PERFORMANCE EVALUATION OF INTEGRATED

CO_2 HUFF-N-PUFF AND WAG IN LOW-PRESSURE HETEROGENEOUS RESERVOIR

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การประเมินสมรรถนะของกระบวนการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักรร่วมกับการอัดก๊าซ
คาร์บอนไดออกไซด์สลับน้ำในแหล่งกักเก็บวิวิธพันธ์แรงดันต่ำ

นายหัฏฐะพงศ์ อยู่สุข

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมทรัพยากรธรณีและปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
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Thesis Title	PERFORMANCE EVALUATION OF INTEGRATED CO_2 HUFF-N-PUFF AND WAG IN LOW-PRESSURE HETEROGENEOUS RESERVOIR
By	Mr. Hutthapong Yoosook
Field of Study	Georesources and Petroleum Engineering
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หัฏฐะพงศ์ อยู่สุข : การประเมินสมรรถนะของกระบวนการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักรร่วมกับการอัดก๊าซคาร์บอนไดออกไซด์สลับน้ำในแหล่งกักเก็บวิวิธพันธ์แรงดันต่ำ (PERFORMANCE EVALUATION OF INTEGRATED CO_2 HUFF-N-PUFF AND WAG IN LOW-PRESSURE HETEROGENEOUS RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร.เกรียงไกร มณีอินทร์, 154 หน้า.

กระบวนการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักรร่วมกับการอัดก๊าซคาร์บอนไดออกไซด์สลับน้ำเป็นเทคโนโลยีใหม่ที่ผสมผสานเทคนิคการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักรในช่วงแรกของกระบวนการเพิ่มผลผลิต และตามด้วยเทคนิคการอัดก๊าซคาร์บอนไดออกไซด์สลับน้ำจะกระทั่งจบกระบวนการทั้งหมด เทคนิคการเพิ่มผลผลิตนี้มีประสิทธิผลในแง่ของการเพิ่มผลผลิตน้ำมันดิบ และ ลดปริมาณการใช้คาร์บอนไดออกไซด์

อย่างไรก็ตามกระบวนการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักรร่วมกับการอัดก๊าซคาร์บอนไดออกไซด์สลับน้ำนี้ประกอบไปด้วยตัวแปรที่เกี่ยวข้องกับการดำเนินการมากมาย ดังนั้นการศึกษาแบบจำลองเชิงตัวเลข และการวิเคราะห์ความไวจึงเข้ามามีบทบาทสำคัญในการวินิจฉัยผลกระทบของตัวแปรหลักแต่ละตัว และยังสามารถประเมินสมรรถนะของการประยุกต์ใช้กระบวนการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักรร่วมกับการอัดก๊าซคาร์บอนไดออกไซด์สลับน้ำในแหล่งกักเก็บวิวิธพันธ์แรงดันต่ำ เพื่อบรรลุผลประโยชน์สูงสุดต่อไป

ผลจากการศึกษาแบบจำลองเชิงตัวเลขแสดงให้เห็นว่า ตัวแปรที่มีความอ่อนไหวสูงที่สุดกับปริมาณน้ำมันที่ถูกผลิตขึ้นมาโดยใช้กระบวนการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักร คือ ระยะเวลาการผลิต และรองลงมา คือ อัตราการผลิตของน้ำมัน ในส่วนของตัวแปรที่มีความอ่อนไหวต่ำที่สุด คือ ระยะเวลาการปิดหลุมผลิต อย่างไรก็ตามปริมาณการอัดคาร์บอนไดออกไซด์ก็เป็นอีกหนึ่งตัวแปรสำคัญที่มีความอ่อนไหวอย่างมากกับปริมาณการใช้คาร์บอนไดออกไซด์ทั้งหมดในเทคนิคนี้ ในส่วนของกระบวนการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักรร่วมกับการอัดก๊าซคาร์บอนไดออกไซด์สลับน้ำนั้น การเพิ่มอัตราการอัดน้ำเพื่อไล่คาร์บอนไดออกไซด์ รวมทั้งขยายช่วงเวลาของกระบวนการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักร จะส่งผลให้น้ำมันที่สามารถผลิตได้มีปริมาณมากขึ้นพร้อมทั้งลดปริมาณการใช้คาร์บอนไดออกไซด์ให้น้อยลง ซึ่งการประยุกต์ใช้เทคนิคการอัดก๊าซคาร์บอนไดออกไซด์แบบวัฏจักรร่วมกับการอัดก๊าซคาร์บอนไดออกไซด์สลับน้ำนี้ สามารถดึงน้ำมันจากชั้นหินแหล่งกักเก็บได้มากกว่าการผลิตขั้นปฐมภูมิถึงร้อยละ ๖๔ ของปริมาณน้ำมันทั้งหมด ซึ่งกลไกสำคัญในการช่วยเพิ่มความสามารถในการผลิตน้ำมันให้ได้มากขึ้นนั้น คือ การเพิ่มและรักษาสภาพความดันภายในชั้นหินแหล่งกักเก็บปิโตรเลียม และการปรับปรุงประสิทธิภาพการกวาดน้ำมันภายในชั้นหินแหล่งกักเก็บปิโตรเลียมสู่หลุมผลิต รวมทั้ง การลดความหนืดของน้ำมันดิบซึ่งจะส่งผลให้การไหลของนำมันดิบภายในชั้นหินแหล่งกักเก็บปิโตรเลียมดีขึ้นนั้นเอง

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ....

สาขาวิชา วิศวกรรมทรัพยากรธรณีและปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาหลัก ....

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HUTTHAPONG YOOSOOK: PERFORMANCE EVALUATION OF INTEGRATED CO_2 HUFF-N-PUFF AND WAG IN LOW-PRESSURE HETEROGENEOUS RESERVOIR. ADVISOR: ASST. PROF. KREANGKRAI MANEEINTR, Ph.D., 154 pp.

The integrated CO_2 Huff-n-Puff and WAG is a novel technique to combine CO_2 Huff-n-Puff technique that conducted at early state and followed by WAG technique until the end of operating time. This technique is effectiveness in term of increased oil recovery and reduced CO_2 utilization.

However, the integrated CO_2 Huff-n-Puff and WAG process contains numerous adjustable operating parameters. Hence, numerical simulation study and sensitivity analysis become essential to investigate the effects of main operational parameters and evaluate the performance of the integrated CO_2 Huff-n-Puff and WAG process in low-pressure heterogeneous reservoir to achieve the maximum benefits.

According to simulation results, the highest sensitive parameter on oil recovery factor using CO_2 Huff-n-Puff process is production time, followed by production rate. The lowest sensitivity is soaking time. Nevertheless, CO_2 HCPV injection illustrates the highest sensitivity on CO_2 consumption. In term of conducting integrated CO_2 Huff-n-Puff and WAG, higher oil recovery factor with lower CO_2 utilization can be obtained by injecting additional chasing water rate and extending CO_2 Huff-n-Puff period. Last but not least, applying integrated CO_2 Huff-n-Puff and WAG method has capability to extract up to 64% of OOIP beyond primary recovery. Finally, dominant EOR mechanisms of this technique are reservoir pressure maintenance, volumetric sweep efficiency improvement, and oil viscosity reduction.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
Field of Study:	Georesources and Petroleum Engineering		
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LIST OF ABBREVIATIONS

^{o}API	Degree American Petroleum Institute
atm	Atmosphere
^{o}C	Degree Celsius
CO_2 EOR	Carbon Dioxide Enhanced Oil Recovery
^{o}F	Degree Fahrenheit
BBL	Barrel
BHP	Bottomhole Pressure
BOPD	Barrel of Oil per Day
BWPD	Barrel of Water per Day
CCS	Carbon Capture and Storage
CH_4	Methane
CMG	Computer Modeling Group Ltd.
CO_2	Carbon Dioxide
CP	Centipoise
EOR	Enhanced Oil Recovery
FAWAG	Foam Assisted Water Alternating Gas
FT	Feet
FT^2	Square Feet
FT^3	Cubic Feet
GOC	Gas-oil contact
GOR	Gas Oil Ratio
HCPV	Hydrocarbon Pore Volume
HWAG	Hybrid Water Alternating Gas
IPCC	Intergovernmental Panel on Climate Change
IWAG	Immiscible Water Alternating Gas
K	Kelvin
M	Thousand (1,000 of petroleum unit)
m	Meter

mD	Millidarcy
MMP	Minimum Miscibility Pressure
MPa	Megapascal
MWAG	Miscible Water Alternating Gas
OOIP	Original Oil In Place
p-T	pressure-Temperature
psi	Pound per square inch
psia	Pound per square inch, absolute
PVT	Pressure-Volume-Temperature
RF	Recovery Factor
SCAL	Special Core Analysis
SCF	Standard Cubic Feet
SCF/STB	Standard Cubic Feet per Stock Tank Barrel
SF	Safety Factor
SSWAG	Selective Water Alternating Gas
STB/D	Stock Tank Barrel per Day
SWAG	Simultaneous Water Alternating Gas
WAG	Water Alternating Gas
WOC	Water-oil contact

NOMENCLATURES

A	Cross-sectional area
B	Formation volume factor
Bg	Gas formation volume factor
Bo	Oil formation volume factor
Boi	Initial oil formation volume factor
cs	Solubility
cf	Formation compressibility
Ds	Depth
E	Sweep efficiency
EA	Areal sweep efficiency
EV	Volumetric sweep efficiency
fsw	Swelling coefficient
g	Gravitational acceleration
h	Thickness of pay zone
K	Porosity decline constant
k	Permeability
kh	Horizontal permeability
kr	Relative permeability
krg	Gas relative permeability
kro	Oil relative permeability
krw	Water relative permeability
kv	Vertical permeability
MC5+	Molecular Weight of C5+ in crude oil
P	Reservoir pressure
Pb	Bubble point pressure
Pf	Formation pressure
Pff	Fracture pressure
q	Volumetric flow rate

Rs	Solution gas-oil ratio
rw	Wellbore radius
Sf∞	Saturated swelling factor
Sg	Gas saturation
So	Oil saturation
Sw	Water saturation
T	Reservoir temperature
t	Time

GREEK LETTER

ρ_g	Grain density
ρ_l	Liquid density
ø	Porosity
σ_{ob}	Overburden pressure
μ_o	Oil viscosity
μ_w	Water viscosity

CHAPTER 1
INTRODUCTION

1.1 Background

In recent years, many industries have been highly concerned the reduction of Greenhouse Gases emission due to the threat of climate change (Le Gallo, Couillens, & Manai, 2002). Mainly man-made carbon dioxide (CO_2) is one of the key environmental concerns because CO_2 is the heat-trapping gas that its influence is more than any other climate drivers (IPCC, 2007). According to the Intergovernmental Panel on Climate Change (IPCC), measured radiative forcing which is the net increase or decreases in the amount of energy reaching Earth's surface attributable to that climate driver. CO_2 shows the highest positive radiative forcing compared to other climate driver that represent CO_2 caused the highest increasing of Earth's temperature, as shown in Figure 1.1. Moreover, CO_2 is able to remain in the atmosphere longer than the other major heat-trapping gases. It takes about a century to initially release the atmosphere, however, about 20 percent of CO_2 emissions will still exist in atmosphere approximately 800 years (IPCC, 2007). One of the most effective method to prevent and reduce CO_2 emission is Carbon Capture and Storage (CCS), as shown in Figure 1.2. A main issue is the capture and storage of CO_2 that it is captured and injected to underground storage in depleted oil reservoirs (Gunter, Bachu, & Benson, 2004). Furthermore, CO_2 has capability to enhance oil recovery (EOR) that can increase oil recovery by approximately 5-20% beyond typically achievable using conventional recovery processes due to its miscibility mechanism (Hargreaves, 2009). The additional extraction of oil will provide more space available for CO_2 storage in long term. Hence, the using of CO_2 for enhanced oil recovery exceedingly benefits to improve oil production with extending of project's life. Also, it helps minimize environmental impact by reducing CO_2 emission into the atmosphere and storing it underground in depleted reservoir.

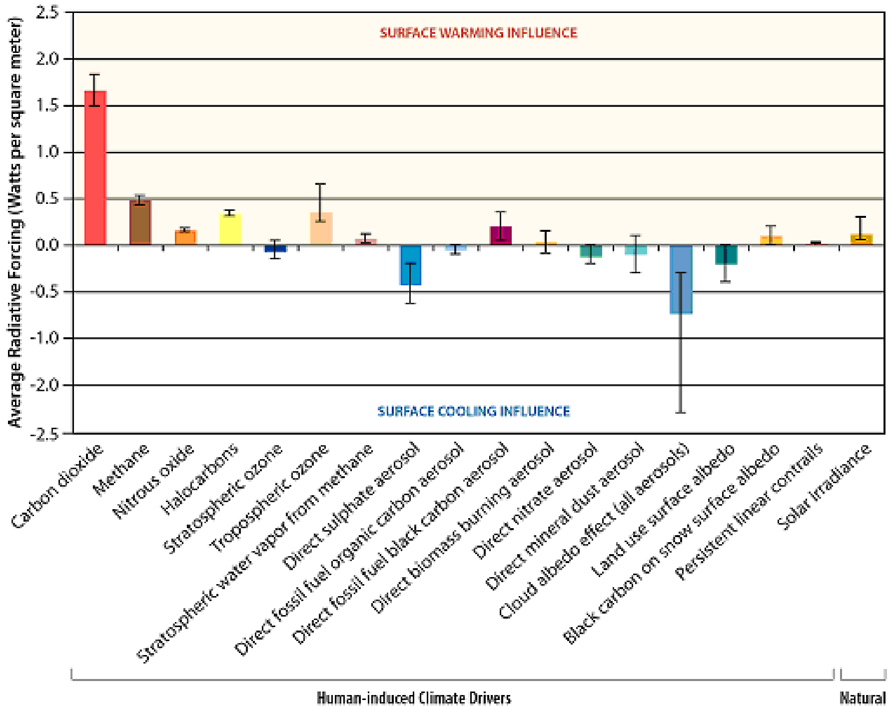

Figure 1.1 Union of concerned scientists (IPCC, 2007)

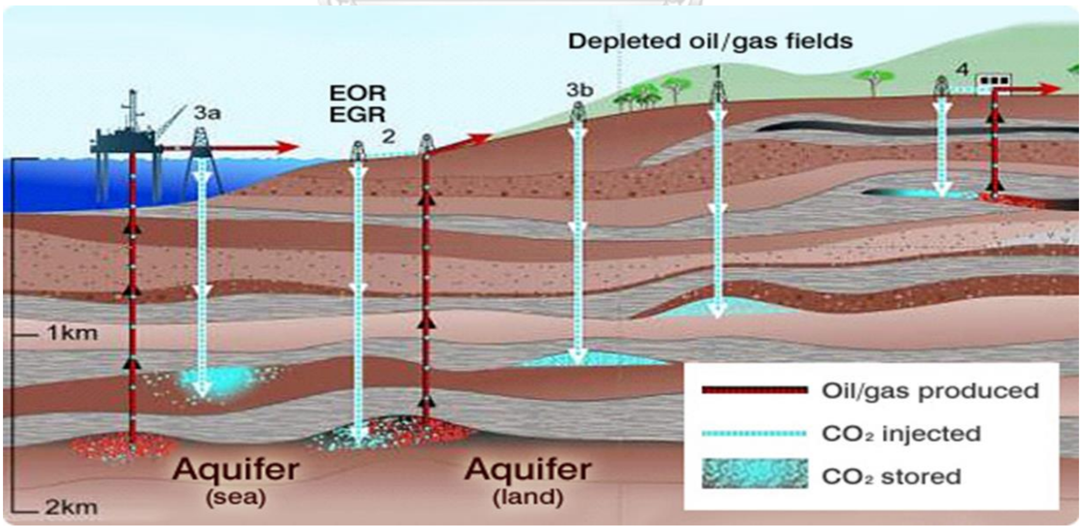

Figure 1.2 Carbon capture and storage (CCS) process (Gunter et al., 2004)

1.2 Enhanced Oil Recovery

Enhanced Oil Recovery (EOR) is the implementation of various recovery techniques that used to extract additional oil from reservoir via injection of some materials, such as carbon dioxide (CO_2), polymer, chemical, steam, and microbial to generate the external reservoir drive mechanisms while reservoir fluid properties are changing by the effect of injection materials. The main EOR mechanisms are classified into three basic mechanisms, including oil viscosity reduction, oil extraction with a solvent, and alteration of capillary and viscous forces between oil, injected fluid, and rock surface (Donaldson, Chilingarian, & Yen, 1985). Also, EOR can be classified into three main categories based on injection materials which are thermal methods (heat injection), miscible or immiscible gas injection methods and chemical methods (chemicals/surfactants injection), as shown in Figure 1.3. Using EOR typically increases production about 5 to 60 percent of the original oil in place (OOIP) beyond primary recovery and secondary recovery (Donaldson, Chilingarian, & Yen, 1989).

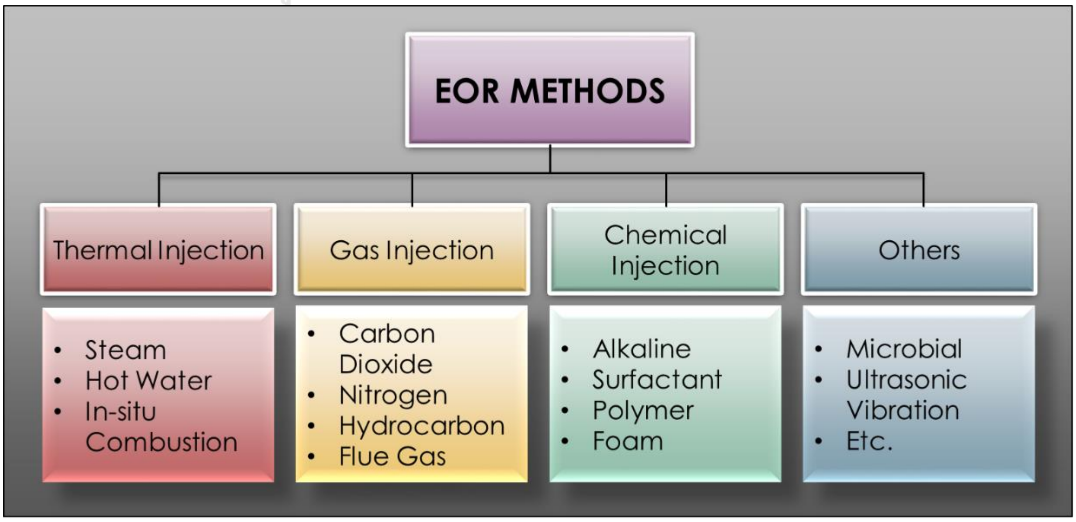

Figure 1.3 Enhanced oil recovery (EOR) method

However, EOR has many challenges in the complex communication of injected fluid and the existing reservoir fluid with the variable reservoir conditions. Also, heterogeneity of reservoir is the key challenges to success EOR due to the differential values of each reservoir parameter in the same area (Branets, Ghai, Lyons, & Wu, 2008). Some challenges are measured from well testing, laboratory and field experience. The difficulty is selecting the suitable injected fluid and designing the optimal processes in specific situation. Selecting the proper EOR technique is a key to economically success long term recovery (Donaldson et al., 1989).

1.2.1 CO_2 Enhanced Oil Recovery

The injection of carbon dioxide (CO_2) into hydrocarbon reservoir is one method of enhanced oil recovery that contain the mechanism contributing to increases oil recover. The main oil recovery mechanisms are the reduction of oil viscosity, dissolution of CO_2 in oil causing oil swelling, removal of near wellbore damage, reduction of water relative permeability, and reduction of interfacial tensions (Mohammed-Singh, Singhal, & Sim, 2006). Also, some oil fields get benefit from other oil recovery mechanisms, such as solution gas drive aided by gravity drainage, improved drainage of reduced viscosity oil by encroaching water, vaporization of lighter components of oil by CO_2, and etc. (Bybee, 2007). In addition, CO_2 injection for enhanced oil recovery (CO_2-EOR) can reduce CO_2 emissions from fossil fuels' burning that has seriously impacted on the environment and its amount in the atmosphere due to greenhouse gas as previously mentioned.

There are several operating strategies for carbon dioxide (CO_2) injection that is separated into four main types, i.e., immiscible CO_2 flooding, miscible CO_2 flooding, CO_2 Huff-n-Puff, and water alternating gas (WAG) (Verma, 2015). CO_2 flooding is a method to enhance oil recovery by injected CO_2 into reservoir, the huge amount of CO_2 is injected through reservoir with injector (injection well) and its recovery mechanism will extract additional oil to produce through producer (production well). The CO_2 flooding can be miscible or immiscible based on average reservoir pressure and some operating parameters (Muslim et al., 2013). Fundamentally, the recovery mechanism of immiscible flooding is a drive mechanism that the injected CO_2 effectively sweeps the crude oil towards the producer. While the miscible CO_2 flooding contains miscibility mechanism that has capability to reduce oil viscosity and density (oil swelling) that results in a higher effective sweep efficiency and displacement efficiency of oil (Whittaker & Perkins, 2013). However, the application of CO_2 flooding may potentially have problems of viscous fingering, gravity overriding and channeling through the upper side of reservoir that caused of early breakthrough and poor sweep efficiency (Whittaker & Perkins, 2013). To reduce the chance of early breakthrough and improve sweep efficiency, the alternating slugs of injected water and CO_2 is applied to the field that known as Water Alternating Gas (WAG) process. Moreover, the huge amount of CO_2 consumption in the conventional CO_2 flooding usually limits its widespread application and allows WAG to be taking place due to economically decisions (Whittaker & Perkins, 2013).

Carbon dioxide Huff-n-Puff is cyclic of CO_2 injection into oil well alternating with producing from the same well to recover residual oil inside the oil reservoir. The operations of CO_2 Huff-n-Puff are compressing CO_2 to approximately 1000 psi and injecting into oil reservoir until reach the desired slug volume (Praxair, 2014). And then, the injection well is shut in for a designated soak period that should be two to four weeks based on the different reservoir conditions and reservoir fluid properties. During soaking period, the injected CO_2 dissolve into crude oil that results in oil swelling, reduced viscosity, and other recovery mechanism (Mohammed-Singh et al., 2006). After soaking period, the well is opened to re-produce and the injected CO_2 provides a solution gas drive cause typically increase oil recovery. In some cases, the injected CO_2 can help to suppress water production from coning and improve reservoirs containing paraffin (Mohammed-Singh et al., 2006). And, these processes are repeated between two to five cycles or operated until insufficient oil production (Bybee, 2007). The cyclic of CO_2 injection proved to be the most suitable for reservoirs with relatively small pool size and poor flowability between injector and producer (Song & Yang, 2013). In addition, the application of CO_2 Huff-n-Puff required a smaller amount of CO_2 consumption, comparing to CO_2 flooding. This process can also provide quicker payout with lower capital investment (Simpson, 1988). Therefore, CO_2 Huff-n-Puff usually perform as pilot test in many field to confirm reservoir fluid response with injected CO_2 before beginning of full field implementation of CO_2 flooding or WAG (Edwards & Anderson, 2002).

The integrated CO_2 Huff-n-Puff and WAG seem to be the effective process to enhance oil recovery in low-pressure reservoir due to the achievement of both immiscible and miscibility effect come together with the development of sweep efficiency. Likewise, the minimizing of CO_2 consumption could also significantly help improve the project’s achievement. Nevertheless, the integrated CO_2 Huff-n-Puff and WAG contains numerous adjustable operating parameters that can directly and indirectly influence recovery factor and amount of CO_2 usage that certainly effect the project decision making and field development plan. Hence, the simulation study and sensitivity study become important to evaluate and optimize the integrated CO_2 Huff-n-Puff and WAG process to achieve the maximum economic and environmental benefits.

1.3 Objectives of this Research

1. To study the sensitivity of operating parameters of CO_2 Huff-n-Puff in low-pressure reservoir including injection rate, injection time, soaking time, production rate, and production time.

2. To investigate the influence of main operational parameters and evaluating performance of the integrated CO_2 Huff-n-Puff and WAG process in low-pressure heterogeneous reservoir based on oil recovery factor and cumulative injected CO_2.

1.4 Outline of Methodology

1. Study and review related theories and literature.

2. Calculate minimum miscibility pressure and formation fracture pressure of reservoir by using empirical correlations with existing data. These two values can control miscibility effect and prevent reservoir leakage, respectively.

3. Create heterogeneous reservoir models based on basic reservoir characteristic, oil composition, relative permeability data and existing fluid properties of low-pressure area in Fang oil field, Thailand.

4. Simulate CO_2 Huff-n-Puff process on the created heterogeneous reservoir models with varying of operating parameters, including hydrocarbon pore volume injection (HCPV), injection time, soaking time, production rate, and production time. The sensitivity analysis is performed based on recovery factor and CO_2 consumption.

5. Select the key operating parameters of CO_2 Huff-n-Puff technique that demonstrate the high sensitivity to oil recovery factor and CO_2 consumption.

6. Simulate the integrated CO_2 Huff-n-Puff and WAG process on created heterogeneous reservoir models with varying of the selected key operating parameters. The comparative study is performed based on recovery factor.

7. Study and evaluate effects of the key operating parameters to achieve the highest oil recovery factor and lowest CO_2 utilization of the integrated CO_2 Huff-n-Puff and WAG technique.

8. Discuss and summarize the results.

9. Conclude the performance evaluation of the integrated CO_2 Huff-n-Puff and WAG technique in low-pressure heterogeneous reservoir.

1.5 Outline of Thesis

This thesis is divided into five chapters. Chapter 1 introduces a background of carbon dioxide enhanced oil recovery (CO_2-EOR) and indicates the objective and also provides methodology of this study. Chapter 2 summarizes several relevant theories of CO_2-EOR and provides various literature reviews that relates to this study. Chapter 3 demonstrates the reservoir models that consists of reservoir details, reservoir model dimensions, entire input data, operational constraints, and several EOR techniques applying into models by using CMG-GEM simulation software. Chapter 4 reports the results and discussion of reservoir simulation and sensitivity study for each interesting key parameters. The results is highly concerned on oil recovery factor and carbon dioxide utilization. Finally, chapter 5 presents conclusions of this study and recommendation for future study.

CHAPTER 2
RELEVANT THEORY AND LITERATURE REVIEW

2.1 Carbon Dioxide Properties

Carbon dioxide (CO_2) is colorless and odorless at low concentration. But it has acidic odor at high concentration. The molecular mass is about 44.01 g/mol. CO_2 is in gas phase with density of approximately 1.98 kg/m^3 at standard condition of pressure and temperature that is higher than density of air (1.225 kg/m^3) (Nealson, 2006). CO_2 can be in liquid phase and solid phase with density of approximately 1032 kg/m^3 and 1562 kg/m^3, respectively (Nealson, 2006). It becomes a solid that commonly known dry ice at temperatures below -78.5^{o}C (-109^{o}F, 195 K) with 1 atmospheric pressure (14.7 psi, 1.01 bar) (Flinn Scientific, 2016). Another form of solid CO_2 is an amorphous glass (carbonia) at very high pressure that is about 400,000 atmospheres (5,878,380 psi, 405,300 bar) (Manaugh, 2006). CO_2 can condense only at pressure above 5.1 atmospheres (74.95 psi, 5.18 bar) (Bank, 2017). From Figure 2.1, the triple point pressure of CO_2 is about 5.11 atmospheres (74.95 psi, 5.18 bar) with temperature of -56.6^{o}C (-69.9^{o}F, 216.5 K). And the critical point is 72.8 atmospheres (1070 psi, 73.8 bar) at 31.1^{o}C (88^{o}F, 304 K) (Seevam, Race, & Downie, 2008). At pressure and temperature above the critical point, CO_2 becomes a supercritical fluid (supercritical CO_2). Supercritical CO_2 contains unique capability to diffuse though solids like a gas, also dissolve fluids like a liquid (Budisa & Schulze-Makuch, 2014). Moreover, its density can be rapidly changed upon small changes in pressure and temperature.

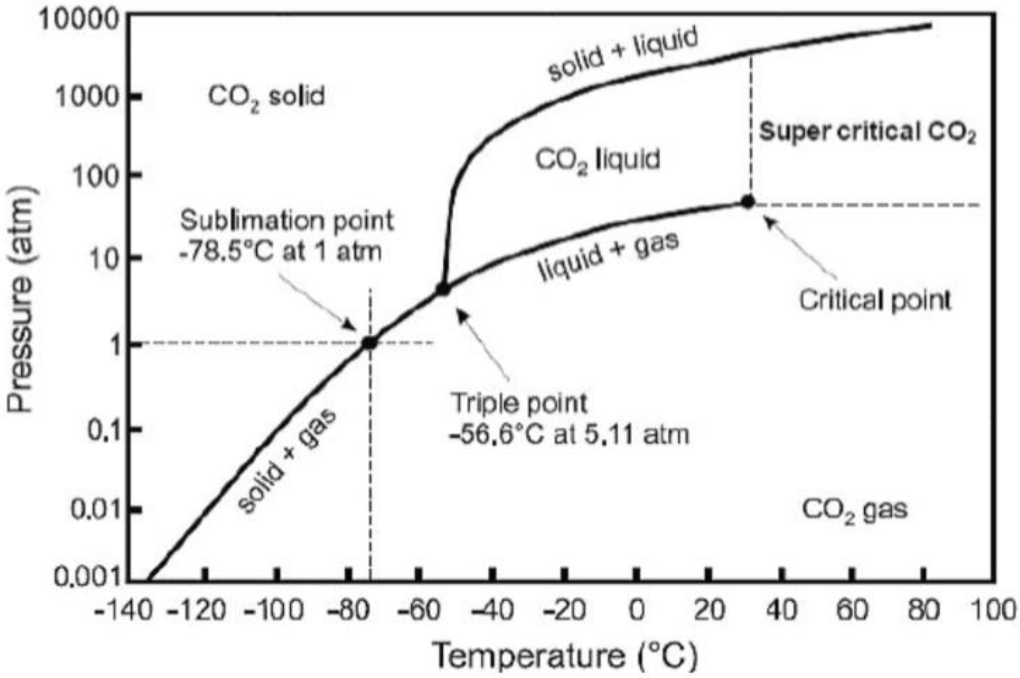

Figure 2.1 CO_2 pressure-temperature phase diagram (Hunter, 2010)

Carbon dioxide has chemical molecular formula of CO_2 with 44.0095 g/mol of molecular weight (Wang & Orr, 1997). Chemical compound of CO_2 is composed of a single carbon atom covalently double bonded with two oxygen atoms that is a liner and centrosymmetric covalent molecule (Ophardt, 2003), as shown in Figure 2.2. The percentage composition by mass of oxygen and carbon is 72.71% and 27.29%, respectively.

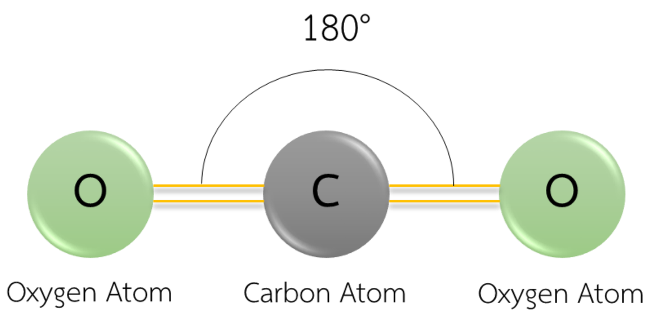

Figure 2.2 Chemical molecular structure of carbon dioxide

2.1.1 Supercritical Carbon Dioxide and Special Properties

Carbon dioxide (CO_2) contains four phases that are the standard solid, liquid, gas phase and also the supercritical phase. Supercritical CO_2 cannot be identified as a liquid or as a gas but as a substance in the supercritical state that its critical point is at 304 K (31.1°C, 88°F) and 73.8 bar (7.38 MPa, 1070 psi) (Budisa & Schulze-Makuch, 2014), as shown in Figure 2.3.

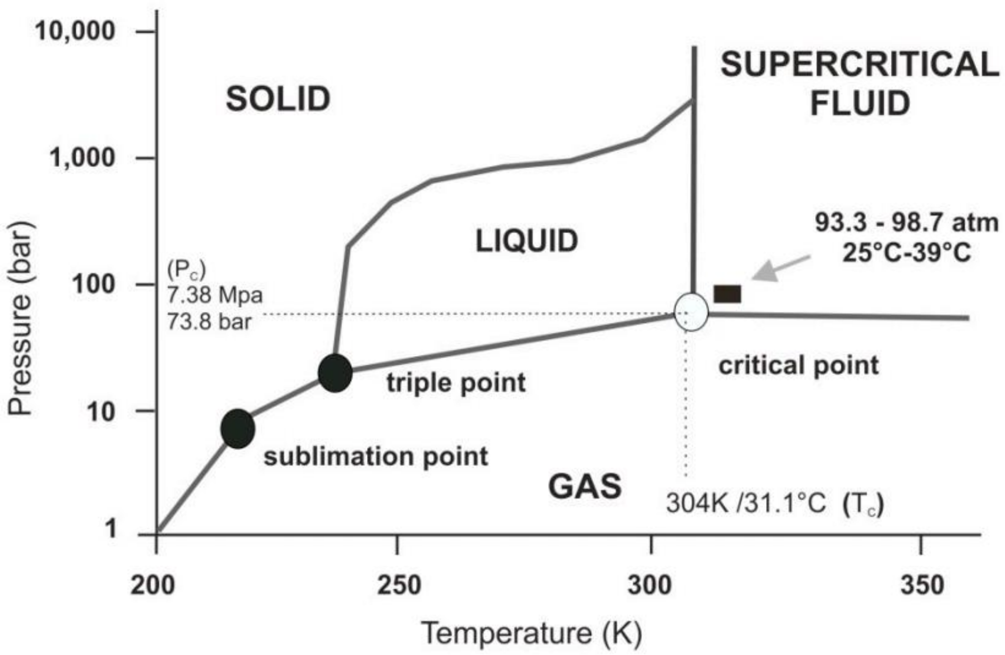

Figure 2.3 Schematic p-T phase diagram of CO_2 (Budisa & Schulze-Makuch, 2014)

Supercritical CO_2 has significantly specific properties, which it consists both liquid-like densities providing good solvent capability and gas-like viscosities, and diffusivities to benefit mass transportation. Near the critical point, small changes in pressure or temperature cause significant changes in solubility, partition coefficient, dipole moment and dielectric constant (Budisa & Schulze-Makuch, 2014). And density of supercritical CO_2 also changed as a function of pressure and temperature because its compressibility is maximum at the critical pressure so a small change of temperature can lead to a large change in its density, as shown in Figure 2.4. The special properties of supercritical CO_2 are high solubility, high miscibility, high density, high diffusion rate, high dissolving power, and low toxicity (Budisa & Schulze-Makuch, 2014). Supercritical CO_2 has been utilized in petroleum industries to enhance oil recovery for more than thirty years. These processes are able to reduce crude oil's effective viscosity by dissolving of supercritical CO_2 into the oil, resulting in higher mobility (NETL, 2010). Also, the movement of supercritical CO_2 front within the reservoir can sweep oil to production wells. Extraction of additional crude oil also provides more space available for CO_2 storage in the long-term.

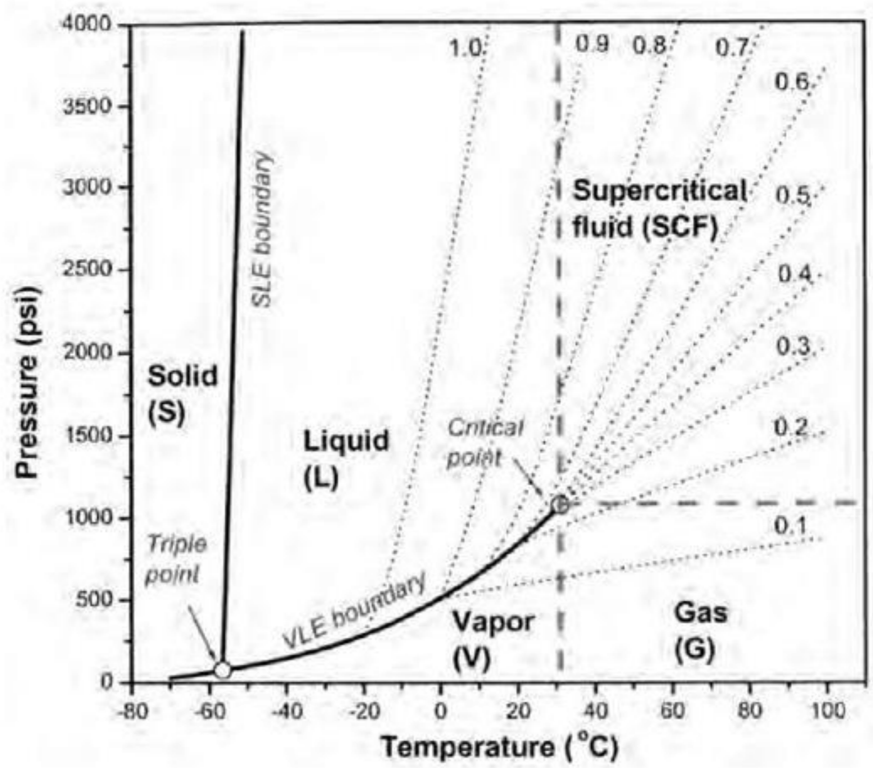

Figure 2.4 Phase diagram for CO_2 with constant density lines (g/cm^3) (Khan, 2007)

2.1.2 Minimum Miscibility Pressure

Minimum Miscibility Pressure (MMP) is the lowest pressure which crude oil and gas are completely miscible in a multiple contact process at with a given reservoir temperature (Donaldson et al., 1989). This pressure plays an important role in miscible gas injection, including CO_2 Huff-n-Puff, conventional CO_2 flooding and Water alternating gas (WAG) because it can determine the possibilities and capabilities of CO_2 to enhance oil recovery by miscibility mechanism.

Minimum Miscibility Pressure commonly determined by three method that are experiment, empirical correlation, and equation of state. Slim tube test and rising bubble apparatus (RBA) test are the most commonly used in experimental method, but it required large amounts of time and cost (Wang & Orr, 1997). Equation of state method is accuracy and fast, but the miscibility function is hard to contribute a clear judgment standard, because a characterization procedure of the plus-fraction have to be used and it extremely effect on the calculated result. Therefore, the empirical correlation method is usually used to calculate MMP value, because most of the MMP empirical correlations are proposed based on the experimental data of CO_2 and crude oil system. In the literature, there are eleven popular and highly accurate empirical correlations that can be calculated CO_2 and crude oil MMP (Rudyk, Sogaard, Abbasi, & Jorgensen, 2009) that is shown in Appendix A.

2.2 Carbon Dioxide Injection Techniques and Enhance Oil Recovery Mechanisms

2.2.1 Carbon Dioxide Huff-n-Puff

Carbon dioxide Huff-n-Puff (cyclic carbon dioxide stimulation) is one technique of enhanced oil recovery (EOR) with injected CO_2 into oil reservoir to increase oil recovery. This technique is included three main phases, as shown in Figure 2.5. The first phase is Huff phase that is to inject CO_2 into a single well over a designed slug size and time. The second phase is soaking phase that is to shut-in a well and leave the injected CO_2 in reservoir for days, weeks or up to months depending on engineering considerations (Whittaker & Perkins, 2013). And the third phase is Puff phase that is to produce reservoir fluid back from the same well. The cycle of CO_2 Huff-n-Puff is repeated to enhance oil recovery until the oil production declined to economic limit. This method is mostly conducted in small fields or in a pilot test to suitability for CO_2 EOR because of lower capital investment compared with full field CO_2 flooding and significantly generate quick payouts (Simpson, 1988). Applications of CO_2 Huff-n-Puff targets to extract residual oil from reservoir and increase recovery factor by several drive mechanisms such as, oil viscosity reduction, oil swelling, near wellbore damage removal, solution gas drive, suppression of water production, and other mechanisms (Mohammed-Singh et al., 2006).

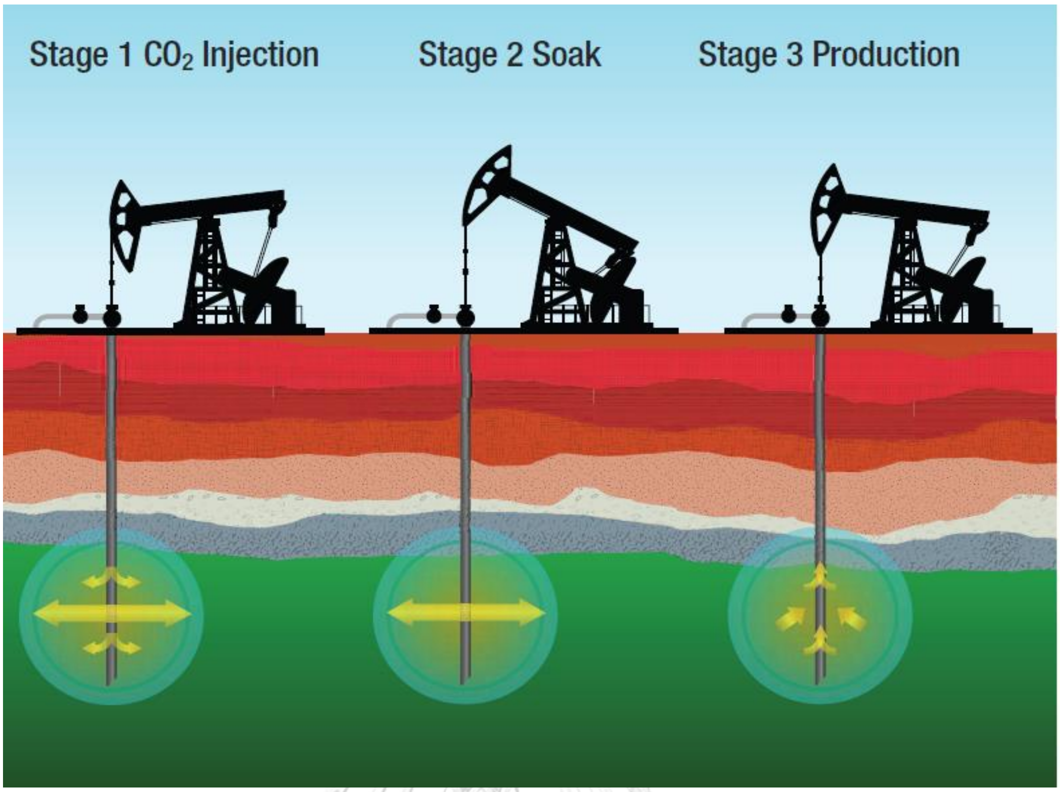

Figure 2.5 Three main phases of CO_2 Huff-n-Puff Technique (Praxair, 2014)

CO_2 Huff-n-Puff process can contribute the mechanisms to increase oil recovery. The main recovery mechanisms are oil viscosity reduction, oil swelling due to dissolution of CO_2 in crude oil, near wellbore damage removal, solution gas drive, and lowering of water production (Mohammed-Singh et al., 2006). Furthermore, there are additional oil recovery mechanisms due to CO_2 Huff-n-Puff process demonstrated in some fields, such as improved oil drainage area by encroaching water, vaporization of lighter components of oil, reduction of water relative permeability due to trapped gas reduce water saturation, reduction of relative permeability to water and gas during production due to hysteresis, and reduction of interfacial tensions (Bybee, 2007).

Using a compositional reservoir simulator can determine effects of CO_2 Huff-n-Puff on oil recovery mechanisms. At the end of CO_2 injection (Huff phase), near wellbore is effected due to the injected CO_2 pushes formation water away from the wellbore, while the intermediate components of crude oil are being vaporized. At the same time, the injected CO_2 dissolves into the crude oil that result in oil swelling and oil viscosity reduction (Song & Yang, 2013). During the shut-in well period (soaking phase), the injected CO_2 diffuses further into the reservoir and both oil and water phases flow back to the wellbore. The re-saturation of the oil phase with viscosity reduction goes toward the wellbore and the high gas phase saturation are around the wellbore. At the beginning of production period (Puff phase), the high oil saturation is produced with high gas oil ratio (GOR). As the production proceeds, both oil saturation and GOR are slowly decreased, whereas more water continuously flows toward the wellbore (Yu, Lashgari, & Sepehrnoori, 2014). At the end of the production period, the reservoir fluid composition almost reaches a new equilibrium condition. In conclusion, the CO_2 Huff-n-Puff process can effects oil recovery by a combination of several mechanisms. The dominant recovery mechanisms are vaporization of intermediate components, oil viscosity reduction, and oil phase swelling (Hsu & Brugman, 1986).

2.2.2 Conventional Carbon Dioxide Flooding

Conventional carbon dioxide flooding is an enhanced oil recovery technique that CO_2 is injected through a reservoir formation in order to extract more oil from reservoir. When the pressure of oil reservoir is continuously depleted through primary and secondary production, CO_2 flooding can be an efficient tertiary recovery method (Ghahfarokhi, Pennell, Matson, & Linroth, 2016). The proper reservoir to conduct CO_2 flooding could be both sandstone and carbonate reservoirs due to CO_2 is not affected by the lithology of the reservoir, but basically by the reservoir porosity and permeability (Verma, 2015). This process can be performed in low permeability reservoir because CO_2 can diffuse more easily comparing to other injected fluid. The suitable remaining oil saturation would be greater than 20% (Muslim et al., 2013). By injecting CO_2 through oil reservoir, the viscosity of crude oil will be reduced thus it would be easier to sweep or naturally flow from reservoir through producer. The conventional CO_2 flooding is operated by injecting of CO_2 through the injection wells. When the CO_2 diffuse into reservoir and contact with crude oil, the miscibility possibly occur based on reservoir pressure. If reservoir pressure is greater than minimum miscibility pressure (MMP), CO_2 and crude oil would be miscible and the effect of miscibility is occurred (Ennin & Grigg, 2016). The characteristic of miscible CO_2 flooding is shown in Figure 2.6.

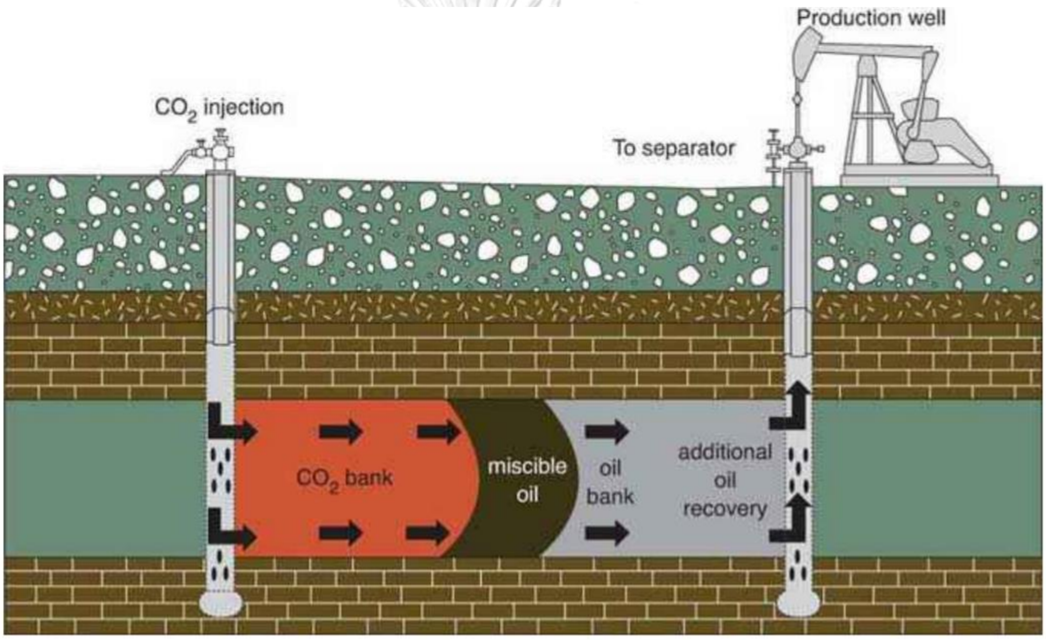

Figure 2.6 Characteristic of miscible CO_2 Flooding process (Khan, 2007)

In term of miscibility, CO_2 is a very powerful vaporizer of hydrocarbons, it is able to develop miscibility even though there may be very little of ethane (C_2) through hexane (C_6) components in crude oil (Holm & Josendal, 1974). The CO_2 and crude oil miscibility mechanism occurs through multiple contact or dynamic miscibility which required higher reservoir pressure than minimum miscibility pressure (MMP), sufficient contacted time and also distance of CO_2 move through reservoir. There are mainly two mechanism to develop CO_2 and crude oil miscibility including vaporization gas-drive process that is the intermediate and higher molecular weight hydrocarbons of crude oil vaporize into the injected CO_2, and condensation gas-drive process is the part of the injected CO_2 dissolves into the oil.

These mass transfer between crude oil and CO_2 allows the two phases to become completely miscible without any interface and help develop a transition zone that the miscible with oil in the front and with CO_2 in the back (Jarrel, Fox, Stein, & Webb, 2002). The transition zone of CO_2 miscible process is presented in Figure 2.7. As the miscible bank forms and moves it tends to be dispersed both transversely and longitudinally. The proper oil components are usually in C_5-C_{30} range and in the 25-45 ^{o}API range. The reservoir depth should be deep enough to allow reservoir pressure above the minimum miscibility pressure (MMP) (Kuuskraa & Vello, 2012).

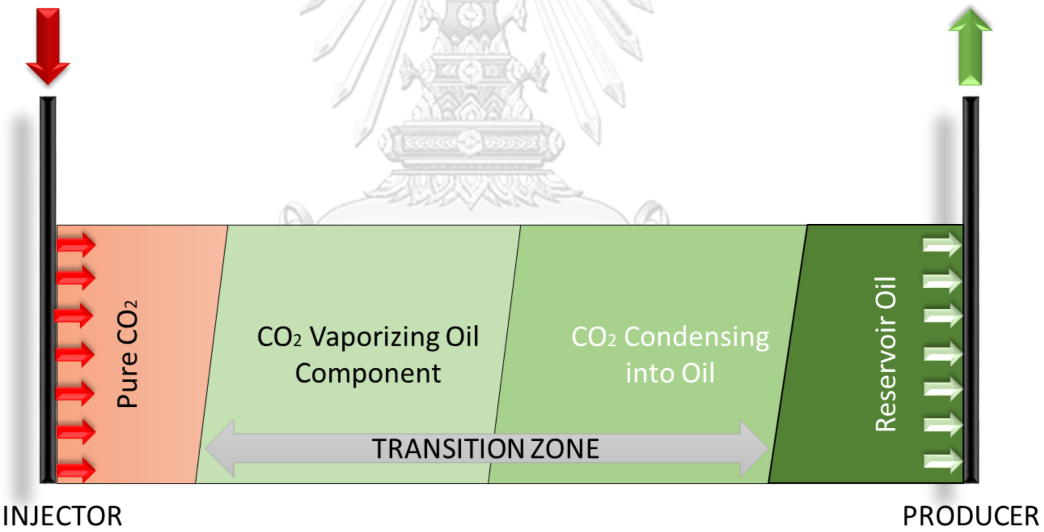

Figure 2.7 Schematic of CO_2 miscible process presenting the transition zone

Although, miscible CO_2 flooding is efficient process to enhance oil recovery due to over 95% of the crude oil contacted by injected CO_2 capably displaced (Verma, 2015). Several fields are usually not achieve miscibility with heavy oil reservoir that consists large amount of C_{30+} components. Also the performing of miscible CO_2 in low-pressure reservoir is challenged due to lower reservoir pressure than minimum miscibility pressure (MMP), hence huge amount of injected CO_2 is required to maintain reservoir pressure to be more than MMP and this situation likely disrupt the project economic (Muslim et al., 2013). However, immiscible CO_2 is highly soluble in crude oils causing of oil swelling that it can reduce oil viscosity, so the crude oil is more readily displaced by injected fluid. The suitability of crude oil for CO_2 flooding where the minimum miscibility pressures are impractical commonly can be determined by CO_2 solubility, oil swelling, and reduction of oil viscosity tests in the laboratory (Holm, 1982). Another the oil recovered mechanism by both CO_2 miscible flooding or immiscible flooding is identified as the trapped-gas effect that the injected CO_2 is able to create a small free gas saturation which is maintained in the reservoir. These fee gas will replace a part of the residual oil that would have been left in the reservoir, hence more residual oil saturation can be reduced (Donaldson et al., 1989). Enhanced oil recovery with immiscible CO_2 is conducted in various field projects and the oil recovery is satisfied. For example, the Lick Creek project in Arkansas was successfully flooded with immiscible CO_2. The 55% initial oil saturation was lowered to 46% after immiscible CO_2 flooding was conducted in 1640 acre of thick shallow sandstone formation (Reid & Robinson, 1981). Moreover, the Wilmington project in California was achieved by immiscible CO_2 flooding with 10-15% of oil recovery factor at a CO_2 requirement of only 6 Mscf/bbl oil (Saner & Patton, 1983).

Reservoir problems with CO_2 flooding can be separated in to three main categories. First, early CO_2 breakthrough that has happened in several CO_2 EOR project around the world due to high permeability zone (thief zone) and gravity overriding effect. The problem of early breakthrough usually occur after 0.05-0.2 hydrocarbon pore volume injection that causes a continually increasing fraction of CO_2 to be circulated through the reservoir without contacting or displacing crude oil (Donaldson et al., 1989). Poor sweep efficiency is the result of this problem that cause of project failure. To correct the early CO_2 breakthrough is alternate water slug that known as water alternating gas (WAG) or the use of CO_2 foam can also solve this problem. Second, unstable CO_2 flood fronts that occurs when viscosity ratio at the CO_2 and oil bank front is unfavorable, it causes viscous fingering and unstable flood front due to the growth of fingers disperses less energy than maintain a smooth front movement. The result of unstable flood fronts is poor sweep efficiency. One decent method of reducing the CO_2 mobility is to inject slugs of water and CO_2 alternately. Because the injected slug of water reduces relative permeability to CO_2, thus the mobility is lower (Donaldson et al., 1989). Finally, the reduction of injectivity occurs when CO_2 contacts reservoir crude oil and a heavy liquid or solid hydrocarbon phase form. This problem is solved by alternated injection of CO_2 and water (WAG). The mechanism of increasing injectivity by WAG is the injected slug of water gradually dissolve residual saturation of carbon dioxide in the formation (Donaldson et al., 1989).

2.2.3 Water Alternating Gas (WAG)

Based on high economic cost of carbon dioxide (CO_2), a more economical technique was developed to reduce the huge amount of CO_2 requirement in conventional CO_2 flooding (Han & Gu, 2014). This technique involves injection of CO_2 and water alternatively that commonly known as water alternating gas (WAG) flooding. In addition, WAG flooding is able to efficiently solve the serious problems of conventional CO_2 flooding such as, early breakthrough, unstable flood front, and low injectivity (Whittaker & Perkins, 2013). WAG flooding processes relate to the injection of a CO_2 slug in to oil reservoir followed by slug of water that serves as the chasing fluid that help maintain reservoir pressure, displace injected CO_2 and crude oil, adjust flood front to be more stable, reduce mobility of CO_2, and increase injectivity (Donaldson et al., 1989). And this cycle is repeated as operational design. Hence, the WAG process fundamentally consists two mechanism including the injected CO_2 reacts with crude oil thereby reducing the oil viscosity consequently making the oil can flow easily due to miscible and immiscible effects. And the alternating water injection can maintain reservoir pressure and help reduce amount of CO_2 usage, consequently solve various problems of conventional CO_2 flooding that already motioned. The characteristic of WAG flooding is shown in Figure 2.8.

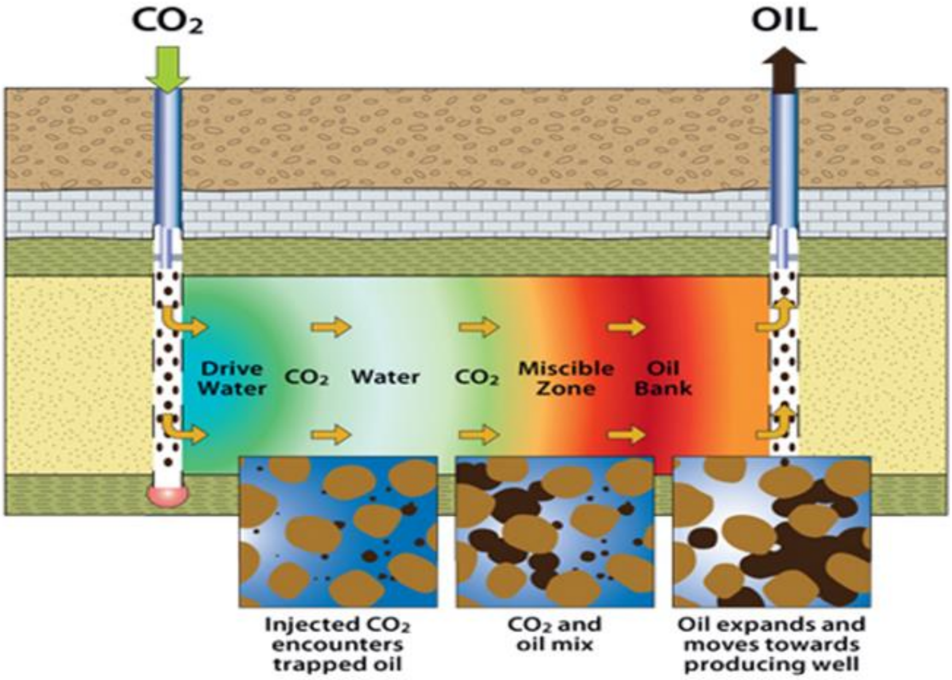

Figure 2.8 Characteristic of WAG process (Whittaker & Perkins, 2013)

Currently, various study have proposed comprehensive classification of the WAG processes which includes MWAG (Miscible Water Alternating Gas), IWAG (Immiscible Water Alternating Gas), HWAG (Hybrid Water Alternating Gas), FAWAG (Foam Assisted Water Alternating Gas), SWAG (Simultaneous Water Alternating Gas), and SSWAG (Selective Water Alternating Gas) (Whittaker & Perkins, 2013). In the miscible WAG injection process, the reservoir pressure and minimum miscibility pressure (MMP) are the key factors to achieve. When the reservoir pressure is maintained above the MMP, the miscibility occur between CO_2 and crude oil that defined as both the displacing and displaced fluid mix in all proportions without interference (Ennin & Grigg, 2016). One the reservoir pressure drops below MMP, miscible WAG will be lost and become to immiscible WAG. In the foam assisted WAG process, the slug of water is injected alternatingly foam of CO_2. The simultaneous WAG (SWAG) is the process to inject water and CO_2 at the same time by mixing of water and CO_2 at the surface before injection through reservoir (Gong & Gu, 2015). For the selective WAG (SSWAG) method, water is injected at the top of reservoir formation and CO_2 is injected at the bottom of the formation through a single injector (Tarek, 2001). The difference of injected fluid densities will provide a better sweep efficiency due to water tends to sweep crude oil downward and the CO_2 tends to sweep crude oil upward of reservoir that displayed in Figure 2.9. Finally, one of key considerations is the time to initiate WAG process. Due to the WAG process could be started at very beginning of a project that known as initial WAG. Otherwise, it could be implemented after breakthrough which can be referred to post-breakthrough WAG. Therefore, laboratory experiments and numerical simulations become an extremely significant in order to make a knowledgeable and economical decision.

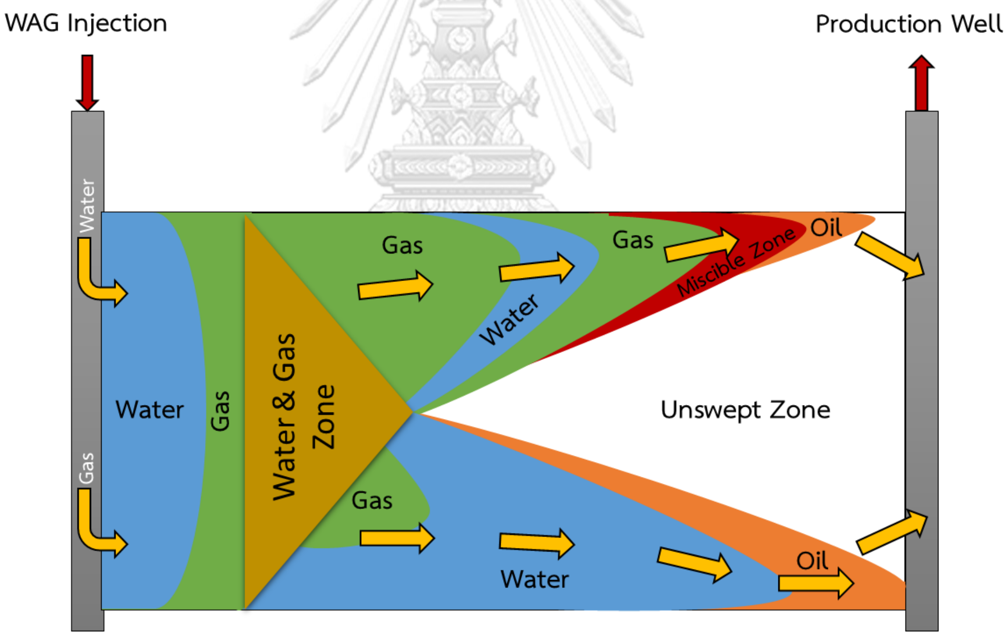

Figure 2.9 Schematic of selectively Simultaneous WAG process

2.2.4 Design Step of CO_2 EOR

The following Table 2.1 shows the carbon dioxide enhanced oil recovery (CO_2EOR) design steps that is from the recent paper by Holm and O'Brien (1986):

Table 2.1 Carbon dioxide enhance oil recovery design steps

Step1	Measure gravity, molecular weight, C_5-C_{30} content and type, and asphaltene content using oil sample from candidate reservoir.
Step2	If the reservoir flow paths are not primarily fractures and if the gravity of the oil is lighter than 12 degree API, it is likely to be candidate for CO_2 flooding, either miscible or immiscible.
Step3	Estimate minimum miscibility pressure (MMP) using correlation. Conduct slim-tube experiments to establish MMP more accurately.
Step4	Based upon the above data and taking into account the reservoir pressure and depth. Decide whether oil displacement will be miscible or immiscible.
Step5	Process core and well log data to establish a geological model of the reservoir. Conduct pressure transient and oil saturation measurements in the field.
Step6	Construct a computer model based upon the reservoir data and determine the well pattern, injection and production rate, and slug size that will maximize sweep efficiency.
Step7	For thick reservoirs, consider zonal injection techniques.
Step8	Prepared to inject water in alternate slugs in the event carbon dioxide production becomes excessive.
Step9	Consider installation of a carbon dioxide recovery plant, because it could be a sound economic investment.

2.3 Determine Candidate well for Carbon Dioxide Huff-n-Puff Operation

Study of successful CO_2 Huff-n-Puff project is conducted by reviewing design and performance data in several wells. By correlating various performance characteristic with different operational parameters can be used to determine a candidate well that could highly benefit from CO_2 Huff-n-Puff technique. Also, the optimal design and operational configurations are identified in several specific situation. Screening criteria and favorable factors for CO_2 Huff-n-Puff operations shown in Table 2.2, can increase the chance of success of CO_2 Huff-n-Puff projects. They are very important to support engineering considerations and decisions for designing appropriate operation. The successful projects are conducted in mild pressure supported reservoirs that contain crude oil gravities between 11 to 38 ^{o}API and oil viscosities between 0.5 and 3000 cp. In term of reservoir properties, the projects are achieved in reservoirs with range of porosities from 11 to 32%, reservoir permeability from 10 to 2500 md, and reservoir depths ranging from 1150 to 12870 feet (345 to 3900 meters) with the pay zone thicknesses of 6 to 220 feet (2 to 67 meters). The optimal design and operational configurations of successful projects have injected CO_2 utilization from 0.3 to 22 Mscf/barrel with soaking interval of 2 to 4 weeks, and the maximum cycle of 3 cycles. The main factors to economically optimize the CO_2 Huff-n-Puff techniques are operating pressure, permeability and oil viscosity (Mohammed-Singh et al., 2006).

Table 2.2 Screening criteria and guidelines for CO_2 Huff-n-Puff technique

Parameters of Successful Reservoir	Light Oils	Medium Oils	Heavy Oils
Oil Viscosity (cp)	0.4 to 8	32 to 46	415 to 3000
Oil Gravity (API)	23 to 38	17 to 23	11 to 14
Porosity (%)	13 to 32	25 to 32	12 to 32
Depth (feet)	1200 to 12870	2600 to 4200	1150 to 4125
Thickness (feet)	6 to 60	36 to 220	200
Permeability (md)	10 to 3000	150 to 388	250 to 350
Factors Favorable to Huff-n-Puff Operations			
High oil saturations Thick pay intervals Mild pressure support to production Soak intervals 2 to 4 weeks High injection volumes and rates Deep reservoirs Maximum of 3 cycles			

2.4 Simulation Study for Carbon Dioxide Huff-n-Puff Operation

In the simulation study, a numerical model is created to simulate CO_2 Huff-n-Puff process by using fluid and rock properties from Middle Bakken oil reservoir. And the reservoir is assumed to be homogeneous. This numerical model is validated with field production data to ensure more reliable of simulated results. Comparison of oil recovery factor with and without CO_2 injection is shown as the cases of CO_2 injection demonstrates more oil recovery factor than the cases without injected CO_2. This is because the injected CO_2 dissolves into crude oil, yields oil swelling and oil viscosity reduction that result in the increasing of oil recovery. Based on the simulation results, the most significant parameter for CO_2 Huff-n-Puff method is CO_2 injection rate, followed by CO_2 injection time period, number of cycle, and CO_2 diffusivity, as shown in Figure 2.10. The other parameters such as, CO_2 soaking period, permeability, and fracture conductivity are less sensitive to increased oil recovery. The sensitivity of all uncertain parameters on the incremental oil recovery factor is shown in Tornado plot (Figure 2.11) (Yu et al., 2014).

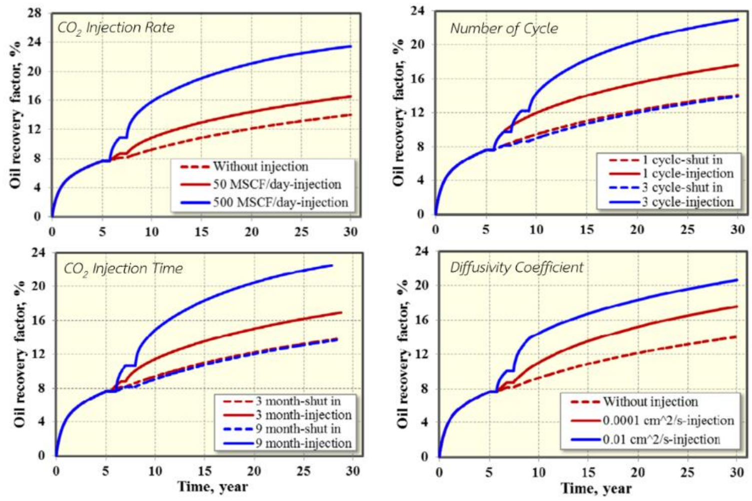

Figure 2.10 Effect of parameters on oil RF using CO_2 Huff-n-Puff (Yu et al., 2014)

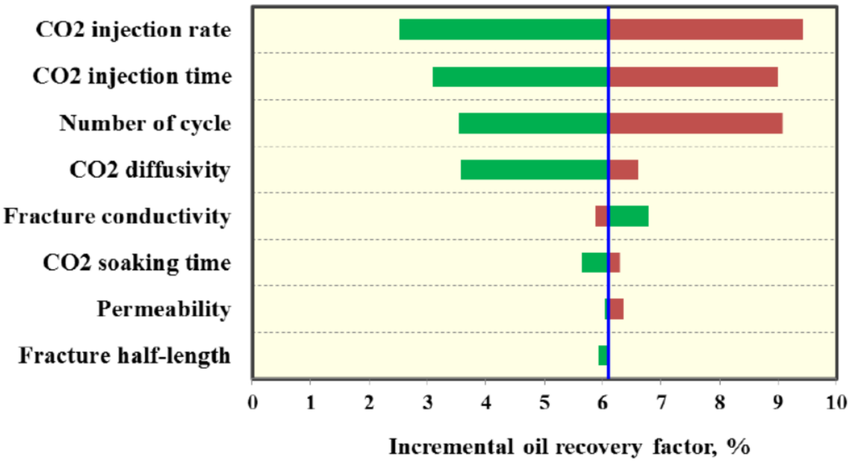

Figure 2.11 Sensitivity of parameters on the incremental oil RF

2.5 Optimization of Water Alternating Gas (WAG) Process in the Rangely Oil Field

In 1986, a miscible carbon dioxide (CO_2) project commenced in the Rangely Weber sand unit in northwest Colorado. Over several years, the project development processes have converted from continuous adding numerous CO_2 injectors to management of existing CO_2 injection resource. The aim of maximizing oil recovery and reducing operating costs can be achieved by optimization of the water alternating gas (WAG) process.

Based on reservoir simulation study, flood performance of WAG is optimized by varying of CO_2 slug size and WAG ratio tapering sequence to maximize project economics. The simulation studies and field tests is also completed to determine an optimum half-cycle for the WAG process in Rangely Weber Sand Unit. A half-cycle is defined as amount of injected CO_2 or water that measured in hydrocarbon pore volumes. The results of these study shown that the decreasing of half-cycle has favorable economics. In addition, the cross-sectional model is used to provide vertical sweep efficiency data and to evaluate sensitivities of CO_2 injection volume, WAG ratio, and injection profile. Also, the areal and one dimensional models are built to determine the areal sweep efficiency and displacement path, respectively.

The study showed that injecting of 30% hydrocarbon pore volume (0.3HCPV) slug size of CO_2 with a 1:1 WAG ratio provide the optimum economic recovery. And it showed low sensitivity to the WAG ratio used. The using of 2:1 WAG ratio shows a slightly higher ultimate recovery but the sooner initial response to CO_2 injection under 1:1 WAG design provides the greater project economics. The WAG performance for a production well in the Rangely Weber sand unit is shown in Figure 2.12.

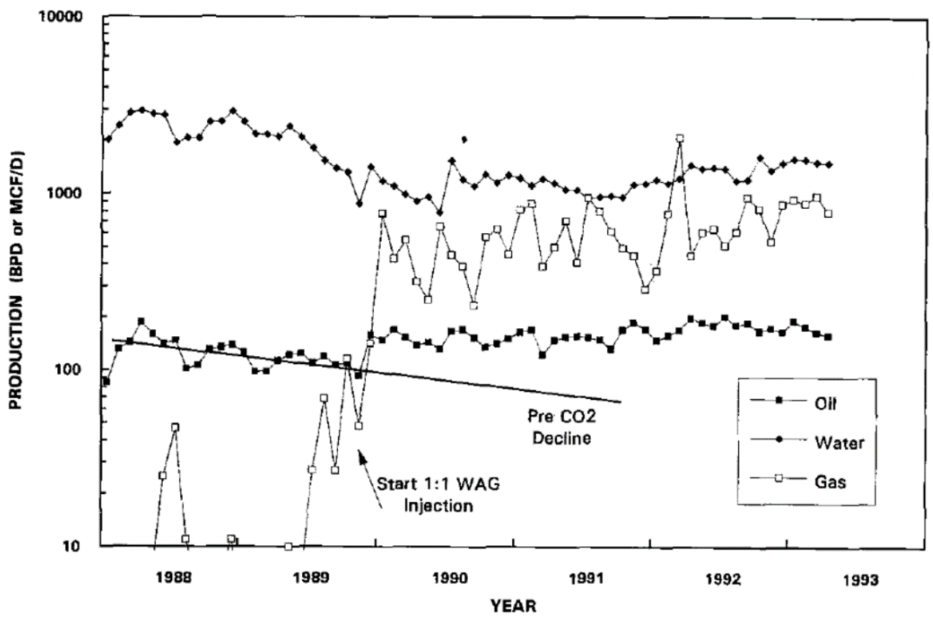

Figure 2.12 Production well response to WAG using 0.3HCPV and 1:1 WAG ratio (Attanucci, Aslesen, Hejl, & Wright, 1993)

Nevertheless, the goals to reduce costs and maximize the profitability of CO_2 injection still improved by designing of WAG tapering strategies. These WAG process improvement is considerably focused on optimizing methods for maximum oil recovery from WAG injection patterns. The results of reservoir simulation demonstrate that WAG tapering is an economical effective way to improve efficiency of the CO_2 recovery process. This tapering continuously converts WAG injection from 1:1 to 2:1 to chasing water. These processes can effectively reduce CO_2 production and improve the efficiency of the CO_2 recovery mechanisms. The tapering WAG performance in the Rangely oil field is shown in Figure 2.13. Finally, the WAG management in this study can result in significant resource conservation and have a major impact on CO_2 project economics (Attanucci et al., 1993).

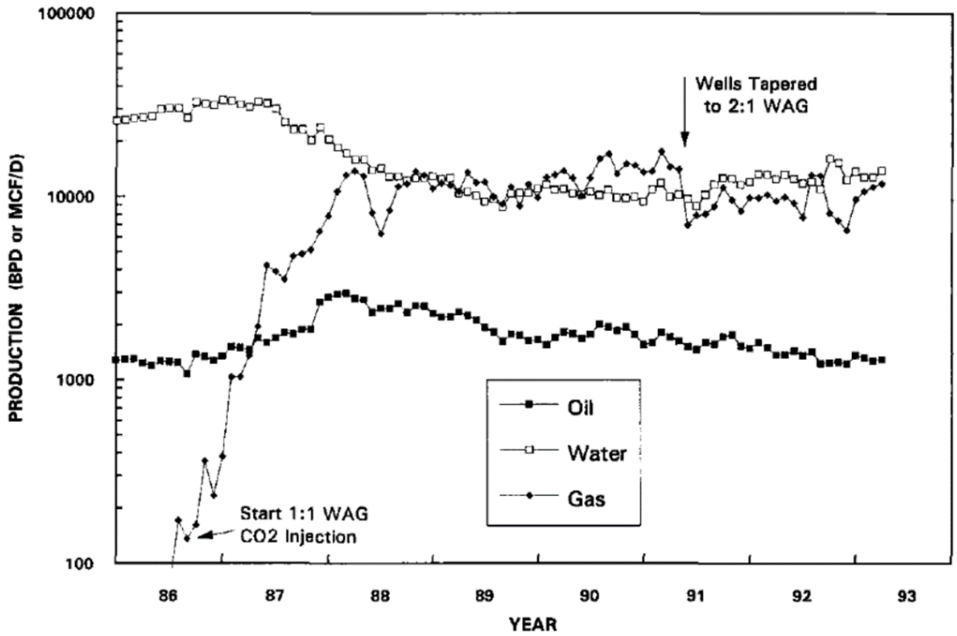

Figure 2.13 Characteristic of WAG tapering (Attanucci et al., 1993)

2.6 Optimization of Carbon Dioxide Huff-n-Puff in Low-Pressure and Low-Permeability Oil Reservoir

The performance of CO_2 Huff-n-Puff process is determined in a low pressure and low permeability reservoir with a closed boundary. And optimized operational parameters are investigated to maximize the process response of CO_2 Huff-n-Puff. The average porosity and average permeability of investigated reservoir are 9.6% and 2.3 md, respectively. The reservoir pressure is 12.9 MPa or 1874 psi that is far below the measured minimum miscible pressure (MMP) of 23 MPa (3336 psi). This reservoir pressure has no sufficient energy to drive crude oil through low permeability reservoir so there is no primary production in this situation. Water flooding, which can provide the external energy to depleted reservoir is not an efficient choice for this situation because of very low permeability reservoir. Thus injectivity required to success water injection is not achievable; on the other hand, the injectivity problem of CO_2 injection do not exist. In term of pressure, the reservoir pressure are lower than measured minimum miscible pressure that represents the partial miscibility or near-miscible CO_2 and crude oil condition in this reservoir. The results demonstrate that 0.1PV responses to be an optimal CO_2 slug size for the first cycle with 14.52% incremental recovery factor when the minimum reservoir pressure depleted to 3 MPa (435 psi), as shown in Figure 2.14. Moreover, economically optimum operating cycle for CO_2 Huff-n-Puff is three cycles with a potential recovery factor of 34.65%. The observations in a soaking time indicate that a longer time is required in the third cycle, comparing to the other two previous cycles. Thomas and Monger-McClure (1991) state that the optimum soaking time is one month base on some field Huff-n-Puff projects that extends soaking time up to four weeks can significantly improve response. Furthermore, the recovery factor is sensitive to maximum reservoir pressure, hence shut in period in soaking phase should be long enough to allow maximum reservoir pressure built up to as high as formation permits, as shown in Figure 2.15. Finally, injecting nitrogen as chasing gas after CO_2 injection can significantly improve the cycle performance based on assisting of maximum pressure build-up. Also, injected nitrogen reduce the CO_2 utilization as low as 0.324 MSCF/STB (Wang et al., 2013).

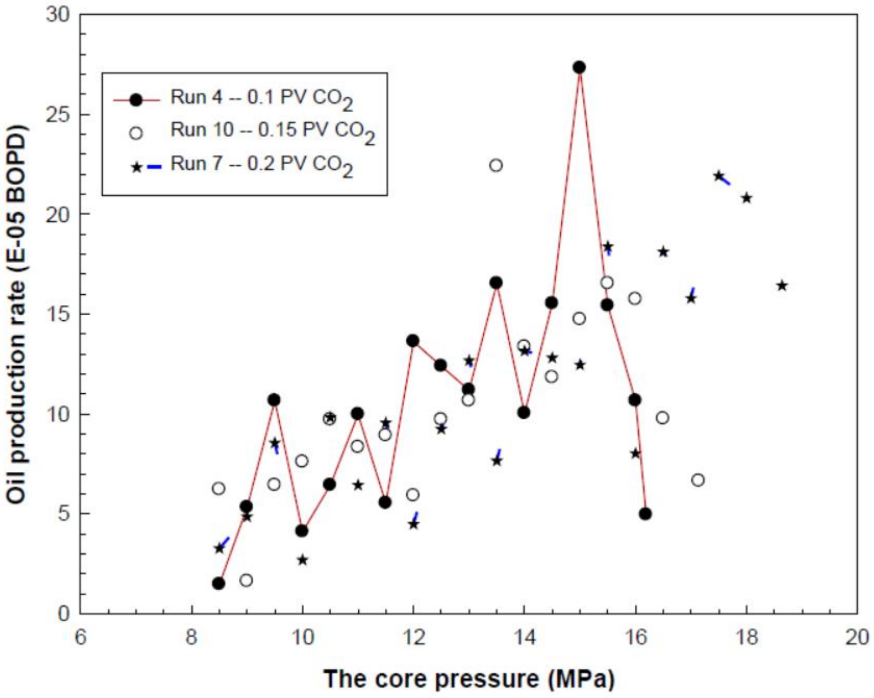

Figure 2.14 Oil production profile of different CO_2 slug size (Wang et al., 2013)

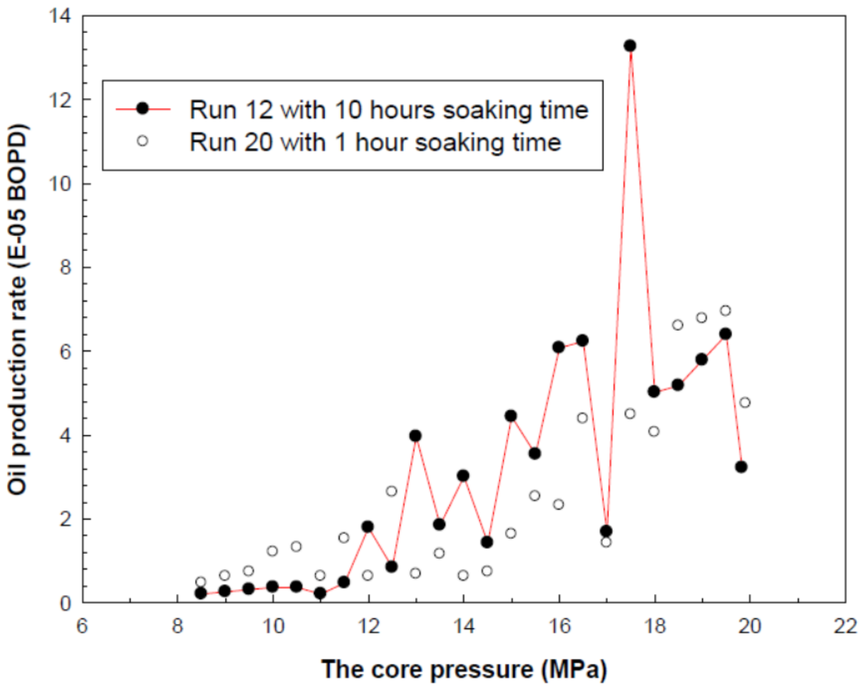

Figure 2.15 Effects of soaking time on oil production rate (Wang et al., 2013)

2.7 Evaluation of Oil Recovery by Water Alternating Gas (WAG) Injection

Water alternating gas (WAG) is usually applied to reduce the mobility of gas in EOR flooding system and the result of applying of WAG is better sweep efficiency. Consequently, the oil recovery efficiency is improved. Huang and Holm (1988) stated that the definition of WAG injection is alternated injection of water and gas with ratios of 0.5 to 4.0 water to 1.0 reservoir volume of gas at alternation frequencies of 0.1 to 2.0% of hydrocarbon pore volume slug size for each fluid. And Panada et al. (2010) indicated that 5-20% additional oil recovery over water flood can be achieved by WAG injection process. However, the WAG injection have to be carefully designed due to the possibility of blocking the oil flow into reservoir with injected water that will reduce oil recovery factor. Also, the poor designs can caused the preventing of CO_2 to contact crude oil by injected water that results in the reduction of displacement efficiency. The performance of WAG process is significantly influenced by WAG ratio, number of WAG cycles, slug size, injection rate, cycle period, and system wettability (Chen & Reynolds, 2015).

The effect of WAG ratio on the performance of CO_2 flood is investigated by conducting six runs of 1:1, 2:1, 1:2, 3:1, and 1:3 WAG ratio. A fixed pore volume of CO_2 injection of 20% hydrocarbon pore volume injected (0.2 HCPV) was used for all runs. The oil recovery factor versus CO_2 pore volume injection for all cases is shown in Figure 2.16. Results of these simulation study demonstrates that the WAG ratio significantly effect on the performance of CO_2 flooding process. The highest oil recovery can be achieved by using WAG ratio of 1:1 or 1:2. The continuous Injection of CO_2 present the lowest recovery performance due to high CO_2 mobility that is the cause of low volumetric sweep efficiency. Commonly, increasing the WAG ratio improves the performance of the WAG process by developing the volumetric sweep efficiency (Zekri, Nasr, & AlShobakyh, 2011).

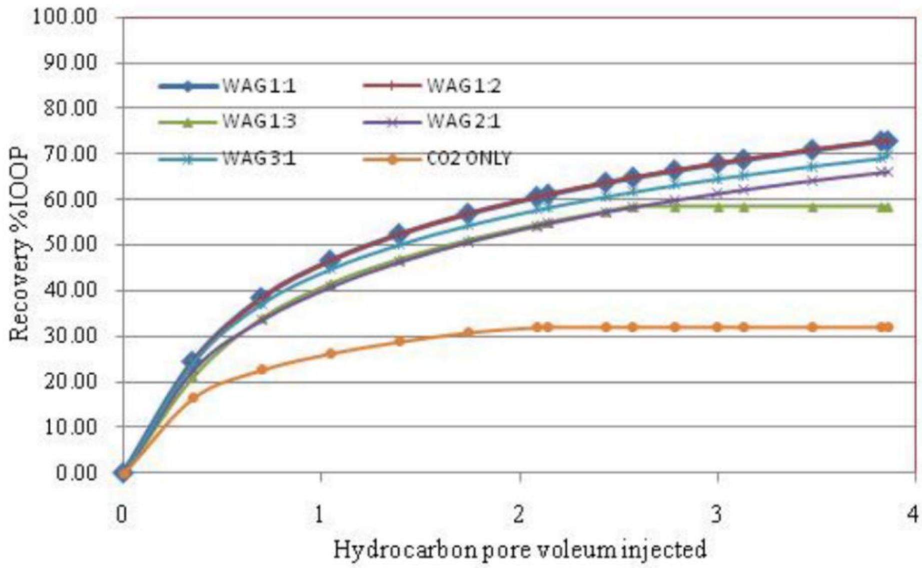

Figure 2.16 Relationship between oil recovery factor and CO_2 pore volume injection for different WAG ratios (Zekri et al., 2011)

The presence of water in reservoir possibly reduce CO_2 flooding performance due to lesser accessible oil interacted by CO_2, the most of injected CO_2 will be consumed by the formation water interaction. These effects are defined as water shielding (Zekri et al., 2011). Consequently, several runs are performed to investigate the effect of water saturation on the performance of WAG injection process. The WAG ratio of 1:1 is used at varying initial water saturations of 20%, 45%, 60%, and 75%. The simulation results illustrated that higher oil recovery factor can be obtained if the WAG flooding process is applied in low water saturation, as shown in Figure 2.17. This situation occurs because more available oil can be contacted with the injected CO_2 which will accelerate the extraction mechanisms. Therefore, it is important to note that water shielding has a significant effect on the WAG performance (Zekri et al., 2011).

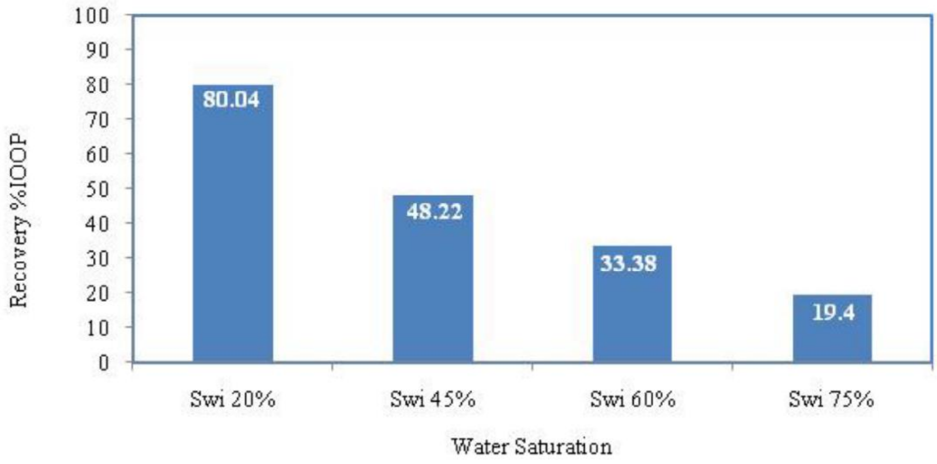

Figure 2.17 Relationship between oil recovery factor and water saturation (Zekri et al., 2011)

Sensitivity analysis is conducted to study the effect of heterogeneity on oil recovery factor of WAG injection process, using the different values of Dykstra Parson's coefficient. In this study, four different values of Dykstra Parson's coefficient of 0.1, 0.3, 0.7, and 0.85 are employed. The relationship between oil recovery factor and WAG ratio for different values of Dykstra Parson's coefficient is demonstrated in Figure 2.18. These results show that the increasing of Dykstra Parson's coefficient, which defined as increasing of heterogeneity, causes oil recovery factor reduction. The low permeability variation of 0.1 that represented the homogenous reservoir provides the best performance of 1:1 WAG ratio. In contrast, The WAG ratio of 2:1 is the optimum scheme for the heterogeneous reservoir of permeability variation of 0.85. Hence, the reservoir heterogeneity should be taken into account when optimum selecting WAG ratio (Zekri et al., 2011).

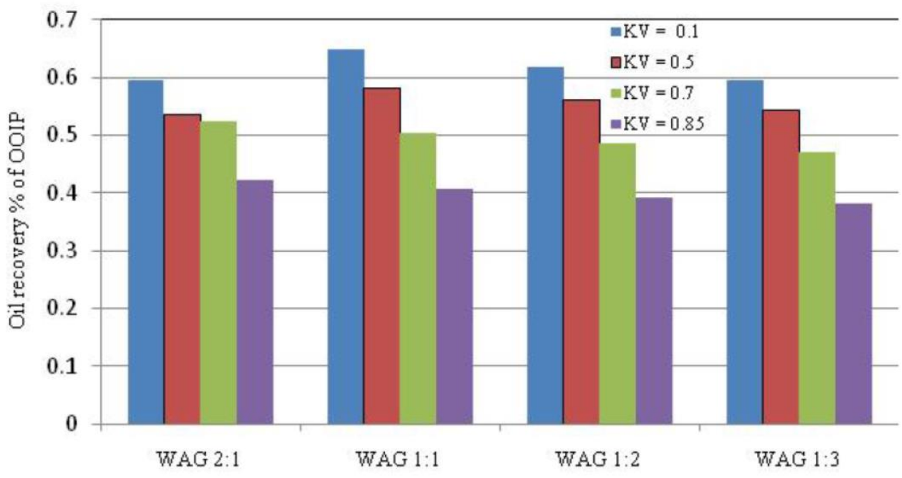

Figure 2.18 Oil RF versus WAG ratio for different Kv (Zekri et al., 2011)

2.8 CO_2 Solubility Characteristic and Oil Swelling Factor

This research has investigated the physical properties of the Carbon Capture and Utilization (CCU), especially Enhanced Oil Recovery (EOR). The application of immiscible CO_2 to enhanced oil recovery is introduced as one of CCU that the main related physical properties are CO_2 solubility in crude oil and oil swelling factor. The measurement equipment of this study included dead oil samples of intermediate and heavy oil that their API gravity are 29.3 and 11.5 API, respectively. Core sample, which contain 21% of porosity and 500 to 600 md of permeability, is prepared to saturate 77.1% of oil and 22.9% of water before performing of experiment. In addition, oil swelling factor is measured by high pressure cell that the oil swelling will be evaluated by photography of surface movement of the oil column, and then visual inspection of photographs (Sasaki & Sugai, 2017).

The results of this research, which reservoir pressure is less than 1,450 psi and reservoir temperature of 122°F, show that the swelling factor will be increased with increasing CO_2 pressure. Moreover, supercritical CO_2 provides almost twice time of gas diffusion coefficients in oil (Sasaki & Sugai, 2017). The relationship between oil swelling factor and CO_2 injection pressure is shown in Figure 2.19.

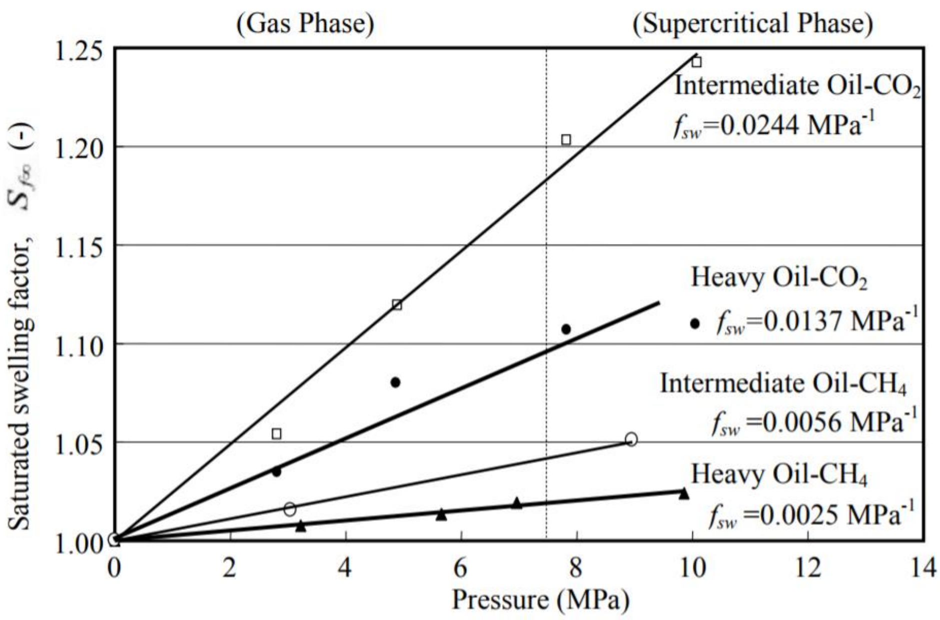

Figure 2.19 Swelling factor versus CO_2 injection pressure (Sasaki & Sugai, 2017)

Moreover, the relationship between PVT measurement solubility for CO_2 and CH_4 and reservoir pressure is presented in Figure 2.20. The results shows that solubility of gas and crude oil is increased rapidly by increasing pressure below bubble point pressure and the solubility will be slowly increased with additional pressure above bubble point pressure. Finally, the relationship between gas dissolution and the oil swelling factor is proportional (Sasaki & Sugai, 2017), as shown in Figure 2.21.

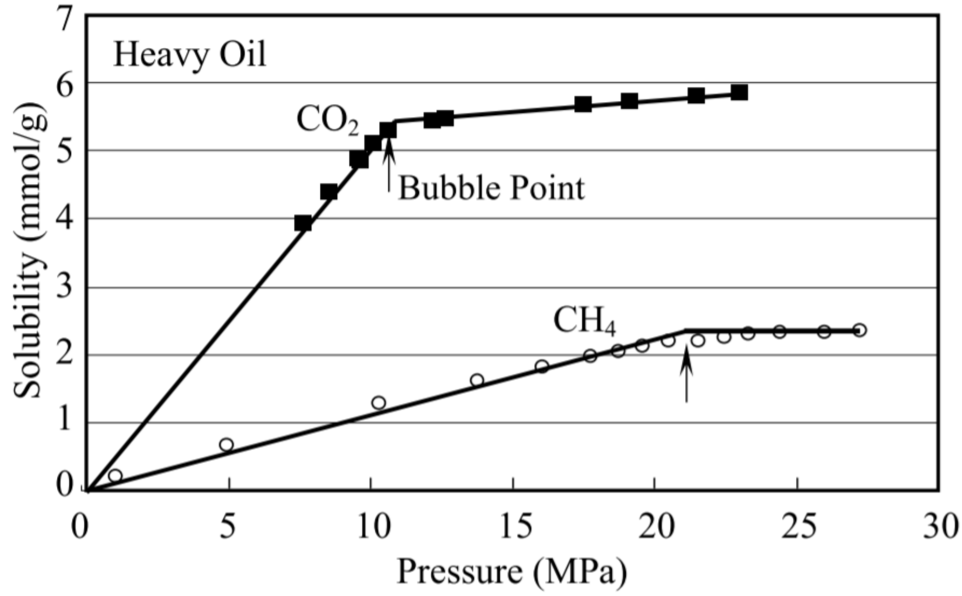

Figure 2.20 CO_2 and CH_4 solubility measured by PVT (Sasaki & Sugai, 2017)

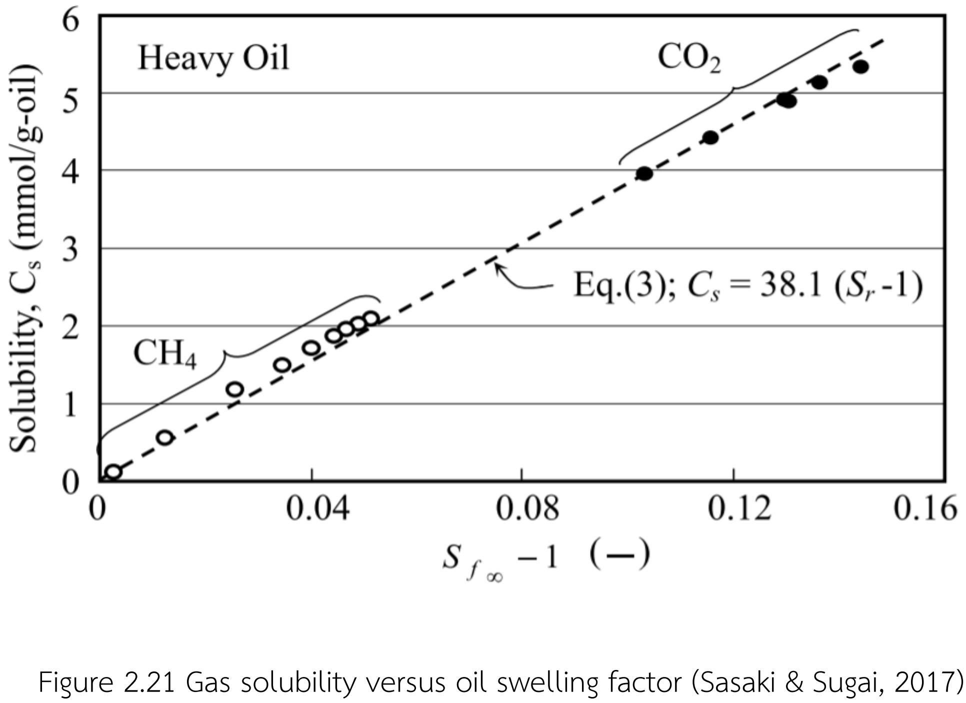

Figure 2.21 Gas solubility versus oil swelling factor (Sasaki & Sugai, 2017)

According to these literatures, CO_2 Huff-n-Puff process and WAG process are individually investigated using numerical simulation. Several parameters of these two processes are evaluated, but the combination of CO_2 Huff-n-Puff and WAG processes has not been evaluated yet. The integrated CO_2 Huff-n-Puff and WAG method is interested to study because several field development projects usually required more than one EOR methods to economically achieve the maximum oil recovery with the limited injected supply. Thus, the effective combination techniques is important due to each EOR technique contains its own benefits and advantages above each other techniques. However, the integrated CO_2 Huff-n-Puff and WAG method contains numerous variable operating parameters that can considerably affect the project achievement. Hence, the sensitivity analysis is important to select the appropriate dominant parameters. Likewise, the simulation study can help to design optimum values of these key parameters to achieve the highest benefit. Moreover, several study assume the simulation model to be homogeneous reservoir that is easier to perform and analyze, but the actual reservoir is barely possible to be homogeneous due to complex geological stratigraphy. So heterogeneous model is the better choice to be effectively represent the actual reservoir characteristic. Last but not least, several related researches have been investigated the CO_2 EOR performance of reservoirs that contain higher pressure than MMP. Consequently, the miscibility mechanisms absolutely occur in these situations. However, numerous reservoirs have been recently depleted after many decades of primary recovery period. This situation becomes a challenge to develop this field with CO_2 EOR. Therefore, this study design to perform the CO_2 EOR in low-pressure reservoir that several related researches have not been investigated yet. Finally, this study will investigate the performance of integrated CO_2 Huff-n-Puff and WAG in low-pressure heterogeneous reservoir to fulfill the area of knowledge in CO_2 enhanced oil recovery operation.

CHAPTER 3
RESERVOIR SIMULATION AND METHODOLOGY

This chapter describes the details of reservoir simulation models in this study. The heterogeneous reservoir models which are created by using random values of porosity and permeability between the ranges of measured data from Fang oil field, are constructed to perform numerical simulation. Furthermore, the important input data in these reservoir models are presented in this chapter and divided into 4 sections, i.e., reservoir properties, oil composition and PVT properties, special core analysis (SCAL), and parameters related to injector and producer. A numerical reservoir simulator used for the performance evaluation of CO_2 enhanced oil recovery methods is CMG's compositional simulator (GEM). Finally, the detailed methodology is also explained at the end of this chapter.

3.1 Reservoir Simulation Model

Reservoir model is created with Cartesian grid type. The reservoir model's dimensions are 1,250, 1250, and 30 ft. in x, y, and z direction, respectively based on one of reservoir segment areas and its thickness in Fang oil field, Thailand. Numbers of grid block in each direction are 25, 25, and 6 blocks in x, y, and z directions, respectively. This model also consists of two layers of shale formation above the reservoir and two shale layers below the reservoir to ensure that the injected carbon dioxide (CO_2) will not visibly leak out the sandstone formation. The thickness of above 30 ft. shale formation is the same as that of below shale formations. The total number of grid block are 6,250 blocks which are still less than the maximum grid block of CMG-GEM academic package. The total area of this model is 1,562,500 ft^2 (35.87 acres) with the total thickness of 90 feet including 30 feet of above shale formation, 30 feet of sandstone formation, and 30 feet of below shale formation. In addition, the pattern of production well and injection well in this model is quarter five-spot pattern that comprises one injection well and one production wells at the opposite corners of model and well spacing is 1,768 feet. The dimensions of model together with location of two wells are displayed in Figure 3.1.

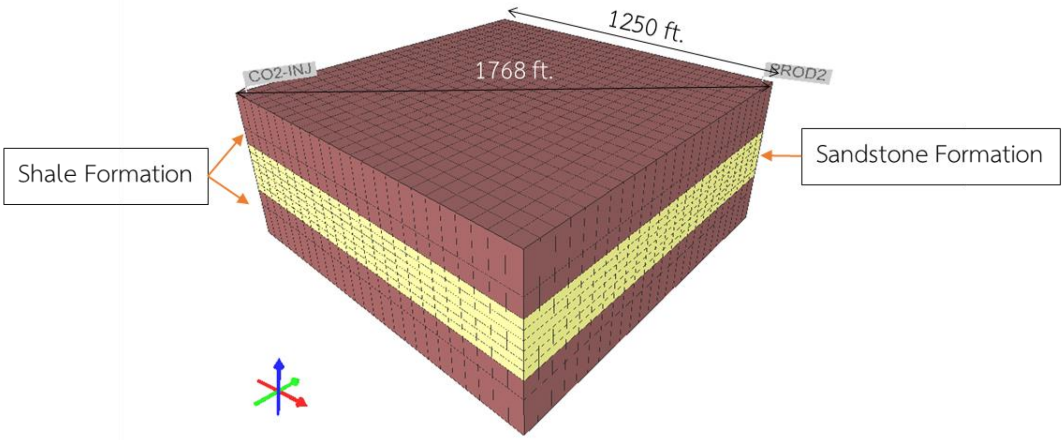

Figure 3.1 Dimensions of reservoir model with location of two wells, representing quarter five-spot pattern

The heterogeneous reservoir models are constructed by random 3,750 values between the ranges of measured porosity from Fang oil field, ranging from 0.2 to 0.3. Moreover, permeability of this heterogeneous reservoir model is also varied between 110 md and 190 md and put these data randomly into 3,750 grid blocks of reservoir. The average porosity of constructed reservoir model is 0.25 and the average permeability is 150 md. More details about heterogeneous reservoir model will be described in the next section, named “Reservoir Model with Heterogeneity”. Furthermore, there are two layers of shaly sandstone at each formations above and below the reservoir following with shale formation. The porosity of these two layers are 0.05 and 0.01, respectively. Moreover, the permeability of shaly sandstone is 0.000175 md and 3.32×10^{-9} md for shale formation. The reservoir physical properties using for this reservoir model are summarized in Table 3.1.

Table 3.1 Reservoir properties using for reservoir model construction

Parameter	Values	Unit
Grid dimension	25 x 25 x 6	block
Reservoir size	1250 x 1250 x 30	ft
Top of reservoir	4420	ft
Reservoir thickness	30	ft
Porosity	0.2–0.3	fraction
Median porosity	0.25	fraction
Horizontal permeability	110-190	md
Vertical permeability	0.1 x kh	md
Median horizontal permeability	150	md
Rock compressibility	0.000003	1/psi
Reservoir pressure	680	psi
Reservoir temperature	144	degree F
Reservoir Type	Sandstone	

3.2 Reservoir Model with Heterogeneity

The heterogeneous reservoir model is constructed based on existing data from a reservoir segment of Fang oil field that located in the northern part of Thailand. The heterogeneous reservoir properties, including porosity, horizontal permeability, and vertical permeability are input individually in 3,750 grids of sandstone formation. These numbers are selected randomly from existing data by using of Microsoft excel software®. The range of porosity is between 0.2 and 0.3. Figure 3.2 presents the heterogeneous reservoir model of varied porosities that are separated into six layers of sandstone formation and four layers of shale formation. And normal distribution of random porosity is presented in Figure 3.3 that their mean, median and mode are 0.25, 0.25, and 0.24 respectively. Moreover, the horizontal permeabilities, which are between 110 and 190 md, are also randomly input in every grid blocks of sandstone formation, as shown in Figure 3.4. The normal distribution of random permeability is presented in Figure 3.5 that its mean, median, and mode of these data are 150, 150, and 152 md, respectively. Finally, vertical permeability is defined as 10% of the horizontal permeability in their own grids. More details of the heterogeneous values for both porosity and permeability are shown in Appendix B.

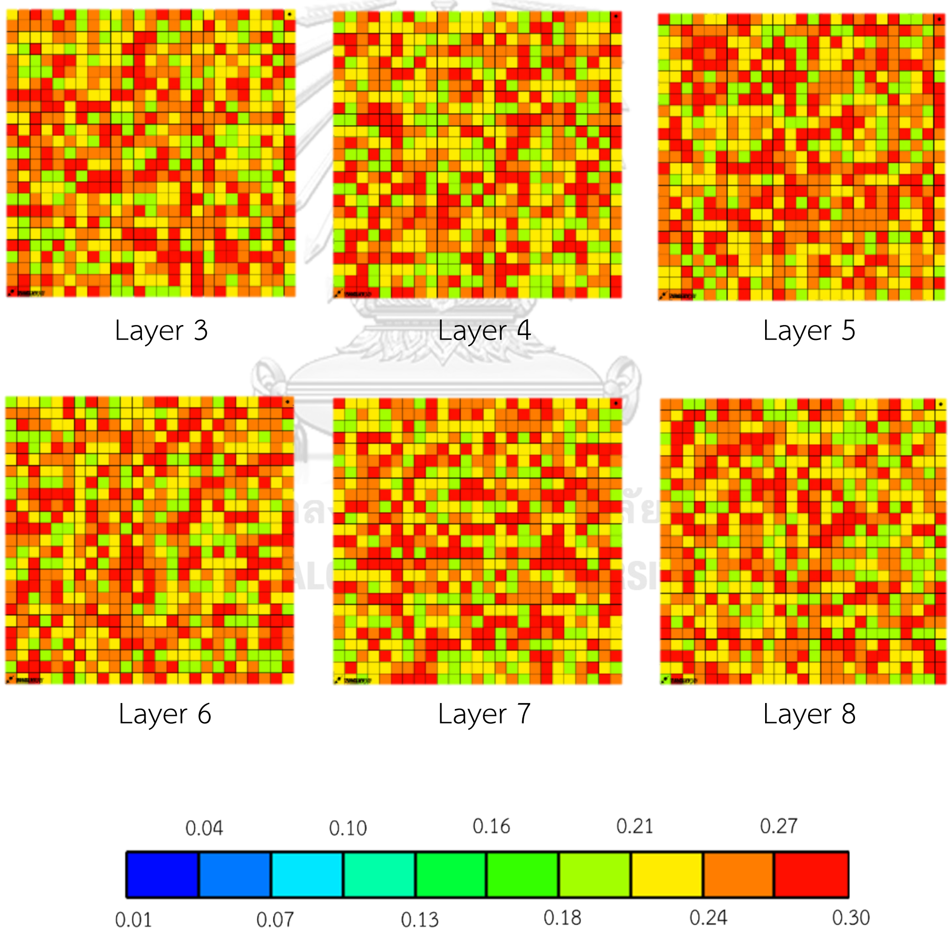

Figure 3.2 Six layers of heterogeneous porosity and its color scale

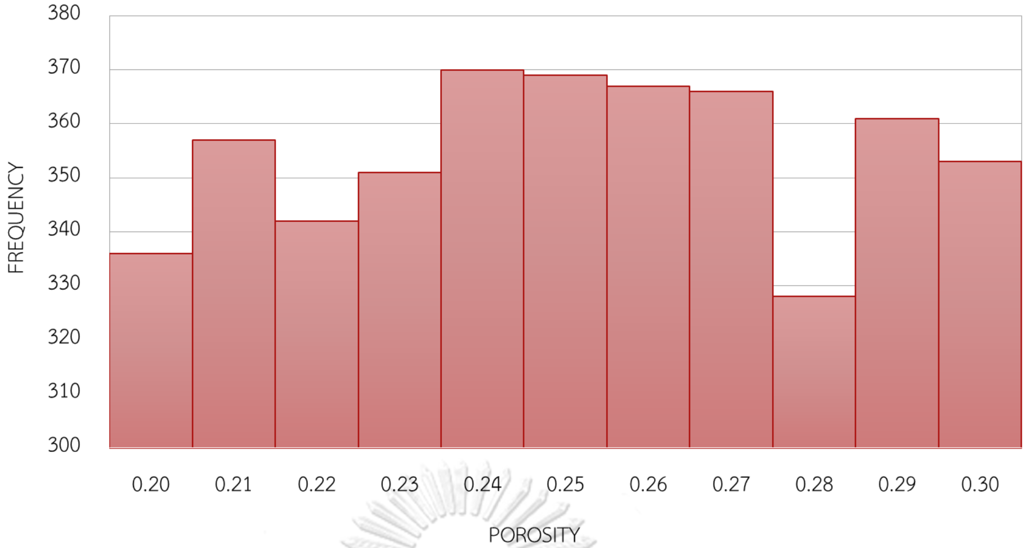

Figure 3.3 Histogram of porosity in heterogeneous reservoir model

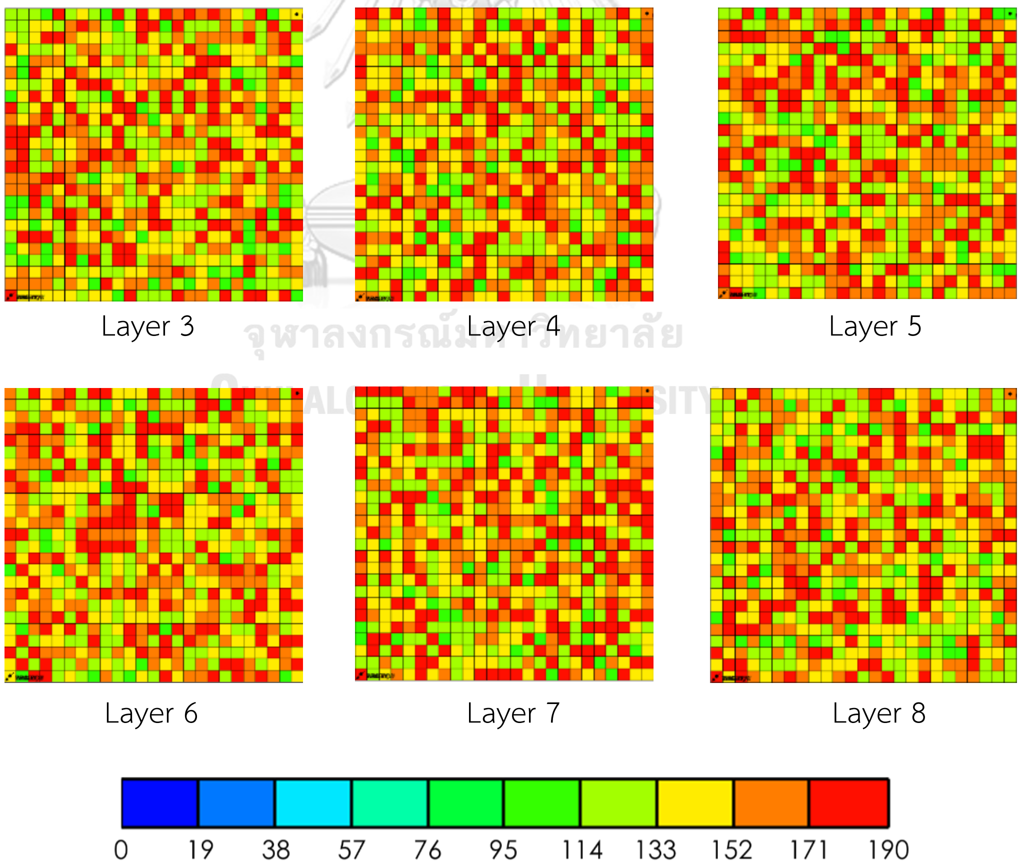

Figure 3.4 Six layers of heterogeneous permeability and color scale

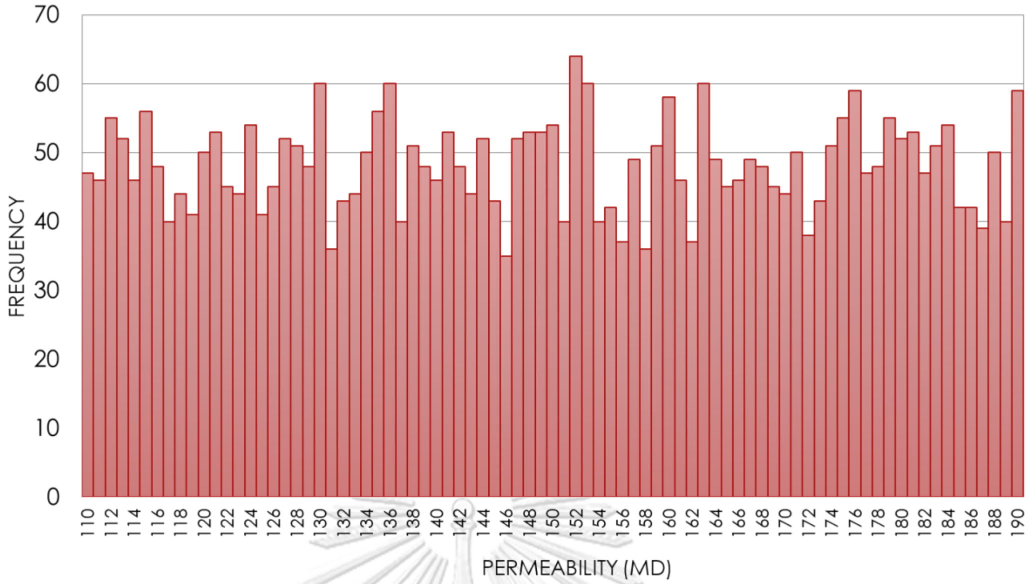

Figure 3.5 Histogram of permeability in heterogeneous reservoir model

3.3 Crude Oil Composition and PVT Properties

From Asavaritikrai (2015), there are 29 components between C_7 and C_{35+} and API gravity of the crude oil sample is about 31 ^{o}API. The composition of oil sample from Fang oil field are shown in Table 3.2.

Table 3.2 Compositions of oil sample from Fang oil field (Asavaritikrai, 2015)

No.	Component	Percent by weight (%)	No.	Component	Percent by weight (%)
1	FC7	0.05	15	FC21	4.81
2	FC8	0.68	16	FC22	4.48
3	FC9	0.93	17	FC23	4.97
4	FC10	1.00	18	FC24	4.26
5	FC11	1.45	19	FC25	4.42
6	FC12	1.84	20	FC26	4.33
7	FC13	3.06	21	FC27	4.56
8	FC14	3.52	22	FC28	3.58
9	FC15	4.86	23	FC29	3.97
10	FC16	3.87	24	FC30	3.72
11	FC17	4.71	25	FC31	3.27
12	FC18	3.49	26	FC32	2.87
13	FC19	6.33	27	FC33	3.64
14	FC20	5.23	28	FC34	1.70
			29	FC35	4.40

Pressure-Volume-Temperature (PVT) properties of reservoir fluids are defined by using various correlations. To generate PVT properties, it requires some measured initial parameters, including oil gravity, bubble point pressure, and solution gas-oil ratio. These parameters are presented in Table 3.3. And, the summary of correlations used to generate PVT properties is shown in Table 3.4.

Table 3.3 Initial parameters required for generating of PVT properties

Parameter	Value	Unit
Oil Gravity	31	^{o}API
Solution Gas-Oil Ratio (Rs)	120	SCF/STB
Bubble Point Pressure (Pb)	741	PSI

Table 3.4 Summary of used correlations for PVT properties

Parameter	Option
Oil Properties (P_b, R_s, B_o) Correlation	Standing
Oil Compressibility Correlation	Glaso
Dead Oil Viscosity Correlation	Ng and Egbogah
Live Oil Viscosity Correlation	Beggs and Robinson
Gas Critical Properties Correlation	Standing

Figure 3.6 to 3.12 demonstrate oil and gas PVT properties generated by CMG® software. The plots of PVT properties are included oil formation volume factor (B_o), oil density, oil viscosity, gas-oil ratio, gas formation volume factor (B_g), and gas density, as functions of pressure and temperature.

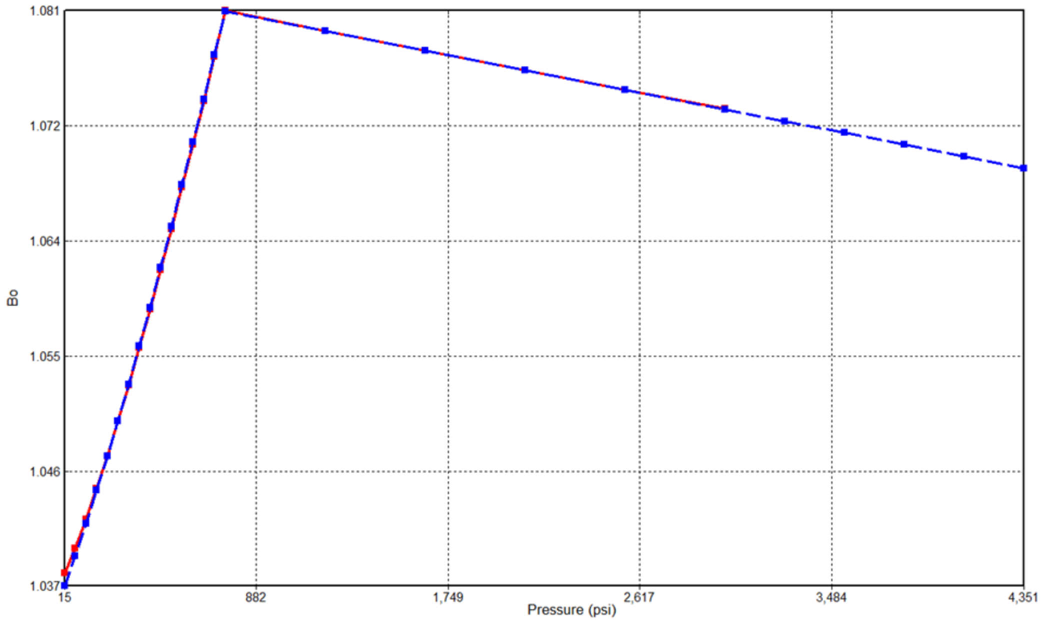

Figure 3.6 Oil formation volume factor (B_o) as a function of reservoir pressure

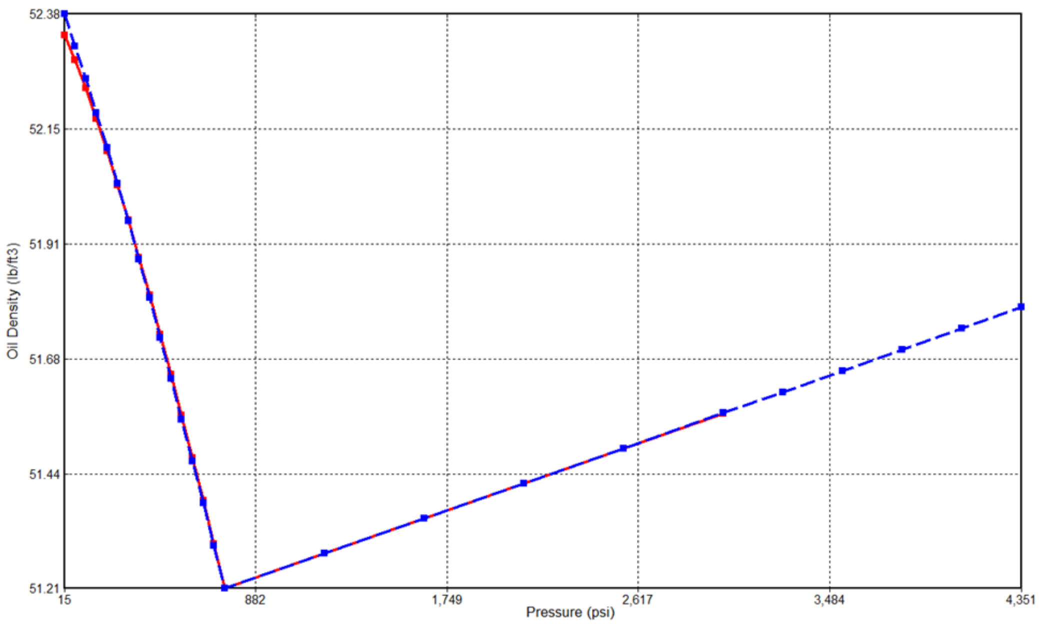

Figure 3.7 Oil density as a function of reservoir pressure

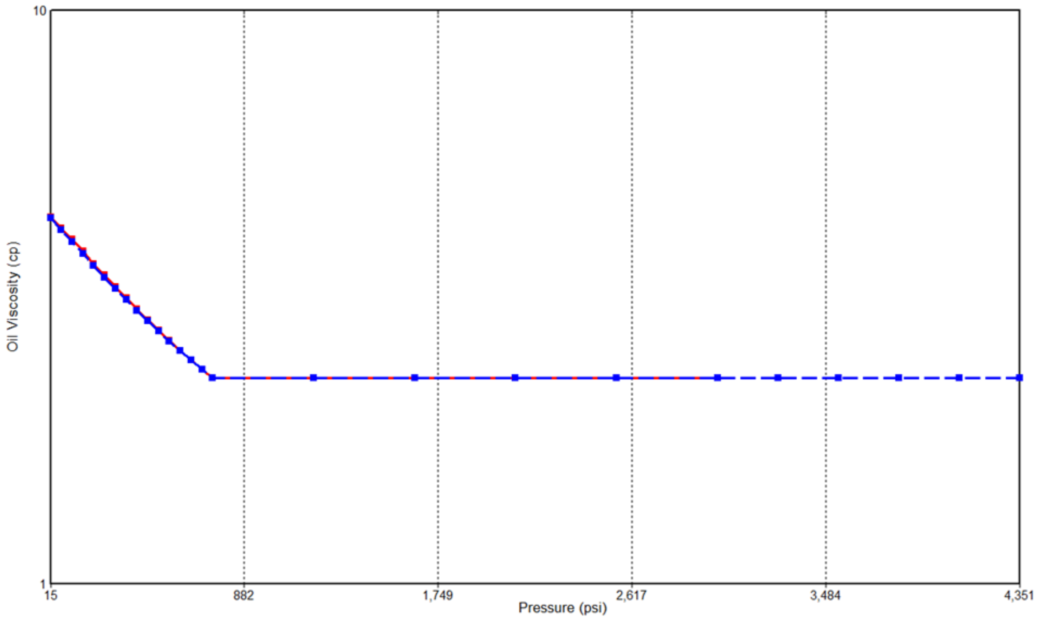

Figure 3.8 Oil viscosity as a function of reservoir pressure

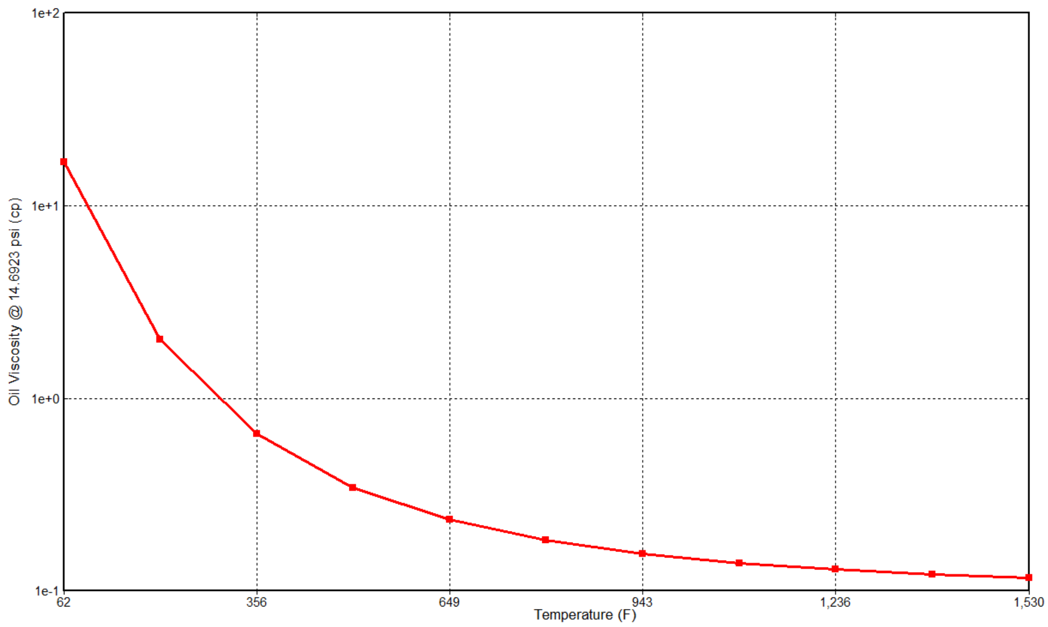

Figure 3.9 Oil viscosity as a function of reservoir temperature

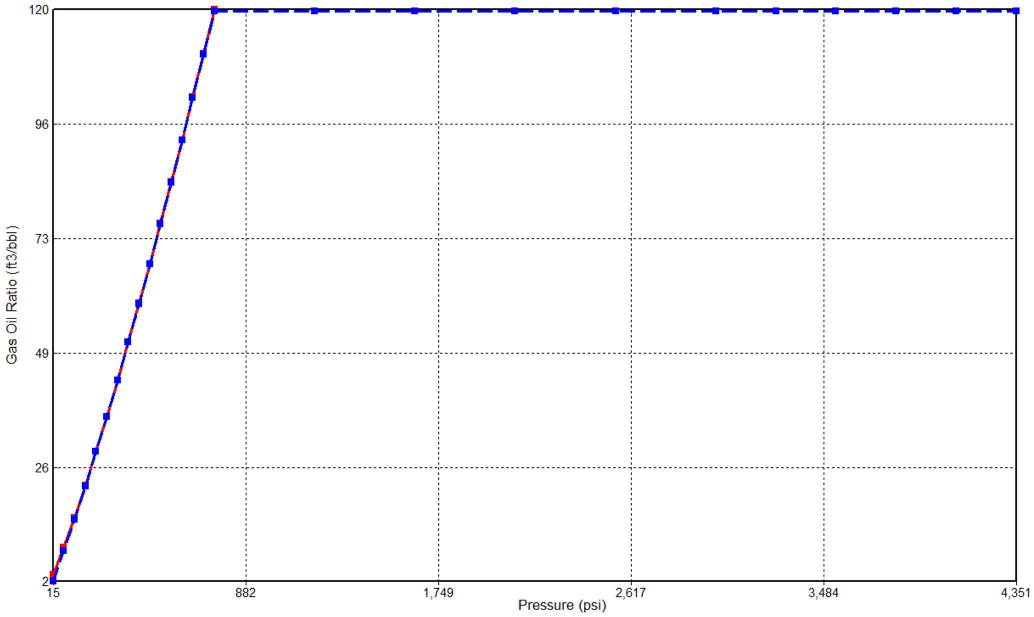

Figure 3.10 Gas-Oil Ratio as a function of reservoir pressure

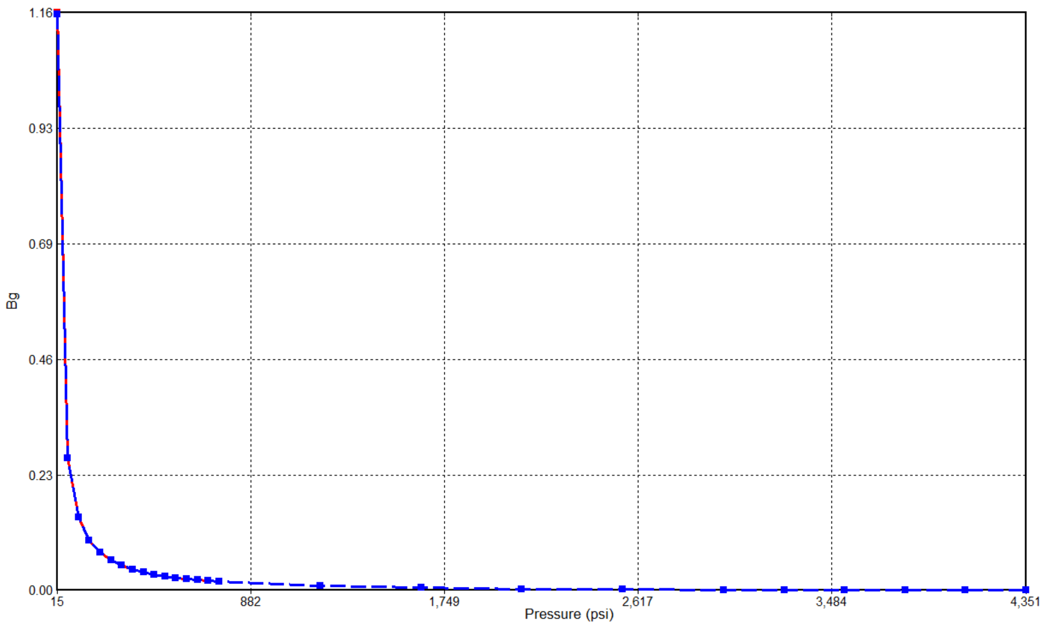

Figure 3.11 Gas formation volume factor as a function of reservoir pressure

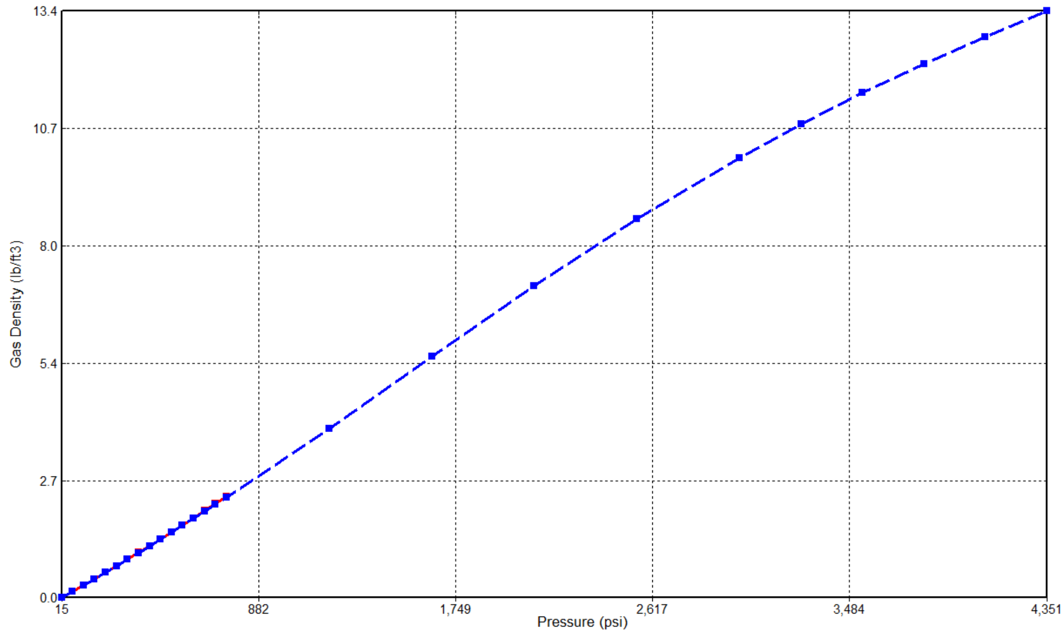

Figure 3.12 Hydrocarbon gas density as a function of reservoir pressure

3.4 Special Core Analysis (SCAL)

In this section, relative permeability is required for constructing of reservoir model because production from petroleum reservoir under primary, secondary, or tertiary processes usually involves the simultaneous flow of two or more fluids, known as multi-phase flow inside reservoir (Donaldson et al., 1985). Basically, relative permeability can be defined as an ability of porous media to behave one fluid when one or more fluids are present. The relative permeability can be represented by two curves, including relative permeability to oil and relative permeability to water in oil/water system. Likewise, there are other two curves that are relative permeability to gas and relative permeability to liquid in gas/liquid system. Based on Fang oil field's data, relative permeability curve of oil/water system as a function of water saturation that used in this reservoir model are shown in Figure 3.13. In addition, Figure 3.14 illustrates the relative permeability curves of gas/liquid system as a function of liquid saturation.

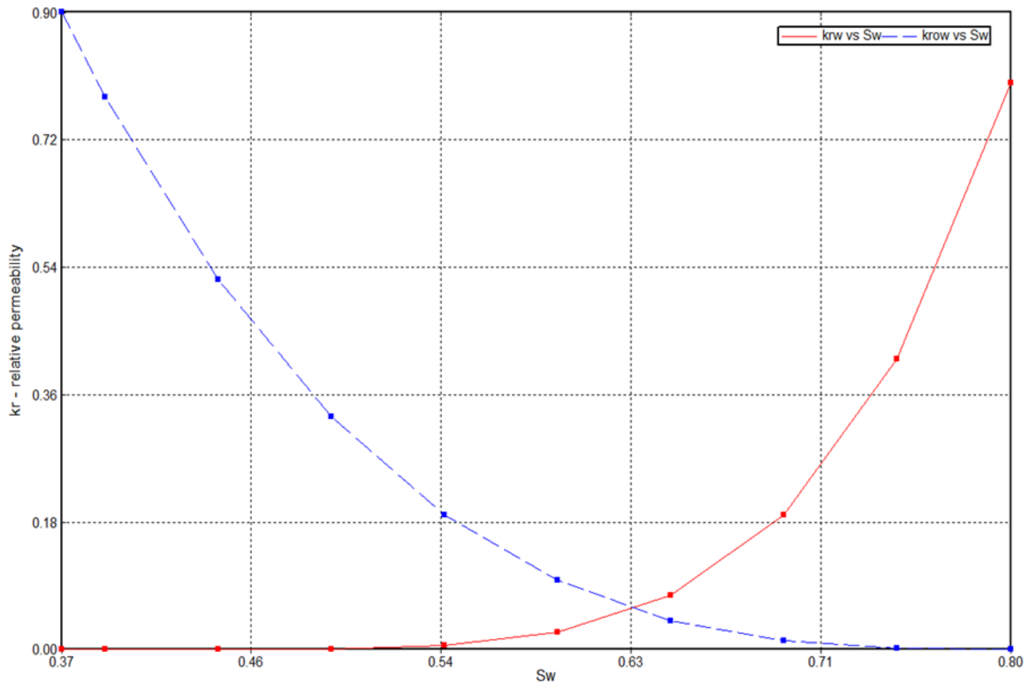

Figure 3.13 Relative permeability curves of oil/water system as a function of water saturation

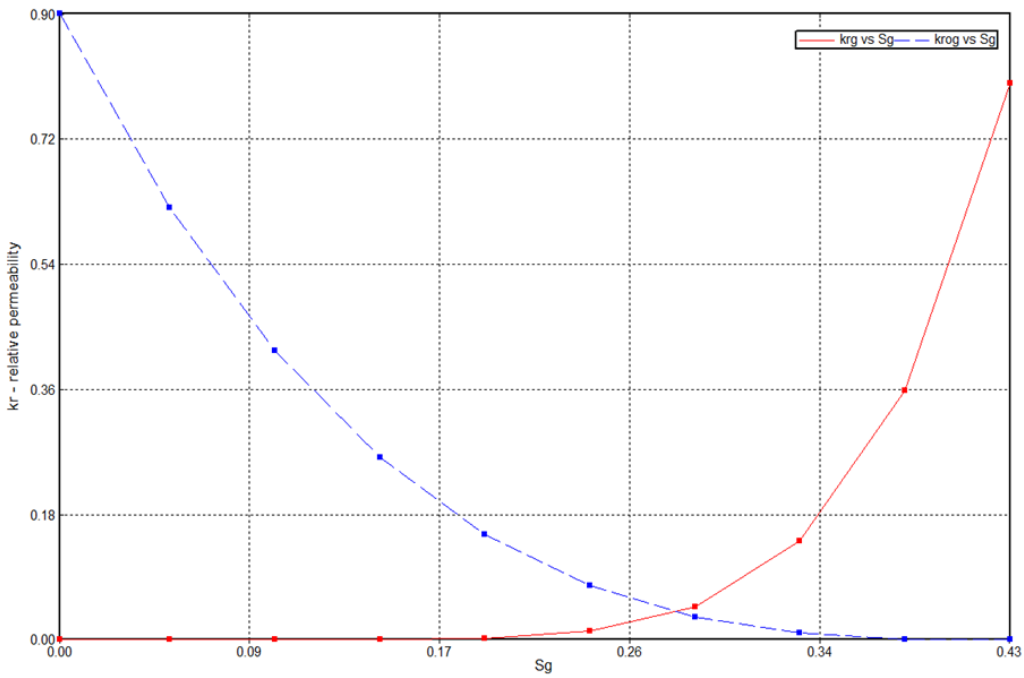

Figure 3.14 Relative permeability curves of gas/liquid system as a function of liquid saturation

3.5 Parameters Related to Injection and Production Wells

In this study, wellbore radius of both injection well and production well is 0.35 feet based on 8 1/2" open hole size in Fang oil field. The skin factor is assumed to be zero due to lack of well testing data in this segment. Both injector and producer are fully-perforated along the reservoir thickness. The injection pattern of this model is quarter five-spot that includes one injector and one producer located diagonally at corner of the model. Carbon dioxide (CO_2) injection rate is calculated from hydrocarbon pore volume (HCPV) injection which is determined as a unit of pore volume (PV). Moreover, pure CO_2 (100% of CO_2) is assumed for every injecting process. Chasing water injection rate is determined in a unit of bbl/d or bwpd assigned to be the same with oil production rate. This study is included two main operating parts that are CO_2 Huff-n-Puff method and integrated CO_2 Huff-n-Puff and WAG method. The sensitivity analysis is performed in the first part that aims to understand the sensitivity of each parameter to oil recovery factor and CO_2 consumption. Also this part can help to eliminate less sensitive parameters before performing of the next part. In the first part of this study, maximum bottom hole pressure is limited as 2,480 psi calculated from 80% safety factor of the formation fracture pressure by using Hubbert and Willis equation (Hubbert & Willis, 1972). The fracture pressure (P_{ff}) and overburden pressure (σ_{ob}) can be expressed as follows:

$$P_{ff} = \frac{\sigma_{ob} + 2P_f}{3} \tag{3.1}$$

$$\sigma_{ob} = g\rho_g D_S - \frac{g(\rho_g - \rho_l)\phi_o}{K}\left(1 - e^{-KD_S}\right) \tag{3.2}$$

Moreover, minimum bottomhole pressure of production well is set as 50 psi to be sufficient for flowing of reservoir fluid through the wellbore. The other operating parameters of CO_2 Huff-n-Puff method are considered to vary within fixed 3 cycles based on the range of favorable factors of CO_2 Huff-n-Puff operation (Mohammed-Singh et al., 2006). The varied parameters of this study's part consisted of HCPV injection, injection time, production rate, production time, and soaking time. The injection and production constraints and varied operating parameters of CO_2 Huff-n-Puff process are shown in Table 3.5

Table 3.5 Constraints and varied parameters of CO_2 Huff-n-Puff process

Parameter	Phase	Value
Maximum bottom hole pressure (psi)	Huff (Injection)	2,480
HCPV injection (PV)		0.5, 1.0, 1.5
Injection time (day)		30, 60, 90
Soaking time (day)	Soak (Shut-in)	5, 10, 15
Minimum bottom hole pressure (psi)	Puff (Production)	50
Maximum production rate (STB/D)		150, 300, 450
Production time (day)		40, 80, 120
Number of cycle (cycle)	-	3

The second part of this study is integrated CO_2 Huff-n-Puff and WAG process defined as the performing of CO_2 Huff-n-Puff method at early state of enhanced oil recovery (EOR) followed by water alternating gas (WAG) method until the end of EOR period. The simulation study is conducted to investigate the sensitivity of oil recovery and to evaluate the performance of integrated CO_2 Huff-n-Puff and WAG process. The maximum bottom hole pressure of injection well and minimum bottom hole pressure of production well are the same as those numbers in the first part of this study as mentioned earlier. Moreover, the varied operating parameters after some low sensitive parameters have been specified are HCPV injection, chasing water injection rate, and production time of CO_2 Huff-n-Puff process. The production rate is set up to be the same as chasing water injection rate due to the material balance. The injection time, soaking time, and number of cycles are fixed at 30 days, 5 days, and 3 cycle, respectively. Furthermore, ten-year period is assumed for total operating time of integrated CO_2 Huff-n-Puff and WAG process. Table 3.6 presents the injection and production constraints and varied operating parameters of integrated CO_2 Huff-n-Puff and WAG process.

Table 3.6 Constraints and varied parameters of integrated CO_2 Huff-n-Puff and WAG

Parameter	**Well Type**	**Value**
Maximum bottom hole pressure (psi)	Injector	2,480
CO_2 injection time (day)		30
Soaking time (day)		5
Number of Huff-n-Puff Cycle (cycle)		3
HCPV injection (PV)		0.5, 1.0, 1.5, 2.0
Chasing water injection rate (STB/D)		300, 450, 600
Minimum bottom hole pressure (psi)	Producer	50
Maximum production rate (STB/D)		300, 450, 600
Production time of Huff-n-Puff (day)		195, 285, 375
Total operating time (year)		10

3.6 Thesis Methodology

1. Study and review related theories and literature.

2. Calculate minimum miscibility pressure and formation fracture pressure of reservoir by using equations and/or correlations with existing data.

3. Create heterogeneous reservoir models based on basic reservoir characteristic, oil composition, relative permeability data and existing fluid properties of low-pressure area in Fang oil field, Thailand as shown in Table 3.1.

4. Simulate CO_2 Huff-n-Puff process on the heterogeneous reservoir models with varying of operating parameters, including HCPV injection, injection time, soaking time, production rate, and production time, as presented in Table 3.5.

5. Perform sensitivity analysis of these operating parameters based on oil recovery factor and CO_2 consumption and then select the key operating parameters of CO_2 Huff-n-Puff process presenting the high sensitivities on both oil recovery factor and CO_2 consumption.

6. Simulate the integrated CO_2 Huff-n-Puff and WAG process on created heterogeneous reservoir models with varying of the selected key operating parameters and chasing water injection rate, as illustrated in Table 3.6.

7. Evaluate the effects of the operating parameters to achieve the highest oil recovery factor and lowest CO_2 utilization of the integrated CO_2 Huff-n-Puff and WAG process.

8. Discuss the results.

9. Conclude the performance evaluation of the integrated CO_2 Huff-n-Puff and WAG process in low-pressure heterogeneous reservoir.

10. Writing the thesis and publication

Thesis methodology diagrams of integrated CO_2 Huff-n-Puff and WAG process in low-pressure heterogeneous reservoir are illustrated in Figure 3.15 to 3.18

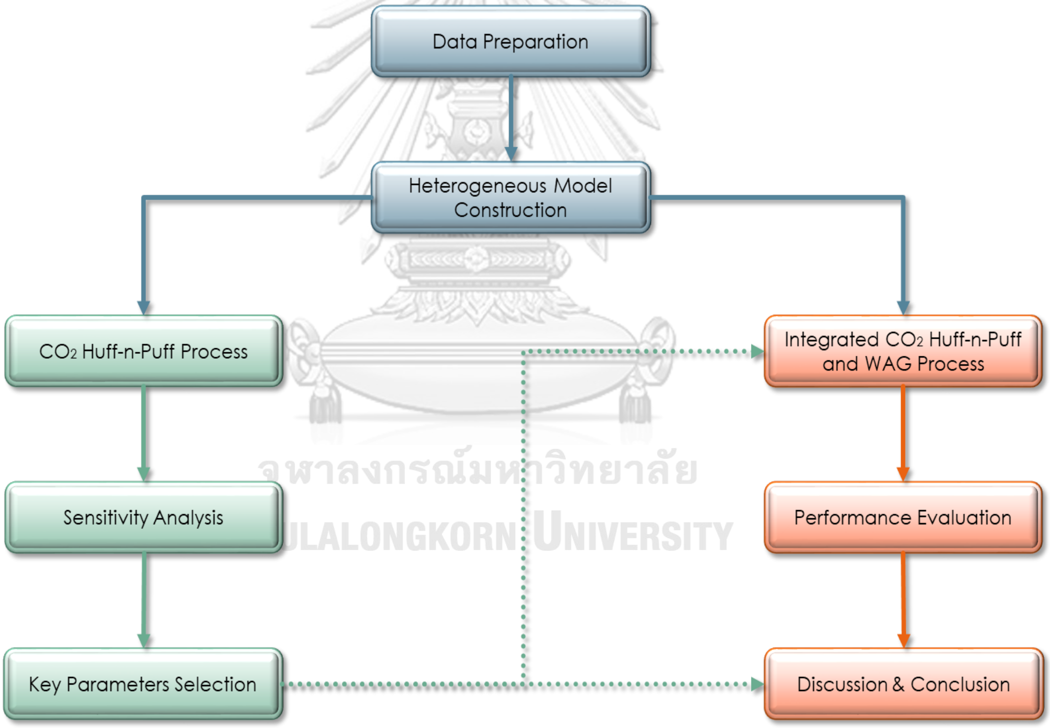

Figure 3.15 Basic flow chart of thesis methodology

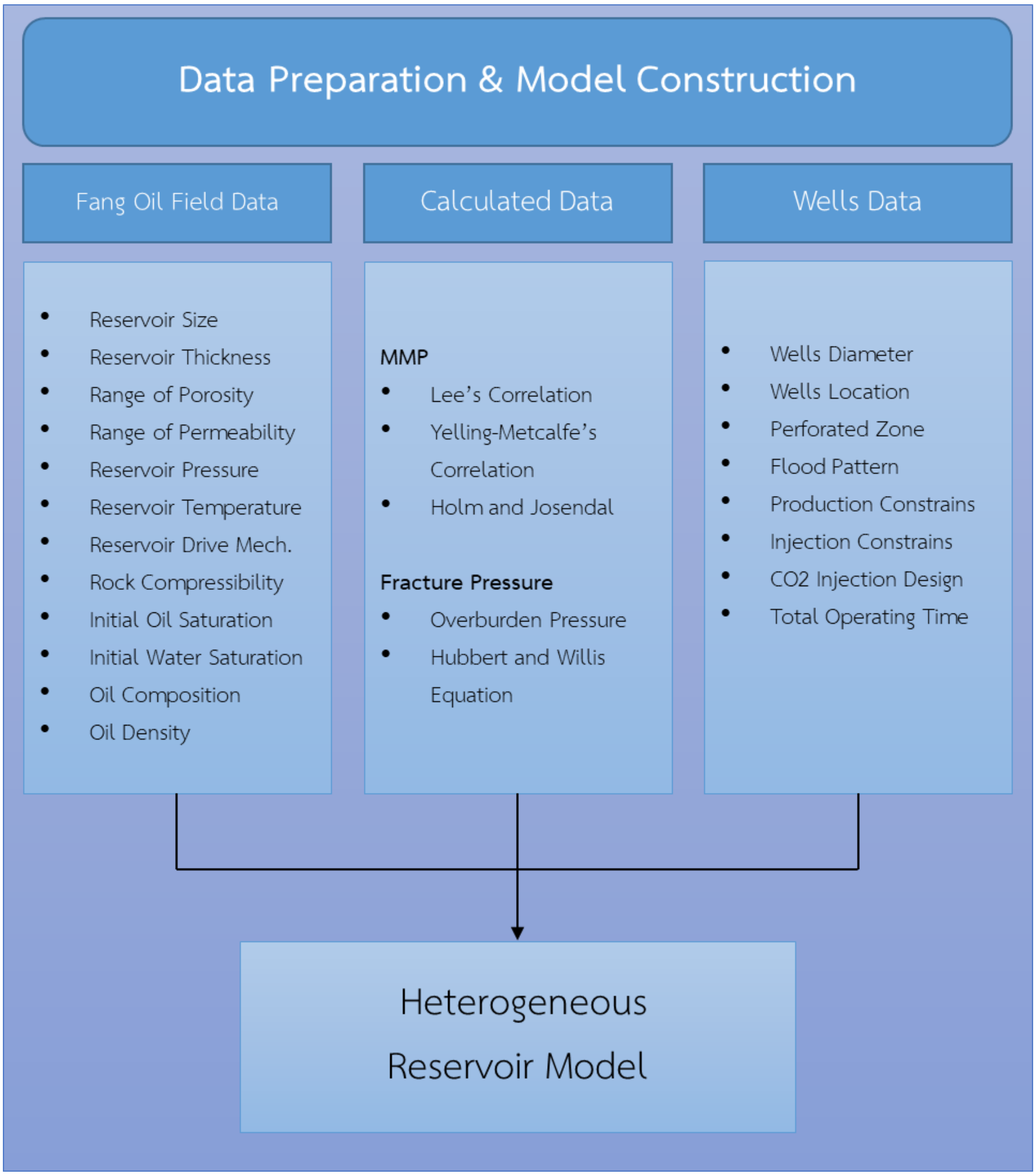

Figure 3.16 Thesis methodology diagram of data preparation and reservoir model construction (Part 1)

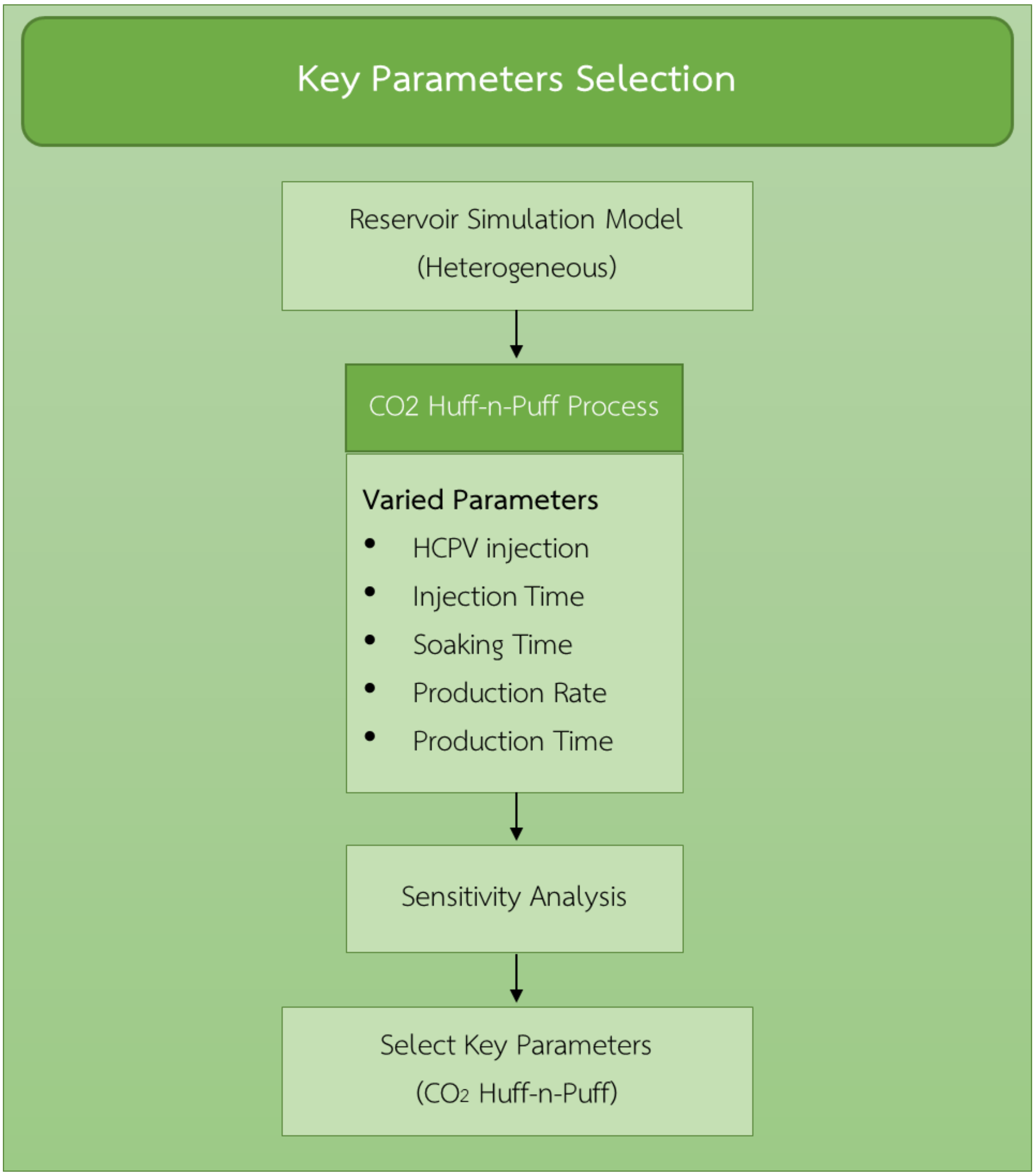

Figure 3.17 Thesis methodology diagram of key parameters selection (Part 2)

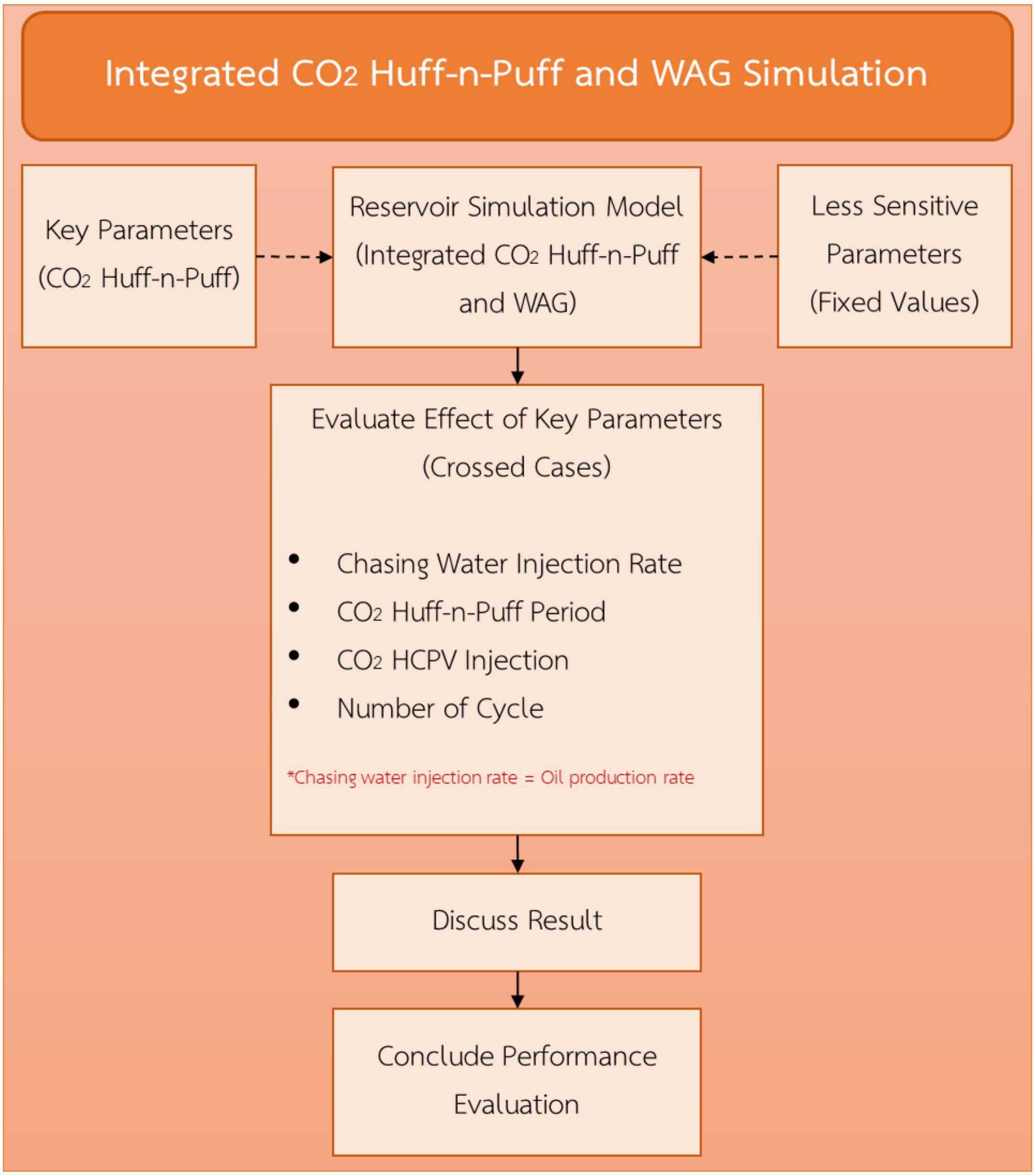

Figure 3.18 Thesis methodology diagram of integrated CO_2 Huff-n-Puff and WAG simulation (Part 3)

CHAPTER 4
RESULTS AND DISCUSSION

In the first part of methodology, known as data preparation and reservoir model construction, the heterogeneous reservoir model is constructed based on reservoir characteristics of a reservoir in Fang oilfield. Likewise, the fluid properties and relative permeability data that are collected from Fang oilfield are added into the model. Moreover, the injection constraints are determined by using of correlation and also used as the limitation of injection pressure to prevent the fracture of formation that causes of injected fluid leakage from reservoir. The heterogeneous reservoir model is shown as Figure 4.1.

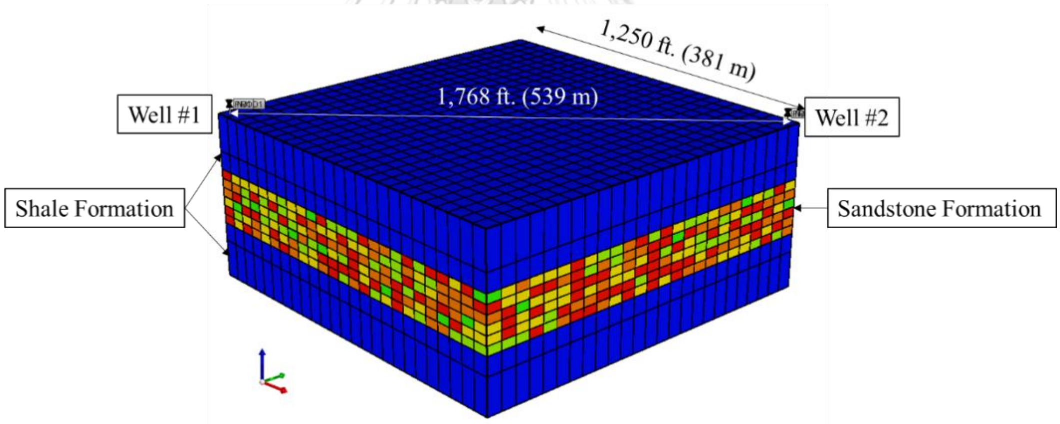

Figure 4.1 The heterogeneous reservoir model with location of wells

After the reservoir model is completed, the second part of methodology is started by using this reservoir model to evaluate the performances of CO_2 Huff-n-Puff process in low-pressure heterogeneous reservoir and investigate the sensitivity of these operating parameters based on oil recovery factor and CO_2 consumption within 3 cycles of operation. The operating parameters that are varied to perform simulation and sensitivity study are hydrocarbon pore volume injection (HCPV), CO_2 injection time, soaking time, production rate, and production time. The values of these varied operating parameters using CO_2 Huff-n-Puff process are presented in Table 4.1 and the middle value are defined as based case parameters. Consequently, the sensitivity analysis of these operating parameters in CO_2 Huff-n-Puff process has been performed aiming to identify the key operational parameters that illustrate high sensitivity on oil recovery factor and CO_2 consumption. The selected key parameters of CO_2 Huff-n-Puff process are HCPV injection, production rate, and production time.

Once the key operational parameters of CO_2 Huff-n-Puff process are identified, the third part of this study is ready to perform. It is called integrated CO_2 Huff-n-Puff and WAG simulation. This process is to inject a slug of water alternating a slug of CO_2 that is injected in the previous stage. In this simulation, pure CO_2 is injected by using CO_2 Huff-n-Puff process. After 3 cycles of Huff-n-Puff have been accomplished, a slug of water is injected into reservoir to alternate a slug of CO_2 that remains in reservoir and displaces both reservoir fluid and injected CO_2 through the production well. The main objectives of this part are to investigate the influence of the operational parameters and to evaluate performance of the integrated CO_2 Huff-n-Puff and WAG process in low-pressure heterogeneous reservoir. In this part, three main parameters, including HCPV injection, CO_2 Huff-n-Puff period, and chasing water injection rate are evaluated the effects on oil recovery factor and CO_2 utilization by conducting of crossed cases simulation. Moreover, other parameters which demonstrate less sensitivity are determined to be fixed values. The total operating time of this simulation is 10 years which is sufficient to recover oil from this reservoir by using enhanced oil recovery (EOR) technique. The values of these varied operating parameters using integrated CO_2 Huff-n-Puff and WAG process are shown in Table 4.2.

Table 4.1 The values of varied operating parameters in CO_2 Huff-n-Puff process

Parameter	**Values**		
HCPV Injection (PV)	0.5	1.0	1.5
Injection Time (day)	30	60	90
Production Rate (STB/D)	150	300	450
Production Time (day)	40	80	120
Soaking Time (day)	5	10	15

Table 4.2 The values of varied operating parameters in integrated CO_2 Huff-n-Puff and WAG process

Parameter	**Values**			
HCPV injection (PV)	0.5	1.0	1.5	2.0
Chasing water injection rate (STB/D)	300	450	600	-
CO2 Huff-n-Puff period (day)	195	285	375	-

4.1 CO_2 Huff-n-Puff Base Case

CO_2 Huff-n-Puff process is simulated in order to ensure that the injection of CO_2 has capabilities to enhance oil recovery. Therefore, the simulation of CO_2 Huff-n-Puff process is compared to primary recovery in terms of oil recovery factor, cumulative oil production, oil production rate, and reservoir pressure. The results of the base-case simulation indicates that CO_2 Huff-n-Puff process can enhance oil recovery for 1.7% of original oil in place (OOIP) more than primary recovery with three cycles of operation, as shown in Figure 4.2. In term of cumulative oil production, Figure 4.3 presents the amount of oil that is produced with using CO_2 Huff-n-Puff and primary production process. Using three cycles of CO_2 Huff-n-Puff process can produce 51,967 bbl of oil. However, the cumulative oil production produced by primary recovery is 28,125 bbl. Moreover, the comparative oil production rate with using CO_2 Huff-n-Puff process and primary production is illustrated in Figure 4.4. From the primary recovery, oil production rate can be maintained at 300 bbl/day with a short period of operating time and the rate is dropped rapidly due to insufficient reservoir pressure. Applying the CO_2 Huff-n-Puff process can improve oil production rate after it declined to zero because the injected CO_2 increases reservoir pressure that is the important factor to drive oil from reservoir through wellbore. The reservoir pressure when performing of these two processes is presented in Figure 4.5. Furthermore, crude oil flows easier when the CO_2 Huff-n-Puff process is conducted because oil viscosity is reduced due to the dissolution of CO_2 in crude oil (Mohammed-Singh et al., 2006). This mechanism can occur even reservoir pressure is lower than minimum miscibility pressure (MMP). In addition, the drainage area from using primary recovery and CO_2 Huff-n-Puff process are presented in Figure 4.6. From the figure, oil saturation around wellbore is reduced with using CO_2 Huff-n-Puff process.

In conclusion, the using of CO_2 Huff-n-Puff process apparently extracts additional oil from low-pressure reservoir. Crude oil produced in primary recovery is very low, which is approximately 2% of OOIP, because of extremely low reservoir pressure and no natural pressure support. Hence, reservoir pressure is declined very fast while oil is being produced. When the CO_2 Huff-n-Puff is applied into low-pressure reservoir, it can help to maintain reservoir pressure that consequently increases oil production and also the dissolution of CO_2 in crude oil causes of oil swelling that provides oil viscosity reduction. However, these mechanism is limited in small drainage area around the operating wellbore. Therefore, more suitable application for CO_2 Huff-n-Puff process to enhance oil recovery (EOR) is relatively small pool size (Liu, Wang, & Zhou, 2005).

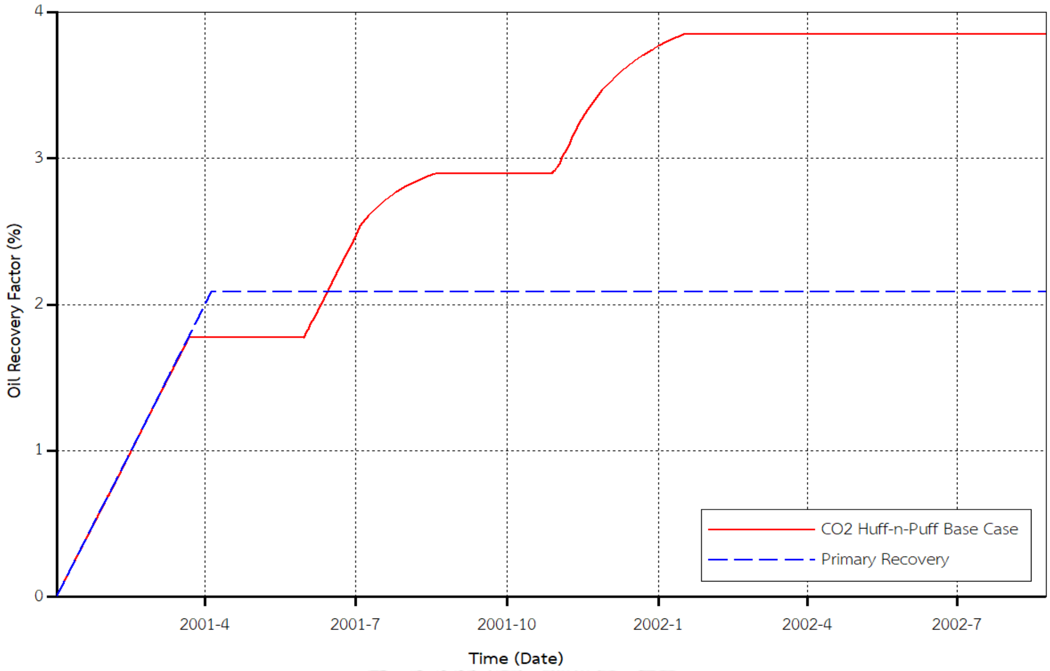

Figure 4.2 Oil recovery factor versus time for using CO_2 Huff-n-Puff base-case and primary recovery

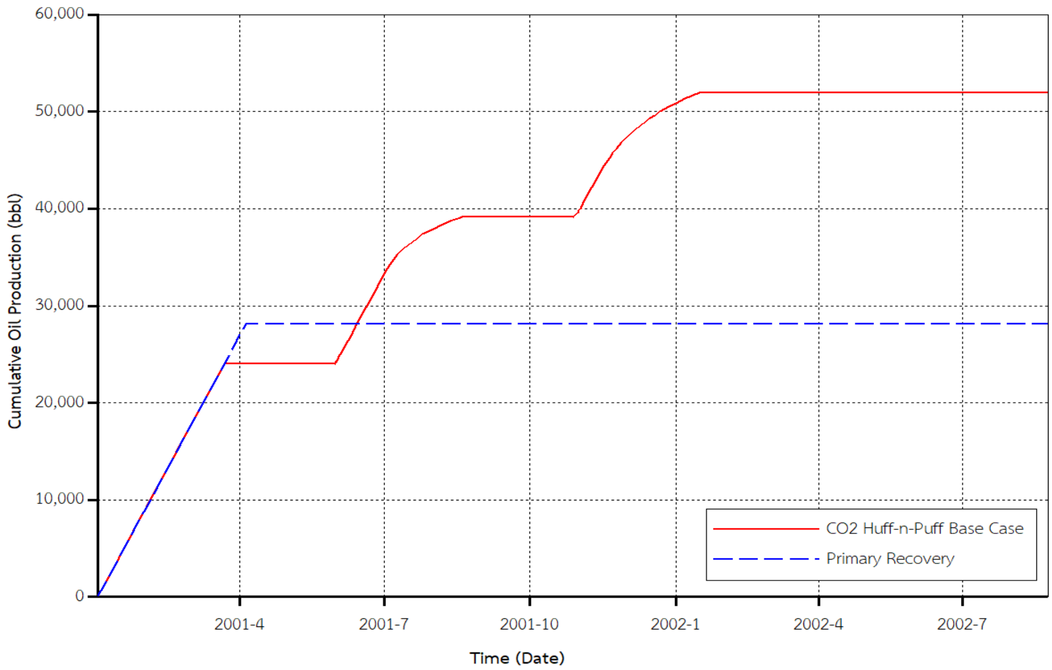

Figure 4.3 Cumulative oil production versus time for using CO_2 Huff-n-Puff base-case and primary recovery

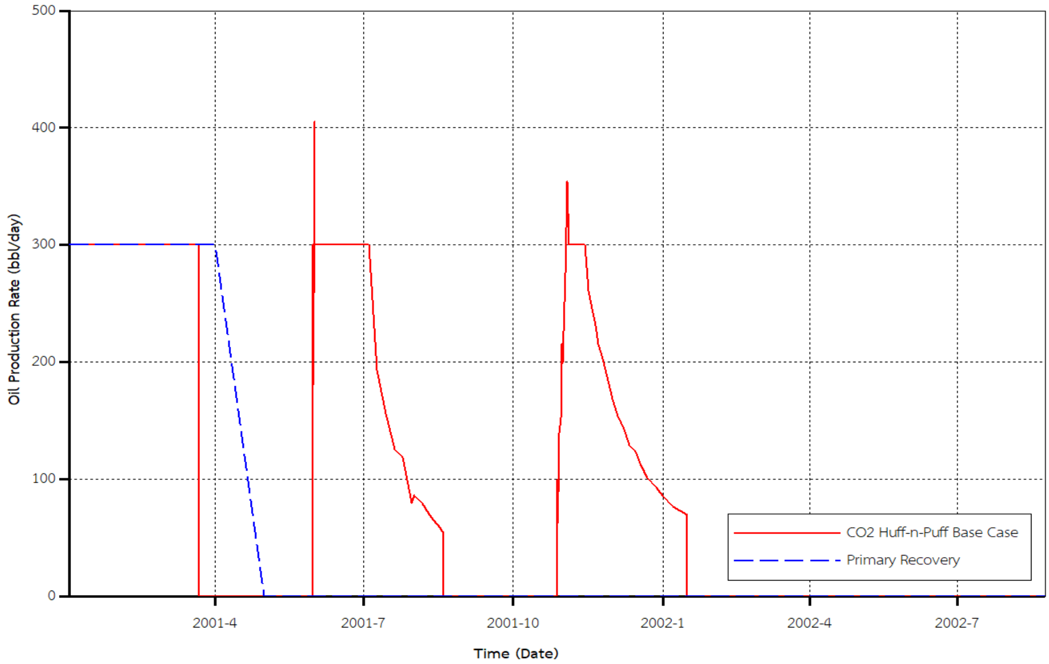

Figure 4.4 Oil production rate versus time for using CO_2 Huff-n-Puff base-case and primary recovery

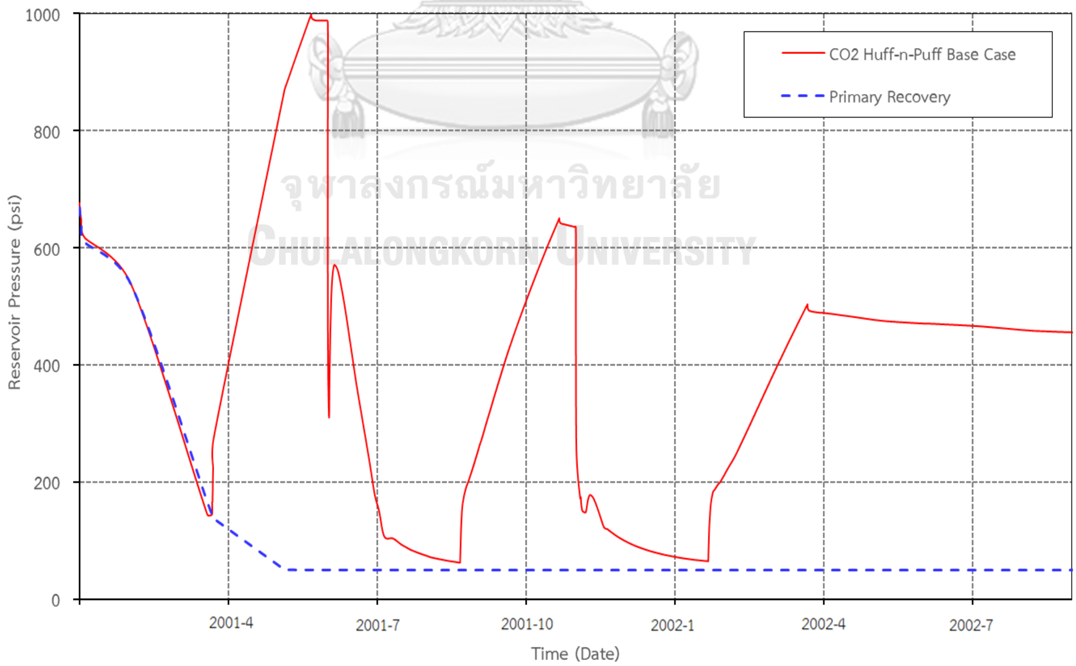

Figure 4.5 Reservoir Pressure versus time for using CO_2 Huff-n-Puff base-case and primary recovery

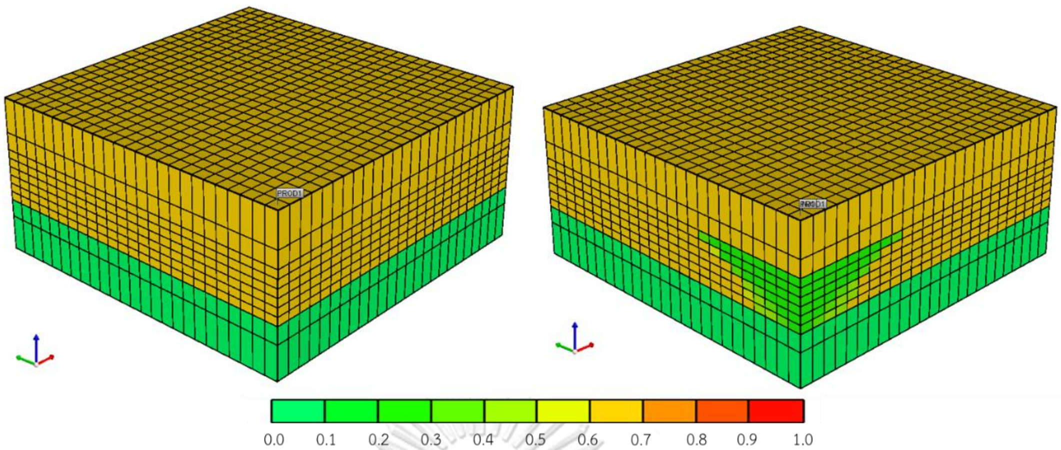

Figure 4.6 3-D models with presented oil saturation reduction for using of primary recovery (left) and CO_2 Huff-n-Puff base-case (right)

4.2 Performance Evaluation of CO_2 Huff-n-Puff Process

To investigate the performance evaluation of CO_2 Huff-n-Puff process in low-pressure heterogeneous reservoir will require minimum three numerical simulation runs for each operating parameters. Five operating parameters are simulated, including HCPV injection, injection time, production rate, production time, and soaking time. And a fixed three number of cycles are used for all runs. The values of these varied operating parameters using CO_2 Huff-n-Puff process are presented in Table 4.1.

4.2.1 Effect of HCPV injection

The effect of hydrocarbon pore volume injection (HCPV) on the performance of CO_2 Huff-n-Puff process is investigated by conducting three runs as follows: 0.5 HCPV, 1.0 HCPV, and 1.5 HCPV. Other operating parameters are fixed as base-case values and a fixed three numbers of cycles are used for all runs. The effect of HCPV injection on oil recovery factor using CO_2 Huff-n-Puff process for all cases is presented in Figure 4.7. The results of these plots indicate that the higher oil recovery factor can be obtained by increasing of the HCPV injection. However, the improvement of oil recovery is continuously reduced by further increasing of HCPV injection. In addition, effect of HCPV injection on cumulative CO_2 injection using CO_2 Huff-n-Puff process for all cases is presented in Figure 4.8. The results show that higher HCPV injection requires proportional increase in cumulative CO_2 injection. According to these results, injection of 0.5 HCPV consumes the lowest amount of CO_2 that is 11.7 MMscf and provide the lowest oil recovery factor of 3.45% of original oil in place (OOIP). While, 1.5 HCPV injection shows the highest oil recovery factor among these all runs that is 4.17% of OOIP with consuming 35.1 MMscf of CO_2. Table 4.3 presents the values of oil recovery factor, cumulative oil production, and CO_2 consumption provided by different values of HCPV injection using CO_2 Huff-n-Puff process.

This is because the injection of greater HCPV injection provides higher reservoir pressure and creates slightly larger drainage area around the operating wellbore, as shown in Figure 4.9. Therefore, oil recovery and cumulative CO_2 injection are increased by injecting of larger slug of CO_2. However, further increase in HCPV injection is unable to provide proportional incremental rate of oil recovery factor compared to cumulative CO_2 consumption due to the limited drainage area and the restriction of reservoir pressure. When reservoir pressure is still low, it is easier to improve with the slug size of CO_2. Nevertheless, while reservoir pressure is higher, the reservoir pressure is more difficult to be increased due to the compressibility of CO_2.

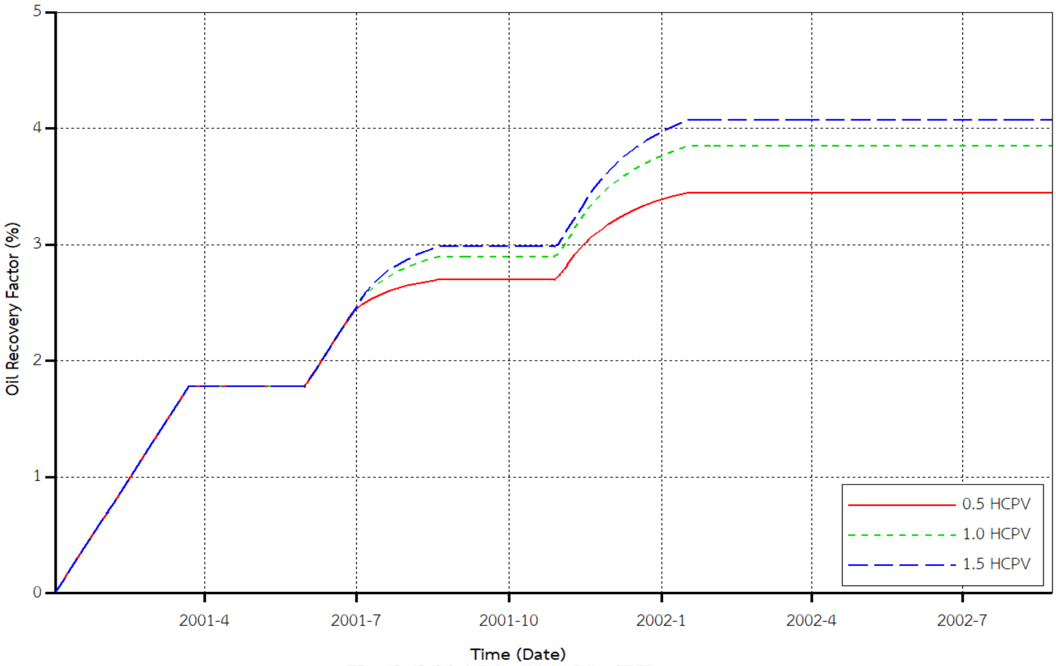

Figure 4.7 Effect of HCPV injection on oil recovery factor using Huff-n-Puff process

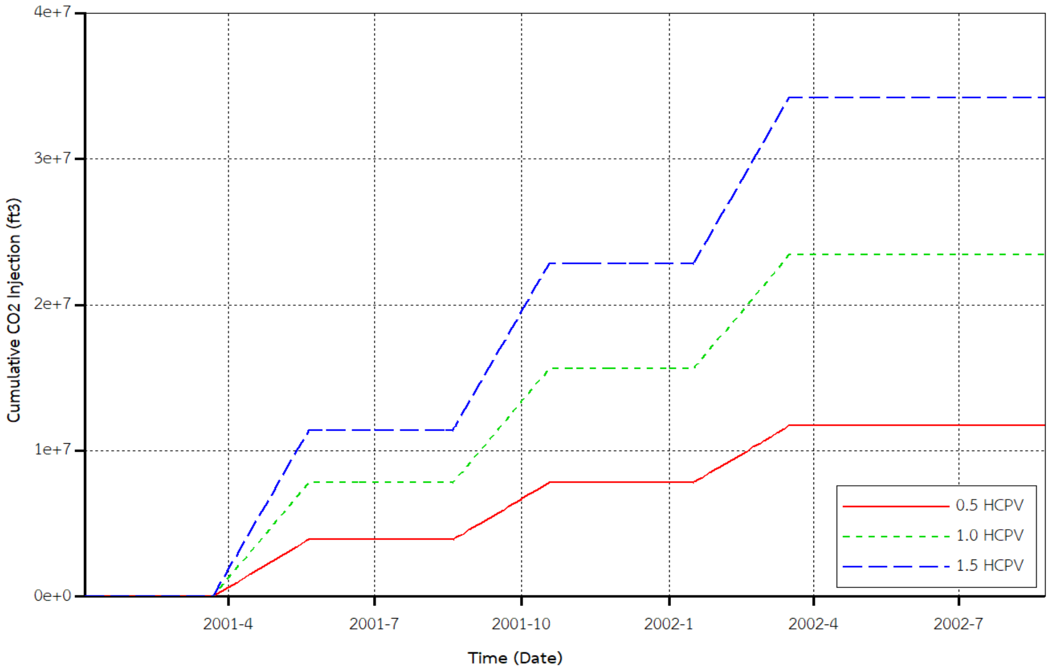

Figure 4.8 Effect of HCPV injection on cumulative CO_2 injection using Huff-n-Puff process

Table 4.3 Results summarized by three cases of different CO_2 HCPV injection

Case	HCPV Injection	Oil Recovery Factor	Cumulative Oil Production	CO_2 Consumption
	PV	*%*	*MSTB*	*MMSCF*
1	0.5	3.45	46.54	11.7
2	1.0	3.85	51.97	23.4
3	1.5	4.17	56.31	35.1

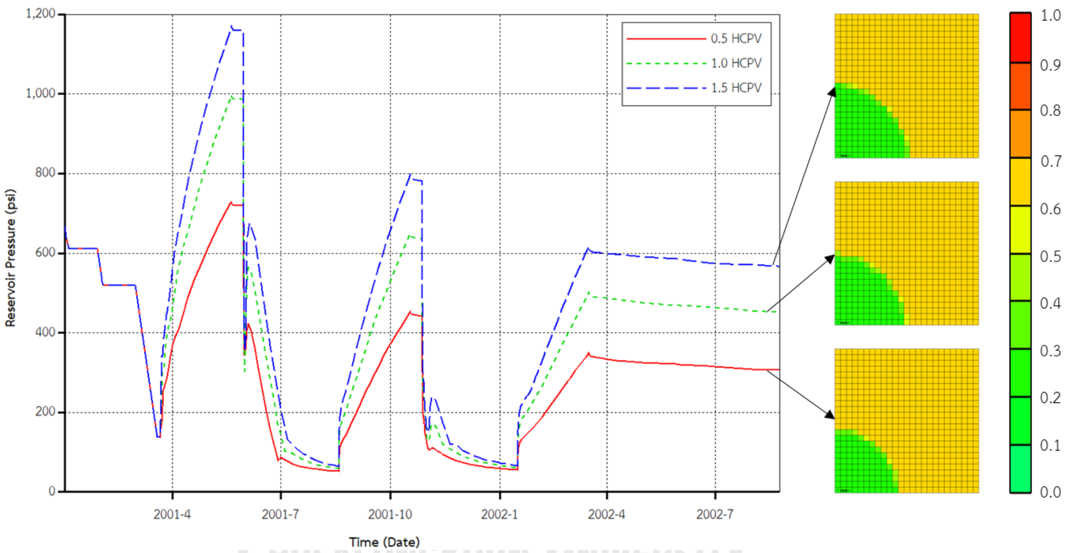

Figure 4.9 Effect of CO_2 HCPV injection on reservoir pressure and drainage area using Huff-n-Puff process

4.2.2 Effect of injection time

The effect of CO_2 injection time on performance of CO_2 Huff-n-Puff process is investigated by performing three runs with different injection time, including 30, 60, and 90 days. Base-case values and fixed 3 cycles of operation is applied for all runs.

Figure 4.10 presents the effect of injection time period on oil recovery factor that more injection time tends to provide higher oil recovery factor. The highest recovery factor is obtained with using 90 days of injection time that this oil recovery is 4.08% of OOIP. On the other hand, minimum oil recovery is 3.71% of OOIP that obtained by using 30 days of injection time. In term of cumulative CO_2 injection, there is no different between amounts of CO_2 injection but the shorter injection time can reach the maximum cumulative CO_2 injection earlier, as shown in Figure 4.11. The values of oil recovery factor, cumulative oil production, and CO_2 consumption provided by different values of injection time using CO_2 Huff-n-Puff process are presented in Table 4.4.

The reasons that higher injection time indicates higher oil recovery factor is the drainage area around the operational wellbore of greater injection time is larger than that in shorter time of injection, as shown in Figure 4.12. According to results, the peak reservoir pressure of these three cases using different injection time is similar but the drainage area is relatively different because the same amount of injected CO_2 has opportunity to diffuse further away from the wellbore with conducting of longer injection time. Hence, the area that is influenced with the CO_2 is extensive by longer period of CO_2 injection.

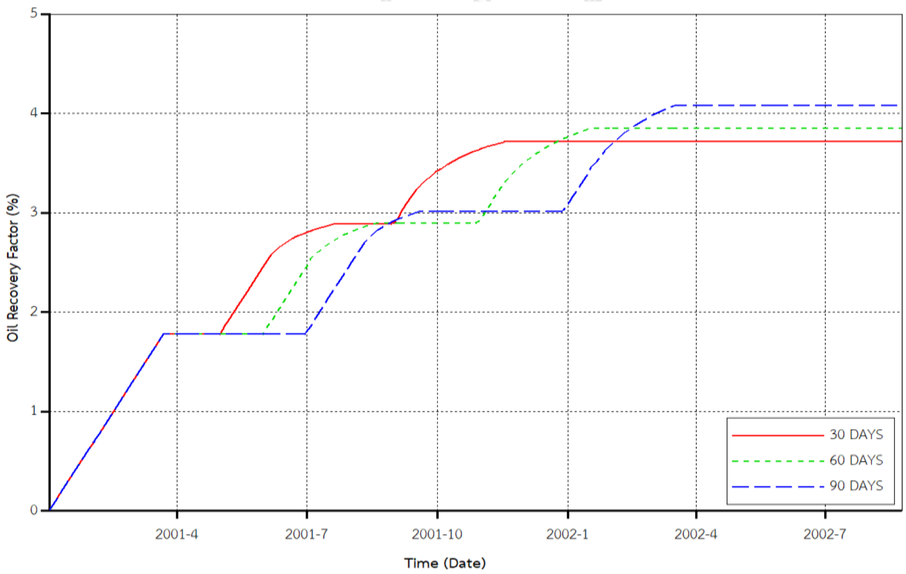

Figure 4.10 Effect of injection time on oil recovery factor using Huff-n-Puff process

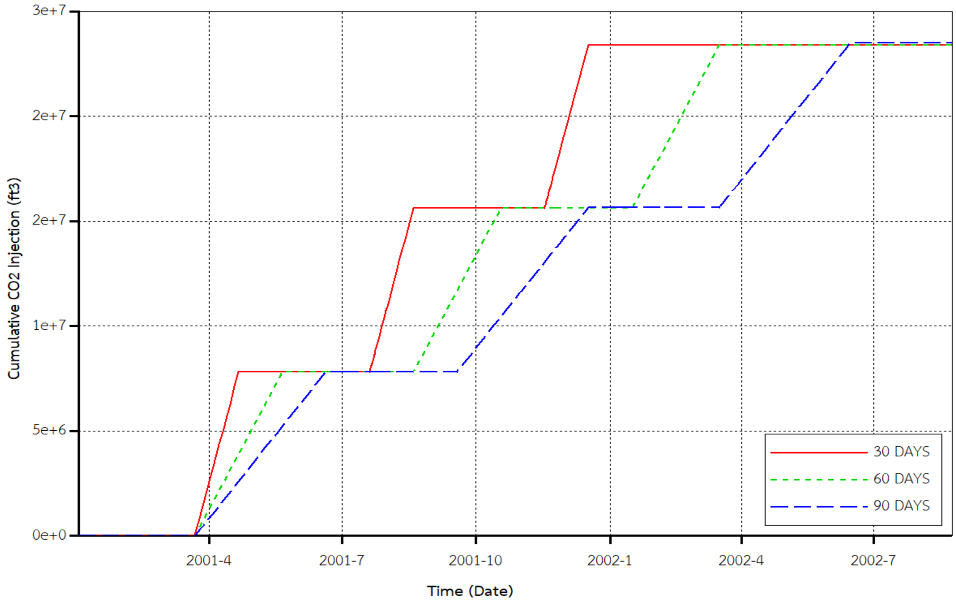

Figure 4.11 Effect of injection time on cumulative CO_2 injection using Huff-n-Puff process

Table 4.4 Results summarized by three cases of different CO_2 injection time

Case	Injection Time	Oil Recovery Factor	Cumulative Oil Production	CO_2 Consumption
	DAY	*%*	*MSTB*	*MMSCF*
1	30	3.71	50.16	23.40
2	60	3.85	51.97	23.40
3	90	4.08	55.12	23.40

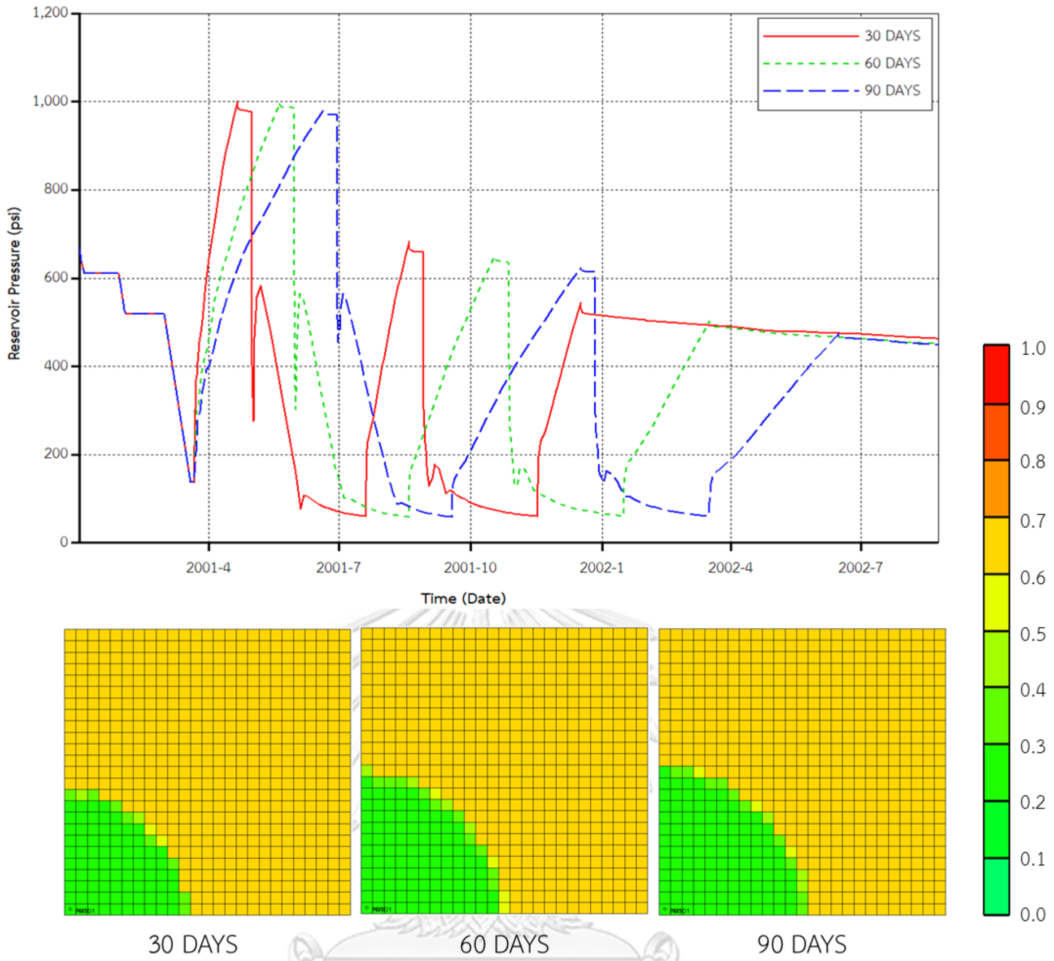

Figure 4.12 Effect of injection time period on reservoir pressure and drainage are using Huff-n-Puff process

4.2.3 Effect of maximum oil production rate

To investigate the effect of maximum oil production rate on performance of CO_2 Huff-n-Puff process is conducted three runs, including 150, 300, 450 BOPD of maximum oil production rate. Other operating parameters are set as base-case values and the operation is repeated into three cycles for all runs. Figure 4.13 presents the effect of maximum oil production rate on oil recovery factor using CO_2 Huff-n-Puff process. These results indicate that higher oil recovery factor can be obtained by additional maximum oil production rates. Maximum production rate of 450 BOPD shows the highest oil recovery factor of 4.75% of OOIP. In contrast, setting of 150 BOPD of maximum oil production can provide 2.66% of oil recovery factor. Moreover, the varied maximum oil production rates using in CO_2 Huff-n-Puff process do not effect on cumulative CO_2 injection, as shown in Figure 4.14. Three runs of varied maximum oil production rates show the same plots of cumulative CO_2 injection that the overall amount of injected CO_2 is 23.4 MMscf. Table 4.5 presents the results, including oil recovery factor, cumulative oil production, and CO_2 consumption provided by different values of maximum oil production rate using CO_2 Huff-n-Puff process.

Based on results, higher maximum oil production rate can increase oil recovery factor because majority of oil is recovered in the first cycle of operation that the production rate of 450 BOPD can be maintained until end of cycle and it still maintained for one-fourth of production period in second cycle, as presented in Figure 4.15. Although the lower maximum production rate can maintain longer plateau rate, the overall recovery is lower than producing at high rate due to the limitation of production time and number of cycles.

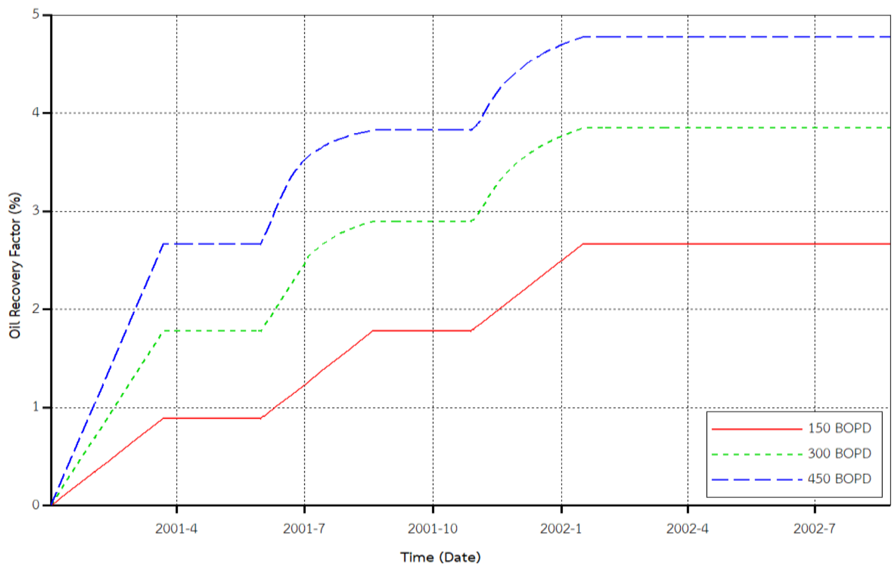

Figure 4.13 Effect of oil production rate on oil recovery factor using Huff-n-Puff process

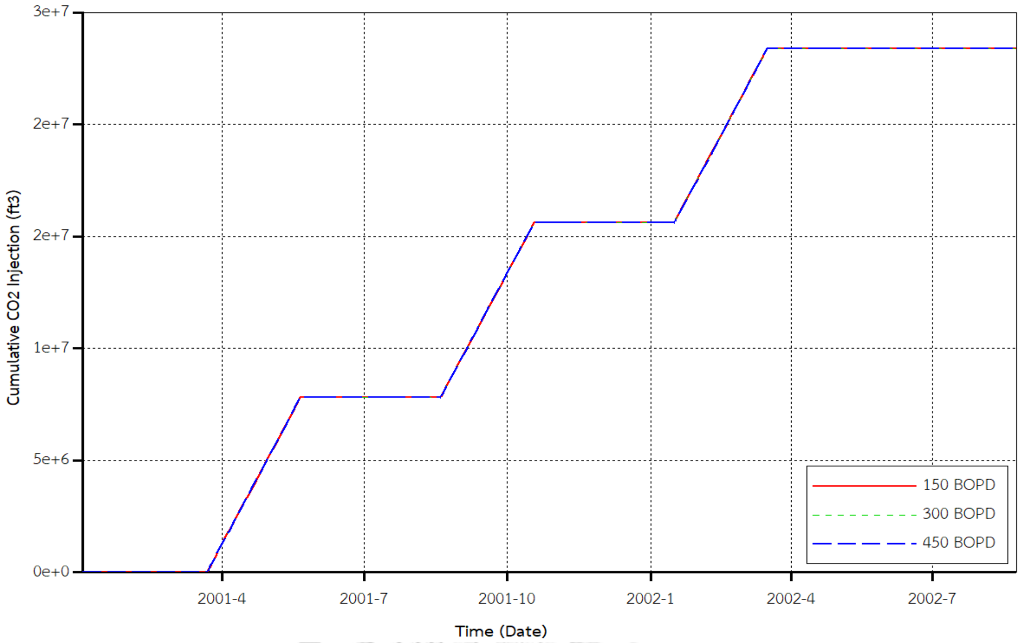

Figure 4.14 Effect of oil production rate on cumulative CO_2 injection using Huff-n-Puff process

Table 4.5 Results summarized by three cases of different maximum oil production rate

Case	Oil Production Rate	Oil Recovery Factor	Cumulative Oil Production	CO_2 Consumption
	BBL/D	*%*	*MSTB*	*MMSCF*
1	150	2.66	35.96	23.40
2	300	3.85	51.97	23.40
3	450	4.75	64.22	23.40

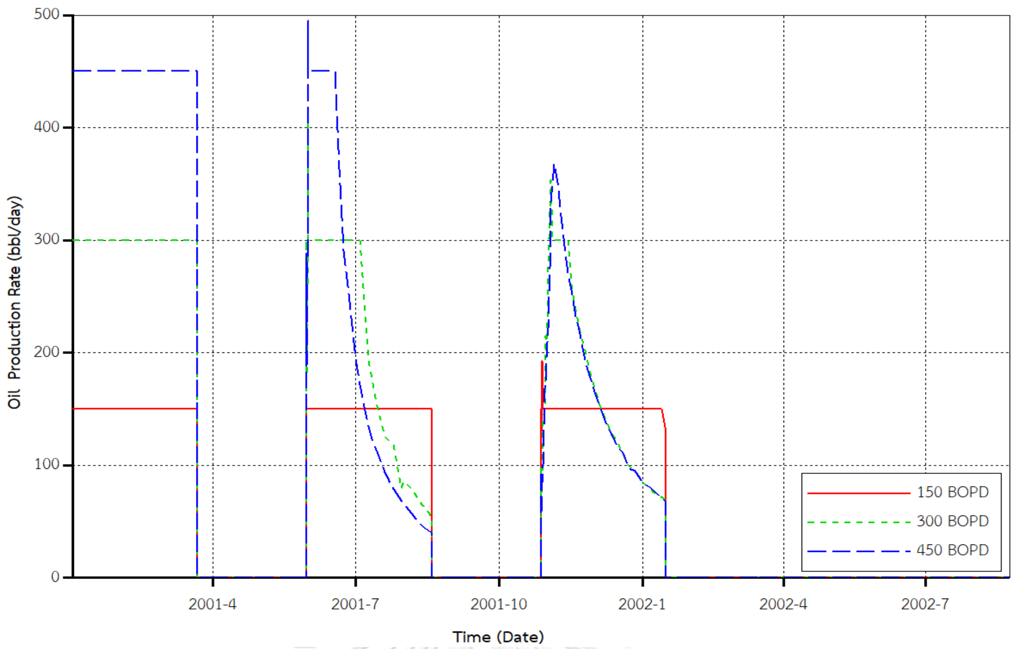

Figure 4.15 Effect of oil production rate on oil production rate using Huff-n-Puff process

4.2.4 Effect of production time

The performance evaluation of CO_2 Huff-n-Puff process is investigated by varying of production time, which is the period of production (Puff) phase in each cycle. The production time of 40, 80, and 120 days is used in reservoir simulation with fixed three numbers of cycles. In addition, other related operating parameters are selected as base-case values. The relationship between oil recovery factor and operating time for these three values of production time is illustrated in Figure 4.16. The results of these simulations indicate that longer production time can provide higher oil recovery factor. The highest oil recovery factor of 4.98% of OOIP is obtained by using the longest production time of 120 days. In contrast, the lowest oil recovery factor (2.61%) can be obtained with 40 days of production time. And 3.85% of OOIP is recovered by using 80 days of production time. Furthermore, changing of production time does not affect cumulative CO_2 injection but it can impact total operating time, as shown in Figure

4.17. Using of shorter production time can reach maximum cumulative CO_2 injection earlier than using longer ones. The values of oil recovery factor, cumulative oil production, and CO_2 consumption provided by different values of production time using CO_2 Huff-n-Puff process are summarized in Table 4.6.

The reason of increased oil recovery factor with longer production time is shown in Figure 4.18, which is the plot of oil production rate versus time for different production time. In the first cycle of operation, three cases of different production time can maintain plateau rate until end of cycle that the case of 120 days can recover oil much more than other cases. Although shorter production time can maintain slightly longer plateau rate in second and third cycle, amount of produced oil is lesser than the longer ones due to insufficient production time to recover oil around the wellbore. Hence, some available oil is not produced before end of production stage by using shorter production time.

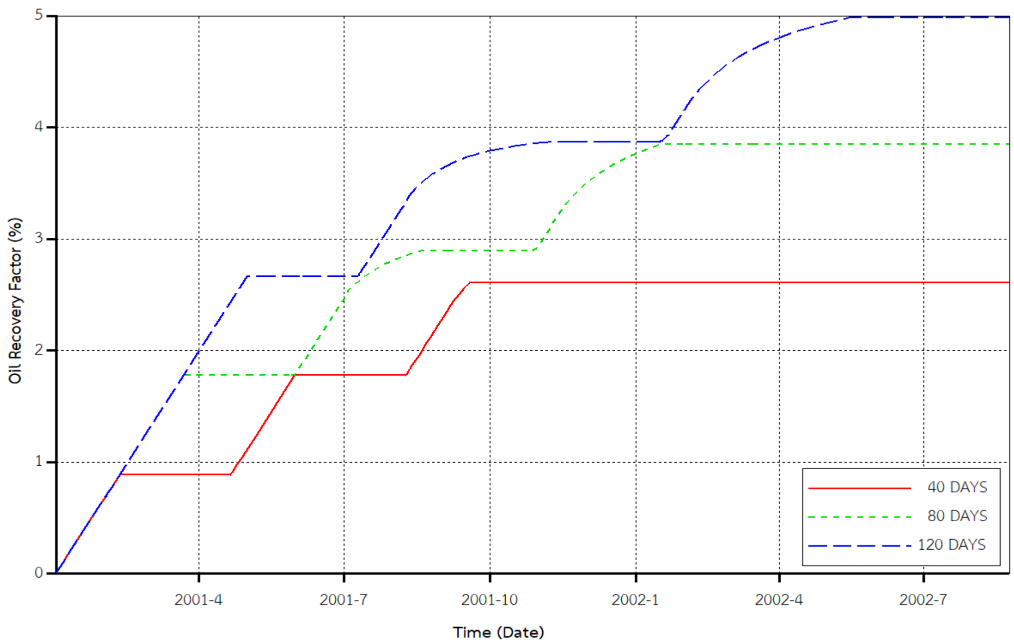

Figure 4.16 Effect of production time on oil recovery factor using Huff-n-Puff process

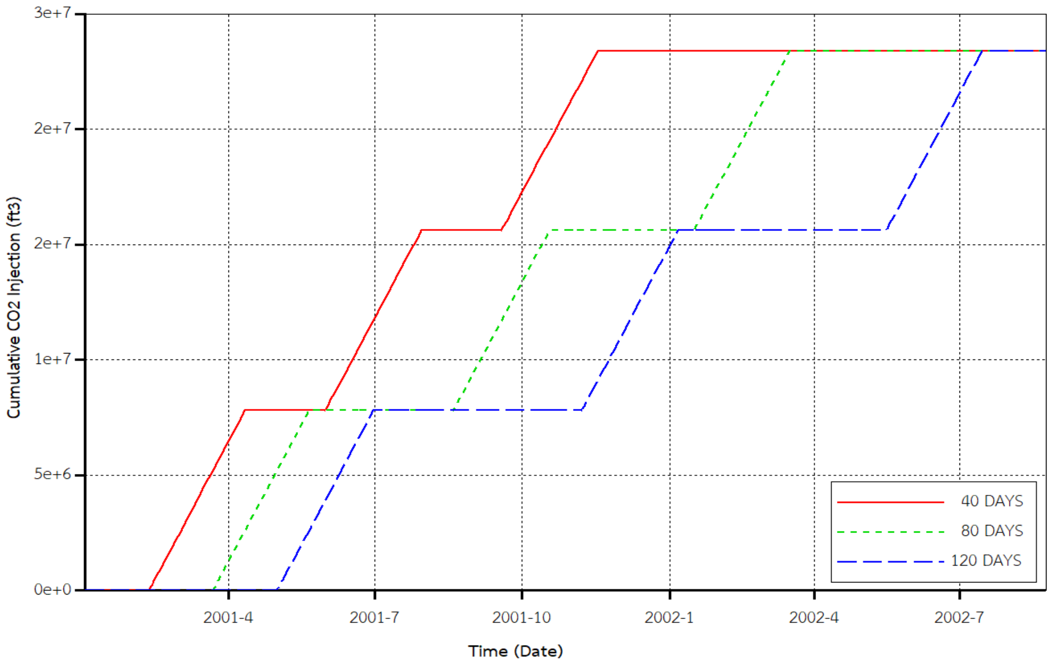

Figure 4.17 Effect of production time on cumulative CO_2 injection using Huff-n-Puff process

Table 4.6 Results summarized by three cases of different production time

Case	Production Time	Oil Recovery Factor	Cumulative Oil Production	CO_2 Consumption
	DAY	*%*	*MSTB*	*MMSCF*
1	40	2.61	35.22	23.40
2	80	3.85	51.97	23.40
3	120	4.98	67.32	23.40

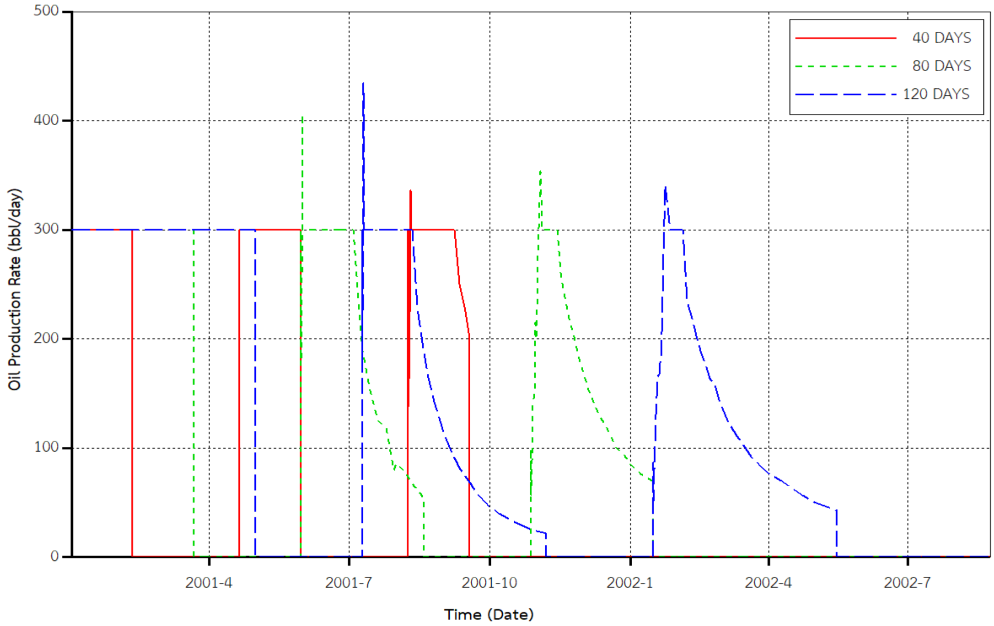

Figure 4.18 Effect of production time on oil production rate using Huff-n-Puff process

4.2.5 Effect of soaking time

The effect of soaking time on performance of CO_2 Huff-n-Puff process in low-pressure reservoir is investigated by performing three runs for 5, 10, and 15 days of soaking time in fixed three numbers of cycles. Base-case values are used for other operating parameters. Figure 4.19 shows that soaking time has relatively insignificant effect on oil recovery factor. The results get along well with the previous results reported by Yu et al., 2014. Using longer soaking time can provide slightly higher oil recovery factor, comparing to shorter time. The oil that is recovered by using these three soaking time is approximately 3.8% of OOIP. Moreover, Figure 4.20 presents that adjusting of soaking time does not affect cumulative CO_2 injection because this parameter does not involve to injection phase. But using of lesser soaking time requires shorter overall operating time to reach the same amount of CO_2 injection. Table 4.7 summarizes the results, including oil recovery factor, cumulative oil production, and CO_2 consumption provided by different values of soaking time using CO_2 Huff-n-Puff process. Finally, soaking time provide less significant effect on oil recovery factor because there is very low pressure built-up rate in low-pressure reservoir. Accordingly, the peak reservoir pressure of different soaking time is about the same for all cases, as shown in Figure 4.21.

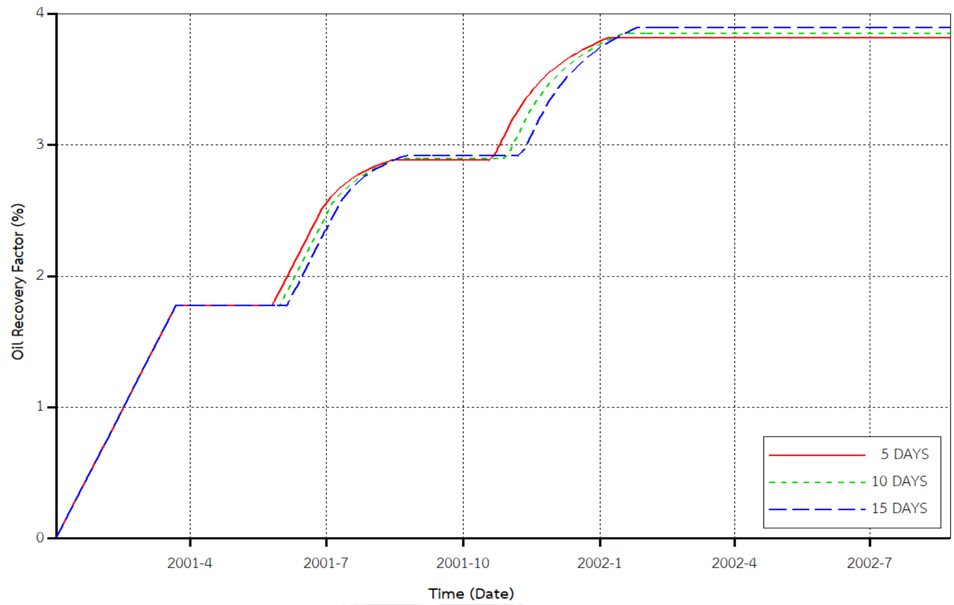

Figure 4.19 Effect of soaking time on oil recovery factor using Huff-n-Puff process

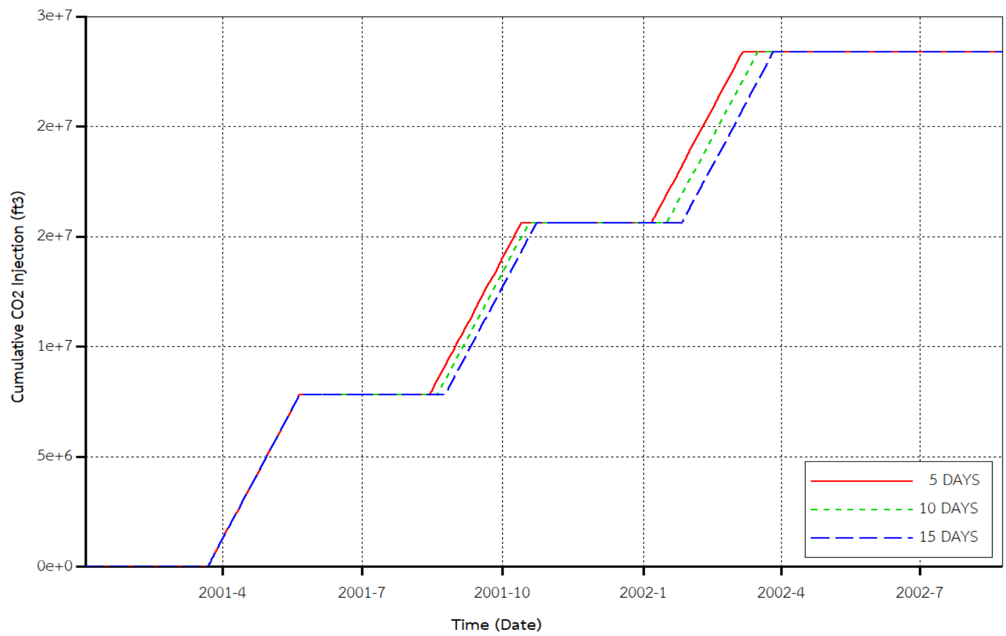

Figure 4.20 Effect of soaking time on cumulative CO_2 injection using Huff-n-Puff process

Table 4.7 Results summarized by three cases of different soaking time

Case	Soak Time	Oil Recovery Factor	Cumulative Oil Production	CO_2 Consumption
	DAY	*%*	*MSTB*	*MMSCF*
1	5	3.82	51.53	23.40
2	10	3.85	51.97	23.40
3	15	3.89	52.58	23.40

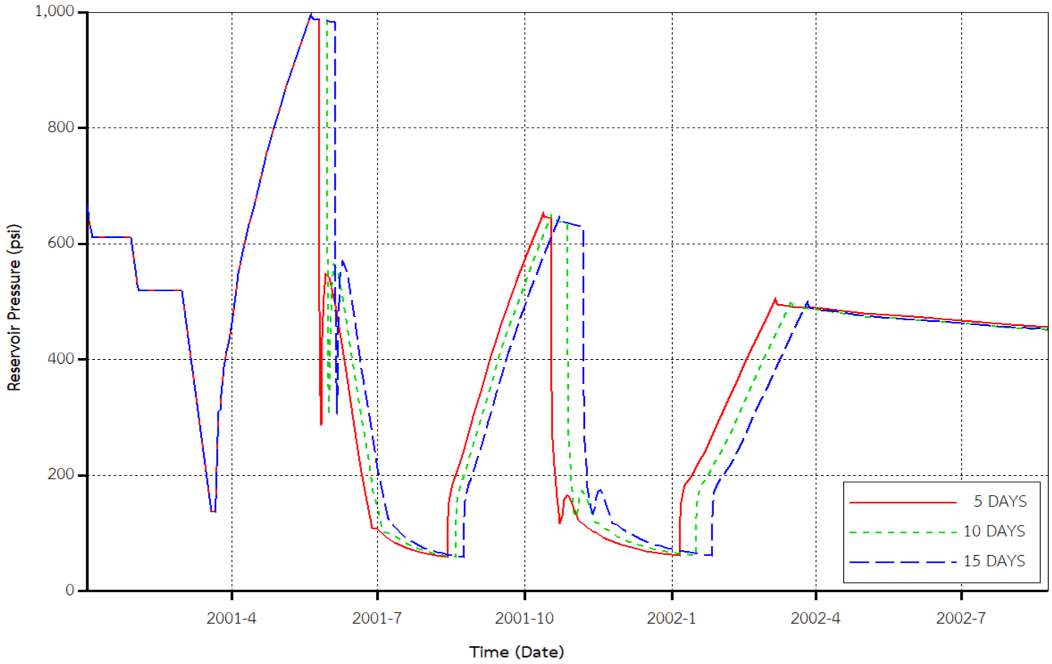

Figure 4.21 Effect of soaking time on oil reservoir pressure using Huff-n-Puff process

4.3 Sensitivity Analysis and Key Parameters Selection

There are several operating parameters in CO_2 Huff-n-Puff process, including HCPV injection, injection time, maximum production rate, production time, and soaking time, are able to affect oil recovery factor and cumulative CO_2 injection with different degree. Hence, the sensitivity analysis is performed to investigate the impacts of these operating parameters on the performance of CO_2 Huff-n-Puff process within three cycles of operation. Figure 4.22 presents the sensitivity analysis of operational parameters on oil recovery factor using CO_2 Huff-n-Puff process. From the figure, the highest sensitive parameter is production time, followed by production rate because these two parameters play the important role in amounts of oil that can be recovered from reservoir. Moreover, HCPV injection and injection time show lower sensitivity on oil recovery due to limitation of drainage area around the wellbore. And the lowest sensitivity is soaking time because pressure built-up rate of low-pressure reservoir is very low resulting in insignificant changing of oil recovery factor. The range of oil recovery factor using CO_2 Huff-n-Puff process is between 2.61 and 4.98 % of OOIP.

Furthermore, the sensitivity analysis of operational parameters on cumulative CO_2 injection using CO_2 Huff-n-Puff process is presented in Figure 4.23. From the results, only one operating parameter, which is HCPV injection, can affect cumulative CO2 injection due to this parameter used to determine slugs of CO_2 that is injected to reservoir. The range of cumulative CO_2 injection using Huff-n-Puff process is obtained as 11.7 MMscf to 34.2 MMscf.

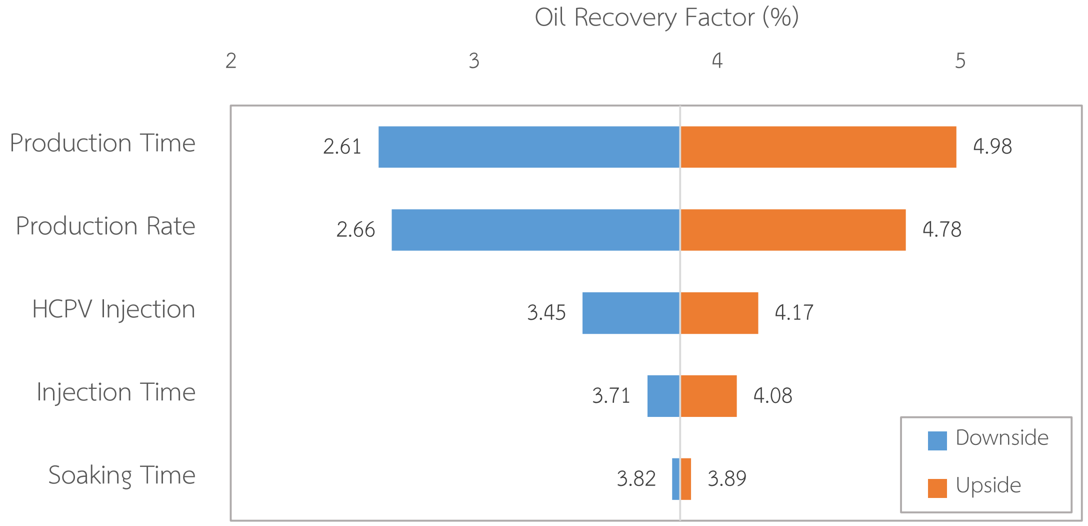

Figure 4.22 Sensitivity analysis of operational parameters on oil recovery factor using CO_2 Huff-n-Puff process

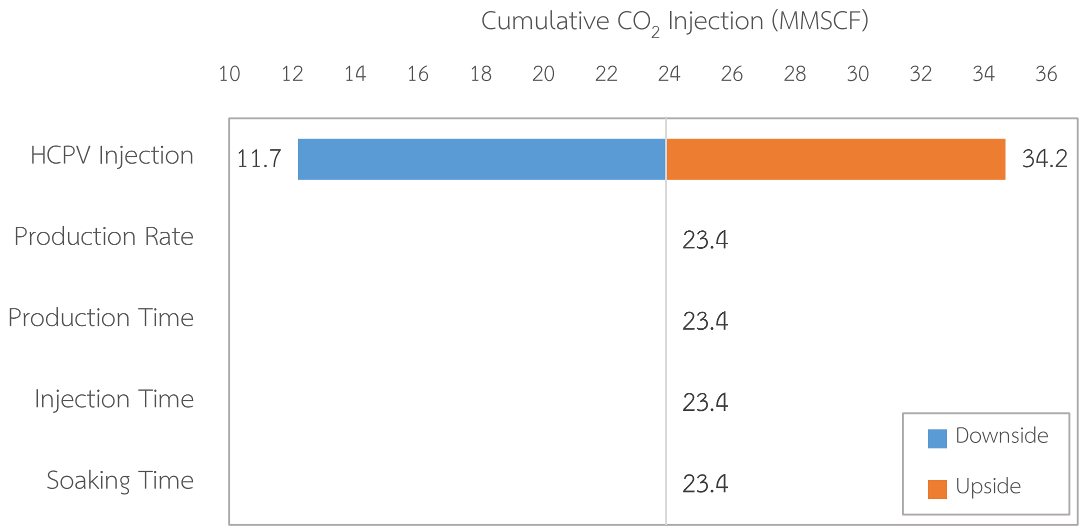

Figure 4.23 Sensitivity analysis of operational parameters on cumulative CO_2 injection using CO_2 Huff-n-Puff process

According to the sensitivity analysis, the key operational parameters are selected, based on the parameters that illustrate high sensitivity on oil recovery factor and cumulative CO_2 injection. Production time and production rate are two operating parameters that show high sensitivity on oil recovery factor. Thus these two parameters are selected as key operational parameters of CO_2 Huff-n-Puff process that they will be varied again in the performance evaluation of integrated CO_2 Huff-n-Puff and WAG process. Another parameter that is selected as a key operational parameter is HCPV injection because this parameter is only one operating parameter that can affect the cumulative CO_2 injection.

Furthermore, other parameters, which illustrate low sensitivity, are determined on a fixed values for using in further studies. To select the best value of injection time, it requires five runs of different values, including 30, 60, 90, 120, and 150 days. And a fixed three cycles of operation is applied for all runs. Average oil rate versus injection time for all cases is presented in Figure 4.24. The results indicate that additional injection time tends to reduce the average oil rate. Therefore, the value of injection time is selected as 30 days because it provides the highest average oil production rate which requires the shortest operating time.

In term of soaking time, six runs of different soaking period are conducted to determine the best value of soaking time. Soaking periods of 5, 10, 15, 20, 25, 30 days are run within three cycles of operation and fixed values of other operating parameters as base-case values. Figure 4.25 illustrates the relationship between average oil rate and soaking time. The results of this plot indicate that the shorter soaking time tends to increase the average oil production rate and the shortest soaking period among these runs is five days that provides the highest average oil rate. This is because low-pressure reservoir contains very low pressure build-up rate due to a lack of natural reservoir pressure support. Therefore, the longer time of soaking period is not able to develop existing reservoir pressure after CO_2 injection. According to results, five days of soaking time is properly selected to use for in further study. Finally, the selected key operational parameters and fixed values of less sensitive parameters using CO2 Huff-n-Puff process are concluded in Table 4.8

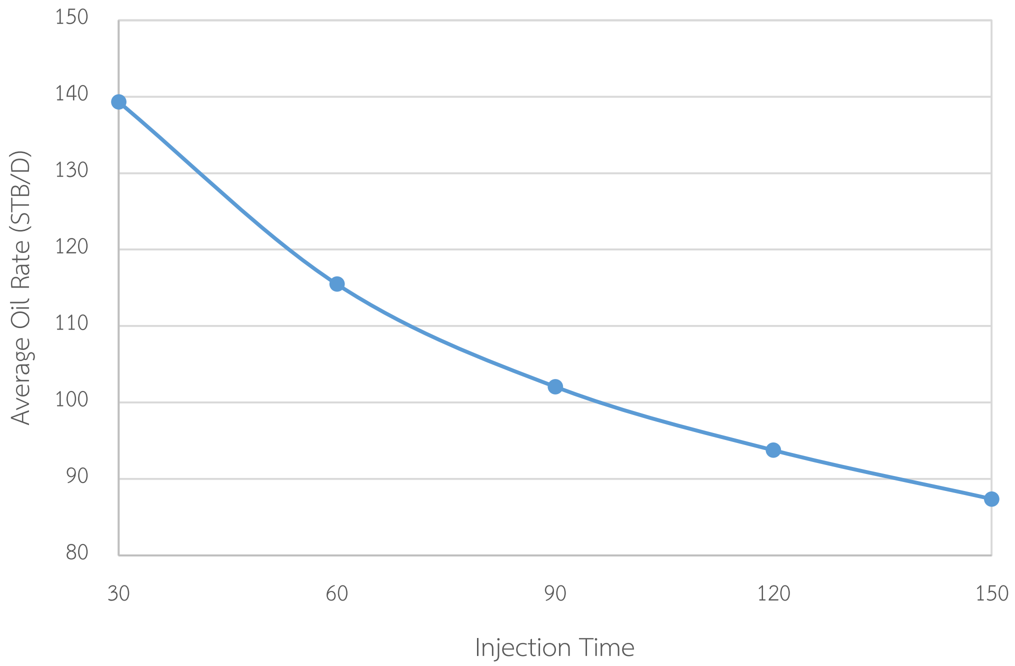

Figure 4.24 Value selection of CO_2 injection time

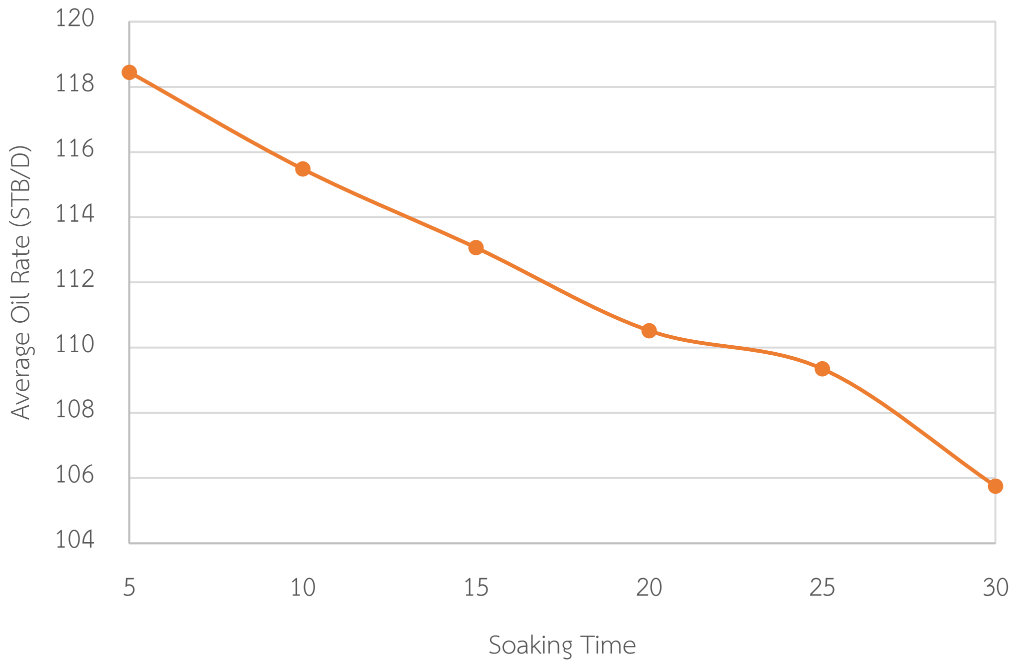

Figure 4.25 Value selection of soaking time

Table 4.8 Key operational parameters and fixed values selection

Parameter	Value
HCPV injection (PV)	Key Parameter
Maximum production rate (STB/D)	Key Parameter
Production time (day)	Key Parameter
Injection time (day)	30
Soaking time (day)	5
Number of cycle (cycle)	3

4.4 Integrated CO_2 Huff-n-Puff and WAG Base Case and Comparative Study

Integrated CO_2 Huff-n-Puff and WAG is a process to enhance oil recovery with the combination of two processes, i.e., CO_2 Huff-n-Puff at early stage of operation followed by alternating of water injection. The CO_2 Huff-n-Puff process is performed to confirm reservoir response by CO_2 EOR mechanisms and to recover oil around the wellbore with low capital investment and quick payout (Simpson, 1988). Moreover, the desired slug of CO_2 is injected and remained into reservoir by this process. After CO_2 Huff-n-Puff process has already ended, a slug of water is injected to reservoir for pressure maintenance, sweep efficiency improvement. Also, an alternating of water can help to reduce CO_2 utilization, which is one of the most important factor for CO_2 EOR project decision (Donohue, 2017).

The simulation of integrated CO_2 Huff-n-Puff and WAG base-case is compared to that of conventional CO_2 flooding, conventional water flooding, and primary recovery based on oil recovery factor, as shown in Figure 4.26. The results of these simulation illustrate that the highest oil recovery of 63.2% of OOIP can be achieved by applying the integrated CO_2 Huff-n-Puff and WAG process, followed by conventional water flooding accounting for 50.6% of OOIP. On the other hand, conventional CO_2 flooding offers poor performance (oil recovery of 25.1% of OOIP because the continuous injection of CO_2 can be attributed to the low volumetric sweep efficiency as previously reported by Zekri et al. (2011). The lowest oil recovery factor among these processes is oil production with primary recovery that can recover just 2.1% of OOIP due to very low reservoir pressure and lack of natural drive mechanism.

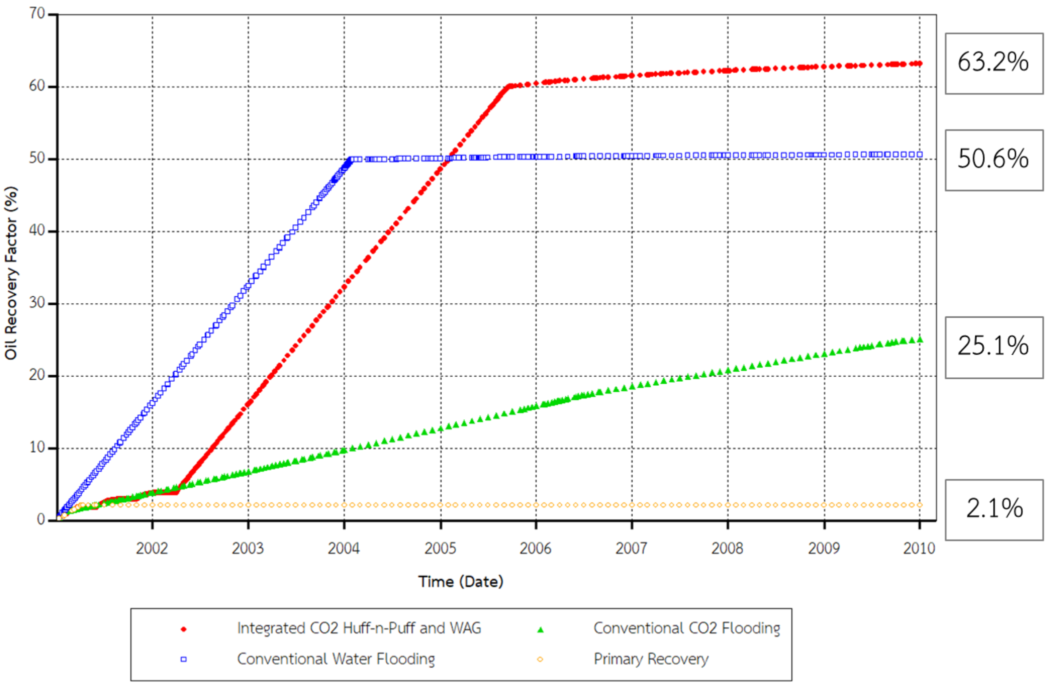

Figure 4.26 Comparison of oil recovery factor between integrated CO_2 Huff-n-Puff and WAG and other oil recovery processes

4.4.1 Comparison of Integrated CO_2 Huff-n-Puff and WAG and CO_2 Flooding

Oil recovery factor obtained from using integrated CO_2 Huff-n-Puff and WAG process is 37.1% which is higher than that of conventional CO_2 flooding, as shown in Figure 4.27. Because a slug of water injected after a slug of CO_2 has capability to increase and maintain reservoir pressure. Figure 4.28 presents the reservoir pressure while using these two processes. The results show that integrated CO_2 Huff-n-Puff and WAG process can increase pressure approximately 850 psi higher than that of conventional CO_2 flooding. Furthermore, producing gas-oil ratio and 3-D models of flood front of using integrated CO_2 Huff-n-Puff and WAG and conventional CO_2 flooding are presented in Figure 4.29. The producing gas-oil ratio of conventional CO_2 flooding is rapidly increase after five and a half years of operation that can be assumed that injected CO_2 initiates breakthrough at this time.

The continuously injected CO_2 is more buoyant and less viscous than oil, so the early breakthrough potentially occurred by channeling or fingering through the upper reservoir (Whittaker & Perkins, 2013). Moreover, the 3-D models of oil saturation for these two processes are compared to evaluate the flood front. According to models, the flood front of integrated CO_2 Huff-n-Puff and WAG process is more stable as piston-like displacement. Nonetheless, conventional CO_2 flooding demonstrates the unstable flood front which can displace oil only upper side of reservoir due to gravity overriding effect of CO_2. Hence, an alternating of slug of water can provide more stable flood front that improve the volumetric sweep efficiency. The reason is that water has viscosity relatively similar to oil than CO_2, therefore it can provide more uniform flood front. Likewise, water is heavier than oil and CO_2, so it tends to displace the lower portion of oil in the reservoir than CO_2. The results of this mechanism are improvement of oil recovery factor.

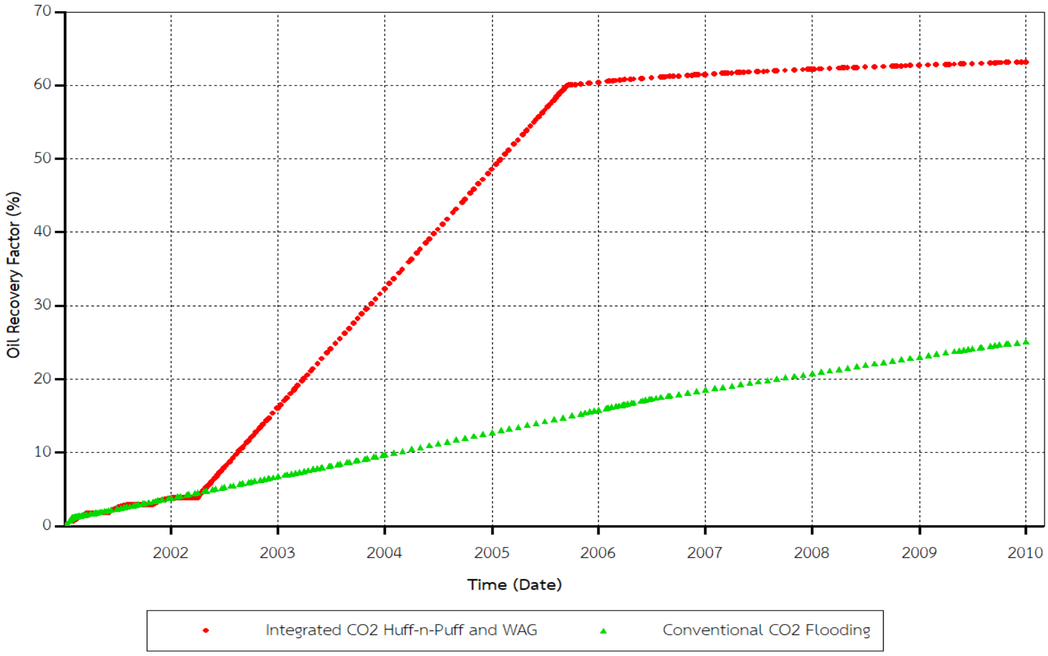

Figure 4.27 Comparing of oil recovery factor between using integrated CO_2 Huff-n-Puff and WAG and conventional CO_2 flooding

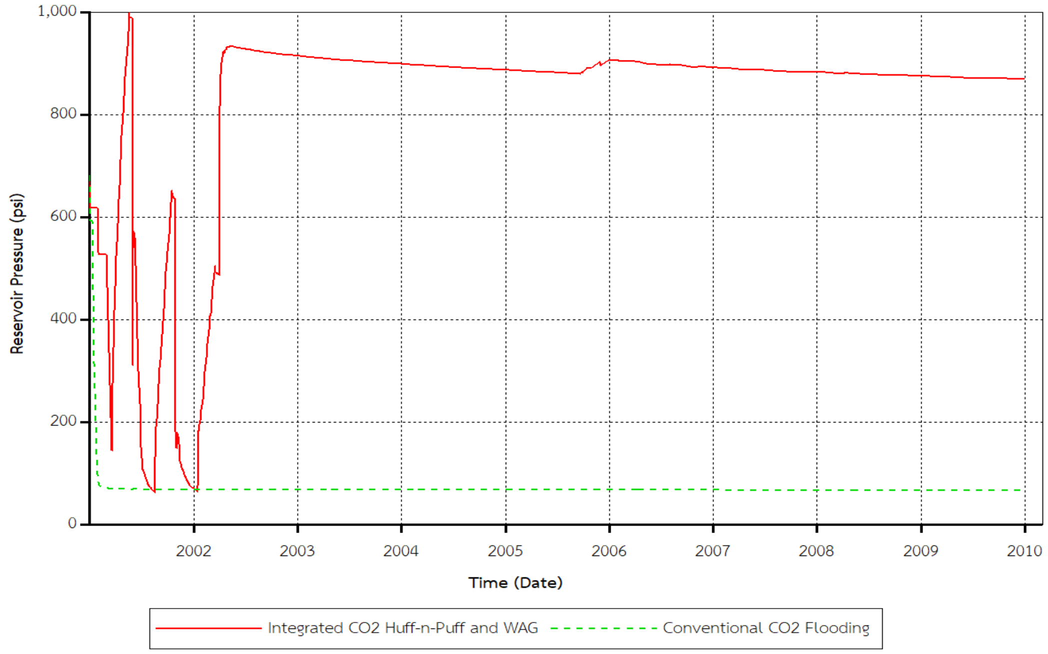

Figure 4.28 Reservoir pressure of using integrated CO_2 Huff-n-Puff and WAG and conventional CO_2 flooding

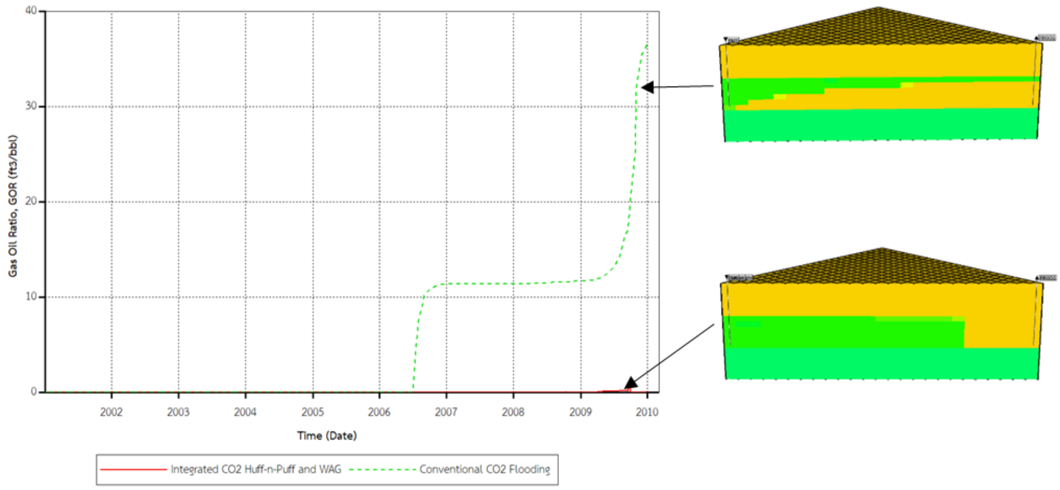

Figure 4.29 Producing gas oil ratio of using integrated CO_2 Huff-n-Puff and WAG and conventional CO_2 flooding

4.4.2 Compared of Integrated CO_2 Huff-n-Puff and WAG and Water Flooding

According to simulation results, integrated CO_2 Huff-n-Puff and WAG process provides 12.6% of oil recovery factor above oil producing with conventional water flooding, as shown in Figure 4.30. These results are corresponding with the previous research's conclusion which indicated that WAG floods can yield 5-20% additional oil recovery over conventional water flooding (Panda, Nottingham, & Lenig, 2010).

The process of integrated CO_2 Huff-n-Puff and WAG can improve oil recovery factor because a slug of CO_2 injected into reservoir by Huff-n-Puff process is able to delay breakthrough time of injected water. Figure 4.31 presents that the breakthrough time of using conventional water flooding is occurred after three years of operation and the cumulative water production is rapidly increase after that time. Comparing to oil recovered from the integrated CO_2 Huff-n-Puff and WAG process, breakthrough time is prolonged about one year and eight months that approximately 10% of oil recovery is obtained within this duration. The early breakthrough of water provides lower sweep efficiency due to potential channeling and fingering of injected water at the lower side of reservoir, known as gravity under-running (Smith & Cobb, 1997).

The continuous injection of water after water breakthrough can provide slightly more oil recovery due to the bypassing of water through a production well. In addition, the injected slug of CO_2 tends to sweep oil through upper reservoir and a slug of water tends to sweep lower reservoir (Whittaker & Perkins, 2013). Hence, the integrated of these two injected fluid can provide preferable sweep efficiency. Moreover, Figure 4.32 presents the comparing of producing water rate after water breakthrough between integrated CO_2 Huff-n-Puff and WAG and conventional water flooding. Almost hundred percent of injected water from conventional water flooding process is produced after breakthrough that can be considered as continuous water injection after water breakthrough is bypassed through production well and low capability to displace oil. However, smaller water production rate is produced after water breakthrough with integrated CO_2 Huff-n-Puff and WAG process that can be defined as some injected water still displace oil to production well. Therefore, the integrated CO_2 Huff-n-Puff and WAG process can provide higher oil recovery when continuous injection of water after water breakthrough because the injected CO_2 can reduce oil viscosity (Bybee, 2007). Thus, certain residual oil is still displaced by continuous injected water. Also, the integrated CO_2 Huff-n-Puff and WAG process provides trapped gas effect to reduce residual oil saturation after water breakthrough (Mohammed-Singh et al., 2006).

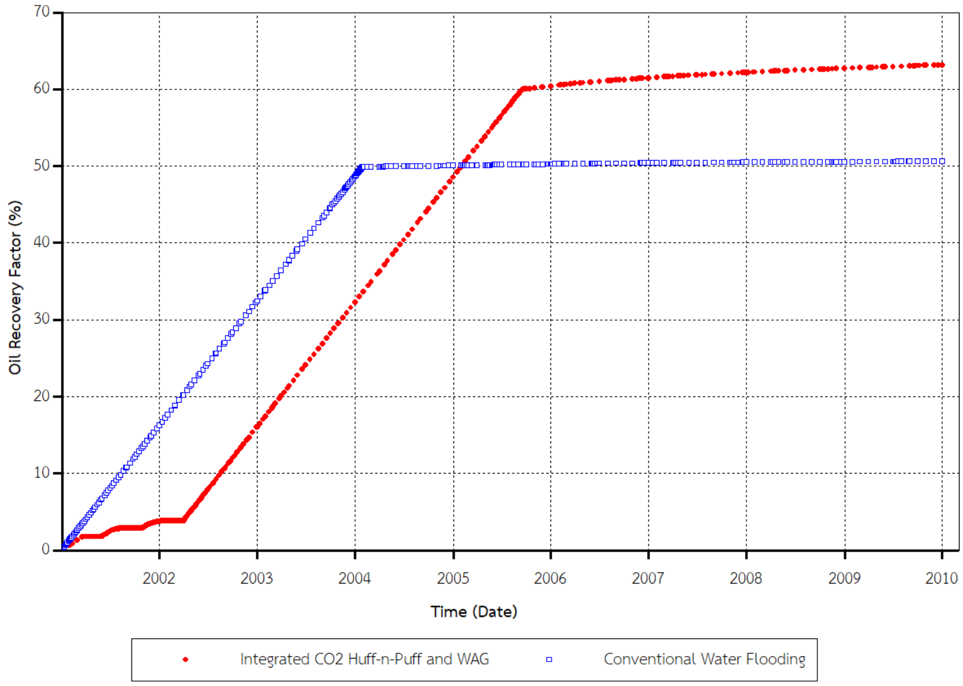

Figure 4.30 Comparing of oil recovery factor between using integrated CO_2 Huff-n-Puff and WAG and conventional water flooding

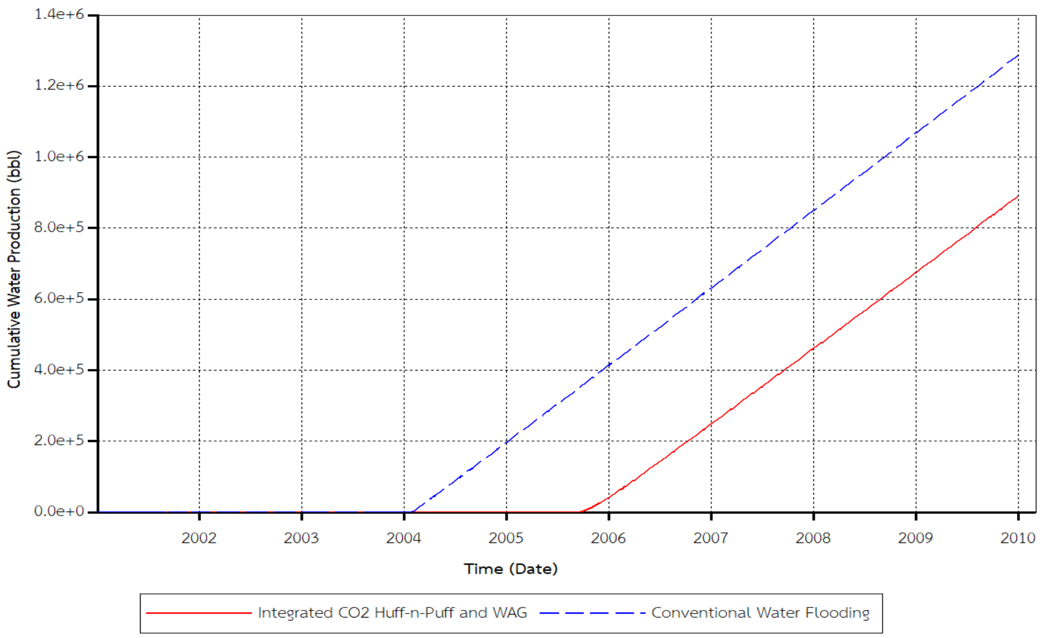

Figure 4.31 Comparing of cumulative water production between using integrated CO_2 Huff-n-Puff and WAG and conventional water flooding

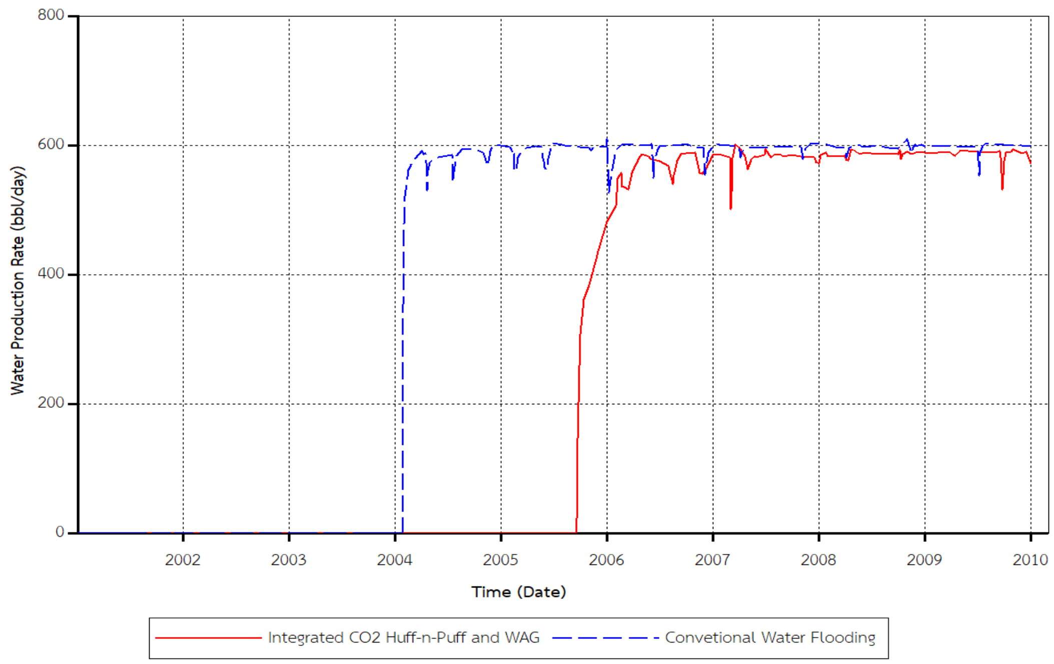

Figure 4.32 Comparing of producing water rate between using integrated CO_2 Huff-n-Puff and WAG and conventional water flooding

4.4.3 Comparison of Integrated CO_2 Huff-n-Puff and Primary Recovery

Figure 4.33 illustrates the comparing of oil recovery factor obtained by the integrated CO_2 Huff-n-Puff and WAG process and the primary production process. Using the integrated CO_2 Huff-n-Puff and WAG process can provide oil recovery up to 63.1% of original oil in place (OOIP) which is much higher than the oil recovery factor from primary recovery (2.1% of OOIP).

In this study, primary recovery can provide extremely low oil recovery factor due to the low-pressure reservoir which contains very low reservoir pressure and barely supported by natural drive mechanisms. Thus, the reservoir pressure of primary recovery is rapidly dropped from 680 to 45 psi by only 124 days of production, as shown in Figure 4.34. On the other hand, the integrated CO_2 Huff-n-Puff and WAG process can support reservoir pressure. The injected CO_2 in early stage of operation increases reservoir pressure to approximately 1,000 psi and it continuously reduced by additional oil production. After a slug of alternating water is injected into reservoir, the reservoir pressure is maintained around 900 psi until the end of operation, as shown in Figure 4.34. From the simulation results, slugs of CO_2 and water in low-pressure reservoir can offer the recovery factor of 61.1% higher than that of the primary oil production. The most important factor of additional oil recovery is reservoir pressure maintenance with injecting of CO_2 and water into low-pressure reservoir.

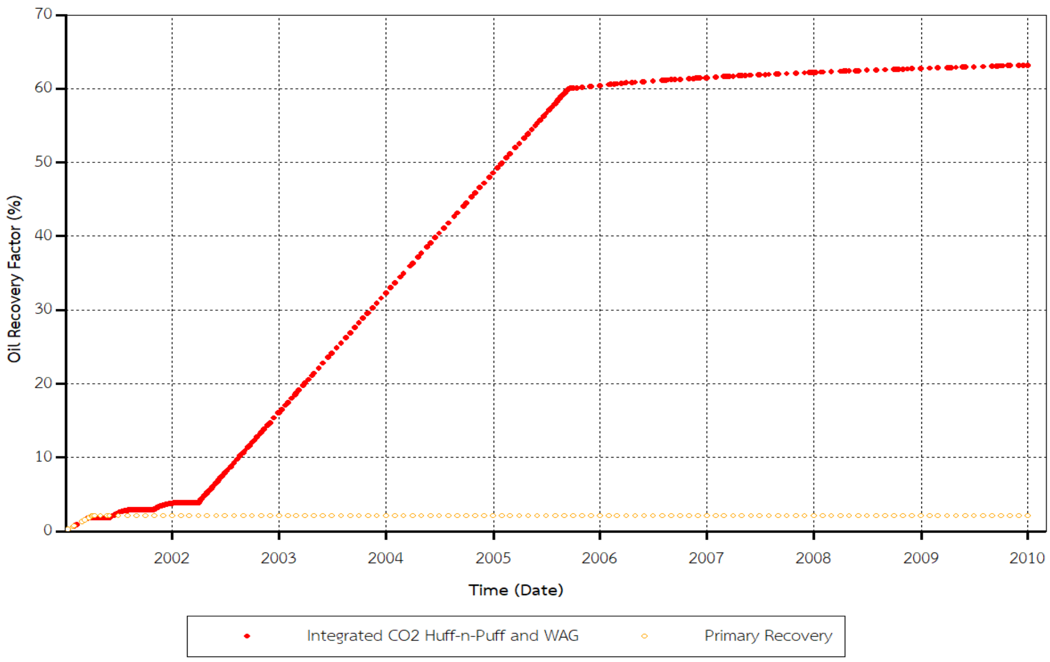

Figure 4.33 Comparing of oil recovery factor between using integrated CO_2 Huff-n-Puff and WAG and primary recovery

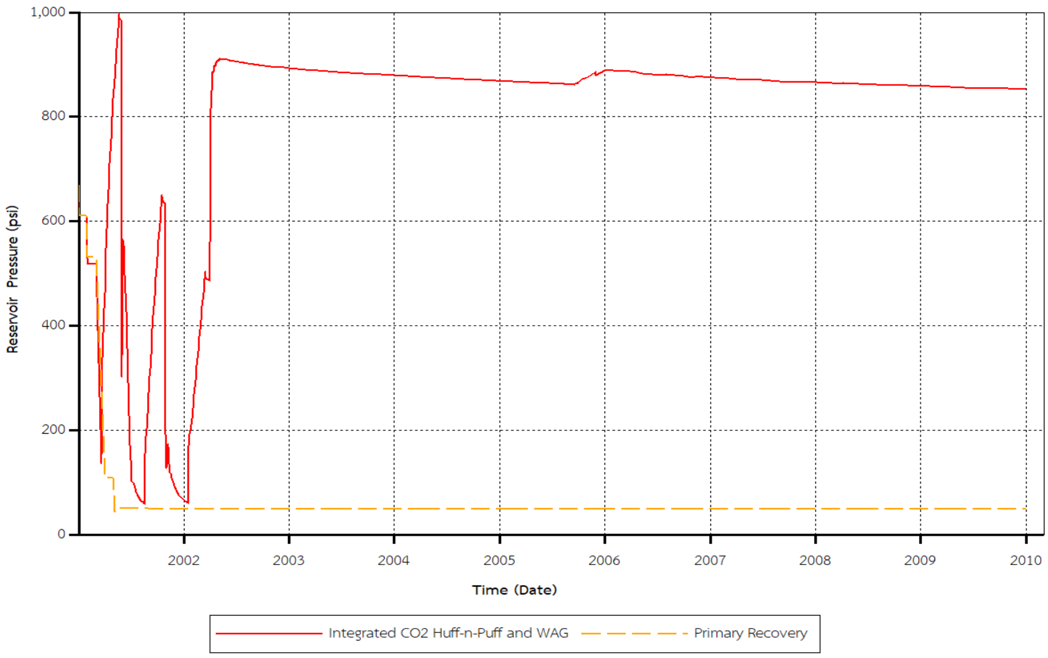

Figure 4.34 Comparing of reservoir pressure between using integrated CO_2 Huff-n-Puff and WAG and primary recovery

4.5 Performance Evaluation of Integrated CO_2 Huff-n-Puff and WAG Process

The performance evaluation of integrated CO_2 Huff-n-Puff and WAG process in low-pressure heterogeneous reservoir is investigated by performing 36 simulated crossed-cases. The three main operating parameters that are varied in these crossed-cases are selected from high sensitive parameters in CO_2 Huff-n-Puff process. The varied parameters in integrated CO_2 Huff-n-Puff and WAG process are hydrocarbon pore volume injection (HCPV), production time in CO_2 Huff-n-Puff process, and oil production rate. The HCPV injection is used to determine CO_2 injection rate that is extremely important to investigate CO_2 utilization. Moreover, the production time is one of important parameter that can affect the period of CO_2 Huff-n-Puff prior to injection of alternating slug of water. Also the oil production rate is assumed to be the same as chasing water injection rate due to material balance that total mass input is equal to total mass output for reservation of mass inside reservoir. This results in the reservoir pressure maintenance (Felder & Rousseau, 1986).

Furthermore, the fixed values of others operating parameters that show lower sensitivity to oil recovery factor and CO_2 consumption in sensitivity analysis and key parameters selection section, are used for all runs. Moreover, the total simulated time for this integrated CO_2 Huff-n-Puff and WAG process is ten years of operation, and the fixed value of three cycles of CO_2 Huff-n-Puff process is conducted at early stage of operation prior to a slug of alternating water is injected into reservoir. The vales of varied parameters and other fixed parameters are presented in Table 4.3.

Table 4.9 Values of parameters using in integrated CO_2 Huff-n-Puff and WAG process

Varied Parameters	**Value**
HCPV Injection (PV)	0.5, 1.0, 1.5, 2.0
Production Time (day)	30, 60, 90
Oil Production Rate (STB/D)	300, 450, 600
Water Injection Rate (STB/D)	300, 450, 600
Fixed Parameters	**Value**
Injection Time (day)	30
Soaking Time (day)	5
Huff-n-Puff Cycle (cycle)	3
Total Simulated Time (year)	10

4.5.1 Effect of chasing water injection rate

The effect of chasing water rate on oil recovery factor and CO_2 utilization is investigated by conducting three runs with 300, 450, and 600 bwpd for each CO_2 hydrocarbon pore volume injection (HCPV), including 0.5, 1.0, 1.5, and 2.0 HCPV. And fixed CO_2 Huff-n-Puff period of 195, 285, and 375 days are used for all runs. Total operating period of integrated CO_2 Huff-n-Puff and WAG process is 10 years and a fixed number of three cycles of CO_2 Huff-n-Puff process used for these simulation.

The relationship between oil recovery factor and CO_2 HCPV injection for different chasing water injection rate with 195 days of CO_2 Huff-n-Puff process is presented in Figure 4.35. The results of these plots indicates that higher oil recovery can be obtained by increasing injection rate of chasing water. According to the results, injection of 600 bwpd provides approximately 63.5% of original oil in place (OOIP). The injection of 600 bwpd with 2.0HCPV injection provides the highest values of oil recovery factor which is 63.8% of OOIP. However, the lowest oil recovery factor is obtained by injected 300 bwpd of chasing water rate with the lowest HCPV injection of 0.5HCPV is 61.12% of OOIP. Moreover, an increase in chasing water injection rate can reduce CO_2 utilization at all HCPV injection, as shown in Figure 4.36. The lowest CO_2 utilization is achieved with 600 bwpd injection rate at 0.5HCPV that is about 13.7 scf/stb. On the other hand, the highest CO_2 utilization is 56.4 scf/stb obtained by injecting water of 300 bwpd at 2.0HCPV. Based on CO_2 utilization results, lower CO_2 utilization can be obtained by using higher water injection rate with lower CO_2 HCPV injection.

Furthermore, these simulations are performed again by changing CO_2 Huff-n-Puff period from 195 days to 285 and 375 days. The results of changed CO_2 Huff-n-Puff period demonstrate the similar trend with 195 days for both oil recovery factor versus HCPV injection and CO_2 utilization versus HCPV injection, as shown from Figure 4.37 to Figure 4.40. Figure 4.37 presents the relationship between oil recovery factor and HCPV injection with different chasing water rates with by using 285 days of CO_2 Huff-n-Puff process. The highest oil recovery factor of 64.8% of OOIP is obtained by using 2.0HCPV and 600 bwpd which both values are the highest values within these runs. Conversely, the smallest CO_2 slug size with lowest chasing water injection rate provide the lowest oil recovery factor of 61.7% of OOIP. In term of CO2 utilization, using 285 days of CO_2 Huff-n-Puff period provides the same trend of using 195 days that the lowest CO_2 utilization of 13.5 scf/stb can be obtained by injecting of the highest chasing water rate and the smallest CO_2 HCPV injection, as shown in Figure 4.38. Also, the similar results are shown by using 375 days of CO_2 Huff-n-Puff period that higher chasing water injection rate can provide more oil recovery factor and less CO_2 utilization. The highest oil recovery factor is 65.7% with using 600 bwpd and 375 days of CO_2 Huff-n-Puff period, as shown in Figure 4.39. And Figure 4.40 presents CO_2 utilization versus HCPV for different chasing water injection rates with 375 days of CO_2 Huff-n-Puff process that the lowest CO_2 utilization is 13.2 scf/stb and the highest one is 55.7 scf/stb.

Accordingly, the results of all simulation cases indicated that higher chasing water injection rate can provide higher oil recovery factor and lower CO_2 utilization for every CO_2 slug sizes. This is because higher water injection rate can provide additional reservoir pressure, as shown in Figure 4.41. With 600 bwpd of injection rate, reservoir pressure is built-up to approximately 900 psi that can maintain constant production rate at 600 bopd for around 3.5 years after initial chasing water injection, as shown in Figure 4.42. However, 300 and 450 bwpd injection rates of chasing water provide lower reservoir pressure. So, they have capability to maintain lower oil production rate than the cases of injecting 600 bwpd of chasing water. Even though the lower rate of water injection can maintain longer plateau rate, cumulative oil production of those is still lower. Moreover, higher chasing water injection rate can reduce additional oil saturation, as shown in Figure 4.43. Based on oil saturation models, 600 bwpd injection shows the most favorable areal sweep efficiency because excess water injection can displace more crude oil in reservoir and also higher chasing water injection rate can provide additional reservoir pressure that increase oil swelling factor and CO_2 solubility in crude oil (Sasaki & Sugai, 2017). Then, additional residual oil can be recovered by higher injection rate of chasing water. In term of CO_2 utilization, the cases of higher chasing water injection rate demonstrate lower CO_2 utilization because high water injection rate can provide additional oil production with constant CO_2 consumption. Consequently, CO_2 utilization, which defined as the amount of injected CO_2 per unit volume of incremental oil production (Wang et al., 2013), is reduced.

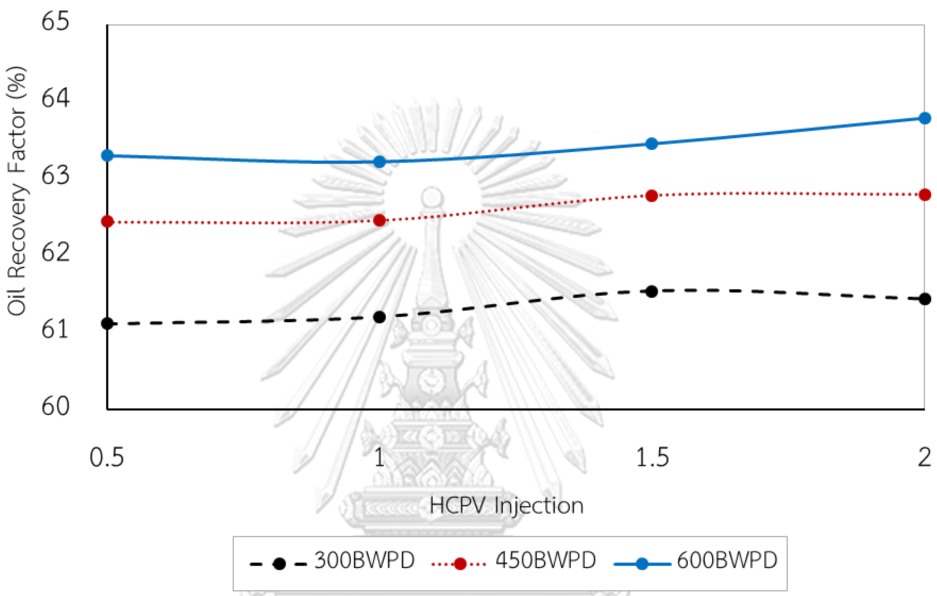

Figure 4.35 Oil recovery factor versus CO_2 HCPV injection for different chasing water injection rate using 195 days of CO_2 Huff-n-Puff period

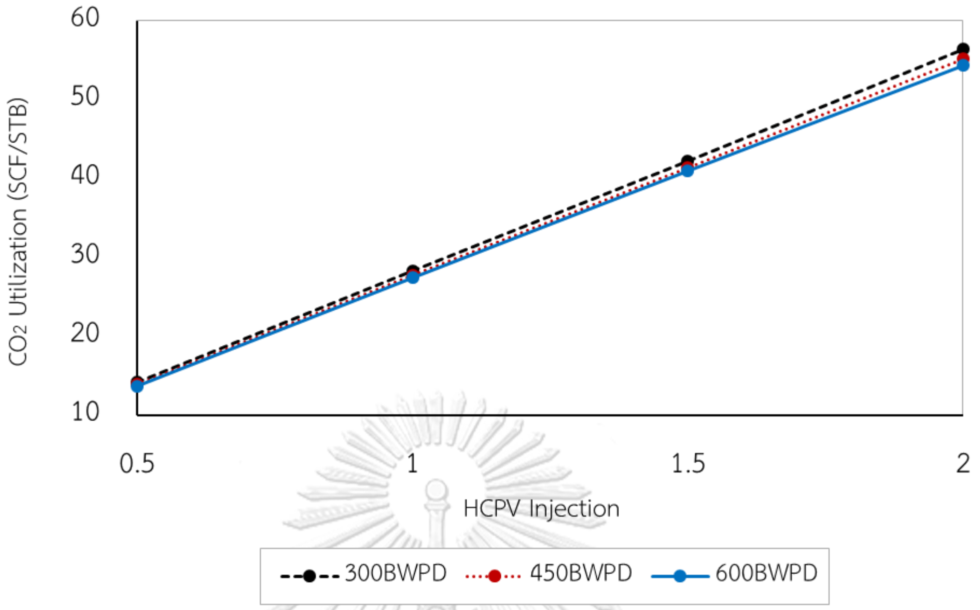

Figure 4.36 CO_2 utilization versus HCPV for different chasing water injection rate using 195 days of CO_2 Huff-n-Puff period

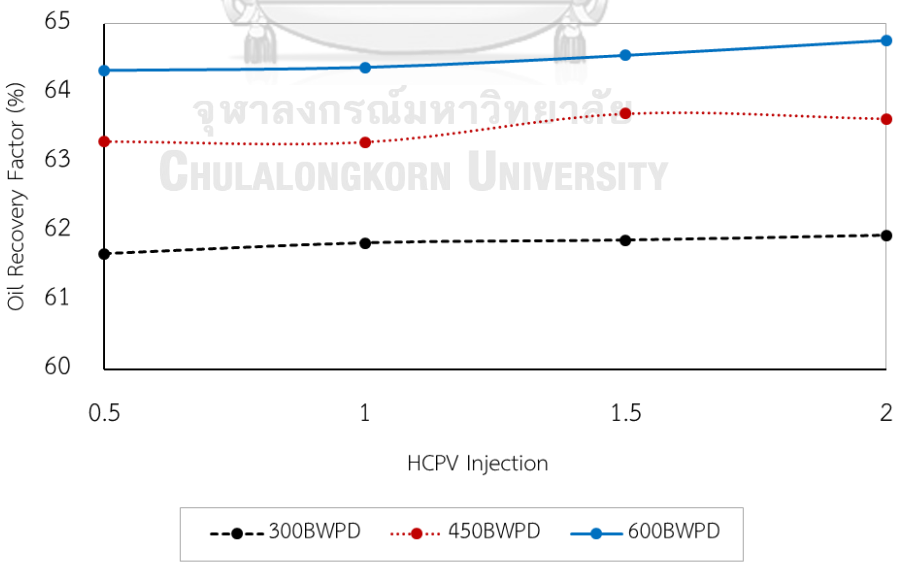

Figure 4.37 Oil recovery factor versus CO_2 HCPV injection for different chasing water injection rate using 285 days of CO_2 Huff-n-Puff period

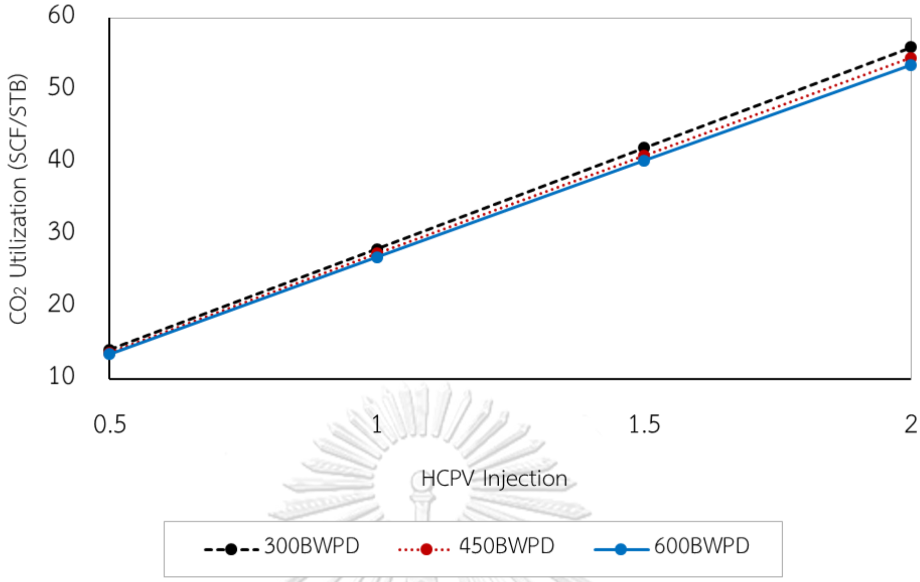

Figure 4.38 CO_2 utilization versus HCPV for different chasing water injection rate using 285 days of CO_2 Huff-n-Puff period

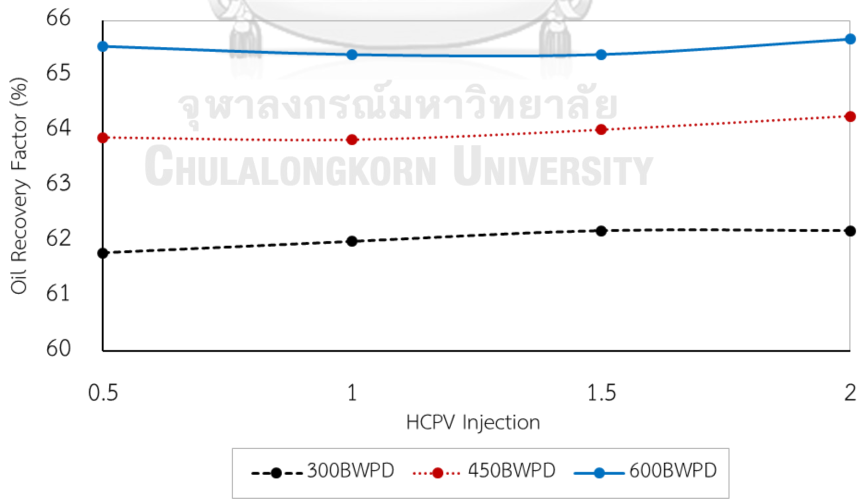

Figure 4.39 Oil recovery factor versus CO_2 HCPV injection for different chasing water injection rate using 375 days of CO_2 Huff-n-Puff period

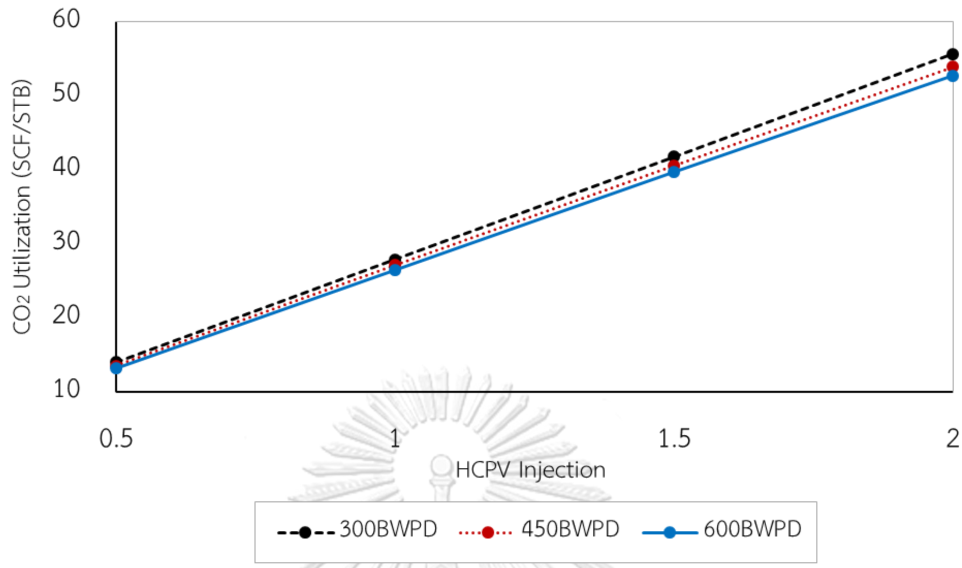

Figure 4.40 CO_2 utilization versus HCPV for different chasing water injection rate using 375 days of CO_2 Huff-n-Puff period

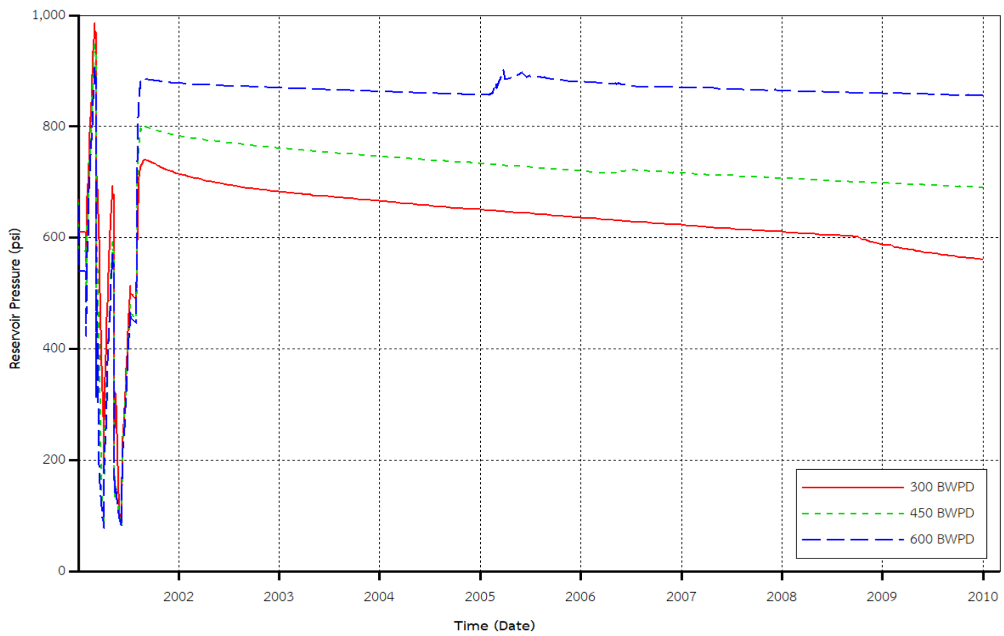

Figure 4.41 Effect of chasing water injection rate on reservoir pressure using integrated CO_2 Huff-n-Puff and WAG process

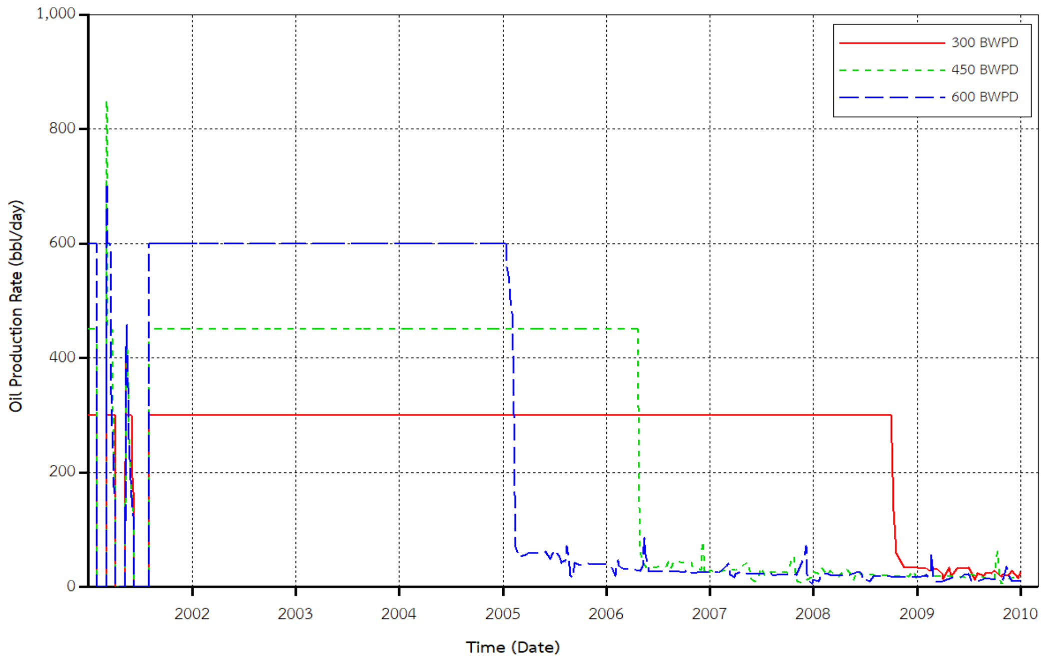

Figure 4.42 Effect of chasing water injection rate on oil production rate using integrated CO_2 Huff-n-Puff and WAG process

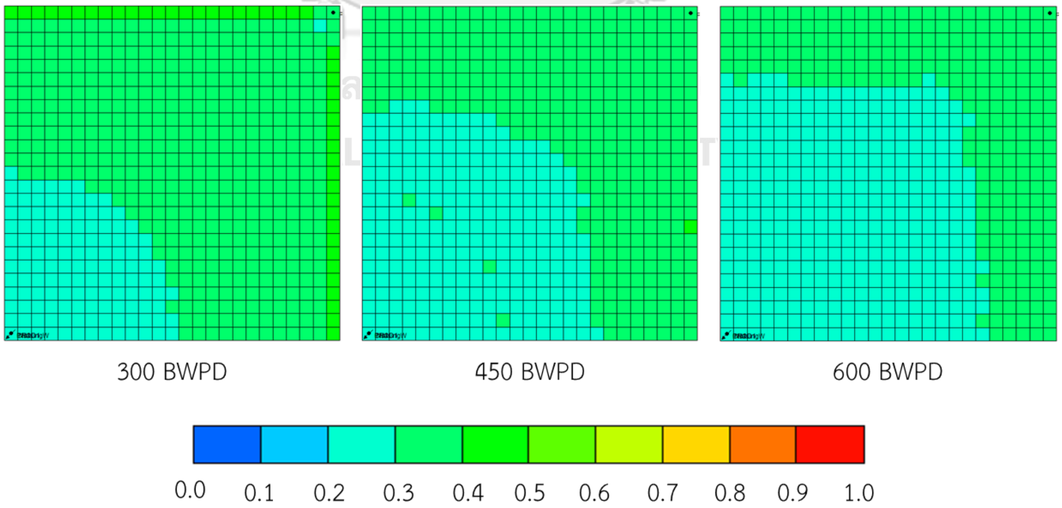

Figure 4.43 Effect of chasing water injection rate on oil saturation using integrated CO_2 Huff-n-Puff and WAG process

Effect of chasing water injection rate of above 600 bwpd is also investigated by conducting five runs, including 600, 650, 700, 750, and 800 bwpd and the values of others operating parameter are fixed for every run. HCPV injection and CO_2 Huff-n-Puff period are selected as 1.5HCPV and 375 days, respectively. And other parameters are fixed as same as previous conditions, as shown in Table 4.1.

Effect of chasing water injection rate above 600 bwpd, on oil recovery factor is shown in Figure 4.44. The results of this plot indicate that increasing chasing water injection rate above 600 bwpd can slightly affect to oil recovery factor. The increasing of water injection rate from 600 to 650 bwpd provides additional 0.04% of oil recovery factor. However, further increasing of chasing water injection rate gradually reduces oil recovery factor with continuous increasing of cumulative water injection, as shown in Figure 4.45. Moreover, increasing water injection rate results in earlier water breakthrough time, as shown in Figure 4.46. The water breakthrough time is continuously decreased from 1693 to 1371 days by continuous increasing of chasing water rate, as presented in Figure 4.47.

Figure 4.48 presents the effect of chasing water injection rate above 600 bwpd on reservoir pressure. The results of these runs indicate that reservoir pressure is significantly increased when chasing water rate is added from 600 to 650 bwpd, however, further additional chasing water rate beyond 650 bwpd can slightly rise the reservoir pressure. Subsequently, water injection above 650 bwpd provide short period of constant production rate due to insufficient reservoir pressure to maintain at that rate, as shown in Figure 4.49. Therefore, oil recovery factor obtained from water injecting of above 650 bwpd, slowly decreases.

In term of CO_2 utilization, Figure 4.50 presents the effect of chasing water injection rate above 600 bwpd on oil recovery factor and CO_2 utilization. The CO_2 utilization is slightly reduced at injection of 650 bwpd of chasing water and continuously increases after that point. The trend of CO_2 utilization is in the opposite directions of oil recovery factor because while CO_2 consumption is constant, more oil recovery can reach lower CO_2 utilization. According to simulation results, the lowest CO_2 utilization of 13.2 scf/stb is achieved by injecting 650 bwpd of chasing water, but the highest one obtained by using 800 bwpd is 13.4 scf/stb.

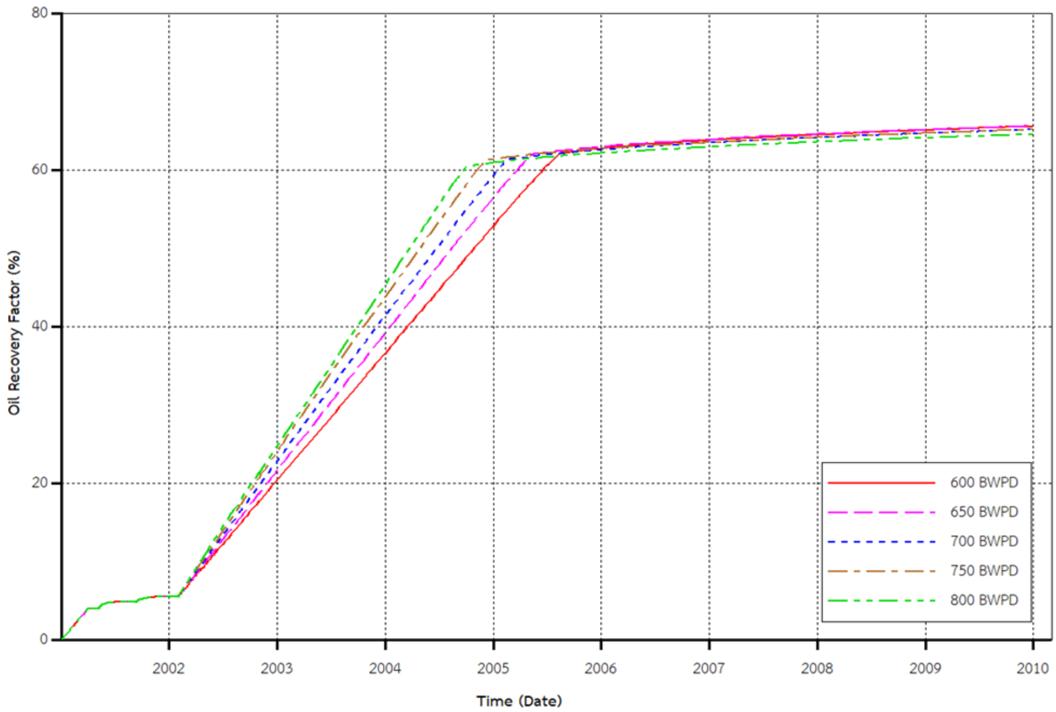

Figure 4.44 Effect of chasing water injection rate above 600 bwpd on oil recovery factor

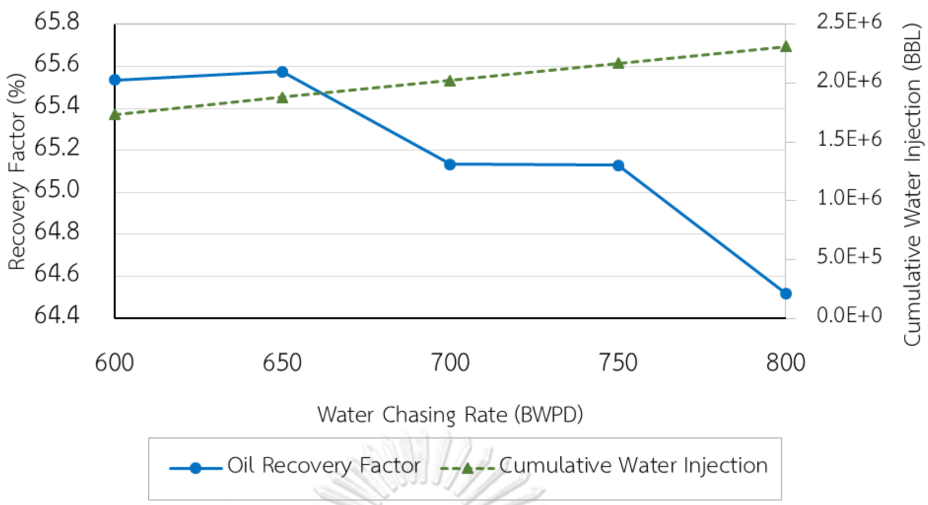

Figure 4.45 Effect of chasing water injection rate above 600 bwpd on oil recovery factor and cumulative water injection

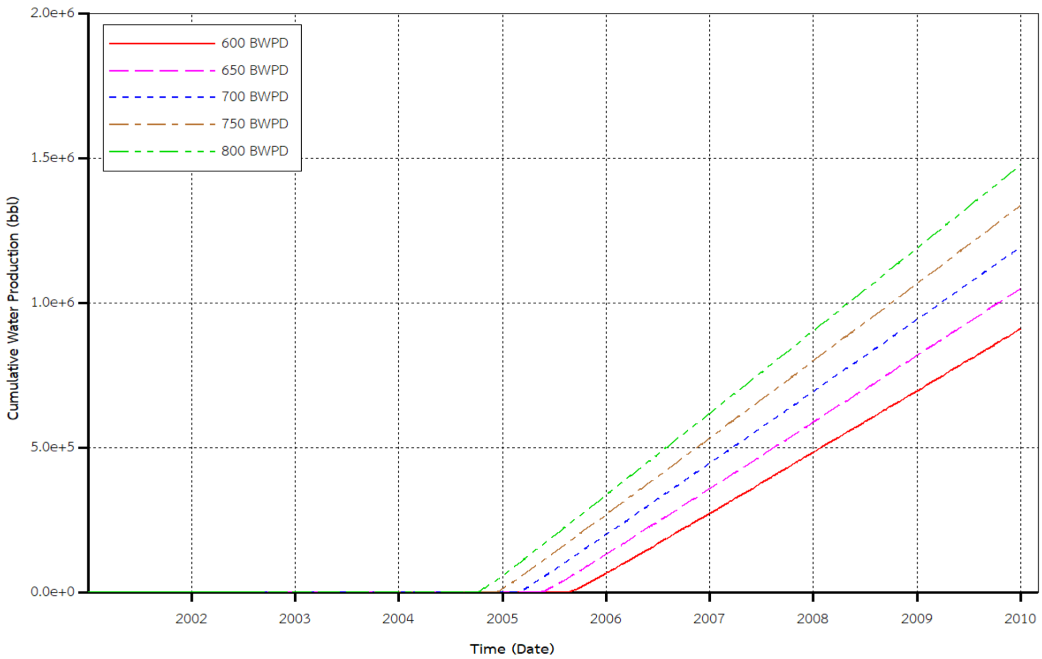

Figure 4.46 Effect of chasing water injection rate above 600 bwpd on cumulative water production

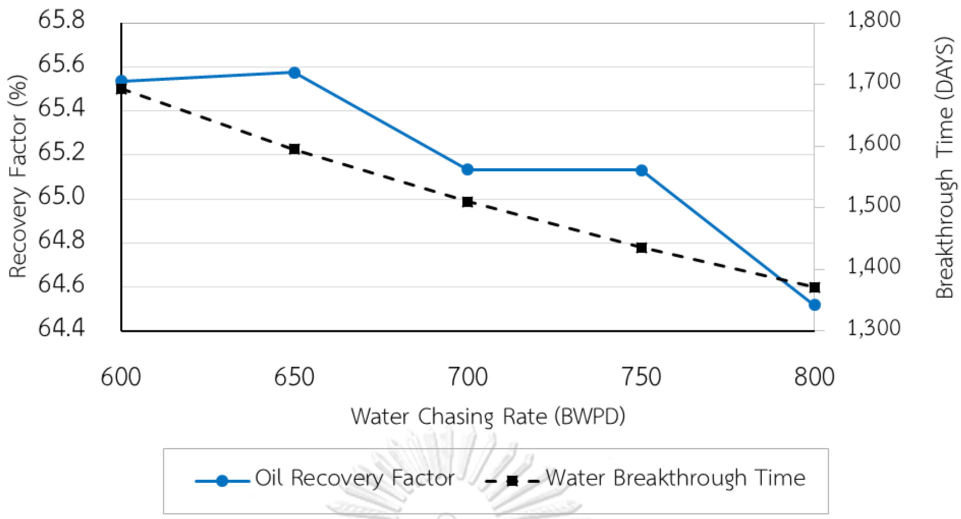

Figure 4.47 Effect of chasing water injection rate above 600 bwpd on oil recovery factor and water breakthrough time

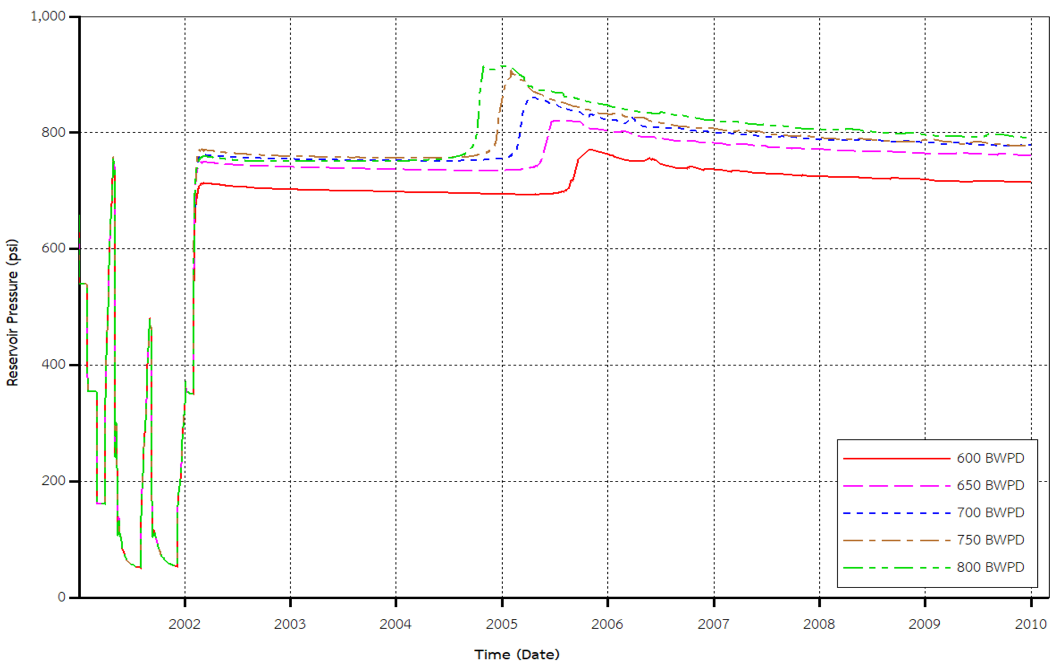

Figure 4.48 Effect of chasing water injection rate above 600 bwpd on reservoir pressure

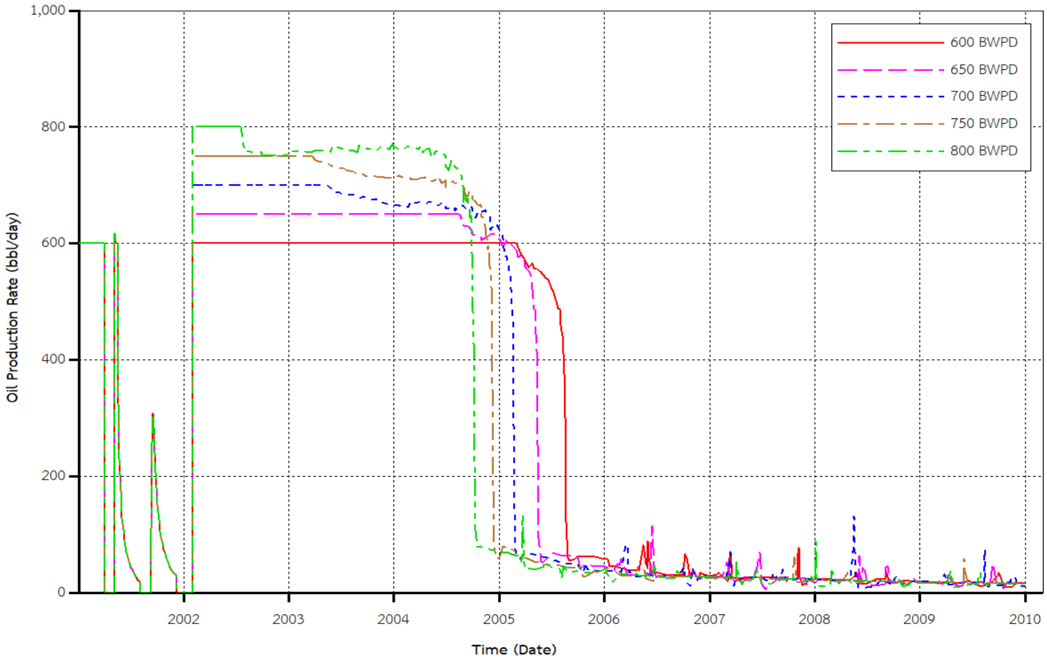

Figure 4.49 Effect of chasing water injection rate above 600 bwpd on oil rate

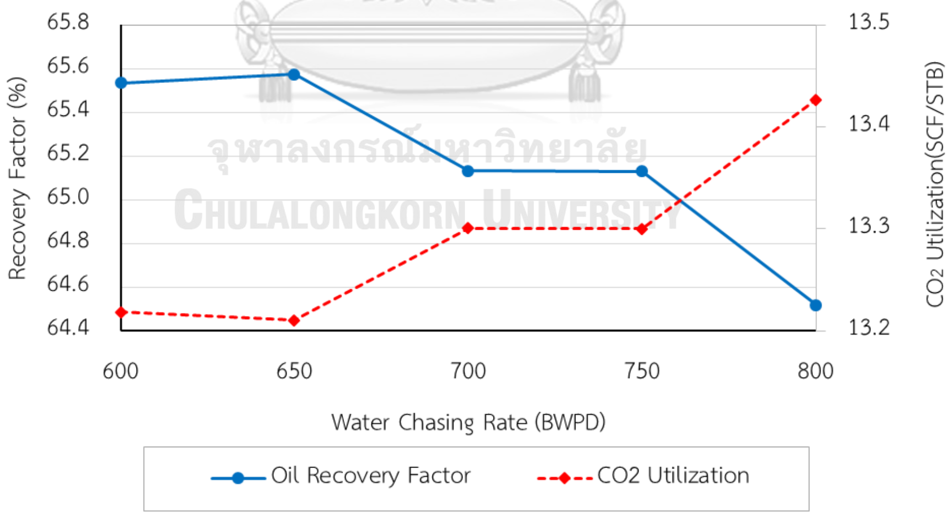

Figure 4.50 Effect of chasing water injection rate above 600 bwpd on oil recovery factor and CO_2 utilization

4.5.2 Effect of CO_2 Huff-n-Puff period

The effect of CO_2 Huff-n-Puff period on oil recovery factor and CO_2 utilization is investigated by conducting 36 simulation crossed-cases with fixed number of three cycles of Huff-n-Puff process. Moreover, low sensitive parameters, which are selected in sensitivity analysis, are also fixed as favorable values, including 30 days of CO_2 injection time and 5 days of soaking time. Thus, only production time, which shows the highest sensitivity on oil recovery factor, is chosen to vary in this performance evaluation part. Accordingly, CO_2 Huff-n-Puff period is varied by adjusting of only production time. In this study, three production time is selected and they allow three different CO_2 Huff-n-Puff periods, including 195, 285, and 375 days that used in 36 simulation cases. And, the values of other varied parameters, including HCPV injection, oil production rate, and chasing water injection rate are shown in Table 4.1.

According to the simulation results, increasing CO_2 Huff-n-Puff period from 195 to 375 days can provide higher oil recovery factor, as shown in Figure 4.51. At low chasing water injection rate, increasing of CO_2 Huff-n-Puff period from 285 to 375 days slightly enhances oil recovery factor. However, oil recovery factor is continuously increased by additional CO_2 Huff-n-Puff period with high rate of chasing water injection. The maximum oil recovery factor obtained from using longest CO_2 Huff-n-Puff period of 375 days with highest chasing water injection rate of 600 bwpd, is 65.5%. And the lowest one is 61.1% of oil recovery factor obtained from using lowest CO_2 Huff-n-Puff period and injected water rate at 195 days and 300 bwpd, respectively. Furthermore, the plots of CO_2 utilization with using fixed 0.5HCPV of CO_2 injection illustrate the reverse trends of oil recovery factor plots, as shown in Figure 4.52. From the results, the maximum CO_2 utilization of 14.2 scf/stb is obtained by injecting 300 bwpd which is the lowest water rate among these runs and using shortest CO_2 Huff-n-Puff period which is 195 days. In contrast, 13.2 scf/stb is the lowest CO_2 utilization that can be achieved by injecting of 600 bwpd with longest CO_2 Huff-n-Puff period at 375 days. Figure 4.53, Figure 4.55, and Figure 4.57 present the relationship between oil recovery factor and chasing water rate for different CO_2 Huff-n-Puff periods with using 1.0, 1.5, and 2.0HCPV of CO2 injection, respectively. The results report the same trends with injecting 0.5HCPV in that longer CO_2 Huff-n-Puff period provides higher oil recovery factor for every chasing water injection rates.

For CO_2 utilization with 1.0, 1.5, and 2.0HCPV of CO2 injection, the results are similar to injecting 0.5HCPV that lower CO_2 utilization can be obtained by using longer period of CO_2 Huff-n-Puff and higher rate of chasing water injection, as shown in Figure 4.54, Figure 4.56, and Figure 4.58. Based on the simulation results, these three cases of different CO_2 HCPVs show that the lowest values of CO_2 utilization can be achieved by processing 375 days of CO_2 Huff-n-Puff period. Using 1.0, 1.5, and 2.0HCPV with 375 days provide the lowest CO_2 utilization for each case as 26.5, 39.8, and 52.8 scf/stb, respectively.

According to the results, additional time of CO_2 Huff-n-Puff process is able to provide higher oil recovery factor for every chasing water rate and CO_2 HCPV injection. Moreover, the lower CO_2 utilization is achieved by using more CO_2 Huff-n-Puff period because volume of injected CO_2 does not change with different periods of CO_2 Huff-n-Puff process, but cumulative oil production is changed by adjusting CO_2 Huff-n-Puff period. From the results, the longer period can provide higher cumulative oil production, as shown in Figure 4.59. Hence, the longer CO_2 Huff-n-Puff period causes lower CO_2 utilization. In addition, the reasons of increased cumulative oil production with longer CO_2 Huff-n-Puff period are larger drainage area around wellbore prior to injecting of chasing water and later breakthrough time. Figure 4.60 illustrates the drainage area around wellbore when the last slug of CO_2 is injected into reservoir or immediately once a slug of water is initially injected. The green color of grids is represented the low oil saturation that is approximately 10% to 50% of oil saturation and the orange color is the initial oil saturation which is 70%. When performing CO_2 Huff-n-Puff process at 195 days, the drainage area is smaller than that of longer CO_2 Huff-n-Puff period because this time period is insufficient to allow CO_2 to diffuse into reservoir further away from the wellbore. In these simulation cases, the time period of

CO_2 Huff-n-Puff is varied by adjusting production time in Huff-n-Puff process. Then, using short production time period is not adequate to flow-back crude oil from reservoir before starting a new cycle. Certain crude oil placed around wellbore still remains inside reservoir while reservoir pressure is sufficient to recover. When a next CO_2 slug is injected into reservoir, it is not able to diffuse further away from wellbore due to crude oil from the previous cycle. Therefore, the additional production time, which rise CO_2 Huff-n-Puff period, can provide larger drainage area that results in improve oil recovery factor and increase cumulative oil production.

Finally, the second reason of increased oil recovery with longer CO_2 Huff-n-Puff period is determined by water breakthrough time. While longer time period of CO_2 Huff-n-Puff process is applied, water breakthrough time is prolonged, as shown in Figure 4.61. Based on the simulation results, the earliest water breakthrough is obtained by using the shortest time period because chasing water is started firstly in this situation, but the drainage area provided in CO_2 Huff-n-Puff process is the smallest one, as mentioned previously. Then, the injected water can breakthrough before other cases with the lowest oil recovery factor. In addition, the shape of drainage area, which occurs when performing CO_2 Huff-n-Puff process, is invert cone caused by CO_2 tend to sweep oil through the upper reservoir. On the other hand, water has tendency to sweep oil at lower side of reservoir due to gravity. When the drainage area of upper reservoir is small due to short CO_2 Huff-n-Puff period, the injected water is easier to flow at bottom of reservoir with unstable flood front and breakthrough earlier.

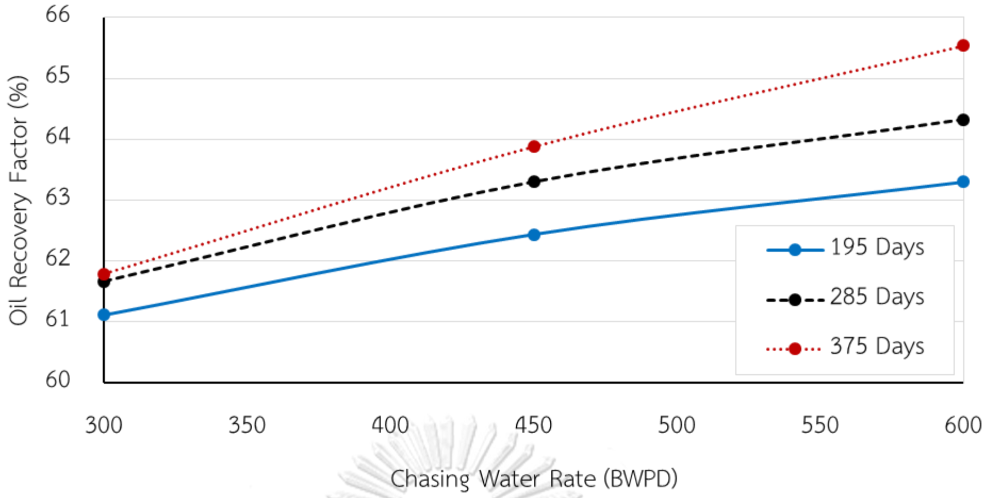

Figure 4.51 Oil recovery factor versus chasing water rate for different CO_2 Huff-n-Puff period using 0.5HCPV injection

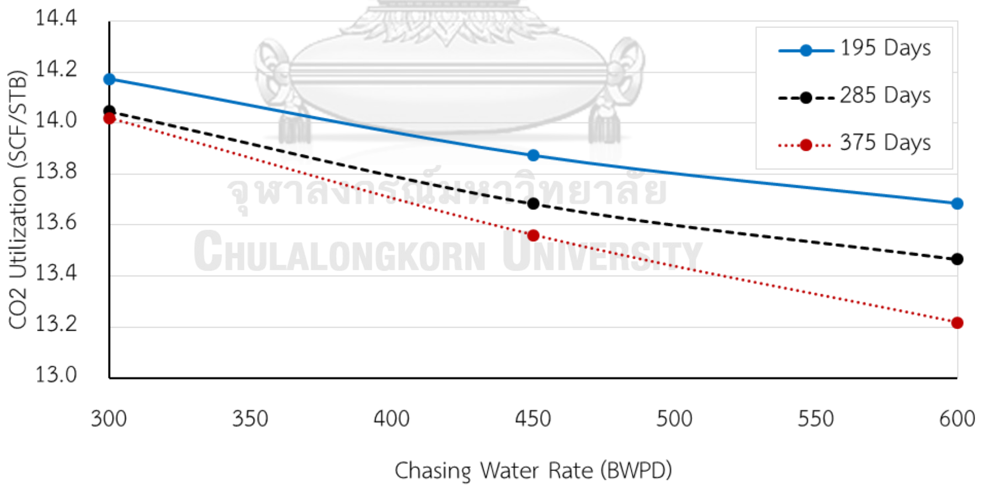

Figure 4.52 CO_2 utilization versus chasing water rate for different CO_2 Huff-n-Puff period using 0.5HCPV injection

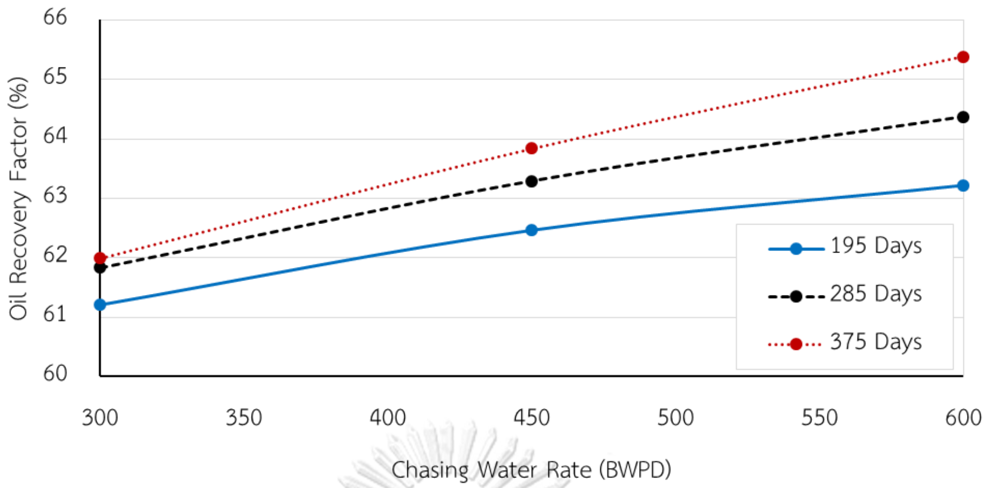

Figure 4.53 Oil recovery factor versus chasing water rate for different CO_2 Huff-n-Puff period using 1.0HCPV injection

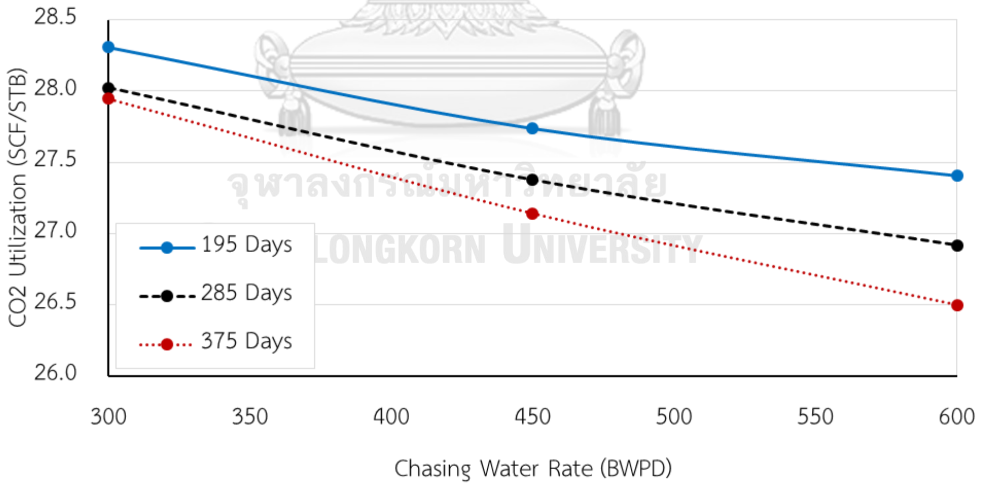

Figure 4.54 CO_2 utilization versus chasing water rate for different CO_2 Huff-n-Puff period using 1.0HCPV injection

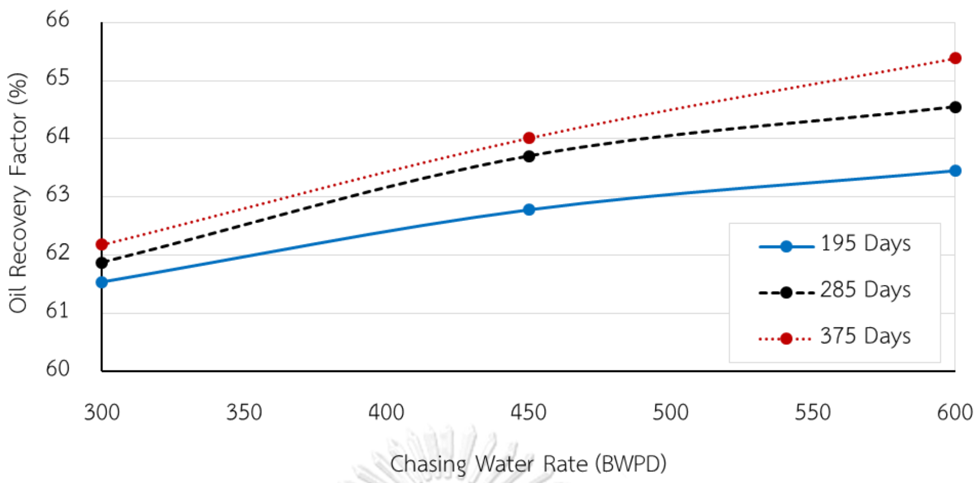

Figure 4.55 Oil recovery factor versus chasing water rate for different CO_2 Huff-n-Puff period using 1.5HCPV injection

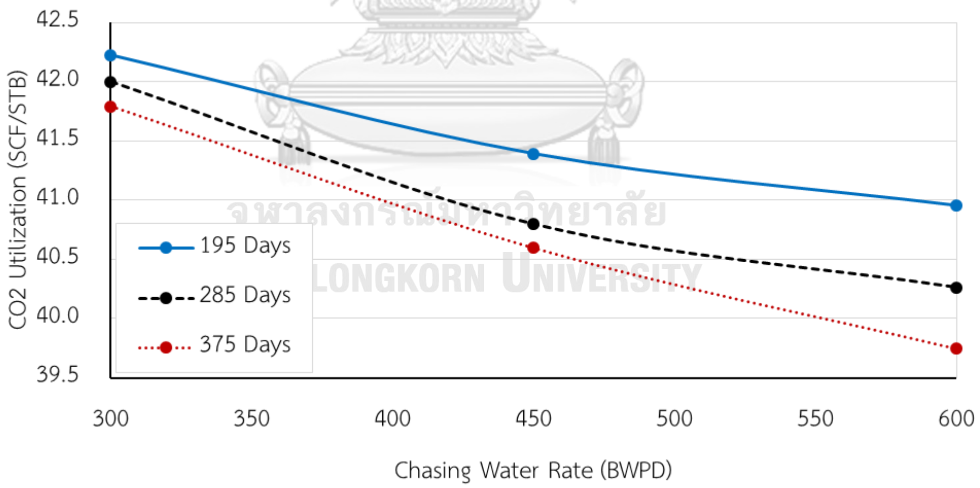

Figure 4.56 CO_2 utilization versus chasing water rate for different CO_2 Huff-n-Puff period using 1.5HCPV injection

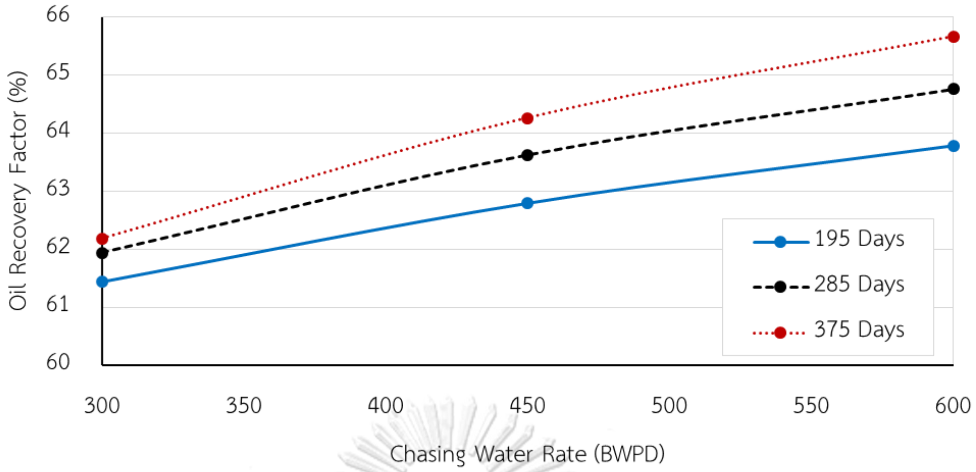

Figure 4.57 Oil recovery factor versus chasing water rate for different CO_2 Huff-n-Puff period using 2.0HCPV injection

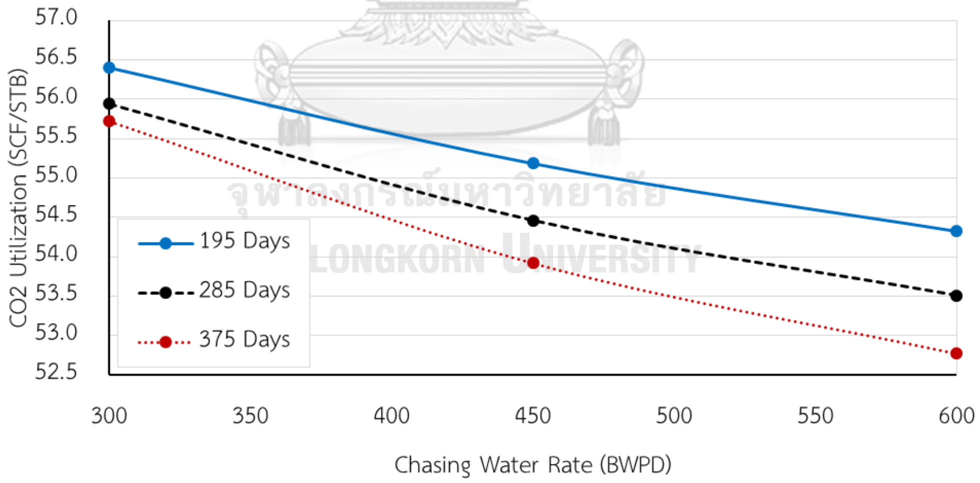

Figure 4.58 CO_2 utilization versus chasing water rate for different CO_2 Huff-n-Puff period using 2.0HCPV injection

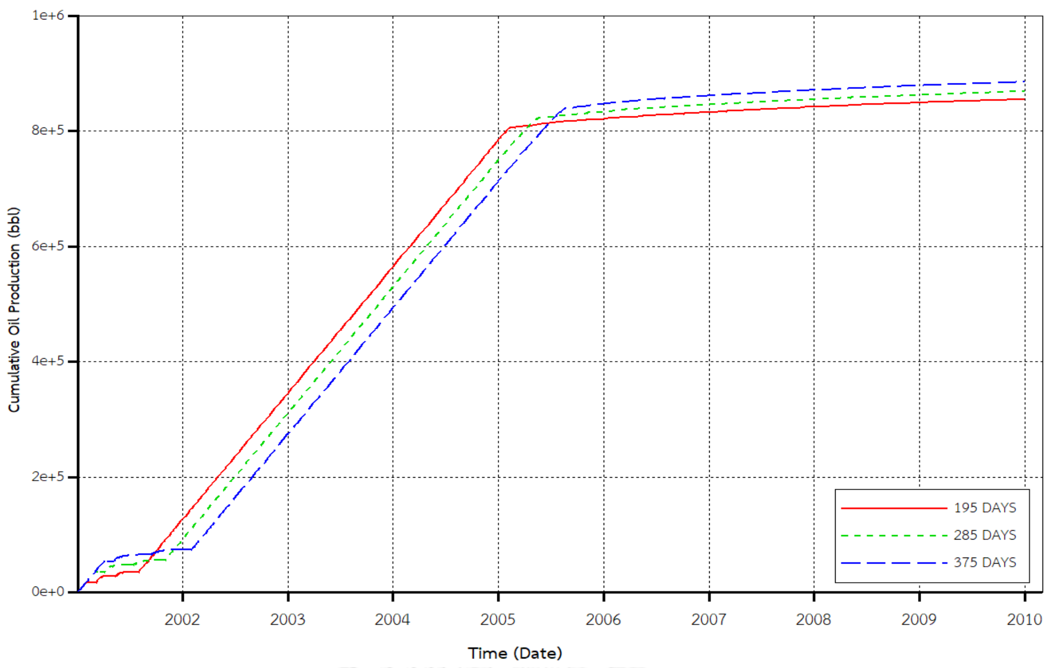

Figure 4.59 Effect of CO_2 Huff-n-Puff period on cumulative oil production using integrated CO_2 Huff-n-Puff and WAG process

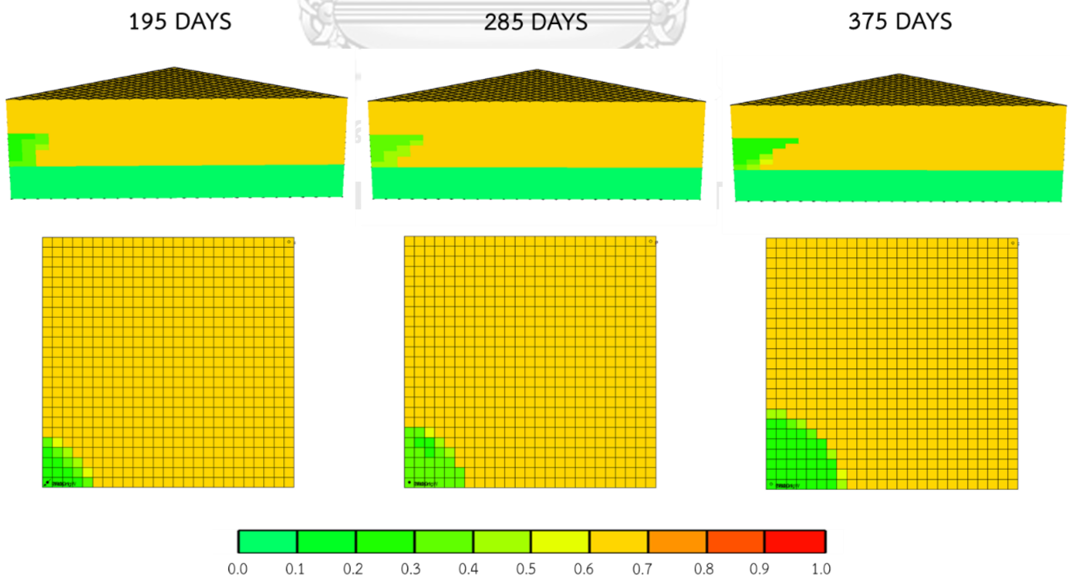

Figure 4.60 Effect of CO_2 Huff-n-Puff period on oil saturation prior chasing water injection

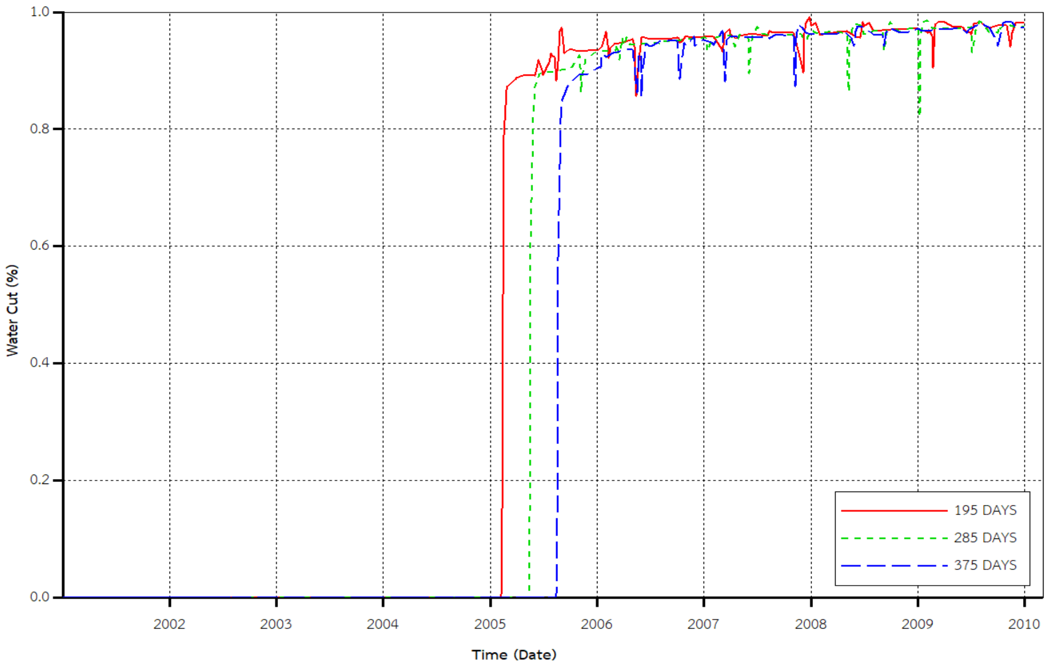

Figure 4.61 Effect of CO_2 Huff-n-Puff period on water cut

The effect of CO_2 Huff-n-Puff period, which is more than 375 days, on oil recovery factor and CO_2 consumption is also investigated by conducting five runs as follows: CO_2 Huff-n-Puff time period of 375, 465, 555, 645, 735 days. The fixed pore volume of CO_2 injection of 1.0HCPV and chasing water injection rate of 600 bwpd are used for all runs. In addition, other operating parameters, i.e., injection time, soaking time, number of cycle, and total operating time are fixed as 30 days, 5 days, 3 cycles, and 10 years, respectively.

Figure 4.62 presents the effect of CO_2 Huff-n-Puff period on oil recovery factor, which is simulated more than 375 days. The results of these runs indicate that the time period of CO_2 Huff-n-Puff process which is longer than 375 days provide slightly lower oil recovery factor due to insignificant oil recovered by CO_2 Huff-n-Puff process. Using 375 days or more, CO_2 Huff-n-Puff time periods provide equal cumulative oil production at the end of Huff-n-Puff process, as shown in Figure 4.63. This is because the extended time of production period in Huff-n-Puff process does not provide more oil due to insufficient reservoir pressure, as shown in Figure 4.64. Based on the simulation results, reservoir pressure is dropped rapidly to minimum reservoir pressure by using around 90 days of production time that is in the case of 375 days of CO_2 Huff-n-Puff period. Hence, the excessive time beyond 375 days does not provide additional oil recovery due to the reservoir pressure has already reached the lowest point. And the drainage area obtained by two cases of different CO_2 Huff-n-Puff period is similar because almost the same amount of oil is recovered by these two cases, as shown in Figure 4.64. However, simulation cases of more than 375 days of CO_2 Huff-n-Puff period show slightly lower oil recovery factor because these cases spend exceeding time without oil production in CO_2 Huff-n-Puff process. Thus, they contain lesser time period to recover oil with injecting of chasing water in WAG process.

In term of CO_2 consumption, Figure 4.65 presents the effect of CO_2 Huff-n-Puff period more than 375 days on cumulative CO_2 injection. The results of these runs indicate that varied CO_2 Huff-n-Puff periods do not effect to total CO_2 consumption, only time to reach maximum cumulative CO_2 injection is changed. The longer time period of CO_2 Huff-n-Puff process, the later time to reach maximum CO_2 consumption. Varied CO_2 Huff-n-Puff period shows no effect on CO_2 consumption because CO_2 HCPV injection and injection time which involve in the amount of CO_2 injection, do not change with varying CO_2 Huff-n-Puff period. Finally, the effect of CO_2 Huff-n-Puff period beyond 375 days on oil recover factor and cumulative CO_2 injection are shown in Figure 4.66. Based on this plot, increasing time period of CO_2 Huff-n-Puff process tends to reduce oil recovery factor from 65.5% to 64% of OOIP, and 11,700 Mscf of CO_2 consumption is consistent for all CO_2 Huff-n-Puff period.

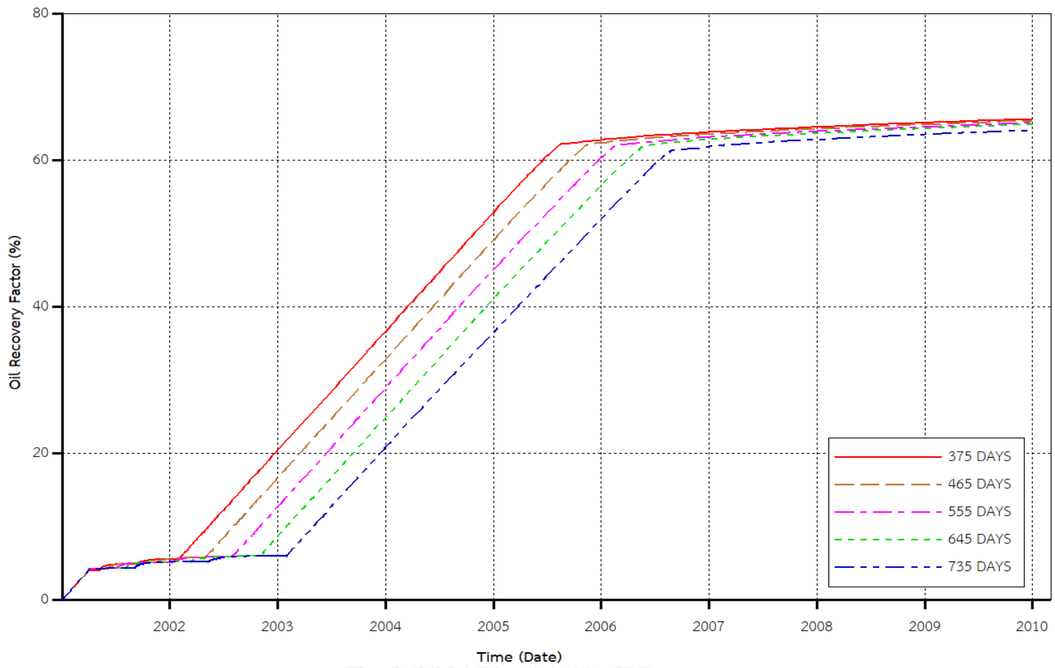

Figure 4.62 Effect of CO_2 Huff-n-Puff period more than 375 days on oil recovery factor

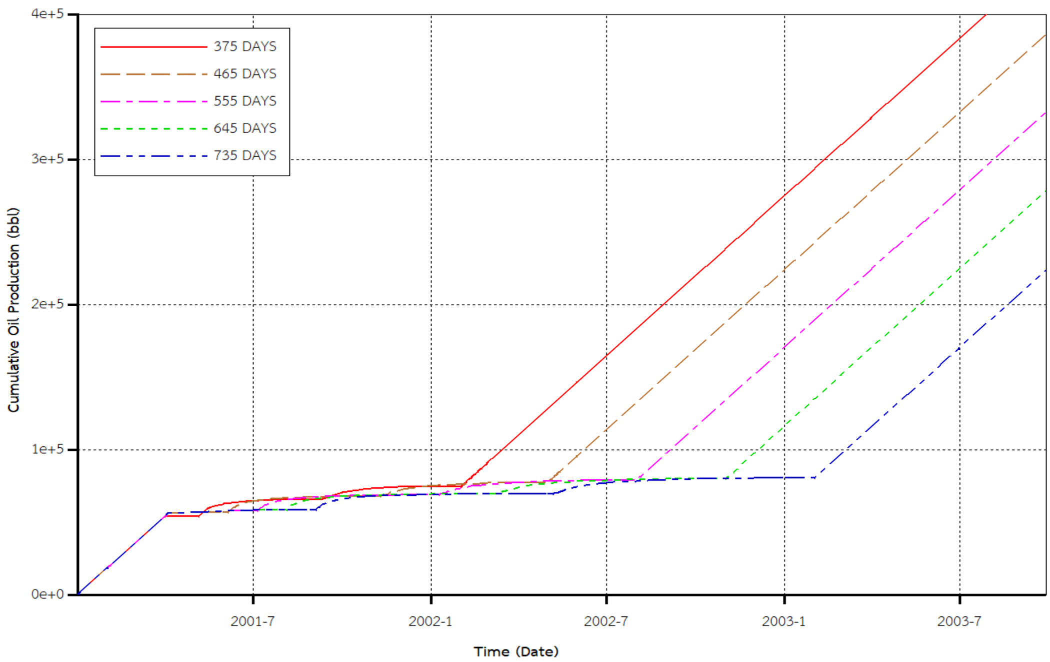

Figure 4.63 Effect of CO_2 Huff-n-Puff period more than 375 days on cumulative oil production after ending Huff-n-Puff process

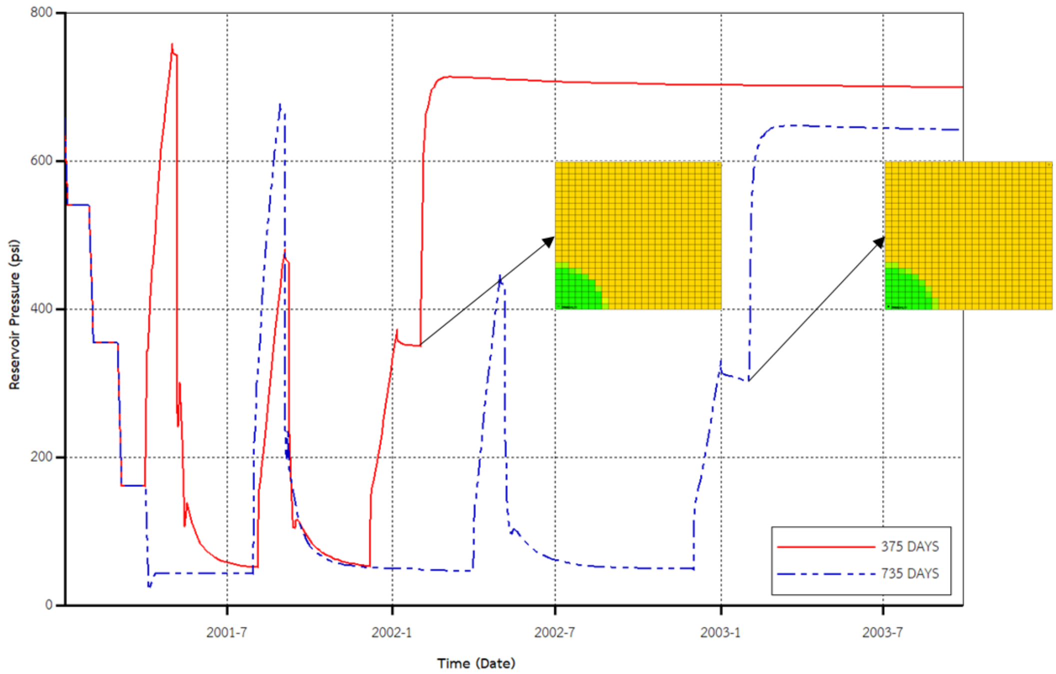

Figure 4.64 Comparing of 375 and 735 days of CO_2 Huff-n-Puff period based on reservoir pressure and drainage area

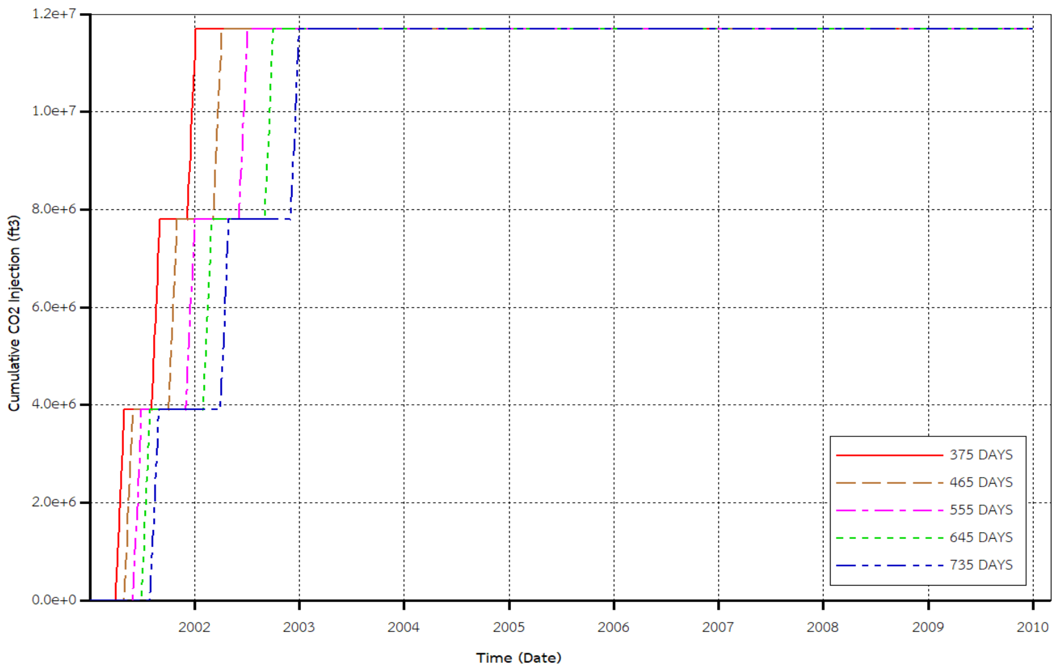

Figure 4.65 Effect of CO_2 Huff-n-Puff period more than 375 days on cumulative CO_2 injection

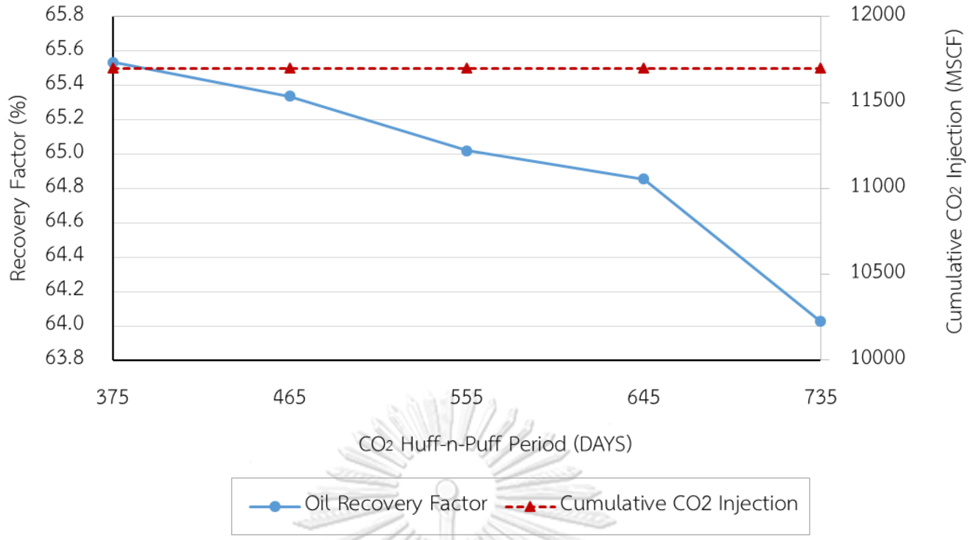

Figure 4.66 Effect of CO_2 Huff-n-Puff period of more than 375 days on oil recovery factor and cumulative CO_2 injection

4.5.3 Effect of CO_2 HCPV injection

The effect of CO_2 hydrocarbon pore volume (HCPV) injection on oil recovery factor and CO_2 utilization is investigated by performing 12 crossed-cases that varied CO_2 HCPV and chasing water injection rate. Four values of CO_2 HCPV injection, which used in this study, are 0.5, 1.0, 1.5, 2.0 HCPV. Moreover, chasing water injection rate is also varied into three values, including 300, 450, and 600 bwpd. Other operating parameters are fixed, as shown in Table 4.3. Also, CO_2 Huff-n-Puff period is fixed as 375 days due to this time period presenting the most favorable results in previous section (Effect of CO_2 Huff-n-Puff period).

Based on the simulation results, the highest oil recovery factor of each chasing water injection rate is obtained by injecting 2.0HCPV of CO2 which is the highest values among these runs, as shown in Figure 4.67. When chasing water is injected at 300, 450, and 600 bwpd with CO_2 injection of 2.0HCPV, oil recovery factor is achieved at the maximum values of 62.2, 64.3, and 65.7% of OOIP, respectively. And the oil recovery factor is slightly reduced by decreasing CO_2 HCPV injection for every chasing water injection rate, as shown in Figure 4.67. The minimum oil recovery factor of 61.8% is obtained by the lowest CO_2 HCPV injection of 0.5HCPV and the smallest slug of chasing water injection which is 300 bwpd. The reasons that can explain these circumstances are CO_2 solubility into crude oil and oil swelling factor that relate to reservoir pressure. According to literature, Sasaki and Sugai (2017) stated that the swelling factor increases with increasing pressure and CO_2 and crude oil solubility also increases rapidly by increasing pressure below bubble point. From the simulation results, higher CO_2 HCPV injection provide more reservoir pressure in every rate of chasing water. Figure 4.68, 4.69, and 4.70 show the effect of CO_2 HCPV injection on reservoir pressure with 300, 450, 600 bwpd of chasing water injection rates, respectively. The results of these plots indicate the similar trends that higher reservoir pressure can be achieved by additional CO_2 HCPV injection. Therefore, oil swelling factor and solubility of CO_2 in crude oil is also increased by the increasing CO_2 HCPV injection. When the swelling factor and solubility is increased, residual oil can be flowed easier due to the reduction of oil viscosity (Sasaki & Sugai, 2017). Subsequently, oil recovery factor is increased due to more oil can be recovered from reservoir. Furthermore, additional chasing water injection rate help to increase reservoir pressure that results in the higher oil recovery factor due to reservoir pressure maintenance and oil viscosity reduction as mention previously.

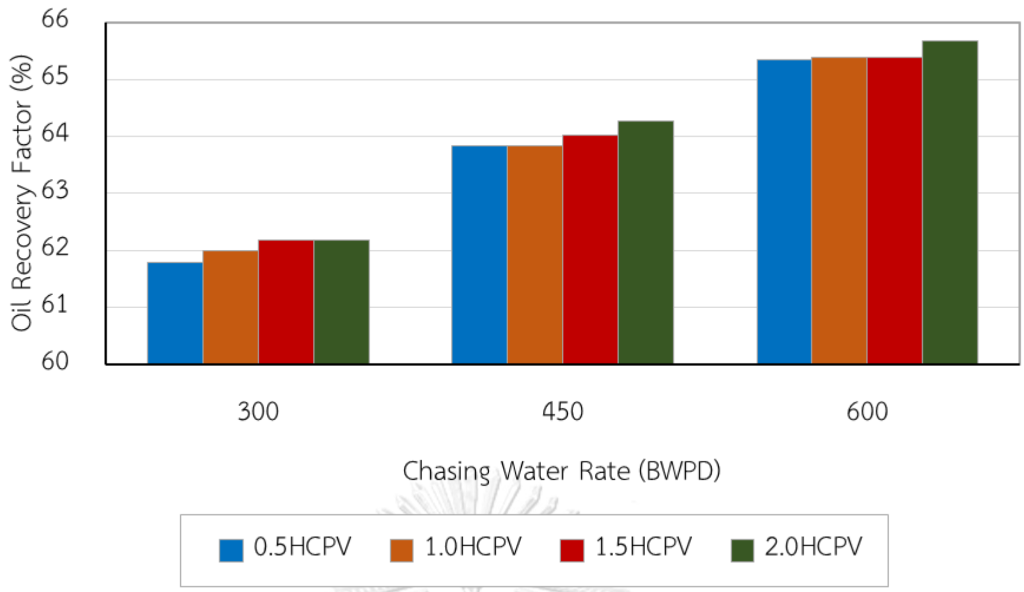

Figure 4.67 Oil recovery factor versus chasing water rate for different CO_2 HCPV injection

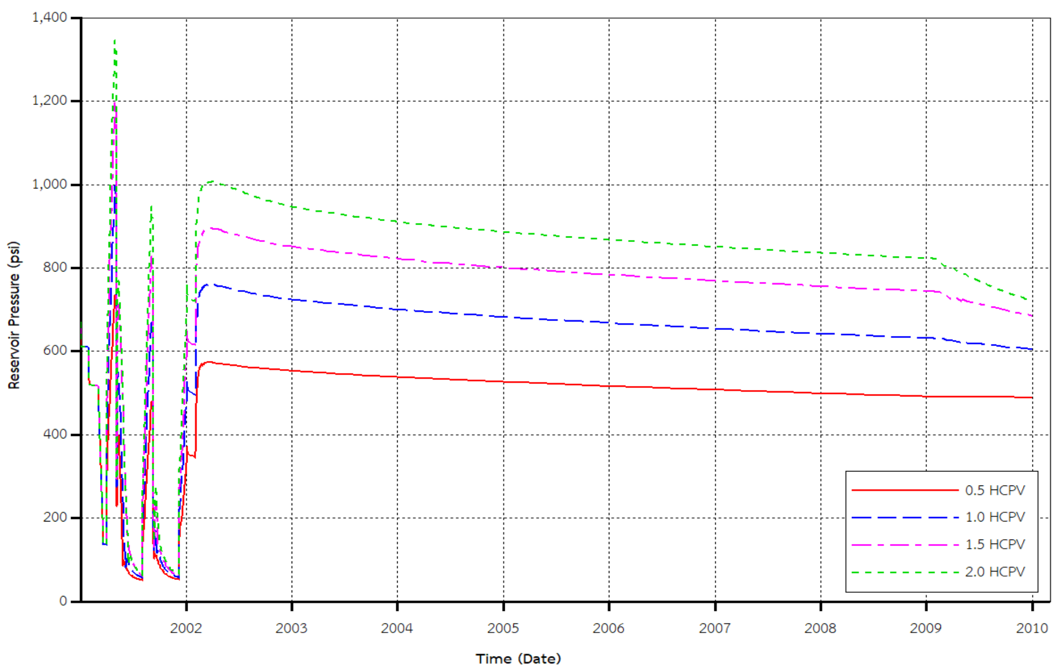

Figure 4.68 Effect of CO_2 HCPV injection on reservoir pressure with using 300 bwpd of chasing water injection rate

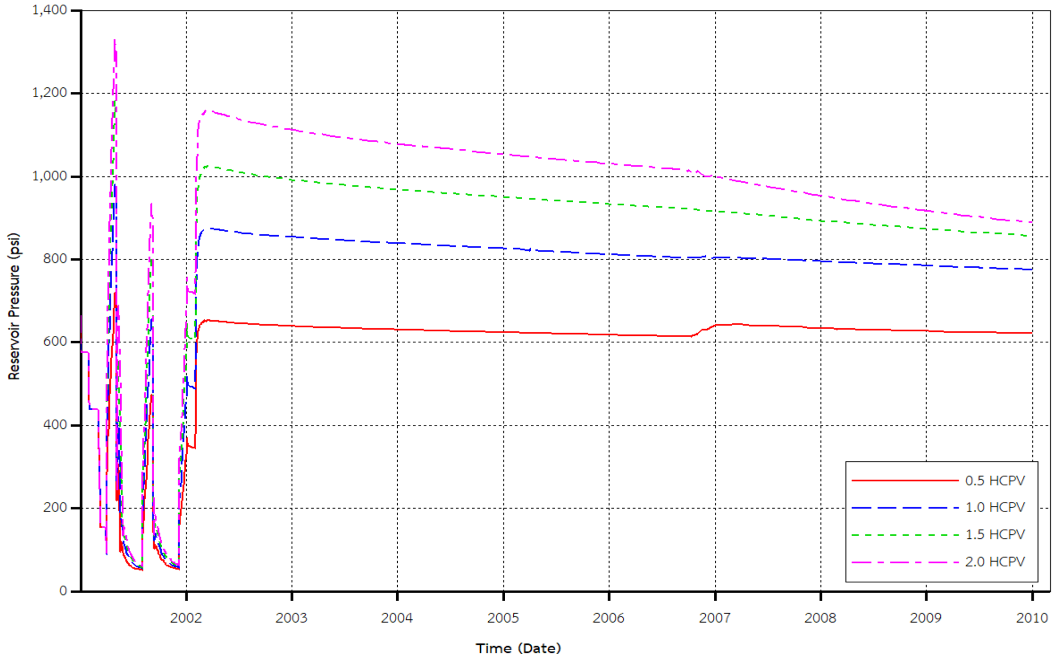

Figure 4.69 Effect of CO_2 HCPV injection on reservoir pressure with using 450 bwpd of chasing water injection rate

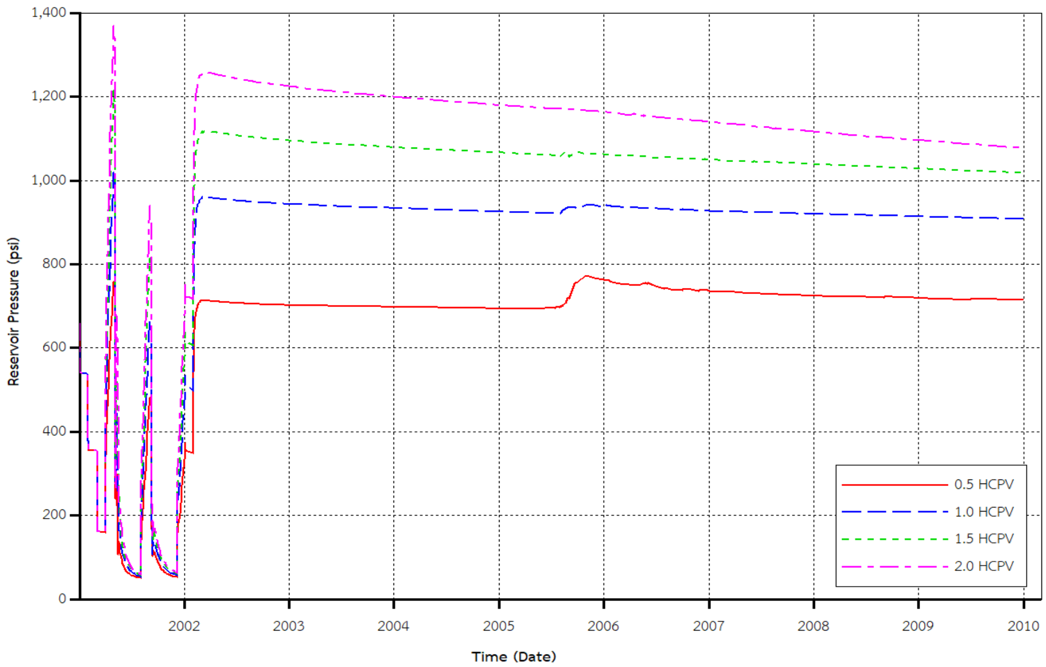

Figure 4.70 Effect of CO_2 HCPV injection on reservoir pressure with using 600 bwpd of chasing water injection rate

In term of CO_2 utilization, the relationship between CO_2 utilization and chasing water injection rate with different values of CO_2 HCPV injection is shown in Figure 4.68. The results of these simulation runs indicate that lower CO_2 utilization can be achieved by using lower CO_2 HCPV injection at the same rate of chasing water. Moreover, the increasing of chasing water injection rate slightly reduces CO_2 utilization at the same amount of CO_2 injection. According to the simulation results, the lowest CO_2 utilization of 13.2 scf/stb can be achieved by injecting the lowest CO_2 HCPV (0.5HCPV) with the highest chasing water rate (600 bwpd). In contrast, using the highest CO_2 HCPV injection of 2.0HCPV together with injecting 300 bwpd of chasing water rate provides the highest CO_2 utilization as 55.7 scf/stb. The reason of these behaviors is basically described by the definition of CO_2 utilization that is ratio of cumulative CO_2 injection and cumulative oil production. Figure 4.72 presents the cumulative CO_2 injection of each CO_2 HCPV injection. This plot indicates that additional CO_2 HCPV injection provide much more cumulative CO_2 injection. However, higher CO_2 HCPV injection can insignificantly increase cumulative oil production, as shown in Figure 4.73. Therefore, the CO_2 utilization is exceedingly increased by injecting more CO_2 HCPV.

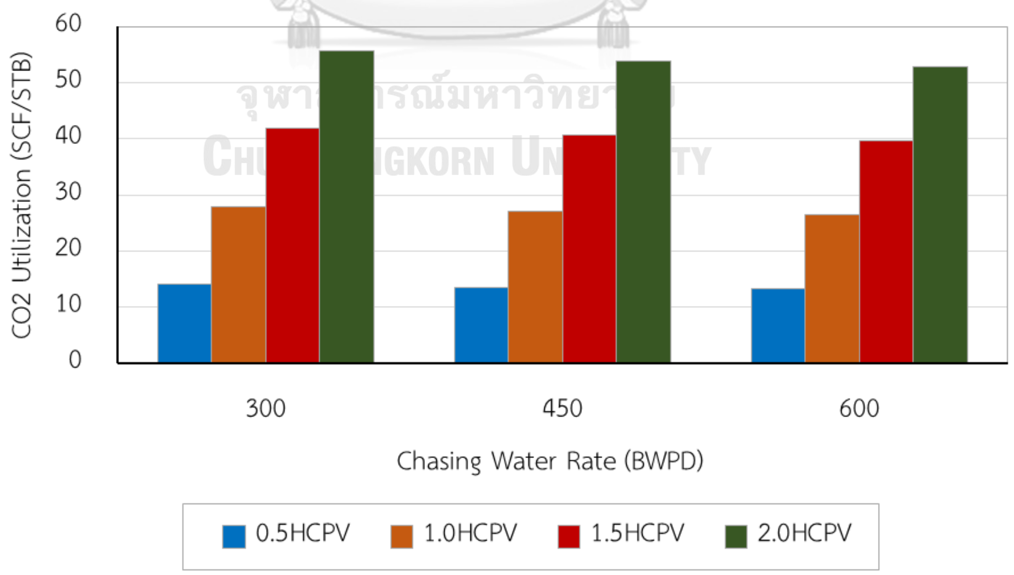

Figure 4.71 CO_2 utilization versus chasing water rate for different CO_2 HCPV injection

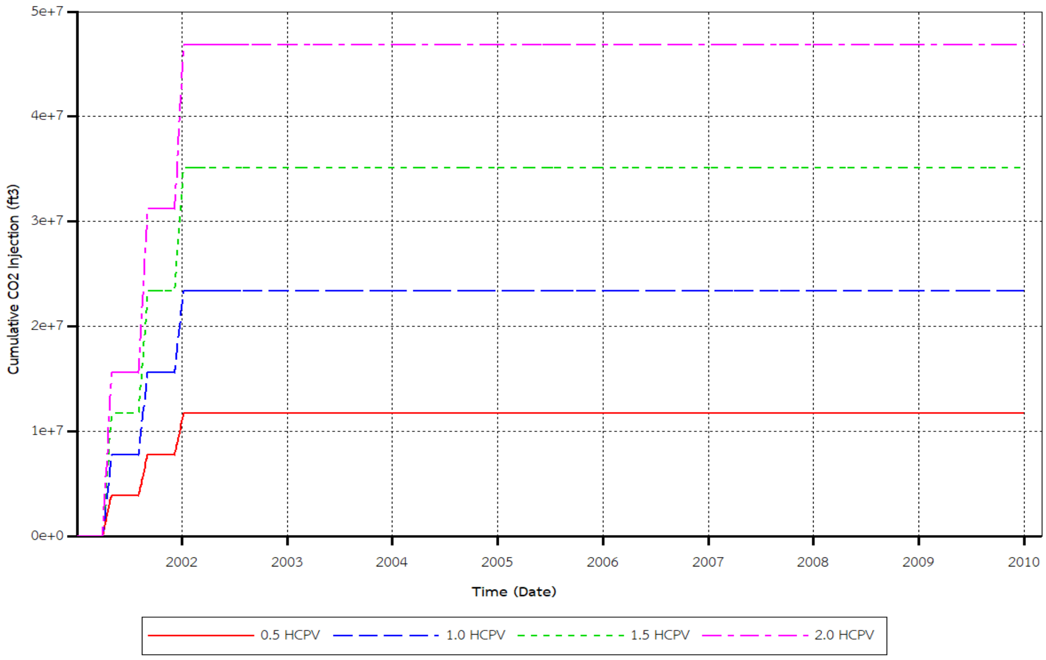

Figure 4.72 Effect of CO_2 HCPV injection on cumulative CO_2 injection using 600 bwpd of chasing water injection

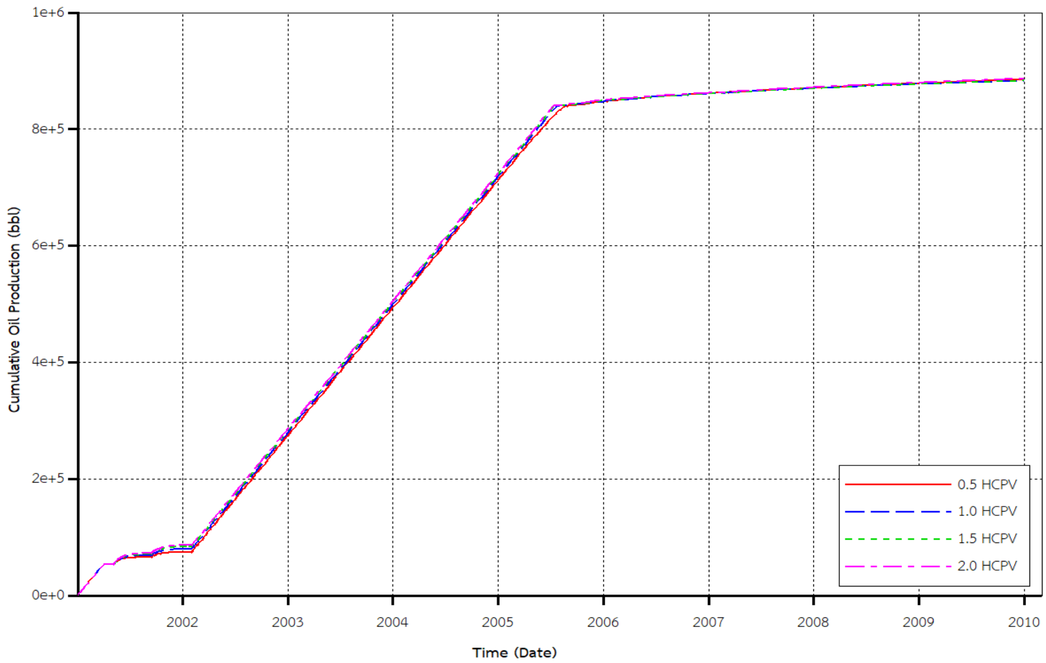

Figure 4.73 Effect of CO_2 HCPV injection on cumulative oil production using 600 bwpd of chasing water injection

4.5.4 Effect of number of CO_2 Huff-n-Puff cycles

The last operating parameter of integrated CO_2 Huff-n-Puff and WAG process that investigated is the number of CO_2 Huff-n-Puff cycles prior to chasing water injection. The effect of number of cycles is investigated by performing 6 runs of varied CO_2 Huff-n-Puff cycles, including 3, 6, 9, 12, 15 cycles. Other operating parameters are fixed as the most favorable values, as described in previous section of this study.

According to the simulation results, the minimum number of CO_2 Huff-n-Puff cycles that is 3 cycles providing the highest oil recovery factor, and increasing the number of cycles tend to reduce oil recovery factor, as shown in Figure 4.74. The highest oil recovery factor of 65.5% of OOIP can be achieved by conducting 3 cycles of CO_2 Huff-n-Puff process which is the lowest number of cycles in this study. Moreover, oil recovery factor is extremely reduce after added number of cycle from 3 to 6 cycles, but additional cycles more than 6 cycles illustrate insignificant effects on oil recovery factor. The oil recovery factor that obtained with 6 or more CO_2 Huff-n-puff cycles is approximately 61.1% of OOIP. The reason of reducing oil recovery factor with higher numbers of CO_2 Huff-n-Puff cycles is insufficient time period to back-produce oil and CO_2 and smaller CO_2 slug size per cycle. Figure 4.75 presents the relationship between oil production rate and operating time using 3 and 6 cycles of CO_2 Huff-n-Puff process. The simulation results indicate that constant production rate at 600 bopd can be entirely maintained in the first cycle of applying 3 Huff-n-Puff cycles, but the case of using 6 cycles can maintain only short period prior to the injection of initial CO_2. Later, the injected CO_2 pushes oil that located around wellbore away and some part of CO_2 dissolve into oil to reduce oil viscosity. After soaking period, oil is ready to flow-back due to proper reservoir pressure and oil viscosity. In the next production period, well is opened to flow-back CO_2 and crude oil from reservoir. With using 3 cycles of Huff-n-Puff process, it provides long enough period to flow-back almost entire injected CO_2 and crude oil from reservoir until the reservoir pressure is inadequate to produce before the next CO_2 slug is re-injected into reservoir. However, the production time period with 6 cycles of Huff-n-Puff process is not sufficient to flow-back entire CO_2 and crude oil prior to the injection of the next slug of CO_2 because each production period with 6 cycles is only equal to a half of those using 3 cycles. Therefore, the short production period within 6 cycles can flow-back a huge amount of injected CO_2 with a small amount of crude oil because most injected CO_2 are located closer to wellbore and also CO_2 contains higher flowability than crude oil. Another reason of lower cycle providing higher oil recovery is that CO_2 slug size of using lower cycle is larger because the total amount of injected CO_2 is fixed the same as for all cases, but the cases of more cycles inject smaller CO_2 slug size for each cycle. Based on the simulation result, using 3 cycles with Huff-n-Puff process provides higher reservoir pressure than that of 6 cycles due to the larger slug size of CO_2 in each cycle, as shown in Figure 4.76. When reservoir pressure is higher, the effect of CO_2 solubility and swelling factor is increased (Sasaki & Sugai, 2017). Subsequently oil recovery factor is increased by using lesser CO_2 Huff-n-Puff cycle.

Finally, CO_2 utilization is rapidly increased by added number of cycles from 3 to 6 cycle and the slope is gradually reduced when the number of cycle is increased more than 6 cycles, as shown in Figure 4.77. The lowest CO_2 utilization of 13.2 scf/stb can be achieved by using 3 cycles of CO_2 Huff-n-Puff process. On the other hand, 14.2 scf/stb is the highest CO_2 utilization that is obtained by using 15 cycles of Huff-n-Puff process. According to the results, the plots of CO_2 utilization tend to increase in opposite direction of oil recovery factor because the number of cycles does not impact cumulative CO_2 injection, but oil recovery factor does. When the number of cycles becomes more, the volume of oil recovered is reduced. Thus, the CO_2 utilization of higher number of CO_2 Huff-n-Puff cycles is continuously increased.

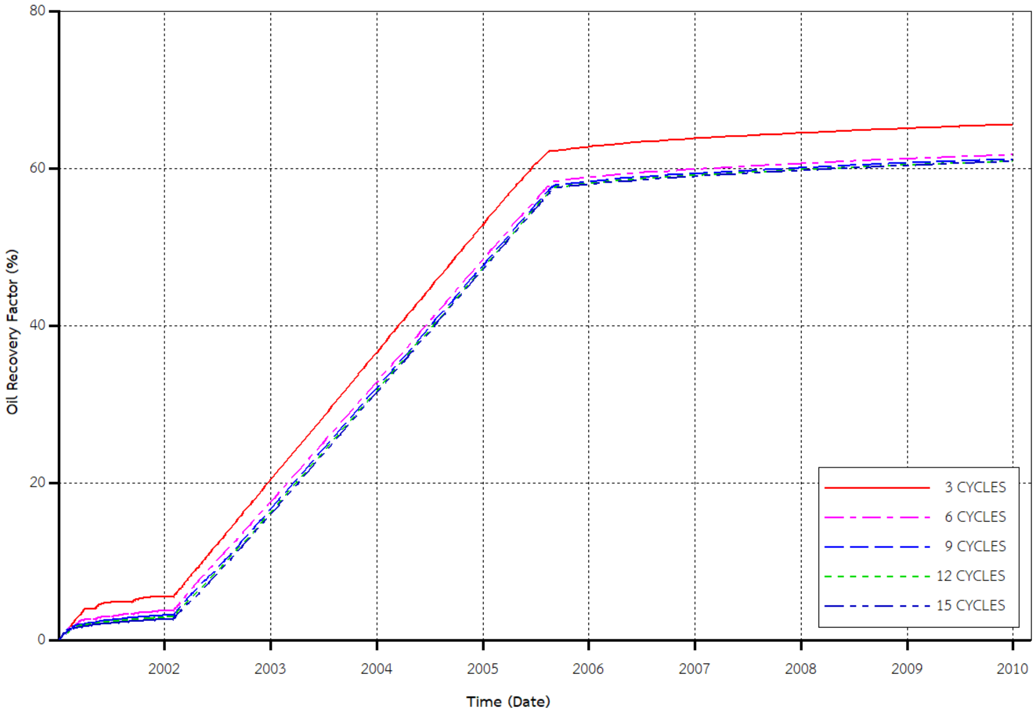

Figure 4.74 Effect of number of CO_2 Huff-n-Puff cycles on oil recovery factor

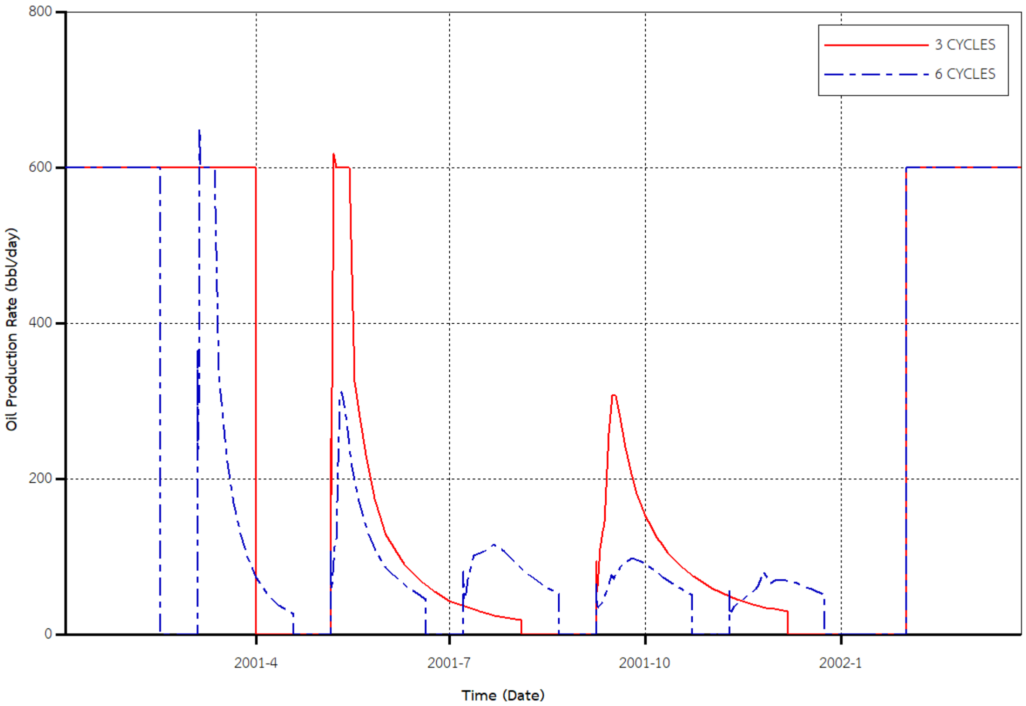

Figure 4.75 Effect of number of CO_2 Huff-n-Puff cycles on oil production rate

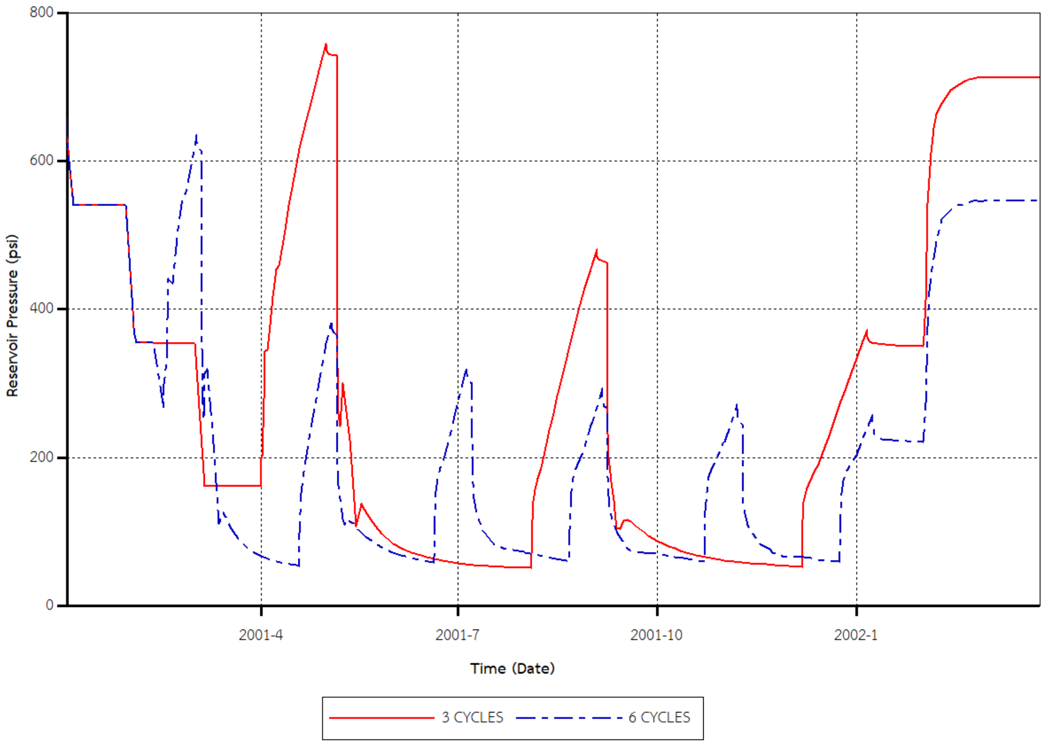

Figure 4.76 Effect of number of CO_2 Huff-n-Puff cycles on reservoir pressure

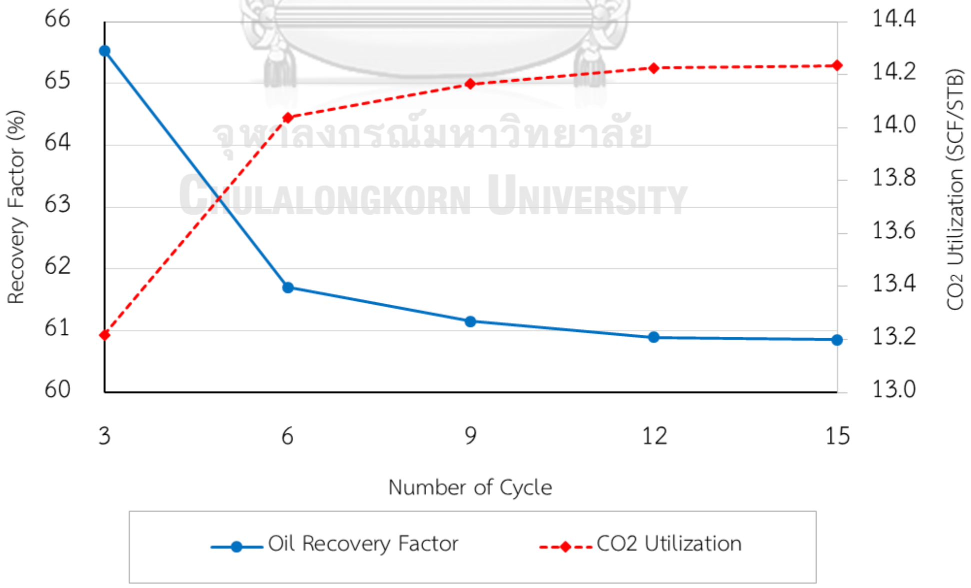

Figure 4.77 Effect of number of cycles on oil recovery factor and CO_2 utilization

CHAPTER 5
CONCLUSIONS AND RECOMMENDATIONS

This chapter concludes the results of performance evaluation of CO_2 Huff-n-Puff and WAG in low-pressure heterogeneous reservoir. Furthermore, recommendations for further studies are also provided.

5.1 Conclusion

The results and discussion from previous chapter indicate that integrated CO_2 Huff-n-Puff and WAG method is an effective EOR technique to enhance oil recovery in low-pressure reservoir. Meanwhile, the effectiveness of this method depends on several parameters. Study of the key operational parameters is useful as a guideline for conducing the integrated CO_2 Huff-n-Puff and WAG method in low-pressure heterogeneous reservoir. Moreover, the effects of these key operating parameters on oil recovery factor and CO_2 utilization are considerably important factors for EOR project's decisions. The conclusions of this study are summarized below.

1. The key operational parameters of CO_2 Huff-n-Puff process in low-pressure reservoir are oil production rate and production time because they influence amount of extracted oil prior to a slug of CO_2 is injected and declining rate of reservoir pressure in each cycle. Thus, these two parameters should be sufficient to produce the injected CO_2 and crude oil from reservoir until reservoir pressure nearly reaches inadequate pressure to recover oil, after that the new CO_2 slug will be injected.

2. CO_2 HCPV injection illustrates high sensitivity on CO_2 consumption in CO_2 Huff-n-Puff process because this parameter directly effects on amount of CO_2 injection. However, it shows low sensitivity on oil recovery factor due to the gaining of reservoir pressure is continuously decreased with higher CO_2 HCPV injection.

3. Soaking time period has the lowest sensitivity on oil recovery factor using CO_2 Huff-n-Puff process because the low-pressure reservoir contains very low pressure build-up rate due to low initial reservoir pressure without natural drive mechanisms.

4. An integrated CO_2 Huff-n-Puff and WAG provides oil recovery factor up to 61% higher than that of primary recovery, 38% higher than that of conventional CO_2 flooding, and approximately 13% more than that of conventional water flooding. The main EOR mechanisms are reservoir pressure maintenance, volumetric sweep efficiency improvement, and oil viscosity reduction.

5. Chasing water injection rate shows the significant effect on the performance of integrated CO_2 Huff-n-Puff and WAG technique to enhance oil recovery in that injecting with higher chasing water rate is able to increase oil recovery factor and decrease CO_2 utilization because the injected water help to rise and maintain reservoir pressure. Also, it can displace both crude oil and injected CO_2 from injection well to production well. However, the excessive water injection rate can be the cause of lower oil recovery due to early water breakthrough time.

6. CO_2 Huff-n-Puff period of integrated CO_2 Huff-n-Puff and WAG technique should be long enough to recover oil from upper part of reservoir with the injected CO_2 and to confirm reservoir fluid response with injected CO_2 before beginning full field implementation of WAG process.

7. Increasing CO_2 HCPV injection in integrated CO_2 Huff-n-Puff and WAG technique slightly provide additional oil recovery factor due to increased swelling factor and CO_2 solubility. However, the exceeding CO_2 HCPV injection requires considerably huge amount of CO_2 that will extremely increase CO_2 utilization.

8. Higher oil recovery factor and lower CO_2 utilization can be achieved by using less number of CO_2 Huff-n-Puff cycles because more sufficient production time period and larger CO_2 slug size per cycle in less number of cycle scenarios.

5.2 Recommendation

Several recommendation is suggested for the further studies in this particular field as follows:

1. Other injected gases such as nitrogen, methane, and LPG can be applied with integrated Huff-n-Puff and WAG process. And alkaline, surfactant, and/or polymer can be added to normal chasing water for more oil production.

2. In this study, a single injection of CO_2 and water slug is performed for integrated CO_2 Huff-n-Puff and WAG method. For further study, the multiple injection of CO_2 Huff-n-Puff and WAG process should be considered to enhance more oil recovery.

3. Since this study focuses on only the effect of operational parameters of CO_2 Huff-n-Puff method and integrated CO_2 Huff-n-Puff and WAG method, the further studies can be done with an investigation the effect of heterogeneity, reservoir characteristic and reservoir fluid properties.

4. CMG® reservoir simulator used in this study is an academic license. The number of grid blocks are limited at 10,000 grids. Accordingly, more accurate results can be obtained by using more grid blocks provided in full license software or other simulators.

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APPENDIX

APPENDIX A

MMP empirical correlations

From literature, there are eleven popular and highly accurate empirical correlations that can be calculated CO_2 and crude oil minimum miscibility pressure (MMP), lists of these empirical correlations is shown below:

1. Cronquist's correlation

$$MMP = 0.11027(1.8T + 32)^{0.744206+0.0011038M_{C5}+0.0015279X_{VOL}}$$

Where;

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (°C)

M_{C5} = Molecular Weight of C_{5+} in the crude oil (g/mol)

X_{VOL}= Mole Fraction of Volatile Components (CH_4+N_2) in crude oil (mol%)

Remarks;

(i) The tested oil gravity ranged from 23.7 to 44.8°API

(ii) The tested T ranged from 21.67 to 120.8°C

(iii) The tested experimental MMP ranged from 7.4 to 34.5 MPa

2. Lee's correlation

$$MMP = 7.3924 \times 10^{2.772-[1519/(492+1.8T)]}$$

Where;

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (°C)

Remarks;

(i) Based on equating MMP with CO_2 vapor pressure when T < CO_2 critical temperature, while using the corresponding correlation when T ≥ CO_2 critical temperature

(ii) If MMP < P_b, P_b is taken as MMP

3. Yelling-Metcalfe's correlation

$$MMP = 12.6472 + 0.01553(1.8T + 32) + 1.24192 \times 10^{-4}(1.8T + 32)^2 - \frac{716.9427}{(1.8T + 32)}$$

Where;

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (°C)

Remarks;

(i) Limitations: 35.8 ≤ T < 88.9 °C

(ii) MMP < P_b, P_b is taken as MMP

4. Orr-Jensen's correlation

$$MMP = 0.101386\ exp\left[10.91 - \frac{2105}{255.372 + 0.5556(1.8T + 32)}\right]$$

Where;

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (°C)

Remarks;

(i) Based on extrapolated vapor pressure (EVP) method

(ii) Used to estimate the MMP for low temperature reservoir (T < 49 °C)

5. Glaso's correlation

When X'_{MED} < 18 mol%

$$MMP = 5.58657 - 2.3477 \times 10^{-2} M_{C7+} + 1.1725 \times 10^{-11} M_{C7+}^{3.73} exp^{786.8 M_{C7+}^{-1.058}} (1.8T + 32)$$

When X'_{MED} > 18 mol%

$$MMP = 20.33 - 2.3477 \times 10^{-2} M_{C7+} + 1.1725 \times 10^{-11} M_{C7+}^{3.73} exp^{786.8 M_{C7+}^{-1.058}} (1.8T + 32) - 0.836 X'_{MED}$$

Where;

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (°C)

M_{C7+} = Molecular Weight of M_{C7+} in the crude oil (g/mol)

X'_{MED} = Mole Fraction of Intermediate Components (CO_2, H_2S, and C_2-C_6) in crude oil (mol%)

Remarks;

Considers the effect of intermediates (C_2-C_6) only when X'_{MED} (C_2-C_6) < 18 mol%

6. Alston's correlation

When $P_b \geq 0.345$ MPa

$$MMP = 6.0536 \times 10^{-6}(1.8T + 32)^{1.06}(M_{C5+})^{1.78}\left(\frac{X_{VOL}}{X_{MED}}\right)^{0.136}$$

When $P_b < 0.345$ MPa

$$MMP = 6.0536 \times 10^{-6}(1.8T + 32)^{1.06}(M_{C5+})^{1.78}$$

Where;

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (^oC)

M_{C5+} = Molecular Weight of M_{C5+} in the crude oil (g/mol)

X_{MED} = Mole Fraction of Intermediate Components (CO_2, H_2S, and C_2-C_6) in crude oil (mol%)

X_{VOL} = Mole Fraction of Volatile Components (CH_4+N_2) in crude oil (mol%)

Remarks;

If MMP < P_b, P_b is taken as MMP

7. Emera-Sarma's correation

When $P_b \geq 0.345$ MPa

$$MMP = 5.0093 \times 10^{-5}(1.8T + 32)^{1.164}(M_{C5+})^{1.2785}\left(\frac{X_{VOL}}{X_{MED}}\right)^{0.1073}$$

When $P_b < 0.345$ MPa

$$MMP = 5.0093 \times 10^{-5}(1.8T + 32)^{1.164}(M_{C5+})^{1.2785}$$

Where;

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (°C)

M_{C5+} = Molecular Weight of M_{C5+} in the crude oil (g/mol)

X_{MED} = Mole Fraction of Intermediate Components (CO_2, H_2S, and C_2-C_6) in crude oil (mol%)

X_{VOL} = Mole Fraction of Volatile Components (CH_4+N_2) in crude oil (mol%)

Remarks;

Limitations: 40.8 < T < 112.2 °C

8.28 < MMP < 30.2 MPa

166.2 < M_{C5+} < 267.5 g/mol

8. Yuan's correlation

$$MMP = a_1 + a_2 M_{C7+} - a_3 X'_{MED} + \left(a_4 + a_5 M_{C7+} + a_6 \frac{X'_{MED}}{M_{C7+}}\right)(1.8T + 32) + (a_7 + a_8 M_{C7+} - a_9 M_{C7+}^2 - a_{10} X'_{MED})(1.8T + 32)^2$$

Where; a_1 = -9.8912 | a_6 = 5.6303×10^{1}

a_2 = 4.5588×10^{-2} | a_7 = -8.4516×10^{-4}

a_3 = -3.1012×10^{-1} | a_8 = 8.8825×10^{-6}

a_4 = 1.4748×10^{-2} | a_9 = -2.7684×10^{-8}

a_5 = 8.0441×10^{-4} | a_{10} = -6.3830×10^{-6}

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (°C)

M_{C7+} = Molecular Weight of M_{C7+} in the crude oil (g/mol)

X'_{MED}= Mole Fraction of Intermediate Components (CO_2, H_2S, and C_2-C_6) in crude oil (mol%)

Remarks;

Limitations: 21.7 < T < 148 °C

MMP < 70 MPa

139 < M_{C7+} < 319 g/mol

9. Shokir's correlation

$$MMP = -0.068616Z^3 + 0.31733Z^2 + 4.9804Z + 13.432$$

$$Z = \sum_{i=1}^{4} Z_i$$

$$Z_i = a_i + b_i x_i + c_i x_i^2 + d_i x_i^3$$

Where;

a_1 = -2.91802; a_2 = -3.1227 x 10^{-1}; a_3 = -4.9485 x 10^{-2}; a_4 = 25.430

b_1 = 7.5340 x 10^{-2}; b_2 = -7.9169 x 10^{-3}; b_3 = 4.2165 x 10^{-2}; b_4 = -3.9750 x 10^{-1}

c_1 = -5.5996 x 10^{-4}; c_2 = 1.3644 x 10^{-3}; c_3 = -2.7853 x 10^{-3}; c_4 = 1.9860 x 10^{-3}

d_1 = 2.3660 x 10^{-6}; d_2 = -1.3721 x 10^{-5}; d_3 = 3.551 x 10^{-5}; d_4 = -3.1604 x 10^{-6}

MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (^oC)

M_{C5+} = Molecular Weight of M_{C5+} in the crude oil (g/mol)

Remarks;

Limitations: 32.2 < T < 112.2 ^oC

6.9 < MMP < 30.28 MPa

185 < M_{C5+} < 268 g/mol

10. Chen's correlation

$$MMP = 3.9673 \times 10^{-2} T^{0.8293} (M_{C7+})^{0.5382} \left(X_{C1+N_2}\right)^{0.1018} (X_{C2-C6})^{-0.2316}$$

Where; MMP = Minimum Miscibility Pressure (psi)

T = Reservoir Temperature (°C)

M_{C7+} = Molecular Weight of M_{C7+} in the crude oil (g/mol)

X_{C1+N2} = Mole Fraction of Volatile Components (CH_4+N_2) in the crude oil (mol%)

X_{C2-C6} = Mole Fraction of Intermediate Components (C_2 – C_6) in the crude oil (mol%)

Remarks; Limitations: 32.2 < T < 118.3 °C

6.9 < MMP < 28.17 MPa

185 < M_{C7+} < 249 g/mol

11. Ju's correlation

$$MMP = -0.04562S^3 + 0.33399S^2 + 4.9811S + 13.569$$

$$S = \sum_{i=1}^{8} S_i$$

$$S_i = a_i + b_i x_i + c_i x_i^2 + d_i x_i^3$$

Where; MMP = Minimum Miscibility Pressure (psi)

(The Detailed Parameters refer to Emera-Sarma's correation)

Remarks; Limitations: MMP < 40 Mpa

APPENDIX B

Heterogonous porosity and permeability

From reservoir model with heterogeneity section, the values of porosity and permeability input in reservoir model are random using Microsoft excel software®. The values frequency and their percentage for both heterogeneous porosity and permeability are shown below:

1. Porosity

Table B 1. Random values of porosity and percentage of each value

POROSITY	Values Frequency	Percentage (%)
0.20	336	8.62
0.21	357	9.15
0.22	342	8.77
0.23	351	9.00
0.24	370	9.49
0.25	369	9.46
0.26	367	9.41
0.27	366	9.38
0.28	328	8.41
0.29	361	9.26
0.30	353	9.05
TOTAL	3900	100

2. Permeability

Table B 2. Random values of porosity and percentage of each value

PERMEABILITY	Values Frequency	Percentage (%)	PERMEABILITY	Values Frequency	Percentage (%)
110	47	1.21	151	40	1.03
111	46	1.18	152	64	1.64
112	55	1.41	153	60	1.54
113	52	1.33	154	40	1.03
114	46	1.18	155	42	1.08
115	56	1.44	156	37	0.95
116	48	1.23	157	49	1.26
117	40	1.03	158	36	0.92
118	44	1.13	159	51	1.31
119	41	1.05	160	58	1.49
120	50	1.28	161	46	1.18
121	53	1.36	162	37	0.95
122	45	1.15	163	60	1.54
123	44	1.13	164	49	1.26
124	54	1.38	165	45	1.15
125	41	1.05	166	46	1.18
126	45	1.15	167	49	1.26
127	52	1.33	168	48	1.23
128	51	1.31	169	45	1.15
129	48	1.23	170	44	1.13
130	60	1.54	171	50	1.28
131	36	0.92	172	38	0.97
132	43	1.10	173	43	1.10
133	44	1.13	174	51	1.31
134	50	1.28	175	55	1.41
135	56	1.44	176	59	1.51
136	60	1.54	177	47	1.21
137	40	1.03	178	48	1.23
138	51	1.31	179	55	1.41
139	48	1.23	180	52	1.33
140	46	1.18	181	53	1.36
141	53	1.36	182	47	1.21
142	48	1.23	183	51	1.31
143	44	1.13	184	54	1.38
144	52	1.33	185	42	1.08
145	43	1.10	186	42	1.08
146	35	0.90	187	39	1.00
147	52	1.33	188	50	1.28
148	53	1.36	189	40	1.03
149	53	1.36	190	59	1.51
150	54	1.38	TOTAL	3900	100.00

APPENDIX C
CMG-GEM® Software Overview

GEM is the world-leading Equation-of-State (EoS) reservoir simulator for compositional, chemical and unconventional reservoir modelling.

Enhanced Oil recovery

Achieve accurate simulation of miscible/immiscible displacement, chemical EOR and non-steam based thermal recovery processes to improve and optimize the recovery factor from oil and gas reservoirs.

- Equation-of-State (EOS) compositional simulator that models flow of three phase, multi-component fluids.
- Advanced handling of complex phase behavior of all types of petroleum fluids.
- Accurately and robustly models the physics and chemistry related to all type of non-thermal EOR processes.
- Full physics associated with handling of advanced relative permeability as a function of IFT, velocity and composition, hysteresis effects in miscible and WAG processes.
- Model the physics of in-situ Asphaltene precipitation related effects and its impact on reservoir performance when modelling gas/solvent based EOR process.
- Capture pore blockage effects and its impact on the efficiency of the process by modelling adsorption of aqueous phase components on rock surface.

Chemical EOR (cEOR)

Design and evaluate the effectiveness of chemical additives with GEM's advanced cEOR features. GEM is the only simulator that models Miscible Injection + Foam + ASP + Low salinity in a single model.

- Full physics capability for modelling ASP, Foam and other cEOR processes in both clastic and carbonate reservoirs.
- Model polymer, surfactant or Alkali injection with geochemical effects.
- Accurate ASP process modelling with saponification and salinity gradients in full-field 3D environment.
- Achieve optimum recovery and prevent process failures by maintaining a strict salinity gradient during an ASP flood.
- Models Windsor type I, II and III phase behavior during ASP injection process.
- Models Micro Emulsion (ME) phase using two liquid phases (oil and water).
- Simulate mobility control by polymers or foam injection, and interfacial tension reduction using surfactants and/or alkalis.
- Study complex effects of foam with the empirical foam model.
- Forecast production/recovery factor by configuring lab scale or full-field ASP or Foam models, using Builder process wizard.
- Improve recovery and NPV by optimizing chemical slug size, concentration, injection schedule, and optimal injector-producer well location.

<u>Unconventional Reservoirs: Matrix to Fracture Modelling</u>

Industry leading, most advanced and easy to use workflow for modelling hydraulic and natural fractures in Shale and Tight oil and gas reservoirs.

- Flexible workflow for modelling natural and hydraulic fractures, multi-component adsorption, geomechanical effects, inter-phase mass transfer, multi-phase diffusion and non-Darcy flow.
- Feature-rich reservoir simulator for modelling primary and advanced EOR processes, in all types of unconventional reservoirs.
- Accurate representation of fluid flow physics in the matrix and the fractures using a CMG's Tartan Grid for modelling planar and network (SRV) hydraulic fractures.
- Achieve better accuracy around hydraulic fractures due to logarithmically spaced gridding.
- Explicit representation of fracture dimensions in grid design, non-Darcy flow and velocity-dependent relative permeability effects.
- Easy-to-use model building wizard for creating hydraulic fractures using physical HF parameters, microseismic data or imported fracture simulation data, from 3rd-party software, for better fracture characterization, history matching and forecasting.
- Perform coupled geomechanics simulation to understand hydraulic fracture conductivity variation as a function of stress change during production & injection.
- Automate the history matching, optimization and uncertainty analysis by parametrizing the uncertain parameters associated with reservoir, hydraulic fracture and operating parameters.

<u>Carbon Capture and Storage</u>

Accurately model the long-term effects of carbon dioxide (CO2) injection into a geological formation or saline aquifer and help determine the viability of the CCS project.

- Model and visualize the long-term effects of CO2 storage in geological reservoirs and saline aquifers
- Increase accuracy by including gas trapping effects due to hysteresis, water phase density and viscosity alteration due to solubility and salinity change, mineral precipitation and dissolution mechanisms
- Water vaporization model reformulated for two-phase hydrocarbon systems to allow for increase accuracy
- Improve CCS model reliability by including complete aqueous phase chemical equilibrium calculations
- Extensive library of aqueous and mineral reactions available for use in simulation models
- Use Builder to quickly and efficiently develop CO_2 Sequestration simulation models

VITA

Mr. Hutthapong Yoosook (MINK) was born on September 17th, 1987 in Nakhonsawan, Thailand. He received a full scholarship for Bachelor Degree from Department of Defense Energy, Ministry of Defense. And he graduated his Bachelor Degree from Colorado School of Mines, USA in Petroleum Engineering in 2012. From that day forward, he had worked as drilling engineer and production engineer for Northern Petroleum Development Center, Department of Defense Energy, Ministry of Defense up until 2016. After that, he received full scholarship for Master Degree from Department of Defense Energy, Ministry of Defense. And he continued his further study in Master's Degree program in Georesources and Petroleum Engineering in the academic year 2016 at Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University, Thailand.