ENHANCED OIL RECOVERY BY WATER ALTERNATING GAS INJECTION USING COMPUTER SIMULATION OF OIL FIELDS IN PHITSANULOK BASIN

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การเพิ่มปริมาณการผลิตน้ำมันด้วยวิธีอัดน้ำสลับก๊าซโดยใช้แบบจำลองคอมพิวเตอร์ของแหล่งน้ำมันในแอ่งพิษณุโลก

นางสาวสุภัทรา จตุรคณาวาณิชย์

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต

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Suranaree University of Technology has approved this thesis submitted in partial fulfillment of the requirements for a Master's Degree.

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สุภัทรา จตุรคณาวาณิชย์ : การเพิ่มปริมาณการผลิตน้ำมันด้วยวิธีอัดน้ำสลับก๊าซ โดยใช้แบบจำลองคอมพิวเตอร์ของแหล่งน้ำมันในแอ่งพิษณุโลก (ENHANCED OIL RECOVERY BY WATER ALTERNATING GAS INJECTION USING COMPUTER SIMULATION OF OIL FIELDS IN PHITSANULOK BASIN) อาจารย์ที่ปรึกษา : อาจารย์ ดร.อัฆพรรค์ วรรณโกมล, 175 หน้า.

การอัดน้ำสลับก๊าซเป็นวิธีการหนึ่งที่มีประสิทธิภาพในการเพิ่มปริมาณการผลิตปิโตรเลียมจากแหล่งกักเก็บปิโตรเลียม วิธีการนี้ได้รวมข้อดีของวิธีการอัดน้ำเข้ากับวิธีการอัดก๊าซธรรมชาติเข้าด้วยกัน การอัดน้ำสลับก๊าซสลับกันไปเรื่อย ๆ นั้นสามารถทำให้เพิ่มประสิทธิภาพการกวาดน้ำมันที่ผลิตในระดับจุลภาคได้ ในการศึกษาครั้งนี้วิธีการดังกล่าวได้ถูกนำมาใช้กับแหล่งน้ำมันที่ถูกสร้างจำลองขึ้นซึ่งตั้งอยู่ภายในแอ่งสะสมตะกอนพิษณุโลกเพื่อคาดการณ์สภาพการผลิตน้ำมันที่เหมาะสมโดยการใช้แบบจำลองแหล่งกักเก็บคอมพิวเตอร์ แหล่งน้ำมันที่ถูกสร้างจำลองขึ้นมานี้เป็นแหล่งที่มีปริมาณสำรองที่สามารถผลิตขึ้นมาได้ขนาด 5 ล้านบาร์เรล และจะถูกทำการทดสอบการอัดน้ำสลับก๊าซแบบให้ผสมเป็นเนื้อเดียวกัน แผนการปฏิบัติการของแหล่งน้ำมันที่ถูกสร้างขึ้นมานี้ถูกออกแบบให้เป็น 5 รูปแบบด้วยกัน ประกอบด้วย แบบไม่มีการอัดน้ำสลับก๊าซ แบบที่มีการอัดน้ำสลับก๊าซในปีที่ 1 แบบที่มีการอัดน้ำสลับก๊าซในปีที่ 2 แบบที่มีการอัดน้ำสลับก๊าซในปีที่ 4 และแบบที่มีการอัดน้ำสลับก๊าซในปีที่ 8 ภายหลังจากการปล่อยให้มีการผลิตโดยไหลแบบธรรมชาติ ตามลำดับ การผลิตที่เหมาะสมที่ได้จากการศึกษาของแต่ละรูปแบบจะถูกนำไปวิเคราะห์ทางเศรษฐศาสตร์ ผลกระทบจากราคาน้ำมันและตัวคูณส่วนลดต่อผลกำไรของแต่ละรูปแบบการปฏิบัติการจะถูกนำมาศึกษาด้วยการทำการวิเคราะห์ความไวด้วย ผลที่ได้จากการศึกษาพบว่ารูปแบบการปฏิบัติการที่มีประสิทธิภาพมากที่สุดคือการอัดน้ำสลับก๊าซในปีที่ 2 ของการผลิต ซึ่งจะมีประสิทธิภาพในการผลิตน้ำมันถึง 71.05 เปอร์เซ็นต์

สาขาวิชาเทคโนโลยีธรณี	ลายมือชื่อนักศึกษา ______________________
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SUPHATTRA JATURAKHANAWANIT : ENHANCED OIL RECOVERY BY WATER ALTERNATING GAS INJECTION USING COMPUTER SIMULATION OF OIL FIELDS IN PHITSANULOK BASIN. THESIS ADVISOR : AKKHAPUN WANNAKOMOL, Ph.D., 175 PP.

WATER ALTERNATING GAS INJECTION/RECOVERY EFFICIENCY/ COMPUTER RESERVOIR SIMULATION/PHITSANULOK BASIN

Water Alternating Gas injection (WAG) is a powerful method that can be applied to increase petroleum recovery efficiency of petroleum reservoirs. It is a method that combines advantages of waterflooding and gas injection methods. Repetition of the WAG injection process can further improve sweep efficiency in micro scale. In this study WAG was applied to a setup oil field located within the Phitsanulok Basin to estimate its optimized operation condition by using reservoir simulation approach. The setup oil field has 5 MMSTB recovery size and it was applied miscibility flood for WAG test. Operation plan of the setup oil field was designed to 5 scenarios as no injection, 1st year, 2nd year, 4th year, and 8th year after natural flow production periods, respectively. The resulted optimum operation of each scenario was then used to do economic analysis. Effect of oil price and discount factor to the economic return of each scenario were also studied by doing sensitivity analysis. As the result, it was found that the most effective scenario was the 2nd year injection of WAG which has recovery efficiency 71.05%.

School of Geotechnology | Student Signature ____________________

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LIST OF ABBREVIATIONS

BBL, bbl	=	Barrel
BHP	=	Bottom hole pressure
C	=	Land's parameter
C_{kg}	=	Mass fraction of component k present in the gas phase
C_{ko}	=	Mass fraction of component k present in the oil phase
C^{trans}	=	Transition parameter of Land's parameter
Capex	=	Capital expense
FGPR	=	Field gas production rate
FGOR	=	Field gas-oil-ratio
FGPT	=	Field gas production total
FOPR	=	Field oil production rate
FOPT	=	Field oil production total
FPR	=	Field pressure
FWCT	=	Field water cut
FWPR	=	Field water production rate
FWPT	=	Field water production total
IRR	=	Internal rate of return
K	=	Absolute permeability
K_{igo}	=	Absolute permeability
K_{rg}^{drain}	=	Calculated secondary drainage relative permeability as a function of S_g

LIST OF ABBREVIATIONS (Continued)

K_{rg}^{input}	=	Input relative permeability at S_g
$K_{rg}^{input}(Sg^{start})$	=	Input relative permeability at the gas saturation at the start of the secondary drainage curve
$K_{rg}^{imb}(Sg^{start})$	=	The relative permeability at the start of the secondary drainage process (that is the Kr at the end of the imbibition curve)
K_{ro}	=	Oil relative permeability
K_{rocw}	=	Oil relative permeability in the presence of connate water only
k_{rog}	=	Oil relative permeability for a system with oil, gas and connate water
k_{row}	=	Oil relative permeability for a system with oil and water only
K_{rni}	=	Relative permeability for a particular saturation on the scanning curve
K_{rni}	=	Relative permeability values on the imbibition curves
K_{rnd}	=	Relative permeability values on the drainage curves
K_{rw}^{drain}	=	Calculated drainage relative permeability
K_{rw}^{imb}	=	Calculated imbibition relative permeability
K_{rw2}	=	Two-phase relative permeability at Sw

LIST OF ABBREVIATIONS (Continued)

K_{rw3}	=	Three-phase relative permeability at Sw
MSCF/STB	=	Thousand cubic feet per stock tank barrel
MMbbl	=	Million barrels
MMUS$	=	Million US$
MSCF	=	Thousand cubic feet
MW	=	Molecular weight
OPEX	=	Operation expense
P	=	Pressure
Pb	=	Bubble point pressure
Pc	=	Critical pressure
Pcgo	=	Capillary pressure in gas-oil phase
Pcow	=	Capillary pressure in oil-water phase
PI	=	Productivity index
PIR	=	Profit per investment ratio
Pg	=	Pressure in gas phase
Po	=	Pressure in oil phase
Pw	=	Pressure in water phase
RB	=	Reservoir barrel
RF	=	Recovery factor
S_{gcr}	=	Critical gas saturation
Sg^{drain}	=	Gas saturation at the start of the drainage process
S_{gm}	=	Maximum gas saturation

LIST OF ABBREVIATIONS (Continued)

$Sg_{\max}$	=	Maximum attainable gas saturation
Sg_{start}	=	Gas saturation at the start of the imbibition process
S_{gtd}	=	Dynamic trapped saturation
S_{gtrap}	=	Trapped gas saturation
S_{hy}	=	Maximum non-wetting phase saturation
S_{ncri}	=	Critical saturation of the imbibition curve
S_{ncrd}	=	Critical saturation of the drainage curve
S_{ncrt}	=	Trapped critical saturation
S_{nmax}	=	Maximum saturation value
So_{gcr}	=	The critical oil-to-gas saturation.
S_{om}	=	Minimum residual oil saturation
S_{owcr}	=	Minimum of the critical oil-to-water saturation
S_{ogcr}	=	Minimum of the critical oil-to-gas saturation
$S_{ogcr}^{(d)}$	=	The critical oil-to-gas drainage
$S_{ogcr}^{(h)}$	=	The critical oil-to-gas actual
$S_{ogcr}^{(i)}$	=	The critical oil-to-gas imbibition
$S_{owcr}^{(d)}$	=	The critical oil-to-water drainage
$S_{owcr}^{(h)}$	=	The critical oil-to-water actual
$S_{owcr}^{(i)}$	=	The critical oil-to-water imbibition
Sw_{co}	=	Connate water saturation

LIST OF ABBREVIATIONS (Continued)

SOM	=	Minimum residual oil saturation
SOM_{mod}	=	Minimum residual oil saturation with trapping gas
Sw_{start}	=	Water saturation at the start of the secondary drainage curve
SCF	=	Standard cubic feet
STB	=	Stock tank barrel
T	=	Time
Tc	=	Critical temperature
WBHP	=	Well bottom hole pressure
WCT	=	Water cut
μg	=	Gas viscosity
μo	=	Oil viscosity
μw	=	Water sviscosity
α	=	Reduction exponent
ρg	=	Gas density
ρo	=	Oil density
ρw	=	Water density
Ø	=	Porosity

CHAPTER 1

Introduction

1.1 Problem and Rationale

Even though petroleum resources are finite, they remain among the most important sources of energy in the world. With the decline of hydrocarbon reservoir, improved recovery of these resources to boost production is becoming increasingly important. There are many methods that can be applied to increase recovery from hydrocarbon reservoirs such as Waterflooding, Gas injection, Polymer flooding and Water Alternating Gas injection (WAG).

Generally, Waterflooding is the most preferable method to improve oil recovery because it is simple and inexpensive. However, in reservoir that had been Waterflooding, it is still possible to recover a significant quantity of the remaining oil by WAG. Injecting gas can occupy parts of the pore space where formerly occupied by oil and can reduce the viscosity of these remaining oil to make them mobile easier. Water is then injected subsequently to displace these remaining oil and gas. Repetition of the WAG injection process can further improve the recovery of the remaining oil in the reservoir (Tehrani *et al*., 2001). WAG has been proved by many researches (Blanton *et al*., 1970; Stalkup, 1980; Christensen, 1998) that it has more efficiency than Waterflooding method in term of recovery both in practical operations and computer simulations.

Reservoir simulation generated by computer software is a powerful and inexpensive tool, which can predict what is going on in the reservoir and the amount of production from alternative operations. Phitsanulok Basin is an appropriate choice to apply the WAG for two reasons. First, oil fields in this basin have been applied Waterflooding successfully since 1983 (Rattanapranudej, 2004). Second, it has the sufficient free gas and ground water which are required for inject in this method. Because oil fields within this basin are on production in present day, therefore this basin is suitable for matching the result between computer simulation and its actual production data.

1.2 Research Objectives

The main objective of this research is to study the applicability of Water Alternating Gas (WAG) injection method to an oil field of the Phitsanulok Basin. In addition, the Elipse_300 program was used to determine through a comparative evaluation the suitable operation method to increase the oil recovery for the petroleum system of the Phitsanulok Basin.

1.3 Scope and Limitations of the Study

1. The reservoir simulations were carried out by Ecilpse_300 program for compositional reservoir fluid.

2. The data used in the WAG studies were from Sirikit oil field, which is the biggest field in Phitsanuloke Basin.

3. Some required data were simulated and assumed from appropriate assumption under available data.

4. Thailand III, the present Petroleum Acts of Thailand, was applied in economic evaluation.

1.4 Research methodology

1.4.1. Literature review

Literature review was carried out to study the state of the art of Phitsanulok Basin overview and WAG injection method. The topics reviewed in this research included applications, limitations, and problems of WAG. The sources of information were from the published document such as American Associate of Petroleum Geologist (AAPG), Social Petroleum Engineering (SPE), journals, researches, dissertation, and conference papers.

1.4.2. Methodology study

Water Alternating Gas injection methods and reservoir simulation program, including theories, procedures, and its applications were researched and studied.

1.4.3. Required data preparing

The petroleum system of Phitsanulok Basin was studied for reservoir models establish. The simulation model was created. It contains 5 layers, 625 cells/layer with homogeneous and isotropic properties. Next, reservoir properties, rock properties, fluid properties, composition of fluids in reservoir, and binary interaction coefficients and the other necessary data were prepared for making computer simulation and running the Eclipse_300 Program.

1.4.4. Technical and economical conditions consideration

Simulation in various conditions were run and the optimized conditions for oil recovery enhancement process for Phitsanulok Basin both in term of technical considerations, e.g. optimized Water injection, Gas injection, production rate and economic consideration, e.g. Internal Rate of Return (IRR), Profit to Investment Ratio (PIR), and sensitivity analysis were considered.

1.4.5. Conclusions and report writing

Results from all conditions were evaluated and prepared for discussion and conclusion. All research activities, methods, and results of reservoir simulation and petroleum economics evaluation were fully documented and complied with the thesis.

CHAPTER 2

Literature Review

The topics reviewed in this research included characteristics of Phitsanulok Basin applications, limitations, and problem of WAG.

2.1. History of Phitsanulok Basin

Phitsanulok Basin situates about 400 km north of Bangkok, with areal extent in the order of 6000 km^2. The area covers 5 provinces; Phichit, Phitsanulok, Sukhothai, Kamphaeng Phet and Uttaradit. This basin is the largest of the string of Tertiary intracratonic extensional basins of onshore in Thailand.

The Phitsanulok Basin is a tertiary basin, with N-S trending intracratonic rift basin, probably formed during the Oligocene period (Gerard *et al*., 1997). This basin formed as a result of the relative movement of the Shan-Thai and Indosinian Blocks (Figure 2.1). The Phitsanulok Basin has been generated by the eastward displacement, governed in turn by the movements along four major fault systems:

a) The Western boundary fault system with NNW-SSE trending which take up the basement and basin extension as normal fault. Fault dip has approximately 45 degree. The fault system is not continuous, separate segments are connected by NNE-SSW strike-slip fault (Uttaradit fault). Extension at basement level is in order of 10 km.

b) The Uttaradit fault with ENE-WSW running sinistal strike-slip fault. The Uttaradit fault truns into the Western Boundary Fault System and does not extend.

c) The Mae Ping fault with NW-SE running dextral strike-slip fault. This fault is a pre-existing basement fault as shown by the offset of up to 100 km of Palaeozoic rocks (Trumpy, 1983).

d) The Petchabun fault zone with N-S running dextral strike-slip fault. This fault separates the structurally complex Shan-Thai Block from Indosinian Block. Total displacement of at least 50 km (Trumpy, 1983)

The basement rocks of Phitsanulok Basin, grouped into the Khorat Group, are primarily of Jurassic and Cretaceous age, are complexly folded, partially metamorphosed and block faulted. The lower part of the Khorat group has been affected by the latest stage of the Indosinian Orogeny (Upper Triassic to Lower Jurassic) while the lower and the upper part has been affected by the Himalayan Orogeny (Late Cretaceous - Present).

The structural configurations are determined by the relative movements, in four phases. The Tertiary (Oligocene) to recent fill of the basin was subjected to extensional tectonics in Phase I, extensional to transtensional tectonics during Phase II, and gradually increasing to transpressional tectonics through Phases III and IV. The block faulted nature of the basement allows for the shifting of the subsidence axis within the basin related to the formation of several, so-called basement highs (Mäkel *et al*., 1997). One of the most prominent of these basement highs marks the position of the Sirikit Field. The main formations were Ping, Yom, PTO, Main Seal, LKU, and PTT (Basement).

The structural history of the Phitsanulok Basin and adjacent areas enclosed by the four major faults can be subdivided into four phases (Figure 2.2). With the possible exception of Phase I they cannot be sharply defined but rather they show an overlap in features described.

a) Phase I - starts with the onset of extensional rifting. Extension in the basin occurs along NNW-SSE oriented faults which are offset along NNE-SSW faults. The extensional direction is WSW-ENE. The main extension occurs along the Western Boundary Fault System.

The Uttaradit Fault acts as the northern basin limit and accommodates the extension with sinistral slip of the basement. Dextral movement of the Indosinian Block along the Phetchabun Fault leads to a space problem in the Northeast causing compression in the Soi Dao area. The sinistral block movement along the Mae Ping Fault combined with the movement along the Phetchabun Fault leads to divergence near the junction of these faults. This compensates to some extent for the compression in the northeast.

b) Phase II - begins when extensional movement along the Mae Ping Fault is blocked. This leads to inversion in the southern area as a result of the continued movement along the Petchabun Fault. The divergence which during Phase I compensated for the compression in the northeast disappears and consequently the compression in the Soi Dao area increases.

The change in the conditions along the boundary faults has a distinct effect on the conditions in the Phitsanulok Basin of which the change from almost exclusively lacustrine to alluvial is the most dramatic. The start of this phase marks the onset of the deposition of the Pratu Tao Formation. The change is locally marked by a mild unconformity in the Phitsanulok Basin. According to Bal *et al*., 1992 the unconformity is more pronounced towards the south and the basin margins.

c) Phase III - The extension in the northern part of the Phitsanulok Basin stops. Compression here continued and overthrusts develop in the Soi Dao area. The blockage of the fault systems (Uttaradit and northern part of the Petchabun Fault) in the northeast leads to the development of a hinge zone on the eastern flank upthrowing the Nakhon Thai area and increasing the downthrow along the Western Boundary Fault System. To the north of the Uttaradit Fault the Phichai Graben develops and maximum downthrow occurs in the Sukhothai depression which already started to form in Phase II.

To the south the extension still continues and as a result an anti-clockwise rotation of the southern Phitsanulok Basin occurs. The rotation is compensated by dextral displacement along NW-SE oriented faults

d) Phase IV - The extension in the southern part of the area is blocked. As a result the basin is subjected to increasing compressional stresses and inversion features and dextral wrench faulting, parallel to the Petchabun Fault, affect pre-existing structures. Basaltic and (younger) rhyolitic volcanism, which started 13.7×10^6 years ago, is associated with this phase.

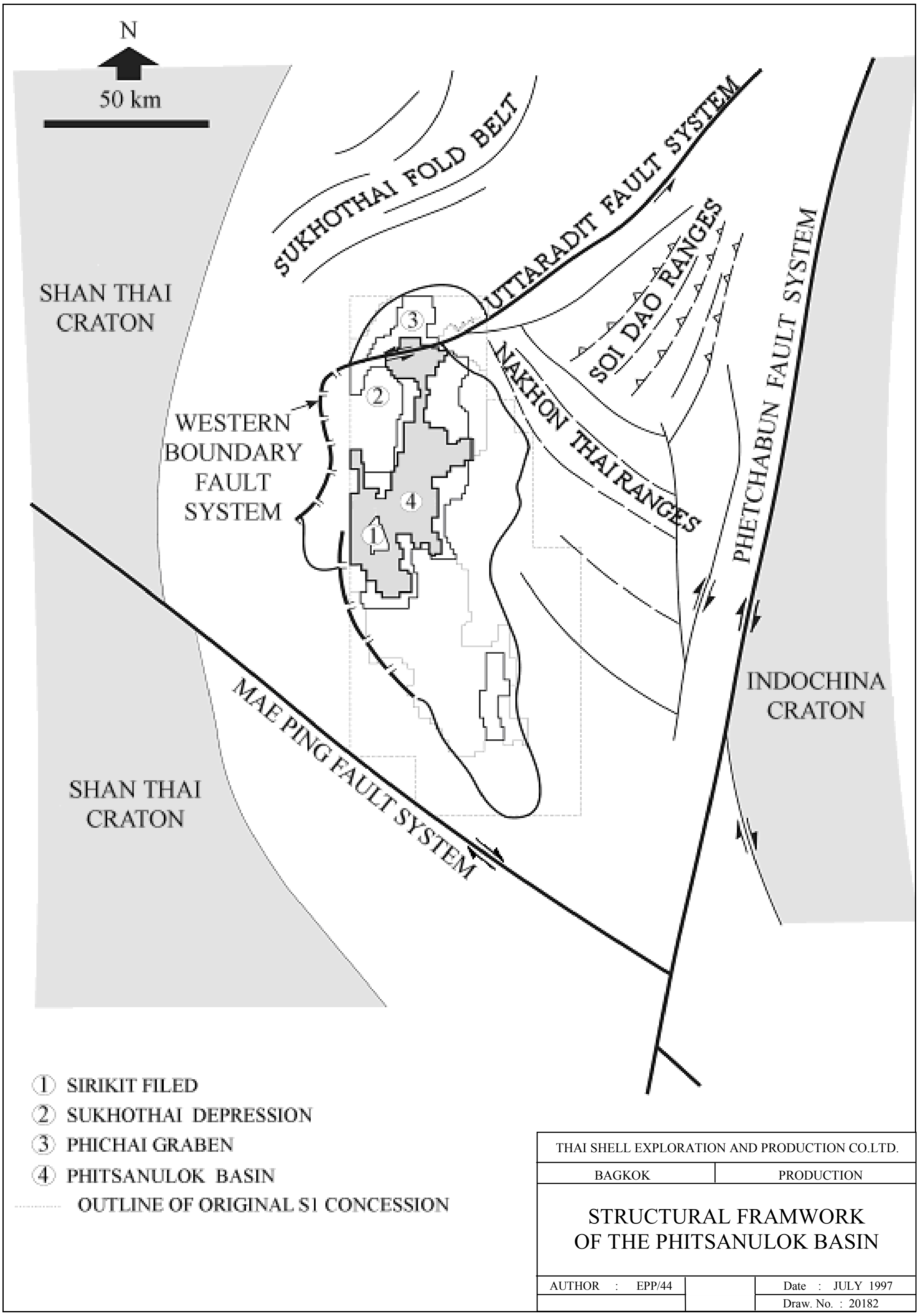

Figure 2.1 Phitsanulok Basin tectonic setting, (Modified after Gerard *et al*., 1997).

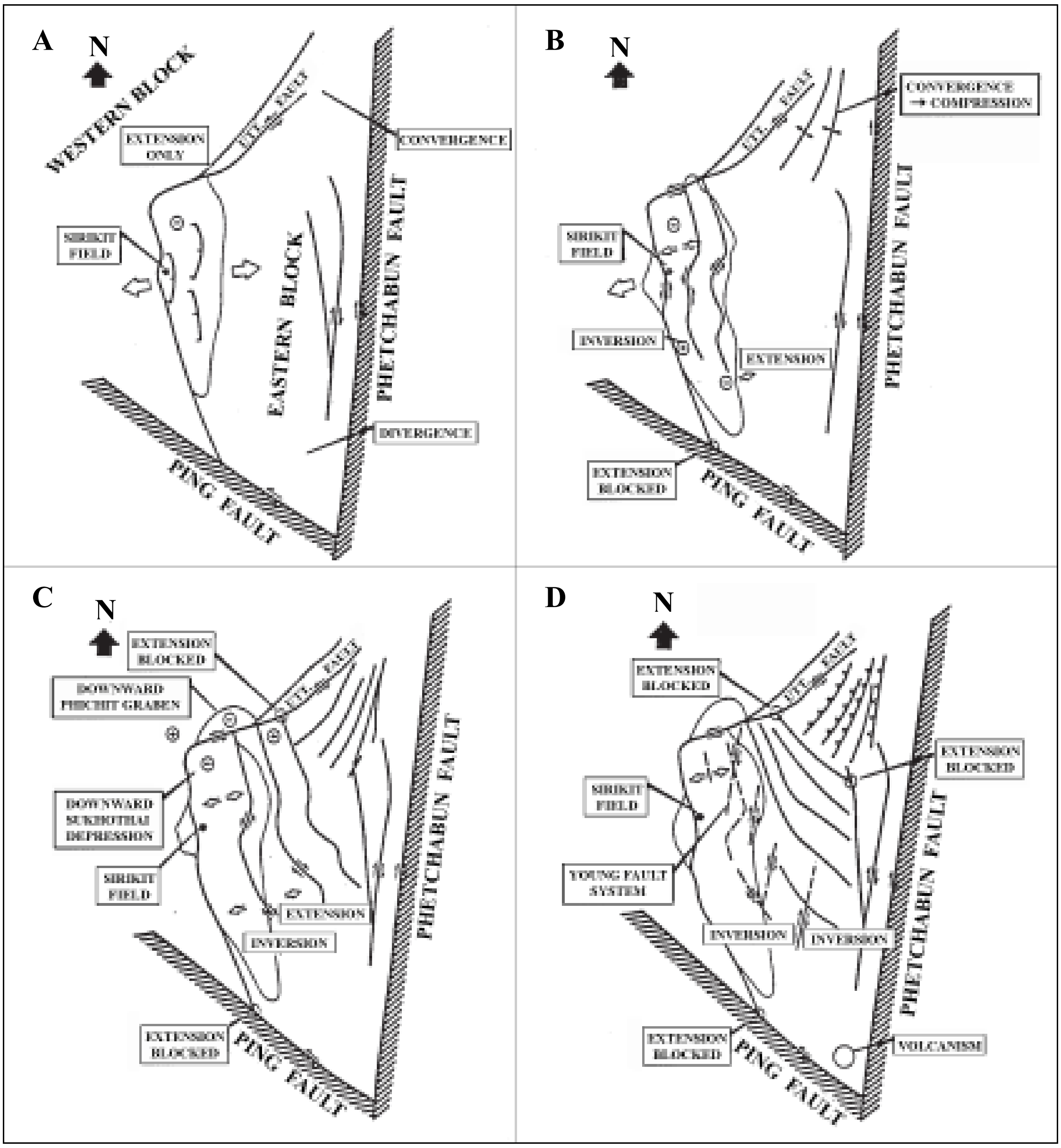

Figure 2.2 Phitsanulok Basin structural evolution, (After Ball, A.A., 1992).

2.2. Stratigraphy setting of Phitsanulok Basin

The sedimentary fill in the Phitsanulok Basin can be subdivided into 3 main sequences (Figure 2.3). They are:

2.2.1. Lacustrine and fluvio-lacustrine sequence (Oligocene-Early Middle Miocene). The main formations of this sequence are Lan Krabu and Chumsaeng Formations. Lan Krabu is sand and shale sequence of fluviatile and lacustrine deltaic deposit while Chumsang is shale sequence of the open lake deposit.

2.2.2. Fluvial sequence (Early Middle Miocene to Late Middle Miocene). The main formations deposited in this period are fluviatile and flood plain deposits, name; Pratu Tao, Yom and Ping Formations.

2.2.3. Fluvial sequence (Late Middle Miocene to Recent). Ping Formation, the only one formation in this period, consists mainly of fluviatile and alluvial plain deposit.

2.3. Petroleum system and potential of Phitsanulok basin

2.3.1. Source Rock

According to Bal *et al*. (1992), the lacustrine source rock facies or depositional environments of the Phitsanulok Basin were divided into:

a. Open deep lake lacustrine, with type I/II source rocks containing predominantly fresh-water algae and structureless organic matter (SOM). TOC's are variable and hydrogen indices (HI) are very high, up to 700 or more. Generally, it presents in the lower part of the Syn-rift sequence (Chumsaeng Formation). It is prime oil prone source rock with outstanding richness. Gross source rock thickness of the Chumsaeng Formation is about 400 m. in Sirikit area, and average net to gross ratios range of 50 to 80%. In the deep depocenter a gross thickness of over 1,000 m. is estimated. Geochemically, average hydrocarbon yields are in the range of 20 to 40 kg/m^3 with maximum yield as high as 170 kg/m^3.

b. Fluvio-lacustrine shales, Lan Krabu Formation, with mainly kerogen type II/III source rocks, the organic matter is primarily algae and SOM with minor vitrinite. TOC's are higher than the open deep lacustrine but hydrogen indices are generally less than 300. It is also oil prone source and exist in the synrift sequence. The fluvio-lacustrine thickness is commonly in range of 150 to 300 m. with average net to gross ratios of 30 to 50%. Geochemically, average hydrocarbon yields are in the range of 20 to 30 kg/m^3.

c. Marginal swamps, with type II/III organic material, principally vitrinite with some algae and SOM. It is less common and is gas prone. It has high TOC's but low hydrocarbon indices (less than 300).

2.3.2. Maturation and migration

The main source rock intervals are currently in gas window with in the central depocenter, (Sukhothai depression) and on its flanks are in the oil window. Therefore, in the Phitsanulok Basin a total kitchen area is about 800 - 1,000 km^2 and several billion barrels of oil is believed to have generated from the very rich source rocks in the kitchen. Additionally, it is estimated that STOIIP of about 700 million barrels in the Sirikit field (Bal *et al*., 1992).

Further, the geochemical and basin modeling indicate that the oil generation started 16 million years ago (Middle Miocene). The fluvio-lacustrine reservoir (Lan Krabu Fm.) had been deposited until just before the oil maturation. Figure 2.3 tabulates the petroleum system analysis of the Phitsanulok Basin.

2.3.3. Reservoir

The Lan Krabu fluvio lacustrine sandstones constitute one of the reservoir targets of the basin. The two major reservoir facies identified in the Lan Krabu Formation in the Sirikit Field area are (i) mouthbars and (ii) fluvial channels. The key to identification of sand depositional environment lies in correlation with surrounding wells. Predicted mouthbar geometries are larger than average well spacing (400 to 600 m). Predicted channel geometries are less than average well spacing. Therefore a mouthbar has to be observed in at least two (and probably more) wells whilst a channel sand can probably not be correlated with other wells. Hence, log shape can provide an indication of depositional environment but only when the equivalent stratigraphic interval in adjacent wells have been analysed, can a depositional environment be assigned to a specific sand. The 600-700 m thick Lan Krabu Formation consists of a series of progradational deltaic tongues (M, L, K and D Members). These tongues interdigitate with and are separated by the open lacustrine shales of the Chum Saeng Formation. In the Sirikit area, the intercalations of the Chum Saeng are known as the Basal Seal (BS; between P and M), Lower Intermediate Seal (LIS; between M and L), Upper Intermediate Seal (UIS; between L and K), and Main Seal (MS; between K and D and above D; Figure 2.4).

2.3.4. Trap and seal

The Cenozoic sequence contains potential reservoirs in practically all of the formations encountered to date. Potential seals also exist throughout with the possible exception of the youngest sand and gravel-dominant Ping Formation. The Sirikit hydrocarbon accumulation is contained within the fluvio-lacustrine Lan Krabu Formation. Stacked hydrocarbon-bearing sand packages occur which are sealed by overlying and intervening massive lacustrine clays. Other hydrocarbon bearing reservoirs have been encountered in basin Pratu Tao Formation fluviatile sand intercalated with ephemeral lacustrine clays.

2.3.5. Small Lacustrine Basins

The Phitsanulok Basin contains significant lacustrine sequences of probably Oligocene to Early Miocene age. The lacustrine deposits, confirmed by the high pristane/phytane ratio, possess high TOC.

2.3.6. Oil Prone System

In Phitsanulok Basins the lacustrine sequences which deposited during the syn-rift period are very thick (at least 2,500 m.) in the depocenter. Generally, the average total organic carbon content (TOC) of these sediment is fairly high (at least about 2.0%), also hydrogen indices (HI) are high to very high (300 - 800 unit) indicating an excellent oil prone system. Consequently, sufficient amount of oil is believed to be generated and expulsed in the small basins with particularly in the Phitsanulok basins where a considerable surplus amount of oil is believed to had been generated and expulsed from these lacustrine sequences. The oils generated from these lacustrine sequences are typical waxy, high pour point and low sulfur crudes.

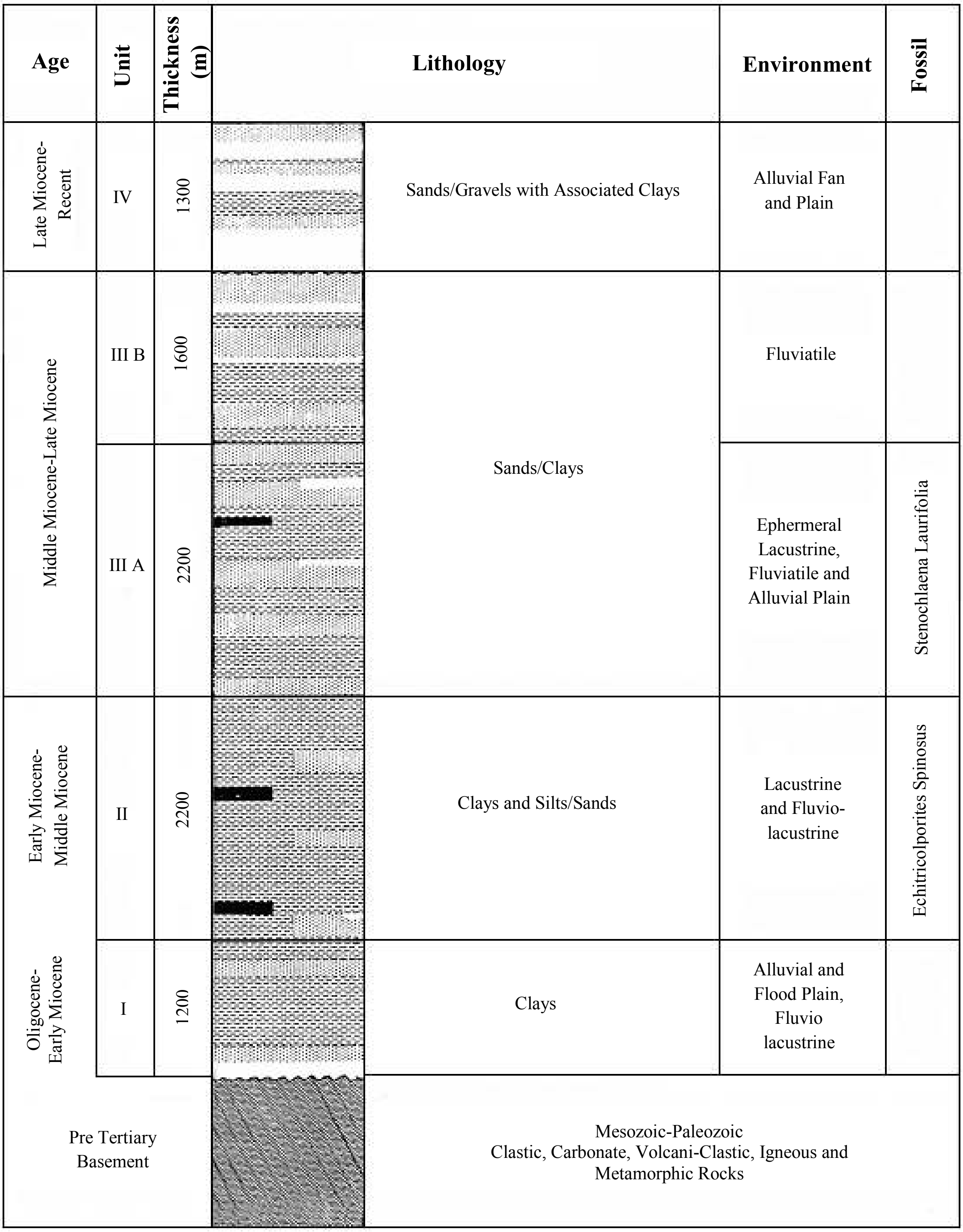

Figure 2.3 Generalized stratigraphic of Phitsanulok Basin, (After Knox and Wakefield, 1983).

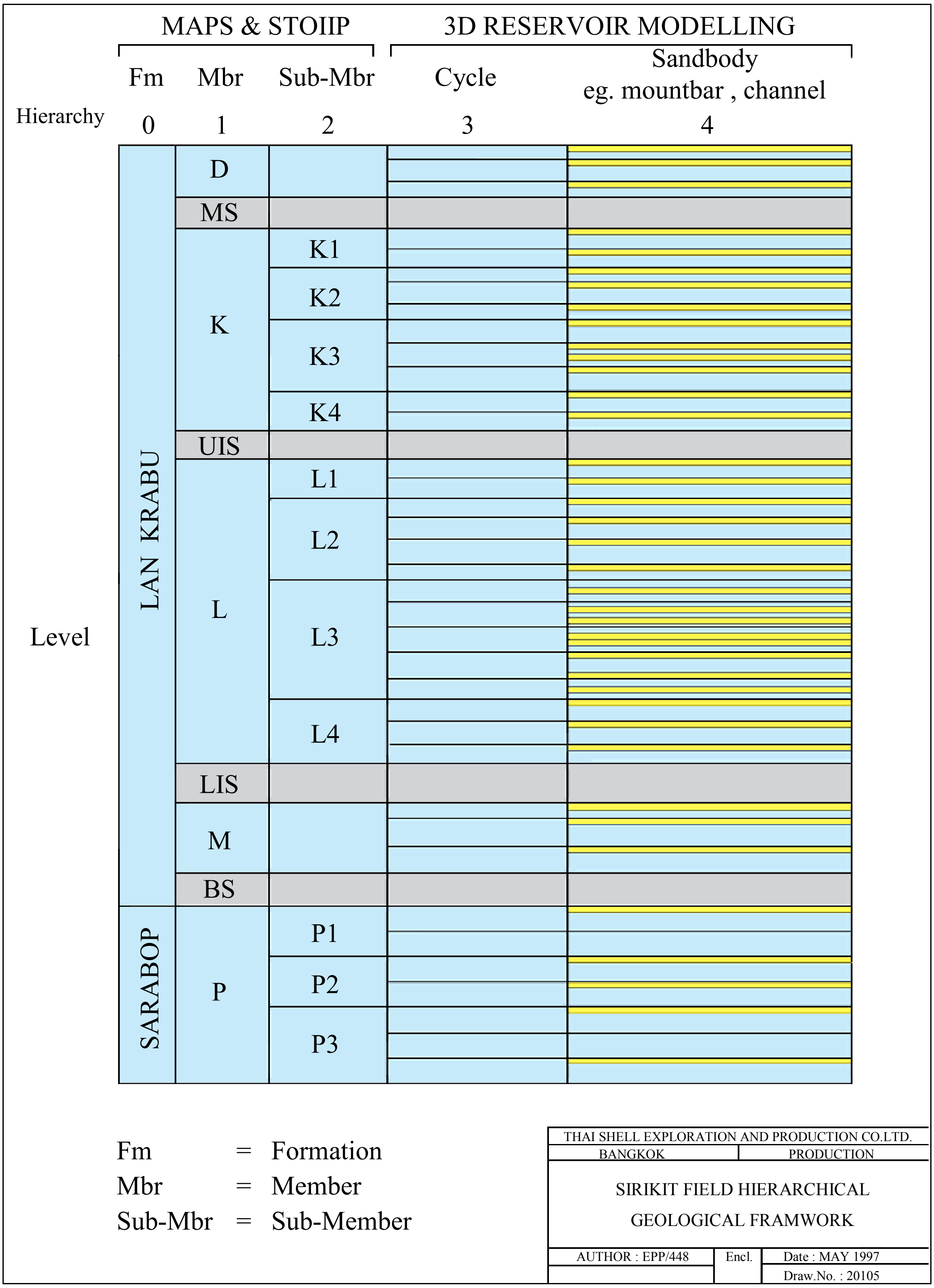

Figure 2.4 Lithostratigraphy of Phitsanulok Basin, (After Gerard *et al*., 1997).

2.4. Case study on WAG and Phitsanulok Basin

The Sirikit oil field is the largest field in the S1 Concession and situate within this basin. The Sirikit was waterflooded successfully. This project is manifested by reaching a peak production of 2130 bopd in January 2008 against the 200 bopd estimation, when no further activity was carried out (Vitoonkijvanich *et al*., 2008).

The field has an estimated STOIIP (stock tank oil initially in place) of 800 MMbbl. The main reservoirs contain undersaturated, light (~39°API) oil with initially hydrostatic pressure about 2760 psi at 1830 m. The bubble point is 400 psi or lower. Reservoir pressure quickly dropped below bubble point after production started during 1982, which resulted in higher producing gas/oil ratios (GOR) and lower oil rates. The reservoir drive energy was determined to be limited to solution gas expansion, which is aided by gas-cap expansion in some reservoirs. To preserve this energy and to optimize oil recovery, GOR limitations were set for different reservoirs. (Ainsworth *et al*., 1999)

WAG is an enhance oil recovery method as Waterflooding. WAG was analyzed in different ways. Most of these studies seek for improvement in oil recovery. Some of the useful applications of WAG are summarized below.

Larsen *et al*. (2000) was concerned with planning and optimization of three-phase immiscible WAG injection processes. This goal was achieved by applying an iterative procedure linking the pore-level displacement mechanisms with a macroscopically defined WAG process. The field-scale reservoir simulations were carried out by Eclipse_100.

Stakup (1983) studied methods for miscible flooding. It has been researched and field tested since the early 1950's. This paper reviewed the technical state of the art and field behavior to date for the major miscible processes: first-contact miscible, condensing-gas drive, vaporizing-gas drive, and CO_2 flooding. Important technological areas selected for review include phase behavior and miscibility, sweepout, unit displacement efficiency, and process design variations. CO_2 -flood technology was emphasized, and several technical issues were identified that still need to be resolved. Rules of thumb and ranges of conditions were discussed for applicability of each process. A comparison was made of the incremental recovery and solvent slug effectiveness observed in field trials of the different processes. From the limited data available, there was no clear-cut evidence that field results on average and for a given slug size had been appreciably better or poorer for one process compared with another.

Kane (1979) reviewed the performance of the CO_2-WAG. The project demonstrated that large volumes of CO_2 could be transported long distances, distributed to injection, and injected in a WAG-type operation successfully. Methods had been developed for handling at reasonable cost the additional operation problems associated with CO_2 production and the attendant scaling and corrosion. The project showed that substantial incremental oil recovery over Waterflooding could be achieved with CO_2 processing of a carbonate reservoir.

In Rangely Weber the objective was to optimise the injection since the wells were switched manually. The recovery was slightly higher (0.5%) and the GOR in producers was more stable compared with a normal WAG. The disadvantage was increased monitoring of the injection system, since it was more unstable. Increased corrosion control and prevention of backflow (injectors) were very important, since the mixing of CO_2 gives carbonate acid. The injectivity was not drastically decreased in the SWAG.

In Kuparuk the objective of the pilot was to have only one injection system, instead of having separate injection systems for both gas and water. Thus the mixing of the gas and water phase was done before injection and the mixture pumped to the injection site. This gives challenges to the tubing since a branch with acts as a separation device. The infectivity was reduced when increasing the gas fraction of the injection mixture.

Some of oil fields had inappropriate condition for Waterflooding, like B.Kozluca Field gained (Mustafa, 2001). This field has viscosity of 500 cp at reservoir condition with very weak bottom water drive. However WAG can increase oil produced more than 7 MMSTB with over $20MM profit gained. Under optimum parameters, WAG process can give a recovery factor higher than water injection (Wongdontri, 2004). About 60 different fields reviewed, few field trials have been reported as unsuccessful, but operational problems are often commented (Christensen *et al*., 1998).

2.5. Enhance Oil Recovery Methods

In the early of production petroleum industry, reservoirs have been produced by natural drive until its depleted, primary recovery (Latil *et al*., 1980). Nearly 2.0×10^{12} barrels of conventional oil and 5.0×10^{12} barrels of heavy oil will remain in reservoirs worldwide after conventional recovery methods have been exhausted (Thomas, 2007). Those large volumes of remaining oil need stimulate and improve oil recovery by enhance oil recovery (EOR) methods. Many EOR methods had been used in the past. The degree of success is more highly if applying suitable EOR to appropriate condition reservoir. EOR can be simply classified into two categories:

a) Thermal Methods

The major mechanism is supply heat to the reservoir, and vaporizes some of the oil to reduce viscosity, and mobility ratio. Thermal methods have been highly successful in Canada, USA, Venezuela, Indonesia and other countries. These methods have been applied in many ways such as cyclic steam stimulation, steamflooding, steam assisted gravity drainage, and in-situ combustion.

b) Non-thermal Methods

Most non-thermal methods require considerable laboratory studies for process selection and optimization. The three major classes under non-thermal methods are: miscible, chemical and immiscible gas injection methods. A number of miscible methods have been commercially successful. A few chemical methods are also notable. Among immiscible gas drive processes, CO_2 immiscible method has been more successful than others. The two major objectives in non-thermal methods are lowering the interfacial tension, improving the mobility ratio.

2.6. Water Alternating Gas (WAG) Process

The Water Alternating Gas (WAG) has been classified as a non thermal method. WAG was found in the literature today from the first reported WAG in 1957 in Canada (Poollen, 1980). Table 2.1 shows some WAG injection studying with location and injected gas type. It is a part of worldwide usage from 1957 to 1994. The study has been used in different lithology and injectant. Beside, Table 2.2 presents improved recovery from Waterflooding and details of injection. As depicted in Table 2.2 WAG has more significant incremental oil recovery than Waterflooding generally about 5 – 15%.

The original propose is a method to improve sweep of gas injection, mainly by using water to control mobility of the displacement and to stabilize the front (Christensen *et al*., 1998). Since the microscopic displacement of the oil by gas normally is better than by water the WAG injection combines the improved displacement efficiency of the gas flooding with an improved macroscopic sweep by the injection of water. Furthermore, WAG injection can give less residual oil saturation than those obtained from Waterflooding and from gas injection alone (Tehrani *et al*., 1999).

Table 2.1 WAG injection study, (Modified after Christensen, 1998).

Name	Start up	Location	Injectant	Type of displacement	Lithology
North Pembina	1957	Alberta,Canada	Hydrocarbon	Miscible	Sandstone
Fairway	1966	Texas	Hydrocarbon	Miscible	Limestone
Kelly Synder	1972	Texas	CO_2	Miscible	Carbonate
South Swan	1973	Alberta,Canada	NGL	Miscible	Carbonate
Slaughter Estate	1976	Texas	CO_2	Miscible	Dolomite
Garber	1980	Oklahoma	CO_2	Miscible	Sandstone
Purdy Springer NE	1980	Oklahoma	CO_2	Miscible	Sandstone
Jay Little Escambia	1981	-	N2	Miscible	Dolomite
Little knife	1981	N.Dakota	CO_2	Miscible	Carbonate
Quatantine Bay	1981	Louisiana	CO_2	Miscible	Sandstone
Wilmington	1982	California	CO_2/N_2	Immiscible	Sands
San Andres Means	1983	USA,SESSAU, Texas	CO_2	Miscible	Dolomite
Fenn Big Valley	1983	Alberta	Hydrocarbon	Miscible	Dolomite
Judy creek	1985	Alberta	Hydrocarbon	Miscible	Limestone
East Vacuum	1985	New Mexico	CO_2	Miscible	Dolomite
Hanford	1986	Texas	CO_2	Miscible	Dolomite
Gullfaks	1989	North Sea	Hydrocarbon	Immiscible	Sandstone
Brage	1994	North Sea	Hydrocarbon	Immiscible	Sandstone

Table 2.2 Injection pattern, incremental recover factor from Waterflooding, slug size and WAG ratio of WAG injection studied, (Modified after Christensen, 1998).

Name	**Injection pattern**	**Incremental recover factor over Waterflood (%)**	**Slug size HCPV (%)**	**WAG ratio**
North Pembina	Inverted 5 spot	9.4	-	-
Fairway	-	13	5	-
Kelly Synder	Inverted 9 spot	10	1.5	3
South Swan	9 spot	20	10	1-1.25
Slaughter Estate	5 spot	19.6	25	0.5
Garber	5 spot	10	35	1
Purdy Springer NE	5 spot	7.5	7.5	2
Jay Little Escambia	Line	6.5	less than 1	4
Little knife	-	18	-	1
Quatantine Bay	-	2	18.9	1
Wilmington	Line	12.5	-	-
Fenn Big Valley	-	15	15	1.3
Judy creek	Inverted 5 spot	6.5	15	1
East Vacuum	Inverted 9 spot	3.8	10	2
Hanford	5 spot	14.2	3	1
Gullfaks	Line/Pattern	5	5	1
Brage	Injected from rim	9-12	-	1

2.6.1 Problem in WAG process

A problem of the WAG process is that the injected water blocks contact between the injected gas phase and the residual oil (Green and Whillhite, 1998). The fields should have water and gas supplied for good economic consideration. Some operational problem cannot be avoided in the production life of an oil field. The WAG injection is more demanding than a pure gas or water injection since the injection need to be changed frequently. It is basically problems from the different fields. Some of the problems believed to have been most severe are discussed below.

a) Early breakthrough in production wells

Poor understanding of the reservoir or inadequate reservoir description can lead to unexpected events such as early gas breakthrough. Several field cases report early gas breakthrough due to channeling or to override. For offshore fields override can be very critical since the number of wells in the projects generally is very limited.

b) Reduced Infectivity

Reduced infectivity means less gas and water injected in the reservoir. This will cause rapid pressure drop in the reservoir which affects displacement and the production.

c) Corrosion

Corrosion is a problem that needs to be solved in almost all WAG injection projects. This is mainly due to the fact, that the WAG injection normally is applied as a secondary or tertiary recovery method. The project will have to take over old injection and production facilities originally not designed for this kind of injection. These problems have in most cases been solved by usage of high quality steel (different kinds of stainless steels or ferritic steel), coating of pipes and treatment of equipment.

d) Scale formation

The occurrence of scales in WAG field trials is usually and logically found when CO_2 is the injected gas source. The scale formation may stress the pipelines and can lead to failure. In CO_2 floods casings many times have been coated with an extra layer for corrosion protection. This layer can be damaged by scale and corrosion (pitting) can occur. In worst cases, production stops have been needed either for chemical squeeze treatments or while repairing the damage.

2.6.2 Classification of WAG

WAG processes can be grouped in many ways. The most common is to distinguish between miscible and immiscible displacements as a first classification (Christensen *et al*., 1998).

a) Miscible WAG

It is difficult to distinguish between miscible and immiscible WAG. In many cases a multi-contact gas-oil miscibility may have been obtained, but a lot of uncertainty remains about the actual displacement process. It has not been possible to isolate the degree of compositional effect on oil recovery by WAG. Miscible projects are mostly found onshore and the early cases used expensive solvents like propane, which seem to be a less economic favorable process at current time. Most of the miscible projects reviewed are repressurized in order to bring the reservoir pressure above the minimum miscibility pressure (MMP) of the fluids. Since failure to maintain sufficient pressure, meaning loss of miscibility, real field cases may oscillate between miscible and immiscible gas during the life of the oil production. Most miscible WAG have been performed on a close well spacing, but recently miscible processes have also been tried out even at offshore-type well spacing.

b) Immiscible WAG

This type of WAG process has been applied with the aim of improved frontal stability or contacting unswept zones. Application have been in reservoirs where gravity stable gas injection can not be applied because of limited gas resources or the reservoir properties like; low dip of strong heterogeneities. In addition to sweep, the microscopic displacement efficiency may be improved as well. Residual oil saturation are generally lower for WAG than for a Waterflood and sometimes even lower than a gas flood, due to the effect of three phase- and cycle dependent- relative permeability.

Sometimes the first gas slug dissolves to some degree into the oil. This can cause mass exchange (swelling and stripping) and a favorable change in the fluid viscosity or density relations at the displacement front. The displacement can then become near miscible.

c) Hybrid WAG

Hybrid WAG uses a first large slug of gas injected instead of water followed by a number of small slugs of water and gas the process. The result of field test is quite similar to miscible WAG process.

d) Simultaneous Water-Gas injection (SWAG)

2.7. Reservoir simulation

Reservoir simulation, or modeling, is one of the most powerful techniques currently available to the reservoir engineer. Modeling requires a computer, and compared to most other reservoir calculations, large amounts of data. Basically, the model requires that the field under study be described by a grid system, usually referred to as cells or gridblocks. Each cell must be assigned reservoir properties to describe the reservoir.

2.7.1. Compositional model

Components in reservoir are calculated in individual (Methane, ethane, propane … N). In reservoir containing light oil, the hydrocarbon composition as well as pressure affects fluid properties. Equilibrium flash calculation using K values and equation of state (EOS) must be used to determine hydrocarbon phase compositions. In a compositional model, in principle make mass balance for each hydrocarbon component, such as methane, ethane, propane etc are made. In practical numbers of component are limited included and group components into pseudo components. Then, we define:

C_{kg} is mass fraction of component k present in the gas phase

C_{ko} is mass fraction of component k present in the oil phase

Thus, we have conditions that for a system of Nc components:

$$\sum_{k=1}^{Nc} C_{kg} = 1 \tag{2.1}$$

$$\sum_{k=1}^{Nc} C_{ko} = 1 \tag{2.2}$$

Then, a mass balance of component k may be written (in one dimension for simplicity):

$$-\frac{\partial}{\partial x}(C_{kg}\rho_g u_g + C_{ko}\rho_o u_o) = \frac{\partial}{\partial t}[\phi(C_{kg}\rho_g S_g + C_{ko}\rho_o S_o)] \qquad (2.3)$$

Darcy's equations for each flowing phase are identical to the Black Oil equations:

$$u_o = -\frac{kk_{ro}}{\mu_o}\frac{\partial P_o}{\partial x} \qquad (2.4)$$

$$u_g = -\frac{kk_{rg}}{\mu_g}\frac{\partial P_g}{\partial x} \qquad (2.5)$$

where

Pcog = Pg – Po (2.6)

Pcow = Po – Pw (2.7)

and So + Sg = 1

Thus, we may write flow equations for Nc components as:

$$\frac{\partial}{\partial x}(C_{kg}\rho_g \frac{kk_{rg}}{\mu_g}\frac{\partial P_g}{\partial x} + C_{ko}\rho_o \frac{kk_{ro}}{\mu_o}\frac{\partial P_o}{\partial x}) = \frac{\partial}{\partial t}[\phi(C_{kg}\rho_g S_g + C_{ko}\rho_o S_o)] \qquad (2.8)$$

when k = 1, N_c

The properties of oil and gas phases depend on pressure and composition, so that the functional dependencies may be written:

ρg (Pg, C1g, C2g, ..)

ρo (Po, C1o, C2o, ..)

μg (Pg, C1g, C2g, ..)

μo (Po, C1o, C2o, ..)

The equilibrium K values may be used to determine component ratios:

$$\frac{C_{ig}}{C_{io}} = K_{igo}(T, P, C_{ig}, C_{io}) \tag{2.9}$$

where	K	is absolute permeability [mD]
	Kro,Krw,Krg	is relative permeability oil, water and gas [fraction]
	K_{igo}	is equilibrium K values
	C_{kg}	is mass fraction of component k present in the gas phase
	C_{ko}	is mass fraction of component k present in the oil phase
	Po,Pw,Pg	is pressure in oil, water and gas phase [psi]
	Pcow,Pcgo	is capillary pressure in oil-water and gas-oil phase [psi]
	μo,μw, μg	is oil, water and gas viscosity [cp]
	ρo,ρw,ρg	is oil, water and gas density [lb/cuft]
	So, Sw, Sg	is oil, water and gas saturation [fraction]
	Ø	is porosity [dimensionless]
	T	is time [day]
	P	is pressure [psi]

2.7.2. Adaptive Implicit Method

Adaptive Implicit Method (AIM) is used as formulation in this simulation study. The advantage of this method to avoid time step restrictions imposed by small block particularly those containing wells. Basically, the AIM is a compromise between the fully implicit and implicit pressures explicit saturations (IMPES) procedures. The IMPES formulation is strictly an IMPEM (Implicit pressure explicit mobility) method. Cells with a high throughput ratio are chosen to be implicit for stability and obtain large time-steps, while the majority of cells can still be treated as IMPES where the solution may be changing little. All completions are treated implicitly with target fraction of implicit cells in a compositional run is 1%. The timesteps are iterating until all residuals have been reduced to saturation changes to 5%.

2.8. Impact of relative permeability hysteresis on the numerical simulation of WAG injection

Pore-scale physics, laboratory investigations, and field experience, dictate that three-phase relative permeabilities exhibit strong dependence on the saturation path and the saturation history. The effect of using different interpolation models in field-scale simulations could be significantly recovery predictions different depending on the three-phase relative permeability model. Experiments use a synthetic model of a quarter five-spot pattern in a homogenous reservoir in field-scale, and a more realistic heterogeneous reservoir simulation with multiple injection and production wells. The results of this investigation support the view that WAG injection cannot be modeled correctly without accounting for hysteresis effects. Three-phase hysteresis models lead to much larger recovery predictions than nonhysteretic models, because they account for the reduced mobility due to trapping of the gas phase during water injection (Elizabeth *et al*., 2006).

2.9. Relative permeability hysteresis in the non-wetting phase for two phase model

A typical pair of relative permeability curves for a non-wetting phase is shown in Figure 2.5. The curve 1 to 2 represents the drainage relative permeability curve, and the curve 2 to 3 represents the imbibition relative permeability curve. These curves must meet at the maximum saturation value (S_{nmax}).

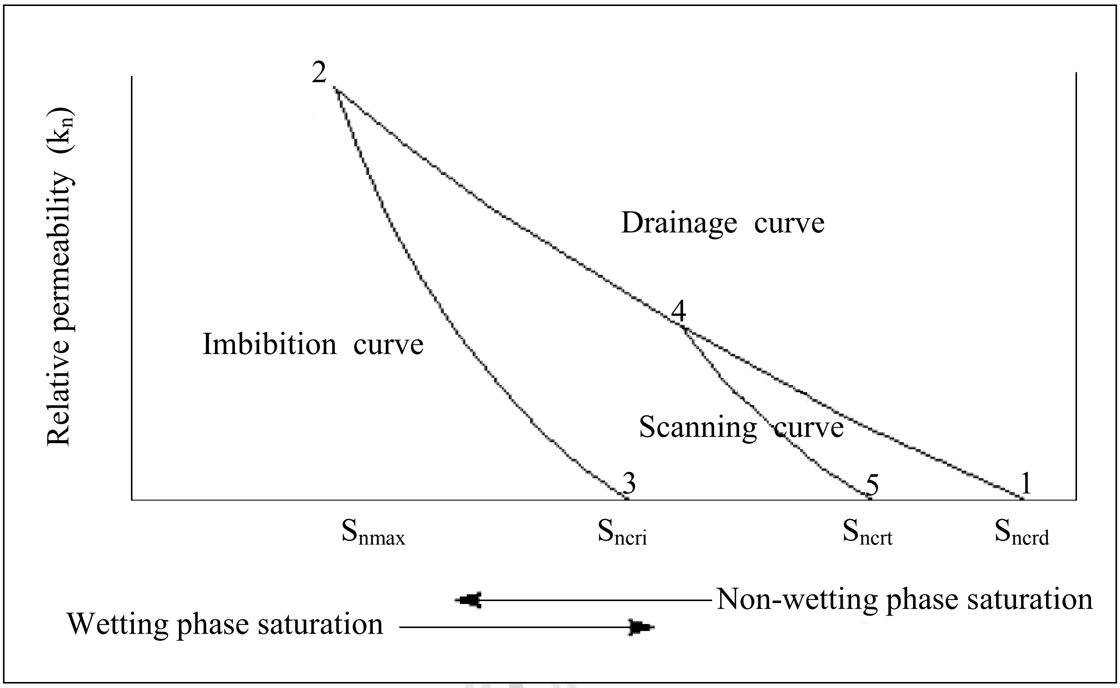

Figure 2.5 A typical pair of relative permeability curves for a non-wetting phase.

For WAG, the drainage and imbibition process are used when alternate water and gas injected. If the drainage or imbibition process is reversed at some point, the data used does not simply run back over its previous values but runs along a scanning curve (curve 4 to 5). A further drainage process begins from any point on the scanning curve 5 to 4, the same scanning curve is retraced until maximum non-wetting phase saturation, S_{hy} is reached.

2.10. Hysteresis in WAG Floods

The WAG hysteresis model aims to provide a simple method of modeling these 3-phase effects. The model essentially consists of three components: a non-wetting phase model for the gas phase, a wetting phase model for water and a modification to the residual oil saturation in the STONE 1 three-phase oil relative permeability model. The non-wetting gas phase hysteresis model is based on the theory developed by Land and Carlson. The wetting phase model (for the water phase) is based on input two-phase and three-phase relative permeability curves. In this case the imbibition curves are interpreted as the 3-phase water relative permeability, which is the relative permeability following a gas flood.

2.10.1. Non-wetting phase model (Gas)

a) Two-phase model

The gas phase model is based on the theory developed by Land and Carlson. Consider a typical drainage process followed by an imbibition process (as shown in Figure 2.6).

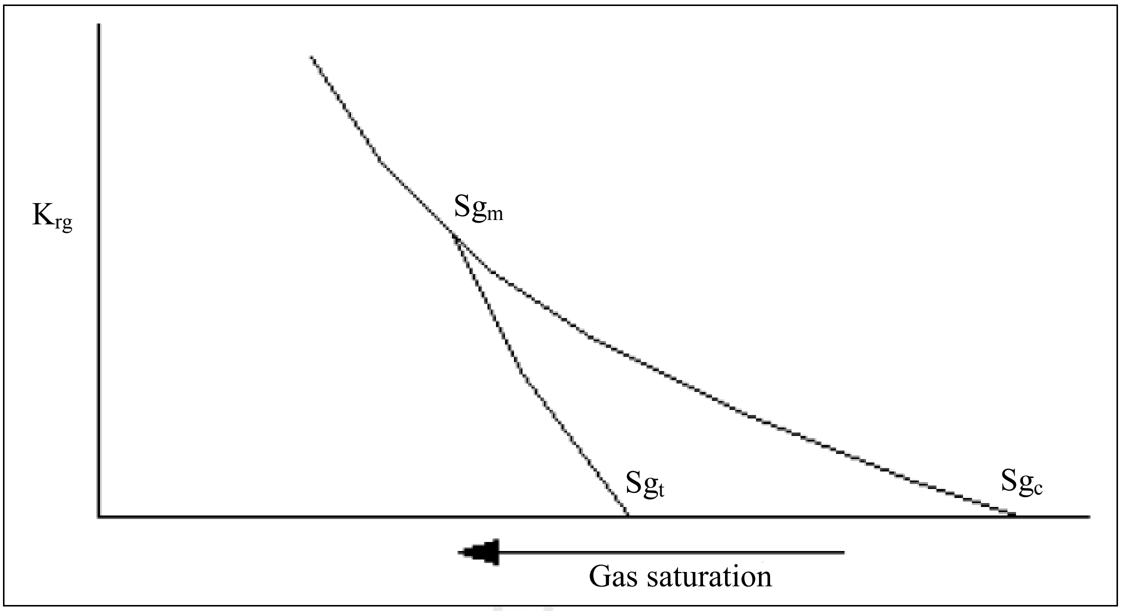

Figure 2.6 A typical drainage process followed by an imbibition process.

Consider a drainage process reaching a maximum gas saturation S_{gm} followed by an imbibition process leading to a trapped gas saturation S_{gtrap}. The trapped gas saturation S_{gtrap} is given by

$$S_{gtrap} = S_{gcr} + \frac{S_{gm} - S_{gcr}}{(A + C(S_{gm} - S_{gcr})} \tag{2.10}$$

$$A = 1 + a(S_{gm} - S_{gcr}) \tag{2.11}$$

where C is Land's parameter, specified by the transition parameter.

The gas relative permeability on the imbibition curve is given by:

$$K_{rg}(S_g) = K_{rg}^{drain}(S_{gf}) \tag{2.12}$$

where

$$S_{gf} = S_{gcr} + \frac{1}{2}\left\{(S_g - S_{gtrap}) + \sqrt{(S_g - S_{gtrap})^2 + \frac{4}{C^{trans}}(S_g - S_{gtrap})}\right\} \tag{2.13}$$

$$C^{trans} = \frac{1}{(S_{ncri} - S_{ncrd})} - \frac{1}{(S_{n\max} - S_{ncrd})} \tag{2.14}$$

If the gas saturation increases following an imbibition process, the gas relative permeability follows the imbibition curve provided that the model remains in 2-phase mode, that is if the displacing phase is oil. The criterion for the model to remain in 2-phase mode is that the water saturation at the start of the secondary drainage process must be less than the connate water saturation plus a threshold value.

b) Three-phase model

The gas relative permeability follows a secondary drainage curve when the gas saturation increases and where the water saturation exceeds the connate value at the turn-around point. A typical secondary drainage curve is illustrated in Figure 2.7.

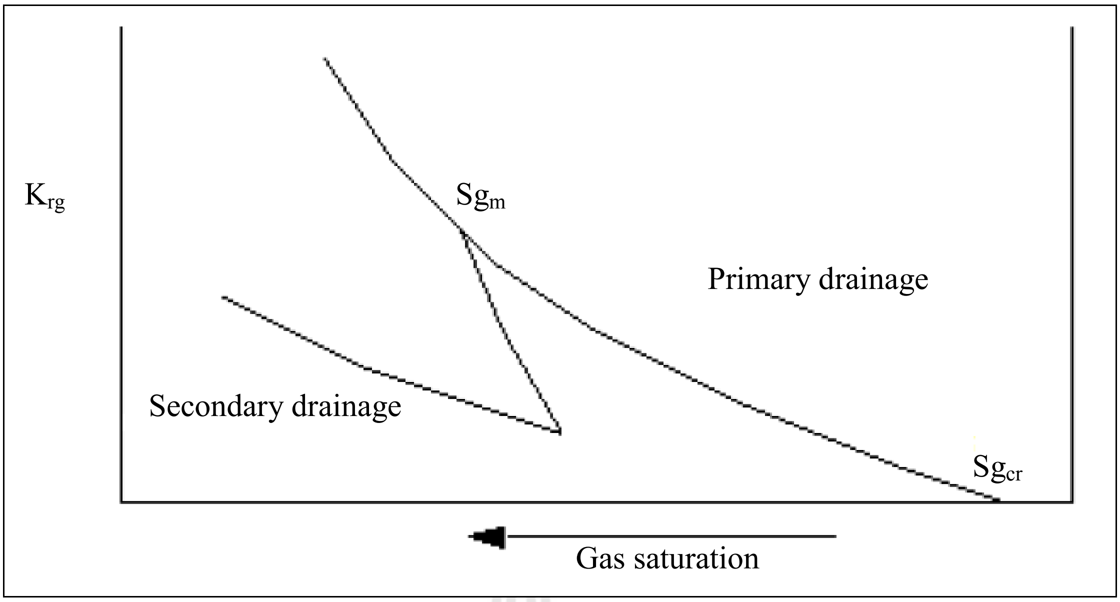

Figure 2.7 Schematic diagram showing a typical secondary drainage curve.

These secondary drainage curves are calculated using the following equation

$$K_{rg}^{drain} = [K_{rg}^{input} - K_{rg}^{input}(Sg^{start})]\left[\frac{Sw_{co}}{Sw^{start}}\right]^{\alpha} + \left[K_{rg}^{imb}(Sg^{start})\right] \qquad (2.15)$$

where K_{rg}^{drain} is the calculated secondary drainage relative permeability as a function of S_g

K_{rg}^{input} is the input relative permeability at S_g

$K_{rg}^{input}(Sg^{start})$ is the input relative permeability at the gas saturation at the start of the secondary drainage curve

Sw_{co} is the connate water saturation

Sw_{start} is the water saturation at the start of the secondary drainage curve.

$K_{rg}^{imb}(Sg^{start})$ is the relative permeability at the start of the secondary drainage process (that is the Kr at the end of the imbibition curve)

α is the reduction exponent

2.10.2. Three phase oil relative permeability models

Hysteresis cannot account in the oil phase because there is no fluctuation in the oil saturation. Residual oil saturation is modify to account for the trapped gas saturation, that represents the trapped hydrocarbon rather than just the trapped oil.

$$SOM_{mod} = SOM - (a - Sg_t) \tag{2.16}$$

where SOM is the minimum residual oil saturation

Sg_t is the trapped gas saturation

a is input constant which can vary between 0 and 1. If the construction from the trapped gas saturation exceeds SOM, the residual oil saturation sat to 0.

2.10.3. Wetting phase model (Water)

The wetting phase model is based on the observation that the water relative permeability curve measured following a gas flood shows significantly less mobility. An example of the two relative permeability curves is shown in Figure 2.8.

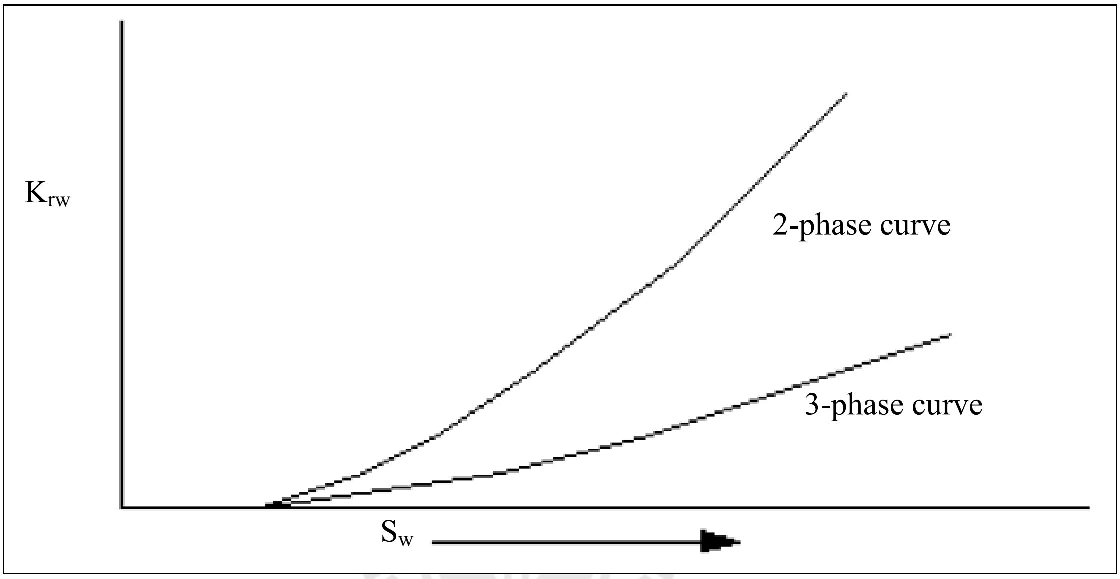

Figure 2.8 Two-phase and three-phase relative permeability curves

The two-phase curves are taken to be the drainage curves and the three-phase curves to be the imbibition curves. These curves are not strictly drainage and imbibition but apply to the two-phase and three-phase cases respectively. For an imbibition process, with S_w increasing, the relative permeability function used is interpolated between the two-phase and three-phase curves using the following equation

$$K_{rw}^{imb} = K_{rw2} \cdot \left(1 - \frac{Sg^{start}}{Sg_{\max}}\right) + K_{rw3}\left(\frac{Sg^{start}}{Sg_{\max}}\right) \tag{2.17}$$

where K_{rw}^{imb} is the calculated imbibition relative permeability

K_{rw2} is the two-phase relative permeability at Sw

K_{rw3} is the three-phase relative permeability at Sw

$Sg_{\max}$ is the maximum attainable gas saturation

Sg_{start} is the gas saturation at the start of the imbibition process

Sw_{co} is the connate water saturation

So_{gcr} is the critical oil-to-gas saturation

A subsequent drainage relative permeability is calculated by interpolation between the imbibition curve and either the three-phase curve or the two-phase curve, depending on the gas saturation. A typical case is shown in Figure 2.9.

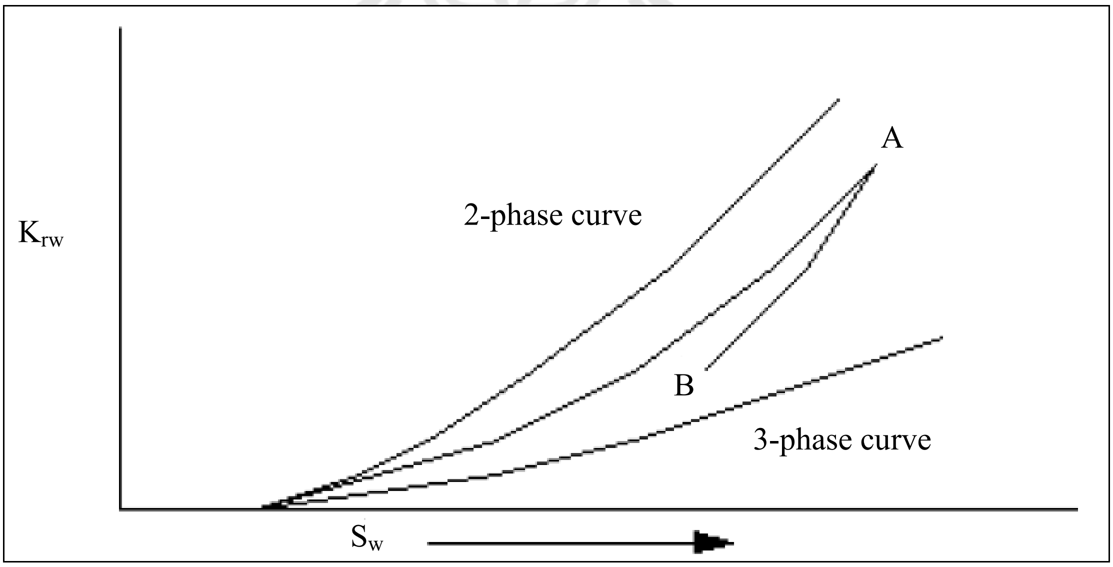

Figure 2.9 Subsequent drainage relative permeability

An initial imbibition process may reach point A. The subsequent drainage process in this case moves to point B, on a curve interpolated between the original imbibition curve and the input three-phase curve. The drainage curve moves either side of the imbibition curve depending on the prevailing gas saturation relative to the gas saturation at the start of the drainage process Sg^{drain}. If $Sg > Sg^{sdrain}$ then,

$$K_{rw}^{drain} = K_{rw}^{imb} \cdot \left(1 - \frac{Sg - Sg^{sdrain}}{Sg_{\max} - Sg^{sdrain}}\right) + K_{rw3} \cdot \left(\frac{Sg - Sg^{sdrain}}{Sg_{\max} - Sg^{sdrain}}\right) \tag{2.18}$$

If $Sg < Sg^{sdrain}$ then

$$K_{rw}^{drain} = K_{rw}^{imb} \cdot \left(1 - \frac{Sg^{sdrain} - Sg}{Sg^{sdrain}}\right) + K_{rw2} \cdot \left(\frac{Sg^{sdrain} - Sg}{Sg^{sdrain}}\right) \tag{2.19}$$

where Sg^{sdrain} is the gas saturation at the start of the drainage process, point A

K_{rw}^{drain} is the calculated drainage curve

K_{rw}^{imb} is the previous imbibition relative permeability at Sw

K_{rw2} is the input two-phase curve at Sw

K_{rw3} is the input three-phase curve at Sw.

Subsequent secondary drainage processes follow an interpolated curve in much the same manner as the primary imbibition, but using a modified Sg^{start} arranged such that the curve runs through point B.

2.11. Trapping models

2.11.1. Land trapping model

The first trapping model we investigate was proposed by Land, and is the most widely used empirical trapping model published by Carlson S. Land in 1968. His model was developed for trapped gas saturation as a function of the initial saturation based on published experimental data from water-wet sandstone cores. He also developed an analytical model for imbibition gas relative permeability based on his trapping model that will be discussed later in this report. Most relative permeability models that incorporate hysteresis are based on the trapping model proposed by Land. In this model, the trapped nonwetting phase saturation is computed as:

$$S_{gt}(S_{gi}) = \frac{S_{gi}}{1 + CS_{gi}} \tag{2.20}$$

where S_{gi} is the initial gas saturation, or the saturation at the flow reversal,

C is the Land trapping parameter. The Land coefficient is computed from the bounding drainage and imbibition curves as follows:

$$C = \frac{1}{S_{gt,\max}} - \frac{1}{S_{g,\max}} \tag{2.21}$$

where $S_{g,max}$ is the maximum gas saturation,

$S_{gt,max}$ is the maximum trapped gas saturation, associated with the bounding imbibition curve.

All these quantities are illustrated in Figure 2.10. The value of the Land trapping parameter is dependent on the type of rock and fluids.

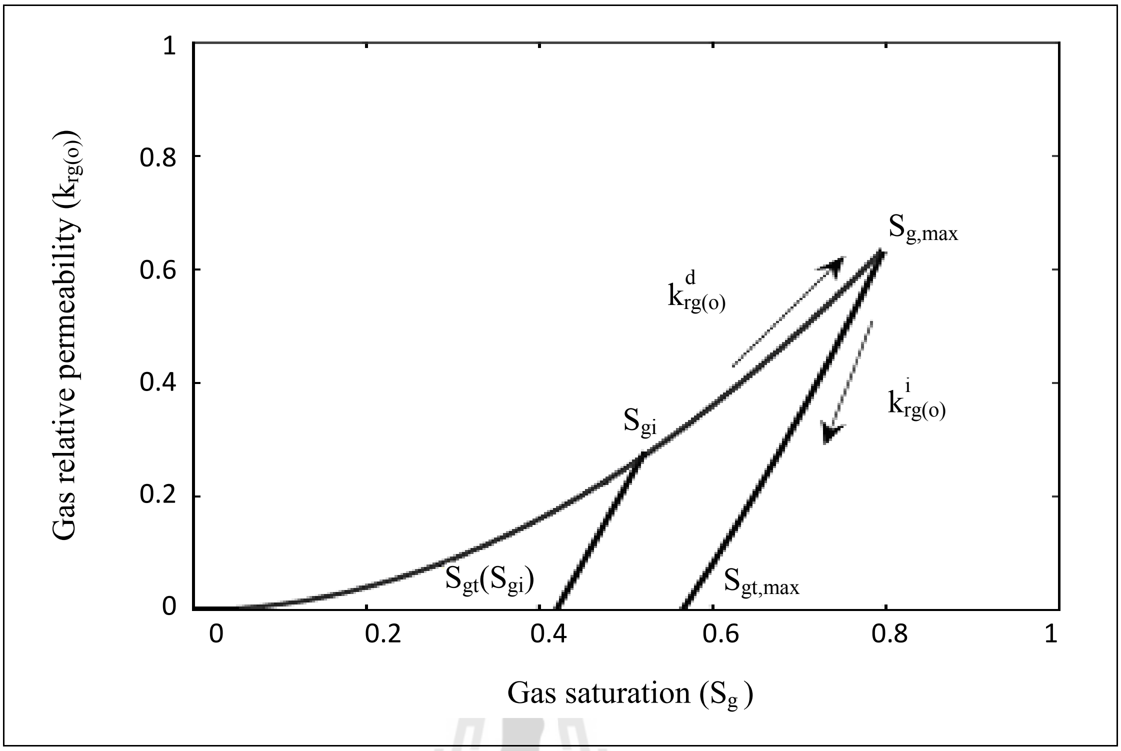

Figure 2.10 Relative permeability hysteresis model by Land trapping model

2.11.2. Carlson trapping model

A simplified hysteresis and trapping model developed by Carlson, requires the bounding drainage and imbibition curves. The trapped gas saturation is determined by shifting the bounding imbibition curve to intersect the intermediate initial gas saturation at the flow reversal. The idea behind Carlson's interpretation is to use the model of the imbibition relative permeability scanning curves as being parallel to each other. This geometric extrapolation procedure is illustrated in Figure 2.11. The trapped wetting-phase saturation is computed as

$$S_{gt} = S_{gr} - \Delta S_g \tag{2.22}$$

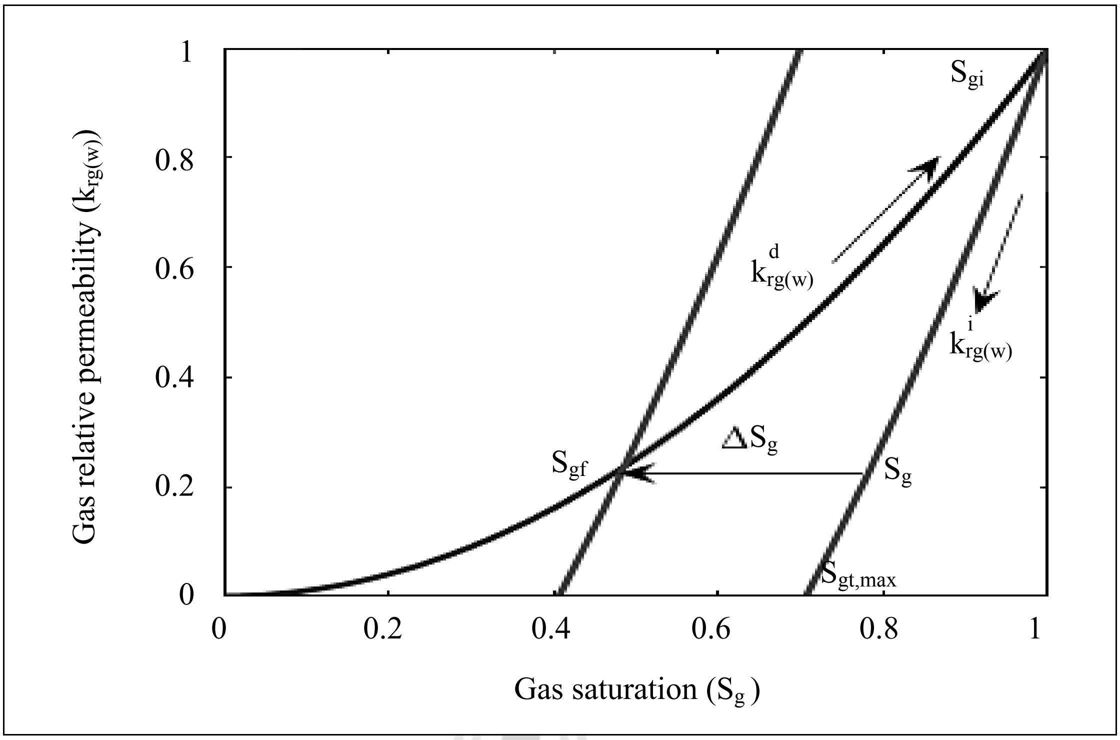

Figure 2.11 Relative permeability hysteresis model by Carson trapping model

where δ Sg is the shift in the imbibition scanning with respect to the imbibition scanning curve (see Figure 2.11).

This model is adequate if the intermediate scanning curves are almost parallel and there is little curvature in the imbibition curve. The model is problematic when the system is oil wet. The large curvature of the bounding imbibition relative permeability curve at low saturations does not allow prediction of intermediate relative permeability curves since any shifting will make the end-point trapped gas saturation negative, a non-physical value.

CHAPTER 3

Methods of study

This chapter describes the methods of the study on reservoir simulation and economic consideration.

3.1 Reservoir simulation

Reservoir simulation model is separated in to two main categories; Black Oil and Compositional Oil Model. Reservoir simulation models of this work had been run under Compositional Oil Model by using Eclipse_300 version 2009.2 licensed of Schlumberger Oversea S.A. It is more suitable than the Black Oil Model because Eclipse_300 can handle composition exchanges between compositional of reservoir fluid and injected gas. For all scenarios used and studied here, the reservoir was assumed to homogeneous, anisotropic and water-wet system.

3.1.1 Data preparation

The data required for the simulation consist of flow rate data, fluid data, rock data, production data, and reservoir geometry. These required data are collected from several sources, e.g. core data, laboratory analyze, well test, seismic, etc.

3.1.2 Input data

The simulation model was designed for 5 MMbbl of oil in place (OIP). The input data in the reservoir simulation consist of reservoir data, rock and fluid properties, and well data as showed in Tables 3.1 through 3.3. Well data provide well and completion locations, production and injection rates of wells, and other necessary data such as skin factors, well radius, and well controls. This study assumed that producing and injection wells have 0.71 ft diameter.

Table 3.1 Reservoir properties.

Properties	
Initial reservoir pressure	3000 psia
Bubble point pressure	1800 psia
Depth Oil-Water contact	5000 ft
Thickness	44 ft
Formation temperature	203 °F
Pressure gradient	0.7 psi/ft

Table 3.2 Rock properties.

Properties	
Rock type	Consolidated Sandstone
Porosity	0.2225 - 0.2325
Permeability	105.439 - 195.434 md
Vertical relative permeability = 0.1 ratio of Horizontal relative permeability	

Table 3.3 Fluid properties.

Properties	
Oil gravity	39.4 API
Gas gravity	0.8 (SG Air = 1)
Densities of water	62.43 lb/ft^3
Water compressibility @ 3500 psi	3.08 x 10^6/psi
Viscosity of water	0.296 cp
Salinity	0 (fraction)
Surface condition:	
Standard temperature	60 ºF
Standard pressure	14.7 psia

The other necessary data for WAG are relative permeability which has direct effect on the WAG process. Table 3.4 shows the set of three phase permeability in function of oil, water, and gas. A set of composition of injected fluid and reservoir fluid is also needed and shown in Table 3.5. Properties of the fluid that used in equation of state are showed in Table 3.6 and 3.7. Binary interaction coefficients (BIC) are generated from PVTi which is a subprogram of Eclipse 300.

Table 3.4 Relative permeability to water, oil, and gas.

Sw	**Krw**	**Pc**	**So**	**Krow**	**Krowg**	**Sg**	**K_{rg}**	**P_c**
0.25	0	1	0	0	0	0	0	0
0.3	0	0.5	0.2	0	0	0.04	0	0.015
0.4	0.04	0.2	0.3	0.01	0.03	0.15	0.022	0.036
0.5	0.11	0.1	0.4	0.03	0.04	0.2	0.05	0.086
0.6	0.2	0.05	0.45	0.05	0.07	0.3	0.113	0.167
0.7	0.3	0.03	0.5	0.1	0.12	0.4	0.21	0.276
0.75	0.44	0.01	0.55	0.15	0.17	0.5	0.4	0.4
0.8	0.68	0	0.6	0.2	0.25	0.6	0.45	0.5
			0.65	0.6	0.62	0.7	0.55	0.6
			0.7	0.8	0.82	0.75	0.6	0.65
			0.75	1	1			

Table 3.5 Composition of reservoir fluid.

Composition	**Molefraction of reservoir fluid**
C1	0.5
C2	0.04
C3	0.02
C4	0.01
C5	0.01
C6	0.03
C7+	0.39

Table 3.6 Fluid properties of composition in reservoir.

Composition	Pc(Psia)	Tc (R)	MW	Acentric factor	Critical Z
C1	666.40	343.33	16.04	0.0104	0.2902
C2	706.50	549.92	30.07	0.0979	0.2830
C3	616.00	666.06	44.10	0.1522	0.2785
C4	550.60	765.62	58.12	0.1852	0.2756
C5	488.60	845.80	72.15	0.1995	0.2744
C6	436.90	913.60	86.18	0.2280	0.2719
C7+	285.00	1287.00	215.00	0.5200	0.2451

Table 3.7 Binary interaction coefficients.

Composition	C1	C2	C3	C4	C5	C6	C7+
C1	0	0	0	0	0	0.029	0.049
C2	0	0	0	0	0	0.010	0.010
C3	0	0	0	0	0	0.010	0.010
C4	0	0	0	0	0	0	0
C5	0	0	0	0	0	0	0
C6	0.029	0.010	0.010	0	0	0	0
C7+	0.049	0.010	0.010	0	0	0	0

3.1.3 Simulation model

The conceptual study model had been generated in sandbox geometry as showed in Figure 3.1. Grid blocks are 25x25x5 in the x-, y-, and z- directions, respectively and active all cells. The dimensions are 87.5 ft in x-, y- directions, and 8.8 ft in z-direction. The production and injection wells are located at x-y coordinate 5,12 and 20,12. The depth of top reservoir is 4,956 ft below the surface.

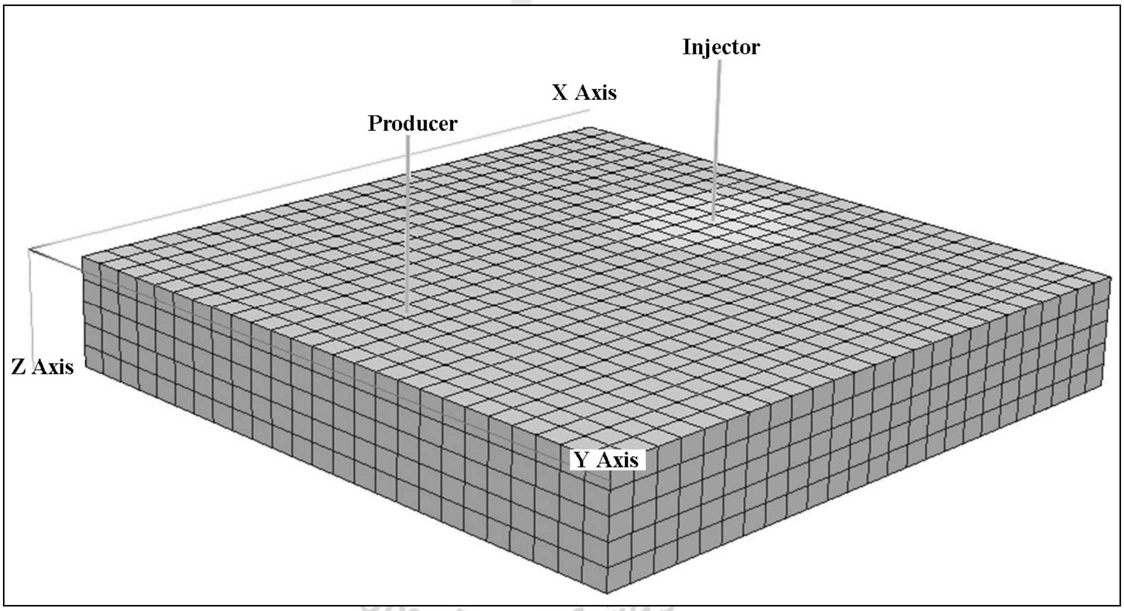

Figure 3.1 Geometry of the conceptual reservoir model and wells location

3.1.4 Simulator procedure

In this study, all of scenarios employed the same geometry and properties. The base case reservoir, was set the bottom hole pressure (BHP) of production above 2,165 psia for hydraulic pressure and having 90% water cut as limitation in producing period. If one or both criterion is reached, the well will be shut-in. Simulation was run in several scenarios, and sensitivity analyses in production rate were taken into account to optimize recovery efficiency.

3.1.5 Sensitivity analysis

Sensitivity of recovery efficiency resulted from each scenario had been analyzed by varying parameters as follows,

a) Scenario 1 : Natural flow, NF

This study had been varied only the production rate and calculated the maximized recovery of production under 20 years of production plan.

b) Scenario 2 : Base case

For the base case of WAG method, this study had been varied both of production and injection rate. Reservoir pressure was not constant during the WAG was in processing. For the injection well, water and gas were injected at the same fluid rate alternately and controlled by downhole rate instead. In this scenario volume ratio of injected water and gas equals 1. Cycle of injecting period was 12 months and injection was operated at the first year of production.

c) Other scenario : WAG

These studied was developed from base case. Cycles of injecting period were varied from 1 to 15 months. Injection at the first year of production was changed to 2^{nd}, 4^{th}, and 8^{th} year of production respectively to study reservoir pressure that was affected by production and injection rate variation.

3.2 Economic evaluation

To find out the best suitable profit from the project, all of scenarios were analyzed economically to determine the most suitable economically viable development plan. This evaluation consists of the pay back period, net present value, profit investment ratio and internal rate of return.

3.2.1. Exploration and production plan

The period of exploration and production plan under “Thiland III” acts is divided into 4 years of exploration period and 20 years of production period (start at the end of exploration period).

1^{st} year @ 2010	: Petroleum concession
2^{nd} year @ 2011	: Geological and geophysical survey
3^{rd} year @ 2012	: Drill one appraisal wells
4^{th} year @ 2013	: Drill development well and prepare to start production plan
5^{th} year @ 2014	: Starting economic production and stop at the end of 20^{th} year or reach the limit.

The production plan in this study was divided in to 2 main scenarios.

- Natural flow
- WAG with free gas injection at 1^{st}, 2^{nd}, 4^{rd}, and 8^{th} year of the production plan

3.2.2. Basic assumptions of economic study

For economic evaluation purpose, some economics parameters were assumed and defined as follows;

a. Oil price (US$)	40, 80, 120
b. Income tax (%)	50
c. Escalation factor (%)	2
d. Discount rate (%)	6, 10, 15
e. Tangible cost (%)	20
f. Intangible cost (%)	80
g. Depreciation of tangible cost (%)	20
h. Sliding scale royalty	
Production Level (BPD)	Rate (%)
0-2,000	5.00
2,000-5,000	6.25
5,000-10,000	10.00
10,000-20,000	12.50
> 20,000	15.00

3.2.3. Other cost assumptions

a. Oil price is constant over all project life.

b. Increasing rate of capital expenditure comes from the price increasing of machineries and other equipments used in oil industries, and given to two percent per year.

c. Discount rate of money is 6.00 percent (Bangkok Bank, 1 October 2010)

d. Operating cost is escalated 2 percent each year forward.

e. The expenses used in cash flow analysis are listed in Table 3.8.

Table 3.8 Cash flow expenditure cost detail.

Expenditure Cost Detail	Cost
Petroleum concession	500,000 US$
Geological and geophysical surveys	1,000,000 US$
Pipe for WAG process	100,000 US$
WAG distribute	200,000 US$
WAG plant	700,000 US$
Compressor	5,000,000 US$
Appraisal well	3,000,000 US$/well
Processing production facilities	5,000,000 US$
Drilling and completion production well	1,500,000 US$/well
Facility costs of injection well	350,000 US$/well
Abandonment cost	12,500 US$/well
Maintenance costs of injection well	140,000 US$/year
Operational costs of Production well	30 US$/bbl (oil)
Operational cost of Injection water	0.5 US$/bbl (water)
Costs of reworking for inject WAG	86,900 US$/period

3.2.4. Cash flow table explanations

The cash flow tables are shown in Appendix A. Detail of each column in the cash flow table is explained as follows;

A = Year

B = Oil production per year (bbl/year)

C = Gross revenue sale income (US$)

B x oil price

D = C x Royalty sliding scale (0.0500, 0.0625, 0.1000, 0.1250, or 0.1500) of gross revenue (US$)

E	=	2% of escalation factor
F, G, H	=	Investment cost is 100 percent of the intangible cost
F	=	Concession (US$): Investment cost
G	=	Geological and geophysical surveys (US$): Investment cost
H	=	Appraisal wells (US$): Investment cost
I, J	=	Investment cost is divided to intangible cost 80 percent and tangible cost 20 percent
I	=	Drilling cost of the intangible cost 80 percent Well cost x intangible cost 80 percent (US$)
J	=	Drilling cost of the tangible cost 20 percent Well cost x tangible cost 20 percent (US$)
K	=	Facility cost of production and injection process (US$): Investment cost
L	=	Abandonment cost (US$)
M	=	Facility cost of injection well (US$)
N	=	Depreciation; Depletion; Amortization rate 20 percent of tangible expenses (straight forward 5 years) (F + G + H + J + K + M) x 0.20
O	=	Water injection rate (bbl/year)
P	=	Gas injection rate (MSCF/year)
Q	=	Operating expenses (OPEX) (US$) (B x 30 US$/bbl)
R	=	Maintenance cost of water injection facility (US$)

S	=	Operation cost of water injection (OPEX) (US$)
		(O x 0.5 US$/bbl)
T	=	Operation cost of gas rework injection (OPEX) (US$)
U	=	Total allow expense (US$)
		((F + G + H + I + J +K + L + M) x E (2% Escalation factor)) + (Q + R + S + T)
V	=	Taxable income (US$)
		C – D – N – U
W	=	Income tax (50%) (US$)
		V x 0.50
X	=	Annual cash flow (US$)
		C – D – U – W
Y	=	Discounted factor each year
Z	=	Net present value; NPV@6, 10 or 15 % (US$)
		X x Y
AA	=	Cumulative Net present value; NPV@ discount factor % (US$)

CHAPTER 4

Results of study

Results of the study were showed and discussed for each optimized parameters of WAG under specific reservoir condition. These results were focused on 7 main graphs including field cumulative production, field production rate, gas-oil-ratio, cross plot of pressure and water cut, and cross plot of bottom hole pressure of injection and production wells, respectively.

4.1. Reservoir simulation results

As mentioned in previous chapter that the simulation were run under various required parameters. The model had been performed and tested by 2 types of production scenarios; natural flow drive mechanism (NF) and WAG which injected fluid at 1^{st}, 2^{nd}, 4^{th}, and 8^{th} after production period. In all study cases the primary production was design to begin in January 2010. The detail of the 6 conceptual production and injection scenarios and recovery efficiency of each scenario are illustrated and summarized in Table 4.1.

Table 4.1 Recovery factor resulted from the 6 conceptual injection and production scenarios.

Pattern	Scenario	Start injection time (Year)	Production and injection rate (RB/D)	Water period (Months)	Gas period (Months)	RF (%)	PI (%)
NF	1	-	400	-	-	10.54	-
WAG : base case	2	1st	700	12	12	49.70	67.45
WAG : freegas	3	1st	700	12	1	65.13	86.88
	4	2nd	1000	13	1	71.05	70.98
	5	4th	1000	15	1	58.60	92.81
	6	8th	300	15	1	24.88	123.19

4.1.1 Scenario 1 (Natural flow, NF).

Scenario 1 is the oil and gas production by natural drive with 400 RB/D of produced fluid within the 20 years production periods. The results of the study are presented in Figure 4.1 to 4.7.

Table 4.2 Summary detail of scenario 1.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	544,231	5,151,893	10.56
Gas (MSCF)	511,882	3,240,928	15.79
Water (STB)	-	1,668,268	-

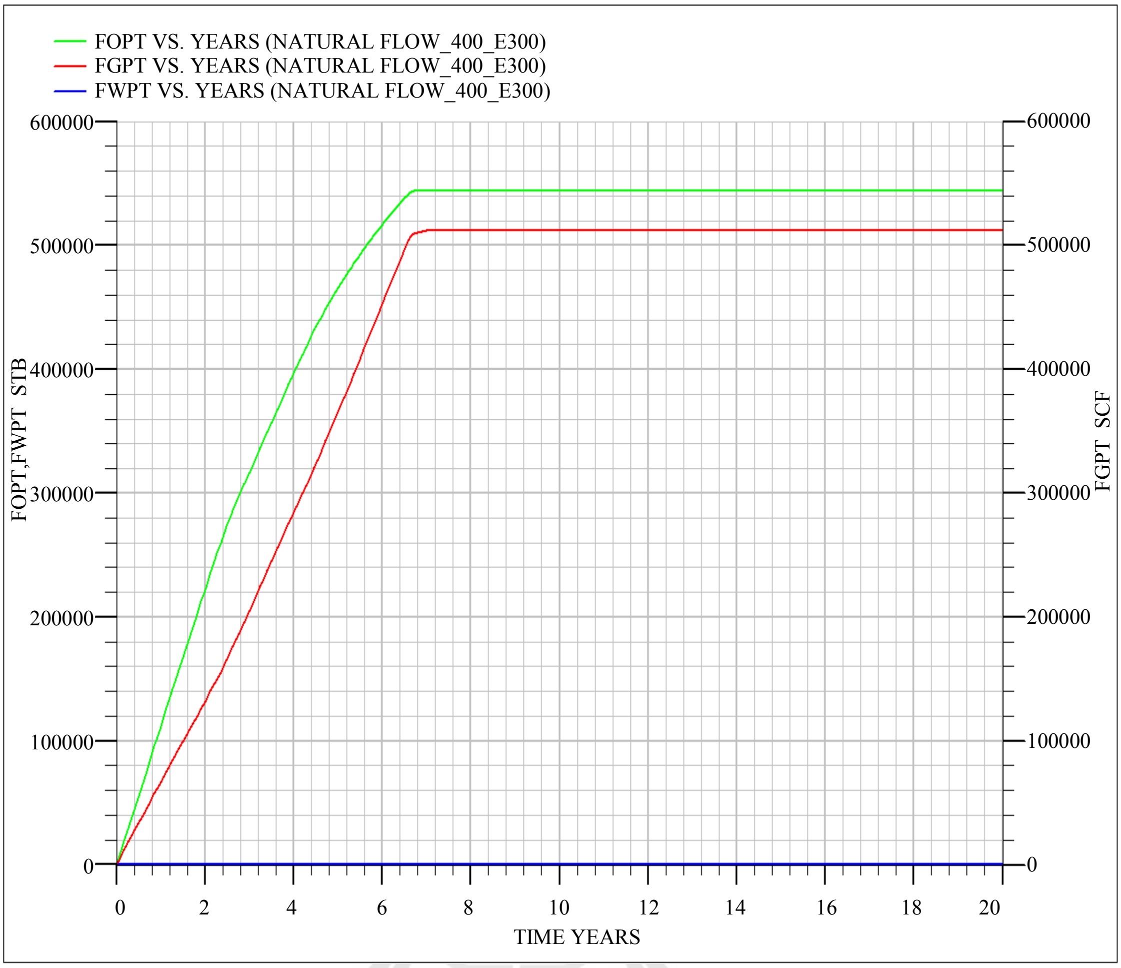

Figure 4.1 Cumulative fluid productions vs. time of scenario 1.

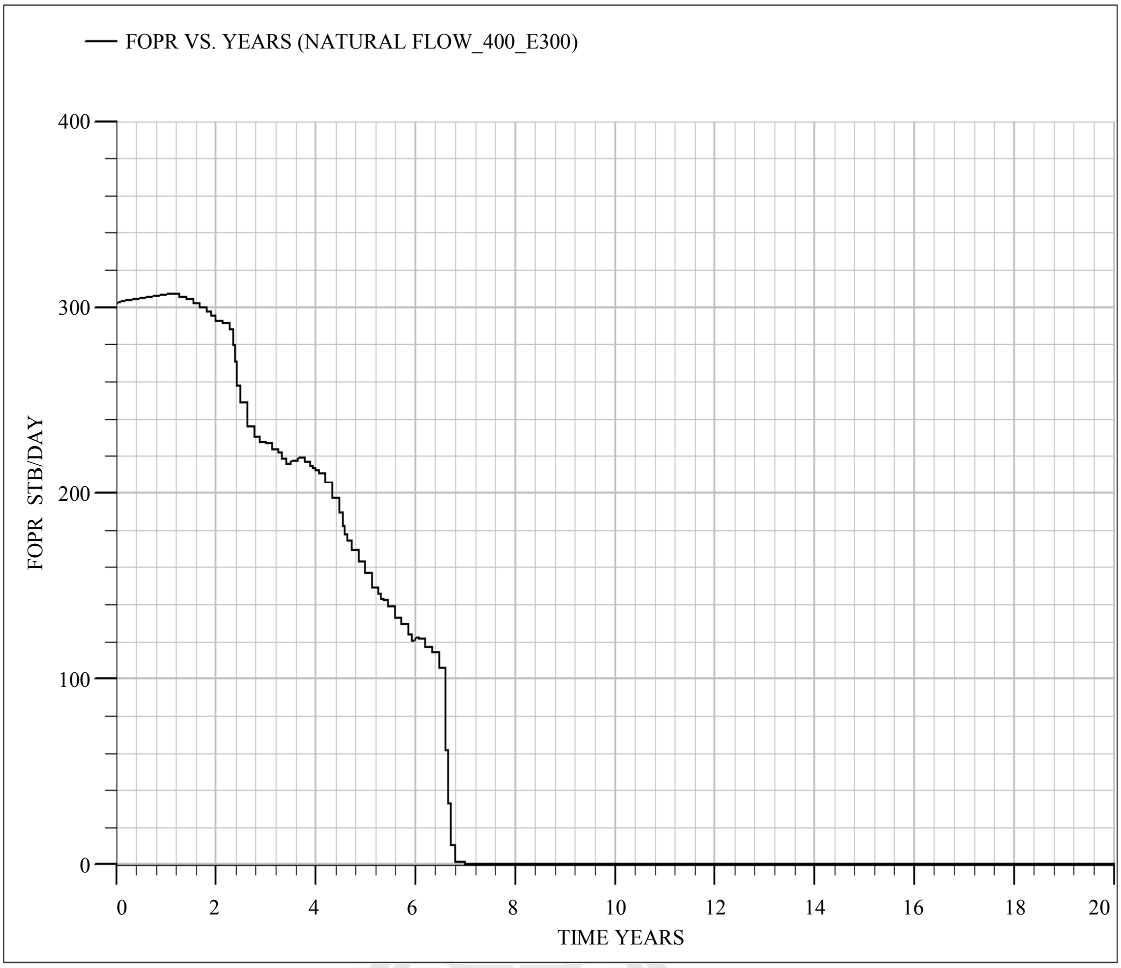

Figure 4.2 Oil production rates vs. time of scenario 1.

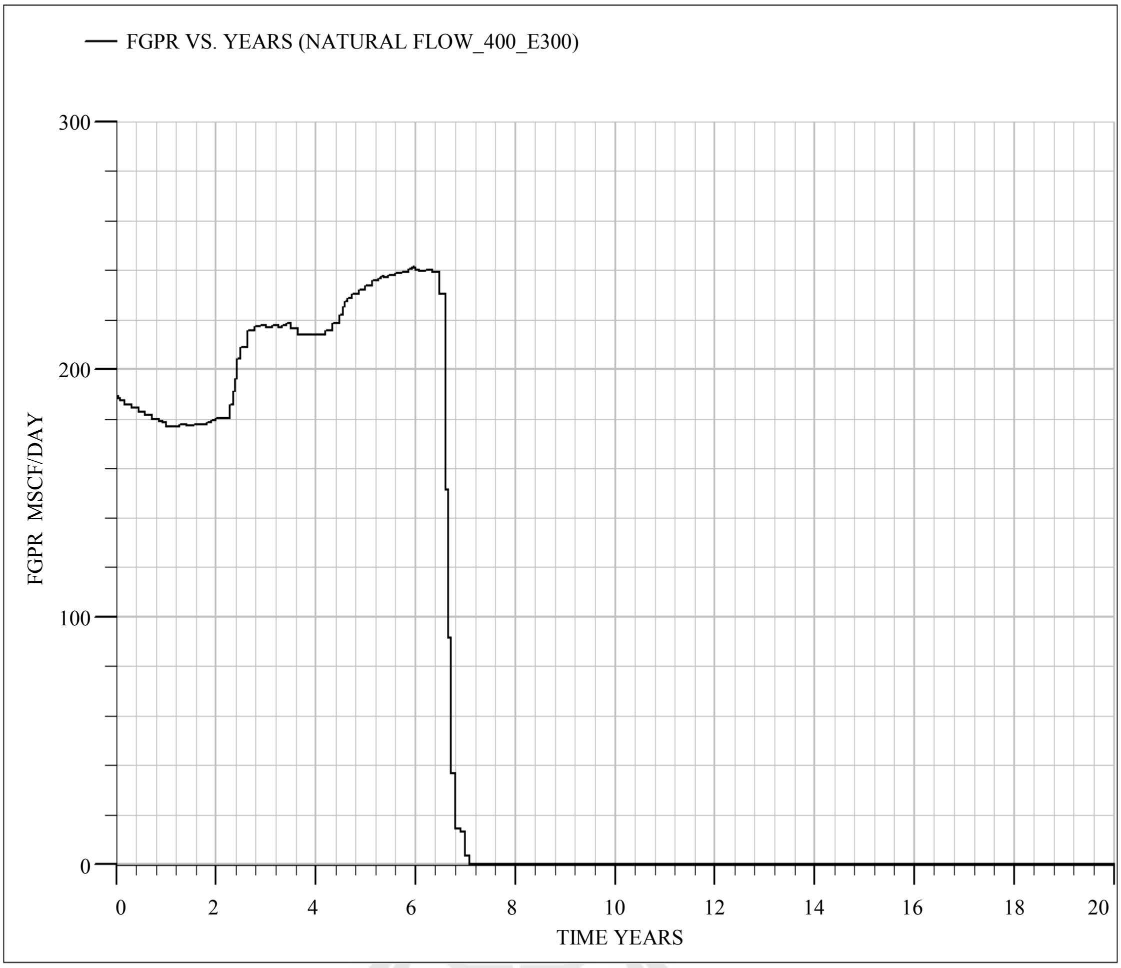

Figure 4.3 Gas production rates vs. time of scenario 1.

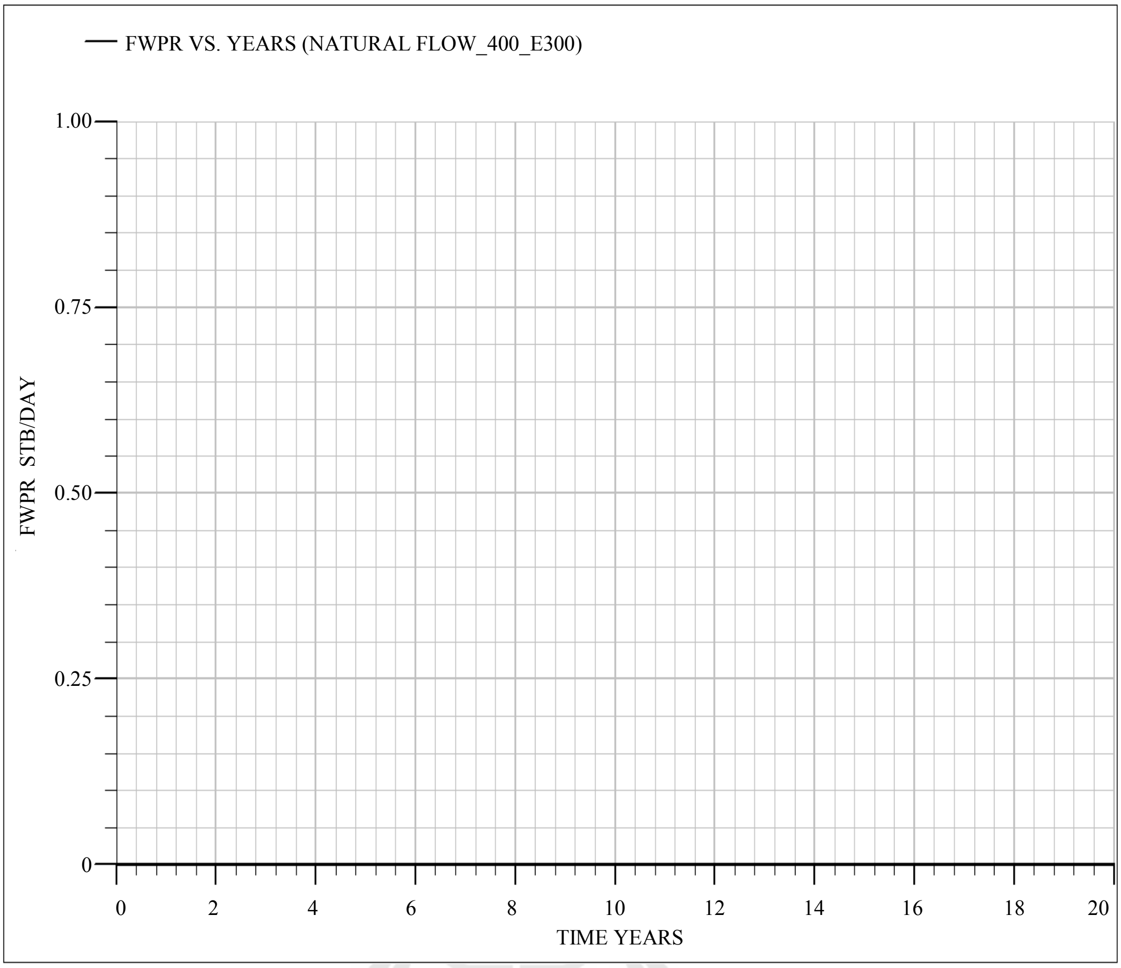

Figure 4.4 Water production rates vs. time of scenario 1.

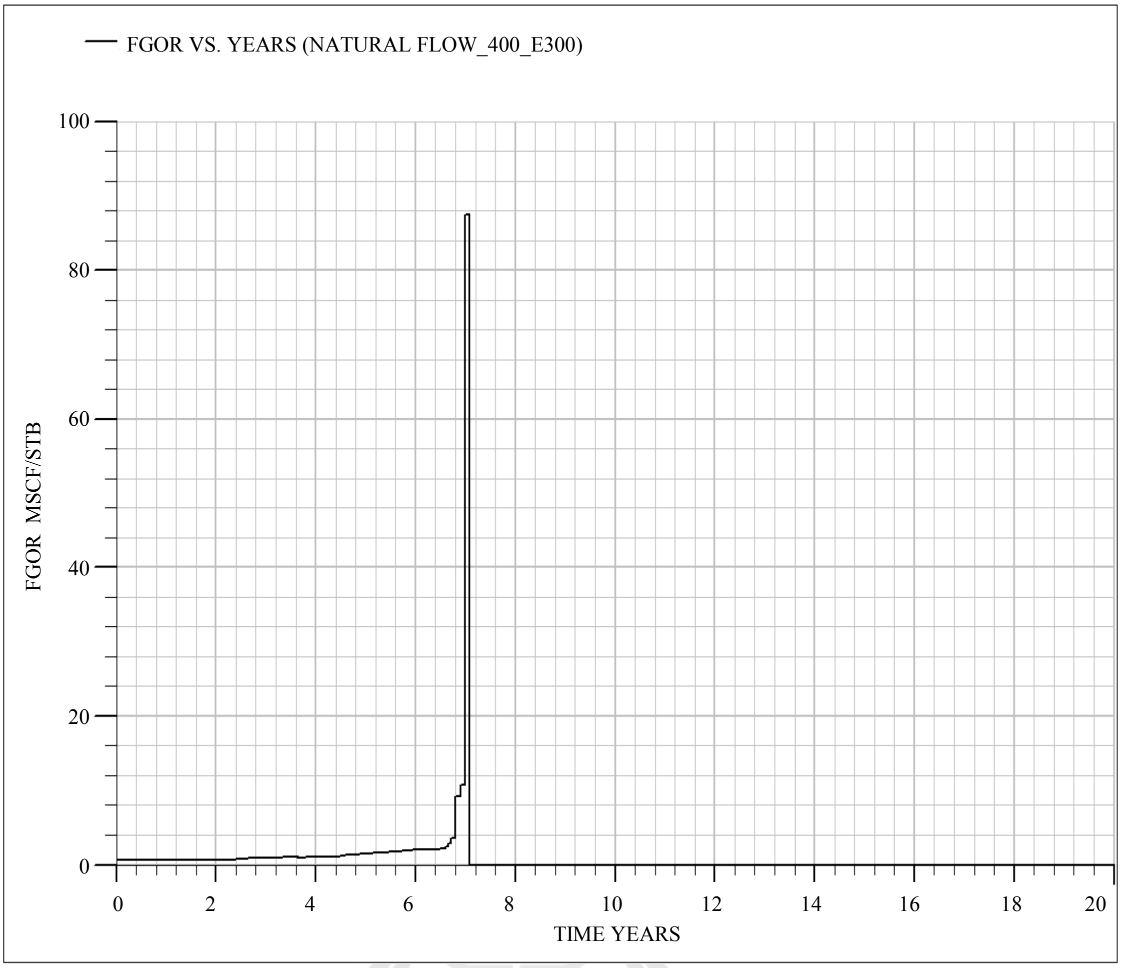

Figure 4.5 Gas-oil ratio vs. time of scenario 1.

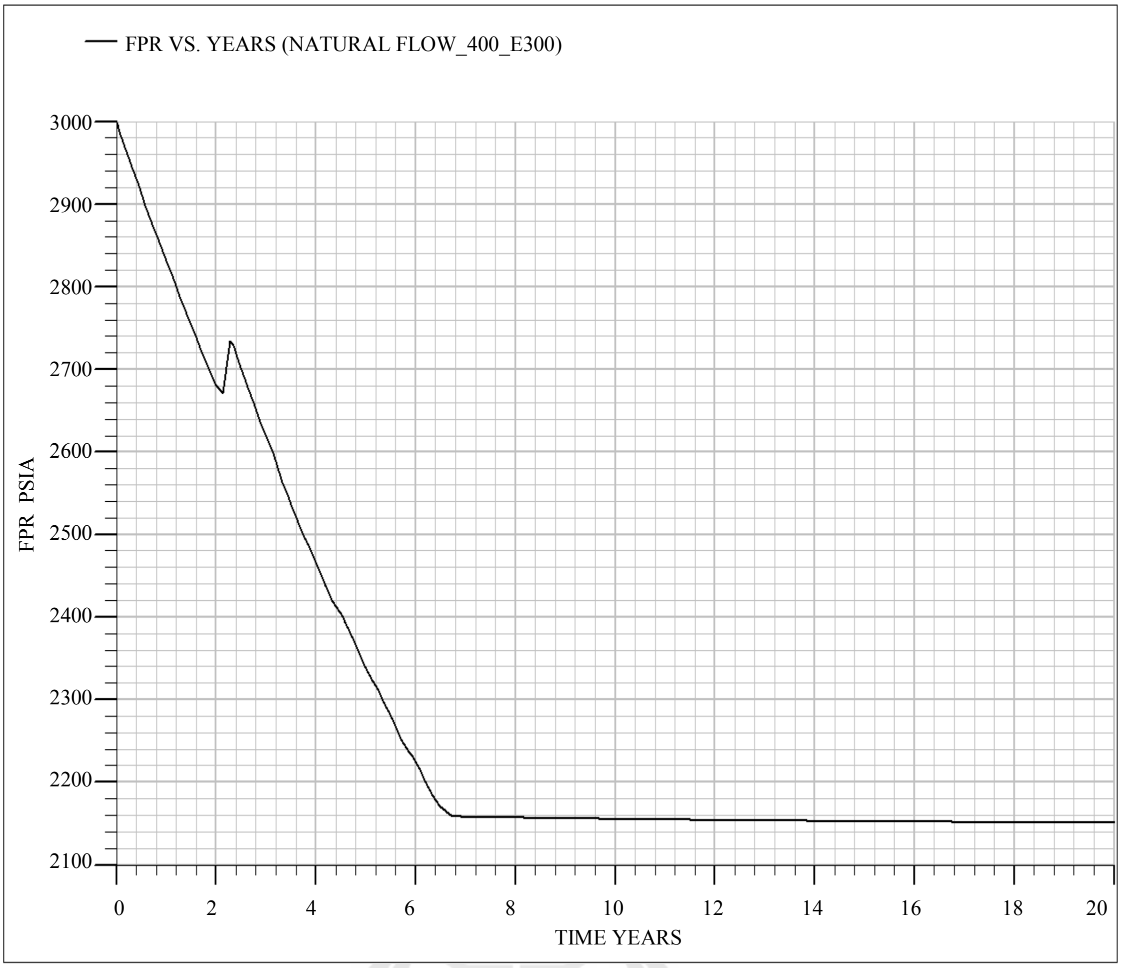

Figure 4.6 Pressure of reservoir vs. time of scenario 1.

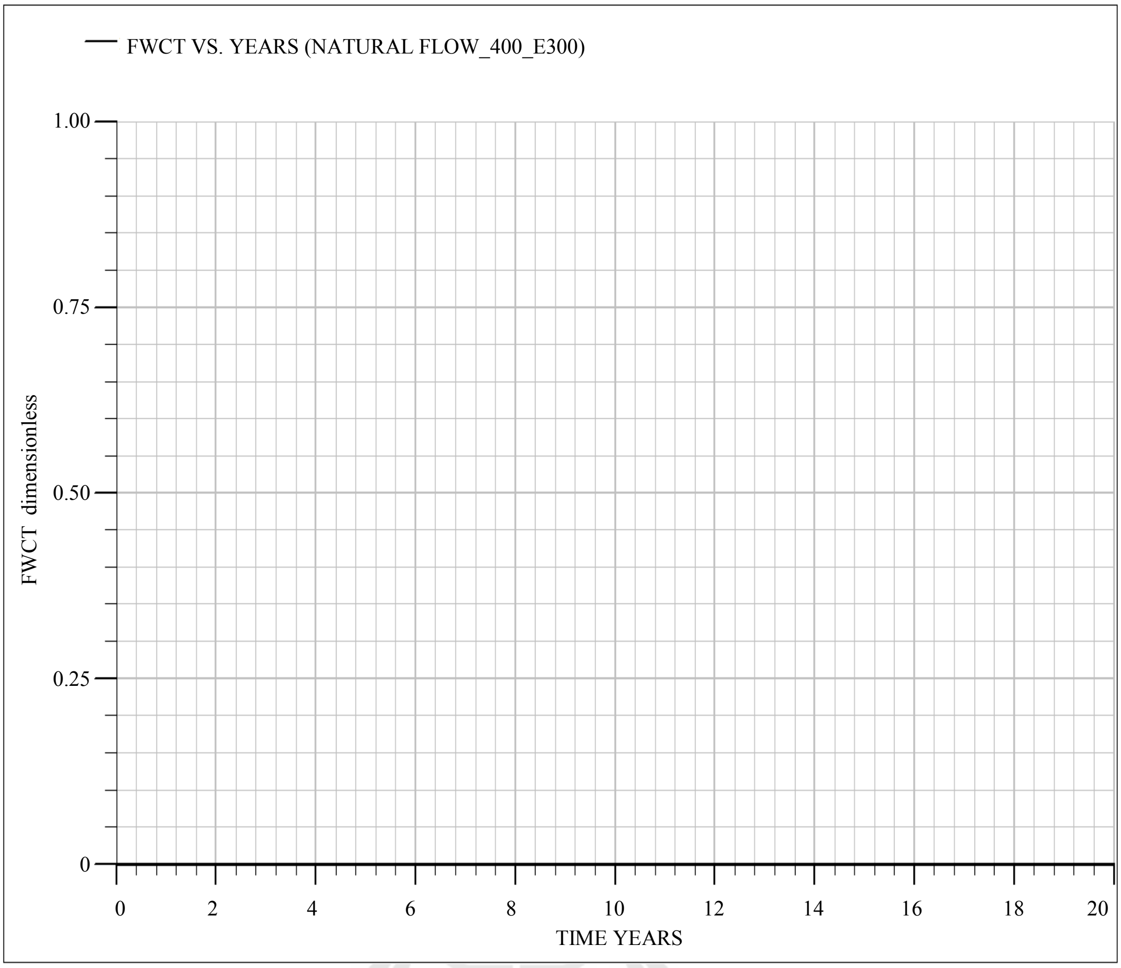

Figure 4.7 WCT vs. time of scenario 1.

Cumulative oil production was estimated about 0.54 MMSTB with the recovery of 10.54% of original oil in place (Figure 4.1). During oil production, some free gas (512 MMSCF) could deliver due to the decreasing of reservoir pressure. The oil production profile is shown in Figure 4.2. During production, the oil production rate was maintained at the rate of 300 STB/D (400 RB/D) for the first two years and then decline. Production rate was dropped sharply after the seventh year of the production due to reservoir pressure drop rapidly (Figure 4.2). The plateau period could be longer if production rate or critical condition had been set to lower. This rapid production rate cause drop by the reservoir pressure limitation was reached as showed in Figure 4.6.

4.1.2 Scenario 2 (WAG: Base case).

Scenario 2 consists of oil production rate of 700 RB/D with water injection for 12 months and gas injection for 12 months alternately. Cumulative oil production was 2.56 MMSTB at the end of production with the recovery of 49.70% of original oil in place (Figure 4.8). There were some free gas (3.34 MMSCF) delivered during the oil production due to the reservoir pressure decreasing until below than the bubble point pressure.

Table 4.3 Summary detail of scenario 2.

Fluid type	Production volume , RB	Injection volume , RB
Oil	3,423,930	-
Gas	-	2,517,986
Water	-	2,558,500
PI (%)	67.45	

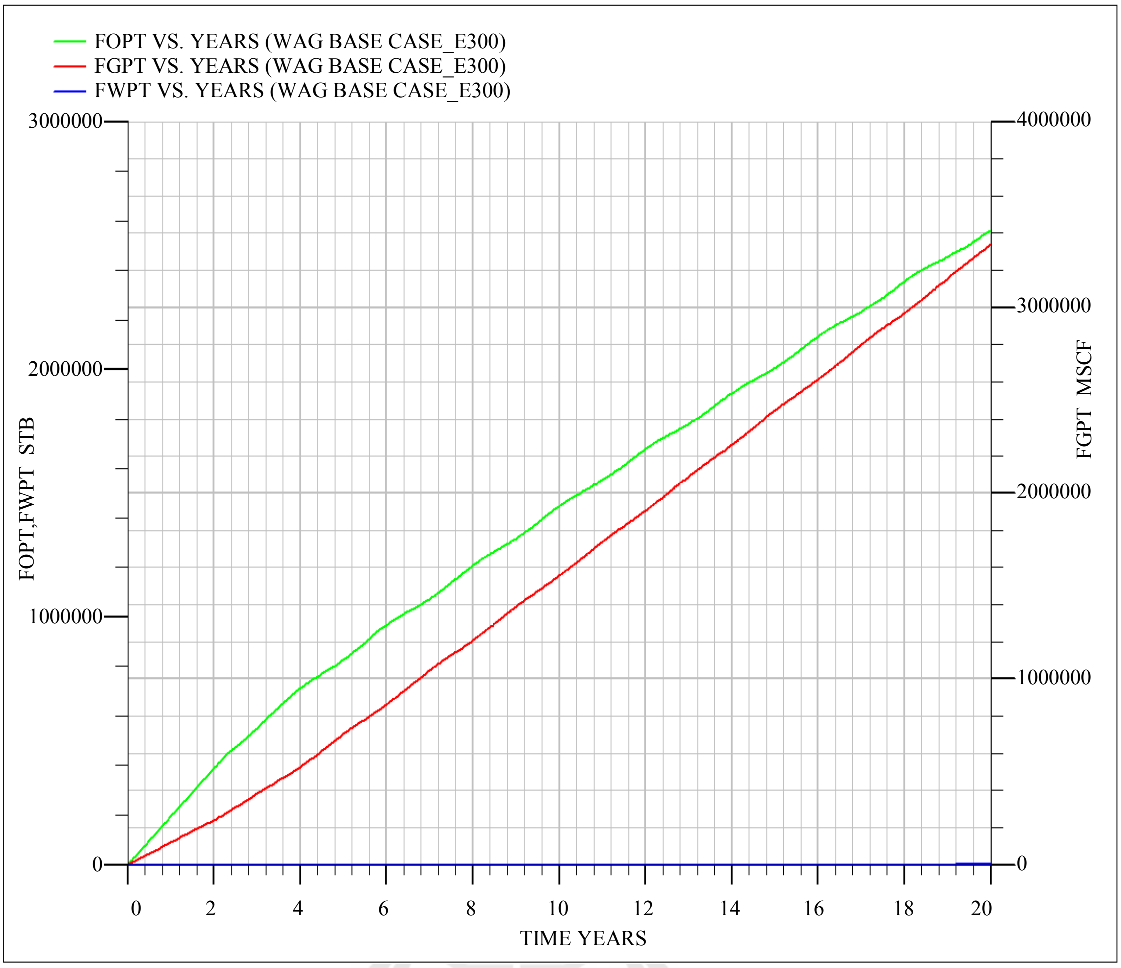

Figure 4.8 Cumulative fluid productions vs. time of scenario 2.

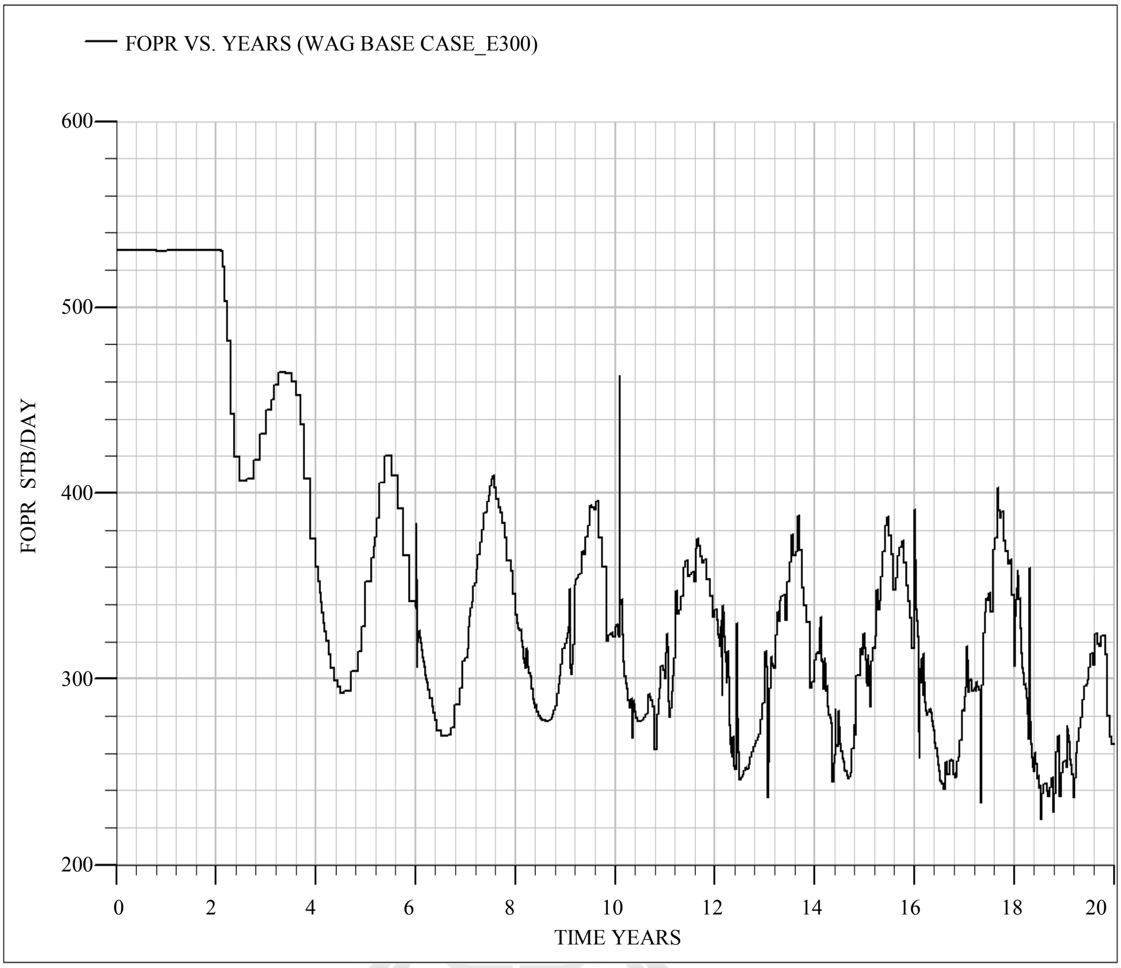

Figure 4.9 Oil production rates vs. time of scenario 2.

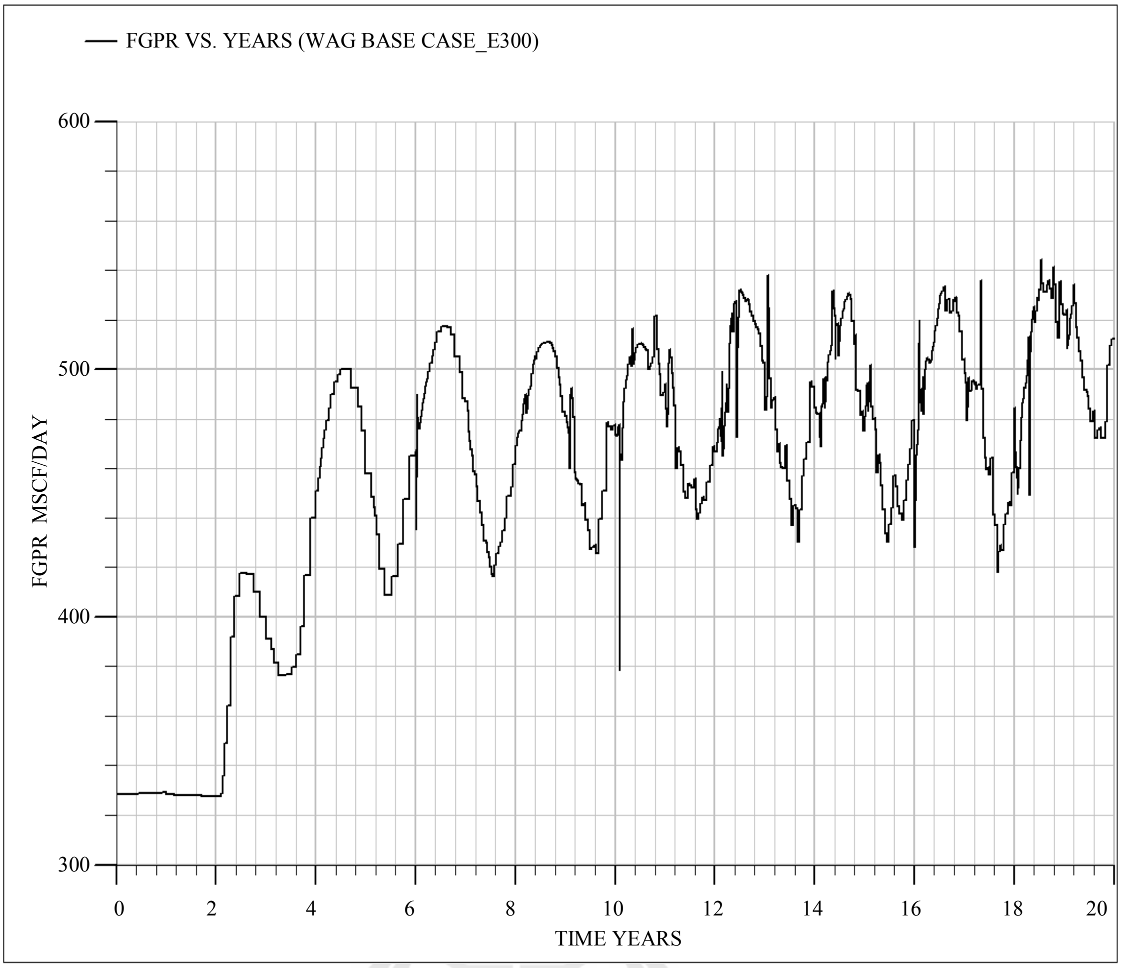

Figure 4.10 Gas production rates vs. time of scenario 2.

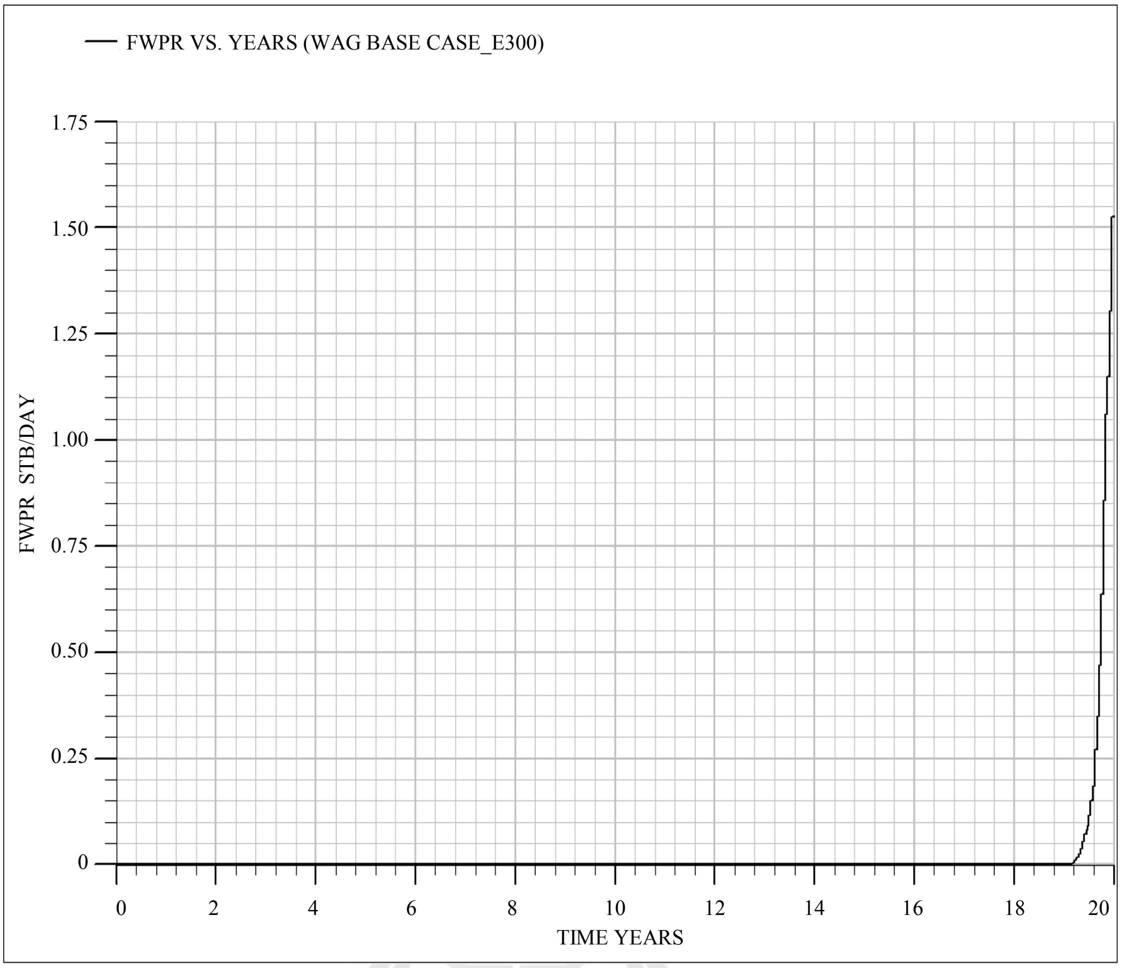

Figure 4.11 Water production rates vs. time of scenario 2.

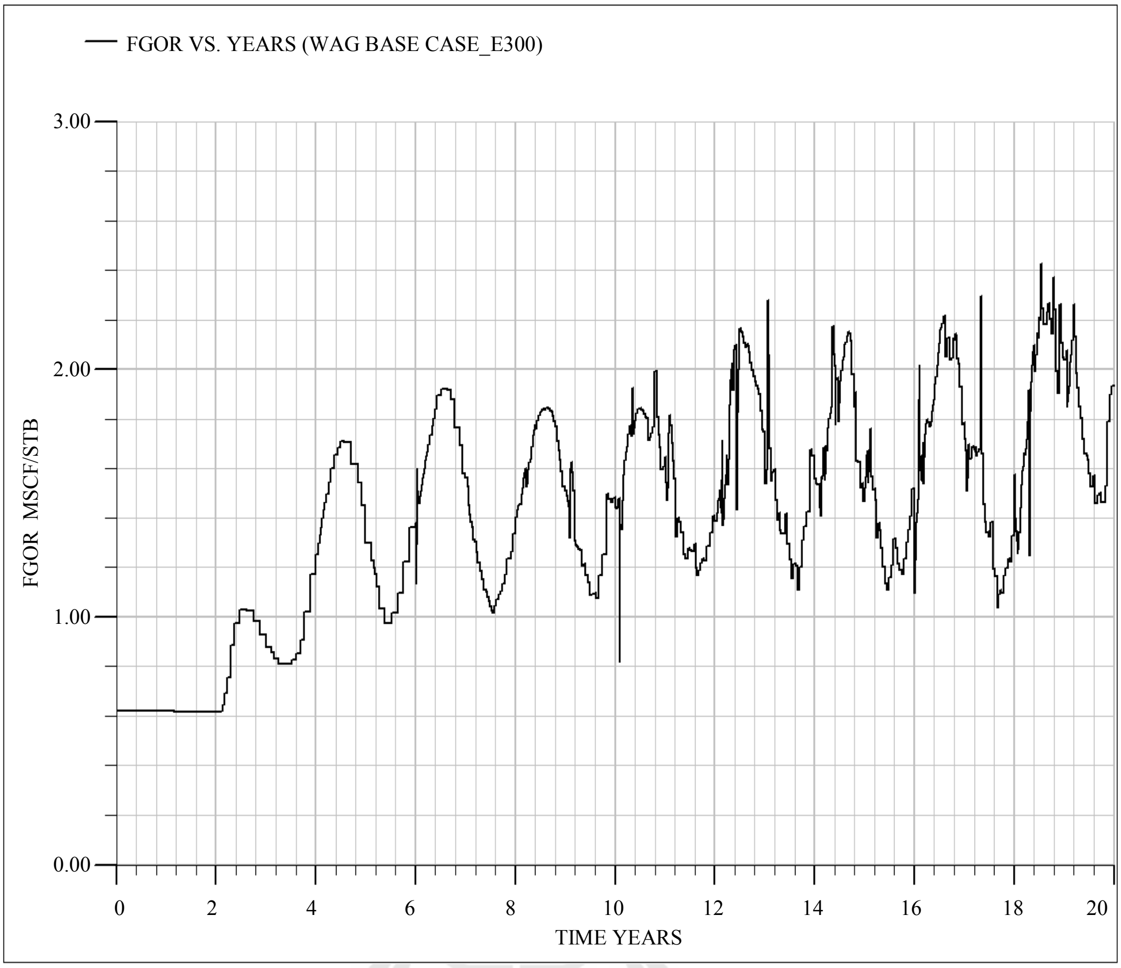

Figure 4.12 Gas-oil ratio vs. time of scenario 2.

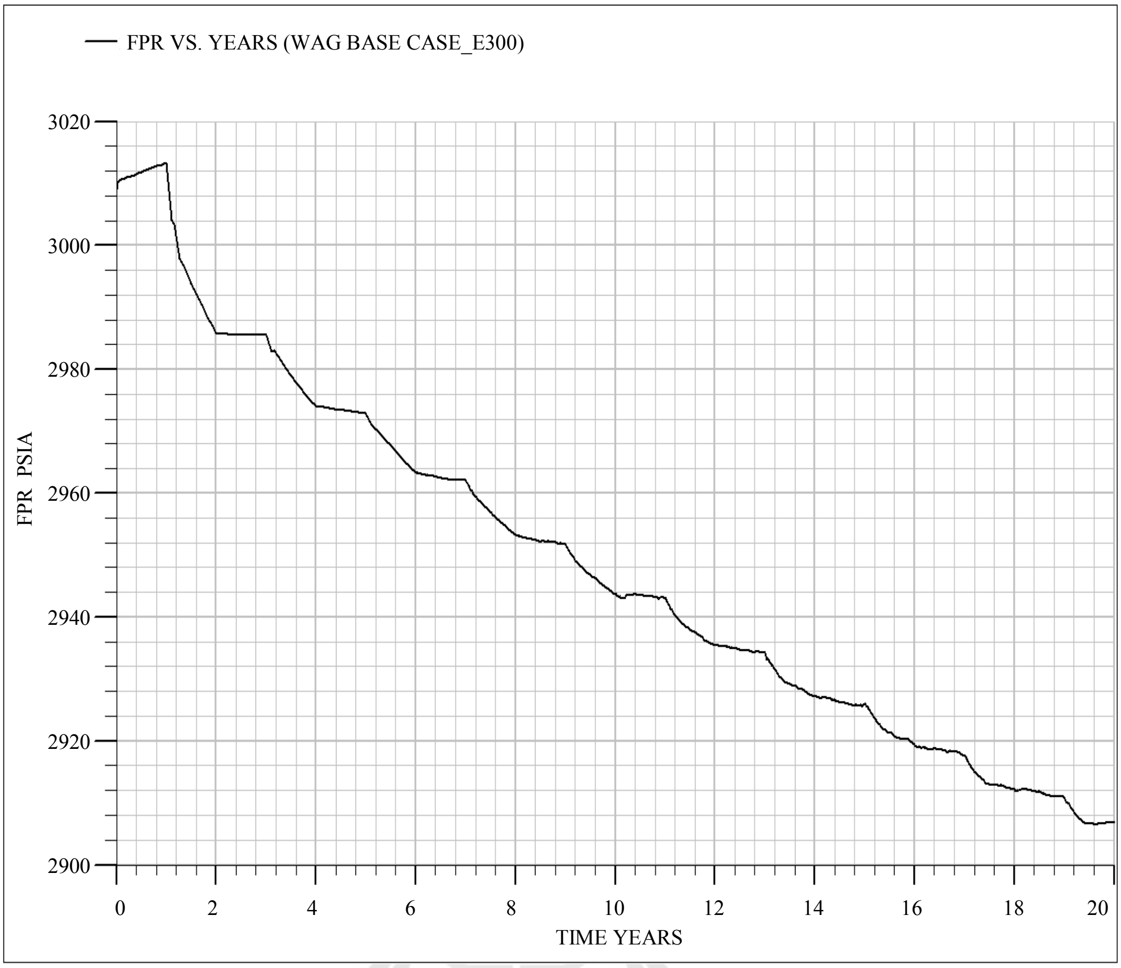

Figure 4.13 Pressure of reservoir vs. time of scenario 2.

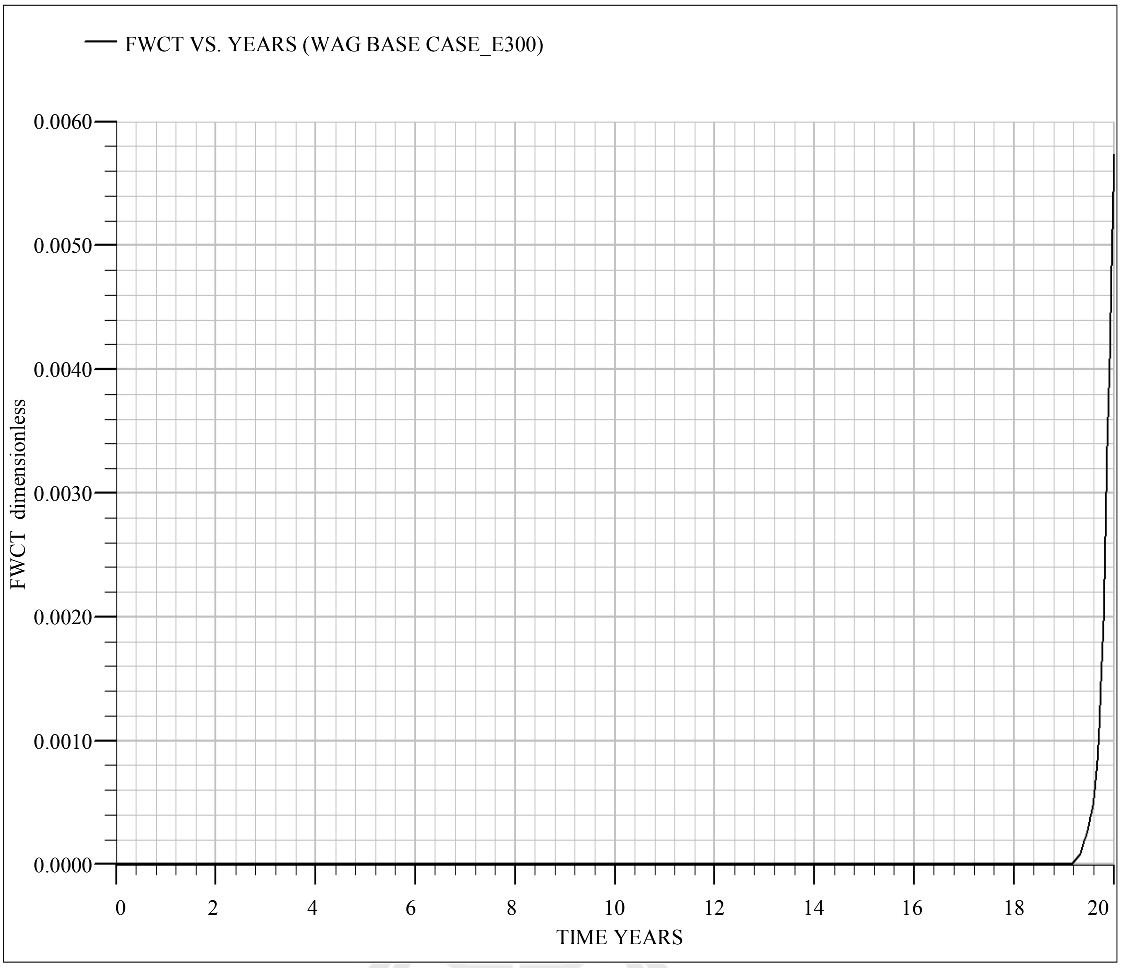

Figure 4.14 WCT vs. time of scenario 2.

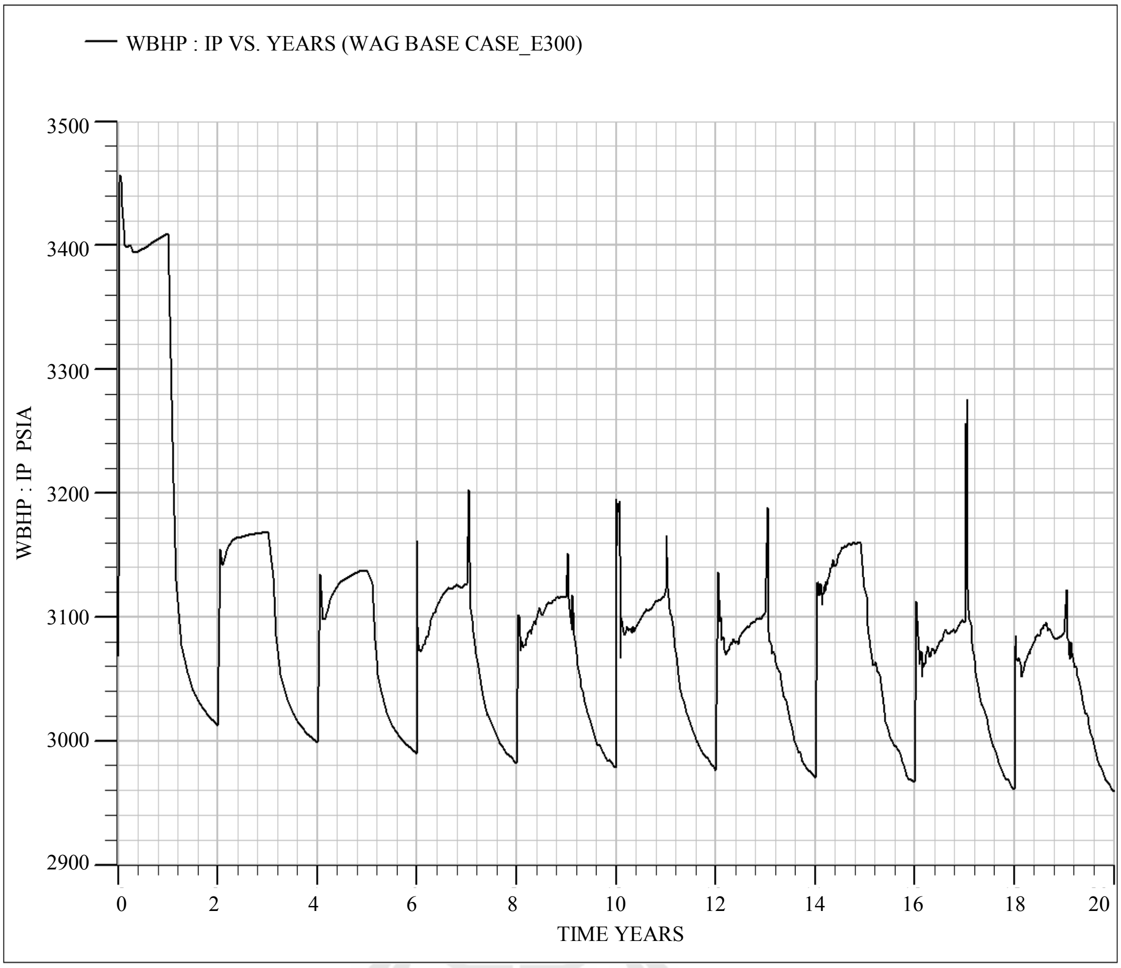

Figure 4.15 BHP of injection well vs. time of scenario 2.

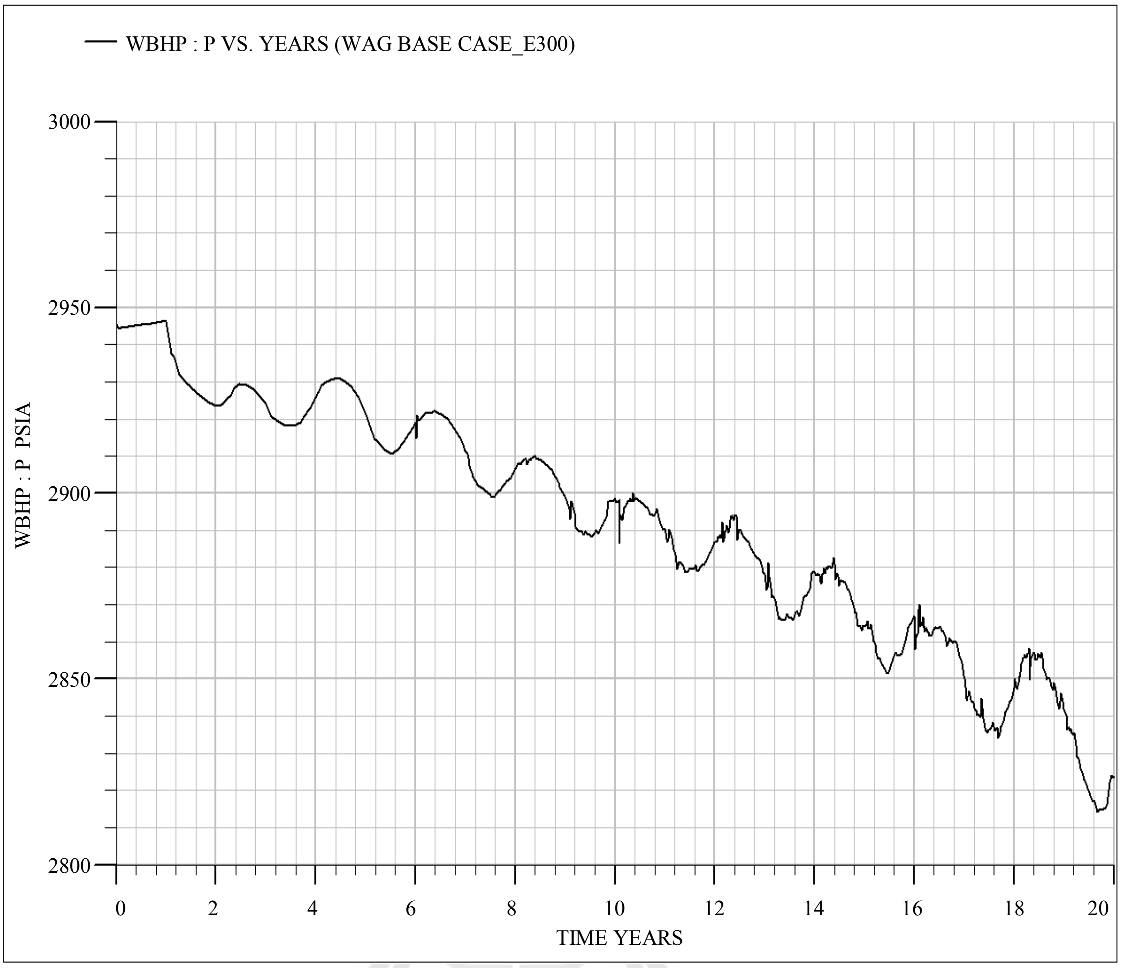

Figure 4.16 BHP of production well vs. time of scenario 2.

The oil production profile is shown in Figure 4.9. The oil production rate was maintained at the rate of 530 STB/D (700 RB/D) for the first two years then decline and ended at 260 STB/D. Then, the production rate declined and increased in a cyclic loop and followed a declining trend throughout the producing time due to the decrease of reservoir pressure. The cyclic of oil production were resulted from water and gas alternately injected. The reservoir pressure would be increased when water was injected and resulting in the increasing of oil production rate. On the other hand, the reservoir pressure would be decreased when gas was injected, and resulting in the decreasing of oil production rate.

The gas production rate during the first two years had the same trend as the oil production rate (Figure 4.9 and Figure 4.10). In this period solution gas come from internal gas only, solution gas was constant at 330 MSCF/STB (Figure 4.12). At the tenth year of the production, the injected gas could be reaches the production well and could be used to reinject into the reservoir as a supply gas again. The gas-oil ratio tented to be increase in a cycle when injected gas slug reached the production well. Since the water and gas were steadily injected, the oil rate tended to decline. This is due to the reduction of oil relative permeability and reservoir pressure.

Figure 4.11 shows that water breakthrough at nineteenth year of the production and dramatically increase. The water cut profile does not fluctuated as the gas production whereas the water production does follow a similar trend as the oil production profile. This is because water cut is a ratio of produced water to produced liquid (oil and water).

The reservoir pressure slightly fluctuated in the range of 2900 to 3010 psia due to the alternation of fluid injection. The reservoir pressure was increased when the water was injected but decreased when the gas was injected.

The bottom hole pressure of the production well decreased as oil was produced from the reservoir until it reached 2165 psia which is the minimum allowable bottom hole pressure in this study. The production well had to be adjusted the bottom hole pressure in order to achieve a plateau rate of 700 RB/D at initial period of production. After that, oil was produced at bottomhole pressure of 2,165 psia. Bottom hole pressure of injection well at the beginning of the injection is about 3,450 psia (Figure 4.15), while the initial reservoir pressure is 3,000 psia. Bottom hole pressure of injection well was generally increased during water injection and decreased during gas injection, followed reservoir pressure trend. Since gas has higher compressibility than water, gas injection did not create a large amount of pressure increase when compared to water. At the same time the producer was still producing, thus the bottom hole pressure of the injector was also reduced during the gas injection.

4.1.3 Scenario 3 (WAG: free gas @ 1st).

Scenario 3 consists of the oil production rate of 700 RB/D with 12 months of water injection and 1 month of free gas injection at start of production time. Cumulative oil production was 3.35 MMSTB at the end of production with the recovery of 65.17% of original oil in place (Figure 4.17). Free gas delivered during oil production was 0.38 MMSCF and 4.63 MMSTB of water was also produced.

Table 4.4 Summary detail of scenario 3.

Fluid type	Production volume , RB	Injection volume , RB
Oil	4,430,508	-
Gas	-	368,997
Water	-	4,730,659
PI(%)	86.88	

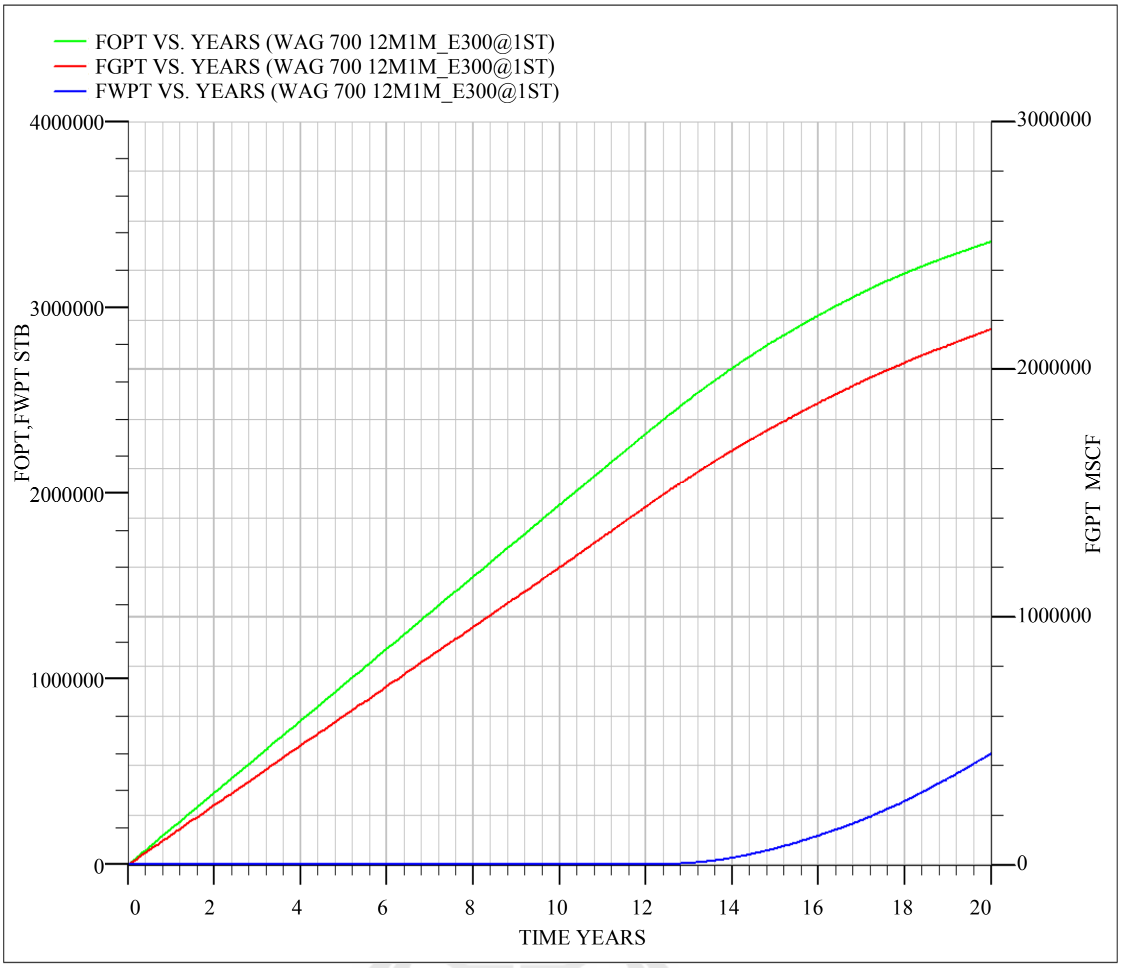

Figure 4.17 Cumulative fluid productions vs. time of scenario 3.

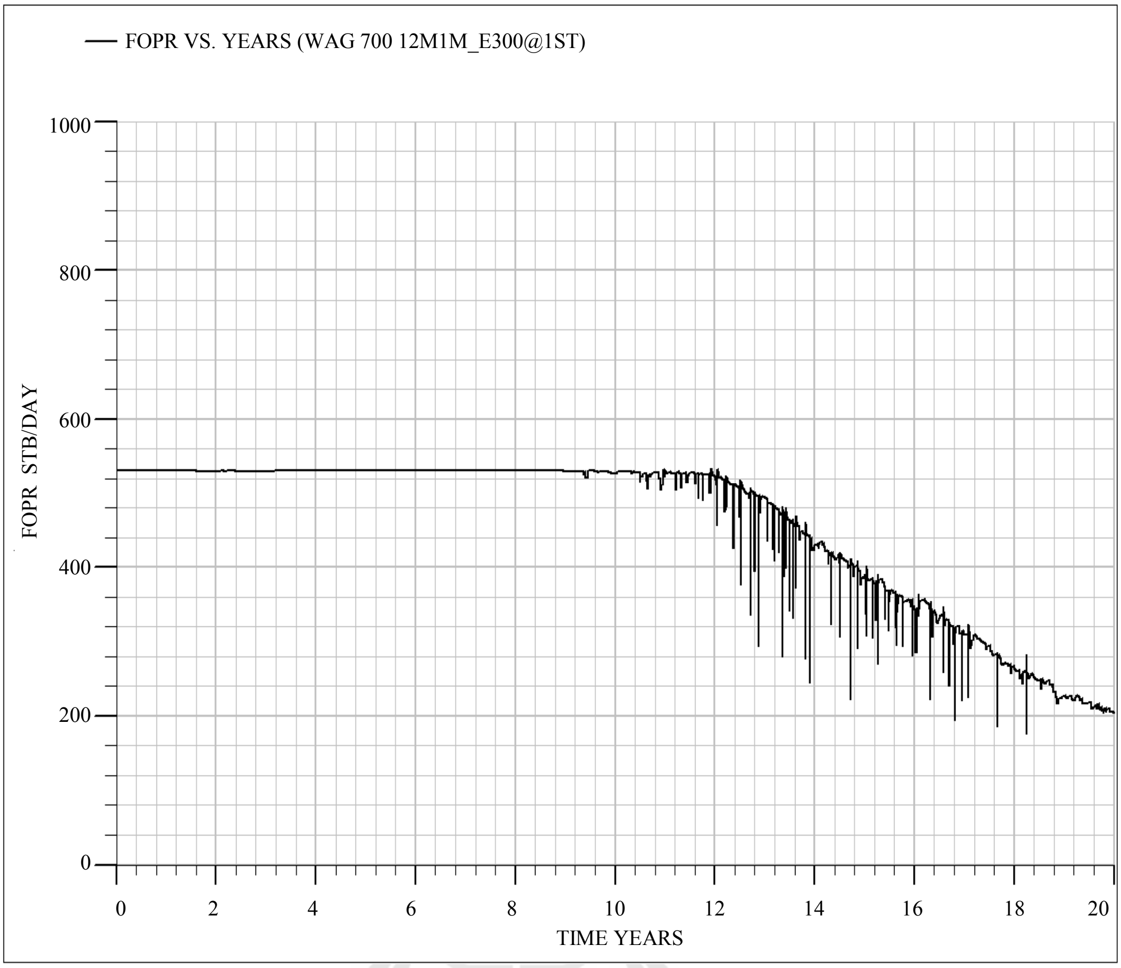

Figure 4.18 Oil production rates vs. time of scenario 3.

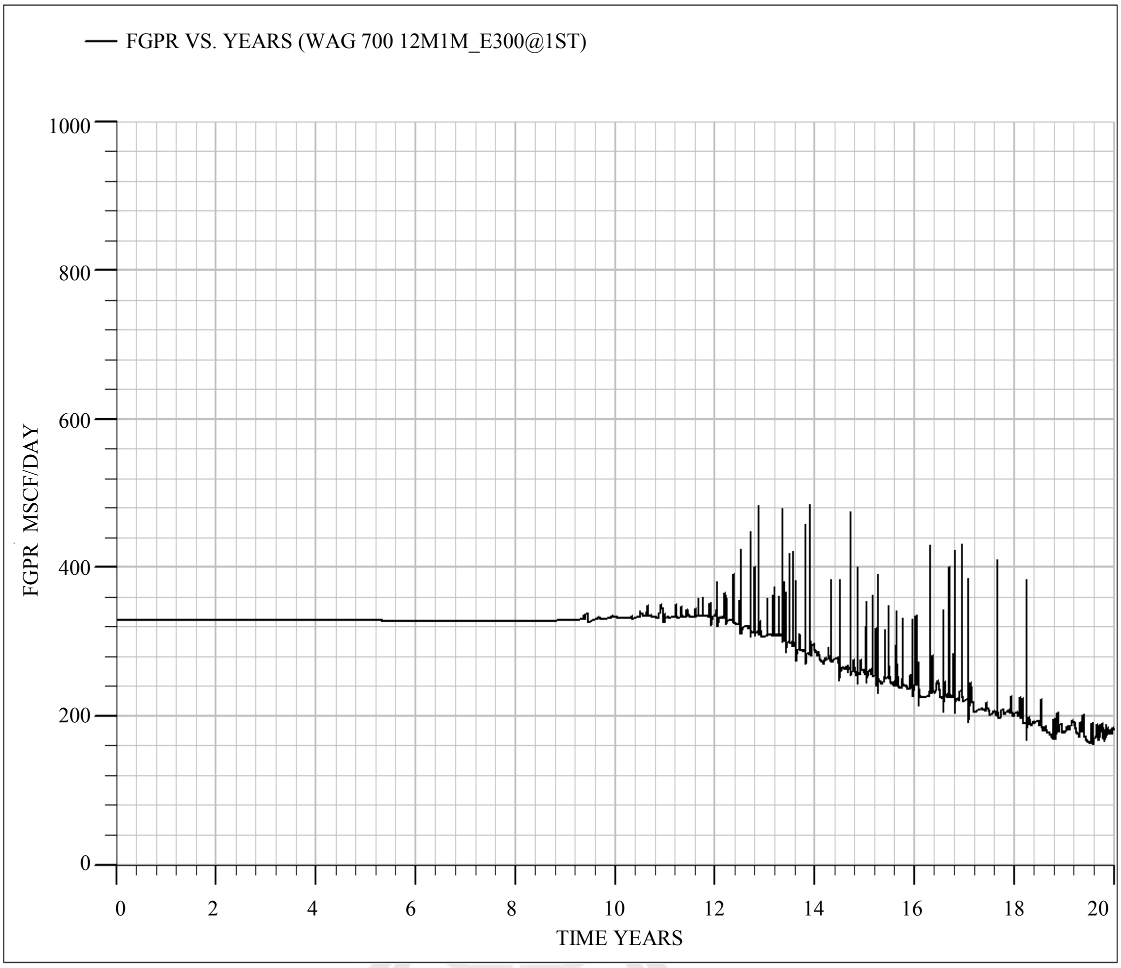

Figure 4.19 Gas production rates vs. time of production of scenario 3.

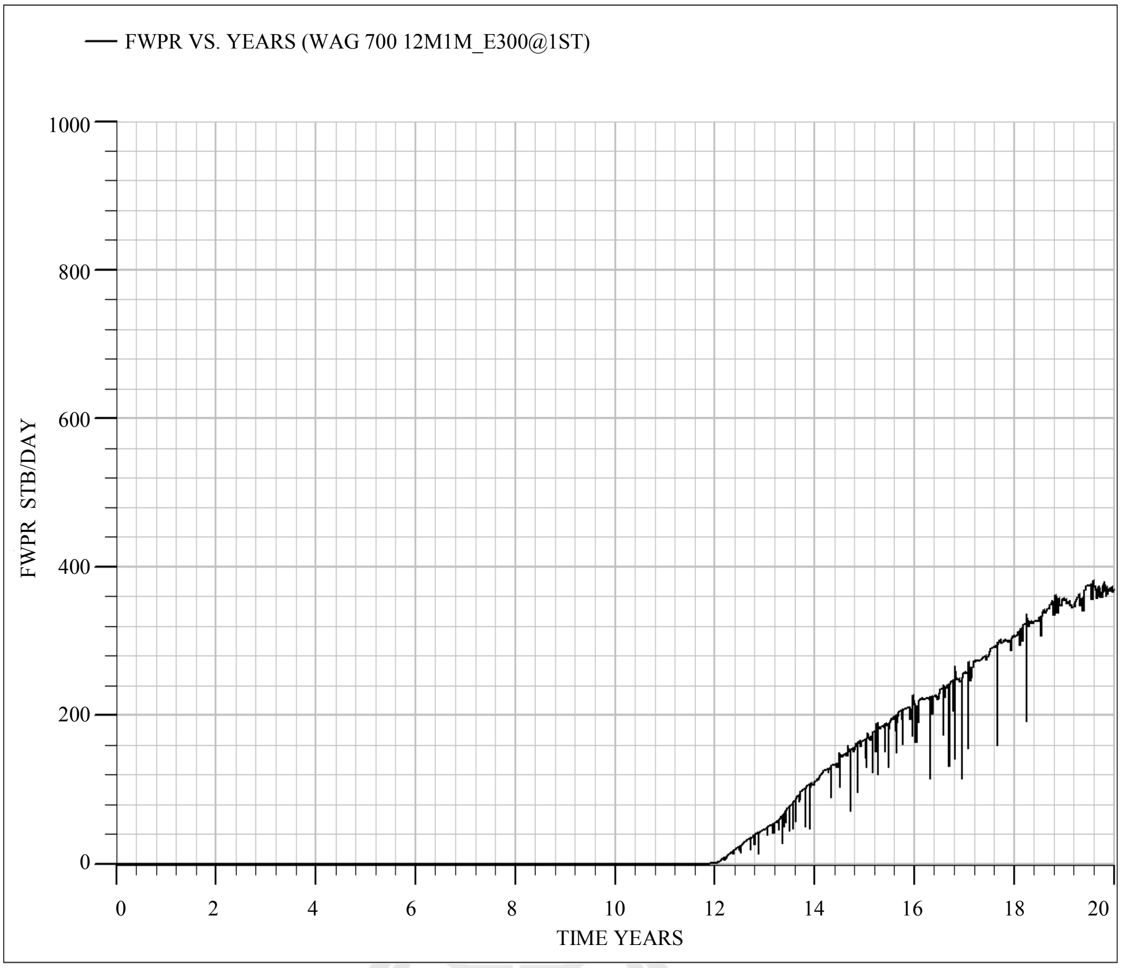

Figure 4.20 Water production rates vs. time of production of scenario 3.

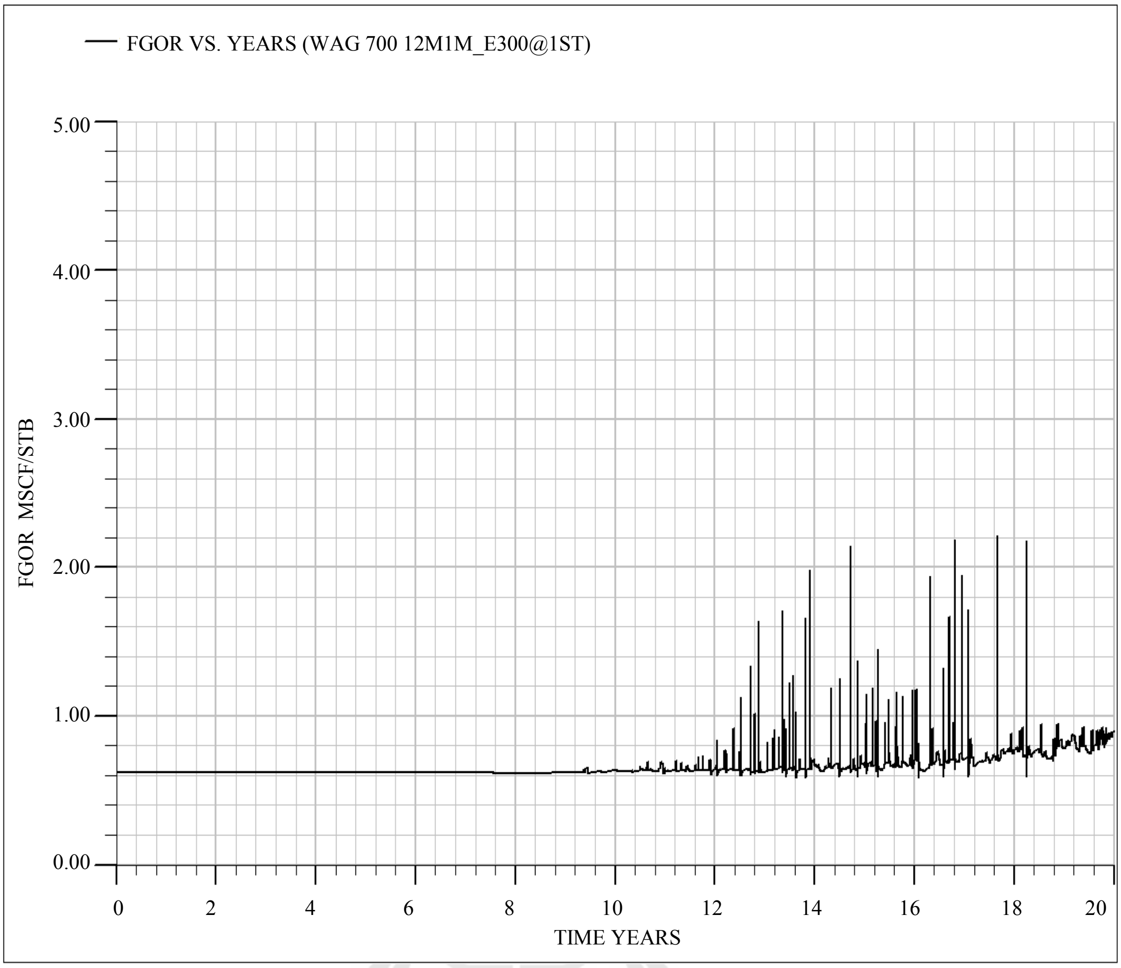

Figure 4.21 Gas-oil ratio vs. time of scenario 3.

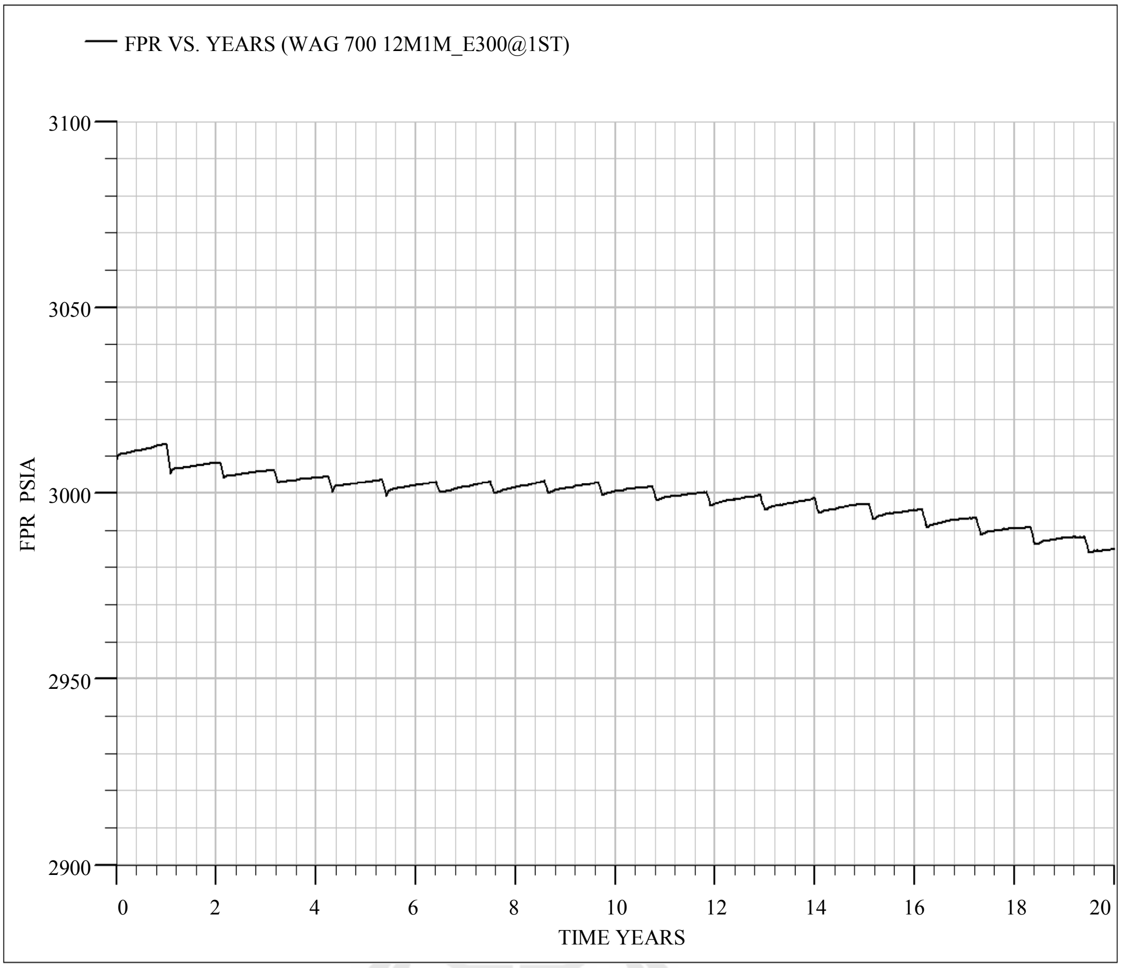

Figure 4.22 Pressure of reservoir vs. time of scenario 3.

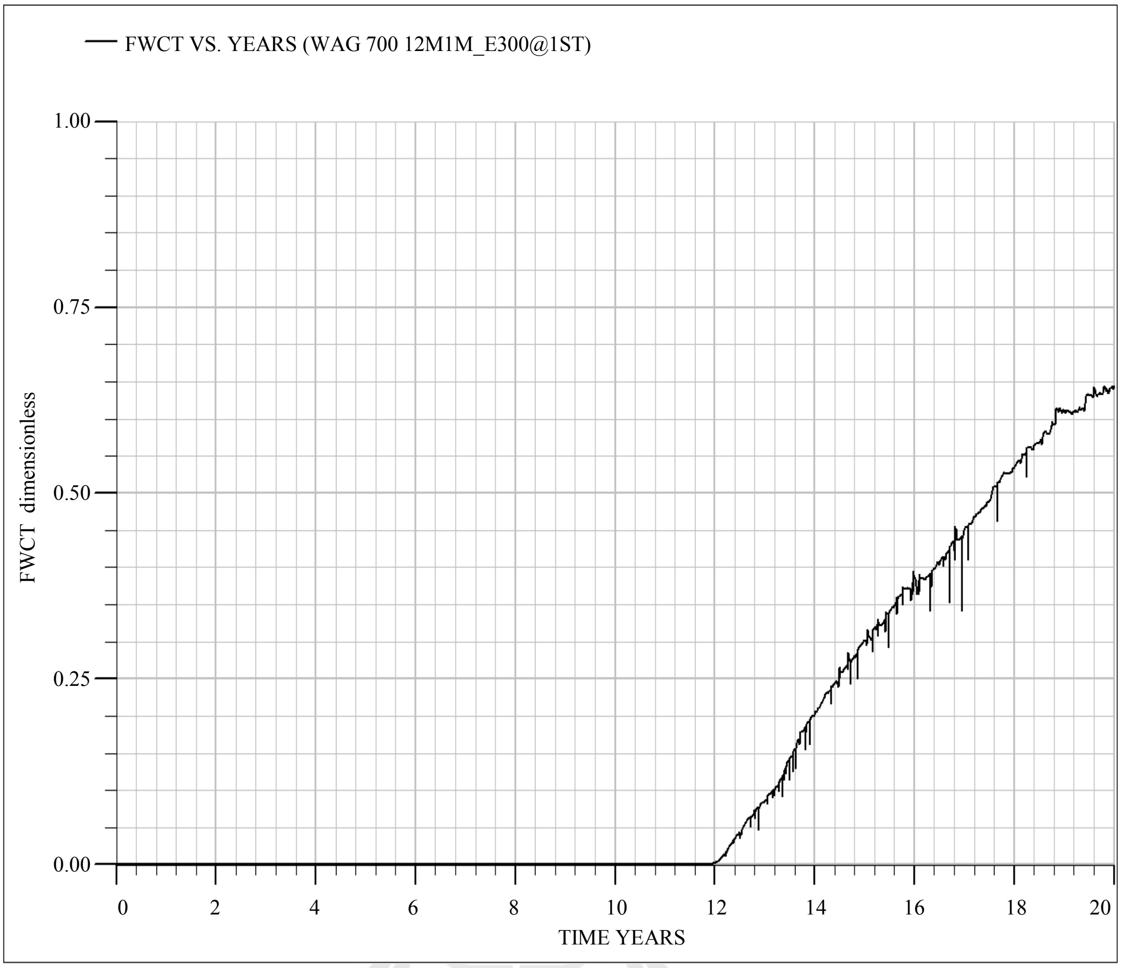

Figure 4.23 WCT vs. time of scenario 3.

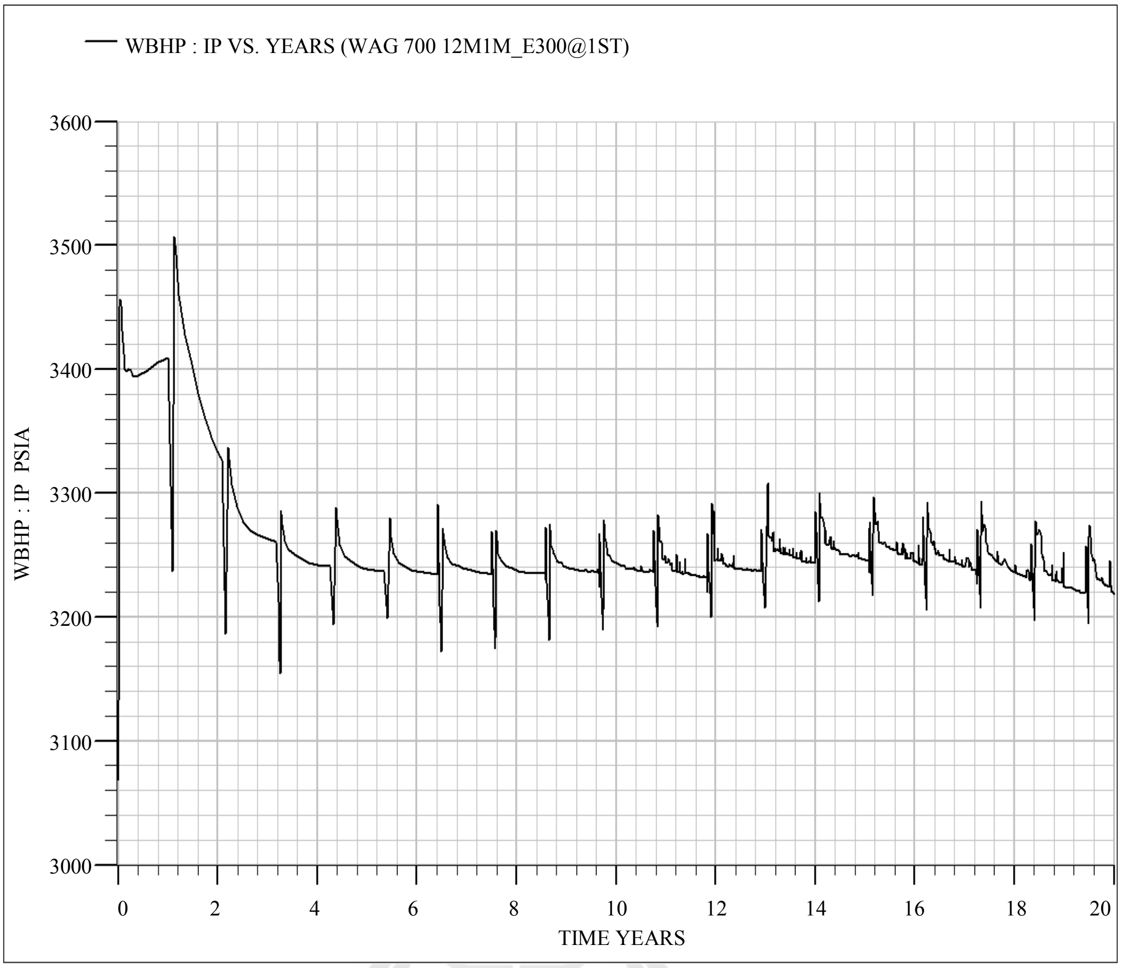

Figure 4.24 BHP of injection well vs. time of scenario 3.

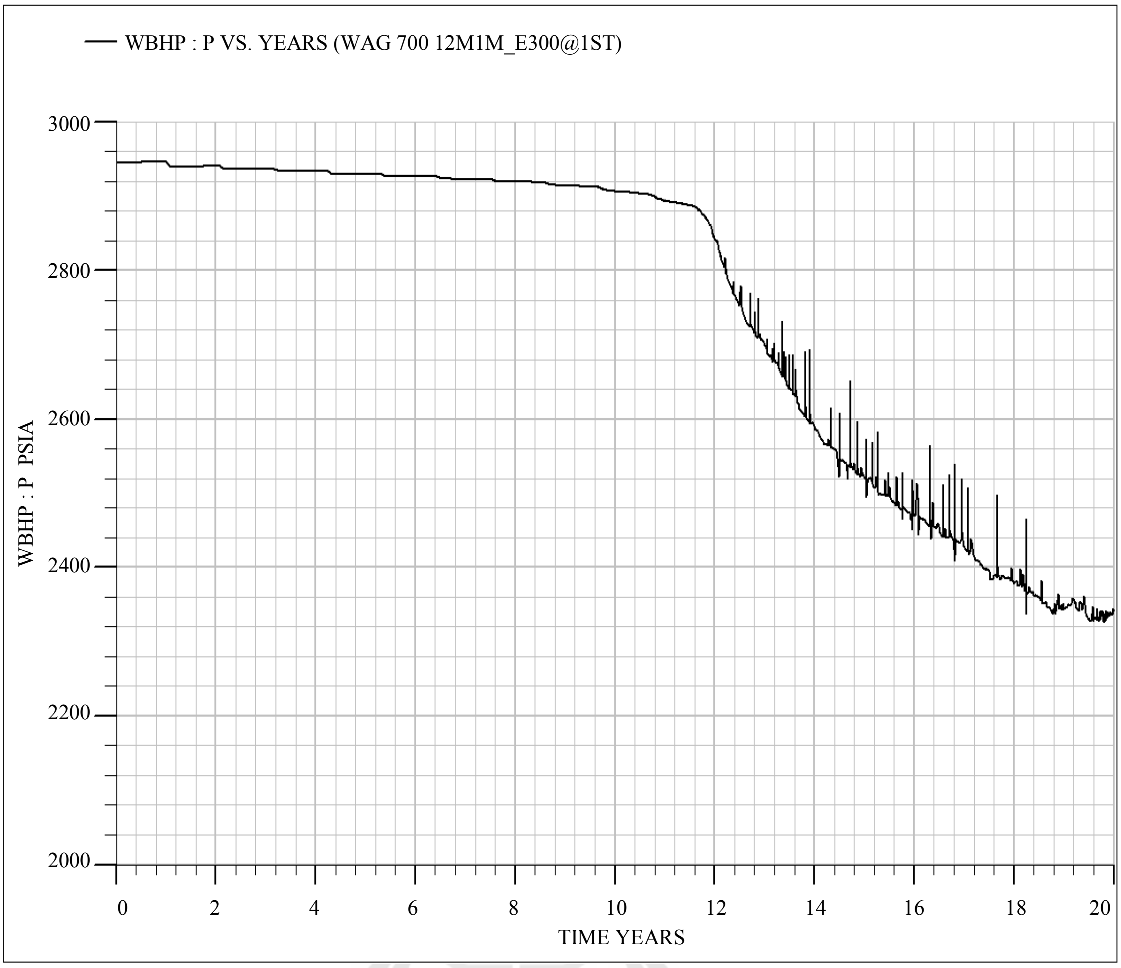

Figure 4.25 BHP of production well vs. time of scenario 3.

Figure 4.18, show field oil production rate, FOPR which is remain constant rate at 530 STB/D (700 RB/D) over the first 9 years. This is cause by a long reservoir pressure maintaining from more water injection activity. After that, oil production rate, gas production rate and gas-oil ratio rate were more fluctuated because of the hysteresis effect. Finally oil and gas production rate decreased gradually to 200 STB/D and reached 180 MSCF/D at the end. While water has breakthrough at the tenth year of production, water production was fluctuated and reached a peak of 380 STB/D at the end. The reservoir pressure slightly fluctuated in the range of 2,980 to 3,020 psia due to the alternation of fluid injection. The reservoir pressure had been increased when the water was injected, and decreased when the gas was injected like the base case.

4.1.4 Scenario 4 (WAG: free gas @ 2nd).

Scenario 4 consists of oil production of 1000 RB/D with 13 months of water injection alternate with 1 month of gas injection at 2nd year of production time. Cumulative oil production was 3.66 MSTB at the end of production with the recovery of 70.15% of original oil in place (Figure 4.26).

Table 4.5 Summary detail of scenario 4.

Fluid type	Production volume , RB	Injection volume , RB
Oil	4,660,148	-
Gas	-	441,741
Water	-	6,124,000
PI(%)	70.98	

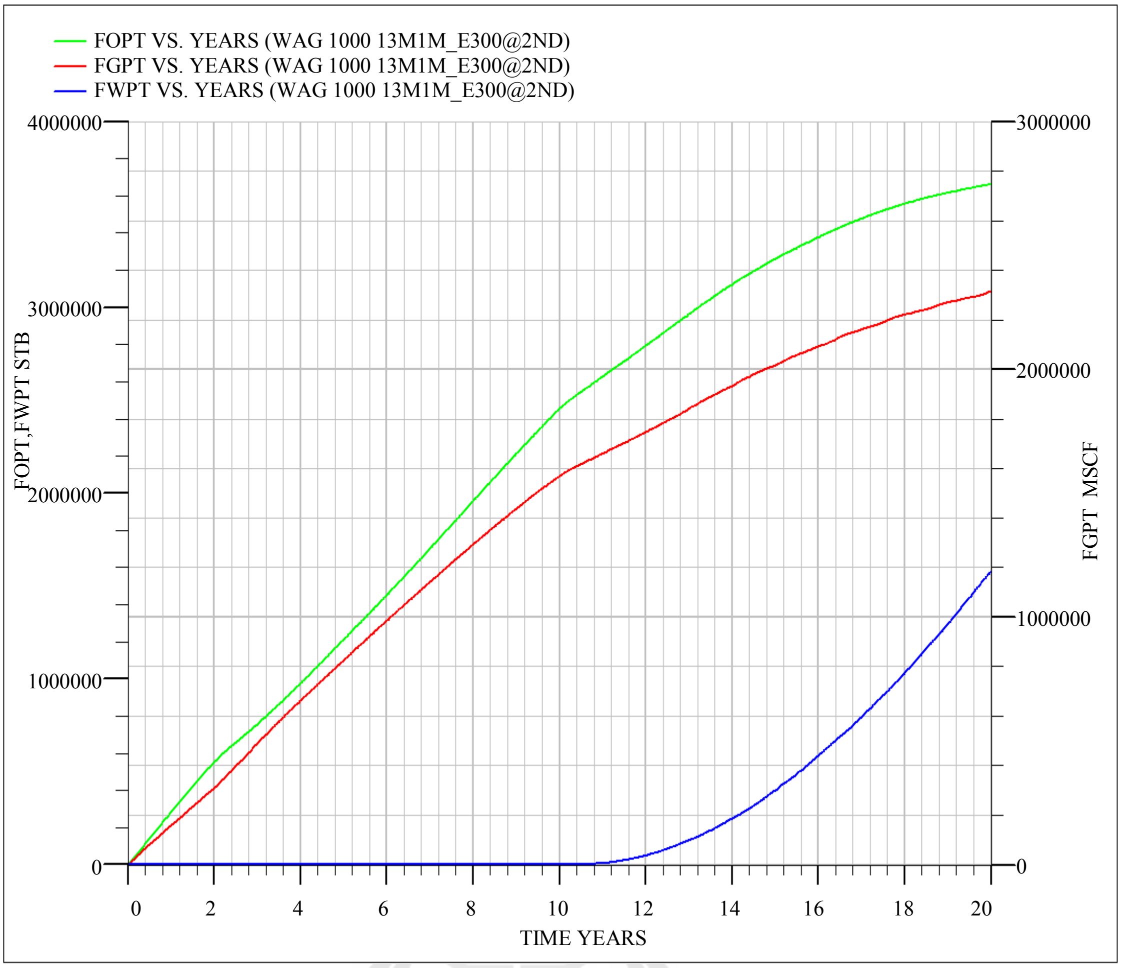

Figure 4.26 Cumulative fluid productions vs. time of scenario 4.

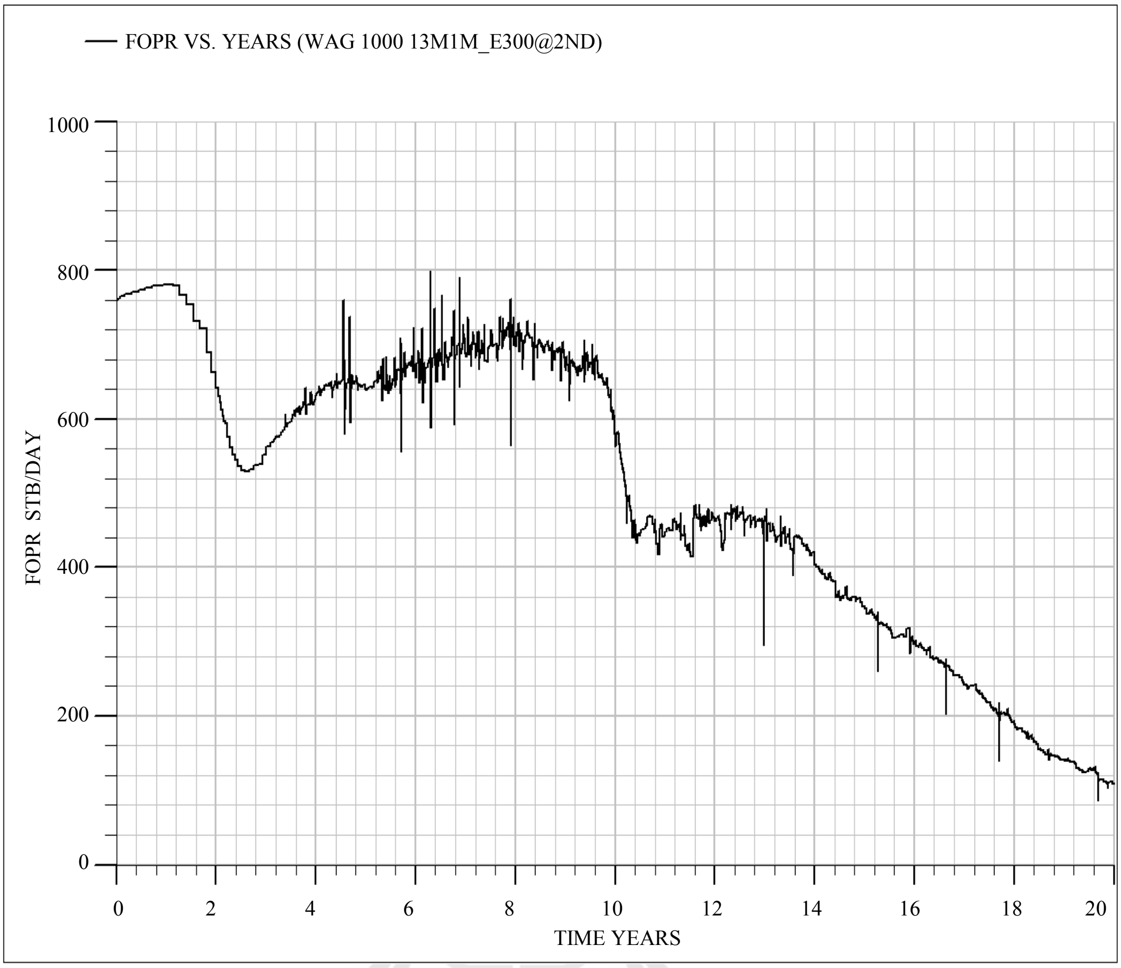

Figure 4.27 Oil production rates vs. time of scenario 4.

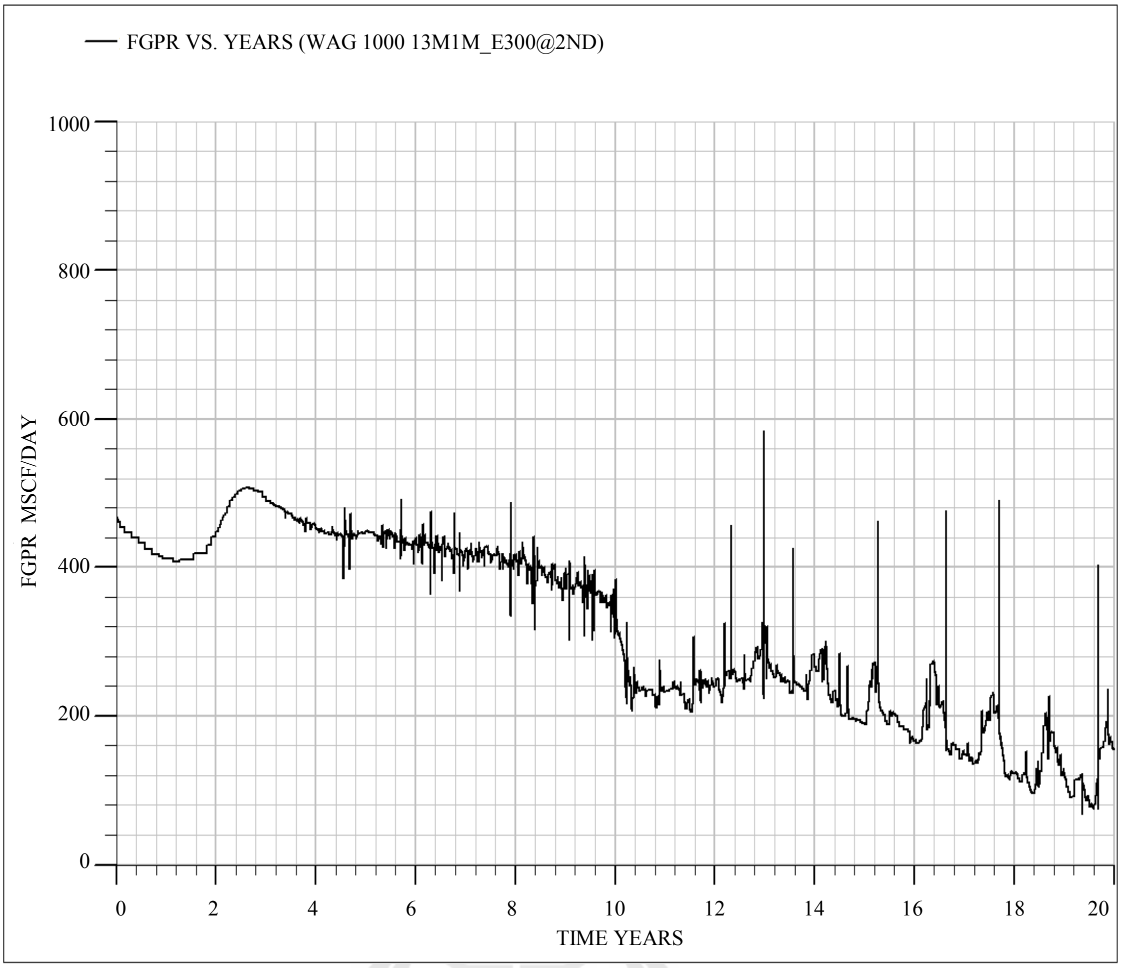

Figure 4.28 Gas production rates vs. time of scenario 4.

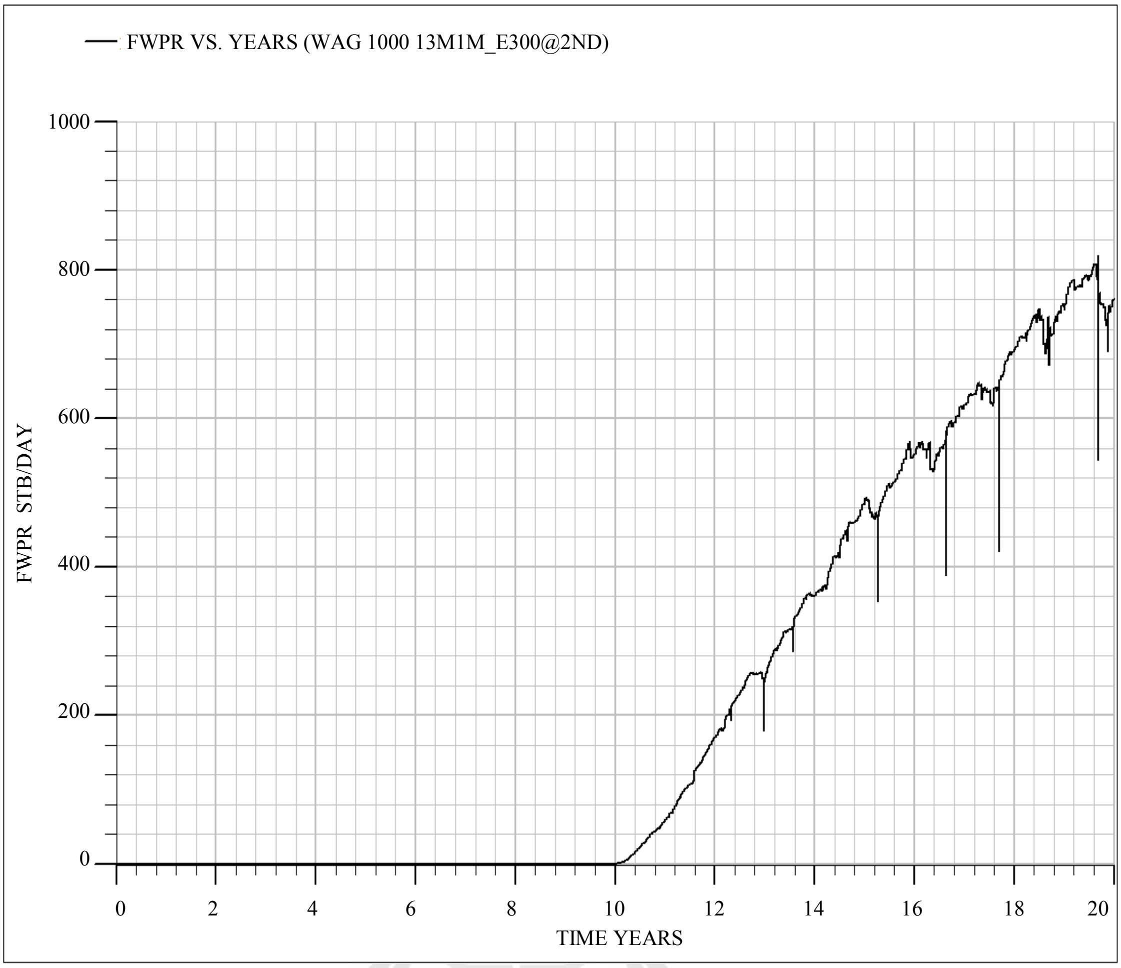

Figure 4.29 Water production rates vs. time of scenario 4.

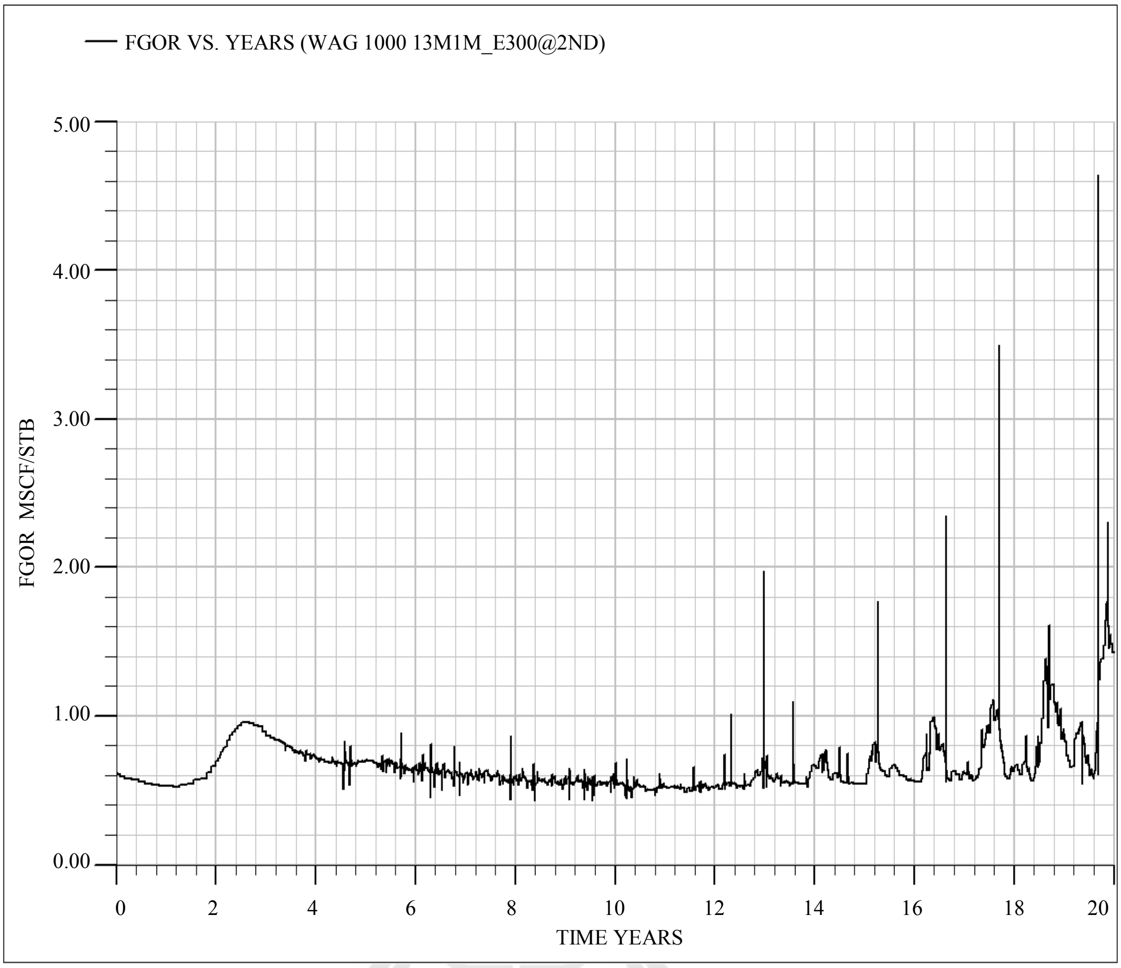

Figure 4.30 Gas-oil ratio vs. time of scenario 4.

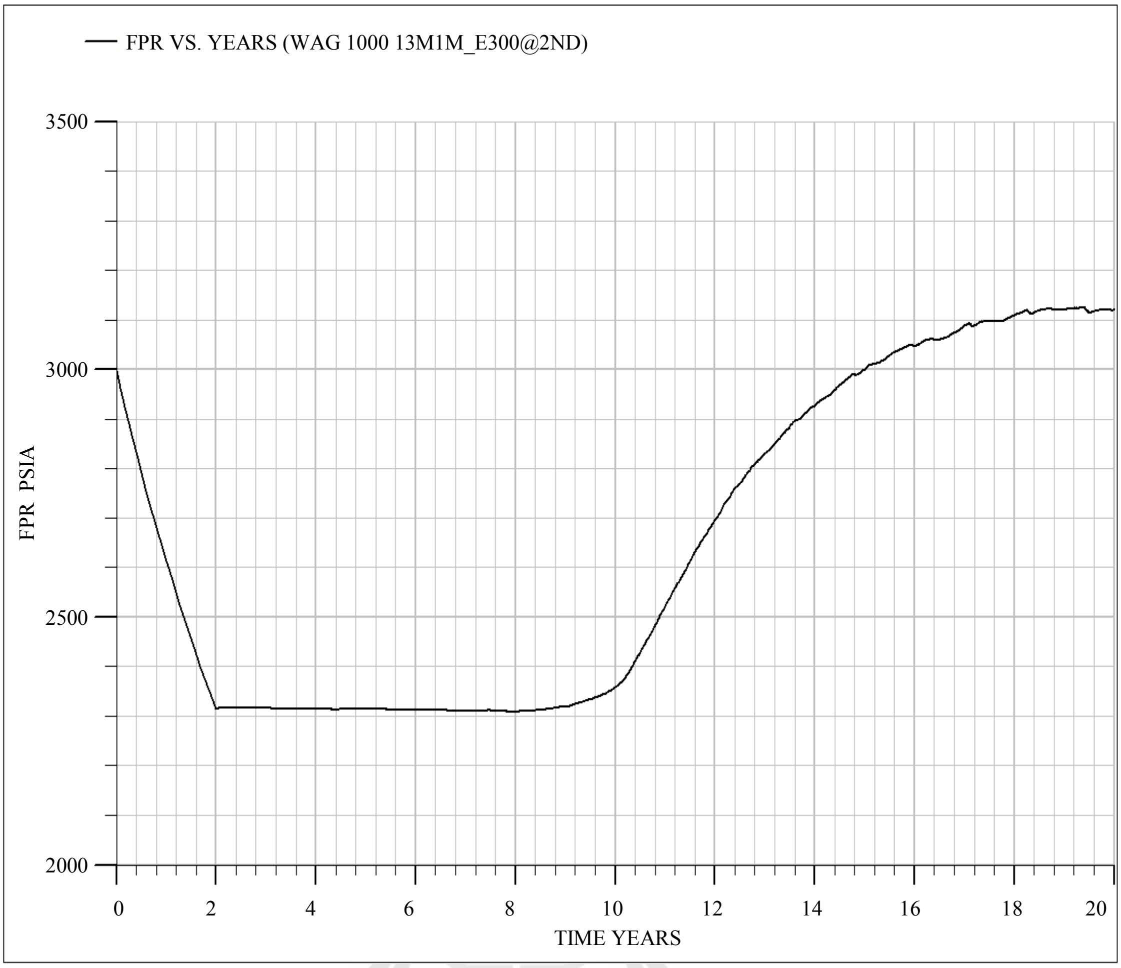

Figure 4.31 Pressure of reservoir vs. time of scenario 4.

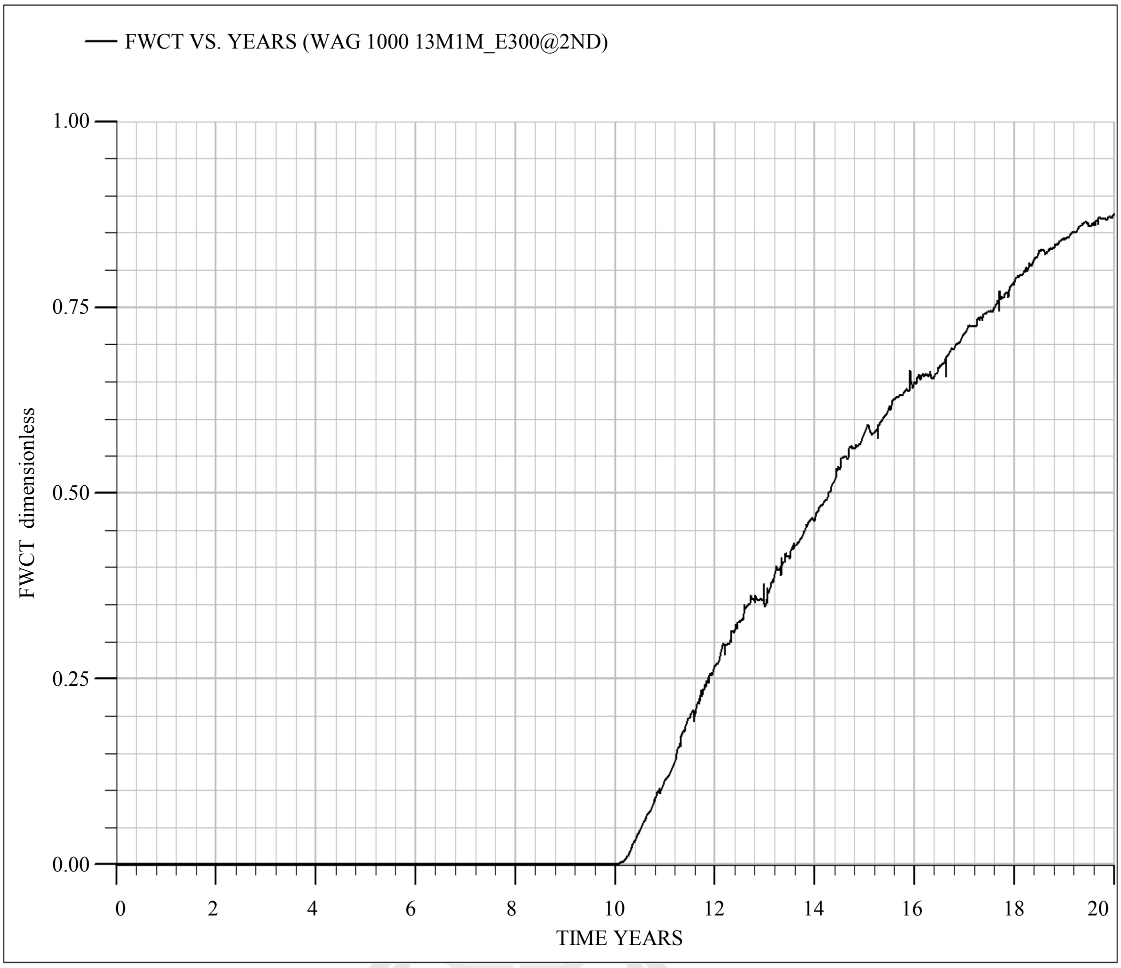

Figure 4.32 WCT vs. time of scenario 4.

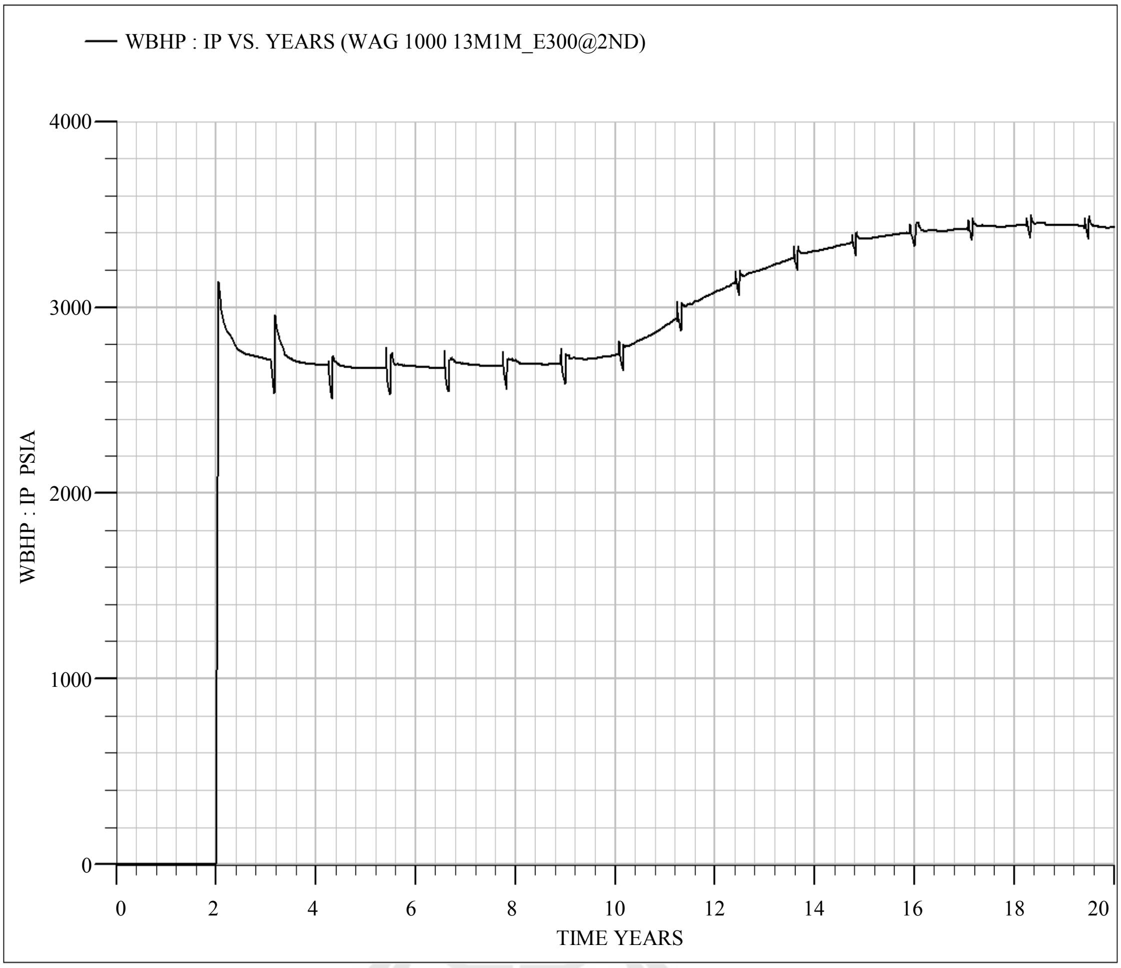

Figure 4.33 BHP of injection well vs. time of scenario 4.

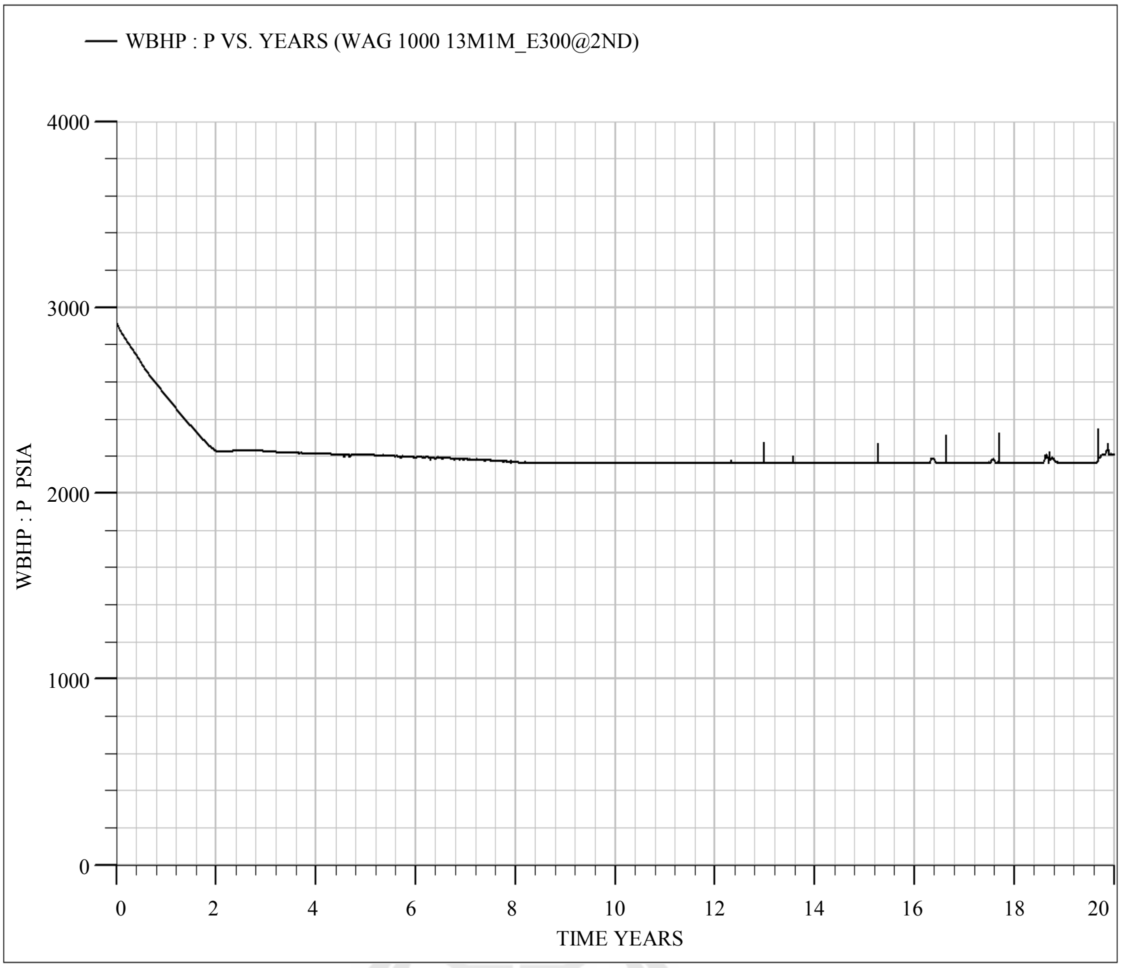

Figure 4.34 BHP of production well vs. time of scenario 4.

The oil production profile is shown in Figure 4.27. The oil production rate was maintained at the rate of 760 STB/D (1000 RB/D) for one year and it was rapid dropped until the starting of water injection in the second year. Reservoir pressure had been significantly dropped to 2,200 psia and pressure had been maintained until significantly increased at the tenth year of production because of water breakthrough (Figure 4.31). Bottom hole pressure of production well had been significantly decreased in the early period and remained constant pressure at 2,300 psia as same as reservoir pressure. After starting the injection, bottom hole pressure trend of the injection well was built up and remained constant until water breakthrough at the tenth year of production (Figure 4.33).

4.1.5 Scenario 5 (WAG: free gas @ 4^{th}).

Scenario 5 consists of oil production rate at 1000 RB/D with 15 months of water injection alter with 1 month of gas injection at 4^{th} of production time. Cumulative oil production was 3.02 MSTB at the end of production with the recovery of 58.60% of original oil in place (Figure 4.35).

Table 4.6 Summary detail of scenario 5.

Fluid type	Production volume , RB	Injection volume , RB
Oil	3,796,764	-
Gas	-	257,425
Water	-	3,833,375
PI(%)	92.81	

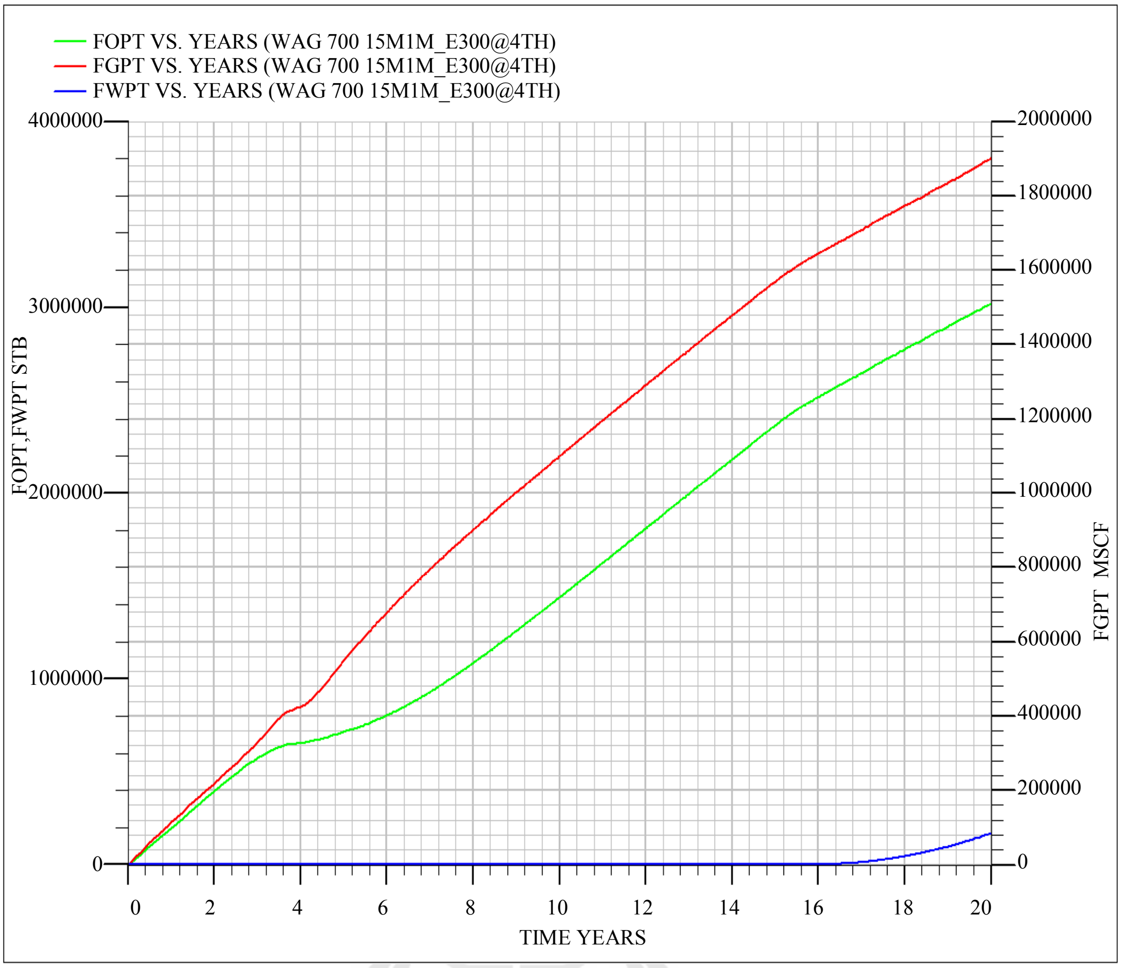

Figure 4.35 Cumulative fluid productions vs. time of scenario 5.

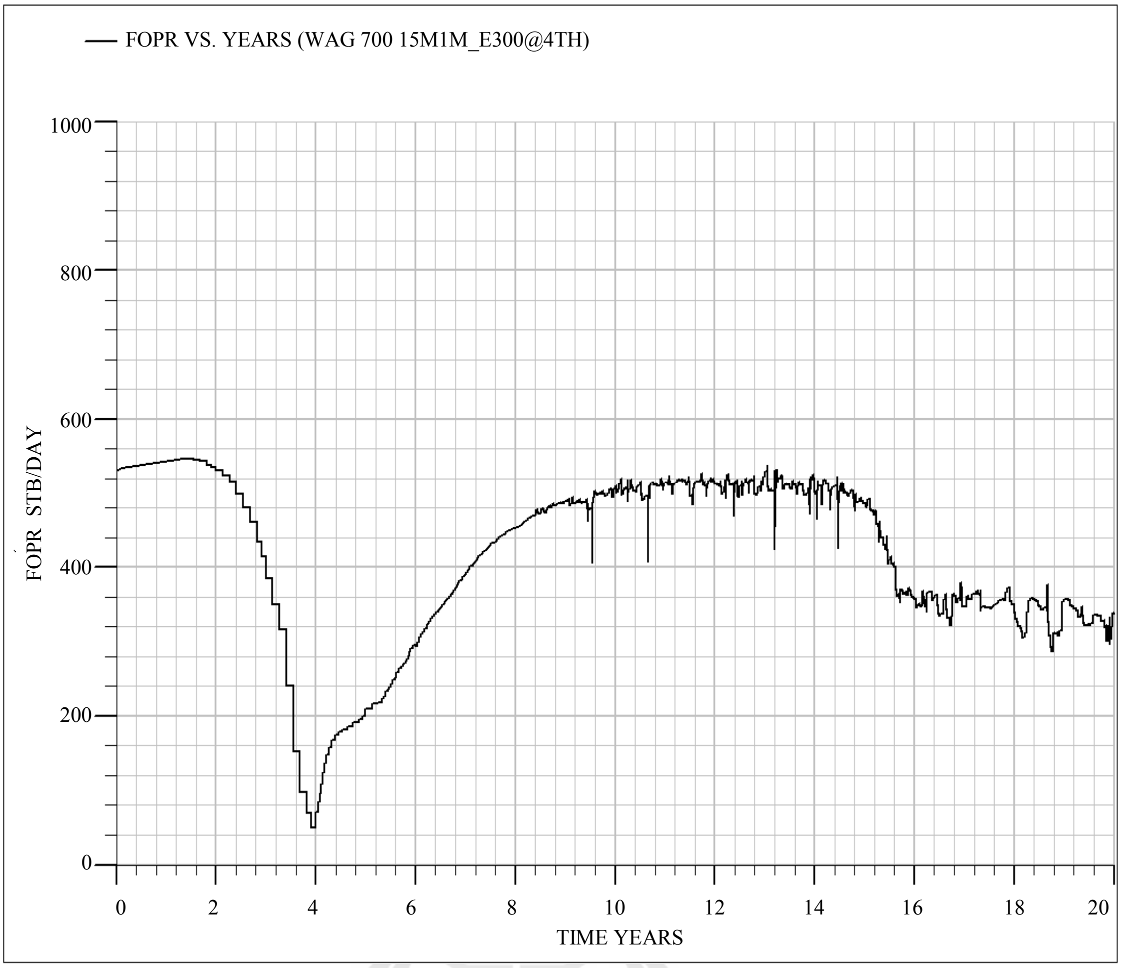

Figure 4.36 Oil production rates vs. time of scenario 5.

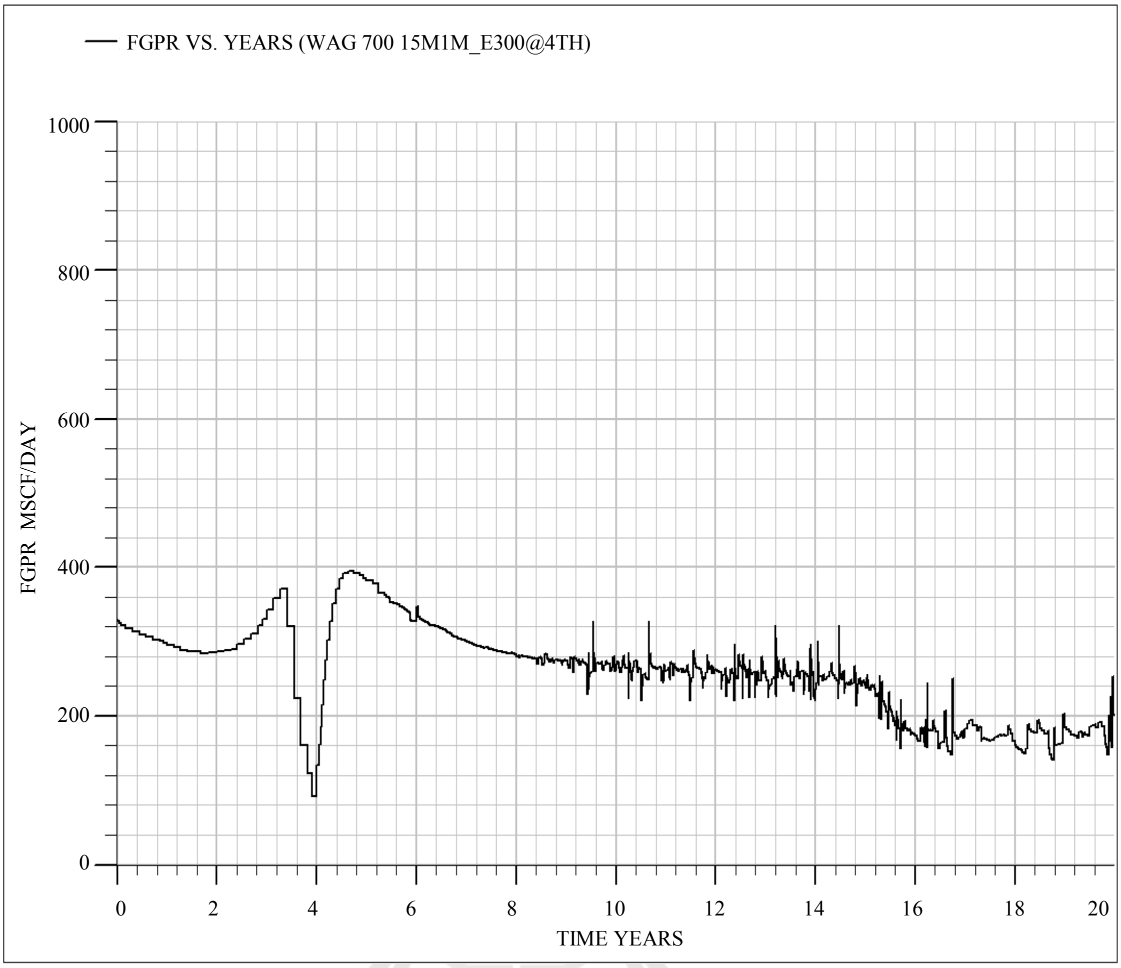

Figure 4.37 Gas production rates vs. time of scenario 5.

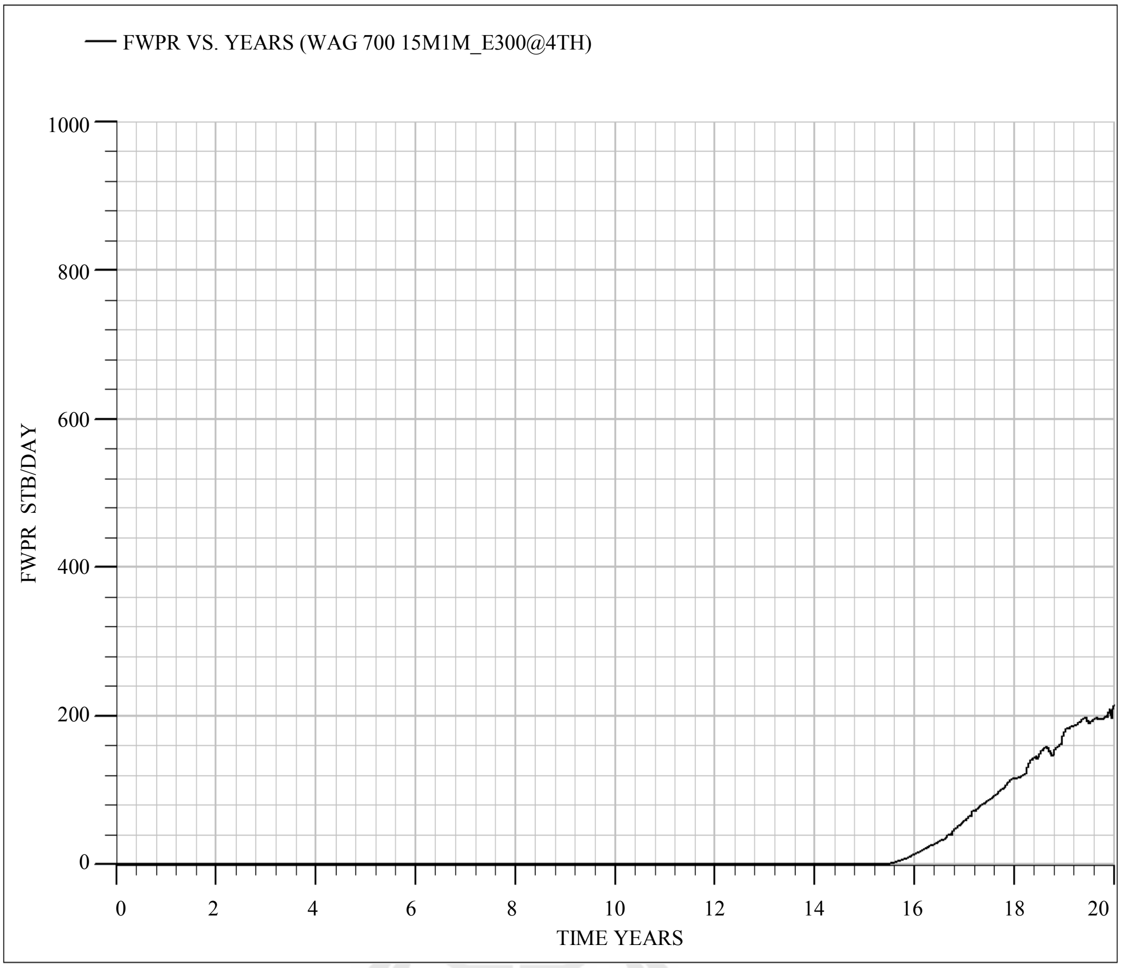

Figure 4.38 Water production rates vs. time of scenario 5.

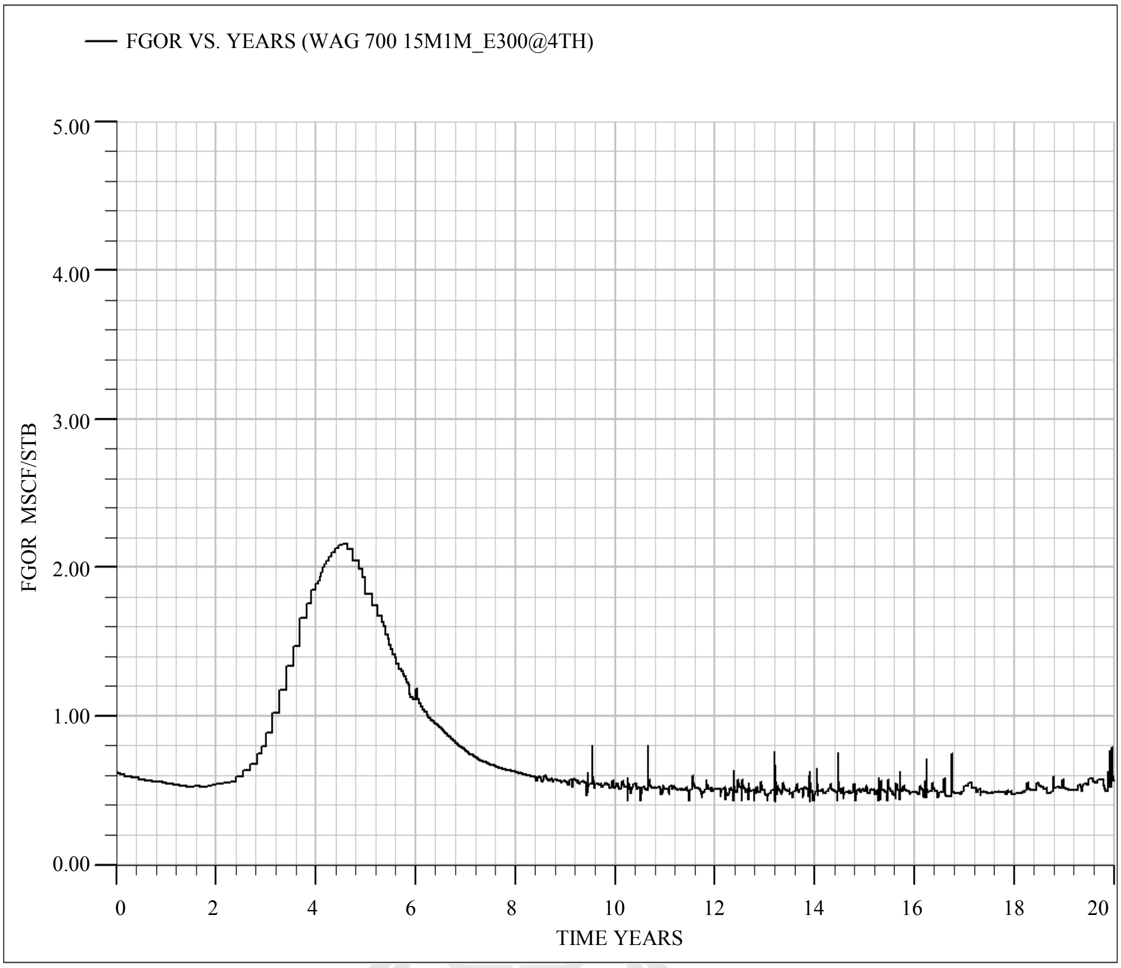

Figure 4.39 Gas-oil ratio vs. time of scenario 5.

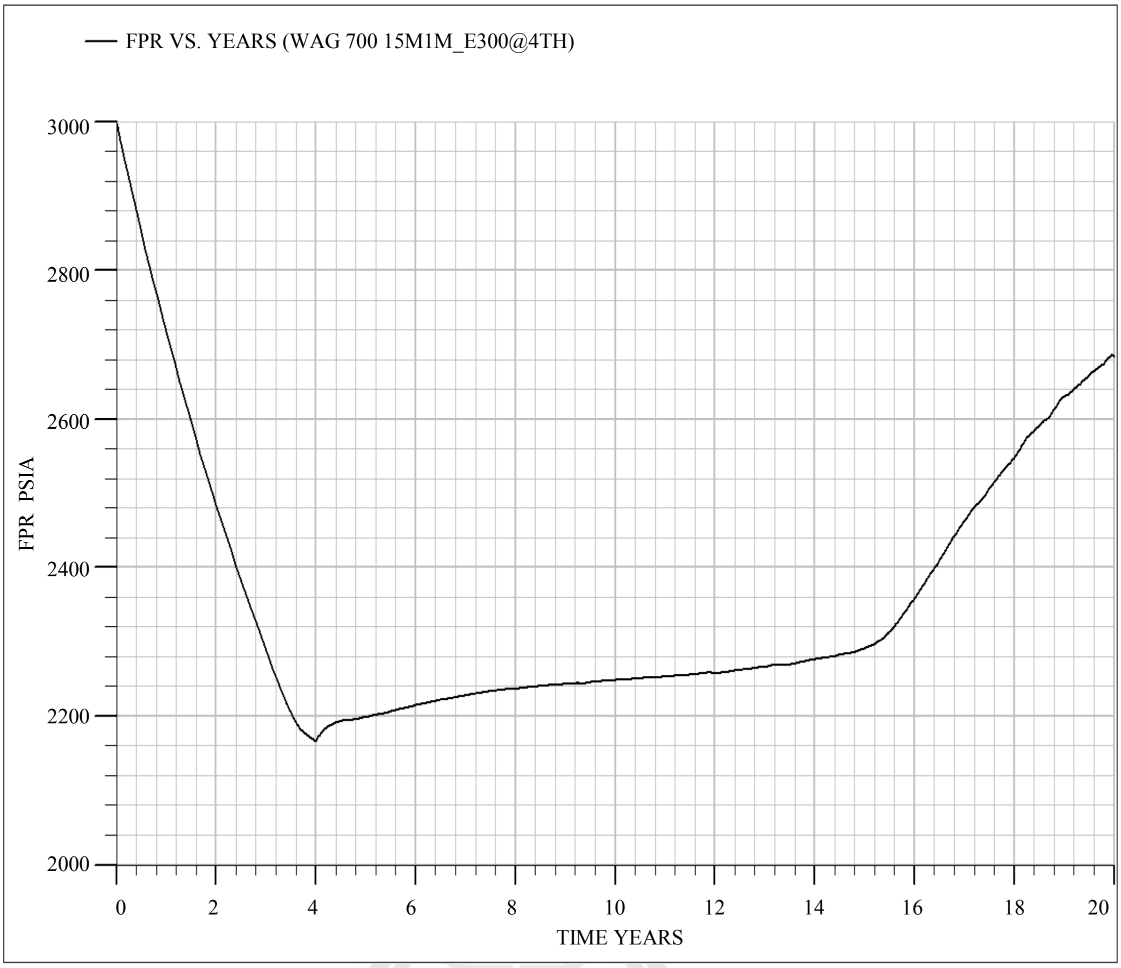

Figure 4.40 Pressure of reservoir vs. time of scenario 5.

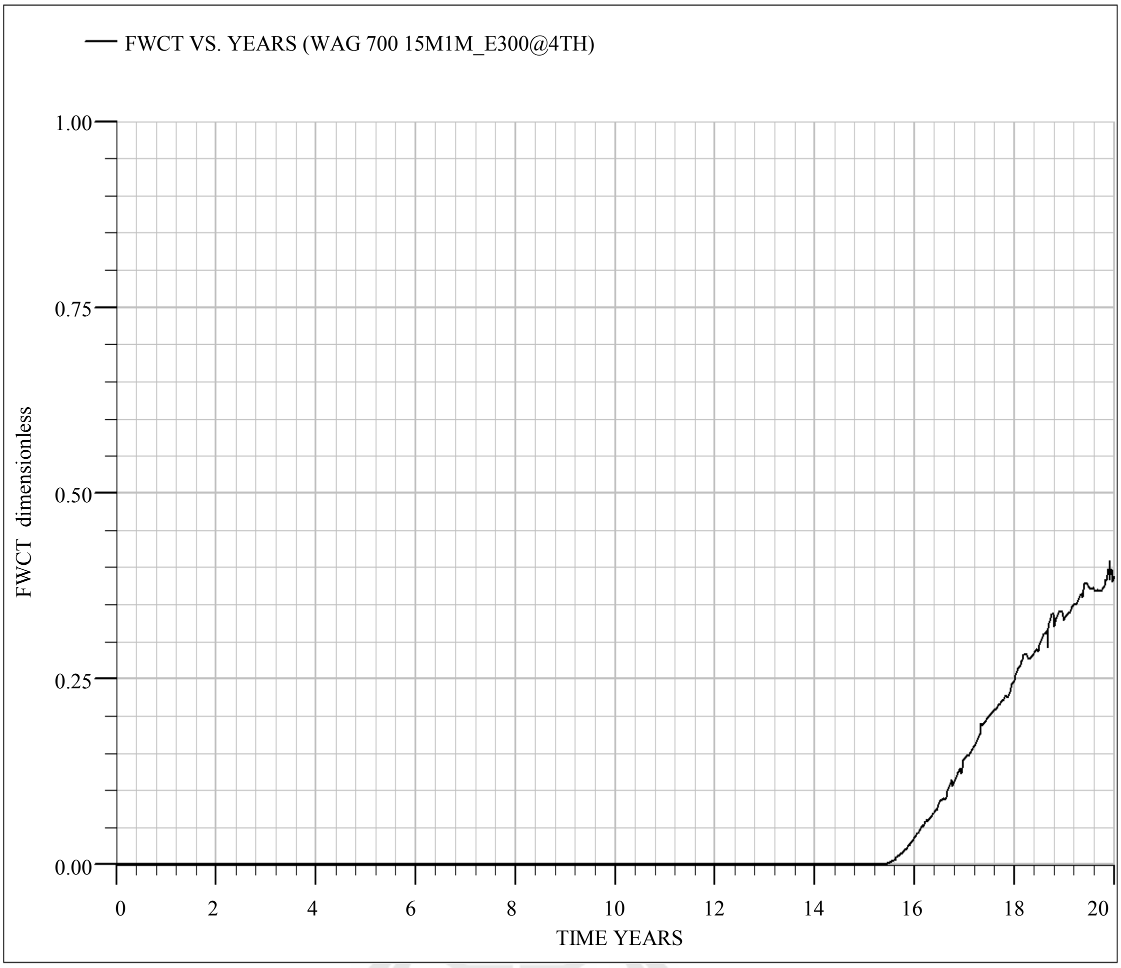

Figure 4.41 WCT vs. time of scenario 5.

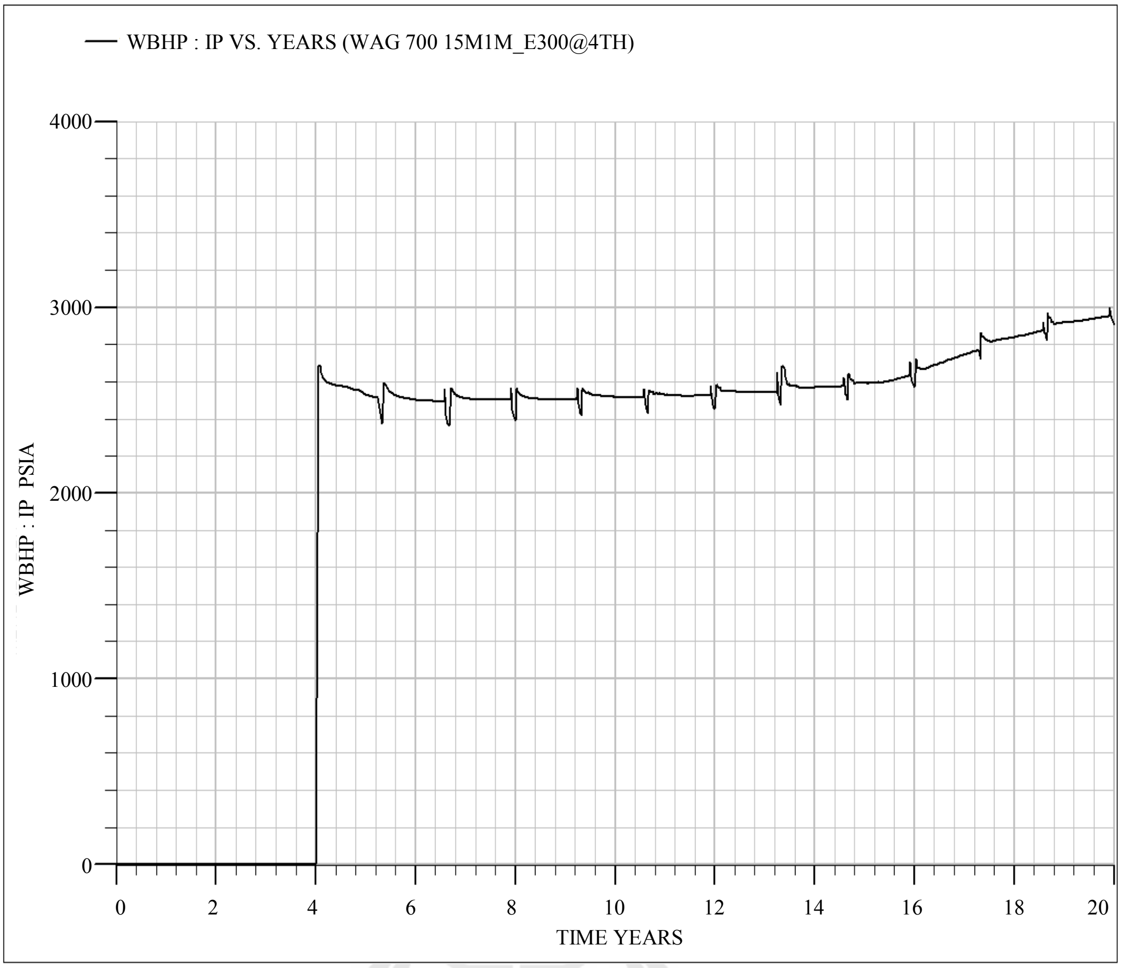

Figure 4.42 BHP of injection well vs. time of scenario 5.

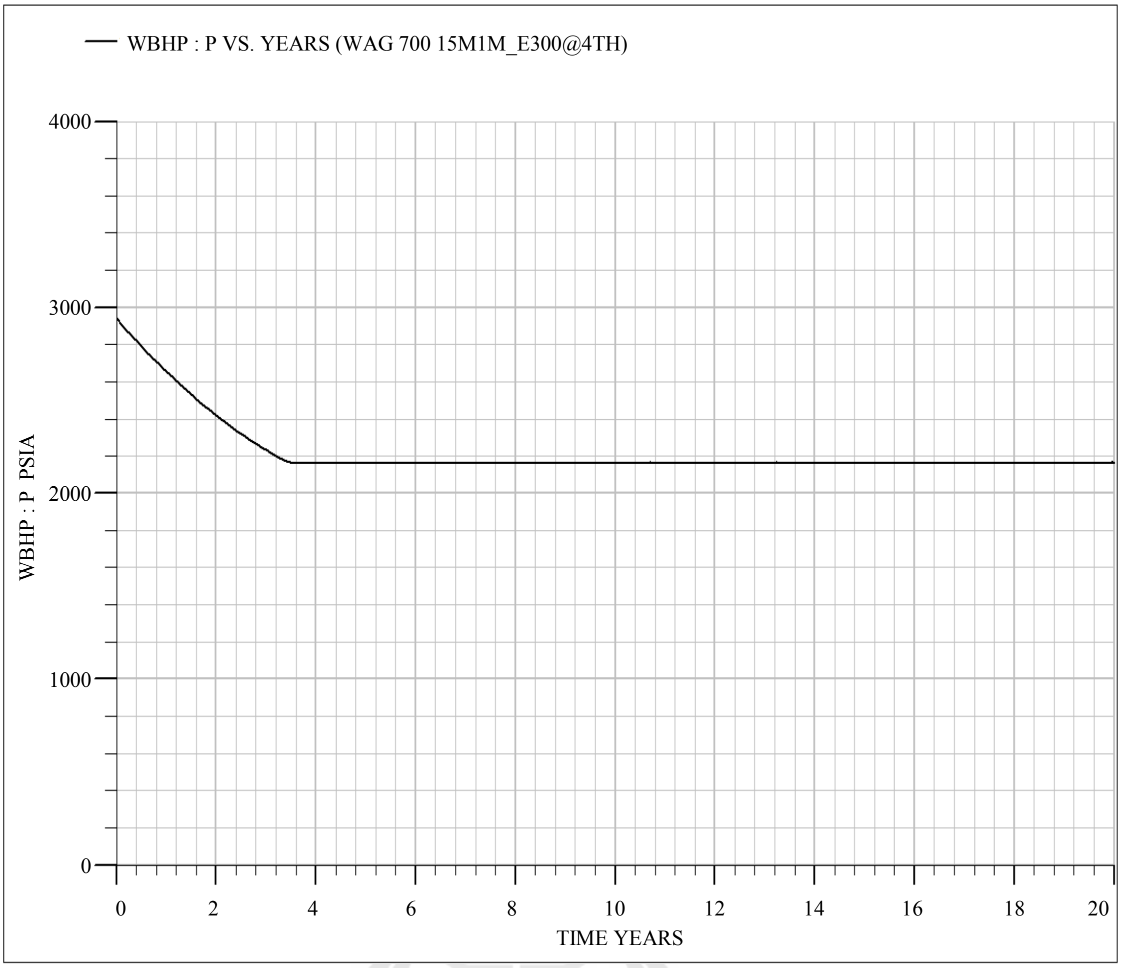

Figure 4.43 BHP of production well vs. time of scenario 5.

Figure 4.36 shows the oil production rate which it was maintained at the rate of 530 STB/D (1000 RB/D) for the first two years and drop rapidly until the starting of water injection at the 4th year of production same as the scenario 2. After that, oil production rate was moderately increased and stable for 4 years before dropping again at the fifteenth year of production. Reservoir pressure was dropped rapidly to 2,180 psia and increased moderately until water breakthrough at the fifteenth year of production (Figure 4.40).

4.1.6 Scenario 6 (WAG: free gas @ 8th).

Scenario 6 consists of oil production rate at 300 RB/D with 15 months of water injection alternate with 1 month of gas injection at the 8th year of production time. Cumulative oil production was 1.28 MSTB at the end of production with the recovery of 24.88% of original oil in place (Figure 4.44).

Table 4.7 Summary detail of scenario 6.

Fluid type	Production volume , RB	Injection volume , RB
Oil	1,619,779	-
Gas	-	82,575
Water	-	1,232,325
PI(%)	123.19	

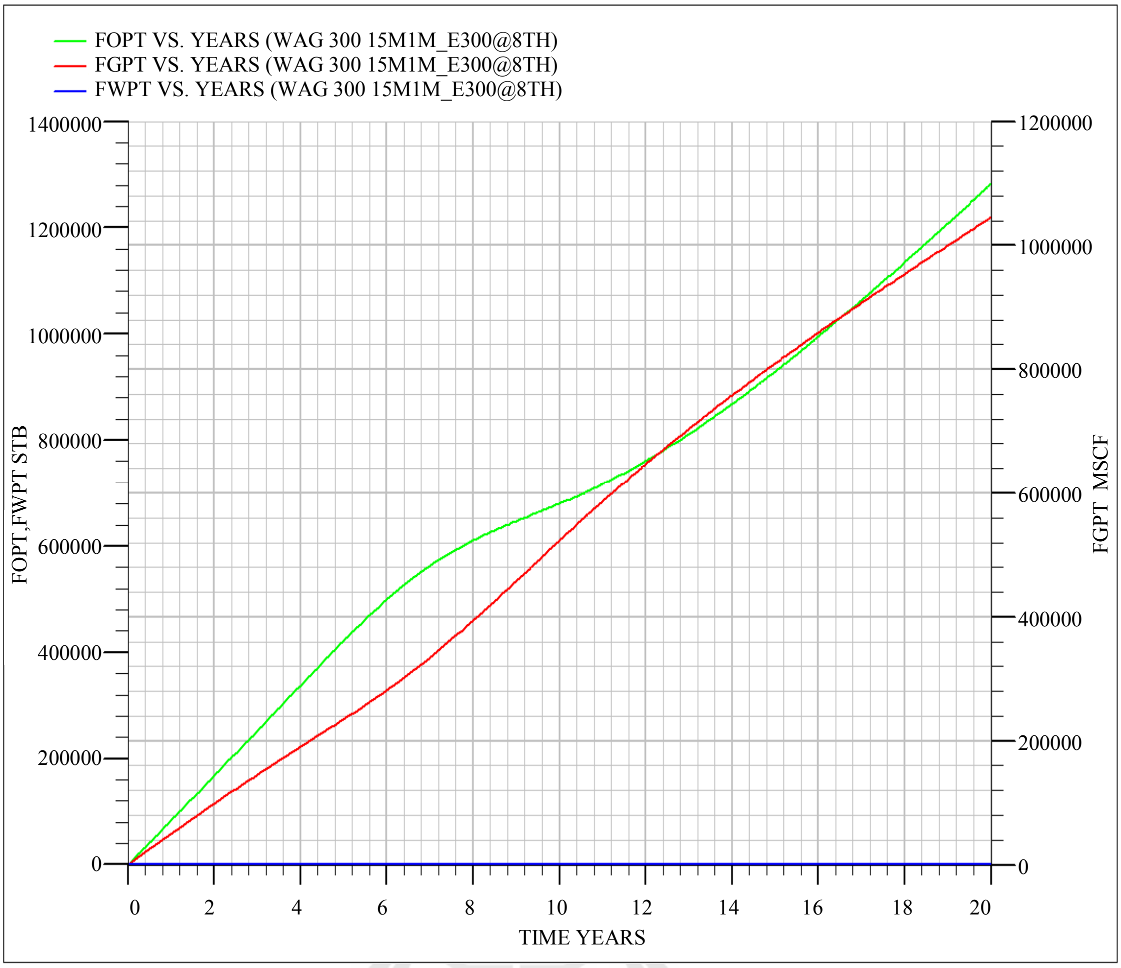

Figure 4.44 Cumulative fluid productions vs. time of scenario 6.

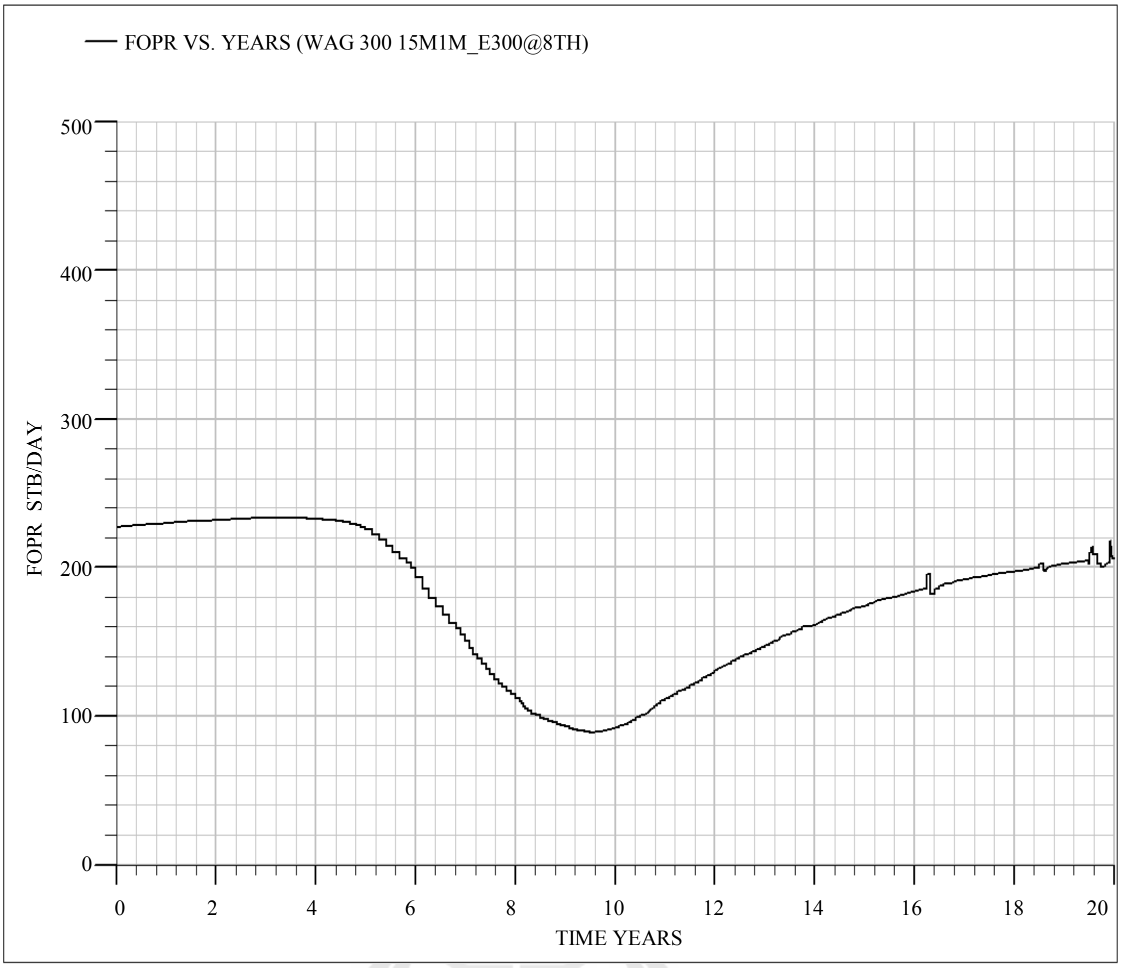

Figure 4.45 Oil production rates vs. time of scenario 6.

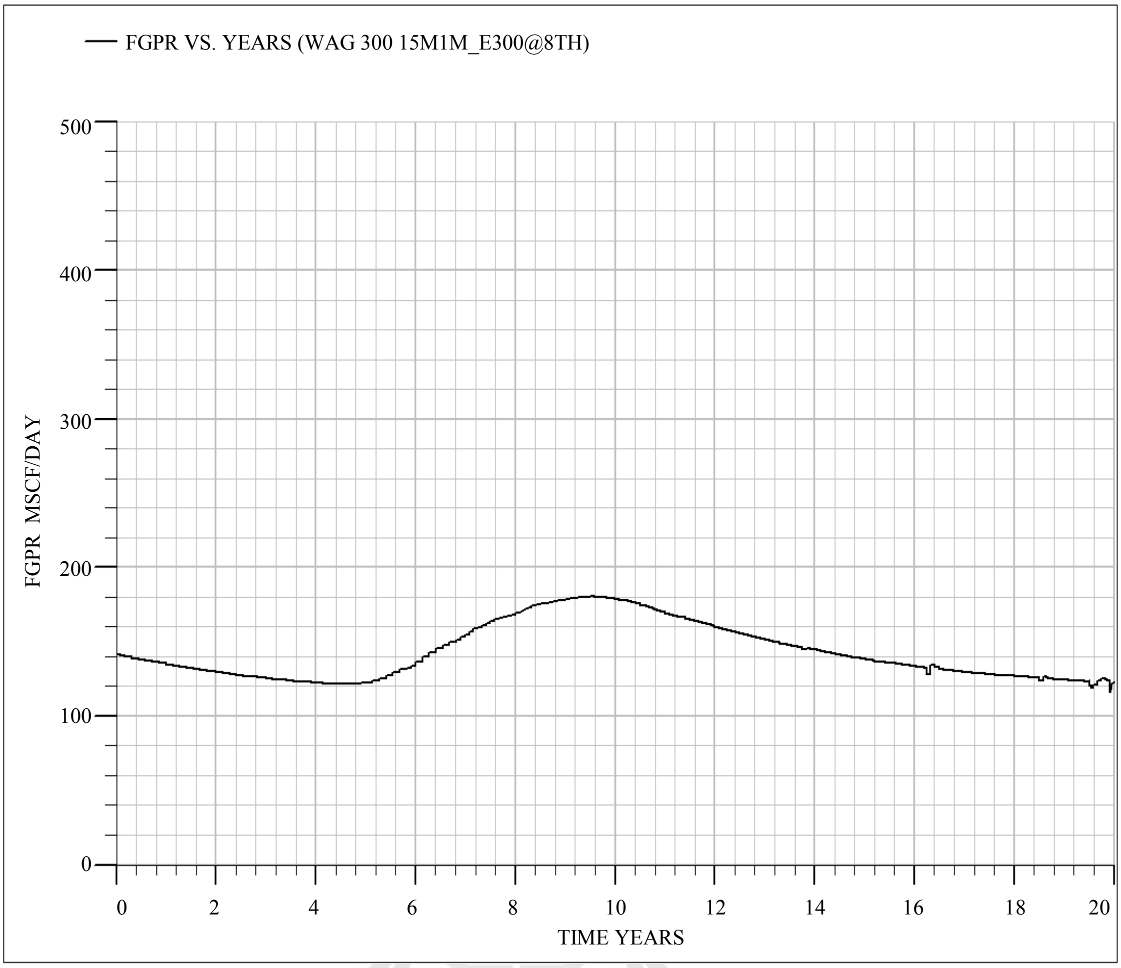

Figure 4.46 Gas production rates vs. time of scenario 6.

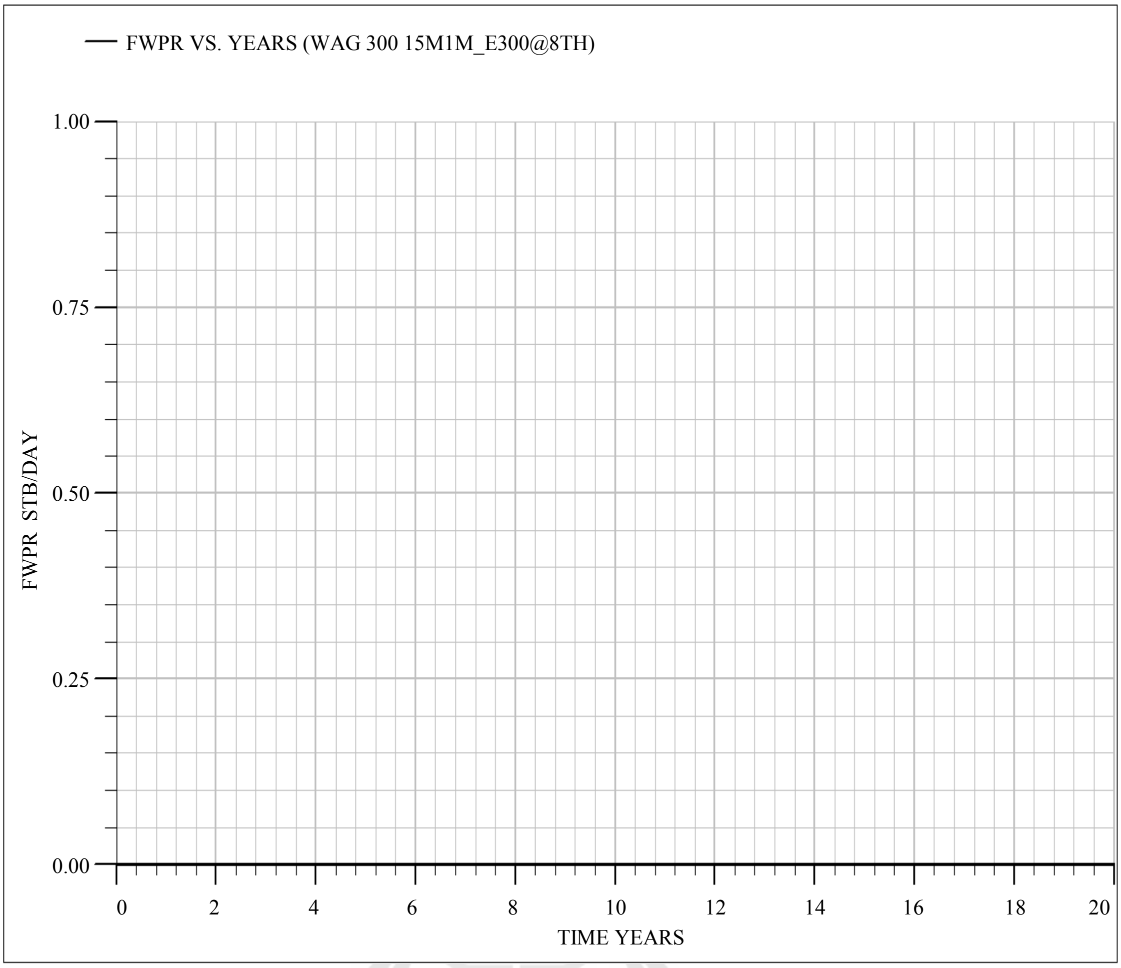

Figure 4.47 Water production rates vs. time of scenario 6.

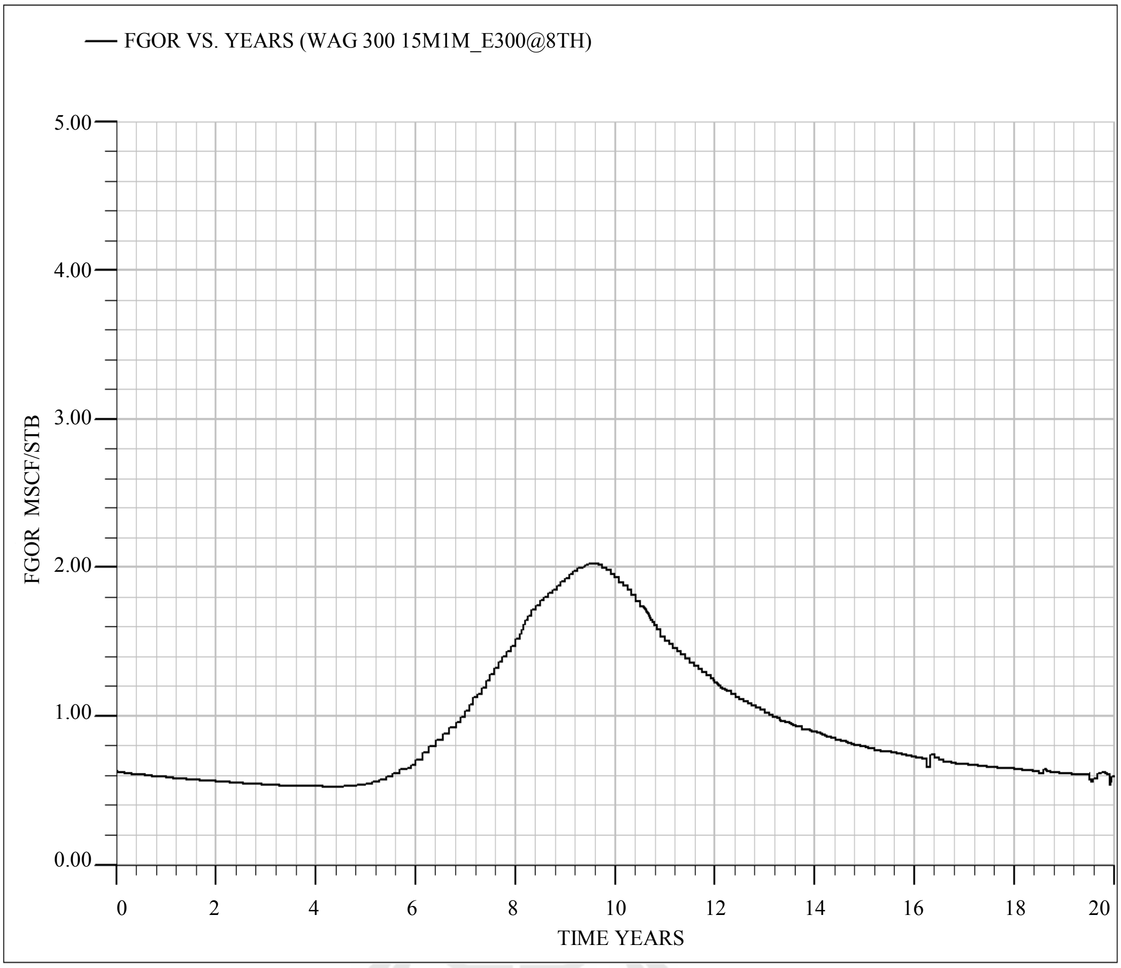

Figure 4.48 Gas-oil ratio vs. time of scenario 6.

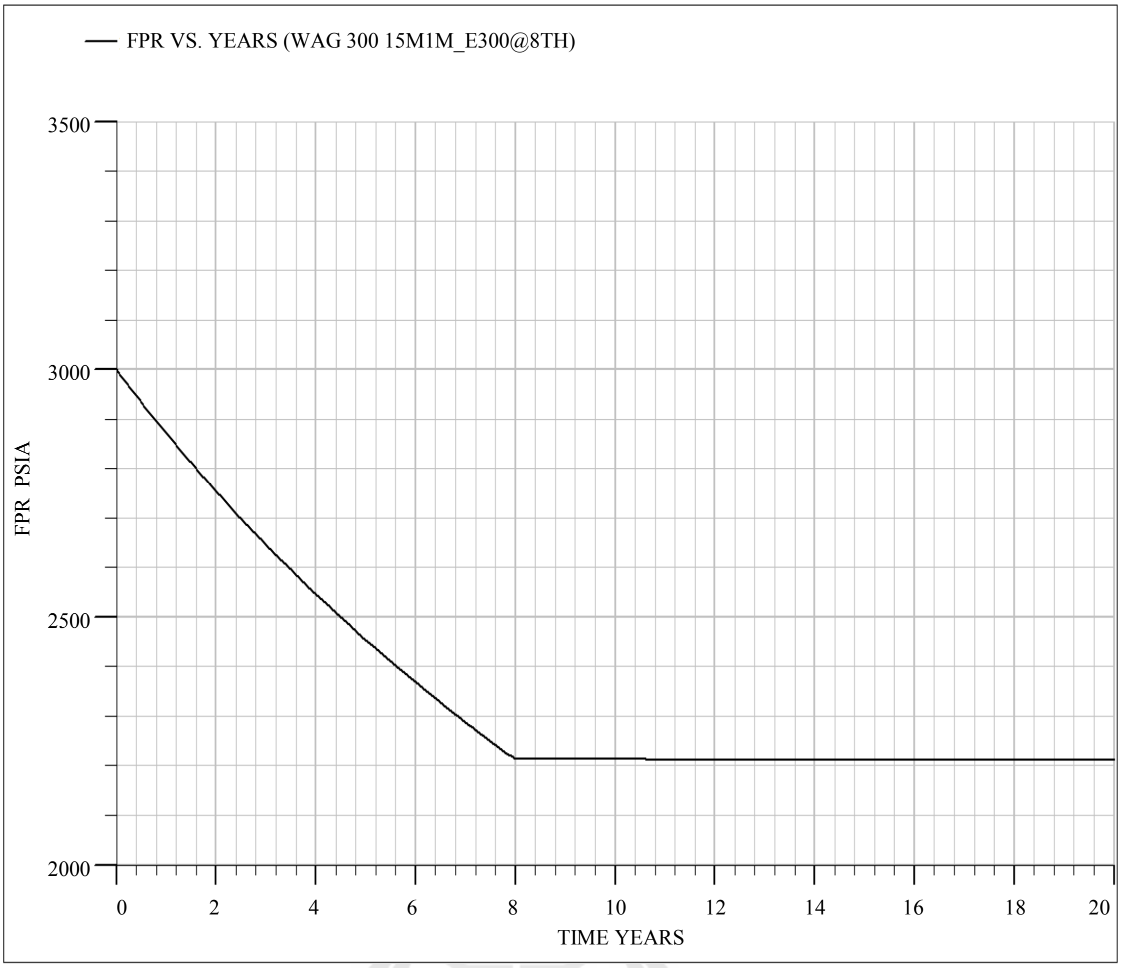

Figure 4.49 Pressure of reservoir vs. time of scenario 6.

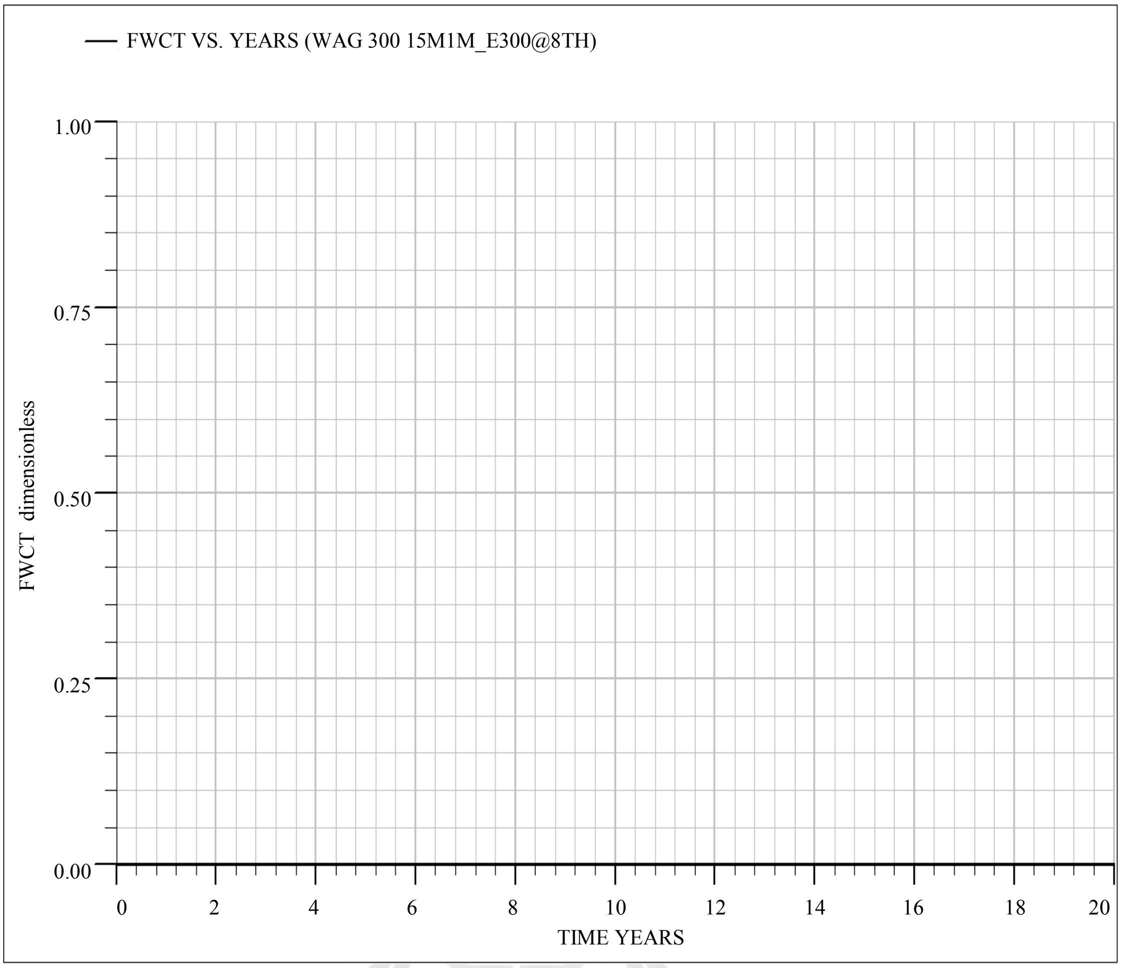

Figure 4.50 WCT vs. time of scenario 6.

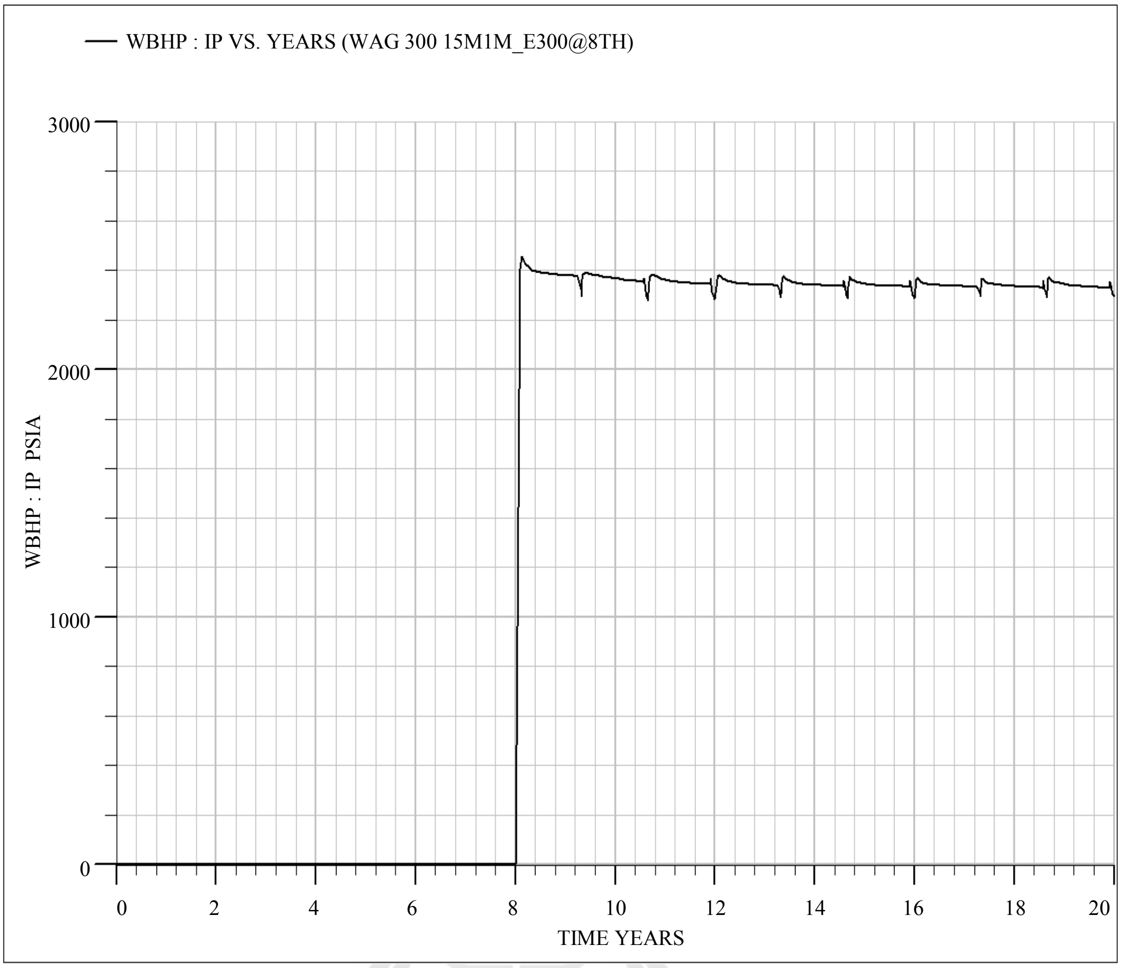

Figure 4.51 BHP of injection well vs. time of scenario 6.

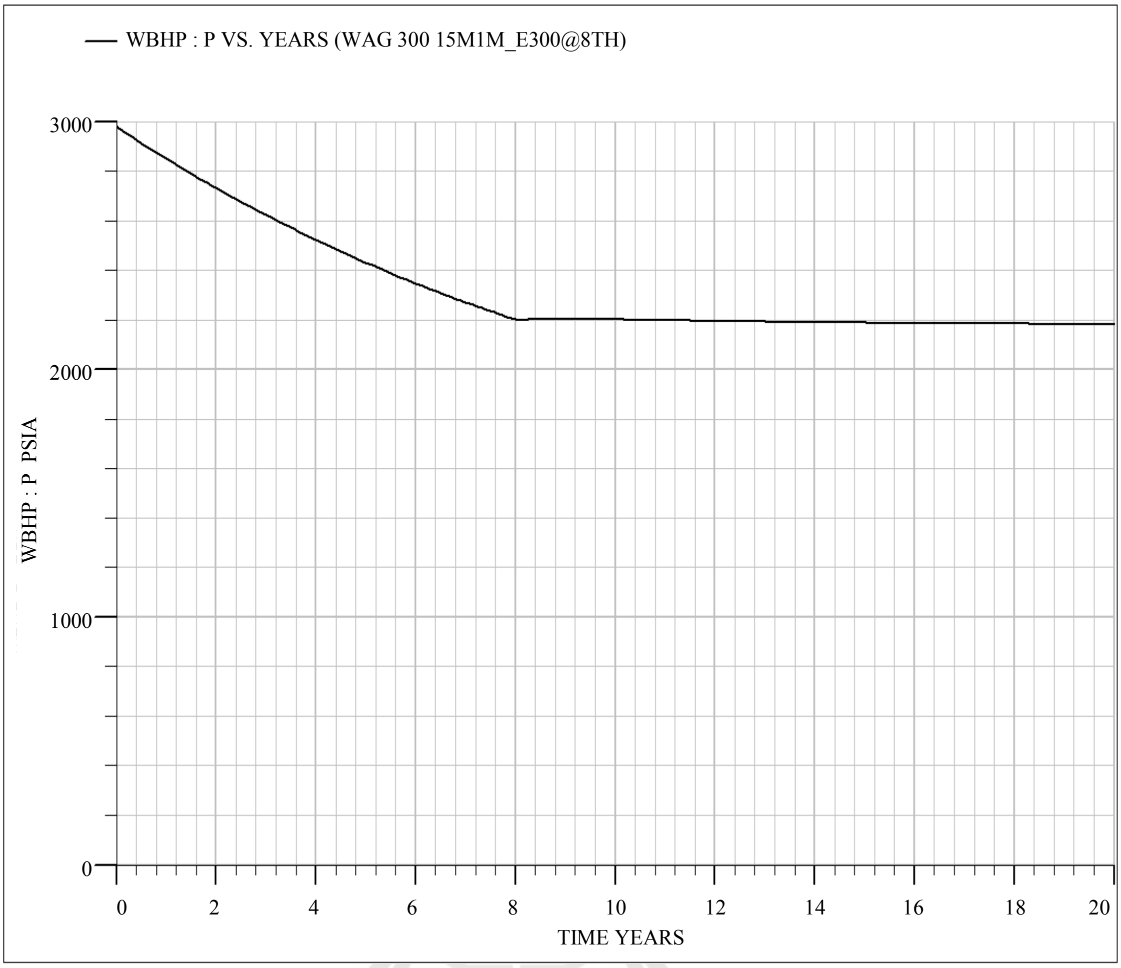

Figure 4.52 BHP of production well vs. time of scenario 6.

The oil production profile is showed in Figure 4.45. The oil production rate was maintained at the rate of 230 STB/D (300 RB/D) for five year and steadily dropped until the starting of water injection at the 8^{th} year of production plan. The production rate was longer than those of scenario 5 this is because the oil production rate was set to lower. Water did not breakthrough because of late of water injection.

4.2. Economic evaluation results

The economic analysis was done and analyzed by using Microsoft Excels 2007. Sensitivity analysis consists of oil price which has vary between ±50 percent of 80.00 US$/BBL and discount factor of 6%, 10%, and 15% were tested. The results of sensitivity analysis are showed and summarized in Table 4.8;

Table 4.8 Table of economic evaluation sensitivity analysis.

Pattern	Scenario	Rate of production, RB	Water period, Mths	Gas period, Mths	Cash flow of 80US$/bbl and 6% discount	Cash flow of all scenarios
NF	1	400	-	-	4.9	4.10
WAG : Base case	2	700	12	12	4.11	4.12
WAG : Free gas	3	700	12	1	4.13	4.14
	4	1000	13	1	4.15	4.16
	5	1000	15	1	4.17	4.18
	6	300	15	1	4.19	4.20

Tables 4.9 through Table 4.20 show the results of cash flow analysis for the six cases. This table contains of internal rate of return (IRR), profit to investment ratio (PIR), and present worth net profits. These values are variable to make economic decision.

Table 4.9 Cash flow summary of natural flow production, scenario 1

(80 US$/bbl, 6% discount factor).

Time	Cash flow							Discounted cash flow, MMUS$
	Cum. Oil Prod. , bbl/year	Revenue, MUS$	CAPEX, MMUS$	OPEX, MMUS$	Government take		Annual cash flow , MMUS$	
					Royalty, MMUS$	Income tax, MMUS$		
1	0	0	0.500	0.000	0.000	0.000	-0.500	-0.500
2	0	0	1.020	0.000	0.000	0.000	-1.020	-0.962
3	0	0	3.121	0.000	0.000	0.000	-3.121	-2.778
4	0	0	6.898	0.000	0.000	0.000	-6.898	-5.792
5	126,625	10.130	0.000	3.799	0.506	0.000	5.825	4.614
6	109,822	8.786	0.000	3.295	0.439	0.000	5.052	3.775
7	80,383	6.431	0.000	2.412	0.322	0.000	3.698	2.607
8	80,044	6.404	0.000	2.401	0.320	0.000	3.682	2.449
9	76,597	6.128	0.000	2.298	0.306	0.220	3.303	2.072
10	45,933	3.675	0.000	1.378	0.184	1.056	1.056	0.625
11	24,825	1.986	0.030	0.745	0.099	0.556	0.556	0.310
	544,230	43.538	11.570	16.327	2.177	1.833	11.633	6.421
						IRR	23.201%	16.228%
						PIR	1.005	0.677

Table 4.10 Cash flow summary of natural flow production, scenario 1.

Oil price, US$/bbl	Discount rate, %	IRR Undiscount	IRR With Discount	PIR Undiscount	PIR With Discount
40	6	-21.405%	-25.854%	-0.624	-0.738
	10		-28.550%		-0.807
	15		-31.657%		-0.888
80	6	23.201%	16.228%	1.005	0.677
	10		12.001%		0.491
	15		7.132%		0.286
120	6	42.839%	34.754%	1.899	1.488
	10		29.854%		1.256
	15		24.208%		1.000

Table 4.11 Cash flow summary of WAG production, scenario 2 (80 US$/bbl, 6% discount factor).

Time	Cash flow							Discounted cash flow, MMUS$
	Cum. Oil Prod. , bbl/year	Revenue, MMUS$	CAPEX, MMUS$	OPEX, MMUS$	Government take		Annual cash flow , MMUS$	
					Royalty, MMUS$	Income tax, MMUS$		
1	0	0	0.500	0.000	0.000	0.000	-0.500	-0.500
2	0	0	1.020	0.000	0.000	0.000	-1.020	-0.962
3	0	0	3.121	0.000	0.000	0.000	-3.121	-2.778
4	0	0	6.898	0.000	0.000	0.000	-6.898	-5.792
5	214,844	17.188	6.873	6.797	0.859	0.000	2.658	2.105
6	183,085	14.647	0.000	5.726	0.732	0.000	8.188	6.119
7	153,000	12.240	0.000	4.848	0.612	0.000	6.780	4.779
8	161,033	12.883	0.000	5.058	0.644	0.000	7.181	4.776
9	128,475	10.278	0.000	4.206	0.514	1.337	4.221	2.648
10	126,664	10.133	0.000	4.028	0.507	2.799	2.799	1.657
11	105,416	8.433	0.000	3.427	0.422	2.292	2.292	1.280
12	135,513	10.841	0.000	4.292	0.542	3.003	3.003	1.582
13	112,658	9.013	0.000	3.732	0.451	2.415	2.415	1.200
14	125,939	10.075	0.000	4.006	0.504	2.783	2.783	1.305
15	107,167	8.573	0.000	3.480	0.429	2.333	2.333	1.032
16	125,146	10.012	0.000	3.981	0.501	2.765	2.765	1.154
17	106,992	8.559	0.000	3.562	0.428	2.285	2.285	0.849
18	121,951	9.756	0.000	3.891	0.488	2.689	2.689	0.999
19	99,069	7.926	0.000	3.232	0.396	2.149	2.149	0.753
20	126,274	10.102	0.000	4.015	0.505	2.791	2.791	0.922
21	102,303	8.184	0.000	3.421	0.409	2.177	2.177	0.679
22	122,895	9.832	0.000	3.916	0.492	2.712	2.712	0.798
23	96,359	7.709	0.000	3.153	0.385	2.085	2.085	0.579
24	104,777	8.382	0.039	3.370	0.419	2.277	2.277	0.596
	2,559,561	204.765	18.452	82.141	10.238	38.892	55.042	25.778
						IRR	34.468%	26.851%
						PIR	2.983	1.665

Table 4.12 Cash flow summary of WAG production, scenario 2.

Oil price, US$/bbl	Discount rate, %	IRR Undiscount	IRR With Discount	PIR Undiscount	PIR With Discount
40	6	-2.061%	-7.605%	-0.180	-0.493
	10		-10.965%		-0.606
	15		-14.836%		-0.695
80	6	34.468%	26.851%	2.983	1.665
	10		22.235%		1.166
	15		16.916%		0.753
120	6	58.844%	49.851%	5.619	3.303
	10		44.401%		2.452
	15		38.121%		1.765

Table 4.13 Cash flow summary of WAG production, scenario 3 (80 US$/bbl, 6% discount factor).

Time	Cash flow							Discounted cash flow, MMUS$
	Cum. Oil Prod. , bbl/year	Revenue, MMUS$	CAPEX, MMUS$	OPEX, MMUS$	Government take		Annual cash flow , MMUS$	
					Royalty, MMUS$	Income tax, MMUS$		
1	0	0	0.500	0.000	0.000	0.000	-0.500	-0.500
2	0	0	1.020	0.000	0.000	0.000	-1.020	-0.962
3	0	0	3.121	0.000	0.000	0.000	-3.121	-2.778
4	0	0	6.898	0.000	0.000	0.000	-6.898	-5.792
5	210,066	16.805	6.873	6.654	0.840	0.000	2.438	1.931
6	193,517	15.481	0.000	6.070	0.774	0.000	8.637	6.454
7	177,601	14.208	0.000	5.660	0.710	0.000	7.838	5.525
8	193,545	15.484	0.000	6.148	0.774	0.528	8.034	5.343
9	220,128	17.610	0.000	6.962	0.881	4.249	5.519	3.462
10	193,671	15.494	0.000	6.151	0.775	4.284	4.284	2.536
11	167,715	13.417	0.000	5.356	0.671	3.695	3.695	2.063
12	193,775	15.502	0.000	6.154	0.775	4.286	4.286	2.258
13	202,079	16.166	0.000	6.409	0.808	4.475	4.475	2.224
14	193,053	15.444	0.000	6.133	0.772	4.269	4.269	2.002
15	184,107	14.729	0.000	5.859	0.736	4.066	4.066	1.799
16	191,458	15.317	0.000	6.085	0.766	4.233	4.233	1.766
17	190,774	15.262	0.000	6.069	0.763	4.215	4.215	1.659
18	162,836	13.027	0.000	5.232	0.651	3.572	3.572	1.326
19	148,967	11.917	0.000	4.811	0.596	3.255	3.255	1.141
20	133,331	10.666	0.000	4.342	0.533	2.895	2.895	0.957
21	125,141	10.011	0.000	4.100	0.501	2.705	2.705	0.844
22	103,191	8.255	0.000	3.435	0.413	2.204	2.204	0.648
23	87,876	7.030	0.000	2.975	0.352	1.852	1.852	0.514
24	79,042	6.323	0.039	2.713	0.316	1.627	1.627	0.426
	3,351,873	268.150	18.452	107.320	13.407	56.410	72.560	34.846
						IRR	38.583%	30.739%
						PIR	3.932	2.250

Table 4.14 Cash flow summary of WAG production, scenario 3.

Oil price, US$/bbl	Discount rate, %	IRR Undiscount	IRR With Discount	PIR Undiscount	PIR With Discount
40	6	0.954%	-4.760%	0.087	-0.325
	10		-8.224%		-0.480
	15		-12.214%		-0.607
80	6	38.583%	30.739%	3.932	2.250
	10		25.985%		1.602
	15		20.507%		1.063
120	6	62.370%	53.179%	7.384	4.382
	10		47.609%		3.250
	15		41.191%		2.327

Table 4.15 Cash flow summary of WAG production, scenario 4 (80 US$/bbl, 6% discount factor).

Time	Cash flow							Discounted cash flow, MMUS$
	Cum. Oil Prod. , bbl/year	Revenue, MMUS$	CAPEX, MMUS$	OPEX, MMUS$	Government take		Annual cash flow , MMUS$	
					Royalty, MMUS$	Income tax, MMUS$		
1	0	0	0.500	0.000	0.000	0.000	-0.500	-0.500
2	0	0	1.020	0.000	0.000	0.000	-1.020	-0.962
3	0	0	3.121	0.000	0.000	0.000	-3.121	-2.778
4	0	0	6.898	0.000	0.000	0.000	-6.898	-5.792
5	281,967	22.557	0.000	8.459	1.128	0.000	12.970	10.274
6	283,398	22.672	7.011	8.652	1.134	0.000	5.876	4.391
7	191,931	15.354	0.000	6.067	0.768	2.274	6.246	4.404
8	218,033	17.443	0.000	6.932	0.872	3.654	5.984	3.980
9	236,120	18.890	0.000	7.474	0.944	4.601	5.871	3.683
10	239,627	19.170	0.000	7.579	0.959	4.681	5.951	3.523
11	250,011	20.001	0.000	7.891	1.000	5.555	5.555	3.102
12	256,367	20.509	0.000	8.081	1.025	5.702	5.702	3.003
13	255,389	20.431	0.000	8.052	1.022	5.679	5.679	2.822
14	241,544	19.324	0.000	7.564	0.966	5.396	5.396	2.530
15	174,473	13.958	0.000	5.626	0.698	3.817	3.817	1.688
16	165,807	13.265	0.000	5.365	0.663	3.618	3.618	1.510
17	168,693	13.495	0.000	5.451	0.675	3.685	3.685	1.451
18	160,762	12.861	0.000	5.214	0.643	3.502	3.502	1.301
19	136,117	10.889	0.000	4.474	0.544	2.935	2.935	1.028
20	116,560	9.325	0.000	3.887	0.466	2.486	2.486	0.822
21	100,057	8.005	0.000	3.320	0.400	2.142	2.142	0.668
22	79,769	6.382	0.000	2.785	0.319	1.639	1.639	0.482
23	59,127	4.730	0.000	2.165	0.237	1.164	1.164	0.323
24	45,612	3.649	0.039	1.759	0.182	0.834	0.834	0.218
	3,661,363	292.909	18.589	116.795	14.645	63.365	79.515	41.170
						IRR	52.703%	44.059%
						PIR	4.277	2.694

Table 4.16 Cash flow summary of WAG production, scenario 4.

Oil price, US$/bbl	Discount rate, %	IRR Undiscount	IRR With Discount	PIR Undiscount	PIR With Discount
40	6	2.725%	-3.089%	0.202	-0.180
	10		-6.613%		-0.337
	15		-10.673%		-0.472
80	6	52.703%	44.059%	4.277	2.694
	10		38.821%		2.050
	15		32.785%		1.493
120	6	77.872%	67.804%	8.020	5.141
	10		61.702%		3.987
	15		54.672%		3.007

Table 4.17 Cash flow summary of WAG production, scenario 5 (80 US$/bbl, 6% discount factor).

Time	Cash flow							Discounted cash flow, MMUS$
	Cum. Oil Prod. , bbl/year	Revenue, MMUS$	CAPEX, MMUS$	OPEX, MMUS$	Government take		Annual cash flow , MMUS$	
					Royalty, MMUS$	Income tax, MMUS$		
1	0	0	0.500	0.000	0.000	0.000	-0.500	-0.500
2	0	0	1.020	0.000	0.000	0.000	-1.020	-0.962
3	0	0	3.121	0.000	0.000	0.000	-3.121	-2.778
4	0	0	6.898	0.000	0.000	0.000	-6.898	-5.792
5	223,487	17.879	0.000	6.705	0.894	0.000	10.280	8.143
6	197,719	15.818	0.000	5.932	0.791	0.378	8.717	6.514
7	151,939	12.155	0.000	4.558	0.608	2.665	4.325	3.049
8	82,384	6.591	7.294	2.618	0.330	0.000	-3.651	-2.428
9	68,721	5.498	0.000	2.336	0.275	0.808	2.078	1.304
10	84,038	6.723	0.000	2.851	0.336	1.133	2.403	1.422
11	121,150	9.692	0.000	3.970	0.485	1.984	3.254	1.817
12	155,922	12.474	0.000	5.019	0.624	2.781	4.051	2.134
13	180,414	14.433	0.000	5.682	0.722	4.015	4.015	1.995
14	174,946	13.996	0.000	5.586	0.700	3.855	3.855	1.807
15	182,126	14.570	0.000	5.803	0.729	4.019	4.019	1.778
16	187,268	14.981	0.000	5.959	0.749	4.137	4.137	1.726
17	190,502	15.240	0.000	5.982	0.762	4.248	4.248	1.672
18	185,074	14.806	0.000	5.893	0.740	4.086	4.086	1.518
19	180,361	14.429	0.000	5.750	0.721	3.979	3.979	1.394
20	152,141	12.171	0.000	4.905	0.609	3.329	3.329	1.100
21	133,884	10.711	0.000	4.286	0.536	2.944	2.944	0.918
22	127,774	10.222	0.000	4.173	0.511	2.769	2.769	0.814
23	117,706	9.416	0.000	3.869	0.471	2.538	2.538	0.704
24	121,785	9.743	0.039	3.995	0.487	2.611	2.611	0.684
	3,019,339	241.547	18.873	95.873	12.077	52.278	62.446	28.033
						IRR	39.144%	31.268%
						PIR	3.309	1.882

Table 4.18 Cash flow summary of WAG production, scenario 5.

Oil price, US$/bbl	**Discount rate, %**	**IRR Undiscount**	**IRR With Discount**	**PIR Undiscount**	**PIR With Discount**
40	6	-0.007%	-5.66662	-0.001	-0.366
	10		-9.09692		-0.502
	15		-13.04923		-0.611
80	6	39.144%	31.268%	3.309	1.882
	10		26.495%		1.339
	15		20.995%		0.894
120	6	63.589%	54.329%	6.431	3.826
	10		48.718%		2.848
	15		42.252%		2.057

Table 4.19 Cash flow summary of WAG production, scenario 6 (80 US$/bbl, 6% discount factor).

Time	Cash flow							Discounted cash flow, MMUS$
					Government take			
	Cum. Oil Prod. , bbl/year	Revenue, MMUS$	CAPEX, MMUS$	OPEX, MMUS$	Royalty, MMUS$	Income tax, MMUS$	Annual cash flow , MMUS$	
1	0	0	0.500	0.000	0.000	0.000	-0.500	-0.500
2	0	0	1.020	0.000	0.000	0.000	-1.020	-0.962
3	0	0	3.121	0.000	0.000	0.000	-3.121	-2.778
4	0	0	6.898	0.000	0.000	0.000	-6.898	-5.792
5	83,350	6.668	0.000	2.501	0.333	0.000	3.834	3.037
6	84,211	6.737	0.000	2.526	0.337	0.000	3.874	2.895
7	85,095	6.808	0.000	2.553	0.340	0.000	3.914	2.759
8	85,044	6.803	0.000	2.551	0.340	0.000	3.912	2.602
9	84,097	6.728	0.000	2.523	0.336	0.000	3.868	2.427
10	77,867	6.229	0.000	2.336	0.311	0.823	2.759	1.633
11	63,471	5.078	0.000	1.904	0.254	1.460	1.460	0.815
12	51,127	4.090	7.895	1.678	0.205	0.000	-5.688	-2.996
13	33,259	2.661	0.000	1.187	0.133	0.000	1.341	0.666
14	32,973	2.638	0.000	1.265	0.132	0.000	1.241	0.582
15	36,715	2.937	0.000	1.377	0.147	0.000	1.413	0.625
16	43,896	3.512	0.000	1.593	0.176	0.000	1.743	0.727
17	50,701	4.056	0.000	1.714	0.203	0.202	1.937	0.762
18	56,617	4.529	0.000	1.974	0.226	1.164	1.164	0.432
19	61,564	4.925	0.000	2.123	0.246	1.278	1.278	0.448
20	65,397	5.232	0.000	2.238	0.262	1.366	1.366	0.452
21	68,607	5.489	0.000	2.252	0.274	1.481	1.481	0.462
22	71,020	5.682	0.000	2.407	0.284	1.495	1.495	0.440
23	73,075	5.846	0.000	2.468	0.292	1.543	1.543	0.428
24	74,633	5.971	0.039	2.515	0.299	1.559	1.559	0.408
	1,282,717	102.617	19.474	41.685	5.131	12.372	23.956	9.573
						IRR	20.236%	13.431%
						PIR	1.230	0.674

Table 4.20 Cash flow summary of WAG production, scenario 6.

Oil price, US$/bbl	Discount rate, %	IRR Undiscount	IRR With Discount	PIR Undiscount	PIR With Discount
40	6	-13.712%	-18.597%	-0.638	-0.724
	10		-21.557%		-0.762
	15		-24.967%		-0.799
80	6	20.236%	13.431%	1.230	0.674
	10		9.306%		0.423
	15		4.553%		0.187
120	6	36.812%	29.068%	2.470	1.569
	10		24.374%		1.180
	15		18.967%		0.825

CHAPTER 5

Conclusion and discussion

This chapter concludes the research study results in term of recovery efficiency of WAG simulation, and its economic evaluation in Phitsanulok Basin. Finally, discussion about research results, problems, and the possible idea for future works are given.

5.1 Discussion

The objective of this research is to simulate the WAG method and analyzed the operation condition that optimizes oil recovery for an oil field in Phitsanulok Basin. The 6 conceptual scenarios of production and injection plan were created (no injection, 1st year, 2nd year, 4th year, and 8th year after natural flow production periods). The economic analysis and sensitivity analysis in oil price and discount factor were taken into account. Some interesting points resulted from the study can be discussed and listed as follows;

5.1.1 Reservoir simulation results

All results of simulations are listed in Table 5.1. and a brief discussion are as follows;

a) The reservoir simulation result indicated that the WAG technique can improved oil recovery efficiency (compare to natural flow) of oil field in Phitsanulok Basin under the same condition.

b) To compare with the natural flow drive mechanism, the injection at the 2^{nd} year of production scenarios is the best case of operation and development due to the recovery efficiency and economic values are more favorable than the others.

c) When operation starts water injection late, reservoir needs more water injection volume for maintaining the reservoir pressure.

d) The high injection rate gives high oil recovery because there is more sweeping volume of the displacement. However, this but is not always happened if water cut is too high or bottom hole pressure is more than fracture pressure.

e) Gas and water controlling are necessary to prevent gas fingering effect and early water breakthrough that reduces the recovery.

f) Reservoir pressure, oil production rate, bottom hole pressure of injection and production well tend to increase when water is injected and tend to decrease when gas is injected.

Table 5.1 Result summary

Pattern	**Scenario**	**Start injection time (Year)**	**Production and injection rate (RB/D)**	**Water period (Months)**	**Gas period (Months)**	**RF (%)**	**PI (%)**
NF	1	-	400	-	-	10.54	-
WAG : base case	2	1^{st}	700	12	12	49.70	67.45
WAG : freegas	3	1^{st}	700	12	1	65.13	86.88
	4	2^{nd}	1000	13	1	71.05	70.98
	5	4^{th}	1000	15	1	58.60	92.81
	6	8^{th}	300	15	1	24.88	123.19

5.1.2 Economic evaluation results

Economic analysis in this study had been performed to each scenario to consider the possible of project feasibility and it's realizable to operate in practical.

a) Even though the reservoir simulation results indicated that the WAG technique can improved oil recovery efficiency, WAG incapable apply in all operations because costs of WAG facilities are very high.

b) Results also show that all operations can not make a profit at oil price lower than 40 US$/bbl because costs of WAG facilities.

c) At oil price 80 US$/bbl, results show that natural flow gained 7.132 - 23.201% of IRR (PIR 0.286 - 1.005), base case scenarios gained 16.916 - 34.468% of IRR (PIR 0.753 - 2.983), the 1st year injection scenarios gained 20.507 - 38.583% of IRR (PIR 1.063 - 3.932), the 2nd year injection scenarios gained 32.785 - 52.703% of IRR (PIR 1.493 - 4.277), the 4th year injection scenarios gained 20.995 - 39.144% of IRR (PIR 0.894 - 3.309), and the 8th year injection scenarios gained 20.995 - 39.144% of IRR (PIR 0.894 - 3.309), respectively.

d) At oil price 120 US$/bbl, results show that natural flow gained 24.208 - 42.839% of IRR (PIR 1.000 - 1.899), base case scenarios gained 38.121 - 58.844% of IRR (PIR 1.765 - 5.619), the 1st year injection scenarios gained 41.191 - 62.370% of IRR (PIR 2.327 - 7.384)the 2nd year injection scenarios gained 54.672 - 77.872% of IRR (PIR 3.007 - 8.020), the 4th year injection scenarios gained 42.252 - 63.589% of IRR (PIR 2.057 - 6.431), and the 8th year injection scenarios gained 42.252% - 63.589% of IRR (PIR 2.057 - 6.431).

5.2 Conclusions

In this study, the maximum oil recovery from primary production is 10.54% of the size of the original oil in place. While WAG can achieves the highest recovery up to 71.05%. Results from economic evaluation show that in case of the oil price is 40US$/bbl or lower, WAG method is not promoted because the WAG facility cost is too high and it is not economics. The efficiency of recovery would decrease, if water breakthrough and gas fingering early occur and the bottom hole pressure is more than fracture pressure, then controlling injection are required

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APPENDIX A

ECONOMIC CALCULATION

DETAIL OF BASE CASE

Table A.1 Economic analysis calculation detail of scenario 1.

A	B	C	D	E	F	G	H
Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**CAPEX**		
					Concession (US$)	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
1				1.0000	500,000		
2				1.0200		1,000,000	
3				1.0404			3,000,000
4	0	0	0	1.0612			
5	126,625	10,129,970	506,498	1.0824			
6	109,822	8,785,750	439,288	1.1041			
7	80,383	6,430,675	321,534	1.1262			
8	80,044	6,403,542	320,177	1.1487			
9	76,597	6,127,775	306,389	1.1717			
10	45,933	3,674,634	183,732	1.1951			
11	24,825	1,986,028	99,301	1.2190			
Total	**544,230**	**43,538,375**	**2,176,919**		**500,000**	**1,000,000**	**3,000,000**

Table A.1 Economic analysis calculation detail of scenario 1 (continued).

A	I	J	K	L	M	N
Year	**CAPEX**					
	Drilling and completion cost of production well		**Facility cost of production well (US$)**	**Abandonment cost (US$)**	**Facility cost of injection well (US$)**	**Total Depreciation (20%) tangible expense**
	INTANG (US$)	**TANG (US$)**				
1						100,000
2						300,000
3						900,000
4	1,200,000	300,000	5,000,000	0	0	1,960,000
5	0	0	0	0	0	1,960,000
6	0	0	0	0	0	1,860,000
7	0	0	0	0	0	1,660,000
8	0	0	0	0	0	1,060,000
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	25,000	0	0
Total	**1,200,000**	**300,000**	**5,000,000**	**25,000**	**0**	**9,800,000**

Table A.1 Economic analysis calculation detail of scenario 1 (continued).

A	O	P	Q	R	S	T
Year	Water Injection Rate (bbl/year)	Gas Injection Rate (MSCF/year)	OPEX			
			Operation cost of production well (US$)	Maintenance cost of water injection facility (US$)	Operation cost of water injection (US$)	Operation cost of gas rework injection (US$)
1						
2						
3						
4	0	0	0	0	0	0
5	0	0	3,798,739	0	0	0
6	0	0	3,294,656	0	0	0
7	0	0	2,411,503	0	0	0
8	0	0	2,401,328	0	0	0
9	0	0	2,297,916	0	0	0
10	0	0	1,377,988	0	0	0
11	0	0	744,760	0	0	0
Total	**0**	**0**	**16,326,891**	**0**	**0**	**0**

Table A.1 Economic analysis calculation detail of scenario 1 (continued).

A	U	V	W	X	Y	Z	AA
Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(6%) Discount factor**	**Discount cash flow (US$)**	**Cumulative discounted cash flow (US$)**
1	500,000	-600,000	0	-500,000	1.000	-500,000	-500,000
2	1,020,000	-1,320,000	0	-1,020,000	0.943	-962,264	-1,462,264
3	3,121,200	-4,021,200	0	-3,121,200	0.890	-2,777,857	-4,240,121
4	6,897,852	-8,857,852	0	-6,897,852	0.840	-5,791,570	-10,031,691
5	3,798,739	3,864,733	0	5,824,733	0.792	4,613,734	-5,417,957
6	3,294,656	3,191,806	0	5,051,806	0.747	3,775,004	-1,642,953
7	2,411,503	2,037,638	0	3,697,638	0.705	2,606,689	963,736
8	2,401,328	2,622,037	0	3,682,037	0.665	2,448,765	3,412,501
9	2,297,916	3,523,471	220,316	3,303,154	0.627	2,072,440	5,484,941
10	1,377,988	2,112,915	1,056,457	1,056,457	0.592	625,316	6,110,256
11	775,235	1,111,491	555,746	555,746	0.558	310,325	6,420,582
Total	**27,896,418**	**3,665,039**	**1,832,519**	**11,632,519**		**6,420,582**	

Table A.2 Economic analysis calculation detail of scenario 2.

A	B	C	D	E	F	G	H
Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**CAPEX**		
					Concession (US$)	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
1				1.0000	500,000		
2				1.0200		1,000,000	
3				1.0404			3,000,000
4	0	0	0	1.0612			
5	214,844	17,187,531	859,377	1.0824			
6	183,085	14,646,839	732,342	1.1041			
7	153,000	12,239,965	611,998	1.1262			
8	161,033	12,882,605	644,130	1.1487			
9	128,475	10,277,985	513,899	1.1717			
10	126,664	10,133,155	506,658	1.1951			
11	105,416	8,433,288	421,664	1.2190			
12	135,513	10,841,024	542,051	1.2434			
13	112,658	9,012,608	450,630	1.2682			
14	125,939	10,075,144	503,757	1.2936			
15	107,167	8,573,344	428,667	1.3195			
16	125,146	10,011,712	500,586	1.3459			
17	106,992	8,559,352	427,968	1.3728			
18	121,951	9,756,112	487,806	1.4002			
19	99,069	7,925,520	396,276	1.4282			
20	126,274	10,101,936	505,097	1.4568			
21	102,303	8,184,240	409,212	1.4859			
22	122,895	9,831,624	491,581	1.5157			
23	96,359	7,708,736	385,437	1.5460			
24	104,777	8,382,184	419,109	1.5769			
Total	**2,559,561**	**204,764,904**	**10,238,245**		**500,000**	**1,000,000**	**3,000,000**

Table A.2 Economic analysis calculation detail of scenario 2 (continued).

A	I	J	K	L	M	N
Year	CAPEX					
	Drilling and completion cost of production well		Facility cost of production well (US$)	Abandonment cost (US$)	Facility cost of injection well (US$)	Total Depreciation (20%) tangible expense
	INTANG (US$)	TANG (US$)				
1						100,000
2						300,000
3						900,000
4	1,200,000	300,000	5,000,000	0	0	1,960,000
5	0	0	6,000,000	0	350,000	3,230,000
6	0	0	0	0	0	3,130,000
7	0	0	0	0	0	2,930,000
8	0	0	0	0	0	2,330,000
9	0	0	0	0	0	1,270,000
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	0	0	0	0	0	0
13	0	0	0	0	0	0
14	0	0	0	0	0	0
15	0	0	0	0	0	0
16	0	0	0	0	0	0
17	0	0	0	0	0	0
18	0	0	0	0	0	0
19	0	0	0	0	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	25,000	0	0
Total	**1,200,000**	**300,000**	**11,000,000**	**25,000**	**350,000**	**14,850,000**

Table A.2 Economic analysis calculation detail of scenario 2 (continued).

A	O	P	Q	R	S	T
			OPEX			
Year	Water Injection Rate (bbl/year)	Gas Injection Rate (MSCF/year)	Operation cost of production well (US$)	Maintenance cost of water injection facility (US$)	Operation cost of water injection (US$)	Operation cost of gas rework injection (US$)
1						
2						
3						
4	0	0	0	0	0	0
5	249,821	28,000	6,445,324	140,000	124,911	86,900
6	13,688	227,500	5,492,565	140,000	6,844	86,900
7	236,798	0	4,589,987	140,000	118,399	0
8	0	255,500	4,830,977	140,000	0	86,900
9	249,792	28,000	3,854,244	140,000	124,896	86,900
10	1,711	227,500	3,799,933	140,000	855	86,900
11	248,757	0	3,162,483	140,000	124,378	0
12	0	255,500	4,065,384	140,000	0	86,900
13	249,775	9,100	3,379,728	140,000	124,888	86,900
14	1,344	246,400	3,778,179	140,000	672	86,900
15	249,109	0	3,215,004	140,000	124,555	0
16	0	255,500	3,754,392	140,000	0	86,900
17	249,762	10,996	3,209,757	140,000	124,881	86,900
18	10,264	244,403	3,658,542	140,000	5,132	86,900
19	240,176	0	2,972,070	140,000	120,088	0
20	0	255,500	3,788,226	140,000	0	86,900
21	249,749	5,498	3,069,090	140,000	124,875	86,900
22	5,374	249,994	3,686,859	140,000	2,687	86,900
23	245,054	0	2,890,776	140,000	122,527	0
24	0	255,419	3,143,319	140,000	0	86,900
Total	**2,501,173**	**2,554,810**	**76,786,839**	**2,800,000**	**1,250,586**	**1,303,500**

Table A.2 Economic analysis calculation detail of scenario 2 (continued).

A	U	V	W	X	Y	Z	AA
Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(6%) Discount factor**	**Discount cash flow (US$)**	**Cumulative discounted cash flow (US$)**
1	500,000	-600,000	0	-500,000	1.000	-500,000	-500,000
2	1,020,000	-1,320,000	0	-1,020,000	0.943	-962,264	-1,462,264
3	3,121,200	-4,021,200	0	-3,121,200	0.890	-2,777,857	-4,240,121
4	6,897,852	-8,857,852	0	-6,897,852	0.840	-5,791,570	-10,031,691
5	13,670,579	-572,425	0	2,657,575	0.792	2,105,049	-7,926,642
6	5,726,309	5,058,189	0	8,188,189	0.747	6,118,691	-1,807,951
7	4,848,386	3,849,581	0	6,779,581	0.705	4,779,337	2,971,386
8	5,057,877	4,850,598	0	7,180,598	0.665	4,775,508	7,746,894
9	4,206,040	4,288,045	1,337,468	4,220,577	0.627	2,648,042	10,394,936
10	4,027,689	5,598,809	2,799,404	2,799,404	0.592	1,656,963	12,051,899
11	3,426,861	4,584,762	2,292,381	2,292,381	0.558	1,280,054	13,331,953
12	4,292,284	6,006,689	3,003,344	3,003,344	0.527	1,582,124	14,914,077
13	3,731,516	4,830,462	2,415,231	2,415,231	0.497	1,200,296	16,114,373
14	4,005,751	5,565,636	2,782,818	2,782,818	0.469	1,304,694	17,419,067
15	3,479,559	4,665,118	2,332,559	2,332,559	0.442	1,031,693	18,450,760
16	3,981,292	5,529,834	2,764,917	2,764,917	0.417	1,153,703	19,604,463
17	3,561,538	4,569,847	2,284,923	2,284,923	0.394	848,539	20,453,002
18	3,890,574	5,377,732	2,688,866	2,688,866	0.371	998,549	21,451,552
19	3,232,158	4,297,086	2,148,543	2,148,543	0.350	752,729	22,204,280
20	4,015,126	5,581,713	2,790,857	2,790,857	0.331	922,414	23,126,695
21	3,420,865	4,354,163	2,177,082	2,177,082	0.312	678,824	23,805,519
22	3,916,446	5,423,597	2,711,798	2,711,798	0.294	797,690	24,603,209
23	3,153,303	4,169,996	2,084,998	2,084,998	0.278	578,598	25,181,807
24	3,409,641	4,553,433	2,276,717	2,276,717	0.262	596,038	25,777,845
Total	**100,592,844**	**77,783,815**	**38,891,907**	**55,041,907**		**25,777,845**	

Table A.3 Economic analysis calculation detail of scenario 3.

A	B	C	D	E	F	G	H
					CAPEX		
Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**Concession (US$)**	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
1				1.0000	500,000		
2				1.0200		1,000,000	
3				1.0404			3,000,000
4	0	0	0	1.0612			
5	210,066	16,805,291	840,265	1.0824			
6	193,517	15,481,376	774,069	1.1041			
7	177,601	14,208,048	710,402	1.1262			
8	193,545	15,483,565	774,178	1.1487			
9	220,128	17,610,260	880,513	1.1717			
10	193,671	15,493,708	774,685	1.1951			
11	167,715	13,417,176	670,859	1.2190			
12	193,775	15,502,024	775,101	1.2434			
13	202,079	16,166,336	808,317	1.2682			
14	193,053	15,444,216	772,211	1.2936			
15	184,107	14,728,560	736,428	1.3195			
16	191,458	15,316,664	765,833	1.3459			
17	190,774	15,261,936	763,097	1.3728			
18	162,836	13,026,880	651,344	1.4002			
19	148,967	11,917,344	595,867	1.4282			
20	133,331	10,666,440	533,322	1.4568			
21	125,141	10,011,256	500,563	1.4859			
22	103,191	8,255,264	412,763	1.5157			
23	87,876	7,030,096	351,505	1.5460			
24	79,042	6,323,360	316,168	1.5769			
Total	**3,351,873**	**268,149,800**	**13,407,490**		**500,000**	**1,000,000**	**3,000,000**

Table A.3 Economic analysis calculation detail of scenario 3 (continued).

A	I	J	K	L	M	N
Year	CAPEX					
	Drilling and completion cost of production well		Facility cost of production well (US$)	Abandonment cost (US$)	Facility cost of injection well (US$)	Total Depreciation (20%) tangible expense
	INTANG (US$)	TANG (US$)				
1						100,000
2						300,000
3						900,000
4	1,200,000	300,000	5,000,000	0	0	1,960,000
5	0	0	6,000,000	0	350,000	3,230,000
6	0	0	0	0	0	3,130,000
7	0	0	0	0	0	2,930,000
8	0	0	0	0	0	2,330,000
9	0	0	0	0	0	1,270,000
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	0	0	0	0	0	0
13	0	0	0	0	0	0
14	0	0	0	0	0	0
15	0	0	0	0	0	0
16	0	0	0	0	0	0
17	0	0	0	0	0	0
18	0	0	0	0	0	0
19	0	0	0	0	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	25,000	0	0
Total	**1,200,000**	**300,000**	**11,000,000**	**25,000**	**350,000**	**14,850,000**

Table A.3 Economic analysis calculation detail of scenario 3 (continued).

A	O	P	Q	R	S	T
Year	Water Injection Rate (bbl/year)	Gas Injection Rate (MSCF/year)	OPEX			
			Operation cost of production well (US$)	Maintenance cost of water injection facility (US$)	Operation cost of water injection (US$)	Operation cost of gas rework injection (US$)
1						
2						
3						
4	0	0	0	0	0	0
5	249,821	21,700	6,301,984	140,000	124,911	86,900
6	249,818	0	5,805,516	140,000	124,909	0
7	209,435	20,300	5,328,018	140,000	104,718	86,900
8	228,598	21,700	5,806,337	140,000	114,299	86,900
9	263,503	21,000	6,603,848	140,000	131,752	86,900
10	228,597	21,700	5,810,141	140,000	114,298	86,900
11	195,744	21,000	5,031,441	140,000	97,872	86,900
12	228,597	21,700	5,813,259	140,000	114,298	86,900
13	239,348	21,700	6,062,376	140,000	119,674	86,900
14	229,281	21,000	5,791,581	140,000	114,641	86,900
15	218,529	21,700	5,523,210	140,000	109,265	86,900
16	229,280	21,000	5,743,749	140,000	114,640	86,900
17	238,176	21,700	5,723,226	140,000	119,088	86,900
18	240,229	2,749	4,885,080	140,000	120,114	86,900
19	229,277	18,951	4,469,004	140,000	114,639	86,900
20	230,645	19,600	3,999,915	140,000	115,323	86,900
21	238,172	21,700	3,754,221	140,000	119,086	86,900
22	225,067	21,000	3,095,724	140,000	112,534	86,900
23	223,897	21,700	2,636,286	140,000	111,948	86,900
24	229,327	20,942	2,371,260	140,000	114,664	86,900
Total	**4,625,341**	**382,842**	**100,556,175**	**2,800,000**	**2,312,671**	**1,651,100**

Table A.3 Economic analysis calculation detail of scenario 3 (continued).

A	U	V	W	X	Y	Z	AA
Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(6%) Discount factor**	**Discount cash flow (US$)**	**Cumulative discounted cash flow (US$)**
1	500,000	-600,000	0	-500,000	1.000	-500,000	-500,000
2	1,020,000	-1,320,000	0	-1,020,000	0.943	-962,264	-1,462,264
3	3,121,200	-4,021,200	0	-3,121,200	0.890	-2,777,857	-4,240,121
4	6,897,852	-8,857,852	0	-6,897,852	0.840	-5,791,570	-10,031,691
5	13,527,239	-792,213	0	2,437,787	0.792	1,930,956	-8,100,735
6	6,070,425	5,506,882	0	8,636,882	0.747	6,453,981	-1,646,754
7	5,659,636	4,908,010	0	7,838,010	0.705	5,525,488	3,878,734
8	6,147,536	6,231,851	527,739	8,034,112	0.665	5,343,143	9,221,877
9	6,962,499	8,497,248	4,248,624	5,518,624	0.627	3,462,453	12,684,330
10	6,151,339	8,567,684	4,283,842	4,283,842	0.592	2,535,599	15,219,929
11	5,356,213	7,390,104	3,695,052	3,695,052	0.558	2,063,298	17,283,227
12	6,154,457	8,572,465	4,286,233	4,286,233	0.527	2,257,934	19,541,161
13	6,408,950	8,949,069	4,474,535	4,474,535	0.497	2,223,707	21,764,868
14	6,133,122	8,538,884	4,269,442	4,269,442	0.469	2,001,681	23,766,549
15	5,859,375	8,132,757	4,066,379	4,066,379	0.442	1,798,563	25,565,112
16	6,085,289	8,465,542	4,232,771	4,232,771	0.417	1,766,187	27,331,299
17	6,069,214	8,429,625	4,214,813	4,214,813	0.394	1,659,145	28,990,445
18	5,232,094	7,143,442	3,571,721	3,571,721	0.371	1,326,410	30,316,855
19	4,810,542	6,510,934	3,255,467	3,255,467	0.350	1,140,533	31,457,387
20	4,342,138	5,790,981	2,895,490	2,895,490	0.331	956,997	32,414,384
21	4,100,207	5,410,486	2,705,243	2,705,243	0.312	843,508	33,257,892
22	3,435,157	4,407,343	2,203,672	2,203,672	0.294	648,222	33,906,114
23	2,975,134	3,703,457	1,851,728	1,851,728	0.278	513,864	34,419,978
24	2,752,246	3,254,946	1,627,473	1,627,473	0.262	426,068	34,846,046
Total	**125,771,864**	**112,820,446**	**56,410,223**	**72,560,223**		**34,846,046**	

Table A.4 Economic analysis calculation detail of scenario 4.

A	B	C	D	E	F	G	H
					CAPEX		
Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**Concession (US$)**	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
1				1.0000	500,000		
2				1.0200		1,000,000	
3				1.0404			3,000,000
4	0	0	0	1.0612			
5	281,967	22,557,358	1,127,868	1.0824			
6	283,398	22,671,813	1,133,591	1.1041			
7	191,931	15,354,490	767,724	1.1262			
8	218,033	17,442,615	872,131	1.1487			
9	236,120	18,889,637	944,482	1.1717			
10	239,627	19,170,168	958,508	1.1951			
11	250,011	20,000,872	1,000,044	1.2190			
12	256,367	20,509,360	1,025,468	1.2434			
13	255,389	20,431,152	1,021,558	1.2682			
14	241,544	19,323,520	966,176	1.2936			
15	174,473	13,957,800	697,890	1.3195			
16	165,807	13,264,536	663,227	1.3459			
17	168,693	13,495,464	674,773	1.3728			
18	160,762	12,860,960	643,048	1.4002			
19	136,117	10,889,360	544,468	1.4282			
20	116,560	9,324,776	466,239	1.4568			
21	100,057	8,004,520	400,226	1.4859			
22	79,769	6,381,544	319,077	1.5157			
23	59,127	4,730,160	236,508	1.5460			
24	45,612	3,648,920	182,446	1.5769			
Total	**3,661,363**	**292,909,024**	**14,645,451**		**500,000**	**1,000,000**	**3,000,000**

Table A.4 Economic analysis calculation detail of scenario 4 (continued).

A	I	J	K	L	M	N
Year	CAPEX					
	Drilling and completion cost of production well		Facility cost of production well (US$)	Abandonment cost (US$)	Facility cost of injection well (US$)	Total Depreciation (20%) tangible expense
	INTANG (US$)	TANG (US$)				
1						100,000
2						300,000
3						900,000
4	1,200,000	300,000	5,000,000	0	0	1,960,000
5	0	0	0	0	0	1,960,000
6	0	0	6,000,000	0	350,000	3,130,000
7	0	0	0	0	0	2,930,000
8	0	0	0	0	0	2,330,000
9	0	0	0	0	0	1,270,000
10	0	0	0	0	0	1,270,000
11	0	0	0	0	0	0
12	0	0	0	0	0	0
13	0	0	0	0	0	0
14	0	0	0	0	0	0
15	0	0	0	0	0	0
16	0	0	0	0	0	0
17	0	0	0	0	0	0
18	0	0	0	0	0	0
19	0	0	0	0	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	25,000	0	0
Total	**1,200,000**	**300,000**	**11,000,000**	**25,000**	**350,000**	**14,850,000**

Table A.4 Economic analysis calculation detail of scenario 4 (continued).

A	O	P	Q	R	S	T
Year	Water Injection Rate (bbl/year)	Gas Injection Rate (MSCF/year)	OPEX			
			Operation cost of production well (US$)	Maintenance cost of water injection facility (US$)	Operation cost of water injection (US$)	Operation cost of gas rework injection (US$)
1						
2						
3						
4	0	0	0	0	0	0
5	0	0	8,459,009	0	0	0
6	19,513	0	8,501,930	140,000	9,757	0
7	337,577	0	5,757,934	140,000	168,789	0
8	328,795	22,463	6,540,981	140,000	164,398	86,900
9	326,843	24,196	7,083,614	140,000	163,422	86,900
10	326,842	24,190	7,188,813	140,000	163,421	86,900
11	326,841	25,059	7,500,327	140,000	163,421	86,900
12	325,864	25,108	7,691,010	140,000	162,932	86,900
13	325,866	25,235	7,661,682	140,000	162,933	86,900
14	356,136	0	7,246,320	140,000	178,068	0
15	328,918	24,115	5,234,175	140,000	164,459	86,900
16	327,147	27,121	4,974,201	140,000	163,573	86,900
17	326,240	29,028	5,060,799	140,000	163,120	86,900
18	327,508	30,997	4,822,860	140,000	163,754	86,900
19	327,505	31,000	4,083,510	140,000	163,753	86,900
20	326,591	31,000	3,496,791	140,000	163,295	86,900
21	356,946	0	3,001,695	140,000	178,473	0
22	329,598	28,000	2,393,079	140,000	164,799	86,900
23	328,642	30,000	1,773,810	140,000	164,321	86,900
24	327,666	30,000	1,368,345	140,000	163,833	86,900
Total	**5,981,036**	**407,512**	**109,840,884**	**2,660,000**	**2,990,518**	**1,303,500**

Table A.4 Economic analysis calculation detail of scenario 4 (continued).

A	U	V	W	X	Y	Z	AA
Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(6%) Discount factor**	**Discount cash flow (US$)**	**Cumulative discounted cash flow (US$)**
1	500,000	-600,000	0	-500,000	1.000	-500,000	-500,000
2	1,020,000	-1,320,000	0	-1,020,000	0.943	-962,264	-1,462,264
3	3,121,200	-4,021,200	0	-3,121,200	0.890	-2,777,857	-4,240,121
4	6,897,852	-8,857,852	0	-6,897,852	0.840	-5,791,570	-10,031,691
5	8,459,009	11,010,481	0	12,970,481	0.792	10,273,836	242,145
6	15,662,599	2,745,623	0	5,875,623	0.747	4,390,607	4,632,752
7	6,066,722	5,590,043	2,273,547	6,246,496	0.705	4,403,533	9,036,285
8	6,932,278	7,308,206	3,654,103	5,984,103	0.665	3,979,770	13,016,055
9	7,473,935	9,201,220	4,600,610	5,870,610	0.627	3,683,293	16,699,349
10	7,579,134	9,362,526	4,681,263	5,951,263	0.592	3,522,543	20,221,892
11	7,890,648	11,110,181	5,555,090	5,555,090	0.558	3,101,933	23,323,825
12	8,080,842	11,403,050	5,701,525	5,701,525	0.527	3,003,492	26,327,318
13	8,051,515	11,358,079	5,679,040	5,679,040	0.497	2,822,309	29,149,626
14	7,564,388	10,792,956	5,396,478	5,396,478	0.469	2,530,080	31,679,706
15	5,625,534	7,634,376	3,817,188	3,817,188	0.442	1,688,346	33,368,052
16	5,364,674	7,236,635	3,618,317	3,618,317	0.417	1,509,797	34,877,849
17	5,450,819	7,369,872	3,684,936	3,684,936	0.394	1,450,561	36,328,411
18	5,213,514	7,004,398	3,502,199	3,502,199	0.371	1,300,592	37,629,003
19	4,474,163	5,870,729	2,935,365	2,935,365	0.350	1,028,387	38,657,389
20	3,886,986	4,971,551	2,485,775	2,485,775	0.331	821,581	39,478,971
21	3,320,168	4,284,126	2,142,063	2,142,063	0.312	667,905	40,146,876
22	2,784,778	3,277,689	1,638,845	1,638,845	0.294	482,075	40,628,951
23	2,165,031	2,328,621	1,164,311	1,164,311	0.278	323,102	40,952,053
24	1,798,500	1,667,974	833,987	833,987	0.262	218,335	41,170,389
Total	**135,384,290**	**126,729,283**	**63,364,642**	**79,514,642**		**41,170,389**	

Table A.5 Economic analysis calculation detail of scenario 5.

A	B	C	D	E	F	G	H
Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**CAPEX**		
					Concession (US$)	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
1				1.0000	500,000		
2				1.0200		1,000,000	
3				1.0404			3,000,000
4				1.0200			
5				1.0404			
6	0	0	0	1.0612			
7	223,487	17,878,987	893,949	1.0824			
8	197,719	15,817,535	790,877	1.1041			
9	151,939	12,155,113	607,756	1.1262			
10	82,384	6,590,750	329,537	1.1487			
11	68,721	5,497,640	274,882	1.1717			
12	84,038	6,723,026	336,151	1.1951			
13	121,150	9,691,985	484,599	1.2190			
14	155,922	12,473,773	623,689	1.2434			
15	180,414	14,433,136	721,657	1.2682			
16	174,946	13,995,648	699,782	1.2936			
17	182,126	14,570,048	728,502	1.3195			
18	187,268	14,981,472	749,074	1.3459			
19	190,502	15,240,128	762,006	1.3728			
20	185,074	14,805,880	740,294	1.4002			
21	180,361	14,428,904	721,445	1.4282			
22	152,141	12,171,240	608,562	1.4568			
23	133,884	10,710,720	535,536	1.4859			
24	127,774	10,221,880	511,094	1.5157			
Total	**3,019,339**	**241,547,120**	**12,077,356**		**500,000**	**1,000,000**	**3,000,000**

Table A.5 Economic analysis calculation detail of scenario 5 (continued).

A	I	J	K	L	M	N
Year	CAPEX					
	Drilling and completion cost of production well		Facility cost of production well (US$)	Abandonment cost (US$)	Facility cost of injection well (US$)	Total Depreciation (20%) tangible expense
	INTANG (US$)	TANG (US$)				
1						100,000
2						300,000
3						900,000
4	1,200,000	300,000	5,000,000	0	0	1,960,000
5	0	0	0	0	0	1,960,000
6	0	0	0	0	0	1,860,000
7	0	0	0	0	0	1,660,000
8	0	0	6,000,000	0	350,000	2,330,000
9	0	0	0	0	0	1,270,000
10	0	0	0	0	0	1,270,000
11	0	0	0	0	0	1,270,000
12	0	0	0	0	0	1,270,000
13	0	0	0	0	0	0
14	0	0	0	0	0	0
15	0	0	0	0	0	0
16	0	0	0	0	0	0
17	0	0	0	0	0	0
18	0	0	0	0	0	0
19	0	0	0	0	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	25,000	0	0
Total	**1,200,000**	**300,000**	**11,000,000**	**25,000**	**350,000**	**14,850,000**

Table A.5 Economic analysis calculation detail of scenario 5 (continued).

A	O	P	Q	R	S	T
Year	Water Injection Rate (bbl/year)	Gas Injection Rate (MSCF/year)	OPEX			
			Operation cost of production well (US$)	Maintenance cost of water injection facility (US$)	Operation cost of water injection (US$)	Operation cost of gas rework injection (US$)
1						
2						
3						
4	0	0	0	0	0	0
5	0	0	6,704,620	0	0	0
6	0	0	5,931,576	0	0	0
7	0	0	4,558,167	0	0	0
8	13,653	0	2,471,531	140,000	6,826	0
9	268,982	0	2,061,615	140,000	134,491	0
10	206,867	15,806	2,521,135	140,000	103,434	86,900
11	217,117	16,698	3,634,494	140,000	108,559	86,900
12	228,049	16,958	4,677,665	140,000	114,025	86,900
13	259,947	0	5,412,426	140,000	129,974	0
14	222,113	16,533	5,248,368	140,000	111,056	86,900
15	224,648	17,197	5,463,768	140,000	112,324	86,900
16	228,066	17,249	5,618,052	140,000	114,033	86,900
17	254,602	0	5,715,048	140,000	127,301	0
18	227,331	16,774	5,552,205	140,000	113,666	86,900
19	224,832	17,473	5,410,839	140,000	112,416	86,900
20	228,107	18,010	4,564,215	140,000	114,053	86,900
21	259,602	0	4,016,520	140,000	129,801	0
22	225,683	18,231	3,833,205	140,000	112,842	86,900
23	222,152	19,822	3,531,180	140,000	111,076	86,900
24	228,350	20,366	3,653,541	140,000	114,175	86,900
Total	**3,740,100**	**211,116**	**90,580,170**	**2,380,000**	**1,870,050**	**1,042,800**

Table A.5 Economic analysis calculation detail of scenario 5 (continued).

A	U	V	W	X	Y	Z	AA
Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(6%) Discount factor**	**Discount cash flow (US$)**	**Cumulative discounted cash flow (US$)**
1	500,000	-600,000	0	-500,000	1.000	-500,000	-500,000
2	1,020,000	-1,320,000	0	-1,020,000	0.943	-962,264	-1,462,264
3	3,121,200	-4,021,200	0	-3,121,200	0.890	-2,777,857	-4,240,121
4	6,897,852	-8,857,852	0	-6,897,852	0.840	-5,791,570	-10,031,691
5	6,704,620	8,320,418	0	10,280,418	0.792	8,143,054	-1,888,637
6	5,931,576	7,235,083	378,224	8,716,859	0.747	6,513,744	4,625,107
7	4,558,167	5,329,190	2,664,595	4,324,595	0.705	3,048,669	7,673,776
8	9,912,512	-5,981,299	0	-3,651,299	0.665	-2,428,323	5,245,453
9	2,336,106	1,616,652	808,326	2,078,326	0.627	1,303,967	6,549,420
10	2,851,468	2,265,406	1,132,703	2,402,703	0.592	1,422,156	7,971,577
11	3,969,953	3,967,433	1,983,716	3,253,716	0.558	1,816,858	9,788,435
12	5,018,589	5,561,495	2,780,747	4,050,747	0.527	2,133,883	11,922,318
13	5,682,400	8,029,080	4,014,540	4,014,540	0.497	1,995,103	13,917,421
14	5,586,324	7,709,541	3,854,771	3,854,771	0.469	1,807,267	15,724,688
15	5,802,992	8,038,554	4,019,277	4,019,277	0.442	1,777,730	17,502,418
16	5,958,985	8,273,414	4,136,707	4,136,707	0.417	1,726,103	19,228,521
17	5,982,349	8,495,773	4,247,886	4,247,886	0.394	1,672,165	20,900,686
18	5,892,771	8,172,815	4,086,408	4,086,408	0.371	1,517,546	22,418,233
19	5,750,155	7,957,304	3,978,652	3,978,652	0.350	1,393,896	23,812,129
20	4,905,168	6,657,510	3,328,755	3,328,755	0.331	1,100,197	24,912,325
21	4,286,321	5,888,863	2,944,432	2,944,432	0.312	918,088	25,830,413
22	4,172,947	5,537,839	2,768,920	2,768,920	0.294	814,493	26,644,906
23	3,869,156	5,076,500	2,538,250	2,538,250	0.278	704,377	27,349,283
24	4,034,038	5,221,599	2,610,799	2,610,799	0.262	683,500	28,032,783
Total	**114,745,648**	**98,574,116**	**52,277,707**	**62,446,408**		**28,032,783**	

Table A.6 Economic analysis calculation detail of scenario 6.

A	B	C	D	E	F	G	H
					CAPEX		
Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**Concession (US$)**	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
1				1.0000	500,000		
2				1.0200		1,000,000	
3				1.0404			3,000,000
4	0	0	0	1.0612			
5	83,350	6,668,009	333,400	1.0824			
6	84,211	6,736,918	336,846	1.1041			
7	85,095	6,807,578	340,379	1.1262			
8	85,044	6,803,480	340,174	1.1487			
9	84,097	6,727,795	336,390	1.1717			
10	77,867	6,229,365	311,468	1.1951			
11	63,471	5,077,660	253,883	1.2190			
12	51,127	4,090,146	204,507	1.2434			
13	33,259	2,660,680	133,034	1.2682			
14	32,973	2,637,834	131,892	1.2936			
15	36,715	2,937,200	146,860	1.3195			
16	43,896	3,511,670	175,584	1.3459			
17	50,701	4,056,065	202,803	1.3728			
18	56,617	4,529,340	226,467	1.4002			
19	61,564	4,925,120	246,256	1.4282			
20	65,397	5,231,795	261,590	1.4568			
21	68,607	5,488,585	274,429	1.4859			
22	71,020	5,681,560	284,078	1.5157			
23	73,075	5,845,992	292,300	1.5460			
24	74,633	5,970,600	298,530	1.5769			
Total	**1,282,717**	**102,617,392**	**5,130,870**		**500,000**	**1,000,000**	**3,000,000**

Table A.6 Economic analysis calculation detail of scenario 6 (continued).

A	I	J	K	L	M	N
Year	**CAPEX**					
	Drilling and completion cost of production well		**Facility cost of production well (US$)**	**Abandonment cost (US$)**	**Facility cost of injection well (US$)**	**Total Depreciation (20%) tangible expense**
	INTANG (US$)	**TANG (US$)**				
1						100,000
2						300,000
3						900,000
4	1,200,000	300,000	5,000,000	0	0	1,960,000
5	0	0	0	0	0	1,960,000
6	0	0	0	0	0	1,860,000
7	0	0	0	0	0	1,660,000
8	0	0	0	0	0	1,060,000
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	0	0	6,000,000	0	350,000	1,270,000
13	0	0	0	0	0	1,270,000
14	0	0	0	0	0	1,270,000
15	0	0	0	0	0	1,270,000
16	0	0	0	0	0	1,270,000
17	0	0	0	0	0	0
18	0	0	0	0	0	0
19	0	0	0	0	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	25,000	0	0
Total	**1,200,000**	**300,000**	**11,000,000**	**25,000**	**350,000**	**14,850,000**

Table A.6 Economic analysis calculation detail of scenario 6 (continued).

A	O	P	Q	R	S	T
Year	Water Injection Rate (bbl/year)	Gas Injection Rate (MSCF/year)	OPEX			
			Operation cost of production well (US$)	Maintenance cost of water injection facility (US$)	Operation cost of water injection (US$)	Operation cost of gas rework injection (US$)
1						
2						
3						
4	0	0	0	0	0	0
5	0	0	2,500,503	0	0	0
6	0	0	2,526,344	0	0	0
7	0	0	2,552,842	0	0	0
8	0	0	2,551,305	0	0	0
9	0	0	2,522,923	0	0	0
10	0	0	2,336,012	0	0	0
11	0	0	1,904,123	0	0	0
12	9,193	0	1,533,805	140,000	4,596	0
13	97,607	0	997,755	140,000	48,804	0
14	98,095	6,733	989,188	140,000	49,048	86,900
15	98,022	7,030	1,101,450	140,000	49,011	86,900
16	97,729	7,068	1,316,876	140,000	48,865	86,900
17	106,800	0	1,521,024	140,000	53,400	0
18	98,095	6,816	1,698,503	140,000	49,048	86,900
19	98,022	7,131	1,846,920	140,000	49,011	86,900
20	97,729	7,155	1,961,923	140,000	48,865	86,900
21	106,800	0	2,058,219	140,000	53,400	0
22	98,095	6,884	2,130,585	140,000	49,047	86,900
23	98,022	7,183	2,192,247	140,000	49,011	86,900
24	97,729	7,203	2,238,975	140,000	48,864	86,900
Total	**1,201,937**	**63,201**	**38,481,522**	**1,820,000**	**600,969**	**782,100**

Table A.6 Economic analysis calculation detail of scenario 6 (continued).

A	U	V	W	X	Y	Z	AA
Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(6%) Discount factor**	**Discount cash flow (US$)**	**Cumulative discounted cash flow (US$)**
1	500,000	-600,000	0	-500,000	1.000	-500,000	-500,000
2	1,020,000	-1,320,000	0	-1,020,000	0.943	-962,264	-1,462,264
3	3,121,200	-4,021,200	0	-3,121,200	0.890	-2,777,857	-4,240,121
4	6,897,852	-8,857,852	0	-6,897,852	0.840	-5,791,570	-10,031,691
5	2,500,503	1,874,105	0	3,834,105	0.792	3,036,970	-6,994,720
6	2,526,344	2,013,728	0	3,873,728	0.747	2,894,675	-4,100,045
7	2,552,842	2,254,357	0	3,914,357	0.705	2,759,467	-1,340,578
8	2,551,305	2,852,001	0	3,912,001	0.665	2,601,704	1,261,126
9	2,522,923	3,868,482	0	3,868,482	0.627	2,427,134	3,688,260
10	2,336,012	3,581,885	822,753	2,759,132	0.592	1,633,126	5,321,385
11	1,904,123	2,919,655	1,459,827	1,459,827	0.558	815,160	6,136,545
12	9,573,828	-6,958,189	0	-5,688,189	0.527	-2,996,467	3,140,078
13	1,186,559	71,087	0	1,341,087	0.497	666,479	3,806,557
14	1,265,135	-29,193	0	1,240,807	0.469	581,739	4,388,296
15	1,377,361	142,979	0	1,412,979	0.442	624,962	5,013,258
16	1,592,641	473,446	0	1,743,446	0.417	727,479	5,740,737
17	1,714,424	2,138,837	202,064	1,936,773	0.394	762,404	6,503,141
18	1,974,450	2,328,423	1,164,212	1,164,212	0.371	432,347	6,935,488
19	2,122,831	2,556,033	1,278,017	1,278,017	0.350	447,745	7,383,233
20	2,237,688	2,732,518	1,366,259	1,366,259	0.331	451,566	7,834,799
21	2,251,619	2,962,536	1,481,268	1,481,268	0.312	461,866	8,296,666
22	2,406,532	2,990,950	1,495,475	1,495,475	0.294	439,902	8,736,568
23	2,468,158	3,085,535	1,542,767	1,542,767	0.278	428,126	9,164,693
24	2,554,162	3,117,908	1,558,954	1,558,954	0.262	408,130	9,572,823
Total	**61,158,492**	**20,178,030**	**12,371,596**	**23,956,435**		**9,572,823**	

APPENDIX B

PUBLICATION

Publication

Jaturakhanawanit, S., and Wannakomol, A. (2011). **WATER ALTERNATING GAS INJECTION FOR ENHANCED OIL RECOVERY IN PHITSANULOK BASIN**. In Proceedings of the 4th Suranaree University Graduate Conference, Suranaree University of Technology, Thailand. 8-9 July 2011. (submited)

Water Alternating Gas Injection for enhanced oil recovery in Phitsanulok Basin

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Abstract

Even though petroleum resources are finite, they remain among the most important sources of energy in the world. With the decline of hydrocarbon reservoir, improved recovery of these resources to boost production is becoming increasingly important. There are many methods that can be applied to increase recovery from hydrocarbon reservoirs such as Waterflooding, Gas injection, Polymer flooding and Water Alternating Gas injection (WAG). Water Alternating Gas injection (WAG) is a powerful method that can be applied to increase petroleum recovery efficiency of petroleum reservoirs. It is a method that combines advantages of waterflooding and gas injection methods. Repetition of the WAG injection process can further improve sweep efficiency in micro scale. In this study WAG was applied to a setup oil field located within the Phitsanulok Basin to estimate its optimized operation condition by using reservoir simulation approach. The sandbox model with both a production and an injection well is set up at 5MMSTB. The miscibility flood is also set up for WAG reservoir simulation setting. Results from simulation testing indicate that the WAG has recovery 65.13% of the original oil in place.

Keywords: Water alternating gas injection, computer reservoir simulation, Phitsanulok Basin, Optimized technical parameters

1. Introduction

The Water Alternating Gas injection (WAG) is one of the most famous methods for enhance oil recovery. Injecting gas can occupy parts of the pore space where formerly were occupied by oil, and can reduce the viscosity of these remaining oil to make them more mobile. Water is injected subsequently to displace these remaining oil and gas. Repetition of the WAG injection process can further improve the recovery of the remaining oil in the reservoir [12]. Phitsanulok Basin is an appropriate choice to apply the WAG for two reasons. First, the Waterflooding has been applied successfully in this oil field since 1980. Second, there are enough free gas and ground water for injection in this oil field. The objectives of this study are (1) to determine the appropriate operation program of the study field and, (2) to estimate the recovery efficiency by the WAG methods. In this study reservoir simulation Eclipse_300 software is use for these proposes. Reservoir simulation is a powerful and inexpensive tool which can predict what is going on in the reservoir and the amount of production from alternative operations.

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* Corresponding author

2. Materials and Methods

2.1. Materials

2.1.1. Reservoir Simulation Input Data

The input data for each model were collected and obtained from the review of concessionaire results, the laboratory measurement, and the assumptions. Required data for simulation comprise reservoir, rock and fluid properties as presented in Table 1 and Table2, respectively. The other necessary data for WAG are relative permeability which has direct effect on the WAG process. It has shown in Figure 6, Figure 7, and Figure 8 which consists of the set of three phase permeability in function of gas, oil, and water. A set of composition of injected fluid and reservoir fluid is also needed, as shown in Table 3. Molefraction of gas injection are from separator. Properties of the fluid that used in equation of state are shown in Tables 4 and 5. Binary interaction coefficients (BIC) are generated from PVTi which is subprogram of Eclipse by input the fluid properties in reservoir. The other calculated fluid properties were obtained from built in software of Eclipse Office software.

2.1.2. Sensitivity Analysis

The sensitivity analyse is will be applied for the WAG method. The study was to compare recovery efficiency by varied parameters, to observe and to analyse as follows:

a) Rate of production and injection wells

The case will vary the rate of production and injection by injection at the first year production. The results will be compared with the recovery factor under the limitation. The reservoir pressure is not constant during the WAG process and formation volume factor of oil and gas is a strong function of reservoir pressure. The control of the injection rate by surface is impossible. For the injection well, water and gas are injected at the same fluid rate alternately and controlled by the downhole rate.

b) Slug size

The ratio of water injection alternated to gas is 1. Cycles of alternated injection are 1 to 15 months.

2.2. Methods of reservoir simulation model development

2.2.1. Reservoir simulation

The reservoir simulation, or modeling, is one of the most powerful techniques currently available to the reservoir engineer. Modeling requires a computer, because it contains large amounts of data compared to most other reservoir calculations. Basically, the model requires that the field under study be described by a grid system, usually referred to as cells or gridblocks. Each cell must be assigned reservoir properties to describe the reservoir.

2.2.2. Compositional model

The components in reservoir are calculated in individual (Methane, ethane, propane … N). In reservoir containing light oil, the hydrocarbon composition as well as the pressure affects fluid properties. The equilibrium flash calculation using K values and equation of state (EOS) must be used to determine hydrocarbon phase compositions. In a compositional model, we in principle make mass balance for each hydrocarbon component, such as methane, ethane, propane etc. In practice, we limit the number of components included and group components into pseudo- components.

The sizes of reservoir simulation model of 5 MMSTB oil in place was developed by utilizing "Eclipse Office" software. This model has been constructed in sandbox geometry. Grid blocks are 25x25x5 in the x-, y-, and z- directions, and active all cells. The dimensions are 87.5 ft in x-, y-directions, and 8.8 ft in z-direction with field unit. The production and injection wells are located at x-y coordinate 5,12 and 20,12. The depth of top reservoir is 4956 ft below the surface datum. The geometry of the model is shown in Figure 1. For the production well, the minimum bottom hole pressure was set to 2165 psia, in order to prevent the reservoir pressure dropping to below the hydraulic pressure. The 50 STB/D minimum oil production rate and the 90% water cut are two economic limits to be specified for the production well. When one or both is reached, the well will be shut in. Both injection and production wells are controlled by the same downhole rate.

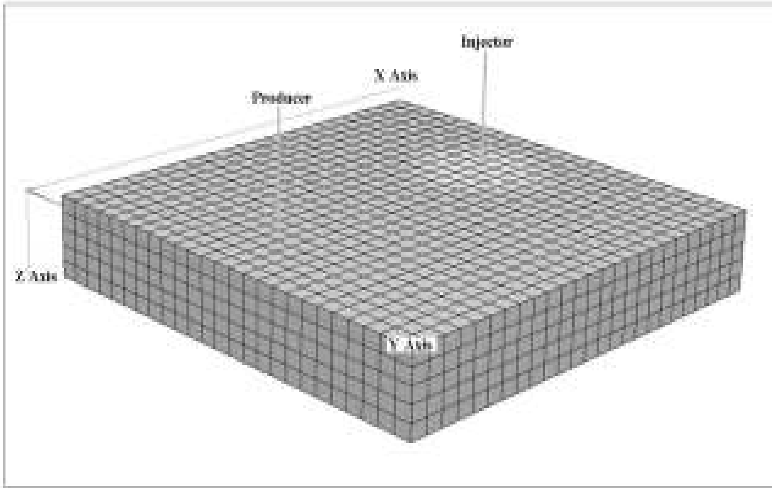

Figure 1 Geometry of reservoir model and well locations

3. Results and Discussion

All results of simulations are presented in Table 6. The production and injection pattern for each case resulted from trial and error to obtain the optimum recovery. The optimized recovery factor of the WAG is 65.17% at 700 RB/D with 1 month gas injection and 12 months water injection.

The high injection rate yields more oil recovery, because of more sweeping volume of the displacement, but is not always the appropriate condition if the water cut too is high or the bottom hole pressure is more than the fracture pressure. Also, the controlling gas is necessary in order to prevent gas fingering effect that reduces the recovery. Moreover, the excessive water rate causes early water breakthrough. The set of simulation results are illustrated below.

The production and injection rate was maintained at the rate of 700 RB/D. There are switching injection between 12 months of water and 1 month of gas. After running the program, the result is 10 years plateau production and the final rate is 270 RB/D (Figure 2). The cumulative oil production is 4.44 million reservoir barrels at the end of the 20th year production with the recovery of 65.13% of original oil in place (Figure 3). In comparison with at 13 months water and 1 month gas injection, the others the highest recovery is but the bottom hole pressure of the injection well is higher than the fracture pressure limit.

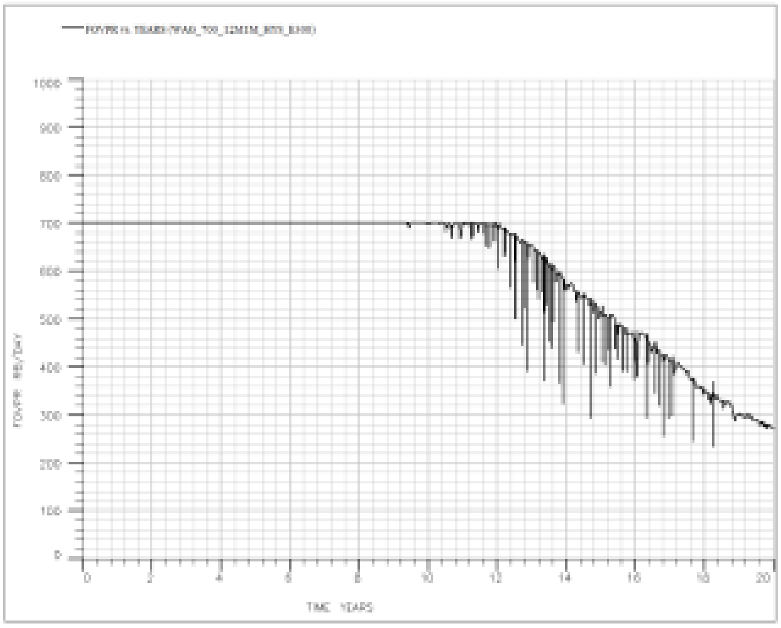

Figure 2 Oil production rate vs. Time plot of 700 RB/D

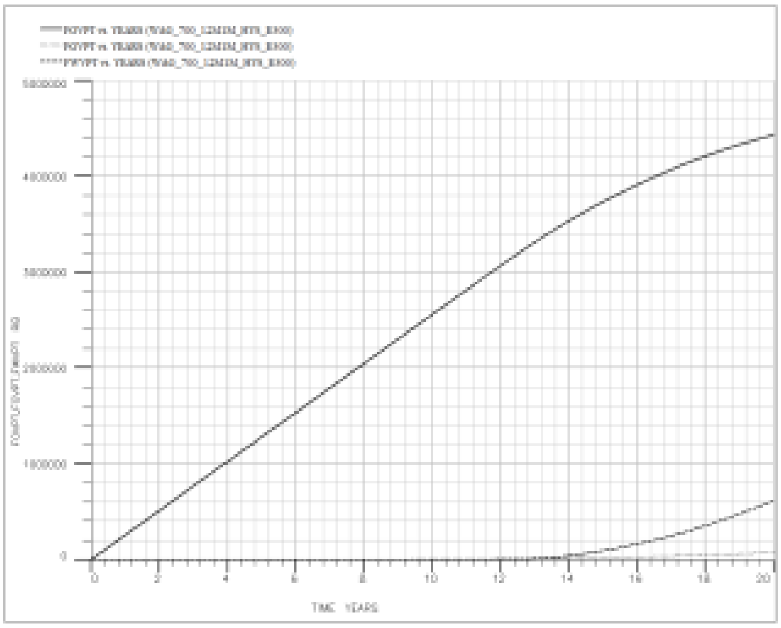

Figure 3 Cumulative fluid production vs. Time plot of 700 RB/D

Although the maintain of oil production rate of 800 RB/D has more recovery than those of 700RB/D at the same 12 months water and 1 month gas injection, but the bottom hole pressure of injection well reaches the fracture pressure (Table 6).

4. Conclusions

Reservoir simulation is a powerful and flexible tool to predict reservoir performance in many operational designs. The most suitable condition for individual projects can be achieved by performing reservoir simulation in WAG method. The WAG achieves the recovery of 65% of the original oil in place. The earlier water injection is used (after starting oil production), the more oil recovery will be. This is because of the reservoir pressure is still high allowing more oil displacement efficiency. The efficiency of the stimulation will decrease, if early water breakthrough occurs. The controlling injection is required when the bottom hole pressure is more than the fracture pressure or the gas fingering effect. Using of trial and error to get the best fit for individual projects is needed.

Acknowledgement

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Appendices

Table 1 Reservoir properties.

Properties	
Initial reservoir pressure	3000 psia
Bubble point pressure	1800 psia
Depth Oil-Water contact	5000 ft
Thickness	44 ft
Formation temperature	203 °F
Pressure gradient	0.7 psi/ft

Table 2 Rock and fluid properties.

Properties	
Rock type	Consolidated Sandstone
Porosity	0.2225 - 0.2325
Permeability	105.439 - 195.434 md
Vertical relative permeability = 0.1 ratio of Horizontal relative permeability	
Properties	
Oil gravity	39.4 API
Gas gravity	0.8 (SG Air = 1)
Densities of water	62.43 lb/ft3
Water compressibility @ 3500 psi	3.08 x 106/psi
Viscosity of water	0.296 cp
Salinity	0 (fraction)
Surface condition:	
Standard temperature	60 °F
Standard pressure	14.7 psia

Table 3 Composition of fluid.

Composition	Molefraction of reservoir fluid
C1	0.5
C2	0.04
C3	0.02
C4	0.01
C5	0.01
C6	0.03
C7+	0.39

Table 4 Fluid properties of composition in reservoir.

Composition	Pc(Psia)	Tc (R)	MW	Acentric factor	Critical Z
C1	666.40	343.33	16.04	0.0104	0.2902
C2	706.50	549.92	30.07	0.0979	0.2830
C3	616.00	666.06	44.10	0.1522	0.2785
C4	550.60	765.62	58.12	0.1852	0.2756
C5	488.60	845.80	72.15	0.1995	0.2744
C6	436.90	913.60	86.18	0.2280	0.2719
C7+	285.00	1287.00	215.00	0.5200	0.2451

Table 5 Binary interaction coefficients.

Composition	C1	C2	C3	C4	C5	C6	C7+
C1	0	0	0	0	0	0.029	0.049
C2	0	0	0	0	0	0.010	0.010
C3	0	0	0	0	0	0.010	0.010
C4	0	0	0	0	0	0	0
C5	0	0	0	0	0	0	0
C6	0.029	0.010	0.010	0	0	0	0
C7+	0.049	0.010	0.010	0	0	0	0

Table 6 Recovery factor

Production rate,RB/D	Injection rate,RB/D	Water period,months	Gas period,months	RF,%	BHP (max),psi
700	700	11	1	64.95	3483
700	700	12	1	65.13	3498
700	700	13	1	65.26	3520
800	800	10	1	68.57	3570
800	800	12	1	68.63	3576

Figure 6 Relative permeability to gas.

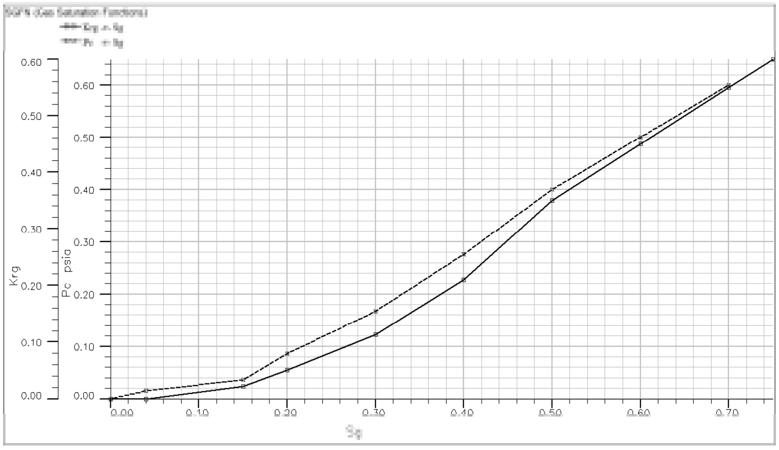


Figure7 Relative permeability to oil.

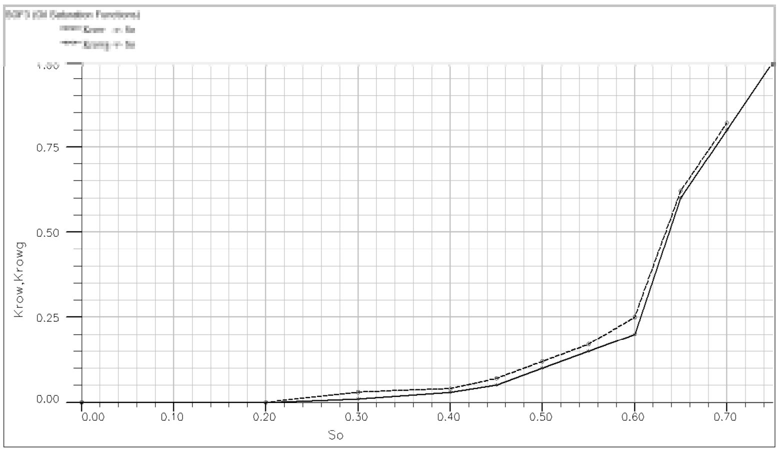
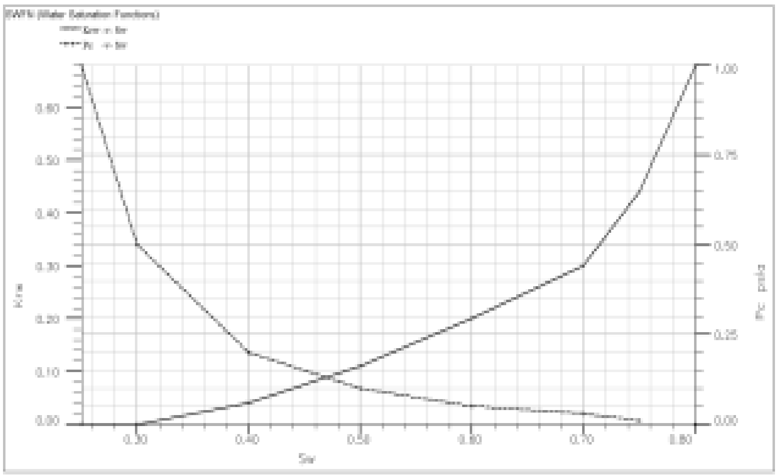


Figure8 Relative permeability to water.



BIOGRAPHY

Ms. Suphattra Jaturakhanawanit was born on the 1st of March 1985 in Bangkok but she has spent most of her life in Nakhon Ratchasima with her family since she was young. She earned her high school diploma in science-math from St. Mary School in 2003. She received her Bachelor's Degree in Engineering (Geotechnology) from Suranaree University of Technology (SUT) in 2007. After graduation, she continued with her Master's Degree of Engineering at School of Geotechnology, Institute of Engineering at SUT with the major in Petroleum Engineering. Her strong background is in the areas of reservoir simulation.