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EVALUATION OF IN-SITU GAS LIFT FOR MONOBORE OIL WELLS WITH COMMINGLED PRODUCTION IN PATTANI BASIN

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
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จิตรลดา อรรถศิวานนท์: การประเมินการใช้แก๊สจากแหล่งกักเก็บเพื่อช่วยผลิตน้ำมัน สำหรับหลุมผลิตที่มีแหล่งกักเก็บน้ำมันสำรองหลายชั้นในแอ่งปัตตานี. (EVALUATION OF IN-SITU GAS LIFT FOR MONOBORE OIL WELLS WITH COMMINGLED PRODUCTION IN PATTANI BASIN) อ. ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 106 หน้า

โดยทั่วไปแล้ว แหล่งกักเก็บน้ำมันในแอ่งปัตตานีในอ่าวไทย มักจะมีลักษณะเป็นชั้นย่อยๆที่ถูกแบ่งแยกโดยรอยเลื่อนของชั้นหิน แต่ละชั้นหินกักเก็บน้ำมันมักจะมีขนาดเล็กเมื่อเทียบกับชั้นกักเก็บน้ำมันแบบอื่นๆ และโดยส่วนใหญ่แล้ว ชั้นหินกักเก็บเหล่านี้มักจะซ้อนทับกันเป็นชั้นๆ ซึ่งทำให้ทางออกในการพัฒนาแหล่งกักเก็บน้ำมันที่เล็กดังกล่าวในเชิงพาณิชย์นั้นมีอยู่อย่างจำกัด ด้วยสาเหตุนี้เองหลุมผลิตขนาดเล็กแบบผลิตร่วมกันจึงกลายเป็นวิธีส่วนใหญ่ที่ถูกเลือกใช้ในการขุดเจาะและผลิต หลุมผลิตขนาดเล็กสามารถขุดเจาะผ่านแหล่งกักเก็บหลายๆชั้นได้ โดยปกติแล้วแหล่งกักเก็บทั้งหมดในหลุมผลิตนี้จะถูกผลิตพร้อมๆกัน เป็นที่น่าสังเกตุว่าแหล่งกักเก็บขนาดเล็กเหล่านี้จะมีระยะเวลาการผลิตด้วยการไหลโดยธรรมชาติที่ค่อนข้างสั้น ดังนั้นในบางกรณีหลุมผลิตขนาดเล็กเหล่านี้จะมีการติดตั้งอุปกรณ์ช่วยผลิตโดยใช้แก๊ส แต่เนื่องด้วยค่าใช้จ่ายในการลงทุนและการดำเนินการที่สูงจึงทำให้มีผลกระทบต่อการผลิตเชิงพาณิชย์ในบางกรณี เพราะสาเหตุนี้เองหลุมผลิตขนาดเล็กจำนวนไม่น้อยที่ผลิตโดยไม่การติดตั้งอุปกรณ์ช่วยผลิต

เพราะฉะนั้นหลุมผลิตขนาดเล็กที่ในแหล่งกักเก็บมีชั้นกักเก็บก๊าซจะมีความสำคัญมากต่อประสิทธิภาพการผลิตของหลุม โดยถ้าได้รับการจัดการอย่างเหมาะสม แก๊สจากชั้นกักเก็บในหลุมจะช่วยเพิ่มอัตราส่วนแก๊สต่อของเหลวให้เหมาะสมในการช่วยเพิ่มปริมาณการผลิต และเพิ่มปริมาณสำรอง

วิทยานิพนธ์นี้ได้ศึกษาตัวแปรบางตัวของแหล่งกักเก็บที่มีผลกระทบต่อการเพิ่มปริมาณสำรองของน้ำมันโดยใช้เทคนิคของการใช้แก๊สจากชั้นกักเก็บในหลุมเพื่อช่วยผลิตน้ำมันสำหรับหลุมผลิตขนาดเล็กที่ผลิตจากชั้นกักเก็บร่วมกันหลายชั้นในแอ่งปัตตานี เทียบกับการผลิตโดยใช้อุปกรณ์ช่วยผลิตที่ใช้แก๊ส

จากการศึกษาสามารถสรุปได้ว่า หลุมผลิตน้ำมันที่ใช้แก๊สจากแหล่งกักเก็บในหลุมจะสามารถผลิตน้ำมันได้โดยมีค่าระดับการได้คืนของปริมาณสำรองที่ผลิตได้นั้นใกล้เคียงและในบางกรณีมากกว่าหลุมผลิตน้ำมันที่ติดตั้งอุปกรณ์ช่วยผลิตที่ใช้แก๊ส นอกจากนั้นแล้วยังพบว่าระดับการได้คืนของปริมาณสำรองจากการใช้แก๊สจากชั้นกักเก็บในหลุมเพื่อช่วยผลิตน้ำมันสามารถจะขึ้นกับความลึกของชั้นกักเก็บ และหรือ ความหนาของชั้นกักเก็บ หรือปริมาณสำรองแก๊สที่มากขึ้น หรือตารางการยิงเจาะหลังจากที่มีการผลิตไปแล้ว แต่ปริมาณสำรองอาจจะไม่ได้เพิ่มขึ้นเสมอไปถ้าค่าการซึมผ่านของชั้นกักเก็บแก๊สเพิ่มขึ้น

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สาขาวิชา.....วิศวกรรมปิโตรเลียม............. ลายมือชื่ออาจารย์ที่ปรึกษาวิทยานิพนธ์หลัก..........................

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KEYWORDS: IN-SITU GAS LIFT FOR MONOBORE OIL WELLS WITH COMMINGLED PRODUCTION IN PATTANI BASIN

CHITRLADA ARDTHASIVANON: EVALUATION OF IN-SITU GAS LIFT FOR MONOBORE OIL WELLS WITH COMMINGLED PRODUCTION IN PATTANI BASIN. THESIS ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 106 pp.

Typically, oil reservoirs in Pattani Basin in the Gulf of Thailand are highly faulted, relatively small compared to other reservoirs elsewhere, and most of the time they are multiple and stacked. In order to make the marginal reservoirs economically attractive, there is limited development option and almost by default the slim monobore completion is selected to justify the small reserves. Basically, this monobore completion allows one single well to accommodate as many hydrocarbon zones as possible. Most of the time, all zones are perforated and produced commingledly. It is generally observed that natural flow periods of these small reservoirs are short. In some cases, these monobore oil wells can be completed with conventional gas lift to extend its production or increase recovery factor. However, in some cases, both capital and operating costs of gas lift have a great impact on these economically burdened fields, especially the offshore environment. As a result, it is not always economic to drill and complete oil wells with conventional gas lift and many monobore oil wells are completed without gas lift for economic reason. Therefore, the gas zones in these monobore oil wells without gas lift become very important because these gas zones, if managed properly, can provide additional in-situ gas to increase or optimize the well's GLR; thus increased oil production rate or reserve recovery factor.

This thesis is to study some pre-determined variables that affect the oil recovery factor using the in-situ gas lift technique in the monobore oil wells with commingled production and compared to the monobore oil wells with the conventional gas lift.

It can be concluded that the recovery factor of oil wells using the in-situ gas lift is very comparable to that of the oil wells with conventional gas lift. The higher recovery factor can be achieved from having the deeper or the thicker in-situ gas zone or the time-lapsed perforation schedule of the in-situ gas zone; however, this is not always true for increasing permeability.

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Field of Study: Petroleum Engineering...........   Advisor's Signature...Suwat Athichanagorn...
Academic Year.........2010.......................

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I really treasure my family that endures me; no word can express my gratefulness.

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NOMENCLATURES

A	drainage area
B_g	gas formation volume factor
B_{gi}	initial gas formation volume factor
B_o	oil formation volume factor
B_{oi}	initial oil formation volume factor
B_w	water formation volume factor
C	conversion constant for oil or gas wells
c_f	rock pore volume compressibility
c_g	gas compressibility
c_o	oil compressibility
c_t	total fluid compressibility
c_w	water compressibility
D	turbulence coefficient
D_f	depth of formation, mid perforation
D_{ov}	depth of injection valve
dp/dL	the total pressure drop (ΔP) in a tubing component
E_o	expansion of oil
E_g	gas cap
$E_{f,w}$	expansion of formation and connate water
F	underground withdrawal
G	initial gas in place
G_{pc}	cumulative gas-cap gas produced
G_{av}	average pressure gradient above injection point, a function of the gas rate injected
G_{bv}	average pressure gradient of flowing formation fluid below injection point
h	reservoir thickness
H	zone height
H_L	liquid hold up
H_G	gas hold up
J	productivity index
J_o	productivity index for oil
J_g	productivity index for gas

k	absolute permeability
k_{rg}	gas relative permeability
k_{rw}	water relative permeability
k_o	oil permeability
k_{ro}	oil relative permeability
m	ratio of gas cap volume to oil volume
n	reciprocal slope of best fit plot of q vs. $(p^2 - p_{wf}{}^2)$
n	flow exponent
N	initial oil in place
N_p	cumulative oil production
N_{pt}	cumulative oil produced during transient period
p	pressure
P_i	initial pressure
P_b	bubble point pressure
P_e	static average pressure measured at the drainage radius, r_e
p_R	average reservoir pressure
P_{wf}	bottom-hole flowing pressure measured at the wellbore radius, r_w
P_{wh}	wellhead pressure
p_{ws}	shut-in pressure
q	production flow rate
q_c	critical gas flow rate
q_L	liquid production rate
q_m	producing rate when $p_{wf} = 0$
q_o	oil production rate
$(q_o)_{max}$	maximum oil production rate
q_w	water production rate
R	production gas-oil ratio
r_d	external drainage area
r_e	external boundary radius
r_w	wellbore radius
R_p	cumulative production gas-oil ratio
R_s	solution gas-oil ratio
S	skin

S'	skin factor which include effect of turbulence and formation damage
S_g	gas saturation
S_{gc}	critical gas saturation
S_o	oil saturation
S_{oi}	initial oil saturation
S_{or}	residual oil saturation
S_w	water saturation
S_{wc}	connate water saturation
T	temperature (deg. R)
t_s	stabilization time
μ	viscosity, cp
v_t	terminal velocity, ft/sec
W_e	cumulative aquifer influx
W_p	total water produced
Z	gas deviation factor
μ_o	viscosity for oil
μ_g	viscosity for gas
ρ_L	liquid density
ρ_G	gas density
γ_g	gas gravity

CHAPTER I
INTRODUCTION

Typically, reservoirs in Pattani Basin in the Gulf of Thailand are highly faulted, relatively small compared to other reservoirs elsewhere, and most of the time they are multiple and stacked. In order to make the marginal reservoirs economically attractive, there is limited development option and almost by default the slim monobore completion is selected to justify the small reserves. Basically, this monobore completion allows one single well to accommodate as many hydrocarbon zones as possible. There could be up to 20-40 zones per well. Most of the time, all zones are perforated and produced commingledly.

Even though commingled production has several advantages, it results in several difficulties in reservoir management, for examples, a difficulty in predicting the production performance and reserve allocation, high pressure differences between zone inducing cross flow, difficulty in identifying water sources for water shut-off, problem with fluid compatibility from each zone, and requiring of close monitoring and surveillance.

It is generally observed that natural flow periods of these marginal reservoirs in the monobore oil wells are short. In some cases, these monobore oil wells can be completed with the conventional gas lift, i.e. the lower section of the well is still completed in basic monobore while the upper section of the well can have gas lift mandrels installed. This type of completion is called monotrip gas lift (MTGL) completion for monobore oil wells as shown in Figure 1.1.

According to the MTGL completion procedure, once the open hole is drilled to desired total depth, the monotrip completion string consisting of a float shoe, a float collar, a hydraulically set packer, a hydrostatic close circulating valve (HCCV), three to five cement-thru-side pocket mandrels and a cement-safe tubing retrievable safety valve (TRSV) is run. The pre-determined volume of cement is then pumped into the monotrip gas lift string up the annulus with the desired top of cement approximately 500 ft above the 7” shoe. After the cement is pumped, the special design of a cement wiper plug is launched to displace the cement in the tubing.

Once the wiper plug is bumped, the hydraulically set packer will be set. As the packer is set, the tubing pressure continues to increase until the rupture disc in the HCCV is burst to allow the circulation between the tubing and the annulus so that the excessive cement above the 7” case shoe in the annulus can be circulated out. Once the annulus is clear of excessive cement, the outer sleeve of the HCCV will be closed to regain tubing-annulus integrity.

However, in some cases, both capital and operating costs of artificial lift have a great impact on these economically burdened fields, especially the offshore environment. As a result, it is not always economic to drill and complete oil wells with MTGL completion.

Instead, several monobore oil wells are completed without gas lift or a typical monobore completion (Figure 1.2) for economic reason – cost saving is not only from lower drilling and completion cost, but mainly from no expensive gas lift surface facilities, such as gas lift compressors and flow lines. As stated previously, these monobore oil wells only rely on natural depletion or solution gas-oil ratio (GOR), resulting in low reserve recovery and they would be dead or loaded up very soon as the water cut increases up to 40 to 60%. As a result, the gas zones in these monobore oil wells are very important because these gas zones, if managed properly, can provide additional in-situ gas to increase or optimize the well’s GOR or GLR, thus increased oil production rate or reserve recovery.

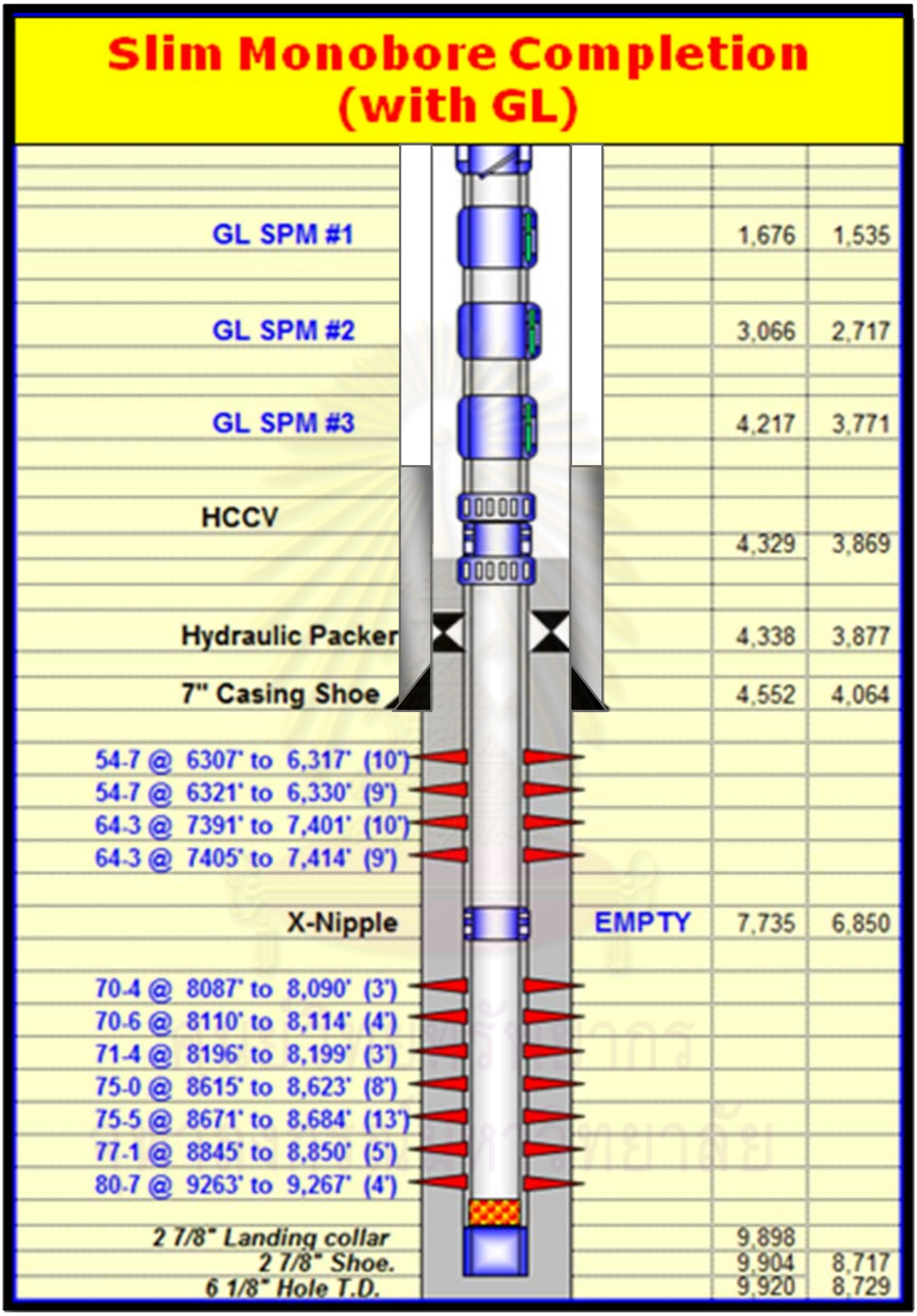


Figure 1.1 Well Schematic for Commingled Reservoirs in Slim Monobore Completion with Gas Lift Mandrels

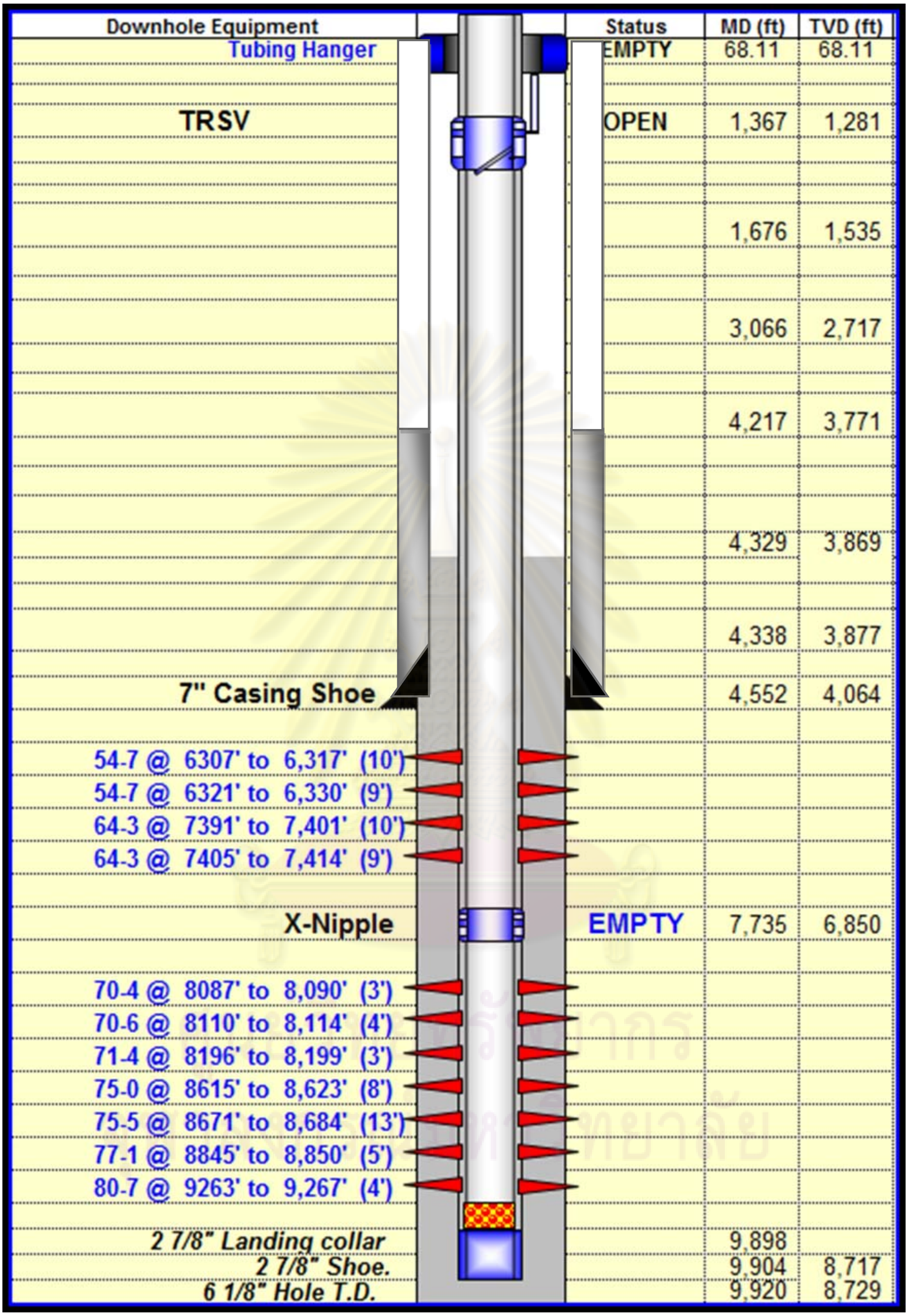


Figure 1.2 Well Schematic for Commingled Reservoirs in Slim Monobore Completion without Gas Lift Mandrels

Apart from understanding difficulties in reservoir management in commingled reservoirs in monobore oil wells, determining the following variables that affect the effectiveness of the in-situ gas lift in term of optimizing oil reserve recovery is also very crucial:

(i) Variables that affect inflow performance of in-situ gas zone: reservoir pressure (or depth of the reservoir), permeability and total net pay thickness. Other variables that affect inflow performance are assumed constant or follow certain correlations.

(ii) Variables that affect outflow or tubing performance. In this study, most variables that affect outflow or tubing performance are assumed constant, such as tubing size, gas viscosity; however, the liquid viscosity varies with temperature and solution gas.

(iii) Perforation schedule and perforation design. Papers related to in-situ gas lift in the literature survey examined the concept of in-situ gas lift or production of oil by in-situ gas using such a completion design with packers to isolate a gas zone and using surface-controlled downhole valve to control the in-situ gas rate to achieve optimal recovery and production rate. However, such a completion design is very expensive for marginal fields. Therefore, the perforation schedule and perforation design will be used instead to control the in-situ gas rate in the commingled reservoirs. This thesis should also provide a good opportunity to evaluate any other alternatives available that can optimize or control the in-situ gas lift rate in slim monobore completion, such as perforation interval on an in-situ gas zone.

1.1 Thesis Objectives:

The objectives for this study are as follows:

(i) To evaluate some variables on using the in-situ gas lift technique that impact the oil recovery factor of monobore oil wells with commingled production in Pattani Basin by comparing oil recovery factors using in-situ gas lift to conventional gas lift.

(ii) To come up with recommendations for using the in-situ gas lift in monobore oil wells with commingled production in Pattani Basin based on the studied variables.

1.2 Outline of Methodology

This thesis is to study variables that affect the oil recovery factor using the in-situ gas lift technique in monobore oil wells with commingled production in Pattani Basin. The oil recovery factors as a result of using in-situ gas lift techniques in different scenarios will be compared to the base case well that is a monobore oil well producing with a conventional gas lift.

The approach to conduct the systematic analysis consists of the following steps:

1. Gather and prepare data required to construct the reservoir model. The representative fluid and rock properties using available PVT and some core analysis data.
2. Refine the simulation cases and range of the data. This step is to validate the gathered data in step #1.
3. Construct the reservoir well model that represents the base case which is the monobore completion type consisting of commingled or multilayered oil reservoirs with a single gas lift orifice valve.
4. Perform simulation runs to validate the base case well model. Record the oil recovery for this base case, both in natural flow and with gas lift.
5. Construct the reservoir well model that represents the well with the presence of an in-situ gas zone of which variables are varied.
6. Perform simulation runs to predict the oil recovery factors in each of pre-determined scenarios.
7. Analyze the results and perform additional simulation studies if required. Compare the oil recovery factors from using in-situ gas lift technique in all scenarios to that of the base case.
8. Make conclusion and recommendation.

1.3 Outline for this thesis

This thesis consists of 6 chapters.

Chapter 2 reviews previous studies that are related to the in-situ gas lift technique and commingled production from multi-layered reservoirs.

Chapter 3 describes all principles and basic theories related to this study as follows:

Section 3.1 discusses nodal analysis and the effect of various variables on the inflow performance relationship (IPR) and tubing performance relationship (TPR).

Section 3.2 describes the principle and basic theory of material balance and explains the technique developed by Havlena and Odeh which is relevant to the simulation software.

Section 3.3 reviews the principle of reservoir drive mechanisms to explain different types of driving energy which depends on the original characteristics of hydrocarbon reservoirs.

Section 3.4 describes the principle and basic theory of gas lift theory and the in-situ gas lift.

Chapter 4 explains the basic introduction of a reservoir simulator used in this study which is the Integrated Production Model (IPM) Toolkit and describes how to set up the reservoir model for the base case and other scenarios for sensitivity runs.

Chapter 5 analyzes the results of the simulation runs in each pre-determined scenarios and attempts to explain what affect the recovery factors.

Chapter 6 concludes the results of the study and comes up with recommendations for using the in-situ gas lift technique to optimize oil production in monobore oil wells with commingled production.

CHAPTER II
LITERATURE REVIEW

The following studies are related to the in-situ gas lift technique and hydrocarbon production from commingled reservoirs.

Vasper [1] presented the basic theory behind in-situ gas lift and how to apply it. The in-situ gas lift system uses gas from a gas-bearing formation, or gas cap to artificially lift an oil producing zone. The completion design involves isolation of the gas zone from the oil zones using a packer. The flow rate of in-situ gas is controlled by an auto gas-lift valve which can be hydraulically cycled from surface to one of five open positions namely 20%, 40%, 60%, 80% or 100%, plus a 0% or closed position. The calculation of auto gas-lift valve setting depth and sizing was discussed and several auto gas-lift performance curves were plotted to determine the effect of the valve open positions on pressure ratio (pressures immediately downstream / upstream of a valve or orifice) and in-situ gas rate. The results suggested that in the right environment, the in-situ gas lift using auto gas-lift valve can provide significant financial benefits over conventional gas-lift systems through the elimination of capital cost items and ability to rejuvenate wells where space restrictions prevent installation of gas-lift compression facilities.

Al-Somali and Al-Aqeel [2] presented the first in-situ gas lift system equipment, gas lift operation principles utilizing the gas cap, installation procedure, production strategy and well performance utilizing online monitoring system. The completion was designed to isolate each of three hydrocarbon zones by a packer. All of two lower oil zones and a gas cap zone at the top were produced commingledly. Effective in-situ gas lift is achieved with sliding sleeves containing an orifice insert valve that controls the rate of in-situ gas flowing into the hydrocarbon stream. The sensitivity analysis on water cuts, tubing sizes, and completion skins was conducted to determine the effect on the amount of in-situ gas required or the total GLR required at a given production rate. The result indicated that the amount of oil delivered is a function of water cut, skin, and the amount of gas needed for lifting purpose at a given oil rate.

Betancourt, *et al.* [3] examined the concept of production of oil by in-situ gas from either contiguous or non-contiguous gas zone. They presented the results of numerical modeling of the contiguous gas-lift for horizontal wells to be drilled into reservoirs where the drive mechanism is dual drive (water encroachment at the bottom and gas expansion on top). The in-situ gas rate entering the tubing was controlled using a surface-controlled valve. The sensitivities on well placement (standoff) from water-oil contact and target liquid production rate were made to determine impact on total oil recovery and gas break through time. The results indicated that higher recoveries were achieved when the well was placed closer to the water-oil contact, and was produced at high rates and that gas breakthrough time is noticeably delayed by placing the well far from the gas cap. Another simple sensitivity was made to observe the impact of the gas cap and aquifer size on the production performance of the well. The results indicated that for a given size of gas cap, as the aquifer is stronger, there is a delay in the breakthrough time of the gas, and also the water-cut increases at a faster rate. The use of a deeper non-contiguous gas bearing zone to assist an upper oil zone was studied using a reservoir model. Both zones are commingled through a vertical well. The results indicated that a higher recovery using in-situ gas lift approach might be achieved by optimizing the valve position changes and in-situ gas lift is feasible provided that the pressure in the gas zone is in hydrostatic equilibrium or higher than the pressure in the oil zone. For both cases, the main advantage of in-situ gas lift process is the reduction in costs in artificial lift infrastructure, especially for offshore location.

Ferrer [4] summarized the applications, advantages, limitations, surveillance process and selection criteria for commingled production in the pilot test design. One of the selection criteria is that static pressure differences of the production intervals should not be greater than 300 psia. His paper suggested that the key factor for successful commingled production is to keep the bottom-hole flowing pressure of the system below the lowest static reservoir pressure to avoid cross flow. He also proposed a new methodology to estimate composite IPR curves for a commingled system, taken into account of distance between the zones, the tubing size, mechanical configuration of the well, and their distinct fluid properties that can have effect on the flowing pressure gradient along the tubing. To apply this methodology, all the pertinent data should be available including well completion diagram, producing intervals, individual IPR's and the fluid characteristics (oil gravity, GLR, water cut, etc.) for commingled production.

Larsen [5] presented a method to determine the wellbore-pressure behavior of wells producing two commingled zones with unequal initial pressures and reservoir properties. The paper also presented a method to determine the ratio of flow capacities or

$(kh)_1/(kh)_2$ if the initial pressures in two-layer are sufficiently different and in addition known. The result of analysis could be used to explain the behavior or wellbore pressure of commingled zones from the simulation results.

Raghavan [6] summarized understanding of multilayered reservoirs and examined a method to predict the performance and productivity of wells producing from commingled reservoirs which also permits consideration of the influence of interlayer communication or crossflow. This study helps explain some behavior of wells with commingled production.

Ryou *et al.* [7] presented new correlating parameters for boundary dominated constant rate production from multilayer reservoirs. They also examined the use of correlating parameters to model flow from multilayer reservoirs with constant bottom-hole pressure production.

Prabowo and Rinadi [8] presented a method to approximate the ratio of flow rate and cumulative production for each reservoir in a commingled gas completion. The numerical reservoir simulation was used to describe flow rate and pressure response of wells completed in multiple producing reservoirs without inter-layer crossflow. The simulated cases were for homogeneous multilayer systems with unequal initial reservoir pressures and properties with constant bottomhole flowing pressure but no crossflow.

Permadi *et al.* [9] presented a procedure to construct composite IPR of (two) multilateral wells and method to predict the production decline. There were two laterals which were produced commingledly with the same flowing pressure at the junction and no crossflow. Even though the paper focused on multilateral well, the concept for IPR can be used to explain the pressure or performance behavior of vertical well with commingled production.

Fetkovich *et al.* [10] analyzed commingled gas reservoirs using type-curve matching. While Arevalo *et al.* [11] extended the studies of El-Banbi and Wattenbarger [12, 13] on stabilized flow equation with gas material balance equation of multilayer gas reservoirs to match and forecast production rates for commingled gas wells. The approach used in commingled system is based on calculating the individual layer behavior and adding up the commingled performance. After solving each layer's commingled flow model for every time step, the total flow rate of the system can be evaluated by integrating the flow rate of each layer at the corresponding time. However, this approach may not be unique for the system consisting of more than 4 layers. These papers could help analyze simulation results for the wells with commingled production.

Kuppe *et al.* [14] developed a simple material balance model to estimate original gas in place (OGIP), layer productivity and recoverable reserves for well with commingled production, completed in multilayer tight gas reservoirs. The concept of grouping the various *kh* terms, from all "high permeability" layers into one model layer and all "low permeability" *kh* values into the tighter model layer is helpful for setting up the base case for this study, e.g. simplify the oil reservoirs into four oil layers or *kh* values.

CHAPTER III

RELATED THEORIES

The following theories related to this study and the reservoir simulation are discussed in this chapter:

(i) Nodal analysis

(ii) Material balance

(iii) Reservoir drive mechanisms

(iv) Gas lift theory

3.1 Nodal Analysis

The system analysis approach called Nodal Analysis will be applied to this research. Nodal Analysis is the determination of the production capacity for any combination of interactive system components and the identification of locations of excessive flow resistance or pressure drop for remedial action.

The three major components of a well's production system are as follows:

1) Flow through the porous medium (reservoirs)
2) Vertical, inclined or horizontal tubing flow
3) Horizontal flowline or pipeline flow

Figure 3.1 illustrates both the location of various nodes in the system and possible pressure losses in the system.

The nodes for nodal analysis can be either at separator, surface choke, wellhead, safety valve, restriction, P_{wf}, P_{wfs}, and P_r. The pressures that are keys to the optimization of a well are:

1) **The drainage boundary pressure (P_e)** or **the average reservoir pressure (P_r)**. P_e or P_r is the highest pressure in the system and is the reservoir energy that causes production to occur.
2) **The flowing bottom-hole pressure (P_{wf})** which is immediately downstream of a well's completion is also a key parameter in determining the magnitude of flow from the reservoir. At a given reservoir pressure, the higher the P_{wf}, the smaller the drawdown and the lower the production rate from the reservoir.
3) **The wellhead (tubing) pressure (P_{wh})** is the pressure measured at the wellhead. The setting of the wellhead pressure using a choke plays another key role in the

pressure loss taken through the system, the back pressure on the reservoir and ultimately the productivity of the well.

4) **The separator pressure (P_{sep}).** The separator pressure, in situations where sub-critical flow occurs through a wellhead choke, does affect the productivity of the well; otherwise, it does not affect productivity.

5) **The stock tank or sales line pressure (P_{ST}).** The stock tank pressure is the lowest pressure in the well's system, if there is no pump or compressor.

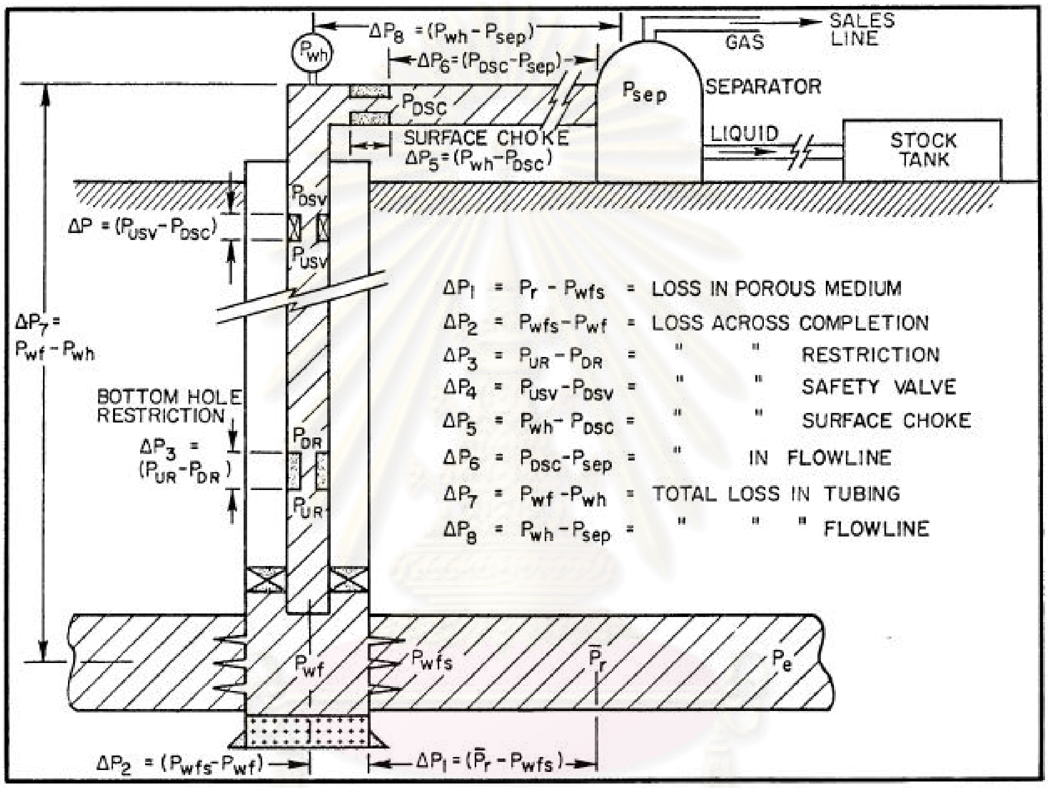


Figure 3.1 Possible Pressure Losses in a Complete System (after Beggs) [15].

In nodal analysis, the pressures listed above are related through the inflow and outflow equations. Examples of general inflow and outflow equation for node placed anywhere are:

Inflow to the node:

$$P_r - \Delta P_{(upstream\_components)} = P_{node} \tag{3.1}$$

Outflow from the node:

$$P_{sep} + \Delta P_{(downstream\_components)} = P_{node} \tag{3.2}$$

3.1.1 Inflow Performance Relationship (IPR)

Inflow Performance Relationship (IPR) is an equation that defines the manner by which the flowing bottom-hole pressure and the surface production rate are related. On the other hand, an IPR equation describes reservoir fluid inflow into the wellbore and constitutes a major component of the nodal analysis technique for well performance optimization. Although the term "back pressure curve" is used by some to refer to the gas well analogue, the bottom-hole pressure versus wellhead gas rate equation is also referred to as IPR.

There are different methods to determine IPR; however, IPR equation for oil and gas wells can be generally expressed in the form of [16]

$$q = J\,f\,(P_e, P_{wf}) \qquad P \text{ for oil and } P^2 \text{ for gas wells} \tag{3.3}$$

where

$$J_o = C\,f\,(k_o, h, \mu_o, B_o, r_e, r_w, S) \tag{3.4}$$

and

$$J_g = C\,f\,(k_g, h, \mu_g, Z, T, r_e, r_w, S) \tag{3.5}$$

In these equations,

q = production rate (stb/d for oil, scf/d for gas)

$f(.....)$ = function of (variables)

J = productivity index (J_o for oil in stb/d/psi and J_g for gas in scf/d/psi^2)

C = conversion constant for oil or gas wells

P_e or P_r = static average pressure measured at the drainage radius, r_e (psia).

P_{wf} = bottom-hole flowing pressure measured at the wellbore radius, r_w (psia)

k_o, k_g = permeability for oil and gas (md)

μ_o, μ_g = viscosity for oil and gas (cp)

h = net pay thickness (ft)

B_o = oil formation volume factor (bbl/stb)

r_e, r_w = drainage radius and wellbore radius (ft)

S = total skin factor (dimensionless)

Z = gas compressibility factor (dimensionless)

T = temperature (deg. R)

The simplest relation of IPR is the straight-line for undersaturated oil wells producing above the bubble point or J is a constant (Figure 3.2).

$$q_o = J_o\,(P_r - P_{wf}) \tag{3.6}$$

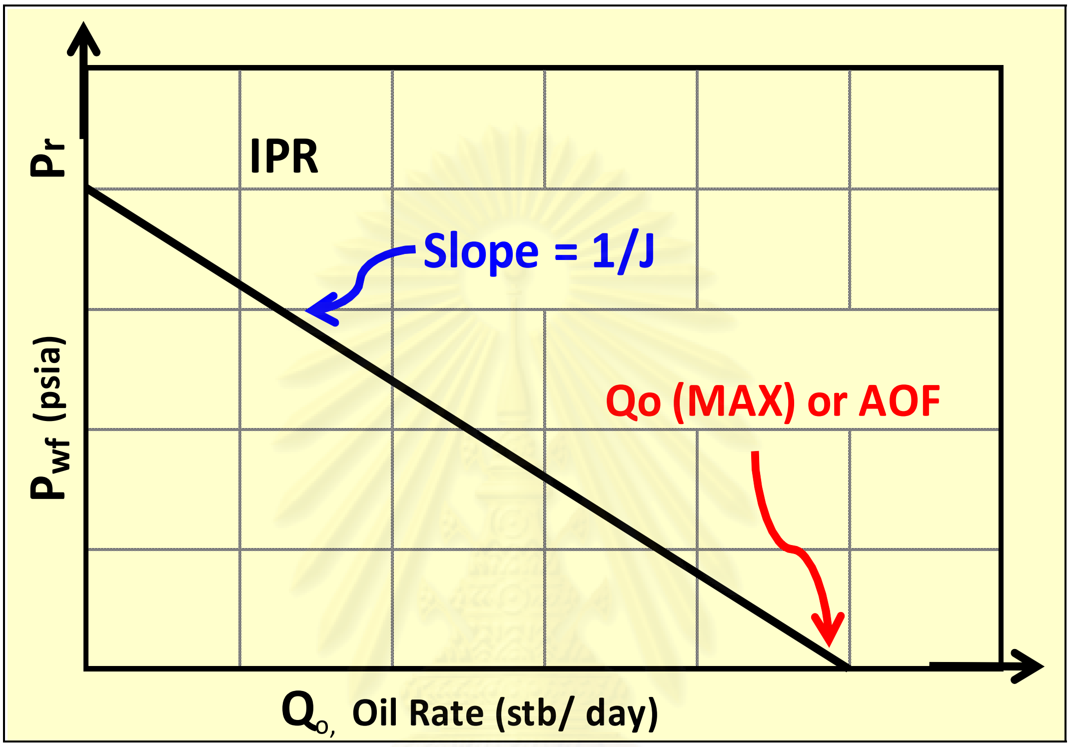


Figure 3.2 Straight-line IPR of an Undersaturated Oil Well Producing above Bubble Point [17]

The maximum rate of flow, $q_{o(MAX)}$ or absolute open flow (AOF), corresponds to P_{wf} equals to zero. Although, in practice, this may not be a condition at which the well can produce, it is useful definition, particularly for comparing the performance or potential of different wells in the same field.

3.1.2 Productivity Index

The productivity index is the ratio of the producing rate of a well to its drawdown at that particular rate. It is related to the formation capacity to produce fluids under a pressure difference between the static and the bottom-hole flowing pressure. The productivity index, J, is a famous term used to describe well deliverability, represents only one point on the inflow performance curve. By re-arranging (3.6), the productivity index is defined as

$$J_o = \frac{q_o}{(P_r - P_{wf})} \tag{3.7}$$

Most reservoirs exhibit at least partial decline and the industry standard is to use the pseudo-steady-state assumption in productivity calculation. To define the productivity index in terms of reservoir parameters

$$J_o = \frac{2\pi kh}{\left[\ln(\frac{r_e}{r_w}) - 0.75 + S\right](\mu_o B_o)_{avg}} \tag{3.8}$$

For an undersaturated oil reservoir, the viscosity and formation volume factor is an average value, $(\mu_o B_o)_{avg}$ at the average pressure, $P_{av} = (P_r + P_{wf})/2$.

The production rate usually drops off significantly from a straight-line relation at higher wellbore pressure drawdown with two-phase flow or the well is producing below the bubble point, P_b. In this case, the productivity index is not constant but decreases with rate below the bubble point. A typical representation of this behavior is shown in Figure 3.3, which depicts a straight line at flowing pressures above the bubble point and curvature below.

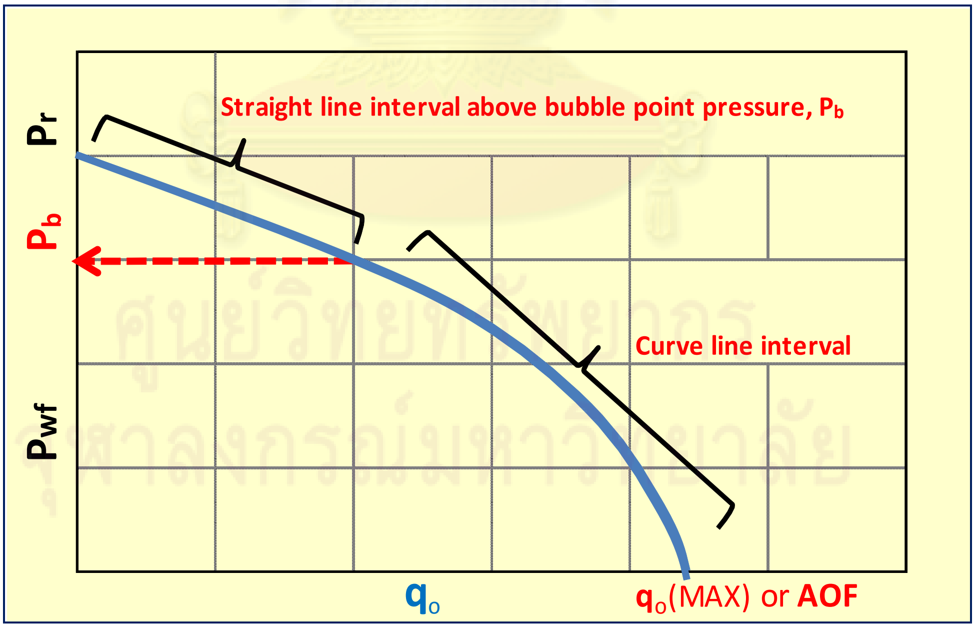


Figure 3.3 Typical IPR of an Undersaturated Oil Well Producing Below Bubble Point [17].

3.1.3 Key variables that affect IPR

1) **Flow capacity (*kh*).** From (3.8), the flow capacity (*kh*) is directly proportional to the productivity index (*J*) or production rate from a well. Both *k* (permeability) and *h* (net pay thickness) have significant influence on IPR's – the higher the values, the higher the production rate.
2) **Total Skin (*S*).** Skin around the wellbore has significant effect on IPR's. Skin removal by stimulating or fracturing can be evaluated using nodal analysis.
3) **Completion Type**. Although completion type is a factor rather than a variable, the type of completion significantly affects the IPR. Whether the well is cased and perforated or open hole makes a big difference to the wells reservoir-wellbore communication. Completion type affects flow efficiency which is computed using skin factor. The better the completion efficiency, the smaller the skin factor. The higher flow efficiency and the higher expected rate from the well.
4) **Perforation**. The effect of perforations on the IPR is usually expressed as a skin factor which depends on the perforation geometry and perforation quality. The most important parameters are:

   i) Perforation length (penetration) – longer perforations are more productive.

   ii) Perforation diameter – wider perforation will show a reduced frictional pressure loss

   iii) Perforation density (shot density) – the more shots per foot, the better the performance.

   iv) Perforation phasing – for a given shot density, the phasing that provides the greatest distance between perforations, and thus least interference between them.

   v) Depth and permeability reduction caused by formation damage – formation damage has limited effect on well productivity provided it is penetrated or by-passed by perforation.

   vi) Permeability and depth of crushed zone around the perforation – perforation clean up procedure such as underbalanced perforation should be designed to remove this impaired crushed zone prior to production.

   vii) Drawdown and properties of the produced fluids - high gas and very high oil flow rates through the perforation lead to extra pressure losses from non-Darcy flow effects.

5) **Other variables**. Relative permeability changes as fluid saturation changes, formation volume factors (shrinkage or expansion), and turbulence are other variables that affect IPR.

Composite IPR for Commingled Reservoirs

Nind [18] concluded that the composite IPR for three commingled reservoirs is the sum of each individual IPR curve. Figure 3.4 and Figure 3.5 illustrate a typical performance of commingled production system and describes the behavior of the IPR curve in a stratified three-layered reservoir with permeabilities of 1, 10, and 100 md. Initially, the IPR curve of Zone A which has the highest reservoir pressure will be the same as the composite IPR since Zone B and Zone C which have lower reservoir pressure cannot be produced. With increase in flow rate or decrease in the bottom-hole flowing pressure until a certain point, Zone B and Zone C can be produced, resulting in a change in the composite IPR.

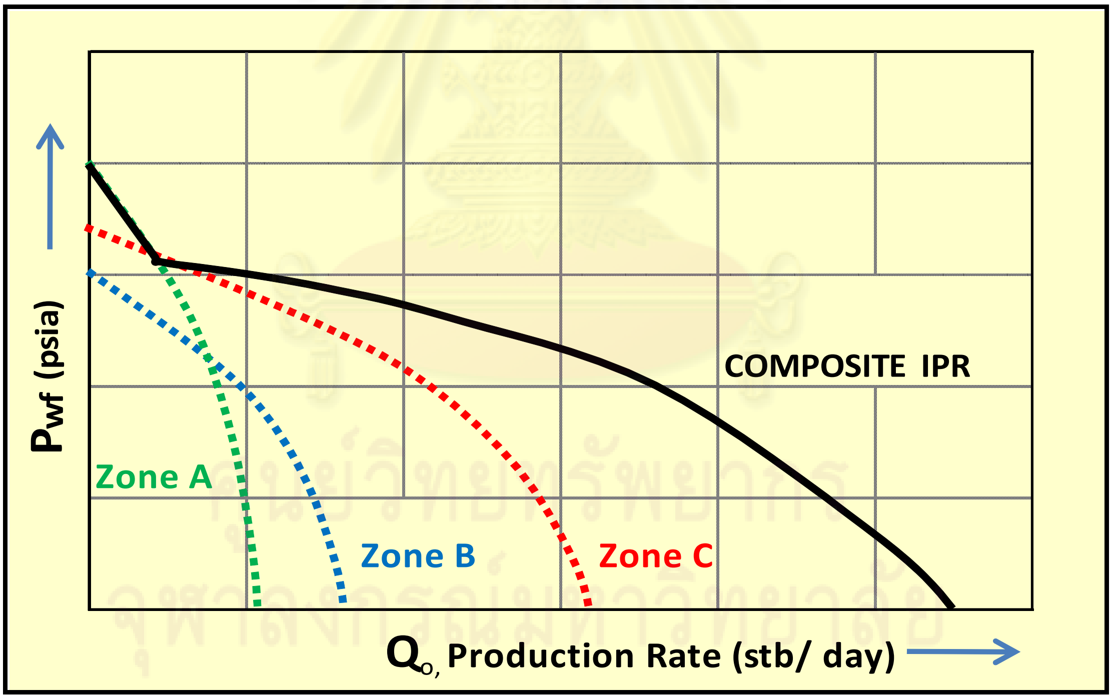


Figure 3.4 The Composite IPR Curve Calculated in Conventional Way as the Sum of Three Individual IPR Curves [18]

Figure 3.5 also exhibits an improved productivity index with increasing production rate at the lower rates, but a deteriorated productivity index at the higher rate.

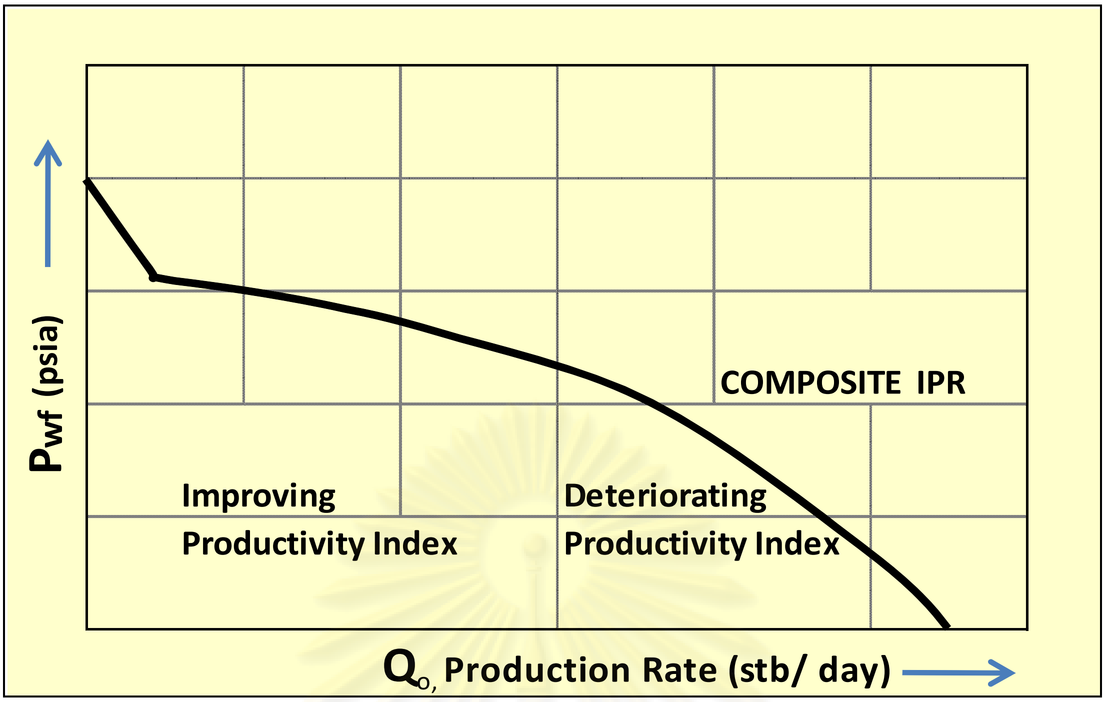


Figure 3.5 The Composite IPR Curve in Relationship with Productivity Index [18]

3.1.4 Tubing Performance Relationship (TPR)

The pressure drop required to lift a fluid through the production tubing at a given flow rate is one of the main factors determining the deliverability of a well. The pressure drop along the production tubing can be calculated by charts or correlations, and the resulting flowing pressure at the other end of the tubing can be determined. The resulting relation between bottom-hole flowing pressure and oil rate is called "Tubing Performance Relationship" (TPR), and it is valid only for a specified wellhead pressure. Sometimes, it is referred as the Vertical Lift Performance (VLP) relationship.

There are numerous fluid flow correlations for computing pressure losses for flow in vertical and inclined wellbores. These correlations have been derived empirically using statistic methods on data obtained by laboratory and/or field experimentation. Starting from the general energy balance equation and making necessary substitutions from thermodynamic principles, the general pressure gradient equation is derived as

$$\frac{dp}{dL} = \frac{g}{g_c}\rho \sin\Phi + \frac{f\rho v^2}{2\,g_c d} + \frac{\rho v dv}{g_c\, dL} \tag{3.9}$$

where:

$\frac{dp}{dL}$ = the total pressure gradient (ΔP) in a tubing component

ρ $= \rho_L H_L + \rho_G H_G$

ρ_L, ρ_G = Liquid and Gas density, respectively

H_L, H_G = Liquid and Gas hold up, respectively

For vertical flow, Φ= 90 degrees, making sin Φ= 1, $dL= dZ$ and (3.9) can be reduced to

$$\frac{dp}{dZ} = \left(\frac{dp}{dZ}\right)_{elevation} + \left(\frac{dp}{dZ}\right)_{fricion} + \left(\frac{dp}{dZ}\right)_{acceleration} \tag{3.10}$$

or

$$(\Delta P)_{\text{total}} = (\Delta P)_{\text{elevation}} + (\Delta P)_{\text{friction}} + (\Delta P)_{\text{acceleration}} = P_{wf} - P_{wh} \tag{3.11}$$

This equation is used to account for three components of pressure losses in wellbore fluid flow which are:

1) The elevation component of the total pressure drop, $(\Delta P)_{elevation}$ or the hydrostatic pressure due to gravity and the elevation change between wellhead and the intake of the tubing
2) The frictional component of the total pressure drop, $(\Delta P)_{friction}$ which includes irreversible pressure losses due to viscous drag and slippage.
3) The acceleration component of the total pressure drop, $(\Delta P)_{acceleration}$ due to acceleration of an expanding fluid. This term is usually insignificant when compared with the other losses and therefore neglected in most design calculations.

Figure 3.6 illustrates the three components of pressure in a TPR curve for single-phase liquid, dry gas, and a two-phase gas/oil mixture.

In case of single-phase liquid (e.g. undersaturated oil or water), the density is assumed constant. Therefore, the hydrostatic pressure gradient (pressure loss per unit length) is a constant. Friction loss, on the other hand, is rate-dependent, characterized by two flow regimes – laminar and turbulent – separated by a transition zone. The rate dependence of friction-related pressure loss differs with the flow regime. At low rates, the flow is laminar and the pressure gradient changes linearly with rate or flow velocity.

At high rates, the flow is turbulent and the pressure gradient increases more than linearly with increasing flow rate. In gas wells, there is interdependence between flow rate, flow velocity, density and pressure. In general, increasing gas rate results in increasing total pressure loss. In multiphase mixtures, friction-related and hydrostatic pressure losses vary with rate in a much more complicated manner than for gas. Increasing rate may change the governing pressure loss mechanism from predominantly gravitational to predominantly friction. The result of this shift is a change of trend in the TPR curve.

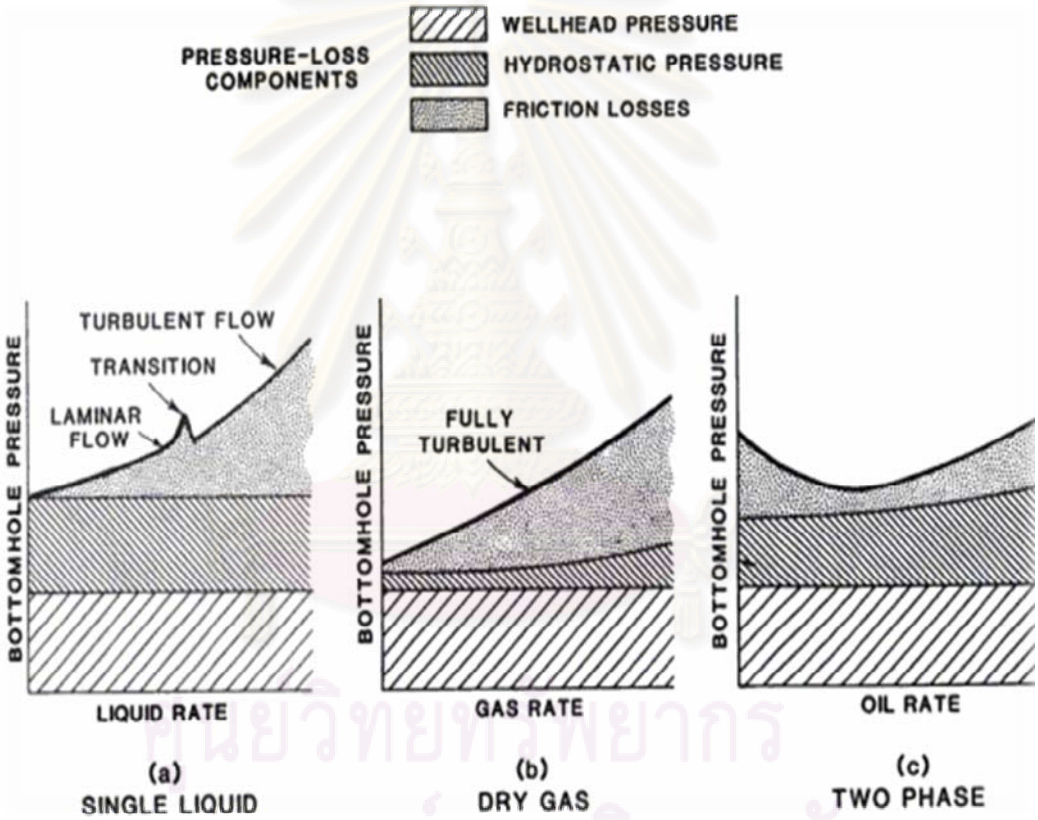


Figure 3.6 Components of Pressure Losses in Tubing [17]

3.1.5 Key Variables that Affect TPR

The variables that affect TPR are discussed as follows:

1) **Wellhead Pressure (P_{wh}).** The setting wellhead pressure using the choke plays another key role in the pressure loss occurring through the system since it affects

back pressure on the reservoir and ultimately the productivity of the well. The wellhead pressure serves as a back-pressure to well productivity. The higher the wellhead pressure, the lower the rate from particular well assuming that reservoir energy and reserves are available. Increasing the wellhead pressure by reducing the choke opening will shift the TPR curve upward, resulting in a decrease in rate.

2) **Gas-Liquid Ratio (GLR).** Effect of changing the GLR is not as straight forward as for the case of changing the well head pressure. It has different effects on two components of pressure loss in the tubing – friction and hydrostatic. Increasing GLR lightens the mixture density and therefore reduces the pressure loss due to hydrostatic forces. Larger quantities of gas will however, usually result in larger pressure losses due to friction. An increase in GLR tends to shift TPR to the right, resulting in an increase in natural flow rate. The trend continues up to a certain GLR where the trend is then reversed. One of methods that is used to increase GLR by injecting gas from the surface to lower section of tubing is so-called a conventional gas lift.

3) **Water-Gas or Water-Oil Ratio or % WC**. Water-Gas and Water-Oil Ratio have major influence on the gravitational component of the wellbore pressure drop. Because the density of water is higher than that of either of oil or gas, the presence of water in the wellbore drastically affects well performance and productivity. Increasing water cut (% WC) in the flowing wellbore fluid creates a higher flowing bottomhole pressure, which impedes flow from the reservoir, and lowers well productivity and the well will completely load up. It is analogous to large tubing size case. Some form of artificial lift will be required to produce such a well at decent rates for water cut exceeding 50%.

4) **Tubing Sizes.** There is an optimum tubing size for each well. The larger the tubing size, the higher the flow rate through it due to reduced frictional pressure drop. However, if the tubing is too large for the well, the liquid loading can result pre-maturely and force production to cease. This is due to the fact that, the upward (gas) flow velocity has decreased so much (due to tubing diameter increase), that it is no longer sufficient to efficiently lift the liquid to surface, i.e. slip phenomena commence and liquid loading begins. Tubing sizes significantly affect tubing performance and hence well productivity.

5) **Separator Pressure (P_{sep}).** The separator pressure is often the main component in the surface pressure losses. It exerts a restrictive "back pressure" on the well production which limits the total pressure drop available for fluid inflow from the reservoir and onward transportation to the surface. In situations where sub-critical flow occurs through the wellhead choke, P_{sep} does affect the productivity of the well; otherwise, does not affect productivity.
6) **The Stock Tank or Sales Line Pressure (P_{ST}).** The stock tank is the lowest pressure in the well's system, if there is no pump or compressor. If there is a pump (liquid) or a compressor (gas case) in the system, the P_{ST} is not the lowest pressure in the system. In the instance, where either the liquid pump or gas compressor exists in the system, then the intake pressure to the pump or compressor may be lower than the sales line pressure.
7) **Changing the Production Components.** The prediction of the gas well performance in the future is critical under existing as well as modified conditions. For example, for a gas-condensate reservoir, we would like to know when the gas well will start loading under existing conditions so that appropriate production components can be changed before the actual loading occurs. These alterations include changing choke size, changing the tubing size or reducing the well head pressure. Based on the production scenarios under existing as well as altered conditions, a proper method can be selected for continued gas production.

3.1.6 Natural Flow

It is possible to calculate and plot both inflow and tubing performance relations. At a specific rate, the wellbore flowing pressure and tubing intake pressure are equal, the flow system is in equilibrium and flow is stable. The intersection of the IPR and TPR curves determines the rate of stable flow that can be expected from the particular well. The equilibrium rate and pressure constitute what is called the "natural flow point". The equilibrium rate is called the "natural flow rate". Figure 3.7 illustrates typical IPR and TPR for the natural flow condition.

Natural flow rate and pressure change with reservoir depletion, depending on the variation in IPR and TPR resulting from changes in the reservoir pressure and flow characteristics. Usually, the change of natural flow is toward a lower rate. However, it is possible to change equipment or operating criteria to maintain a desired rate of production. Lowering the wellhead pressure by choke manipulation or lowering separator pressure is perhaps the simplest and most common adjustment.

Introducing artificial lift or treating wells by stimulation are more complicated and costly alternatives for maintaining a desired rate of production. One form of artificial lifts commonly used to improve the well performance is the conventional gas lift – which can be either continuous or intermittent. The details of the continuous and intermittent gas lift will be discussed in section 3.4.1 and 3.4.2, respectively.

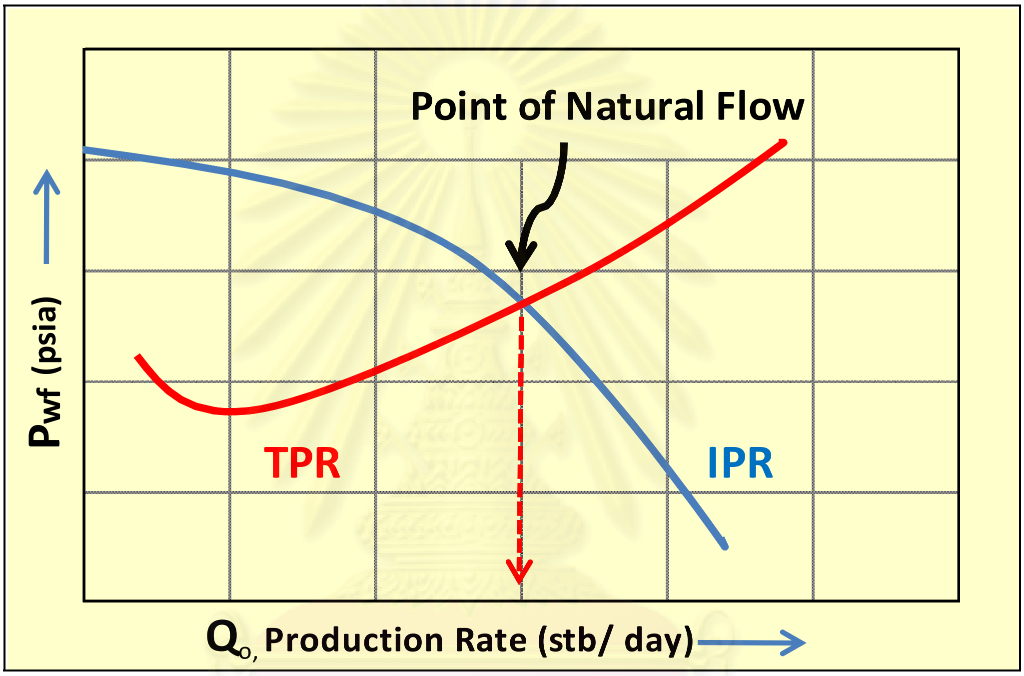


Figure 3.7 Natural Flow Condition [16]

3.2 Material Balance

The material balance equation has long been regarded as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance. In this chapter, the material balance is derived and subsequently applied, using mainly the interpretative technique of Havlena and Odeh [21, 22] to gain an understanding of reservoir drive mechanisms under primary recovery conditions. Finally, some uncertainties associated with estimation of in situ pore compressibility, a basic component in the material balance equation, are qualitatively discussed. Although the classical material balance techniques have now largely been superseded by numerical simulators, which are essentially multidimensional, multi-phase, dynamic material balance programs, the classical approach is well worth studying since it provides a valuable insight into the behavior of hydrocarbon reservoirs.

The general form of material balance equation is derived as a volume balance which equates the cumulative observed production, expressed as an underground withdrawal, to the expansion of the fluids in the reservoir resulting from a finite pressure drop. If the total observed surface production of oil and gas is expressed in terms of an underground withdrawal, evaluated at a lower pressure, p, which means effectively taking all the surface production back down to the reservoir at this lower pressure can be expressed in the terms as below:

Underground withdrawal = Expansion of oil and originally dissolved gas (rb) + Expansion of gas cap (rb) + Reduction in Hydrocarbon Pore Volume (*HCPV*) due to connate water expansion and decrease in pore volume (rb) + Water influx

Before evaluating the various components in the equation, it is necessary to define the following parameters:

$N = V\,Ø\,(1-S_{wc})/\,B_{oi}$ in stb (3.12)

m = initial reservoir volume of the gas cap / initial reservoir volume of the oil (a constant being defined under initial conditions)

N_p = cumulative oil production in stb

R_p = cumulative GOR in scf/stb

3.2.1 Expansion of Oil and Originally Dissolved Gas

Liquid expansion:

The stock tank oil initially in place, N (stb) occupies a reservoir volume of NB_{oi} (rb), at the initial pressure, while at the lower pressure p, the reservoir volume occupied by the oil will be NB_o, where B_o is the oil formation volume factor at the lower pressure. The difference gives the liquid expansion as:

$$N(B_o - B_{oi}) \qquad \text{(rb)} \qquad (3.13)$$

Liberated gas expansion:

If the initial oil is in equilibrium with the gas cap at saturation or bubble point pressure, reducing the pressure below *pi* will result in the liberation of solutions gas. The total amount of solution gas in the oil is NR_{si} (scf). Therefore, the gas volume liberated during the pressure drop Δp, expressed in reservoir barrels at the lower pressure is:

$$N(R_{si} - R_s)B_g \qquad \text{(rb)} \tag{3.14}$$

3.2.2 Expansion of Gas-cap Gas

The total volume of gas-cap gas is mNB_{oi} (rb), which in scf may be expressed as

$$G = \frac{mNB_{oi}}{B_{gi}} \qquad \text{(scf)} \tag{3.15}$$

This amount of gas at the reduced pressure p will occupy a reservoir volume

$$mNB_{oi}\frac{B_g}{B_{gi}} \qquad \text{(rb)} \tag{3.16}$$

Therefore, the expansion of the gas cap is

$$mNB_{oi}\left(\frac{B_g}{B_{gi}} - 1\right) \qquad \text{(rb)} \tag{3.17}$$

3.2.3 Change in HCPV due to Connate Water Expansion and Pore Volume Reduction

The total volume change due to these combined effects can be mathematically expressed as

$$d(HCPV) = dV_w + dV_f \tag{3.18}$$

Or as a reduction in hydrocarbon pore volume as

$$d(HCPV) = -(c_w V_w + c_f V_f)\Delta p \tag{3.19}$$

where V_f is the total pore volume $= \dfrac{(HCPV)}{(1-S_{wc})}$

and V_w is the connate water volume = $V_f \times S_{wc}$ $= \dfrac{(HCPV)S_{wc}}{(1-S_{wc})}$

Since the total *HCPV*, including the gas cap is

$$(1+m)NB_{oi} \qquad \text{(rb)} \qquad (3.20)$$

Then the HCPV reduction can be expressed as

$$-d(HCPV) = (1+m)NB_{oi}\left(\frac{c_w S_{wc} + c_f}{1 - S_{wc}}\right)\Delta p \qquad \text{(rb)} \qquad (3.21)$$

This reduction in the volume that can be occupied by the hydrocarbons at the lower pressure, p, must correspond to an equivalent amount of fluid production expelled from the reservoir and hence should be added to the fluid expansion terms.

3.2.4 Underground Withdrawal

The observed surface production during the pressure drop Δp is N_p (stb) of oil and N_pR_p (scf) of gas. At reservoir conditions, this volume of oil plus dissolved gas is N_pB_o (rb). All that is known about the total gas production is that, the lower pressure, N_pR_s (scf) will be dissolved in N_p (stb) of oil. The remaining produced gas, $N_p(R_p - R_s)$ (scf) is therefore, the total amount of liberated and gas-cap gas produced during the pressure drop Δp and will occupy a volume $N_p(R_p - R_s)B_g$ (rb) at the lower pressure. The total underground withdrawal term is therefore

$$N_p(B_o + (R_p - R_s) B_g) \qquad \text{(rb)} \qquad (3.22)$$

Therefore, equating this withdrawal to the sum of the volume changes in the reservoir, equations (3.13), (3.14), (3.17) and (3.21), gives the general expression for the material balance as

$$N_p[B_o+(R_p-R_s)B_g] =$$

$$NB_{oi}\left[\frac{(B_o-B_{oi})+(R_{si}-R_s)B_g}{B_{oi}}+m\left(\frac{B_g}{B_{gi}-1}\right)+(1+m)\left(\frac{c_w S_{wc}+c_f}{1-S_{wc}}\right)\Delta p\right]+(W_e-W_p)B_w \qquad (3.23)$$

in which the final term $(W_e - W_p)B_w$ is the net water influx into the reservoir. This term has been intuitively added to the right hand side of the balance since any such influx must expel an equivalent amount of production from the reservoir thus increasing the left hand side of the equation by the same amount.

where:

B_o	=	oil formation volume factor
B_g	=	gas formation volume factor
B_w	=	water formation volume factor
c_w	=	water compressibility
c_f	=	rock pore volume compressibility
m	=	the ratio of gas cap pore volume to oil pore volume
N_p	=	cumulative oil production
N	=	initial oil in place
p	=	average reservoir pressure; subscript i= initial
R_s	=	solution gas-oil ratio
R_p	=	cumulative production gas-oil ratio
S_w	=	water saturation
W_e	=	cumulative water influx from the into the reservoir
W_p	=	cumulative amount of aquifer water produced

3.2.5 The Material Balance Expressed as a Linear Equation

The material balance equation can be developed further to be expressed as a linear equation. Havlena and Odeh [21, 22] presented two interesting papers which described the technique of interpreting the material balance as the equation of the straight line and also illustrating the application to reservoir case histories. The way Havlena and Odeh [21, 22] presented requires the definition of the following terms:

Underground withdrawal

$$F = N_p [B_o + (R_p - R_s) B_g] + W_p B_w \qquad \text{(rb)} \tag{3.24}$$

Expansion of oil and its originally dissolved gas

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s)\, B_g \qquad \text{(rb/stb)} \tag{3.25}$$

Expansion of gas-cap gas

$$Eg = B_{oi}\left(\frac{B_g}{B_{gi} - 1}\right) \tag{3.26}$$

Expansion of connate water and reduction in the pore volume

$$E_{f,w} = (1+m)B_{oi}\left(\frac{c_w S_w + c_f}{1 - S_w}\right)\Delta p \tag{3.27}$$

Using these terms, the material balance equation can be written as

$$F = N\,(E_o + mE_g + E_{f,w}) + W_e B_w \tag{3.28}$$

Havlena and Odeh [21, 22] have shown in many cases that the above equation can be interpreted as a linear function. For instance, in the case of a reservoir which has no gas cap, negligible water influx and for which the connate water and rock compressibility term is neglected, the equation can be reduced to

$$F = N\,E_o \tag{3.29}$$

in which the observed production, evaluated as an underground withdrawal, should plot as a linear function of the expansion of oil plus its originally dissolved gas, the latter being calculated from a knowledge of the PVT parameters at the current reservoir pressure. This interpretation technique is useful, in that, if a simple linear relationship is expected for a reservoir and yet the actual plot turns out to be non linear, then this deviation can itself be diagnostic in determining the actual drive mechanisms in the reservoir.

3.3 Reservoir Drive Mechanisms

Producing oil and gas needs energy. Usually some of this required energy is supplied by nature. The hydrocarbon fluids are under pressure because of their depth. The gas and water in petroleum reservoirs under pressure are the two main sources that help move the oil to the well bore and sometimes up to the surface. Depending on the original characteristics of hydrocarbon reservoirs, the type of driving energy is different. Generally there are five important drive mechanisms (or combinations) which are

(i) Solution gas drive

(ii) Gas cap drive

(iii) Water drive

(iv) Gravity drainage

(v) Combination or mixed drive

3.3.1 Solution Gas Drive

This drive mechanism requires the reservoir rock to be completely surrounded by impermeable barriers. As the production occurs the reservoir pressure drops, and this causes emerging and expansion of the dissolved gases in the oil and water providing most of the reservoirs drive energy. The process is shown schematically in Figure 3.8. A solution gas drive reservoir is initially either considered to be undersaturated or saturated depending on its pressure:

- Undersaturated: Reservoir pressure > bubble point of oil.
- Saturated: Reservoir pressure ≤ bubble point of oil.

For an undersaturated reservoir, no free gas exists until the reservoir pressure falls below the bubble point. In this regime reservoir drive energy is provided only by the bulk expansion of the reservoir rock and liquids (water and oil).

For a saturated reservoir, any oil production results in a drop in reservoir pressure that causes gas to come out of solution and expand. When the gas comes out of solution the oil (and water) shrinks slightly. However, the volume of the gas, and its subsequent expansion more than makes up for this. Thus gas expansion is the primary reservoir drive for reservoirs below the bubble point.

Solution gas drive reservoirs show a particular characteristic pressure, GOR (or R) and fluid production history as shown in Figure 3.9. If the reservoir is initially undersaturated, the reservoir pressure p_i can drop by a great deal (several hundred psi over a few months).

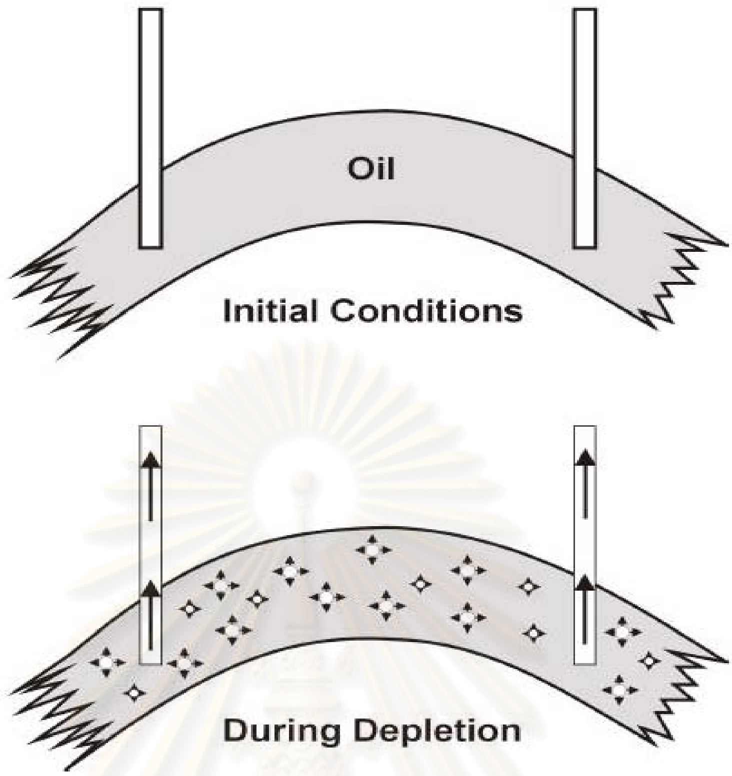


Figure 3.8 Solution Gas Drive Reservoir [21]

This is because of the small compressibility of the rock water and oil, compared to that of gas. In this undersaturated phase, gas is only exsolved from the fluids in the well bore, and consequently the GOR is low and constant. When the reservoir reaches the bubble point pressure p_b, the pressure declines less quickly due to the formation of gas bubbles in the reservoir that expand taking up the volume exited by produced oil and hence protecting against pressure drops. When this happens, the GOR rises dramatically. Further fall in reservoir pressure, as production continues, can; however, lead to a decrease in GOR again when reservoir pressures are such that the gas expands less in the borehole. When the GOR initially rises, the oil production falls and artificial lift systems are then instituted. The efficiency of solution gas drive depends on the amount of gas in solution, the rock and fluid properties and the geological structure of the reservoir. Recovery based on solution gas drive is low, in the order of 10-15 % of the original oil in place (OOIP).

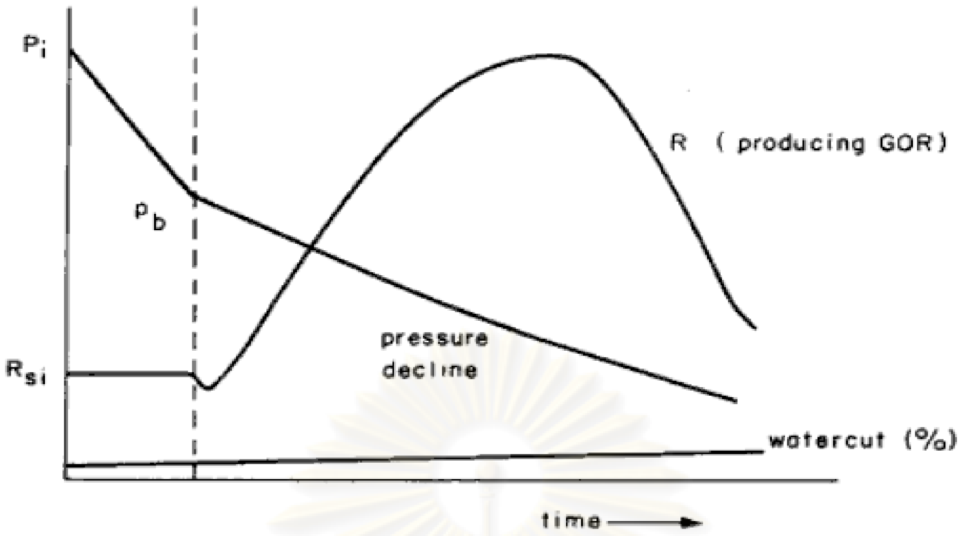


Figure 3.9 Schematic of Production History of a Solution Gas Drive Reservoir [22]

3.3.2 Gas Cap Drive

Sometimes, the pressure in the reservoir is below the bubble point initially; so there is more gas in the reservoir than the oil can retain in solution. This extra gas, because of density difference, accumulates at the top of the reservoir and forms a cap.

The process is shown schematically in Figure 3.10. This kind of reservoirs is called gas cap drive reservoirs. In gas cap drive reservoirs, wells are drilled into the oil zone of the formation. As oil production causes a reduction in pressure, the gas in gas cap expands and pushes oil into the well bores. Expansion the gas cap is limited by the desired pressure level in the reservoir and by gas production after gas comes into production wells.

From Figure 3.11, the GOR (or R) rises only slowly in the early stages of production from such a reservoir because the pressure of the gas cap prevents gas from coming out of solution in the oil and water. As production continues, the gas cap expands pushing the gas-oil contact (GOC) downwards (Figure 3.10). Eventually the GOC will reach the production wells and the GOR will increase by large amounts (Figures 3.11). The slower reduction in pressure experienced by gas cap reservoirs compared to solution drive reservoirs results in the oil production rates being much higher throughout the life of the reservoir, and needing artificial lift much later than for solution drive reservoirs. The actual rate of pressure decrease is related to the size of the gas cap. Moreover, gas cap reservoirs produce very little or no water.

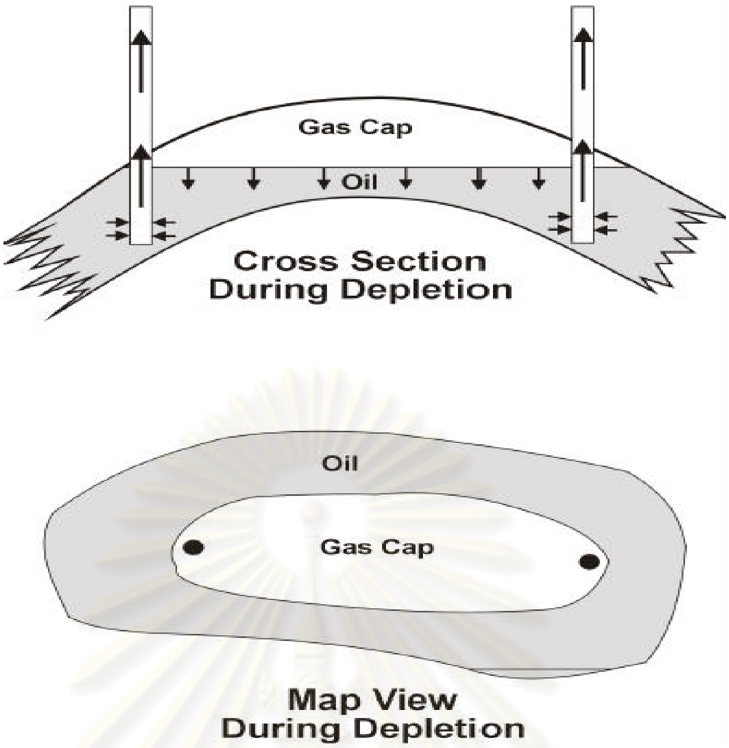


Figure 3.10 Gas-Cap Drive Reservoir [21]

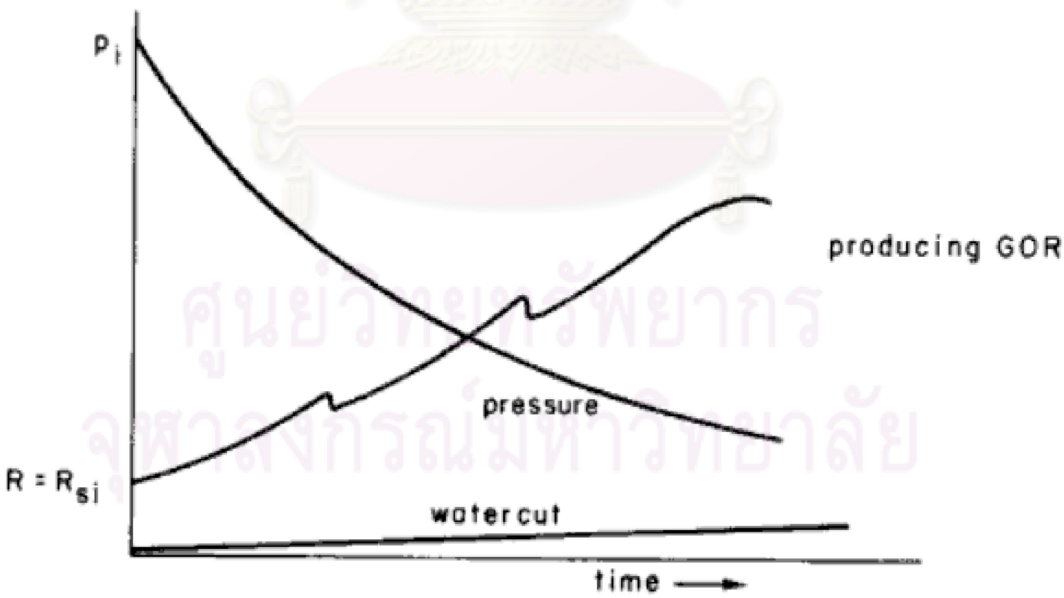


Figure 3.11 Schematic of Production History of a Typical Gas-Cap Drive Reservoir [22]

3.3.3 Water Drive

Most oil or gas reservoirs have water aquifers. When this water aquifer is an active one, continuously fed by incoming water, this water will expand as pressure of the oil/gas zone is reduced because of production causing an extra driving energy. This kind of reservoirs is called water drive reservoirs. The process is shown schematically in Figure 3.12. The expanding water also moves and displaces oil or gas in an upward direction from lower parts of the reservoir, so the pore spaces partially by oil or gas produced are filled by water. The oil and gas are progressively pushed towards the well bore. The pressure history of a water driven reservoir depends critically upon:

(i) The size of the aquifer.
(ii) The permeability of the aquifer.
(iii) The reservoir production rate.

If the production rate is low, and the size and permeability of the aquifer is high, then the reservoir pressure will remain high because all produced oil is replaced efficiently with water. If the production rate is too high then the extracted oil may not be able to be replaced by water in the same timescale, especially if the aquifer is small or low permeability. In this case the reservoir pressure will fall (Figure 3.13).

The GOR remains very constant in a strongly water driven reservoir as the pressure decrease is small and constant, whereas if the pressure decrease is higher (weakly water driven reservoir) the GOR increases due to gas exsolving from the oil and water in the reservoir. Likewise the oil production from a strongly water driven reservoir remains fairly constant until water breakthrough occurs. Recovery efficiency of 70 to 80 % of the original oil in place (OOIP) is possible in some water drive oil reservoirs.

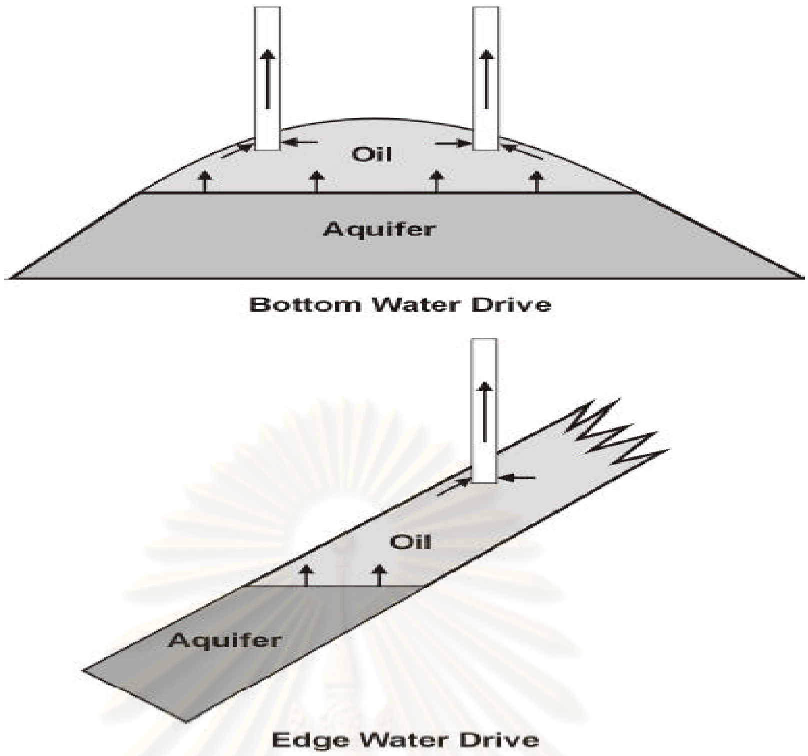


Figure 3.12 Water Drive Reservoir [21]

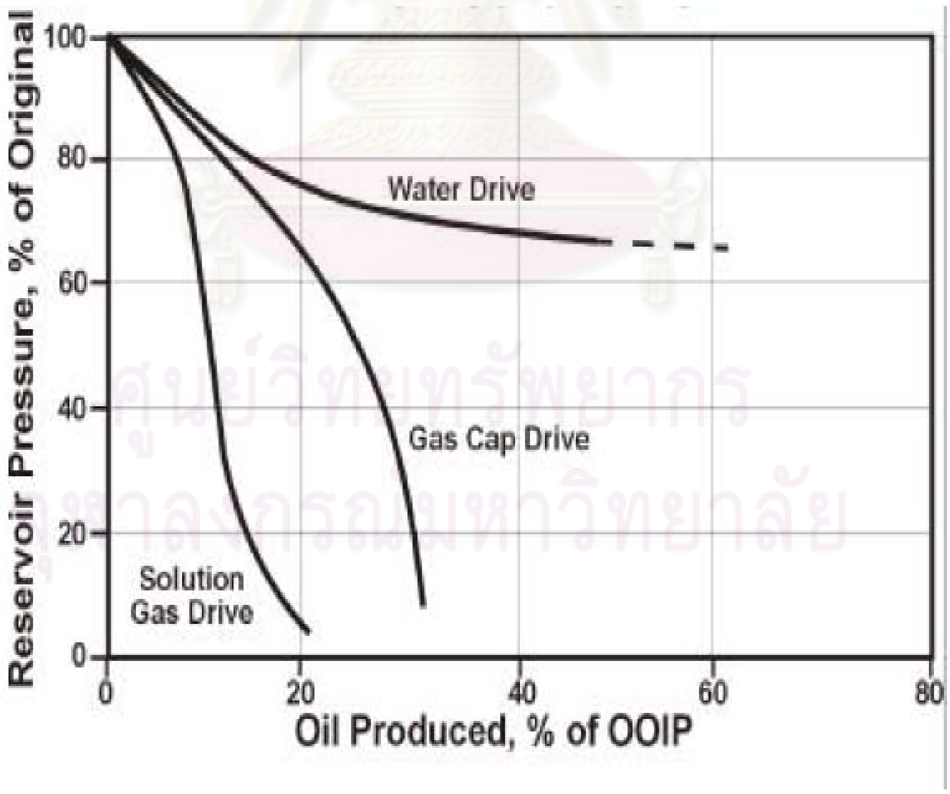


Figure 3.13 Reservoir Pressure Trends for Drive Mechanisms [21]

3.3.4 Gravity Drainage

Gravity drainage may be a primary producing mechanism in thick reservoirs that have a good vertical communication or in steeply dipping reservoirs. The density differences between oil and gas and water result in their natural segregation in the reservoir. Gravity drainage is a slow process because the rate of oil drainage is slower than the gas migration. This process can be used as a drive mechanism, but is relatively weak, and in practice is only used in combination with other drive mechanisms. Figure 3.14 shows production by gravity drainage. The rate of production engendered by gravity drainage is very low compared with the other drive mechanisms examined so far. However, it is extremely efficient over long periods and can give rise to extremely high recoveries (50-70% OOIP). Consequently, it is often used in addition to the other drive mechanisms.

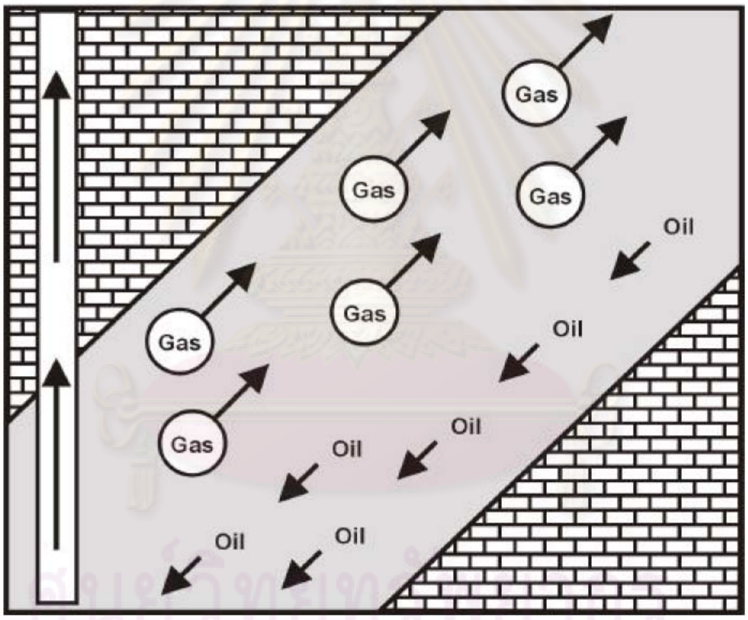


Figure 3.14 Gravity Drainage Reservoir [21]

3.3.5 Combination Drive

In practice a reservoir usually incorporates at least two main drive mechanisms For example, in the case shown in Figure 3.15, it can be seen that the management of the reservoir for different drive mechanisms can be diametrically opposed (e.g. low perforation for gas cap reservoirs compared with high perforation for water drive reservoirs). If both occur as in Figure 3.15, a compromise must be sought, and this compromise must take into account the strength of each drive present, the size of the gas cap, and the size/permeability of the aquifer.

It is the job of the reservoir manager to identify the strengths of the drives as early as possible in the life of the reservoir to optimize the reservoir performance.

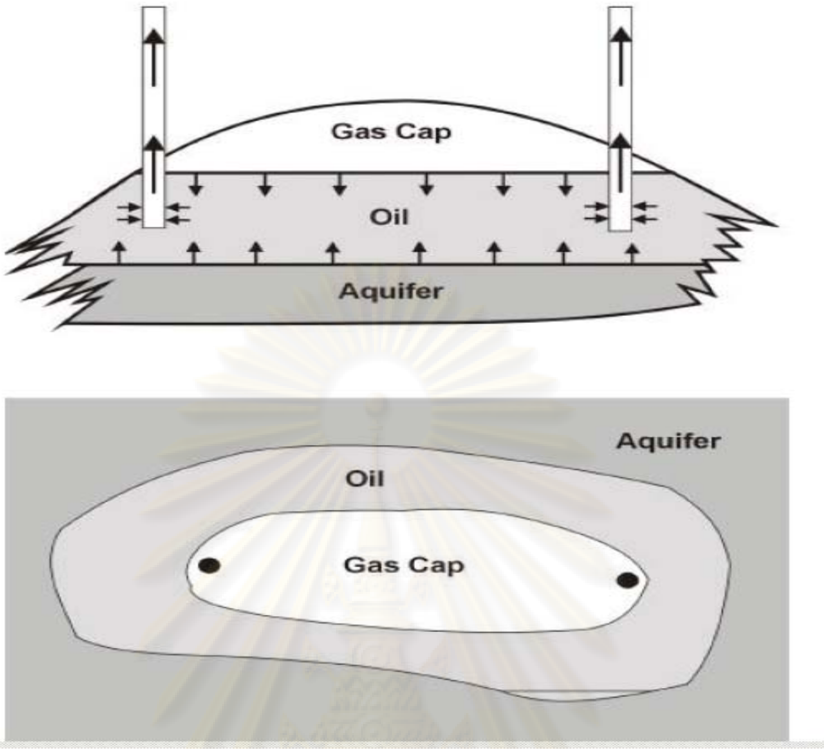


Figure 3.15 Combination Drive Reservoir [21]

3.4 Gas Lift Theory

Generally, there are several types of gas lift applications used in oil wells. However, only two main gas lift applications are discussed in this study, the conventional gas lift and in-situ gas lift. These two types of gas lift applications may result in different oil recovery factors. Conventional gas lift can be divided into two main categories, the continuous gas lift and intermittent gas lift. The continuous gas lift is used in this study for setting up the base case model.

3.4.1 Continuous Gas Lift

Gas is continuously injected into the tubing through a gas lift valve at a fixed depth. The injected gas increases gas liquid ratio (GLR) from the valve to the surface and decreases the hydrostatic pressure gradient in the tubing, thus decreasing the wellbore flowing pressure, P_{wf} even though the friction loss increases. The only difference between in-situ gas lift operation and a flowing valve is that the gas liquid ratio changes at some point in the tubing for the gas lift valve.

A simplified schematic and pressure traverse for a gas lift operation shown in Figure 3.16 indicated that if the gas is injected deeper in the well, it has the ability to decrease the gradient more effectively.

As the diagram indicates, P_{wf} is determined by the pressure traverse in the tubing above and below the injection point.

Assuming linear pressure traverse below and above injection point, P_{wf} can be expressed as

$$P_{wf} = P_{wh} + G_{av} D_{ov} + G_{bv} (D_f - D_{ov}) \quad [17] \qquad (3.30)$$

where

P_{wh} = wellhead pressure (psia)

D_{ov} = depth of injection valve (ft)

D_f = depth of formation, mid perforation (ft)

G_{av} = average pressure gradient above injection point, a function of the gas rate injected (psi/ ft)

G_{bv} = average pressure gradient of flowing formation fluid below injection point (psi/ ft)

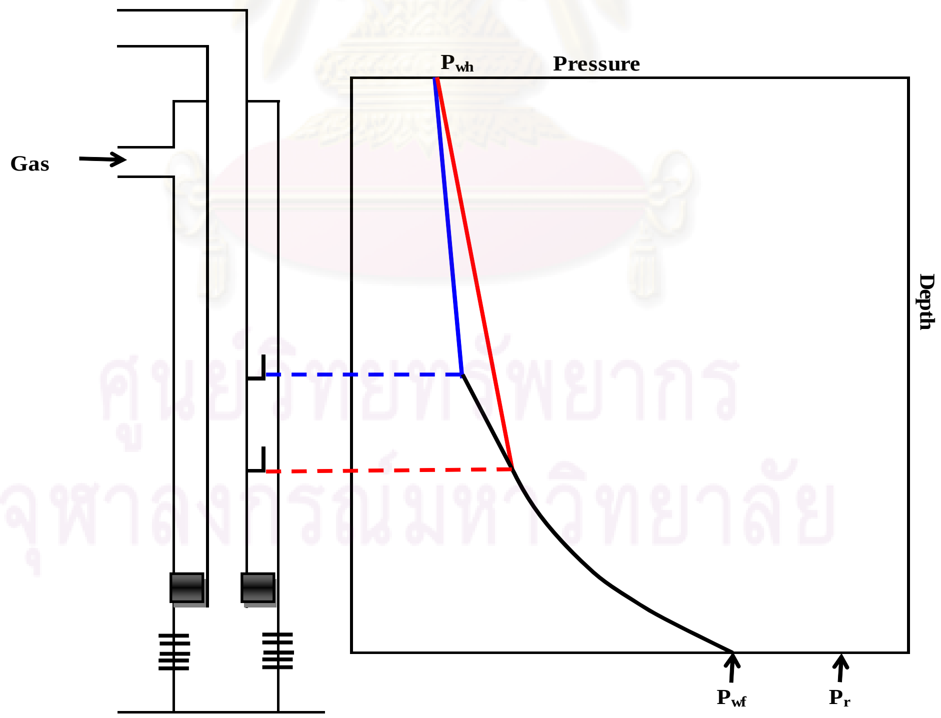


Figure 3.16 Pressure Diagram for a Gas-Lift Well [17]

Two parameters in (3.30), the injection depth and the flowing pressure gradient above the injection point, may be varied independently by the designer in a given wellhead pressure and tubing size. The ability to control the bottom-hole flowing pressure and production rate in a gas-lift well thus amounts to the ability to control the depth of injection and the flowing pressure gradient.

The depth of injection is controlled by the amount of surface gas injection pressure available. The more pressure available, the deeper the injection point can be. As seen in Figure 3.16, the deeper the injection depth, the higher the pressure in the tubing at the point of injection. Also, as the depth of injection increases, less injection gas is required to achieve the same bottom-hole flowing pressure.

The second independent parameter in the diagram, the flowing gradient in the tubing, is controlled by the gas injection rate. At a given rate and constant wellhead pressure, the tubing intake pressure varies with GLR. For each flow rate in a given tubing size, there is a particular GLR that yields minimum tubing intake pressure or minimum flowing gradient resulting in maximum liquid rate. This GLR is referred as favorable or optimal GLR. A plot of favorable GLR versus the corresponding rates in a given tubing size is given in Figure 3.17. Favorable GLR decreases as oil rate increases. The favorable GLR is seldom equal to reservoir GLR and it may be achieved by adding gas to the tubing. The amount of gas injection rate required to achieve a favorable GLR is difference between the favorable and formation GLRs.

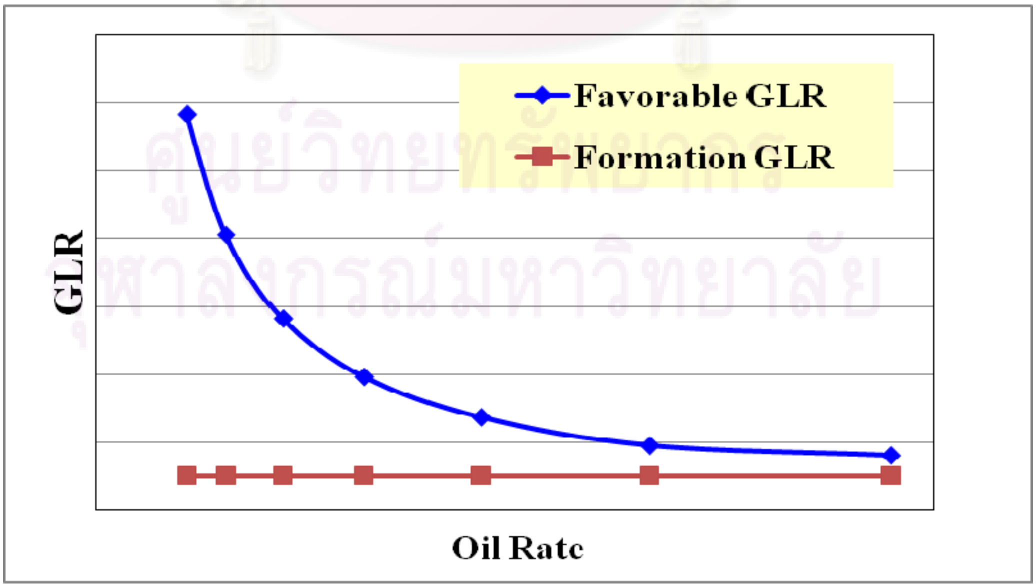


Figure 3.17 Example Plot of Favorable and Formation GLR vs. Oil Rate [17]

From Figure 3.18, increasing gas injection rate increases the gas-liquid ratio (GLR) in the tubing and up to a certain limit, decreases the flowing gradient. Beyond this limit, the flowing pressure gradient is increased by larger GLR or because the injected GLR becomes too large, the increasing in piping system pressure drop due to friction will exceed the decrease in the hydrostatic pressure in the tubing above the valve or injection point.

For a particular well, if the formation GLR is lower than the favorable GLR, injection of gas will increase the production. On the other hand, in wells where formation GLR is higher than the favorable GLR there is no gain in production by gas lift.

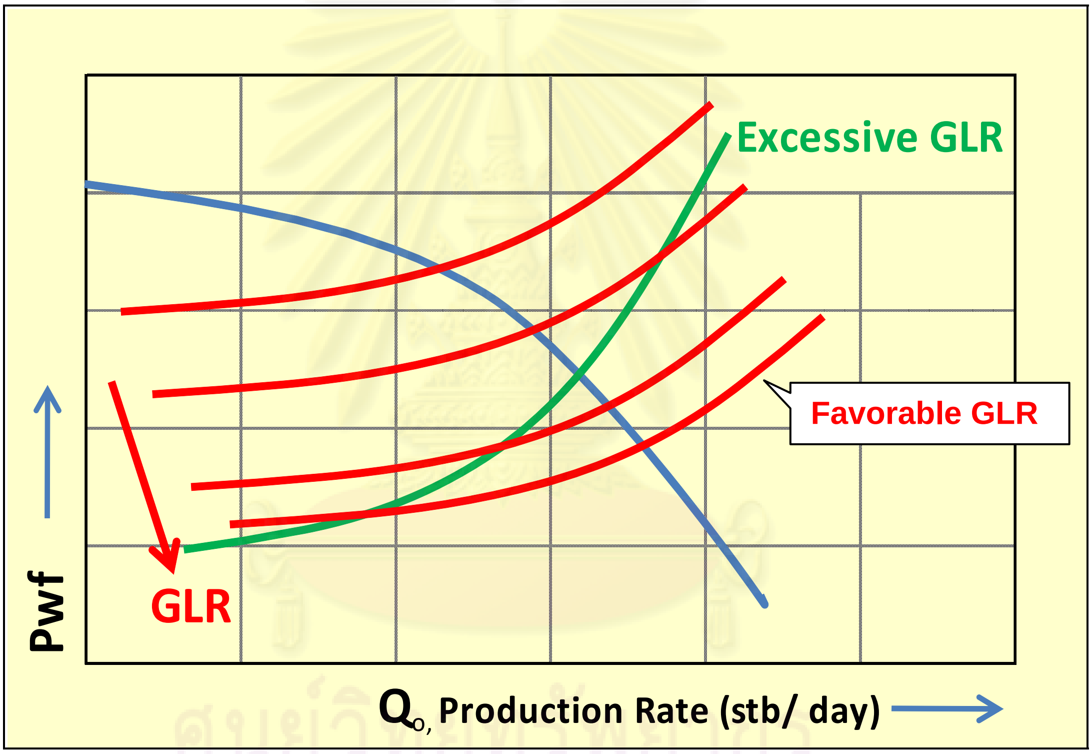


Figure 3.18 Gas-lift Well Analysis [17]

Figure 3.18 also illustrates the significance of intersection points in term of a tubing performance curve. It shows that tubing performance curves for any GLR higher or lower than the favorable GLR will intersect the IPR at a lower liquid rate.

The favorable GLR for a given liquid rate is independence of reservoir behavior. Therefore, in spite of depletion, the locus of favorable GLRs does not change. In gas injection rate required to maintain the maximum liquid rate as the reservoir depletes is the difference between the favorable GLR and formation GLR.

For solution gas-drive reservoirs, the needed gas-injection GLR increases at early stages but drops rapidly as reservoir GLR increases when reservoir pressure drops below the bubble point.

3.4.2 Intermittent Gas Lift

As the bottom-hole pressure declines, a point is reached where the well can no longer support continuous gas lift and the well is converted to intermittent gas lift. The intermittent gas lift (IGL) is an artificial lift method employed to produce oil when the reservoir is somewhat exhausted or its productivity is too low to use a higher producing method. A high-pressure gas supply provides the supplement of energy necessary to intermittently lift the reservoir's liquids (oil and water) up to the surface. The IGL cycle may be described by stages as follows:

(a) injection (gas input into the casing)
(b) elevation (gas-lift of the liquid slug inside the tubing)
(c) production (output of liquid at the surface)
(d) decompression (gas flow out of the tubing)
(e) loading (liquid flow from the reservoir into the well)

The IGL cyclic operation is controlled by setting up the cycle period and the gas injection period on the timer controller of the injection motor valve at the surface and by pressure-charging the dome of the operating gas lift-valve located inside the tubing string, near to the casing bottom. The IGL assisted wells can produce within a somewhat wide range of flow rates.

3.4.3 In-situ Gas Lift

Another method of gas lift is in-situ gas lift which is different from the continuous and intermittent gas lift. The in-situ gas lift has been developed without external gas sources. This method is applied to wells in which a gas zone(s) is available. In many cases, one or more gas zones are perforated with limited or partial perforation interval and produced along with the oil zones for production. The perforation interval may range from 1 to 3 feet with and 2" scallop guns, 6 shots per foot perforation density and 60 degrees of phasing.

Theoretically, conventional gas lift should provide better optimal GLR than in-situ gas lift; however, the in-situ gas lift may give more favorable economics in some certain scenarios.

In practice, the injection depth of gas lift in slim monobore completion is normally limited by the depth of the casing shoe which is typically set at about 4,000 ft TVD in Pattani Basin. For the in-situ gas lift, the depth of the in-situ gas zone(s) can be inferred as the injection depth which can be located deeper than 4,000 ft TVD. This could be one of the advantages of in-situ gas lift over the conventional gas lift.

Moreover, for the conventional gas lift, the maximum gas injection pressure is limited by the capacity of a gas lift compressor. The maximum gas injection pressure from typical gas lift compressors designed for the offshore application in the Gulf of Thailand is approximately 1,200 psi whereas the reservoir pressure of the in-situ gas zone(s) can be as high as 5,000 psi.

Usually, the gas injection rate required for monobore wells with conventional gas lift is about 0.5 – 1.0 MMscfd per well. Unlike the conventional gas lift, the in-situ gas lift has more difficulty in controlling or optimizing the downhole in-situ gas lift rate to achieve optimal GLR. However, the in-situ gas rate from the gas zone(s) can be controlled by limited or partial perforation or mechanical devices such as downhole choke or straddle pack-off assembly with an orifice valve. A rate greater than 1.0 MMscfd for in-situ gas zone can be achieved.

Table 3.1 Comparison between Conventional Gas Lift and In-situ Gas Lift

Parameter	Conventional Gas Lift	In-Situ Gas Lift
Injection depth	Limited by casing shoe +/- 4,000’ TVD (monobore completion)	Vary with depth, could be as deep as 8,000’ TVD
Injection pressure	Limited by compressor capacity +/-1,200 psi (typical model)	Vary, could be as high as 5,000 psi from a gas zone(s)
Control of gas injection rate	Can be controlled to achieve optimal GLR.	More difficult to be controlled by perforating or a mechanical device
Any limit on gas injection rate or GLR?	May be limited by the capacity, 0.5 – 1.0 MMscfd/ well.	Vary, could be higher than 1.0 MMscfd.

CHAPTER IV
MODEL SET UP

This thesis is to study the some predetermined variables that affect the oil recovery using the in-situ gas lift technique in the commingled reservoirs in slim monobore completion. The results from using in-situ gas lift techniques in different scenarios will be compared to the base case which is a monobore well producing with the conventional gas lift.

Thus, this thesis study requires a very systematic approach in order to incorporate some key variables with minimum error possible. The base case is discussed in this chapter to provide the basic understanding for further discussion on the results from the other scenarios. Moreover, the basic understanding of the reservoir simulator used in this study is also discussed in this chapter.

4.1 Introduction to Integrated Production Model (IPM) Toolkit

The tool used for this study is known as Integrated Production Model (by Petroleum Experts). The tool itself has three main parts being GAP, PROSPER and MBAL which can be linked together to form an Integrated Production System. Some of the features of this software are briefly mentioned in the following sections.

General Allocation Package (GAP)

GAP is an extremely powerful and useful tool offered to the petroleum engineering community. Some of the tasks GAP can achieve are complete Surface Production and Injection Network Modeling. It also has a powerful optimizer that is capable of handling a variety of wells in the same network such as naturally flowing oil wells, gas-lifted wells, ESP operated wells, etc. The optimizer controls production rates using wellhead chokes to maximize the hydrocarbon production while honoring constraints at the gathering system at well and reservoirs levels. GAP models both production and injection system simultaneously, containing oil, gas, condensate and/or water wells to generate production and/or injection profiles.

GAP’s powerful optimization engine can, for example, allocate gas for gas lift wells, sets wellhead chokes for naturally flowing wells to maximize revenue or oil production while honoring constraints at any level. GAP can also model and optimize injection networks associated with the production systems (both together).

GAP is used as the master controller to access instances of PROSPER and MBAL. Integration of the well and reservoir elements provides the ability to understand the dynamic interactions of the complete petroleum engineering system. The value of well re-design and well stimulation efforts can easily be evaluated in context of the complete petroleum engineering system.

During a prediction, MBAL passes the evolving reservoir fluids to GAP well elements. GAP uses the evolving reservoir fluids to capture well stability phenomena during a prediction enabling well contingency planning strategies to be developed.

GAP's scheduling power provides the ability to automatically develop well completion and drilling schedules that are required to meet a given overall flow objective. Drilling queues, workover, etc., can automatically be activated based on an objective function being set at any level in a given system.

Predicting measured reality is the ultimate goal of integrated studies and GAP offers a Model Validation utility to interrogate the system response. The model validation utility enables well model performance to be updated based on latest test data ensuring consistent model prediction ability.

Production Forecasting

GAP calculates full field production forecast including gas or water injection volumes required to meet reservoir unit pressure constraints. Reservoir pressures are obtained from decline curves, material balance or simulation models. The associated injection systems can be modeled and optimized so as to achieve injection targets for pressure maintenance programs. Apart from that, GAP also can be linked to MBAL and PROSPER for integrated calculations. GAP uses PROSPER to generate well IPR's and lift curve tables which are used to characterize the performance of the wells. GAP can be run in forecasting mode. At each time step, it transfers data to and receives data from MBAL. One well in GAP are connected to multiple MBAL tanks (or oil layers). Separate IPR can be defined for each tank. MBAL has strong aquifer modeling features.

Relative permeability curves can be defined to match the historical WGRs and to use in predictive mode.

Fully Compositional or Compositional Tracking Mode

GAP can calculate PVT properties fully compositionally and track compositions from the well/source level through to the separators. In a prediction, GAP can take compositions calculated by MBAL and record the evolution of compositions throughout the system with time.

MBAL

MBAL is in a package made up of various tools designed to gain a better understanding of the reservoir and perform prediction run. Some of the tools are material balance, reservoir allocation, decline curve analysis, Monte Carlo volumetrics and multilayer.

This incorporates the classical use of material balance calculations for history matching through graphical methods (like Havlena-Odeh, Cambell, Cole, etc.). Detailed PVT models can be constructed for oils, gases and condensates. Furthermore, predictions can be made with or without well models and using relative permeabilities to predict the amount of associated phase productions.

MBAL can also be tied into GAP for integrated production modeling studies, providing an accurate and fast reservoir model as long as the assumptions of material balance are valid for the real situation to be modeled.

PROSPER

PROSPER is functional element in the IPM mainly used for all the calculations in the pipeline and tubing section including various artificial lift designing capabilities. Its PVT section can generate fluid properties using standard correlations and allows them to be modified to better fit the measured lab data. It allows detailed PVT data in the form of tables to be imported for use in the calculations.

Apart from that, the tool can also be used to model reservoir inflow performance (IPR) for single layer, multilayer, or multilateral wells with complex and highly deviated completions, optimizing all aspects of a completion design including perforation details and gravel packing. It can be used to accurately predict both pressure and temperature profiles in producing wells and along surface flow lines. There are also sensitivity calculation capabilities to model and optimize tubing as well as surface flow line pressure. The multiphase flow correlations implemented can be adjusted to match measured field data to generate vertical lift performance curves (VLP) for use in simulators and net work models.

4.2 Base Case Well Model Discussion

Below is summary of general information and assumptions used for constructing the well model.

a) The completion design is the typical slim monobore type with 7" casing shoe (6.184" ID) set at approximately 4,000' TVD, and the production tubing is 2-7/8" tubing (2.441" ID).
b) The base case is a monobore oil well with conventional gas lift and no in-situ gas zone. In normal practice, the deepest gas lift valve in the monobore completion is set no lower than the 7" casing shoe which is, most of the time, set at approximate 4000' TVD (at 5825 ft MD in this case). It was assumed that only a single point injection (orifice valve) installed at 4,000 ft TVD and with the maximum injection pressure of 1,200 psi.
c) No booster compressor is installed. The separator pressure is fixed at 300 psia.
d) The total oil thickness from the referenced fields is between 20 ft up to 300 ft or an average mean of 160 ft per well while the number of oil zones per well can be as many as 20 to 40 zones. The hydrocarbon or pay window or reservoir depths where most of the oil and gas zones reside are between 5000 ft and 8000 ft TVD. The in-situ gas zones can be found in a variety of reservoir depths and thicknesses in the mentioned pay window. Therefore, in order to simplify the model and save simulation run time while maintaining representation of the multi-layered reservoir pattern, only four main layers will be modeled to represent the commingled oil reservoirs at 5000 ft, 6000 ft, 7000 ft and 8000 ft TVD. Thickness of each oil layer is 40 ft or a total of 160 ft per well.
e) The initial reservoir pressure are based on the reservoir pressure profile as shown in Figure A1 in Appendix A and all oil reservoirs are assumed to be undersaturated or above the bubble point. The original oil in place (OOIP) for

each oil layer is calculated using volumetric correlation in equation (4.1). The OOIP and parameters used for each oil layer is summarized in Table 4.1 and Table 4.2.

Table 4.1 OOIP for Oil Zones

Depth of Oil Layer (ft TVD)	h(ft)	A (acre)	Porosity	Swc	B_{oi}** (rb/ stb)	OOIP (stb) = 7758 Ah (Porosity) (1-S_{wc})/B_{oi}	OOIP (MMstb)
5000	40	61	0.24	0.25	1.00	3,406,119	**3.406**
6000	40	61	0.22	0.25	1.20	2,613,166	**2.613**
7000	40	61	0.2	0.25	1.43	1,988,245	**1.988**
8000	40	61	0.16	0.25	1.71	1,331,237	**1.331**
						Total	**9.339**

** *Boi* is from Figure A4 or a correlation: *Boi* = 0.4108 x e^(0.000178 x TVD)

Table 4.2 Tanks Parameters for Oil Layers

Name	Tank Parameters for Oil									
	Depth (ft TVD)	Reservoir Type	Reservoir Temp. (deg. F)	Initial Reservoir Pressure (psi)	Porosity (%)	Connate Sw (%)	Thickness, h (ft)	Area (acre)	Boi (rb/ stb)	Original Oil in Place (MMstb)	Permeability, k (mD)
Oil Layer #1	**5000**	Oil	240	2500	24%	15%	40	61.00	1.00	3.406	200
Oil Layer #2	**6000**	Oil	270	3000	22%	15%	40	61.00	1.20	2.613	150
Oil Layer #3	**7000**	Oil	290	3500	20%	15%	40	61.00	1.43	1.988	100
Oil Layer #4	**8000**	Oil	310	4000	16%	15%	40	61.00	1.71	1.331	50
						Total	**160**	**244**	**Total**	**9.339**	

f) One additional layer will be modeled as an in-situ gas zone at various depths or initial reservoir pressures, gas permeabilities, and thicknesses as shown in Table 4.5. The top depths of the in-situ gas zone are based on the distribution of the gas zone in the field data and in order to simplify the model each in-situ gas zone will be located in between the oil layers. The original gas in place (*OGIP*) for in-situ gas zone is calculated using volumetric correlation in equation (4.2) based on the average drainage area of 51 acres per layer. *OGIP* for each in-situ gas zone in each depth and thickness parameters used in in-situ gas layer are summarized in Table 4.3 and Table 4.4, respectively.

$$OOIP = \frac{Ah\phi(1 - S_{wc})\ 7758}{B_{oi}} \tag{4.1}$$

$$OGIP = \frac{Ah\phi(1 - S_{wc})\ 43560}{B_{gi}} \tag{4.2}$$

where

$OOIP$ = original oil in place (stb)

$OGIP$ = original gas in place (scf)

A = drainage area (acre)

h = thickness (ft)

ϕ = porosity (fraction)

S_{wc} = connate water saturation (fraction)

B_{oi} = initial oil formation volume factor (rb/stb)

B_{gi} = initial gas formation volume factor (rcf/scf)

Table 4.3 OGIP for In-situ Gas Zone

Depth of In-situ Gas Zone (ft TVD)	h (ft)	A (acre)	Porosity	Swc	B_{gi}* (rcf/ scf)	OGIP (scf) = 43560 Ah (Porosity) (1-Swc)/Bgi	OGIP (MMscf)
5500	15	51	0.17	0.15	0.0085	567,910,787	**568**
5500	45	51	0.17	0.15	0.0085	1,703,732,361	**1704**
5500	90	51	0.17	0.15	0.0085	3,407,464,723	**3407**
6500	15	51	0.17	0.15	0.0067	722,352,108	**722**
6500	45	51	0.17	0.15	0.0067	2,167,056,325	**2167**
6500	90	51	0.17	0.15	0.0067	4,334,112,649	**4334**
7500	15	51	0.17	0.15	0.0059	815,767,595	**816**
7500	45	51	0.17	0.15	0.0059	2,447,302,786	**2447**
7500	90	51	0.17	0.15	0.0059	4,894,605,573	**4895**

* B_{gi} is from correlations below:

If TVD > 6250 ft, B_{gi} = 1 / [(0.0194 x TVD) + 23.914]

If TVD <= 6250 ft, B_{gi} = 1 / [-0.000002598 x TVD^2 + 0.062 x TVD -144.47)]

Table 4.4 Tanks Parameters for In-situ Gas Zones

Name	Tank Parameters for In-situ Gas Zone									
	Depth (ft TVD)	Reservoir Type	Reservoir Temp. (deg. F)	Initial Reservoir Pressure (psi)	Porosity (%)	Connate Sw (%)	Thickness, h (ft)	Area (acre)	Bgi (rf/ scf)	Original Gas in Place (MMscf)
In-Situ Gas	5500	Gas	255	2750	0.17	0.15	15	51	0.00848	568
In-Situ Gas	5500	Gas	255	2750	0.17	0.15	45	51	0.00848	1,704
In-Situ Gas	5500	Gas	255	2750	0.17	0.15	90	51	0.00848	3,407
In-Situ Gas	6500	Gas	280	3250	0.17	0.15	15	51	0.00667	722
In-Situ Gas	6500	Gas	280	3250	0.17	0.15	45	51	0.00667	2,167
In-Situ Gas	6500	Gas	280	3250	0.17	0.15	90	51	0.00667	4,334
In-Situ Gas	7500	Gas	300	3750	0.17	0.15	15	51	0.00590	816
In-Situ Gas	7500	Gas	300	3750	0.17	0.15	45	51	0.00590	2,447
In-Situ Gas	7500	Gas	300	3750	0.17	0.15	90	51	0.00590	4,895

g) Fluid properties of oil and gas layers are based on field data and some of them are assumed constant or calculated according to correlations.

h) The initial reservoir pressure (Figures A1 in Appendix A), reservoir temperature (Figure A2 in Appendix A) and permeability of each oil layer are estimated from field data mentioned-above.

i) Other parameters that may affect inflow and tubing performance are assumed constant or calculated according to correlations.

Figure 4.1 represents the completion schematic of the base case well model that is based on the information above whereas Figure 4.2 illustrates the completion schematic for different scenarios and also indicates reservoir depth of each in-situ gas zone at 5500', 6500' and 7500' TVD.

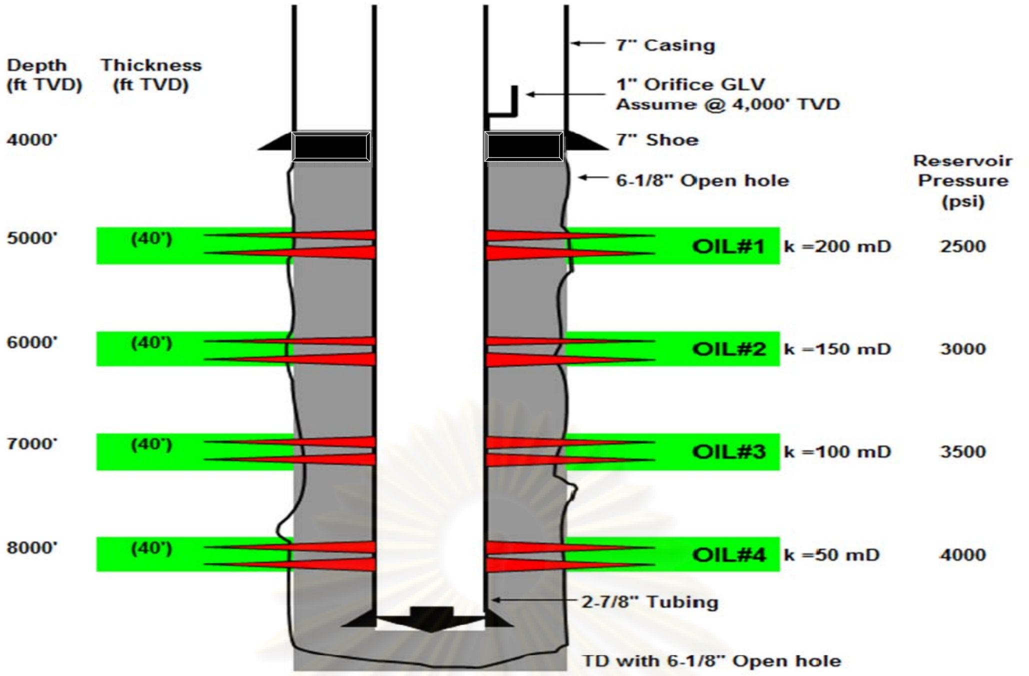


Figure 4.1 Completion Schematic for Base Case Scenario with an Orifice Gas Lift Valve

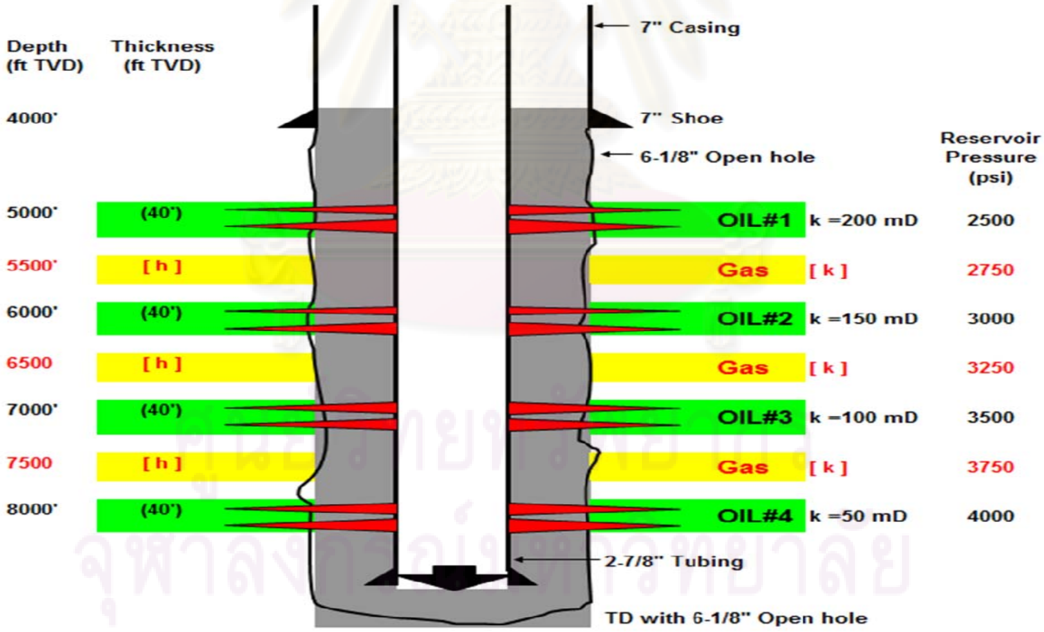


Figure 4.2 Completion Schematic for Different Scenarios by Varying Depth, k and h of an In-situ Gas Zone

Model Setup

The completion schematic for base case in Figure 4.1 can be constructed as the IPM diagram as shown in Figure 4.3 which represents the base case well model with gas lift (WELL GL) and well without a gas lift (WELL NATURAL) connected to four simplified oil reservoirs (green oil tanks) with 40 ft thickness each and one gas zone (red in-situ gas tank) with 40 ft thickness to the choke and then to the separator but the in-situ gas zone is masked or disabled from the prediction runs for the base case.

This IPM diagram allows the prediction runs for the well with the natural flow (WELL NATURAL) until the oil rate reaches abandonment rate of 10 stb/d or ceases flowing then switched to the gas lift (WELL GL) with the abandonment rate of 20 stb/d due to higher operating cost or until the well stops flowing. This type of gas lift application is generally called "post-production gas lift".

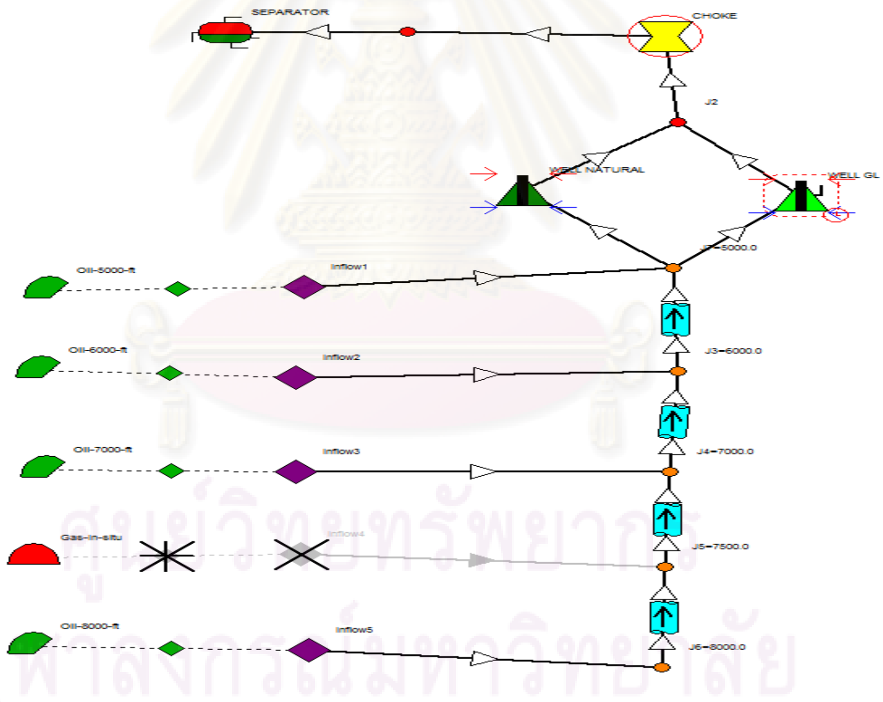


Figure 4.3 Base Case Well Model Diagram in IPM for Gas Lift

Figures 4.4, 4.5 and 4.6 represent the IPM well model with each in-situ gas zone which is located at 5500', 6500' and 7500' TVD, respectively.

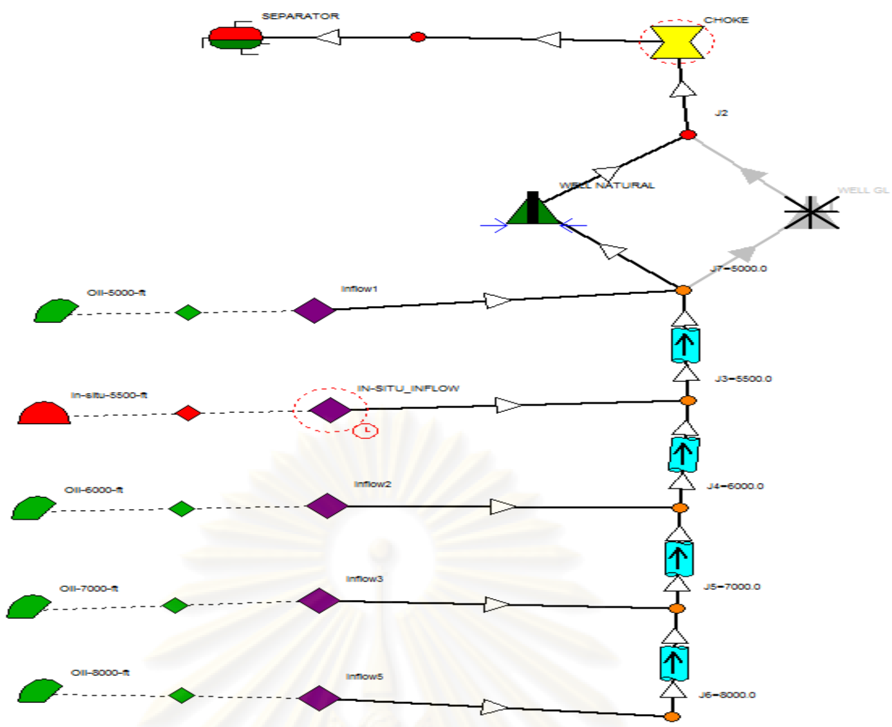


Figure 4.4 Well Model Diagram in IPM for In-situ Gas Zone @ 5500’ TVD

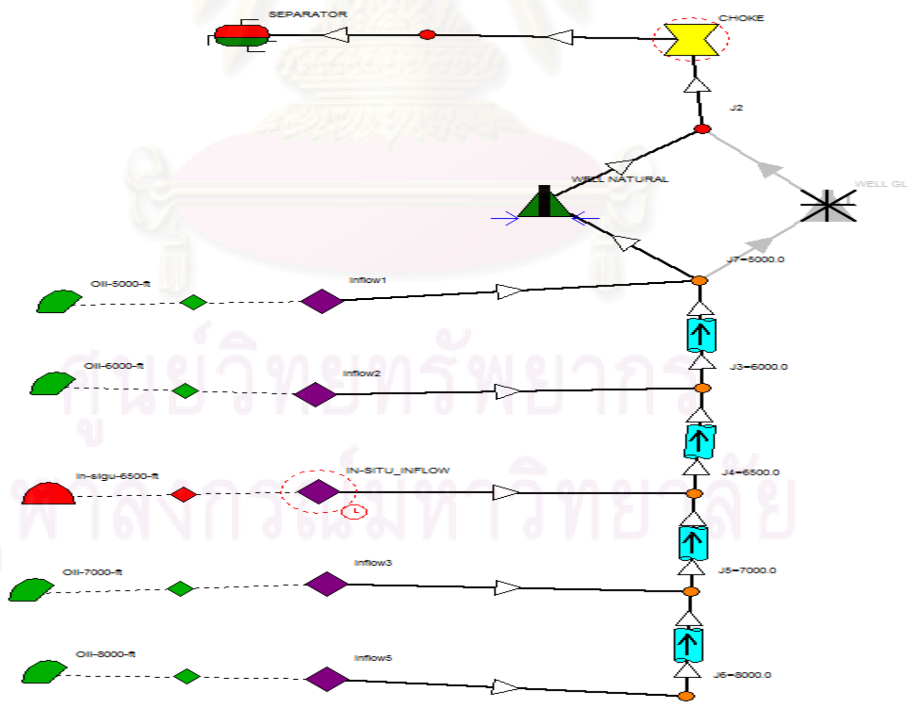


Figure 4.5 Well Model Diagram in IPM for In-situ Gas Zone @ 6500’ TVD

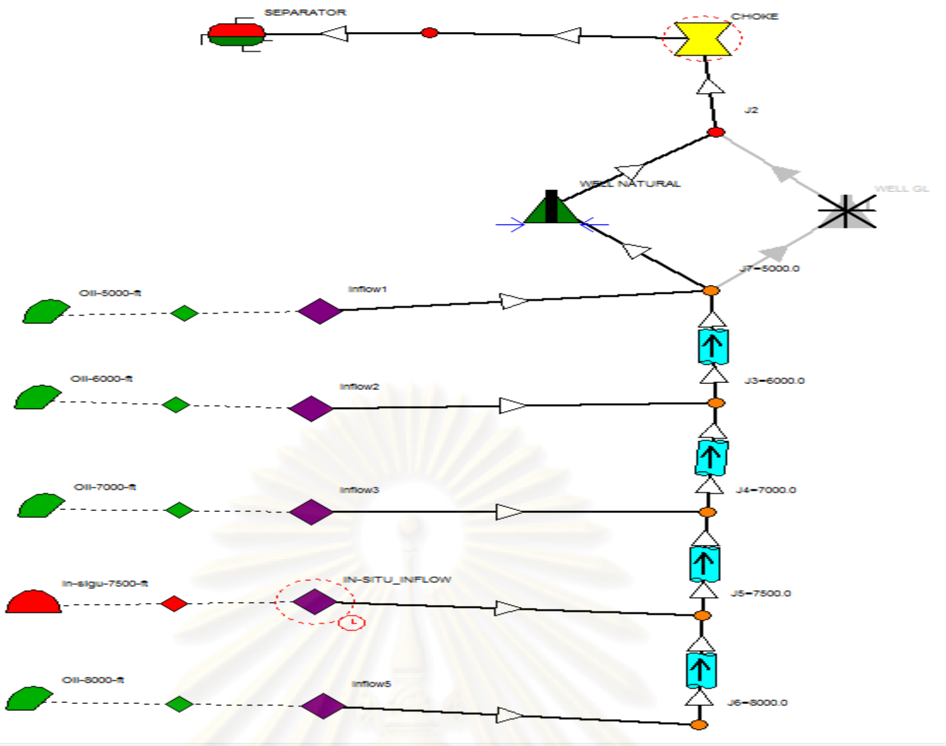
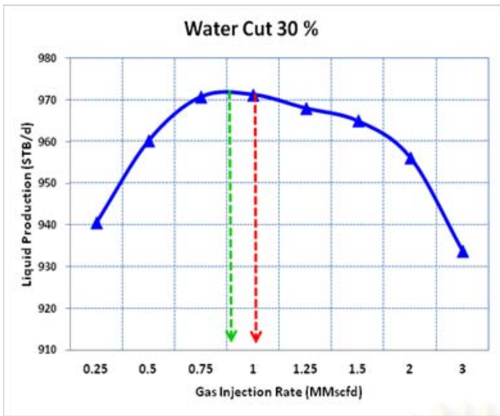


Figure 4.6 Well Model Diagram in IPM for In-situ Gas Zone @ 7500' TVD

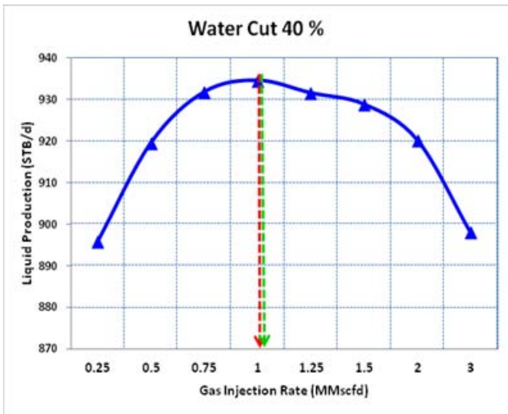
4.3 Conventional Gas Lift Operation Practice

The control of the gas lift in the base case model is based on the normal practice in the offshore environment in the studied fields, i.e., the gas injection rate, most of the time, is set at constant or fixed injection rate or at maximum injection gas available when the well is producing at high water cut or loaded up. Practically, the gas lift injection rate is available between 0.5 – 1.0 MMscfd per well with 1,200 – 1,500 psi injection pressure which is the normal capacity of the gas lift compressor currently installed in the studied offshore fields.

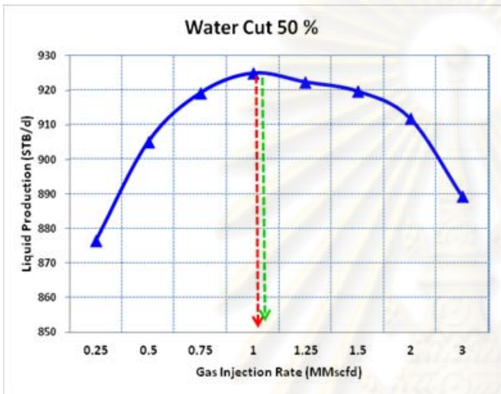
To verify which gas injection rate is suitable for such a base case, the initial liquid production rate (plateau) at 1,500 stb/d was assumed while the sensitivity run on gas lift injection rates of 0.25, 0.5, 0.75, 1.0, 1.25, 1.5, 2.0, and 3.0 MMscfd and various water cuts (30%, 40%, 50%, 60%, 70%, 80%, 90% and 95%) were run to identify the optimal GLR. According to the results shown in Figure 4.7 (a), (b), (c), (d), (e), (f), (g) and (h), it can be observed that at any given water cuts, the gas injection rate of 1.0 MMscfd could provide GLR that is close to the optimal GLR for wider range of water cuts with excessive GLR for one case only.


Water Cut 30 %
Liquid Production (STB/d)
980
970
960
950
940
930
920
910
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

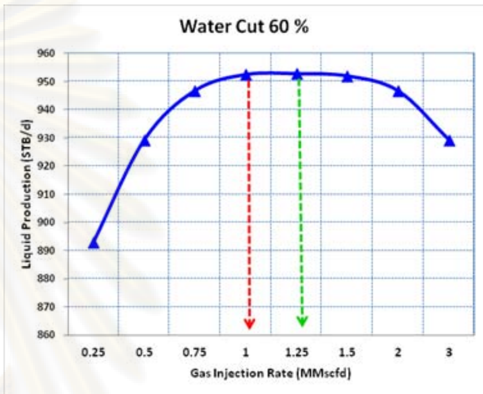
(a)


Water Cut 40 %
Liquid Production (STB/d)
940
930
920
910
900
890
880
870
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

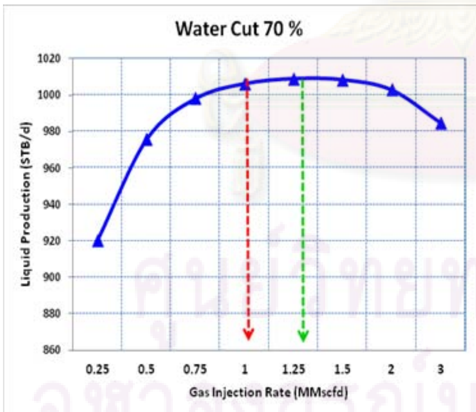
(b)


Water Cut 50 %
Liquid Production (STB/d)
930
920
910
900
890
880
870
860
850
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

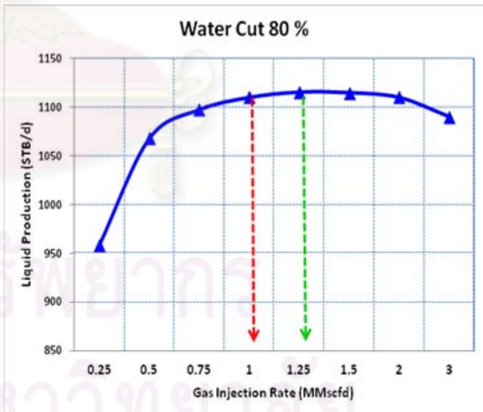
(c)


Water Cut 60 %
Liquid Production (STB/d)
960
950
940
930
920
910
900
890
880
870
860
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

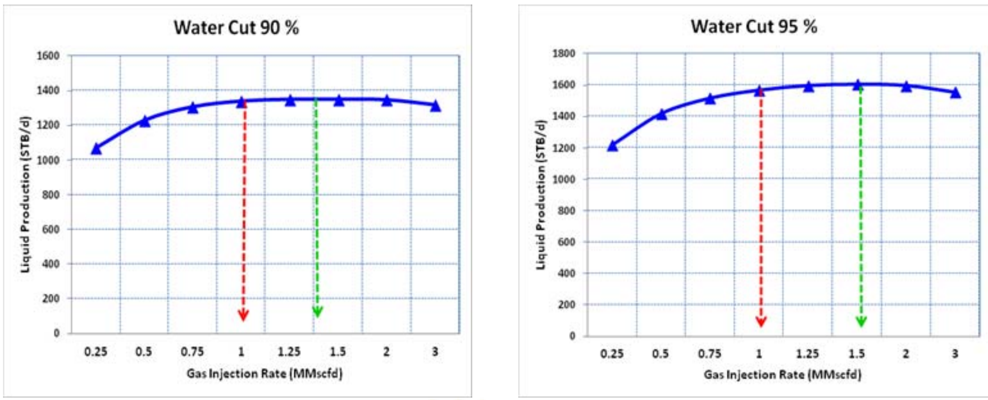
(d)


Water Cut 70 %
Liquid Production (STB/d)
1020
1000
980
960
940
920
900
880
860
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

(e)


Water Cut 80 %
Liquid Production (STB/d)
1150
1100
1050
1000
950
900
850
0.25 0.5 0.75 1 1.25 1.5 2 3
Gas Injection Rate (MMscfd)

(f)



(g) (h)

Figure 4.7 Gas Lift Performance Curve for Various Water Cuts at (a) 30%, (b) 40%, (c) 50%, (d) 60%, (e) 70%, (f) 80%, (g) 90%, and (h) 95%

4.4 Favorable Gas to Liquid Ratio (GLR)

In this study, the initial reservoir pressures of all oil reservoirs are assumed undersaturated or above the bubble point. As a result, at the beginning of the production with natural depletion of the oil reservoirs (without an in-situ gas zone), the producing GLR is consequently low and constant (see also Section 3.3.1 Solution Gas Drive).

After the oil production falls, the gas lift system is then instituted. It is necessary to determine the amount of gas injection rate required to achieve the favorable or optimal GLR to obtain the maximum oil production rate possible. However, this favorable GLR may not be achieved mainly due to limited amount of injection gas or high cost of the gas compression and separation equipment needed to separate large gas quantities.

As a result, the maximum oil rate is not necessarily the most economic one. However, for solution gas drive reservoirs (Section 3.3.1), the needed gas-injection GLR increases at early stages but drops rapidly as reservoir GLR increases when reservoir pressure drops below the bubble point.

At a given rate where the formation GLR is higher than the favorable GLR needed as shown in Figure 4.8, there is no gain in production by injecting more gas. Injecting a constant gas lift rate of 1.0 MMscfd may not give the favorable or optimal GLR; however, it will not cause excessive GLR in most cases as discussed in Figure 4.7 previously and is in line with the current gas lift operation practice in the studied fields.

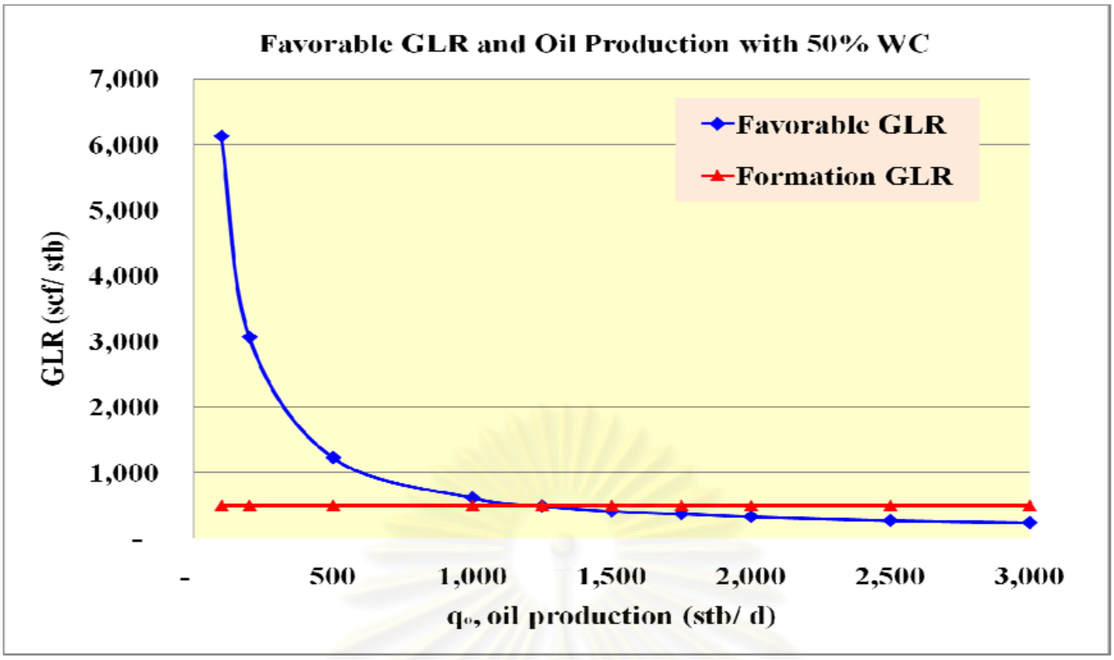


Figure 4.8 Favorable GLR Curve for the Base Case with Injection Gas Rate of 1.0 MMscfd, 50% WC and Formation GLR of 500 scf/stb

4.5 Tank Model (MBAL)

Each of oil and gas reservoir or layer is simplified with the reservoir properties shown in the Table 4.2 and Table 4.4 to represent multi-layered reservoirs in monobore completions. All of reservoir parameters are based on the typical fluid properties obtained from the actual field data of two major oil fields in one of the concession blocks in Pattani Basin in the Gulf of Thailand. This block is approximately 2,891 square kilometers in size and lies on the north-western edge of Pattani Basin with production from fluvial sands of Miocene and Oligocene age. Two different petroleum systems are identified in this block primarily inferred from analyses of produced hydrocarbons.

Upper Oligocene lacustrine intervals in the block represent the primary source for liquid hydrocarbons. Most of the reservoir section was deposited in a fluvial or coastal plain environment, with linear, discontinuous sands through laterally extensive amalgamated sand sequences. Hydrocarbon accumulations are generally associated with three-way dip closures formed along normal faults. Stratigraphic closure in the strike direction, at the depositional edge of fluvial sand, is also common. Wells are usually directionally drilled parallel to the trapping fault and encounter multiple stacked pay sands. The individual sands are generally thin, averaging about 10 to 40 feet; however, some sands are as thick as 90 up to 150 feet.

The average drainage areas for oil and gas reservoirs are 61 and 51 acres per layer, respectively. These drainage areas are estimated from the field data using Swanson's rule. Swanson's rule defines the mean as $0.3(P_{10})+0.4(P_{50})+ 0.3(P_{90})$, and provides a good approximation to the mean values for modestly skewed distributions to present a range of geologically possible models for a range of prospect reserve estimates.

Most of oil reservoirs in Pattani Basin are not only multi-layered, but also driven by radial aquifer drive apart from their solution GOR. These wells have tendency to die or load up around 40% to 60% water cut. As a result, the aquifer parameters for all four oil layers in MBAL are required. The input data for the aquifer model is shown in Table A1 in Appendix A. As mentioned before, PVT input data in MBAL for all four oil layers as shown in Table A2 in Appendix A are based on the typical fluid properties of the two major fields in Pattani Basin. The example input data for relative permeability for oil and gas layers are also shown in Table A3 in Appendix A, while Table A4 in Appendix A contains input data for residual saturation and Corey exponents for oil and gas layers to match the core data analysis. Figure A8 in Appendix A is water-oil relative permeability calculated in MBAL to match the data from core analysis shown in Figure A9 in Appendix A. Similarly, Figure A11 in Appendix A is the gas-oil relative permeability calculated in MBAL to match the data from core analysis shown in Figure A12 in Appendix A.

Inflow Performance Relation (IPR)

The IPR describes reservoir fluid inflow into the wellbore and constitutes a major component of the nodal analysis technique for well performance optimization. For the base case, the nodal analysis model for each oil and gas layer was constructed in PROSPER based on the input data in Tables A5 and A6 in Appendix A.

Geothermal gradient is also estimated from average field data per Table A8 in Appendix A while the deviation of the well is picked up from one of the existing oil wells in Pattani Basin as shown in Table A9 in Appendix A.

Vertical Lift Performance (VLP)

Fluid Flow Correlation

For oil wells, Hagedorn & Brown correlation has remained the most widely used and most reliable even though it is one of the very first multiphase flow correlations developed. However, since OLGA flow correlation which is the best correlation available in the industry is available in the current software used, OLGAS 3P (Steady State Offshoot of OLGA) is selected in all the tubing in the base case well model. The OLGAS 3P is the mechanistic model in which all flow equations are solved by a numerical method and suitable for all the flow conditions.

In order to allow GAP to produce the VLP, the well model is constructed in PROSPER using the input data in Tables A7, A8 and A9 in Appendix A.

The sensitivity variables for VLP are as follows:

1. Liquid rate ranges from 20 to 5,000 stb/d for 20 values using geometric spacing.
2. Manifold pressure ranges from 50 to 2,000 psi for 10 values using geometric spacing.
3. GOR ranges from 250 to 20,000 scf/stb for 10 values using geometric spacing.
4. Water cut ranges from 0 to 99% for 10 values by manual spacing.
5. Gas injection rate ranges from 0.25 to 1.25 MMscfd for 6 values using linear spacing.

The in-situ gas lift scenarios are generated for the prediction runs to record the oil recovery factors with various values of variables as shown in Table 4.5. Each variable in the sensitivity runs has three values, being low, medium and high. The combination of variables is varied and simulation runs are made based on these different combinations.

Table 4.5: Variables for Thesis Study

Variable	Value #1	Value #2	Value #3
Estimated initial reservoir pressure for in-situ gas zone (psia) or Reservoir depth (ft TVD)	2750 psia or 5500' TVD	3250 psia or 6500' TVD	3750 psia or 7500' TVD
Permeability of in-situ gas zone (mD)	10 mD	100 mD	1000 mD
Total gas pay thickness (ft)	15 ft	45 ft	90 ft
Perforation schedule of in-situ gas zone	Concurrent vs. Time-lapsed		

In this thesis, the concurrent and time-lapsed perforation schedules of in-situ gas zone are studied. The concurrent perforation schedule for the in-situ gas zone is the case that the in-situ gas zone is perforated at the same time as the oil zones and produced commingledly while the time-lapsed perforation schedule will let the well produce naturally for a certain duration or until the well reaches the abandonment rate of 10 stb/d, and require the in-situ gas zone to be perforated later on. In this study, approximate 50% water cut is used as a trigger for the time-lapsed perforation schedule of the in-situ gas zone. For both cases, the gas zone is perforated with 1-ft interval and the mechanical straddle pack-off with check-valve is assumed to be installed across the perforation to prevent cross-flow into the in-situ gas zone.

Moreover, after a few scenarios for in-situ gas zone were simulated, a problem with crossflow into the in-situ gas zone occurred, resulting in well instability phenomena during a prediction run. To prevent the crossflow problem, there has been proven technology and equipment and is viable practice in the studied fields which is to set a mechanical straddle pack-off with a check valve across the perforation interval of the in-situ gas zone. This mechanical pack-off will prevent the crossflow into the in-situ gas zone. As a result, this equipment is assumed to be set across the perforation interval on the in-situ gas zone in every scenario. This can be achieved in the simulation by making the positive differential pressure. The pressure drop due to its restriction of the pack-off is assumed negligible.

CHAPTER V
RESULTS AND DISCUSSION

5.1 Base Case Results

The base case scenario is that the well is made to flow naturally until it is loaded up or produces less than 10 stb/d of abandonment oil rate whichever comes first. The oil recovery factor for the "natural flow" scenario is recorded. After that, gas lift is started with a fixed injection rate between 0.5 to 1.0 MMscfd according to current gas lift operation practice in the studied fields. However, the gas injection rate of 1.0 MMscfd which has been discussed in Section 4.3 appears to be the most suitable. Therefore, it has been selected for the base case simulation. Then, the well is kept producing until it is loaded up or reaches the abandonment oil rate of 20 stb/d whichever comes first. The total oil recovery factor for the "base case with gas lift" or "conventional gas lift" is then captured.

Figure 5.1 illustrates the production and GLR profile of the natural flow for the initial flowing period of the base case. It can be observed that the well would cease flowing when the water cut increases quickly. Even though there is an increase in GLR, it seems to be too low or unable to help lighten the hydrostatic column from increasing water production. It can be inferred that the well is probably loaded up before the oil reservoir reaches the bubble point where the formation GLR should rise dramatically. The recovery factor from the natural flow period of the base case is 32.1% which relatively high. This is probably due to the fact that there is water influx or water drive mechanism for each oil layer apart from its solution-gas drive during the model set up.

Figure 5.2 illustrate the production profile of the base case well model with gas fixed injection rate of 1.0 MMscfd to bring the well back on line. The well continues to flow until it is loaded up. It is very obvious that conventional gas lift is very effective in term of extending the life of the well and improvement of the oil recovery factor from 32.1% (natural flow) to 41.4%. Figure 5.3 shows better illustration of gas injection rate and GLR. As the production continues, GLR increases because the gas injection rate remains constant at 1.0 MMscfd while the total liquid production decreases until the well reaches the abandonment rate.

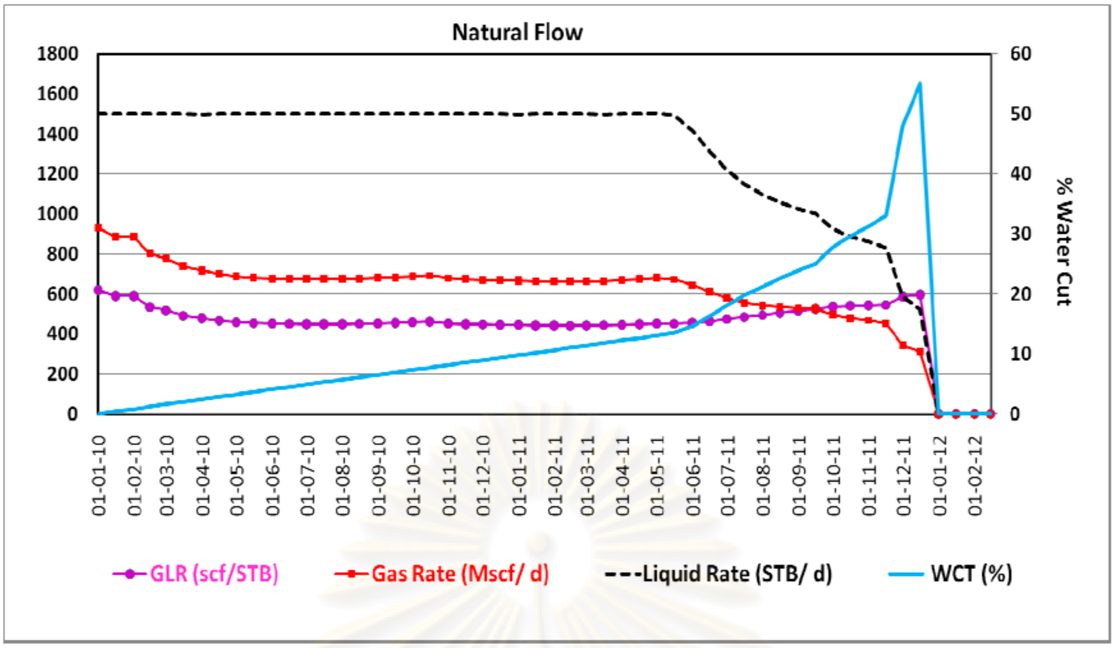


Figure 5.1 Production Profile of the Natural Flow Case

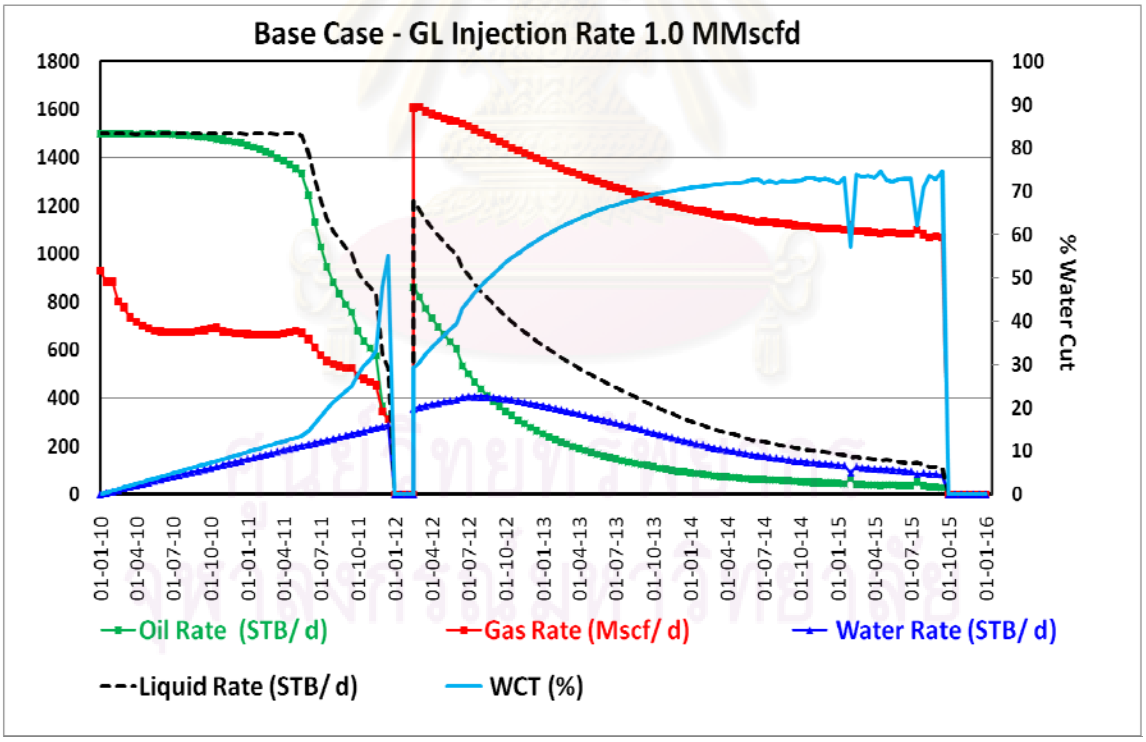


Figure 5.2 Production Profile of the Base Case

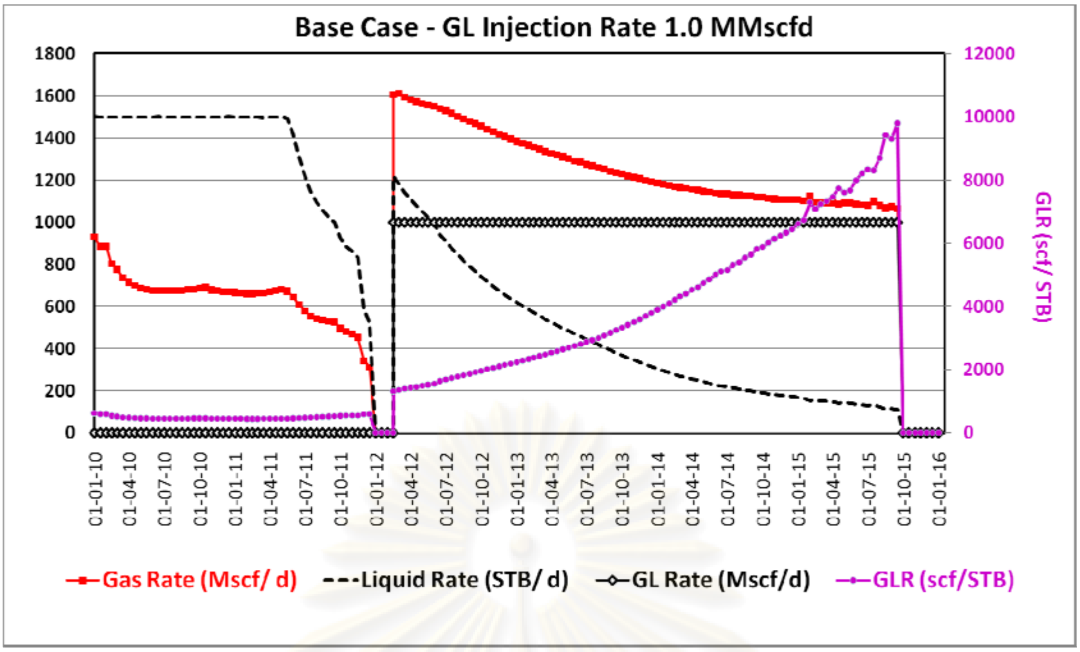


Figure 5.3 Production Profile with Gas Rate and GLR of the Base Case.

After the results for the base case were obtained, the prediction run for each in-situ gas lift scenario was conducted as per previous discussion. All the results and discussion are presented later in this chapter. The recorded results are at times subjected to the software error and hence the bigger picture is of the primary concern rather than being exact on the delivered values.

5.2 Impact of Perforation Schedule of In-situ Gas Zone on Oil Recovery Factor

5.2.1 In-situ Gas Zone @ 5500' TVD

According to Figure 5.4, with the same depth of the in-situ gas zone, it can be observed that

(a) For all scenarios at any given thickness and permeability, the time-lapsed perforation schedule of the in-situ gas zone provides better recovery factors than the concurrent perforation schedule. Referring to Figure 4.8, at the beginning of the production or at high oil rate, a need for GLR is low to avoid too much pressure drop due to friction. Therefore the time-lapsed perforation schedule should prevent too much GLR at the beginning of production. As the production declines, the need for GLR increases. As a result, when the in-situ gas zone is perforated later on or in time-lapsed perforation schedule, it should provide additional gas to increase the total GLR at the better timing even though it may not be at the favorable GLR. In this study, the time-lapsed perforation of the in-situ gas zone occurs when the water cut reaches about 50%.

(b) The scenario with 90-ft thickness and 10 mD and time-lapsed perforation schedule provides the highest recovery factors mainly due to, apart from time-lapsed perforation schedule, effects of thickness and permeability which will be discussed later in Section 5.4.1 (a) and 5.5.1 (a).

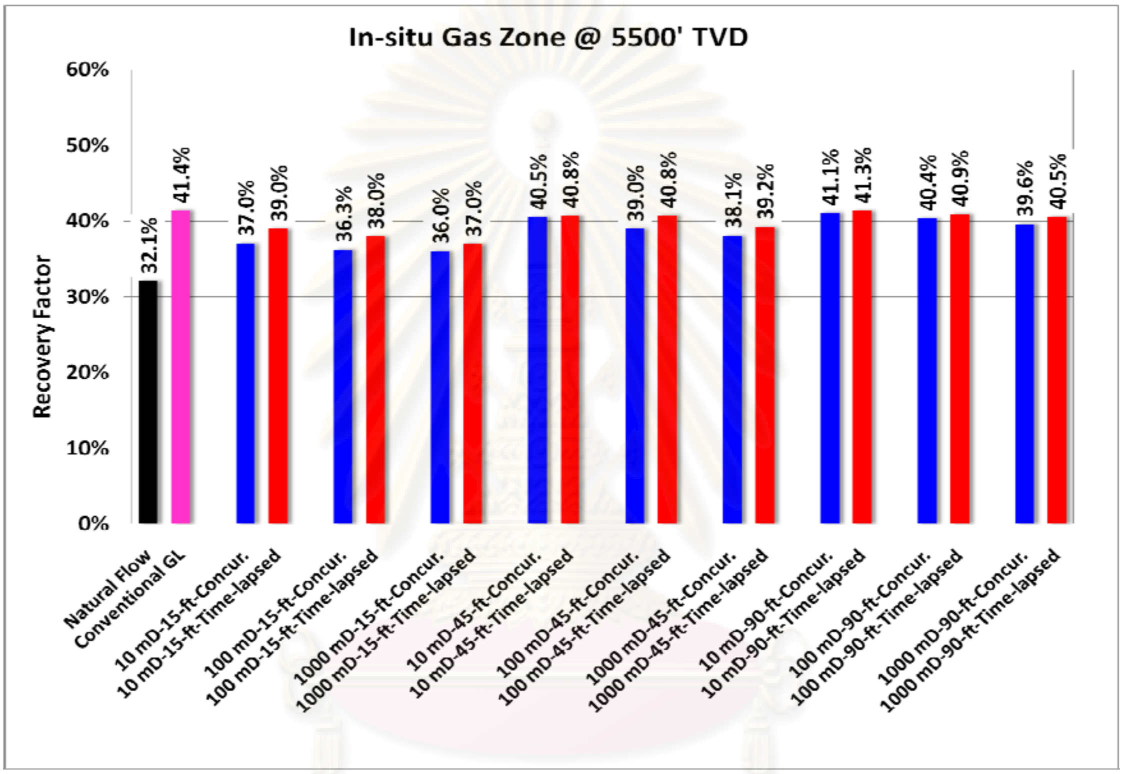


Figure 5.4 Oil Recovery Factors for Concurrent and Time-lapsed Perforation Schedules of In-situ Gas Zone @ 5500' TVD

5.2.2 In-situ Gas Zone @ 6500' TVD

According to Figure 5.5, with the same depth of the in-situ gas zone, it can be observed that

(a) Similar to the previous case of in-situ gas zone at 5500' TVD in Section 5.2.1 (a), in all scenarios at any given thickness and permeability, the time-lapsed perforation schedule of the in-situ gas zone provides better recovery factors than the concurrent perforation schedule.

(b) The scenario with 90-ft thickness, 10 mD and time-lapsed perforation schedule provides the highest recovery factors mainly due to, apart from time-lapsed perforation schedule, effects of thickness and permeability which will be discussed later in Section 5.4.1 (a) and 5.5.1 (a).

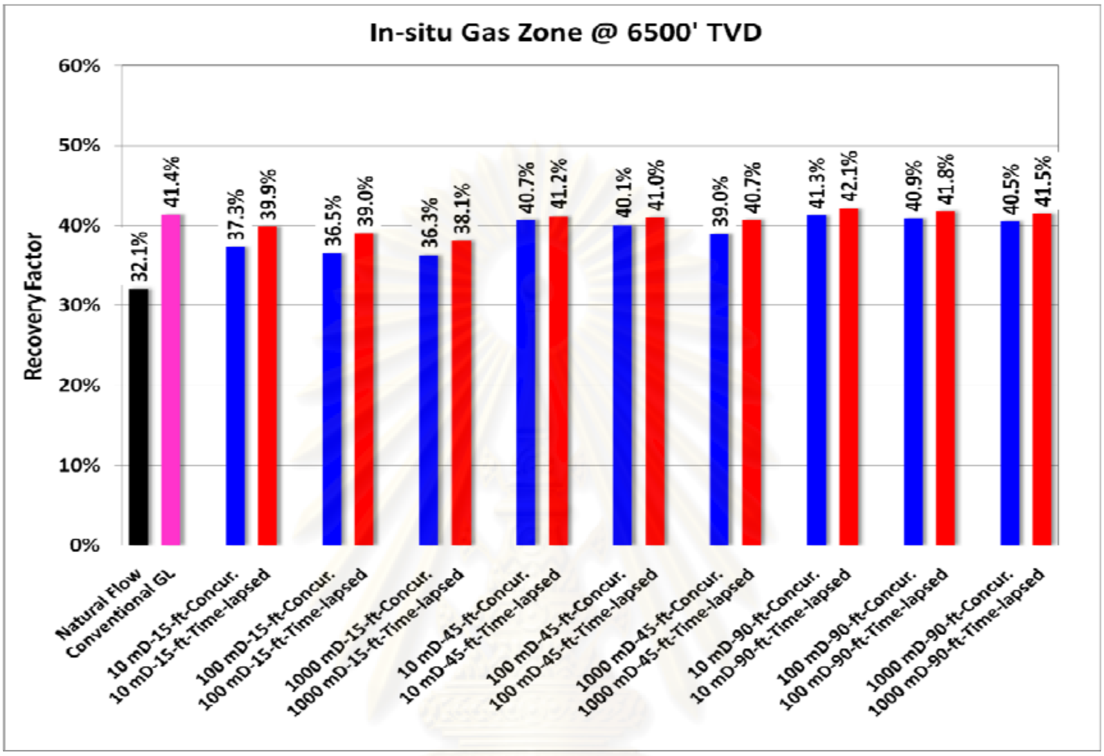


Figure 5.5 Oil Recovery Factors for Concurrent and Time-lapsed Perforation Schedules of In-situ Gas Zone @ 6500’ TVD

5.2.3 In-situ Gas Zone @ 7500’ TVD

According to Figure 5.6, with the same depth of the in-situ gas zone, it can be observed that

(a) Similar to the previous cases of in-situ gas zone at 5500’ TVD and 6500’ TVD in Sections 5.2.1 (a) and 5.2.2 (a), respectively, in all scenarios at any given thickness and permeability, the time-lapsed perforation schedule of the in-situ gas zone provides better recovery factors than the concurrent perforation schedule.

(b) The scenario with 90-ft thickness and 10 mD and time-lapsed perforation schedule provides the highest recovery factors mainly due to effects of thickness and permeability which will be discussed later in Section 5.4.1 (a) and 5.5.1 (a).

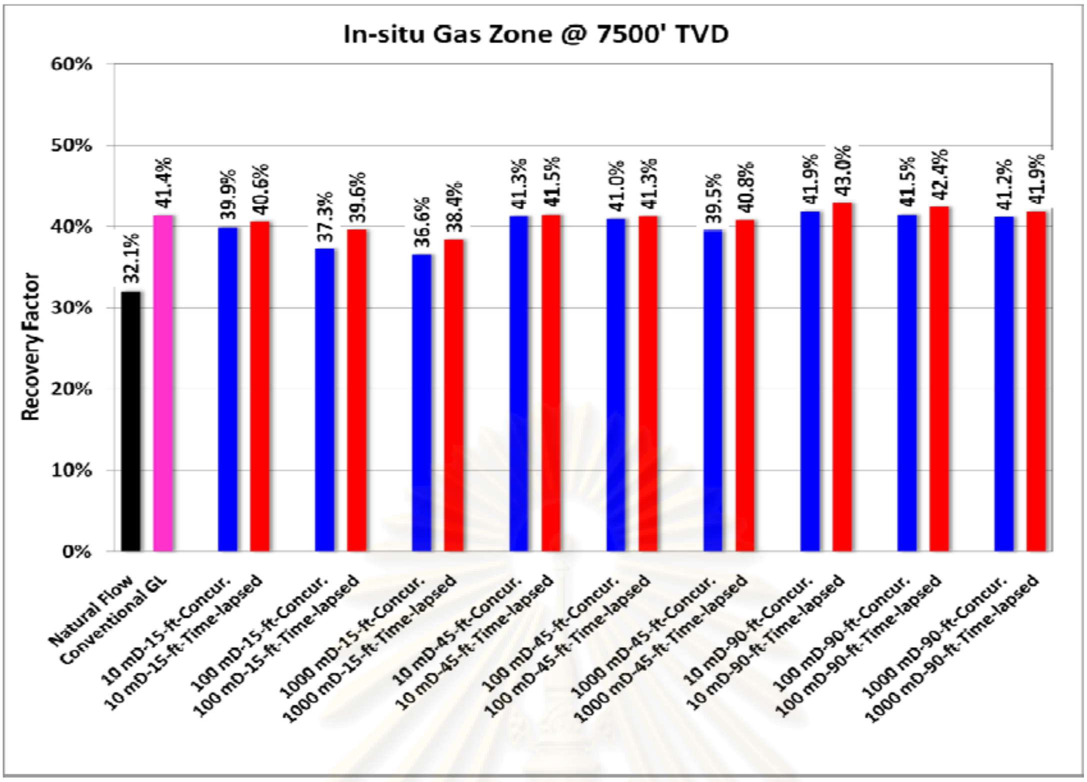


Figure 5.6 Oil Recovery Factors for Concurrent and Time-lapsed Perforation Schedules of In-situ Gas Zone @ 7500' TVD

In summary, at the same depth, *k* and thickness of an in-situ gas zone, the time-lapsed perforation schedule of the in-situ gas zone provides higher recovery factor for every scenario.

5.3 Impact of Depths of In-situ Gas Zone on Oil Recovery Factor

5.3.1 In-situ Gas Zone with 15-ft Thickness

According to Figure 5.7, with the same thickness of in-situ gas zone, it can be observed that

(a) The oil recovery factors appear to slightly increase with depth of the in-situ gas zone in either concurrent or time-lapsed perforation schedule. This effect is similar to the effect of the gas injection depth in conventional gas lift.

(b) The recovery factors for all in-situ gas lift scenarios are less than the base case (41.4%) because of the decline of in-situ gas zone compared to the constant gas injection rate for the base case. As a result, when the in-situ gas zone declines to a point where the GLR is too low to help lighten the hydrostatic column, the well will be loaded up.

(c) The scenario with the in-situ gas zone at 7500' TVD and 10 mD provides the highest oil recovery factor in time-lapsed perforation schedule because of effects of depths and time-lapsed perforation schedule of the in-situ gas zone. The positive effect of time-lapsed perforation has been previously explained in Section 5.2.1 (a). With the same permeability of 10 mD, the in-situ gas zone at 7500' TVD has better effect than 5500' and 6500' TVD in term of gas injection depth similar to conventional gas lift. Moreover, increasing reservoir pressure and temperature of the in-situ gas zone at 7500' TVD provides higher expansion ratio of gas when gas is flowing or migrating up the well than the in-situ gas zone at 5500' and 6500' TVD. This helps lift the hydrostatic column better as long as it does not exceed favorable GLR.

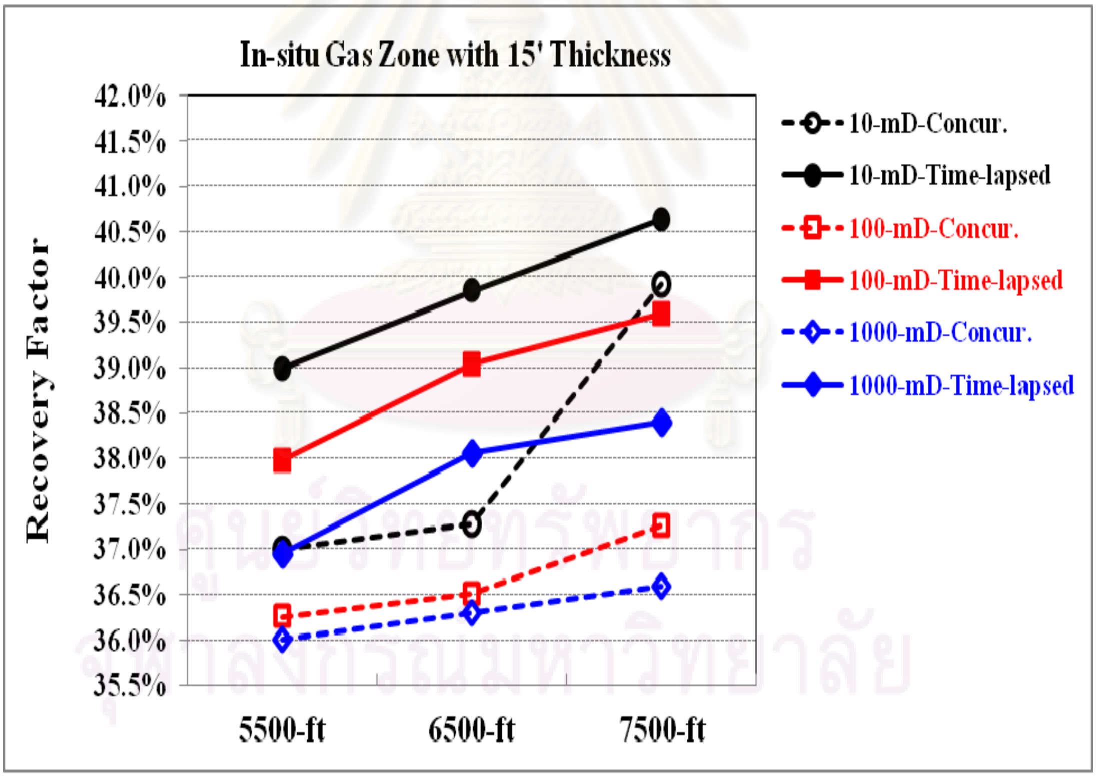


Figure 5.7 Oil Recovery Factors for In-situ Gas Zone with 15' Thickness

5.3.2 In-situ Gas Zone with 45-ft Thickness

According to Figure 5.8, with the same thickness of in-situ gas zone, it can be observed that

(a) Similar to the previous case of in-situ gas zone with 15-ft thickness, oil recovery factors appear to slightly increase with depth of the in-situ gas zone in either concurrent or time-lapsed perforation schedule. This effect is similar to the effect of the gas injection depth in conventional gas lift.

(b) There is one scenario in which the in-situ gas zone at 7500' TVD with 10 mD is perforated in time-lapsed schedule can catch up with or exceed the oil recovery factor of the base case (41.4%). This scenario also provides highest oil recovery because of effects of time-lapsed perforation schedule and depth of the in-situ gas zone which have been already discussed in Sections 5.2.1 (a) and 5.3.1 (a), respectively.

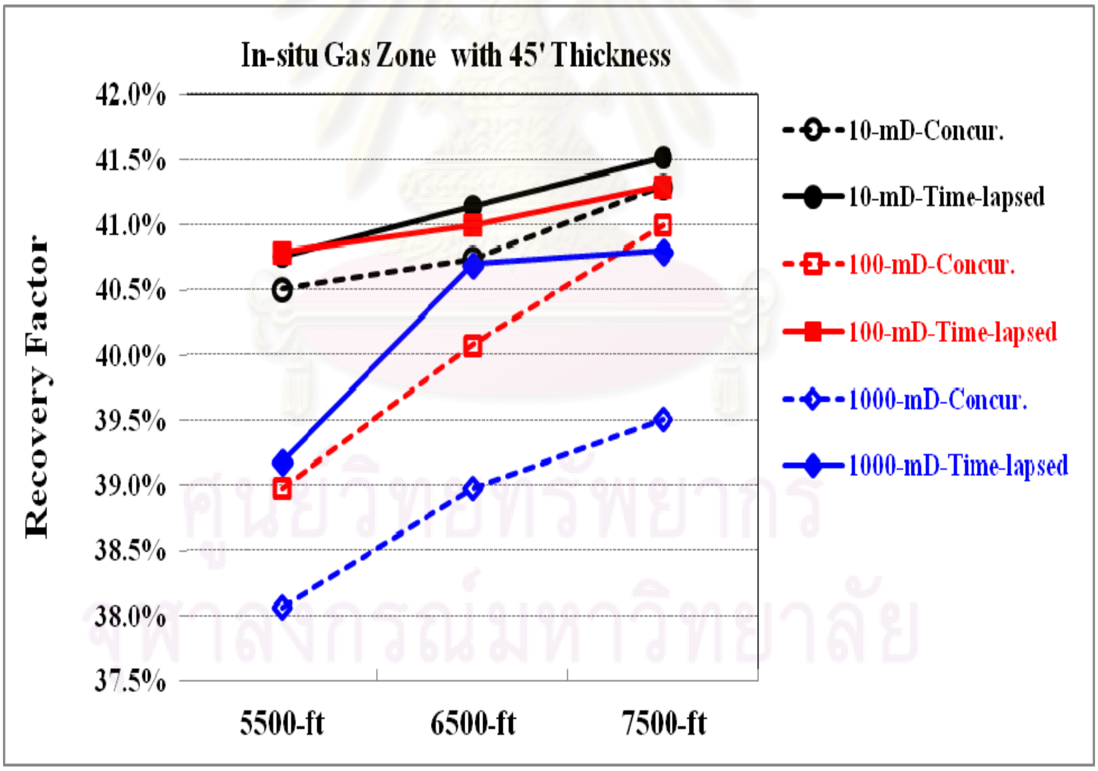


Figure 5.8 Oil Recovery Factors for In-situ Gas Zone with 45' Thickness

5.3.3 In-situ Gas Zone with 90-ft Thickness

According to Figure 5.9, with the same thickness of in-situ gas zone, it can be observed that

(a) Similar to the previous cases of in-situ gas zone with 15-ft and 45-ft thickness, oil recovery factors still appear to slightly increase with depth of the in-situ gas zone in either concurrent or time-lapsed perforation schedule. This effect is similar to the effect of the gas injection depth in conventional gas lift.

(b) The following eight scenarios can catch up with or exceed the oil recovery factor of the base case (or 41.4% in conventional gas lift):

  (i) concurrent perforation schedule:
    - in-situ gas zones at 7500' TVD with 10 mD and 100 mD

  (ii) time-lapsed perforation schedule:
    - in-situ gas zones at 6500' TVD with 10 mD, 100 mD and 1000 mD
    - in-situ gas zones at 7500' TVD with 10 mD, 100 mD and 1000 mD

(c) The scenario with the in-situ gas zone at 7500' TVD and 10 mD provides the highest oil recovery in time-lapsed perforation because of effects of time-lapsed perforation schedule and depth of the in-situ gas zone which have been already discussed in Sections 5.2.1 (a) and 5.3.1 (a), respectively. Figure 5.10 illustrates the production profile of this particular case.

Figures 5.11 and 5.12 also illustrate that the summary of oil recovery factors which appear to increase with depth of the in-situ gas zone and this holds true in either concurrent or time-lapsed perforation schedule.

In summary, given the same thickness and *k* of an in-situ gas zone, the oil recovery factors appear to increase with depth of the in-situ gas zone in either concurrent or time-lapsed perforation schedule. This effect is similar to the effect of the gas injection depth in conventional gas lift.

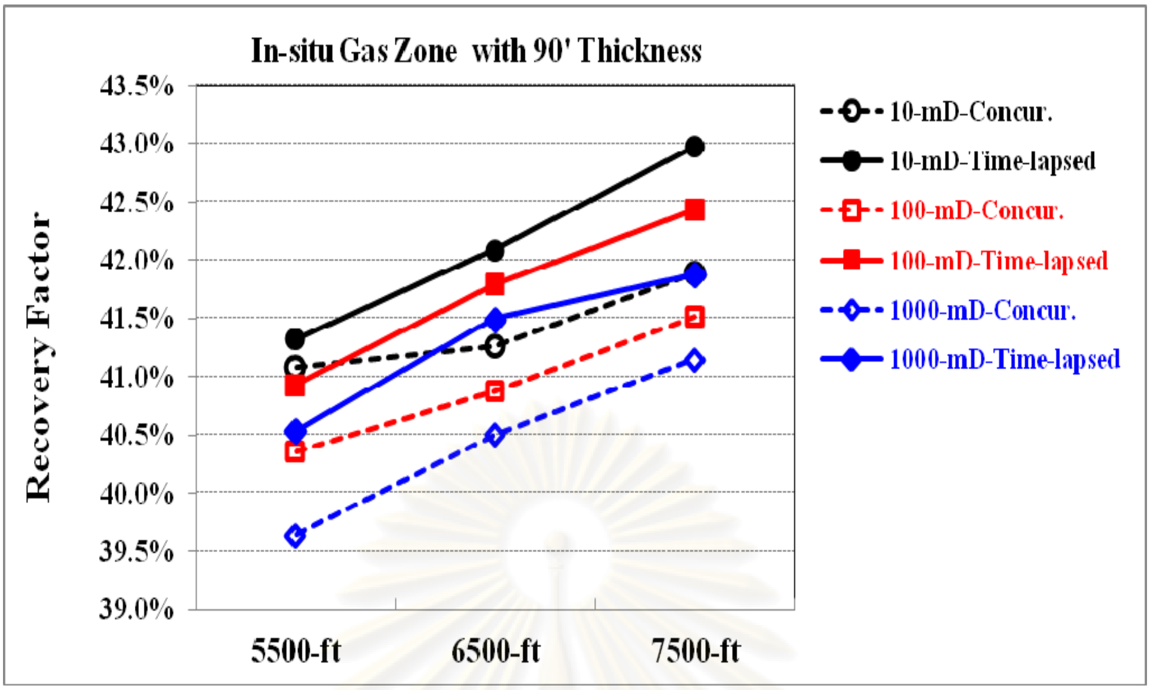


Figure 5.9 Oil Recovery Factors for In-situ Gas Zone with 90' Thickness

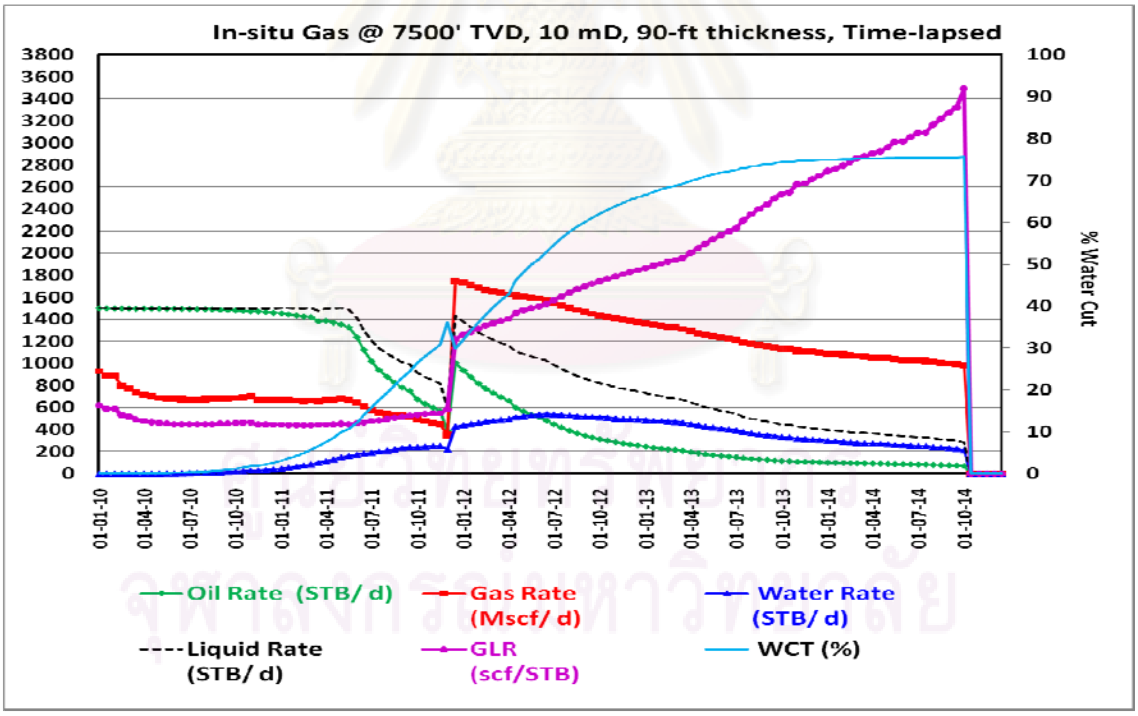


Figure 5.10 Production Profile for Well with In-situ Gas Zone at 7500' TVD with 10 mD, 90' Thickness and Time-lapsed Perforation Schedule

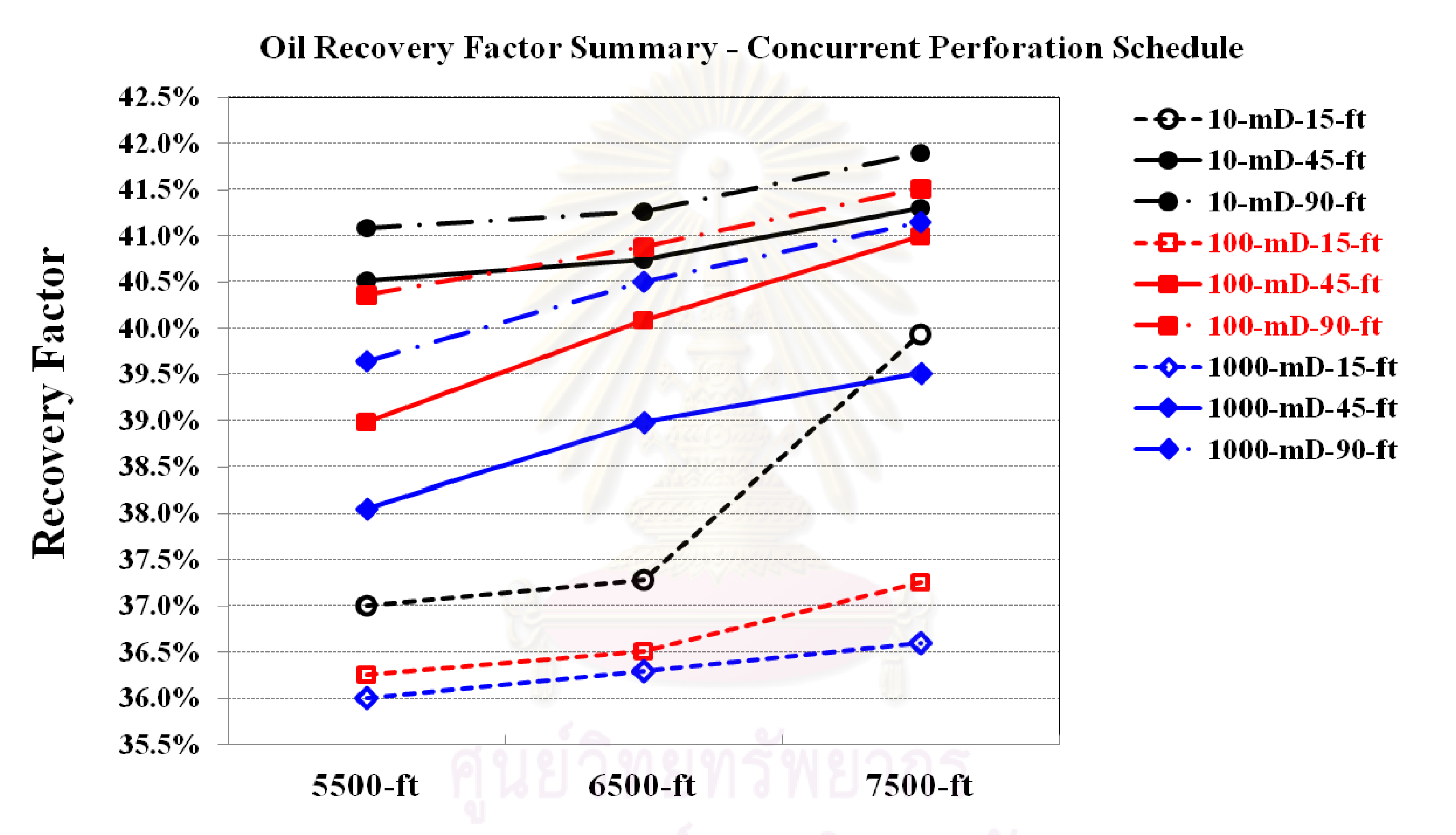


Figure 5.11 Oil Recovery Factor Summary for Concurrent Perforation Schedule of In-situ Gas Zone

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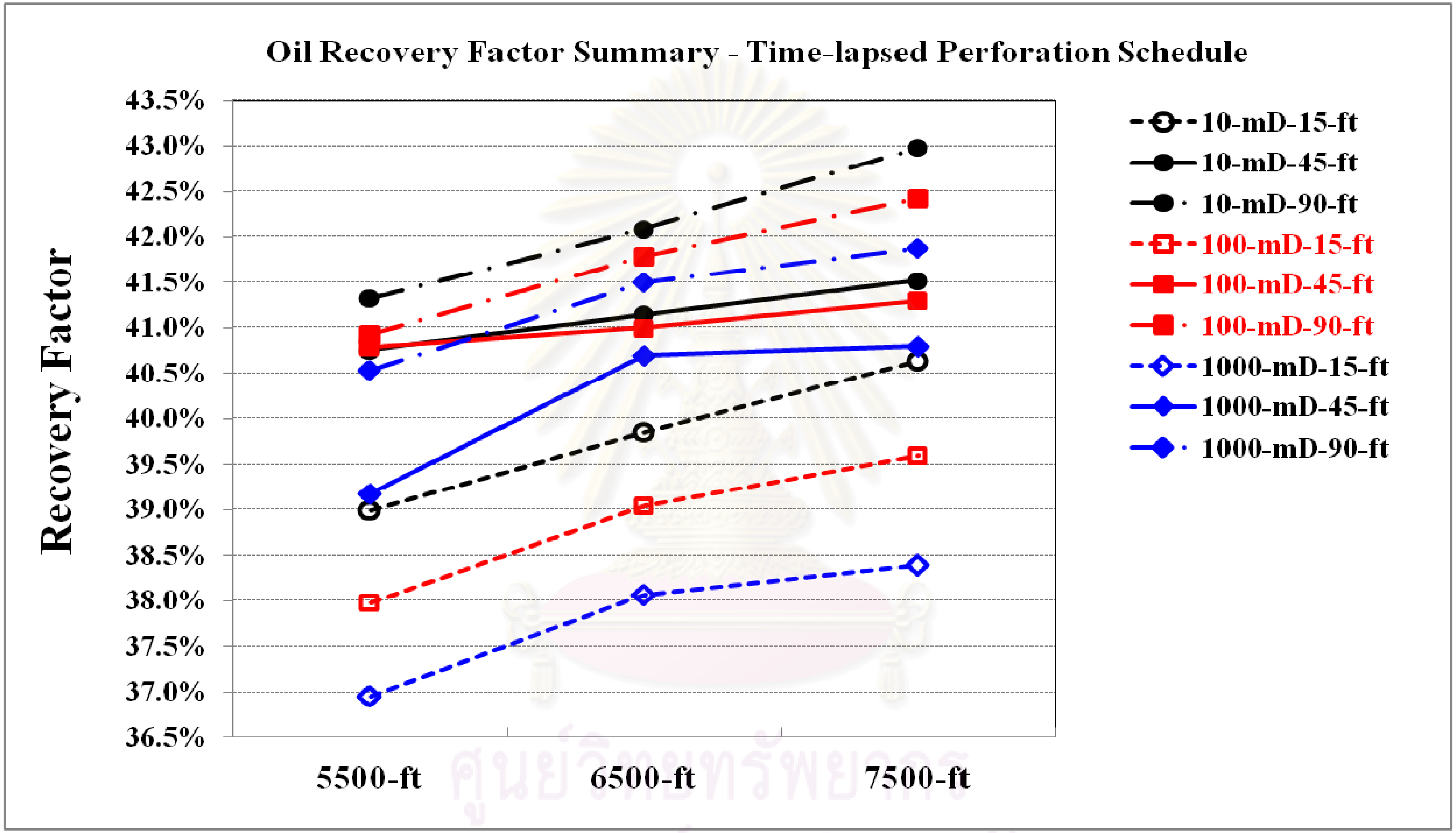

Figure 5.12 Oil Recovery Factor Summary for Time-lapsed Perforation Schedule of In-situ Gas Zone

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5.4 Impact of Thickness of In-situ Gas Zone on Oil Recovery Factor

5.4.1 In-situ Gas Zone @ 5500' TVD

According to Figure 5.13, with the same depth of the in-situ gas zone, it can be observed that

(a) In either concurrent or time-lapsed perforation schedule, increasing the thickness of the in-situ gas zone helps improve the recovery factors. According to Figure 4.8, as oil rate declines, a need for GLR increases. Figures 5.14 (a), (b) and (c) compare oil production profiles of in-situ gas zone at 5500' TVD with 10 mD and concurrent perforation schedule among 15-ft, 45-ft and 90-ft thickness. It can be observed that the thicker the in-situ gas zone, the longer the gas can produce (or higher cumulative gas production), resulting in higher cumulative oil production or recovery factor. On the other hand, the larger OGIP (increasing with thickness as referred to Table 4.3), can provide gas rate to maintain sufficient GLR for longer period of time. For this reason, in each scenario at any given depth and k in either concurrent or time-lapsed perforation schedule, the in-situ gas zone with 90-ft thickness or the largest OGIP will provide higher recovery factor than the scenarios with 15-ft and 45-ft thicknesses.

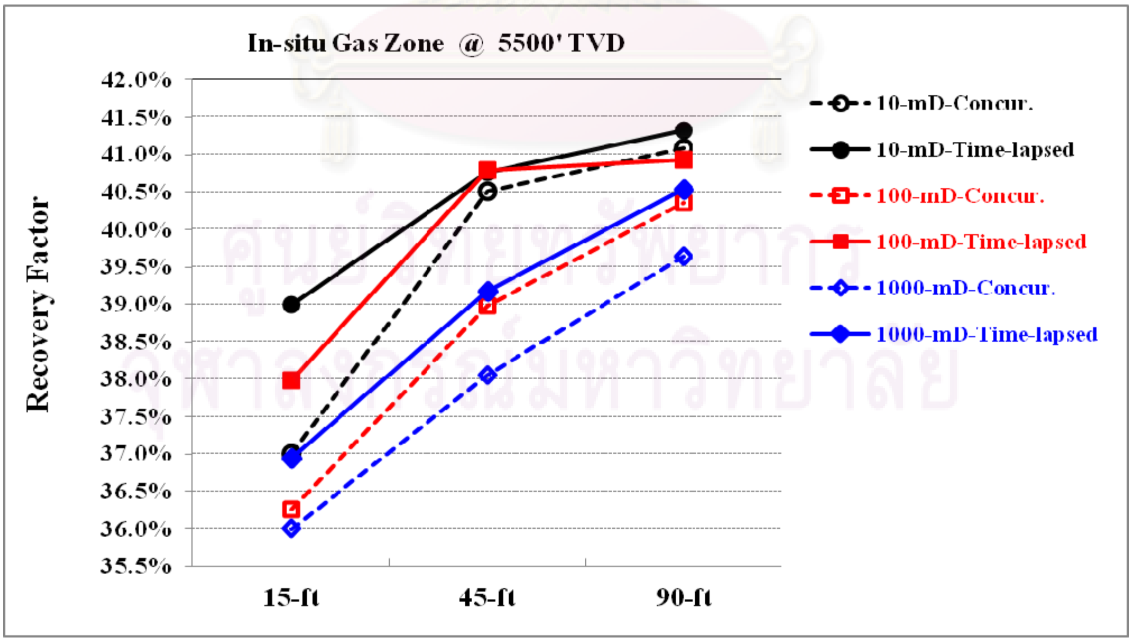

Figure 5.13 Oil Recovery Factors for In-situ Gas Zone @ 5500' TVD with Various Thicknesses

(b) The scenario in which the in-situ gas zone is 90-ft thickness with 10 mD and perforated in time-lapsed schedule provides the highest oil recovery factor mainly due to the benefits of time-lapsed perforation schedule and its thickness or OGIP which have been previously discussed in Section 5.2.1 (a) and 5.4.1 (a), respectively.

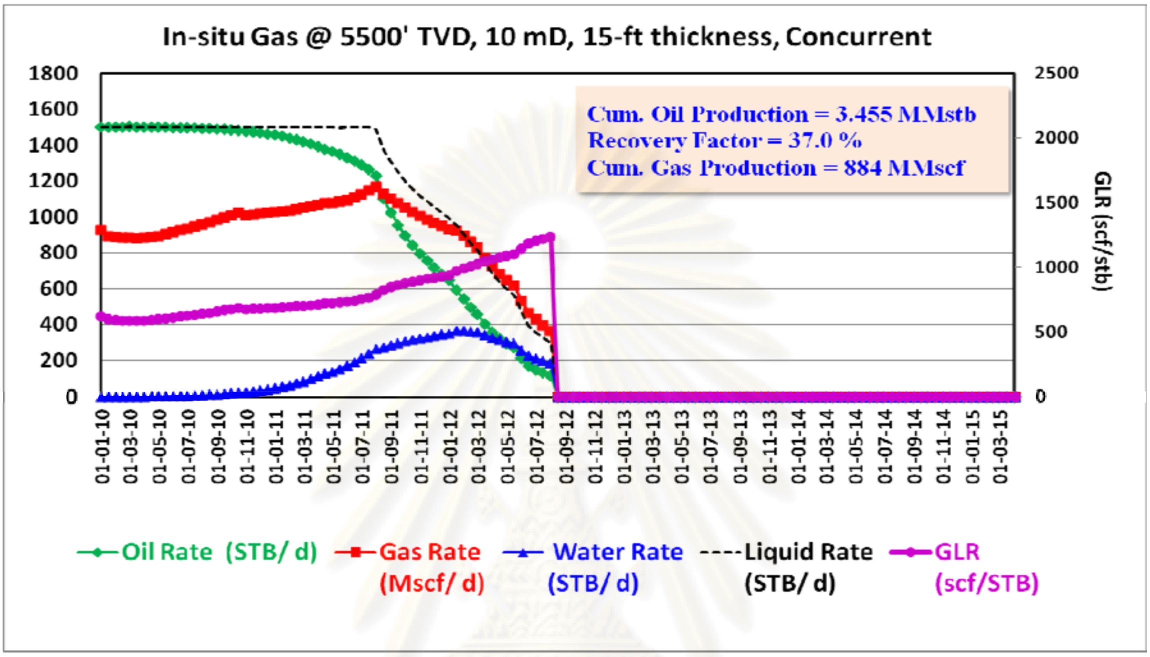

Figure 5.14 (a) 15-ft Thickness

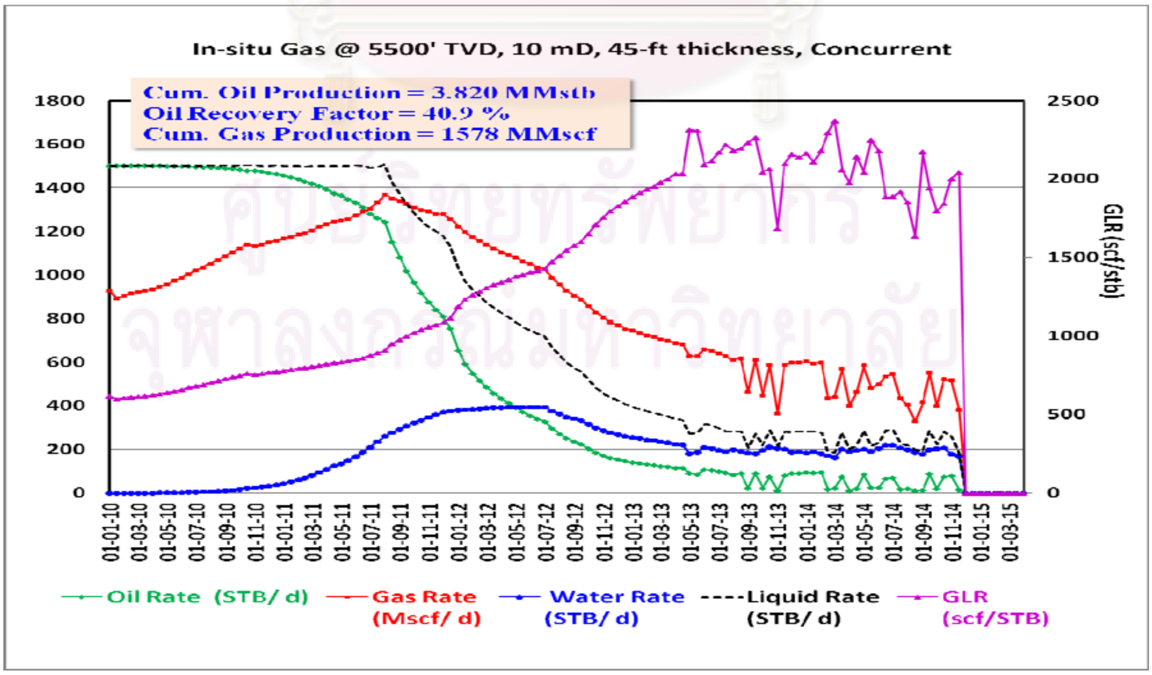

Figure 5.14 (b) 45-ft Thickness

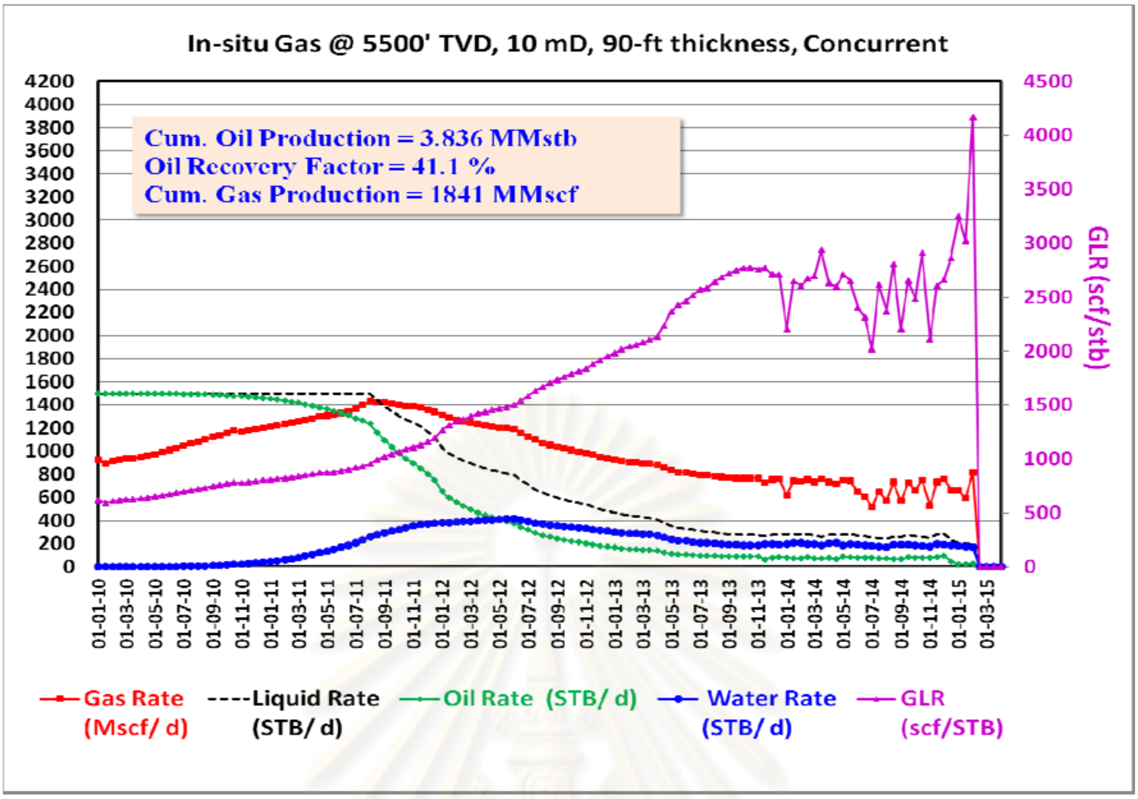

Figure 5.14 (c) 90-ft Thickness

Figure 5.14 Comparison of Cumulative Oil Production, Recovery Factor and Production Profile of In-situ Gas Zone at 5500' TVD, 10 mD, Concurrent Perforation Schedule with Various Thicknesses (a) 15-ft, (b) 45-ft and (c) 90-ft

5.4.2 In-situ Gas Zone @ 6500' TVD

According to Figure 5.15, with the same depth of the in-situ gas zone, it can be observed that

(a) Similar to the previous case of in-situ gas zone at 5500' TVD, in either concurrent or time-lapsed perforation schedule, increasing the thickness of the in-situ gas zone helps improve the recovery factors.

(b) Three scenarios in time-lapsed perforation schedule for in-situ gas zones with 90-ft thickness and 10 mD, 100 mD and 1000 mD can exceed the oil recovery factor of the base case (or conventional gas lift). All scenarios have 90 ft thickness or the largest OGIP that provides gas rate to maintain sufficient GLR for longer period.

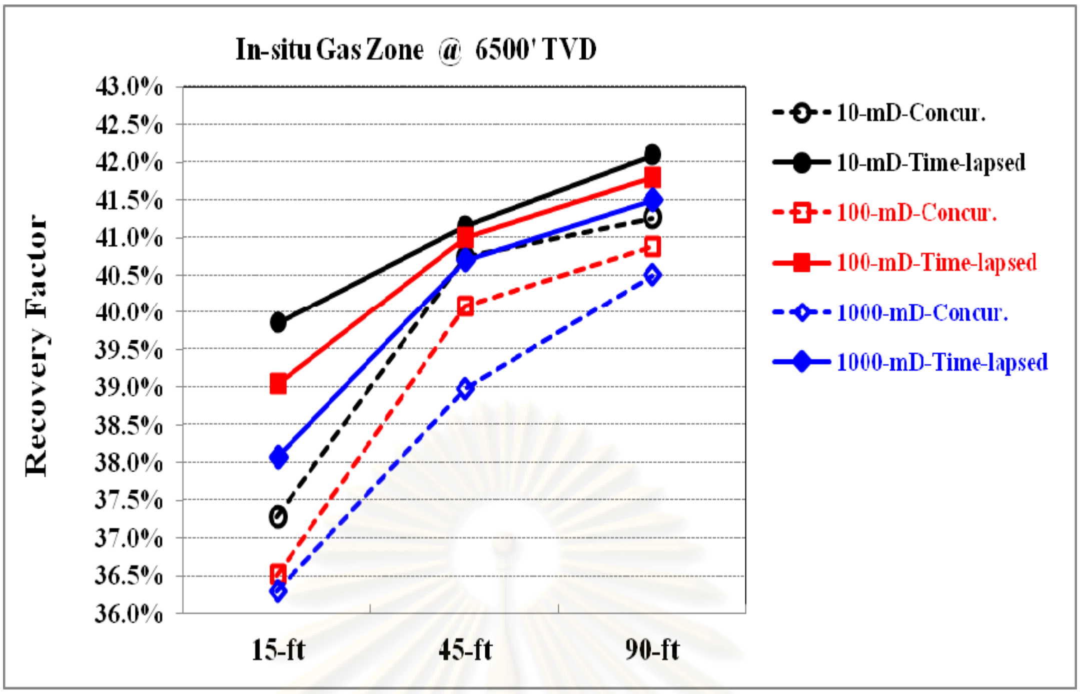

Figure 5.15 Oil Recovery Factors for In-situ Gas Zone @ 6500’ TVD with Various Thicknesses

5.4.3 In-situ Gas Zone @ 7500’ TVD

According to Figure 5.16, with the same depth of the in-situ gas zone, it can be observed that

(a) Similar to the previous cases of in-situ gas zone at 5500’ and 6500’ TVD, in either concurrent or time-lapsed perforation schedule, increasing the thickness of the in-situ gas zone helps improve the recovery factors.

(b) The following six scenarios can exceed the oil recovery factor of the base case (or conventional gas lift):

(i) concurrent perforation schedule:

- in-situ gas zones with 90-ft thickness and *k* of 10 mD and 100 mD

(ii) time-lapsed perforation schedule:

- in-situ gas zones with 45-ft thickness and *k* of 10 Md
- in-situ gas zones with 90-ft thickness and *k* of 10 mD, 100 mD and 1000 mD

(c) The scenario in which the in-situ gas zone is 90-ft thickness with 10 mD and perforated in time-lapsed schedule provides the highest oil recovery factor mainly due to the benefits of both time-lapsed perforation schedule and its thickness or OGIP.

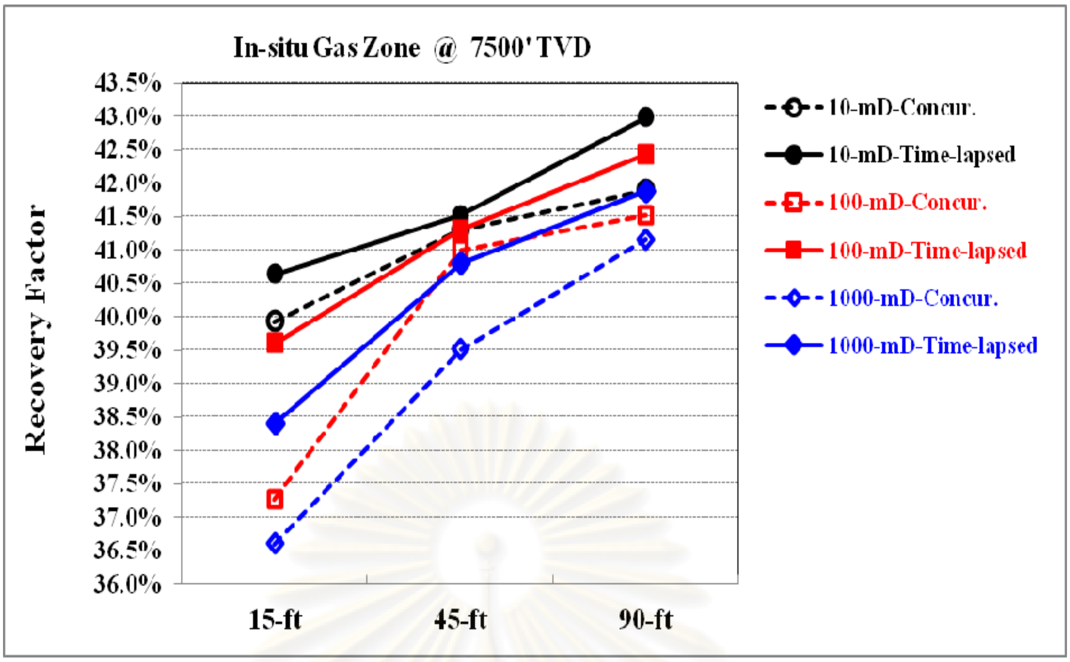

Figure 5.16 Oil Recovery Factors for In-situ Gas Zone @ 7500' TVD with Various Thicknesses

In summary, at the same depth and *k* of an in-situ gas zone, the oil recovery factors appear to increase with thickness (or OGIP as referred to Table A2 in Appendix A) of the in-situ gas zone in either concurrent or time-lapsed perforation schedule. Some scenarios can catch up with or exceed the base case's oil recovery factor.

5.5 Impact of Permeability of In-situ Gas Zone on Oil Recovery Factor

5.5.1 In-situ Gas Zone @ 5500' TVD.

According to Figure 5.17, with the same depth of the in-situ gas zone, it can be observed that

(a) All scenarios with the same thickness in either concurrent or time-lapsed perforation schedule, the recovery factor decreases with increasing *k* of the in-situ gas zone. The scenarios with the higher *k* provide the higher gas rate and GLR than the scenarios with lower *k*. From Figures 5.18 (a) and (b) illustrate a comparison between scenarios with the in-situ gas zone with *k* of 10 mD and 1000 mD. The case with higher *k* provides higher in-situ gas rate, resulting in higher or excessive GLR that adversely affect the recovery factor. In addition, according to Table 5.1, for each thickness in the time-lapsed perforation schedule, apparently the immediate gas rate and GLR after perforation on in-situ gas zone increases with increasing *k*. The immediate oil rate after the in-situ gas zone is perforated is about 900 stb/d which requires about 800 scf/stb of GLR according to Figure 4.8. Even though immediate GLR from all cases with each *k* are excessive, GLR from cases with *k* of 100 mD and 1000 mD appear be much more excessive than the cases with *k* of 10 mD. As a result, the case with *k* of 10 mD which has less friction due to less excessive GLR provides higher recovery factor.

(b) None of scenario can provide recovery factor greater than the base case. However, the scenario in which the in-situ gas zone is 90-ft thickness with 10 mD and perforated in time-lapsed schedule provides the highest oil recovery factor mainly due to the benefits of time-lapsed perforation schedule, its thickness or OGIP and its lowest *k* previously explained in Section 5.5.1 (a).

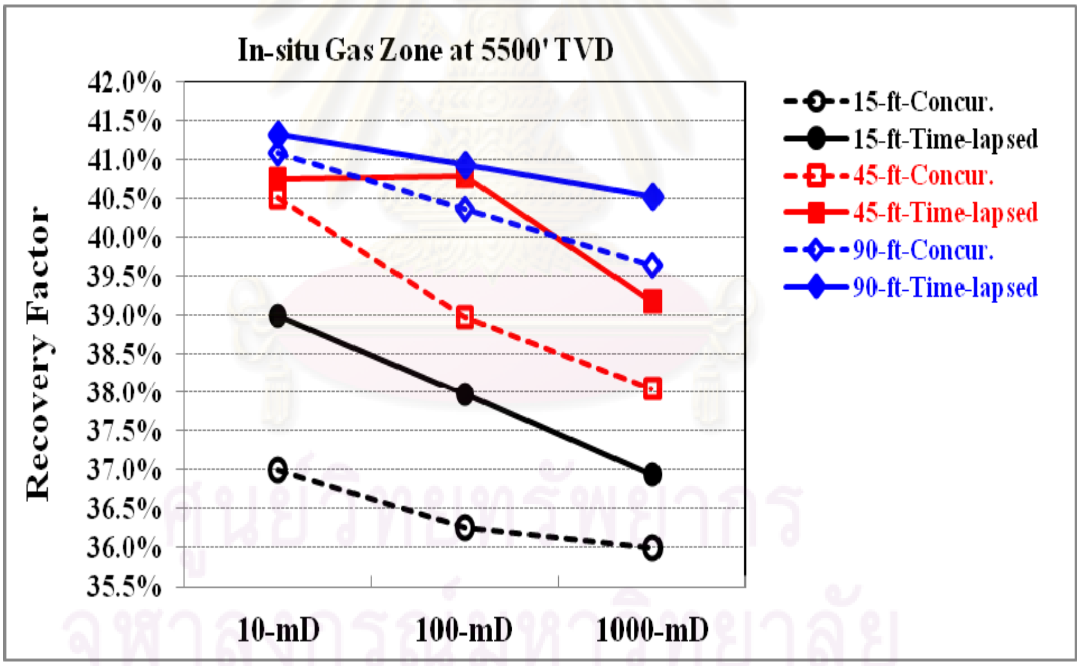

Figure 5.17 Oil Recovery Factors for In-situ Gas Zone @ 5500' TVD with Various Permeabilities

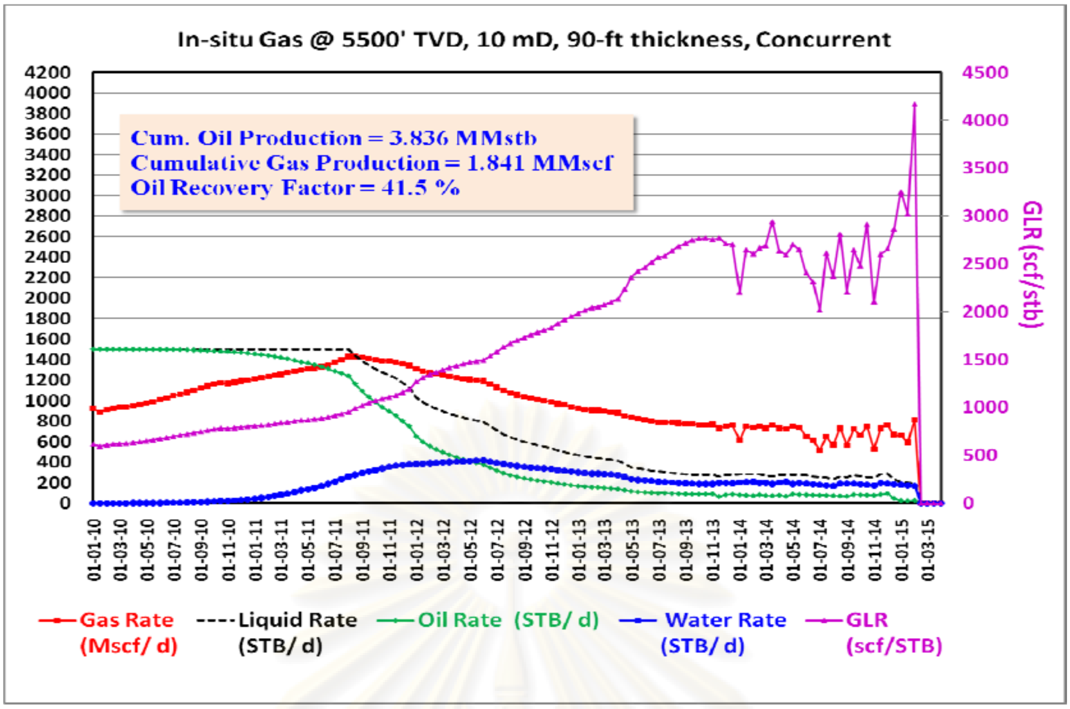

Figure 5.18 (a)

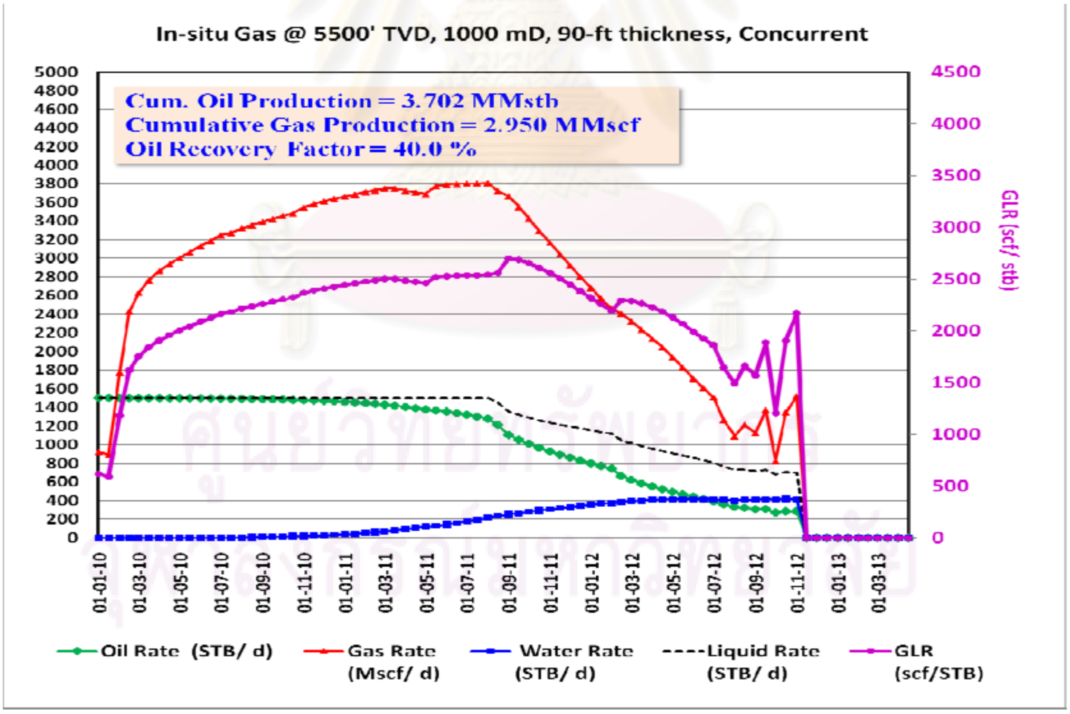

Figure 5.18 (b)

Figure 5.18 Comparison of Production Profiles of In-situ Gas Zone at 5500' TVD, 90-ft Thickness, Concurrent Perforation Schedule between (a) 10 mD vs. (b) 1000 mD

Table 5.1 Immediate Gas Rate and GLR after Time-lapsed Perforation on In-situ Gas Zone at 5500’ TVD

Thickness (ft)	Permeability (mD)	Immediate Gas Rate (MMscfd)	Immediate GLR (scf/stb)
15	10	1.380	1085
	100	3.230	2739
	1000	8.186	20824
45	10	1.436	1111
	100	3.279	2799
	1000	8.219	21069
90	10	1.448	1118
	100	3.299	2912
	1000	8.179	21261

5.5.2 In-situ Gas Zone @ 6500’ TVD

According to Figure 5.19, with the same depth of the in-situ gas zone, it can be observed that

(a) Similar to the previous case of in-situ gas zone at 5500’ TVD, all scenarios with the same thickness in either concurrent or time-lapsed perforation schedule, the recovery factor decreases with increasing *k* of the in-situ gas zone. This effect has been already discussed in section 5.5.1 (a) using Table 5.2.

(b) The scenarios in which the in-situ gas zone is 90-ft thickness with 10 mD and perforated in time-lapsed schedule can exceed the oil recovery factor of the base case mainly due mainly due to the benefits of time-lapsed perforation schedule, its thickness or OGIP and its lowest *k* previously explained in Section 5.5.1 (a).

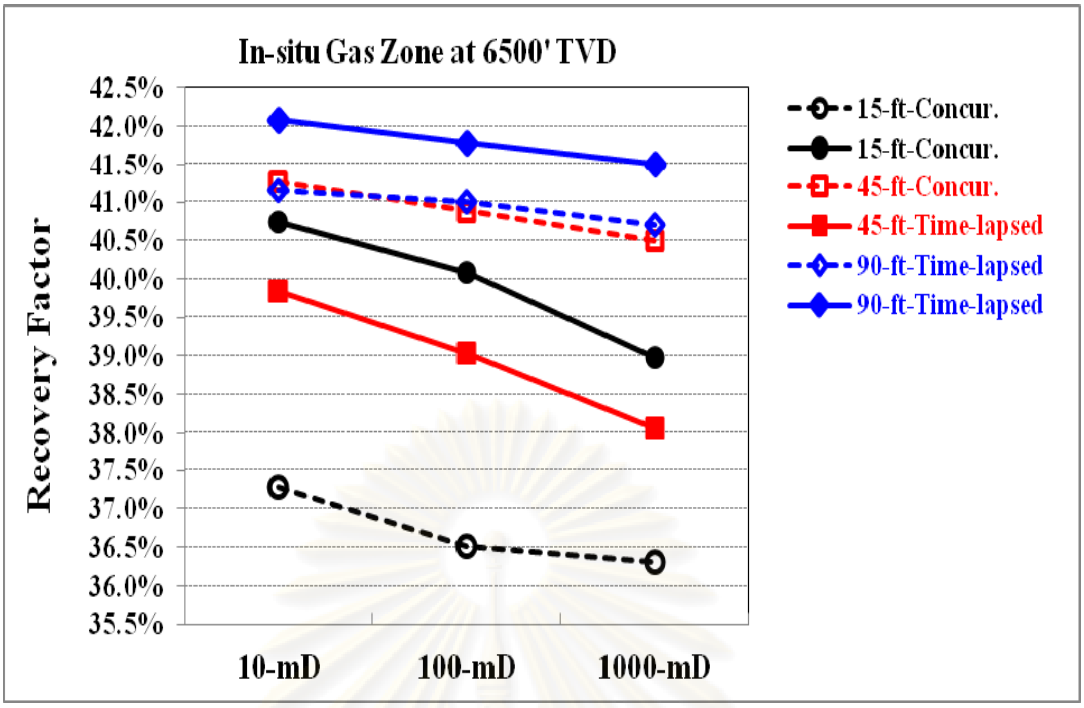

Figure 5.19 Oil Recovery Factors for In-situ Gas Zone @ 6500' TVD with Various Permeabilities

Table 5.2 Immediate Gas Rate and GLR after Time-lapsed Perforation on In-situ Gas Zone at 6500' TVD

Thickness (ft)	**Permeability (mD)**	**Immediate Gas Rate (MMscfd)**	**Immediate GLR (scf/stb)**
15	10	1.525	1130
	100	3.672	2993
	1000	8.855	22828
45	10	1.590	1118
	100	3.727	3059
	1000	8.878	23024
90	10	1.604	1125
	100	3.740	3076
	1000	8.883	23073

5.5.3 In-situ Gas Zone @ 7500' TVD

According to Figure 5.20, with the same depth of the in-situ gas zone, it can be observed that

(a) Similar to the previous cases of in-situ gas zone at 5500' TVD and 6500' TVD, all scenarios with the same thickness in either concurrent or time-lapsed perforation schedule, the recovery factor decreases with increasing *k* of the in-situ gas zone. This effect has been already discussed in section 5.5.1 (a) using Table 5.3

(b) The scenarios in which the in-situ gas zone is 90-ft thickness with 10 mD and perforated in time-lapsed schedule can exceed the oil recovery factor of the base case mainly due to the benefits of time-lapsed perforation schedule, its thickness or OGIP and its lowest *k* previously explained in Section 5.5.1 (a).

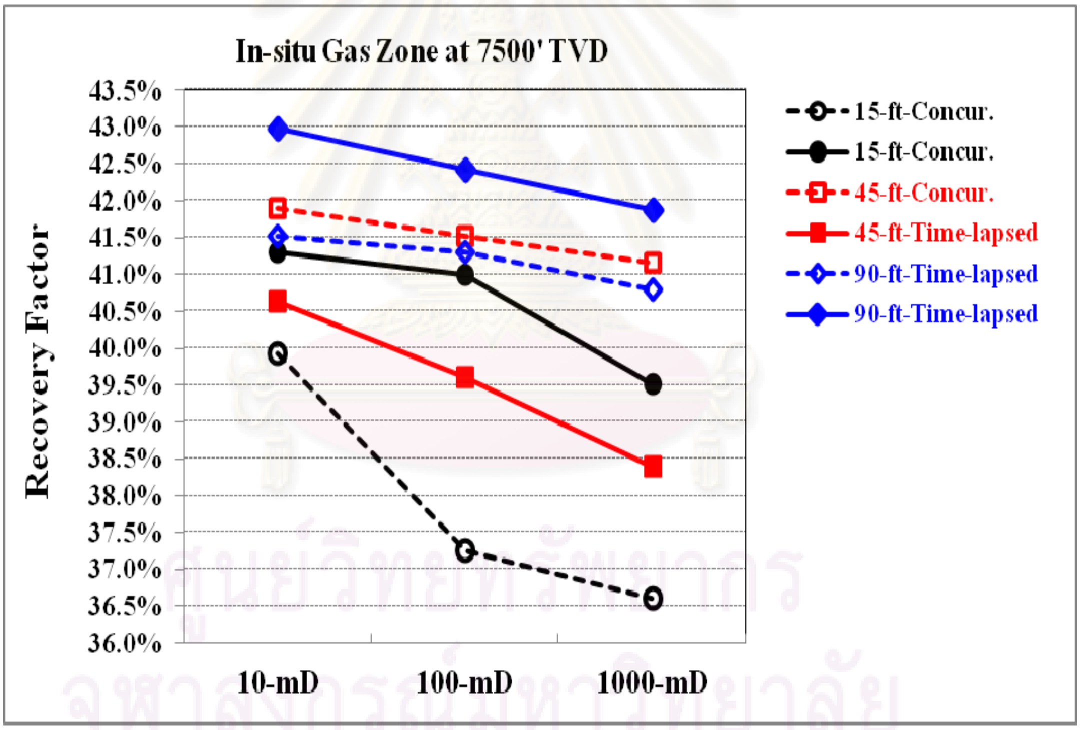

Figure 5.20 Oil Recovery Factors for In-situ Gas Zone @ 7500' TVD with Various Permeabilities

Table 5.3 Immediate Gas Rate and GLR after Time-lapsed Perforation on In-situ Gas Zone at 7500’ TVD.

Thickness (ft)	Permeability (mD)	Immediate Gas Rate (MMscfd)	Immediate GLR (scf/stb)
15	10	1.67	1174
	100	4.13	3631
	1000	9.17	24816
45	10	1.734	1257
	100	4.188	3708
	1000	9.188	25021
90	10	1.747	1219
	100	4.203	3729
	1000	9.193	25070

5.6 Impact of Perforation Interval on Recovery Factor

In order to improve the recovery factor based on understandings of effects of *k* and time-lapsed perforation schedule, there are some attempts to vary the perforation interval of the in-situ gas zone to observe its impact on the recovery factors.

5.6.1 Increased Perforation Intervals on In-situ Gas Zone with *k* of 10 mD

Figures 5.21 (a) and (b) is a comparison of cumulative oil production, recovery factor and production profile of in-situ gas zone at 7500’ TVD with 10 mD, 15-ft thickness and time-lapsed perforation schedule between 1 ft and 2 ft perforation interval on the in-situ gas zone. It is noted that increasing the perforation interval on the in-situ gas zone with low *k* can improve the recovery factor due to the fact that the gas rate from 2 ft perforation interval is higher from larger open flow area (more perforation holes) than 1 ft perforation interval resulting in higher GLR.

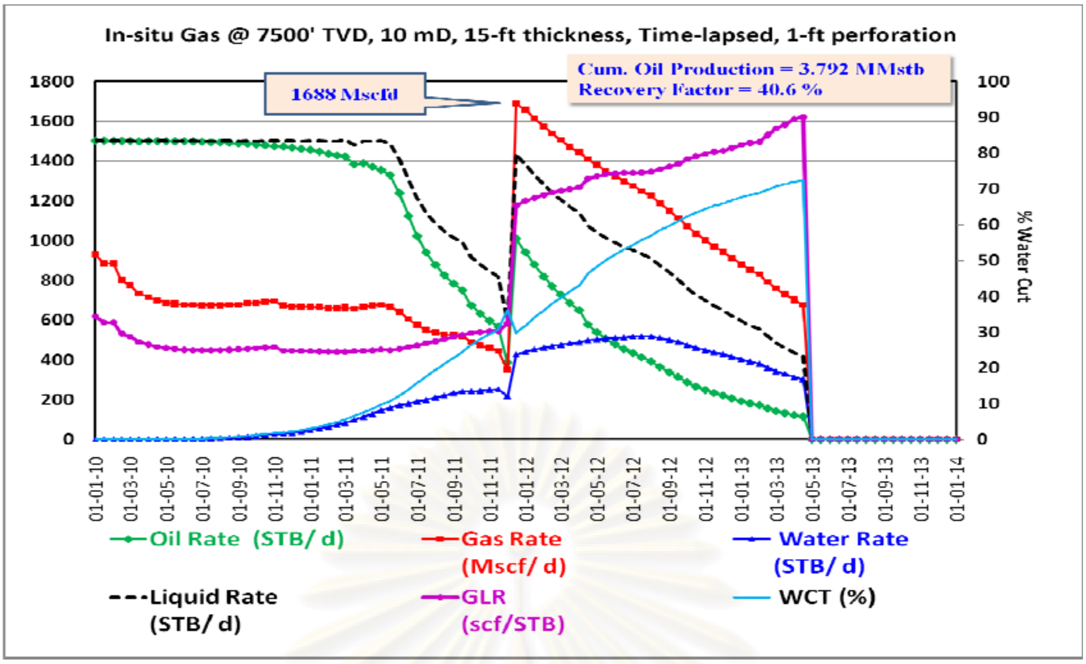

Figure 5.21 (a) 1 ft Perforation Interval

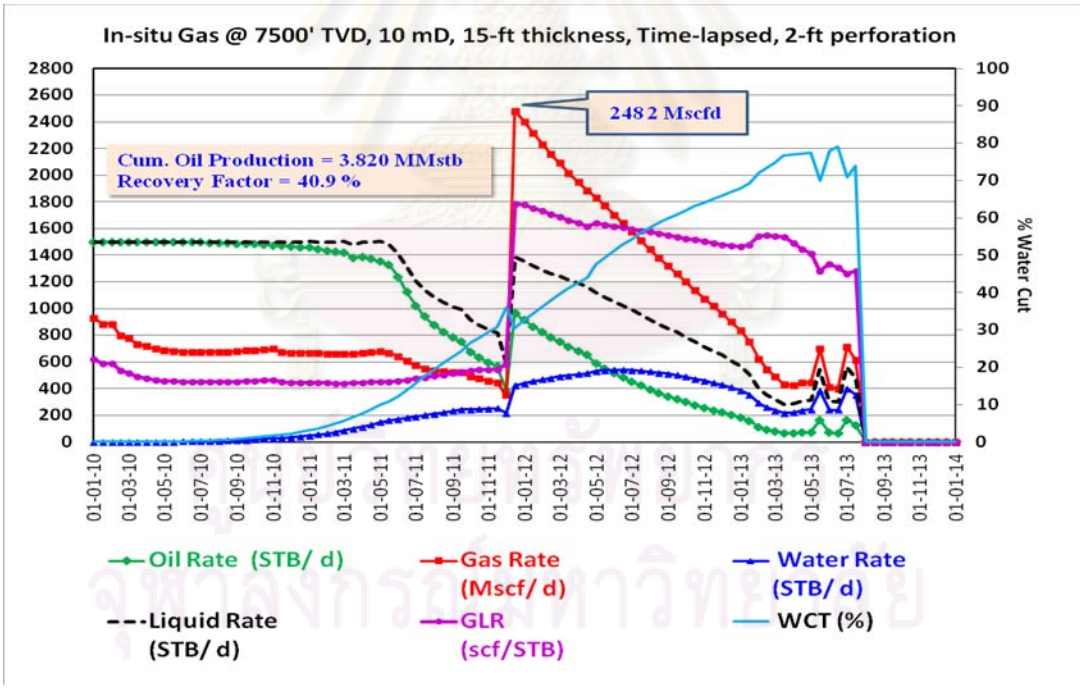

Figure 5.21 (b) 2 ft Perforation Interval

Figure 5.21 Comparison of Cumulative Oil Production, Recovery Factors and Production Profiles of In-situ Gas Zone at 7500' TVD with 10 mD, 15-ft Thickness and Time-lapsed Perforation Schedule with (a) 1-ft and (b) 2-ft Perforation Interval on In-situ Gas Zone

5.6.2 Decreased Perforation Intervals on In-situ Gas Zone with *k* of 1000 mD

Figures 5.22 (a) and (b) is a comparison of cumulative oil production, recovery factor and production profile of in-situ gas zone at 5500' TVD with 1000 mD, 15-ft thickness and time-lapsed perforation schedule between 1 ft (6 shots) and 0.33 ft (2 shots) of perforation interval on the in-situ gas zone. It is noted that decreasing the perforation interval or number of shots on the in-situ gas zone with high *k* can improve the recovery factor due to the fact that the excessive gas rate from 1 ft perforation interval is reduced by less flow area (less perforation holes); thus reducing friction.

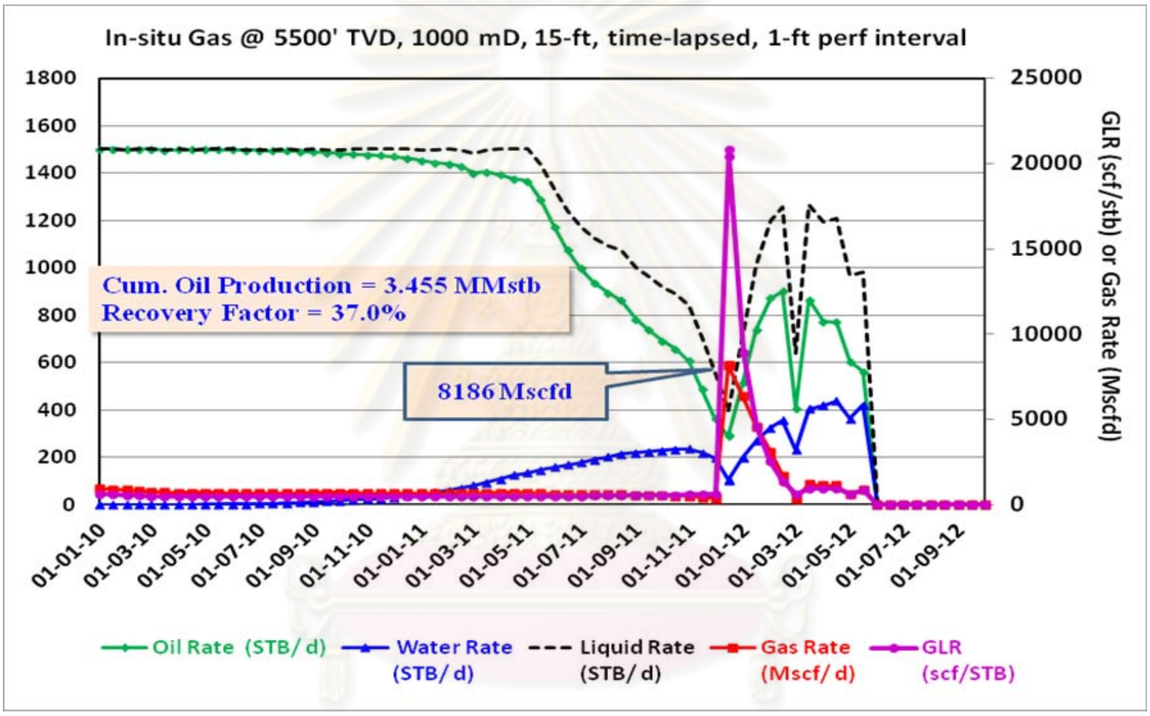

Figure 5.22 (a) 1 ft Perforation Interval

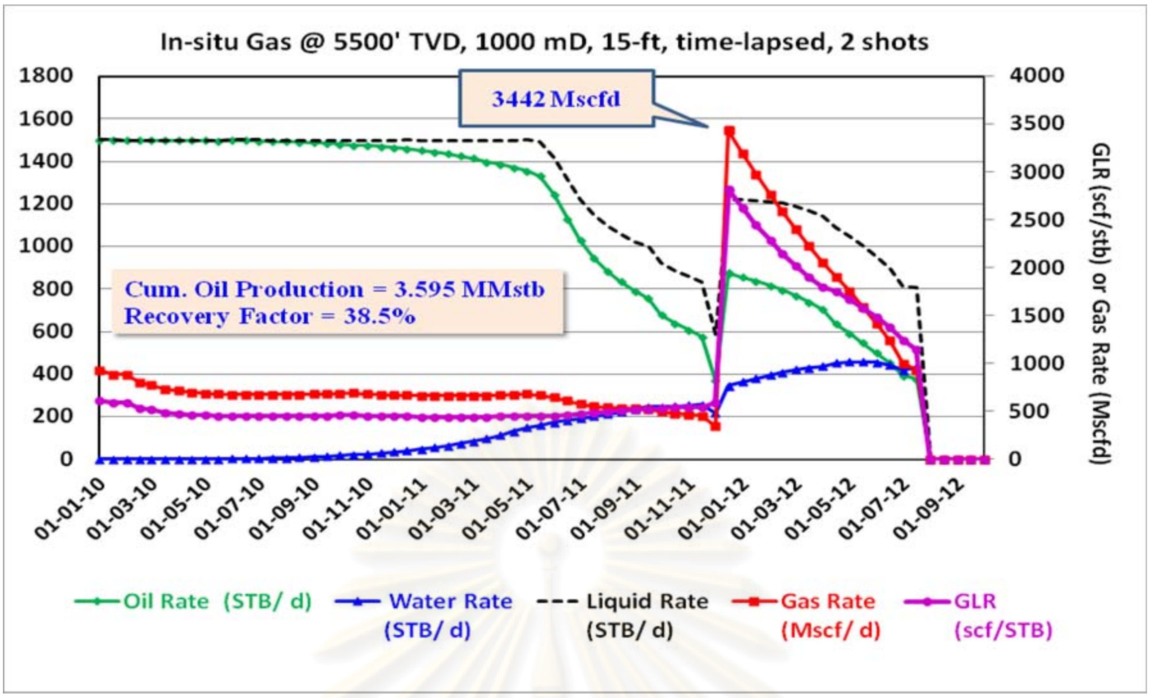

Figure 5.22 (b) 0.33 ft (2 shots) of Perforation Interval

Figure 5.22 Comparison of Cumulative Oil Production, Recovery Factors and Production Profile of In-situ Gas Zone at 5500' TVD with 1000 mD, 15-ft Thickness and Time-lapsed Perforation Schedule with (a) 1-ft and (b) 0.33-ft (2 shots) Perforation Interval on In-situ Gas Zone

5.6.3 Effect of Perforation Interval of In-situ Gas Zone at 7500-ft with 100 mD on Oil Recovery Factor

In order to further evaluate the impact of the perforation intervals of the in-situ gas zone with 15-ft and 45-ft thickness, some more simulation cases were run.

According to Table 5.4 and Table 5.5, increasing perforation interval of the in-situ gas lift zone from 1 ft to 1.5 ft for both concurrent and time-lapsed perforation schedules slightly improves the recovery factors. However, further increasing the perforation interval of the in-situ gas lift zone from 1.5 ft to 2.0 ft decreases the recovery factors. This can be explained using the data for the cases with the concurrent perforation schedule in Table 5.4 as an example that increasing the perforation interval of the in-situ gas lift zone from 1 ft to 1.5 ft increases the initial gas rate or GLR which has a positive impact on the recovery factor resulting in a gain in recovery factor by about 0.45%.

However, further increasing the perforation interval of the in-situ gas lift zone to 2.0 ft results in higher initial gas rate or GLR which slightly improves the recovery factor by 0.06% only when compared to the case with the perforation interval of 1 ft and this is worse than the case with the perforation interval of 1.5 ft. Very small improvement for the case with the perforation interval of 2 ft could be mainly due to the fact that the GLR start to become excessive resulting in higher friction in the tubing.

It can be inferred that every case with 1.5 ft perforation interval provides the highest recovery factors among three perforation intervals.

Table 5.4 Effect of Perforation Interval of In-situ Gas Lift Zone at 7500-ft with 100 mD and 15 ft thickness on Recovery Factors

Perforation Interval of In-situ Gas Zone	Concurrent					Time-lapsed			Diff. in RF (Time-lapsed) - (Concur.)
	Initial Gas Rate (Mscfd)	Initial GLR (scf/stb)	Cum. Oil Production (MMstb)	Recovery Factor (%)	Gain/ Loss in RF Compared to 1-ft Case (%)	Cum. Oil Production (MMstb)	Recovery Factor (%)	Gain/ Loss in RF Compared to 1-ft Case (%)	
1 ft	1804	1203	3.480	37.26%		3.699	39.60%		**2.34%**
1.5 ft	5724	3816	3.552	37.71%	**0.45%**	3.759	39.91%	0.31%	**2.20%**
2.0 ft	6483	4322	3.485	37.32%	**0.06%**	3.714	39.77%	0.17%	**2.45%**

Table 5.5 Effect of Perforation Interval of In-situ Gas Lift Zone at 7500-ft with 100 mD and 45 ft thickness on Recovery Factors

Perforation Interval of In-situ Gas Zone	Concurrent					Time-lapsed			Diff. in RF (Time-lapsed) - (Concur.)
	Initial Gas Rate (Mscfd)	Initial GLR (scf/stb)	Cum. Oil Production (MMstb)	Recovery Factor (%)	Gain/ Loss in RF Compared to 1-ft Case (%)	Cum. Oil Production (MMstb)	Recovery Factor (%)	Gain/ Loss in RF Compared to 1-ft Case (%)	
1 ft	4964	3309	3.829	41.00%		3.857	41.30%		**0.30%**
1.5 ft	5950	3900	3.902	41.78%	**0.78%**	3.930	42.08%	0.78%	**0.30%**
2.0 ft	6698	4465	3.885	41.60%	**0.60%**	3.919	41.96%	0.66%	**0.36%**

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

The observation made from the interpretation of the simulation results indicates that there is potential use of the in-situ gas lift technique from understanding different sets of variables that have an effect on its performance. Some scenarios can provide higher recovery factors than the base case well with conventional gas lift. In term of maximizing recovery factor, the in-situ gas lift technique can be used for oil wells with presence of certain thickness (or OGIP) of gas zone while the depth and the permeability of the in-situ gas zone may give different impacts on the recovery factors. Some attempts were also made to increase or reduce the perforation interval of the in-situ gas zone in some scenarios that cannot catch up the base case's recovery factor.

6.1 Conclusions

According to the simulation results, the summary of oil recovery factor for each scenario is shown in Table 6.1.

Table 6.1 Summary of Oil Recovery Factors using In-situ Gas Lift Technique

In-situ Gas Zone Scenario		15-ft Thickness			45-ft Thickness			90-ft Thickness		
Permeability (mD)	Depth (ft TVD)	OGIP (MMscf)	Oil Recovery Factor		OGIP (MMscf)	Oil Recovery Factor		OGIP (MMscf)	Oil Recovery Factor	
			Concurrent Perforation	Time-lapsed Perforation		Concurrent Perforation	Time-lapsed Perforation		Concurrent Perforation	Time-lapsed Perforation
10	5500	568	37.0%	39.0%	1704	40.5%	40.8%	3407	41.1%	41.3%
10	6500	722	37.3%	39.9%	2167	40.7%	41.2%	4334	41.3%	42.1%
10	7500	816	39.9%	40.6%	2447	41.3%	41.5%	4895	41.9%	43.0%
100	5500	568	36.3%	38.0%	1704	39.0%	40.8%	3407	40.4%	40.9%
100	6500	722	36.5%	39.0%	2167	40.1%	41.0%	4334	40.9%	41.8%
100	7500	816	37.3%	39.6%	2447	41.0%	41.3%	4895	41.5%	42.4%
1000	5500	568	36.0%	37.0%	1704	38.1%	39.2%	3407	39.6%	40.5%
1000	6500	722	36.3%	38.1%	2167	39.0%	40.7%	4334	40.5%	41.5%
1000	7500	816	36.6%	38.4%	2447	39.5%	40.8%	4895	41.2%	41.9%

Note: The recovery factors for natural flow and the base case are 32.1 % and 41.4%, respectively.
The recovery factor for the base case is the sum of the natural flow and conventional gas lift.

According to all simulation results, the following can be concluded:

(a) All scenarios with in-situ gas lift zone in both concurrent and time-lapsed perforation schedule can provide the recovery factor exceeding that of the natural flow (32.1%).

(b) In order to improve the recovery factor, the time-lapsed perforation schedule of the in-situ gas zone should be always used. Basically, in this study, the well is initially produced naturally for certain duration until the water cut reaches 50% and the in-situ gas zone is then perforated with 1-ft interval.

(c) In order to obtain comparable recovery factor with the base case, the thickness of the in-situ gas zone needs to be in a high range or 45 ft and 90 ft (OGIP between 1704 and 4895 MMscf) which actually means that larger OGIP will contribute to the success of the in-situ gas lift technique. Increasing in thickness or OGIP provides more gas rate to maintain sufficient GLR for longer period of time. It is also noted that the scenarios with 90-ft thickness (OGIP between 3407 – 4895 MMscf) of in-situ gas zone provide the highest recovery factor for a given depth and permeability of in-situ gas zone.

(d) In either concurrent or time-lapsed perforation schedule, the recovery factor increases with the depth of the in-situ gas zone. This increasing depth effect is similar to the effect of the depth of gas injection in conventional gas lift. Moreover, the deeper the in-situ gas zone, the higher reservoir pressure and temperature, resulting in higher expansion ratio of gas when migrating up the well which better helps lift the liquid column than shallower in-situ gas zones. As a result, it is also noted that for given thickness and permeability of in-situ gas zone, the scenarios with 7500-ft TVD (or deepest) of in-situ gas zone provide the highest recovery factor.For scenarios with an in-situ gas zone with low permeability (k = 10 mD) there is a need to increase the amount of gas produced into the well to increase or optimize GLR. For this study, an attempt to increase the perforation interval of the in-situ gas zone from 1 ft to 2 ft was made to improve the recovery factor successfully.

(e) For scenarios with an in-situ gas zone with high permeability (k = 1000 mD), there is a need to control the amount of gas produced into the well to prevent excessive GLR. For this study, an attempt to reduce the perforation interval of the in-situ gas zone from 1 ft (6 shots) to 0.33 ft (2 shots) was made to improve the recovery factor successfully.

(f) For scenarios with an in-situ gas zone with moderate permeability (k = 100 mD), increasing perforation interval of the in-situ gas zone from 1 ft to 1.5 ft will help improve recovery factor; however, increasing perforation interval of the in-situ gas zone from 1.5 ft to 2.0 ft, the recovery factor will decrease. On the other words, there appears to the optimal perforation interval of the in-situ gas lift zone with 100 mD which is 1.5 ft.

6.2 Recommendations

As a result, given similar fluid properties and arrangement of the oil and gas reservoirs in the well model, the recommendations for using the in-situ gas lift for monobore oil wells with commingled production in Pattani Basin are as follows:

(a) Any monobore oil well consisting of an in-situ gas zone(s) with 45 ft or 90 ft thickness can be completed using in-situ gas lift or without conventional gas lift and still obtain very comparable recovery factor with the base case. The completion using in-situ gas lift technique also gives significant savings due to the costs of the gas lift compressor and its surface facilities.

(b) The time-lapsed perforation schedule of the in-situ gas zone is recommended for any monobore oil well with an in-situ gas zone with "*kh*" between 150 mD-ft to 90,000 mD-ft which is the range used in this study.

(c) In order to improve the recovery factor of any monobore oil well with an in-situ gas zone with high permeability (k = 1000 mD), the perforation interval on in-situ gas zone should be reduced, i.e. from 1 ft (6 shots) to 0.33 ft (or 2 shots) whereas other monobore oil well with low permeability (k = 10 mD), the perforation interval of in-situ gas zone should be increased, i.e. from 1 ft to 2 ft in this study.

(d) In order to improve the recovery factor of any monobore oil well with an in-situ gas zone with moderate permeability (k = 100 mD), the perforation interval of the in-situ gas zone should be increased from 1 ft to 1.5 ft only.

(e) In order to gain better understanding of the use of in-situ gas lift technique in monobore oil wells with commingled production, other parameters that affect IPR or TPR, such as tubing size and other fluid properties are recommended to be further studied.

(f) It appears that the time-lapsed perforation schedule provides better results or higher recovery factors than the concurrent. However in this study only 50% water cut is used as the trigger for time-lapsed perforation of the in-situ gas zone. As a result, it is recommended that the timing of time-lapsed perforation schedule of the in-situ gas zone be further evaluated to optimize the recovery factor.

(g) In this study, some simulation attempts were made to reduce or increase the perforation interval of the in-situ gas zone with a good sign of improvement in recovery factors. However, not many simulation runs were made in this study for wider range of the perforation intervals of the in-situ gas zone. Therefore, it is recommended that the perforation interval of the in-situ gas zone be further evaluated to optimize the GLR or improve the recovery factors.

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APPENDIX

APPENDIX A

General Information for Well Model

Table A1 Water Influx Parameters for Oil Layers

Name	Water Influx for Each Oil Layers							
	Depth (ft TVD)	Water Influx Model	Water Influx System	Reservoir thickness (ft)	Reservoir Radius (ft)	Outer/Inner Radius Ratio	Encroachment Angle (degrees)	Aquifer Permeability (md)
Oil Layer #1	**5000**	Hurst-van Everdingen-Modified	Radial Aquifer	40	920	6	180	200
Oil Layer #2	**6000**			40	920	6	180	150
Oil Layer #3	**7000**			40	920	6	180	100
Oil Layer #4	**8000**			40	920	6	180	50

Table A2 PVT Input Data in MBAL for Oil Layers

Reservoir Fluid	Oil @ 5000' TVD	Oil@ 6000' TVD	Oil@ 7000' TVD	Oil@ 8000' TVD
Separator	Single-Stage			
Use Tables	No			
Use Matching	No			
Controlled Miscibility	No			
Solution GOR	275 (scf/stb)	400 (scf/stb)	540 (scf/stb)	750 (scf/stb)
Oil gravity	40 (API)			
Gas gravity	0.8 (sp. gravity)			
Water salinity	10000 (ppm)			
Mole percent H2S	0 (percent)			
Mole percent CO2	5 (percent)			
Mole percent N2	0 (percent)			
Pb, Rs, Bo correlation	Vazquez-Beggs			
Oil viscosity correlation	Petrosky et al			

Table A3 Input Data - Relative Permeability for Oil and Gas Layers

	Relative Permeability	
Parameters	**Oil Layers**	**Gas Layer**
Rel. Perm. From	Corey Functions	Corey Functions
Hysteresis	No	No
Modified	No	N/A
Water Sweep Efficiency	100%	100%
Gas Sweep Efficiency	100%	N/A

Table A4 Input Data - Residual Saturation and Corey Exponents for Oil and Gas Layers

Oil Layers	**Residual Saturation (fraction)**	**End Point (fraction)**	**Exponent**
Krw	0.15	0.5	4
Kro	0.2	0.8	4
Krg	0.02	0.5	2
Gas Layers	**Residual Saturation (fraction)**	**End Point (fraction)**	**Exponent**
Krw	0.15	0.6	3
Krg	0.05	0.8	2

Table A5 Input Data for Option Summary in PROSPER

Parameters	**Input Data**		
	Oil Gas Lift	**Oil Non-Gas Lift**	**Gas Non-Gas Lift**
Fluid	Oil		Dry and Wet Gas
PVT Method	Black Oil		
Equation Of State	N/A		
Separator	Single-Stage		
Hydrates	Disable Warning		
Water Viscosity	Use Pressure Corrected Correlation		
Water Vapour	No Calculations		Calculated Condensed Water Vapour
Viscosity Model	Newtonian Fluid		
Steam Option	No Steam Calculations		
Flow Type	Tubing		
Well Type	Producer		
Artificial Lift	Gas Lift (Continuous)	None	N/A
Lift Type	No Friction Loss In Annulus	N/A	
Predicting	Pressure and Temperature (offshore)		
Temperature Model	Rough Approximation		
Range	Full System		
Completion	Cased Hole		
Sand Control	None		
Inflow Type	Single Branch		
Gas Coning	No		

Table A6 Input Data for IPR

Parameter	**For Oil Layers**	**For Gas**
Reservoir Model	Fetkovich	Petroleum Expert
Mechanical/ Geometrical Skin	Enter Skin by Hand	Enter Skin by Hand
Drainage Area (acres per layer)	61	51
Dietz Shape Factor	31.6	31.6
Wellbore Radius	0.255 ft	0.255 ft
Mechanical Skin	5	5

Table A7 Input Data for Downhole Equipment

Tubing OD	2.875”
Tubing ID	2.441”
Tubing Inside Roughness	0.0006
Casing OD	7”
Casing ID	6.184”
Gas Lift Valve Size / Type	1” Orifice
Gas Lift Valve Setting Depth	5825’ MD/ 4000’ TVD

Table A8 Input Data for Geothermal Gradient

Formation Measured Depth (ft)	**Formation Temperature (deg F.)**
0	70
7064	240
10912	310

Table A9 Input Data for Directional Survey

ft MD	**ft TVD**
0	0
1020	1019
2010	1986
3000	2561
4020	3075
5010	3562
5825	4000
7020	4963
7064	5000
8298	6000
9601	7000
10912	8000

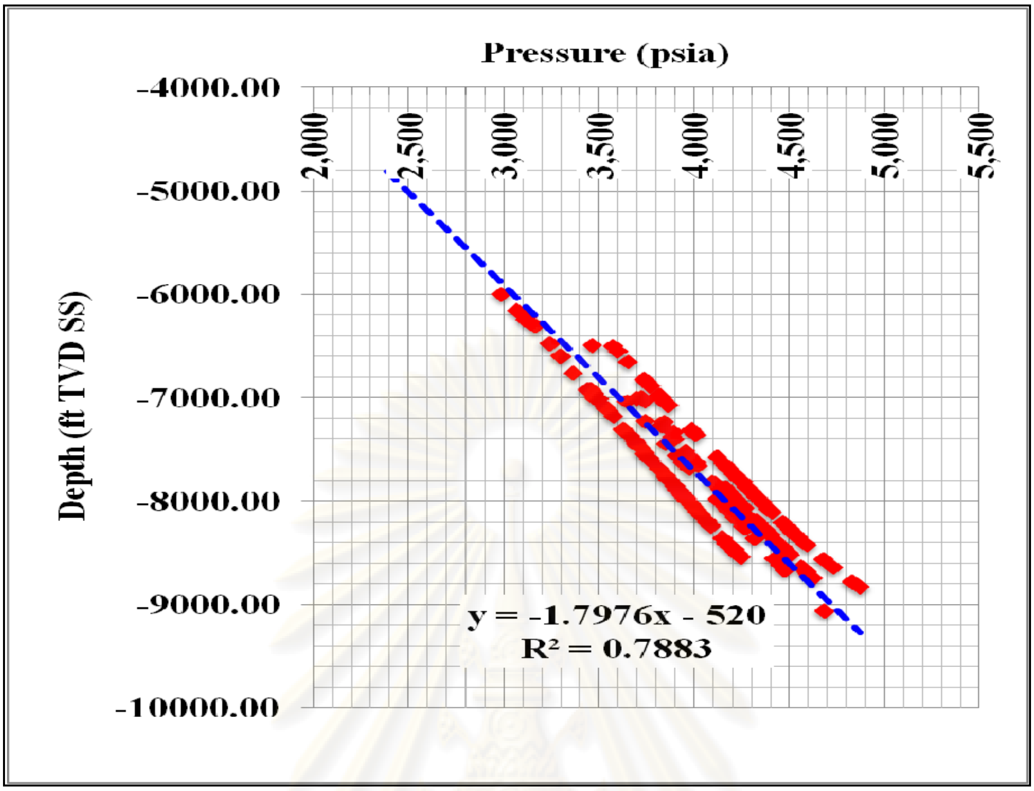


Figure A1 Reservoir Pressure Profile

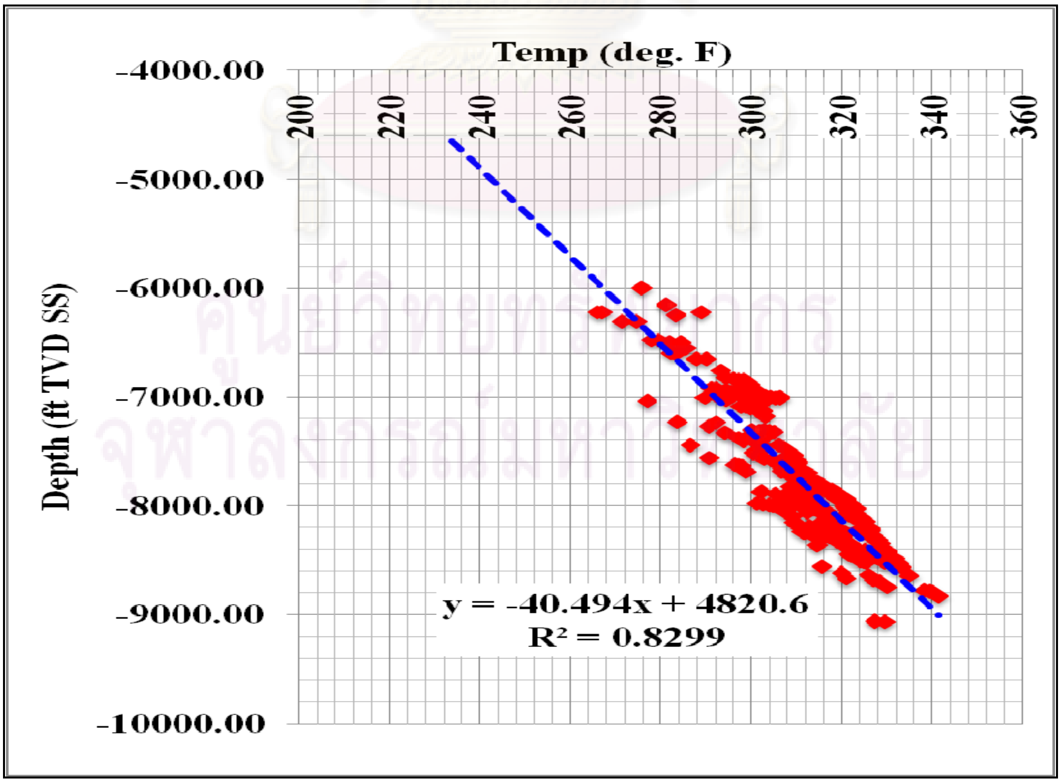


Figure A2 Reservoir Temperature Profile

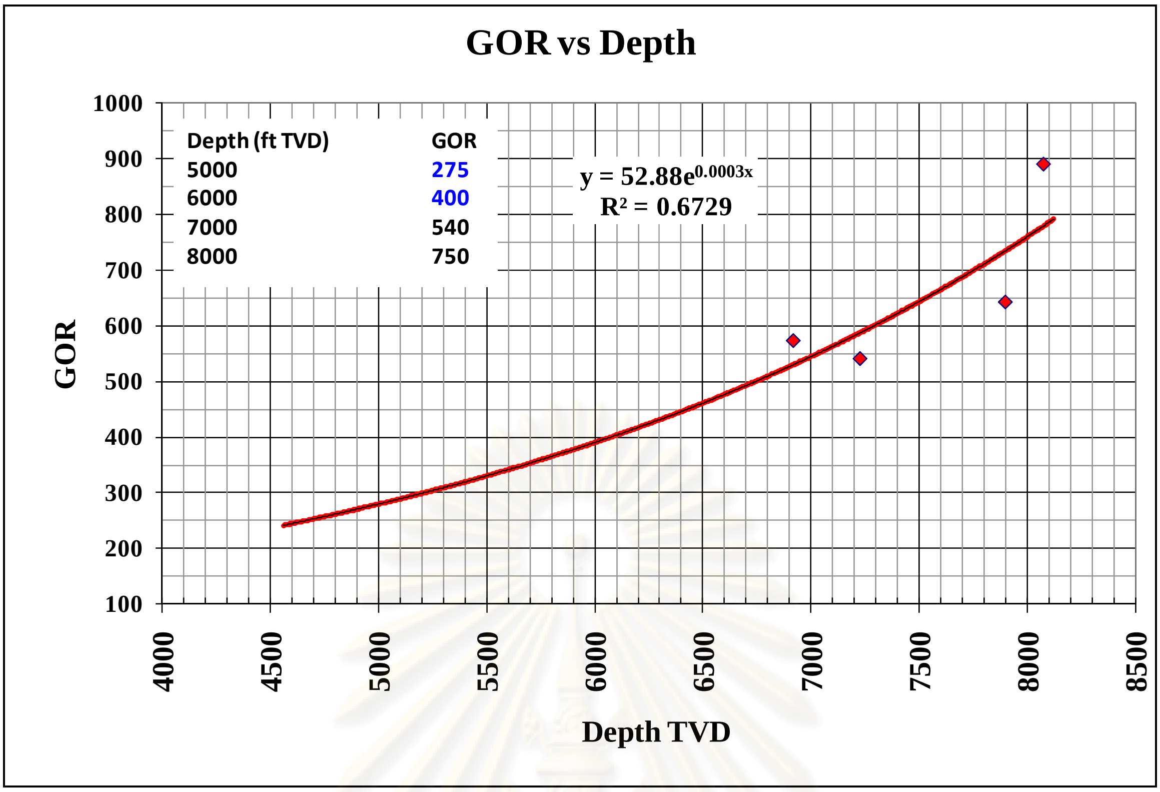


Figure A3 Initial Formation GOR Correlation

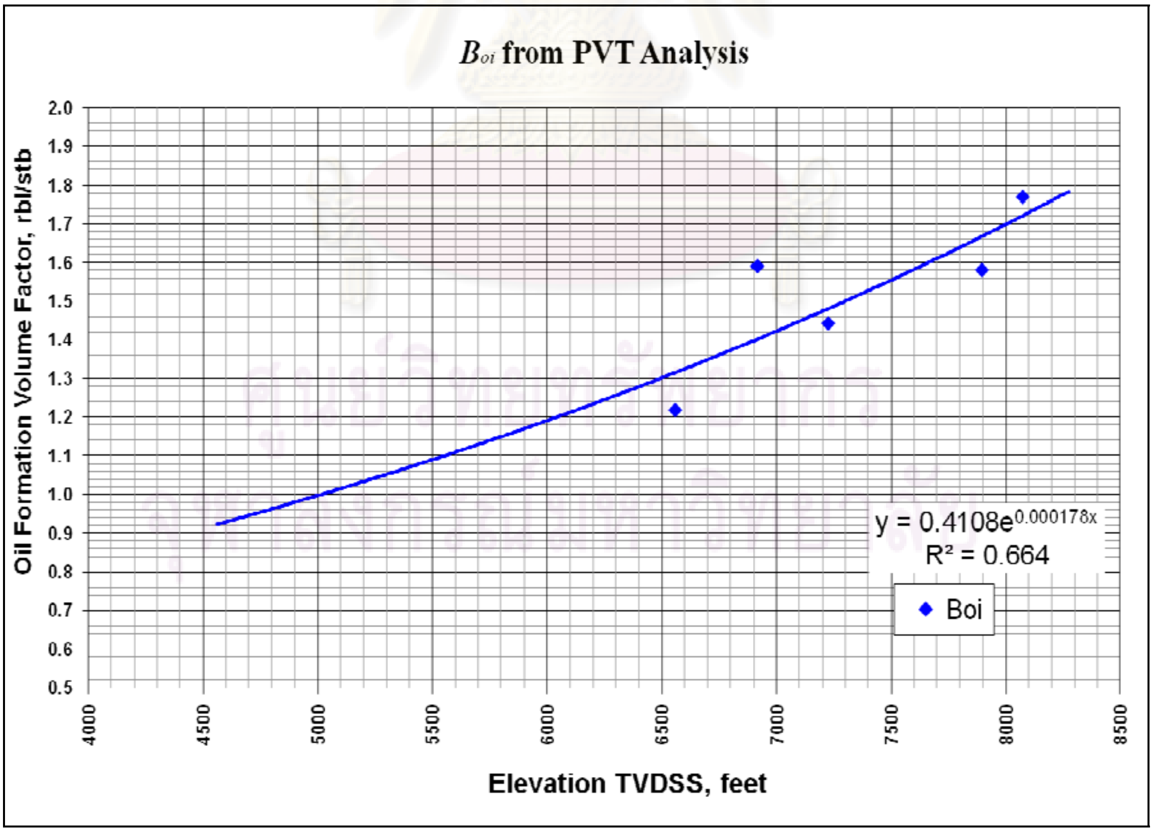


Figure A4 Initial Oil Formation Volume Factor (B_{oi}) Correlation

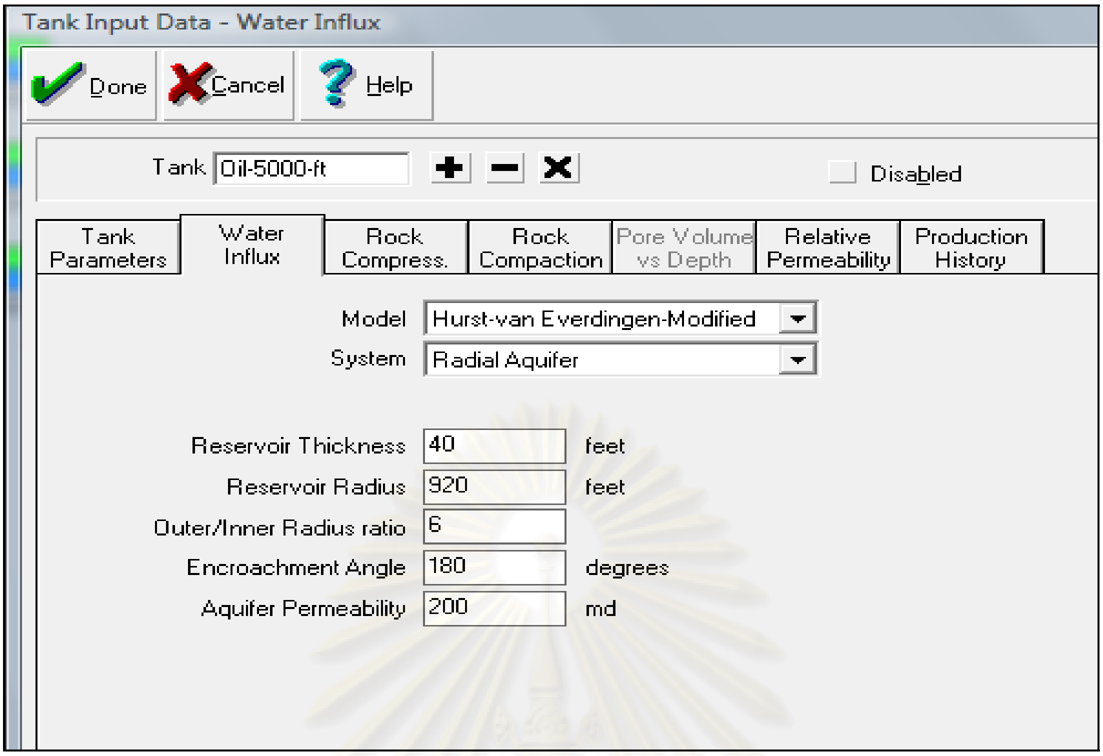


Figure A5 Tank Input Data – Water Flux for Oil Layer @ 5000' TVD

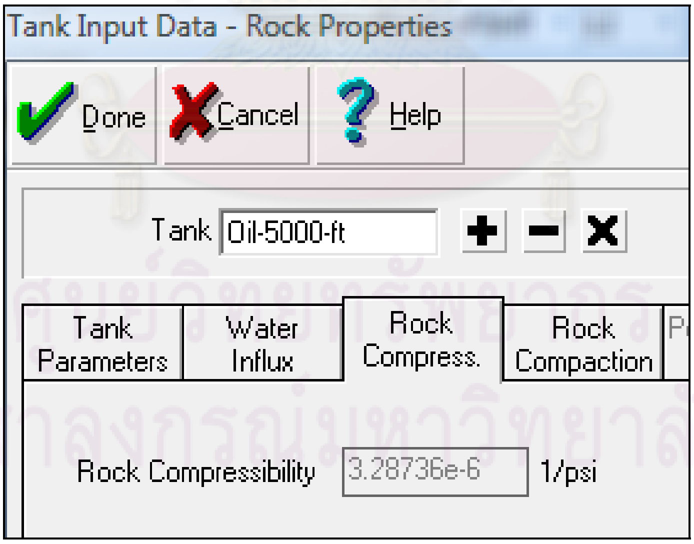


Figure A6 Tank Input Data - Rock Compressibility for Oil Layer @ 5000' TVD

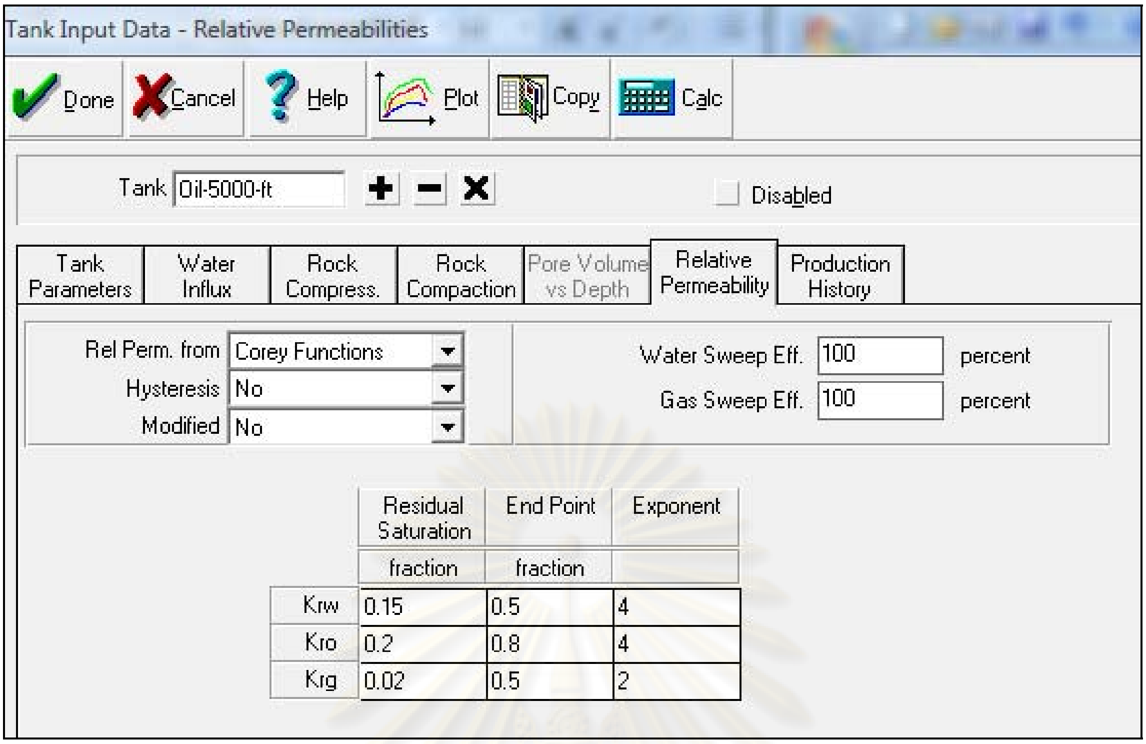


Figure A7 Tank Input Data - Relative Permeability for Oil Layer @ 5000’ TVD

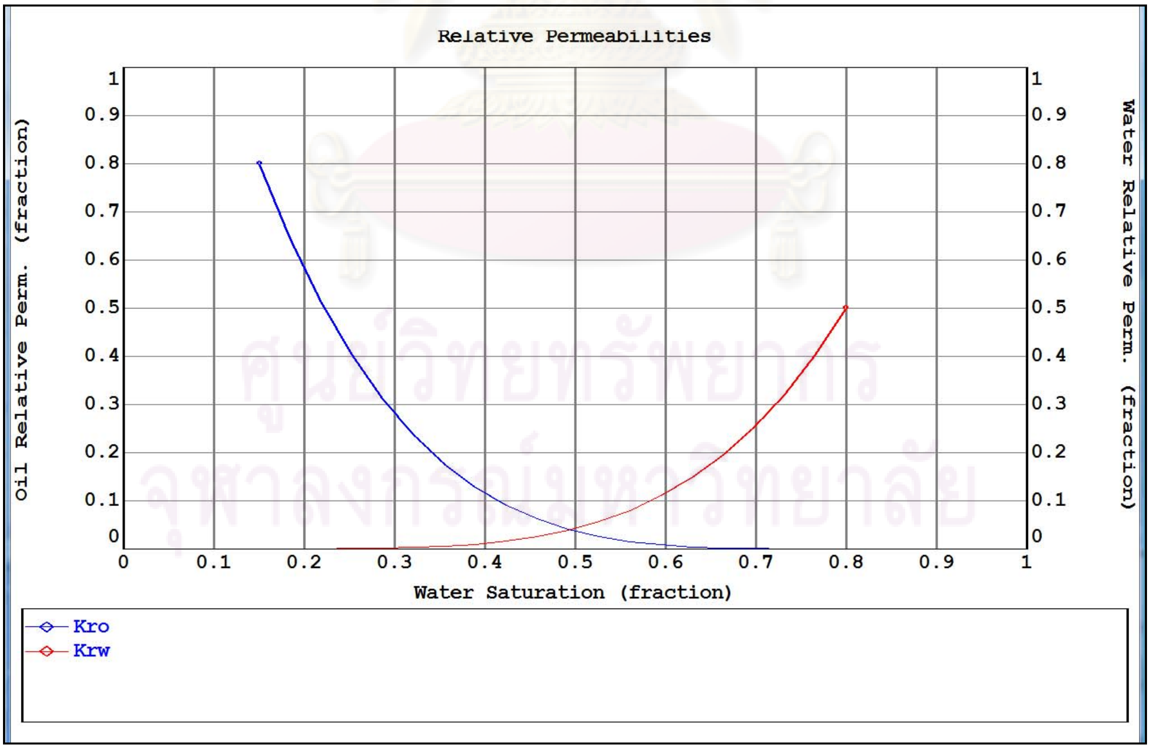


Figure A8 Water-Oil Relative Permeability from MBAL

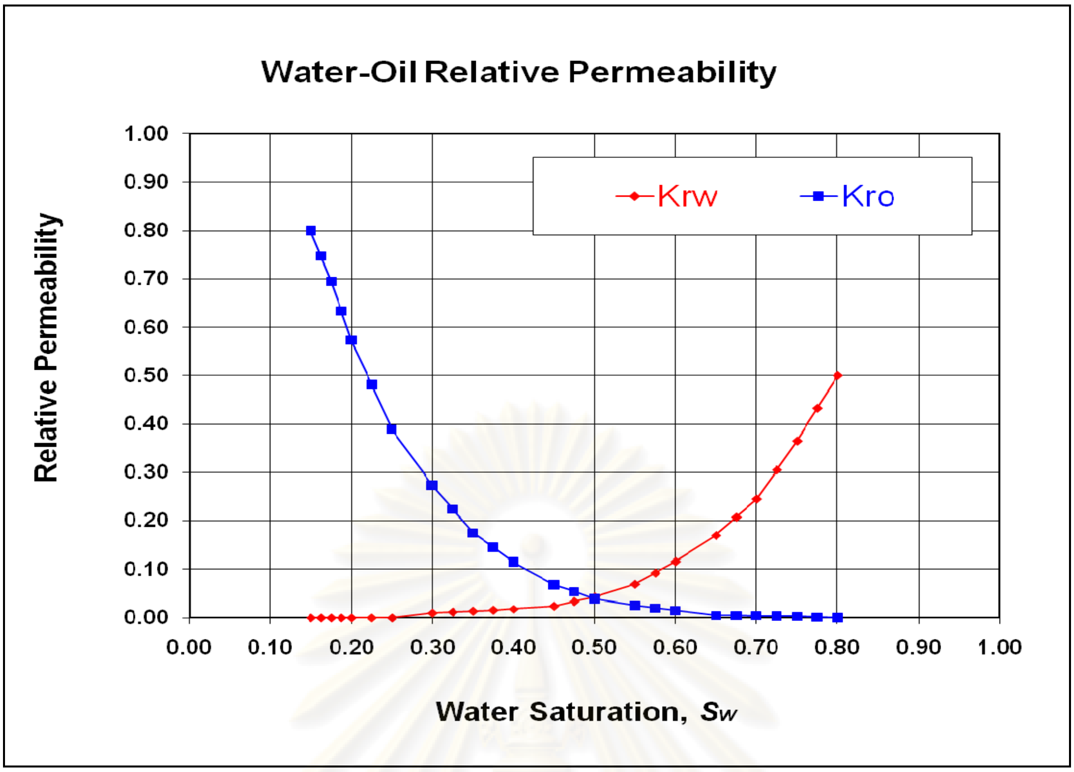


Figure A9 Water-Oil Relative Permeability from Core Analysis

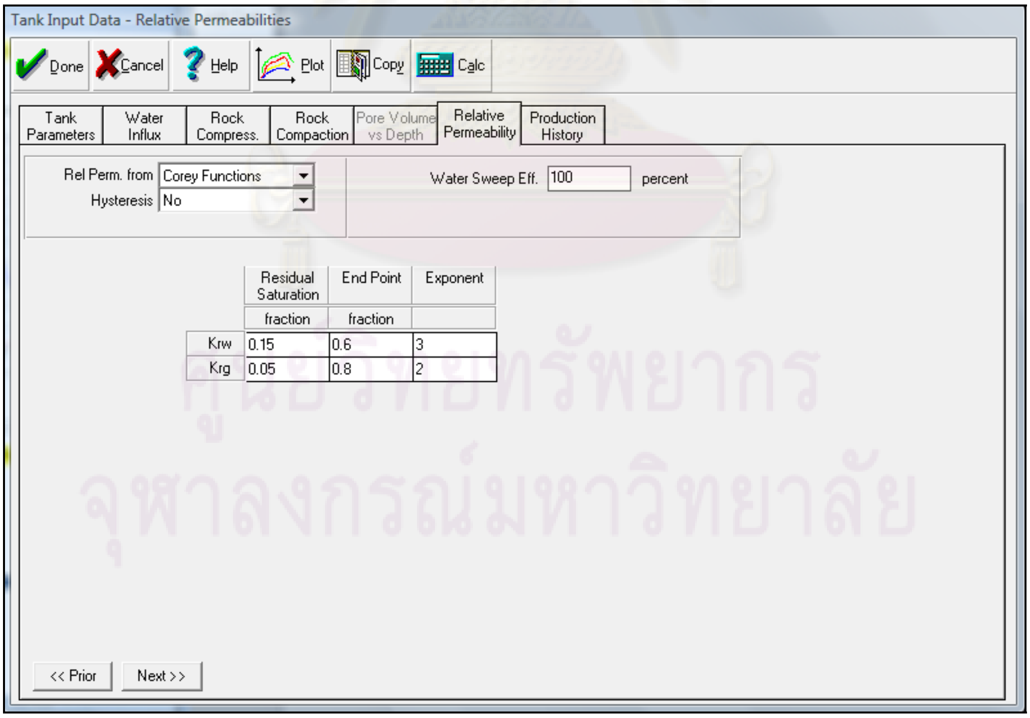


Figure A10 Tank Input Data - Relative Permeability for In-situ Gas Zone

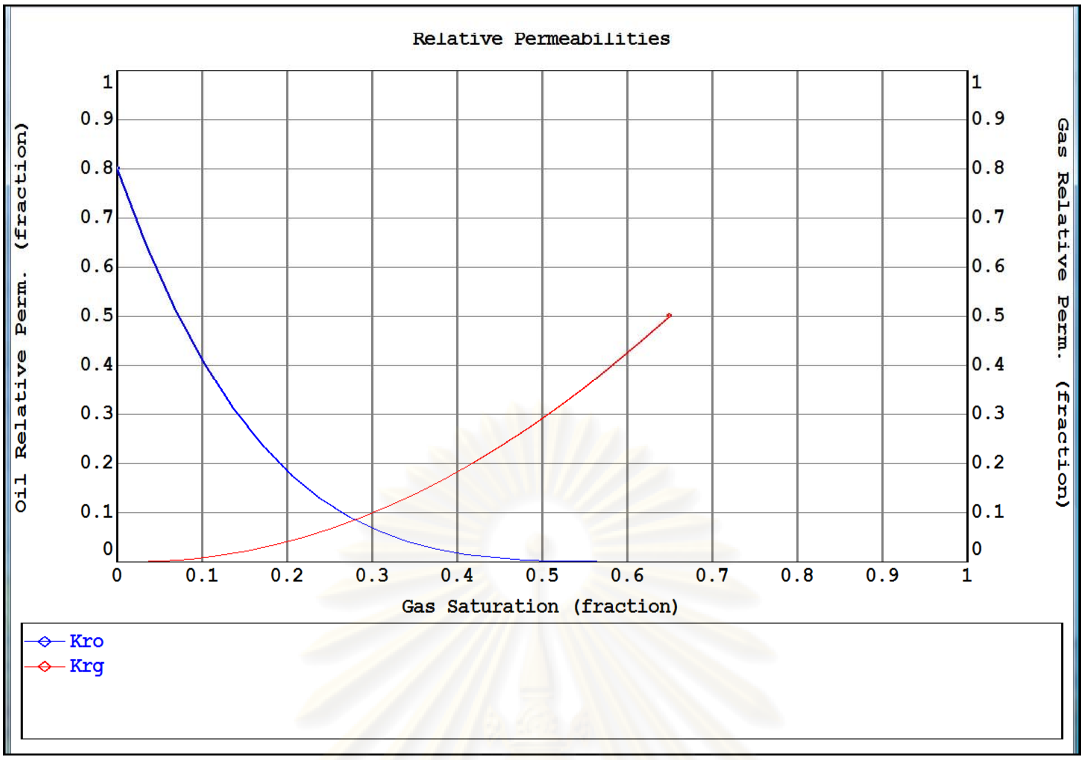


Figure A11 Gas-Oil Relative Permeability from MBAL

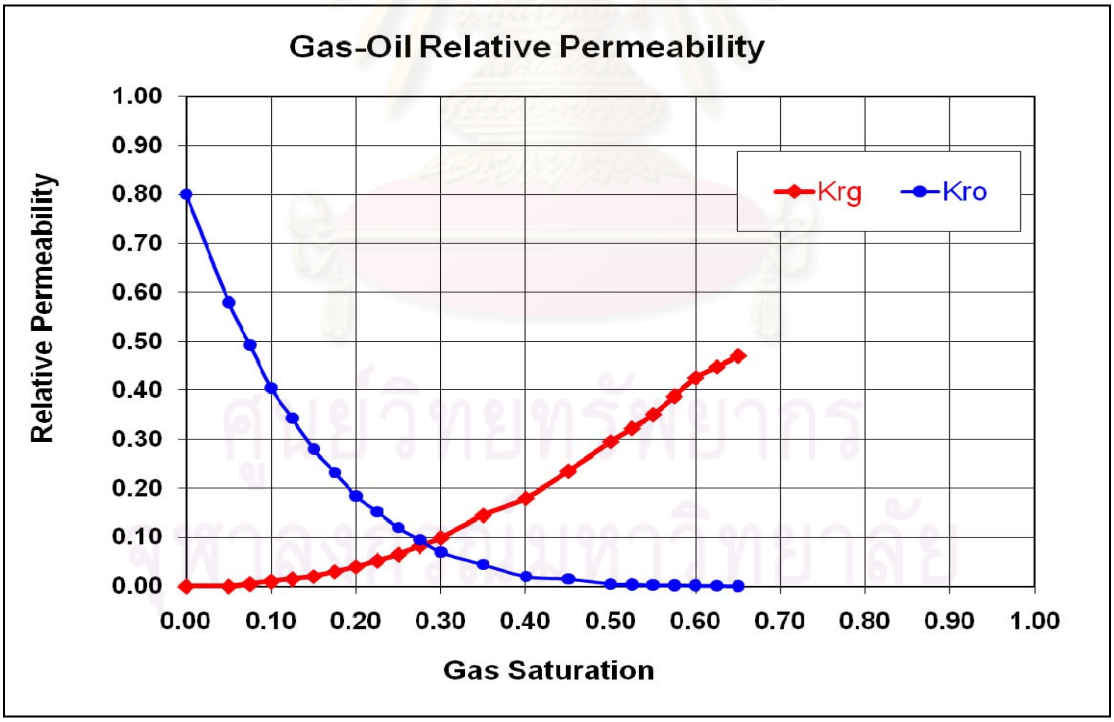
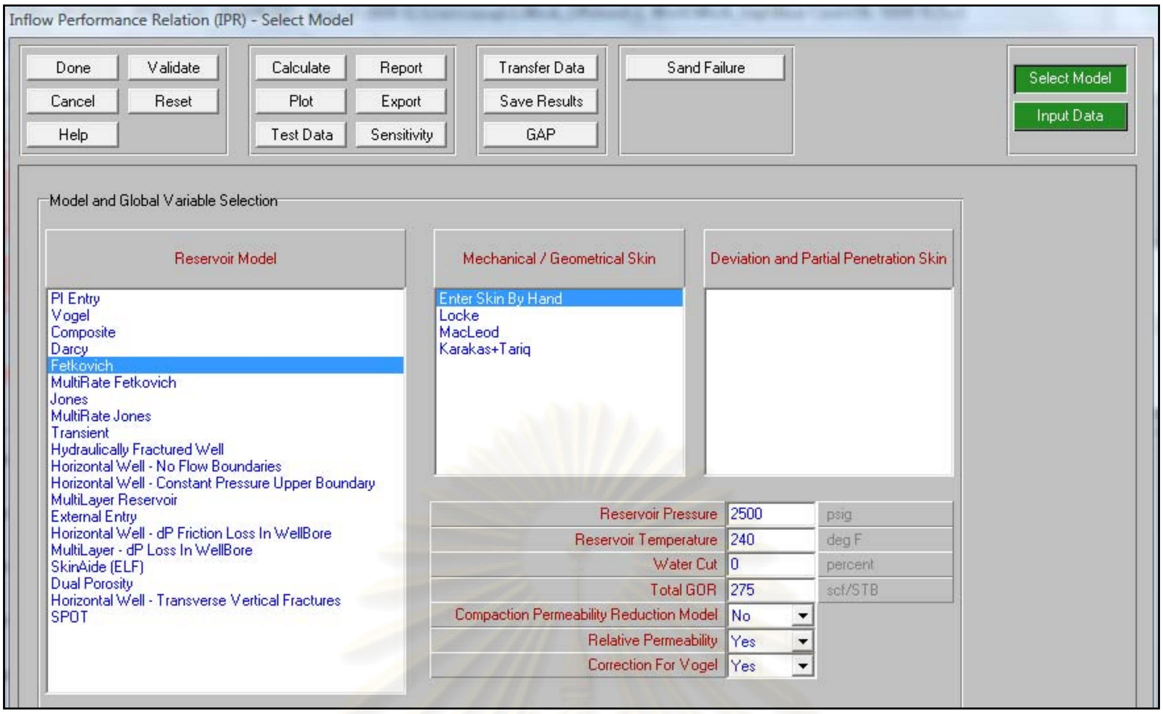
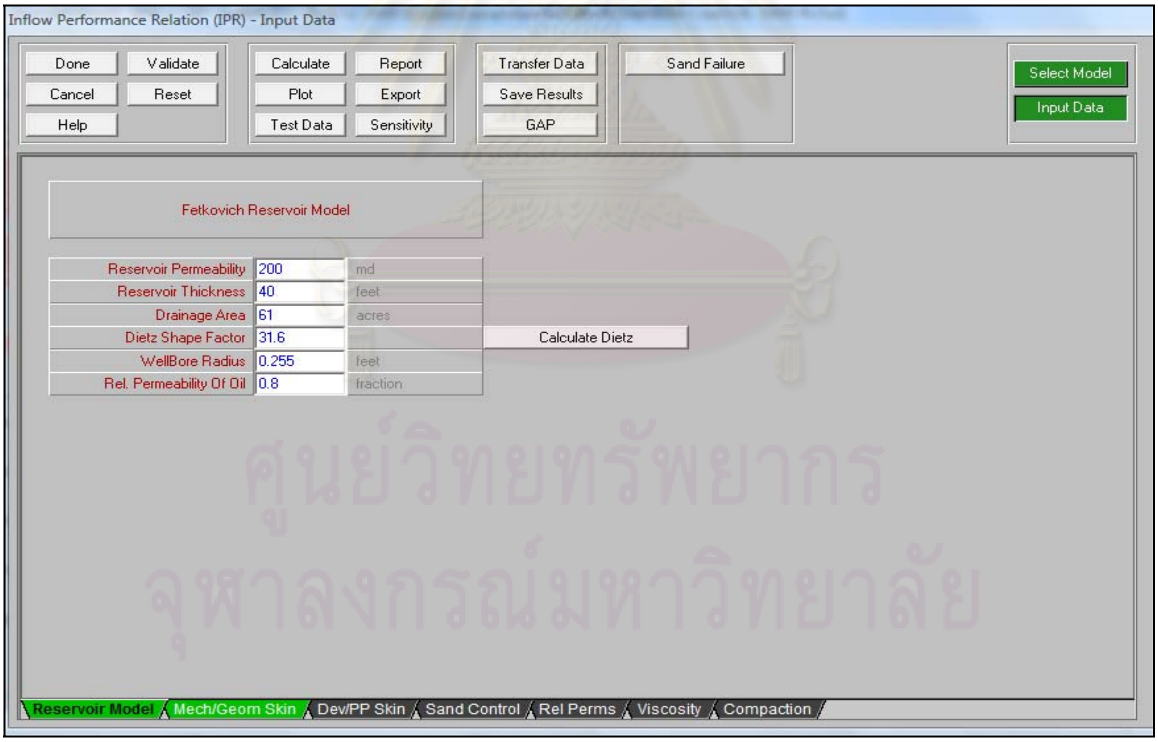


Figure A12 Gas-Oil Relative Permeability from Core Analysis

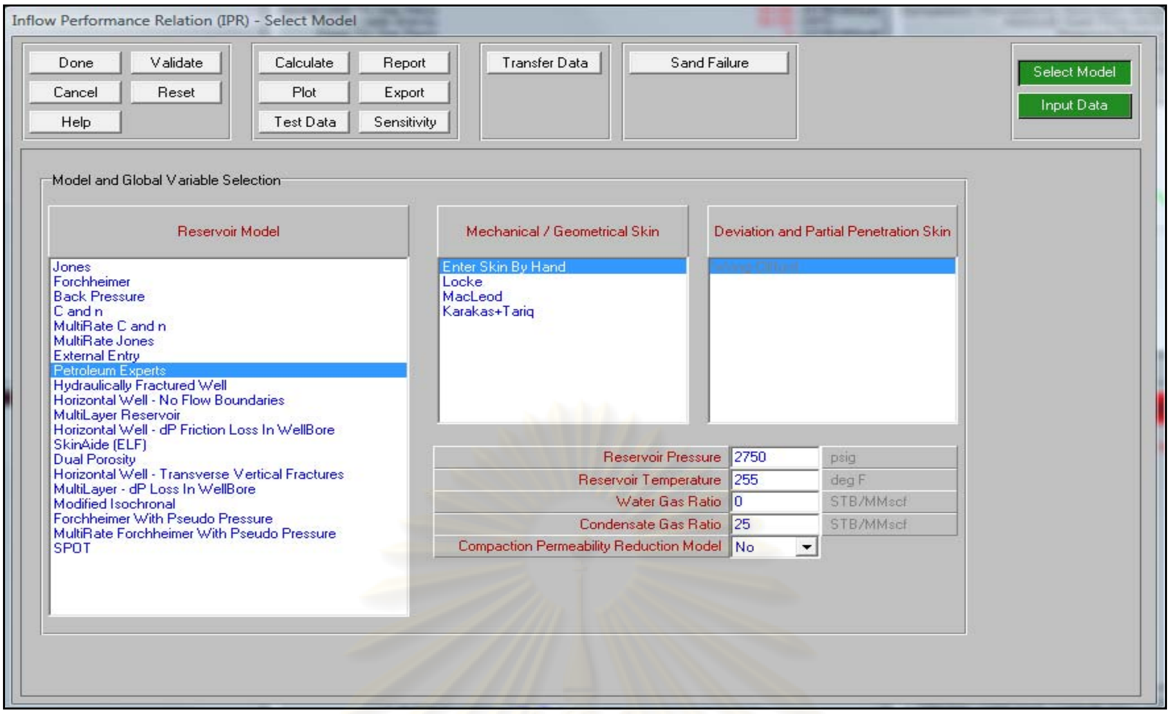


(a)

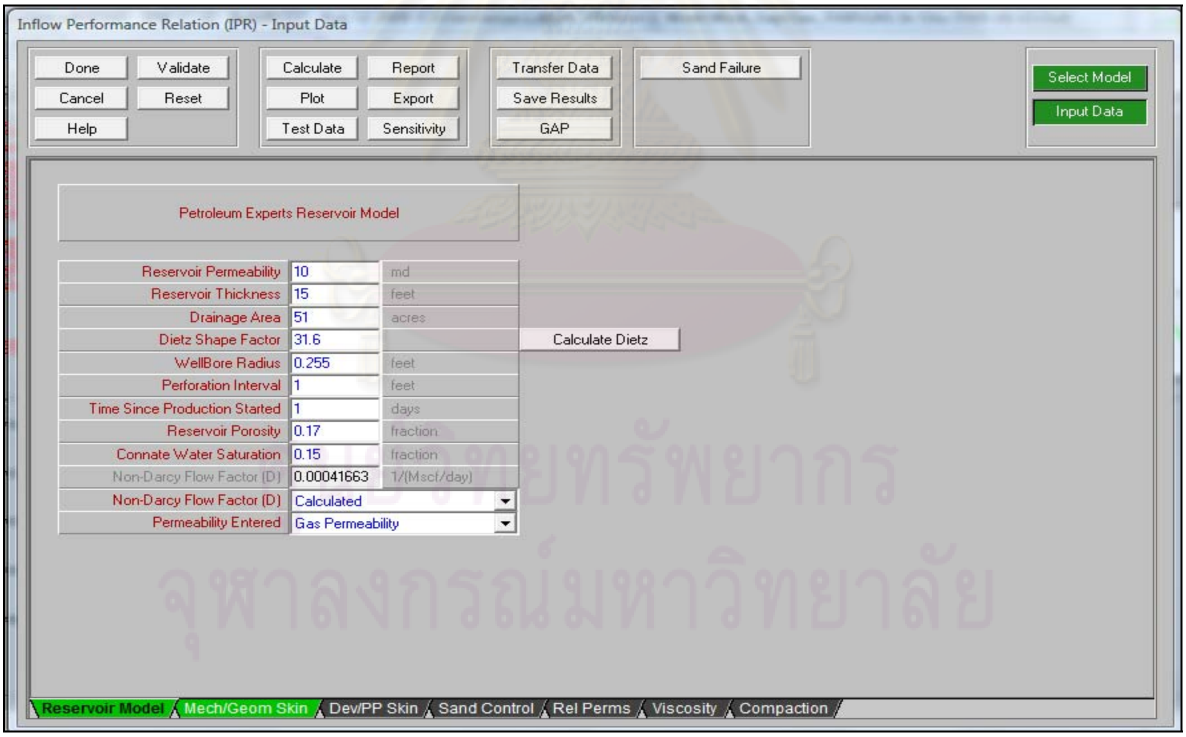


(b)

Figure A13 (a) and (b) Examples of IPR – Input Data for Oil Layer



(a)



(b)

Figure A14 (a) and (b) Example of IPR – Input Data for Gas Layer

VITAE

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