and total production if implemented on 4-spot pattern when compared with 5-spot pattern.

Al-Ghanim et al. [8] studied the effect of different design parameters on modified SSWAG by mean of numerical simulation. Designed parameters included gas-to-oil viscosity ratio, water-to-oil mobility ratio, locations of water injector and gas injector, and water and gas injection rates. The value of fractional oil production by water injection was compared with fractional oil production by gas injection for specific cases. They concluded that the fraction oil swept by water is more than that swept by gas. Later on in 2009, they performed similar study on actual field data in the Middle East [9]. The simulation results showed that the highest oil recovery could be obtained when using higher gas-to-oil viscosity ratio or lower water-to-oil mobility ratio, longer distance between gas and water injectors and higher injection rate for both gas and water. Additionally, the investigated parameters have effect on amount of gas saturation after flooding. This fact can be considered when performing gas storage design and operations.

2.2 Gas Assisted Gravity Drainage (GAGD)

GAGD process was initiated by researcher team from Louisiana State University and expected to be used as an alternative for WAG which provides disappointing performance in the field. Christensen et al. [9] reviewed 37 WAG field projects in the US. These projects yielded incremental oil recoveries in the range of 5 to 10%, with an average incremental recovery of 9.7%. Less oil recovery is possible due to natural gravity segregation and leads to poor sweep efficiency and low recovery as depicted in Figure 2.2 a), in contrast with earlier expected performance of WAG process as shown in Figure 2.2 b). Unlike WAG, GAGD method has been developed by taking advantage of gravity segregation of injected gas into crude oil in the reservoir [10]. The process consists of continuously injecting gas through some vertical wells in the upper part of the reservoir and letting gas flow upward and expand in order to help sweeping oil down towards another horizontal producer located at the bottom of the pay zone. The authors also conducted core flood experiments and found that GAGD had potential to yield higher oil recovery when compared with WAG and Continuous Gas Injection (CGI).



a) Possible break down of WAG (after Rao et al. [10])

b) Expected perfomance of WAG

Figure 2.2 Comparison of expected and actual performance of WAG

Mahmoud et al. [11] performed laboratory experiments to visualize performance of GAGD by placing two glass plates with vertical and horizontal perforated tubing inserted in the model. These two plates were packed with sand sample and CO_2 was injected through vertical tubing. The result showed that GAGD is possible to be implemented as a secondary or tertiary recovery method. Immiscible GAGD flooding experiments proved that high density difference between injected gas and oil allows gravity force to dominate over viscous force by observing near horizontal flood front. Nevertheless, viscous fingering could still be observed due to unfavorable mobility ratio. Unfortunately, there were some limitations in setting up experiments for miscible gas flooding. Unrealistic results were obtained. However, this process was believed to provide better result than immiscible case. Oil recoveries were found around 65% to 87% of IOIP in secondary mode while tertiary mode provided more than 54% of residual oil saturation.

In 2008, another set of experiments was performed to examine the range of operability of GAGD in different characteristics of reservoirs [12]. The experiments have shown that higher gas injection rate provides better recovery. GAGD gives good oil recovery in fractured reservoirs as fractures provide additional exchange path between gas and oil in matrix. Oil-wet model also provided higher recovery than water-wet because forming of oil-film on oil-wet rock surface helped drainage into horizontal producer. Moreover, GAGD was found effectively to be used in reservoirs containing high viscosity oil. Lastly, GAGD flooding performance was compared with WAG and normal gas injection in this visualized model, and it was concluded that GAGD gave highest oil recovery among three processes.

In 2010, a cash flow model was constructed to evaluate economic feasibility of implementing GAGD in an actual field in Northeastern Louisiana [13]. This field was shut in since 1972 after completion of waterflooding and has remaining reserve about 4.7 MMSTB. Data required in the model were gathered from well logs, historical production data with additional information of optimized GAGD production parameters obtained from numerical simulation. Specific fiscal terms in the model were taken from Louisiana’s concessionary fiscal regime including tax and royalty with estimation for CAPEX and OPEX. The indications used to assess feasibility of the project were NPV, IRR, PI and GRR. The results showed that GAGD project had potential in providing attractive benefit return.

As stated previously, many literatures utilized SSWAG and GAGD techniques in their studies and showed such improvement in oil production. However, until now no work has been done on dipping reservoir yet. In this study, these two processes will be analyzed for dipping reservoirs by performing sensitivity analysis through various design parameters.

CHAPTER III

THEORY AND CONCEPT

This chapter describes the important theory used to explain mechanism of SSWAG and GAGD processes as well as the key concept related to these methods.

3.1 Selective Simultaneous Water Alternating Gas (SSWAG)

SSWAG is typically composed of two horizontal injectors and one vertical producer placed on opposite side of the two injectors. The water injector is usually located on top of the gas injector, and oil is produced through the vertical well as shown in Figure 3.1. In this scheme, we get benefit of injecting water above gas to help impeding vertically flow of gas to the upper portion of the reservoir and allow gas to penetrate horizontally deeper into the formation. As a result, naturally gravity segregation is delayed when compared with normal WAG in which the segregation usually occurs in a short distance from the injectors.

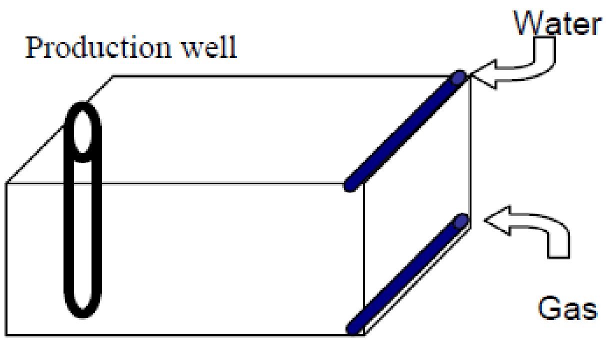


Figure 3.1 Schematic view of modified SSWAG (after Al-Ghanim et al. [14])

3.1.1 Gravity segregation length

Even though SSWAG gives deeper penetration of the mixed zone, fluid segregation still occurs due to gravity difference between gas and water phases. Lower density gas overrides to top of the reservoir while denser water underrides to the bottom. The sooner the phenomenon happens, the lesser sweep efficiency we can get from flowing of combined fluid. Stone [15] and Jenkins [16] predicted the distance that gas and water travel together before they segregate completely into underride and override zones called gravity segregation length [17]. The equations describe steady state, uniform co-injection of gas and water in a homogeneous porous medium. The word 'uniform co-injection' means injection of gas and water with uniform water fractional flow and uniform superficial velocity all along the height of the formation. Stone [15] assumed that at steady state the reservoir splits into three regions of uniform saturation with sharp boundaries between them as illustrated in Figure 3.2. These regions include

a) an override zone with only gas flowing
b) an underride zone with only water flowing
c) a mixed zone with both gas and water flowing

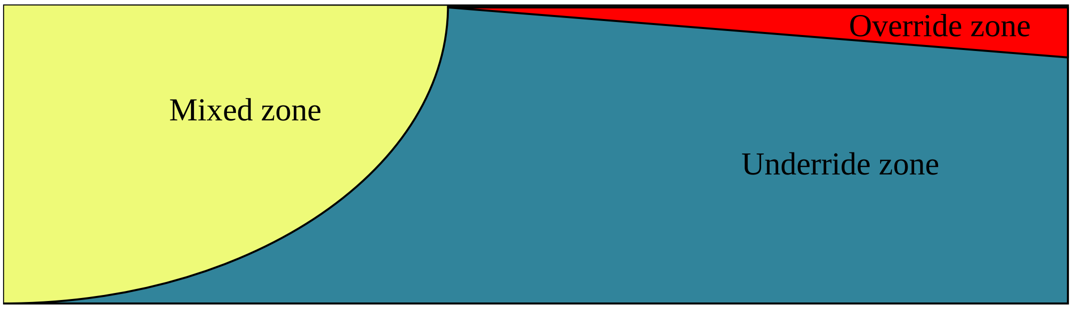


Figure 3.2 Three uniform zones with sharp boundary of uniform co-injection

Stone [15] and Jenkins [16] derived the distance L_g and R_g that the injected mixture flows before gas and water are completely segregated for rectangular and cylindrical models, respectively

$$L_g = \sqrt{\frac{Q}{k_z(\rho_w-\rho_g)gW\lambda_{rt}^m}} \tag{3.1}$$

$$R_g = \sqrt{\frac{Q}{\pi k_z(\rho_w-\rho_g)g\lambda_{rt}^m}} \tag{3.2}$$

where Q = total volumetric injection rate of gas and water

ρ_w = density of water

ρ_g = density of gas

g = gravitational acceleration

W = thickness of the rectangular reservoir perpendicular to flow

λ_{rt}^m = total relative mobility in the mixed zone

In 1998, Shi and Rossen [18] derived Equations 3.1 and 3.2 in a different way as follows:

$$\frac{L_g}{L} = \frac{1}{N_g R_L} \equiv \left(\frac{|\nabla p|_m}{(\rho_w - \rho_g)g}\right)\left(\frac{Hk_h}{Lk_z}\right) \tag{3.3}$$

$$2 = \frac{1}{N_g(R_g)R_L(R_g)} \equiv \left(\frac{|\nabla p|_m(R_g)}{(\rho_w - \rho_g)g}\right)\left(\frac{Hk_h}{Lk_z}\right) \tag{3.4}$$

where L = length of the reservoir

H = height of the reservoir

N_g = dimensionless gravity number

R_L = reservoir aspect ratio

$|\nabla p|_m$ = lateral pressure gradient in the mixed zone at the injection face

k_h = horizontal permeability

k_z = vertical permeability

The above equations can be used as guideline to design SSWAG project parameters in order to maximize the length of segregation as well as oil recovery.

3.2 Gas Assisted Gravity Drainage (GAGD)

GAGD method is composed of placing one horizontal producer near the bottom of the pay zone and injecting gas through a couple of existing vertical wells used in prior waterflood as shown in Figure 3.3. GAGD utilizes gravity segregation as an advantage to let gas flow to the top of the reservoir and form a gas cap zone. As more gas is continuously injected into the reservoir, the gas cap zone in the upper part of formation grows bigger and displaces crude oil vertically down to the horizontal producer. As injection continues, gas chamber grows downward and sideways resulting in a larger portion of the reservoir being swept by gas without increasing in water saturation in the reservoir. Moreover, gravity segregation also helps in delaying gas breakthrough to the producer as well as preventing the gas phase from competing flow with oil.

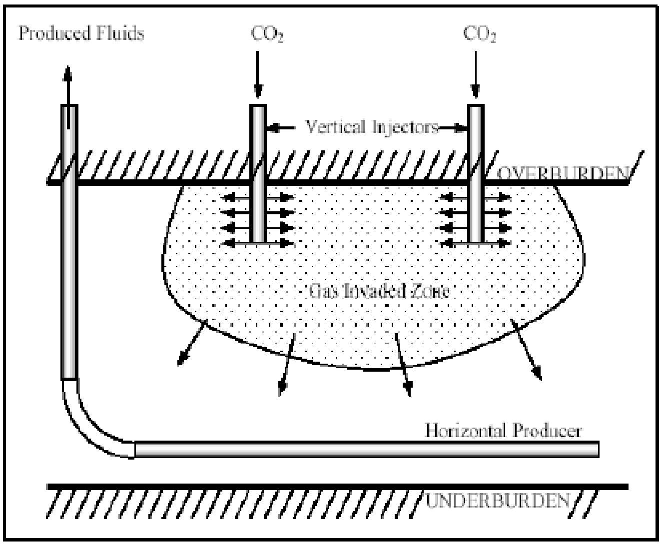


Figure 3.3 Schematic view of GAGD process (after Rao et al. [10])

3.2.1 Factors affecting gravity drainage

Gravity drainage process in porous media is affected by complex interaction between three phases of fluids filling in pore space which can be explained by some important physical phenomena as outlined in this section [19].

3.2.1.1 Wettability

Wettability is used to explain the adhesion characteristics of fluid on rock surface. It plays an important role in displacing oil out of pore space in gravity drainage process as it affects oil spreading behavior and performance of gas injection. In case of water-wet formation, water is likely to be held back and adhere on rock surface. Immobile oil is transformed into mobile oil which can be displaced by injected gas. For an oil-wet system, oil tends to connect together and form continuous film on rock surface resulting in drainage path for oil to flow more.

3.2.1.2 Spreading coefficient

Spreading coefficient, shorted as *S*, quantifies the tendency in spreading of preferential phase of fluid over the other phases. As gravity drainage efficiency depends on performance of oil film forming, this coefficient together with wettability are used to explained oil filming behavior. The spreading coefficient of gas, oil and water system is defined as

$$S = \sigma_{gw} - \sigma_{go} - \sigma_{ow} \qquad (3.5)$$

where σ_{gw} = gas-water interfacial tension

σ_{go} = gas-oil interfacial tension

σ_{ow} = oil-water interfacial tension

Having $S > 0$ means that oil is likely to form thin film between gas and water phases; therefore, oil spreads spontaneously at the interface which results in reduction of residual oil. However, if *S* is negative, it means that a large quantity of trapped oil left in reservoir thus yield poor oil recovery. Stability of oil film is also another parameter to consider since it affects effectiveness of oil gravity drainage. It can be described by the parameter α. This parameter governs the distribution of oil, water and gas in vertical equilibrium for a spreading system and is quantified as

$$\alpha = \sigma_{ow}(\rho_o - \rho_g) \; / \; \sigma_{go}(\rho_w - \rho_o) \qquad (3.6)$$

where ρ_o = density of oil

ρ_g = density of gas

ρ_w = density of water

$\alpha > 1$ indicates that oil exists as molecular film while $\alpha < 1$ means that a large amount of oil remaining inside pore space, and gravity drainage is not suitable.

3.2.1.3 <u>Capillarity</u>

Capillarity or capillary action is the ability of fluid to flow in narrow space under presence of gravity force. This parameter has direct effect on oil recovery performance by gravity drainage. In a water-wet system, capillary force has advantage for gravity drainage as it allows water to imbibe into low permeability matrix and displace oil out of reservoir pore. According to Lewis [20], oil drainage downward through sand under the impulse of its own weight occurs in two zones. At the top, where the liquid is in contact with free gas, the sand is only partial oil saturated and capillarity controls the flow. Below the base of this capillary zone, which corresponds to a free surface, the sand is saturated or nearly saturated with liquid, and flow follows hydraulic laws. Thus, the adequate information of capillary interaction between phases of fluid is necessary to predict saturation and displacement process.

3.2.1.4 <u>Viscosity</u>

Viscosity is an important parameter to determine frontal stability in EOR process through equation of mobility ratio between displacing and displaced phase. Mobility ratio of gas-oil system is defined as

$$M = \frac{\lambda_g}{\lambda_o} = \frac{k_{rg}\mu_o}{\mu_g k_{ro}} \qquad (3.7)$$

where λ_g = mobility of gas

λ_o = mobility of oil

μ_g = viscosity of gas

μ_o = viscosity of oil

Since gas has low viscosity, unfavorable mobility ratio (M > 1) usually occurs in gas injection. However, the efficiency of gravity drainage is characterized by both gravity and viscous forces. Gravity force, which is a strong function of gas displacement velocity, needs to be effectively controlled in order to reduce impact of viscous force. A dimensionless number to determine dominance between gravity and viscous force is called gravity number symbolized as N_G. It represents the ratio of gravity force over viscous force as follows [11]:

$$N_G = \frac{\Delta \rho g K}{\Delta \mu v_d} \qquad (3.8)$$

where k = absolute permeability of the porous media (m^2)

$\Delta\mu$ = viscosity difference between oil and gas (Pa.S)

v_d = Darcy velocity given by injection rate/(cross sectional area * porosity) (m/s)

$\Delta\rho$ = density contrast between oil and gas phase (kg/m^3)

g = gravitational acceleration (m/sec^2)

Under favorable gravity number ($N_G > 1$), we would get higher oil recovery as the gravity number indicates that gravity force is dominant over viscous force.

3.2.1.5 Reservoir heterogeneity

Heterogeneity can be characterized by vertical-to-horizontal permeability ratio (k_v/k_h). Higher ratio leads to more chance that fluid tends to flow in the vertical direction which is problematic in horizontal flooding as it speeds up gravity segregation which results in reduction in oil recovery. However, gravity flooding seems to be insensitive to heterogeneity effects. This statement agrees with many laboratory experiments of stable displacing front observed in core flooding results.

3.3 Three-phase relative permeability

Three-phase relative permeability is an important parameter to consider as SSWAG and GAGD involve three phases of fluid flowing. It can be calculated by many available models. However, the default model in ECLIPSE reservoir simulation software is discussed below as it is used in this study. The ECLISE default model is shown in Figure 3.4.

Three-phase relative permeability relation is built based on assumption of complete segregation of water and gas. Water saturation in the gas zone is equal to the connate saturation, S_{wco}. Oil saturation is assumed to be constant and equal to the block average value, S_o, throughout the cell. The full breakdown, assuming block average saturations for S_o, S_w and S_g (with $S_o + S_w + S_g = 1$) is as follows [21]

In a fraction $S_g/(S_g + S_w - S_{wco})$ of the cell (the gas zone),

the oil saturation is S_o

the water saturation is S_{wco}

the gas saturation is $(S_g + S_w - S_{wco})$

In a fraction $(S_w - S_{wco})/(S_g + S_w - S_{wco})$ of the cell (the water zone),

the oil saturation is S_o

the water saturation is $S_g + S_w$

the gas saturation is 0

The oil relative permeability is then given by

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

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

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

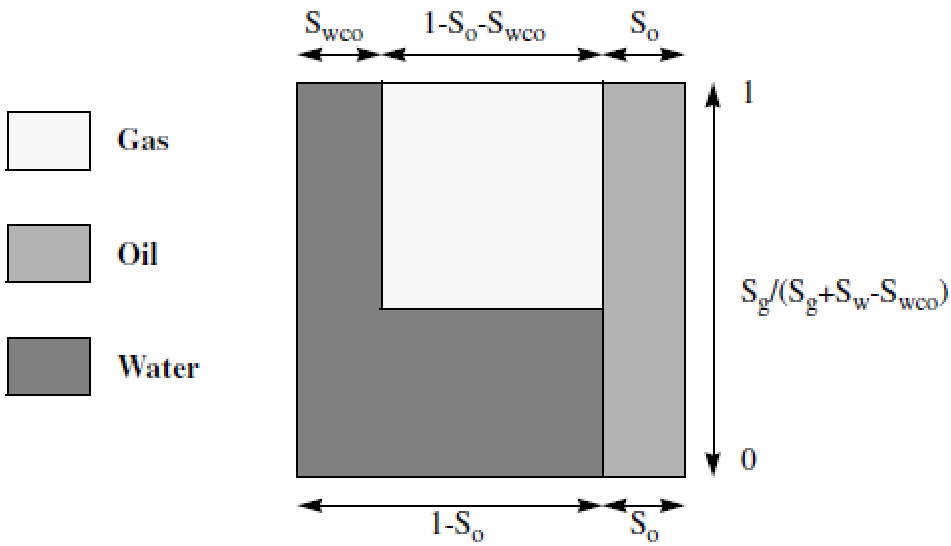


Figure 3.4 Default model of three-phase relative permeability assumed by ECLIPSE (after Schlumberger technical manual [21])

3.4 Economic evaluation

In order to assess any projects, economic analysis is an important process to perform to evaluate the projects in term of monetary value. The concept of time value of money is worth mentioning first then follows with the common economic decision tools. There are some important tools used in the industry to evaluate the selected projects including Net Present Value (NPV), Internal Rate of Return (IRR), Payback period and Discounted Profitability Index (DPI).

3.4.1 Time value of money

Since every oil and gas projects usually take many years to be complete and they all involve with dynamic flow of cash that occur in different period of time. Time value of money is an important concept that needs to take into account in our economic analysis. Its principle is to convert future expenditures and revenues into common equivalent value in a common point of time to account for interest or inflation rate. This common point in time may be the present, future, or even annual. Commonly, present is chosen for the analysis. This present is also referred as time zero. In capital budget calculation, all cash flows either in or out flow need to be converted into its equivalent value at time zero or called *discounting*. Present value of future amount can be found with Equation 3.9 [22].

$$P_v = \frac{F_v}{(1+i)^t} \qquad (3.9)$$

where P_v = present value at time zero of the future amount

F_v = the future value at time t

i = the interest or discount rate

t = the time period

3.4.2 Net Present Value (NPV)

Net Present Value is the summation of discounted Net Cash Flow (NCF) for every time period as shown in Equation 3.10. Alternatively, NPV can be calculated by subtracting the present value of the total cash outflows from the present value of total cash inflow. When NPV of an investment at a certain discount is positive, it means that the investment generates revenue that is equal to the positive value. Conversely, a negative NPV indicates the investment is not generating earnings thus causing opportunity loss. However, if NPV is equals to zero, investor gets the same return as the investment value. The basic decision rules based on NPV calculation is to invest in project that generates positive NPV and reject if it indicates a negative NPV [22].

$$NPV = \sum_{t=1}^{n} \frac{NCF_t}{(1+i)^t} \tag{3.10}$$

where NCF_t = net cash flow at time t

3.4.3 Internal Rate of Return (IRR)

Internal Rate of Return is the discount rate that makes NPV exactly equal to zero, or the present value of cash inflow equals to present value of cash outflows [22]. The equation for calculating IRR is

$$\sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t} = 0 \tag{3.11}$$

IRR value can be calculated by two methods either trial-and-error or by graphically. The basic rule for making decision based on IRR value is to accept project that generates IRR values that is greater than the defined interest rate. Inversely, investor should reject project that yields IRR value less than the interest rate.

3.4.4 Discounted Profitability Index (DPI)

NPV and IRR described earlier can be used to make an economic decision, however the calculations does not reflect the size of the investment which can be varied for individual project. To overcome this problem, Discounted Profitability Index (DPI) is initiated. DPI values can be obtained by following equation.

$$DPI = 1 + \left[\frac{NPV}{PV\ of\ capital\ investment} \right] \qquad (3.12)$$

The value of calculated DPI is usually more than 1. It indicates how much of present value of benefits is added per dollar of investment. DPI is best utilized for comparing mutually-exclusive projects that have similar risk and cash profile. The investor should consider investing in the projects that generates higher value of DPI.

CHAPTER IV

RESERVOIR SIMULATION MODEL

In order to evaluate the performance of both SSWAG and GAGD, a reservoir simulator is an important tool to complete this objective. The black oil reservoir simulator called ECLIPSE 100 is used in this work. This chapter discusses the detail of reservoir model constructed in ECLIPSE program. The reservoir model is built based on corner point grid, set up with dip angle of 10 degree for all cases. Fully Implicit method is chosen as a calculation approach to solve for the fluid flow equations. The producer and injector wells are located differently in each case in accordance to the chosen recovery process (SSWAG vs. GAGD). The ECLIPSE input keywords are provided in the Appendix.

4.1 Reservoir model

The reservoir dimension is 6000 x 2000 x 210 ft with the total number of grid block of 73 x 31 x 21 in the *x*-, *y*- and *z*-direction, respectively with 10 degree dip angle as illustrated in Figure 4.1. The reservoir is built using Cartesian coordinate with homogeneous reservoir properties as listed in Table 4.1. The reservoir is initially undersaturated as the initial reservoir pressure is equal to the bubble point pressure. The topmost grid is located at the datum depth of 6000 ft.

Table 4.1 Reservoir properties

Parameter	**Value**	**Units**
Porosity	15.09	%
Horizontal permeability	32.529	mD
Vertical permeability	3.2529	mD
Datum depth	6000	ft
Bubble point pressure	2377.1	psia
Initial pressure @ datum depth	2377.1	psia

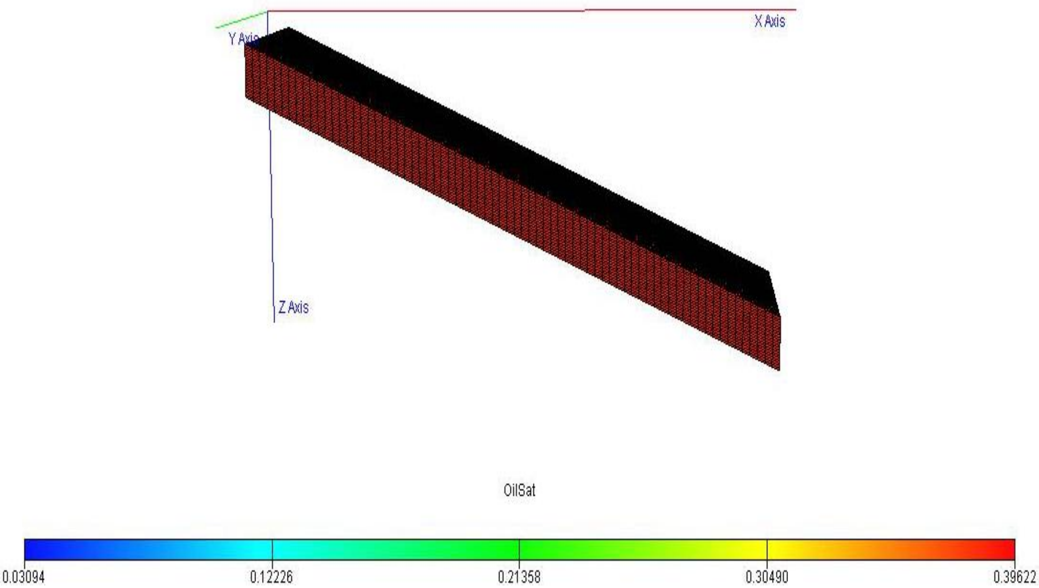


Figure 4.1 Reservoir model with initial condition

In case of SSWAG base case, two horizontal injectors are placed at the updip side while a vertical producer is located on an opposite side of the strata or at the downdip side. The horizontal water injector is located above gas injector. Figure 4.2 display SSWAG well placement.

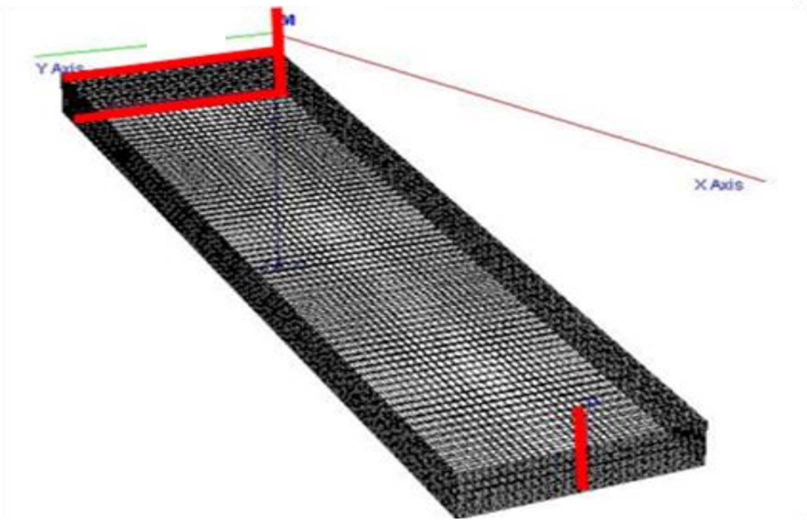


Figure 4.2 Well placement of SSWAG base case model

In case of GAGD base case, the horizontal producer is located at the bottom of the pay zone with one vertical injector at the middle of the *y*-direction span at the updip side of the reservoir. Figure 4.3 illustrates well placement of GAGD model

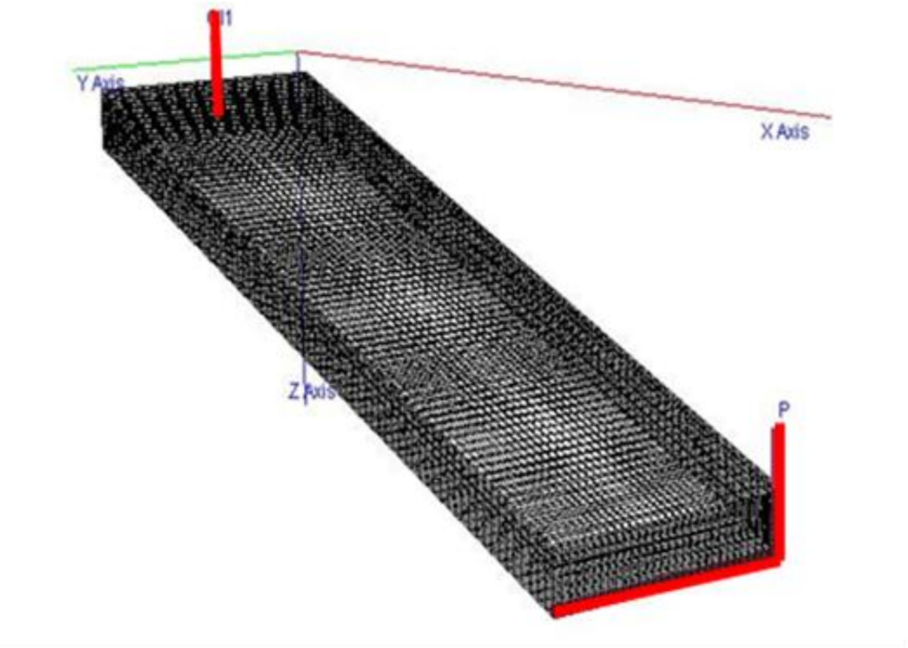


Figure 4.3 Well schematic of GAGD base case model

4.2 PVT properties

This section specifies pressure-volume-temperature properties of reservoir fluid. The information is taken from data obtained from an onshore field in Thailand. Table 4.2 demonstrates PVT properties of water and Table 4.3 addresses fluid densities at surface condition. Dry gas and live oil PVT properties are illustrated in Figure 4.4 and Figure 4.5, respectively.

Table 4.2 Water PVT properties

Property	**Value**	**Units**
Reference pressure(Pref)	3000	psia
Water FVF at Pref	1.021057	rb/stb
Water compressibility	3.083002E-6	/psi
Water viscosity at Pref	0.3051548	cp
Water viscosibility	3.350528E-6	/psi

Table 4.3 Fluid densities at surface condition

Property	**Value**	**Units**
Oil density	51.6375	lb/cuft
Water density	62.42841	lb/cuft
Gas density	0.04981752	lb/cuft

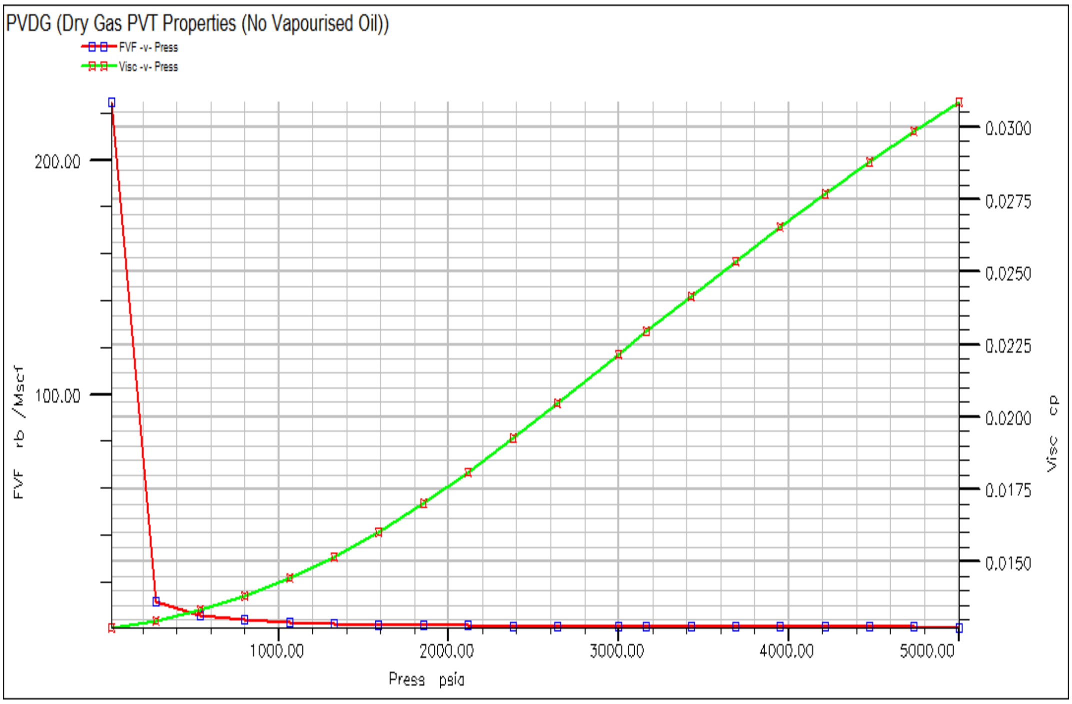


Figure 4.4 Dry gas PVT properties (no vaporized oil)

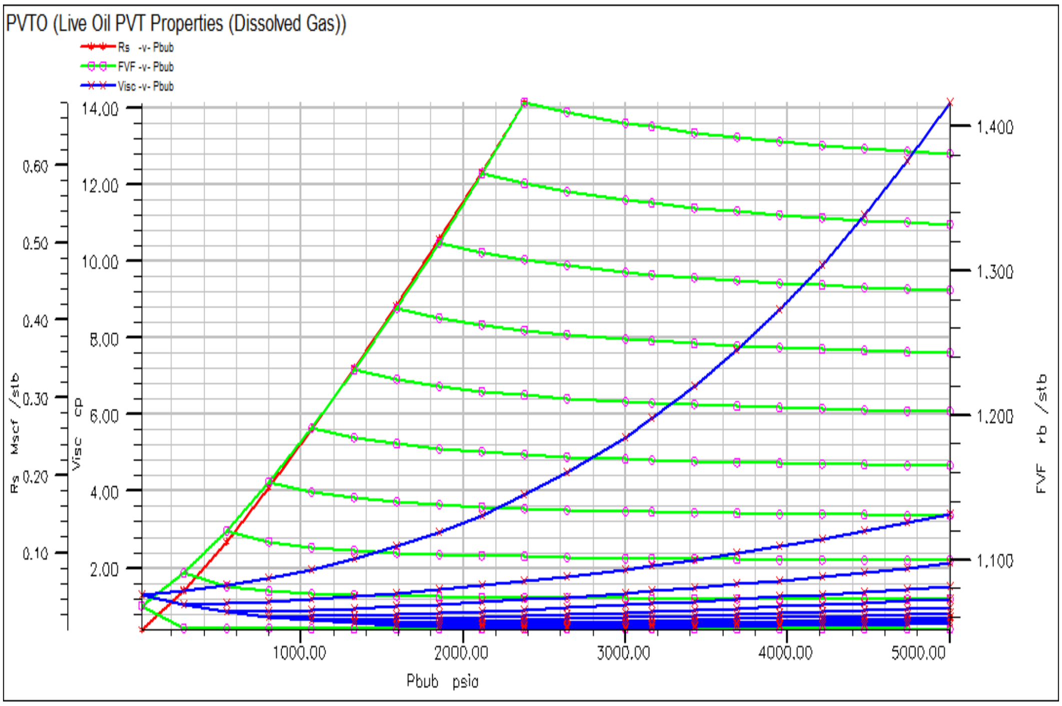


Figure 4.5 Live oil PVT properties (dissolved gas)

4.3 SCAL (Special Core Analysis) Section

Two sets of two phase relative permeability are required as input in this section. The data points are obtained from an onshore field in Thailand. The water/oil and gas/oil relative permeabilities are shown in Table 4.4 and Table 4.5, respectively. These functions are plotted in Figure 4.6 and Figure 4.7, respectively.

Table 4.4 Water and oil relative permeabilities

S_w	k_{rw}	k_{ro}
0.61	0	0.8
0.631111	0.033333	0.654833
0.652222	0.066667	0.521848
0.673333	0.100000	0.401546
0.694444	0.133333	0.294528
0.715556	0.166667	0.201549
0.736667	0.200000	0.12359
0.757778	0.233333	0.062034
0.778889	0.266667	0.019093
0.8	0.3	0
1	1	0

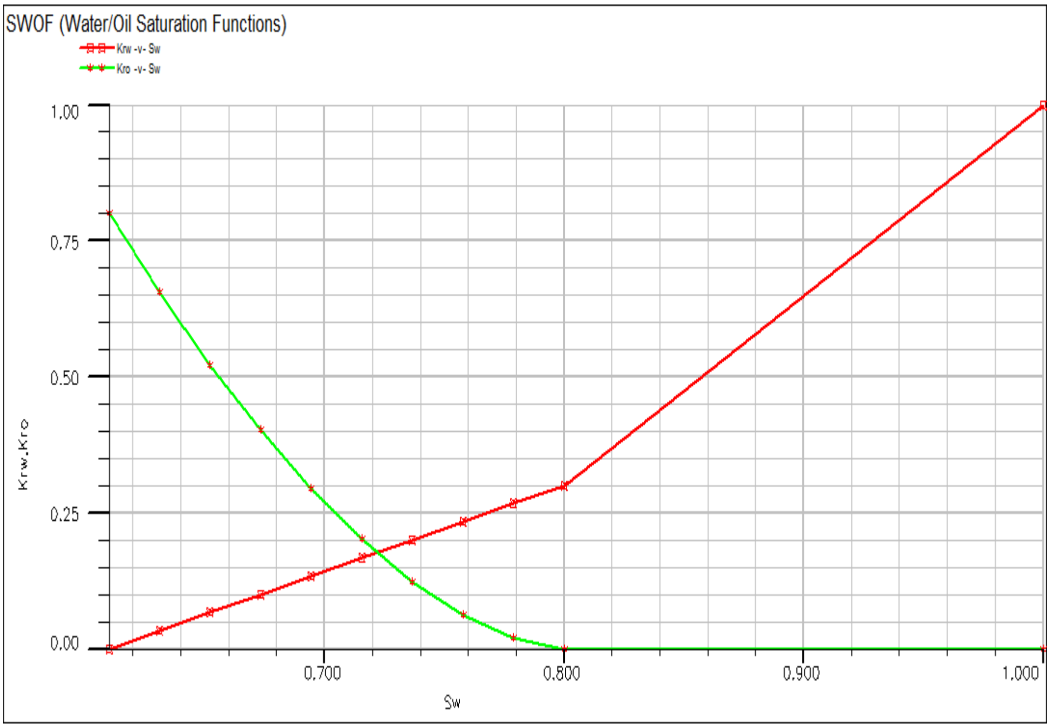


Figure 4.6 Water/oil saturation function

Table 4.5 Gas and oil relative permeabilities

S_g	k_{rg}	k_{ro}
0	0	0.8
0.04	0	0.56952
0.07875	0.1	0.39186
0.11750	0.2	0.25450
0.15625	0.3	0.15275
0.19500	0.4	0.08178
0.23375	0.5	0.03654
0.27250	0.6	0.01174
0.31125	0.7	0.00169
0.35	0.8	0
0.39	1	0

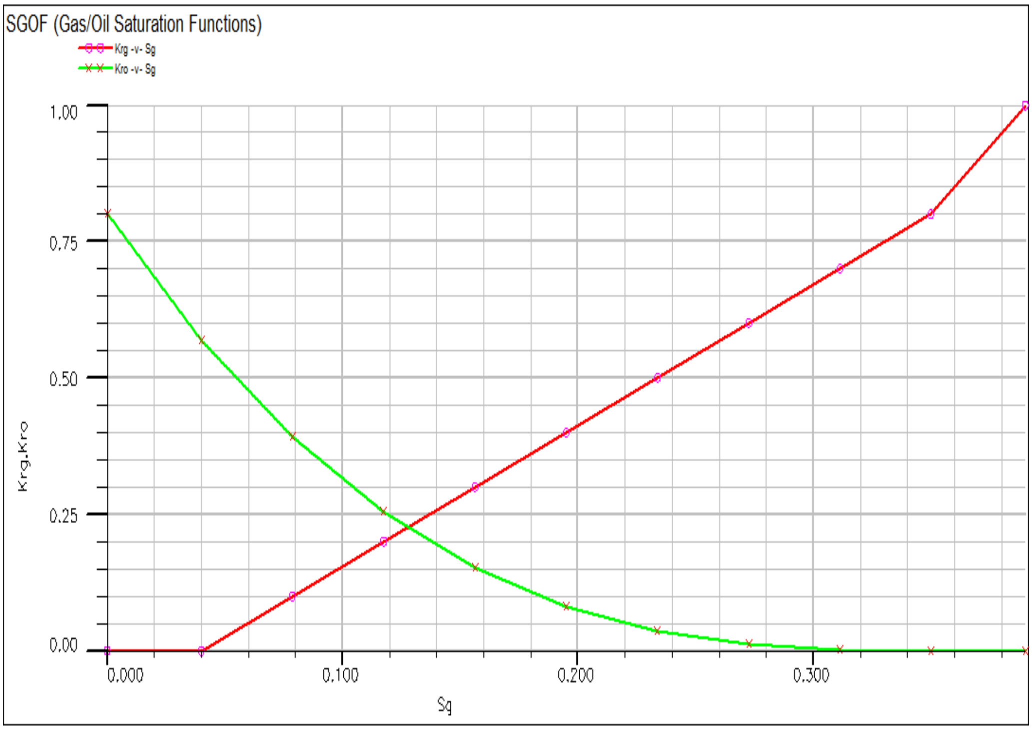


Figure 4.7 Gas/oil saturation function

4.4 Well schedule

All wells in this study have the same wellbore diameter which is 6-5/8 inches under assumption of no presence of skin. To specify the production economic limit for this study, the well production constraint of the onshore field selected for this study is used. The selected production conditions are described as shown in Table 4.6.

Table 4.6 Production constraints

Parameter	Value	Units
Economic oil production rate of each well	20	STB/D
Maximum field GOR	30	MSCF/STB
Maximum water cut of each well	96	%
Fracturing pressure	4500	psia

CHAPTER V

SIMULATION RESULT AND DISSCUSSION

After constructing the reservoir model, SSWAG and GAGD were individually simulated under different sets of design parameters to quantify their effect on oil recovery and production profile. Water flooding and gas injection alone were simulated first in order to use as a reference. Then, the base case for each method is discussed in order to observe the response from the reservoir from individual method. After that, simulation runs under different scenarios are studied and the results are compared with the base case. We also analyze and discuss SSWAG and GAGD simulation result with previous study on DDP from Suwannakul [2]. A target of bottom hole pressure was controlled at 500 psia for all cases. The liquid production rate is controlled between 1000 – 3500 STB/D depending on injection rate and injection pressure in order to balance the subsurface pressure. The maximum gas production rate is practically limited by capacity of production facility which is assumed at 20 MMSCF/D. The simulated production time is limited at 100 years with economic limit of 96% of water cut or GOR 30 MSCF/STB, whichever comes first. The results at 40 years of production are also presented to consider the performance at the end of assumed concession period.

5.1 Stand-alone water flooding and stand-alone gas injection

The performances of stand-alone water flooding and stand-alone gas injection are studied in this section. Both water and gas injectors are horizontal wells while the producer is a vertical well. The well schematics for these two cases are, however, different. The up-dip water injection and down-dip gas injection are implemented with well placement as shown in Figure 5.1. The maximum water and gas injection rate is set at 1000 STB/D and 1000 MSCF/D, respectively. As long as the injection pressure does not exceed the fracture pressure, water and gas is injected at their maximum rates. Both injectors are controlled under assumption of fracture pressure of 4500 psia. The maximum liquid production is controlled at 1000 STB/D. Oil production rate and oil recovery efficiency under water flooding and gas injection is depicted in Figure 5.2 and Figure 5.3, respectively.

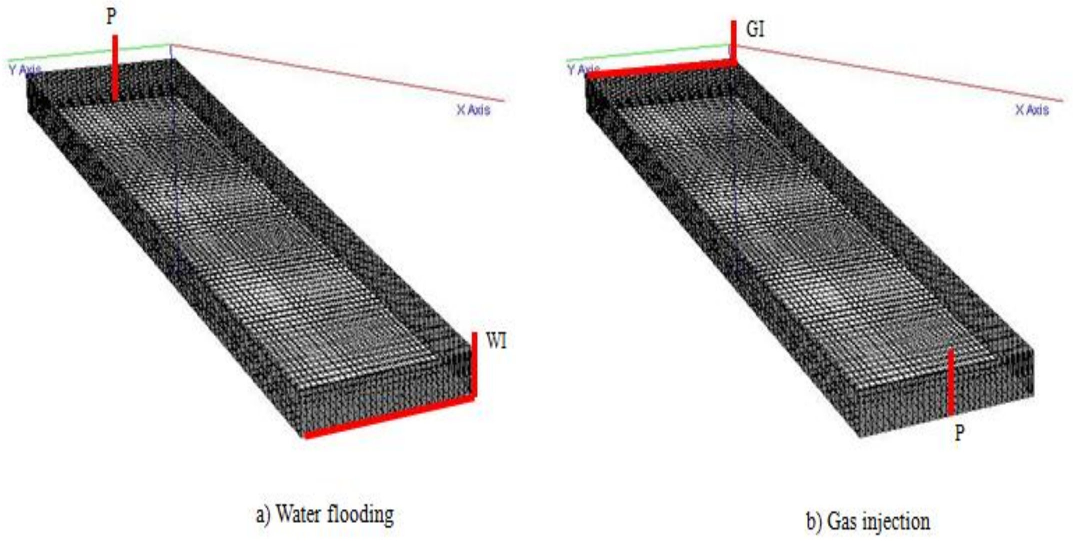


Figure 5.1 Well placement of water flooding and gas injection

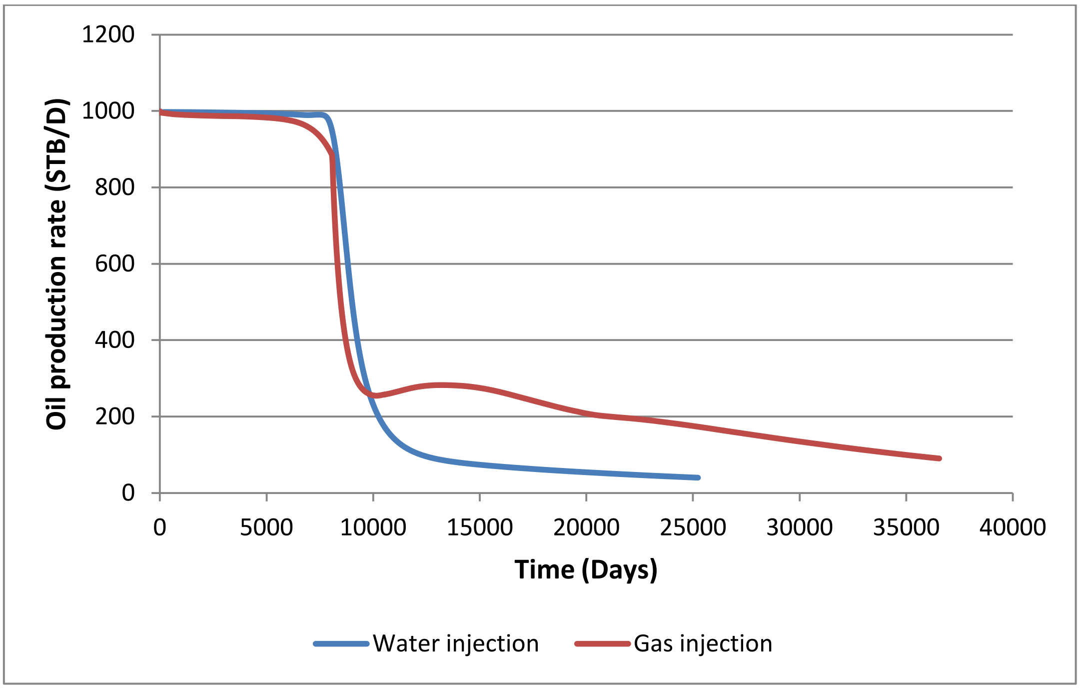


Figure 5.2 Oil production rate under water flooding and gas injection

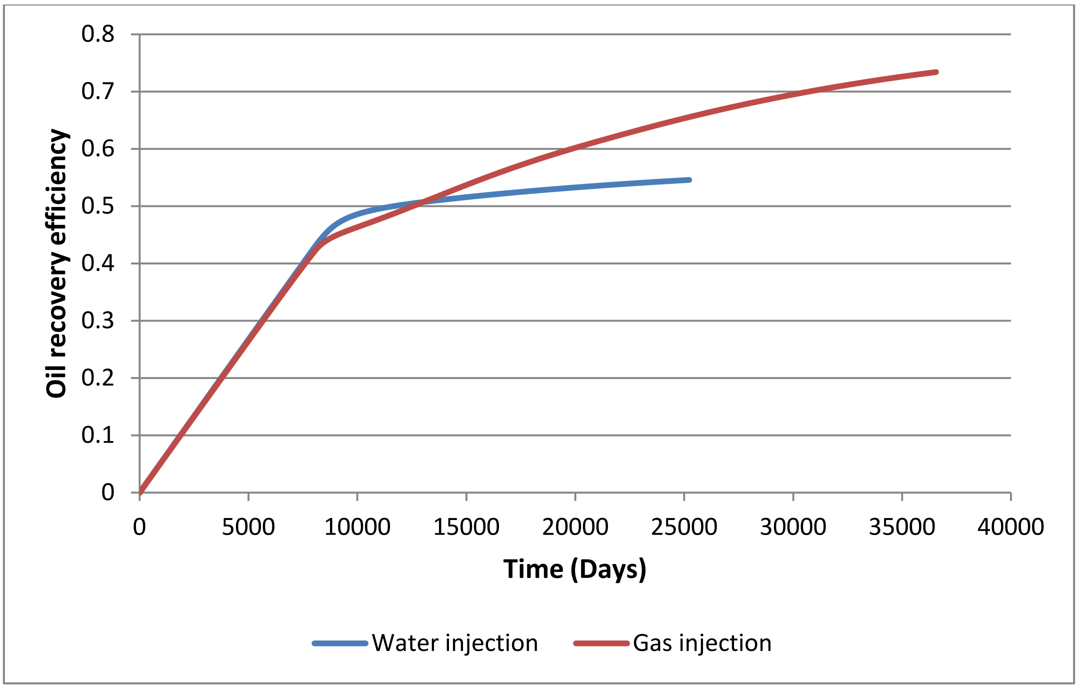


Figure 5.3 Oil recovery efficiency for stand-alone water flooding and stand-alone gas injection

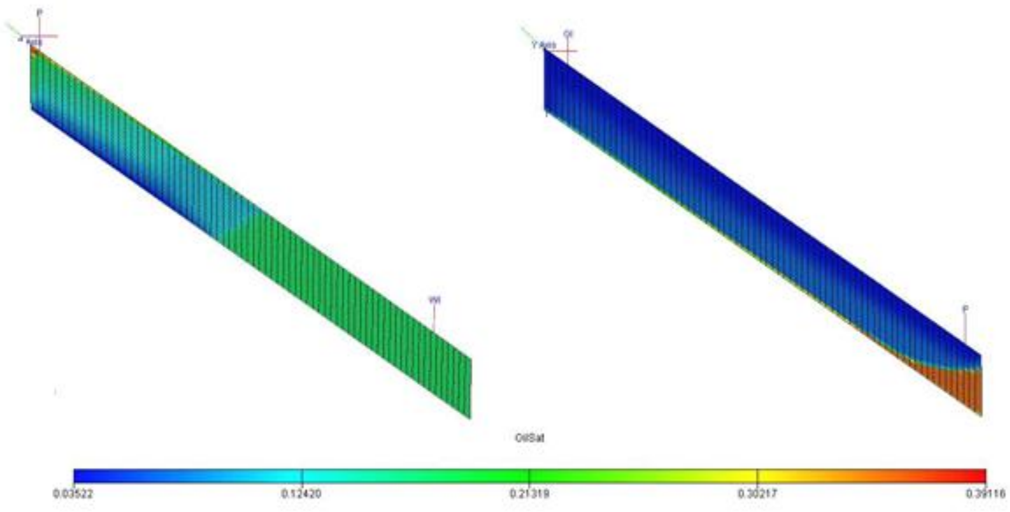
Table 5.1 shows the summary of cumulative oil production, oil recovery efficiency and production time for stand-alone water flooding and stand-alone gas injection processes at the end of production and Table 5.2 shows summary at 40 years of production. From the results, we can see that gas injection alone yields significantly higher oil recovery efficiency than water flooding. This is because microscopic displacement efficiency of gas is almost complete as lower value of remaining oil saturation in comparison with water flooding is obtained as illustrated in Figure 5.4. We can see from Figure 5.4a that the region that is swept by water has higher residual oil saturation (shown in green color) when compared to region that is swept by gas as shown in blue color in Figure 5.4b. Moreover, in case of a dipping reservoir, gas breakthrough is delayed when compared with horizontal reservoir due to the geometry of the reservoir itself (see Figure 5.4b). In case of water flooding, the production time is shorter than that of gas injection process due to water load up and economic limitation.

Table 5.1 Summary of cumulative oil production, oil recovery efficiency and production time for water flooding and gas injection at the end of production

Method	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
Water flooding	10.161	0.545	69
Gas injection	13.671	0.734	100

Table 5.2 Summary of cumulative oil production, oil recovery efficiency and production time for water flooding and gas injection at 40 years of concession

Method	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
Water flooding	9.576	0.514	40
Gas injection	9.906	0.532	40



a) Water flooding b) Gas injection

Figure 5.4 Oil saturation for water flooding and gas injection at the end of production

5.2 Selective Simultaneous Water Alternating Gas base case

The base case simulation results for SSWAG method are presented in this section in order to analyze its performance. Well placement of SSWAG base case is shown again in Figure 5.5. The horizontal water injector is laid along the *y*-axis at *z*-layer 1 with gas injector below at *z*-layer 21. The vertical producer is located at coordinate (73, 16) with full perforation interval. The process of water and gas injection is started from the first day of production as the initial reservoir pressure is at bubble point pressure. The maximum water injection rate is set at 1000 STB/D with maximum gas injection rate of 1000 MSCF/D. As long as the injection pressure does not exceed the fracture pressure, water and gas is injected at their maximum rates. Both injectors are controlled under assumption of fracture pressure of 4500 psia. The maximum liquid production rate is controlled at 1080 STB/D in order to keep the reservoir pressure as constant as possible. The bottom hole pressure limit is set at 500 psia.

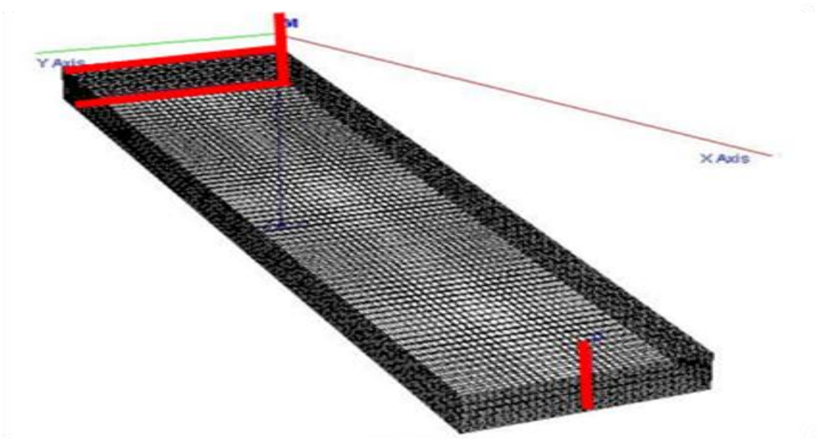


Figure 5.5 Well placement of SSWAG base case

Figure 5.6 shows bottomhole pressure of water and gas injectors as a function of time. Since water and gas injections are implemented from the first day of production, the bottomhole pressures rises at the beginning of the production period. After that, the reservoir starts to deplete as indicated by reduction in pressure. Then, the pressure stabilizes once the reservoir is under equilibrium. The maximum liquid production rate is selected consistently with the pattern of bottomhole pressure in order to assure that the reservoir reaches steady-state. The oil production rate obtained from the simulation is illustrated in Figure 5.7. The cumulative oil production is shown in Figure 5.8 which results in oil recovery efficiency of 64.35% after 100 years of production. As shown in Figure 5.7, at early time, the oil production rate is at the controlled rate of 1080 STB/D until the time that water reaches the producer and starts to load the well up, causing reduction in oil production rate as well as reduction in gas production rate and increase in water production rate as shown in Figure 5.9. Gas starts breaking through after 9 years of production as indicated by a sharp increase in gas production rate and field gas-oil ratio shown in Figure 5.10. However, it decreases once the oil production decreases due to water load-up.

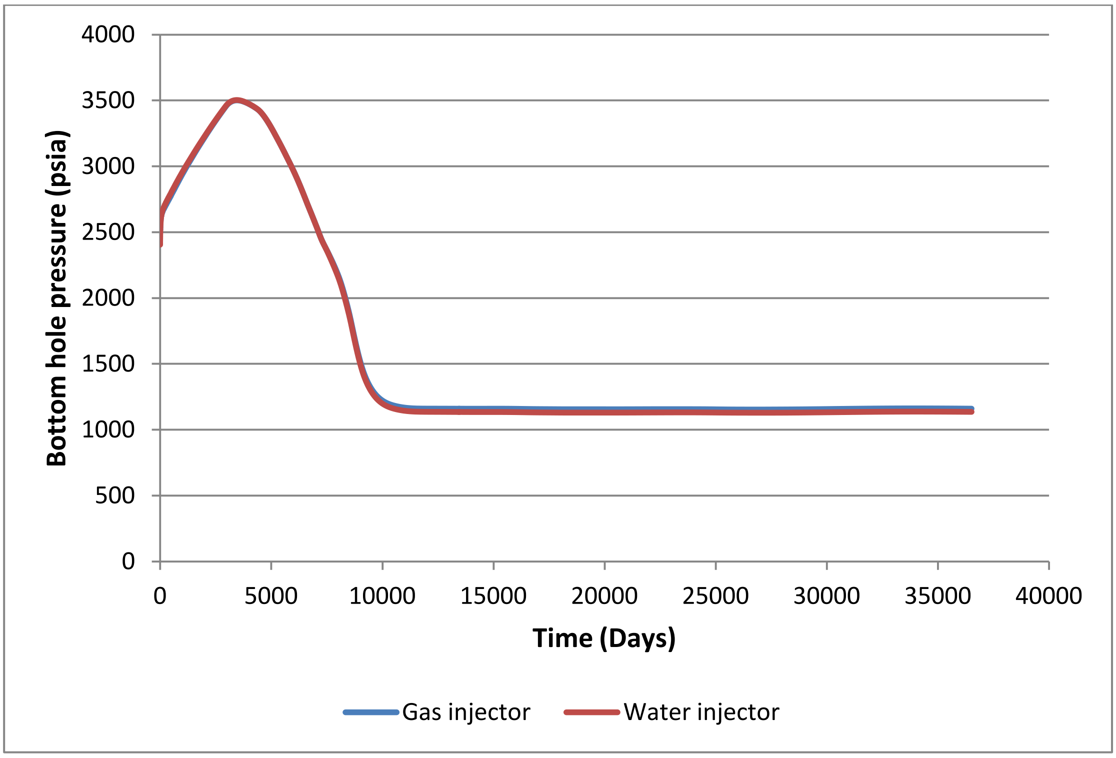


Figure 5.6 Bottomhole pressure of gas and water injectors of SSWAG base case

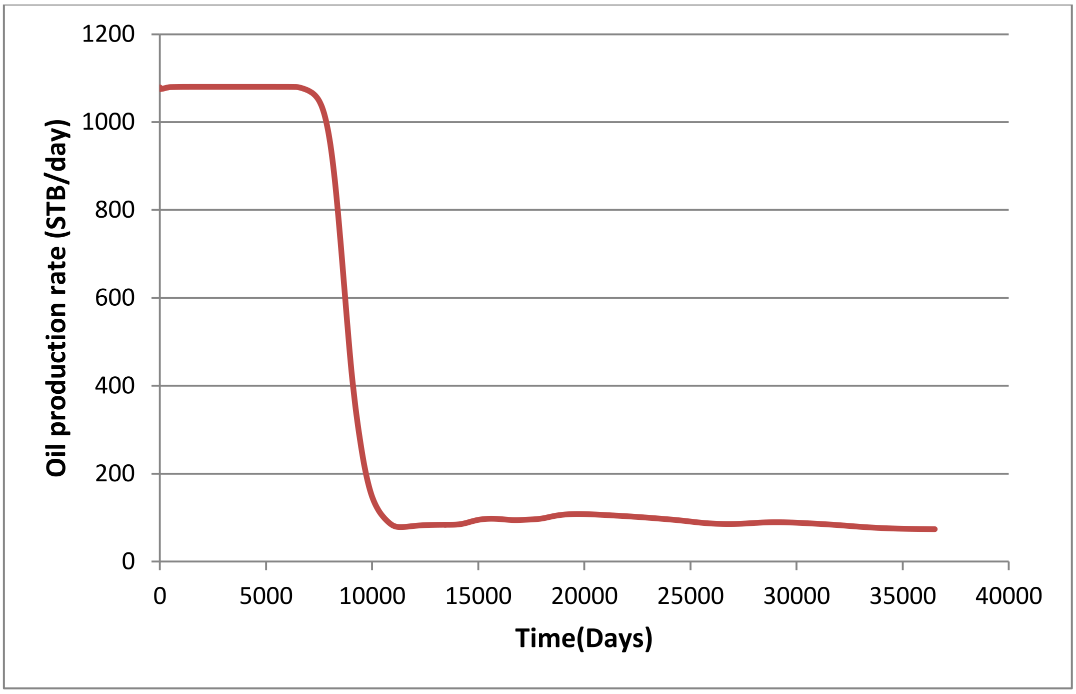


Figure 5.7 Oil production rate of SSWAG base case

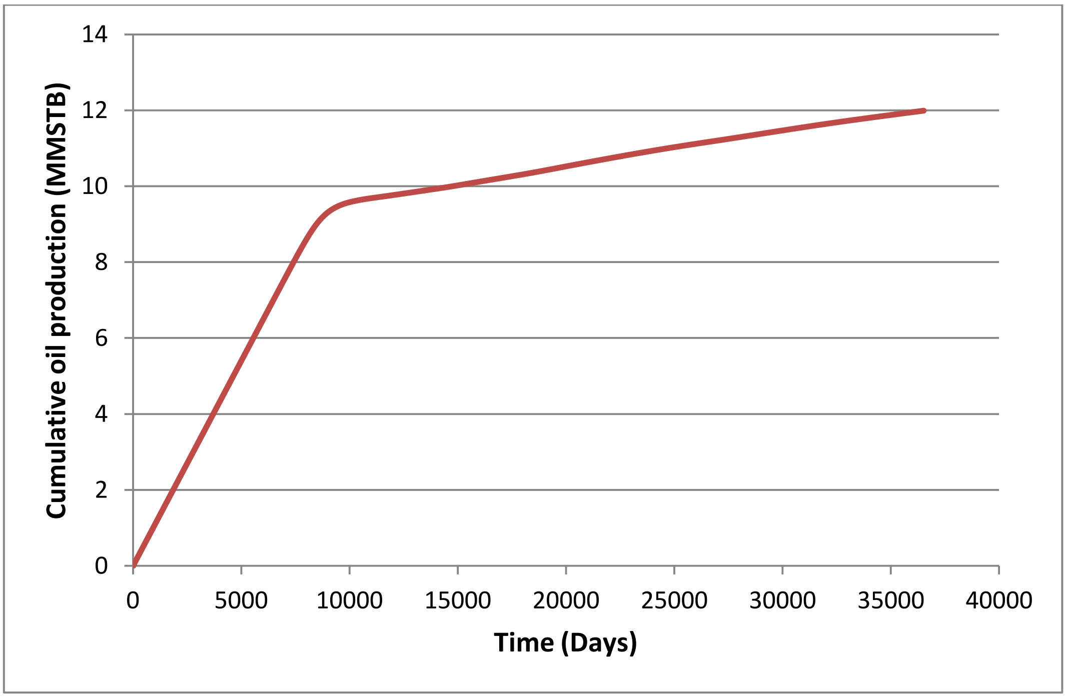


Figure 5.8 Cumulative oil production of SSWAG base case

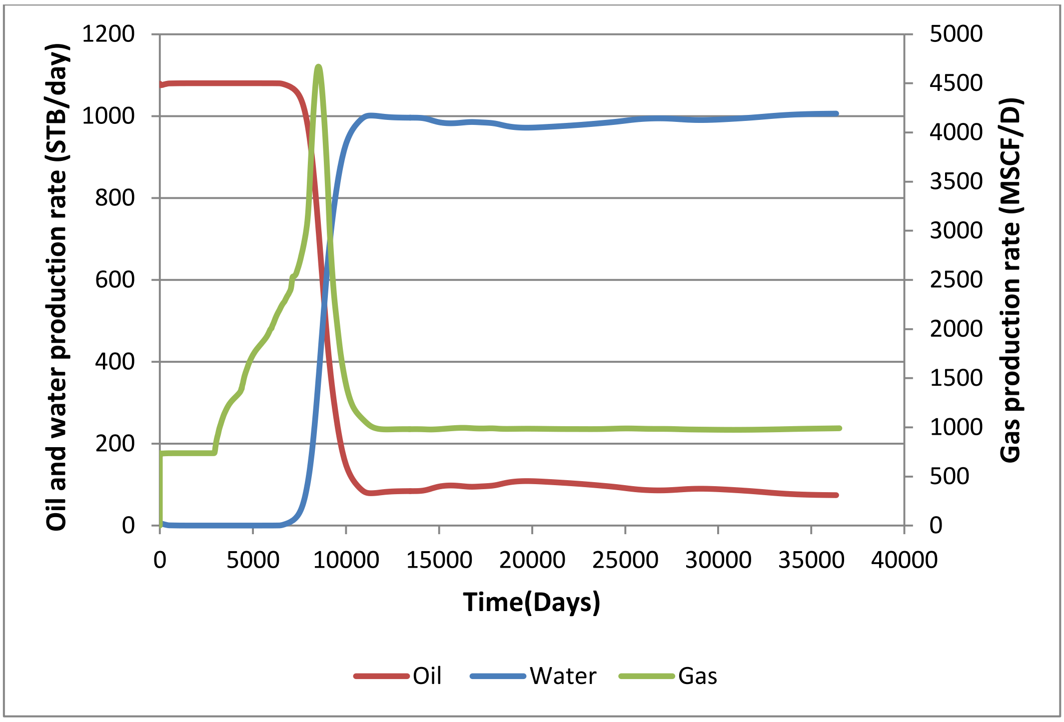


Figure 5.9 Oil, gas and water production rate of SSWAG base case

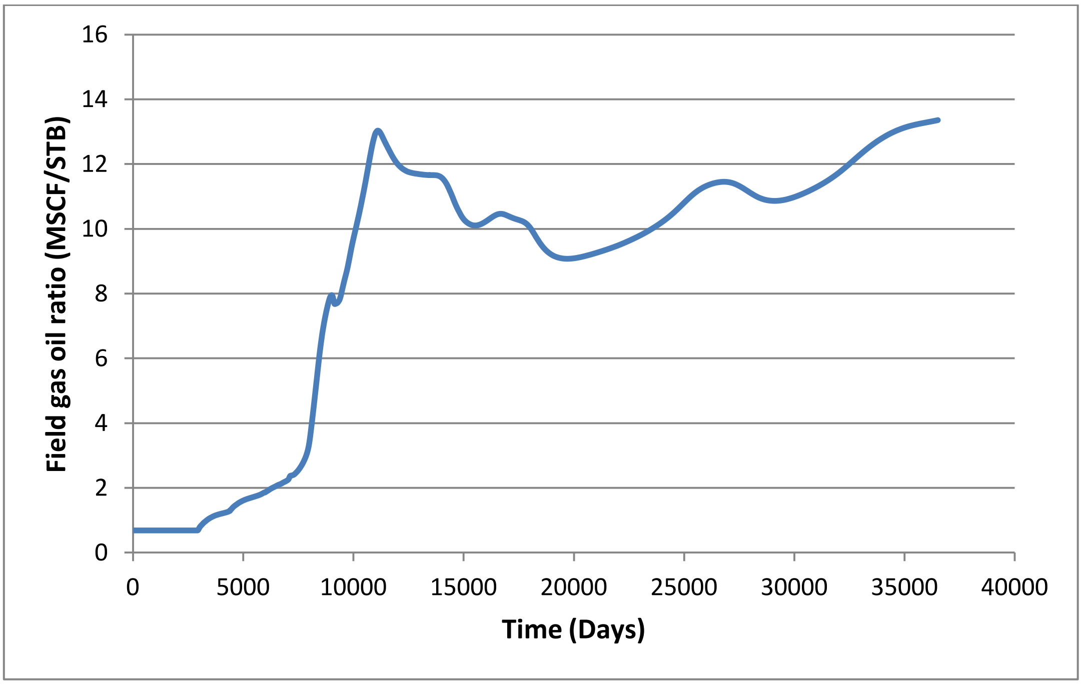


Figure 5.10 Field gas oil ratio of SSWAG base case

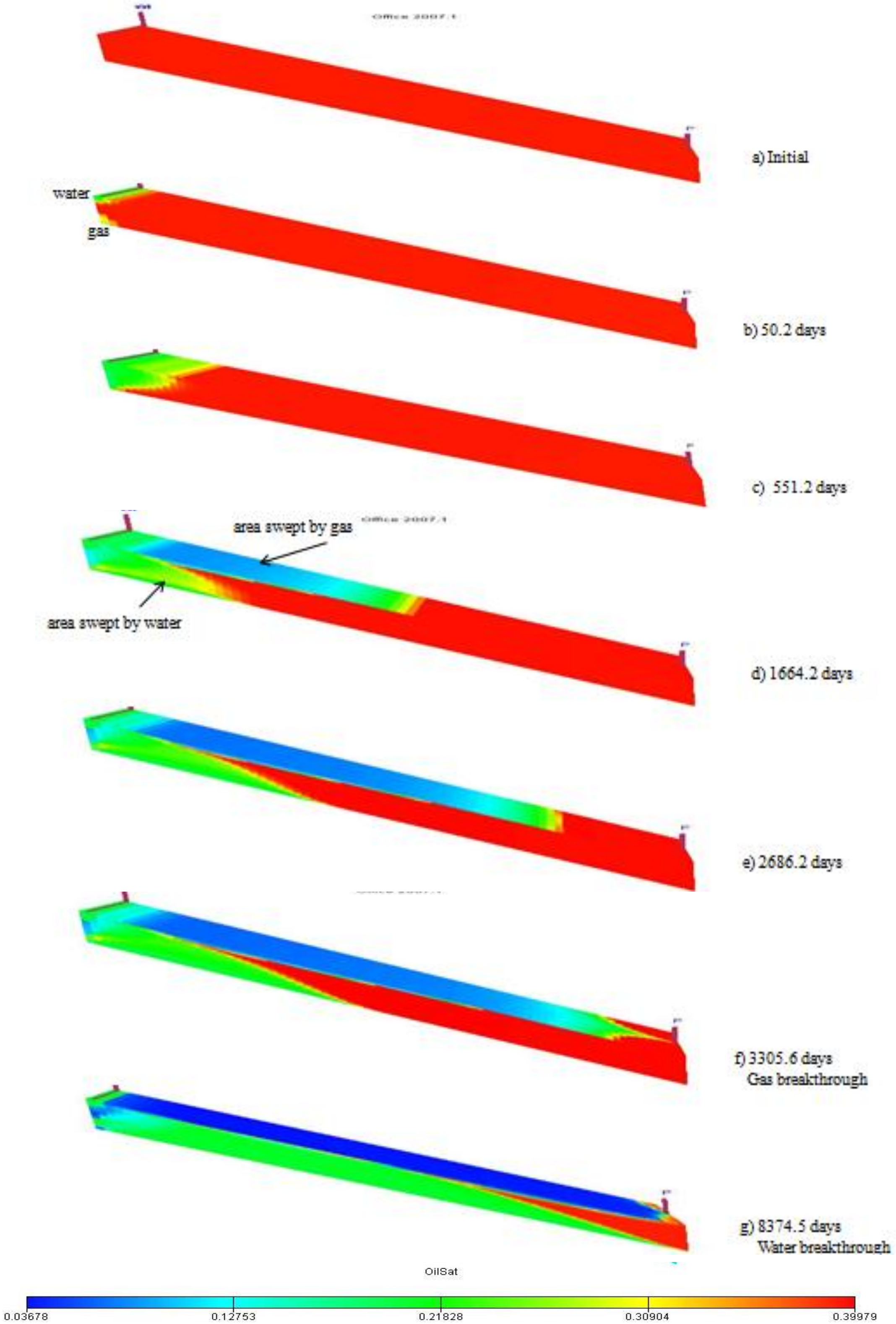


Figure 5.11 Oil saturation distribution of SSWAG base case

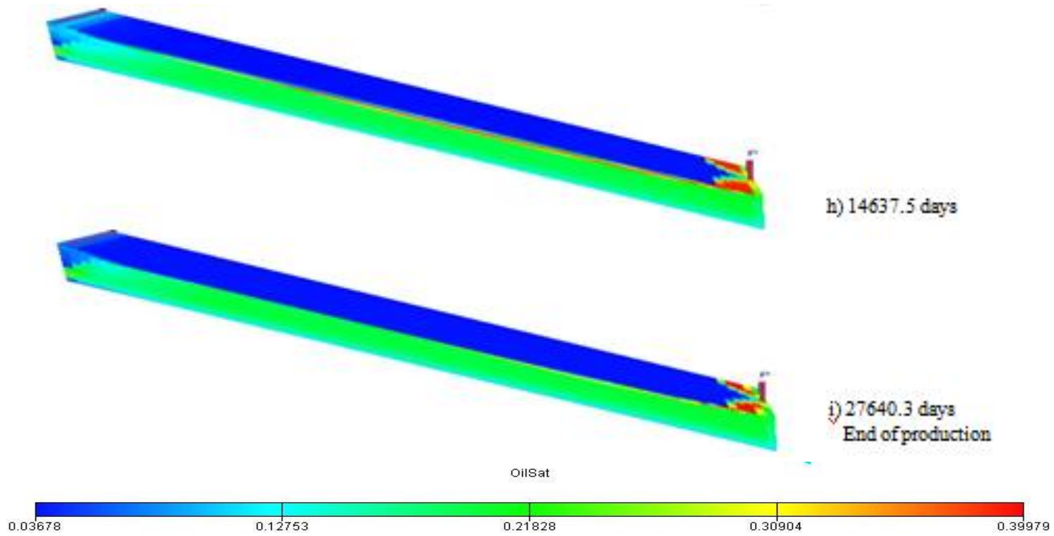


Figure 5.11 Oil saturation distribution of SSWAG base case (continued)

The detail of SSWAG sweeping mechanism is illustrated by Figure 5.11 (a) to (i) in term of oil distribution at different times. As seen from the pictures, injected gas and water flow together as a mixed phase only for a short distance from the injectors and segregated into two individual phases as shown Figure 5.11 (d). The upper portion of the reservoir is swept by gas phase only while water sweeps only in the lower part; thus, the benefit of having mixed fluid flow together is lost after this point. In order to determine the segregation length of the mixed fluids, the system is required to reach steady state of gravity segregation between water and gas with no mobile oil present. Figure 5.12 zooms up a side view of the up-dip side of the reservoir. From the figure, we can see that complete segregation occurs at only 328.8 feet measured from injector in the *x*-direction.

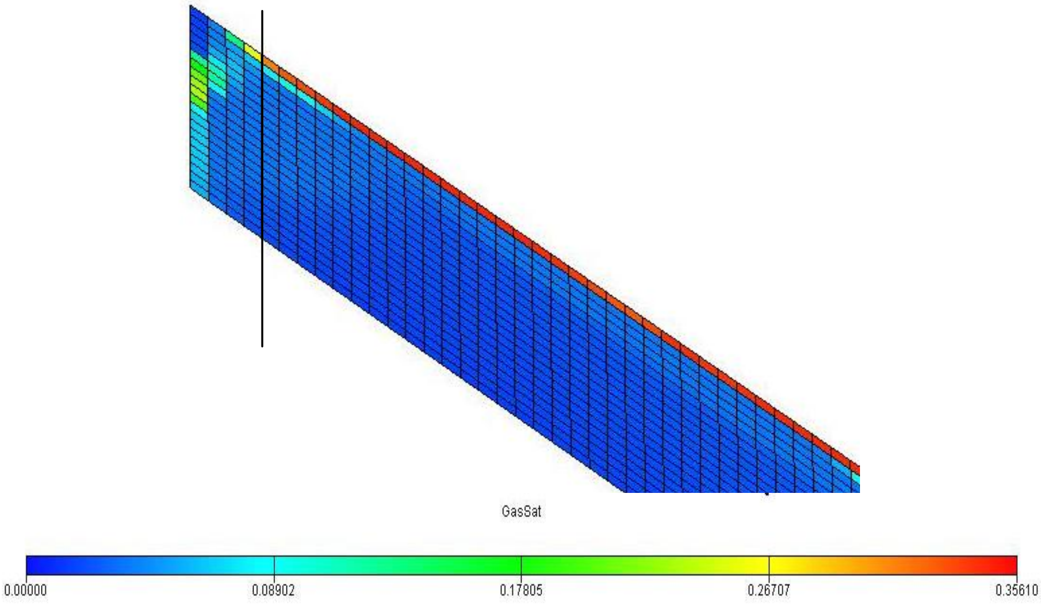


Figure 5.12 Segregation length of SSWAG base case

5.3 Effect of different design parameters on SSWAG

In this section, different sets of design parameters are studied to quantify the effect on production performance of SSWAG method. These include

- gas and water injection rates
- gas and water injection pressures
- well locations of injectors and producer
- length of horizontal injectors and vertical producer

This section also includes the comparison between the results of down-dip and up-dip injection.

5.3.1 Effect of gas and water injection rates

5.3.1.1 Constant injection rate

First, the effect of gas injection rate is studied. Four different values of gas injection rate, i.e., 500, 1000, 2000 and 3000 MSCF/D are considered while keeping water injection rate at constant value of 1000 STB/D. Figure 5.13 shows oil recovery efficiency for different gas injecion rates. The production can prolong to 100 years for almost all cases except for the case of 3000 MSCF/D gas injection in which the producer is shut due to GOR limit of 30 MSCF/STB. We can see from the figure that as gas injection rate increases, oil recovery efficiency gets higher as well. Higher fraction of gas in total injection volume (water plus gas) results in more contact area of reservoir being swept by gas as shown in Figure 5.14. As illustrated in the saturation map, Figure 5.14 a) has narrower area of oil swept by gas (indicated by red area) when compared with Figure 5.14 b). Gas has benefit over water as it has better microscopic displacement efficiency thus leaves less residual oil saturation in the reservoir. Moreover, at higher gas injection rate, the mixed phases of water and gas travel further into the reservoir before segregation occurs; thus, higher recovery is obtained. As observed in Figure 5.14, the complete segregation length occurs at 246.6 and 575.3 feet measured from injector in *x*-direction when the gas injection rate is 500 and 2000 MSCF/D, respectively.

Gas production rate and cumulative gas production are illustrated in Figure 5.15 and Figure 5.16, respectively. At higher injection rate, gas breakthrough occurs earlier as gas movement gets accerelated toward the producer. At the end of the production, cumulative gas production for the case of high gas injection rate is significantly higher than that for low gas injection rate. This is because a large amount of injected gas is produced back to the surface when the gas injection rate is high. Water also breaks through earilier in case of high gas injection rate as observed from Figure 5.17 since water is accerelated toward the producer together with the gas.

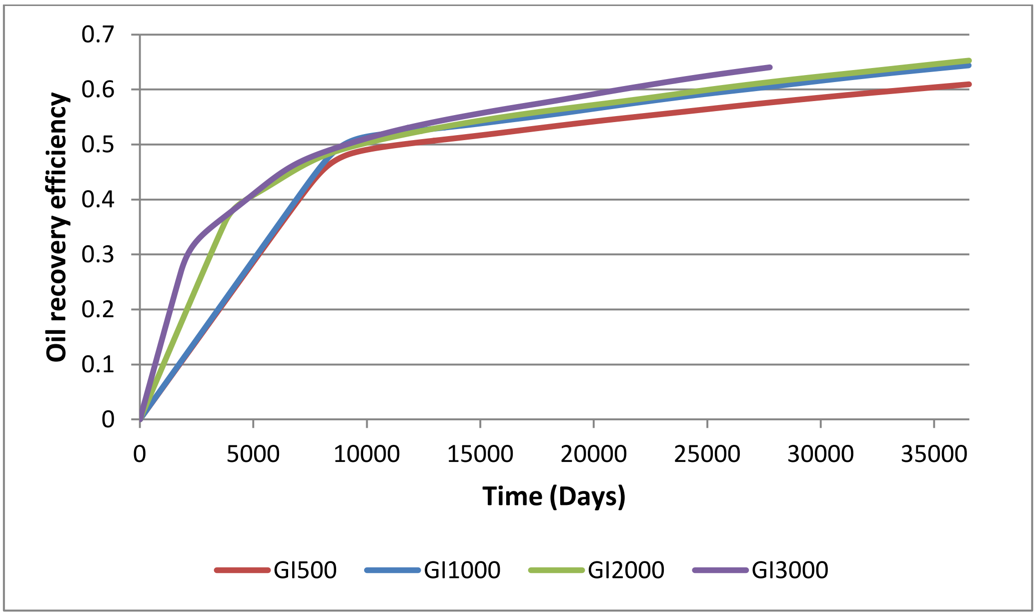
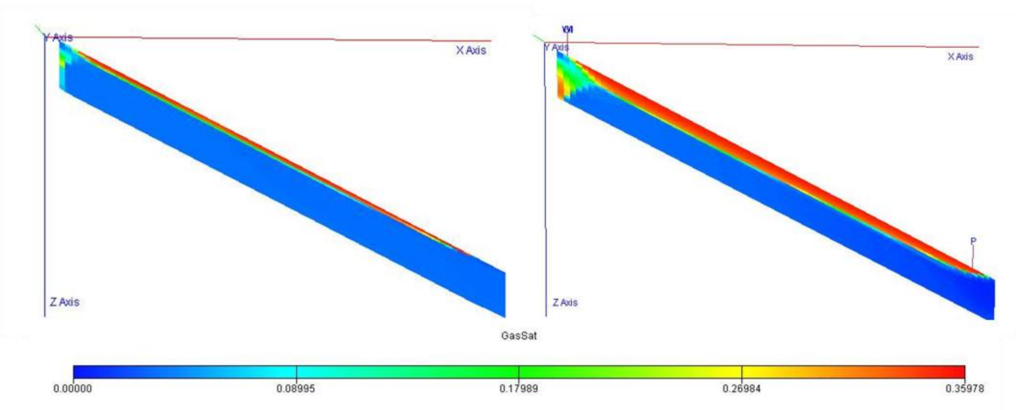


Figure 5.13 Oil recovery efficiency at different gas injection rates with water injection rate of 1000 STB/D



a)Gas injection rate of 500 MSCF/D

b)Gas injection rate of 2000 MSCF/D

Figure 5.14 Comparison of gas saturation distribution at gas injection rate of 500 and 2000 MSCF/D with water injection rate of 1000 STB/D

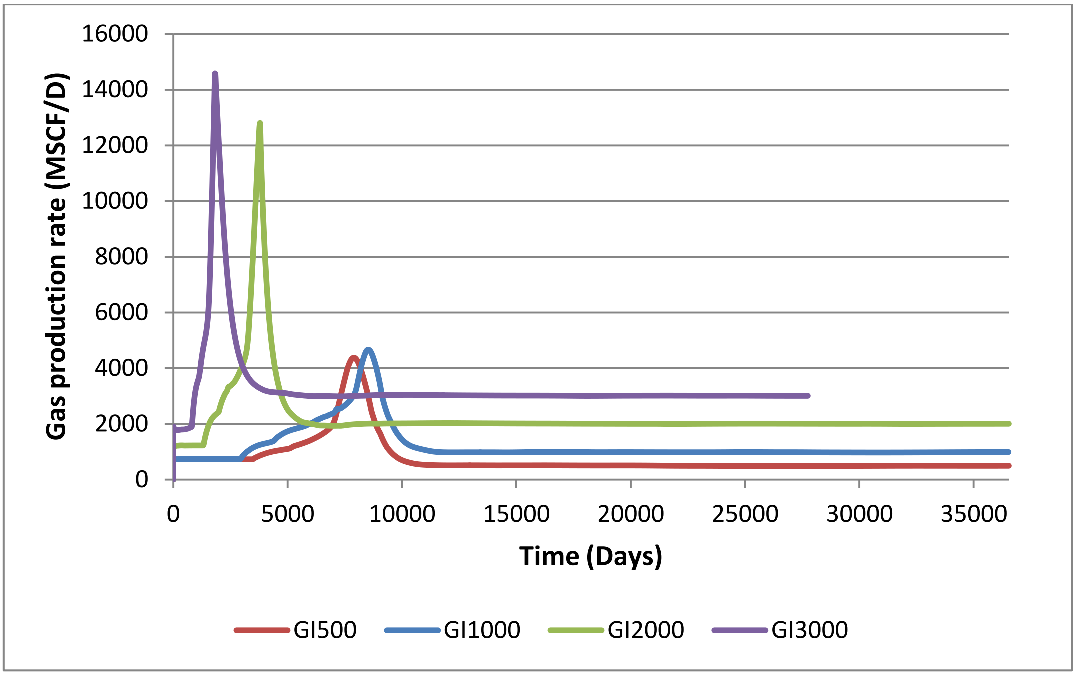


Figure 5.15 Gas production rate at different gas injection rates with water injection rate of 1000 STB/D

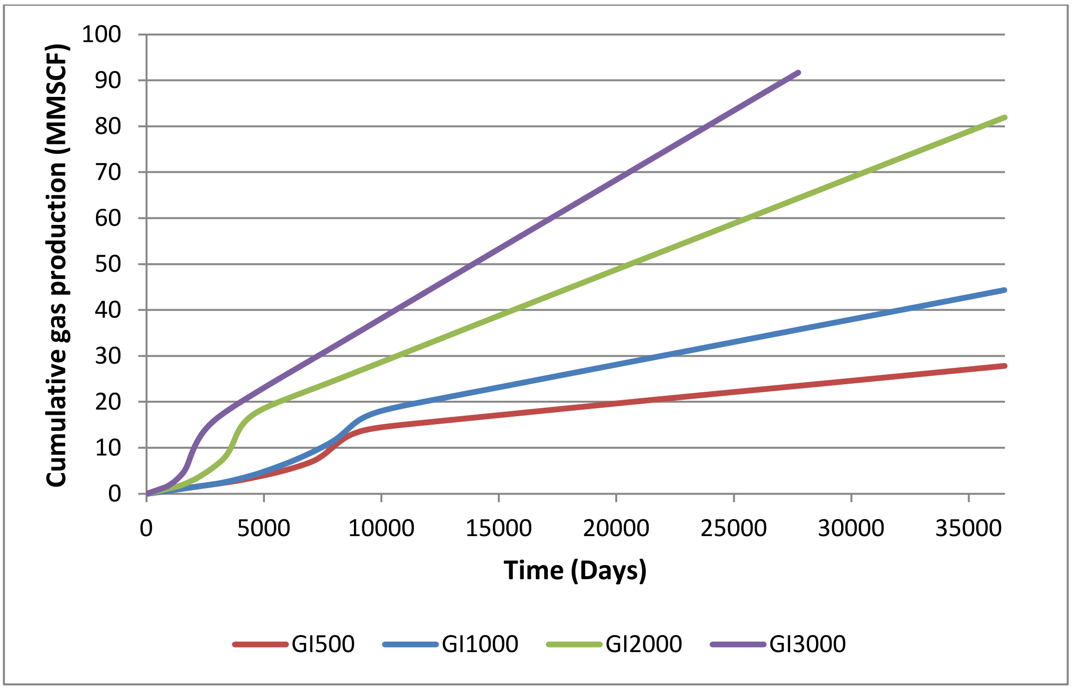


Figure 5.16 Cumulative gas production at different gas injection rates with water injection rate of 1000 STB/D

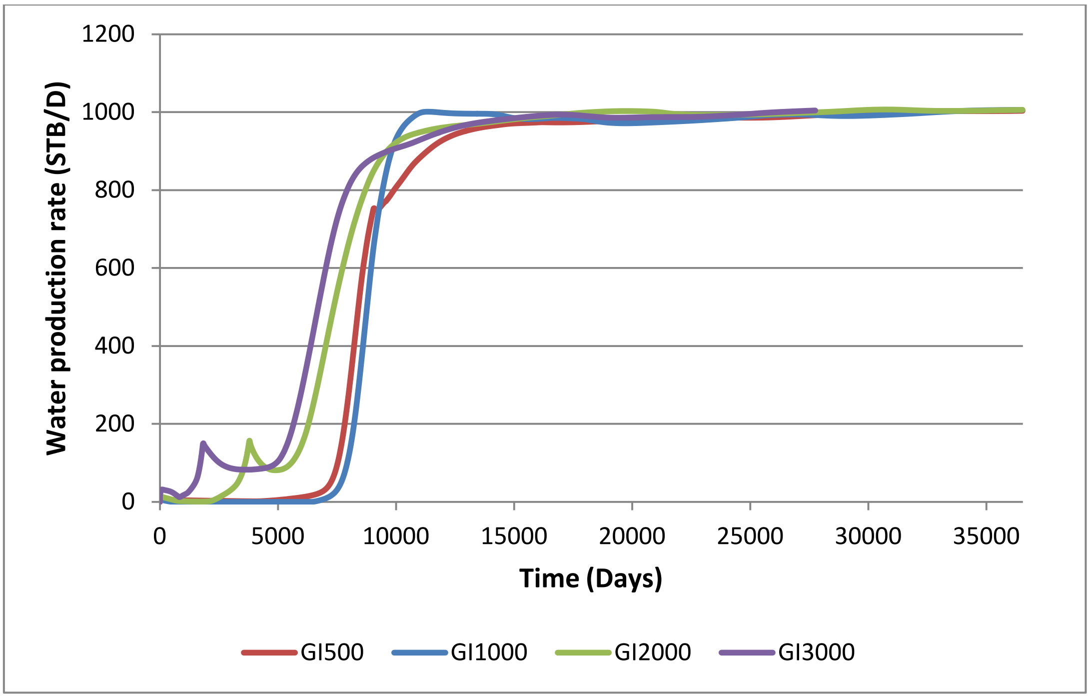


Figure 5.17 Water production rate at different gas injection rates with water injection rate of 1000 STB/D

Next, the effect of water injection rate is studied. Four different values of water injection rate, i.e., 500, 1000, 2000 and 3000 STB/D are considered while keeping gas injection rate constant at 1000 MSCF/D. Figure 5.18 depicts oil recovery efficiency for different water injecion rates. From the figure, we can conclude that as water injection rate increases, the oil recovery is lower. A wider area of reservoir is swept by water at higher water injection rate; thus, less area is swept by gas as shown in Figure 5.19. Figure 5.20 and Figure 5.21 illustrate water production rate and water cut, respectively. At higher water injection rate, water breaks through and loads up faster; thus, the production life of the producer is shorter. At high water injection rate, water movement is accerelated toward the producer; thus, the oil recovery decreases. Gas also breaks through earlier in case of higher water injection rate as gas is accererated together with water as shown in Figure 5.22.

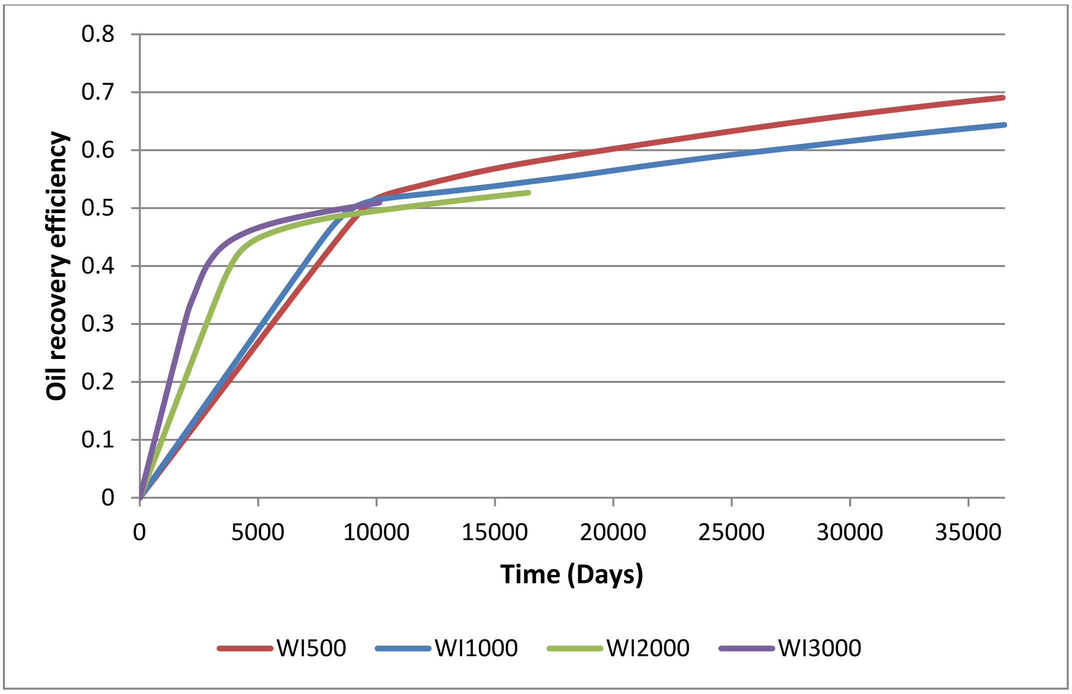
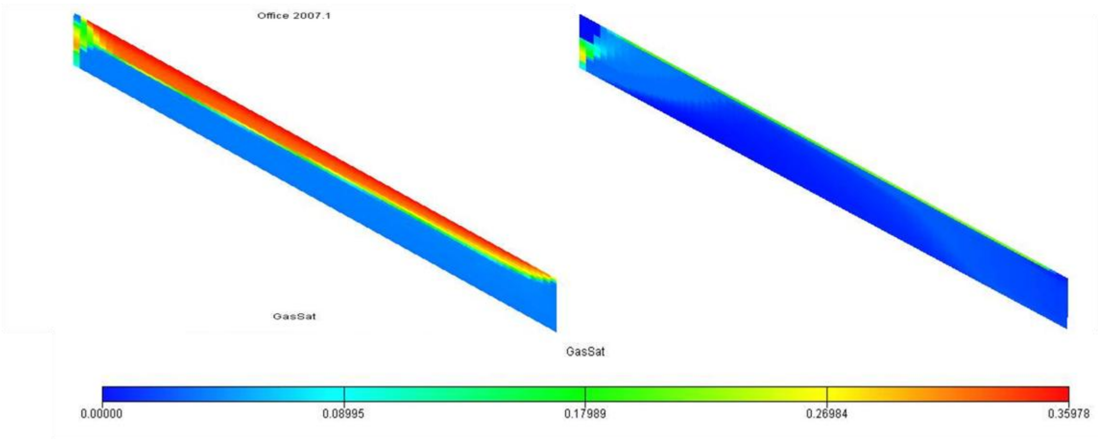


Figure 5.18 Oil recovery efficiency at different water injection rates with gas injection rate of 1000 MSCF/D



a) Water injection rate of 500 MSCF/D

b) Water injection rate of 2000 MSCF/D

Figure 5.19 Comparison of gas saturation distribution at water injection rate of 500 and 2000 STB/D with gas injection rate of 1000 MSCF/D

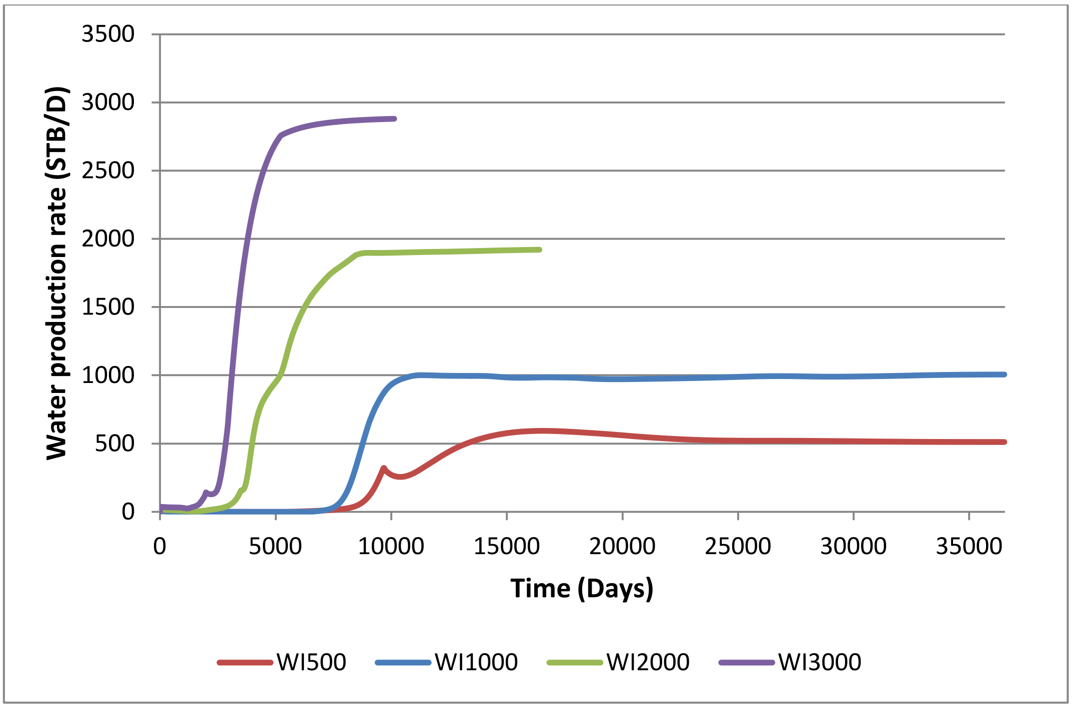


Figure 5.20 Water production rate at different water injection rates with gas injection rate of 1000 MSCF/D

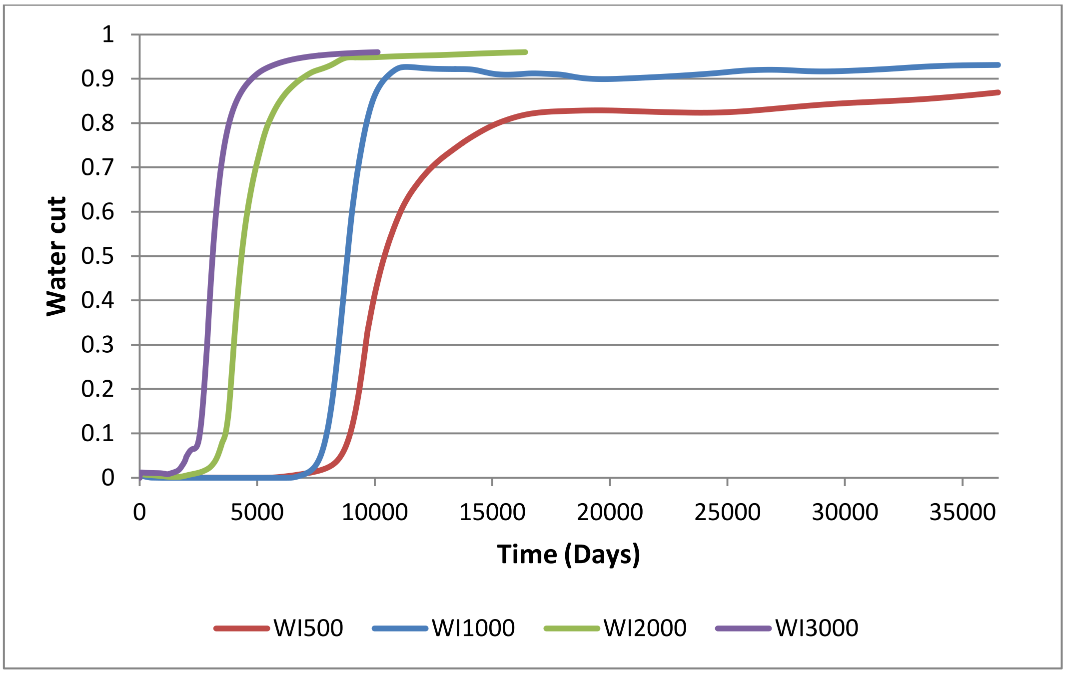


Figure 5.21 Water cut at different water injection rates with gas injection rates of 1000 MSCF/D

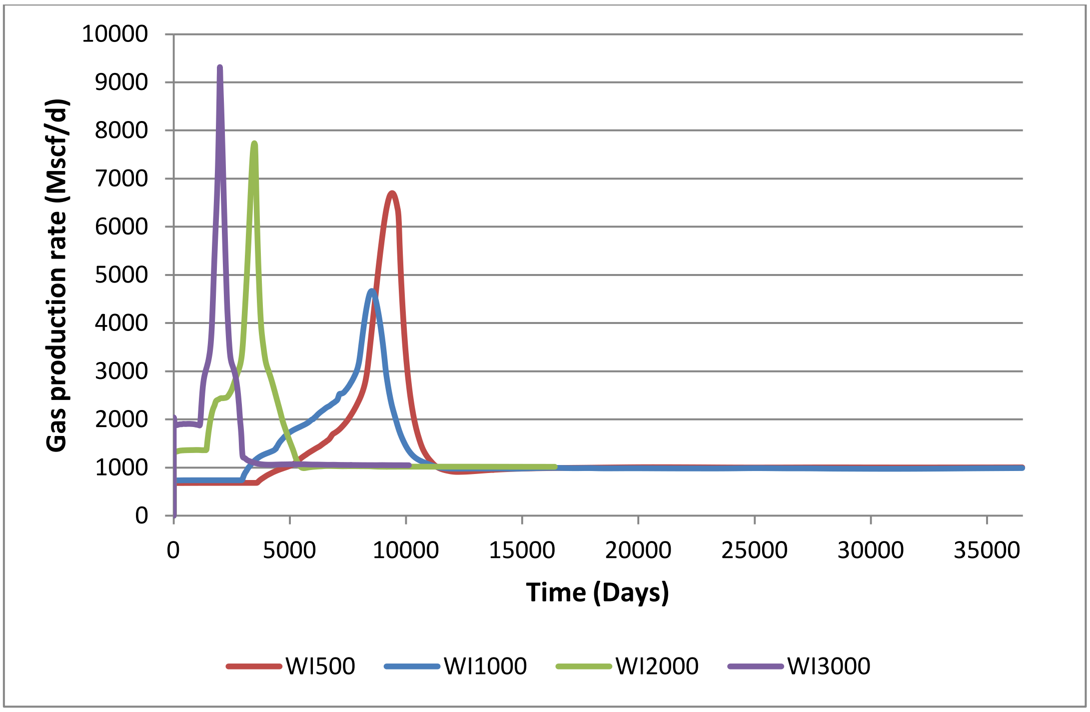


Figure 5.22 Gas production rate at different water injection rates with gas injection rate of 1000 MSCF/D

Other combinations of gas and water injection rates are investigated and the result of cumulative oil production, oil recovery efficiency and production time are summarized in Table 5.3. The result summary at 40 years of concession is listed in Table 5.4. The results obtained in these cases have the same trends with the ones in previously shown cases. In general, more oil is recovered with high gas injection rate and low water injection rate. However, when there is too much gas, the oil recovery efficiency reversely becomes less. For example, in case of 3000 MSCF/D of gas injection rate, the oil recovery is less than that of the case 2000 MSCF/D for all water injection rates. This is because the production time is shorter since the well reaches maximum GOR limit of 30 MSCF/STB faster.

Table 5.3 Summary of cumulative oil production, oil recovery efficiency and production time under different water and gas injection rates at end of production

Gas injection rate (MSCF/D)	Water injection rate (STB/D)	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
500	500	12.453	0.6686	100
500	1000	11.356	0.6097	100
500	2000	10.008	0.5373	37
500	3000	9.222	0.4951	26
1000	500	12.855	0.6901	100
1000	1000	11.987	0.6435	100
1000	2000	10.989	0.5900	100
1000	3000	9.489	0.5095	28
2000	500	13.342	0.7163	100
2000	1000	12.159	0.6528	100
2000	2000	11.053	0.5934	66
2000	3000	10.472	0.5622	38
3000	500	12.933	0.6943	75
3000	1000	11.930	0.6405	76
3000	2000	9.293	0.4989	26
3000	3000	9.418	0.5056	20

Table 5.4 Summary of cumulative oil production, oil recovery efficiency and production time under different water and gas injection rates at 40 years of concession

Gas injection rate (MSCF/D)	Water injection rate (STB/D)	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
500	500	10.399	0.5583	40
500	1000	9.590	0.5149	40
500	2000	10.008	0.5373	37*
500	3000	9.222	0.4951	26*
1000	500	10.514	0.5645	40
1000	1000	9.981	0.5359	40
1000	2000	9.654	0.5183	40
1000	3000	9.489	0.5095	28*
2000	500	10.568	0.5674	40
2000	1000	10.075	0.5409	40
2000	2000	10.046	0.5394	40
2000	3000	10.472	0.5622	38*
3000	500	10.994	0.5902	40
3000	1000	10.317	0.5539	40
3000	2000	9.293	0.4989	26*
3000	3000	9.418	0.5056	20*

∗ The results are shown at end of production as time is less than 40 years.

5.3.1.2 Step reduction in injection rate

As stated before that the length of production period is too short in cases that have high injection rate which results in oil recovery lower than expected. In order to prolong the production period, reduction of injection rate should improve oil recovery. In this section, two selected cases are studied by reducing the injection rate in half at the beginning of water and gas breakthrough whichever happens earlier.

The first selected case is water injection rate of 3000 STB/D with gas injection rate of 500 MSCF/D. The water injection rate is reduced to 1500 STB/D after the value of water cut equal to 0.05 which happens after five years of production while keeping gas injection rate constant at 500 MSCF/D. The water production rate and water cut for cases of constant injection rate and step reduction in injection rate are plotted in Figure 5.23 and Figure 5.24, respectively while Figure 5.25 and Figure 5.26 show oil production rate and oil recovery efficiency, respectively.

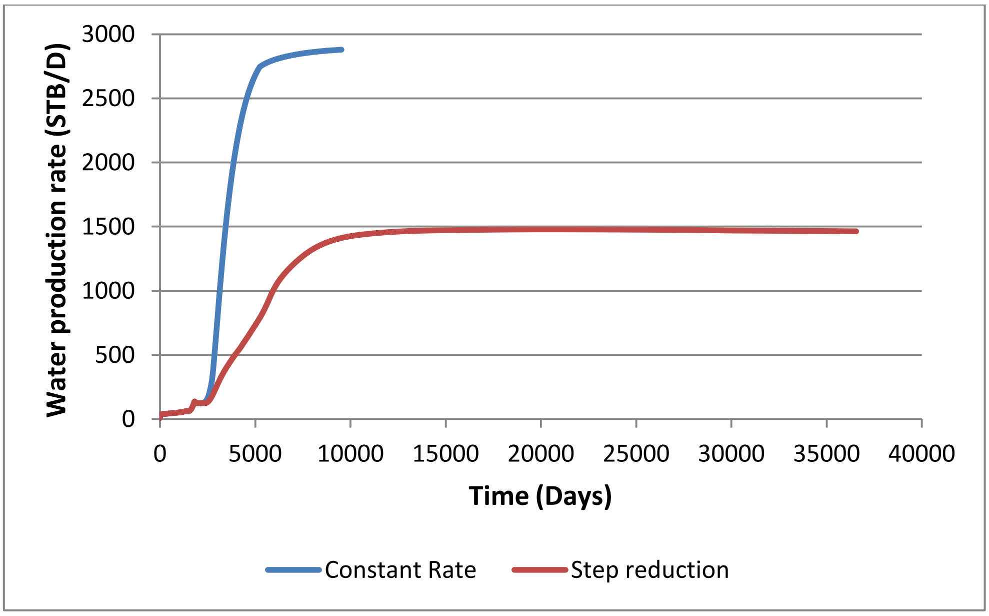


Figure 5.23 Comparison of water production rate of constant and step reduction in water injection rate cases

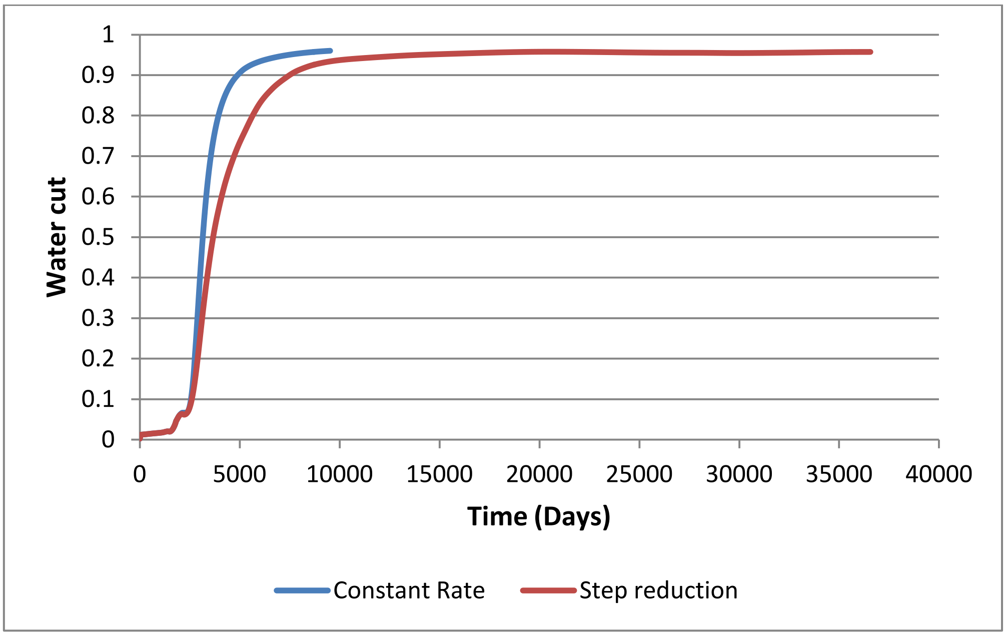


Figure 5.24 Comparison of water cut of constant and step reduction in water injection rate cases

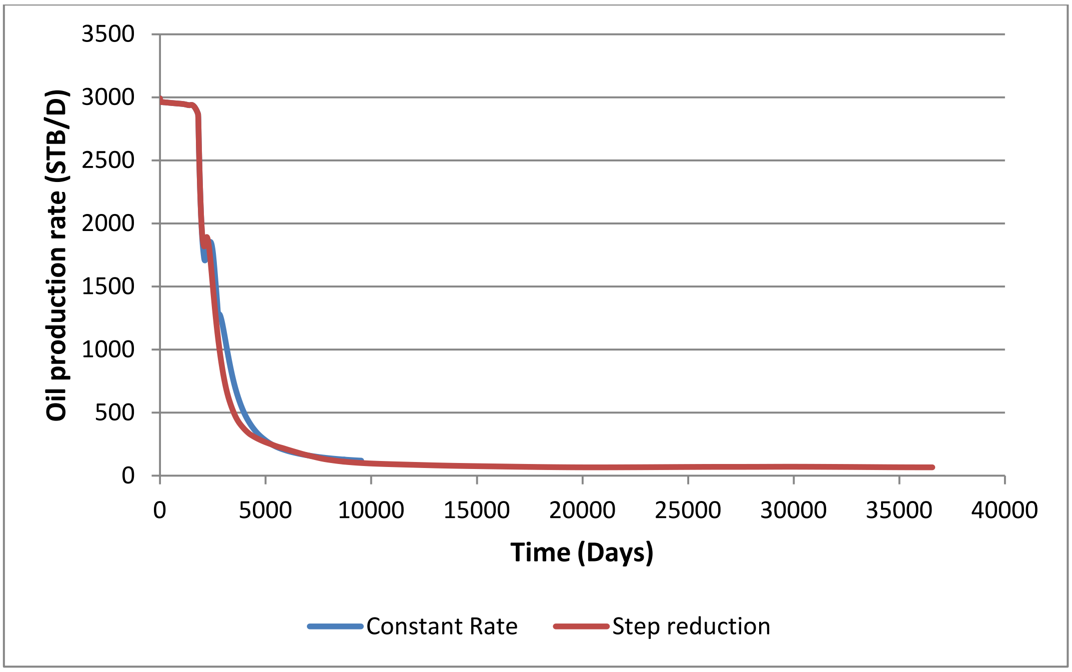


Figure 5.25 Comparison of oil production rate of constant and step reduction in water injection rate cases

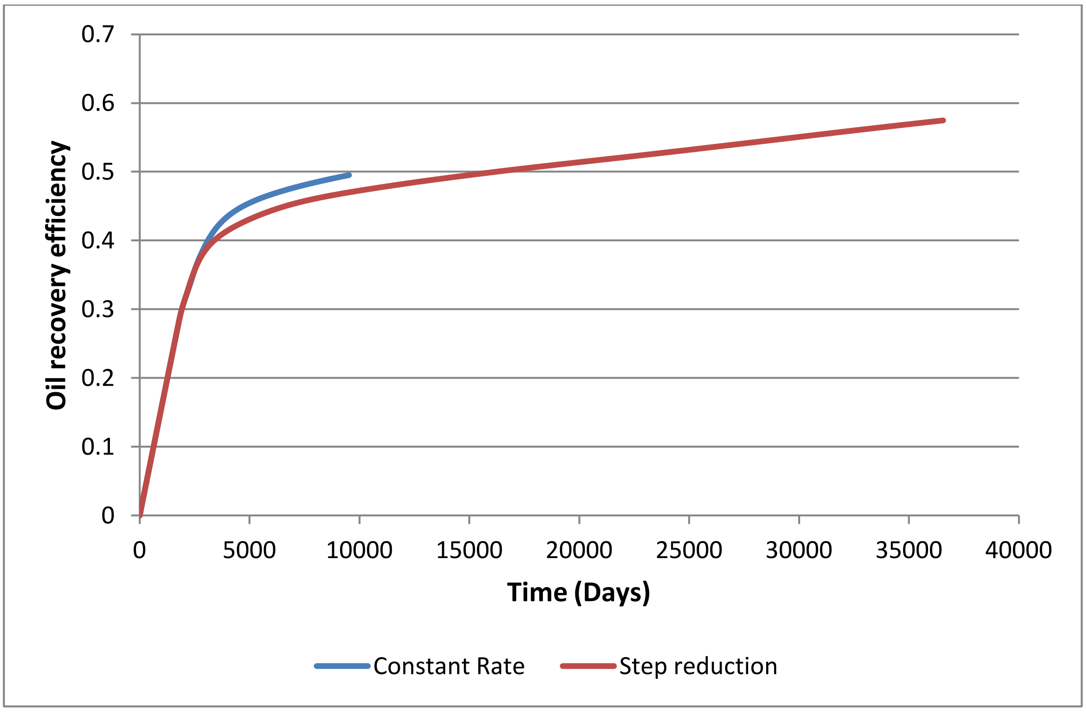


Figure 5.26 Comparison of oil recovery efficiency of constant and step reduction in water injection rate cases

We can see from the plots that reducing water injection rate can delay water breakthrough a little bit later than the original case. Also water cut value is less than the limit of 0.96 since volume of the produced water is reduced. Therefore, the production time is extended. The ultimate oil recovery at the end of production of the case with step reduction in water injection rate is more due to longer production.

A similar study is carried out for the case of water injection rate of 500 STB/D and gas injection rate of 3000 MSCF/D. The gas injection rate is reduced to 1500 MSCF/D after the value of gas-oil ratio reaches 1.0 MSCF/STB which happens after two and a half years of production while water injection rate is kept constant at 500 STB/D. The gas production rate and gas-oil ratio for cases of constant gas injection rate and step reduction gas injection rate are plotted in Figure 5.27 and Figure 5.28, respectively. Oil production rate and oil recovery efficiency are shown in Figure 5.29 and Figure 5.30, respectively.

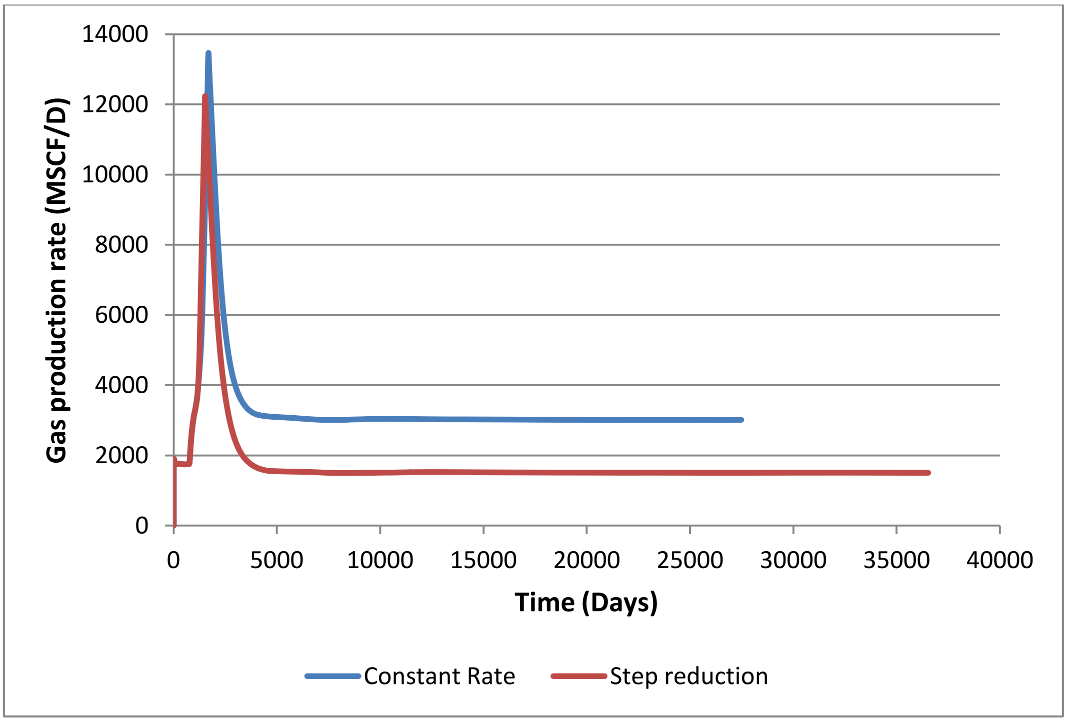


Figure 5.27 Comparison of gas production rate of constant and step reduction in gas injection rate cases

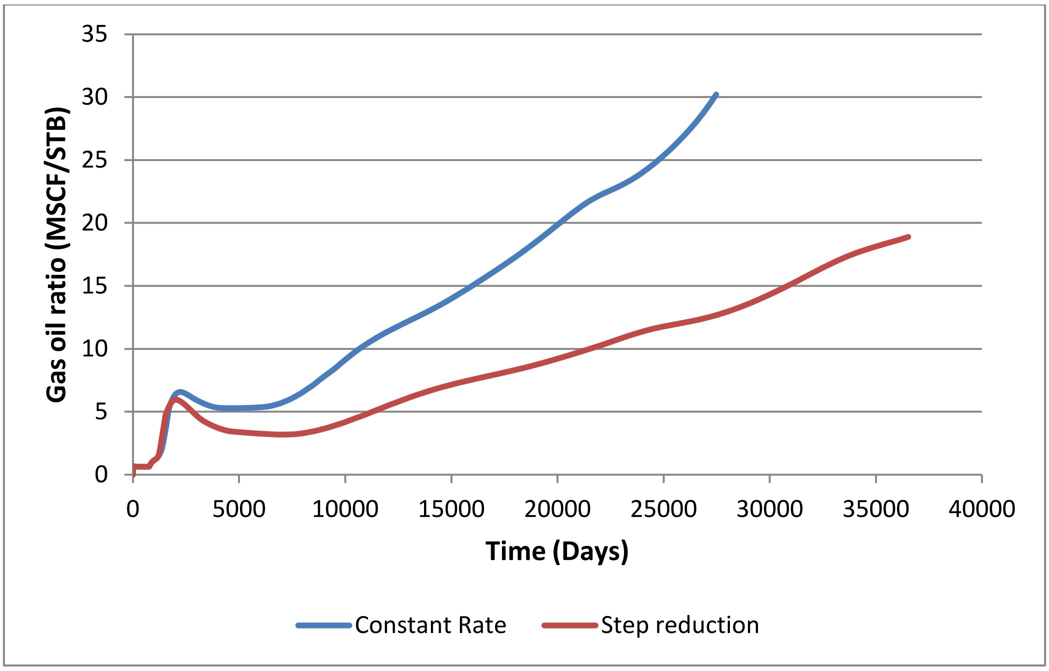


Figure 5.28 Comparison of gas-oil ratio of constant and step reduction in gas injection rate cases

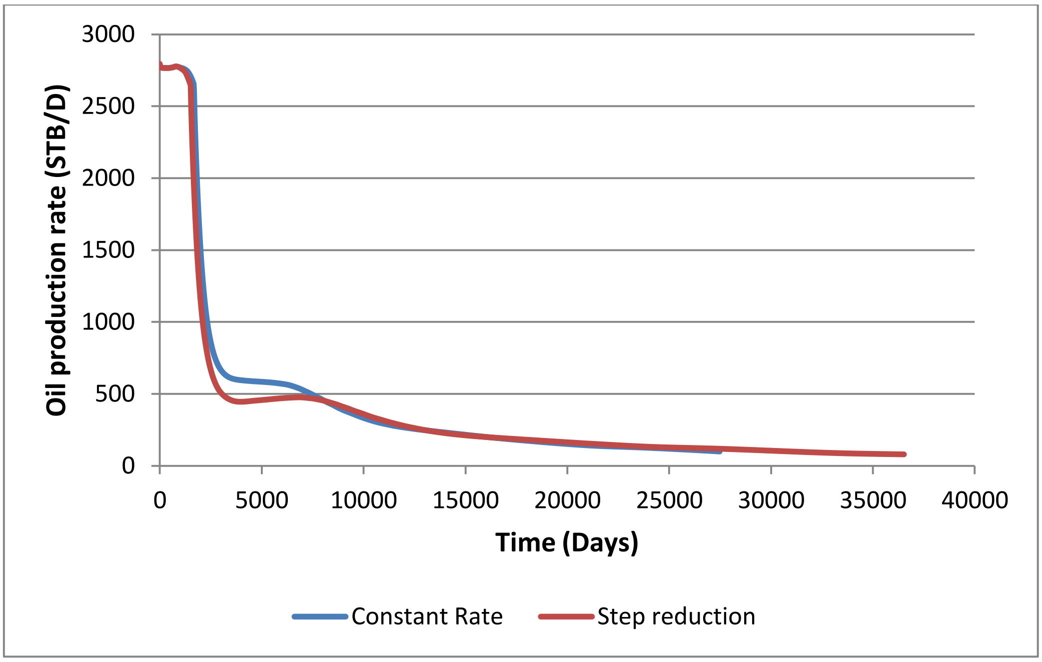


Figure 5.29 Comparison of oil production rate of constant and step reduction in gas injection rate cases

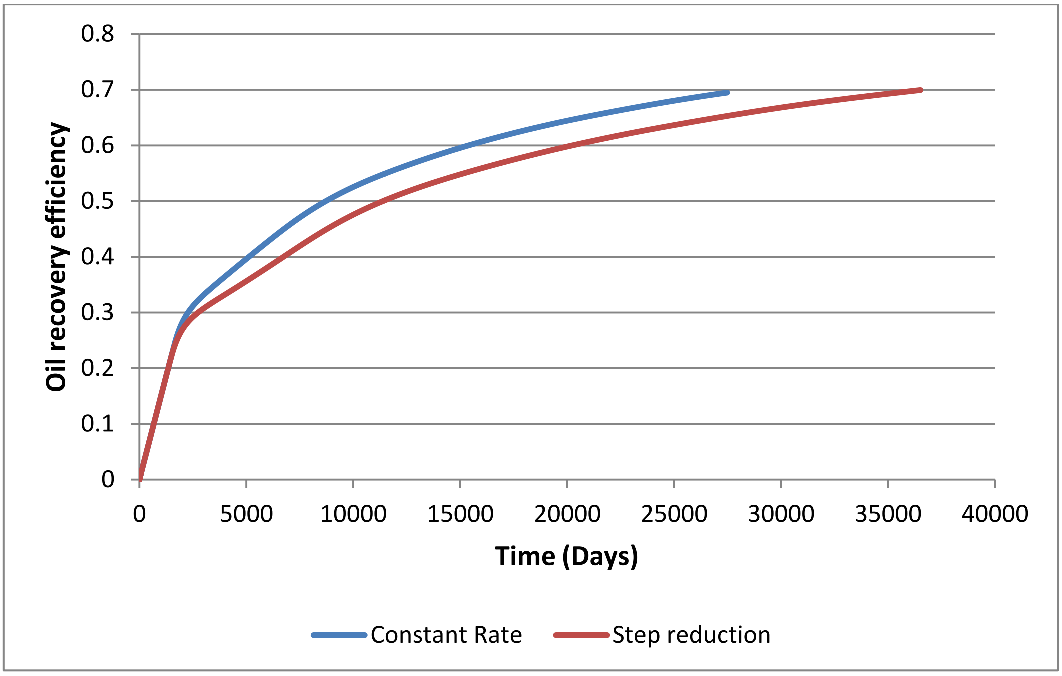


Figure 5.30 Comparison of oil recovery efficiency of constant and step reduction in gas injection rate cases

The simulation result shows that the value of GOR is reduced when step reduction in gas injection rate is implemented. Thus, the production time is slightly extended. As a result, the oil recovery efficiency is not significantly different. Table 5.5 shows the summary of oil recovery for the cases with constant and step reduction in gas and water injection rates.

Table 5.5 Summary of cumulative oil production, oil recovery efficiency and production time of constant and step reduction in gas and water injection rate cases

Cases	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
Water injection rate constant at 3000 STB/D	9.222	0.4951	26
Reduce water injection rate to 1500 STB/D at WCT = 0.05	10.700	0.5745	100
Gas injection rate constant at 3000 MSCF/D	12.933	0.6943	75
Reduce gas injection rate to 1500 MSCF/D at GOR = 1 MSCF/STB	13.021	0.6990	100

5.3.2 Effect of gas and water injection pressures

In this section, water and gas injections are controlled by constant bottom hole pressure instead of injection rate as implemented in Section 5.3.1. Injection pressures for both injectors are assumed to be the same. Four values of injection pressure are considered, i.e., 2550, 2700, 3000 and 3200 psia. Figure 5.31 depicts oil recovery efficiency for cases with different injection pressures. We can conclude from the figure that at higher injection pressure, oil recovery is significantly higher. This is because at higher fixed injection pressure, the injection rate of gas is much higher as shown in Figure 5.32 so as water injection rate as shown in Figure 5.33. Water cut and gas oil ratio are plotted in Figure 5.34 and Figure 5.35, respectively. In the case of high injection rate, breakthrough of water and gas occurs sooner than other cases as shown in water cut and gas oil ratio plot. In addition, the production time for high injection pressure is also shorter. Table 5.6 lists the summary of cumulative oil production, oil recovery efficiency and production time for different water and gas injection pressures at the end of production and Table 5.7 lists the summary at 40 years of concession.

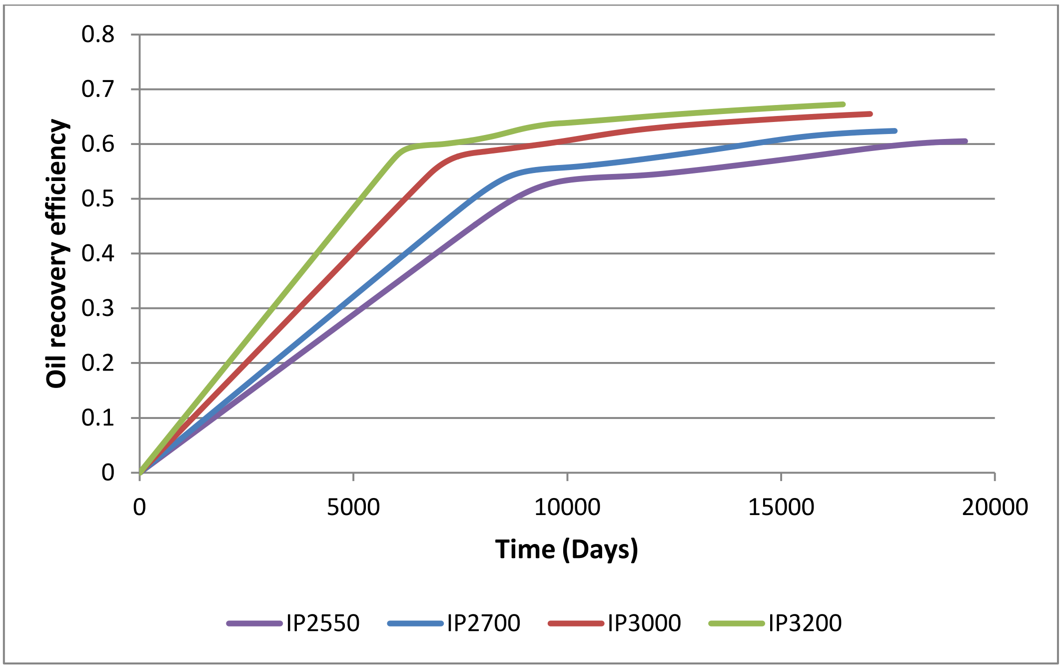


Figure 5.31 Oil recovery efficiency for different water and gas injection pressures

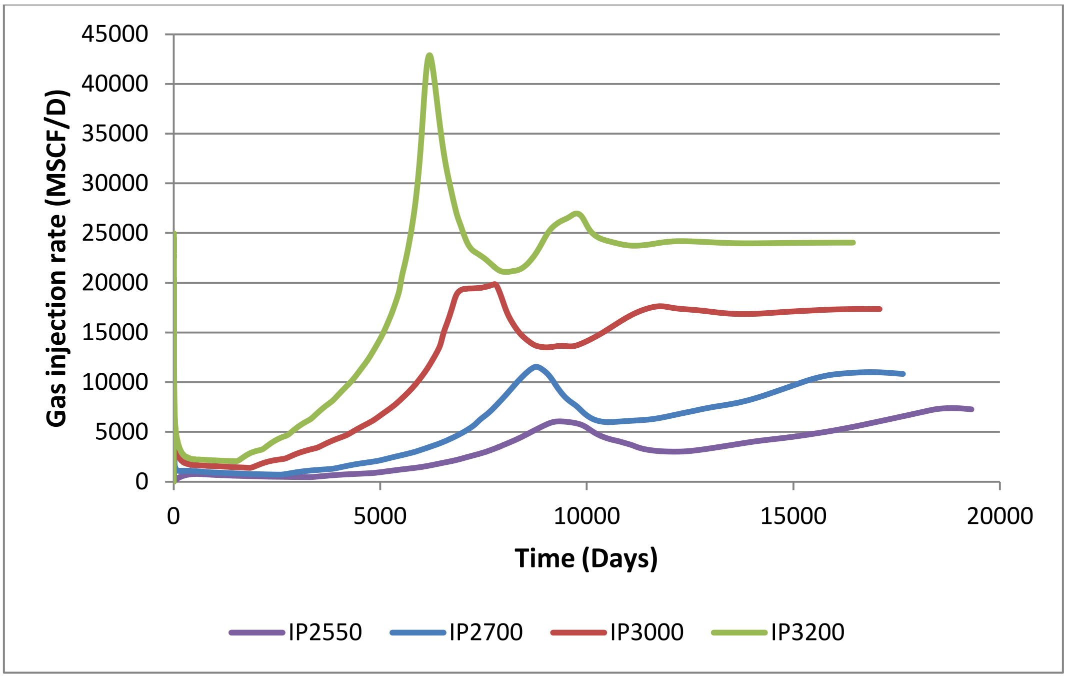


Figure 5.32 Gas injection rate for different water and gas injection pressures

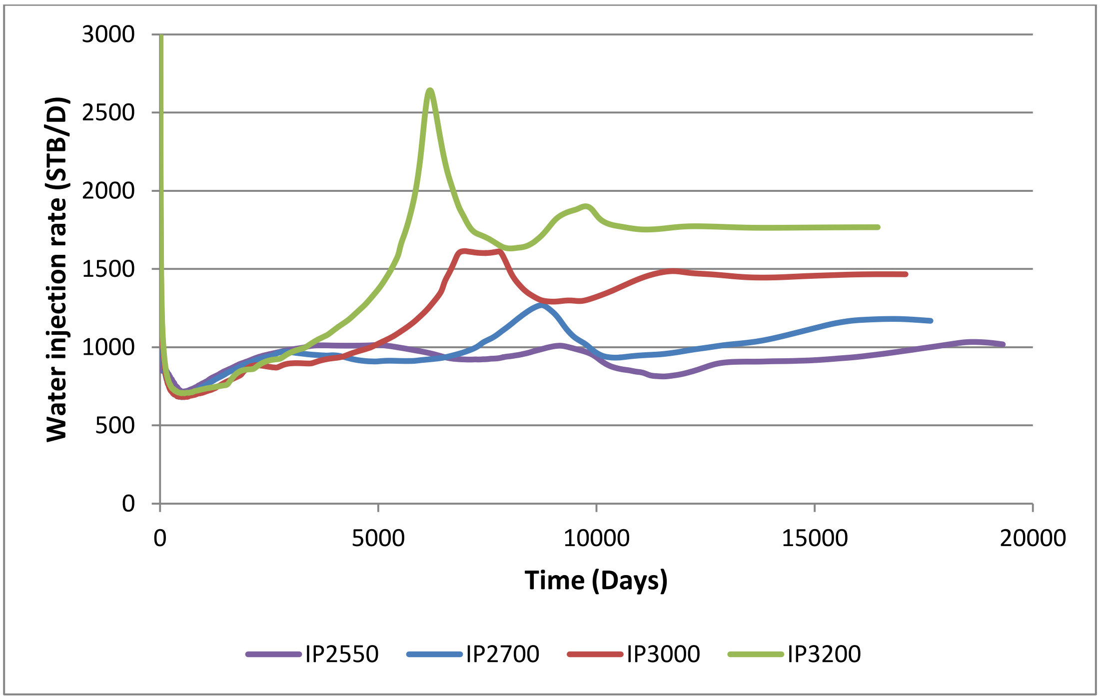


Figure 5.33 Water injection rate for different water and gas injection pressures

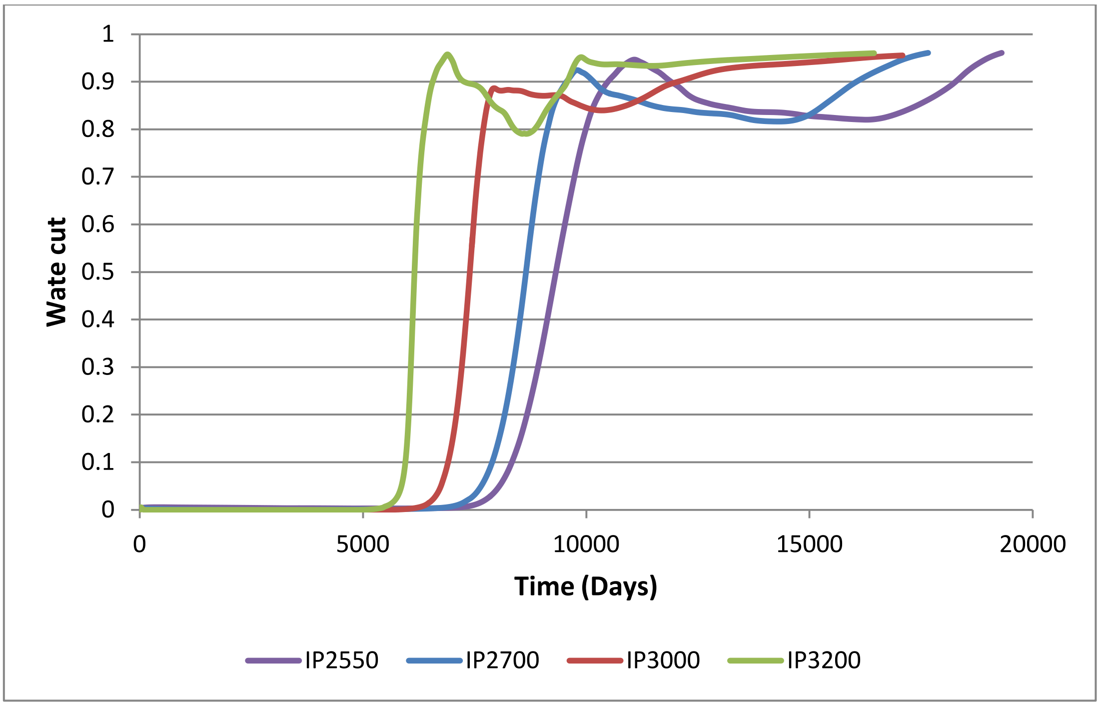


Figure 5.34 Water cut for different water and gas injection pressures

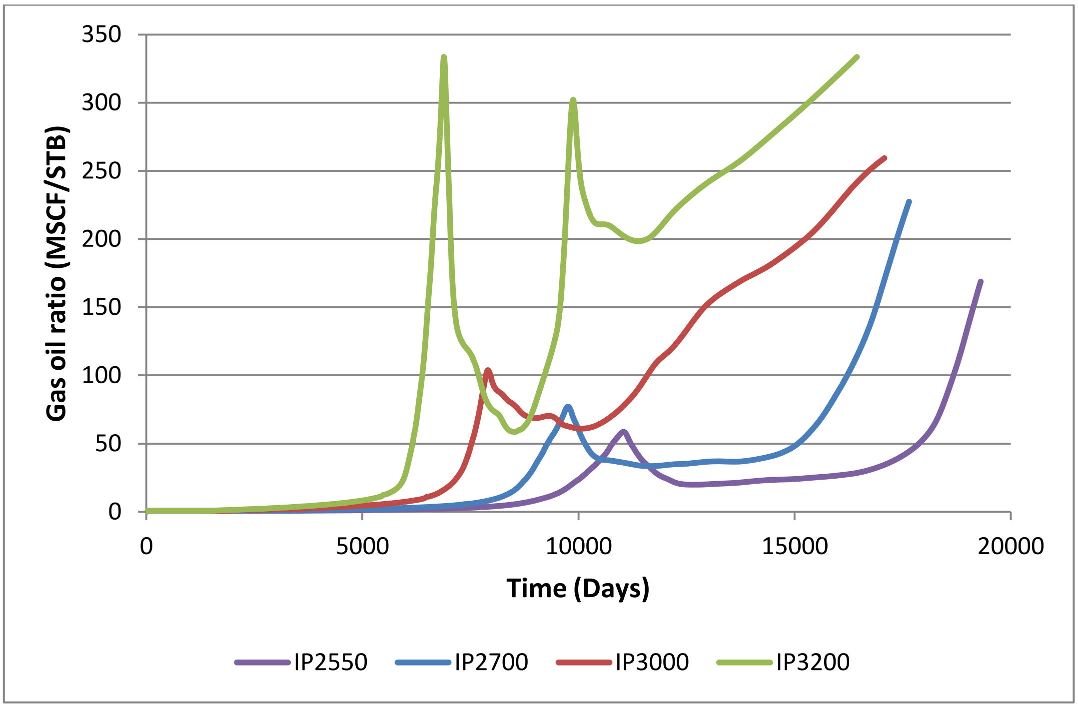


Figure 5.35 Gas oil ratio for different water and gas injection pressures

Table 5.6 Summary of cumulative oil production, oil recovery efficiency and production time for different water and gas injection pressures at the end of production

Injection pressure (psia)	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
2550	11.273	0.605	53
2700	11.624	0.624	48
3000	12.196	0.655	47
3200	12.523	0.672	45

Table 5.7 Summary of cumulative oil production, oil recovery efficiency and production time for different water and gas injection pressures at 40 years of concession

Injection pressure (psia)	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
2550	10.565	0.567	40
2700	11.259	0.604	40
3000	12.002	0.644	40
3200	12.380	0.665	40

Figure 5.36 shows comparison of oil recovery between constant injection pressure of 2550 psia and constant water and gas injection rate of 1000 STB/D and 1000 MSCF/D. As illustrated in Figure 5.36, oil recovery from the case with constant injection rate is poorer than the case with constant injection pressure. This is because higher gas injection rate is achieved with constant injection pressure than the case of constant injection rate. Moreover, in the case of fixed injection pressure, the mixed

zone of water and gas penetrates deeper into the formation before complete segregation occurs as illustrated in Figure 5.37, resulting in higher oil recovery. As observed from Figure 5.37, complete segregation occurs after mixed phases travel for 657.5 and 328.8 feet for constant injection pressure and constant injection rate, respectively.

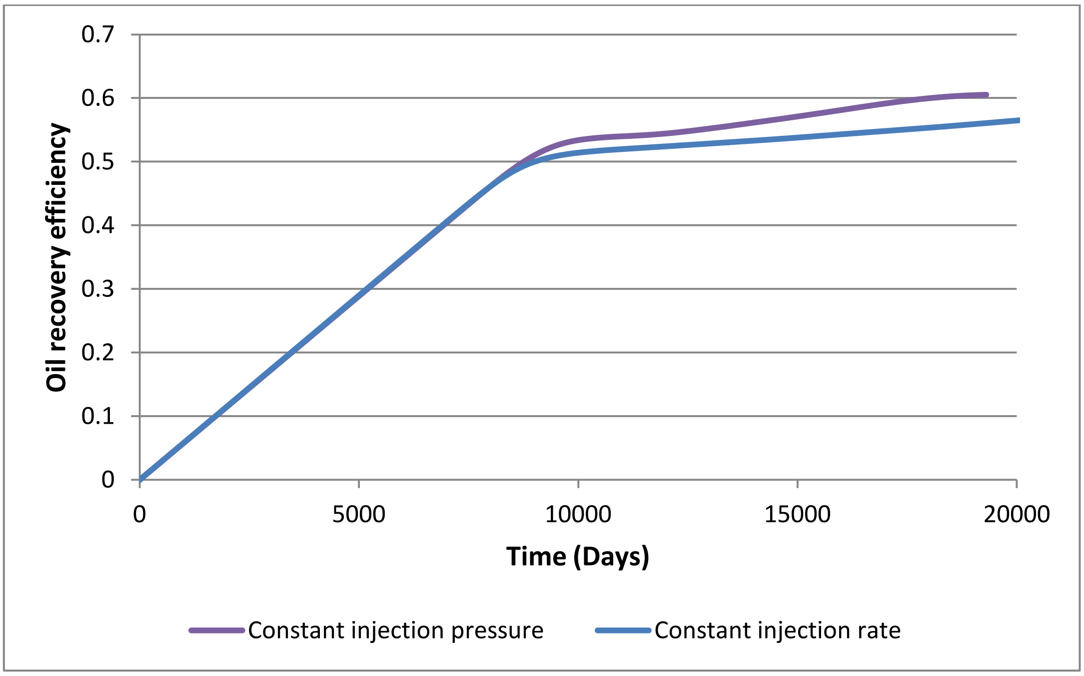
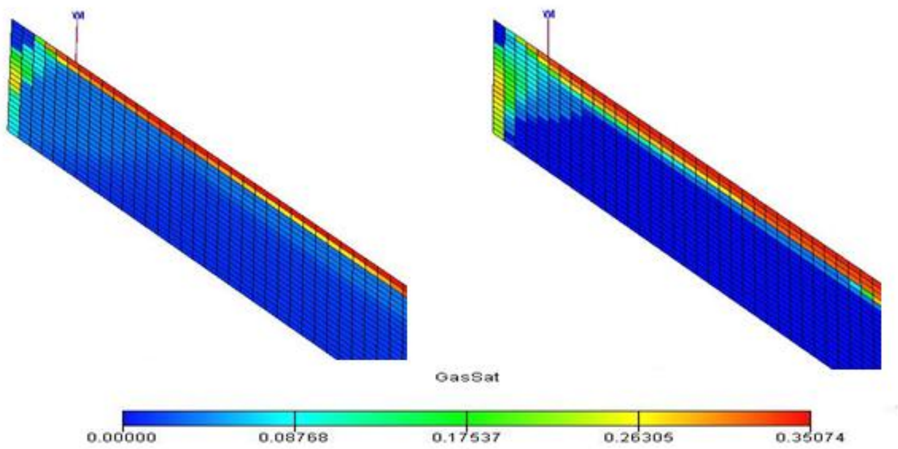


Figure 5.36 Comparison of oil recovery between constant injection pressure of 2550 psia and constant water and gas injection rate of 1000 STB/D and 1000 MSCF/D.



a) Water injection rate of 1000 STB/D and gas injection rate of 1000 MSCF/D

b) Constant injection pressure of 2550 psia

Figure 5.37 Comparison of segregation length between constant injection rate and constant injection pressure

However, in order to keep injection pressure at constant value, high volume of injected gas is needed. Therefore, a large amount of produced gas is resulted as well especially at higher injection pressure as observed from the gas oil ratio plots in Figure 5.35. These GOR values highly exceed the assumed limitation of the production capacity of 30 MSCF/STB. Additionally, controlling constant bottom hole pressure of the injectors is quite difficult in the field. Therefore, this method is not practical even though it yields higher oil recovery.

For these stated reasons, we chose to control water and gas injectors with constant injection rate instead of constant injection pressure for the rest of the SSWAG simulation cases by setting water injection rate of 500 STB/D and gas injection rate of 3000 MSCF/D.

5.3.3 Effect of injector locations

In this section, effects of water and gas injector locations are investigated by changing their locations along the *z*-axis. Four locations of water injectors are considered, i.e., layer 1, 5, 10 and 15 while keeping gas injector at layer 21 (bottommost layer). Gas injector locations are also varied for four different locations, i.e., layer 5, 10, 15 and 21 while keeping water injector location at layer 1 (topmost layer). The oil recovery efficiencies for different locations of water injectors are illustrated in Figure 5.38 and summarized in Table 5.8. The summary of oil production at 40 years of concession is also listed in Table 5.9. According to the results, moving water injector down the vertical axis or closer to gas injector tends to increase oil recovery factor but only small increment is observed. Additionally, the production times are more or less the same except for the case of placing water injector at deeper depth which takes a little less time of production.

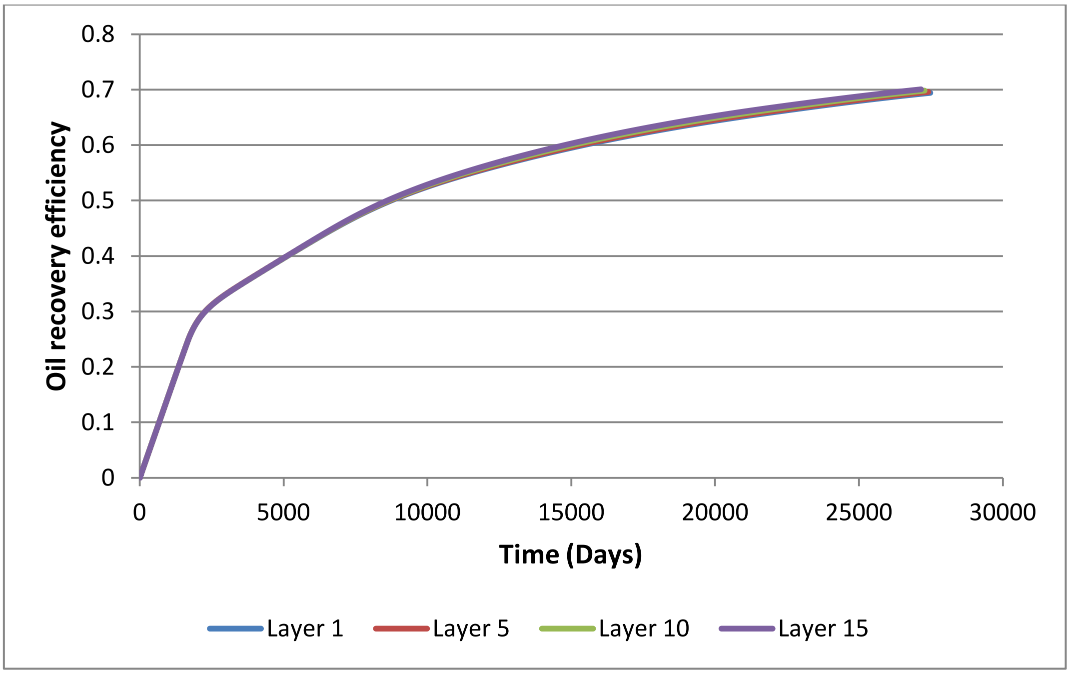


Figure 5.38 Oil recovery efficiency for different water injector locations

Table 5.8 Summary of cumulative oil production, oil recovery efficiency and production time for different water injector locations at the end of production

Layer number of water injector location	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
1	12.933	0.694	75
5	12.956	0.696	75
10	13.004	0.698	75
15	13.052	0.701	74

Table 5.9 Summary of cumulative oil production, oil recovery efficiency and production time for different water injector locations at 40 years of concession

Layer number of water injector location	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
1	11.007	0.591	40
5	11.023	0.592	40
10	11.083	0.595	40
15	11.142	0.598	40

Figure 5.39 and Figure 5.40 illustrate gas and water production rate, respectively. We can see from the figures that gas production profiles for all values of water injector location are not different but the water production profiles indicate that water breaks through slightly earlier for the case in which the water injector is close to the gas injector.

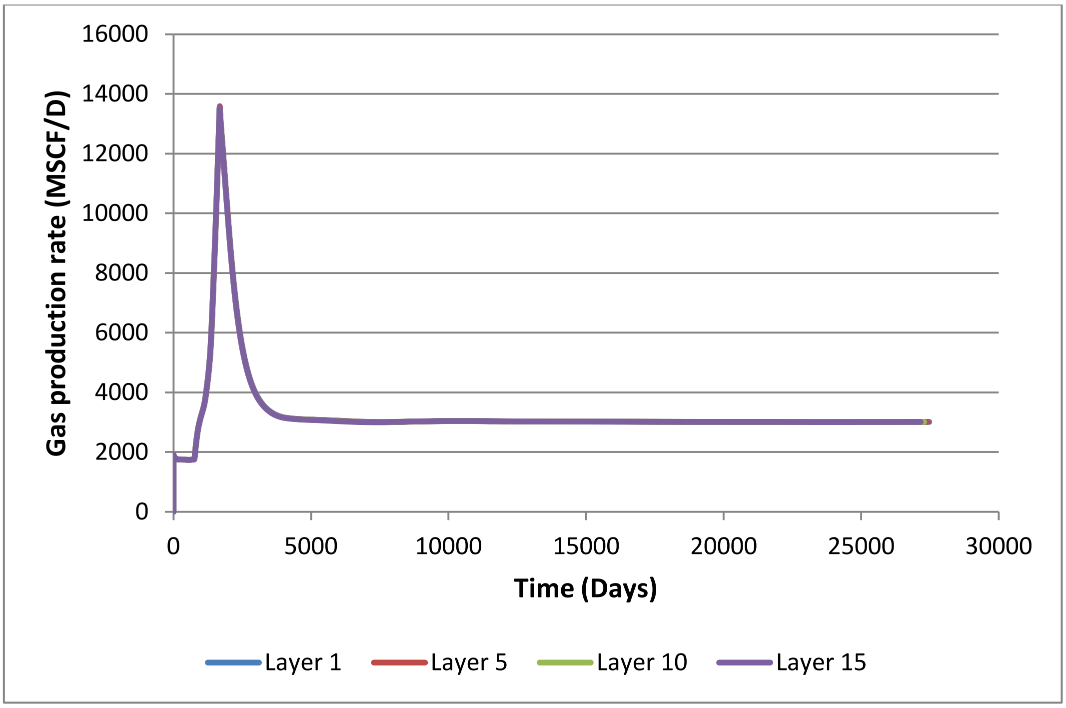


Figure 5.39 Gas production rate for different water injector locations

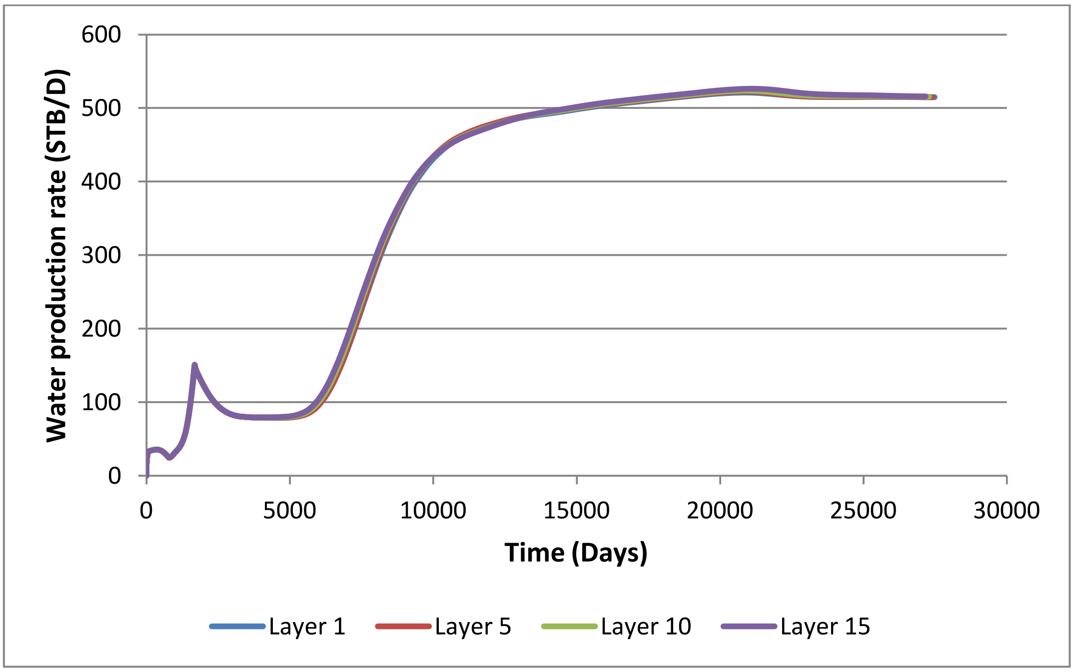


Figure 5.40 Water production rate for different water injector locations

A parallel study is performed by varying location of gas injection while keeping water injector at layer 1 (topmost layer). Four locations of gas injector are used layer 5, 10, 15 and 21 (bottommost layer). Oil recovery efficiency is shown in Figure 5.41 and summarized in Table 5.10 for different gas injector locations. The summary of oil production at 40 years of concession is also listed in Table 5.11. As observed from the result that oil recovery tends to increase when moving gas injector down the planar but again a small increment is observed. Moreover, moving gas injector upward has no effect on production time. The overall profile for gas production rate for different gas injector locations is similar to the one illustrated in Figure 5.39. If we focus on behavior at the time around the breakthrough of gas as illustrated in Figure 5.42, we observe that gas breaks through the producer faster when the gas injector is placed closer to the water injector. Figure 5.43 shows water production rate for different gas injector locations which are the same.

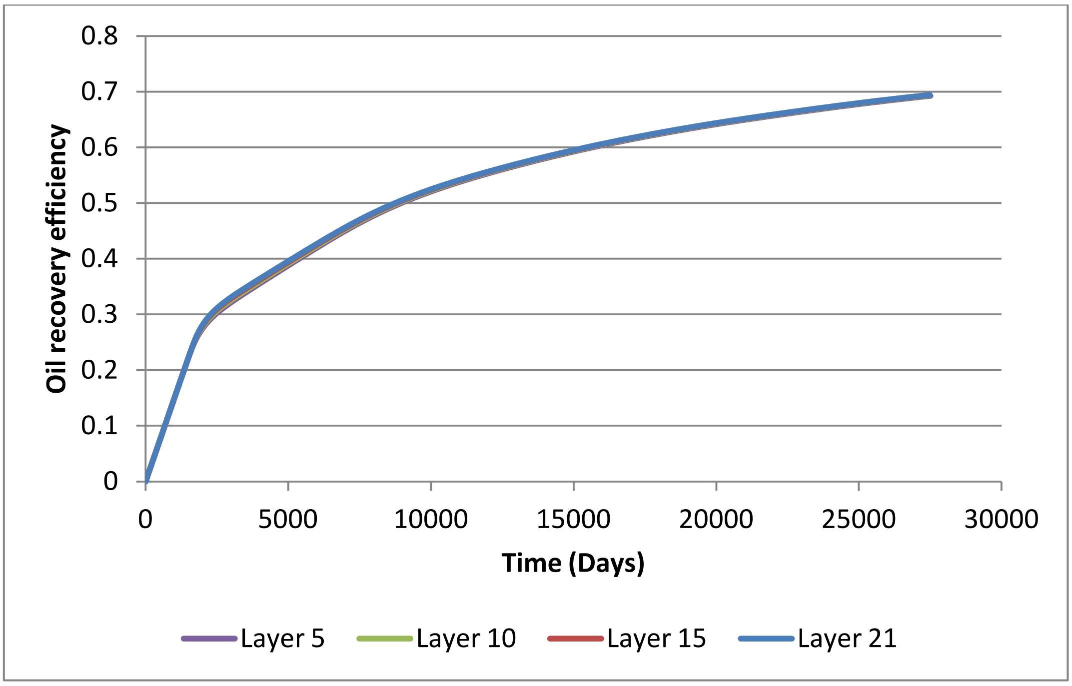


Figure 5.41 Oil recovery efficiency for different gas injector locations

Table 5.10 Summary of cumulative oil production, oil recovery efficiency and production time for different gas injector locations at the end of production

Layer number of gas injector location	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
5	12.895	0.692	75
10	12.904	0.693	75
15	12.922	0.694	75
21	12.933	0.694	75

Table 5.11 Summary of cumulative oil production, oil recovery efficiency and production time for different gas injector locations at 40 years of concession

Layer number of gas injector location	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
5	10.945	0.588	40
10	10.967	0.589	40
15	10.989	0.590	40
21	11.007	0.591	40

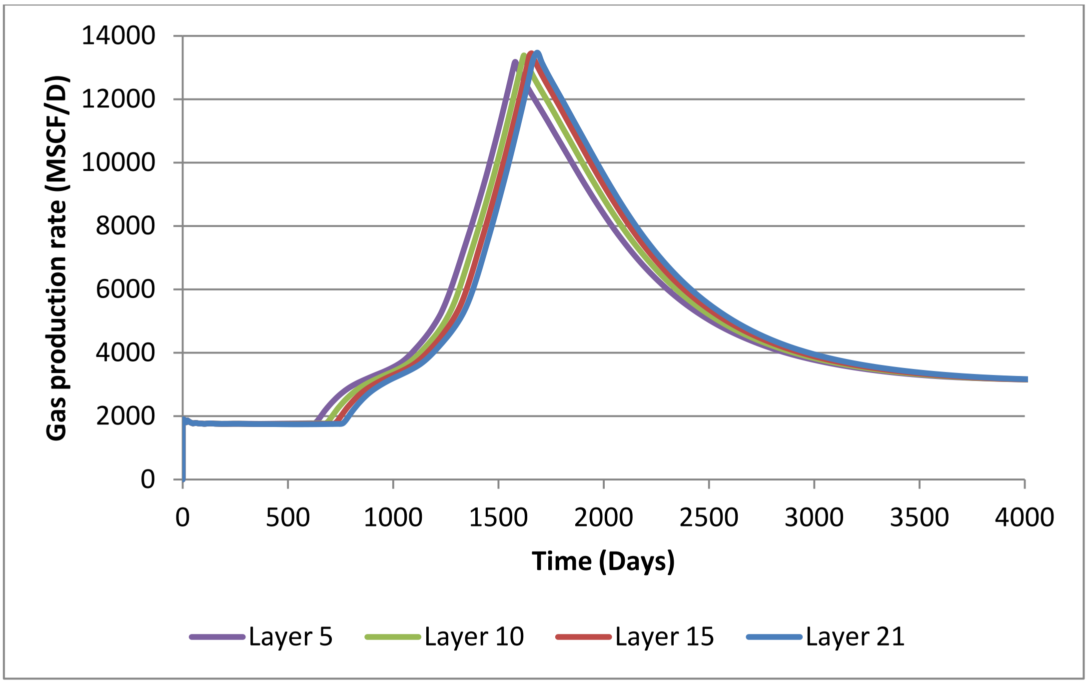


Figure 5.42 Gas production rate within 4000 days of production for different gas injector locations

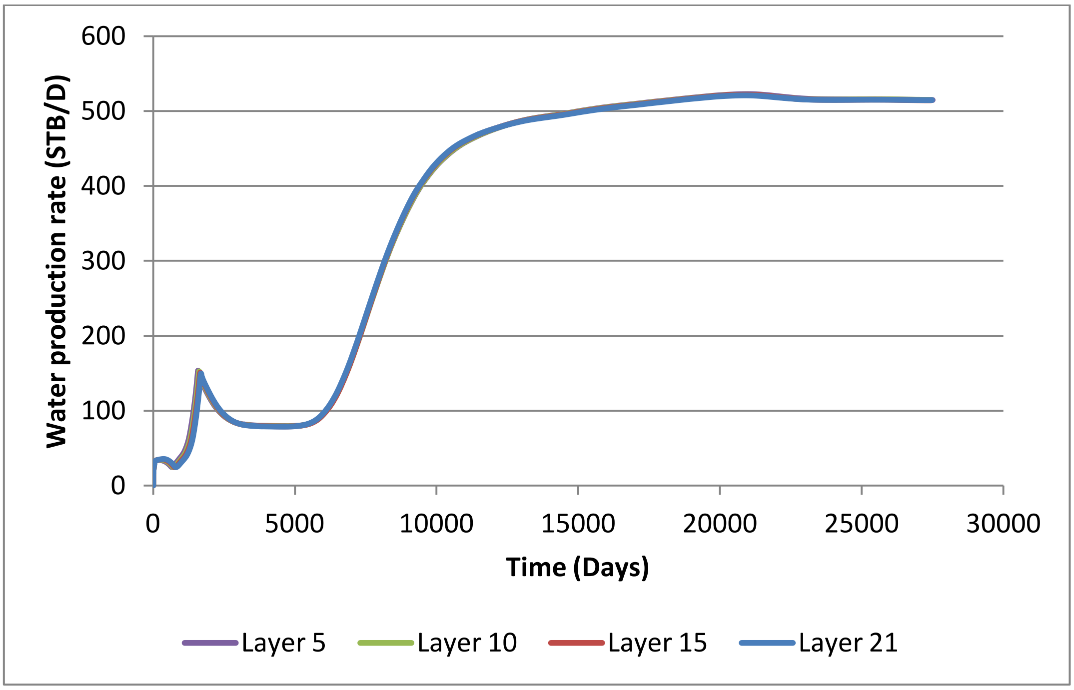


Figure 5.43 Water production rate for different gas injector locations

5.3.4 Effect of producer location

Three different locations, named by (*x*,*y*) grid coordinate, of producion well are studied in this section. The first two locations (73,16) and (73,1) are investigated to see effect of changing location along the *y*-axis while the last location of (60,16) is considered to see the effect of changing location along the *x*-axis. The locations of these three coordinates are illustrated in Figure 5.44. Figure 5.45 depicts oil recovery efficiency for different locations of the production well which clearly shows that changing location of the production well along the *y*-axis does not affect oil recovery performance. However, moving the oil producer up-dip can significantly reduce oil recovery efficiency for almost 5% as listed in Table 5.12. This is mainly due to the fact that more area of reservoir down dip of the production well is left unswept as in the case of production well being located at (60,16), illustrated in Figure 5.46. Moreover, moving the production well up-dip results in acceleration of water breakthrough, increase in gas production, and decrease in oil production rate in general as observed in Figure 5.47 and Figure 5.48.

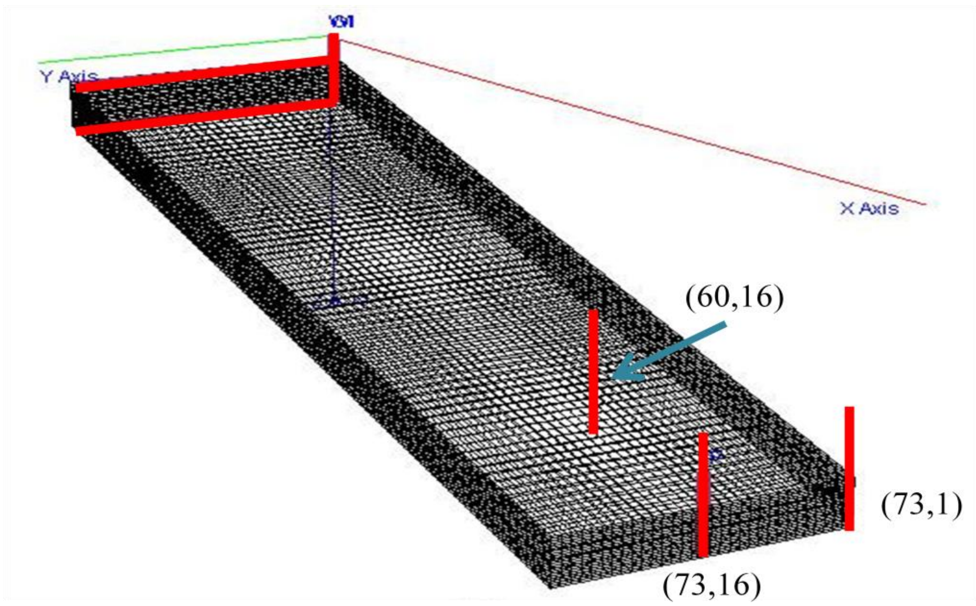


Figure 5.44 Well placements for three different locations of production well

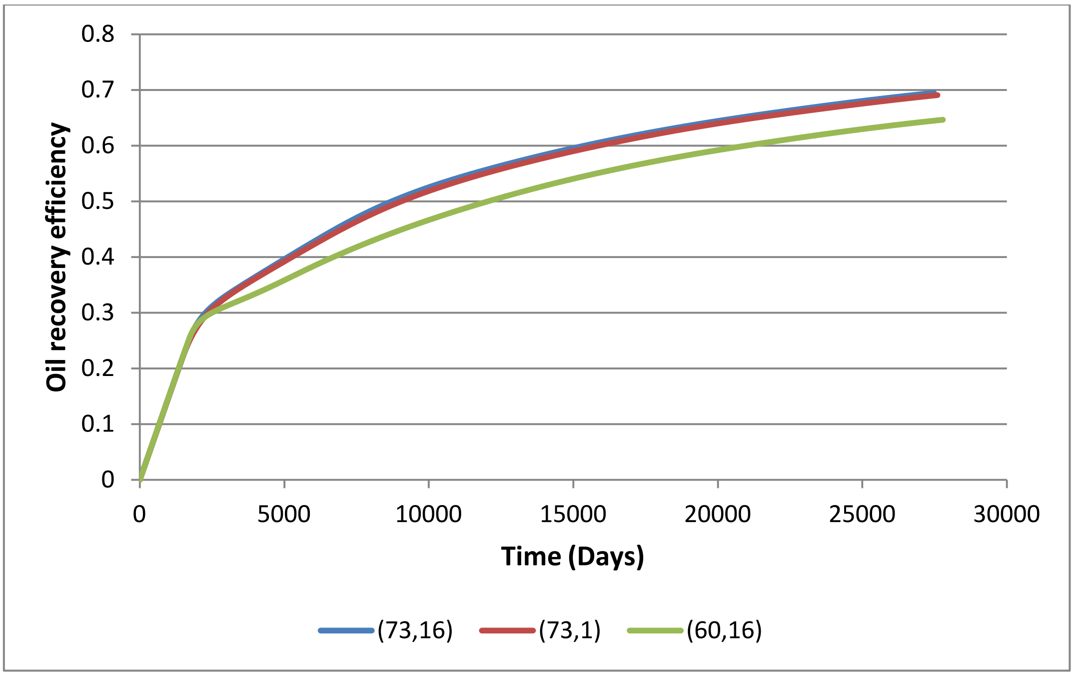


Figure 5.45 Oil recovery efficiency for different producer locations

Table 5.12 Summary of cumulative oil production, oil recovery efficiency and production time for different producer locations at the end of production

Producer location	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
(73,16)	12.933	0.694	75
(73,1)	12.862	0.691	76
(60,16)	12.059	0.647	77

Table 5.13 Summary of cumulative oil production, oil recovery efficiency and production time for different producer locations at 40 years of concession

Producer location	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
(73,16)	11.007	0.591	40
(73,1)	10.904	0.585	40
(60,16)	9.975	0.536	40

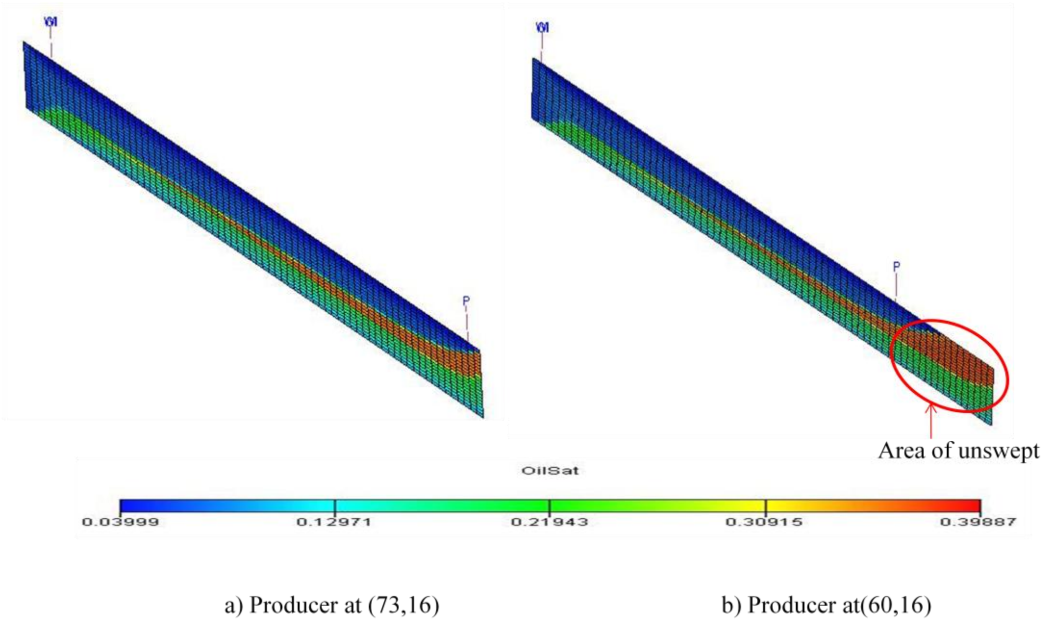


Figure 5.46 Comparison of oil saturation profile between producer location of (73,16) and (60,16) at 40 years of production

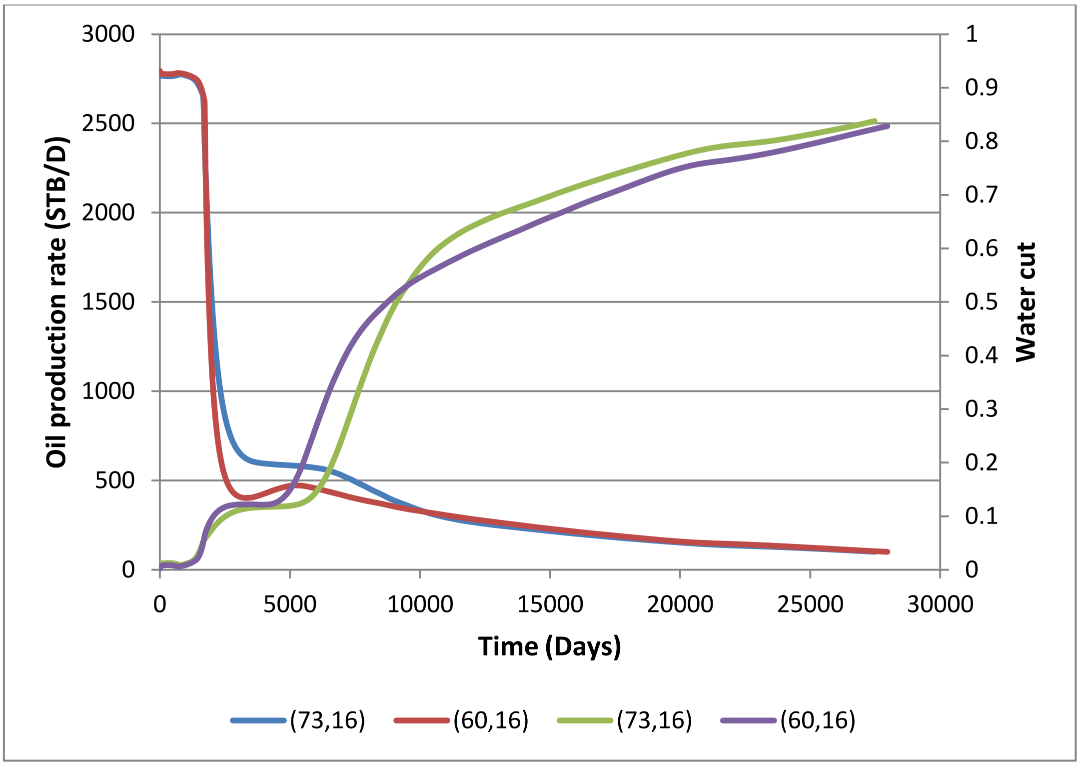


Figure 5.47 Oil production rate and water cut of producer location at (73,16) and (60,16)

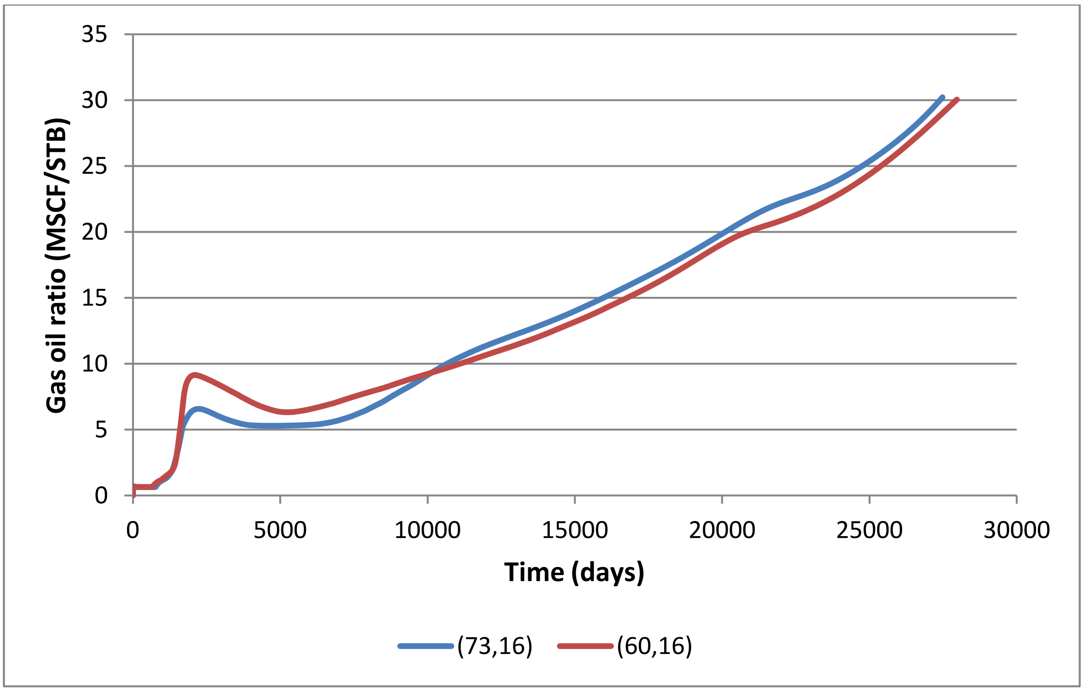


Figure 5.48 Gas oil ratio of producer location at (73,16) and (60,16)

5.3.5 Effect of horizontal injector length

The lengths of both water and gas injectors are studied with three different values, i.e., 645.2, 1290.3 and 2000.0 feet with the same originating point in the horizontal section. These three values equal to the lengths of 10, 20, and 31 gridblocks in the *y*-axis, respectively. First, the length of water injector is varied while keeping gas injector length at full penetration. Figure 5.49 illustrates oil recovery efficiency for different water injector lengths, and the result is summarized in Table 5.14. Table 5.15 shows summary of oil production at 40 years of concession. The oil recovery seems to increase for a longer length of water injector; however, the amount of incremental oil is not much. The production times for all cases are more or less the same except the case of longer injector. Figure 5.50 and Figure 5.51 illustrates gas and water production rate, respectively. We can see from the figures that gas production profiles for all water injector lengths are the same but water production profile indicates that water breaks through slightly earlier for the case of shorter length.

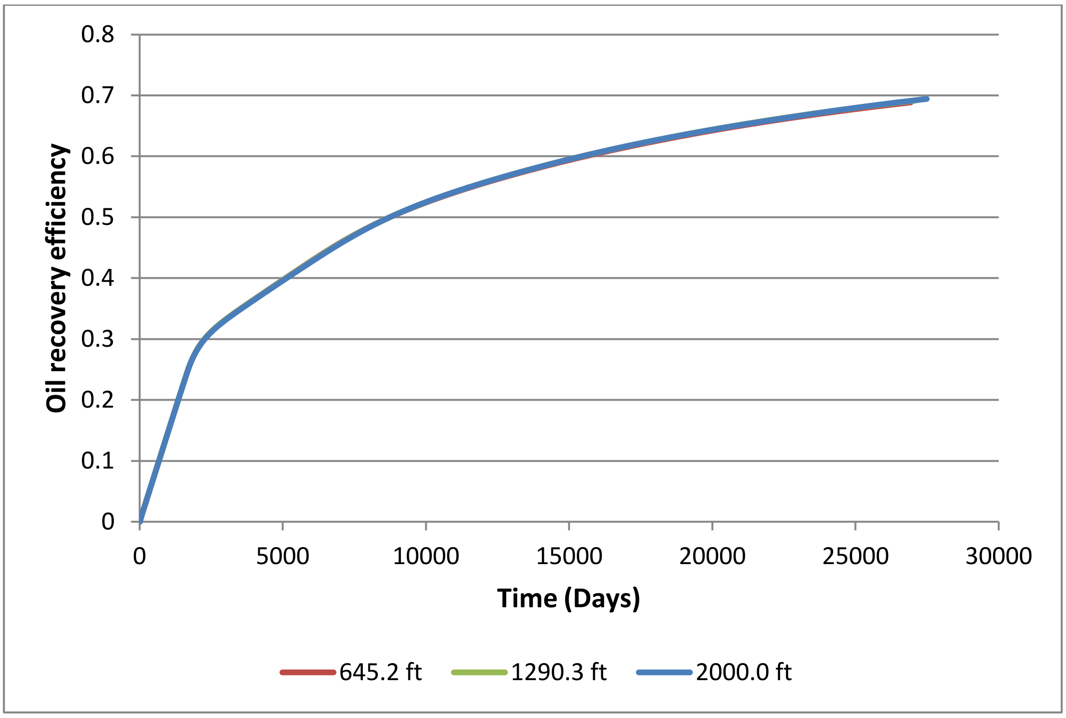


Figure 5.49 Oil recovery efficiency for different water injector lengths

Table 5.14 Summary of cumulative oil production, oil recovery efficiency and production time for different water injector lengths at the end of production

Water injector length (feet)	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
645.2	12.827	0.689	74
1290.3	12.878	0.691	74
2000.0	12.933	0.694	75

Table 5.15 Summary of cumulative oil production, oil recovery efficiency and production time for different water injector lengths at 40 years of concession

Water injector length (feet)	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
645.2	10.977	0.589	40
1290.3	10.993	0.590	40
2000.0	11.007	0.591	40

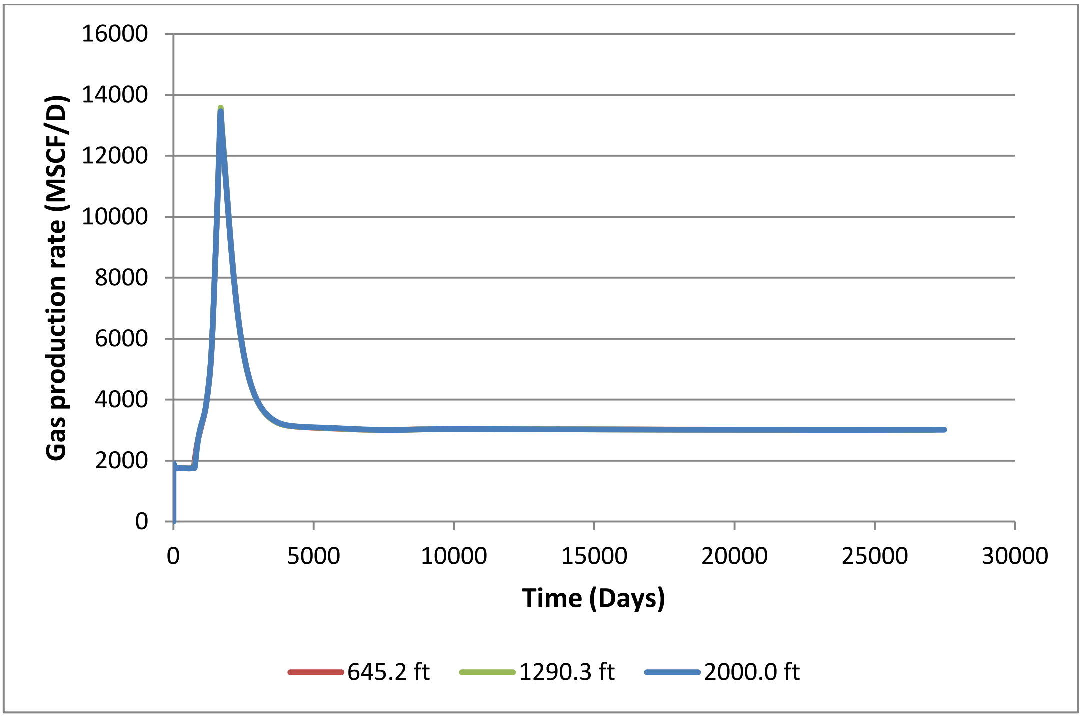


Figure 5.50 Gas production rate for different water injector lengths

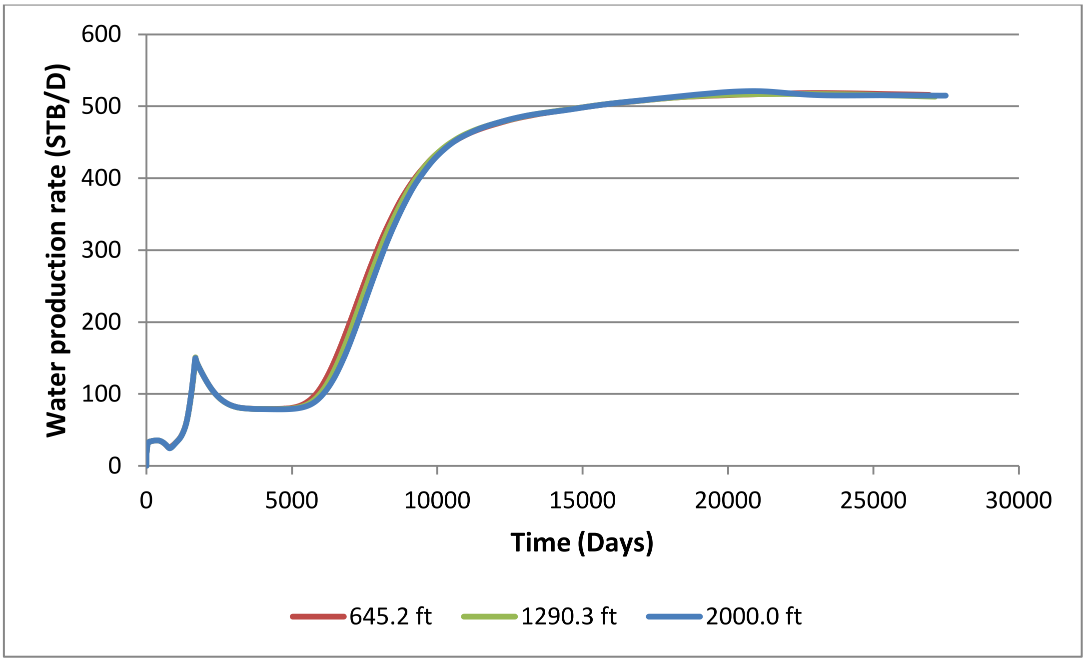


Figure 5.51 Water production rate for different water injector lengths

A similar study is performed for gas injector length by varying three different values, i.e., 645.2, 1290.3 and 2000.0 feet with the same originating point in the horizontal section and keeping water injector length at full penetration.

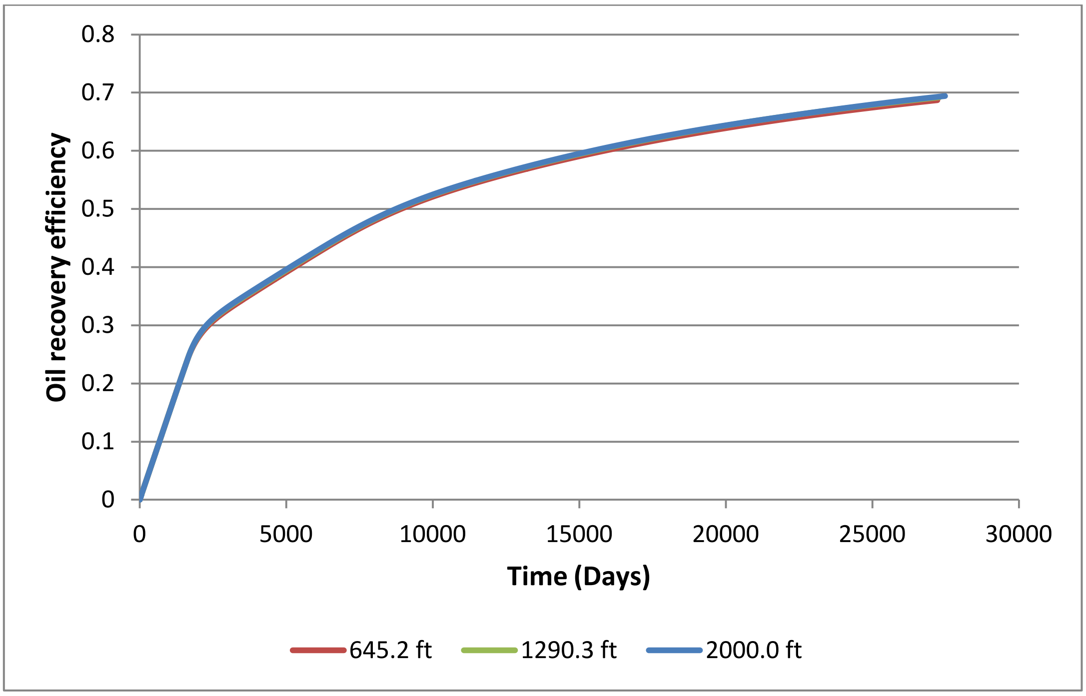


Figure 5.52 Oil recovery efficiency for different water injector lengths

Table 5.16 Summary of cumulative oil production, oil recovery efficiency and production time for different gas injector lengths at the end of production

Gas injector length (feet)	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
645.2	12.799	0.687	75
1290.3	12.891	0.692	75
2000.0	12.933	0.694	75

Table 5.17 Summary of cumulative oil production, oil recovery efficiency and production time for different gas injector lengths at 40 years of concession

Gas injector length (feet)	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
645.2	10.920	0.586	40
1290.3	10.987	0.590	40
2000.0	11.007	0.591	40

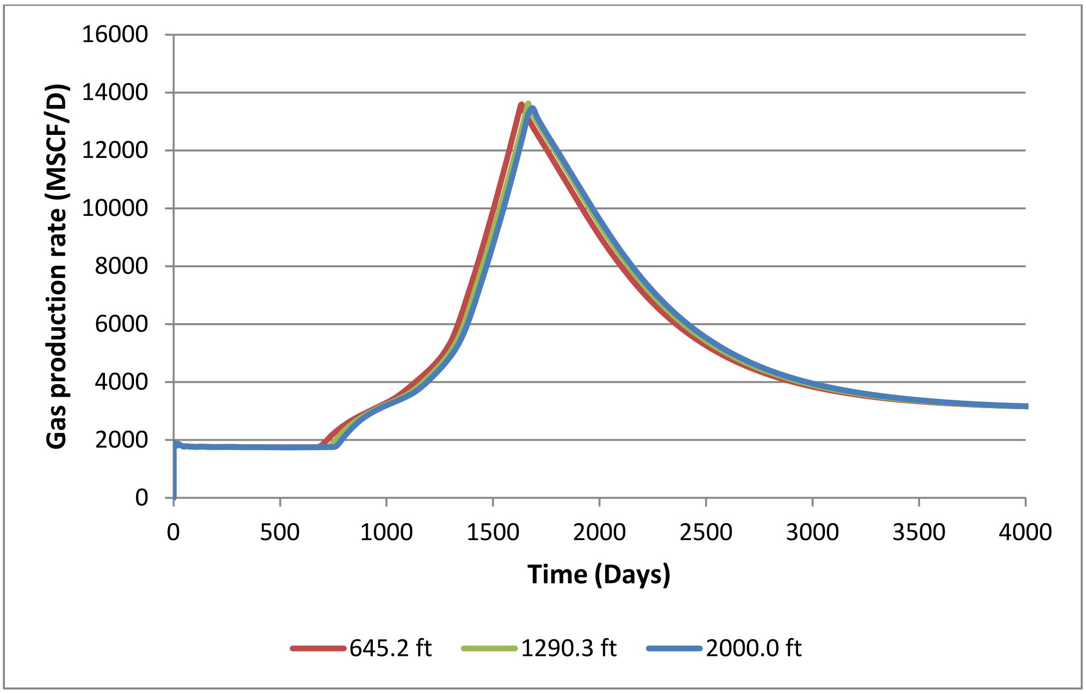


Figure 5.53 Gas production rate within 4000 days of production for different water injector lengths

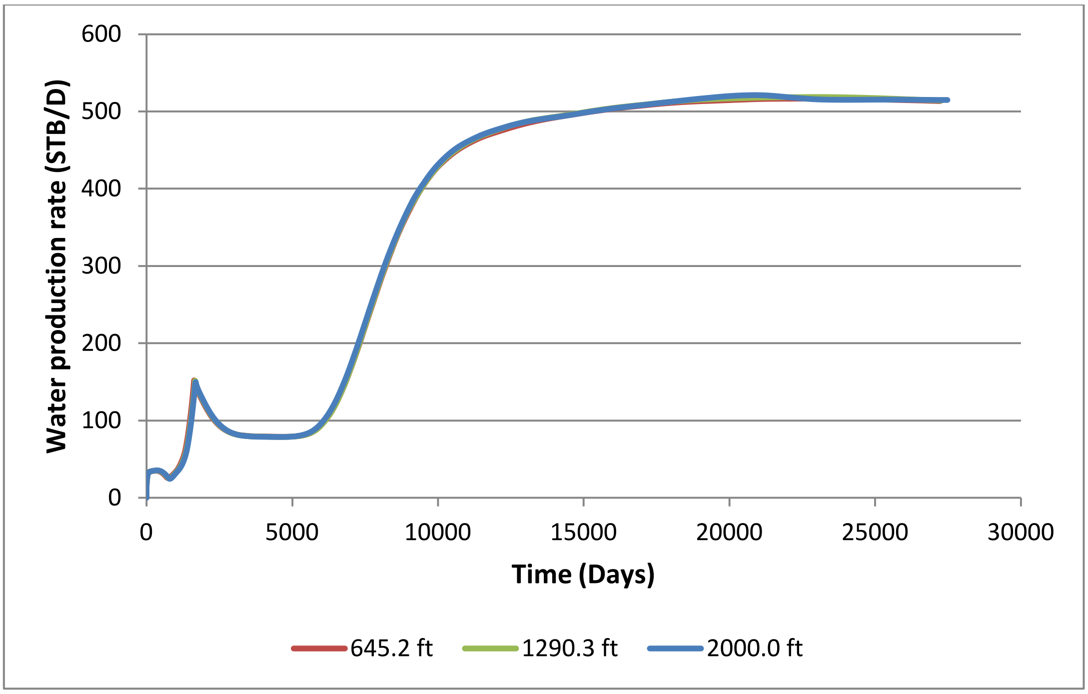


Figure 5.54 Water production for different water injector lengths

The simulation results show that there is a slight increase in oil recovery when the length of the gas injector increases and the durations of production time are the same. Gas production rates for different water injector lengths have similar pattern as the ones shown in Figure 5.50. However, when we focus its behavior around the breakthrough period as illustrated in Figure 5.53, it is clearly seen that earlier gas breakthrough occurs for shorter gas injector length. Figure 5.54 shows water production for different water injector lengths which are more or less the same.

5.3.6 Effect of perforated heights of vertical producer

The effect of producer length is considered in this section by comparing three cases having different producer lengths. For the first, second and third case, the producer length is 50, 100 and 210 feet, respectively. Figure 5.55 shows oil recovery efficiency for different perforated intervals. Results from all cases are summarized in Table 5.18. It can be seen from the table that when a shorter interval is perforated, a slightly higher oil recovery is achieved. This is because shorter perforated interval allows less amount of water to flow into the well. Thus, water load-up is minimized and oil recovery is improved.

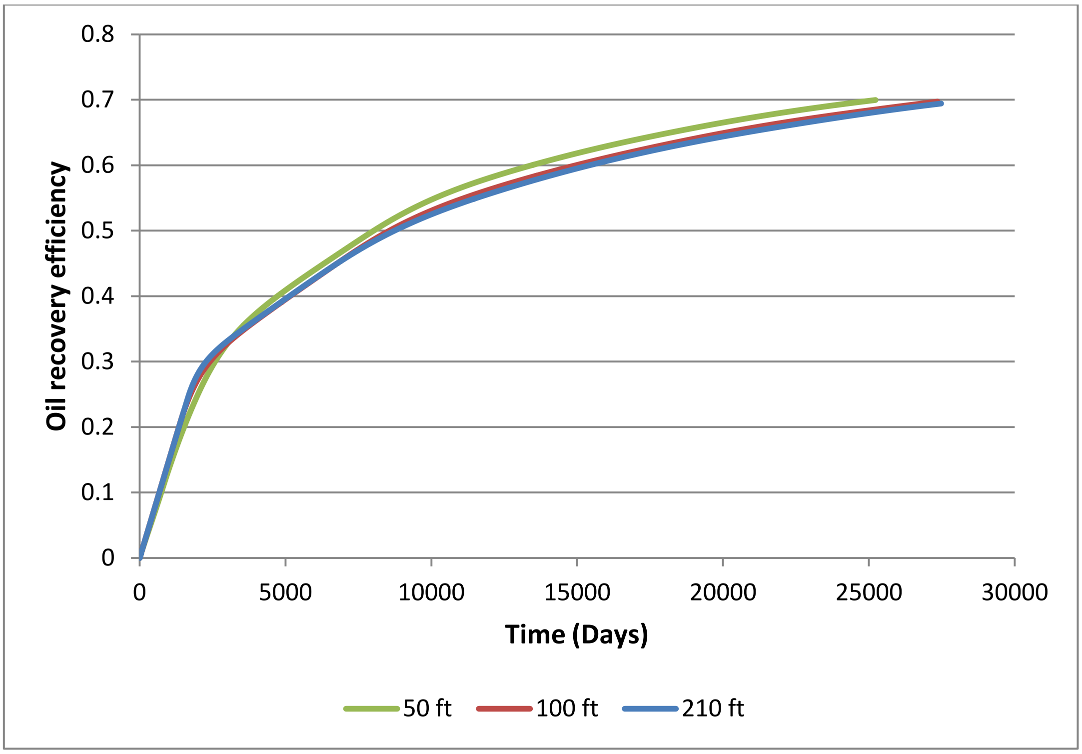


Figure 5.55 Oil recovery efficiency for different heights of vertical producer

Figure 5.56 and Figure 5.57 represent oil and water production rate, respectively. As observed from these two figures, for the case that only the top five layers are perforated, the oil production rate cannot reach the defined plateau production rate. However, it produces at a higher rate when compared with other cases for most of the times due to lower water production rate (see Figure 5.57).

Additionally, water breakthrough is significantly delayed in case of short perforated interval since water needs to travel upward for longer distance to reach to the bottom of the perforated interval. In term of gas-oil ratio, a well with shorter perforated interval reaches the GOR limit of 30 MSCF/STB faster as shown in Figure 5.58 due to lower oil production rate and higher gas production rate at late time. As a result, the production time is shorter.

Table 5.18 Summary of cumulative oil production, oil recovery efficiency and production time for different producer heights at the end of production

Producer height (feet)	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
50	13.026	0.699	69
100	12.988	0.697	75
210	12.933	0.694	75

Table 5.19 Summary of cumulative oil production, oil recovery efficiency and production time for different producer heights at 40 years of concession

Producer height (feet)	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
50	11.432	0.614	40
100	11.104	0.596	40
210	11.007	0.591	40

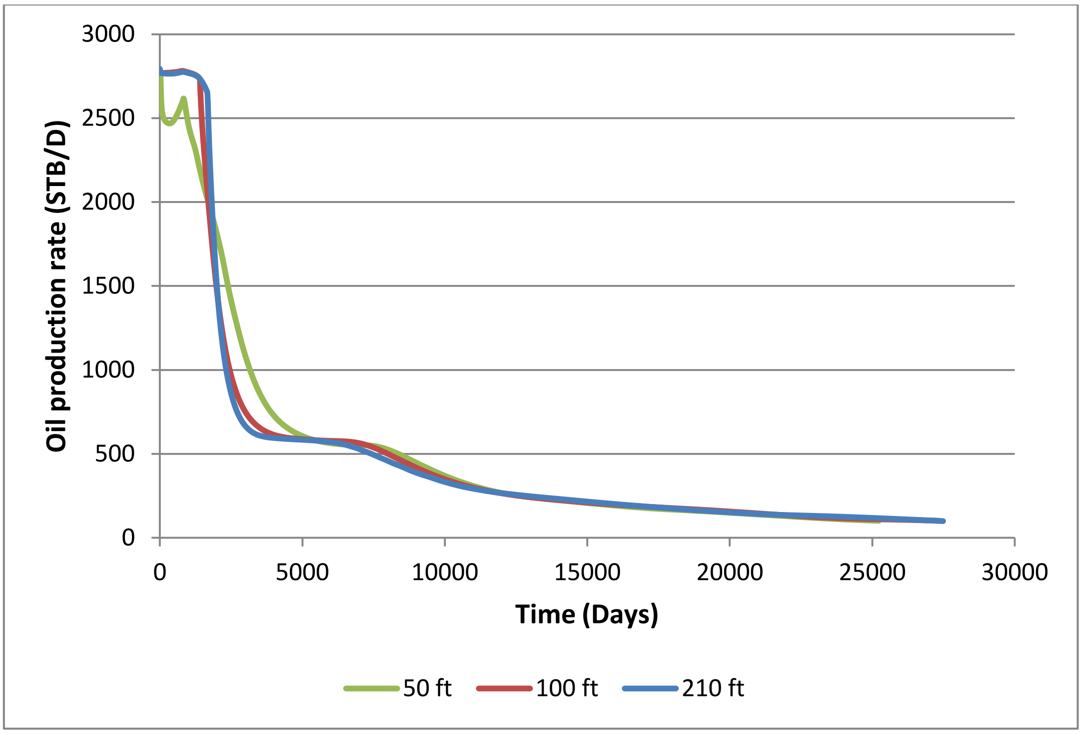


Figure 5.56 Oil production rate for different heights of vertical producer

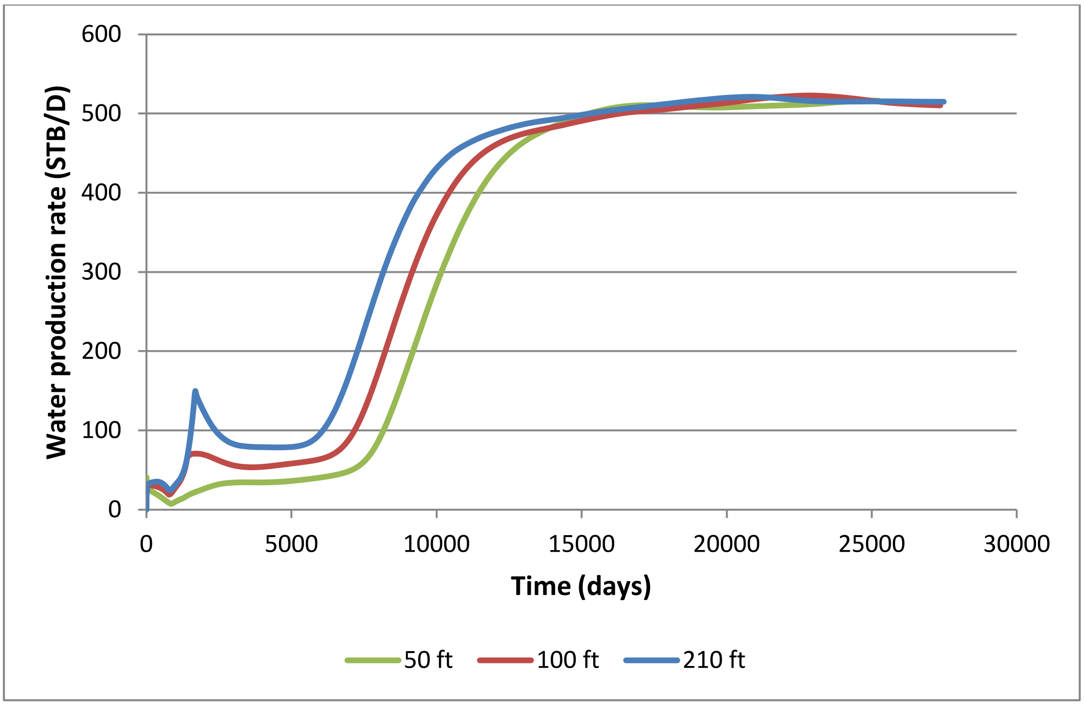


Figure 5.57 Water production rate for different heights of vertical producer

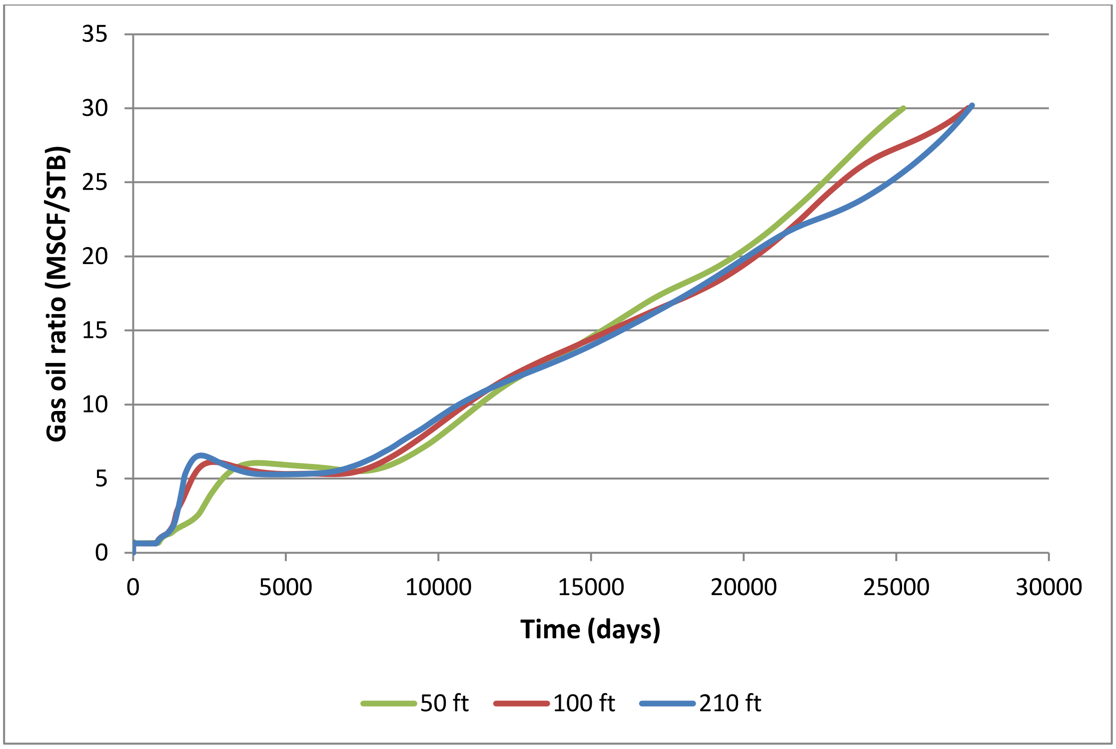


Figure 5.58 Gas oil ratio for different heights of vertical producer

5.3.7 Down-dip SSWAG injection

Earlier, gas and water injectors are placed on the up-dip side of the reservoir and inject fluid to sweep oil down to the producer. In this section, the position of injectors and producer are switched around. Gas and water are injected down the structure toward the producer on the up-dip side. 3000 MSCF/D and 500 STB/D of gas and water injection rates are selected equally with the up-dip injection case in order to be able to compare the results. It turns out that down-dip injection case has considerably poorer performance than up-dip injection as seen from oil recovery factor plot in Figure 5.59. Due to its low density, gas tends to flow to the top part of the reservoir toward the production well that is situated on the up structure and accumulates on the top structure. Thus, it bypasses most area of the reservoir. This area left untouched by gas, will be swept by water instead. As stated earlier that water yields poor displacement efficiency as it leaves more residual oil in the reservoir, the performance of down-dip injection is not efficient. If compared with up-dip injection, gravity force helps delay flow of gas toward the producer as well as pulls gas upward and allow gas chamber to grow bigger and sweep more area. This phenomenon is shown in Figure 5.60.

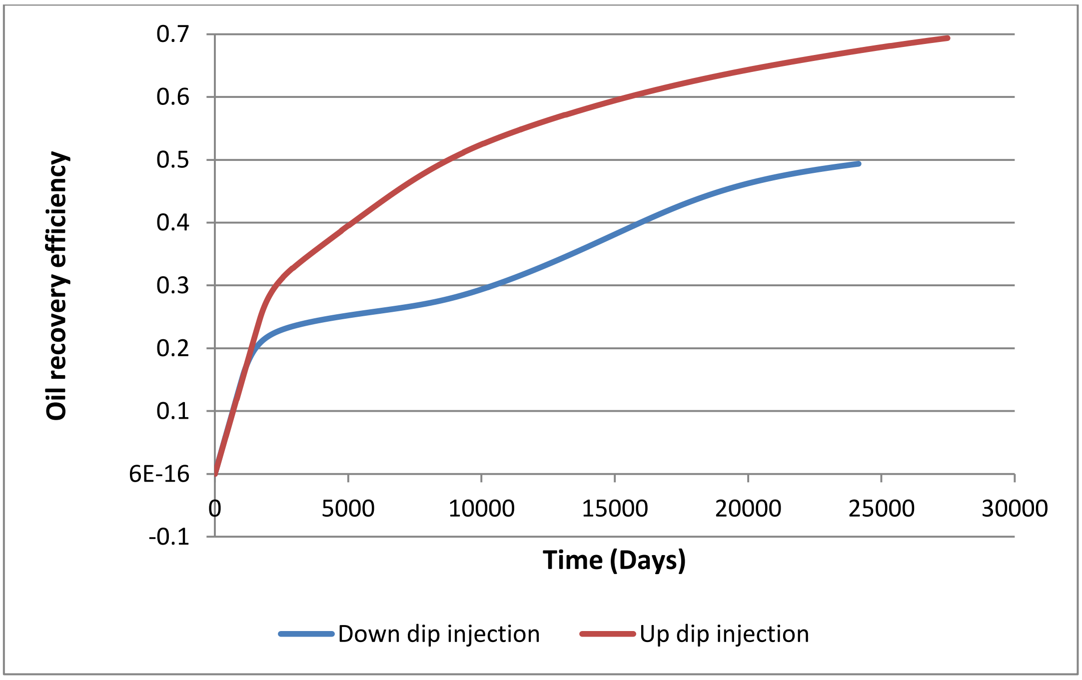
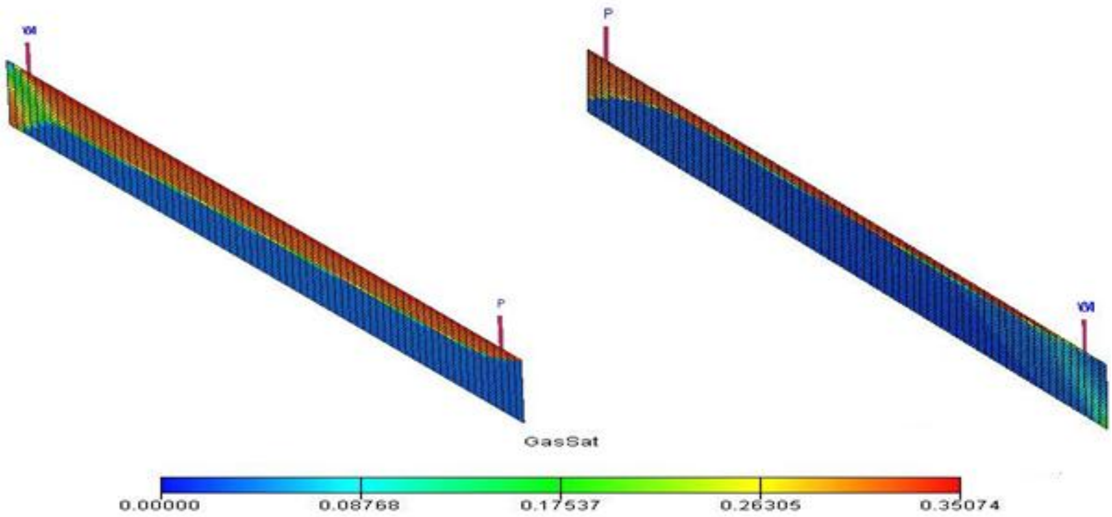


Figure 5.59 Oil recovery efficiency of up-dip and down-dip SSWAG injection



b) Up-dip injection a) Down-dip injection

Figure 5.60 Comparison of gas saturation profile between down-dip and up-dip SSWAG injection

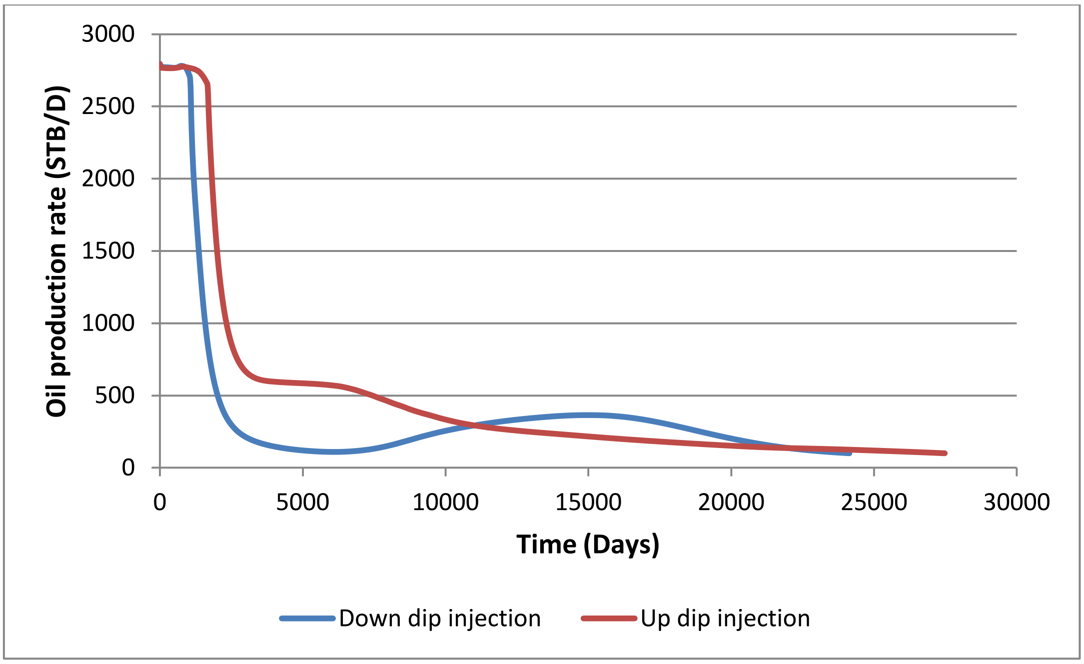


Figure 5.61 Oil production rate of up-dip and down-dip SSWAG injection

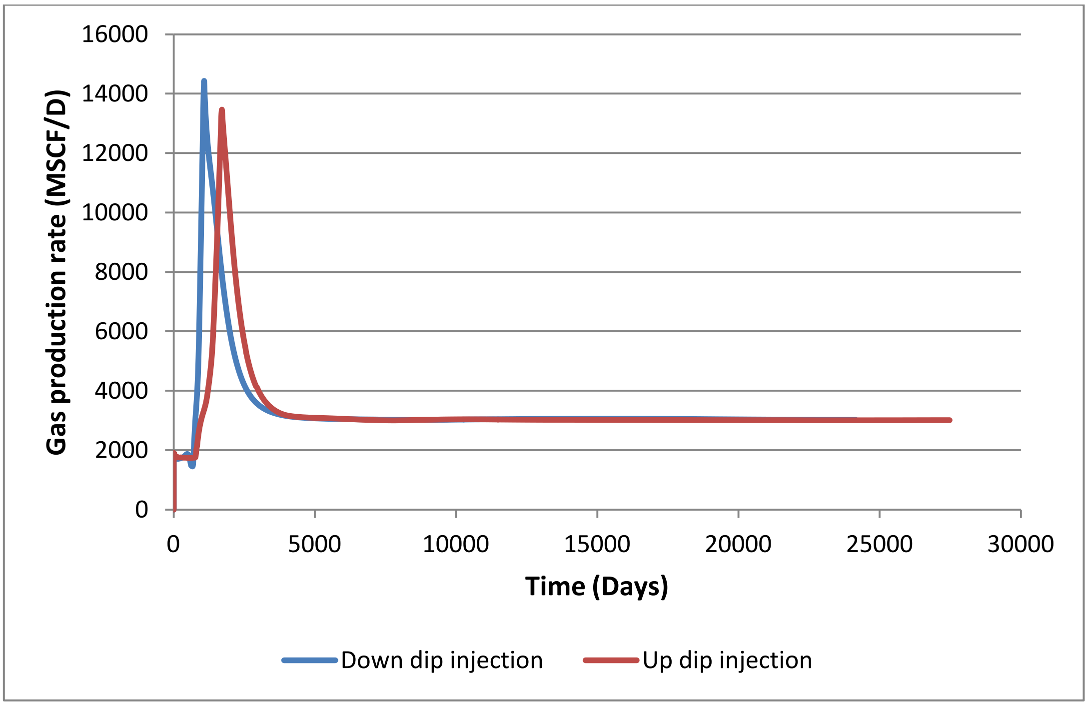


Figure 5.62 Gas production rate of up-dip and down-dip SSWAG injection

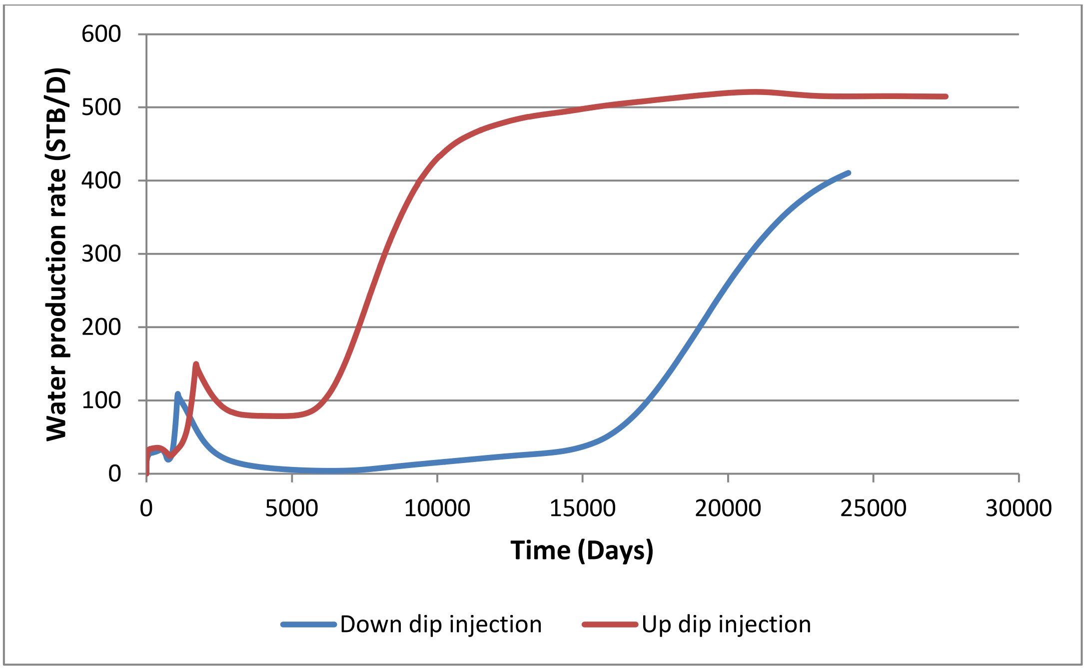


Figure 5.63 Water production of up-dip and down-dip SSWAG injection

Oil, gas and water production rates are shown in Figure 5.61, Figure 5.62 and Figure 5.63, respectively. As observed from these figures that the reservoir depletes faster for down-dip than up-dip injection case. Water breakthrough occurs considerably later for down-dip injection case as gravity force is dominant and pulls water back down. Thus, water travel slower toward the producer. Gas breakthrough also occurs later for up-dip injection case. However, the performance of down-dip injection method presented in this section will be different for other sets of input parameters which can make result different from this study.

5.3.8 Summary of effect of different design parameters on SSWAG

Each design parameter affects oil production performance in different ways as summarized below:

- Injection rate has significant effect on oil recovery. Higher gas injection rate with lower water injection rate yields better oil recovery. This setting allows gas to sweep a larger area of the reservoir; thus, less amount of oil remains in the reservoir.
- If injection pressure can be controlled constantly, oil producing under constant injection pressure yields better oil recovery than constant injection rate. At higher injection pressure, gas injection rate is significantly higher and segregation length is longer. Thus, better oil recovery is achieved. However, there are some drawbacks of using high injection pressure as production time is shortened and ultimate oil recovery is reduced. Additionally, a bigger capacity of gas processing facility is required to accommodate for high amount of produced gas.
- Locations of water and gas injectors have minimal effect on oil recovery.
- Lengths of water and gas injectors also have minimal effect on oil recovery.
- Shorter producer length results in better oil recovery as it can delay water breakthrough and limit the amount of water flowing into the wellbore. Thus, more oil is allowed to be recovered.
- Production well should be placed at the deepest depth at the most downdip location as it maximizes volumetric sweep efficiency as well as delays the breakthrough of water.
- Down-dip injection is not efficient when compared with up-dip injection due to the fact that gas bypasses most area of the reservoir and flows directly toward the producer. As a result, oil recovery performance is poor.

5.4 Gas Assisted Gravity Drainage base case

The base case simulation results for GAGD method are presented in this section in order to study the response of the technique. Well placement of GAGD base case is illustrated in Figure 5.64. A vertical gas injector is placed at up-dip side of the reservoir at coordinate (1, 15) with full perforation interval and a horizontal producer is located at the most down-dip of the reservoir which is along the *y*-axis at *z*-layer 21 (bottommost layer). Similar to SSWAG, the process of gas injection is started from the first day of production. The maximum gas injection rate is 1000 MSCF/D. Gas is injected at this rate as long as the maximum fracture pressure of 4500 psia is not exceeded. The maximum liquid production rate is 1000 STB/D with minimum bottom hole pressure of 500 psia.

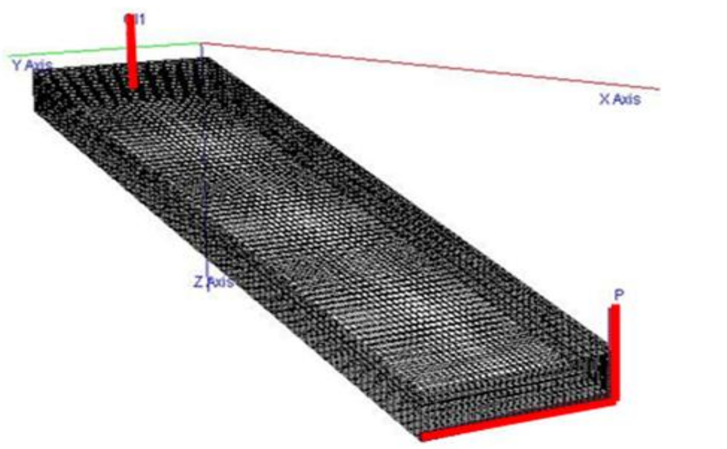


Figure 5.64 Well placement of GAGD base case

Figure 5.65 illustrates cumulative oil production which results in oil recovery efficiency at 77.93% of oil-in-place volume after 100 years of production. Oil and gas production rates are depicted in Figure 5.66. As shown in the oil production plot, at early time, oil production rate is at the maximum rate of 1000 STB/D until the reservoir pressure depletes. Then, the oil rate starts to decrease. Gas starts breaking through the producer after 20 years of production which is significantly longer than stand-alone gas injection in Section 5.1 and SSWAG in Section 5.2 as the horizontal producer is laid at the most down dip of the strata. Gas production decreases once the oil production rate decreases. Figure 5.67 and Figure 5.68 depict field gas oil ratio and water cut, respectively. In this case, water production is coming from expansion of connate water contained in the reservoir only. Thus, the water cut is very small amount. Water load-up is not a problem.

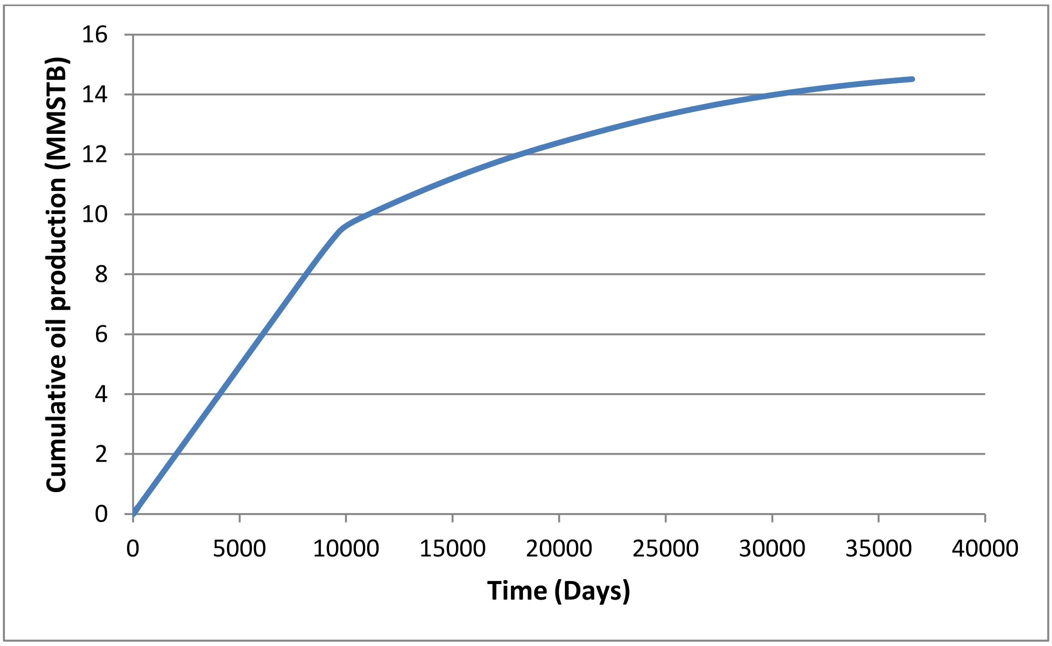


Figure 5.65 Cumulative oil production of GAGD base case

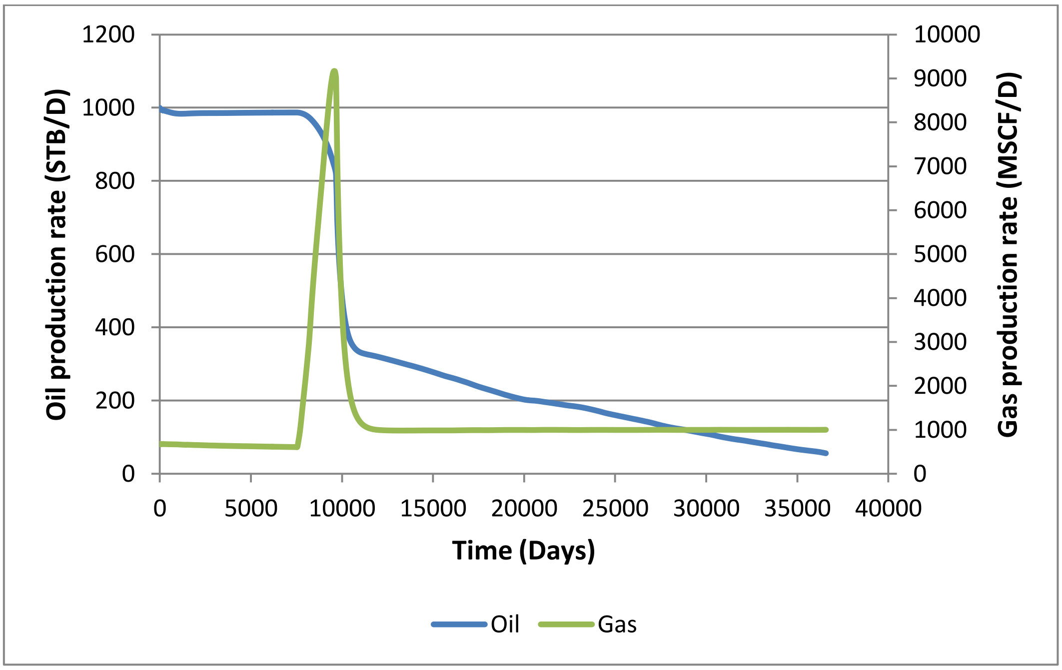


Figure 5.66 Oil and gas production rate of GAGD base case

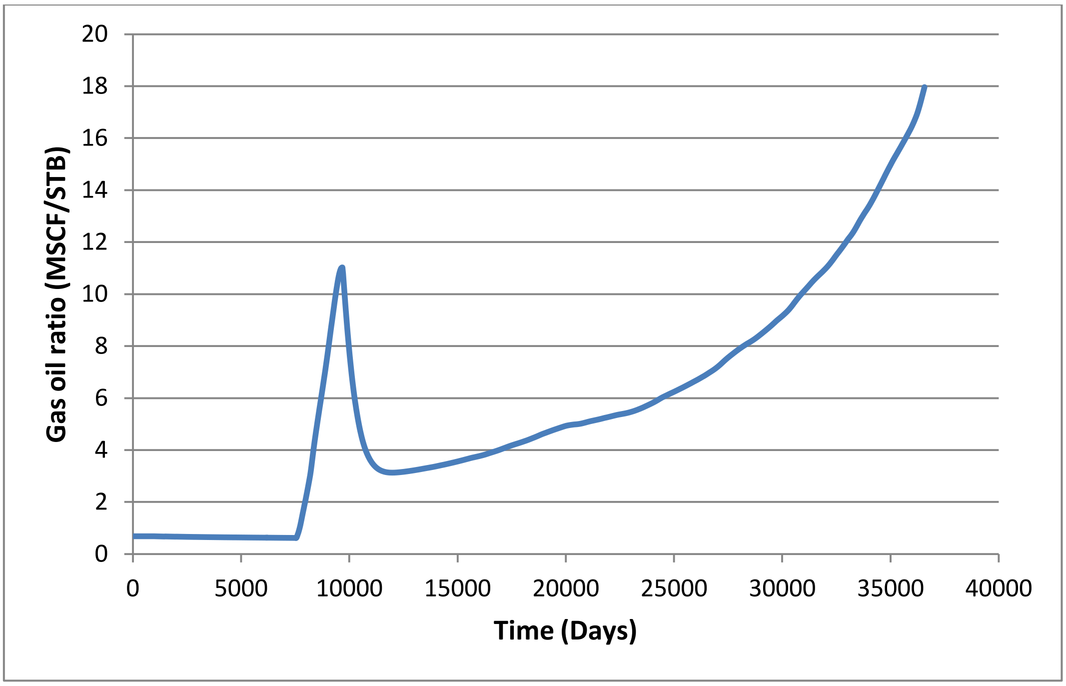


Figure 5.67 Gas oil ratio of GAGD base case

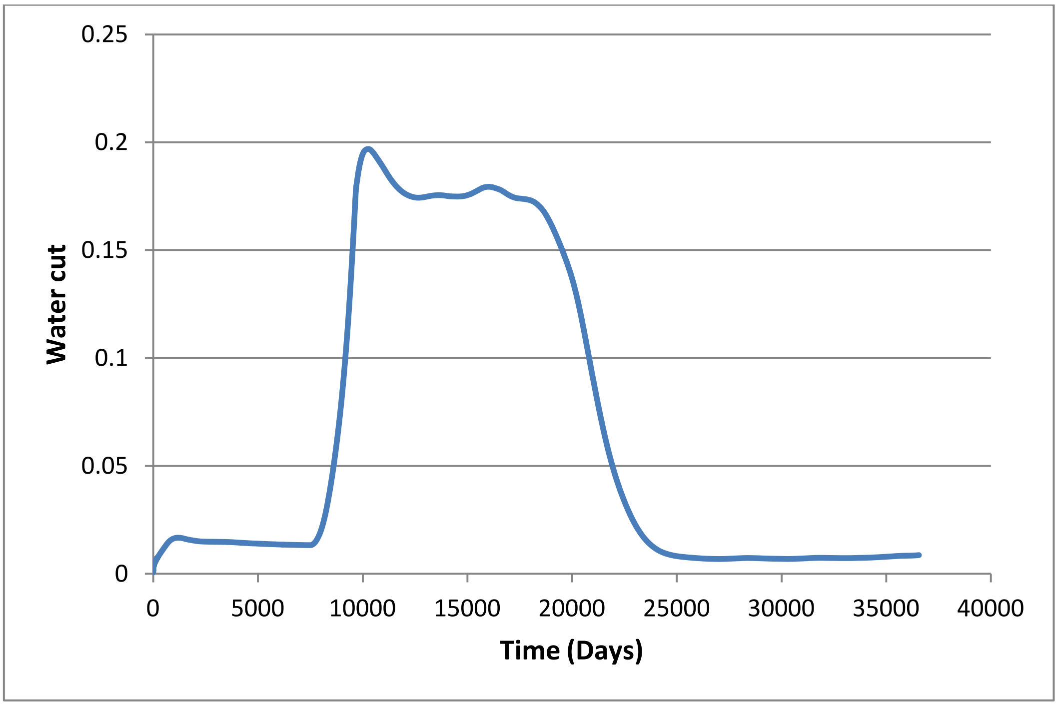


Figure 5.68 Water cut of GAGD base case

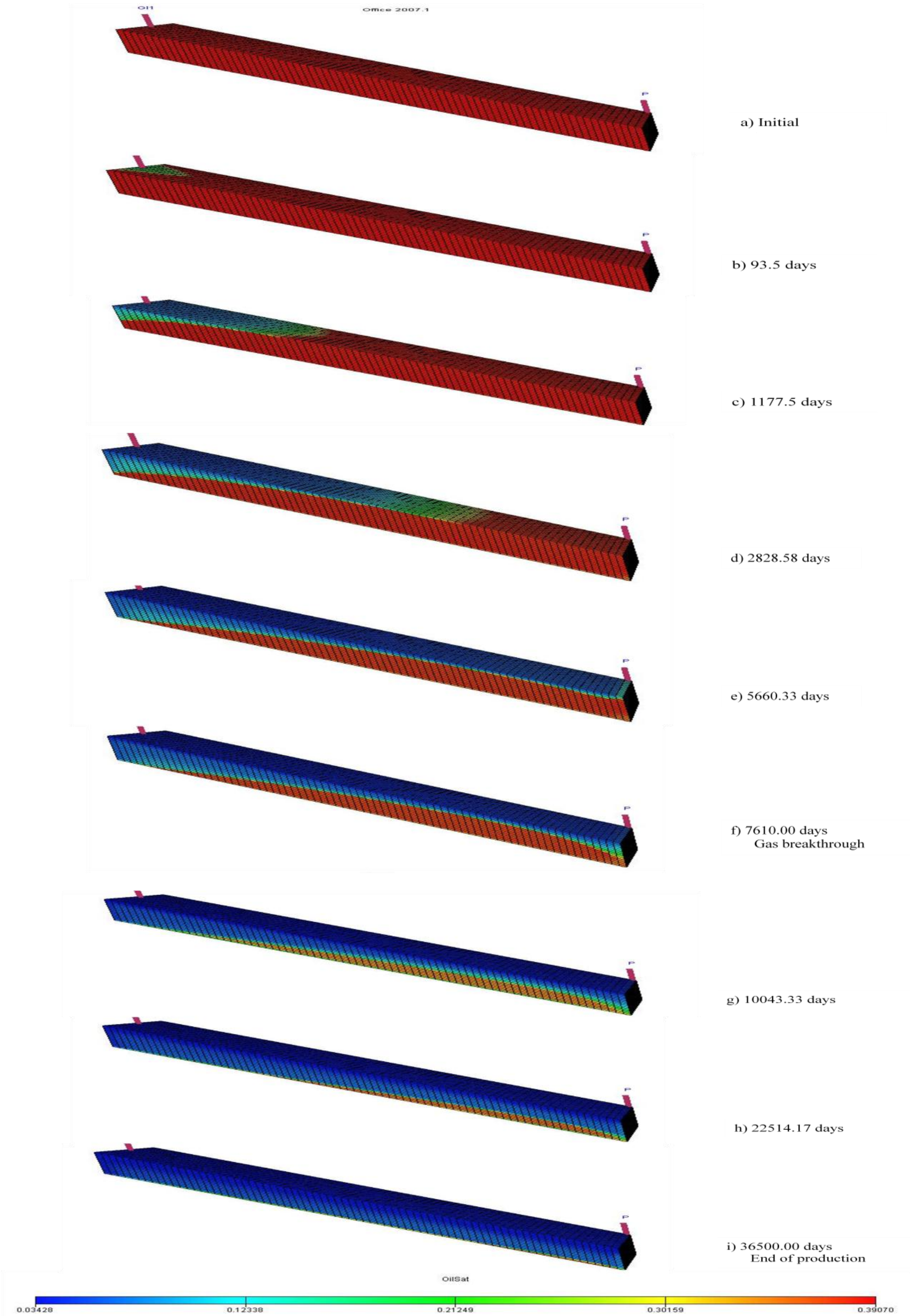


Figure 5.69 Oil saturation distribution of GAGD base case

The detail of GAGD sweeping mechanism in terms of oil saturation distribution can be visualized in Figure 5.69 (a) to (i). As gas is continuously injected into the reservoir, gas chamber is formed at the up-dip part of the formation. Because gas has lower density and low mobility than oil, gas tends to flow upward to the top part of the formation until reaches the end of the formation as illustrated in Figure 5.69 (c) to (e). Then, gas flows downward towards the horizontal producer and breaks through as illustrated by Figure 5.69 (f). As injection continues, gas chamber continues to grow vertically and diagonally down the structure. Thus, more area of the reservoir is swept by gas. At the end of production as shown in Figure 5.69 (i), most part of the reservoir is well swept with only a small amount of residual oil saturation left. Thus, higher oil recovery is achieved.

5.5 Effect of different design parameters on GAGD

In this topic, different sets of design parameters are studied to quantify the effect on production performance of GAGD method. These include

- gas injection rate
- perforation interval of vertical injectors
- location and number of gas injector
- length and location of horizontal producer

5.5.1 Effect of gas injection rate

Four different values of injection rate are selected for this study 1000, 2500, 3500 and 5000 MSCF/D. Figure 5.70 shows result of oil recovery efficiency for different values of gas injection rate. As gas injection rate increases, more oil can be recovered. Eventhough the curve for oil recovery efficiency for high injection rate is always above that for low injection rate, its production period is shorter due to early gas breakthrough and GOR constraint of 30 MSCF/STB. The summary of cumulative oil production, oil recovery efficiency and production time for different gas injection rates can be found in Table 5.20 and summary at 40 years of concession is shown in Table 5.21. We can see from the table that oil recovery at high injection rate is smaller at the end of production period because of shorter production time.

Table 5.20 Summary of cumulative oil production, oil recovery efficiency and production time for different gas injector rates at the end of production

Gas injection rate (MSCF/D)	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
1000	14.516	0.779	100
2500	14.266	0.766	76
3500	14.009	0.752	63
5000	13.574	0.729	50

Table 5.21 Summary of cumulative oil production, oil recovery efficiency and production time for different gas injector rates at 40 years of concession

Gas injection rate (MSCF/D)	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
1000	11.096	0.596	40
2500	11.959	0.642	40
3500	12.381	0.665	40
5000	12.813	0.688	40

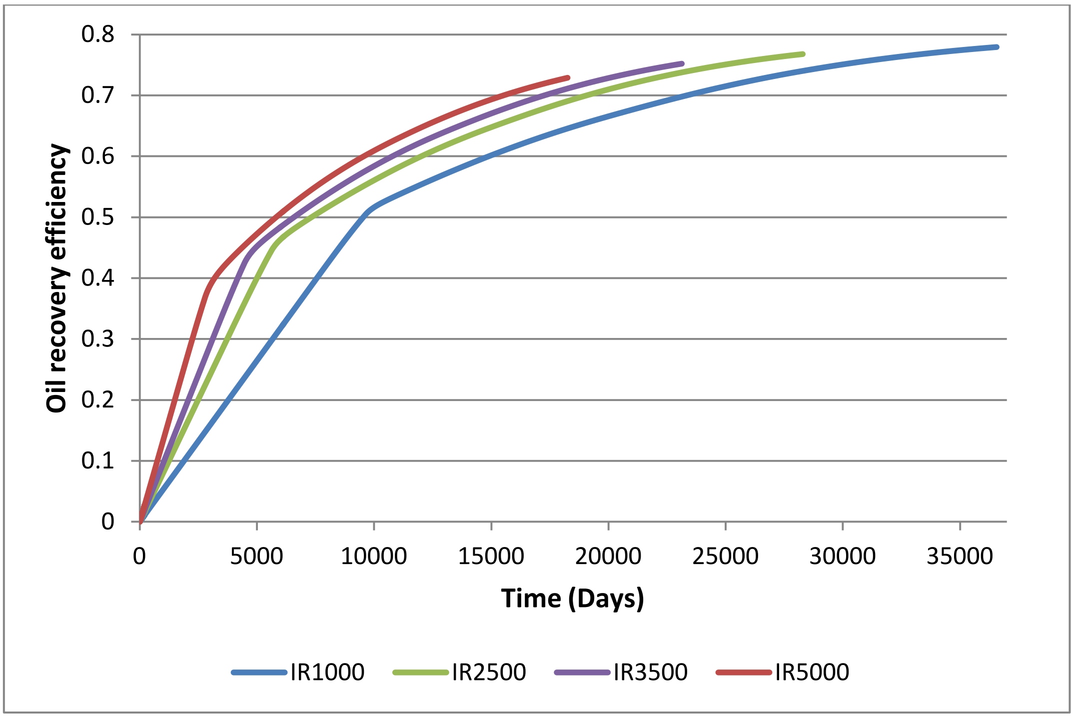


Figure 5.70 Oil recovery efficiency for different gas injection rates

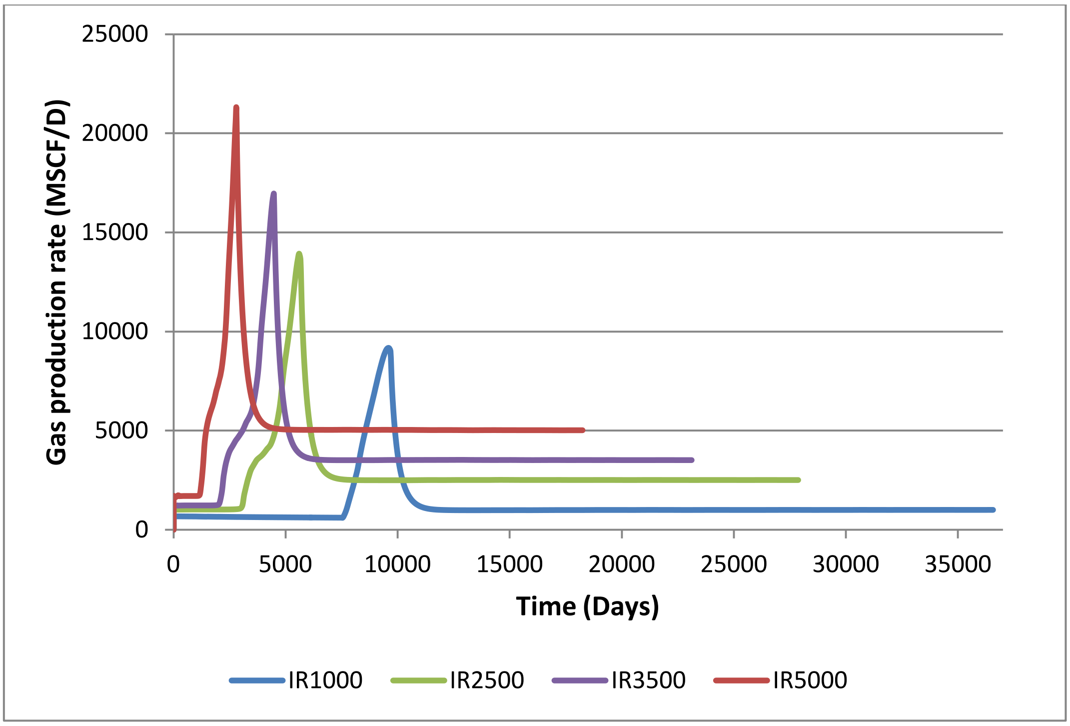


Figure 5.71 Gas production rate for different gas injection rates

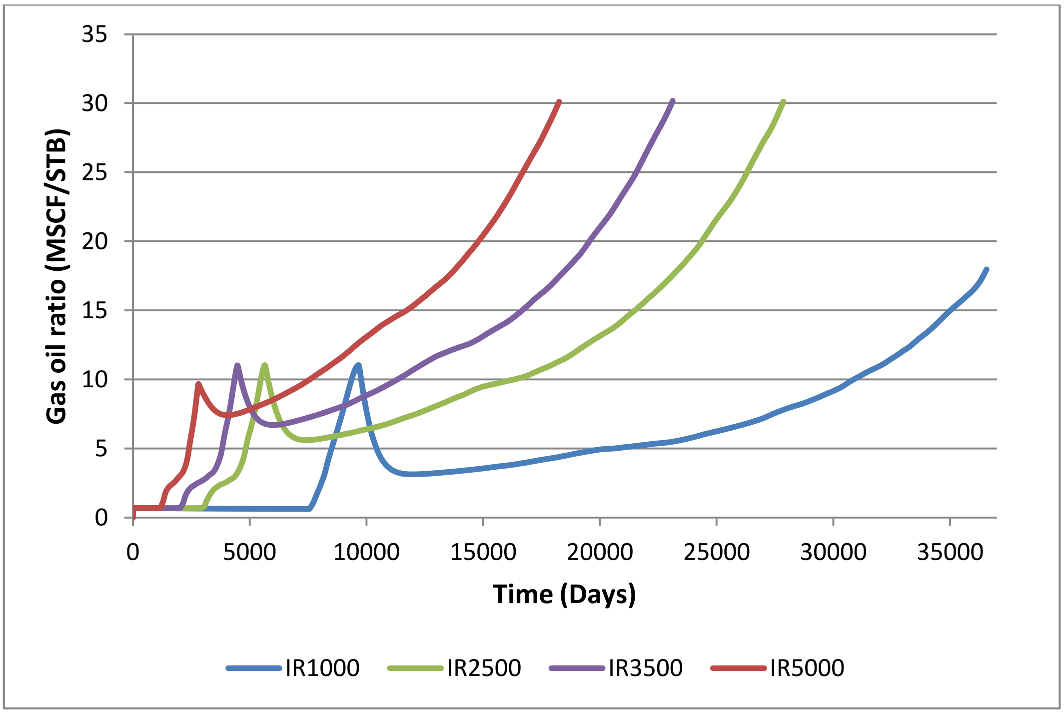


Figure 5.72 Gas oil ratio for different gas injection rates

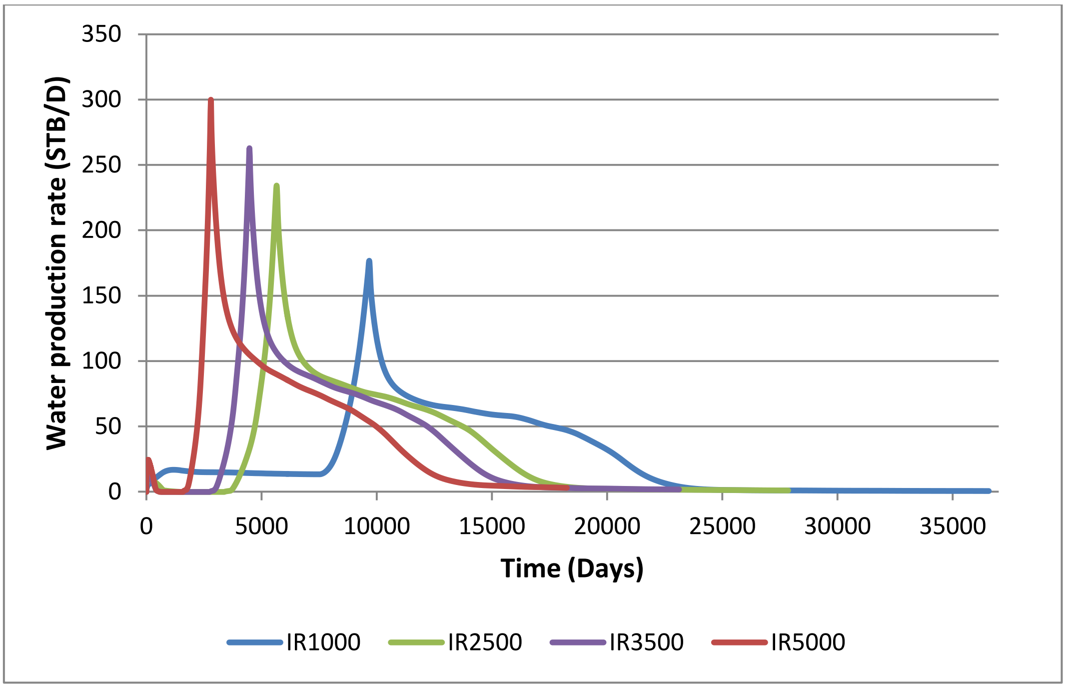


Figure 5.73 Water production rate for different gas injection rates

Gas production rate and gas oil ratio comparisons are shown in Figure 5.71 and Figure 5.72, respectively. It is clearly seen from the figures that, gas breaks through sighnificantly earlier in case of high injection rates. Thus, more amount of produced gas, coming from solution and injection, is obtained. High injection rate not only causes premature gas breakthrough, but it might also cause instability of the flood front according to Equation 3.8 of dimensionless gravity number which is a function of injection rate. The displacement process becomes more unfavourable at high injection rate.

Water production rate is illustrated in Figure 5.73. It can be seen that water production occurs faster for higher gas injection rate. High gas injection rate can accelerate both oil and water production because injected gas sweeps both oil and connate water in the pore space.

5.5.2 Effect of perforation intervals of vertical injectors

In this section, the effect of perforation interval of the vertical injector is studied. Three different partial perforation schemes are used top perforation (grids 1-10), bottom perforation (grids 11-21) and full perforation grid 1-21). The gas injection rate selected for this study is 3500 MSCF/D. Figure 5.74 and Figure 5.75 illustrate oil recovery efficiency and oil production rate for different perforated intervals of the injector, respectively. According to these figures, effect of perforated interval is insignificant to oil production performance. This is because after injection starts, gas immediately flows to the top of formation due to gravity force and sweep oil down-dip as shown in Figure 5.69. Therefore, the depth that gas is being injected out of the injector does not affect the sweeping efficiency as well as oil recovery performance. Note that for a horizontal reservoir with small distance between the injector and producer, the depth that gas flows out of the injector might after the results. Table 5.22 shows almost identical oil production performance for each individual case.

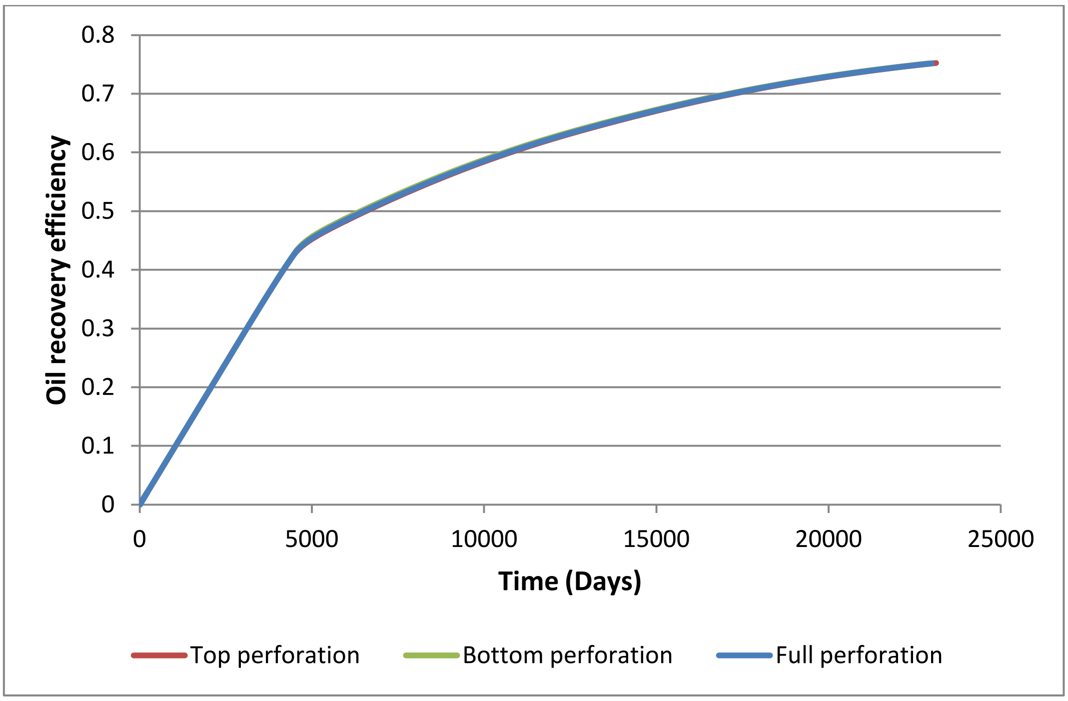


Figure 5.74 Oil recovery efficiency for different perforation intervals of injector

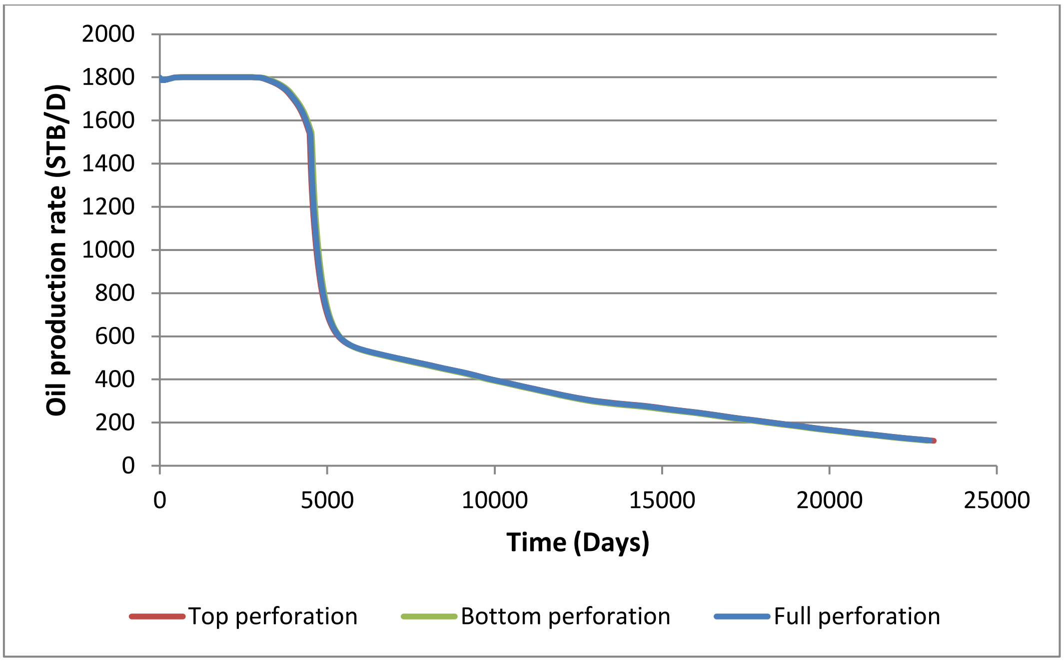


Figure 5.75 Oil production rate for different perforation intervals of injector

Table 5.22 Summary of cumulative oil production, oil recovery efficiency and production time for different perforation intervals of gas injector at the end of production

Perforation interval	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
Top	14.009	0.752	63
Bottom	14.001	0.752	63
Full	14.002	0.752	63

5.5.3 Effect of location of gas injector

In this section, effect of locations of gas injector are investigated by using four different locations, named by (*x*, *y*) grid coordinates as (1,15), (1,1), (10,15) and (20,15). The locations of these four coordinates are illustrated in Figure 5.76. The gas injection rate selected for this study is 3500 MSCF/D. Oil recovery efficiency and oil production rate resulted from different injector locations are shown in Figure 5.77 and Figure 5.78, respectively. An observation obtained from these pictures is that as the injector is moved down-dip towards the producer, oil recovery efficiency is less when considered at the same production time. However, the ultimate recovery is more or less the same for all cases. This means that moving the injector down dip simply delays the recovery of oil. A possible explanation for this is that when the injector is placed furthur down-dip, injected gas tends to flow in both downward and upward directions. Gas flowing upward sweeps the area above the injector. Given enough time, oil segregates to the bottom and flows downward towards the producer. This causes slower oil recovery when compared to other cases. In addition, moving the location of the injector along the *y*-axis does not have much effect on the performance.

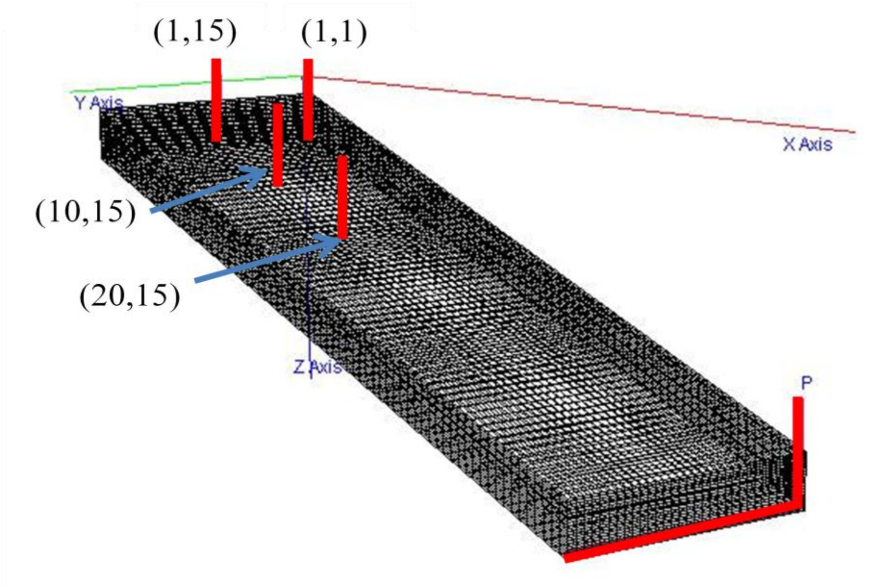


Figure 5.76 Well placements for four different locations of injector well

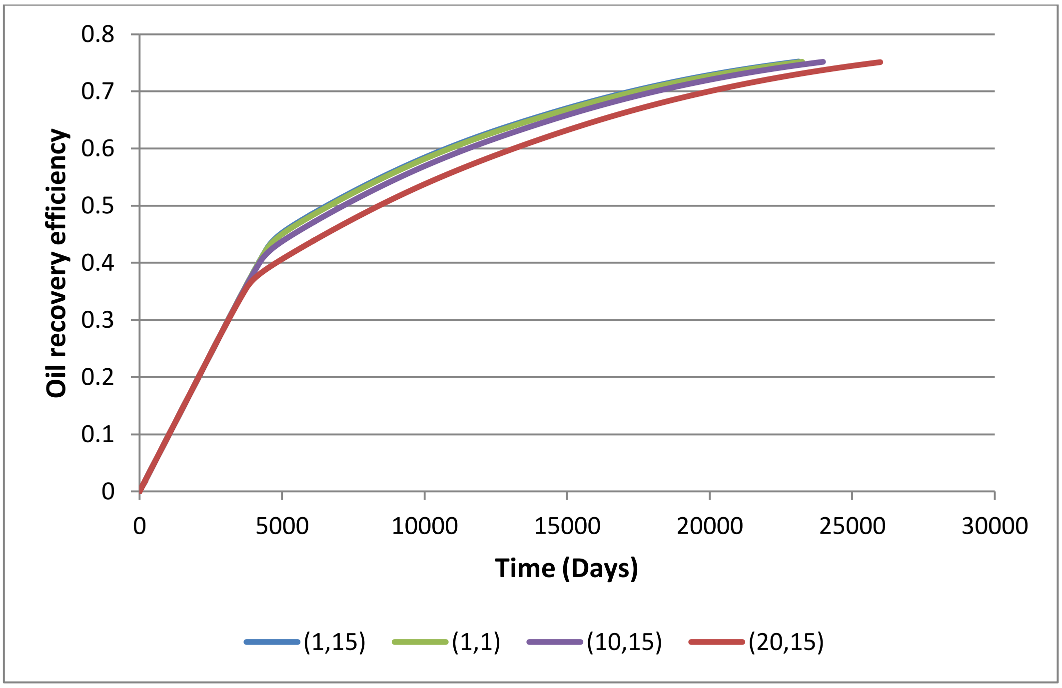


Figure 5.77 Oil recovery efficiency for different injector locations

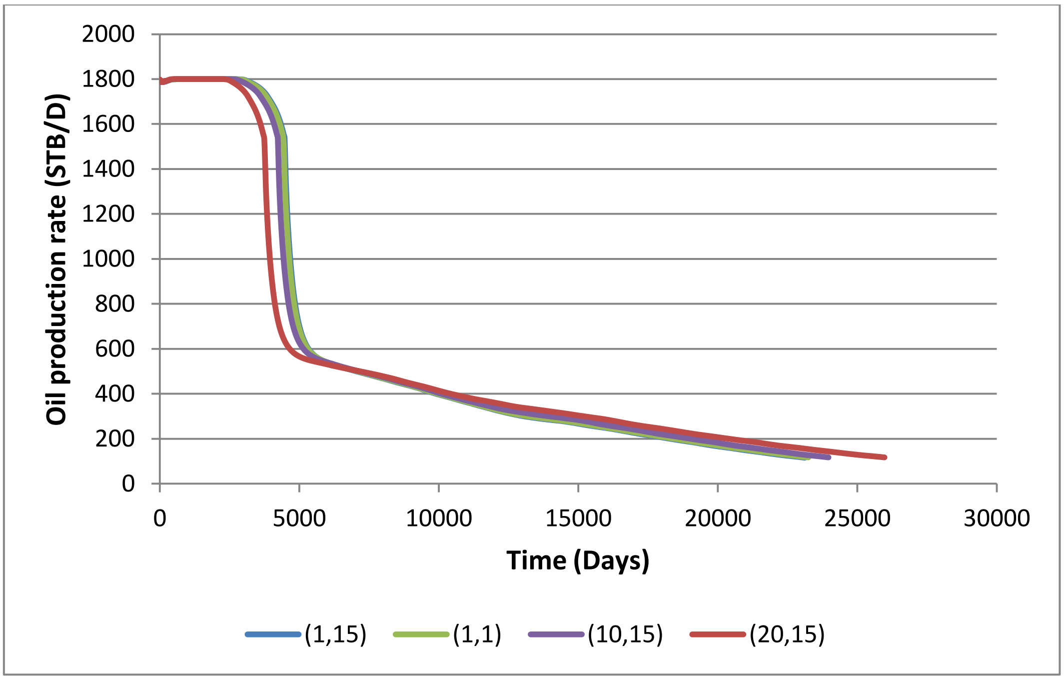


Figure 5.78 Oil production rate for different injector locations

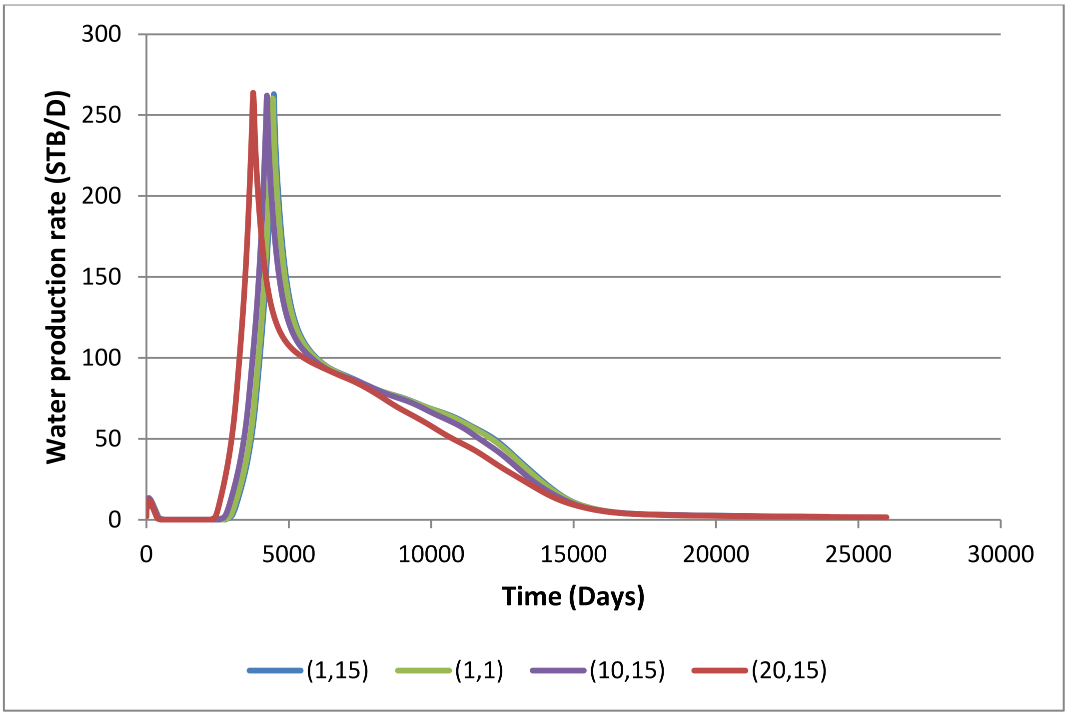


Figure 5.79 Water production rate for different injector locations

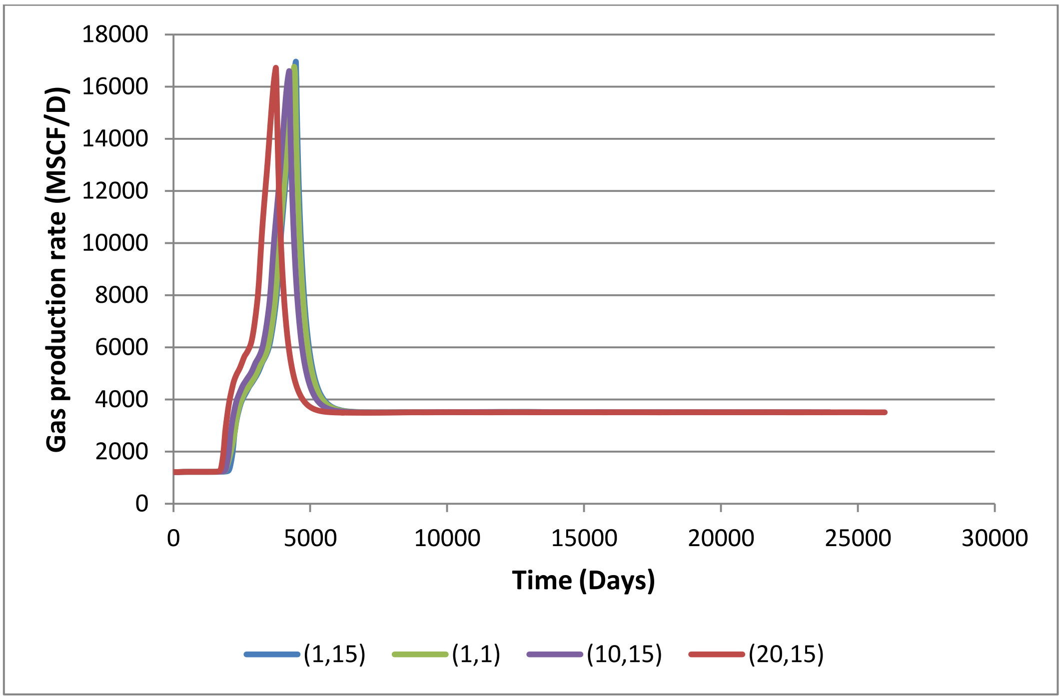


Figure 5.80 Gas production rate for different injector locations

Water and gas production rate are illustrated in Figure 5.79 and Figure 5.80, respectively. We can see that gas breakthrough for case of injector location at (20,15) occurs the earliest as the injector is closest to the producer. The water production gets accelerated as well. When we consider gas oil ratio plot shown in Figure 5.81, we can see that, at late time, GOR rises at a slower rate for (20,15) location due to higher oil production rate. Therefore, the production period is extended, causing oil recovery efficiency to be almost the same as that of other cases at the end of the production period. Table 5.23 summarizes cumulative oil production, oil recovery efficiency and production time for different injector locations and Table 5.24 summarizes oil production at 40 years of concession.

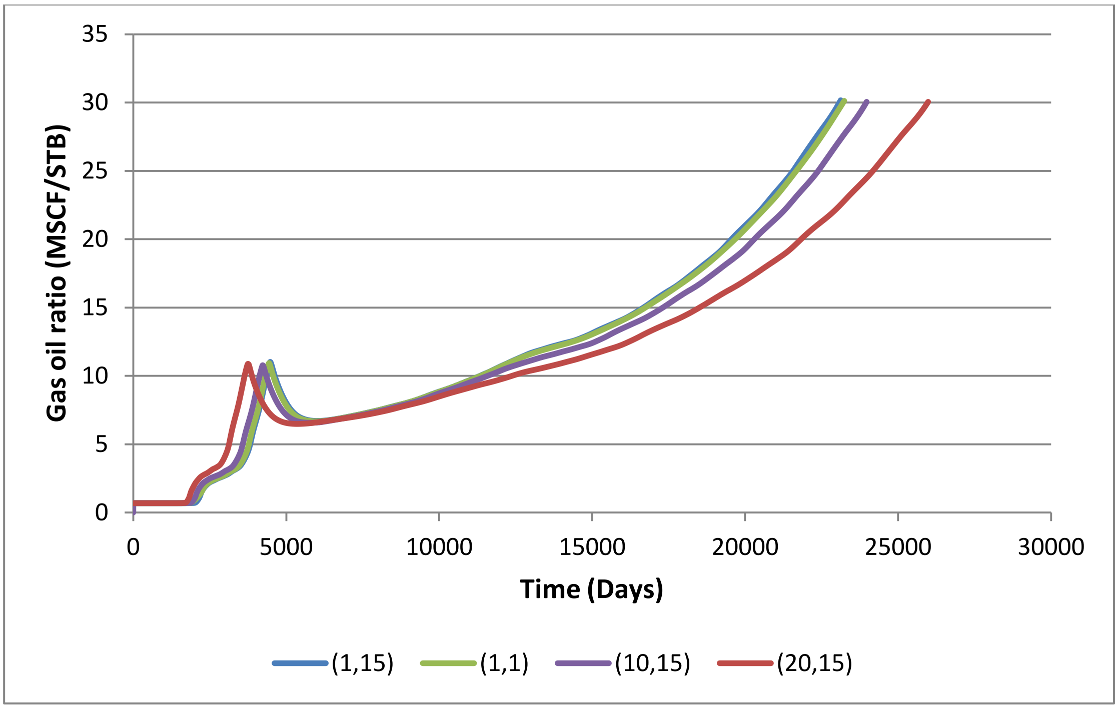


Figure 5.81 Gas oil ratio rate for different injector locations

Table 5.23 Summary of cumulative oil production, oil recovery efficiency and production time for different injector locations at the end of production

Injector location (x,y)	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
(1,15)	14.009	0.752	63
(1,1)	13.997	0.751	64
(10,15)	14.002	0.752	66
(20,15)	13.984	0.751	71

Table 5.24 Summary of cumulative oil production, oil recovery efficiency and production time for different injector locations at 40 years of concession

Injector location (x,y)	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
(1,15)	12.381	0.665	40
(1,1)	12.339	0.662	40
(10,15)	12.154	0.653	40
(20,15)	11.647	0.625	40

5.5.4 Effect of numbers of gas injectors

In this section, effects from the numbers of gas injectors are investigated. Since the result of previous case shows that placing gas injector at the uppermost dip location gives the highest oil recovery, the location of injector is fixed at the shallowest depth. More injectors are added along the *y*-axis. The second injector is at location (1,1) while the third one is placed at location (1,31). The summation of injection rate of all injectors is kept constant at 3500 MSCF/D. Oil recovery efficiency and oil production rate are shown in Figure 5.82 and Figure 5.83, respectively. We can see that adding more injector does not affect oil production performance as long as the total injection rate is equal. Table 5.25 is a confirmation as it shows almost identical oil production performance for individual case.

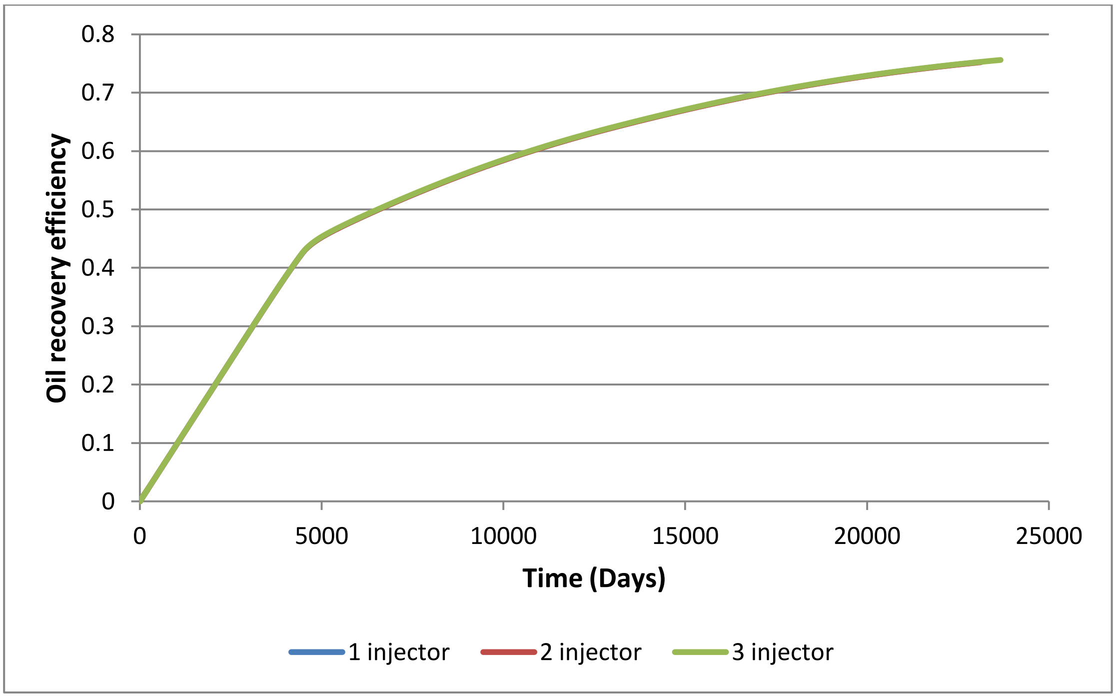


Figure 5.82 Oil recovery efficiency for different numbers of injectors

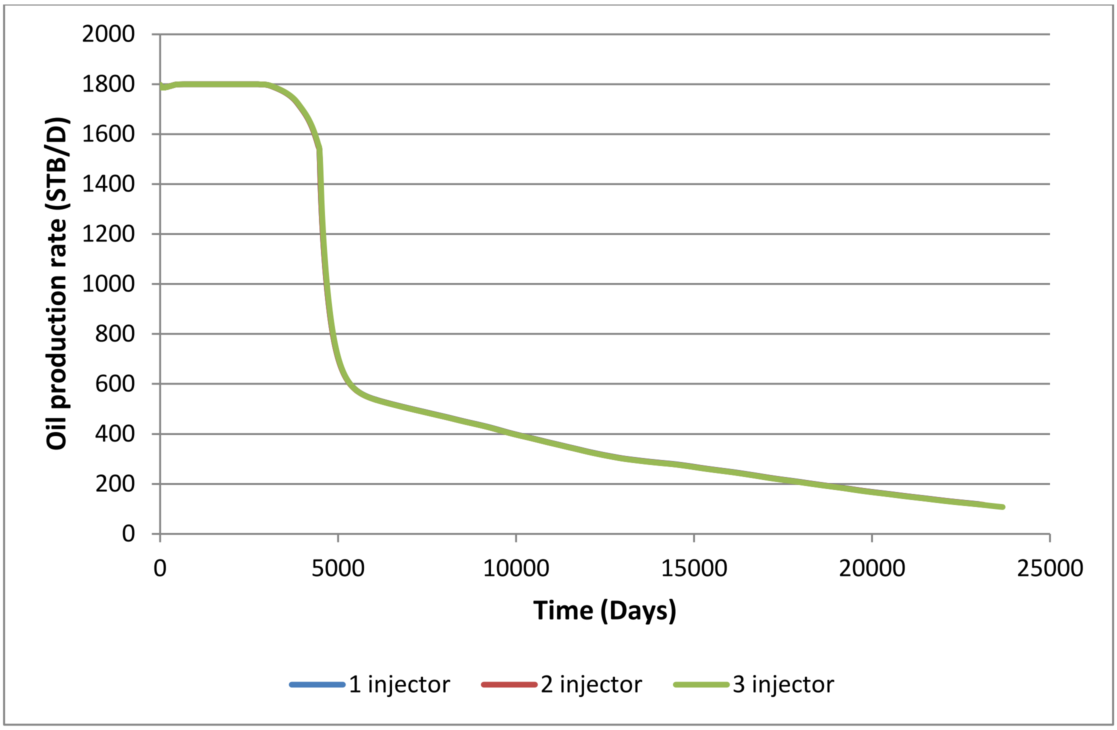


Figure 5.83 Oil production rate for different numbers of injectors

Table 5.25 Summary of cumulative oil production, oil recovery efficiency and production time for different numbers of injectors

Numbers of injectors	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
1	14.009	0.752	63
2	14.007	0.752	63
3	14.008	0.752	63

5.5.5 Effect of locations of horizontal producer

The location of horizontal producer is investigated by using three different settings. The base case with the producer placed at the most downdip location as shown in Figure 5.64 is compared with other two cases by moving the producer diagonally upward along the dip direction (at *x*-layer 60 and *z*-layer 21) and vertically upward (at *x*-layer 73 and *z*-layer 10). These three locations of the producer are illustrated in Figure 5.84. The gas injection rate is constant at 3500 MSCF/D, similar to previous cases. Figure 5.85 shows oil recovery efficiency for different producer locations. Oil, water and gas production rates are plotted in Figure 5.86, Figure 5.87 and Figure 5.88, respectively. Figure 5.89 illustrates gas oil ratio plot. Table 5.26 lists summary of cumulative oil production, oil recovery efficiency and production time and Table 5.27 shows oil production at 40 years of concession.

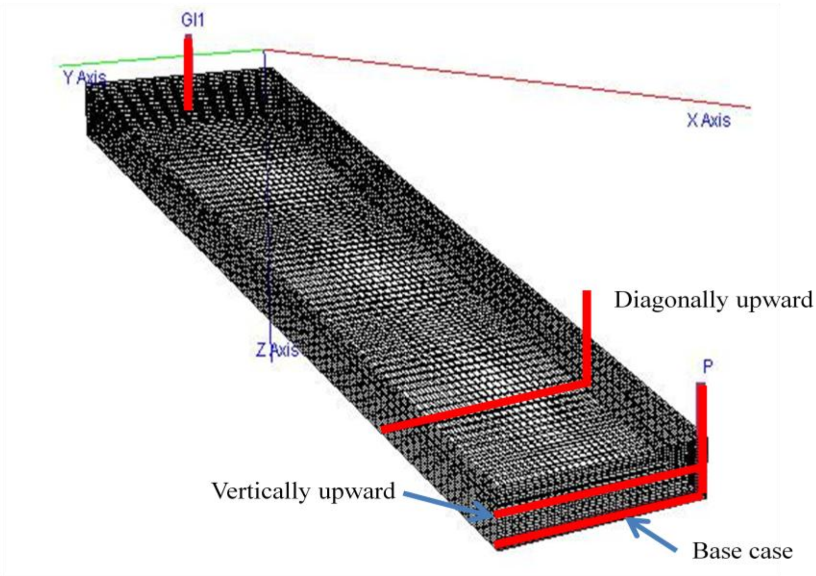


Figure 5.84 Well placements for three different locations of production well

Considering between base case and vertically upward location, we can see that moving the producer upward clearly reduces oil recovery efficiency. This is because gas reaches the producer faster and causes premature gas breakthrough, thus reducing sweep efficiency. Area below the producer is left untouched by gas as illustrated in Figure 5.90. When we compare production performance between base case and diagonally upward location, the results shows that moving the producer along dip direction increases in oil production efficiency at early time because gas and water break through the producer slower than the base case. Thus, the plateau period is extended. However, once gas reaches the producer, oil recovery tends to reduce drastically even lower than the case of vertically upward location since more area of the reservoir is left unswept behind the producer as shown in Figure 5.91. Additionally, production period for case of diagonal movement is shorter as oil production rate is lower. Thus, GOR increases and reaches the limit faster as illustrated in Figure 5.89.

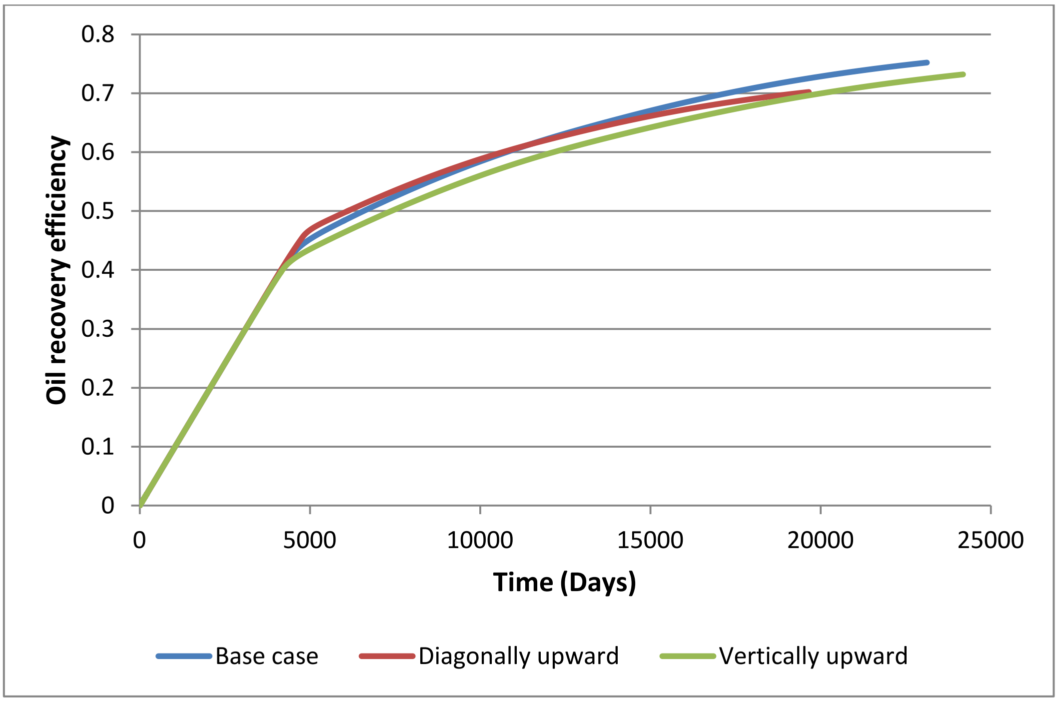


Figure 5.85 Oil recovery efficiency for different producer locations

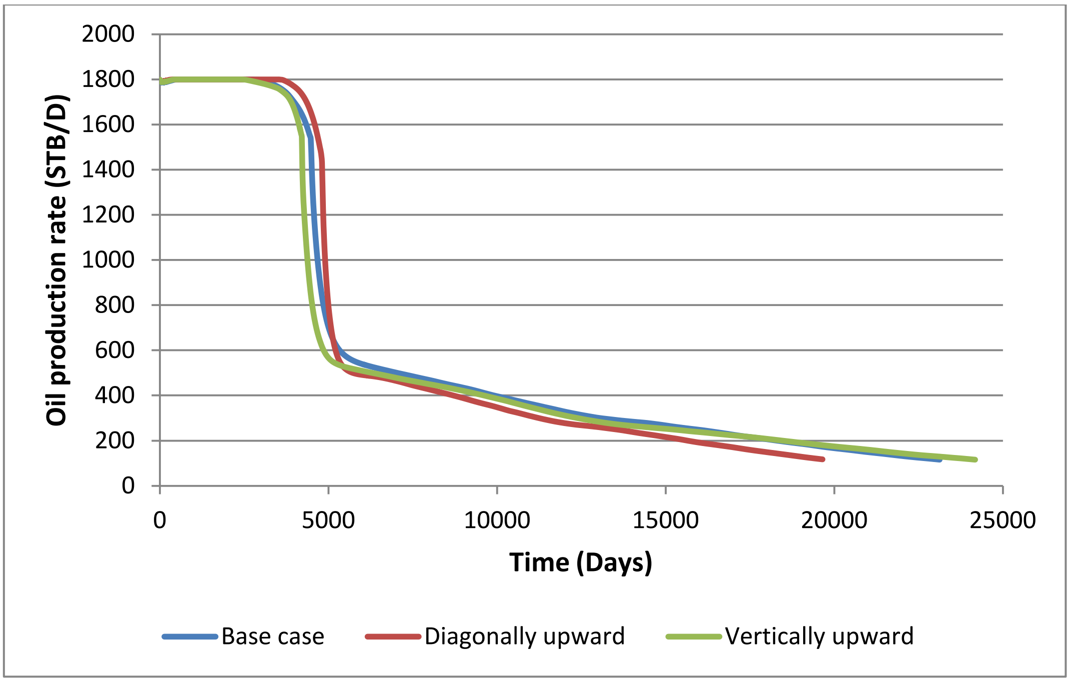


Figure 5.86 Oil production rate for different producer locations

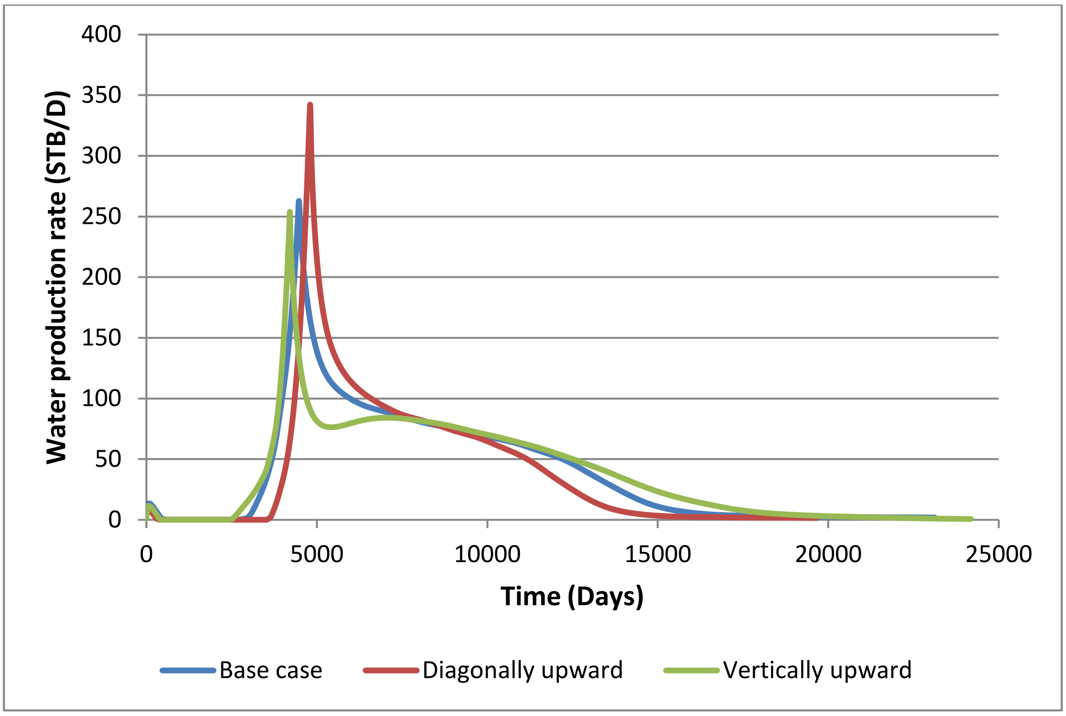


Figure 5.87 Water production rate for different producer locations

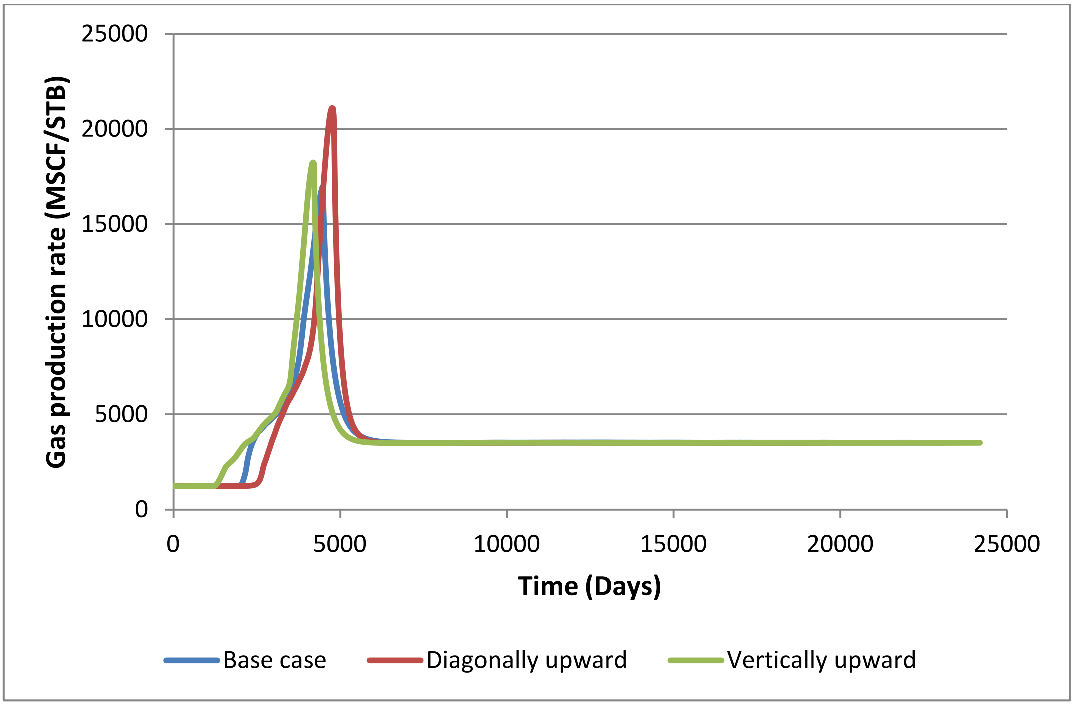


Figure 5.88 Gas production rate for different producer locations

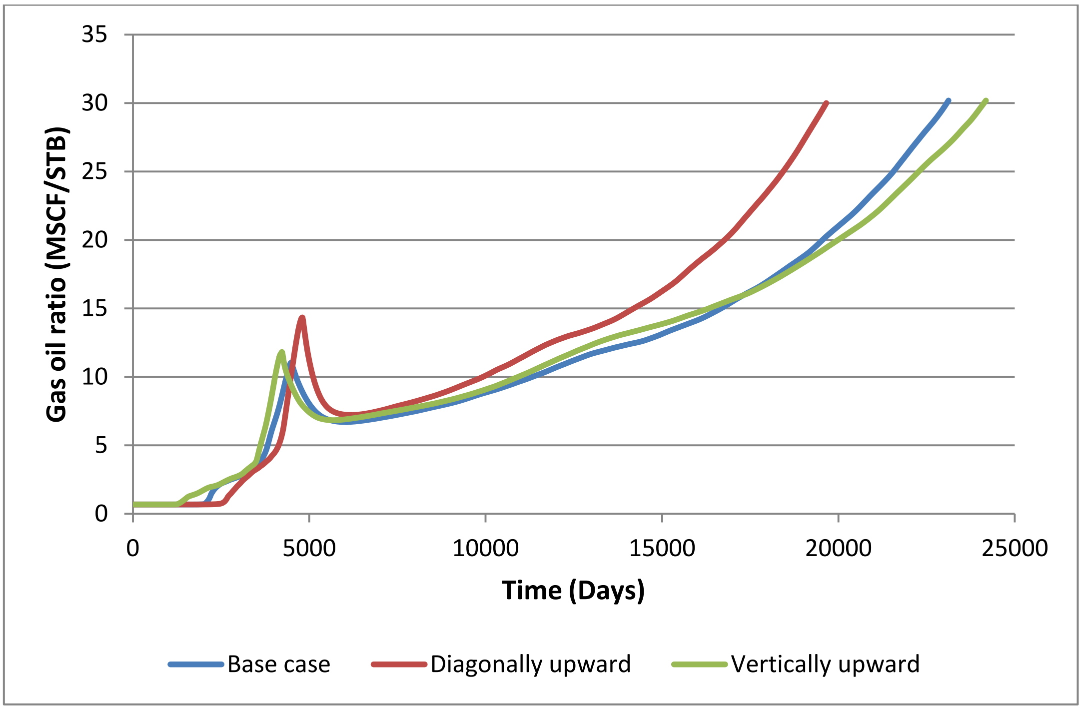


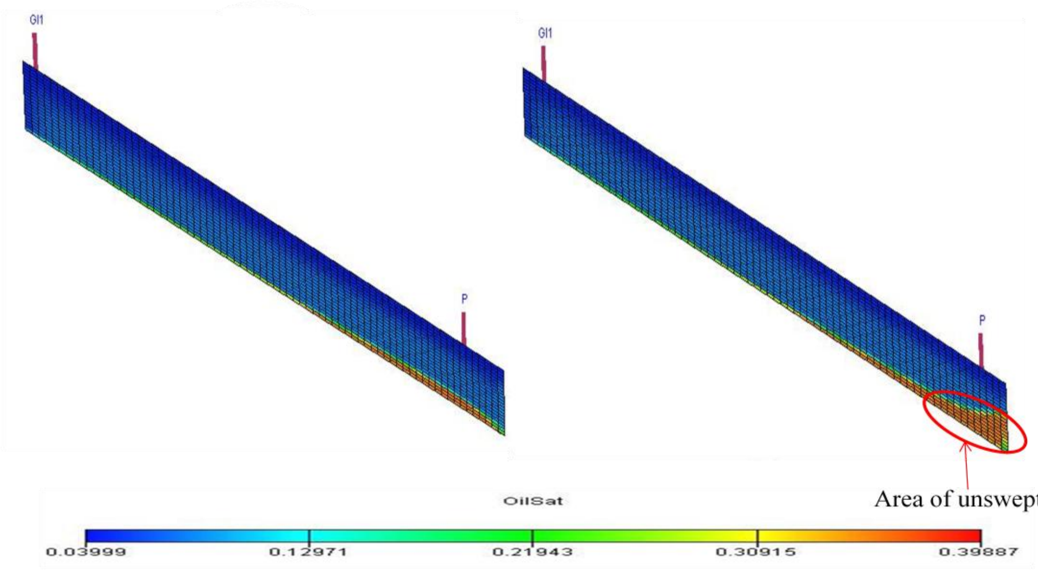
Figure 5.89 Gas oil ratio for different producer locations

Table 5.26 Summary of cumulative oil production, oil recovery efficiency and production time for different locations of producer at the end of production

Producer location	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
Base case	14.009	0.752	63
Diagonally upward	13.079	0.702	54
Vertically upward	13.630	0.732	66

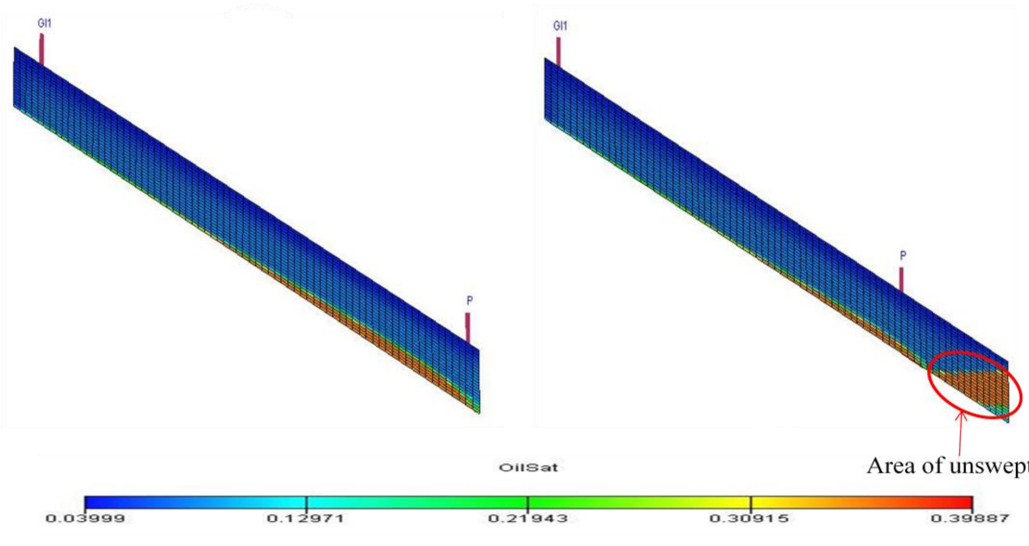
Table 5.27 Summary of cumulative oil production, oil recovery efficiency and production time for different locations of producer at 40 years of concession

Producer location	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
Base case	12.381	0.665	40
Diagonally upward	12.232	0.657	40
Vertically upward	11.857	0.637	40



a) Base case b) Producer move vertically upward

Figure 5.90 Comparison of oil saturation profile between base case and case of vertically upward location at 60 years of production



a) Base case b) Producer move diagonally upward

Figure 5.91 Comparison of oil saturation profile between base case and case of diagonally upward location at 60 years of production

5.5.6 Effect of length of horizontal producer

Three different lengths of horizontal producer are considered 645.2, 1290.3 and 2000.0 feet with the same originating point in the horizontal section. These three values equal to the lengths of 10, 20, and 31 gridblocks in the *y*-axis, respectively. The gas injection rate is set at 3500 MSCF/D for all cases. Figure 5.92 illustrates oil recovery efficiency for different producer lengths. It is clearly shown that as the producer has shorter length, it yields less oil recovery even though it takes longer production time as summarized in Table 5.28. Oil, water and gas production rate are depicted in Figure 5.93, Figure 5.94 and Figure 5.95, respectively. There is less oil recovery in case of shorter producer because of earlier gas and water breakthrough. Also, more area of the reservoir is left unswept in this case as gas tends to flow directly toward the horizontal section of the producer as illustrated in Figure 5.97 for the comparison of oil saturation distributions.

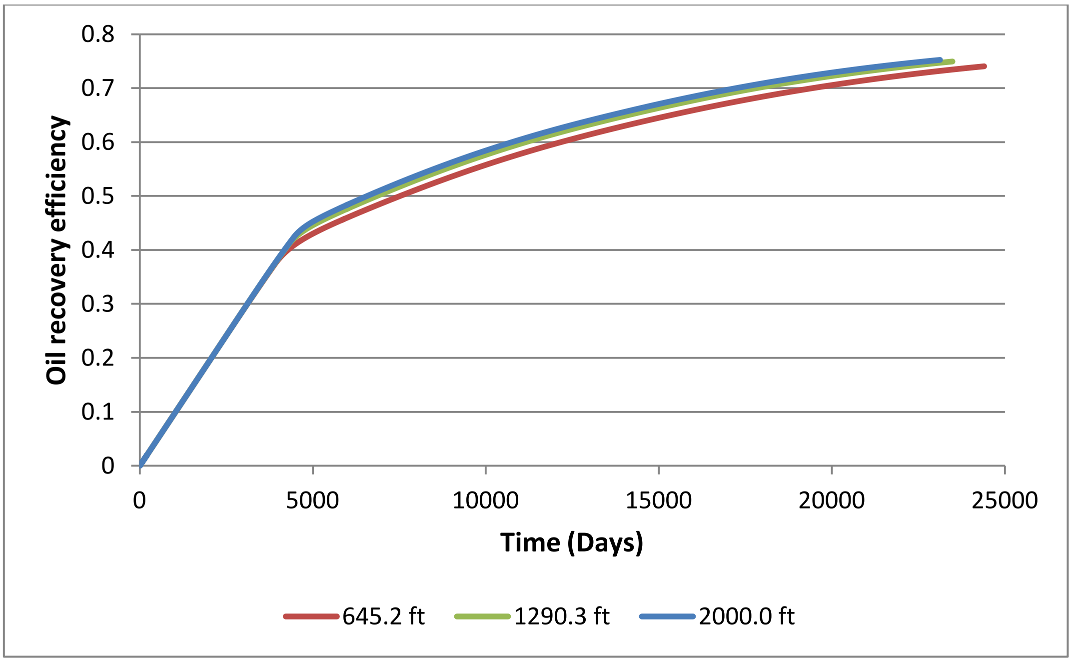


Figure 5.92 Oil recovery efficiency for different producer lengths

Table 5.28 Summary of cumulative oil production, oil recovery efficiency and production time for different producer lengths at the end of production

Length (feet)	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
645.2	13.790	0.740	67
1290.3	13.956	0.749	64
2000.0	14.009	0.752	63

Table 5.29 Summary of cumulative oil production, oil recovery efficiency and production time for different producer lengths at 40 years of concession

Length (feet)	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
645.2	11.904	0.639	40
1290.3	12.244	0.657	40
2000.0	12.381	0.665	40

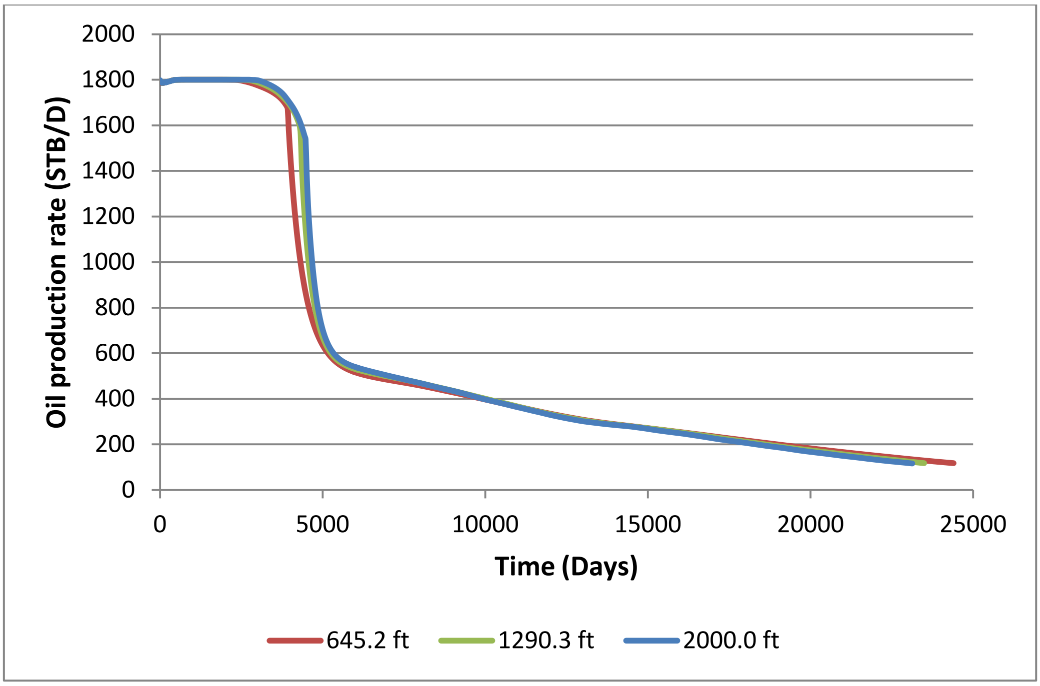


Figure 5.93 Oil production rate for different producer lengths

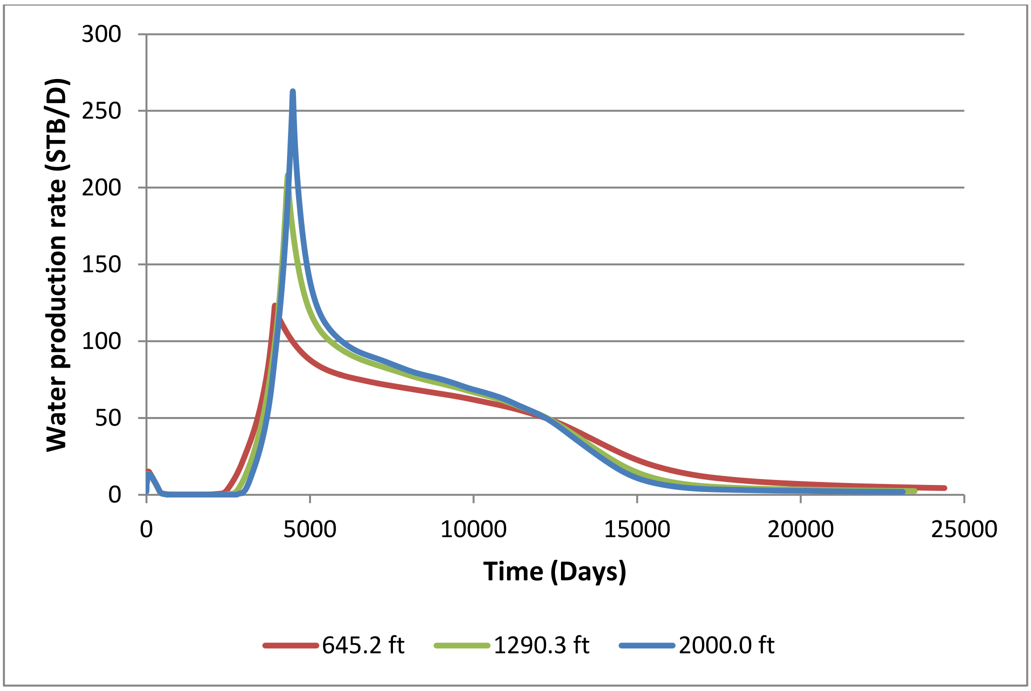


Figure 5.94 Water production rate for different producer lengths

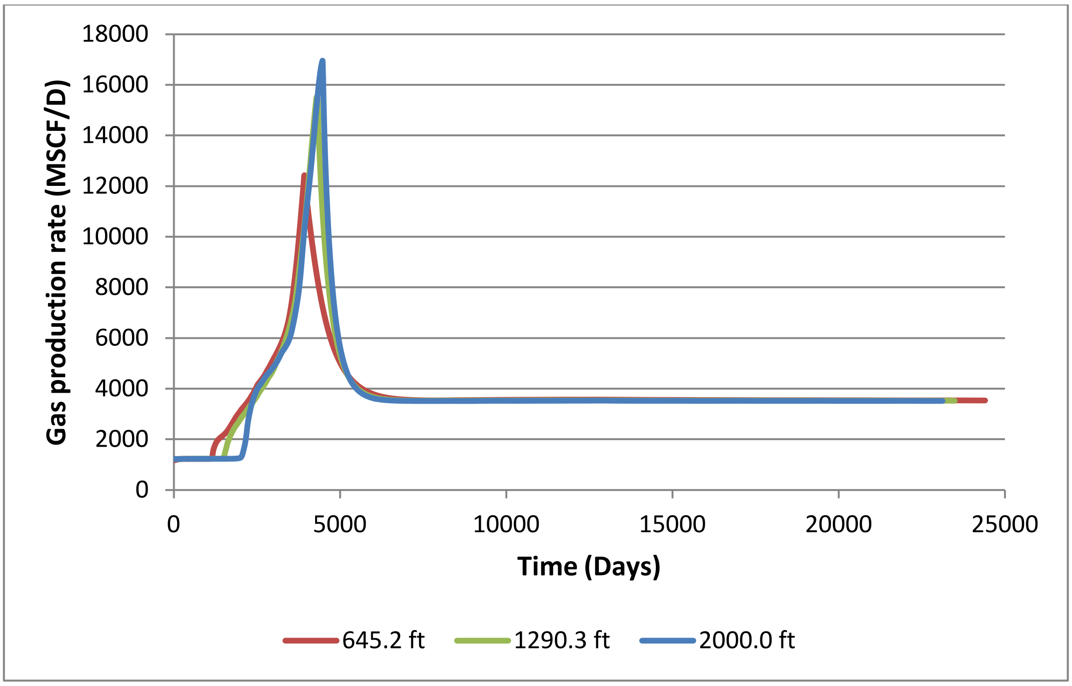


Figure 5.95 Gas production rate for different producer lengths

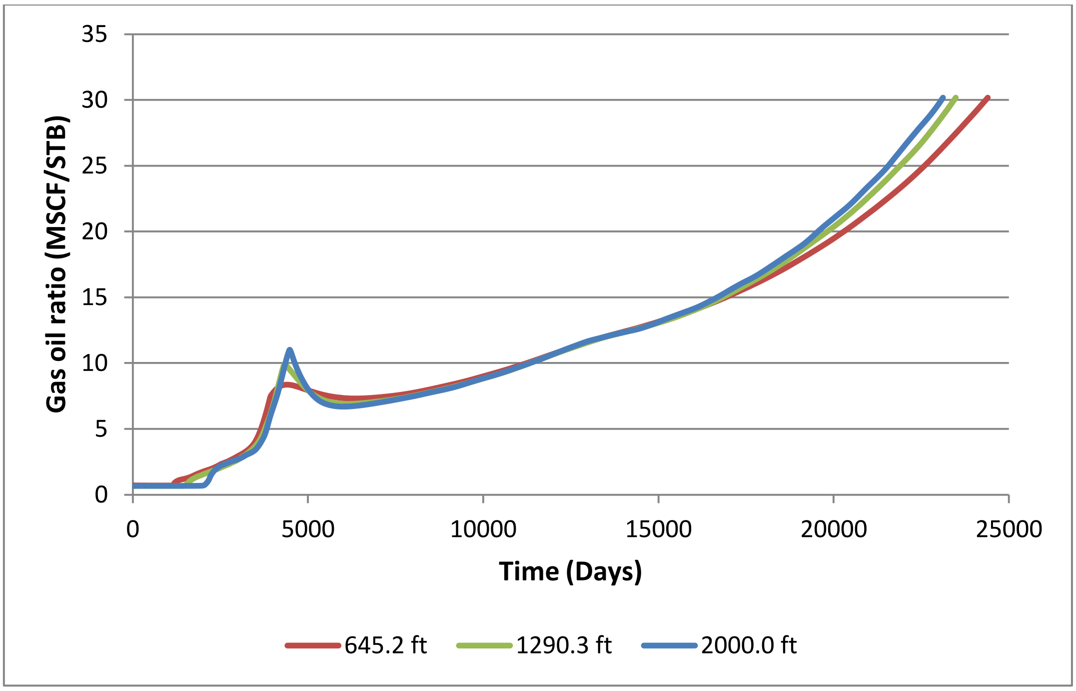


Figure 5.96 Gas oil ratio for different producer lengths

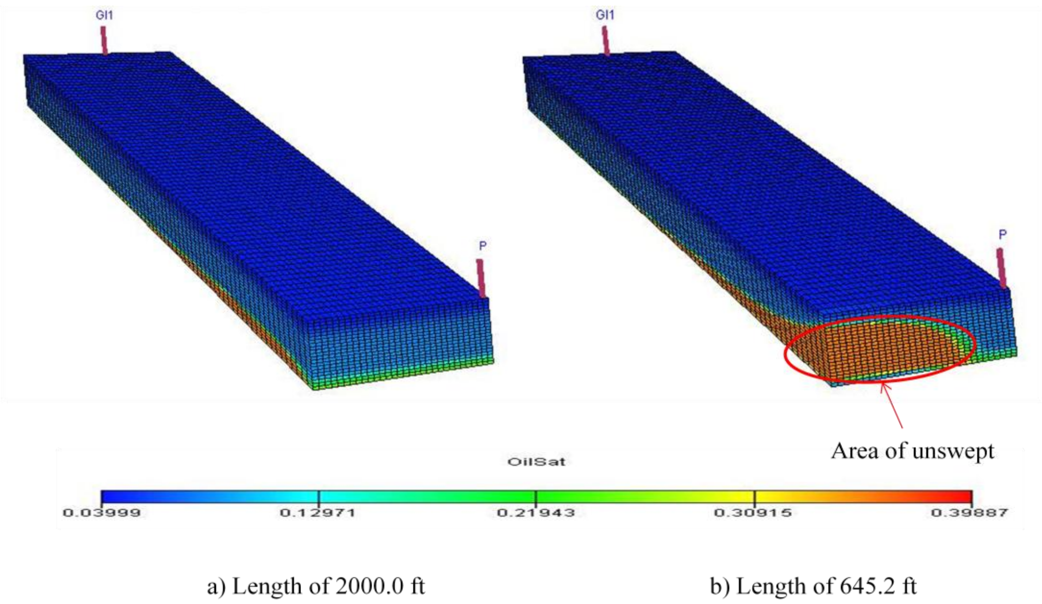


Figure 5.97 Comparison of oil saturation profile between producer lengths of 645.2 and 2000.0 feet at 50 years of production

5.5.7 Summary of effect of different design parameters on GAGD

Each design parameter affects oil production performance in different ways as summarized below:

- Increasing of total gas injection rate from all injectors yields higher oil recovery regardless of the numbers of injectors if consider at the same production time. However, too high injection rate results in shorter production time as well as reduction in ultimate oil recovery.
- Perforated height of gas injector has no effect on oil recovery because gas tends to flow and accumulate at top structure and sweep oil in the same manner.
- The vertical gas injector should be placed at the most updip location in the reservoir regardless of the position in the *y*-axis because this location takes less time to produce an equal amount of ultimate oil recovery.
- The number of gas injectors does not have an effect on oil recovery as long as the total gas injection rate remains the same.
- The horizontal producer should be placed at the most downdip location and at the deepest depth possible to maximize the volumetric sweep efficiency.
- Longer horizontal producer has more benefit on oil production performance because gas and water breakthroughs are delayed, and the volumetric sweep efficiency is maximized.

5.6 Production performance comparative study

5.6.1 Comparison of stand-alone waterflooding, stand-alone gas injection, SSWAG and GAGD

The simulation results of SSWAG base case and GAGD base case are compared with stand-alone waterflooding and stand-alone gas injection. Figure 5.98 illustrates the oil recovery efficiency of all four methods. Oil production rate is also provided in Figure 5.99. We can see from the figure that SSWAG yields higher oil recovery at the early production time just because of higher production rate of 1080 STB/D while the other methods produce at 1000 STB/D. However if consider the overall performance, GAGD yields the highest oil recovery among other methods while waterflooding yields the least oil recovery. This is mainly because of better displacement efficiency of gas over water. If consider between gas injection and GAGD, we can see that oil production performance of GAGD is significantly better than normal gas injection. This is proven that horizontal producer well can improve oil production over vertical well.

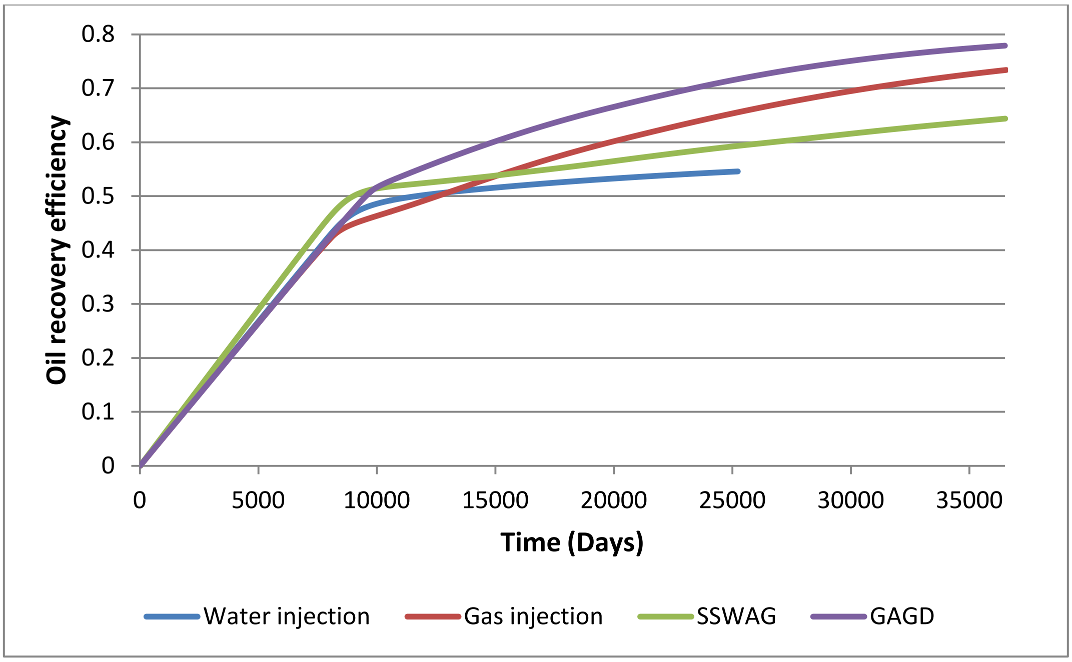


Figure 5.98 Oil recovery efficiency of stand-alone waterflooding, stand-alone gas injection, SSWAG base case and GAGD base case

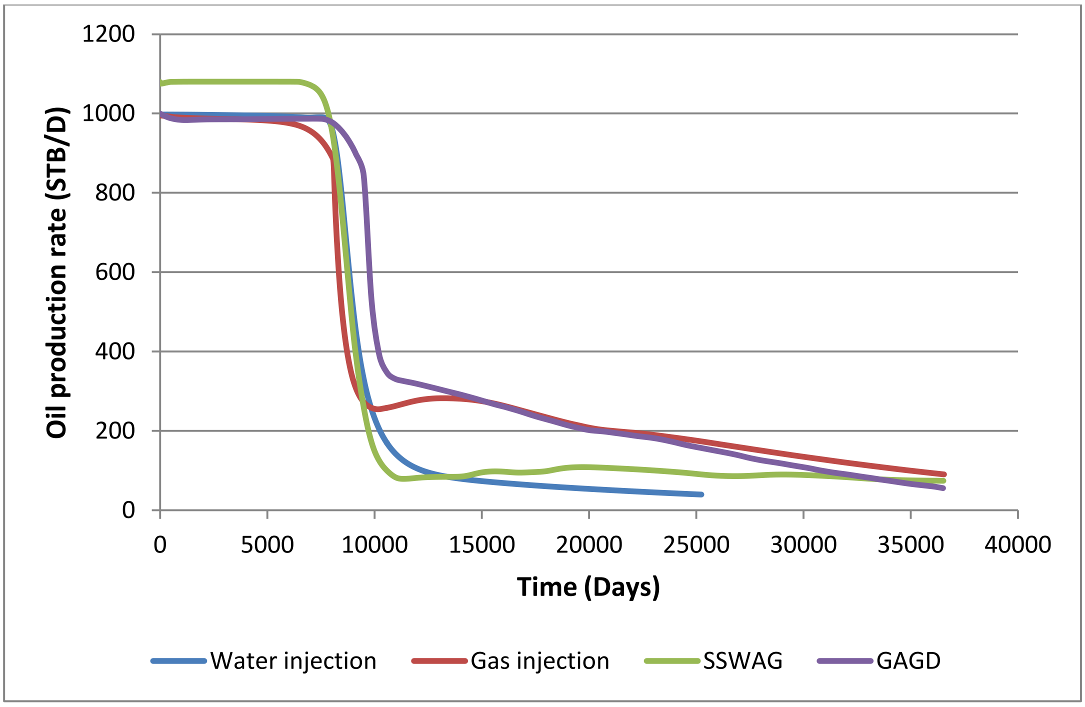


Figure 5.99 Oil production rate of stand-alone waterflooding, stand-alone gas injection, SSWAG base case and GAGD base case

In practice, an oil company usually receives lease of concession in a specific length of time which is assumed to be 40 years in this study. In order to maximize oil production within time limitation, the best set of design parameters should be applied. The best case of SSWAG is the case that uses 3000 MSCF/D of gas injection rate, 500 STB/D of water injection rate and 50 feet of the producer length. The other parameters are the same as those in SSWAG base case. The best case of GAGD is the case that uses 5000 MSCF/D with the same values for other parameters as in those in GAGD base case. Figure 5.100 depicts oil recovery efficiency of stand-alone waterflooding, stand-alone gas injection, SSWAG best case and GAGD best case at 40 years of concession. We can see from the figure that GAGD yields highest oil recovery for most of the time and SSWAG produces less oil than GAGD but more than stand-alone gas injection and stand-alone waterflooding. These oil production profiles are used in economic calculation in Chapter VI.

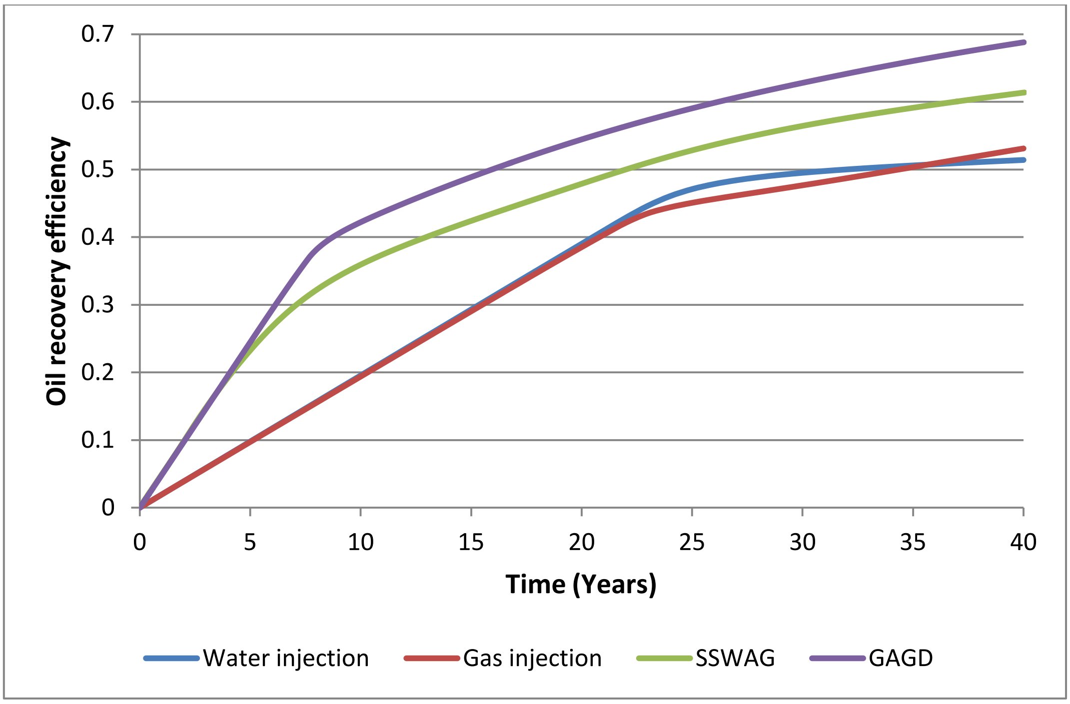


Figure 5.100 Oil recovery efficiency of stand-alone waterflooding, stand-alone gas injection, SSWAG best case and GAGD best case at 40 years of concession

5.6.2 Comparison of SSWAG, GAGD and DDP

The simulation result of DDP process from Suwannakul [2] is also incorporated in this study. The case of conventional DDP method is chosen in this study as this is the case that yields highest ultimate oil recovery. Four wells are used in conventional DDP and located at different locations as shown in Figure 5.101.

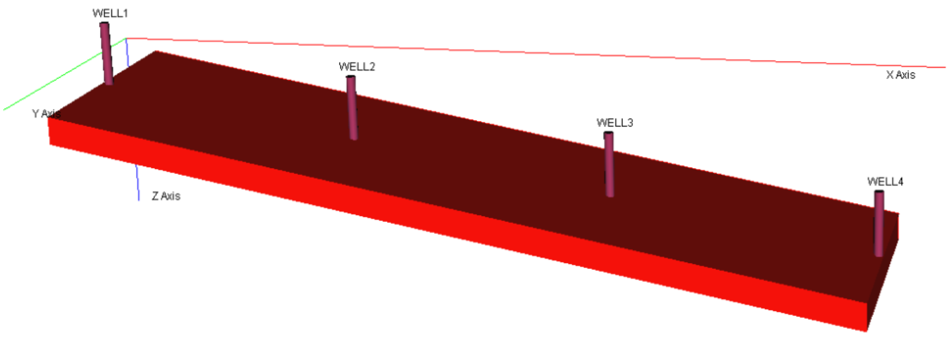


Figure 5.101 Conventional DDP well configuration (after Suwannakul [2])

The injection and production sequence of conventional DDP is summarized in the table. The process starts with water flooding. Initially, water is injected from the most downdip well while three wells located at higher locations in the structure are oil producers. Each production well is open until water cut reaches 85%. Wells 3, 2, and 1 are sequentially shut in as the water level rises up the structure. Then, gas is injected in 3 stages. In the first stage, gas is injected at well 1 while well 2 is opened to produce oil. When gas breaks through well 2, the well is shut in. In the second stage, well 3 is opened until gas breaks through the well. In the final stage, well 4 is opened to produce oil.

Stage	Well 1	Well 2	Well 3	Well 4
Waterflood	Producer	Producer	Producer	Water injector
1st stage of gas injection	Gas injector	Producer	Shut-in	Shut-in
2nd stage of gas injection	Gas injector	Shut-in	Producer	Shut-in
3rd stage of gas injection	Gas injector	Shut-in	Shut-in	Producer

Oil recovery efficiency from SSWAG base case, GAGD base case and DDP methods are depicted in Figure 5.102. The summary of cumulative oil production, oil recovery efficiency and production time for different gas injection rates can be found in Table 5.30. It is clearly seen that oil recovery from DDP is better than other cases at early time due to the fact that DDP uses more numbers of producers; thus, total liquid production rate from DDP is higher. However, oil recovery gets lower after waterflooding is finished because of poor displacement efficiency of water. During this period, GAGD production performance is better than DDP. After the third stage of gas injection of DDP starts, oil recovery improves significantly because oil globules get reconnected and drained toward the production well. Even though oil recovery efficiency of DDP is higher at late time, it is still less than GAGD’s. Among these three methods, SSWAG yields the least oil recovery for most of the time.

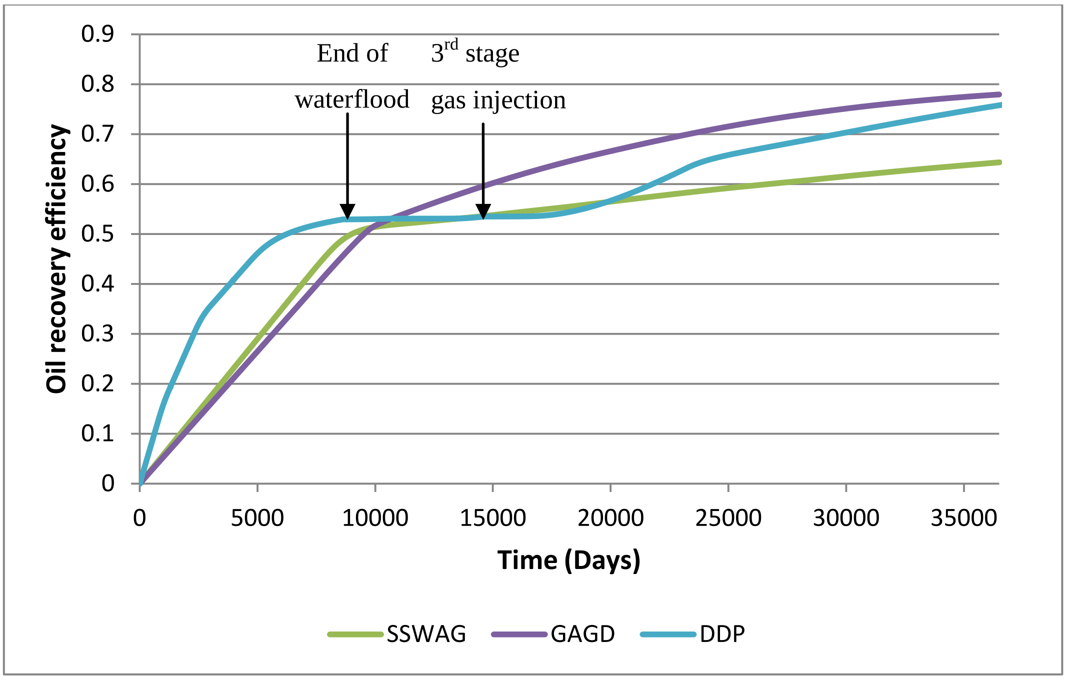


Figure 5.102 Oil recovery efficiency of SSWAG base case, GAGD base case and DDP

Table 5.30 Summary of cumulative oil production, oil recovery efficiency and production time for different methods of production at the end of production

Method	Cumulative oil production (MMSTB)	Oil recovery efficiency (fraction)	Production time (years)
Stand-alone water flooding	10.161	0.545	69
Stand-alone gas injection	13.671	0.734	100
SSWAG base case	11.987	0.644	100
GAGD base case	14.513	0.779	100
Conventional DDP	14.153	0.758	100

The summary of production profile at 40 years of concession is shown in Table 5.31. GAGD yields the highest oil recovery while waterflooding yields the lowest. Oil recovery from DDP is lower than SSWAG due to the fact that third stage of gas injection is just started. Reconnection of oil globules requires certain period of time. Thus, oil recovery performance of DDP is not efficient at this time period.

Table 5.31 Summary of cumulative oil production, oil recovery efficiency and production time for different methods of production at 40 years of concession

Method	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (fraction)**	**Production time (years)**
Stand-alone water flooding	9.573	0.514	40
Stand-alone gas injection	9.895	0.531	40
SSWAG base case	9.983	0.536	40
GAGD base case	11.097	0.596	40
Conventional DDP	9.984	0.535	40

CHAPTER VI

ECONOMIC ANALYSIS

In this chapter, both SSWAG and GAGD are evaluated in term of monetary value of the projects. Best cases of SSWAG and GAGD are selected in this study and compared against stand-alone gas and stand-alone water injection. The evaluation starts with comparison among four methods by using basic assumptions. Then sensitivity analysis is conducted by varying gas and oil prices and discount rate. The basic assumptions used in this evaluation are as follows

1) Each production profile represents an independent project.
2) Oil price equals to 90.0 US$/BBL with escalation rate of 5 %.
3) Gas price equals to 5.0 US$/MSCF with escalation rate of 2 %.
4) Year end discounting with constant discounted rate of 10.0 % is applied.
5) Total fixed investment cost of vertical and horizontal wells are 2,300,000 US$ and 4,000,000 US$, respectively and abandonment cost of 500,000 US$.
6) Total cost of gas compressor is 2,725,000 US$ [23].
7) 5 years of linear depreciation is applied for gas compressor. The compressor has 15 years of lifetime.
8) Daily operating cost for waterflooding operation is 3000 US$/Day.
9) Operating cost for gas injection comes from electricity consumption only which is summarized in Table 6.1 [23].
10) 2% of inflation rate for CAPEX and 5% of escalation rate for OPEX are used.
11) The gas processing cost is not accounted in the analysis.
12) Production facility is assumed to be existed before the first day of operation; thus, the cost of installation is not accounted in this analysis.
13) 100% of fixed cost is subtracted from the first year and the production is started in the second year.
14) 12.5 % royalty and 50% taxable income is applied.
15) 40 years of concession is applied for all projects.

To recall the input parameters and the simulation results of waterflooding, gas injection, SSWAG best case and GAGD best case, we refer back to Section 5.1, 5.3 and 5.5, respectively.

Table 6.1 Total fixed investment cost of vertical and horizontal wells

Gas injection rate (MSCF/D)	**Cost (US$/year)**
1000	$23,539
3000	$70,620
5000	$117,697

6.1 Analysis with basic assumptions

The result of economic evaluation with earlier defined assumption shows that all four projects can recover capital cost within the first year of production. Figure 6.1 illustrates net cash flow of four methods in each year. The summary of NPV, IRR and DPI is listed in Table 6.2, and NPV plot is illustrated in Figure 6.2. According to the table, NPV value of GAGD is the highest while waterflooding is the lowest. Higher NPV value of GAGD comes from higher oil production rate for most of production periods when compared with other methods as illustrated in Figure 5.100. However, if we consider DPI values, waterflooding turns out to be the most attractive project to invest as it generates the highest DPI. This is mainly because of the amount of capital cost of waterflooding is the least. SSWAG yields less DPI value than waterflooding due to higher capital cost even though SSWAG produces more amount of oil. IRR value of GAGD is the highest while gas injection yields the least IRR value.

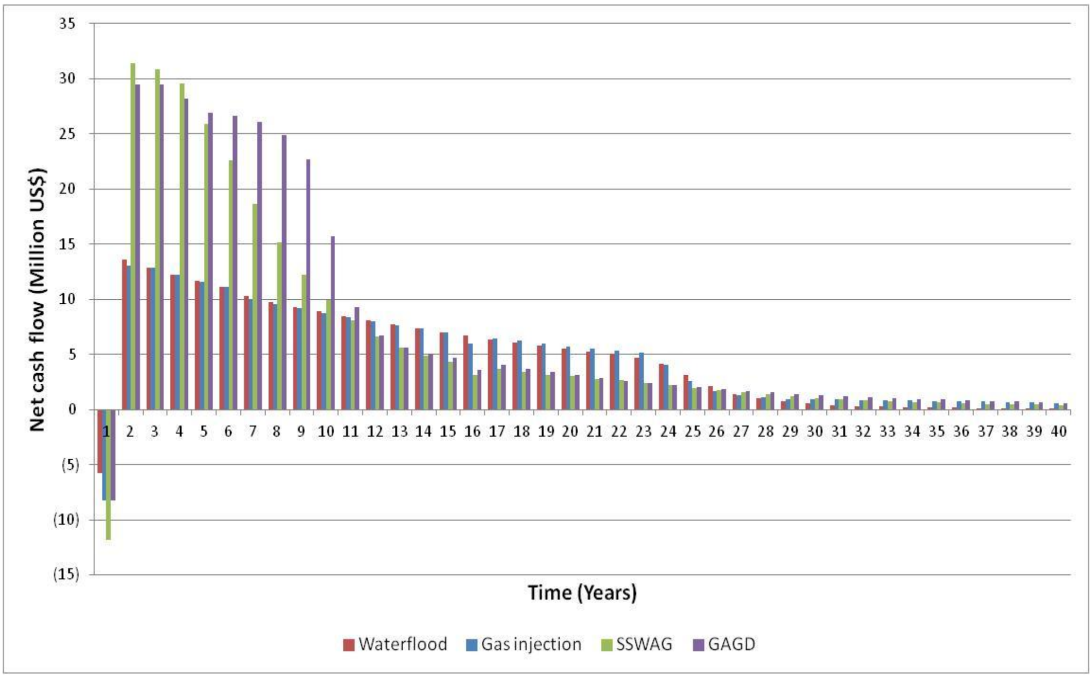


Figure 6.1 Net cash flow of four methods with basic assumption

Table 6.2 Summary of NPV, IRR and DPI with basic assumptions

Method	NPV (US$)	IRR (%)	DPI
Water injection	193,024,247	265.34	29.39
Gas injection	194,847,536	181.71	16.91
SSWAG best case	255,273,547	298.48	16.71
GAGD best case	299,436,027	404.03	25.44

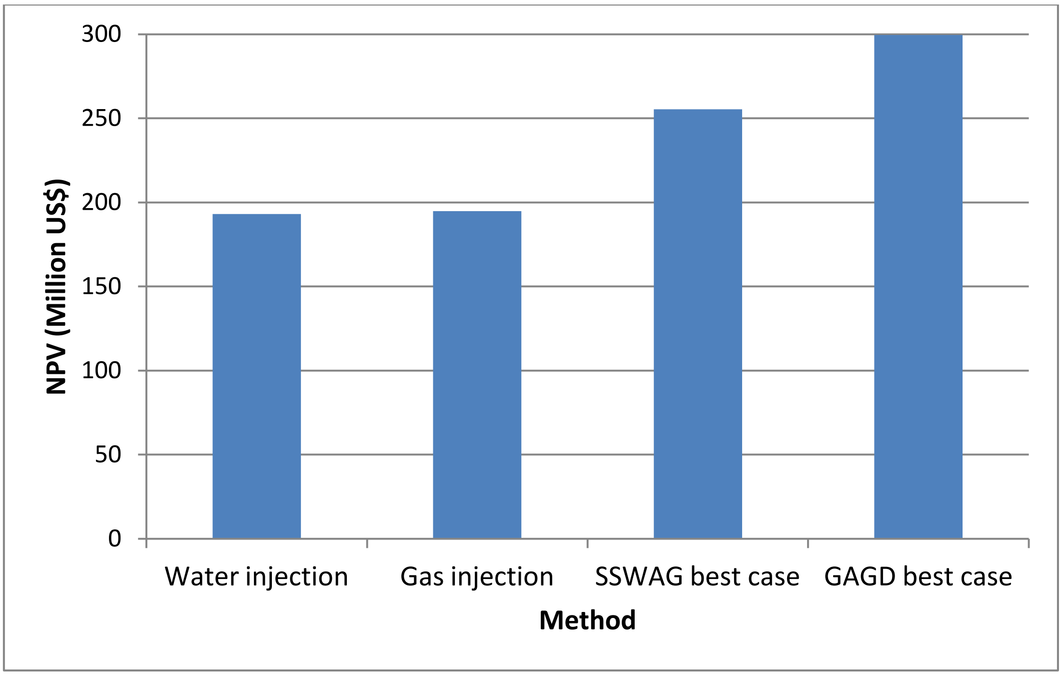


Figure 6.2 NPV plot from calculation with basic assumptions

6.2 Effect of discount rate

The effect of discount rate is investigated in this section. Two other values of discount rate are used to compare with the basic assumptions of 10.0% which includes 7.0% and 12.5%. The result of NPV and DPI for different discount rates is summarized in Table 6.3, and NPV plot is illustrated in Figure 6.3. The result shows that NPV and DPI are reasonably increased with lower value of discount rate. However, one interesting point can be drawn is that as discount rate increases, waterflooding project becomes more attractive over gas injection as it generates higher value of NPV. This is because gas injection has more capital cost at late time from buying the second gas compressor. At higher discount rate, DPI of SSWAG becomes higher than DPI of gas injection. This is possibly because incremental oil recovery of gas injection is less at late time when compared with SSWAG.

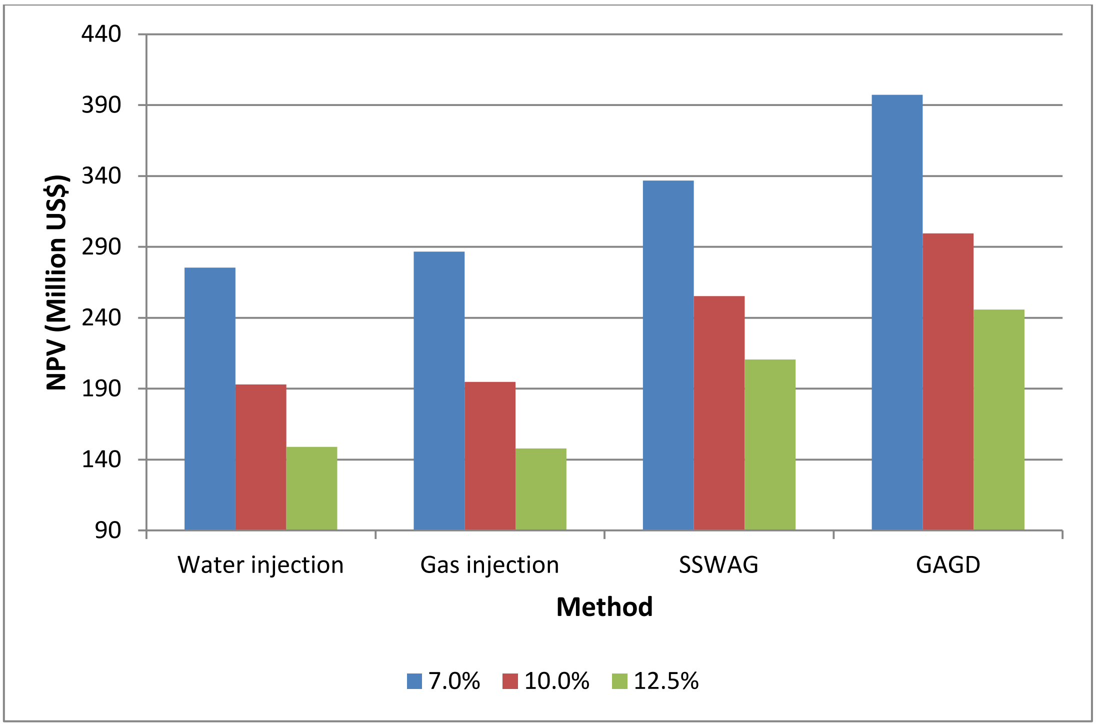


Figure 6.3 NPV plot of different discount rates

Table 6.3 Summary of NPV and DPI for different discount rates

	Discount rate = 7.0 %		***Discount rate = 10.0 %***		***Discount rate = 12.5 %***	
Method	**NPV (US$)**	**DPI**	**NPV (US$)**	**DPI**	**NPV (US$)**	**DPI**
Water injection	275,263,227	41.48	193,024,247	29.39	149,048,232	22.92
Gas injection	286,661,879	24.40	194,847,536	16.91	147,860,723	13.07
SSWAG best case	336,646,194	21.72	255,273,547	16.71	210,477,109	13.95
GAGD best case	397,155,559	33.42	299,436,027	25.44	245,736,026	21.06

6.3 Effect of oil price

Oil price is the most dynamic variable in oil and gas industry. Thus effect of oil price is essential to investigate. Oil price of 50 and 130 US$/BBL are considered additionally from earlier assumed value of 90 US$/BBL. The results of NPV, IRR and DPI values are listed in Table 6.4 and NPV plot for all values of oil price is illustrated in Figure 6.4. It is rational that as oil price is increasing, NPV, IRR and DPI also increase as it generates more revenue but the fixed costs are unchanged. However, we can see that the oil price does not affect the ranking of NPV, IRR and DPI among these four projects.

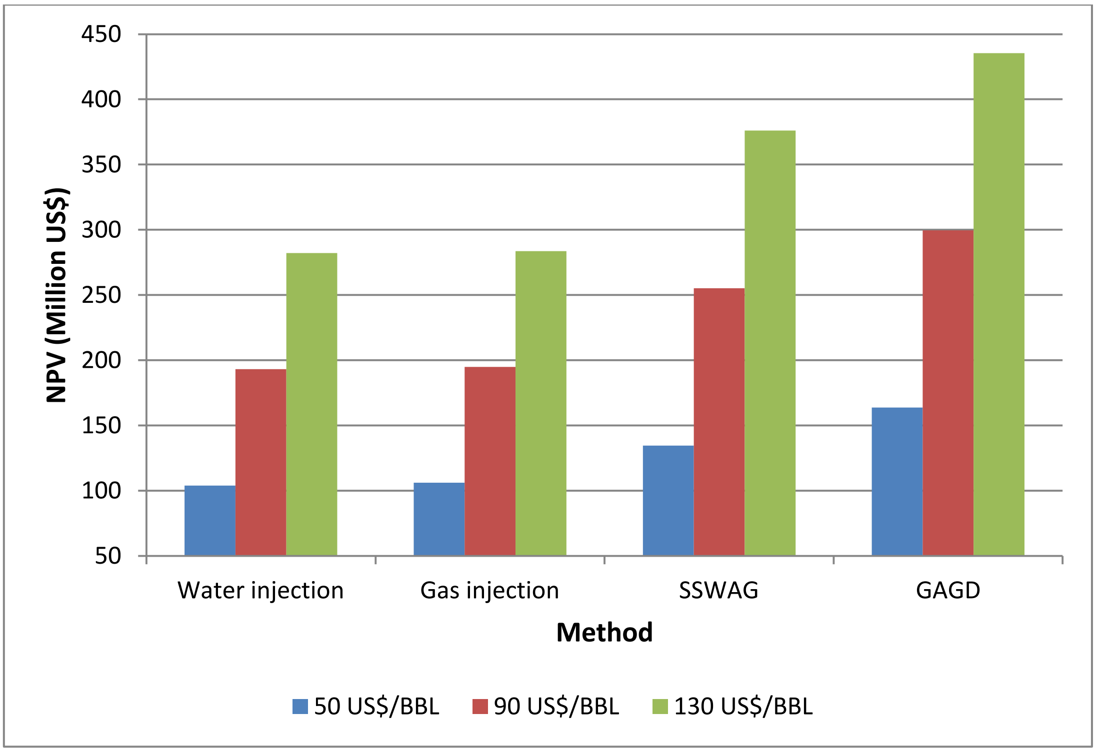


Figure 6.4 NPV plot of different oil prices

Table 6.4 Summary of NPV, IRR and DPI for different oil prices

	Oil price = 50 US$/BBL			***Oil price = 90 US$/BBL***			***Oil price = 130 US$/BBL***		
Method	**NPV (US$)**	**IRR (%)**	**DPI**	**NPV (US$)**	**IRR (%)**	**DPI**	**NPV (US$)**	**IRR (%)**	**DPI**
Water injection	103,844,700	153.05	16.27	193,024,247	265.34	29.39	282,194,376	377.46	42.50
Gas injection	106,057,674	104.41	9.66	194,847,536	181.71	16.91	283,637,398	259.21	24.15
SSWAG best case	134,458,601	162.36	9.27	255,273,547	298.48	16.71	376,088,493	435.02	24.14
GAGD best case	163,577,042	211.82	14.35	299,436,027	404.03	25.44	435,295,011	597.73	36.53

6.4 Effect of gas price

Even though the gas price is less dynamic when compared with oil, it is necessary to incorporate in this study as it has effect on the operating expenses. Gas injection, SSWAG and GAGD require source of gas to be injected into the reservoir and we assume to recycle the produced gas. However, in some years that gas production is not adequate to the required amount of the injectant. If that is the case, then additional amount of gas needs to be purchased. Thus, operating expenses is increased. Gas price of 2 and 9 US$/MSCF are considered additionally from earlier assumed value of 5 US$/MSCF. The results of NPV, IRR and DPI are summarized in Table 6.5. NPV, IRR and DPI plots are depicted in Figure 6.5, Figure 6.6 and Figure 6.7, respectively.

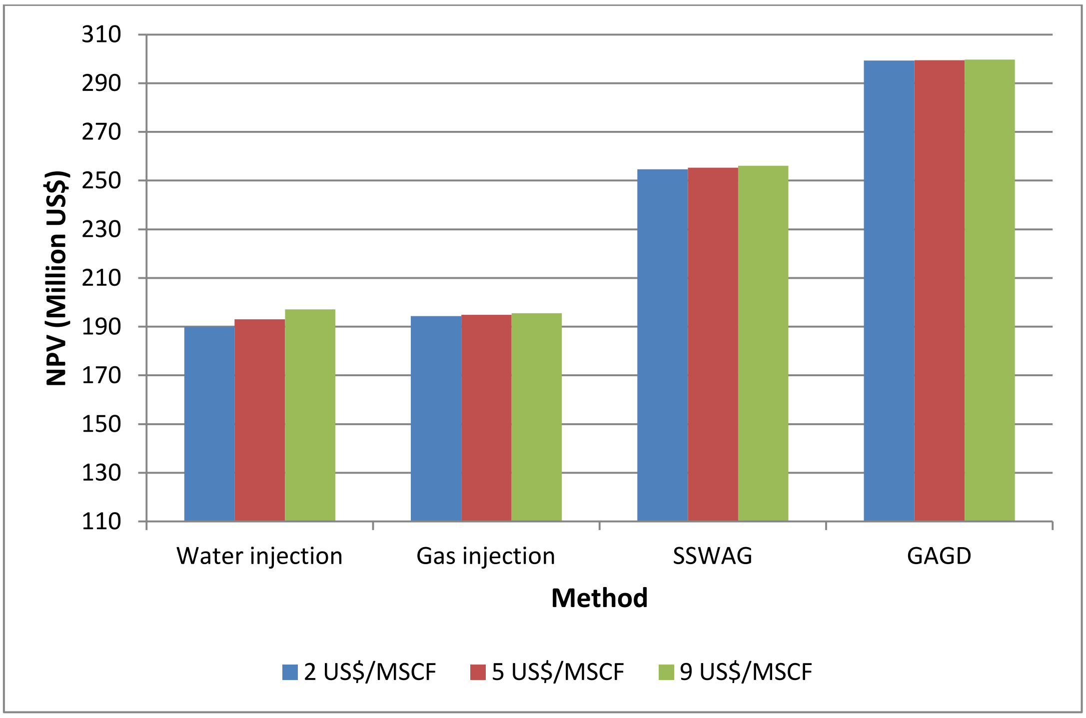


Figure 6.5 NPV plot of different gas prices

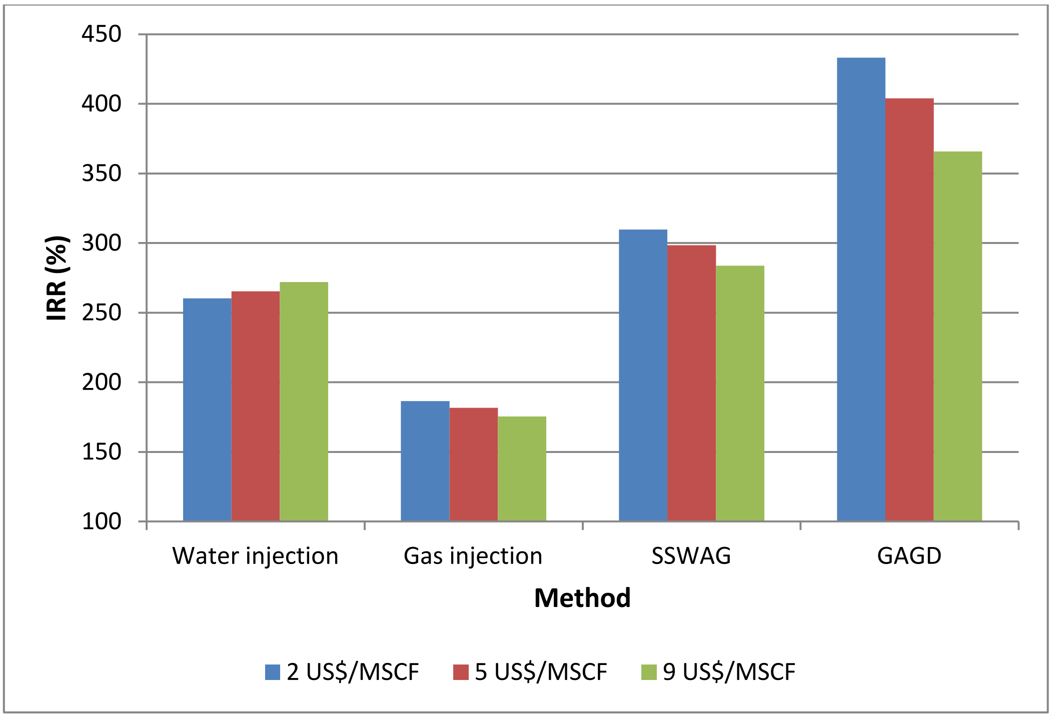


Figure 6.6 IRR plot of different gas prices

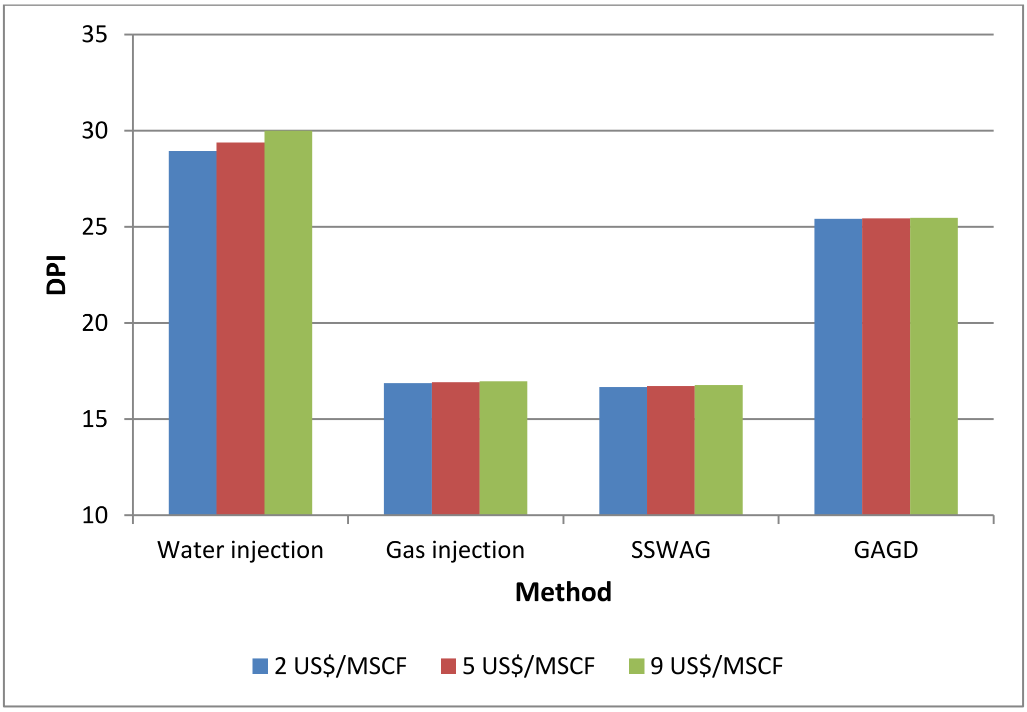


Figure 6.7 DPI plot of different gas prices

Table 6.5 Summary of NPV, IRR and DPI for different gas prices

	Gas price = 2 US$/MSCF			***Gas price = 5 US$/MSCF***			***Gas price = 9 US$/MSCF***		
Method	**NPV (US$)**	**IRR (%)**	**DPI**	**NPV (US$)**	**IRR (%)**	**DPI**	**NPV (US$)**	**IRR (%)**	**DPI**
Water injection	189,929,143	260.31	28.93	193,024,247	265.34	29.39	197,151,051	272.05	29.99
Gas injection	194,330,794	186.40	16.86	194,847,536	181.71	16.91	195,536,527	175.54	16.96
SSWAG best case	254,624,131	309.62	16.67	255,273,547	298.48	16.71	256,139,434	283.80	16.76
GAGD best case	299,235,544	433.08	25.43	299,436,027	404.03	25.44	299,703,337	365.78	25.47

According to the results of economic analysis, the important points are summarized as follows:

- NPV of all methods are more or less the same except for waterflooding. NPV of waterflooding is higher with higher gas price. This is because the whole amount of produced gas can be sold together with the produced oil as gas is not required to be reinjected into the reservoir.
- Gas injection, SSWAG and GAGD are the process that require gas cycling. Higher gas price causes increase in operating cost; thus, IRR reduces.
- IRR of waterflooding increases when gas price is high due to the fact that waterflooding makes higher revenue from gas sale.
- DPI of waterflooding increases with higher gas price as well as the other methods but not sighnificantly higher.
- Gas price does not affect IRR and DPI ranking.

CHAPTER VII

CONCLUSION AND RECOMMENDATION

This chapter concludes the production performance of SSWAG and GAGD including the effects of individual parameters and evaluation of both methods in term of monetary values. After that, some recommendations of possible future study are stated.

7.1 Conclusion

Results from this study show that recovery factor of SSWAG and GAGD in range of 50% to 80% which is dependent on the design parameters. The most suitable set of design parameters need to be selected carefully in order to achieve desired production performance under required period of production time. The summary of effect from each parameter on both processes is listed as follows:

1. ***SSWAG***

- Injection rate has significant effect on oil recovery. Higher gas injection rate with lower water injection rate yields better oil recovery. This setting allows gas to sweep a larger area of the reservoir; thus, less amount of oil remains in the reservoir.
- If injection pressure can be controlled constantly, oil producing under constant injection pressure yields better oil recovery than constant injection rate. At higher injection pressure, gas injection rate is significantly higher and segregation length is longer. Thus, better oil recovery is achieved. However, there are some drawbacks of using high injection pressure as production time is shortened and ultimate oil recovery is reduced. Additionally, a bigger capacity of gas processing facility is required to accommodate for high amount of produced gas.
- Locations of water and gas injectors have minimal effect on oil recovery.
- Lengths of water and gas injectors also have minimal effect on oil recovery.

- Shorter producer length results in better oil recovery as it can delay water breakthrough and limit the amount of water flowing into the wellbore. Thus, more oil is allowed to be recovered.
- Production well should be placed at the deepest depth at the most downdip location as it maximizes volumetric sweep efficiency as well as delays the breakthrough of water.
- Down-dip injection is not efficient when compared with up-dip injection due to the fact that gas bypasses most area of the reservoir and flows directly toward the producer. As a result, oil recovery performance is poor.

2. GAGD

- Increasing of total gas injection rate from all injectors yields higher oil recovery regardless of the numbers of injectors if consider at the same production time. However, too high injection rate results in shorter production time as well as reduction in ultimate oil recovery.
- Perforated height of gas injector has no effect on oil recovery because gas tends to flow and accumulate at top structure and sweep oil in the same manner.
- The vertical gas injector should be placed at the most updip location in the reservoir regardless of the position in the *y*-axis because this location takes less time to produce an equal amount of ultimate oil recovery.
- The number of gas injectors does not have an effect on oil recovery as long as the total gas injection rate remains the same.
- The horizontal producer should be placed at the most downdip location and at the deepest depth possible to maximize the volumetric sweep efficiency.

  Longer horizontal producer has more benefit on oil production performance because gas and water breakthroughs are delayed, and the volumetric sweep efficiency is maximized.

When comparing among SSWAG, GAGD and DDP, we found that SSWAG might not be suitable to implement in dipping reservoir as it has poorer performance than GAGD and DDP. DDP produces more oil only at early time until waterflooing is finished. After that, production performance of GAGD is better. Even though oil production of DDP is improved after gas injection, the ultimate oil recovery of GAGD is higher. DDP requires longer production time than GAGD in order to reach the equal amount of cumulative oil production.

In investment point of view, GAGD generates the highest NPV for 40 years of concession due to highest oil recovery efficiency while waterflooding generates the least NPV. However, when considering the size of capital cost, waterflooding turns out to be the most attractive project as it generates highest DPI value. This is because it generates more revenue with small amount of capital cost required. The choice of the selected method to implement can be varied by different oil company depending on the economic criteria.

Additionally, discount rate, oil price as well as gas price are important to consider as they have strong effect on NPV, IRR and DPI of the projects. These values can be changed at different time depends on the current situation in the world. Therefore, the decision can be different at various times.

7.2 Recommendation

The following points are recommended for future study.

1. Three phase relative permeability is the important calculation that can affect the performance of SSWAG and GAGD. Since this study is based on the ECLIPSE default correlation, other correlations such as Stone I and II, IKU may be investigated.
2. The performance of up-dip injection in SSWAG is based on the selected set of design parameters only. Thus, other sets of parameters should be investigated to see the effect on the performance.
3. This study is performed on a reservoir that has 10 degree of dipping. Other dipping angle might have different results.
4. Sensitivity analysis of relative permeability characteristics of fluid especially S_{org} should be conducted to see its effect on production performance.
5. More numbers of injectors and producers may be applied by spreading them out in the reservoir and production and injection are done in similar manner to DDP configuration.

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APPENDIX

Appendix

Reservoir model

A reservoir model is generated by entering required data into 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.

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	32.529 md
Porosity	0.1509
Dip angle	10 degree
Grid block sizes	based on calculation with dip angle

3. PVT

Fluid densities at surface condition	Oil density	51.6375	lb/cu.ft
	Water density	62.42841	lb/cu.ft
	Gas density	0.04981752	lb/cu.ft
Water PVT properties	Reference pressure (Pref)	3000	psia
	Water FVF at Pref	1.021057	rb/stb
	Water compressibility	3.08E-06	/psi
	Water viscosity at Pref	0.3051548	cp
	Water viscosibility	3.35E-06	/psi
Rock properties	Reference pressure	2500	psia
	Rock compressibility	2.23183E-06	psi-1

<u>Live oil PVT properties (dissolved gas)</u>

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.001487023	14.7	1.0681108	1.3127257
	277.08421	1.0526951	1.3925997
	539.46842	1.0522782	1.5344885
	801.85263	1.0521342	1.7211519
	1064.2368	1.0520612	1.9514282
	1326.6211	1.052017	2.22775
	1589.0053	1.0519875	2.5541898
	1851.3895	1.0519663	2.9358124
	2113.7737	1.0519504	3.3783753
	2377.1	1.051938	3.8901081
	2638.5421	1.0519281	4.4717768
	3000	1.0519172	5.4094568
	3163.3105	1.0519131	5.8882815
	3425.6947	1.0519074	6.735162
	3688.0789	1.0519025	7.6836247
	3950.4632	1.0518982	8.7401876
	4212.8474	1.0518944	9.9108943
	4475.2316	1.0518911	11.20115
	4737.6158	1.0518882	12.615558
	5000	1.0518856	14.157761
0.051143728	277.08421	1.0906066	1.0422891
	539.46842	1.0811864	1.0728171
	801.85263	1.0779506	1.1200812
	1064.2368	1.076314	1.1805878
	1326.6211	1.075326	1.2528013
	1589.0053	1.0746648	1.335993
	1851.3895	1.0741912	1.4298355
	2113.7737	1.0738354	1.53422

	2377.1	1.0735573	1.6495903
	2638.5421	1.0733362	1.7747267
	3000	1.073094	1.9653042
	3163.3105	1.0730028	2.0581591
	3425.6947	1.0728744	2.2162075
	3688.0789	1.0727643	2.3852196
	3950.4632	1.0726689	2.5651972
	4212.8474	1.0725853	2.7560864
	4475.2316	1.0725115	2.9577697
	4737.6158	1.0724459	3.1700599
	5000	1.0723872	3.3926957
0.11413173	539.46842	1.1200769	0.8518502
	801.85263	1.1124111	0.8750336
	1064.2368	1.1085461	0.9071613
	1326.6211	1.1062164	0.9468239
	1589.0053	1.1046589	0.9932351
	1851.3895	1.1035442	1.0459281
	2113.7737	1.102707	1.1046148
	2377.1	1.102053	1.1693534
	2638.5421	1.1015331	1.2392961
	3000	1.1009639	1.3451364
	3163.3105	1.1007495	1.3963907
	3425.6947	1.1004478	1.4831583
	3688.0789	1.1001891	1.5753064
	3950.4632	1.0999649	1.6727454
	4212.8474	1.0997686	1.7753668
	4475.2316	1.0995953	1.8830397
	4737.6158	1.0994413	1.9956076
	5000	1.0993035	2.1128867
0.18398687	801.85263	1.1538138	0.7236678
	1064.2368	1.1468702	0.7428902
	1326.6211	1.1426948	0.767762
	1589.0053	1.1399068	0.7975587
	1851.3895	1.1379132	0.8318197
	2113.7737	1.1364169	0.870238
	2377.1	1.1352486	0.9127577
	2638.5421	1.1343203	0.9587439
	3000	1.1333042	1.0282869
	3163.3105	1.1329215	1.0619139
	3425.6947	1.1323833	1.1187417
	3688.0789	1.1319218	1.1789424
	3950.4632	1.1315218	1.2424221
	4212.8474	1.1311718	1.3090806
	4475.2316	1.1308629	1.3788081
	4737.6158	1.1305882	1.4514836
	5000	1.1303425	1.5269729

0.25876733	1064.2368	1.1909941	0.6325872
	1326.6211	1.1843639	0.6491822
	1589.0053	1.1799457	0.6696831
	1851.3895	1.17679	0.6936622
	2113.7737	1.1744233	0.7208224
	2377.1	1.1725767	0.7510628
	2638.5421	1.17111	0.7838816
	3000	1.1695053	0.8336094
	3163.3105	1.1689012	0.8576684
	3425.6947	1.1680517	0.8983208
	3688.0789	1.1673235	0.9413587
	3950.4632	1.1666924	0.9866954
	4212.8474	1.1661403	1.0342428
	4475.2316	1.1656531	1.0839094
	4737.6158	1.16522	1.1355981
	5000	1.1648325	1.1892055
0.33745756	1326.6211	1.2311619	0.5646109
	1589.0053	1.2246405	0.5792881
	1851.3895	1.219991	0.5968255
	2113.7737	1.2165075	0.6169469
	2377.1	1.2137915	0.6395315
	2638.5421	1.2116356	0.6641673
	3000	1.2092783	0.7016325
	3163.3105	1.2083911	0.7197915
	3425.6947	1.2071439	0.7504995
	3688.0789	1.2060752	0.7830245
	3950.4632	1.2051492	0.8172877
	4212.8474	1.2043391	0.8532117
	4475.2316	1.2036245	0.8907181
	4737.6158	1.2029894	0.9297268
	5000	1.2024213	0.9701543
0.41942037	1589.0053	1.2740113	0.5118596
	1851.3895	1.2674798	0.5250539
	2113.7737	1.2625948	0.5404274
	2377.1	1.2587895	0.557856
	2638.5421	1.2557711	0.5769922
	3000	1.2524727	0.6062386
	3163.3105	1.251232	0.6204532
	3425.6947	1.2494883	0.6445265
	3688.0789	1.2479947	0.6700555
	3950.4632	1.2467009	0.6969685
	4212.8474	1.2455694	0.7251963
	4475.2316	1.2445714	0.7546708
	4737.6158	1.2436846	0.7853238
	5000	1.2428914	0.8170855
0.50421417	1851.3895	1.3193158	0.469646

	2113.7737	1.3126977	0.4816474
	2377.1	1.3075514	0.4954101
	2638.5421	1.3034726	0.5106411
	3000	1.2990188	0.5340626
	3163.3105	1.2973444	0.5454865
	3425.6947	1.294992	0.5648728
	3688.0789	1.2929778	0.5854691
	3950.4632	1.2912336	0.6072092
	4212.8474	1.2897087	0.630031
	4475.2316	1.288364	0.653874
	4737.6158	1.2871695	0.6786786
	5000	1.2861013	0.7043852
0.59151284	2113.7737	1.3668978	0.4350262
	2377.1	1.3601181	0.4460822
	2638.5421	1.354754	0.4584242
	3000	1.3489019	0.4775423
	3163.3105	1.3467031	0.486907
	3425.6947	1.3436153	0.502839
	3688.0789	1.3409726	0.5198048
	3950.4632	1.3386851	0.5377434
	4212.8474	1.3366858	0.5565979
	4475.2316	1.3349234	0.576314
	4737.6158	1.3333581	0.5968388
	5000	1.3319587	0.6181201
0.68138989	2377.1	1.4167945	0.405968
	2638.5421	1.4098782	0.4161048
	3000	1.402347	0.4319294
	3163.3105	1.3995193	0.4397196
	3425.6947	1.3955503	0.4530123
	3688.0789	1.392155	0.4672075
	3950.4632	1.3892174	0.4822482
	4212.8474	1.3866508	0.4980818
	4475.2316	1.3843891	0.514659
	4737.6158	1.382381	0.5319321
	5000	1.3805862	0.5498547

Dry gas PVT properties (no vapourised oil)

Press (psia)	FVF (rb /Mscf)	Visc (cp)
14.7	224.98177	0.0127419
277.08421	11.543356	0.0129672
539.46842	5.7371338	0.0133372
801.85263	3.7395964	0.0138274
1064.2368	2.7357394	0.0144384

1326.6211	2.1378138	0.0151737
1589.0053	1.7463019	0.0160338
1851.3895	1.474605	0.0170118
2113.7737	1.278751	0.0180922
2377.1	1.1332741	0.0192559
2638.5421	1.0240261	0.0204628
3000	0.91256865	0.0221679
3163.3105	0.87309757	0.0229387
3425.6947	0.82007509	0.024165
3688.0789	0.77698746	0.0253669
3950.4632	0.74140401	0.0265382
4212.8474	0.71157522	0.0276756
4475.2316	0.68622679	0.028778
4737.6158	0.6644184	0.0298457
5000	0.64544666	0.0308798

4. SCAL

Water/oil saturation functions

Sw	Krw	Kro	Pc (psia)
0.61	0	0.8	0
0.63111111	0.033333333	0.65483321	0
0.65222222	0.066666667	0.52184844	0
0.67333333	0.1	0.40154558	0
0.69444444	0.13333333	0.29452809	0
0.71555556	0.16666667	0.20154856	0
0.73666667	0.2	0.12359015	0
0.75777778	0.23333333	0.062033847	0
0.77888889	0.26666667	0.019093156	0
0.8	0.3	0	0
1	1	0	0

Gas/oil saturation functions

Sg	Krg	Kro	Pc (psia)
0	0	0.8	0
0.04	0	0.56952423	0
0.07875	0.1	0.39186345	0
0.1175	0.2	0.25449763	0
0.15625	0.3	0.15274825	0
0.195	0.4	0.081776443	0
0.23375	0.5	0.036542626	0
0.2725	0.6	0.011742058	0
0.31125	0.7	0.00168601	0
0.35	0.8	0	0
0.39	1	0	0

5. Initialization

Equilibration data specification

Datum depth	6000 ft
Pressure at datum depth	2377.1 psia
WOC depth	12000 ft
GOC depth	6000 ft

6. Schedule

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

6.1 SSWAG

Oil vertical production well

Well specification

Well name	P
Group	PRODUCER
I location	73
J location	16
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	1
K lower	21
Open/shut flag	OPEN
Well bore ID	0.5522083 ft
Direction	Z

Production well control

Well	P
Open/shut flag	OPEN
Control	LRAT
Liquid rate	1080 stb/day
BHP target	500 psia

Production well economic limits

Well	P
Maximum water cut	0.96
Workover procedure	NONE
End run	YES
Quantity for economic limit	RATE
Secondary workover procedure	NONE

Water horizontal injection well

Well specification

Well name	WI
Group	INJECTOR
I location	1
J location	1
Preferred phase	WATER
Inflow equation	STD
Automatic shut-in instruction	SHUT

Crossflow	YES
Density calculation	SEG

Well connection data

Well connection data	WI
I Location	1
J Location	1
K upper	1
K lower	1
Open/shut flag	OPEN
Well bore ID	0.5522083 ft
Direction	Z

The keyword of well connection data is repeated for J Location of 2 through 21. By this way, the horizontal section of the well can be created.

Injection well control

Well	WI
Injector type	WATER
Open/shut flag	OPEN
Control mode	RATE
Liquid surface rate	1000 stb/day
BHP target	4500 psia

The keywords required for gas horizontal injection well is the same as water injector well except the preferred phase and injector type keywords are change from WATER into GAS.

6.2 GAGD

Oil horizontal production well

Well specification

Well name	P
Group	PRODUCER
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
I Location	73
J Location	1
K upper	21
K lower	21
Open/shut flag	OPEN
Well bore ID	0.5522083 ft
Direction	Z

The keyword of well connection data is repeated for J Location of 2 through 21. By this way, the horizontal section of the well can be created.

Production well control

Well	P
Open/shut flag	OPEN
Control	LRAT
Liquid rate	1000 stb/day
BHP target	500 psia

Production well economic limits

Well	P
Maximum water cut	0.96
Workover procedure	NONE
End run	YES
Quantity for economic limit	RATE
Secondary workover procedure	NONE

Gas vertical injection well

Well specification

Well name	GI
Group	INJECTOR
I location	1
J location	15
Preferred phase	GAS
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

Well connection data

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

Injection well control

Well	WELL1
Injector type	GAS
Open/shut flag	OPEN
Control mode	RATE
Liquid surface rate	1000 Mscf/day
BHP target	4500 psia

Vitae

Oranat Santidhananon was born on February 11^{th}, 1985 in Bangkok, Thailand. She received her Bachelor Degree in Electrical Engineering from the Faculty of Engineering, Chulalongkorn University in 2007. Then, she joined Schlumberger as a Wireline Field Engineer and was based in Pau, France and Phitsanulok, Thailand for nearly three years. After that, she continued her study in Master Degree of Petroleum Engineering at graduate school of the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2010.