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PERFORATION STRATEGY FOR MULTILAYERED GAS RESERVOIRS USING INTEGRATED PRODUCTION MODELING

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
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ลิน นอง: กลยุทธ์การยิงท่อกรุสำหรับแหล่งกักเก็บก๊าซแบบหลายชั้นโดยใช้การจำลองการผลิตแบบบูรณาการ (PERFORATION STRATEGY FOR MULTILAYERED GAS RESERVOIRS USING INTEGRATED PRODUCTION MODELING)
อ. ที่ปรึกษา : ผศ. ดร. สุวัฒน์ อธิชนากร, 134 หน้า.

แหล่งไฮโดรคาร์บอนใต้พื้นผิวมีปริมาณที่จำกัด จึงมีความสำคัญมากที่ต้องผลิตออกมาในปริมาณที่มากที่สุดเท่าที่จะเป็นไปได้เสมอ ในหลายต่อหลายครั้ง กลยุทธ์การเปิดชั้นการผลิตที่ได้กระทำไปนั้นจะขึ้นอยู่กับประสบการณ์ของผู้ทำการผลิต และยังไม่เคยมีโอกาสได้ทำการตรวจสอบถึงกลยุทธ์การเปิดชั้นการผลิตอื่นๆ ซึ่งอาจให้ผลลัพธ์ที่ดีกว่า ในงานวิจัยนี้เราเริ่มด้วยการสร้างแบบจำลองด้วยโปรแกรมอินทิเกรทโพรดักชั่นโมเดลลิ่ง (ไอพีเอ็ม) กลยุทธ์การเปิดชั้นการผลิตต่างๆ ถูกนำมาใช้กับหลุมผลิต เพื่อทำการวิเคราะห์หากลยุทธ์ที่จะทำให้ได้ผลผลิตมากที่สุด จุดประสงค์ของงานวิจัยนี้คือเพื่อสืบหาผลกระทบของแรงขับเคลื่อนแบบต่างๆ และกลยุทธ์การยิงท่อกรุต่ออัตราการผลิตสำหรับแหล่งกักเก็บก๊าซหลายชั้น แหล่งกับเก็บที่ใช้สำหรับงานวิจัยนี้เป็นแหล่งกักเก็บก๊าซธรรมชาติซึ่งอยู่ในอ่าวไทย

ในงานวิจัยชิ้นนี้มีกรณีศึกษาด้วยกัน 3 กรณี ได้แก่ (1) แหล่งกักเก็บทั้งหมดถูกผลิตโดยความดันของก๊าซในแหล่งกักเก็บ (2) แหล่งกักเก็บก๊าซทั้งหมดมีการเชื่อมต่อกับแหล่งกับเก็บน้ำซึ่งถูกผลิตโดยมีน้ำเป็นกลไกในการขับเคลื่อน และ (3) มีแหล่งกักเก็บ 2 ชั้นเชื่อมต่อกับแหล่งกักเก็บน้ำและแหล่งกักเก็บ 2 ชั้นถูกผลิตด้วยความดันของก๊าซในแหล่งกักเก็บ

จากงานวิจัยชิ้นนี้ ปริมาณก๊าซสะสมที่ผลิตได้สำหรับกลยุทธ์แบบต่างๆมีความแตกต่างไม่มากในกรณีที่แหล่งกักเก็บทั้งหมดถูกผลิตโดยความดันก๊าซในแหล่งกักเก็บ อย่างไรก็ตาม สำหรับแหล่งกักเก็บที่มีน้ำเป็นกลไกขับเคลื่อนและแหล่งกักเก็บแบบผสมผสาน การเปิดชั้นแหล่งกักเก็บจากล่างขึ้นบนร่วมกับการปิดชั้นที่ถูกผลิตไปจนหมดและการปิดชั้นที่ผลิตน้ำช่วยทำให้ปริมาณก๊าซที่สามารถผลิตขึ้นมาได้มีจำนวนเพิ่มขึ้น

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ....

สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่ออ.ที่ปรึกษาวิทยานิพนธ์หลัก ....

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The hydrocarbon resources we have at subsurface are limited and hence top priority has always been to get maximum out of it. Many times perforation strategy has been done based on experience, and we have never had a chance to check if other perforation strategies will be able to deliver a better result. In this study, reservoir models are built using Integrated Production Modeling (IPM) suite. Then, different strategies are applied to the same well in order to determine the strategy that delivers the highest recovery. The aim of this study is to investigate the impact of different drive mechanisms and various perforation strategies on recovery factor (RF) for multilayered gas reservoirs. The reservoirs for this study are dry gas reservoirs in the Gulf of Thailand (GoT).

There are 3 cases in this study: (1) all reservoirs are depletion-drive gas reservoirs, (2) all reservoirs are water-drive gas reservoirs and (3) two reservoirs are depletion-drive and another two reservoirs are water-drive.

Based on this study, the cumulative gas productions for different strategies are not much different for depletion-drive gas reservoirs. However, for water-drive gas reservoirs and combination-drive gas reservoirs, bottom-up perforation together with shutting off depleted zone and water producing zone provides better gas recovery.

Department: Mining and Petroleum Engineering Student's Signature ....
Field of study: Petroleum Engineering Advisor's Signature Suwat Athichanagorn
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CONTENTS

CHAPTER **Page**

CHAPTER **Page**

LIST OF TABLES

Table **Page**

LIST OF FIGURES

Figure **Page**

Figure **Page**

Figure **Page**

Figure **Page**

Figure **Page**

LIST OF ABBREVIATIONS

Bscf	billion standard cubic feet
CGR	condensate gas ratio
DCQ	daily contract quantity
GAP	General Allocation Package (software by Petroleum Experts)
GOR	gas oil ratio
GoT	Gulf of Thailand
ID	internal diameter
IPM	Integrated Production Model (software by Petroleum Experts)
IPR	Inflow Performance Relationship
lb/ft^3	pound per cubic feet
MBAL	Material Balance (software by Petroleum Experts)
MMscf/d	million standard cubic feet per day
MMMscf/d	billion standard cubic feet per day
OFIP	original fluid in place
OGIP	original gas in place
PROSPER	Production and System Performance (software by Petroleum Experts)
PVT	pressure volume temperature
psi	pound per square inch
psia	pound per square inch absolute
OOIP	original oil in place

Rb/stb	reservoir barrel per stock tank barrel
RF	recovery factor
SCAL	special core analysis
SG	specific gravity
stb/MMscf	stock tank per million standard cubic feet
TD	true depth
TVD	true vertical depth
WGR	water gas ratio
WHP	wellhead pressure
VLP	vertical lift performance

NOMENCLATURE

A_r	cross-sectional to flow at radius r
A	area open to flow
A_e	encroachment angle
a	constant (calculated from reservoir properties)
B_g	gas formation volume factor
B_{gi}	initial gas formation volume factor
B_w	water formation volume factor
b	constant (calculated from reservoir properties)
c_f	formation compressibility
c_w	water compressibility
G	initial gas in place
J	productivity index
h	reservoir thickness
k	absolute permeability
k_a	aquifer permeability
k_{rg}	gas relative permeability
k_{rw}	water relative permeability
p	pressure
p_D	dimensionless pressure
p_i	initial reservoir pressure
$\bar{p}_R$	average reservoir pressure
p_r	reservoir pressure
p_{ref}	reference pressure

p_{wf}	bottom-hole flowing pressure
q	flow rate
q_r	volumetric flow rate at radius r
R_D	outer / inner radius ratio
r_D	dimensionless radius
r_o	the outer radius of the reservoir
S_{gi}	initial gas saturation
S_w	water saturation
S_{wi}	initial water saturation
t	time
t_D	dimensionless time
U	aquifer constant
v	apparent velocity
W_e	cumulative water influx
W_P	cumulative water production
z	gas compressibility factor
z_i	initial gas compressibility factor
$\left(\frac{\partial p}{\partial x}\right)$	pressure gradient in the direction of flow
$\left(\frac{\partial p}{\partial r}\right)_r$	pressure gradient at radius r

GREEK LETTER

α	pressure diffusivity
β	velocity coefficient μ viscosity

μ_w	water viscosity
δ	density
ϕ	porosity

SUBSCRIPTS

a	aquifer
e	encroachment
f	formation
g	gas
i	initial condition
ref	reference condition
r	radial
w	water

CHAPTER I

INTRODUCTION

Many different perforation/production strategies are applied in the recovery of hydrocarbons from petroleum reservoirs. These strategies vary from field to field and well to well. There are several factors that affect on perforation/production strategy. However, this study focuses on performance of different perforation strategies for multilayered gas reservoirs in order to maximize the recovery of hydrocarbons and with minimize the water production.

Multilayered gas reservoirs in the Gulf of Thailand (GoT) are generally dominated by fluvio-deltaic sands. Therefore, a single area may consist of a large number of single reservoirs. Trapping is generally achieved in faulted anticlines or sand lens structures. The basins are generally gas prone, mainly with the result from high heat flows and deep burial depths. There are two types of reservoir drive mechanisms in the gas fields in the GoT; volumetric-depletion drive and water drive. This is because of multiple depositional environment of the basin.

Two reservoir sand types mostly can be found in the GoT; bar or channel sands. The bar sands are thinner than the channel sands. The bar sands have been found with both aquifer support and without aquifer support. The channel sands are typically thicker than the bar sands and mainly support by aquifers.

In bar sands type reservoir, the porosity for the bar sand is less than the channel sands at the same depth. The porosity is ranging from (8-25%) and (1md-10D) for the permeability. The thickness for the bar sand is ranging from (1-20 meters) (3-60 feets). The porosity for the channel sand is ranging from (8-30%) and (1md-10D) for the permeability. The thickness for the channel sand is at the range of (5-30 meters) (16-100 feets).

In term of fluid flow, these two sand types cannot be distinguished between each other. There are only thick or thin reservoirs with either volumetric-depletion drive or water drive mechanisms. The complicated encountered on both bar and channel sand reservoir's rock, fluid properties and with different drive mechanisms creates difficulties for engineers to find optimum perforation/production strategies when these multiple reservoirs are producing through common wells.

With complicated of the reservoir characteristics, the gas fields in the GoT gives one of the most challenging reservoir management aspects for reservoir engineers due to the multilayered characteristics of the reservoirs in combination with volumetric-depletion and water drive mechanisms.

The main work to be done under this study is to predict and evaluate reservoir performance for different perforation strategies for multilayered gas reservoirs using Integrated Production Modeling (IPM) suite.

1.1 Dissertation Outline

Chapter II reviews previous works concerning with this study.

Chapter III discusses the basic theory and concept in this study.

Chapter IV presents the description of reservoir model, fluid PVT properties and the characteristics of multilayered gas reservoirs in GoT.

Chapter V summarizes results and analysis.

Chapter VI discusses conclusions and remarks.

CHAPTER II

LITERATURE REVIEW

The following describes previous studies related with multilayered gas reservoirs and the application of Integrated Production Modeling in predicting reservoir performance.

Harms [1] presented a way to optimize solution by using cooperation of three engineering teams: reservoir engineering, production engineering, and facility engineering. IPM software was used to compare the results of various production options (i.e. well head compression or increase tubing size). The study demonstrates that IPM can provide integrated multi-discipline solutions to a gas well problem and solutions are better than typical single discipline or integrated single point in time approaches.

Wang *et al.* [2] presented a methodology which uses nodal analysis, material balance, pressure transient analysis, and Integrated Production Modeling (IPM) to determine reservoir boundary, original fluid in place (OFIP), and completion strategy for one of the reservoirs in West Seno field. Results of this research indicate that although reservoir size and OFIP were evaluated with various methods, the final results are very similar. It shows successful history matching with IPM and 3D simulation models.

Tejaswi and Suzanne [3] investigated a best-practice workflow that was followed in an Integrated Production Modeling (IPM) study of a region in the Cooper Basin, Australia. The presented procedures improve time efficiency in development of a surface network model, including rigorous validation of tank, simulation, VLP, IPR and compressor models.

Raghavan R. [4] investigated methods to determine layer properties, examine the consequences of selectively stimulating the layers of the reservoir (well productivity), and methods to predict well performance. Each of these aspects is examined for both commingled and cross flow systems. This examination also permits consideration of the influence of interlayer communication.

Fetkovich *et al.* [5] presented the performance prediction of multilayered, depletion-drive gas reservoirs using material balance and radial flow equation. The study was based on actual field data with no cross flow between each layer and high contrast between layer permeability. The conclusion is that for multiple depletion drive gas reservoirs, combining all reservoirs into a single reservoir with average reservoir properties is possible in long term performance prediction.

M.S. Nadar *et al.* [6] described the development of an integrated production model (IPM) for Heera offshore oil field, India. The result showed that an integrated production model of the Heera field has been successfully constructed, history matched and used to optimize lift gas allocation for increasing oil production.

Jiraratwaro, K. [7] has studied the effect of perforation strategy for multilayered oil and gas reservoirs using IPM software. He performed history matching to find-tune the the model and used IPM software to predict future reservoir performance under different perforation strategies.

Ronasak, M. [8] studied to determine the optimum depletion scenario for multilayered reservoirs with different drive mechanisms using Eclipse reservoir simulator. His study included computer modeling of the reservoirs as well as several simulation runs to determine the effect of drive mechanism on the recovery performance under various perforation strategies.

Umut Ozdogan *et al.* [9] presented an Integrated Production Model construction and forecasting workflow along with three practical real field applications from the Jack asset located in deepwater Gulf of Mexico. Their studies included the Integrated Production Model construction process consists of five steps:

Step-1 Framing

Step-2 Modeling

Step-3 Static quality check (Reservoir to separator)

Step-4 Initialization (Link surface network to subsurface model)

Step-5 Dynamic quality check followed by forecasting

Chow *et al.* [10] used IPM to evaluate various artificial lift alternatives and to quantify the impact of various platform upgrade design parameters, such as separator capacity, gas injection and completion efficiency of new drills.

Acosta *et al.* [11] used an IPM within a probabilistic framework to study various secondary and enhanced recovery mechanisms.

CHAPTER III

THEORY AND CONCEPT

This chapter covers the basic theories and concepts for this study that included a brief description of material balance, Darcy's Law, IPR, VLP, NODAL analysis, water influx models and IPM suite.

The reservoir modeling technique is used in this study because it offers advantage on phenomenon of gas and water flowing in reservoirs, the interaction between each reservoir in multilayered reservoirs through the common producing well(s), and the effect of different drive mechanisms on the performance of the multilayered reservoirs. This advantage is important in order to understand the behavior of multilayered reservoirs and to determine the optimal production / perforation strategies. The two important concepts that are used in the reservoir modeling are the concepts of fluid flow in porous media and material balance. Understanding the fundamentals of fluid flow in porous media and in pipes is necessary for optimizing well and reservoir productivity.

The concept of fluid flow in porous media is based on Darcy's Law. Darcy's Law is an empirical relationship derived for the vertical flow of fluid through packed sand. The continued use of this empirical equation to solve complex reservoir engineering problems.

The material balance equation is one of the basic tools in reservoir engineering. Practically all reservoir engineering techniques involve some application of material balance. Material balance calculation may be used for several purposes. It can be used to estimate original oil in place (OOIP), original gas in place (OGIP), predict future reservoir performance and aid in estimating recovery efficiency.

IPR is used for evaluating reservoir deliverability in production engineering. The IPR curve is a graphical presentation of the relation between the flowing bottom-hole pressure and flow rate.

NODAL analysis combining IPR and VLP has been used to analyze the performance of systems composed of interacting components. It can be applied to both oil and gas wells.

Many gas and oil reservoirs are produced by a mechanism termed water drive. Hydrocarbon production from the reservoir and the subsequent pressure drop prompt a response from the aquifer to offset the pressure decline. This response comes in the form of a water influx. Water-bearing rocks called aquifers surround nearly all the hydrocarbon reservoirs. These aquifers may be a substantially larger than the oil or gas reservoirs they adjoin as to appear infinite in size, and they may be so small in size as to be negligible in their effect on reservoir performance. As reservoir fluids are produced and reservoir pressure declines, a pressure differential develops from the surrounding aquifer into the reservoir.

The IPM suite is the industry standard for integrated field modeling and production optimization. Moreover, the tools provide production forecasts. The IPM suite which models the reservoirs, the production and injection wells and the surface gathering system. Multiple reservoirs, naturally and artificially lifted wells, plus single and looped surface pipelines networks can be handled in an integrated way.

3.1 Material Balance

The law of conservation of mass is the basis of material balance calculations. Material balance is an accounting of material entering or leaving a system. The calculation treats the reservoir as a large tank of material and uses quantities that can be measured to determine the amount of a material that cannot be directly measured. The material balance is based on the principle of the conservation of mass:

Mass of fluids originally in place = Fluids produced + Remaining fluids in place

The material balance program uses a conceptual model of the reservoir to predict the reservoir behavior based on the effects of reservoir fluids production and gas to water injection. The material balance equation is zero-dimensional, meaning that it is based on a tank model and does not take into account the geometry of the reservoir, the drainage areas, the position and orientation of the wells, etc.

Measurable quantities include cumulative fluid production volumes for oil, water and gas phases, reservoir pressure and fluid properties data from samples of produced fluid. Material balance calculation may be used for several purposes. They provide an independent method of estimating the volume of oil, water and gas in a reservoir for comparison with volumetric estimates. The magnitude of various factors in the material balance equation indicates the relative contribution of different drive mechanisms at work in the reservoir. Material balance can be used to predict future reservoir performance and aid in estimating recovery efficiency.

3.2 Material Balance in Gas Reservoir

Reservoirs containing only free gas are termed gas reservoirs. Such a reservoir contains a mixture of hydrocarbons which exists wholly in the gaseous state. The mixture may be dry, wet, or condensate gas, depending on the composition and the pressure and temperature at which the accumulation exists.

Gas reservoirs may have water influx from contiguous water-bearing portion of the formation or maybe volumetric (i.e., have no water influx). The general material balance equation applied to a volumetric gas reservoir is in the form of

$$G\left(B_g - B_{gi}\right) + GB_{gi}\left(\frac{c_w S_{wi} + c_f}{\left(1 - S_{wi}\right)}\right)\Delta\overline{p} + W_e = G_p B_g + B_w W_p \tag{3.1}$$

where

B_g = gas formation volume factor, ft^3/SCF

B_{gi} = initial gas formation volume factor, ft^3/SCF

B_w = water formation volume factor, bbl/STB

c_w = water isothermal compressibility, psi^{-1}

c_f = formation isothermal compressibility, psi^{-1}

G = initial reservoir gas volume, SCF

G_p = cumulative gas production, SCF

$\Delta \bar{p}$ = change in volumetric average reservoir pressure, psia

S_{wi} = water saturation at initial reservoir conditions, fraction, unitless

W_e = water influx, bbl

W_p = cumulative produced water, STB

Equation (3.1) is derived by applying the law of conservation of mass to the reservoir and associated production.

For most gas reservoirs, the gas compressibility term is much greater than the formation and water compressibilities, and the second term on the left-hand side of Equation (3.1) becomes negligible.

The new equation becomes

$$G\left(B_g - B_{gi}\right) + W_e = G_p B_g + B_w W_p \tag{3.2}$$

When there is neither water encroachment into the reservoir nor water production from the reservoir, the reservoir is said to be volumetric. In this case Equation (3.2) reduces to

$$G\left(B_g - B_{gi}\right) = G_p B_g \tag{3.3}$$

Substituting B_g into Equation (3.3), we have

$$\frac{p}{z} = -\frac{p_i}{z_i G} G_p + \frac{p_i}{z_i} \tag{3.4}$$

where

p = pressure, psia

p_i = pressure at initial reservoir pressure, psia

z = gas deviation factor or gas compressibility factor, ratio, unitless

z_i = gas deviation factor at initial reservoir pressure, ratio, unitless

Because p_i, z_i and G are constants for a given reservoir, Equation (3.4) suggests that a plot of *p/z* as the ordinate versus G_p would yield a straight line with

$$\text{slope}=-\frac{p_i}{z_i G}$$

$$\text{y intercept}=-\frac{p_i}{z_i}$$

The p/z plot versus cumulative production is shown in Figure 3.1

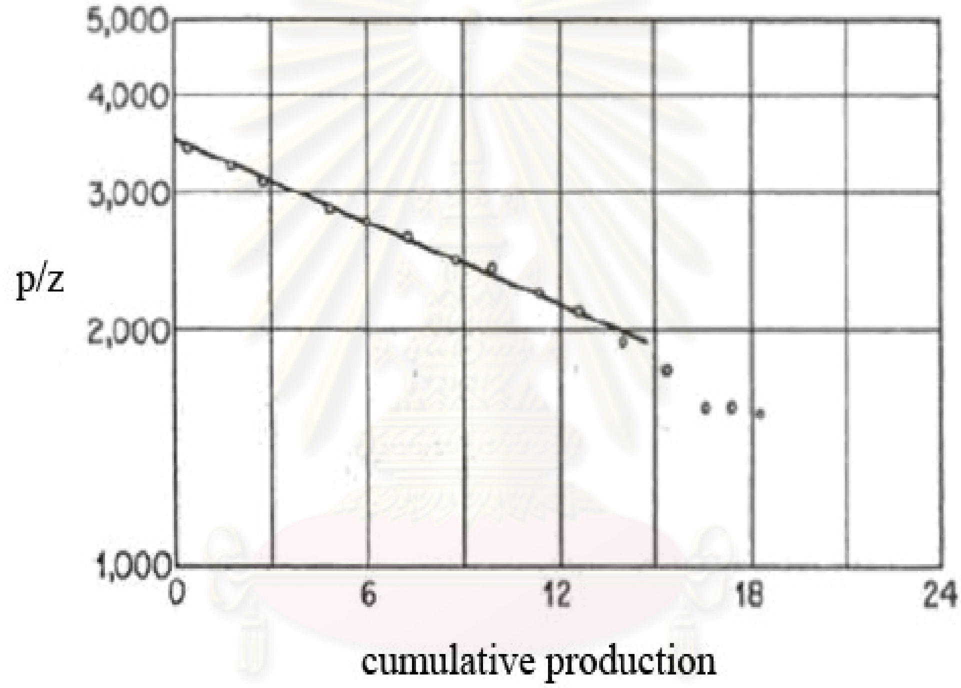

Figure 3.1 : p/z versus cumulative production plot (*Craft and Hawkins*)[13]

If p/z is set equal to zero, which would represent the production of all the gas from reservoir, then the corresponding G_p equals G, the initial gas in place.

3.3 Darcy's Law

The fundamental law of fluid flow in porous media is Darcy's law. The mathematical expression developed by Darcy in 1856 states that the velocity of a homogeneous fluid in a porous medium is proportional to the head (or potential), and inversely proportional to the fluid viscosity. For a horizontal linear system, this relationship is

$$q = -A\left(\frac{k}{\mu}\right)\cdot\left(\frac{\partial p}{\partial x}\right) \tag{3.5}$$

where

q	=	flow rate, cubic centimeter per second
k	=	permeability of the porous medium, Darcy
A	=	area open to flow, centimeter square
μ	=	fluid viscosity, centipoise
$\left(\frac{\partial p}{\partial x}\right)$	=	pressure gradient in the direction of flow, atm/cm

For a horizontal radial system, the pressure gradient is positive and Darcy's equation can be expressed in the following generalized form:

$$v = \frac{q_r}{A_r} = -\left(\frac{k}{\mu}\right)\cdot\left(\frac{\partial p}{\partial r}\right)_r \tag{3.6}$$

where

q_r	=	volumetric flow rate at radius r, cubic centimeter per second
A_r	=	cross-sectional area to flow at radius r = $2\pi rh$, centimeter square
$\left(\frac{\partial p}{\partial r}\right)_r$	=	pressure gradient at radius r, atm/cm
v	=	apparent velocity at radius r, centimeter per second

The cross-sectional area at radius r is essentially the surface area of a cylinder. For a fully penetrated well with a net thickness of h.

3.3.1 Non Darcy Flow

Darcy's law only applies to laminar flow situations. This is considered to be a valid assumption for the majority of oil wells where in in situ velocities even around the wellbore are relatively low. For gas wells and some very high flow rate (light crude) oil wells, the volumetric expansion as fluid approaches the wellbore is very high and this can result in turbulent flow. In such cases, we use a modified form of the Darcy equation, known as the Forchheimer equation, where we add to the Darcy viscous flow term $v \cdot \frac{v}{k}$, a quadratic velocity term to account for the inertial flow as

$$\frac{\partial p}{\partial r} = \frac{\mu \cdot v}{k} + \beta \rho v^2 \tag{3.7}$$

where

$\left(\frac{\partial p}{\partial r}\right)$ = pressure gradient at radius *r*, centimeter square

μ = viscosity, cp

v = apparent velocity at radius *r*, centimeter per second

k = permeability, md

β = velocity coefficient, hr^{-1}

ρ = density, lb/ft^3

3.4 IPR

The flow from the reservoir into the well is known as the **Inflow Performance**. The plot of **Bottomhole Flowing Pressure** versus **Producing Rate** is called the **Inflow Performance Relationship** or **IPR** or **Inflow Curve.**

The inflow performance models are listed in the following Table 3.1.

Table 3.1: Inflow performance models[12]

IPR models	Oil & Gas	Dry & Wet Gas	Retrograde Condensate
Back Pressure		✓	✓
C and n		✓	✓
Darcy	✓		
Fetkovich	✓		
Forchheimer		✓	✓
Jones	✓	✓	✓
Multi-layer	✓	✓	✓
Multi-rate C & n		✓	✓
Multi-rate Fetkovich	✓		
Multi-rate Jones	✓	✓	✓
Modified Isochronal IPR		✓	✓
Petroleum Experts		✓	✓
Vogel	✓		
SPOT	✓	✓	✓

Jones inflow performance model is used in this study. The Jones equation is a modified form of Darcy equation, which allows for both Darcy and non-Darcy pressure drops. The Jones equation can be expressed in the form:

$$(p_r - p_{wf}) = aq^2 + bq \tag{3.8}$$

where

a, b = constant (calculated from reservoir properties), unitless

p_r = reservoir pressure, psia

p_{wf} = bottom-hole flowing pressure, psia

q = flow rate at standard condition, STB/day or SCF/day

The required input in this model is

- gas PVT properties
- initial pressure and temperature
- reservoir permeability
- reservoir thickness
- drainage area
- wellbore radius
- Dietz shape factor
- perforation interval

3.5 Water Influx Models

Several models have been developed for estimating water influx that is based on assumptions that describe the characteristics of the aquifer. Due to the inherent uncertainties in the aquifer characteristics, all of the proposed models require historical reservoir performance data to evaluate constants representing aquifer property parameters since these are rarely known from exploration and development drilling with sufficient accuracy for direct application. The material balance equation can be used to determine historical water influx provided original oil-in-place is known from pore volume estimates. This permits evaluation of the constants in the influx equations so that future water influx rate can be forecast.

The mathematical water influx models [12] that are commonly used in the petroleum industry include

- pot aquifer
- Schilthuis steady state
- Hurst modified steady state
- van Everdingen and Hurst unsteady state
  - edge-water drive
  - bottom-water drive
- Carter–Tracy unsteady state
- Fetkovich method
  - radial aquifer
  - linear aquifer

From the above these infux models, Fetkovich steady state model is used in this study for water drive and combination drive reservoirs.

3.5.1 Hurst-van Everdingen-Odeh

The Hurst-van Everdingen-Odeh model is essentially the same as the Hurst-van Everdingen-Dake model. The only difference is instead of entering all the aquifer dimensions to evaluate aquifer constant and t_D constant we enter the values of the constants as directly. The dimensionless solutions i.e. W_D functions are the same as of the Hurst-van Everdingen Dake method. The assumption in this model is that the rate and pressure stay constant over the duration of each time step.

$$W_e(t) = 10^{-6} \sum_{j=0}^{n-1} U \Delta p_j W_D(\alpha(t_n - t_j), R_D) \qquad (3.9)$$

where

W_e = cumulative water influx, bbl

R_D= outer/inner radius ratio, ratio, unitless

$\Delta p = \dfrac{(p_{j-1} - p_{j+1})}{2}$, psia

α = pressure diffusivity, psi/cp

U = aquifer constant, bbl/psi

3.5.2 Hurst-van Everdingen-Dake

The Hurst-van Everdingen-Dake model is essentially the same as the Hurst-van Everdingen-Odeh model. The only difference is instead of entering the t_D constant and aquifer constant directly, we enter the various physical parameters (e.g. permeability, reservoir radius) that are used to calculate the two constants. Once we have calculated these constants, they are used in the summation formula in exactly the same way as the Hurst-van Everdingen-Odeh model.

There is one other slight variation with the Odeh model. For all Hurst-van Everdingen-Dake models, for each term in the summation MBAL uses the fluid properties at the pressure for the time in the summation term. So in the summation formula above, the U and α are calculated using the fluid properties with the pressure at tj. This is an improvement to the original published model where the fluid properties were taken from the pressure at tn. Note that this correction is obviously not possible in the Odeh model as the t_D and alpha constants are entered as single values for all time steps.

All the models previously discussed with the exception of Hurst simplified are based on the assumption that the pressure disturbance travels instantaneously throughout the aquifer and reservoir system. On the other hand if we do not make this assumption but rather say that the speed will depend on the pressure diffusivity of the system.

$$\frac{1}{r_D}\frac{\partial}{\partial r_D}\left(r_D\frac{\partial p_D}{\partial t_D}\right)=\frac{\partial p_D}{\partial t_D} \tag{3.10}$$

where

$r_D=\frac{r}{r_o}$ = dimensionless radius, ratio, unitless

r_o = the outer radius of the reservoir, ft

p_D = dimensionless pressure, ratio, unitless

$$t_D=\alpha\times t=\frac{kt}{\varphi\mu_w\left(c_w+c_f\right)r_o^2} \tag{3.11}$$

where

t_D = dimensionless time, ratio, unitless

α = pressure diffusivity

k = absolute permeability, md

t = time, hour

ϕ = porosity, fraction

μ_w = viscosity, cp

c_w = water isothermal compressibility, psi^{-1}

c_f = formation isothermal compressibility, psi^{-1}

Radial Aquifers

Reservoir Thickness	This parameter is used to calculate the surface of encroachment of the aquifer by multiplying it with the radius and encroachment angle
Reservoir Radius	This parameter is used to calculate the surface of encroachment of the aquifer by multiplying it with the thickness and encroachment angle
Outer/Inner Radius Ratio	Defines the ratio of the outside radius (aquifer radius) to the inside radius (reservoir radius)
Encroachment Angle	Defines the portion of the reservoir boundary through which the aquifer invades the reservoir
Aquifer Permeability	Defines the total permeability within the aquifer pore volume

α is pressure diffusivity of the system and is also called t_D constant in MBAL.

In modeling aquifer behavior since we are interested in finding rates with pressure changes, this diffusivity equation solved for constant terminal pressure i.e. constant pressure at reservoir-aquifer boundary gives the following general solution,

$$W_e = U \times \Delta p \times W_D\left(t_D, R_D\right) \tag{3.12}$$

where

R_D = reservoir radius/ aquifer outer radius, ratio, unitless

U = aquifer constant, unitless

$$U = \frac{1.119 A_e \phi h \left(c_f + c_w\right) r^2{}_o}{360} \tag{3.13}$$

where

A_e = encroachment angle, degrees

h = reservoir thickness, feet

$$\alpha = \frac{2.309k_a}{365.25\phi\mu_w\left(c_f + c_w\right)r_o^{\ 2}} \tag{3.14}$$

where

k_a = aquifer permeability, md

α = pressure diffusivity,

ϕ = porosity, fraction

μ_w = water viscosity, cp

c_w = water isothermal compressibility, psi^{-1}

c_f = formation isothermal compressibility, psi^{-1}

r_o = the outer radius of the reservoir, ft

The function W_D is called dimensionless aquifer function and is depends on dimensionless time and the size of the aquifer with respect to the reservoir. There are algebraic approximations to the W_D function available this form is the most general form of the equation as it gives the behavior of the pressure diffusivity equation for both the finite and infinite acting aquifers (bounded) depending on the value of R_D.

In real production, this terminal pressure (at the reservoir-aquifer boundary) does not remain constant, but changes. Hurst-Van-Everdingen and Dake using the principle of superposition solved this problem. They found the real-time water influx using Equation (3.12) and approximating the pressure decline as a step function. The water influx equation thus after superposition is given by

$$W_e\left(t\right) = 10^{-6}\sum_{j=1}^{n-1} U\Delta p_j W_D\left(\alpha\left(t_n - t_j\right), R_D\right) \tag{3.15}$$

where

W_e = cumulative water influx, bbl

R_D = reservoir radius/ aquifer outer radius, ratio, unitless

U = aquifer constant, unitless

W_D = dimensionless water influx, ratio, unitless

And, $$\Delta p_j = \frac{\left(p_{j-1} - p_{j+1}\right)}{2}$$

If $j=0$ i.e. the first, use p_i i.e. initial reservoir pressure, instead of p_{j-1}

3.5.3 Fetkovich Steady State

The Fetkovich theory looks at water influx as well inflow calculated using productivity index. Thus, the influx rate is a function given as,

$$\frac{dW_e}{dt} = J(p_i - p) \tag{3.16}$$

In the steady state model, the productivity index is calculated similar to a Darcy well inflow model. This PI is supposed to remain constant. Depending on the geometry the PI is calculated as follows in oil field units:

Radial Aquifers

$$J = \frac{0.00708 A_e k_a h}{360 \mu \log(R_d)} \tag{3.17}$$

where

J = productivity index, STB/day-psi

A_e = encroachment angle, degrees

3.6 VLP

The flow in the well is from top of the perforations to surface is known as the **<u>V</u>ertical <u>L</u>ift <u>P</u>erformance**. The plot of **Producing Rate** versus **Bottomhole**

Flowing Pressure is called a variety of names: **VLP Curve**, **Lift Curve**, **Outflow Curve** or **Tubing Curve** to name a few. Many investigators have conducted research into multiphase flow in tubing. Most of the investigative approaches have made basic assumptions which can be used to classify the correlations derived as follows:

1. methods which do not consider
    a. slippage between phases
    b. the use of flow regime or pattern
2. methods which consider slippage between the phases but not flow regimes
3. methods which consider both flow regime and slippage

The required input in VLP is:

- top node pressure
- gas water ratio
- deviation survey of the well
- temperature gradient

3.6.1 Vertical Flow Correlations

The flowing pressure gradient in a producing well comprises 3 terms:[12]

Gravity	due to density of the produced fluid mixture
Friction	from shear stress between the flowing fluids and the pipe wall
Acceleration	as a result of expansion of fluids as the pressure reduces

For oil wells, the main component of pressure loss is the gravity or hydrostatic term. Calculation of the hydrostatic pressure loss requires knowledge of the proportion of the pipe occupied by liquid (holdup) and the densities of the liquid and gas phases. Accurate modeling of fluid PVT properties is essential to obtain in-situ gas/liquid proportions, phase densities and viscosities.

Calculation of holdup is complicated by the phenomenon of gas/liquid slip. Gas, being less dense than liquid flows with a greater vertical velocity than liquid. The difference in velocity between the gas and liquid is termed the slip velocity. The effect of slip is to increase the mixture density and hence the gravity pressure gradient.

Multi-phase flow correlations are used to predict the liquid holdup and frictional pressure gradient. Correlations in common use consider liquid/gas interactions - the oil and water are lumped together as one equivalent fluid. They are therefore more correctly termed 2-phase flow correlations. Depending on the particular correlation, flow regimes are identified and specialized holdup and friction gradient calculations are applied for each flow regime.

There are numerous correlations that give excellent results depending upon the ranges of flow conditions. Table 3.2 presents those correlations that have contributed either significantly or slightly to the vertical multiphase flow problem. The most important correlations are those of Duns and Ros, Orkiszeski, Hagedorn and Brown, Beggs and Brill and Petroleum Experts. As yet, no single correlation performs better than others for all flow conditions.

Table 3.2 : Multiphase vertical flow correlations[12]

Fancher Brown	is a no-slip hold-up correlation that is provided for use as a quality control. It gives the lowest possible value of VLP since it neglects gas/liquid slip it should always predict a pressure which is

	less than than the measured value. Even if it gives a good match to measured downhole pressures, Fancher Brown should not be used for quantitative work. Measured data falling to the left of Fancher Brown on the correlation comparison plot indicates a problem with fluid density (i.e PVT) or field pressure data.
Hagedorn Brown	performs well in oil wells for slug flow at moderate to high production rates (well loading is poorly predicted). **Hagedorn Brown** should not be used for condensates and whenever mist flow is the main flow regime. It under predicts VLP at low rates and should not be used for predicting minimum stable rates.
Duns and Ros	usually performs well in mist flow cases and should be used in high GOR oil and condensate wells. It tends to over-predict VLP in oil wells. Despite this, the minimum stable rate indicated by the minimum of the VLP curve is often a good estimate
Duns and Ros Original	is the original published method, without the enhancements applied in the primary Duns and Ros correlation. The primary Duns and Ros correlation in PROSPER has been enhanced and optimised for use with condensates.
Petroleum Experts	correlation combines the best features of existing correlations. It uses the **Gould *et al*** flow map and the Hagedorn Brown correlation in slug flow, and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist results are used.

Petroleum Experts 2	includes the features of the PE correlation plus original work on predicting low-rate VLPs and well stability.
Petroleum Experts 3	includes the features of the PE2 correlation plus original work for viscous, volatile and foamy oils.
Petroleum Experts 4	is an advanced mechanistic model suitable for any angled wells (including downhill flow) suitable for any fluid (including Retrograde Condensate). Especially good for pipeline pressure drop calculations and instability calculations (detecting the conditions at which instability will occur).
Petroleum Experts 5	The PE5 mechanistic correlation is an advancement on the PE4 mechanistic correlation. PE4 showed some instabilities (just like other mechanistic models) that limited its use across the board. PE5 reduces the instabilities through a calculation that does not use flow regime maps as a starting point.PE5 is capable of modeling any fluid type over any well or pipe trajectory. This correlation accounts for fluid density changes for incline and decline trajectories. The stability of the well can also be verified with the use of PE5 when calculating the gradient traverse, allowing for liquid loading, slug frequency, etc. to be modeled.
Orkiszewski	correlation often gives a good match to measured data. However, its formulation includes a discontinuity in its calculation method. The discontinuity can cause instability during the pressure matching process, therefore we do not encourage its use.

Beggs and Brill	is primarily a pipeline correlation. It generally over-predicts pressure drops in vertical and deviated wells.
Gray	correlation gives good results in gas wells for condensate ratios up to around 50 bbl/MMscf and high produced water ratios. Gray contains its own internal PVT model which over-rides PROSPER's normal PVT calculations. For very high liquid dropout wells, use a Retrograde Condensate PVT and the Duns and Ros correlation.

There is no universal rule for selecting the best flow correlation for a given application. It is recommended that a Correlation Comparison always be carried out. By inspecting the predicted flow regimes and pressure results, the User can select the correlation that best models the physical situation. **Petroleum Experts** correlation is used in this study because it combines the best features of existing correlations. It uses the **Gould *et al*** flow map and the Hagedorn and Brown correlation in slug flow, and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist results are used.

3.7 Systems Analysis Approach (NODAL Analysis)

This approach consists of selecting a node in the well and dividing the system at this point. This is often called the solution node. This can be the bottom node or top node (wellhead). All the components upstream of the solution node comprise the **Inflow** section, and all the components downstream of the solution node comprise the **Outflow** section. A relationship between flow rate and pressure must be available for each section. The flow rate through the system can be determined once the flow into the solution node equals the flow out of the solution node. The inflow and outflow pressures at the solution node can be calculated separately for a number of given flow rates to produce an inflow and an outflow curve. A plot of solution node pressure versus flow rate will produce two curves, the intersection of which will give the solution node pressure and flow rate that satisfies the inflow and outflow sections simultaneously as shown in Figure 3.2. This intersection thus represents the actual conditions at which the well will flow for a given set of constraints (reservoir pressure and separator pressure).

For many years, NODAL analysis has been used to analyze systems where various components are interactive. The procedure consists of first selecting an appropriate division point or node. In the whole system, any point can be considered as a node, and nodal analysis can be performed. The flow rate for the specific system or set of components can be determined by satisfying the following relationships:

1. Flow into the node = Flow out of the node
2. Only one pressure can exist at a node

The average reservoir pressure and the separator pressure are considered to be fixed for any given time in a well flow system. The basic procedure is to calculate the pressure at the node both ways from the fixed pressure points as follows:

Inflow to the node:

$$\overline{p}_R - \Delta p_{(upstream-components)} = p_{node}$$

Outflow from the node:

$$p_{separator} - \Delta p_{(downstream-components)} = p_{node}$$

The pressure drop Δp, in any component varies with flow rate q; therefore, a plot of flow rate vs. node pressure will produce two curves, the intersection of which gives the one flow rate which satisfies the two conditions above.

A change in the pressure drop across an upstream component (inflow section) will leave the outflow curve unchanged, but the intersection point will change, and

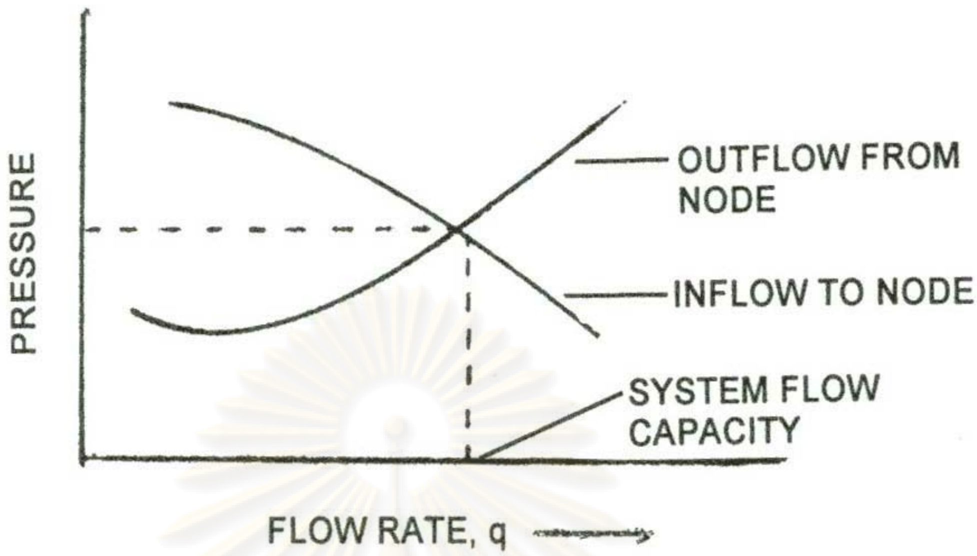

Figure 3.2 : Determination of flow capacity (*Beggs H.D.*)[15]

thus the flow rate will change. Likewise, a change in the pressure drop across a downstream component will result in an adjustment in the flow rate. Finally, a change in either of the fixed pressures (the average reservoir pressure or the separator pressure) occurring during the life of the well will result in a change in the flow rate.
A frequently used node or division point is inside the casing at the perforations; i.e., between the reservoir and the piping system. Thus, the flow through the rock, the perforations, and the gravel pack (if installed) is one system, and flow up the tubulars, through the wellhead and through the flow line and manifold to the separator is the second system. The total system is optimized by selecting the combination of component characteristics which will maximize production rate for the lowest cost.

The system analysis approach is basically used to optimize flowing well performance, but can also be applied to artificial lift situations in oil wells if the effect of the artificial lift system on the pressure is a function of the flow rate. Possible applications include

1. selection of tubing and/or flow line size
2. surface choke or subsurface safety valve sizing
3. analyzing effect of perforation density
4. analyzing effect of gravel pack design
5. artificial lift design

6. predicting the effect of depletion on producing capacity

3.8 Integrated Production Modeling (IPM)

The **Integrated Production Modeling** (software by Petroleum Experts) **IPM** [12] suite has been used in the industry to address field development decisions. IPM is a composite modeling strategy that couples subsurface (material balance or simulation) models to a surface network model via well-bore models. Moreover, the tools provide production forecasts and predict the reservoir performance. Multiple reservoirs, naturally and artificially lifted wells, plus single and looped surface pipelines networks can be handled in an integrated way.

This software is integrated with three parts: GAP, PROSPER and MBAL.

3.8.1 GAP

GAP is a multiphase optimizer of the surface network which links with PROSPER and MBAL to model entire reservoir and production systems. GAP can model production systems containing oil, gas and condensate, in addition to gas or water injection systems.

Wellhead chokes can be set, compressors and pumps optimized, and gas for gas lifted wells, allocated to maximize oil production or revenue while honoring constraints at any level. With MBAL, field production forecast can be run.

GAP is part of the IPM suite, which allows the engineer to build complete system models, including the reservoirs, wells and surface system. GAP has the most powerful and fastest **optimization engine** in the industry, as it is based on **non-linear SQP technique** (Sequential Quadratic Programming). Production and Injections systems include producing / injecting elements (wells) that are connected via common manifolds and pipelines to a fixed system pressure called separator in GAP. The separator in GAP does not have to be the physical separator in the field; it is simply a point of fixed pressure in the network.

Applications

- full field surface network design
- field optimization studies with mixed systems (ESP, Gas Lift, Naturally Flowing)
- multiphase looped network optimization
- field gas lift optimization
- models full field injection system performance, using MBAL reservoir tank models
- compressor and pump system modeling
- production forecasting
- easy to use graphical interface for drawing system network (using icons for separators, compressors, pipelines, manifolds and wells, inline chokes and reservoir tanks)
- GAP is unique in being able to model, optimize and predictions of the entire production system, with MBAL and PROSPER
- GAP links to PROSPER (well model) and MBAL (tank model) to allow entire production systems to be modeled and optimized over the life of the field

3.8.2 PROSPER

PROSPER is a well performance, design and optimization program which is part of the Integrated Production Modeling Toolkit (IPM). This tool is the industry standard well modeling with the major operators worldwide. PROPSER is designed to allow the building of reliable and consistent well models, with the ability to address each aspect of well bore modeling, PVT fluid characterization), VLP correlations (for calculation of flow line and tubing pressure loss) and IPR (reservoir inflow).

PROSPER provides unique matching features, which tune PVT, multiphase flow correlations and IPR to match measured field data, allowing a consistent well model to be built prior to use in prediction (sensitivities or artificial lift design), PROSPER enables detailed surface pipeline performance and design: flow regimes, pipeline stability, slug size and frequency.

According to the inflow model, the following data are required:

a. oil and gas PVT properties
b. initial pressure and temperature
c. permeability
d. reservoir thickness
e. drainage area
f. perforation interval
g. skin

According to the vertical lift performance, the following data are required:

a. top node pressure
b. water gas ratio
c. condensate gas ratio and gas oil ratio
d. deviation survey of the well
f. temperature gradient

Applications

- design and optimize well completions including multi-lateral, multilayer and horizontal wells
- design and optimize tubing and pipeline sizes
- design, diagnose and optimize gas lifted, hydraulic pumps and ESP wells
- generate lift curves for use in simulators
- calculate pressure losses in wells, flow lines and across chokes
- calculate total skin and determine breakdown (damage, deviation or partial penetration)

3.8.3 MBAL

The MBAL package contains the classical reservoir engineering tool, which is part of the Integrated Production Modeling Toolkit (IPM) of Petroleum Experts. MBAL has redefined the use of material balance in modern reservoir engineering.

MBAL is the industry standard for accurate Material Balance Modeling. Efficient reservoir developments require a good understanding of reservoir and production systems. MBAL helps the engineer define the reservoir drive mechanisms and hydrocarbon volumes more easily. This is a prerequisite for reliable simulation studies.

For existing reservoirs, MBAL provides extensive matching facilities. Realistic production profiles can be run for reservoirs, with or without history matching. The intuitive program structure enables the reservoir engineer to achieve reliable results quickly. MBAL is commonly effects prior to building a numerical simulator model.

Applications

- history matching reservoir performance to identify hydrocarbons in place and aquifer drive mechanisms
- building multi-tank reservoir model
- generate production profiles
- run development studies
- determine gas contract DCQ's
- model performance of retrograde condensate reservoirs for depletion and re-cyling
- decline curve analysis
- Monte Carlo simulation
- 1D flood front modeling
- calibrate relative permeability curves against field performance data
- control miscibility
- control recycling of injection gas
- fully compositional

CHAPTER IV

RESERVOIR MODEL

This chapter describes fluid PVT properties, their characteristics and the reservoir model under study.

4.1 Description of Reservoir Model

The reservoir model for this study is selected from available reservoir models in the GoT. The selection for this model is best described in terms of geological setting/depositional environment. Two models have been selected : one for bar sand and another for channel sand. The bar sand reservoirs will be representative of thin, small reservoirs and the channel sand reservoirs will be representative for thick, large reservoirs which are normally connected with aquifer.

4.1.1 Bar Sand Reservoir Model

Bar sand reservoir model has been well identified from geological modeling in combination with 3D seismic amplitude anomaly and well log correlations. Based on data collected and correlated, the reservoirs have the following characteristics:

1. Reservoir fluid type: Dry Gas
2. Top reservoir depth (ft): 6,319-6,553
3. Average thickness (ft): 15.4
4. Net to Gross Sand (%): 0-100%(Average 25%)
5. Porosity (%): 10-35% (Average 21%)
6. Permeability (md): 22-1000
7. Average reservoir pressure (psia): 2,740-2,841

8. Reservoir temperature (Deg F): 237-244

9. Reservoir fluid SG (air = 1): 0.97

10. OGIP (Bscf): 8.57

The reservoir model is built based on the geological data. Summarized data for reservoir model including phase equilibrium data, reservoir and fluid properties are described below. PVT properties and rock properties are tabulated in Table 4.1.

Table 4.1 : PVT properties of reservoir fluid and rock properties

Water Properties	Reference pressure(P_{ref})	2,740-2,841	psia
	Water FVF at P_{ref}	1.0636	rb/stb
	Water viscosity at P_{ref}	0.1907	cp
Fluid Densities at Surface Condition	Water density	62.43	lb/ft^3
	Gas density	0.060	lb/ft^3
	Reference Pressure	2,740-2,841	psia
Rock Properties	Rock Compressibility	5.4092E-6	1/psi

SCAL (Special Core Analysis)

Initial Reservoir Fluid Properties

Initial Water Saturation (S_{wi}) : 0.40

Initial Gas Saturation (S_{gi}) : 0.60

The gas saturation and relative permeability relation is tabulated in Table 4.2 and shown in Figure 4.1.

Table 4.2 : Water saturation, gas saturation and water relative permeabilities

S_w	k_{rg}	k_{rw}
0.4000	1.0000	0.0000
0.4411	0.5549	0.0040
0.4822	0.2846	0.0183
0.5233	0.1317	0.0446
0.5644	0.0529	0.0840
0.6056	0.0173	0.1372
0.6467	0.0041	0.2049
0.6878	0.0005	0.2876
0.7289	0.0000	0.3859
0.7700	0.0000	0.5000
1.0000	0.00000	1.0000

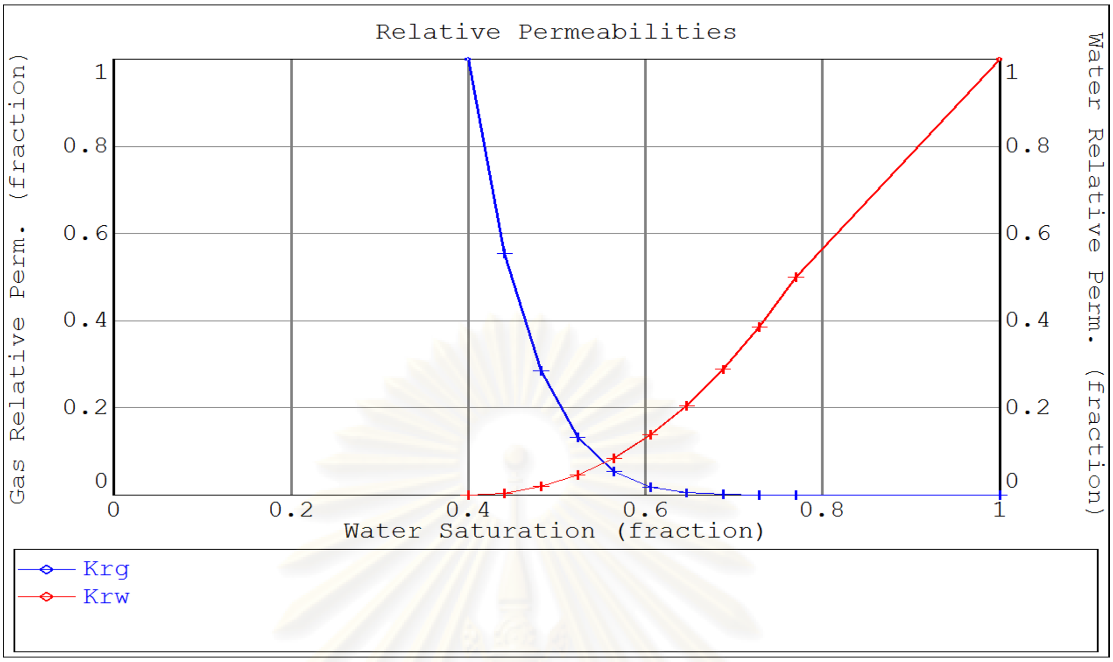

Figure 4.1 : Bar sand reservoirs relative permeability curve

4.1.2 Channel Sand Reservoir Model

Similar to bar sand reservoirs, channel sand reservoirs model has been well-identified from geological modeling in combination with 3D seismic amplitude anomaly and well log correlations. Based on data collected and correlated, the characteristics of the reservoirs have the following characteristics:

1. Reservoir fluid type: Dry Gas
2. Top reservoir depth (ft): 6,200-6,434
3. Average thickness (ft): 18.9
4. Net to Gross Sand (%): 0-100%(Average 40%)
5. Porosity (%): 15-34% (Average 21%)
6. Permeability (md): 24-1000
7. Average reservoir pressure (psia): 2,689-2,790

8. Reservoir temperature (Deg F): 233-241

9. Reservoir fluid SG (air = 1): 0.97

10. OGIP (Bscf): 49.7

The reservoir model was built based on the geological data. Summarized data for reservoir model including phase equilibrium data, reservoir and fluid properties are described below. PVT properties and rock properties are tabulated in Table 4.3.

Table 4.3 : PVT properties of reservoir fluid and rock properties

Water Properties	Reference pressure(P_{ref})	2,689-2,790	psia
	Water FVF at P_{ref}	1.0897	Rb/stb
	Water viscosity at P_{ref}	0.1601	cp
Fluid Densities at Surface Condition	Water density	62.43	lb/ft^3
	Gas density	0.068	lb/ft^3
	Reference Pressure	2,689-2,790	psia
Rock Properties	Rock Compressibility	5.4092E-6	1/psi

SCAL (Special Core Analysis)

Initial Reservoir Properties

Initial Water Saturation (S_{wi}) : 0.38

Initial Gas Saturation (S_{gi}) : 0.62

The gas saturation and relative permeability relation is tabulated in Table 4.4 and shown in Figure 4.2.

Table 4.4 : Water saturation, gas saturation and water relative permeabilities

S_w	k_{rg}	k_{rw}
0.3800	1.0000	0.00000
0.4233	0.5549	0.0040
0.4667	0.2846	0.0183
0.5100	0.1317	0.0446
0.5533	0.0529	0.0840
0.5967	0.0173	0.1372
0.6400	0.0041	0.2049
0.6833	0.0005	0.2876
0.7267	0.0000	0.3859
0.7700	0.0000	0.5000
1.0000	0.0000	1.0000

4.2 Well Model

The well model for this study is single well model created using GAP and PROSPER (softwares by Petroleum Experts). The model is built based on monobore well design which is widely applied in the GoT. The wellbore diameter of 6 1/8 inches with 3 ½ inches production casing (ID 2.992 inches). The well is perforated from 6,209 ft to 6,569 ft depending on the reservoir depth in each case. The completion schematic, the properties of well and reservoir model and the vertical flow performance are shown in Figure 4.3 and Table 4.5 and Table 4.6.

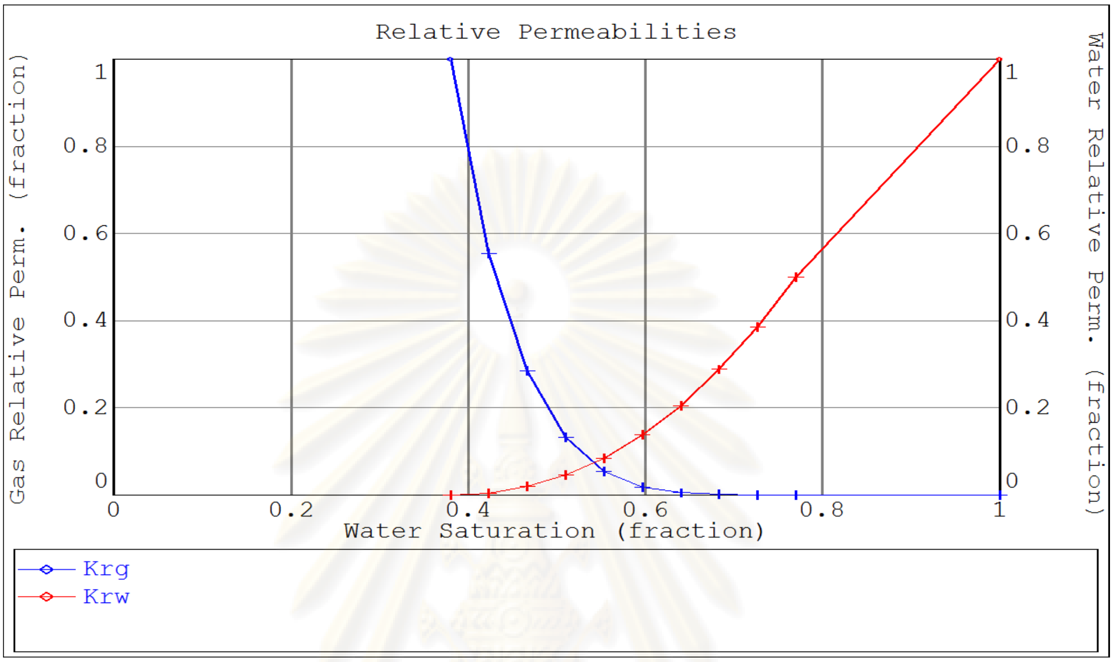

Figure 4.2 : Channel sand reservoirs relative permeability curve

Table 4.5 Vertical flow performance (VFP)

Fluid type	Dry Gas
Inflow model	Jones
VLP model	Petroleum Experts (PE)
Wellhead pressure (psig)	450-2,400
WGR (bbl/MMscf)	0-300

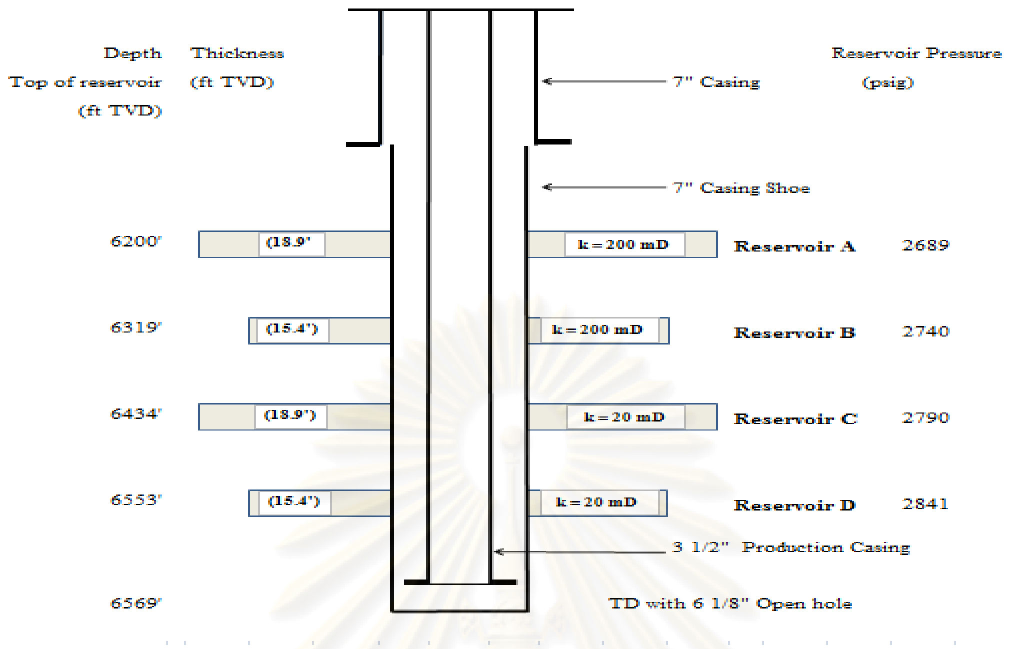

Figure 4.3 : The completion schematic of well model

Table 4.6 : The properties of reservoir model

Reservoir	Top of Reservoir depth(ft)	Original Gas in Place (MMscf)	Thickness (ft)	Permeability (md)	Pressure (psig)
A	6,200	49,999	18.9	200	2,689
B	6,319	8,575	15.4	200	2,740
C	6,434	49,999	18.9	20	2,790
D	6,553	8,575	15.4	20	2,841

4.3 Reservoir Model Arrangement

The reservoir model is created by two main characteristics of the reservoirs that may effect on perforation strategy determination:

1. The size of the reservoirs. In the GoT reservoirs there are two types of sand reservoirs, one is big, continuous and thick as mostly encountered in channel sand type reservoirs. Other is small, thin reservoirs normally called bar sand type reservoirs.

2. The permeability of the reservoirs. For permeability, 20 md is chosen for low permeability reservoirs while 200 md for high permeability reservoirs.

Therefore, putting these two characteristics together would result in four layered reservoirs. The reservoir model is used as representative model in this study. The channel sand reservoirs represent the thick, continuous reservoirs, and the bar sand reservoirs represents the small, thin reservoirs. The reservoir model arrangement is shown in Table 4.7. The top depth of the reservoirs is 6,200 feet and each reservoir is 100 feet apart, with shale in between them. The initial reservoir pressure is assumed to be hydrostatic.

Therefore, putting these two characteristics together would result in four layered reservoirs. The reservoir model is used as representative model in this study. The channel sand reservoirs represent the thick, continuous reservoirs, and the bar sand reservoirs represents the small, thin reservoirs. For permeability, 20 md is chosen for low permeability reservoirs while 200 md for high permeability reservoirs. The reservoir model arrangement is shown in Table 4.7. The top depth of the reservoirs is 6,200 feet and each layer is 100 feet apart, with shale in between them. The initial reservoir pressure is assumed to be hydrostatic.

Table 4.7 : Reservoir model arrangement

Reservoir	**Size**	**Permeability**
A	Thick	200 md
B	Thin	200 md
C	Thick	20 md
D	Thin	20 md

4.4 Reservoir Drive Mechanism Arrangement

1. **Case 1**: All reservoirs are under volumetric-depletion drive gas reservoirs. In this case, the reservoirs are depleted based on the expansion of gas in the reservoirs only. As a result, the reservoir pressure will play an important role on production strategy. The case is initiated to study the behavior of pressure and their influence on production.

2. **Case 2**: All reservoirs are under water-drive gas reservoirs. In this case, each reservoir is set to be connected with an aquifer. As the gas is produced from the well, the reservoir pressure declines and causes the supporting aquifer to expand and invade into the gas zone. As a result, there will be an influence from both pressure and water invasion that plays an important role on perforation strategy determination.

3. **Case 3**: Two thick reservoirs are water-drive and two thin reservoirs are volumetric-depletion drive reservoirs. This combination drive represents more realistic multilayered gas reservoirs in the GoT.

4.5 Perforation Scenarios

The production scenario under this study can be categorized into 4 groups. The first group (scenario 1a-1c) is the set of scenario using a bottom-up approach. The bottom-up approach is one of the widely used strategies in gas fields in GoT. This strategy allows the gas to be produced from the deepest reservoir first and subsequent upper reservoirs in sequence.

The second group concerns with permeability of the reservoirs. There are two scenario under this group: scenario 2a where high permeability reservoirs are perforated first and scenario 2b where low permeability reservoirs are produced first.

The third group concerns with the size of the reservoirs. Therefore, in order to study the multilayered reservoirs, two scenarios are added to this study: scenario 3a where the thick reservoirs are produced first and scenario 3b where the thin reservoirs are perforated first.

The fourth group concerns with commingled production. In Scenario 4a, all reservoirs are put into production altogether since the first day of production. In scenario 4b, all reservoirs are produced together but when any reservoir produces water more than 1000 bbl/MMscf, we shut off this reservoir and leave the other reservoirs producing.

The production plateau for all scenarios is set at 20 MMscf/d and the economic limit of all scenarios is set at 0.1 MMscf/d. The minimum wellhead pressure is set at 450 psig. The perforation scenarios for each group is listed in Table 4.8.

Table 4.8 : Perforation scenarios

Scenario	Description	Explanation
1a	Fully depleted	The deepest reservoir is produced first until the economic limit (0.1 MMscf/d) and shut off, and then the next upper reservoirs are opened in sequence.
1b	Half depleted	The deepest reservoir is produced first until the rate drops below 10 MMscf/d, and then the next upper reservoirs are opened in sequence.
1c	Maintain production plateau	The deepest reservoir is produced first until the rate drops below the plateau (20 MMscf/d), and then the next upper reservoirs are opened in sequence.
2a	High permeability reservoirs first	High permeability reservoirs (A&B) are produced first until the rate drops below the plateau rate (20 MMscf/d) and then the next low permeability reservoirs (C&D) are opened.
2b	Low permeability reservoirs first	Low permeability reservoirs (C&D) are produced first until the rate drops below the plateau rate (20 MMscf/d) and then the next high permeability reservoirs (A&B) are opened.
3a	Thick reservoirs first	Thick reservoirs (A&C) are produced first until the rate drops below the plateau rate (20 MMscf/d) and then the next thin Reservoirs (B&D) are opened
3b	Thin reservoirs first	Thin Reservoirs (B&D) are produced first until the rate drops below the plateau rate (20 MMscf/d) and then the next thick reservoirs A&C) are opened.
4a	Commingled	All reservoirs (A,B,C,D) are produced together since the first day of production.
4b	Commingled with water shut off	All reservoirs (A,B,C,D) are produced together but when any reservoir produces water more than 1000 bbl/MMscf, shut off this reservoir and leave the other reservoirs producing.

CHAPTER V

RESULTS AND ANALYSIS

This chapter presents the prediction results and analysis for 3 cases in this study as follows:

5.1 Recovery Factor for Volumetric-Depletion Drive Gas Reservoirs

Table 5.1 : Recovery factor for volumetric-depletion drive gas reservoirs

Scenario	Description	RF (%)
Scenario 1: Bottom-up		
1a	Fully depleted	81.60
1b	Half depleted	81.55
1c	Maintain production plateau	79.92
Scenario 2: Permeability selective		
2a	High permeability reservoirs first	81.29
2b	Low permeability reservoirs first	81.51

Table 5.1 : Recovery factor for volumetric-depletion drive gas reservoirs (continued)

Scenario 3: Reservoir size selective		
3a	Thick reservoirs first	81.52
3b	Thin reservoirs first	81.56
Scenario 4 : Commingled		
4a	All reservoirs are produced together since the first day of production	81.61

Based on the prediction results, the results can be summarized in details as follows:

Scenario 1a: Bottom-up (Fully Depleted)

The RF for this scenario is approximately the same as that of scenario 4 as listed in Table 5.1. This scenario, the bottom most reservoir is produced until fully depleted and then the next upper layer is opened in sequence. The gas production rate is shown in Figure 5.1. The cumulative gas production for this scenario is 95.6 MMMscf as depicted in Figure 5.2.

First, the deepest reservoir (Reservoir D) is perforated. Although the maximum production rate is specified at 20 MMscf/d, the well can produce only 11 MMscf/d at the beginning and starts to decline right away as depicted in Figure 5.3. The production time is short due to small reservoir size and low permeability. The production from the first perforated zone continues until it reaches economic rate of 0.1 MMscf/d. Then, the zone is shut off, and the upper zone (Reservoir C) is opened. The cumulative gas production from Reservoir D is 7.0 MMMscf as shown in Figure 5.4.

Reservoir C can produce at a maximum rate of 12.0 MMscf/d and drops gradually until the economic rate of 0.1 MMscf/d. It can produce for a long time due to thick reservoir size and low permeability. The low value of permeability results in low production rate. As a result, it takes a long time to produce from a large reservoir at a small production rate. The cumulative gas production for this reservoir is 41.1 MMMscf as depicted in Figure 5.4.

After Reservoir C is fully depleted, it is shut off, and the next upper zone (Reservoir B) is perforated as illustrated in Figure 5.3. Reservoir B can produce at a gas rate of 20 MMscf/d and maintain production plateau of 20 MMscf/d for a while. Afterward, the gas production rate declines very fast due to small reservoir size and high permeability of the reservoir. The production time of this reservoir is very short compared to other reservoirs and cannot maintain pressure declining rate. The cumulative production for this reservoir is 7.0 MMMscf as shown in Figure 5.4.

The last reservoir (Reservoir A) is perforated after shutting in Reservoir B. The production rate of 20 MMscf/d can be maintained for a few years. This reservoir can maintain pressure for a short period due to big reservoir size and high permeability. The production time is longer than that for Reservoirs B and D. The cumulative gas production for this reservoir is 41.1 MMMscf as illustrated in Figure 5.4.

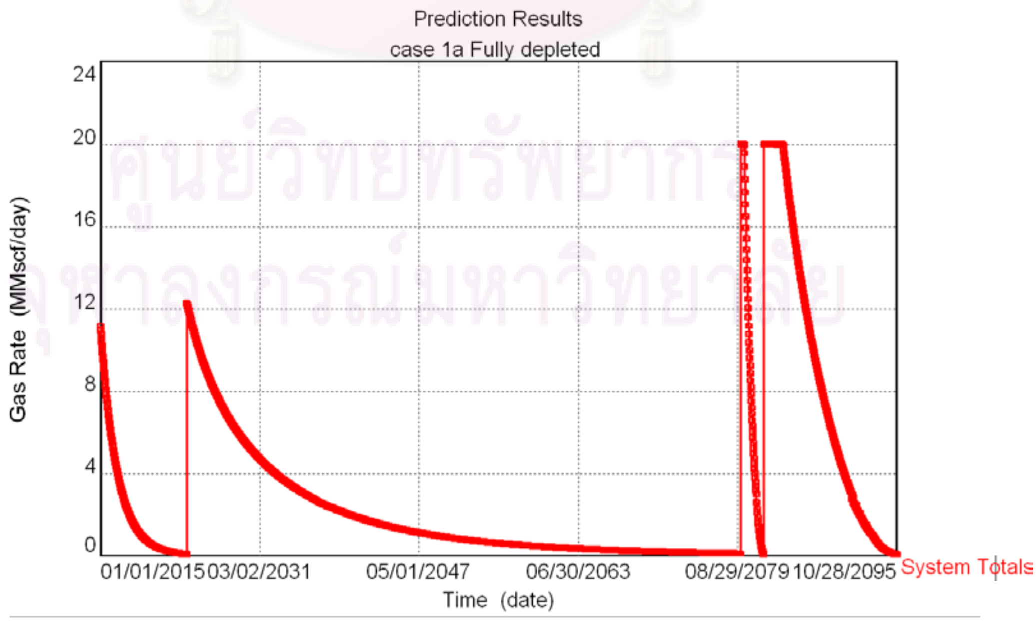

Figure 5.1 : Prediction result for case 1: scenario 1a

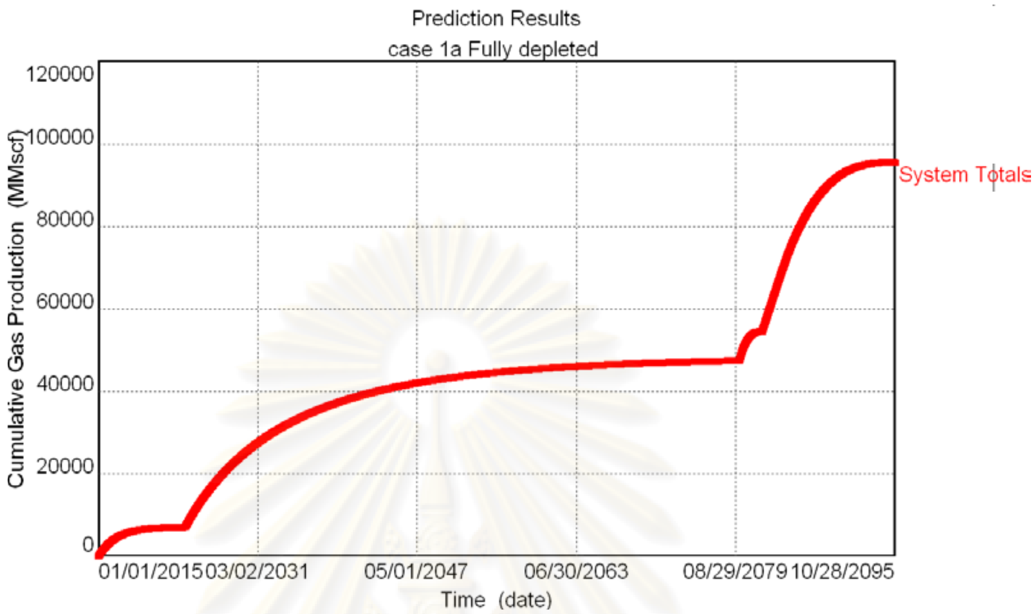

Figure 5.2 : Cumulative gas production versus time (case 1: scenario 1a)

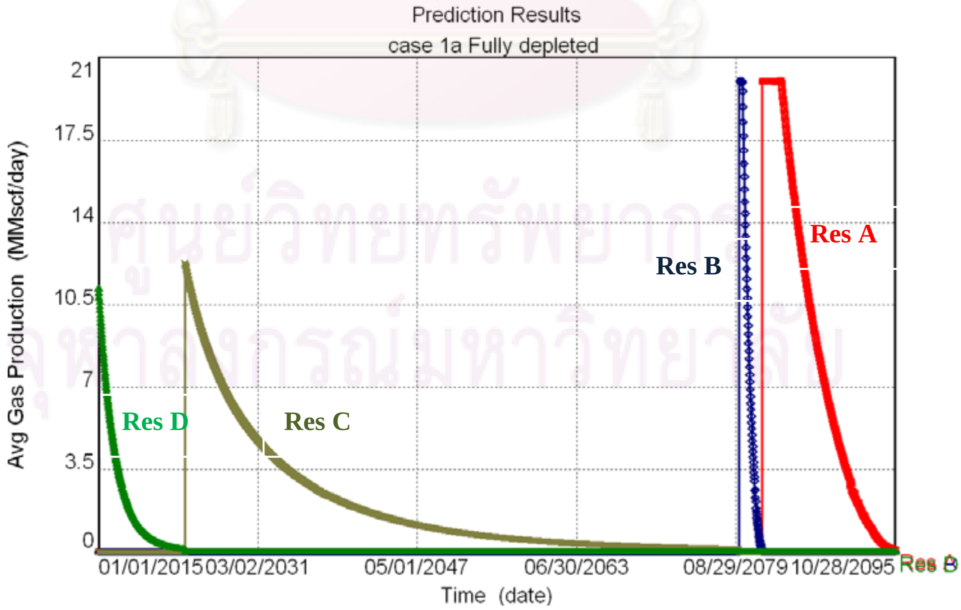

Figure 5.3 : Average gas production versus time for Reservoirs A,B,C,D (case 1: scenario 1a)

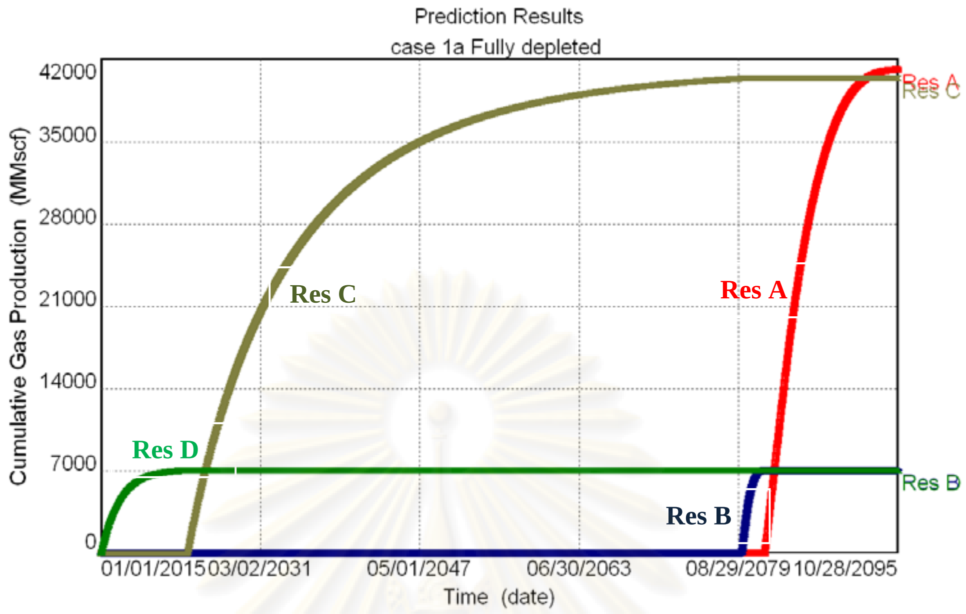

Figure 5.4 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 1: scenario 1a)

Scenario 1b: Bottom-up (Half Depleted)

Scenario 1b (half-depleted) provides a little bit lower RF than that of Scenario 1a as listed in Table 5.1. In this scenario, the bottom most reservoir is produced until the rate declines to half of the plateau rate (20MMscf/d) which equals to 10 MMscf/d, then the next upper layer is opened. The gas production rate is illustrated in Figure 5.5. The cumulative gas production for this scenario is 95.6 MMMscf as shown in Figure 5.6.

First, Reservoir D is put on production. The well can initially produces 11 MMscf/d. It takes less than a day for the rate to decline to 10 MMscf/d. Then, the next upper layer (Reservoir C) is opened. Up to this point, the cumulative production for reservoir D is 5 MMMscf as shown in Figure 5.8. However, the cumulative production at the end of the well life is 7 MMMscf because the layer still flows at around 0.2 MMscf/d until abandonment.

Reservoir C can produce before the rate drops to 10 MMscf/d for a short period of time. Then, the rate declines below 10 MMscf/d and the next upper reservoir

(Reservoir B) is opened. Up until this point, Reservoir C has produced 13.3 MMMscf. However, the cumulative gas production for Reservoir C is 40 MMMscf since it still produces a certain amount of gas until abandonment.

Reservoir B is perforated after the rate declined below 10 MMscf/d. At this point, three reservoirs Reservoirs D, C and B are producing together. These reservoirs can provide gas production of 20 MMscf/d for a short period. At the end of the well life, the cumulative gas production from Reservoir B is 7.1 MMMscf.

As the production from the three reservoirs drops below 10 MMscf/d, Reservoir A is put into production. The production rate reaches production plateau after this reservoir is perforated. At this point, four reservoirs are producing leading to a long period of gas production during the decline period. The cumulative gas production for this reservoir is 41 MMMscf as shown in Figure 5.8.

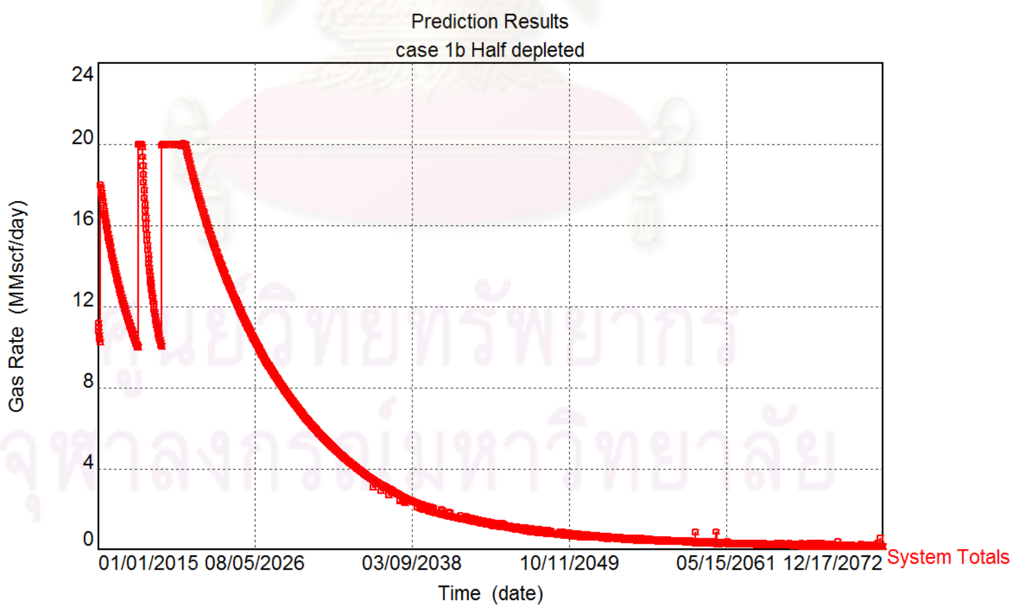

Figure 5.5 : Prediction result for case 1: scenario 1b

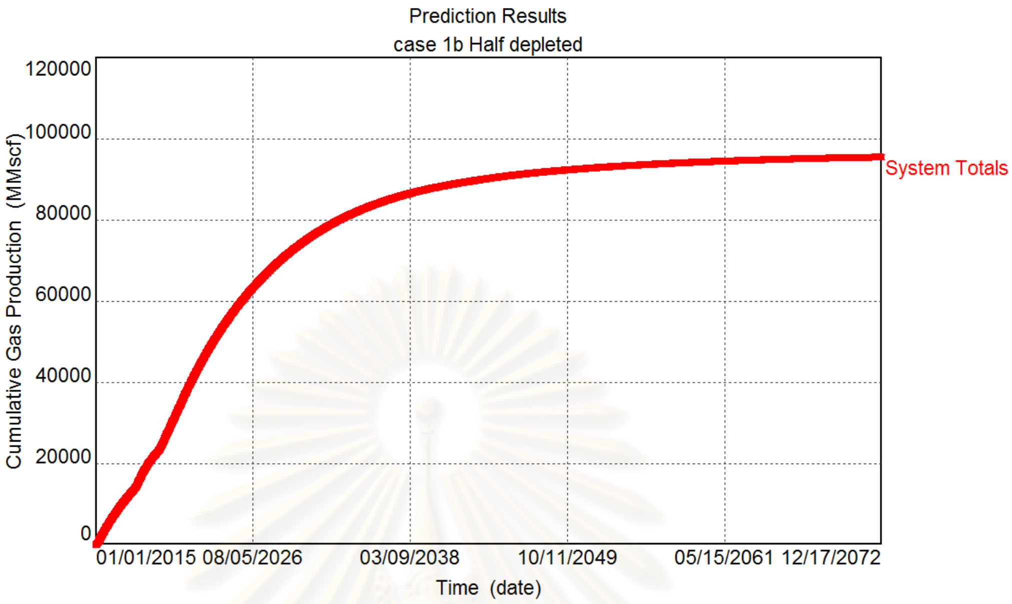

Figure 5.6 : Cumulative gas production versus time (case 1: scenario 1b)

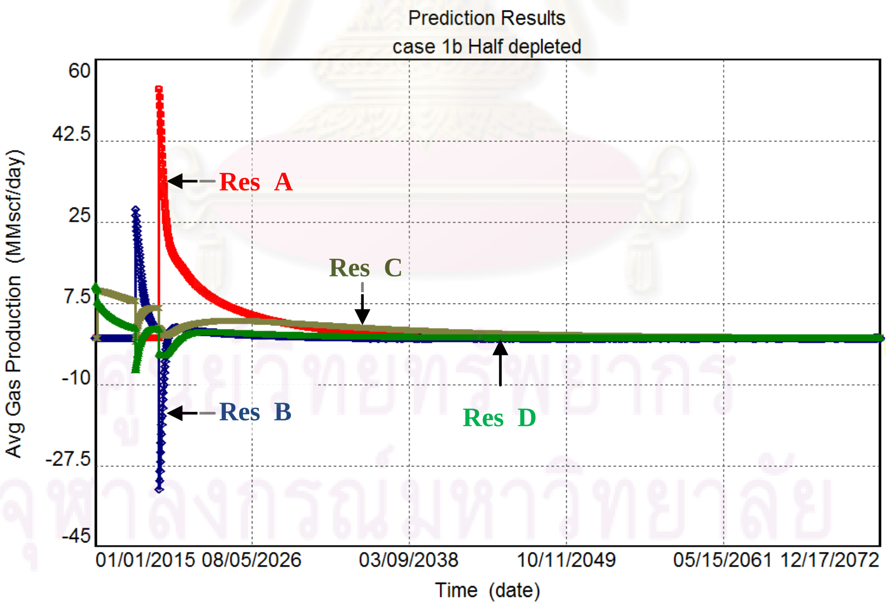

Figure 5.7 : Average gas production versus time for Reservoirs A,B,C,D

(case 1: scenario 1b)

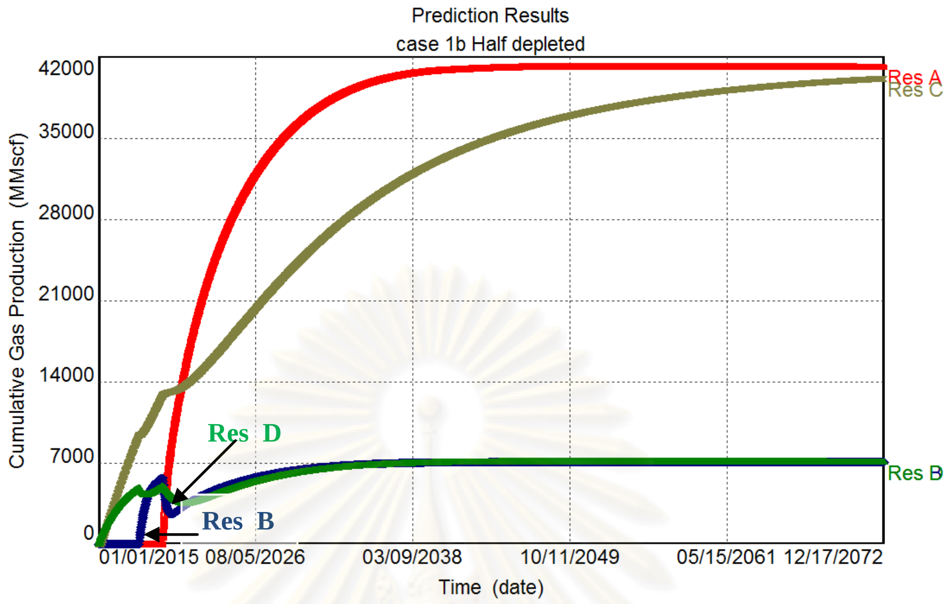

Figure 5.8 : Cumulative gas production versus time for Reservoirs A,B.C,D (case 1: scenario 1b)

Scenario 1c: Bottom-up (Maintain Production Plateau)

Scenario 1c (maintain production plateau) provides lower RF than that of Scenario 1a as listed in Table 5.1. In this scenario, the bottom most reservoir is produced until the rate drops below 20 MMscf/d, then the next upper reservoir is opened. The gas production rate for this scenario is shown in Figure 5.9. The cumulative gas production for this scenario is 93.6 MMMscf as depicted in Figure 5.10.

First, the deepest Reservoir D is perforated. This reservoir cannot produce 20 MMscf/d. Therefore, the next upper Reservoir C is opened to provide the plateau rate. The cumulative gas production for Reservoir D is 4.8 MMMscf as shown in Figure 5.12.

After Reservoir C is opened, both Reservoirs C and D can provide the plateau rate for a short period. The cumulative gas production for Reservoir C is 40.7 MMMscf as shown in Figure 5.12.

Although Reservoirs C and D are producing, Reservoir B is needed to perforate to maintain the plateau rate. The cumulative production for Reservoir B is 7.0 MMMscf as shown in Figure 5.12.

Even though Reservoirs B,C,D are producing, the gas rate cannot be maintained at the plateau rate for a long time. Therefore, Reservoir A is put into production. Up from this point, all reservoirs are producing together until the abandonment. The cumulative gas production for Reservoir A is 41 MMMscf as shown in Figure 5.12.

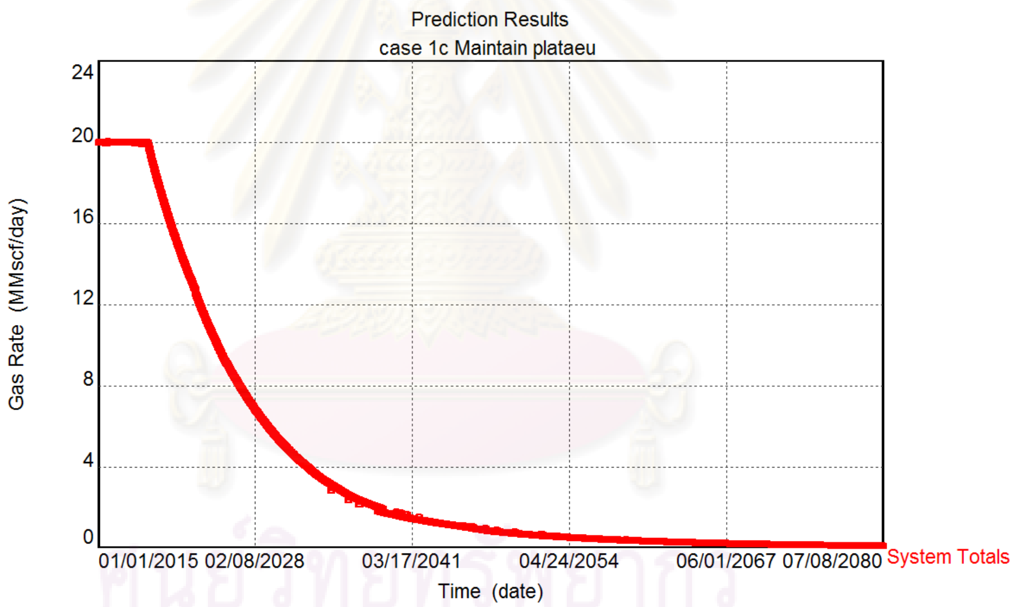

Figure 5.9 : Prediction result for case 1: scenario 1c

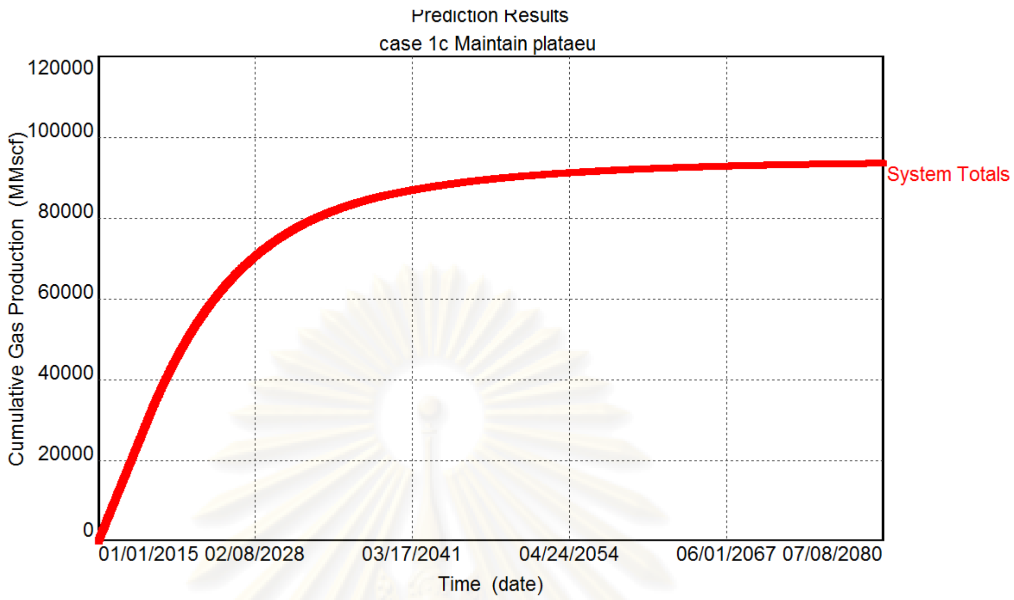

Figure 5.10 : Cumulative gas production versus time (case 1: scenario 1c)

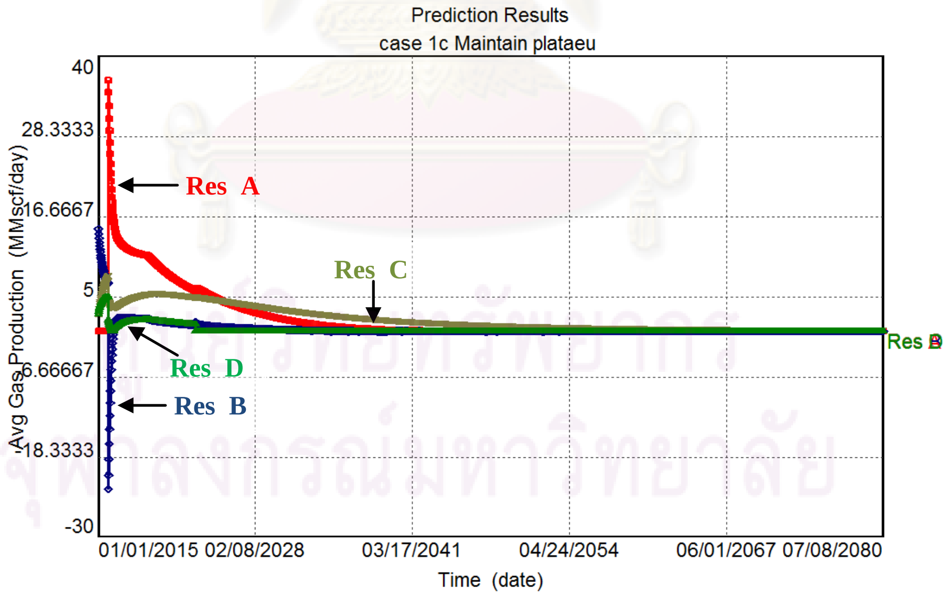

Figure 5.11 : Average gas production versus time for Reservoirs A,B,C, D
(case 1: scenario 1c)

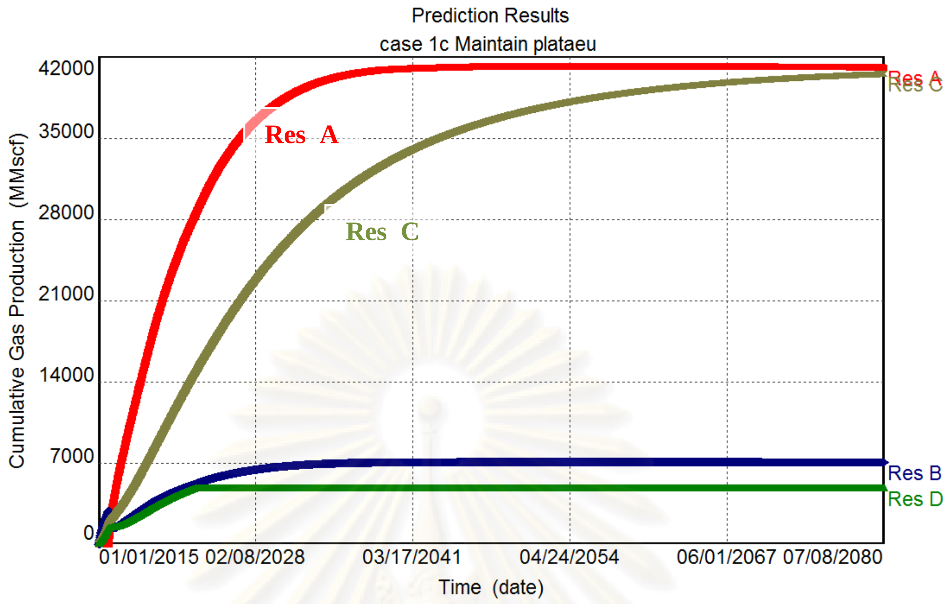

Figure 5.12 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 1: scenario 1c)

Scenario 2a: Permeability Selective (High Permeability Reservoirs First)

The RF for Scenario 2a is slightly lower than that of Scenario 1a as listed in Table 5.1. In this scenario, the high permeability reservoirs (A&B) are produced first until the rate drops below 20 MMscf/d, then the next two low permeability reservoirs (C&D) are opened. The gas production rate for this scenario is shown in Figure 5.13. The cumulative gas production for this scenario is 95.6 MMMscf as illustrated in Figure 5.14.

Reservoir A is opened together with Reservoir B. These reservoirs can produce at a rate of 20 MMscf/d and maintain a plateau production for a few years. These reservoirs can produce at high gas rate due to big reservoir size and high permeability. The cumulative gas production for Reservoir A and Reservoir B is 41 and 7.2 MMMscf, respectively, as shown in Figure 5.16.

After the production rate drops below 20 MMscf/d, low permeability Reservoir C is opened together with Reservoir D. These reservoirs can produce for a long life due to big size and low permeability. The cumulative production for Reservoir C and D is 40 and 7 MMMscf, respectively, as shown in Figure 5.16.

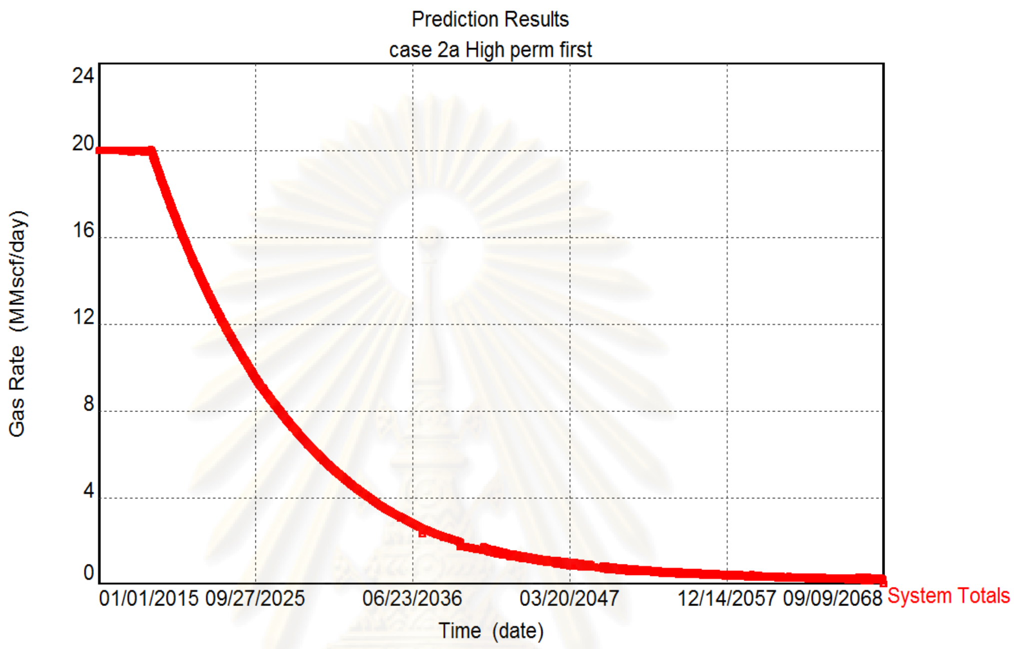

Figure 5.13 : Prediction result for case 1: scenario 2a

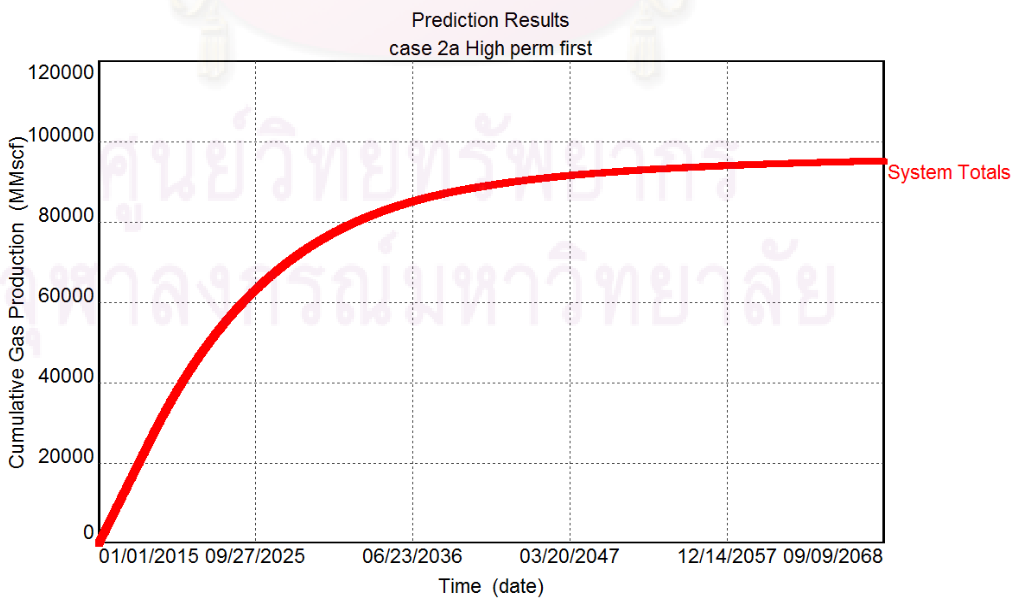

Figure 5.14 : Cumulative gas production versus time (case 1: scenario 2a)

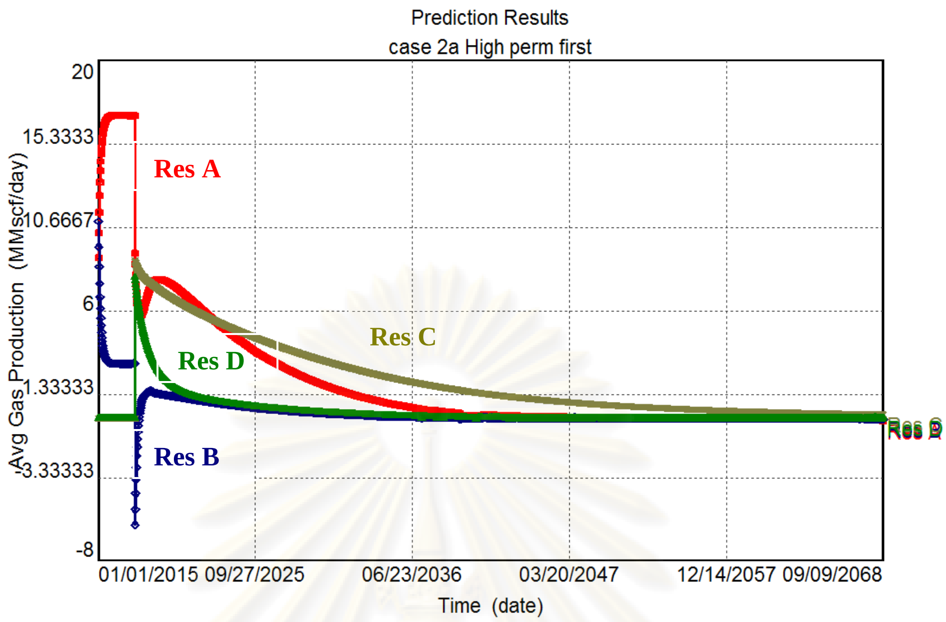

Figure 5.15 : Average gas production versus time for Reservoir A,B,C,D (scenario 2a)

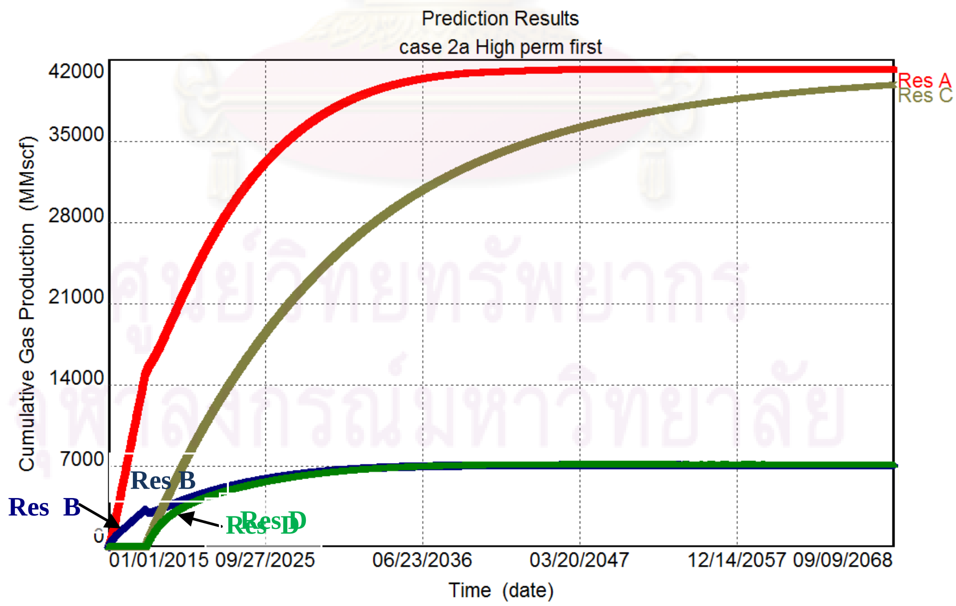

Figure 5.16 : Cumulative gas production versus time for Reservoirs A,B,C, D (case 1: scenario 2a)

Scenario 2b: Permeability Selective (Low Permeability Reservoirs First)

The RF for Scenario 2b is slightly lower than that of Scenario 1a as listed in Table 5.1. In this scenario, low permeability reservoirs (C&D)are produced first until the rate drops below 20 MMscf/d, then the next two high permeability reservoirs (A&B) are opened. The gas production rate for this scenario is shown in Figure 5.17. The cumulative gas production for this scenario is 95.4 MMMscf as shown in Figure 5.18.

First, Reservoir C is perforated together with Reservoir D. This batch cannot produce at a high rate of 20 MMscf/d due to low permeability. Although both reservoirs (C,D) are producing, the gas production rate cannot provide the plateau rate for a long time. Therefore, the next two high permeability reservoirs (A,B) are opened. At abandonment, the cumulative gas production for Reservoir C and D is 40 and 7 MMMscf, respectively, as depicted in Figure 5.20.

Reservoirs A and B can produce at high rate at the beginning but the rate drops very fast due to small reservoir size and high permeability. After this point, all reservoirs are producing together until abandonment. The cumulative gas production for Reservoir A and B is 41.2 and 7.1 MMMscf, respectively, as illustrated in Figure 5.20.

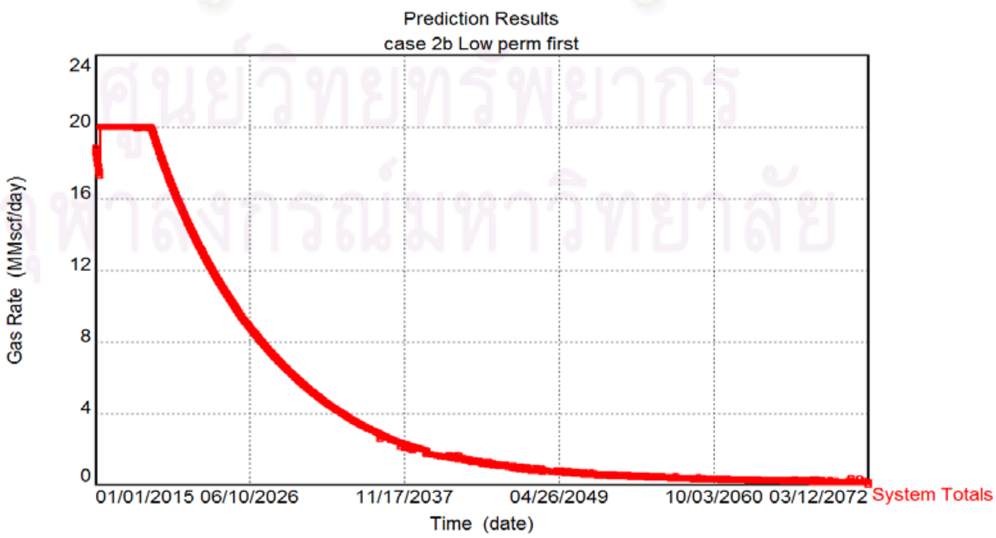

Figure 5.17 : Prediction result for case 1 : scenario 2b

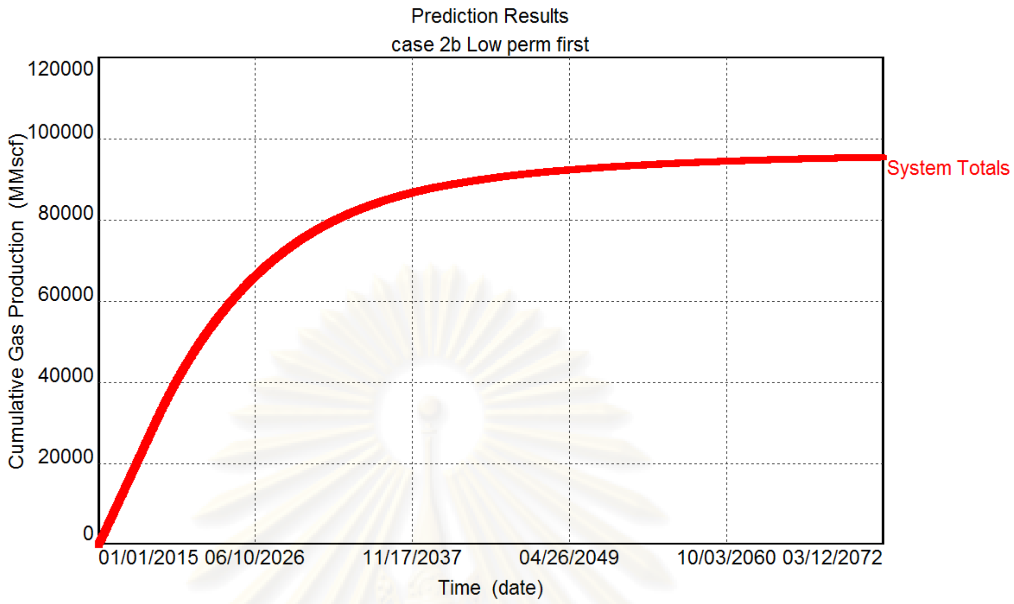

Figure 5.18 : Cumulative gas production versus time (case 1 : scenario 2b)

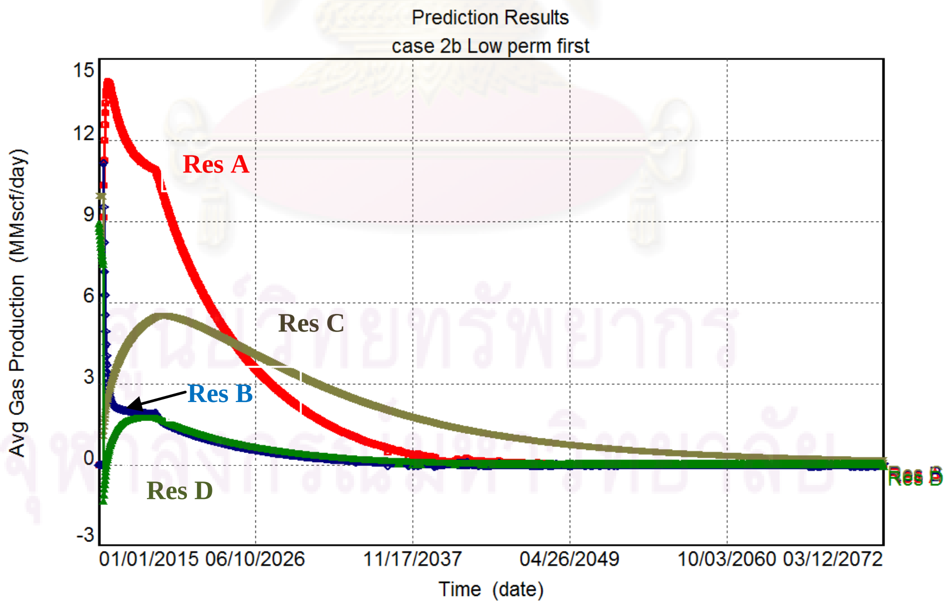

Figure 5.19 : Average gas production versus time for Reservoirs A,B,C,D
(case 1 : scenario 2b)

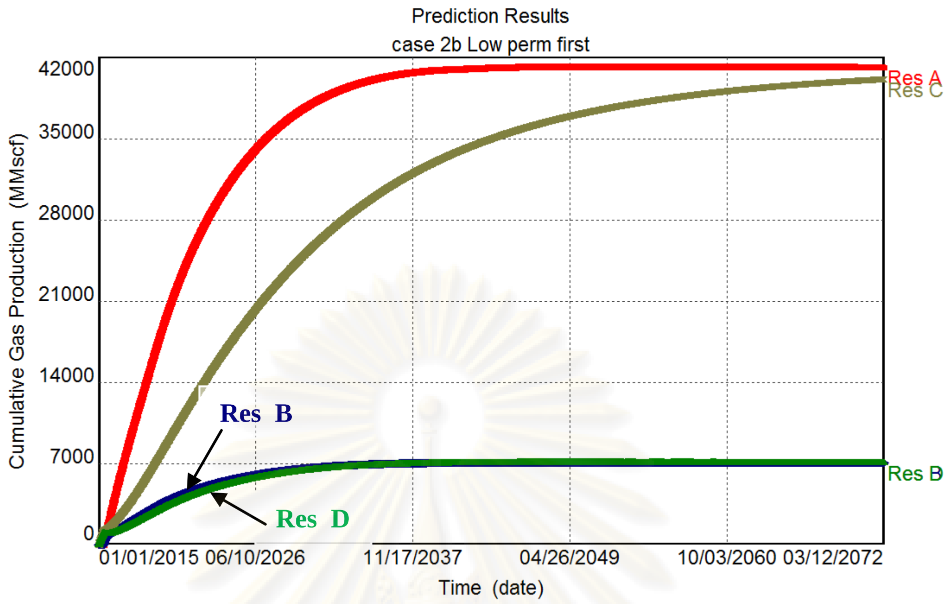

Figure 5.20 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 1 : scenario 2b)

Scenario 3a: Reservoir Size Selective (Thick Reservoirs First)

The RF for Scenario 3a is slightly lower than that of Scenario 1a as listed in Table 5.1. In this scenario, the thick and big reservoirs (A&C) are produced first until the rate drops below 20 MMscf/d, then the next two small and thin reservoirs (B&D) are opened. The gas production rate for this scenario is shown in Figure 5.21. The cumulative gas production for this scenario is 95.4 MMMscf as shown in Figure 5.22.

For thick reservoirs, Reservoir A is perforated with Reservoir C at the same time. This reservoir is produced at a high production rate. The cumulative production for Reservoir A is 41.2 MMMscf as depicted in Figure 5.24. Reservoir C can provide a plateau rate with Reservoir A. Afterward, the production rate declines below the plateau rate, then the next two thin reservoirs C, D are opened. The cumulative gas production for Reservoir C is 40 MMMscf as shown in Figure 5.24.

For thin reservoirs, Reservoir B is perforated with Reservoir D. Both reservoirs can be produced at a low production rate due to small reservoir size. The cumulative production for Reservoir B is 7.1 MMMscf as shown in Figure 5.24. The production life for Reservoir D is longer than that of Reservoir B. At this point, all reservoirs are producing together and provide the plateau rate for a few years until the well economic is reached. The cumulative production for Reservoir D is 7.1 MMMscf as depicted in Figure 5.24.

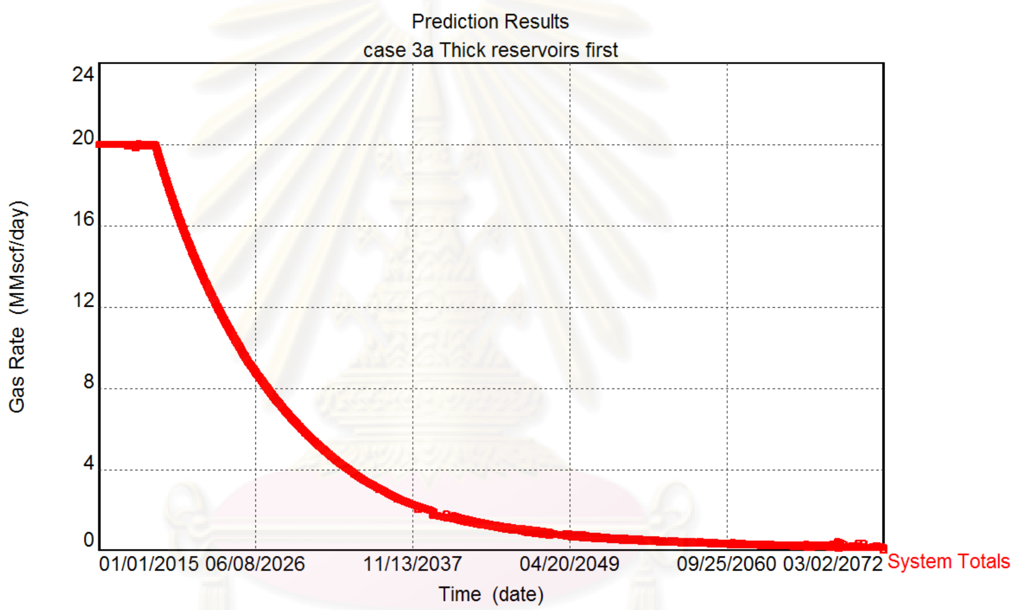

Figure 5.21 : Prediction result for case 1 : scenario 3a

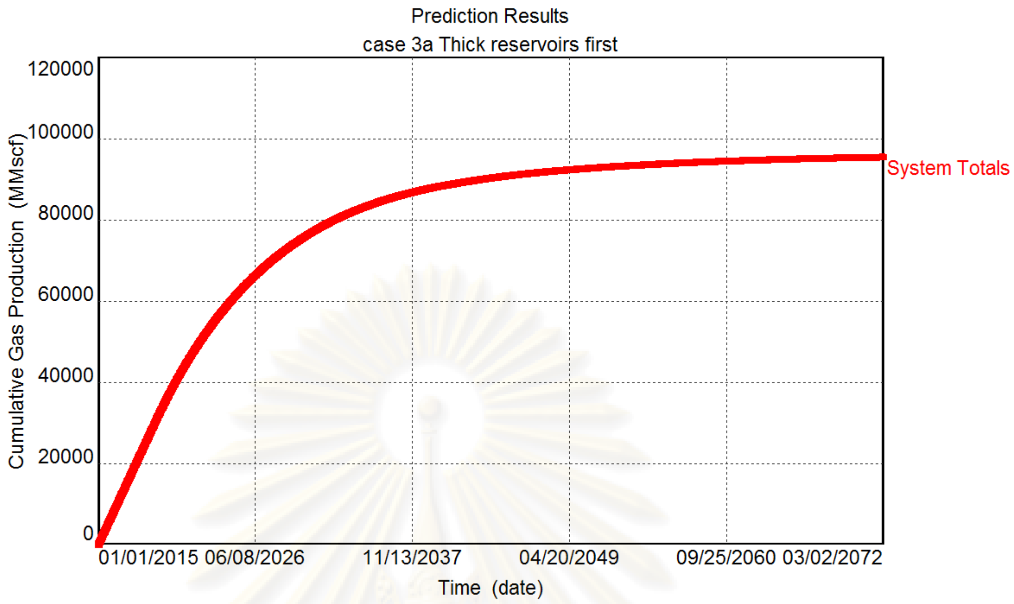

Figure 5.22 : Cumulative gas production versus time (case 1 : scenario 3a)

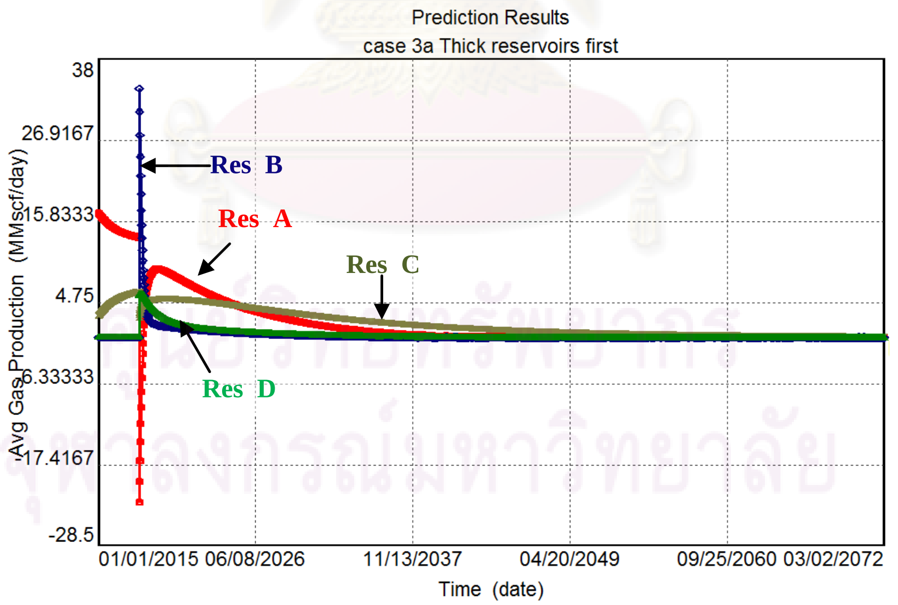

Figure 5.23 : Average gas production versus time for Reservoirs A,B,C,D
(case 1 : scenario 3a)

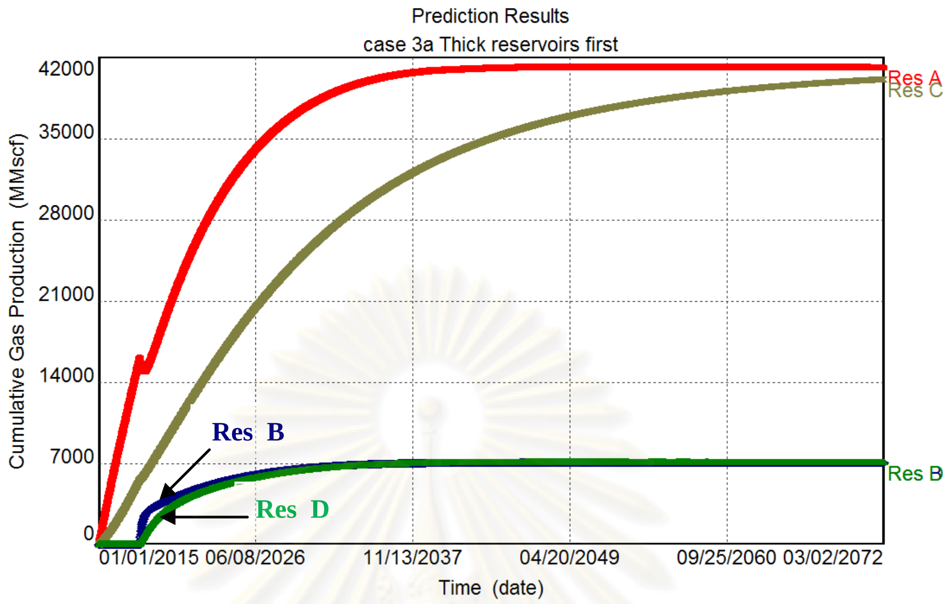

Figure 5.24 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 1 : scenario 3a)

Scenario 3b: Reservoir Size Selective (Thin Reservoirs First)

The RF for Scenario 3b is slightly lower than that of Scenario 1a as listed in Table 5.1. In this scenario scheme, two small and thin reservoirs (C,D) are produced first until the rate drops below 20 MMscf/d, then the next two big and thick reservoirs (A&C) are opened. The gas production rate for this scenario is shown in Figure 5.25. The cumulative gas production for this scenario is 95.7 MMMscf as illustrated in Figure 5.26.

For thin reservoirs, Reservoir B is perforated together with Reservoir D. Although these reservoirs are put into production, both can supply a plateau rate for a while due to small reservoir size. The rate drops very fast for Reservoir B. The cumulative production for Reservoir B and D is both 7 MMMscf as depicted in Figure 5.28.

Although thin reservoirs are produced first, both cannot supply the plateau rate for a long time. So, the next two big reservoirs have to be perforated. Reservoir A is perforated with Reservoir C at the same time to provide and maintain the plateau rate of 20 MMscf/d. At this point, all reservoirs (B,D,A,C) are put into production until the economic limit is reached. The cumulative gas production for Reservoir A and C is 41.2 and 40.2 MMMscf, respectively, as shown in Figure 5.28.

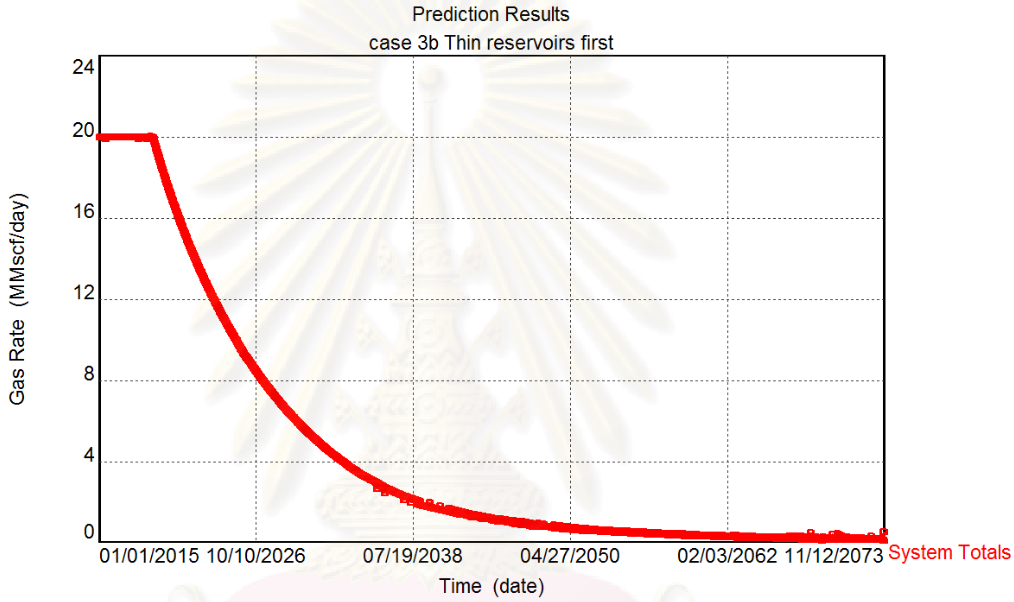

Figure 5.25 : Prediction result for case 1 : scenario 3b

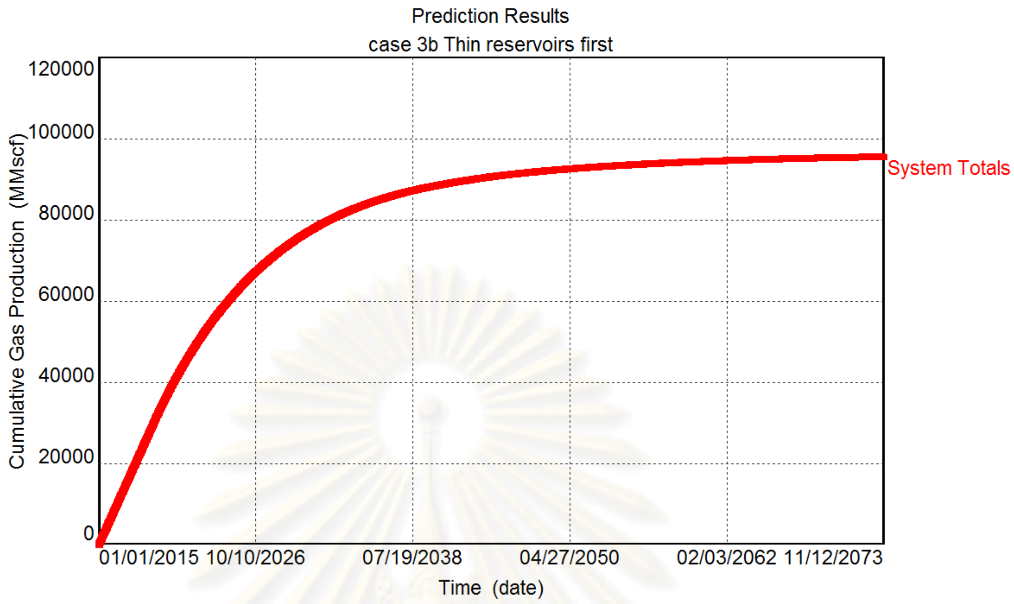

Figure 5.26 : Cumulative gas production versus time (case 1 : scenario 3b)

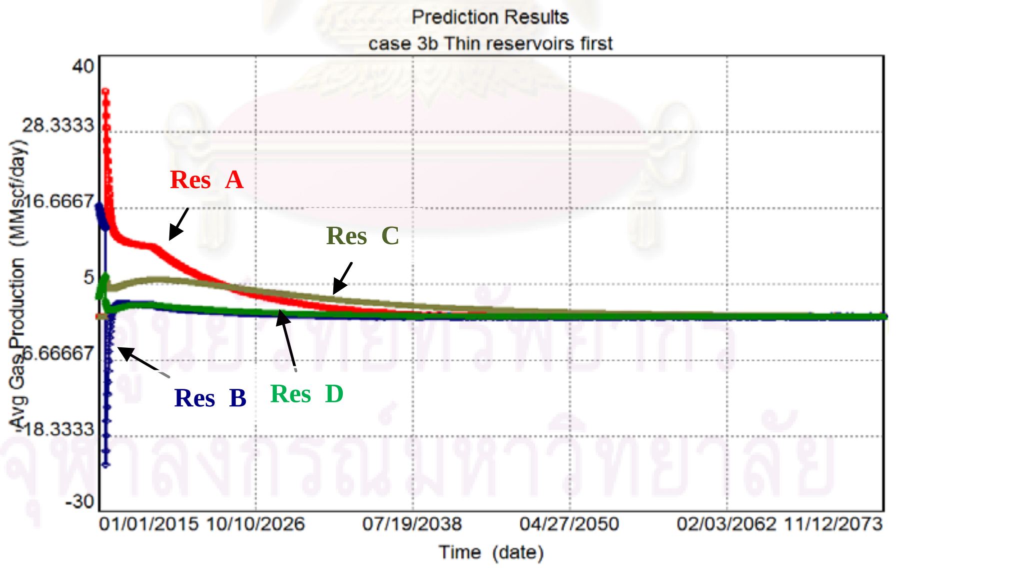

Figure 5.27 : Average gas production versus time for Reservoirs A,B,C,D

(case 1 : scenario 3b)

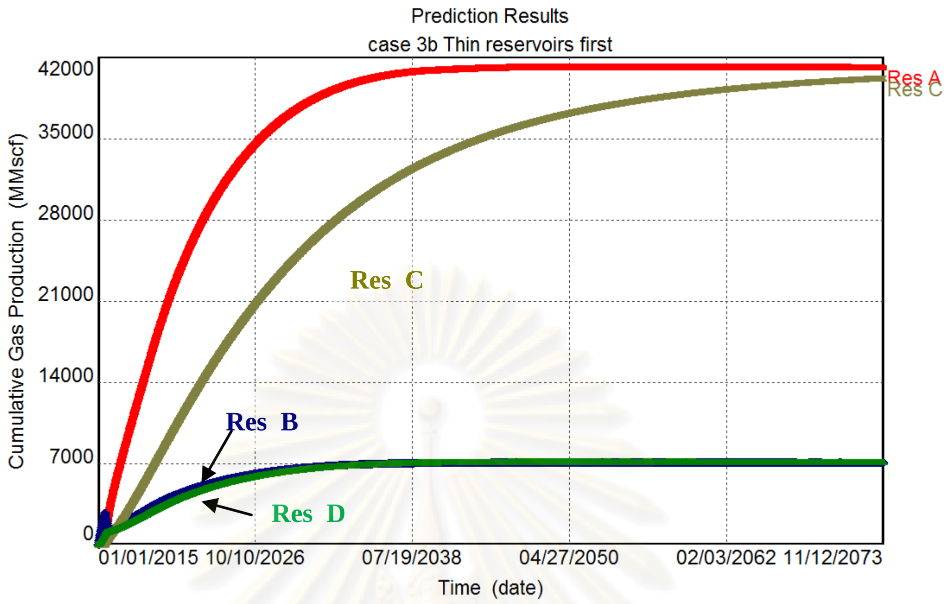

Figure 5.28 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 1 : scenario 3b)

Scenario 4a: Commingled

This scenario provides the highest RF for case 1 (volumetric-depletion drive gas reservoirs) as listed in Table 5.1. In this scenario, all reservoirs (A,B,C&D) are produced altogether at the same time since the start of production. The gas production rate is shown in Figure 5.29. The cumulative gas production for this scenario is 95.4 MMMscf as illustrated in Figure 5.30.

Reservoir A can provide the highest production rate compared with other reservoirs. Reservoir B can produce at a high rate but the production life is very short compared with other reservoirs. Reservoir C can produce at a high rate and take a long time to deplete. The pressure drops very slow due to high permeability. Reservoir D cannot produce at a high rate due to small reservoir size and low permeability. The production from all reservoirs (A,B,C,D) can provide a plateau rate for a few years and declines to the economic rate. The cumulative gas production for Reservoir A,B,C, and D is 41.3, 7, 40, and 7 MMMscf, respectively, as shown in Figure 5.32.

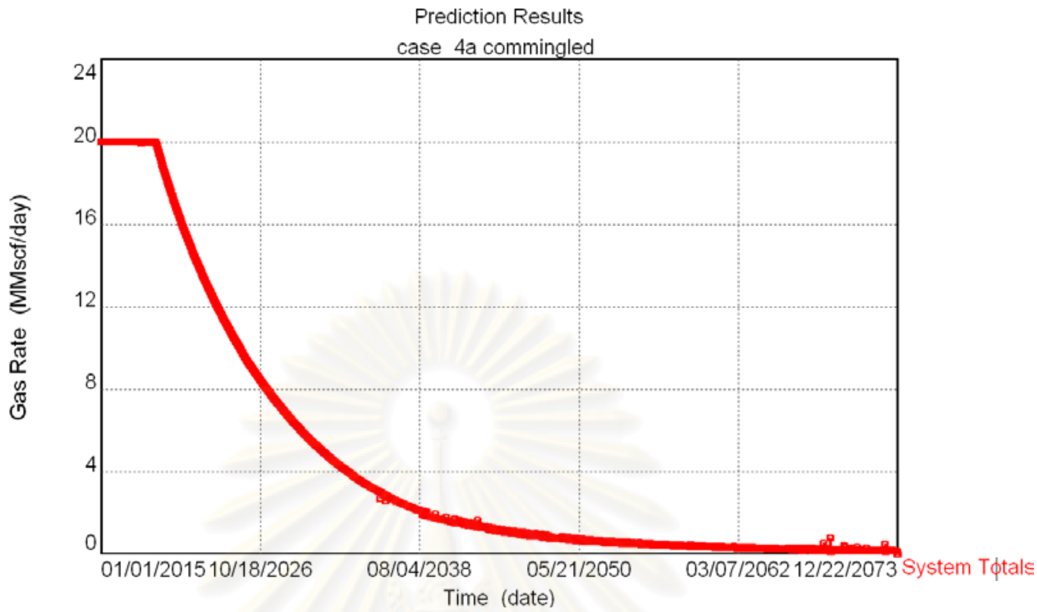

Figure 5.29 : Prediction result for case 1 : scenario 4a

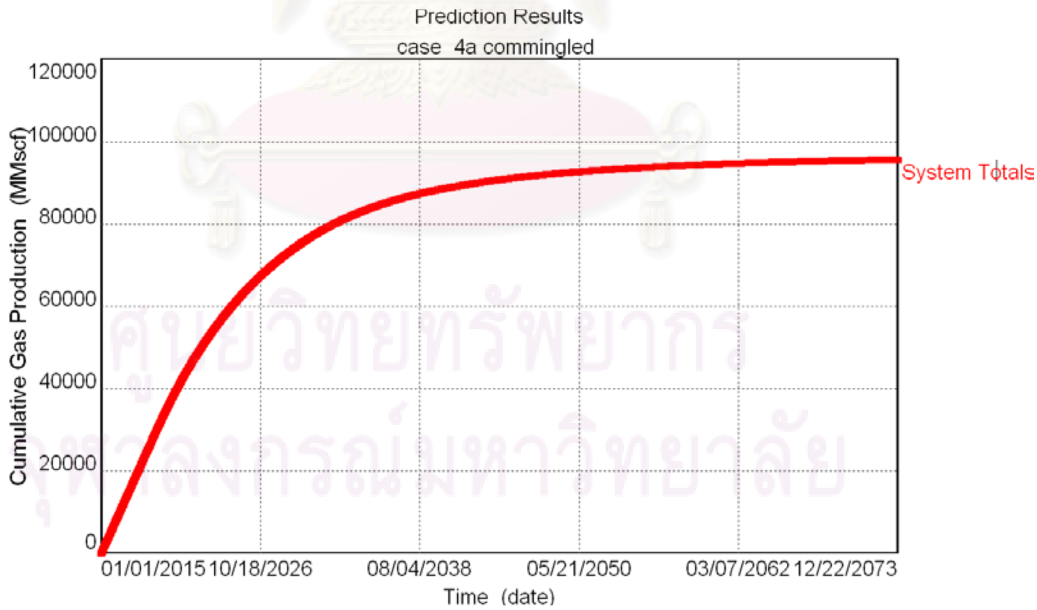

Figure 5.30 : Cumulative gas production versus time (case 1 : scenario 4a)

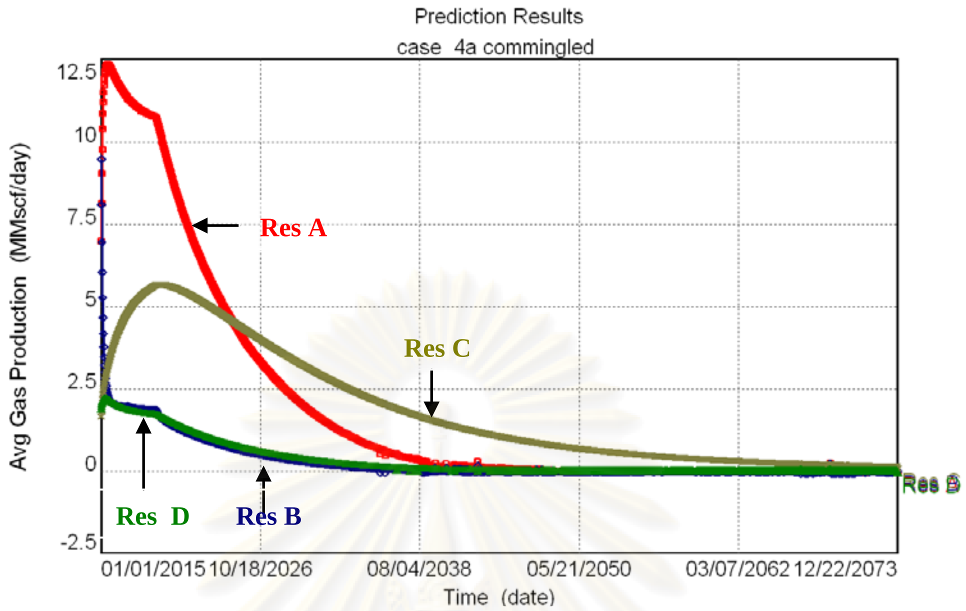

Figure 5.31 : Average gas production versus time for Reservoirs A,B,C,D (case 1 : scenario 4a)

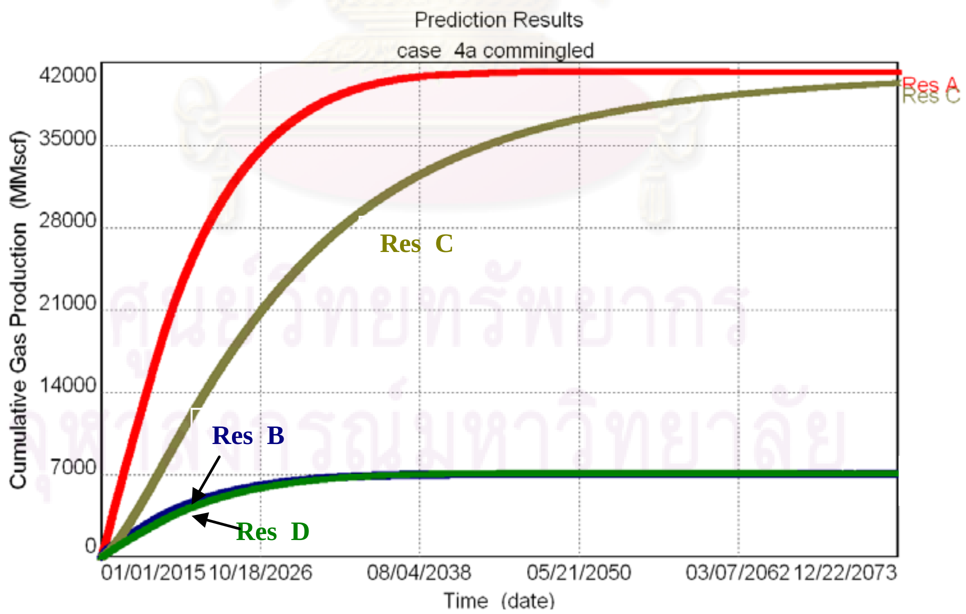

Figure 5.32 : Cumulative gas production versus time for Reservoirs A,B,C D (case 1 : scenario 4a)

5.2 Recovery Factor for Water Drive Gas Reservoirs

Table 5.2 : Recovery factor for water drive gas reservoirs

Scenario	Description	RF (%)
Scenario 1: Bottom-up		
1a	Fully depleted	62.90
1b	Half depleted	20.80
1c	Maintain plateau	32.95
Scenario 2: Permeability selective		
2a	High permeability first	28.69
2b	Low permeability first	29.02
Scenario 3: Reservoir size selective		
3a	Thick reservoirs first	27.83
3b	Thin reservoirs first	29.39
Scenario 4 : Commingled		
4a	All reservoirs are producing since start of production	28.94
4b	All reservoirs are producing since start of production with water shut off	45.10

Based on the prediction from IPM, the results can be summarized in details as follows:

Scenario 1a: Bottom-up (Fully Depleted)

This scenario provides the highest RF in water drive gas reservoirs as listed in Table 5.2. The RF and production time for water drive reservoirs are less than half compared with volumetric-depletion gas reservoirs. The invasion of the aquifer plays an important role and reduces the gas saturation in the reservoirs. The gas production rate for this scenario is depicted in Figure 5.33. The overall cumulative gas production for this scenario is 73.7 MMMscf as shown in Figure 5.34.

The deepest Reservoir D is perforated first. The well can produce 11 MMscf/d at the beginning and starts to decline right away. However, the well cannot produce until economic limit is reached due to high water production. The cumulative gas production for this reservoir is 5.7 MMMscf as depicted in Figure 5.36.

The next upper Reservoir C is opened after the reservoir D is shut in. The well can produce 12 MMscf/d at the beginning and the rate declines gradually and does not reach the economic limit. The production time is the longest compared with other reservoirs. The cumulative production for reservoir C is 40.0 MMMscf as illustrated in Figure 5.36.

Reservoir B is opened in sequence after Reservoir C is shut in. The well can produce for a short time from this reservoir and cannot produce until the economic limit is reached. The well can provide the plateau rate for a while. The cumulative gas production for this reservoir is 4.3 MMMscf as shown in Figure 5.36.

The upper most Reservoir A is then perforated after Reservoir B is shut in. The well can produce at a high rate until the economic limit is reached due to the large size of the reservoir and high permeability. The well can provide the plateau rate for few years. The cumulative production for this reservoir is 23.9 MMMscf as shown in Figure 5.36.

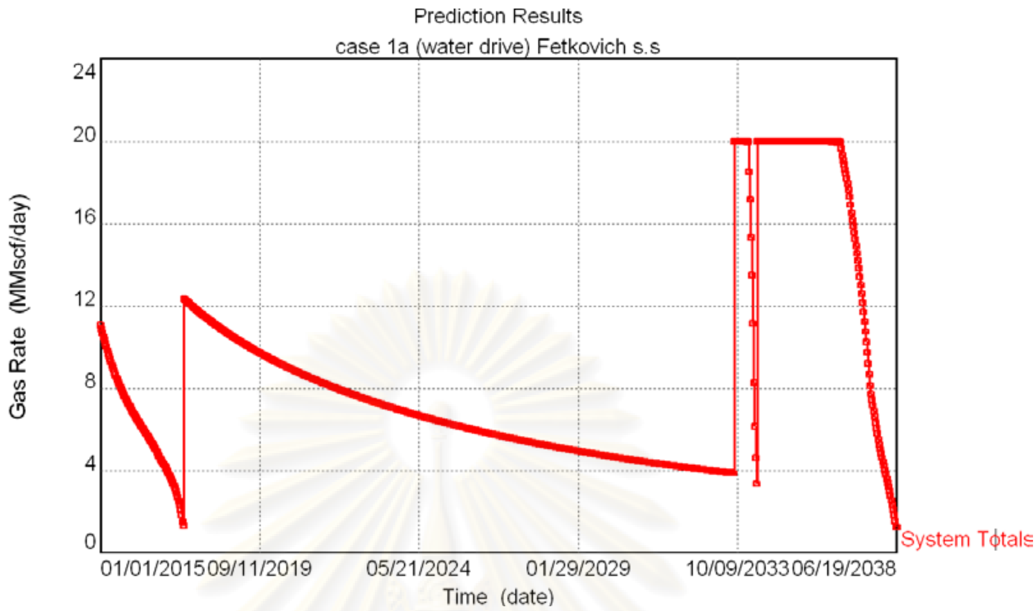

Figure 5.33 : Prediction result for case 2 : scenario 1a

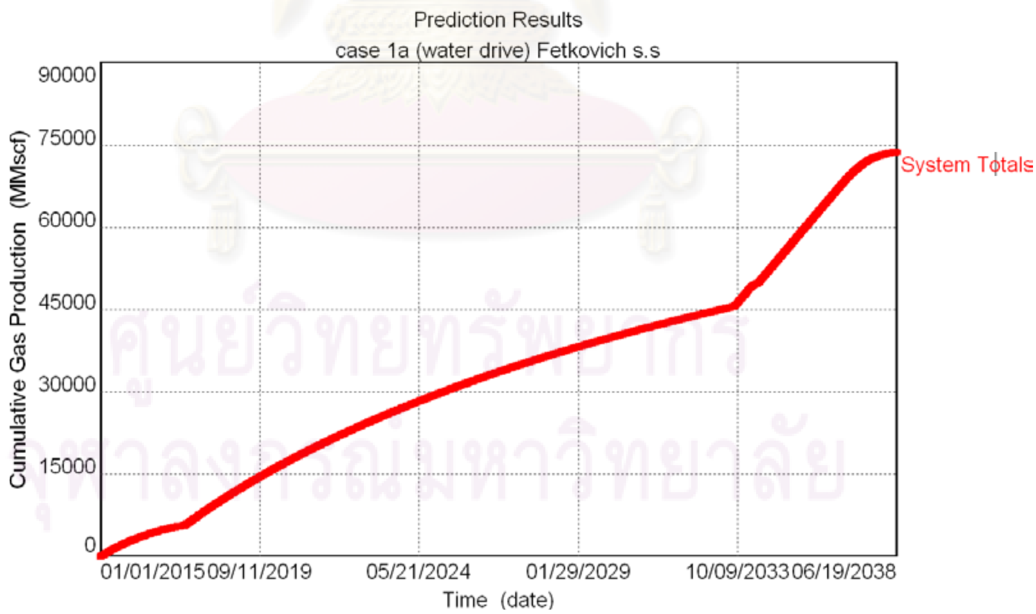

Figure 5.34 : Cumulative gas production versus time (case 2 : scenario 1a)

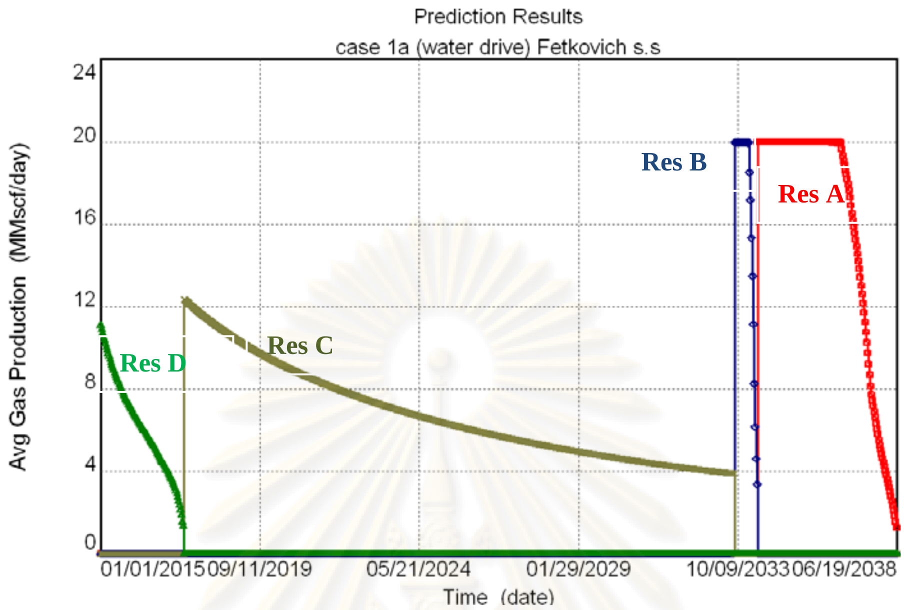

Figure 5.35 : Average gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 1a)

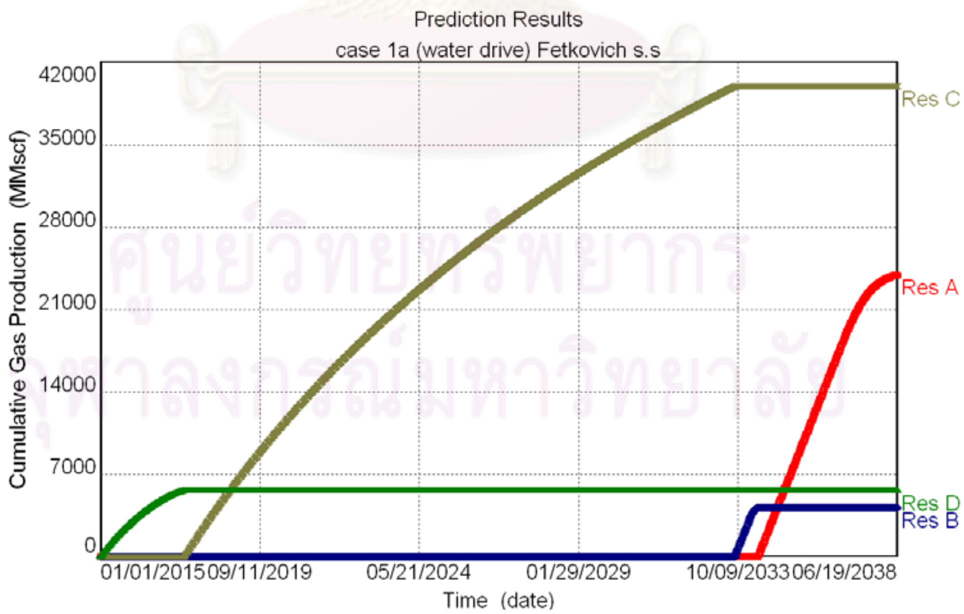

Figure 5.36 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 1a)

Scenario 1b: Bottom-up (Half Depleted)

This scenario provides the lowest RF for water drive gas reservoirs as listed in Table 5.2. All reservoirs cannot produce until the economic limit is reached. The well stops production for reservoirs (B,C,D) at 10 MMscf/d . This scenario provides the shortest production life for water drive reservoirs. The gas production rate for this scenario is shown in Figure 5.37. The overall cumulative production for this scenario is 24.4 MMMscf as illustrated in Figure 5.38.

Reservoir D is perforated first. The well can produce 11 MMscf/d at the beginning. The rate drops suddenly at some point, decreases gradually and stops flowing at 2.5 MMscf/d. The cumulative production for this reservoir is 4.5 MMscf/d as shown in Figure 5.40.

Reservoir C is opened when the production rate drops below 10 MMscf/d. The well can produce more than 10 MMscf/d at the beginning, and the rate drops due to high water influx rate. The cumulative production for this reservoir is 8.8 MMscf as depicted in Figure 5.40.

Reservoir B is perforated after the production from Reservoirs C and D drops below 10 MMscf/d. Although the well can provide the plateau rate but the rate drops very fast compared with other reservoirs. The cumulative gas production is 4.4 MMMscf as shown in Figure 5.40.

Reservoir A is opened when the gas rate from Reservoirs D, C, and B drops below 10 MMscf/d. The well can produce the plateau rate for a few years and declines until the abandonment. The cumulative gas production for this reservoir is 6.6 MMMscf as shown in Figure 5.40.

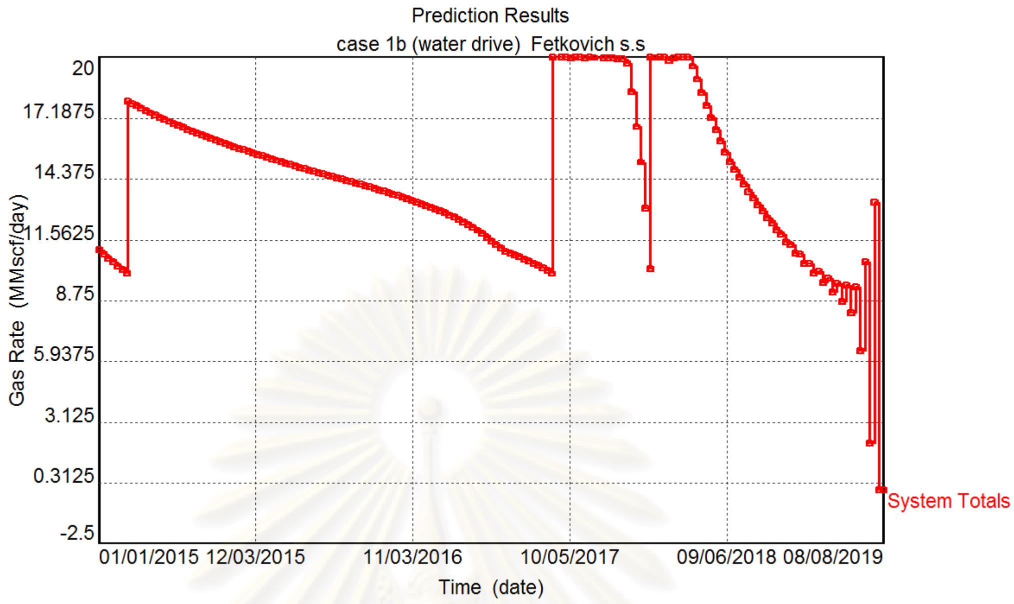

Figure 5.37 : Prediction result for case 2 : scenario 1b

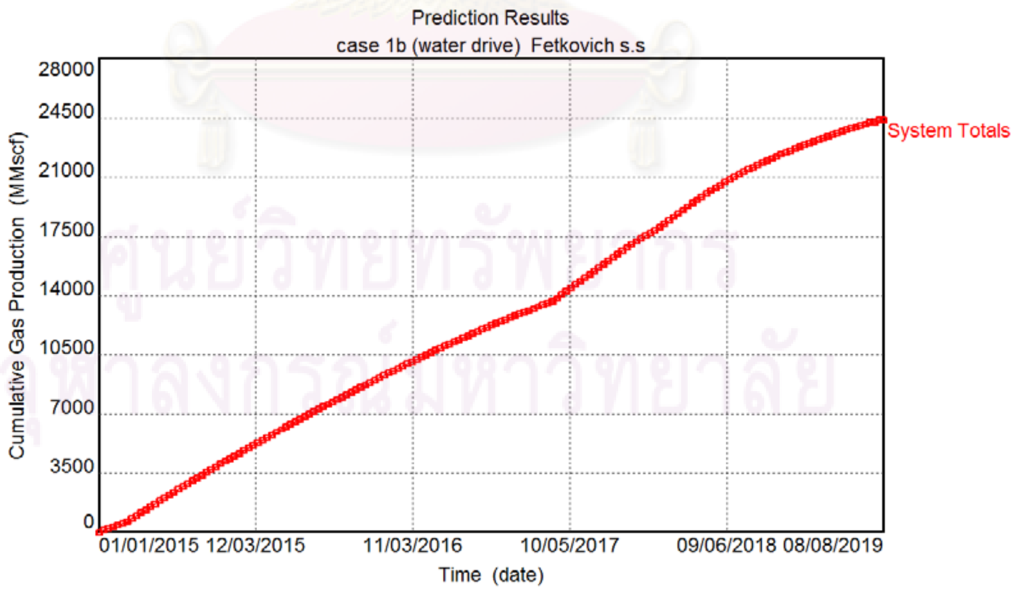

Figure 5.38 : Cumulative gas production versus time (case 2 : scenario 1b)

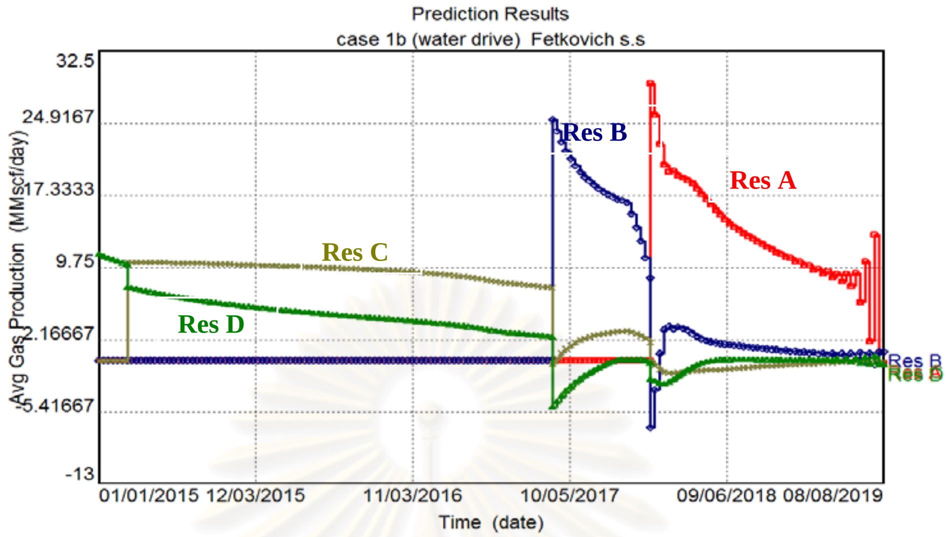

Figure 5.39 : Average gas production versus time for Reservoirs A,B,C, D (case 2 : scenario 1b)

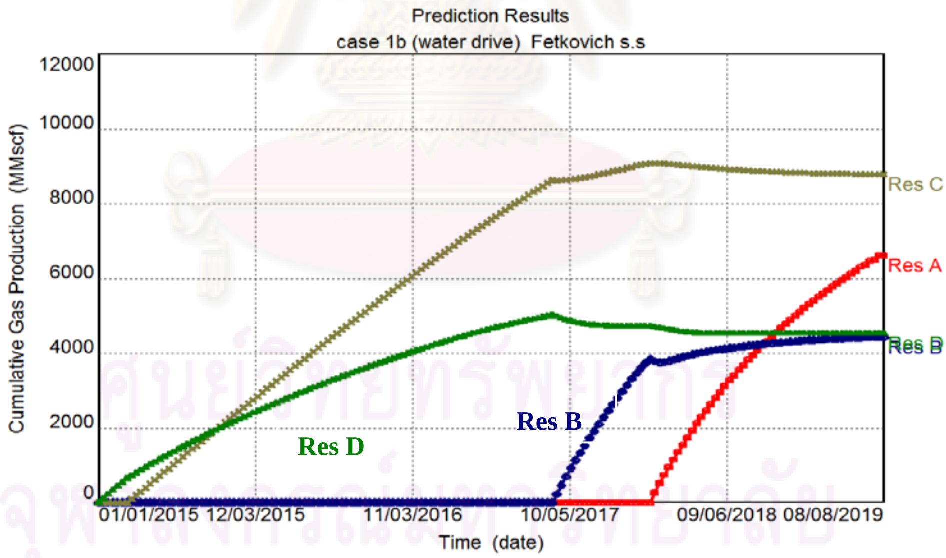

Figure 5.40 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 1b)

Scenario 1c: Maintain Production Plateau

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.2. This scenario can maintain the plateau rate only for one year and declines. The gas production rate for this scenario is shown in Figure 5.41. The cumulative production for this scenario is 38.6 MMMscf as illustrated in Figure 5.42.

The bottom most Reservoir D is perforated first. The well can produce only 10 MMscf/d at the beginning and drops very fast. Then, the next upper Reservoir C is opened to reach the plateau rate. The cumulative production for this reservoir is 3.5 MMMscf as depicted in Figure 5.44.

Reservoir C is opened to increase the production rate. Reservoir C can produce 2.5 MMscf/d at the beginning and increases to 5 MMscf/d and drops very fast. Both reservoirs (C,D) cannot produce at high rate and the production life is very short. The cumulative production for Reservoir C is 8.6 MMMscf (see Figure 5.44).

Reservoir B is opened to increase the production rate. The cumulative gas production for Reservoir B is 4.6 MMMscf as shown in Figure 5.44.

Reservoir A is opened after the gas production from Reservoirs D, C, and B drops below the plateau rate. At this point, all reservoirs (D,C,B,A) are producing together until the abandonment. The cumulative gas production for Reservoir A is 21.9 MMMscf as shown in Figure 5.44.

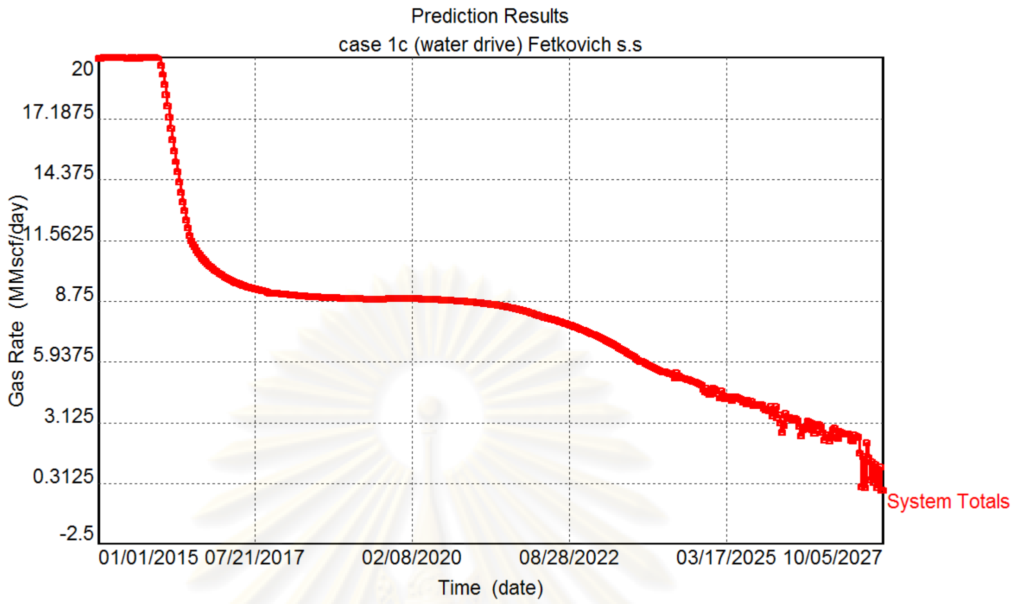

Figure 5.41 : Prediction result for case 2 : scenario 1c

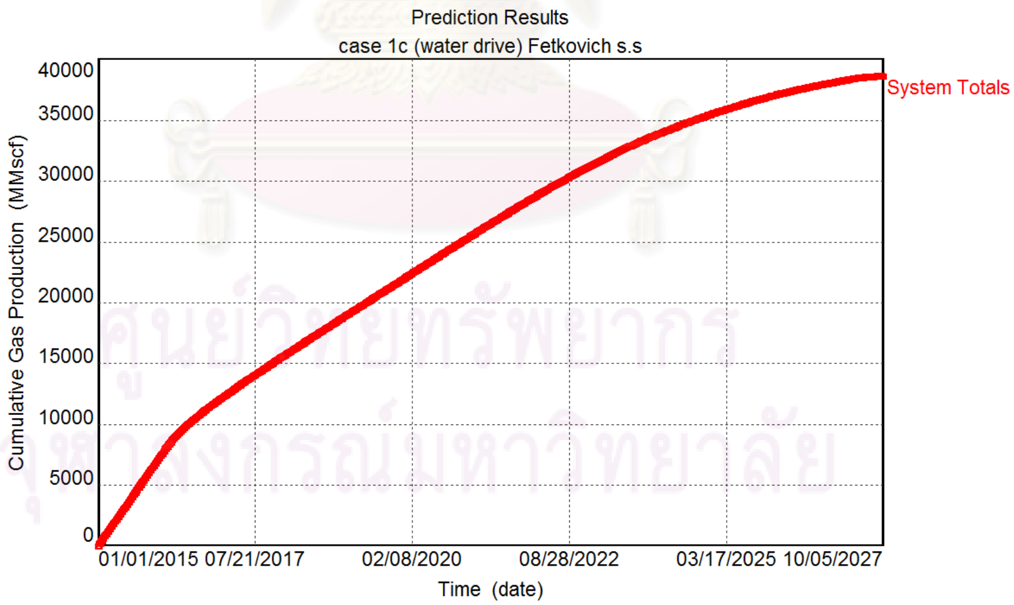

Figure 5.42 : Cumulative gas production versus time (case 2 : scenario 1c)

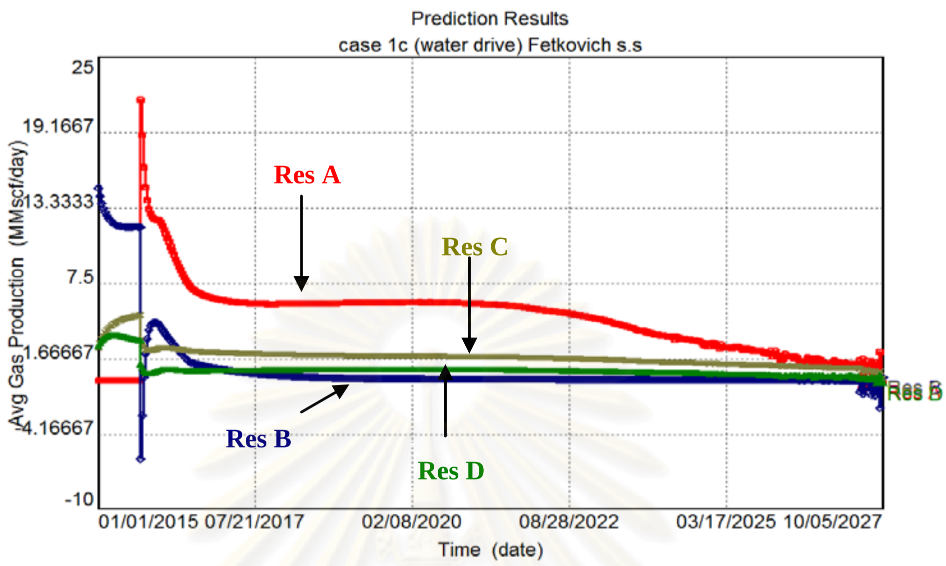

Figure 5.43 : Average gas production versus time for Reservoirs A,B,C, D (case 2 : scenario 1c)

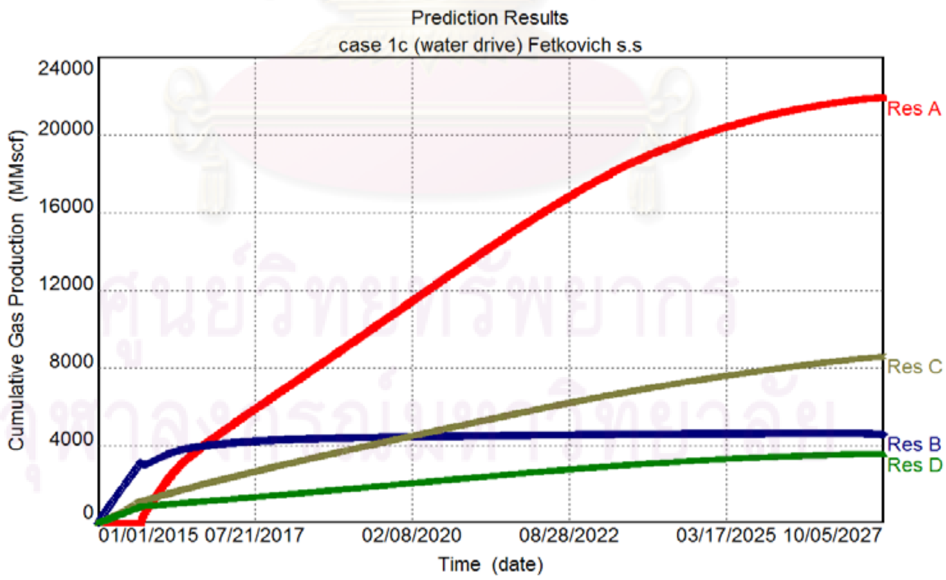

Figure 5.44 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 1c)

Scenario 2a: Permeability Selective (High Permeability Reservoirs First)

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.2. The production strategy for this scenario is the same as that of the volumetric-depletion gas reservoirs (scenario 2a). The high permeability reservoirs (A&B) are produced first. The production rate for this scenario is shown in Figure 5.45. The overall cumulative gas production for this scenario is 33.6 MMMscf as depicted in Figure 5.46.

First, Reservoir A is perforated with Reservoir B at the same time. Reservoir A produces 9 MMscf/d at the beginning, and the production rate increases gradually to 13 MMscf/d. After that, the production rate drops very fast. The cumulative production for Reservoir A is 21.5 MMMscf as shown in Figure 5.48.

Reservoir B is opened with the Reservoir A. The reservoir produces 11 MMscf/d at the beginning, and then the production rate declines right away. Reservoirs A and B can produce the plateau rate for about one year. The cumulative gas production for Reservoir B is 4.6 MMMscf as illustrated in Figure 5.48.

Then, Reservoir C is opened together with Reservoir D. Reservoir C produces 3.6 MMscf/d at the beginning and drops gradually. It can be seen that the gas rate is not stable before the well stops flowing. The production life of Reservoir C is longer than other reservoirs (A,B,D). The cumulative production for Reservoir C is 4.4 MMMscf (see Figure 5.48).

Reservoir D is opened with Reservoir C. The maximum rate Reservoir D can produce is 3.5 MMscf/d. The gas rate is also not stable due to high water influx rate. The cumulative gas production for Reservoir D is 3.2 MMMscf as depicted in Figure 5.48.

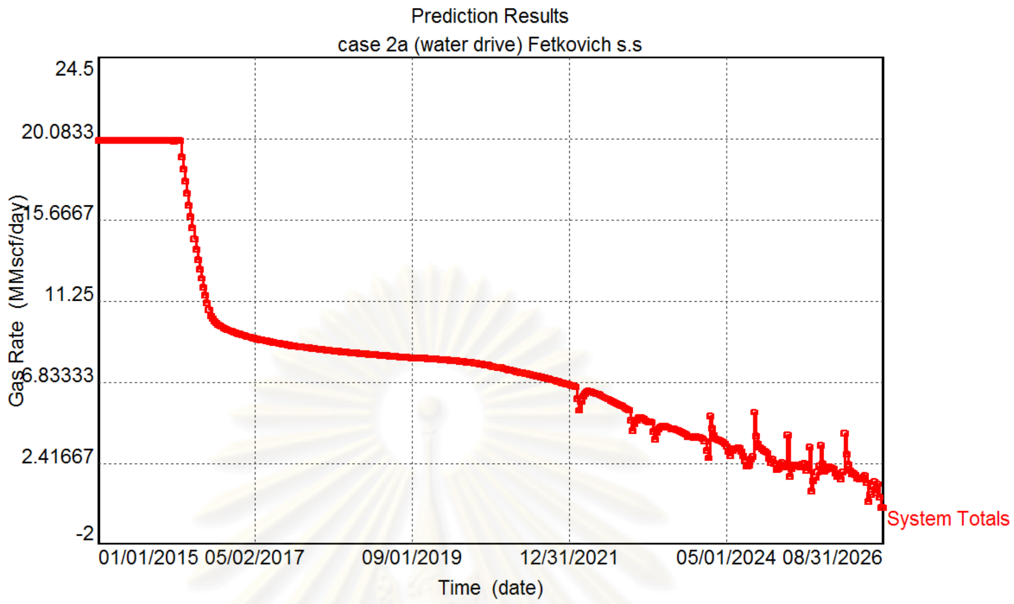

Figure 5.45 : Prediction result for case 2 : scenario 2a

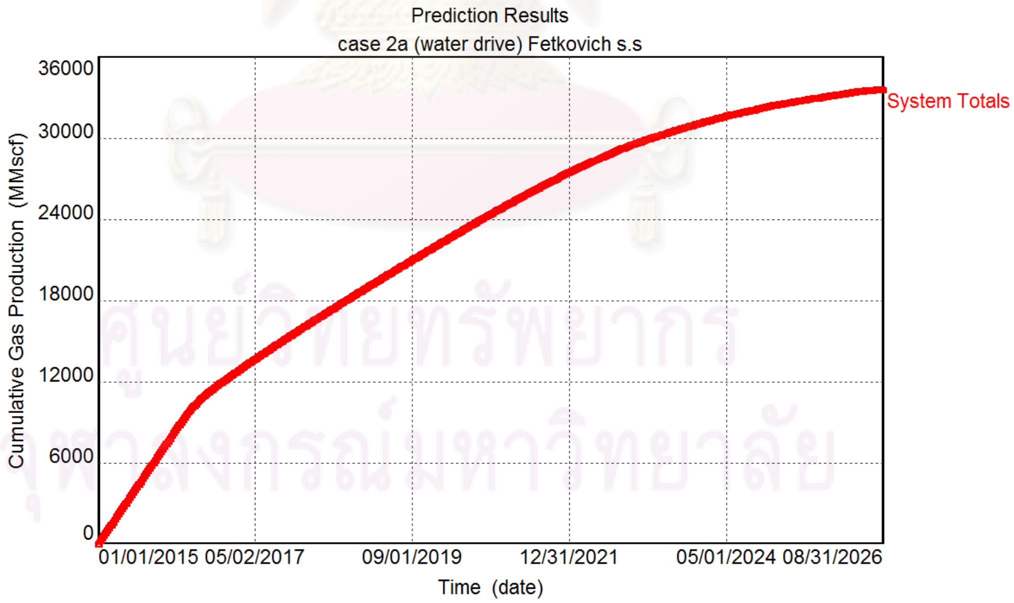

Figure 5.46 : Cumulative gas production versus time (case 2 : scenario 2a)

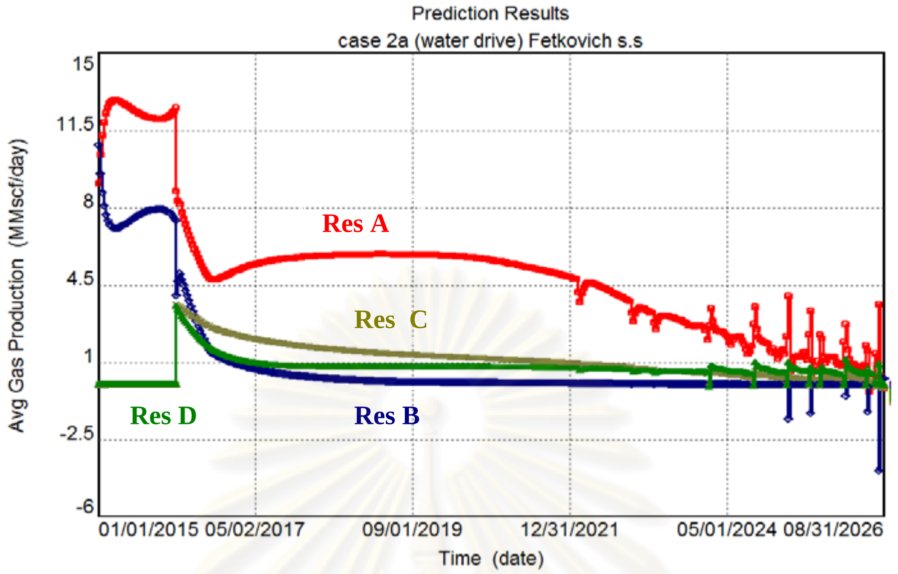

Figure 5.47 : Average gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 2a)

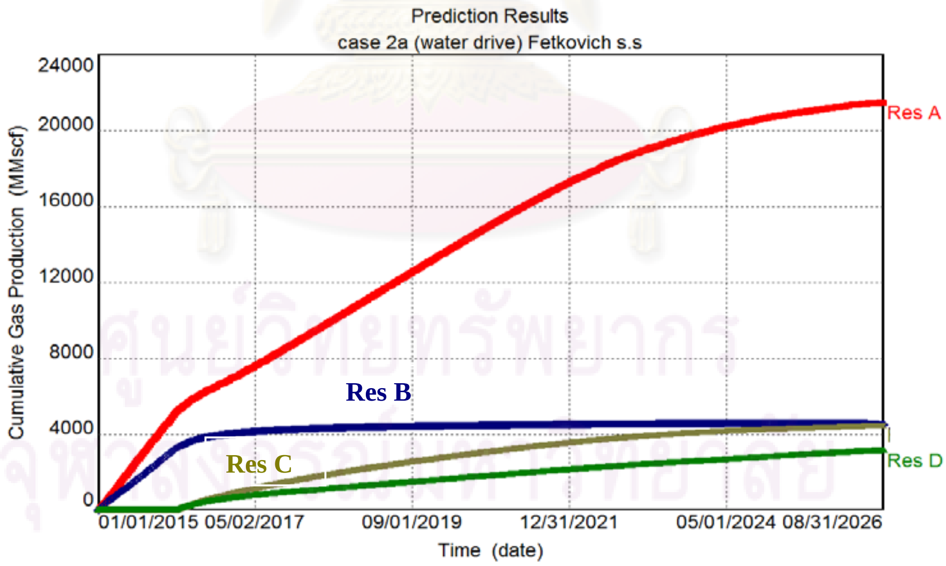

Figure 5.48 : Cumulative gas production versus time for Reservoirs A,B,C D (case 2 : scenario 2a)

Scenario 2b: Permeability Selective (Low Permeability Reservoirs First)

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.2. The production strategy for this scenario is the same as that of the volumetric-depletion gas reservoirs (scenario 2b) which is to produce from low permeability reservoirs (C&D) first. The gas production rate for this scenario is shown in Figure 5.49. The overall cumulative gas production for this scenario is 34.0 MMMscf as shown in Figure 5.50.

First, Reservoir C is perforated with Reservoir D at the same time. Reservoir C produces at low rates. It can be seen that the gas rate is not stable for this reservoir. The cumulative production for Reservoir C is 4.8 MMMscf as shown in Figure 5.52.

Reservoir D is opened together with Reservoir C. Reservoir D also produces at low rates. Both reservoirs C and D can provide the plateau for a short period. The cumulative production for Reservoir D is 3.4 MMscf/d (see Figure 5.52).

High permeability reservoirs are opened after low permeability reservoirs. Reservoir A is opened together with Reservoir B. The well produces at high gas rate at the beginning. The cumulative production for Reservoir A is 21.4 MMMscf as shown in Figure 5.52.

Reservoir B is opened together with Reservoir A. The production from both reservoirs (A,B) can provide the plateau rate . After this point, all reservoirs are producing together until the end of the well life. The cumulative production for Reservoir B is 4.4 MMMscf as shown in Figure 5.52.

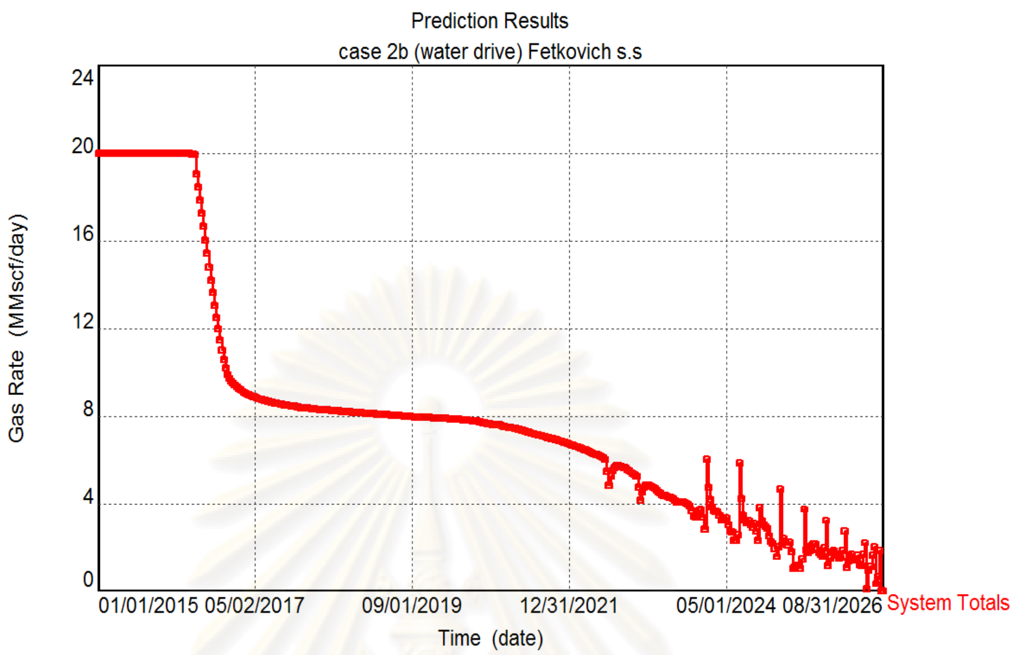

Figure 5.49 : Prediction result for case 2 : scenario 2b

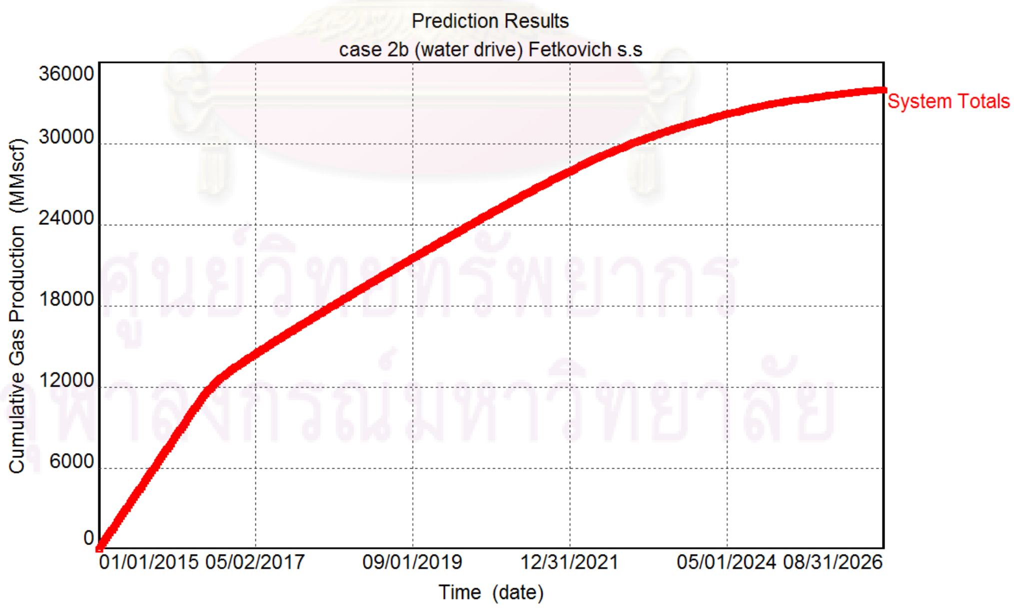

Figure 5.50 : Cumulative gas production versus time (case 2 : scenario 2b)

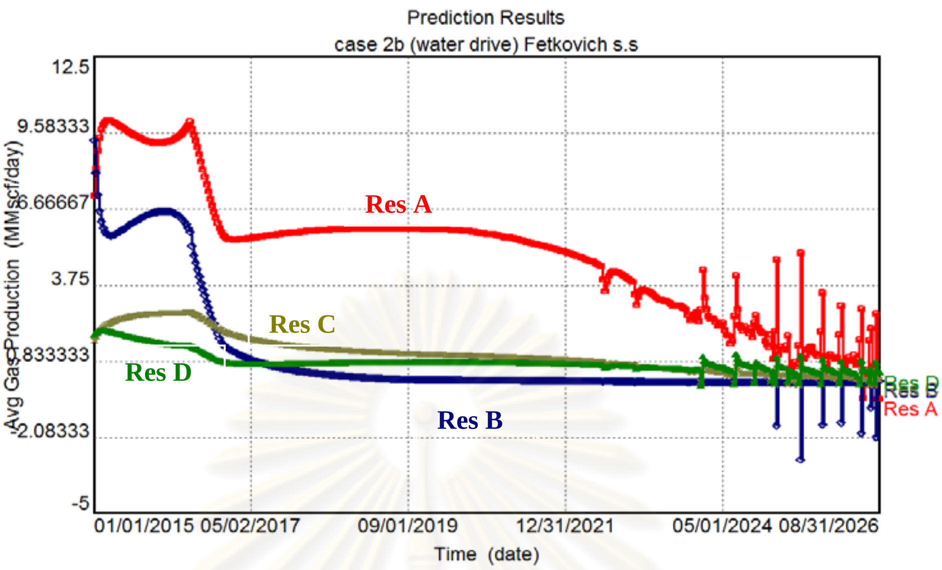

Figure 5.51 : Average gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 2b)

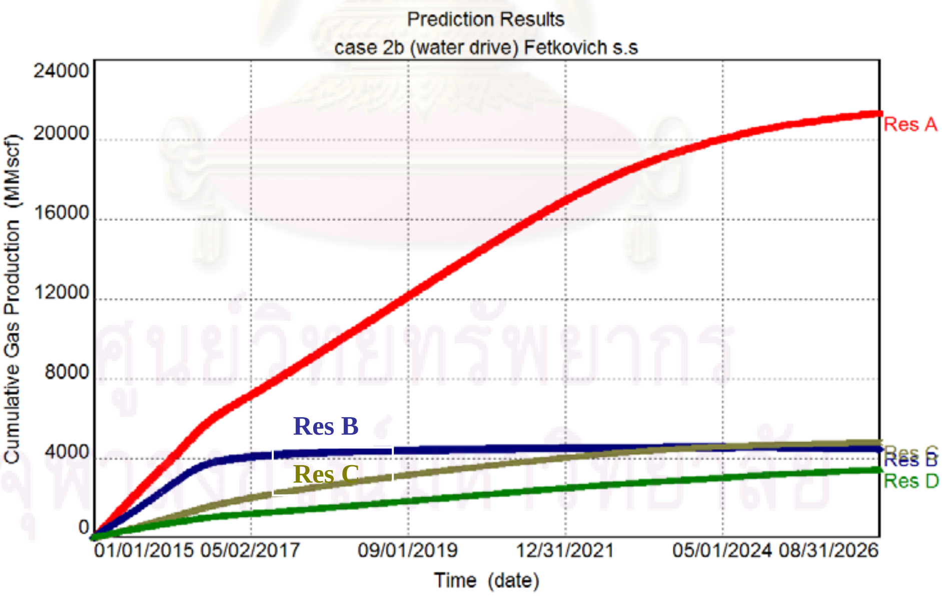

Figure 5.52 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 2b)

Scenario 3a: Reservoir Size Selective (Thick Reservoirs First)

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.2. The production strategy for this scenario is the same as that of the volumetric-depletion drive gas reservoirs (case 1: scenario 3a) which is to produce from thick reservoirs (A&C) first. The production rate for this scenario is illustrated in Figure 5.53. The overall cumulative gas production for this scenario is 32.6 MMMscf as shown in Figure 5.54.

First, Reservoir A is perforated together with Reservoir C. Reservoir A can produce at high rates due to high permeability and big reservoir size. The cumulative production for Reservoir A is 21.7 MMMscf as illustrated in Figure 5.56. Reservoir C cannot produce at high gas rate due to low permeability. The cumulative production for Reservoir C is 5.2 MMMscf as depicted in Figure 5.56.

Then, Reservoir B is opened together with Reservoir D. Reservoir B produces at high rate at the beginning and drops very fast due to high permeability. The cumulative production for Reservoir B is 4.2 MMMscf as shown in Figure 5.56. Reservoir D produces at low production rate. After this point, all reservoirs are producing together and can provide the plateau rate for a long time. The cumulative production for Reservoir D is 1.5 MMMscf (see Figure 5.56).

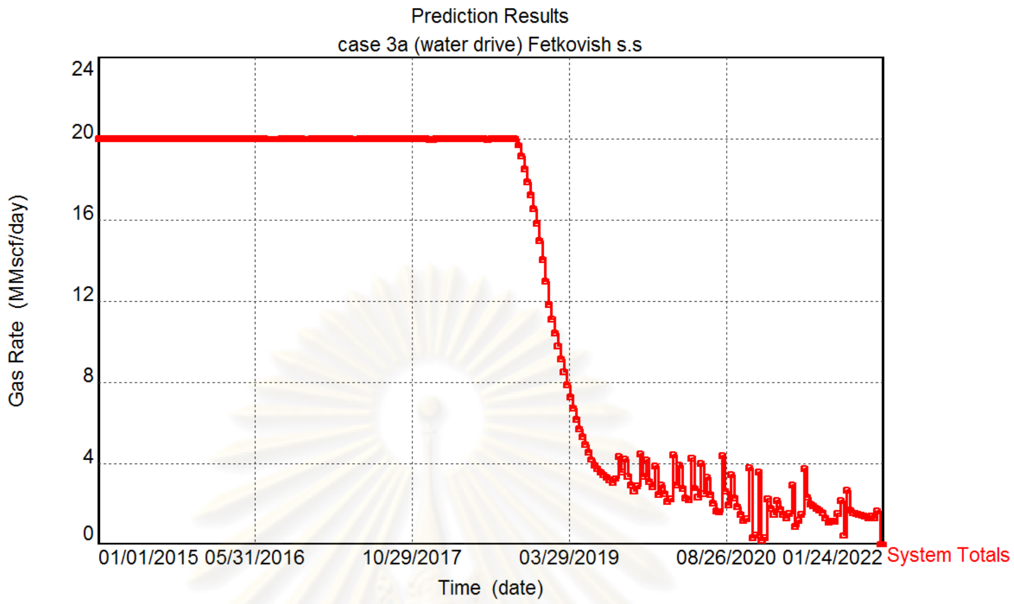

Figure 5.53 : Prediction result for case 2 : scenario 3a

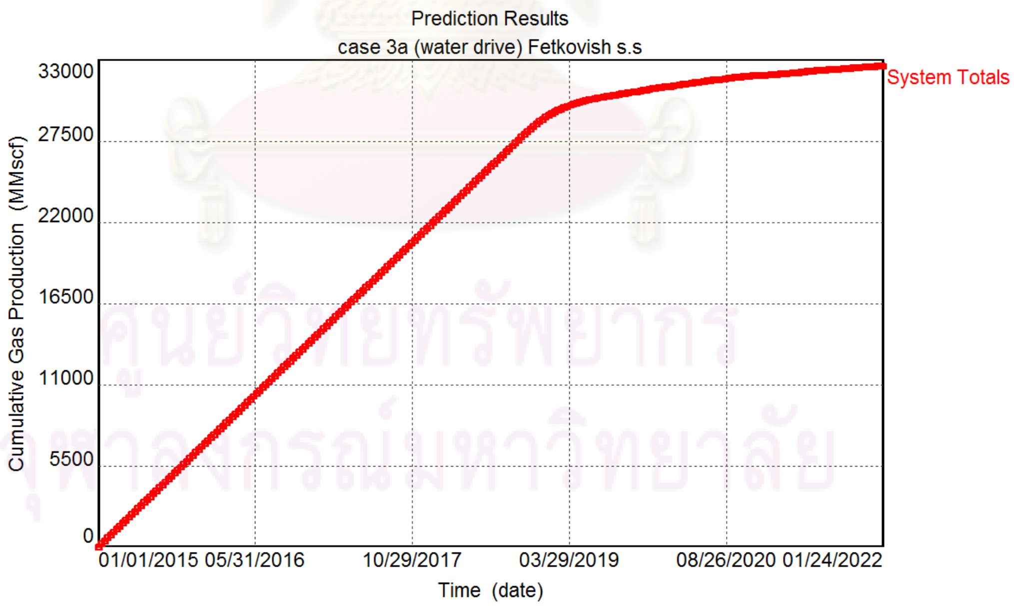

Figure 5.54 : Cumulative gas production versus time (case 2 : scenario 3a)

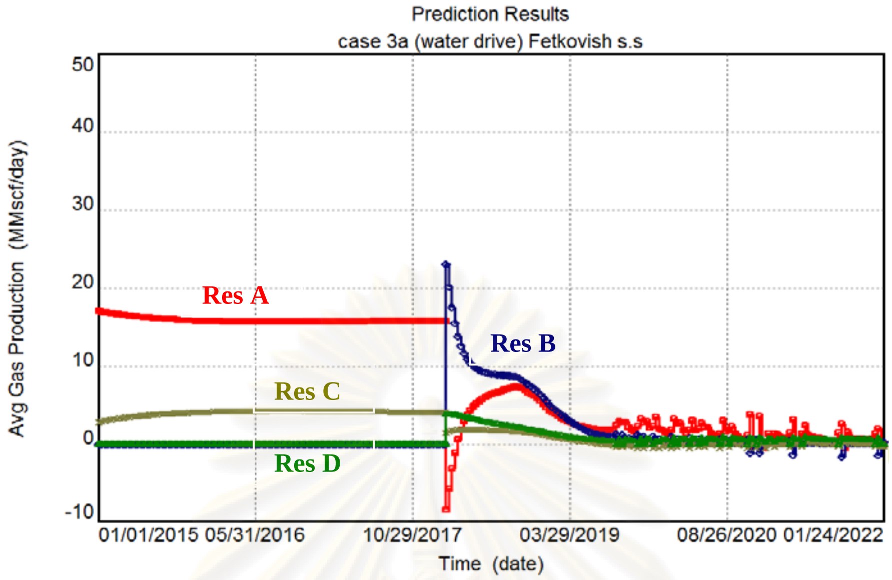

Figure 5.55 : Average gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 3a)

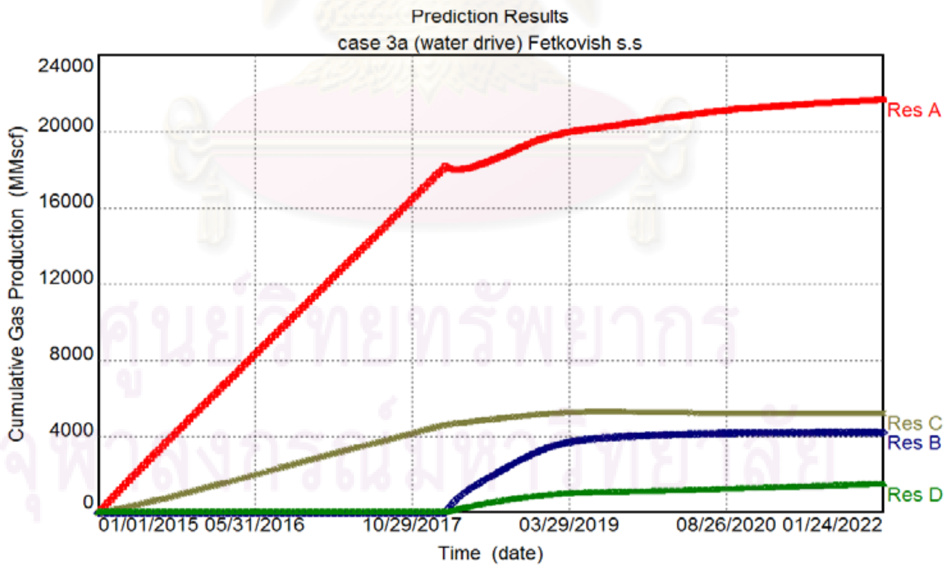

Figure 5.56 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 3a)

Scenario 3b: Thin Reservoirs First

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.2. The production strategy for this scenario is the same as that of the volumetric-depletion drive reservoirs (scenario 3b) which is to produce from the thin reservoirs (B&D) first. The gas production rate for this scenario is shown in Figure 5.57. The overall cumulative gas production for this scenario is 34.5 MMMscf as illustrated in Figure 5.58.

First, Reservoir B is perforated together with Reservoir D. Reservoir B can produce at high rate for a while due to high permeability and big reservoir size. Reservoir B can produce at the plateau rate with Reservoir D. The cumulative production for Reservoir B is 4.9 MMMscf (see Figure 5.60). Reservoir D produces at low rate due to small reservoir size and low permeability. The cumulative production for Reservoir D is 3.4 MMMscf as shown in Figure 5.60.

Then, Reservoir A is opened together with Reservoir C. Reservoir A can produce at high rates due to big size and high permeability. The cumulative production for Reservoir A is 22 MMMscf as shown in Figure 5.60. Reservoir C produces at low rate due to low permeability. The cumulative production for Reservoir C is 4.9 MMMscf as depicted in Figure 5.60.

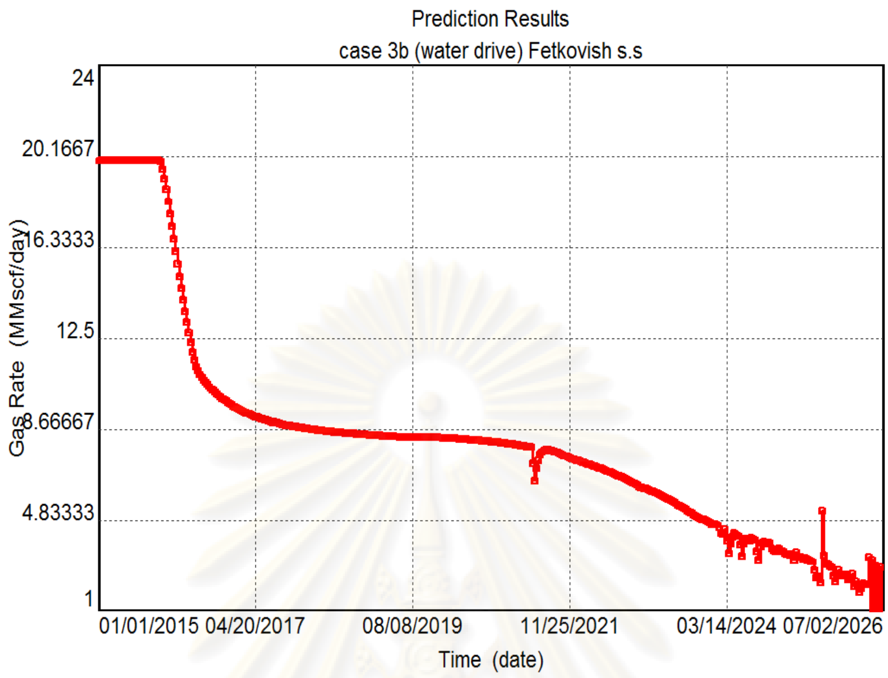

Figure 5.57 : Prediction result for case 2 : scenario 3b

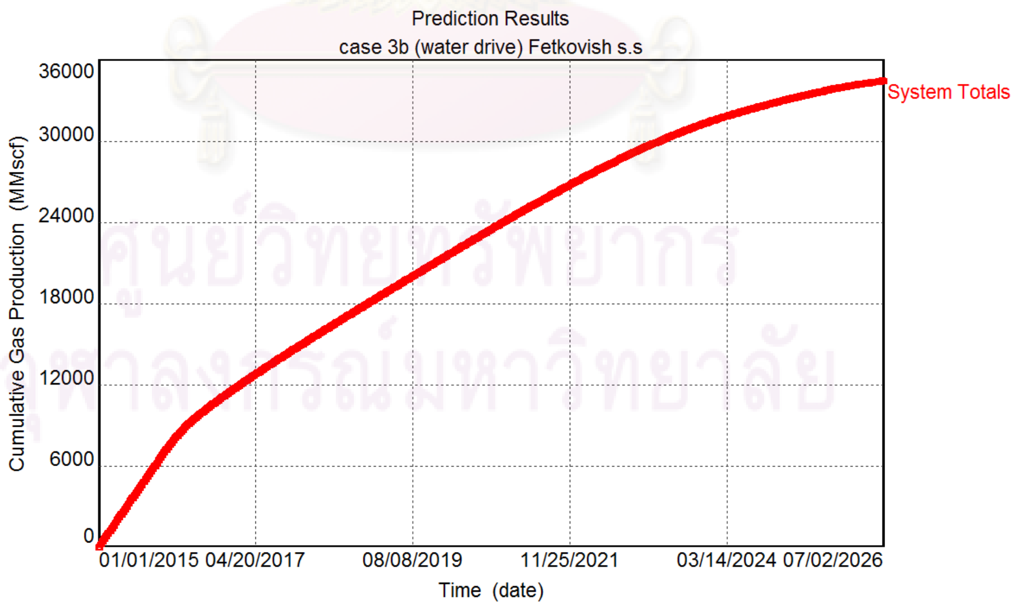

Figure 5.58 : Cumulative gas production versus time (case 2 : scenario 3b)

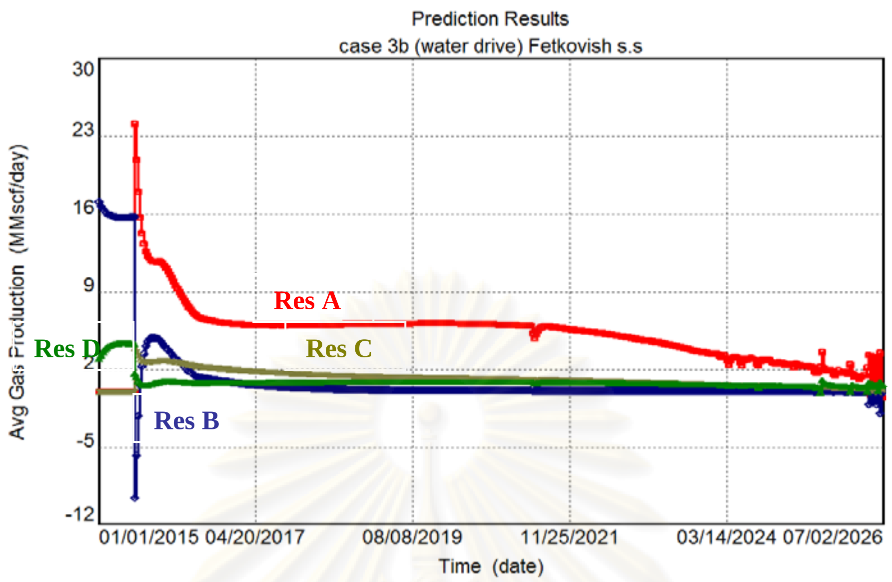

Figure 5.59 : Average gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 3b)

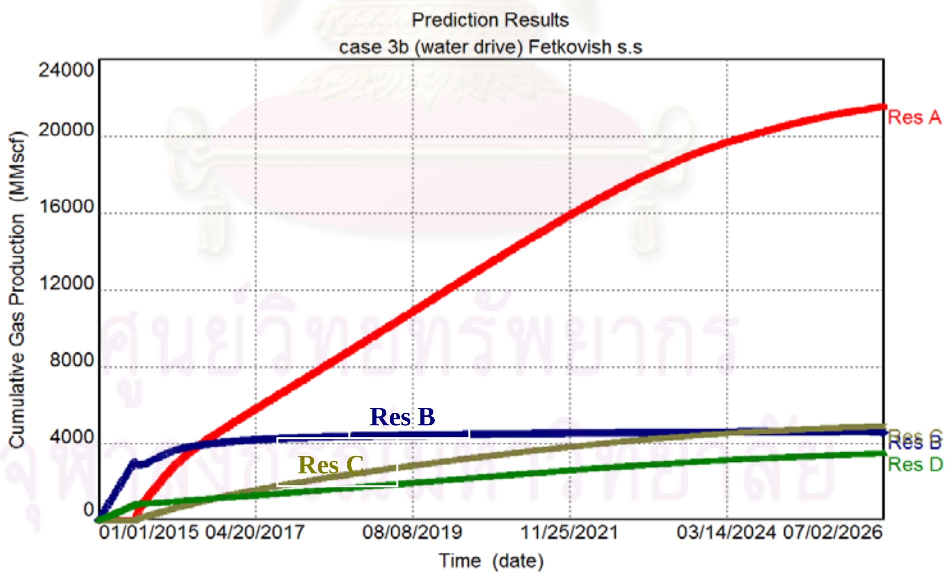

Figure 5.60 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 3b)

Scenario 4a: Commingled

This scenario provides lower RF than that of Scenario 1a as listed in Table 5.2. The production strategy for this scenario is the same as the scenario 4 for volumetric-depletion drive gas reservoirs. All Reservoirs (A,B,C,D) are perforated at the same time since the start of production. The gas production rate for this scenario is illustrated in Figure 5.61. The overall cumulative production for this scenario is 33.9 MMMscf as depicted in Figure 5.62.

Under this scenario, Reservoir A is perforated together with the other reservoirs (B,C,D). Reservoir A produces at high rate like the previous scenarios. The cumulative production for Reservoir A is 21.3 MMMscf (Figure 5.64).

Reservoir B can also produce at high rate due to high permeability and big reservoir size. The cumulative production for Reservoir B is 4.5 MMMscf as depicted in Figure 5.64.

Reservoir C cannot produce at high rate due to low permeability. The cumulative production for Reservoir C is 4.8 MMMscf (Figure 5.64).

Reservoir D produces at low rate like Reservoir C. The cumulative production for Reservoir D is 3.3 MMMscf as shown in Figure 5.64.

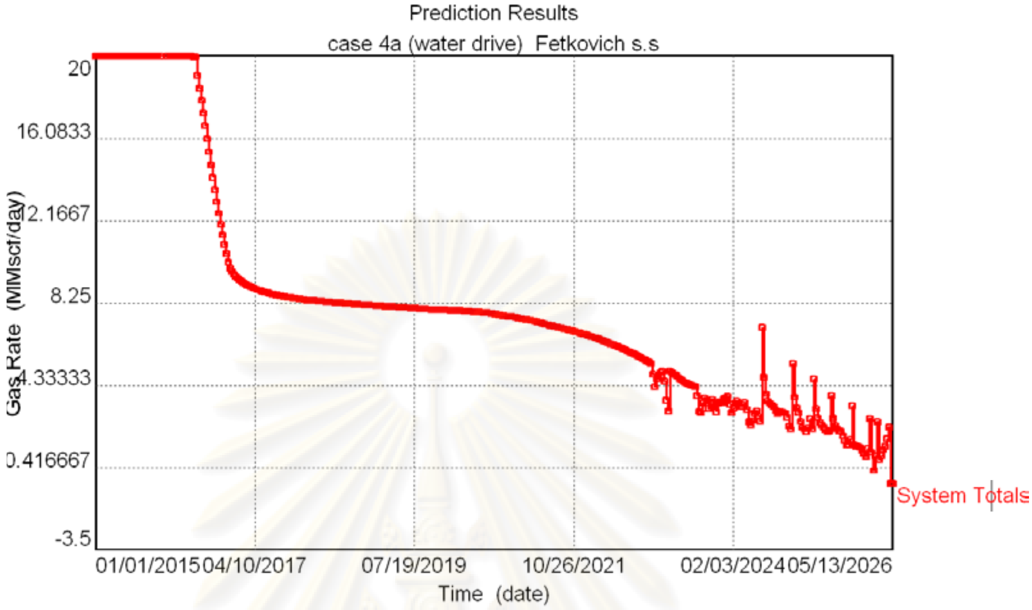

Figure 5.61 : Prediction result for case 2 : scenario 4a

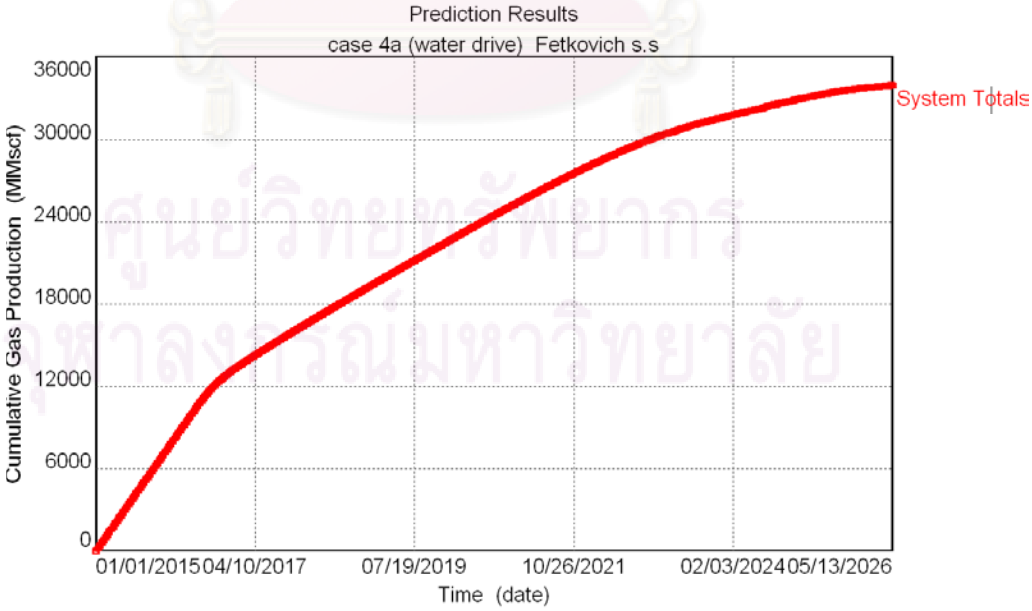

Figure 5.62 : Cumulative gas production versus time (case 2 : scenario 4a)

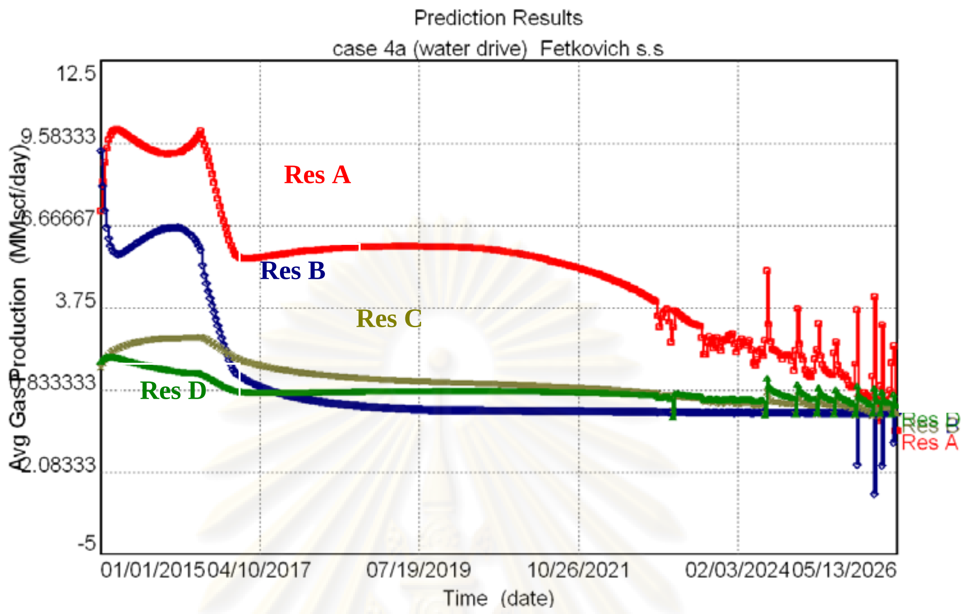

Figure 5.63 : Average gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 4a)

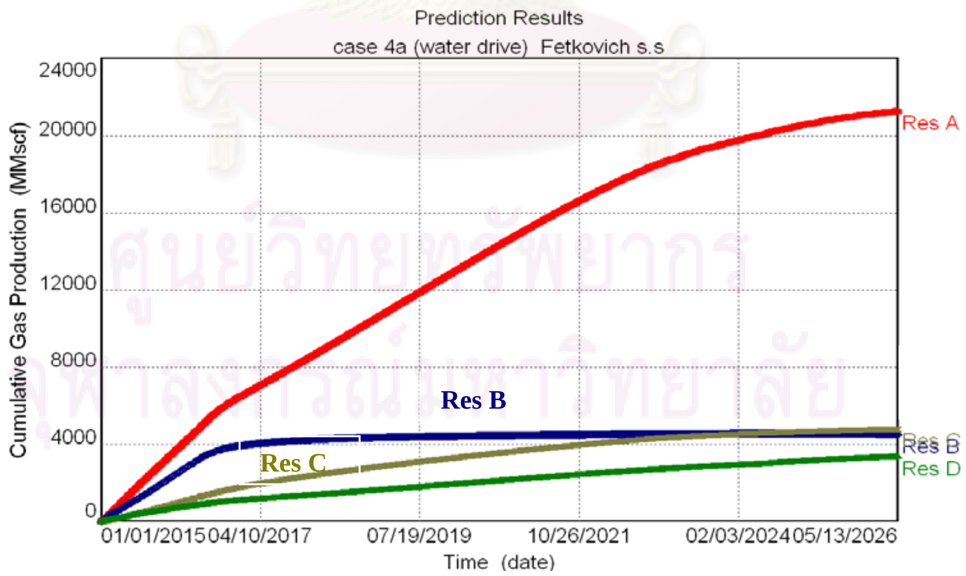

Figure 5.64 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 4a)

Scenario 4b: Commingled with Water Shut Off

This scenario provides lower RF than that of Scenario 1a as listed in Table 5.2. All Reservoirs (A,B,C,D) are perforated at the same time since the start of production but when any reservoir produces water more than 1,000 bbl/MMscf, we shut in this reservoir and then leave the other reservoirs producing. The gas production rate for this scenario is as depicted in Figure 5.65. The overall cumulative production for this scenario is 52.83 MMMscf as shown in Figure 5.66.

Reservoir A produces at high rate. When the water production reaches 1,000 bbl/MMscf which is after two years production, we shut off this reservoir and leave the other reservoirs producing. The cumulative production for Reservoir A is 12.7 MMMscf (Figure 5.68).

Reservoir B produces gas for a certain duration and is shut off when the well produces water more than 1,000 bbl/MMscf. Early water invasion is because of high permeability of the reservoir itself. The cumulative production for Reservoir B is 1.1 MMMscf (Figure 5.68).

Reservoir C produces gas for the longest time. There is no water production due to low permeability. The cumulative production for Reservoir C is 37.3 MMMscf (Figure 5.68).

Reservoir D produces at low production rate and high water invasion after two years of production because of low permeability. After that, we shut off this reservoir and leave the other reservoirs producing. The cumulative production for Reservoir D is 1.9 MMMscf (Figure 5.68).

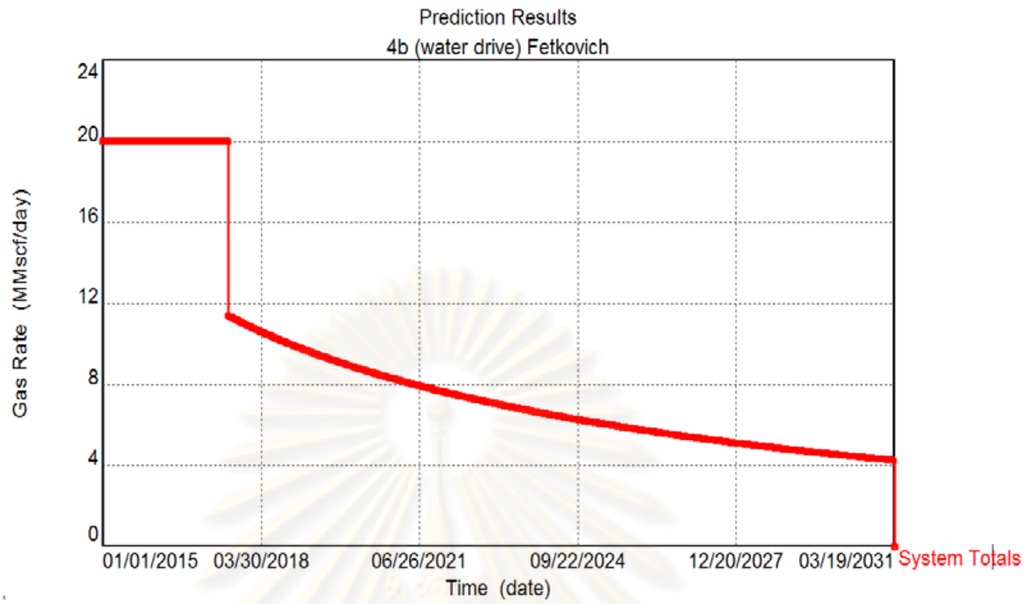

Figure 5.65 : Prediction result for case 2 : scenario 4b

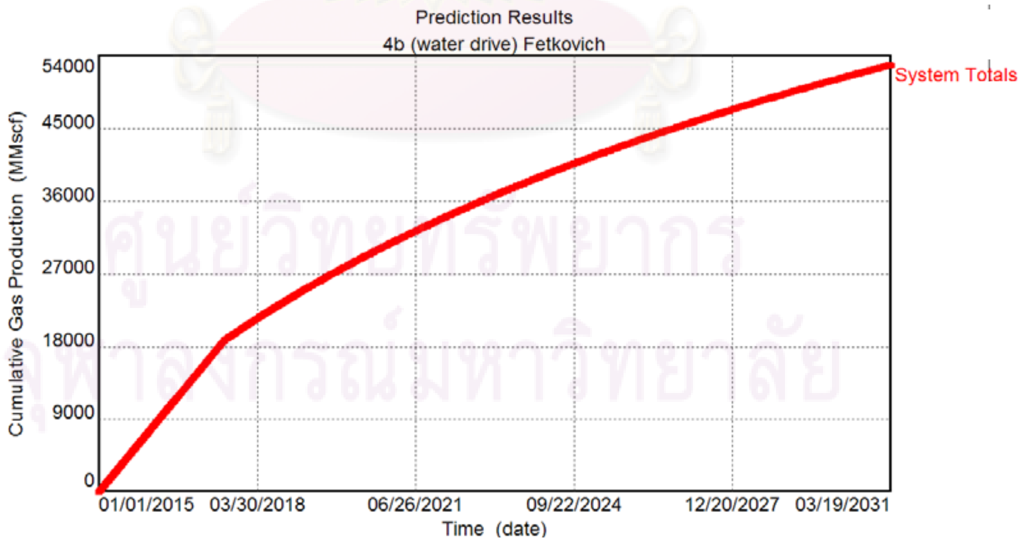

Figure 5.66 : Cumulative gas production versus time (case 2 : scenario 4b)

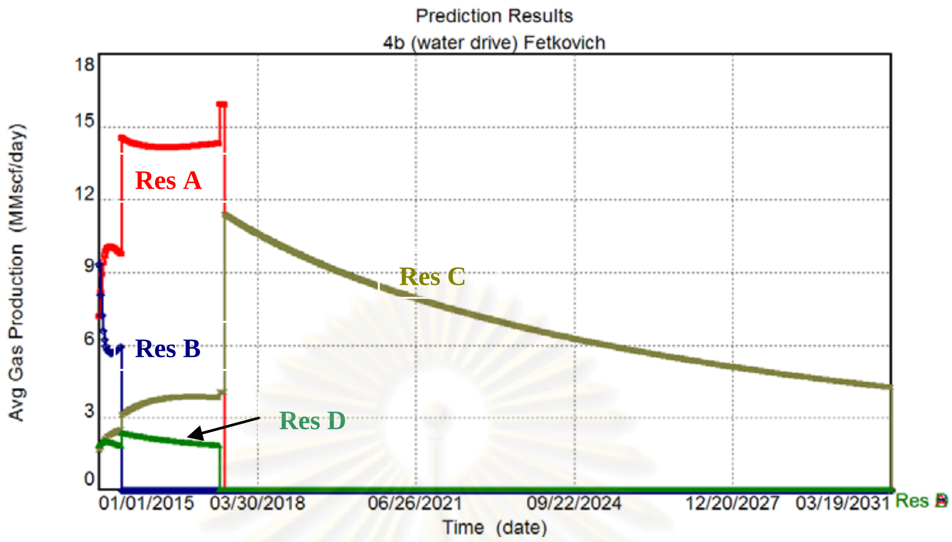

Figure 5.67 : Average gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 4b)

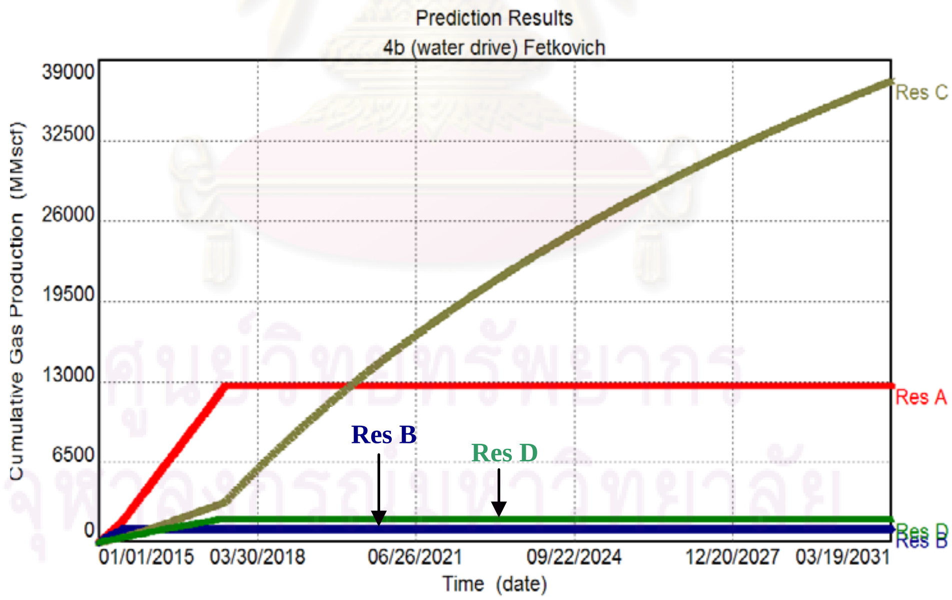

Figure 5.68 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 2 : scenario 4b)

5.3 Recovery Factor for Combination Drive Gas Reservoirs

Table 5.3 : Recovery factor for combination drive gas reservoirs

Scenario	Description	RF (%)
Scenario 1: Bottom-up		
1a	Fully depleted	34.09
1b	Half depleted	40.17
1c	Maintain plateau	28.93
Scenario 2: Permeability selective		
2a	High permeability first	27.54
2b	Low permeability first	28.13
Scenario 3: Reservoir size selective		
3a	Thick reservoirs first	27.52
3b	Thin reservoirs first	28.05
Scenario 4 : Commingled		
4a	All reservoirs are producing since start of production	28.94
4b	All reservoirs are producing since start of production with water shut off	48.41

Based on the prediction from IPM, the results can be summarized in details as follows:

Scenario 1a: Bottom-up (Fully Depleted)

This scenario provides a moderate RF for combination drive gas reservoirs as listed in Table 5.3.The RF and production time for combination drive reservoirs falls between volumetric-depletion drive gas reservoirs and water drive gas reservoirs. The reservoir arrangement is two thick reservoirs are connected with aquifers and another two thin reservoirs are volumetric-depletion drive. The gas production rate for this scenario is shown in Figure 5.69. The overall cumulative production for this scenario is 34.09 MMMscf as depicted in Figure 5.70.

The deepest Reservoir D is perforated first. This reservoir is produced under volumetric-depletion. Therefore, the production behavior is similar to that of Scenario 1a in case 1. Reservoir D cannot provide the plateau rate due to low production rate, and the rate declines right away until the abandonment. The cumulative production for Reservoir D is 6.8 MMMscf as shown in Figure 5.72.

Reservoir C is opened after Reservoir D is fully depleted. This reservoir is produced under water drive. The well cannot produce until the economic limit due to high water influx. The production life for this reservoir is the longest compared with the other reservoirs. The cumulative production for Reservoir C is 40 MMMscf (Figure 5.72).

The next upper layer Reservoir B is opened after Reservoir C is shut off. Reservoir B is produced under volumetric-depletion like Reservoir D and can provide the production plateau rate for a while. The cumulative production for Reservoir B is 7 MMMscf as shown in Figure 5.72.

The upper most Reservoir A is opened after shutting off Reservoir B. This reservoir is produced under water drive like the Reservoir C. Reservoir A can provide the plateau rate for a few years. The cumulative production for Reservoir A is 23.8 MMMscf as illustrated in Figure 5.72.

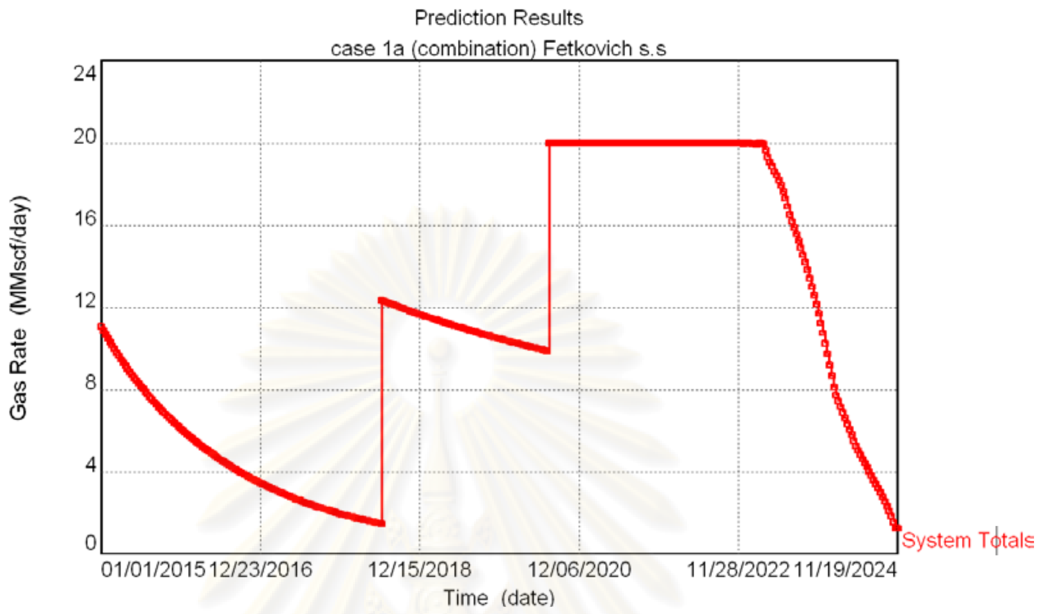

Figure 5.69 : Prediction result for case 3 : scenario 1a

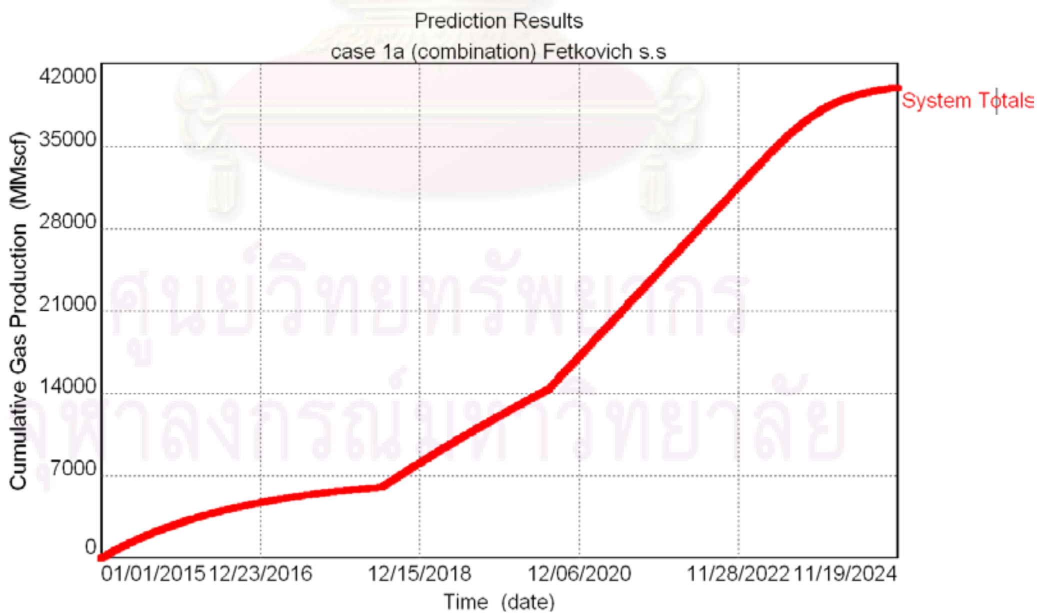

Figure 5.70 : Cumulative gas production versus time (case 3 : scenario 1a)

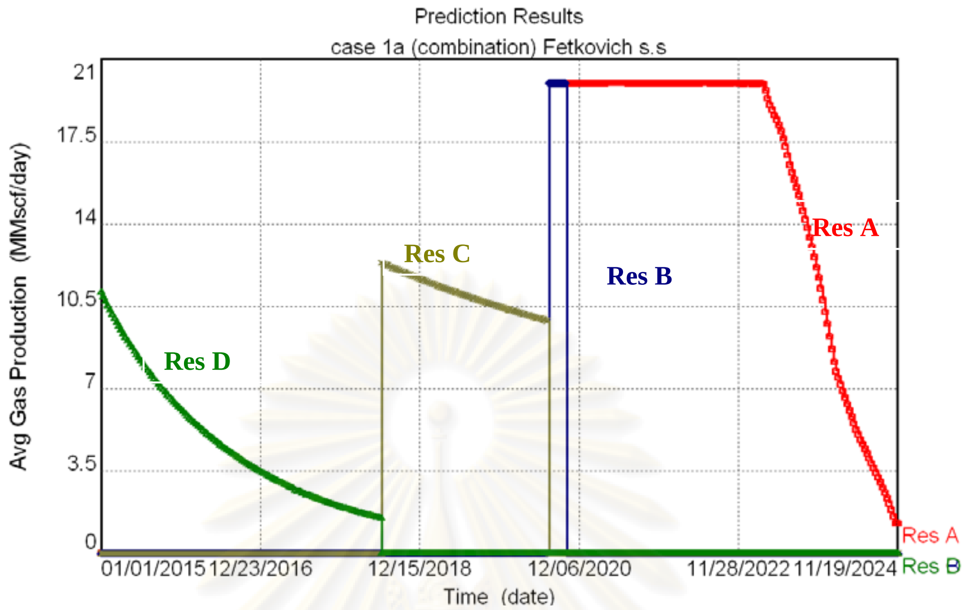

Figure 5.71 : Average gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 1a)

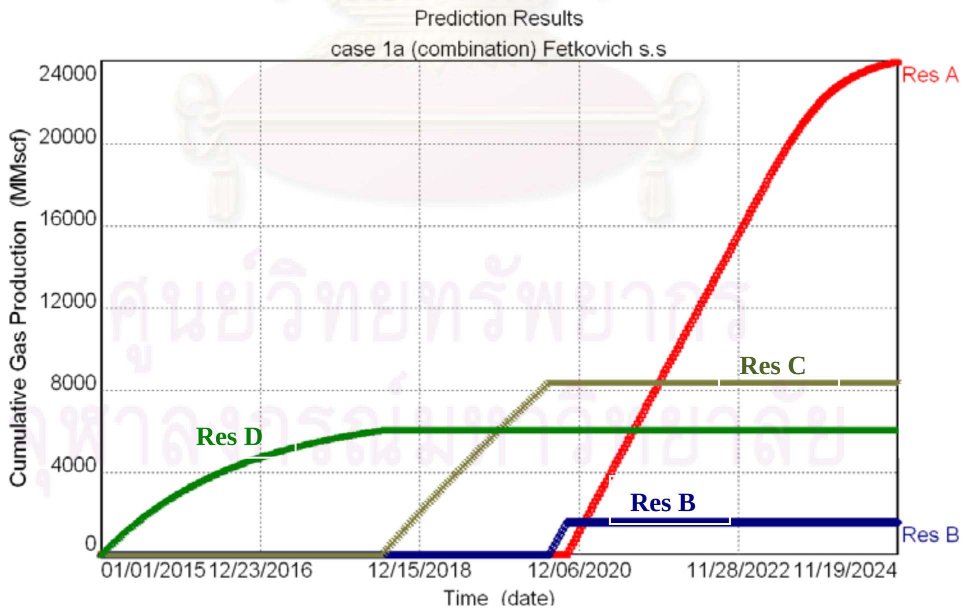

Figure 5.72 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 1a)

Scenario 1b: Bottom-up (Half Depleted)

This scenario provides higher RF than that of Scenario 1a as listed in Table 5.3. In this scenario, the bottom most reservoir is producing until the rate declines to half of the plateau rate (20MMscf/d) which equals to 10 MMscf/d, then the next upper layer is opened. The gas production rate for this scenario is shown in Figure 5.73. The cumulative gas production for this scenario is 47 MMMscf as shown in Figure 5.74.

The deepest Reservoir D is perforated first. Reservoir D produces 11 MMscf/d due to water influx into the reservoir and drops gradually. When the rate drops below 10 MMscf/d, and then the next upper layer Reservoir C is opened. The cumulative production for this reservoir increases to 5.1 MMMscf and drops to 2.3 MMMscf due to cross flow as shown in Figure 5.74.

Reservoir C is opened after Reservoir D to obtain the plateau rate. Reservoir C also produces 10 MMscf/d at the beginning. Both reservoirs (C, D) cannot supply the plateau rate. The cumulative production for Reservoir C is 17.9 MMMscf as shown in Figure 5.76.

Reservoir B is opened when the well rate drops below 10 MMscf/d. Reservoir B can produce at the plateau rate. The cumulative production for Reservoir B increases to 5.7 MMMscf and drops to 1.8 MMMscf due to cross flow as shown in Figure 5.76.

Reservoir A is opened after the rate drops below 10 MMscf/d. Reservoir A also produces at high production rate and can provide the plateau rate for a long time. There is no cross flow for this reservoir. The cumulative production for Reservoir A is 25 MMMscf as depicted in Figure 5.76.

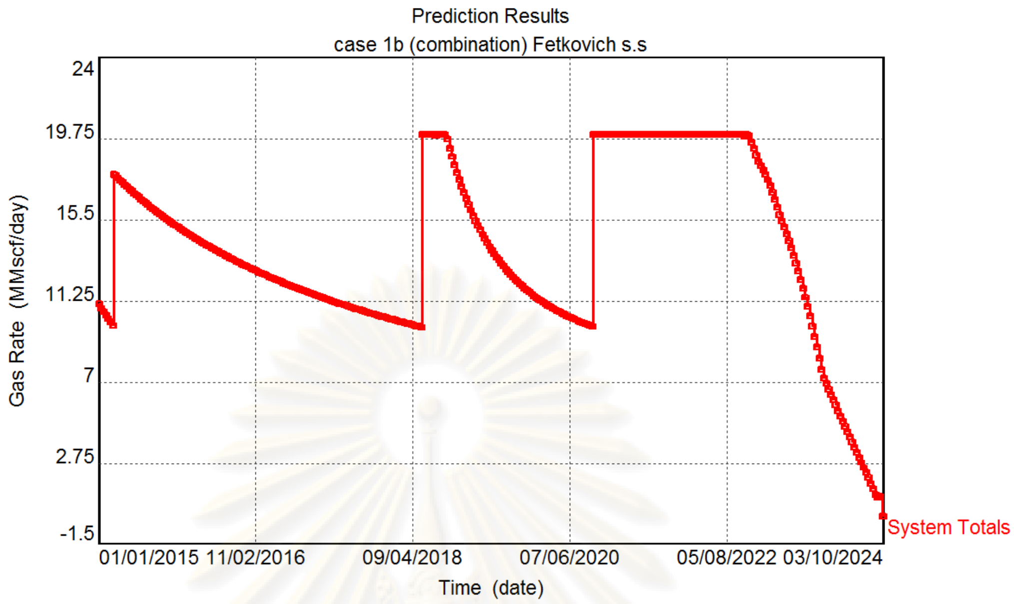

Figure 5.73 : Prediction result for case 3 : scenario 1b

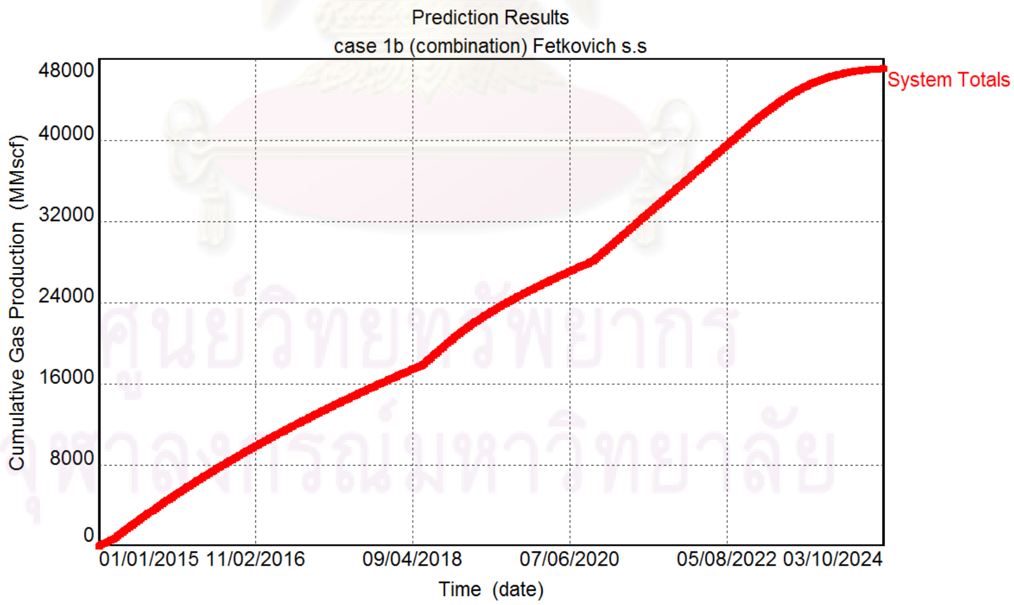

Figure 5.74 : Cumulative gas production versus time (case 3 : scenario 1b)

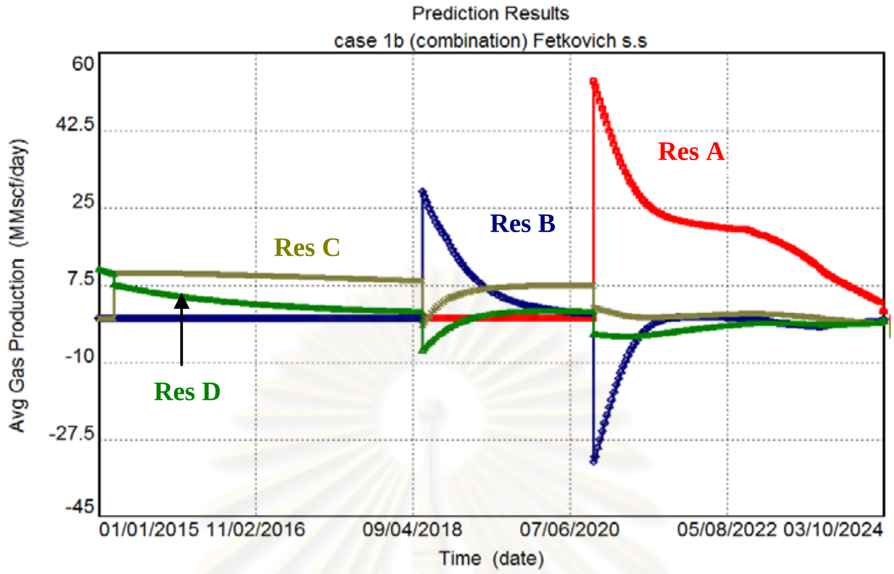

Figure 5.75 : Average gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 1b)

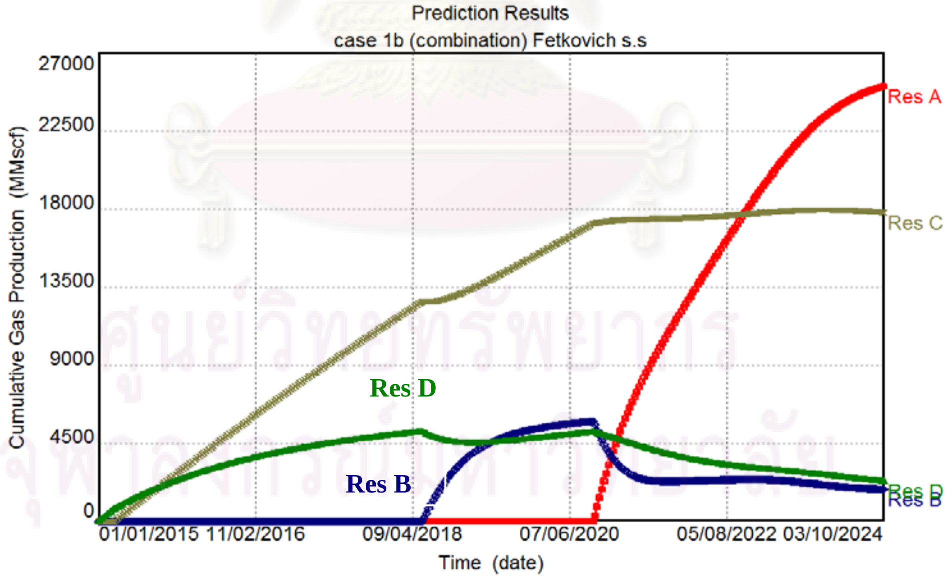

Figure 5.76 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 1b)

Scenario 1b: Bottom-up (Maintain Production Plateau rate)

This scenario provides lower RF than that of Scenario 1a as listed in Table 5.3. In this scenario, the bottom most reservoir is produced first and when the rate declines below the plateau rate (20MMscf/d), then the next upper layer is opened. The gas production rate for this scenario is shown in Figure 5.77. The production life for this scenario is very short compared to other scenarios. The overall cumulative production for this scenario is 33.9 MMMscf as shown in Figure 5.78.

The bottom most Reservoir D is perforated first. Reservoir D cannot produce at the plateau rate. The cross flow occurs for this reservoir at late time of production. The cumulative production for Reservoir D increases to 1.9 MMMscf and drops to 1.5 MMMscf due to cross flow as shown in Figure 5.80.

The upper Reservoir C is opened when the production from Reservoir D cannot reach the plateau rate. The production rate of Reservoir C is low at the beginning and increases to 8.5 MMscf/d and drops gradually. There is no cross flow for this reservoir. The cumulative production for Reservoir C is 7.4 MMMscf as shown in Figure 5.80.

The next upper Reservoir B is opened after the gas production from Reservoirs C and D cannot reach the plateau rate. At this point, three reservoirs (B,C,D) are producing together to maintain the plateau rate. The cross flow occurs for this reservoir. The cumulative production for Reservoir B increases to 3 MMMscf and drops to 1.3 MMMscf due to cross flow as shown in Figure 5.80.

The upper most Reservoir A is opened when the production from reservoirs (B,C,D) drops below the plateau rate. This reservoir produces high gas rate and drops gradually. There is no cross flow for this reservoir. The cumulative production for Reservoir A is 23.8 MMMscf as depicted in Figure 5.80.

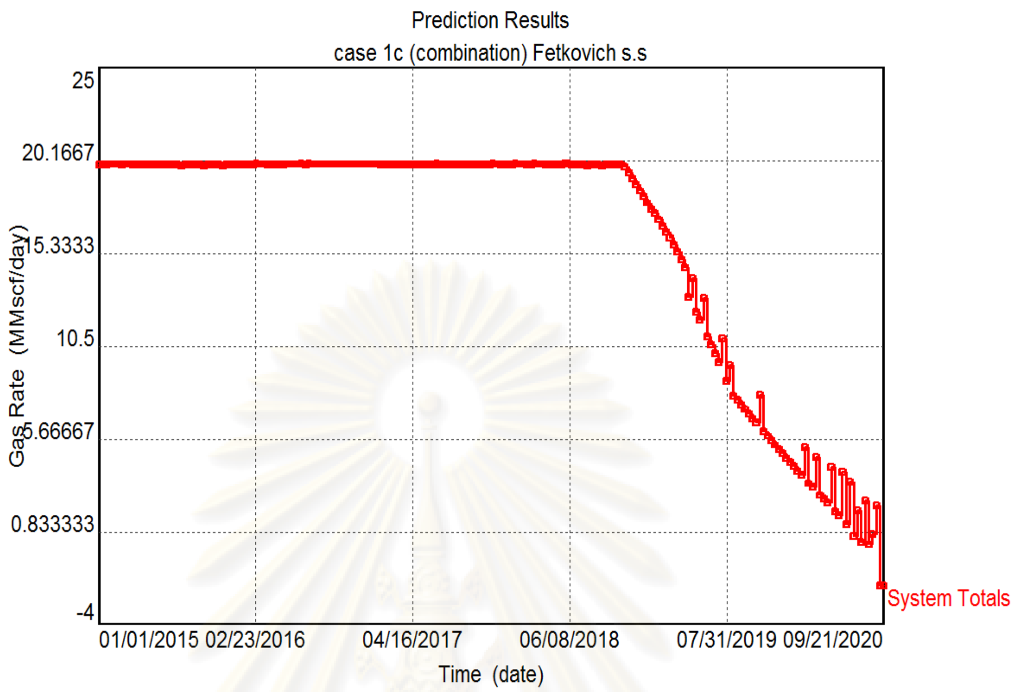

Figure 5.77 : Prediction result for case 3 : scenario 1c

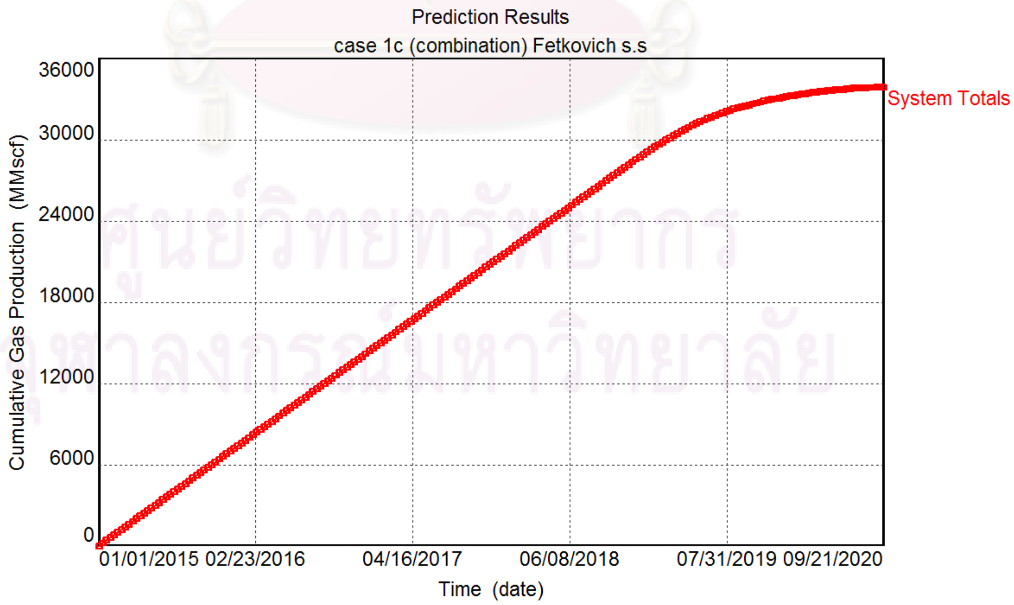

Figure 5.78 : Cumulative gas production versus time (case 3 : scenario 1c)

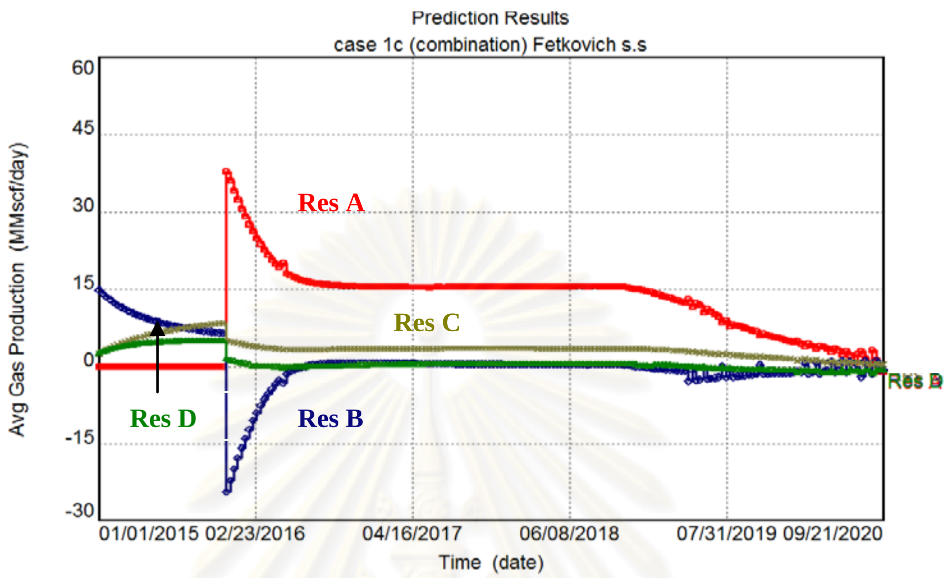

Figure 5.79 : Average gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 1c)

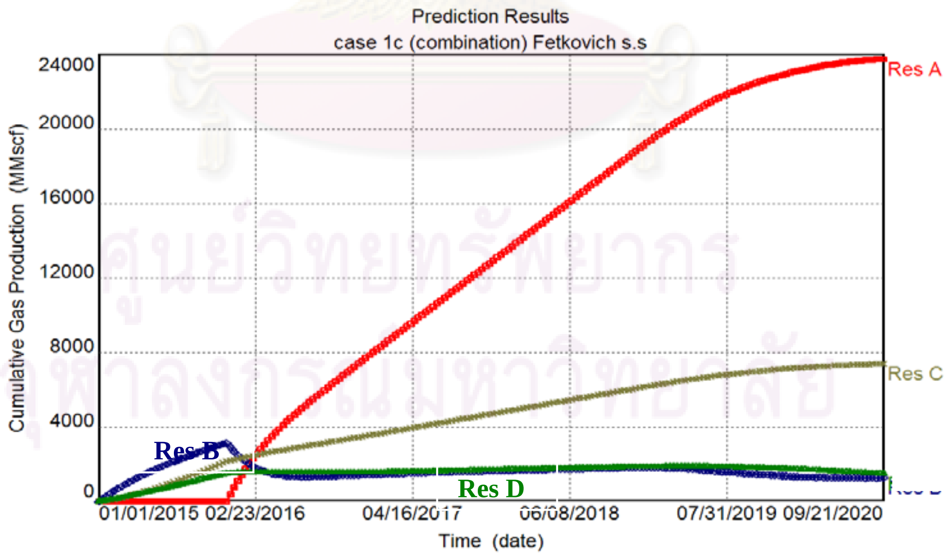

Figure 5.80 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 1c)

Scenario 2a: Permeability Selective (High Permeability Reservoirs First)

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.3. In this scenario, the high permeability reservoirs (A,B) are produced first. When the rate drops below the plateau rate, the next two low permeability reservoirs (C,D) are opened. The gas production rate for this scenario is shown in Figure 5.81. The overall cumulative production for this scenario is 32.3 MMMscf as shown in Figure 5.82.

First, Reservoir A is perforated together with Reservoir B. Due to high permeability and high water influx rate, Reservoir A produces at high rate, increases gradually and drops very fast. There is no cross flow from this reservoir. The cumulative production for Reservoir A is 23.7 MMMscf as shown in Figure 5.84.

Reservoir B produces at high rate at the beginning and drops very fast due to small reservoir size. There is cross flow from this reservoir. The cumulative production for Reservoir B is 1.0 MMscf as shown in Figure 5.84.

Then, Reservoir C is perforated together with Reservoir D. The production rate is 6.5 MMscf/d at the beginning and stops at 1.8 MMscf/d. There is no cross flow from this reservoir. The cumulative production for Reservoir C is 6.4 MMMscf as shown in Figure 5.84.

For Reservoir D, The rate is high at the beginning and drops until the cross flow occurs. The cumulative production for Reservoir D increases to 1.3 MMMscf and drops to 1.2 due to cross flow MMMscf (Figure 5.84).

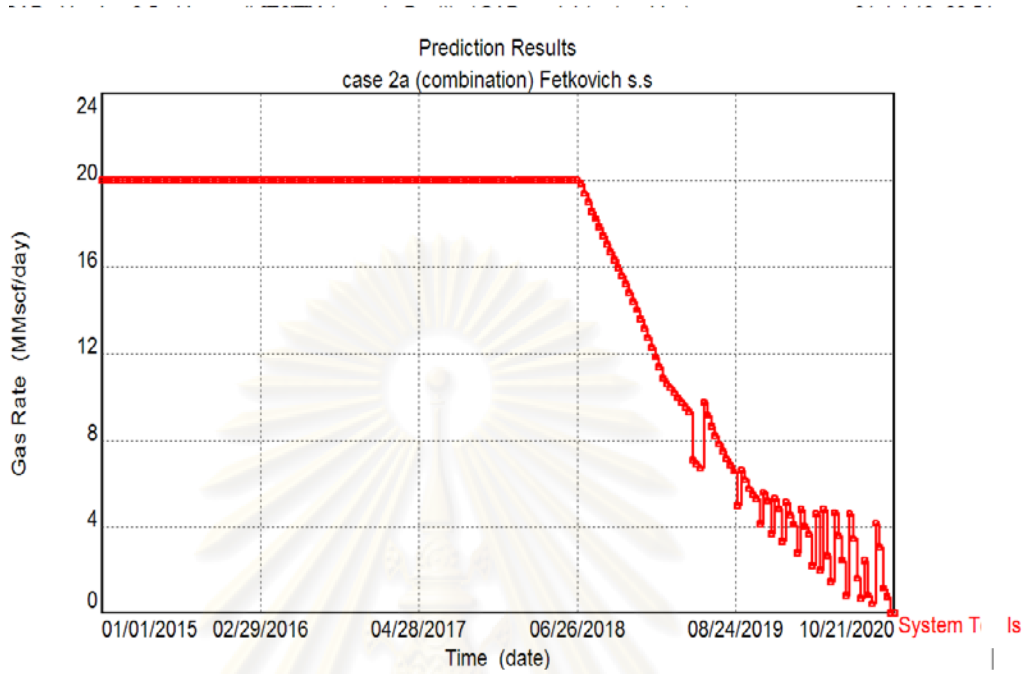

Figure 5.81 : Prediction result for case 3 : scenario 2a

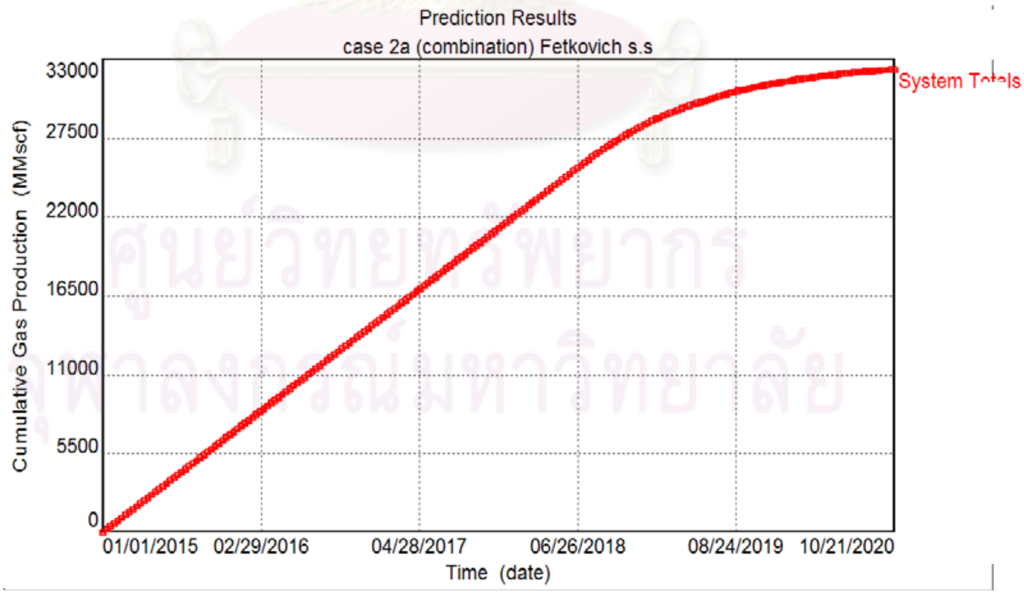

Figure 5.82 : Cumulative gas production versus time (case 3 : scenario 2a)

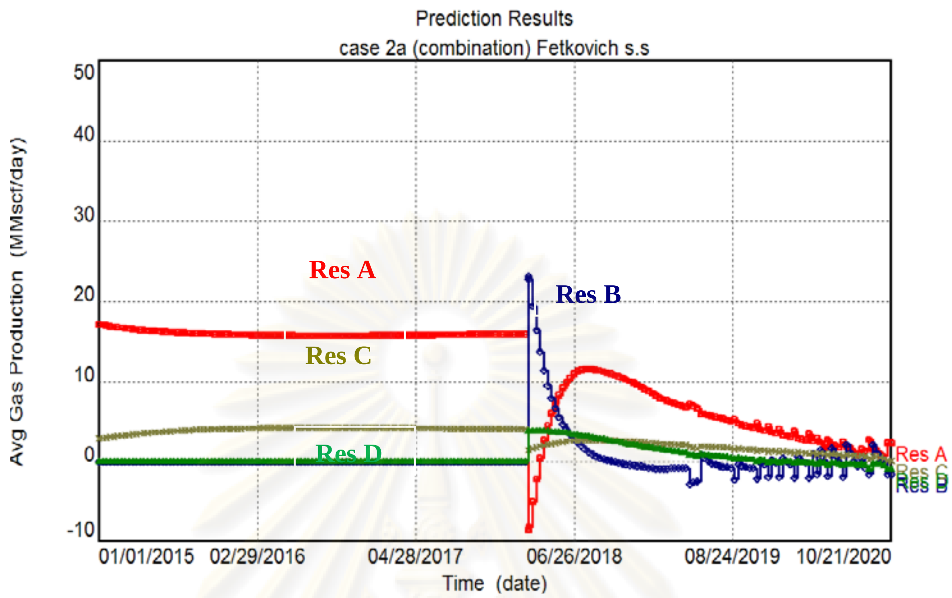

Figure 5.83 : Average gas production versus time for Reservoir A,B,C,D (case 3 : scenario 2a)

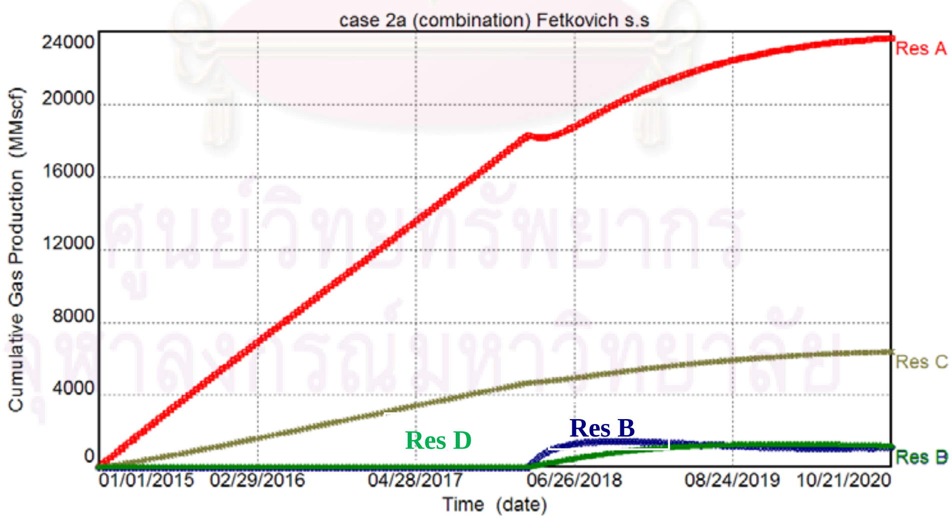

Figure 5.84 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 2a)

Scenario 2b: Permeability Selective (Low Permeability Reservoirs First)

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.3. In this scenario, the low permeability reservoirs (C,D) are produced first. When the rate drops below the plateau rate, the next two high permeability reservoirs (A,B) are opened. The gas production rate for this scenario is shown in Figure 5.85. The overall cumulative production for this scenario is 33 MMMscf as illustrated in Figure 5.86.

First, Reservoir C is perforated together with Reservoir D. Reservoir C produces 10 MMscf/d at the beginning and stops flowing at 8.5 MMscf/d due to high water influx rate. After that, there is cross flow from this reservoir at late time of the production. The cumulative production for Reservoir C is 6.4 MMMscf (see Figure 5.88).

Reservoir D produces 8.5 MMscf/d at the beginning drops and stops flowing at 1.5 MMscf/d. Cross flow occurs from this reservoir. The cumulative production for Reservoir D is 1.4 MMMscf as depicted in Figure 5.88.

Then, Reservoir A is perforated together with Reservoir B. Reservoir A can produce to reach the plateau rate. There is no cross flow for this reservoir. The cumulative production for Reservoir A is 24.0 MMMscf as shown in Figure 5.88.

Reservoir B produces at high production rate and drops gradually until the cross flow occurs. The cumulative production for Reservoir B is 4.4 MMMscf (Figure 5.88).

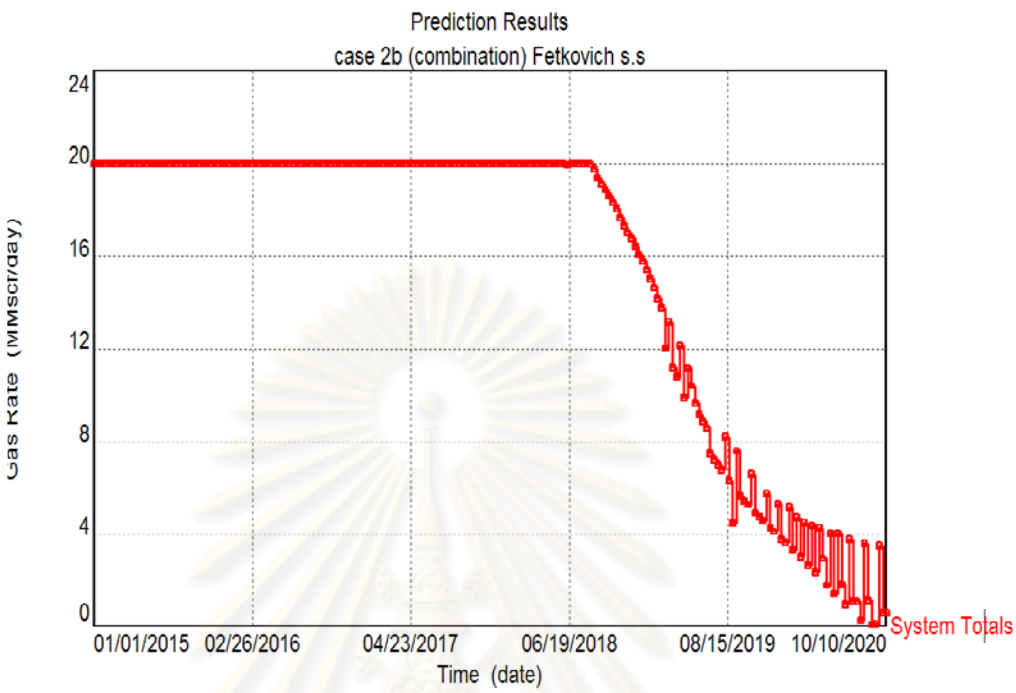

Figure 5.85 : Prediction result for case 3 : scenario 2b

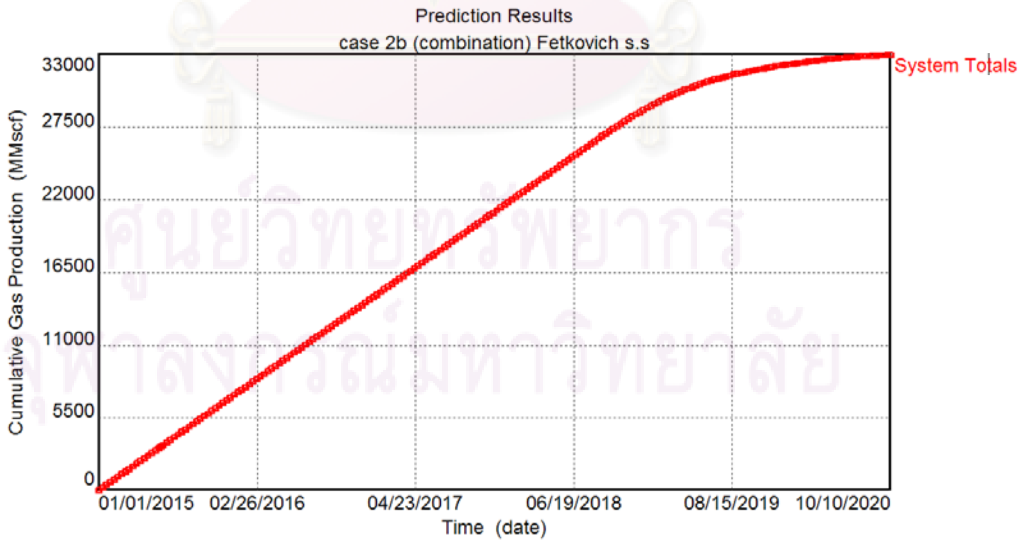

Figure 5.86 : Cumulative gas production versus time (case 3 : scenario 2b)

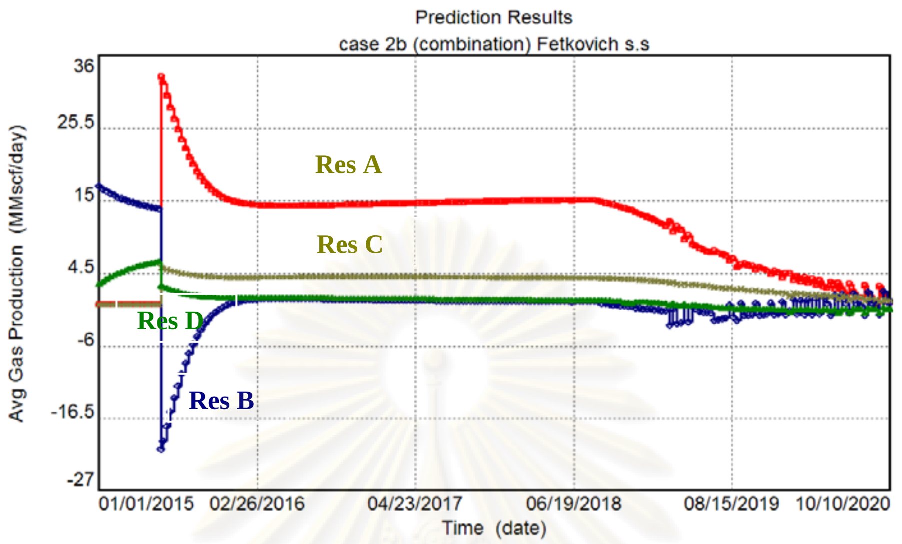

Figure 5.87 : Average gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 2b)

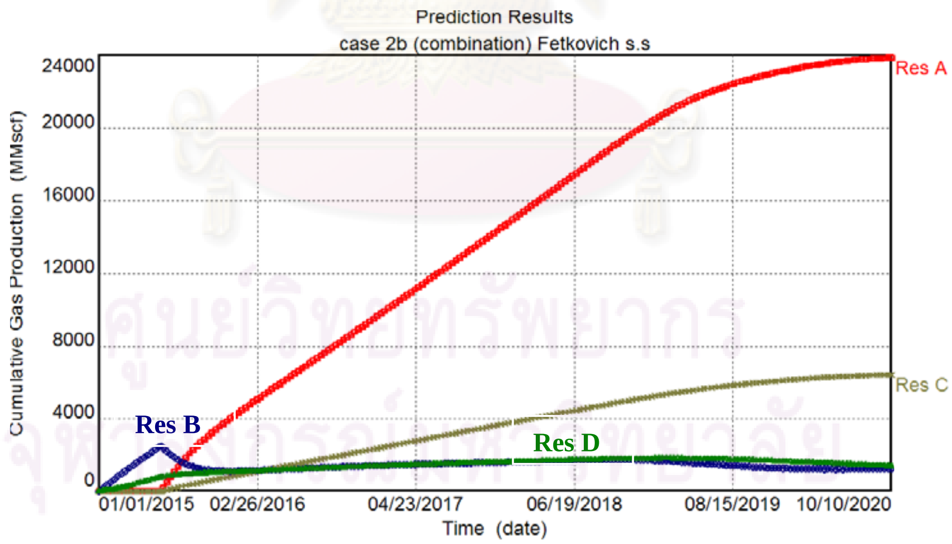

Figure 5.88 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 2b)

Scenario 3a: Reservoir Size Selective (Thick Reservoirs First)

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.3. In this scenario, the thick reservoirs (A,C) are produced first. When the rate drops below the plateau rate, the next two thin reservoirs (B,D) are opened. The production rate for this scenario is shown in Figure 5.89. The overall cumulative production for this scenario is 41.7 MMMscf (Figure 5.90).

First, Reservoir A is perforated together with Reservoir C. Reservoir A can provide the plateau rate with Reservoir C. Reservoir A produces at 17.1 MMscf/d and stops at 16 MMscf/d due to high water influx rate. There is no cross flow from this reservoir. The cumulative production for Reservoir A is 23.6 MMMscf as depicted in Figure 5.92.

The production rate for Reservoir C increases to 4.1 MMscf/d and drops to 1.5 MMscf/d, and then increases again to 2.8 MMscf/d. There is no cross flow from this reservoir. The cumulative production for Reservoir C is 6.3 MMMscf as illustrated in Figure 5.92.

Then, Reservoir B is perforated together with Reservoir D. Reservoir C produces at high rate at the beginning and drops very fast. The production life for this reservoir is very short and there is cross flow from this reservoir. The cumulative production for Reservoir C increases to 1.5 MMMscf and declines to 1.1 MMMscf due to cross flow (Figure 5.92).

For Reservoir D, the production rate at the beginning is 3.8 MMscf/d and drops until the cross flow occurs. The cumulative production for Reservoir D is 1.2 MMMscf (see Figure 5.92).

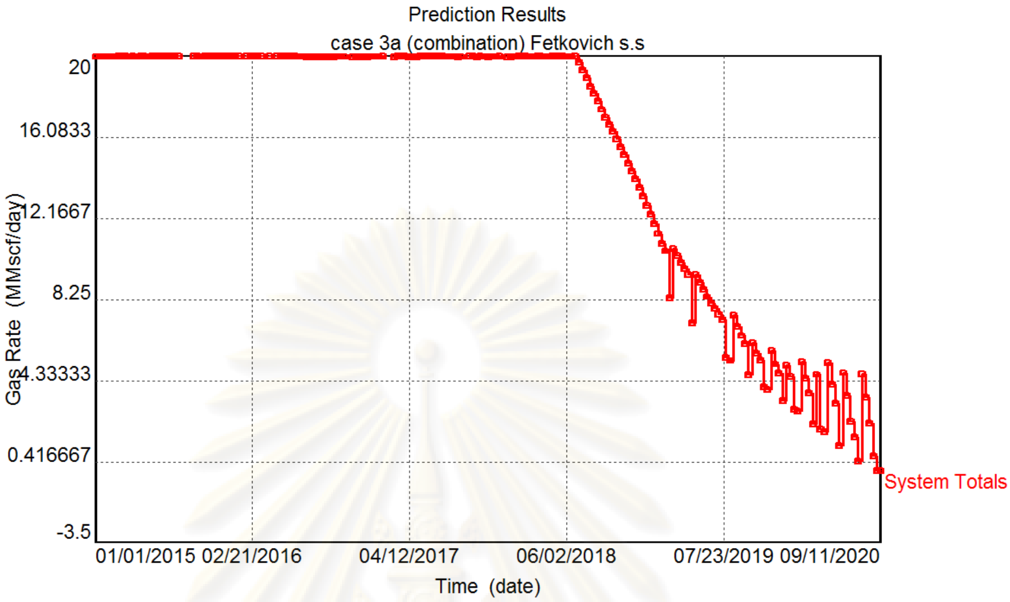

Figure 5.89 : Prediction result for case 3 : scenario 3a

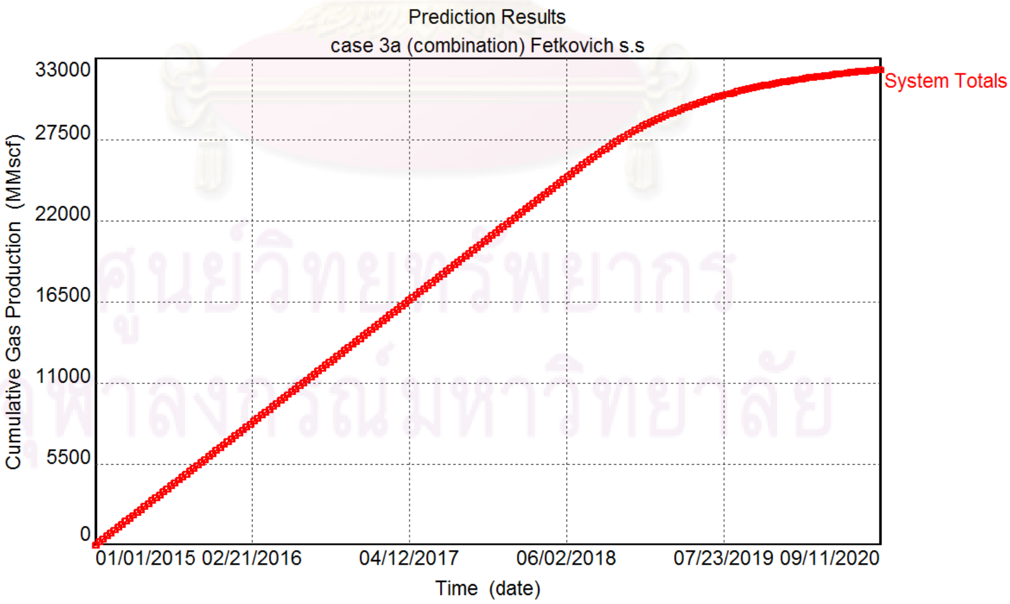

Figure 5.90 : Cumulative gas production versus time (case 3 : scenario 3a)

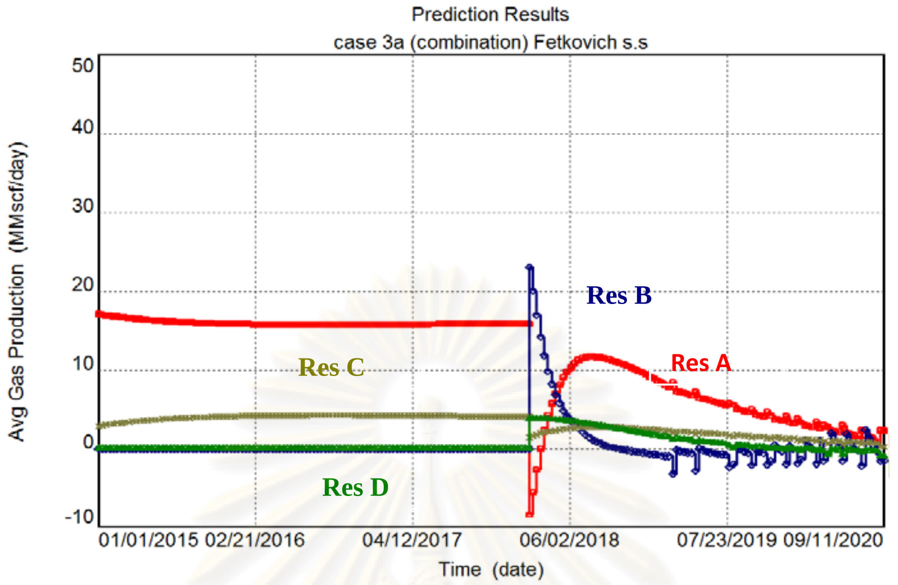

Figure 5.91 : Average gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 3a)

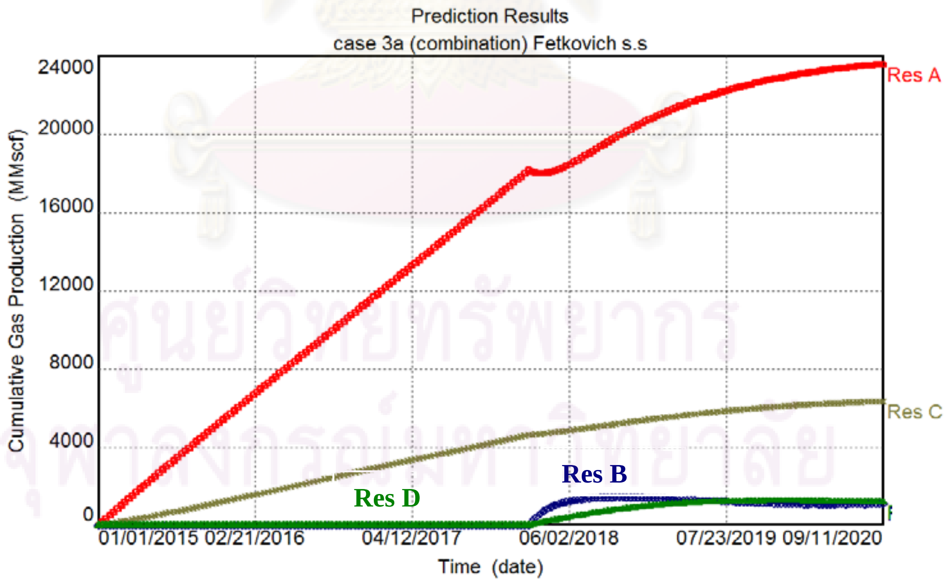

Figure 5.92 : Cumulative gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 3a)

Scenario 3b: Reservoir Size Selective (Thin Reservoirs First)

The RF for this scenario is lower than that of Scenario 1a as listed in Table 5.3. In this scenario, the thin reservoirs (B,D) are produced first. When the rate drops below the plateau rate, the next two thick reservoirs (A,C) are opened. The gas production rate for this scenario is shown in Figure 5.93. The overall cumulative production for this scenario is 32.9 MMMscf as shown in Figure 5.94.

First, Reservoir B is perforated together with Reservoir D. Reservoir B produces 17 MMscf/d at the beginning and drops gradually until cross flow occurs. The cumulative production for Reservoir B reaches 2.6 MMMscf at one point and varies during late production time due to cross flow as depicted in Figure 5.96.

The gas rate from Reservoir D increases to 6.2 MMscf/d and drops very fast. Cross flow can be seen from this reservoir. The cumulative production for Reservoir D increases to 1.8 MMMscf and declines to 1.4 MMMscf due to cross flow (Figure 5.96).

Then, Reservoir A is perforated together with Reservoir C. For Reservoir A, the high production rate is high at the start of production, then declines, and becomes stable at 14 MMscf/d for a few years and drops until the economic limit is reached. There is no cross flow from this reservoir. The cumulative production for Reservoir A is 23.8 MMMscf (Figure 5.96).

Reservoir C produces at 5.3 MMscf/d and declines right away. Cross flow is not observed in this reservoir. The cumulative production for Reservoir C is 6.4 MMMscf (Figure 5.96).

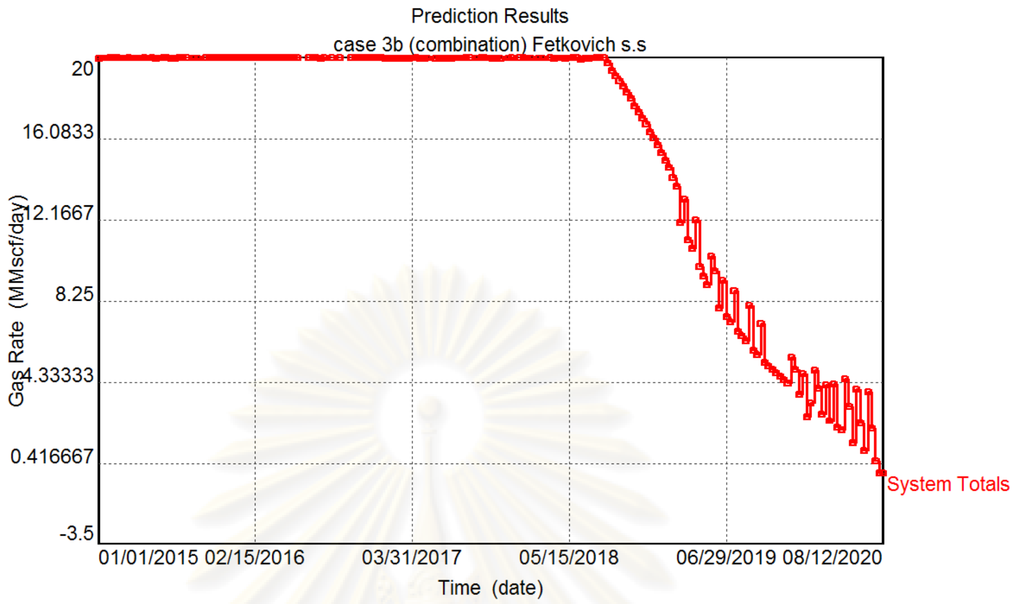

Figure 5.93: Prediction result for case 3 : scenario 3b

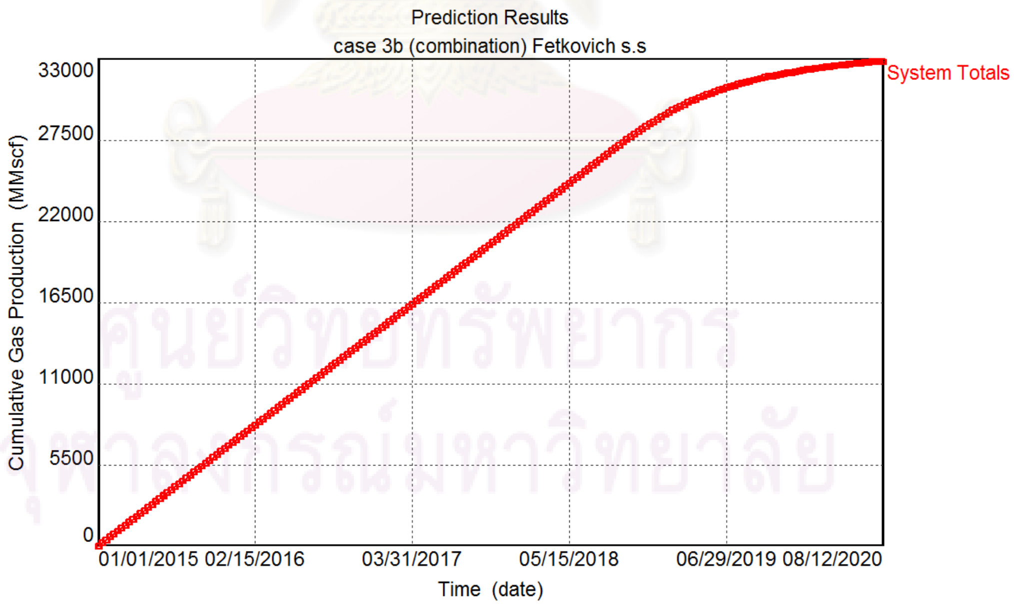

Figure 5.94 : Cumulative gas production versus time (case 3 : scenario 3b)

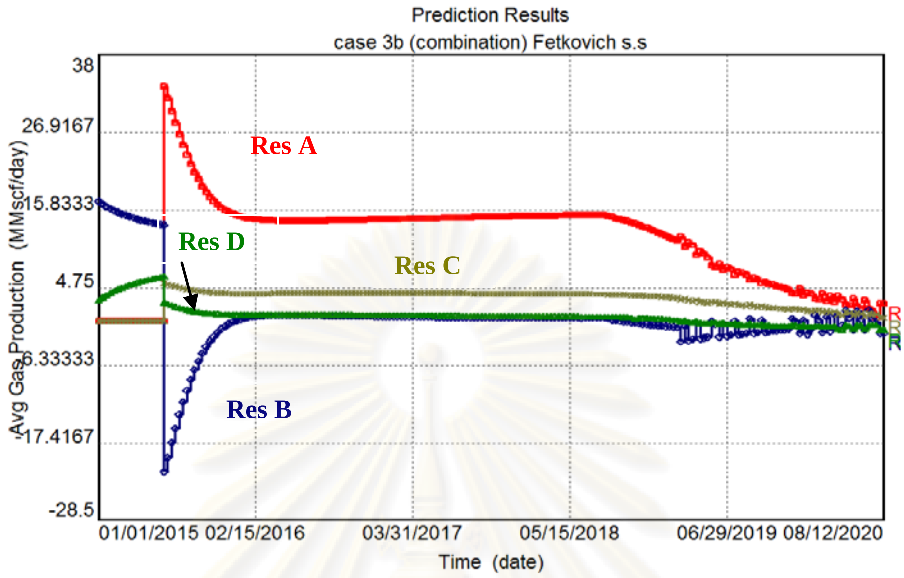

Figure 5.95 : Average gas production versus time for Reservoirs A,B,C,D

(case 3 : scenario 3b)

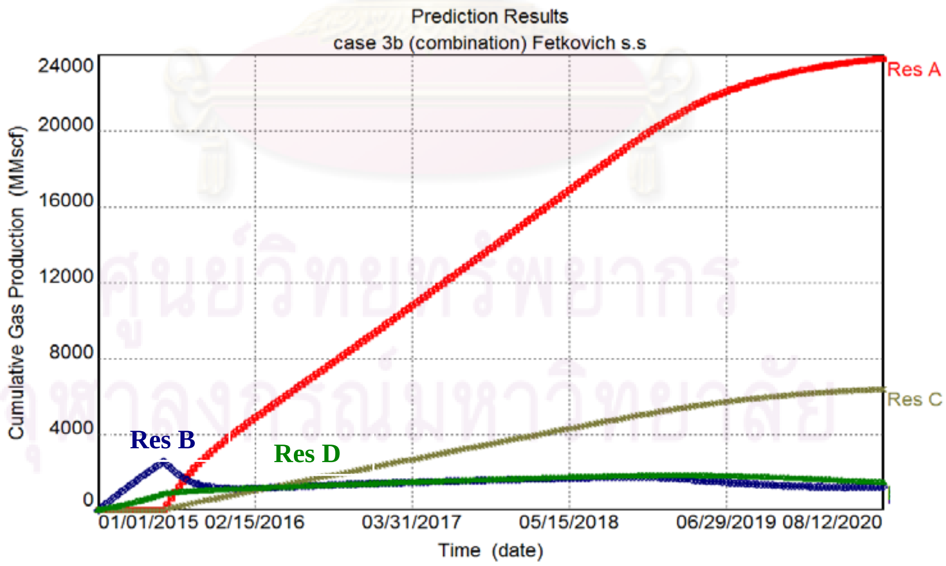

Figure 5.96 : Cumulative gas production versus time for Reservoirs A,B,C,D

(case 3 : scenario 3b)

Scenario 4a: Commingled

This scenario provides lower RF than that of Scenario 1a as listed in Table 5.3. In this scenario, all reservoirs (A,B,C,D) are perforated at the same time since the start of production. The gas production rate for this scenario is shown in Figure 5.97. The cumulative gas production for this scenario is 32.7 MMMscf (Figure 5.98).

The uppermost Reservoir A is perforated altogether with the other reservoirs. It can provide the plateau rate for this scenario. There is no cross flow from this reservoir. The cumulative production for Reservoir A is 23.6 MMMscf (see Figure 5.100).

Reservoir B produces at high rate at the beginning and declines right away until the cross flow is flowed. The cumulative production for Reservoir B increases to 1.7 MMMscf and declines to 1.2 MMMscf due to cross flow as shown in Figure 5.100.

The production rate for Reservoir C varies along the production life. There is no cross flow from this reservoir. The cumulative production for Reservoir C is 6.4 MMMscf as illustrated in Figure 5.100.

The production rate for Reservoir D increases to 2.2 MMscf/d and declines right away until cross flow is observed. The cumulative production for Reservoir D increases to 1.8 MMMscf and declines to 1.5 MMMscf due to cross flow as shown in Figure 5.100.

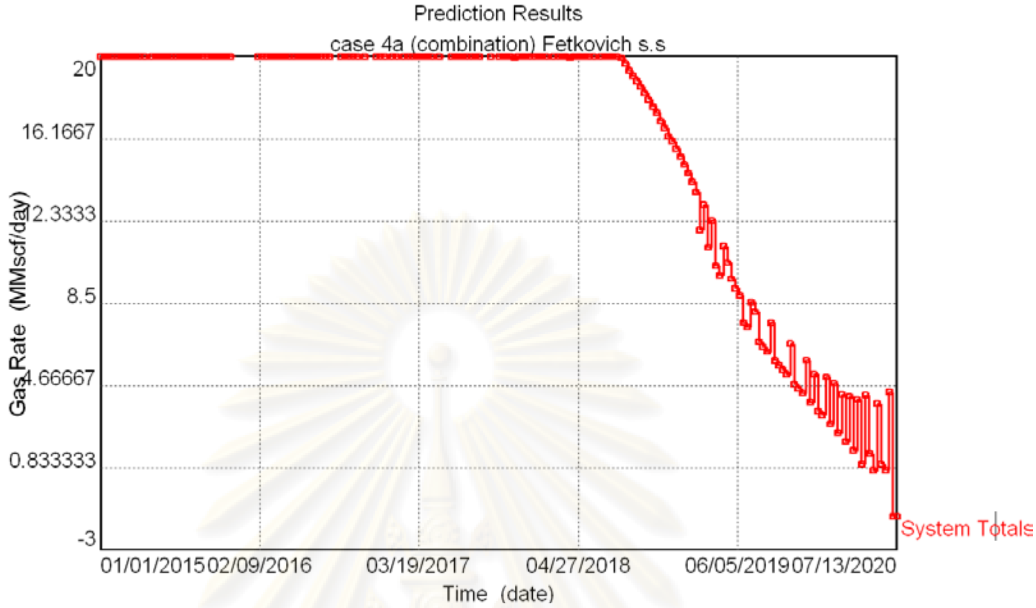

Figure 5.97 : Prediction result for case 3 : scenario 4a

Figure 5.98 : Cumulative gas production versus time (case 3 : scenario 4a)

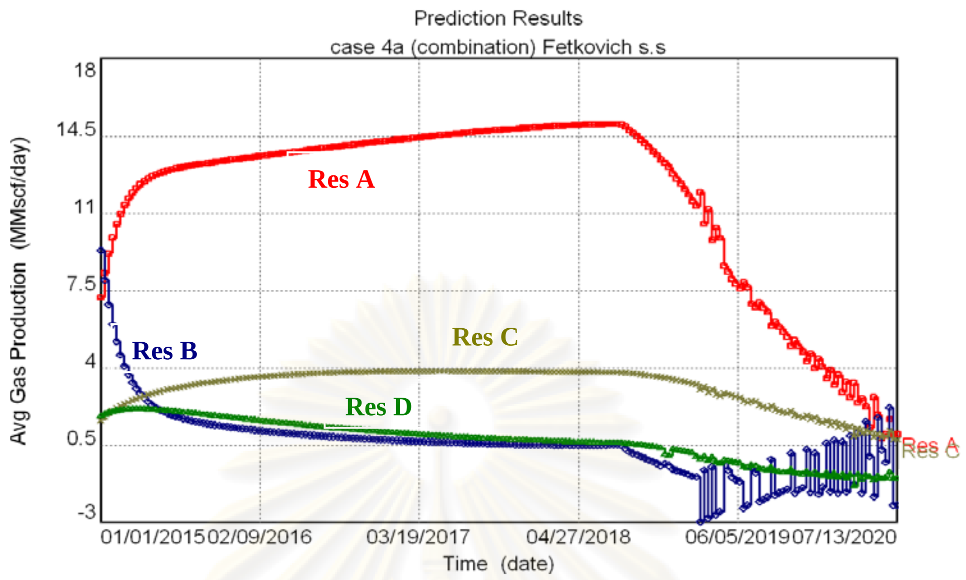

Figure 5.99 : Average gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 4a)

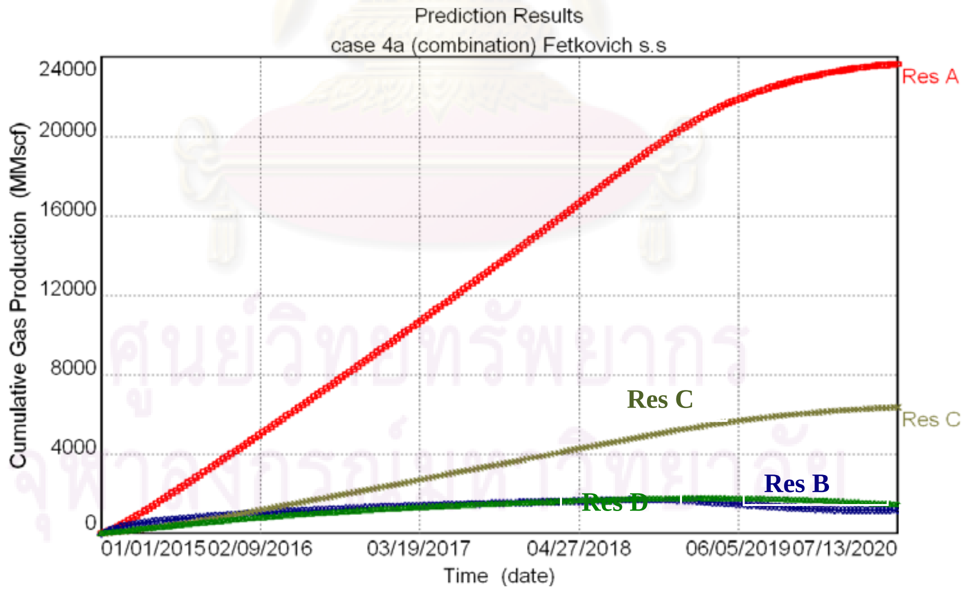

Figure 5.100: Cumulative gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 4a)

Scenario 4b: Commingled with Water Shut off

This scenario provides the highest RF as listed in Table 5.3. All reservoirs (A,B,C,D) are perforated at the same time since the start of production but when any reservoir produces water more than 1,000 bbl/MMscf, we shut in the reservoir and leave the other reservoirs producing. The gas production rate for this scenario is depicted in Figure 5.101. All reservoirs can provide the plateau rate for this scenario. The overall cumulative production for this scenario is 56.7 MMMscf as shown in Figure 5.102.

Reservoir A is perforated together with the other Reservoirs (B,C,D) at the same time. This reservoir produces at high production rate that can provide plateau rate due to big reservoir size. Due to high permeability, when the water production reaches 1,000 bbl/MMscf which is after two years production, we shut off this reservoir and then leave the other reservoirs producing. The cumulative production for Reservoir A is 12.6 MMMscf (Figure 5.104).

Reservoir B is volumetric-depletion drive. There is no water production. The reservoir can produce for a long time which helps increase the recovery efficiency. The cumulative production for Reservoir B is 1.5 MMMscf (Figure 5.104).

Reservoir C is perforated together with the other Reservoirs (A,B,D) at the same time. Although this reservoir is under water drive, it produces gas for the longest time. There is no water production due to low permeability and big reservoir size. The cumulative production for Reservoir C is 37.0 MMMscf (Figure 5.104).

Reservoir D is volumetric-depletion drive. Hence, there is no water production. The reservoir can produce for a long time. The cumulative production for Reservoir D is 5.7 MMMscf (Figure 5.104).

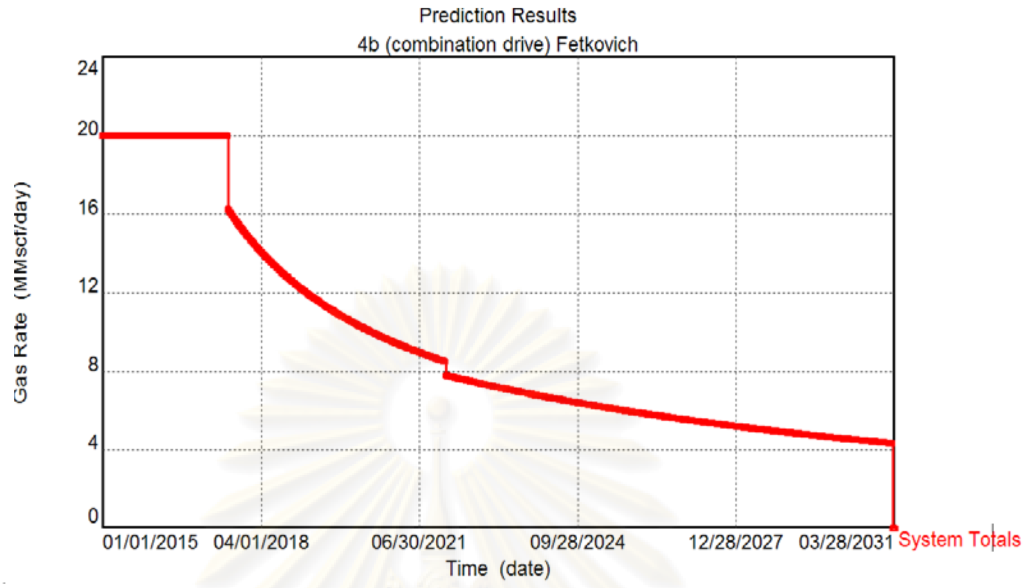

Figure 5.101 : Prediction result for case 3 : scenario 4b

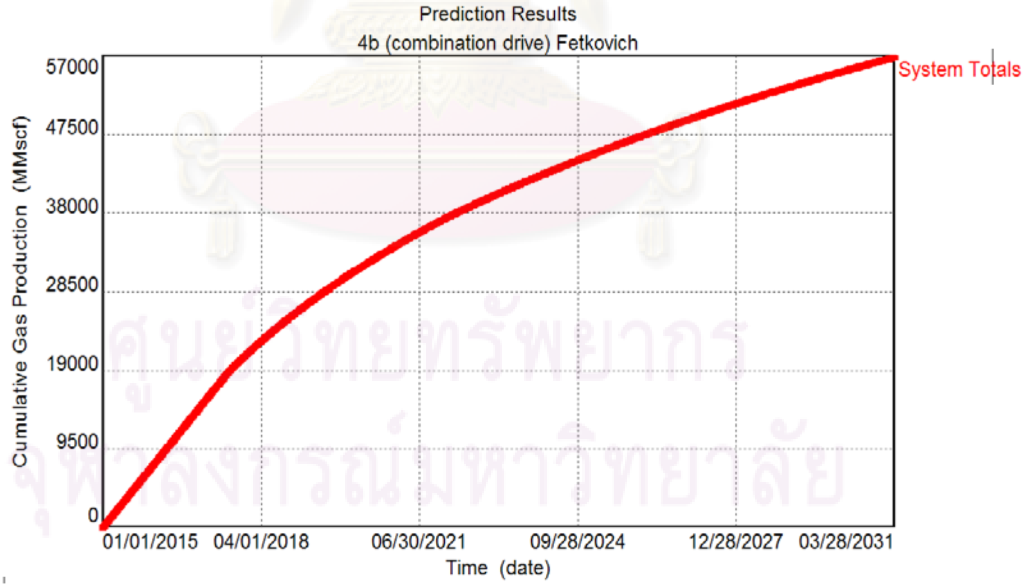

Figure 5.102 : Cumulative gas production versus time (case 3 : scenario 4b)

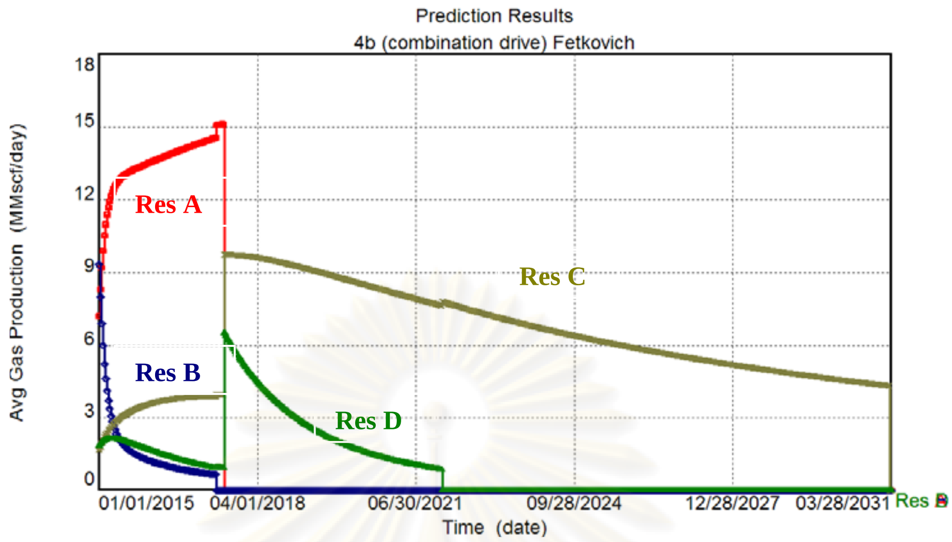

Figure 5.103 : Average gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 4b)

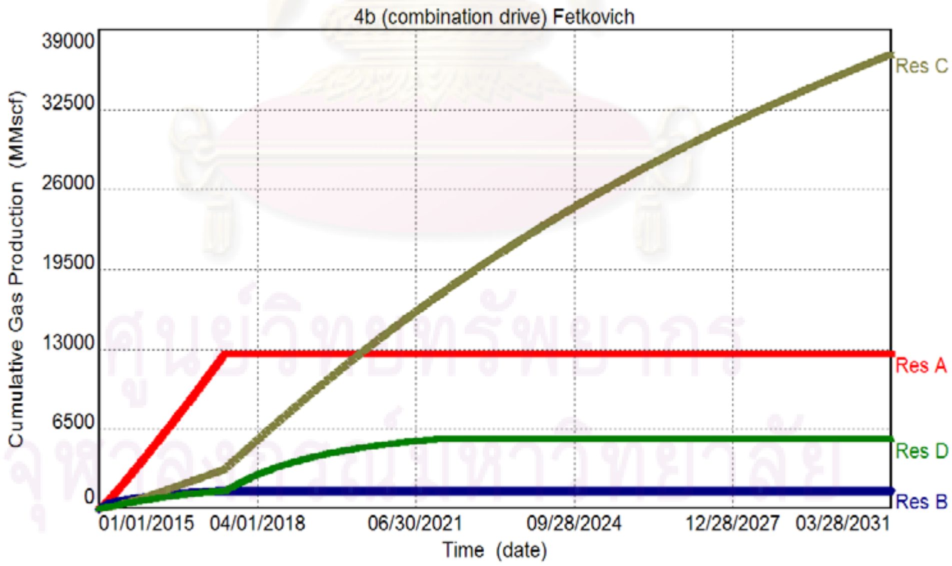

Figure 5.104: Cumulative gas production versus time for Reservoirs A,B,C,D (case 3 : scenario 4b)

5.4 Summary for Volumetric-Depletion Drive Gas Reservoirs

Table 5.4: Observation from volumetric-depletion drive gas reservoirs results for case 1

Scenario	RF (%)	Cross Flow (% of OGIP)	Cumulative Production (MMMscf)	Production Time (Years)
1a	81.60	0	95.6	80
1b	81.55	4.84	95.5	60
1c	79.92	0.40	93.7	65
2a	81.29	0.14	95.2	53
2b	81.51	0	95.5	60
3a	81.52	1.11	95.5	60
3b	81.56	0.40	95.4	61
4a	81.61	0	95.6	61

The followings are observed from Table 5.4:

The level of cross flow is in the range of 0 - 4.84 % of OGIP. In fact, these amounts of cross flow are recovered at later time. The disadvantage of cross flow is the delay in recovering gas that crosses into other reservoirs. The cross flow volume is the highest in Scenario 1b : Bottom-up (Half depleted). The level of cross flow can be larger where the rock and fluid properties are good and difference in reservoir pressure between each reservoir is high. The cross flow level can be reduced by avoiding opening of new reservoir when the producing reservoir pressure is low.

The cross flow volume is none for Scenarios 2b (Low permeability reservoirs first) and 4a (Commingled). The recovery efficiency in each case is almost similar. Scenario 4a (Commingled) provides the highest RF, the longest production life, and also the cumulative production.

5.5 Summary for Water Drive Gas Reservoirs

Table 5.5: Observation from water drive gas reservoirs results for case 2

Scenario	RF (%)	Cross Flow (% of OGIP)	Cumulative Production (MMMscf)	Production Time (Years)
1a	62.90	0	73.7	23
1b	20.80	0.76	24.4	4
1c	32.95	0	38.6	12
2a	28.69	0.10	33.6	11
2b	29.02	0.10	34.0	5
3a	27.83	0.22	32.6	7
3b	29.39	0.16	34.5	11
4a	28.94	0.07	34.0	11
4b	45.10	0	52.8	16

The followings are observed from Table 5.5:

The level of cross flow is in the range of 0 – 0.76 % of OGIP. The cross flow volume is the highest in Scenario 1b : Bottom-up (Half depleted) and none for Scenario 1c : Bottom-up (Maintain the plateau rate) and Scenario 4b (Commingled with water shut off). Scenario 1a : Bottom-up (Fully depleted) provides the highest RF and cumulative production among other scenarios for water drive gas reservoirs. This scenario also provides the longest production life.

5.6 Summary for Combination Drive Gas Reservoirs

Table 5.6: Observation from combination drive gas reservoirs results for case 3

Scenario	RF (%)	Cross Flow (% of OGIP)	Cumulative Production (MMMscf)	Production Time (Years)
1a	34.09	0	40.0	9
1b	40.17	4.50	47.1	9
1c	28.93	0.86	33.9	4
2a	27.54	0.23	32.26	5
2b	28.13	2.03	33.0	11
3a	27.52	0.34	32.2	5
3b	28.05	0.81	32.9	5
4a	28.94	0.32	32.7	5
4b	48.41	0	56.7	16

The followings are observed from Table 5.6:

The level of cross flow is in the range of 0.23 – 4.50 % of OGIP. The cross flow volume is the highest in Scenario 1b : Bottom-up (Half depleted) and none for Scenario 4b. Scenario 4b (Commingled with water shut off) provides the highest RF and cumulative production among other scenarios for combination drive gas reservoirs. This scenario also provides the longest production life.

CHAPTER VI

CONCLUSIONS AND REMARKS

This chapter provides the conclusions for 3 cases on the effect of various perforation/production scenarios with different drive mechanisms for multilayered gas reservoirs.

The reservoir model is built using single well model based on bar and channel sands that are commonly encountered in gas fields in Gulf of Thailand (GoT).

There are 3 cases in this study:

Case 1 : all reservoirs are depletion-drive gas reservoirs.

Case 2: all reservoirs are water-drive gas reservoirs

Case 3: two reservoirs are depletion-drive and another two reservoirs are water-drive.

There are 6 main perforation/production scenarios used in this study on each of the cases as follows:

1. Bottom-up: In this scenario, the deepest reservoir is produced first and then the next upper reservoirs are opened in sequence. This scenario allows the plugging of depleted reservoirs without problem on the next upper reservoirs. This scenario is commonly applied in gas fields in Gulf of Thailand. There are four scenarios in this study.

   1a. Fully depleted: In this scenario, The deepest reservoir is produced first until the economic limit and then the next upper reservoirs are opened in sequence.

   1b: Half depleted: In this scenario, the deepest reservoir is produced first until the rate drops below half the origin rate and then the next upper reservoirs are opened in sequence.

   1c: Maintain the plateau rate: In this scenario, the deepest reservoir is produced first until the rate drops below the origin rate and then the next upper reservoirs are opened in sequence.

2. Permeability Selective

   2a. The high permeability reservoirs are produced first until the rate drops below the plateau rate and then the next low permeability reservoirs (C&D) are opened.

2b. The low permeability reservoirs are produced first until the rate drops below the plateau rate and then the next high permeability reservoirs are opened.

3. Reservoir Size Selective

3a. Thick reservoirs are produced first until the rate drops below the plateau rate and then the next thin reservoirs are opened.

3b. Thin reservoirs are produced first until the rate drops below the plateau rate and then the next thick reservoirs are opened.

4. Commingled

4a. All reservoirs are opened together since the first day of production.

4b. All reservoirs are produced together but when any reservoir produces water more than 1000 bbl/MMscf, we shut off the reservoir and leave the other reservoirs producing.

The results are compared in terms of RF, percentage of cross flow from one reservoir to another, and cumulative production as listed in Tables 5.4, 5.5 and 5.6.

6.1 Conclusions

Based on the study, the results can be summarized as follows:

1. The level of cross flow through well in multilayered gas reservoirs depends on two main factors: one is the difference between the reservoir pressures and another is the reservoir rock and fluid properties.
2. There are two factors that affect gas production from multilayered gas reservoirs with active aquifer (water influx). The first one is that the aquifer, as it expands through lowering reservoir pressure, traps the gas behind and reduces the recovery efficiency. This factor affects each individual reservoir. The second one is the water breakthrough which increases the pressure loss in tubing and thus increases bottom-hole flowing pressure. This factor affects all reservoirs. It creates difference in recovery efficiency for different production scenarios.

3. Permeability is another factor that plays an important role in production scenarios in term of recovery efficiency. The higher the permeability, the shorter the production life for multilayered gas reservoirs.
4. In volumetric-depletion drive gas reservoirs, Scenario 4a (Commingled) provides the optimal scenario in multilayered gas reservoirs. However, there is no significant difference in RF among different scenarios. Commingled production also reduces the well production problems such as well intervention to perforate other reservoirs and workover
5. In water drive gas reservoirs, Scenario 1a : Bottom-up (Fully Depleted) provides the highest RF among the other scenarios that avoids high water with less gas production. The water production problems depend on the active aquifer and the reservoir characteristics such as permeability, relative gas permeability of the gas and distance from water zone to well.
6. In combination drive gas reservoirs (both volumetric-depletion drive and water drive), the Scenario 4b : (Commingled with water shut off) provides the highest RF and the cumulative gas production among the other scenarios.

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