COMPARATIVE PRODUCTION PERFORMANCE BETWEEN CONVENTIONAL WATER ALTERNATING GAS FLOODING AND WATER DUMPFLOOD ALTERNATING GAS INJECTION

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เหงียน ถาน เกียง : การเปรียบเทียบสมรรถนะการผลิตระหว่างการอัดน้ำสลับแก๊สแบบธรรมดากับการใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊ส (COMPARATIVE PRODUCTION PERFORMANCE BETWEEN CONVENTIONAL WATER ALTERNATING GAS FLOODING AND WATER DUMPFLOOD ALTERNATING GAS INJECTION) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 159 หน้า.

งานวิจัยฉบับนี้นำเสนอการผลิตแบบการอัดน้ำสลับแก๊สที่ใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊สเพื่อเพิ่มค่าการผลิตน้ำมัน การลดเครื่องมือที่ใช้ในการอัดฉีดน้ำโดยให้น้ำจากแหล่งกักเก็บไหลอย่างอิสระสู่แหล่งกักเก็บน้ำมันสลับกับการอัดแก๊ส ซึ่งหลุมที่ให้น้ำไหลสู่แหล่งกักเก็บน้ำมันนั้นถูกเจาะให้เชื่อมกันเพื่อให้เกิดการไหลผ่านของน้ำมายังชั้นของน้ำมันได้ แบบจำลองแหล่งกักเก็บได้ถูกสร้างขึ้นเพื่อศึกษาการอัดน้ำสลับแก๊สแบบธรรมดา กับการใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊ส โดยแหล่งกักเก็บอื่นนั้นมาจากแหล่งน้ำที่อยู่ด้านล่างและด้านบนของชั้นน้ำมัน ทั้งนี้แหล่งกักเก็บน้ำที่อยู่ในระดับความลึกต่างๆ อัตราการอัดแก๊ส และรอบของการอัดน้ำและแก๊สได้ถูกศึกษาในงานวิจัยนี้

จากงานวิจัยพบว่าวิธีการอัดน้ำสลับแก๊สแบบธรรมดา และการใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊สให้ค่าการผลิตน้ำมันสูงสุดที่รอบการอัดน้ำและแก๊ส ในอัตราส่วน 1 ต่อ 1 เดือน และที่การอัดแก๊สด้วยอัตราสูง โดยที่อัตราการอัดแก๊สและรอบการอัดน้ำและแก๊สให้ผลกระทบเพียงเล็กน้อยต่อการอัดน้ำสลับแก๊สแบบธรรมดา แต่มีผลกระทบอย่างมีนัยยะสำคัญสำหรับการใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊ส จากการศึกษาค่าความผันแปรพบว่าการเพิ่มอัตราส่วนปริมาตรของแหล่งกักเก็บน้ำและน้ำมันนั้น เพิ่มค่าการผลิตน้ำมันเพียงเล็กน้อยในวิธีการใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊ส ส่วนระยะห่างของชั้นกักเก็บน้ำที่อยู่ด้านล่างของชั้นน้ำมันแสดงผลกระทบเพียงเล็กน้อยต่อวิธีการผลิตแบบใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊ส แต่เมื่อแหล่งกักเก็บน้ำอยู่ด้านบนของชั้นน้ำมันและอยู่ในระยะใกล้แหล่งชั้นน้ำมันให้ค่าการผลิตน้ำมันได้ดีกว่ากรณีที่แหล่งกักเก็บน้ำอยู่ห่างจากชั้นน้ำมัน กรณีของอัตราการอัดแก๊สสูงสุดที่ 16 ล้านลูกบาศก์ฟุตต่อวันพบว่าวิธีการผลิตแบบใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊สให้ค่าการผลิตน้ำมันน้อยกว่าการอัดน้ำสลับแก๊สแบบธรรมดา 2% อย่างไรก็ตามการใช้น้ำที่ไหลมาจากแหล่งกักเก็บอื่นสลับการอัดแก๊สนั้นไม่ต้องใช้เครื่องมือในการอัดน้ำ

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NGUYEN THANH GIANG: COMPARATIVE PRODUCTION PERFORMANCE BETWEEN CONVENTIONAL WATER ALTERNATING GAS FLOODING AND WATER DUMPFLOOD ALTERNATING GAS INJECTION. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 159 pp.

Water dumpflood alternating gas injection (WDAG) to improve oil recovery is proposed in this thesis. Eliminating water flooding system at surface, water flows freely through a dumping well from an aquifer to the oil reservoir alternating gas injection from surface. The water dumping well is perforated in both the aquifer and oil zones to allow cross flow of water. A reservoir simulation model was built to investigate conventional water alternating gas injection (WAG) and water dumpflood alternating gas injection from underlying and overlying aquifer. Several scenarios of aquifer depths, target gas injection rates and water-gas injection cycles were investigated.

It has been found that conventional WAG and WDAG yield the highest recovery factor at water-gas injection cycles of 1: 1 month and at high target gas injection. Target gas injection rate and water-gas injection cycle slightly affect the performance of conventional WAG but significantly impact WDAG. The sensitivity study indicates that an increase in volumetric ratio of aquifer to oil reservoir slightly increases the recovery factor in WDAG. The depth of underlying aquifer shows minor effect the performance of WDAG while a shallower overlying aquifer yields slightly better oil recovery factor than those for a deeper overlying aquifer. At the highest target gas injection rate of 16 MMSCF / D, WDAG recovery factor is about 2% lower than conventional WAG. However, WDAG does not require any water injection from surface.

Department:	Mining and Petroleum Engineering	Student's Signature	....
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LIST OF ABBREVIATIONS

BCF	Billion cubic feet
BHP	Bottomhole pressure
BOE	Barrel of oil equivalent
CO_2	Carbon dioxide
cp	Centipoise
EOR	Enhanced oil recovery
F or °F	Degree Fahrenheit
FL	Friction loss in casing or tubing (psi/STB/day)
FRAC.S.G	Fracturing pressure gradient
ft	feet
GOR	Gas-oil ratio
HWAG	Hybrid water alternating gas
IWAG	Immiscible water alternating gas injection
lb/cuft	Pound per cubic foot
M	Mobility ratio
mD	Millidarcy
MMSCF	Million standard cubic feet
MMSCF/D	Million standard cubic feet per day
MSCF/STB	Thousand standard cubic feet per stock tank barrel
MWAG	Miscible water alternating gas
psi	Pound per square inch
psia	Pound per square inch absolute
psi/ft	Pound per square inch per foot
PV	Pore volume ratio of aquifer to oil reservoir
PVT	Pressure-Volume-Temperature
rb/stb	Reservoir barrel per stock tank barrel
RF	Recovery factor

SCAL	Special core analysis
SCF/STB	Standard cubic feet per stock tank barrel
STB	Stock tank barrel
STB/D	Stock tank barrel per day
SWAG	Simultaneously water alternating gas
TVD	True vertical depth
WAG	Water alternating gas
WDAG	Water dumpflood alternating gas
WGIC	Water-gas injection cycle

NOMENCLATURES

ρ_g	Density of gas
ρ_w	Density of water
$\Delta\rho$	Density difference between water and gas
λ_{rt}^{m}	Total relative mobility in the mixed zone
μ_o	Oil viscosity
μ_w	Water viscosity
B_o	Formation volume factor of oil (RB/STB)
c_t	Total compressibility in oil zone (1/psi)
c_{tw}	Total compressibility in water zone (1/psi)
C_w	Corey water exponent
E_V	Vertical displacement efficiency
E_H	Horizontal displacement efficiency
E_m	Microscopic displacement efficiency
g	Gravitational acceleration
G_I	Cumulative gas injection
G_p	Cumulative production
I	Injectivity index of receiver zone (STB/d/psi)
J	Productivity index of source zone (STB/d/psi)
k	Absolute permeability
k_h	Horizontal 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
k_v	Vertical permeability
L_g	Distance in flow direction required for complete segregation
N_w	Original water in place (MMSTB)

N	Original oil in place (MMSTB)
N_p	Cummulative oil production
P_{iw}	Boundary pressure in water zone at initial condition (psi)
P_{io}	Boundary pressure in oil zone at initial condition (psi)
P_{ew}	Boundary pressure in water zone (psi)
P_{eo}	Boundary pressure in oil zone (psi)
Q	Total volumetric injection rate of gas and water
q_t	Total flow rate
Q_{tg}	Target gas injection rate
q_w	Water transfer rate (STB/d)
R_g	Radius at which segregation is complete
R_s	Solution gas-oil ratio
S_g	Gas saturation
S_l	Liquid saturation
S_{om}	Minnimum oil saturation (to gas)
S_{org}	Residual oil saturation (to gas)
S_{orw}	Residual oil saturation (to water)
S_w	Water saturation
$\overline{S}_w$	Average water saturation behind floodfront
S_{wc}	Connate water saturation
S_{wcr}	Critical water saturation
S_{wi}	Initial water saturation (connate water saturation)
S_{wmax}	Maximum water saturation
S_{wmin}	Minimum water saturation (irreducible water saturation)
t_p	Production time
W	Thickness of the rectangular reservoir perpendicular to flow
W_I	Cumulative water injection
W_p	Cumulative water production

CHAPTER 1

INTRODUCTION

This chapter introduces the background of conventional water alternating gas injection and the viability of water dumpflood alternating gas injection. The objectives and methodology are also pointed out in this chapter.

1.1 Background

Enhanced oil recovery (EOR) or tertiary recovery has been developed for several years to extract more oil from the reservoir commercially. Water alternating gas (WAG) injection is one of EOR techniques that has been successfully implemented for more than 50 years [1] to enhance oil recovery. In this method of WAG injection, water and gas are injected alternately into the reservoir. Therefore, WAG injection is governed by both microscopic oil displacement due to gas injection and macroscopic sweep due to water flooding. In addition, water is injected along with gas to reduce mobility which helps prevent early gas breakthrough.

Besides the advantages of WAG injection, the implementation of WAG injection obliges oil companies to pay for costly surface facility for both water and gas injection. However, water is generally readily available from an underground aquifer. The water can be dumped into the oil reservoir directly via a dumping well. Combining the principle of conventional WAG injection and water dumpflood, water dumpflood alternating gas injection (WDAG) is an innovation technique of conventional water alternating gas injection. In WDAG method, the dumping water well is perforated in the aquifer and the oil reservoir to allow water to flow freely from the aquifer into the oil zone in alternation with gas injection from surface. Therefore, the recovery mechanisms are the same as those for conventional WAG injection. The benefits gained from water dumpflood are reduced capital and operating costs while the disadvantage is inability to control the amount of dumped water which results in smaller oil recovery.

The purposes of this work are to compare the performance between conventional WAG injection and WDAG in terms of oil recovery, cumulative gas injection and water injection and to evaluate the effect of aquifer location, aquifer size. The reservoir model was constructed by a simulator named ECLIPSE100. This study evaluated favorable conditions for both conventional and WDAG such as target gas injection rate, water-gas injection cycle, aquifer location, aquifer size and depth of aquifer.

1.2 Objectives

i. To compare the performance in terms of oil recovery, cumulative gas and water injection between conventional water alternating gas injection and water dumpflood alternating gas injection.

ii. To estimate the effect of target gas injection rate and water-gas injection cycle on conventional water alternating gas injection and water dumpflood alternating gas injection.

iii. To evaluate the effect of aquifer to the performance of water dumpflood alternating gas injection such as aquifer location, aquifer size, distance between aquifer and oil reservoir.

1.3 Outline of methodology

i. Study various published literatures and gather required data relevant to the topic.

ii. Construct a homogeneous reservoir model to be base case for WAG and WDAG.

iii. Compare the recovery factors of both method of conventional WAG and WDAG to see the feasibility of both application and determine the favorable conditions for both method that give the highest oil recovery.

iv. Simulate the conventional WAG and WDAG models with different target gas injection rates, water-gas injection cycles and WDAG model with various pore volume ratios of aquifer to oil reservoir and aquifer locations. Table 1.1 and Table 1.2 show cases studied in this thesis.

Table 1.1 Cases studied for conventional WAG

Water injection duration (month)	Gas injection duration (month)	Gas injection rate (MMSCF/D)
1	1	2 4 8 16
2	1	2 4 8 16
2	2	2 4 8 16
3	1	2 4 8 16
3	2	2 4 8 16
3	3	2 4 8 16

Table 1.2 Cases studied for WDAG

Aquifer parameters			Operating parameters	
Location of aquifer	Volumetric ratio (PV)	Distance from oil reservoir (ft)	Water dumpflood and gas injection cycle (month:month)	Target gas Injection rate (MMSCF/D)
Underlying aquifer	5 10 20	1000	1:1 2:1 2:2 3:1 3:2 3:3	2 4 8 16
Underlying aquifer	10	500 1500 2500	1:1 2:1 2:2 3:1 3:2 3:3	2 4 8 16
Overlying aquifer	10	500 1500 2500	1:1 2:1 2:2 3:1 3:2 3:3	2 4 8 16

v. Analyze the results obtained from simulation and discuss on rational thought.

vi. Summarize the most suitable criteria for both conventional WAG and water dumpflood alternating gas injection that yields the optimum production in terms oil recovery factor, cumulative oil production, cumulative gas production, barrel of oil equivalent, cumulative water injection, cumulative gas injection and production time.

1.4 Outline of thesis

This thesis contains six chapters as outlined below:

Chapter I presents the background of water alternating gas injection and water dumpflood alternating gas injection and indicates the objectives and methodology of this study.

Chapter II introduces various published literatures related to water alternating gas injection and water dumpflood.

Chapter III introduces important concepts related to water alternating gas injection, water dumpflood and petrophysical properties.

Chapter IV describes reservoir model in details, rock properties, fluid properties and production condition set in the simulator.

Chapter V presents simulation results and discussion on study parameters. The investigated results by conventional WAG and WDAG are compared and summarized. The discussion on the sensitivity of several parameters is also included in this chapter.

Chapter VI provides conclusions and recommendations of this study.

CHAPTER 2

LITERATURE REVIEW

This chapter evaluates the information found in the literature related to WAG and water dumpflood.

2.1 Water alternating gas injection

To appreciate the effectiveness of WAG injection, Christensen, Stenby & Skauge [1] reviewed the performance results of 59 oil fields which were started to do WAG from 1957 to 1996. The major fields are in Canada and United States. Immiscible WAG (IWAG) and miscible WAG (MWAG) have been performed in sandstone, limestone, and dolomite. The injected gas was CO_2, N_2, and hydrocarbon gas. The average increase in oil recovery (over water flooding) is from 5% to 10%. The survey shows the potential of incremental oil recovery by using WAG injection method.

Caudle & Dyes [2] are ones of the early researchers who studied the displacement efficiency of miscible WAG injection. In their studies, a five spot laboratory model was built, and the X-ray shadowgraph was used to observe the displacement efficiency. The results show that there was 90% sweep efficiency when performing miscible WAG and 60% sweep efficiency when performing gas injection alone.

To understand the physics of multiphase flow when implementing WAG, Minssieux [3] studied the flow mechanisms in porous media where water and gas were injected alternately. The experiment used a 80 cm of clean water wet sandstone core sample under reservoir conditions (saturated and undersaturated) to determine oil swelling effect when injecting methane. The study also considered the effect of hysteresis on gas relative permeability. The results show that the swelling of oil in the undersaturated reservoir had better oil recovery than the saturated reservoir. The three-phase gas hysteresis model had significant effect on the amount of oil recovered from numerical simulator. During imbibition process, the reduction of relative permeability of gas due to gas-trapped phase eliminated early gas breakthrough.

Using cycle dependent three-phase relative permeability, Larsen & Skauge [4] simulated immiscible WAG with different cycles of injection and gas water ratios. In this study, the oil recovery was compared between two cases which are results from simulation with and without the three-phase relative permeability hysteresis. In hysteresis model, the interpolation of three-phase relative permeability from two-phase relative permeability was done by using Land trapping model and Stone 1 model. The results show that recovery factor is 6.5% on average higher when hysteresis was included. The three-phase relative permeability hysteresis significantly affects the predicted oil recovery by IWAG. However, slug injection length and gas-water ratio slightly affect the performance of IWAG. In addition, this study was based on water-wet rock. Thus, there may be errors when applying this model for intermediate or oil-wet rock.

A recent study of Skauge & Sorbie [5] observed the flow mechanisms for miscible and immiscible WAG by using a 2D micromodel to capture the saturation image of three-phase flow of oil, gas and water in IWAG and MWAG. The mechanism of the flow was analyzed in pore scale, core scale and reservoir scale. In IWAG, the second gas injection did not re-establish the same gas finger, so that the reduction of oil saturation was explained by the gas fingering diversion and fluid redistribution. After subsequent injection of IWAG cycles, the spreading of injected gas into larger areas increase the amount of produced oil. Thus, a smaller slug of gas and water injection in IWAG gave a better microscopic diversion of trapped gas.

Pitakwatchara [6] investigated the effect of well locations, target water and gas injection rate and injection cycle on conventional water alternating gas injection (WAG) and water alternating gas dumpflood. A homogeneous reservoir model which had the size of 4,900x1,900x50 (ft^3) was constructed by using ECLIPSE100 reservoir simulator. In conventional WAG, the results showed that the well locations significantly affect the prediction of oil recovery factor. A short distance between injector and producer causes lower sweep efficiency because of early gas and water breakthrough. The reservoir containing three wells which have the well distances of 2000 ft gives the best result in term recovery factor and cost of drilling and completion. The target gas injection rate has small effect on the recovery factor but significantly affects the duration of the production time. A higher injection rate yields shorter production time than a smaller injection rate. The injection cycle and water injection rate show a minor effect on the performance of water alternating gas injection.

2.2 Water dumpflood

Davies [7] is one of the early researchers who studied the method of water dumpflood to maintain the oil reservoir pressure and improve the oil recovery factor. The author derived an equation of fluid transfer from a source zone to the received zone. If the reservoir pressures of both zones are maintained, the transfer rate is constant and depends on the productivity index of the source zone, the capacity of received zone and the friction loss when fluid moves from these zones. If the two zones are finite, there will be a reduction of reservoir pressure of the source zone after dumpflood is carried out. Although water dumpflood has high potential, it was difficult to perform water dumpflood due to limited completion technology at that period.

Osharode et al. [8] reviewed the oil production of a pilot water dumpflood scheme started in 1997 and ran simulation for full field development of water dumpflood in the Egbema West field. After 12 years of performing pilot test, the pressure at the production well located in the Western part of the field has been increased by 8 psi. Furthermore, the simulation shows that cumulative oil production is 33% above the case without water dumpflood. Then, a reservoir model was built to evaluate the effectiveness of water dump food for full field development by drilling six dumper wells and re-opening six of the shut-in oil wells. The result shows that there is 400% increase in production rate, and the recovery factor is 62%.

In 2011, Anansupak [9] investigated the effect of water dumpflood method by varying well location, size and depth of aquifer. The study used finite difference, three-dimensional numerical black oil model from Chervon’s in-house simulator named CHEARS. According to the study, overlying aquifer gives better recovery factor than underlying aquifer. A larger aquifer size which means better injectivity index gives better recovery factor. However, too large aquifer causes high water cut and low amount of recovered oil. The injector locations had strong effect on oil production. Edge well injections yield better recovery factor. In addition, the oil that has API gravity ranging from 30 to 40 was seen to be the best candidate for water dumpflood.

Shizawi et al. [10] published a paper to review the performance of a water dumpflood field trial in Oman. Water source is an underlying aquifer, and ESP was installed to support the water production flowing into the depleted oil reservoir. Water dumpflood started by end of March 2009. After 9 months, the reservoir pressure monitoring surrounding the well showed a positive response. The recovery factor was 40%. The result proved the effective performance of water dumpflood with a lower cost compared to conventional water injection especially for small field projects. Due to the success of filed trial, there is high potential to apply this method for the entire field.

Helaly et al. [11] researched about the application of water dumpflood at an onshore oil field in Egyptian Western Desert which is 10 km away from the water source. There were a lot of problems for operation activity when performing conventional water injection such as surface leakages, casing leakages and ESP's maintenance. To eliminate the problems and reduce operation cost, water dumpflood has been implemented in this field. Acidizing was performed to improve water production of dumpflood wells. The paper also gave a typical cost of initiating conventional water injection project compared to water dumpflood project. The cost for installing 10 km of pipe may be 263% higher for capital cost in case of conventional water injection. Furthermore, expensive operational cost can be eliminated if water dumpflood is performed at this field.

CHAPTER 3

THEORY AND CONCEPT

This chapter shows general theory and concept related to WAG and water dumpflood. The main contents discuss about the parameters affect the flow of oil, gas and water and the displacement efficiency of WAG and water dumpflood.

3.1 Four main types of WAG

Water alternating gas injection is defined as the injection of both water and gas into the same reservoir. Figure 3.1 shows a typical scheme of WAG. The process of WAG can be classified into four main types.

i. Miscible water alternating gas injection (MWAG) is the process in which the reservoir pressure is higher than the minimum miscibility pressure in order to develop miscibility when injecting gas into the reservoir. In this method, gas is miscible and displaces oil effectively while the water injection improves the volumetric sweep efficiency. Therefore, MWAG yields higher oil recovery factor than other process of WAG. However, it is difficult to maintain the miscible front due to reduction of the reservoir pressure during the period of production.

ii. Immiscible water alternating gas injection (IWAG) is the process in which the injected gas cannot develop miscibility with oil. Water injection may stabilize the flood front and gas injection improves the microscopic displacement efficiency. Although IWAG shows lower recovery efficiency than MWAG, IWAG has been applied widely since it is flexibly applied for the oil reservoir where the pressure cannot be raised above the minimum miscibility pressure.

iii. Hybrid water alternating gas injection (HWAG) is the injection strategy that a large slug of gas is injected for a period of time and followed by water alternating gas injection. Hybrid WAG first takes the advantages of the microscopic sweep efficiencies of the gas injection process which offers earlier oil response than pure WAG yet retains the good vertical sweep efficiency under WAG operations.

iv. Simultaneously water alternating gas injection (SWAG) is a process in which water and gas are injected at the same time into the formation. The higher density of water tends to sweep hydrocarbons downward. On the other hand, the lower density of gas tends to sweep hydrocarbons upward. The two displacing mechanisms are expected to establish flood front which increases sweep efficiency and thus yields higher recovery factor.

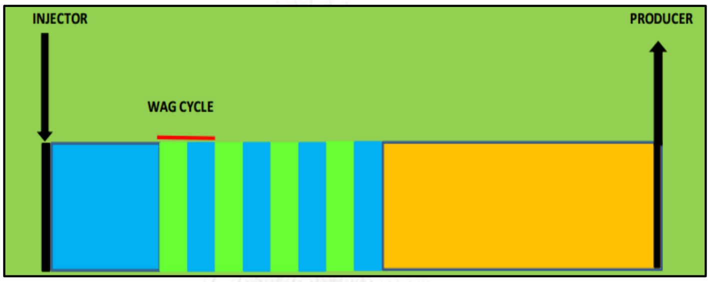

Figure 3.1 A typical scheme of WAG injection [12]

3.2 Screening criteria for WAG flooding

Manrique et al. [13] reviewed the data from worldwide projects of IWAG and MWAG injection. Base on the relevant parameters of crude oil and reservoir properties, the author suggested criteria for water alternating gas projects which may be used as a first look to identify a suitable candidate for the implementation of WAG flooding. Table 3.1 shows main oil properties and reservoir characteristics for successful international WAG projects.

Table 3.1 Suggested criteria for WAG projects [13].

Fluid Properties:	
Oil viscosity (cP)	< 2 (31/56)
Gravity (°API)	30-45 (31/56)
Viscosity ratio	10--30 (19/56)
Reservoir characteristics / properties	

Previous production method	Water flooding preferred
Temperature (^oF)	Not critical
Depth (ft)	Not critical
Net thickness (ft)	<100 unless dipping (30/56)
Average permeability (mD)	<100 (30/56)

a = number of WAG projects evaluated / total of WAG projects

3.3 Gravity segregation

After flowing for a distance from the injector, the mobile gas overrides into the upper zone while the mobile water undersides into the lower zone. Near the injector, there is a mixed zone in which both gas and water flow together as depicted in Figure 3.2.

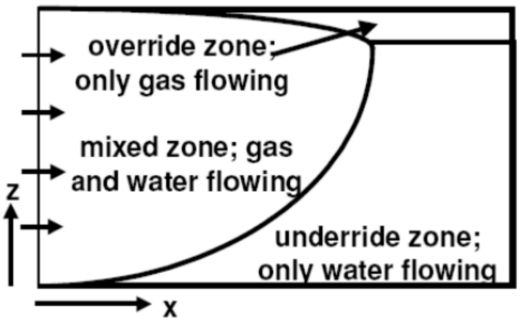

Figure 3.2 Vertical conformance of WAG [14].

Stone [14] and Jenkins [15] introduced a gravity segregation model in horizontal flow and homogenous-rectangular and cylindrical reservoir:

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

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

where:

L_g = distance in flow direction required for complete segregation

R_g = radius at which segregation is complete.

Q = total volumetric injection rate of gas and water.

ρ_w = density of water.

ρ_g = density of gas.

g = gravitational acceleration.

W = thickness of the rectangular reservoir perpendicular to flow.

λ^m_{rt} = total relative mobility in the mixed zone.

3.4 Relative permeability

Relative permeability is the ratio of effective permeability of a particular fluid at a particular saturation to absolute permeability of that fluid at total saturation. If a single fluid is present in a rock, its relative permeability is 1.0. Calculation of relative permeability allows comparison of the different abilities of fluids to flow in the presence of each other since the presence of more than one fluid generally inhibits flow.

3.4.1 Two phase relative permeability

Corey's correlation [16] is used in ECLIPSE reservoir simulator to calculate the relative permeability in oil/water system and oil/gas system and can be defined as:

Oil-water system:

$$K_{ro} = \left(\frac{1 - S_w - S_{or}}{1 - S_{wi} - S_{or}} \right)^{N_o} \tag{3.3}$$

$$K_{rw} = K_{rwend} \left(\frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}} \right)^{N_w} \tag{3.4}$$

Oil-gas system:

$$K_{ro} = \left(\frac{1 - S_{wg} - S_{wi} - S_{or}}{1 - S_{wi} - S_{or}} \right)^{N_o} \tag{3.5}$$

$$K_{rg} = \left(\frac{S_g - S_{gc}}{1 - S_{wi} - S_{or} - S_{gc}} \right)^{N_g} \tag{3.6}$$

where

S_w = water saturation.

S_{or} = residual oil saturation.

S_{wi} = initial water saturation or connate water saturation.

S_{gc} = critical gas saturation.

S_g = gas saturation.

K_{ro} = relative permeability to oil at any water saturation.

K_{rw} = relative permeability to water at any water saturation.

K_{rg} = relative permeability to gas at any water saturation.

K_{rwen} = relative permeability to water at minimum water saturation.

N_w = Corey water exponent.

N_o = Corey oil exponent.

N_g = Corey gas exponent.

3.4.2 Three-phase relative permeability

3.4.2.1 Three- phase relative permeability in ECLIPSE

In ECLIPSE reservoir simulator, there are three options for three phase relative model that are Stone I [17], Stone II [18] and Aziz- Settari [19] model. The default model is shown in Figure 3.3. The model is based on the assumption that the total saturation in each block is unity (S_g+S_o+S_w =1), the water saturation is equal to connate water saturation (S_{wco}) in the gas zone and the oil saturation is constant and is equal to average oil saturation in the block of water zone.

Gas zone:

Within the fraction $\dfrac{S_g}{S_g + S_w - S_{wco}}$ of the cell

where:

S_g = the gas saturation.

S_w = the water saturation.

S_{wco} = the connate water saturation.

Water zone:

Within the fraction $\frac{S_w - S_{wco}}{S_g + S_w - S_{wco}}$ of the cell

where:

S_g = the gas saturation.

S_w = the water saturation.

S_{wco} = the connate water saturation.

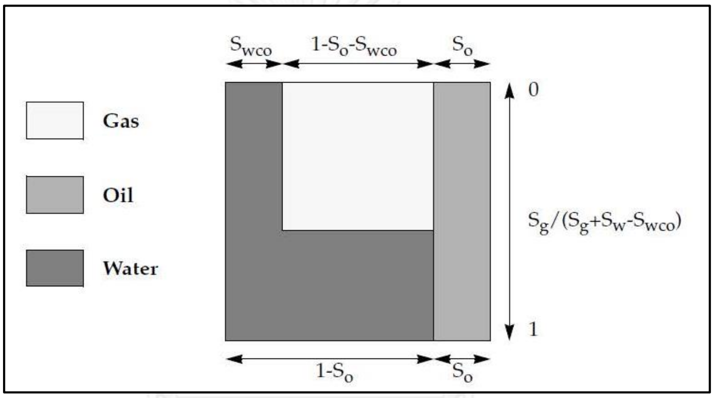

Figure 3.3 The default 3-phase oil relative permeability model in ECLIPSE [20].

The oil relative permeability can be defined as

$$K_{ro} = \frac{S_g K_{rog} + K_{row}\left(S_w - S_{wco}\right)}{S_g + S_w - S_{wco}} \qquad (3.7)$$

where

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

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

3.4.2.2 Stone's model 1

Stone's model 1 [17] is based on the assumptions that water displaces oil and gas displaces oil. There-phase relative permeability is obtained by interpolating from two-phase relative permeability.

The normalized saturations for Stone's model 1 are defined by treating connate water and irreducible oil as immobile fluids which are:

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

$$S_w^* = \frac{S_w - S_{wc}}{(1 - S_{wc} - S_{om})} \tag{3.9}$$

$$S_g^* = \frac{S_g}{(1 - S_{wc} - S_{om})} \tag{3.10}$$

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

$$K_{ro} = S_o^* \beta_W \beta_g \tag{3.11}$$

$$K_{ro} = S_o^* \beta_w \beta_g \tag{3.12}$$

The two multipliers β_w and β_g can be calculated from

$$\beta_w = \frac{K_{row}}{1 - S_w^*} \tag{3.13}$$

$$\beta_g = \frac{K_{rog}}{1 - S_w^*} \tag{3.14}$$

where

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

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

S_{om} = minimum oil saturation.

S_{orw} = critical oil saturation in the oil-water system.

S_{org} = residual oil saturation in gas-oil system (S_{org}).

3.4.2.3 Stone's model 2

Based on Stone's model 1, Stone [18] developed the second model named Stone's model 2 that tried to avoid difficulties in choosing minimum oil saturation. The equation of this model is defined as:

$$K_{ro} = \left(K_{row} + K_{rw}\right)\left(K_{rog} + K_{rg}\right) - K_{rw} - K_{rg} \tag{3.15}$$

From the above equation can be rearranged into normalized form as

$$K_{ro} = K_{rocw}[\left(\frac{K_{row}}{K_{rocw}} + K_{rw}\right)\left(\frac{K_{rog}}{K_{rocw}} + K_{rg}\right) - K_{rw} - K_{rg} \tag{3.16}$$

where

K_{rocw} = the oil relative permeability in the presence of connate water only.

3.5 Water dumpflood

Water dumpflood is the unconventional water injection that water is driven from a separated aquifer to oil reservoir for the purpose of pressure support or to improve oil recovery. Figure 3.4 represents a dumpflooding technique.

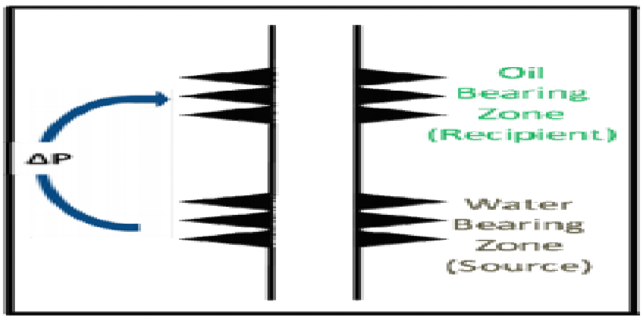

Figure 3.4 presentation of dumpflooding technique [11].

Water dumpflood method reduces the investment of capital cost by eliminating the installation of flow lines, transfer pumps, water gathering system and water treating facilities. Therefore, it helps cut down the annual operation cost. Water dumpflood may be the best candidate in a remote area where there is insufficient water or needs an extremely expensive pipeline investment. Furthermore, the tendency to corrode the completion assembly is minimized because there is a shorter distance between the dumper and receiver reservoirs.

Beside the advantages, there are disadvantages when performing water dumpflood. It is difficult to control and measure the quantity of water being transferred to the reservoir. In addition, completion assembly of the dumper well may be more complicated and cost more money. Furthermore, there may be sand production problems in the dumper well and incompatible water from aquifer and fluid in the receiver reservoir that may cause formation damage and scale precipitation.

In case that the pressure of the source zone and the receiver zone are maintained, the transfer rate from an aquifer to the oil zone is shown in Equation 3.17 [7] which is dependent on the productivity index of the aquifer, the injectivity index of the receiver zone, the friction loss in casing or tubing and the pressure difference between two zones.

$$q_w = \left(\frac{1}{I} + \frac{1}{J} + FL\right)\left(P_{ew} - P_{eo}\right) = constant \tag{3.17}$$

where

q_w = water transfer rate (STB/d).

I = injectivity index of receiver zone (STB/d/psi).

J = productivity index of source zone (STB/d/psi).

FL = friction loss in casing or tubing (psi/STB/day).

P_{ew} = boundary pressure in water zone (psi).

P_{eo} = boundary pressure in oil zone (psi).

If the source zone is finite, there will be a reduction of reservoir pressure of the source zone after dumpflood is carried out. The water transfer rate is dependent on time and was determined by Equation 3.18-3.22 [7].

$$q_w = \frac{1}{R_1}\left(P_{iw} - P_{io}\right)e^{-BCt} + \frac{A}{B}\left(1 - e^{-BCt}\right) \tag{3.18}$$

$$R_1 = \left(\frac{1}{I} + \frac{1}{J} + FL \right) \tag{3.19}$$

$$A = q_o B_o N_w c_{tw} \tag{3.20}$$

$$B = Nc_t + N_w c_{tw} \tag{3.21}$$

$$C = \frac{1}{R_1 N c_t N_w c_{tw}} \tag{3.22}$$

where

B_o = formation volume factor of oil (RB/STB).

N_w = original water in place (MMSTB).

N = original oil in place (MMSTB).

c_t = total compressibility in oil zone (1/psi).

c_{tw} = total compressibility in water zone (1/psi).

P_{iw} = P_{ew} at initial condition (psi).

P_{io} = P_{eo} at initial condition (psi).

3.6 Recovery factor

The improvement of displacement efficiency is one of advantages of WAG flooding leading to increase recovery factor. There are three components in the recovery factor: horizontal displacement efficiency (E_H), vertical displacement efficiency (E_V) and microscopic displacement efficiency (E_m). The recovery factor (RF) is defined as

$$RF = E_V \times E_H \times E_m \tag{3.23}$$

3.6.1 Horizontal displacement efficiency

Horizontal displacement efficiency is affected by the mobility ratio (M) and the reservoir heterogeneity. The mobility ratio for immiscible water displacement and immiscible gas displacement are defined by Equation 3.24 and 3.25, respectively. It depends on relative permeability and viscosity of oil (displaced phase) and gas (displacing phase). The displacement efficiency will be favorable when M is less than or equal to one. It helps to stabilize the flood front and prevent early gas or water breakthrough.

$$M_{go} = \frac{K_{rg} / \mu_g}{K_{ro} / \mu_o} \tag{3.24}$$

$$M_{wo} = \frac{K_{rw} / \mu_w}{K_{ro} / \mu_o} \tag{3.25}$$

where

M_{go} = mobility ratio in gas-oil system.

M_{wo} = mobility ratio in water-oil system.

K_{rg} = relative permeability to gas.

K_{ro} = relative permeability to oil.

K_{rw} = relative permeability to water.

μ_o = oil viscosity (cp).

μ_w = water viscosity (cp).

3.6.2 Vertical displacement efficiency

The vertical displacement efficiency is defined as the ratio of cross-sectional area connected by displacing agent to total cross-sectional area. It strongly depends on parameters such as mobility ratio, total volume of fluid injected. As depicted in Figure 3.5, nonuniform permeability may affect vertical displacement efficiency since the injected fluid is able to flow faster in high-permeability zones than in low-permeability zones.

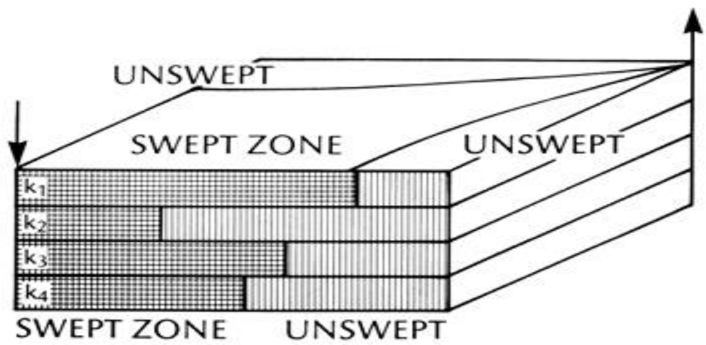

Figure 3.5 Illustration of vertical sweep efficiency [21].

3.6.3 Microscopic displacement efficiency

Microscopic displacement efficiency represents the ability of displacing fluid mobilizing the residual oil and depends on interfacial and surface tension forces, wettability, capillary pressure and relative permeability. In this thesis, the relative permeability is an important parameter in the study of immiscible WAG injection while neglecting the effect of interfacial and surface tension forces, wettability and capillary pressure. The presence of two or three fluid phases affects the saturation and the permeability of the other phases. A typical water-oil relative permeability curves is depicted in Figure 3.6. Water saturation and gas saturation increases when injecting water and gas alternately into the oil reservoir, the oil saturation reduces until it reaches the residual oil saturation (S_{or}).

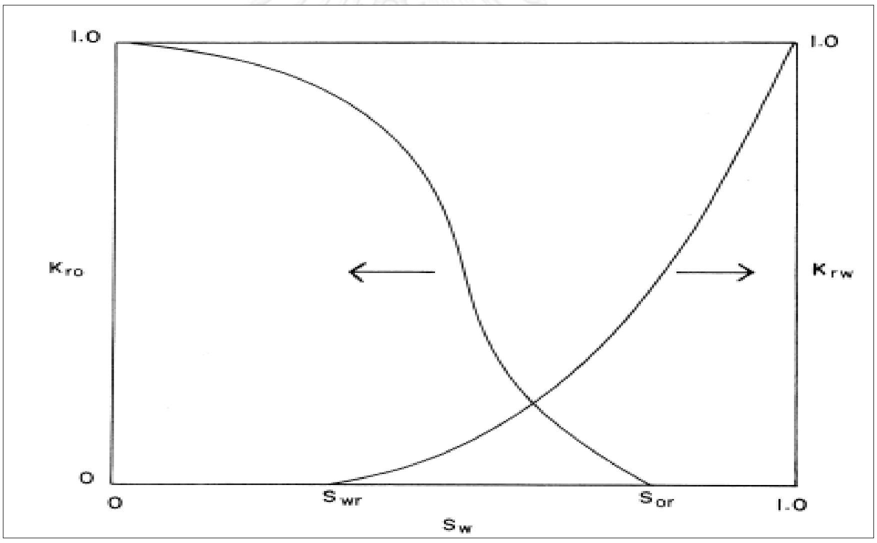

Figure 3.6 Typical water-oil relative permeability curves [22].

3.7 Pressure gradient, temperature gradient and fracture pressure

When performing WAG to enhance oil recovery, it is necessary to control injection pressure to be less than fracture pressure. For a specific filed in the Gulf of Thailand, the pressure gradient, temperature gradient and fracture pressure correlation can be defined as Equation 3.26-3.29 [23].

$$Pressure\ (psi) = TVD(ft) \times 0.3048 \times 1.462\ (psi/m) + 14.7 \qquad (3.26)$$

$$Temperture\ (^{o}C)=0.059(\frac{^{0}C}{m})\times TVD(ft)\times 0.3048 + 21.38 \tag{3.27}$$

$$FRAC.S.G = 1.22 + \left(TVD \times 1.6 \times 10^{-4}\right) \tag{3.28}$$

$$Fracture\ Pressure\left(bar\right) = \frac{FRAC.S.G \times TVD}{10.2} \tag{3.29}$$

where

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

TVD = true vertical depth below rotary table (meter)

3.8 Barrel of oil equivalent

It is necessary to convert amount of gas into the oil equivalent to summarize the amount of energy that is equivalent to the amount of energy found in a barrel of crude oil. Barrel of oil equivalent (BOE) is determined by the cumulative oil production and the difference between cumulative gas production and cumulative gas injection. Common industry gas conversion factors usually range between 1 barrel of oil equivalent (BOE) = 6,000 standard cubic feet of gas [24]. Thus, Barrel of oil equivalent by the following equation:

$$\begin{aligned} NET\ BOE\ (STB) &= Cumulative\ Oil\ Production\ (STB) \\ &+ Cumulative\ Gas\ Production\ (MMSCF) \times 166.7 \\ &- Cumulative\ Gas\ Injection\ (MMSCF) \times 166.7 \end{aligned} \tag{3.30}$$

CHAPTER 4

RESERVOIR SIMULATION MODEL

Inheriting the reservoir model from Pitakwatchara [6], the number of grid blocks, size of reservoir are retained as Pitakwatchara's study. The reservoir characteristics of the oil zone and aquifer, liquid properties and relative permeability model are shown in this chapter.

4.1 Rock properties

The reservoir is assumed to be homogeneous and contains an overlying aquifer or underlying aquifer. Detail of aquifer properties and oil reservoir properties are described in Table 4.1 and Table 4.2. To study the effect of volumetric ratio of aquifer to oil reservoir, the thickness of aquifer is retained at 500 ft. The aquifer is 1000 ft away from the oil reservoir while the aquifer porosity is varied from 10.75 to 43 % in order to vary the pore volume of the aquifer while maintaining its bulk volume and shape. The details of aquifer properties such as top depth, initial pressure and temperature are shown in Table 4.3

Table 4.1 Summary of oil reservoir model.

Parameters	Oil Reservoir	Units
Number of grid blocks	19×45×5	grid blocks
Size of reservoir	1,900×4,500×50	ft.
Effective porosity	21.5	%
Horizontal permeability	126	mD.
Vertical permeability	12.6	mD.
Top of reservoir	4,500	ft.
Datum depth	4,500	ft.
Initial pressure at datum depth	2,020	psi
Reservoir temperature	216	°F
Fracturing pressure	2,807	psi
Rock compressibility	1.323E-6	psi^{-1}
Initial water saturation	25	%

Table 4.2 Summary of aquifer model.

Parameters	Aquifer	Units
Number of grid blocks	19×45×5	grid blocks
Size of aquifer	1,900×4,500×500	ft^3.
Horizontal permeability	126	mD.
Vertical permeability	12.6	mD.

Table 4.3 Summary of underlying aquifer model with different pore volume ratio of aquifer to oil reservoir.

PV	Porosity (%)	Distance between aquifer and oil reservoir (ft)	Top depth (ft)	P_i at top depth (ft)	T at mid depth (°F)
5	10.75	1000	5550	2488	258
10	21.5				
20	43				

To study effect of aquifer location, both underlying and overlying aquifers are built in the simulation. The distance between the underlying aquifer and the oil reservoir is determined as the depth difference between the top of the aquifer and the bottom of the oil reservoir while the distance between the overlying aquifer and the oil reservoir is the depth difference between the top of the oil reservoir and the bottom depth of aquifer. The details of underlying and overly aquifer properties are presented in Table 4.4 and Table 4.5.

Table 4.4 Summary of underlying aquifer model with different distance between aquifer and oil reservoir.

	Underlying aquifer		
Distance between aquifer and oil reservoir (ft)	500	1500	2500
Porosity (%)	21.5	21.5	21.5
Top of aquifer (ft)	5,050	6,050	7,050
Pi at top depth (psi)	2,265	2,711	3,136
T at mid depth of aquifer (°F)	242	274	307

Table 4.5 Summary of overlying aquifer model with different distance between aquifer and oil reservoir.

	Overlying aquifer		
Distance between aquifer and oil reservoir (ft)	500	1500	2500
Porosity (%)	21.5	21.5	21.5
Top of aquifer (ft)	3,500	2,500	1,500
Pi at top depth (psi)	1,574	1,129	683
T at mid depth of aquifer (^{o}F)	192	160	127

4.2 Fluid properties

Surface oil properties are set at 30 ^{o}API, 350 SCF/STB initial GOR and 0.8 gas specific gravity. The reservoir fluid properties are generated by using ECLIPSE correlation set II. The fluid properties are shown from Table 4.6 to Table 4.8. Live oil and dry gas PVT properties are represented in Figure 4.1 and Figure 4.2, respectively.

Table 4.6 Fluid densities at surface condition.

Property	Value	Units
Oil density	54.643	lbm/cuft
Water density	62.428	lbm/cuft
Gas density	0.05	lbm/cuft

Table 4.7 Water PVT.

Property	Value	Units
Reference pressure (Pref)	2,020	psia
Water FVF at Pref	1.029	rb/stb
Water compressibility	3.13E-06	psi^{-1}
Water viscosity at Pref	0.279	cP

Table 4.8 PVT data.

Parameter	Value	Units
Oil gravity	30	°API
Gas specific gravity	0.8	(air =1)
Water salinity	2500	ppm
CO_2, N_2, H_2S content	0	%
Solution gas-oil ratio @ initial condition	350	scf/STB
Bubble point pressure	1857	psi
Oil formation volume factor @ initial condition	1.12	RB/STB
Oil viscosity @ initial condition	1.392	cP

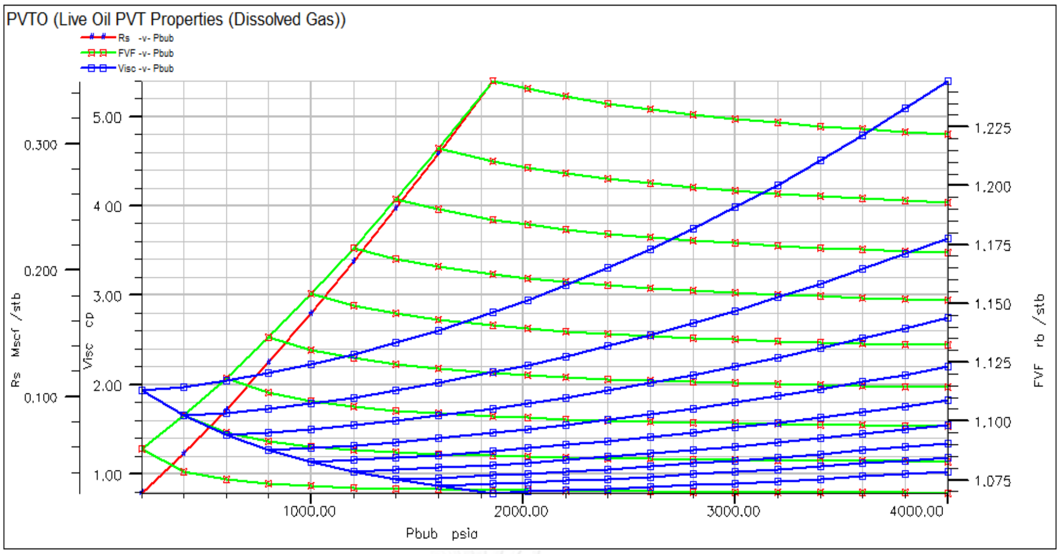

Figure 4.1 Live oil PVT properties in oil reservoir (dissolved gas).

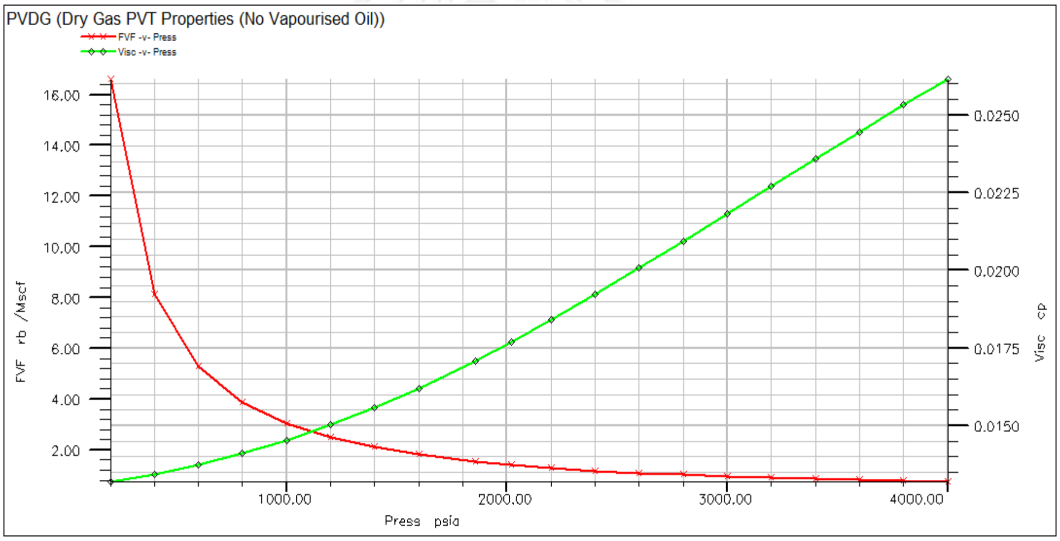

Figure 4.2 Dry gas PVT properties in oil reservoir (no vaporized oil).

4.3 Special core analysis (SCAL)

The parameters in Table 4.9 are used to generate the two-phase relative permeability by using Corey's correlation. The default model in ECLIPSE is used to the determine three-phase relative permeability. The input parameters for Corey's correlation are based on a study conducted for a reservoir in Thailand. Relative permeability values are tabulated in Table 4.10 and Table 4.11. The relative permeability curves for water-oil and gas-oil systems are illustrated in Figure 4.3 and Figure 4.4.

Table 4.9 Input parameters for Corey's correlation.

Corey Water	3	Corey Gas	3	Corey Oil/Water	1.5
S_{wmin}	0.25	S_{gmin}	0	Corey Oil/Gas	1.5
S_{wcr}	0.25	S_{grc}	0.15	S_{org}	0.1
S_{wi}	0.25	S_{gi}	0.15	S_{orw}	0.3
S_{wmax}	1	K_{rg} (S_{org})	0.4	K_{ro} (S_{win})	0.8
K_{rw} (S_{orw})	0.3	K_{rg} (S_{gmax})	0.4	K_{ro} (S_{gmin})	0.8
K_{rw} (S_{wmax})	1				

Table 4.10 Water and oil relative permeability.

S_w	K_{rw}	K_{ro}
0.25	0	0.8
0.3	0.00041	0.67044
0.35	0.00329	0.54875
0.4	0.01111	0.43546
0.45	0.02634	0.33127
0.5	0.05144	0.23704
0.55	0.08889	0.15396
0.6	0.14115	0.08381
0.65	0.2107	0.02963
0.7	0.3	0
1	1	0

Table 4.11 Gas and oil relative permeability.

S_g	K_{rg}	K_{ro}
0	0	0.8
0.15	0	0.53973
0.2125	0.00078	0.44176
0.275	0.00625	0.35056
0.3375	0.02109	0.26668
0.4	0.05	0.19082
0.4625	0.09766	0.12394
0.525	0.16875	0.06747
0.5875	0.26797	0.02385
0.65	0.4	0
0.75	0.8	0

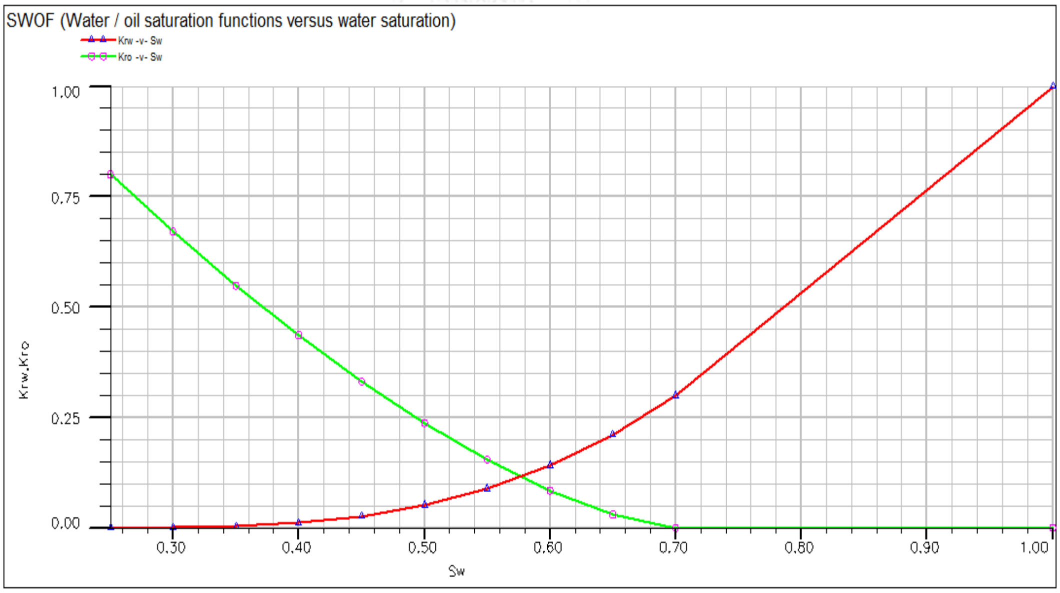

Figure 4.3 Relative permeability to oil and water in water/oil system.

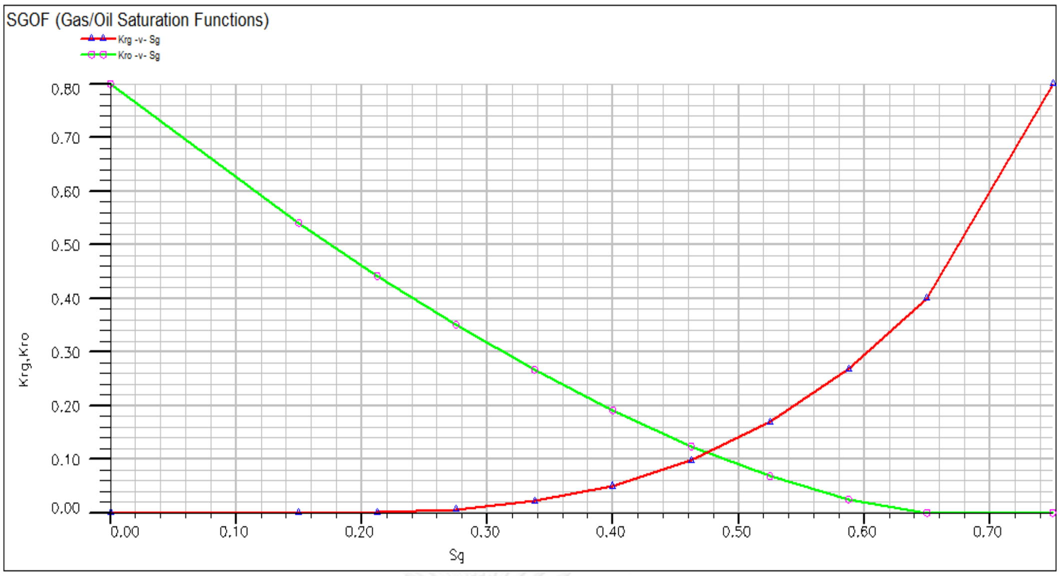

Figure 4.4 Relative permeability to oil and gas in gas/oil system.

4.4 Well location

As this work inherits the study of Pitakwatchara [6], the field contains three wells which are two production wells and one injection (or dumping) well. Well coordinates are shown in Table 4.12, and well locations are depicted in Figure 4.5 and Figure 4.6.

Table 4.12 Well coordinates.

Well	i	j
I1	10	23
P1	10	3
P2	10	43

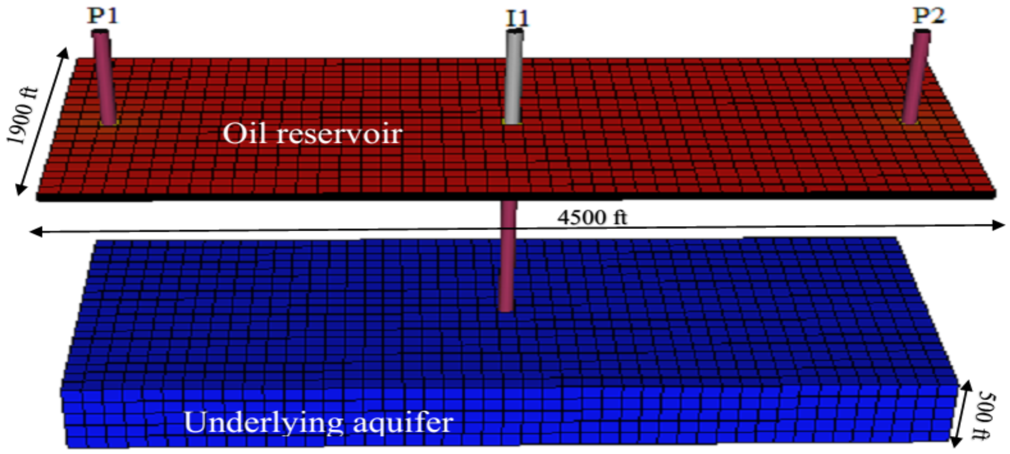

Figure 4.5 Well locations set for water for conventional WAG and WDAG from underlying aquifer (P1 and P2 = production well, I1 = injector or dumpflood well).

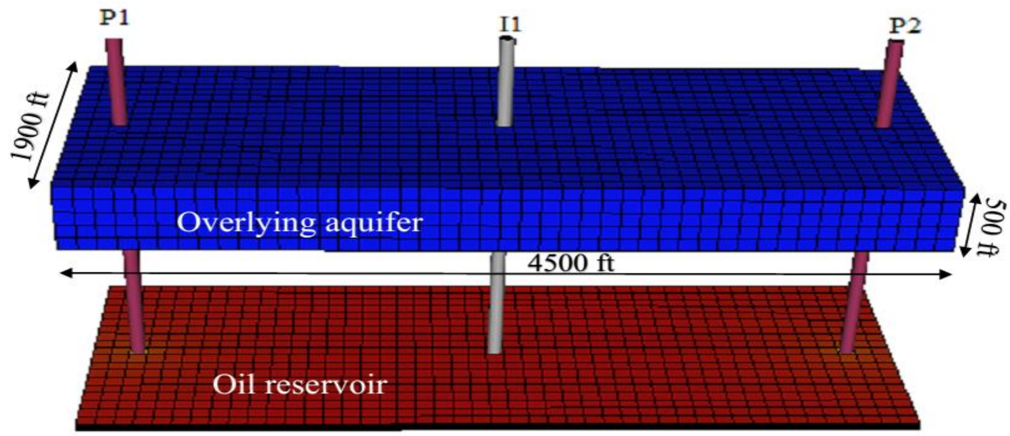

Figure 4.6 Well locations set for water for conventional WAG and WDAG from overlying aquifer (P1 and P2 = production well, I1 = injector or dumpflood well).

4.5 Well schedule

4.5.1 Conventional water alternating gas injection

For conventional WAG, water and gas are injected alternately at well I1. The target water injection rate is set at 6,000 STB/D while the target gas injection rate is varied as 2, 4, 8 and 16 MMSCF/D. In addition, water-gas injection cycles are varied as 1:1, 2:1, 2:2, 3:1, 3:2 and 3:3 (month: month) to find the most suitable operating conditions. The maximum bottomhole pressure for injection well is set at 2700 psi to avoid fracturing. Wells P1 and P2 are used to produce oil with the target liquid production rate of 3000 STB/D/well.

4.5.2 Water dumpflood alternating gas injection

4.5.2.1 WADG from underlying aquifer

In this study, water is allowed to flow naturally from the underlying aquifer into the oil reservoir at the beginning of production without any downhole rate control device while gas is injected alternatively from surface. Apart from water dumpflood, other operating conditions are the same as those specified in the case of conventional WAG.

4.5.2.2 WDAG from overlying aquifer

In WDAG from overlying aquifer, water flows down naturally from overlying aquifer through dumper well I1 to the oil zone alternating the gas injection from surface. However, the reservoir has to be naturally depleted for 15 days before performing WDAG injection since there is inadequate pressure difference between the overlying aquifer and the oil reservoir for water to flow to the oil zone at the beginning of production. Besides the operation conditions for water dumpflood, the target gas injection rate, injection cycle, and production condition are the same as the case of conventional WAG.

4.5.3 Abandonment conditions

The production wells are produced until the economic rate of 50 STB/D/well or the gas-oil ratio exceeds 50 MSCF/STB or the production time reaches the concession period of 30 years. Table 4.13 presents the injection and production constrain parameters for both conventional WAG injection and WDAG injection.

Table 4.13 Injection and Production constrain parameters

Parameters	Conventional WAG	WDAG	Units
Liquid production rate	3,000	3,000	STB/D/Well
Economic oil rate for production well	50	50	STB/D/Well
Maximum water cut for production well	95	95	%
Maximum GOR for production well	50	50	MSCF/STB
BHP control for producing well	200	200	psia
Target water injection rate	6,000	-	STB/D
BHP target for injection well	2,700	2,700	psia
Concession period	30	30	years

CHAPTER 5

SIMULATION RESULTS AND DISCUSSIONS

This chapter discusses the effect of target gas injection rate, water-gas injection cycle on the performance of conventional WAG and WDAG as well as the impact of volumetric ratio of aquifer to oil reservoir and aquifer location on WDAG. The comparison of different performances between conventional WAG and WADG is presented, and the favorable operational conditions for both conventional WAG and WDAG are also suggested in this chapter.

5.1 Base case

5.1.1 Conventional WAG injection

For conventional WAG, water and gas are injected alternately until the economic limits are reached. In the base case, the target water injection rate is 6000 STB/D, the target gas injection rate is 8 MMSCF/D and water-gas injection cycle is 2:2 (month: month). The injection schedule is shown in Figure 5.1.

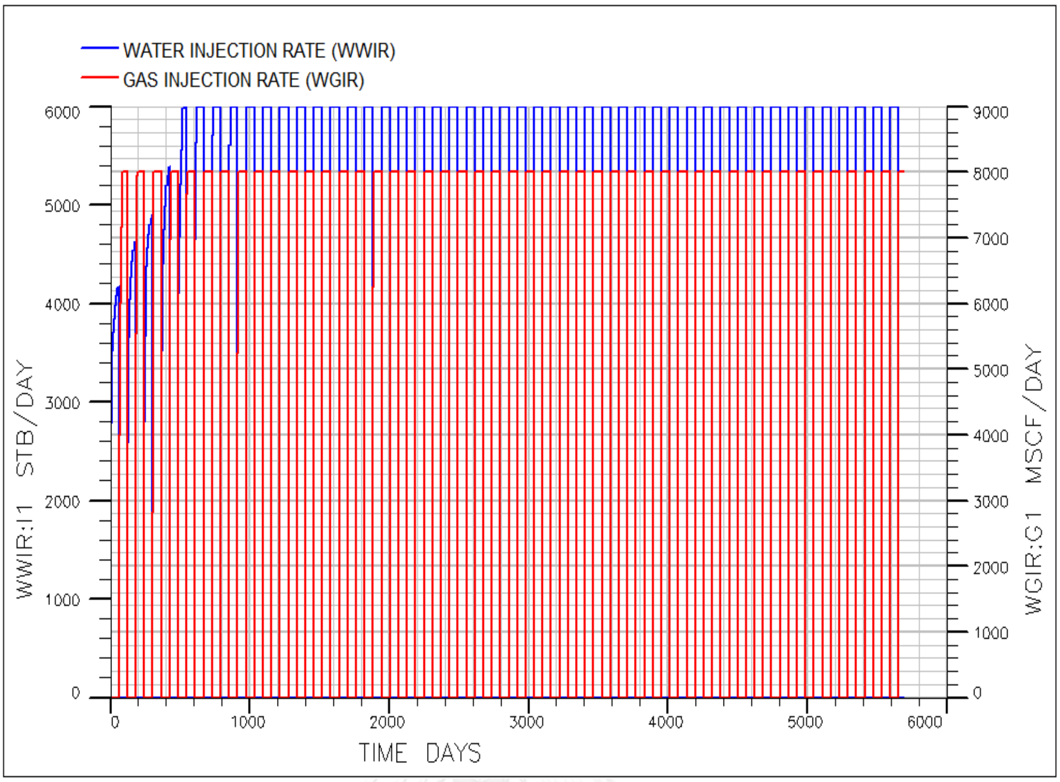

Figure 5.1 The injection schedule of conventional WAG under base case condition

Figure 5.2 represents the field oil, gas and water production rate during 5690 days. The field oil production rate retains at 6000 STB/D during the first 435 days and gradually declines until it reaches the economic oil production rate. The water production rate rapidly increases after water breakthrough (day 980th) and fluctuates in the following days according to the injection cycle. The average water production rate is around 3000 STB/D which is around half of target water injection rate. The gas production rate at the first 150 days fluctuates with small amplitude and rapidly increases in the following days due to gas breakthrough. After gas breakthrough, gas production rate is about the same behavior as water production rate and the average gas production rate is 4000 MSCF/D which is approximately half of target gas injection rate.

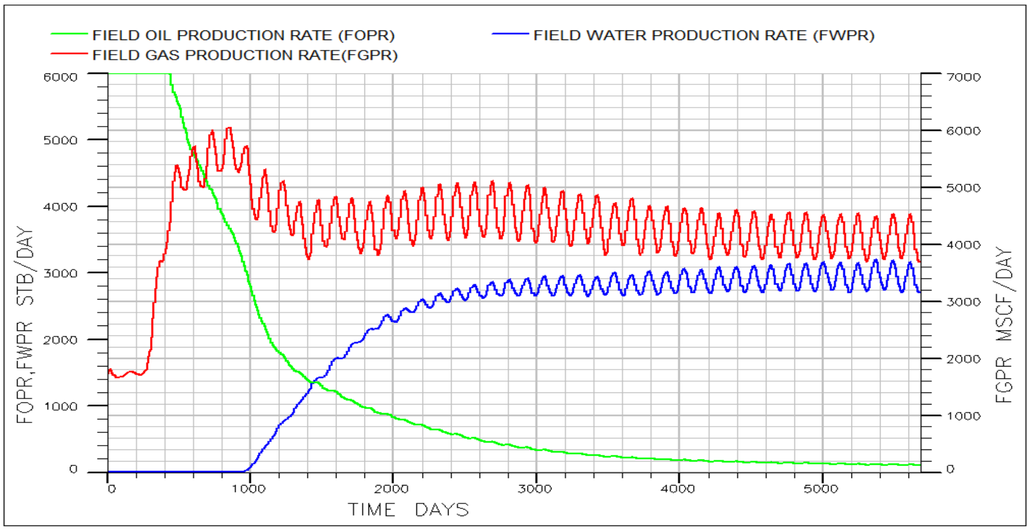

Figure 5.2 Field oil, water and gas production rates by conventional WAG under base case condition.

Figure 5.3 shows the oil saturation profile at mid cross section after one year of production. Near the injector, the oil saturation is low because water and gas displace oil flowing towards the producers. The top of reservoir shows the effect of gas overriding causing low oil saturation. The oil saturation around the bottom part of reservoir is still high and the oil bank is still maintained because injected water has not arrived at the producers. However, oil saturation is low at bottom part of reservoir after water breakthrough (day 980th) due to the effect of water underrunning (Figure 5.4).

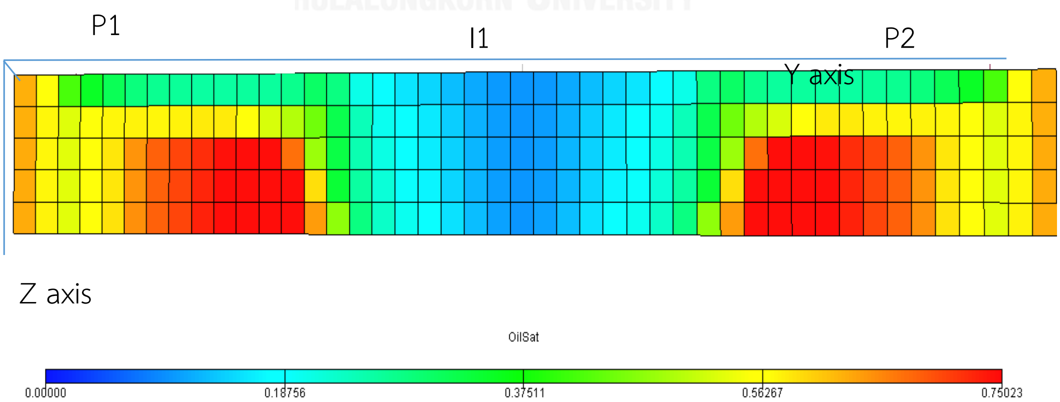

Figure 5.3 Oil saturation profile (mid cross section) after 1 year production by conventional WAG under base case condition.

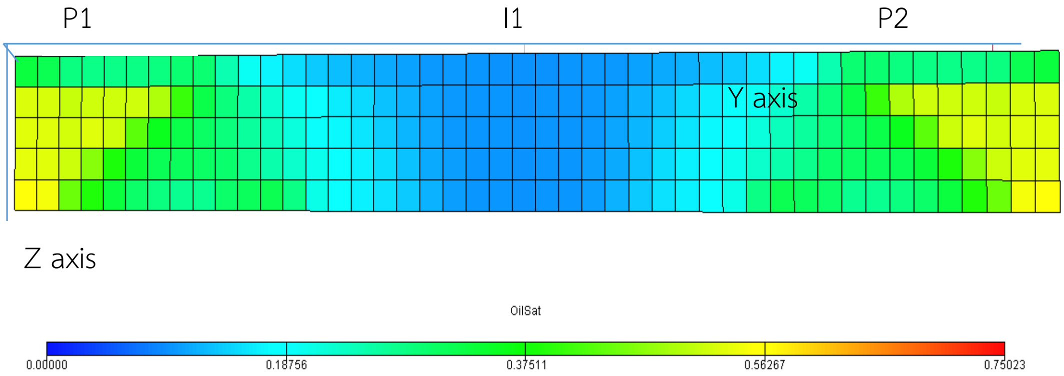

Figure 5.4 Oil saturation profile at mid cross section when water breakthrough by conventional WAG under base case condition

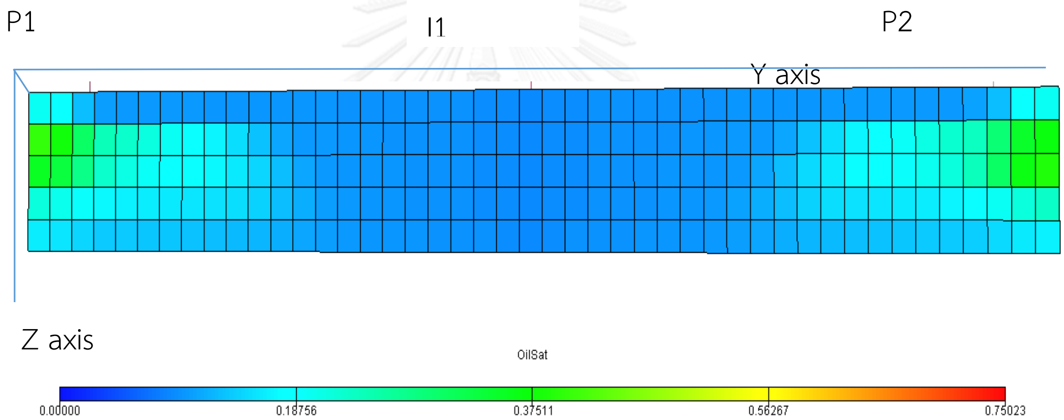

Figure 5.5 Oil saturation profile at the end of production by conventional WAG under base case condition

At the end of production, the oil saturation in the middle of mid cross section near the producers is higher than the top and the bottom because the effect of gas overriding and water underrunning. The effect of the border causes high oil remaining around the border (Figure 5.5).

5.1.2 Water dumpflood alternating gas injection

The zoomed-in injection schedule for water dumpflood alternating gas injection is depicted in Figure 5.6. Water from an underlying aquifer is allowed to flow to the oil reservoir when starting production. The top of aquifer is 1500 ft below the bottom of the oil reservoir. The aquifer thickness is 500 ft which is ten times larger than that of the oil reservoir. The porosity of the aquifer is 21.5%. Water dumpflood and gas injection are performed alternately for each two-month, and the target gas injection rate is 8 MMSCF/D.

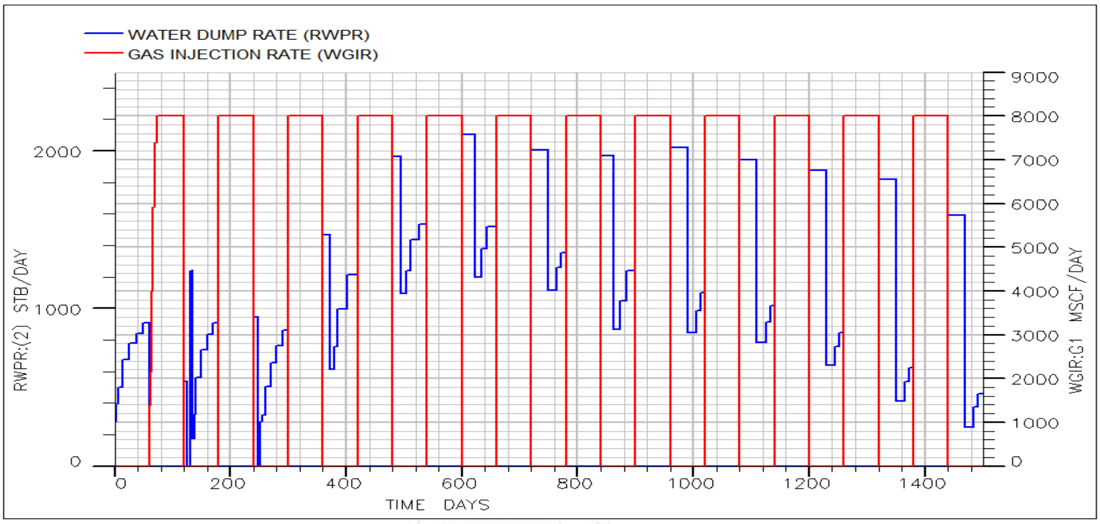

Figure 5.6 The injection schedule of WDAG under base case condition.

The field oil, gas and water production rate during 9544 days are shown in Figure 5.7. The field oil production rate can be maintained at 6000 STB/D for the first 300 days of production which is shorter than the case of conventional WAG. The oil production rate fluctuates with higher amplitude and takes longer time to reach the economic limit than the case of conventional WAG. The behavior of the field gas production in this case is almost the same as the case of conventional WAG. The water production rate is less than that of conventional WAG since the average water dump rate is just about 690 STB/D (see Figure 5.8) which is much less than target water injection rate in WAG. Thus, the water breakthrough occurs at late time compared to the case of conventional WAG.

Figure 5.8 represents the total water production from aquifer which is around 3.18 MMSTB at the end of production. The total water production rapidly increases until the day 1600th. Then, it gradually increases in the following days due to the reduction of pressure in the aquifer. The total water production from WDAG implies the flow ability of water from the aquifer which depends on aquifer properties.

Figure 5.9 depicts the oil saturation profile at mid cross section for the case of WDAG after one year of production. The effect of gas overriding is indicated by the low oil saturation at the top of reservoir. However, the oil saturation profile at the bottom part of the reservoir is higher than that for the case of conventional WAG due to uncontrolled flow rate of water transferred from the aquifer to the oil reservoir.

When water breaks through (day 2600th), the oil saturation profile shows the effect of water underrunning causing low oil saturation at the bottom area of the reservoir (Figure 5.10). At the end of production, the oil saturation at the middle area of the reservoir is slightly higher than that for the case of conventional WAG since the flood front is less smooth than the case of conventional WAG. The oil saturation near the border is the highest because of the border effect (Figure 5.11).

Table 5.1 shows the summary of results for conventional WAG and WDAG under base case. At the end of production, WDAG yields recovery factor of 69.20% with 6.846 MMSTB total oil production within 25.5 years while conventional WAG provides recovery factor of 74.12% which is 4.92 % higher than WDAG. Conventional WAG recovers 7.33 MMSTB of BOE while WDAG yields 6.85 MMSTB of BOE. However, conventional WAG needs 12.87 MMSTB of water injection while WDAG does not require any water injection from the surface.

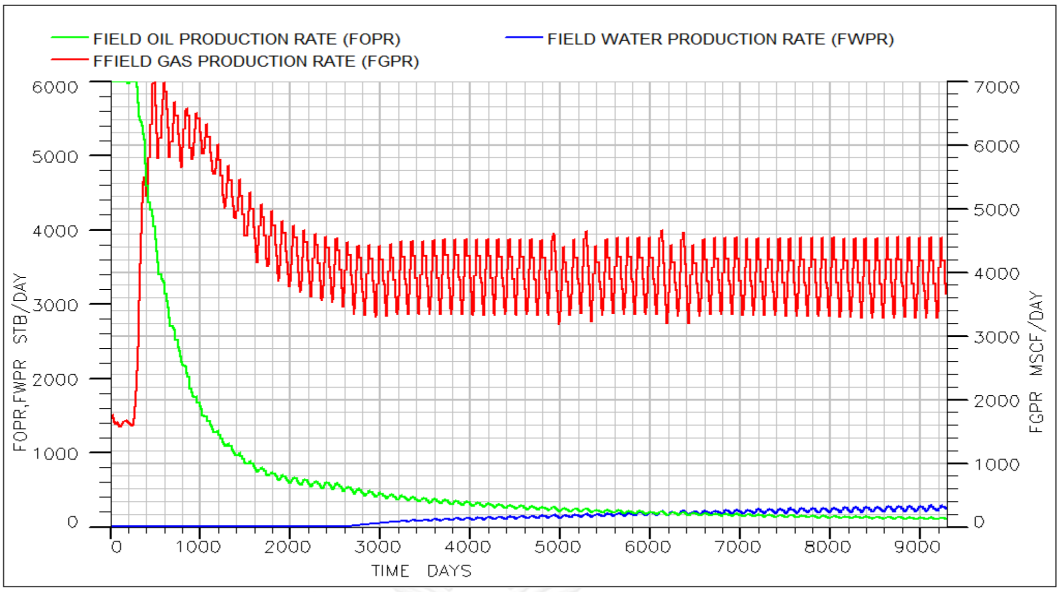

Figure 5.7 Field oil, water and gas production rates by WDAG under base case condition

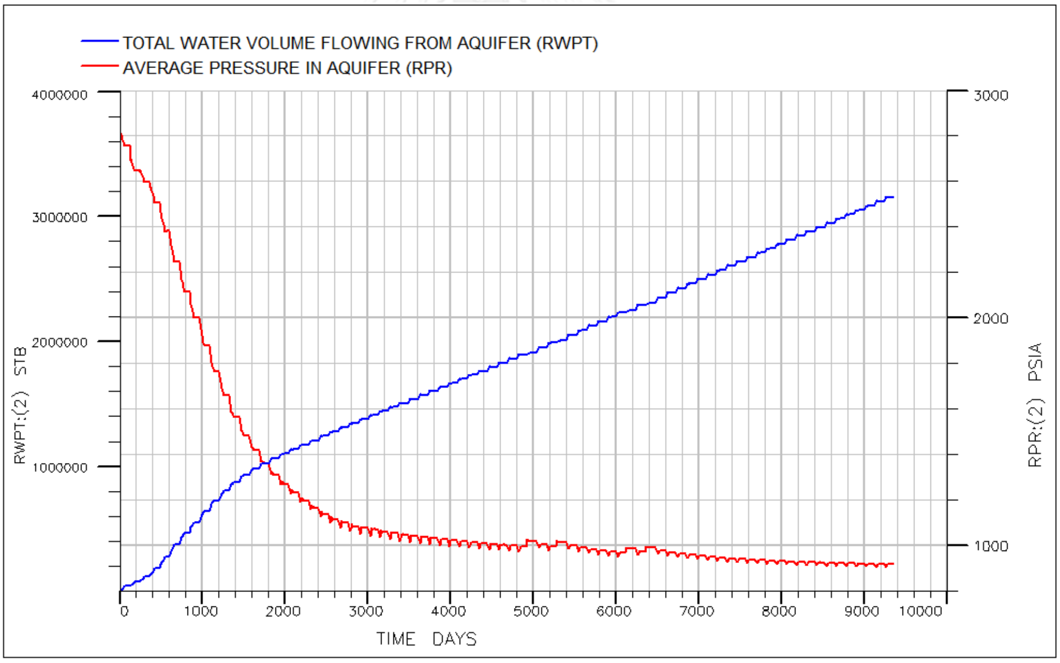

Figure 5.8 Total water volume flowing from aquifer and average pressure in aquifer by WADG under base case condition

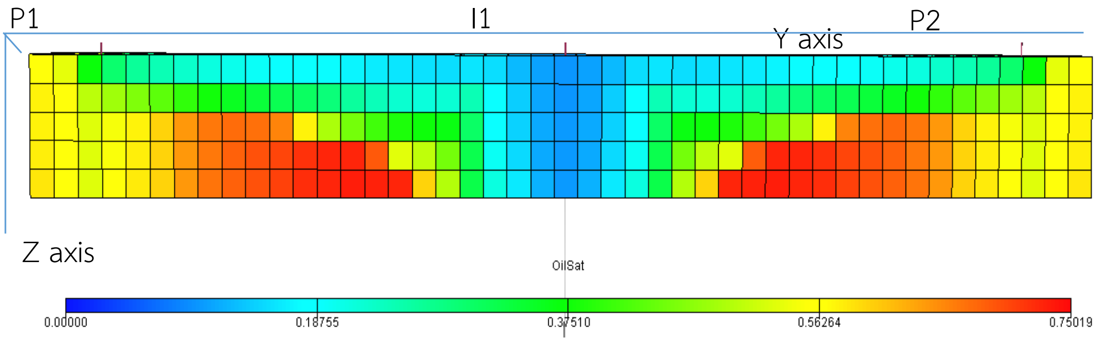

Figure 5.9 Oil saturation profile (mid cross section) after 1 year production by WDAG under base case condition.

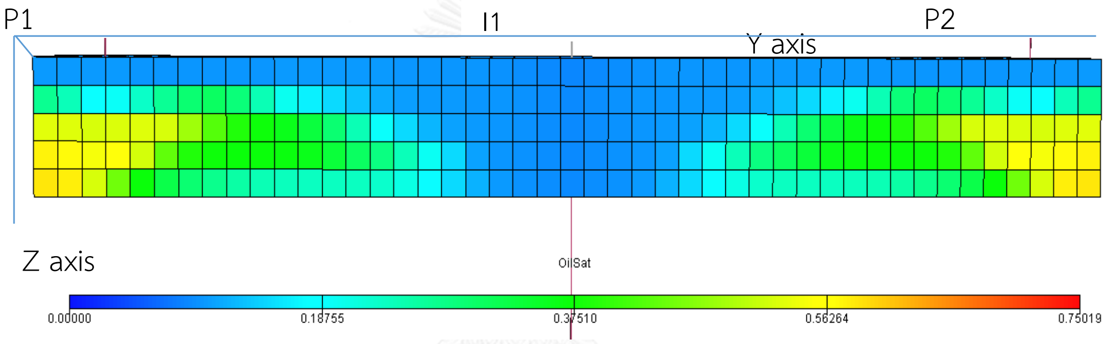

Figure 5.10 Oil saturation profile at mid cross section when water breakthrough by WDAG under base case condition.

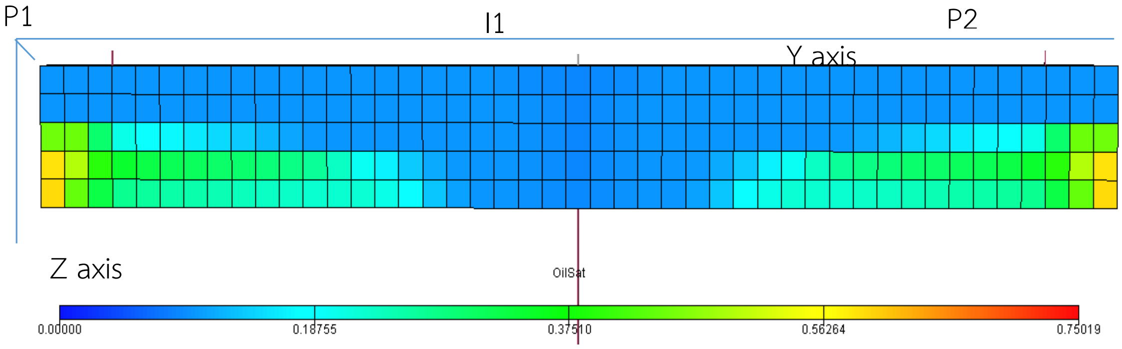

Figure 5.11 Oil saturation profile at the end of production by WDAG under base case condition.

Table 5.1 Summary of results for conventional WAG and WDAG under base case condition.

Base case by method	WAG	WDAG
Recovery factor (%)	74.12	69.20
Cumulative oil production (MMSTB)	7.33	6.85
Cumulative water production (MMSTB)	8.10	1.11
Cumulative water injection (MMSTB)	12.87	0
Cumulative gas production (BCF)	19.18	38.68
Cumulative gas injection (BCF)	17.59	36.96
Barrel of oil equivalent (BOE)	7.33	6.85
Production time (Years)	12.2	25.5

5.2 Effect of different design parameters on WAG and WDAG

The design parameters in conventional WAG are target water injection rate, target gas injection rate and water-gas injection cycle. However, the water injection rate slightly impacts the performance of conventional WAG [6], and it is impossible to control water dump rate from aquifer in WDAG. In order to compare the performance between conventional WAG and WDAG, the target water injection rate in conventional WAG is retained at 6000 STB/D while varying the target gas injection rate and water-gas injection cycle.

5.2.1 Effect of target gas injection rate

5.2.1.1 Conventional WAG injection

To evaluate the effect of target gas injection rate on conventional WAG, the target gas injection rate is varied as 2, 4, 8 and 16 MMSCF/D while the water-gas injection cycle is 2:2 (month: month) and the target water injection rate is controlled at 6000 STB/D. Figure 5.12 presents the recovery factor for conventional WAG with different target gas injection rates. A higher target gas injection rate yields slightly better oil recovery factor since injecting at high gas rate maintains the reservoir pressure and improves microscopic oil displacement better than injecting gas at low rate. The highest target gas injection rate of 16 MMSCF/D yields the highest oil recovery factor of 75.86% and 7.74 MMSTB of BOE but it also requires 31.18 BCF of injected gas while injecting gas at 2 MMSCF/D yields 71.82% of oil recovery factor and 7.46 MMSTB of BOE, it needs 5.04 BCF of injected gas (see Figure 5.13 and Table 5.2). When performing conventional WAG injection at a higher target gas injection rate, it also shows higher total oil production (see Figure 5.16) and requires a smaller amount of injected water (see Figure 5.14) since a higher target gas injection rate hastens the oil production ceasing production sooner (see Figure 5.15).

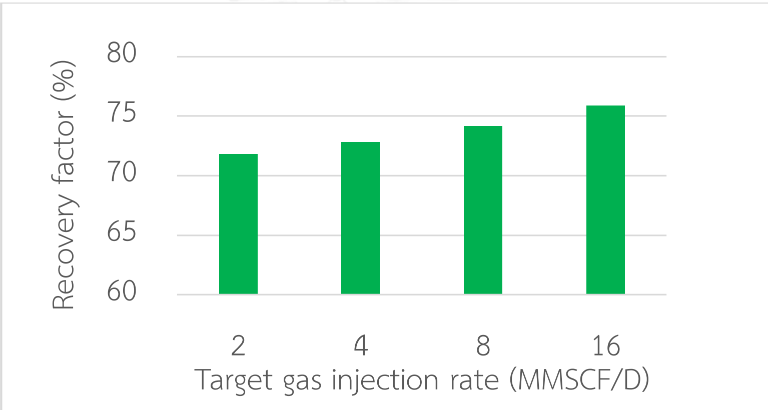

Figure 5.12 Oil recovery factor for conventional WAG (injection cycle 2:2, target gas injection rate 8 MMSCF/D)

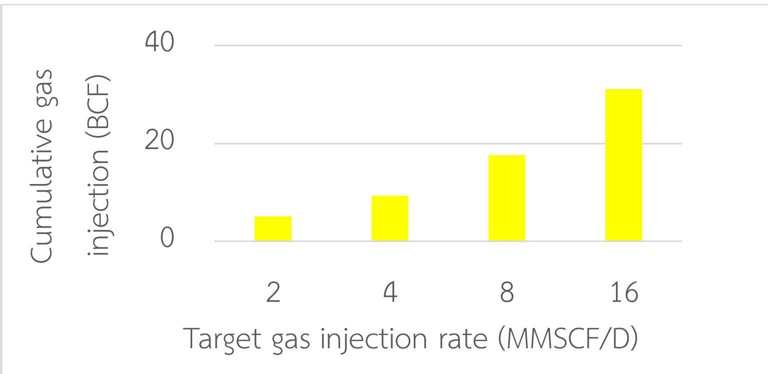

Figure 5.13 Cumulative gas injection for conventional WAG (injection cycle 2:2, target gas injection rate at 8 MMSCF/D)

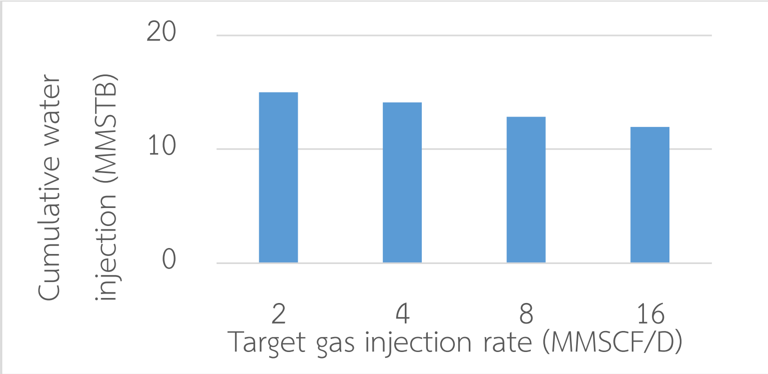

Figure 5.14 Cumulative water injection for conventional WAG (injection cycle 2:2, target gas injection rate at 8 MMSCF/D)

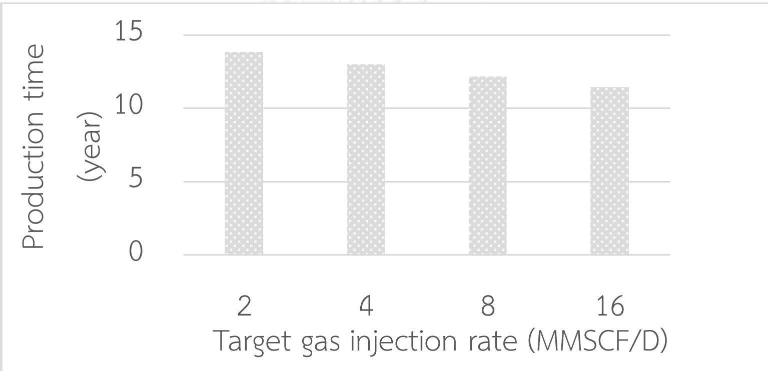

Figure 5.15 Production time for conventional WAG (injection cycle 2:2, target gas injection rate at 8 MMSCF/D)

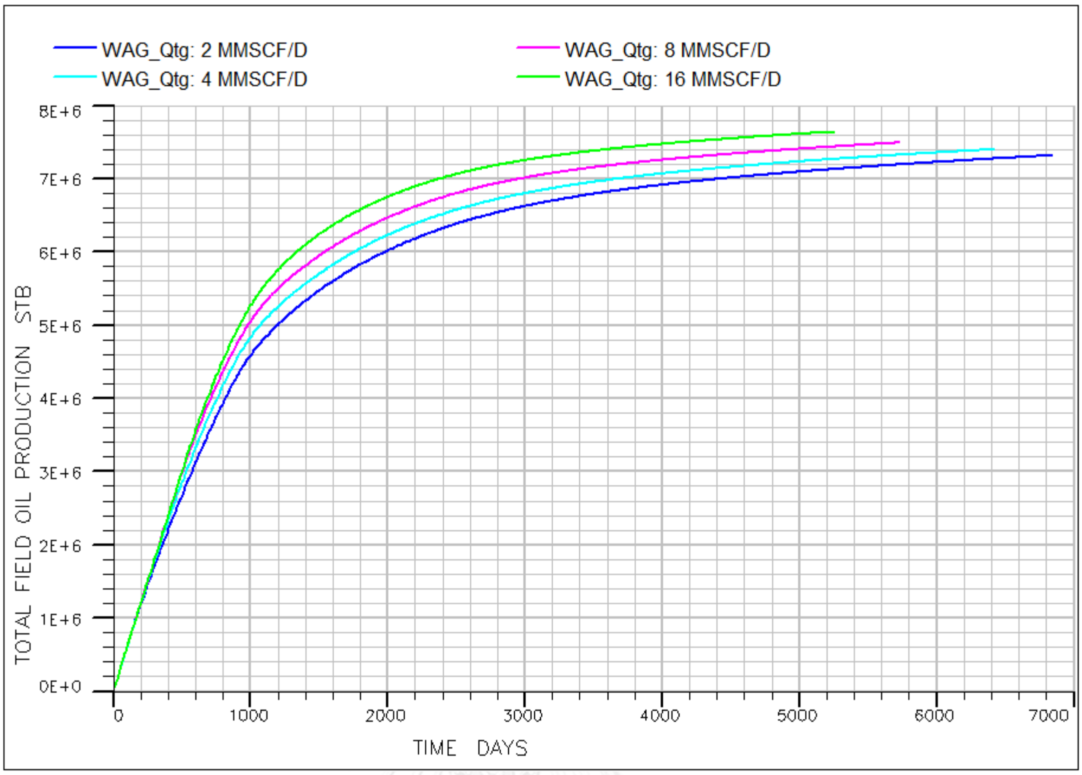

Figure 5.16 Total field oil production by conventional WAG at different target gas injection rates.

5.2.1.2 Water dumpflood alternating gas injection

In WDAG injection, the aquifer is underlying 1500 ft below oil reservoir. When performing WDAG injection, it is impossible to control water dump rate from the aquifer. Thus, the target gas injection rate is one of important parameters to be controlled in WDAG. Figure 5.17 shows recovery factor for WDAG at water-gas injection cycle of 2:2 (month: month). The recovery factors are significantly different between low and high target gas injection rates. A higher target gas injection rate yields much better oil recovery and total oil production (see Figure 5.20) but consumes much higher amount of injected gas (see Figure 5.18). As mentioned in the base case, the average water dump rate from the aquifer in WDAG is lower than controlled target water injection rate in conventional WAG, leading to low macroscopic oil displacement due to water dumping. If the target gas injection rate is low, the microscopic displacement efficiency due to gas injection will be inferior and the total displacement efficiency will be lower than performing of WDAG at high target gas injection rate. When there is sufficient amount of gas, injecting gas at 16 MMSCF/D hastens production time (see Figure 5.19) and yields 73.13 % of recovery factor and 7.46 MMSTB of BOE which are only 2.73% (RF) and 0.28 MMSTB (BOE) less than that for conventional WAG while WDAG does not obligate any water injection system from the surface.

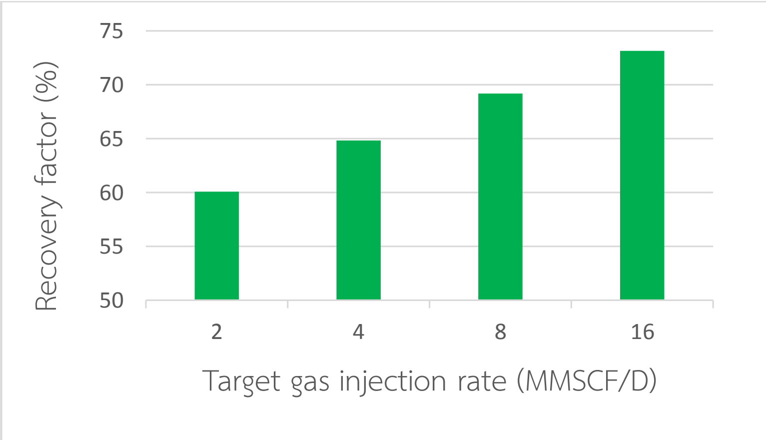

Figure 5.17 Oil recovery factor for WDAG (injection cycle 2:2, target gas injection rate 8 MMSCF/D)

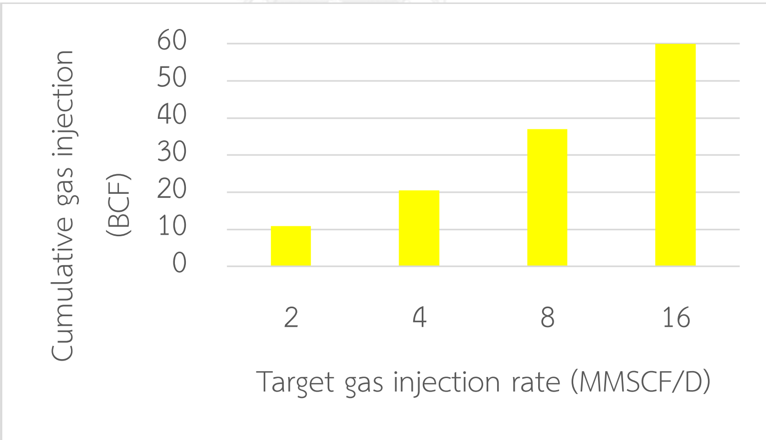

Figure 5.18 Cumulative gas injection for WDAG (injection cycle 2:2, target gas injection rate 8 MMSCF/D)

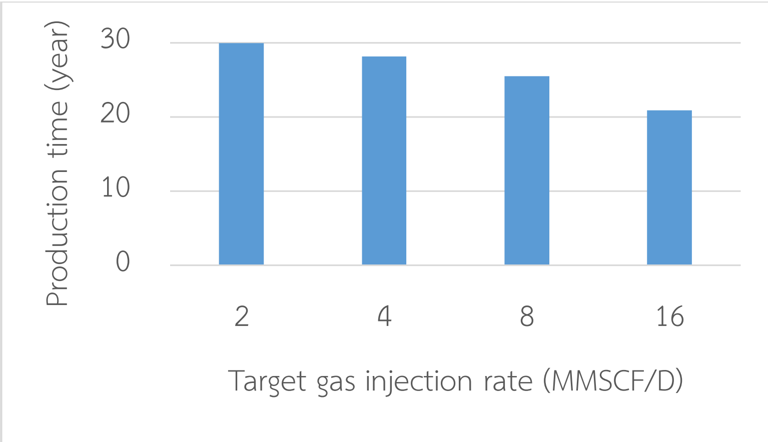

Figure 5.19 Production time for WDAG (injection cycle 2:2, target gas injection rate 8 MMSCF/D)

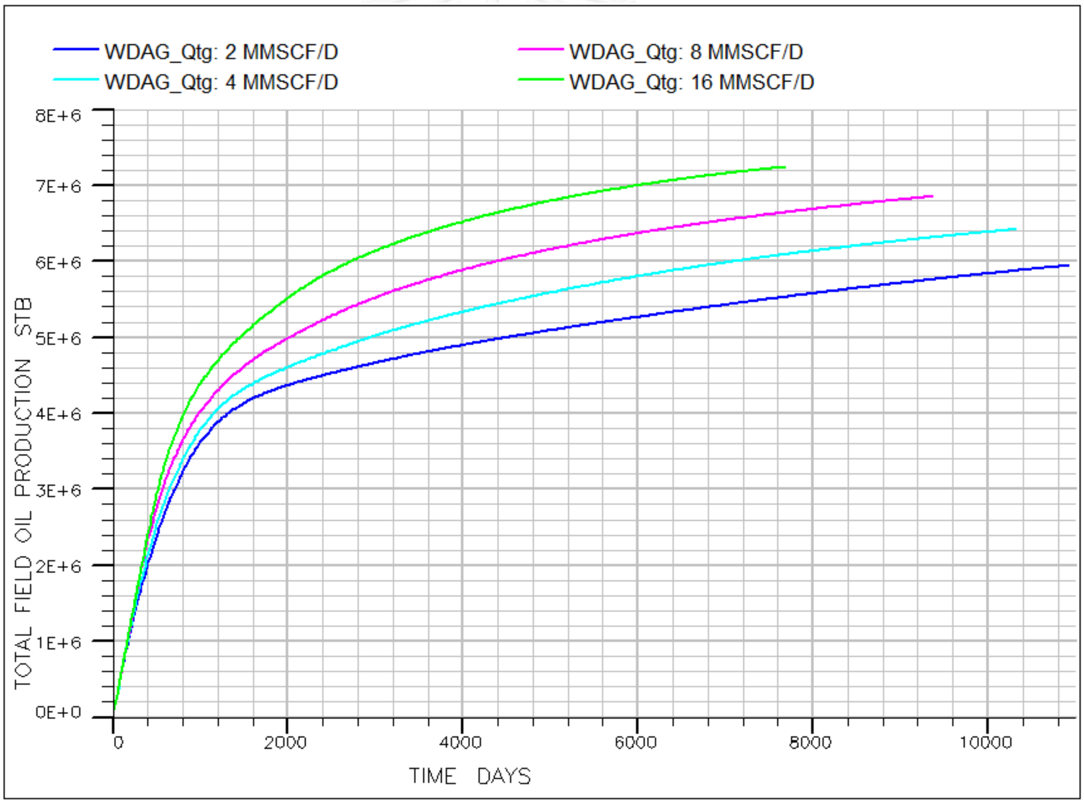

Figure 5.20 Total field oil production by WDAG at different target gas injection rates.

5.2.2 Effect of water-gas injection cycle

5.2.2.1 Conventional WAG injection

Figure 5.21 illustrates oil recovery factor of conventional WAG injection with different water-gas injection cycles which are 1:1, 2:2, 3:1, 3:2, 3:3 (month: month) while the target gas and water injection rate is retained at 8 MMSCF/D and 6000 STB/D, respectively. Water-gas injection cycle slightly affects the performance of conventional WAG.

The recovery factors are not much different between the cases. However, the water-gas injection cycles of 1:1, 2:2 and 3:3 show higher oil recovery factor than the cases of 2:1. 3:1 and 3:2 since a longer time for water injection in each cycle causes earlier water breakthrough (for example, when using injection cycle of 2:2, the water breakthrough occurs earlier than the case of 2:1). This causes water cut to increase rapidly after water breakthrough and reach the maximum water cut for production well earlier. Thus, the cases of 2:1, 3:1 and 3:2 require less amount of injected water than the cases of 1:1, 2:2 and 3:3 (see Figure 5.23). The water-gas injection cycle of 3:3 can produce the oil production better than the cases of 1:1 and 2:2 due to the improvement of sweep efficiency when injecting a large slug size of water and gas. Comparison of cumulative oil production is shown in Figure 5.24.

The cumulative gas injection for conventional WAG is shown in Figure 5.22. The water-gas injection cycles of 1:1, 2:2 and 3:3 require greater amount of injected gas than the cases of 2:1, 3:1 and 3:2 since a longer time for gas injection consumes more gas. The water-gas injection cycles of 1:1, 2:2 and 3:3 yields better microscopic displacement of the oil and improves recovery factor. In addition, the water-gas injection cycle of 1:1 and 3:3 month yields the highest BOE of 7.62 MMSTB (see Table 5.2).

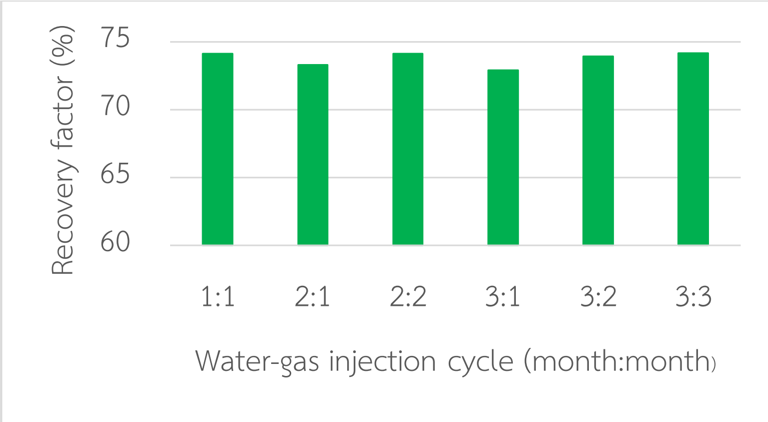

Figure 5.21 Oil recovery factor for conventional WAG (target gas injection rate 8 MMSCF/D).

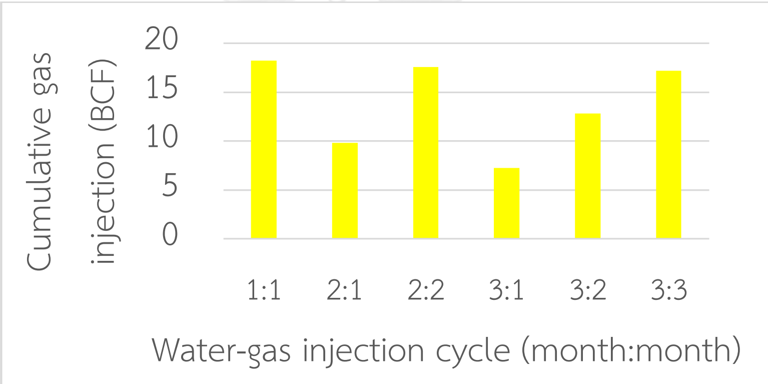

Figure 5.22 Cumulative gas injection for conventional WAG (target gas injection rate 8 MMSCF/D).

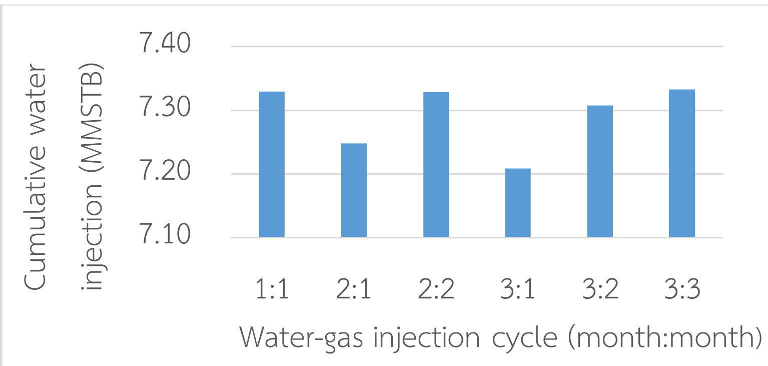

Figure 5.23 Cumulative water injection for conventional WAG (target gas injection rate 8 MMSCF/D).

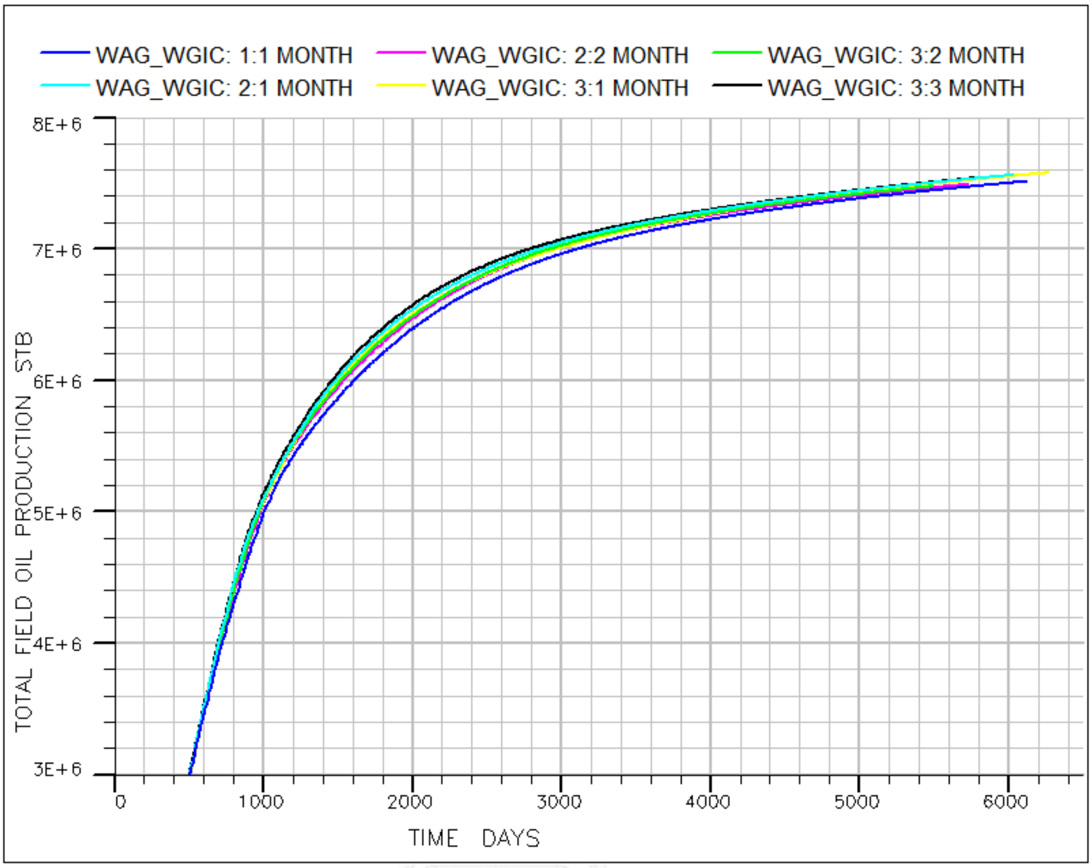

Figure 5.24 Total field oil production by conventional WAG at different water-gas injection cycles.

5.2.2.2 Water dumpflood alternating gas injection

The performance of WDAG injection from underlying aquifer (1500 ft distance from the oil reservoir) is evaluated under different water-gas injection cycles. Recovery factors for WDAG injection are shown in Figure 5.25. The results show that water–gas injection cycle strongly affects the performance of WDAG. The injection cycle of 1:1 (month: month) yields the highest recovery factor and the highest total oil production. Comparison of total field oil production by WDAG at different water-gas injection cycles is shown in Figure 5.27. A lower ratio of water-gas injection cycle yields better oil recovery factor since it can utilize the benefits of gas displacement while the amount of water flows from aquifer is limited and the water displacement is poorer than the case of conventional WAG injection.

The case of water-gas injection cycle of 1:1 also requires the highest amount of injected gas (see Figure 5.26). As depicted in Table 5.3, water-gas injection cycle of 1:1 yields the highest BOE (7.21 MMSTB) while water-gas injection cycle of 3:1 gives the worst BOE (6.65 MMSTB). Thus, water-gas injection cycle of 1:1 is the best operation condition for WDAG.

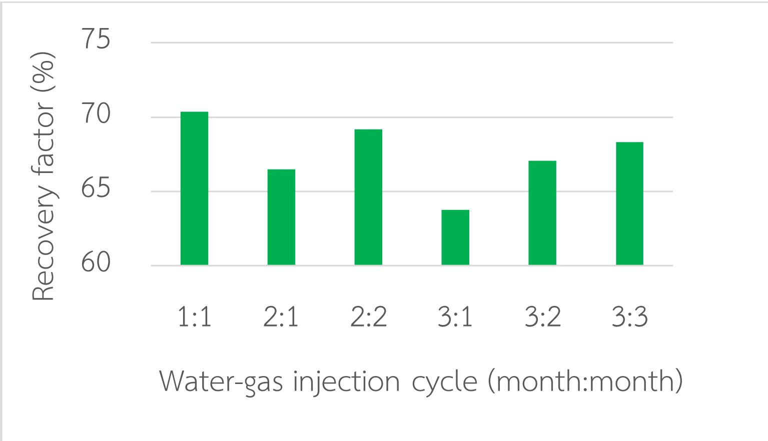

Figure 5.25 Oil recovery factor for WDAG (target gas injection rate 8 MMSCF/D).

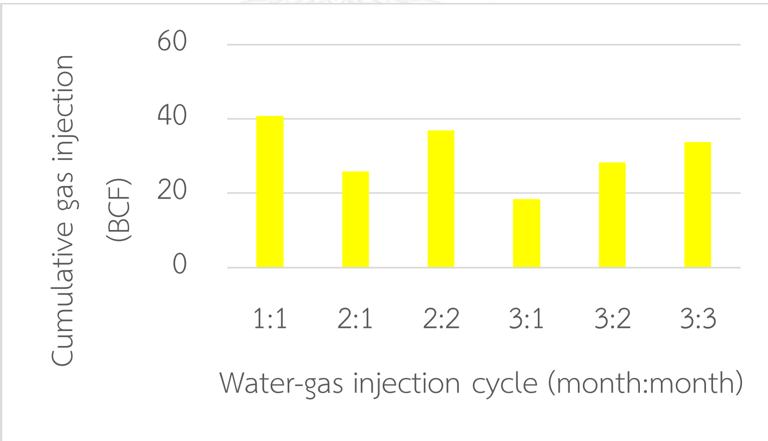

Figure 5.26 Cumulative gas injection for WDAG (target gas injection rate 8 MMSCF/D).

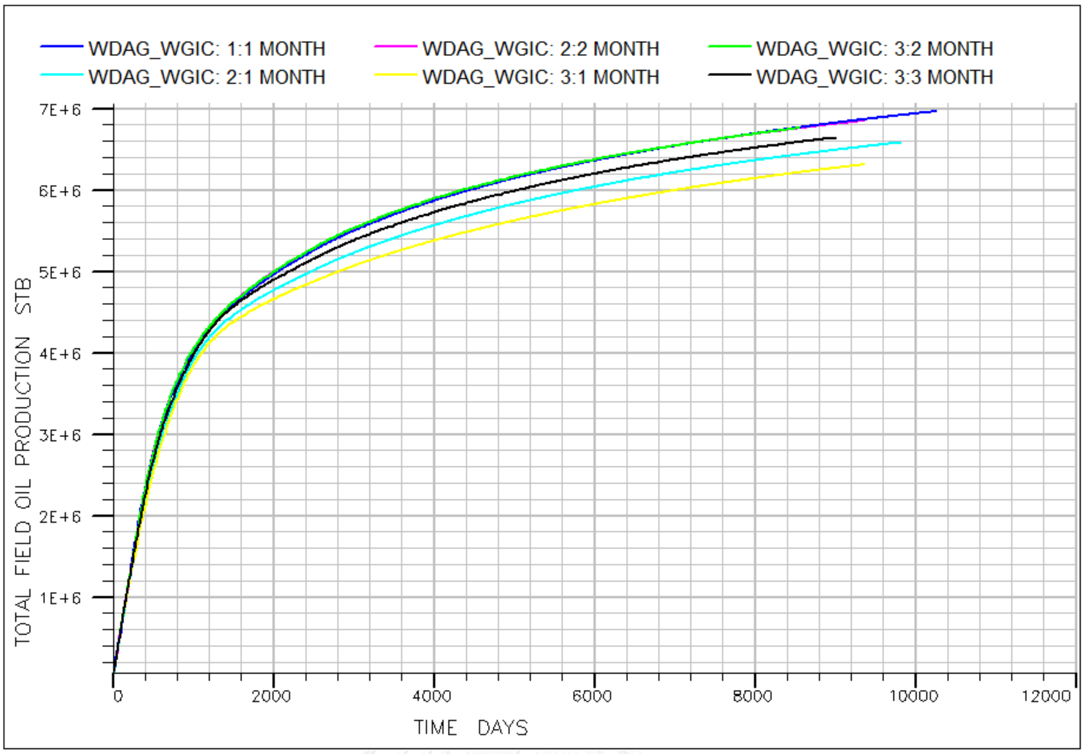

Figure 5.27 Total field oil production by WDAG at different water-gas injection cycles.

5.2.3 Summary on effect of target gas injection rate and water-gas injection cycle

5.2.3.1 Conventional WAG injection

Figure 5.28 shows the recovery factor for conventional WAG injection at different target gas injection rates and water-gas injection cycles. For all target gas injection rates, the recovery factors of water-gas injection cycles of 1:1 are quite the same as 2:2 and 3:3 month and shows slightly higher recovery factors than other ratios. However, the 1:1 ratio requires the highest amount of injected gas but less amount of injected water. For all water-gas injection cycles, a higher target gas injection rate yields slightly better oil recovery factor but requires higher amount of injected gas (see Figure 5.29). Thus, the favorable conditions for conventional WAG are 16 MMSCF/D of target gas injection rate and 1:1, 2:2, 3:3 of water-gas injection cycles. However, if there is limited amount of available gas, injecting at 2 MMSCF/D and 1:1 month of water-gas injection cycle yields 7.47 MMSTB of BOE and consumes only around 5 BCF of injected gas while injecting at 16 MMSCF/D and 1:1month of water-gas injection cycle yields

7.72 MMSTB of BOE but requires much more injected gas, about 32.87 BCF (see Table 5.2). Since the target water injection is retained at 6000 STB/D, the cumulative water injection between the cases are not much different, and conventional WAG requires approximately 14.5 MMSTB of injected water (see Figure 5.30). It may causes problems when there is insufficient amount of water or costly water injection system.

The recovery factors for conventional WAG at water-gas injection cycles of 1:1, 2:2 and 3:3 are about the same when applying target gas injection rate of 16 MMSCF/D. However, water-gas injection cycle of 1:1 yields the highest BOE of 7.72 MMSTB. Thus, the favorable conditions for conventional WAG are water-gas injection cycle of 1:1 and target gas injection rate of 16 MMSCF/D.

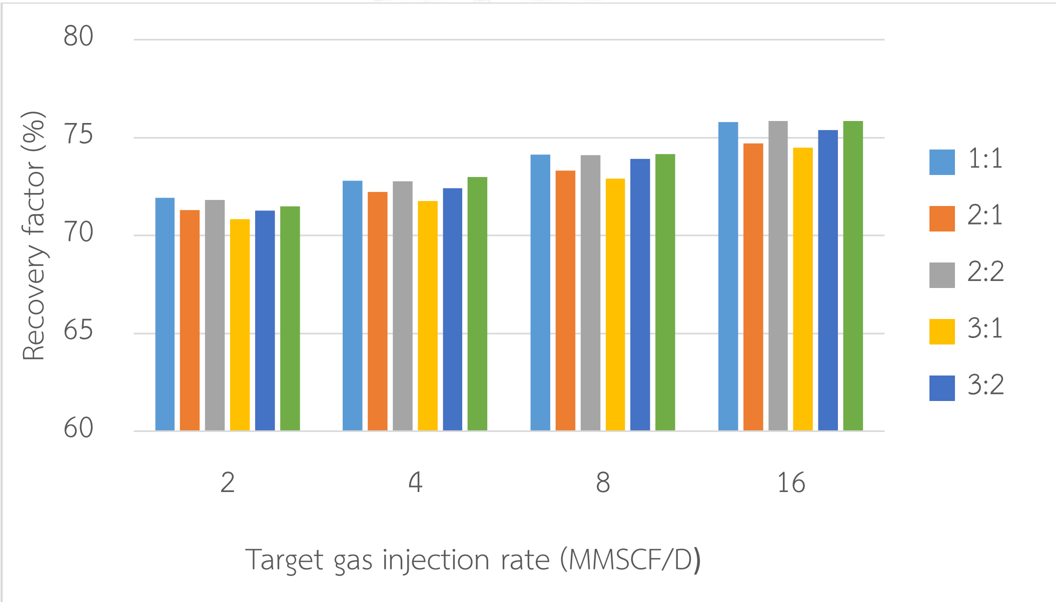

Figure 5.28 Oil recovery factor for conventional WAG

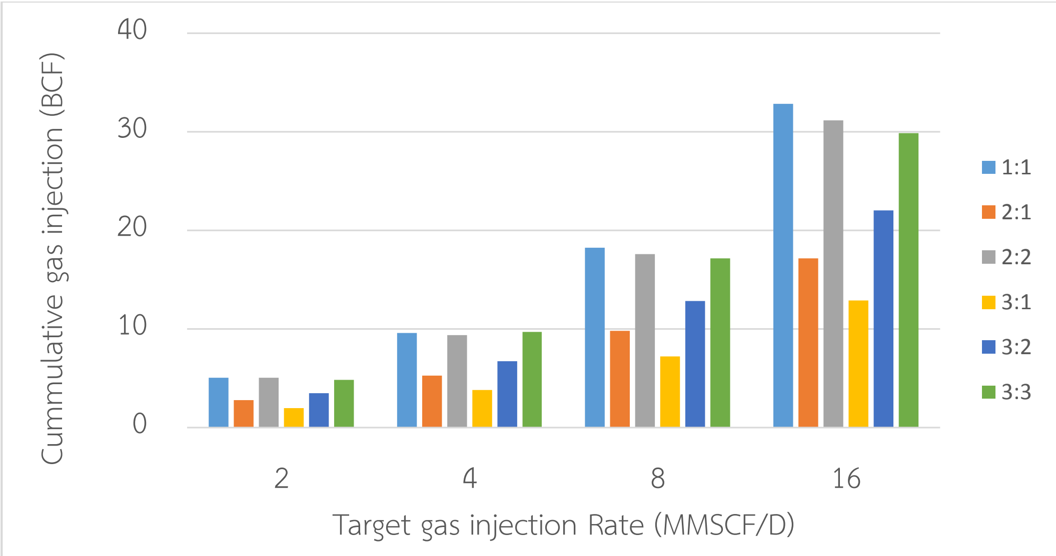

Figure 5.29 Cumulative gas injection for conventional WAG

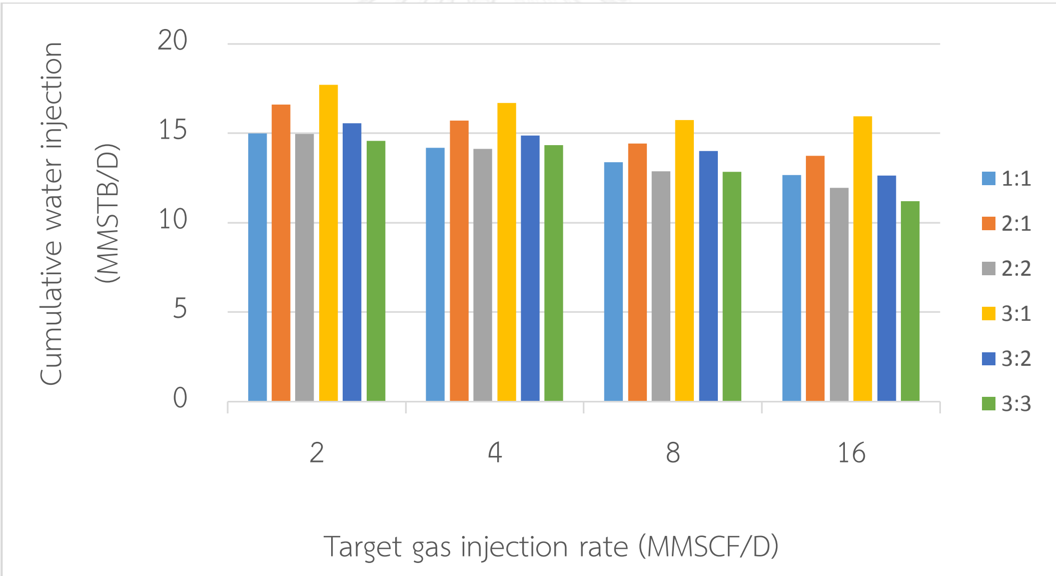

Figure 5.30 Cumulative water injection for conventional WAG

Table 5.2 Summary of results for conventional WAG injection

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	W_I (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (Years)
1:1	2	71.93	7.11	9.66	15.01	7.21	5.04	7.47	13.85
	4	72.80	7.20	9.05	14.20	11.62	9.58	7.54	13.19
	8	74.13	7.33	8.54	13.39	20.00	18.24	7.62	12.66
	16	75.81	7.50	8.15	12.66	34.19	32.87	7.72	12.16
2:1	2	71.31	7.05	11.01	16.62	4.64	2.76	7.36	11.51
	4	72.23	7.14	10.26	15.73	7.04	5.29	7.43	11.03
	8	73.31	7.25	9.22	14.43	11.30	9.83	7.49	10.38
	16	74.71	7.39	8.80	13.76	18.28	17.15	7.57	10.16

Table 5.2 Summary of results for conventional WAG injection (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	W_I (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (Years)
2:2	2	71.82	7.10	9.69	14.98	7.18	5.04	7.46	13.84
	4	72.78	7.20	8.92	14.12	11.42	9.36	7.54	12.99
	8	74.12	7.33	8.10	12.87	19.18	17.59	7.59	12.16
	16	75.86	7.50	7.45	11.94	32.42	31.18	7.71	11.45
3:1	2	70.83	7.00	12.00	17.70	3.75	1.98	7.30	11.01
	4	71.77	7.10	11.14	16.71	5.44	3.82	7.37	10.60
	8	72.91	7.21	10.35	15.75	8.62	7.23	7.44	10.22
	16	74.50	7.37	10.75	15.95	13.91	12.89	7.54	10.55

Table 5.2 Summary of results for conventional WAG injection (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	W_I (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (Years)
3:2	2	71.29	7.05	10.14	15.56	5.41	3.48	7.37	12.00
	4	72.42	7.16	9.61	14.87	8.47	6.71	7.45	11.56
	8	73.91	7.31	9.01	14.02	14.24	12.82	7.54	11.11
	16	75.38	7.45	7.94	12.64	22.92	22.04	7.60	10.30
3:3	2	71.49	7.07	9.28	14.57	6.96	4.86	7.42	13.43
	4	72.99	7.22	9.32	14.34	11.61	9.71	7.53	13.34
	8	74.16	7.33	8.00	12.86	18.89	17.17	7.62	12.00
	16	75.85	7.50	6.87	11.22	30.72	29.87	7.64	10.86

5.2.3.2 Water dumpflood alternating gas injection

In WDAG, for all target gas injection rates, the water-gas injection cycle of 1:1 month gives the highest oil recovery factor (see Figure 5.31). For all of water-gas injection cycles, a higher target gas injection rate gives significantly higher oil recovery factor but also requires a higher amount of cumulative gas injection (see Figure 5.32). As depicted in Table 5.3, WDAG yields the highest BOE (7.30 MMSTB) when performing at 16 MMSCF/D of target gas injection rate and 1:1 month of injection cycle. Thus, the favorable conditions for WDAG are water-gas injection cycle of 1:1 month and target gas injection rate of 16 MMSCF/D. The highest BOE in conventional WAG is 7.50 MMSTB which is only 0.2 MMSTB more than that for WDAG. In the case that the field has a lot of gas but needs costly water injection system, WDAG may be an alternative to conventional WAG.

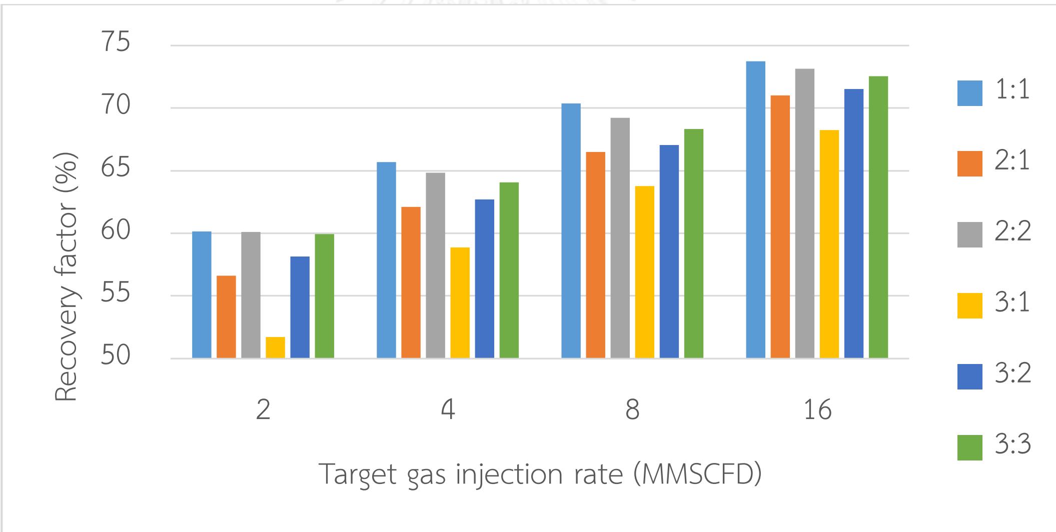

Figure 5.31 Oil recovery factor for WDAG

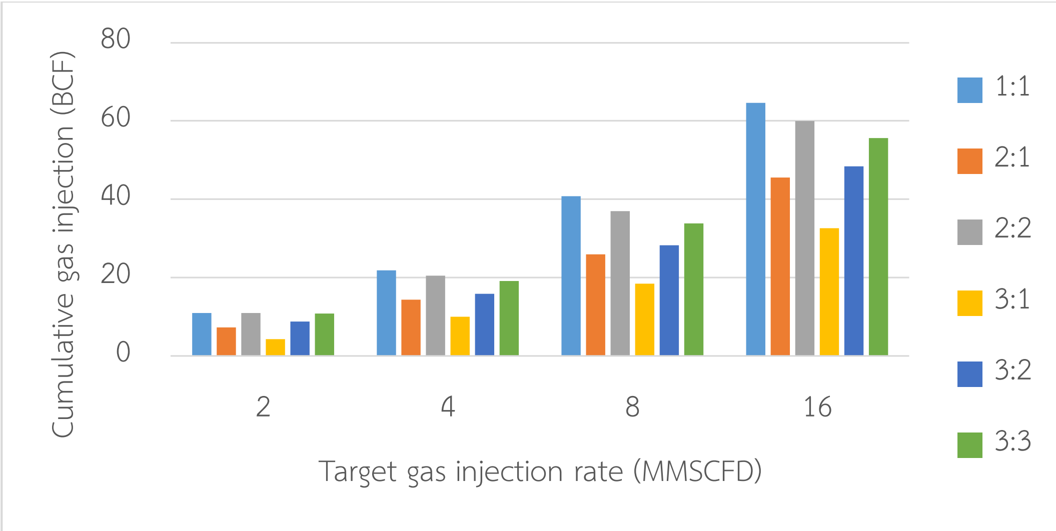

Figure 5.32 Cumulative gas injection for WDAG

Table 5.3 Summary of results for WDAG injection from underlying aquifer, distance 1500ft

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	60.15	5.95	1.21	13.08	10.92	6.31	30
	4	65.7	6.5	1.56	23.74	21.84	6.82	30
	8	70.38	6.96	1.56	42.32	40.8	7.21	28.05
	16	73.74	7.29	1.2	65.73	64.64	7.47	22.46
2:1	2	56.59	5.6	0.88	9.56	7.26	5.98	30
	4	62.12	6.15	1.13	16.35	14.3	6.49	29.53
	8	66.51	6.58	1.12	27.72	25.93	6.88	26.82
	16	71.01	7.03	1.05	46.98	45.59	7.26	23.86

Table 5.3 Summary of results for WDAG injection from underlying aquifer, distance 1500ft (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	60.09	5.94	1.13	13.06	10.92	6.30	29.92
	4	64.85	6.42	1.24	22.41	20.43	6.75	28.13
	8	69.2	6.85	1.11	38.68	36.96	7.14	25.5
	16	73.13	7.24	0.94	61.27	59.94	7.46	20.9
3:1	2	51.73	5.12	0.26	6.78	4.22	5.55	23.29
	4	58.88	5.82	0.69	12.25	9.98	6.20	27.55
	8	63.76	6.31	0.71	20.52	18.46	6.65	25.57
	16	68.26	6.75	0.74	34.43	32.62	7.05	22.94

Table 5.3 Summary of results for WDAG injection from underlying aquifer, distance 1500ft (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	58.16	5.75	1	10.93	8.76	6.11	30
	4	62.7	6.2	1	17.93	15.84	6.55	27.38
	8	67.06	6.63	0.91	30.19	28.31	6.94	24.5
	16	71.53	7.08	0.84	50.05	48.44	7.35	21.2
3:3	2	59.95	5.93	1.07	13.04	10.82	6.30	29.87
	4	64.08	6.34	1.04	21.15	19.1	6.68	26.4
	8	68.33	6.76	0.89	35.69	33.8	7.08	23.42
	16	72.52	7.17	0.77	57.18	55.65	7.43	19.5

5.3 Sensitivity analysis of WDAG

The aquifer properties which are pore volume ratio of the aquifer to the oil reservoir and aquifer locations play an important role in WDAG since they affect the flow ability from the aquifer, then impact on the macroscopic displacement efficiency due to water. The sensitivity analysis of aquifer properties is combined with the study of target gas injection rate and water-gas injection cycle to evaluate the best condition for WDAG. In addition, the comparison between conventional WAG and WDAG is also presented in this section.

5.3.1 Volumetric ratio of aquifer to oil reservoir

In reservoir model, the aquifer is 500 ft thick and located 1000 feet below the reservoir while the oil zone thickness is 50 ft. Varying the porosity in the aquifer from 10.75% to 21.5% and 43%, the volumetric ratio of aquifer to oil reservoir becomes 5 PV, 10 PV and 20 PV, respectively. The summary of recovery factor and cumulative gas injection for each volumetric ratio of aquifer to oil, the comparison among volumetric ratios of aquifer to oil reservoir and the comparison between WDAG injection and conventional WAG injection are shown in this section.

5.3.1.1 Water dumpflood alternating gas injection

When the aquifer is 5 times the reservoir pore volume, a small cumulative amount of water can enter the oil reservoir. In this case, the microscopic displacement due to the gas could dominate the displacement efficiency. If there is a limit on amount of gas injection, there is insufficient amount of displacing fluids to displace the oil. Thus, injecting at low target gas injection rate shows significantly lower oil recovery factor than performing WDAG at high target gas injection rate (see Figure 5.33). Because of water limitation from aquifer, it is better to perform WDAG with high target gas injection rate and low water-gas injection cycle to take the advantage of gas displacement. Although it is not necessary to inject water from surface, it requires high amount of cumulative gas injection to yield the highest oil recovery factor (see Figure 5.34). The summary of results for WDAG injection from the aquifer which is 5 times the reservoir pore volume is shown in Table 5.4. WDAG yields the highest recovery factor (73.99 %) at 16 MMSCF/D of target gas injection rate and 1:1 month of water-gas injection cycle with the highest BOE of is 7.53 MMSTB. However, the cumulative gas injection for the highest target gas injection rate is approximately six times that for the lowest target gas injection rate.

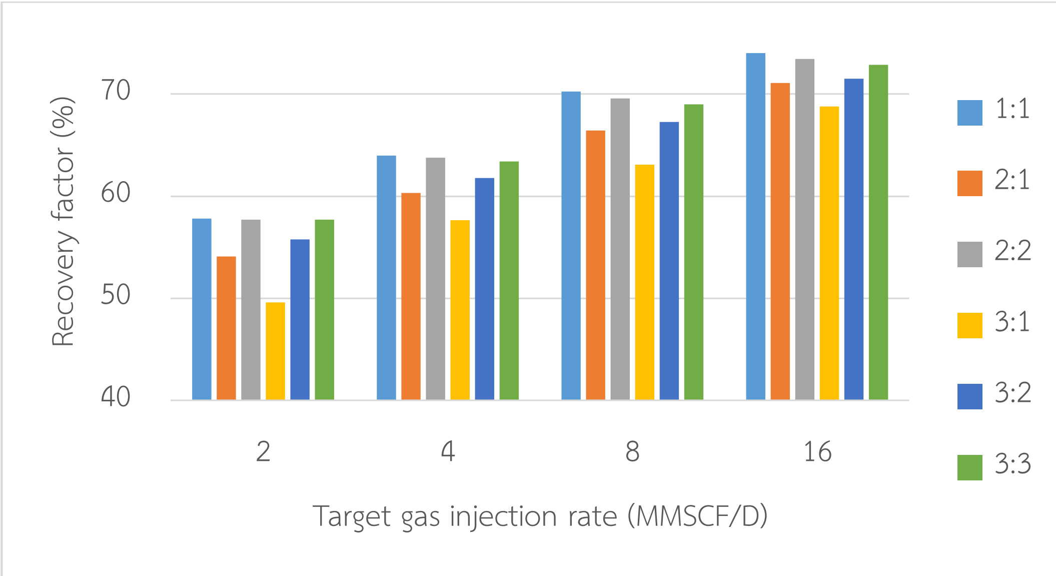

Figure 5.33 Recovery factor for WDAG (5 PV aquifer).

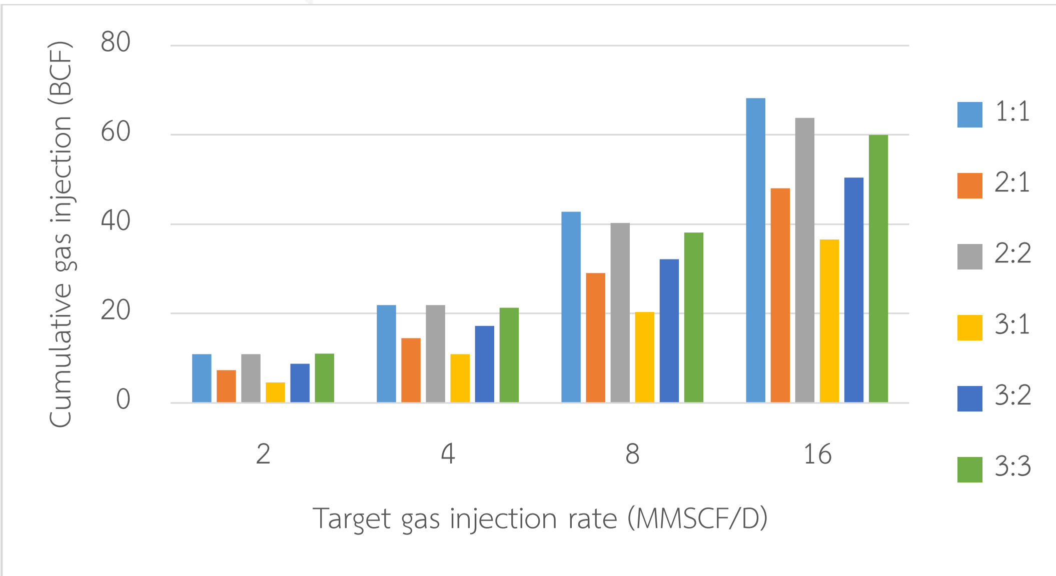

Figure 5.34 Cumulative gas injection for WDAG (5 PV aquifer).

Table 5.4 Summary of results for WDAG injection from 5 PV underlying aquifer.

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	57.80	5.72	0.58	13.21	10.92	6.10	30.00
	4	64.00	6.33	0.77	23.89	21.83	6.67	30.00
	8	70.22	6.95	0.89	44.41	42.82	7.21	29.39
	16	73.99	7.32	0.72	69.42	68.16	7.53	23.61
2:1	2	54.09	5.35	0.36	9.67	7.26	5.75	30.00
	4	60.34	5.97	0.52	16.71	14.51	6.34	30.00
	8	66.44	6.57	0.65	30.94	28.98	6.90	30.00
	16	71.09	7.03	0.62	49.56	47.99	7.29	25.08

Table 5.4 Summary of results for WDAG injection from 5PV underlying aquifer (continued).

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	57.72	5.71	0.50	13.19	10.92	6.09	29.92
	4	63.78	6.31	0.62	23.84	21.84	6.64	29.92
	8	69.55	6.88	0.61	42.13	40.31	7.18	27.79
	16	73.45	7.27	0.52	65.34	63.84	7.52	22.20
3:1	2	49.62	4.91	0.06	7.10	4.56	5.33	24.99
	4	57.66	5.70	0.31	13.18	10.92	6.08	29.92
	8	63.10	6.24	0.34	22.53	20.38	6.60	28.20
	16	68.79	6.81	0.44	38.37	36.54	7.11	25.57

Table 5.4 Summary of results for WDAG injection from 5PV underlying aquifer (continued).

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	55.77	5.52	0.42	11.07	8.76	5.90	30.00
	4	61.75	6.11	0.51	19.48	17.28	6.48	29.84
	8	67.28	6.66	0.53	34.11	32.15	6.98	27.79
	16	71.48	7.07	0.44	52.14	50.41	7.36	22.03
3:3	2	57.71	5.71	0.46	13.25	10.98	6.09	30.08
	4	63.40	6.27	0.52	23.43	21.30	6.63	29.38
	8	68.97	6.82	0.47	40.07	38.15	7.14	26.39
	16	72.86	7.21	0.47	61.63	60.02	7.48	20.97

After increasing the porosity in the aquifer to 21.5 %, the pore volume ratio of aquifer to oil reservoir is 10 PV. Figure 5.35 and Figure 5.36 depict recovery factor and cumulative gas injection for WDAG from underlying aquifer for which its volume is 10 times the oil reservoir. The trends in the recovery factor and cumulative gas injection are the same as the ones for 5 PV. As the total volume of water from the aquifer enters the oil reservoir is more than the 5 PV case, the macroscopic sweep due to water dumping is improved. The summary of results for WDAG injection regarding to oil recovery factor, cumulative oil production, cumulative gas production, cumulative gas injection and barrel of oil equivalent are shown in Table 5.5. At the lowest target gas injection rate, WDAG yields the highest recovery factor of 59.92 % at 1:1 month of water-gas injection cycle which is higher than that for the cases of 5 PV. At the highest target gas injection rate and 1:1 month of injection cycle, WDAG yields the highest recovery factor of 73.87 %. This is equivalent to 7.53 MMSTB of BOE, which is about the same as the one for 5 PV.

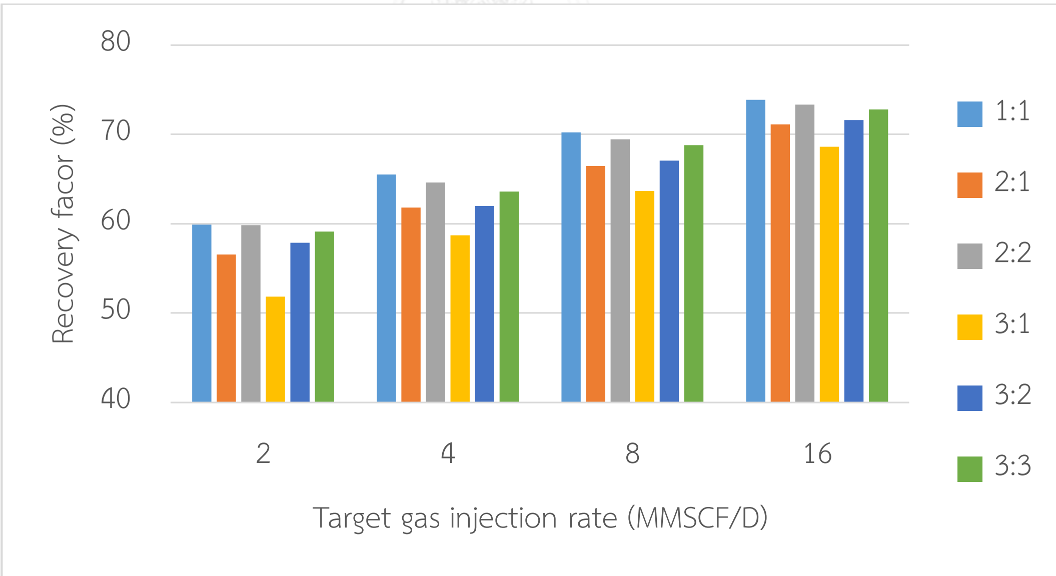

Figure 5.35 Recovery factor for WDAG (10PV aquifer)

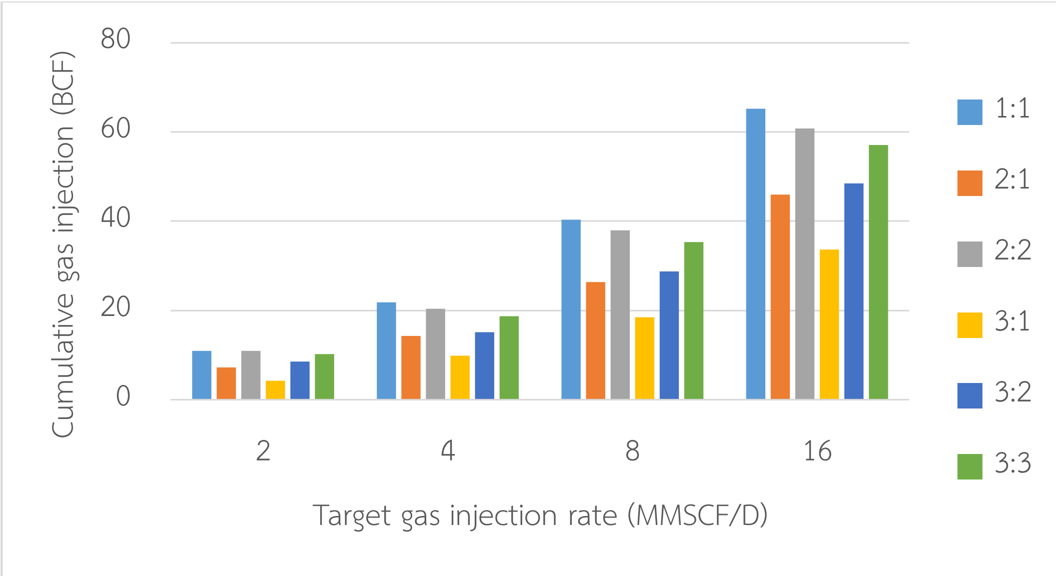

Figure 5.36 Cumulative gas injection for WDAG (10PV aquifer).

Table 5.5 Summary of results for WDAG injection from 10 PV underlying aquifer.

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	59.92	5.93	0.98	13.25	10.92	6.31	30.00
	4	65.48	6.48	1.23	23.94	21.83	6.83	30.00
	8	70.22	6.95	1.14	42.09	40.34	7.24	27.72
	16	73.87	7.31	0.97	66.49	65.17	7.53	22.62
2:1	2	56.56	5.60	0.73	9.70	7.26	6.00	30.00
	4	61.78	6.11	0.92	16.41	14.27	6.47	29.34
	8	66.44	6.57	0.86	28.16	26.34	6.88	27.12
	16	71.14	7.04	0.88	47.15	45.92	7.24	23.92

Table 5.5 Summary of results for WDAG injection from 10 PV underlying aquifer (continued).

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	59.84	5.92	0.91	13.22	10.92	6.30	29.92
	4	64.59	6.39	0.95	22.60	20.47	6.74	28.16
	8	69.45	6.87	0.89	39.81	37.94	7.18	26.16
	16	73.33	7.25	0.79	62.39	60.82	7.52	21.20
3:1	2	51.85	5.13	0.25	6.90	4.28	5.57	23.62
	4	58.68	5.81	0.57	12.25	9.90	6.20	27.25
	8	63.63	6.30	0.58	20.66	18.46	6.66	25.57
	16	68.62	6.79	0.67	35.54	33.65	7.10	23.61

Table 5.5 Summary of results for WDAG injection from 10 PV underlying aquifer (continued).

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	57.84	5.72	0.78	10.94	8.53	6.12	29.44
	4	62.00	6.13	0.73	17.38	15.15	6.51	26.16
	8	67.07	6.64	0.73	30.84	28.81	6.98	24.92
	16	71.60	7.08	0.73	50.20	48.50	7.37	21.22
3:3	2	59.14	5.85	0.78	12.68	10.28	6.25	28.39
	4	63.59	6.29	0.76	20.96	18.72	6.66	25.90
	8	68.77	6.80	0.71	37.28	35.31	7.13	24.44
	16	72.81	7.20	0.71	58.76	57.05	7.49	19.95

For 20 PV cases, the water displacement is improved since the quantities of water being transferred to the reservoir are higher than those in the cases of 5 PV and 10 PV. Thus, the macroscopic displacement of oil due to water is better while the sensitivity to target gas injection rate in WDAG is reduced. For the same water-gas injection cycle, the difference in recovery factors between low and high target gas injection rates is smaller than that of the cases of 5 PV and 10 PV. The trends in the recovery factor and cumulative gas injection are the same as the ones for 5PV and 10PV cases as shown in Figure 5.37 and Figure 5.38. Nevertheless, the performances of the 20PV cases are better as their recovery factors are slightly higher while requiring lower amounts of injected gas. As shown in Table 5.6, the maximum oil recovery is 73.81% when applying WDAG at 16 MMSCF/D of target gas injection rate and 1:1 of water-gas injection cycle, and it obtains 7.55 MMSTB of BOE which is not different from 5 PV and 10 PV.

For all aquifer sizes, 16 MMSCF/D of target gas injection rate and 1:1 month of water-gas injection cycle are favorable condition for WDAG injection.

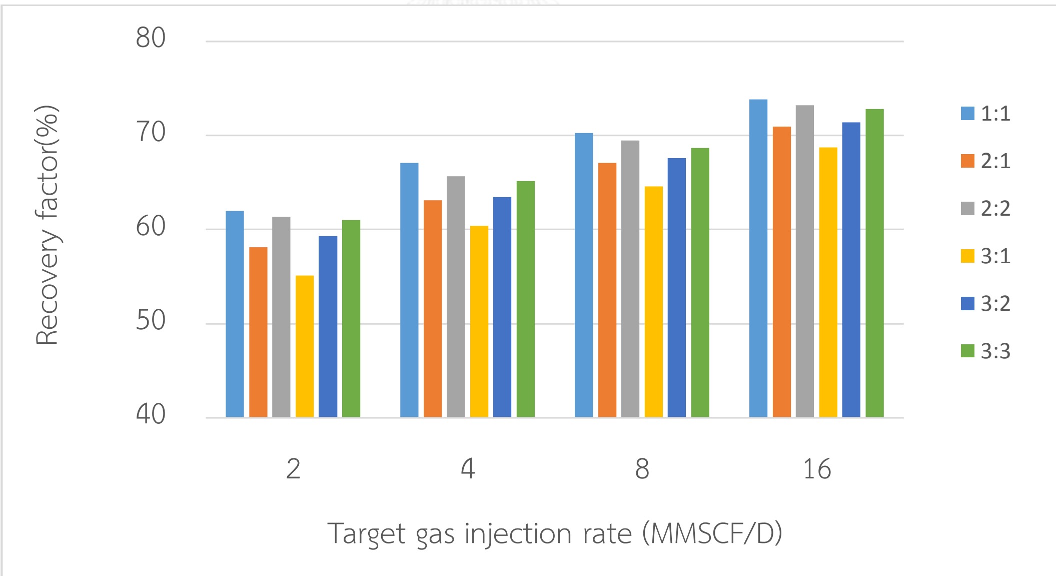

Figure 5.37 Recovery factor for WDAG (20PV aquifer).

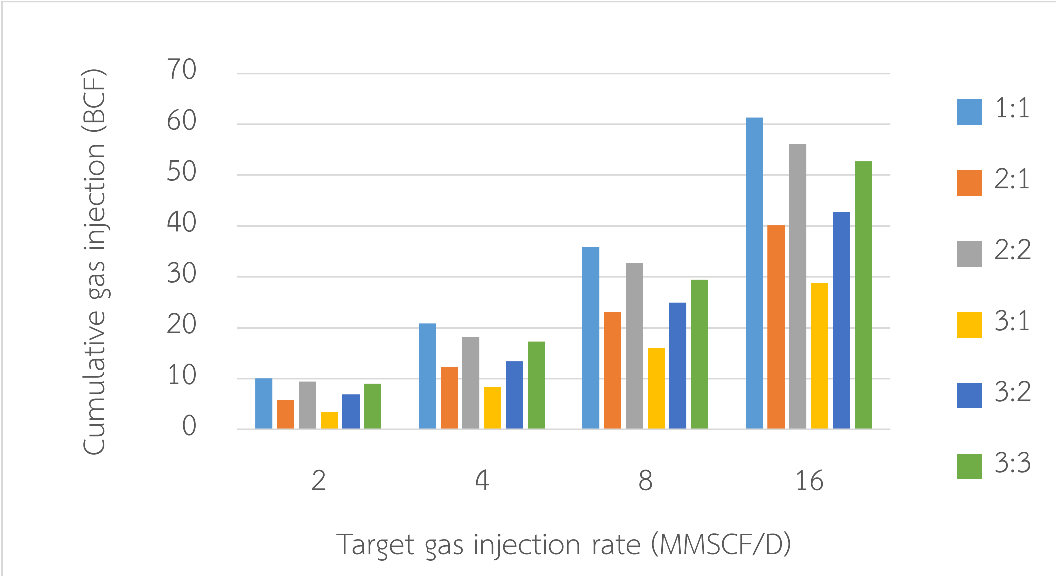

Figure 5.38 Cumulative gas injection for WDAG (20PV aquifer).

Table 5.6 Summary of results for WDAG injection from 20 PV underlying aquifer.

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	61.96	6.13	1.63	12.54	10.10	6.54	27.73
	4	67.10	6.64	2.00	23.10	20.90	7.00	28.70
	8	70.26	6.95	1.64	37.72	35.81	7.27	24.61
	16	73.81	7.30	1.48	62.73	61.26	7.55	21.31
2:1	2	58.14	5.75	1.08	8.35	5.79	6.18	23.88
	4	63.09	6.24	1.46	14.63	12.26	6.64	25.33
	8	67.09	6.64	1.41	25.18	23.03	7.00	23.85
	16	70.96	7.02	1.29	42.03	40.19	7.33	21.13

Table 5.6 Summary of results for WDAG injection from 20 PV underlying aquifer (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	61.34	6.07	1.44	11.85	9.38	6.48	25.84
	4	65.65	6.50	1.60	20.55	18.28	6.87	25.17
	8	69.45	6.87	1.36	34.69	32.65	7.21	22.54
	16	73.21	7.24	1.31	57.71	56.04	7.52	19.57
3:1	2	55.08	5.45	0.64	6.21	3.49	5.90	19.33
	4	60.41	5.98	1.12	10.93	8.40	6.40	23.27
	8	64.61	6.39	1.15	18.38	16.06	6.78	22.29
	16	68.72	6.80	1.11	30.87	28.82	7.14	20.32

Table 5.6 Summary of results for WDAG injection from 20 PV underlying aquifer (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	59.28	5.86	1.17	9.40	6.87	6.29	23.72
	4	63.46	6.28	1.35	15.82	13.45	6.67	23.27
	8	67.58	6.69	1.25	27.12	24.96	7.05	21.63
	16	71.40	7.06	1.19	44.58	42.77	7.37	18.76
3:3	2	61.00	6.04	1.35	11.51	9.01	6.45	24.92
	4	65.17	6.45	1.47	19.60	17.27	6.84	23.91
	8	68.67	6.79	1.19	31.65	29.48	7.15	20.47
	16	72.81	7.20	1.24	54.46	52.68	7.50	18.49

5.3.1.2 Comparison among volumetric ratios of aquifer to oil reservoir

The comparison on recovery factor among volumetric ratios of aquifer to oil reservoir is shown in Figure 5.39 to Figure 5.44. At the lowest target gas injection rate, the volumetric ratio of the aquifer to the oil reservoir significantly affects the recovery factor for all of water-gas injection cycles. In other words, the line of 2 MMSCF/D shows the steepest slope. The slope becomes flatter when increasing target gas injection rate from 2 MMSCF/D to 4 MMSCF/D, 8 MMSCF/D and 16 MMSCF/D. At low target gas injection rates, larger aquifer helps supply the energy to the reservoir, resulting in higher recovery factors. At high target gas injection rates, the energy from gas injection is enough to help recover the oil regardless of aquifer strength. At the highest target gas injection rate, the slope is nearly zero. The volumetric ratio of the aquifer to the oil reservoir shows a minor effect the performance of WDAG.

At the target gas injection of 2 MMSCF/D, the water-gas injection cycle of 3:1 gives the highest difference in recovery factor (ΔRF = 5.46 %) between the cases of 5 PV and 20 PV aquifers since a longer time of water dumpflood from a larger aquifer gives higher amount of water entered the oil reservoir, leading a great difference in recovery factor between a larger and a smaller aquifer.

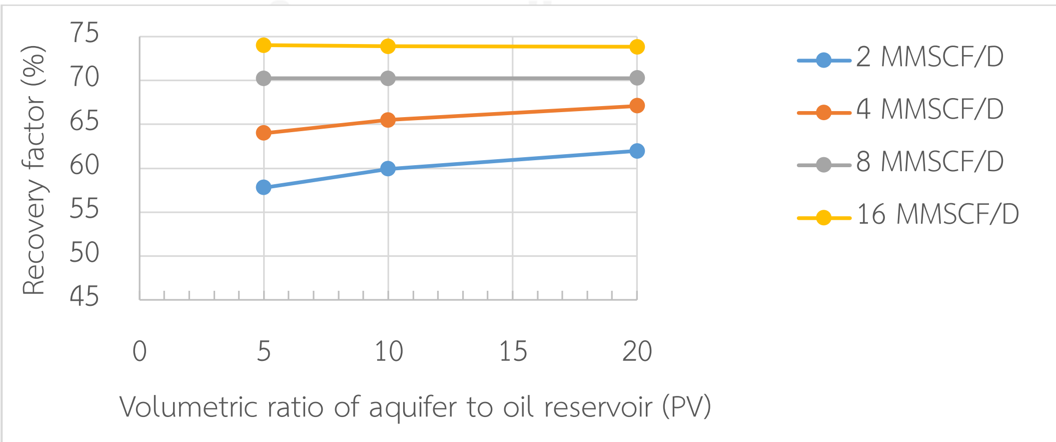

Figure 5.39 WDAG recovery factors for different volumetric ratios of aquifer to oil reservoir in the case of water-gas injection cycle of 1:1 month.

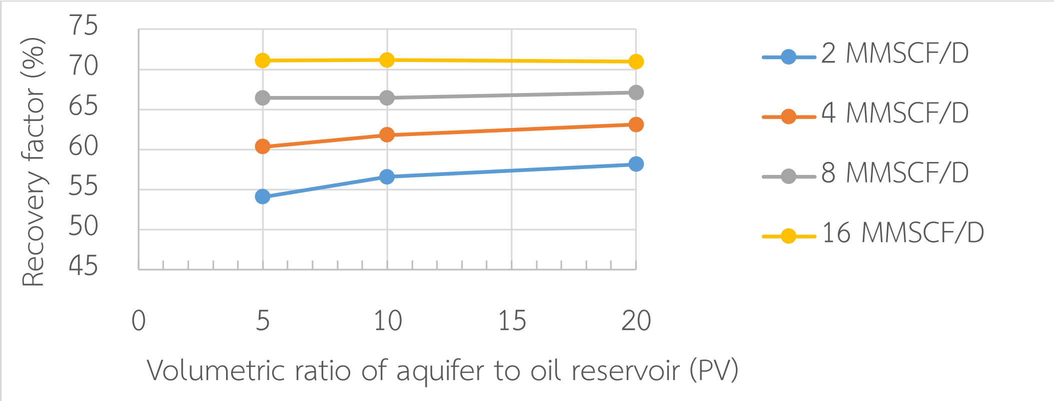

Figure 5.40 WDAG recovery factors for different volumetric ratios of aquifer to oil reservoir in the case of water-gas injection cycle of 2:1 month.

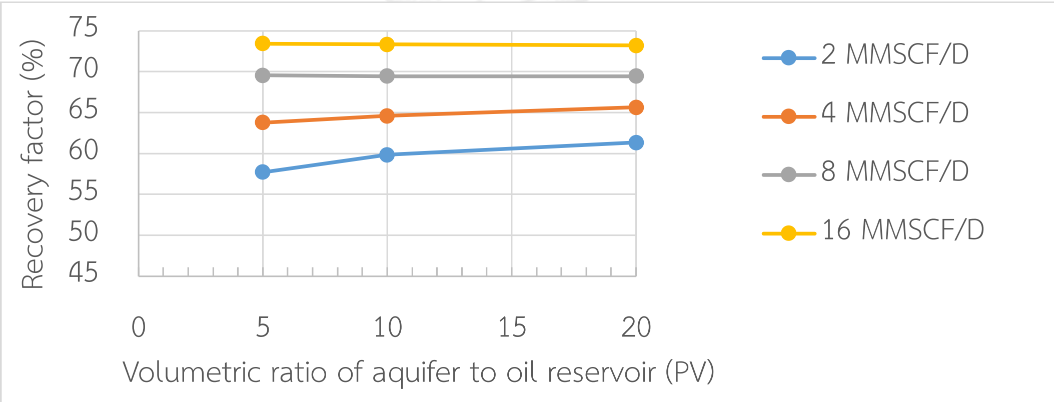

Figure 5.41 WDAG recovery factors for different volumetric ratios of aquifer to oil reservoir in the case of water-gas injection cycle of 2:2 month.

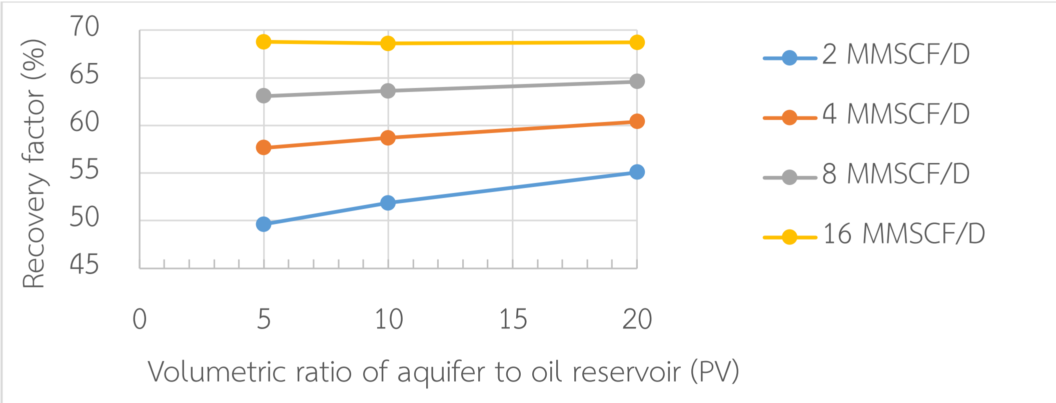

Figure 5.42 WDAG recovery factors for different volumetric ratios of aquifer to oil reservoir in the case of water-gas injection cycle of 3:1 month.

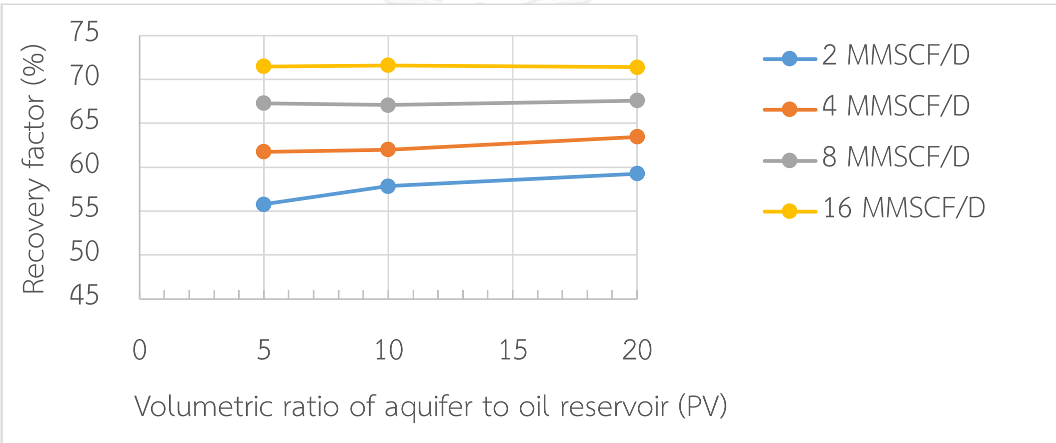

Figure 5.43 WDAG recovery factors for different volumetric ratios of aquifer to oil reservoir in the case of water-gas injection cycle of 3:2 month.

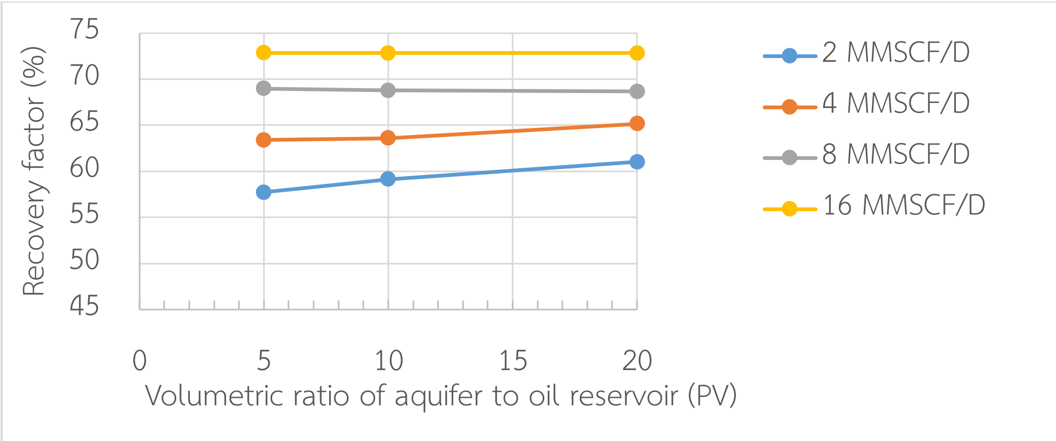

Figure 5.44 WDAG recovery factors for different volumetric ratios of aquifer to oil reservoir in the case of water-gas injection cycle of 3:3 month. .

5.3.1.3 Comparison between WDAG injection and conventional WAG injection

The comparison on recovery factor between conventional WAG and WDAG with different aquifer sizes is depicted in Figure 5.45 to Figure 5.50 for different water-gas injection cycles. At the lowest target gas injection rate (2 MMSCF/D), the recovery factors for WDAG are much lower than the ones for conventional WAG for all aquifer sizes and water-gas injection cycles. However, as the aquifer size becomes larger, this difference gets smaller. In addition, when the target gas injection rate is increased, the difference in recovery factors for the two processes becomes significantly smaller as well. The smallest difference happens at target gas injection rate of 16 MMSCF/D and water-gas injection cycle of 1:1 month (see Figure 5.45) for all three aquifer sizes. For this particular case, the amount of cumulative water injection for conventional WAG is 12.66 MMSTB while WDAG requires none.

From the comparison, we can conclude that WDAG is not suitable for cases in which there is limitation on gas injection as its recovery is much lower than conventional WAG. However, WDAG is an attractive alternative to WAG in cases where there is a large amount of gas available as its recovery factor is slightly lower but the process requires no water injection facility. Moreover, in the case of WDAG, changing of target gas injection rate has more effect compared to increment of aquifer size.

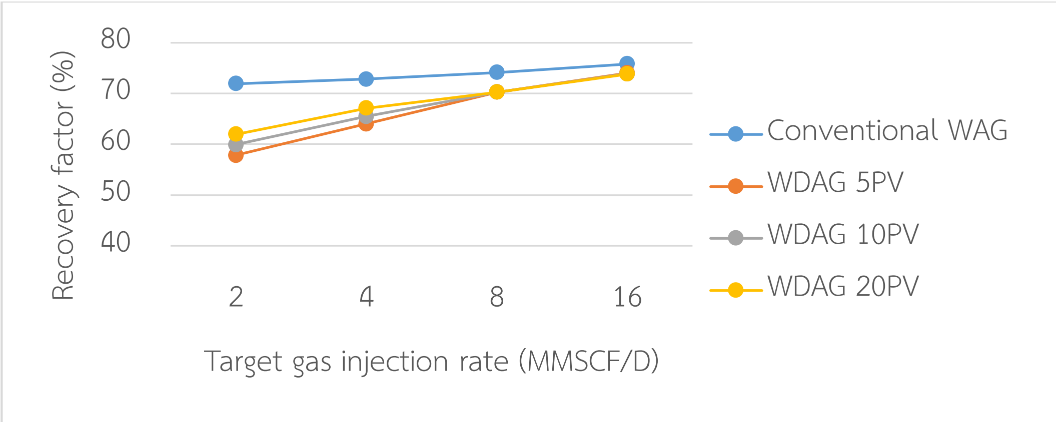

Figure 5.45 WAG and WDAG recovery factors in the case of water-gas injection cycle of 1:1 month.

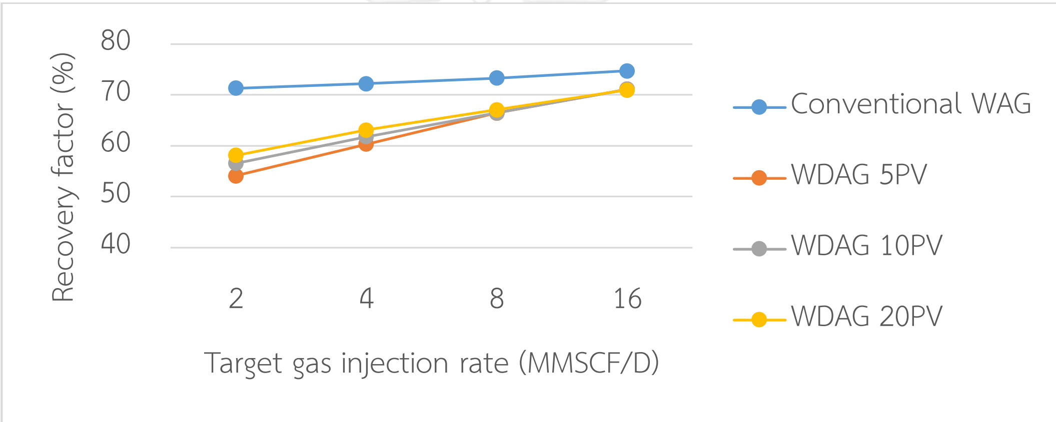

Figure 5.46 WAG and WDAG recovery factors in the case of water-gas injection cycle of 2:1 month

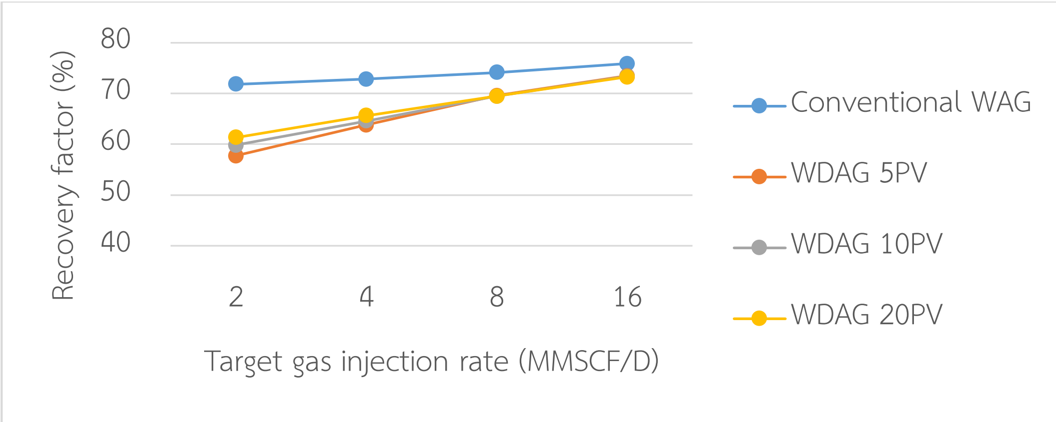

Figure 5.47 WAG and WDAG recovery factors in the case of water-gas injection cycle of 2:2 month.

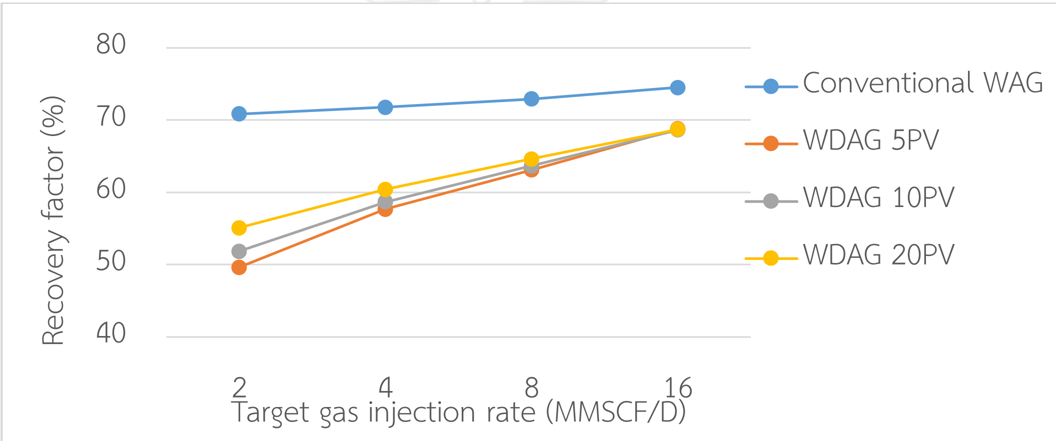

Figure 5.48 WAG and WDAG recovery factors in the case of water-gas injection cycle of 3:1month.

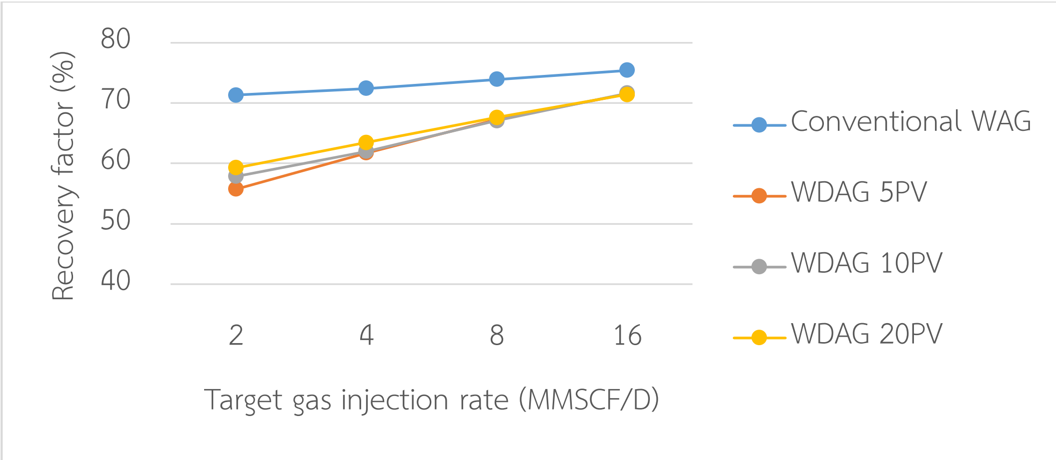

Figure 5.49 WAG and WDAG recovery factors in the case of water-gas injection cycle of 3:2 month.

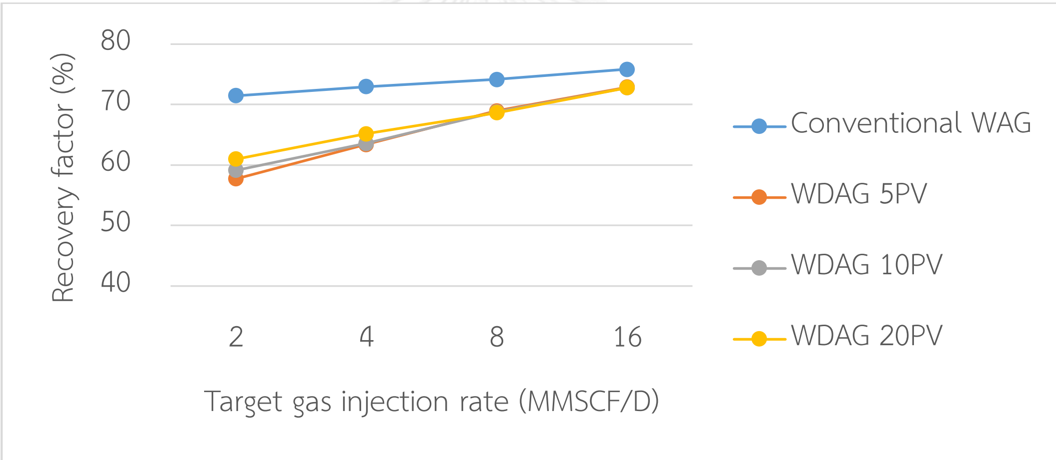

Figure 5.50 WAG and WDAG recovery factors in the case of water-gas injection cycle of 3:3 month.

5.3.2 Aquifer location

As mentioned in Section 3.5, the water transfer rate from the aquifer to the oil reservoir depends on the initial pressure in the aquifer. Different aquifer locations imply different initial aquifer pressures which differently impact the performance of WDAG. The study on effect of aquifer location of both underlying and overlying aquifer is presented in this section.

5.3.2.1 Underlying aquifer

5.3.2.1.1 WDAG injection from underlying aquifer

In WDAG injection from underlying aquifer, the distance between the aquifer and the oil reservoir is varied from 500 ft to 1500 ft and 2500 ft while the thickness and shape of the aquifer are retained. When changing the distance between the bottom depth of oil reservoir and the top depth of aquifer, the trends in the recovery factor and cumulative gas injection are similar to those in the base as depicted in Figure 5.51 to Figure 5.56. For all distances, the target gas injection rate significantly affects the oil recovery factor. A higher target gas injection rate yields higher recovery factor but requires higher amount of injected gas. The water-gas injection cycle moderately affects the performance of WDAG from different depths of underlying aquifer. The water-gas injection cycle of 1:1 gives better recovery factor for all cases of underlying aquifer as depicted in Table 5.7, Table 5.8 and Table 5.9, Applying injection cycle of 1:1 and target gas injection rate of 16 MMSCF/D yields the highest recovery factor of 74.19% and BOE of 7.60 MMSTB for the case of 500 ft distance between the aquifer and the oil reservoir.

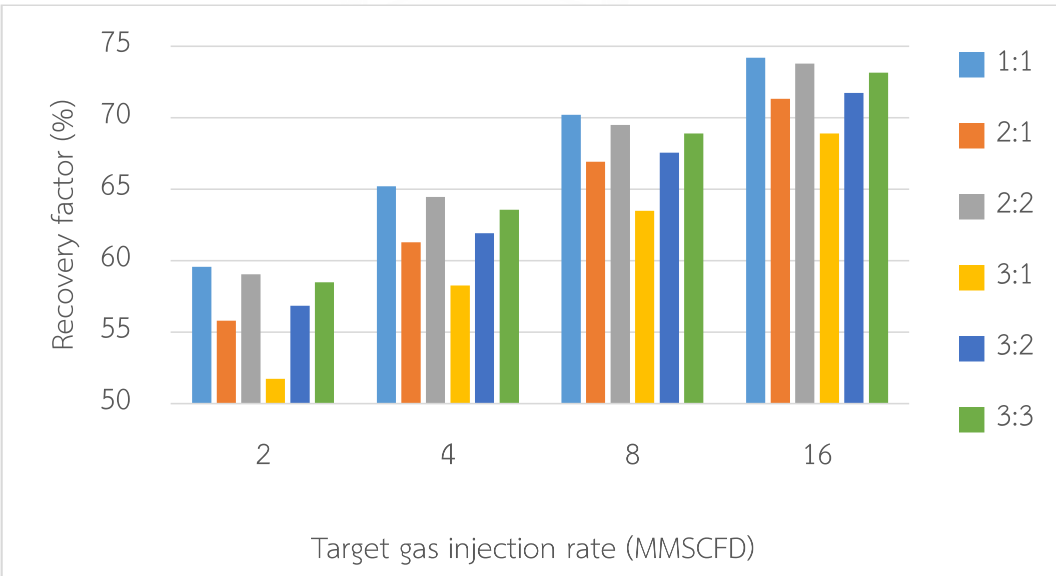

Figure 5.51 Recovery factor for WDAG from underlying aquifer (distance 500ft).

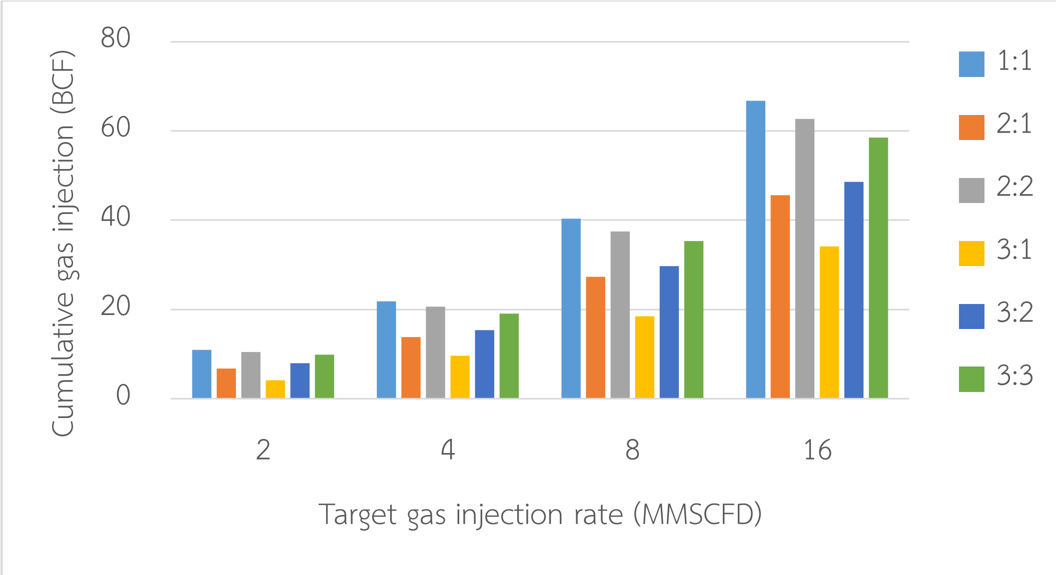

Figure 5.52 Cumulative gas injection for WDAG from underlying aquifer (distance 500ft).

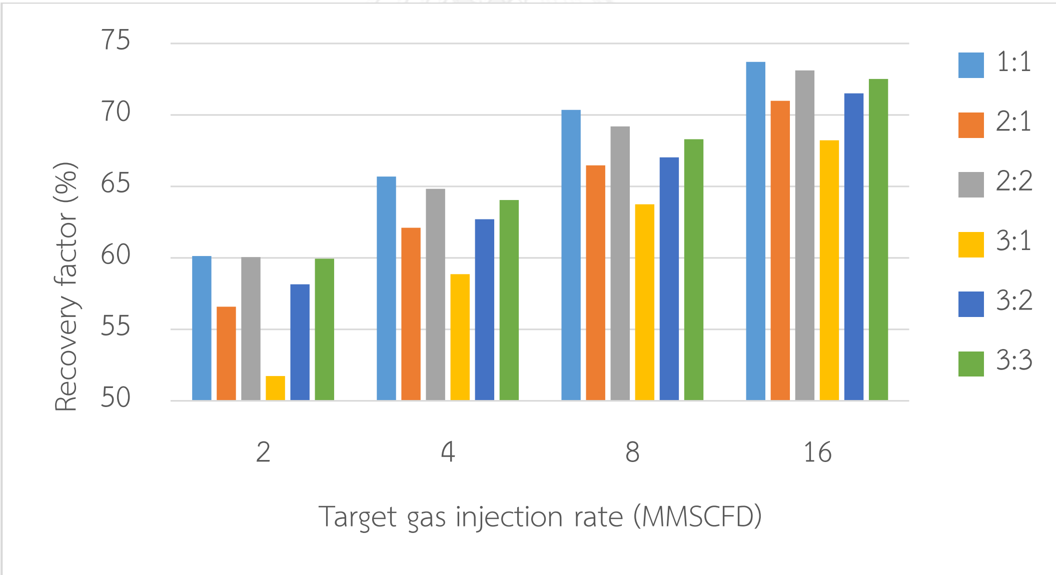

Figure 5.53 Recovery factor for WDAG from underlying aquifer (distance 1500ft).

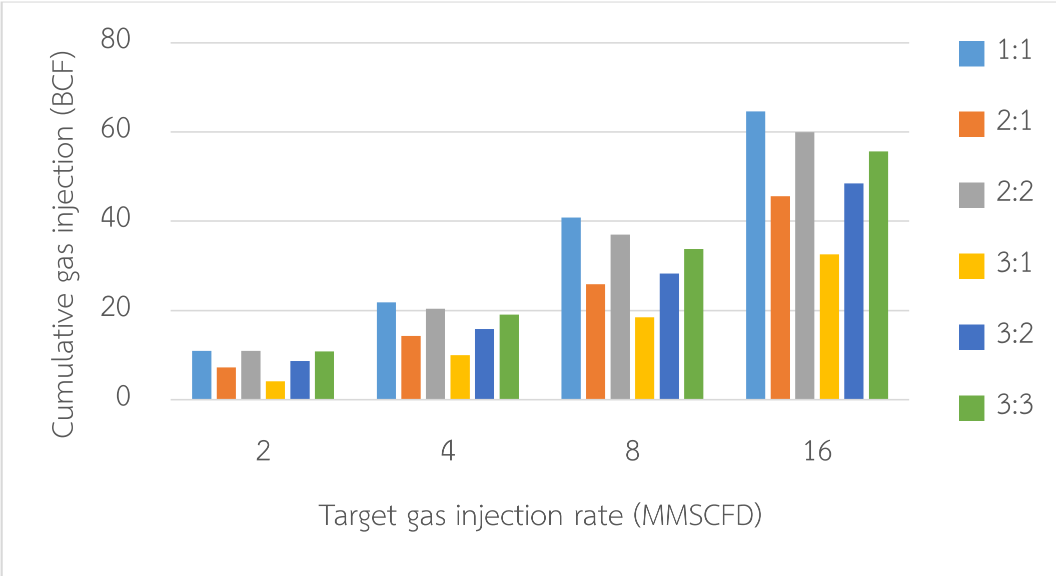

Figure 5.54 Cumulative gas injection for WDAG from underlying aquifer (distance 1500ft).

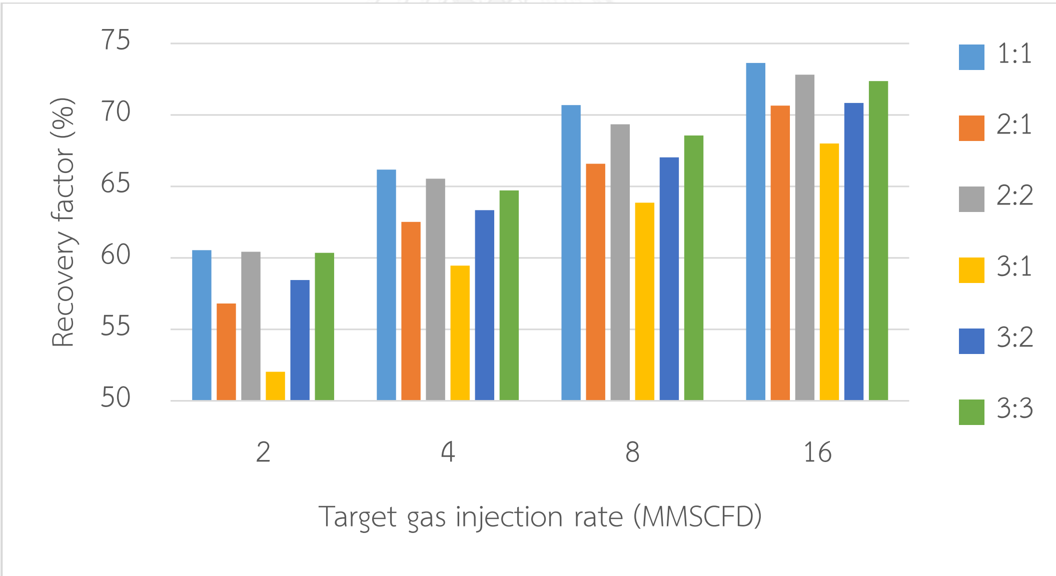

Figure 5.55 Recovery factor for WDAG from underlying aquifer (distance 2500ft).

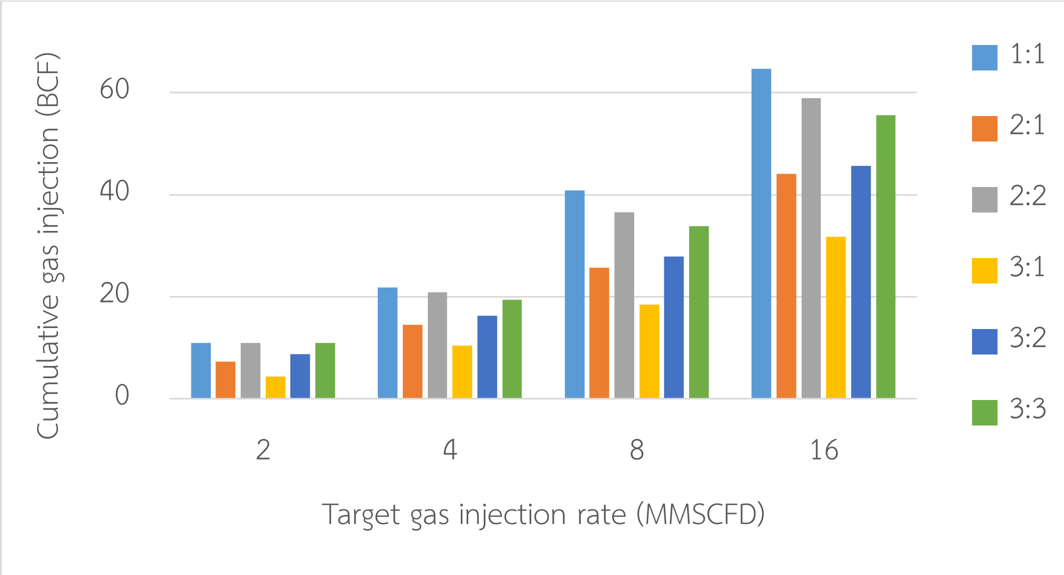

Figure 5.56 Cumulative gas injection for WDAG from underlying aquifer (distance 2500ft).

Table 5.7 Summary of results for WDAG injection from underlying aquifer, 500 ft distance

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	59.55	5.89	0.74	13.42	10.92	6.31	30.00
	4	65.20	6.45	0.81	24.13	21.83	6.83	30.00
	8	70.21	6.95	0.78	42.30	40.34	7.27	27.72
	16	74.19	7.34	0.74	68.23	66.69	7.60	23.12
2:1	2	55.78	5.52	0.50	9.44	6.86	5.95	28.30
	4	61.27	6.06	0.60	16.25	13.84	6.46	28.55
	8	66.90	6.62	0.67	29.52	27.34	6.98	28.29
	16	71.30	7.05	0.63	47.44	45.58	7.36	23.85

Table 5.7 Summary of results for WDAG injection from underlying aquifer, 500 ft distance (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	59.05	5.84	0.62	12.97	10.46	6.26	28.79
	4	64.44	6.38	0.64	23.00	20.68	6.76	28.47
	8	69.49	6.88	0.61	39.49	37.46	7.21	25.83
	16	73.78	7.30	0.63	64.44	62.72	7.59	21.87
3:1	2	51.74	5.12	0.21	6.91	4.22	5.57	23.29
	4	58.25	5.76	0.41	12.15	9.63	6.18	26.57
	8	63.46	6.28	0.43	20.82	18.48	6.67	25.58
	16	68.89	6.82	0.56	36.16	34.13	7.15	23.93

Table 5.7 Summary of results for WDAG injection from underlying aquifer, 500 ft distance (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	56.83	5.62	0.50	10.50	7.93	6.05	27.39
	4	61.92	6.13	0.52	17.79	15.38	6.53	26.57
	8	67.54	6.68	0.55	31.95	29.78	7.04	25.75
	16	71.73	7.10	0.58	50.40	48.55	7.40	21.22
3:3	2	58.47	5.78	0.54	12.45	9.92	6.21	27.40
	4	63.56	6.29	0.51	21.49	19.11	6.68	26.41
	8	68.87	6.81	0.54	37.41	35.31	7.16	24.43
	16	73.13	7.23	0.62	60.31	58.49	7.54	20.47

Table 5.8 Summary of results for WDAG injection from underlying aquifer, distance 1500ft

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	60.15	5.95	1.21	13.08	10.92	6.31	30
	4	65.7	6.5	1.56	23.74	21.84	6.82	30
	8	70.38	6.96	1.56	42.32	40.8	7.21	28.05
	16	73.74	7.29	1.2	65.73	64.64	7.47	22.46
2:1	2	56.59	5.6	0.88	9.56	7.26	5.98	30
	4	62.12	6.15	1.13	16.35	14.3	6.49	29.53
	8	66.51	6.58	1.12	27.72	25.93	6.88	26.82
	16	71.01	7.03	1.05	46.98	45.59	7.26	23.86

Table 5.8 Summary of results for WDAG injection from underlying aquifer, distance 1500ft (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	60.09	5.94	1.13	13.06	10.92	6.30	29.92
	4	64.85	6.42	1.24	22.41	20.43	6.75	28.13
	8	69.2	6.85	1.11	38.68	36.96	7.14	25.5
	16	73.13	7.24	0.94	61.27	59.94	7.46	20.9
3:1	2	51.73	5.12	0.26	6.78	4.22	5.55	23.29
	4	58.88	5.82	0.69	12.25	9.98	6.20	27.55
	8	63.76	6.31	0.71	20.52	18.46	6.65	25.57
	16	68.26	6.75	0.74	34.43	32.62	7.05	22.94

Table 5.8 Summary of results for WDAG injection from underlying aquifer, distance 1500ft (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	58.16	5.75	1	10.93	8.76	6.11	30
	4	62.7	6.2	1	17.93	15.84	6.55	27.38
	8	67.06	6.63	0.91	30.19	28.31	6.94	24.5
	16	71.53	7.08	0.84	50.05	48.44	7.35	21.2
3:3	2	59.95	5.93	1.07	13.04	10.82	6.30	29.87
	4	64.08	6.34	1.04	21.15	19.1	6.68	26.4
	8	68.33	6.76	0.89	35.69	33.8	7.08	23.42
	16	72.52	7.17	0.77	57.18	55.65	7.43	19.5

Table 5.9 Summary of results for WDAG injection from underlying aquifer, distance 2500ft

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	60.56	5.99	1.60	12.76	10.92	6.29	30.00
	4	66.18	6.55	2.14	23.31	21.84	6.79	30.00
	8	70.71	7.00	2.25	41.88	40.81	7.17	28.05
	16	73.65	7.29	1.67	65.34	64.69	7.39	22.46
2:1	2	56.83	5.62	1.19	9.26	7.26	5.96	30.00
	4	62.53	6.19	1.53	16.21	14.51	6.47	30.00
	8	66.59	6.59	1.44	27.11	25.69	6.82	26.57
	16	70.67	6.99	1.28	45.24	44.10	7.18	23.11

Table 5.9 Summary of results for WDAG injection from underlying aquifer, distance 2500ft (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	60.43	5.98	1.51	12.77	10.92	6.29	29.92
	4	65.55	6.49	1.83	22.49	20.91	6.75	28.79
	8	69.36	6.86	1.65	37.81	36.52	7.08	25.18
	16	72.85	7.21	1.27	59.94	58.89	7.38	20.55
3:1	2	52.04	5.15	0.36	6.73	4.35	5.55	23.95
	4	59.46	5.88	0.97	12.46	10.48	6.21	28.89
	8	63.89	6.32	0.88	20.26	18.47	6.62	25.58
	16	68.02	6.73	0.82	33.32	31.78	6.99	22.29

Table 5.9 Summary of results for WDAG injection from underlying aquifer, distance 2500ft (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	58.45	5.78	1.38	10.62	8.76	6.09	30.00
	4	63.37	6.27	1.46	18.05	16.34	6.55	28.21
	8	67.03	6.63	1.20	29.38	27.85	6.89	24.10
	16	70.85	7.01	0.92	47.00	45.61	7.24	19.98
3:3	2	60.38	5.97	1.47	12.82	10.98	6.28	30.08
	4	64.74	6.40	1.53	21.16	19.48	6.69	26.91
	8	68.58	6.78	1.32	35.33	33.84	7.03	23.44
	16	72.40	7.16	1.07	56.84	55.62	7.37	19.48

5.3.2.1.2 Comparison among underlying aquifers

The comparison on recovery factor for different underlying aquifers is depicted in Figure 5.57 to Figure 5.62. The recovery factor are almost similar when performing WDAG from different depths of underlying aquifers for the same water-gas injection cycles and the same target gas injection rates. A longer distance means a deeper aquifer has higher initial aquifer pressure than shallower aquifer. However, the water from a deeper aquifer losses its pressure due to hydrostatic and friction losses when water flows from the underlying aquifer to the oil zone. The hydrostatic loss is more or less cancelled with the high initial pressure. The friction loss is quite small and does not have much impact. Thus, the depth of underlying aquifer shows a minor effect the performance of WDAG injection.

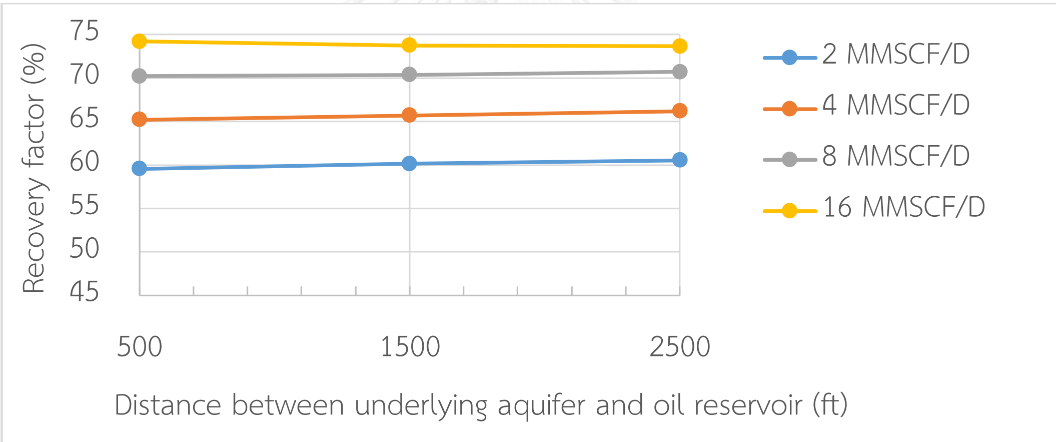

Figure 5.57 WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 1:1 month.

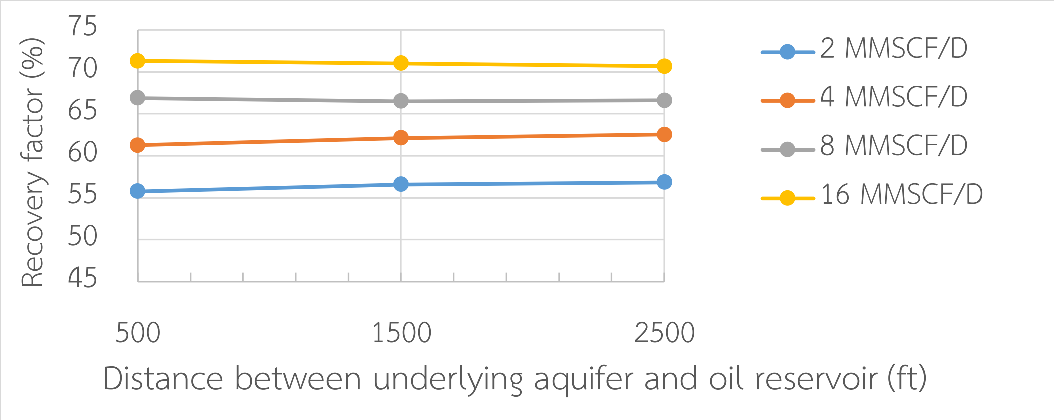

Figure 5.58 WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 2:1 month.

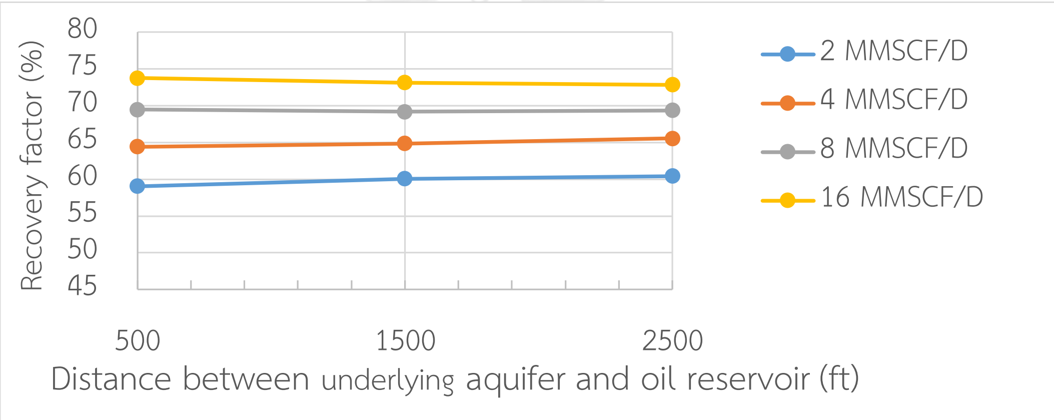

Figure 5.59 WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 2:2 month.

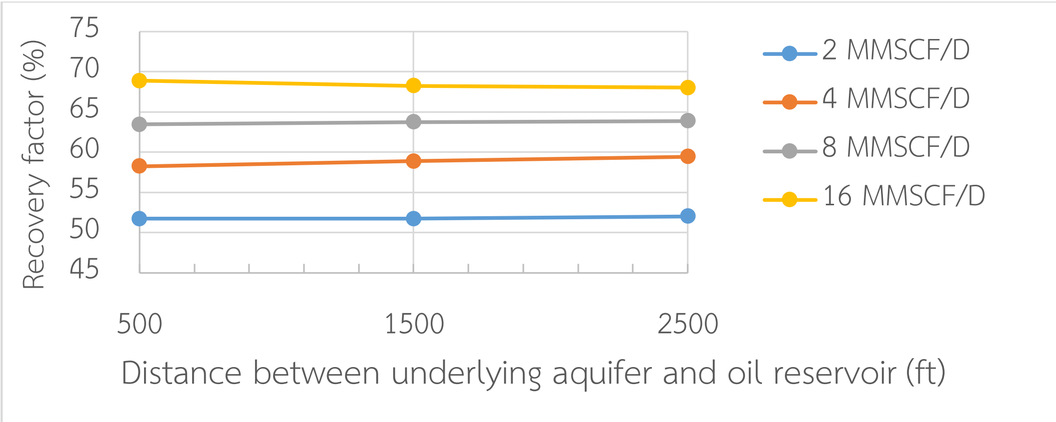

Figure 5.60 WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 3:1 month.

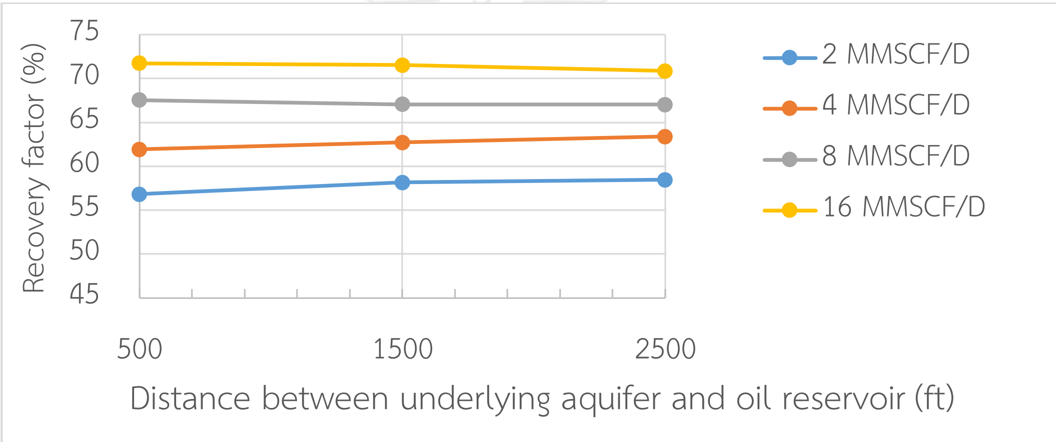

Figure 5.61 WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 3:2 month.

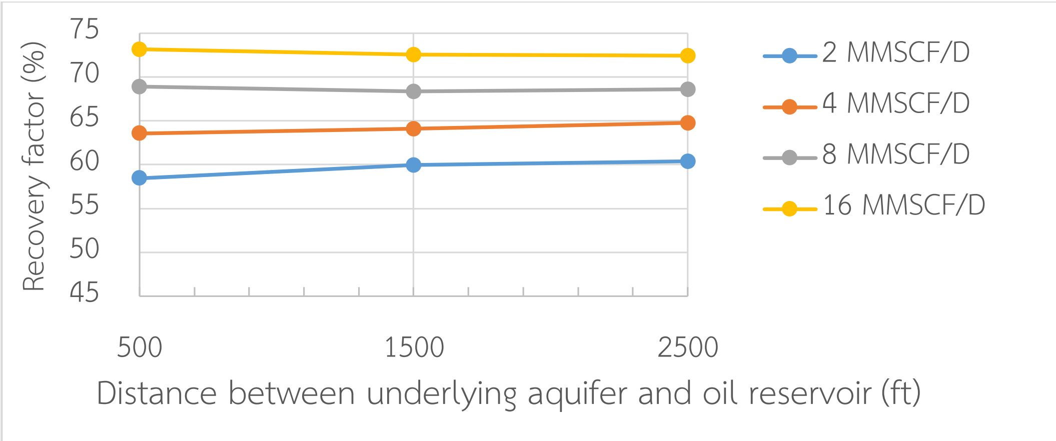

Figure 5.62 WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 3:3 month.

5.3.2.2 Overlying aquifer

5.3.2.2.1 WDAG injection from overlying aquifer

In WDAG injection from overlying aquifer, the distance between the aquifer and the oil reservoir is varied from 500 ft to 1500 ft and 2500 ft. Similar to underlying aquifer, the performance of WDAG from overlying aquifer is dominated by the target gas injection rate. The recovery factor is the highest when injecting gas at 16 MMSCF/D. The water-gas injection cycle of 1:1 and target gas injection rate of 16 MMSCF/D are favorable operating conditions for WDAG for all depths of overlying aquifers (see Figure 5.63, Figure 5.65 and Figure 5.67). They give higher recovery factor than other water-gas injection cycles and target gas injection rates but require higher amount of injected gas (see Figure 5.64, Figure 5.66 and Figure 5.68).

The summary of results for WDAG injection from overlying aquifer for which the distances are 500 ft, 1500 ft and 2500 ft are shown in Table 5.10, Table 5.11 and Table 5.12, respectively. When using injection cycle of 1:1 and target gas injection rate at 16 MMSCF/D, WDAG from overlying aquifer with the distance 500 ft yields the highest recovery factor of 74.06 % (7.58 MMSTB of BOE) but it requires 65.4 BCF of injected gas. If there is a limit on the amount of available gas, WDAG from overlying aquifer (2500 ft distance) yields 61.15 % of recovery factor (6.46 MMSTB of BOE) and requires

10.92 BCF of injected gas when injecting gas at 2 MMSCF/D and 1:1 month of water-gas injection cycle (see Table 5.12).

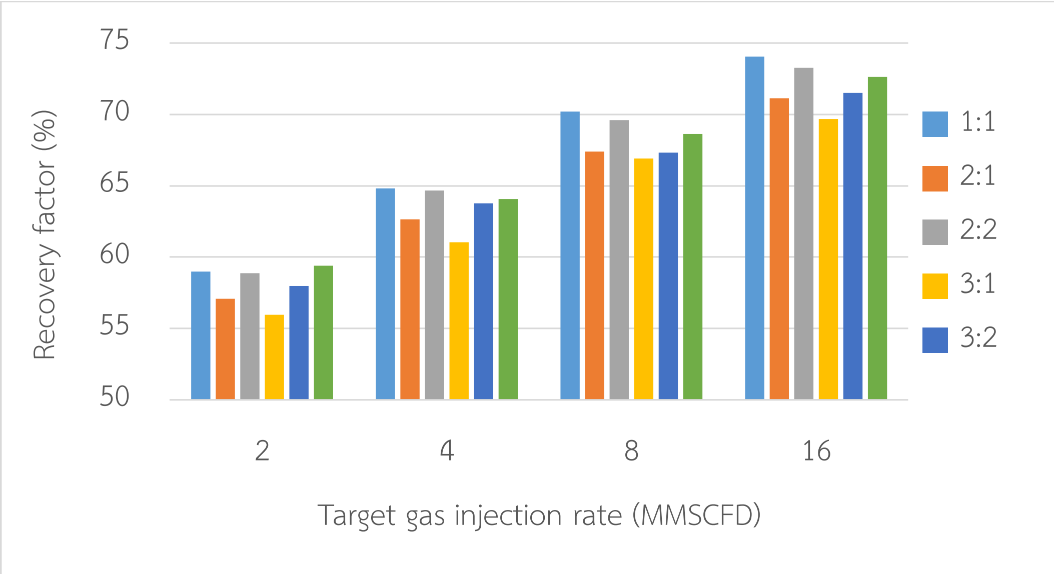

Figure 5.63 Recovery factor for WDAG from overlying aquifer (distance 500ft).

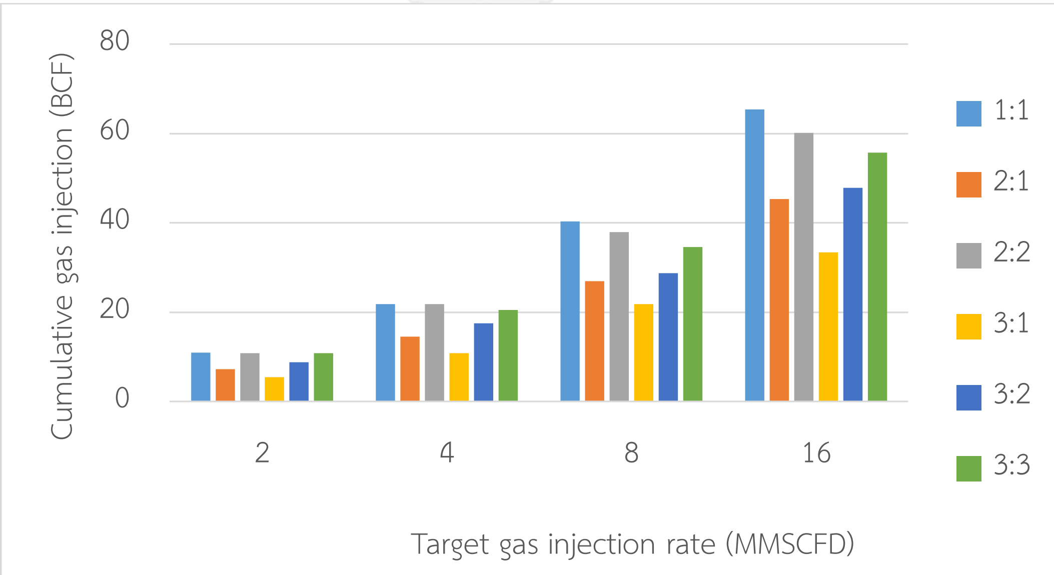

Figure 5.64 Cumulative gas injection for WDAG from overlying aquifer (distance 500ft).

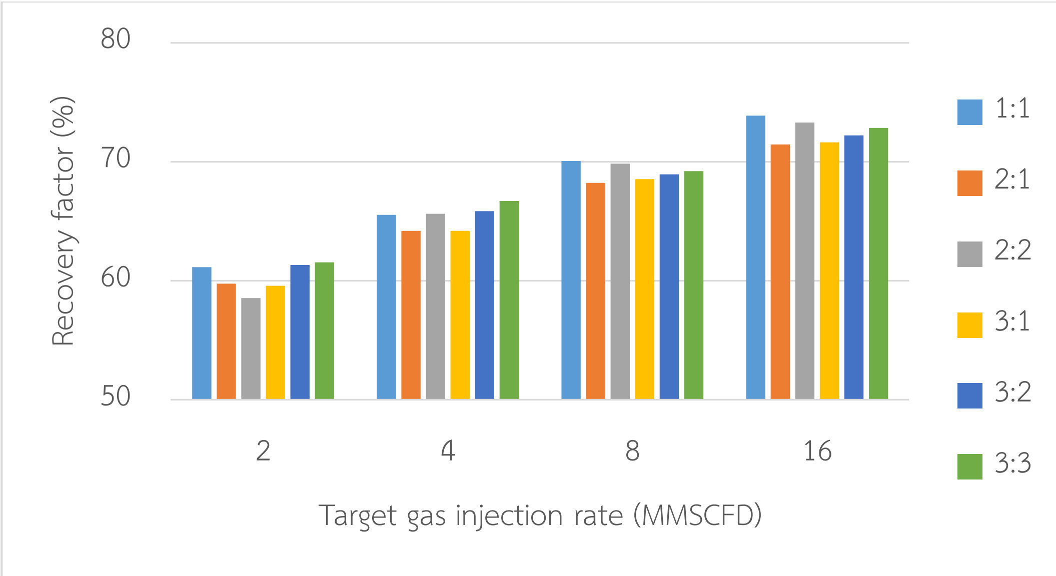

Figure 5.65 Recovery factor for WDAG from overlying aquifer (distance 1500ft).

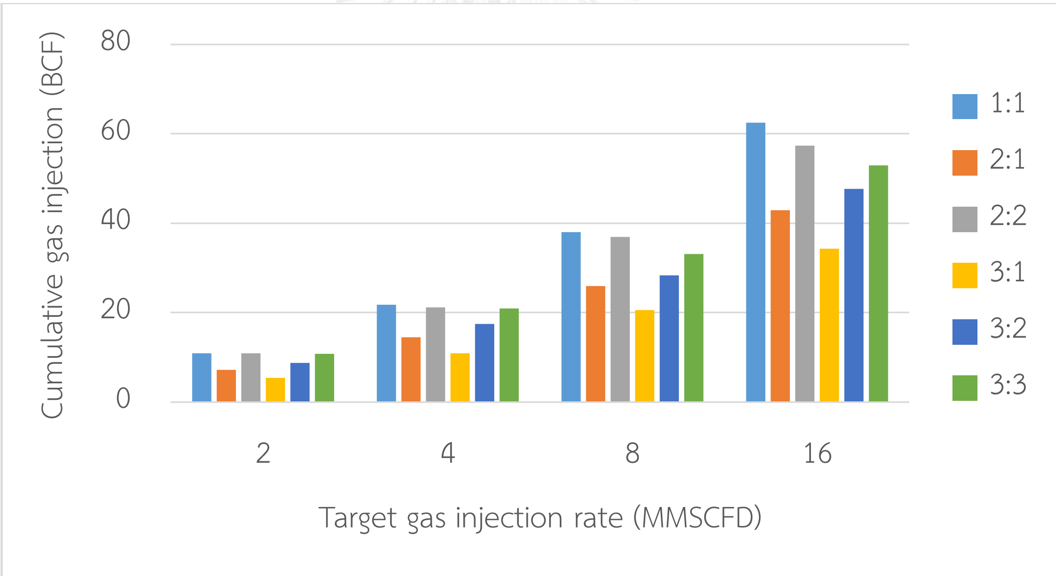

Figure 5.66 Cumulative gas injection for WDAG from overlying aquifer (distance 1500ft).

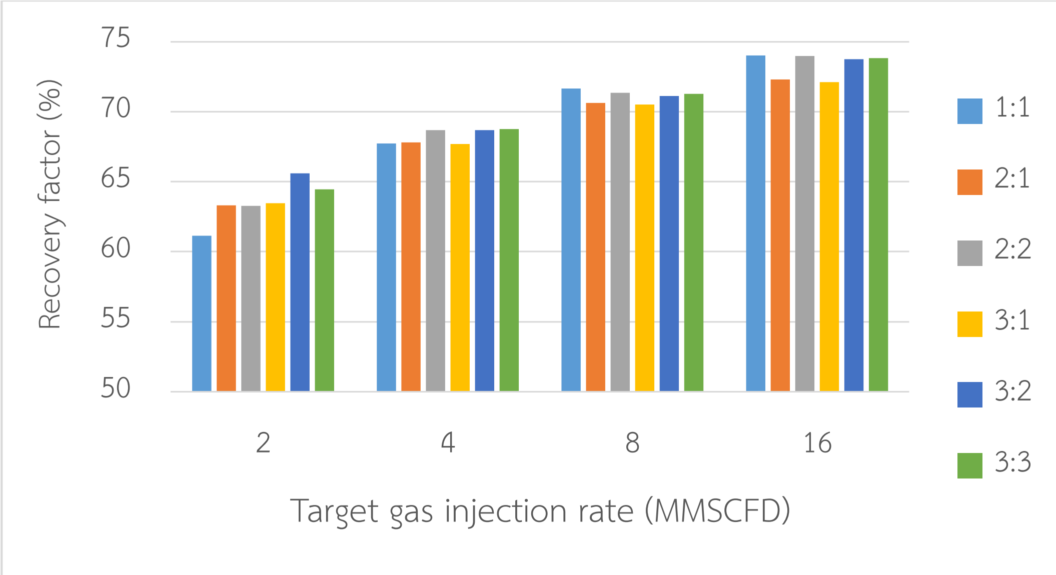

Figure 5.67 Recovery factor for WDAG from overlying aquifer (distance 2500ft).

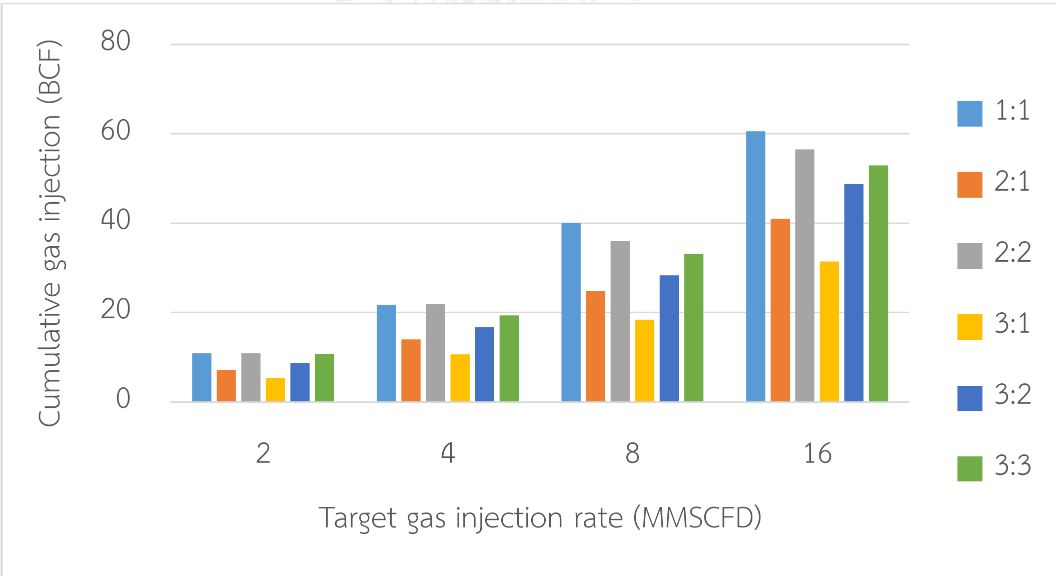

Figure 5.68 Cumulative gas injection for WDAG from overlying aquifer (distance 2500ft).

Table 5.10 Summary of results for WDAG injection from overlying aquifer, 500 ft distance.

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	59.00	5.84	0.58	13.50	10.92	6.27	30.04
	4	64.84	6.41	0.61	24.21	21.83	6.81	30.04
	8	70.22	6.95	0.74	42.37	40.34	7.28	27.76
	16	74.06	7.33	0.98	66.89	65.38	7.58	22.66
2:1	2	57.07	5.65	1.53	9.76	7.26	6.06	30.04
	4	62.65	6.20	1.85	16.76	14.51	6.57	30.04
	8	67.40	6.67	1.87	28.85	26.92	6.99	27.84
	16	71.14	7.04	1.66	46.96	45.32	7.31	23.63

Table 5.10 Summary of results for WDAG injection from overlying aquifer, 500 ft distance (continued).

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	58.88	5.83	0.52	13.40	10.82	6.26	29.82
	4	64.66	6.40	0.55	24.12	21.83	6.78	29.96
	8	69.59	6.89	0.79	39.97	37.93	7.23	26.19
	16	73.26	7.25	1.24	61.63	60.16	7.49	20.93
3:1	2	55.98	5.54	1.77	7.92	5.46	5.95	29.96
	4	61.05	6.04	2.51	13.04	10.89	6.40	29.94
	8	66.89	6.62	3.46	23.39	21.80	6.88	29.96
	16	69.67	6.89	2.76	34.76	33.43	7.12	23.32

Table 5.10 Summary of results for WDAG injection from overlying aquifer, 500 ft distance (continued).

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	57.97	5.74	1.16	11.20	8.76	6.14	30.04
	4	63.79	6.31	1.52	19.65	17.52	6.67	30.04
	8	67.31	6.66	1.11	30.86	28.81	7.00	24.96
	16	71.52	7.08	1.45	49.37	47.85	7.33	20.86
3:3	2	59.41	5.88	0.89	13.32	10.80	6.30	29.88
	4	64.07	6.34	0.65	22.88	20.53	6.73	28.41
	8	68.63	6.79	0.97	36.61	34.55	7.13	23.97
	16	72.64	7.19	1.11	57.46	55.79	7.46	19.52

Table 5.11 Summary of results for WDAG injection from overlying aquifer, 1500 ft distance.

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	61.15	6.05	1.38	13.36	10.92	6.46	30.04
	4	65.52	6.48	0.91	24.16	21.83	6.87	30.04
	8	70.07	6.93	1.27	39.88	37.98	7.25	26.13
	16	73.87	7.31	1.43	63.92	62.51	7.54	21.66
2:1	2	59.77	5.91	3.05	9.46	7.26	6.28	30.04
	4	64.19	6.35	2.85	16.59	14.52	6.70	30.04
	8	68.21	6.75	2.63	27.74	25.94	7.05	26.86
	16	71.46	7.07	2.68	44.23	42.89	7.29	22.40

Table 5.11 Summary of results for WDAG injection from overlying aquifer, 1500 ft distance (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	58.57	5.79	0.49	13.43	10.92	6.21	29.96
	4	65.61	6.49	1.20	23.40	21.14	6.87	29.15
	8	69.82	6.91	1.60	38.85	36.97	7.22	25.54
	16	73.27	7.25	1.84	58.61	57.31	7.47	19.94
3:1	2	59.57	5.89	3.77	7.53	5.46	6.24	29.96
	4	64.21	6.35	4.24	12.71	10.92	6.65	29.96
	8	68.54	6.78	5.10	22.04	20.61	7.02	28.56
	16	71.62	7.09	5.37	35.12	34.32	7.22	23.96

Table 5.11 Summary of results for WDAG injection from overlying aquifer, 1500 ft distance (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	61.33	6.07	3.03	10.87	8.76	6.42	30.04
	4	65.86	6.52	2.92	19.40	17.52	6.83	30.04
	8	68.92	6.82	2.66	30.12	28.37	7.11	24.56
	16	72.22	7.14	2.47	48.91	47.72	7.34	20.84
3:3	2	61.53	6.09	2.74	13.02	10.80	6.46	29.88
	4	66.68	6.60	2.47	22.94	20.92	6.94	28.91
	8	69.21	6.85	1.97	34.93	33.09	7.15	22.97
	16	72.85	7.21	2.16	54.19	52.92	7.42	18.50

Table 5.12 Summary of results for WDAG injection from overlying aquifer, 2500 ft distance.

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
1:1	2	61.15	6.05	1.38	13.36	10.92	6.46	30.04
	4	67.74	6.70	3.18	23.77	21.83	7.02	30.04
	8	71.65	7.09	3.41	41.41	40.00	7.32	27.48
	16	74.01	7.32	2.24	61.82	60.59	7.53	21.00
2:1	2	63.32	6.26	5.25	9.13	7.26	6.58	30.04
	4	67.81	6.71	5.12	15.79	14.04	7.00	29.05
	8	70.61	6.98	5.44	26.23	24.92	7.20	25.85
	16	72.31	7.15	3.95	42.05	41.05	7.32	21.42

Table 5.12 Summary of results for WDAG injection from overlying aquifer, 2500 ft distance (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
2:2	2	63.28	6.26	4.32	12.80	10.92	6.57	29.96
	4	68.66	6.79	4.42	23.44	21.84	7.06	29.96
	8	71.35	7.06	3.64	37.51	36.01	7.31	24.88
	16	73.99	7.32	3.14	57.30	56.55	7.44	19.65
3:1	2	63.47	6.28	5.59	7.24	5.46	6.58	29.96
	4	67.69	6.70	6.30	12.25	10.68	6.96	29.53
	8	70.52	6.98	6.85	19.49	18.44	7.15	25.60
	16	72.11	7.13	5.88	32.03	31.43	7.24	21.99

Table 5.12 Summary of results for WDAG injection from overlying aquifer, 2500 ft distance (continued)

WGIC (month)	Q_{tg} (MMSCF/D)	RF %	N_p (MMSTB)	W_p (MMSTB)	G_p (BCF)	G_I (BCF)	BOE (MMSTB)	t_p (year)
3:2	2	65.59	6.49	5.51	10.48	8.73	6.78	30.00
	4	68.69	6.80	5.76	18.32	16.80	7.05	29.03
	8	71.14	7.04	5.47	29.42	28.29	7.23	24.53
	16	73.76	7.30	4.85	49.45	48.78	7.41	21.26
3:3	2	64.44	6.37	4.35	12.74	10.80	6.70	29.88
	4	68.76	6.80	4.73	21.14	19.44	7.09	26.92
	8	71.28	7.05	4.50	34.40	33.09	7.27	22.97
	16	73.84	7.30	3.78	53.69	52.94	7.43	18.52

5.3.2.2.2 Comparison among overlying aquifers

Figure 5.69 to Figure 5.74 show the recovery factor from WDAG injection with different distances between overlying aquifer and oil reservoir. A longer distance which represents a shallower aquifer shows higher recovery factor than a shorter distance which represent a deeper aquifer. When implementing water dumpflood, the aquifer pressure declines. Some gas also crosses flow from the oil reservoir into the aquifer. The shallower aquifer means the more difference in pressure between the aquifer and the oil reservoir. This large difference in pressure causes more gas flow into the shallower overlying aquifer through the dumping well (as depicted in Figure 5.75). The producing mechanism of water from aquifer is dominated by water expansion, rock expansion and gas flooding. As depicted in Figure 5.76, Figure 5.80, Figure 5.84, Figure 5.88, Figure 5.92, Figure 5.96, Figure 5.100, Figure 5.104, Figure 5.108, Figure 5.112, Figure 5.116, Figure 5.120, the water saturation at mid cross section around the well bore at the top of aquifer at the end of production in the cases of 2,500-ft distance is lower and spreads in larger area than those for the cases of 500-ft and 1,500-ft distance. In other words, the gas saturation at mid cross section around the well at the top of aquifer in the case of 2,500-ft distance is higher and spreads in larger area than those for the cases of 500-ft and 1,500-ft distance due to gas flowing from the oil reservoir (see Figure 5.77, Figure 5.81, Figure 5.85, Figure 5.89, Figure 5.93, Figure 5.97, Figure 5.101, Figure 5.105, Figure 5.109, Figure 5.113, Figure 5.117, Figure 5.121). Therefore, the total water flowing from a shallower overlying aquifer into the oil reservoir is higher than that from a deeper overlying aquifer, leading higher water saturation and lower oil saturation at mid cross section near the producer in the oil reservoir at the end of production when applying low target gas injection rate (see Figure 5.78, Figure 5.79, Figure 5.82, Figure 5.83, Figure 5.86, Figure 5.87, Figure 5.90, Figure 5.91, Figure 5.94, Figure 5.95, Figure 5.98, Figure 5.99, Figure 5.102, Figure 5.103, Figure 5.106, Figure 5.107,Figure 5.110, Figure 5.111). At the highest target gas injection rate, the microscopic oil displacement due to gas injection dominates the recovery efficiency, leading the water saturation and oil saturation at mid cross section in the oil reservoir at the end of production to be about the same among the depth of overlying aquifers (see Figure

5.114, Figure 5.115, Figure 5.118, Figure 5.119, Figure 5.122, Figure 5.123). Thus, the depth of overlying aquifers shows a minor effect on the performance of WDAG at high target gas injection rate while WDAG from a shallower aquifer yields higher oil recovery than a deeper aquifer at low target gas injection rate.

At low target gas injection rates, the increase in recovery factor due to an increase in the distance between the aquifer and the oil reservoir is higher than those for the cases of high target gas injection rates (see Figure 5.69 to Figure 5.74). This gain in recovery factor becomes small when target gas injection rate is 16 MMSCF/D. Thus, the depth of overlying significantly affects WDAG injection at low target gas injection rates but slightly impacts WDAG injection at high target gas injection rates.

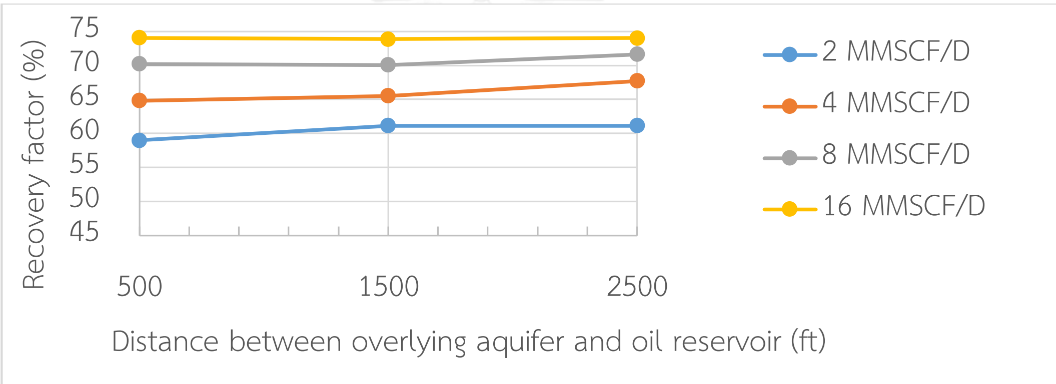

Figure 5.69 WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 1:1 month.

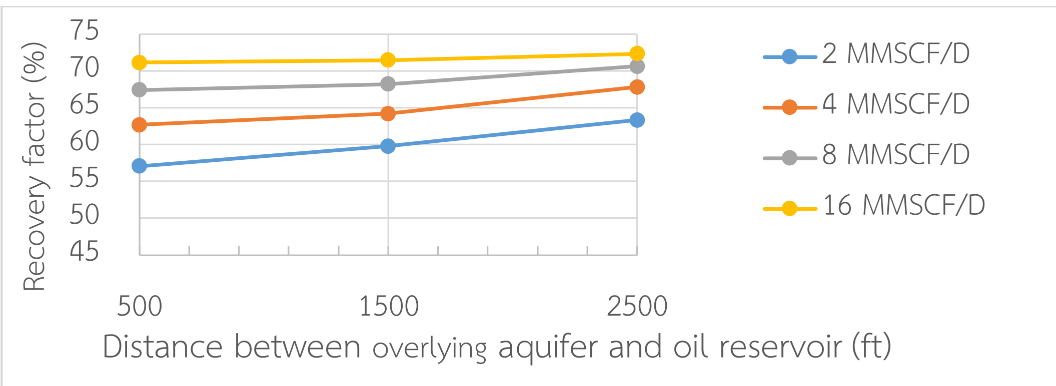

Figure 5.70 WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 2:1 month.

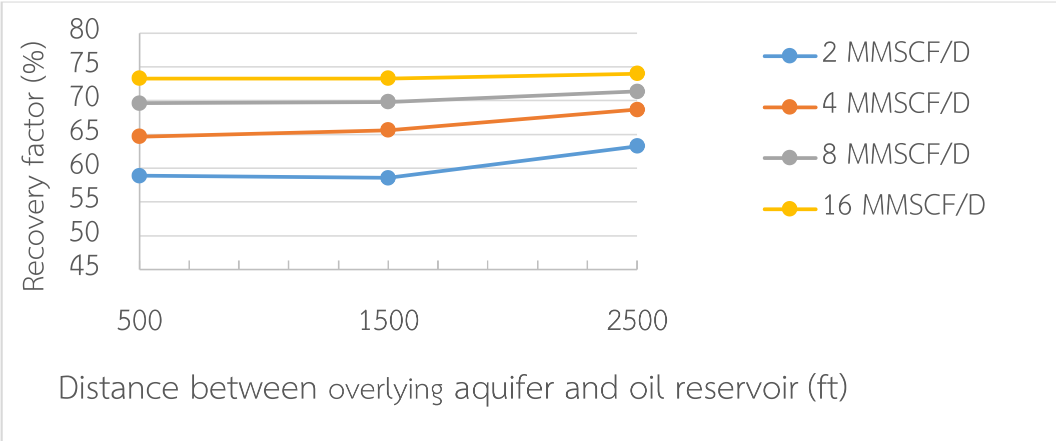

Figure 5.71 WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 2:2 month.

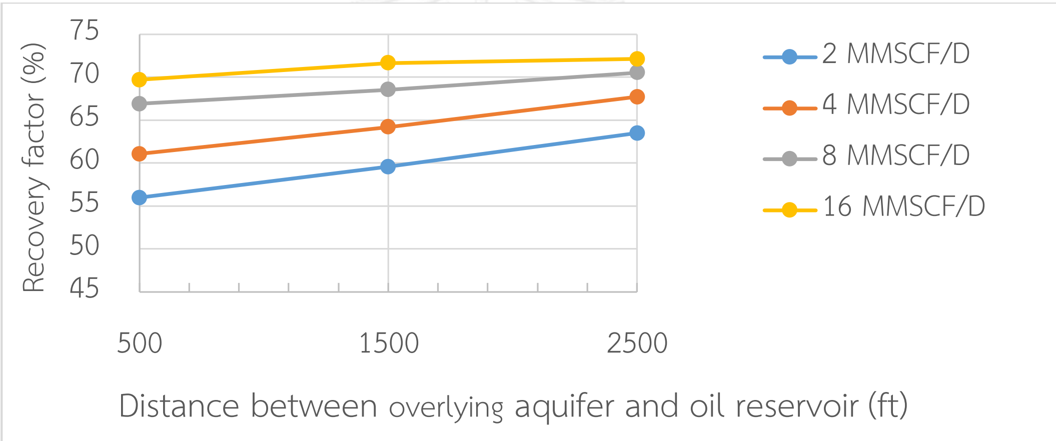

Figure 5.72 WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 3:1 month.

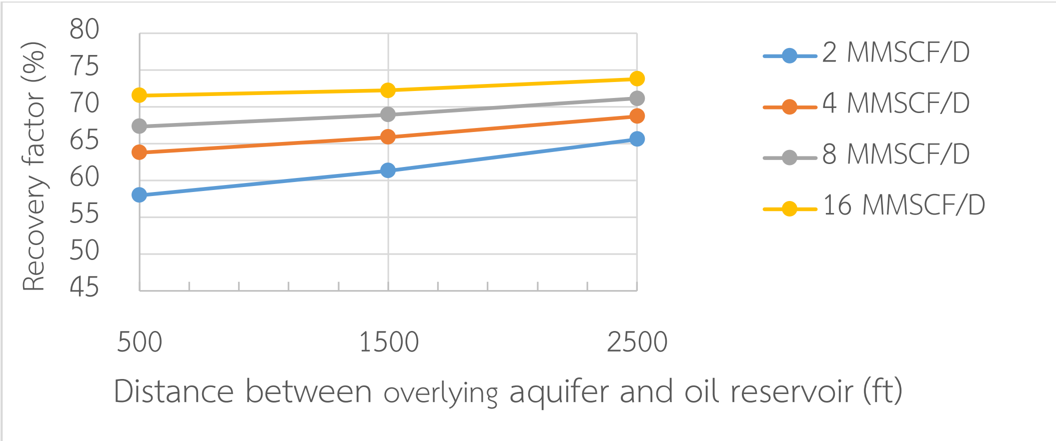

Figure 5.73 WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 3:2 month.

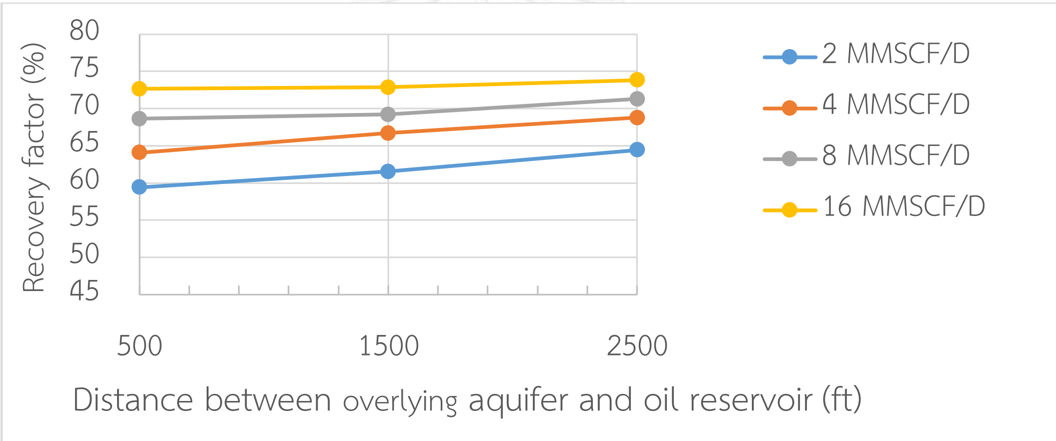

Figure 5.74 WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 3:3 month.

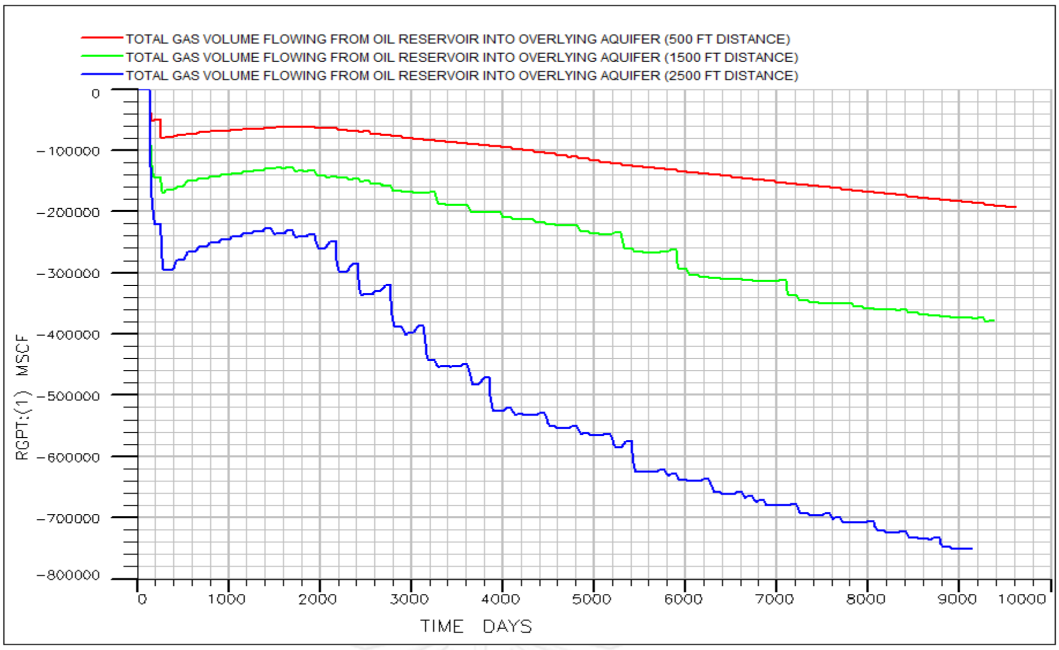

Figure 5.75 Total gas volume flowing from oil reservoir into various depths of overlying aquifer

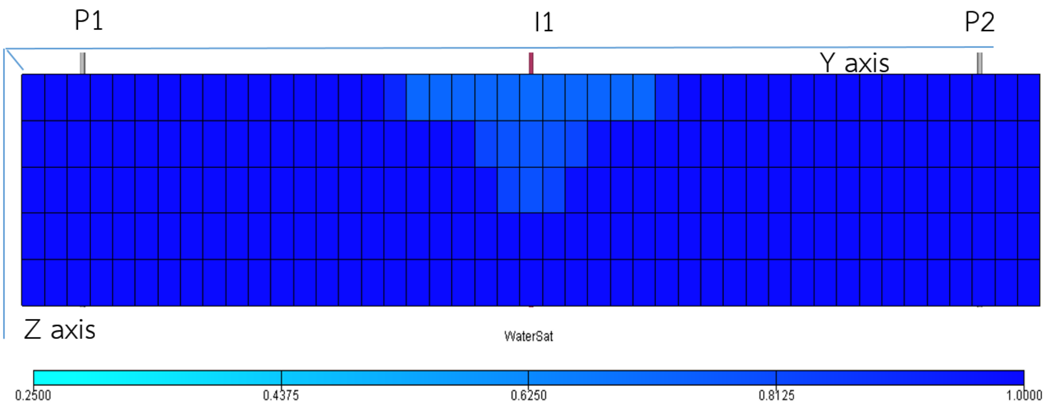

Figure 5.76 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 500 ft distance).

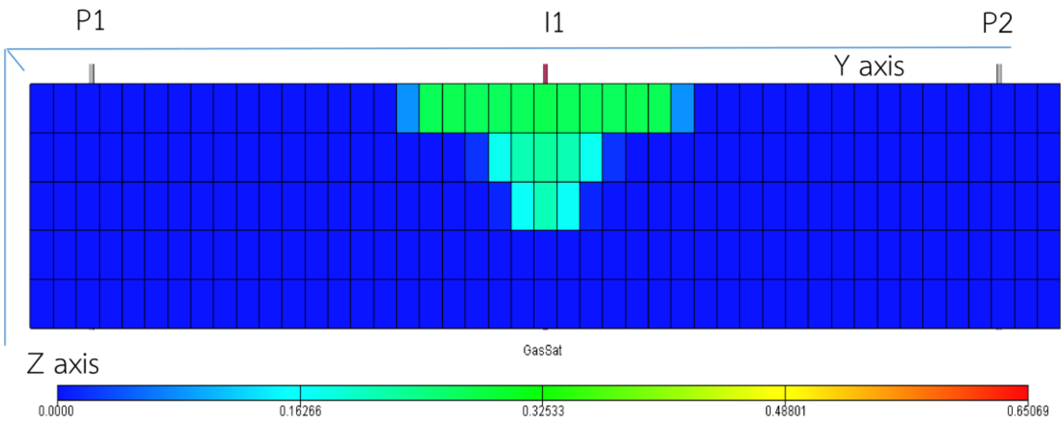

Figure 5.77 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 500 ft distance).

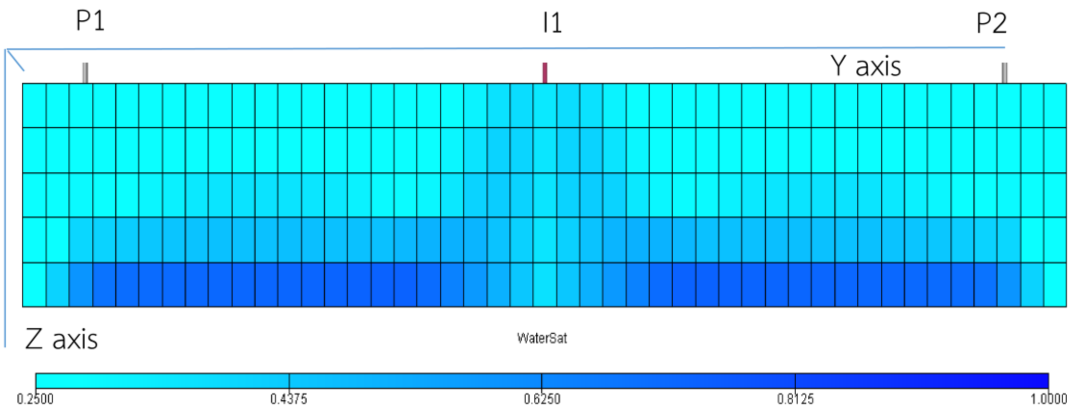

Figure 5.78 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 500 ft distance).

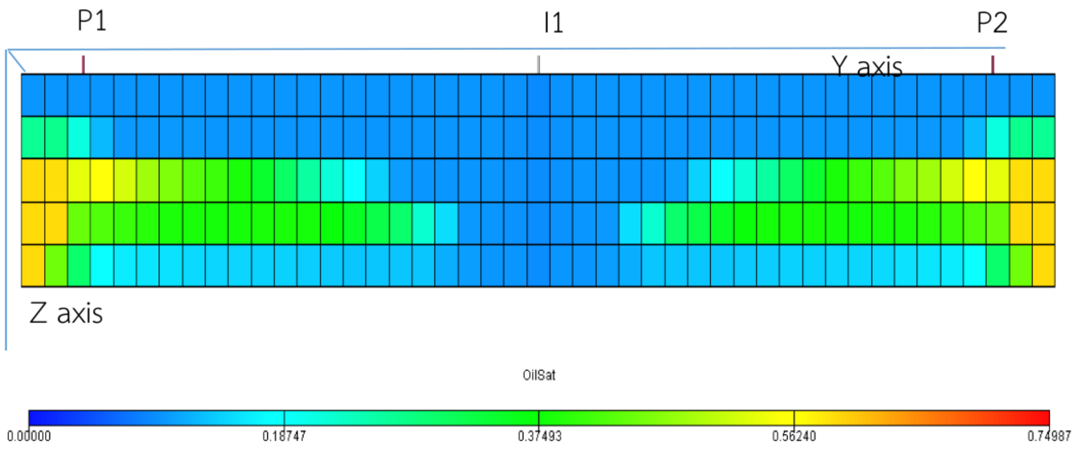

Figure 5.79 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 500 ft distance).

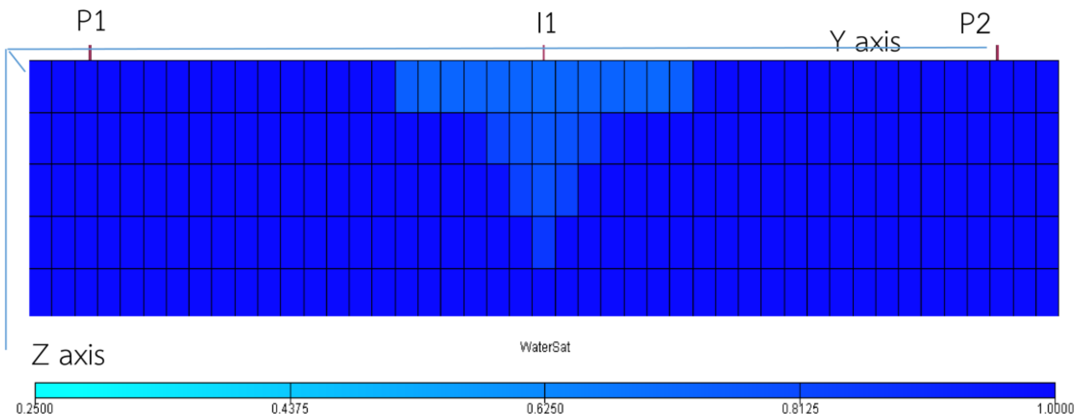

Figure 5.80 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 1500 ft distance).

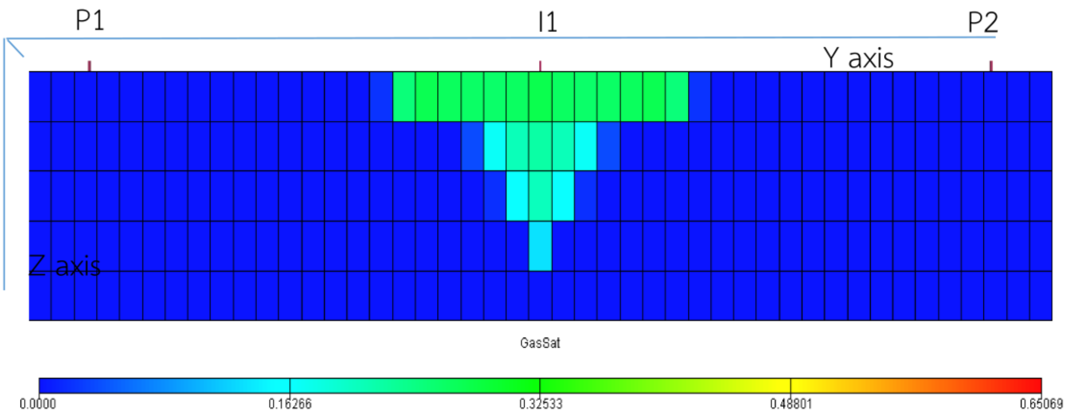

Figure 5.81 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 1500 ft distance).

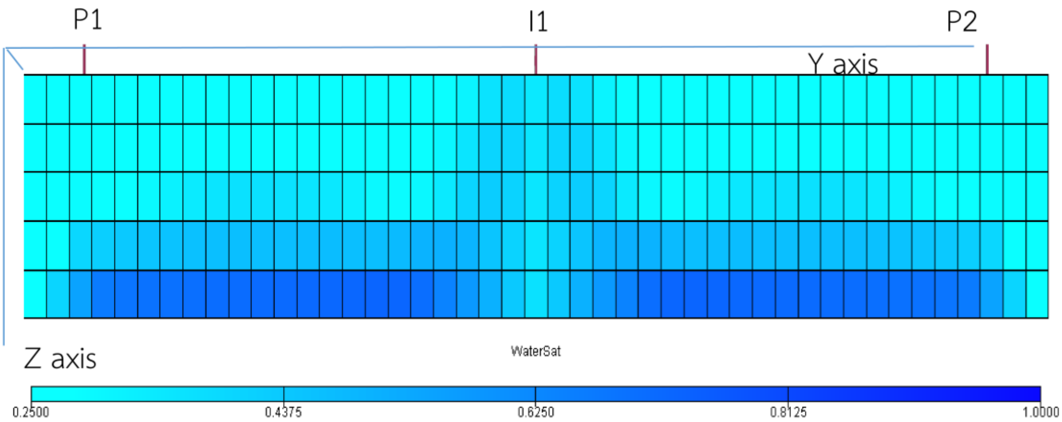

Figure 5.82 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 1500 ft distance).

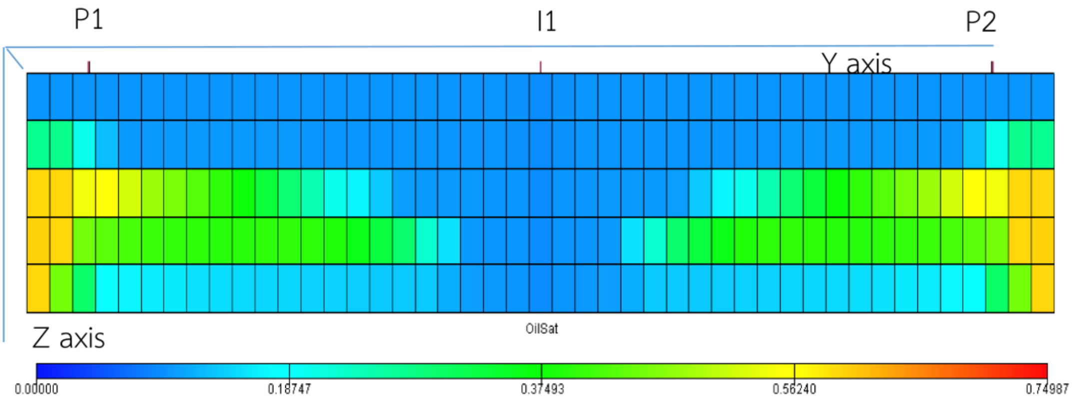

Figure 5.83 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 1500 ft distance).

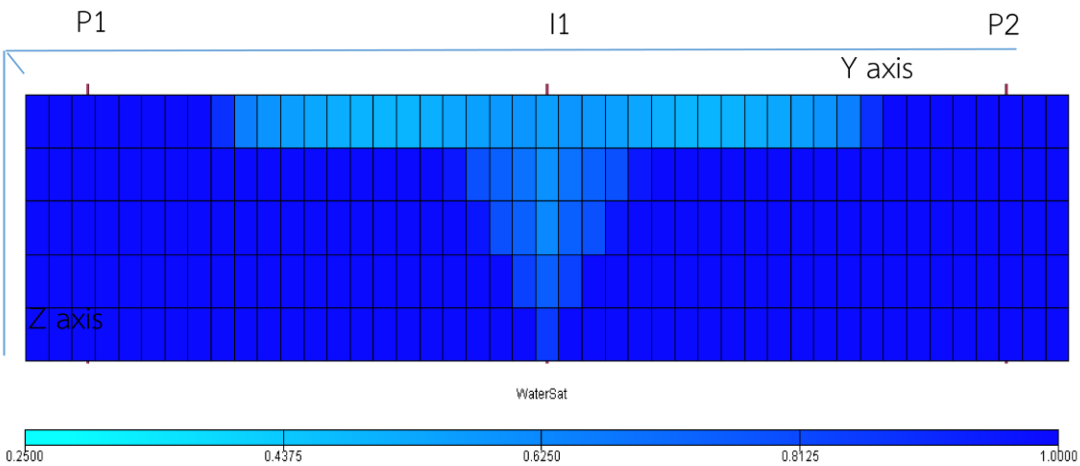

Figure 5.84 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 2500 ft distance).

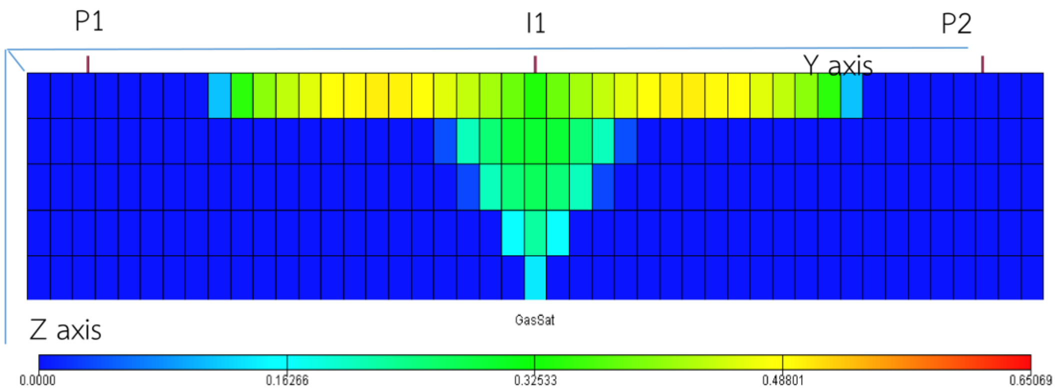

Figure 5.85 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 2500 ft distance).

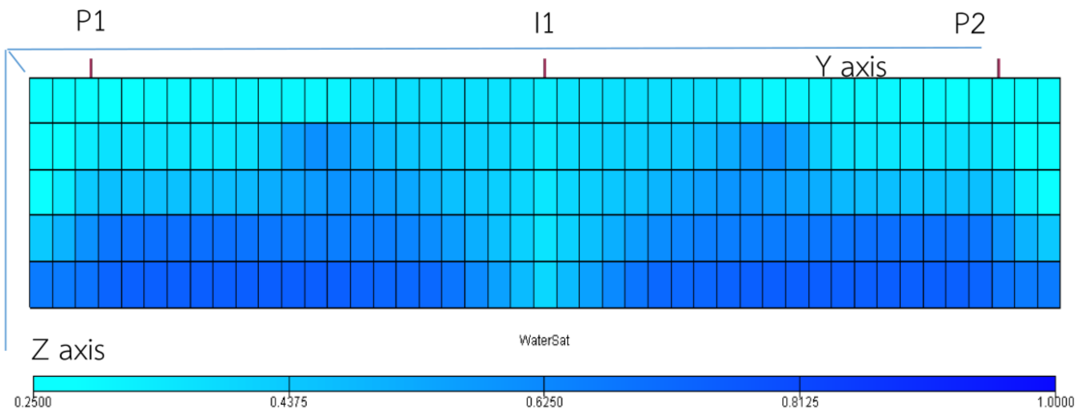

Figure 5.86 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 2500 ft distance).

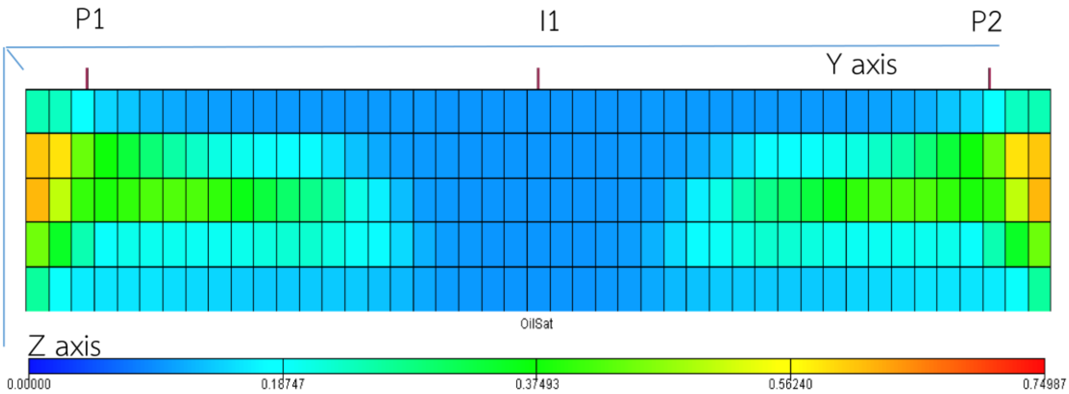

Figure 5.87 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 2 MMSCF/D, 2500 ft distance).

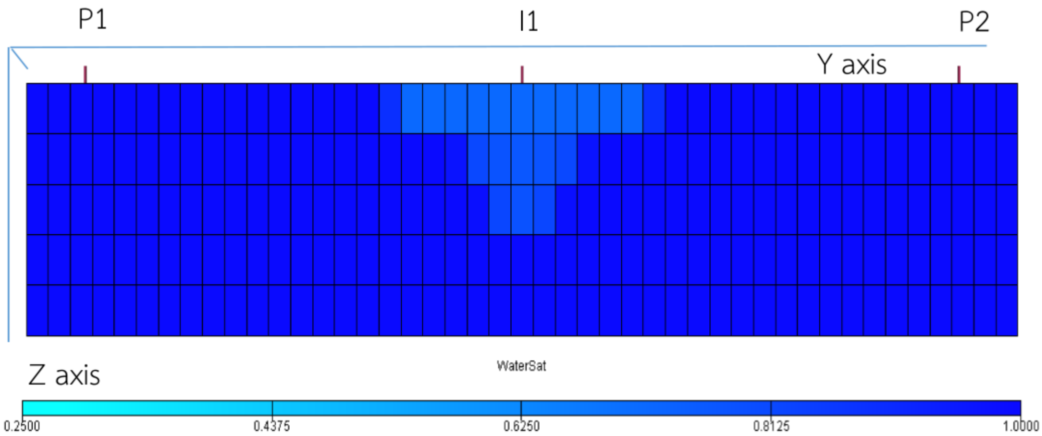

Figure 5.88 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 500 ft distance).

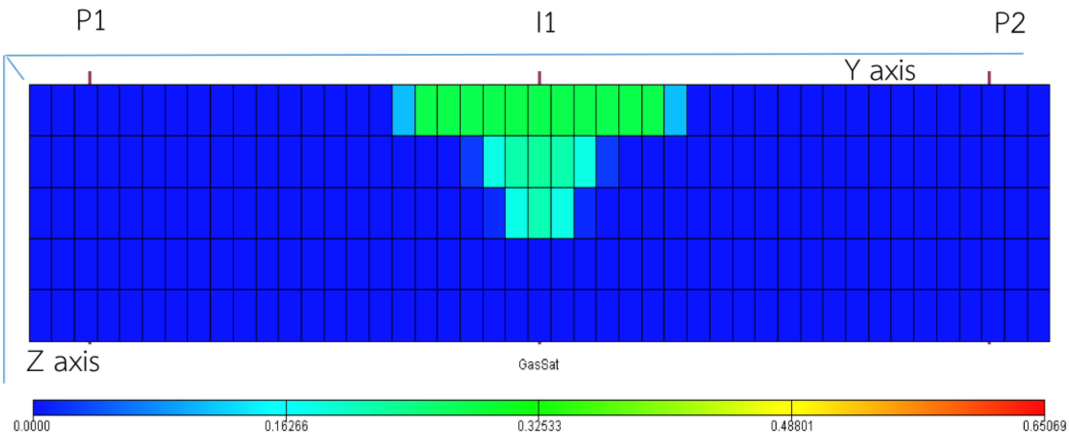

Figure 5.89 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 500 ft distance).

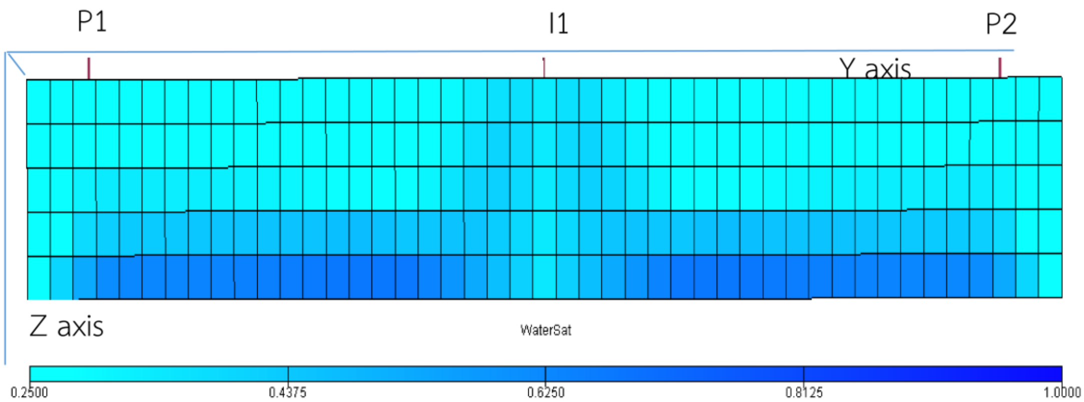

Figure 5.90 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 500 ft distance).

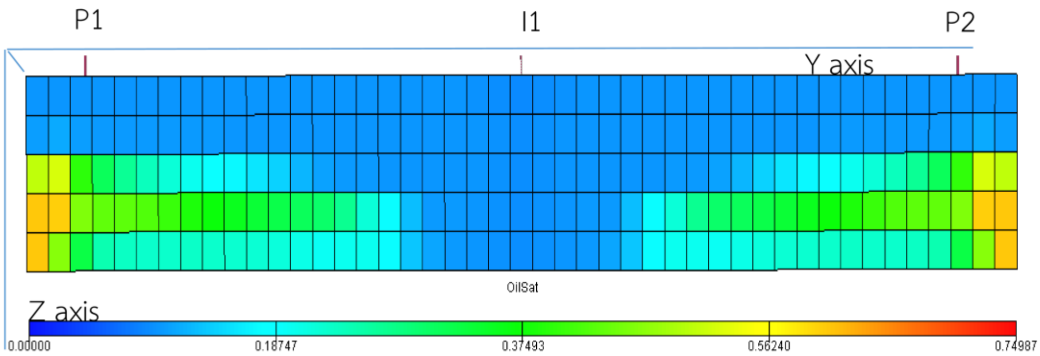

Figure 5.91 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 500 ft distance).

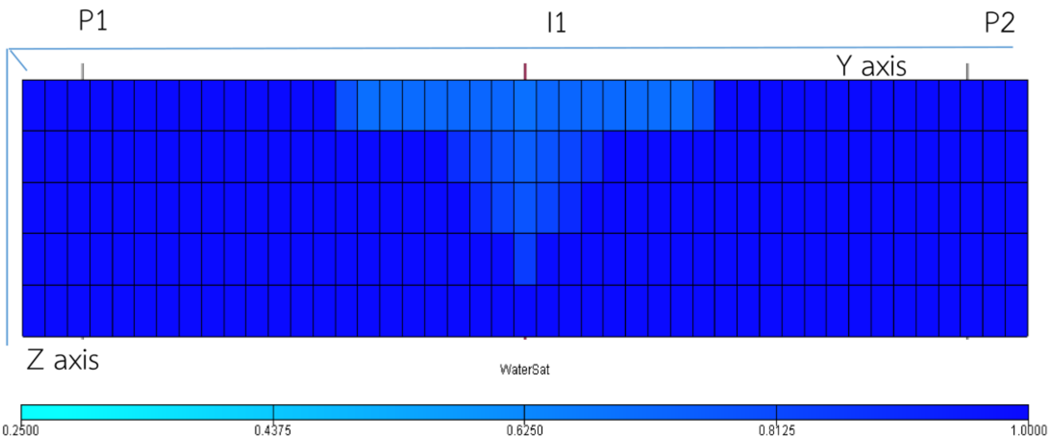

Figure 5.92 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 1500 ft distance).

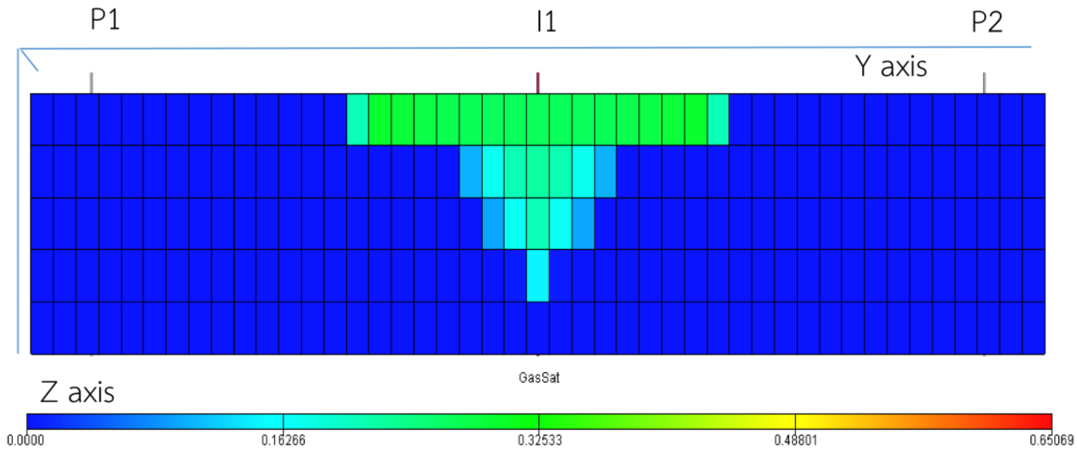

Figure 5.93 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 1500 ft distance).

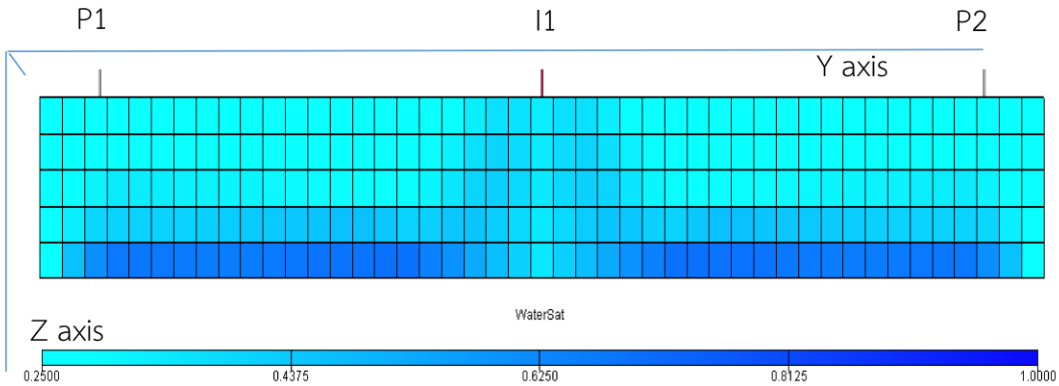

Figure 5.94 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 1500 ft distance).

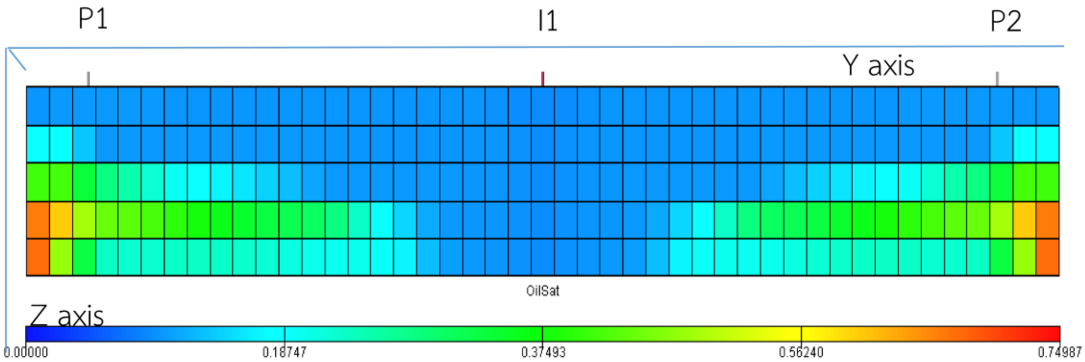

Figure 5.95 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 1500 ft distance).

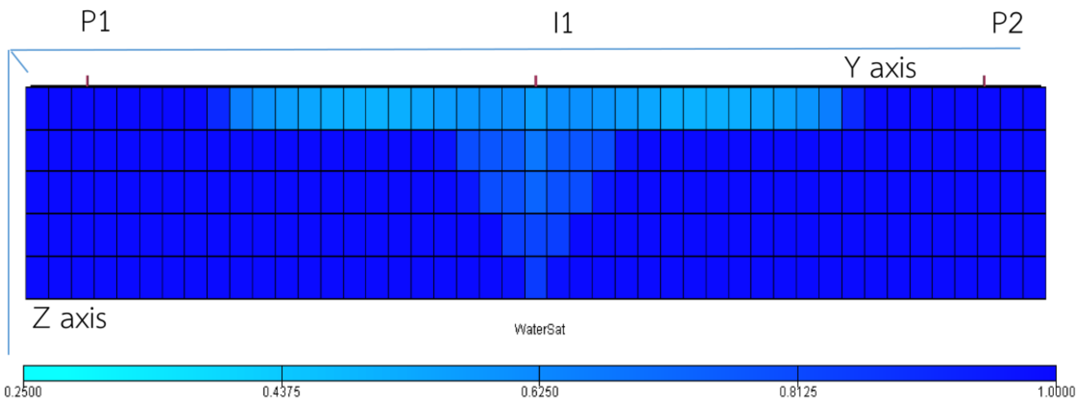

Figure 5.96 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 2500 ft distance).

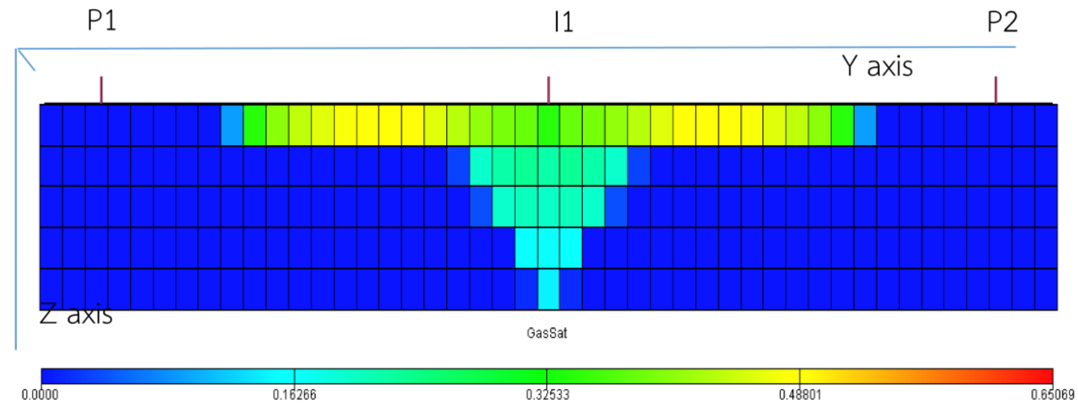

Figure 5.97 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 2500 ft distance).

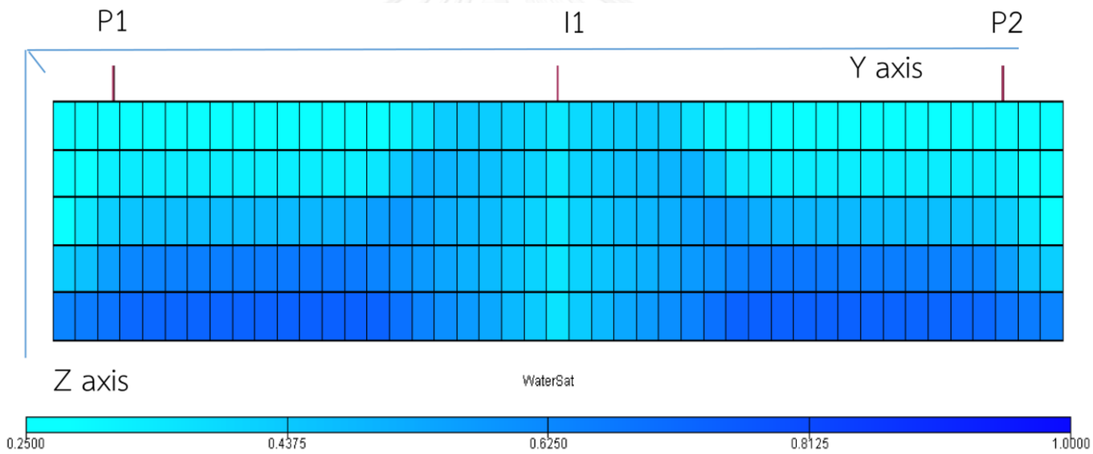

Figure 5.98 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 500 ft distance).

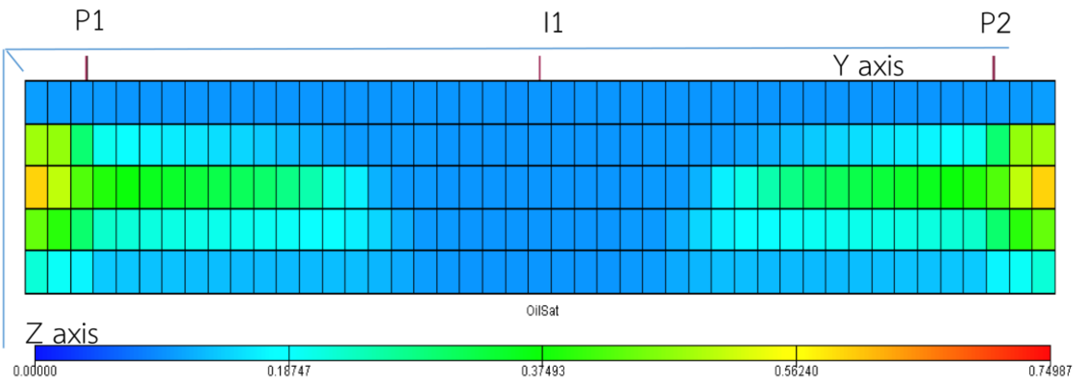

Figure 5.99 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 4 MMSCF/D, 2500 ft distance).

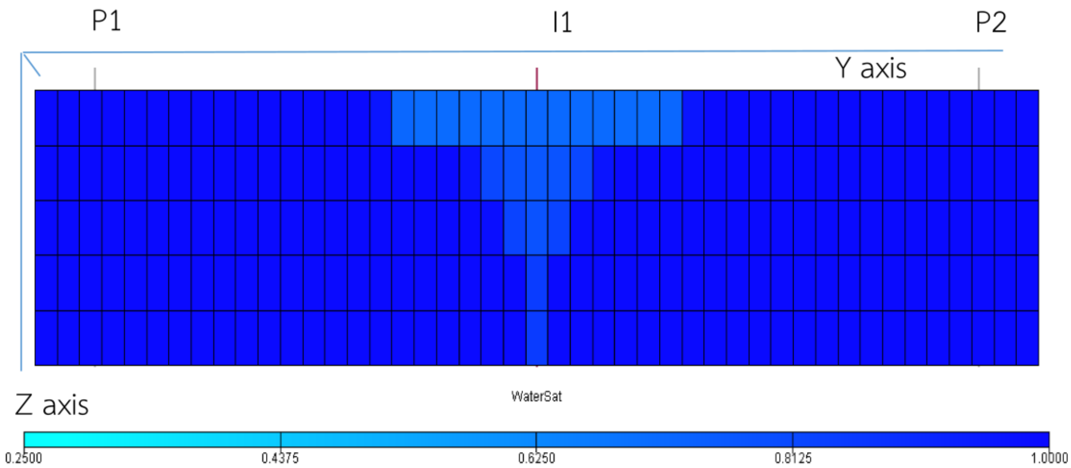

Figure 5.100 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 500 ft distance).

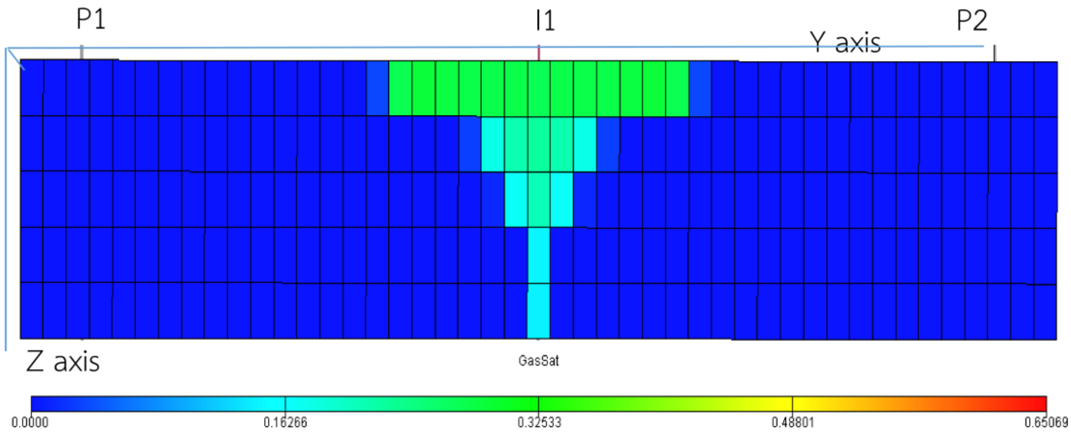

Figure 5.101 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 500 ft distance).

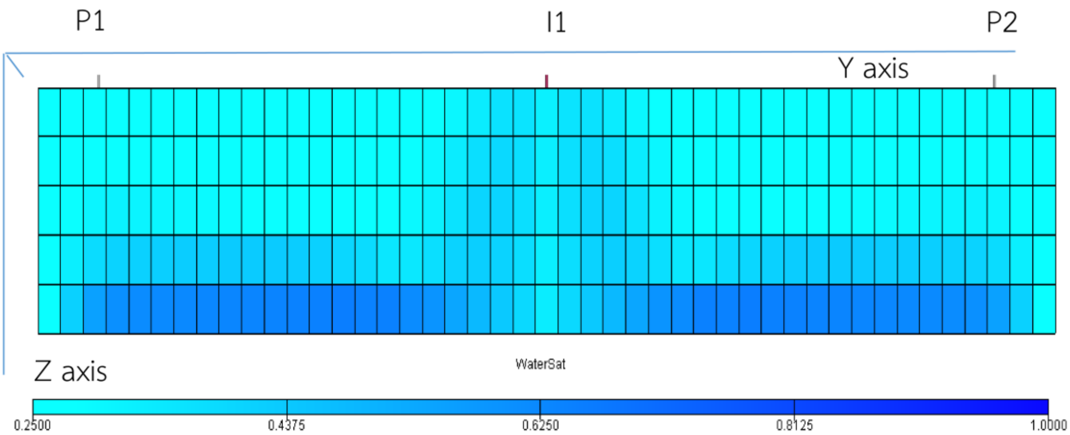

Figure 5.102 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 500 ft distance).

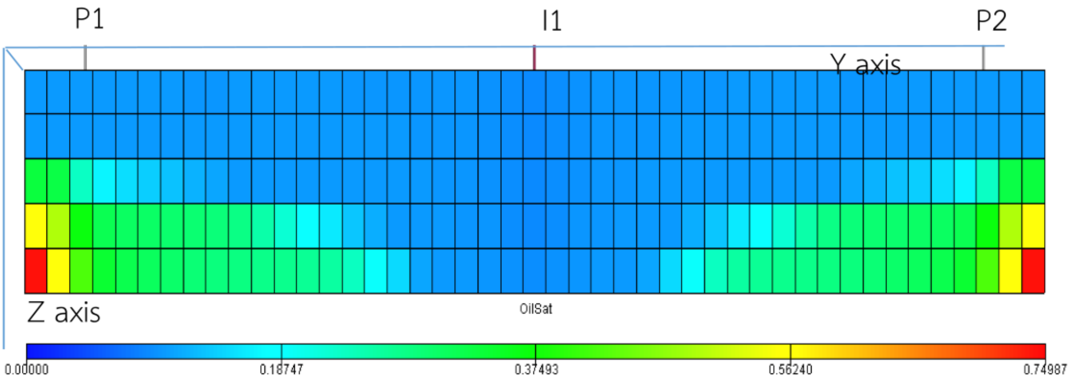

Figure 5.103 oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 500 ft distance).

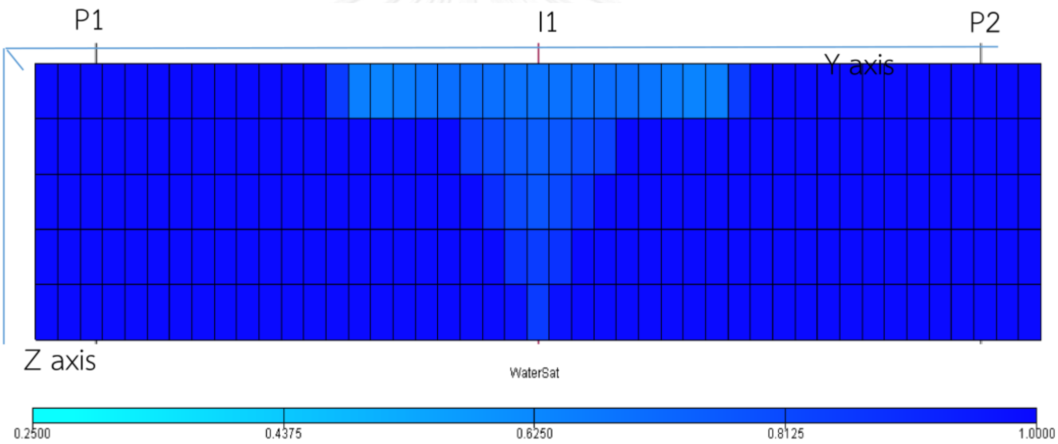

Figure 5.104 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 1500 ft distance).

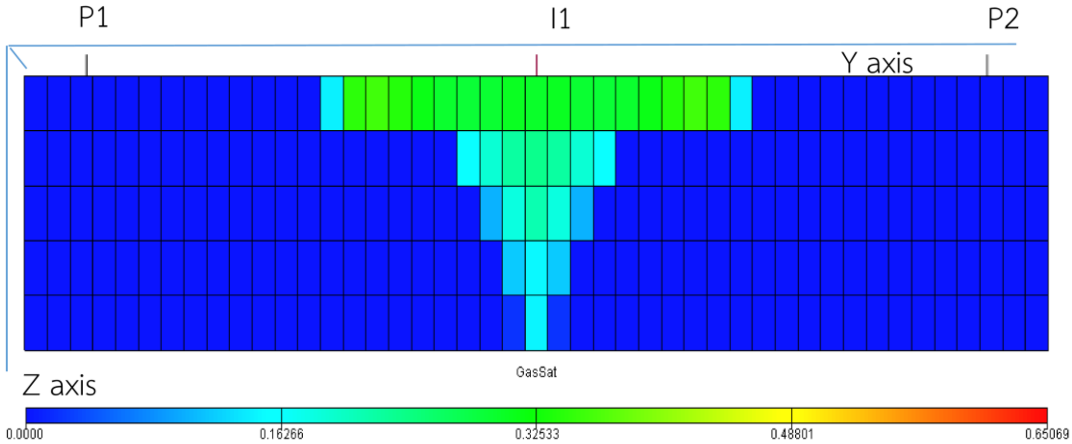

Figure 5.105 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 1500 ft distance).

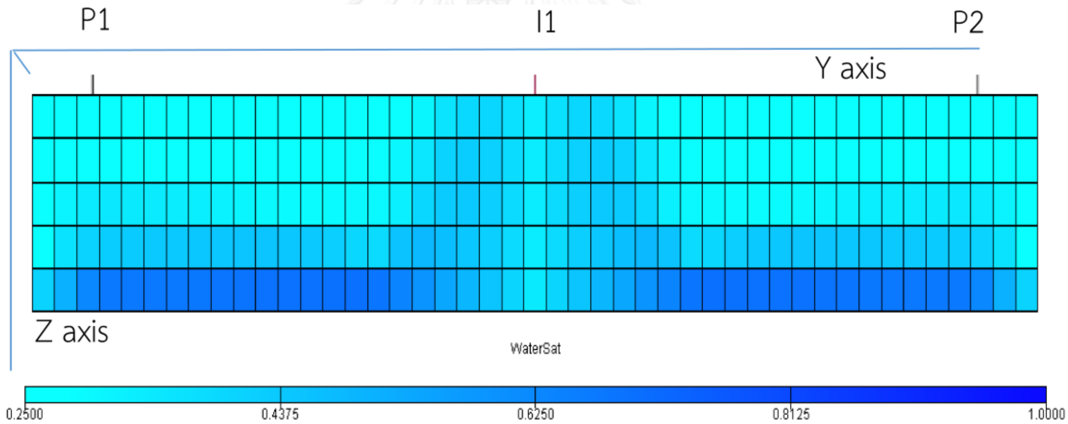

Figure 5.106 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 1500 ft distance).

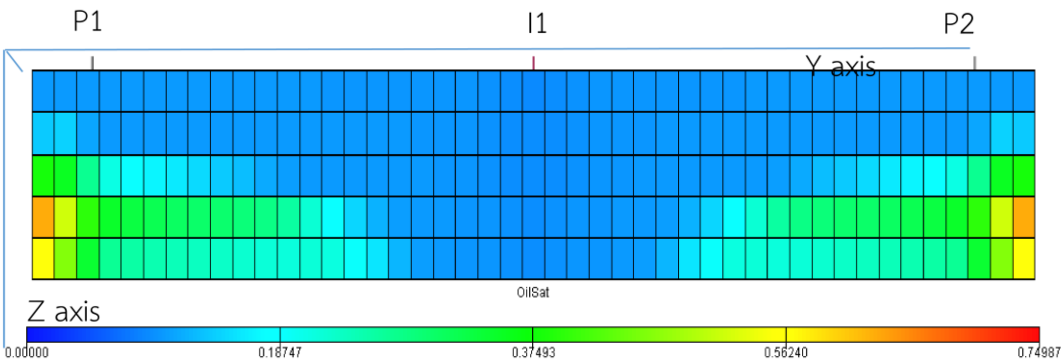

Figure 5.107 oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 1500 ft distance).

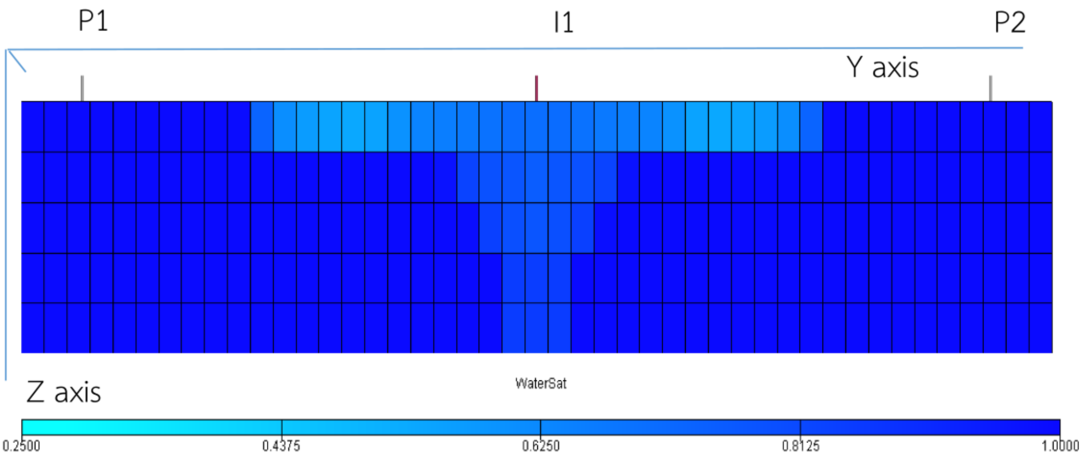

Figure 5.108 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 2500 ft distance).

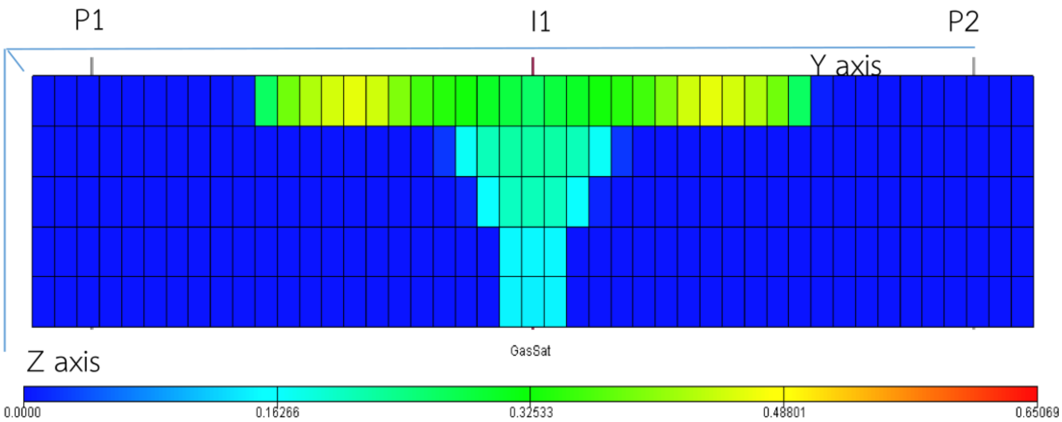

Figure 5.109 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 2500 ft distance).

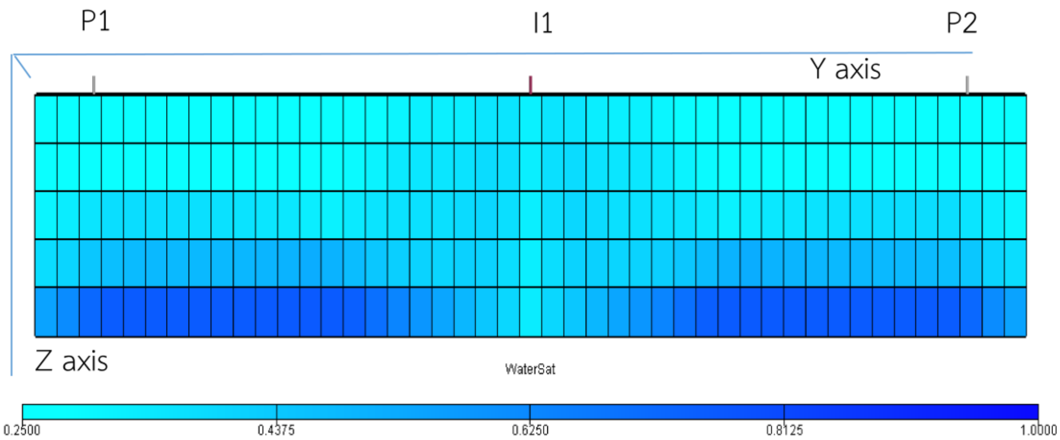

Figure 5.110 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 2500 ft distance).

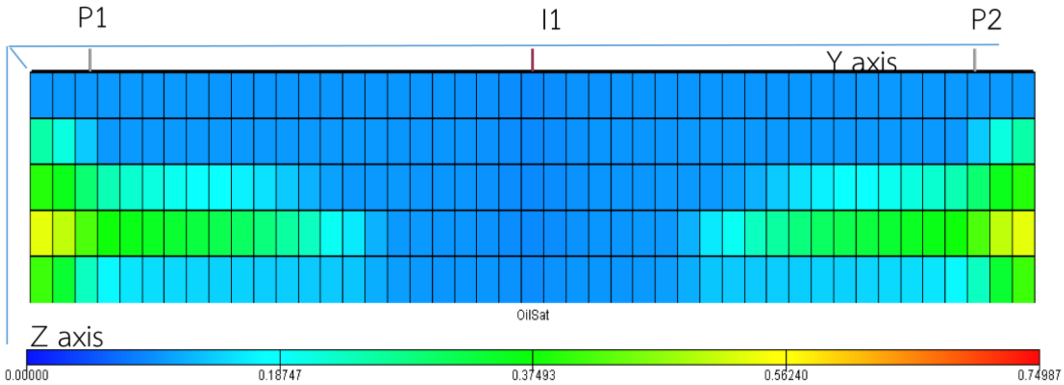

Figure 5.111 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 8 MMSCF/D, 2500 ft distance).

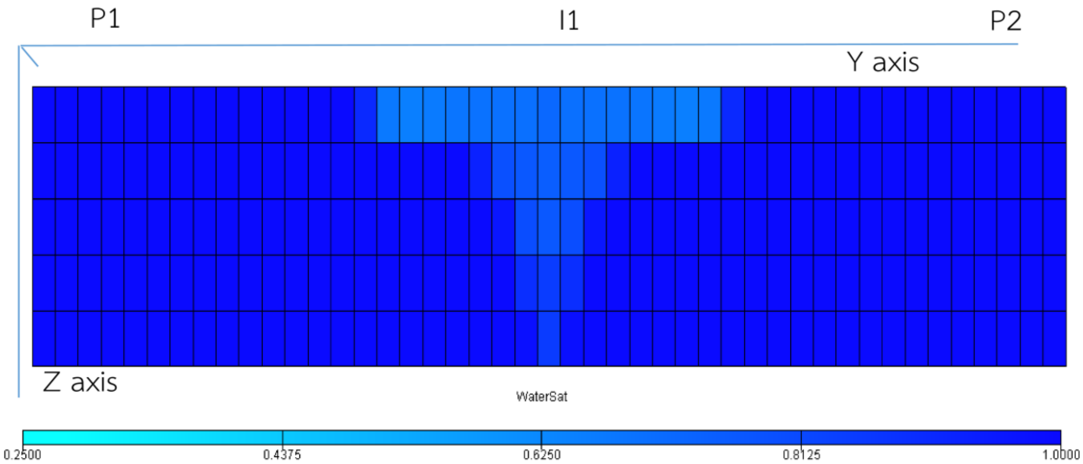

Figure 5.112 Water saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 500 ft distance).

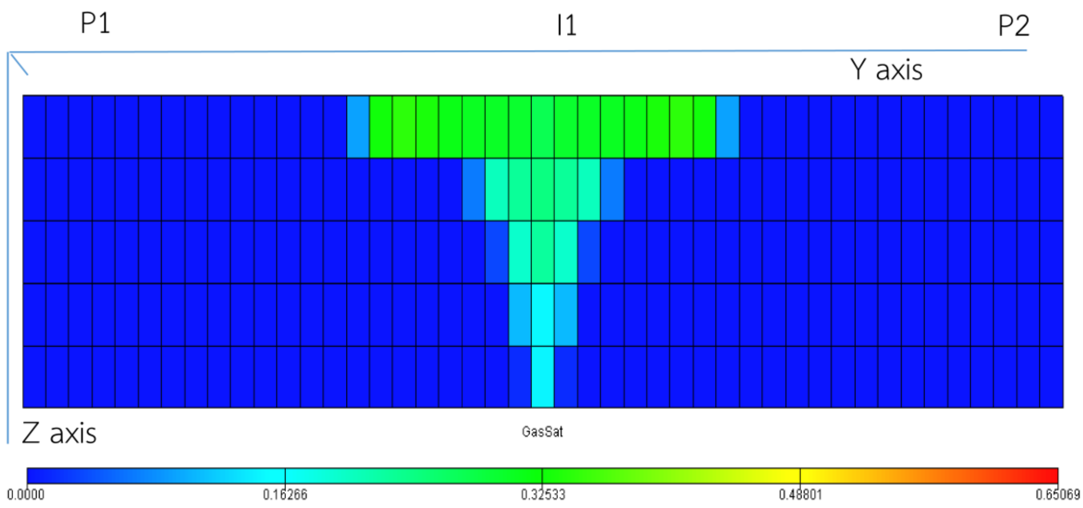

Figure 5.113 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 500 ft distance).

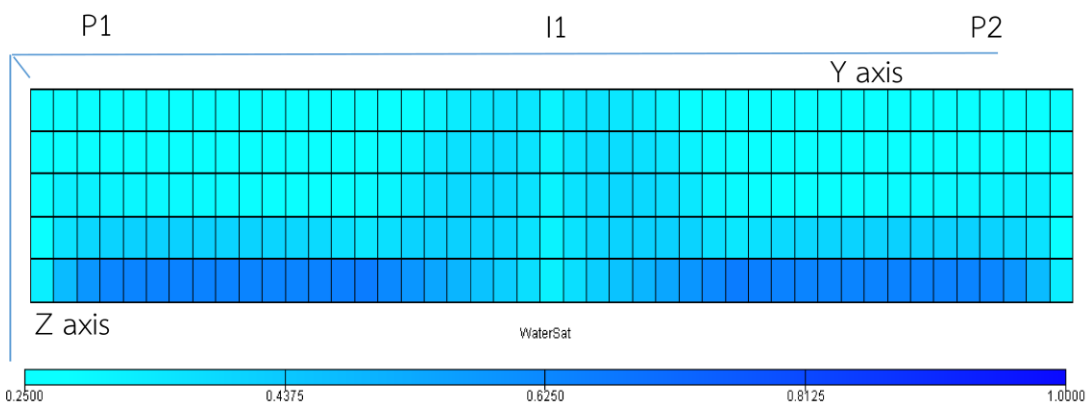

Figure 5.114 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 500 ft distance).

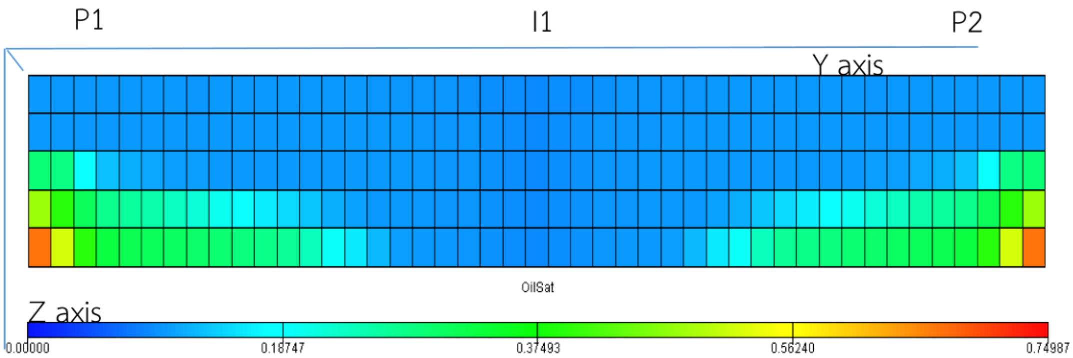

Figure 5.115 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 500 ft distance).

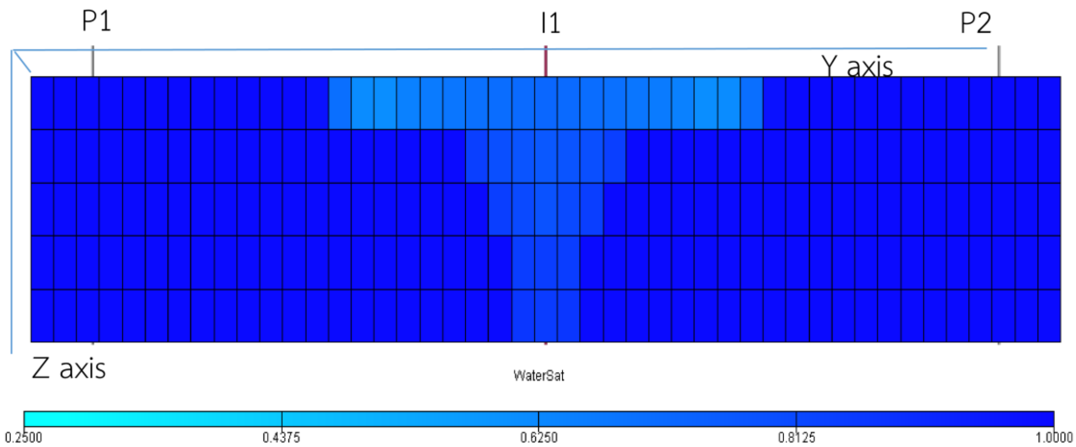

Figure 5.116 Water saturation in aquifer (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 1500 ft distance).

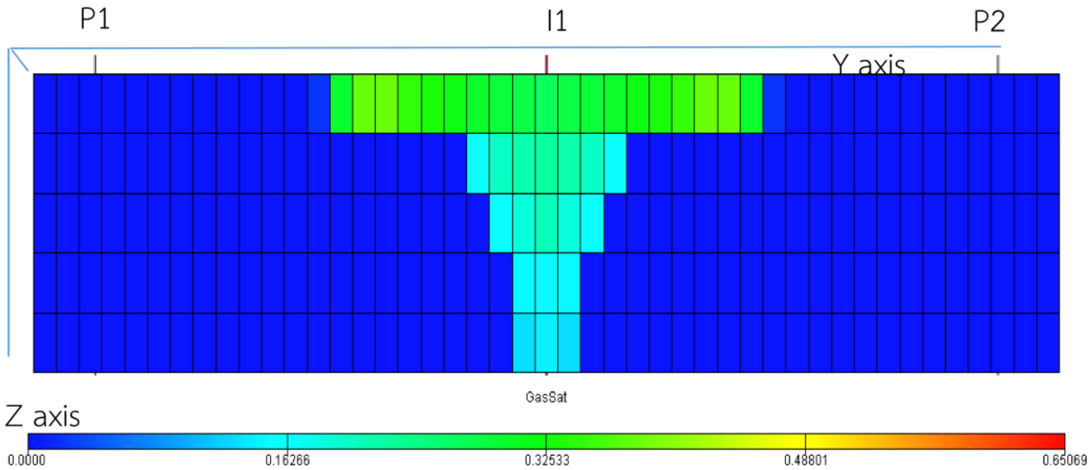

Figure 5.117 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 1500 ft distance).

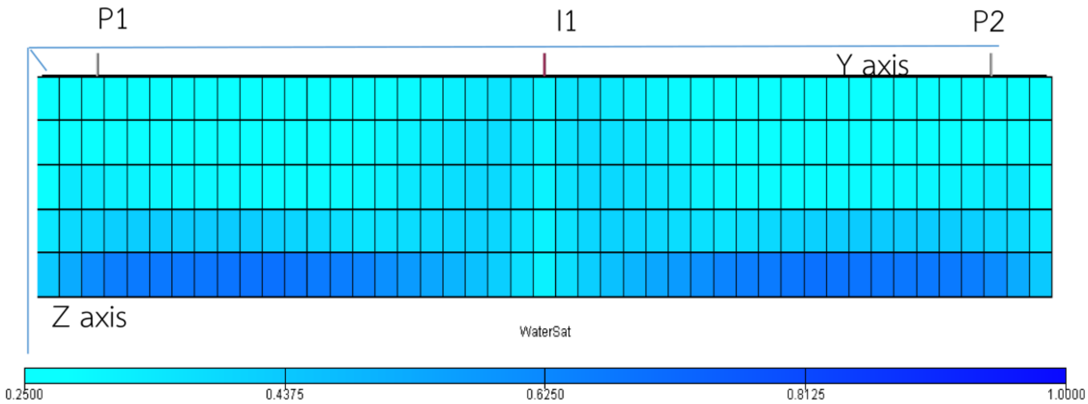

Figure 5.118 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 1500 ft distance).

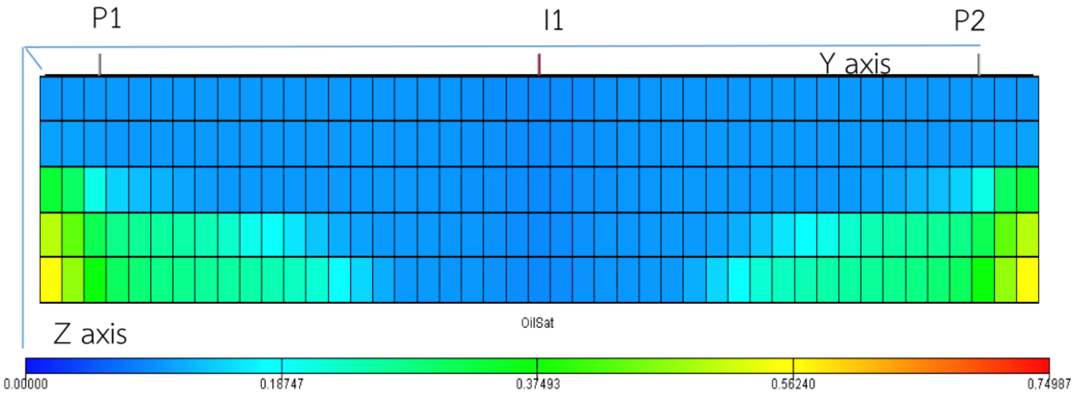

Figure 5.119 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 1500 ft distance).

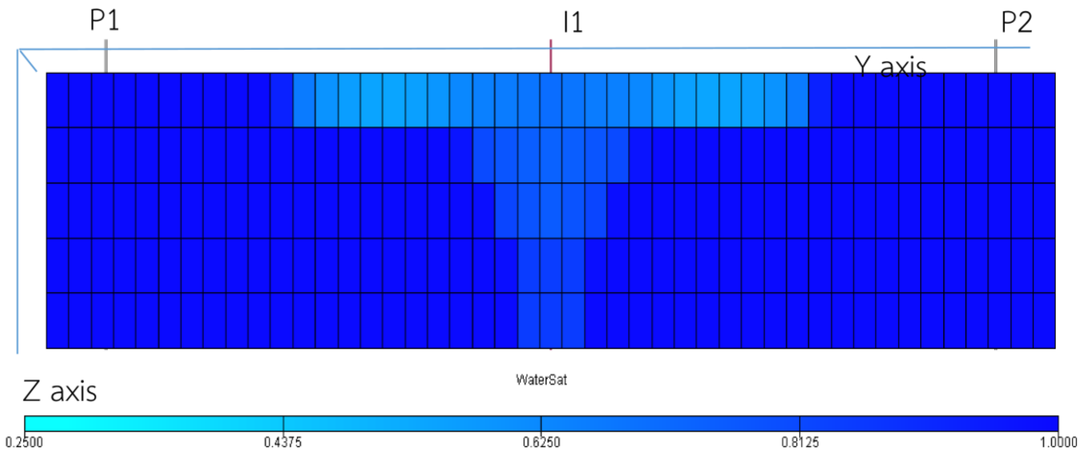

Figure 5.120 Water saturation in aquifer (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 2500 ft distance).

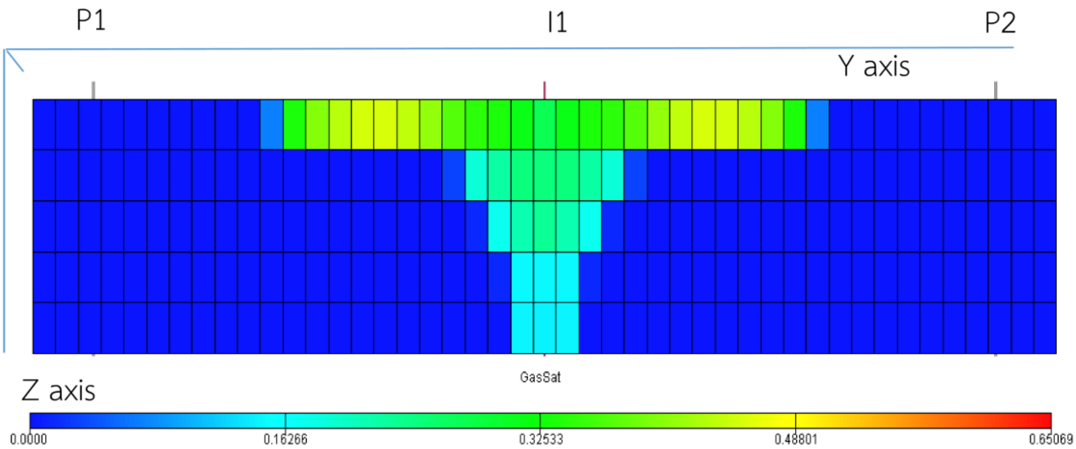

Figure 5.121 Gas saturation in aquifer at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 2500 ft distance).

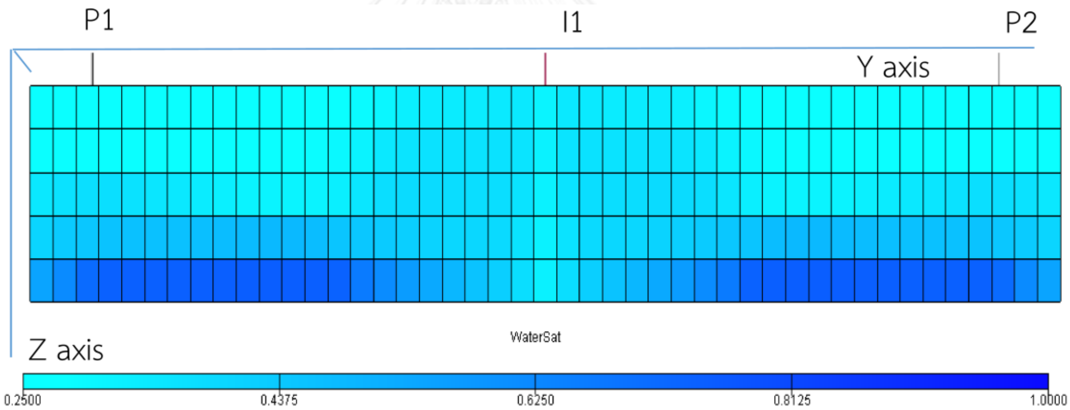

Figure 5.122 Water saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 2500 ft distance).

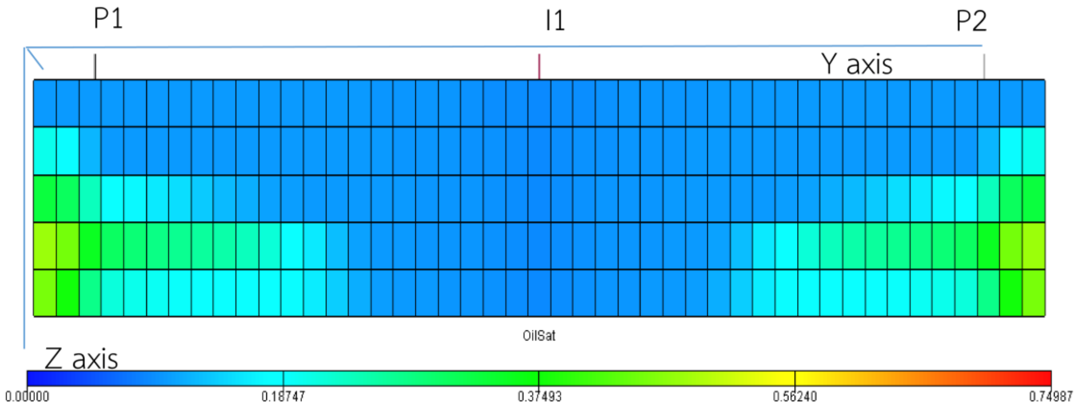

Figure 5.123 Oil saturation in oil reservoir at the end of production (water-gas injection cycle of 2:2, target gas injection rate of 16 MMSCF/D, 2500 ft distance).

5.3.2.3 Comparison between WADG injection and conventional WAG injection

5.3.2.3.1 Conventional WAG injection and WDAG injection from underlying aquifer

The comparison on recovery factor between conventional WAG injection and WDAG injection with different distances between underlying aquifer and the oil reservoir is shown in Figure 5.124 to Figure 5.129. For all water-gas injection cycles, the results indicate that if there is a limited amount of gas, conventional WAG may be a better candidate for EOR than WDAG since the recovery factor for WDAG is much lower than that for conventional WAG injection at low target gas injection rates. However, in case that there is unlimited gas, WDAG would be an alternative to conventional WAG where the distance from the underlying aquifer and the oil reservoir is not a major concern.

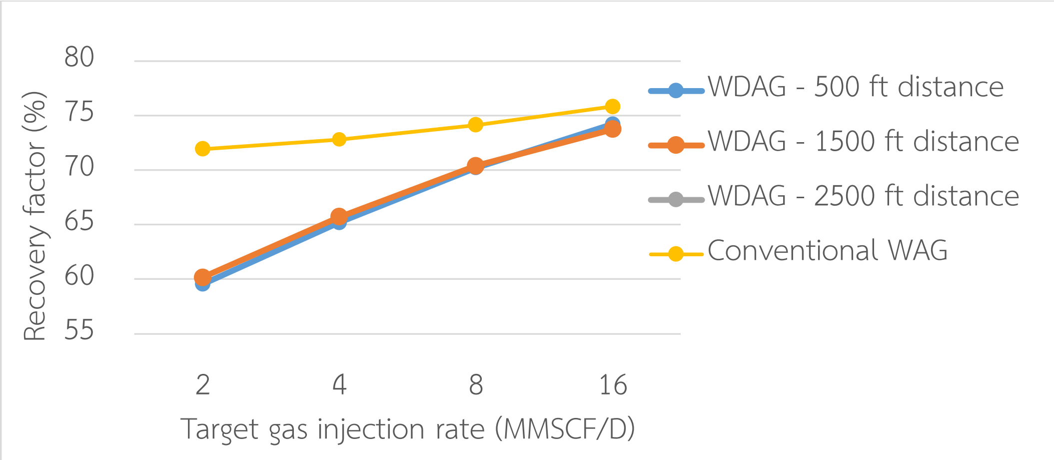

Figure 5.124 WAG and WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 1:1 month.

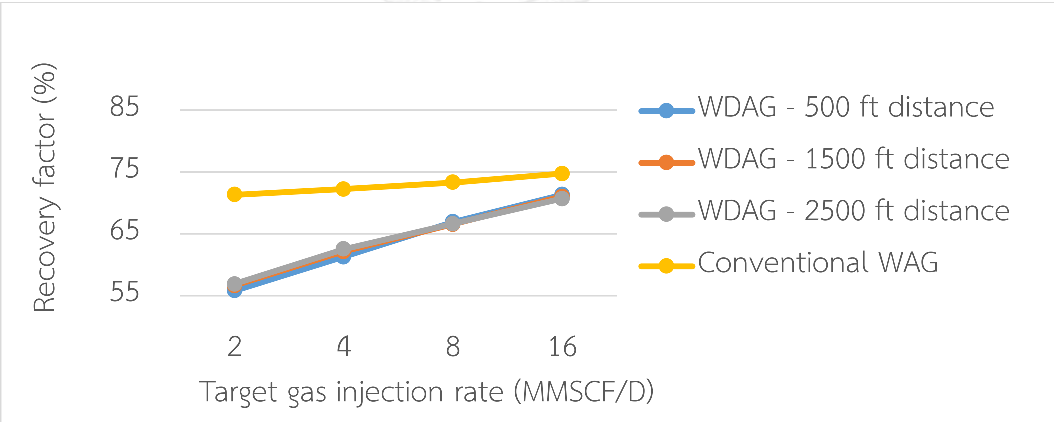

Figure 5.125 WAG and WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 2:1 month.

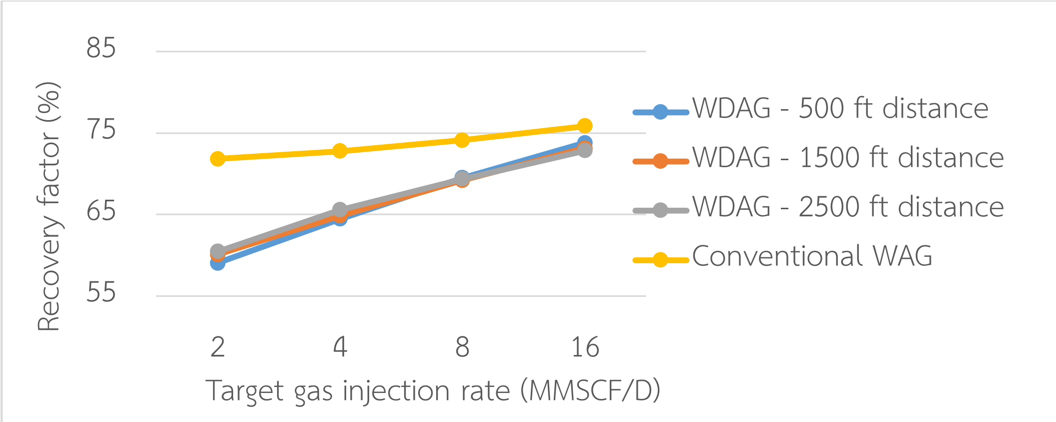

Figure 5.126 WAG and WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 2:2 month.

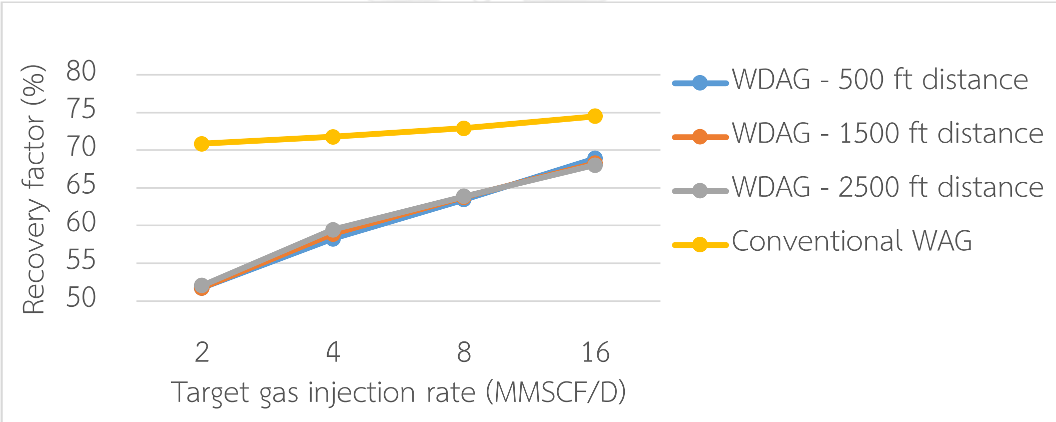

Figure 5.127 WAG and WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 3:1 month.

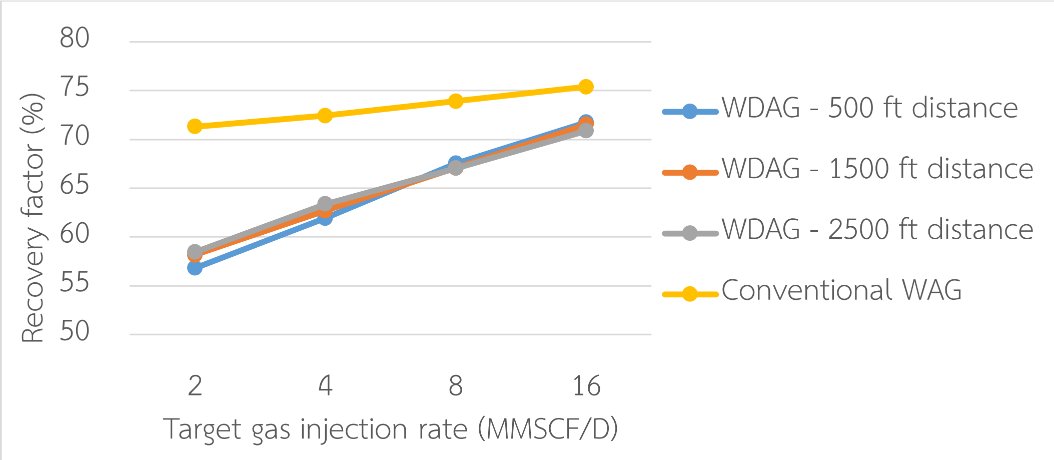

Figure 5.128 WAG and WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 3:2 month.

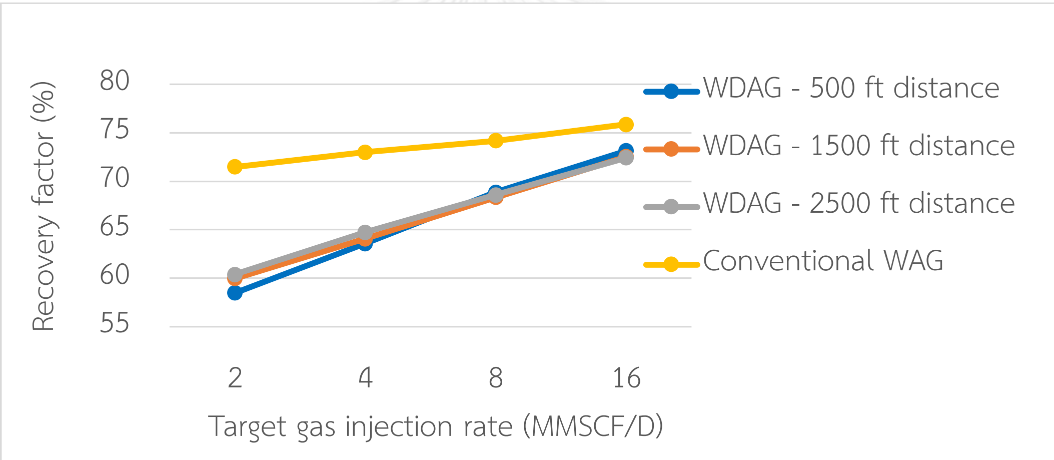

Figure 5.129 WAG and WDAG recovery factors for various depths of underlying aquifer in the case of water-gas injection cycle of 3:3 month.

5.3.2.3.2 Conventional WAG injection and WDAG injection from overlying aquifer

Figure 5.130 to Figure 5.135 depict the recovery factor from conventional WAG injection and WDAG injection with different distances between overlying aquifer and oil reservoir. At the same target gas injection rate, the shallowest aquifer yields the highest recovery factor. However, there is a big gap of recovery factors between conventional WAG and WDAG at 2 MMSCF/D target gas injection rate. The gap becomes smaller when increasing target gas injection from 2 to 4, 8, and 16 MMSCF/D since the progress of microscopic displacement of gas causes slightly different recovery factors between WAG and WDAG at high target gas injection rates. The depth of aquifer and the amount of available gas injection are considered as the key factors when making decision that the process should be conventional WAG or WDAG.

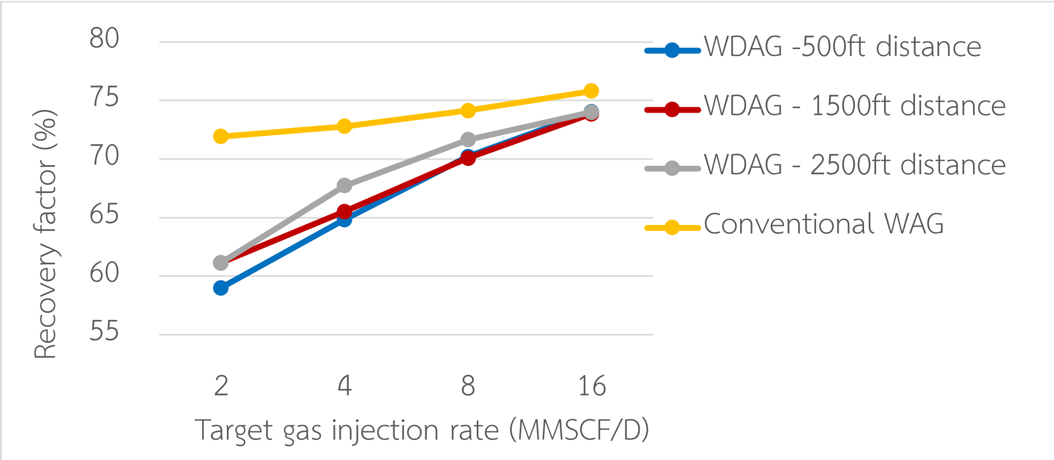

Figure 5.130 WAG and WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 1:1 month.

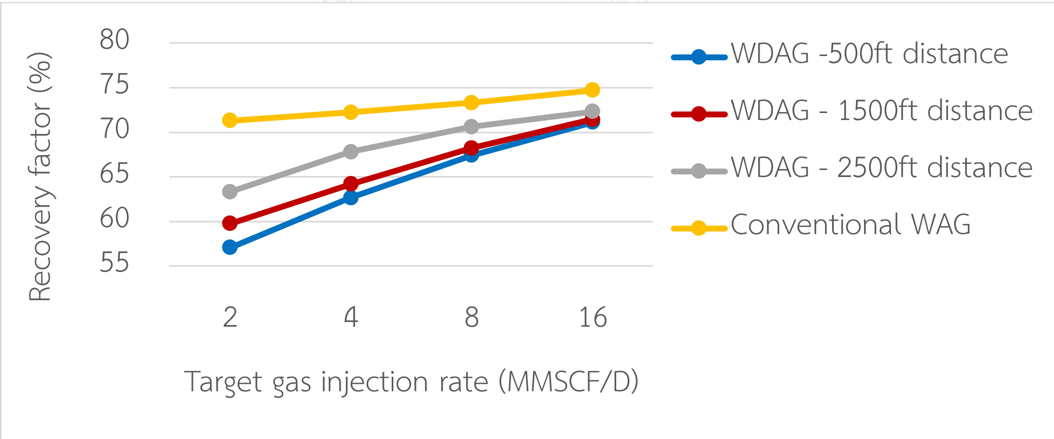

Figure 5.131 WAG and WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 2:1 month.

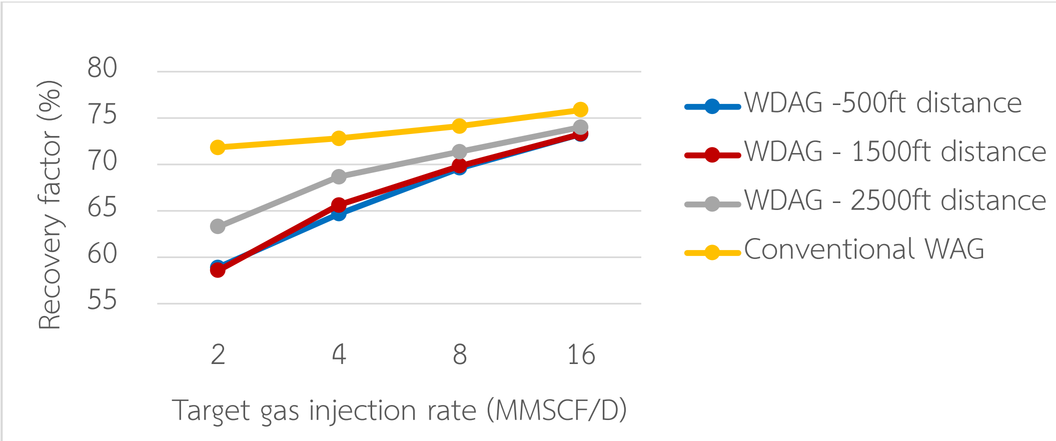

Figure 5.132 WAG and WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 2:2 month.

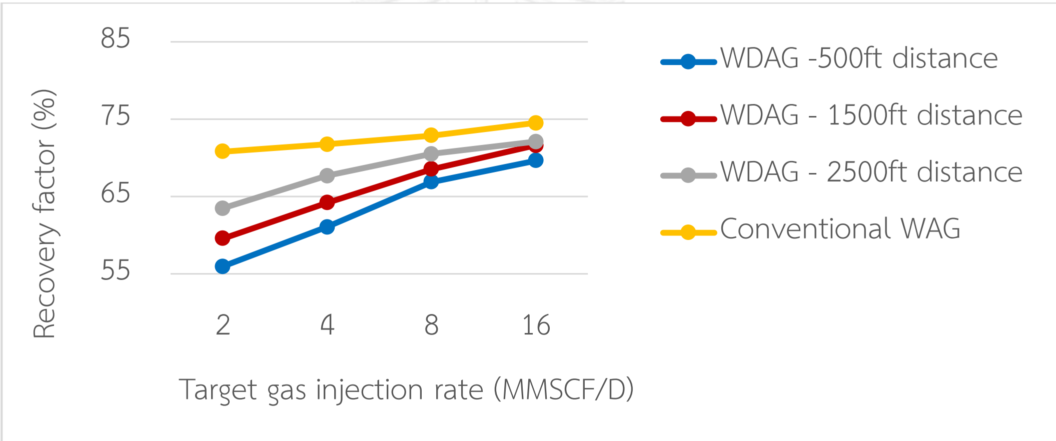

Figure 5.133 WAG and WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 3:1 month.

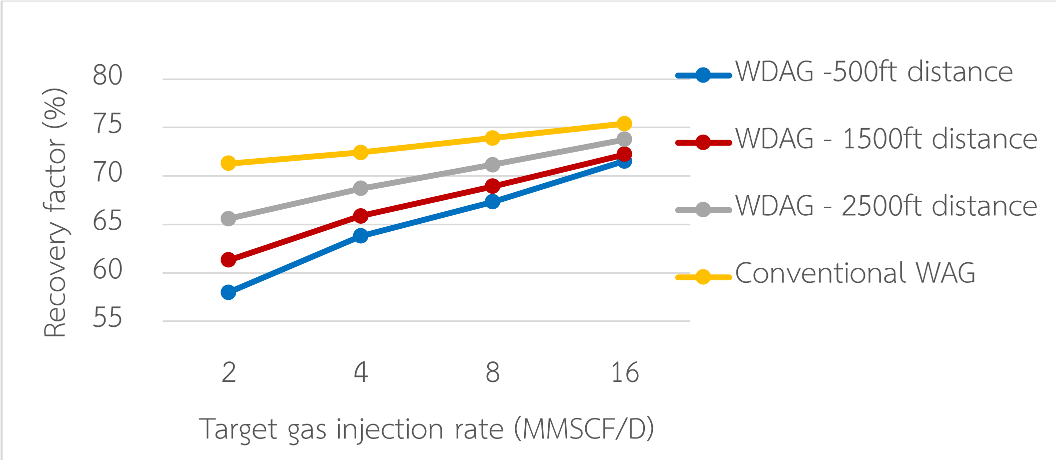

Figure 5.134 WAG and WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 3:2 month.

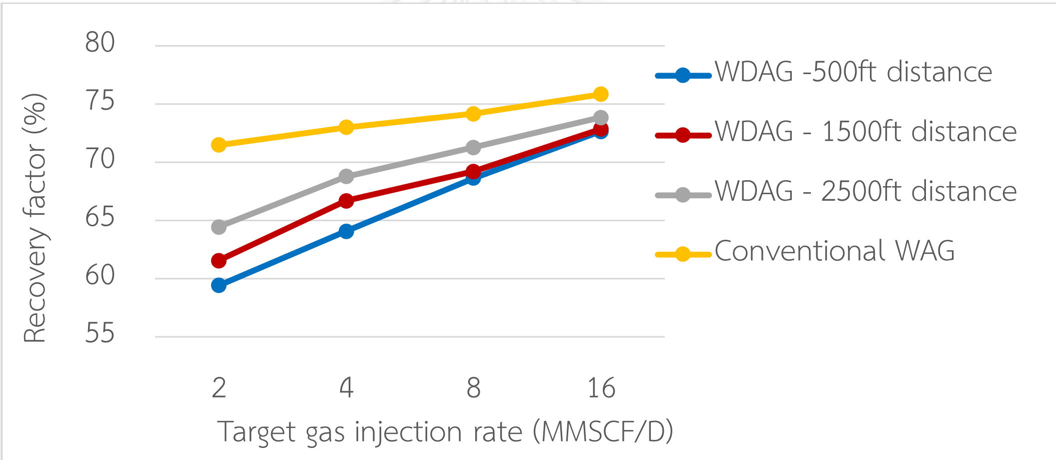

Figure 5.135 WAG and WDAG recovery factors for various depths of overlying aquifer in the case of water-gas injection cycle of 3:3 month.

5.3.2.4 Comparison between WDAG from underlying and overlying aquifer

To compare between WDAG performances from overlying aquifer and underlying aquifer, recovery factor for WDAG from overlying aquifer is subtracted from recovery factor for WDAG from underlying aquifer for corresponding distances between the aquifer and the oil reservoir which are 500 ft, 1500 ft and 2500 ft. Difference in recovery factor between WDAG from overlying aquifer and underlying aquifer is shown in Figure 5.136 to Figure 5.141. The recovery factors for WDAG from overlying and underlying aquifer are slightly different when performing WDAG at water-gas injection cycles of 1:1, 2:2 and 3:3 as depicted in Figure 5.136, Figure 5.138 and Figure 5.141 , respectively. A long period of gas injection in water–gas injection cycle gives better microscopic displacement of oil due to gas injection that dominates displacement efficiency in WDAG for WDAG from both underlying and overlying aquifer.

For the water-gas injection cycles of 2:1, 3:1 and 3:2, a long period of water dumping means that the macroscopic displacement of oil due to water shows more effectiveness than the cases of 1:1, 2:2 and 3:3 as shown in Figure 5.137, Figure 5.139 and Figure 5.140, respectively. For those water-gas injection cycles, WDAG injection from overlying aquifer yields much higher recovery than WDAG from underlying aquifer at low target gas injection rates. The results imply that overlying aquifer gives better cross flow of water than underlying aquifer.

A longer distance from the aquifer and the oil reservoir gives larger difference in recovery factor between WDAG from overlying and underlying aquifer. As mentioned in Section 5.3.2.1.2, the depth of underlying aquifer shows minor effect on the performance of WDAG while a longer distance from the overlying aquifer to the oil reservoir yields higher recovery factor at low target gas injection rate (see Section 5.3.2.2.2). Thus, there is small difference between WDAG from underlying and overlying aquifer for 500 ft distance but remarkable difference for 1500 ft and 2500 ft distance. This is because a longer distance gives a higher hydrostatic force of overlaying aquifer, causing a higher water cross-flow rate from the overlying aquifer than that for the underlying aquifer.

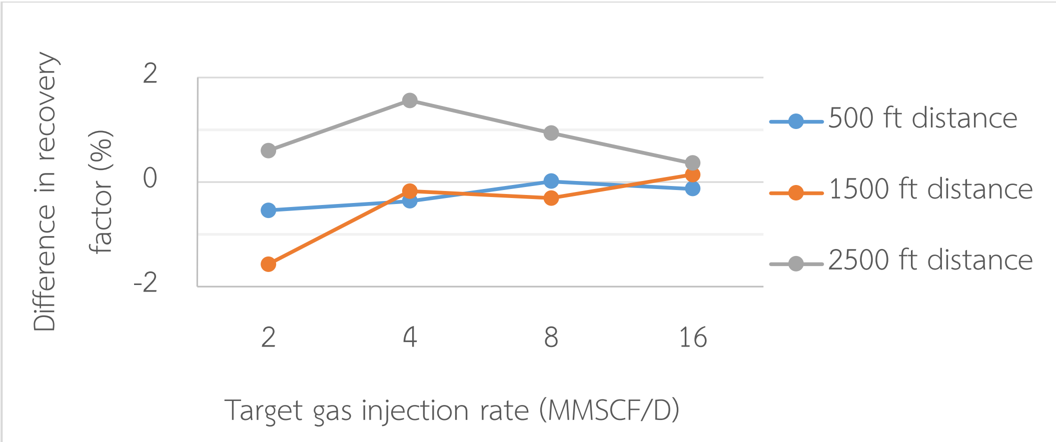

Figure 5.136 Difference in recovery factors for overlying and underlying aquifer in the case of water-gas injection cycle of 1:1 month.

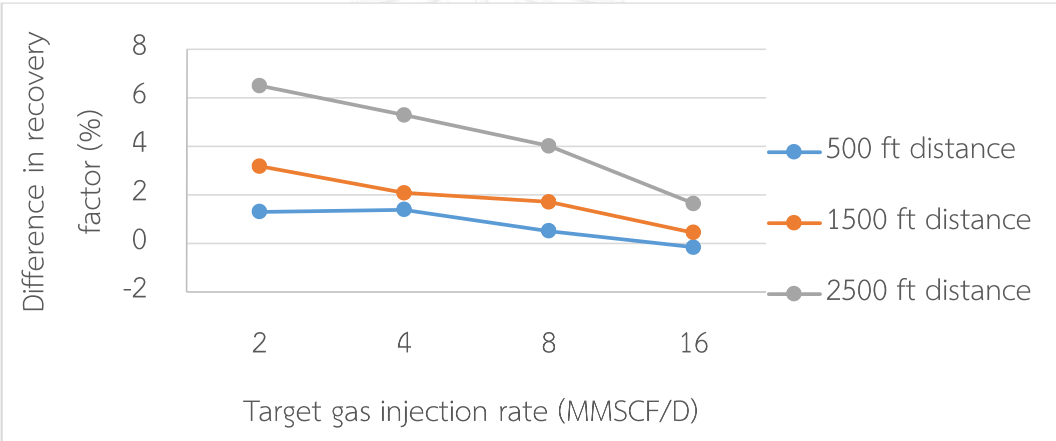

Figure 5.137 Difference in recovery factors for overlying and underlying aquifer in the case of water-gas injection cycle of 2:1 month.

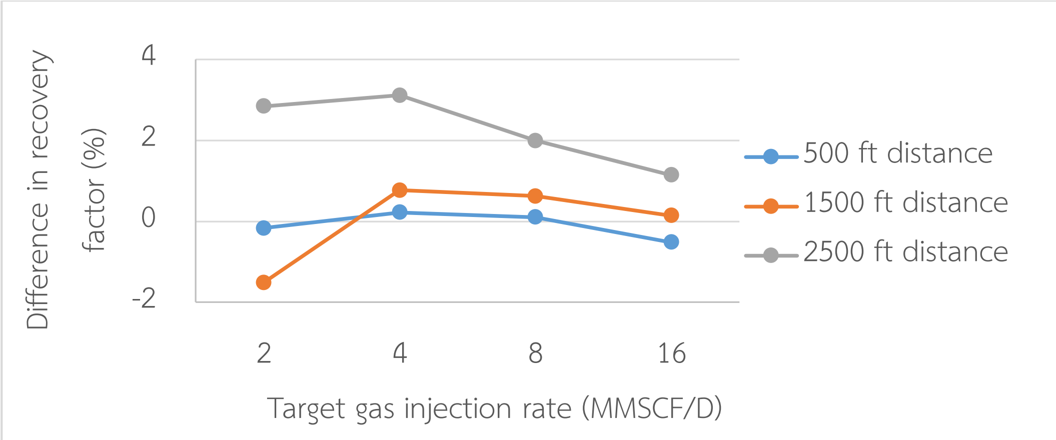

Figure 5.138 Difference in recovery factors for overlying and underlying aquifer in the case of water-gas injection cycle of 2:2 month.

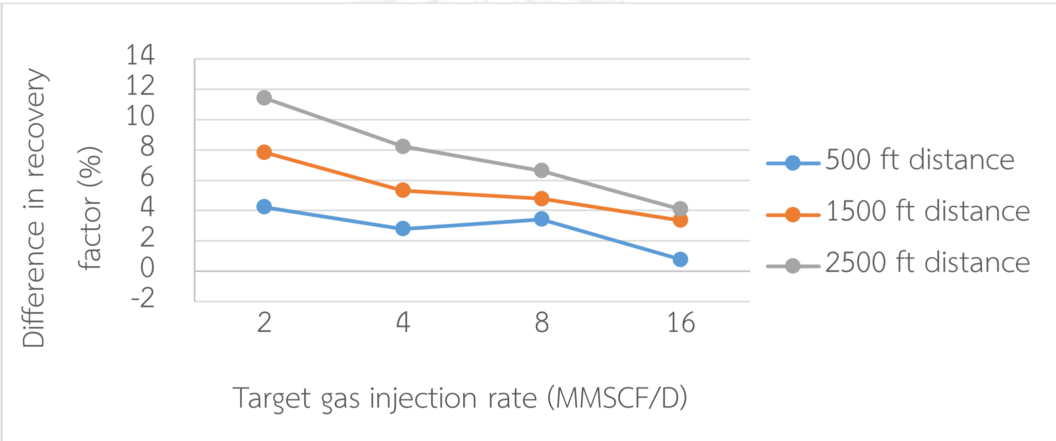

Figure 5.139 Difference in recovery factors for overlying and underlying aquifer in the case of water-gas injection cycle of 3:1 month.

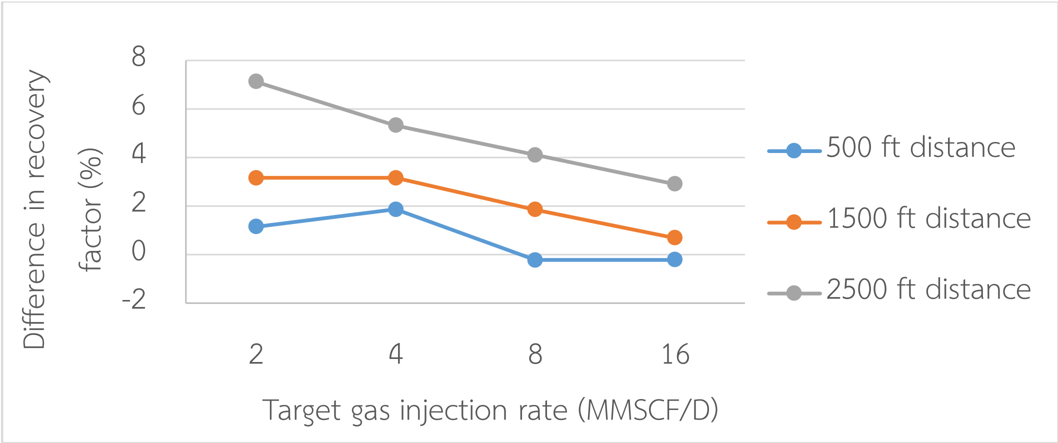

Figure 5.140 Difference in recovery factors for overlying and underlying aquifer in the case of water-gas injection cycle of 3:2 month. .

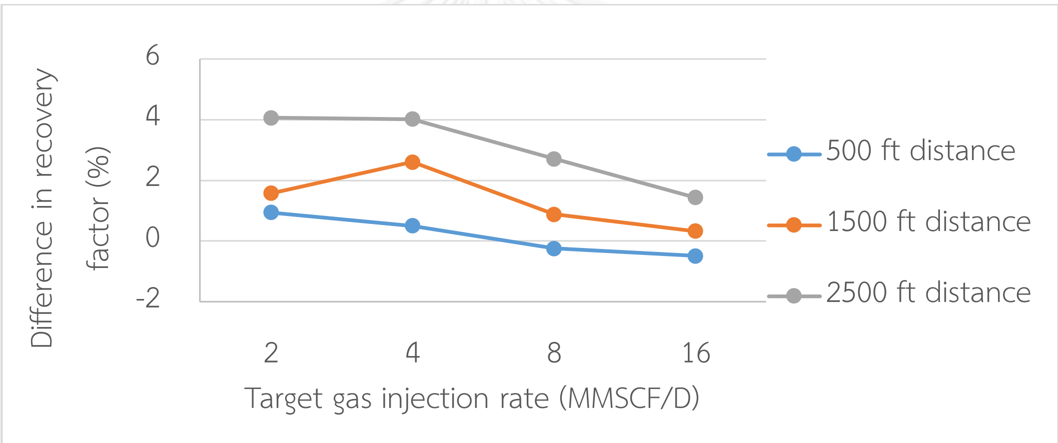

Figure 5.141 Difference in recovery factors for overlying and underlying aquifer in the case of water-gas injection cycle of 3:3 month.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

The study of "Comparative Production Performance between Conventional Water Alternating Gas Flooding and Water Dumpflood Alternating Gas Injection" provides effective information that helps improve the understanding of both conventional WAG injection and water dumpflood alternating gas injection.

6.1 Conclusions

From this study, the details of conclusions are drawn as follows:

1. In conventional WAG, target gas injection rate and water-gas injection cycle have slight effect on the performance of WAG. The water-gas injection cycle of 1:1 and the target gas injection rate of 16 MMSCF/D are favorable conditions for conventional WAG.
2. Target gas injection rate and water-gas injection cycle have significant influence on WDAG from both underlying and overlying aquifer. The water-gas injection cycle of 1:1 and the target gas injection rate of 16 MMSCF/D are favorable conditions for WDAG.
3. The study of volumetric ratio of aquifer to oil reservoir points out that a larger aquifer size gives better oil recovery factor when performing WDAG at low target gas injection rate while it shows smaller effect at higher target gas injection rates.
4. For all sizes of aquifer, WDAG shows much lower recovery factor than conventional WAG at low target gas injection rates but slightly smaller recovery at high target gas injection rates.

5. When varying the distance between underlying aquifer and oil reservoir, the depth of underlying aquifer shows a minor effect to the performance of WDAG injection.
6. For WDAG from overlying aquifer, a shallower aquifer shows a significant rise in recovery factor at low target gas injection rates but the depth of overlying aquifer does not impact the performance of WDAG at high target gas injection rates.
7. Comparing between conventional WAG and WDAG injection from both underlying and overlying aquifers, WDAG injection gives slightly smaller oil recovery factor than WAG injection at high target gas injection rates but it does not require any water injection system from surface. When injecting at low target gas injection rates, WAG yields much better recovery factor than WDAG.
8. Between WDAG from underlying and overlying aquifer, WDAG from overlying shows slightly higher oil recovery factor than WDAG from underlying aquifer at low target gas injection rates. At high target gas injection rates, the results are not much different between depths of aquifers.

6.2 Recommendations

1. In this thesis, the temperature in overlying aquifer and underlying aquifer is assumed to be equal to the temperature of the oil reservoir. For more precise results, the thermal effect from different depths of aquifers should be included.
2. Hysteresis is an important phenomena in WAG that should be included in further study.
3. This study found the smallest difference in oil recovery factor between conventional WAG and WDAG at target gas injection of 16 MMSCF/D which is around 2 %. To minimize the difference in recovery factor between the two methods, the study of target gas injection rate should be extended over 16 MMSCF/D and the water-gas injection cycle should be shorter than 1:1 month.

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