EVALUATION AND OPTIMIZATION OF SECOND CONTACT WATER DISPLACEMENT PROCESS (SCWD)

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การประเมินและหาค่าที่ดีที่สุดของกระบวนการแทนที่ด้วยน้ำครั้งที่สอง

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การฉีดแก๊สในแหล่งกักเก็บลาดเอียงเป็นวิธีหนึ่งที่มีประสิทธิภาพมากที่สุดในการนำน้ำมันที่เหลือจากการฉีดน้ำขึ้นมา กระบวนการนี้ประกอบด้วยกระบวนการแทนที่สองครั้งซึ่งคือการฉีดแก๊สตามหลังจากฉีดน้ำลงในแหล่งน้ำมัน และกระบวนการแทนที่ด้วยน้ำที่เชื่อมต่ออันดับสองซึ่งคือการแทนที่ด้วยน้ำใหม่ในแหล่งน้ำมันที่ฉีดแก๊สลงไป หลังจากที่แก๊สในกระบวนการแทนที่สองครั้งมาถึงหลุมผลิต แรงโน้มถ่วงจะมีผลโดยตรงต่อการไหลของน้ำมัน ทำให้อัตราการไหลของน้ำมันช้ามาก หลังจากที่น้ำมันผลิต อัตราการผลิตของน้ำมันจะต่ำ ใช้เวลานาน และได้ค่าความอิ่มตัวของน้ำมันต่ำ เพื่อลดช่วงเวลาของการผลิตน้ำมันต่ำ กระบวนการแทนที่ด้วยน้ำที่เชื่อมต่ออันดับสองจึงถูกแนะนำ และกระบวนการนี้คือการต่อยอดของกระบวนการแทนที่สองครั้ง

ผลกระทบของความลาดเอียงได้ถูกศึกษา ผลการศึกษาบ่งบอกว่าแหล่งกักเก็บที่มีความลาดเอียงน้อยกว่าให้ประสิทธิภาพมากกว่า สำหรับเวลาในการหยุดการฉีดน้ำและแก๊ส อัตราส่วนในการผลิตน้ำที่ 60 เปอร์เซ็นต์และค่าอัตราส่วนแก๊สต่อน้ำมันที่ 5 MSCF/STB ให้ประสิทธิภาพดีที่สุด ในส่วนของอัตราการฉีดน้ำและแก๊ส เราได้ปริมาณน้ำมันที่นำขึ้นมาได้มากที่สุดเมื่อใช้อัตราการฉีดน้ำครั้งที่หนึ่งที่ 2,000 STB/D อัตราการฉีดแก๊สที่ 2,000 MSCF/D และอัตราการฉีดน้ำครั้งที่สองที่ 2,000 STB/D โดยใช้รูปแบบการวางหลุมแบบ 4 หลุมแนวตั้งจะได้ปริมาณน้ำมันที่นำขึ้นมาได้มากที่สุดสำหรับแหล่งกักเก็บที่มีความลาดเอียง 0 และ 15 องศา ขณะที่รูปแบบการวางหลุมแบบ 2 หลุมแนวนอนจะให้ผลดีที่สุดสำหรับแหล่งกักเก็บที่มีความลาดเอียง 30 องศา สำหรับปริมาณน้ำมันที่นำขึ้นมาจากการวิเคราะห์เชิงละเอียดจาก ECLIPSE default และ Stone 1 ต่างกันเพียงเล็กน้อย แต่ปริมาณน้ำมันที่นำขึ้นมาจาก Stone 2 มีค่าน้อยกว่าทั้งสองอันแรก ขณะที่อัตราส่วนในแนวตั้งและแนวนอนของค่าความซึมผ่านมาก ปริมาณน้ำมันที่นำขึ้นมาได้ก็เพิ่มขึ้นและขณะที่ค่าความอิ่มตัวที่เหลือของน้ำมันลดลง ทำให้ปริมาณน้ำมันที่นำขึ้นมาได้เพิ่มขึ้น นอกจากนี้ในด้านของความสามารถในการเปียกน้ำ ระบบแบบเปียกน้ำจะให้ประสิทธิภาพทั้งช่วงได้ดีกว่าระบบแบบเปียกน้ำมัน เนื่องจากน้ำมันสามารถไหลได้ง่ายในระบบแบบเปียกน้ำ

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
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Gas injection into a dipping reservoir is one of the most efficient methods to recover residual oil left by water flooding. This process includes Double Displacement Process (DDP) which consists of injecting gas into waterflooded oil zones and Second Contact Water Displacement (SCWD) process which consists of submitting these gas-flooded zones to a new water displacement process. After gas breakthrough in DDP, gravity has a major effect on oil film flow so that the oil flow rate is very low. After the oil bank is produced, the oil production rate is very low, and then a very long time is needed to reach very low oil saturation. To shorten the period of low oil production, SCWD has been suggested. This process is considered an extension of the DDP.

The effect of dip angles is studied. The results show that the less the dip angle, the better the SCWD performance. For stopping time for water and gas injection, water cut of 60% and gas-oil ratio of 5 is the best stopping criteria to provide the best SCWD performance. In term of water and gas injection rate, the best oil recovery is provided when using the 1st water injection rate of 2,000 STB/D, gas injection rate of 2,000 MSCF/D and the 2nd water injection rate of 4,000 STB/D. Using 4 vertical wells yields the highest oil recovery for reservoir with 0 and 15 degree dip angle while two horizontal wells works best for a reservoir with 30 degree dip angle. For sensitivity analysis, the oil recovery from ECLIPSE default and Stone 1 are insignificantly different but the oil recovery from Stone 2 is less than the others. A higher vertical to horizontal permeability ratio results in higher oil recovery, and smaller residual oil saturation yields higher oil recovery. Moreover, in term of wettability, water-wet system shows better overall performance than oil-wet system because oil can flow easily in the water-wet system.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
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Abbreviations

SCWD	Second contact water displacement
DDP	Double displacement process
mD	Millidarcy
MMscf/d	Million standard cubic feet per day
Mscf/d	Thousand standard cubic feet per day
psi	Pounds per square inch
psia	Pounds per square inch absolute
PVT	Pressure-volume-temperature
RF	Recovery factor
SCAL	Special core analysis
scf	Standard cubic foot
stb	Stock-tank barrel
STB/D	Stock-tank barrel per day
BOE	Barrel of oil equivalent
W_p	Amount of water production
W_{inj}	Amount of water injection
G_p	Amount of gas production
G_{inj}	Amount of gas injection
N_p	Cumulative oil production

Nomenclatures

Δp	Water-oil density difference
μ_o	Oil viscosity
μ_w	Water viscosity
C_o	Corey-oil exponent
C_w	Absolute permability
k	Absolute permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil (oil/water function)
k_{rog}	Relative permeability to oil (gas/liquid function)
k_{rw}	Relative permeability to water
S_w	Water saturation
S_{wc}	Connate water saturation
S_{wcr}	Critical water saturation
S_{wi}	Initial water saturation (connate water saturation)
S_{wmin}	Minimum water saturation (irreducible water saturation)
S_{wmax}	Maximum water saturation
S_{orw}	Residual oil saturation (to water)

CHAPTER I
INTRODUCTION

1.1 Background

In the last few years, Enhanced Oil Recovery (EOR) processes have received a lot of interest from research and development phase to oilfield EOR implementation. This interest has been furthered by high oil price, increasing worldwide oil demand and maturation of oilfields worldwide. Gas injection into a dipping reservoir is one of the most efficient methods to recover residual oil left by water flooding. This process includes Double Displacement Process (DDP), which is a process of injecting gas into waterflooded oil zones and Second Contact Water Displacement (SCWD) process, which is a process of submitting these gas-flooded zones to a new water displacement process.

After gas breakthrough in DDP, gravity has a major effect on oil film flow so that the oil flow rate is very low. After the oil bank is produced, the oil production rate is very low, and then a very long time is needed to reach very low oil saturation. To shorten the period of low oil production, SCWD has been suggested. This process is considered an extension of the DDP.

In this study, ECLIPSE reservoir simulation is used to investigate the effect of different system parameters (fluid and reservoir properties) on the performance of SCWD.

1.2 Objectives

1. To study effect of different system parameters (fluid and reservoir properties) on the performance of Second Contact Water Displacement (SCWD) process.
2. To determine the best condition for SCWD process which provides the highest ultimate oil recovery.

1.3 Outline of methodology

1. Construct a base simulation model.
2. Construct a reservoir model with different dip angles (0°, 15°, 30°) and study the effects on production performance of SCWD.
3. For each dip angle, design parameters are varied in order to optimize the oil production. These parameters are as follows:
   - Stopping time for water injection
   - Water and gas injection rates
   - Well pattern
4. Analyze the results from simulation to determine the best production strategy for each dip angle.
5. Simulate models with different system parameters in order to study their effects on production performance. These parameters are as follows:
   - Three-phase relative permeability models (Stone I, II, ECLIPSE default)
   - Vertical permeability or vertical to horizontal permeability ratio (0.01, 0.1, 1)
   - Residual oil saturation by gas displacement (S_{org}) (0.05, 0.1, 0.15)
   - Wettability (oil-wet, water-wet)
6. Compare and analyze the results that obtained from reservoir simulation.
7. Summarize the most suitable criteria for SCWD.

1.4 Outline of thesis

This thesis is divided into six parts as mentioned below:

Chapter I introduces background of SCWD and objectives and methodology of this study.

Chapter II describes previous studies and researches that are related to SCWD.

Chapter III reviews significant theories that used in this study.

Chapter IV provides detail of reservoir model and reservoir properties used in this study.

Chapter V discusses results obtained from reservoir simulation.

Chapter VI provides conclusions and recommendations for further study.

CHAPTER II
LITERATURE REVIEW

This chapter describes previous studies and works related to Second Contact Water Displacement (SCWD) process.

Lepski et al. [1] investigated the DDP process and observed that a certain amount of oil was displaced when injecting water in gas flooded zones (SCWD). In their experiments, consolidated cores and unconsolidated sandpacks were flooded at high pressure and high temperature by using transparent cells. They proved that SCWD could recover up to 20% of oil remaining after gas injection and shorten the time of DDP process.

Ren et al. [2] studied both DDP and SCWD processes. Experiments were conducted in a transparent sand-pack micromodel, and a pore-level observation was performed to investigate the microscopic mechanisms of the two processes. The result showed that the oil films have a very significant role in achieving high recovery efficiencies in the DDP. For SCWD process, residual oil can be recovered rapidly by a second water flood since trapped gas reduces the chance of the residual oil being trapped in the center of the pores. Therefore, the SCWD process is appropriate for reservoir where the source of gas is insufficient, and where the formation has a high irreducible gas saturation.

Ren et al. [3] [4] [5] performed reservoir simulations using an adaptive-implicit scheme to study the macroscopic mechanisms of the DDP and SCWD processes. They studied the effects of injection and production rates and reservoir dip angle on the performance of the DDP to improve the oil production and to develop a set of screening criteria for selecting candidate reservoirs for the process. In addition, the SCWD process was simulated to investigate its possibility. Moreover, the two processes were simulated in a micromodel transparent cell, and the results showed that the injection and production rates play a very important role in controlling the formation of oil bank, highly dipping reservoir are favorable for the gravity assisted tertiary gas injection process and the SCWD process is much shorter when compared to the period of low oil production of the DDP. Trapped gas reduces the possibility of the residual oil being trapped in the center of pores. Therefore, for situations where the source of gas is not sufficient, and where the formation has high irreducible gas saturation, the SCWD process is a good choice.

Lepski et al. [6] performed transparent cell experiments to support the assumption of film flow of water displacing residual oil and the dependence of DDP and SCWD efficiency on fluid distribution in the pore space. The capacity of oil to form a film is stated by the spreading coefficient in terms of interfacial and surface tensions. The drop volume and pendant techniques were used to measure IFT at high pressure and high temperature condition. IFT measurements showed that a positive spreading coefficient is needed for an efficient recovery of residual oil and for creating an oil film that controls oil recovery efficiency.

Gachuz-Muro et al. [7] investigated the efficiency of oil recovery using DDP and SCWD in fractured reservoirs. Two experiments were designed to illustrate both natural depletion and tertiary gas injection. Natural and nitrogen gas were used during the experiments. Results showed that DDP was capable of mobilizing oil and thus reducing the residual oil saturation from natural fractured reservoir with light oil under reservoir condition and injection of natural gas in DDP could recover more oil than nitrogen injection since nitrogen required a longer period of time to make direct contact with oil in matrix. The study revealed that an amount of residual oil can be recovered by tertiary gas injection after injecting water for a long period.

CHAPTER III
THEORY AND CONCEPT

3.1 Double displacement process (DDP)

DDP is the process of gas displacement of waterflooded oil zones. When contacted with the injected gas, residual oil globules spread out and form a thin film. The drainage of the oil film creates a bank which migrates down dip and can be produced later.

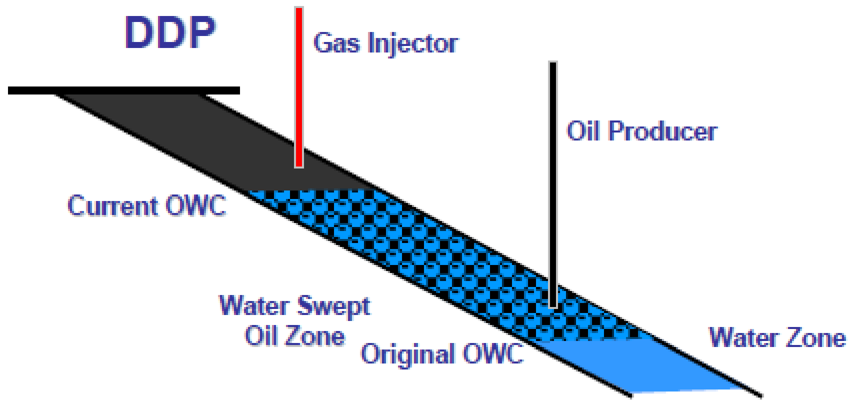

Figure 3. 1 DDP process [7].

3.2 Second Contact Water Displacement (SCWD) process

The Second Contact Water Displacement (SCWD) process is an extension of the Double Displacement Process (DDP). It is introduced to shorten the operating time of DDP by implementing a second waterflood after the main oil production of the DDP. The second waterflood of the reservoir can be implemented by injecting water into the bottom of the reservoir immediately after stopping gas injection.

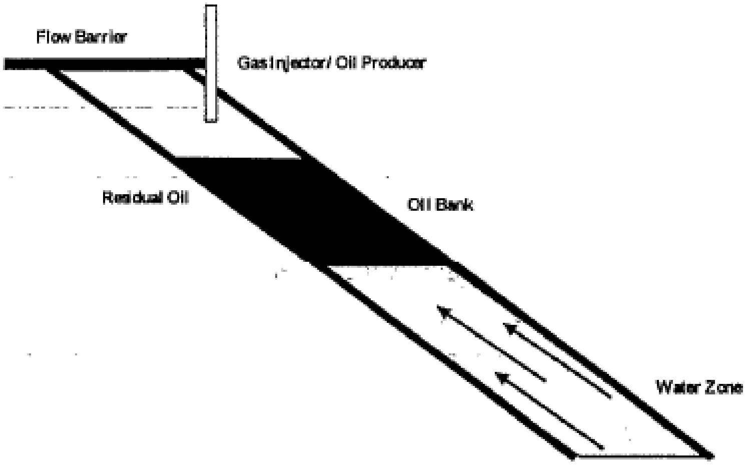

Figure 3. 2 SCWD process

3.3 Fundamental principles governing fluid and rock interactions

3.3.1 Wettability

Wettability is tendency of the reservoir rock surface to preferentially contact in a multiphase or two-phase fluid system. Wettability can be estimated by determining the contact angle or calculating the spreading coefficient. Wetting or spreading of a liquid on a solid surface depends on the solid surface properties. Wettability is a function of rock and fluid properties. The preferred fluid is known as the wetting phase while the other phase is the non-wetting phase [8].

3.3.2 Spreading coefficient

The spreading coefficient (*S*) is ability of oil to spread on water in the presence of gas. It is representation of the force balance where the three phases meet. Spreading coefficient is defined as

$$S = \sigma_{gw} - \sigma_{go} - \sigma_{ow} \tag{3.1}$$

where σ_{gw}, σ_{go} and σ_{ow} are the gas-water, gas-oil and oil-water interfacial tensions, respectively. If $S>0$, oil will spread between water and form a continuous film. If $S<0$, oil does not spread on water but stays discontinuous. Another important factor in gravity drainage process is the stability of the oil film since it controls the equilibrium of oil, water and gas in the spreading system. The thickness and stability of the oil film can be determined using a parameter α. This term is defined as

$$\alpha = \sigma_{ow}(\rho_o - \rho_g) / \sigma_{go}(\rho_w - \rho_o) \tag{3.2}$$

where ρ_o, ρ_g, and ρ_w are the density of oil, gas, and water, respectively. If α >1, oil is present in a form of molecular film. When α <1, it means gravity drainage is not efficient since large quantities of oil remain in the pore space, resulting in poor recoveries.

3.3.3 Capillarity

Capillarity or capillary action is the ability of a narrow tube to draw a liquid upwards against the force of gravity. The distribution of oil, gas, and water in the reservoir pores is controlled by their capillary interaction and the wetting characteristics of the reservoir rock. In immiscible flooding, capillary force exists and traps the non-wetting fluid in the pore space. The oil is driven downward through sand by its own weight resulting in two separate zones. At the top, where the liquid is in contact with free gas, capillarity controls the flow since the sand is only partially oil saturated. Lower of this capillary zone, which corresponds to a free surface, the sand is saturated or nearly saturated with liquid and flow follows hydraulic laws. Therefore, the complete data of the capillarity is essential to predict the saturations and displacement of the displaced phase.

3.3.4 Relative Permeability

3.3.4.1 Two-phase relative permeability model

In many cases, relative permeability data on actual samples from reservoir may not be available. In which case, it is necessary to obtain the desired relative permeability data by some other methods. Several methods have been developed for calculating relative permeability relationship. In addition, most of correlations use the effective phase saturation as a correlating parameter. The effective phase saturation is defined by the following:

$$S_o^* = \frac{S_o}{1 - S_{wc}} \tag{3.3}$$

$$S_w^* = \frac{S_w - S_{wc}}{1 - S_{wc}} \tag{3.4}$$

$$S_g^* = \frac{S_g}{1 - S_{wc}} \tag{3.5}$$

where

S_o^*, S_w^*, S_g^* = effective oil, water, and gas saturation, respectively

S_o, S_w, S_g = oil, water, and gas saturation, respectively

S_{wc} = connate water saturation

3.3.4.1.1 Wyllie and Gardner Correlation

Wyllie and Gardner [9] observed that, in some rocks, the relationship between the reciprocal capillary pressure squares $(\frac{1}{Pc^2})$ and the effective water saturation S_w^* is linear over a wide range of saturation.

Type of formation	k_{ro}	k_{rw}
Unconsolidated sand, well sorted	$(1 - S_w^*)$	$(S_w^*)^3$
Unconsolidated sand, poorly sorted	$(1 - S_w^*)^2(1 - S_w^{*1.5})$	$(S_o^*)^{3.5}$
Cemented sandstone, limestone	$(1 - S_o^*)^2(1 - S_w^{*2})$	$(S_o^*)^4$

Type of formation	k_{ro}	k_{rw}
Unconsolidated sand, well sorted	$\left(S_o^*\right)^3$	$\left(1-S_o^*\right)^3$
Unconsolidated sand, poorly sorted	$\left(S_o^*\right)^{3.5}$	$\left(1-S_o^*\right)^2\left(1-S_o^{*1.5}\right)$
Cemented sandstone, limestone	$\left(S_o^*\right)^4$	$\left(1-S_o^*\right)^2\left(1-S_o^{*2}\right)$

3.3.4.1.2 Pirson's Correlation

Pirson [9] derived generalized relationships to determine relative permeability for the wetting and nonwetting phase. The generalized expressions are practical for water-wet rocks.

<u>For the water phase</u>

$$k_{rw} = \sqrt{S_w^*}\, S_w^3$$

The above expression is valid for both the imbibition and drainage processes.

<u>For the non-wetting phase</u>

Imbibition

$$(k_r)_{nonwetting} = \left[1-\left(\frac{S_w - S_{wc}}{1 - S_w - S_{nw}}\right)\right]^2 \tag{3.6}$$

Drainage

$$(k_r)_{nonwetting} = (1 - S_w^*)\left[1 - (S_w^*)^{0.25}\sqrt{S_w}\right]^{0.5} \tag{3.7}$$

where

S_{nw} = saturation of the non-wetting phase

S_w = water saturation

S_w^* = effective water saturation

3.3.4.2 Three-phase relative permeability model

3.3.4.2.1 ECLIPSE model

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

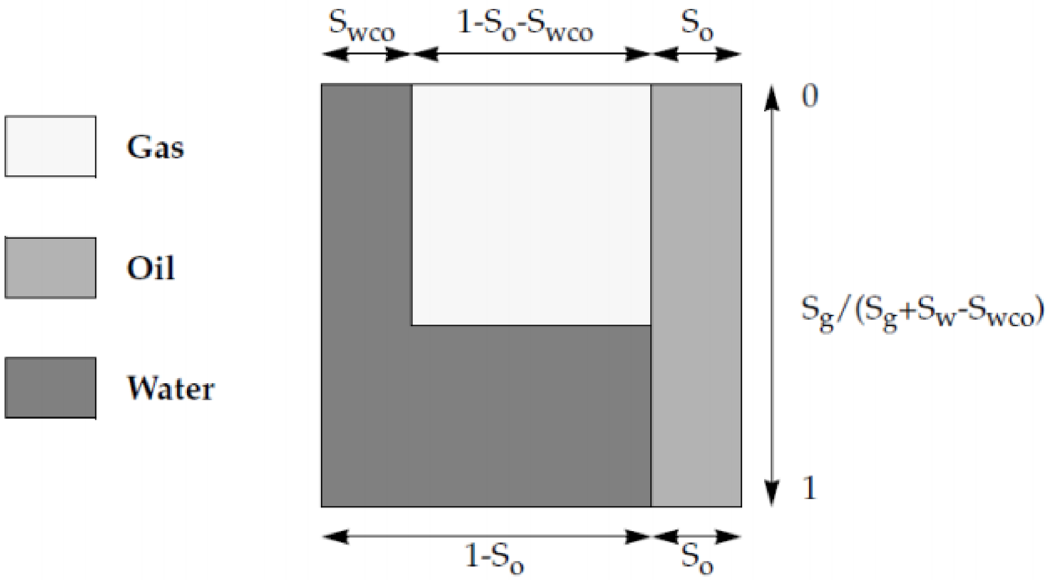

Figure 3. 3 Default model of three-phase relative permeability assumed by ECLIPSE

$$k_{ro} = \frac{S_g k_{rog} + (S_w - S_{wco}) k_{row}}{S_g + S_w - S_{wco}} \tag{3.8}$$

where

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

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

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

S_{wco} = the connate saturation

3.3.4.2.2 Stone's Model 1

This model was developed by Stone [10] based on flow theory. This model was first introduced as an interpolation technique between two phase flow conditions. Stone defined normalized saturations as

$$S_o^* = \frac{S_o - S_{om}}{(1 - S_{wc} - S_{om})} \tag{3.12}$$

$$S_w^* = \frac{S_w - S_{wc}}{(1 - S_{wc} - S_{om})} \tag{3.13}$$

$$S_g^* = \frac{S_g}{(1 - S_{wc} - S_{om})} \tag{3.14}$$

Stone [11] also defined the weighing coefficients as:

$$\beta_w = \frac{k_{row}}{1 - S_w^*} \tag{3.15}$$

$$\beta_g = \frac{k_{rog}}{1 - S_g^*} \tag{3.16}$$

where

S_{om} = minimum oil saturation

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

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

The three phase oil relative permeability as constructed my Stone's model 1 may now be defined as

$$k_{ro} = S_o^* \beta_w \beta_g \tag{3.17}$$

3.3.4.2.3 Stone's Model 2

Stone [11] realized that it was very difficult to choose S_{om} correctly, leading him to develop a new correlation called Stone's Model 2.

$$k_{ro} = (k_{ro})_{S_{wc}} \left[\left(\frac{k_{row}}{(k_{ro})_{S_{wc}}} + k_{rw} \right) + \left(\frac{k_{rog}}{(k_{ro})_{S_{wc}}} + k_{rg} \right) - \left(k_{rw} + k_{rg} \right) \right] \quad (3.18)$$

This model gives a reasonable approximation to the three-phase relative permeability.

CHAPTER IV
RESERVOIR SIMULATION

A black oil ECLIPSE 100 reservoir simulation is used as a tool to evaluate the performance of SCWD in this study. This chapter explains important information used to construct the reservoir model in each section of the simulator.

4.1 Reservoir model

The base reservoir model is created by using Cartesian coordinate and corner point grid. The size of the reservoir is 2,000×2,000×210 ft with the number of grid blocks of 73×31×21 in the x, y, and z direction, respectively. The reservoir is assumed to be homogenous. Summary of reservoir model and properties are shown in Table 4.1. Figure 4.1 shows the schematic of the base reservoir model.

Table 4. 1 Summary of reservoir model and properties.

Parameters	Values	Units
Number of grids	73×31×21	Block
Size of reservoir	2,000×2,000×210	ft
Porosity	15.09	%
X permeability	32.529	mD
Y permeability	32.529	mD
Z permeability	3.2529	mD
Top of reservoir	5,000	ft
Initial pressure @ 5,000 ft	2,242	psia
Bubble point pressure	2,242	psia

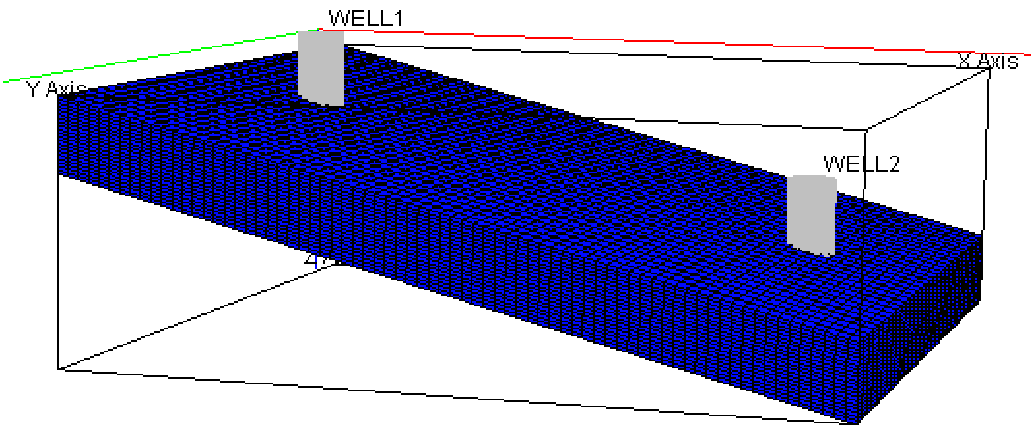

Figure 4. 1 Reservoir model

4.2 PVT properties

The PVT properties of reservoir fluids are generated from ECLIPSE 100 correlation. Table 4.2 show the parameters required for the correlation. The properties of dry gas and live oil PVT obtained from the correlation are shown in Figure 4.3 and 4.4.

Table 4. 2 Input data for PVT correlation.

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

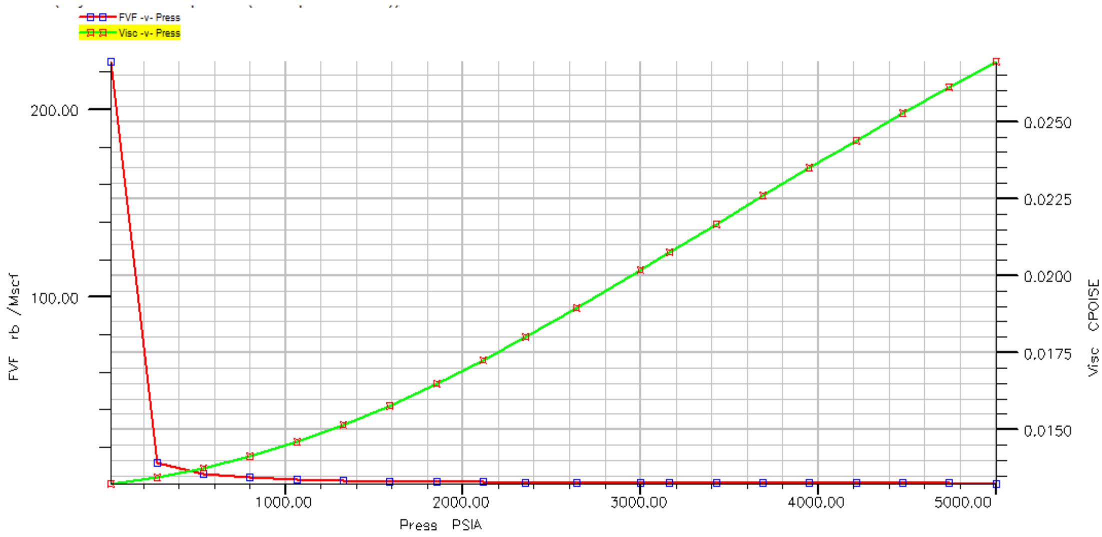

Figure 4. 2 Dry gas PVT properties (no vaporized oil).

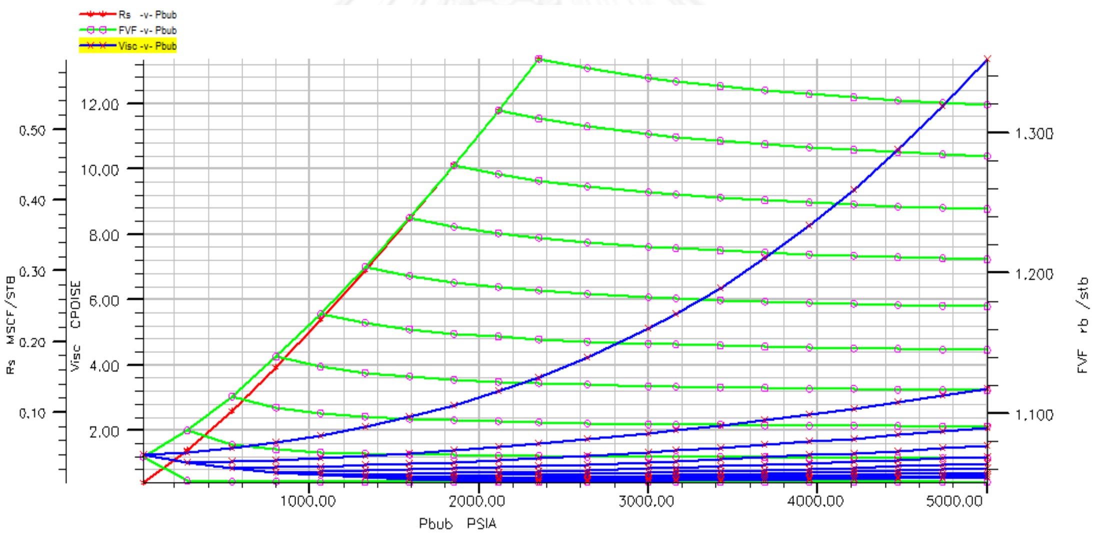

Figure 4. 3 Live oil PVT properties (dissolved gas).

4.3 SCAL properties

In this study, Corey's correlation is used to create relative permeability curves. Table 4.3 show the input parameters used in Corey's correlation. Figures 4.4 and 4.5 show the generated relative permeability curves.

Table 4. 3 Input parameters for Corey's correlation.

Corey water	2	Corey gas/oil	3	Corey oil/water	3
S_{wmin}	0.1	S_{gmin}	0	Corey oil/gas	3
S_{wcr}	0.1	S_{gcr}	0.15	S_{org}	0.1
S_{wi}	0.1	S_{gi}	0.15	S_{orw}	0.3
S_{wmax}	1	$k_{rg}(S_{org})$	0.8	$k_{ro}(S_{wmin})$	0.8
$k_{rw}(S_{orw})$	0.7	$k_{rg}(S_{gmax})$	0.8	$k_{ro}(S_{gmin})$	0.8
$k_{rw}(S_{wmax})$	0.7				

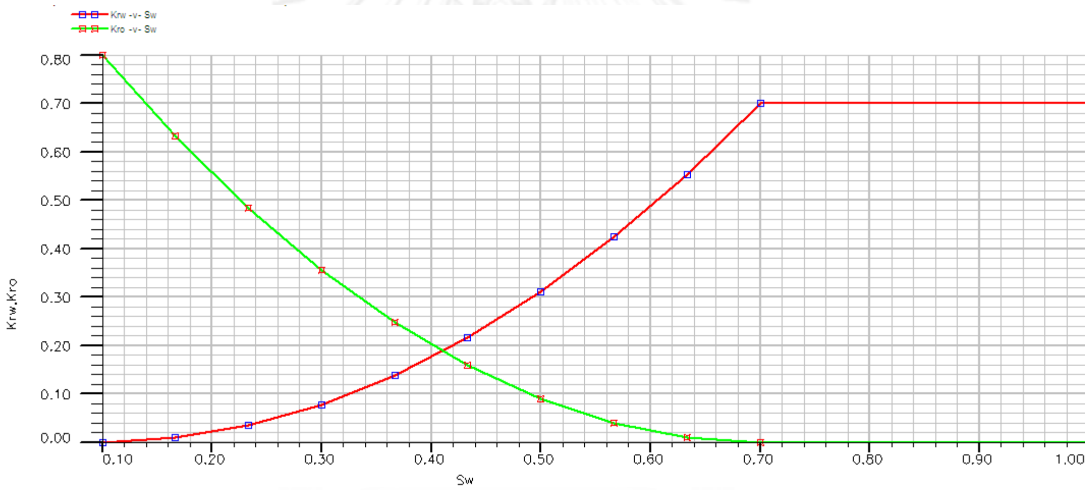

Figure 4. 4 Water/oil saturation function.

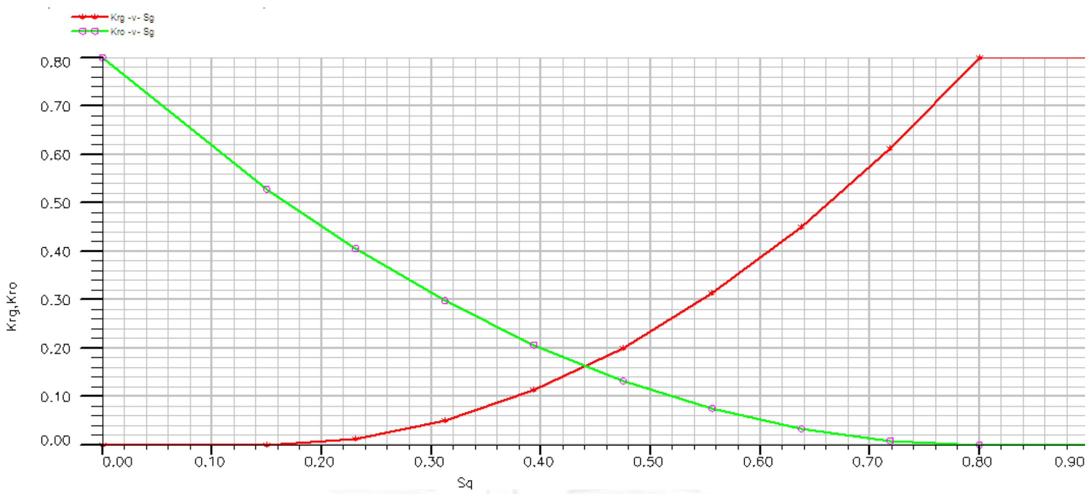

Figure 4. 5 Gas/oil saturation function.

4.4 Well schedules

In this study, well 1, which is an updip well, is located at i=12, j=16 and the fracture pressure is 3231 psia. Well 2, which is a downdip well, is located at i=62, j=16 and the fracture pressure is 3507 psia for the base model. The economic oil production rate is 100 STB/D with minimum bottomhole pressure of 500 psia.

CHAPTER V
SIMULATION RESULTS AND DISCUSSIONS

In this chapter, the reservoir model is simulated under different conditions by varying parameters which are dip angle, stopping time for water injection, water and gas injection rate and well pattern. The results of all parameters and sensitivities are illustrated and discussed. Finally, all sensitivities parameters are simulated from base case and the results of sensitivities caused by relative permeability correlation, vertical to horizontal permeability ratio, residual oil saturation by gas displacement and wettability are studied.

5.1 Base case

Firstly, the base case of reservoir model is simulated. The base case is simulated for the reservoir model with dip angle of 15 degrees. Two vertical wells are placed as shown in Figure 5.1. During the first period which is waterflooding, well 1 is a producer and well 2 is an injector. We inject 4,000 STB/D of water until the water cut reaches the criteria. After that, we shut in both wells for 6 months to stabilize to the reservoir pressure. Then, we inject 4,000 MSCF/D of gas at well 1 and reopen well 2 for production until gas/oil ratio reaches 5 MSCF/STB. Then, we inject water again at rate of 4,000 STB/D at well 2 with maximum bottomhole pressure of 3,172 psia and change well 1 to be a producer again. Note that the minimum bottomhole pressure of each producer is set at 500 psia. The economic limit oil rate is 100 STB/D with a concession period of 30 years.

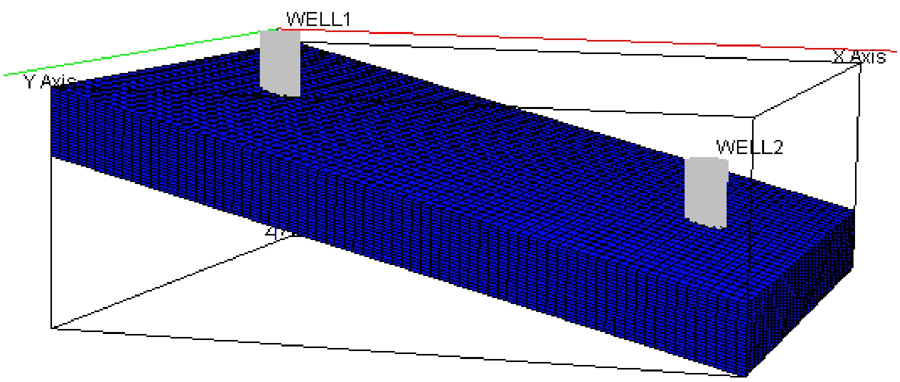

Figure 5. 1 Well locations for 15 degree dipping reservoir.

Figure 5.2 shows the oil, water and gas production rates of the reservoir. Oil is produced at the maximum rate of 4,000 STB/D for about 2 years, then decreases slightly while water production rate increases. Gas is produced at the maximum rate of 146,000 MSCF/D at year 7th which is during gas injection period.

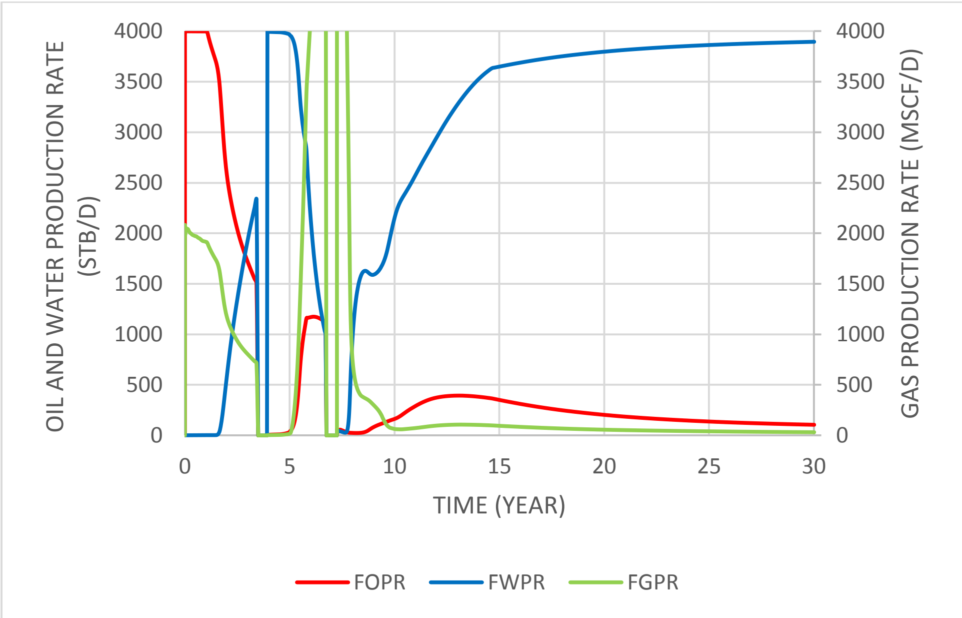

Figure 5. 2 Oil, water and gas production rates of the reservoir.

The water injection rate and bottomhole pressure of well 2, which is the water injector, during the initial and second waterflooding, are shown in Figure 5.3. At the maximum water injection rate of 4,000 STB/D, the bottomhole pressure of well 2 is around 2,700 psia then drops to 1,900 psia during gas injection period and becomes stable around 2,000 psia in the 2nd water injection period. Figure 5.4 shows the gas injection rate with bottomhole pressure of well 1, which is the gas injector, during the gas injection period. The bottomhole pressure of well 1 sharply decreases at early time then becomes stable around 500 psia, then increases again in gas injection period to 3,500-4,400 psia. In the 2nd water injection period, bottomhole pressure of well 1 becomes stable around 500 psia and slightly increases after 15 years.

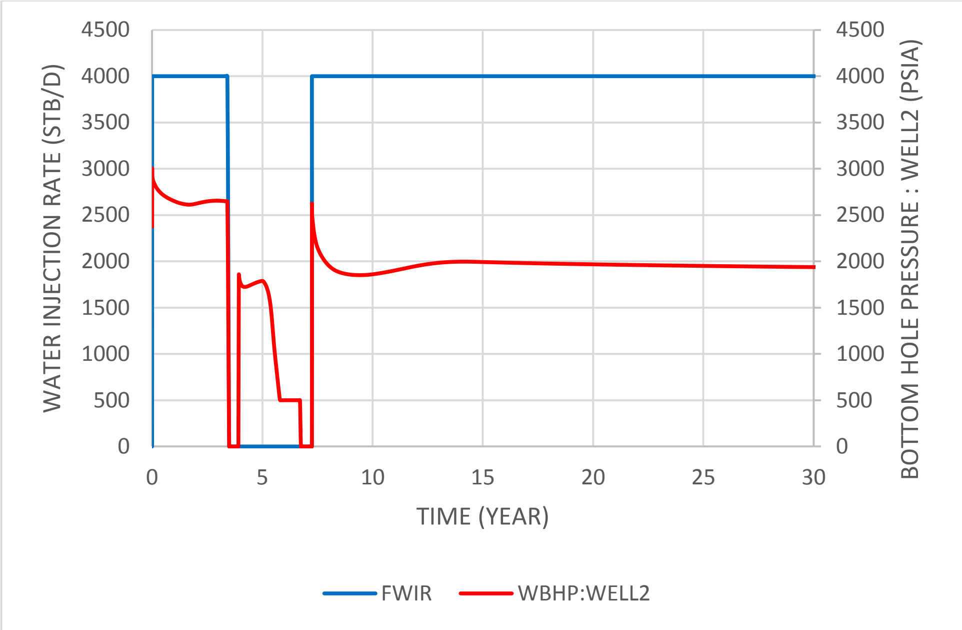

Figure 5. 3 Water injection rate with bottomhole pressure of well 2.

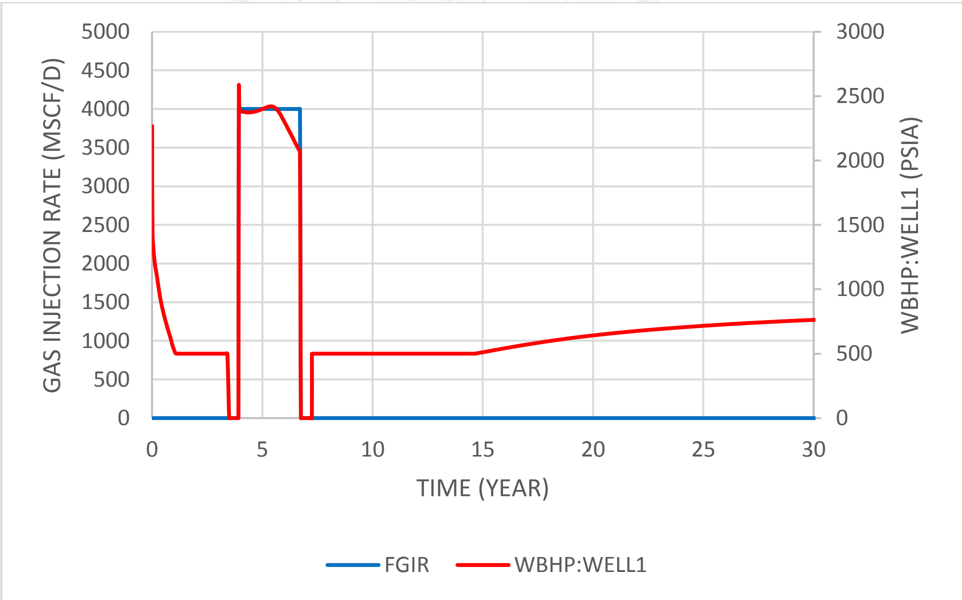

Figure 5. 4 Gas injection rate with bottomhole pressure of well 1.

As shown in Figure 5.5, cumulative oil production and oil recovery factor have the same increasing trend. At 30 years, cumulative oil production is about 6 MMSTB and oil recovery factor is 0.5.

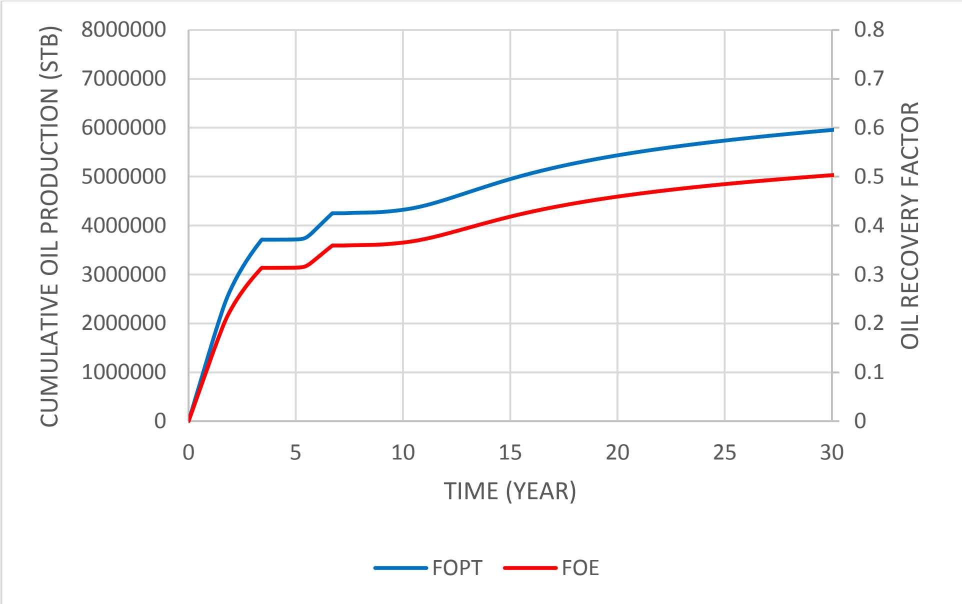

Figure 5. 5 Cumulative oil production with oil recovery factor.

In Figure 5.6, the cumulative gas production becomes steady around 1.8 BSCF during 1st water injection period. Then, it suddenly increases in the gas injection period. After that, cumulative gas production slightly increases during the 2nd water injection period.

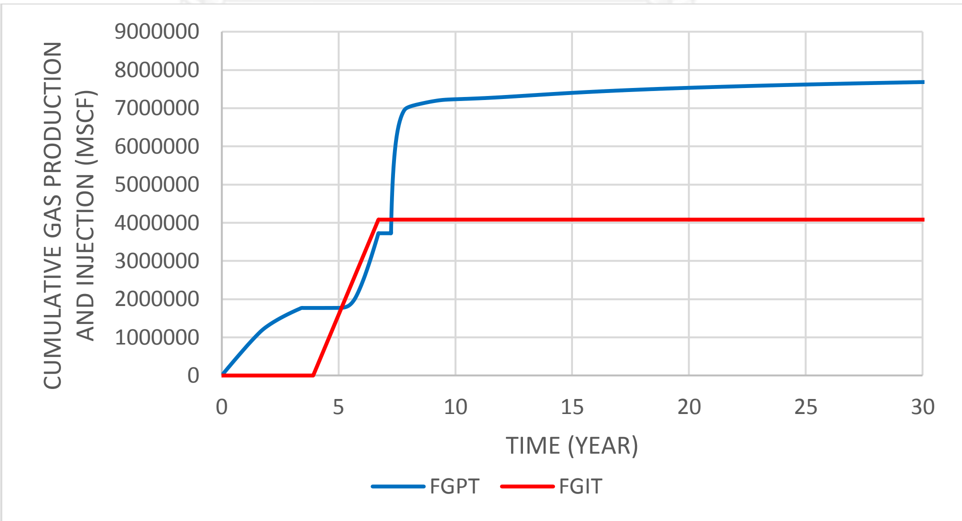

Figure 5. 6 Cumulative gas production and injection.

Cumulative water production and injection increase in the same trend as shown in Figure 5.7. Figure 5.8 shows gas-oil ratio and water cut. Gas-oil ratio yields a peak value of 23,000 MSCF/STB at 7 years because the gas that has been injected around well 1 is being produced during the initial period of the second water injection phase. Water-cut during year 4-5 is around 1 since there is a lot of water around well 2 which is a gas injection. So water are produced from well 2 during the early period of gas injection.

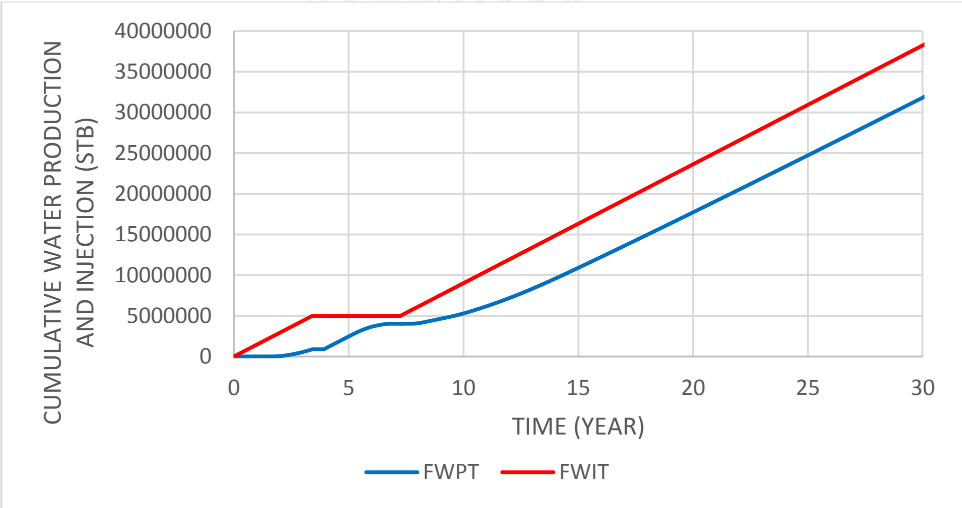

Figure 5. 7 Cumulative water production and injection.

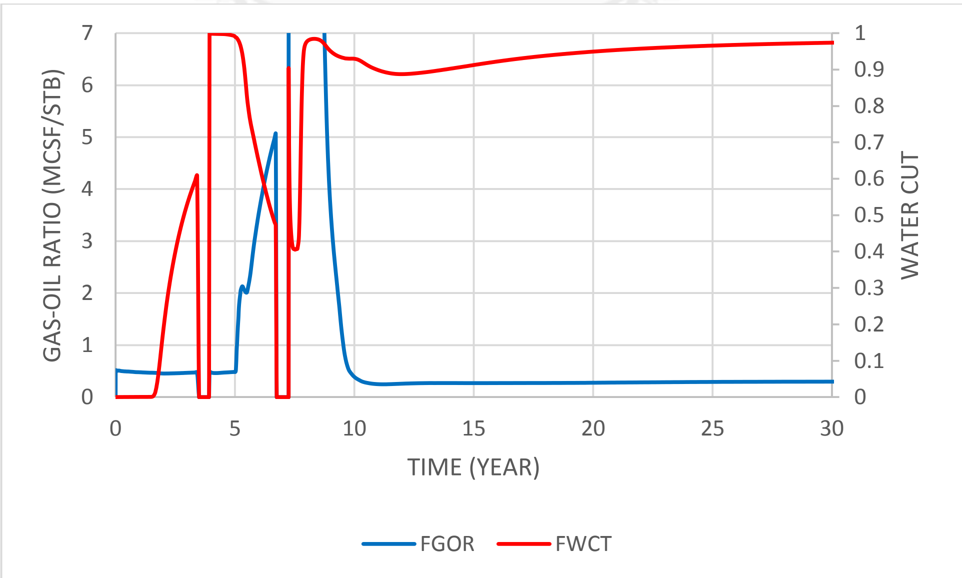

Figure 5. 8 Gas-oil ratio and water cut.

Table 5.1 shows the summary of cumulative oil production, oil recovery factor, cumulative gas production, cumulative gas injection, cumulative water production and cumulative water injection. At the end of 30 year concession, the total oil production is 5.953 MMSTB. This amount to 50.3% recovery factor. The amount of water injection is more than six times the total oil production. In addition, the water production is more than five times the oil production.

Table 5. 1 Summary of results at the end of 30 years.

t_p (year)	30
FOPT (MMSTB)	5.953
FOE	0.503
FGPT (BSCF)	7.683
FGIT (BSCF)	4.081
FWPT (MMSTB)	31.808
FWIT (MMSTB)	38.231

5.2 Reservoir with 0-degree dip angle

5.2.1 Effect of stopping time for water injection

We varied the time that initial waterflooding is stopped based on water cut criteria to investigate the effect of time of initial waterflood in SCWD performance. Three water cuts are used as criteria which are 60%, 75%, 90%. During the first period which is waterflooding, well 1 is a producer and well 2 is an injector. We inject 4,000 STB/D of water until the water cut reaches the criteria. After that, we shut in all wells for 6 months to stabilize the reservoir pressure. Then, we inject 4,000 MSCF/D of gas at well 1 and reopen well 2 for production until gas/oil ratio reaches 5 MSCF/STB. Then, we inject water again at rate of 4,000 STB/D at well 2 and produce from well 1.

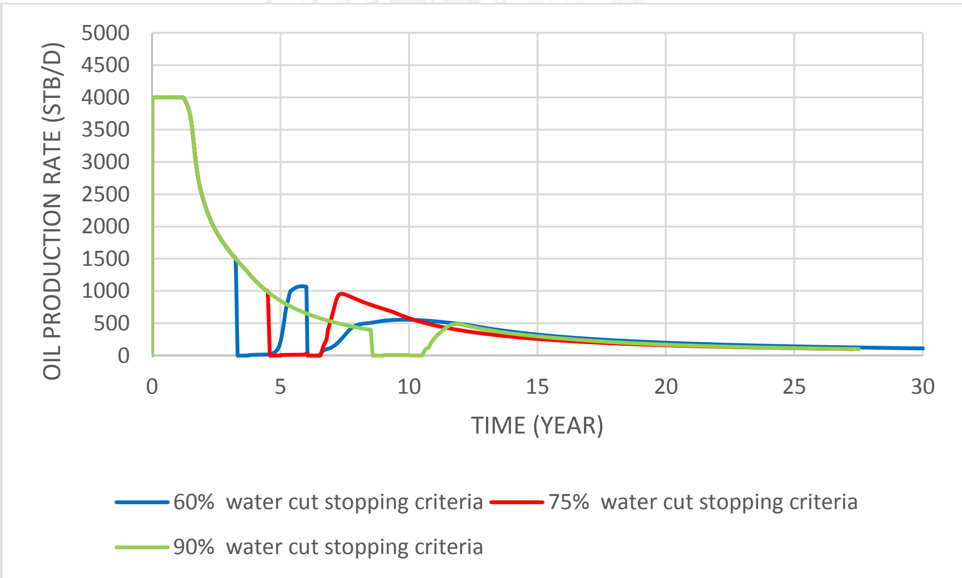

Figure 5. 9 Oil production rate for each WCT criteria (0-degree dip angle).

The oil production rates for different stopping times of water flooding are shown in Figure 5.9. The case of 60% water cut criteria has shorter well life than the case of 75% and 90% water cut criteria since it takes a shorter time to produce water to 60% water cut. During gas and water injection periods, oil production rate of the case of 75% and 90% water cut criteria drop to 0 for the entire gas injection period and the second period of water injection because there is too much amount of water around well 2, so oil cannot produce in that period but oil production rate of the case of 60% water cut criteria is not zero for entire periods of gas and second water injection because there is less amount of water around well 2, so the case of 60% water cut criteria can produce oil earlier than the other cases.

From Figure 5.10, the gas-oil ratio for the case of 60% water cut criteria has the highest peak of gas production during the second water injection period. For water cut, the water cut for the case of 60% water cut criteria reaches 1 earlier than other cases as shown in Figure 5.11 since the initial water injector is converted to a producer at the earliest time.

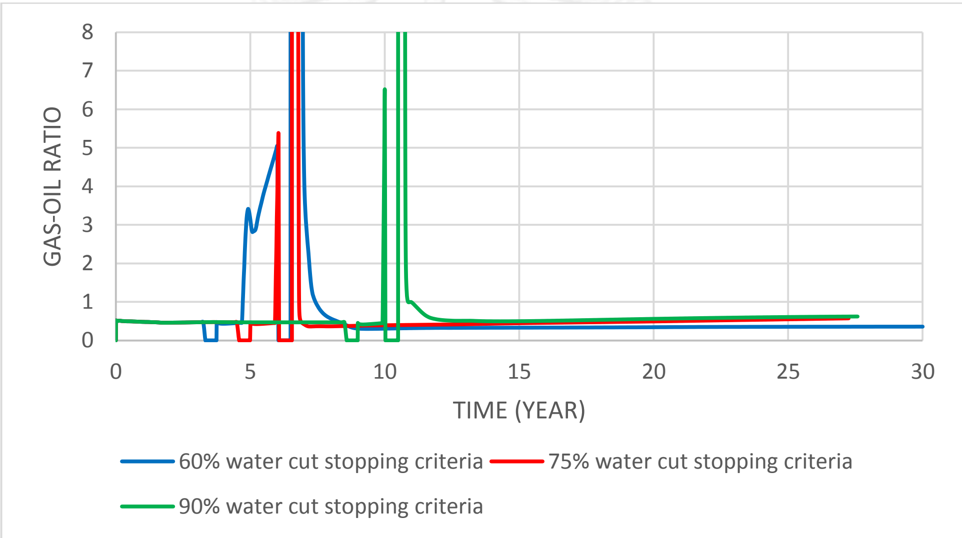

Figure 5. 10 Gas-oil ratio for each WCT criteria (0-degree dip angle).

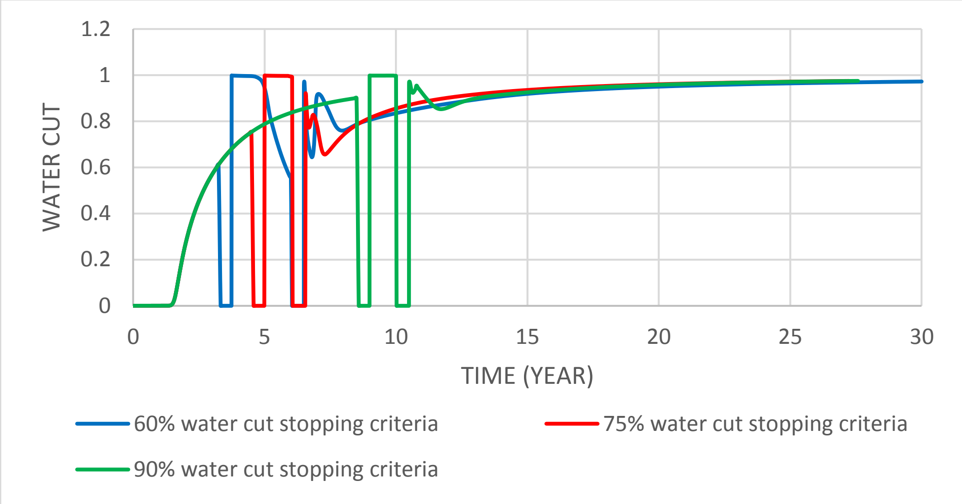

Figure 5. 11 Water cut for each WCT criteria.

Table 5.2 summarizes the results in term of production time, cumulative oil production, oil recovery factor, cumulative gas production, cumulative gas injection, cumulative water production, cumulative water injection for the reservoir with 0-degree dip angle for various WCT criteria. The results show that oil production total and oil recovery factor are slightly different. The case of 75% water cut criteria gives the highest value of oil production and takes the shortest time to produce. Additionally, the water that is used for injection is less than the other cases although the amount of gas injection is slightly higher than the one for 90% water cut criteria. So, we choose the case of 75% water cut criteria the optimal case.

Table 5. 2 Summary of results for various WCT criteria (0-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
60% WCT	30.02	6.23	52.62	6.46	3.30	33.06	39.09	6.75
75% WCT	27.26	6.37	53.94	4.44	1.54	30.75	36.81	6.85
90% WCT	27.51	6.33	53.61	4.58	1.47	31.42	37.26	6.84

5.2.2 Effect of water and gas injection rates

In this section, the effect of water and gas injection rates on SCWD performance is investigated. Since there are three periods of injection: first water injection, gas injection, and second water injection, we need to vary the flow rate during the three periods. The water and gas injection rates should not be too low as we want to maintain the reservoir pressure not too high as an early breakthrough is not desirable. Thus, we have to choose the appropriate injection rates.

In this study, three different water and gas injection rates are investigated. Table 5.3 shows the water and gas injection rates for each strategy.

Table 5. 3 Water and gas injection rates and maximum liquid production rates for three different injection periods.

Case	1st Water injection rate (STB/D)	1st Maximum liquid production rate (STB/d)	Gas injection rate (MSCF/D)	2nd Maximum liquid production rate (STB/d)	2nd Water injection rate (STB/D)	3rd Maximum liquid production rate (STB/d)
1	2,000	2,000	2,000	2,000	4,000	4,000
2	2,000	2,000	2,000	2,000	6,000	6,000
3	2,000	2,000	2,000	2,000	8,000	8,000
4	4,000	4,000	4,000	4,000	4,000	4,000
5	4,000	4,000	4,000	4,000	6,000	6,000
6	4,000	4,000	4,000	4,000	8,000	8,000
7	8,000	8,000	8,000	8,000	4,000	4,000
8	8,000	8,000	8,000	8,000	6,000	6,000
9	8,000	8,000	8,000	8,000	8,000	8,000

From Figure 5.12, the oil rate during the initial period for cases 1-3 is constant around 2,000 stb/d. The oil rate for cases 4-6 around 4,000 stb/d. The oil rates for cases 7-9 vary between 5,600-6,200 stb/d. And cases 3, 6, 9 give higher oil rates during the 2nd water injection period.

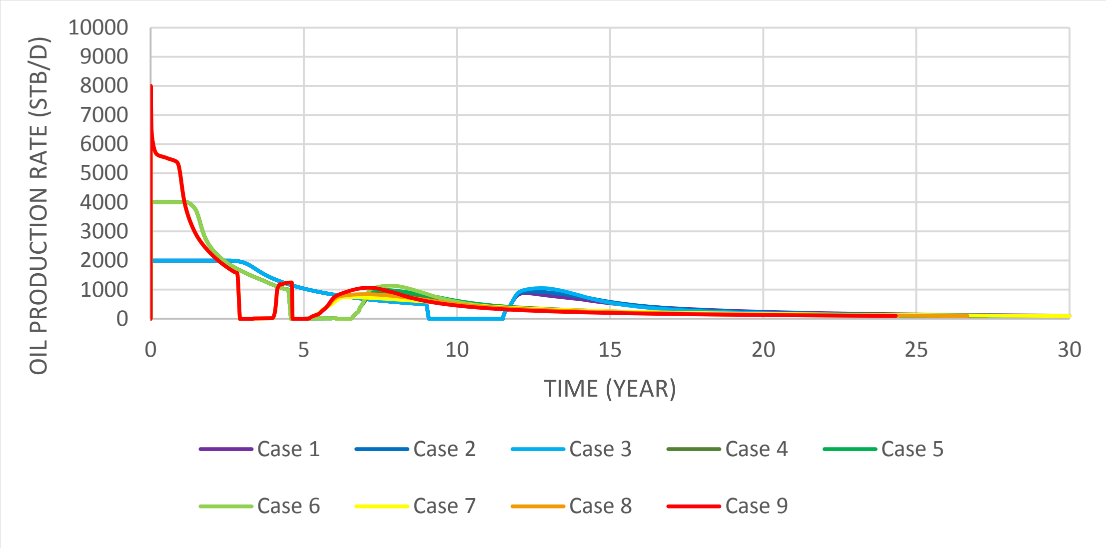

Figure 5. 12 Oil production rate for combination of different water and gas injection rates (0-degree dip angle).

As shown in Figure 5.13, cases 7-9 give the highest gas-oil ratio around 40,000 MSCF/STB in gas injection period. For water cut, cases 7-9 reach 1 in 4 years which is earlier than other cases as shown in Figure 5.14.

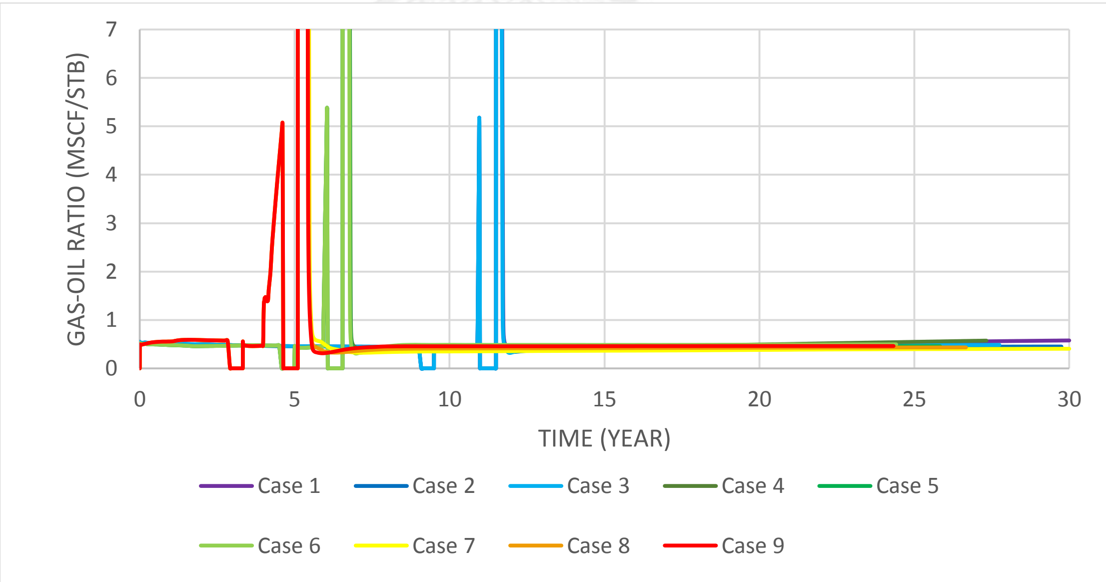

Figure 5. 13 Gas-oil ratio for combination of different water and gas injection rates (0-degree dip angle).

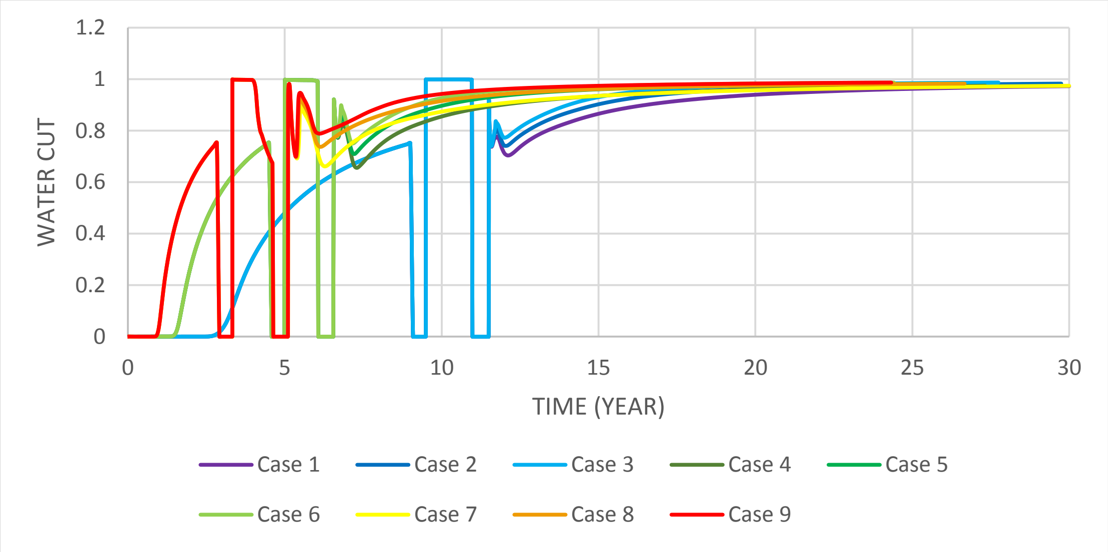

Figure 5. 14 Water cut for combination of different water and gas injection rates (0-degree dip angle).

Furthermore, Table 5.4 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 0 degree dip angle for various injection rates.

Table 5. 4 Summary of result of various injection rates (0-degree dip angle).

Case no.	1st water injection rate (STB/D)	Gas injection rate (MSCF/D)	2nd water injection rate (STB/D)	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
1	2,000	2,000	4,000	30.00	6.33	53.62	4.03	1.07	27.64	33.61	6.83
2	2,000	2,000	6,000	29.75	6.36	53.82	3.96	1.07	39.78	46.57	6.84
3	2,000	2,000	8,000	27.75	6.24	52.80	3.98	1.07	46.86	54.06	6.72
4	4,000	4,000	4,000	27.33	6.37	53.97	4.44	1.54	30.87	36.93	6.86
5	4,000	4,000	6,000	25.83	6.32	53.55	4.39	1.54	42.04	48.84	6.80
6	4,000	4,000	8,000	24.41	6.25	52.88	4.42	1.54	51.60	58.78	6.72
7	8,000	8,000	4,000	30.00	6.43	54.40	6.74	3.74	37.08	43.22	6.93
8	8,000	8,000	6,000	26.67	6.27	53.11	6.70	3.74	47.25	54.09	6.77
9	8,000	8,000	8,000	24.33	6.16	52.14	6.70	3.74	55.79	62.99	6.65

From the results shown in Table 5.4, cumulative oil production, oil recovery factor, and BOE are slightly different. Cases 1, 2, 4, and 7 give good cumulative oil production around 6.33, 6.36, 6.37, and 6.43 MMSTB, respectively, and BOE around 6.83, 6.84, 6.86, and 6.93 MMSTB, respectively. However, the amounts of water injection and production in these cases are high. Although case 1 yields slightly lower BOE, it has much less water injection and production. Thus, we choose case 1 as the optimal case.

5.2.3 Effect of well pattern

In this section, we will study the SCWD performance for different well patterns and numbers as shown in Figures 5.15-5.21. The production wells are controlled by minimum bottomhole pressure of 500 psia while the injection wells are controlled by fracture pressure.

For well pattern 1, there are two wells as shown in Figure 5.15. Water is injected at well 2 (i=12, j=16) while well 1 (i=62, j=16) is a producer. Then, we shut in both wells for six months after WCT of well 1 reaches the criteria. Then, we inject gas at well 1 and switch well 2 to be a producer until GOR reaches the criteria. Then, we shut in both wells for six months again. After that, we inject water again at well 2 and produce from well 1. The formation fracture pressure and injection and production sequence of well pattern 1 are shown in Tables 5.5 and 5.6 respectively.

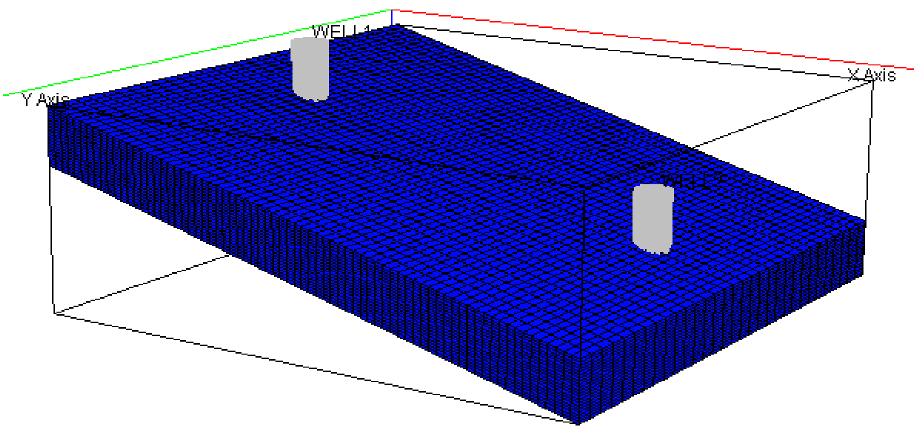

Figure 5. 15 Schematic of well pattern 1.

Table 5. 5 Formation fracture pressure of well pattern 1.

No. of well	Formation fracture pressure (psia)
well 1	3172
well 2	3172

Table 5. 6 Injection and production sequence for well pattern 1.

Stage	Well 1	Well 2
Initial water injection	Producer (4,000 STB/D)	Water injector (4,000 STB/D)
WCT at well 1 = 0.9	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)
GOR at well 2 = 5	Shut in for 6 months	Shut in for 6 months
Second water injection	Producer (4,000 STB/D)	Water injector (4,000 STB/D)

For well pattern 2, there are four wells as shown in Figure 5.16. Water is injected at well 4 (i=70, j=16) while well 1 (i=4, j=16), well 2 (i=26, j=16), and well 3 (i=48, j=16) are producers. Then, we shut in well 3 after WCT reaches the criteria. Wells 1 and 2 continue to produce until WCT of well 2 reaches the criteria. Then, we shut in well 2, and well 1 continues to produce until WCT of well 1 reaches the criteria. Then, we shut in all the wells for six months. Then, we inject gas at well 1 while wells 2, 3, and 4 are producers until GOR of well 2 reaches the criteria. Then, we shut in well 2 while wells 3 and 4 are still producers until the GOR of well 3 reaches the criteria. Then, we shut in well 3 and let well 4 produce until GOR of well 4 reaches the criteria. Then, we shut in all the wells for six months again. After that, we inject water again at well 4 with the previous water injection strategy. Wells 1, 2, and 3 are now producers. The formation fracture pressure and injection and production sequence of well pattern 2 are shown in Tables 5.7 and 5.8, respectively.

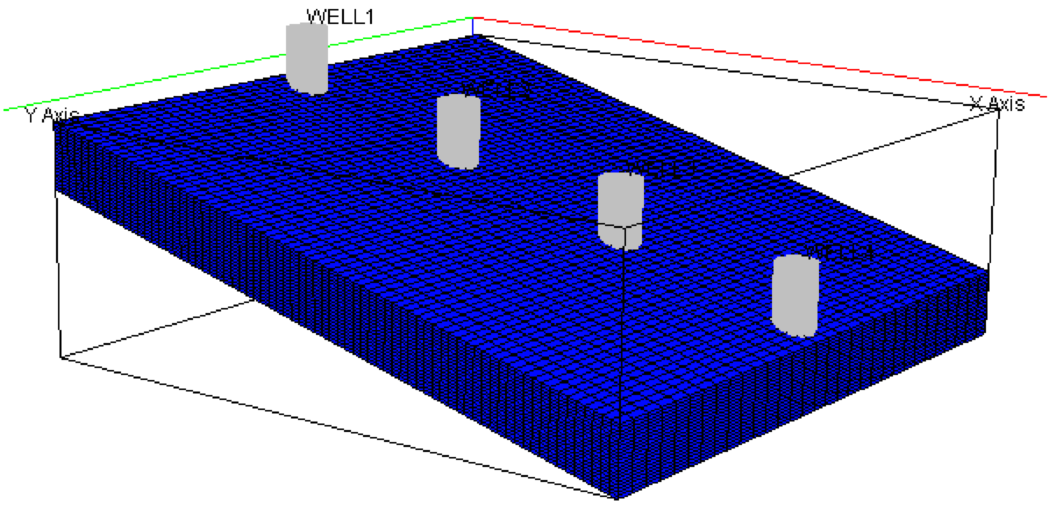

Figure 5. 16 Schematic of well pattern 2.

Table 5. 7 Formation fracture pressure of well pattern 2.

No. of well	Formation fracture pressure (psia)
well 1	3172
well 2	3172
well 3	3172
well 4	3172

Table 5. 8 Injection and production sequence for well pattern 2.

Stage	Well 1	Well 2	Well 3	Well 4
Initial water injection	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Water injector (4,000 STB/D)
WCT at well 3 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Water injector (4,000 STB/D)
WCT at well 2 = 0.9	Producer (4,000 STB/D)	Shut-in	Shut-in	Water injector (4,000 STB/D)
WCT at well 1 = 0.9	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)
GOR at well 2 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Producer (4,000 STB/D)	Producer (4,000 STB/D)
GOR at well 3 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Shut-in	Producer (4,000 STB/D)
GOR at well 4 = 5	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Second water injection	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Water injector (4,000 STB/D)

For well pattern 3, there are four wells as shown in Figure 5.17. Water is injected at well 4 (i=70, j=16) while well 1 (i=4, j=16), well 2 (i=26, j=16), and well 3 (i=48, j=16) are producers. Then, we shut in well 3 after WCT reaches the criteria. Wells 1 and 2 continue to produce until WCT of well 2 reaches the criteria. Then, we shut in well 2, and well 1 continues to produce until WCT reaches the criteria. Then, we shut in all the wells for six months. Then, we inject gas at well 1 while well 2 is producer until

GOR of well 2 reaches the criteria. We shut in well 2 and open well 3 to produce until the GOR of well 3 reaches the criteria. Then, we shut in well 3 and open well 4 to produce until GOR of well 4 reaches criteria. Then, we shut in all the wells for six months again. After that, we inject water again at well 4 with the previous water injection strategies. At this time, wells 1, 2, and 3 become producer again. The formation fracture pressure and injection and production sequence of well pattern 3 are shown in Table 5.9 and 5.10, respectively.

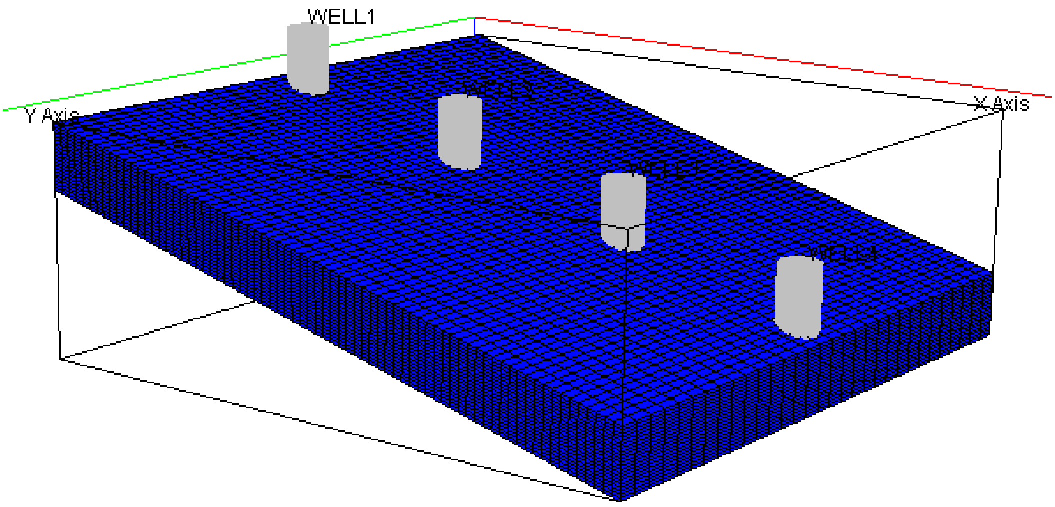

Figure 5. 17 Schematic of well pattern 3.

Table 5. 9 Formation fracture pressure of well pattern 3.

No. of well	Formation fracture pressure (psia)
well 1	3172
well 2	3172
well 3	3172
well 4	3172

Table 5. 10 Injection and production sequence for well pattern 3.

Stage	Well 1	Well 2	Well 3	Well 4
Initial water injection	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Water injector (4,000 STB/D)
WCT at well 3 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Water injector (4,000 STB/D)
WCT at well 2 = 0.9	Producer (4,000 STB/D)	Shut-in	Shut-in	Water injector (4,000 STB/D)
WCT at well 1 = 0.9	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)	Shut-in	Shut-in
GOR at well 2 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Producer (4,000 STB/D)	Shut-in
GOR at well 3 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Shut-in	Producer (4,000 STB/D)
GOR at well 4 = 5	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Second water injection	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Water injector (4,000 STB/D)

For well pattern 4, there are four wells as shown in Figure 5.18. Water is injected at well 4 (i=70, j=16) while well 1 (i=4, j=16), well 2 (i=26, j=16), and well 3 (i=48, j=16) are producers. Then, we shut in well 3 after WCT reaches the criteria. Wells 1 and 2 continue to produce until WCT of well 2 reaches the criteria. Then, we shut in well 2 while well 1 continues to produce until WCT of well 1 reaches the criteria. Then, we shut in all the wells for six months. Then, we inject gas at well 1 while well 2 is producer until GOR of well 2 reaches the criteria. Then, we change well 2 to inject gas while open well 3 to produce until the GOR of well 3 reaches the criteria. Then, we inject gas at well 3 while open well 4 to produce until GOR of well 4 reaches criteria. Then, we shut in all the wells for six months again. After that, we inject water again at well 4 while well 3 is a producer until WCT reaches the criteria. We shut in well 3 and open well 1, and 2 to produce until abandonment. The formation fracture pressure and injection and production sequence of well pattern 4 are shown in Table 5.11 and 5.12, respectively.

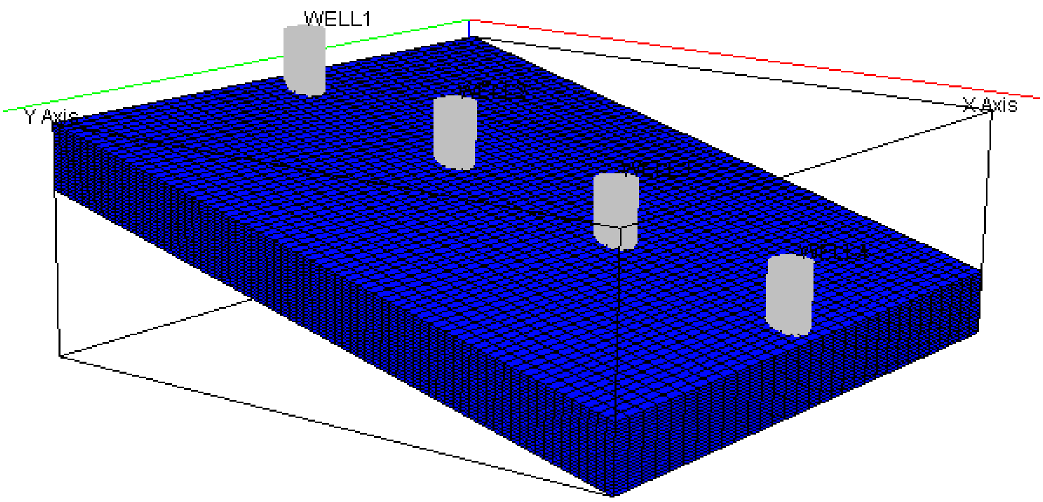

Figure 5. 18 Schematic of well pattern 4.

Table 5. 11 Formation fracture pressure of well pattern 4.

No. of well	Formation fracture pressure (psia)
well 1	3172
well 2	3172
well 3	3172
well 4	3172

Table 5. 12 Injection and production sequence for well pattern 4.

Stage	Well 1	Well 2	Well 3	Well 4
Initial water injection	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Water injector (4,000 STB/D)
WCT at well 3 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Water injector (4,000 STB/D)
WCT at well 2 = 0.9	Producer (4,000 STB/D)	Shut-in	Shut-in	Water injector (4,000 STB/D)
WCT at well 1 = 0.9	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)	Shut-in	Shut-in
GOR at well 2 = 5	Shut-in	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)	Shut-in
GOR at well 3 = 5	Shut-in	Shut-in	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)
GOR at well 4 = 5	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Second water injection	Shut-in	Shut-in	Producer (4,000 STB/D)	Water injector (4,000 STB/D)
WCT at well 3 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Water injector (4,000 STB/D)

For well pattern 5, there are eight wells as shown in Figure 5.19. Water is injected at well 8 (i=70, j=16) while well 1 (i=2, j=16), well 2 (i=12, j=16), well 3 (i=22, j=16), well 4 (i=32, j=16), well 5 (i=42, j=16), well 6 (i=52, j=16), and well 7 (i=62, j=16) are producers. Then, we shut in the well 7 after WCT reaches the criteria. Wells

1-6 continue to produce until WCT of well 6 reaches the criteria. Then, we shut in well 6 while well 1-5 continue to produce and keep doing the same sequence until WCT of well 1 reaches the criteria. Then, we shut in all the wells for six months. Then, we inject gas at well 1 while well 2 is producer until GOR of well 2 reaches the criteria. Then, we shut in well 2 while open well 3 to produce until the GOR of well 3 reaches the criteria. Then, we shut in well 3 while open well 4 to produce and keep doing the same sequence until GOR of well 8 reaches criteria. Then, we shut in all the wells for six months again. At this point, we open wells 1-7 for production. After that, we inject water again at well 8 with the previous water injection strategy. The formation fracture pressure and injection and production sequence of well pattern 5 are shown in Table 5.13 and 5.14, respectively.

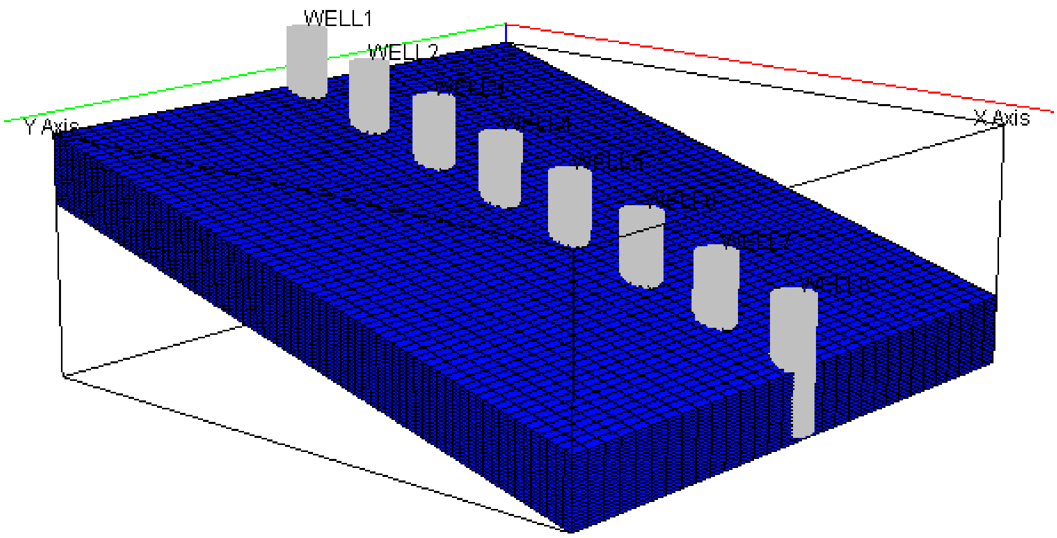

Figure 5. 19 Schematic of well pattern 5.

Table 5. 13 Formation fracture pressure of well pattern 5.

No. of well	Formation fracture pressure (psia)
well 1	3172
well 2	3172
well 3	3172
well 4	3172
well 5	3172
well 6	3172
well 7	3172
well 8	3172

Table 5. 14 Injection and production sequence for well pattern 5.

Stage	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
Initial water injection	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Water injector (4,000 STB/D)
WCT at well 7 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Water injector (4,000 STB/D)
WCT at well 6 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Shut-in	Water injector (4,000 STB/D)
WCT at well 5 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Shut-in	Shut-in	Water injector (4,000 STB/D)
WCT at well 4 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Water injector (4,000 STB/D)
WCT at well 3 = 0.9	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Water injector (4,000 STB/D)
WCT at well 2 = 0.9	Producer (4,000 STB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Water injector (4,000 STB/D)
WCT at well 1 = 0.9	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in
GOR at well 2 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Producer (4,000 STB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in
GOR at well 3 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Shut-in	Producer (4,000 STB/D)	Shut-in	Shut-in	Shut-in	Shut-in
GOR at well 4 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Shut-in	Shut-in	Producer (4,000 STB/D)	Shut-in	Shut-in	Shut-in
GOR at well 5 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Shut-in	Shut-in	Shut-in	Producer (4,000 STB/D)	Shut-in	Shut-in
GOR at well 6 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Producer (4,000 STB/D)	Shut-in
GOR at well 7 = 5	Gas injector (4,000 MMSCF/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Producer (4,000 STB/D)
GOR at well 8 = 5	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Second water injection	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Producer (4,000 STB/D)	Water injector (4,000 STB/D)

For well pattern 6, there are two horizontal wells as shown in Figure 5.20. Water is injected at well 2 (i=12, j=1-31) while well 1 (i=72, j=1-31) is producer. Then, we shut in both wells for six months after WCT reaches the criteria. Then, we inject gas at well 1 while well 2 is producer until GOR reaches the criteria. Then, we shut in both wells for six months again. After that, we inject water again at well 2 and open well 1 for production. The formation fracture pressure and injection and production sequence of well pattern 6 are shown in Tables 5.15 and 5.16, respectively.

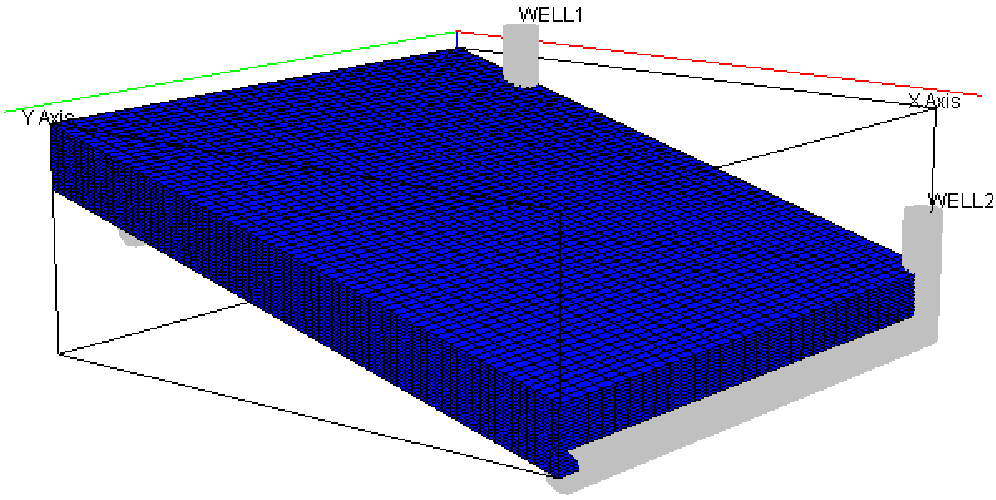

Figure 5. 20 Schematic of well pattern 6.

Table 5. 15 Formation fracture pressure of well pattern 6.

No. of well	Formation fracture pressure (psia)
well 1	3172
well 2	3172

Table 5. 16 Injection and production sequence for well pattern 6.

Stage	Well 1	Well 2
Initial water injection	Producer (4,000 STB/D)	Water injector (4,000 STB/D)
WCT at well 1 = 0.9	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)
GOR at well 2 = 5	Shut in for 6 months	Shut in for 6 months
Second water injection	Producer (4,000 STB/D)	Water injector (4,000 STB/D)

For well pattern 7, there are one vertical well and one horizontal well as shown in Figure 5.21. Water is injected at well 2 (i=12, j=16) while well 1 (i=72, j=16) is producer. Then, we shut in both wells for six months after WCT reaches the criteria. Then, we inject gas at well 1 while well 2 is producer until GOR reaches the criteria. Then, we shut in the well for six months again. After that, we inject water again at well 2 and open well 1 for production. The formation fracture pressure and injection and production sequence of well pattern 7 are shown in Tables 5.17 and table 5.18, respectively.

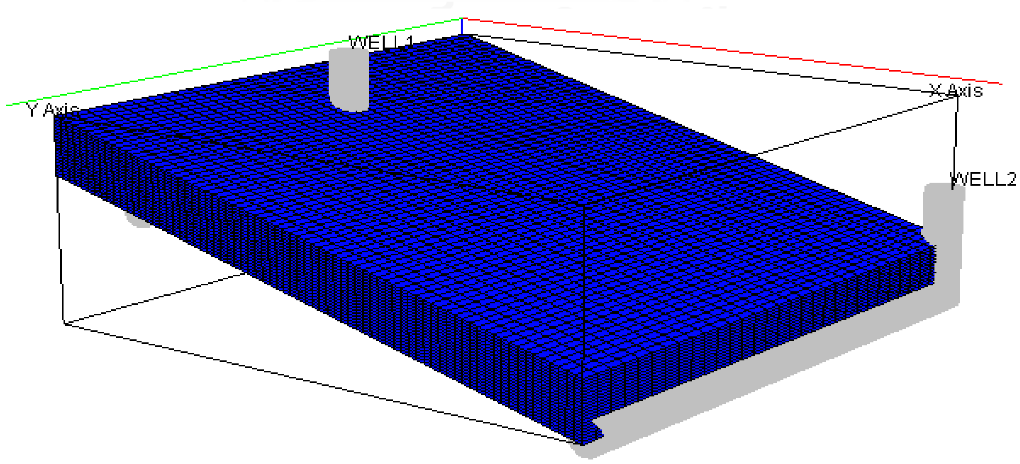

Figure 5. 21 Schematic of well pattern 7.

Table 5. 17 Formation fracture pressure of well pattern 7.

No. of well	Formation fracture pressure (psia)
well 1	3172
well 2	3172

Table 5. 18 Injection and production sequence for well pattern 7.

Stage	Well 1	Well 2
Initial water injection	Producer (4,000 STB/D)	Water injector (4,000 STB/D)
WCT at well 1 = 0.9	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (4,000 MMSCF/D)	Producer (4,000 STB/D)
GOR at well 2 = 5	Shut in for 6 months	Shut in for 6 months
Second water injection	Producer (4,000 STB/D)	Water injector (4,000 STB/D)

The filed oil production rate for each well pattern is shown in Figure 5.22. The pattern of 8 wells yield high oil production rate at the beginning because there are many wells to produce. Pattern of a vertical well with a horizontal well gives the highest production rate in the 2nd water injection period. And pattern 6 gives the highest gas-oil ratio around 17,000 MSCF/STB as shown in Figure 5.23.

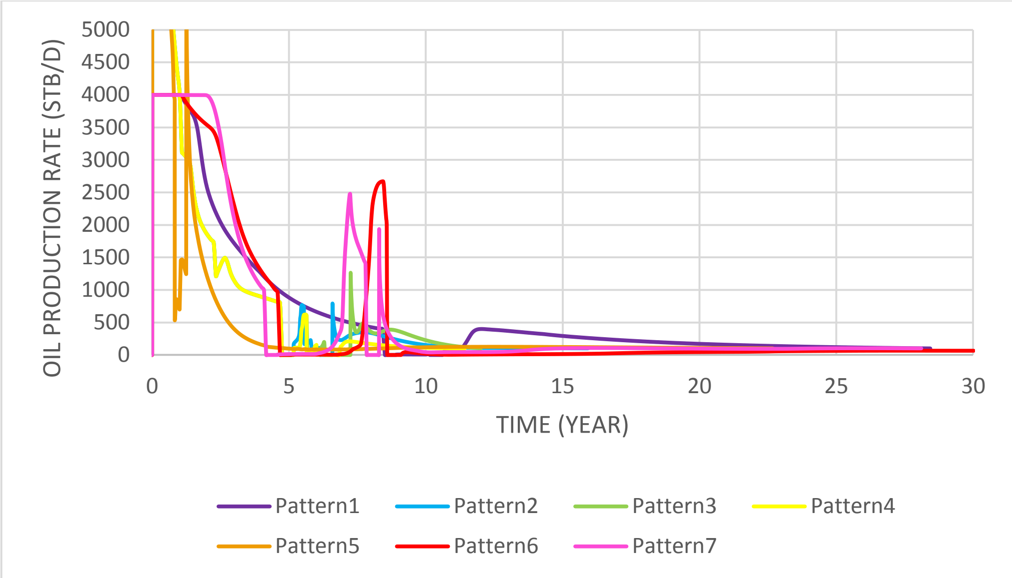

Figure 5. 22 Oil production rate for different well patterns (0-degree dip angle).

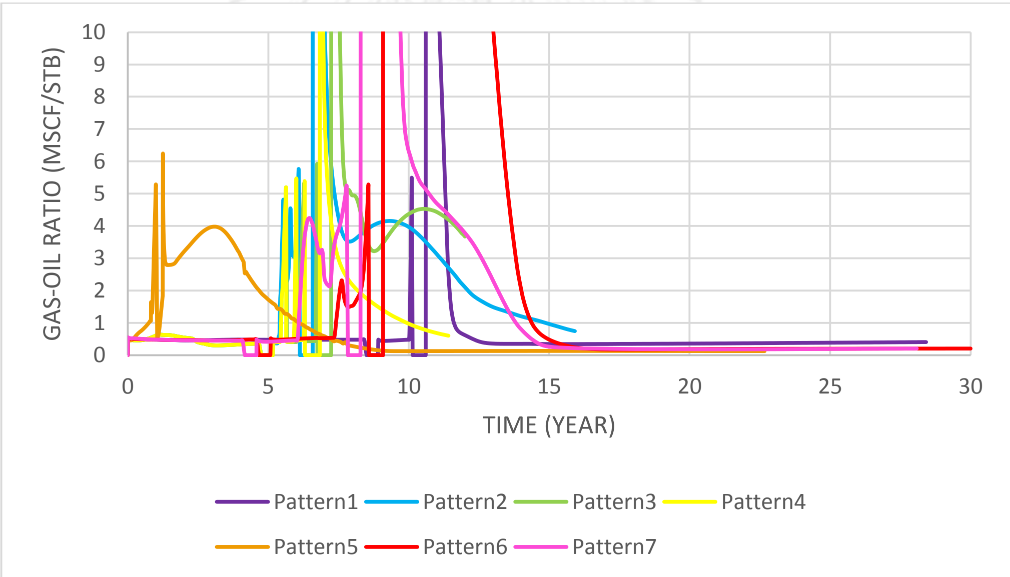

Figure 5. 23 Gas-oil ratio for different well patterns (0-degree dip angle).

In term of water cut, the results are shown in Figure 5.24. The shorter the time for gas breakthrough, the higher the cumulative gas production. Pattern of 8 wells gives the shortest time for gas breakthrough because the distance between the injector and the producer is closer than that for the other patterns.

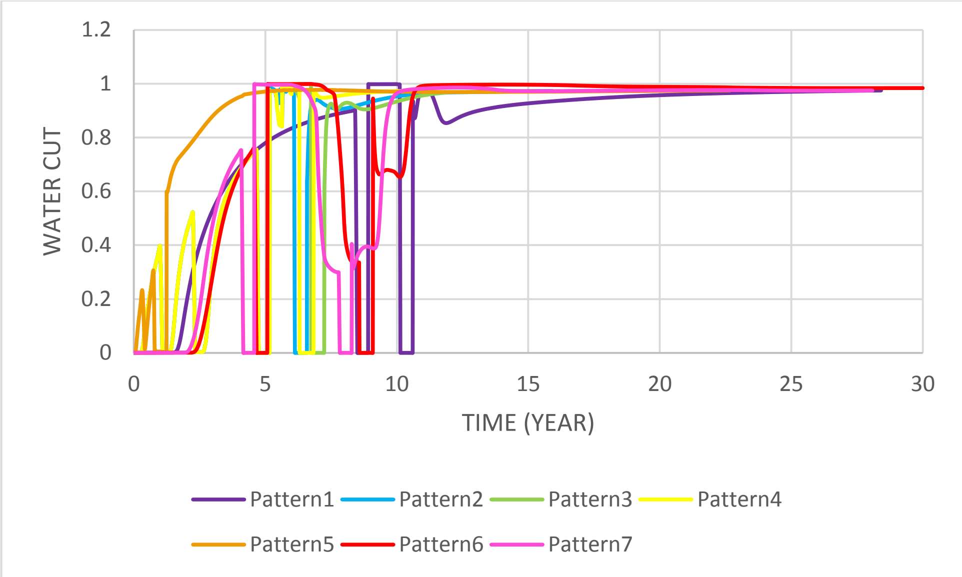

Figure 5. 24 Water cut for different well pattern (0-degree dip angle).

Moreover, Table 5.19 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 0 degree dip angle for different well patterns. From the results shown in Table 5.19, cumulative oil production, oil recovery factor, and BOE are significantly different. Patterns of 2 vertical wells, 2 horizontal wells, a vertical well with a horizontal well, and 4 vertical wells give good cumulative oil production around 6.37, 5.95, 5.73, and 5.39 MMSTB, respectively and BOE around 6.89, 6.66, 6.48 and 6.18 MMSTB, respectively. In addition, there are significant differences in amount of water and gas injection and time to reach the economic constraint. Pattern 6 yields the highest gas production of 9.55 BSCF while pattern 5 needs the largest amount of gas injection (6.12 BSCF). Among the seven patterns, patterns 2, 3, and 4 produce smaller amount of water and require lower amount of water injection than the rest. Judging from high amount of oil production, low amount of gas and water injection and production, pattern of 4 vertical wells with 1st sequence (pattern 3) is the best case.

Table 5. 19 Summary of results of different well pattern case (0-degree dip angle).

Case no.	Pattern	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
1	2 vertical wells	28.43	6.37	53.85	4.95	1.75	32.11	38.32	6.89
2	4 vertical wells	15.92	5.39	45.56	6.12	1.35	15.85	20.45	6.18
3	4 vertical wells with 1^{st} sequence	12.01	5.28	44.63	6.83	2.30	10.16	13.77	6.04
4	4 vertical wells with 2^{nd} sequence	11.42	5.03	42.48	3.25	1.65	9.89	13.51	5.29
5	8 vertical wells	22.68	5.04	42.55	5.57	6.12	29.94	32.50	4.95
6	A vertical well with a horizontal	30.02	5.73	48.47	9.55	5.10	30.39	37.25	6.48
7	2 horizontal wells	28.10	5.95	50.25	8.96	4.69	29.21	34.90	6.66

5.2.4 Comparison with DDP

When making the comparison, pattern of 2 vertical wells is used for both SCWD and DDP. We inject 4,000 STB/D of water and 4,000 MSCF/D of gas for both SCWD and DDP. Oil production rates of SCWD and DDP are compared in Figure 5.25. During the first 6 years of production, both SCWD and DDP give the same result as both processes start with initial waterflooding followed by gas injection. The oil rate of DDP increases to its highest value sooner than that for SCWD since continuous gas injection helps reduce remaining oil in the reservoir. However, the mobility ratio in gas injection is less favorable than that in water injection. Thus, the oil production rate of DDP drops earlier than that for SCWD. Gas-oil ratio of DDP is higher than that for SCWD after 7 years as shown in Figure 5.26 because DDP continues injecting gas.

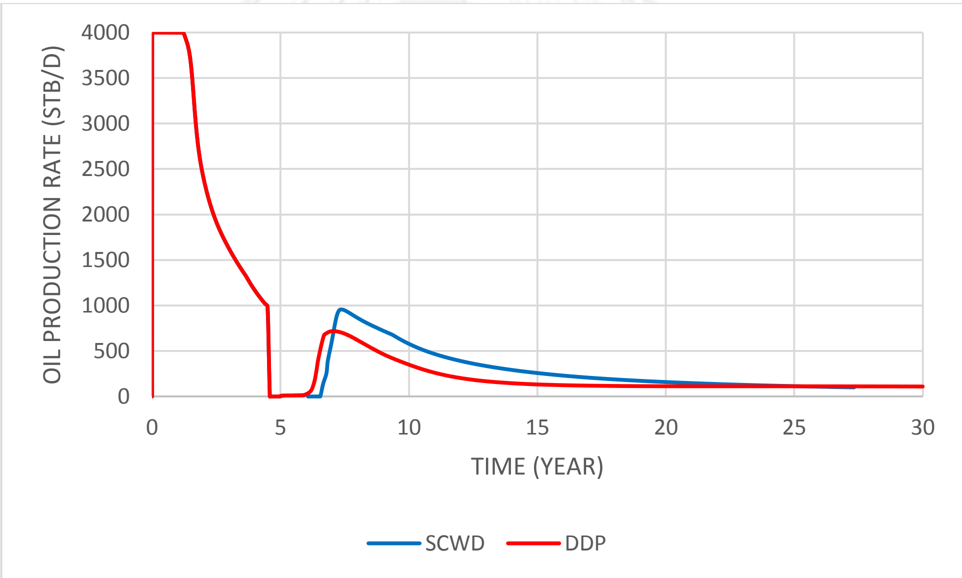

Figure 5. 25 Oil production rate of SCWD and DDP (0-degree dip angle).

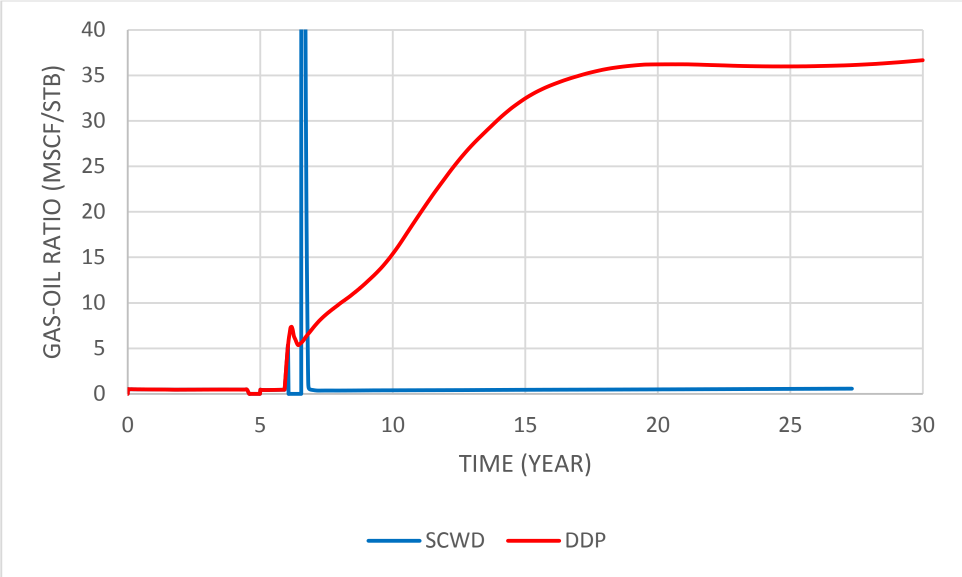

Figure 5. 26 Gas-oil ratio of SCWD and DDP (0-degree dip angle).

In term of water cut, both processes give the same water cut during the first 6 years as shown in Figure 5.27. SCWD gives higher water cut after gas injection period because there is a second water injection for SCWD.

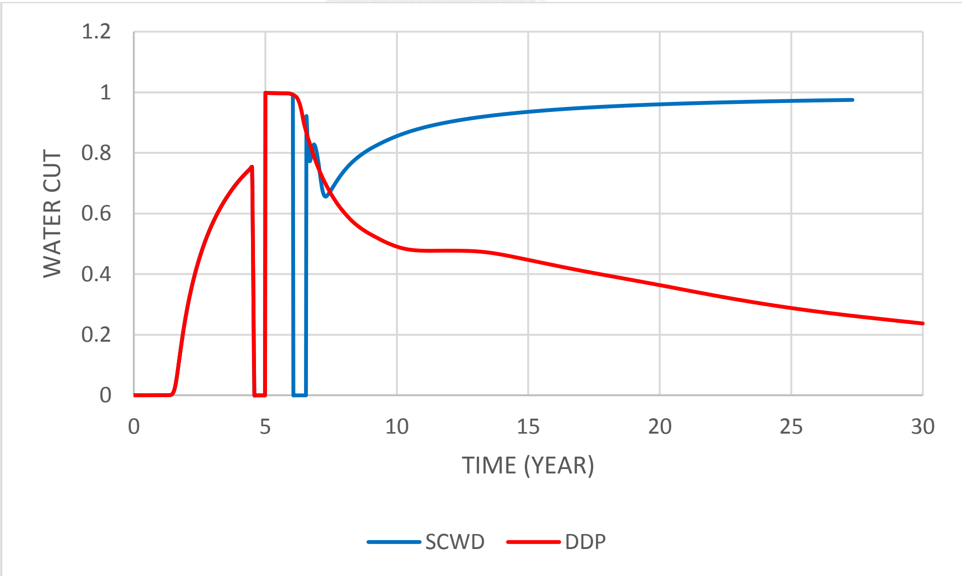

Figure 5. 27 Water cut of SCWD and DDP (0-degree dip angle).

Table 5.20 shows the results of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 0 degree dip angle for SCWD and DDP. From the results, SCWD shows better performance than DDP because SCWD gives good cumulative oil production around 6.37 MMSTB and BOE around 6.86 MMSTB while DDP can recover only 5.83 MMSTB of oil and 6.45 MMSTB of BOE. In addition, SWCD provides lower amounts of gas production, higher amount of water production and injection, and shorter production period than DDP.

Table 5. 20 Summary of result of SCWD and DDP (0-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
SCWD	27.25	6.37	53.94	4.44	1.54	30.75	36.81	6.86
DDP	30.00	5.83	49.30	40.28	36.54	6.43	6.57	6.45

5.2.5 Effect of relative permeability correlation

In order to investigate the effect of relative permeability correlation on the performance of SCWD, we run simulation using three relative permeability models available in ECLIPSE, namely, default, Stone 1, and Stone 2 models. In this case, there are two wells in the reservoir. The 1st water injection rate, the gas injection rate, and the 2nd water production rate are 4,000 STB/D, 4,000 MSCF/D, and 4,000 STB/D, respectively. Oil production rate, gas-oil ratio and water cut for dip angle of 0 degree are illustrated in Figures 5.28-5.30. During the initial water injection period, the oil rates are rather similar for the three relative permeability models. In the 2nd water injection period, Stone 1 and ECLIPSE default models provide higher oil and gas production rate than Stone 2 model. Regarding gas-oil ratio, Stone 2 model yields the highest peak of gas-oil ratio during gas injection period and Stone 1 model yields slightly more than ECLIPSE default model and Stone 2 afterwards. The water cuts from all correlations are quite the same during the 1st water injection and the gas injection. In the 2nd water injection, Stone 2 model yields higher water cut.

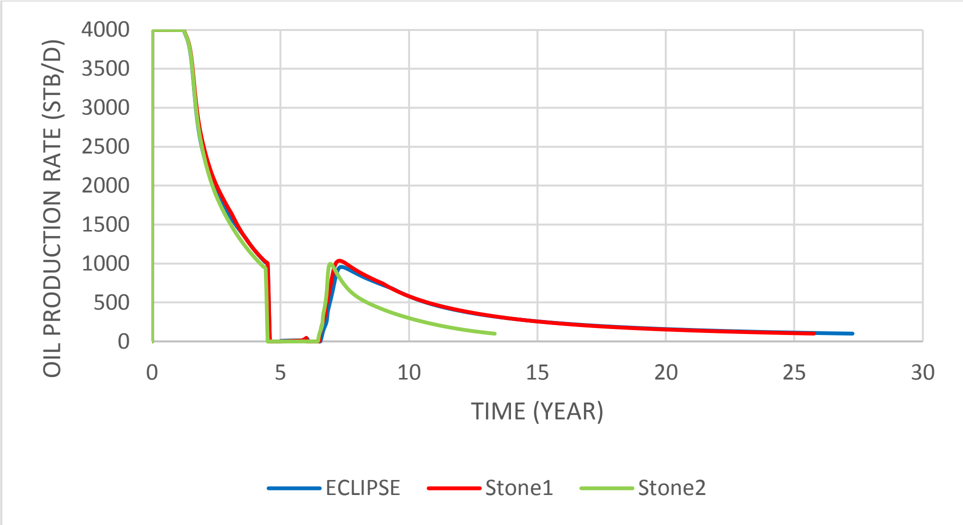

Figure 5. 28 Oil production rate for each three phase relative permeability correlation model (0-degree dip angle).

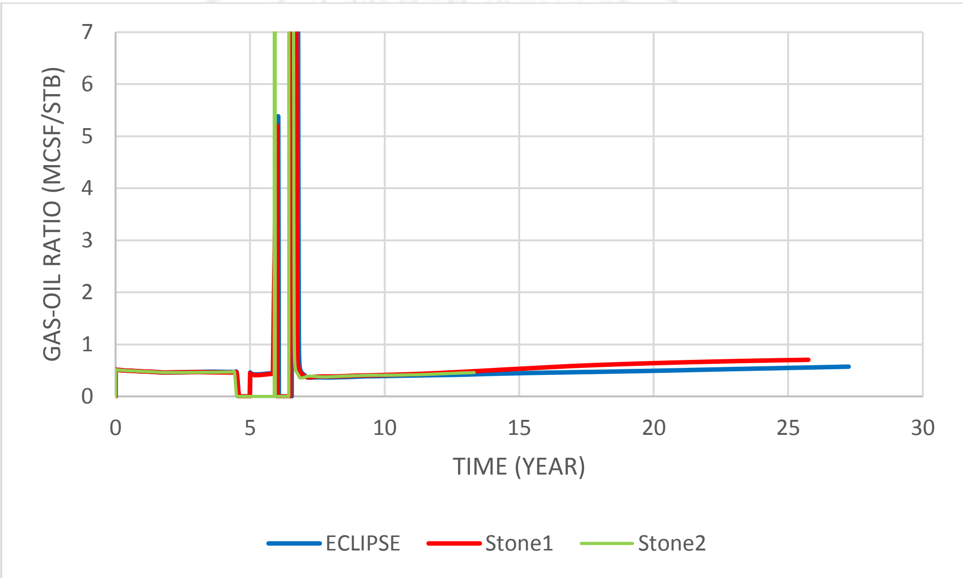

Figure 5. 29 Gas-oil ratio for each three phase relative permeability correlation model (0-degree dip angle).

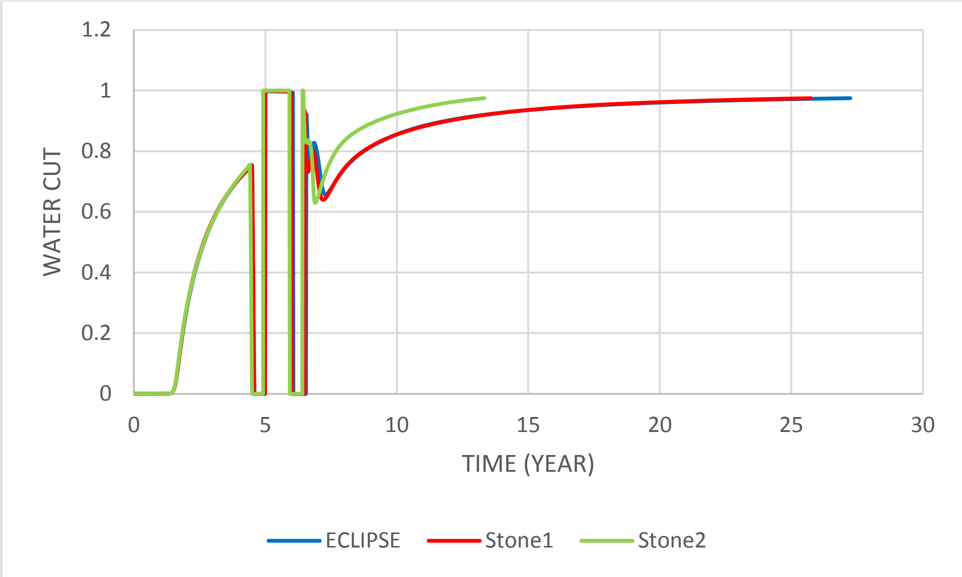

Figure 5. 30 Water cut for each three phase relative permeability correlation model (0-degree dip angle).

Table 5. 21 Summary of result of each three phase relative permeability correlation model (0-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
ECLIPSE default	27.25	6.37	53.94	4.44	1.54	30.75	36.81	6.86
Stone 1	25.75	6.43	54.39	4.52	1.48	28.75	34.70	6.93
Stone 2	13.33	4.88	41.34	3.68	1.46	11.65	16.56	5.25

Table 5.21 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, and cumulative gas production for a reservoir with 0 degree dip angle for all correlation models. From the results, ECLIPSE default model and Stone 1 model give similar cumulative oil production of 6.37 and 6.43 MMSTB, respectively and BOE of 6.86 and 6.93 MMSTB, respectively while Stone 2 model yields a lower value for cumulative oil production and BOE since Stone 2 model yields low relative permeability to oil at very high oil saturation compared to Stone 1 model as shown in Figure 5.31. Furthermore, Stone 2 model gives lower gas and much

lower water production and needs less gas and much lower water injection as well as less time to produce.

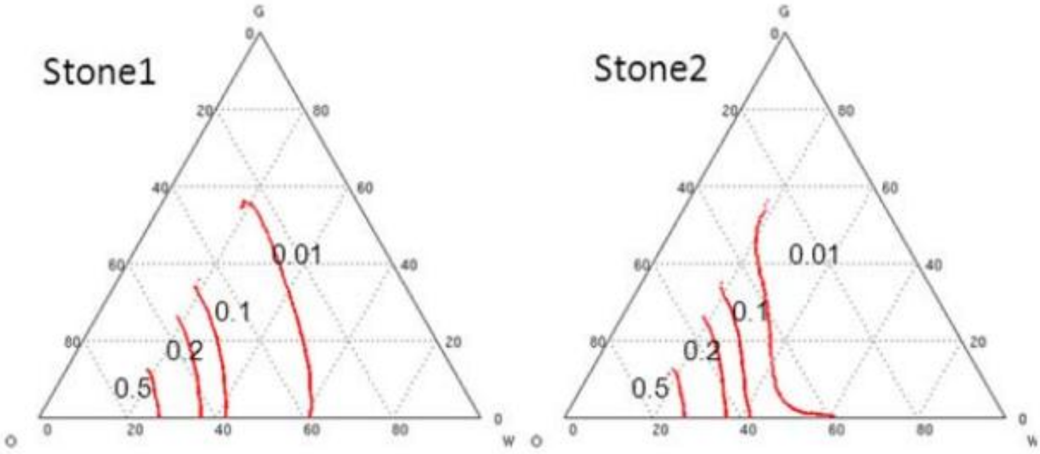

Figure 5. 31 Ternary saturation diagram of Stone 1 and Stone 2 models [12].

5.2.6 Effect of vertical to horizontal permeability ratio

In this section, we study the effect of three different values of vertical to horizontal permeability ratios on SCWD performance. Table 5.22 shows the value of vertical to horizontal permeability ratios varied by fixing the horizontal permeability. The well pattern in this case is pattern 1 in which there are two vertical wells located on each side of the reservoir.

Table 5. 22 Vertical and horizontal permeabilities for different anisotropy ratios.

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

The oil production rate and gas-oil ratio and water cut for all vertical to horizontal ratios are shown in Figures 5.31-5.33. Case 3 takes a longer time to inject water than other cases during the 1st water injection period because water can flow in both vertical and horizontal permeabilities reservoir easily allowing better segregation of oil and water. So, early breakthrough of water does not occur in case 3. Later on, the oil rate starts to decline because water and gas start to produce as well and give the highest gas-oil ratio around 18,500 MSCF/STB.

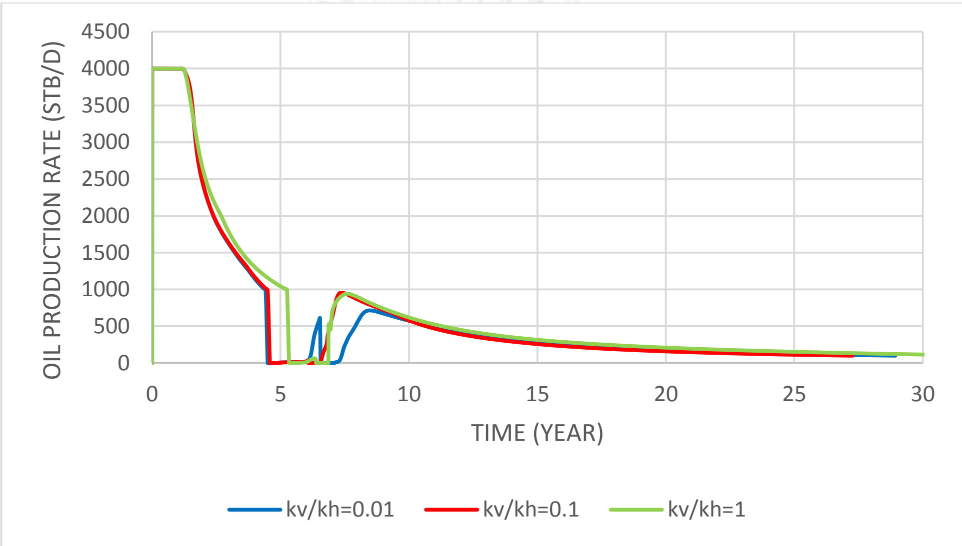

Figure 5. 32 Oil production rate for different anisotropy ratios (0-degree dip angle).

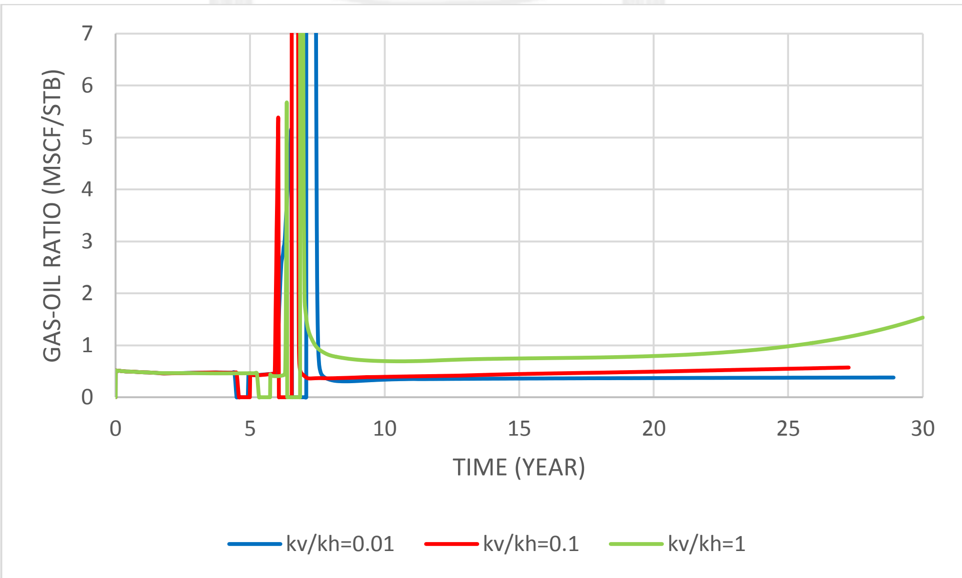

Figure 5. 33 Gas-oil ratio for different anisotropy ratios (0-degree dip angle).

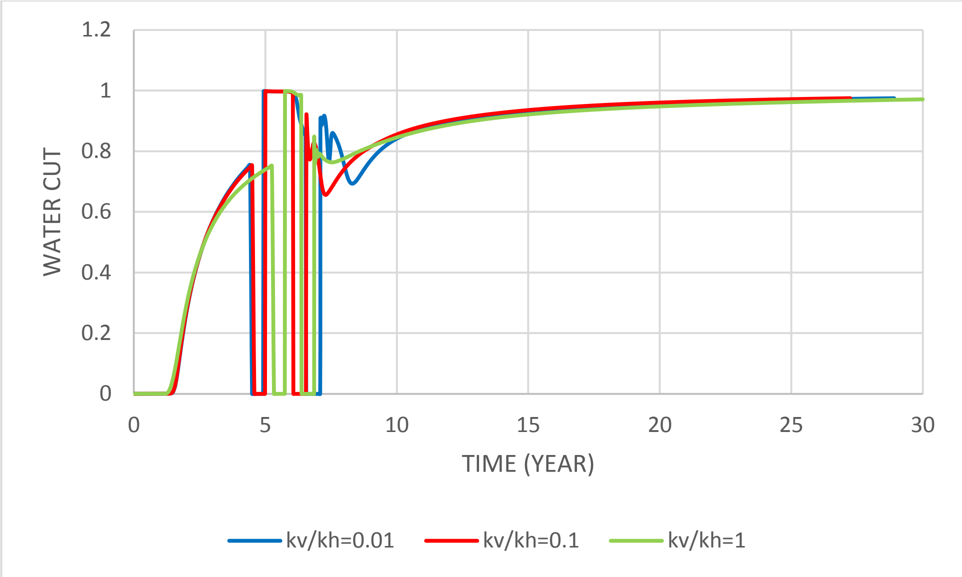

Figure 5. 34 Water cut for different anisotropy ratios (0-degree dip angle).

Table 5. 23 Summary of results for different vertical to horizontal permeability ratios (0-degree dip angle).

k_v/k_h	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
0.01	28.91	6.21	52.60	5.13	2.36	32.45	38.34	6.67
0.1	27.25	6.37	53.94	4.44	1.54	30.75	36.81	6.85
1	30.00	7.27	61.56	5.24	0.91	34.89	41.48	7.99

As shown in Table 5.23, case 3 provides higher cumulative oil production, cumulative gas production, cumulative water production, and oil recovery factor than other cases because oil, gas and water can flow easily in high vertical permeability reservoir.

5.2.7 Effect of residual oil saturation by gas displacement (S_{org})

To study the effect of relative permeability to oil and gas, we vary the residual oil saturation in gas-oil system (S_{org}) among 0.05, 0.1 and 0.15. The rest of Corey's parameters are the same as those in the base case.

Oil production rate, gas-oil ratio and water cut are illustrated in Figures 5.34-5.36. In the 2nd water injection, the oil production rate of S_{org} is 0.05 is a bit higher than other cases. At the end, this case provides the highest cumulative oil production because when S_{org} is lower, higher amount of recoverable oil can be produced.

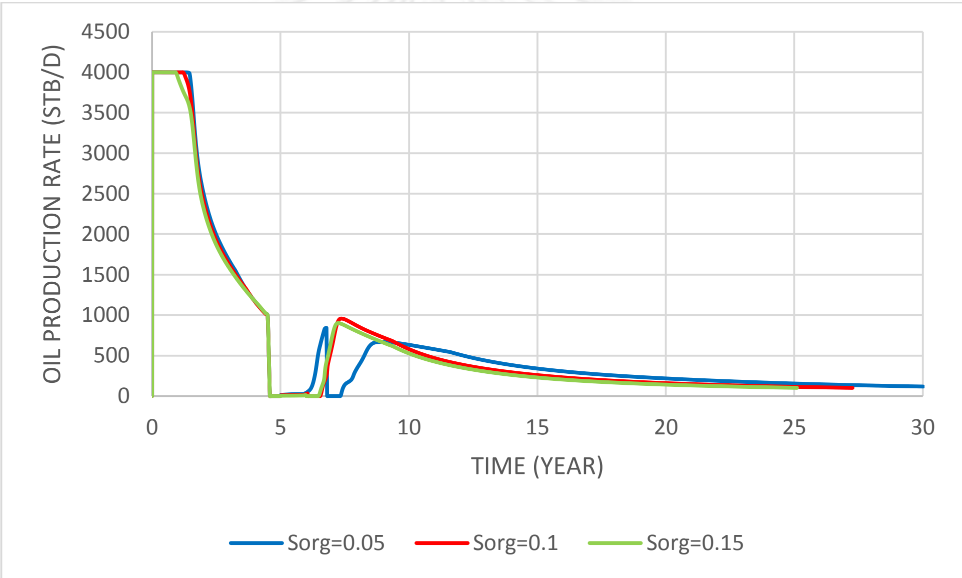

Figure 5. 35 Oil production rate for different residual oil saturations (0-degree dip angle).

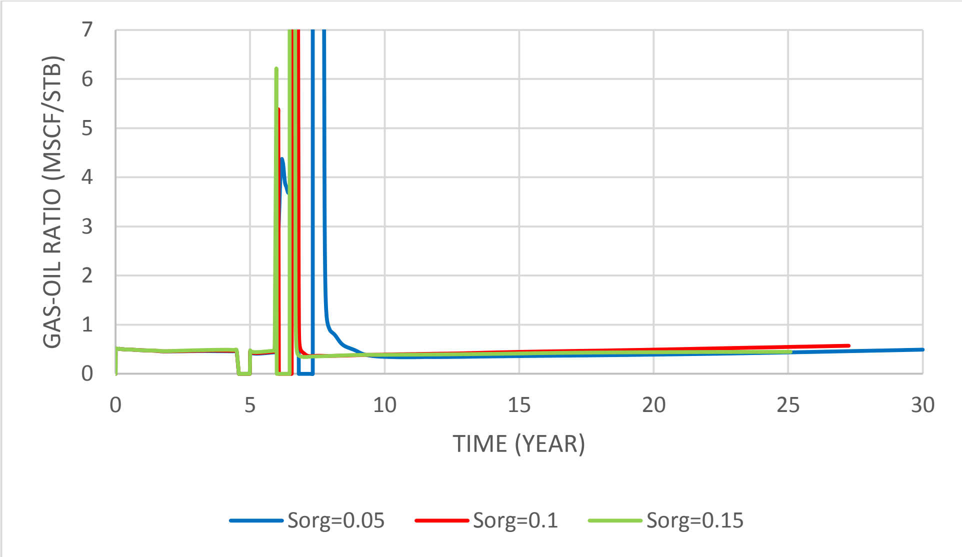

Figure 5. 36 Gas-oil ratio for different residual oil saturations (0-degree dip angle).

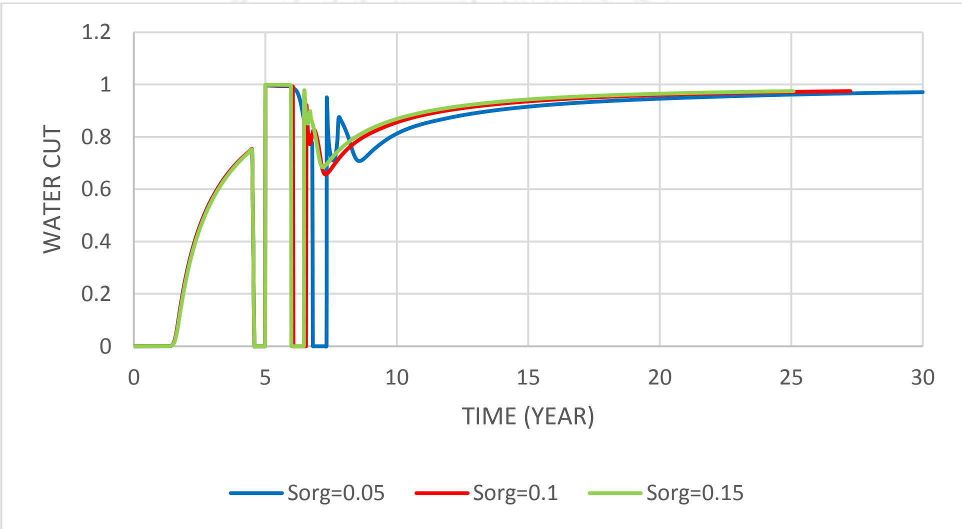

Figure 5. 37 Water cut for different residual oil saturations (0-degree dip angle).

As shown in Table 5.24, the production time is 30.00, 27.25, and 25.09 years when S_{org} equal to 0.05, 0.10, and 0.15, respectively. This is because when S_{org} is lower, higher amount of recoverable oil can be produced. Thus, it takes longer production time for the same production rate. S_{org} of 0.05, 0.1, and 0.15 give cumulative oil production around 6.72, 6.59, and 6.02 MMSTB, respectively and oil recovery factor around 56.87, 55.81, and 50.97%, respectively. Furthermore, total amount of gas production and injection is higher when S_{org} is lower because of the longer production time.

Table 5. 24 Summary of results for different residual oil saturations (0-degree dip angle).

S_{org}	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
0.05	30.00	6.72	56.87	5.78	2.62	33.54	39.69	7.25
0.1	27.25	6.59	55.81	5.72	2.62	29.64	35.67	7.11
0.15	25.09	6.02	50.97	4.17	1.44	27.74	33.36	6.49

5.2.8 Effect of wettability

In this section, we create the relative permeability curve from Table 5.25. The input parameter of Corey's correlation for water-wet and oil-wet are shown in Tables 5.26-5.27.

Table 5. 25 Classification of rock wettability from relative permeability curve.

Property	Water-wet	Oil-wet
Irreducible water saturation	Usually greater than 20 to 25 % PV	Generally less than 15% PV
Cross over saturation	Greater than 50% water saturation	Less than 50% water saturation
Relative permeability to water at residual oil saturation	Generally less than 30%	Greater than 50% and can approach 100%

Table 5. 26 List of input parameters for Corey's correlation (water-wet system).

Corey Water	3	Corey Gas	2	Corey Oil/Water	2
Swmin	0.3	Sgmin	0	Corey Oil/Gas	2
Swcr	0.3	Sgcr	0.15	Sorg	0.1
Swi	0.3	Sgi	0.15	Sorw	0.3
Swmax	1	Krg(Sorg)	0.8	Kro(Swmin)	0.8
Krw(Sorw)	0.2	Krg(Sgmax)	0.8	Kro(Sgmin)	0.8
Krw(Swmax)	0.2				

Table 5. 27 List of input parameters for Corey's correlation (oil-wet system).

Corey Water	2	Corey Gas	3	Corey Oil/Water	3
Swmin	0.1	Sgmin	0	Corey Oil/Gas	3
Swcr	0.1	Sgcr	0.15	Sorg	0.1
Swi	0.1	Sgi	0.15	Sorw	0.3
Swmax	1	Krg(Sorg)	0.8	Kro(Swmin)	0.8
Krw(Sorw)	0.7	Krg(Sgmax)	0.8	Kro(Sgmin)	0.8
Krw(Swmax)	0.7				

Figures 5.37-5.40 show the relative permeability curves of both water-wet system and oil-wet system. Oil production rate, gas-oil ratio and water cut are shown in Figures 5.41-5.43. Oil production rate of water-wet is lower than that for oil-wet because the mobility of water is low, so water cannot flow easily in water-wet system and the amount of oil is still in the reservoir after waterflooding. For gas-oil ratio and water cut, the oil-wet system yields higher than the water-wet system after gas flooding because water can flow easily in oil-wet system.

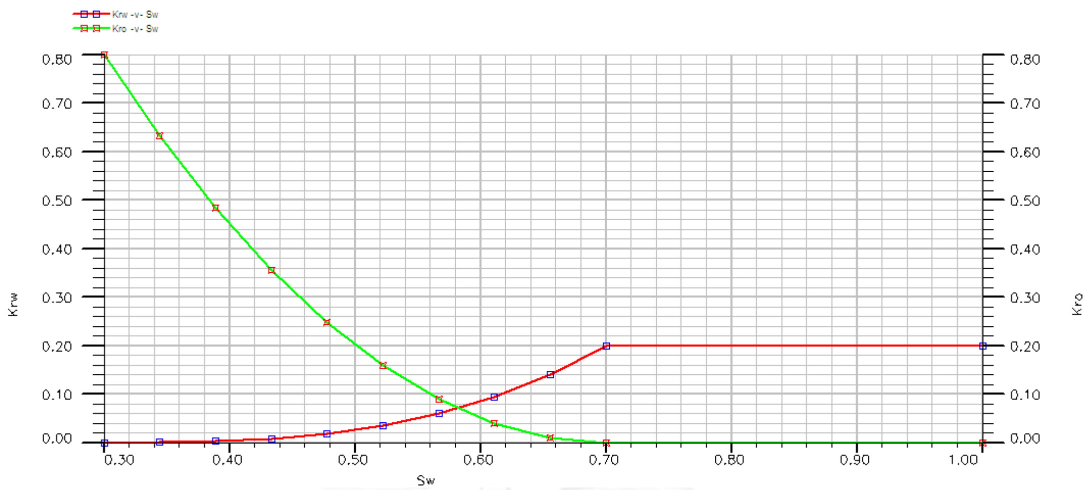

Figure 5. 38 Water/oil saturation function (water-wet system).

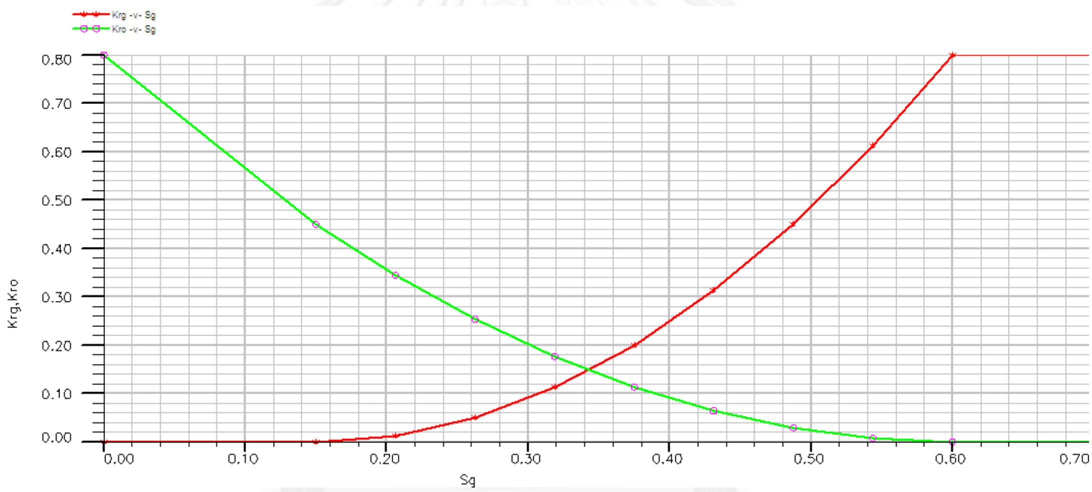

Figure 5. 39 Gas/oil saturation function (water-wet system).

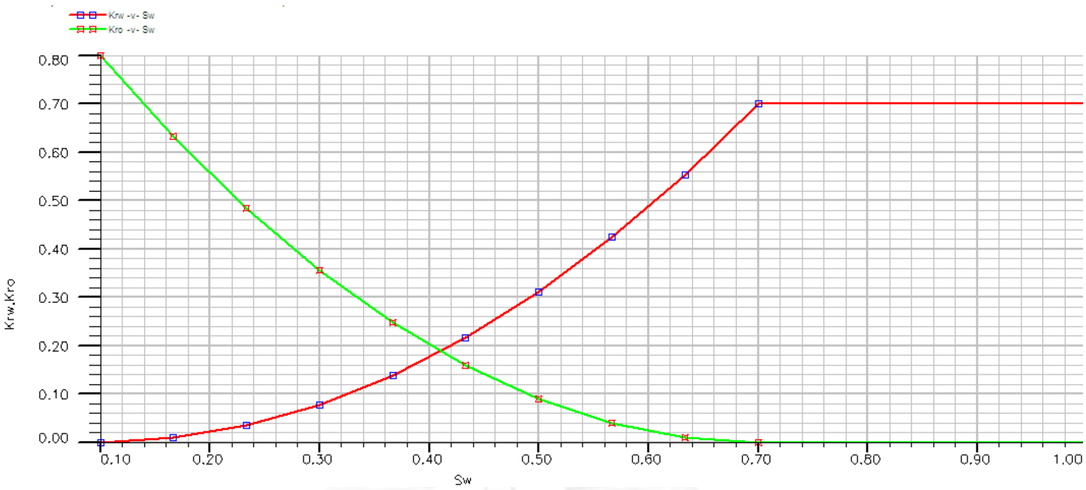

Figure 5. 40 Water/oil saturation function (oil-wet system).

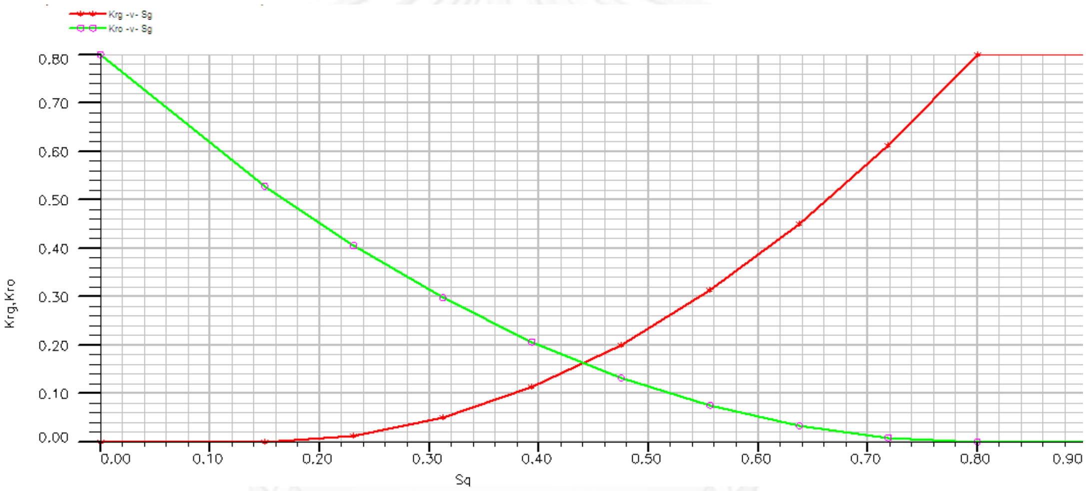

Figure 5. 41 Gas/oil saturation function (oil-wet system).

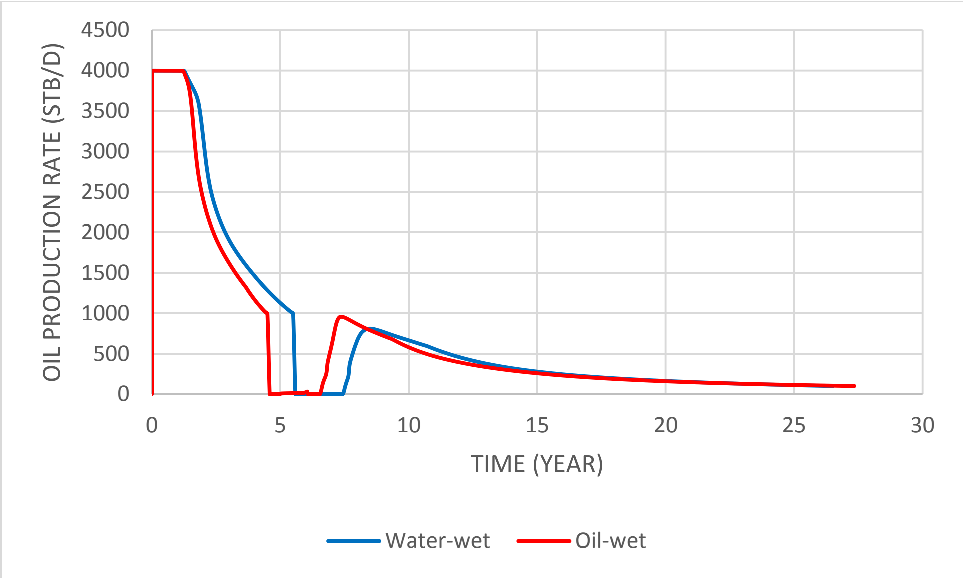

Figure 5. 42 Oil production rate for water-wet and oil-wet reservoir (0-degree dip angle).

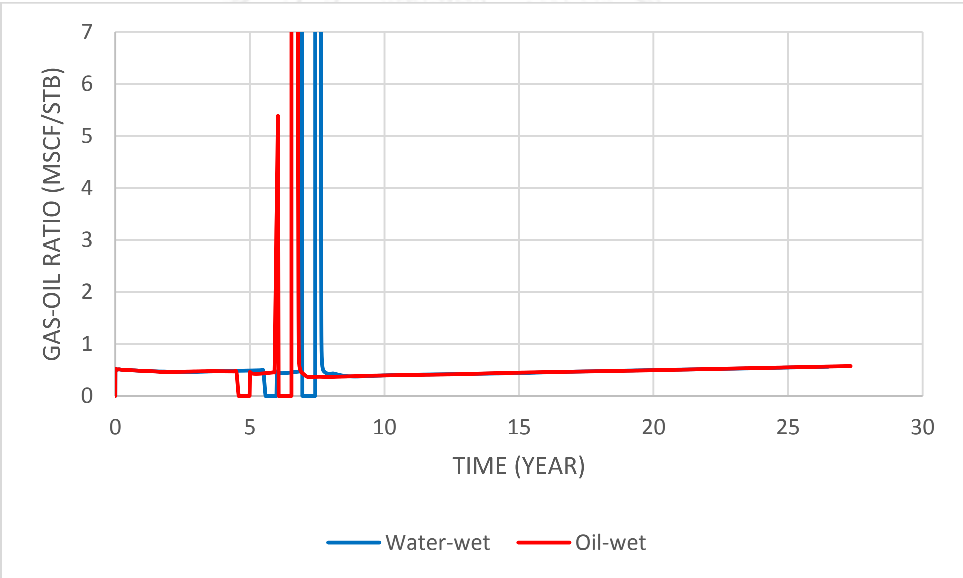

Figure 5. 43 Gas-oil ratio for water-wet and oil-wet reservoir (0-degree dip angle).

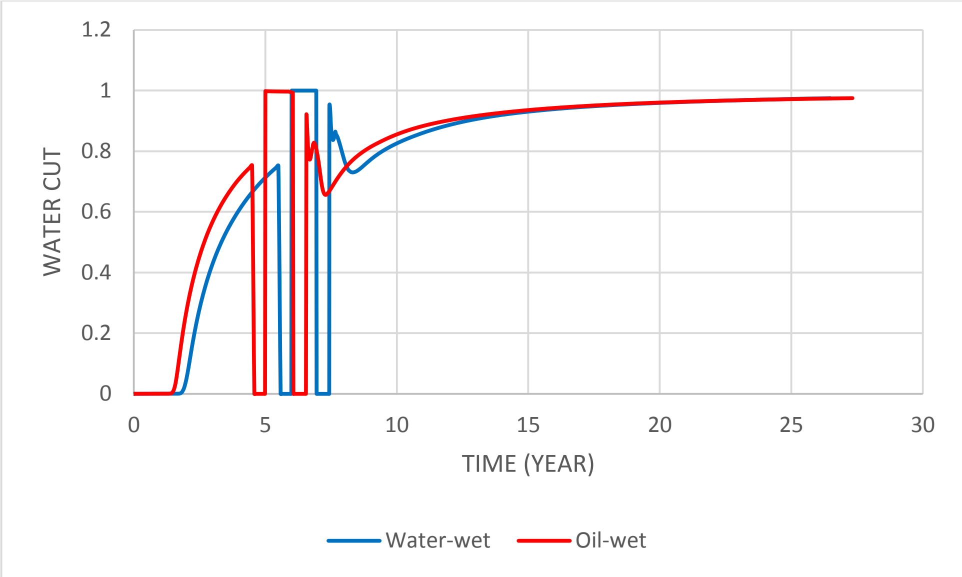

Figure 5. 44 Water cut for water-wet and oil-wet reservoir (0-degree dip angle).

Table 5. 28 Summary of results for water-wet and oil-wet reservoir (0-degree dip angle).

Wettability	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
Water-wet	26.51	7.03	59.47	4.59	1.38	28.76	35.88	7.56
Oil-wet	27.32	6.37	53.97	4.44	1.54	30.87	36.93	6.86

As shown in Table 5.28, the water-wet system provides higher cumulative oil production, oil recovery factor and BOE around 7.03 MMSTB, 59.47% and 7.56 MMSTB, respectively because oil can flow easily in the water-wet system. The oil-wet system yields higher water injection and production because the formation prefers to adhere oil more than water so water can flow and produce easily.

5.3 Reservoir with 15-degree dip angle

5.3.1 Effect of stopping time for water injection

The oil production rates for different stopping times of waterflooding are shown in Figure 5.44. The case of 60% water cut criteria has shorter well life than the case of 75% and 90% water cut criteria since it takes a shorter time to produce water to 60% water cut. During gas injection period of the case of 60% and 75% water cut criteria, cumulative oil production is increased because there are amount of water less than the case of 90% water cut criteria, so oil can be produced sooner than the case of 90% water criteria.

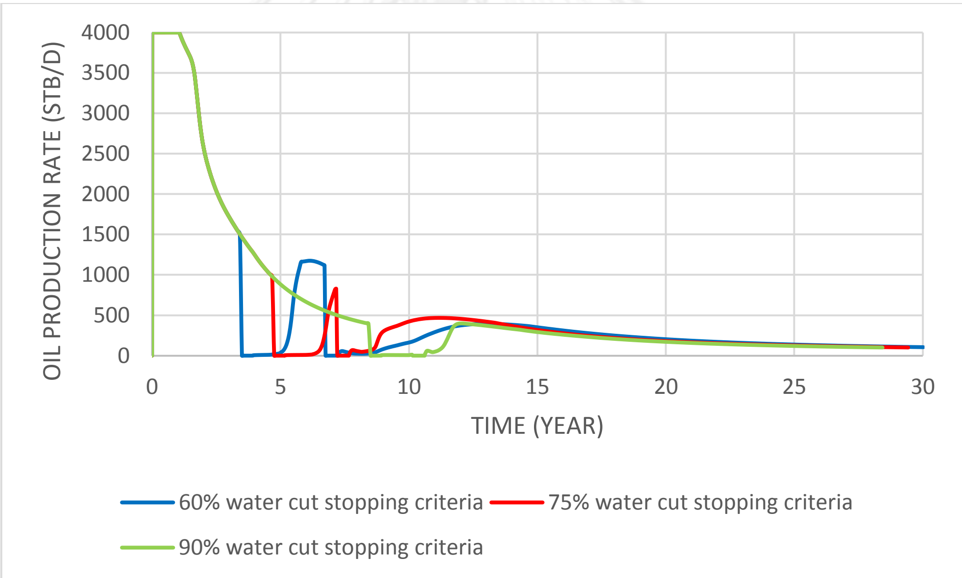

Figure 5. 45 Oil production rate for each WCT criteria (15-degree dip angle).

From Figure 5.45, the gas-oil ratio for the case of 60% water cut criteria has the highest peak of gas production during the second water injection period. For water cut, the case of 60% water cut criteria reaches 1 earlier than other cases as shown in Figure 5.46 since the initial water is converted to a producer at the earliest time.

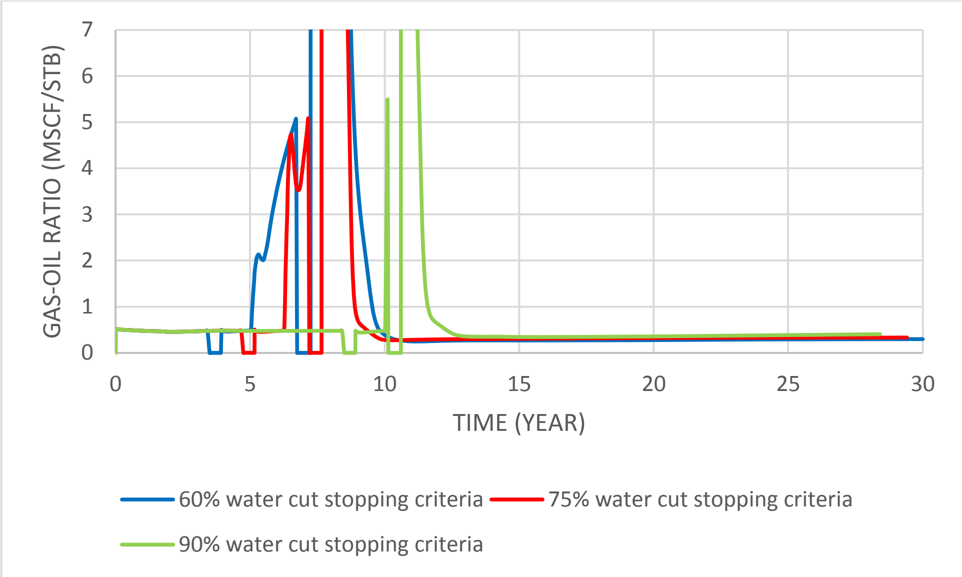

Figure 5. 46 Gas-Oil ratio for each WCT criteria (15-degree dip angle).

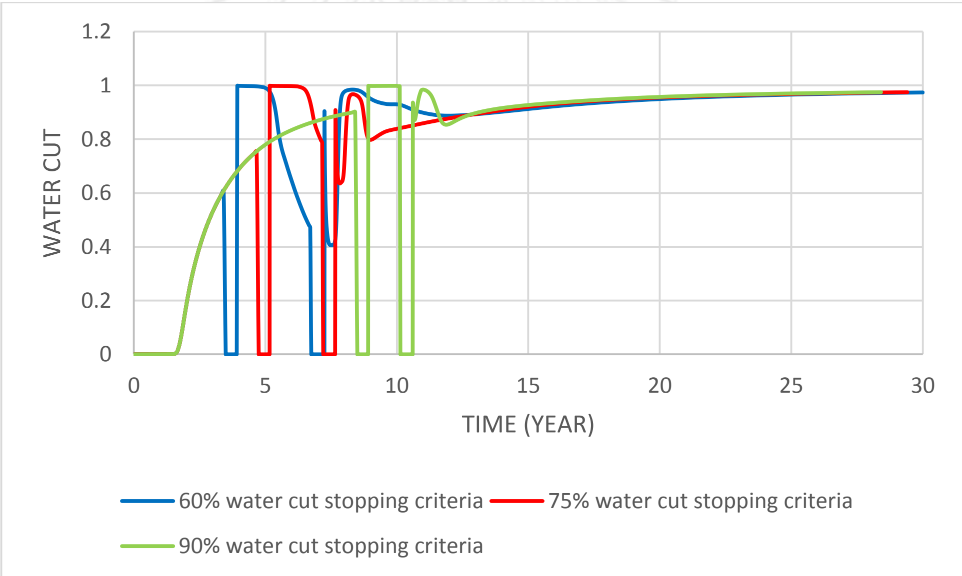

Figure 5. 47 Water cut ratio for each WCT criteria (15-degree dip angle).

Table 5.29 summarizes the results in term of production time, cumulative oil production, oil recovery factor, cumulative gas production, cumulative gas injection, cumulative water production, cumulative water injection for the reservoir with 15-degree dip angle for various WCT criteria. The results show that oil production total and oil recovery factor are slightly different. The case of 90% water cut criteria gives the highest value of oil production and takes the shortest time to produce.

Additionally, the gas that is used for injection is less than the other cases although the amount of water injection is slightly higher than the one for 60% water cut criteria. So, we choose the case of 90% water cut the optimal case.

Table 5. 29 Summary of result for various WCT criteria (15-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
60% WCT	30.00	5.95	50.29	7.68	4.08	31.81	38.23	6.55
75% WCT	29.41	6.21	52.51	6.26	2.92	32.19	38.61	6.77
90% WCT	28.41	6.37	53.85	4.95	1.75	32.11	38.32	6.91

5.3.2 Effect of water and gas injection rates

From Figure 5.47, the oil rate during the initial period for cases 1-3 are constant around 2,000 stb/d. The oil rate for cases 4-6 is around 4,000 stb/d. The oil rate for cases 7-9 varies between 5,800-6,000 stb/d. And cases 3, 6, 9 give higher oil rates during the 2^{nd} water injection period.

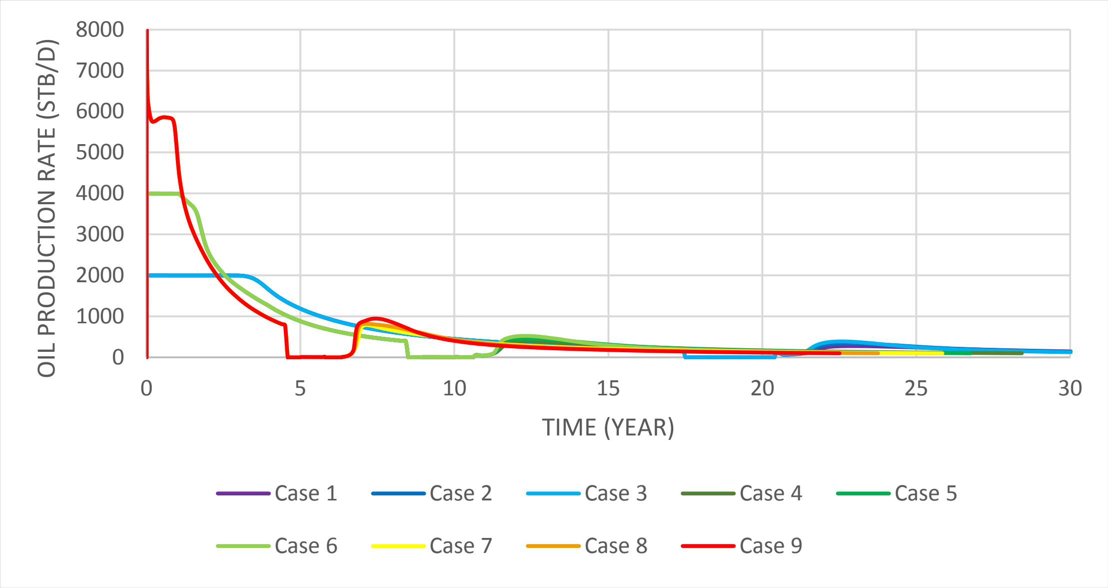

Figure 5. 48 Oil production rate for combination of different water and gas injection rate (15-degree dip angle).

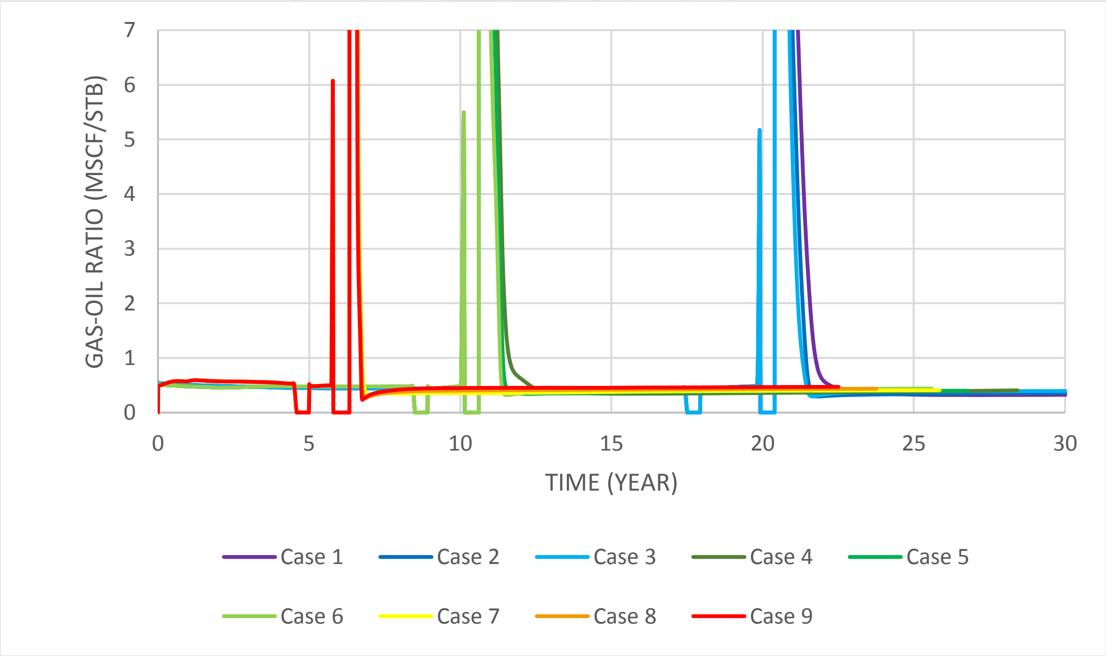

Figure 5. 49 Oil production rate for combination of different water and gas injection rate (15-degree dip angle)

As shown in Figure 5.48, cases 7-9 give the highest gas-oil ratio around 21,000 MSCF/STB in gas injection period and take shorter time since they inject higher water and gas rates. For water cut, 60% cases 7-9 reach 1 in 5 years which is earlier than other cases as shown in Figure 5.49.

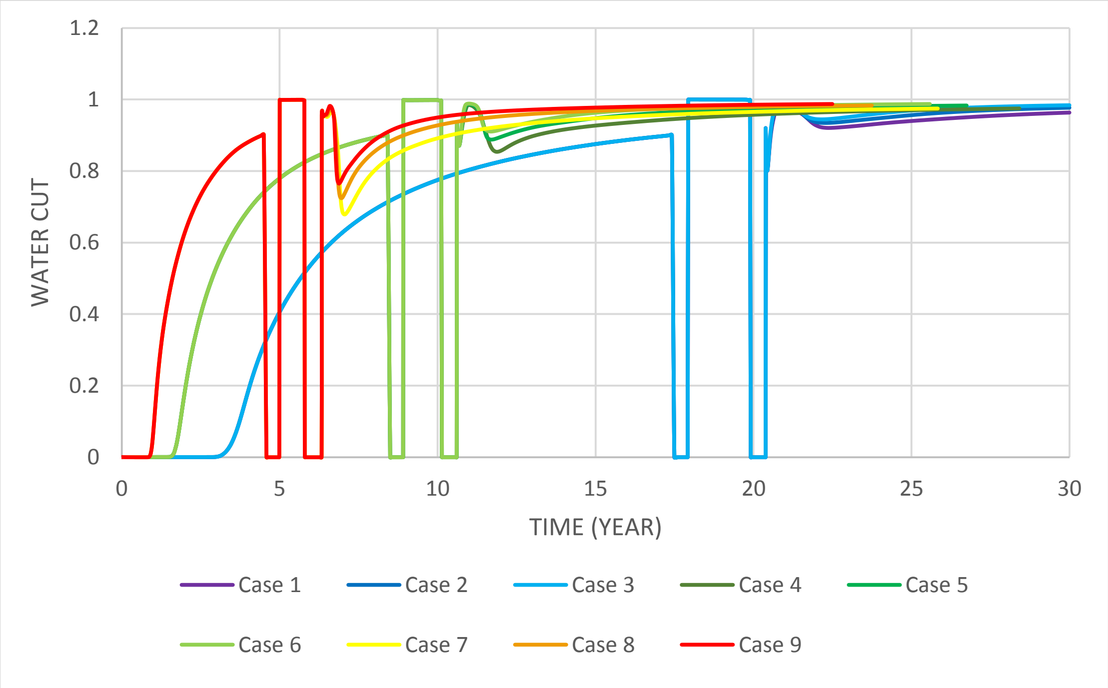

Figure 5. 50 Water cut for combination of different water and gas injection rate (15-degree dip angle).

Furthermore, Table 5.30 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 15 degree dip angle for various injection rates. From the results show in Table 5.30, cumulative oil production, oil recovery factor, and BOE are slightly different. Cases 1, 4, and 5 give good cumulative oil production around 6.17, 6.37, and 6.35 MMSTB, respectively, and BOE around 6.71, 6.91, and 6.86 MMSTB, respectively. However, the amounts of water injection and production in these cases are high. Although case 1 yields slightly lower BOE, it has much less water injection and production. Thus, we choose case 1 as the optimal case.

Table 5. 30 Summary of results for various injection rates (15-degree dip angle)

Case no.	1st water injection rate (STB/D)	Gas injection rate (MSCF/D)	2nd water injection rate (STB/D)	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
1	2,000	2,000	4,000	30.02	6.17	52.15	4.69	1.44	20.88	26.77	6.71
2	2,000	2,000	6,000	30.02	6.24	52.75	4.59	1.44	27.30	33.99	6.76
3	2,000	2,000	8,000	30.02	6.25	52.80	4.55	1.44	33.63	40.82	6.77
4	4,000	4,000	4,000	28.43	6.37	53.85	4.95	1.75	32.11	38.32	6.91
5	4,000	4,000	6,000	26.76	6.35	53.66	4.83	1.75	40.80	47.67	6.86
6	4,000	4,000	8,000	25.59	6.31	53.29	4.78	1.75	48.82	56.06	6.81
7	8,000	8,000	4,000	25.85	6.31	53.28	5.37	2.31	34.37	40.78	6.81
8	8,000	8,000	6,000	23.76	6.21	52.49	5.32	2.31	43.49	50.46	6.71
9	8,000	8,000	8,000	22.51	6.17	52.11	5.31	2.31	52.27	59.53	6.67

5.3.3 Effect of well pattern

Table 5.31 shows the formation fracture pressure of reservoir with 15 degree dip angle for different well patterns. The field oil production rate for each well pattern is shown in Figure 5.50. Pattern of 8 wells yield high oil production rate at the beginning because there are many wells to produce. Pattern of a vertical well with a horizontal well gives the highest production rate in 2nd water injection period. And, pattern 6 gives the highest gas-oil ratio around 6,200 MSCF/STB as shown in Figure 5.51.

Table 5. 31 Formation fracture pressure of reservoir with 15 degree dip angle for different well patterns.

Well pattern	No. of well	Formation fracture pressure (psia)
1	well 1	3231
	well 2	3507
2	well 1	3193
	well 2	3314
	well 3	3435
	well 4	3558
3	well 1	3193
	well 2	3314
	well 3	3435
	well 4	3558
4	well 1	3193
	well 2	3314
	well 3	3435
	well 4	3558
5	well 1	3183
	well 2	3237
	well 3	3292
	well 4	3347
	well 5	3402
	well 6	3457
	well 7	3513
	well 8	3569
6	well 1	3231
	well 2	3507
7	well 1	3231
	well 2	3507

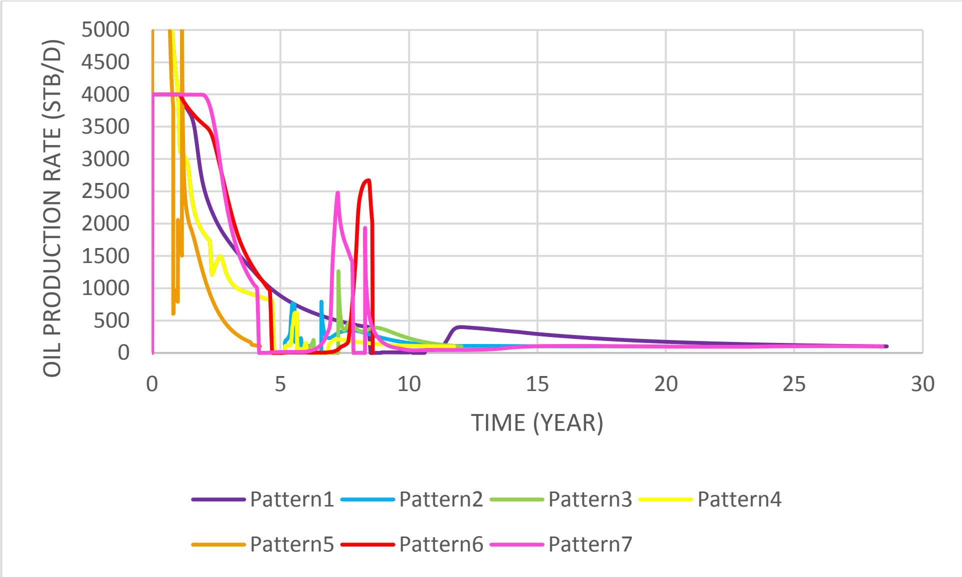

Figure 5. 51 Oil production rate for each well pattern (15-degree dip angle).

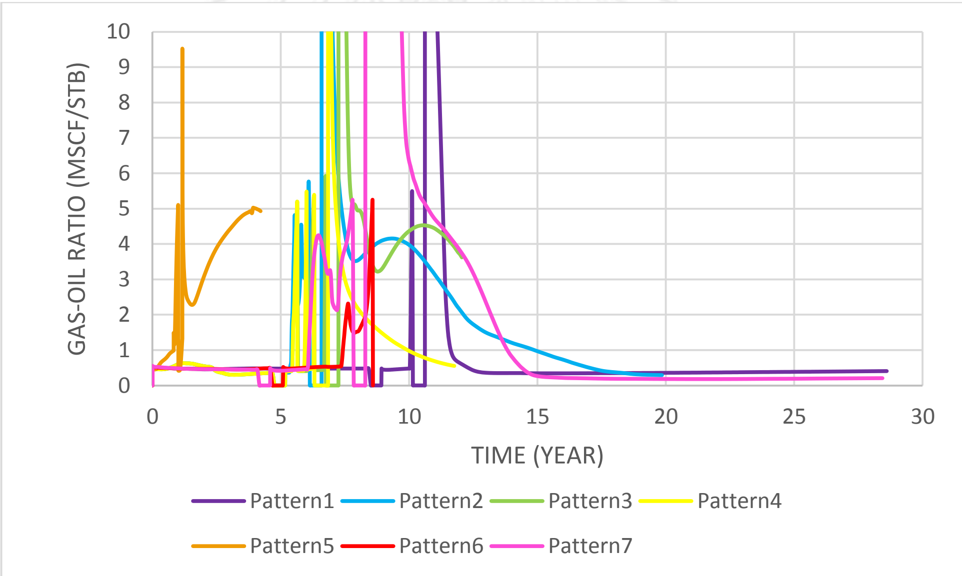

Figure 5. 52 Gas-oil ratio for each well pattern (15-degree dip angle).

In term of water cut, the results are shown in Figure 5.52. The shorter the time for gas breakthrough, the higher the yield of cumulative gas production. Pattern of 8 wells gives the shortest time for gas breakthrough because the distance between the injector and the producer is closer than that for the other patterns.

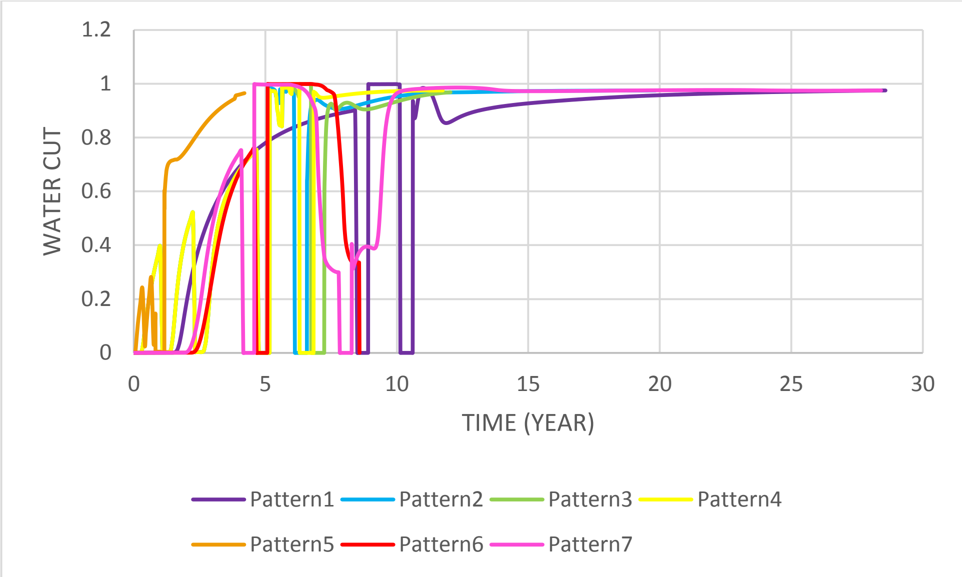

Figure 5. 53 Water cut for each well pattern (15-degree dip angle).

Moreover, Table 5.32 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 15 degree dip angle for different well patterns. From the results shown in Table 5.32, cumulative oil production, oil recovery factor, and BOE are significantly different. Patterns of 2 vertical wells, 2 horizontal wells, 4 vertical wells, and a vertical well with a horizontal well give good cumulative oil production around 6.38, 5.96, 5.53, and 5.43 MMSTB, respectively and BOE around 6.91, 6.67, 6.34 and 5.22 MMSTB, respectively. In addition, there are significant differences in amount of water and gas injection and time to reach the economic constraint. Pattern 7 yields the highest gas production of 8.96 BSCF while pattern 6 needs the largest amount of gas injection (5.10 BSCF). Among the seven patterns, pattern 3 and 4 produce smaller amount of water and require lower amount of water injection than the rest. Judging from high amount of oil production, low amount of gas and water injection and production, pattern of 4 vertical wells with 1^{st} sequence (pattern 3) is the best case.

Table 5. 32 Summary of results of different well pattern case (15-degree dip angle).

Case no.	Pattern	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
1	2 vertical wells	28.60	6.38	53.91	4.95	1.75	32.34	38.56	6.91
2	4 vertical wells	19.84	5.53	46.77	6.18	1.35	21.42	26.30	6.34
3	4 vertical wells with 1st sequence	12.05	5.28	44.64	6.84	2.30	10.21	13.84	6.04
4	4 vertical wells with 2nd sequence	11.75	5.04	42.58	3.26	1.65	10.37	13.99	5.30
5	8 vertical wells	4.21	4.28	36.19	5.22	4.94	42.42	56.51	4.33
6	A vertical well with a horizontal	8.58	5.43	45.94	3.79	5.10	58.11	66.95	5.22
7	2 horizontal wells	28.43	5.96	50.35	8.96	4.69	29.68	35.38	6.67

5.3.4 Comparison with DDP

When making the comparison, pattern of 2 vertical wells is used for both SCWD and DDP. We inject 4,000 STB/D of water and 4,000 MSCF/D of gas for both SCWD and DDP. Oil production rates of SCWD and DDP are compared in Figure 5.53. During the first 10 years of production, both SCWD and DDP give the same result as both processes start with initial waterflooding followed by gas injection. The oil rate of DDP increases to its highest value sooner than that for SCWD since continuous gas injection helps reduce remaining oil in the reservoir. However, the mobility ratio in gas injection is less favorable than that in water injection. Thus, the oil production rate of DDP drops earlier than that for SCWD. Gas-oil ratio of DDP is higher than that for SCWD after 7 years as shown in Figure 5.54 because DDP continues injecting gas.

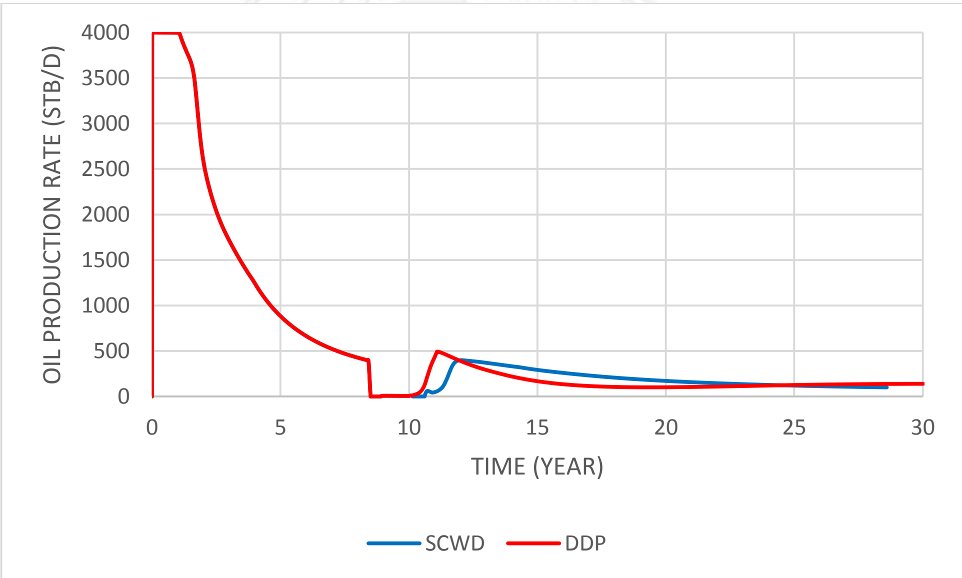

Figure 5. 54 Oil production rate of SCWD and DDP (15-degree dip angle).

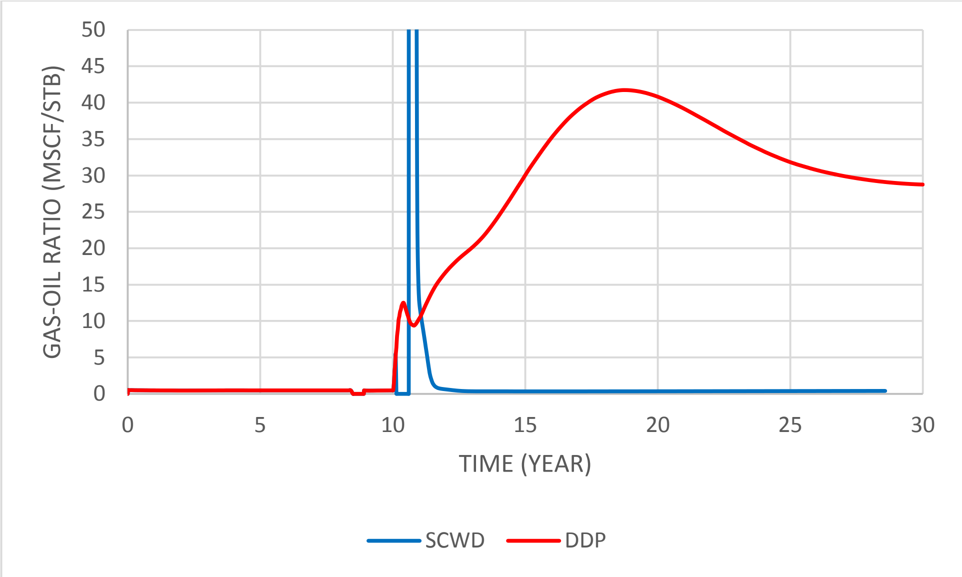

Figure 5. 55 as-oil ratio of SCWD and DDP (15-degree dip angle).

In term of water cut, both processes give the same water cut during the first 10 years as shown in Figure 5.55. SCWD gives higher water cut after gas injection period because there is a second water injection for SCWD.

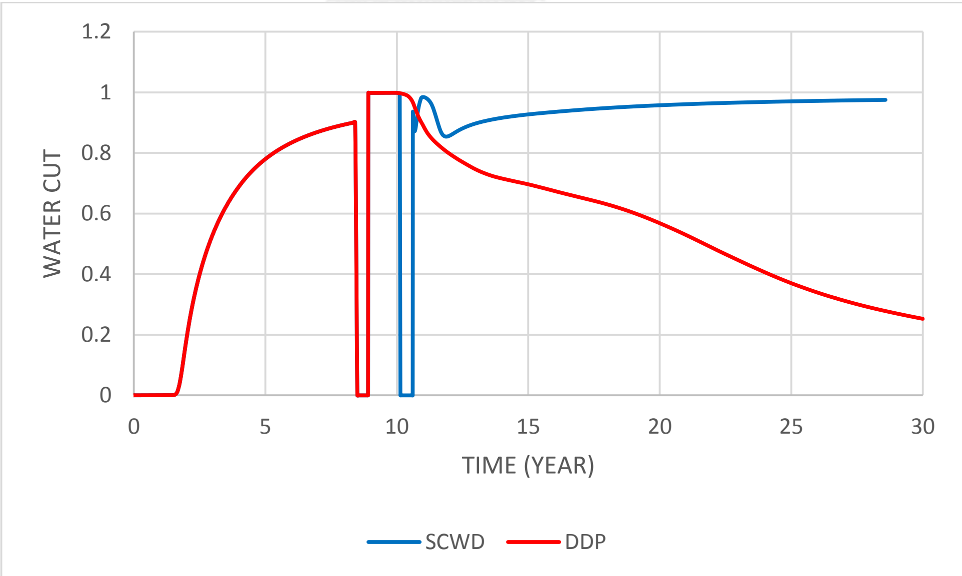

Figure 5. 56 Water cut of SCWD and DDP (15-degree dip angle).

Table 5.33 shows the results of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 15 degree dip angle for SCWD and DDP. From the results, SCWD shows the better performance than DDP for reservoir with 15 degree dip angle because SCWD gives BOE around 6.90 MMSTB while DDP can recover only 6.84 MMSTB of BOE. In addition, SWCD provides the lower amount of gas production and injection, higher amount of water production and injection, and shorter production period than DDP.

Table 5. 33 Summary of result of SCWD and DDP (15-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
SCWD	28.60	6.38	53.91	4.95	1.75	32.34	38.56	6.90
DDP	30.00	6.26	52.93	34.24	30.81	12.15	12.29	6.84

5.3.5 Effect of relative permeability correlation

Oil production rate, gas-oil ratio and water cut for dip angle of 15 degree are illustrated in Figures 5.56-5.58. During both water and gas injection period, Stone 1 and ECLIPSE default models provide higher oil and gas production rate than Stone 2 model. Regarding gas-oil ratio, Stone 2 model yields the highest peak of gas-oil ratio during gas injection period. The water cuts from all correlations are quite the same but Stone 2 model takes shorter time than Stone 1 and ECLIPSE default model.

Table 5.34 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, and cumulative gas production for a reservoir with 0 degree dip angle for all correlation models.

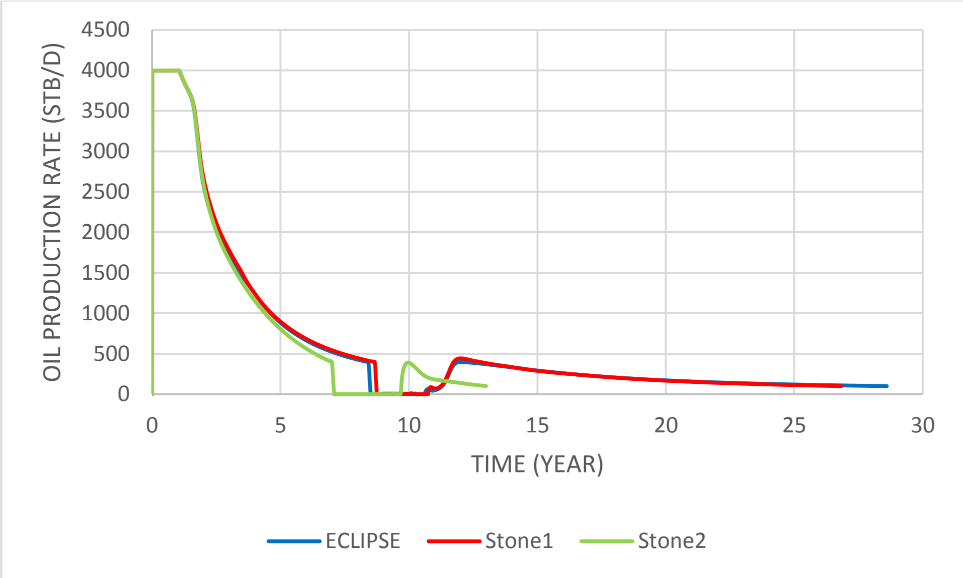

Figure 5. 57 Oil production rate for each three phase relative permeability correlation model (15-degree dip angle).

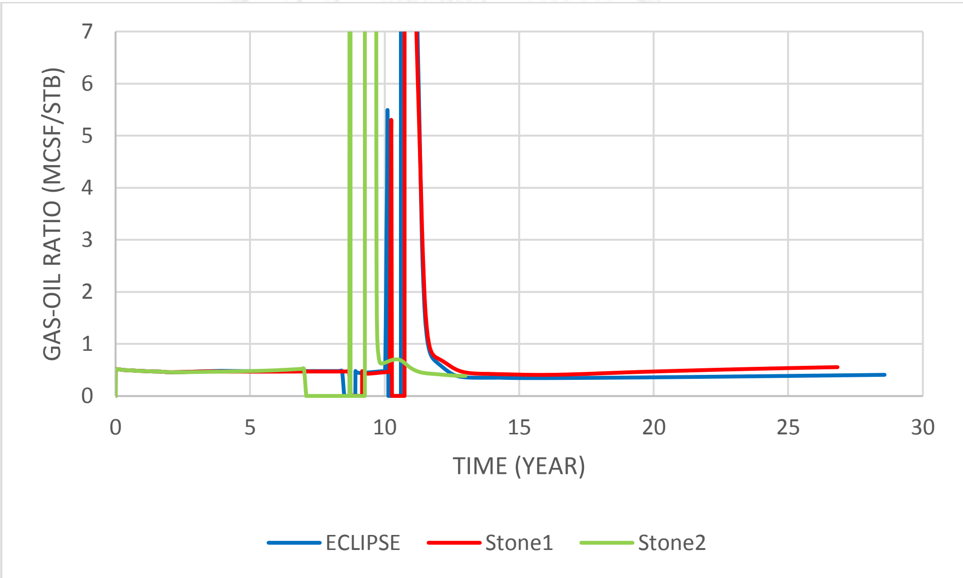

Figure 5. 58 Gas-oil ratio for each three phase relative permeability correlation model (15-degree dip angle).

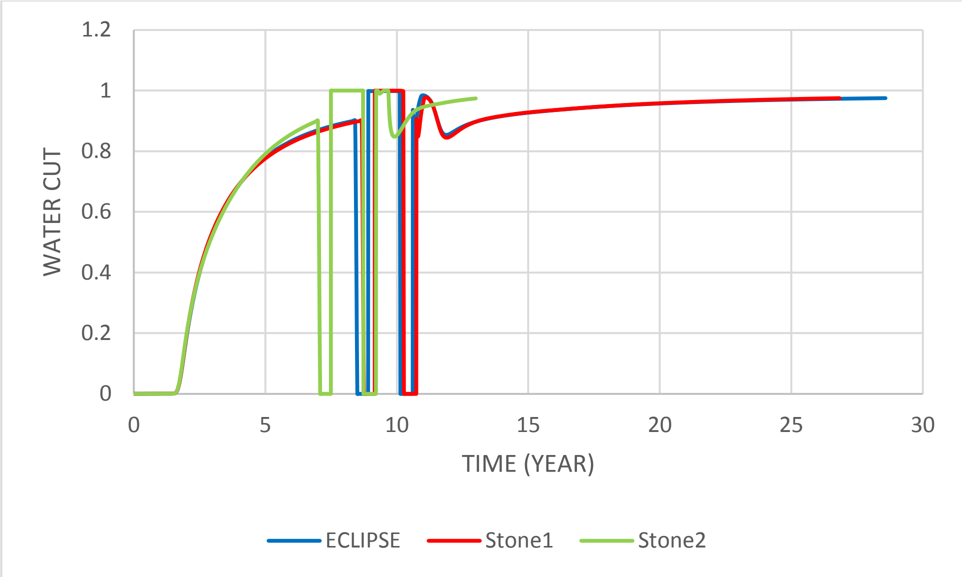

Figure 5. 59 Water cut for each three phase relative permeability correlation model (15-degree dip angle).

Table 5. 34 Summary of result of each three phase relative permeability correlation model (15-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
ECLIPSE default	28.41	6.37	53.85	4.95	1.75	32.11	38.32	6.90
Stone 1	26.75	6.43	54.30	4.90	1.59	29.96	36.05	6.98
Stone 2	13.00	4.96	41.89	4.38	1.78	10.74	15.77	4.92

From the results, ECLIPSE default model and Stone 1 model give similar cumulative oil production of 6.37 and 6.43 MMSTB, respectively and BOE of 6.90 and 6.98 MMSTB, respectively while Stone 2 model yields a lower value for cumulative oil production and BOE. Furthermore, Stone 2 model gives lower gas and much lower water production and needs less gas and much less water injection as well as less time to produce.

5.3.6 Effect of vertical to horizontal permeability ratio

The oil production rate and gas-oil ratio and water cut for all vertical to horizontal ratios are shown in Figures 5.59-5.61. Case 3 takes a longer time to inject water than other cases during the 1st water injection period because water can flow in both vertical and horizontal permeabilities reservoir easily allowing better segregation of oil and water. So, early breakthrough of water does not occur in case 3. Later on, the oil rate starts to decline because water and gas start to produce as well and give the highest gas-oil ratio around 15,000 MSCF/STB.

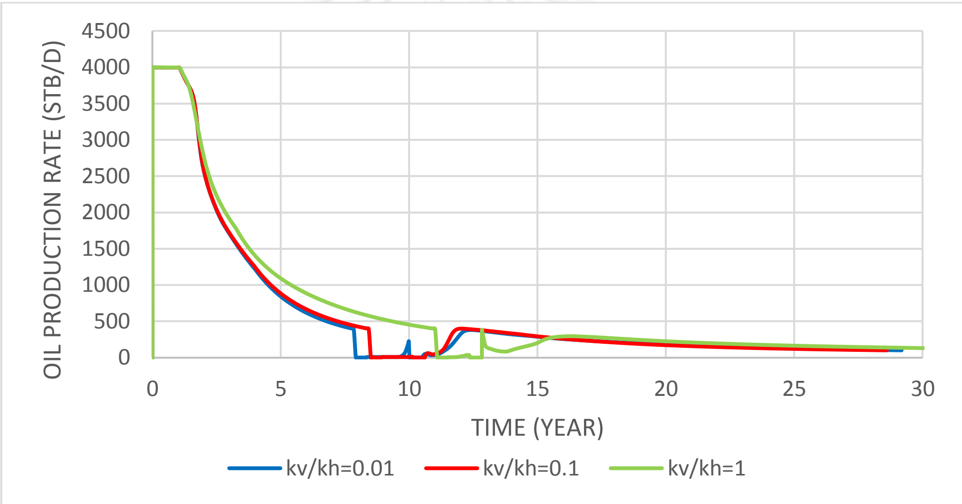

Figure 5. 60 Oil production rate for different anisotropy ratios (15-degree dip angle).

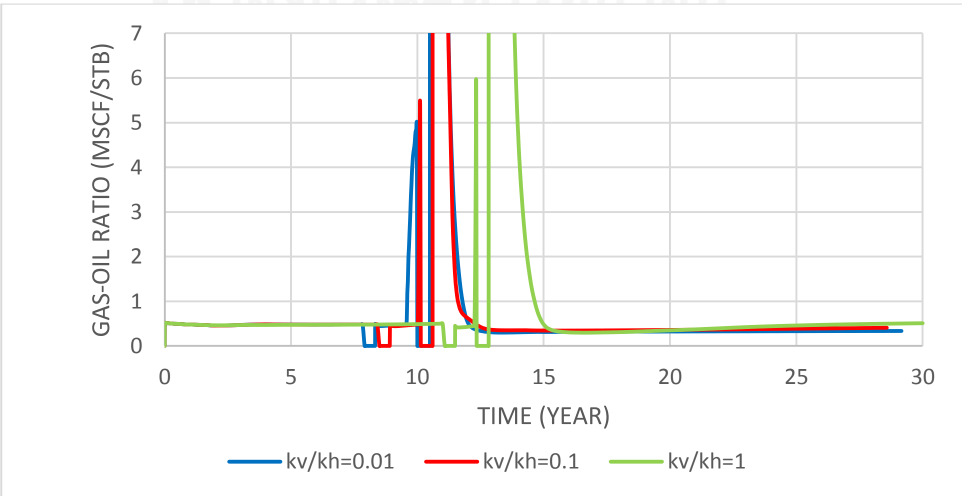

Figure 5. 61 Gas-oil ratio for different anisotropy ratios (15-degree dip angle).

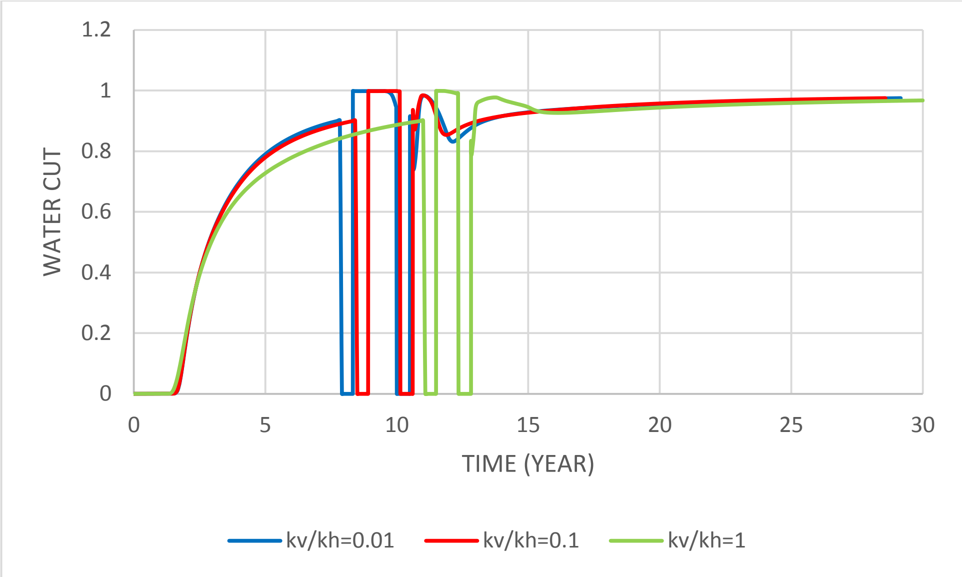

Figure 5. 62 Water cut for different anisotropy ratios (15-degree dip angle).

Table 5. 35 Summary of results for different vertical to horizontal permeability ratios (15-degree dip angle).

k_v/k_h	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
0.01	29.00	6.22	52.56	5.49	2.41	32.28	38.48	6.73
0.1	28.41	6.37	53.85	4.95	1.75	32.11	38.32	6.91
1	30.00	7.22	61.04	5.32	1.22	34.40	41.17	7.91

As shown in Table 5.35, case 3 provides higher cumulative oil production, cumulative gas production, cumulative water production, and oil recovery factor than other cases because oil, gas and water can flow easily in high vertical permeability reservoir.

5.3.7 Effect of residual oil saturation by gas displacement (S_{org})

Oil production rate, gas-oil ratio and water cut are illustrated in Figures 5.62-5.64. In the 2nd water injection, the oil production rate of S_{org} is 0.05 is a bit higher than other cases. At the end, this case provides the highest cumulative oil production because when S_{org} is lower, higher amount of recoverable oil can be produced.

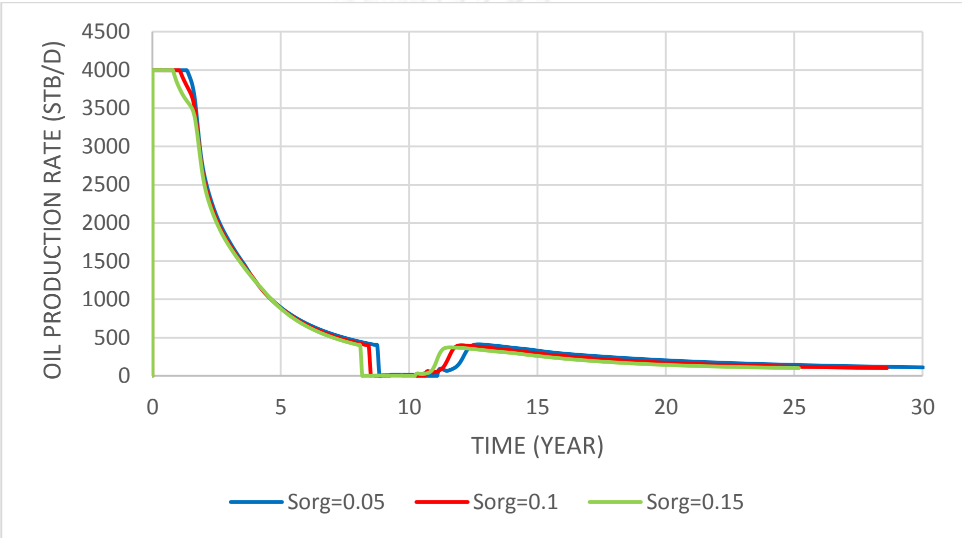

Figure 5. 63 Oil production rate for different residual oil saturations (15-degree dip angle).

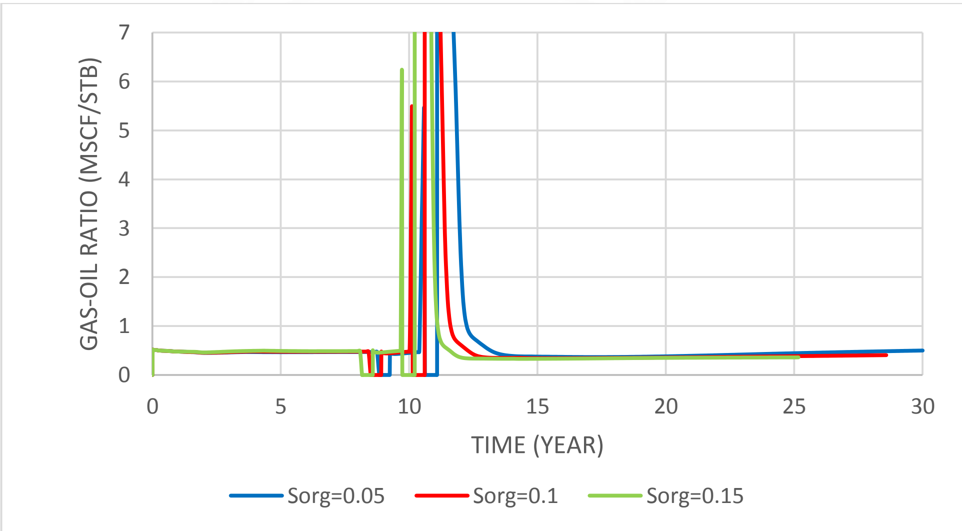

Figure 5. 64 Gas-oil ratio for different residual oil saturations (15-degree dip angle).

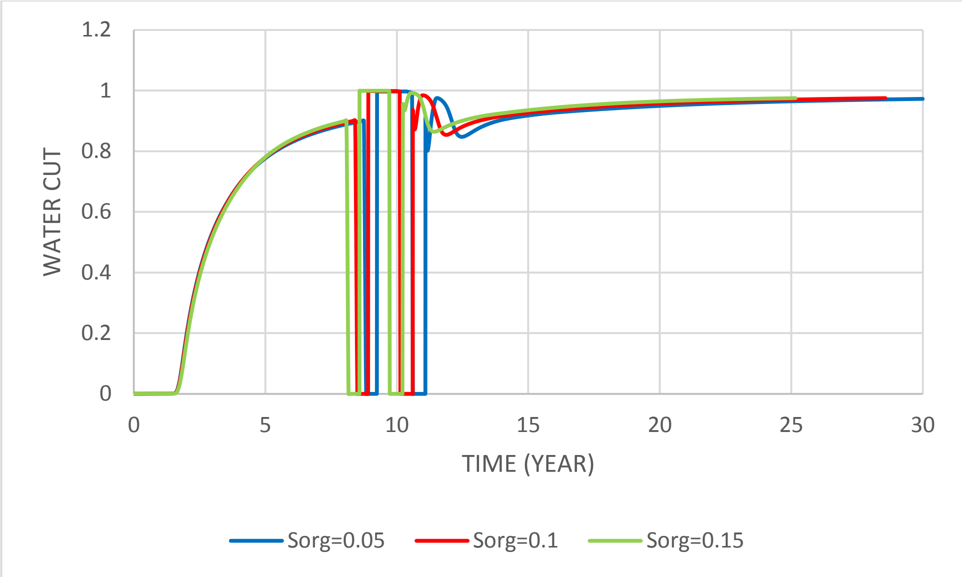

Figure 5. 65 Water cut for different residual oil saturations (15-degree dip angle).

As shown in Table 5.36, the production time is 30.00, 28.41, and 25.00 years when S_{org} equal to 0.05, 0.10, and 0.15, respectively. This is because when S_{org} is lower, higher amount of recoverable oil can be produced. Thus, it takes longer production time for the same production rate. S_{org} of 0.05, 0.1, and 0.15 give cumulative oil production around 6.68, 6.37, and 5.99 MMSTB, respectively and oil recovery factor around 56.49, 53.85, and 50.67%, respectively. Furthermore, total amount of gas production and injection is higher when S_{org} is lower because of the longer production time.

Table 5. 36 Summary of results for different residual oil saturations (15-degree dip angle).

S_{org}	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
0.05	30.00	6.68	56.49	5.35	1.95	34.05	40.42	7.25
0.1	28.41	6.37	53.85	4.94	1.75	32.11	38.32	6.91
0.15	25.00	5.99	50.67	4.68	1.66	27.39	33.42	6.50

5.3.8 Effect of wettability

Oil production rate, gas-oil ratio and water cut are shown in Figures 5.65-5.67. Oil production rate of water-wet is lower than that for oil-wet because the mobility of water is low, so water cannot flow easily in water-wet system and the amount of oil is still in the reservoir after waterflooding. For gas-oil ratio and water cut, the oil-wet system yields higher than the water-wet system after gas flooding because water can flow easily in oil-wet system.

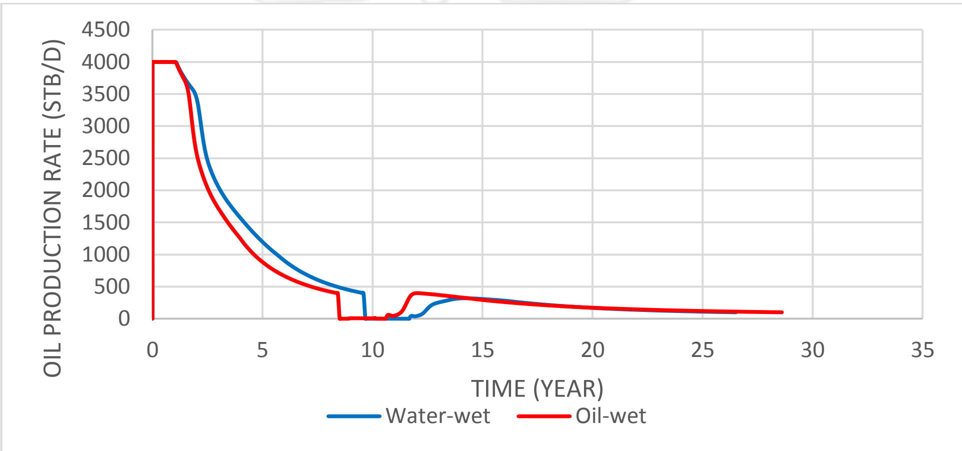

Figure 5. 66 Oil production rate for water-wet and oil-wet reservoirs (15-degree dip angle).

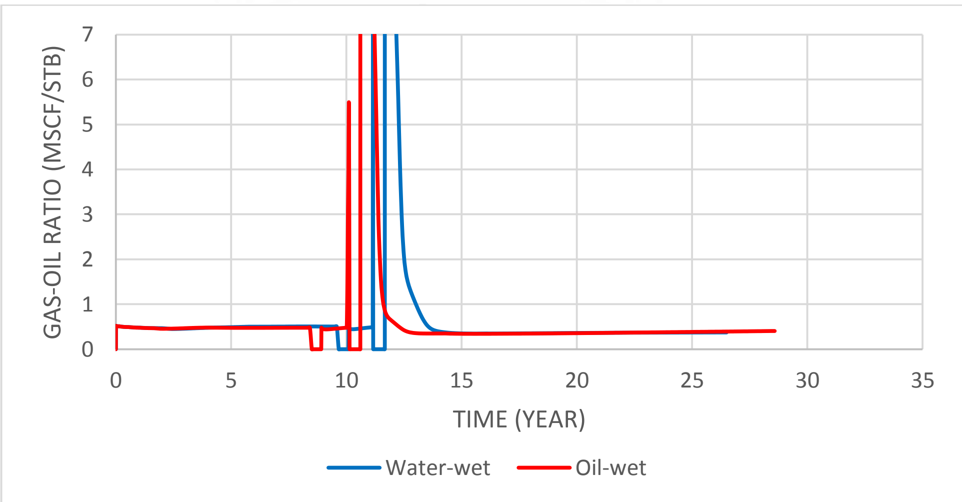

Figure 5. 67 Gas-oil ratio for water-wet and oil-wet reservoirs (15-degree dip angle).

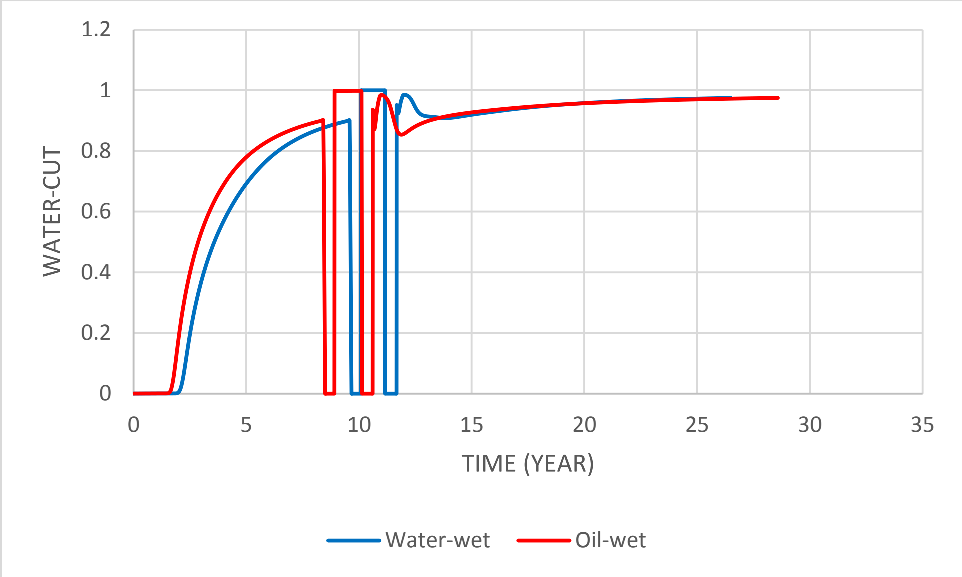

Figure 5. 68 Water cut for water-wet and oil-wet reservoirs (15-degree dip angle).

Table 5. 37 Summary of results for water-wet and oil-wet reservoirs (15-degree dip angle).

Wettability	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
Water-wet	26.49	7.04	59.49	5.03	1.55	28.34	35.66	7.62
Oil-wet	28.60	6.38	53.90	4.95	1.75	32.34	38.56	6.91

As shown in Table 5.37, the water-wet system provides higher cumulative oil production, oil recovery factor and BOE around 7.04 MMSTB, 59.49% and 7.62 MMSTB, respectively because oil can flow easily in the water-wet system. The oil-wet system yields higher water injection and production because the formation prefers to adhere oil more than water so water can flow and produce easily.

5.4 Reservoir with 30-degree dip angle

5.4.1 Effect of stopping time for water injection

The oil production rates for different stopping times of water flooding are shown in Figure 5.68. The case of 60% water cut criteria has shorter well life than the case of 75% and 90% water cut criteria since it takes a shorter time to produce water to 60% water cut. During gas injection period of the case of 60% and 75% water cut criteria, cumulative oil production is increased because there are amount of water less than the case of 90% water cut criteria, so oil can be produced sooner than the case of 90% water criteria.

From Figure 5.69, the gas-oil ratio for the case of 90% water cut criteria has the highest peak of gas production during the second water injection period. For water cut, the water cut for the case of 60% water cut criteria reaches 1 earlier than other cases as shown in Figure 5.70 because the initial water is converted to a producer at the earliest time.

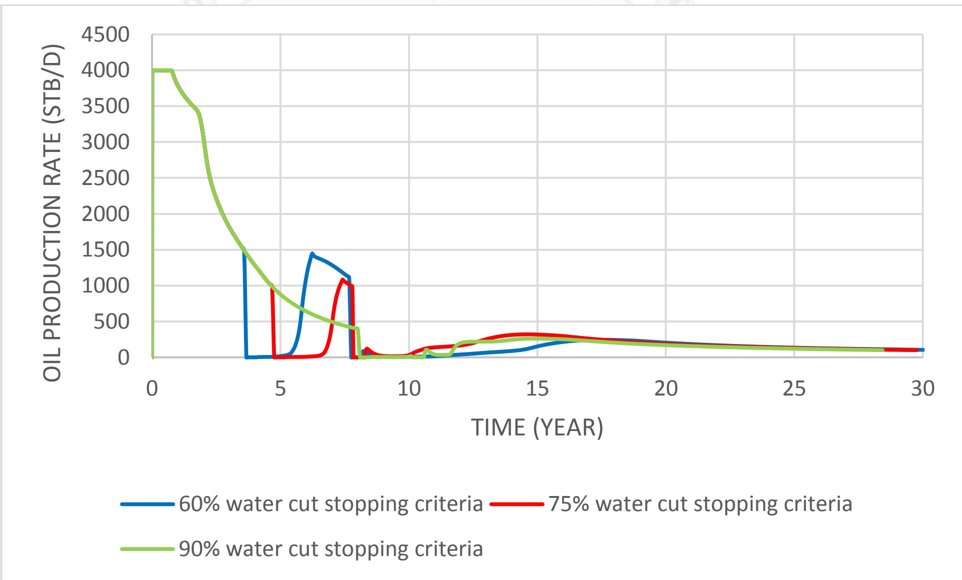

Figure 5. 69 Oil production rate for each WCT criteria (30-degree dip angle).

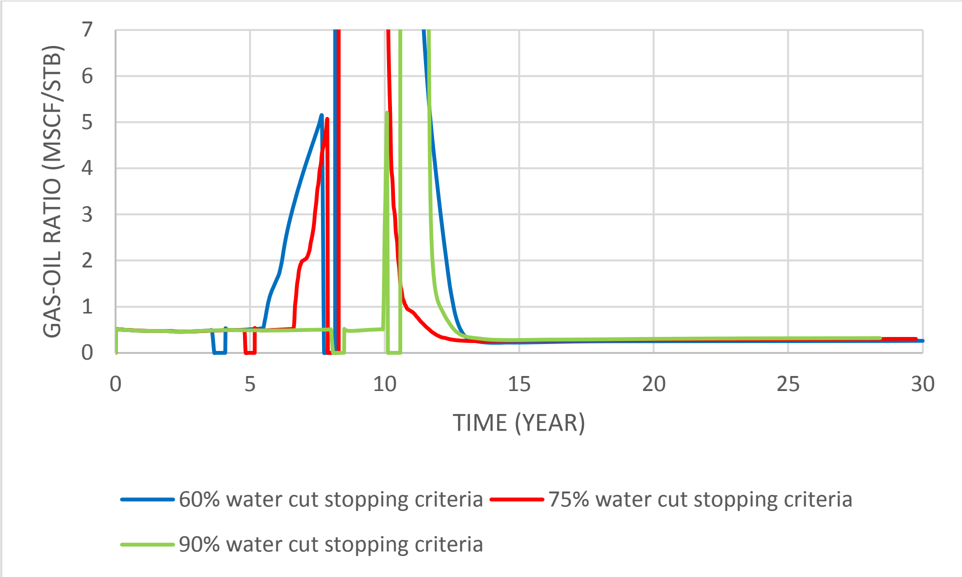

Figure 5. 70 Gas-Oil ratio for each WCT criteria (30-degree dip angle).

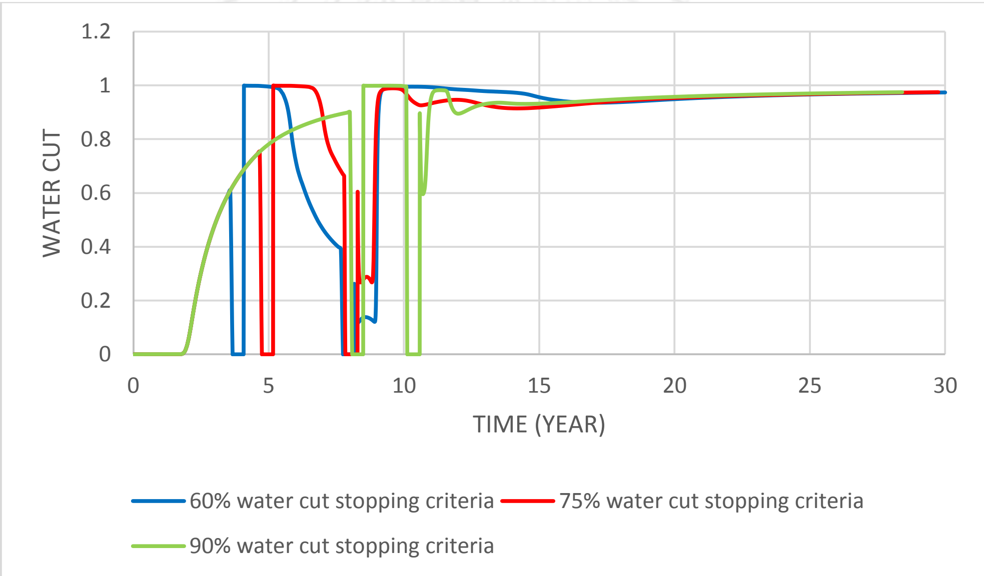

Figure 5. 71 Water cut for each WCT criteria (30-degree dip angle).

Table 5.38 summarizes the results in term of production time, cumulative oil production, oil recovery factor, cumulative gas production, cumulative gas injection, cumulative water production, cumulative water injection for the reservoir with 15-degree dip angle for various WCT criteria. The results show that oil production total and oil recovery factor are slightly different. The case of 90% water cut gives the highest value of oil production and takes the shortest time to produce. Additionally, the gas that is used for injection is less than the other cases. So, we choose the case of 90% water cut the optimal case.

Table 5. 38 Summary of result for various WCT criteria (30-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
60% WCT	30.02	5.82	49.05	8.99	5.25	30.47	37.14	6.44
75% WCT	29.77	6.01	50.70	7.40	3.84	31.45	38.18	6.60
90% WCT	28.43	6.19	52.24	5.72	2.33	31.12	37.74	6.76

5.4.2 Effect of water and gas injection rates

From Figure 5.71, the oil rate during the initial period for cases 1-3 is constant around 2,000 STB/D. The oil rate for cases 4-6 is around 4,000 STB/D. The oil rate for cases 7-9 varies between 5,600-6,200 STB/D. And cases 3, 6, 9 give higher oil rates during the 2nd water injection period.

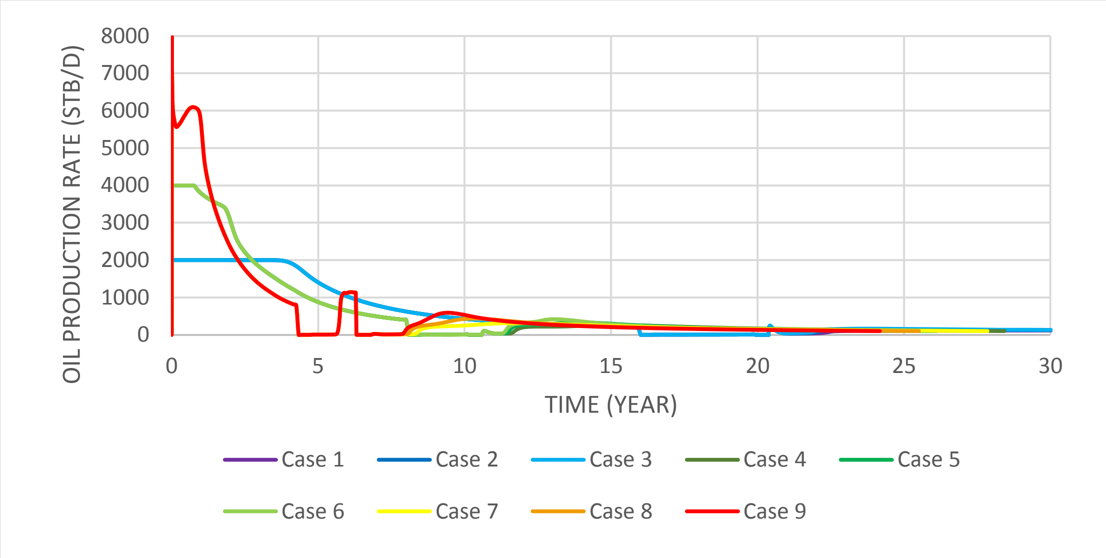

Figure 5. 72 Oil production rate for combination of different water and gas injection rate (30-degree dip angle).

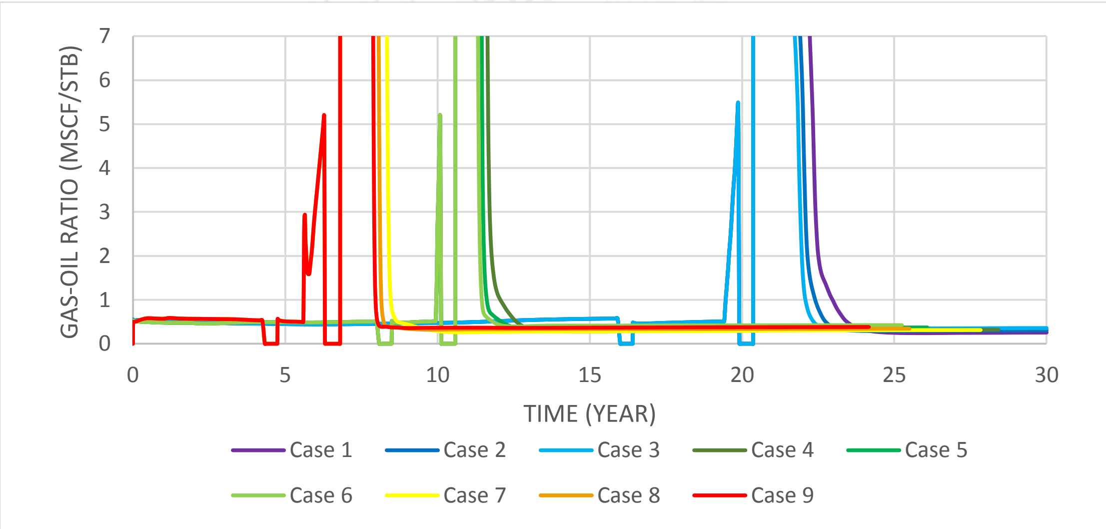

Figure 5. 73 Oil production rate for combination of different water and gas injection rate (30-degree dip angle).

As shown Figure 5.72, cases 7-9 give the highest gas-oil ratio around 32,000 MSCF/STB in gas injection period and take shorter time since they inject higher water and gas rates. For water cut, case 7-9 reach 1 in 5 years which is earlier than other cases as shown in Figure 5.73.

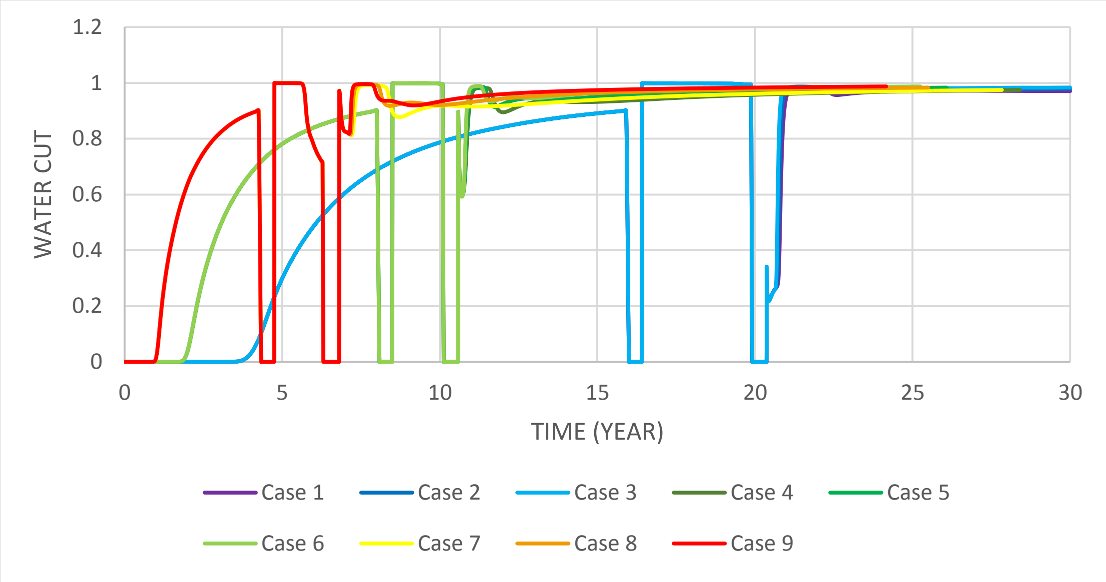

Figure 5. 74 Water cut for combination of different water and gas injection rate (30-degree dip angle).

Furthermore, Table 5.39 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 30 degree dip angle for various injection rates. From the results shown in Table 5.39, cumulative oil production, oil recovery factor, and BOE are slightly different. Cases 1, 4, 5, and 6 give good cumulative oil production around 5.88, 6.19, 6.16, and 6.17 MMSTB, respectively, and BOE around 6.48, 6.76, 6.70, and 6.69 MMSTB, respectively. However, the amounts of water injection and production in these cases are high. Although case 1 yields slightly lower BOE, it has much less water injection and production. Thus, we choose case 1 as the optimal case.

Table 5. 39 Summary of result of various injection rates (30-degree dip angle).

Case no.	1st water injection rate (STB/D)	Gas injection rate (MSCF/D)	2nd water injection rate (STB/D)	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
1	2,000	2,000	4,000	30.00	5.88	49.58	6.12	2.53	19.41	25.70	6.48
2	2,000	2,000	6,000	30.00	5.95	50.23	5.95	2.53	25.84	32.74	6.53
3	2,000	2,000	8,000	30.00	6.01	50.69	5.83	2.53	32.54	39.78	6.56
4	4,000	4,000	4,000	28.41	6.19	52.24	5.72	2.33	31.12	37.74	6.76
5	4,000	4,000	6,000	26.08	6.16	51.96	5.56	2.33	38.55	45.67	6.70
6	4,000	4,000	8,000	25.25	6.17	52.04	5.46	2.33	47.18	54.54	6.69
7	8,000	8,000	4,000	27.83	6.09	51.39	7.95	4.48	35.87	42.57	6.67
8	8,000	8,000	6,000	25.49	6.09	51.35	7.77	4.48	45.65	52.81	6.63
9	8,000	8,000	8,000	24.16	6.12	51.65	7.64	4.48	55.19	62.57	6.65

5.4.3 Effect of well pattern

Table 5.40 shows formation fracture pressure of reservoir with 30 degree dip angle for different well patterns. Figure 5.74 shows the field oil production rate for each well pattern. Pattern of 8 wells yields high oil production rate at the beginning because there are many wells to produce. Pattern of a vertical well with a horizontal well gives the highest production rate in gas in 2nd water injection period. And, pattern 1 gives the highest gas-oil ratio around 5,100 MSCF/STB as shown in Figure 5.75.

Table 5. 40 Formation fracture pressure of reservoir with 30 degree dip angle for different well patterns.

Well pattern	No. of well	Formation fracture pressure (psia)
1	well 1	3300
	well 2	3507
2	well 1	3219
	well 2	3408
	well 3	3746
	well 4	4017
3	well 1	3219
	well 2	3408
	well 3	3746
	well 4	4017
4	well 1	3219
	well 2	3408
	well 3	3746
	well 4	4017
5	well 1	3195
	well 2	3313
	well 3	3432
	well 4	3552
	well 5	3673
	well 6	3795
	well 7	3918
	well 8	4042
6	well 1	3300
	well 2	3905
7	well 1	3300
	well 2	3905

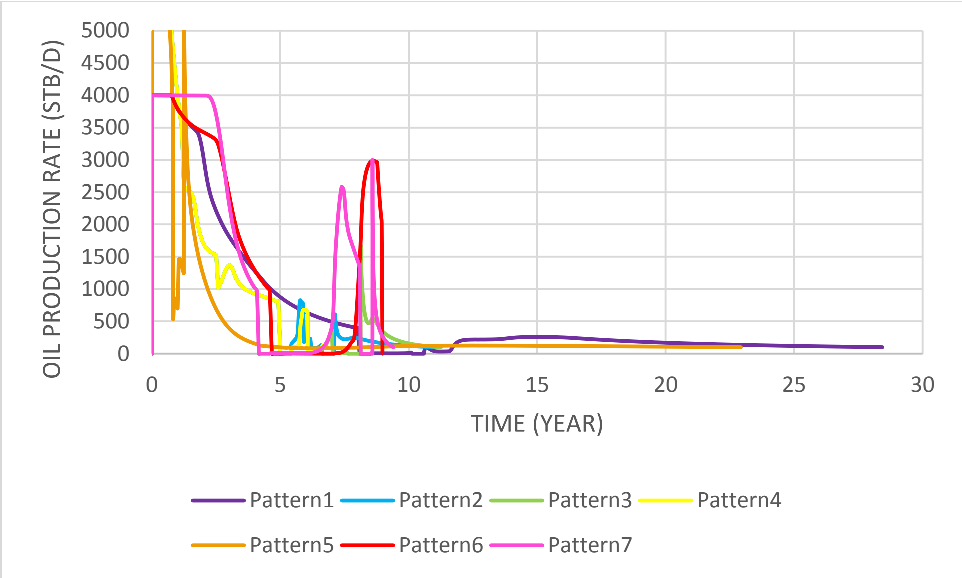

Figure 5. 75 Oil production rate for different well patterns (30-degree dip angle).

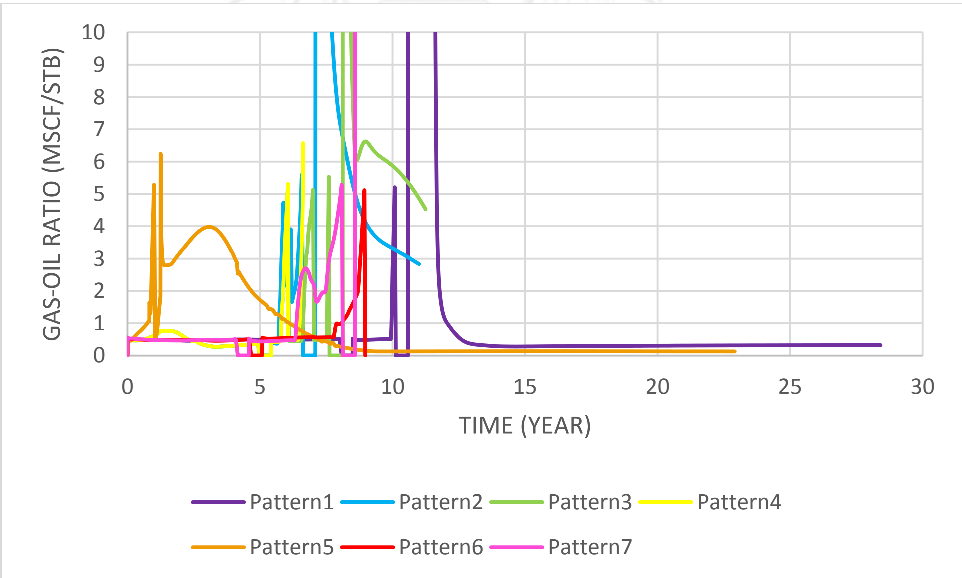

Figure 5. 76 Gas-oil ratio for different well patterns (30-degree dip angle).

In term of water cut, the results are shown in Figure 5.76. The shorter of the time of gas breakthrough, the higher the cumulative gas production. Pattern of 8 wells gives shortest time of gas breakthrough because the distance between the injector and the producer is closer than that for the other patterns.

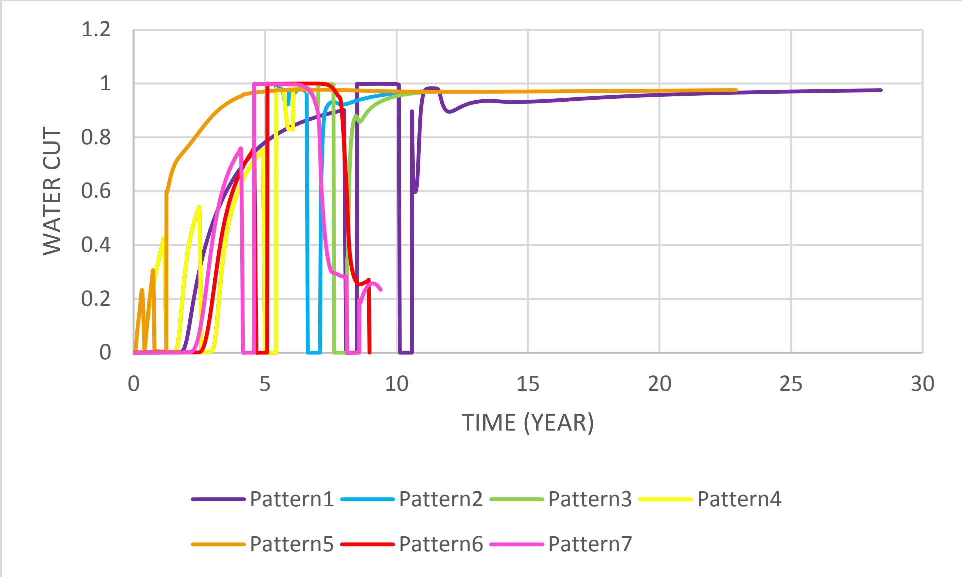

Figure 5. 77 Water cut for different well patterns (30-degree dip angle).

Moreover, Table 5.41 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 30 degree dip angle for different well patterns. From the results shown in Table 5.41, cumulative oil production, oil recovery factor, and BOE are slightly different. Patterns of 2 vertical wells, a vertical well with a horizontal well, 2 horizontal wells, 4 vertical wells with 1st sequence give good cumulative oil production around 6.19, 5.68, 5.61, and 5.23 MMSTB, respectively, and BOE around 6.76, 6.18, 5.42, and 5.94 MMSTB, respectively. In addition, there are significant differences in amount of water and gas injection and time to reach the economic constraint. Pattern 7 yields the highest gas production of 8.59 BSCF while pattern 5 needs the largest amount of gas injection (6.12 BSCF). Among the seven patterns pattern 2, 3, 4, 6, and 7 produce smaller amount of water and require lower amount of water injection than the rest. Judging from high amount of oil production, low amount gas and water injection and production, pattern of 2 horizontal wells (pattern 7) is the best case.

Table 5. 41 Summary of results of different well patterns (30-degree dip angle).

Case no.	Pattern	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
1	2 vertical wells	28.41	6.19	52.24	5.72	2.33	31.12	37.74	6.76
2	4 vertical wells	11.00	5.15	43.44	6.06	1.70	9.29	12.90	5.87
3	4 vertical wells with 1st sequence	11.24	5.23	44.08	7.47	3.19	8.42	11.75	5.94
4	4 vertical wells with 2nd sequence	6.62	4.88	41.14	2.65	1.76	3.45	7.18	5.02
5	8 vertical wells	22.91	5.05	42.62	5.57	6.12	30.30	32.86	4.96
6	A vertical well with a horizontal	8.97	5.68	47.93	4.05	5.64	5.95	6.69	5.42
7	2 horizontal wells	9.39	5.61	47.30	8.59	5.12	5.27	7.16	6.18

5.4.4 Comparison of DDP

When making comparison, pattern of 2 vertical wells is used for both SCWD and DDP. We inject 4,000 STB/D of water and 4,000 MSCF/D of gas for both SCWD and DDP. Oil production rate of SCWD and DDP are shown in Figure 5.77. In the first 8 years of production, both SCWD and DDP give the same results as both processes start with initial waterflooding followed by gas injection. The oil rate of DDP increases to its highest value sooner than that for SCWD since continuous gas injection helps reduce remaining oil in the reservoir. However, the mobility ratio in gas injection is less favorable than that in water injection. Thus, the oil production rate of SCWD drops earlier than DDP. Gas-oil ratio of DDP is higher than that for SCWD after 7 years as shown in Figure 5.78 because DDP continues injecting gas.

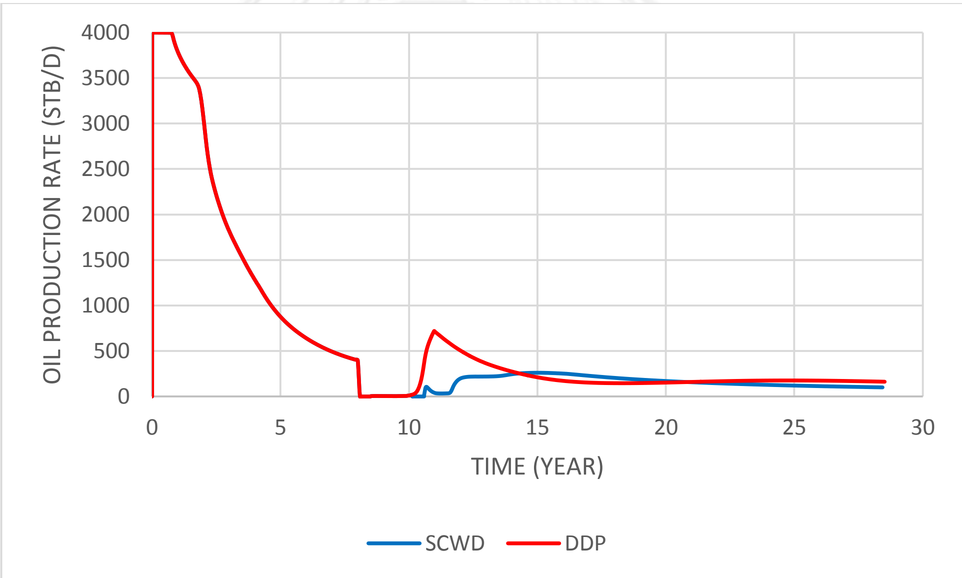

Figure 5. 78 Oil production rate of SCWD and DDP (30-degree dip angle).

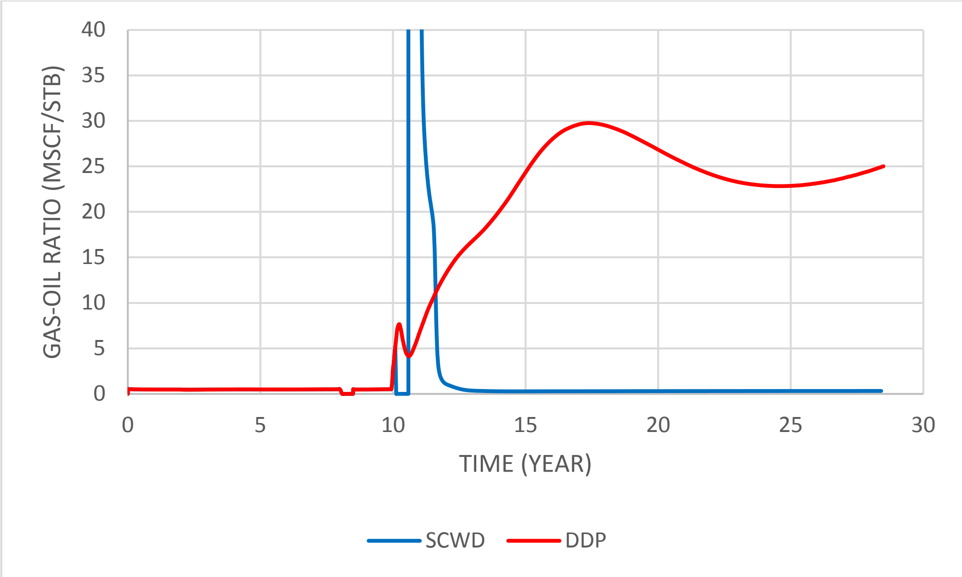

Figure 5. 79 Gas-oil ratio of SCWD and DDP (30-degree dip angle).

In term of water cut, both processes give the same water cut during the first 10 years as shown in Figure 5.79. SCWD gives higher water cut after gas injection period because there is a second water injection for SCWD.

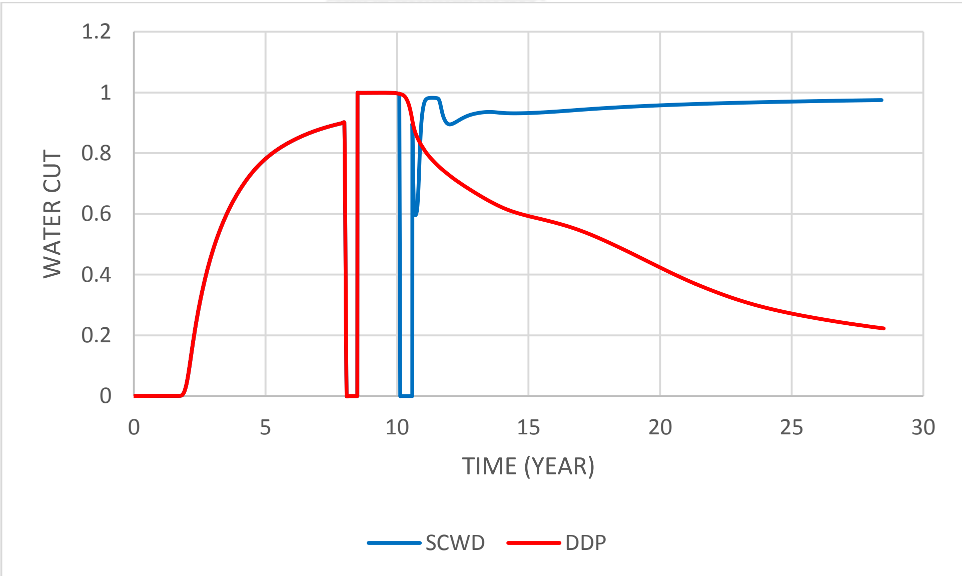

Figure 5. 80 Water cut of SCWD and DDP (30-degree dip angle).

Table 5.42 shows the results of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of reservoir with 30 degree dip angle for each case. From the results, DDP shows better performance than SCWD because DDP gives good cumulative oil production around 6.60 MMSTB and BOE around 7.13 MMSTB while SCWD can recover only 6.19 MMSTB of oil and 6.76 MMSTB of BOE. In addition, SWCD provides much lower amount of gas production and injection, much higher amount of water production and injection, and slightly shorter production period than DDP.

Table 5. 42 Summary of result of SCWD and DDP (30-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
SCWD	28.43	6.19	52.24	5.72	2.33	31.12	37.74	6.76
DDP	28.27	6.60	55.65	32.04	28.86	11.55	11.69	7.13

5.4.5 Effect of relative permeability correlation

Figure 5.80-5.82 show oil production rate, gas-oil ratio and water cut for reservoir with 30 degree dip angle. During both water and gas injection period, Stone 1 and ECLIPSE default models provide higher oil and gas production rate than Stone 2 model. Regarding gas-oil ratio, Stone 2 model yields the highest peak of gas-oil ratio during gas injection period. The water cuts from all correlations are quite the same but Stone 2 model takes shorter time than Stone 1 and ECLIPSE default model.

Table 5.43 shows the summary of cumulative oil production, oil recovery factor, cumulative water production, and cumulative gas production of reservoir with 30 degree dip angle for all correlation models.

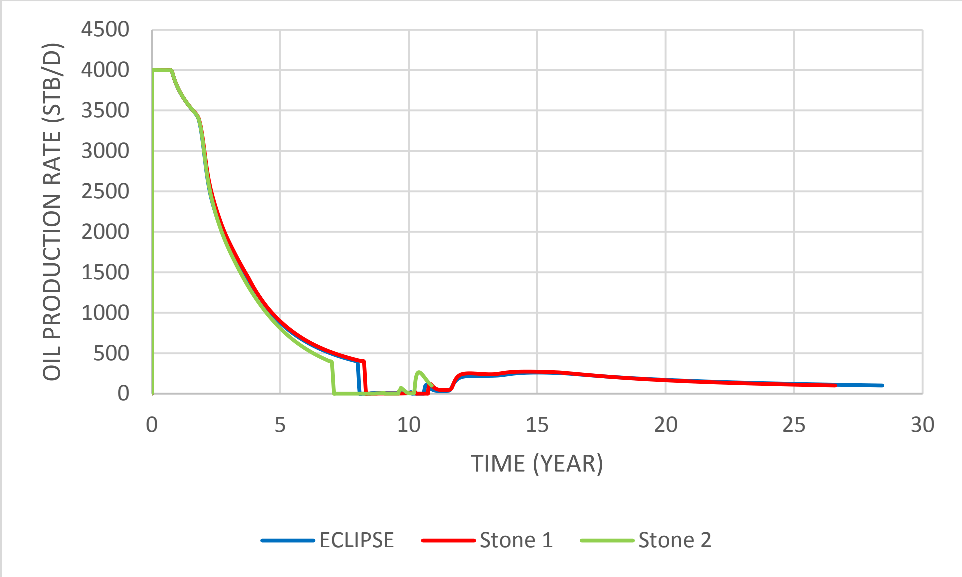

Figure 5. 81 Oil production rate for each correlation model (30-degree dip angle).

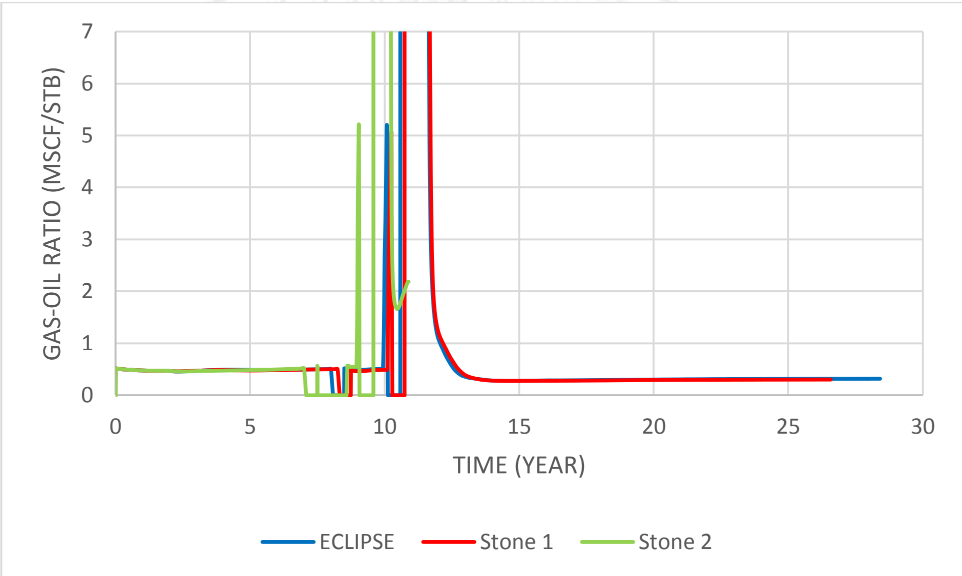

Figure 5. 82 Gas-oil ratio for each correlation model (30-degree dip angle).

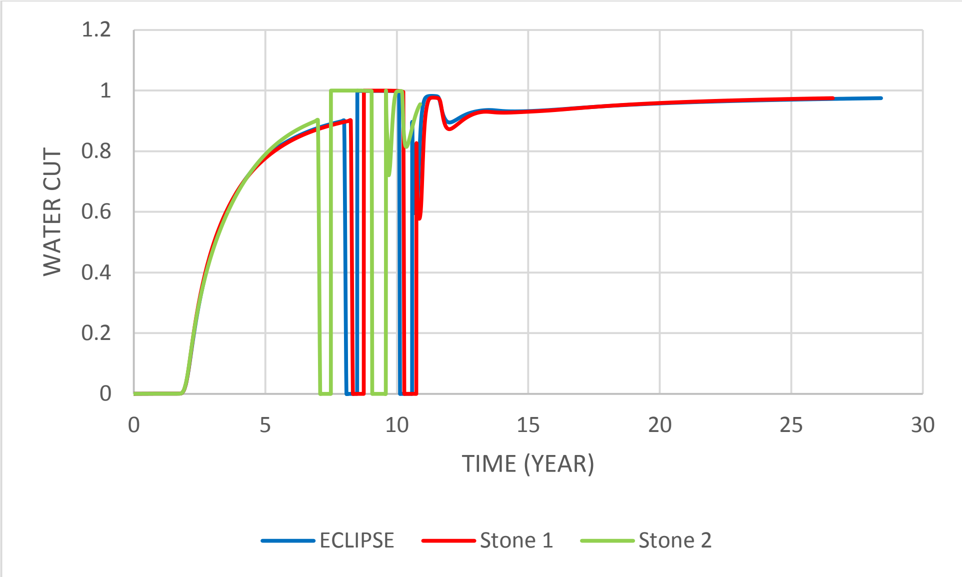

Figure 5. 83 Water cut for each correlation model (30-degree dip angle).

Table 5. 43 Summary of results for each three phase relative permeability correlation model (30-degree dip angle).

Case	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
ECLIPSE default	28.41	6.19	52.24	5.72	2.33	31.12	37.74	6.76
Stone1	26.58	6.24	52.60	5.62	2.20	28.67	35.19	6.81
Stone2	10.89	4.88	41.19	4.99	2.26	7.41	12.14	5.34

From the results, ECLIPSE default model and Stone 1 model give similar cumulative oil production that around 6.19 and 6.24 MMSTB, respectively, and BOE around 6.76 and 6.81 MMSTB, respectively while Stone 2 model yields a lower value for cumulative oil production and BOE. Furthermore, Stone 2 model gives lower gas and much lower water production and needs less gas and much less water injection as well as less time to produce.

5.4.6 Effect of vertical to horizontal permeability ratio

Oil production rate and gas-oil ratio and water cut for all vertical to horizontal ratios are shown in Figures 5.83-5.85. Case 3 takes a longer time to inject water than other cases in 1st water injection period because water can flow in both vertical and horizontal permeabilities reservoir easily allowing better segregation of oil and water. So, early breakthrough of water does not occur in case 3. Later on, the oil rate starts to decline because water and gas are start to produce as well and give the highest gas-oil ratio around 15,500 MSCF/STB.

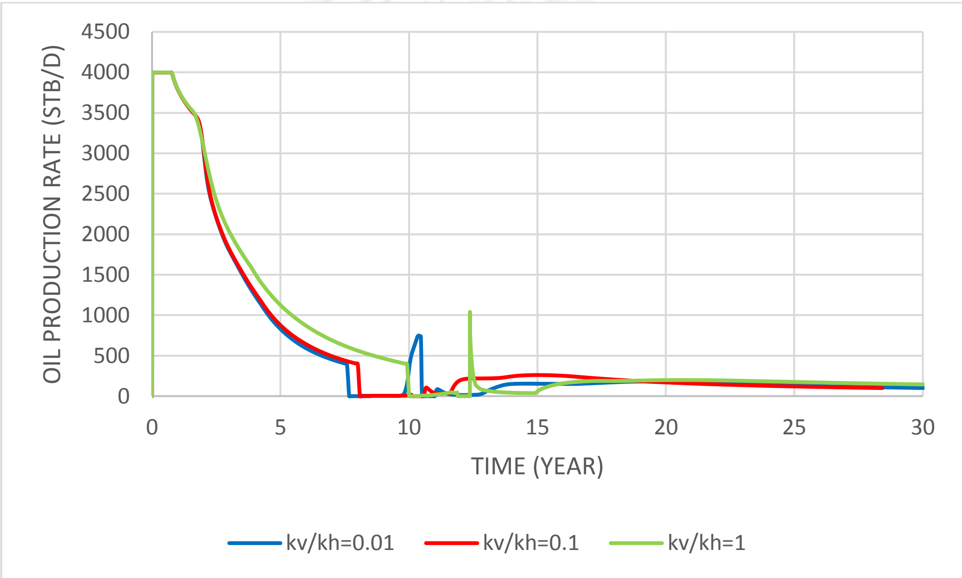

Figure 5. 84 Oil production rate for different anisotropy ratios (30-degree dip angle).

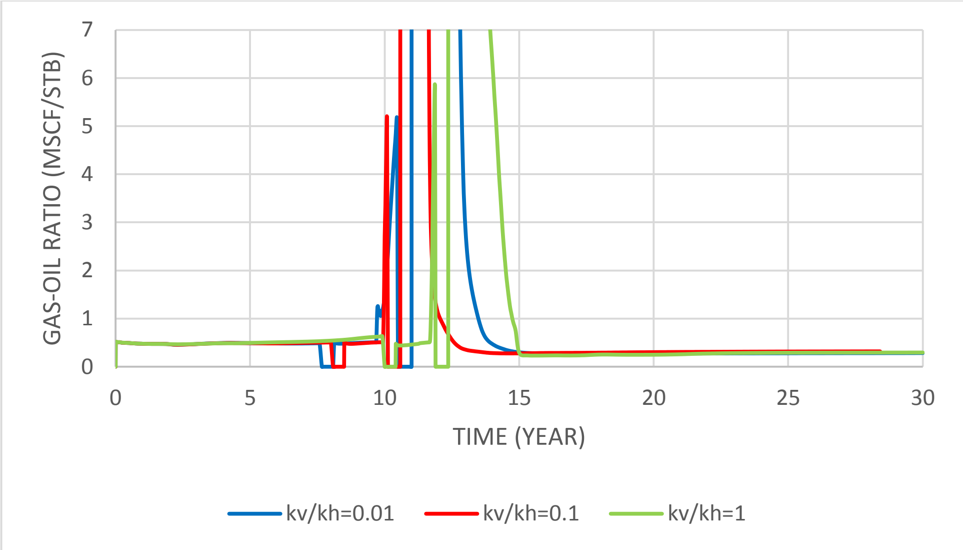

Figure 5. 85 Gas-oil ratio for different anisotropy ratios (30-degree dip angle).

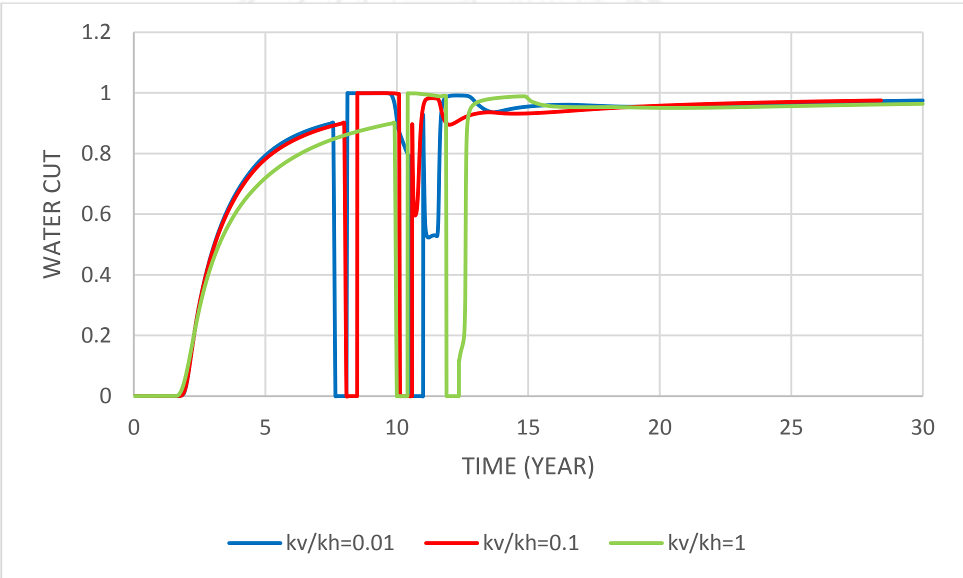

Figure 5. 86 Water cut for different anisotropy ratios (30-degree dip angle).

Table 5. 44 Summary of results for different vertical to horizontal permeability ratios (30-degree dip angle).

k_v/k_h	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
0.01	30.00	6.00	50.59	6.90	3.46	32.27	38.83	6.57
0.1	28.41	6.19	52.24	5.72	2.33	31.12	37.74	6.76
1	30.00	6.97	58.78	6.28	2.13	33.03	40.25	7.66

As shown in Table 5.44, case 3 provides higher cumulative oil production, cumulative gas production, cumulative water production, and oil recovery factor than other cases because oil, gas and water can flow easily in high vertical permeability reservoir.

5.4.6 Effect of residual oil saturation by gas displacement (S_{org})

Oil production rate, gas-oil ratio and water cut are illustrated in Figures 5.86-5.88. In the 2nd water injection, the oil production rate of S_{org} is 0.05 is a bit higher than other cases. At the end, this case provides the highest cumulative oil production because when S_{org} is lower, higher amount of recoverable oil can be produced.

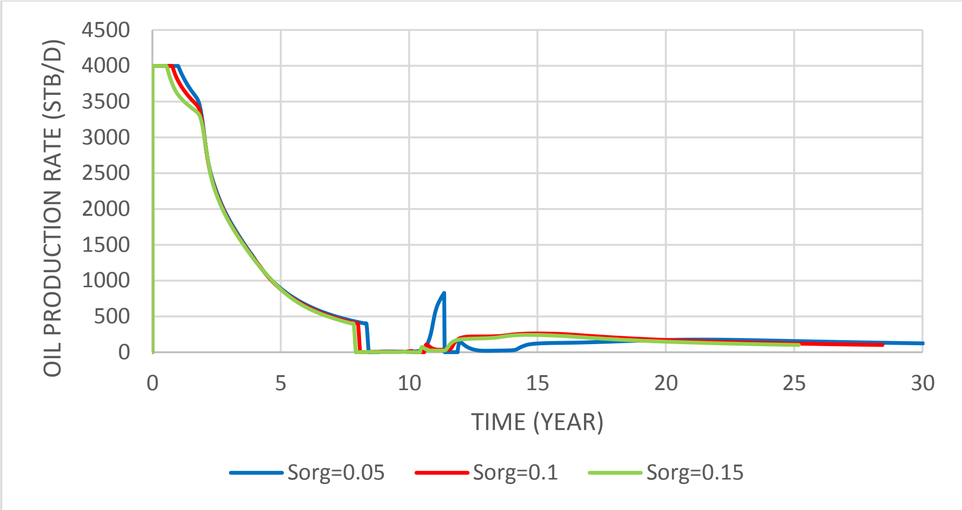

Figure 5. 87 Oil production rate for different residual oil saturations (30-degree dip angle).

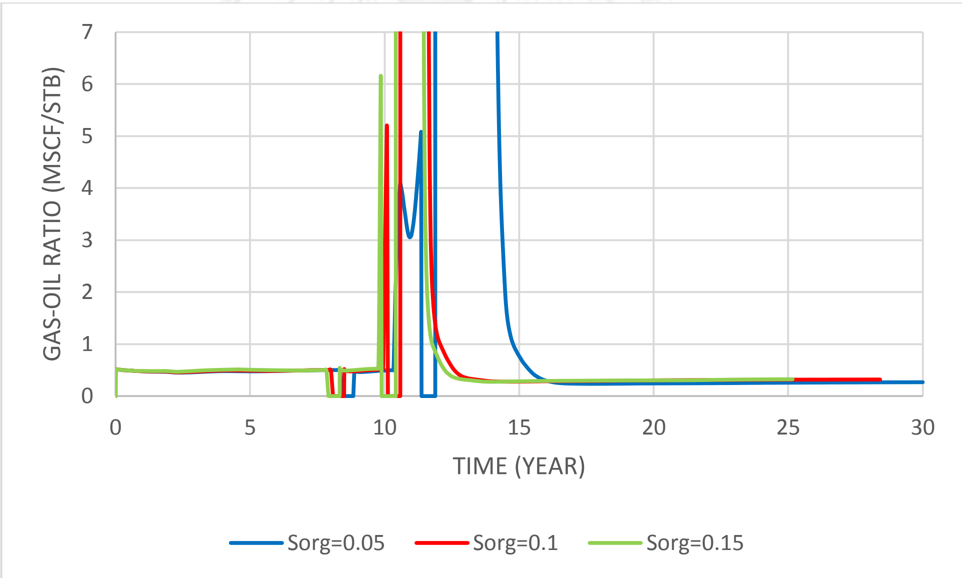

Figure 5. 88 Gas-oil ratio for different residual oil saturations (30-degree dip angle).

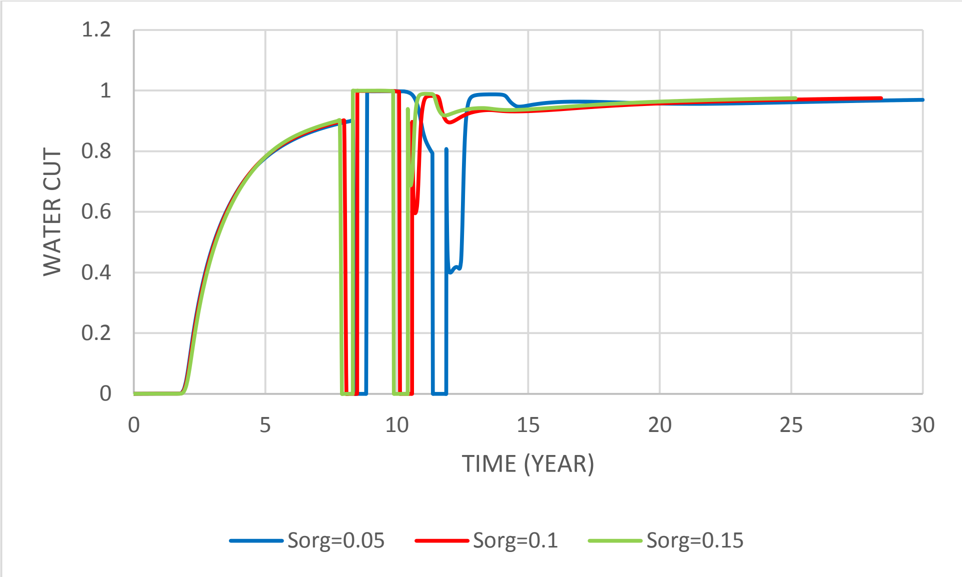

Figure 5. 89 Water cut for different residual oil saturations (30-degree dip angle).

As shown in Table 5.45, the production time is 30.00, 28.41, and 25.16 years when Sorg equal to 0.05, 0.10, and 0.15, respectively. This is because when Sorg is lower, higher amount of recoverable oil can be produced. Thus, it takes longer production time for the same production rate. Sorg of 0.05, 0.1, and 0.15 give cumulative oil production around 6.72, 6.19, and 5.84 MMSTB, respectively, and oil recovery factor around 52.91, 52.24, and 49.25%, respectively. Furthermore, total amount of gas production and injection is higher when Sorg is lower because of the longer production time.

Table 5. 45 Summary of results for different residual oil saturations (30-degree dip angle).

S_{org}	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
0.05	30.00	6.27	52.91	7.40	3.68	31.95	38.64	6.89
0.1	28.41	6.19	52.24	5.72	2.33	31.12	37.74	6.76
0.15	25.16	5.84	49.25	5.52	2.24	26.56	32.99	6.38

5.4.8 Effect of wettability

Oil production rate, gas-oil ratio and water cut are shown in Figures 5.89-5.91. Oil production rate of water-wet is lower than that for oil-wet because the mobility of water is low, so water cannot flow easily in water-wet system and the amount of oil is still in the reservoir after waterflooding. For gas-oil ratio and water cut, the oil-wet system yields higher than the water-wet system after gas flooding because water can flow easily in oil-wet system.

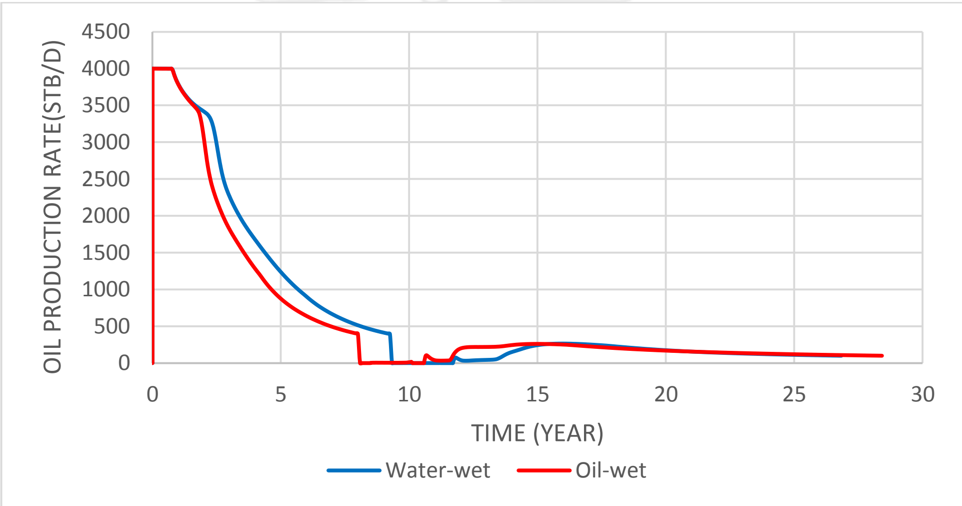

Figure 5. 90 Oil production rate for water-wet and oil-wet reservoir (30-degree dip angle).

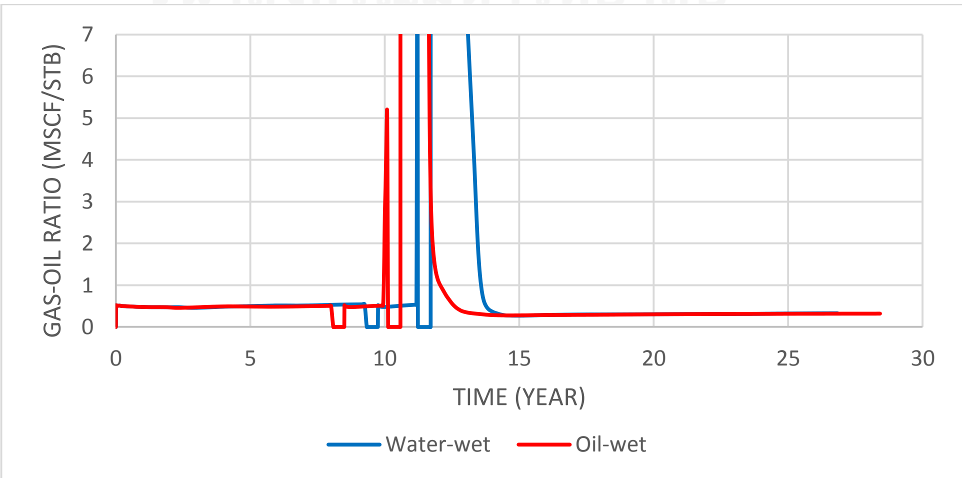

Figure 5. 91 Gas-oil ratio for water-wet and oil-wet reservoir (30-degree dip angle).

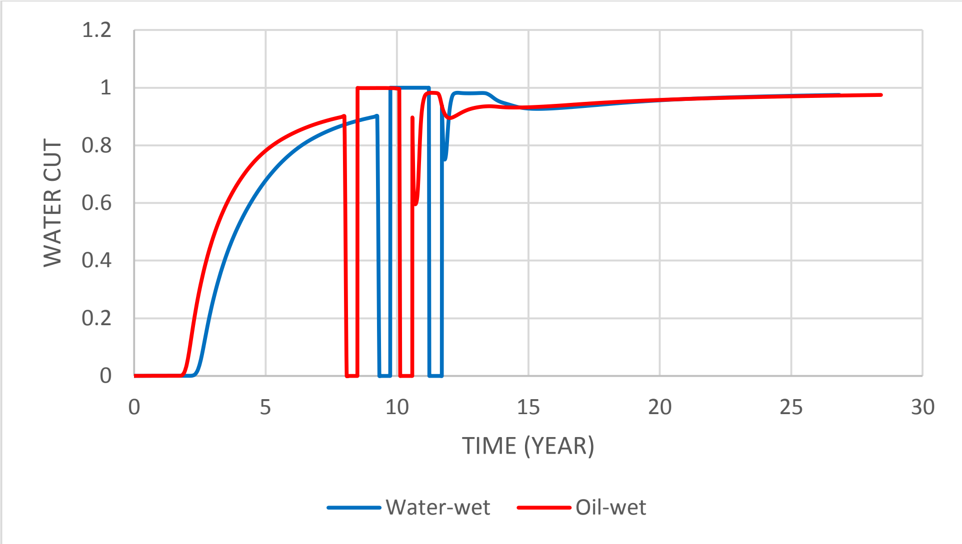

Figure 5. 92 Water cut for water-wet and oil-wet reservoir (30-degree dip angle).

Table 5. 46 Summary of results for water-wet and oil-wet reservoir (30-degree dip angle).

Wettability	t_p (YEAR)	FOPT (MMSTB)	FOE (%)	FGPT (BSCF)	FGIT (BSCF)	FWPT (MMSTB)	FWIT (MMSTB)	BOE (MMSTB)
Water-wet	26.85	6.97	58.75	5.89	2.15	27.76	35.61	7.59
Oil-wet	28.41	6.19	52.24	5.72	2.33	31.12	37.74	6.76

As shown in Table 5.46, the water-wet system provides higher cumulative oil production, oil recovery factor, and BOE around 6.97 MMSTB, 58.75%, and 7.59 MMSTB because oil can flow easily in the water-wet system. The oil-wet system yields higher water injection and production because the formation prefers to adhere oil more than water so water can flow and produce easily.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

The result from SCWD performance under different condition is summarized in this chapter. Effects of uncertainty in sensitivity are concluded as well. Some recommendations for further study are also mentioned.

6.1 Conclusions

In term of the stopping time for water injection, 3 different WCT criteria which are 60%, 75%, and 90% are simulated. The more WCT, the more the oil recovery factor. For 3 different dip angles, 90% WCT criteria gives the highest oil recovery factor for 15, and 30 degree dips angle but 75% WCT criteria gives the highest oil recovery factor for 0 degree dip angle. So, the 75% WCT case is selected for 0 degree dip angle and the 90% WCT case is selected for 15, and 30 degree dip angle, since they provide good oil recovery factor while the production life and amount of water production are not too high.

For water and gas injection rate, 1st water injection rate during water-flooding of 2,000 STB/D, gas injection rate of 2,000 MSCF/D, and 2nd water injection rate of 4,000 STB/D yield the highest oil recovery and the shortest production period.

In this study, 7 different well patterns are investigated which are 2 vertical wells, 4 vertical wells, 4 vertical wells with 1st sequence, 4 vertical well with 2nd sequence, 8 vertical wells, a vertical well with a horizontal well, and 2 horizontal wells to find the best option for well pattern. For reservoir with no dip angle, pattern of 4 vertical wells with 1st sequence (which is water is injected at well 4 while well 1, well 2, and well 3 are producers. Then, well 3 is shut in after WCT reaches the criteria. Wells 1 and 2 continue to produce until WCT of well 2 reaches the criteria. Then, well 2 is shut in, and well 1 continues to produce until WCT reaches the criteria. Then, all the wells are shut in for six months. Then, gas is injected at well 1 while well 2 is producer until GOR of well 2 reaches the criteria. Well 2 is shut in and open well 3 to produce until the GOR of well 3 reaches the criteria. Then, well 3 is shut in and open well 4 to produce until GOR of well 4 reaches criteria. Then, all the wells are shut in for six months again. After that, water are injected again at well 4 with the previous water injection strategies. At this time, wells 1, 2, and 3 become producer again) provides the best performance with high oil recovery factor, low amount of water and gas injection, and short production period, although pattern of 2 vertical wells and 2 horizontal wells provide higher oil recovery factor. For reservoir with 15 degree dip angle, pattern of 4 vertical wells with 1st sequence is the best case because it provides high oil recovery factor with low amount of water injection and short production period. For reservoir with 30 degree dip angle, pattern of 2 horizontal wells is the best case because it provides high oil recovery factor with low amount of water and gas injection and short production period.

In addition, a reservoir with no dip angle yields the best SCWD performance. So, the less the dip angle of the reservoir, the better the SCWD performance in comparison with DDP.

For three-phase relative permeability correlations, ECLIPSE default model and Stone 1 model give similar cumulative oil production, oil recovery factor, and BOE while Stone 2 model yields a lower value for cumulative oil production, oil recovery factor, and BOE since Stone 2 model yields low relative permeability to oil at very high oil saturation compared to Stone 1 model. Furthermore, Stone 2 model gives lower gas and water production and needs less gas and water injection as well as time to produce.

In term of anisotropy ratio, a higher vertical to horizontal permeability ratio results in higher oil recovery due to better segregation between oil, water, and gas.

For residual oil saturation by gas displacement (S_{org}), when S_{org} is lower, higher amount of recoverable oil can be produced.

For the effect of wettability, the water-wet system provides higher cumulative oil production, oil recovery factor, and BOE because oil can flow easily in the water-wet system. The oil-wet system yields higher water injection and production because the formation prefers to adhere oil more than water so water can flow and produce easily.

6.2 Recommendations

1. Besides SCWD, there are other processes that can improve oil recovery such as GAGD, DDP. We should study the performance of these methods and compare them with SCWD in order to find the best strategy to improve oil recovery in a particular reservoir.
2. The performance of different wells patterns is based on the selected set of production and injection rate. Thus, effect of different sets of injection and production rates for each well pattern should be investigated.

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APPENDIX

APPENDIX

RESERVOIR MODEL CONSTRUCTION

Reservoir model

The reservoir simulation model is constructed by inputting the required data in Eclipse simulator. The geological model comprises of number of cells or blocks in the direction of X, Y and Z. The number of block in this study is 73 x 31 x 21.

1. Case Definition

Simulator : BlackOil

Model dimensions

Number of grid in x direction : 73

Number of grid in y direction : 31

Number of grid in z direction : 21

Simulation start date : 1 Jan 2000

Grid type : Cartesian

Geometry type : Corner Point

Oil-gas-water properties: Water, oil, gas and dissolved gas

Solution type : Fully Implicit

2. Grid

<u>Properties</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 : 30 degree in base case

Grid block sizes : based on calculation with dip angle

Geometry

Grid Block Coordinate Lines

Grid Block Corners

Grid data units

Grid Axes wrt Map Coordinatesr

3. PVT

Fluid densities at surface conditions

Oil density : 51.6375 lb/ft3

Water density : 62.42841 lb/ft3

Gas density : 0.04981752 lb/ft3

Water PVT properties

Reference pressure (Pref) : 3000 psia

Water FVF at Pref : 1.021057 rb/stb

Water compressibility : 3.083002 x 10-6 psi-1

Water viscosity at Pref : 0.3051548 cp

Water viscosity : 3.350528 x 10-6 psi-1

Live oil PVT properties (dissolved gas)

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.00128	14.7	1.06912	1.32774
	277.084	1.05225	1.40853

	539.468	1.0518	1.55204
	801.853	1.05164	1.74084
	1064.24	1.05156	1.97375
	1326.62	1.05151	2.25323
	1589.01	1.05148	2.58341
	1851.39	1.05145	2.96939
	2113.77	1.05144	3.41702
	2376.16	1.05142	3.93262
	2588.57	1.05141	4.40441
	3000	1.0514	5.47133
	3163.31	1.0514	5.95564
	3425.69	1.05139	6.8122
	3688.08	1.05138	7.77152
	3950.46	1.05138	8.84017
	4212.85	1.05138	10.0243
	4475.23	1.05137	11.3293
	4737.62	1.05137	12.7599
	5000	1.05137	14.3197
0.04402	277.084	1.0872	1.08195
	539.468	1.07724	1.11364
	801.853	1.07382	1.1627
	1064.24	1.07209	1.22551
	1326.62	1.07104	1.30047
	1589.01	1.07034	1.38683
	1851.39	1.06984	1.48424
	2113.77	1.06947	1.59259
	2376.16	1.06917	1.71191
	2588.57	1.06898	1.81657

	3000	1.06868	2.04008
	3163.31	1.06859	2.13647
	3425.69	1.06845	2.30053
	3688.08	1.06833	2.47597
	3950.46	1.06823	2.6628
	4212.85	1.06815	2.86095
	4475.23	1.06807	3.07031
	4737.62	1.068	3.29068
	5000	1.06794	3.52178
0.09824	539.468	1.11076	0.89844
	801.853	1.10292	0.92289
	1064.24	1.09897	0.95678
	1326.62	1.09659	0.99861
	1589.01	1.095	1.04756
	1851.39	1.09386	1.10313
	2113.77	1.093	1.16503
	2376.16	1.09234	1.23305
	2588.57	1.0919	1.29252
	3000	1.09122	1.41871
	3163.31	1.091	1.47276
	3425.69	1.09069	1.56428
	3688.08	1.09043	1.66147
	3950.46	1.0902	1.76423
	4212.85	1.09	1.87247
	4475.23	1.08982	1.98603
	4737.62	1.08967	2.10475
	5000	1.08953	2.22845
0.15837	801.853	1.13761	0.77039

	1064.24	1.13071	0.79085
	1326.62	1.12657	0.81733
	1589.01	1.1238	0.84905
	1851.39	1.12182	0.88552
	2113.77	1.12034	0.92642
	2376.16	1.11918	0.97151
	2588.57	1.11842	1.01098
	3000	1.11725	1.09467
	3163.31	1.11687	1.13047
	3425.69	1.11633	1.19096
	3688.08	1.11587	1.25505
	3950.46	1.11548	1.32263
	4212.85	1.11513	1.39359
	4475.23	1.11482	1.46782
	4737.62	1.11455	1.54519
	5000	1.11431	1.62555
0.22273	1064.24	1.16708	0.67734
	1326.62	1.16066	0.69511
	1589.01	1.15639	0.71706
	1851.39	1.15333	0.74274
	2113.77	1.15104	0.77182
	2376.16	1.14926	0.80408
	2588.57	1.14809	0.8324
	3000	1.14628	0.89259
	3163.31	1.1457	0.91835
	3425.69	1.14488	0.96188
	3688.08	1.14417	1.00796
	3950.46	1.14356	1.05651

	4212.85	1.14303	1.10742
	4475.23	1.14255	1.1606
	4737.62	1.14214	1.21594
	5000	1.14176	1.27334
0.29047	1326.62	1.19883	0.60688
	1589.01	1.19266	0.62266
	1851.39	1.18825	0.64151
	2113.77	1.18496	0.66313
	2376.16	1.18239	0.68732
	2588.57	1.1807	0.70865
	3000	1.17811	0.75416
	3163.31	1.17727	0.77368
	3425.69	1.17609	0.80668
	3688.08	1.17508	0.84164
	3950.46	1.1742	0.87847
	4212.85	1.17343	0.91709
	4475.23	1.17276	0.9574
	4737.62	1.17215	0.99933
	5000	1.17162	1.04278
0.36102	1589.01	1.23262	0.55164
	1851.39	1.22655	0.56586
	2113.77	1.22202	0.58243
	2376.16	1.21849	0.60114
	2588.57	1.21617	0.61775
	3000	1.21262	0.65335
	3163.31	1.21146	0.66867
	3425.69	1.20984	0.69462
	3688.08	1.20846	0.72213

	3950.46	1.20725	0.75113
	4212.85	1.206	0.78156
	4475.23	1.20528	0.81332
	4737.62	1.20445	0.84636
	5000	1.20371	0.88059
0.434	1851.39	1.26827	0.50711
	2113.77	1.26223	0.52007
	2376.16	1.25755	0.53487
	2588.57	1.25447	0.54811
	3000	1.24975	0.57666
	3163.31	1.24822	0.589
	3425.69	1.24607	0.60993
	3688.08	1.24423	0.63217
	3950.46	1.24264	0.65565
	4212.85	1.24124	0.68029
	4475.23	1.24002	0.70603
	4737.62	1.23892	0.73282
	5000	1.23795	0.76057
0.50915	2113.77	1.30566	0.47039
	2376.16	1.29959	0.4823
	2588.57	1.2956	0.49303
	3000	1.28949	0.51636
	3163.31	1.28751	0.52649
	3425.69	1.28474	0.54371
	3688.08	1.28236	0.56206
	3950.46	1.2803	0.58145
	4212.85	1.2785	0.60184
	4475.23	1.27692	0.62316

	4737.62	1.27551	0.64535
	5000	1.27425	0.66836
0.58623	2376.16	1.34468	0.43954
	2588.57	1.3396	0.44836
	3000	1.33186	0.4677
	3163.31	1.32936	0.47613
	3425.69	1.32584	0.49053
	3688.08	1.32283	0.50591
	3950.46	1.32023	0.5222
	4212.85	1.31795	0.53934
	4475.23	1.31595	0.5573
	4737.62	1.31417	0.57601
	5000	1.31258	0.59542
0.64993	2588.57	1.37739	0.41793
	3000	1.36812	0.43468
	3163.31	1.36512	0.44202
	3425.69	1.36092	0.45459
	3688.08	1.35732	0.46804
	3950.46	1.35421	0.48232
	4212.85	1.35149	0.49738
	4475.23	1.3491	0.51316
	4737.62	1.34697	0.52962
	5000	1.34507	0.54671

Dry gas PVT properties (no vapourised oil)

Pressure (psia)	FVF (rb /stb)	Visc (cp)
14.7	225.771	0.01325
277.084	11.6844	0.01344
539.468	5.86041	0.01374
801.853	3.85571	0.01413
1064.24	2.84654	0.0146
1326.62	2.24321	0.01515
1589.01	1.84548	0.01578
1851.39	1.56657	0.01648
2113.77	1.36258	0.01725
2376.16	1.20883	0.01808
2588.57	1.11063	0.01878
3000	0.96701	0.02019
3163.31	0.92258	0.02076
3425.69	0.86218	0.02168
3688.08	0.81251	0.02259
3950.46	0.77111	0.0235
4212.85	0.73619	0.02439
4475.23	0.70639	0.02527
4737.62	0.6807	0.02613
5000	0.65832	0.02696

<u>Rock properties (For ECLIPSE 100)</u>

Reference pressure : 3000 psia

Rock compressibility : 3.013923 x 10-6 psi^{-1}

4. SCAL

Water/oil saturation functions

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

Gas/oil saturation functions

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

0.7	0.8	0	0

5. Initialization

Equilibration data specification

Datum depth : 5,000 ft

Pressure at datum depth : 2,242 psia

WOC depth : 12000 ft

GOC depth : 5000 ft

6. Regions : N/A

7. Schedule

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

7.1 Oil production well

Well specification

Well name : WELL1

Group : 1

I location : 12

J location : 16

Preferred phase : OIL

Inflow equation : STD

Automatic shut-in instruction : SHUT

Crossflow : YES

Density calculation : SEG 106

<u>Well connection data</u>

Well connection data : WELL1

K upper : 1

K lower : 21

Open/shut flag : OPEN

Well bore ID : 0.5522083 ft

Direction : Z

<u>Production well control</u>

Well : WELL1

Open/shut flag : OPEN

Control : RESV

Liquid rate : Depend on injection rate

BHP target : 500 psia

<u>Production well economic limits</u>

Well : WELL1

Workover procedure : NONE

End run : YES

Quantity for economic limit : RATE

Secondary workover procedure: NONE

There is a few difference in setting between production well and injection well. The first two setting, well specification and well connection data, are the same as previous but we need to change the keyword from production well control to be injection well control.

When we start gas injection we change only the preferred phase and injection rate in injection well control.

7.2 Water injection well

Well specification

Well name	: WELL2
Group	: WELL
I location	: 62
J location	: 16
Preferred phase	: WATER
Inflow equation	: STD
Automatic shut-in instruction	: SHUT
Crossflow	: YES
Density calculation	: SEG

Well connection data

Well connection data	: WELL2
K upper	: 1
K lower	: 21
Open/shut flag	: OPEN
Well bore ID	: 0.5522083 ft
Direction	: Z

Injection well control

Well	: WELL2
Injector type	: WATER
Open/shut flag	: OPEN
Control mode	: RESV
Liquid surface rate	: Depend on injection strategies
BHP target	: Depend on formation fracture pressure

7.3 Gas injection well

Well specification

Well name	: WELL1
Group	: WELL
I location	: 12
J location	: 16
Preferred phase	: GAS
Inflow equation	: STD
Automatic shut-in instruction	: SHUT
Crossflow	: YES
Density calculation	: SEG

Well connection data

Well connection data	: WELL1
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	: RESV
Liquid surface rate	: Depend on injection strategies
BHP target	: Depend on formation fracture pressure

VITA

Pasit Udomlaxsananon was born on June 28th, 1989 in Bangkok, Thailand. He received his Bachelor degree in Petrochemical Science from Faculty of Science, King Mongkut's Institute of Technology Ladkrabang in 2010. Afterwards, he continued his study in Master Degree of Petroleum Engineering at graduate school of the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2011.