กลยุทธ์การอัดก๊าซและการผลิตที่เหมาะสมที่สุดสำหรับการนำก๊าซกลับมาใช้อีกในแหล่งกักเก็บที่มีทั้งก๊าซธรรมชาติและก๊าซธรรมชาติเหลว

นายศุภนัย แจ่มสุธี

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OPTIMAL INJECTION AND PRODUCTION STRATEGY FOR GAS RECYCLING IN GAS CONDENSATE RESERVOIR

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
Faculty of Engineering
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Thesis Title	OPTIMAL INJECTION AND PRODUCTION STRATEGY FOR GAS RECYCLING IN GAS CONDENSATE RESERVOIR
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ศุภนัย แจ่มสุธี : กลยุทธ์การอัดก๊าซและการผลิตที่เหมาะสมที่สุดสำหรับการนำก๊าซกลับมาใช้อีกในแหล่งกักเก็บที่มีทั้งก๊าซธรรมชาติและก๊าซธรรมชาติเหลว (OPTIMAL INJECTION AND PRODUCTION STRATEGY FOR GAS RECYCLING IN GAS CONDENSATE RESERVOIR) อ. ที่ปรึกษา: ผศ.ดร. สุวัฒน์ อธิชนากร, 107 หน้า.

การศึกษานี้ได้ศึกษากลยุทธ์ต่าง ๆ ที่ให้ค่าทางเศรษศาสตร์สูงสุดในการผลิตก๊าซและก๊าซธรรมชาติเหลวโดยใช้ผลที่ได้จากการจำลองแหล่งกักเก็บชนิดพิจารณาองค์ประกอบ แบบจำลองแหล่งกักเก็บแบบง่ายถูกสร้างขึ้นและมีการใช้ข้อมูลสภาวะเริ่มต้น คุณสมบัติและองค์ประกอบของของเหลวที่ได้จากแหล่งกักเก็บจริงมาใช้ในแบบจำลอง เพื่อจำลองการผลิตด้วยกลยุทธ์การผลิตแบบต่าง ๆ กัน ได้แก่ การผลิตตามธรรมชาติ การผลิตพร้อมกับการใช้ก๊าซไซคลิ่งและการผลิตโดยมีการอัดก๊าซ ณ เวลาที่เหมาะสม โดยทำการจำลองที่อัตราการผลิต อัตราการอัดกลับและเวลาในการเริ่มอัดก๊าซกลับหลาย ๆ ค่า หลังจากนั้นจึงทำการวิเคราะห์ทางเศรษฐศาสตร์เพื่อประเมินผลของแบบจำลองแต่ละกลยุทธ์ การศึกษาสามารถสรุปได้ว่าการผลิตพร้อมกับการใช้ก๊าซไซคลิ่งโดยมีการอัดก๊าซ ณ เวลาที่เหมาะสม คือกลยุทธ์ที่เหมาะสมที่สุดในการผลิตก๊าซธรรมชาติและก๊าซธรรมชาติเหลว และก๊าซไซคลิ่งสามารถเพิ่มปริมาณการผลิตสารประกอบไฮโดรคาร์บอนเหลวได้อย่างมีประสิทธิภาพ

ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม.......... ลายมือชื่อนิสิต.......................................
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This study investigated different strategies to maximize the economics of gas and condensate production using results obtained from a compositional simulator. A simple reservoir model was constructed, and the actual initial reservoir conditions, fluid properties and composition were used in the model. Different production strategies, namely, production by natural depletion, production with gas cycling, and production with timely gas injection were simulated. The production rate, injection rate, and appropriate time to start gas injection were varied. Economic analyses were performed in order to evaluate each simulated scenario. The study concluded that production with gas cycling and timely gas injection is the optimal strategy in this gas-condensate production, and gas cycling can increase the recovery of hydrocarbon liquid, effectively.

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List of Abbreviations

AIM	Adaptive IMplicit
API	degree (American Petroleum Institute)
bbl	barrel (bbl/d : barrel per day)
BTU	British thermal unit
C_1	methane
C_2	ethane
C_3	propane
i-C_4 or I-C_4	isobutane
i-C_5 or I-C_5	isopentane
n-C_4 or N-C_4	normal butane
n-C_5 or N-C_5	normal pentane
C_6	hexane
C_{7+}	alkane hydrocarbon account from heptanes forward
CO_2	carbon dioxide
CGR	condensate gas ratio
D	darcy
EOS	equation of state
FGPT	field gas production total
FOPT	field oil production total
IMPES	IMplicit Pressure, Explicit Saturations
IRR	internal rate of return
K	kilo- (10^3 or 1,000)
M	[1] thousand (1,000 of petroleum unit), [2] million (dollar)
MSCF/D	thousand standard cubic feet per day
NEI	non-equilibrium initialisation
NPV	net present value
PVT	pressure-volume-temperature
PSIA or psia	pounds per square inch absolute
SCAL	special core analysis
SGAS	gas saturation
SGFN	gas saturation function

SOFN	oil saturation function
STB or stb	stock-tank barrel
STB/D	stock-tank barrels per day
SWAT	water saturation
SWFN	water saturation function
TVD	true vertical depth or total vertical depth
VLE	vapor/liquid equilibrium
BHP	bottom hole pressure
GIR	gas injection rate
GPT	gas production total
GPR	gas production rate
OPR	oil production rate
OPT	oil production total

Nomenclature

a	attraction parameter
a_T	temperature-dependent coefficient in Peng-Robinson equations of state
A	cross-section area
b	repulsion parameter
c_g	gas compressibility
E	areal sweep efficiency at breakthrough
k	[1] permeability , [2] discount rate (cost of capital)
k_{rg}	gas relative permeability
k_{rw}	water relative permeability
k_{rog}	oil relative permeability for a system with oil, gas and connate water
k_{row}	oil relative permeability for a system with oil and water only
k_{rowg}	oil relative permeability for a system with oil and water at $S_g = 0$
K	equilibrium constant
M	molecular weight
M_g	apparent molecular weight of gas
m	mass per unit volume
$\dot{m}$	mass flux (mass per unit area per unit time)
n	[1] last period of project, [2] number of mole
O_t	cash outflow in period t
p	pressure
p_c	capillary pressure
$\tilde{q}$	volumetric flow rate
Q	mass injection or production
r	internal rate of return *(IRR)*
R_t	cash inflow in period t
R	universal gas constant
S	saturation
t	time period (e.g.,year)
u_x	flow velocity

V_b	bulk fluid volume
x	liquid phase
y	[1] mole fraction of component in gas, [2] vapor phase
z	compressibility factor

GREEK LETTER

ϕ	[1] porosity, [2] coefficient of fugacity
f	fugacity
ρ	fluid density (mass/volume)
μ	[1] fluid viscosity, [2] chemical potential
Δ	difference operator
α	[1]constant in temperature-dependent coefficient for Peng-Robinson equation of state, [2] fractional mole of gas
Ω	constant in equation of state
ω	acentric factor of the component
δ	binary interaction coefficients

SUPERSCRIPTS

n	current time level
$n+1$	new time level

SUBSCRIPTS

A	areal
c	critical property
d	displacement
g	gas
i	[1] grid block location , [2] component i, [3] invasion
j	component j
k	component k
o	oil
r	reduced
w	water

CHAPTER I

INTRODUCTION

Petroleum is the most important energy that is closely involved with human activities. Oil and natural gas produced from the petroleum industry is necessarily required for transportation, electrical power generation, and source energy of all industries that produce fundamental necessities of life.

Condensate reservoir is one of the various types of reservoir. It has unique characteristics of phase behavior as illustrated in Figure 1.1, schematically. This reservoir initially contains single-phase ***gas*** (point A) where its pressure is above the ***dew point*** (point B). When the reservoir is on production and its pressure declines continuously until it reaches the dew point pressure, at this point, ***liquid*** begins to condense and dropout. At the envelope entry, the condensate liquid leaves out from gas phase with low liquid content. This phenomenon continues until the liquid saturation or maximum volume is reached (point C). After that, lowering the pressure will cause the liquid to ***re-vaporize*** (point D). In typical field operations, this pressure is below the economic life of the field, and this stage of re-vaporization will not be reached. Gas-condensate reservoirs are important since condensate has higher value than natural gas. The production from these reservoirs yields certain amounts of gas and condensate to supply worldwide consumption.

While the gas-condensate reservoir is put on production, the reservoir pressure continuously declines until reaching the dew point pressure. Subsequently, gas starts to condense and dropout in the reservoir. This phenomenon will create a certain quantity of liquid in the reservoir leading to a condensate blockage problem. This condensate blockage drastically reduces the well productivity and deliverability. Furthermore, some of the valuable condensate will be left in the reservoir as residual oil. The pressure declining below the dew point pressure and the reduction in well productivity by condensate bank is predominantly a challenge to be avoided. One of the most effective methods of solving this problem is gas injection. During this process, condensate is vaporized into the mobile injected gas phase since the reservoir pressure is increased. This gas injection method to improve well productivity is often included in production plan for 'Gas-Condensate Reservoir'.

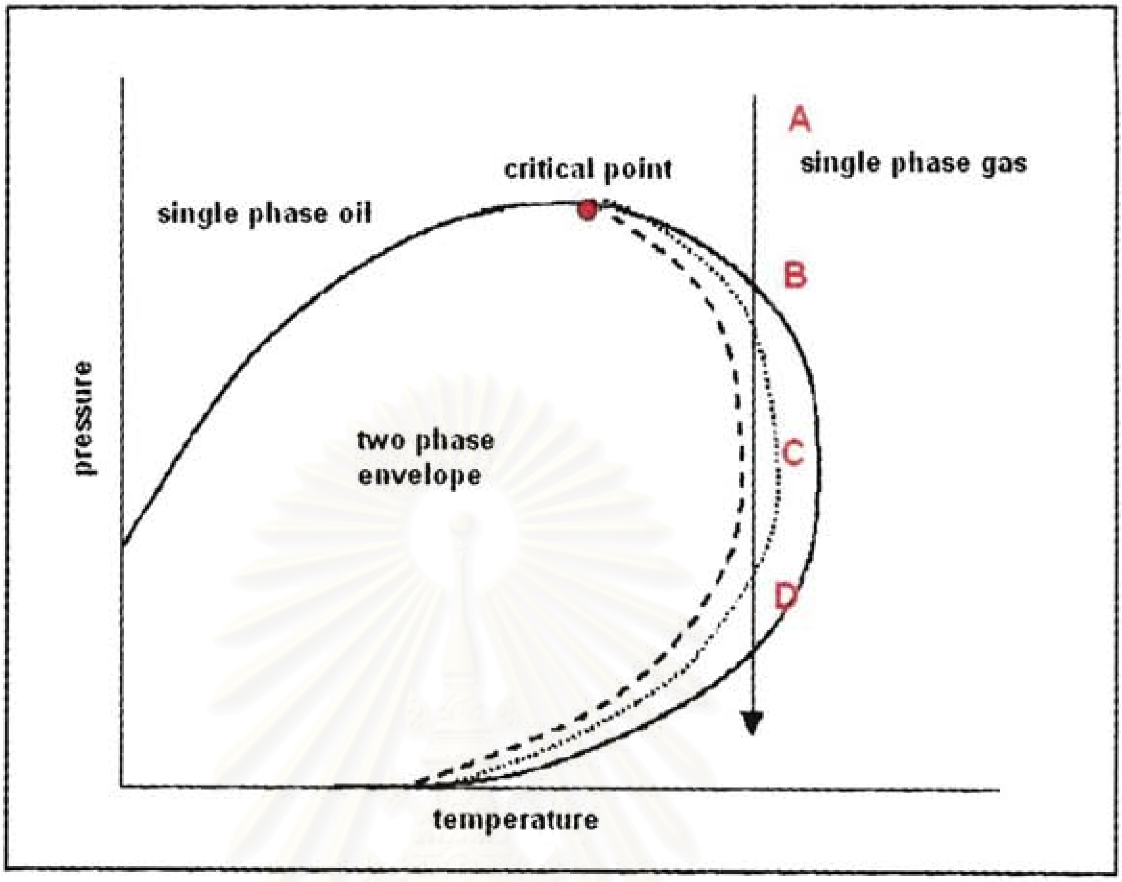


Figure 1.1: Pressure-Temperature diagram of condensate.

To maximize condensate production and to prevent condensate dropout to be immobile liquid in the reservoir, the reservoir pressure must be maintained above the dew point. A condition could be achieved by injecting gas into the reservoir. The injected gas can be natural gas or other inert gases, depend on gas availability of each reservoir. Injection of natural gas produced from reservoir is known as 'Gas Cycling' or 'Gas Recycling'.

However, since the prior produced natural gas will be used as injected gas instead of the product to sale, condensate production planning must be certain and strictly reviewed for pros and cons. A good planning for optimal injection and production will result in maximum hydrocarbon recovery. For a fixed period of well production, implementation of this gas recycling will be designed to maximize hydrocarbon recovery. Those gas recycling characteristics may include production/injection wells ratio, gas composition, injection rate, amount of recycled gas used to inject, appropriate time to start gas injection, etc. Therefore, to maximize hydrocarbon recovery, injection and production strategy must be optimized.

1.1 Outline of Methodology

This thesis is to optimize the hydrocarbon injection and production for gas-condensate reservoir. Compositional reservoir simulations are performed to study different strategies of gas-cycling or gas injection as listed below:

(a) Produce hydrocarbon from the reservoir with natural depletion at various production rates from one production well. After the oil rate reaches the economic limit of oil production, gas production is continued till abandonment (economic limit of gas production).

(b) Start producing hydrocarbon from one well together with gas injection from another well. After the oil rate reaches the economic limit of oil production, the injection well is then switched to produce gas in parallel with the first well.

(c) Produce hydrocarbon from one well and then selectively perform gas injection with different starting times on the other well. After the oil rate reaches economic limit of oil production, the injection well is then switched to produce gas in parallel with the first well.

(d) The results are then summarized. Economic analysis is performed based on NPV, IRR, and Payback period.

1.2 Thesis Outline

This thesis paper consists of six chapters.

Chapter II outlines a list of related works/studying on gas-condensate reservoir and gas injection in order to enhance hydrocarbon recovery.

Chapter III describes the principle of reservoir simulation, the theory of gas-condensate reservoir, and data required by the simulation program.

Chapter IV discusses the applications of economic and its decision tools used to assess each production/injection profile and as criteria for optimal recovery strategy of gas-condensate reservoir.

Chapter V discusses the results of reservoir simulation obtained from different values of controlled variables which are production and injection rates and time to start the injection process.

Chapter VI provides conclusion and recommendation for further study.

CHAPTER II

LITERATURE REVIEW

This chapter discusses some of works related to gas injection and the development of production of gas-condensate reservoir. Some works that applied simulation in their studies are also outlined.

2.1 Previous works on gas injection/production

The production of gas-condensate reservoir by natural pressure depletion is accompanied by liquid condensate dropout within the reservoir. This phenomenon occurs whenever the condensate reservoir pressure declines below the dew point pressure. The majority of liquid dropout composes of heavy components of hydrocarbon. A fraction of the liquid dropout may be left as residual oil in the reservoir. An ordinary method applied to prevent this liquid dropout within the reservoir is to maintain the reservoir pressure above the dew point pressure. The following literatures discuss some related works in maintaining the gas-condensate reservoir pressure by gas injection.

Pires *et al.* [1] presented a coherent thermodynamic analysis of the effects of lean gas injection in two Brazilian gas-condensate reservoirs through the determination of the phase behavior of injected/original gas mixtures. The accuracy of the thermodynamic model employed is verified through the comparison of the method predictions with laboratory data. The results obtained from this analysis are used to determine the maximum amount and optimal composition of lean gas to be injected in gas-condensate reservoirs in order to change the composition and shift the phase envelope to a point where the liquid drop-out can be eliminated or minimized during the isothermal depletion of the reservoir. The results can also be used to optimize the operation of gas pipelines and production equipment and facilities.

In this work, they presented their investigation of the gas cycling projects proposed for two reservoir fluids. The authors analyzed the effect of lean gas injection on the condensate recovery. They also evaluated the effect of using an equimolar lean gas/nitrogen mixture as the injection fluid. The phase behavior of the reservoir fluid and reservoir fluid/injected gas mixtures was determined using a thermodynamic model based on reservoir fluid liquid drop-out laboratory data.

Jessen and Orr, Jr. [2] presented a detailed analysis of the development of miscibility during gas cycling in condensate displacements and the formation of condensate banks at the leading edge of the displacement front. They used dispersion-free, analytical 1D calculation to determine the enhanced condensate recovery by gas injection. The analytical approach allows investigation of possible formation of condensate banks and allows fast screening of optimal injection-gas compositions. All analytical solutions were verified by numerical calculations.

The authors used an analysis of key equilibrium tie lines that are part of the displacement composition path to demonstrate that the mechanism controlling the development of miscibility in gas condensate may vary from first-contact miscible drives to pure vaporizing and combined vaporizing/condensing drives. Depending on the compositions of the condensate and the injected gas, multi-contact miscibility can develop at or below the dew point pressure of the reservoir fluid mixture.

R.Smith and Yarborough [3] presented their study results of the equilibrium revaporization of retrograde condensate by dry gas injection. They performed laboratory experiments by flow test of dry gas injection in 10.6-ft long, stainless steel tube contained unconsolidated sand packs at 100 F and 1,500 psi. Methane was injected through liquid, n-pentane-methane mixture, and the impacts of injected gas volume and wettability were observed. The study demonstrated that vapor-liquid equilibrium exists when a dry gas is injected into a porous medium containing retrograde condensate. It also provides an indication of the amount of dry gas necessary to recover the heavy components from a condensate that contain a large concentration of hydrogen sulfide.

The authors concluded that when dry gas is injected into a porous medium containing wet gas below the dew point, a part or all of the retrograde liquid is revaporized and the flowing fluid is the vapor in equilibrium with the liquid. Dry injection gas becomes saturated within a short distance after first contact with the liquid. The quantity of dry gas required for complete recovery of retrograde liquid is influenced by the heaviest components of the liquid. However, the amount required in an actual reservoir situation depends on the temperature and pressure conditions, the nature of the condensate fluid and sweep efficiency in the fluid injection process. The fluid arrangement in the pore space has no effect on the equilibrium revaporization of retrograde liquid at the flow rate employed, indicating that reservoir wettability is not a factor in the revaporization recovery of retrograde liquids.

Lopez [4] described a technical study for the implementation of recovery methods improved with gases, and different hydrocarbon recovery factors obtained using different gases such as dry gas, CO_2, nitrogen, flue-gas, and other feasible combinations of injection gases. The best method obtained in such study is the injection of a dry gas in the zone of interest very near the water front in order to avoid the entry of the water to the well and to reduce the level of the current water in the perforations with high water cut, thus recovering trapped hydrocarbons, therefore obtaining high recovery factors of the order of 70 to 90% of the original volume.

Luo *et al.* [5] experimentally investigated the condensate recovery of high dew point pressure reservoir by gas cycling while the reservoir pressure is above and below the dew point pressure. They found in PVT cell that lean gas does not only effectively re-vaporize the intermediate but also C_{20+} components. Comparison of tests in long core system illustrates that more condensate can be recovered if the gas cycling starts when the pressure is still above the dew point. This is consistent with the conventional idea that full pressure maintenance is superior to partial pressure maintenance when considering condensate recovery.

Siregar *et al.* [6] investigated the potential of nitrogen injection to be applied as an alternative for gas cycling in rich retrograde condensate-gas reservoirs, with an emphasis on the condensate dropout problem. One-dimensional, compositional simulator was used to evaluate the displacement efficiency. From their study, they concluded that nitrogen injection causes much higher liquid dropout than methane injection due to mixing. The result, however, indicates that nitrogen is a potential alternative to gas cycling in condensate reservoirs, but two and three dimensional simulations are recommended to be performed in order to assess the effect of heterogeneity and layering.

Sänger and Hagoort [7] studied the recovery of gas condensate by nitrogen injection compared with methane injection. The main conclusion of their study is that the displacement of gas condensate by both nitrogen and methane is a developed miscible process, which results in high condensate recoveries. The displacement of gas condensate by nitrogen is a multi-contact miscible process. The displacement by methane is either first-contact miscible or multiple-contact miscible. Multiple–contact miscibility is disturbed by dispersion. Nitrogen flooding is more sensitive to dispersion than methane flooding.

Morokane, Logmo-Ngog, and Sarkar [8] conducted a study to investigate the applicability of one-time produced gas injection in removing the condensate bank around the wellbore and thereby restoring well productivity. The study focused on two major issues: the optimum time of commencing gas injection and the optimum volume that will remove the condensate bank permanently and restore well productivity. The practice will accelerate the production rate per well and maximize the ultimate hydrocarbon recovery. The reservoir simulation results indicated that, for the lean gases, the best time to start gas injection when the average reservoir pressure around the producing well fell below the maximum liquid dropout pressures. For rich gas, however, gas injection starting at an average reservoir pressure above the maximum liquid dropout pressure resulted in a better recovery.

El-Banbi *et al.* [9] presented the results of a full field compositional reservoir simulation study that compares the application of waterflooding and gas injection to a rich gas-condensate reservoir. The authors concluded that both water injection and gas injection result in a higher recovery factor than normal depletion. The gas injection showed a higher condensate recovery factor. Comparing with water injection, gas cycling process may not be economical due to the requirement of large initial investment, higher operating costs, and delay of gas sales. Moreover, the authors proposed that water injection has a major advantage over gas injection, the produced gas can be immediately sold and compression cost is saved.

In the literatures reviewed in this study, several subjects related with gas cycling and the concerned investigation for developing gas-condensate reservoir are presented. For gas cycling, the optimal composition of injected gas, the determination of injected gas volume, the equilibrium of revaporization, the technical study of using different injected gases, and the optimum time of commencing gas injection, are reviewed. For the related theory, miscibility during gas cycling, studying of phase behavior, and the prediction of gas condensate recovery are also presented.

CHAPTER III

THEORY AND CONCEPT

Petroleum hydrocarbon fluids naturally occur as mixture of natural gas and oil. Petroleum reservoirs exist at elevated temperatures and pressures. Hydrocarbon-fluid compositions typically include hundreds or thousands of hydrocarbon and a few non-hydrocarbons, such as nitrogen, carbon dioxide, and hydrogen sulfide. The physical properties of these mixtures depend on reservoir composition, temperature, and pressure. Reservoir temperature can be assumed to be constant due to a small temperature gradient as a function of depth.

Gas-condensate reservoirs have been considered the most complex reservoir among other types of petroleum reservoirs. These reservoirs have unusual phase behaviors of reservoir fluids such as the condensing and vaporizing mechanism within the reservoirs. As the gas condensate is produced, the reservoir pressure decreases. After it reaches the dew point pressure, there are changes in composition, volumetric properties, and phase behavior of the hydrocarbon mixtures. Gas injection process can also change reservoir-fluid composition and properties. These changes and characteristics have been simultaneously studied and described as theories, mathematics, and thermodynamics correlations that applied for compositional-reservoir simulation.

3.1 Review of Gas-Condensate Reservoir

As described in Chapter I, gas-condensate reservoir is a type of reservoir that exhibit complex phase behaviors. The phase diagram of gas condensate depicted in Figure 3.1 shows that gas-condensate reservoir has reservoir temperature between the critical temperature, T_c, and the cricondenterm. The fluid contained in this reservoir is initially in the gas phase, point A. As the pressure declines because of production, from point A to point B, gas composition remains constant. At point B where the reservoir pressure reaches the dew point pressure, liquid starts to condense from gas. A portion of the liquid is immobile due to interfacial tension and is left in the reservoir as residual oil. The other portion is movable. However, this condensed liquid has higher viscosity than gas thus, requires a higher drawdown in order to produce. This phenomenon provides the behavior known as retrograde condensation. This phenomenon was given the name because it is contradictory to the phase behavior of pure components, which condense with increasing pressure and or decreasing temperature. The retrograde condensation continues from point B until liquid saturation is reached at point C. After that, reducing the reservoir pressure, from point C to point D, will cause liquid to vaporize. The composition of hydrocarbon gas will change during the retrograde condensation process. The condensate to gas ratio on the surface will change due to liquid dropout and re-vaporization in the reservoir.

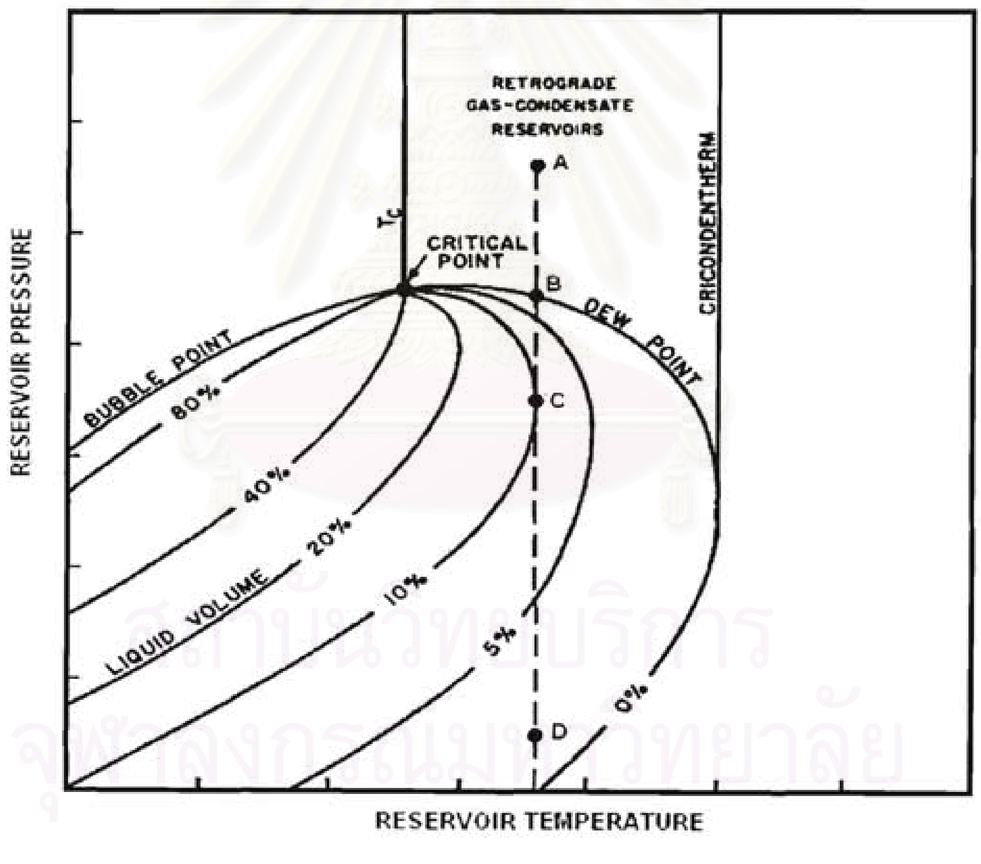


Figure 3.1: Pressure-Temperature phase diagram of gas-condensate.

To describe phase behavior and the changing of hydrocarbon composition within gas-condensate reservoir, the correlations for PVT of gas and equations of state (EOS's) are introduced.

3.1.1 Correlations for PVT Properties of Gas

The behavior of gases at low pressures was originally described by the experiments of Charles and Boyle, which results in ideal-gas law as follows:

$$pV = nRT \tag{3.1}$$

where

p = pressure (psia)

V = volume (cu.ft)

n = number of pound moles

R = universal gas constant

T = absolute temperature (°R)

For gas mixture at moderate to high pressure or at low temperature, Equation 3.1 does not give accurate prediction for gas behavior because the bulk volume of gas composition and molecules and intermolecular forces significantly affect the volumetric behavior of gas. The deviation from ideal behavior is expressed as the z factor where z is the compressibility factor.

$$z = \frac{volume\ of\ 1\ mole\ of\ real\ gas\ at\ p\ and\ T}{volume\ of\ 1\ mole\ of\ ideal\ gas\ at\ p\ and\ T} \tag{3.2}$$

Then, the correlation for real-gas with the deviation term or compressibility factor is

$$pV = znRT \tag{3.3}$$

All volumetric properties of gases can be derived from the real-gas law.
Gas density is given by

$$\rho_g = \frac{pM_g}{zRT} \tag{3.4}$$

where

ρ_g = density of gas (lb/cu.ft)

M_g = apparent molecular weight of gas (lb/lb.mole)

The gas coefficient of isothermal compressibility is given by

$$c_g \quad = \quad -\frac{1}{V_g}\left(\frac{\partial V_g}{\partial p}\right) \quad = \quad \frac{1}{p}-\frac{1}{z}\left(\frac{\partial z}{\partial p}\right)_T \tag{3.5}$$

where

c_g = gas coefficient of isothermal compressibility (psi $^{-1}$)

V_g = volume of gas (cu.ft)

The dew point pressure can be found from a correlation based on composition and C_{7+} properties as proposed by Nemeth and Kennedy [10].

$$\begin{aligned}\ln p_d \quad = \quad & A_1\left[z_{c_2} + z_{co_2} + z_{H_2S} + z_{c_6} + 2\left(z_{c_3} + z_{c_4}\right) + z_{c_5} + 0.4z_{c_1} + 0.2z_{N_2}\right] \\ & + A_2\gamma_{c_{7+}} + A_3\left[\frac{z_{c_1}}{\left(z_{c_{7+}} + 0.002\right)}\right] + A_4T + \left(A_5 z_{c_{7+}} M_{c_{7+}}\right) + \\ & A_6\left(z_{c_{7+}} M_{c_{7+}}\right)^2 + A_7\left(z_{c_{7+}} M_{c_{7+}}\right)^3 + A_8\left[\frac{M_{c_{7+}}}{\gamma_{c_{7+}} + 0.0001}\right] + \\ & A_9\left[\frac{M_{c_{7+}}}{\gamma_{c_{7+}} + 0.0001}\right]^2 + A_{10}\left[\frac{M_{c_{7+}}}{\gamma_{c_{7+}} + 0.0001}\right]^3 + A_{11},\end{aligned} \tag{3.4}$$

where

z	=	gas compressibility factor			
γ	=	specific gravity			
A_1	=	- 2.0623054,	A_2	=	6.6259728,
A_3	=	- 4.4670559 x 10^{-3}	A_4	=	1.0448346 x 10^{-4}
A_5	=	3.2673714 x 10^{-2}	A_6	=	- 3.6453277 x 10^{-3}
A_7	=	7.4299951 x 10^{-5}	A_8	=	- 1.1381195 x 10^{-1}
A_9	=	6.2476497 x 10^{-4}	A_{10}	=	- 1.0716866 x 10^{-6}
A_{11}	=	1.0746622 x 10^{1}			

3.1.2 Equation of State [EOS]

Equations of states (EOS) are equations that describe the volumetric and phase behavior of pure compounds and mixtures. These equations relate pressure, volume and temperature (PVT). The critical properties and acentric factor of each component are required in calculating the properties of gas in the reservoir.

After van der Waals proposed his EOS, the equation of state have been developed and widely used. There are the Redlich and Kwong EOS (RK EOS), the Zudkevitch and Joffee *et al.* EOS (ZJRK EOS), the Soave EOS (SRK EOS), the Peng and Robinson EOS (PR EOS), and the Martin volume translation.

The development of EOS starts from *Compressibility Equation of State* which is Equation 3.3. Arranging Equation 3.3 in term of z and molar volume $(v = M / \rho)$, we obtain

$$z = \frac{pv}{RT} \tag{3.5}$$

The volumetric behavior is calculated by solving this simple equation expressed in terms of compressibility factor, z.

$$z^3 + E_2 z^2 + E_1 z + E_0 = 0 \tag{3.6}$$

where constants E_0, E_1, and E_2 are functions of pressure, temperature, and phase composition.

3.1.2.1 van der Waals Equation of State

van der Waals proposed a simple, qualitatively accurate relation between pressure, temperature and molar volume.

$$p = \frac{RT}{v-b} - \frac{a}{v^2} \tag{3.7}$$

where a = "attraction" parameter, b = "repulsion" parameter. van der Waals equations offers two important improvements; the term $v - b$ makes the volume approaches a limited value that prediction of fluid behavior is more accurate and the term a/v^2 reduces the system pressure from molecular attraction.

The constants a and b in van der Waals equation are given by

$$a = \frac{27}{64}\frac{R^2T_c^2}{p_c} \tag{3.7a}$$

and
$$b = \frac{1}{8}\frac{RT_c}{p_c} \tag{3.7b}$$

where

T_c = critical temperature (°R)

p_c = critical pressure (psia)

3.1.2.2 Peng-Robinson Equation of State

Peng and Robinson equation is the one most widely used in petroleum calculations. They proposed a different term for molecular attraction which improved the fluid density prediction. The equation is given as

$$p = \frac{RT}{v-b} - \frac{a_T}{v(v+b) + b(v-b)} \tag{3.8}$$

The constants in the equation are given by

$$a_T = a_c\alpha \tag{3.8a}$$

$$\alpha^{1/2} = 1 + m(1 - T_r^{1/2}) \tag{3.8b}$$

$$a_c = 0.45724\frac{R^2T_c^2}{p_c} \tag{3.8c}$$

$$m = 0.37464 + 1.54226\omega - 0.26992\omega^2 \tag{3.8d}$$

$$b = 0.07780\frac{RT_c}{p_c} \tag{3.8e}$$

where ω is the acentric factor of the component and T_r is the reduced temperature. For Peng-Robinson EOS, the mixing rule is used to determine the properties of mixture as

$$b = \sum_k y_k b_k \tag{3.8f}$$

and

$$a_T = \sum_j \sum_k y_j y_k (a_{Tj} a_{Tk})^{1/2} (1 - \delta_{jk}) \tag{3.8g}$$

where the term δ_{jk} are binary interaction coefficients, which are assumed to be independent of pressure and temperature.

3.1.2.3 Martin-Volume Translation

The two fundamental equations used in developing his general form of all equations of state are,

$$z = z(p, T, x) \tag{3.9}$$

$$f_i = f_i(p, T, x), \quad i = 1, 2, \ldots.. n, \tag{3.10}$$

Martin shows that all EOS's can be represented a by single general form as Equation 3.6 and by solving with thermodynamics relationships yields generalized forms for Equation 3.9 and Equation 3.10 as follow

From Equation 3.6

$$z^3 + E_2 z^2 + E_1 z + E_0 = 0$$

where

$$E_2 = (m_1 + m_2 - 1)B - 1 \tag{3.11}$$

$$E_1 = A - (m_1 + m_2 - m_1 m_2)B^2 - (m_1 + m_2)B \tag{3.12}$$

$$E_0 = -[AB + m_1 m_2 B^2 (B + 1)] \tag{3.13}$$

The coefficients m_1 and m_2 depend upon the equation used. For the Redlich-Kwong equation(RK EOS), the Soave-Redlich-Kwong equation(SRK EOS), and the Zudkevitch-Joffe-Redlich-Kwong equation(ZJRK EOS), $m_1 = 0$ and $m_2 = 1$. For the Peng-Robinson equation(PR EOS), $m_1 = 1+\sqrt{2}$ and $m_2 = 1-\sqrt{2}$. To solve for coefficients A and B, the thermodynamics equations defining fugacity are proposed and fugacity coefficients are calculated using

$$\ln\left(\frac{f_i}{(px_i)}\right) = -\ln(z-B)+\frac{A}{(m_1-m_2)B}\left(\frac{2\sum_i}{A}-\frac{B_i}{B}\right)\ln\left(\frac{z+m_2B}{z+m_1B}\right) + \frac{B_i}{B}(z-1) \quad (3.14)$$

where

$$\sum_i = \sum_j A_{ij}x_j \quad (3.15)$$

$$A = \sum_{j=1}^{n}\sum_{k=1}^{n} x_j x_k A_{jk} \quad (3.16)$$

$$B = \sum_{j=1}^{n} x_j B_j \quad (3.17)$$

$$A_{jk} = (1-\delta_{jk})(A_j A_k)^{1/2} \quad (3.18)$$

$$A_j = \Omega_a(T,j)\frac{P_{rj}}{T_{rj}^2} \quad (3.19)$$

$$B_j = \Omega_b(T,j)\frac{P_{rj}}{T_{rj}} \quad (3.20)$$

δ_{jk} is the binary interaction parameter (BIP's) where normally $\delta_{jj} = 0$ and $\delta_{jk} = \delta_{kj}$. Binary interaction parameters are usually equal to zero for most hydrocarbon/hydrocarbon pairs, except C_1/C_{7+} pairs. Binary interaction parameters for non-hydrocarbon/hydrocarbon are usually not zero, for example, they are 0.1 to 0.15 for N_2/HC and CO_2/HC pairs. The EOS constants $\Omega_a(T,j)$ and $\Omega_b(T,j)$ are functions of the acentric factor ω_j and the reduced temperature T_{rj}. Table 3.1 shows these constants used in different EOS.

a) For Redlich-Kwong

$$\Omega_a(T,j) = \Omega_{a_0} T_{rj}^{-1/2} \tag{3.19a}$$

$$\Omega_b(T,j) = \Omega_{b_0} \tag{3.20a}$$

b) For Soave-Redlich-Kwong

$$\Omega_a(T,j) = \Omega_{a_0}\left[1+(0.48+1.574\omega_j - 0.176\omega_j^2)(1-T_{rj}^{1/2})\right]^2 \tag{3.19b}$$

$$\Omega_b(T,j) = \Omega_{b_0} \tag{3.20b}$$

c) For Zudkevitch-Joffe

$$\Omega_a(T,j) = \Omega_{a_0} F_{aj}(T) T_{rj}^{-1/2} \tag{3.19c}$$

$$\Omega_b(T,j) = \Omega_{b_0} F_{bj}(T) \tag{3.20c}$$

d) For Peng-Robinson

$$\Omega_a(T,j) = \Omega_{a_0}\left[1+(0.37464+1.54226\omega_j - 0.26992\omega_j^2)(1-T_{rj}^{1/2})\right]^2 \tag{3.19d}$$

$$\Omega_b(T,j) = \Omega_{b_0} \tag{3.20d}$$

Table 3.1: The value of Ω_a and Ω_b for different equations of state.

Equation of state	Ω_{a_0}	Ω_{b_0}
RK, SRK, ZJRK	0.4274802	0.08664035
PR	0.457235529	0.07796074

3.1.3 Vapor/Liquid Equilibrium (VLE)

Phase equilibria are calculated with the equation of state (EOS). The criterion of thermodynamic equilibrium for a two-phase system is that the chemical potential of each component in the liquid phase $\mu_i(x)$ must equal to the chemical potential of each component in the vapor phase $\mu_i(y)$.

$$\mu_i(x) = \mu_i(y) \tag{3.21}$$

Equation 3.21 is true for all components $i = 1,...,N$ (and all phases).
Chemical potential is expressed in terms of fugacity, f_i,

$$\mu_i = RT \ln f_i + \lambda_i(T) \tag{3.22}$$

where $\lambda_i(T)$ are constant terms that are ignored in most calculations.
Substituting Equation 3.22 into Equation 3.21 and arranging the equation, the equal-chemical-potential can be written as

$$f_{Li} = f_{vi}, \qquad i = 1,...,N \tag{3.23}$$

The coefficient of fugacity ϕ is defined as

$$\phi_{Li} = \frac{f_{Li}}{x_i p} \tag{3.24}$$

$$\phi_{vi} = \frac{f_{vi}}{y_i p} \tag{3.25}$$

Equation 3.24 and Equation 3.25 are solved for the coefficient of fugacity for each phase using Equation 3.14 and an appropriate EOS.

The equilibrium ratio or equilibrium constant (K-value) for each component can be defined as

$$K_i = \frac{y_i}{x_i} \tag{3.26}$$

and commonly estimated using Wilson equation [11]

$$K_i = \frac{1}{p_{r,i}} \exp\left[5.3727\,(1+\omega_i)\left(1-\frac{1}{T_{r,i}}\right)\right] \tag{3.27}$$

The mole fractions of each component in the liquid phase (x_i) and vapor phase (y_i) can be defined as

$$x_i = \frac{z_i}{1+(K_i-1)\alpha} \tag{3.28}$$

$$y_i = \frac{K_i z_i}{1+(K_i-1)\alpha} \tag{3.29}$$

where

$$\alpha = \frac{lb\ mole\ of\ the\ vapor\ leaving\ the\ separator\ ,(v)}{lb\ mole\ of\ the\ fluid\ stream\ entering\ the\ separator\ ,(n)}$$

The mole fractions of equilibrium phases and the overall mixture must sum to unity.

$$\sum_{i=1}^{N} y_i = \sum_{i=1}^{N} x_i = \sum_{i=1}^{N} z_i = 1 \tag{3.30}$$

From material balance, the total number of moles in the system, n, equal to the sum of total number of moles in liquid phase at equilibrium, L, and total number or moles in vapor phase at equilibrium, v.

$$n = L+v \tag{3.31}$$

then, obtain

$$\sum_{i=1}^{N} \frac{(K_i-1)z_i}{(v/n)(K_i-1)+1} = 0 \tag{3.32}$$

In summary, the equations of states (EOS's) are used to calculate and describe the volumetric and phase behavior of gas-condensate reservoir. The compositional simulator used in this study incorporates equation of states with generalized form using Martin's equation. The 3-parameter Peng-Robinson equation (PR EOS) is used for this simulation. Flash calculation is used to specify liquid and gas composition obtained from surface separator. The formula including equation of state are computed and processed till final timestep. After that, the results from simulation are analyzed for optimal injection/production strategy.

3.2 Gas Injection in Gas-Condensate Reservoir

A gas-condensate reservoir may be developed in one of two ways as follows:

(a) The reservoir is produced by natural depletion. The produced fluids are gas and condensate liquid hydrocarbon that are ready to be sold.

(b) Injection of all or portion of the produced gas back into the reservoir. This process is called gas cycling or gas recycling interchangeably with gas injection [12]. Gas injection processes are designed to enhance the recovery of oil. The primary objective of gas injection is simply to maintain the reservoir pressure at a level that would sustain existing production rates. Another purpose for pressure maintenance in gas-condensate reservoirs was to avoid low liquids recovery resulting from retrograde condensation. In gas-condensate reservoirs, lean-gas injection can be miscible if the reservoir pressure is above the dew point; otherwise, lean gas can revaporize liquids that dropout by retrograde condensation, which occurs when the reservoir pressure drops below the dew point. This process is called the vaporizing gas miscible drive [14]. A gas recycling project generally ends with a natural depletion after the dry gas has broken through at the production wells and the depletion is continued until the abandonment pressure is reached. Typically, this pressure might be around 10 psia/100 ft.[12].

3.2.1 Flooding Patterns and Sweep Efficiency

Production wells and injection wells are typically arranged in a certain pattern for an EOR project. The most common patterns are,

(a) Two-spot

(b) Three-spot

(c) Regular four-spot and skewed four-spot

(d) Normal five-spot and inverted five-spot

(e) Normal seven-spot and inverted seven-spot

(f) Normal nine-spot and inverted nine-spot

(g) Direct line drive

(h) Staggered line drive

Different areal sweep efficiencies at breakthrough have been reported for a variety of flooding patterns. The most popular pattern for studying is the five-spot pattern. There is satisfactory agreement among most investigators that the five-spot flooding pattern gives the highest sweep efficiency. The areal sweep efficiency at breakthrough was determined by various experimental techniques. The percentage of such areal sweep efficiency performance was calculated for a mobility ratio of unity. Table 3.2 presents the percentage of areal sweep efficiency at breakthrough calculated at unity mobility ratio for different flooding pattern.

Table 3.2: Areal sweep efficiency for various flooding patterns. [15]

Flooding Pattern	**Mobility Ratio**	**Areal sweep efficiency at breakthrough (%)**
Isolated two-spot	1.0	52.5 – 53.8
Isolated three-spot	1.0	78.5
Skewed four-spot	1.0	55.0
Normal five-spot	1.0	105.0
Inverted five-spot	1.0	80.0
Normal seven-spot	1.0	74.0-82.0
Inverted seven-spot	1.0	82.2

The overall efficiency at breakthrough is defined as

$$E = E_A \times E_i \times E_d \tag{3.33}$$

where E_A is areal sweep efficiency, E_i is invasion or vertical sweep efficiency, and E_d is displacement efficiency.

Gas cycling is performed by injecting produced gas from production wells into injection wells. In this study, injection-production well arrangement is selected by considering the highest areal sweep efficiency. Normal and inverted five-spot flooding patterns have been studied and reported to have the highest sweep efficiency at breakthrough. Figure 3.2 shows the schematic of five-spot flooding pattern. The injection well is located at the center of a square defined by four production wells.

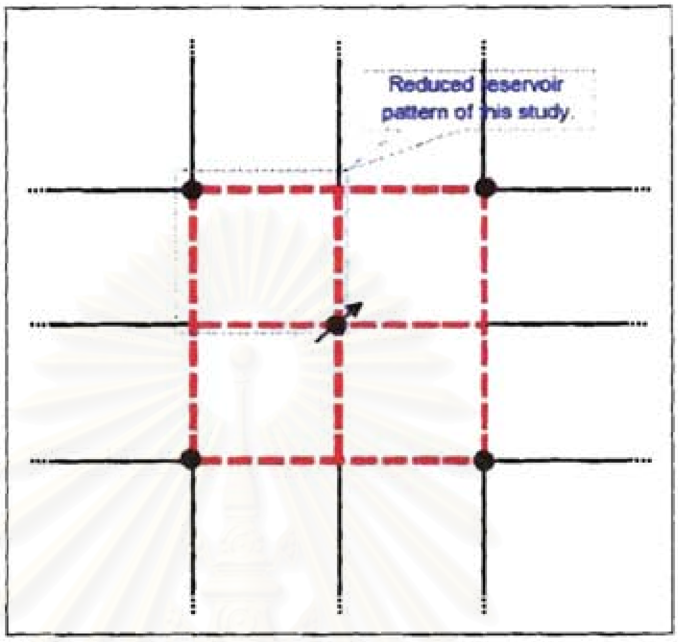


Figure 3.2: Flooding pattern (Five-Spot; Inverted five-spot).

3.2.2 Miscible Fluid Displacement

A miscible fluid displacement would be defined as a displacement process where no phase boundary or interface exists between the displaced and displacing fluids. In this process, the displacing fluid is miscible, or will mix in all proportions with the displaced fluid. According to the definition described above, the main miscible fluid displacement processes are as follows: [13]

(1) High pressure dry gas miscible displacement.

(2) Enriched gas miscible displacement.

(3) Miscible slug flooding, where the leading edge of the slug is miscible with the displaced fluid.

(4) Aqueous and oleic miscible slug flooding (such as several of the alcohols).

(5) Carbon dioxide, flue or inert gas displacements.

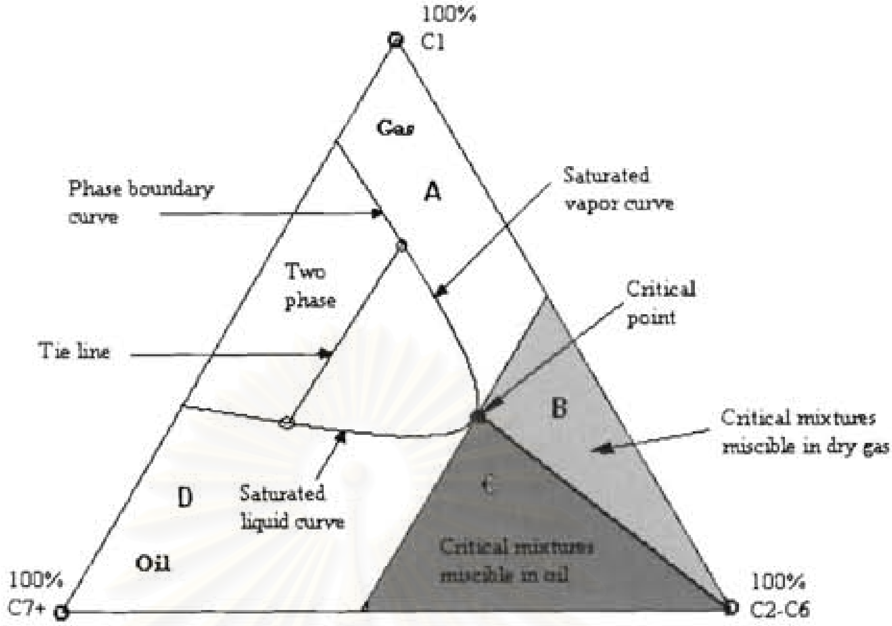


Figure 3.3: Ternary diagram for a hydrocarbon system.

The basic process of hydrocarbon miscible, fluid-fluid displacement can be described using a ternary diagram for a hydrocarbon system as shown in Figure 3.3. The diagram is a visual picture of phase behavior for a system consisting of three-component: methane (C_1), the intermediates ($C_2 - C_6$), and the heavier components (C_{7+}). The phase behavior of gases and liquids are a function of pressure, temperature and composition. Region A is gaseous which mostly methane (C_1) and region D is liquid which mostly heptanes plus (C_{7+}) for reservoir pressure and temperature. The intermediate component (region B and C) possibly incline to the prevailing phase both gaseous and liquid depend on particular temperature and pressure. The phase boundary curve enfolds two phase region that gas and liquid exist. The tie line shows two points connection of saturated vapor curve and saturated liquid curve that represent the equilibrium composition of gas and liquid. For a high pressure dry-gas displacement (lean gas injection), the injected gas represented by region A will be miscible with the displaced fluid that is rich in intermediate components represented by region C. The injected gas will vaporize the intermediate components in the displaced fluid until a zone is totally miscible. This process is vaporizing gas miscible drive as stated previously.

3.3 Reservoir Simulation

Reservoir simulation is an efficiency tool to describe the flow of multiple phases quantitatively in a heterogeneous reservoir. It is, therefore, used and applied widely in order to determine reservoir performance, investment strategy and reservoir management.

The reservoir model is constructed by amount of established volume elements namely 'grid blocks' that represent the geological reservoir construction. A appropriate equations were used to replace the partial differential equation that describes fluid flow in the reservoir and can be solved numerically. Input data such as basic reservoir properties are required in each grid block. Similarly, well locations and well conditions have to be specified. The required flow in/out rate is specified as a function of time. The appropriate equations are solved for pressures and saturations of each block as well as the production of each phase from each well.

3.3.1 Compositional Simulation

Compositional simulation [15] is a computer run of a reservoir model over time to examine the flow of fluid within the reservoir and from the reservoir. The compositional simulator is designed to describe hydrocarbons fluid behavior when the composition of the hydrocarbons is changing with regard to temperature and pressure. The changing of hydrocarbons fluid occurs with the reservoir contained either condensate or volatile crude oil. The compositional simulator incorporates with cubic equation of state, pressure dependent K-value and black oil fluid treatment. It has several equations of state implemented through Martin's generalized equation. These include the Redlich-Kwong, Soave-Redlich-Kwong, Zudkevitch-Joffe, and Peng-Robinson.

The compositional simulation requires additional data on top of those required for conventional simulation. These required data are phase-equilibrium information, phase densities, phase viscosities, and compositions of reservoir hydrocarbons and injected hydrocarbons. Moreover, separator conditions through which hydrocarbons are produced are needed.

3.3.2 Formulation of Simulation Equations

The basic equations of reservoir simulation are obtained by combining conservation of mass (material balance equation) with conservation of momentum (Darcy's Law). These equations along with appropriate constraints, constitutive relations, and initial conditions can be solved by approximate numerical techniques to predict the performance of reservoirs under different operating conditions.

3.3.2.1 Mass Conservation

Mass conservation states that the accumulation of mass generated in the control volume must equal to the difference between the mass flowing into the control volume and mass flowing out the control volume. For one dimension, the control volume can be illustrated as shown in Figure 3.4.

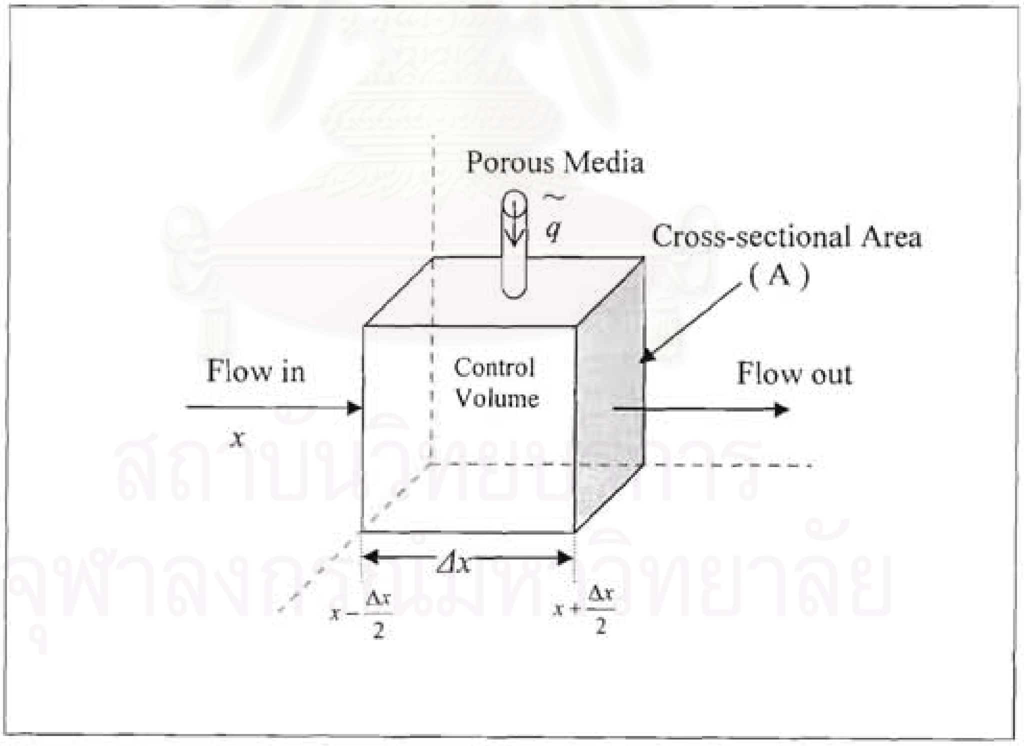


Figure 3.4: Fluid flow in porous media.

From definition, the mass conservation can be written in simple equation as follow:

$$[\text{Mass in}] - [\text{Mass out}] + [\text{Production/Injection}] = [\text{Accumulation}] \qquad (3.33)$$

The mass accumulation is due to compressibility as the pressure changes.

From Figure 3.4,

$\dot{m}$ = Mass flux (mass per unit area per unit time)

m = Mass per unit volume = $\rho\phi$

$\tilde{q}$ = Volumetric flow rate

$\rho(x,t)$ = Fluid density (mass/volume)

$\phi(t)$ = Rock porosity in control volume

$A\Delta x$ = Volume of control volume = V_b

Remark : $\tilde{q} > 0$ for injection (+) into system

$\tilde{q} < 0$ for production (-) out of system

Over the time interval Δt, the material balance equation is

$$\text{Mass in} = \left(\dot{m}\Big|_{x-\frac{\Delta x}{2}}\right) A\Delta t \qquad (3.34)$$

$$\text{Mass out} = \left(\dot{m}\Big|_{x+\frac{\Delta x}{2}}\right) A\Delta t \qquad (3.35)$$

Accumulation = [mass in place at time $t+\Delta t$] - [mass in place at time t]

$$= V_b\left(m\big|_{t+\Delta t} - m\big|_{t}\right) \qquad (3.36)$$

where $\dot{m}$ = mass flux in or out of control volume = mass flow/area/time

Then,

$$\left(\dot{m}\Big|_{x-\frac{\Delta x}{2}}\right) A\Delta t - \left(\dot{m}\Big|_{x+\frac{\Delta x}{2}}\right) A\Delta t + \rho\tilde{q}\Delta t = V_b\left(m\big|_{t+\Delta t} - m\big|_{t}\right) \qquad (3.37)$$

Dividing through by Δt, arranging the equation, and multipling the first term by $\frac{\Delta x}{\Delta x}$,

we obtain

$$\frac{-\left[\dot{m}A\Big|_{x+\frac{\Delta x}{2}} - \dot{m}A\Big|_{x-\frac{\Delta x}{2}}\right]\Delta x}{\Delta x} + \rho\tilde{q} \quad = \quad \frac{V_b\left(m\big|_{t+\Delta t} - m\big|_t\right)}{\Delta t} \tag{3.38}$$

Taking the limit as $\Delta x \to 0$, $\Delta t \to 0$, and dividing through by V_b, we obtain

$$\frac{-\partial \dot{m} A \Delta x}{\partial x \,.\, V_b} + \frac{\rho \tilde{q}}{V_b} = \frac{\partial m}{\partial t} \tag{3.39}$$

Then, the mass conservation in the x-direction becomes

$$-\frac{\partial \dot{m}}{\partial x} = \frac{\partial}{\partial t}(\phi\rho) - Q \tag{3.40}$$

3.3.2.2 Solution of Equations

The major solution approaches that can be used to solve system of equations are as follows:

(1) Fully Implicit Method or implicit pressure implicit saturation method.

This approach uses saturations at the old time step (S^n) to implicitly calculate pressures and saturations at the new time step (p^{n+1} and S^{n+1}). The pressures and saturations at the new time level are determined simultaneously. The fully implicit method is totally stable, i.e., no limit for the time step size. However, numerical dispersion, an error in calculating the movement of saturation front becomes more pronounced when the time step size increases.

(2) IMPES or Implicit Pressure and Explicit Saturation method.

This approach uses saturations and pressures at the old time step (p^n) to implicitly calculate pressures at the new time step (p^{n+1}), then uses saturations at the old time step (S^n) and the pressures at the current time step (p^{n+1}) to explicitly calculate saturations at the new time step (S^{n+1}). The IMPES method has a few severe stability constraints such as a throughput for a grid block cannot exceed 10% of the pore volume and time step lengths cannot be large.

(3) Adaptive IMplicit method (AIM) [23] is a compromise between the fully implicit and IMPES procedures. Cells with a high throughput ratio are chosen to be implicit for stability and to obtain large time steps, while the majority of cells can still be treated as IMPES where the cells have a low throughput ratio. The target fraction of implicit cells in a compositional run is 1%. The fully implicit technique does more calculations in a time step than the IMPES procedure, but is stable over longer time steps. The unconditional stability of the fully implicit technique means that a fully implicit simulator can solve problems faster than the IMPES technique by taking a significantly longer time step.

3.4 Description of Reservoir Model

The reservoir model for compositional simulation study of a gas-condensate reservoir was constructed as follows:

1. Describe the general reservoir model data in case definition such as type of simulator, structure/dimensions, type of PVT, geometry type and grid type, number of components, and pressure saturation solution type.
2. Define grid properties which are active grid blocks, porosity, permeability, net thickness, and reservoir geometry features.
3. Define PVT data for reservoir gas-condensate, water PVT properties, fluid densities at surface conditions, and rock properties. The fluid compositional data are also identified in this step: component names and component properties such as critical properties, molecular weight, and acentric factor.
4. Describe fluid saturation function and reservoir initial equilibration: initial composition, initial water saturation, initial gas saturation, initial pressure, and initial dew point.
5. Select an appropriate type of simulation. Reservoir simulator is classified as different types based on the following characteristics:

a) Fluid description

(a) Black oil

(b) Equation of state (EOS) –compositional

(c) Chemical

b) Temperature

(a) Isothermal

(b) Thermal

c) Simulation solution method

(a) IMPES

(b) Fully implicit

(c) AIM

d) Coordinates systems

(a) Cartesian

(b) Radial

(c) Spherical

In this study, the reservoir simulator ECLIPSE 300 specializing in compositional modeling was used. ECLIPSE 300 is a compositional and isothermal simulator. The adaptive implicit (AIM) mode which makes implicit calculation when necessary was selected as simulation solution method. The selected grid system is Cartesian coordinate.

This simulation application examines the change of the fluid phase according to hydrocarbon composition and considers the flow behavior of fluid in porous media. This chapter discusses the detail of reservoir simulation for injection and production scenarios, and workflow for reservoir model construction. The simple conventional wellbore model was established from reservoir depth and reservoir thickness. The reservoir was assumed to be homogeneous and the grid block was defined from choosing an appropriate grid block size. Finally, basic reservoir properties and hydrocarbon composition were fed into the model to complete the reservoir model.

3.4.1 Review of Reservoir Model

A simple reservoir model with plane geometry and homogeneous reservoir properties was used in this study. The gas-condensate reservoir is approximately 490,000 ft^2 in area and 8,000 ft TVD (depth of top-face) below the surface. The reservoir thickness is 100 ft. The five-spot injection pattern was selected for the study. Since a quarter of the pattern has no-flow boundaries on its four sides, a quarter five-spot pattern acts as a closed boundary reservoir and has been typically used in the literature. Thus, the reservoir defined in this study is a quarter five-spot with an injector at one of the corners, and a producer at the opposite corner. A schematic drawing of injection well and production well on the five-spot pattern is shown in Figure 3.5.

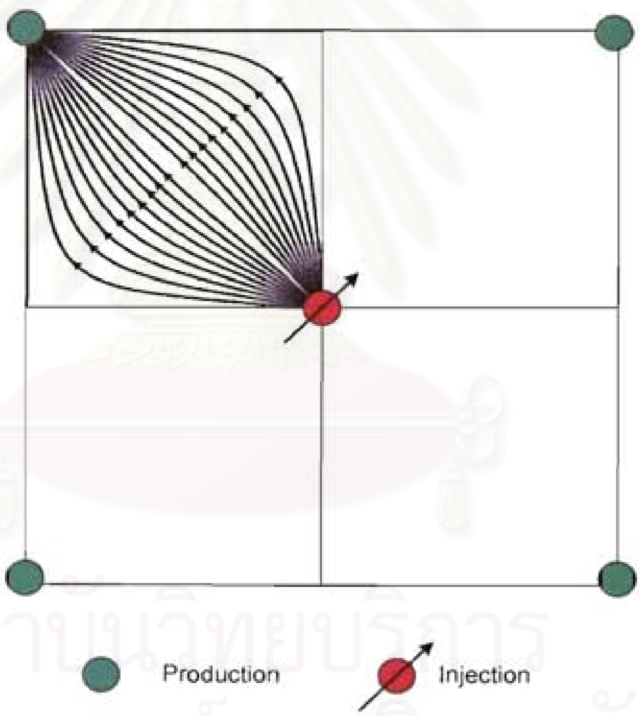


Figure 3.5: Injection well and production well on the five-spot pattern.

3.4.2 Wellbore Model

The production and injection wells in this study have the same type wellbore diameter of 3-1/2 inches with an inside diameter of 2.992 inches. The perforation interval is from the top to the bottom of the reservoir. The schematic of wellbore and configuration is shown in Figure 3.6.

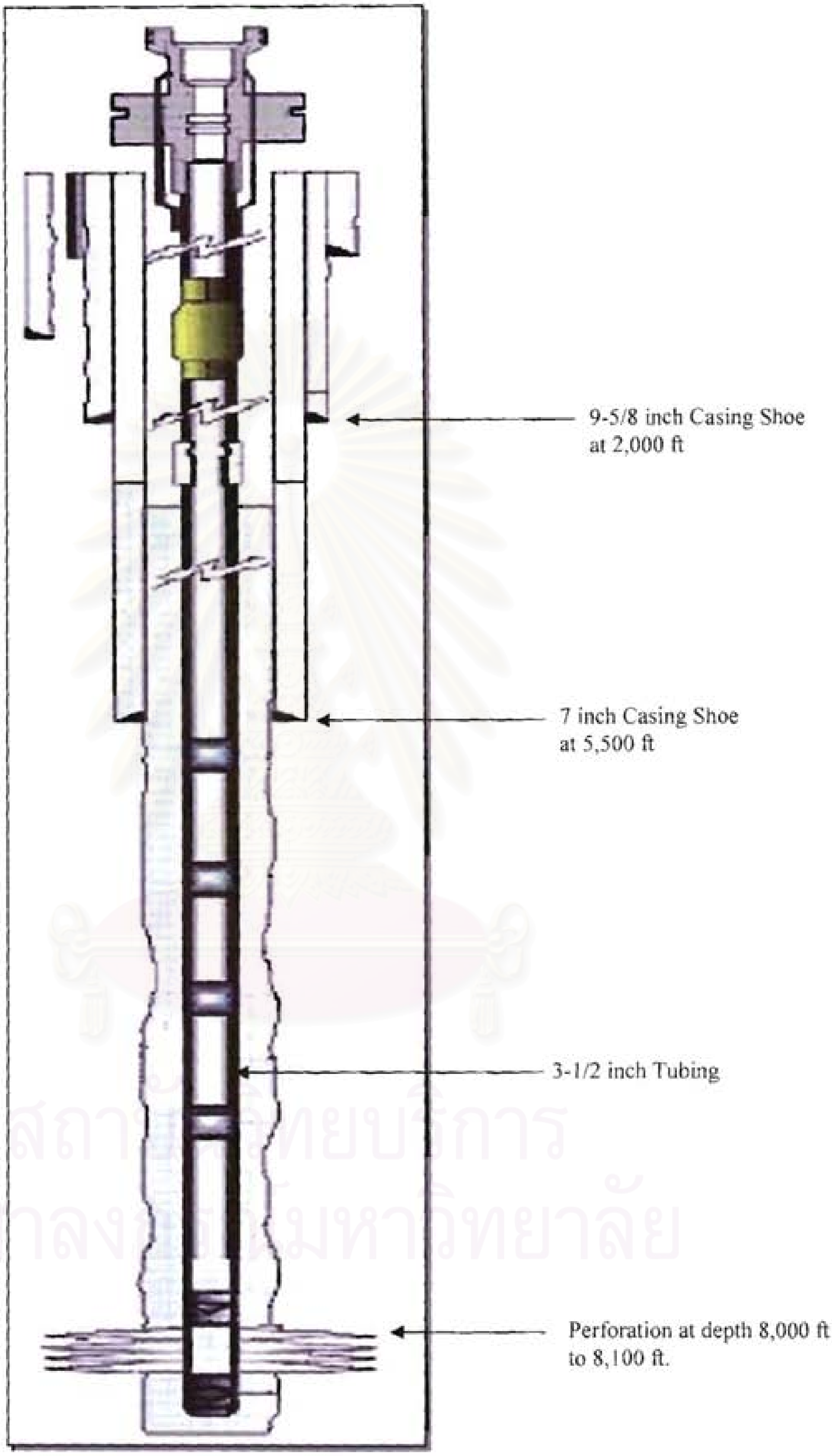


Figure 3.6: Casing and tubing flow model used in this study.

3.4.3 Input Data for Reservoir Simulation

The required data for the compositional simulation are physical characteristics of the reservoir and wells, phase equilibrium data, reservoir and fluid properties, and injection/production scenario. The PVT properties, and rock properties are tabulated in Table 3.3.

a) Case Definition

Simulator:	Compositional	
Model Dimensions:	Number of cells in the x direction	35
	Number of cells in the y direction	35
	Number of cells in the z direction	8
Grid type:	Cartesian	
Geometry type:	Block Centered	
Oil-Gas-Water Options:	Water, Gas Condensate (ISGAS)	
Number of Components:	10	

Pressure Saturation Options (Solution Type): AIM

b) Grid

Properties:	Porosity		=	0.165	
	Permeability	k-x	=	10.85	mD
		k-y	=	10.85	mD
		k-z	=	1.27	mD
	Net thickness	100	feet (12.5 x 8)		
Geometry:	Grid data units				
	X Grid block sizes		=	20 ft	
	Y Grid block sizes		=	20 ft	
	Z Grid block sizes		=	12.5 ft	
Depth of Top face			=	8,000 ft	

Table 3.3: PVT properties of reservoir fluids and rock properties.

Water PVT Properties	Reference pressure(Pref)	3000	psia
	Water FVF at Pref	1.060897	rb/stb
	Water viscosity at Pref	0.1892652	cp
	Water viscosibility	5.376165E-6	/psi
Fluid Densities at Surface Conditions	Oil density	49.99914	lb/ft^3
	Water density	62.42797	lb/ft^3
	Gas density	0.04947417	lb/ft^3
Rock Properties	Reference Pressure	3000	psia
	Rock Compressibility	2.403571E-6	/psi
Fluid property	Dew Point Pressure	2,150	psia

c) SCAL (Special Core Analysis)

Initial reservoir properties

Initial Water Saturation (SWAT) : 0.11

Initial Gas Saturation (SGAS) : 0.89

Initial Pressure : 3,000 psia

The initial water/gas saturation used in this study is an average value from one gas field in the Gulf of Thailand. The dew point pressure of gas condensate is obtained from the PVT data of one sample in this field. The oil saturation and oil relative permeability relation is tabulated in Table 3.4 and shown in Figure 3.7. Two types of relative permeability, K_{row} and K_{rowg}, are presented where K_{row} is the oil relative permeability for a system with oil and water only and K_{rowg} is the oil relative permeability for a system with oil, water and gas.

Table 3.4: Oil saturation and oil relative permeabilities.

So	K_{row}	K_{rowg}
0	0	0
0.2	0	0
0.32	0.00463	0.015625
0.44	0.037037	0.125
0.56	0.125	0.421875
0.68	0.296296	1
0.95	1	1

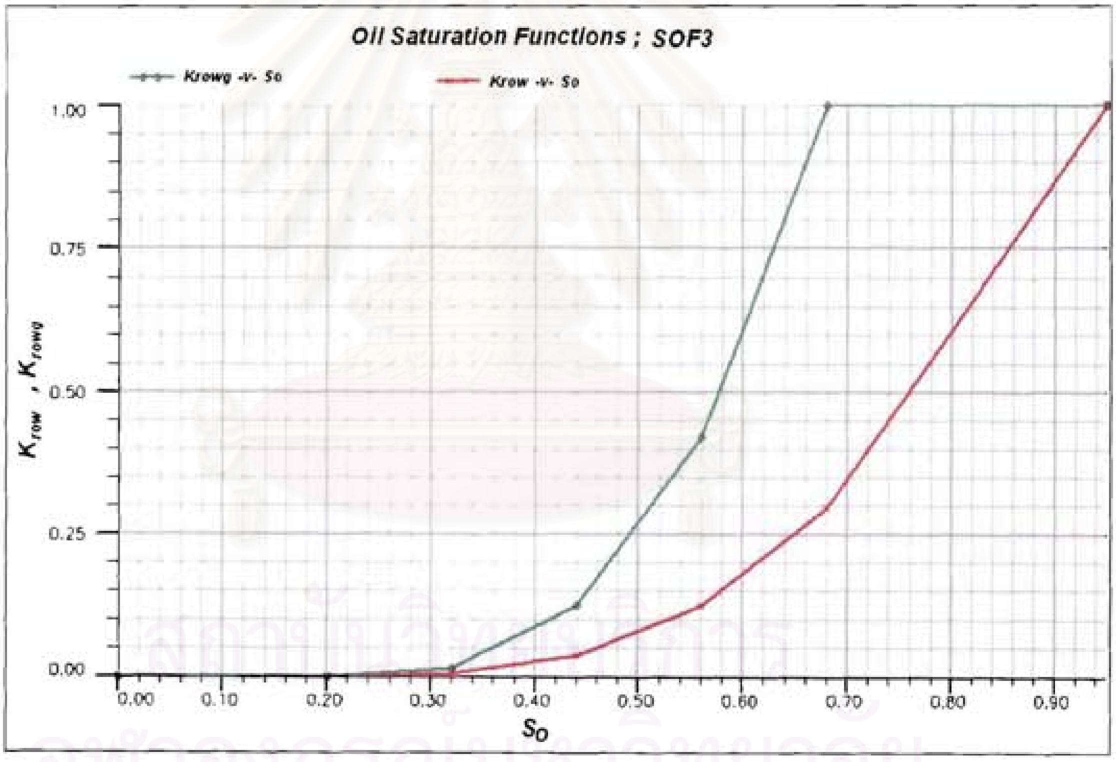


Figure 3.7: Relative permeability function.

Table 3.5: Water saturation and water relative permeability.

Sw	Krw
0.11	0
0.157	0
0.216	0
0.313	0.02
0.44	0.06
0.56	0.10
0.68	0.15
0.80	0.30
0.90	0.65

The water saturation and water relative permeability relation is tabulated in Table 3.5 and shown in Figure 3.8.

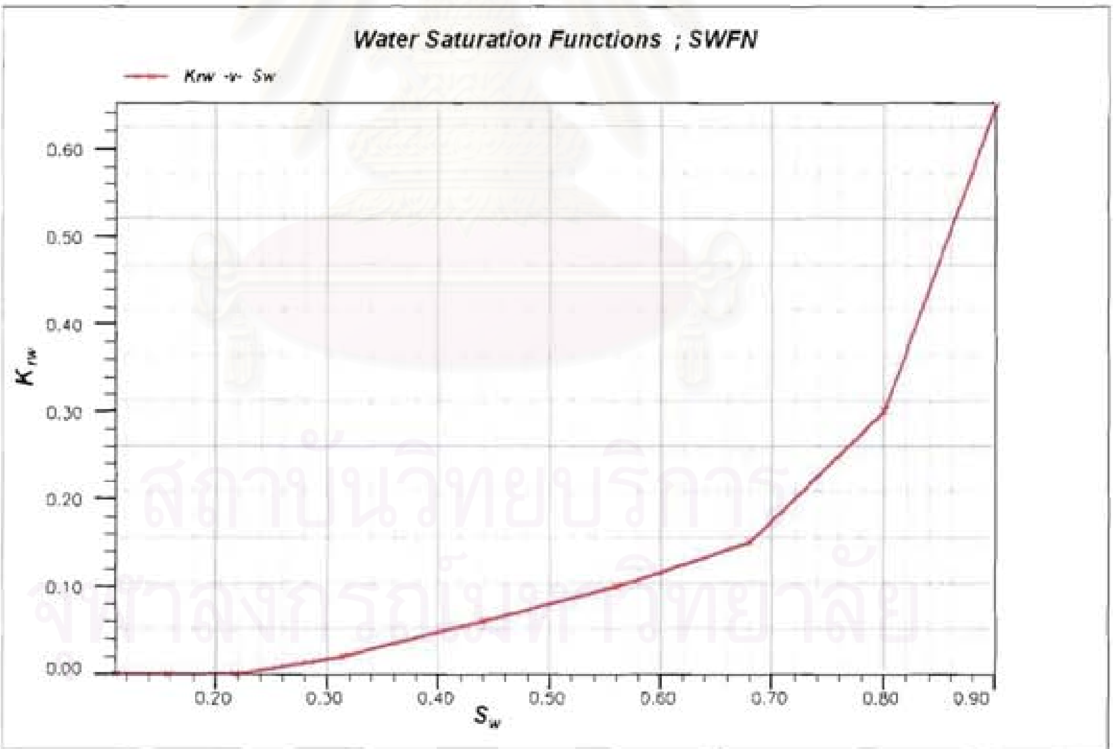


Figure 3.8: Water relative permeability as a function of water saturation.

The gas saturation and gas relative permeability relation is tabulated in Table 3.6 and shown in Figure 3.9.

Table 3.6: Gas saturation function and relative gas permeability.

Sg	Krg
0	0
0.1	0
0.2	0
0.3	0.2
0.4	0.4
0.6	0.85
0.7	0.90
0.8	0.92
0.9	0.95
0.95	0.95

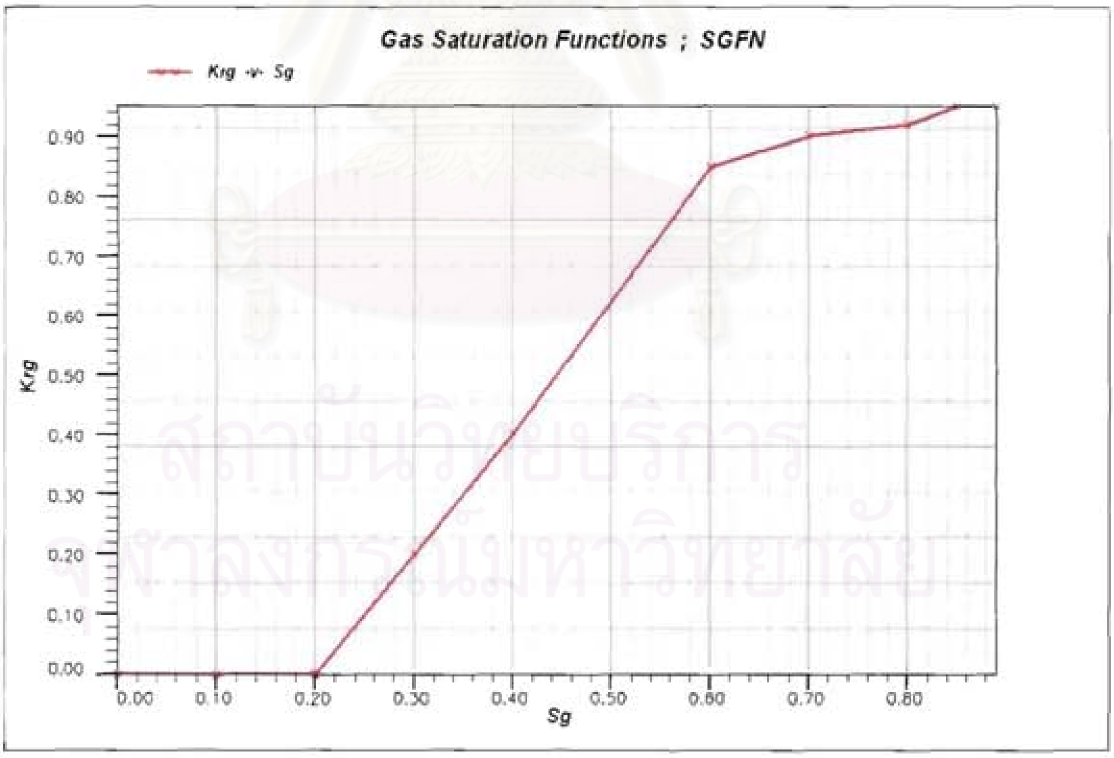


Figure 3.9: Gas relative permeability as a function of gas saturation.

The water saturation and capillary pressure is tabulated in Table 3.7, and their relation curve is shown in Figure 3.10.

Table 3.7: Water saturation and capillary pressure.

Sw	Pc (psia)
0.11	250
0.157	53
0.216	13
0.313	1
0.44	0
0.56	0
0.68	0
0.80	0
0.90	0

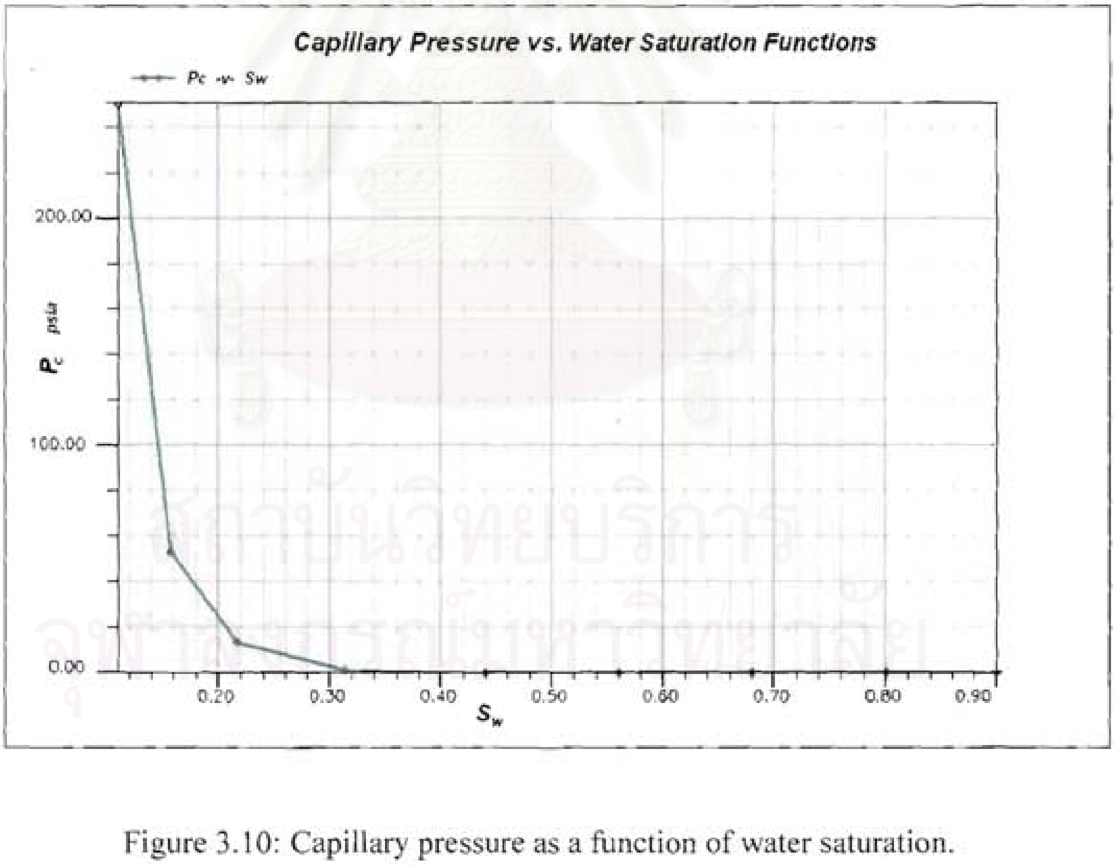


Figure 3.10: Capillary pressure as a function of water saturation.

Gas-condensate reservoir properties in this compositional simulation were obtained from average values of special core analysis data of samples collected from one of the gas fields in the Gulf of Thailand.

d) Initialization

The initial fluid composition in gas-condensate reservoir was specified in NEI section of simulation program. The NEI (Non-Equilibrium Initialisation) is used to generate consistent oil and gas compositions for each cell. The initial composition for the study is specified and tabulated in Table 3.8

Table 3.8: Initial fluid composition of reservoir fluid.

NEI (Non-Equilibrium Initialisation)	
Component	**Fraction**
Methane	0.59991
Ethane	0.084326
Propane	0.063988
Isobutane	0.034127
Normal butane	0.038989
Isopentane	0.014286
Normal pentane	0.013988
Hexane	0.072718
Hepthane plus	0.065366
Carbon dioxide	0.012302

CHAPTER IV

ECONOMICS EVALUATION

Economic analysis will be performed for each specific case in order to assess pros and cons in term of monetary value among the studied cases. This result can be used as criteria for optimizing the injection and production strategy.

4.1 Time Value of Money

Each project investment involves capital budgeting which is the subtraction of outflows from inflows. Since these various flows occur at disparate times in the future, they must be adjusted to an equivalent value at an identical time. The differences in the values of the flows are based on the **time value of money.**

Time value of money means that a unit of money today is worth than a unit of money in a year later or in the future. This is because the value of money today will be increased by percent interest or inflation. Thus, project investment must consider cash flows originating at different times on an equal basis and apply interest rate to each of the flows so that cash flows can be expressed at the same point of time. In capital budgeting calculations, cash flows are usually brought back from various points in the future to the beginnings of the project-time zero. It is then said that all cash flows are **discounted** to the present to obtain a present value. The two methods that do discount cash flows to a present value are **net present value (NPV)** and **internal rate of return (IRR)**. Both of these techniques satisfy the two major criteria requirements for evaluating the project: use of cash flow and use of the time value of money [17,18,19].

4.2 Economic Decision Tools

Various methods are used to make capital budgeting decisions, that is, to evaluate the worth of investment projects. The used methods must have sufficient requirement in order to judge and cover all economic criteria.

4.2.1 Net Present Value (NPV)

Net present value (NPV) of the project investment is the difference between the total present value of each cash inflows and the total present value of each cash outflows. The net present value (NPV) of a project can be calculated by discounting all flows to the present and subtracting the present value of all outflows from the present value of all inflows. Therefore, the net present value of an investment can be interpreted as

$$NPV = \sum_{t=1}^{n} \frac{R_t}{(1+k)^t} - \sum_{t=0}^{n} \frac{O_t}{(1+k)^t} \tag{4.1}$$

where t = time period (e.g.,year)

n = last period of project

R_t = cash inflow in period t

O_t = cash outflow in period t

k = discount rate (cost of capital)

The discount rate, k, is the interest rate used to evaluate the project. This rate represents considered the minimum required rate of return. A positive value of NPV is financially acceptable for project investment. On the other hand, a negative value of NPV indicates financially unacceptable investment. If NPV is exactly zero, the project appears to be acceptable since the return equals the required rate of return.

4.2.2 Internal Rate of Return (IRR)

The internal rate of return (IRR) is the interest value or discount value that equates the present value of future inflows of a project to the initial cost or outlay. The equation for calculating the internal rate of return is simply the NPV formula equal to zero:

$$\sum_{t=1}^{n} \frac{R_t}{(1+r)^t} - \sum_{t=0}^{N} \frac{O_t}{(1+r)^t} = 0 = NPV \qquad (4.2)$$

where r = internal rate of return (IRR)

Using Equation 4.2, the internal rate of return (IRR) can be solved. The accepting/rejecting criteria for the internal rate of return is based on the comparison of IRR with discount rate used in that certain project. If internal rate of return is larger than discount rate (IRR > k), it signals acceptance. If internal rate of return is smaller than discount rate (IRR < k), the project is considered unacceptable. If both values are equal (IRR = k), the project should be accepted at the margin.

4.2.3 NPV versus IRR

Net present value (NPV) and internal rate of return (IRR) are applicable to validate project investment and capital decision. Both methods have their significant criteria of judgment based on individual case of project. For an independent project, either NPV or IRR can be used with confidence. These two methods give corrected accepting/rejecting indicators when

1. NPV > 0 , IRR > k
2. NPV = 0 , IRR = k
3. NPV < 0 , IRR < k

If NPV and IRR are consistent, we will have a high confidence of making the right decision for project investment. The two variables, however, may give inconsistent or conflicting values. For instance, NPV may suggest that the project should be accepted while IRR indicates the opposite. This event can occur when the following conditions are present.

1. The initial costs of two considered options are different.
2. The patterns of the subsequent cash inflow are different in the project; e.g. option I obtains early cash inflow with only one or two spot of large value but option II gains slightly increasing cash inflow through the end of project.

4.2.4 Payback Period Analysis

The payback period is the expected number of years of operation required to recover an investment. When project cash flows are discounted using an appropriate cost of capital, the discounted payback period is the expected number of years required to recover the initial investment from discounted net cash flows. Payback period is calculated using actual or discounted net cash flows. In equation form, the payback period is

$$\text{Payback Period} = \text{Number of Years to Recover Investment}$$

The shorter the payback period, the more attractive the investment is.

In this study, the financial aspect of each production profile of condensate reservoir is evaluated using economic decision tools mentioned above: NPV, IRR, and Payback Period. The assumptions for this economic evaluation are:

a) Each production profile represents an independent project.
b) Oil price equal to 62.5 US$/bbl
c) Gas price equal to 3.5 US$/MMBTU
d) Constant interest rate at 10 %
e) Total fixed cost/investment cost of production well and injection well equal to 1,200,000 US$.
f) Total cost of compressor is 2,725,000 US$

g) Apply linear depreciation for salvage cost of compressor, and compressor life time is defined at 5 years.

h) Operating cost varies only on electricity consumption.

i) The gas processing cost is not accounted in the economic evaluation.

j) The composition of injection gas is constant through out the entire production period.

k) The existing production facility can handle all the produced gas and condensate. Therefore, the cost of production facility is not considered.

l) The economic limit for minimum gas production rate is 100 MSCF/D

m) The economic limit for minimum oil production rate is 3 STB/D for production by natural depletion. In case of gas cycling and timely gas injection, this value changes with production/injection rate as shown below:

Gas production rate (MSCF/D)	Minimum oil rate (STB/D)
1,000	4.03
2,000	5.06
3,000	6.10
4,000	7.13
5,000	8.16
6,000	9.19
7,000	10.22
8,000	11.25
9,000	12.29
10,000	13.32

In this study, additional cost, or investment is not considered during production period. The capital cost is invested since starting the project; therefore, net present value (NPV) is used as economical criteria of each production profile. In additional, internal rate of return (IRR) may be used for making decision. The payback period is calculated using discounted net cash flow.

CHAPTER V

SIMULATION RESULT

In this chapter, the productions of gas-condensate reservoir simulated under different production/injection scenarios are reported. The results are discussed in term of production life, oil and gas production volume, and economic.

In this study, three different sets scenarios were simulated. The gas production rate and a bottom hole pressure target of 500 psia are used for production well control. A common economic limit was applied to all cases. The economic limits are defined at minimum gas rate of 100 MSCF/D and minimum oil production rates that varied with each scenario. The three scenarios are

1. Natural depletion of gas-condensate reservoir

In this scenario, the gas-condensate reservoir is developed by natural depletion. The production is simulated with one production well located at the center of reservoir. The schematic of well and reservoir for this scenario is shown in Figure 5.1.

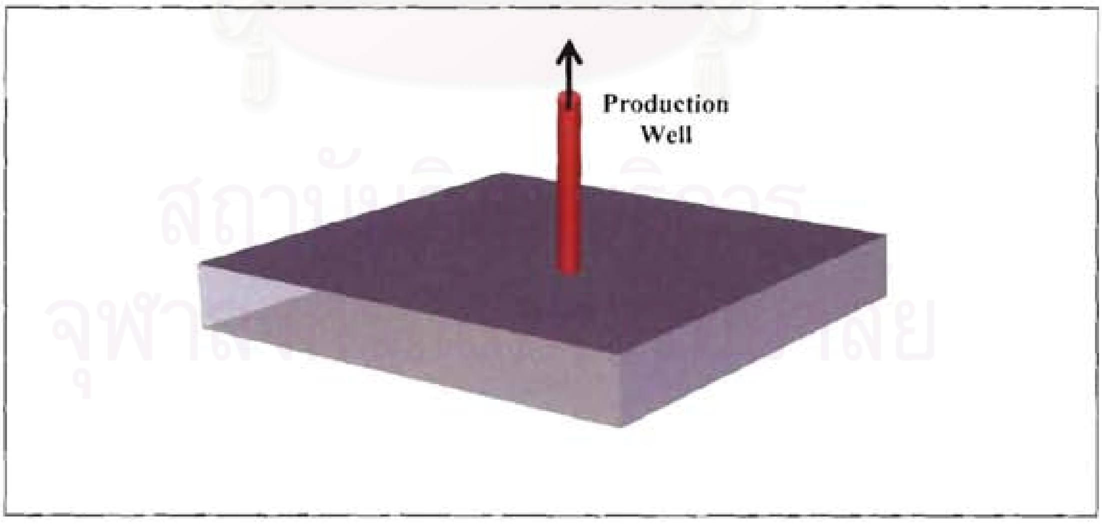


Figure 5.1: A production well in gas-condensate reservoir when produced by natural depletion.

2. Production of gas-condensate reservoir with gas cycling

In this scenario, the gas-condensate reservoir is developed by gas cycling. The production is from one of the wells, and gas is injected into another well for reservoir pressure maintenance. The schematic of well and reservoir for this scenario is shown in Figure 5.2.

3. Production and timely gas injection

In this scenario, the gas-condensate reservoir initially has two production wells. After a certain period of time, one production well is switched to injection well. The schematic of well and reservoir for this scenario is the same as that in scenario 2 as shown in Figure 5.2.

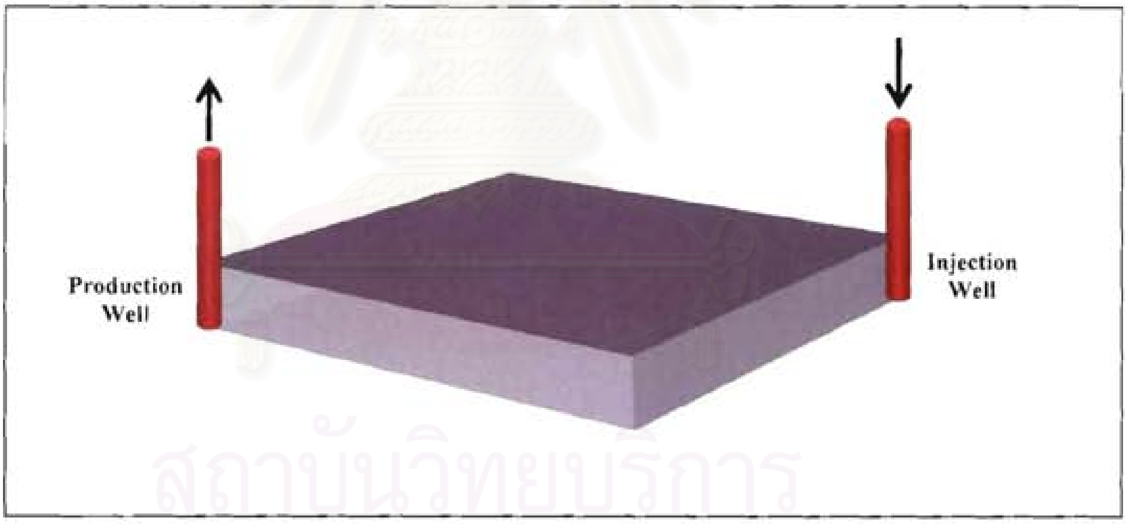


Figure 5.2: A production well and an injection well in gas-condensate reservoir for production with gas cycling.

5.1 Production of Gas-Condensate Reservoir with Natural Depletion

In this scenario, the production of gas-condensate reservoir is simulated to produce by natural depletion method. The gas production rate is defined and input in the simulator as the control variable. The maximum gas production rate is varied in the range of 1,000 MSCF/D to 10,000 MSCF/D in order to observe the production life and cumulative production of oil and gas. For each simulated production rate, the gas production rate is kept constant as long as the reservoir can sustain such rate. The bottom hole pressure declines as the production of gas-condensate reservoir keeps onwards. At a certain reservoir condition, the gas production rate drops, and gas is produced till abandonment. The gas production rate (GPR) and oil production rate (OPR) are shown in Figures 5.3 and 5.4, respectively. The gas production total (GPT) and oil production total (OPT) are shown in Figures 5.5 and 5.6, respectively. Table 5.1 summarizes the cumulative production of gas and oil and the production life. Figure 5.7 depicts the oil and gas production total as a function of maximum gas production rate. Figure 5.8 plots the production life as a function of maximum gas production rate. Figure 5.9 shows the field saturation of oil and gas at certain gas production rate. Figure 5.10 the relationship between gas production rate, oil production rate, and bottom hole pressure (BHP) at certain gas production rates.

The performance of gas-condensate reservoir with natural depletion can be summarized as follows:

a) When the maximum gas production rate increases, the production life declines. The production lives are drastically reduced in the initial range of production rate of 1,000 – 3,000 MSCF/D. For production rate of 4,000 – 10,000 MSCF/D, the production lives are slightly different as shown in Figure 5.8.

b) The production total of oil and gas do not have a significant change when producing with various high maximum gas rates. The total production volume of oil and gas fall in a narrow range of 86,635 – 87,776 STB and 1,021.8 – 1,023.0 MMSCF, respectively as tabulated in Table 5.1. For each gas production rate specified, the oil production rate starts to decline sooner than the gas rate. This oil rate reduction is caused by the fact that the reservoir pressure falls below the dew point pressure, and then gas condenses and is traps in the reservoir. The amount of condensate in the reservoir increases as the reservoir pressure drops causing a slightly increase in oil production. However, at low pressure, the condensate re-vaporizes into the gas phase, resulting in a decrease in oil production.

c) When the gas-condensate reservoir is produced at a high gas production rate, the reservoir pressure falls below the dew point pressure very quickly. High molecular weight hydrocarbons start to condense into the liquid form in the reservoir very early. The condensate volume then has a declining trend as the gas rate increase.

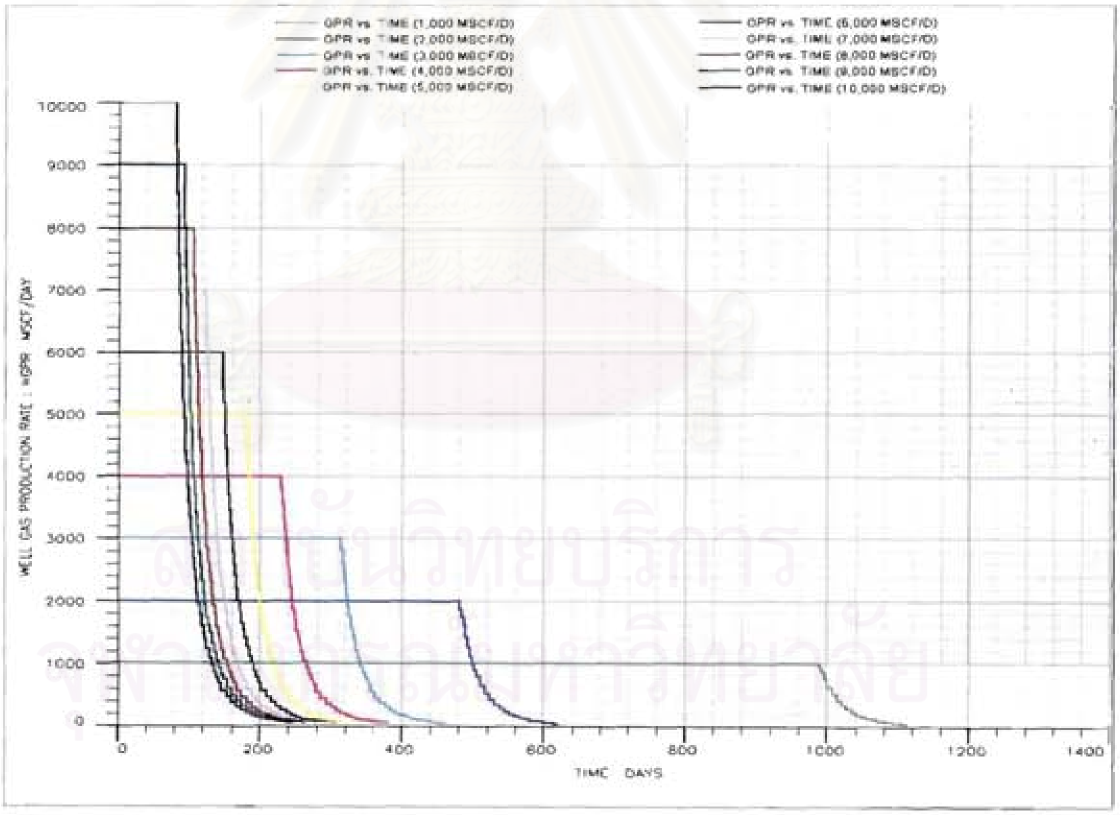


Figure 5.3: Gas production rates (GPR) for production with natural depletion.

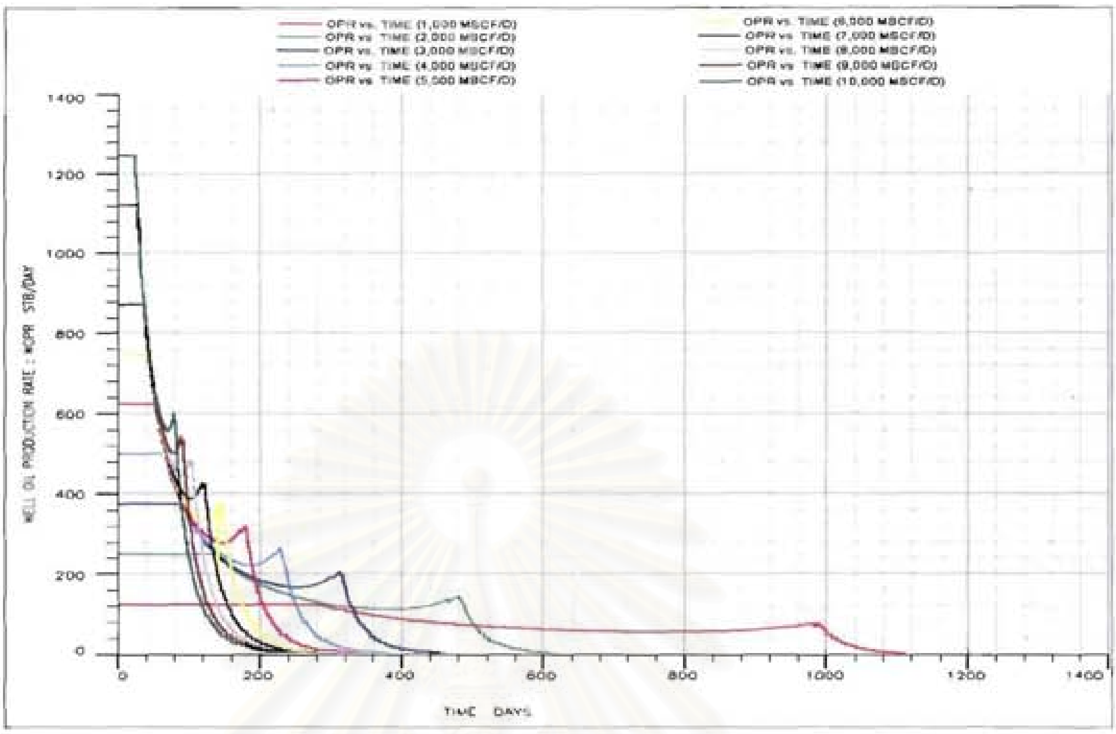


Figure 5.4: Oil production rate (OPR) for production with natural depletion.

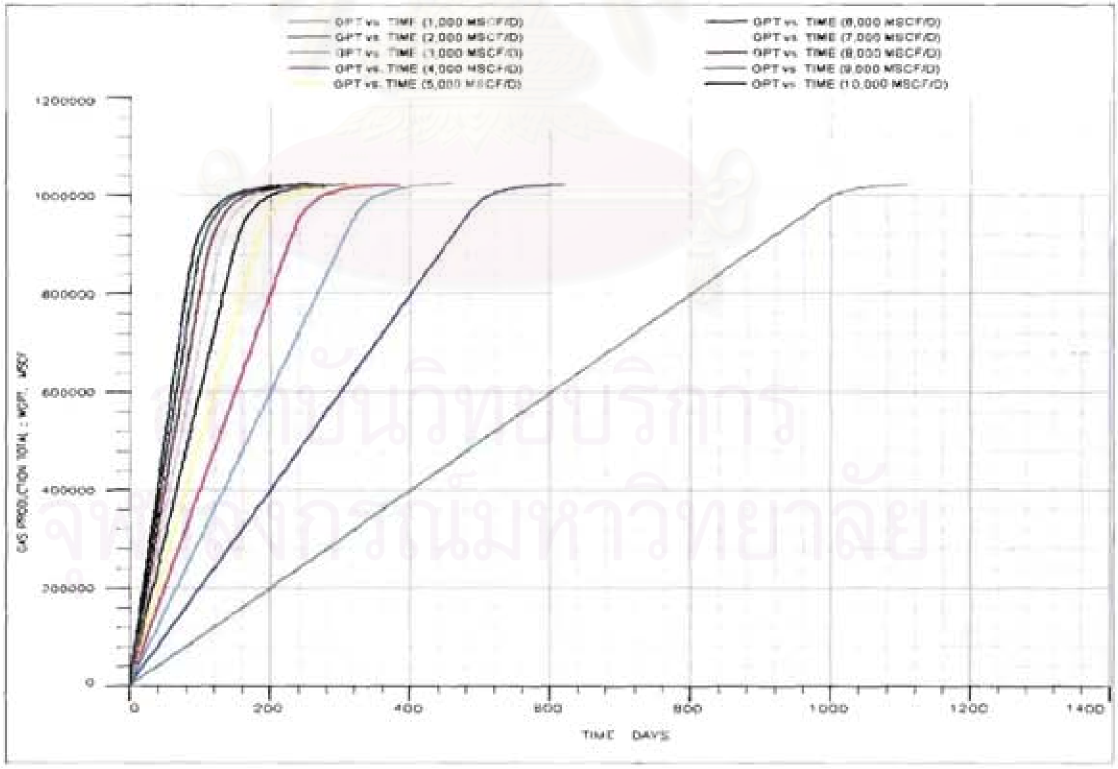


Figure 5.5: Gas production total for maximum gas production rate between 1,000 - 10,000 MSCF/D by natural depletion.

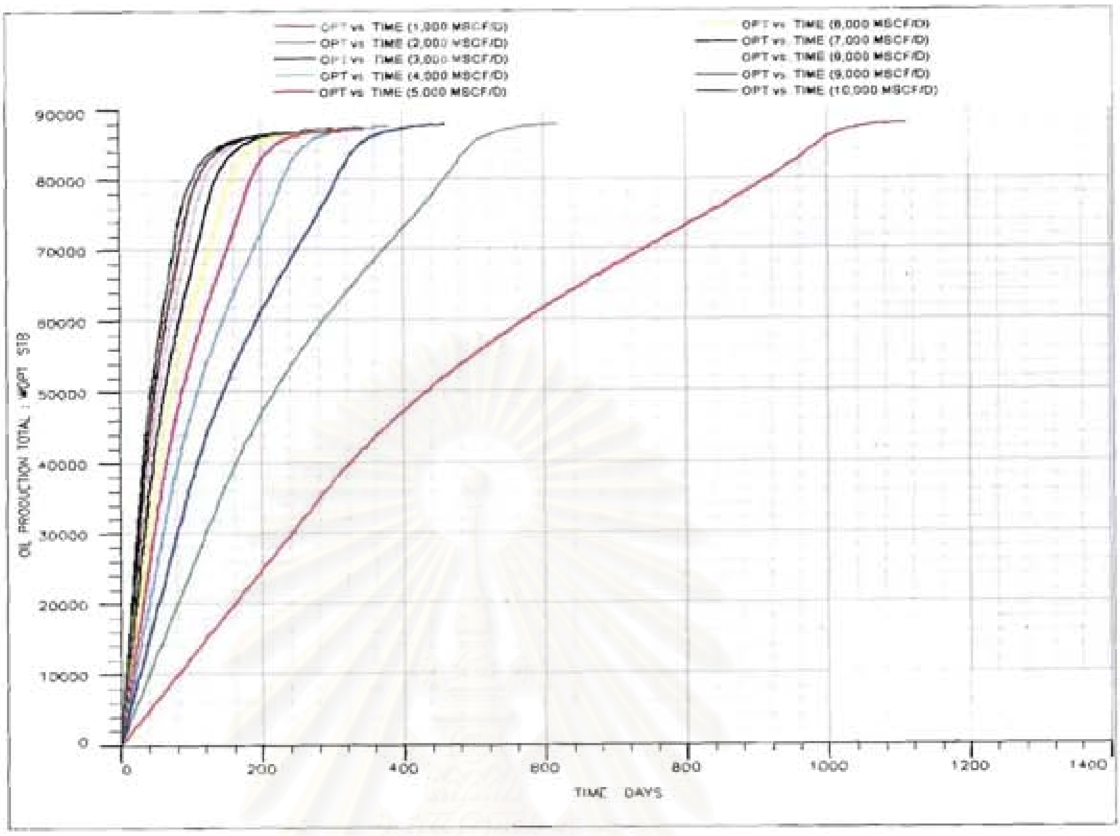


Figure 5.6: Oil production total for maximum gas production rate between 1,000 - 10,000 MSCF/D by natural depletion.

Table 5.1: Oil production total (OPT) and gas production total (GPT) with maximum gas production rate between 1,000 -10,000 MSCF/D by natural depletion.

Production Rate (MSCF/D)	Production Life (Days)	Oil production total (STB)	Gas production total (MMSCF)
1,000	1,112	87,776	1,021.8
2,000	622	87,746	1,022.4
3,000	461	87,717	1,023.0
4,000	384	87,540	1,022.7
5,000	342	87,356	1,022.6
6,000	307	87,083	1,023.1
7,000	286	87,065	1,022.5
8,000	272	86,918	1,022.4
9,000	265	86,800	1,022.7
10,000	251	86,635	1,022.4

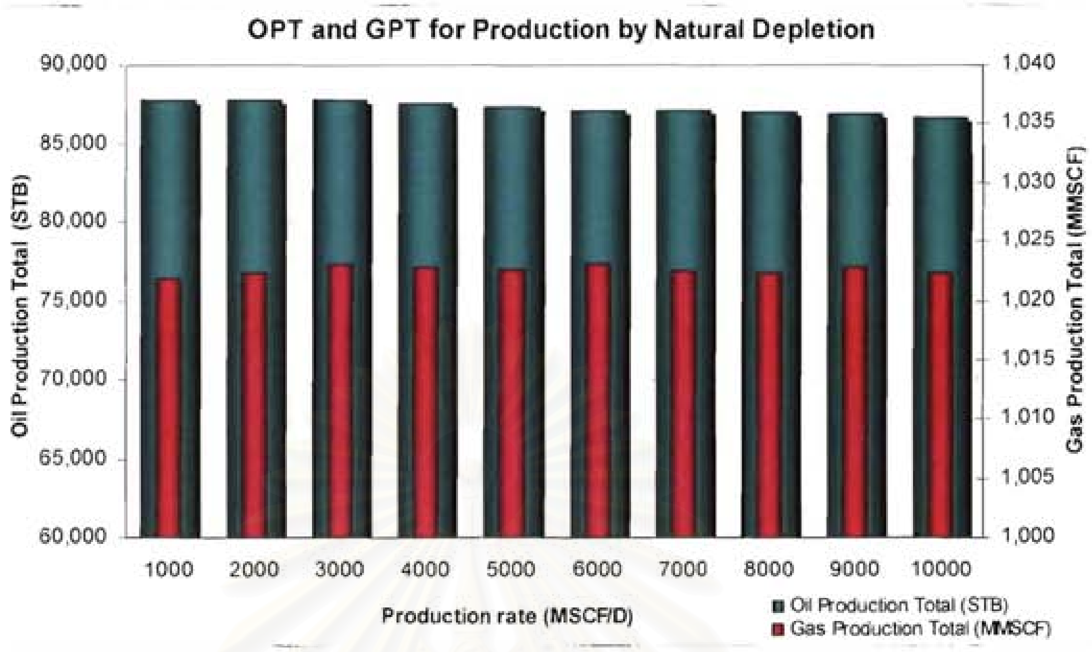


Figure 5.7: Oil production total (OPT) and gas production total (GPT) with maximum gas production rate between 1,000-10,000 MSCF/D by natural depletion.

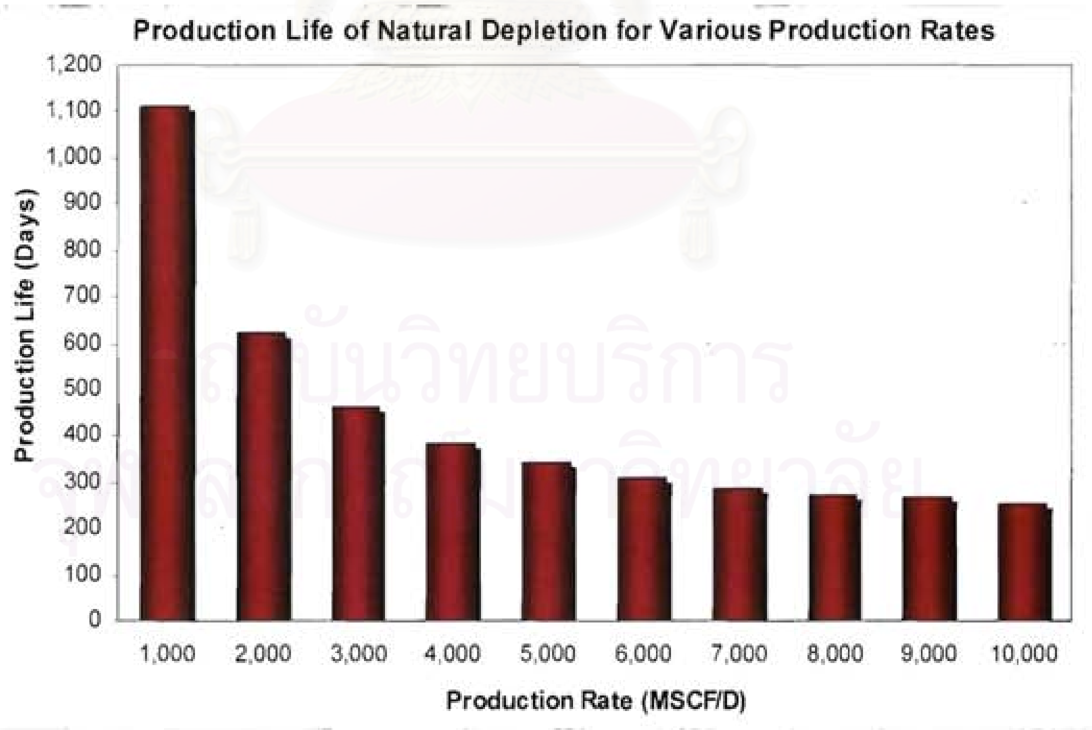
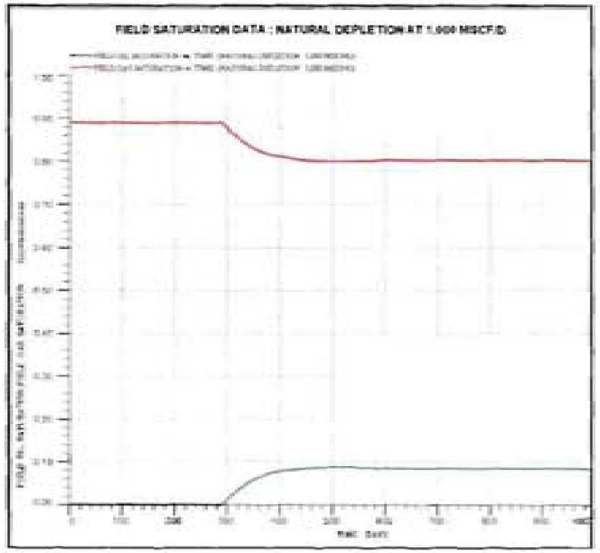
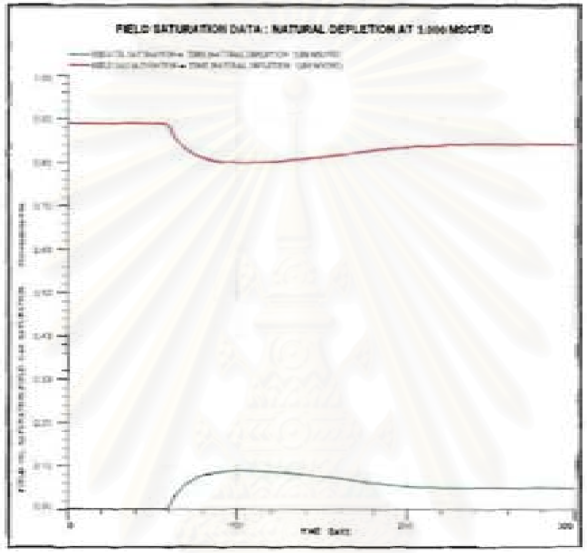


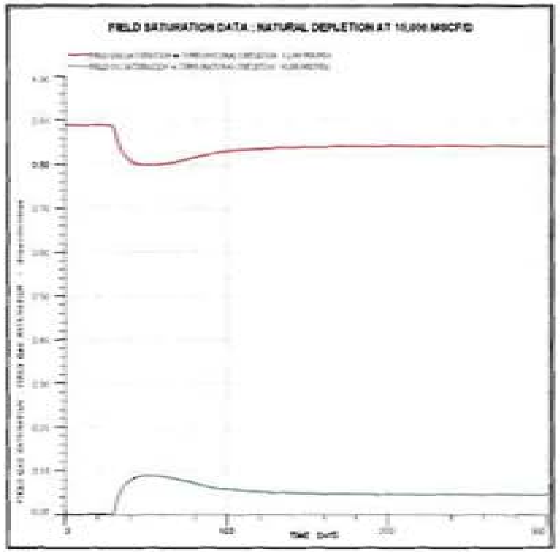
Figure 5.8: Production life of natural depletion for maximum gas production rate between 1,000 - 10,000 MSCF/D.



(a) Field oil and gas saturation for gas production rate 1,000 MSCF/D.



(b) Field oil and gas saturation for gas production rate 5,000 MSCF/D.



(c) Field oil and gas saturation for gas production rate 10,000 MSCF/D.

Figure 5.9: Field oil saturation and field gas saturation for controlled maximum gas production rate 1,000, 5,000 and 10,000 MSCF/D by natural depletion.

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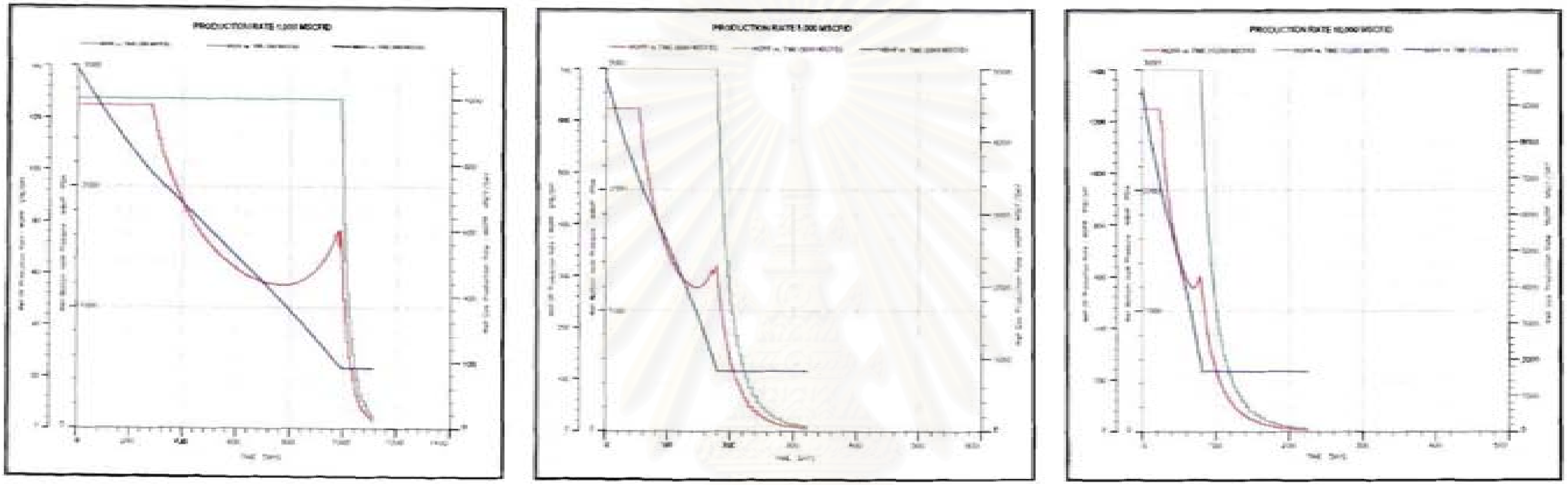

(a) Gas production rate (GPR), oil production rate (OPR), and bottom hole pressure (BHP) at gas production rate 1,000 MSCF/D.

(b) Gas production rate (GPR), oil production rate (OPR), and bottom hole pressure (BHP) at gas production rate 5,000 MSCF/D.

(c) Gas production rate (GPR), oil production rate (OPR), and bottom hole pressure (BHP) at gas production rate 10,000 MSCF/D.

Figure 5.10: Gas production rate (GPR), oil production rate (OPR) and bottom hole pressure (BHP) with maximum gas production rate 1,000, 5,000 and 10,000 MSCF/D by natural depletion.

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5.2 Economic Analysis for Production of Gas-Condensate Reservoir with Natural Depletion

Economic analysis for natural depletion scenario is summarized in Table 5.2, and NPV is illustrated in Figure 5.11. All the cases simulated give positive net present values and high internal rates of return. A discount rate of 10% was used in this study. A higher gas production rate gives a higher net present value and internal rate of return and a shorter payback period.

The economic analysis for production of gas-condensate reservoir with natural depletion can be summarized as follows:

a) All the cases with production rate ranging from 1,000 to 10,000 MSCF/D give positive net present values (NPV > 0). At low production rates of 1,000 – 3,000 MSCF/D, the net present value increases distinctly from 8.75 to 9.59 million US\$. For the production rates 4,000 – 10,000 MSCF/D, the net present value slightly increases from 9.70 to 9.86 million US\$.

b) All the cases studied give positive internal rates of return (IRR > 0). All the IRR are more than the discount rate of 10% used in this study. The IRR increases doubly while the production rate increases for every increment of 1,000 MSCF/D.

c) A higher production rate has a shorter payback period, which is economically preferential for project investment.

Table 5.2: NPV, IRR and Payback period of natural depletion at production rate 1,000 – 10,000 MSCF/D.

Production Rate (MSCF/D)	Net Present Value (NPV , US$)	Internal Rate of Return (IRR , %)	Payback Period (Days)
1,000	8,746,181	395	91
2,000	9,384,212	794	46
3,000	9,591,705	1,175	31
4,000	9,701,580	1,572	24
5,000	9,756,619	1,989	19
6,000	9,802,882	2,393	16
7,000	9,831,469	2,802	13
8,000	9,846,545	3,221	12
9,000	9,860,223	3,636	10
10,000	9,863,642	4,064	9

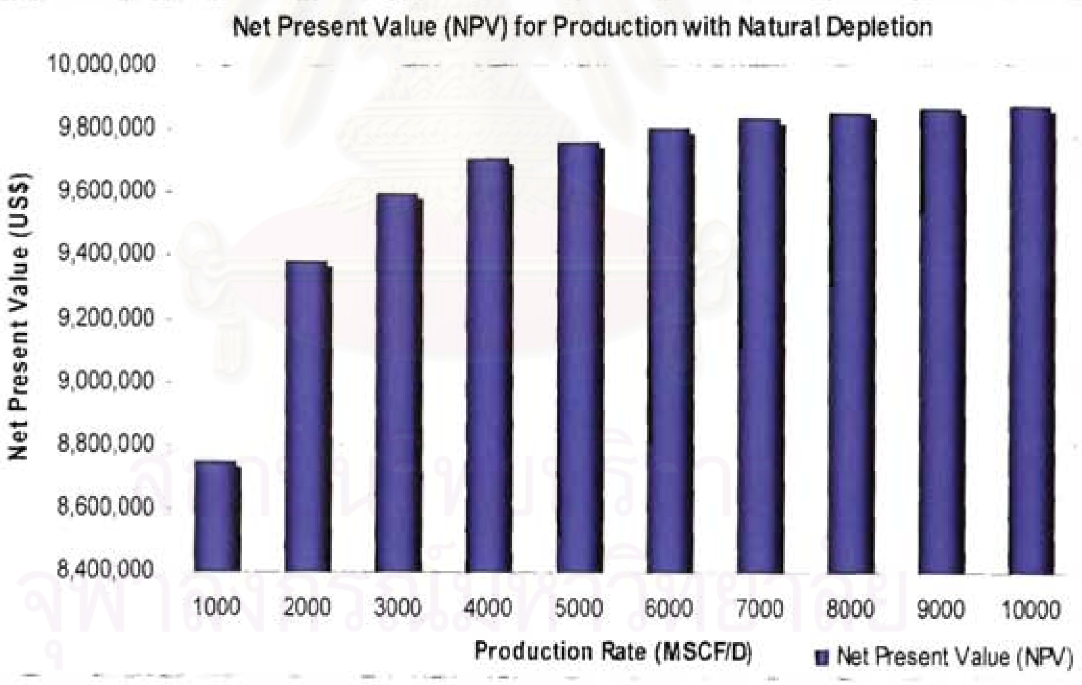


Figure 5.11: Net present values (NPV) for natural depletion of production rate 1,000 – 10,000 MSCF/D.

5.3 Production of Gas-Condensate Reservoir with Gas Cycling

In this scenario, the gas-condensate reservoir is produced together with cycling gas injection in order to maintain the reservoir pressure to be above the dew point pressure. The cycling or gas injection starts at the same time as the production. The injection rate is set to be equal to the production rate for each profile varying from 1,000 MSCF/D to 10,000 MSCF/D in a step of 1,000 MSCF/D increment. In the simulator program, the production well is set on block (1,1), and the injection well is set on block (35,35) to simulate a quarter five-spot pattern. At the production well, the gas production is controlled at a specific rate. At early times, the gas produced is injected back into the reservoir at the injector. When the production via gas recycling reaches the economic limits, gas injection is stopped. Then, the production well continues to produce gas and the injection well is switched to production until abandonment. Figure 5.12 shows the gas production rate from simulation. The red-flat line for each rate represents the gas rate produced from producer that is cycled to inject into injector. Figure 5.13 shows the oil production rate as function of time, and Figure 5.14 presents the profiles of oil and gas production rate at gas production rate of 1,000, 5,000 and 10,000 MSCF/D. Figures 5.15 and 5.16 show production total of gas and oil. The oil production total and gas production total are summarized in Table 5.3. Figure 5.17 depicts the oil and gas production total as a function of maximum gas production rate. In Figure 5.15, the straight red line represent the produced gas from production well used in gas cycling process, and the end part of those line represent for gas production after switching the injection well to second production well. Figure 5.18 shows production life for controlled maximum gas production rate 1,000 to 10,000 MSCF/D.

The performance of gas-condensate reservoir with gas cycling can be summarized as follows:

a) When the production rate and injection rate increases in step of 1000 MSCF/D, the production life declines. The production life is drastically reduced in the initial range of production rate of 1,000 – 3,000 MSCF/D in a similar manner as in the case of natural depletion. The production life slightly declines at production rates of 4,000 – 10,000 MSCF/D

b) The oil production total and gas production total do not significantly change with increasing production/injection rate. The oil production total (OPT) is in the range of 149,163 – 149,599 STB, and the gas production total (GPT) is around 1,012 MMSCF.

c) The produced gas is recycled to inject into injection well, to maintain the reservoir pressure above dew point. The OPT does not change with production rate/injection rate.

d) Unlike production by natural depletion that the decline in oil production rate is caused by the fact that the pressure drops below the dew point which results in the trapping of condensate liquid within the reservoir, the declination of oil production rate in this case results from produced fluid composition. The produced lean gas is recycled to maintain the reservoir pressure. Injected gas (displacing) first contacts with original gas (displaced) in the reservoir and initiates the gas miscible zone. This miscible displacement process with lean gas injection results in diluting the original gas composition. When the injected gas reaches the production well, the oil production rate decreases.

e) The oil production rate limit is reached while the reservoir pressure is maintained nearly at the initial pressure. Thus, the remaining gas in the reservoir contains less fractions of heavy-end hydrocarbons. The gas production after injection is stopped has a slight change in composition.

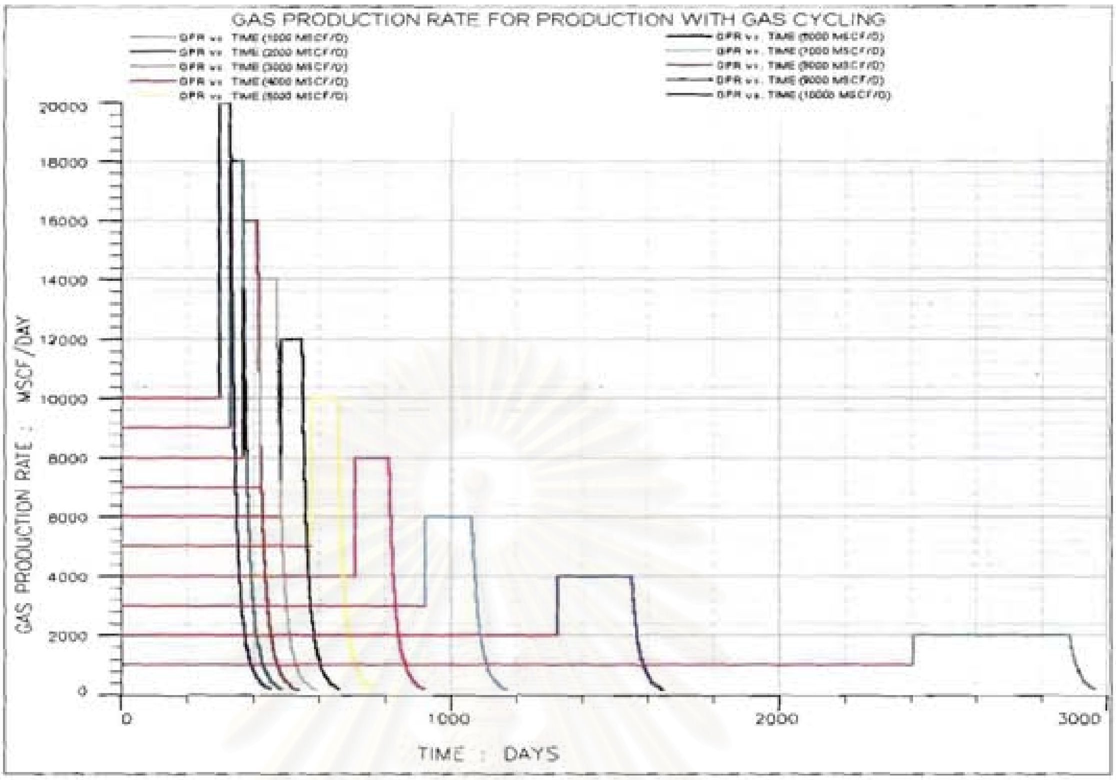


Figure 5.12: Gas production rates (GPR) for production with gas cycling.

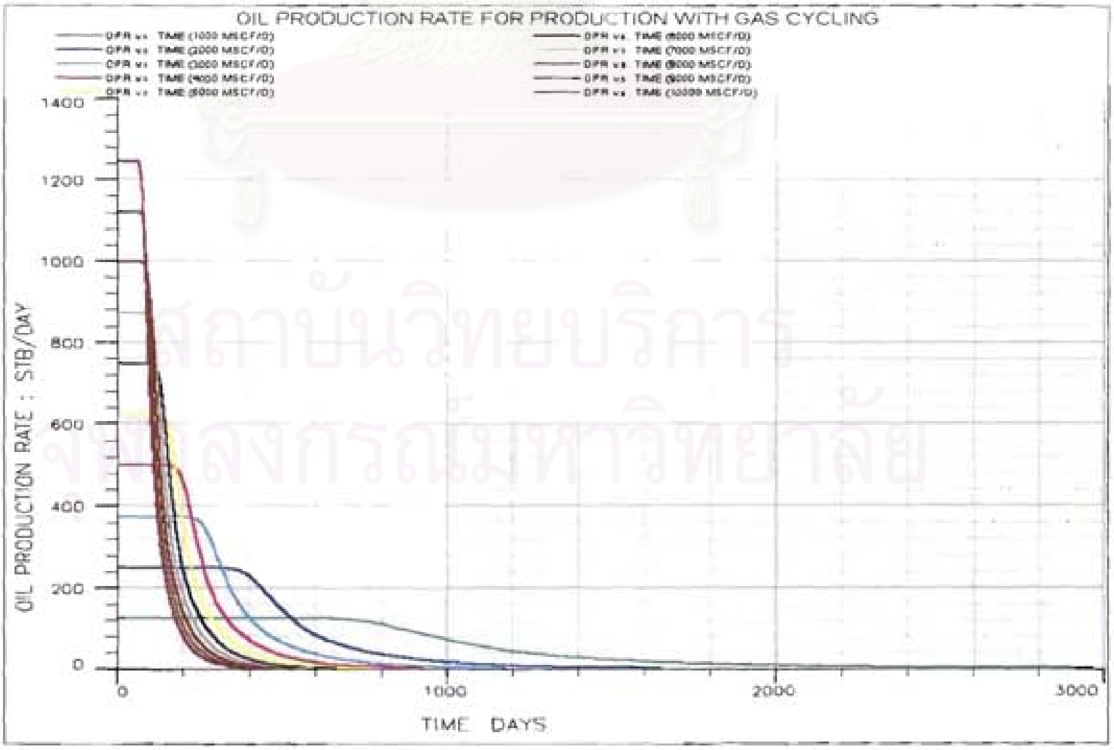
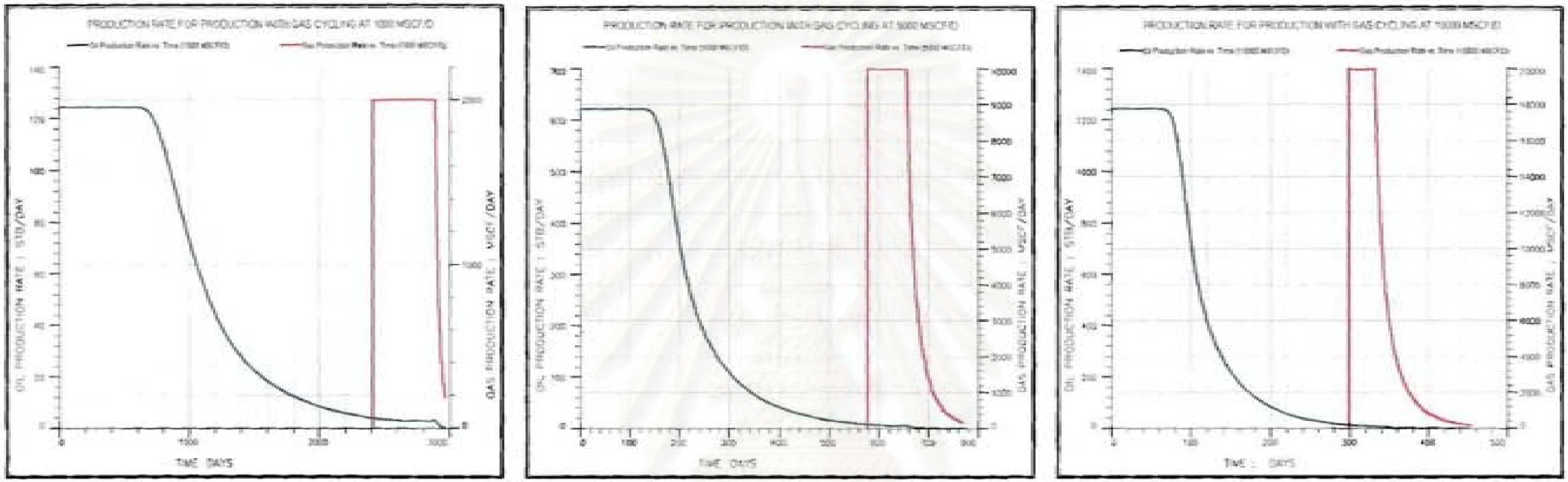


Figure 5.13: Oil production rates for production with gas cycling.



(a) Oil production rate (OPR) and gas gas production rate (GPR) at gas production rate 1,000 MSCF/D with gas cycling.

(b) Oil production rate (OPR) and gas production rate (GPR) at gas production rate 5,000 MSCF/D with gas cycling.

(c) Oil production rate (OPR) and gas production rate (GPR) at gas production rate 10,000 MSCF/D with gas cycling.

Figure 5.14: Oil production rate (OPR), and gas production rate (GPR) with maximum gas production rate 1,000, 5,000 and 10,000 MSCF/D with gas cycling.

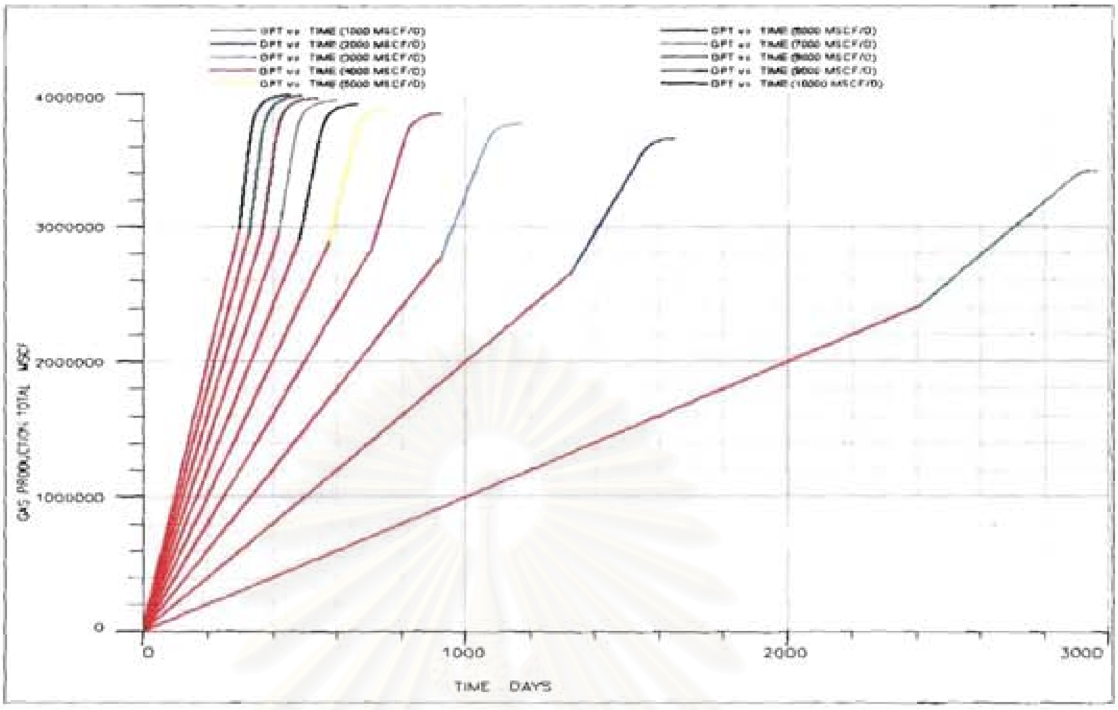


Figure 5.15: Gas production total for maximum gas production rate between 1,000 - 10,000 MSCF/D with gas cycling.

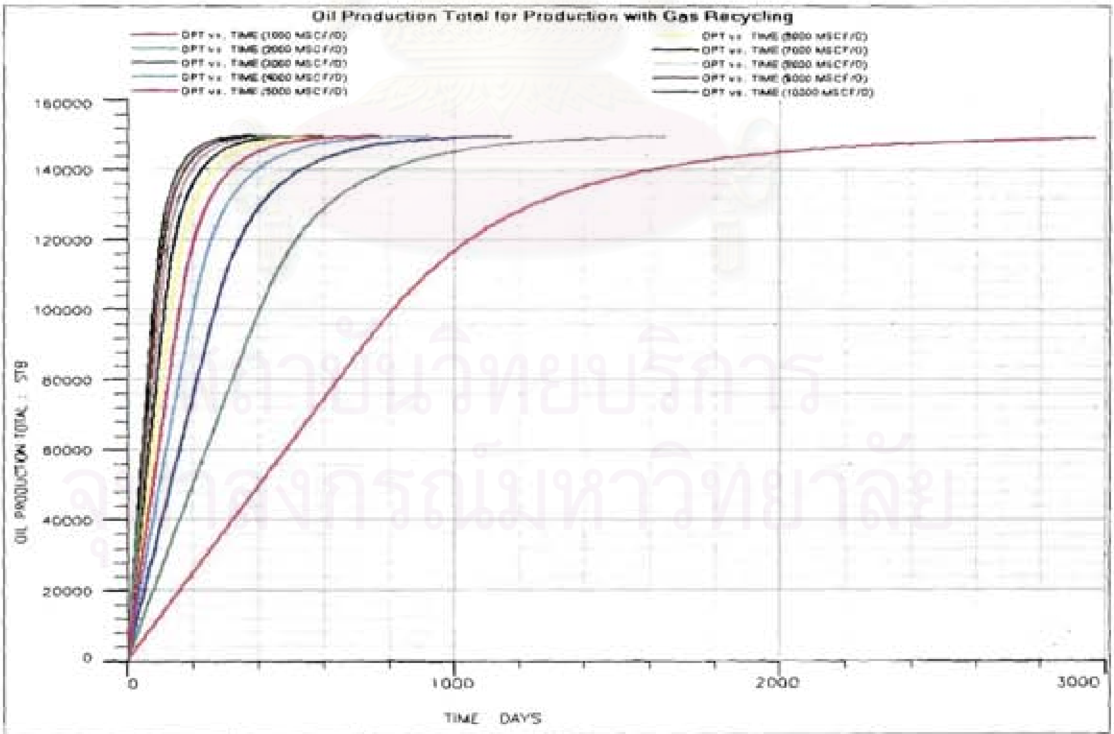


Figure 5.16: Oil production total (OPT) for maximum gas production rate between 1,000 - 10,000 MSCF/D with gas cycling.

Table 5.3: Oil production total (OPT) and gas production total (GPT) with maximum gas production rate between 1,000 -10,000 MSCF/D with gas cycling.

Production Rate (MSCF/D)	Production Life (Days)	Oil production total (STB)	Gas production total (MMSCF)
1,000	2,967	149,136	1,012
2,000	1,651	149,368	1,012
3,000	1,174	149,453	1,012
4,000	922	149,525	1,011
5,000	769	149,539	1,011
6,000	664	149,554	1,011
7,000	594	149,579	1,012
8,000	538	149,582	1,012
9,000	489	149,599	1,011
10,000	454	149,599	1,011

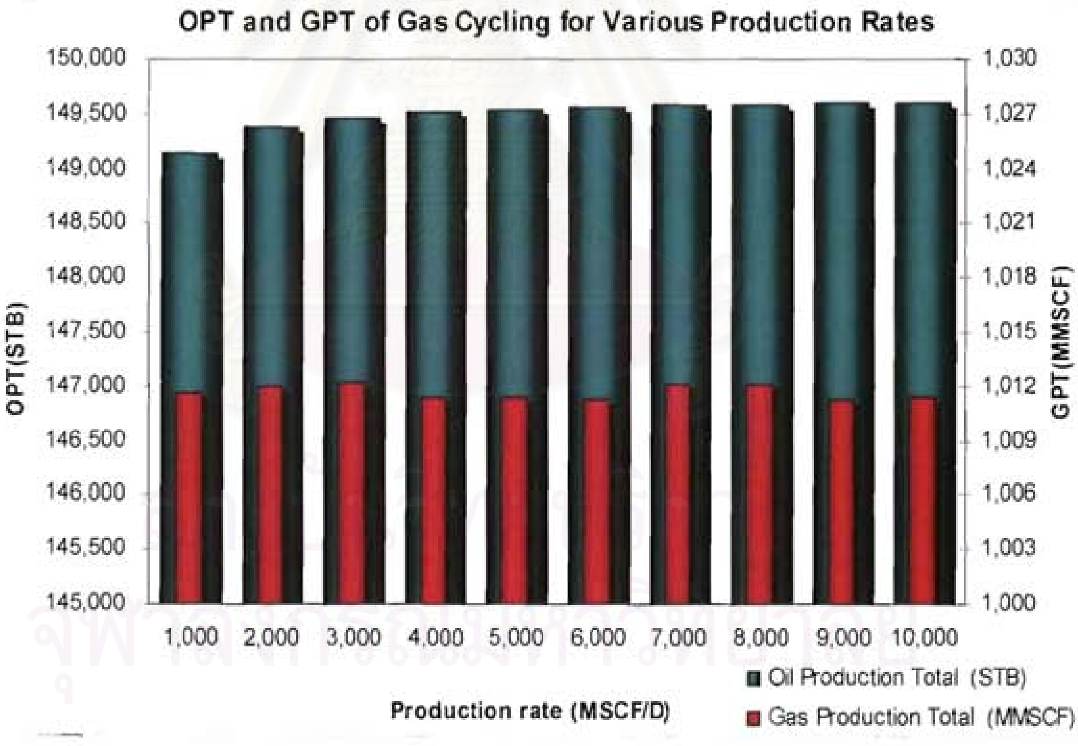


Figure 5.17: Oil production total (OPT) and gas production total (GPT) with maximum gas production rate between 1,000 -10,000 MSCF/D with gas cycling.

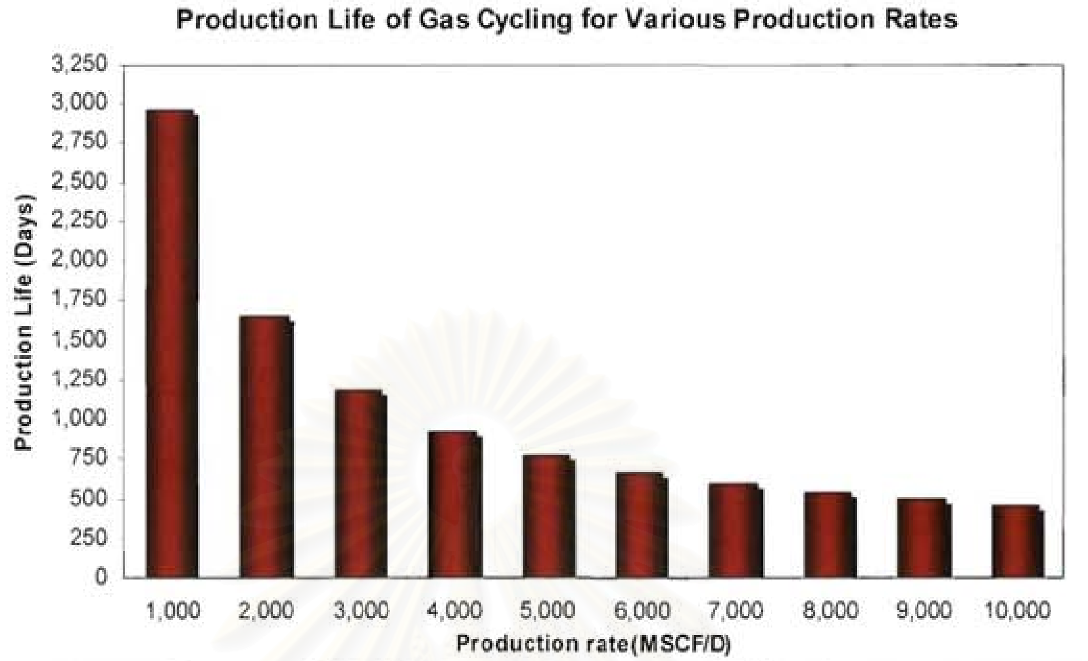


Figure 5.18: Production life of production with maximum gas production rate between 1,000 -10,000 MSCF/D with gas cycling.

5.4 Economic Analysis for Production of Gas-Condensate Reservoir with Gas Cycling

Economic analysis for production with gas cycling is summarized in Table 5.4 and NPV of each case is graphically illustrated in Figure 5.18. All production profiles give positive net present values and higher internal rate of return than discount rate (10%) used in this study. All production rates with gas cycling are financially acceptable for investment. A higher gas production rate gives a higher net present value and internal rate of return and a shorter payback period.

The economic analysis for production of gas-condensate reservoir with gas cycling can be summarized as follows:

a) All the cases with production rate ranging from 1,000 to 10,000 MSCF/D are economically acceptable for project investment. Each net present value (NPV) is more than zero, and the internal rate of return (IRR) is higher than the discount rate of 10 %.

b) Although oil production total (OPT) and gas production total (GPT) of the simulated cases are not significantly different, the production profile of lower production rate is longer, resulting in a longer payback period.

c) When producing at a high production rate, we partially recover the capital cost from salvage. In addition, selection of the appropriate compressor capacity for specific production rate can reduce investment cost and improve the economics of the project.

d) The oil production total (OPT) contributes to the net present value more than the gas production total (GPT). The elevated recovery of cumulative oil production is a result of gas cycling process and results in a high net present value.

Table 5.4: Net present value (NPV), internal rate of return (IRR) and payback period for maximum gas production rate between 1,000 – 10,000 MSCF/D with gas cycling.

Production Rate (MSCF/D)	Net Present Value (NPV, US$)	Internal Rate of Return (IRR, %)	Payback Period (Days)
1,000	8,266,859	125	296
2,000	10,179,164	267	145
3,000	11,066,246	431	96
4,000	11,219,176	502	94
5,000	11,596,086	666	75
6,000	11,860,672	836	63
7,000	11,847,922	900	66
8,000	12,022,066	1,069	58
9,000	12,156,129	1,241	52
10,000	12,113,794	1,303	55

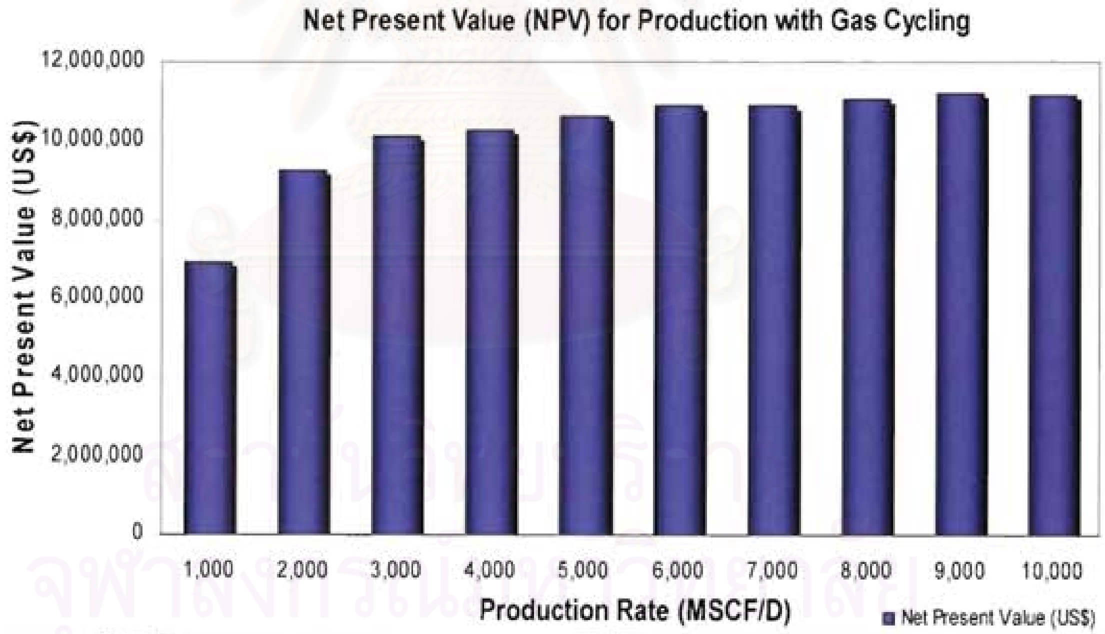


Figure 5.19: Net present value (NPV) for maximum gas production rate between 1,000 – 10,000 MSCF/D with gas cycling.

5.5 Production and Timely Gas Injection

In this scenario, the gas-condensate reservoir was simulated to produce gas at low, moderate, and high rate which are 1,000, 5,000 and 10,000 MSCF/D. Each production rate was simulated as production with gas cycling starting at 20, 40, and 60 days after initial production. At the initial stage, the two wells in the reservoir are production wells producing gas at the same gas production rate. After a certain period of time, one of the producers is converted to a gas injection well. The produced gas from the production well is transferred to surface separator and delivered to the compressor in order to supply gas for cycling process. The injection rate was set equal to the with gas production rate. When the production via gas recycling reaches the economic limit of oil production rate, gas injection is stopped. Then, the production well continues to produce gas and injection well is switched to production until abandonment. Figure 5.20 to Figure 5.22 show the combination of the gas production rate, the oil production rate, and the gas injection rate for controlled maximum gas production rate of 1,000, 5,000, and 10,000 MSCF/D, and starting gas injection at 20, 40, and 60 days, respectively. Figures 5.23 and 5.24 show simulation result of oil and gas production rate from production well and injection well, and average gas injection rate in case of production rate 10,000 MSCF/D and starting gas injection at 40 days and 60 days, respectively. Table 5.5 and Table 5.6 summarize the cumulative oil production and cumulative gas production, respectively, for starting gas injection at 20, 40, and 60 days for each controlled maximum gas production rate of 1,000, 5,000, 8,000, and 10,000 MSCF/D. These results are also depicted in Figure 5.25 and 5.26, respectively. The production lives of each controlled maximum gas production rate with different starting times of gas injection are summarized in Table 5.7 and depicted in Figure 5.27. Figure 5.28 shows condensate gas ratio with time for production rate 10,000 MSCF/D and timely gas injection 20, 40 and 60 days. Figure 5.29 show the relation of condensate gas ratio, bottom hole pressure and gas production rate for the gas production rate 10,000 MSCF/D and timely gas injection 20, 40 and 60 days, respectively.

The performance of gas-condensate reservoir with timely gas injection can be summarized as follows:

a) Figure 5.20 shows plateau rate of produced oil at controlled maximum production rate 1,000 MSCF/D with different timely gas injection. The oil production profiles have similar pattern. The time the production starts to decline is around 700 days. The simulation result of plateau rates denote that timely gas injection for controlled maximum gas production rate of 1,000 MSCF/D at 20, 40, and 60 days can maintain the reservoir pressure before reaching the dew point pressure.
b) Figure 5.21 shows plateau rate of produced oil at controlled maximum production rate of 5,000 MSCF/D with different timely gas injection. Similar to the case with gas production rate of 1,000 MSCF/D, the oil production profiles with timely gas injection at 20 days have the same pattern. Except the production profile with timely gas injection at 40 and 60 days, oil production rate starts to decline after producing for 24 days. Meaningly, timely gas injection for controlled maximum gas production rate of 5,000 MSCF/D that can maintain the reservoir pressure before reaching the dew point pressure should be commenced prior to 24 days.
c) Figure 5.22 shows oil production rate for controlled maximum production rate of 10,000 MSCF/D with different timely gas injection that has a distinguishing pattern from the gas production rate of 1,000 and 5,000 MSCF/D. At this gas production rate, oil production rate starts to decline after producing for 9 days. From the simulation result, not only the oil production rate drops before gas injection is started, but the gas production rate also starts to decline at 32 days which is prior to the starting date of gas injection at 40 and 60 days.
d) In case of controlled production rate of 10,000 MSCF/D and starting date of gas injection at 40 and 60 days, the simulation results after 32 days show lower gas production rate than the rate required for gas injection at specific time. The gas injection at 40 and 60 days is then performed with available gas production rate which is averaged at 4,500 MSCF/D and

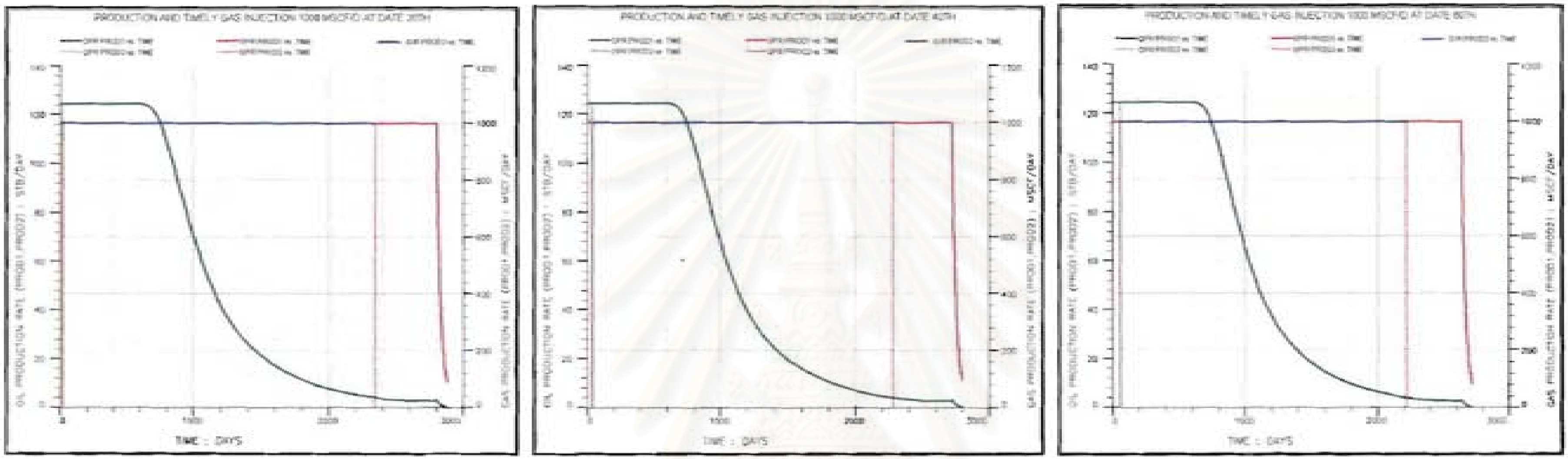
2,000 MSCF/D, respectively. The maximum controlled production rate of 8,000 MSCF/D is simulated as another high production rate to confirm the result of production rate 10,000 MSCF/D. Figures 5.23 and 5.24 show oil production rate, gas production rate and average gas injection rate for production rate of 10,000 MSCF/D and timely gas injection at 40 and 60 days, respectively.

e) For the production rate of 1,000 and 5,000 MSCF/D that were simulated without reducing the gas injection rate to available producing gas, the oil production total (OPT) and gas production total are insignificantly different for various timely gas injections 20, 40, and 60 days. When the production rate increases, oil production total tends to increase but gas production rate tends to reduce.

f) At high production rate of 8,000 and 10,000 MSCF/D, starting gas injection at 40 days gives the highest oil production total.

g) Figure 5.27 illustrates that for each controlled maximum gas production rate of 1,000 and 5,000 MSCF/D, the production life is insignificantly different for timely gas injection starting at 20, 40, and 60 days. For gas production rate of 10,000 MSCF/D and gas injection rate is reduced to available gas production rate of 40 and 60 days, the production life is longer than starting gas injection at 20 days.

h) For each particular starting time of timely gas injection except for the production rate of 10,000 MSCF/D at 40 and 60 days, the production life tends to shorten when the controlled gas production rate increase.



(a) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 1,000 MSCF/D. with timely gas injection 20 days.

(b) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 1,000 MSCF/D with timely gas injection 40 days.

(c) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 1,000 MSCF/D with timely gas injection 60 days.

Figure 5.20: Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) with maximum gas production rate 1,000 MSCF/D with timely gas injection 20, 40, and 60 days.

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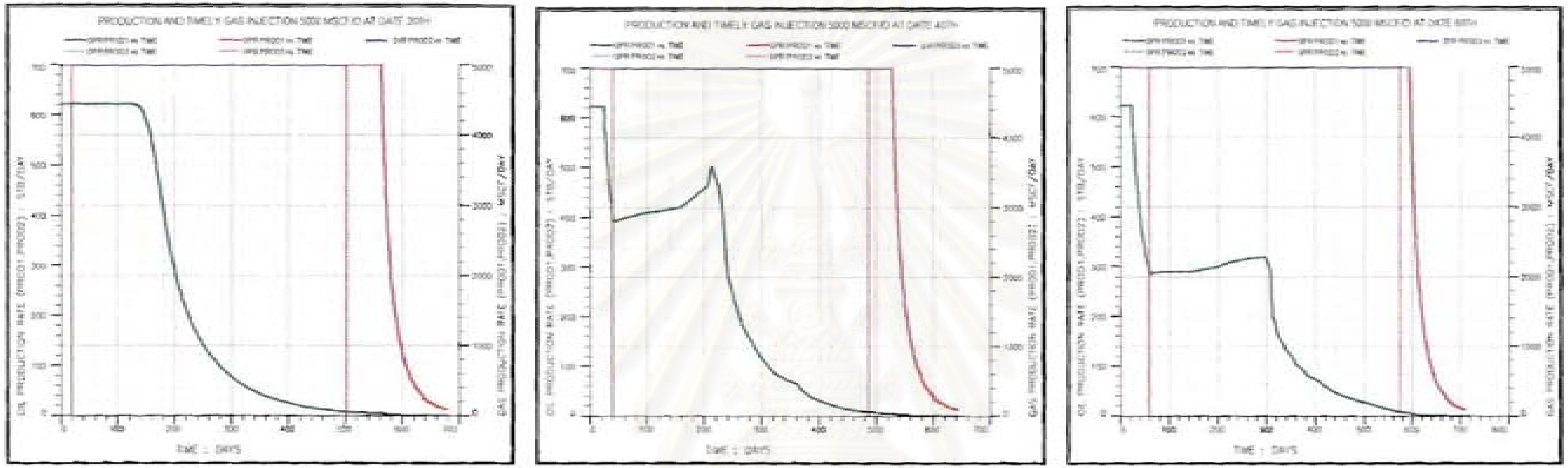
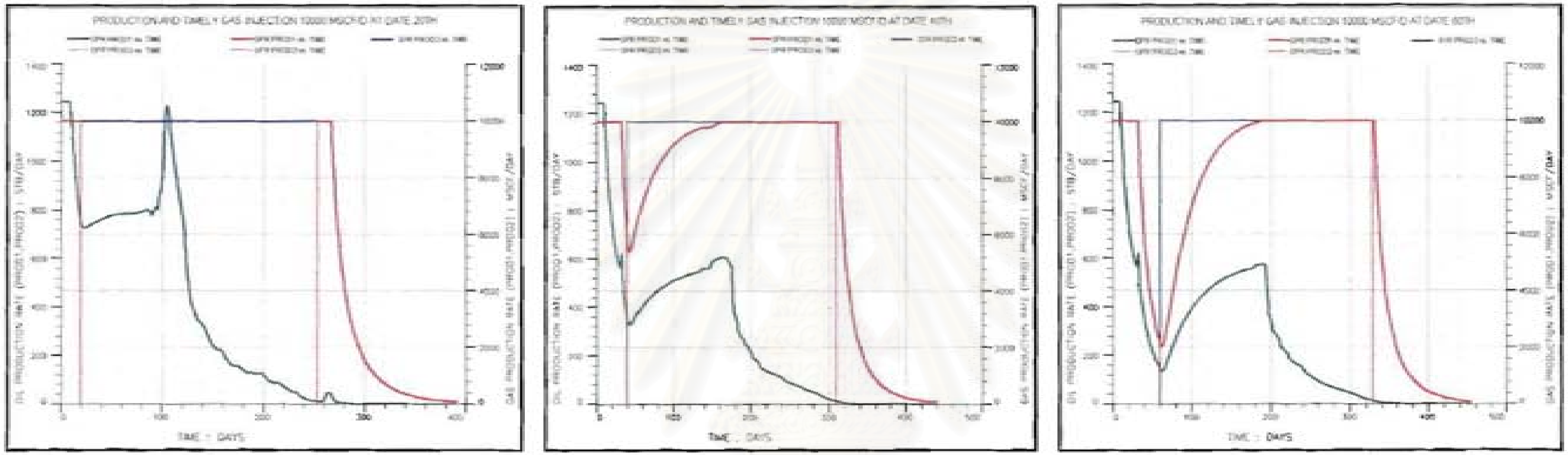


(a) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 5,000 MSCF/D. with timely gas injection 20 days.

(b) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 5,000 MSCF/D with timely gas injection 40 days.

(c) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 5,000 MSCF/D with timely gas injection 60 days.

Figure 5.21: Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) with maximum gas production rate 5,000 MSCF/D with timely gas injection 20, 40, and 60 days.



(a) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 10,000 MSCF/D. with timely gas injection 20 days.

(b) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 10,000 MSCF/D with timely gas injection 40 days.

(c) Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) at gas production rate 10,000 MSCF/D with timely gas injection 60 days.

Figure 5.22: Oil production rate (OPR), gas production rate (GPR) and gas injection rate (GIR) with maximum gas production rate 10,000 MSCF/D with timely gas injection 20, 40, and 60 days.

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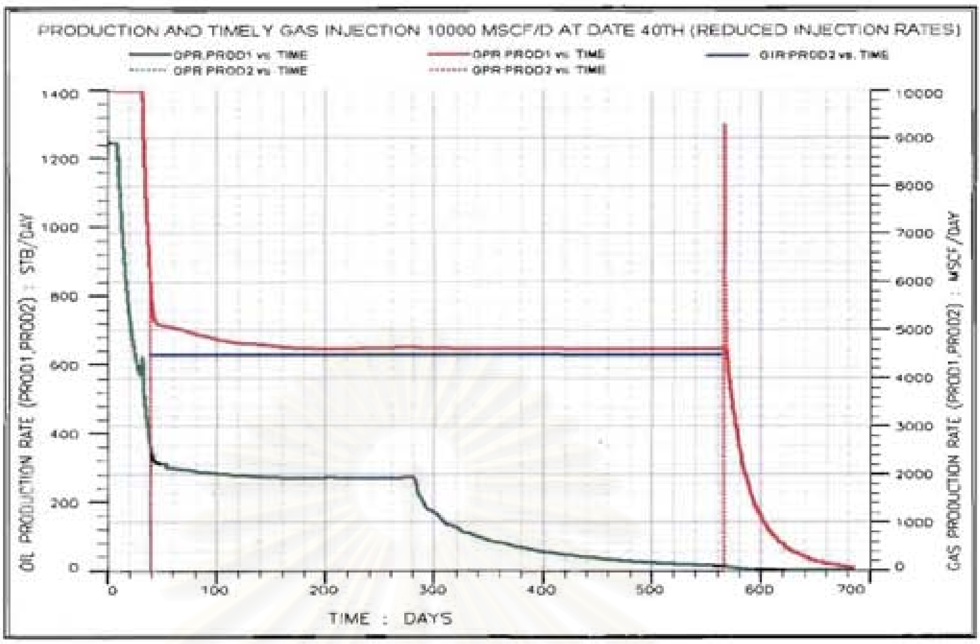


Figure 5.23: Oil production rate(OPR),gas production rate(GPR) for gas production rate 10,000 MSCF/D with timely gas injection 40 days and average gas injection rate(GIR) 4,500 MSCF/D.

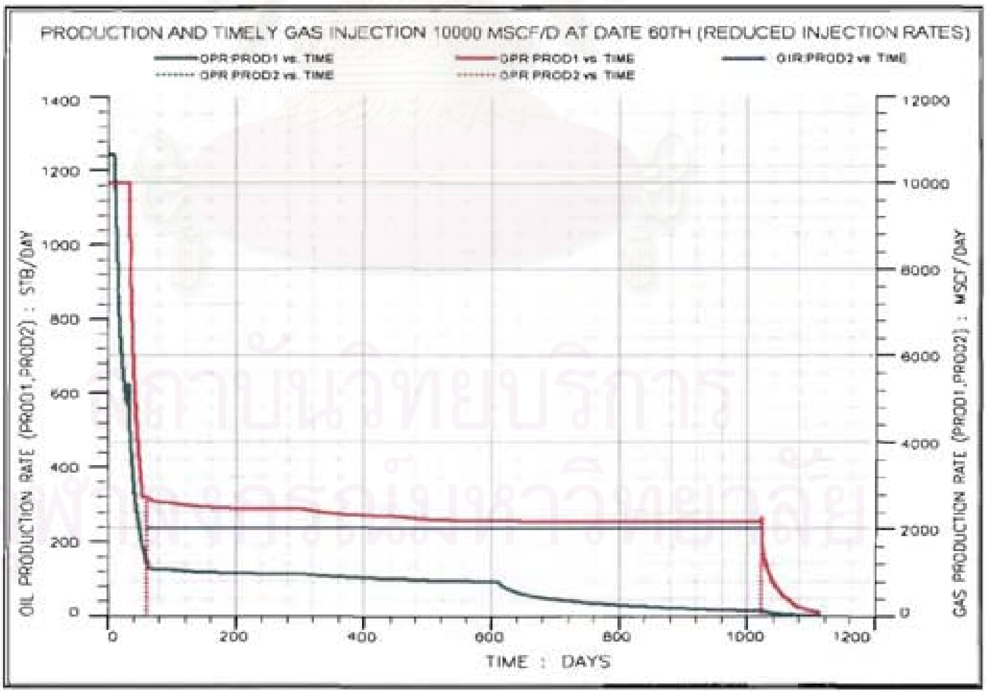


Figure 5.24: Oil production rate(OPR),gas production rate(GPR) for gas production rate 10,000 MSCF/D with timely gas injection 60 days and average gas injection rate(GIR) 2,00 MSCF/D.

Table 5.5: Oil production total (OPT) for timely gas injection with gas production rate 1,000, 5,000, 8,000 and 10,000 MSCF/D.

Production Rate (MSCF/D)	Oil production total for Various Timely Gas Injection (STB)		
	20 Days	40 Days	60 Days
1,000	149,136	149,146	149,155
5,000	149,370	149,310	149,486
8,000	149,299	**151,030**	**147,431**
10,000	149,529	**151,037**	**147,623**

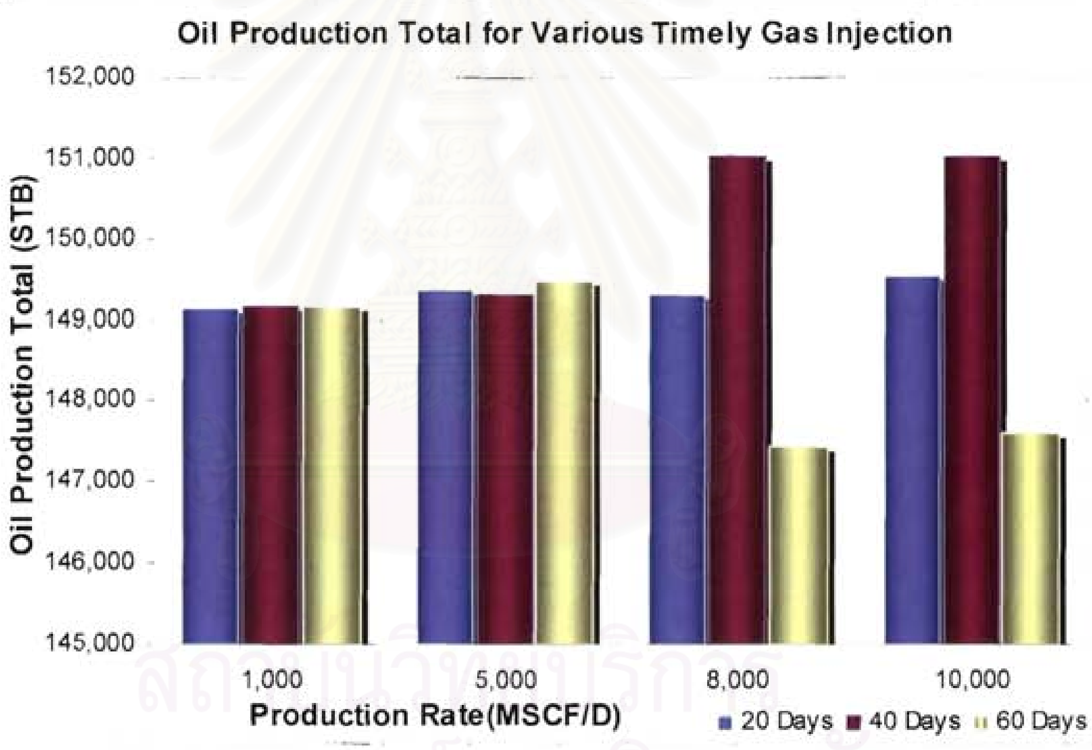


Figure 5.25: Oil production total (OPT) with timely gas injection at 20, 40 and 60 days for gas production rate of 1,000, 5,000, 8,000 and 10,000 MSCF/D.

Table 5.6: Gas production total (GPT) for timely gas injection with gas production rate of 1,000, 5,000, and 10,000 MSCF/D.

Production Rate (MSCF/D)	Gas production total for Timely Gas Injection (MMSCF)		
	20 Days	40 Days	60 Days
1,000	1,011.9	1,011.4	1,012.4
5,000	1,011.8	1,010.8	1,007.1
8,000	1,010.9	**1,006.3**	**1,004.4**
10,000	1,010.1	**985.3**	**984.9**

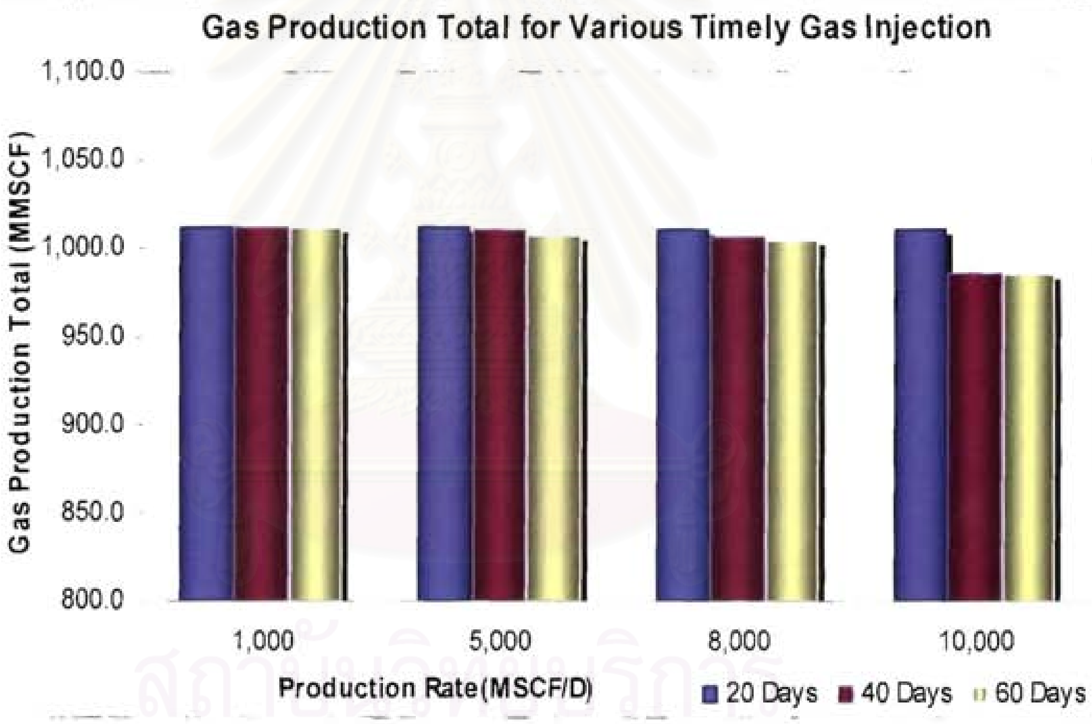


Figure 5.26: Gas production total (GPT) with timely gas injection at 20, 40 and 60 days for gas production rate of 1,000, 5,000 and 10,000 MSCF/D.

Table 5.7: Production lives with timely gas injection for controlled maximum gas production rate of 1,000, 5,000, and 10,000 MSCF/D.

Production life for timely gas injection (Days)			
Production Rate (MSCF/D)	Time before gas Injection		
	20 Days	40 Days	60 Days
1,000	2,883	2,799	2,722
5,000	678	643	711
10,000	391	**685**	**1,112**

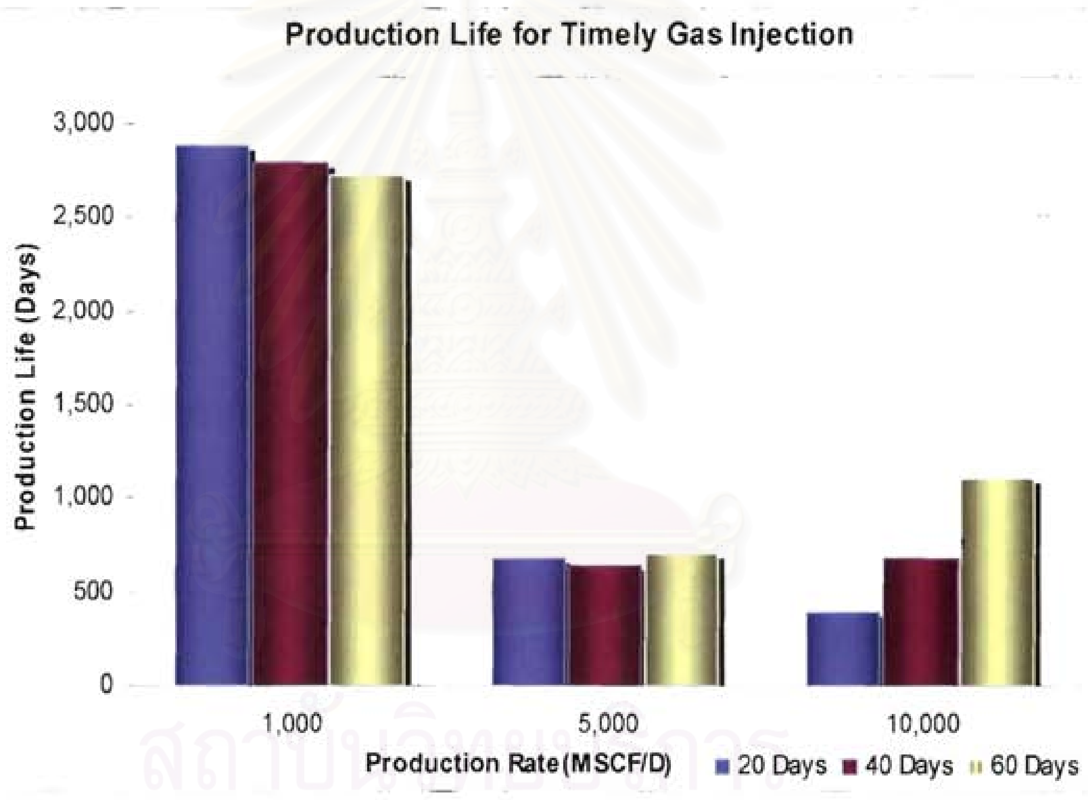


Figure 5.27: Production lives with timely gas injection for controlled maximum gas production rate of 1,000, 5,000 and 10,000 MSCF/D.

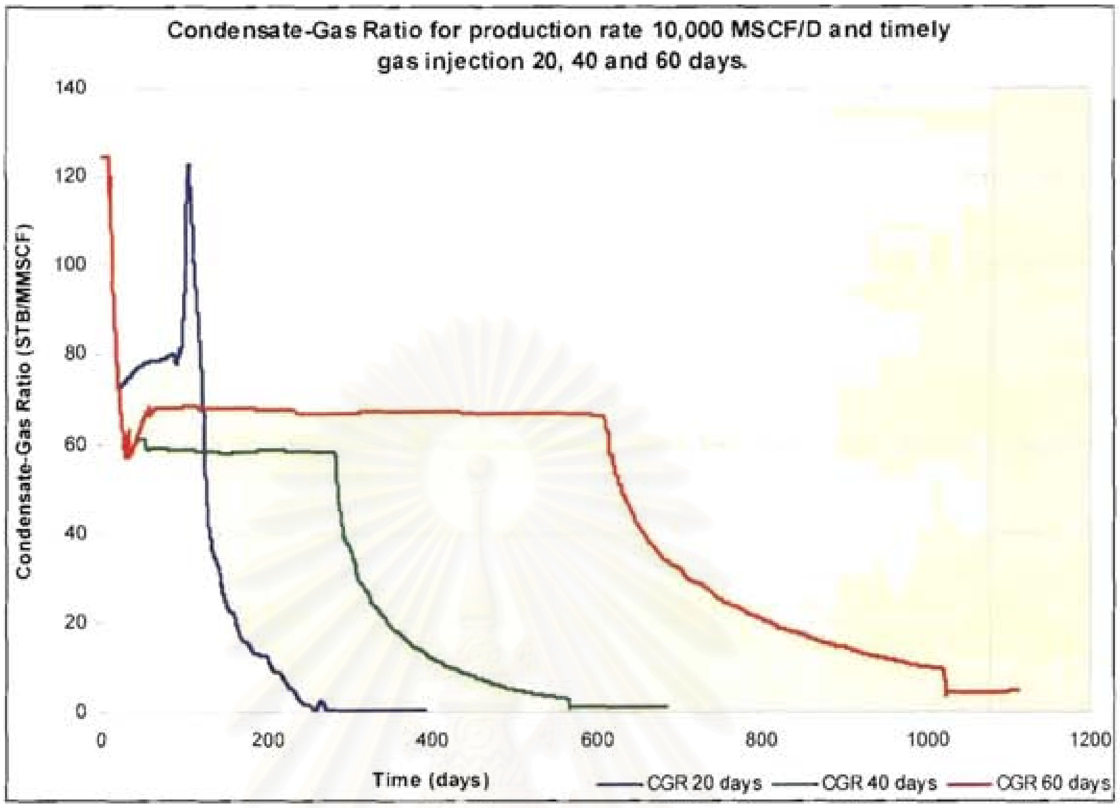
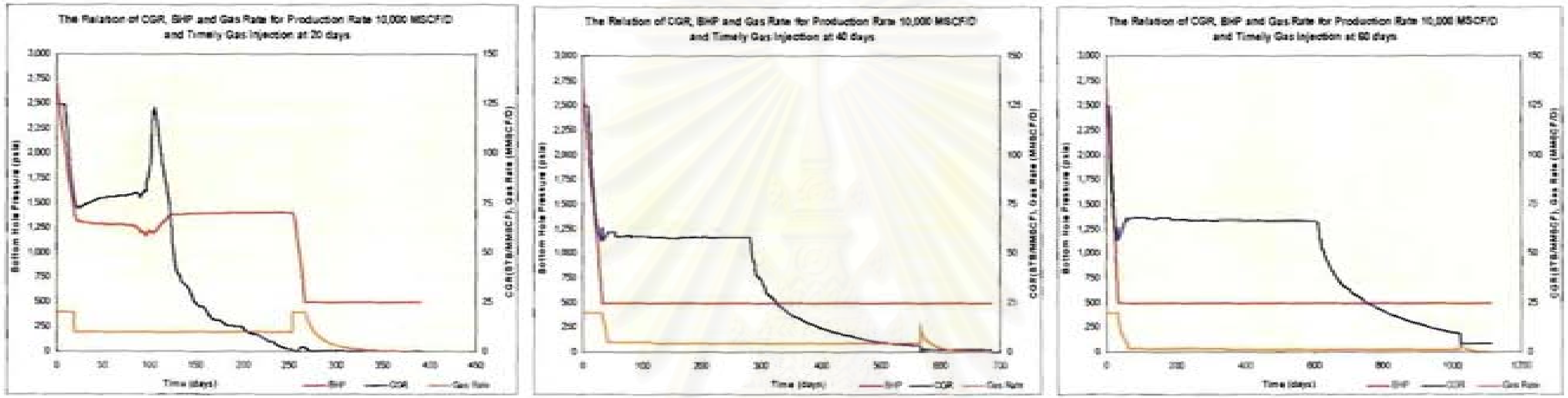


Figure 5.28: Condensate Gas Ratio for control production rate 10,000 MSCF/D and timely gas injection at 20, 40, and 60 days.

i) Condensate gas ratio (CGR) of high production rate of 10,000 MSCF/D and timely gas injection at 20, 40 and 60 days have the same initial value at 124 STB/MMSCF. The CGR is constant and then starts to drop at 9 days when the bottom hole pressure falls below the dew point. Starting gas inject at 20 days can exert pressure to the reservoir and then maintain it at range 1,250 – 1,500 psia, but starting gas injection at 40 and 60 days delays the maintenance to the time after the minimum bottom hole pressure of 500 psia has been reached. In these cases, gas production rate decreases continuously, thus gas injection are performed with average rate of 4,500 and 2,000 MSCF/D at 40 and 60 days, respectively. The gas injection can enhance condensate recovery and then maintain CGR at certain level.



(a) Condensate-Gas Ratio(CGR), bottom hole pressure(BHP), and gas production rate (GPR) for gas production rate 10,000 MSCF/D with timely gas injection 20 days.

(b) Condensate-Gas Ratio(CGR), bottom hole pressure(BHP), and gas production rate (GPR) for gas production rate 10,000 MSCF/D with timely gas injection 40 days.

(c) Condensate-Gas Ratio(CGR), bottom hole pressure(BHP), and gas production rate (GPR) for gas production rate 10,000 MSCF/D with timely gas injection 60 days.

Figure 5.29: Condensate Gas Ratio(CGR), bottom hole pressure(BHP), and gas production rate(GPR) for control production rate 10,000 MSCF/D and timely gas injection at 20, 40, and 60 days.

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5.6 Economic Analysis for Production and Timely Gas Injection

Economic analysis for production and timely gas injection scenario is summarized in Table 5.8 to Table 5.10, and NPV is illustrated in Figure 5.30. All the cases simulated give positive net present values and high internal rates of return. A higher gas production rate gives a higher net present value and internal rate of return and shorter payback period.

The economic analysis for production of gas-condensate reservoir and timely gas injection can be summarized as follows:

a) All the cases with production rate of 1,000, 5,000 and 10,000 MSCF/D give positive net present values (NPV > 0). For the specific production rate of 1,000 and 5,000 MSCF/D, net present values increase for increasing time of starting gas injections. Meanwhile, the high production rate gives higher net present value than the low production rate, for all timely gas injection regardless the production rate 10,000 MSCF/D and timely gas injection at 40 and 60 days.

b) All the cases studied give positive internal rate of return (IRR>0). All the IRR are more than the discount rate of 10% used in this study.

c) For a specific production rate, the longer time to start gas injection the shorter the payback period. In the same manner, for a specific time in starting gas injection, a higher production rate has a shorter payback period. Both conditions are economically preferential for project investment.

d) Comparing the same production rate between production with gas cycling and production with timely gas injection, cumulative gas production from production with gas cycling is higher than that from production with timely gas injection while the cumulative oil productions are equivalent. Production with timely gas injection has higher NPV than production with gas cycling, resulting from the fact that the gas produced prior the start of gas injection can be sold earlier, and this income increases the net present value.

e) For high production rate of 10,000 MSCF/D and timely gas injection at 40 and 60 days, net present values do not conformably increase with increased production rate or time of starting gas injection due to the fact that both profiles have longer production life.

Table 5.8: Net present value (NPV) of production and timely gas injection for controlled maximum production rate 1,000, 5,000 and 10,000 MSCF/D.

Production Rate (MSCF/D)	Net Present Value for Various Timely Gas Injection (NPV, US$)		
	20 Days	40 Days	60 Days
1,000	8,480,262	8,706,246	8,923,205
5,000	11,986,536	12,161,215	12,175,372
10,000	12,464,254	11,758,051	10,747,472

Table 5.9: Internal rate of return (IRR) of production and timely gas injection for controlled maximum production rate 1,000, 5,000 and 10,000 MSCF/D.

Production Rate (MSCF/D)	Internal Rate of Return for Various Timely Gas Injection (IRR, %)		
	20 Days	40 Days	60 Days
1,000	150	185	225
5,000	1,753	2,260	2,263
10,000	4,396	4,445	4,369

Table 5.10: Payback period of production and timely gas injection for controlled maximum production rate 1,000, 5,000 and 10,000 MSCF/D.

Production Rate (MSCF/D)	Payback Period for Various Timely Gas Injection (Days)		
	20 Days	40 Days	60 Days
1,000	248	192	143
5,000	28	22	22
10,000	17	17	17

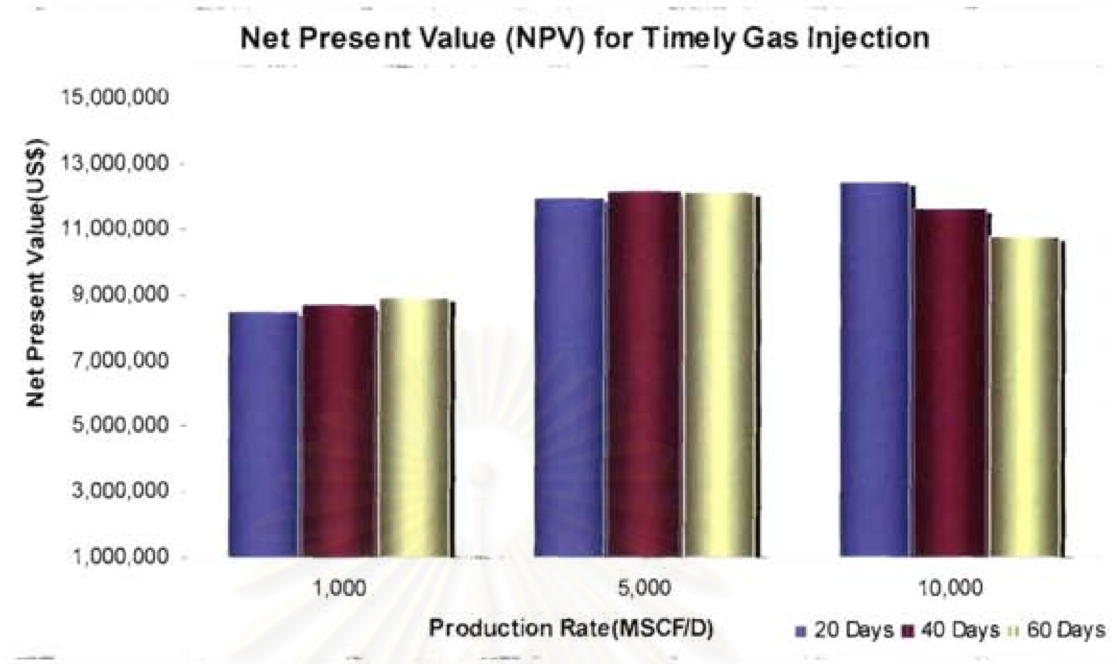

Figure 5.30: Net present value (NPV) of production and timely gas injection for controlled maximum production rate 1,000, 5,000 and 10,000 MSCF/D.

5.7 Natural Depletion and Production with Gas Cycling

As described in Chapter I about gas-condensate reservoir characteristic and the strategy to maximize hydrocarbon recovery, simulation results of production by natural depletion and production with gas cycling are compared.

5.7.1 Production Life

The simulation results of production life obtained from producing gas-condensate reservoir by natural depletion and with gas cycling for controlled maximum production rate between 1,000-10,000 MSCF/D are shown in Figure 5.31. For each production rate, production with gas cycling has longer life than production with natural depletion. The lower the production rate, the higher the difference between the production lives.

The main reason that gas-condensate reservoir being produced with gas cycling has a longer production life compared to production by natural depletion is that the produced gas is recycled into the reservoir in order to support and maintain the reservoir pressure to be above the dew point pressure. Gas cycling helps extend the plateau period and delay the decline in both gas and oil rates. Thus, the time at which economic limit is reached is extended. As a result, production life for a reservoir with gas cycling is longer.

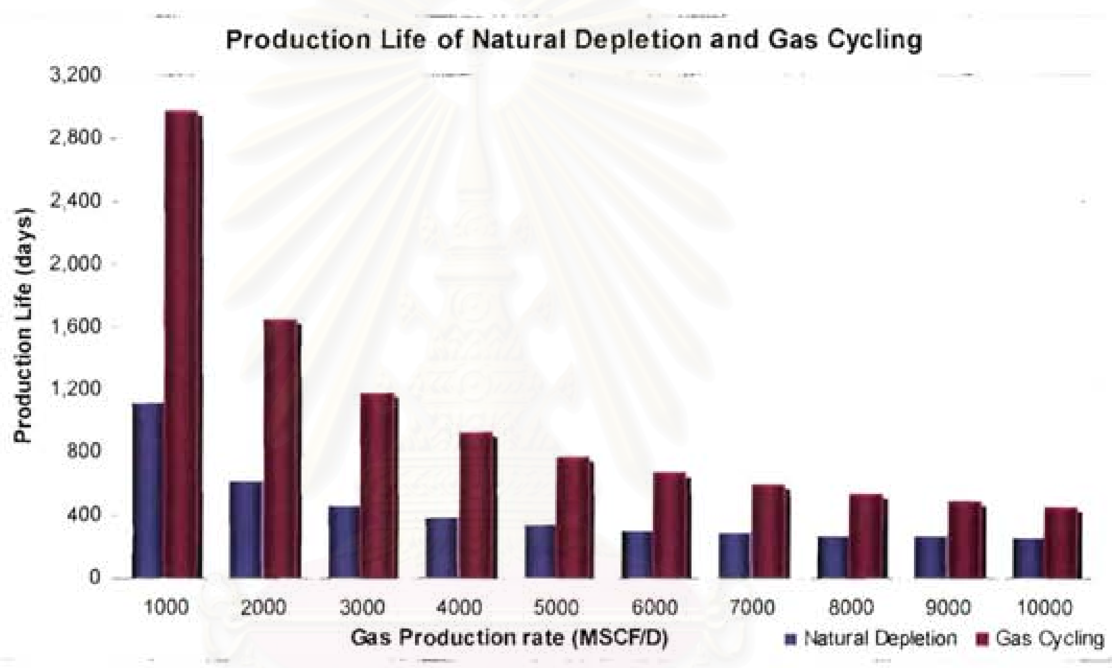

Figure 5.31: Production life of production with natural depletion and production with gas cycling for controlled maximum production rate between 1,000–10,000 MSCF/D.

5.7.2 Bottom Hole Pressure (BHP)

As mentioned earlier, the main objective of gas injection or gas cycling is to maintain the gas-condensate reservoir pressure above the dew point. In order to confirm the effect of gas injection on pressure, the bottom hole pressure (BHP) of the production well in the case of natural depletion and gas cycling scenario obtained from the simulations are shown in Figures 5.32 to 5.34, respectively.

The bottom hole pressure of the production well in the case of natural depletion steeply declines from the initial reservoir pressure to the bottom hole pressure target or minimum bottom hole pressure at 500 psia. During this period, the well produces at a constant gas production rate. Thus, the bottom hole pressure is reduced in order to sustain that constant rate. However, when the reservoir cannot produce gas at the given rate any longer, the control is switched to constant bottom hole pressure rather than constant rate. Thus, the bottom hole pressure is kept constant and gas continues to produce till the production well is shut-in at abandonment.

In case of production with gas cycling, the bottom hole pressure of the production well is more horizontally flat and maintained approximately at the initial pressure. This constant bottom hole pressure results from gas cycling. The well bottom hole pressure is constant until the well oil production rate reaches the minimum oil production rate or economic limit. At this condition, gas cycling process is stopped and the injection well is switched to production well. Consequently, the bottom hole pressure immediately drops to 500 psia, and is constant onward till both production wells are shut-in at abandonment.

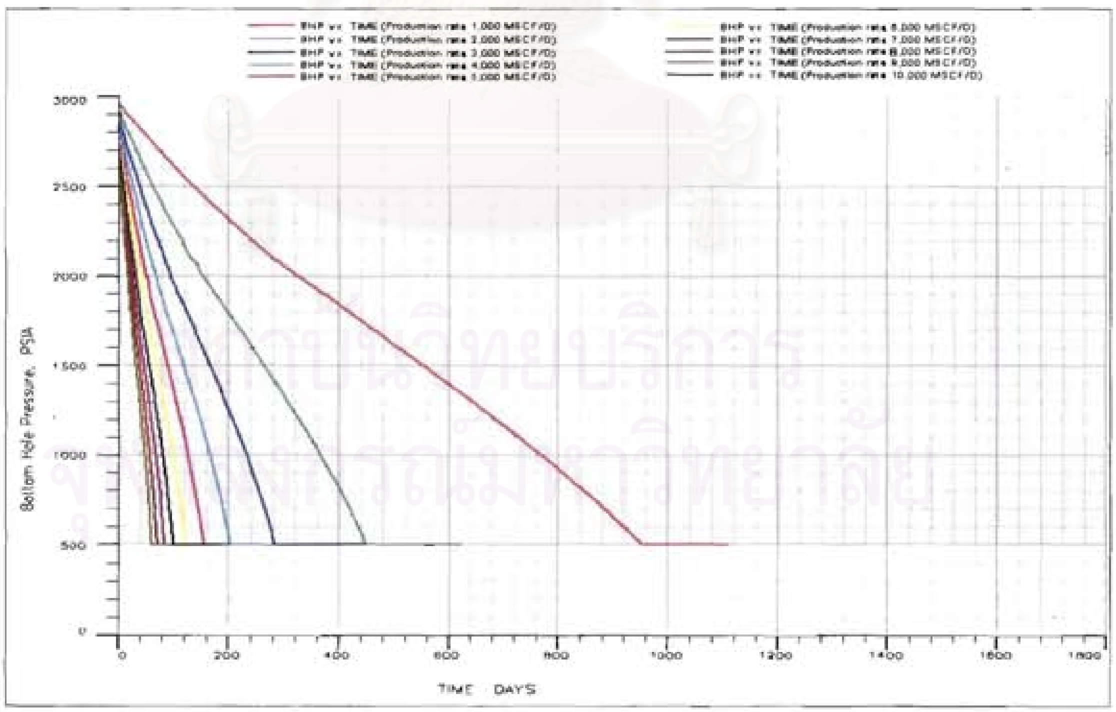

Figure 5.32: Bottom hole pressure (BHP) of production well for maximum gas production rate between 1,000-10,000 MSCF/D with natural depletion.

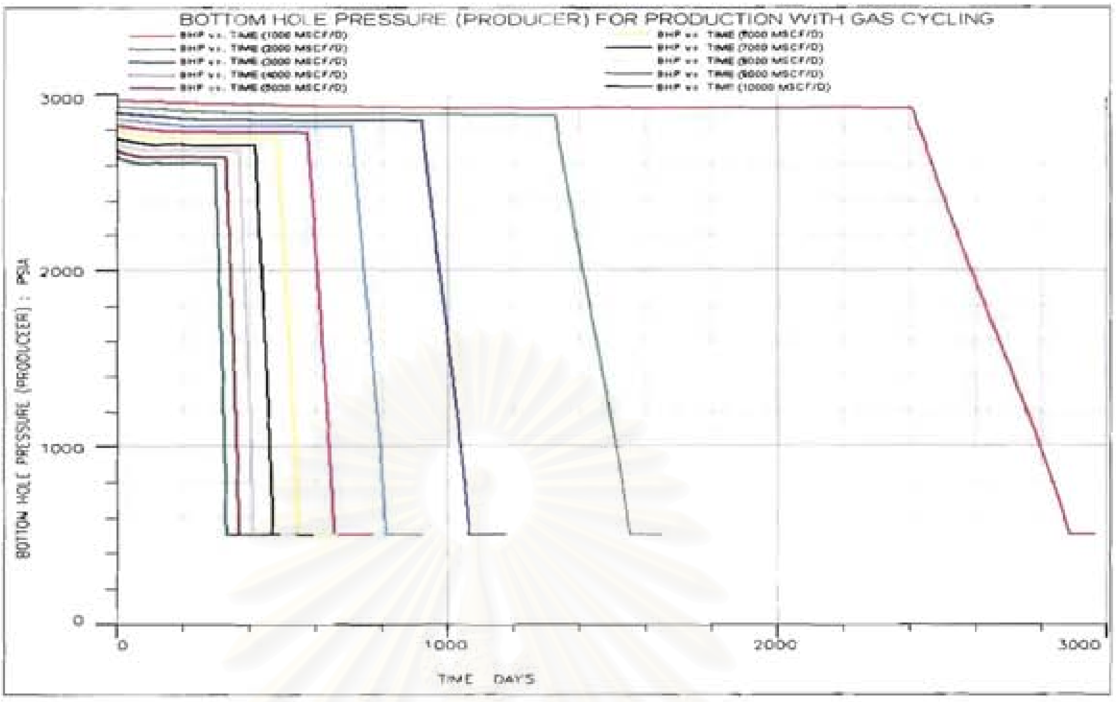

Figure 5.33: Bottom hole pressure (BHP) of production well for maximum gas production rate between 1,000-10,000 MSCF/D with gas cycling.

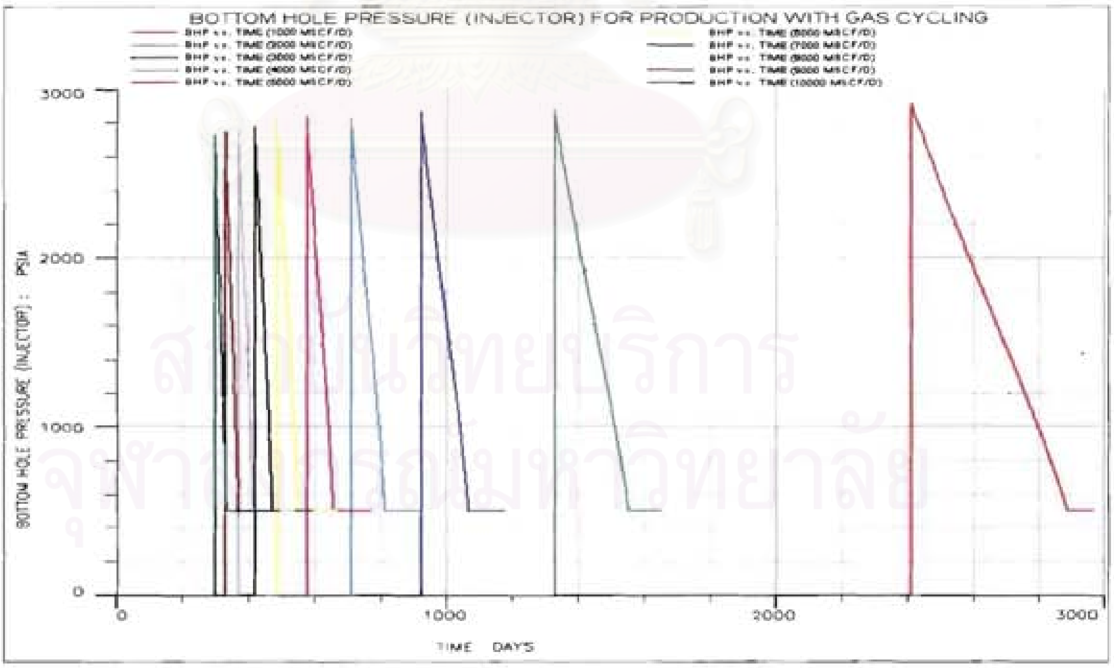

Figure 5.34: Bottom hole pressure (BHP) of injection well for maximum gas production rate between 1,000-10,000 MSCF/D with gas cycling.

5.7.3 Gas Production Total

From the simulation results, natural depletion of gas condensate reservoir produces an equivalent cumulative gas or gas production total (GPT) to the production with gas cycling. Table 5.11 summarizes results of gas production total from both production by natural depletion and production with gas cycling for maximum production rate between 1,000-10,000 MSCF/D. Figure 5.35 depicts the simulation result of GPT. At each production rate, gas production total from production with gas cycling yields about 1% lower than production by natural depletion.

Table 5.11: Field gas production total (FGPT) for maximum gas production rate between 1,000 – 10,000 MSCF/D by natural depletion and gas cycling.

Production Rate (MSCF/D)	Gas Production Total : Production by Natural Depletion (MMSCF)	Gas Production Total : Production with Gas Cycling (MMSCF)	Percentage of Gas Reduction (%)
1,000	1,022	1,012	**0.96**
2,000	1,022	1,012	**1.02**
3,000	1,023	1,012	**1.08**
4,000	1,023	1,011	**1.14**
5,000	1,023	1,011	**1.13**
6,000	1,023	1,011	**1.18**
7,000	1,023	1,012	**1.03**
8,000	1,022	1,012	**1.02**
9,000	1,023	1,011	**1.14**
10,000	1,022	1,011	**1.12**

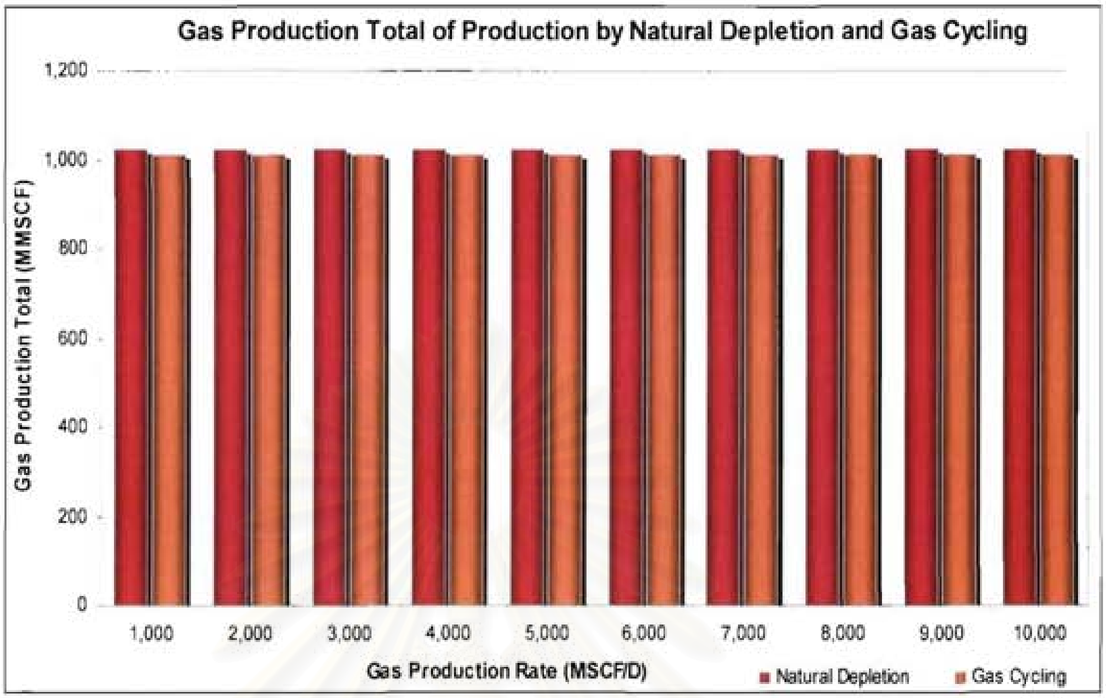

Figure 5.35: Gas production total (GPT) of production with natural depletion and with gas cycling for maximum production rate between 1,000-10,000 MSCF/D.

5.7.4 Oil Production Total

The oil production total (OPT) for both scenarios of production is tabulated in Table 5.12. Figure 5.36 depicts the data shown in Table 5.12 in a graphical form. The oil production total from production with gas cycling is about 68-73% higher than production by natural depletion. The reservoir pressure maintenance with gas cycling significantly increases oil production total (OPT).

Table 5.12: Oil production total (OPT) of production with natural depletion and with gas cycling for maximum production rate between 1,000 – 10,000 MSCF/D.

Production Rate (MSCF/D)	Natural Depletion : Oil production total (STB)	Gas Cycling : Oil production total (STB)	Percentage of Oil Increasing (%)
1,000	87,878.84	148,076.31	**68.50**
2,000	87,849.08	148,920.95	**69.52**
3,000	87,826.16	149,209.70	**69.89**
4,000	87,647.77	149,379.05	**70.43**
5,000	87,455.78	149,456.80	**70.89**
6,000	87,199.38	149,512.41	**71.46**
7,000	87,181.66	149,569.34	**71.56**
8,000	87,029.41	149,573.03	**71.86**
9,000	86,898.48	149,612.47	**72.17**
10,000	86,746.99	149,630.44	**72.49**

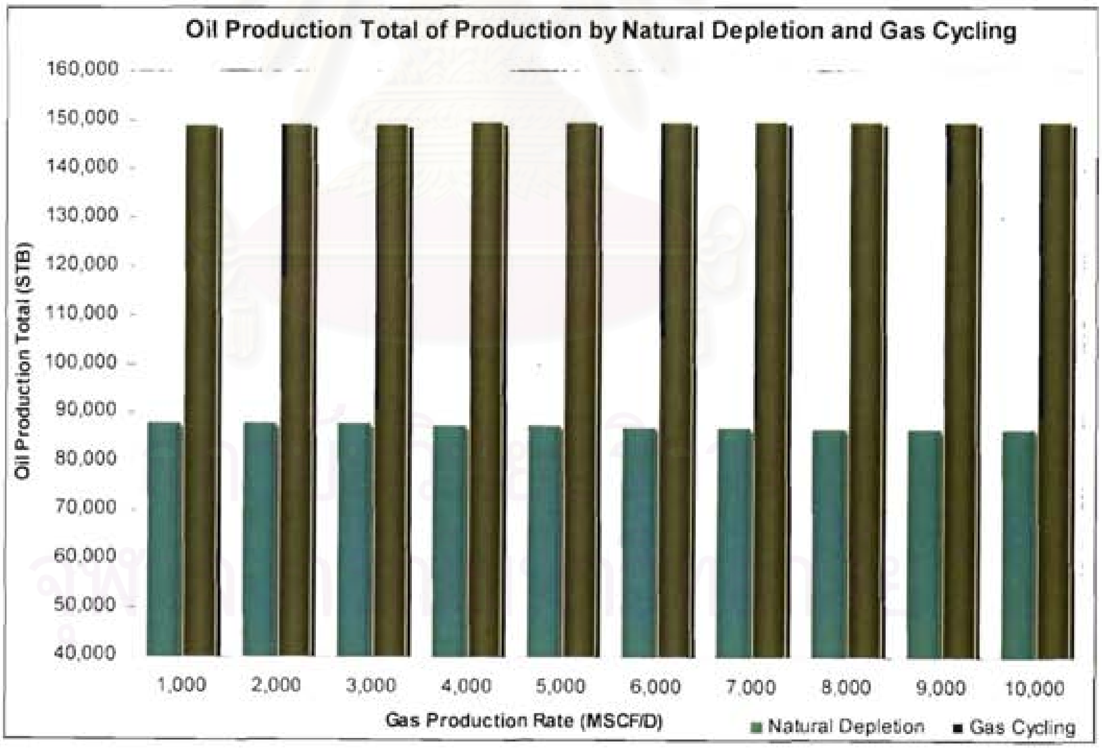

Figure 5.36: Oil production total (OPT) of production with natural depletion and with gas cycling for maximum production rate between 1,000-10,000 MSCF/D

5.7.5 Economic Comparison for Production Profiles

In summary, the simulation results for all production scenarios are analyzed in term of economics. As discussed at the end of Chapter IV, net present value (NPV) is an appropriate economic parameter that can be used as a criterion for the optimum production profile of gas-condensate reservoir. The net present values for all production scenarios in this study are tabulated in Table 5.13. For this particular gas-condensate reservoir, production with gas cycling remunerates the higher net present value compared with production by natural depletion. In additional, longer starting time of gas injection contributes to higher net present value compared with production with gas cycling. Disregarding the case of production rate of 10,000 MSCF/D and timely gas injection 40 and 60 days, the net present values of all scenarios have the same trend that NPV increases when producing at increasing production rate. For production with gas cycling, timely gas injection is slightly superior to injecting gas right at the beginning.

Table 5.13: Net present value (NPV) for all studied scenarios.

Net Present Value (NPV, US$)					
Production Rate (MSCF/D)	Production Profiles				
	Natural Depletion	Gas Cycling	Timely Gas Injection		
			20 days	40 days	60 days
1,000	8,746,181	8,266,859	8,480,262	8,706,246	8,923,205
2,000	9,384,212	10,179,164			
3,000	9,591,705	11,066,246			
4,000	9,701,580	11,219,176			
5,000	9,756,619	11,596,086	11,986,536	12,161,215	12,175,372
6,000	9,802,882	11,860,672			
7,000	9,831,469	11,847,922			
8,000	9,846,545	12,022,066			
9,000	9,860,223	12,156,129			
10,000	9,863,642	12,113,794	12,464,254	11,758,051	10,747,472

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

This chapter presents the conclusions of the optimal injection and production strategy for gas-condensate reservoir. The simulation results and economic analysis for various scenarios and the recommendations for future works are outlined.

To evaluate the strategy of optimizing hydrocarbon production from gas-condensate reservoir, pressure maintenance by gas cycling was selected as an alternative strategy besides natural completion. A simple reservoir model and normal five-spot flooding pattern was used in the study. After constructing the reservoir model and entering required input data, three different scenarios were simulated:
(1) producing the gas-condensate reservoir by natural depletion with one production well, located at the center of the reservoir, (2) producing the gas-condensate reservoir with gas cycling for reservoir pressure maintenance, and (3) producing the gas-condensate reservoir with timely gas injection. The gas production rate during the plateau period was varied between 1,000-10,000 MSCF/D. Results from simulation runs such as cumulative gas and oil production, production and injection rates, well bottom hole pressure were analyzed. The scenario details for the simulation are described as follows:

1. Natural depletion
    a) One production well located at center of reservoir and was opened to production by natural depletion. The production rate during the plateau period varied between 1,000-10,000 MSCF/D.
    b) The production stopped when controlled production rate reaches economic limit: oil production rate less than 3 STB/D and gas production rate less than 100 MSCF/D.
    c) Each profile was economically evaluated using economic decision tools: NPV, IRR and Payback period.

2. Production with gas cycling
   a) One production well and one injection well located at opposite corners of a quarter five-spot flooding pattern. Gas cycling is started right away after the producer was put on production. All of the gas produced was reinjected back into the reservoir. The production/injection rate was varied between 1,000-10,000 MSCF/D.
   b) When the oil production rate reaches the economic limit, the injection well is switched to production well. The economic rate for each scenario was calculated based on the cost of gas injection. From this point, the production continues from two producers till abandonment at gas production rate less than 100 MSCF/D.
   c) Each profile was economically evaluated using economic decision tools: NPV, IRR and Payback period.

3. Production and timely gas injection
   a) One production well and one injection well located at opposite corners of a quarter five-spot flooding pattern. Initially, both wells were used for production until the timely gas injection at 20, 40, and 60 days, when the injection well resumed its function. The production/injection rate was varied at 1,000, 5,000 and 10,000 MSCF/D, respectively.
   b) When the oil production rate reaches the economic limit, the injection well is switched to production well. The economic rate for each scenario was calculated based on the cost of gas injection. From this point, the production continues from two producers till abandonment at gas production rate less than 100 MSCF/D.
   c) Each profile was economically evaluated using economic decision tools: NPV, IRR and Payback period.

6.1 Conclusions

Based on a specific set of input data, simulation results obtained from ECLIPSE 300 simulator, and economic data, the optimal production and injection strategy for gas-condensate reservoir can be concluded as follows:

6.1.1 Theoretical Point of View

a) Gas injection or gas cycling does effectively maintain the reservoir pressure above the dew point pressure, preventing condensate dropout within the reservoir.

b) Gas cycling enhances the production of condensate from gas-condensate reservoir with significantly improved oil recovery while compared to production by natural depletion.

6.1.2 Quantitative Point of View

a) Production by natural depletion yields equivalent volume of cumulative gas production compared to the result from production with gas cycling.

b) Production with gas cycling gives about 68-73% increase in cumulative oil production compared to production by natural depletion.

c) Timely gas injection provides insignificant difference on oil production total (OPT) relative to production with gas cycling.

6.1.3 Economic Point of View

a) For this particular gas-condensate reservoir, production with reservoir pressure maintenance: gas cycling or timely gas injection, has superior economic criterion (NPV) compared to production by natural depletion.

b) For all scenarios, production at the higher production rate results in higher NPV and shorter payback period.

6.2 Recommendations

The following points are recommended for future study:

a) Since the oil price has fluctuated according to world economic situation, sensitivity of oil price could affect the economic analysis. The changes in the oil and gas prices may affect the decision to determine which scenario is the most economic.

b) Equality of production and injection rate for production with gas cycling can maintain gas-condensate reservoir pressure above the dew point. The reservoir pressure can be kept close to the initial reservoir pressure during the plateau period. After that, gas injection is then stopped. Gas is then produced until abandonment. In this case, we loss the opportunity to sell gas at the starting production. Therefore, we may inject only a certain amount of the produced gas and sell the un-injected amount. The injected gas should be able to support the reservoir pressure to a certain degree, and at the same time, we still have a certain amount of income from selling gas.

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APPENDICES

APPENDIX A

A-1) Reservoir model

The reservoir model is generated by input the required data in Eclipse simulator. The geological model composes of number of cells or blocks in X, Y and Z directions and in this study, the number of block is 35 x 35 x 8.

<u>Reservoir</u>

- Grid option	
Grid type	Cartesian
- Geometry option	
Geometry type	Block Centred

<u>PVT</u>

- Oil-Gas-Water Options	Water
	Gas Condensate (ISGAS)
- Simulation Types	Number of Components 10

<u>Misc/Sched</u>

Pressure Saturation Options	
Solution Type	AIM
General Option	
Max rate of Pc change	0.01
Number of cells in domain	500
Size of vector property table	1000
Number of Iterations to Update Well Flow Targets	3
Parallel Option	
Type of run	Distributed

A-2) Reservoir properties

Grid

Properties:	Active grid blocks	X (35)	=	1	
		Y (35)	=	1	
		Z (8)	=	1	
	Porosity		=	0.165	
	Permeability	k-x	=	10.85	mD
		k-y	=	10.85	mD
		k-z	=	1.27	mD
	Net thickness	100	feet (12.5 x 8)		

PVT [Gas Condensate]: PVT Table

Water PVT Properties	Reference pressure(Pref)	3000	Psia
	Water FVF at Pref	1.060897	Rb/stb
	Water viscosity at Pref	0.1892652	cp
	Water viscosibility	5.376165E-6	/psi
Fluid Densities at Surface Conditions	Oil density	49.99914	Lb/ft^3
	Water density	62.42797	Lb/ft^3
	Gas density	0.04947417	Lb/ft^3
Rock Properties	Reference Pressure	3000	Psia
	Rock Compressibility	2.403571E-6	/psi

A-3) Miscellaneous

Number of Component	Number of Component	10	
Standard Condition	Standard Temperature	60	F
	Standard Pressure	14.7	Psia
Component Names	Component 1	C_1	
	Component 2	C_2	
	Component 3	C_3	
	Component 4	$i\text{-}C_4$	
	Component 5	$n\text{-}C_4$	
	Component 6	$i\text{-}C_5$	
	Component 7	$n\text{-}C_5$	
	Component 8	C_6	
	Component 9	C_{7+}	
	Component 10	CO_2	
PROPS Reporting Options	Oil PVT Tables	No output	
	Gas PVT Tables	No output	
	Water PVT Tables	No output	

EoS Res Tables

Pure Component Boiling Points (Reservoir EoS)	Component C_1	200.94	R
	Component C_2	332.18	R
	Component C_3	415.92	R
	Component IC_4	470.45	R
	Component NC_4	490.75	R
	Component IC_5	521.79	R
	Component NC_5	556.59	R
	Component C_6	615.39	R
	Component C_{7+}	734.08	R
	Component CO_2	350.413	R
Critical Temperature (Reservoir EoS)	Component C_1	343	R
	Component C_2	549.59	R
	Component C_3	665.73	R
	Component IC_4	734.13	R
	Component NC_4	765.29	R
	Component IC_5	828.77	R
	Component NC_5	845.47	R
	Component C_6	913.27	R
	Component C_{7+}	1061.29	R
	Component CO_2	547.58	R
Constant Reservoir Temperature	Initial Reservoir Temperature	293	F
Critical Volume (Reservoir EoS)	Component C_1	0.0988	ft^3/lb-mole
	Component C_2	0.0783	ft^3/lb-mole
	Component C_3	0.0727	ft^3/lb-mole
	Component IC_4	0.0714	ft^3/lb-mole
	Component NC_4	0.0703	ft^3/lb-mole
	Component IC_5	0.0679	ft^3/lb-mole
	Component NC_5	0.0675	ft^3/lb-mole
	Component C_6	0.0688	ft^3/lb-mole
	Component C_{7+}	7.509	ft^3/lb-mole
	Component CO_2	0.0344	ft^3/lb-mole
Overall Composition	Component C_1	59.991	%
	Component C_2	8.4326	%
	Component C_3	6.3988	%
	Component IC_4	3.4127	%
	Component NC_4	3.8989	%
	Component IC_5	1.4286	%
	Component NC_5	1.3988	%
	Component C_6	7.2718	%
	Component C_{7+}	6.5366	%
	Component CO_2	1.2302	%

Critical Pressure (Reservoir EoS)	Component C_1	666.4	Psia
	Component C_2	706.5	Psia
	Component C_3	616	Psia
	Component IC_4	527.9	Psia
	Component NC_4	550.6	Psia
	Component IC_5	490.4	Psia
	Component NC_5	488.6	Psia
	Component C_6	436.9	Psia
	Component C_{7+}	403.29	Psia
	Component CO_2	1071	Psia
Equation of State (Reservoir EoS)	Equation of State Method	PR (Peng-Robinson)	
Molecular Weights (Reservoir EoS)	Component C_1	16.043	
	Component C_2	30.07	
	Component C_3	44.097	
	Component IC_4	58.123	
	Component NC_4	58.123	
	Component IC_5	72.15	
	Component NC_5	72.15	
	Component C_6	86.177	
	Component C_{7+}	115	
	Component CO_2	44.01	
Binary Interaction Coefficients (Reservoir EoS)	BIC_1 to BIC_9		
Acentric Factor (Reservoir EoS)	Component C_1	0.0104	
	Component C_2	0.0979	
	Component C_3	0.1522	
	Component IC_4	0.1852	
	Component NC_4	0.1995	
	Component IC_5	0.228	
	Component NC_5	0.2514	
	Component C_6	0.2994	
	Component C_{7+}	0.38056	
	Component CO_2	0.2667	

A-4) SCAL

Saturation Function

Oil Saturation Functions	Row	So	Krow	Krowg
	1	0	0	0
	2	0.2	0	0
	3	0.32	0.00463	0.015625
	4	0.44	0.037037	0.125
	5	0.56	0.125	0.421875
	6	0.68	0.296296	1
	7	0.95	1	1

Water Saturation Function	Row	Sw	Krw	Pc (psia)
	1	0.11	0	250
	2	0.157	0	53
	3	0.216	0	13
	4	0.313	0.02	1
	5	0.44	0.06	0
	6	0.56	0.10	0
	7	0.68	0.15	0
	8	0.80	0.30	0
	9	0.90	0.65	0
Gas Saturation Function	Row	Sg	Krg	Pc (psia)
	1	0	0	
	2	0.1	0	
	3	0.2	0	
	4	0.3	0.2	
	5	0.4	0.4	
	6	0.6	0.85	
	7	0.7	0.90	
	8	0.8	0.92	
	9	0.9	0.95	
	10	0.95	0.95	

A-5) Initialization Equilibration

Equilibration Region	Keywords	NEI (Non-Equilibrium Initialisation)	
EquilReg 1	Non-Equilibrium Initialisation	Row	Fractions
		1	0.59991
		2	0.084326
		3	0.063988
		4	0.034127
		5	0.038989
		6	0.014286
		7	0.013988
		8	0.072718
		9	0.065366
		10	0.012302

Region/Array

Initial Water Saturation (SWAT) : 0.11

Initial Gas Saturation (SGAS) : 0.89

Initial Pressure : 3000 psia

Dew Point Pressure : 2150 psia

A-6) Region N/A

A-7) Schedule

Production

Well Specification (Prod1) [WELSPECS]

Well	Prod1
Group	1
I Location	1
J Location	1
Preferred Phase	Gas
Inflow Equation	STD
Automatic Shut-In instruction	Shut
Cross Flow	Yes
Density calculation	SEG
Type of Well Model	STD

Well Connection Data (Prod1) [COMPDAT]

Well	Prod1
K Upper	1
K Lower	8
Open/Shut Flag	Open
Well bore ID	0.625 ft.
Direction	Z

Production Well Control (Prod1) [WCONPROD]

Well	Prod1
Open/Shut Flag	Open
Control	GRAT
Gas rate	1000 MSCF/D
BHP target	500 psia

Production Well Economics Limit [WECON]

Well	Prod1
Minimum oil rate	3 STB/D
Minimum gas rate	100 MSCF/D
Workover procedure	None
End run	YES

Print File Output Control [RPTSCHED]

Grid block pressure
Grid block oil saturation
Grid block water saturation
Grid block gas saturation
Liquid component mole fraction

Restart File Output Control [RPTRST]

Grid block pressure
Grid block oil saturation
Grid block water saturation
Grid block gas saturation
Restart No Output

Injection

Well Specification (Inj1) [WELSPECS]

Well	Inj1
Group	-
I Location	35
J Location	35
Preferred Phase	Gas
Inflow Equation	STD
Automatic Shut-In instruction	Shut
Cross Flow	Yes
Density calculation	SEG
Type of Well Model	STD

Well Connection Data (Inj1) [COMPDAT]

Well	Inj1
K Upper	1
K Lower	8
Open/Shut Flag	Open
Well bore ID	0.625 ft
Direction	Z

Injection Well Control (Inj1) [WCONINJE]

Well	Inj1
Injector type	Gas
Open/Shut Flag	Open
Control Mode	Rate
Gas Surface Rate	1000 MSCF/D

Nature of Injection Gas (Inj1) [WINJGAS]

Well	Inj1
Injection fluid	Gas
Well stream	1

Injection Gas Composition [WELLSTRE]

Well Stream	1
Comp1	0.67018
Comp2	0.09385
Comp3	0.07031
Comp4	0.03648
Comp5	0.04082
Comp6	0.01354
Comp7	0.01256
Comp8	0.04387
Comp9	0.00469
Comp10	0.0137

APPENDIX B

Flash calculation and standard condition

Expt FLASH1 : Flash Calculation

Peng-Robinson (3-Parm) on ZI with PR corr.
Lohrenz-Bray-Clark Viscosity Correlation
Two phase state

Specified temperature	Deg F	60.0000
Specified pressure	PSIA	14.7000
Mole Percentage in vapour		90.1970
Calculated GOR	MSCF/BBL	8.9307

Fluid properties	Liquid	Vapour
	Calculated	Calculated
Mole Weight	101.0560	28.4821
Z-factor	0.0058	0.9942
Viscosity	0.4636	0.0113
Density LB/FT3	46.0377	0.0755
Molar Vol CF/LB-ML	2.1951	377.1522

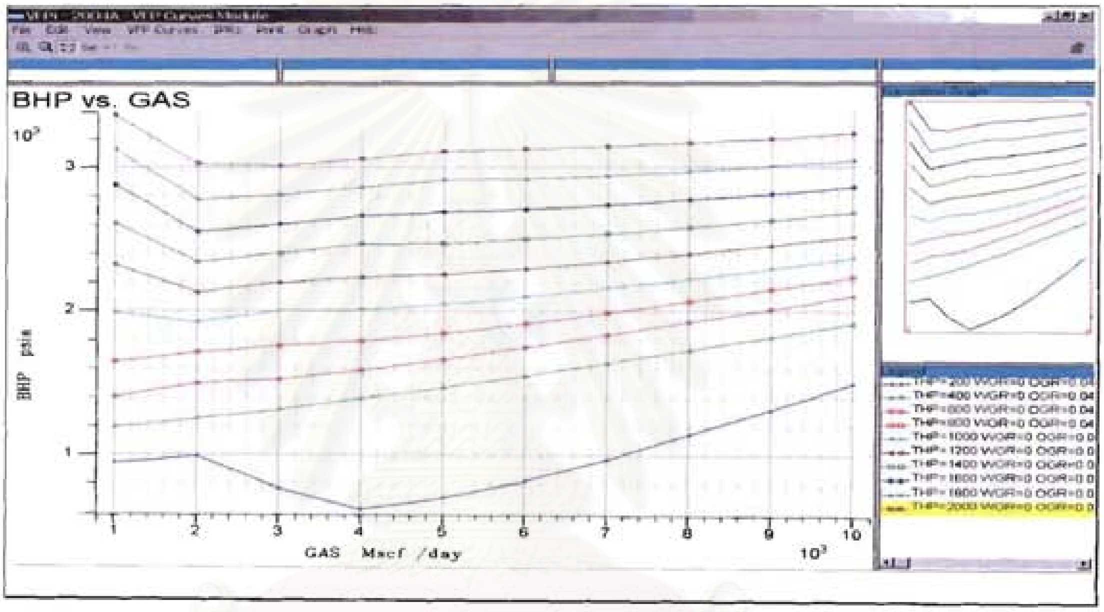
Molar Distributions Components		Total, Z	Liquid,X	Vapour,Y	K-Values
Mnemonic	Number	Measured	Calculated	Calculated	Calculated
CO_2	1	1.2302	0.0840	1.3548	16.1223
C_1	2	59.9910	0.2890	66.4797	230.0125
C_2	3	8.4326	0.3501	9.3110	26.5967
C_3	4	6.3988	0.9774	6.9880	7.1494
$I\text{-}C_4$	5	3.4127	1.8282	3.5849	1.9609
$N\text{-}C_4$	6	3.8989	2.0886	4.0957	1.9609
$I\text{-}C_5$	7	1.4286	2.2477	1.3396	0.5960
$N\text{-}C_5$	8	1.3988	2.2008	1.3116	0.5960
C_6	9	7.2718	29.4002	4.8668	0.1655
C_{7+}	10	6.5366	60.5339	0.6679	0.0110
Composition Total		100.0000	100.0000	100.0000	

APPENDIX C

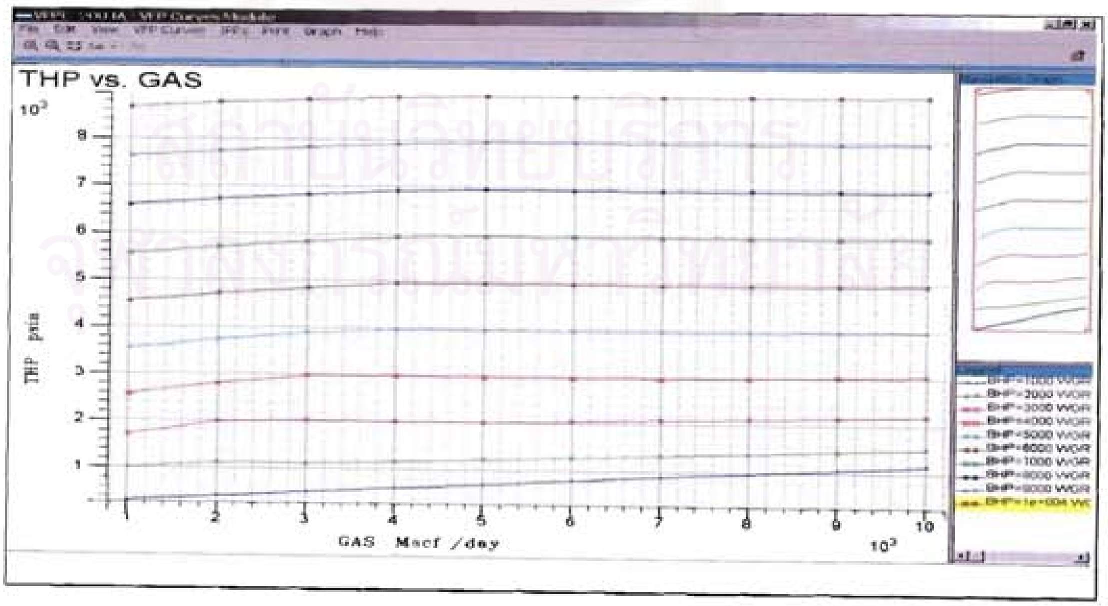
C-1) Vertical Flow Performance (VFPi)

Vertical Flow Performance or VFPi is used in study the aspects of pressure traverse calculations along wells of production and injection. The VFP table can be generated and examine production and injection. The pressure loss from wells is examined.

1) Vertical flow performance for production well



2) Vertical flow performance for injection well



APPENDIX D

D-1) Compressor specification and Cost

Compressor Spec

Make	:	
Type	:	Reciprocating
Design capacity	:	14.0 MMSCFD
Operating capacity	**:**	**12.5 MMSCFD**
Operating suction pressure	:	275 psig
Operating discharge pressure	:	1,350 psig (Δp = 1,075 psig)
Operating temperature	:	50 C
Estimated required power	:	1,400 HP
Driver	:	

Table D-1 Cost estimate

Items	**Cost[1] (1000 US$)**	**Cost (MTHB)**
PDS Tariff - Detailed design - Construction - Project management	 25.0 30.0 25.0	 1.0 1.2 1.0
Materials - Compressor package - Compressor frame and cylinders - F&G lube system - Pulsation dampener and separator - Air cooler - Gas engine driver - Skid - Water cooling system - PLC control unit - Drawings	1,760	70.4
- Transportation and insurance for major equipment	137.5	5.5
- Foundation and grouting work	100.0	4.0
- Mechanical modification	50.0	2.0
- Instrumentation (replace the aging facility)	25.0	1.0
- Electrical modification (hook-up to power supply from the existing facility)[2] - Soft starter panel, 110 kW, IP55 for fan motor - Cables - RCU - Small distribution board - Lightings - Splice box - Accessories	112.5	4.5
- Modification of fire and gas detection system - New sensor units (5 sets) - Modification of existing fire and gas alarm panel - Software	30.0	1.2
- Commissioning spare parts[3]	0.0	0.0

- Other bulks	25.0	1.0
Construction and Commissioning Cost		
- Civil work	20.0	0.8
- Mechanical work	37.5	1.5
- Electrical work4	20.0	0.8
- Instrument work	5.0	0.2
- Third party inspection of K-3850 at the factory	15.0	0.6
- Installation, commissioning, and training (vendor)	60.0	2.4
- Contingency (10%)	247.75	9.91
Total	**2,725.25**	**109.01**

The above costs form part of BI 5DXX

Notes:

1. Assumed currency exchange rate = 40 Baht/USD
2. Cost for electrical facility has been based on the estimated electrical consumption (by the air cooler fan) of 90-110 kW.

D-2) Electrical/Power consumption calculation

Pumping power is defined as the time-rate of pumping work. It is related to pumping rate and pressure by

$$power = \frac{work}{time} = q\Delta p$$

The customary unit of power for combustion engines is horsepower (HP) and for electrical motors is the kilowatt (kw). The power units are related by

1 HP = 0.746kw.

The approximate compressor power

$$P = 0.23q_g\left[\left(\frac{p_2}{p_1}\right)^{0.2} - 1\right]$$

where

q_g	is gas compression rate, mscf/D
p_1	is compressor suction pressure, psia
p_2	is compressor discharge pressure, psia
P	is compression power, HP

Production / Injection Rate: (MSCF/D)	Power (HP)	Power (kw)	Consumption Total Power Cost(USD/Year) EGAT Power	Consumption TPC(US$/Day) EGAT Power	Economic Limit : Minimum Oil Rate (STB/D)
1000	83.58	59.84	23,538.66	64.49	4.03
2000	167.16	119.68	47,077.32	128.98	5.06
3000	250.73	179.53	70,619.91	193.48	6.10
4000	334.31	239.37	94,158.97	257.97	7.13
5000	417.89	299.21	117,697.23	322.46	8.16
6000	501.47	359.05	141,235.89	386.95	9.19
7000	585.05	418.89	164,774.55	451.44	10.22
8000	668.62	478.73	188,313.21	515.93	11.25
9000	752.2	538.58	211,855.80	580.43	12.29
10000	835.78	598.42	235,394.46	644.92	13.32

D-3) Calculation of Btu for produced gas

Component	**Mole Fraction** y_j	**Gross Heating value, (Btu/scf)** L_{cj}	$y_j{*}L_{cj}$	**Compressibility Factor at Standard Conditions**	
				z_j	$y_j(1\text{-}zj)^{0.5}$
C1	0.67018	1010.0	676.8818	0.9980	0.0299714
C2	0.09385	1769.6	166.077	0.9919	0.0084465
C3	0.07031	2516.1	176.907	0.9825	0.0093011
i-C4	0.03648	3251.9	118.6293	0.9711	0.0062016
n-C4	0.04082	3262.3	133.1671	0.9667	0.007449
i-C5	0.01354	4000.9	54.17219	0.9480	0.0030876
n-C5	0.01256	4008.9	50.35178	0.9420	0.0030248
C6	0.04387	4755.9	208.6413	0.9100	0.013161
C7+	0.00469	5502.5	25.80673	0.8520	0.0018043
CO2	0.0137	0.0	0	0.9943	0.0010343
	1.0000		**1610.634**		**0.0834816**

$$Z = 1 - (\textstyle\sum y_j (1-z_j)^{0.5})^2$$

$$Z = 1 - (0.0834816)^2$$

$$= 0.993031$$

$$L_c = L_{c\ ideal} \ / \ z$$

$$L_c = (1610.634 \text{ Btu/scf}) / 0.993031$$

$$\textbf{Btu / scf} = \textbf{1621.938}$$

Vitae

Suphanai Jamsutee was born on November 12th , 1974 in Rayong, Thailand. He received his Bachelor of Engineering in Chemical Engineering from the Faculty of Engineering, Burapha University in 1997. He has been a graduate student in the Master's Degree Program in Petroleum Engineering of the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2003.