WATER DUMPFLOOD INTO MULTIPLE LOW-PRESSURE GAS RESERVOIRS

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กระบวนการแทนที่แบบถ่ายเทด้วยน้ำเข้าสู่แหล่งกักเก็บแก๊สหลายชั้นที่มีความดันต่ำ

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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กระบวนการแทนที่แบบถ่ายเทด้วยน้ำเข้าสู่แหล่งกักเก็บแก๊สเป็นวิธีการใหม่ที่มีสัญญาณที่ดีเพื่อเพิ่มการนำแก๊สขึ้นมาโดยการรักษาความดันของแหล่งกักเก็บ ทั้งยังมีค่าใช้จ่ายที่ถูกกว่าการอัดฉีดน้ำ ดังนั้นการจำลองการไหลในแหล่งกักเก็บของกระบวนการแทนที่แบบถ่ายเทด้วยน้ำเข้าสู่แหล่งกักเก็บแก๊สที่บางหลายชั้นที่ใกล้จะถูกทิ้งซึ่งพบได้ทั่วไปในอ่าวไทยถูกนำมาศึกษาเพื่อแสดงให้เห็นถึงประโยชน์ของวิธีการที่นำเสนอ และพิจารณาตัวแปรที่ในการผลิตที่เหมาะสมที่สุดสำหรับแหล่งกักเก็บแก๊สที่มีตัวแปรระบบแตกต่างกัน

การศึกษาการจำลองการไหลในแหล่งกักเก็บพบว่า กระบวนการแทนที่แบบถ่ายเทด้วยน้ำสามารถเพิ่มการนำแก๊สขึ้นมาได้สูงสุดถึง 10.5% ทั้งนี้ค่าดังกล่าวขึ้นอยู่กับสภาวะที่ใช้ในการผลิต และตัวแปรของระบบแหล่งกักเก็บ ช่วงที่ดีที่สุดสำหรับการเริ่มกระบวนการแทนที่แบบถ่ายเทสำหรับระบบที่มีชั้นน้ำขนาดใหญ่ และระยะระหว่างหลุมที่ยาวคือ เริ่มเมื่ออัตราการผลิตแก๊สต่ำกว่าอัตราการผลิตสูงสุดที่ตั้งไว้ เพราะว่าระยะหลุมที่ยาวจะชะลอการเคลื่อนที่ของน้ำมาถึงหลุมผลิต และการเริ่มกระบวนการแทนที่แบบถ่ายเทไวกว่าจะใช้เวลาในการผลิตทั้งหมดสั้นกว่า ในทางกลับกัน สำหรับระบบมีชั้นน้ำขนาดใหญ่ และระยะระหว่างหลุมที่สั้น การเริ่มกระบวนการแทนที่แบบถ่ายเทด้วยน้ำเมื่ออัตราการผลิตแก๊สใกล้อัตราการผลิตต่ำสุดจะให้ผลที่ดีกว่า เนื่องจากน้ำจะเคลื่อนที่มาถึงหลุมผลิตได้เร็วเมื่อระยะระหว่างหลุมสั้น สำหรับระบบที่มีชั้นน้ำขนาดกลาง และขนาดเล็ก น้ำจะเคลื่อนที่มาถึงหลุมผลิตช้า ดังนั้นจึงควรเริ่มกระบวนการแทนที่แบบถ่ายเทด้วยน้ำเมื่ออัตราการผลิตแก๊สต่ำกว่าอัตราการผลิตสูงสุดที่ตั้งไว้เพราะว่าใช้เวลาในการผลิตแก๊สทั้งหมดสั้นกว่า อย่างไรก็ตามกระบวนการแทนที่ด้วยน้ำไม่ควรถูกนำมาใช้ ในกรณีที่ใช้เครื่องอัดแก๊ส เนื่องจากกระบวนการนี้เพิ่มการนำแก๊สขึ้นมาได้น้อยมาก

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Water dumpflood into nearly abandoned gas reservoirs is a new promising approach to increase gas recovery by maintaining the reservoir pressures with much cheaper costs than waterflooding. Thus, a simulation study of water dumpflood into multiple nearly abandoned thin-bedded gas reservoirs commonly found in the Gulf of Thailand was conducted to demonstrate the advantage of the proposed method and to determine the most suitable operation conditions for reservoirs having different system parameters.

This simulation study found that water dumpflood can increase gas recovery up to 10.5% depending on operational conditions and system parameters. It is best to start water dumpflood when the gas rate is below the plateau rate for systems having a large aquifer and long distance between wells because the long well distance helps delay water breakthrough and earlier dumpflood operation requires shorter production duration. On the other hand, for the systems having a large aquifer and short distance between the two wells, performing water dumpflood when the rate is close to the economic rate is better because water is more likely to cause an early breakthrough when the distance is short. For system having small or moderate aquifer size, water breakthrough is more likely to occur later, thus, dumpflood should be performed when the gas rate is below plateau as it requires shorter production duration. However, if booster compressor is used, water dumpflood is not recommended to perform because it yields very small incremental recovery factors.

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

bbl	Reservoir barrel
bbl/STB	Reservoir barrel per stock tank barrel
BCF	Billion standard cubic feet
cos	Cosine function
cp	Centipoise
cuft	Cubic feet
ft	Feet
GOR	Gas-oil ratio
m	meter
mD	Millidarcy
OGIP	Original gas-in-place
psi	Pound per square inch
psia	Pound per square inch absolute
PV	Pore volume
PVT	Pressure-Volume-Temperature
SCAL	Special core analysis
SCF	Standard cubic feet
SCF/STB	Standard cubic feet per stock tank barrel
sec	Second
STB	Stock tank barrel
STB/D	Stock tank barrel per day
TVD	True vertical depth

Nomenclatures

B_g	Gas formation volume factor, bbl/SCF
B_{ga}	Gas formation volume factor at abandonment pressure, bbl/SCF
B_{gi}	Initial gas formation volume factor, bbl/SCF
B_w	Water formation volume factor, bbl/STB
^oC	Degree Celsius
d	Pipe diameter, inch
E_A	Areal sweep efficiency, -
E_D	Displacement efficiency, -
E_I	Vertical sweep efficiency, -
E_R	Gas Recovery, %
E_V	Volumetric sweep efficiency
f	Darcy-Weisbach friction factor, -
^oF	Degree Fahrenheit
$FRAC.S.G.$	Fracture pressure gradient
G	Gas in place, cuft
g_c	Conversion constant equal to 32.174 lb-ft/lb_f-sec^2
G_p	Cumulative gas production, SCF
h	Reservoir thickness, ft
H_g	Gas holdup, -
H_L	Liquid holdup, -

J	Productivity index, SCF/D-psi^2
k	Absolute permeability, mD
k_{rg}	Relative permeability to gas, -
k_{rgcw}	Relative permeability to gas at connate water saturation, -
k_{rw}	Relative permeability to water, -
k_{rwgc}	Relative permeability to water at critical gas saturation, -
L	Pipe length, ft
lb	Pound mass
lb_f	Pound force
lb/ft^3	Pound per cubic foot
M	Mobility ratio, -
$MSCF/D$	Thousand standard cubic feet per day
$MMSCF/D$	Million standard cubic feet per day
n_g	Corey gas exponent
n_w	Corey water exponent
p	Pore pressure, psi
p_f	Fracture pressure, psi
p_{inj}	Injection pressure, psi
p_R	Reservoir pressure, psi
p_{wf}	Well flowing pressure, psi
$\overline{p}_r$	Average reservoir pressure, psi
q_g	Gas flow rate, SCF/D

q_L	Liquid flow rate, STB/D
q_{inj}	Water injection rate, STB/D
r_e	Reservoir radius, ft
r_w	Wellbore radius, ft
S	Skin factor
s_g	Gas saturation
s_{gc}	Critical gas saturation
s_{gr}	Residual gas saturation
s_w	Water saturation
s_{wi}	Initial water saturation or connate water saturation
T_R	Reservoir temperature, °F
v_m	Mixture velocity, ft/sec
v_{Sg}	Superficial gas velocity, ft/sec
v_{SL}	Superficial liquid velocity, ft/sec
w	Mass flow rate, lb/D
W_e	Water influx into the reservoir, bbl
W_p	Cumulative water production, STB
z	Gas compressibility factor

Greek symbol

Δ	Difference, -
γ	Poisson’s ratio
λ_g	Gas no-slippage holdup, -

λ_L	Liquid no-slippage holdup, -
μ_g	Gas viscosity, cp
μ_L	Liquid viscosity, cp
μ_w	Water viscosity, cp
θ	Incline angle, degree
ρ	Density, lb/ft^3
$\overline{\rho}_g$	Integrated average gas density at flowing conditions, lb/ft^3
$\overline{\rho}_L$	Integrated average liquid density at flowing conditions, lb/ft^3
$\overline{\rho}_m$	Integrated average density of mixture at flowing conditions, lb/ft^3
σ_o	Vertical overburden stress, psi
σ_V	Vertical matrix stress, psi
$\overline{\sigma}_H$	Average horizontal matrix stress, psi

CHAPTER 1

INTRODUCTION

1.1 Background

Volumetric gas reservoirs are abandoned when the pressures of the reservoirs are low as there is insufficient pressure to flow the gas to surface. Installing compressors and reducing wellhead pressure may help prolong the well life and recover additional gas. However, compressor is used when the project is economically feasible.

Another technique to recover an additional amount of remaining gas is to find a way to increase the reservoir pressure. Waterflooding has been considered as a method to increase gas recovery in low-pressure gas reservoir. However, waterflooding needs water injection which causes high capital and operating costs such as surface pump and surface water management. The economic feasibility of waterflooding in low-pressure gas reservoir depends on these factors.

To eliminate costs of water injection, water from a high pressure aquifer can be used to dump directly into the low-pressure gas reservoirs. This technique called "dumpflood", requires only simple adjustment of downhole completion. Water dumpflood is relatively low-cost and more attractive alternative than waterflooding. The schematic of simple well completion for water dumpflood using underlying aquifer is shown in Figure 1.1.

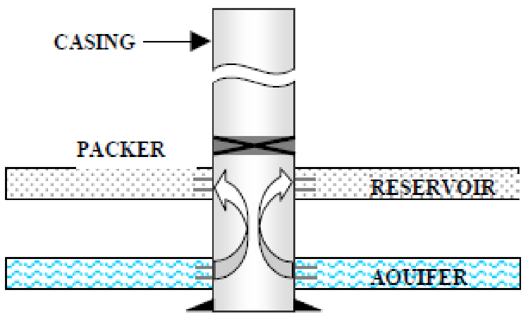


Figure 1.1 The schematic of well completion for water dumpflood using underlying aquifer [1]

In Gulf of Thailand, most gas reservoirs are well-known as several thin bed units [2]. In order to increase gas recoveries from all layers and decrease production period, water dumpflood into multiple low-pressure gas reservoirs should be considered. This method distributes the water flowing from an aquifer to several layers of gas reservoirs. As multiple layers are simultaneously flooded, we can improve overall gas recovery in a single dumpflood operation.

In this study, the reservoir model is constructed and simulated via ECLIPSE 100 reservoir simulator in order to investigate effects of various parameters on the performance of water dumpflood into multiple low-pressure gas reservoirs. Several production scenarios and reservoir system parameters are studied. The operational parameters are minimum wellhead pressures and initiation of water dumpflood conditions. Those operational parameters are optimized to reservoirs having different system parameters consisting of well spacing, aquifer depth, aquifer size and reservoir dip angle. The performances of water dumpflood are evaluated based on production durations and gas recoveries of each case.

1.2 Objectives

1. To determine effect of operational parameter on water dumpflood into multiple low-pressure gas reservoirs in order to increase gas recovery.
2. To determine optimal operational conditions for water dumpflood into multiple low-pressure gas reservoirs having different system parameters.

1.3 Outline of methodology

1. Construct a homogeneous reservoir base case models for natural depletion and water dumpflood into multiple gas reservoirs.
2. Simulate natural depletion model and base case model in order to determine the improvement of gas recovery factor compared to natural depletion model and evaluate feasibility of water dumpflood into multiple low-pressure gas reservoirs.

3. Simulate model with all operational parameters for different reservoir system parameters in order to determine the optimal operational conditions.

The operational parameters include

- Water dumpflood triggering condition
- Minimum wellhead pressure

The reservoir system parameters include

- Well pattern
- Depth difference between gas reservoirs and aquifer
- Size of water aquifer
- Reservoir dip angle

4. Analyze the results from simulations and discuss the results
5. Summarize the results and express the recommendation of this study

1.4 Outline of thesis

The thesis consists of six chapters as follows:

Chapter 1 introduces the background of water dumpflood into gas reservoir and illustrates the objectives as well as outline of methodology of this study.

Chapter 2 discusses various published literatures related to water dumpflood and water injection into gas reservoir.

Chapter 3 summarizes essential theories and concepts related to water dumpflood and water injection into gas reservoir.

Chapter 4 presents reservoir model details, fluid properties, rock properties and production conditions used in simulation.

Chapter 5 presents simulation results and discussions of study parameters. The comparisons and summaries of results are also included in this chapter.

Chapter 6 provides conclusions and recommendations of this study.

CHAPTER 2
LITERATURE REVIEW

Studies related to water dumpflood and water injection into gas reservoirs are summarized in this chapter. These studies are categorized into three sections which are 1) study of increasing recovery by pressure maintenance and pressure support via water injection, 2) study of pressure maintenance by water dumpflood and 3) study of gas displacement by liquid flooding.

2.1 Study of increasing recovery by pressure maintenance and pressure support via water injection

Cason [3] demonstrated the equation of incremental gas recovery from waterflooding into a nearly abandonment gas reservoir which never experienced water influx assuming residual gas saturation equal to half of initial gas saturation. To investigate the magnitude of expected incremental recovery, a 0.65-gravity gas with varying initial pressure of 3,000 to 6000 psi and varying abandonment pressure of 500 to 1000 psi was used in the equation. The results indicated that incremental recovery of 5 to 16% of OGIP can be obtained from waterflooding depending on initial and abandonment pressures. In the early 1970s, waterflooding into nearly abandonment pressure was applied to Duck Lake D-1 reservoir [3], south Louisiana, which was nearly abandoned and experienced water influx, for ten years. By performing water injection, the additional recovery of 25 BCF or 3.6% of OGIP was achieved.

Fishlock and Probert [4] performed the simulations of waterflooding of gas-condensate reservoirs. In this study, water was injected before pressure depletion with the water injection rate of 10% HCPV/year for various time periods. Two types of reservoir fluid were studied, fluid with condensate to gas ratio (CGR) of 180 STB/MMSCF and fluid with CGR of 300 STB/MMSCF. The maximum hydrocarbon recoveries were achieved by injecting 25% and 60% of HCPV for CGR of 180 STB/MMSCF and 300 STB/MMSCF fluids, respectively. The recoveries were increased by 10% and 21% of initial hydrocarbon mass, compared to those obtained by primary recovery. Moreover, the sensitivity analyses of this study indicated that recovery decreases slightly with increasing permeability in full waterflooding and decreases with increasing aquifer size in limited waterflooding.

Valjak et al. [1] presented the physical and economic feasibility of waterflooding of low-pressure gas reservoirs. This study demonstrated 3 feasible technical cases to apply waterflooding of low-pressure gas reservoirs consisting of pressure maintenance, pressure support and waterflooding following by compression. In order to determine technical and economic benefits of waterflooding of low-pressure gas reservoirs, two actual field data were studied: Godchaux Reservoir A and Reservoir X. Waterflooding was hypothetically initiated in the same year that compression was implemented. The results showed that pressure maintenance and waterflooding followed by compression requires a large amount of water injection compared to pressure support but gives higher gas recovery. The recovery from pressure maintenance is slightly higher than the recovery from compression while waterflooding followed by compression gives the highest recovery. Net present value (NPV) and present value of reserve (PVR) were used as the indicators for economic comparison. Although the pressure support case gives lower PVR compared to compression but their NPVs are not different. Moreover, if gas reservoirs are considered as water disposal facilities, commercial water disposal can be added to NPV. As a result, all of waterflooding cases yield higher NPV even for the pressure support case. This paper concludes that waterflooding of low-pressure gas reservoirs is feasible in terms of technical and economic improvement of gas recovery.

2.2 Study of pressure maintenance by water dumpflood

Quttainah et al. [5] developed an optimized technique by combining drilling infill wells with water injection by water dumpflood from shallower water aquifer to maintain reservoir pressure and extend production plateau of oil reservoir. Several reservoir simulation runs were made using Umm Gudair field data in order to optimize dumpflood, infill production and disposal wells. Many development scenarios were evaluated, for example, combining drilling infill wells with water dumpflood (development case), drilling infill wells without dumpflood (infill case) and water dumpflood without drilling infill well. The best development case which consists of 38 infill wells, 16 dumpflood wells and 6 disposal wells gives oil plateau length of 11 years, compared to 3 years for do-nothing case and 4.5 years for 2 dumpflood wells without infill wells.

Fujita [6] presented a pressure maintenance method by dumping formation water into depleted oil reservoir. The Ratawi limestone oil reservoir was produced at maximum rate of 66,000 STB/D. The pressure dropped about 1,000 psi below the original value, and the producing GOR increased rapidly resulting in reduction of oil production rate to 33,000 STB/D. To maintain oil production rate by controlling GOR, pressure maintenance was initiated by dumping water from a shallow aquifer to peripheral oil reservoir. After 5-year operation, pressure was successfully maintained at around 2,600 psi by injecting cumulative water volume of 42.1 MMbbl. Besides, oil production was maintained between 40,000 and 45,000 STB/D as a result of controlling GOR by keeping the pressure high. Consequently, successful pressure maintenance by water dumpflood gives additional oil recovery of 19.58 MMSTB.

Osharode et al. [7] illustrated application of water dumpflood to sustain the reservoir pressure in a depleted oil reservoir, Egbema West. The oil production rate in the D reservoir, Egbema West field was decreased from 32 MSTB/D to around 5 MSTB/D as a result of pressure declining from 3,452 to 2,650 psi. This is because of insufficient pressure support from the aquifer to the reservoir. To solve this depletion problem, water dumpflood was applied to the D reservoir. A pilot well for water dumpflood was placed by converting an old appraisal well. The pilot water dumpflood was performed to maintain the reservoir pressure and increase the oil recovery. The natural water dumpflood successfully sustained the reservoir pressure at 2650 psi. Moreover, the average reservoir pressure increased about 8 psi after 12 years of operation. Cumulative oil production increased 33% from natural depletion. The pilot water dumpflood scheme in Egbema West was proven to be effectively applicable on a full field scale.

2.3 Study of gas displacement by liquid flooding

Geffen et al. [8] did the experiments on waterflooding into core to study factors affecting residual gas saturation after waterflooding. These factors include flooding rate, static pressure, temperature, sample size and saturation condition before flooding. Nellie Bly sand stone with a length of 1 ft was used in this study. The studied parameters were flooding rate, static pressure, temperature and sample size (core diameter). The results indicated that at the reservoir temperature and pressure, the effect of water flood rate on gas displacement efficiency is negligible. Core size did not affect gas displacement efficiency. The pressure and temperature may affect gas displacement efficiency by changing rock wettability. The residual gas saturation varied from 15% to 50% for different sands. This range is similar to the range for residual oil saturation after waterflooding.

CHAPTER 3
THEORY AND CONCEPT

This chapter summarizes essential theories and concepts of water dumpflood and water injection into gas reservoir. This chapter is divided into six sections which are 1) water dumpflood, 2) pressure maintenance, 3) water displacing gas, 4) relative permeability, 5) fracture pressure and 6) two-phase flow in vertical wells.

3.1 Water dumpflood

Water dumpflood of gas reservoir can be achieved using water from underlying or overlying aquifer instead of injecting from the surface. However, aquifer must has appropriate size, permeability and water quality. The greater aquifer size and permeability, the lesser drawdown itself. When the reservoir pressure is depleted, water from aquifer which is higher pressure zone can naturally flow into the reservoir by pressure difference and gravitational support depending on where the aquifer is located, underlying or overlying, without external energy required.

Cumulative volume of water injected cannot be measured directly without flowmeter installed downhole and connected to the surface which is an expensive option. Another method is to calculate cumulative volume of water injected by considering it as water encroached into the reservoir in material balance equation.

$$W_e = G_p B_g + W_p B_w - G\left(B_g - B_{gi}\right) \tag{3.1}$$

where

B_g = gas formation volume factor, bbl/SCF

B_{gi} = initial gas formation volume factor before water dumpflood, bbl/SCF

B_w = water formation volume factor, bbl/STB

G = gas in place before water dumpflood, SCF

G_p = cumulative gas production during water dumpflood, SCF

W_e = water influx into the reservoir, bbl

W_p = cumulative water production, STB

Water dumpflood increases gas recovery by two mechanisms [9], pressure maintenance or pressure support and gas displacement by water. During water dumpflood, the pressure depletion of gas reservoir will be slowed down by pressure maintenance and the plateau period will be extended. At the same time, the invaded water sweeps the portion of the gas that is displaceable. Thus gas is forced to flow to the producer. However, the invasion of water also causes a negative effect on gas recovery as a certain amount of gas is trapped in the water-flooded zone.

However, water dumpflood into gas reservoir may cause risk which is liquid loading. Water breakthrough at a gas well, especially at low reservoir pressure, may cause liquid loading. As gas well at low reservoir pressure has a low production velocity which cannot carry the water to the surface. That water can build up downhole if it is not completely removed from the well with the gas production. As a result, the liquid accumulation causes the gas to flow intermittently, lowering production and eventually killing the well.

3.2 Pressure maintenance

Pressure maintenance slows down the pressure depletion which extends gas production at high rates. IRP equation [10] for a gas well is described as follows:

$$q_g = J\left(\overline{p}_r^2 - p_{wf}^2\right) \tag{3.2}$$

$$J = \frac{k_{rg}kh}{1,422T\left(\mu_g z\right)_{avg}\left(\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S\right)} \tag{3.3}$$

where

h = reservoir thickness, ft

J = productivity index, SCF/D-psi^2

k = absolute permeability, mD

k_{rg} = relative permeability to gas

$\overline{p}_r$ = average reservoir pressure, psi

p_{wf} = well flowing pressure, psi

q_g = gas production rate, SCF/D

r_e = reservoir radius, ft

r_w = wellbore radius, ft

S = skin factor

z = gas compressibility factor

μ_g = gas viscosity, cp

As expressed in the equation, if the average reservoir pressure is maintained, the gas flow rate can be maintained (before water breakthrough).

3.3 Water displacing gas

3.3.1 Theoretical incremental recovery

Craft and Hawkins [11] showed that the recovery for a water drive reservoir can be expressed as

$$E_R = \frac{100\left[\left(1-s_{wi}\right)B_{ga} - s_{gr}B_{gi}\right]}{\left(1-s_{wi}\right)B_{ga}} \tag{3.4}$$

while the recovery from natural depletion is

$$E_R = \frac{100\left(B_{ga} - B_{gi}\right)}{B_{ga}} \tag{3.5}$$

where

B_{ga} = gas formation volume factor at abandonment pressure, bbl/SCF

E_R = gas recovery, %

s_{gr} = residual gas saturation

s_{wi} = initial water saturation or connate water saturation

For imbibition fluid displacements, Naar and Henderson [12] concluded that residual nonwetting-phase saturation should be about one-half the initial nonwetting-phase saturation so that

$$s_{gr} = \tfrac{1}{2} s_{gi} = \tfrac{1}{2}\left(1 - s_{wi}\right) \tag{3.6}$$

Substituting Eq. 3.6 into Eq.3.4 and subtracting by Eq. 3.5

$$\Delta E_R = 50\, {B_{gi}}/{B_{ga}} \tag{3.7}$$

Eq. 3.7 gives the incremental gas recovery after waterflooding based on the assumption that residual gas saturation equals to 50% of initial gas saturation. Therefore, the actual incremental gas recovery depends on actual residual gas saturation and actual sweep efficiency.

3.3.2 Injectivity

The success of water dumpflood depends on aquifer size which should be large enough to supply high pressure water to flow into the reservoir. The water injection rate for water dumpflood is influenced by many factors such as pressure drop in the aquifer and pressure drop in pipe during the flow from the aquifer to the reservoir. Furthermore, there are several factors affecting water injection rate which can be expressed in an equation form as

$$q_{inj} = \frac{kh}{141.2\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]}\left(p_{inj} - \overline{p}_r\right)\frac{k_{rw}}{\mu_w B_w} \tag{3.8}$$

where

k_{rw} = relative permeability to water

q_{inj} = water injection rate, STB/D

p_{inj} = well injection pressure, psi

μ_w = water viscosity, cp

3.3.3 Mobility ratio

Mobility ratio is defined as mobility of the displacing phase divided by the mobility of the displaced phase which can be expressed as

$$M = \left(\frac{k_{rw}}{k_{rg}}\right)\left(\frac{\mu_g}{\mu_w}\right) \tag{3.9}$$

where

M = Mobility ratio

If $M \leq 1$, gas is traveling with a velocity equals to or greater than displacing fluid. There is no tendency for gas to be by-passed which is favorable.

If $M > 1$, water is traveling faster than gas. Some of gas will be by-passed which is unfavorable. However, this condition is very unlikely because gas viscosity is much lower than water viscosity.

3.3.4 Displacement efficiency

The displacement efficiency is fraction of movable gas that is displaced from the swept zone at any given time or pore volume injected. The displacement efficiency can be expressed as

$$E_D = \frac{\frac{s_{gi}}{B_{gi}} - \frac{s_g}{B_g}}{\frac{s_{gi}}{B_{gi}}} \tag{3.10}$$

where

E_D = displacement efficiency

3.3.5 Volumetric sweep efficiency

The volumetric sweep efficiency is a measure of the effectiveness of displacement process that depends on the volume of the reservoir contacted by the injected fluid. The volumetric sweep efficiency can be affected by injection pattern, fractures in the reservoir, position of gas-oil and oil/water contacts, reservoir thickness, permeability, areal and vertical heterogeneities and mobility ratio.

$$E_V = E_I \times E_A \tag{3.11}$$

$$E_A = \frac{\text{Area contacted by displacing phase}}{\text{Total area}} \tag{3.12}$$

$$E_I = \frac{\text{Cross-sectional area connected by displacing agent}}{\text{Total cross-sectional area}} \tag{3.13}$$

where

E_A = areal sweep efficiency

E_I = vertical sweep efficiency

E_V = volumetric sweep efficiency

3.4 Relative permeability

Relative permeability is the ability of fluid to flow in the porous system when there are multiple fluids in the system. It can be defined as the ratio of effective permeability to any particular fluid at a given saturation to the absolute permeability. There are several correlations developed for gas reservoir which is two-phase permeability, gas and water, as follows:

3.4.1 Corey's correlation

The Corey's correlation [13] for relative permeability calculation in gas/water system and can be defined as:

$$k_{rg} = k_{rgcw}\left[\frac{s_g - s_{gc}}{1 - s_{gc} - s_{wi}}\right]^{n_g} \tag{3.14}$$

$$k_{rw} = k_{rwgc}\left[\frac{s_w - s_{wi}}{1 - s_{wi}}\right]^{n_w} \tag{3.15}$$

where

k_{rgcw} = relative permeability to gas at connate water saturation

k_{rwgc} = relative permeability to water at critical gas saturation

n_g = Corey gas exponent

n_w = Corey water exponent

s_g = gas saturation

s_{gc} = critical gas saturation

s_w = water saturation

3.4.2 Wyllie and Boatman empirical models

Zawisza [14] mentioned that Wyllie constructed an empirical model for calculating relative permeability in sandstone-mudstone rock as

$$k_{rw} = \left(s^*\right)^4 \tag{3.16}$$

$$k_{rg} = \left(1-s^*\right)^2 \left[1-\left(s^*\right)^2\right] \tag{3.17}$$

Zawisza [14] mentioned that Boatman's equations for gas-water flow are

$$k_{rw} = \left(s^*\right)^{1.5} s_w^3 \tag{3.18}$$

$$k_{rg} = \left(1-s^*\right)\left[1-\left(s^*\right)^{0.25} s_w^{0.5}\right]^{0.5} \tag{3.19}$$

$$s^* = \frac{s_w - s_{wi}}{1-s_{wi}} \tag{3.20}$$

Since Corey's correlation is widely used in reservoir simulation, it is used to construct two-phase permeability model for gas-water system in this study.

3.5 Fracture pressure

For water injection, the injection pressure should not exceed rock fracture pressure in order to prevent the creation of fracture in the reservoirs. Fracture pressure can be calculated using Eaton's approach [15] as following

$$\sigma_V = \sigma_o - p \tag{3.21}$$

$$\overline{\sigma}_H = \left(\frac{\gamma}{1+\gamma}\right)\sigma_V \tag{3.22}$$

$$p_f = \overline{\sigma}_H + p \tag{3.23}$$

where

p = pore pressure, psi

p_f = fracture pressure, psi

γ = Poisson’s ratio

σ_o = vertical overburden stress, psi

$\overline{\sigma}_H$ = average horizontal matrix stress, psi

σ_V = vertical matrix stress, psi

In the Gulf of Thailand, the fracture pressure of the M field can be calculated using correlation defined as [16]

$$\text{Fracture pressure } (\text{bar}) = \frac{FRAC.S.G. \times TVD}{10.2} \tag{3.24}$$

and

$$FRAC.S.G. = 1.22 + \left(TVD \times 1.6 \times 10^{-4}\right) \tag{3.25}$$

$FRAC.S.G.$ = fracture pressure gradient, bar/meter

TVD = true vertical depth below rotary table, meter

In this study, the correlation for fracture pressure of the M field is used to calculate fracture pressure of reservoir model in order to represent the nature of rock formation in the Gulf of Thailand.

3.6 Two-phase flow in vertical wells

Whenever two fluids with different physical properties flow simultaneously in a pipe, there is a wide range of possible flow patterns which are particular types of geometric distribution of the components. Many of the names given to these flow patterns are now quite standard as illustrated in Figure 3.1.

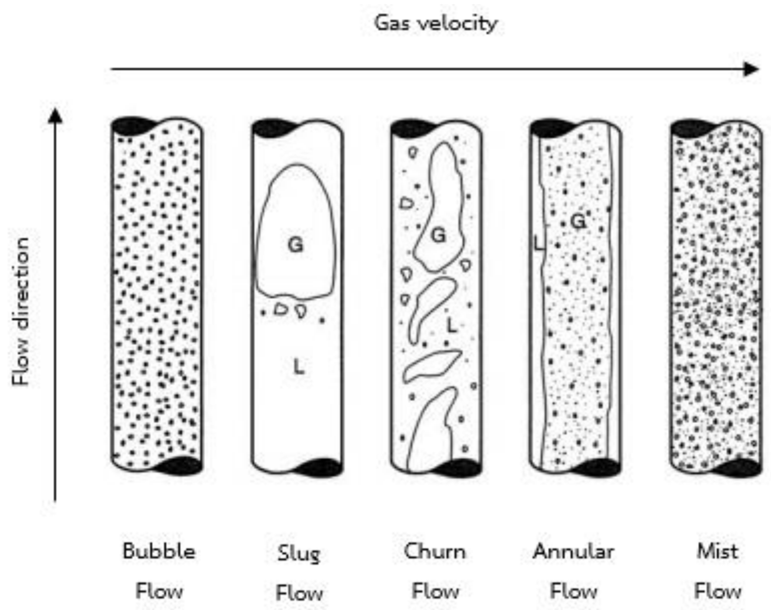


Figure 3.1 Two-phase vertical flow patterns [17]

Bubble flow is defined as a two-phase flow where small bubbles are dispersed or suspended as discrete substances in a continuous liquid phase.

Slug Flow is characterized by the presence of large gas bubble with a size close to the diameter of the pipe separated by liquid slugs.

Churn flow is characterized by the presence of a very thick and unstable liquid film, with the liquid often oscillating up and down.

Annular flow is characterized by the presence of a liquid film flowing on the channel wall and with the gas flowing in the gas core.

Mist Flow is characterized by the flow where liquids are finely dispersed in the continuous gas phase as gas phase has high velocity.

The pressure gradient equation for two-phase flow conditions in terms of quantities normally measured in the field is expressed as

$$\frac{\Delta p}{\Delta L}=\frac{1}{144}\bar{\rho}_m\cos\theta+\frac{1}{144}\frac{fw^2}{2.9652\times10^{11}d^5\bar{\rho}_m}+\frac{1}{144}\frac{\bar{\rho}_m\Delta v_m^2}{2g_c\Delta L} \quad (3.26)$$

the velocity of the mixture is

$$v_m=v_{sL}+v_{sg} \quad (3.27)$$

where

d = pipe diameter, inch

f = Darcy-Weisbach friction factor, -

g_c = conversion constant equal to 32.174 Ib-ft/lb$_f$-sec^2

L = pipe length, ft

v_m = mixture velocity, ft/sec

v_{Sg} = superficial gas velocity, ft/sec

v_{SL} = superficial liquid velocity, ft/sec

w = mass flow rate, lb/D

θ = incline angle, degree

$\bar{\rho}_g$ = integrated average gas density at flowing conditions, lb/ft^3

$\bar{\rho}_L$ = integrated average liquid density at flowing conditions, lb/ft^3

$\bar{\rho}_m$ = integrated average density of mixture at flowing conditions, lb/ft^3

Since the average integrated density $\bar{\rho}_m$ cannot be calculated directly because of the slippage which occurs between the phases, it is necessary to introduce the concept of holdup factor H_L. The holdup factor is theoretically the fractional volume of the conduit actually occupied by the liquid phase. Therefore, the average integrated density of the mixture in the pipe is described by

$$\bar{\rho}_m = \bar{\rho}_L H_L + \bar{\rho}_g H_g \tag{3.28}$$

$$H_g = 1 - H_L \tag{3.29}$$

where

H_g = gas holdup, -

H_L = liquid holdup, -

$\bar{\rho}_g$ = integrated average gas density at flowing conditions, lb/ft^3

$\bar{\rho}_L$ = integrated average liquid density at flowing conditions, lb/ft^3

If assume no slippage, $\bar{\rho}_m$ is described by

$$\bar{\rho}_m = \bar{\rho}_L \lambda_L + \bar{\rho}_g \lambda_g \tag{3.30}$$

$$\lambda_g = 1 - \lambda_L \tag{3.31}$$

$$\lambda_L = \frac{q_L}{q_L + q_g} \tag{3.32}$$

where

q_L = liquid flow rate, STB/D

λ_g = gas no-slippage holdup, -

λ_L = liquid no-slippage holdup, -

CHAPTER 4
RESERVOIR SIMULATION MODEL

In this study, the reservoir model is created and simulated using ECLIPSE 100 in order to investigate the effect of varying parameters on the performance of water dumpflood into multiple low-pressure gas reservoirs. The details of reservoir model used in this study consisting of grid properties, PVT properties, relative permeability model and production constraints as well as thesis methodology are reported in this chapter. The details of keywords used in simulator are shown in Appendix A.

4.1 Grid properties

The reservoir model in this study is constructed using Cartesian coordinate under simple geometry and homogeneous conditions. In the base case, there are four gas reservoirs and one underlying aquifer. The total dimension of grids in this simulation is 34 x 80 x 54. Some of these grids are inactivated to adjust the size of different gas reservoirs and aquifers in different cases. The top depths of each gas reservoir are 5,000 5,225, 5,450 and 5,675 ft respectively, while the top of the aquifer is at depth 6,700 ft for the base case. The permeability, porosity, and initial water saturation of the gas and water reservoirs are obtained from average values from a gas field in the Gulf of Thailand. The properties of the reservoirs under study are summarized below:

4.1.1 Gas reservoirs

Table 4.1 Gas reservoirs properties of base case model

Properties & Geometries	Layer				Unit
	1	2	3	4	
Top depth	5,000	5,225	5,450	5,675	ft
Dimension	15 x 36 x 10	15 x 36 x 10	15 x 36 x 10	15 x 36 x 10	
Grid size	100 x 100 x 1	100 x 100 x 1	100 x 100 x 1	100 x 100 x 1	cuft
Thickness	25	25	25	25	ft

Table 4.2 Gas reservoirs properties of base case model (continued)

Properties & Geometries	Layer				Unit
	1	2	3	4	
Porosity	21.5	21.5	21.5	21.5	%
Initial water saturation	20	20	20	20	%
Horizontal permeability	126	126	126	126	mD
Vertical permeability	$0.1k_h$	$0.1k_h$	$0.1k_h$	$0.1k_h$	mD
Temperature	262	269	276	284	°F
Pressure	2,243	2,343	2,443	2,544	psia

4.1.2 Aquifer

Top depth	6,700 ft
Dimension	24 x 57 x 10
Grid size	100 x 100 x 100 cuft
Thickness	1,000 ft
Porosity	21.5%
Initial water saturation	100%
Horizontal permeability	126 mD
Vertical permeability	12.6 mD
Temperature	333 °F

In order to fix the average pressure of aquifer, the thickness of aquifer is fixed as the aquifer pressure depends on depth and thickness of aquifer. Therefore, the area in xy-plane is varied to adjust the aquifer volume for different cases. Accordingly, the dimension used for the aquifer is different from dimension used for gas reservoirs.

Reference pressure, temperature and fracture pressure are determined based on following formulas [16]

Reservoir pressure

$$p_R = TVD(ft) \times 0.3048 \times 1.462 \left({}^{psi}\!/_{m} \right) + 14.7 \tag{4.1}$$

Reservoir temperature

$$T_R\left({}^{o}C\right) = TVD(ft) \times 0.3048 \times 0.059 \left({}^{o}C\!/_{m} \right) + 37.78 \tag{4.2}$$

4.1.3 Local grid refinement

Local grid refinement (LGR) is used around the dumpflood and production wells in order to obtain accurate calculation around the wellbores. The details of LGR are shown in Table 4.3. Figure 4.1 and Figure 4.2 show the dumpflood reservoir model.

Table 4.3 Description of local grid refinement

LGR name	LGR coordinate			Number of refined cells		
	I	J	K	X	Y	Z
LGR1	16-18	32-34	1-54	9	9	54
LGR2	16-18	47-49	1-54	9	9	54

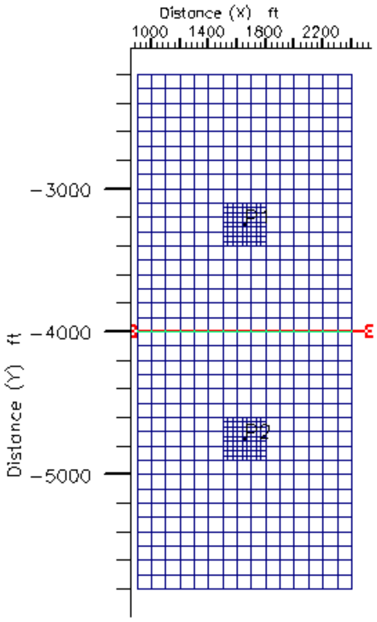


Figure 4.1 Top view of the gas reservoirs model

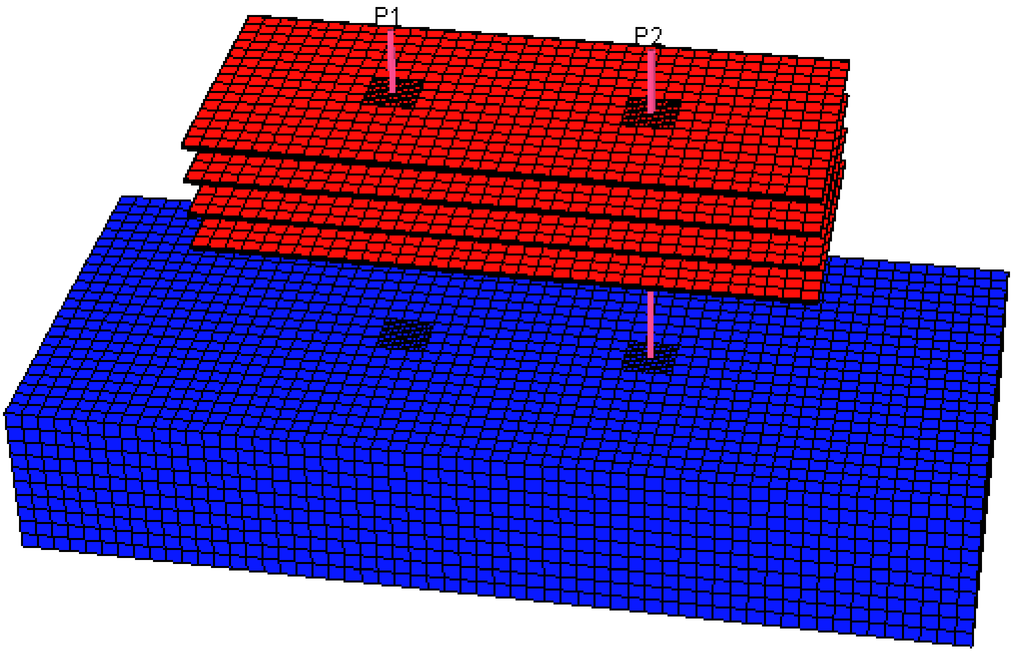


Figure 4.2 3D view of the reservoir model (upper gas reservoirs and lower aquifer)

4.2 PVT properties

In this study, the properties of dry gas are calculated using sets of correlations provided in ECLIPSE 100 with gas specific gravity of 0.7. The properties of dry gas and water for each layer are summarized in Tables 4.4 – 4.5. The generated PVT data are plot in Figure 4.3 – Figure 4.6.

Table 4.4 Properties of water in aquifer

Parameters	Value	Unit
Water FVF at Pref	1.082	bbl/STB
Water compressibility	4.391E-6	psi^{-1}
Water viscosity at Pref	0.168	cp
Water viscosibility	9.982E-6	psi^{-1}
Salinity	2,500	ppm
Reference pressure	3,223	psia
Temperature	333	°F

Table 4.5 PVT properties for dry gas and water in gas reservoirs

Parameters	Layer 1	Layer 2	Layer 3	Layer 4	Unit
PVT properties at surface condition					
Gas gravity	0.7	0.7	0.7	0.7	
Gas density	0.0437	0.0437	0.0437	0.0437	lb/ft^3
Water density	62.428	62.428	62.428	62.428	lb/ft^3
Standard pressure	14.7				psia
Standard temperature	60				°F
Water PVT properties					
Water FVF at Pref	1.0474	1.0504	1.053	1.057	bbl/STB
Water compressibility	2.767E-6	3.647E-6	3.466E-6	3.466E-6	psi^{-1}
Water viscosity at Pref	0.2216	0.2148	0.2084	0.2015	cP
Water viscosibility	7.987E-6	8.250E-6	8.507E-6	8.791E-6	psi^{-1}
Salinity	2,500	2,500	2,500	2,500	ppm
Reference pressure	2,243	2,343	2,443	2,544	psia
Temperature	262	269	276	284	°F

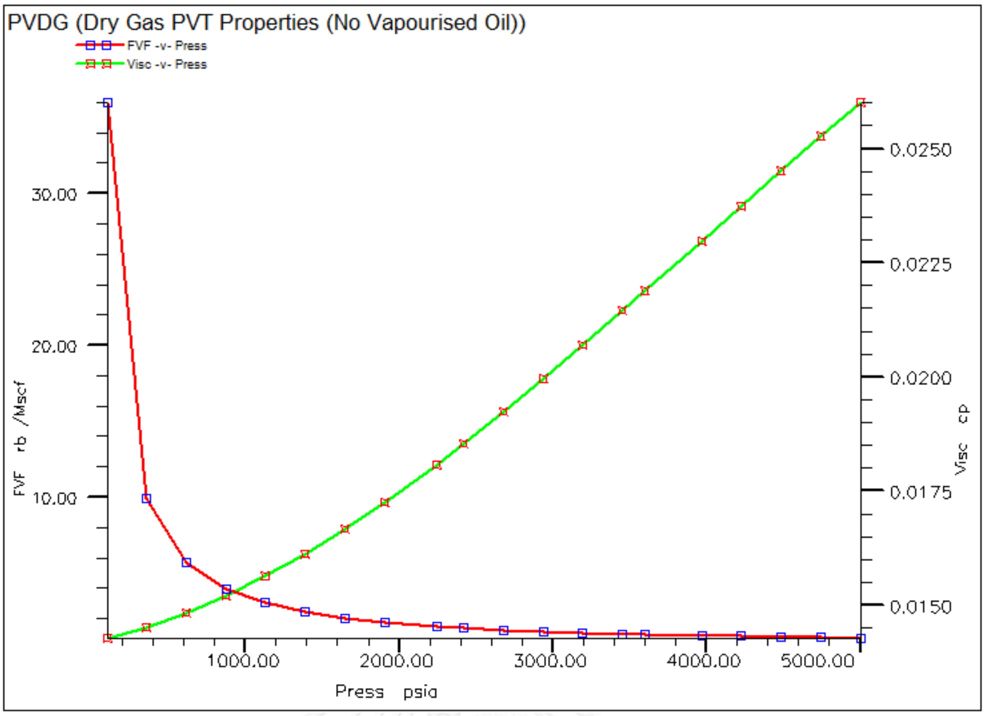


Figure 4.3 Dry gas properties of the first gas layer

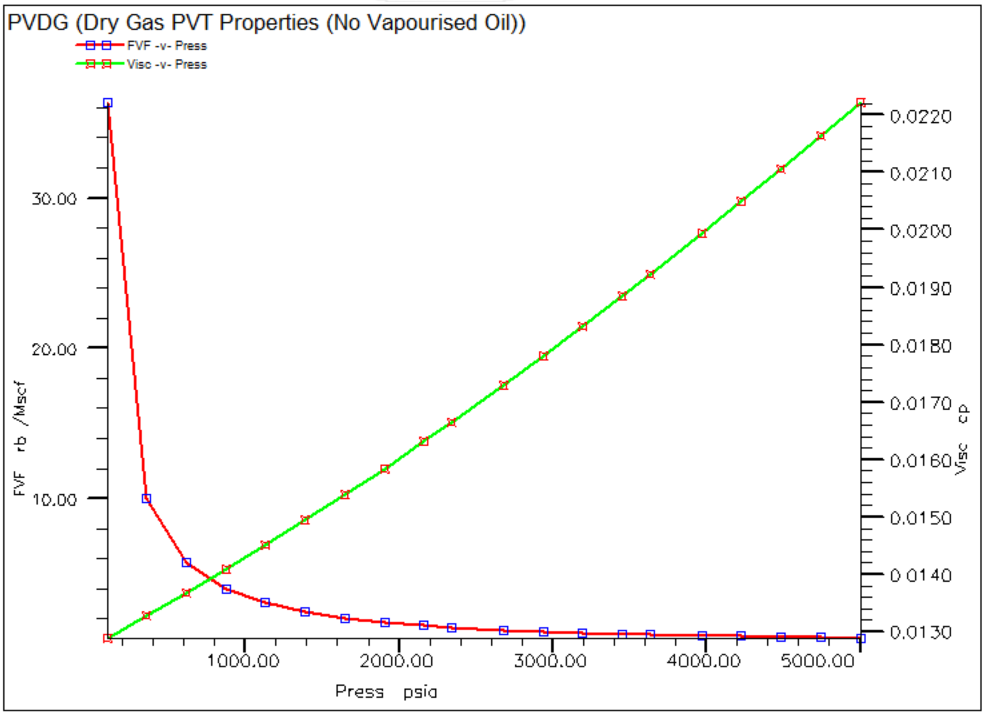


Figure 4.4 Dry gas properties of the second gas layer

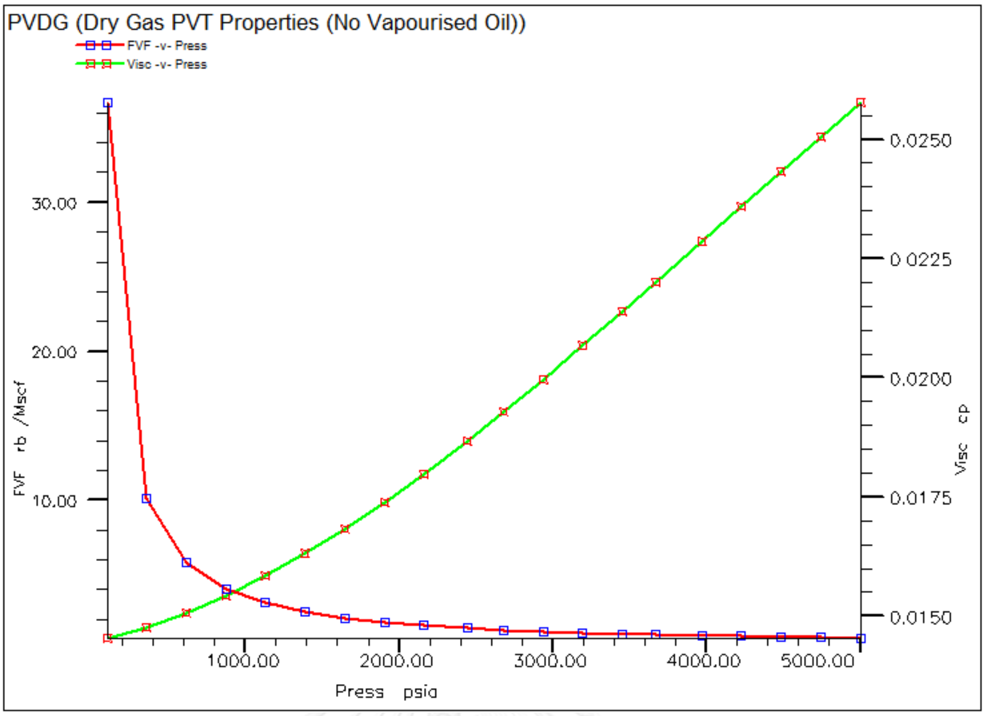


Figure 4.5 Dry gas properties of the third gas layer

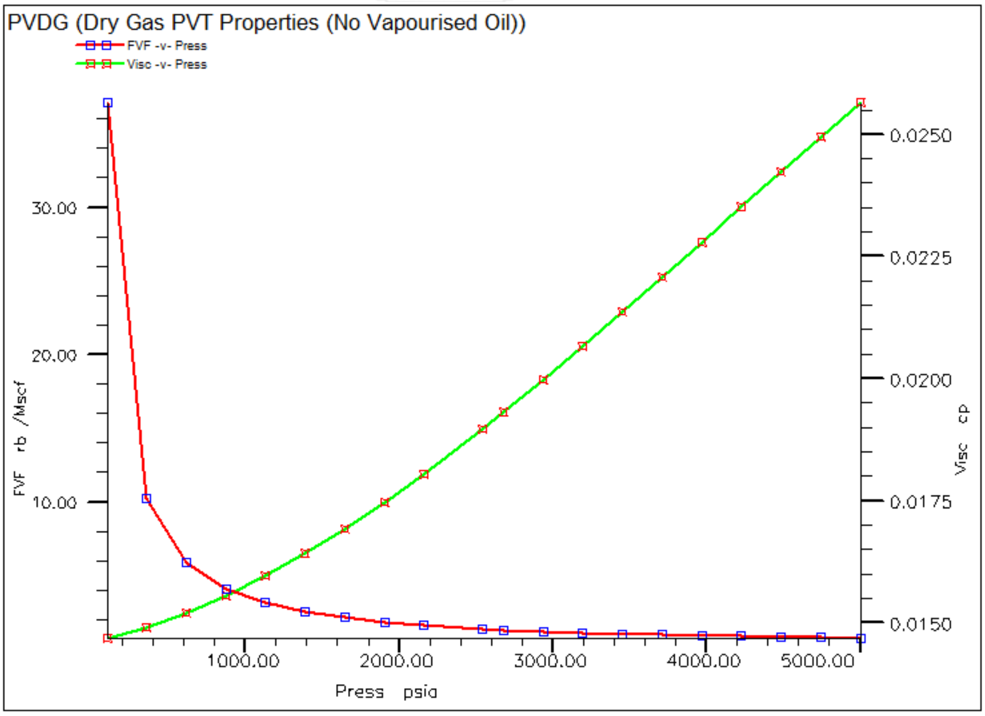


Figure 4.6 Dry gas properties of the fourth gas layer

4.3 SCAL (Special Core Analysis)

In this study, Corey-type relative permeabilities are assumed. The parameters used in Corey relative permeability correlation for the base case are shown in Table 4.6. The graphical relative permeabilities can be seen in Figure 4.7.

Table 4.6 Parameters used in Corey's correlation

Corey water	4	Corey gas	2
s_{wmin}	0.20	s_{grw}	0.25
s_{wcr}	0.25	$k_{rg(Swmin)}$	0.80
s_{wi}	0.20		
$k_{rw(Sgrw)}$	0.20		
k_{rw}(100% sat.)	1		

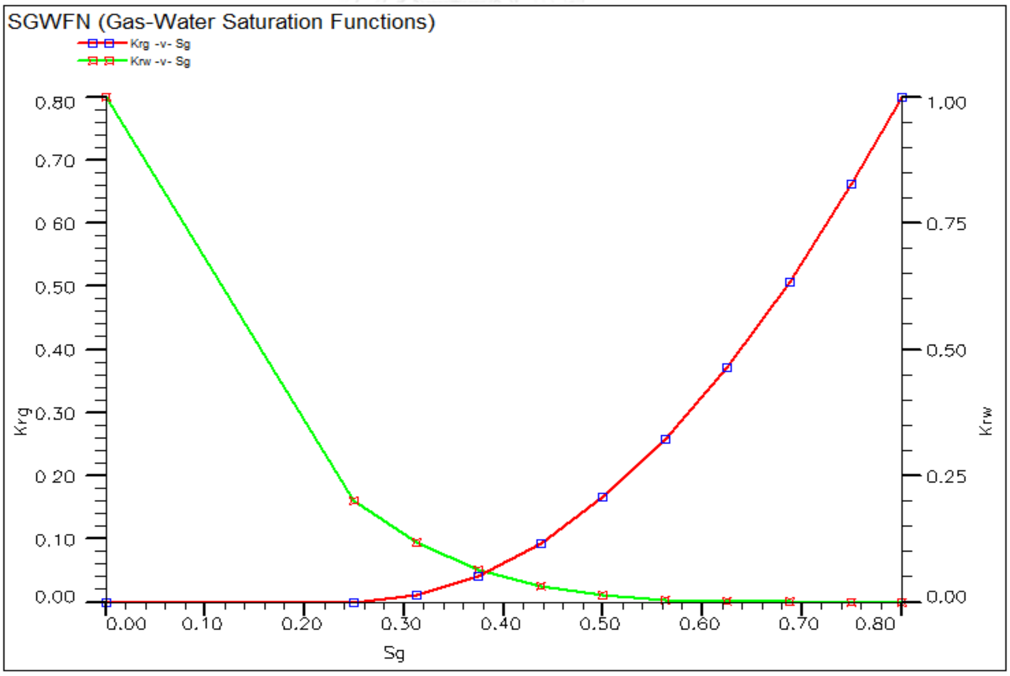


Figure 4.7 Two-phase relative permeabilities of gas/water system

4.4 Production constraints

There are two gas production wells in this study, P1 and P2. Well P2 will be converted to water dumpflood well when production reaches the triggering condition for dumpflood operation. Well production control data and constraints are summarized in Table 4.7 – Table 4.9. Since both well are connected to multiple reservoir, multisegment well option need to be used. The detailed description of multisegment well is included in Appendix A.

Table 4.7 Production control data for wells P1 and P2 before dumpflood operation

Parameters	Wells	
	P1	P2
Open/Shut flag	OPEN	OPEN
Control	Gas rate	Gas rate
Gas Rate	2,500 MSCF/D	2,500 MSCF/D
THP target	500 psia	500 psia
Preferred phase	Gas	Gas

Table 4.8 Production control data for wells P1 and P2 during dumpflood operation

Parameters	Wells	
	P1	P2
Open/Shut flag	OPEN	STOP
Control	Gas rate	-
Gas Rate	2,500 MSCF/D	-
THP target	500 psia	-
Preferred phase	Gas	Water

Table 4.9 Operational constraints

Operations	Constraints
Dumpflood	Field gas production rate < 5,000 MSCF/D
Well abandonment	Well gas production rate < 250 MSCF/D

4.5 Details of methodology

1) Construct homogeneous reservoir base case models for natural depletion and water dumpflood into multiple gas reservoirs.
2) Simulate natural depletion model and base case model in order to determine the improvement of gas recovery factor compared to natural depletion model and evaluate feasibility of water dumpflood into multiple low-pressure gas reservoirs.
3) Simulate model with all operational parameters for different reservoir system parameters in order to determine the optimal operational conditions.

<u>The operational parameters include</u>

- Water dumpflood triggering condition
    - Field gas production rate is below plateau rate (5,000 MSCF/D)
    - Field gas production rate reaches 1,000 MSCF/D
- Minimum wellhead pressure
    - 150 psia for cases assuming that booster compressor is used
    - 500 psia for cases assuming that booster compressor is not used

<u>The reservoir system parameters include</u>

- Well pattern (well pattern schematics are shown in Figure 4.8)
    (A) Distance between wells = 1,500 ft
    (B) Distance between wells = 2,300 ft

(C) Distance between wells = 3,100 ft

- Depth difference between gas reservoirs and aquifer (schematics of aquifer depths are shown in Figures 4.9 – 4.10)
  - 1,000 ft above the topmost gas reservoir
  - 1,000 ft below the bottommost gas reservoir
  - 2,000 ft below the bottommost gas reservoir
- Size of water aquifer (5, 25, 50 PV)
- Reservoir dip angle (0°, 10°)

4) Analyze the results from simulations and discuss the results.

5) Summarize the effects of parameters on performance of water dumpflood into multiple low-pressure gas reservoirs and suggest the operational condition which yields the optimum production for reservoirs having different system parameters in terms of gas recovery and production duration.

As simulation cases for different dip angles are run in the same pattern, only simulation cases for flat reservoir system are illustrated as diagrams in Figures 4.11 – 4.12. Since all branches in the diagram shown in Figure 4.11 have the same pattern, a brunch of 5-PV overlying aquifer case is expanded to show more details in Figure 4.12.

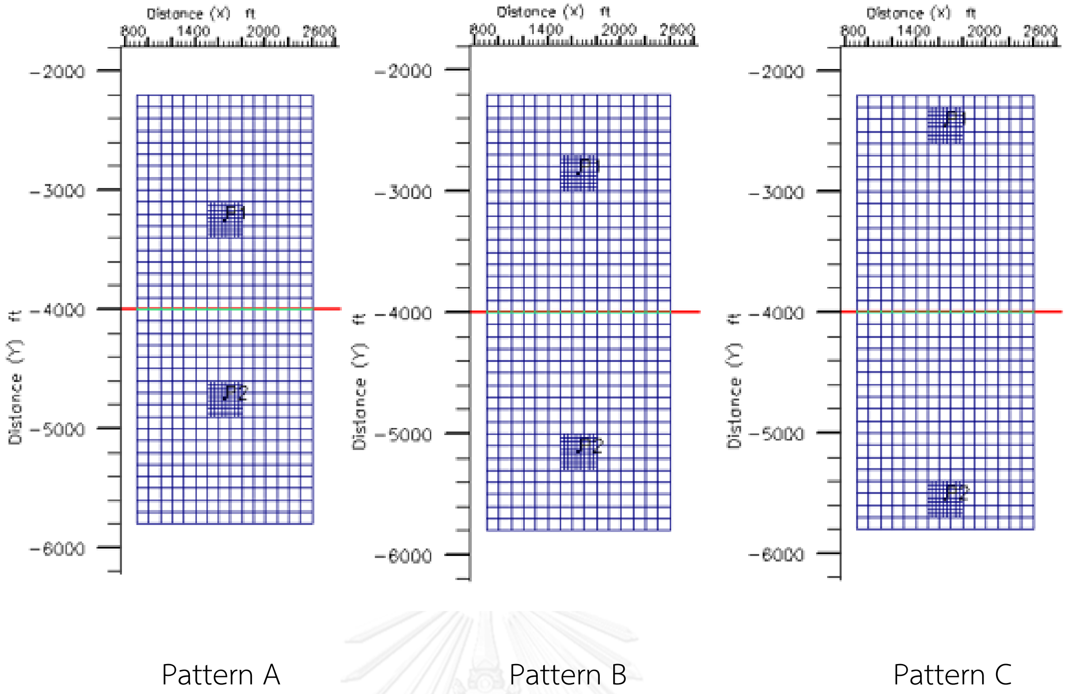


Figure 4.8 Schematics of well patterns

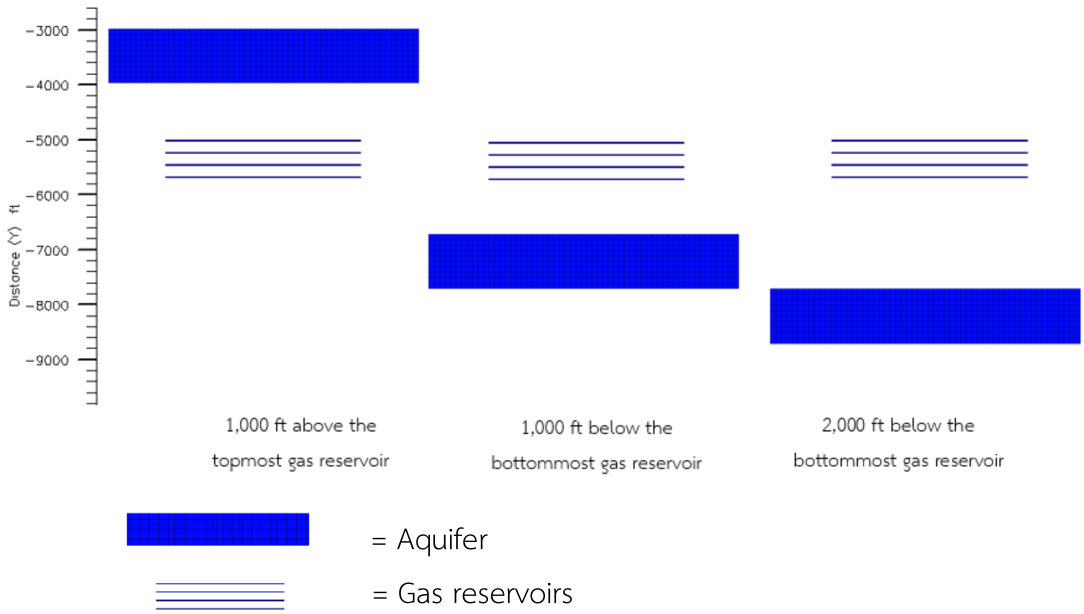


Figure 4.9 Schematics of aquifer depths for reservoir system with no dip angle

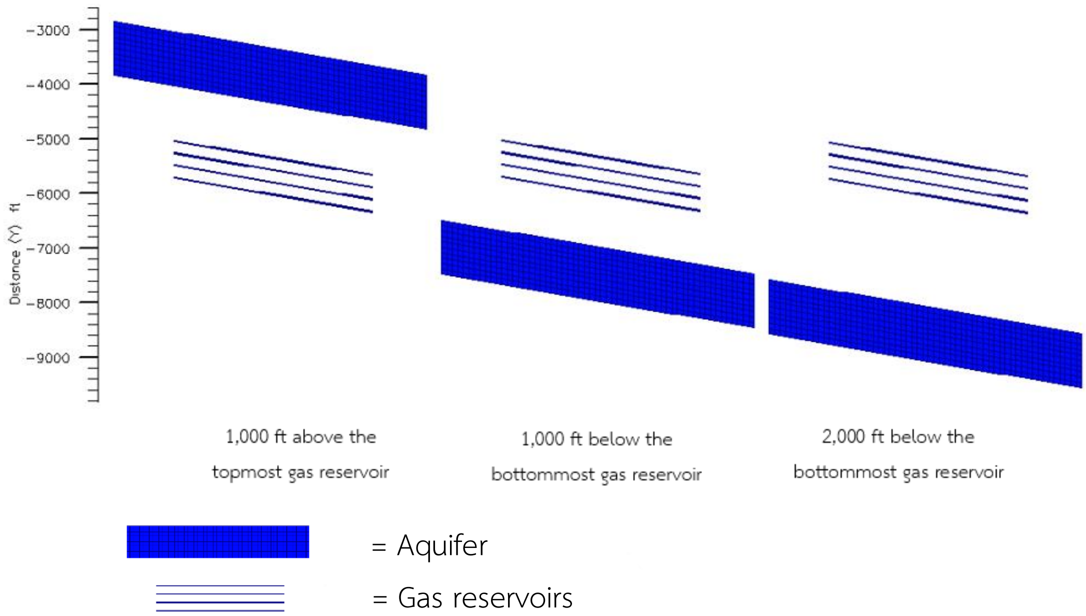


Figure 4.10 Schematics of aquifer depths for reservoir system with 10-degree dip angle

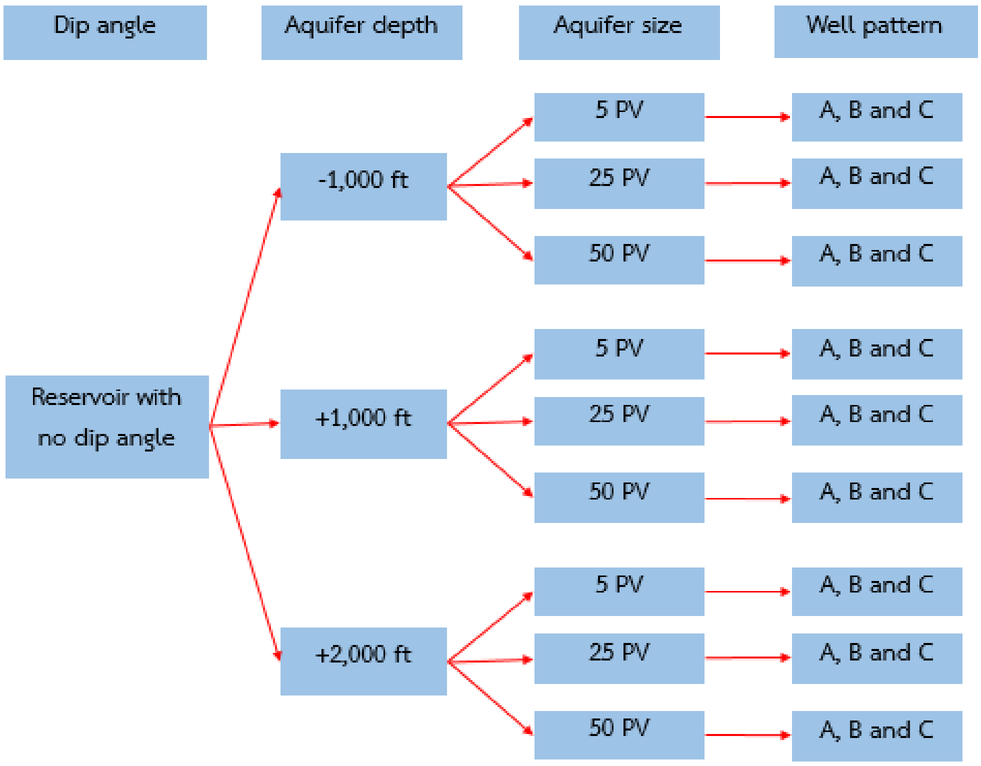


Figure 4.11 Diagram of simulation cases

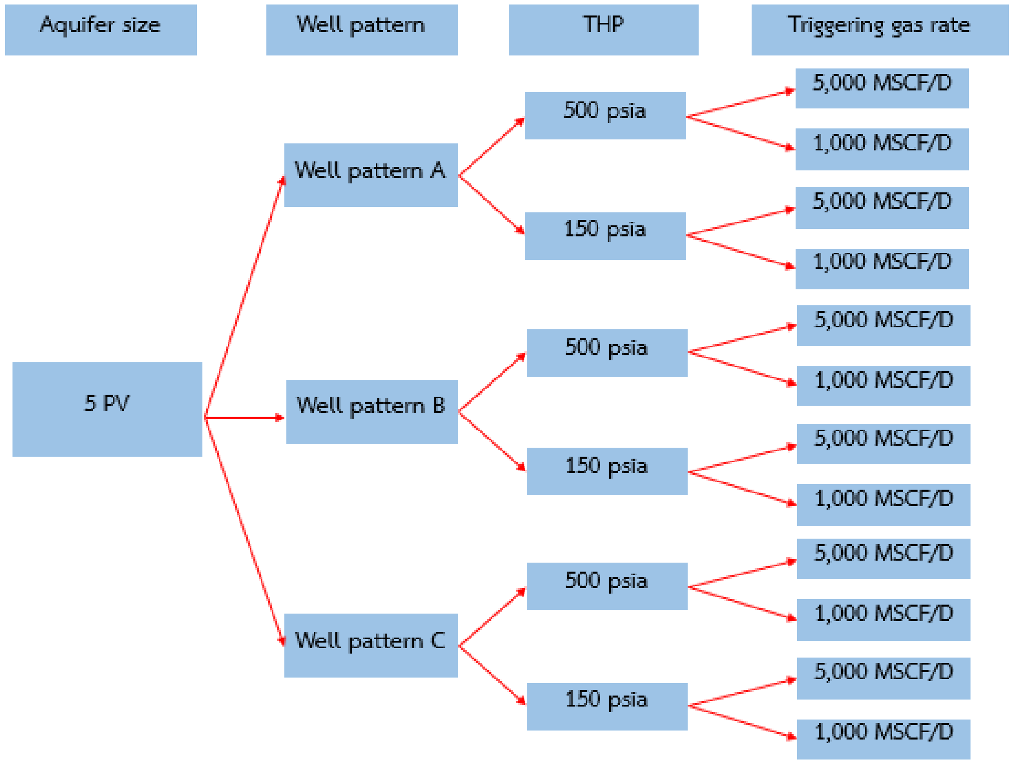


Figure 4.12 Detailed diagram of simulation cases

CHAPTER 5
SIMULATION RESULTS AND DISCUSSION

The simulation results of water dumpflood into multiple low-pressure gas reservoirs are discussed and summarized in this chapter. The reservoir simulations were run in full factorial pattern for every parameter shown in Chapter 4. Initially, two producers were used to produce gas naturally. After the triggering condition was triggered, one of them was converted to dumpflood well flowing water from the aquifer to gas the reservoirs in order to supply pressure to gas reservoirs and drive gas toward to another producer. The performances of water dumpflood are evaluated based on production time and gas recoveries of each case.

Results for the base case are discussed in Section 5.1 in order to illustrate what happens during water dumpflood operation. The result comparison between natural depletion and water dumpflood are also shown in this section.

Since reservoir system parameters may affect the performance of water dumpflood, they need to be investigated in details. These parameters are well pattern, depth difference between gas reservoirs and aquifer, size of water aquifer and reservoir dip angle. As reservoirs with different dip angles have different initial pressures and temperatures which affect PVT properties, the discussions of results are divided into two main sections: Section 5.2 for reservoirs with no dip angle and Section 5.3 for reservoirs with 10-degree dip angle.

Furthermore, operational parameter which is triggering condition is studied for all reservoirs having different system parameters in order to determine the optimal operational condition for each reservoir system.

5.1 Base case

A system with four gas reservoirs having thickness of 25 ft each and an aquifer of which volume is 25 times the reservoir was selected as the base case. The aquifer is located 1,000 ft below the deepest gas reservoir (the top depth of water aquifer is 1,000 ft below the bottom depth of the deepest gas reservoir). The minimum wellhead pressure was set at 500 psia with well distance of 1,500 ft (well pattern A). Water dumpflood was initiated when gas production rate was below 5,000 MSCF/D. The results were compared with natural depletion scenario which has identical reservoir system parameters and production parameters except dumpflood conditions.

Initially, gas was produced from two wells at a rate of 2.5 MMSCF/D each, giving a total production rate of 5 MMSCF/D for 4.7 years before production started to decline below the plateau rate as shown in Figure 5.1. At this point, for dumpflood scenario, well P2 was shut for 30 days to be converted. After well P2 had been additionally completed in the aquifer zone, well P2 was reopened again. The gas production rate declined until water reached the producer at year 6.3 and caused liquid loading. The gas production ended at year 6.3 because of liquid loading. For natural depletion case, gas was initially produced similar to dumpflood case without well conversion until it reached the economic rate. The cumulative amount of gas production for gas dumpflood and natural depletion scenarios are shown in Figure 5.2. At abandonment, 9.501 BCF of gas was recovered in the case of water dumpflood, yielding an additional recovery of 5.1% compared to natural depletion.

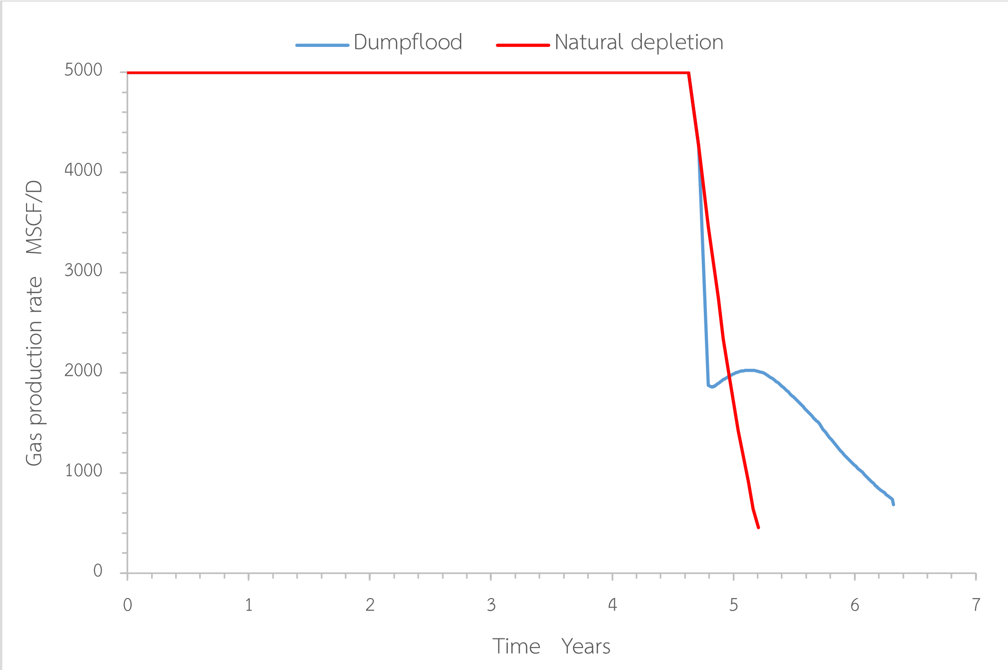


Figure 5.1 Field gas production rate for natural depletion and dumpflood base cases

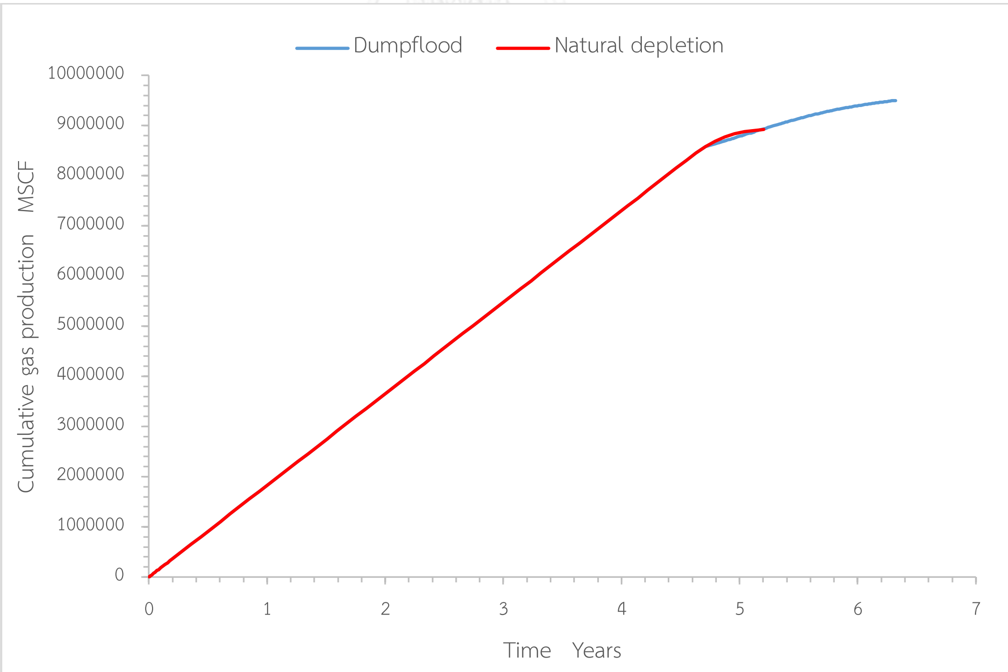


Figure 5.2 Cumulative gas production for natural depletion and dumpflood base cases

Pressures of all gas reservoirs are shown in Figure 5.3. Since the average pressures of the four gas reservoirs have the same trend, only the average pressure of the bottommost one is plotted with the bottomhole and wellhead pressures of the producer and aquifer pressure as shown in Figure 5.4. The pressure of the bottommost gas reservoir decreased rapidly as gas was produced from the reservoir. At the same time, the bottomhole and wellhead pressures were decreased rapidly in order to maintain the plateau rate until the wellhead pressure reached the minimum wellhead pressure of 500 psia. Since the wellhead pressure already reached minimum value, it could not be reduced to maintain the plateau rate anymore. As a result, dumpflood operation was triggered. From year 4.7 to 4.8, well P2 was shut-in in order to convert well P2 to water dumpflood well. After well P2 was reopened and used to dump water to gas reservoirs at year 4.8, the pressure of the bottommost gas reservoir (and the remaining layers) was maintained until production stopped as gas rate reached the economic rate. After the water dumpflood was operated, the aquifer pressure decreased as water flowed out of the aquifer into the gas reservoirs.

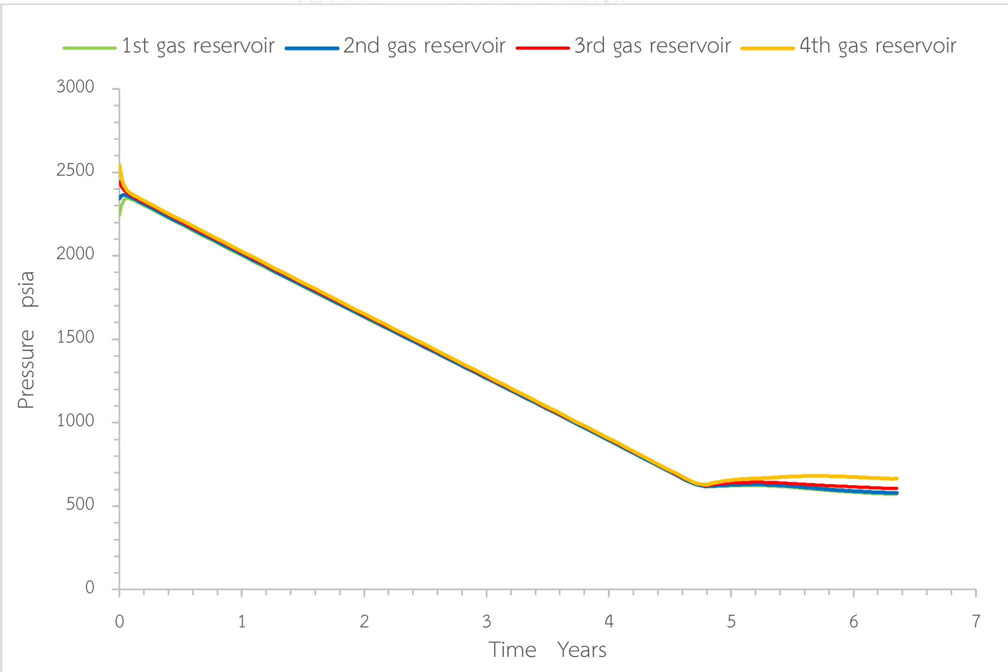


Figure 5.3 Pressures of all gas reservoirs

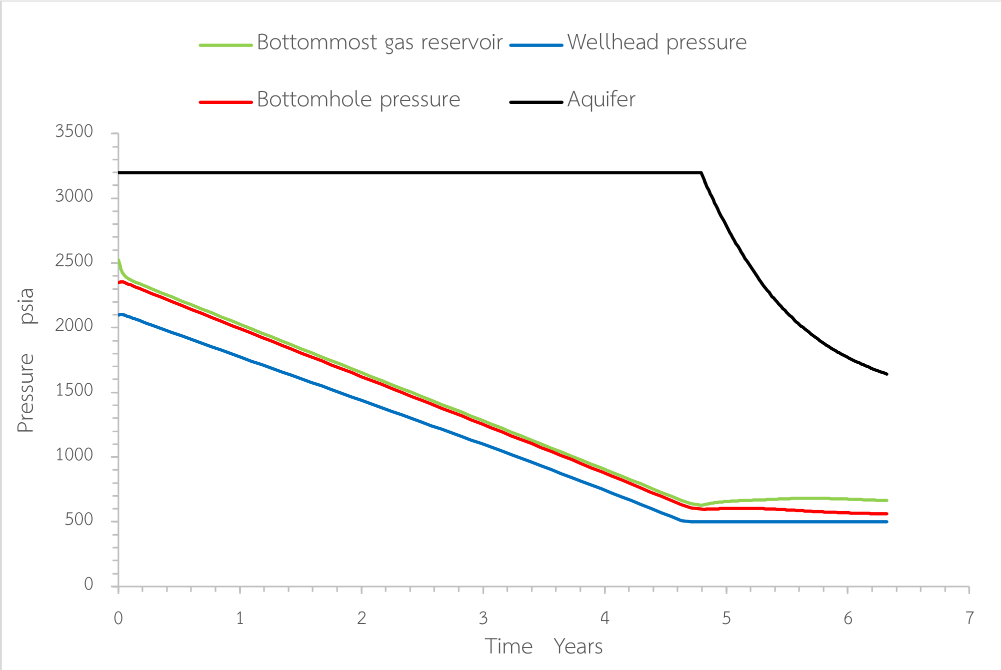


Figure 5.4 Bottomhole pressure and wellhead pressure of the producer, the bottommost reservoir pressure and aquifer pressure

The rates of water flowing into the gas reservoirs are shown in Figure 5.5. The negative rate is the reservoir entering rate. During early period of water dumpflood, water flowed into the gas reservoirs at high rates because gas reservoirs at that point had low pressures but the aquifer had high pressure. As results of re-pressurization of reservoir pressures and aquifer pressure depletion, water entering rate gradually became smaller. According to Figure 5.5, the water entered the bottommost gas reservoir the most and gradually decreased when it flowed up to upper layers as the pressure drop increased.

The early period of dumpflood and final gas saturation distributions of the topmost gas reservoir and bottommost gas reservoirs are shown in Figure 5.6 – Figure 5.9. Water invasion into the gas reservoirs is the most active in the bottommost layer as it is nearest to the water aquifer. At the end of production, water reached the production well at the bottommost layer and caused liquid loading as shown in Figure 5.9. The production ended at that point because of liquid loading.

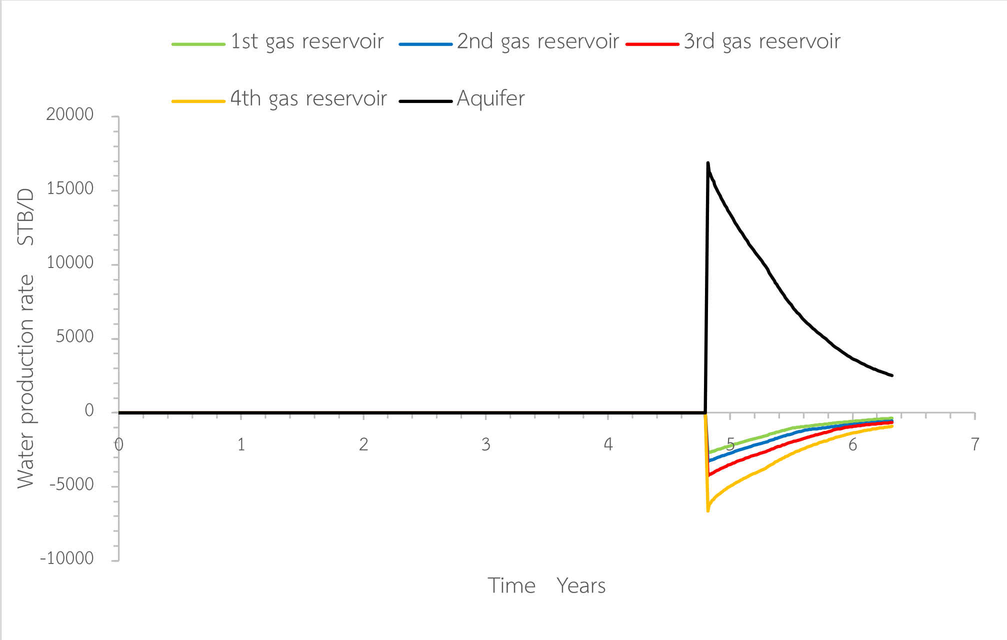


Figure 5.5 Water production rate for each gas reservoirs and aquifer

The results of gas dumpflood are summarized in Table 5.1. At the end of production, an incremental gas recovery factor of 5.1% compared to natural depletion was gained. As the dumpflood was performed, production duration was extended from 5.2 to 6.3 years, yielding the additional production period of 1.1 years compared to natural depletion.

Table 5.1 Results of natural depletion and water dumpflood base cases

Case	Triggering gas production rate (MSCF/D)	Original gas in place (BCF)	Total gas production (BCF)	Gas recovery factor (%)	Duration (year)	Incremental recovery factor (%)
Natural depletion	-	11.508	8.921	77.5	5.2	-
Dumpflood	5,000	11.508	9.501	82.6	6.3	5.1

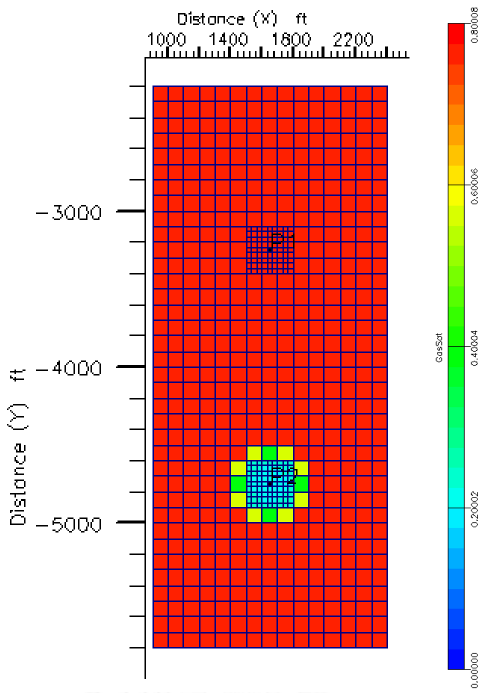


Figure 5.6 Gas saturation distribution of the top layer of the topmost gas reservoir at early period of dumpflood (k = 1)

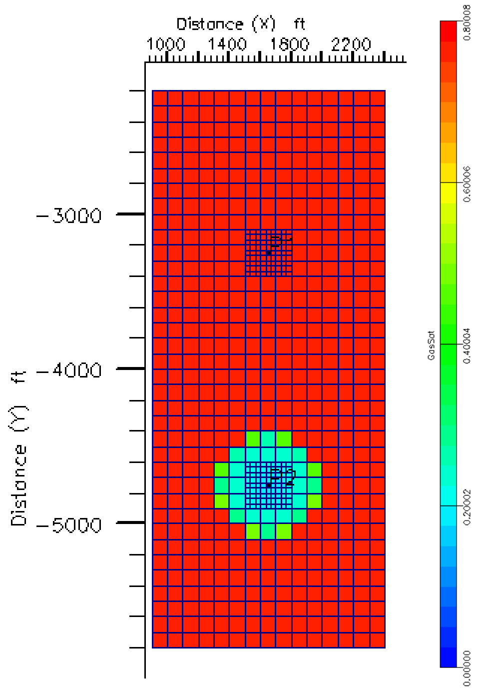


Figure 5.7 Gas saturation distribution of bottom layer of the bottommost gas reservoir at early period of dumpflood (k = 43)

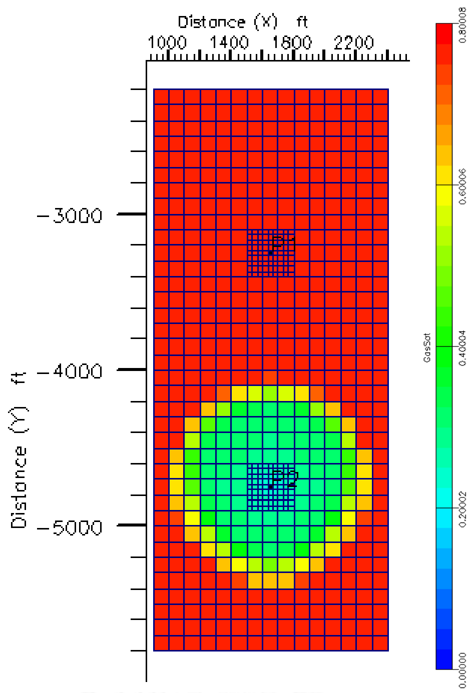


Figure 5.8 Gas saturation distribution of the top layer of the topmost gas reservoir at the end of production (k = 1)

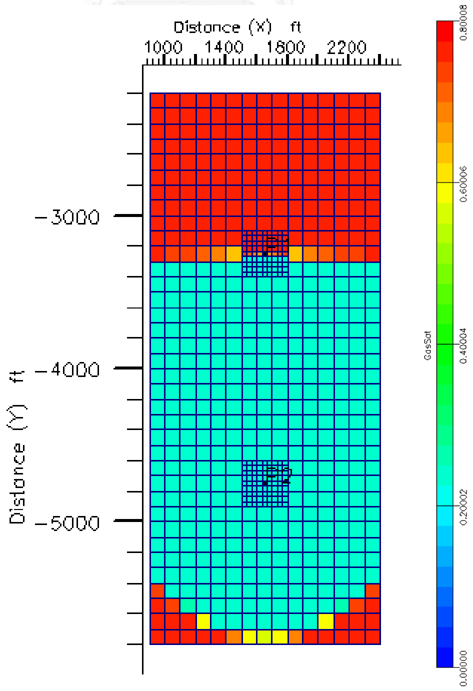


Figure 5.9 Gas saturation distribution of bottom layer of the bottommost gas reservoir at the end of production (k = 43)

5.2 Results for reservoir systems with no dip angle for each well pattern

The combined effects of varying parameters for well patterns A, B and C are individually discussed in Sections 5.2.1 – 5.2.3 and then compared in Section 5.2.4. Table 5.2 shows the variation of reservoir system parameters discussed in Sections 5.2.1 – 5.2.4. Operational conditions studied for all reservoirs in these sections are triggering conditions for the two minimum wellhead pressures as summarized in Table 5.3.

Natural depletion scenarios for all well patterns are run in order to compare with dumpflood scenarios. The results of natural depletion are summarized in Table 5.4. For all well patterns, gas recovery factors are the same at 77.5% when the production well were produced with the minimum wellhead pressure of 500 psia and 93.0% when the production well were produced with the minimum wellhead pressure of 150 psia. Besides having the same recovery factor for the same wellhead pressure for all well patterns, the production durations are also the same.

Table 5.2 Varying reservoir system parameters for different well patterns

Aquifer size	Aquifer location
5 times gas reservoirs (5 PV)	1,000 ft above (-1,000 ft)
	1,000 ft below (+1,000 ft)
	2,000 ft below (+2,000 ft)
25 times gas reservoirs (25 PV)	1,000 ft above (-1,000 ft)
	1,000 ft below (+1,000 ft)
	2,000 ft below (+2,000 ft)
50 times gas reservoirs (50 PV)	1,000 ft above (-1,000 ft)
	1,000 ft below (+1,000 ft)
	2,000 ft below (+2,000 ft)

Table 5.3 Operational conditions studied for all reservoirs

Minimum wellhead pressure	Triggering condition (gas production rate)
500 psia	Gas rate < 5,000 MSCF/D
	Gas rate < 1,000 MSCF/D
150 psia	Gas rate < 5,000 MSCF/D
	Gas rate < 1,000 MSCF/D

Table 5.4 Results of natural depletion for all well patterns

Case	Minimum wellhead pressure (psia)	Original gas in place (BCF)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)
Pattern A	500	11.508	8.921	77.5	5.2
	150	11.508	10.705	93.0	6.6
Pattern B	500	11.508	8.921	77.5	5.2
	150	11.508	10.705	93.0	6.6
Pattern C	500	11.508	8.920	77.5	5.2
	150	11.508	10.699	93.0	6.6

5.2.1 Well pattern A

For well pattern A, the distance between wells P1 and P2 is 1,500 ft as shown in Figure 5.10. Figure 5.11 shows gas recovery factors for cases of which the minimum wellhead pressure is set to 500 psia. The gas recovery factors for cases using the minimum wellhead pressure of 150 psia are shown in Figure 5.15. The simulation results are summarized in Tables 5.5 – 5.6.

From Table 5.5, the cumulative gas productions for water dumpflood with the minimum wellhead pressure of 500 psia vary from 9.027 BCF to 9.6 BCF, yielding incremental recovery factors 0.9% – 5.9% depending on the dumpflood triggering condition, aquifer size and aquifer depth. The production times for this scenario are in the range of 5.8 – 7.2 years. From Table 5.6, there are both increment and decrement in cumulative gas production compared with natural depletion for using booster compressor cases (the minimum wellhead pressure of 150 psia). The minimum cumulative gas production is 10.5 BCF yielding decrement in gas recovery factor of 1.8% while the maximum cumulative gas production is 10.873 BCF yielding incremental gas recovery factor of 1.3%. The production times for this scenario are either less or longer than that for natural depletion scenario. Liquid loading occurs when the aquifer size is 25 PV and 50 PV which affects both production times and gas recovery factors for both minimum wellhead pressure cases. For determining the optimal operational condition, production time is considered as secondary priority when there is no significant difference on gas recovery factors. The effects of different parameters on gas recovery factors are discussed in details in this section.

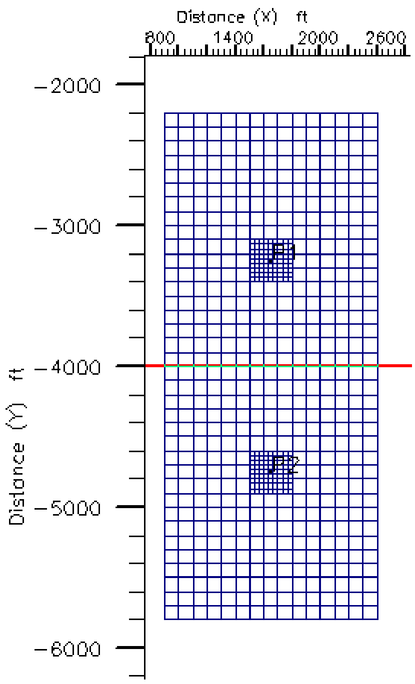


Figure 5.10 Schematic of well pattern A

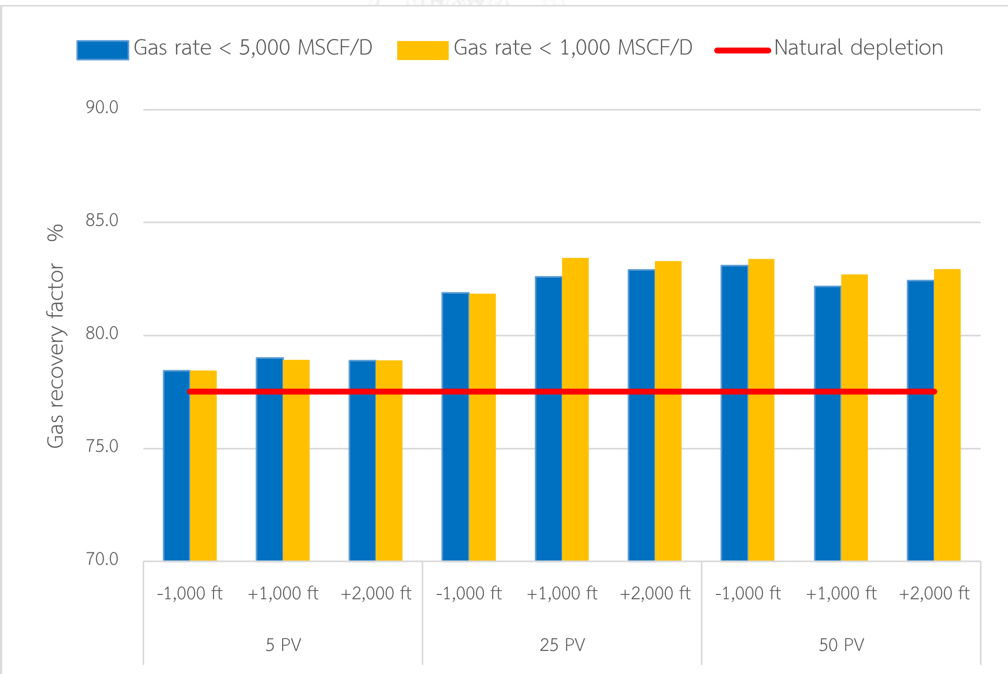


Figure 5.11 Gas recovery factor for varying reservoir system parameters with no dip angle for well pattern A using the minimum wellhead pressure of 500 psia

Table 5.5 Results for reservoir with no dip angle using the minimum wellhead pressure of 500 psia, well pattern A

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	9.027	78.4	5.8	0.9	No
		< 1,000	9.028	78.4	5.8	0.9	No
	+1,000 ft	< 5,000	9.092	79.0	5.9	1.5	No
		< 1,000	9.083	78.9	5.9	1.4	No
	+2,000 ft	< 5,000	9.078	78.9	5.9	1.4	No
		< 1,000	9.081	78.9	6.0	1.3	No
25 PV	-1,000 ft	< 5,000	9.424	81.9	6.3	4.4	No
		< 1,000	9.421	81.9	6.6	4.3	No
	+1,000 ft	< 5,000	9.501	82.6	6.3	5.1	Yes
		< 1,000	9.600	83.4	7.2	5.9	Yes
	+2,000 ft	< 5,000	9.545	82.9	6.6	5.4	Yes
		< 1,000	9.587	83.3	7.1	5.8	Yes
50 PV	-1,000 ft	< 5,000	9.564	83.1	6.2	5.6	Yes
		< 1,000	9.596	83.4	6.9	5.9	Yes
	+1,000 ft	< 5,000	9.456	82.2	6.0	4.6	Yes
		< 1,000	9.518	83.4	7.2	5.9	Yes
	+2,000 ft	< 5,000	9.487	82.4	6.1	4.9	Yes
		< 1,000	9.546	82.9	6.6	5.4	Yes

Table 5.6 Results for reservoir with no dip angle using the minimum wellhead pressure of 150 psia, well pattern A

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	10.737	93.3	7.8	0.3	No
		< 1,000	10.731	93.2	7.0	0.2	No
	+1,000 ft	< 5,000	10.764	93.5	7.8	0.5	No
		< 1,000	10.761	93.5	7.2	0.5	No
	+2,000 ft	< 5,000	10.749	93.5	7.8	0.4	No
		< 1,000	10.750	93.5	7.2	0.4	No
25 PV	-1,000 ft	< 5,000	10.850	94.3	6.3	1.3	No
		< 1,000	10.843	94.2	7.6	1.2	No
	+1,000 ft	< 5,000	10.615	92.2	6.7	-0.8	Yes
		< 1,000	10.830	94.1	7.5	1.1	Yes
	+2,000 ft	< 5,000	10.648	92.5	6.8	-0.5	Yes
		< 1,000	10.847	94.3	7.7	1.3	Yes
50 PV	-1,000 ft	< 5,000	10.724	93.2	7.1	0.2	Yes
		< 1,000	10.873	94.5	7.6	1.5	Yes
	+1,000 ft	< 5,000	10.500	91.2	6.4	-1.8	Yes
		< 1,000	10.828	94.1	7.4	1.1	Yes
	+2,000 ft	< 5,000	10.591	92.0	6.6	-1.0	Yes
		< 1,000	10.841	94.2	7.5	1.2	Yes

For cases of which the minimum wellhead pressure is 500 psia, all water dumpflood cases have higher recovery factors than natural depletion as can be seen in Figure 5.11. Gas recovery factors significantly increase when the aquifer size increases from 5 PV to 25 PV. As a larger aquifer gives higher cumulative water invasion than a small aquifer, the pressures of depleted gas reservoirs increase to higher values for longer periods before slightly decrease again at the end (see Figure 5.12 and Figure 5.13 for results for the bottommost gas layer). Note that results shown in Figure 5.12 and Figure 5.13 are obtained from cases using gas production rate below 5,000 MSCF/D as a triggering condition in which the aquifer is located 1,000 ft below the bottommost gas reservoir. As the reservoir pressures are better maintained in the cases of 25-PV aquifer, higher gas recovery factors are obtained. When the aquifer size increases from 25 PV to 50 PV, the gas recovery factors for overlying aquifer cases moderately increase for the same reason but gas recovery factors for underlying aquifer cases become slightly smaller because liquid loading occurs when the gas production rate is still high as illustrated in Figure 5.14. The reason that liquid loading occurs early is because of a tremendous amount of water invasion from the 50-PV underlying aquifer as the pressure of the gas reservoir in the underlying aquifer cases are higher than those in the overlying aquifer cases.

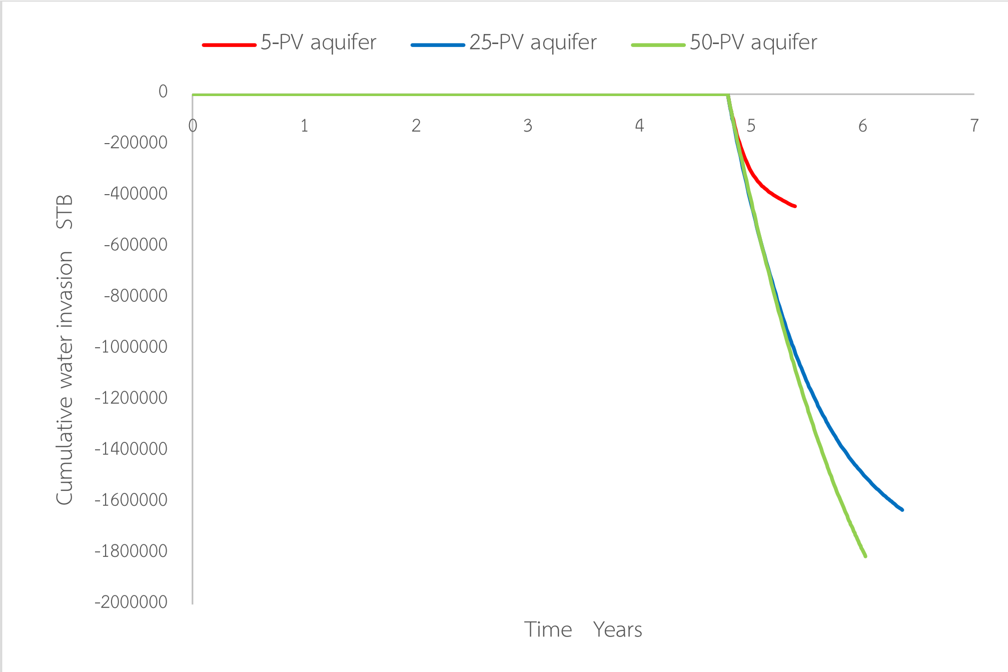


Figure 5.12 Comparison of cumulative water invasions into the bottommost gas reservoir among aquifer sizes located 1,000 ft below the bottommost gas reservoir

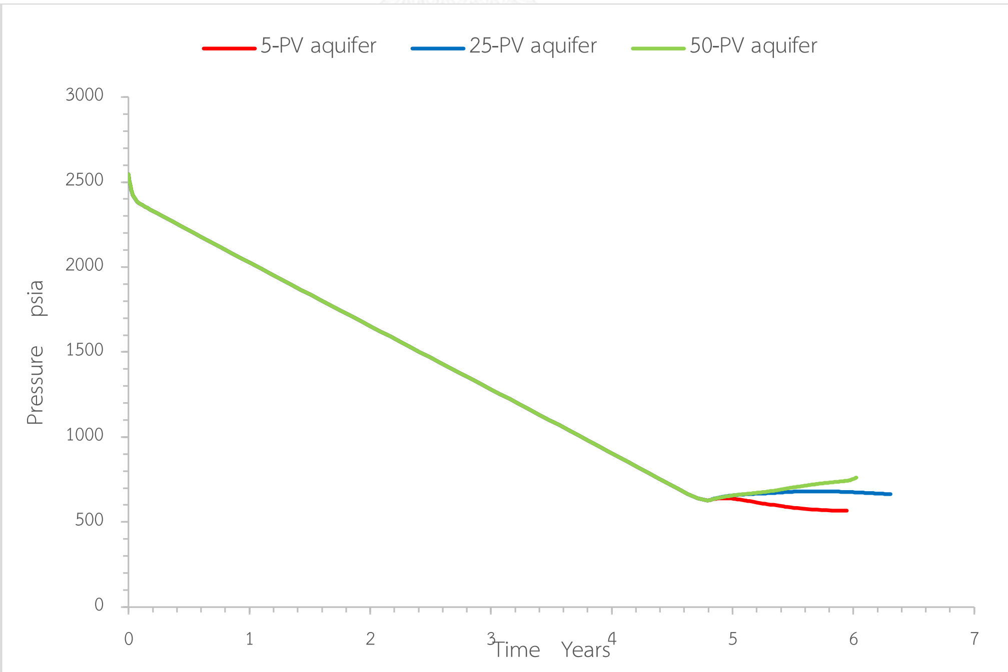


Figure 5.13 Comparison of average pressure of the bottommost gas reservoir among all aquifer sizes cases located 1,000 ft below the bottommost gas reservoir

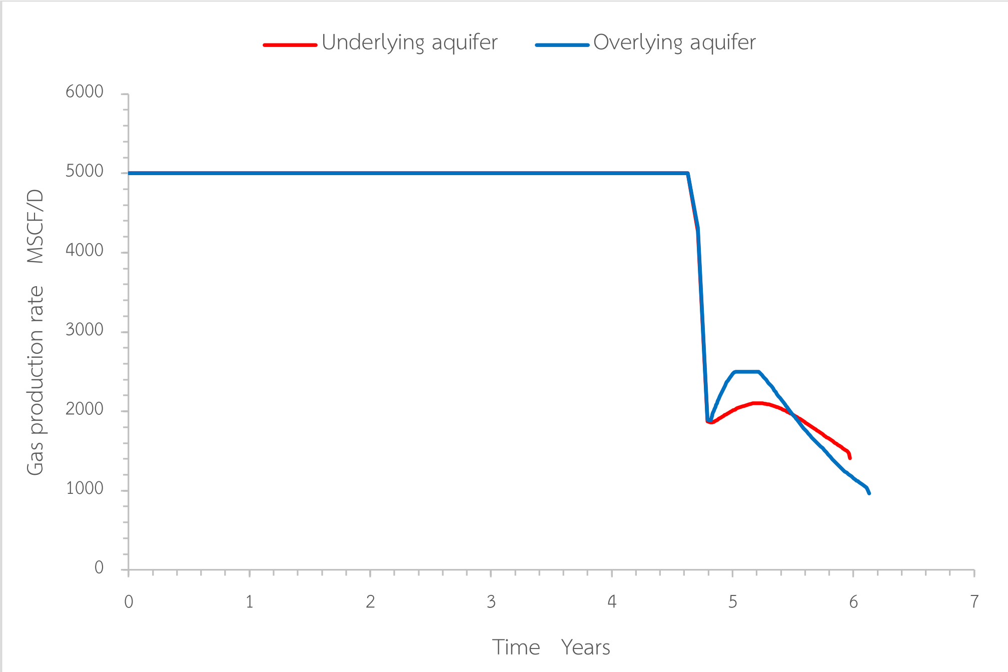


Figure 5.14 Field gas production rate for overlying aquifer and underlying aquifer located 1,000 ft below the bottommost gas reservoir (using gas production rate below 5,000 MSCF/D as triggering condition)

For location of aquifer, different aquifer depths give similar gas recovery factors for 5-PV aquifer size as the aquifer can support reservoir pressures for only a short period. For 25-PV aquifer size, gas recovery factors of underlying aquifers are slightly higher than those for overlying aquifer due to higher pressure support in the cases of underlying aquifer (however, recovery factors for underlying aquifers have no significant difference). This is because the pressure of water increases as it flows downward from the overlying aquifer to the gas reservoirs due to large hydrostatic gain but small friction loss. On the other hand, the pressure of water flowing upward from the underlying aquifer to the gas reservoirs decreases due to hydrostatic and friction losses. However, the pressure of water flowing from the underlying aquifer is higher than that from the overlying aquifer because the formation pressure gradient (which is indicative of initial aquifer pressure) is higher than the hydrostatic gradient of water.

For 50-PV aquifer cases, the overlying aquifer gives higher gas recovery factors than both underlying aquifer cases because underlying aquifers result in too high water pressures at the depths of gas reservoirs which cause higher amount of water to flow into the gas reservoirs and subsequently cause early water breakthrough. Similar to 25-PV cases, the underlying aquifers located at different depths provide no obvious difference on gas recovery factor.

In terms of triggering condition, gas recovery factors are approximately the same when the aquifer size is 5 PV as illustrated in Figure 5.11 because we can produce gas until the economic rate without water breakthrough in all cases. For 25-PV and 50-PV aquifers, most gas recovery factors obtained from cases which dump water when gas production rate is below 1,000 MSCF/D are slightly higher than cases that dump water at gas production rate below 5,000 MSCF/D. For this particular well pattern which has well distance of 1,500 ft, gas recovery factors obtained from later dumpflood are higher as it delays water breakthrough. Therefore, water dumpflood should be performed when gas production is near the economic rate when the well distance is short.

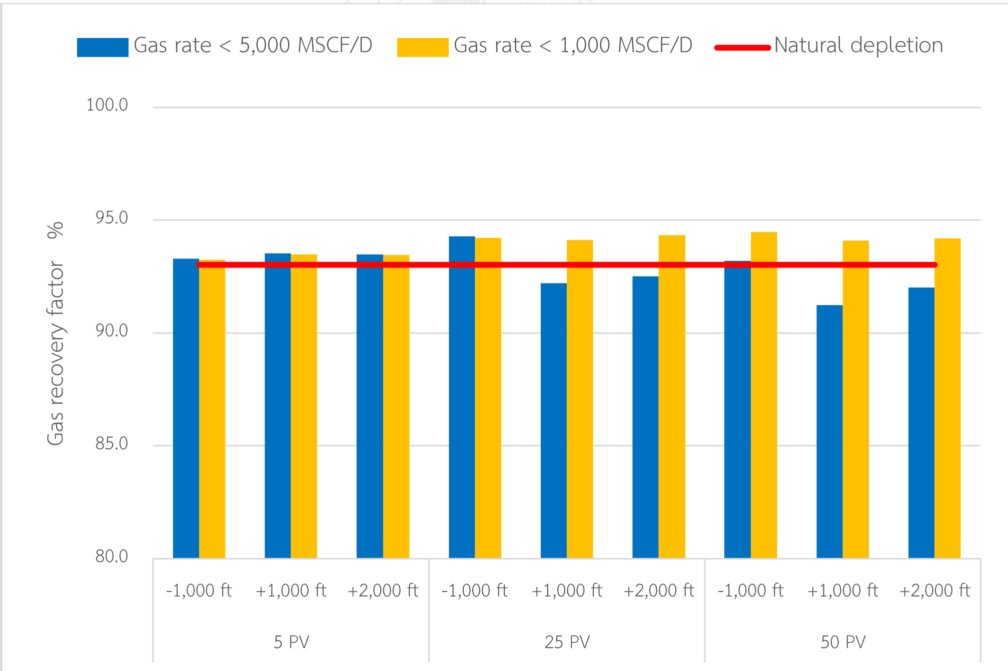


Figure 5.15 Gas recovery factor for varying reservoir system parameters with no dip angle for well pattern A using the minimum wellhead pressure of 150 psia

For results obtained from cases in which booster compressor is used (the minimum wellhead pressure of 150 psia is set), all cases with triggering gas rate of 1,000 MSCF/D for water dumpflood yield slightly higher gas recovery factors than natural depletion while the cases with triggering gas rate of 5,000 MSCF/D have both lower and higher gas recovery factors than natural depletion. As the minimum wellhead pressure is very small, gas can be produced until the reservoir pressure is very low. If the aquifer is large and water dumpflood is started a bit early (gas rate < 5,000 MSCF/D), there is a large amount of water invasion into the gas reservoirs which causes early water breakthrough, resulting in smaller gas recovery factors than natural depletion.

For triggering gas rate of 5,000 MSCF/D, gas recovery factors slightly decrease as the aquifer size increases from 5 PV to 25 PV and 50 PV for the cases of underlying aquifers because liquid loading occurs when the gas production rate is still high as there is a large amount of water invasion when the aquifer is large. For the cases of overlying aquifer, gas recovery factor slightly increases as the aquifer size increases from 5 PV to 25 PV but slightly decreases as the aquifer size increases to 50 PV because 50-PV aquifer provides excess water flowing into the gas reservoirs, causing early water breakthrough. For triggering gas rate of 1,000 MSCF/D, gas recovery factors increase when the aquifer size increase from 5 PV to 25 PV due to better pressure support that helps prolong gas production. However, when the aquifer size increases to 50 PV, the recovery factors stay almost the same due to negative effect from water invasion that causes liquid loading at the production well. For these two cases, the production profiles are quite similar as depicted in Figure 5.16.

For location of aquifer, there is no significant difference between gas recovery factors obtained from 5-PV aquifer cases for different triggering gas rates because the reservoir pressures are maintained for only a short period by a small aquifer. For 25-PV and 50-PV aquifer sizes, gas recovery factors of overlying aquifers for triggering gas rate of 5,000 MSCF/D are higher than those for underlying aquifers due to delayed water breakthrough. Since both underlying aquifers provide higher pressures to the gas reservoirs than the overlying aquifer, water flowing from underlying aquifers causes water breakthrough faster than water flowing from the overlying aquifer as it yields higher water invasion. However, gas recovery factors obtained from triggering gas rate of 1,000 MSCF/D have similar values for all aquifer depths because water breakthrough occurs at late times as water is dumped later. As liquid loading occurs at late time, its effect on gas recovery is small.

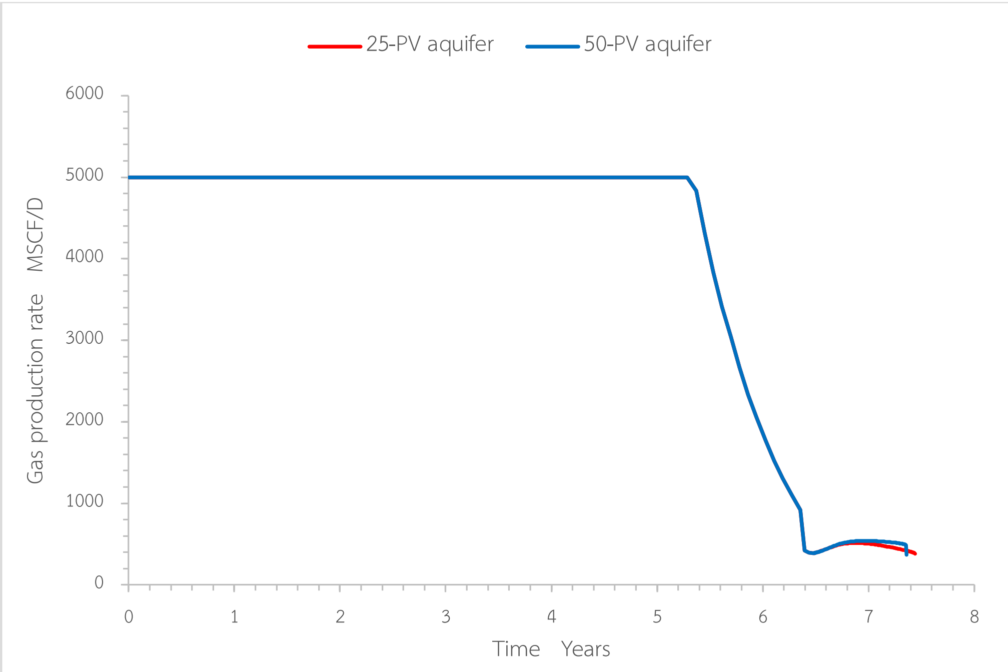


Figure 5.16 Field gas production rate for 25-PV aquifer and 50-PV aquifer located 1,000 ft below the bottommost gas reservoir (using gas production rate below 5,000 MSCF/D as triggering condition)

In summary, for well pattern A with the minimum wellhead pressure of 150 psia (with booster compressor), the best triggering for water dumpflood is when the gas rate is below 1,000 MSCF/D for all aquifer sizes and locations. However, water dumpflood only provides a small increment in gas recovery factor when booster compressor is used.

5.2.2 Well pattern B

The distance between wells P1 and P2 is 2,300 ft for well pattern B as illustrated in Figure 5.17. The gas recovery factors for cases of which the minimum wellhead pressure is set to 500 psia are shown in Figure 5.18. Figure 5.19 shows the gas recovery factors for cases using the minimum wellhead pressure of 150 psia. The simulation results are summarized in Tables 5.7 – 5.8.

From Table 5.7, the minimum and maximum in cumulative gas productions for water dumpflood with the minimum wellhead pressure of 500 psia are 9.025 BCF and 9.905 BCF, respectively which yield 0.9% – 8.5% of incremental recovery factors depending on the dumpflood triggering condition, aquifer size and aquifer depth. The production times for this scenario are in the range of 5.8 – 7.7 years. From Table 5.8, cumulative gas productions for using booster compressor cases (the minimum wellhead pressure of 150 psia) are in the range of 10.731 – 10.963 BCF which yield incremental gas recovery factors in the range of 0.2% – 2.3%. Production times when using booster compressor are extended to 7 – 8.7 years. Liquid loading occurs only in 50-PV aquifer cases. For determining optimal operational condition, production time is considered as secondary priority when there is no significant difference on gas recovery factors. The effects of different parameters on gas recovery factors are discussed in details in this section.

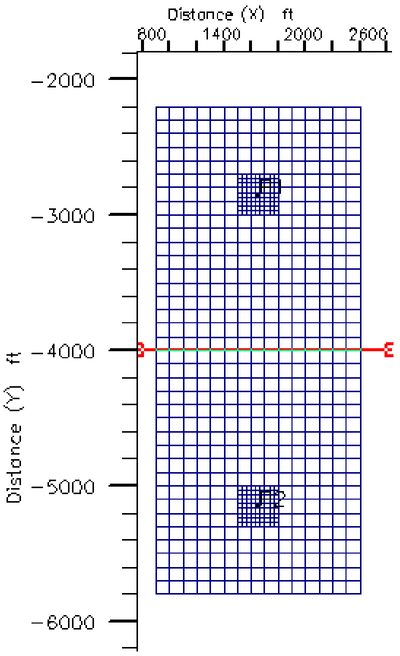


Figure 5.17 Schematic of well pattern B

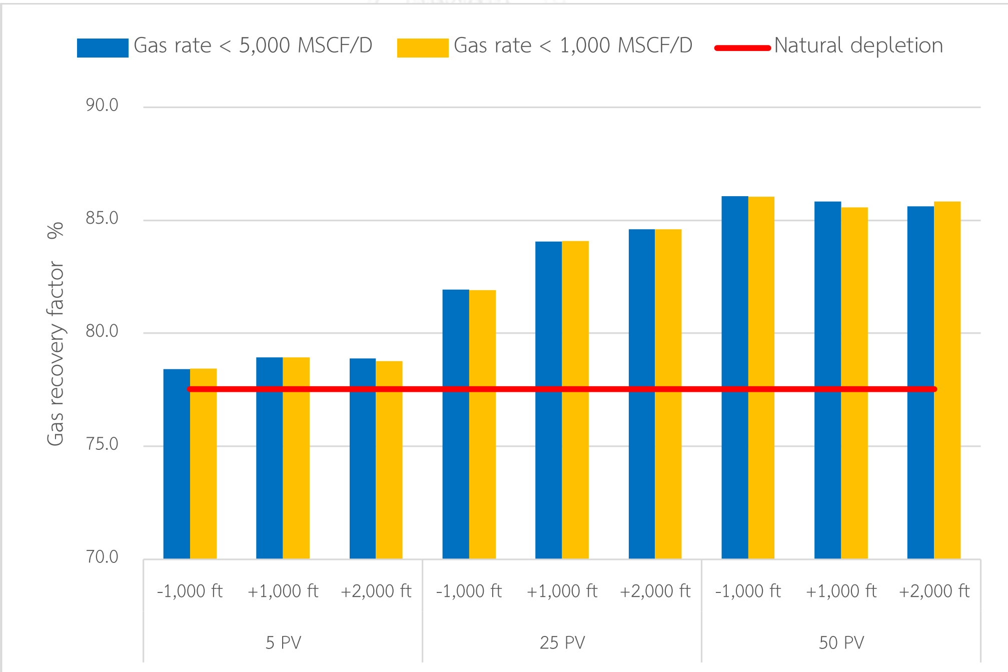


Figure 5.18 Gas recovery factor for varying reservoir system parameters with no dip angle for well pattern B using the minimum wellhead pressure of 500 psia

Table 5.7 Results for reservoir with no dip angle using the minimum wellhead pressure of 500 psia, well pattern B

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	9.025	78.4	5.8	0.9	No
		< 1,000	9.027	78.4	5.8	0.9	No
	+1,000 ft	< 5,000	9.084	78.9	5.9	1.4	No
		< 1,000	9.084	78.9	6.0	1.4	No
	+2,000 ft	< 5,000	9.078	78.9	5.9	1.4	No
		< 1,000	9.065	78.8	5.9	1.3	No
25 PV	-1,000 ft	< 5,000	9.431	81.9	6.3	4.4	No
		< 1,000	9.428	81.9	6.6	4.3	No
	+1,000 ft	< 5,000	9.674	84.1	7.2	6.5	No
		< 1,000	9.676	84.1	7.5	6.5	No
	+2,000 ft	< 5,000	9.738	84.6	7.6	7.1	No
		< 1,000	9.40	84.6	7.9	7.1	No
50 PV	-1,000 ft	< 5,000	9.905	86.1	7.5	8.5	Yes
		< 1,000	9.904	86.1	7.7	8.5	No
	+1,000 ft	< 5,000	9.878	85.8	6.8	8.3	Yes
		< 1,000	9.848	85.6	7.0	8.1	Yes
	+2,000 ft	< 5,000	9.855	85.6	6.9	8.1	Yes
		< 1,000	9.878	85.8	7.4	8.3	Yes

Table 5.8 Results for reservoir with no dip angle using the minimum wellhead pressure of 150 psia, well pattern B

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	10.731	93.2	7.8	0.2	No
		< 1,000	10.728	93.2	7.0	0.2	No
	+1,000 ft	< 5,000	10.759	93.5	7.8	0.5	No
		< 1,000	10.758	93.5	7.2	0.5	No
	+2,000 ft	< 5,000	10.751	93.4	7.8	0.4	No
		< 1,000	10.750	93.4	7.2	0.4	No
25 PV	-1,000 ft	< 5,000	10.853	94.3	7.8	1.3	No
		< 1,000	10.853	94.3	7.6	1.3	No
	+1,000 ft	< 5,000	10.895	94.7	7.8	1.7	No
		< 1,000	10.931	95.0	8.2	2.0	No
	+2,000 ft	< 5,000	10.901	94.7	8.1	1.7	No
		< 1,000	10.938	95.0	8.4	2.0	No
50 PV	-1,000 ft	< 5,000	10.945	95.1	7.7	2.1	No
		< 1,000	10.963	95.3	8.1	2.3	No
	+1,000 ft	< 5,000	10.786	93.7	7.0	0.7	Yes
		< 1,000	10.938	95.0	7.9	2.0	Yes
	+2,000 ft	< 5,000	10.838	94.2	7.3	1.2	Yes
		< 1,000	10.940	95.1	8.1	2.0	Yes

For cases of which the minimum wellhead pressure is 500 psia, all water dumpflood cases have higher recovery factors than natural depletion as shown in Figure 5.18. Gas recovery factors significantly increase when the aquifer size increases from 5 PV to 25 PV but slightly increase when the aquifer size changes from 25 PV to 50 PV. The 50-PV aquifer can provide much better pressure support than 25-PV aquifer but the negative effect of strong pressure support is liquid loading. As a result, the increase in gas recovery factor becomes small when the aquifer size increases from 25 PV to 50 PV.

For location of aquifer, different aquifer depths give approximately the same gas recovery factors for 5-PV aquifer size because there is no water breakthrough as the aquifer can support reservoir pressures for only a short period. For 25-PV aquifer size, gas recovery factors for underlying aquifers are higher than those for overlying aquifers while the recovery factors for the two depths of underlying aquifers have no significant difference. Underlying aquifers have better performance than overlying aquifer because the pressure of water flowing into the gas reservoirs from the underlying aquifer is higher than that from the overlying aquifer. Even though the water from the overlying aquifer gains hydrostatic pressure as it falls downward and the water flowing upward losses its hydrostatic pressure, the water from the underlying aquifers still has higher pressure when it reaches the gas reservoirs because the hydrostatic gradient of water is lower than the formation pressure gradient which makes up the initial aquifer pressure.

For 50-PV aquifer cases, the overlying aquifer gives slightly higher gas recovery factors than underlying aquifer cases because underlying aquifers provide high water pressures at the depths of gas reservoirs which cause higher amount of water flowing into the gas reservoirs. This eventually causes early water breakthrough when the aquifer size is large. For the underlying aquifers located at the two depths, they provide no significant difference on gas recovery factors as happens in 25-PV aquifer cases.

In terms of triggering condition, gas recovery factors obtained from different triggering conditions are approximately the same for all cases as shown in Figure 5.18. For 5-PV aquifer cases, production is carried on until the economic rate as there is no water breakthrough. On the other hand, water breakthrough occurs when gas production rate is near the abandonment rate for 25-PV and 50-PV aquifer cases. Considering production time, we find that the earlier water dumpflood is performed, the shorter production time is needed. Thus, the cases of which the minimum pressure is set as 500 psia, water dumpflood should be performed when gas production rate is below 5,000 MSCF/D.

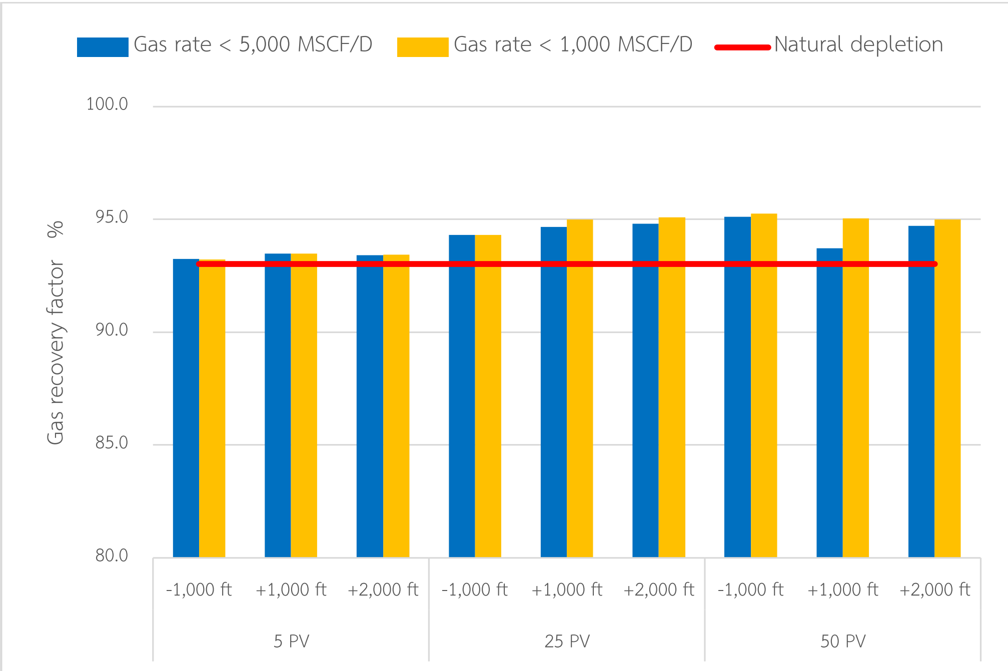


Figure 5.19 Gas recovery factor for varying reservoir system parameters with no dip angle for well pattern B using the minimum wellhead pressure of 150 psia

For results obtained from cases which use the minimum wellhead pressure of 150 psia (using booster compressor), all water dumpflood cases give slightly higher gas recovery factors than natural depletion. For triggering gas rate of 5,000 MSCF/D, gas recovery factors slightly increase as the aquifer size increases from 5 PV to 25 PV because when the aquifer size is large, it gives large amount of water invasion which results in better pressure support. When the aquifer size changes from 25 PV to 50 PV, gas recovery factor slightly increases for the case of overlying aquifer for the same reason but gas recovery factors slightly decrease for underlying aquifer cases due to the negative effect of strong aquifer that causes early liquid loading. For triggering gas rate of 1,000 MSCF/D, gas recovery factors increase when the aquifer size increases from 5 PV to 25 PV as the production is prolonged due to better pressure support. However, when the aquifer size increases to 50 PV, the recovery factors stay almost the same as there is negative effect from water invasion that causes liquid loading for the strong aquifer.

For location of aquifer, there is no significant difference between gas recovery factors obtained from 5-PV aquifer cases for both triggering conditions as the aquifer provides just only a short period of pressure support. For 25-PV aquifer size, gas recovery factors obtained from underlying aquifers are slightly higher than those for overlying aquifer for both triggering gas rates since both underlying aquifers provide better pressure support than the overlying aquifer as discussed in the cases in which the minimum wellhead pressure is 500 psia. For both underlying aquifers, gas recovery factors are almost the same for both triggering conditions as there is no water breakthrough and gas can be produced until the economic limit.

For 50-PV aquifer, gas recovery factor for the overlying aquifer for triggering gas rate of 5,000 MSCF/D is higher than those for underlying aquifers as the water breakthrough is delayed. Since water flowing from underlying aquifers has higher pressure as discussed earlier, it causes water breakthrough faster than water flowing from the overlying aquifer. However, gas recovery factors obtained from triggering gas rate of 1,000 MSCF/D are approximately the same for all aquifer depths because water breakthrough occurs at late time as water dumpflood is started later. As a result, the effect of liquid loading on gas recovery is small.

In summary, for well pattern B with booster compressor (the minimum wellhead pressure is 150 psia), water dumpflood should be started when the gas rate is below 1,000 MSCF/D for all aquifer sizes and locations. However, water dumpflood only provides a small increment in gas recovery factor when booster compressor is used.

5.2.3 Well pattern C

The distance between wells P1 and P2 in well pattern C is 3,100 ft as sketched in Figure 5.20. The gas recovery factors for cases using pressure of 500 psia as the minimum wellhead pressure are shown in Figure 5.21. Figure 5.22 shows the gas recovery factors for cases of which the minimum wellhead pressure of 150 psia is set. The simulation results are summarized in Tables 5.9 – 5.10.

From Table 5.9, the cumulative gas productions for water dumpflood with the minimum wellhead pressure of 500 psia are in the range of 9.022 – 10.132 BCF, which yield 0.9% – 10.5% of incremental recovery factors depending on the dumpflood triggering condition, aquifer size and aquifer depth. The production time needed for water dumpflood operation for this well pattern is around 5.8 – 8.4 years. From Table 5.10, cumulative gas productions for using booster compressor cases (the minimum wellhead pressure of 150 psia) vary around 10.731 – 11.034 BCF which yield incremental gas recovery factors from of 0.2% to 2.9%. Production time for using booster compressor is extended to around 7 – 8.8 years. Liquid loading occurs only in 50-PV aquifer cases. For determining optimal operational condition, production time is considered as secondary priority when there is no significant difference on gas recovery factors. The effects of various parameters on gas recovery factors are discussed in details in this section.

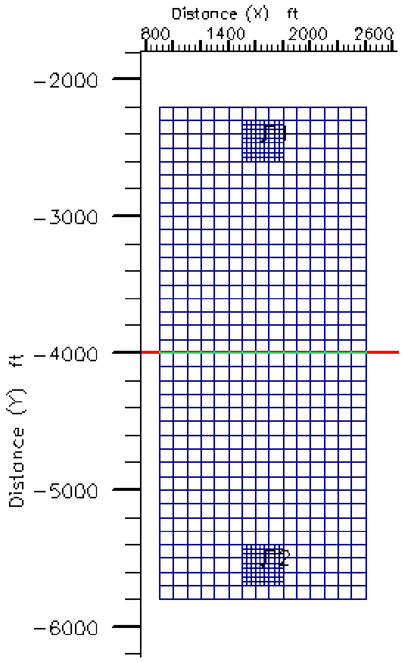


Figure 5.20 Schematic of well pattern C

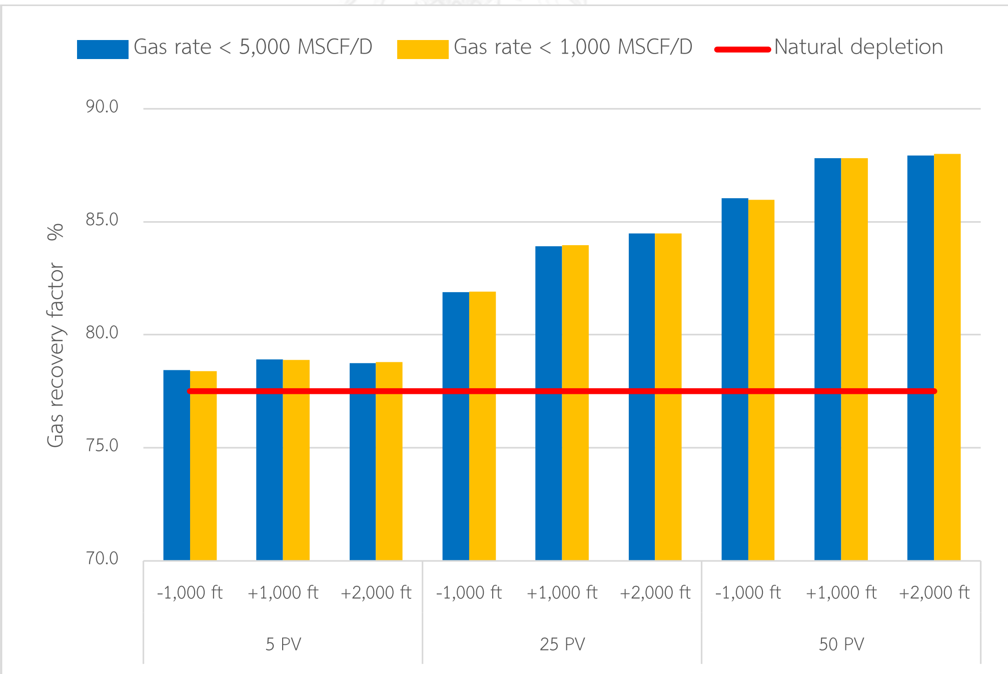


Figure 5.21 Gas recovery factor for varying reservoir system parameters with no dip angle for well pattern C using the minimum wellhead pressure of 500 psia

Table 5.9 Results for reservoir with no dip angle using the minimum wellhead pressure of 500 psia, well pattern C

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	9.027	78.4	5.9	0.9	No
		< 1,000	9.022	78.4	5.8	0.9	No
	+1,000 ft	< 5,000	9.082	78.9	5.9	1.4	No
		< 1,000	9.080	78.9	6.0	1.4	No
	+2,000 ft	< 5,000	9.063	78.8	5.9	1.3	No
		< 1,000	9.067	78.8	6.0	1.3	No
25 PV	-1,000 ft	< 5,000	9.426	81.9	6.4	4.4	No
		< 1,000	9.428	81.9	6.9	4.4	No
	+1,000 ft	< 5,000	9.658	83.9	7.3	6.4	No
		< 1,000	9.663	84.0	7.6	6.5	No
	+2,000 ft	< 5,000	9.722	84.5	7.8	7.0	No
		< 1,000	9.728	84.5	7.9	7.0	No
50 PV	-1,000 ft	< 5,000	9.903	86.0	7.7	8.5	No
		< 1,000	9.896	86.0	7.9	8.5	No
	+1,000 ft	< 5,000	10.106	87.8	8.0	10.3	Yes
		< 1,000	10.107	87.8	8.0	10.3	Yes
	+2,000 ft	< 5,000	10.121	87.9	8.3	10.4	Yes
		< 1,000	10.132	88.0	8.4	10.5	Yes

Table 5.10 Results for reservoir with no dip angle using the minimum wellhead pressure of 150 psia, well pattern C

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	10.737	93.3	7.8	0.3	No
		< 1,000	10.731	93.2	7.0	0.2	No
	+1,000 ft	< 5,000	10.751	93.4	7.8	0.4	No
		< 1,000	10.753	93.4	7.3	0.4	No
	+2,000 ft	< 5,000	10.749	93.4	7.8	0.4	No
		< 1,000	10.745	93.4	7.2	0.4	No
25 PV	-1,000 ft	< 5,000	10.852	94.3	7.8	1.3	No
		< 1,000	10.846	94.2	7.7	1.2	No
	+1,000 ft	< 5,000	10.908	94.8	8.1	1.8	No
		< 1,000	10.927	94.9	8.2	1.9	No
	+2,000 ft	< 5,000	10.901	94.7	8.1	1.8	No
		< 1,000	10.938	95.0	8.4	2.1	No
50 PV	-1,000 ft	< 5,000	10.979	95.4	8.1	2.4	No
		< 1,000	10.947	95.1	8.0	2.1	No
	+1,000 ft	< 5,000	10.901	94.7	7.5	1.8	Yes
		< 1,000	11.014	95.7	8.4	2.7	Yes
	+2,000 ft	< 5,000	10.942	95.1	7.9	2.1	Yes
		< 1,000	11.034	95.9	8.8	2.9	Yes

For cases of which the minimum wellhead pressure is 500 psia, all water dumpflood cases give higher gas recovery factors than natural depletion as shown in Figure 5.21. Gas recovery factors increase when the aquifer size increases for all cases since the reservoir pressures are better maintained when the aquifer is larger. As long as there is no early water breakthrough, the larger aquifer which gives higher cumulative water invasion should support the reservoir pressures better and eventually results in higher gas recovery factors.

For location of aquifer, different aquifer depths give similar gas recovery factors for 5-PV aquifer size because there is no water breakthrough as the 5-PV aquifer can support reservoir pressures for only a short period. For 25-PV and 50-PV aquifer sizes, gas recovery factors of underlying aquifers are higher than those for overlying aquifer as the underlying aquifers provide higher pressure support compared to overlying aquifer while the recovery factors for both underlying aquifers have no significant difference because water breakthrough occurs when gas production rate is low for both cases.

In terms of triggering conditions, gas recovery factors obtained from different triggering conditions are approximately the same for all cases as shown in Figure 5.21. For 5-PV aquifer cases, there is no water breakthrough. For 25-PV and 50-PV aquifer cases, water breakthrough occurs when gas production is near the abandonment condition. Thus, the production ends at either the economic rate or near the economic rate. As a result, the time to start water dumpflood has no significant effect on gas recovery factor for this well pattern. Considering the production time, we find that the earlier water dumpflood is performed, the shorter production time is needed. Thus, for cases of which the minimum pressure is set as 500 psia, water dumpflood should be performed when gas production rate is below 5,000 MSCF/D.

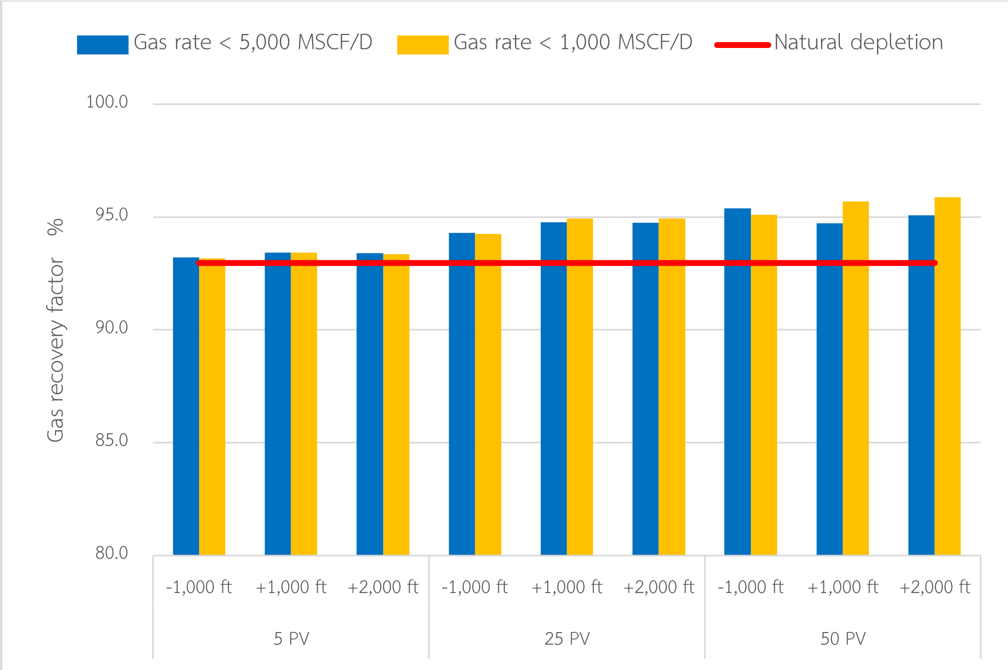


Figure 5.22 Gas recovery factor for varying reservoir system parameters with no dip angle for well pattern C using the minimum wellhead pressure of of 150 psia

For results obtained from cases of the which minimum wellhead pressure is 150 psia (using booster compressor), all water dumpflood cases yield slightly higher gas recovery factors than natural depletion. For triggering gas rate of 5,000 MSCF/D, gas recovery factors slightly increase when the aquifer size increases from 5 PV to 25 PV because the large aquifer can provide better pressure support as it gives larger amount of water invasion. When the aquifer size increases from 25 PV to 50 PV, gas recovery factors obtained from the overlying aquifer case slightly increase for the same reason. However, gas recovery factors obtained from underlying aquifer cases stay almost the same since early liquid loading occurs as the negative effect of strong aquifer. For triggering gas rate of 1,000 MSCF/D, gas recovery factors slightly increase when the aquifer size increases from 5 PV to 25 PV and 50 PV as the production is prolonged due to better pressure support as the aquifer size becomes larger.

For locations of aquifer, there is no significant difference between gas recovery factors obtained from 5-PV aquifer for both triggering conditions as the aquifer can support reservoir pressure for only a short period. For 25-PV aquifer size, underlying aquifers yield slightly higher gas recovery factors than the overlying aquifer for both triggering gas rates because water flowing from underlying aquifers provides better pressure support as discussed in the cases of which the minimum wellhead pressure is 500 psia in Section 5.2.2. For both underlying aquifers, there is no significant difference on gas recovery factors for both triggering conditions because the gas production is continued until the economic limit.

For 50-PV aquifer, gas recovery factors of overlying aquifers for triggering gas rate of 5,000 MSCF/D is higher than those for underlying aquifers because of delayed water breakthrough as discussed in Section 5.2.2. However, for triggering gas rate of 1,000 MSCF/D, gas recovery factors obtained from underlying aquifers are slightly higher than those for overlying aquifer for the same reason as 25-PV aquifer cases. For both underlying aquifers, gas recovery factors are similar as liquid loading occurs slightly above the economic rate for both two depths.

In summary, for well pattern C with booster compressor (the minimum wellhead pressure is 150 psia), water dumpflood should be started when the gas rate is below 1,000 MSCF/D for all aquifer sizes and locations. However, water dumpflood only provides a small increment in gas recovery factor when booster compressor is used.

5.2.4 Comparison among different well patterns for reservoir with no dip angle

Since well distance between wells P1 and P2 plays important role in improving gas recovery via water dumpflood, comparisons in details among well patterns are discussed in this section. Since gas recovery factors obtained from all well patterns in natural depletion are almost the same for individual minimum wellhead pressures as can be seen in Table 5.4, one of them is individually plotted for each minimum wellhead pressure.

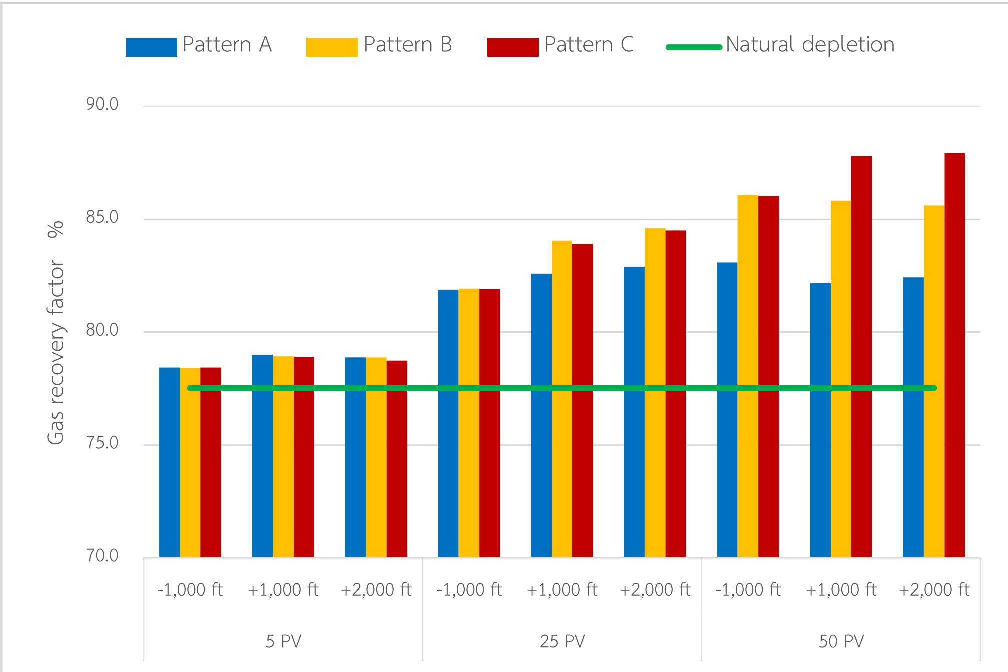


Figure 5.23 Comparison of gas recovery factors for varying reservoir system parameters among well patterns A, B and C using the minimum wellhead pressure of 500 psia and gas rate below 5,000 MSCF/D as triggering condition

As seen in Figures 5.23 – 5.26, results obtained from different triggering conditions and different minimum wellhead pressures have the same trend when comparison is made among the three well patterns. For 5-PV aquifer cases, gas recovery factors obtained from all well patterns are very similar because the aquifer can support pressure to the gas reservoirs for a very short period. As water invades the reservoirs for only a short period, there is no water breakthrough. This means that gas can be produced until the economic rate. Thus, the three well patterns give similar gas recovery factors. For 25-PV aquifer cases, well pattern B gives the highest gas recovery factor because the well distance in pattern B is about right for this aquifer strength, i.e., the production well can produce until either the economic rate without liquid loading or slightly above the economic rate with liquid loading. For 50-PV aquifer cases, gas recovery factors increase when the distance between wells increases because the aquifer has high pressure to support the gas reservoirs and water breakthrough is delayed when the well distance increases. Moreover, increasing well distance improves volumetric sweep efficiency. Thus, well pattern C is the best when the aquifer size is 50 PV.

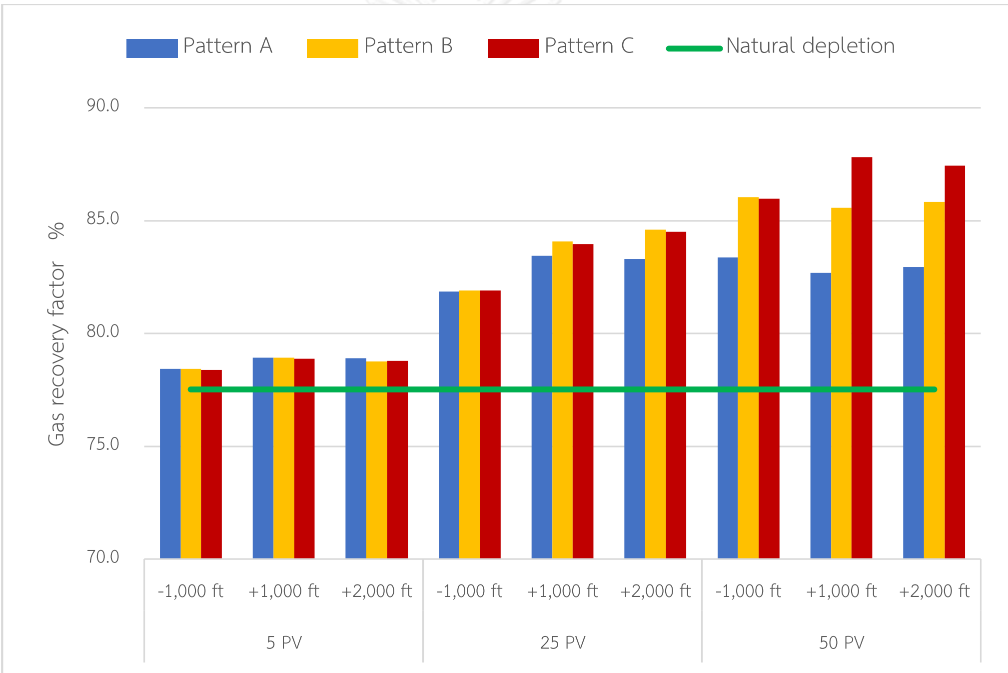


Figure 5.24 Comparison of gas recovery factors for varying reservoir system parameters among well patterns A, B and C using the minimum wellhead pressure of 500 psia and gas rate below 1,000 MSCF/D as triggering condition

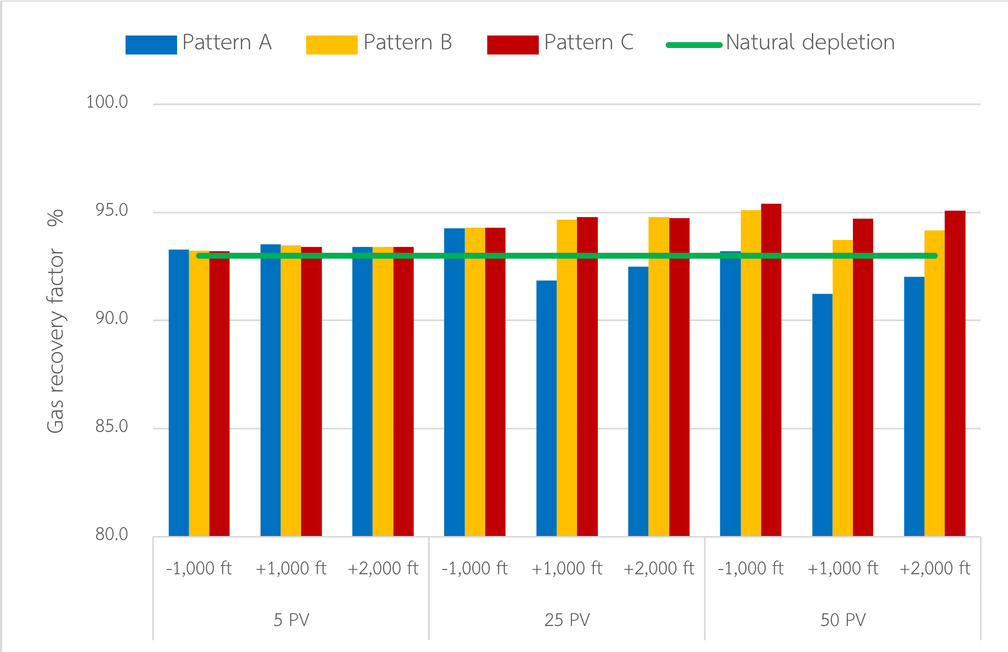


Figure 5.25 Comparison of gas recovery factors for varying reservoir system parameters among well patterns A, B and C using the minimum wellhead pressure of 150 psia and gas rate below 5,000 MSCF/D as triggering condition

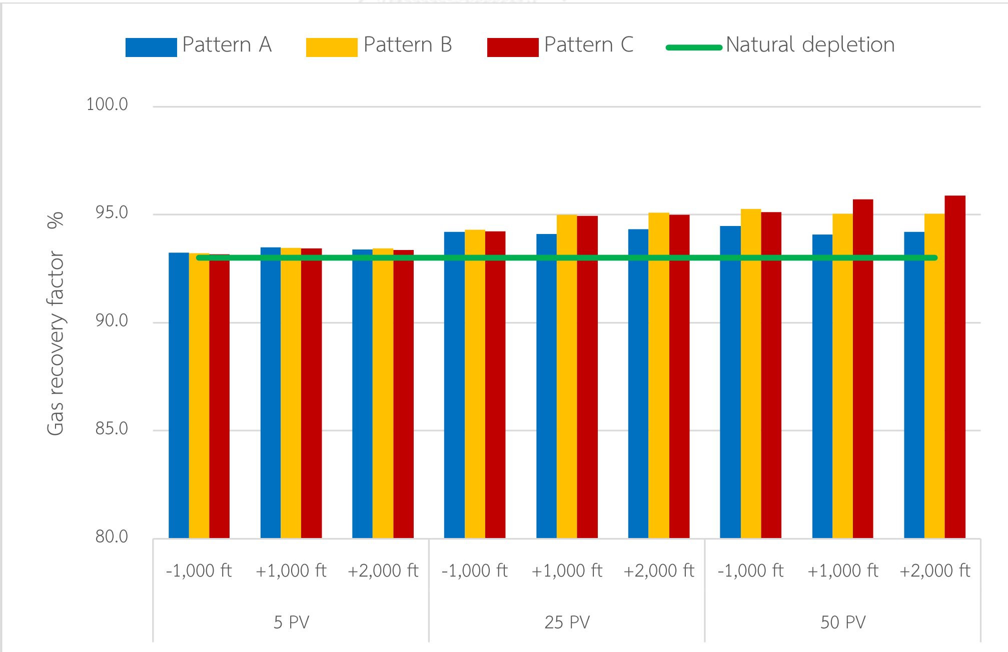


Figure 5.26 Comparison of gas recovery factors for varying reservoir system parameters among well patterns A, B and C using the minimum wellhead pressure of 150 psia and gas rate below 1,000 MSCF/D as triggering condition

5.3 Results for reservoir systems with 10-degree dip angle for each well pattern

The results in this section are discussed in the same manner as in Section 5.2. The combined effects of varying parameters for well patterns A, B and C are individually discussed in Sections 5.3.1 – 5.3.3 and then compared in Section 5.3.4. The summary of reservoir system parameters discussed in this section can be seen in Table 5.2. Furthermore, operational parameters studied for all reservoirs are summarized in Table 5.3.

Natural depletion scenarios for all well patterns are run in order to compare with dumpflood scenarios. The results of natural depletion are summarized in Table 5.11. Gas recovery factors obtained from all well patters are the same at 78.6% when the minimum wellhead pressure of 500 psia is used and 93.3% when the minimum wellhead pressure of 150 psia is used. Besides having the same recovery factor for the same wellhead pressure for all well patterns, the production time are also the same.

Table 5.11 Results of natural depletion for all well patterns

Case	Minimum wellhead pressure (psia)	Original gas in place (BCF)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)
Pattern A	500	11.763	9.247	78.6	5.4
	150	11.763	10.981	93.3	6.8
Pattern B	500	11.763	9.247	78.6	5.4
	150	11.763	10.981	93.3	6.8
Pattern C	500	11.763	9.242	78.6	5.4
	150	11.763	10.975	93.3	6.8

5.3.1 Well pattern A

For well pattern A, the distance between wells P1 and P2 is 1,500 ft. Figure 5.27 shows gas recovery factors for cases of which the minimum wellhead pressure is set to 500 psia. The gas recovery factor for cases using the minimum wellhead pressure of 150 psia are shown in Figure 5.30. The simulation results are summarized in Tables 5.12 – 5.13.

From Table 5.12, the cumulative gas productions for water dumpflood with the minimum wellhead pressure of 500 psia vary from 9.352 BCF to 9.944 BCF, yielding 0.9% – 5.9% incremental recovery factors depending on the dumpflood triggering condition, aquifer size and aquifer depth. The production times for this scenario are in the range of 5.9 – 7.4 years. From Table 5.13, there are both increment and decrement in cumulative gas production compared with natural depletion for using booster compressor cases (the minimum wellhead pressure of 150 psia). The minimum cumulative gas production is 10.807 BCF yielding decrement in gas recovery factor of 1.6% while the maximum cumulative gas production is 11.22 BCF yielding incremental gas recovery factor of 2.1%. The production times for this scenario are either less or longer than that for natural depletion scenario. Liquid loading occurs when the aquifer size is 25 PV and 50 PV which affects both production times and gas recovery factors for both minimum wellhead pressure cases. The effects of various parameters on gas recovery factors are discussed in details in this section.

Table 5.12 Results for reservoir with 10-degree dip angle using the minimum wellhead pressure of 500 psia, well pattern A

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	9.352	79.5	6.0	0.9	No
		< 1,000	9.349	79.5	5.9	0.9	No
	+1,000 ft	< 5,000	9.393	79.9	6.0	1.2	No
		< 1,000	9.392	79.8	6.1	1.2	No
	+2,000 ft	< 5,000	9.455	80.4	6.2	1.8	No
		< 1,000	9.444	80.3	6.2	1.7	No
25 PV	-1,000 ft	< 5,000	9.733	82.7	6.4	4.1	No
		< 1,000	9.735	82.8	6.6	4.1	No
	+1,000 ft	< 5,000	9.944	84.5	7.2	5.9	No
		< 1,000	9.930	84.4	7.4	5.8	No
	+2,000 ft	< 5,000	9.892	84.1	6.6	5.5	Yes
		< 1,000	9.867	83.9	6.8	5.3	Yes
50 PV	-1,000 ft	< 5,000	9.894	84.1	6.2	5.5	Yes
		< 1,000	9.885	84.0	6.4	5.4	Yes
	+1,000 ft	< 5,000	9.772	83.1	6.1	4.5	Yes
		< 1,000	9.827	83.5	6.5	4.9	Yes
	+2,000 ft	< 5,000	9.826	83.5	6.3	4.9	Yes
		< 1,000	9.866	83.9	6.7	5.3	Yes

Table 5.13 Results for reservoir with 10-degree dip angle using the minimum wellhead pressure of 150 psia, well pattern A

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	11.008	93.6	7.9	0.3	No
		< 1,000	11.005	93.6	7.1	0.3	No
	+1,000 ft	< 5,000	11.027	93.7	7.9	0.4	No
		< 1,000	11.034	93.8	7.3	0.5	No
	+2,000 ft	< 5,000	11.043	93.9	7.9	0.6	No
		< 1,000	11.041	93.9	7.4	0.6	No
25 PV	-1,000 ft	< 5,000	11.121	94.5	7.9	1.2	No
		< 1,000	11.112	94.5	7.7	1.2	No
	+1,000 ft	< 5,000	10.917	92.8	6.9	-0.5	Yes
		< 1,000	11.138	94.7	7.9	1.4	Yes
	+2,000 ft	< 5,000	10.922	92.8	6.9	-0.5	Yes
		< 1,000	11.128	94.6	7.8	1.3	Yes
50 PV	-1,000 ft	< 5,000	11.178	95.0	7.9	1.7	Yes
		< 1,000	11.220	95.4	8.3	2.1	Yes
	+1,000 ft	< 5,000	10.807	91.9	6.6	-1.6	Yes
		< 1,000	11.098	94.4	7.5	1.1	Yes
	+2,000 ft	< 5,000	10.860	92.3	6.7	-1.0	Yes
		< 1,000	11.124	94.6	7.7	1.3	Yes

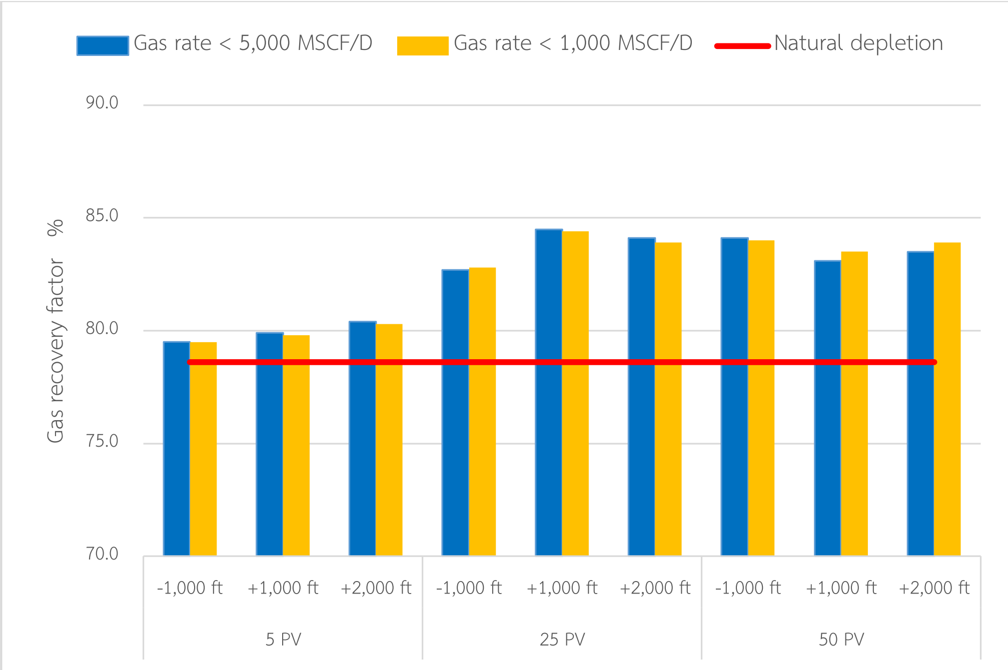
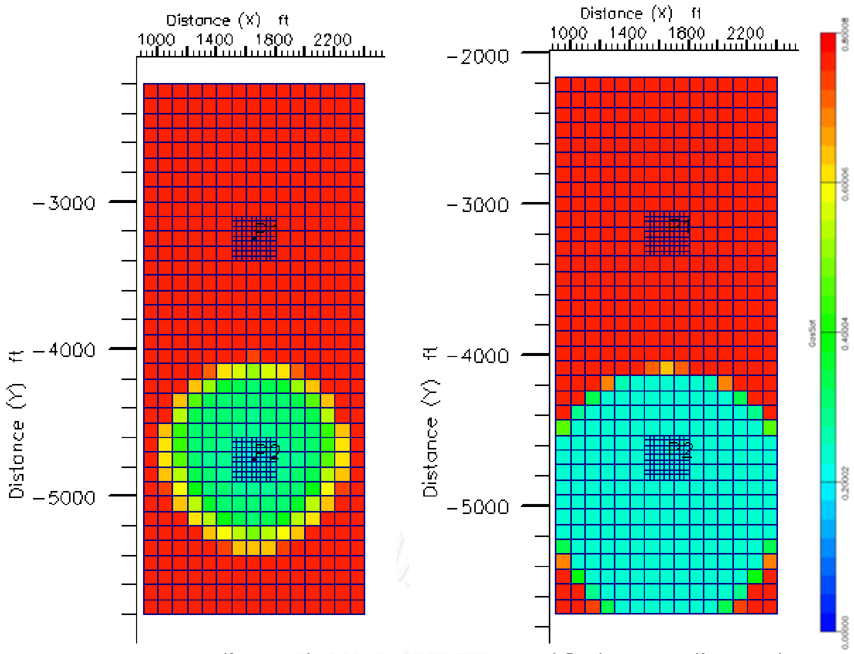


Figure 5.27 Gas recovery factors for varying reservoir system parameters with 10-degree dip angle for well pattern A using the minimum wellhead pressure of 500 psia

For cases of which the minimum wellhead pressure is 500 psia, all water dumpflood cases give higher gas recovery factors than natural depletion as shown in Figure 5.27. Gas recovery factors increase when the aquifer size changes from 5 PV to 25 PV. Since 25-PV aquifer results in larger cumulative water invasion into gas reservoirs than 5-PV aquifer, the reservoir pressures are supported better in this case. As a result, dumping water from 25-PV aquifer gives higher gas recoveries than 5-PV aquifer. However, when the aquifer size increases from 25 PV to 50 PV, the gas recovery factors for overlying aquifer cases moderately increase for the same reason but gas recovery factors for underlying aquifer cases slightly decrease due to liquid loading at high gas production rate. Since 50-PV aquifer provides drastic water invasion into the gas reservoirs, liquid loading occurs early. This behavior is similar to the one for flat reservoir system discussed in Section 5.2.1.

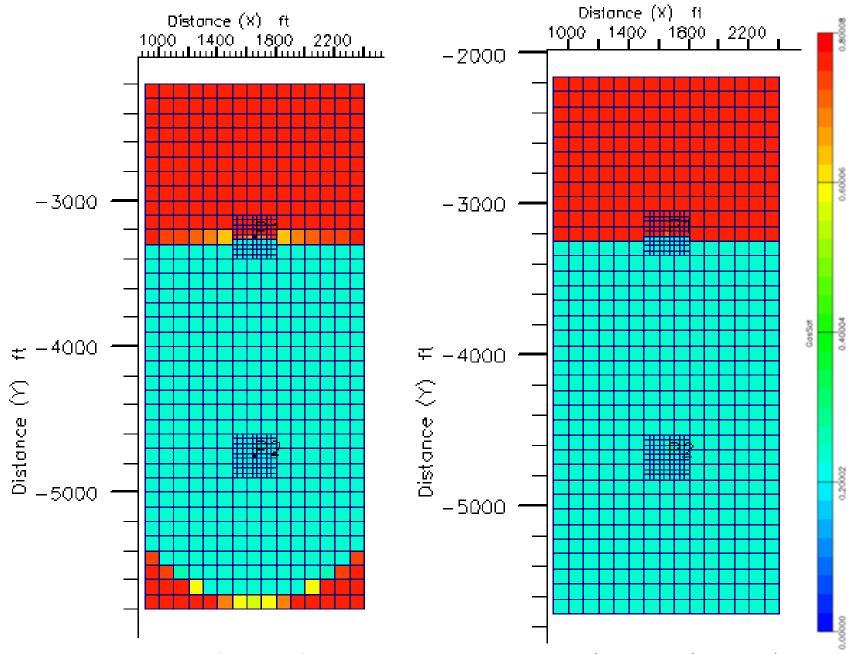
For location of aquifer, different aquifer depths give similar gas recovery factors for 5-PV aquifer size as the reservoir pressures are supported from 5-PV aquifer for only a short period. For 25-PV aquifer size, the underlying aquifers give slightly higher gas recovery factors than those for overlying aquifer as the underlying aquifers yield higher pressure support. The pressure of water flowing downwards from the overlying aquifer to the gas reservoirs increases due to large hydrostatic gain but small friction loss. On the other hand, the pressure of water flowing from the underlying aquifer to the gas reservoirs decreases as it flows upwards due to hydrostatic and friction losses. However, the underlying aquifers give higher water flowing pressure than that the overlying aquifer as the formation pressure gradient (which is indicative of initial aquifer pressure) is higher than the hydrostatic gradient of water. For the underlying aquifers, the deeper aquifer gives slightly lower gas recovery factor because it provides higher cumulative water invasion which causes water breakthrough. However, there is no water breakthrough for 25-PV aquifer located 1,000 ft below the bottommost gas reservoir. This behavior is different from the one seen in the case of flat reservoir system in Section 5.2.1. The reason is that the effect of gravity segregation helps delay water breakthrough at the producer as water moves up-dip for the reservoirs with 10-degree dip angle (see Figure 5.23 and Figure 5.24 for gas saturation distributions of reservoir with different dip angles). Note that gas saturation distributions shown in Figures 5.23 – 5.24 are obtained from cases using gas production rate below 5,000 MSCF/D as the triggering condition in which the aquifer is located 1,000 ft below the bottommost gas reservoir.

For 50-PV aquifer cases, the overlying aquifer gives higher gas recovery factors than both underlying aquifer cases because pressures of water flowing into the gas reservoirs in cases of underlying aquifer are higher than those from overlying aquifer. As a result, they yield higher amount of water invasion and subsequently cause early water breakthrough. Similar to 25-PV cases, the underlying aquifers located at different depths give no significant difference on gas recovery factor.



no dip angle 10-degree dip angle

Figure 5.28 Gas saturation distributions of the top layer of the topmost gas reservoir at the end of production (k = 1)



no dip angle 10-degree dip angle

Figure 5.29 Gas saturation distributions of the bottom layer of the bottommost gas reservoir at the end of production (k = 43)

In terms of triggering condition, there is no significant difference on gas recovery factors obtained from different triggering conditions for all cases as shown in Figure 5.27 because gas can be produced either until the economic rate without liquid loading or close to the economic rate with liquid loading. Considering production time, we find that the earlier water dumpflood is performed, the shorter production time is needed. Hence, water dumpflood should be performed when gas production rate is below 5,000 MSCF/D for 10-degree dip reservoirs with the minimum wellhead pressure of 500 psia.

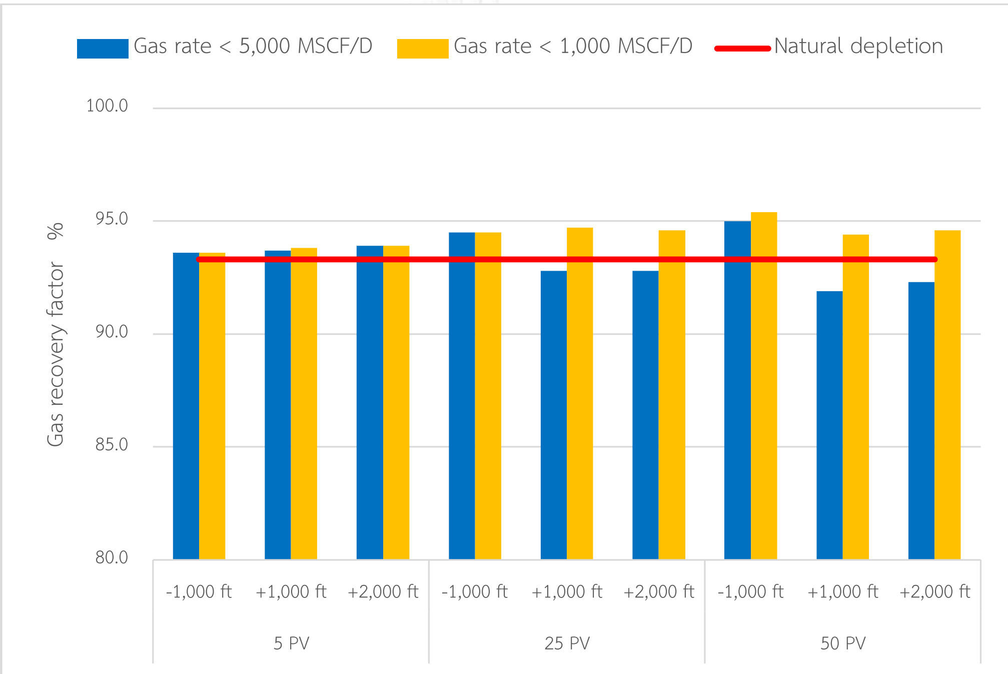


Figure 5.30 Gas recovery factors for varying reservoir system parameters with 10-degree dip angle for well pattern A using the minimum wellhead pressure of 150 psia

For cases of which the minimum wellhead pressure of 150 psia is set, gas recovery factors in all cases of 1,000 MSCF/D triggering condition are higher than that for natural depletion while those in cases of 5,000 MSCF/D may be higher or lower than that for natural depletion. Gas recovery factors for the cases with triggering condition of 5,000 MSCF/D decrease as the aquifer size increases for underlying aquifers as there is early water breakthrough. On the other hand, gas recovery factors obtained from overlying aquifer cases for the same triggering condition increase as the aquifer size increases because water breakthrough occurs slower. Therefore, the larger overlying aquifer yields higher gas recovery factors for the cases with triggering condition of 5,000 MSCF/D because it can support pressure for a longer period. For triggering condition of 1,000 MSCF/D, gas recovery factors for both 25-PV and 50-PV aquifer cases are approximately the same no matter where the aquifer is located but the values are slightly higher than those for 5-PV cases.

Regarding triggering condition, gas recovery factors for 5-PV aquifer are about the same no matter what the triggering rate is. However, gas recovery factors obtained from cases that dumpflood is triggered at gas production rate below the plateau are lower because of early water breakthrough. Consequently, water dumpflood should be performed near the economic rate when a low minimum wellhead pressure is used. In any case, the improvements in gas recovery factor obtained from water dumpflood over natural depletion are quite small when the booster compressor is used to lower the wellhead pressure.

5.3.2 Well pattern B

For well pattern B, the distance between wells P1 and P2 is 2,300 ft. Figure 5.31 shows gas recovery factors for cases of which minimum wellhead pressure is set to 500 psia. The gas recovery factors for cases using minimum wellhead pressure of 150 psia are shown in Figure 5.34. The simulation results are summarized in Tables 5.14 – 5.15.

From Table 5.14, the cumulative gas productions for water dumpflood with the minimum wellhead pressure of 500 psia vary from 9.354 BCF to 10.251 BCF, yielding of 0.9% – 8.5% incremental recovery factors depending on the dumpflood triggering condition, aquifer size and aquifer depth. The production times for this scenario are in the range of 6.0 – 8.2 years. From Table 5.15, cumulative gas productions for using booster compressor cases (the minimum wellhead pressure of 150 psia) vary around 11.001 – 11.258 BCF yielding incremental in gas recovery factor range of 0.2% – 2.4%. The production times for this scenario are extended to around 7.1 – 8.3 years. Liquid loading occurs only in 50 PV aquifer cases and affects both production times and gas recovery factors for both minimum wellhead pressure cases. For determining optimal operational condition, production time is considered as secondary priority when there is no significant difference on gas recovery factors. The effects of different parameters on gas recovery factors are discussed in details in this section.

Table 5.14 Results for reservoir with 10-degree dip angle using the minimum wellhead pressure of 500 psia, well pattern B

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	9.352	79.5	6.0	0.9	No
		< 1,000	9.354	79.5	6.0	0.9	No
	+1,000 ft	< 5,000	9.395	79.9	6.0	1.3	No
		< 1,000	9.395	79.9	6.1	1.3	No
	+2,000 ft	< 5,000	9.447	80.3	6.1	1.7	No
		< 1,000	9.458	80.4	6.4	1.8	No
25 PV	-1,000 ft	< 5,000	9.736	82.8	6.3	4.2	No
		< 1,000	9.738	82.8	6.6	4.2	No
	+1,000 ft	< 5,000	9.915	84.3	7.0	5.7	No
		< 1,000	9.920	84.3	7.3	5.7	No
	+2,000 ft	< 5,000	10.093	85.8	7.6	7.2	No
		< 1,000	10.105	85.9	8.2	7.3	No
50 PV	-1,000 ft	< 5,000	10.119	86.0	7.0	7.4	No
		< 1,000	10.108	85.9	7.2	7.3	No
	+1,000 ft	< 5,000	10.253	87.2	7.3	8.6	Yes
		< 1,000	10.185	86.6	7.1	8.0	Yes
	+2,000 ft	< 5,000	10.200	86.7	6.9	8.1	Yes
		< 1,000	10.183	86.6	7.2	8.0	Yes

Table 5.15 Results for reservoir with 10-degree dip angle using the minimum wellhead pressure of 150 psia, well pattern B

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	11.001	93.5	7.9	0.2	No
		< 1,000	11.002	93.5	7.1	0.2	No
	+1,000 ft	< 5,000	11.060	94.0	7.9	0.7	No
		< 1,000	11.028	93.8	7.3	0.4	No
	+2,000 ft	< 5,000	11.042	93.9	7.9	0.5	No
		< 1,000	11.044	93.9	7.3	0.5	No
25 PV	-1,000 ft	< 5,000	11.120	94.5	7.8	1.2	No
		< 1,000	11.118	94.5	7.8	1.2	No
	+1,000 ft	< 5,000	11.144	94.7	7.9	1.4	No
		< 1,000	11.180	95.0	8.1	1.7	No
	+2,000 ft	< 5,000	11.165	94.9	7.9	1.6	No
		< 1,000	11.224	95.4	7.8	2.1	No
50 PV	-1,000 ft	< 5,000	11.225	95.4	8.0	2.1	No
		< 1,000	11.188	95.1	7.9	1.8	No
	+1,000 ft	< 5,000	11.101	94.4	7.3	1.0	Yes
		< 1,000	11.258	95.7	8.3	2.4	Yes
	+2,000 ft	< 5,000	11.090	94.3	7.3	1.0	Yes
		< 1,000	11.228	95.5	8.2	2.2	Yes

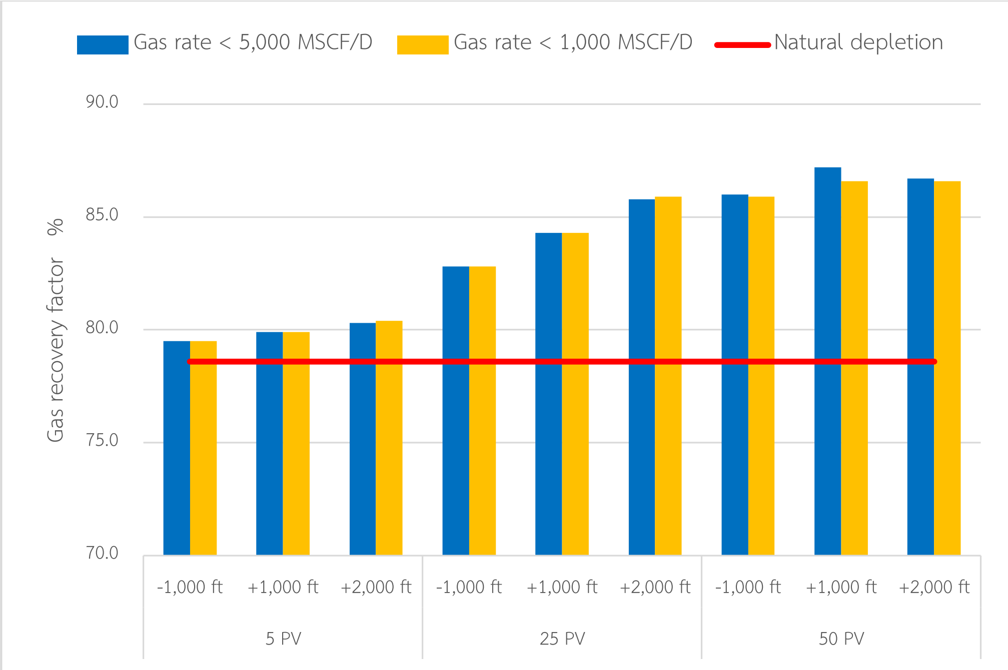


Figure 5.31 Gas recovery factors for varying reservoir system parameters with 10-degree dip angle for well pattern B using the minimum wellhead pressure of 500 psia

For cases using the minimum wellhead pressure of 500 psia, all water dumpflood cases have higher recovery factors than natural depletion as shown in Figure 5.31. Gas recovery factors significantly increase when the aquifer size increases from 5 PV to 25 PV but slightly increase when the aquifer size changes from 25 PV to 50 PV. Since 50-PV aquifer results in higher amount of water invasion than 25-PV aquifer, reservoir pressures are supported better. However, high amount of water invasion can cause liquid loading. As a result, the incremental gas recovery factors become smaller when the aquifer size increases from 25 PV to 50 PV.

For location of aquifer, there is no significant difference on gas recovery factors obtained from 5-PV aquifer cases because the aquifer can provide only a short period of reservoir pressure support. For 25-PV aquifer cases, gas recovery factors for underlying aquifers are higher than those for overlying aquifer for the same reason as described in Section 5.2.2. Unlike the results for a flat reservoir system, the gas recovery factors for the deeper underlying aquifer (+2,000 ft) are larger than those for shallower underlying aquifer (+1,000 ft). This is due to the fact that the deeper underlying aquifer provides higher cumulative water invasion into the gas reservoirs for a longer period as shown in Figure 5.32. As a result, the well in case of deeper underlying aquifer can produce gas for a longer period of time as shown in Figure 5.33.

For 50-PV aquifer cases, gas recovery factors of underlying aquifers are slightly higher than those for overlying aquifer because the underlying aquifers provide better pressure support than the overlying aquifer while the recovery factors for both underlying aquifers have no significant difference as water breakthrough occurs when gas production rate is slightly above the economic rate for both cases.

From Figure 5.31, there is no significant difference between gas recovery factors obtained from different triggering gas production rates for cases using the minimum wellhead pressure of 500 psia. As water breakthrough is delayed due to the extended well distance, we can produce gas until either it reaches the economic limit or gets close to the economic limit for both triggering conditions. As faster production is favourable, water dumpflood should be started when gas production rate is below 5,000 MSCF/D.

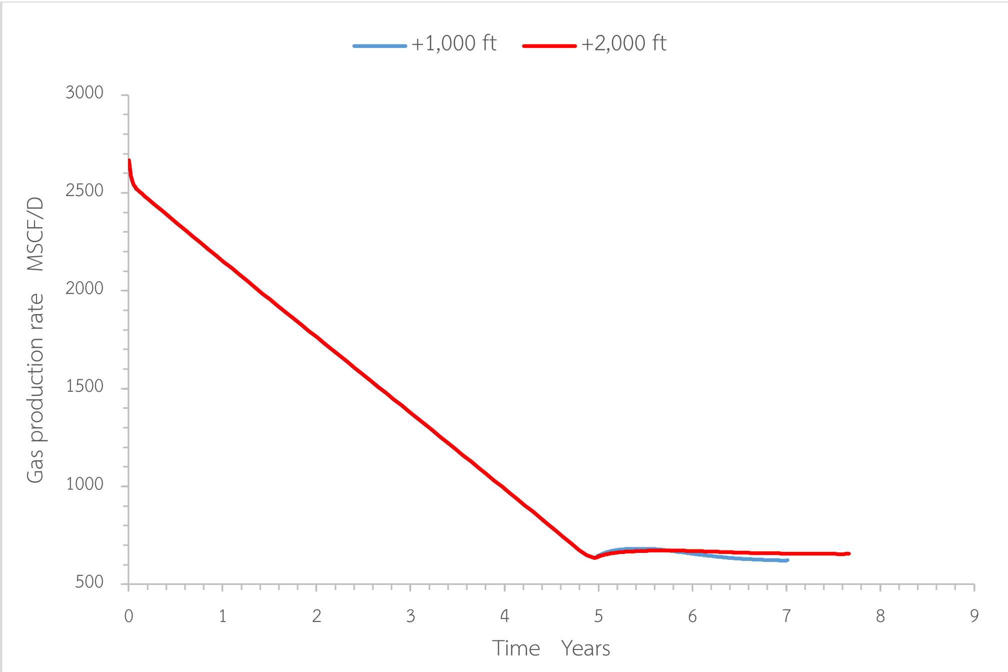


Figure 5.32 Comparison of average pressure of the bottommost gas reservoir among underlying aquifers (using gas production rate below 5,000 MSCF/D as triggering condition)

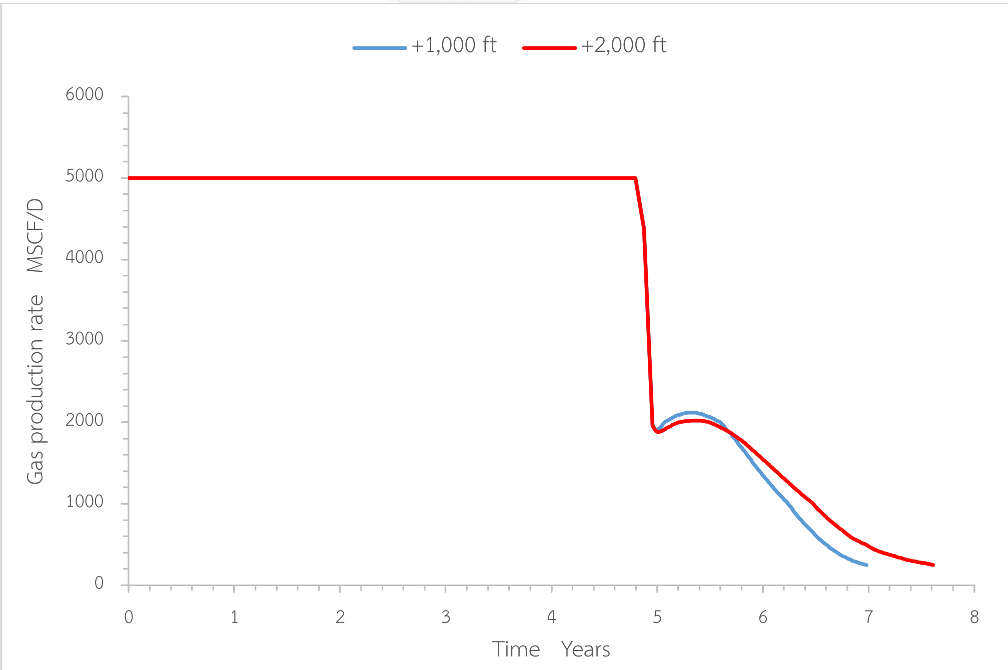


Figure 5.33 Field gas production rates for underlying aquifers (using gas production rate below 5,000 MSCF/D as triggering condition)

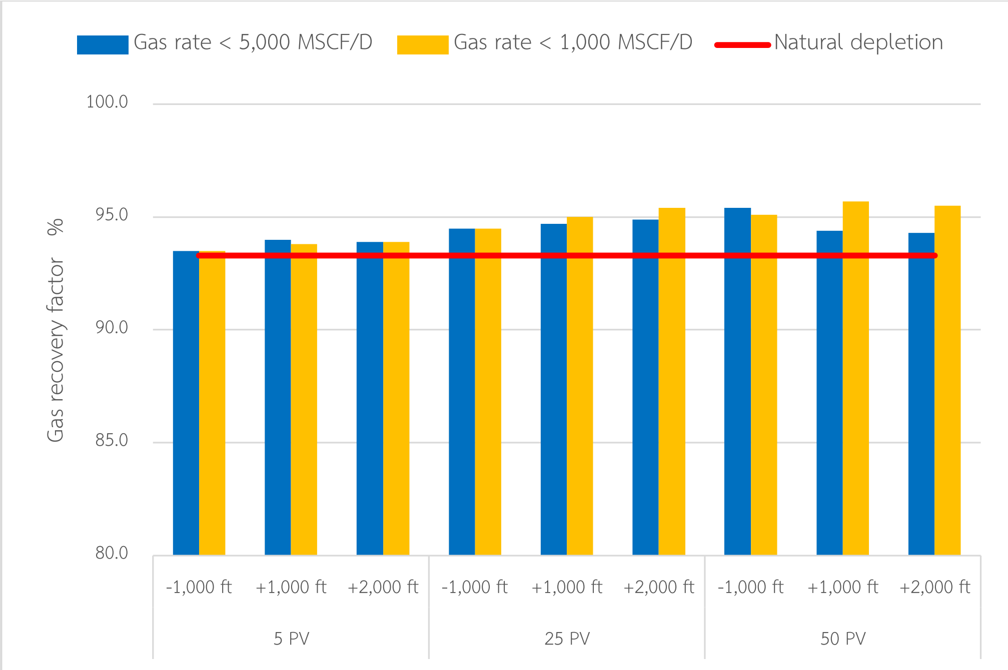


Figure 5.34 Gas recovery factors for varying reservoir system parameters with 10-degree dip angle for well pattern B using the minimum wellhead pressure of 150 psia

For results obtained from cases using the minimum wellhead pressure of 150 psia (using booster compressor), all water dumpflood cases yield slightly higher gas recovery factors than natural depletion. For triggering gas rate of 5,000 MSCF/D, gas recovery factors slightly increase when the aquifer size changes from 5 PV to 25 PV because the large aquifer provides better pressure support as it gives larger amount of water invasion. When the aquifer size increases from 25 PV to 50 PV, gas recovery factors obtained from the overlying aquifer case slightly increase for the same reason. Nonetheless, gas recovery factors obtained from underlying aquifer cases slightly decrease because of early liquid loading. For triggering gas rate of 1,000 MSCF/D, gas recovery factors slightly increase when the aquifer size increases from 5 PV to 25 PV for the same reason as discussed earlier. When the aquifer size increases from 25 PV to 50 PV, gas recovery factors stay almost the same because of liquid loading which is the negative effect of strong aquifer even though there is better pressure support.

For location of aquifer, gas recovery factors are not significantly different among the three locations for 5 PV and 25 PV aquifers because gas can be produced until the economic limit as there is no water breakthrough for both triggering conditions. For 50-PV aquifer cases, gas recovery factor obtained for the overlying aquifer for triggering gas rate of 5,000 MSCF/D is higher than those for the underlying aquifers due to liquid loading from strong aquifer. However, there is no significant difference on gas recovery factors obtained from the three aquifer depths for gas triggering rate of 1,000 MSCF/D as the liquid loading occurs when the gas rate is close to the economic rate.

In summary, for cases of which the minimum wellhead pressure is set at 150 psia, preforming water dumpflood near the economic rate gives better gas recovery factors for almost all aquifer sizes and aquifer depths except for 50-PV overlying aquifer. Consequently, it is better to perform water dumpflood near the economic rate when low minimum wellhead pressure is set. In any case, the incremental gas recovery factors obtained from water dumpflood over natural depletion are small when the booster compressor is used to lower the wellhead pressure.

5.3.3 Well pattern C

The distance between wells P1 and P2 is 3,100 ft for well pattern C. The gas recovery factors for cases of which the minimum wellhead pressure of 500 psia is used are shown in Figure 5.35. Figure 5.36 shows the gas recovery factors for cases using the minimum wellhead pressure of 150 psia. The simulation results are summarized in Tables 5.16 – 5.17.

From Table 5.16, the cumulative gas productions for water dumpflood with the minimum wellhead pressure of 500 psia vary around 9.347 – 10.444 BCF, which yield 0.9 – 10.2% incremental recovery factors depending on the dumpflood triggering condition, aquifer size and aquifer depth. The production times for this scenario are in the range of 6.0 – 8.4 years. From Table 5.17, cumulative gas productions for using booster compressor cases (the minimum wellhead pressure of 150 psia) vary around 10.996 – 11.3 BCF, yielding 0.2% – 2.9% incremental gas recovery factors. Production times for using booster compressor are extended to around 7.2 – 8.8 years. Liquid loading occurs only in 50-PV aquifer cases. For determining optimal operational condition, production time is considered as secondary priority when there is no significant difference on gas recovery factors. The effects of various parameters on gas recovery factors are discussed in details in this section.

Table 5.16 Results for reservoir with 10-degree dip angle using the minimum wellhead pressure of 500 psia, well pattern C

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	9.347	79.5	6.0	0.9	No
		< 1,000	9.347	79.5	6.0	0.9	No
	+1,000 ft	< 5,000	9.396	79.9	6.1	1.3	No
		< 1,000	9.395	79.9	6.1	1.3	No
	+2,000 ft	< 5,000	9.447	80.3	6.2	1.7	No
		< 1,000	9.454	80.4	6.3	1.8	No
25 PV	-1,000 ft	< 5,000	9.731	82.7	6.4	4.2	No
		< 1,000	9.731	82.7	6.7	4.2	No
	+1,000 ft	< 5,000	9.901	84.2	7.1	5.6	No
		< 1,000	9.914	84.3	7.4	5.7	No
	+2,000 ft	< 5,000	10.079	85.7	7.6	7.1	No
		< 1,000	10.105	85.9	8.2	7.3	No
50 PV	-1,000 ft	< 5,000	10.115	86.0	7.1	7.4	No
		< 1,000	10.105	85.9	7.3	7.3	No
	+1,000 ft	< 5,000	10.393	88.4	8.4	9.8	No
		< 1,000	10.393	88.4	8.4	9.8	Yes
	+2,000 ft	< 5,000	10.444	88.8	7.8	10.2	Yes
		< 1,000	10.415	88.5	8.0	10.0	Yes

Table 5.17 Results for reservoir with 10-degree dip angle using the minimum wellhead pressure of 150 psia, well pattern C

Aquifer size	Aquifer location	Triggering gas production rate (MSCF/D)	Total gas production (BCF)	Gas recovery factor (%)	Production time (year)	Incremental recovery factor (%)	Liquid loading
5 PV	-1,000 ft	< 5,000	10.999	93.5	8.0	0.2	No
		< 1,000	10.996	93.5	7.2	0.2	No
	+1,000 ft	< 5,000	11.018	93.7	8.0	0.4	No
		< 1,000	11.019	93.7	7.3	0.4	No
	+2,000 ft	< 5,000	11.033	93.8	8.0	0.5	No
		< 1,000	11.034	93.8	7.5	0.5	No
25 PV	-1,000 ft	< 5,000	11.109	94.4	7.9	1.1	No
		< 1,000	11.112	95.4	7.8	1.2	No
	+1,000 ft	< 5,000	11.144	94.7	7.9	1.4	No
		< 1,000	11.180	95.0	8.1	1.7	No
	+2,000 ft	< 5,000	11.155	94.8	8.0	1.5	No
		< 1,000	11.222	95.4	8.6	2.1	No
50 PV	-1,000 ft	< 5,000	11.223	95.4	8.0	2.1	No
		< 1,000	11.180	95.0	7.9	1.7	No
	+1,000 ft	< 5,000	11.184	95.1	7.8	1.8	Yes
		< 1,000	11.292	96.0	8.7	2.7	Yes
	+2,000 ft	< 5,000	11.196	95.2	7.8	1.9	Yes
		< 1,000	11.300	96.1	8.8	2.8	Yes

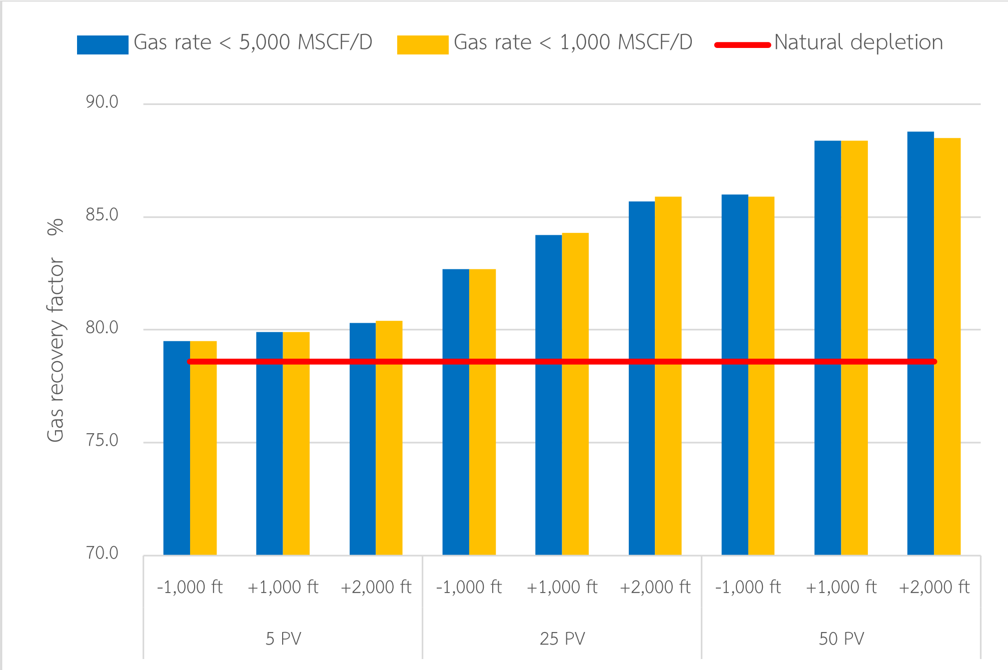


Figure 5.35 Gas recovery factors for varying reservoir system parameters with 10-degree dip angle for well pattern C using the minimum wellhead pressure of 500 psia

For cases of which the minimum wellhead pressure is 500 psia, all water dumpflood cases have higher recovery factors than natural depletion as illustrated in Figure 5.35. Gas recovery factors increase when the aquifer size increases for all cases because the larger aquifer results in better reservoir pressure support. For well pattern C, the large aquifer can support gas reservoir pressures for a long period as water breakthrough occurs at late time as the wells are far apart, resulting in higher gas recovery factors than a small aquifer size.

For location of aquifer, different depths of aquifer give no difference in gas recovery factors for 5-PV aquifer because there is no water breakthrough. For 25-PV and 50-PV aquifer sizes, gas recovery factors increase when the aquifer is located deeper. The underlying aquifers give higher gas recovery factors than the overlying aquifer because the water flowing from both underlying aquifers into the gas reservoirs has higher pressure than that from the overlying aquifer as discussed before.

From Figure 5.24, there is no significant difference between gas recovery factors obtained from different triggering gas production rates for cases using the minimum wellhead pressure of 500 psia. As the extended well distance delays the water breakthrough, gas can be produced until either it reaches the economic limit or gets close to the economic limit for both triggering conditions. As faster production is desirable, water dumpflood should be performed at gas production rate below the plateau rate.

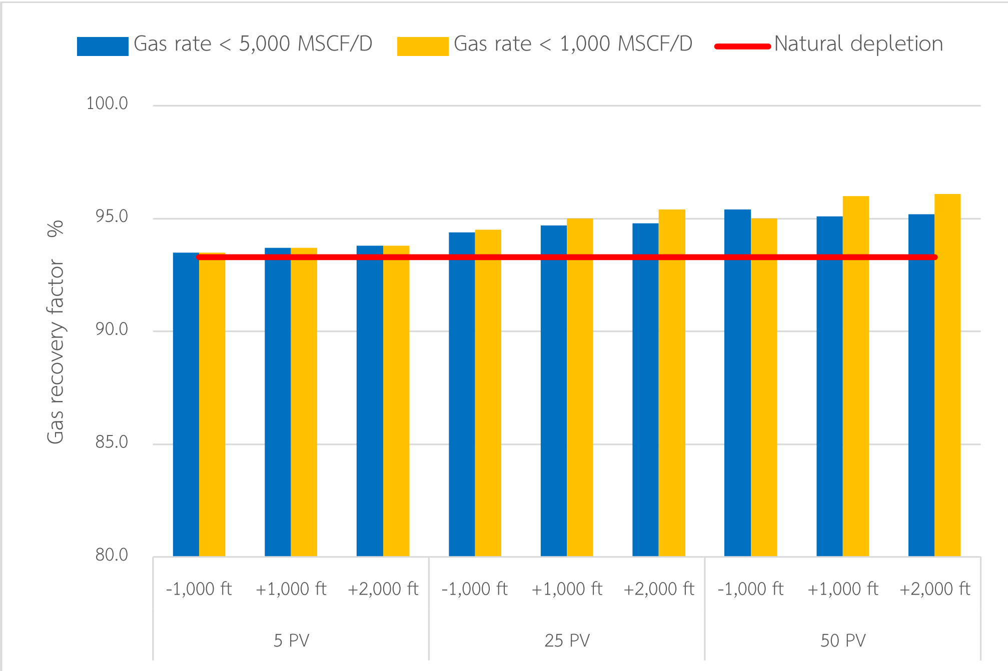


Figure 5.36 Gas recovery factors for varying reservoir system parameters with 10-degree dip angle for well pattern C using the minimum wellhead pressure of 150 psia

The gas recovery factors increase when the aquifer size increases for cases of which the minimum wellhead pressure is 150 psia as shown in Figure 5.36. The larger aquifer can maintain gas reservoir pressures longer than the smaller aquifer. Besides, there is combined effect between longer well distance and gravity segregation as the reservoir has dip angle. In these cases, there is no early water breakthrough. As long as there is no early water breakthrough, the longer the pressure is maintained, the greater the gas recovery is.

For location of aquifer, gas recovery factors are not significantly different among the three locations.

For cases of which the minimum wellhead pressure is set at 150 psia, preforming water dumpflood near the economic rate generally gives better gas recovery factors when the aquifer is 25 PV or 50 PV as seen in Figure 5.36. As the minimum wellhead pressure is small, the bottomhole and the reservoir pressures are small. Thus, the water invades into the gas reservoirs very fast. Hence, the earlier the dumpflood is performed, the faster the liquid loading. Consequently, it is better to perform water dumpflood near the economic rate when low minimum wellhead pressure is set. In any case, the incremental gas recovery factors obtained from water dumpflood over natural depletion are small when the booster compressor is used to lower the wellhead pressure.

5.3.4 Comparison among different well patterns for reservoir with 10-degree dip angle

Since well distance between wells P1 and P2 plays important role in improving gas recovery via water dumpflood, comparisons in details among well patterns are discussed in this section. Since gas recovery factors obtained from all well patterns in natural depletion are almost the same for individual minimum wellhead pressures as can be seen in Table 5.11, one of them is individually plotted for each minimum wellhead pressure.

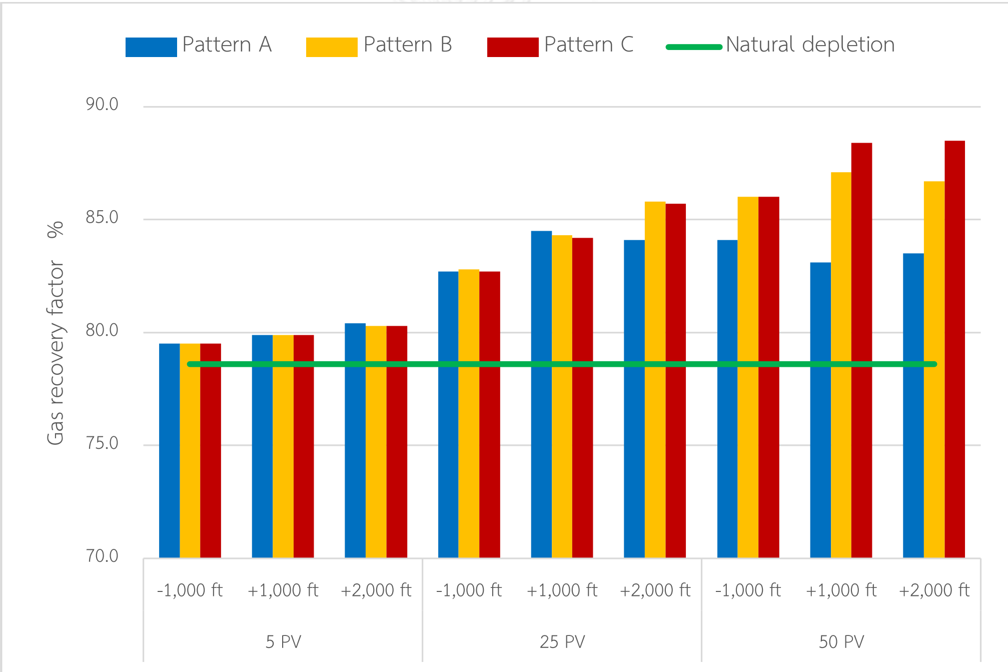


Figure 5.37 Comparison of gas recovery factors for varying reservoir system parameters among well patterns A, B and C using minimum wellhead pressure of 500 psia and gas rate below 5,000 MSCF/D as triggering condition, 10-degree dip angle reservoir

As seen in Figures 5.37 – 5.38, results obtained from different triggering conditions have the same trend when comparison is made among the three well patterns. For 5-PV aquifer cases, gas recovery factors obtained from all well patterns are similar because the aquifer can provide pressure support for only a short period. As there is only a short period of water invasion, there is no water breakthrough. As a result, gas production can be continued until the economic limit. For 25-PV aquifer cases, gas recovery factors for all well patterns obtained from overlying aquifer and underlying aquifer located 1,000 ft below bottommost gas reservoir are quite the same because there is no early water breakthrough. This means that gas can be produced until either the economic limit or slightly above the economic limit with liquid loading. However, for underlying aquifer located 2,000 ft below the bottommost gas reservoir, there is early water breakthrough in well pattern A. Therefore, well patterns B and C which have longer well distance yield higher recovery as they can produce until the economic limit. For 50-PV aquifer cases, gas recovery factors increase when the well distance increases because the aquifer provides a large amount of water invasion to build up the reservoir pressures and water breakthrough is delayed when the well distance increases. Besides, more gas is swept as increasing well distance increases areal sweep efficiency. Thus, well pattern C is the best when the aquifer size is 50 PV.

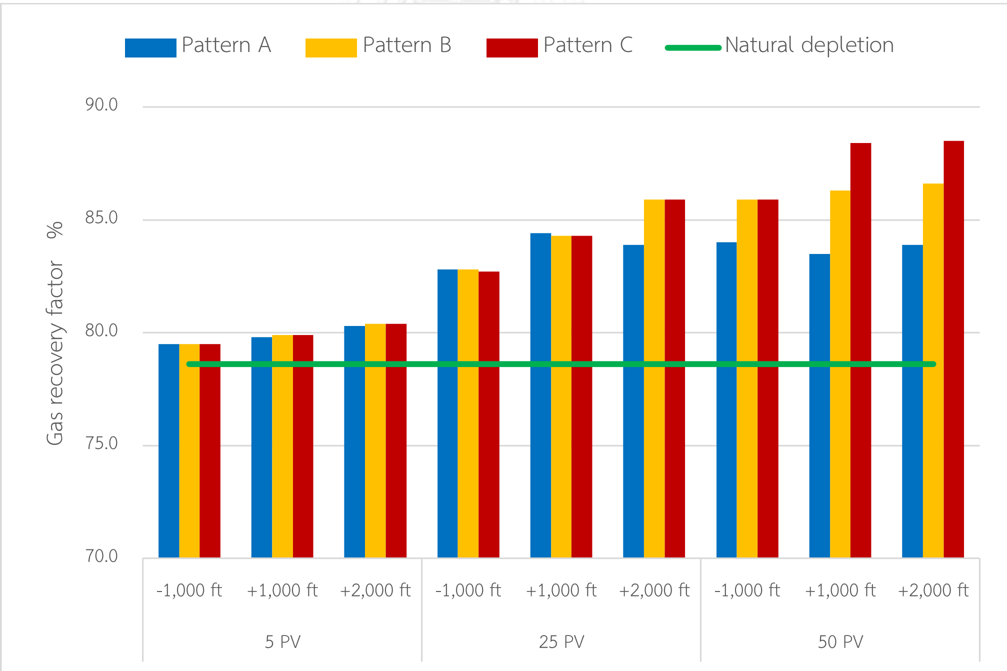


Figure 5.38 Comparison of gas recovery factors for varying reservoir system parameters among well patterns A, B and C using minimum wellhead pressure of 500 psia and gas rate below 1,000 MSCF/D as triggering condition, 10-degree dip angle reservoir

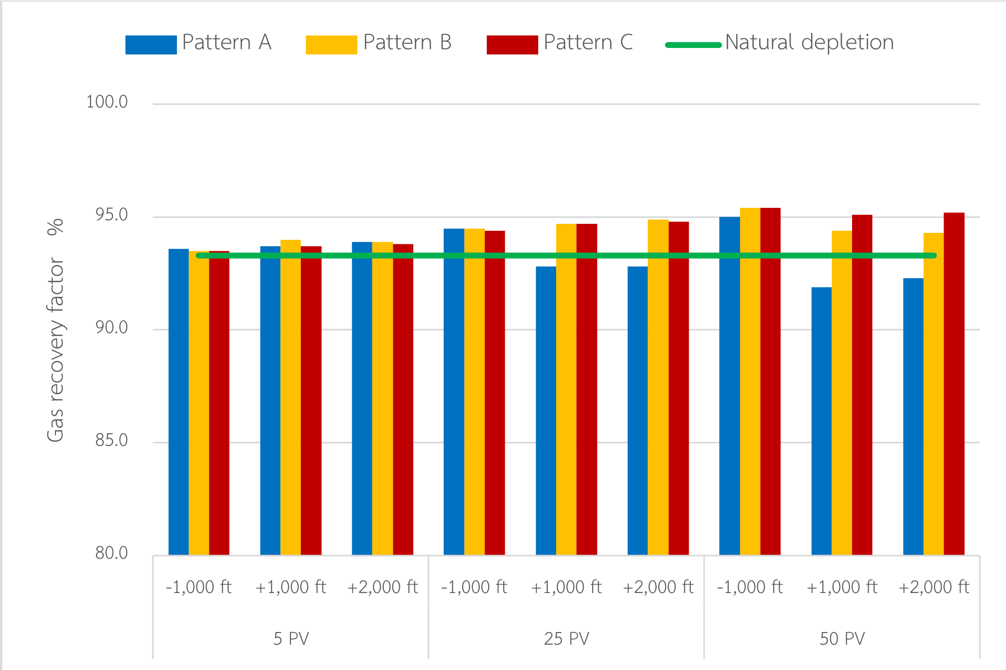


Figure 5.39 Comparison of gas recovery factors for varying reservoir system parameters among well patterns A, B and C using minimum wellhead pressure of 150 psia and gas rate below 5,000 MSCF/D as triggering condition, 10-degree dip angle reservoir

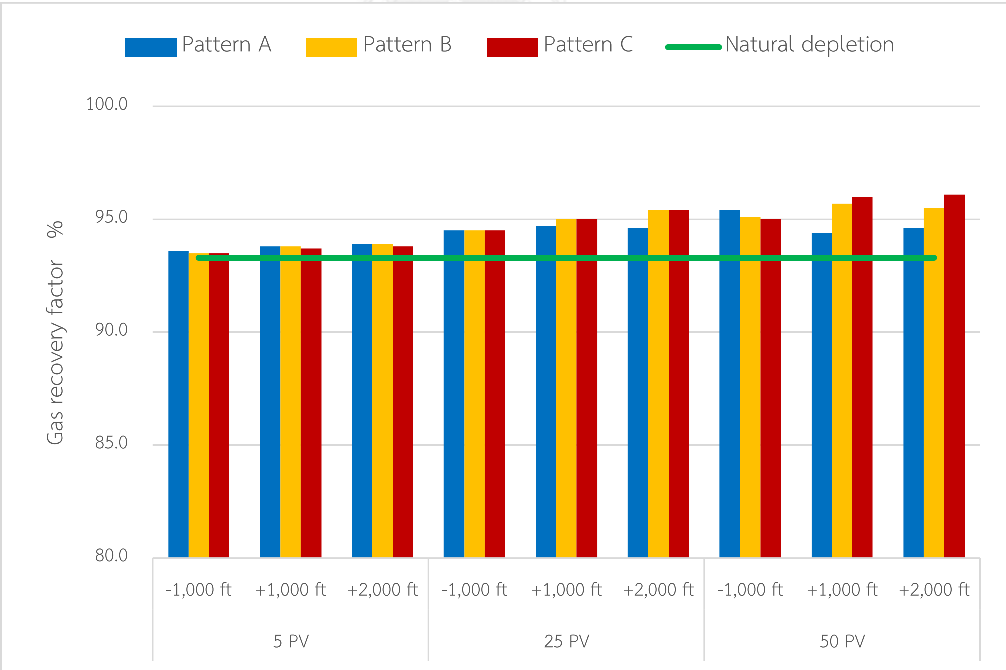


Figure 5.40 Comparison of gas recovery factors for varying reservoir system parameters among well patterns A, B and C using minimum wellhead pressure of 150 psia and gas rate below 1,000 MSCF/D as triggering condition, 10-degree dip angle reservoir

According to Figures 5.39 – 5.40, results obtained from different triggering conditions have almost the same trend when comparison is made among the three well patterns and almost the same trend compared to the cases in which the minimum wellhead pressure is 500 psia except for aquifer size of 25 PV (see Figures 5.37 – 5.38). Consequently, only 25-PV aquifer cases are discussed for results obtained from cases using the minimum wellhead pressure of 150 psia. For overlying aquifer cases, there is no significant difference on gas recovery obtained from all well patterns as there is no water breakthrough. For underlying aquifers, gas recovery factors obtained from well patterns B and C are higher than those for well pattern A when water dumpflood is performed at gas rate below the plateau rate due to early water breakthrough in well pattern A. However, when water dumpflood is performed at gas rate below 1,000 MSCF/D, water breakthrough is delayed. As a result, gas recovery factors obtained from all well patterns when water dumpflood is performed later are similar because gas can be produced until slightly above the economic limit with liquid loading for well pattern A.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

In this chapter, effects from all reservoir system parameters and triggering condition for water dumpflood are concluded. The conclusions can be used to determine the feasibility of water dumpflood into multiple low-pressure gas reservoirs for different reservoir conditions. Moreover, the recommendations which might be useful for further study are also proposed.

6.1 Conclusions

1) This simulation study found that water dumpflood can increase gas recovery factors to the range of 78.4% – 88% of OGIP when the minimum well head pressure of 500 psia is set, yielding the incremental recovery factor compared to natural depletion in the range of 0.9% – 10.5%. For cases using the minimum well head pressure of 150 psia, there are both increment and decrement in gas recovery factors. The minimum gas recovery factor is 91.2%, yielding decrement in gas recovery factor of 1.8% while the maximum gas recovery factor is 96.1%, yielding incremental gas recovery factor of 2.8%. The increments in gas recovery factor depend on operational conditions and system parameters.

2) For operations using the minimum wellhead pressure of 500 psia, water dumpflood should be performed when gas production rate is below the plateau rate because it requires shorter production duration but gives quite similar gas recovery factors to the cases that dumpflood is started near the economic limit. On the other hand, water dumpflood should be performed near the economic rate for operation using minimum wellhead pressure of 150 psia in order to delay water breakthrough. In any case, the incremental gas recovery factor in the case of low minimum wellhead pressure is very small or even negative in some cases.

3) The performance of water dumpflood is reduced when the minimum wellhead pressure used becomes smaller because the amount of gas remaining in the

reservoir in the case of low minimum wellhead pressure is less than that in the case of high minimum wellhead pressure. Moreover, water invades each reservoir very fast at low reservoir pressure condition, causing water breakthrough and subsequently liquid loading. Consequently, water dumpflood is not recommended to perform with the low minimum wellhead pressure because it yields very small incremental gas recovery factors.

4) As the size of the aquifer is changed from 5 PV to 25 PV, gas recovery factors increase because a large aquifer can support pressure to gas reservoirs longer than a small aquifer. However, as the size of the aquifer is changed from 25 PV to 50 PV, gas recovery factors from water dumpflood decrease for well pattern A as there is early water breakthrough but gas recovery factors from water dumpflood increase for well patterns B and C because their well distances are long enough to delay water breakthrough.

5) As the aquifer location is changed from overlying to underlying, gas recovery factors from water dumpflood increase. Since the pressure of water flowing from the underlying aquifer is higher than that from the overlying aquifer, underlying aquifers have better performance than overlying aquifer. For both underlying aquifers, the deeper underlying aquifer provides higher cumulative water invasion into the gas reservoirs for a longer period. As a result, gas recovery factors from water dumpflood increase as aquifer located deeper because the well in case of deeper underlying aquifer can produce gas for a longer time.

6) As the dip angle of the reservoirs and the aquifer is increased from 0 to 10 degrees, gas recovery factors from water dumpflood increase slightly because the aquifer with 10-degree dip angle has higher average pressure. As it has higher pressure, it can maintain the reservoir pressures better. Moreover, for cases having moderate aquifer size, water breakthrough is delayed as result of gravity segregation effect.

7) As the well distance is increased from 1,500 ft to 3,100 ft, gas recovery factors obtained from 25-PV aquifer and 50-PV aquifer cases increase as longer well distance can delay water breakthrough. However, there is no significant difference between gas recovery factors obtained from 5-PV aquifer case.

8) According to the results of this study, water dumpflood is generally recommended to perform when operational conditions and the system parameters are as follows:

   - Using moderate minimum well head pressure (500 psia for this study)
   - The aquifer size is 25 PV or larger
   - Aquifer located at any depth investigated in this study (-1,000 ft, +1,000 ft and +2,000 ft)
   - Well distance between the producer and the dumpflood well is 1,500 ft or longer
   - Reservoir can be flat or has dip angle of 10°

   However, when the wells can be subjected to low minimum well head pressure (150 psia in this study), water dumpflood is generally not recommended to perform except for the systems having operational conditions and the system parameters as follows:

   - Performing water dumpflood when gas production rate is near economic rate
   - The aquifer size is 50 PV or larger
   - Aquifer located at any depth investigated in this study (-1,000 ft, +1,000 ft and +2,000 ft)
   - Well distance between the producer and the dumpflood well is 3,100 ft
   - Reservoir can be flat or has dip angle of 10°

6.2 Recommendations

1) Since the heterogeneity of rock properties strongly affects water breakthrough time, the performance of water dumpflood into gas reservoirs may be different from results in this study which uses homogenous reservoirs. Therefore, water dumpflood into heterogeneous reservoir should be studied in details for better field implementation.

2) As the incremental gas recovery factors depend on residual gas saturation after water flood, sensitivity analysis of this property should be studied in details.

3) For reservoir system having large overlying aquifer and short well distance, we can gradually plug the dumpflood well from the bottommost layer to topmost layer as water flows downward. Since the well is killed by liquid loading, we should find the optimal time to plug the nearly water breakthrough layer in the dumpflood well in order to prevent early water breakthrough and prolong gas production.

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APPENDIX

Appendix A
Schedule

There are two gas production wells in this study: P1 and P2. Well P2 will be converted to water dumpflood well when gas production reaches triggering conditions for dumpflood operation. Well P1 and P2 have 8 segments and 10 segments, respectively. Well specification, completion, segment and production control data are summarized in Tables A.1 – A.13.

Well Specification (keyword: WELSPECL)

Table A.1 Well specification data before dumpflood operation

Parameters	Before dumpflood operation		During dumpflood operation	
	Well P1	Well P2	Well P1	Well P2
LGR	LGR1	LGR2	LGR1	LGR2
I Location	5	5	5	5
J Location	5	5	5	5
Datum depth	5,000 ft	5,000 ft	5,000 ft	5,000 ft
Preferred phase	Gas	Gas	Gas	Water

Completion Data (keyword: COMPDATL)

Table A.2 Well completion data for well P1

Parameters	Layer				Unit
	1	2	3	4	
Well bore ID	0.5104	0.5104	0.5104	0.5104	ft
Fracture pressure	3172	3340	3510	3681	psi
K upper perforated zone	1	12	23	34	
K lower Perforated zone	10	21	32	43	

Note: Fracture pressures are not presented in dumpflood well input data in Eclipse simulator.

Table A.3 Well completion data for well P2

Parameters	Layer					Unit
	1	2	3	4	5	
Well Bore ID	0.5104	0.5104	0.5104	0.5104	0.5104	ft
Fracture Pressure	3172	3329	3487	3647	4443	psi
K Upper Perforated Zone	1	12	23	34	45	
K Lower Perforated Zone	10	21	32	43	54	

Well Segment Definition (keyword: WELSEGS)

Table A.4 Segmented well definition data for well P1

Parameters	Segments								Unit
	1	2	3	4	5	6	7	8	
Length	5000	25	200	25	200	25	200	25	ft
Depth	5000	25	200	25	200	25	200	25	ft
Diameter	0.2034								ft
Roughness	0.00015								ft

Table A.5 Segmented well definition data for well P2

Parameters	Segments										Unit
	1	2	3	4	5	6	7	8	9	10	
Length	5000	25	200	25	200	25	200	25	1000	1000	ft
Depth	5000	25	200	25	200	25	200	25	1000	1000	ft
Diameter	0.2034										ft
Roughness	0.00015										ft

Well Segment Completion (keyword: COMPSEGL)

Table A.6 Segmented well completion data for well P1

Parameters	Segments				Unit
	1	2	3	4	
Strat Point	5,5,1	5,5,12	5,5,23	5,5,34	(i,j,k)
End Point	5,5,10	5,5,21	5,5,32	5,5,43	(i,j,k)
Strat Length (z)	0	225	450	675	ft
End Length (z)	25	250	475	700	ft

Table A.7 Segmented well completion data for well P2

Parameters	Segment					Unit
	1	2	3	4	5	
Strat point	5,5,1	5,5,12	5,5,23	5,5,34	5,5,45	(i,j,k)
End point	5,5,10	5,5,21	5,5,32	5,5,43	5,5,54	(i,j,k)
Strat length (z)	0	225	450	675	1700	ft
End length (z)	25	250	475	700	2700	ft

<u>Production Well Control Part (keyword: WCONPROD)</u>

Table A.8 Production control data for wells P1 and P2

Parameters	Before dumpflood operation		During dumpflood operation	
	Well P1	Well P2	Well P1	Well P2
Open/Shut flag	OPEN	OPEN	OPEN	STOP
Control	Gas rate	Gas rate	Gas rate	-
Gas rate	2,500 MSCF/D	2,500 MSCF/D	2,500 MSCF/D	-
THP target	500 psia	500 psia	500 psia	-
Preferred phase	Gas	Gas	Gas	Water

Vertical Flow Performance (keyword: VFPPROD)

Table A.9 Input data of VFP table for tables 1 – 4

Parameters	Table				Unit
	1	2	3	4	
Fluid	Dry and Wet Gas				
Method	Black oil				
Gas Gravity	0.7				
Condensate to Gas Ratio	0				
Water Salinity	2,500				ppm
Gas Viscosity	Lee et al				
Measure Depth	5,700				ft
Tubing Diameter	2.441				inch
Vertical Lift Correlation	Petroleum Experts 2				
First Node Depth	0	5,025	5,250	5,475	ft
Last Node Depth	5,000	5,225	5,450	5,675	ft
Temperature	262	269	275	282	^{o}F
Enter Rate	0. 1, 0.25, 0.3, 0.5, 1, 1.5, 2.5, 5, 7, 10				MMSCF/D
Variable 1: Water Gas Ratio	0, 10, 50, 100, 500				STB/MMSCF
Variable 2: First Node Pressure	100, 150, 500, 1,000, 1,500, 2,000, 2,500, 3,200				psi

Table A.10 Input data of VFP table for tables 5 – 9

Parameters	Table					Unit
	5	6	7	8	9	
Fluid	Oil and Water					
Method	Black oil					
Gas Gravity	0.7					
GOR	0					SCF/STB
Water Salinity	2,500					ppm
Oil Viscosity	Beal et al					
Correlation P_b, R_s, B_o	Glaso					
Measure Depth	6700					ft
Tubing Diameter	2.441					inch
Rate Type	Liquid Rate					
Vertical Lift Correlation	Petroleum Experts 4					
First Node Depth	0	5,025	5,250	5,475	5,700	ft
Last Node Depth	5,000	5,225	5,450	5,675	6,700	ft
Temperature	262	269	275	282	315	^{o}F
Enter Rate	50, 100, 500, 1,000, 2,000, 3,000, 4,000, 5,000, 6,000, 7,000, 8,000, 9,000, 10,000, 20,000, 40,000					STB/D
Variable 1: Water Cut	0, 100					percent
Variable 2: First Node Pressure	100, 150, 200, 300, 400, 500, 600, 1,000, 2,000, 3,000					psi

<u>Segment Vertical Flow Performance Table (keyword: WSEGTABL)</u>

Table A.11 Segment VFP tables applied for wells P1 and P2 before dumpflood operation

Well	First seg	Last seg	VFP table	P Drop comp	Neg flow	Scale P Drop
P1	3	3	2	FH	FIX	LEN
P1	5	5	3	FH	FIX	LEN
P1	7	7	4	FH	FIX	LEN
P2	3	3	2	FH	FIX	LEN
P2	5	5	3	FH	FIX	LEN
P2	7	7	4	FH	FIX	LEN

Table A.12 Segment VFP tables applied for wells P1 and P2 during dumpflood operation

Well	First seg	Last seg	VFP table	P Drop comp	Neg flow	Scale P Drop
P1	3	3	2	FH	FIX	LEN
P1	5	5	3	FH	FIX	LEN
P1	7	7	4	FH	FIX	LEN
P2-Dump	3	3	6	FH	FIX	LEN
P2-Dump	5	5	7	FH	FIX	LEN
P2-Dump	7	7	8	FH	FIX	LEN
P2-Dump	9	9	9	FH	FIX	LEN

Note: FH stands for "Friction and hydrostatic losses".

FIX stands for “Fixing the lookup value of the flow rate at the first flow point in the table”.

LEN stands for “The interpolated pressure drop which is scaled in proportion to the length of the segment relative to the table’s datum length.”

Table A.13 Operational constraints

Operations	Constraints
Dumpflood	Field gas production rate < 5,000 MSCF/D
Well abandonment	Well gas production rate < 250 MSCF/D

VITA

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