Evaluation of Combined Gas Dumpflood with Gas Injection into Gas Condensate Reservoir

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Georesources and Petroleum Engineering
Department of Mining and Petroleum Engineering
Faculty of Engineering
Chulalongkorn University
Academic Year 2016

การประเมินการไหลเทของแก๊สร่วมกับการฉีดอัดแก๊สเข้าสู่แหล่งกักเก็บแก๊สธรรมชาติเหลว

นายปิยะ พงศ์ทองผาสุข

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมทรัพยากรธรณีและปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
ปีการศึกษา 2559

Thesis Title	Evaluation of Combined Gas Dumpflood with Gas Injection into Gas Condensate Reservoir
By	Mr. Piya Phongtongpasuk
Field of Study	Georesources and Petroleum Engineering
Thesis Advisor	Assistant Professor Suwat Athichanagorn, Ph.D.

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ปิยะ พงศ์ทองผาสุข : การประเมินการไหลเทของแก๊สร่วมกับการฉีดอัดแก๊สเข้าสู่แหล่งกักเก็บแก๊สธรรมชาติเหลว (Evaluation of Combined Gas Dumpflood with Gas Injection into Gas Condensate Reservoir) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 125 หน้า.

การฉีดอัดแก๊สเข้าสู่แหล่งกักเก็บแก๊สธรรมชาติเหลวเป็นวิธีการเพิ่มผลผลิตแก๊สธรรมชาติเหลวโดยการฉีดอัดแก๊สจากพื้นผิวเพื่อแทนที่แก๊สธรรมชาติเหลวและรักษาแรงดันของแหล่งกักเก็บให้สูงกว่าความดันควบแน่น อย่างไรก็ตาม วิธีนี้ต้องการปริมาณแก๊สมหาศาลในการฉีดอัดแบบแทนที่ ซึ่งทำให้เกิดความสิ้นเปลือง การไหลเทของแก๊สเป็นการเพิ่มผลผลิตแก๊สธรรมชาติเหลวอีกวิธีโดยให้แก๊สจากแหล่งกักเก็บแก๊สแห้งด้านล่างไหลเข้าสู่แหล่งกักเก็บแก๊สธรรมชาติเหลวอย่างธรรมชาติ โดยอาศัยหลักความแตกต่างระหว่างความดันของสองชั้นนี้ ซึ่งวิธีข้างต้นทำให้ประหยัดต้นทุนค่าแก๊สสำหรับฉีดอัดแก๊ส แต่อย่างไรก็ตามแหล่งกักเก็บแก๊สบางแหล่งที่มีขนาดเล็ก อาจมีปริมาณแก๊สไม่เพียงพอสำหรับการเพิ่มผลผลิตแก๊สธรรมชาติเหลว ดังนั้นเราควรประยุกต์ใช้สองวิธีข้างต้นรวมกัน คือ ใช้การไหลเทของแก๊สร่วมกับการอัดแก๊สเข้าสู่แหล่งกักเก็บแก๊สธรรมชาติเหลว

แบบจำลองแหล่งกักเก็บ ได้ถูกสร้างขึ้น โดยโปรแกรม ECLIPSE300 เพื่อทำนายผลผลิตแก๊สธรรมชาติเหลวภายใต้วิธีการผลิตที่แตกต่างกัน ซึ่งประกอบไปด้วย การผลิตโดยการลดแรงดันของแหล่งกักเก็บ, การผลิตโดยการฉีดอัดแก๊ส, การไหลเทของแก็ส และ กระบวนการผสมระหว่างการฉีดอัดแก๊สแบบไหลเทร่วมกับการฉีดอัดแก๊ส ตัวแปรที่ศึกษาในครั้งนี้ประกอบไปด้วย ตำแหน่งของหลุม, ขนาดของแหล่งกักเก็บแก๊สแห้ง และ อัตราการฉีดอัดแก๊ส จากการศึกษาพบว่า เมื่อมีแหล่งกักเก็บแก๊สแห้งมีขนาดเล็ก ควรทำการเพิ่มผลผลิตแก๊สธรรมชาติเหลวโดยการฉีดอัดแก๊ส ควรใช้กระบวนการผสมระหว่างการฉีดอัดแก๊สแบบไหลเทร่วมกับการฉีดอัดแก๊สเพื่อเพิ่มผลผลิตแก๊สธรรมชาติเหลวสำหรับแหล่งกักเก็บแก๊สขนาดกลาง เมื่อมีแหล่งกักเก็บแก๊สแห้งมีขนาดใหญ่ควรใช้การไหลเทของแก๊สเพื่อเพิ่มผลผลิตแก๊สธรรมชาติ และ การไหลเทของแก๊สยังคงเป็นวิธีที่น่าสนใจเมื่อมีแหล่งกักเก็บแก๊สหลายขนาดเรียงกันเป็นชั้นๆ

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ....

สาขาวิชา วิศวกรรมทรัพยากรธรณีและปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาหลัก ....

ปีการศึกษา 2559

5871224021 : MAJOR GEORESOURCES AND PETROLEUM ENGINEERING
KEYWORDS: GAS CONDENSATE / GAS DUMPFLOOD / GAS INJECTION / CONDENSATE BLOCKAGE

PIYA PHONGTONGPASUK: Evaluation of Combined Gas Dumpflood with Gas Injection into Gas Condensate Reservoir. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 125 pp.

Conventional gas injection is an improved condensate recovery technique by injecting the gas from surface to displace condensate and maintain the reservoir pressure above the dewpoint pressure as long as possible. However, this method requires large volume of gas to be injected into the reservoir and incurs high capital and operating costs. Gas dumpflood is a condensate recovery technique achieved by allowing the gas from an underlying source gas reservoir to flow through dumping well to displace condensate and maintain the reservoir pressure. Gas dumpflood has lower capital and operation cost. Nevertheless, some of the source gas reservoir is small and may not be enough to recover condensate effectively. In order to extract more condensate, combined gas dumpflood with gas injection should be applied.

A reservoir model was built by using ECLIPSE300 compositional simulator to predict gas and condensate production under different production scenarios including natural depletion, conventional gas injection, gas dumpflood, and combined gas dumpflood with gas injection. Effects of well location, source gas reservoir size, and gas injection rate were investigated. If 0.5 PV (small) source gas reservoir is available, conventional gas injection is the most appropriate technique to recover condensate. If 1 PV (medium) source gas reservoir is available, combined gas dumpflood with 10 MMscf/d gas injection rate is more attractive. If 2 PV (large) source gas reservoir is available, gas dumpflood should be considered. If of all 0.5, 1, and 2 PV source gas reservoirs are present, gas dumpflood from 2 PV is the most attractive.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
Field of Study:	Georesources and Petroleum Engineering		
Academic Year:	2016		

ACKNOWLEDGEMENTS

First of all, I would like to express my sincere gratitude to my thesis advisor, Assistant Professor Suwat Athichanagorn, for his untiring encouragements and guidance throughout this study. His guidance helped me in all the time of research and writing of this thesis. This thesis would not have been possible without furtherance and support from him.

I express deepest sense of thankfulness and also gratitude to all faculty members in Department of Mining and Petroleum Engineering for knowledge, suggestions, and all their help. I also would like to give big thanks to the thesis committee members for their comments and recommendations on my thesis.

I would like to thank Schlumberger for providing ECLIPSE300 compositional simulator software to Department of Mining and Petroleum Engineering, Chulalongkorn University which allows me to achieve my simulation study successfully.

I would like to express my heartfelt thanks to Chevron Thailand Exploration and Production, Ltd. for providing me a scholarship under Thailand University Partnership Program (UPP) throughout this study.

I really appreciate to all of my friends in this department for their help and good relationship during my study.

Finally, I would like to give my special thanks to my family for all their encouragement and support which are the big motivation toward my achievement of the study.

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List of Abbreviation

bcf	Billion standard cubic foot
BHP	Bottomhole pressure
CGR	Condensate to gas ratio
FVF	Formation volume factor
GOR	Gas oil ratio
mD	Millidarcy
MMBOE	Million barrel of oil equivalent
MMscf/d	Million standard cubic foot per day
MMstb	Million stock tank barrel
Mscf/d	Thousand standard cubic foot per day
ppm	Part per million
psia	Pound per square inch absolute
psig	Pound per square inch gauge
PV	Pore volume
PVT	Pressure-volume-temperature
RB/STB	Reservoir barrel per stock tank barrel
stb	Stock tank barrel
stb/d	Stock tank barrel per day
stb/Mscf	Stock tank barrel per thousand standard cubic foot
TVD	True vertical depth
VLP	Vertical lift performance

Nomenclatures

ϕ	Porosity
$(dP/dx)_f$	Fracture pressure gradient
E	Overall sweep efficiency
E_A	Areal sweep efficiency
E_D	Displacement efficiency
E_I	Invasion or vertical sweep efficiency
E_v	Volumetric sweep efficiency
k_{rg}	Relative premeability to gas
k_{ro}	Relative premeability to oil
k_{rw}	Relative premeability to water
P_{bh}	Bottomhole pressure
P_d	Dewpoint pressure
P_f	Fracture pressure
P_R	Reservoir pressure
S_{gcr}	Critical gas saturation
S_{gi}	Initital gas saturation
S_{gmin}	Minimum gas saturation
S_{wcr}	Critical water saturation
S_{wi}	Initital water saturation
S_{wmax}	Maximum water saturation
S_{wmin}	Minimum water saturation
T_R	Reservoir temperature

CHAPTER 1
INTRODUCTION

1.1. Background

A gas-condensate reservoir is composed of a single-phase fluid in the form of gas at initial reservoir conditions where its pressure is above dewpoint. As the reservoir is on production, the reservoir pressure will decline continuously especially near the producing well. At a certain period where the pressure is just below the dewpoint pressure, condensate liquid first drops out from the gas phase, leading to a condensate blockage problem. Condensate that condenses inside the reservoir is partially immobile because of capillary forces acting on the fluids and not enough condensate saturation. The gas relative permeability would reduce and eventually cause additional pressure drop [1]. This condensate blockage is considered as a skin, and it reduces well productivity. Moreover, some of the valuable condensate cannot be recovered and is left inside the reservoir as residual oil.

Producing gas condensate with natural depletion technique will leave valuable condensate fluid inside the reservoir. Condensate blockage plays a major role for a reduction of well productivity. In consequence, there are many recovery solutions that can be used to recover more condensate. Gas dumpflood can be used to maintain reservoir pressure in order to enhance condensate recovery. For gas dumpflood, source gas reservoir is required for this technique. Since gas reservoirs in the Gulf of Thailand are typically thin layers of small sizes [2], the amount of gas that is dumped into the gas condensate reservoir may not be enough, combined gas dumpflood and gas injection into the gas-condensate reservoir should be considered.

To evaluate the performance of combined gas dumpflood and gas injection into a condensate reservoir, ECLIPSE 300 reservoir simulator is used in this study to construct a hypothetical model. The simulation model consists of a gas-condensate reservoir with an underlying thin-layered gas reservoir. Several parameters and production scenarios are considered in this study such as well location, sizes of source reservoirs and injection rate.

1.2. Objectives

1. To compare general performance of natural depletion, gas dumpflood, conventional gas injection, and combined gas dumpflood and gas injection.
2. To investigate effects of well locations and gas injection rate in conventional gas injection scenario.
3. To investigate effects of well locations and source gas reservoir size in gas dumpflood scenario.
4. To investigate effects of well locations, source gas reservoir size and gas injection rate in combined gas dumpflood and gas injection scenario.
5. To determine the most appropriate recovery method for different sizes of source gas reservoir.

CHAPTER 2
LITERATURE REVIEW

This chapter summarizes previous works related to core flooding experiment and simulation, fluid behavior, condensate blockage effect around the well that is associated with gas productivity and condensate recovery.

Abdullah Al-Abri [3] performed experimental investigation on condensate and gas displacement using supercritical CO_2 ($SCCO_2$) and $SCCO_2$-CH_4 mixtures. High pressure and temperature equipment were used to observe the relative permeability at reservoir condition. The core flooding experiments were conducted to determine the displacement of reservoir gas and condensate by an injection of different $SCCO_2$-methane concentrations. To investigate the effect CO_2 concentration in methane on the recovery factor, CO_2 percentages in the mixture were increased successively from 10 % to 25%, 50% and 75% of the in-situ gas. Result from the experiment showed that the condensate recovery is proportional with an increment of $SSCO_2$ in displacing fluid. The relative permeability curves were improved as the CO_2 concentration in the injection gas increases. It is observed that mobility ratio was decreased, providing more stable displacement front.

Shi et. al. [4] performed both experimental measurement and compositional numerical simulation to investigate the behavior of condensate composition variation, condensate saturation build-up and condensate recovery during a gas-condensate production process. The result from experiment showed that the accumulation of condensate not only reduces gas and liquid relative permeability, but also changes the phase composition of the reservoir fluid. In the simulation, different production strategies were compared, and the optimum producing sequences were suggested for maximum condensate recovery. In summary, the author concluded that to minimize the condensate banking and enhance the ultimate gas and liquid recovery, higher BHP may be a better strategy. The optimal approach is likely to be dependent on the original composition.

Al-Anazi [5] performed coreflood experiments to investigate the effectiveness of methane flood in revaporization of condensate phase from cores. A mixture of gas condensate was flowed through a core at a pressure greater than its dewpoint pressure. Then, the pressure of the system was reduced below the dewpoint pressure, allowing the condensate to dynamically accumulate in the core in a way that is similar to condensate accumulation near the wellbore. From the experimental results, they concluded that an increment of methane pressure and flow rate speeds up the revaporization of condensate. Revaporization of heavy components by methane is very slow process and may require several 10s or 100s of pore volumes to achieve. The revaporization of condensate is controlled by the partitioning of the hydrocarbon components into the flowing gas phase when the pressure is below the minimum miscibility pressure (MMP).

Tangkaprasert [6] studied the effect of CO_2 injection mechanism and the effect of different production and injection strategies. The author used compositional simulator in order to find the appropriate production and injection profiles, which are injection timing, production and injection rates. The result demonstrated that CO_2 injection does effectively maintain the reservoir pressure above the dew point pressure when starting CO_2 injection at the beginning. By starting injection before and after the bottomhole pressure of the producer reaches the BHP limit, the liquid drop out around the wellbore is effectively revaporized by CO_2. And maximum oil recovery can be achieved by starting injection CO_2 shortly after the bottomhole pressure declines below the dew point pressure.

Thitaram [7] investigated the effect of different reservoir fluid compositions on CO_2 injection in a gas condensate reservoir. In order to maximize condensate recovery, the reservoir model was build and simulated with ten different reservoir fluid compositions, yielding different condensate to gas ratios. From the simulation results, the dew point pressure decreases with an increment of CO_2 concentration in the new mixture. If CO_2 injection is started too late, the liquid dropout around wellbore will not be completely revaporized. The reservoir fluid which has higher dewpoint pressure requires earlier CO_2 injection or higher injection rate. CO_2 breakthrough time will be accelerated and production life will be shortened if CO_2 injection is started too early or the injection rate is too high. On the other hand, if CO_2 injection is started too late and the injection rate is too low, liquid drop out will not be completely revaporized and recovery factor will be low.

Kridsanan [8] investigated the performance of gas dumpflood into gas condensate reservoir to enhance condensate recovery. A hypothetical model was created and simulated using a compositional simulator. The reservoir model consisted of a gas-condensate reservoir overlaying on a source reservoir. Several production scenarios were simulated such as natural depletion, conventional injection, and gas dumpflood. The simulation result indicated that for both conventional CO_2 injection and gas dumpflood can provide higher condensate recovery than natural depletion. In case of CO_2 injection, it provides a slightly higher cumulative condensate recovery than gas dumpflood, but this process needs more investment for an installation of gas injection system which is the defect of CO_2 injection.

The effect of starting time of the dumpflood process, concentration of CO_2 in source gas reservoir, and the depth difference between these two reservoirs were investigated in this work. The result turns out that, the best starting time to start CO_2 dump flood is any time before the pressure of the gas-condensate reservoir falls below the dewpoint. A higher concentration of CO_2 in the source gas results in a slightly higher condensate recovery. Larger depth difference between the source and target reservoirs slightly increases the condensate recovery, but producing time will be shortened.

Shi et al. [9] studied the behavior of the composition variation, condensate saturation build-up and condensate recovery during the gas-condensate producing process. A core flooding experiment with two components synthetic gas-condensate and compositional simulations of multicomponent gas-condensate fluids were performed. Composition and condensate saturation change significantly as a function of production strategy. Maximum total gas production can be temporarily achieved by lowering BHP. Increasing BHP or slower ramping time for BHP may be a better strategy to enhance the ultimate gas and liquid recovery. From the simulation results, they concluded that optimal approach for condensate recovery is likely to be dependent on the original composition.

Lertthaweedech [10] investigated effects of condensate gas ratio, sizes of source reservoirs, perforation sequence of dumping well, and timing on gas dumpflood process from multiple sources into a condensate reservoir. The hypothetical model consisting of a gas-condensate reservoir with several underlying thin-layered high carbon-dioxide gas reservoirs was run in compositional simulator. Natural depletion, conventional gas injection, and dumpflood from multiple high carbon-dioxide reservoirs scenario were simulated in this study. The performance of each case was evaluated based on condensate recovery.

The simulated result show that, for natural depletion, fluid composition yielding high condensate to gas ratio has less recovery factor for both gas and condensate compared to those in the low CGR cases because of a larger amount of condensate banking. For conventional gas injection scenario, lower gas injection rate provides higher condensate recovery for both high and low CGR cases. For gas dumpflood scenario, perforation sequence and reservoir thickness of source gas reservoirs do not significantly affect hydrocarbon gas and condensate recovery as long as there is the same amount of total original source gas in place. The sooner the dumpflood into high CGR reservoir the higher condensate recovery but more condensate can be recovered when starting dumpflood operation at late time in case of low CGR fluid composition.

The reservoir model in this study is similar to Lertthaweedech's work which has a dry gas reservoir located below the gas condensate reservoir. Since some of the gas condensate field in the Gulf of Thailand are available as a multiple gas reservoir which can be benefit for improving condensate recovery. Basically, conventional gas injection gain better condensate recovery factor over gas dumpflood since there is unlimited of gas for injection process but the idea of combined gas dumpflood with gas injection may provide the same or better condensate recovery factor by reduce cumulative gas injection compared to conventional gas injection.

CHAPTER 3
THEORY AND CONCEPT

Crucial concepts and theories related to gas dumpflood and gas injection into a gas condensate reservoir are summarized in this chapter. The flow behavior of the gas-condensate system and related theories involved with the mechanism of gas flooding in a gas-condensate reservoir are described.

3.1. Gas condensate reservoir

There are five types of reservoir fluids which are black oil, volatile oil, retrograde gas, wet gas, and dry gas. Each type of reservoir fluid has unique characteristics which can be confirmed only by observation in the laboratory. There are five indicators that are primarily used to identify the type of reservoir fluid which consist of initial producing gas-oil ratio, gravity of the stock-tank liquid, color of the stock-tank liquid, oil formation volume factor, and mole fraction of heptane plus [11].

3.1.1. Phase behavior of gas condensate

Gas-condensate or retrograde gas has unique characteristics of phase diagram as illustrated in Figure 3.1. The saturated envelope in the phase diagram of a retrograde gas is smaller than that for oils, and the critical point is further down the left side of the envelope.

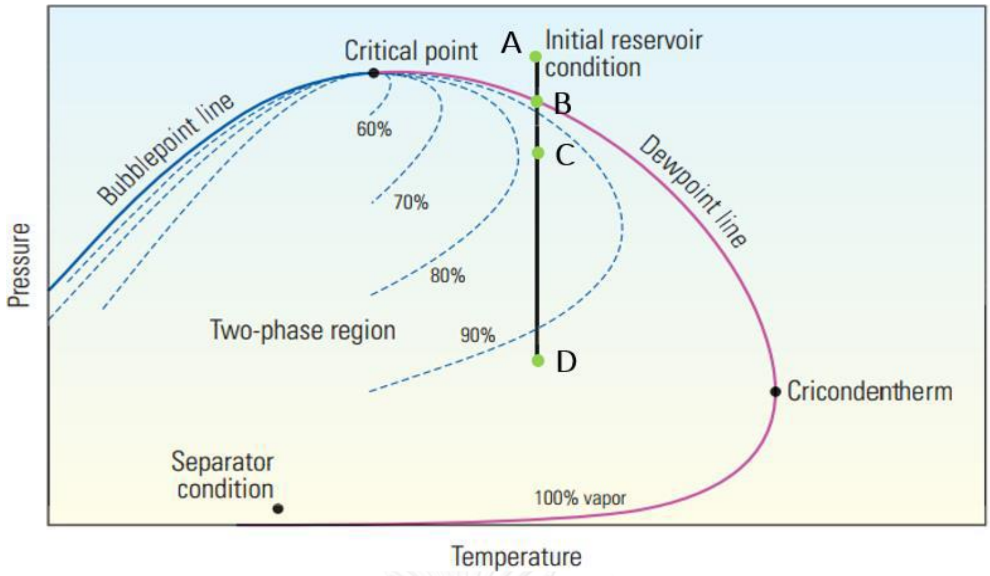


Figure 3.1 Phase diagram of a gas-condensate system [1]

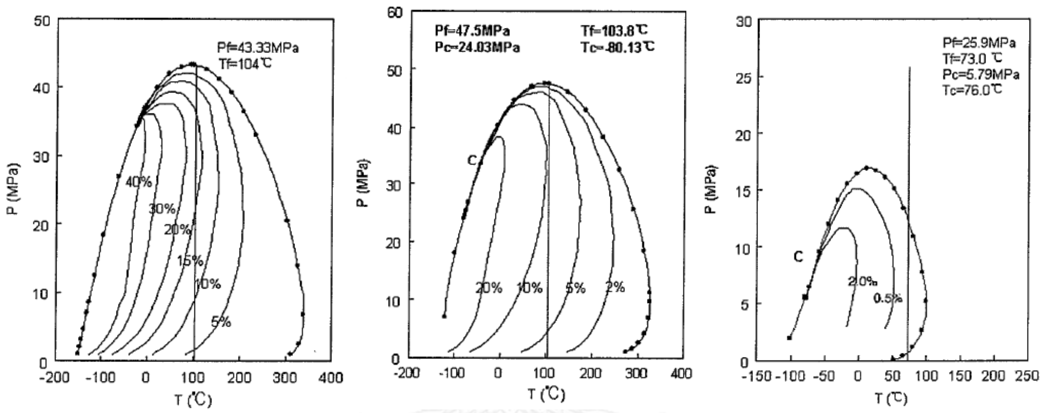
The fluid in the gas-condensate reservoir is totally single phase gas at the original reservoir condition (point A). As the reservoir pressure decreases to the dewpoint pressure, liquid that is a retrograde condensate starts to drop out from the gas phase (point B). The condensate dropout or blockage in the pore space will lead to a reduction in the gas production of the well. The condensate continually drops out more and more until the point of maximum liquid volume is reached (point C). Further reduction in the reservoir pressure will cause revaporization process (point C to point D).

The quantity of condensate dropout does not only depend on the reservoir conditions including temperature and pressure but also depends on the composition of the reservoir fluid. Gas condensate fluid can be classified into three main types: poor, middle, and rich gas condensate [12]. The physical characteristics and the classifications are listed in Table 3.1.

A rich gas condensate as shown in Figure 3.2 (a) forms higher percentage of liquid volume than middle and a poor gas condensate shown in Figure 3.2 (b) and Figure 3.2 (c), respectively.

Table 3.1 Physical characteristics of different types of gas condensate [12]

Fluid type	Heavier hydrocarbon content C7+ Percent mole	Reservoir fluid density g/cm^3	Production GOR m^3/m^3	Condensate content g/m^3
Poor	0.5-0.2	0.20 – 0.25	18000 – 5000	< 150
Middle	2.0-4.0	0.25 – 0.35	5000 – 2000	150 – 350
Rich	4.0-9.0	0.30 – 0.45	2000 – 1000	250 – 600



(a) (b) (c)

Figure 3.2 An example of phase diagram of rich (a), middle (b), and poor (c) gas condensate fluids [11]

3.1.2. Flow behavior of gas condensate

Conceptually, fluid flow in gas condensate reservoirs during production period can be divided into three main flow regions as depicted in Figure 3.3 and Figure 3.4, eventhough not all three regions are present in some situations [1]. The first two regions are closet to the producing well. They exist when the pressure is below the dewpoint pressure and the third region exists when its pressure is above the dewpoint pressure.

The first one is near-wellbore region, close to the producing well. Since condensate saturation here is greater than the critical point, both gas and condensate phase flow in this near-wellbore region with different velocities depending on relative permeability of each phase. The oil relative permeability increases with condensate saturation while gas relative permeability decreases, illustrating the blockage effect.

The second one is condensate-buildup region. The condensate starts to drop out of the gas but it is immobile because of capillary force acting on the liquid. In this condensate-buildup region, both liquid and gas phases are present, but only gas flows. As a consequence, the valuable condensate that forms in this region cannot be produced and the produced gas contains fewer valuable heavy ends of hydrocarbon. The interior boundary of this region is where the condensate saturation reaches the critical point for flowing as shown in Figure 3.4.

The third region is far away from the producing well and includes most of the reservoir. Since the pressure is higher than the dewpoint pressure, only gas phase is present and flowing in this region. The gas composition in this region is similar to the original reservoir gas, and the gas velocity is generally low because the crosssectional area is high. The boundary between third region and second region occurs where the pressure equals the dewpoint pressure of the original reservoir gas. This boundary moves outward from the well as the pressure declines because of the production as shown in Figure 3.3. Eventually, it disappears as the outer-boundary pressure drops below the dewpoint pressure.

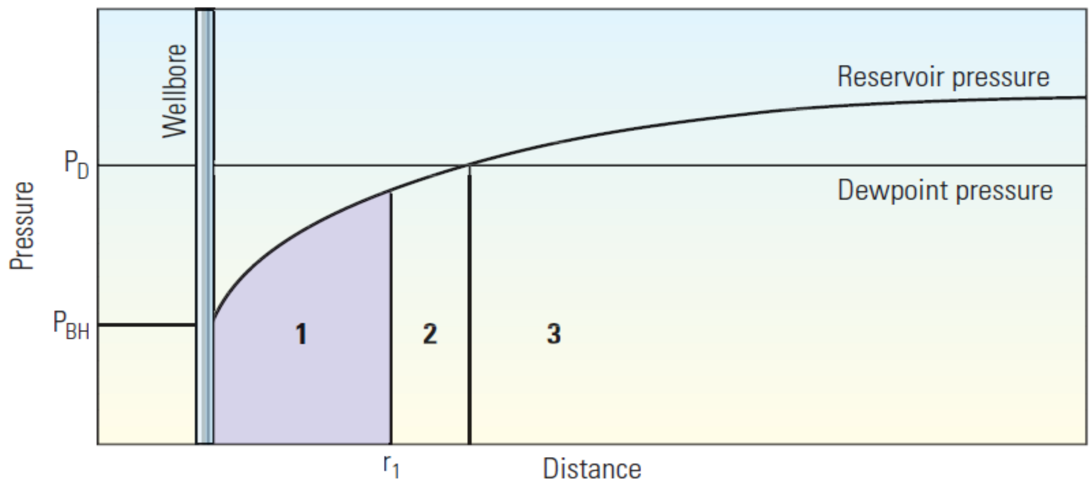


Figure 3.3 Pressure profile of a gas condensate reservoir illustrating flow region [1]

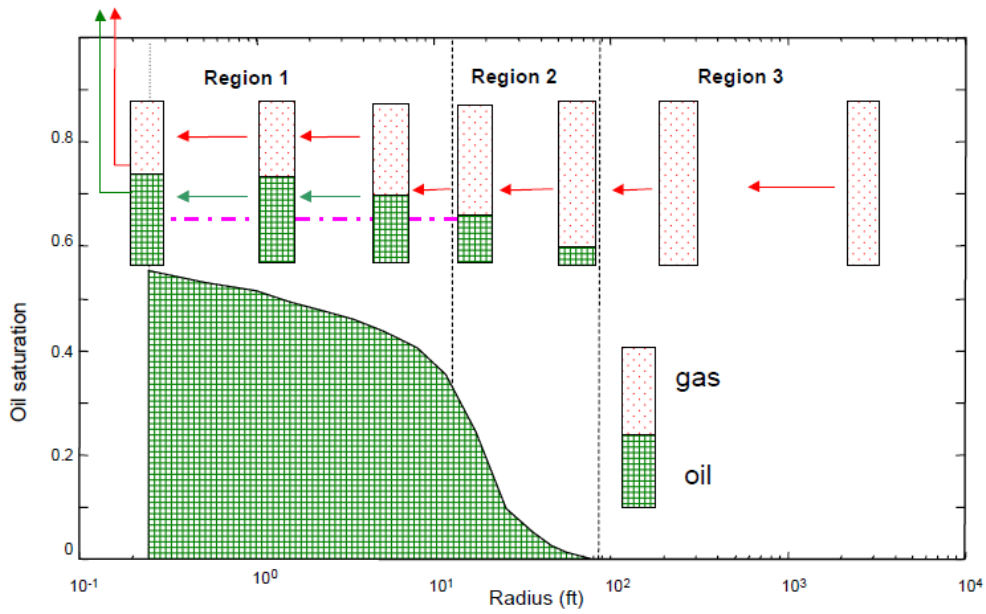


Figure 3.4 Oil saturation profile of a gas condensate reservoir illustrating flow region [13]

3.1.3. Fluid composition change by condensation process

Between the original reservoir condition (point B) and dewpoint pressure (point B1) as illustrated in Figure 3.5, the fluid remains single phase gas as the original fluid. Due to depletion of the gas condensate reservoir, the pressure declines until it is below the dewpoint pressure of the original fluid (point B1). Then, intermediate and heavier components start to condense in the reservoir and only the gas phase is flowing and produced at low condensate saturations. Thus, produced fluid contains lower fractions of intermediate and heavy components compared to the original reservoir fluid. The compositions of the reservoir fluid are subsequently becoming richer in intermediate and heavy components. This transformation of the fluid composition can be demonstrated by a shift of the phase envelope as shown in Figure 3.5. It is important to note that more and more condensate will drop out until the pressure reaches point B'2 where the condensate saturation is the maximum for a given composition of the reservoir fluid. After that, further depletion of the pressure will result in revaporization of the condensate, and a second dewpoint may be encountered eventually.

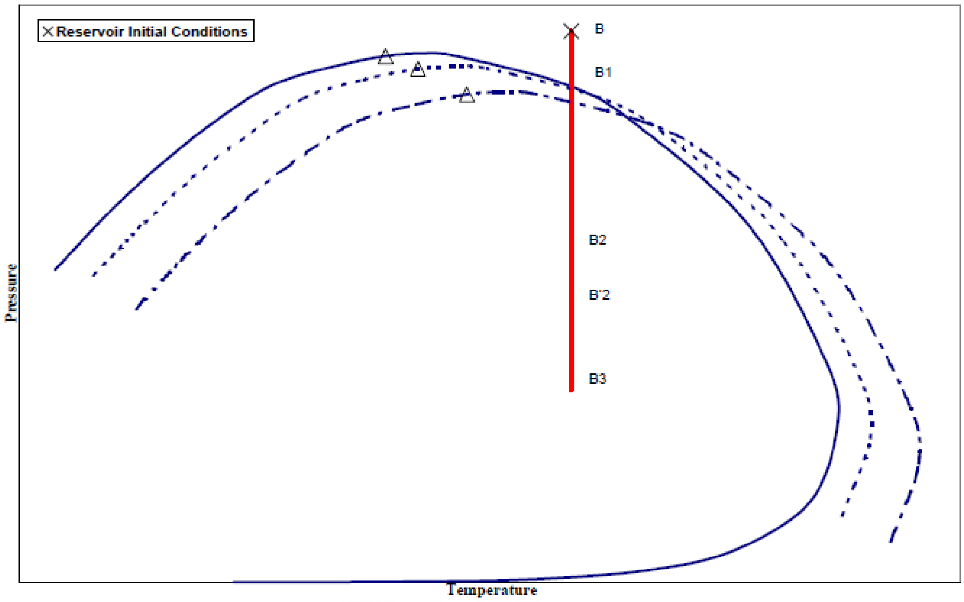


Figure 3.5 Shift of phase envelope with composition change [13]

3.2. CO_2 flooding in gas condensate reservoir

In natural depletion, a gas condensate reservoir is produced and condensate will drop out later on when the dewpoint pressure is reached resulting in condensate blockage. This effect will consequently obstruct productivity of the gas condensate reservoir. As a result of this effect, condensate recovery factor of natural depletion is only 20 - 40% [12].

Repressurizing is a common method for maintaining the reservoir pressure above the dewpoint pressure to prevent the condensate blockage. CO_2 flooding by injection or dumpflood is one of the techniques for pressure maintenance of gas condensate reservoirs. The advantage of CO_2 flooding is revaporization of condensate contents in the reservoir and result in yielding higher condensate recovery than that of natural depletion approach.

3.2.1. Overall sweep efficiency

The overall sweep efficiency is a measure of competence of displacement process by flooding fluids. It depends on the volume of the original reservoir fluids displaced by flooding fluids. The overall sweep efficiency can be affected by injection pattern, mobility ratio, reservoir thickness, permeability, position of gas-oil and oil-water contacts, and areal and vertical heterogeneity. As expressed in Equation (3.1), the overall sweep efficiency is defined as a combination of three efficiencies which are areal sweep efficiency (E_A), invasion or vertical sweep efficiency (E_I), and displacement efficiency (E_D). The volumetric sweep efficiency (E_V) or a combination of areal sweep efficiency and vertical sweep efficiency is the volumetric fraction of the reservoir displaced by the flooding fluids as shown in Equation (3.2) - (3.4). The displacement efficiency (E_D) is fraction of movable fluids that is displaced in the swept zone of the reservoir as shown in Equation (3.5).

$$E=E_A \times E_I \times E_D \tag{3.1}$$

$$E_V=E_A \times E_I \tag{3.2}$$

$$E_A=\frac{\text{Displaced area of the pattern}}{\text{Total area of the pattern}} \tag{3.3}$$

$$E_I=\frac{\text{Displaced crosssectional area}}{\text{Total crosssectional area}} \tag{3.4}$$

$$E_D=\frac{\text{Displaced movable fluids}}{\text{Total movable fluids}} \tag{3.5}$$

where

E= overall sweep efficiency

E_A= areal sweep efficiency

E_V= volumetric sweep efficiency

E_I= invasion or vertical sweep efficiency

E_D= displacement efficiency

3.2.2. Fluid composition change by flooding process

Drying effect is the result from CO_2 mixing with gas condensate fluids which is explained by the shrinking of two-phase envelope. Ramharak et. al. [14] investigated the impact of CO_2 on gas condensate and found that drying effect can affect the phase diagram of gas condensate as shown in Figure 3.6. The shrinking of the two-phase envelope is reduction of cricondentherm and cricondenbar when CO_2 concentration increases. This indicates partial revaporization of the condensate into the gas phase. When the concentration of CO_2 is continuously increasing, this shrinking will be more and more pronounced. Once the cricondentherm of the two-phase envelope is lower than reservoir temperature, only single gas phase is allowed to be present in this condition.

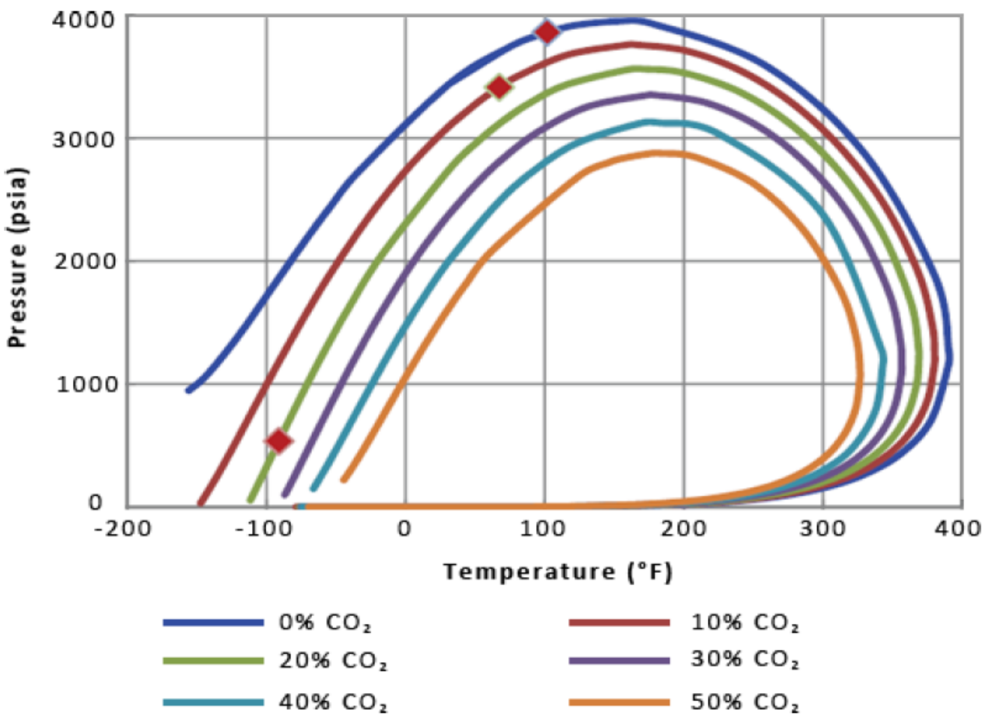


Figure 3.6 Drying effects of CO_2 concentration in mole percent on two-phase envelope for a CO_2 Gas condensate mixture [14]

3.2.3. Fracture pressure

In order to avoid fracturing the reservoir, injection or dumpflood of fluid into the target reservoir should be operated at pressure below the fracture pressure. The correlations as defined in Equations (3.6) and (3.7) are used to calculate the fracture pressure of the M field in Gulf of Thailand [15].

$$P_f = \frac{\left(\frac{dP}{dx}\right) \times TVD}{10.2} \tag{3.6}$$

$$\left(\frac{dP}{dx}\right)_f = 1.22 + (TVD \times 1.6 \times 10^{-4}) \tag{3.7}$$

where

P_f = fracture pressure of the reservoir, bar

$\left(\frac{\mathrm{dP}}{\mathrm{dx}}\right)_f$ = fracturing pressure gradient, bar/meter

TVD = true vertical depth, meter

3.3. Two phase vertical flow regimes

Typically, fluid inside a production well of a gas condensate reservoir are two phase consisting of both gas and condensate. They have different physical properties, resulting in many possible flow regimes as depicted in Figure 3.7 [16]. Empirical correlation are needed for the computation of pressure loss in tubing. These include Duns and Ros, Beggs and Brill, Orkiszewski, Hagedorn and Brown, and Petroleum Expert correlations.

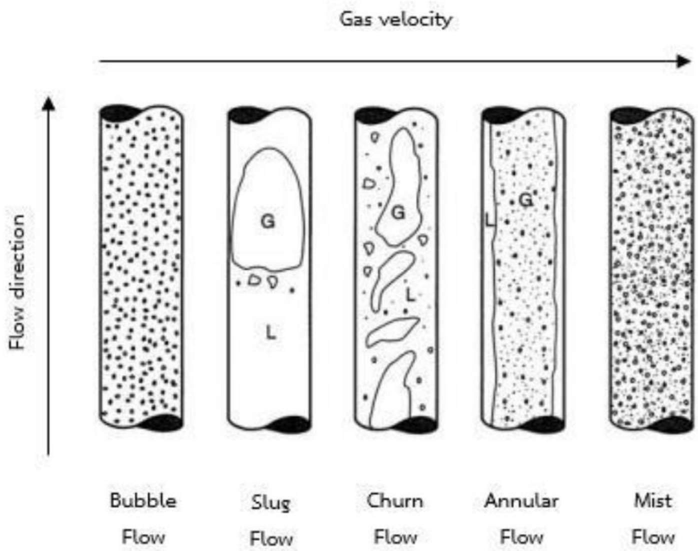


Figure 3.7 Two phase vertical flow regimes [16]

3.4. Recovery calculation

Produced gas in this study in this study are converted to barrel of oil equivalent (BOE) in order to be simple for the analysis. The U.S. Internal Revenue Service defines a BOE as equal to 5.8 million BTU which approximately equals to the higher heating value of 1 STB of crude oil. According to this reason, 1 STB of condensate in this study approximately equal to 1 BOE.

In this study, a volume of gas is converted to barrel of oil equivalent by using higher heating value per standard cubic feet of gas mixture as illustrated in Table 3.2 via Equation (3.8).

$$L_c = \sum_j y_j L_{cj} \tag{3.8}$$

where

L_c = higher heating value of gas mixture, BTU/scf

y_j = mole fraction in gas of component j

L_{cj} = higher heating value of component j, BTU/scf

Table 3.2 The higher heating values of each gas composition

Components	Higher heating value (BTU/SCF)
Carbon dioxide	0.0
Nitrogen	0.0
Methane	1010.0
Ethane	1769.7
Propane	2516.2
Isobutane	3252.0
Normal butane	3262.4
Isopentane	4000.9
Normal pentane	4008.7
Hexane	4756.0
Heptane	5502.5

CHAPTER 4
RESERVOIR SIMULATION MODEL

In this study, ECLIPSE office was used as a tool to create the reservoir model, and ECLISPE 300 specializing in compositional modeling was used as a simulator to predict gas and condensate production under different scenarios. The reservoir model is assumed to be homogeneous with a rectangular shape.

The simulation model can be divided into five main sections including case definition, grid, fluid properties, special core analysis, and production schedule. The details of each section of the base-case model are described separately.

4.1. Case definition

Simulator:	Compositional
Unit:	Field
Model dimensions:	
Number of cells in the x-direction	39
Number of cells in the y-direction	45
Number of cells in the z-direction	14
Grid type:	Cartesian
Geometry type:	Block centered
Oil-Gas-Water options:	Gas, oil, water and gas condensate
Number of components:	11
Pressure saturation options:	Fully Implicit

4.2. Grid

The simulation model consists of a gas-condensate reservoir with a thin-layered of source gas reservoir using cartesian coordinate under simple geometry and homogeneous conditions. The porosity, horizontal and vertical permeability, initial water saturation, and pressure and temperature gradient of the gas-condensate and the source gas reservoirs were obtained from average values of a gas field in the Gulf of Thailand. The geometries and properties of the models are summarized in Table 4.1 and Table 4.2. The illustration of the simulation model is shown as the side and top view in Figure 4.1 and 4.2, respectively.

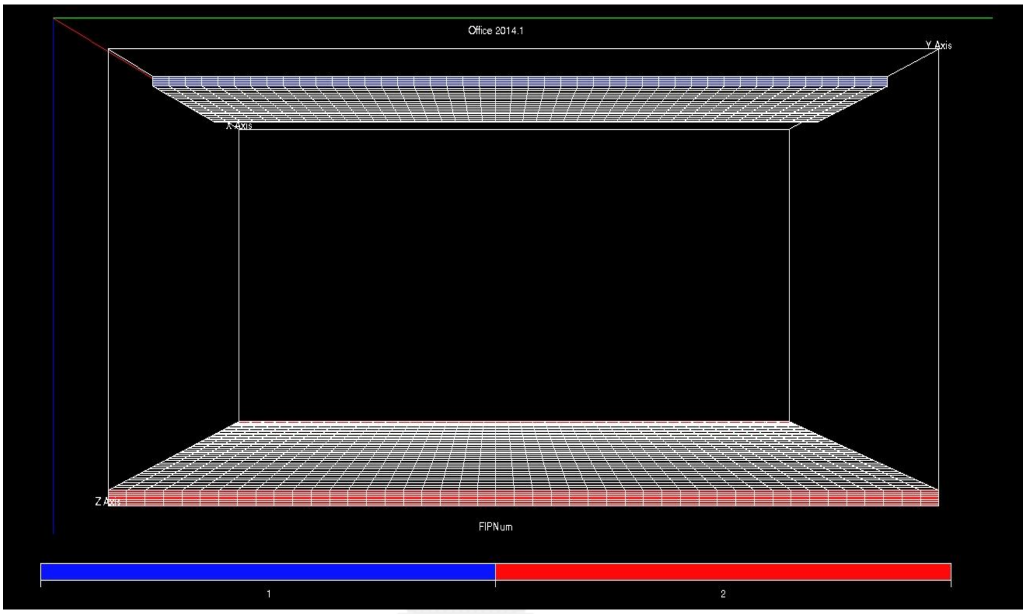


Figure 4.1 Side view of the reservoir model

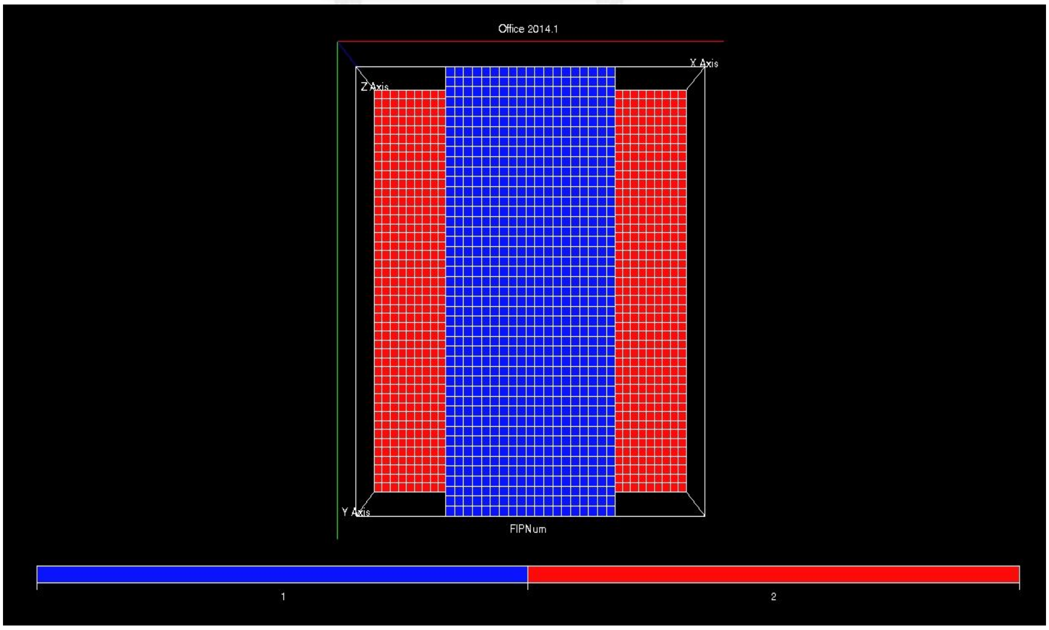


Figure 4.2 Top view of the reservoir model

Table 4.1 Geometries and properties of the target gas-condensate reservoir

Parameter	Target gas-condensate reservoir
Top depth (ft.)	6000
Number of grid	19 × 45 × 5
Grid size (ft. × ft. × ft.)	100 × 100 × 10
Reservoir dimension (ft. × ft. × ft.)	1900 × 4500 × 50
Porosity (%)	21.5
Horizontal permeability (mD)	126
Vertical permeability (mD)	12.6

Table 4.2 Geometries and properties of the source gas reservoirs

<table>
<tr><th>Parameter</th><th>Source reservoir</th></tr>
<tr><td>Top depth (ft.)</td><td>8000</td></tr>
<tr><td rowspan="3">Number of grid</td><td>9 x 45 x 5
for approximately 0.5 PV gas reservoir</td></tr>
<tr><td>19 x 45 x 5 for 1.0 PV gas reservoir</td></tr>
<tr><td>39 x 45 x 5
for approximately 2.0 PV gas reservoir</td></tr>
<tr><td>Grid size (ft. × ft. × ft.)</td><td>100 × 100 × 10</td></tr>
<tr><td rowspan="3">Reservoir dimension
(ft. × ft. × ft.)</td><td>900 x 4500 x 50
for approximately 0.5 PV gas reservoir</td></tr>
<tr><td>1900 x 4500 × 50 for 1.0 PV gas reservoir</td></tr>
<tr><td>3900 x 4500 x 50
for approximately 2.0 PV gas reservoir</td></tr>
<tr><td>Porosity (%)</td><td>21.5</td></tr>
<tr><td>Horizontal permeability (mD)</td><td>126</td></tr>
<tr><td>Vertical permeability (mD)</td><td>12.6</td></tr>
</table>

4.2.1. Target gas condensate reservoir

The top depth of the target gas condensate reservoir is 6,000 ft. deep with the area of 1,900 × 4,500 ft^2 and thickness of 50 ft. The target reservoir located at depth 8,000 ft. has 19 × 45 grids in the x-y plane and 5 grids in z-direction.

4.2.2. Source gas reservoirs

The petrophysical properties of the underlying gas reservoir are the same to those for the target gas condensate reservoir. The geometries and properties of source gas reservoir are shown in Table 4.2

4.3. Fluid properties

This section contains pressure and saturation dependent properties of the reservoir fluids including condensate, gas, and water. The properties of water were specified in PVT table while the properties of condensate and gas were determined using physical properties of each component by using equation of state calculation.

4.3.1. Water properties

The properties of water were calculated using sets of correlations provided in ECLIPSE 300 with the input shown in Table 4.3. The temperatures and pressures of formations in this study were obtained from the typical temperature and pressure gradients in the Gulf of Thailand [15] as illustrated in Equations (4.1) and (4.2). Correlated properties obtained from ECLIPSE 300 are shown in Table 4.4.

Formation pressure

$$P_R = (TVD \times 0.3048 \times 1.462) + 14.7 \tag{4.1}$$

Formation temperature

$$T_R = (TVD \times 0.3048 \times 0.059) + 21.38 \tag{4.2}$$

where P_R = reservoir pressure, psia

T_R = reservoir temperature, ˚C

TVD = true vertical depth, ft.

Table 4.3 Input parameters used to calculate the properties of water

Parameter	Target reservoir	Source reservoir
Reference depth (ft.)	6000	8000
Temperatures at reference depth (°F)	264.7	329.4
Pressures at reference depth (psia)	2688.41	3579.64
Salinity (ppm)	5,000	
Rock type	Consolidated sandstone	
Standard temperature	60 ˚F	
Standard pressure	14.7 psia	

Table 4.4 Water properties resulting from using correlations provided in ECLIPSE 300

Parameter	Target reservoir	Source reservoir
Water density	62.42811 lb/ft3 at standard condition	
p_{ref} (psia) at top depth	2688.41	3579.64
Water FVF at p_{ref} (RB/STB)	1.0479	1.0217
Water compressibility (psi^{-1})	3.6311E-06	3.0998E-06
Water viscosity at P_{ref} (cP)	0.2135	0.3013
Water viscosibility (psi^{-1})	4.2547E-06	3.3609E-06

4.3.1. Gas and condensate properties

A typical composition of gas-condensate found in the Gulf of Thailand was used for the gas-condensate reservoir [7] while a binary-component system was used for the source reservoirs. The properties of gas and condensate were calculated using equation of state provided in ECLIPSE PVTi. The composition yielding high CGR of the fluid in gas condensate reservoir and the composition for the source gas reservoir are shown in Table 4.5 and Table 4.6, respectively.

The physical properties of each component and the binary interaction coefficients of this system were determined by PVTi program based on modified peng-robinson correlation. The results are shown in Tables 4.7 and 4.8, respectively.

Table 4.5 The initial composition of the target-reservoir fluid

Component	Mole fraction
Carbon dioxide	0.0106
Nitrogen	0.0021
Methane	0.6481
Ethane	0.0527
Propane	0.0623
Normal butane	0.0309
Isobutane	0.0167
Normal pentane	0.0131
Isopentane	0.0137
Hexane	0.0159
Heptane	0.1339

Table 4.6 The initial composition of gas in the source reservoirs

Component	Mole fraction
Methane	0.2
Carbon dioxide	0.8

Table 4.7 Physical properties of each component

Component	Critical Pressure (psia)	Critical Temperature (°R)	Critical Volume (ft3/lbmole)	Volume Shift	Molecular Weight	Acentric Factor
CO_2	1071.3311	548.46	1.50574	-0.0427	44.01	0.2250
N_2	492.3126	227.16	1.44166	-0.1313	28.01	0.0400
C_1	667.7817	343.08	1.56981	-0.1443	16.04	0.0130
C_2	708.3424	549.77	2.37073	-0.1033	30.07	0.0986
C_3	615.7582	665.64	3.20369	-0.0775	44.10	0.1524
n-C_4	550.6554	765.36	4.08471	-0.0542	58.12	0.2010
i-C_4	529.0524	734.58	4.21285	-0.0620	58.12	0.1848
n-C_5	488.7856	845.28	4.98174	-0.0303	72.15	0.2510
i-C_5	491.5779	828.72	4.93369	-0.0418	72.15	0.2270
C_6	436.6152	913.50	5.62248	-0.0073	84.00	0.2990
C_7	426.1811	986.40	6.27924	0.0576	96.00	0.3000

Table 4.7 Physical properties of each component (continued)

Component	Critical Volumes for Viscosity Calculation (ft3 /lb-mole)	Critical Z-Factors for Viscosity Calculation	Component Parachors
CO_2	1.5057	0.2741	78.00
N_2	1.4417	0.2912	41.00
C_1	1.5698	0.2847	77.00
C_2	2.3707	0.2846	108.00
C_3	3.2037	0.2762	150.30
n-C_4	4.0847	0.2739	189.90
i-C_4	4.2129	0.2827	181.50
n-C_5	4.9817	0.2684	231.50
i-C_5	4.9337	0.2727	225.00
C_6	5.6225	0.2504	271.00
C_7	6.2792	0.2528	312.50

Table 4.8 Binary interaction coefficient between components

	C_1	C_2	C_3	n-C_4	i-C_4	n-C_5	i-C_5	C_6	C_7	CO_2
C_2	-0.012									
C_3	0.1	0.1								
n-C_4	0.1	0.1	0							
i-C_4	0.1	0.1	0	0						
n-C_5	0.1	0.1	0	0	0					
i-C_5	0.1	0.1	0	0	0	0				
C_6	0.1	0.1	0	0	0	0	0			
C_7	0.1	0.1	0	0	0	0	0	0		
CO_2	0.1	0.1	0.0279	0.01	0.01	0	0	0	0	
N_2	0.1	0.1	0.0331	0.01	0.01	0	0	0	0	0

4.4. Special core analysis

Special core analysis or SCAL section allows users to enter relative permeability of active phases which are gas, oil, and water into the model. Corey's correlation [17] was used in this study to construct water, gas, and oil relative permeability as functions of water or oil saturation. The parameters used in Corey relative permeability correlations for the base case are shown in Table 4.9, and the graphical relative permeability resulting from Corey's correlation is illustrated in Figure 4.3 and Figure 4.4.

Table 4.9 Parameters used in Corey correlation

Corey Water	4	Corey Gas/Oil	3	Corey Oil/Water	3
S_{wmin}	0.2	S_{gmin}	0	Corey Oil/Gas	3
S_{wcr}	0.2	S_{gcr}	0.15	S_{org}	0.2
S_{wi}	0.2	S_{gi}	0.15	S_{orw}	0.2
S_{wmax}	1	$k_{rg}(S_{org})$	0.6	$k_{ro}(S_{wmin})$	0.8
$k_{rw}(S_{orw})$	0.3	$k_{rg}(S_{gmax})$	0.6	$k_{ro}(S_{gmin})$	0.8
$k_{rw}(S_{wmax})$	1				

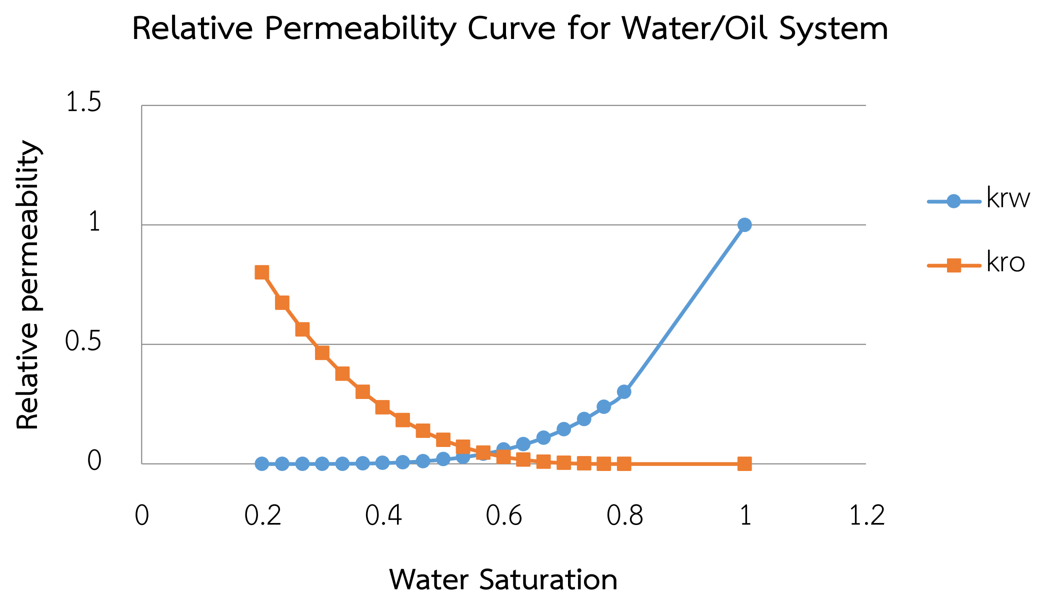


Figure 4.3 Two-phase relative permeability of water/oil system

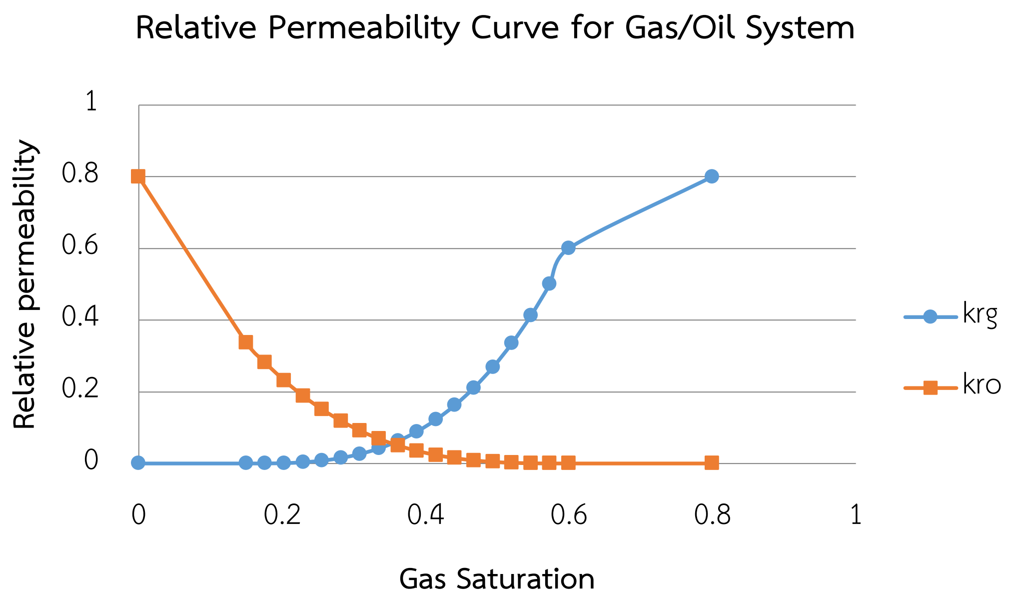


Figure 4.4 Two-phase relative permeability of gas/oil system

4.5. Production schedule

The schedule section specifies the operations to be simulated such as production and injection control. For all cases, there are three wells in the reservoir. All three wells have the same wellbore diameter of 6-1/8 in. and tubing outer diameter of 2-7/8 in. The perforation interval is full to base from the top to the bottom of the reservoir. The vertical lift performance relationship (VLP) were generated by PROSPER. Variables for VLP modeling are shown in Table 4.10. For natural depletion case, three wells are used as producers. For the other cases, the middle well is used as a producer while the other two are either gas injection wells or dumping wells. Gas dumping into gas condensate reservoir is conducted since the start of production while gas injection is started later. The starting time for gas injection was varied as described in Table 4.12. Well production control data and constraints are summarized in Table 4.11.

Table 4.10 Variable for VLP modeling by PROSPER

Variable	Values
Gas rate (MMscf/d)	VFP table 1 (Production well) 0.05, 0.1, 0.5, 1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5, 6, 7, 8, 9, 10, 15, 20, 25
	VFP table 2 (Dumping well) 0.1, 0.5, 1, 2, 3, 4, 5, 7.5, 10, 15, 20, 25, 30, 35, 40, 50, 60, 70, 80, 100
Tubing head pressure (psia)	114.7, 314.7, 514.7, 1014.7, 1514.7, 2014.7, 2514.7, 3014.7, 3514.7, 4014.7
Water gas ratio (stb/Mscf)	0, 1e-6, 1e-5, 0.0001, 0.001
Condensate to gas ratio (stb/Mscf)	0, 0.025, 0.05, 0.075, 0.1, 0.15, 0.2, 0.25, 0.3, 0.4

Table 4.11 Production control data and abandonment condition

Parameters		Value
Control		Gas rate
Field gas rate (Mscf/day)		10000
THP target (psia)		200
Abandonment condition	Injector	Oil production rate is less than 10 stb/day
	Producer	Gas production rate is less than 500 Mscf/day

Table 4.12 Operational constraints of the dumping well and the injector

Operation	Gas dumpflood	Conventional gas injection	Combined gas dumpflood and gas injection
Start of gas dumpflood	At the beginning	-	At the beginning
Stopping of gas dumpflood	When abandonment condition is reached	-	When average reservoir pressure is less than dewpoint pressure
Start of gas injection	-	At the beginning	When average reservoir pressure is less than dewpoint pressure
Stopping of gas injection	-	When abandonment condition is reached	When abandonment condition is reached

4.6. Details of methodology

1. Construct a base-case model
2. Perform base-case simulation of hydrocarbon production using four techniques:

    2.1 Natural depletion

    2.2 Conventional gas injection into condensate reservoir

    2.3 Gas dumpflood from gas reservoir into condensate reservoir

    2.4 Combined gas dumpflood and gas injection into a condensate reservoir

Note that the well locations for natural depletion are distributed in the reservoir as shown in Figure 4.5 to drain as much as possible while well pattern 1 shown in Figure

4.6 is used for conventional gas injection, gas dumpflood, and combined gas dumpflood with gas injection methods.

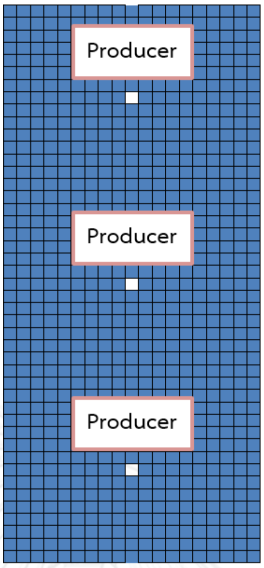


Figure 4.5 Well location for natural depletion case.

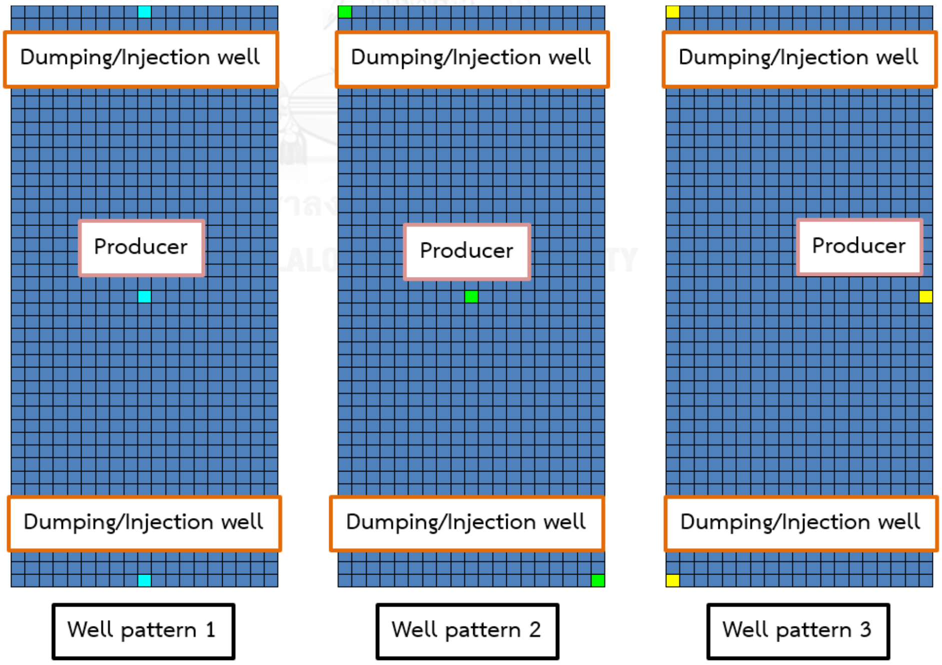


Figure 4.6 Different well location used for conventional gas injection, gas dumpflood, and combined gas dumpflood with gas injection.

3. Simulate conventional gas injection models with different well locations and gas injection rates as shown in Figure 4.7
4. Simulate gas dumpflood models with different source gas reservoir sizes and well locations as shown in Figure 4.8
5. Simulate combined gas dumpflood with gas injection models with different source gas reservoir sizes, well locations, and gas injection rates as shown in Figure 4.9
6. Analyze and conclude the performance of each scenario.

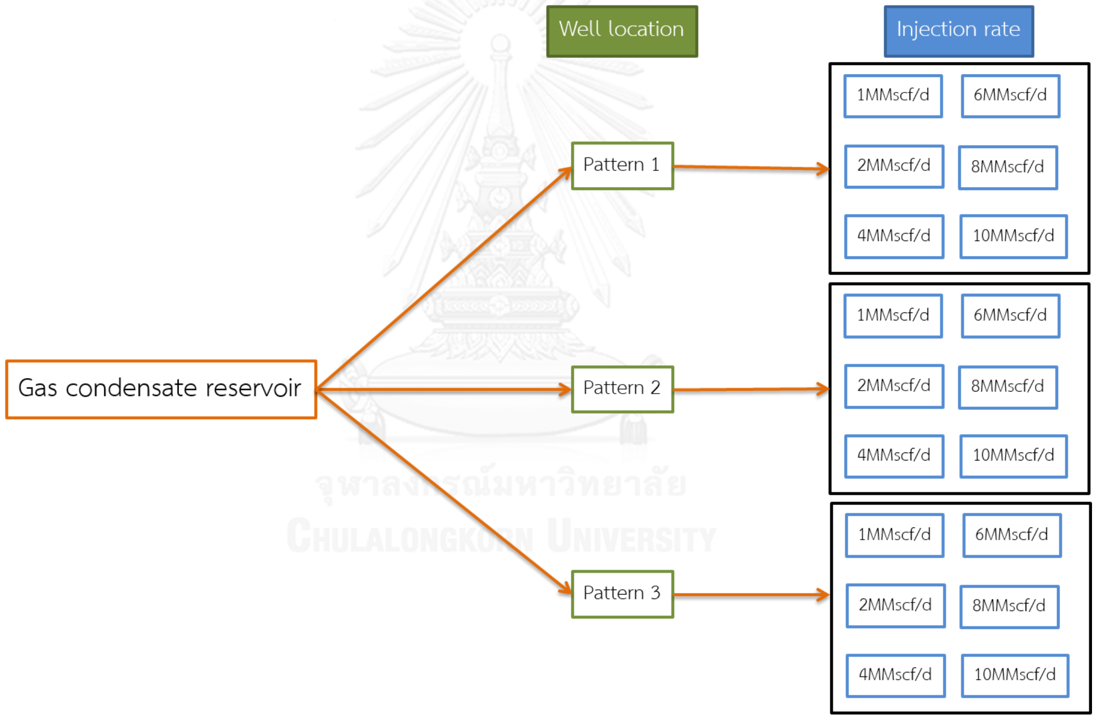


Figure 4.7 Flow chart of simulation cases for conventional gas injection.

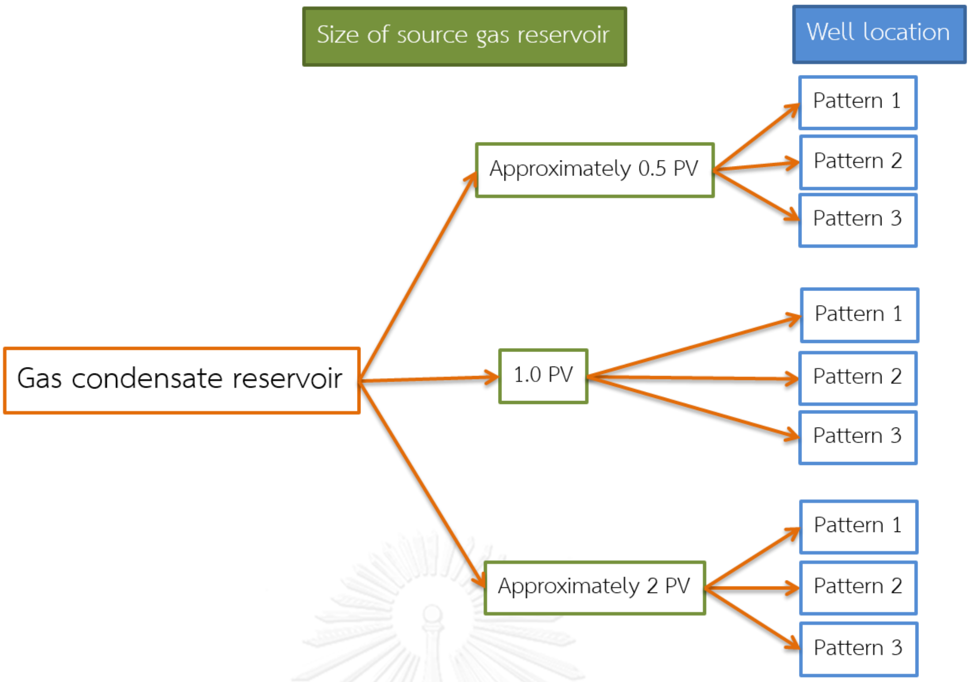


Figure 4.8 Flow chart of simulation cases for gas dumpflood.

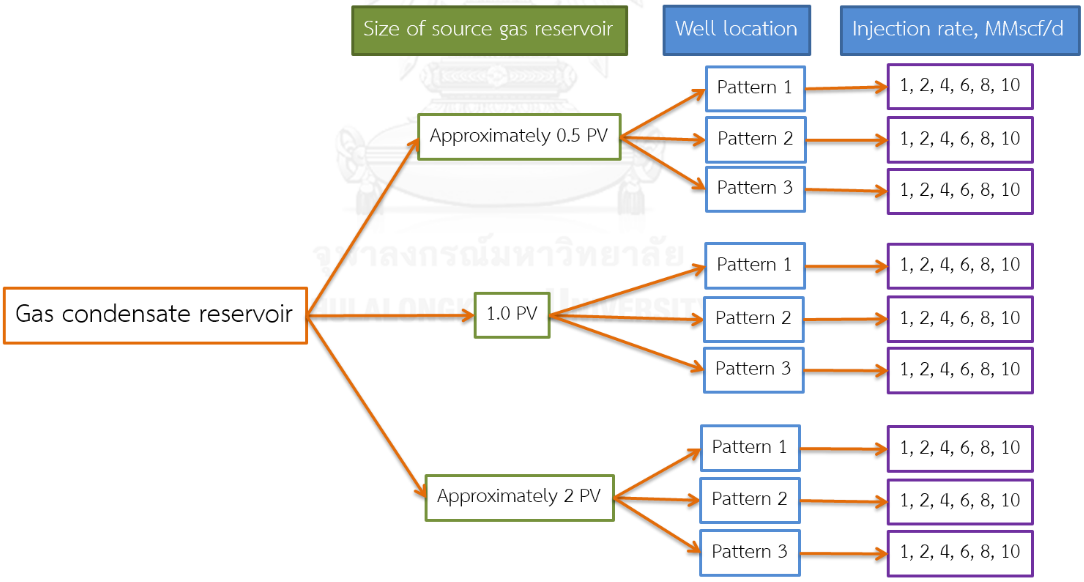


Figure 4.9 Flow chart of simulation cases for combined gas dumpflood with gas injection.

CHAPTER 5
SIMULATION RESULTS AND DISCUSSION

The results from the reservoir simulation model under different scenarios are analyzed and discussed in this chapter. All simulated case are discussed separately into each section starting from natural depletion, gas dumpflood, conventional gas injection and combined gas dumpflood with gas injection, respectively.

Firstly, the chapter starts by introducing the production of gas-condensate reservoir under natural depletion to investigate the condensate blockage which is a primary problem during natural depletion. After that, gas dump flood was implemented to maintain the reservoir pressure and prevent condensate dropout in the reservoir. The results of the cases with conventional gas injection are shown in Section 5.2 which is divided into three subsections in order to investigate the effect well location and different gas injection rates on condensate recovery. Next, the effect of source gas reservoir size and well location of gas dumpflood scenario are analyzed and discussed in Section 5.3. After that, in order to investigate the effect of each parameter on performance of combined gas dumpflood with gas injection into gas condensate reservoir, all three parameters including source gas reservoir size, well pattern and injection rate are analyzed and discussed in Section 5.4 Finally, the optimum case of each production scenario are compared and summarized in Section 5.5.

5.1. Natural depletion

The natural depletion scenario was simulated first in order to investigate the primary problem of gas condensate production. In the natural depletion case, the reservoir model consisting of three producers with a specific field plateau gas production rate of 10 MMscf/d and minimum wellhead pressure of 200 psia was simulated. The case was run until the gas production rate reached 0.5 MMscf/d.

Figures 5.1 and 5.2 illustrate the gas and condensate production rates during natural depletion. At early time, gas production rate is constant at 10 MMscf/d for almost three years before declining due to insufficient pressure support.During gas plateau production period, condensate production rate starts to decline after 100 days of production due to the fact that bottomhole pressure of the producer drops below the dewpoint pressure, resulting in condensate condensation near the producing wells as demonstrated in Figure 5.3

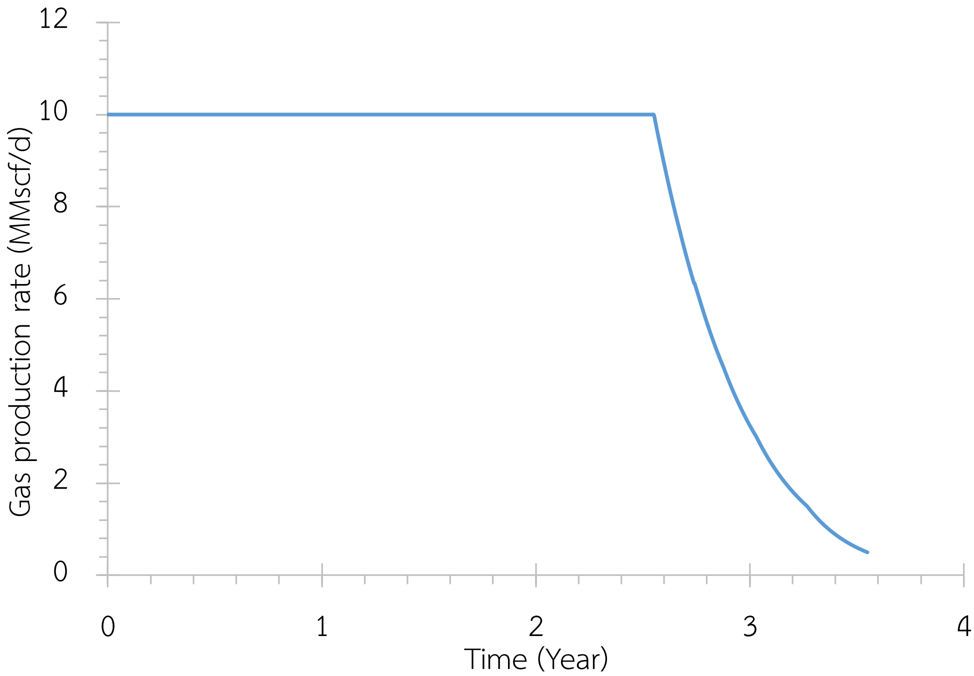


Figure 5.1 Field gas production rate profile for natural depletion case

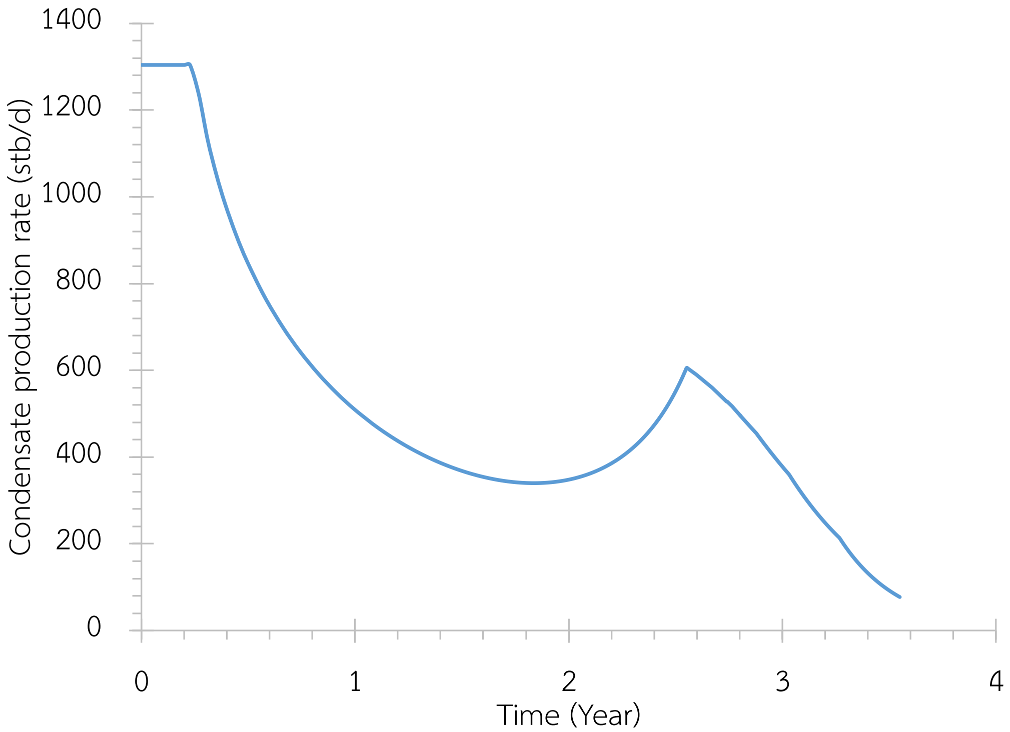


Figure 5.2 Field condensate production rate profile for natural depletion case

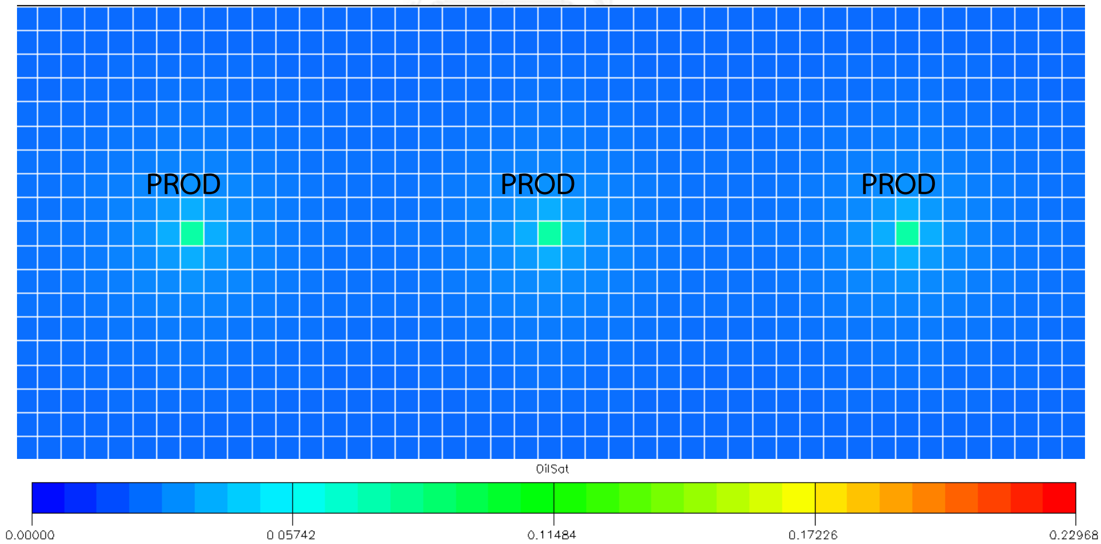


Figure 5.3 Oil saturation distribution of natural depletion when condensate production rate starts to decline (98 days of production)

Condensate blockage causes instantaneous reduction of condensate production rate because when the condensate is formed near the well bore region, only part of condensate higher than the critical condensate saturation (20% in this study) can flow while the remaining is trapped in the pore of the reservoir. As the bottomhole pressure drops below the dewpoint pressure, oil production rate decreases continuously due to the dropout phenomena. As the bottomhole pressure continues to drop, condensate saturation increases until it reaches the critical oil saturation at which oil starts to flow. As a result, condensate production rate declines slower due to additional condensate liquid flow into the well. Figure 5.4 shows oil saturation map at 270 days. Notice that the oil saturation is higher than 0.2 in the well block. After the bottomhole pressure reaches the maximum condensation dropout, some part of condensate around the producer starts to revaporize as indicated by reduction in oil saturation shown in Figure 5.5. This allows intermediate components to flow to the wellbore, resulting in an increment of condensate production rate at late times as shown in Figure 5.2. As depicted in Figure 5.6, at abandonment condition, condensate dropout is partially revaporized while some valuable condensate still remains inside the reservoir, resulting in small condensate recovery factor of 44.9% as illustrated in Table 5.1. Cumulative hydrocarbon gas production in this case is 10.4725 bcf which is equivalent to 2.7926 MMBOE. The total BOE recovery factor is 63.73%.

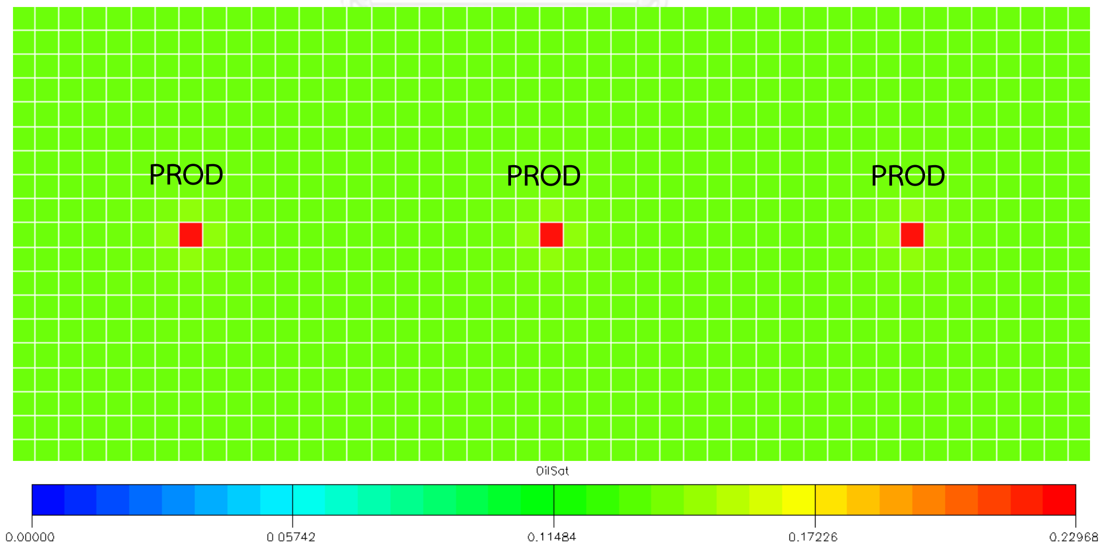


Figure 5.4 Oil saturation distribution of natural depletion when maximum condensate dropout (270 days of production)

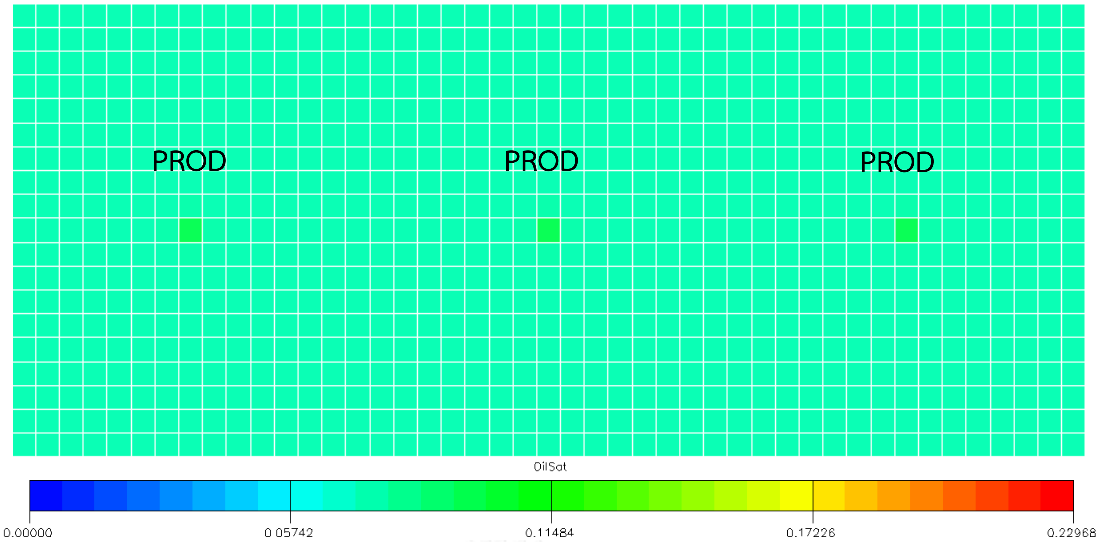


Figure 5.5 Oil saturation distribution of natural depletion when condensate revaporization start (671 days of production)

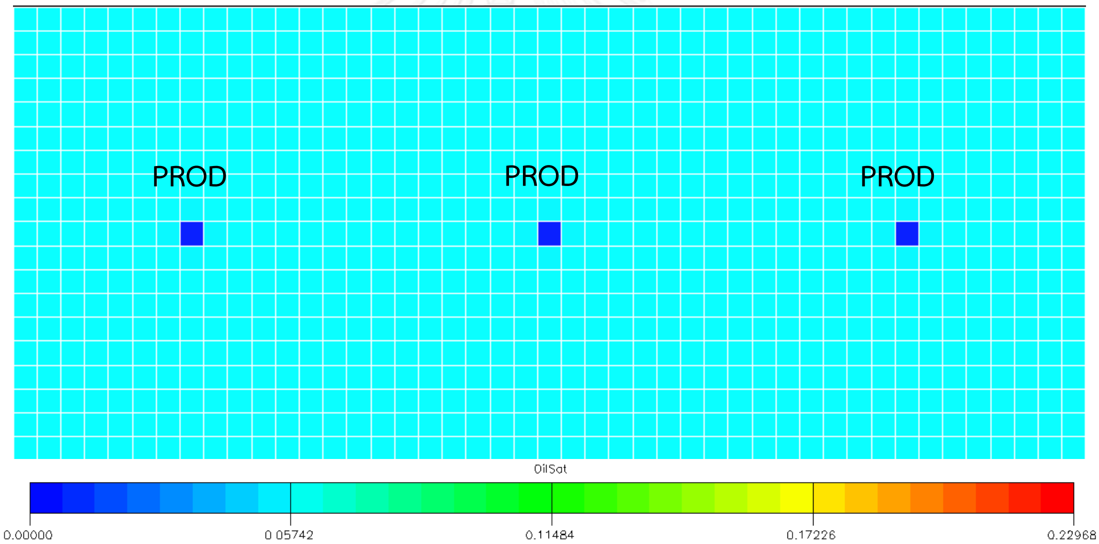


Figure 5.6 Oil saturation distribution of natural depletion at abandonment condition (1295 days of production)

Table 5.1 Summarized results from natural depletion scenario

Parameters	Value
Cumulative condensate production (MMstb)	0.6757
Original condensate in place (MMstb)	1.5045
Condensate recovery factor (%)	44.91
Cumulative gas production (bcf)	10.6260
Original gas in place (bcf)	11.5387
Cumulative hydrocarbon gas production (bcf)	10.4725
Hydrocarbon gas recovery factor (%)	90.76
Cumulative gas production (MMBOE)	2.7926
Cumulative total BOE production (MMBOE)	3.4682
Original BOE in place (MMBOE)	5.4425
Total BOE recovery factor (%)	63.73

5.2. Conventional gas injection

Conventional gas injection scenario was simulated in order to compare its performance with the proposed technique, which is combined gas dumpflood with gas injection into gas condensate reservoir. The same reservoir and composition of gas condensate as the case of natural depletion and gas dumpflood were used. In order to be comparable with gas dumpflood, the injected gas is composed of 80% mole carbon dioxide and 20% mole methane, the same composition with the original gas in place of the source gas reservoir in gas dumpflood case.

Three different well patterns with different gas injection rates were simulated. The gas condensate reservoir was produced at a set rate of 10 MMscf/d using one producer, and the minimum wellhead pressure was 200 psia. Conventional gas injection was performed at the beginning of production. Gas was injected via two wells with injection rate varying from 1 to 2, 4, 6, 8, and 10 MMscf/d. The condition to stop gas injection was condensate production rate below 10 stb/d while the abandonment condition for production was gas production rate below 0.5 MMscf/d. Note that even though gas injection was stopped, gas and condensate were produced until the abandonment condition for the producer was reached.

5.2.1. Conventional gas injection with well pattern 1

In order to describe the effect of injection rate on the production for well pattern 1, different gas injection rates were discussed first. Gas production rate was fixed at a constant rate of 10 MMscf/d for all cases while gas injection rate was varied from 1 to 10 MMscf/d. Gas production profiles for different gas injection rates are illustrated in Figure 5.7. The cases with injection rates of 1, 2, and 4 MMscf/d have two decline trends while other cases have only one decline trend. The first decline trend is caused by insufficient pressure support because the injection rate is much less than the production rate. The second decline is from stopping gas injection due to the abandonment condition for injector (10 stb/d of condensate production). After stopping gas injection, the gas production rate sharply drops due to the fact that there is no pressure support from the injection anymore. The cases with high injection rates including 6, 8, and 10 MMscf/d have only one decline trend from stopping gas injection because these injection rates help slow down the decline in reservoir pressure, resulting in longer plateau gas production periods although the injection rates are lower than the production rate.

In terms of condensate production rate as demonstrated in Figure 5.8, all cases show abrupt drop in condensate production rate at early time. There are different reasons for the decline of condensate production rate for cases with low and high injection rates. For low injection rates (1 to 6 MMscf/d), the abrupt drop of condensate production results from condensate blockage near the producer. This happens because low injection rates cannot sustain reservoir pressure above the dewpoint (2402.35 psia) for a long time as shown in Figure 5.9. Once the pressure drops below the dewpoint pressure, retrograde condensation takes place inside the reservoir as illustrated in Figure 5.10-5.13. For high injection rates (8 to 10 MMscf/d), the decline of condensate production is caused by shrinking effect as demonstrate in Figure 5.14. As the concentration of carbon dioxide inside the reservoir increases, the phase envelope of gas condensate becomes smaller with less amount of intermediate component. Therefore, this results in a fast decline of condensate production.

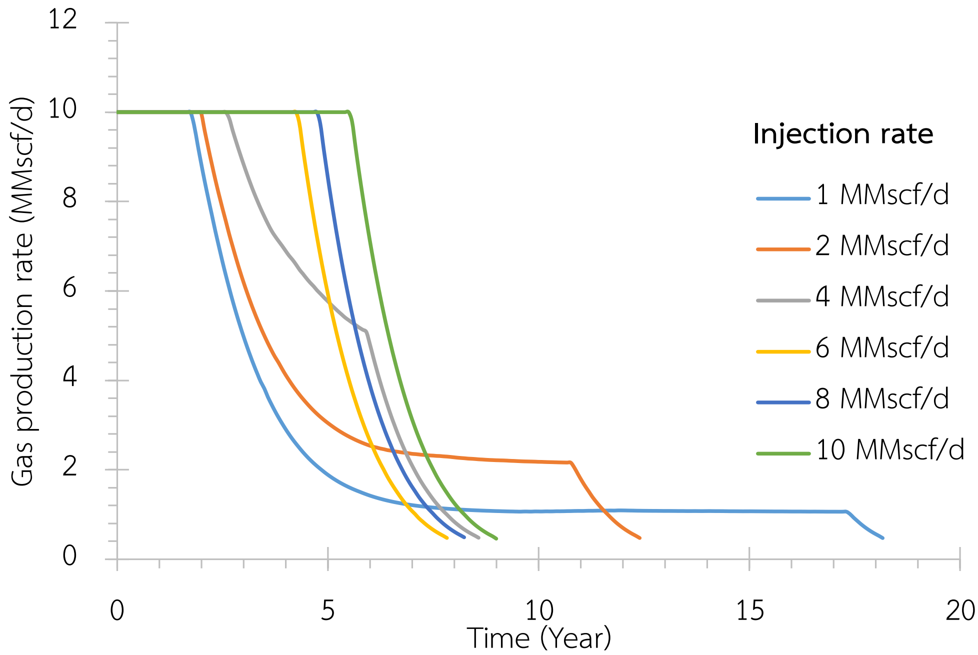


Figure 5.7 Field gas production profiles for different injection rates of conventional gas injection with well pattern 1

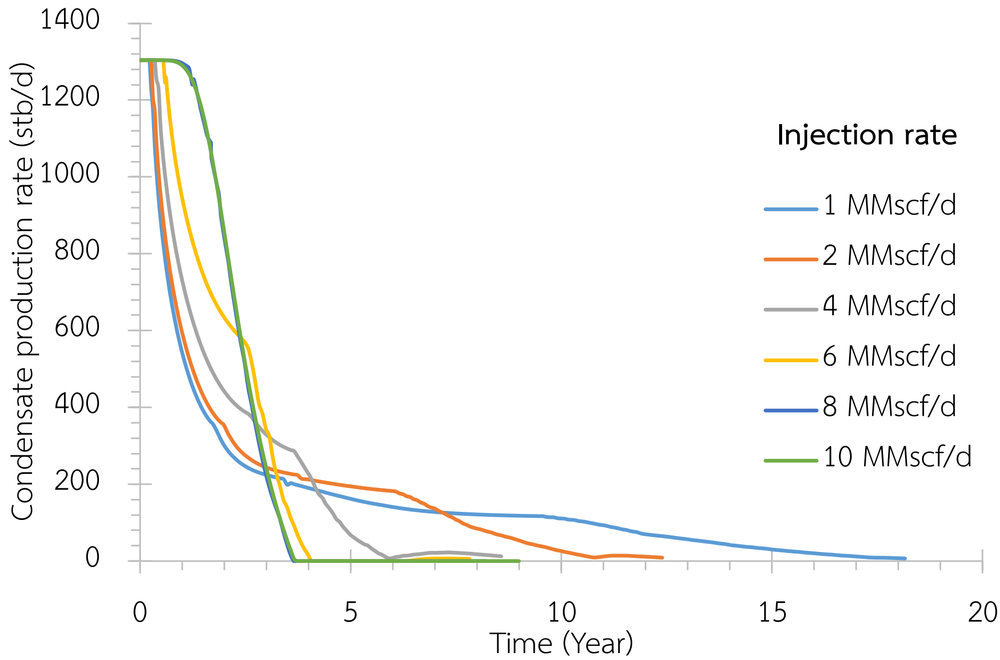


Figure 5.8 Field condensate production profiles for different injection rates of conventional gas injection with well pattern 1

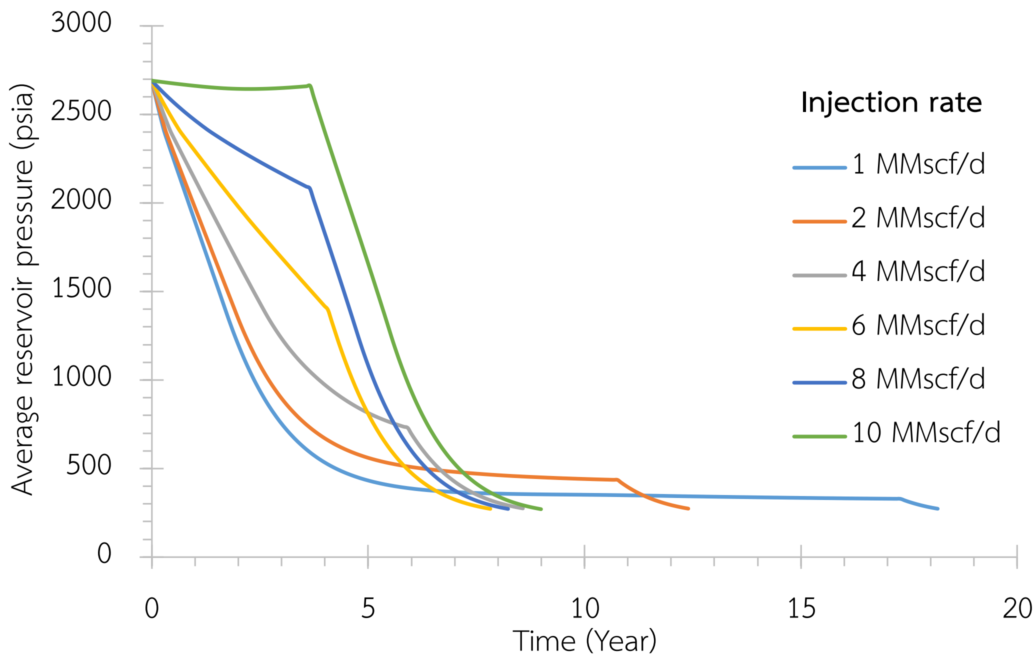


Figure 5.9 Average reservoir pressure profiles for different injection rates of conventional gas injection with well pattern 1

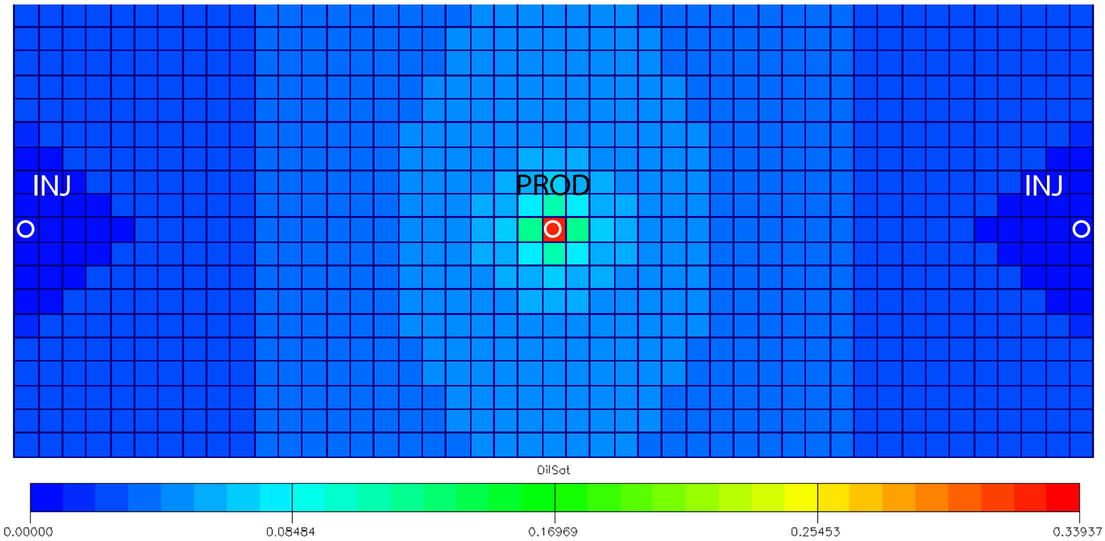


Figure 5.10 Oil saturation distribution of case with injection rate of 1 MMscf/d of conventional gas injection with well pattern 1 when condensate production rate starts to decline (111 days of production)

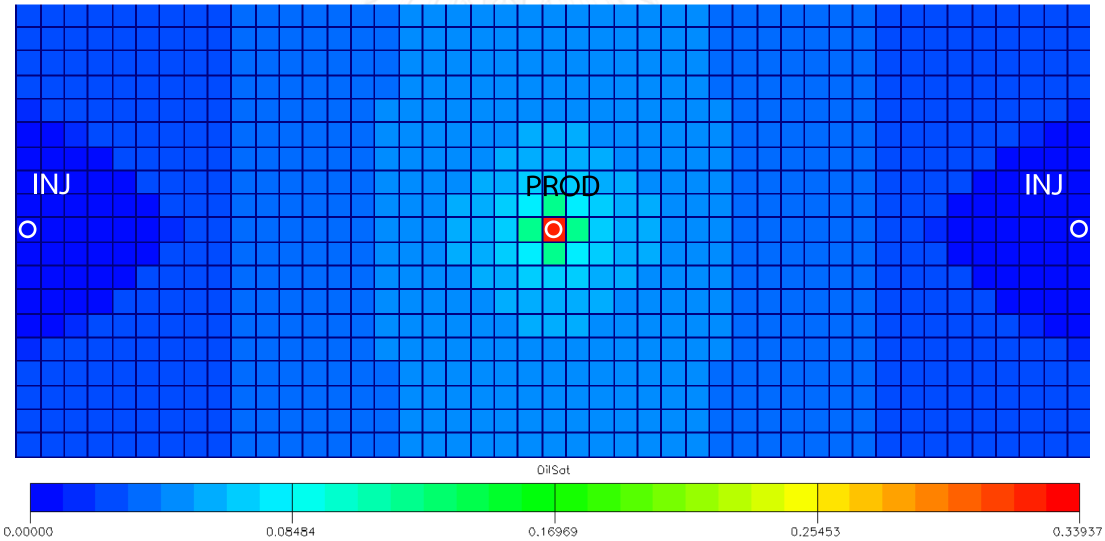


Figure 5.11 Oil saturation distribution of case with injection rate of 2 MMscf/d of conventional gas injection with well pattern 1 when condensate production rate starts to decline (128 days of production)

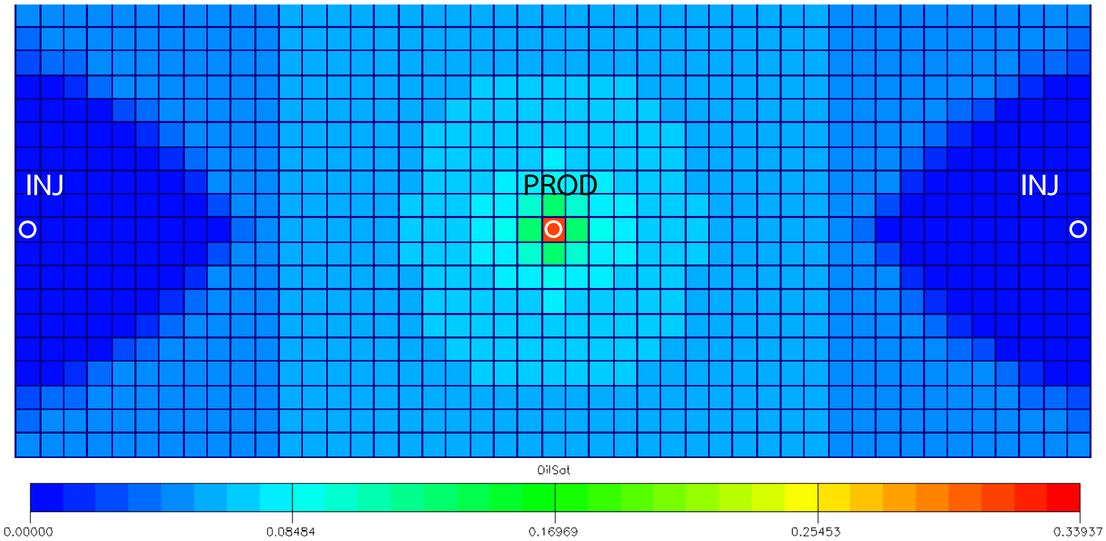


Figure 5.12 Oil saturation distribution of case with injection rate of 4 MMscf/d of conventional gas injection with well pattern 1 when condensate production rate starts to decline (181 days of production)

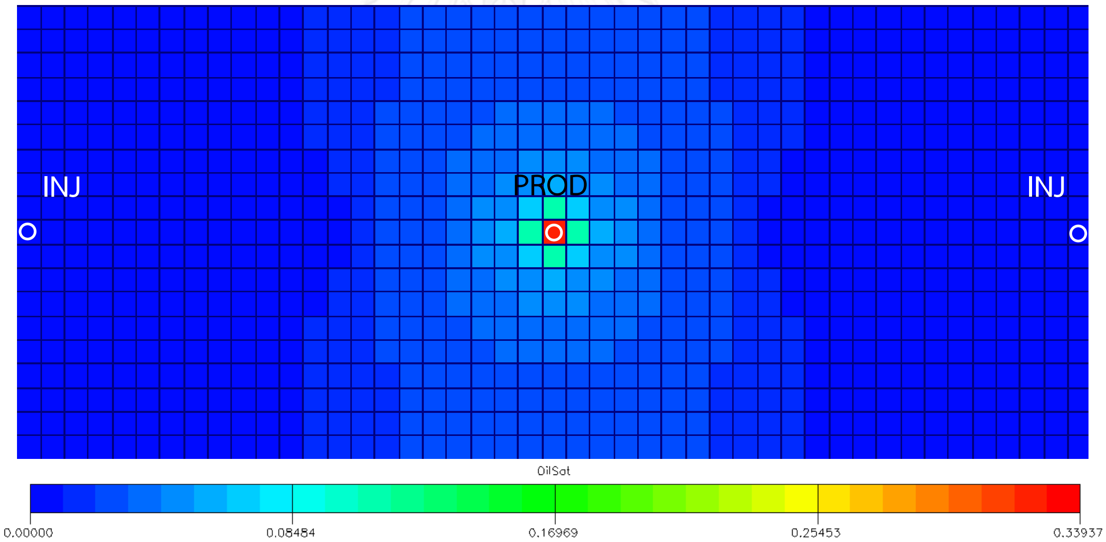


Figure 5.13 Oil saturation distribution of case with injection rate of 6 MMscf/d of conventional gas injection with well pattern 1 when condensate production rate starts to decline (204 days of production)

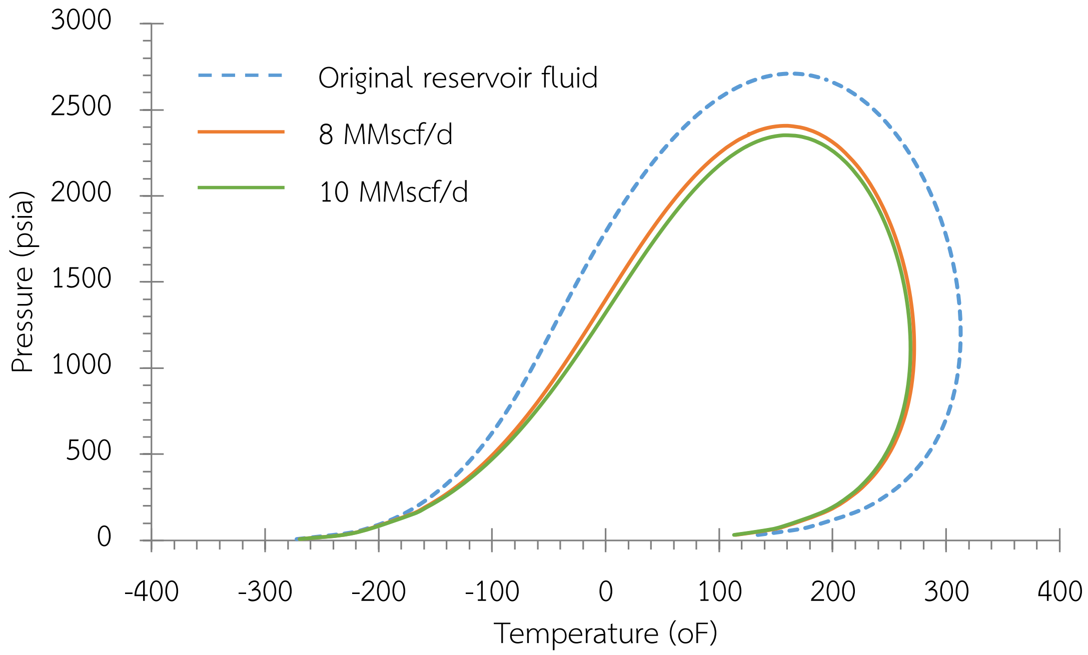


Figure 5.14 Phase diagram of case with gas injection rate of 8 and 10 MMscf/d when condensate production start to decline of conventional gas injection with well pattern 1 compare to original phase diagram

Although low gas injection rates provide early decline in condensate production rate but at later stage condensate production rate declines at a slower pace due to the delay of carbon dioxide breakthrough as shown in Figure 5.16. This results in a fair amount of condensate production at late times as illustrated in Figures 5.8 and 5.15. The case with 4 MMscf/d injection rate provides the lowest condensate recovery because this injection rate cannot maintain the reservoir pressure above the dewpoint resulting in incompletely revaporized of condensate in the reservoir at abandonment condition of producer as shown in Figure 5.17. Although injection rate of 1 MMscf/d recovers less condensate initially but condensate can be recovered more at late time. The reason for this is the poor ability to maintain reservoir pressure resulting in large condensate dropout in the reservoir at early time as depicted in Figure 5.18. As the gas is continuously injected into the reservoir, reservoir fluids mix with injected gas, resulting in better revaporization of condensate into gas phase as shown in Figure 5.19. After 2920 days of the production for the case with injection rate of 1

MMscf/d, most of the condensate are revaporized into gas phase as indicated by the reduction of condensate saturation in Figure 5.20 and phase diagram in Figure 5.21.

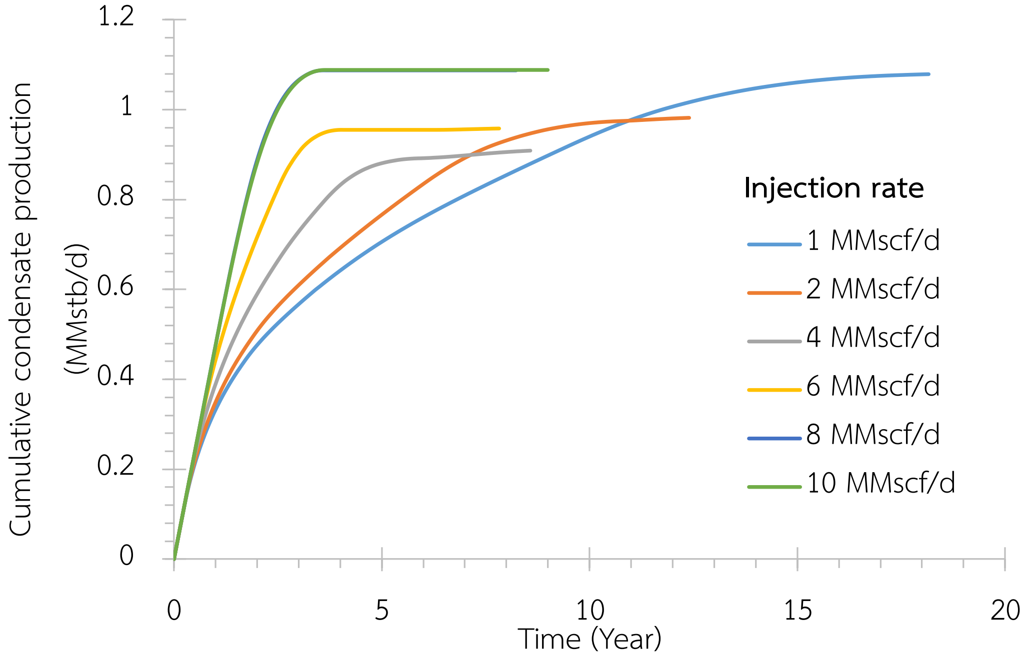


Figure 5.15 Cumulative condensate production for different injection rates of conventional gas injection with well pattern 1

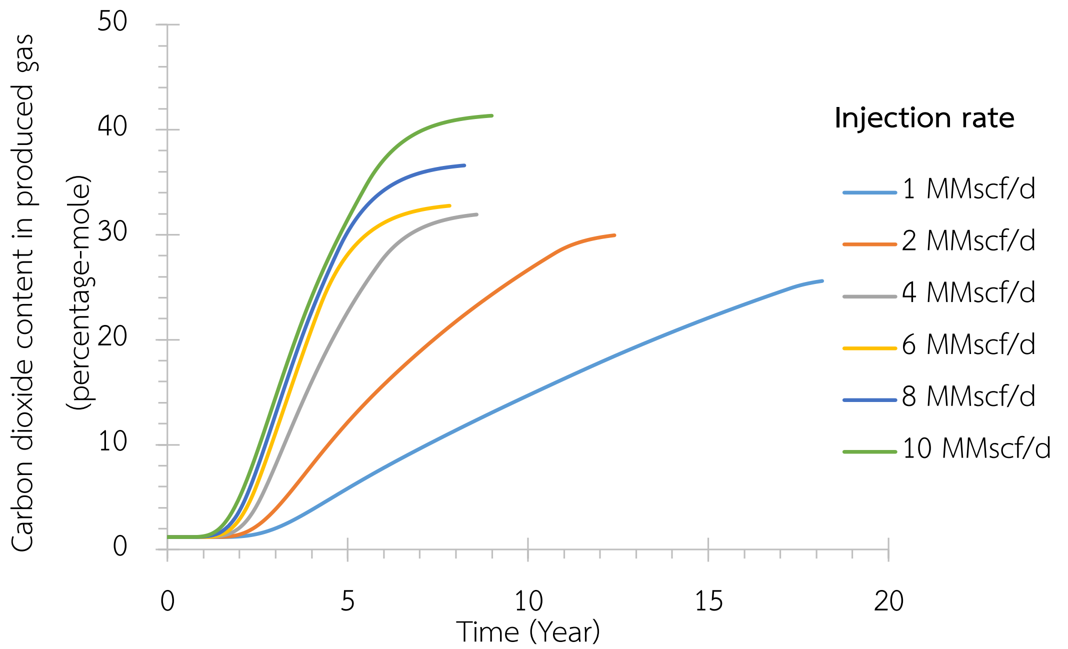


Figure 5.16 Carbon dioxide content in produced gas for different injection rates of conventional gas injection with well pattern 1

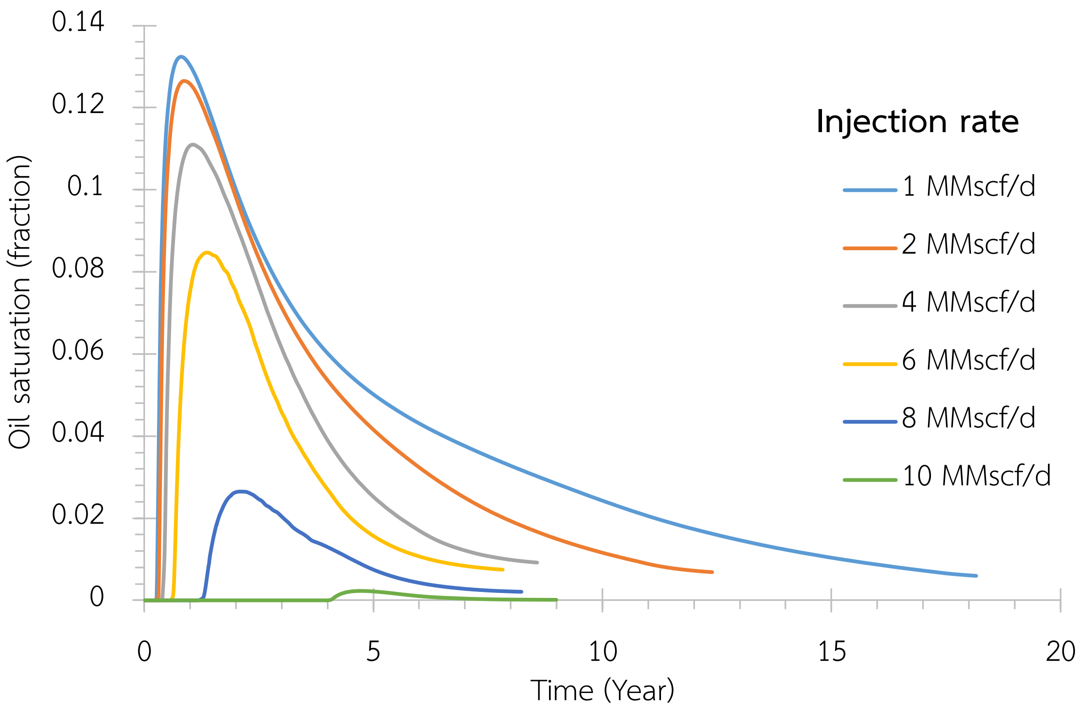


Figure 5.17 Average condensate saturation profiles for different gas injection rates of conventional gas injection with well pattern 1

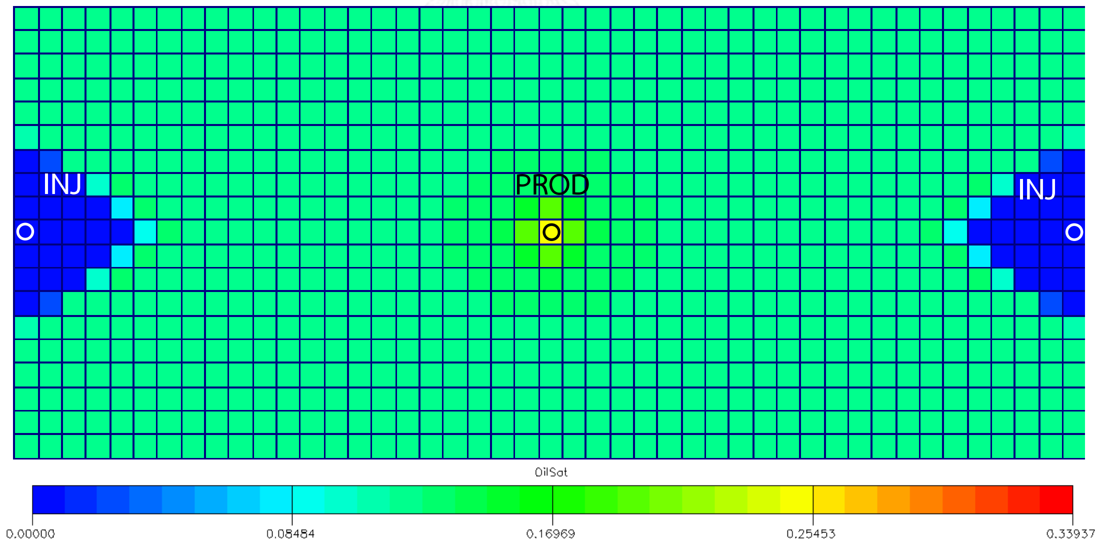


Figure 5.18 Oil saturation distribution of case with injection rate of 1 MMscf/d of conventional gas injection with well pattern 1 when start to drop out for the whole reservoir (486 days of production)

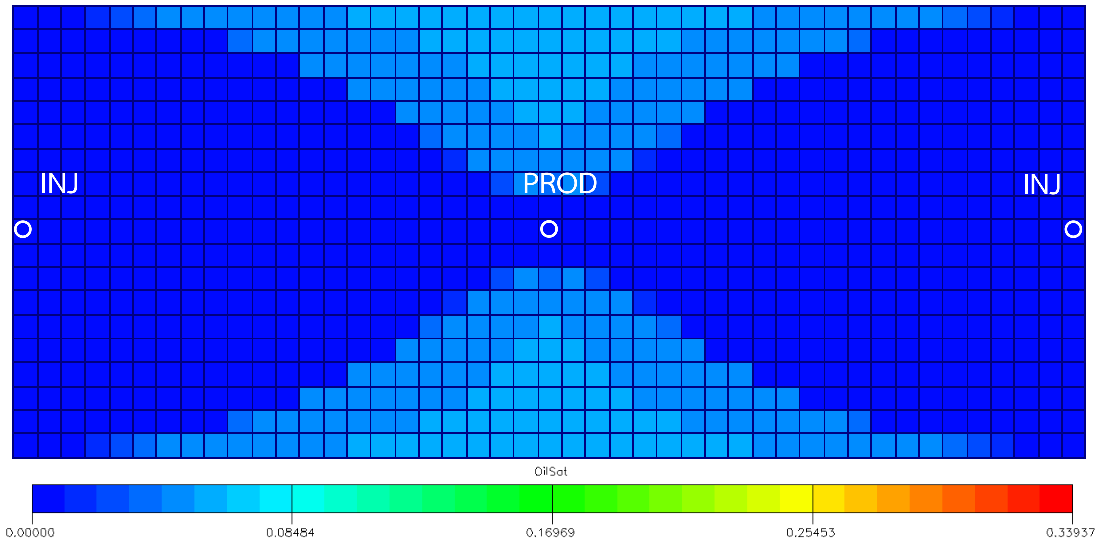


Figure 5.19 Oil saturation distribution of case with injection rate of 1 MMscf/d of conventional gas injection with well pattern 1 during condensate revaporization (2920 days of production)

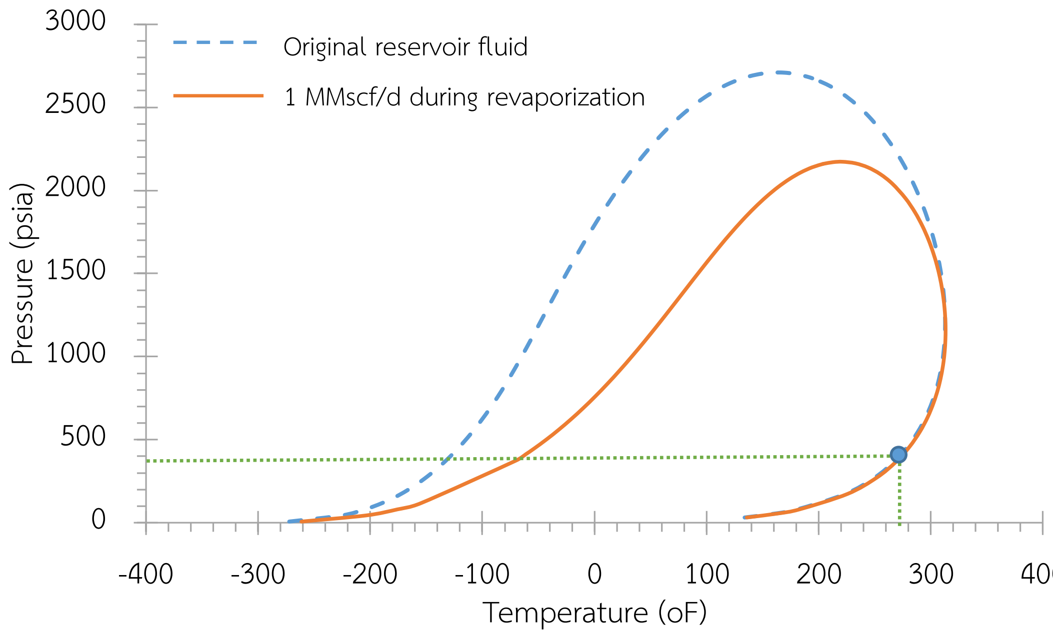


Figure 5.20 Phase diagram of case with gas injection rate of 1 MMscf/d during condensate revaporization (2920 days of production) of conventional gas injection with well pattern 1 compare to original phase diagram

Results from conventional gas injection with pattern 1 are summarized in Table 5.2. Injection rates of 2, 4, and 6 MMscf/d yield less condensate recovery because these injection rate cannot maintain the reservoir pressure higher than dewpoint pressure and the conventional gas injection for these cases is stopped earlier due to gas breakthrough. After gas break through the producer, condensate production rate suddenly falls and gas injection is stopped. Once the gas injection is stopped, the reservoir pressure rapidly declines as depicted in Figure 5.9 and 5.21, and gas production rate reaches the abandonment condition before the condensate is revaporized as revealed by the residual oil saturation in Figure 5.17

Net cumulative hydrocarbon gas production shown in the table is calculated by subtracting the injected gas and impurity gas which are nitrogen and carbon dioxide from the produced gas. Percentage of net hydrocarbon gas recovery factor is compared to the original gas in place. Some cases show the net recovery factor of hydrocarbon gas greater than 100% due to the fact that carbon dioxide from source gas reservoir vaporizes the light end of condensate into the gas phase, resulting in amount of produced hydrocarbon gas more than original gas in place. In term of total BOE recovery factor, the injection rate of 10 MMscf/d has the highest total BOE recovery factor of 82.54 % due to higher ability to maintain the reservoir pressure above the dewpoint as depicted in Figure 5.19 and the lowest amount of oil left inside the reservoir as indicated by the lowest oil saturation in the reservoir at abandonment condition of producer in Figure 5.17. The amount of cumulative gas injection ranges from 6.319 to 13.375 bcf depending on the injection rate, i.e., higher injection rate requires more gas to be injected into the reservoir.

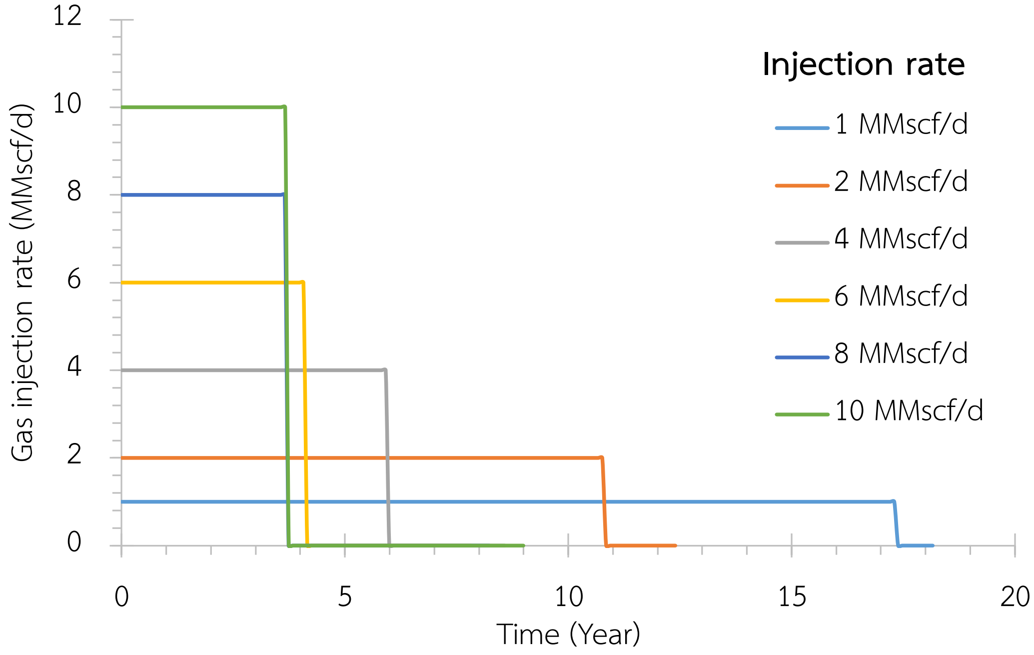


Figure 5.21 Field gas injection profiles for different injection rates of conventional gas injection with well pattern 1

Table 5.2 Summarized results for different injection rates of conventional gas injection with well pattern 1

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.079	0.982	0.909	0.958	1.088	1.088
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	71.73	65.27	60.42	63.69	72.29	72.35
Cumulative gas production (bcf)	17.206	18.832	19.646	19.912	21.610	24.344
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.511	11.593	11.619	11.577	11.539	11.579
Net hydrocarbon gas recovery factor (%)	99.76	100.47	100.70	100.33	100.00	100.35
Cumulative gas production (MMBOE)	3.320	3.395	3.425	3.402	3.369	3.404
Cumulative total BOE production (MMBOE)	4.399	4.377	4.334	4.361	4.457	4.492
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	80.83	80.43	79.63	80.12	81.89	82.54
Cumulative gas injection(bcf)	6.319	7.862	8.639	8.922	10.674	13.375

5.2.2. Conventional gas injection with well pattern 2

In this section, effects of gas injection rate on production performance for well pattern 2 are discussed. The cases with well pattern 2 were simulated with maximum gas production rate of 10 MMscf/d. Gas production starts declining at different times for different gas injection rates as depicted in Figure 5.22. The injection rate of 1 MMscf/d has the earliest decline due to the lowest capability to the maintain reservoir pressure. Similar to gas production profiles of well pattern 1, cases with low injection rates have two decline trends caused by insufficient pressure support and the stop of gas injection at late time while cases with high injection rates have one decline trend as a result of stopping gas injection.

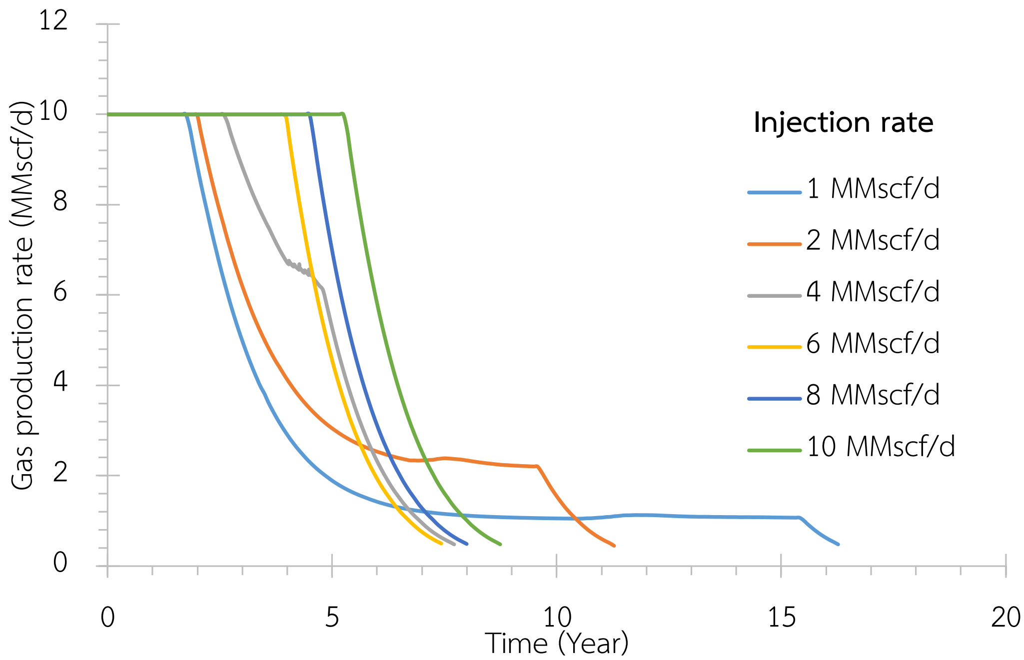


Figure 5.22 Field gas production profiles for different injection rates of conventional gas injection with well pattern 2

In prospect of condensate production rate, Figure 5.23 shows condensate production profiles for different injection rates of conventional gas injection with pattern 2. Cases with low injection rates show abrupt drop of condensate production earlier due to less capability to sustain bottomhole pressure above the dewpoint pressure. Case with high injection rates serve longer condensate plateau production due to better ability to maintain the reservoir pressure. The injection rate of 4 MMscf/d has the lowest condensate recovery among the low injection rate group as shown in Figure 5.24. The reasons that 4 MMscf/d case has the lowest cumulative condensate production are poor capability to maintain reservoir pressure and condensate is not completely revaporized at abandonment condition of producer. In this case, the case with 1 MMscf/d injection rate yields the highest condensate recovery factor due to the fact that the breakthrough time is delayed, resulting in higher condensate production at late times.

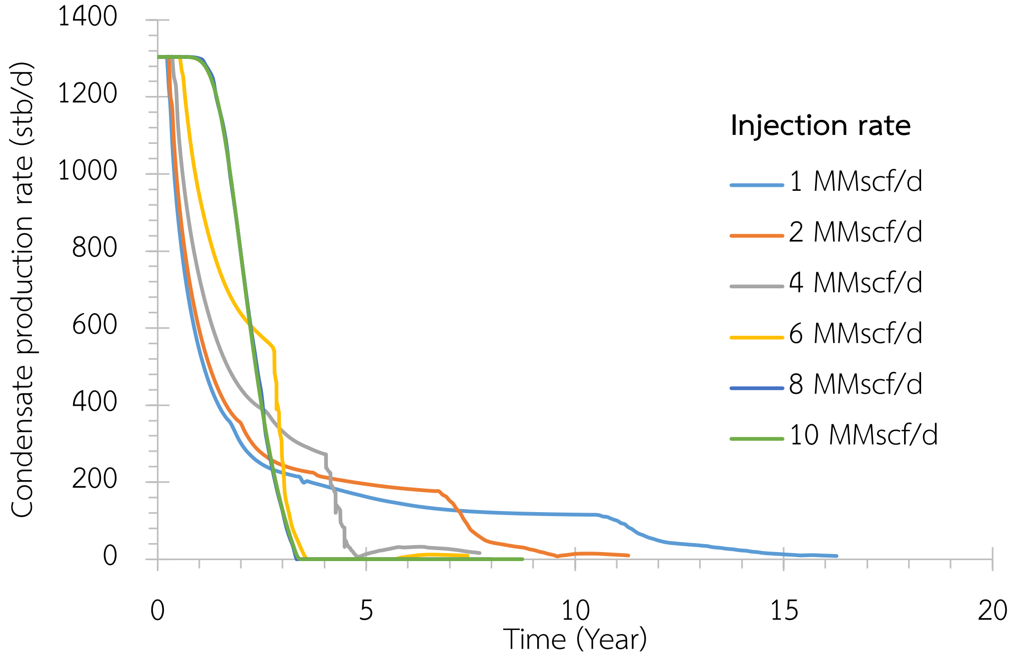


Figure 5.23 Field condensate production profiles for different injection rates of conventional gas injection with well pattern 2

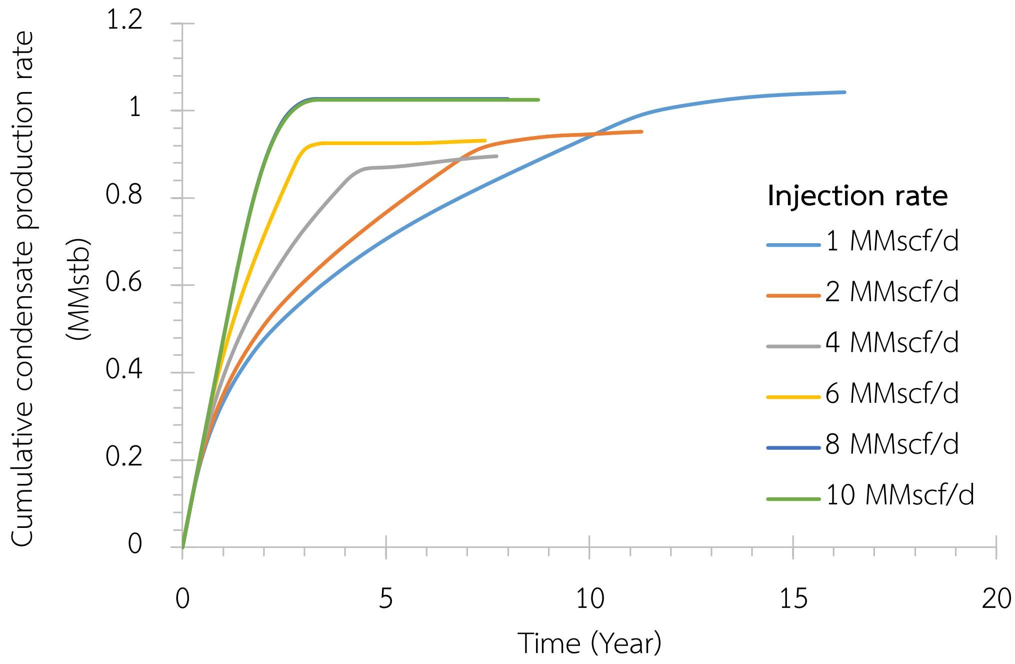


Figure 5.24 Cumulative condensate production for different injection rates of conventional gas injection with well pattern 2

Results from conventional gas injection with well pattern 2 are summarized in Table 5.3. Although the injection rate of 1 MMscf/d has poor ability to maintain the reservoir pressure, causing condensate dropout in the reservoir but this injection rate prolongs the breakthrough and the abandonment for gas injection is delayed. The intermediate components are displaced as gas is being injected into the reservoir, resulting in the highest of condensate production. For overall, the injection rate of 10 MMscf/d gains the highest BOE at 80.95% because most of the intermediate components are extracted at early time and the light hydrocarbon gas are producer at late time after stopping gas injection. There is only one case that can recover net hydrocarbon gas recovery exceeding 100% which is the case with injection rate of 2 MMscf/d. Cumulative gas injection ranges from 5.267 to 12.453 bcf deprnding on the injection rate. Higher gas injection rate requires higher amount of gas to inject into the reservoir before the condensate production rate is less than 10 stb/d.

Table 5.3 Summarized results for different injection rates of conventional gas injection with pattern 2

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.042	0.952	0.896	0.931	1.027	1.025
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	69.27	63.26	59.53	61.91	68.24	68.11
Cumulative gas production (bcf)	16.485	17.932	17.928	18.728	20.658	23.431
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.472	11.540	11.470	11.427	11.422	11.511
Net hydrocarbon gas recovery factor (%)	99.43	100.01	99.41	99.03	98.99	99.76
Cumulative gas production (MMBOE)	3.284	3.349	3.323	3.316	3.312	3.381
Cumulative total BOE production (MMBOE)	4.327	4.301	4.219	4.248	4.339	4.406
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	79.50	79.02	77.51	78.05	79.72	80.95
Cumulative gas injection (bcf)	5.627	6.994	7.008	7.804	9.743	12.453

5.2.3. Conventional gas injection with well pattern 3

In this section, the same gas condensate reservoir was simulated with well pattern 3 for different gas injection rates. Figure 5.25 illustrates field gas production profiles for different injection rates from 1 to 10 MMscf/d. The gas production profiles are similar to the cases with patterns 1 and 2. Cases with low injection rates (1 to 4 MMscf/d) have 2 decline trends due to lack of pressure support and the stop of gas injection while the other three cases have only one trend from stopping gas injection.

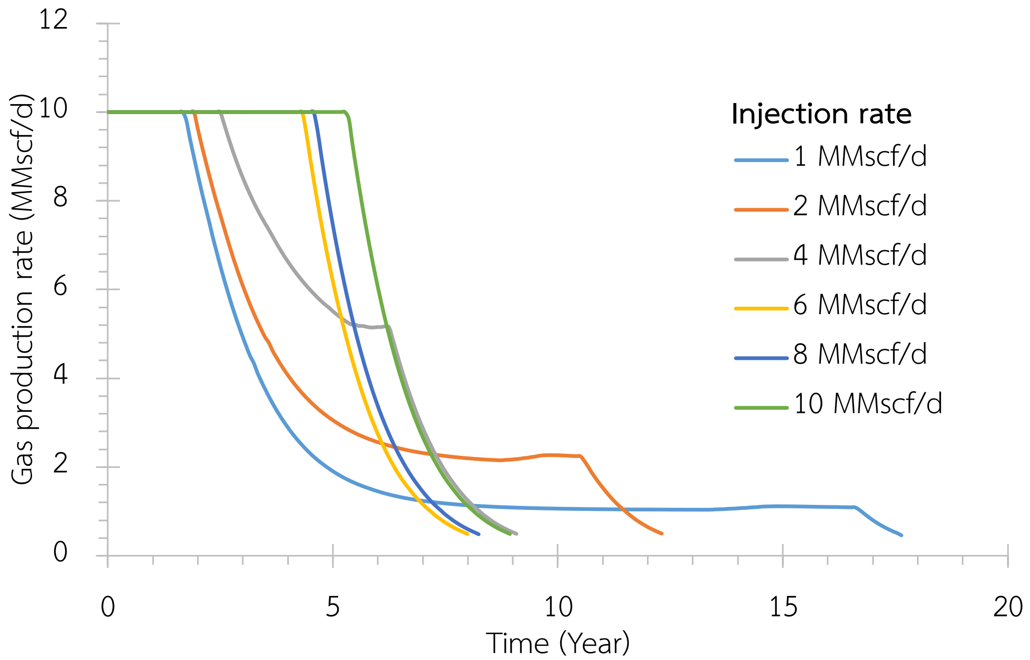


Figure 5.25 Field gas production profiles for different injection rates of conventional gas injection with well pattern 3

The trends of condensate production rate shown in Figure 5.26 are similar to those for the previous two cases except the case with 8 MMscf/d injection rate. Since this pattern has larger distance between injectors and producer, injection rate of 8 MMscf/d cannot support the bottomhole pressure above the dewpoint, resulting in condensate blockage near the production well. As gas is produced, the bottomhole pressure continues dropping. Eventually, condensate saturation is greater than the critical oil saturation, and condensate starts flowing into the well, resulting in a short period of an increase in condensate production rate after the decline from the plateau. After that, the condensate production rate continues to decline as the reservoir pressure continues dropping.

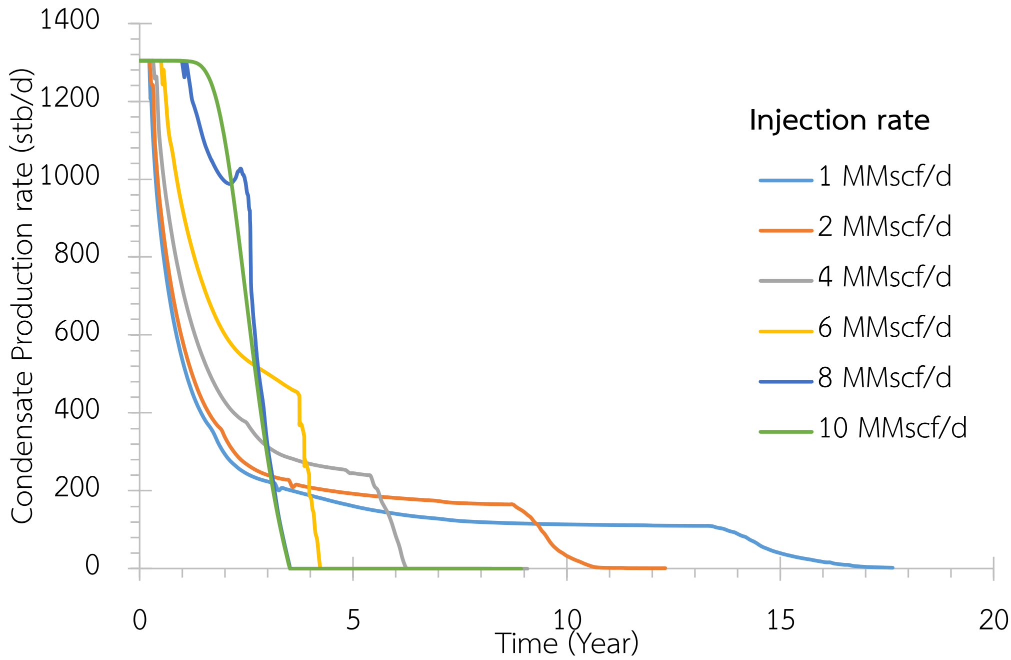


Figure 5.26 Field condensate production profiles for different injection rates of conventional gas injection with well pattern 3

Results for conventional gas injection with well pattern 3 are summarized in Table 5.4. For conventional gas injection with well pattern 3, the injection rate at 8 MMscf/d gains the highest condensate recovery factor similar to the case well pattern 2 due to the fact that the breakthrough time is extended, resulting in long condensate production period. Since this well pattern have longer space between producer and injector, injection rate of 8 MMscf/d cannot serve pressure maintenance to the bottomhole pressure of producer resulting in condensate dropout around the producer as shown in Figure 5.27 and the early decline of condensate production rate. Approximately 2 years after production, condensate production rate slightly increase due to additional condensate above critical condensate saturation around the producer flow to the producer as illustrated in Figure 5.28. The injection rate of 4 MMscf/d gives the lowest total BOE due to the fact that condensed condensate is incompletely revaporized at abandonment condition of producer similar to the one with well pattern 1. The cases with injection rate of 2, 4, 6 MMscf/d recover net hydrocarbon gas more than 100% due to the fact that the injected gas revaporizes the light end condensate into the gas phase. The highest total BOE of 82.73% can be recovered in the case with injection rate of 10 MMscf/d which has high ability to maintain the reservoir pressure. Similar to the previous two cases which are conventional gas injection with well patterns 1 and 2, amount of cumulative gas injection mainly depends on the injection rate.

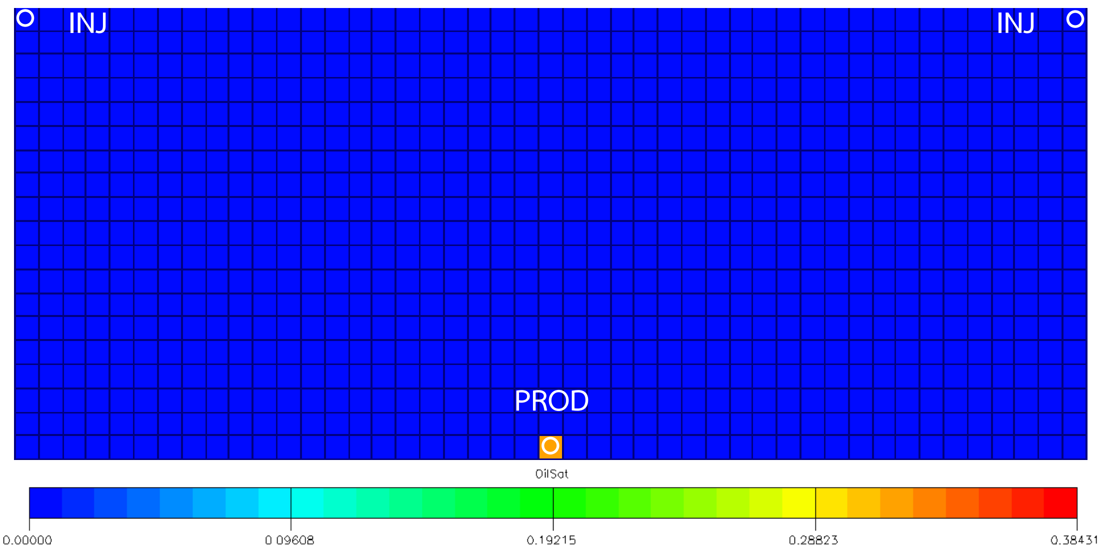


Figure 5.27 Oil saturation distribution of case with injection rate of 8 MMscf/d of conventional gas injection with well pattern 3 when condensate production rate starts to decline (384 days of production)

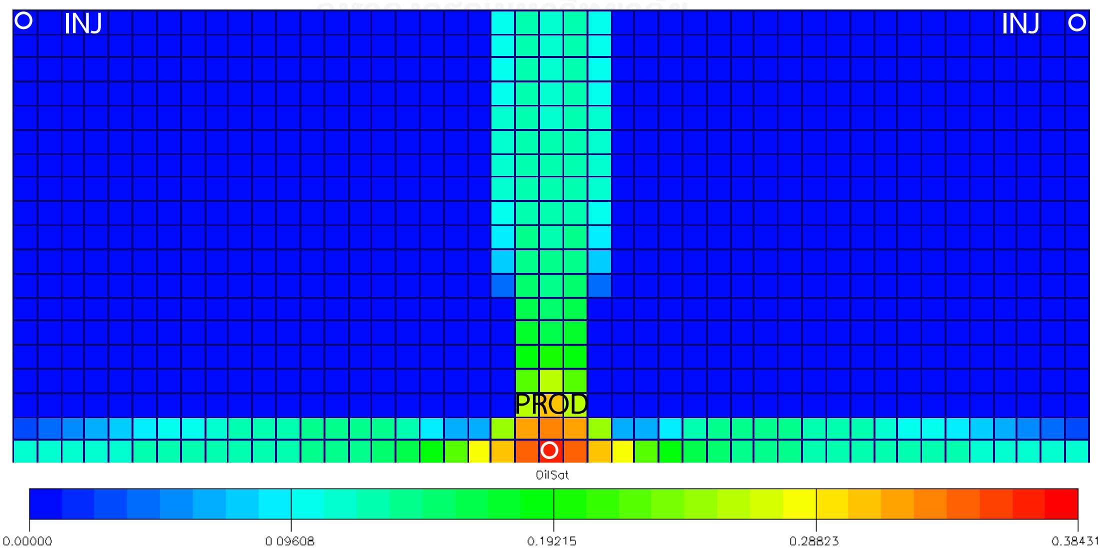


Figure 5.28 Oil saturation distribution of case with injection rate of 8 MMscf/d of conventional gas injection with well pattern 3 when condensate production rate increase (860 days of production)

Table 5.4 Summarized results for different injection rates of conventional gas injection with pattern 3

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.126	1.040	0.980	1.059	1.200	1.190
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	74.86	69.12	65.15	70.36	79.77	79.11
Cumulative gas production (bcf)	16.910	18.596	20.109	20.190	21.047	23.690
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.492	11.575	11.628	11.550	11.446	11.472
Net hydrocarbon gas recovery factor (%)	99.59	100.31	100.78	100.10	99.20	99.43
Cumulative gas production (MMBOE)	3.306	3.384	3.437	3.375	3.286	3.312
Cumulative total BOE production (MMBOE)	4.432	4.423	4.417	4.434	4.486	4.502
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	81.43	81.28	81.16	81.47	82.43	82.73
Cumulative gas injection(bcf)	6.064	7.673	9.126	9.272	10.242	12.864

The second part of conventional gas injection mainly discusses the effect of well pattern on the condensate production. The well pattern was varied by three different well locations from pattern 1, 2 and 3, respectively for various injection rates. Well pattern 1 has the shortest distance between injectors and producer while pattern 3 has the longest. Figure 5.29 shows condensate recovery factor for different gas injection rates of conventional gas injection scenario. The distance between injectors and producer does significantly affect condensate recovery factor. Well pattern 3, which has the longest distance between injectors and producer, provides higher swept area as demonstrated in Figure 5.xx resulting in the highest condensate recovery factor for all injection rates. Although well pattern 2 has longer distance between injectors and producer than well pattern 1 but it has poor sweep efficiency as shown in Figure 5.31, resulting in high gas production at late time and lower condensate recovery factor. Regarding the effect of gas injection rate on condensate recovery factor, as injection rate is increased from 1 to 10 MMscf/d, condensate recovery factor does not increase proportionally. For injection rates of 1 to 4 MMscf/d, condensate recovery factor decreases as the injection rate is increased because this injection rate cannot maintain the reservoir pressure above the dewpoint, resulting in early decline of condensate production rate and the condensate is not completely revaporized at the end of production as illustrated in Figure 5.17. On the other hand, for injection rate of 6 to 10 MMscf/d, condensate recovery factor increases as the injection rate is increased because these injection rates have better ability to sustain the reservoir pressure above the dewpoint longer than the other three cases. In another word, there is less condensate drop out in the reservoir when the injection rate is increased as it has been happened in conventional gas injection with well pattern 1.

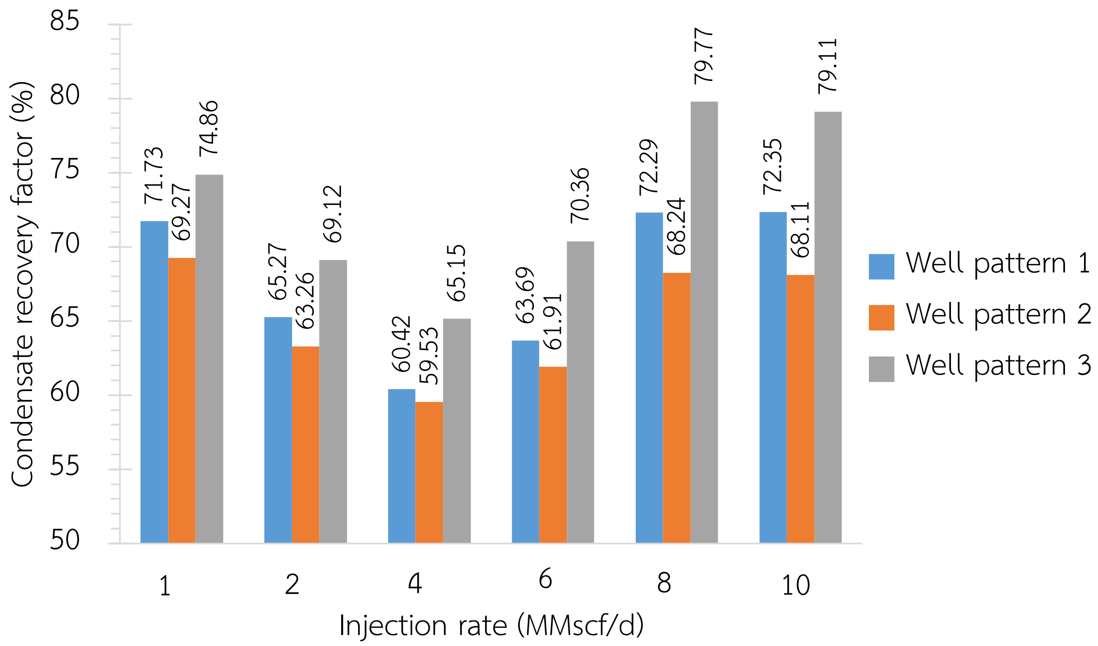


Figure 5.29 Condensate recovery factor for different gas injection rates of conventional gas injection scenario

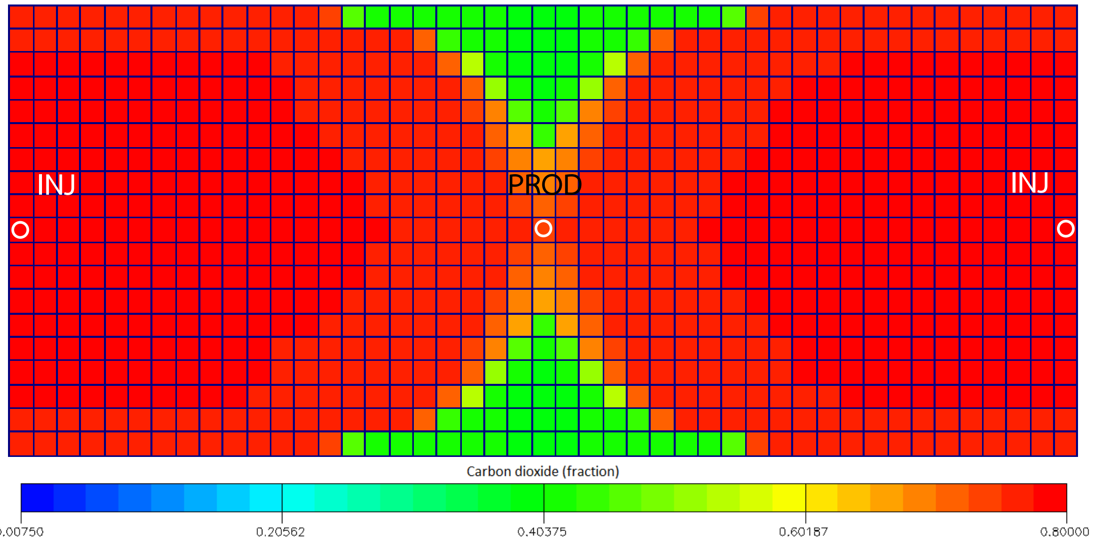


Figure 5.30 Carbon dioxide mole fraction distribution of case with gas injection rate of 1 MMscf/d of conventional gas injection with well patter 1 at the end of production

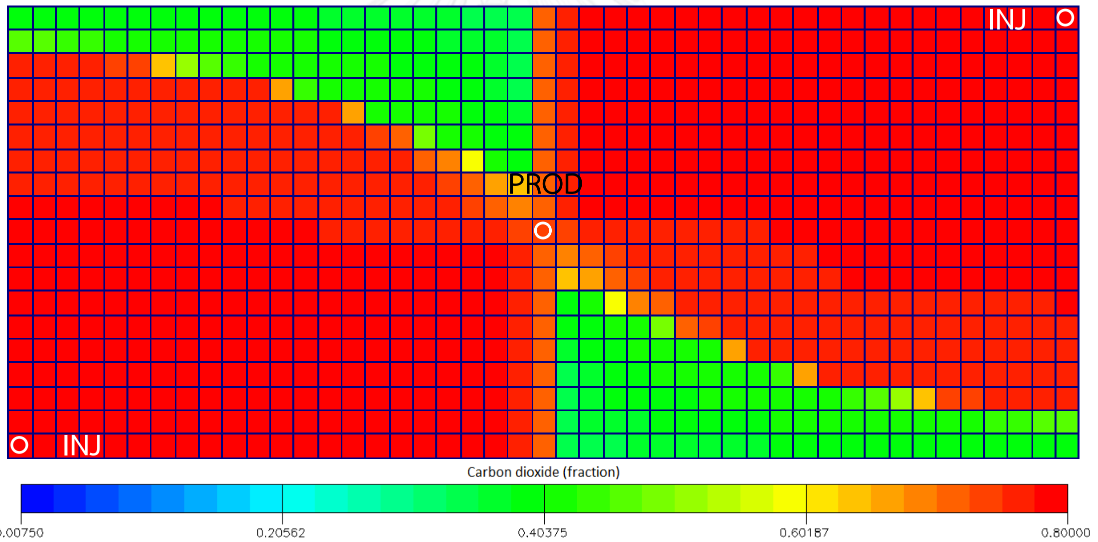


Figure 5.31 Carbon dioxide mole fraction distribution of case with gas injection rate of 1 MMscf/d of conventional gas injection with well patter 2 at the end of production

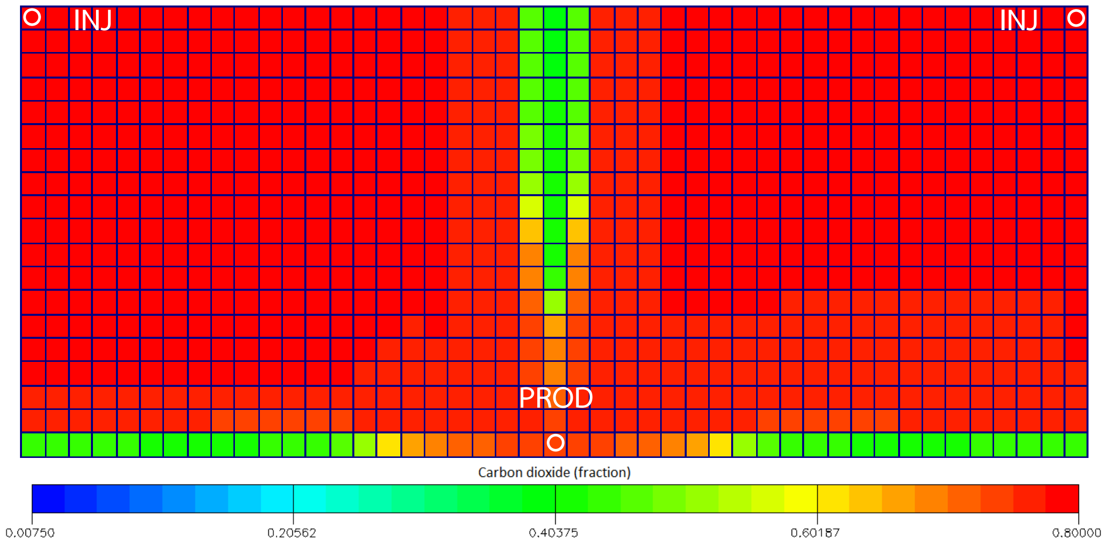


Figure 5.32 Carbon dioxide mole fraction distribution of case with gas injection rate of 1 MMscf/d of conventional gas injection with well patter 3 at the end of production

5.3. Gas dumpflood

For gas dumpflood, the same gas condensate reservoir was used to simulate in order to compare with the proposed technique, which is combined gas dumpflood with gas injection. An underlying source gas reservoir consisting of 20% mole of methane and 80% mole of carbon dioxide was used as a source gas reservoir for gas dumpflood.

Three different sizes of source gas reservoir with the same production schedule were modelled and simulated. The effect of well location on gas and condensate production are individually discussed in Section 5.3.1 to 5.3.3 for 0.5 PV, 1 PV, and 2 PV source gas reservoir, respectively.

One producer was used to produce hydrocarbon at maximum gas rate of 10 MMscf/d and minimum wellhead pressure of 200 psia. The gas from source gas reservoir was dumped into the gas condensate reservoir at the beginning of the production. Gas dumpflood was simulated until the abandonment rate of 0.5 MMscf/d of gas production was reached. Gas recovery factor, HC gas recovery factor, and total BOE recovery factor in this scenario were calculated based on net recovery. This was done by subtracting the reported production by the cumulative dumped gas.

5.3.1. Gas dumpflood from 0.5 PV source gas reservoir

Different well locations having the same starting time of dumpflood operation at the beginning are discussed first in order to investigate the effect of well location on gas and condensate production when gas is dumped from a source gas reservoir (0.5 PV). Figure 5.33 demonstrates gas production profiles for different well patterns. For all of the cases, gas can be produced at the specified plateau rate at 10 MMscf/d for a certain period and declines due to insufficient pressure support. For pattern 3, in which the distance between dumping wells and the producer is the longest, gas production can be maintained at the plateau rate for shorter duration due to the fact that the bottomhole pressure of producer declines faster than the other cases as shown in Figure 5.34 as a result of long distance between dumping wells and producer. On the other hand, patterns 1 and 2 which have closer well spacings, dumped gas has better ability to maintain bottomhole pressure of the producer, resulting in longer plateau gas production. For all pattern, after bottomhole pressure reached the dewpoint (2402.35 psia), some part of the gas are condensed into liquid caused additional pressure drop around the producer, resulting in abrupt drop of bottomhole pressure of the producer Figure 5.35 shows field condensate production rate profile for different well patterns for gas dumpflood from 0.5 PV source gas reservoir. For patterns 1 and 2, condensate can be produced approximately 9 months before the bottomhole pressure of producer reaches the dewpoint pressure, and condensate drops out around the wellbore. Consequently, condensate production rates for all cases suddenly decline. For pattern 3, large distance between dumping wells and producer results in the decline of condensate production earlier. However, large well spacing in pattern 3 has more swept area and can recover more condensate at late time of production. As a result, pattern 3 gains the highest recovery factor as shown in Table 5.5. Well pattern 3 recovers net hydrocarbon gas recovery factor less than 100% while the other two cases yield more than 100% due to the fact that large amount of carbon dioxide from the source gas reservoir, as indicated by large amount of produced carbon dioxide in produced gas in Figure 5.36, vaporizes the light end of condensate into the gas phase, resulting in amount of produced hydrocarbon gas more than original gas in place meanwhile less condensate recovery factor. In term of total BOE recovery factor, the case with well pattern 2 gains the lowest total BOE recovery factor because of poor sweep efficiency.

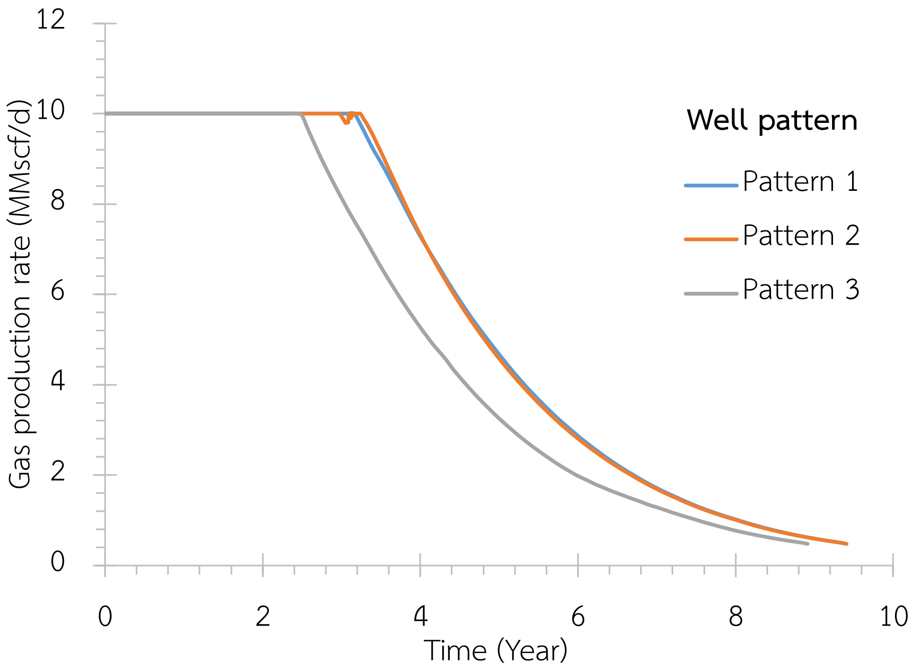


Figure 5.33 Field gas production rate profile for different well patterns of gas dumpflood from 0.5 PV source gas reservoir

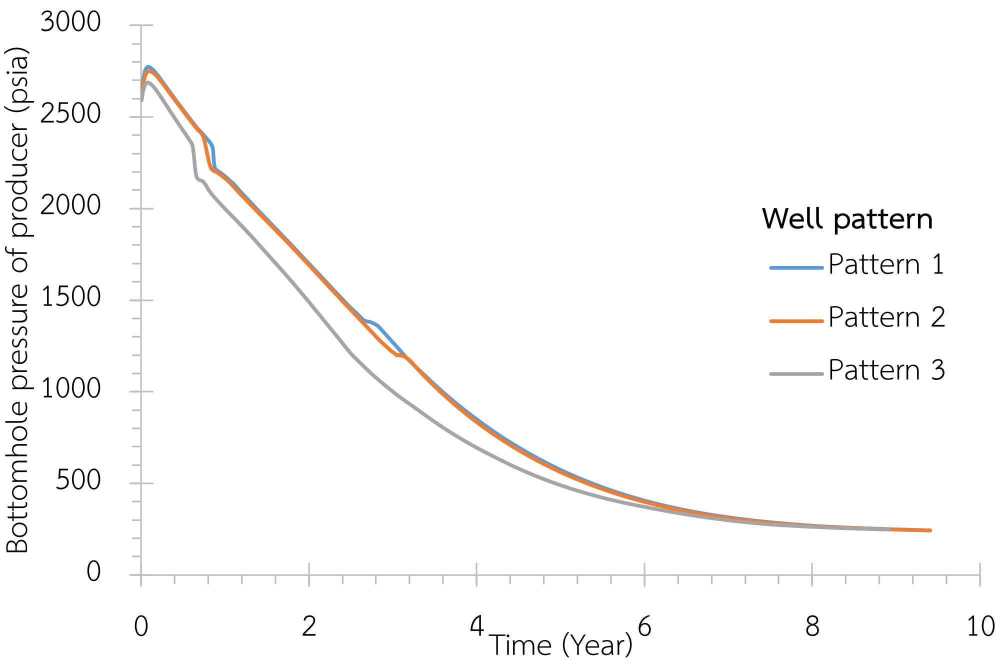


Figure 5.34 Bottomhole pressure of producer for different well patterns of gas dumpflood from 0.5 PV source gas reservoir

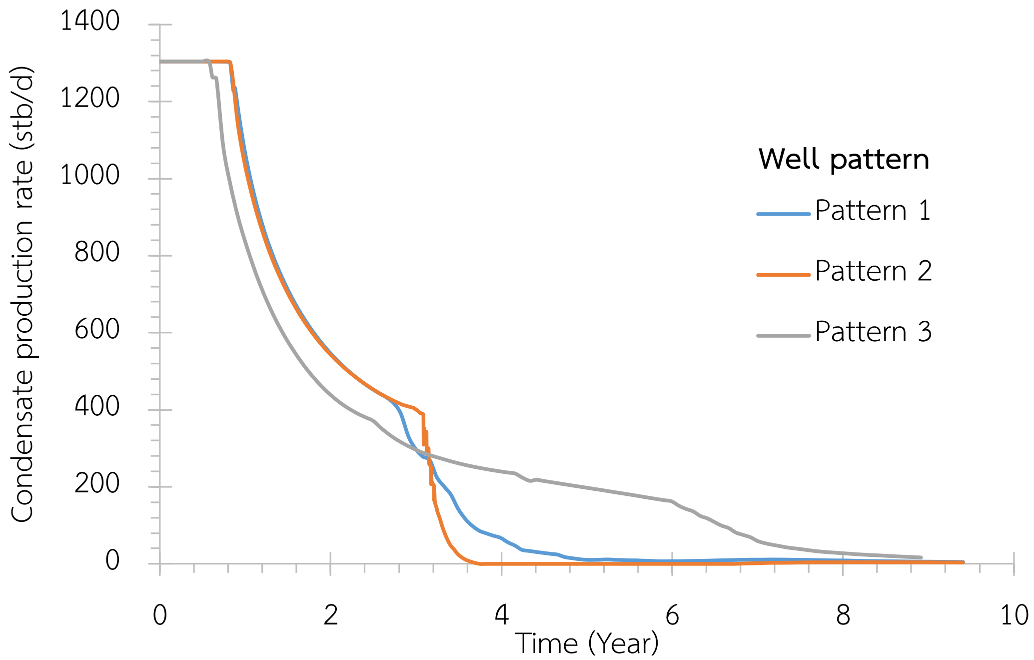


Figure 5.35 Field condensate production rate profile for different well patterns of gas dumpflood from 0.5 PV source gas reservoir

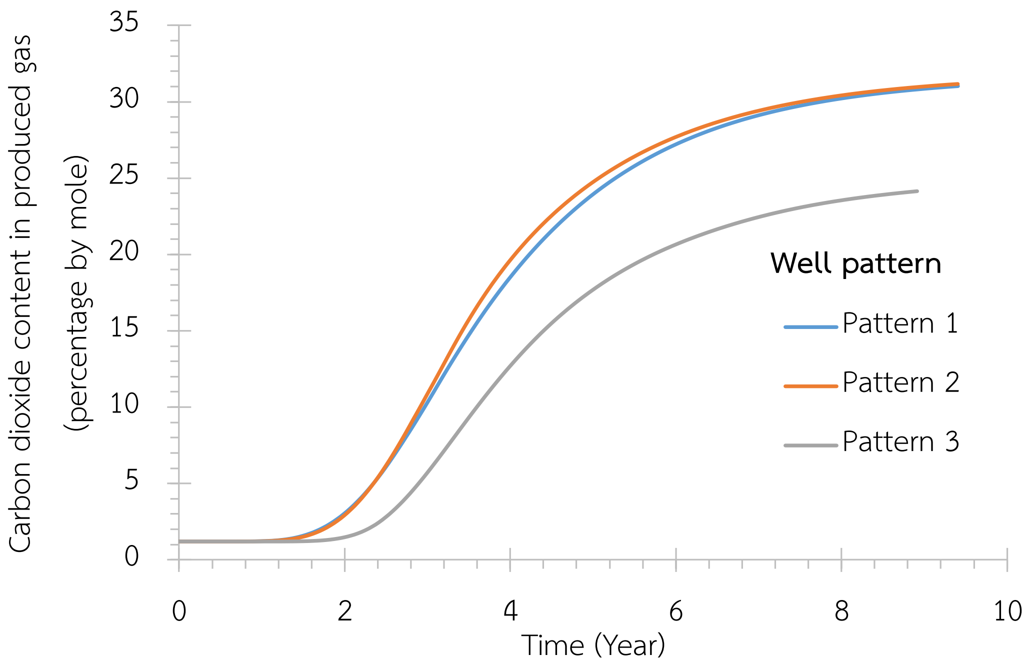


Figure 5.36 Carbon dioxide content in produced gas for different well patterns of gas dumpflood from 0.5 PV source gas reservoir

Table 5.5 Summarized results for different well pattern of gas dumpflood from 0.5 PV source gas reservoir

Parameters	Pattern 1	Pattern 2	Pattern 3
Cumulative condensate production (MMstb)	0.968	0.923	1.072
Original condensate in place (MMstb)	1.504	1.504	1.504
Condensate recovery factor (%)	64.37	61.37	71.22
Cumulative gas production (bcf)	19.233	19.211	16.686
Original gas in place (bcf)	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.584	11.545	10.655
Net hydrocarbon gas recovery factor (%)	100.39	100.05	92.34
Cumulative gas production (MMBOE)	3.400	3.377	3.285
Cumulative total BOE production (MMBOE)	4.368	4.300	4.356
Original BOE in place (MMBOE)	5.442	5.442	5.442
Total BOE recovery factor (%)	80.26	79.01	80.04
Cumulative cross flow(bcf)	8.268	8.254	5.883

5.3.2. Gas dumpflood from 1 PV source gas reservoir

The same gas condensate reservoir with 1 PV of source gas dumped into the gas condensate reservoir since the beginning of the production was simulated. Unlike the case with 0.5 PV source gas reservoir, gas production profile of the cases with 1 PV source gas reservoir show similar trend for all well patterns. The gas production rate can be maintained at 10MMscf/d for more than 5 years before declining as demonstrated in Figure 5.37 due to limited pressure support from the source gas reservoir. In the case of 1 PV source gas reservoir, there is sufficient amount of gas flowing from the gas reservoir into the gas condensate reservoir to support gas production at the producer to produce at similar rates for different well patterns. However, there is slight difference in condensate recovery as illustrated in Figures 5.38 and 5.39. Pattern 2 gains less condensate recovery at late time due to the poor sweep efficiency which results in high gas production at late time as shown in Figure 5.40. Pattern 3 yields the highest condensate recovery because the long distance between dumping wells provide higher swept area and the gas breakthrough time is extended as revealed by an increment of carbon dioxide in produced gas in Figure 5.41.

Result summary of gas dumpflood with 1 PV source gas reservoir having different well locations with 1 PV of source gas is displayed in Table 5.6. All of the cases can recover condensate more than one million stock tank barrels. Net cumulative hydrocarbon gas production in pattern 3 is slightly lower than those of patterns 1 and 2 since light components are better retained in the liquid phase. Net hydrocarbon gas recovery factor is greater than 100% in patterns 1 and 2 because the light components in condensate are vaporized by carbon dioxide (drying effect). Although the case with well pattern 3 yields the lowest net cumulative hydrocarbon gas recovery but it gains the highest total BOE recovery factor.

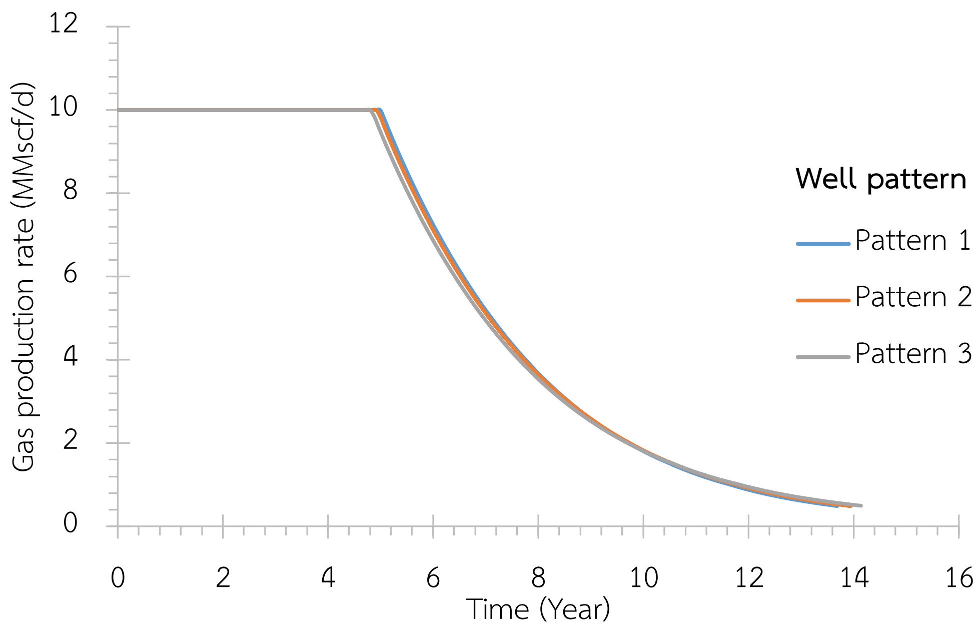


Figure 5.37 Field gas production profiles for different well pattern of gas dumpflood from 1 PV source gas reservoir

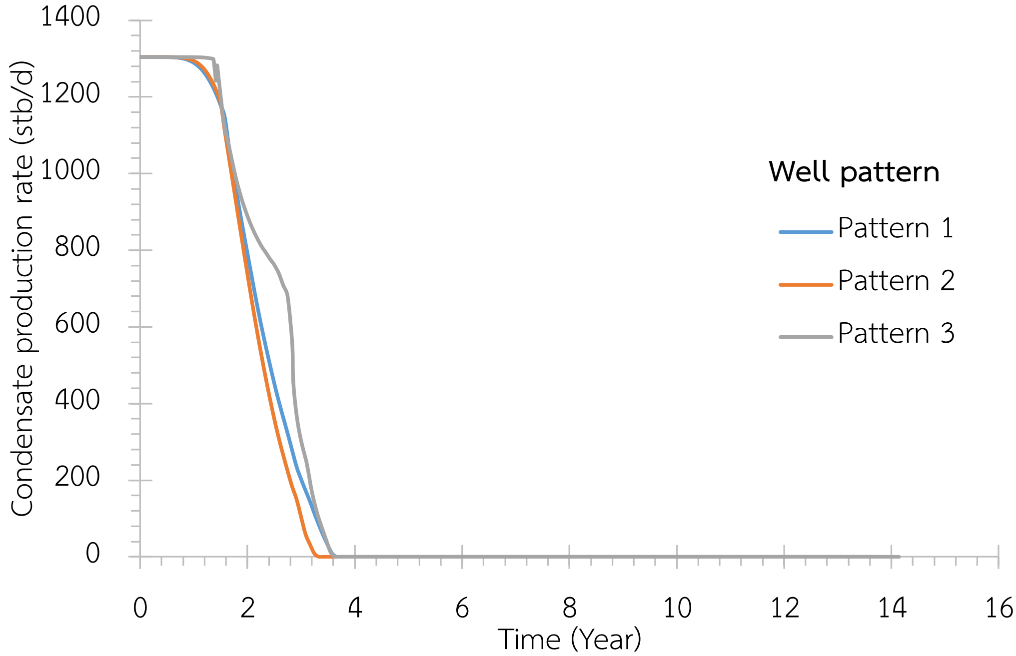


Figure 5.38 Field condensate production profiles for different well pattern of gas dumpflood from 1PV source gas reservoir

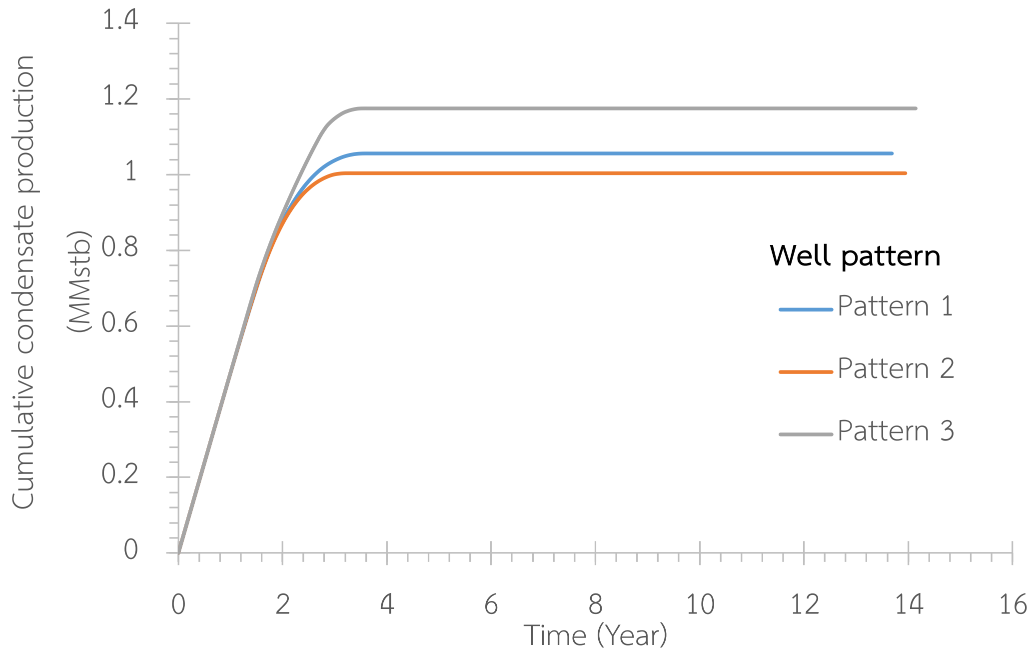


Figure 5.39 Cumulative condensate production for different well patterns of gas dumpflood from 1PV source gas reservoir

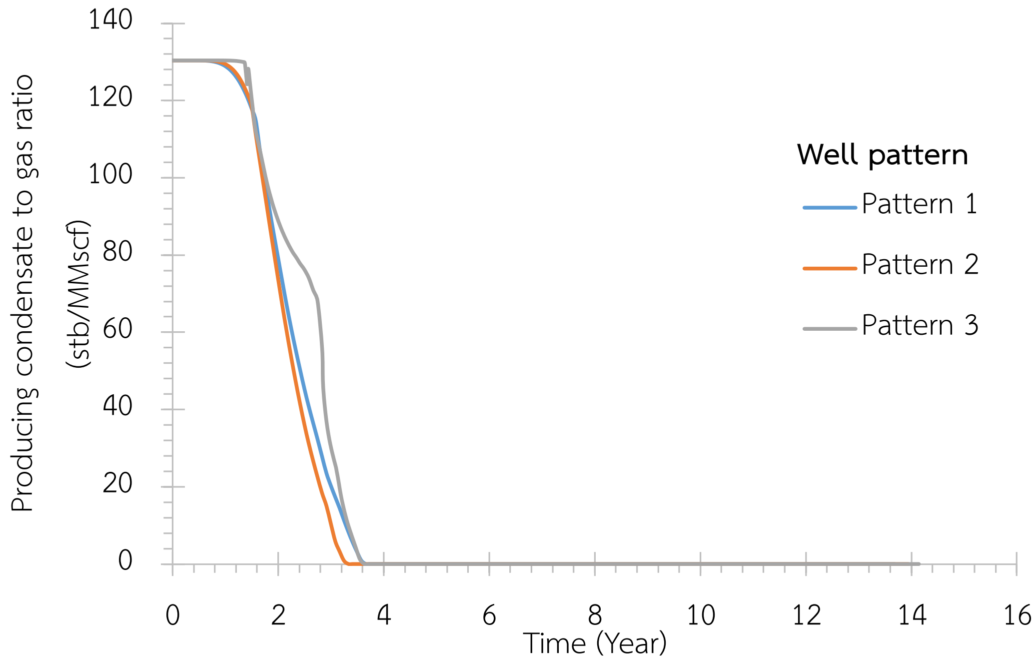


Figure 5.40 Producing condensate to gas ratios for different well patterns of gas dumpflood from 1PV source gas reservoir

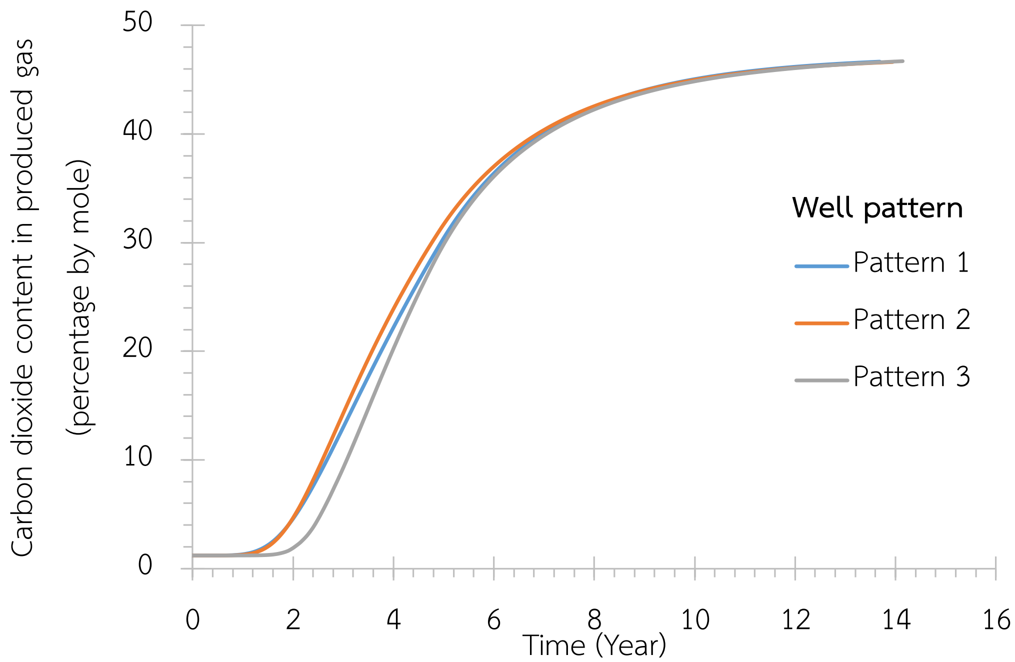


Figure 5.41 Carbon dioxide content in produced gas for different well patterns of gas dumpflood from 1 PV source gas reservoir

Table 5.6 Summarized results for different well patterns of gas dumpflood from 1 PV source gas reservoir

Parameter	Pattern 1	Pattern 2	Pattern 3
Cumulative condensate production (MMstb)	1.056	1.004	1.175
Original condensate in place (MMstb)	1.504	1.504	1.504
Condensate recovery factor (%)	70.21	66.74	78.13
Cumulative gas production (bcf)	28.382	28.357	28.131
Original gas in place (bcf)	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.627	11.631	11.501
Net hydrocarbon gas recovery factor (%)	100.76	100.80	99.67
Cumulative gas production (MMBOE)	3.442	3.444	3.333
Cumulative total BOE production (MMBOE)	4.498	4.448	4.508
Original BOE in place (MMBOE)	5.442	5.442	5.442
Total BOE recovery factor (%)	82.65	81.73	82.83
Cumulative cross flow(bcf)	17.409	17.367	17.307

5.3.3. Gas dumpflood from 2 PV source gas reservoir

Similar to the study in Sections 5.3.1 and 5.3.2, gas dumpflood into the gas condensate reservoir is started since the beginning. However, the size of the source gas reservoir is two times larger in term of pore volume (2PV). As illustrated in Figure 5.42, field gas production profiles exhibit similar trend for different well patterns. Gas can be produced at a plateau rate of 10 MMscf/d for a roughly 8 years before declining. There is no significant difference in the declining trends for different well patterns. The decline of gas production rate is mainly from in sufficient pressure support. For condensate production, pattern 3 gains a little longer condensate plateau rate as shown in Figure 5.43 due to longer distance between dumping wells and producer which results in larger contact area for gas flooding. In term of condensate recovery, pattern 3 provides the highest recovery while pattern 2 yields the lowest as shown in Figure 5.44. The reason that pattern 2 yields the lowest condensate recovery is poor sweep efficiency which results in high gas production after gas breakthrough as shown in Figure 5.45.

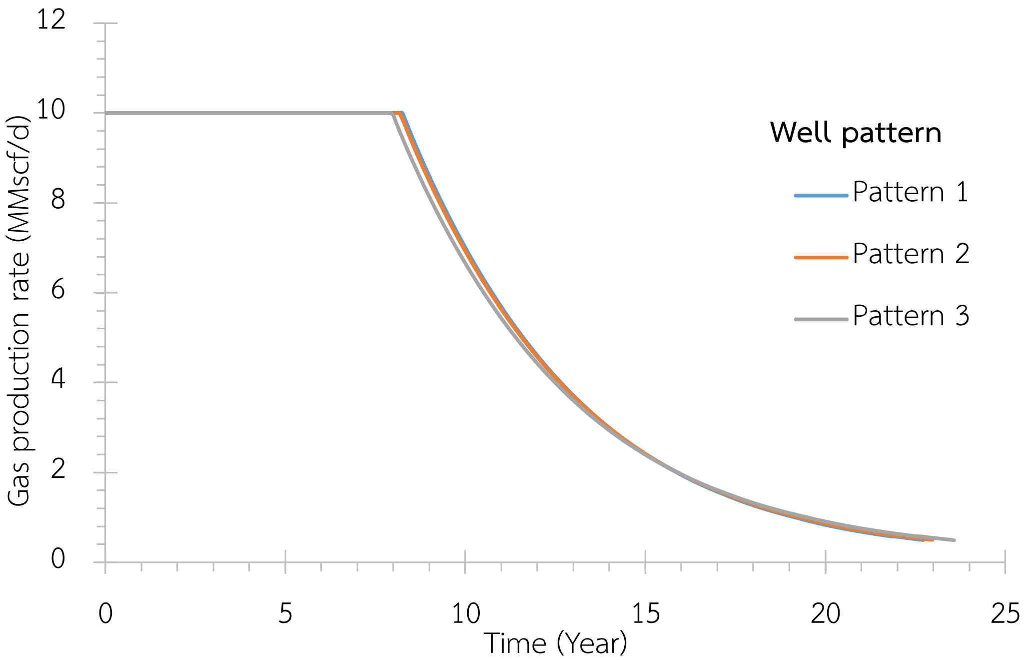


Figure 5.42 Field gas production profiles for different well patterns of gas dumpflood from 2 PV source gas reservoir

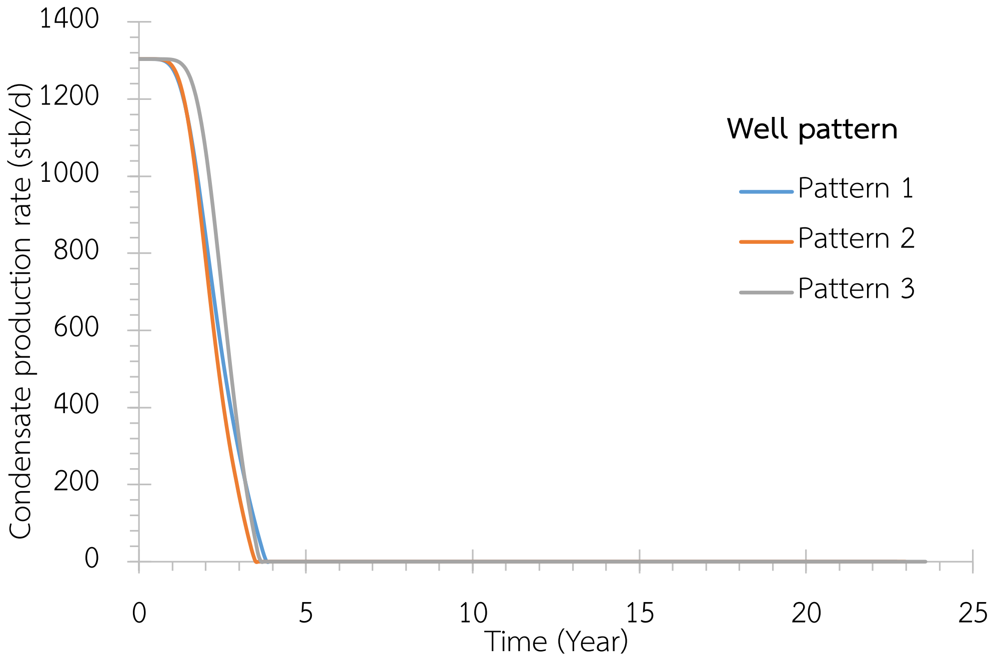


Figure 5.43 Field condensate production profiles for different well patterns of gas dumpflood from 2 PV source gas reservoir

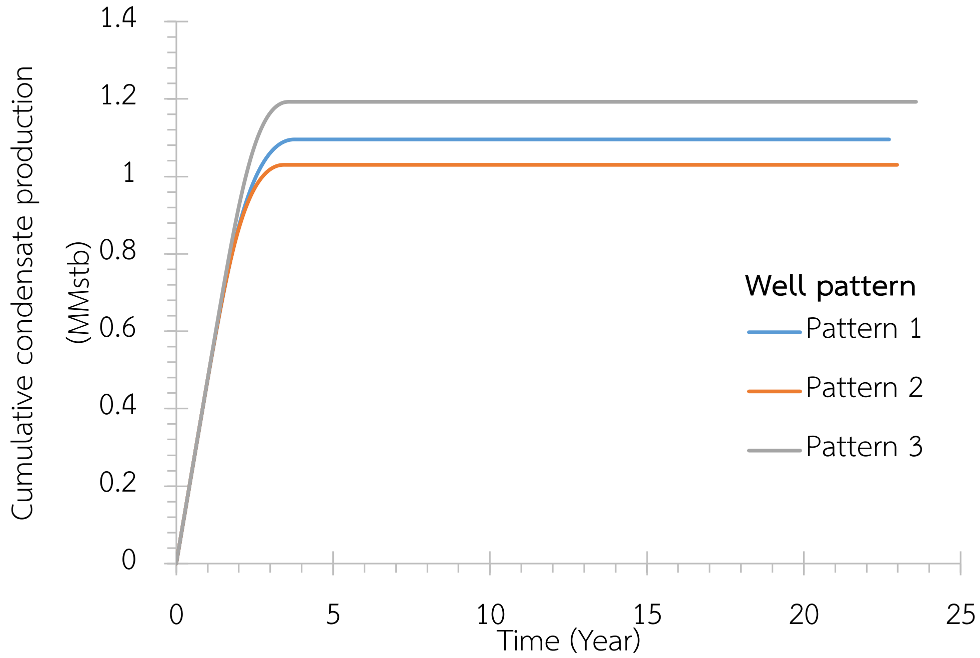


Figure 5.44 Cumulative condensate production for different well patterns of gas dumpflood from 2 PV source gas reservoir

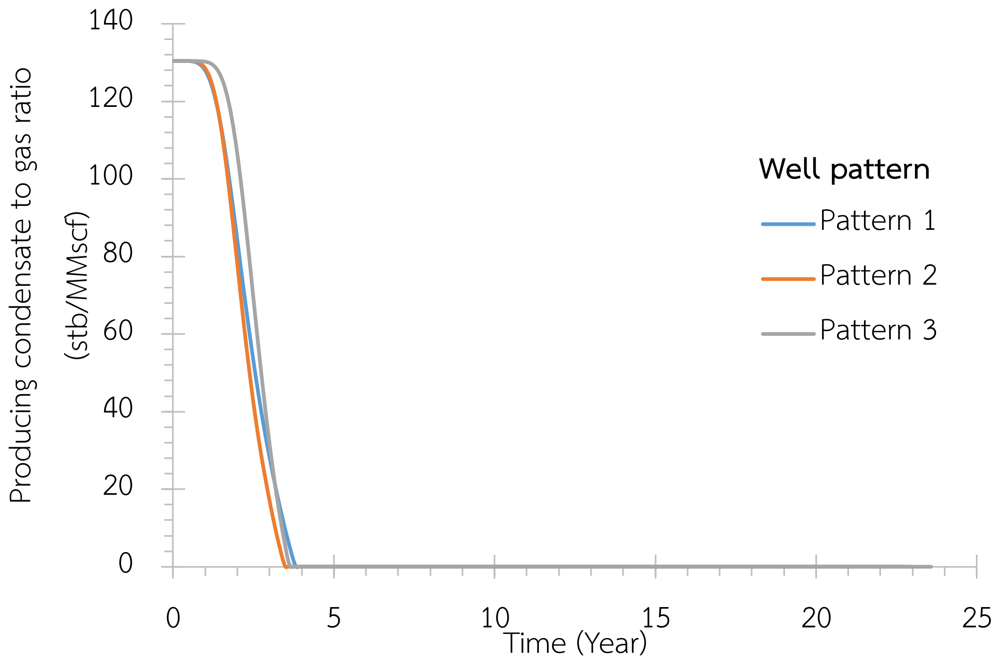


Figure 5.45 Producing condensate to gas ratios for different well patterns of gas dumpflood from 2 PV source gas reservoir

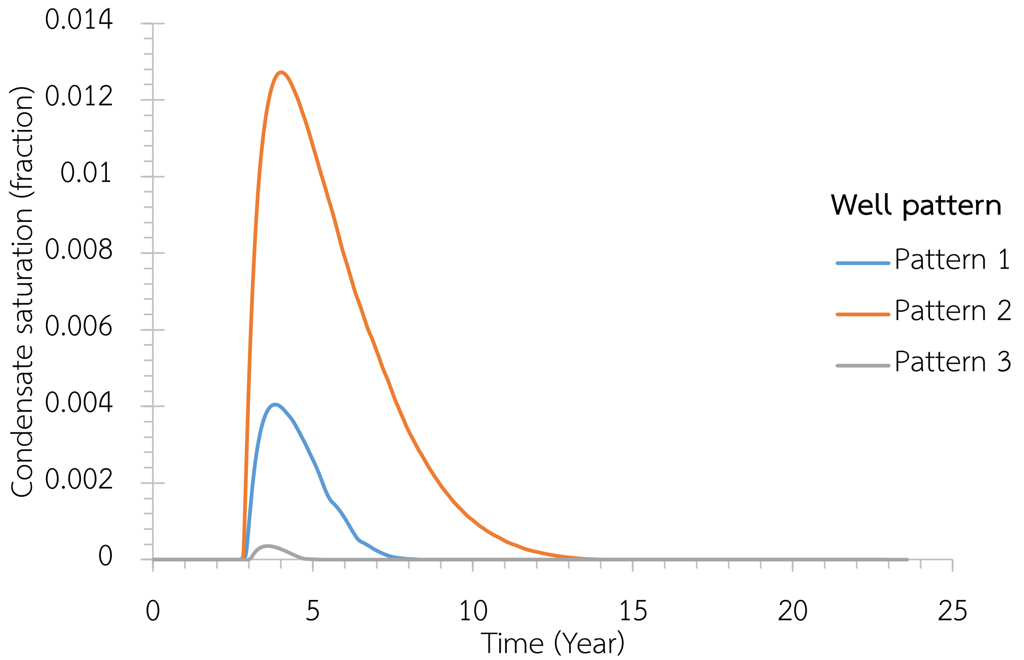


Figure 5.46 Average condensate saturation profiles for different well patterns of gas dumpflood from 2 PV source gas reservoir

Well pattern 2 has the highest condensate saturation as shown in Figure 5.46 due to the poor sweep efficiency. Once gas breakthrough occurs, the intermediate components will not be swept as the reservoir pressure is declining. These intermediate components will drop out inside the reservoir, resulting in the high condensate saturation.

Results for gas dumpflood from 2 PV source gas reservoir are summarized in Table 5.7. Both well patterns 1 and 2 have net hydrocarbon recovery factor more than 100% because the dumped gas revaporizes condensate into gas phase as indicated by the reduction of condensate saturation at later stage in Figure 5.46. Well pattern 3 gains the highest condensate recovery factor because pattern 3 has less condensate condensation inside the reservoir during the production as indicated by the lowest average oil saturation inside the reservoir during the production in Figure 5.46 and has high swept area. Even though the case with well pattern 3 has the lowest net cumulative hydrocarbon gas recovery factor, but it gains the highest cumulative condensate production which results in the highest total BOE recovery factor.

Table 5.7 Summarized results for different well patterns of gas dumpflood from 2 PV source gas reservoir

Parameter	Pattern 1	Pattern 2	Pattern 3
Cumulative condensate production (MMSTB)	1.095	1.030	1.193
Original condensate in place (MMSTB)	1.504	1.504	1.504
Condensate recovery factor (%)	72.83	68.47	79.30
Cumulative gas production (BCF)	46.605	46.591	46.318
Original gas in place (BCF)	11.539	11.539	11.539
Net cumulative HC gas production (BCF)	11.590	11.657	11.360
Net HC gas recovery factor (%)	100.45	101.02	98.45
Cumulative gas production (MMBOE)	3.407	3.469	3.440
Cumulative total BOE production (MMBOE)	4.503	4.498	4.633
Original BOE in place (MMBOE)	5.442	5.442	5.442
Total BOE recovery factor (%)	82.74	82.66	85.14
Cumulative cross flow(BCF)	35.665	35.587	31.942

The second part of gas dumpflood mainly discusses the effect of well pattern on condensate production. The well pattern was varied by three different well locations for different source gas reservoir sizes. Figure 5.47 show condensate recovery factor for different source gas reservoir sizes of gas dumpflood scenario. The distance between dumping wells and producer does significantly affect condensate recovery factor in the same manner as conventional gas injection scenario. Poor sweep efficiency which cause high gas production after breakthrough is still a problem in well pattern 2, resulting in low condensate recovery factor. Increasing source gas reservoir size does play an important role for gas dumpflood. Larger source gas reservoir provides higher condensate recovery factor since there is a large amount of gas to provide pressure support and revaporize the condensate in the reservoir.

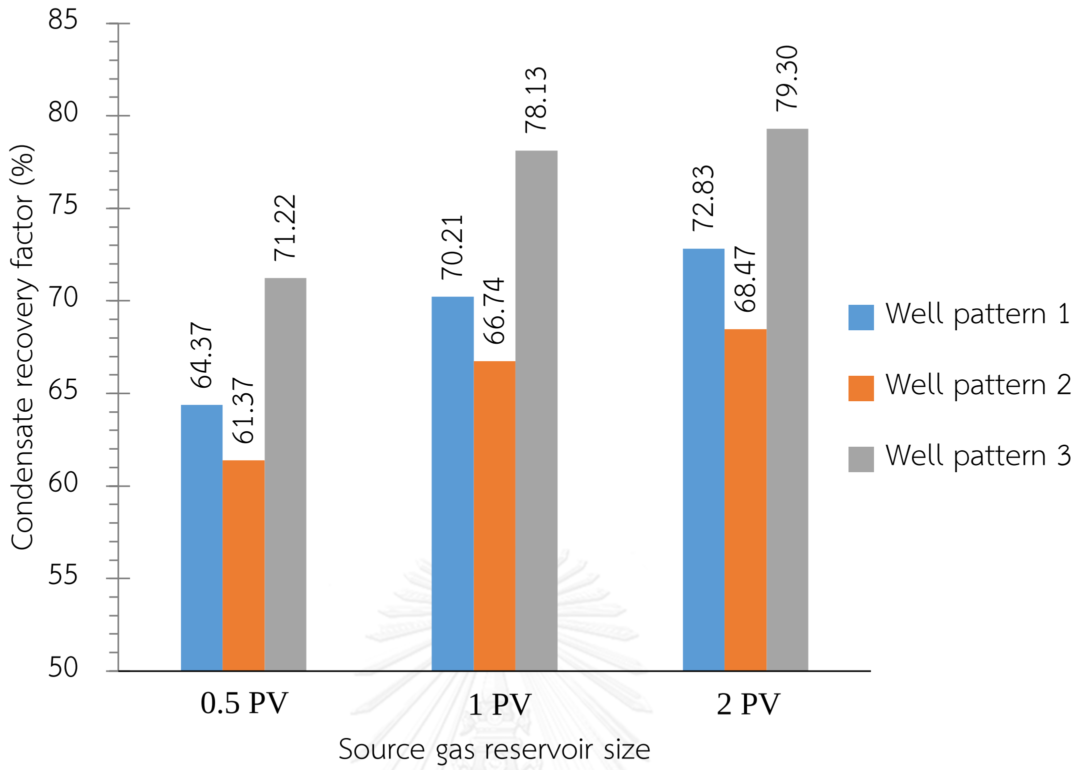


Figure 5.47 Condensate recovery factor for different source gas reservoir size of gas dumpflood scenario

5.4. Combined gas dumpflood with gas injection into gas condensate reservoir

In this scenario, the same gas condensate reservoir underlying with different gas different source gas reservoir sizes was studied. The source gas reservoir in this model contains high carbon dioxide content of 80% mole and the remaining is methane, the same composition as the injected gas in gas injection which is considered as uneconomically produced gas. The well location in this scenario was also varied by three different well patterns, similar to conventional gas injection and gas dumpflood scenario.

As for production schedule, the gas condensate reservoir was produced at a specific plateau rate of 10 MMscf/d with minimum well head pressure of 200 psia. The middle well was used as a producer while the other two were used as dumping/injection wells. Gas dumpflood operation was applied since the beginning of the production until the reservoir pressure reached the dewpotint pressure. Then, both dumping wells were converted into gas injection wells. For each source gas reservoir size and well pattern, the injection rate was varied from 1 to 2, 4, 6, 8, and 10 MMscf/d. The gas injection was performed as long as the condensate production rate is higher than 10 stb/d. The injection wells were shut after condensate production is lower than 10 stb/d while the gas and condensate were still produced at the production well. The abandonment condition for the producer is the gas production rate of 500 Mscf/d.

In order to determine the optimal case for combined gas dumpflood with gas injection, the studied parameter are divided as follows:

1. Reservoir parameter which is source gas reservoir size:
    - 0.5 PV
    - Approximately 1PV
    - Approximately 2 PV
2. Operating parameters which are
    2.1 Gas injection rate:
    - 1 MMscf/d
    - 2 MMscf/d
    - 4 MMscf/d

- 6 MMscf/d
- 8 MMscf/d
- 10 MMscf/d

2.2 Well location:

- Well pattern 1
- Well pattern 2
- Well pattern 3

Effects of both reservoir and operating parameters for each source gas reservoir size are separately discussed in Section 5.4.1, 5.4.2, and 5.4.3 for 0.5 PV, 1PV, and 2 PV, respectively. Sections 5.4.1 to 5.4.3 have three subsections for well pattern 1, 2, and 3, respectively. Effects of different gas injection rates are described in each subsection.

5.4.1. Combined gas dumpflood from 0.5 PV source gas reservoir with gas injection

5.4.1.1. Combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 1

In order to investigate the effect of gas injection rate on condensate production performance in combined gas dumpflood from 0.5 PV source gas reservoir with gas injection, the gas injection rate was varied from 1 to 10 MMscf/d, similar to conventional gas injection scenario. For this case, gas production rate can be maintained at the plateau rate of 10 MMscf/d throughout the dumpflood operation. Figure 5.48 shows the dumped gas rate from 0.5 PV source gas reservoir with well pattern 1. All cases follow the same curve because the operation during gas dumpflood is the same for all cases. The maximum flow rate for the field is 173.8 MMscf/d (86.9 MMscf/d for each well). Gas from the underlying reservoir keeps flowing to maintain gas condensate reservoir pressure for about 330 days of production. Then, dumping wells were converted to injectors, and conventional gas injection was used to maintain the reservoir pressure. Gas production rate shown in Figure 5.49 is constant at 10 MMscf/d for a certain period before it declines. For low injection rates including 1, 2, 4 MMscf/d, there are two decline trends, similar to the ones in conventional gas injection. The first decline is from stopping gas injection when condensate production is lower than 10 stb/d, and the second decline is from insufficient pressure support. For high injection rates, there is only one decline trend from stopping gas injection. Figure 5.50 demonstrates the cumulative condensate production during combined gas dumpflood with gas injection from 0.5 PV source gas reservoir for well pattern 1.

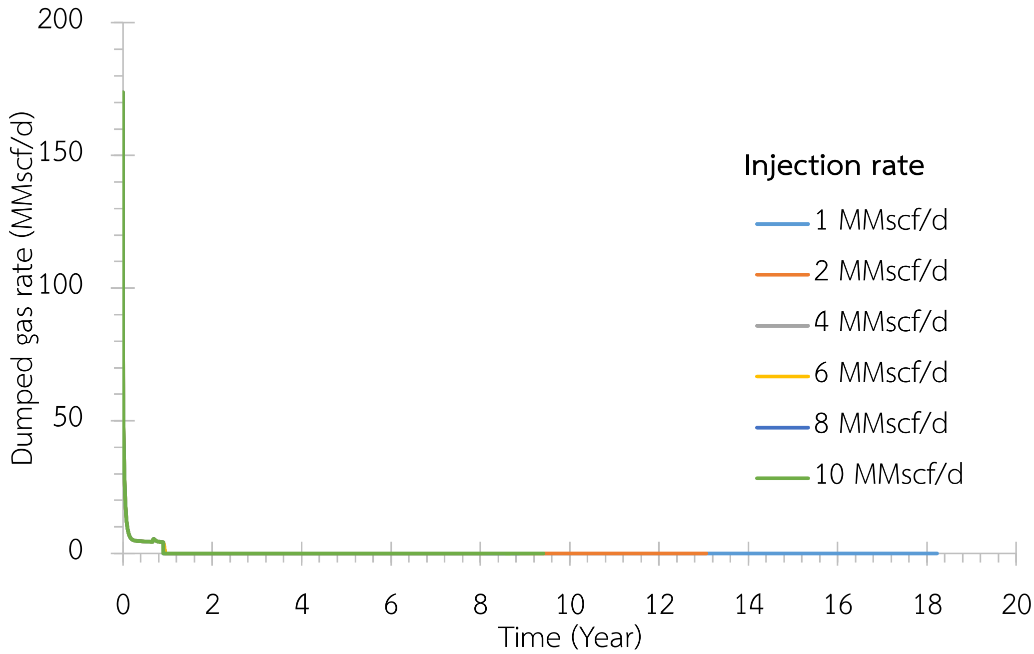


Figure 5.48 Cross flow rate for different gas injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 1

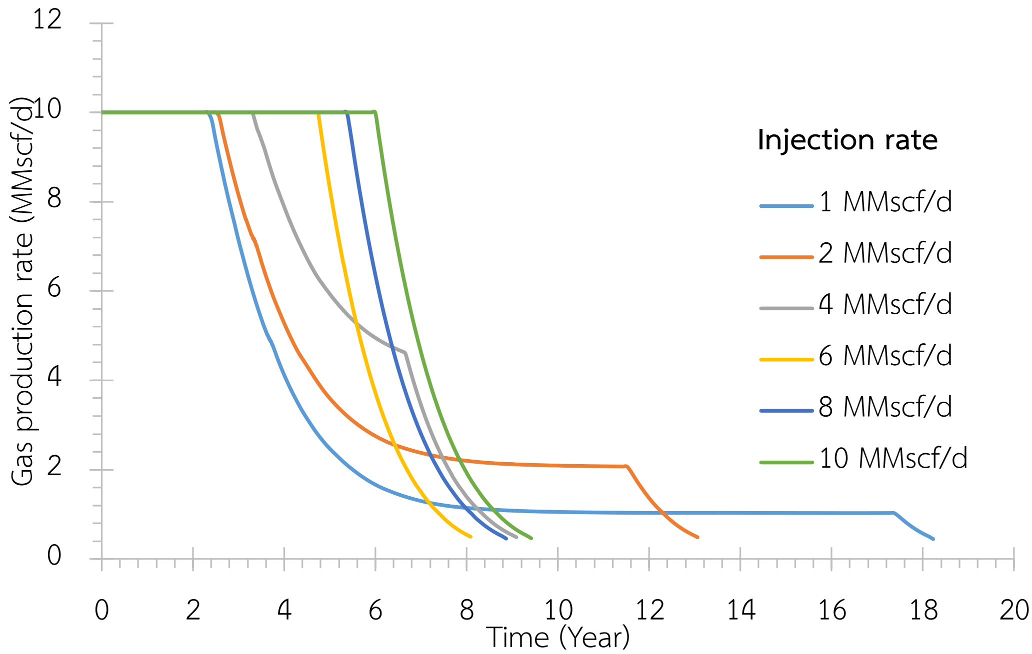


Figure 5.49 Field gas production profiles for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 1

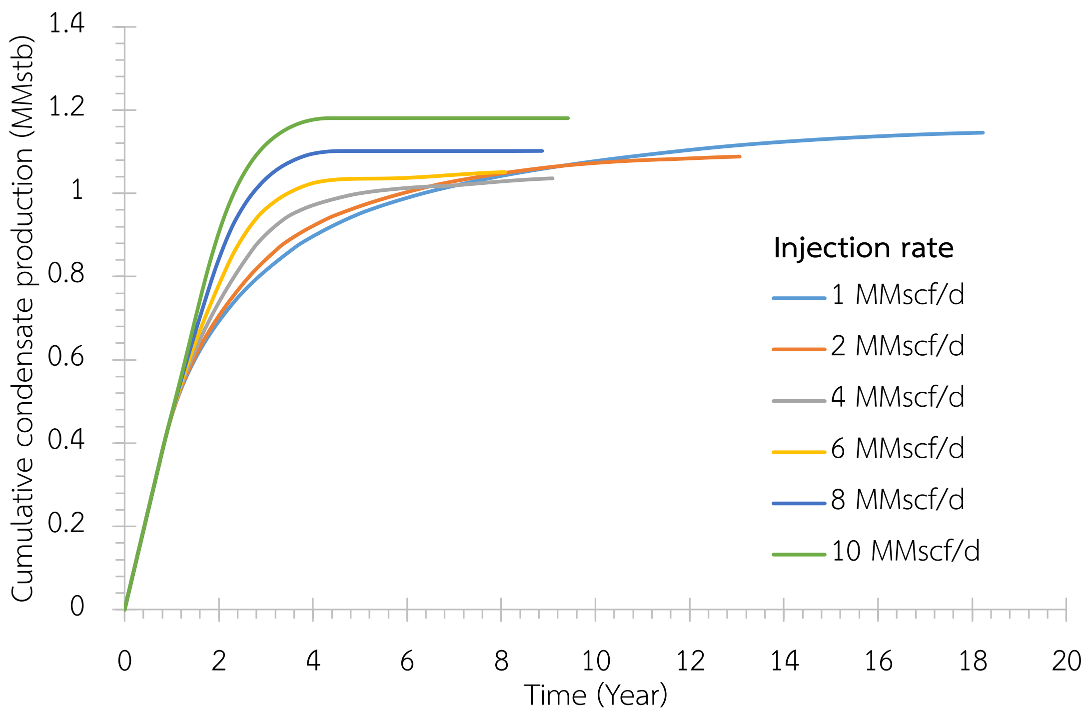


Figure 5.50 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 0.5 PV source gas with gas injection reservoir for well pattern 1

From Figure 5.50, gas injection rate of 10 MMscf/d earns the highest cumulative condensate production because this injection rate can support the reservoir pressure above the dewpoint pressure which is indicated by the lowest of condensate saturation at the end of production life as seen in Figure 5.51. Cumulative condensate production increases as the gas injection rate is increased from 4 to 10 MMscf/d. For injection rates of 1 and 2 MMscf/d, the condensate production increases as the gas injection rate is decreased. The injection rate of 1 MMscf/d can recover less condensate at early time due to poor ability to maintain the reservoir pressure above the dewpoint, resulting in condensate condensation in the reservoir but the large amount of carbon dioxide in the injected gas mixes with reservoir fluids and lowers the dewpoint pressure, initiating condensate revaporization and resulting in more condensate production at late time. Even though gas injection rate of 1 MMscf/d has higher condensate production than injection rate of 2, 4, 6, and 8 MMscf/d, it requires longer production period.

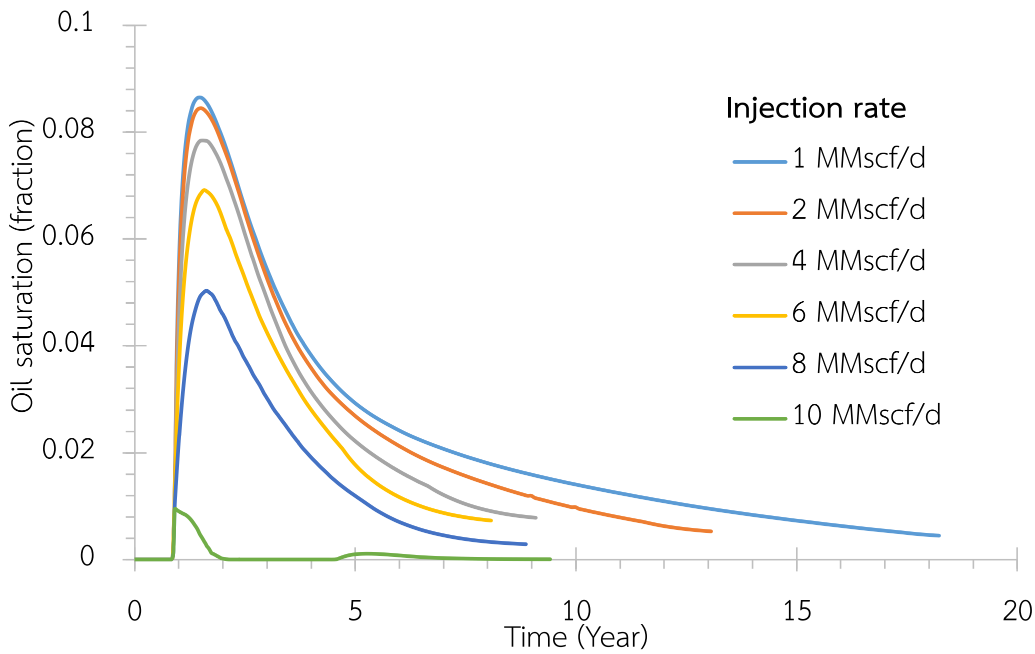


Figure 5.51 Average condensate saturation profiles for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection with well pattern 1

Results for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 1 are summarized in Table 5.8. All cases show the same cumulative gas flow from an underlying source gas reservoir to the gas condensate reservoir since the condition for stopping gas dumpflood is the same (reservoir pressure is below the dewpoint pressure). There are two cases that yield net hydrocarbon gas recovery factor lower than 100 % which are the case with injection rate of 1 and 4 MMscf/d while the other cases yield net cumulative hydrocarbon gas recovery factor more than 100 % as a result of drying effect. The total BOE recovery factor has a similar trend with cumulative condensate production. Total BOE recovery factor decreases as the gas injection rate is increased from 1 to 4 MMscf/d and increases as gas injection rate is increased from 6 to 10 MMscf/d. The cumulative gas injection depends on the gas injection rate.

Table 5.8 Summarized results for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 1

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.056	0.993	0.968	0.989	1.049	1.127
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	70.18	66.02	64.36	65.74	69.71	74.89
Cumulative gas production (bcf)	17.360	18.114	18.141	19.536	21.332	23.291
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.507	11.538	11.506	11.545	11.563	11.542
Net hydrocarbon gas recovery factor (%)	99.73	100.00	99.71	100.05	100.21	100.03
Cumulative gas production (MMBOE)	3.321	3.351	3.339	3.375	3.386	3.368
Cumulative total BOE production (MMBOE)	4.376	4.345	4.308	4.364	4.435	4.495
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	80.41	79.83	79.15	80.18	81.49	82.59
Cumulative gas injection(bcf)	4.158	4.871	4.903	6.263	8.064	10.066
Cumulative cross flow(bcf)	2.314	2.314	2.314	2.314	2.314	2.314

5.4.1.2. Combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 2

In this case, gas dumpflood from 0.5 PV source gas reservoir was initiated at the beginning of the production and then followed by conventional gas injection with rate varied from 1, 2, 4, 6, 8, 10 MMscf/d using well pattern 2. The cumulative condensate production profile is shown in Figure 5.52. At early time, cumulative condensate productions follow the same trend for different gas injection rates since there is the same amount of gas flowing from 0.5 PV from underlying dry gas reservoir to the gas condensate reservoir. For this well pattern, injection rates of 2, 4, 6, and 8 MMscf/d yield cumulative condensate production lower than 1 MMstb because gas breakthrough occurs early, resulting in low condensate production at late time. The case with gas injection rate of 10 MMscf/d provides the highest condensate production because this injection rate can support the reservoir pressure higher than the dewpoint pressure for the longest period as seen in Figure 5.53.

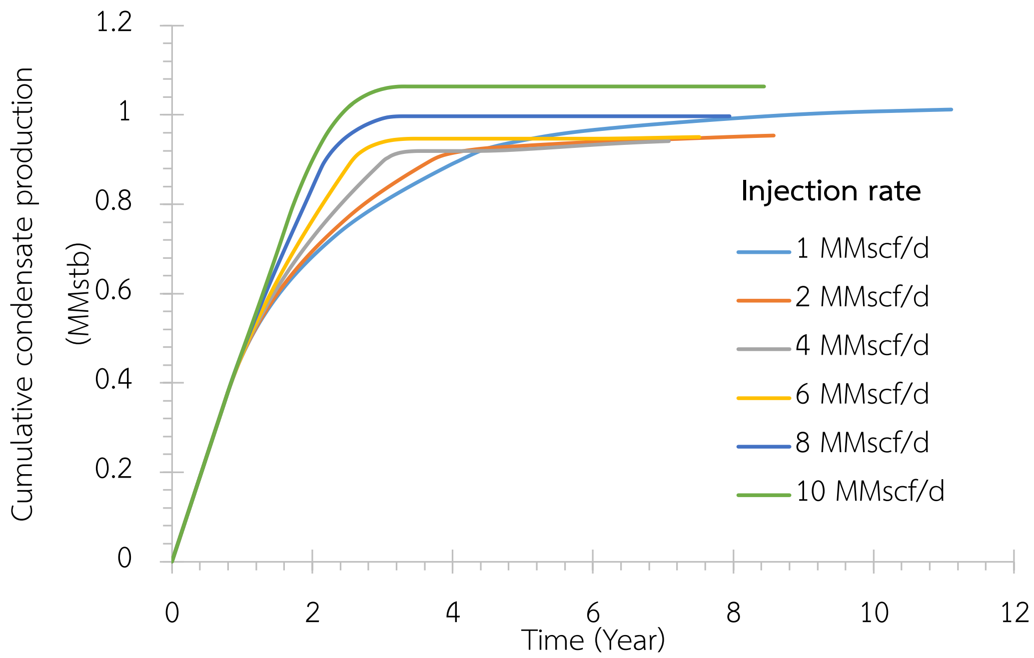


Figure 5.52 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 2

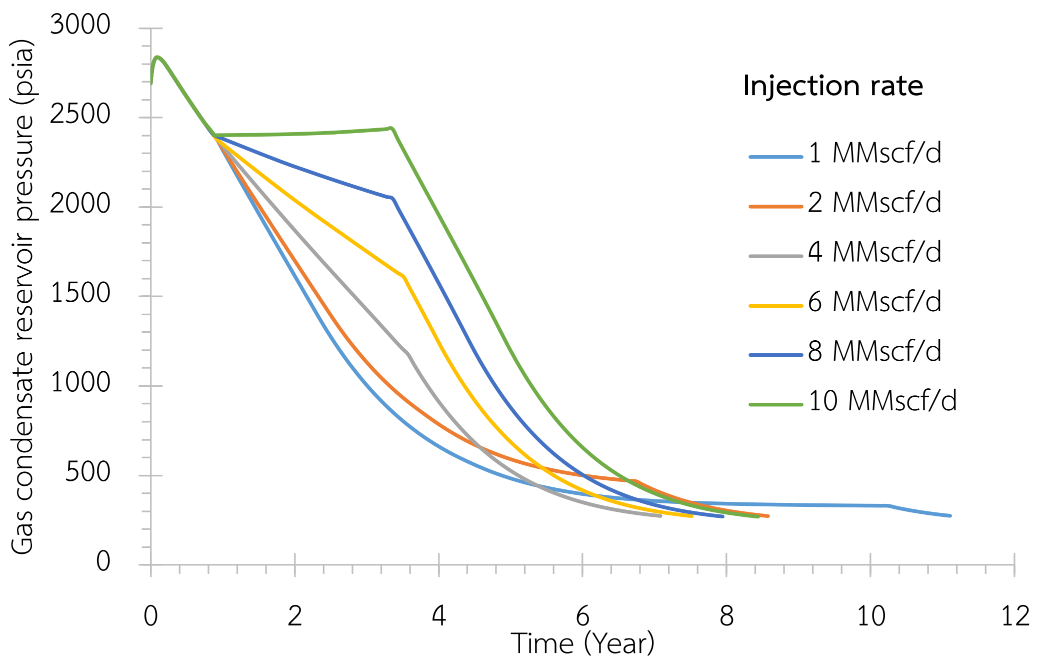


Figure 5.53 Gas condensate reservoir pressure for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 2

Figure 5.53 illustrates the gas condensate reservoir pressure for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 2. At early time, the gas condensate reservoir pressure increases a little due to dumpflood from higher pressure of underlying source gas reservoir. Then, the pressure declines as a result of production until the dewpoint pressure is reached. For 10 MMscf/d injection rate, it has high injection pressure, resulting in better ability to maintain the reservoir pressure higher than the dewpoint pressure. Bottomhole pressure is the location where it has the lowest pressure inside the reservoir when reservoir pressure is at the dewpoint the bottomhole pressure of producer is less than the dewpoint, this allow condensate to drop out around the producer. Once the condensate liquid accumulate around the producer, it required higher pressure to pressurize condensate back into gas phase, resulting in slightly increase in average reservoir pressure for the case with gas injection rate of 10 MMscf/d

Note that the trigger condition for stop gas dumpflood and start gas injection is average reservoir pressure at 2402.35 psia which is dewpoint pressure.

Table 5.9 Summarized results for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 2

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.012	0.954	0.941	0.951	0.997	1.064
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	67.27	63.40	62.57	63.19	66.28	70.70
Cumulative gas production (bcf)	16.534	17.432	17.033	18.886	20.417	22.213
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.442	11.463	11.342	11.414	11.431	11.466
Net hydrocarbon gas recovery factor (%)	99.16	99.35	98.30	98.92	99.07	99.37
Cumulative gas production (MMBOE)	3.272	3.305	3.254	3.309	3.319	3.338
Cumulative total BOE production (MMBOE)	4.284	4.258	4.196	4.259	4.316	4.402
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	78.72	78.25	77.10	78.27	79.30	80.88
Cumulative gas injection(bcf)	3.409	4.258	3.889	5.703	7.255	9.016
Cumulative cross flow(bcf)	2.278	2.278	2.278	2.278	2.278	2.278

Summary of results for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 2 is shown in Table 5.9. Condensate recovery for this case has the same trend with the one obtained from the case with 0.5 PV source gas reservoir for well pattern 1 case. All cases show similar net cumulative hydrocarbon gas recovery around 99%. The total BOE recovery factor follows the trend with cumulative condensate production. Although cumulative gas injection depends on gas injection rate, the case with injection rate of 4 MMscf/d has less cumulative gas injection than the case with injection rate of 2 MMscf/d because gas injection is stopped early due to gas breakthrough. When gas breakthrough occurs, condensate production abruptly drops. Thus, gas injection is stopped due to low condensate production rate.

5.4.1.3. Combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 3

In the same manner with the previously two well patterns, gas dumpflood operation is performed at the begining. Once the gas condensate reservoir pressure reaches the dewpoint pressure, dumping wells are shut and then converted to gas injection wells. The injection rate was varied from 1 to 10 MMscf/d. Figure 5.54 shows cumulative condensate production profiles for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 3. In this case, the injection rate of 4 MMscf/d recovers the lowest condensate production. The reason is the poor ability to maintain the reservoir pressure and early gas breakthrough. Once gas breaks through the producer, condensate production becomes low and reaches the condition for the injector to stop injecting, resulting in the highest remaining condensate saturation at the abandonment condition for producer as illustrated in Figure 5.55.

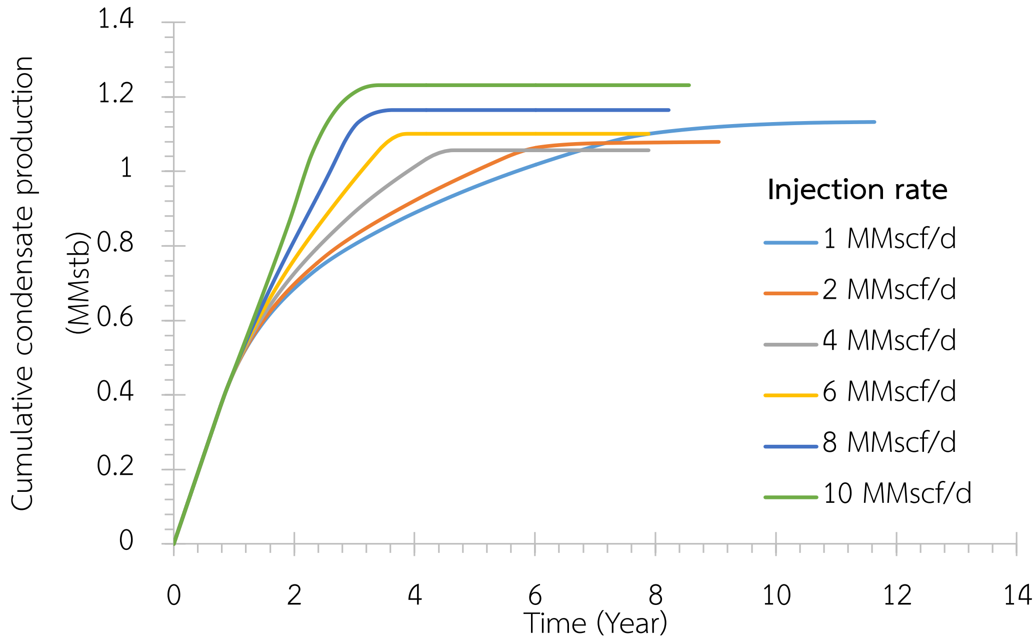


Figure 5.54 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 3

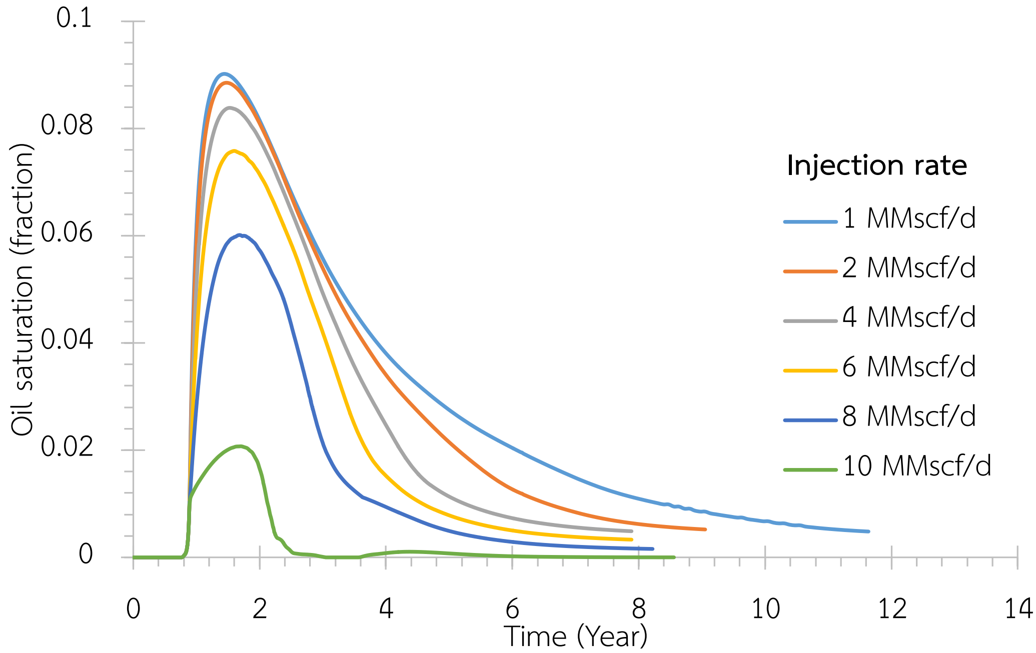


Figure 5.55 Condensate saturation profiles for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 3

Table 5.10 Summarized results for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 3

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.133	1.079	1.057	1.101	1.165	1.231
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	75.28	71.73	70.24	73.17	77.41	81.85
Cumulative gas production (bcf)	16.649	17.641	18.648	19.724	21.084	22.238
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.470	11.515	11.538	11.512	11.475	11.438
Net hydrocarbon gas recovery factor (%)	99.41	99.80	99.99	99.77	99.45	99.12
Cumulative gas production (MMBOE)	3.288	3.331	3.357	3.339	3.309	3.275
Cumulative total BOE production (MMBOE)	4.421	4.410	4.413	4.440	4.474	4.507
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	81.22	81.03	81.09	81.59	82.20	82.81
Cumulative gas injection(bcf)	3.562	4.503	5.472	6.576	7.984	9.180
Cumulative cross flow(bcf)	2.263	2.263	2.263	2.263	2.263	2.263

Table 5.10 shows summarized results for different injection rates of combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for well pattern 3. In this case, all injection rates have cumulative condensate production greater than 1 MMstb because this well pattern provides more swept area than the other two, and gas breakthrough is delayed due to longer distance between producer and dumping/injection wells. All cases gain net cumulative hydrocarbon gas recovery factor around 99%. The total BOE recovery factor has similar trend with the cumulative condensate production. The highest total BOE recovery factor can reach up to 82.81%

in case of gas dumpflood from 0.5 PV source gas reservoir with injection rate of 10 MMscf/d. The amount of injected gas required again depends on gas injection rate used during the injection phase.

5.4.2. Combined gas dumpflood from 1 PV source gas reservoir with gas injection

5.4.2.1. Combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 1

In this case, gas dumpflood from 1 PV source gas reservoir was implemented through two dumping wells at the beginning of the production. Then, gas dumping wells were shut and converted to gas injection wells when the gas condensate reservoir pressure is below the dewpoint pressure. During conventional gas injection operation, gas injection rate was varied from 1 to 2, 4, 6, 8, 10 MMscf/d.

Figure 5.57 demonstrates field gas production rate from combined gas dumpflood from 1 PV source gas with different gas injection rates. The case with injection rate of 1 MMscf/d has two decline trends from insufficient pressure support and stopping gas injection while the others have only one decline trend from stopping gas injection when the condensate production rate is lower than 10 stb/d. Cumulative condensate production for different gas injection rates are shown in Figure 5.58. At early time, all cases follow the same trend during dumpflood operation because the same dumped gas flows into the gas condensate reservoir. At abandonment condition for producer, cumulative condensate productions are slightly different for different gas injection rates. The injection rate of 10 MMscf/d yields the highest condensate production because it has better ability to maintain the reservoir pressure above the dewpoint as indicated by the reduction of oil saturation after dumpflood operation shown in Figure 5.59.

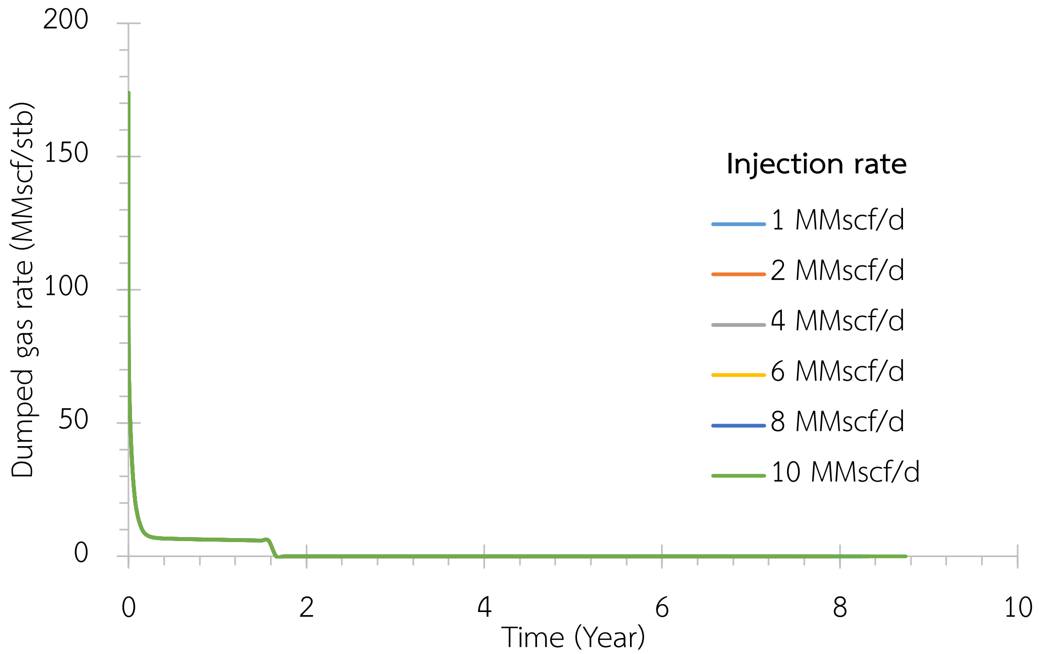


Figure 5.56 Cross flow rate for different gas injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 1

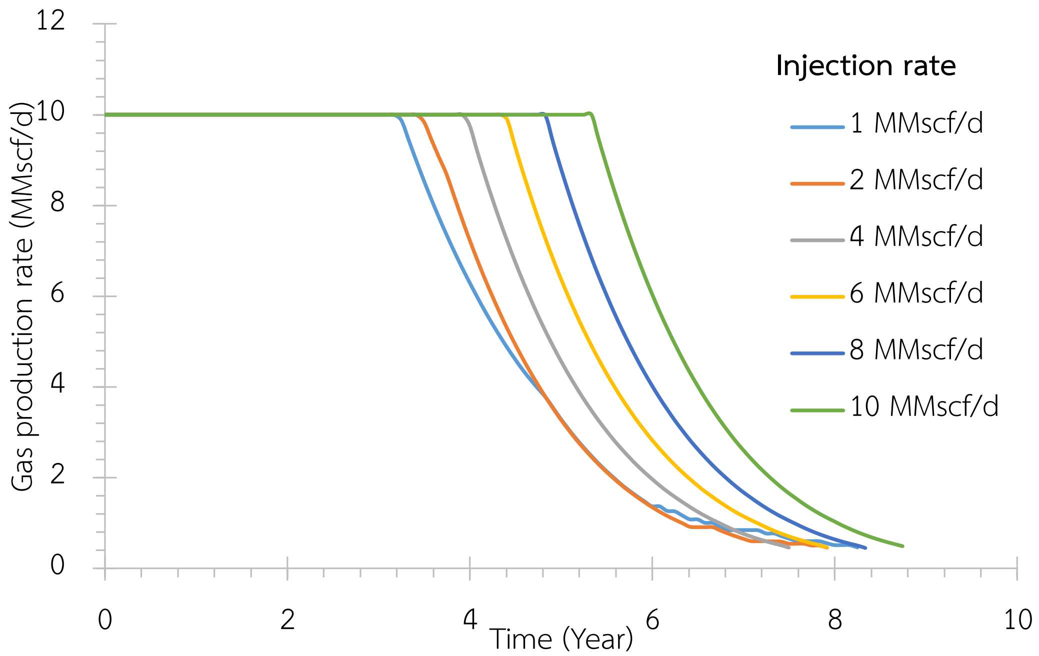


Figure 5.57 Field gas production profiles for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 1

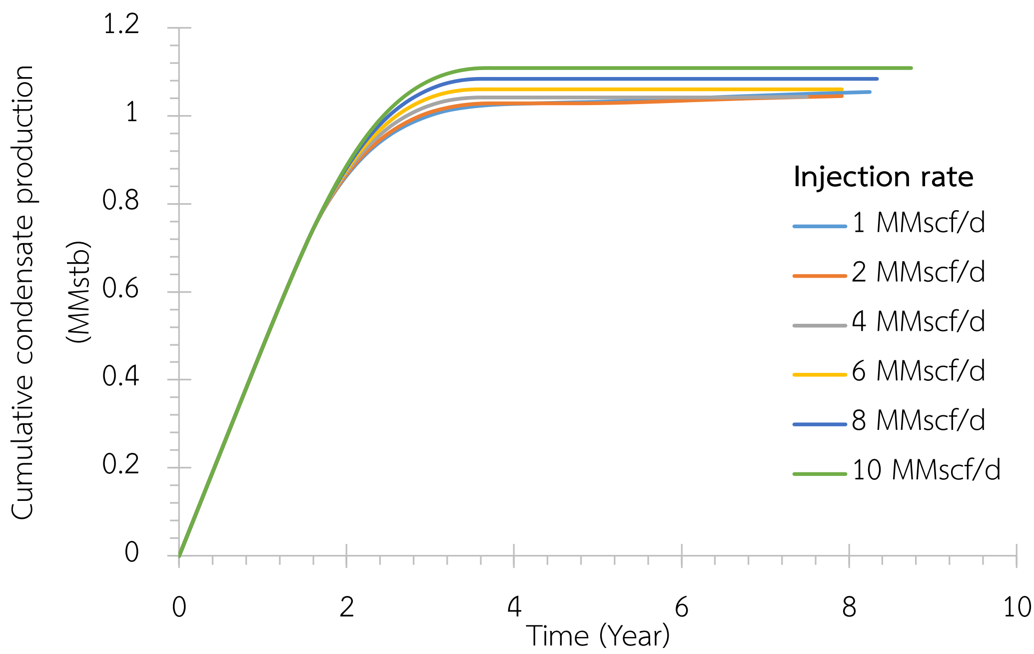


Figure 5.58 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 1

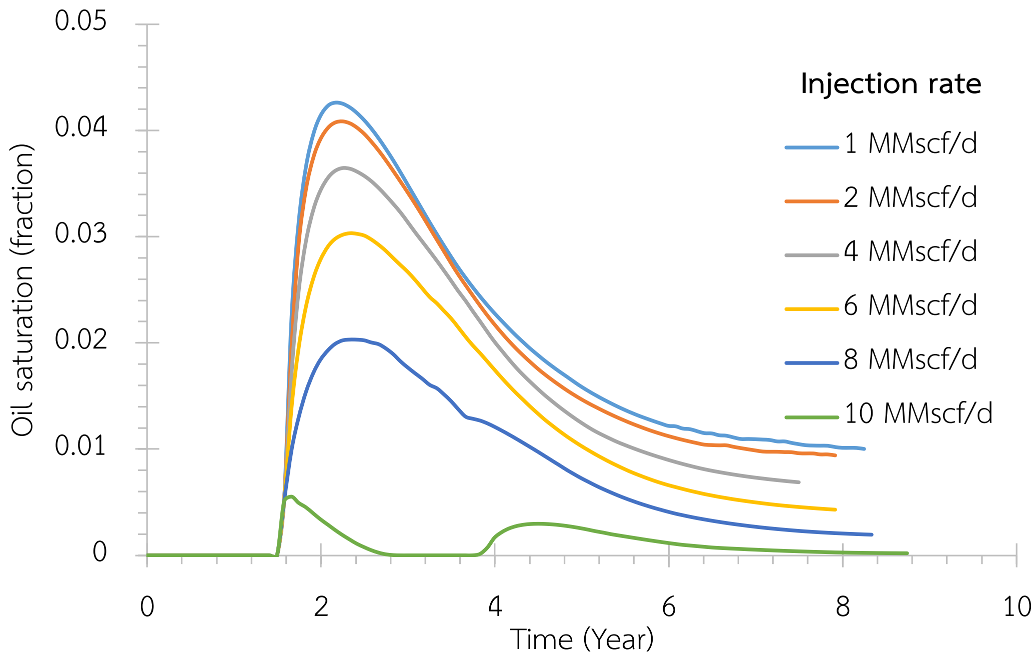


Figure 5.59 Average Condensate saturation profiles for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 1

Summary of results for different gas injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 1 is shown in Table 5.11. The highest condensate production can be recovered at 1.108 MMstb from the case with injection rate of 10 MMscf/d which is the case with high ability to maintain the reservoir pressure above the dewpoint. There are two cases yieldind the net hydrocarbon gas recovery factor more than 100 % which are the injection rate of 8 and 10 MMScf/d. The total BOE recovery factor has the same trend with cumulative condensate production which decreases when injection rate is increased from 1 to 2 MMscf/d and increases when injection rate is increased from 4 to 10 MMScf/d. The cumulative gas injection for this case is depend on the gas injection rate. Higher gas injection rate require larger amount of injected gas.

Table 5.11 Summarized results for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 1

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.054	1.045	1.043	1.060	1.084	1.108
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	70.05	69.43	69.33	70.46	72.04	73.67
Cumulative gas production (bcf)	17.106	17.373	18.685	20.232	21.769	23.576
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.507	11.467	11.469	11.515	11.543	11.555
Net hydrocarbon gas recovery factor (%)	99.73	99.38	99.40	99.80	100.04	100.14
Cumulative gas production (MMBOE)	3.299	3.298	3.324	3.355	3.374	3.384
Cumulative total BOE production (MMBOE)	4.353	4.343	4.368	4.415	4.458	4.492
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	79.99	79.80	80.25	81.12	81.91	82.54
Cumulative gas injection(bcf)	1.188	1.584	3.050	4.575	6.099	7.918
Cumulative cross flow(bcf)	4.725	4.725	4.725	4.725	4.725	4.725

5.4.2.2. Combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 2

In this case, gas from 1 PV source gas was flowed from underlying gas reservoir to the gas condensate reservoir to maintain the reservoir pressure since the start of production until the reservoir pressure reached the dewpoint pressure. Subsequently dumping wells were shut and converted to the gas injection wells. Gas injection operation was performed as long as the condensate production rate is more than 10 stb/d. Figure 5.60 shows cumulative condensate production from combined gas dumpflood from 1 PV source gas reservoir with different gas injection rates for well pattern 2. Condensate productions for all cases follow the same curve during dumpflood operation because the operation during gas dumpflood is the same for all cases but slightly different values are obtained during gas injection operation. The injection rate of 10 MMscf/d can recover the highest condensate production because it has better ability to maintain the gas condensate reservoir pressure higher than the dewpoint after gas dumpflood operation as shown in Figure 5.61.

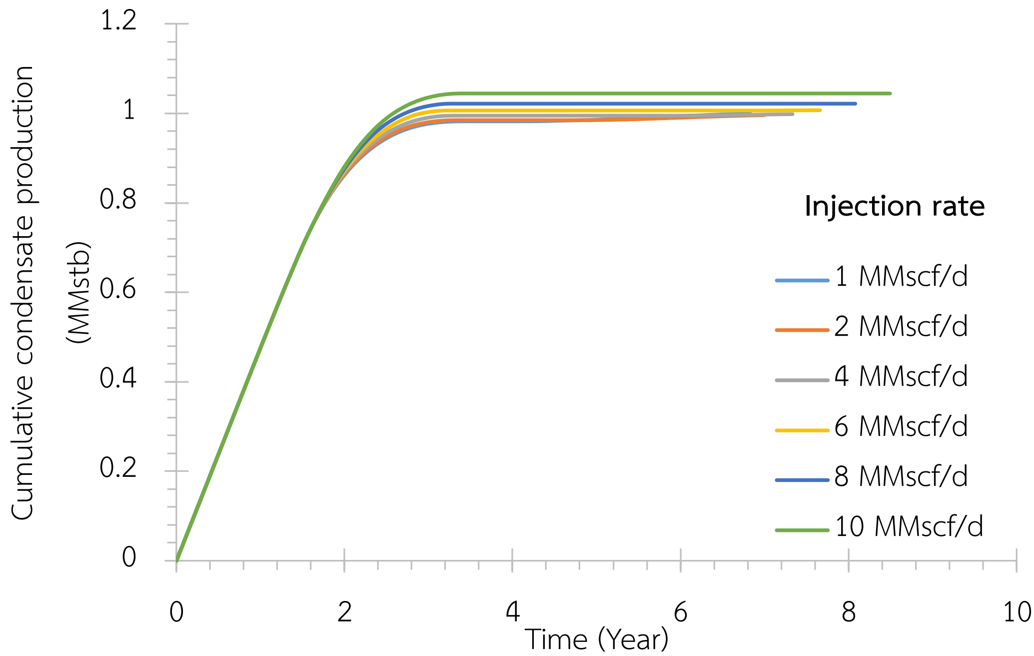


Figure 5.60 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 2

Results for different gas injection rates of combined gas dunpflood from 1 PV source gas with gas injection for well pattern 2 are summarized in Table 5.12. Cumulative condensate production in this case decreases as gas injection rate is increased from 1 to 2 MMscf/d and increases as gas injection rate is increased from 4 to 10 MMscf/d. The net hydrocarbon gas recovery factor, total BOE recovery factor, and cumulative gas injection depend on the gas injection rate. The case with injection rate of 10 MMscf/d yields the highest value in terms of condensate production, net hydrocarbon gas production, total BOE recovery factor and uses the largest cumulative gas injection.

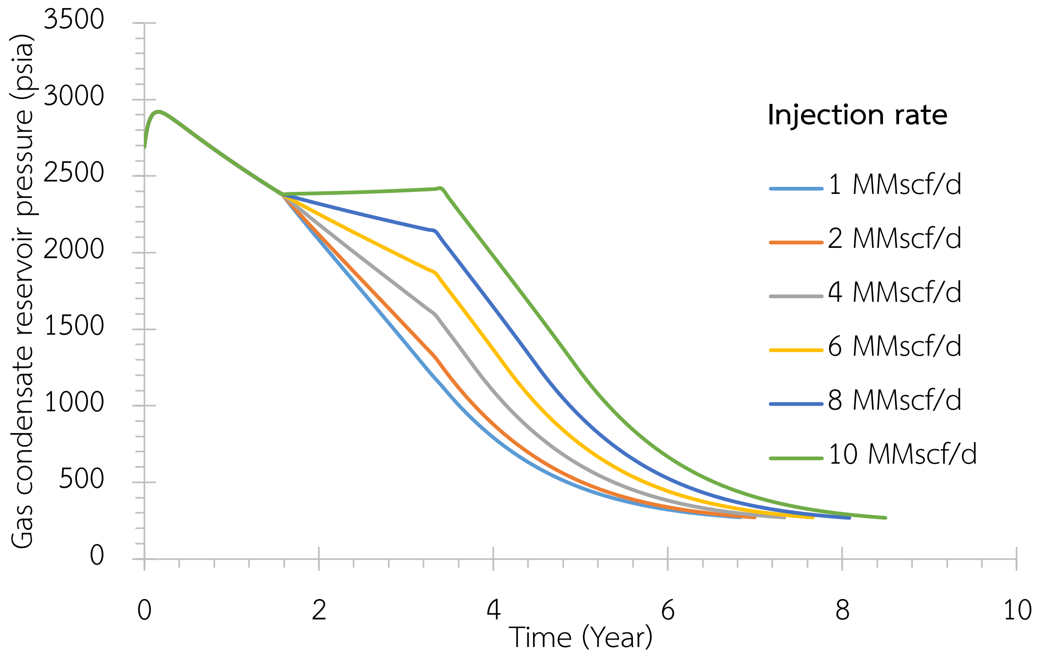


Figure 5.61 Gas condensate reservoir pressure for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 2

Table 5.12 Summarized results for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 2

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.000	0.996	0.998	1.007	1.022	1.045
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	66.43	66.21	66.35	66.94	67.91	69.43
Cumulative gas production (bcf)	16.164	16.800	18.117	19.423	20.740	22.325
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.237	11.278	11.340	11.384	11.425	11.476
Net hydrocarbon gas recovery factor (%)	97.39	97.74	98.28	98.66	99.02	99.45
Cumulative gas production (MMBOE)	3.197	3.222	3.261	3.289	3.315	3.350
Cumulative total BOE production (MMBOE)	4.196	4.218	4.259	4.296	4.337	4.395
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	77.10	77.50	78.25	78.94	79.69	80.75
Cumulative gas injection(bcf)	0.670	1.286	2.571	3.857	5.142	6.702
Cumulative cross flow(bcf)	4.675	4.675	4.675	4.675	4.675	4.675

5.4.2.3. Combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 3

In the same manner with the previous two well patterns, gas dumpflood was performed since the beginning of production. When the reservoir reached the dewpoint, gas dumpflood was stopped and dumping wells were converted to gas injection wells with different gas injection rates. Gas injection rate was varied from 1 to 2, 4, 6, 8, and 10 MMscf/d. Figure 5.62 illustrates the cumulative condensate production for combined gas dumpflood from 1 PV source gas reservoir with different gas injection rates for well pattern 3. In this case, cumulative condensate production depends on the gas injection rate. Lower injection has less ability to maintain the reservoir pressure above the dewpoint, resulting in less condensate production and higher amount if remaining oil left inside the reservoir at abandonment condition for the producer as indicated by the condensate saturation shown in Figure 5.63. There is slightly increment of average oil saturation for the case with injection rate of 8 and 10 MMscf/d around 3.5 years after production due to the fact that gas injection is stopped as a result of condensate production rate is less than 10 stb/b. Once the gas injection is stopped reservoir pressure is sharply declined and allow condensate to drop out, resulting in small increment of condensate saturation after 3.5 years of production.

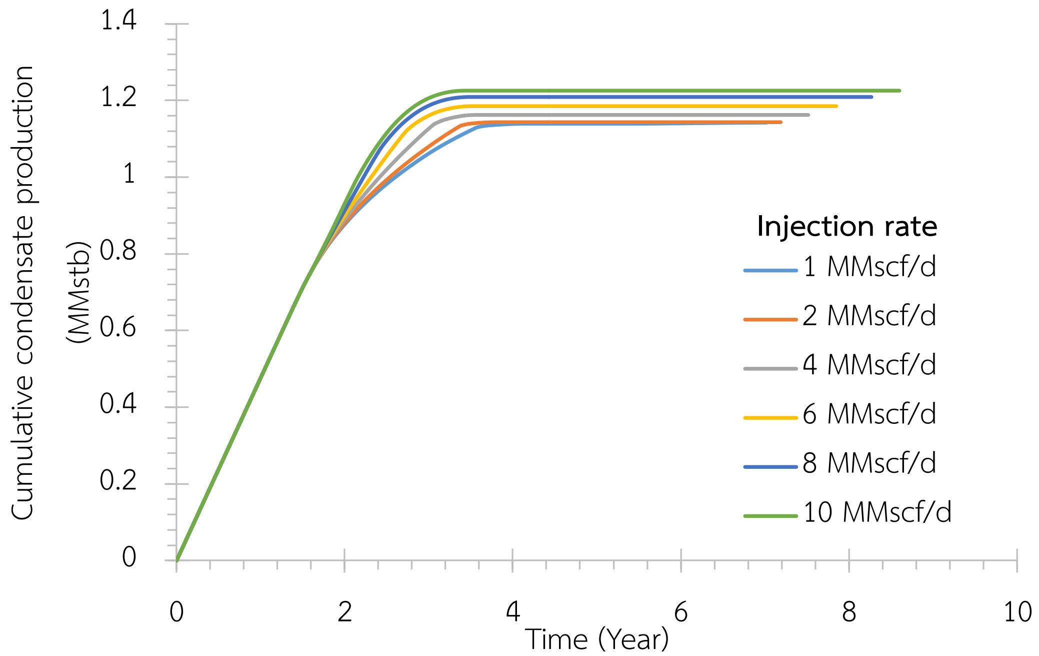


Figure 5.62 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 3

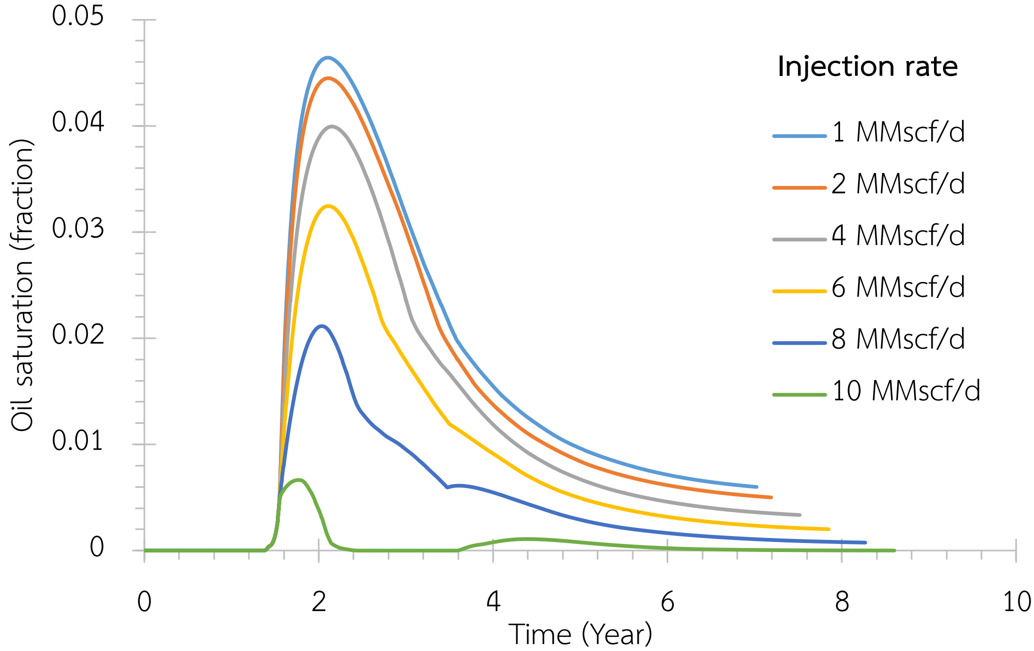


Figure 5.63 Average condensate saturation profiles for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 3

Table 5.13 summarizes results for different gas injection rates of combined gas dumpflood from 1 PV source gas with gas injection for well pattern 3. In this case, cumulative condensate production does go into the same direction with gas injection rate. The highest condensate production at 1.22 MMstb can be recovered by the injection rate of 10 MMscf/d. All cases can recover net cumulative hydrocarbon gas approximately 99 %. The total BOE recovery factor increases as the gas injection rate is increased. And the total gas required into inject to the reservoir after the gas dumpflood operation clearly depends on the gas injection rate. The cumulative cross flow is the same with different gas injection rates due to the same condition for starting and stopping gas dumpflood operation.

Table 5.13 Summarized results for different injection rates of combined gas dumpflood from 1 PV source gas reservoir with gas injection for well pattern 3

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.142	1.143	1.162	1.185	1.209	1.226
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	75.93	76.00	77.25	78.78	80.37	81.47
Cumulative gas production (bcf)	16.378	17.093	18.385	19.727	21.076	22.304
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.388	11.412	11.433	11.437	11.440	11.441
Net hydrocarbon gas recovery factor (%)	98.69	98.91	99.08	99.12	99.14	99.15
Cumulative gas production (MMBOE)	3.248	3.266	3.278	3.281	3.280	3.280
Cumulative total BOE production (MMBOE)	4.391	4.409	4.440	4.466	4.490	4.506
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	80.67	81.02	81.59	82.07	82.49	82.80
Cumulative gas injection(bcf)	0.929	1.622	2.912	4.266	5.616	6.850
Cumulative cross flow(bcf)	4.665	4.665	4.665	4.665	4.665	4.665

5.4.3. Combined gas dumpflood from 2 PV source gas reservoir with gas injection

5.4.3.1. Combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 1

In this case, the gas injection rate was varied from 1 to 10 MMscf/d in order to study the effect of gas injection rate on condensate production performance in combined gas dumpflood from 2 PV source gas reservoir, similar to conventional gas injection scenario. For this case, gas production rate can be maintained at 10 MMscf/d for approximately 5 to 6 years before it declines as depicted in Figure 5.64. All cases have only one decline trend from stopping gas injection. Gas injection was performed just for about one year and stopped as shown in Figure 5.65 due to the fact that condensate production rate is less than 10 stb/d. Higher gas injection rate seems to cause injection to stop earlier due to early gas breakthrough as indicated by the reduction of producing condensate to gas ratios at the producer shown in Figure 5.66. Once gas breaks through the producer, condensate production rate drastically drops and become less than 10 stb/d, resulting in the condition to stop gas injection.

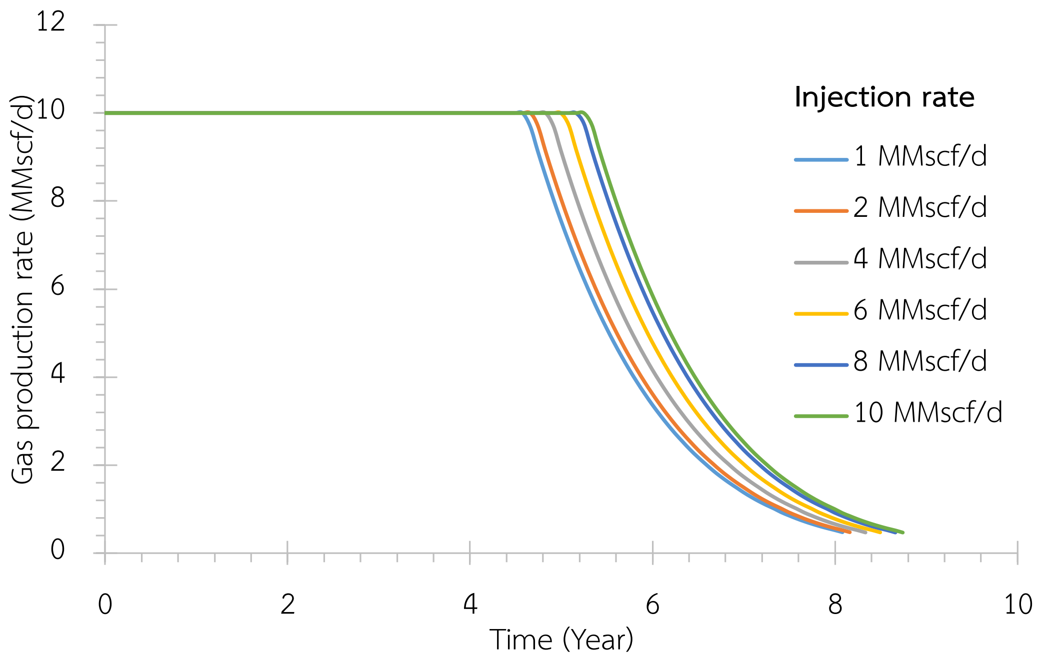


Figure 5.64 Field gas production profiles for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern

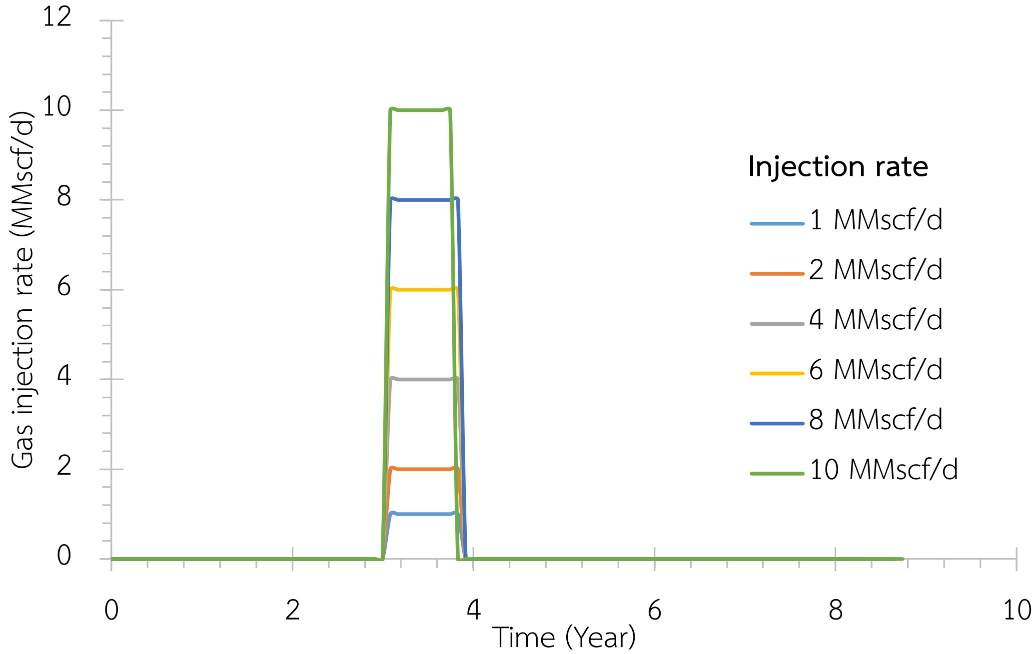


Figure 5.65 Field gas injection profiles for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 1

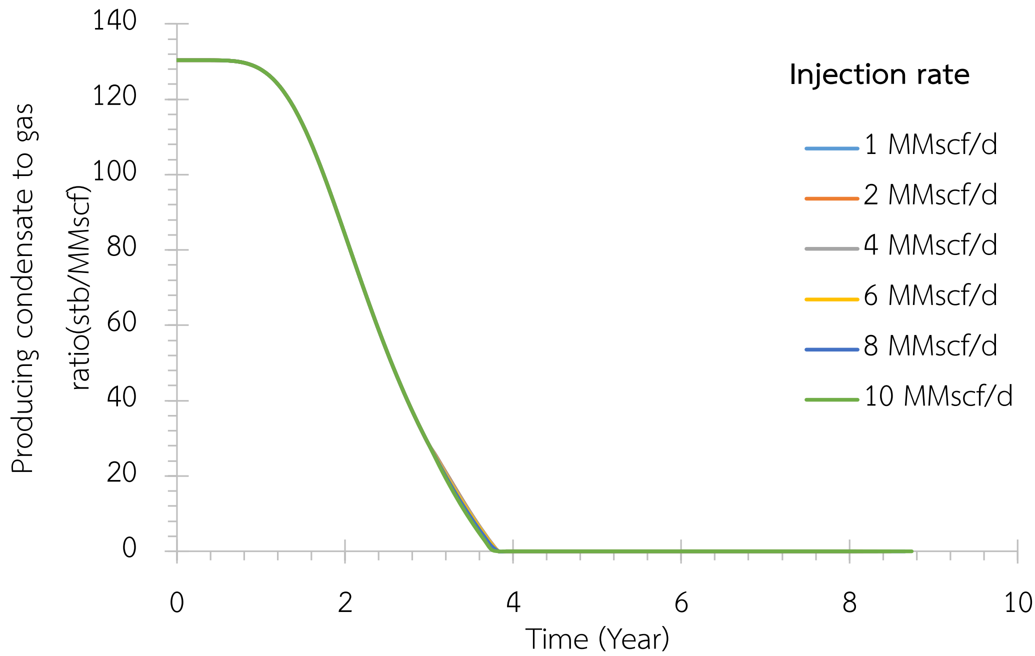


Figure 5.66 Producing condensate to gas ratios for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 1

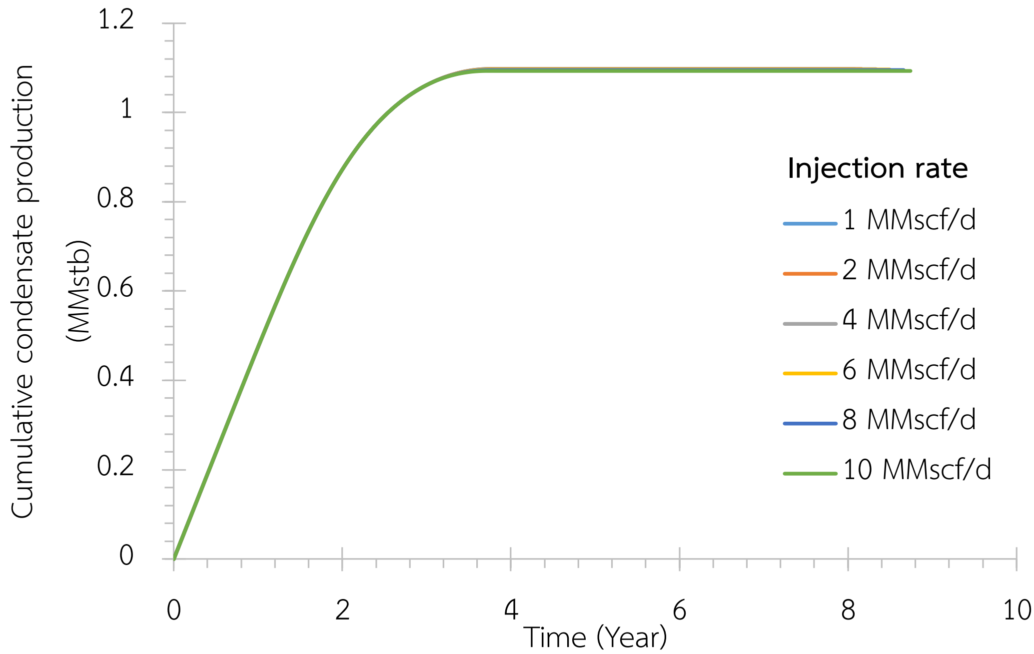


Figure 5.67 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 1

Figure 5.67 shows cumulative condensate production for combined gas dumpflood from 2 PV source gas reservoir with different gas injection rates for well pattern 1. The cumulative condensate production does not have significant different behaviors for different gas injection rates because the condensate inside the reservoir has already been displaced by large amount of dumped gas, and this is one of the reasons for stopping gas injection earlier.

Results for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection varying from 1 to 10 MMscf/d for well pattern 1 are summarized in Table 5.14. In this case, condensate recovery factor, and total BOE recovery factor are not significantly different between injection rates because there is less amount of condensate inside the reservoir after gas dumpflood operation. Three cases with the injection rates of 6, 8, and 10 MMscf/d yield net cumulative hydrocarbon gas recovery factor higher than 100 % since the higher cumulative gas injection helps revaporize of light end of the condensate in the reservoir.

Table 5.14 Summarized results for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 1

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.097	1.097	1.097	1.096	1.095	1.093
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	72.94	72.93	72.90	72.85	72.76	72.63
Cumulative gas production (bcf)	20.995	21.301	21.916	22.530	23.144	23.443
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.513	11.520	11.535	11.547	11.558	11.565
Net hydrocarbon gas recovery factor (%)	99.77	99.84	99.97	100.07	100.17	100.23
Cumulative gas production (MMBOE)	3.357	3.362	3.371	3.380	3.388	3.394
Cumulative total BOE production (MMBOE)	4.454	4.459	4.468	4.476	4.483	4.487
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	81.85	81.94	82.10	82.24	82.37	82.44
Cumulative gas injection(bcf)	0.304	0.608	1.217	1.825	2.433	2.728
Cumulative cross flow(bcf)	9.761	9.761	9.761	9.761	9.761	9.761

5.4.3.2. Combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 2

The same gas condensate reservoir and operating condition with the previous case for well pattern 1, was used for dumpflood operation at the beginning of the production. Both dumping wells were converted to gas injection wells when the reservoir pressure is less than 2402.35 psia which is the dewpoint pressure. The gas injection rate was varied from 1 to 10 MMscf/d. Gas injection was performed until the condensate production rate is less than 10 stb/d. The cumulative condensate production profile for combined gas dumpflood from 2 PV source gas reservoir with different gas injection rates for well pattern 2 is illustrated in Figure 5.68. All cases show the same trend for cumulative condensate production. At early time, condensate is produced by pressure support from the 2 PV source gas reservoir for almost 3 years before the reservoir pressure falls below the dewpoint. Then, gas injection was performed approximately for 5 months before it is stopped as shown in Figure 5.69. The gas injection was performed for a short period due to the fact that a lot of condensate has been previously produced by large amount of dumped gas. Subsequently, there is less condensate left inside the reservoir prior gas injection. This result in the condition to stop gas injection earlier.

Table 5.15 shows results from combined gas dumpflood from 2 PV of source gas reservoir with different gas injection rates for well patter 2. From the table, condensate recovery factor can be recovered around 68 % and does not have any significant difference for different gas injection rates since most of the condensate is produced by gas dumpflood from 2 PV of source gas reservoir. Most of the hydrocarbon gas (approximately 99%) are recovered from the reservoir. In term of total BOE recovery factor, all cases have similar value about 80 % since both condensate recovery factor and net cumulative hydrocarbon gas recovery factor are more or less equal. As for the cumulative gas injection, the amount of injected gas during conventional gas injection does strongly depends on the gas injection rate which is similar to the conventional gas injection case.

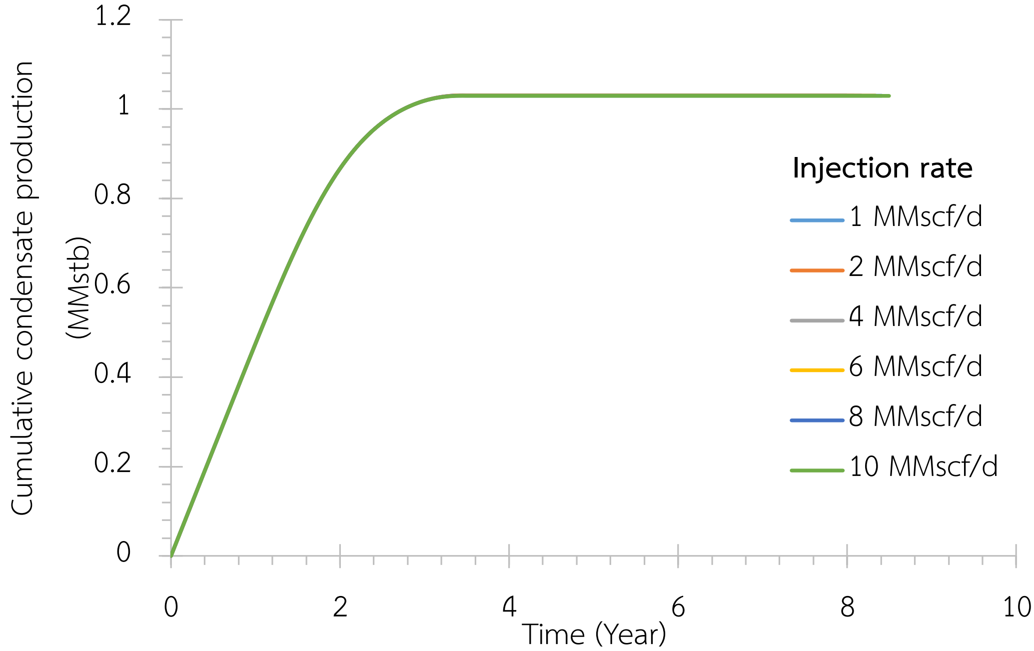


Figure 5.68 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 2

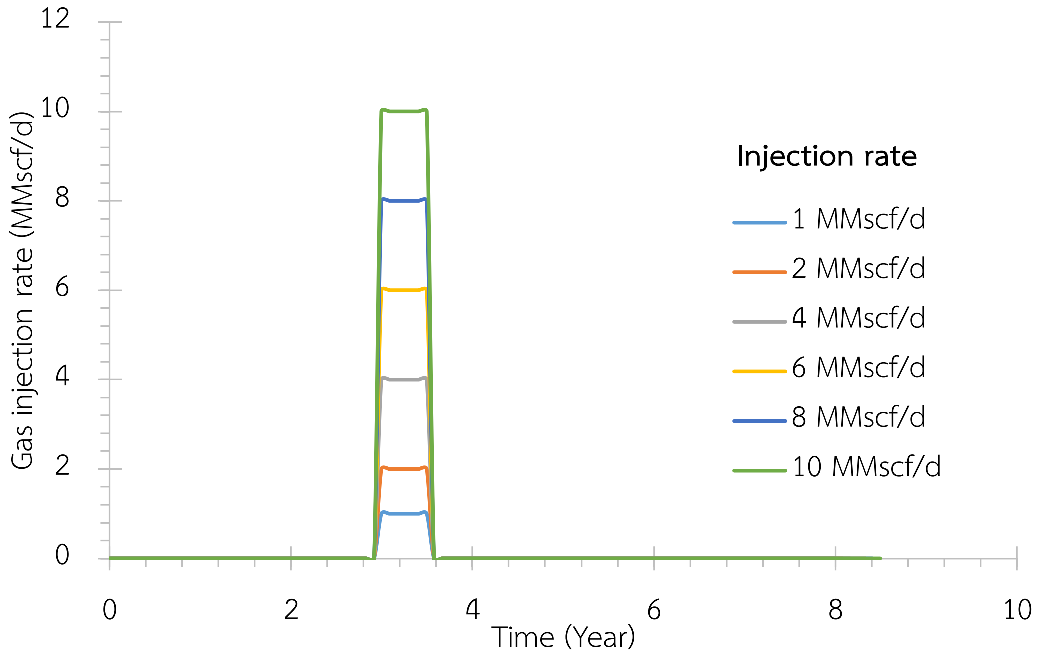


Figure 5.69 Field gas injection profiles for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 2

Table 5.15 Summarized results for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 2

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.031	1.030	1.030	1.030	1.030	1.029
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	68.50	68.49	68.48	68.47	68.44	68.41
Cumulative gas production (bcf)	20.637	20.856	21.281	21.721	22.146	22.574
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.421	11.430	11.441	11.458	11.471	11.484
Net hydrocarbon gas recovery factor (%)	98.98	99.06	99.16	99.30	99.41	99.53
Cumulative gas production (MMBOE)	3.319	3.323	3.332	3.342	3.351	3.362
Cumulative total BOE production (MMBOE)	4.349	4.354	4.362	4.372	4.381	4.391
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	79.91	80.00	80.15	80.33	80.50	80.68
Cumulative gas injection(bcf)	0.212	0.424	0.848	1.272	1.695	2.119
Cumulative cross flow(bcf)	9.500	9.500	9.500	9.500	9.500	9.500

5.4.3.3. Combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 3

In the same manner with the previous two well patterns, gas was dumped from 2 PV source gas reservoir since the beginning. Later on, dumping wells were converted to gas injection wells when the reservoir pressure was below the dewpoint. Conventional gas injection was started after dumping wells were shut. The injection rate was varied from 1 to 10 MMscf/d. Gas injection was performed as long as the condensate production rate stayed higher than 10 stb/d. Figure 5.70 demonstrates the cumulative condensate production for different gas injection rates. All cases follow the same trend, similar to the previous two well patterns, since large source gas reservoir plays a major role for condensate production during gas dumpflood, resulting in insignificant difference in condensate production for different gas injection rates.

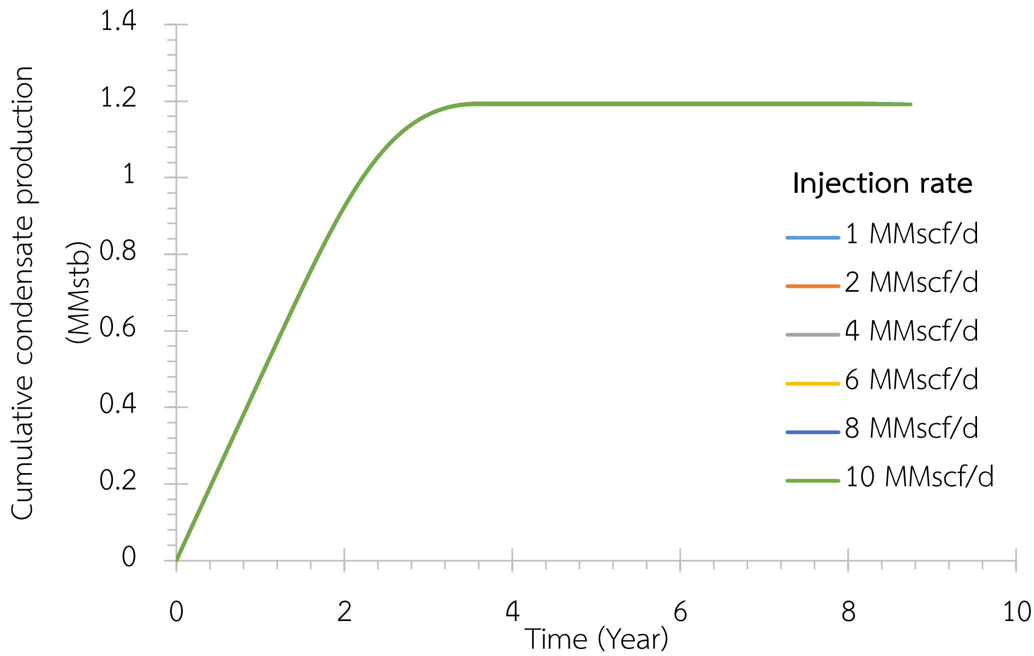


Figure 5.70 Cumulative condensate production profiles for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 3

Figure 5.71 illustrates field gas injection profiles for different gas injection rates. Higher gas injection rate causea gas injection to be stopped earlier than lower injection rate due to the fact that gas breakthrough occurs earlier as detected by the reduction of producing condensate to gas ratios shown in Figure 5.72.

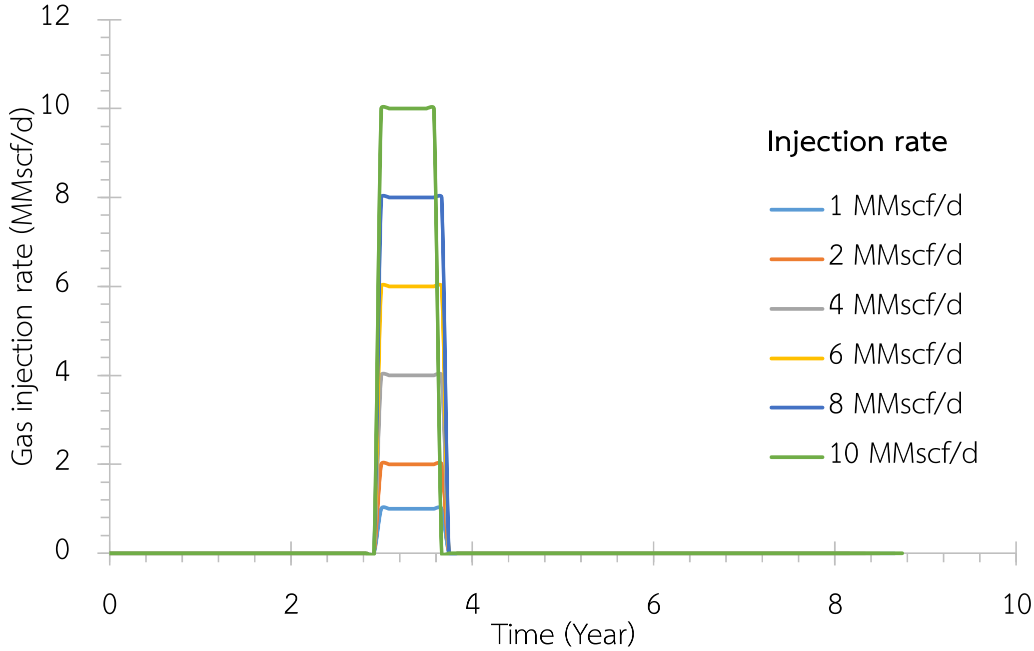


Figure 5.71 Field gas injection profiles for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 3

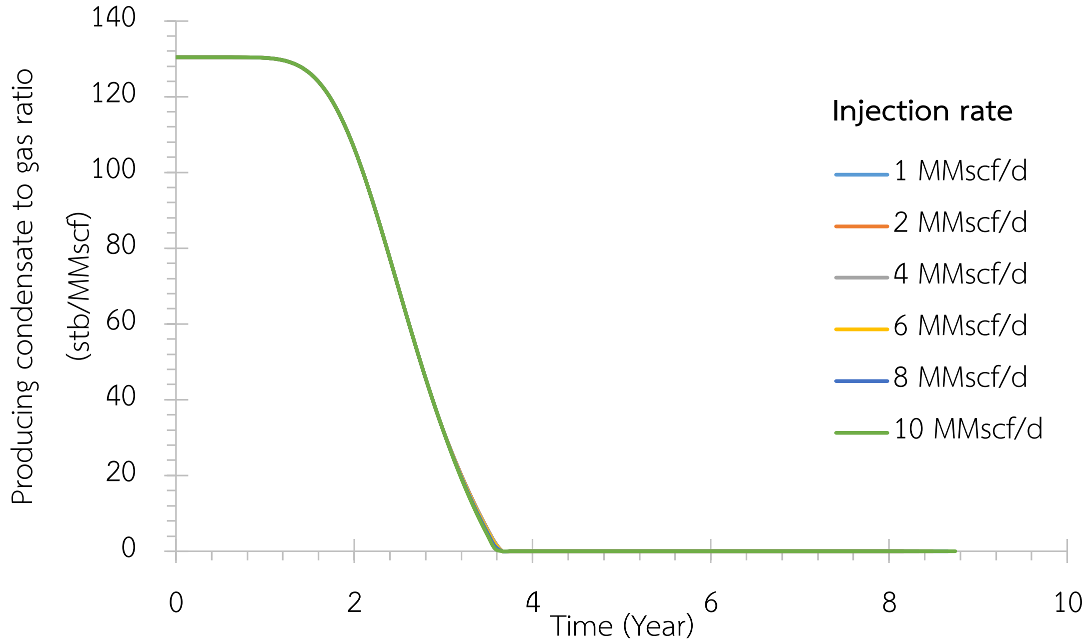


Figure 5.72 Producing condensate to gas ratios for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 3

Table 5.16 shows summarized results for different gas injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 3. In this case, higher gas injection rate tends to yield lower condensate recovery factor due to early gas breakthrough. However, the value of condensate recovery factors are not much different among cases. In term of net cumulative hydrocarbon recovery factor, all cases gain similar value at around 99 %. Regarding the total BOE recovery factor, similar values of cumulative condensate production and net cumulative hydrocarbon gas production result in almost the same total BOE recovery factor. The cumulative gas injection still clearly depends on the gas injection rate, similar to conventional gas injection and other combined gas dumpflood with gas injection scenarios.

Table 5.16 Summarized results for different injection rates of combined gas dumpflood from 2 PV source gas reservoir with gas injection for well pattern 3

Parameters	1MM	2MM	4MM	6MM	8MM	10MM
Cumulative condensate production (MMstb)	1.194	1.194	1.194	1.193	1.192	1.191
Original condensate in place (MMstb)	1.504	1.504	1.504	1.504	1.504	1.504
Condensate recovery factor (%)	79.36	79.36	79.34	79.30	79.25	79.19
Cumulative gas production (bcf)	20.607	20.869	21.422	21.972	22.523	22.758
Original gas in place (bcf)	11.539	11.539	11.539	11.539	11.539	11.539
Net cumulative hydrocarbon gas production (bcf)	11.447	11.447	11.455	11.462	11.468	11.470
Net hydrocarbon gas recovery factor (%)	99.20	99.21	99.28	99.34	99.39	99.41
Cumulative gas production (MMBOE)	3.292	3.294	3.299	3.304	3.308	3.309
Cumulative total BOE production (MMBOE)	4.486	4.488	4.493	4.497	4.500	4.501
Original BOE in place (MMBOE)	5.442	5.442	5.442	5.442	5.442	5.442
Total BOE recovery factor (%)	82.43	82.46	82.55	82.63	82.68	82.70
Cumulative gas injection(bcf)	0.273	0.546	1.091	1.637	2.182	2.413
Cumulative cross flow(bcf)	9.515	9.515	9.515	9.515	9.515	9.515

5.4.4. Comparison among different well patterns for combined gas dumpflood with gas injection into gas condensate reservoir

Effects of different well patterns on condensate recovery factor for each source gas reservoir size are explained separately in this section.

5.4.4.1. Combined gas dumpflood from 0.5 PV source gas reservoir with gas injection for different well patterns

Figure 5.73 shows condensate recovery factor for each injection rate with different well patterns in combined gas dumpflood from 0.5 PV source gas reservoir. Well pattern 3 yields the highest condensate recovery factor while well pattern 2 gain the lowest condensate recovery factor for each gas injection rate. The fact that well pattern 3 has the highest condensate recovery factor is the largest swept area resulted from the longest distance between dumping/injection wells and the producer. Since well pattern 2 has smaller swept area, gas production after breakthrough become high, resulting in low condensate recovery factor.

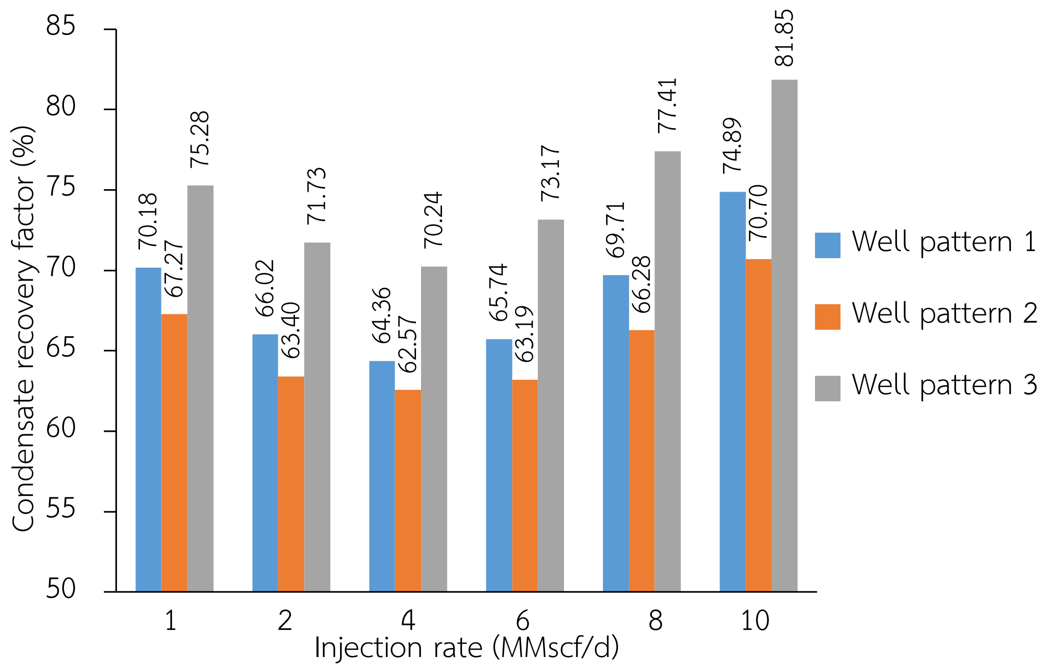


Figure 5.73 Condensate recovery factor for different well patterns of combined gas dumpflood from 0.5 PV source gas reservoir with different gas injection rates

5.4.4.2. Combined gas dumpflood from 1 PV source gas reservoir with gas injection for different well patterns

Figure 5.74 shows condensate recovery factor for each injection rate with different well patterns in combined gas dumpflood from 1 PV source gas reservoir. Similar to the previous case, combined gas dumpflood from 0.5 PV source gas reservoir with gas injection, Well pattern that provides condensate recovery factor from the highest to the lowest are well pattern 3, well pattern 1, and well pattern 2, respectively. Even though well pattern 2 has longer distance between producer and dumping/injection wells but the swept area is smaller than that for well pattern 1, resulting lower condensate recovery factor. Well pattern 3 has the highest condensate recovery factor since well pattern 3 has the largest swept area and the longest distance between dumping/injection wells and the producer, causing a delay in gas breakthrough.

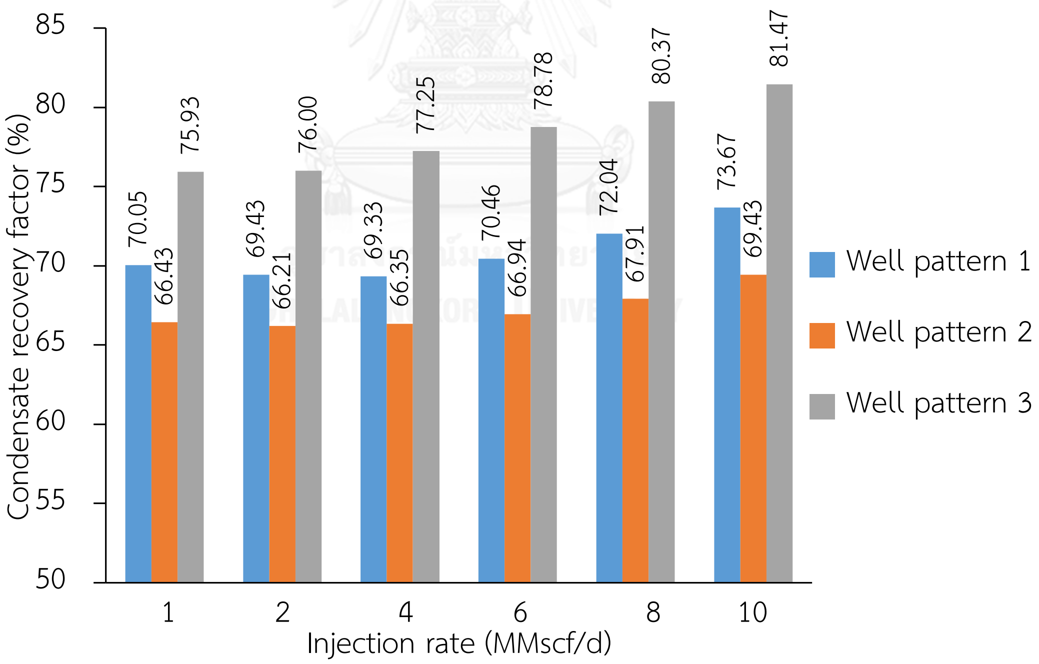


Figure 5.74 Condensate recovery factor for different well patterns of combined gas dumpflood from 1 PV source gas reservoir with different gas injection rates

5.4.4.3. Combined gas dumpflood from 2 PV source gas reservoir with gas injection for different well patterns

Figure 5.75 shows condensate recovery factor for each injection rate with different well patterns in combined gas dumpflood from 2 PV source gas reservoir. In the same manner with the previous two cases of combined gas dumpflood from 0.5 and 1 PV source gas reservoir with gas injection, well pattern 2 still gets the lowest condensate recovery factor due to poor swept area while the pattern 3 has the highest condensate recovery factor due to the highest swept area and the longest distance between dumping/injection wells and the producer.

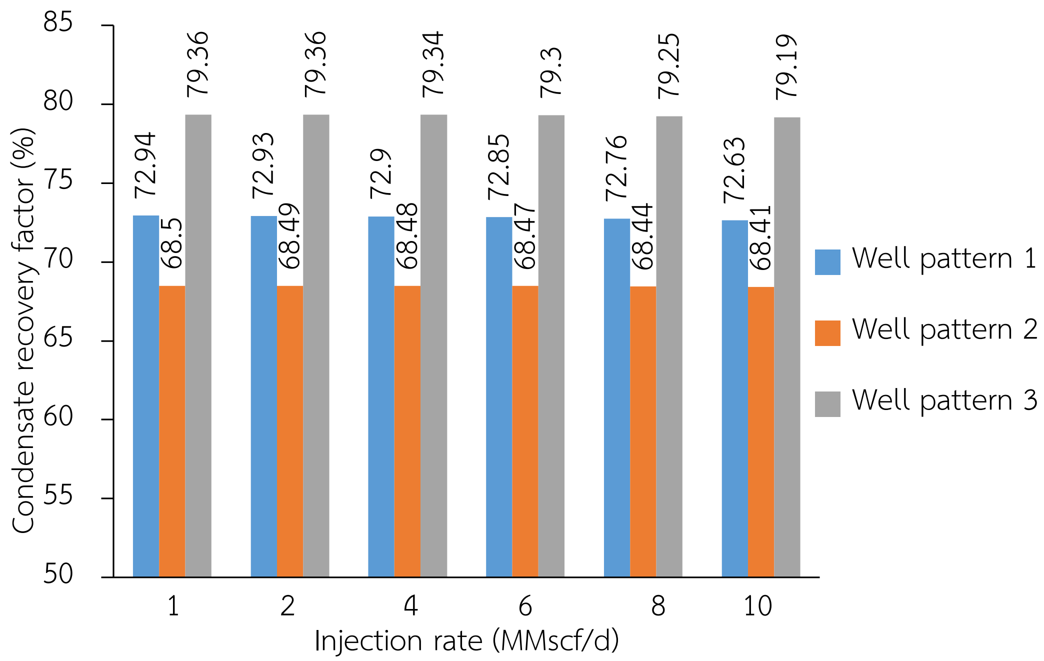


Figure 5.75 Condensate recovery factor for different well patterns of combined gas dumpflood from 2 PV source gas reservoir with different gas injection rates

5.5. Comparison the optimal case for conventional gas injection, gas dumpflood and combined gas dumpflood with gas injection when a specific size of source gas reservoir is available

The optimal case for natural depletion (ND), conventional gas injection (CI), gas dumpflood (DF), and combined gas dumpflood with gas injection (CDI) is compared in this section. Note that there are three producer evenly space in the reservoir while there are two dumping/injection wells in the other three scenarios.

When 0.5 PV source gas reservoir is available, combined gas dumpflood with 10 MMscf/d canrecover condensate recovery factor of 81.85 % which is 36.94 % and 10.63 % higher than natural depletion and gas dumpflood, respectively. There is a slight improvement in condensate recovery factor from combined technique. Cumulative gas injection is reduced from 10.242 bcf needed in conventional gas flooding to 9.180 bcf in the combined method as demonstrated in Table 5.17. But the disadvantage of combined gas dumpflood with gas injection is that the dumping wells need to be drilled deeper in or der to reach the source gas reservoir. Thus, combined gas dumpflood with gas injection may not be attractive as conventional gas injection for this small source gas reservoir case.

Table 5.17 Comparison the optimal case for conventional gas injection, gas dumpflood and combined gas dumpflood with gas injection when 0.5 PV source gas reservoir is available

Parameters	Natural depletion	Conventional gas injection with 8 MMscf/d injection rate	Gas dumpflood from 0.5 PV	Combined gas dumpflood from 0.5 PV source gas reservoir with 10 MMscf/d injection rate
Condensate Recovery factor (%)	44.91	79.77	71.22	81.85
Cumulative cross flow (BCF)	NA	NA	5.883	82.81
Cumulative gas injection(BCF)	NA	10.242	NA	9.180

When 1 PV source gas reservoir is available combined gas dumpflood with 10 MMscf/d yield condensate recovery factor higher than the other two cases (78.13, 79.77, and 81.47 % from gas dumpflood, conventional gas injection and combined gas dumpflood with gas injection, respectively). If the case with Combined gas dumpflood from 1 PV source gas reservoir with 10 MMscf/d injection rate and Conventional gas injection with 8 MMscf/d injection rate are compared, the combined case used very much less in term of cumulative gas injection as shown in Table 5.18.

Table 5.18 Comparison the optimal case for conventional gas injection, gas dumpflood and combined gas dumpflood with gas injection when 1 PV source gas reservoir is available

Parameters	Natural depletion	Conventional gas injection with 8 MMscf/d injection rate	Gas dumpflood from 1 PV	Combined gas dumpflood from 1 PV source gas reservoir with 10 MMscf/d injection rate
Condensate recovery factor (%)	44.91	79.77	78.13	81.47
Cumulative cross flow(BCF)	NA	NA	17.307	4.665
Cumulative gas injection(BCF)	NA	10.242	NA	6.850

When 2 PV source gas reservoir is available, conventional gas injection gas dumpflood and combined gas dumpflood with gas injection does not have significant different for condensate recovery factor as illustrated in Table 5.19. Therefore it is better to perform gas dumpflood when 2 PV source gas reservoir is available because similar condensate recovery factor obtained from three different production strategies and there is no gas required to inject into the reservoir.

Table 5.19 Comparison the optimal case for conventional gas injection, gas dumpflood and combined gas dumpflood with gas injection when 2 PV source gas reservoir is available

Parameters	Natural depletion	Conventional gas injection with 8 MMscf/d injection rate	Gas dumpflood from 2 PV	Combined gas dumpflood from 2 PV source gas reservoir with 1MMscf/d injection rate
Condensate recovery factor (%)	44.91	79.77	79.30	79.36
Cumulative cross flow(BCF)	NA	NA	31.942	9.515
Cumulative gas injection(BCF)	NA	10.242	NA	0.273

If all 0.5, 1, and 2 PV source gas reservoirs are available as multiple gas reservoirs, gas dumpflood from 2 PV may be an appropriate way to select because the condensate recovery factors for the best case of 0.5, 1, 2 PV source gas reservoir are not much different. But the advantage of gas dumpflood from 2 PV source gas reservoir over the other two cases is no need to install the gas compressor for injection unit, and no gas is required for injection.

CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

Effect of well locations and gas injectiorate on condensate production for different production scenarios and the effect of source gas reservoir size on condensate recovery for gas dumpflood and combined gas dumpflood with gas injection scenarios are concluded in this chapter. Note that the target gas production rate for all case is 10 MMscf/d

6.1. Conclusions

1. For conventional gas injection, well pattern 3 as shown in Figure 6.1 yields the highest condensate recovery due to the largest swept area and longest distance between dumping/injection wells and the producer Regarding gas injection rate, condensate recovery factor decreases as gas injection rate is increased from 1 to 4 MMscf/d because better condensate revaporization occurs in the case of 1 MMscf/d injection rate due to low reservoir pressure while the cases with 2 and 4 MMscf/d injection rate have poorer condensate revaporization due to higher reservoir pressure. As gas injection rate is increased from 6 to 10 MMscf/d, condensate recovery factor increases because higher gas injection rate has larger ability to maintain reservoir pressure above the dewpoint, resulting in less condensate dropout in the reservoir during production. The highest condensate recovery factor of 79.77 % which is obtained from 8 MMscf/d gas injection rate.

2. For gas dumpflood, larger source gas reservoir yields higher condensate recovery factor due to the fact that huge amount of carbon dioxide in the dumped gas mixes with the reservoir fluid, reducing the dewpoint pressure and thus inducing the condensate to revaporize, resulting in more condensate recovery factor. Regarding well pattern, pattern 3 still provides the highest condensate recovery factor.

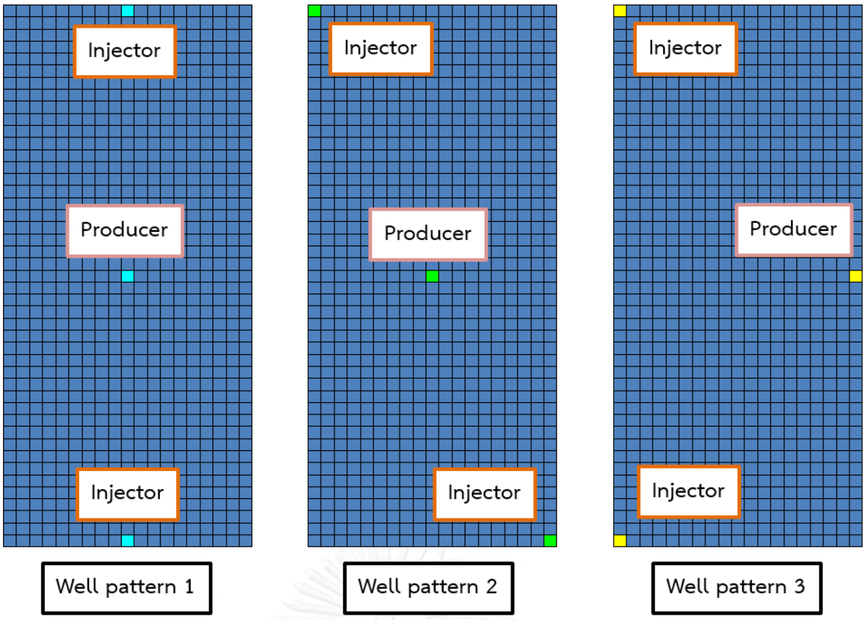


Figure 6.1 Different well patterns for conventional gas injection

3. For combined gas dumpflood from 0.5 PV source gas reservoir, well pattern 3 with 10 MMscf/d gas injection provides the highest condensate recovery factor of 81.85 %. The effect of gas injection rate after dumpflood operation is similar to conventional gas injection scenario. Condensate recovery factor decreases as gas injection rate is increased from 1 to 4 MMscf/d and increases as gas injection rate is increased from 6 to 10 MMscf/d.

4. For combined gas dumpflood from 1 PV source gas reservoir, the highest condensate recovery factor of 81.47 % is obtained from well pattern 3 with 10 MMscf/d gas injection. In this case, Condensate recovery factor increases as injection rate is increased from 1 to 10 MMscf/d.

5. For combined gas dumpflood from 2 PV source gas reservoir, the highest condensate recovery factor of 79.36 % is obtained from well pattern 3 with 1 MMscf/d In this case, most of condensate is recovered during gas dumpflood. So, gas injection rate does not has significant effect on condensate recovery factor.

6. If 0.5 PV of source gas is available, conventional gas injection should be performed because condensate recovery factor is much higher than gas dumpflood. Although combined gas dumpflood from 0.5 PV source gas reservoir with gas injection of 10 MMscf/d yields slightly higher condensate recovery factor than conventional gas

injection with 8 MMscf/d but cumulative gas injection is not significantly lower and there is no need to drill deeper well for conventional gas injection.

7. If 1 PV of source gas is available, combined gas dumpflood from 1 PV source gas reservoir with 10 MMscf/d is more attractive because slightly higher condensate recovery factor is achieved and amount of gas required for injection is much less than conventional gas injection.

8. If 2 PV of source gas is available, conventional gas dumpflood is the most appropriate way because recovery factor is not much different compared to the other two methods, and it has no additional cost for installing gas injection unit and injected gas.

9. If all 0.5, 1, and 2 PV source gas reservoirs are available as multiple gas reservoir, it is better to perform gas dumpflood from 2 PV source gas reservoir due to the reason that there is not much different for condensate recovery factors among different recovery methods and there is no cost for gas injection.

6.2. Recommendations

1. Different timing to perform gas dumpflood and gas injection should be studied further as all cases of conventional gas injection, gas dumpflood, and combined gas dumpflood with gas injection in this study are the same at the beginning of the production. Different starting time to perform gas dumpflood and gas injection might result in different condensate recovery factors.

2. Various fluid composition yielding different condensate to gas ratio should be investigated further. The most appropriate technique to perform improving condensate recovery technique might be different for different reservoir fluid compositions yielding condensate to gas ratio.

3. Various ratios between carbon dioxide and methane in source gas reservoir should be examined since there are different compositions of dry gas reservoir in actual field. The production performance of gas dumpflood and combined gas dumpflood with gas injection case might be different from this study.

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APPENDIX

VITA

Piya Phongtongpasuk was born on January 28th, 1993 in Nakhonpathom, Thailand. He received B.Eng. in Mechanical Engineering from Silpakorn University in 2014. After that, he got a full scholarship from Chevron Thailand Exploration and Production Limited and pursued his study at Department of Mining and Petroleum Engineering, Chulalongkorn University, in 2015 as a full time master student in the field of petroleum engineering.