# ENHANCED OIL RECOVERY BY POLYMER FLOODING FOR HEAVY OIL IN THAILAND

**Krissada Yoosumdangkit**

**A Thesis Submitted in Partial Fulfillment of the Requirements for the**

**Degree of Master of Engineering in Geotechnology**

**Suranaree University of Technology**

**Academic Year 2016**

# การเพิ่มอัตราการผลิตน้ำมันด้วยวิธีอัดพอลิเมอร์ สำหรับน้ำมันหนืดในประเทศไทย

นายกฤษฎา อยู่สำแดงกิจ



วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต

สาขาวิชาเทคโนโลยีธรณี

มหาวิทยาลัยเทคโนโลยีสุรนารี

ปีการศึกษา 2559

# ENHANCED OIL RECOVERY BY POLYMER FLOODING FOR HEAVY OIL IN THAILAND

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

Thesis Examining Committee

(Prof. Dr. Kittitep Fuenkajorn)

Chairperson

(Assoc. Prof. Kriangkrai Trisarn)

Member (Thesis Advisor)

(Dr. Bantita Terakulsatit)

Member



(Prof. Dr. Sukit Limpijumnong)

Vice Rector for Academic Affairs and Innovation

(Assoc. Prof. Flt. Lt. Dr. Kontorn Chamniprasart)

Dean of Institute of Engineering

กฤษฎา อยู่สำแดงกิจ : การเพิ่มอัตราการผลิตน้ำมันด้วยวิธีอัดพอลิเมอร์สำหรับน้ำมันหนืดในประเทศไทย (ENHANCED OIL RECOVERY BY POLYMER FLOODING FOR HEAVY OIL IN THAILAND) อาจารย์ที่ปรึกษา : รองศาสตราจารย์เกรียงไกร ไตรสาร, 168 หน้า

การศึกษานี้ใช้การผลิตน้ำมันดิบด้วยวิธีการขับน้ำและพอลิเมอร์ เพื่อเพิ่มศักยภาพการผลิตในแหล่งกักเก็บบริเวณแอ่งพิษณุโลกที่มีความหนืดสูงซึ่งทำให้การผลิตในขั้นปฐมภูมิไม่ประสบผลสำเร็จ จุดประสงค์ของการศึกษานี้ประกอบไปด้วย (1) ศึกษาเกี่ยวกับการขับน้ำมันด้วยน้ำและการขับด้วยพอลิเมอร์ (2) เปรียบเทียบการผลิตน้ำมันดิบด้วยวิธีการขับน้ำมันดิบด้วยน้ำและการขับด้วยพอลิเมอร์โดยใช้แบบจำลองทางคอมพิวเตอร์เปรียบเทียบประสิทธิภาพการผลิตในแอ่งพิษณุโลก (3) ทำการวิเคราะห์ทางเศรษฐศาสตร์เพื่อใช้ในการตัดสินใจหาโครงการลงทุนที่มีโอกาสและความเป็นไปได้มากที่สุดที่จะนำวิธีการดังกล่าวนี้ไปใช้งานจริง ในการศึกษานี้ได้ทำการสร้างแบบจำลองให้ใกล้เคียงความจริงโดยการรวบรวมมาจากบทความที่เผยแพร่ต่าง ๆ ซึ่งประกอบด้วยข้อมูลทางด้านธรณีฟิสิกส์ ขนาดแหล่งกักเก็บ คุณสมบัติของของไหลในแหล่งกักเก็บและความดันของแหล่งกักเก็บนั้นรวมทั้งใช้ค่าที่ได้จากการคำนวณเชิงทฤษฎี โดยแหล่งกักเก็บมีขนาด 18.29 ล้านบาร์เรล โดยมีการใช้รูปแบบการวางหลุมขับและหลุมผลิตสองรูปแบบคือ Direct Line Drive และ Staggered Line Drive โดยทำการอัดด้วยน้ำด้วยอัตราคงที่ ในปีที่ 1, 3 และ 5 ทำการอัดด้วยพอลิเมอร์ด้วยในปีที่ 1, 2, 3 และ 4 โดยผลจากการทดสอบแบบจำลองพบว่าการผลิตในขั้นปฐมภูมิ (ไม่มีการอัดน้ำหรือพอลิเมอร์) สามารถผลิตน้ำมันดิบได้ 6.43-11.11% ของปริมาณสำรอง กรณีศึกษาที่ทำการขับน้ำมันด้วยน้ำในปีที่ 1, 3 และ 5 ทำให้ประสิทธิภาพการขับน้ำมันเพิ่มเป็น 15.61-16.29%, 14.74-15.42% และ 13.64-14.37% ของปริมาณสำรองตามลำดับ กรณีศึกษาที่ทำการขับน้ำมันด้วยพอลิเมอร์ในปีที่ 1, 3 และ 5 ทำให้ประสิทธิภาพการขับน้ำมันเพิ่มเป็น 17.47-18.04%, 16.84-17.43%, 16, 16-16.77% และ 15.43-16.07% ของปริมาณสำรองตามลำดับ การขับน้ำมันด้วยพอลิเมอร์ในปีที่ 1 จะทำให้ได้ค่าประสิทธิภาพทางการผลิตและผลวิเคราะห์ทางด้านเศรษฐศาสตร์สูงที่สุด การลงทุนจะมีความคุ้มค่าการลงทุนเมื่อราคาน้ำมันดิบอยู่ที่ 51.61 ดอลลาร์สหรัฐต่อบาร์เรล

สาขาวิชาเทคโนโลยีธรณี

ปีการศึกษา 2559

ลายมือชื่อนักศึกษา กฤษฎา อยู่สำแดงกิจ

ลายมือชื่ออาจารย์ที่ปรึกษา เกรียงไกร ไตรสาร

KRISSADA YOOSUMDANGKIT : ENHANCED OIL RECOVERY BY POLYMER FLOODING FOR HEAVY OIL IN THAILAND. THESIS ADVISOR : ASSOC. PROF. KRIANGKRAI TRISARN, 168 PP.

WATERFLOODING/POLYMER FLOODING/RESERVOIR SIMULATION/HEAVY OIL

In this study, water and polymer flooding techniques are employed to improve oil recovery rate in Phitsanulok Basin where the primary production cannot be performed successfully due to the viscous oil. The objective includes (1) studying theory of water and polymer flooding techniques, (2) comparing water and polymer flooding cases by using reservoir simulations of oil recovery in the Phitsanulok Basin, and (3) conducting an economic analysis to investigate the optimization of oil recovery in Phitsanulok Basin and feasibility to apply the approach in real situation. The reservoirs was modeled from data collecting data including geophysics, reservoir measurements, fluid properties, porosity, permeability and pressure of the reservoirs from published documents and theoretical calculations. The reservoir has oil in place of 18.29 million barrels and designed in the Direct Line Drive and Staggered Line Drive patterns. The water injection are conducted at the constant injection rate in the first, third and fifth years, and polymer injection are conducted in the first, second, third and fourth years. After running the simulations, it is found that the primary production (no water or polymer injection) produces crude oil with the amount of 6.43-11.11% of the total oil in place. Case studies in the first, third and fifth years which employ water flooding techniques are found improving oil recovery up to 15.61-16.29%, 14.74-15.42%, and 13.64-14.37% respectively. Case studies in the first, third and fifth years which employ

16.84-17.43%, 16.16-16.77% and 15.43-16.07% respectively. Comparing case studies in the primary production to water flooding and polymer flooding, it is found that polymer flooding is the most efficient technique in terms of production and optimization. In addition, the polymer flooding in the first year yields the most favorable oil recovery efficiency and economic values. The economic worthiness for the investment is found at the crude oil price of USD 51.61 per barrel and above.



School of Geotechnology | Student's Signature Krissada Yoosmindanghit

Academic Year 2016 | Advisor's Signature Kriangkrai Trisarn

# ACKNOWLEDGEMENT

At the end of my thesis, I would like to thank all these people who made this thesis possible.

First and foremost, I would like to express my sincere gratitude to my advisor Associate Professor Kriangkrai Trisarn for his endless support and advice that steered my study to the right direction. The special appreciation is also extending to Dr. Bantita Terakulsatit for helpful suggestion.

I would like to thanks Schlumberger Oversea SA for supporting the data and the ECLIPSE Office software, especially Nattaphon Temkiatvises for his guidance on the program application and solution when technical problems occurred.

Besides, I would like to thank Daraporn Nisyant, Theeradech Thongsumrit, Atiwat Ketsukmanote, Phanuphong Gaewmood and Bunphot Tengking for their kind supports that came in various forms.

Last but not least, I am thankful to my family for their encouragement throughout those years of my study.

Krissada Yoosumdangkit

# TABLE OF CONTENTS

**Page**

# TABLE OF CONTENTS (Continued)

**Page**

# TABLE OF CONTENTS (Continued)

**Page**

# TABLE OF CONTENTS (Continued)

**Page**

# TABLE OF CONTENTS (Continued)

**Page**

# LIST OF TABLES

**Table** **Page**

# LIST OF TABLES (Continued)

**Table** **Page**

# LIST OF TABLES (Continued)

**Table** **Page**

# LIST OF TABLES (Continued)

**Table** **Page**

# LIST OF FIGURES

**Figures** **Page**

# LIST OF FIGURES (Continued)

**Figures** **Page**

# LIST OF FIGURES (Continued)

**Figures** **Page**

# LIST OF FIGURES (Continued)

**Figures** **Page**

# LIST OF FIGURES (Continued)

**Figures** **Page**

# LIST OF FIGURES (Continued)

**Figures** **Page**

# SYMBOLS AND ABBREVIATIONS

| | | |
|---|---|---|
| bbl | = | Barrel |
| bbl/d | = | Barrel per day |
| $/bbl | = | United States dollar per barrel |
| CAPEX | = | Capital expense |
| Disc. | = | Discount |
| EOR | = | Enhanced oil recovery |
| FCIT | = | Field polymer injection total |
| FGIP | = | Field gas in place |
| FGPR | = | Field gas production rate |
| FGPT | = | Field gas production total |
| FOE | = | Field oil efficiency |
| FOIP | = | Field oil in place |
| FOPR | = | Field oil production rate |
| FOPT | = | Field oil production total |
| FPR | = | Field pressure |
| FVF | = | Formation volume factor |
| FWIP | = | Field water in place |
| FWPR | = | Field water production rate |
| FWPT | = | Field water production total |
| GOGD | = | Gas/oil gravity drainage |

# SYMBOLS AND ABBREVIATIONS (Continued)

| | | |
|---|---|---|
| HPAM | = | Hydrolyses polyacrylamides |
| IRR | = | Internal Rate of Return |
| Inc. | = | Income |
| Inj. | = | Injection |
| MSCF/STB | = | Thousand cubic feet per stock tank barrel |
| MMBBL | = | Million barrels |
| MMSTB | = | Million stock tank barrels |
| MMUS$ | = | Million US dollar |
| MMUS$/well | = | Million US dollar per well |
| MSCF | = | Thousand cubic feet |
| NPV | = | Net present value |
| OPEX | = | Operation expense |
| OOIP | = | Original oil in place |
| Pbub | = | Bubble point pressure |
| PIR | = | Profit investment ratio |
| Ply. | = | Polymer |
| ppm | = | Parts per million |
| Prod. | = | Production |
| RB | = | Reservoir barrel |
| RF | = | Recovery factor |
| SCF | = | Standard cubic feet |
| SCFD | = | Standard cubic feet per day |

# SYMBOLS AND ABBREVIATIONS (Continued)

| | | |
|---|---|---|
| STB | = | Stock tank barrel |
| STOIIP | = | Stock tank of oil initial in place |
| Visc. | = | Viscosity |
| TSCF | = | Trillions of standard cubic feet |
| WOC | = | Oil/water contact |

# CHAPTER I

# INTRODUCTION

## 1.1 Rationale

Heavy oil refers to crude with high density (from 10 to 20 API) and high viscosity (more than 100 cP). Heavy oil widely exists in many basins around the world, especially in South America, North America and Middle East.

Generally, oil recovery operations are divided into three stages: primary, secondary and tertiary. In the primary stage, the operation uses natural energy in the reservoir as the main source of energy. Some artificial lifts may be applied to the primary stage. The secondary stage is implemented after the primary production declines. The secondary recovery processes include water flooding, pressure maintenance, and gas injection to displace oil toward producing wells. The tertiary recovery is the result from water flooding (or whatever secondary process was used). This process uses miscible gases, chemicals, polymer and/or thermal energy to displace additional oil (Green and Willhite, 1998).

Polymer flood is the most widely used chemical EOR method. By adding polymers to water, the water–oil mobility is lowered. Such a change can lead to better sweep efficiency. It is generally believed that polymer flooding will not reduce the residual oil saturation, but it will help to reach residual oil saturation in shorter time (Du and Guan, 2004).

This research studies Pru Kathiem oil field that is a part of the Phitsanulok basin. This oil field is an unconsolidated sand reservoir located in the eastern part of Sirikit field. It contains approximately 30 MMSTB of medium heavy oil, 17 API of gravity crude, and viscosity of 54 cp. It has been on production since 1987. However, due to the early water breakthrough and sand production, the cumulative production up to now is only 1.0 MMSTB with the current recovery factor around 3.3%. The reservoir has Initial reservoir pressure of 1430 psia. (Sirisawadwattana, 2004)

## 1.2 Objectives of the Study

1.2.1 Study the efficiency of polymer flooding

1.2.2 Study the efficiency of water flooding

1.2.3 Study economic valuation in the same reservoir. Efficiency of crude oil recovery and economics will be compared to find the best method for the reservoir.

## 1.3 Scopes and Limitations of the Study

1.3.1 Collect and study data of heavy oil in Thailand

1.3.2 Explore potential oil for water flooding and polymer flooding by using simulation program in the Eclipse Office when reservoir data, year to injected and rate of injections are changed.

1.3.3 Analyze data and economic evaluation between polymer flooding and water flooding. Determine the best Internal Rate of Return (IRR) and Net Present Value (NPV).

## 1.4 Research Methodology

### 1.4.1 Literature Review

The review includes overview of the Pru Krathiem, geological information and stratigraphy, theory of water and polymer flooding, and case studies of water and polymer flooding. Literature review has been carried out to study the state-of-art of water and polymer flooding technique.

### 1.4.2 Data Collection and Preparation

The sources of reservoir modeling data were obtained from the published document, additional geological data such as Thai Shell Exploration and Production Co., Ltd, technical report and conference papers.

### 1.4.3 Reservoir Simulation

The reservoir simulators are complex computer program that simulate multiphase displacement processed in two or three dimensions. Reservoir modeling is constructed as hypothetical model by ECLIPSE Office E100. Black Oil Simulation software is required for this study, and then used to predict its dynamic behavior. It solves the fluid-flow equation by using numerical techniques to estimate saturation distribution, pressure distribution, and flow of each phase at discrete points in a reservoir. The reservoir rock properties (porosity, saturation and permeability), the fluid properties (viscosity and the PVT properties) and other necessary data were collected and obtained from literature review, concessionaire result and theoretical assumptions, and based on Pru Kathiem oil field in Phitsanulok basin.

### 1.4.4 Economic Evaluation

Economic evaluation is calculated from results of reservoir simulator to find the optimized production rates of oil, gas and water, as well as cumulative oil production recovery, such as capital costs, operating costs, anticipated revenues, contract terms, fiscal (tax) structure, forecast oil prices, the timing of the project, and the expectation of the company in the investment. Different method of water and polymer flooding scenarios were analyzed to determine the potentially most economically viable project, time to start water or polymer injection for each reservoir. All scenarios were simulated and analyzed to determine the suitable time for each projects.

## 1.5 Expected Results

The research involves improving of the oil recovery and minimizing oil left in the reservoir by using water and polymer flooding techniques. Simulation results are useful as supporting information to study improved oil recovery in Thailand. The research will informatively support for the oil companies to increase oil reserves for the country. Results from the economic analysis can be applied in investment decision-making process, used to select the best method, and led to maximize the value of the existing assets by water and polymer flooding project.

## 1.6 Thesis Contents

**Chapter 1** states the rationale, research objectives, scope and limitations of the study, research methodology and expected result. **Chapter 2** summarizes results of the literature review of Phitsanulok basin overview, water and polymer flooding and reservoir simulation method. **Chapter 3** describes the reservoir simulation data preparations, model characteristics, classification and case study description. **Chapter 4** illustrates result of water and polymer flooding simulation model. **Chapter 5** analyzes result of simulation model in term of economic considerations. Conclusion and discussion for future research needs are given in **Chapter 6**: **Appendix A** illustrates simulation data, **Appendix B** illustrates polymer data.

# CHAPTER II

# LITERATURE REVIEW

## 2.1 Tectonic Setting and Structural Evolution of Phitsanulok Basin

### 2.1.1 Regional Tectonic

In response to India's collision with Asia during the Tertiary Himalayan Orogeny, intracratonic extensional and transitional basins develop throughout Southeast Asia. The onshore Tertiary basins of Thailand are aligned in a board north-south trending belt that corresponds to a Late Paleozoic suture zone between the Shan Thai craton to the west and the Indochaina craton to the east. This suture was reactivated by Tertiary Himalayan tectonism, causing extensional and transitional basin to develop within a regionally extensive strike-slip system. The common tectonic origin for these Tertiary basins has led to many similarities in age, basin fill, structural style and hydrocarbon habitats (Burri, 1989).

### 2.1.2 Main Structural Elements

Within this north-south trending zone, the Phitsanulok Basin is the largest Tertiary basin of onshore Thailand. It developed as an asymmetric half- graben, due to east west extension along the Western Boundary Fault System, with associated sinistral strike-slip movement on Uttradit and Ping Fault Systems, to the north and southwest respectively. To the east lies the dextral Phetchabun Fault System (Figure 2.2).

The half-graben geometry of the Phitsanulok Basin is illustrated by Figure 2.3, which shows the western Boundary Fault flanking the Sukhothai Depression, the main basin depocentre. To the east is the intensely wrench-faulted monocline of the Eastern Flank. At basement level, more than 10 km of extension has occurred on the Western Boundary Fault, with up to 8 km of throw from the axis of the Sukhothai Depression to basement outcrops to the west. To keep peace with this rapid tertiary subsidence, sedimentation rates reach up to 1 meter per 1,000 years.

### 2.1.3 Structural Development

The structural development of the Phitsanulok Basin can be subdivided into four main tectonic phases (Figure 2.5). During phase 1, from Late Oligocene to early Middle Miocene, rapid extension took place along the Western Boundary Fault, and in some places was accommodated by the development of smaller antithetic normal faults on the eastern flank of the basin. Unrestricted strike-slip movement occurred along the Ping, Uttaradit and Phetchabun Fault System during this period (Figure 2.5A).

Structural Phase 2 and 3 took place in the early Middle Miocene and late Middle Miocene respectively. During phase 2, extension continued in the northern, central and southeast parts of the basin. Only in the southwestern Phitsanulok Basin did inversion commence, due to the blockage of sinistral movements on the Ping Fault (Figure 2.5B). During phase 3, extension continued in the north, and resulted in continued rapid subsidence of the Sukhothai Depression. Meanwhile, inversion became more widespread in the south, as sinistral movement on the Uttaradit fault zone become blocked (Figure 2.5C)

Finally, in Late Miocene to recent times (structural phase 4) dextral movement on the Phetchabun fault system became blocked, extensional tectonics ceased, and slow, uniform subsidence took place across the basin. The transpressional tectonic setting of this phase caused structural inversion, and a system of young dextral faults developed across the Eastern Flank of the basin, parallel to the Petchabun Fault System (Figure 2.5D). As a result of this late dextral transpression, complex riedel fault patterns developed at Tertairy level, particularly on the Eastern Flank of the basin. Localized basaltic volcanism accompanied this transpressional phase.

Fault patterns in the Phitsanulok basin are the product of the successive tectonic phase. The resulting trap geometries are often complex, and fault reactivation has had a direct impact on hydrocarbon retention in fault bounded traps. Ninety-eight percent of the hydrocarbon discovered to date in the Phitsanulok Basin is confirmed to the Sirikit and Pru Kratiam structural highs, of which certainly the former pre-dates the first oil generation in the basin. The remaining 2% of the basin's hydrocarbon are found scattered in a small accumulations on the Eastern Flank of the basin, where traps were formed only during late tectonic activity, and retention in any pre-existing traps suffered from fault reactivation.

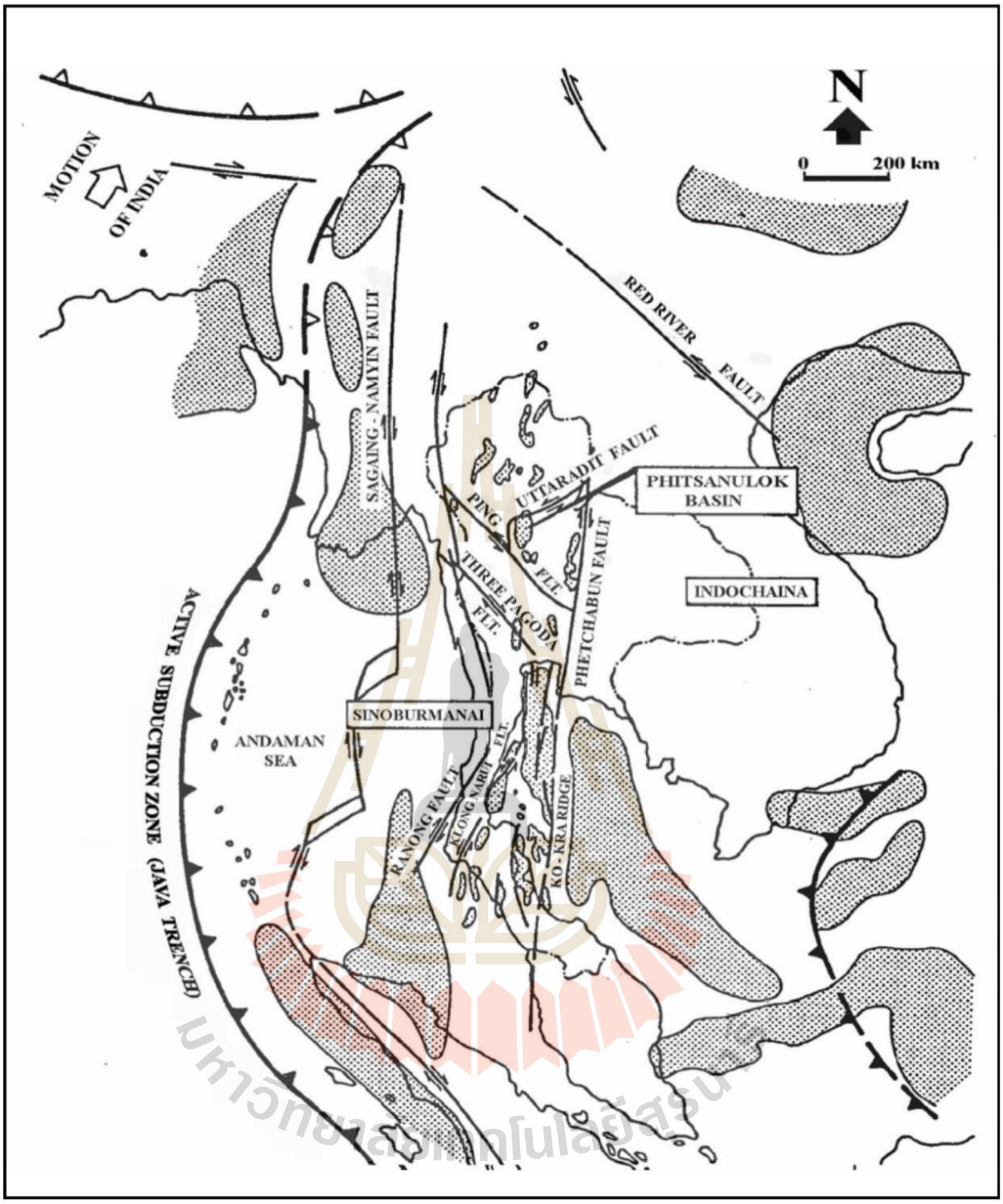


Figure 2.1 Regional tectonic setting and Tertiary Basins of Thailand, (After Bal, 1992)

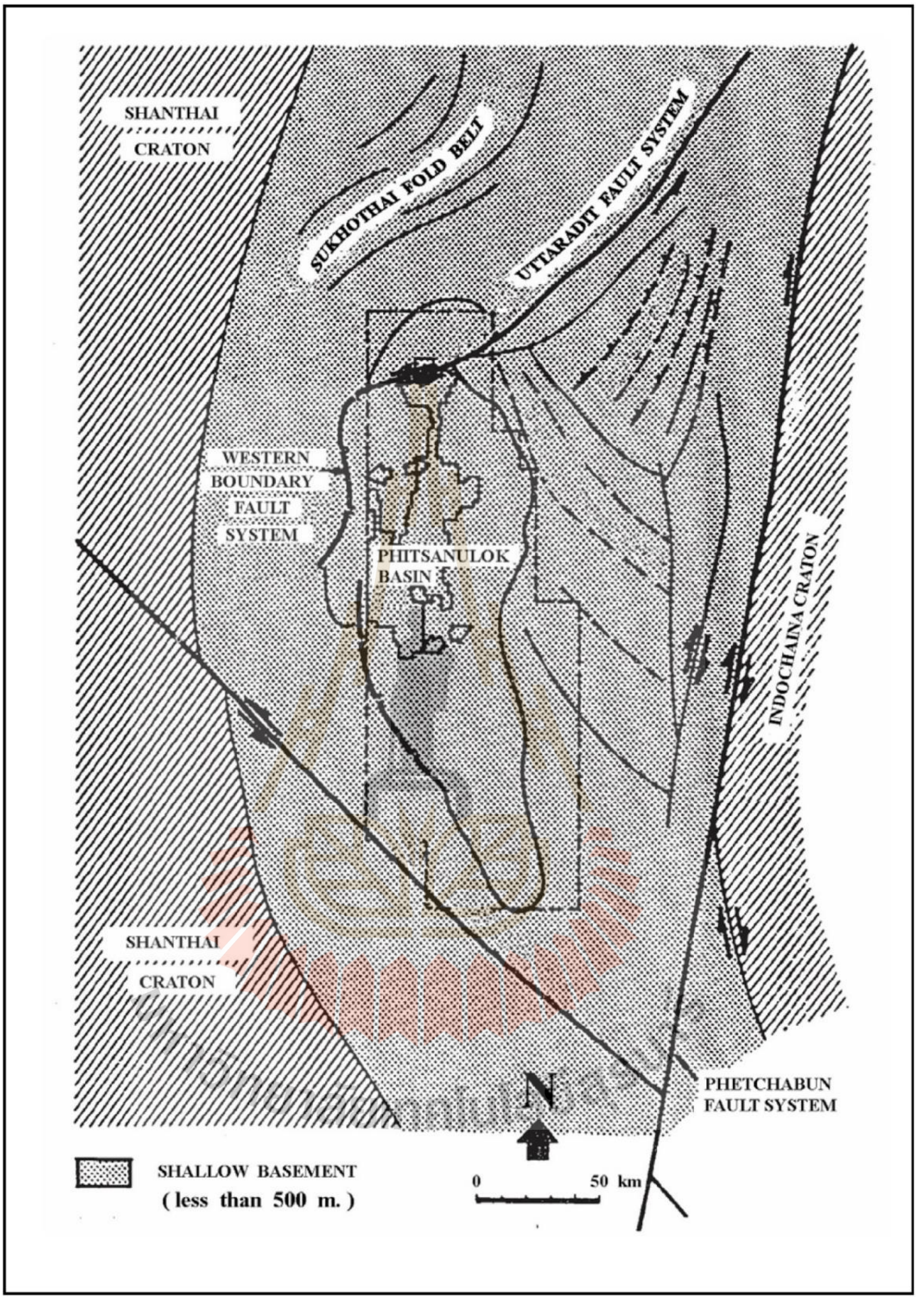


Figure 2.2 Phitsanulok Basin tectonic setting, (After Ball, 1992).

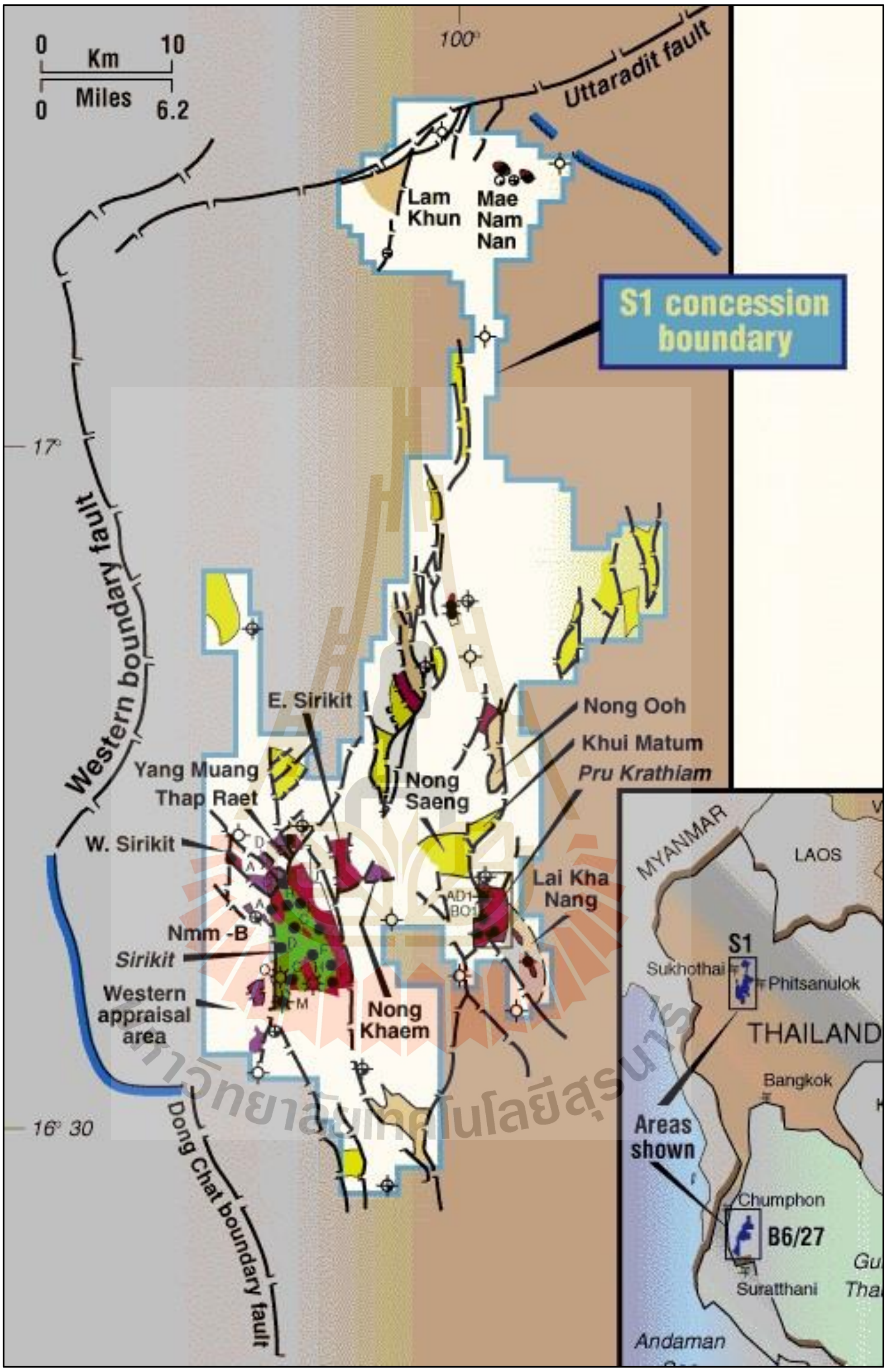


Figure 2.3 Location map of Pru Krathiam,

(Thai Shell Exploration and Production Co., Ltd.)

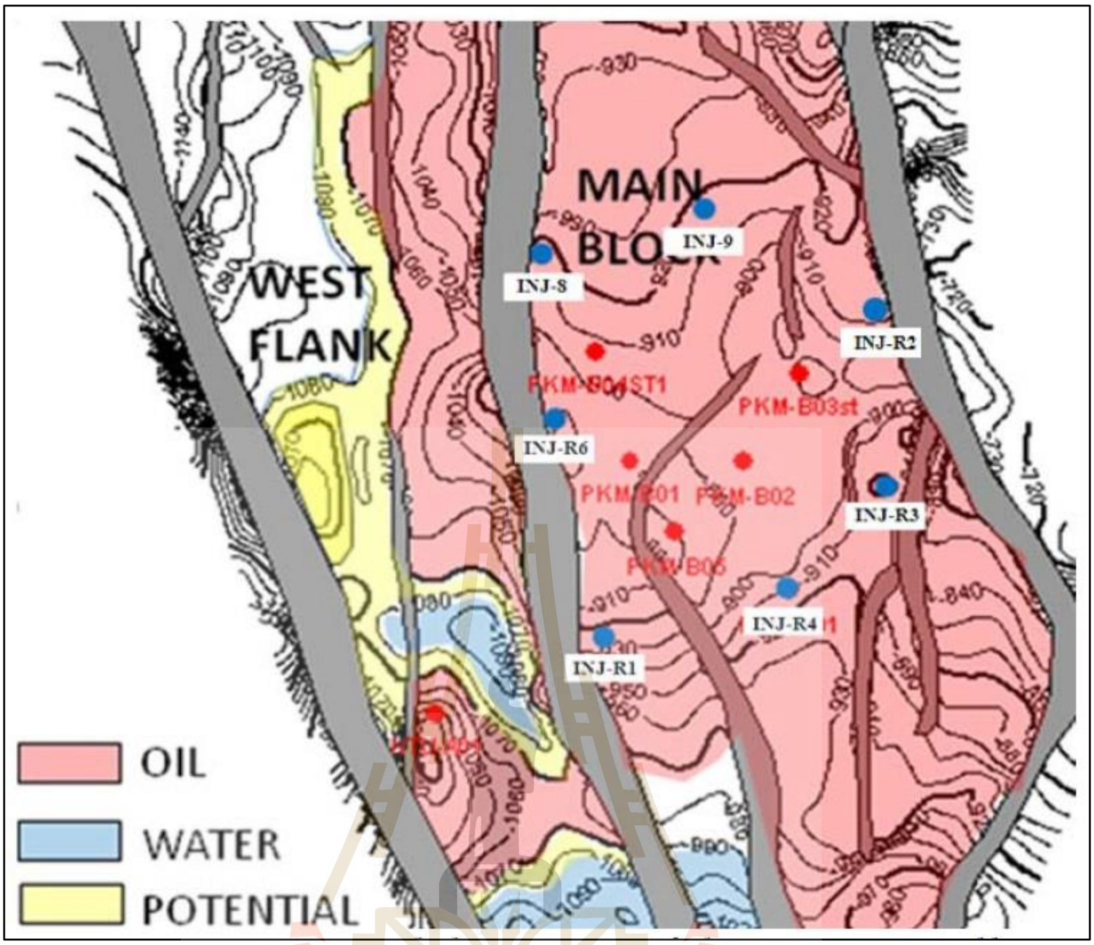


Figure 2.4 Pru Krathiam structural map with well locations, (Sirisawadwattana, 2004)

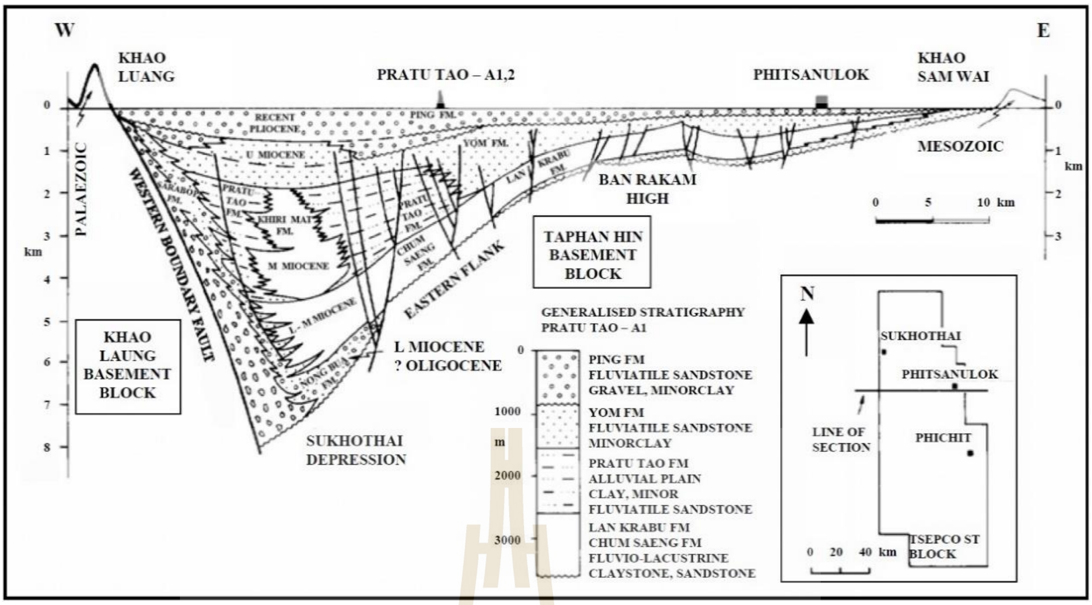


Figure 2.5 E-W Regional cross-section of Phitsanulok Basin,

(After Knox and Wakefield, 1983).

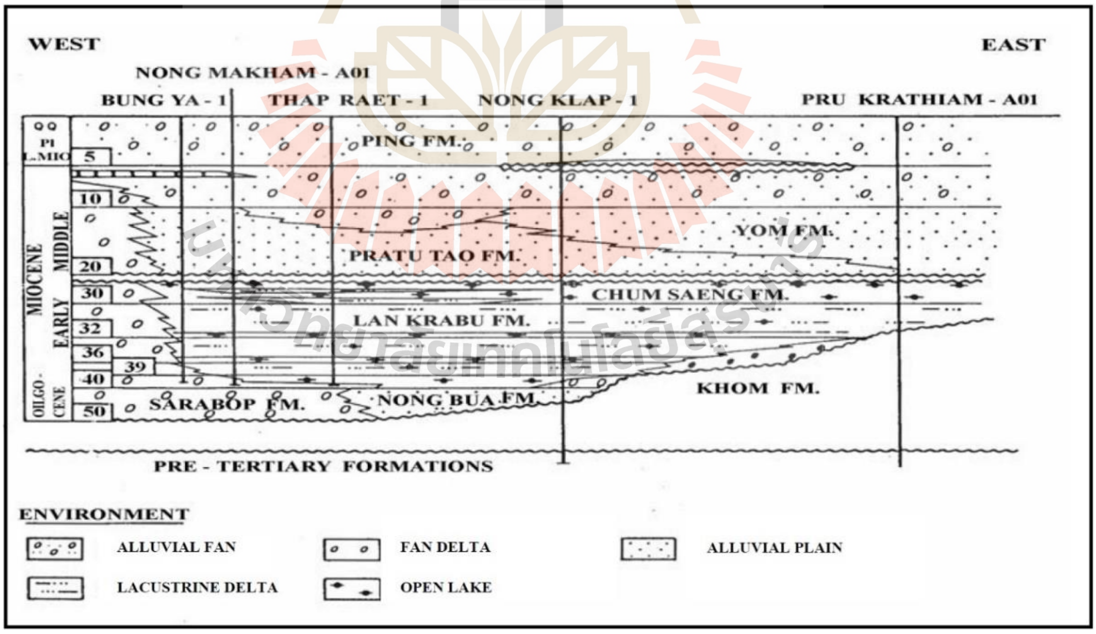


Figure 2.6 Phitsanulok Basin chronostratigraphic cross-section, (After Bal, 1992).

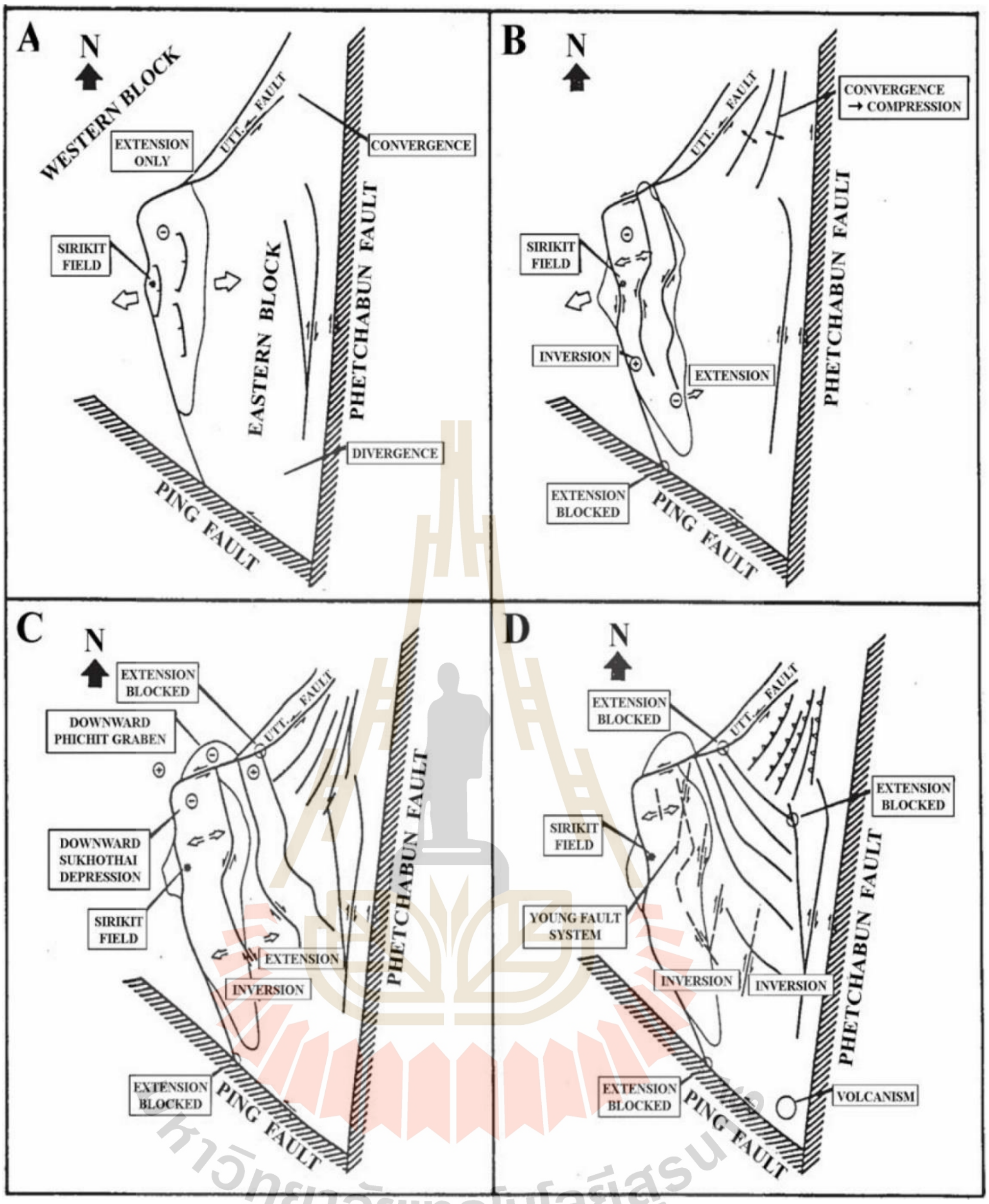


Figure 2.7 Phitsanulok Basin structure evolution, (After Bal, 1992).

## 2.2 Depositional Setting and Stratigraphy

The Tertiary stratigraphy of the Phitsanulok Basin has been subdivided by Thai Shell into eight lithostratigraphic units which together comprise the Oligocene to Recent Phitsanulok Group (Figure 2.4). The lithostratigraphic units were deposited in five main environments within a fluvio-lacustrine depositional system. These main depositional environments are illustrated schematically in Figure 2.6. Adjacent to the Western Boundary Fault, alluvial fans and fan deltas were shed basinwards, while fluvial deposits accumulated on an alluvial plain. Further downstream, lacustrine deltas prograded into a well-developed open lacustrine setting that occupied the rapidly subsiding central portions of the basin.

During the basin's early depositional history in the Oligocene, alluvial fans and fan deltas of the Sarabop Formation were shed from the Western Boundary Fault, while an alluvial plain occupied the basin axis. Several fault blocks were emergent at this time, including the Sirikit High, which was a palaeo-structure from early in the basin's history.

By the end of Oligocene times, open lacustrine conditions were established across the basin for the first time. At its maximum extent, the fresh-water Lake Phitsanulok covered an area up to 4,000 km$^2$ to a shallow depth, not exceeding 50 m. At the same time, fan deltas continued to shed from the Western Boundary Fault, while lacustrine deltas developed in the north. This was the first of several phases of lake expansion, during which organic-rich lacustrine claystone if the Chum Saeng Formation were deposited. Phases of lacustrine transgression were due to variations in base level, subsidence and sedimentation rates and possibly climate.

These transgressive phases were interspersed with periods of rapid delta progadation, giving rise to an alternation of transgressive/regressive lacustrine depositional sequences.

One such phase of delta progradation took place in the mid Early Miocene, when lacustrine deltas prograded southward and occupied much of the northern and central parts of the Phitsanulok Basin. Lacustrine conditions prevailed only in the southern basin at this time. These deltaic deposits comprised sandstones and interbedded claystones of the Lan Krabu Formation, and constitute one of the main hydrocarbon reservoir in the basin. By the end of the early Miocene, open lake conditions were reestablished over the central basin area. Organic-rich lacustrine claystones of the Chum Saeng Formation deposited in this period form the main seal and source rock to the Lan Krabu Formation.

From Middle Miocene times the regional tectonic regime became transpressioal, and alluvial deposits of the Pratu Tao and Yom Formations accumulated across the basin, to the exclusion of any further lacustrine sedimentation. The alluvial depositional setting established in Middle Miocene times has persisted until the present day, with little variation.

The chronostratigraphy of Tertiary lacustrine basins is difficult to define in an absolute sense, because of the scarcity of age-diagnostic biostratigraphic control. Chronostratigraphy in the Phitsanulok Basin is based on K-Ar whole rock dating of a few basaltic lava flows in the upper part of the basin fill, and the recognition of a limited number of ages-diagnostic palynomorphs.

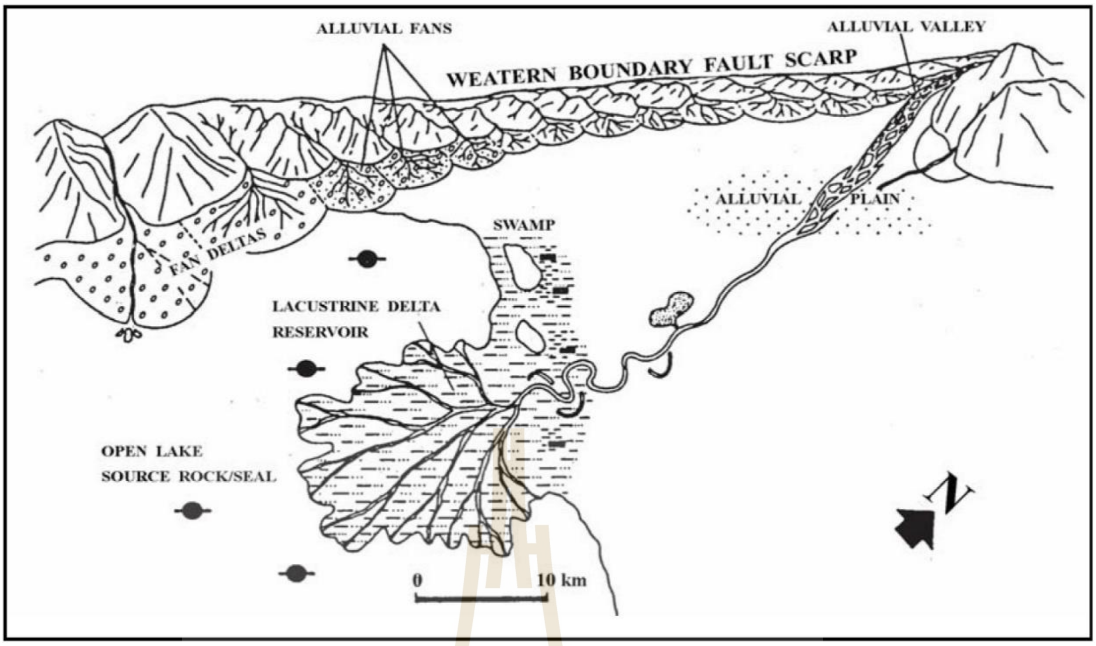


Figure 2.8 Schematic depositional environments of Phitsanulok Basin,

(After Knox and Wakefield, 1983)

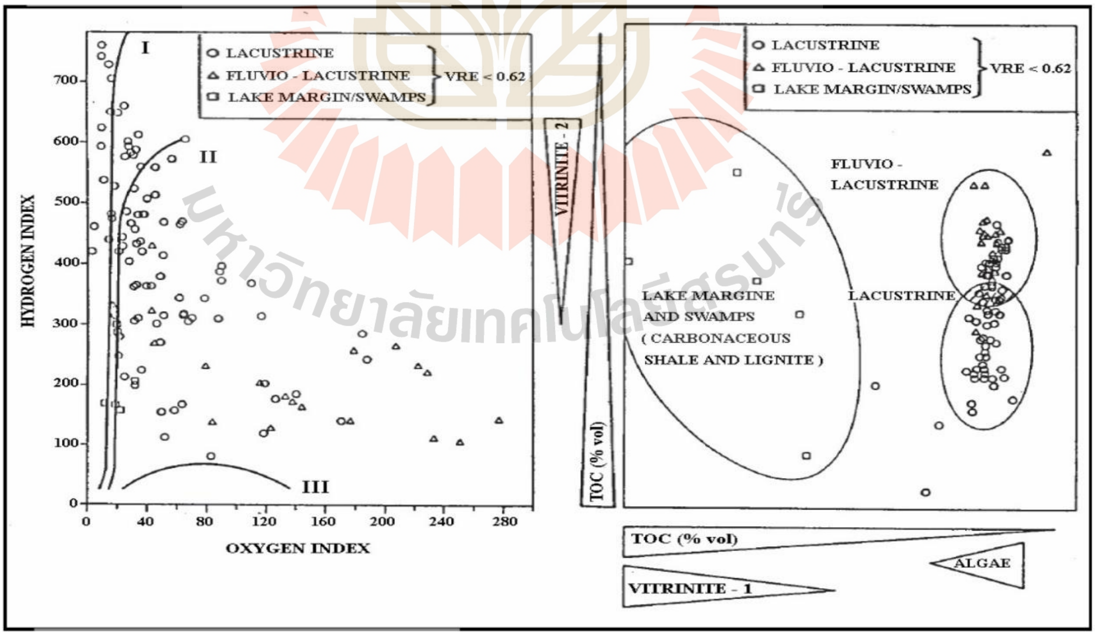


Figure 2.9 A. HI/OI plot., B. Maceral Analyses, (After Bal, 1992)

## 2.3 Hydrocarbon Habitat

### 2.3.1 Source Rocks

Source rocks in the Phitsanulok Basin were deposited in three environments. In order of importance, these environments are:

- open lacustrine environment
- fluvio-lacustrine environment
- marginal lacustrine swamp

The most volumetrically significant source rocks are lacustrine claystones of the Chum Saeng Formation. A plot of hydrogen and oxygen indices (Figure 2.7A) shows that the Chum Saeng Formation contains excellent type I algal/lacustrine source rocks. By comparison, the fluvio-lacustrine and marginal swamp deposits contain fair type II and III source rocks. Maceral compositions of these three groups are illustrated by Figure 2.7B. The lacustrine source rocks contain mainly algae organic matter. Fluvio-lacustrine source rocks form a continuous spectrum with the lacustrine claystones, but have lower total organic content (TOC), a lesser algal component and higher vitrinite. The coaly marginal swamp deposits have a discrete range of compositions, and are characterized by high TOC and high vitrinite.

Thick intervals of high quality algal lacustrine source rocks have accumulated in the Chum Saeng Formation. Gross source rock thicknesses of 400 m are commonly encountered in wells, and average net-to-gross ratios lie in the range 50-80%. In the Sukhothai Depression, seismo-stratigraphic interpretation has shown that lacustrine source rock thickness may exceed 1,000 m. Based on an extensive database of geochemical analyses, it has been established that hydrocarbon yields from these lacustrine source rock can range up to 170 kg/$m^3$, with an average in the range 20-40 kg/m$^3$. These data clearly indicate the outstanding richness and volumes of lacustrine source rocks in the Phitsanulok Basin.

By comparison, fluvio-lacustrine claystones of the Lan Krabu Formation are qualitatively and quantitatively less important, but still have significant source potential. From well data, gross fluvio-lacustrine source rock thicknesses are commonly in the range 150-300 m., with average net-to-gross ratios of 30-50%. Geochemical data indicate average hydrocarbon yields in the range 20-30 kg/m$^3$ for these fluvio-lacustrine claystones.

These source rocks have produced a light (40° API), waxy, low-sulphur, high pour-point oil in the Sirikit Field. Reservoirs shallower than about 1,200 m contain heavy (8° to 23° API) biodegraded oil.

### 2.3.2 Organic Maturity and Hydrocarbon Migration

Mature source rocks occur mainly in the northern part of the basin. The main source rock intervals are currently in the gas window within the central Sukhothai Depression, and in the oil window on its flank. Elsewhere, over a considerable area of the Phitsanulok Basin, the main source rock horizons are immature. Thus, consideration of access to a mature hydrocarbon kitchen area is important for prospect appraisal and ranking in the basin.

The Sirikit Field is situated directly to the south of the Sukhothai Depression, and is well-placed to have received hydrocarbon charge from mature kitchen areas. Detailed mapping has shown that the main reservoirs of the Sirikit Field (“K” and “L” sands) drain present-day kitchen area of 14-21 km2 in area. These relatively small kitchen areas emphasize the lacustrine source rock richness, as they have yield a STOIIP of almost 800 million barrels in the Sirikit Field. Considering that the Phitsanulok Basin has a total kitchen area of about 800 km2, it is likely that several billions of barrels of oil have been generated altogether in the Phitsanulok Basin.

The distribution of oil accumulations and hydrocarbon migration is predominantly lateral migrate. Vertical migration may occur along fault planes, especially when reactivated, and is inferred to have taken place in the Sirikit Field, based in the distribution of hydrocarbons. The dense north-south fault pattern on the Eastern Flank of the basin has caused migrating hydrocarbons to be deflected towards the north and south, leaving a shadow zone in the east.

### 2.3.3 Reservoir/Seal Pairs

The fluvio-lacustrine Tertiary fill of the Phitsanulok Basin offers numerous opportunities to develop potential reservoir/seal pairs, although reservoir quality and distribution are often variable due to rapid lateral and vertical facies changes. A representative log correlation (Figure 2.8) illustrates the main occurrence of Tertiary reservoir and seal in the basin.

Deltaic sandstones of the Lan Krabu Formation sealed by lacustrine claystones of Chum Saeng Formation, from the main reservoir/seal pairs. Due to cyclic delta progradation and lacustrine transgression in this interval, the Lan Krabu Formation contains four reservoir units separated by intraformational seals. From youngest to oldest, these are the “D”, “K”, “L”, and “M” sands. Of these reservoirs, the “K” and “L” sands are laterally continuous over much of the basin, and contain the majority of the Phitsanulok Basin’s reserves. The “K” and “L” sand are quartz litharenites of metamorphic and sedimentary provenance, and have net-to-gross ratios in the range 10-35%. Individual sand bodies are generally less than 7 m. thick, and comprise relatively continuous distributary mouth bars, of 2-3 km. lateral extent, and discontinuous channel sands (Flint et al., 1988).

The oldest Tertiary reservoirs are Oligocene alluvial deposits; seal by the first lacustrine flooding even of Chum Saeng Formation. Potential reservoirs also occur in fluvial sandstones of the Middle Miocene Pratu Tao and Yom Formations. These intervals have fair to good reservoir properties, and compared with the Lan Krabu Formation they show less rapid deterioration with depth. However, Pratu Tao and Yom sands rely on thin and laterally discontinuous intraformational seals, and therefore traps at this level may be easily breached. These sands also require long vertical migration of hydrocarbons to charge them, and are therefore less important reservoirs.

Highly indurate Pre-Tertiary sedimentary, metasedimentary and volcanic strata may constitute fractured reservoirs in buried hill traps in the Phitsanulok Basin, sealed by Tertairy claystones. To date one well in the Sirikit Field has encountered good oil production from a fracture Pre-Tertiary reservoir.

### 2.3.4 Trap Configuration

The trapping configuration of hydrocarbon accumulations in the Phitsanulok Basin is controlled critically in most cases by the complex fault patterns, as exemplified by the Sirikit Field. The Sirikit Field is a tilted fault block bounded by the Western Sirikit Fault and Ket Kason Boundary Fault. In between, the field is broken into numerous compartments by rather intense wrench related faulting (Figure 2.9).

Due to lateral and vertical facies changes as well as rapid variations in fault throw along strike, fault juxtaposition of reservoirs against interbedded claystones can only trap limited hydrocarbon columns. Retention of longer columns depends critically on clay smear along fault planes. Fault sealing potential depends on factors like adjacent clay bed thickness, fault throw direction and the post-or syn- depositional nature of the faults. Thus, clay smear is an important factor, especially in the deltaic "L" sand of the Sirikit Field. Soft lacustrine clay adjacent to the "L" sand at Sirikit Field have good smear potential, allowing the accumulation of a 600 m. hydrocarbon column. Detailed investigations of fluid contact have shown that they are largely controlled by fault seal failure, as the trap is not filled to its lowest structural spill point. Clay smear also plays an important part in this upthrown fault trap at Pru Krathiam-B01, where a 95 m oil column in deltaic "K" sand is sealed laterally by clay smear from overlying lacustrine deposits and by juxtraposition against the same clays across the fault.

A distinctive trap type in the Phitsanulok Basin and in many other Tertiary lacustrine basins of Southeast Asia is the Pre-Tertiary buried hill trap. These traps are sealed by draped Tertiary lacustrine claystones over a Pre-Tertiary palaeotopographic feature (i.e. a buried hill).

A critical point to address in relation to hydrocarbon habitat and trap configuration is trap definition. In order to resolve the complex fault pattern and image valid structure for drilling, 3D seismic data were recorded in the Pretu Tao, Lan Krabu and Lam Khun areas. Early exploration results in the Phitsanulok Basin highlighted the inadequacy of 2D seismic data set in this complex structural setting, asfault miscorrelations undoubtedly contributed to non-optimum placement of some exploration wells.

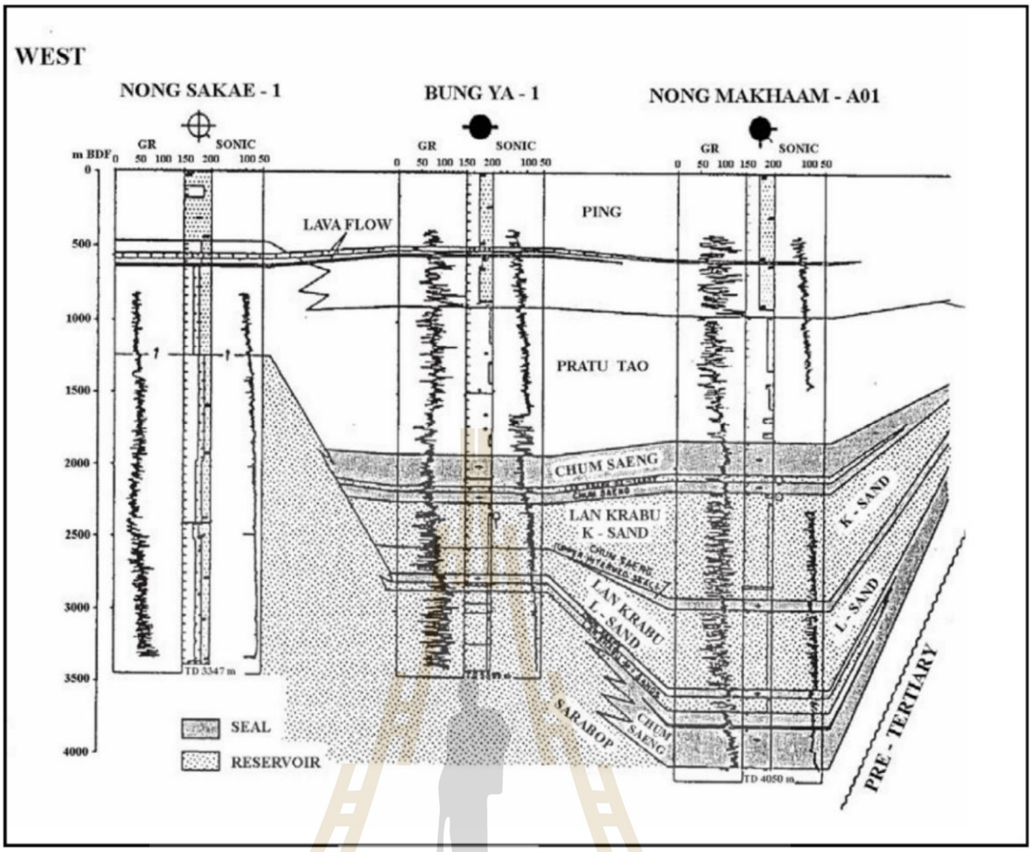


Figure 2.10 Log Correlation showing reservoir/seal pairs, (After Bal, 1992)

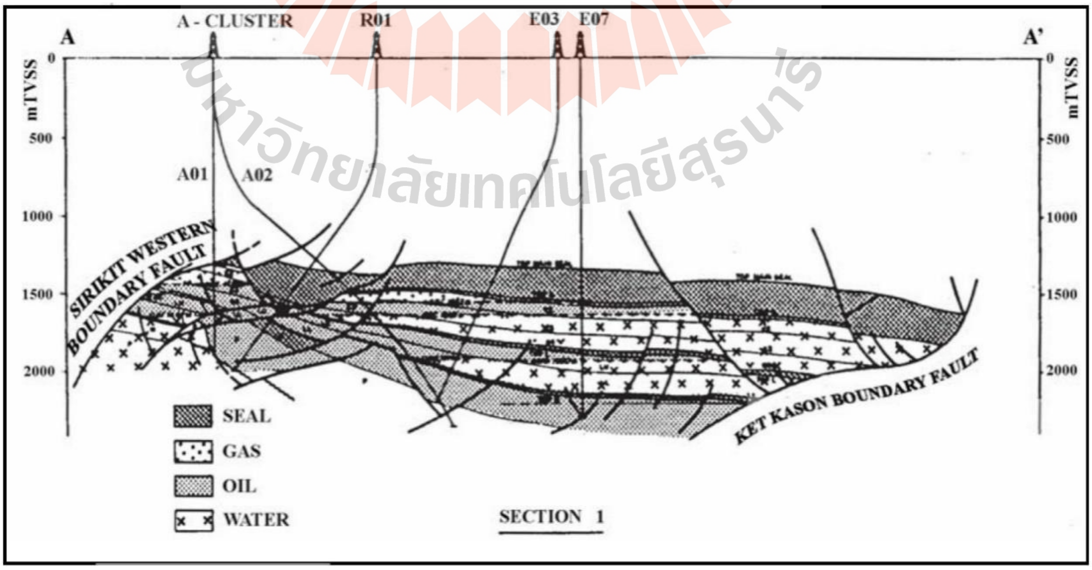


Figure 2.11 Sirikit Field geological cross-section, (After Bal, 1992)

## 2.4 Waterflooding

Secondary recovery replaces natural reservoir drive or enhances with an artificial lift. The injection of water or natural gas into the production reservoir is the most common method. The first waterflooding technique was coincidentally found when an abandoned oil well had been used as a disposal salt water well. It was noticed that production of nearby wells had increased when more water was dumped. Some of the first waterflooding was accomplished by drilling a well (Figure 2.5), or a series of wells, on the perimeter of the reservoir, and injecting water under pressure (Bill and Kenneth, 1992).

The method injects water into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells. Potential problems associated with waterflooding techniques include inefficient recovery due to variable permeability, or similar conditions affecting fluid transport within the reservoir, and early water breakthrough that may cause production and surface processing problems (Schlumberger Oilfield Glossary, 2000).



## 2.5 Case Studies of Waterflooding

### 2.5.1 Suphan Buri Basin, U-Thong field

Suphan Buri Basin, U-Thong Field is the studied area to improve oil recovery by waterflooding. It is constructed as hypothetical model while its geological, petrophysical and production data are based on the data from this field. The reservoir simulation is divided into 5 cases of which one case does not employ water injection, while the other four cases employ water injection in different flood patterns. In the first three years, it can produce around 0.58 MMSTB or 10% of original oil in place (OOIP).

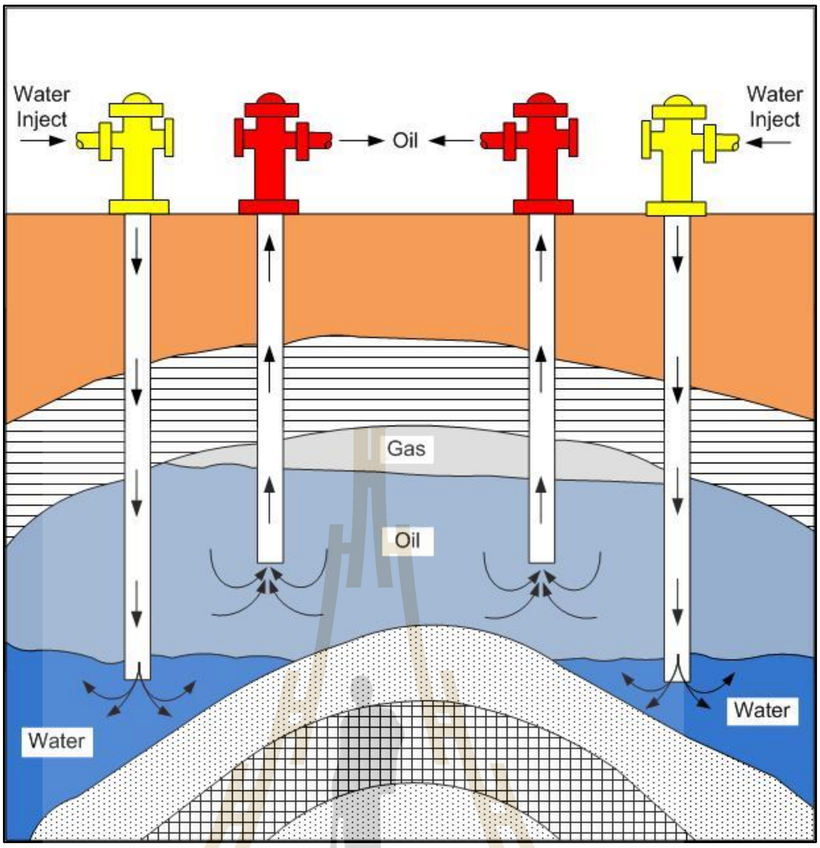


Figure 2.12 Waterflooding method (Berger & Anderson, 1992)

After three years, the field has continued producing oil for 15 years. For Case 1 of which no waterflooding technique is employed, it produces oil recovery factor by 11.93%. The other 4 cases of which employs the waterflooding technique, oil recovery factors increase to 17.59%, 34.69%, 36.10%, and 36.55%, respectively. It is found that Case 1 gives the minimum oil recovery factor. On the other hand, Case 4 and Case 5, which have four injection wells, produce the largest amount of oil production at 3.20 and 3.23 MMSTB. In four cases of which the waterflooding technique is employed, displacement efficiencies are found at 0.55, 0.58, 0.60, and 0.59, respectively.

In economic analysis, Case 4 and Case 5 produce the maximum oil production but require higher investment than other cases. As a result, the cases are not suitable for development. On the other hand, Case 3 is found the most suitable due to economic values which are more favorable than the other cases. (Rattanapranudej, 2004).

### 2.5.2 The Sirikit Oil Field

The Sirikit Oil Field is located in the Phitsanulok Basin. The basin has an areal extent of 6,000 km$^2$ after the relative movement between the Shan Tai and Indonesian blocks. The main reservoir formations are Lan Krabu (LKU) and Pratu Tao (PTO). The Sirikit oil field is geologically very complex. The geological complexity is a product of the multi-phased structural history and the interaction between faulting and deposition through time. However, the complexity and uncertainties of the Sirikit oil field will always be the key factor to determine the successful projects in the future. The waterflooding is one of the successful projects which have been developed in the Sirikit oil fields. The waterflood project began in 1983. A small pilot project in a small area of LKU-E block was designed to test the viability of injecting water into the complex sand shale inter-bedded layers of the Lan Krabu formations. It was proved that the pilot test could maintain pressure under a non-fracturing condition. So it was indicated that the waterflooding of Lan Krabu reservoir was feasible. However, the waterflooding study did not came up to the plan due to problems with deliverability of source-water and response in the reservoirs were very slow. The waterflooding project was studied again during 1993-1994, and increased confidence in recovery factor of the field which increased over 20 percent for the first time. The discovery of oil in Pratu Tao and Yom reservoirs during 1997-1998 gave another upgrade to the recovery factor to the level of around 25 percent. The implement of the previous waterflood project encountered many operational difficulties, but proved waterflood to be a technically viable secondary recovery technique in the Sirikit complex reservoirs. Reviews and studies of reservoir performances and simulations of the Sirikit reservoirs indicated that a reserves volume is recoverable only through waterflood of the Sirikit reservoirs. Recent disappointing results of new infill wells confirmed that the plans to drill hundreds of infill wells would not be as effective as waterflooding. With the advanced of computer modeling techniques compared to 10 years ago, the confidence of successfully implementing waterflooding projects in the Sirikit Field has been reviewed. (Wongsirasawad, 2002)

### 2.5.3 The Jay-LEC field

The Jay-LEC Field has produced from the Smackover carbonate and Norphlet sand formations at depth about 15,400 ft. An oil/water contact is located at a sub-sea depth of 15,480 ft. More than 90% of the oil in place is in Smackover. The reservoir study indicated that natural water drive would not be effective source of reservoir energy. Thus, waterflood was selected among other possible processes to maintain pressure for increasing oil recovery. The waterflooding plan in Smackover formation was developed by using a two-dimensional (2-D) simulation to compare alternative flooding schemes. Four waterflood plans were evaluated: (1) peripheral flood, (2) five-spot pattern (3) a 3:1 staggered line-drive pattern and (4) a combination of peripheral wells and five-spot patterns. From the results of the 2D simulator indicated that the peripheral flood was not effective. For the remaining three waterflooding plans, the 3:1 staggered line-drive plan was recovered more than 200 MMBBL. The 3:1 plan yielded 9.8 MMBBL incremental oil recoveries over the five-spot plan and 14.4 MMBBL over the combination pattern. Moreover the 3:1 plan also has advantages for development plan and economic potential (Willhite, 1986).

### 2.5.4 The Mean field

The Means field in Andrews County, Texas, was discovered in 1934 and developed on 40-acre spacing in early 1950's. Production is from the Grayburg and San Andres formation at depths ranging from 4,200 to 4,800 ft. The Grayburg is about 400 ft. thick with the basal 100 to 200 ft. considered gross pay. Production from Grayburg was by solution-gas drive with the bubble point at the original reservoir pressure of 1,850 psi. The waterflood program was initiated after the operators in the area authorized a major reservoir study to evaluate secondary recovery. Highlights of this study included one of Humble's first full-field computer simulations. For this study, additional data had to be accumulated, including logging, fluid sampling and core data. It was recommended that waterflooding should be initiated on a peripheral pattern that would encompass the more prolific Lower San Andres. A five-spot pattern was implemented later when needed. For the Grayburg, a lease-line pilot with the portion of the field west of the unit was recommended. In 1963, the field was unitized and water injection began with 36 wells, forming a peripheral pattern. The reservoir study was reviewed again in 1969 due to the peripheral injection pattern could no longer provide sufficient pressure support. Barber (Stile and Magruder, 1992) reported the results of a detailed engineering and geologic study conducted during 1968-1969 to determine a new depletion plan more consistent with capacity production. Analysis of pressure data from the pressure observation wells indicated that parts of the South Dome were not receiving adequate pressure support from the peripheral injectors. This study recommended interior injection with a three-to one-line drive following implementation of this program. Production increased from 13,000 bbl/d in 1970 to more than 18,000 bbl/d in 1972. After peaking in 1972, production began to decline again. An in-depth reservoir study indicated that all the pay was not being flooded effectively by the three-to-one line drive pattern. Hence the geologic study provided that the basis for a secondary surveillance program and later to design and implement of the $CO_2$ tertiary project (Stiles and Magruder, 1992).

### 2.5.5 The Fahud field

A fracture model was constructed for the Natih-E reservoir unit of the Fahud field in north Oman. The fracture model indicates that the current gas/oil gravity drainage (GOGD) recovery mechanism is an inefficient oil recovery method for a large part of the lower Natih-E. The optimum well pattern for a waterflood development within two Natih-E subunits is proposed on the basis of simulation results. Nicholls et al (2000) studies the fracture modeling and they expected that the oil recovery is increased from 17 % under GOGD to 40% for the waterflood. A fracture model that includes information from well production and injection performance, borehole-image data, structural map, and fault data has been constructed foe the Natih-E containing sparse and widely spaced fractures. A pilot water injection cell of two horizontal procedures and one injector well oriented parallel to the bedding strike has shown that water injection is a viable alternative to GOGD (Nicholls et al, 2000).

### 2.5.6 The Statfjord Field

The Statfjord field is the largest producing oil field in Europe. The field was discovered in March 1974. The Statfjord field, which is 15 miles long and averages 2.5 miles in width, is located in a westerly tilted and eroded Jurassic fault block. About 75% of the main recoverable reserves are located in the middle Jurassic Brent group, while the remaining 25% is in the Lower Jurassic/ Upper Triassic Statfjord formation. The estimated ultimate recovery is around 3,000 MMBBL of oil and 3.0 TSCF of gas.

Both Brent and Statfjord reservoir contain highly under saturated low sulfur crude oil. The one of reservoir development strategy is to develop the upper and lower Brent as separate reservoirs with pressure maintenance by water injection. The Brent reservoir had a common initial oil/water contact (WOC) and equal reservoir pressure. The original reservoir pressure was 5,561 psia, about 1,550 psia higher than the bubble point pressure. The average reservoir pressure is maintained at around 4,500 psia by balancing total fluid production with water injection. All wells are anticipated to produce with flowing BHP above the BP. In fact, the minimum reservoir pressure was reached in late 1986 if there is no waterflood. The maximum oil production is around 630,000 STB/D and 1,050,000 B/D of water is injected into the Brent reservoir (Haugen et al, 1988).

### 2.5.7 Bradford Field

In early 1880, Carll discovered that it might be possible to increase oil recovery by injecting water to displace oil in the reservoir (Willhite, 1986). Waterflooding began accidentally producing in Bradford Field, PA in 1880's. Many wells were abandoned in Bradford Field by pulling casing without plugging while in some wells casings were left in the wells, thus they were corroded. Therefore, water from shallow horizons could enter the producing interval. The practical water injection began around 1890, when operators realized that water entering the productive formation was stimulating oil production. Later in 1907, the practice of water injection had an impact on oil production from the Bradford Field. The first flooding pattern was a circle flood and it was developed continuously until the present there are many patterns which use in waterflooding.

### 2.5.8 Waterflooding in Heavy Oil Reservoirs

The definition of heavy oil can vary significantly. Jayasekera and Goodyear (2000) defined heavy oil as in-situ oil with a viscosity greater than 5 mPa·s (cP), indicating an adverse mobility ratio between oil and water. This definition is considerably lower than what is generally accepted as heavy oil. Miller (2006) stated that the definition of heavy oil is based on API gravity (≤ 20 °API) rather than viscosity. According to Miller, the failure to set a limit on viscosity is due to the fact that there are problems in accurately measuring viscosity, especially for viscous oil. However, he used a limit of 1,000 to 2,000 mPa·s, whereas Farouq-Ali and Thomas (2000) believed the upper limit to be 1,200 mPa·s. Other sources have placed a limit for determining an oil to be heavy, which is much lower than these numbers. Waterfloods in heavy oil reservoirs are very different than those of conventional oil. These differences are due to several factors. First is the high absolute permeability of the oil sands, which are characterized by having large pore throats with low aspect ratio (Smith, 1992). The most important distinction for these reservoirs, however, is the displacement instability, which occurs as a result of the adverse mobility ratio. This poor mobility ratio induces the formation of viscous fingers during waterflooding, which leads to early water breakthrough and poor macroscopic sweep efficiency at breakthrough. Thus, significant oil can be recovered after water breakthrough, and overall the recovery of heavy oil waterfloods tends to be fairly low. Theoretical development for waterflood recovery predictions in heavy oil reservoirs is sparse. Smith (1992) gave an overview of waterflooding of heavy oils, in which he listed the mechanisms that could potentially aid in the continuous recovery of oil after water breakthrough as: pressure support in the reservoir, multi-phase expansions, gas/oil control (again due to pressure support), water imbibition and gravity drainage of oil. However, he offered few details for these mechanisms. 46 Most research into heavy oil waterflooding has focused on the recovery before breakthrough, the development of models to predict when viscous fingering will occur and the reduced breakthrough recovery that will be the result of these fingers. There have been significant developments in viscous fingering theory to explain early water breakthrough, but there is very little discussion regarding the recovery of oil after breakthrough in the literature. Smith (1992) is one of the few researchers who have identified the importance of capillary imbibition in heavy oil systems. He proposed that at low displacement rates, capillary imbibition could be a significant process after the early arrival of water, where oil production continues to yield ultimately high recovery. Generally, there is very limited field production results reported in the literature for waterflooding of heavy oil. A more recent summary of this data is provided by Kumar et al. (2005).

## 2.6 Polymer flooding

Polymer flooding is a type of chemical flooding to control drive-water mobility and fluid flow patterns in reservoirs. Polymer-long, chainlike, high-weight molecules have three important oil recovery properties. They increase water viscosity, decrease effective rock permeability, and are able to change their viscosity with the flow rate. Small amounts of water-dissolved polymer increase the viscosity of water. This higher viscosity slows the progress of the water flow through a reservoir and makes it less likely to bypass the oil in low permeability rock (Gerding, 1986). Figure 2.6 (Bradley, 1987) shows a schematic of a typical polymer flood injection sequence: a preflush is usually consisting of low salinity brine; an oil bank is injected by polymer; a fresh water buffer to protect the polymer solution from backside dilution; and the last are chase or drive water. Many times the freshwater buffer contains polymer in decreasing amounts (a grading or taper) to lessen the effects of unfavorable mobility ratio between the chase water and the polymer solution. Because of the driving nature of the process, polymer floods always are performed through separate sets of injection and production wells.

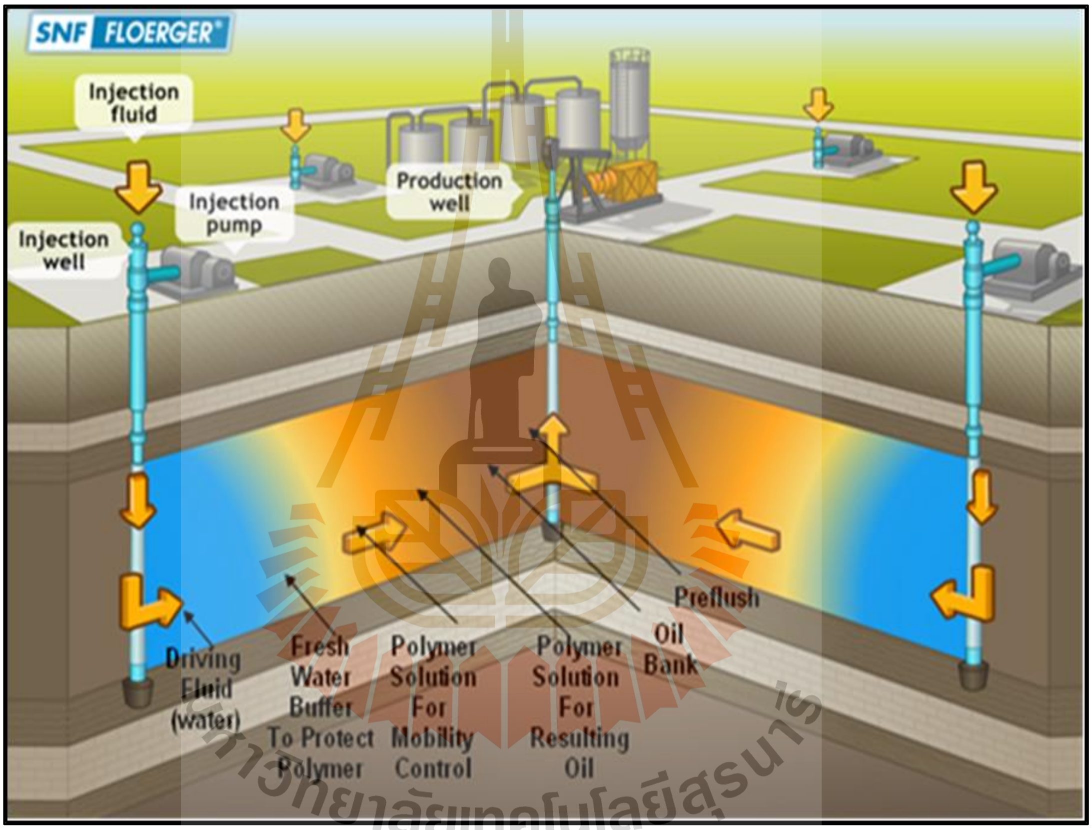


Figure 2.13 Polymer flooding method (Bradley, 1987).

### 2.6.1 Polymer type

According to Noianusontigul (2008), several polymers have been consi dered for polymer flooding; Xanthan gum, hydrolyzed polyacrylamide (HPAM), copolymers (a polymer consisting of two or more different types of monomers) of acrylic acid and acrylamide, copolymers of acrylamide and 2-acrylamide 2-methyl propane sulfonate (AM/AMPS), hydroxyethylcellulose (HEC), carboxymethylhydrox yethylcellulose (CMHEC), polyacrylamide (PAM), polyacrylic acid, glucan, dextran polyethylene oxide (PEO), and polyvinyl alcohol. Although only the first three have actually been used in the field, there are many potentially suitable chemicals, and some may prove to be more effective than those new used. Polymer can be commercially categorized in two types:

**2.6.1.1 Polyacrylamides (PAM)**

These polymers' monomeric unit is the acrylamide molecule (Figure 2.12a). When used in polymer flooding, polyacrylamides have undergone partial hydrolysis, which causes anionic (negatively charged) carboxyl (-COO-) to be scattered along the backbone chain. For this reason these polymers are called partially hydrolyses polyacrylamides (HPAM). Typical degrees of hydrolysis are 30-35% of the acrylamide monomers; hence the HPAM molecule is negatively charged, which accounts for many of its physical properties. This degree of hydrolysis has been selected to optimize certain properties such as water solubility, viscosity, and retention. If hydrolysis is too small, the polymers will not be water-soluble. If it is too large, the polymers will be too sensitive to salinity and hardness.

The viscosity-increasing feature of HPAM lies in its large molecular weight. This feature is accentuated by the anionic repulsion between polymer molecules and between segments in the same molecule. The repulsion cause the molecule in solution to elongate and snag on those similarly elongated, an effect that accentuates the mobility reduction at higher concentrations.

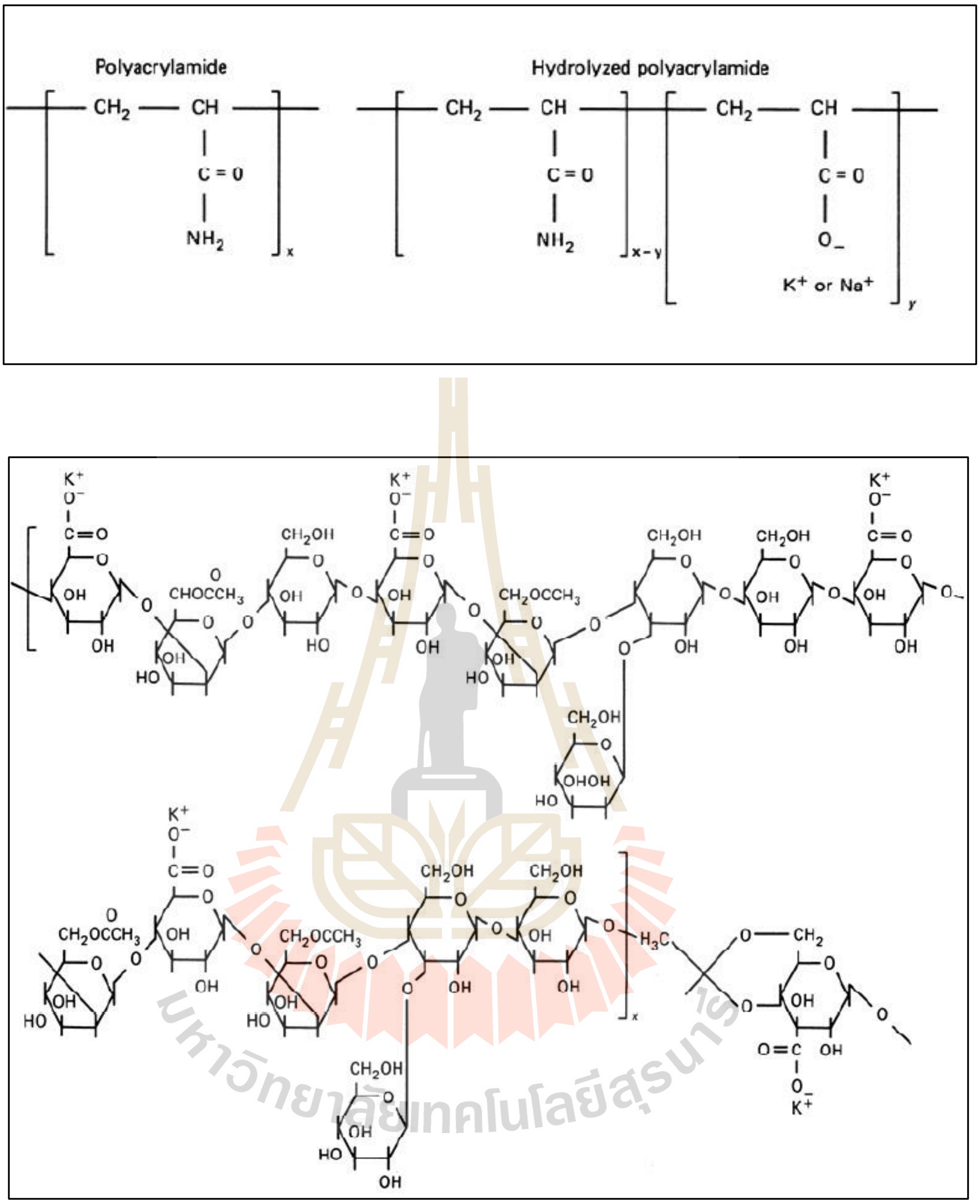


Figure 2.14 Molecular structures, (a) Molecular structure of polyacrylamide. (b) Molecular structure of polysaccharide (biopolymer) (Lake, 1989).

If the brine salinity or hardness is high, this repulsion is greatly decreased through ionic shielding since the freely rotating carbon-carbon bonds allow the molecule to coil up. The shielding causes a corresponding decrease in the effectiveness of the polymer since snagging is greatly reduced. Almost all HPAM properties show a large sensitivity to salinity and hardness, which is an obstacle to use HPAM in many reservoirs; on the other hand, HPAM is inexpensive and relatively resistant to bacterial attack, and it exhibits permanent permeability reduction.

**2.6.1.2 Polysaccharides**

Another widely used polymer, a biopolymer, is xanthan gum (corn sugar gum). This kind of polymer is formed from the polymerization of saccharide molecule (Figure 2.7b), a bacterial fermentation process. This process leaves substantial debris in the polymer product that must be removed before the polymer is injected. The polymer is also susceptible to bacterial attack after it has been introduced into the reservoir. The disadvantages are also offset by the insensitivity of polysaccharide properties to brine salinity and hardness. The polysaccharide molecule is relatively non-ionic and, therefore, free of the ionic shielding effects of HPAM. Polysaccharides are more branched than HPAM, and the oxygen-ringed carbon bond does not rotate fully; hence the molecule increase brine viscosity by snagging and adding a more rigid structure to the solution. Polysaccharides do not exhibit permeability reduction. Molecule weights of polysaccharides are generally around 2 million.

From the study in thermal and rheological of polysaccharides at 55 and 65ºC, an increase in viscosity values was observed. This behavior is interesting for polymer flooding operations into the reservoir, temperatures are in this level or still higher, the cost of polymer could be reduced. Xanthan is supplied as a dry powder or as a concentrated broth. It is often chosen for a field application when no fresh water is available for flooding. Some permanent shear loss of viscosity could occur for polyacrylamide, but not for polysaccharide at the wellbore. It is an advantage in offshore operations.

HPAM is less expensive per unit amount than polysaccharides, but between compared on a unit volume of mobility reduction, particularly at high salinities, the costs are close enough so that the preferred polymer for given application is site specific (Manning et. al., 1983).

### 2.6.2 Polymer flow behavior in porous media

#### 2.6.2.1 Polymer retention

According to Maheshwari (2011), retention of polymer in a reservoir includes adsorption, mechanical trapping, and hydrodynamic retention. Adsorption refers to the interaction between polymer molecules and the solid surface. This interaction causes polymer molecules to be bound to the surface of the solid, mainly by physical adsorption, and hydrogen bonding. Mechanical entrapment and hydrodynamic retention are related and occur only in flow-through porous media. Retention by mechanical entrapment occurs when larger polymer molecules become lodged in narrow flow channels. The level of polymer retained in a reservoir rock depends on permeability of the rock, nature of the rock (sandstone, carbonate, minerals, or clays), polymer type, polymer molecular weight, polymer concentration, brine salinity, and rock surface.

**2.6.2.2 Inaccessible pore volume**

When size of polymer molecules is larger than some pores in a porous medium, the polymer molecules cannot flow through those pores. The volume of those pores that cannot be accessed by polymer molecules is called inaccessible pore volume (IPV). The inaccessible pore volume is a function of polymer molecular weight, mediumpermeability, porosity, salinity, and pore size distribution. In extreme cases, IPV can be 30% of the total pore volume.

**2.6.2.3 Permeability reduction and the resistance factor**

Polymer adsorption/retention causes the reduction in apparent permeability. Therefore, rock permeability is reduced when a polymer solution is flowing through it, compared with the permeability when water is flowing. This permeability reduction is defined by the permeability reduction factor:

$$R_k = \frac{k_w}{k_p} \tag{2.1}$$

Where $R_k$ = Permeability reduction factor

$k_w$ = Rock permeability when water flows

kp = Rock permeability when aqueous polymer solution flows

The resistance factor is defined as the ratio of mobility of water to the mobility of a polymer solution flowing under the same conditions

$$R_f = \frac{\frac{k_w}{\mu_w}}{\frac{k_p}{\mu_w}} \tag{2.2}$$

Where $R_f$ = The resistance factor

$\mu_o$, $\mu_w$ = viscosity of oil and water, cp

The residual resistance factor is the ratio of the mobility of water before to that after the injection of polymer solution

$$R_{rf} = \left(\frac{\frac{k_w}{\mu_w}}{\frac{k_p}{\mu_w}}\right) a \qquad (2.3)$$

Where $R_{rf}$ = The residual resistance factor

Residual resistance factor is a measure of the tendency of the polymer to adsorb and thus partially block the porous medium. Permeability reduction depends on the type of polymer, the amount of polymer retained, the pore-size distribution, and the average size of the polymer relative to pores in the rock.

**2.6.2.4 Relative permeability in polymer flooding**

Some of the researchers have proved from their experiments that polymer flooding does not reduce residual oil saturation in a micro scale. The polymer function is to increase displacing fluid viscosity and thus to increase sweep efficiency. Also, fluid viscosities do not affect relative permeability curves. Therefore, it is believed that the relative permeability in polymer flooding and in water flooding after polymer flooding are the same as those measured in waterflooding before polymer flooding.

**2.6.2.5 Polymer rheology in porous media**

The rheological behavior of fluids can be classified as Newtonian and Non-Newtonian. Water is a Newtonian fluid in that the flow rate varies linearly with the pressure gradient, thus viscosity is independent of flow rate. Polymers are Non-Newtonian fluids.

Rheological behavior can be expressed in the terms of apparent viscosity which can be defined as:

$$\mu = \frac{\tau}{\gamma} \tag{2.4}$$

Where $\tau$ = shear stress

$\gamma$ = shear rate

The apparent viscosity of polymer solutions used in EOR processes decreases as shear rate increases. Fluids with this rheological characteristic are said to be shear thinning. Materials that exhibit shear thinning effect are called pseudo plastic. Polysaccharides such as Xanthan are not shear sensitive and even high shear rate is employed to Xanthan solutions to obtain proper mixing, while polyacrylamides are more shears sensitive. Most significant change in polymer mobility occurs near the wells where fluid viscosities are large.

## 2.7 Case study of polymer flooding

### 2.7.1 Polymer flooding in heavy oil reservoirs in the East Bodo reservoir, Canada

The East Bodo reservoir in alberta was produced from the Lloydminster formation which is part of the Lower Cretaceous Mannville Group (Wassmuth et al., 2009). The porosity was 27-30% and the permeability was 1000 mD. The reservoir oil viscosity was 600-2,000 mPa.s (14O API). For the formation water, the tatal dissolved solid (TDS) content ranged from 25,000 to 29,000 ppm with hardness concentrations ($Ca^{2+}$ and $Mg^{2+}$) of 350-650 ppm. In the pilot area, there were 13 producers and 1 injector. The avenge thickness was 3.2 m.

After coreflood tests, history matching the coreflood tests and having conducted field simulation study, a pilot test was conducted. The pilot was in a mature waterflood area of the highest injectivity for the field. The polymer injection was initiated in May 2006. It was expected that the injected polymer solution of 1,500 ppm wound result in 25 mPa.s. Apparently, the reservoir solution viscosity was 10mPa.s at maximum. So later a fresher water source (TDS=3700 ppm) was used, and the solution viscosity at surface of 1,500 ppm was 60 mPa.s at surface. The polymer concentration at the nearest producing wells were about 100 ppm.

After fill-up, the injection pressure reached 6,000 kPa at 200 $m^3$/D of polymer. Previously, a similar injection pressure was achieved with water at a rate of 250 m3/D. the pilot performance indicated that for polymer injection in the heavy oil reservoir, horizontal wells helps to alleviate injectivity problem.

### 2.7.2 Polymer flooding in heavy oil reservoirs the Tambobaredjo Field, Suriname

This section presents a case of polymer flooding a heavy oil reservoir in the Tambaredjo field in Suriname (Staatsolie's Sarah Maria pilot) (Moe Soe Let et al., 2012). The pilot had three injectors and nine offset producers. The produced oil viscosity ranged from 1,260 to 3,057 mPa.s with an average of 1728 mPa.s. The reservoir "foamy oil" (Sheng et al., 1999) viscosity was believed to be 300-600 mPa.s. The average permeability of the sand exceeded 4D with significant heterogeneity (permeability contrast >10:1). The prepared polymer solutions (1000 ppm SNF Flopaam 3630S in Sarah Maria water of 400-500 ppm TDS) has a viscosity of 50 mPa.s (ambient temperature and $7.3^{s-1}$) at the mixing facility and 45 mPa.s at the closest injection well. Because the injected polymer solution is lower than oil viscosity, obvious fingering was observed in the pilot. It was expected that increasing polymer concentration would improve the performance and they were testing this concept when the paper was written in 2012.

The nine production wells surrounding the injection wells produced 10-60% of the injected polymer concentration. Oil rates in producer were increased while the water cuts were decreased. However, the responses from polymer injection were modest. It was interpreted from calculated injectivity using polymer viscosity at surface that horizontal fractures were formed by polymer injection. However, severe channeling was not witnessed. What could cause these two phenomena was that near wellbore fractures were formed.

The dissolved oxygen levels were ambient (3-8 ppm) throughout the mixing and injection process. Although high dissolved oxygen is not a good general practice, it was argued that the high oxygen levels might be acceptable for the Sarah Maria pilot conditions. The augment is from the experience at Daqing where ambient levels of dissolved oxygen were also present through the mixing and injection process. The Daqing sand contained about 0.25% pyrite and 0.5% siderite. It effectively removed any dissolved oxygen within 1 day and a short distance after polymer enters the reservoir (Seright et al., 2010). A similar result was expected for this pilot, because X-ray diffraction (XRD) analysis showed significant amounts (up to 12%) of siderite and pyrite in some cores.

### 2.7.3 Polymer injection at Daqing oil field (China)

Daqing oilfield is a large non-marine sandstone reservoir onshore oilfield. This is the largest polymer flooding field in the world. The field has been produced since 1960. The tertiary recovery has been started since 1984 and successfully in 13 field tests in 1989. It has been commercially used in the following years. The results of oil recovery were very good of water-cut dropping and grate oil production increase (Liu He et al., 2009). The study of polymer injection has been done both in the laboratory to injection testing and in the field (Thang, 2005).

The studies have started since 1985 with two main purposes as follows: 1) Selecting the type of polymer, 2) Determining the flowing characteristics of the selected polymer. There are two types of the selected polymer, polyacrylamide and xanthan gum. Due to the characteristics of the field with low temperature and low salinity of formation water, polyacrylamide is more effective at Daqing field than the others. Polyacrylamide has been chosen based on principle of low adsorption and high intrinsic viscosity. The quantity of absorbed polymer determined on sample was 20-25 % of the quantity of polymer injection.The test was conducted in two adjacent blocks, PO and PT.



PO pilot: The beginning of water injection in December of 1989 with flow rate of 629bbl/d at injection wells. The polymer solution had injected since August of 1990 and finished in December of 1991. After 150 days of starting polymer injection, the water cut decreases from 92.6% to 76.6% and production rate increases from 314 bbl/d to 943 bbl/d. In the whole process of injection testing has used 161 tons of polymer and produced 460,000 bbl of oil. Thus, the efficiency of polymer injection is about 2,855 bbl of oil/tones of polymer. Oil recovery increases 7.5% OOIP.

PT pilot: The beginning of water injection was in February of 1990 with flow rate of 1,260 bbl/d. The polymer solution has injected with the same flow rate since October of 1990 and finished in January of 1992. After 200 days of starting polymer injection, the water cut decreases from 92% to 82.6% while production rate increases from 346 bbl/d to 1,447 bbl/d. PT pilot has used 285 tons of polymer injection and produced 750,000 bbl of oil. The efficiency of polymer injection about 2,625 bbl of oil/tones of polymer. Oil recovery increases 11.5% OOIP.

**2.7.4 Feasibility study of secondary polymer flooding in Henan oilfield (China)**

Henan oil field is the second largest oil field in Henan Province, People's Republic of China. It is located in Nanyang region. The field was discovered in 1970s. It has accumulated proven oil reserves of 2.7 billion tons. It is operated by Sinopec Henan oilfield Company, a subsidiary of Sinopec (Wikipedia, 2012). During 1996 to 2006, polymer flooding was implemented in Henan oilfield, with average 70 mPa.s of crude oil viscosity and reservoir temperature of 55˚C, polymer of 0.42PV to 0.44PV was injected with above 8% of enhanced recovery. In the next waterflooding, water cut arise rapidly, and part of lower permeability zones were not development, therefore it is necessary to employ relay technology to retain yield. In the other hand, the total produced degree is less than 35%, that is to say, more than 65% of residual crude oil still exists in underground, and both vertical and plane heterogeneity are serious. Therefore, according to characteristic of crude oil and formation, a series of laboratory experiments to study the feasibility of secondary polymer flooding were carried, including microscopic mechanism study and macroscopic physical modeling. In addition, the polymer concentration must be optimized to ensure recovery effect and economics. Filed trial with above optimum parameters was implemented. Up to

2008.12, water cut decreased from 92% to 83%, and cumulative increased crude oil of above 50000 tones.

## 2.8 Recovery efficiency

A key factor in the design of a water or polymer flooding is the estimation of the oil recovery. This factor indicates the portion of the initial oil in place that can be economically recovered by water injection. In equation form, the oil recovery by water or polymer flooding can be expressed by

$$Np = NE_A E_V E_D \tag{2.5}$$

Where $Np$ = Cumulative Waterflooding Recovery, bbl

$N$ = Oil in Place at Start of Injection, bbl

$E_A$ = Areal Sweep Efficiency, Fraction

$E_V$ = Vertical Sweep Efficiency, Fraction

$E_D$ = Displacement Efficiency, Fraction

### 2.8.1 The displacement efficiency

The displacement efficiency $E_D$ is the fraction of movable oil that has been displaced from the swept zone at any given time or pore volume injected. Because an injection fluid (water or polymer) will always leave behind some residual oil, $E_D$ will always be less than 1, the displacement efficiency can be expressed by

$$E_D = \frac{\text{Volume of oil at start of flood - Remaining oil volume}}{\text{Volume of oil at start of flood}} \tag{2.6}$$

$$E_D = \frac{(\text{Pore volume})(\frac{\bar{S}_{oi}}{B_{oi}}) - (\text{Pore volume})(\frac{\bar{S}_o}{B_o})}{(\text{Pore volume})(\frac{\bar{S}_{oi}}{B_{oi}})} \tag{2.7}$$

Or

$$E_D = \frac{(\frac{\bar{S}_{oi}}{B_{oi}}) - (\frac{\bar{S}_o}{B_o})}{(\frac{\bar{S}_{oi}}{B_{oi}})} \tag{2.8}$$

Where $\bar{S}_{oi}$ = volumetric average oil saturation at the beginning of the water or polymer flooding, where the average pressure is $\bar{p}_1$, fraction

$\bar{S}_o$ = volumetric average oil saturation at a particular point during the water or polymer flooding

$B_{oi}$ = oil FVF at pressure is pressure is $\bar{p}_1$, bbl/STB

$B_o$ = oil FVF at a particular point during the water or polymer flooding, bbl/STB

When the oil saturation in the PV swept by water or polymer flooding is reduced to the residual saturation ($S_{or}$),

$$E_D = 1 - (\frac{S_{or}}{\bar{S}_{oi}})(\frac{B_{oi}}{B_o}) \tag{2.9}$$

This becomes

$$E_D = 1 - (\frac{S_{or}}{\bar{S}_{oi}}) \tag{2.10}$$

Where $S_{or}$ = residual oil, fraction

$\overline{S}_{oi}$ = volumetric average oil saturation at the beginning of the water or polymer flooding, where the average pressure is $\overline{p}_1$, fraction

### 2.8.2 The areal sweep efficiency

The areal sweep efficiency $E_A$ is defined as the fraction of the total flood pattern that is contacted by the displacing fluid. It increases steadily with injection from zero at the start of the flood until breakthrough occurs, after which $E_A$ continues to increase at a slower rate.

The areal sweep efficiency depends basically on the following three main factors:

- Mobility ratio M
- Flood pattern
- Cumulative fluid injected

### 2.8.3 The vertical sweep efficiency

The vertical sweep efficiency, $E_V$, is defined as the fraction of the vertical section of the pay zone that is the injection fluid. This particular sweep efficiency depends primarily on (1) the mobility ratio and (2) total volume injected. As a consequence of the nonuniform permeability, any injected fluid will tend to move through the reservoir with an irregular front. In the more permeable portions, the injected water will travel more rapidly than in the less permeable zone.

### 2.8.4 The mobility ratio

The mobility of a fluid is the effective relative permeability of that fluid divided by its viscosity. For an injection scheme, the mobility ratio (M) is the ratio of the mobility of the displacing fluid behind the flood front to that of the displaced fluid ahead of the flood front.

The mobility of any fluid $\lambda$ is defined as the ratio of the effective permeability of the fluid to the fluid viscosity,

$$\lambda_o = \frac{k_o}{\mu_o} = \frac{kk_{ro}}{\mu_o} \tag{2.11}$$

$$\lambda_w = \frac{k_w}{\mu_w} = \frac{kk_{rw}}{\mu_w} \tag{2.12}$$

$$\lambda_g = \frac{k_g}{\mu_g} = \frac{kk_{rg}}{\mu_g} \tag{2.13}$$

Where $\lambda_o$, $\lambda_w$, $\lambda_g$ = mobility of oil, water, and gas, respectively

$\mu_o$, $\mu_w$, $\mu_g$ = viscosity of oil, water, and gas, cp

$k_o$, $k_w$, $k_g$ = effective permeability to oil, water, and gas, respectively

$k_{ro}$, $k_{rw}$ = relative permeability to oil, water, and gas, respectively

k = absolute permeability

for waterflooding,

$$M = \frac{\lambda_w}{\lambda_o} = \left(\frac{k_{rw}}{\mu_w}\right)\left(\frac{\mu_o}{k_{ro}}\right) \tag{2.14}$$

simplifying gives

$$M = \left(\frac{k_{rw}}{k_{ro}}\right)\left(\frac{\mu_o}{\mu_w}\right) \tag{2.15}$$

If mobility ratio $M \leq 1$, oil is capable of traveling with a velocity equal to or more than that water. If mobility ratio $M > 1$, water is capable of traveling faster than oil. As the water is pushing the oil through the reservoir, some of oil will be by-passed.

# CHAPTER III

# RESERVOIR SIMULATION

## 3.1 Objective

The main objective of this chapter is to (1) detail a reservoir simulation modeling data requirement in term of static (reservoir structure and rock properties) and dynamic (fluid saturation, pressure, and fluid flow rate) properties of reservoir, (2) explain reservoir simulation scenarios test selection, and (3) explain polymer flood design of polymer injection rate and flood pattern selection used in this study.

## 3.2 Reservoir simulation model

This study used black-oil reservoir simulation by Eclipse Office E100 to simulate all type of reservoir (primary, secondary and tertiary productions) which based on available data of Pru Kathiem oil field and some of data assumptions. The structure of reservoir simulation is shown in Figure 3.1-3.2 and summarized as follow:

| | |
|---|---|
| - Model dimension (long, wide, thick) | 3500, 3500, 197 feet |
| - Scale grid (x, y, z) | 25, 25, 6 (3,750 grid blocks) |
| - Structure style | Monocline |
| - Unit | Field |
| - Geometry type | Conner Point |
| - Grid type | Cartesian |

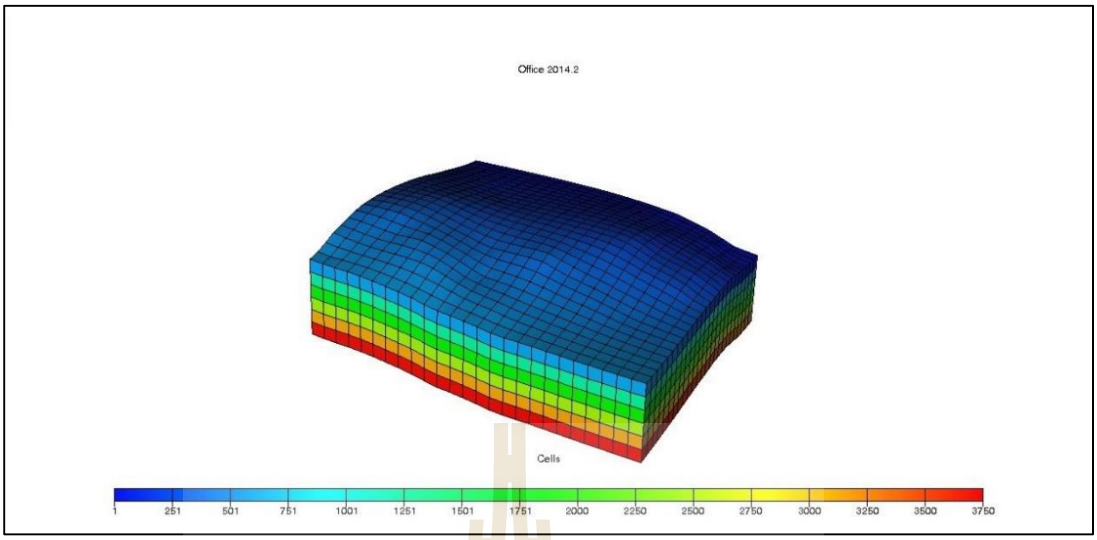


Figure 3.1 Reservoir structure model.

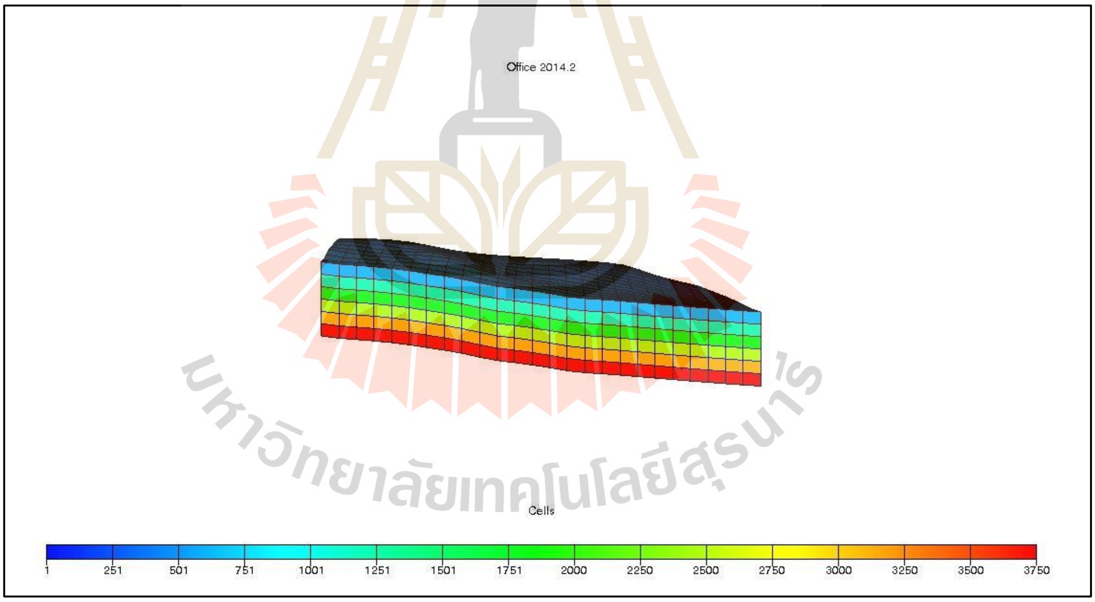


Figure 3.2 Cross-section of reservoir model.

## 3.3 Data input for the reservoir model

The model input parameter description follows the main input section data of the simulator, Grid section, PVT section, SCAL section, Initialization section and Schedule section, respectively.

### 3.3.1 Porosity and Permeability Data of Grid Section

The data input in this section are grid block corner, grid block coordinate lines, porosity and permeability distribution, and net-to-gross ratio.The data for Grid section is as follows:

- Depth of top surface, (feet) 3000 - 4000
- Net-to-gross ratio 0.15 - 0.20

Porosity and permeability are shown in Table 3.5. The x, y, z porosity and x, y permeability set as following table, only z permeability set to 0.1 of represent value.

Table 3.1 Permeability and Porosity for 6 layers

| Layer | Porosity (%) | Permeability (md) |
|---|---|---|
| 1 | 26.00 | 586.0 |
| 2 | 25.00 | 323.5 |
| 3 | 24.00 | 178.6 |
| 4 | 23.00 | 98.6 |
| 5 | 22.00 | 54.5 |
| 6 | 21.00 | 30.1 |

### 3.3.2 PVT section data

The PVT section data are the fluid properties including fluid formation volume factors, viscosities, densities, gas-oil ratio, and rock and water compressibility. The data input for PVT section are detail as follows:

| | |
|---|---|
| - Rock type of reservoir | Consolidated Sandstone |
| - Oil gravity, (API Oil) | 17 |
| - Gas gravity, (SG Air = 1) | 0.8 |
| - Bubble point pressure, (psi) | 1150 |
| - Referenced pressure, (psi) | 1,450 |
| - Standard temperature, (°F) | 60 |
| - Standard pressure, (psi) | 14.7 |

### 3.3.3 SCAL Section Data

The SCAL section refers to the term of rock properties, which are sets of input tables of relative permeability versus saturation. Effectively, this defines the connate (or irreducible), critical and maximum saturation of each phase supplies information for defining the transition zone and defines the conditions of flow of phases relative to one another. Fluid saturation is list as follow:

| | |
|---|---|
| - Initial water saturation | 0.2 |
| - Critical water saturation | 0.3 |
| - Gas saturation | 0.04 |
| - Critical water saturation | 0.1 |

The Table A.1, A.2 and figure A.2, A.3 of PVT and fluid saturation are shown in Appendix A.

### 3.3.4 Fluid initialization section data

Initialization refers to the initial conditions of the simulation. The initial conditions are defined by specifying the OWC (Oil-Water contact) depths and the pressure at a known depth. ECLIPSE uses this information in conjunction with much of the information from previous stages to calculate the initial hydrostatic pressure gradients in each zone of the reservoir model and allocate the initial saturation of each phase in every grid cell prior to production and injection. The data of equilibration are as follows:

| | |
|---|---|
| - Datum depth, (feet) | 3,850 |
| - Pressure at datum depth, (psi) | 3,500 |
| - Water/Oil contact depth, (feet) | 3,915 |
| - The bubble-point at datum depth, (psi) | 1,150 |

**3.3.5 Well data of schedule section data**

Well data provides well and completion locations, production and injection rates of wells and other data such as skin factors, well radius, and well controls, etc. The well data which use in producing wells and injection wells as follows;

| | |
|---|---|
| - Diameter of well bore (feet) | 0.71 |
| - Skin factor | -1 |
| - Effective $K_h$ (mD) | 250 |
| - Perforation of production zone (layer) | $1^{st}$ - $6^{th}$ |
| - Perforation of injection zone (layer) | $1^{st}$ - $6^{th}$ |

**3.3.6 Type of polymer for injection**

The Xanthan Gum (XCD) polymerconcentration 600 and 1200 ppm is used in this study. XCD polymer has a good salt-resistance. The reservoir has a high temperature this polymer can increase the water viscosity but the mobility ratio between polymer solution and oil will be decreased. After study enhanced oil recovery by polymer flooding for oil field in Phisanulok basin (Kanarak, 2008), the reservoir model name A05 can be applied in this study. The polymer concentration 600 ppm is the best case and development for each reserved sizes of reservoir. Recovery efficiency and economic evaluation is more favorable than the others concentrations.

## 3.4 Case study

In this study the reservoir size is 18.291 MMBBL, with the monocline structure style, using two flood pattern (staggered line and direct line drive) to compare the result of production with primary production (natural flow), secondary production (water injection) and tertiary production (polymer injection). Water was injected in the 1st, 3rd and 5th years and polymer was injected in the 1st, 2nd, 3rd and 4th with the constant production rates of 600bbl/d, and constant injection rate of 500 bbl/d. Case study model is shown in Table 3.2 and flood pattern is shown in Figure 3.3 – 3.4.

Table 3.2 Case study model.

| Case | Flood pattern | Type to inject | Year to inject | Initial | After well convert | |
|---|---|---|---|---|---|---|
| | | | | Pro. Well | Inj. Well | Pro. Well |
| 1 | Staggered line | - | no | 3 | 0 | 3 |
| 2 | Direct line | - | no | 4 | 0 | 4 |
| 3 | Staggered line | water | 1st | 1 | 2 | 1 |
| 4 | Direct line | water | 1st | 2 | 2 | 2 |
| 5 | Staggered line | water | 3rd | 3 | 2 | 1 |
| 6 | Direct line | water | 3rd | 4 | 2 | 2 |
| 7 | Staggered line | water | 5th | 3 | 2 | 1 |
| 8 | Direct line | water | 5th | 4 | 2 | 2 |
| 9 | Staggered line | Fresh water | 1st | 1 | 2 | 1 |
| | | Polymer | 2nd | | | |
| 10 | Direct line | Fresh water | 1st | 2 | 2 | 2 |
| | | Polymer | 2nd | | | |
| 11 | Staggered line | Fresh water | 2nd | 3 | 2 | 1 |
| | | Polymer | 3rd | | | |
| 12 | Direct line | Fresh water | 2nd | 4 | 2 | 2 |
| | | Polymer | 3rd | | | |
| 13 | Staggered line | Fresh water | 3rd | 3 | 2 | 1 |
| | | Polymer | 4th | | | |
| 14 | Direct line | Fresh water | 3rd | 4 | 2 | 2 |
| | | Polymer | 4th | | | |
| 15 | Staggered line | Fresh water | 4th | 3 | 2 | 1 |
| | | Polymer | 5th | | | |
| 16 | Direct line | Fresh water | 4th | 4 | 2 | 2 |
| | | Polymer | 5th | | | |

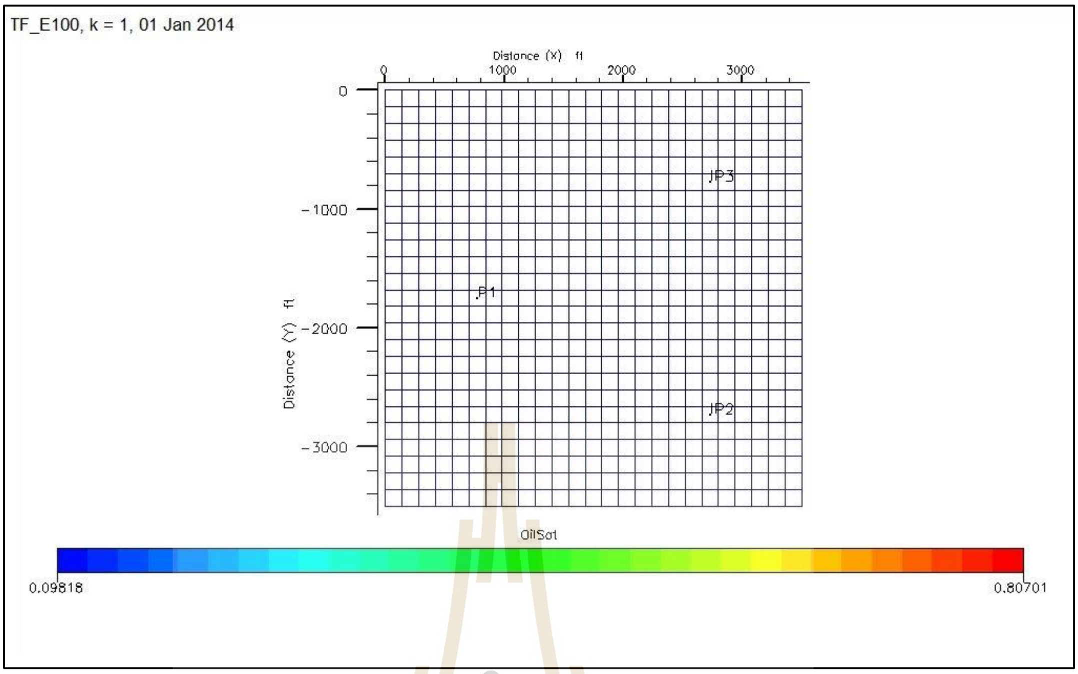


Figure 3.3 Staggered line drive pattern.

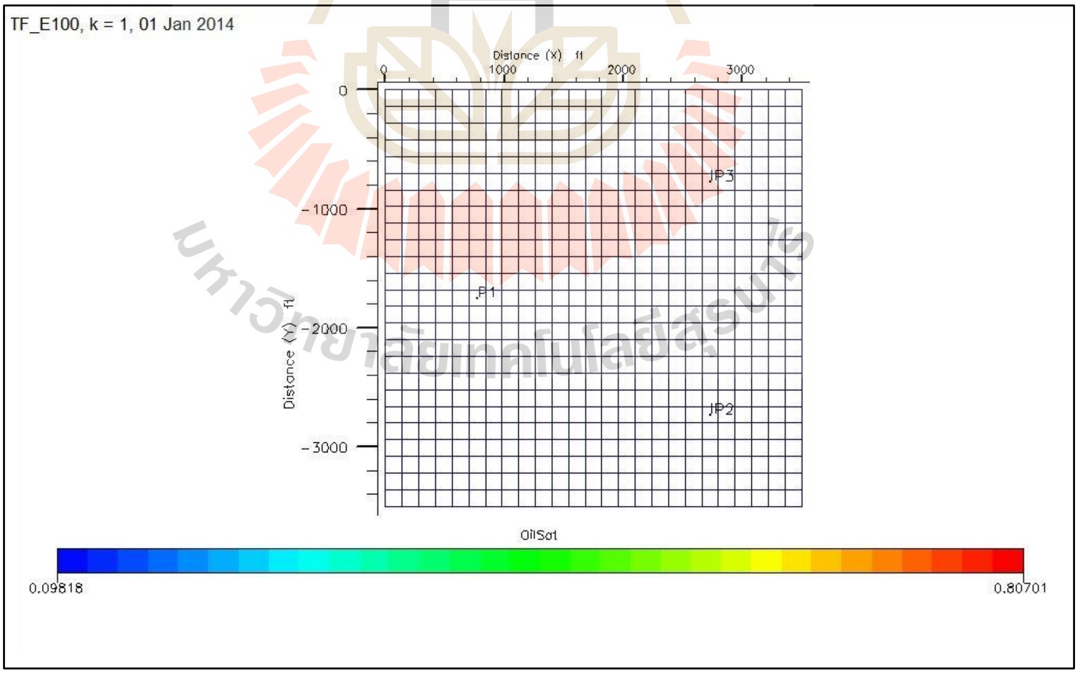


Figure 3.4 Direct line drive pattern.

# CHAPTER IV

# RESERVOIR SIMULATION RESULTS

This chapter shows reservoir simulation results of the total 16 cases studies, comprising of graphs with 3 phases of fluids (oil, water, and gas). The graphs show field fluid in place (volume in the reservoir), field cumulative production (production efficiency), field production rate (production profile), field pressure, field oil efficiency and field polymer injection total. Results from running simulation of the 16 case studies are displayed in 4 cross-plot graphs (Figures 4.1) to explain fluid behavior production by natural flow, water flooding and polymer flooding methods. Moreover, Figure 5 (Field Polymer Injection Total) are shown in case studies 9 to 16 only. Graph descriptions are shown in Table 4.1.

Table 4.1 Display parameter description.

| Figure | Parameters | Description | Common Refer |
|---|---|---|---|
| 1 | FGIP | Field Gas in Place | Original of Gas in Place |
| | FOIP | Field Oil in Place | Original of Oil in Place |
| | FWIP | Field Water in Place | Original of Water in Place |
| 2 | FGPT | Field Gas Production Total | Cumulative Gas Production |
| | FOPT | Field Oil Production Total | Cumulative Oil Production |
| | FWPT | Field Water Production Total | Cumulative Water Production |
| 3 | FGPR | Field Gas Production Rate | Daily Gas Production Rate |
| | FOPR | Field Oil Production Rate | Daily Oil Production Rate |
| | FWPR | Field Water Production Rate | Daily Water Production Rate |
| 4 | FPR | Field Pressure | Reservoir Pressure |
| | FOE | Field Oil Efficiency | Oil Recovery Efficiency |
| 5 | FCIT | Field Polymer Injection Total | Polymer Solution Injection Total |

## 4.1 Reservoir simulation results

### 4.1.1 Result of Model Case 1

Model Case 1 employs the staggered line drive pattern and natural flow method. The production period is 20 years. The production is commenced in 3 production wells at the initial oil production rate of 200 bbl/d/well. The simulation results are shown in Figures 4.1 – 4.4:

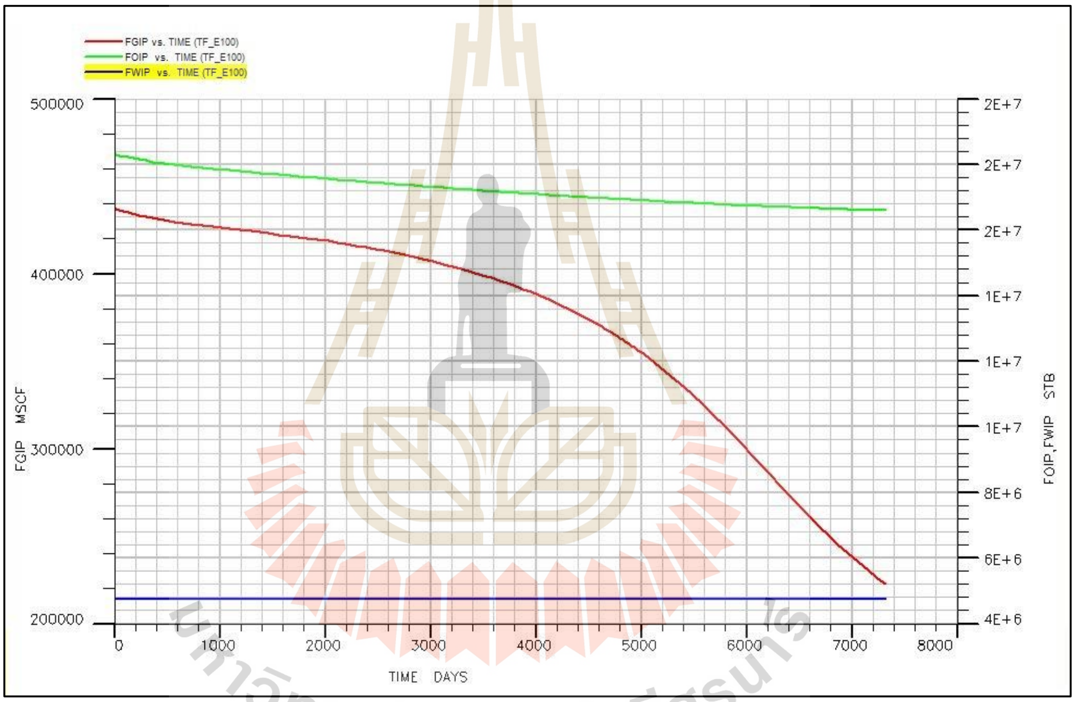


Figure 4.1 Fluid in place profile vs. time of model case 1.

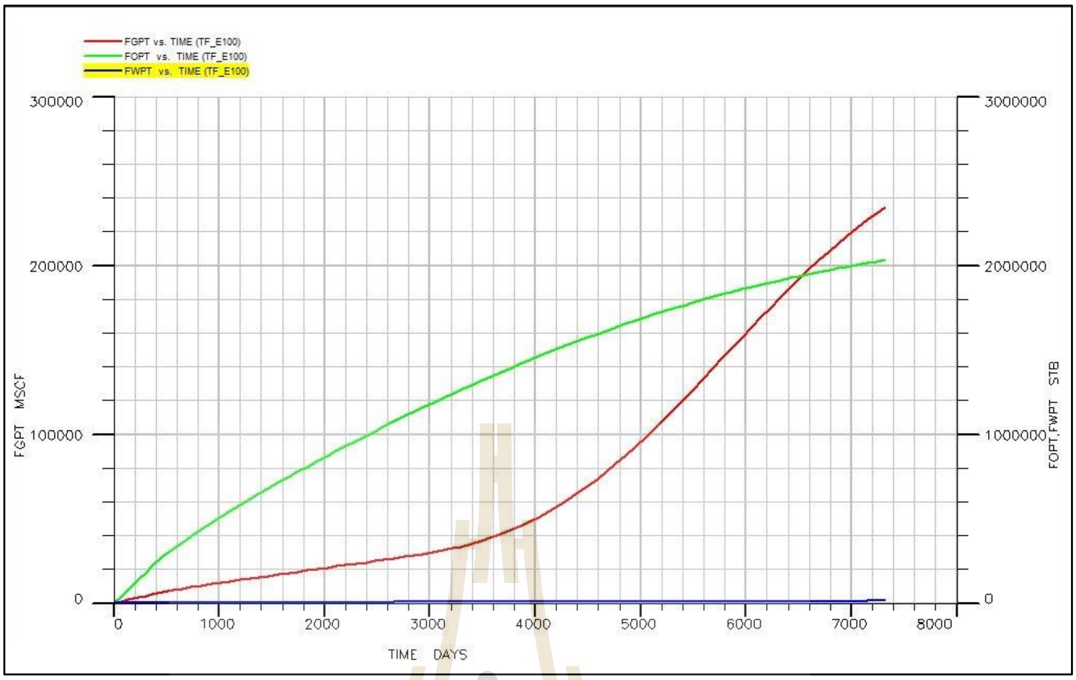


Figure 4.2 Cumulative fluids production profile vs. time of model case 1.

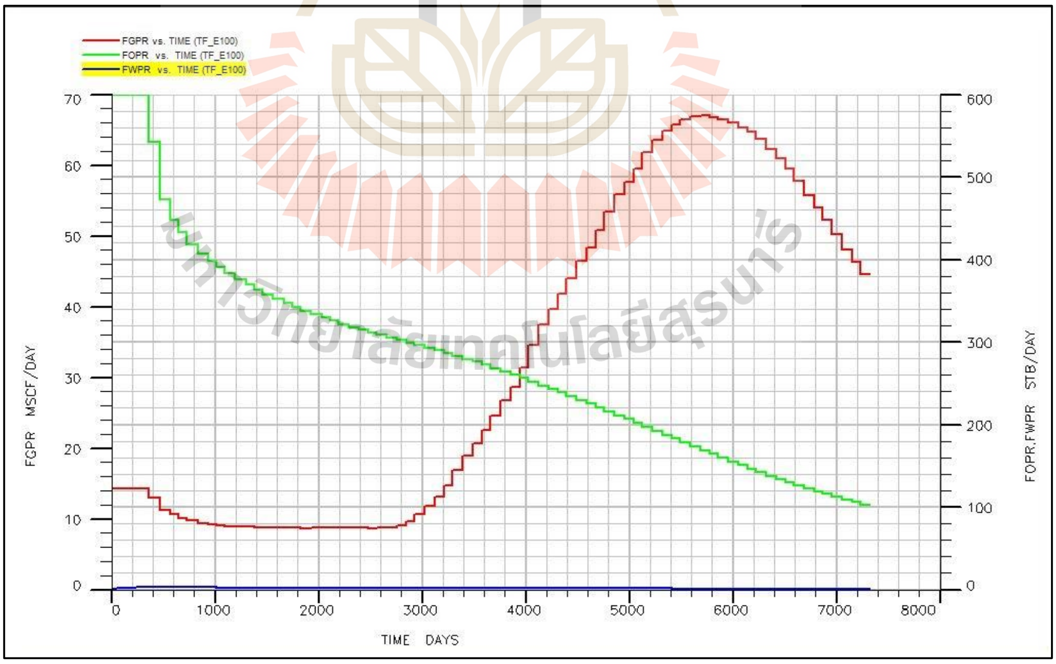


Figure 4.3 Fluids production rate profile vs. time of model case 1.

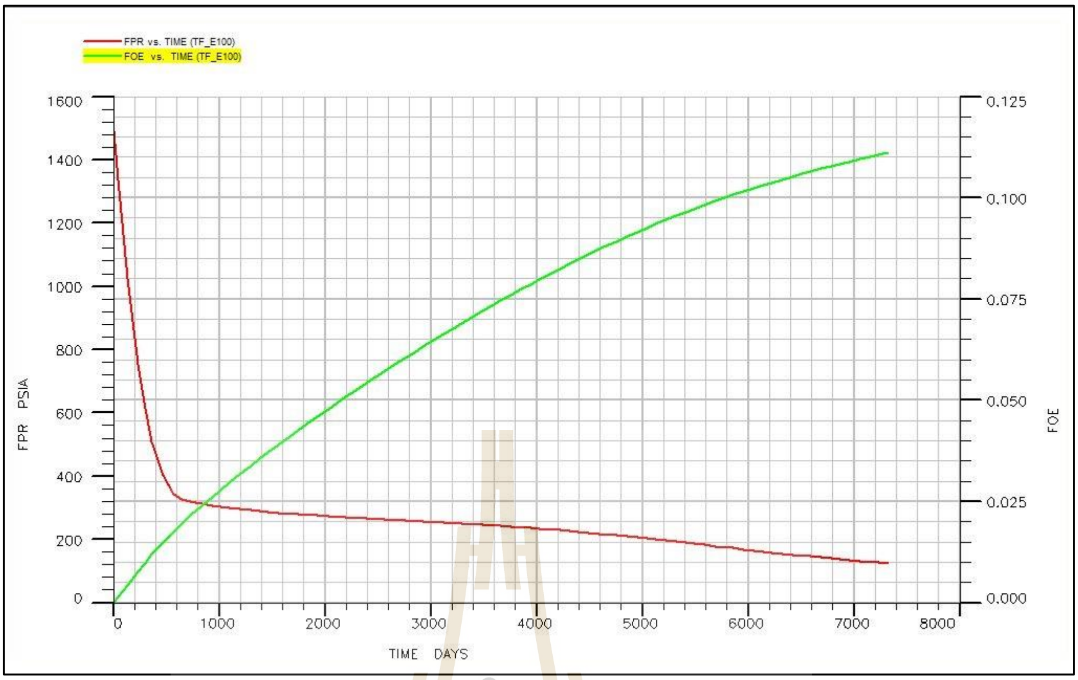


Figure 4.4 Field pressure and oil recovery efficiency vs. time of model case 1.

### 4.1.2 Result of Model Case 2

Model Case 2 employs the direct line drive pattern and natural flow method. The production period is 20 years. The production is commenced in 4 production wells at the initial oil production rate of 150 bbl/d/well. The simulation results are shown in Figures 4.5 – 4.8:

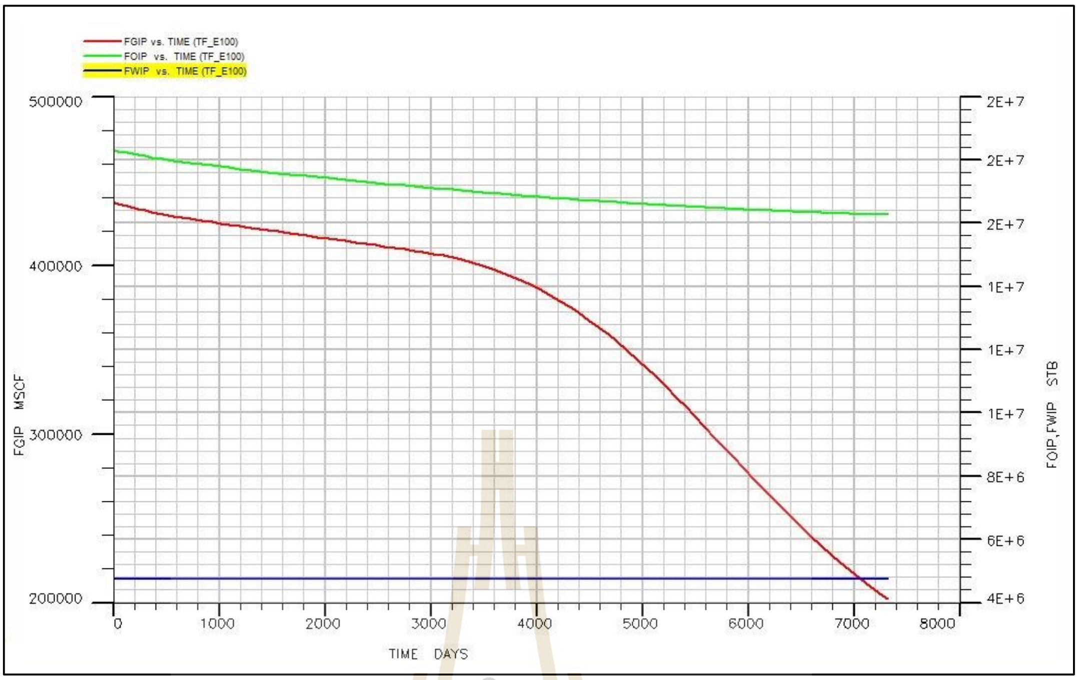


Figure 4.5 Fluid in place profile vs. time of model case 2.

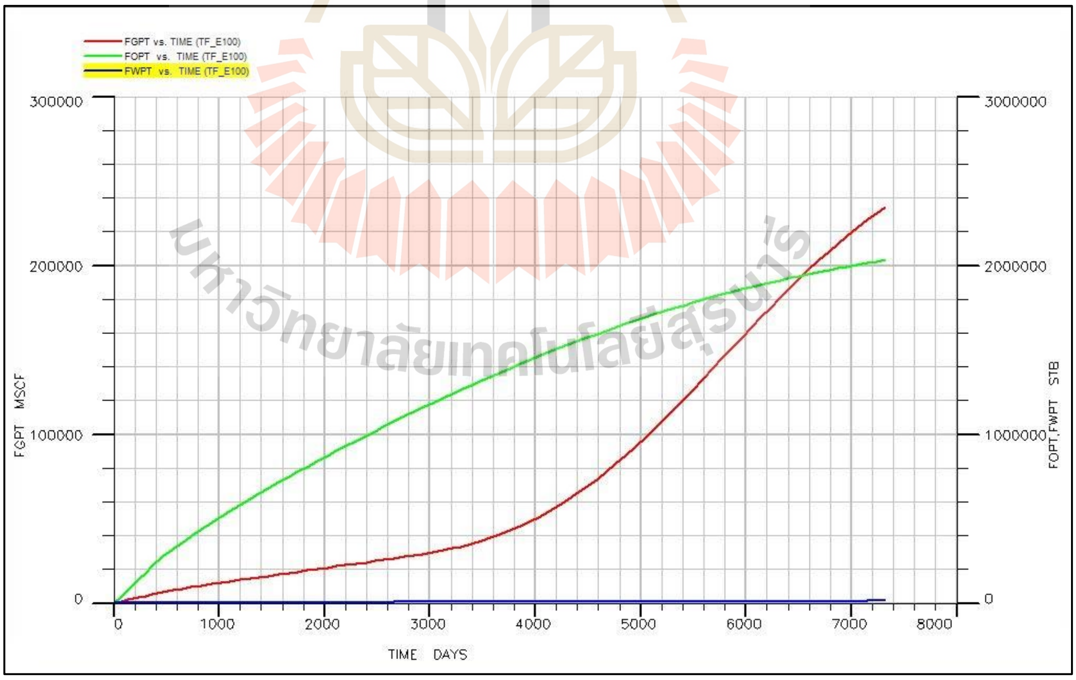


Figure 4.6 Cumulative fluids production profile vs. time of model case 2.

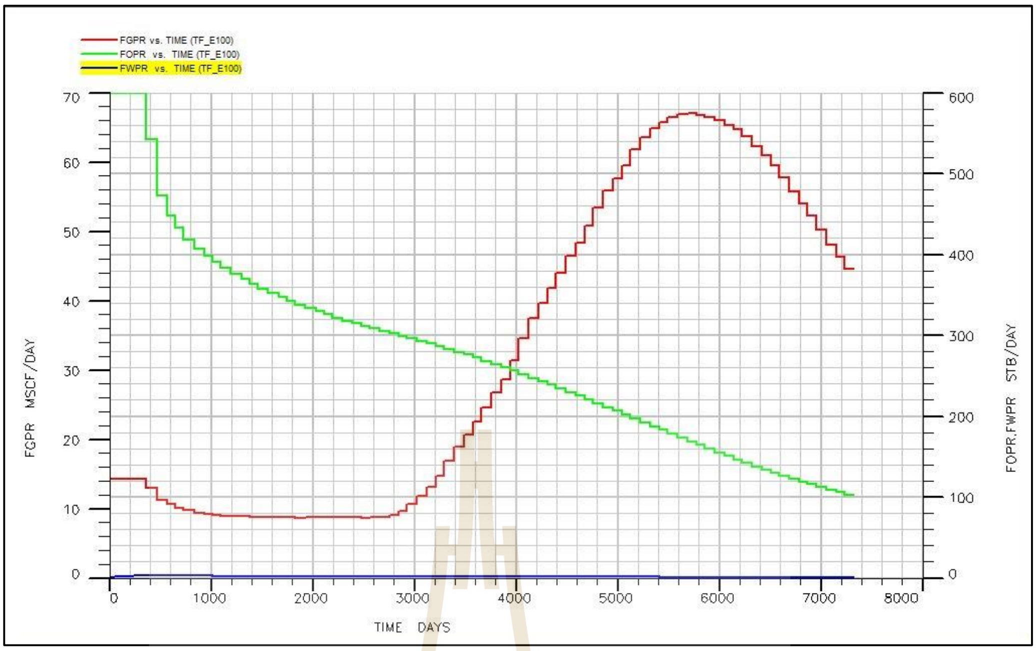


Figure 4.7 Fluids production rate profile vs. time of model case 2.

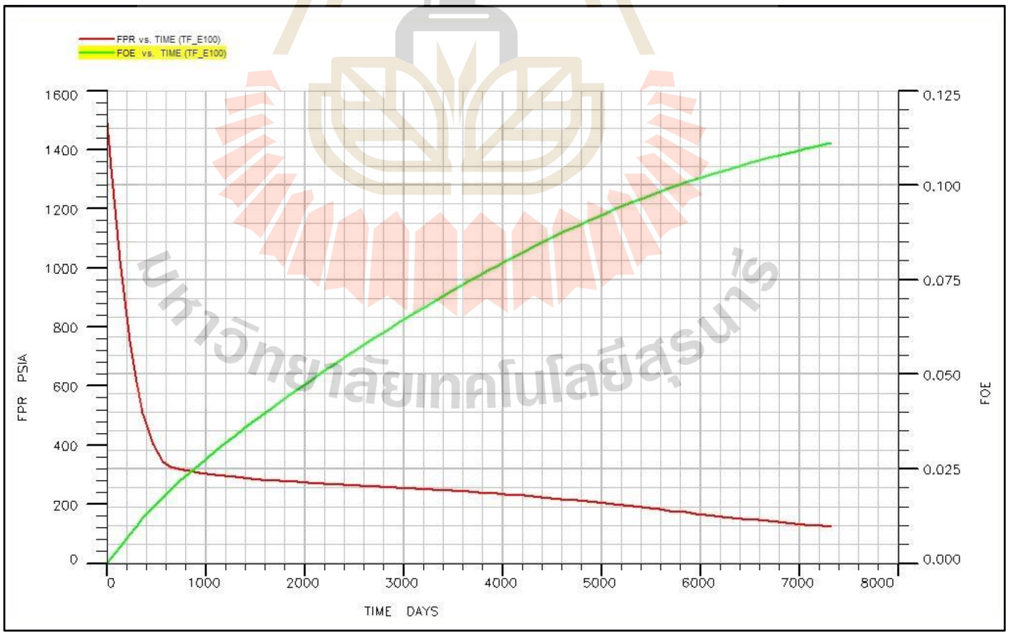


Figure 4.8 Field pressure and oil recovery efficiency vs. time of model case 2.

### 4.1.3 Result of Model Case 3

Model Case 3 employs the staggered line drive pattern and water injection method in the first year. The production period is 20 years. In one well, the production is commended using the initial oil production rate of 600 bbl/d. In the other two, the production are commended at the water injection rate of 250 bbl/d/well. The simulation results are shown in Figures 4.9 – 4.12:

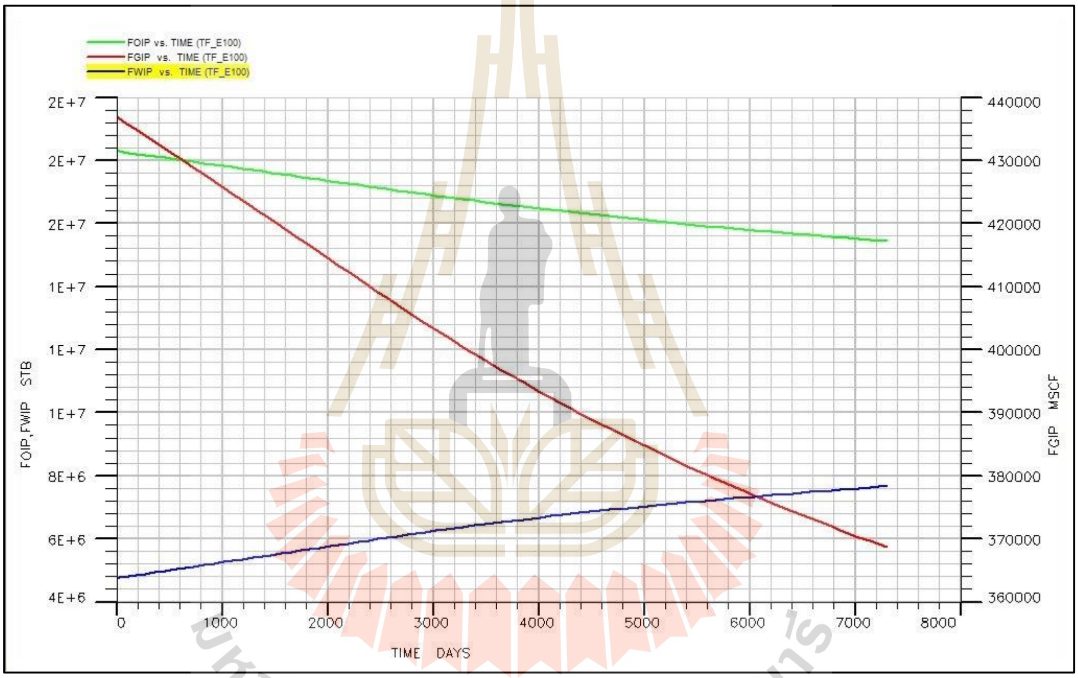


Figure 4.9 Fluid in place profile vs. time of model case 3.

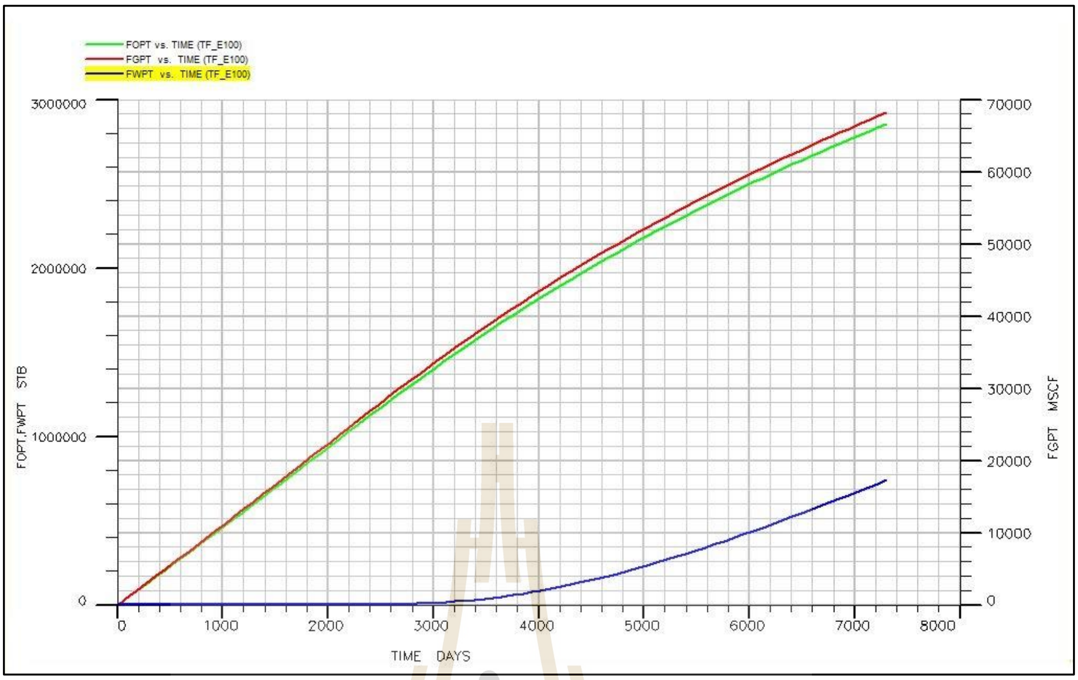


Figure 4.10 Cumulative fluids production profile vs. time of model case 3.

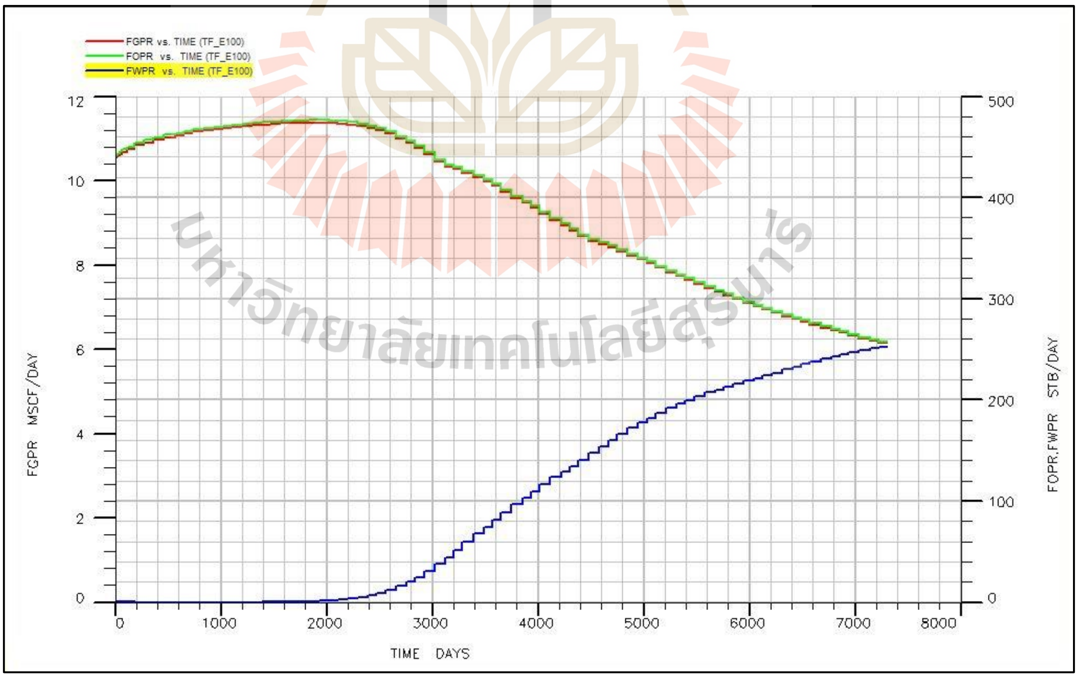


Figure 4.11 Fluids production rate profile vs. time of model case 3.

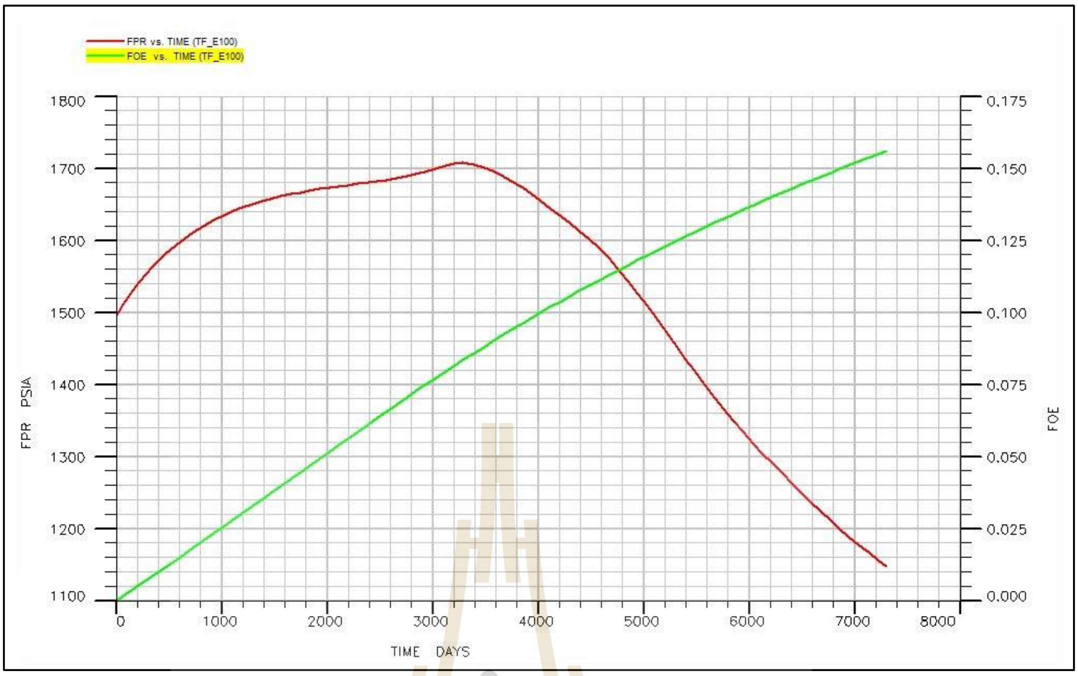


Figure 4.12 Field pressure and oil recovery efficiency vs. time of model case 3.

### 4.1.4 Result of Model Case 4

Model Case 4 employs the direct line drive pattern and water injection method in the first year. The production period is 20 years. The production is commenced at the initial oil production rate of 300 bbl/d/well before converting to the water injection rate of 250 bbl/d/well in two wells. The simulation results are shown in Figures 4.13 – 4.16:

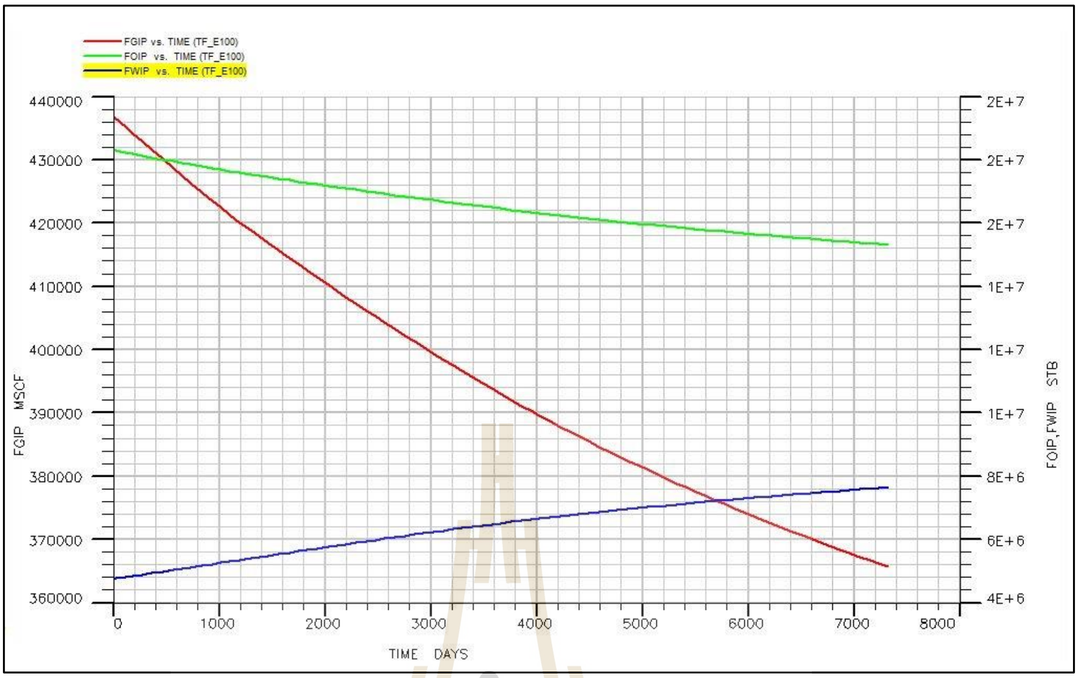


Figure 4.13 Fluid in place profile vs. time of model case 4.

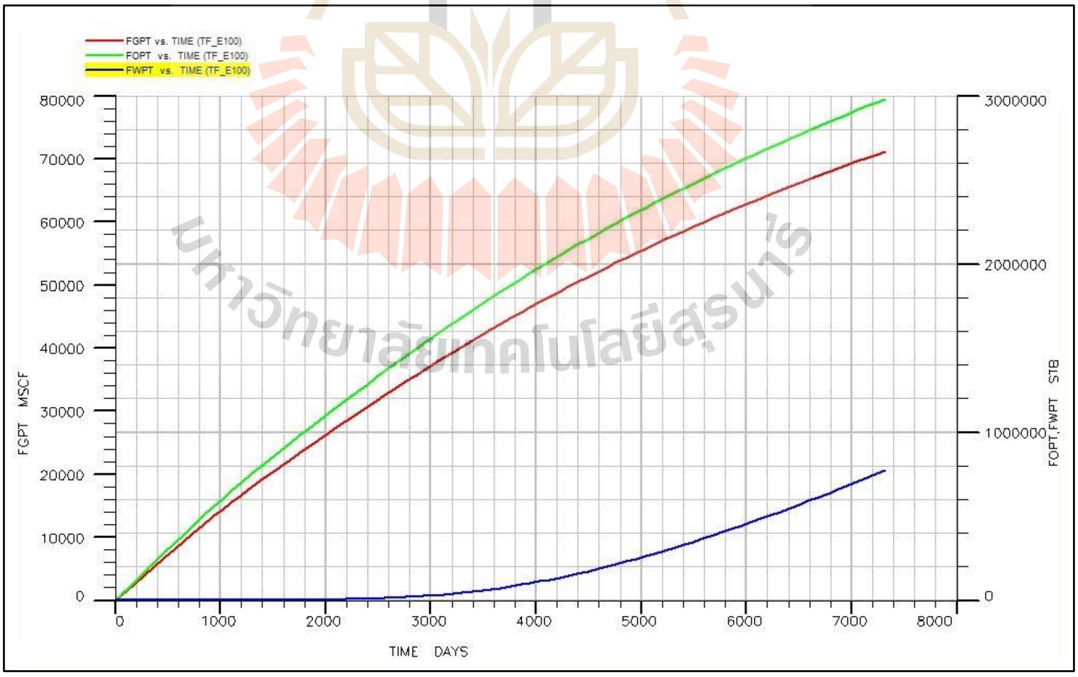


Figure 4.14 Cumulative fluids production profile vs. time of model case 4.

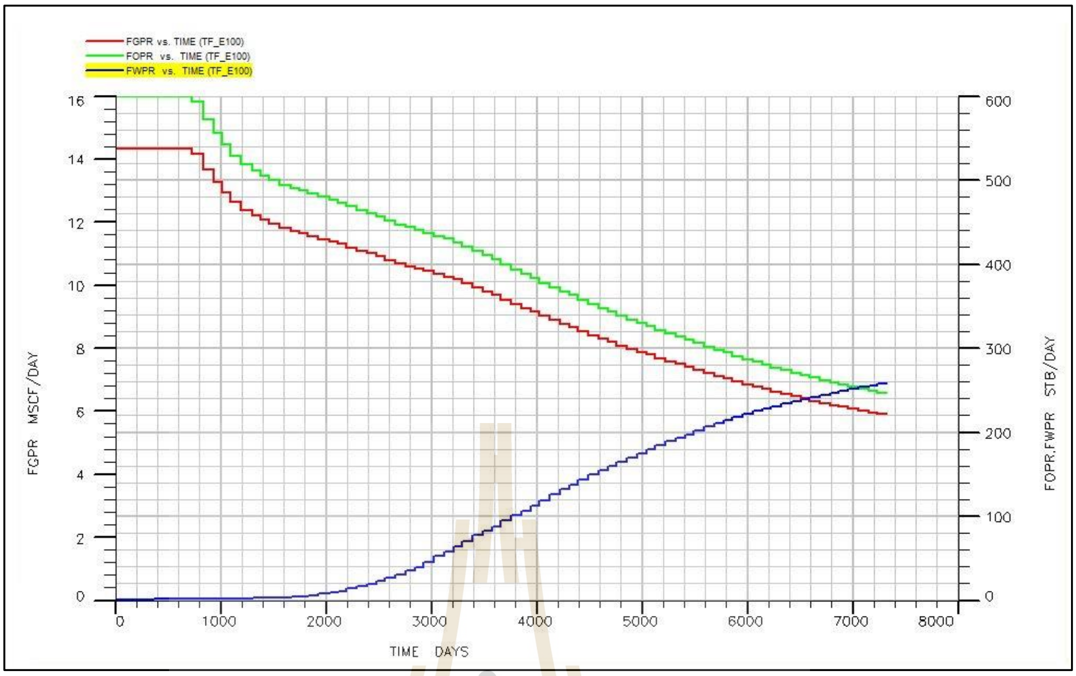


Figure 4.15 Fluids production rate profile vs. time of model case 4.

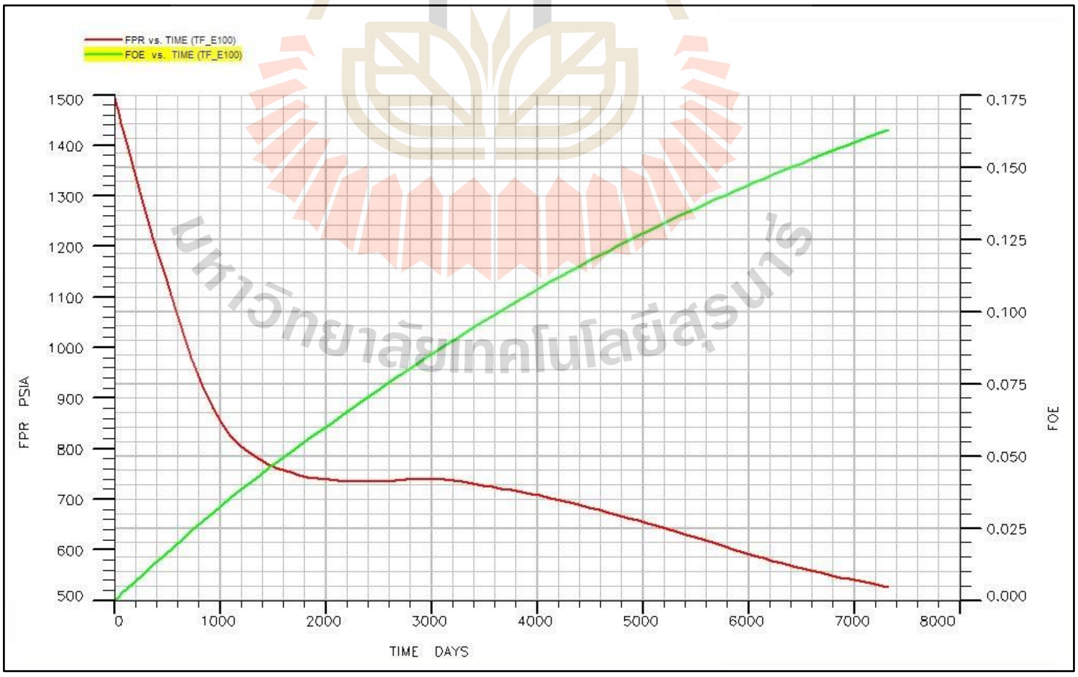


Figure 4.16 Field pressure and oil recovery efficiency vs. time of model case 4.

### 4.1.5 Result of Model Case 5

Model Case 5 employs the staggered line drive pattern and water injection method in the third year. The production period is 20 years. The production is commenced at the initial oil production rate of 200 bbl/d/well in all wells. After 2 years, the water injection are employed in 2 wells with the injection rate of 250 bbl/d/well. Production in the other well is produced at the rate of 600 bbl/d. The simulation results are shown in Figures 4.17 – 4.20:

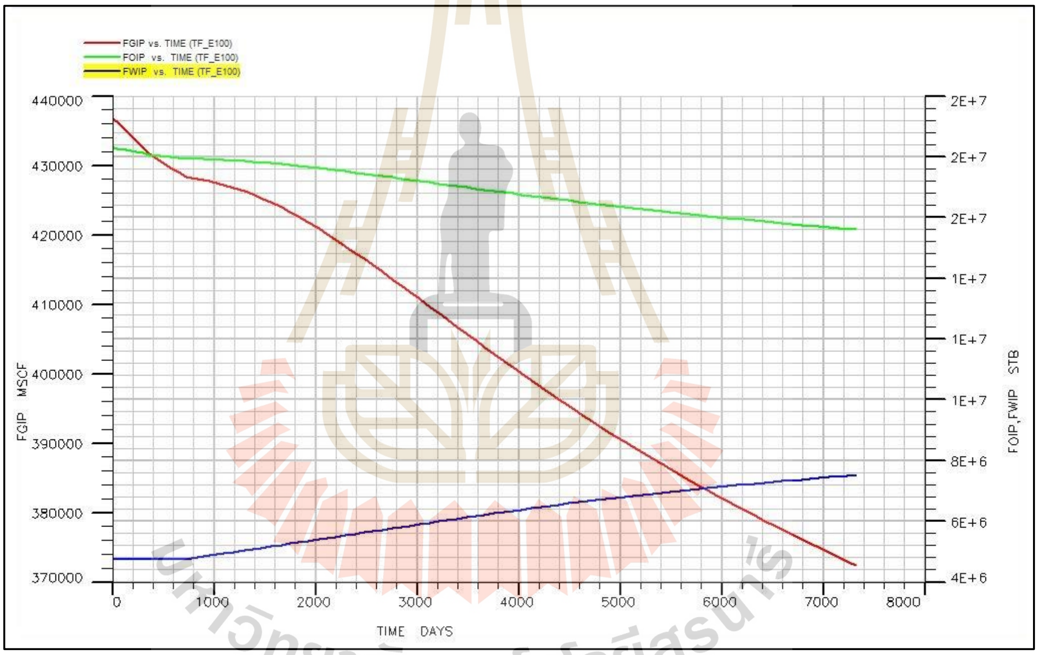


Figure 4.17 Fluid in place profile vs. time of model case 5.

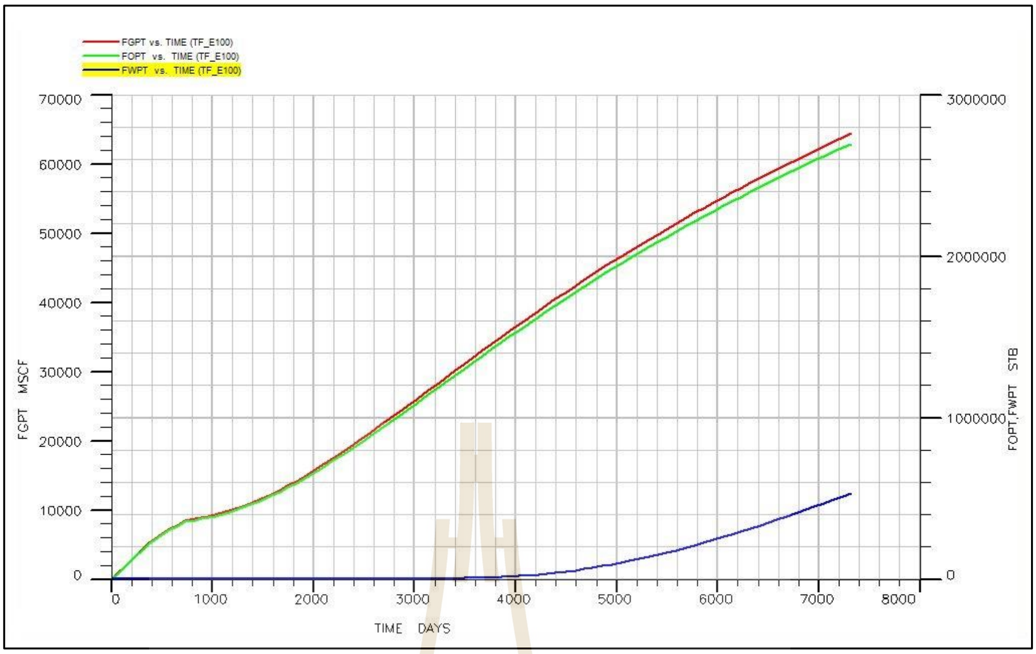


Figure 4.18 Cumulative fluids production profile vs. time of model case 5.

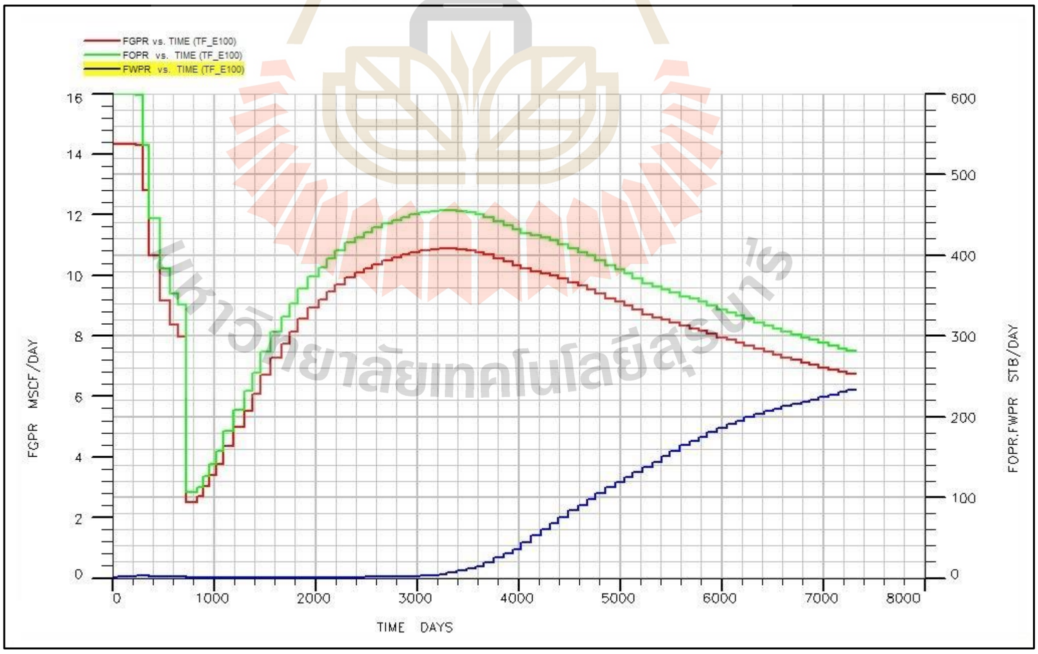


Figure 4.19 Fluids production rate profile vs. time of model case 5.

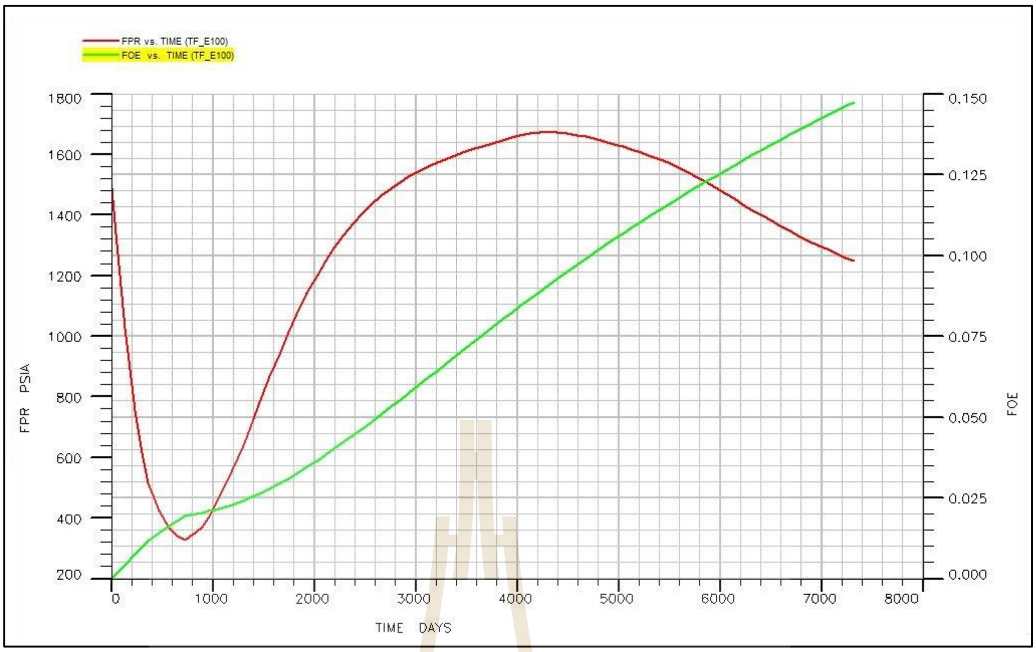


Figure 4.20 Field pressure and oil recovery efficiency vs. time of model case 5.

### 4.1.6 Result of Model Case 6

Model Case 6 employs the direct line drive pattern and water injection method in the third year. The production period is 20 years. The production is commenced in 4 production wells at the initial production rate of 150 bbl/d/well. After 2 years, 2 production wells are converted to start water injection at the injection rate of 250 bbl/d/well. The remaining 2 production wells are produced at the rate of 300 bbl/d/well. The simulation results are shown in Figures 4.21 – 4.24:

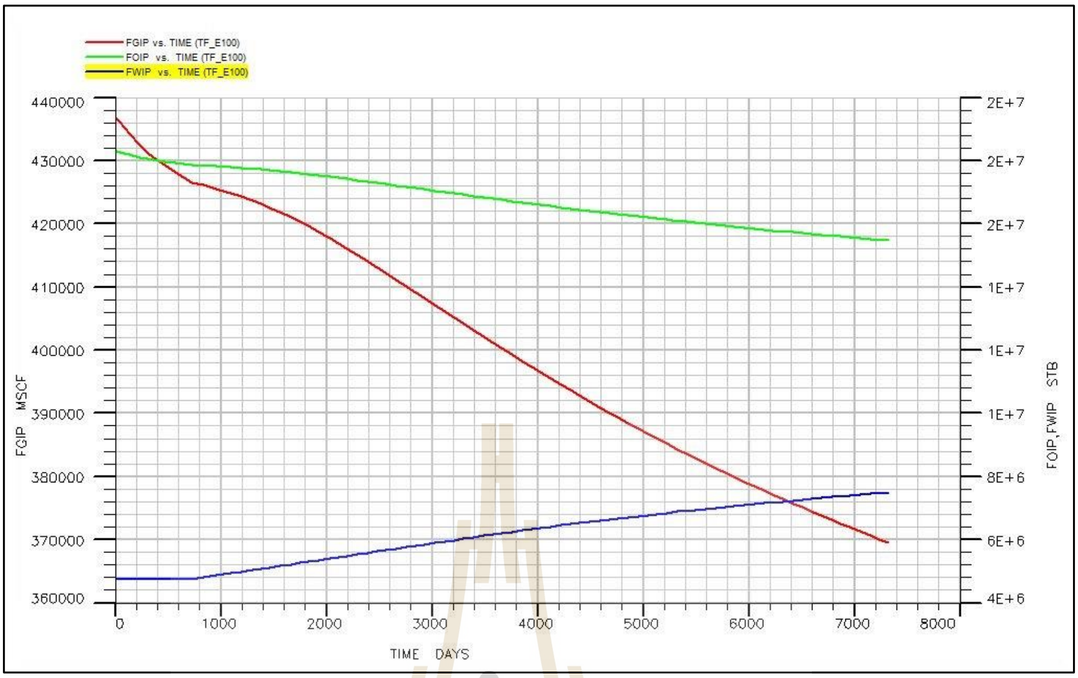


Figure 4.21 Fluid in place profile vs. time of model case 6.

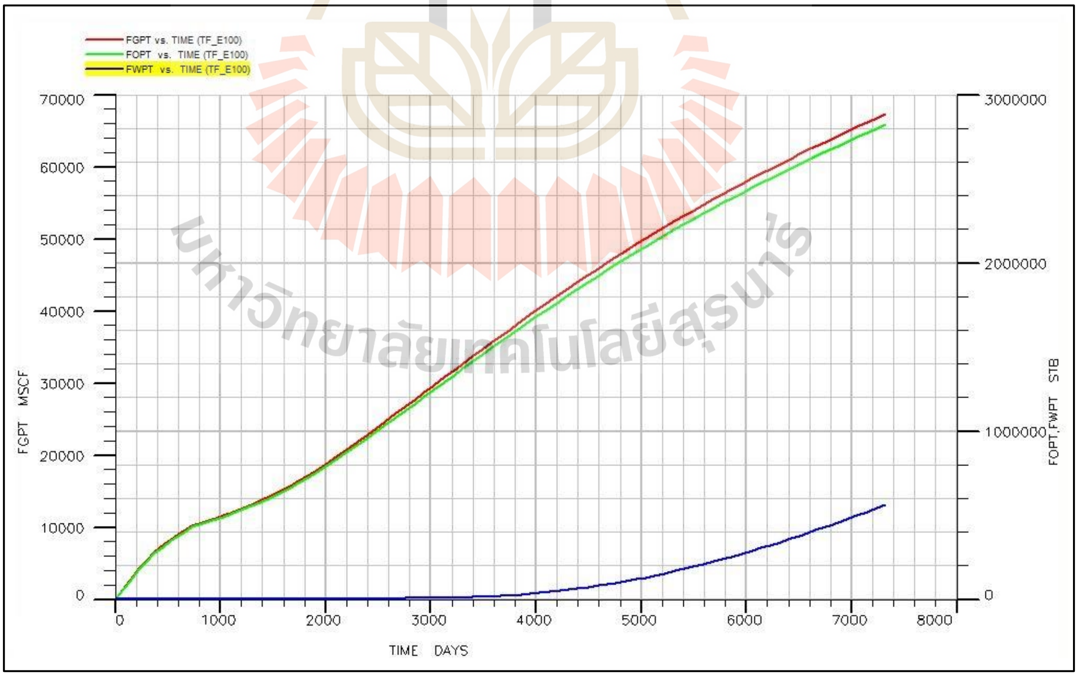


Figure 4.22 Cumulative fluids production profile vs. time of model case 6.

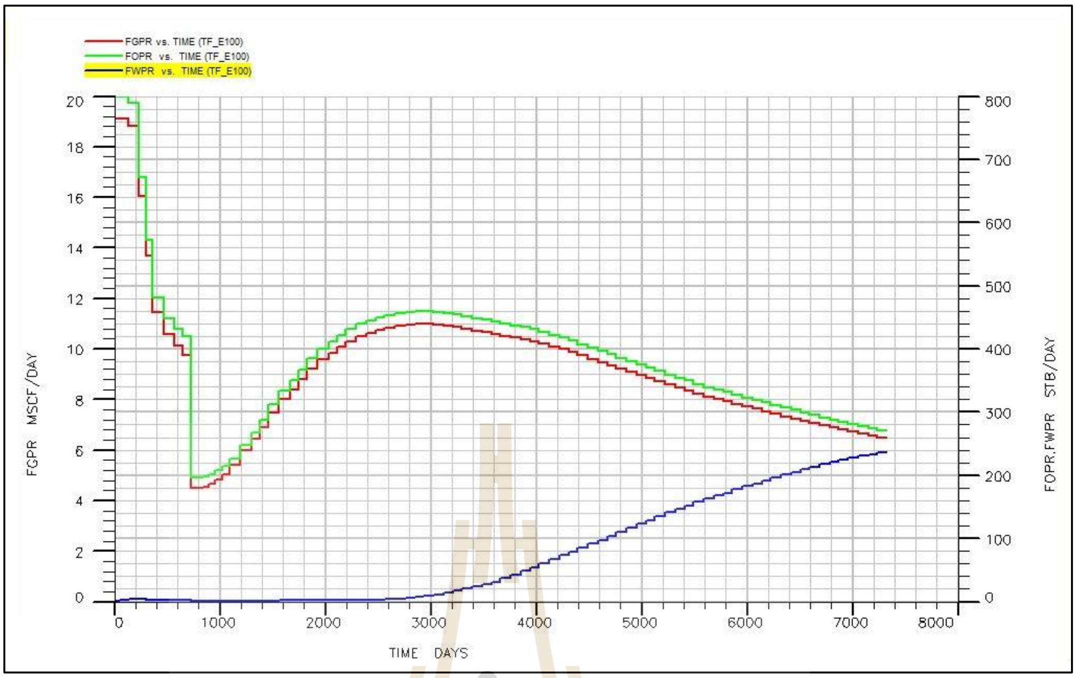


Figure 4.23 Fluids production rate profile vs. time of model case 6.

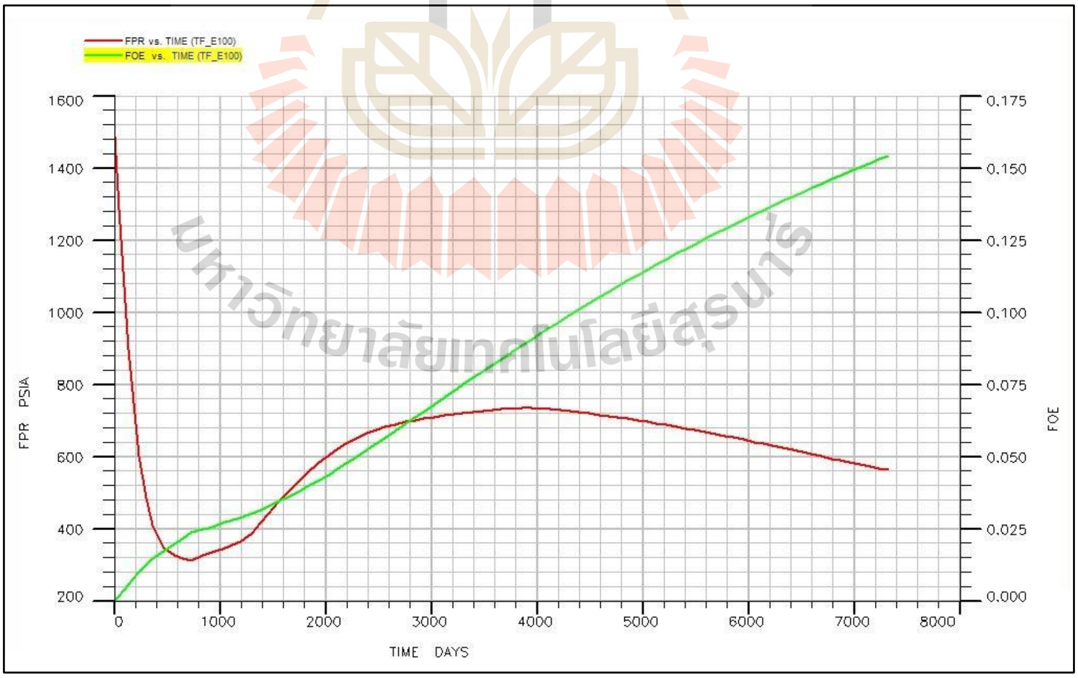


Figure 4.24 Field pressure and oil recovery efficiency vs. time of model case 6.

### 4.1.7 Result of Model Case 7

Model case 7 employs the staggered line drive pattern and water injection method in the fifth year. The production period is 20 years. The production is commended in 3 production wells at the initial oil production rate of 200 bbl/d/well. After 4 years, 2 production wells are converted to start water injection at the injection rate of 250 bbl/d/well. The remaining production wells are produced at the rate of 600 bbl/d. The simulation results are shown in Figures 4.25 – 4.28:

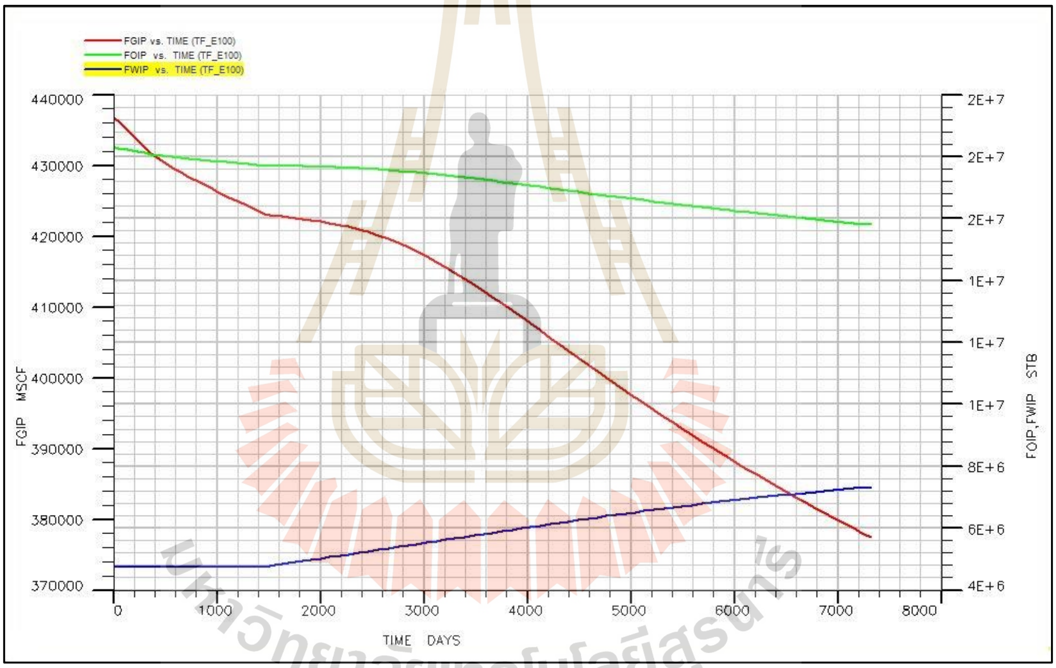


Figure 4.25 Fluid in place profile vs. time of model case 7.

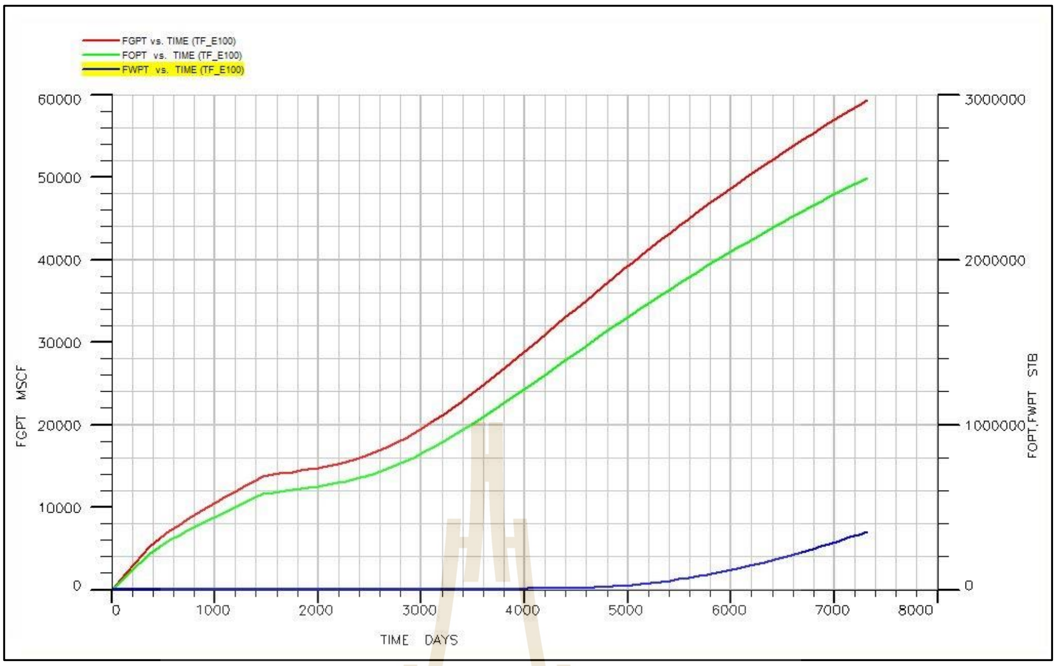


Figure 4.26 Cumulative fluids production profile vs. time of model case 7.

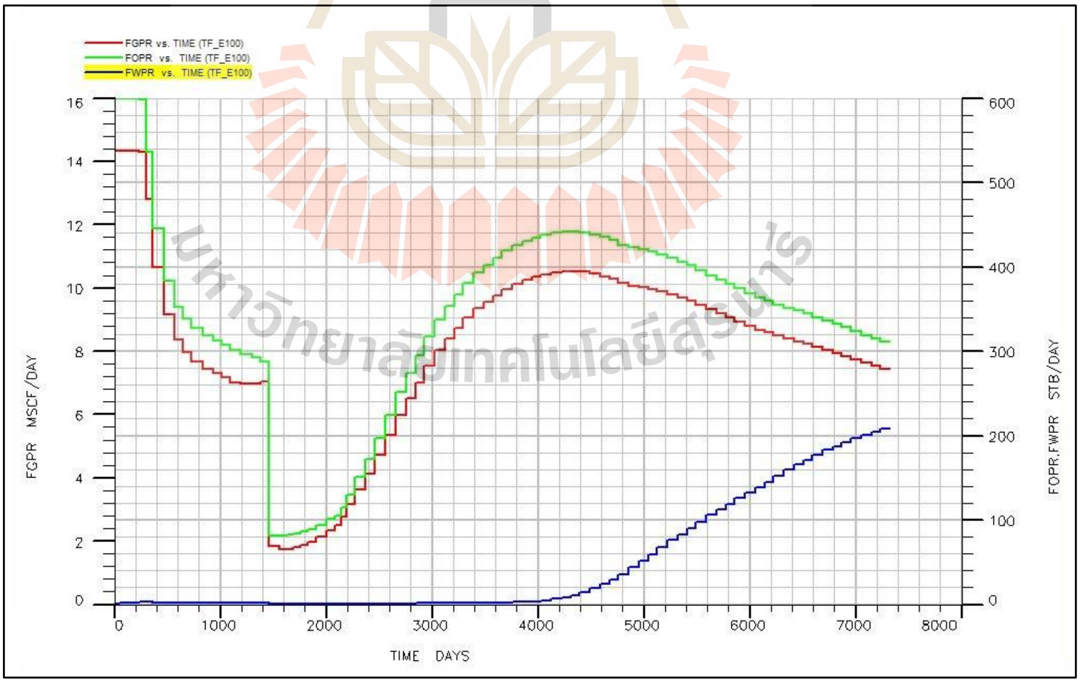


Figure 4.27 Fluids production rate profile vs. time of model case 7.

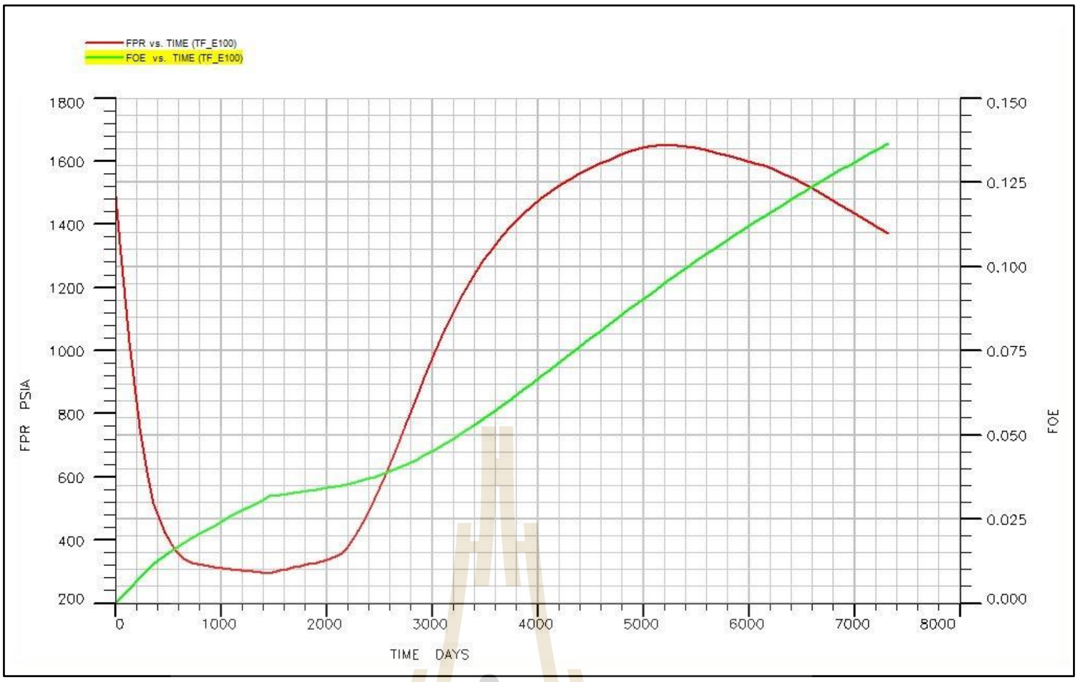


Figure 4.28 Field pressure and oil recovery efficiency vs. time of model case 7.

### 4.1.8 Result of Model Case 8

Model Case 8 employs the direct line drive pattern and water injection method in the fifth year. The production period is 20 years. The production is commenced in 4 production wells at the initial oil production rate of 150 bbl/d/well. After 4 years, 2 production wells are converted to start water injection at the injection rate of 250 bbl/d/well. The remaining 2 production wells are produced at the rate of 300 bbl/d/well. The simulation results are shown in Figures 4.29 – 4.32:

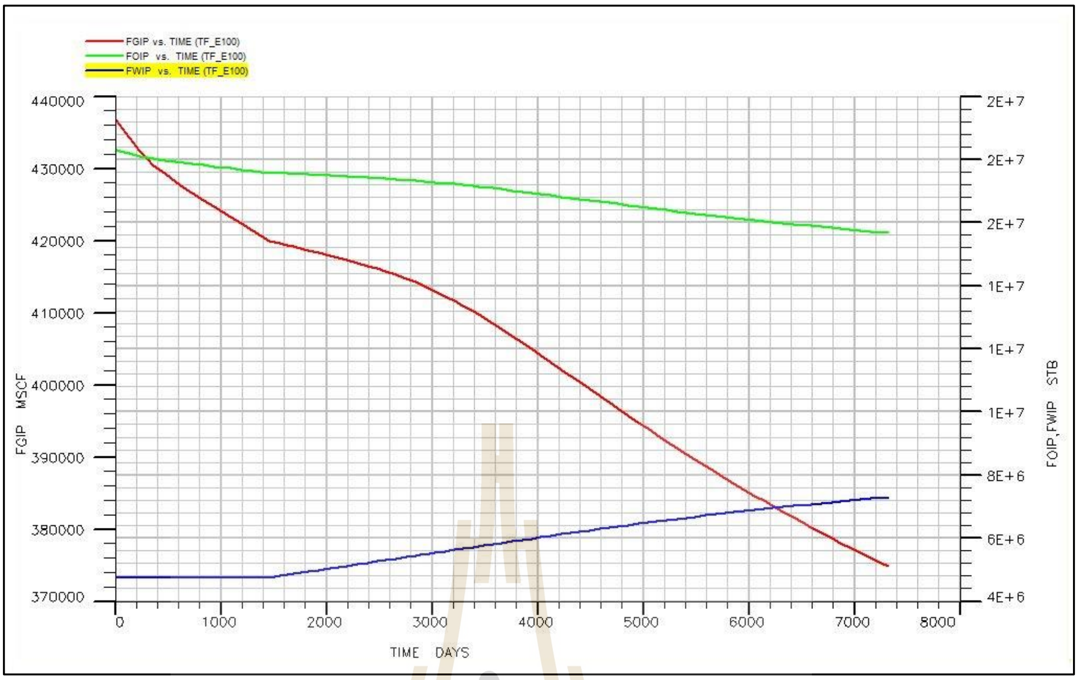


Figure 4.29 Fluid in place profile vs. time of model case 8.

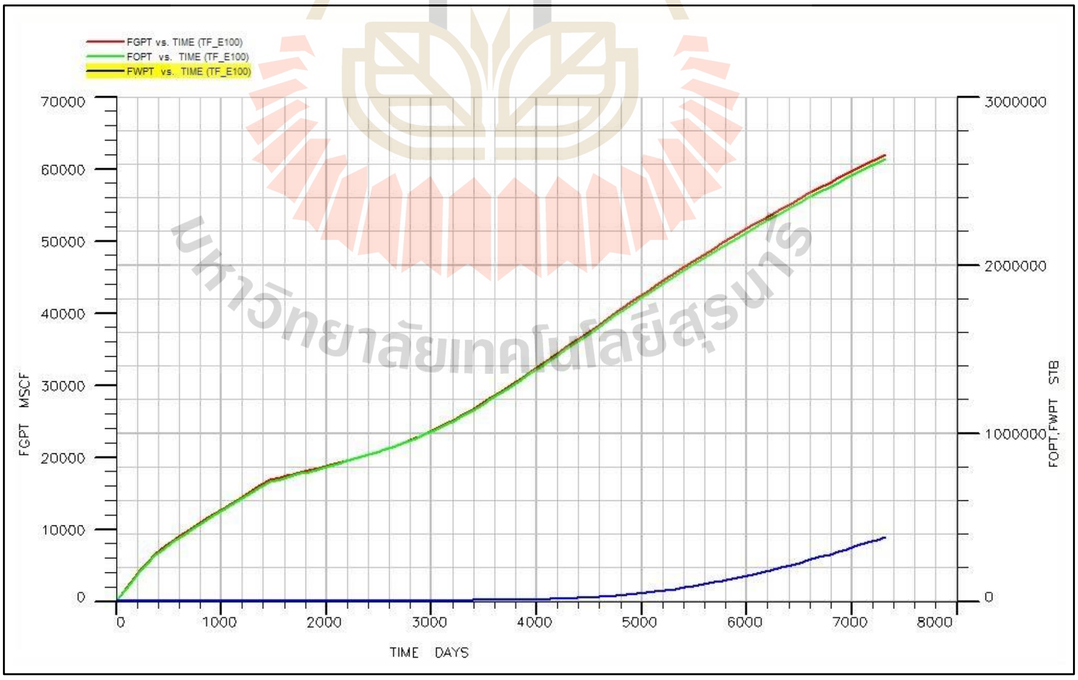


Figure 4.30 Cumulative fluids production profile vs. time of model case 8.

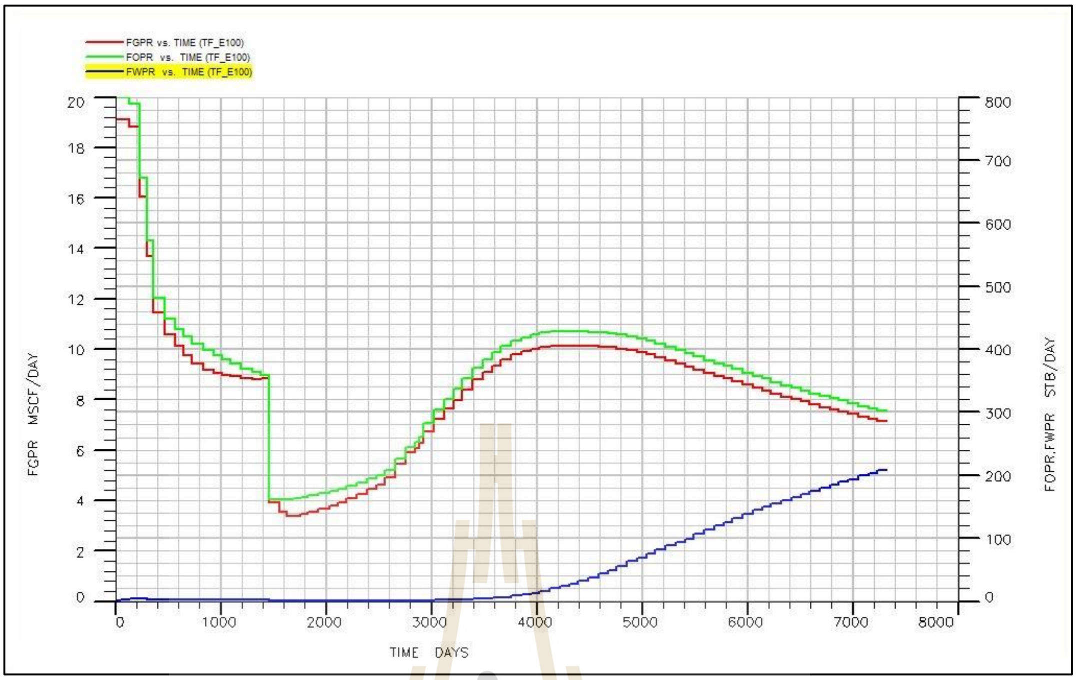


Figure 4.31 Fluids production rate profile vs. time of model case 8.

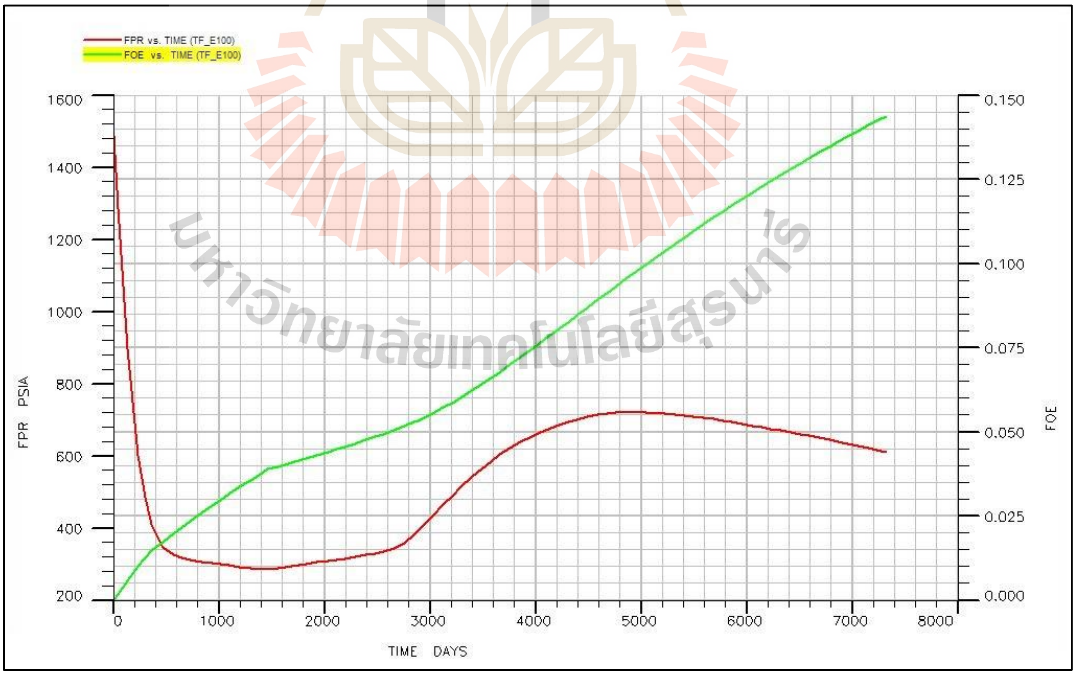


Figure 4.32 Field pressure and oil recovery efficiency vs. time of model case 8.

### 4.1.9 Result of Model Case 9

Model Case 9 employs the staggered line drive pattern and water injection method in the first year, and polymer injection method in the second year. The production period is 20 years. The production is commended at the oil production rate of 600 bbl/d, and water and polymer injection rate of 250 bbl/d/well in 2 injection wells. The simulation results are shown in Figures 4.33 – 4.37:

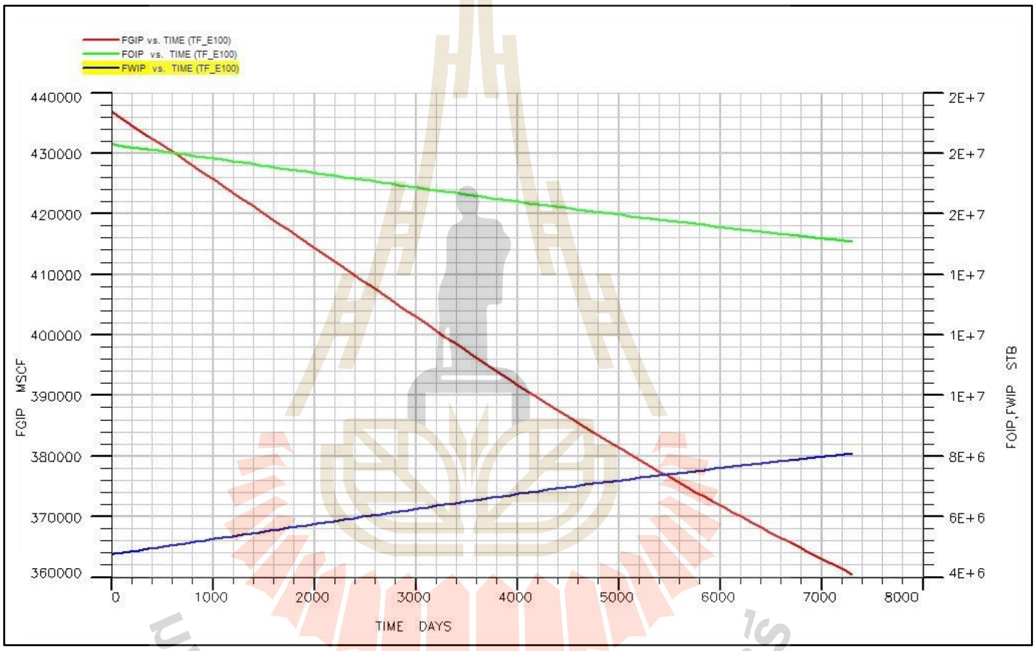


Figure 4.33 Fluid in place profile vs. time of model case 9.

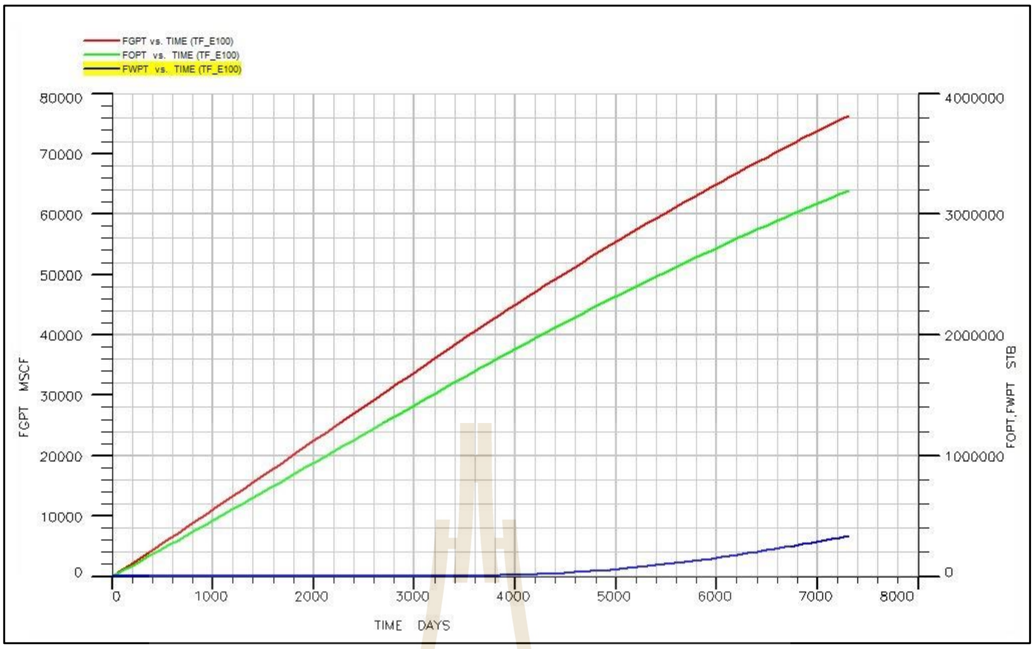


Figure 4.34 Cumulative fluids production profile vs. time of model case 9.

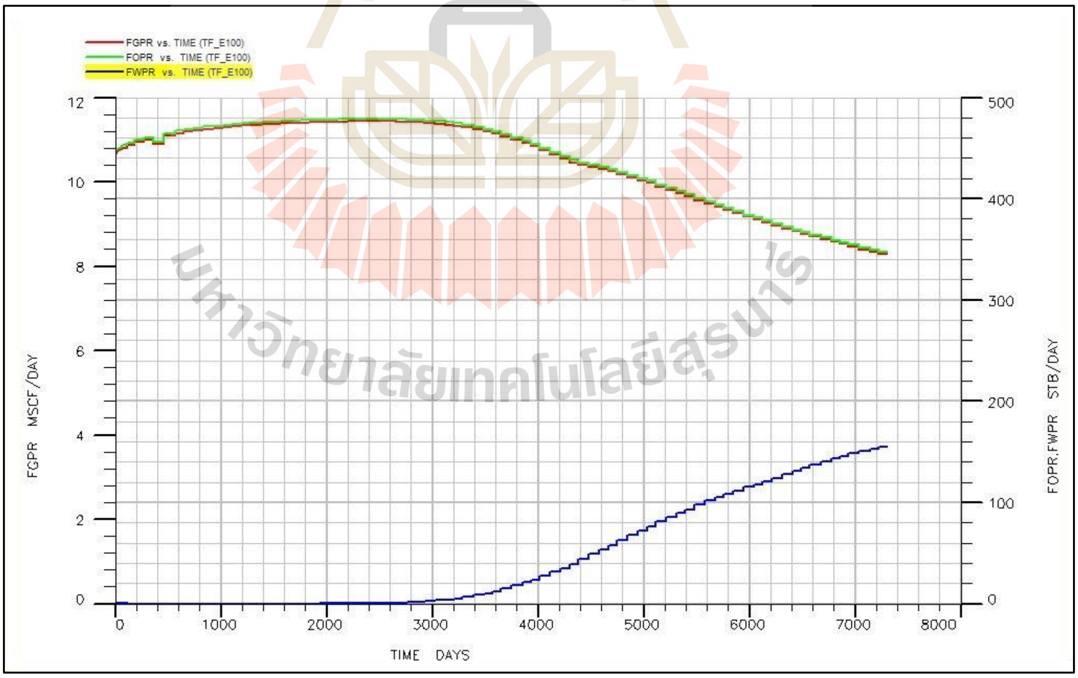


Figure 4.35 Fluids production rate profile vs. time of model case 9.

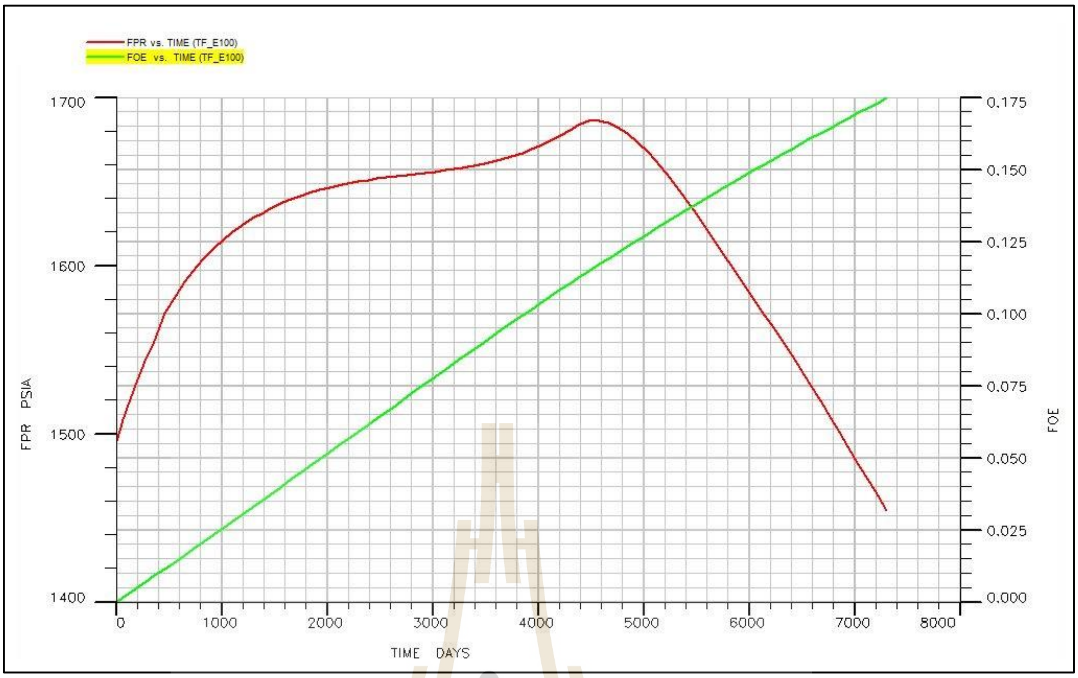


Figure 4.36 Field pressure and oil recovery efficiency vs. time of model case 9.

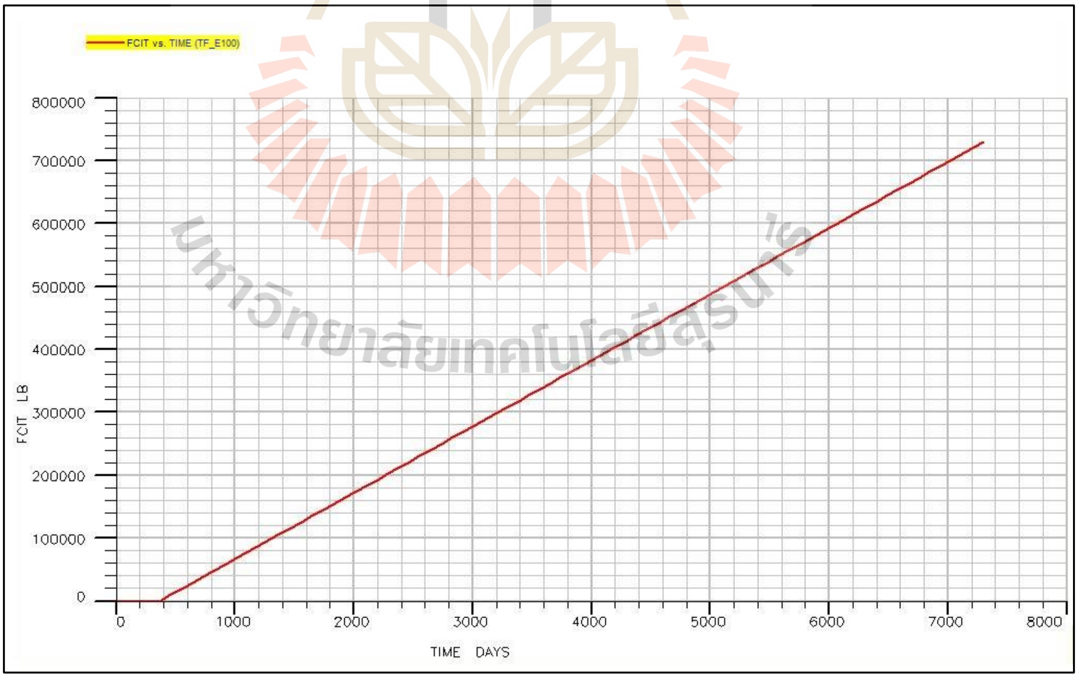


Figure 4.37 Field polymer injection total vs. time of model case 9.

### 4.1.10 Result of Model Case 10

Model Case 10 employs the direct line drive pattern and water injection method in the first year and polymer injection method in the second year. The production period is 20 years. The production is commenced in 2 production wells at the initial oil production rate of 300 bbl/d/well, and in 2 injection wells at the water and polymer injection rate of 250 bbl/d/well. The simulation results are shown in Figures 4.38 – 4.42:

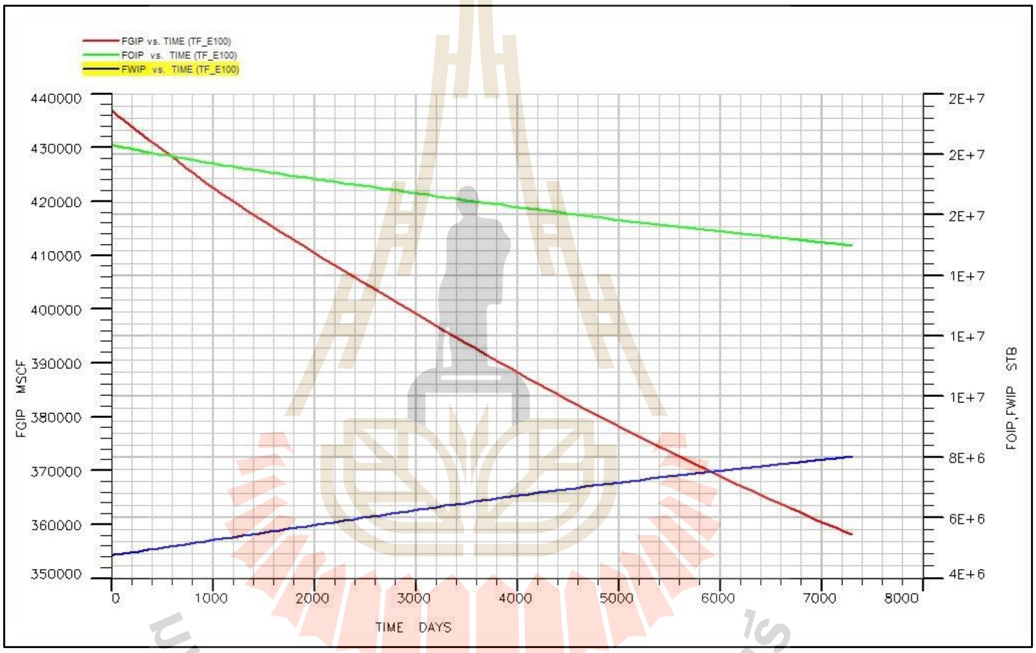


Figure 4.38 Fluid in place profile vs. time of model case 10.

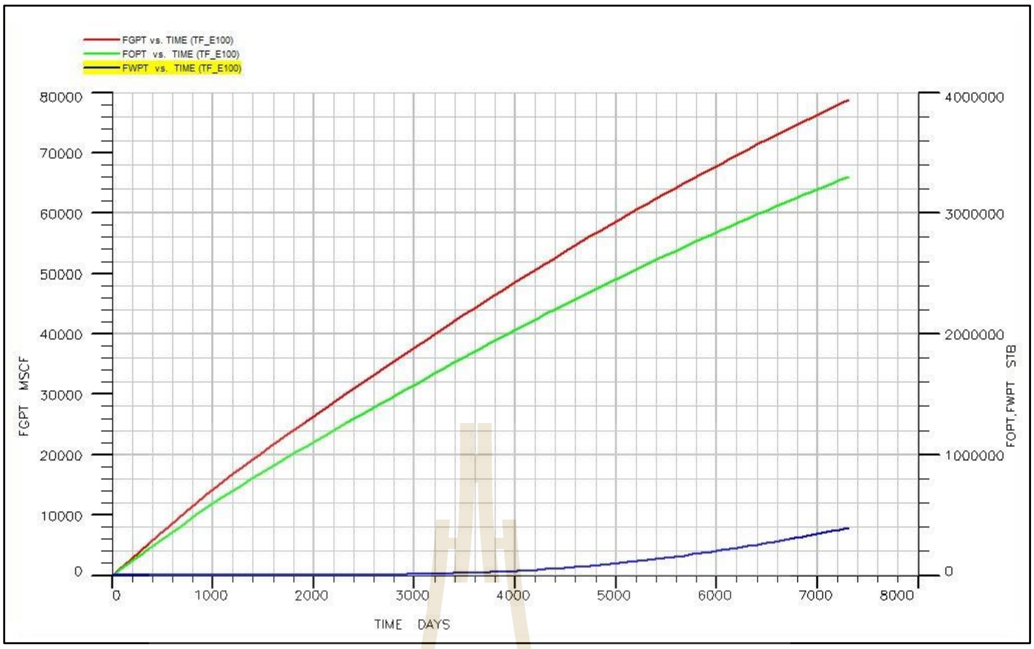


Figure 4.39 Cumulative fluids production profile vs. time of model case 10.

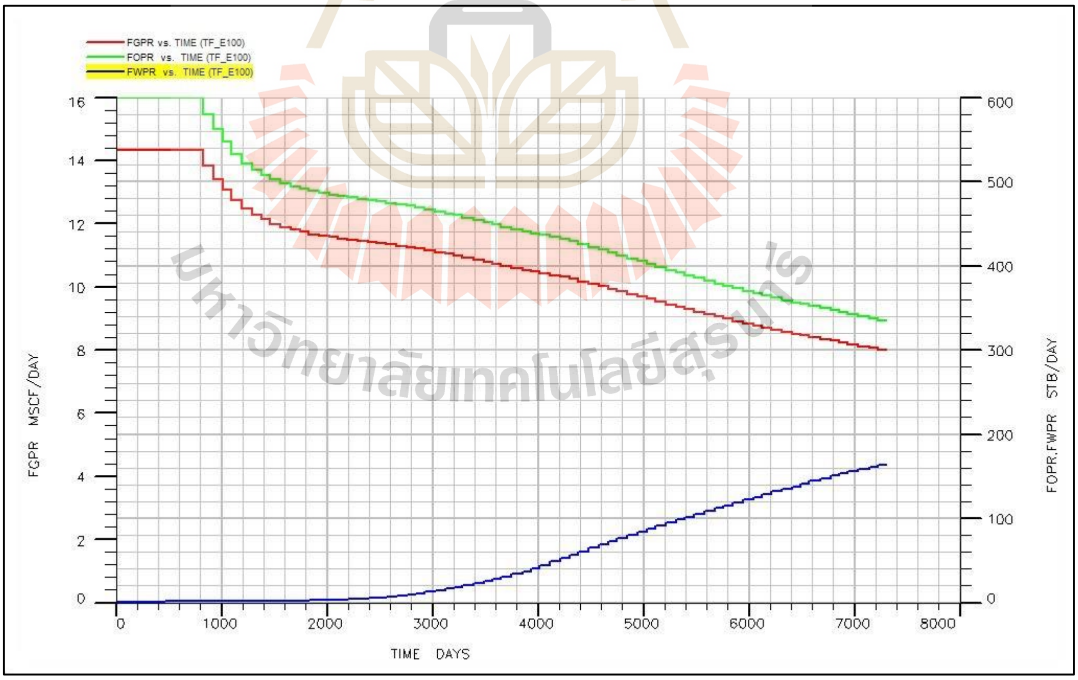


Figure 4.40 Fluids production rate profile vs. time of model case 10.

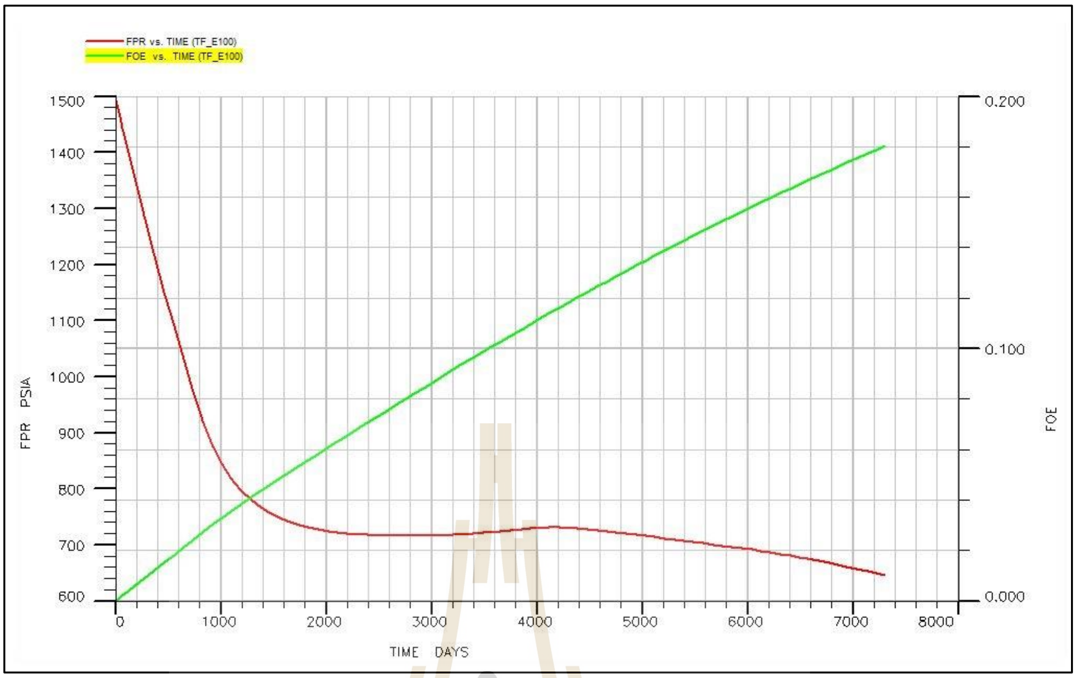


Figure 4.41 Field pressure and oil recovery efficiency vs. time of model case 10.

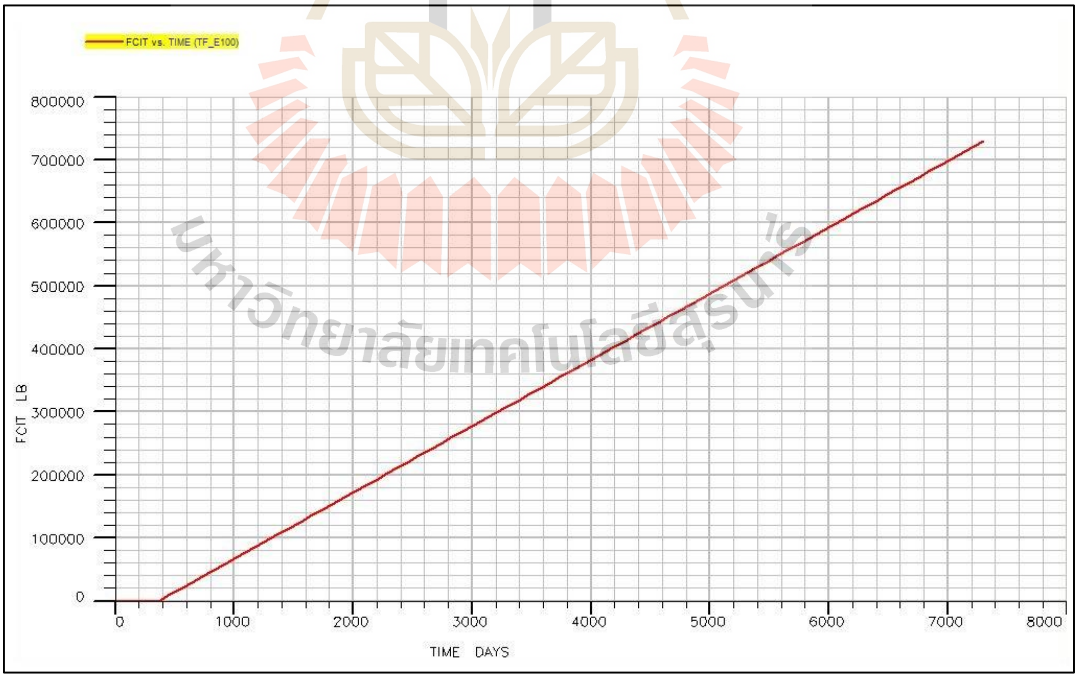


Figure 4.42 Field polymer injection total vs. time of model case 10.

### 4.1.11 Result of Model Case 11

Model Case 11 employs the staggered line drive pattern and water injection method in the second year, and polymer injection method in the third year. The production period is 20 years. The production is commenced in 3 production wells at the initial oil production rate of 200 bbl/d/well. After 2 years, the water injection method is employed. Two production wells are converted to injection well with the water and polymer injection rate of 250 bbl/d/well. The remaining production wells are produced at the rate of 600 bbl/d. The simulation results show in Figures 4.43 – 4.47:

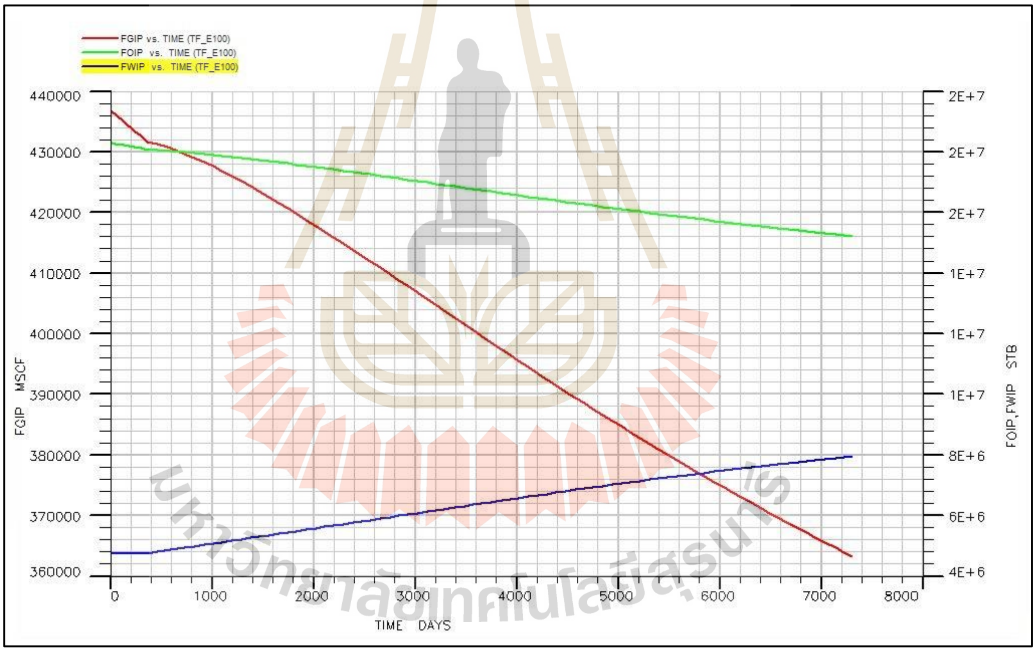


Figure 4.43 Fluid in place profile vs. time of model case 11.

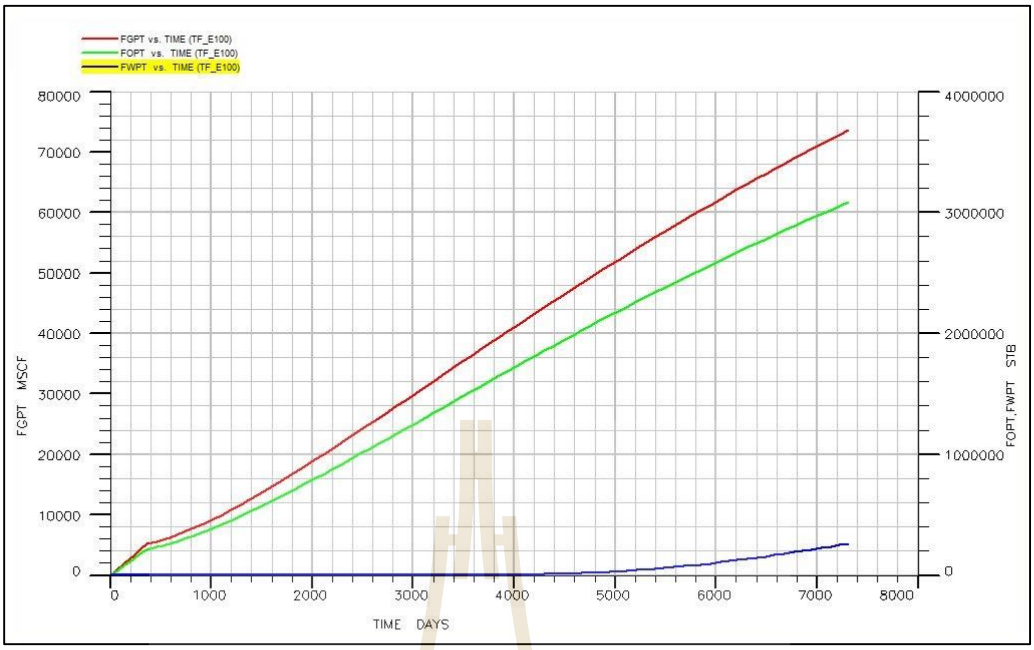


Figure 4.44 Cumulative fluids production profile vs. time of model case 11.

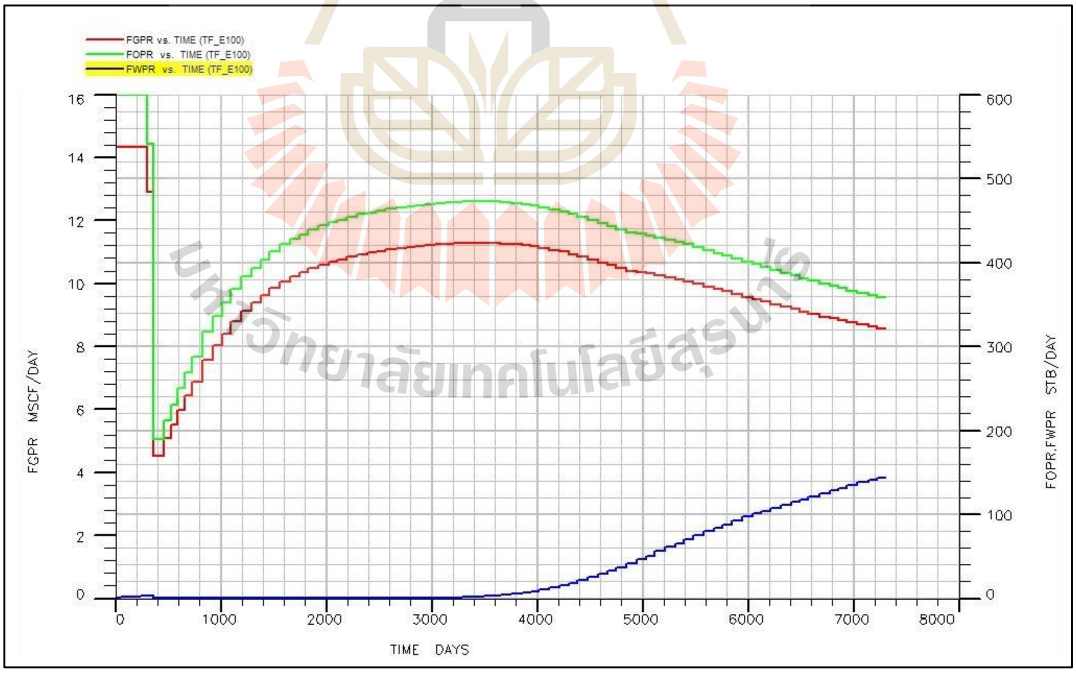


Figure 4.45 Fluids production rate profile vs. time of model case 11.

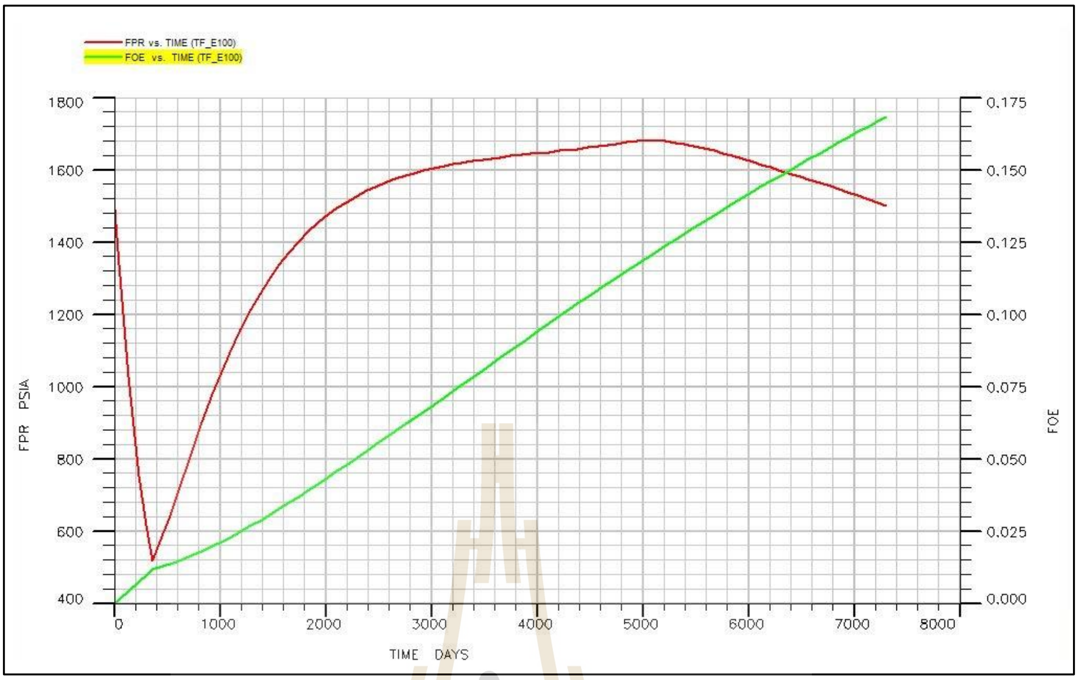


Figure 4.46 Field pressure and oil recovery efficiency vs. time of model case 11.

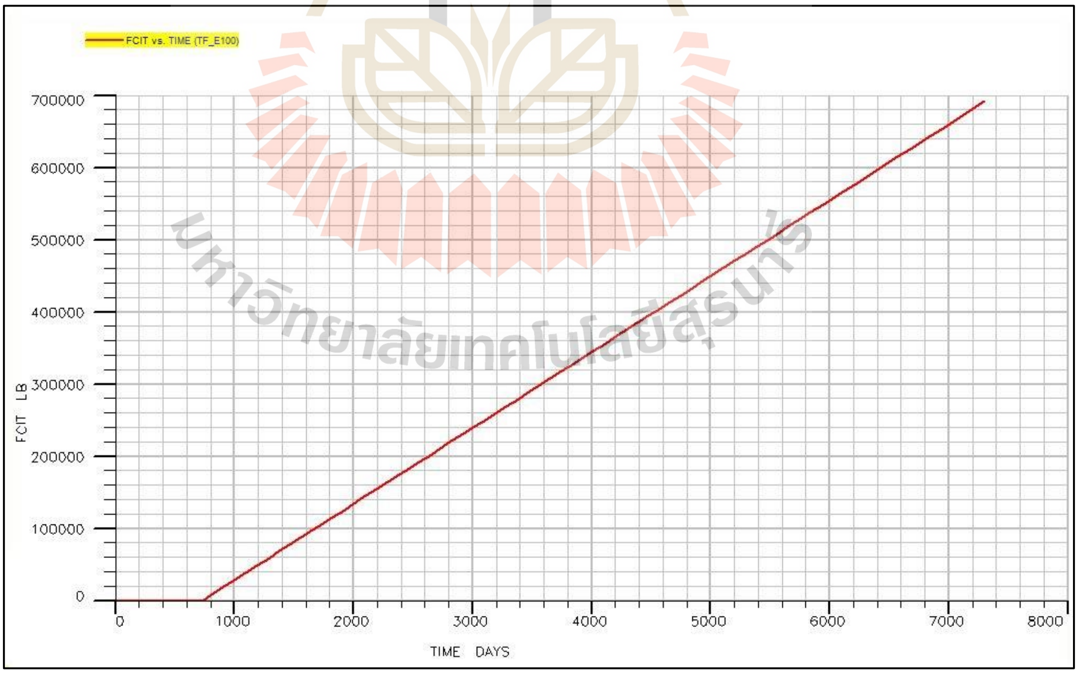


Figure 4.47 Field polymer injection total vs. time of model case 11.

#### 4.1.12 Result of Model Case 12

Model Case 12 employs the direct line drive pattern and water injection in the second year, and polymer injection in the third year. The production period is 20 years. The production is commenced in 4 production wells at the initial oil production rate of 150 bbl/d/well. After 2 years, 2 production wells are converted to injection wells to start water injection with the water and polymer injection rate of 250 bbl/d/well. The remaining production wells are produced at the rate of 300 bbl/d/well. The simulation results are shown in Figures 4.48 – 4.52:

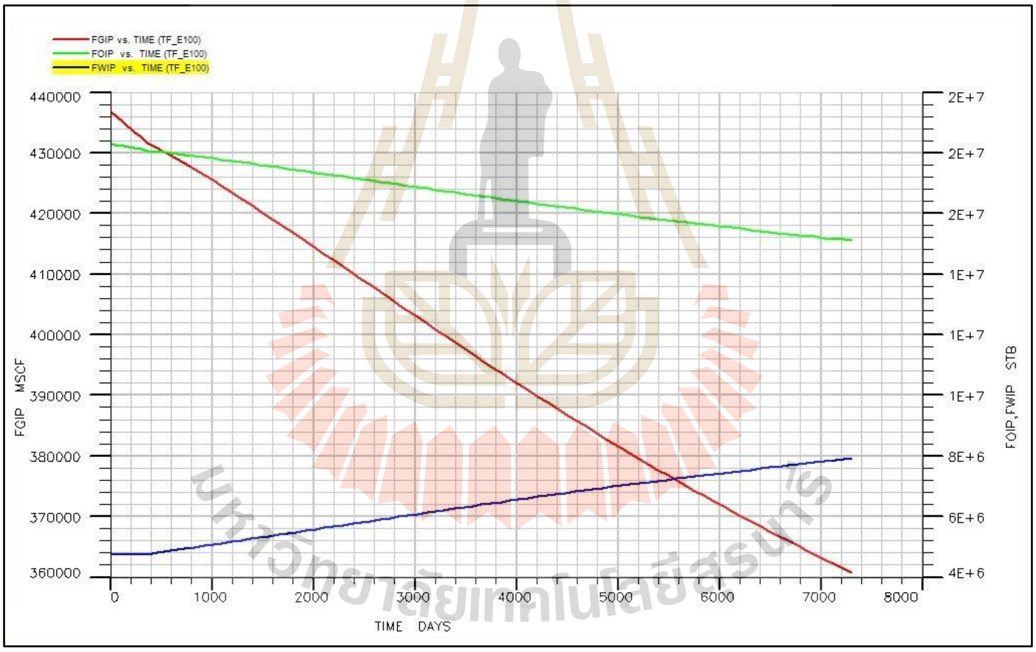


Figure 4.48 Fluid in place profile vs. time of model case 12.

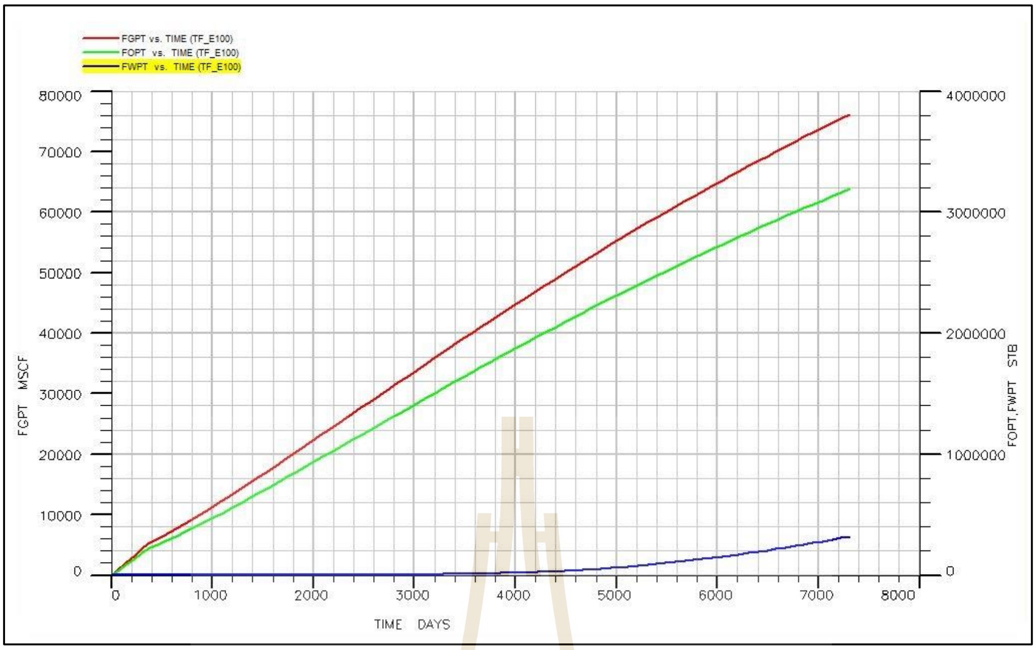


Figure 4.49 Cumulative fluids production profile vs. time of model case 12.

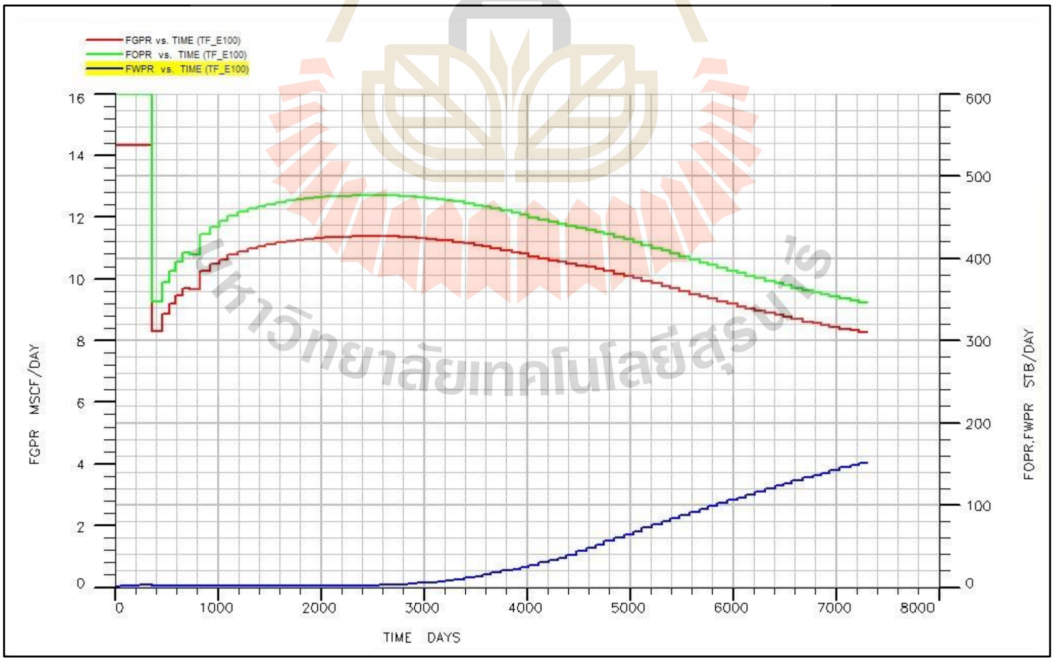


Figure 4.50 Fluids production rate profile vs. time of model case 12.

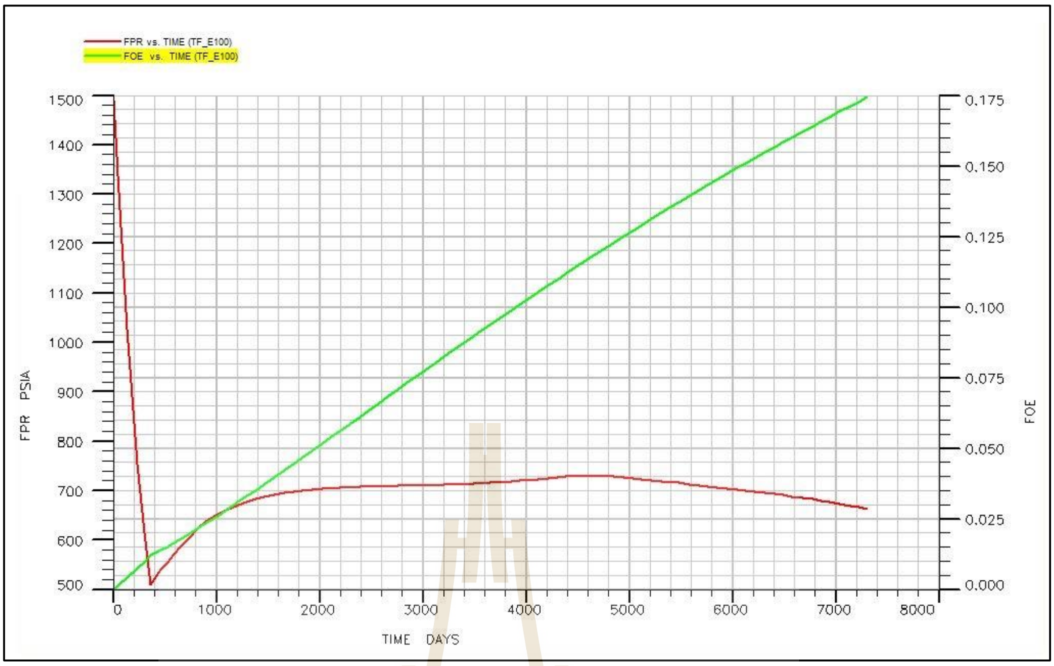


Figure 4.51 Field pressure and oil recovery efficiency vs. time of model case 12.

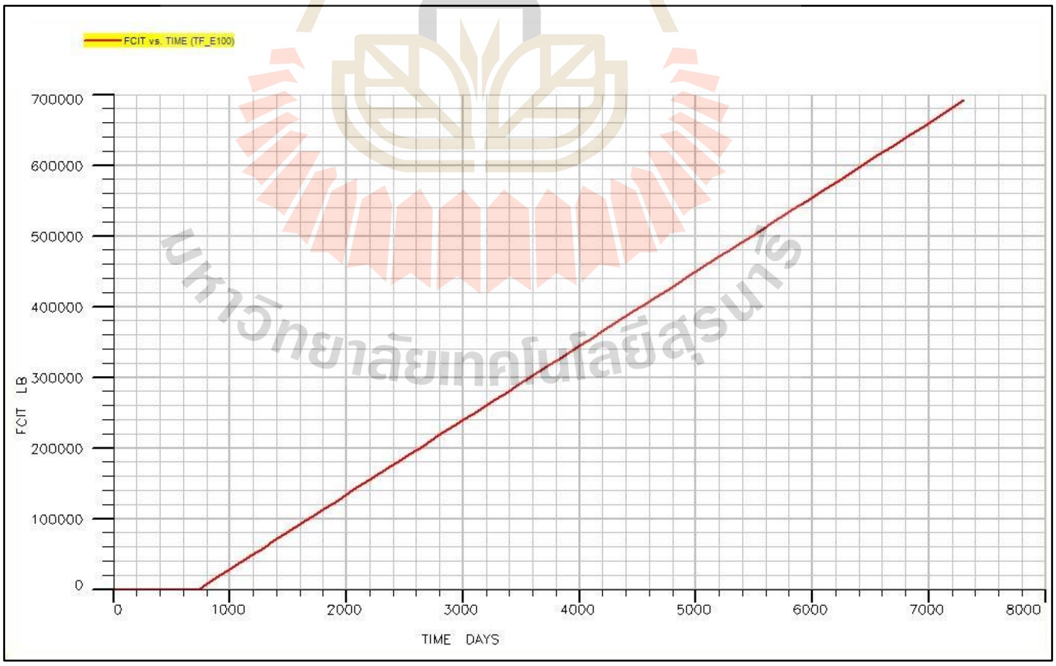


Figure 4.52 Field polymer injection total vs. time of model case 12.

### 4.1.13 Result of Model Case 13

Model Case 13 employs the staggered line drive pattern and water injection method in the third year, and polymer injection method in the fourth year. The production period is 20 years. The production is commenced in 3 production wells at the initial oil production rate of 200 bbl/d/well. After 4 years, 2 production wells are converted to start water injection at the water and polymer injection rate of 250 bbl/d/well. The remaining production wells are produced at the rate of 600 bbl/d. The simulation results are shown in Figures 4.53 – 4.57:

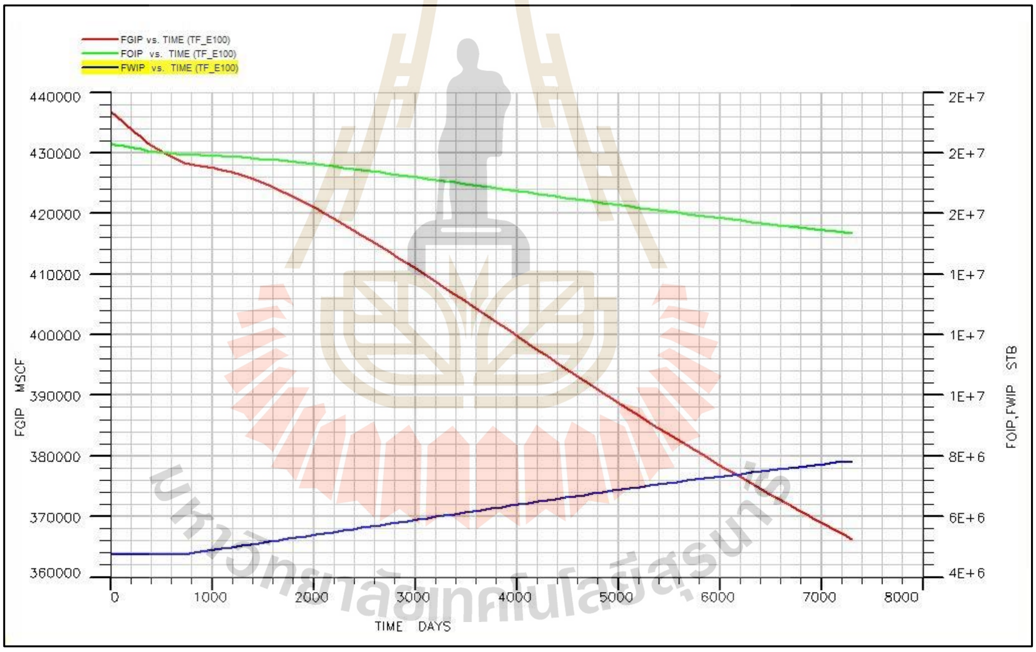


Figure 4.53 Fluid in place profile vs. time of model case 13.

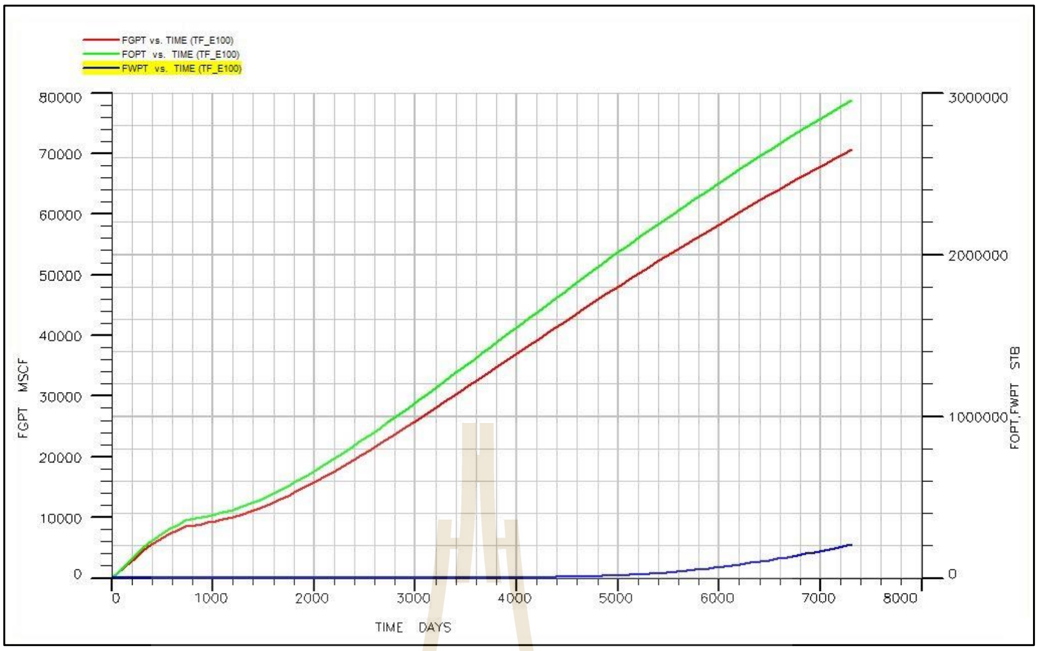


Figure 4.54 Cumulative fluids production profile vs. time of model case 13.

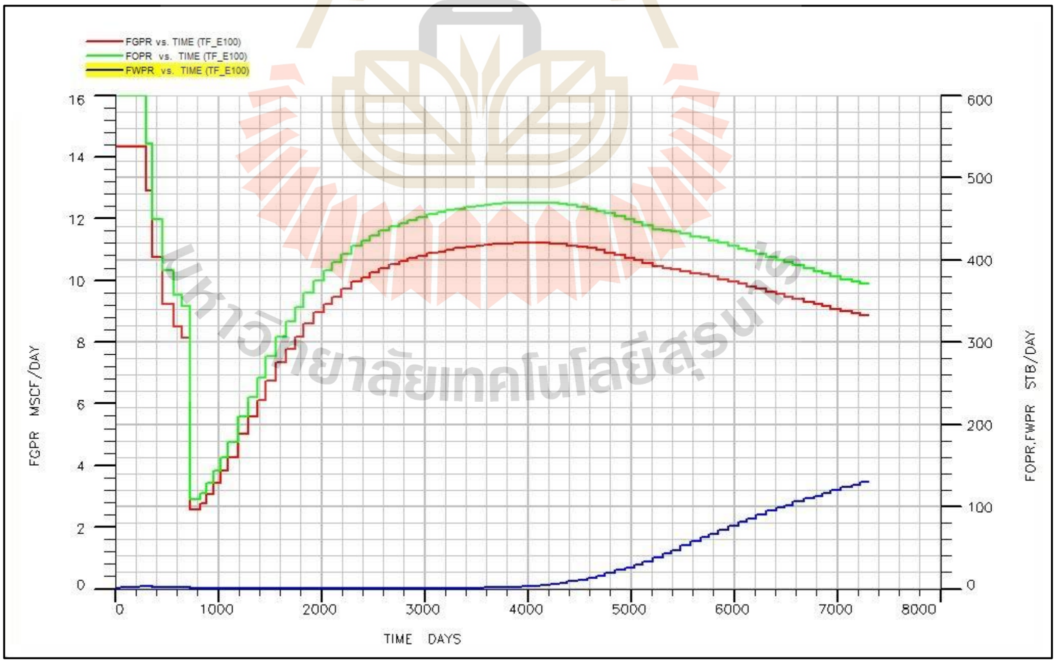


Figure 4.55 Fluids production rate profile vs. time of model case 13.

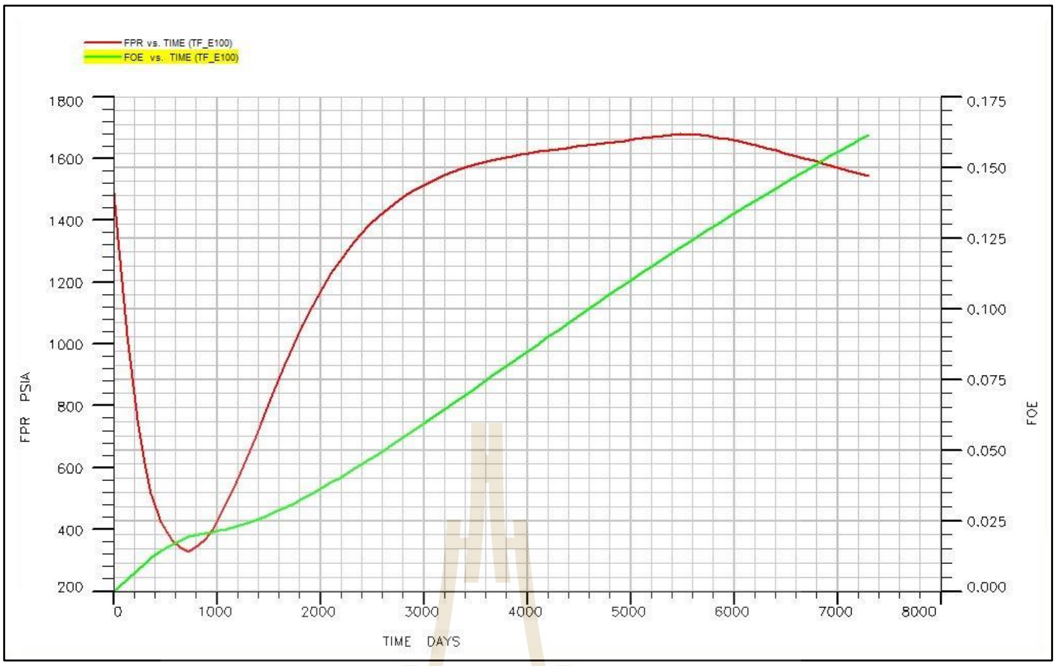


Figure 4.56 Field pressure and oil recovery efficiency vs. time of model case 13.

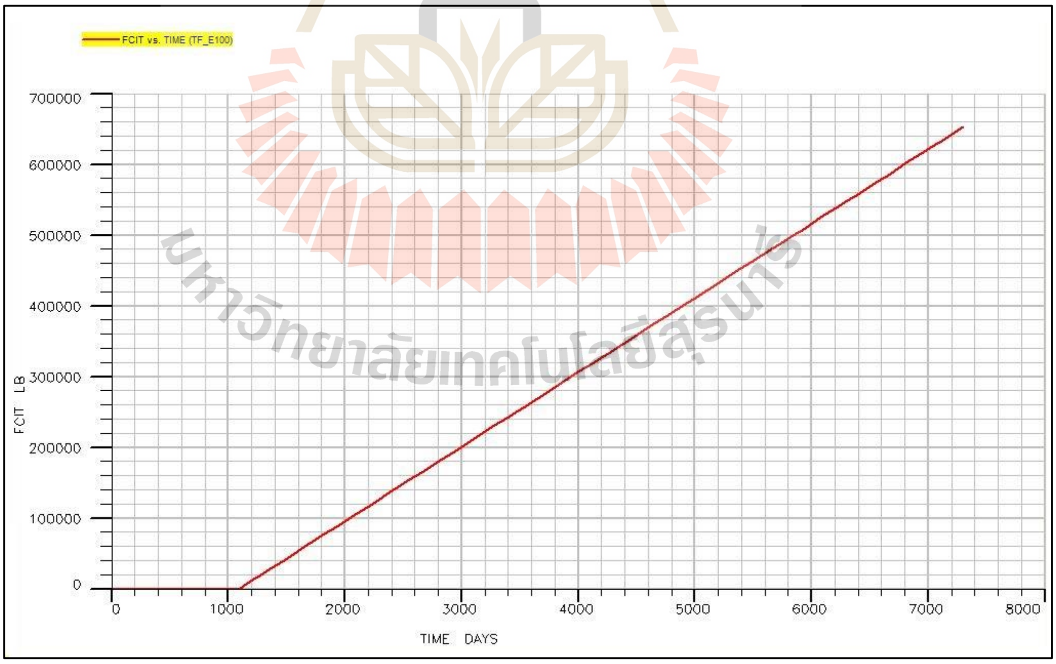


Figure 4.57 Field polymer injection total vs. time of model case 13.

### 4.1.14 Result of Model Case 14

Model Case 14 employs the direct line drive pattern and water injection method in the third year, and polymer injection method in the fourth year. The production period is 20 years. The production is commenced in 4 production wells at the initial oil production rate of 150 bbl/d/well. After 4 years, 2 production wells are converted to start water injection at the water and polymer injection rate of 250 bbl/d/well. The remaining production wells are produced at the rate of 300 bbl/d/well. The simulation results are shown in Figures 4.58 – 4.62:

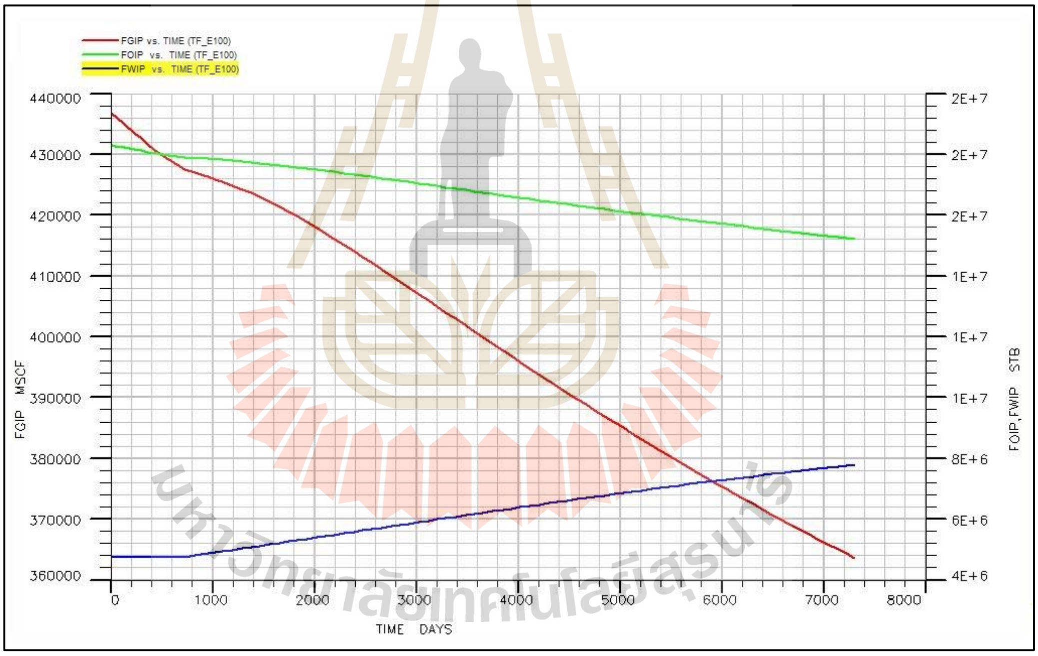


Figure 4.58 Fluid in place profile vs. time of model case 14.

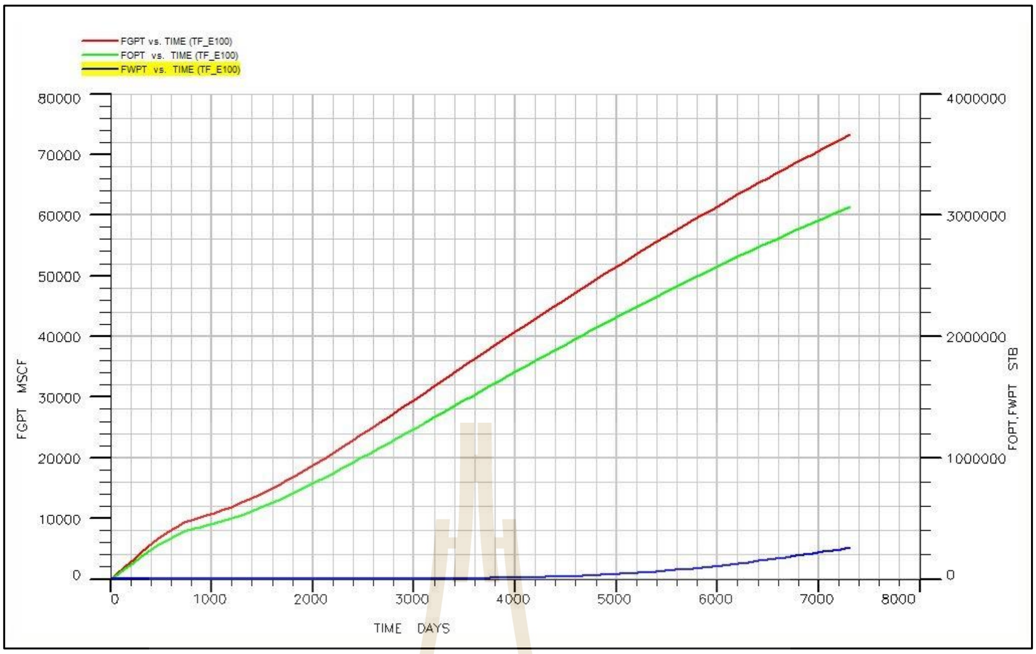


Figure 4.59 Cumulative fluids production profile vs. time of model case 14.

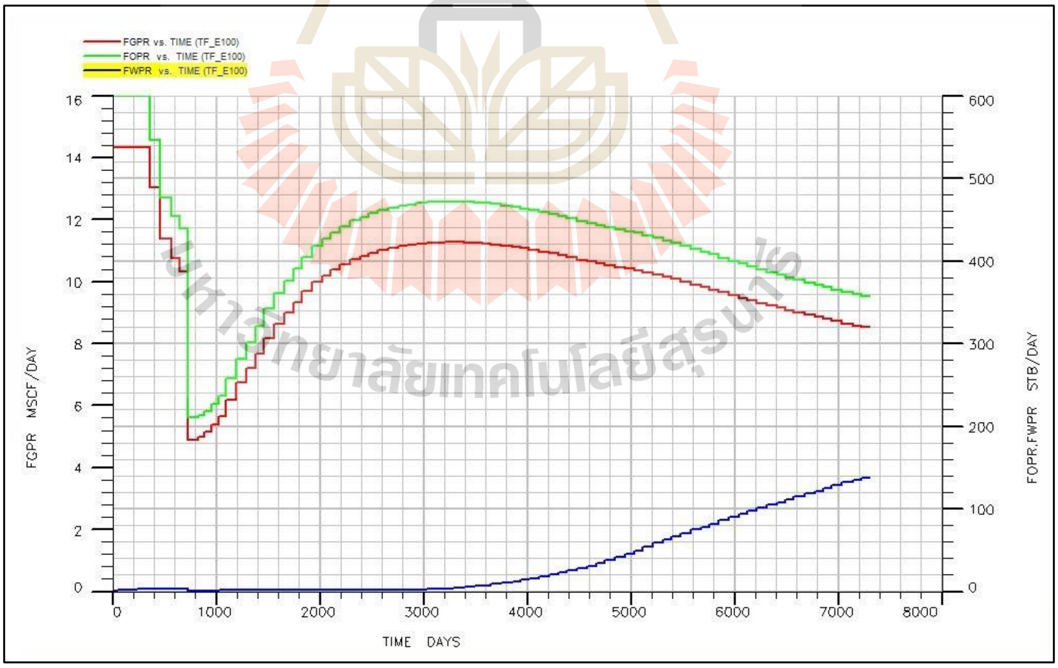


Figure 4.60 Fluids production rate profile vs. time of model case 14.

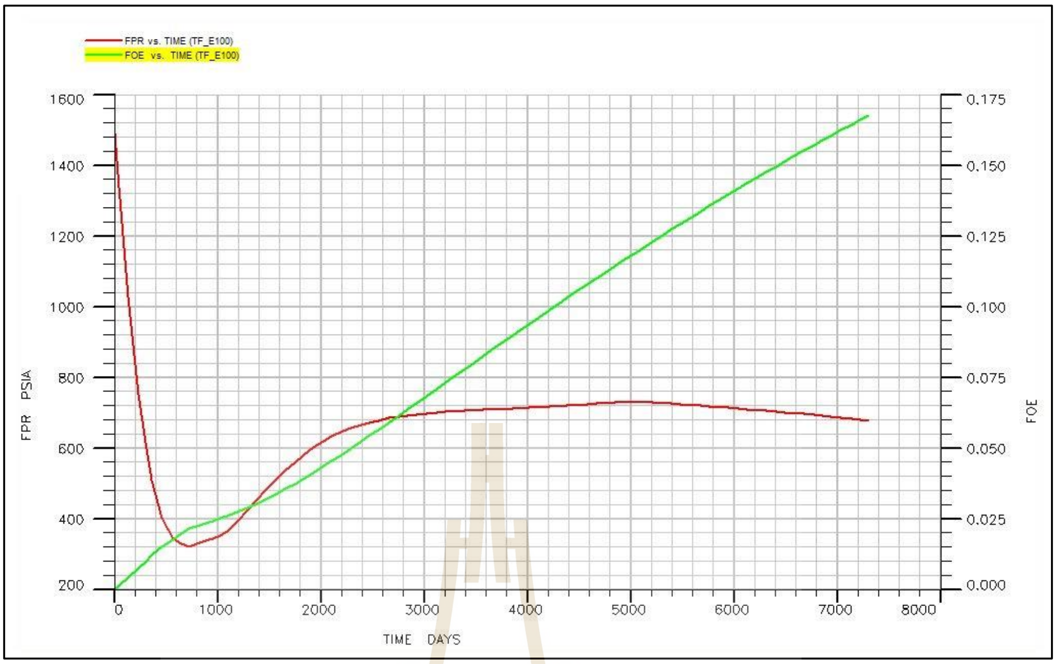


Figure 4.61 Field pressure and oil recovery efficiency vs. time of model case 14.

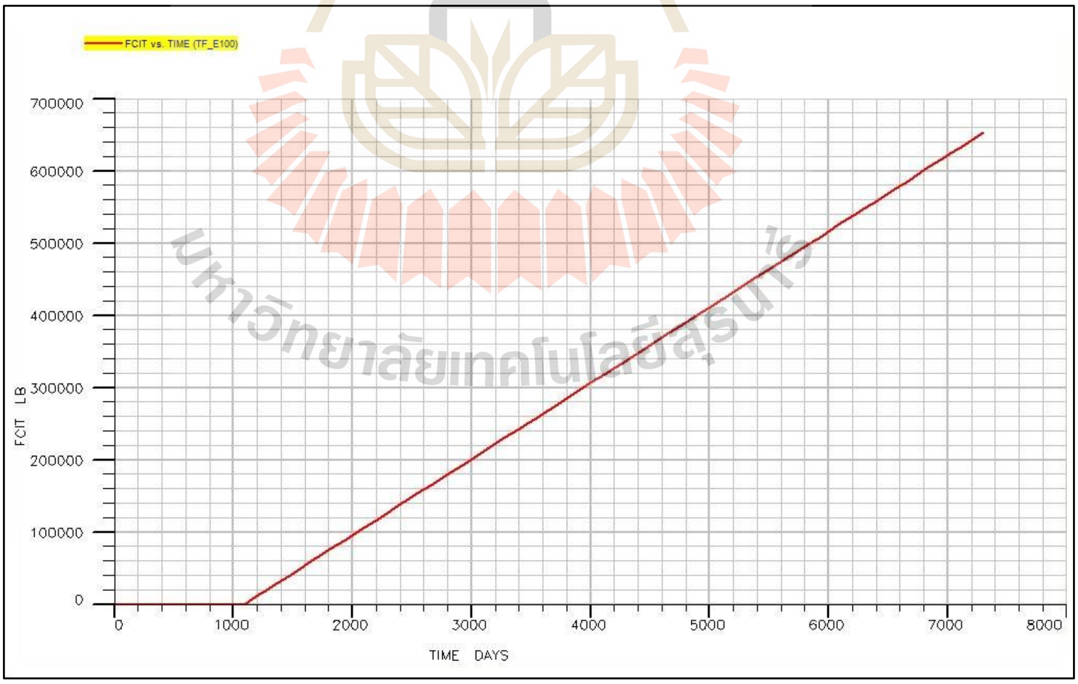


Figure 4.62 Field polymer injection total vs. time of model case 14.

### 4.1.15 Result of Model Case 15

Model Case 15 employs the staggered line drive pattern and water injection method in the fourth year, and polymer injection method in the fifth year. The production period is 20 years. The production is commenced in 3 production wells at the initial oil production rate of 200 bbl/d/well. After 4 years, 2 production wells are converted to start water injection at the water and polymer injection rate of 250 bbl/d/well. The remaining production wells are produced at the rate of 600 bbl/d. The simulation results are shown in Figures 4.63 – 4.67:

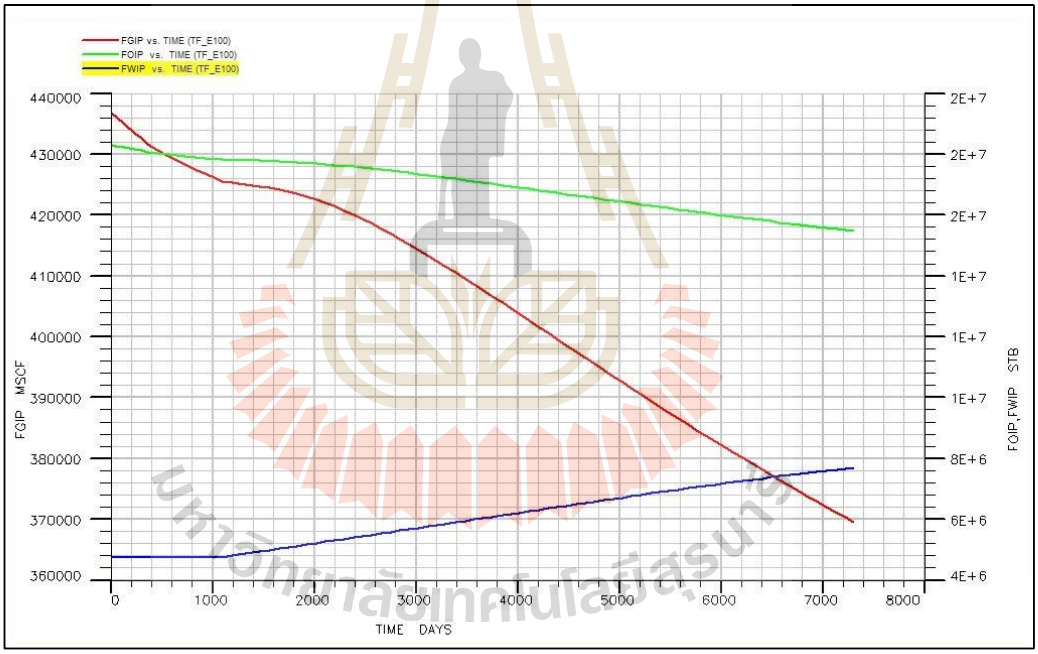


Figure 4.63 Fluid in place profile vs. time of model case 15.

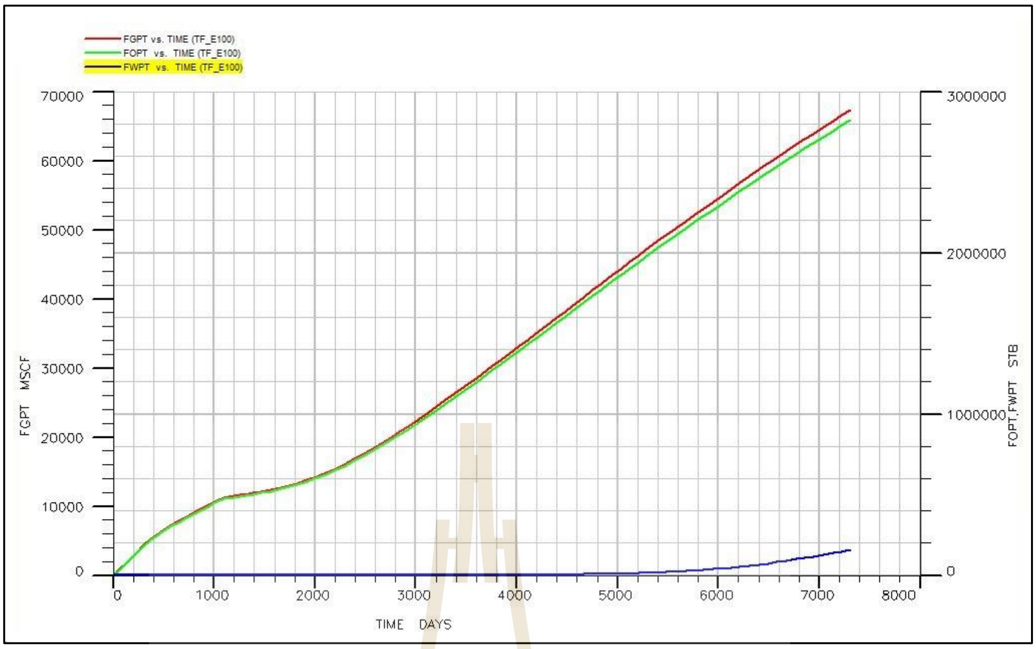


Figure 4.64 Cumulative fluids production profile vs. time of model case 15.

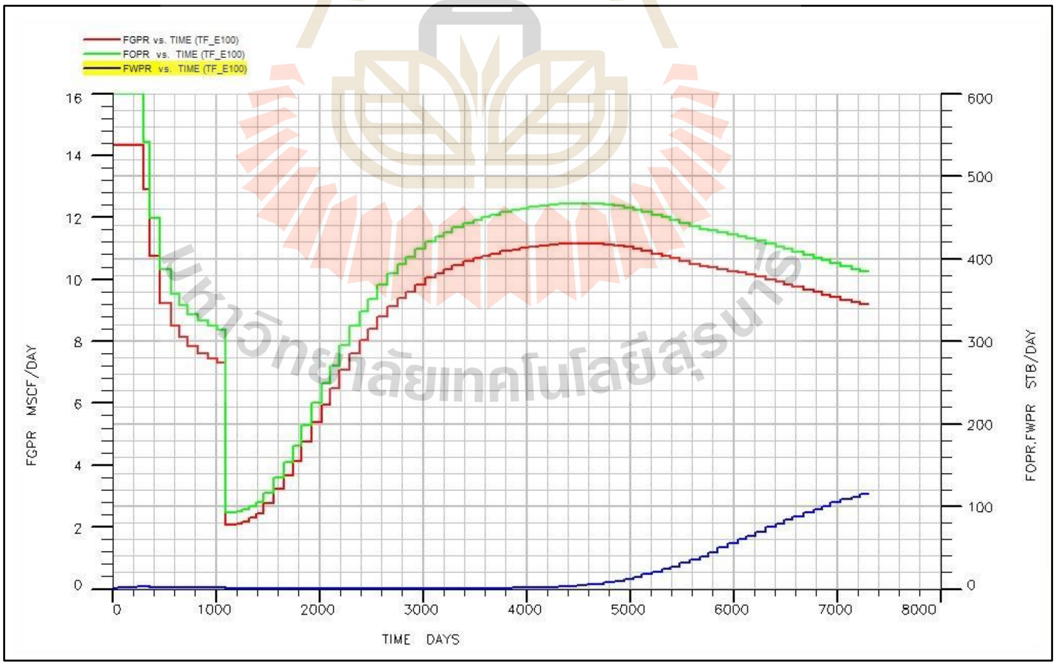


Figure 4.65 Fluids production rate profile vs. time of model case 15.

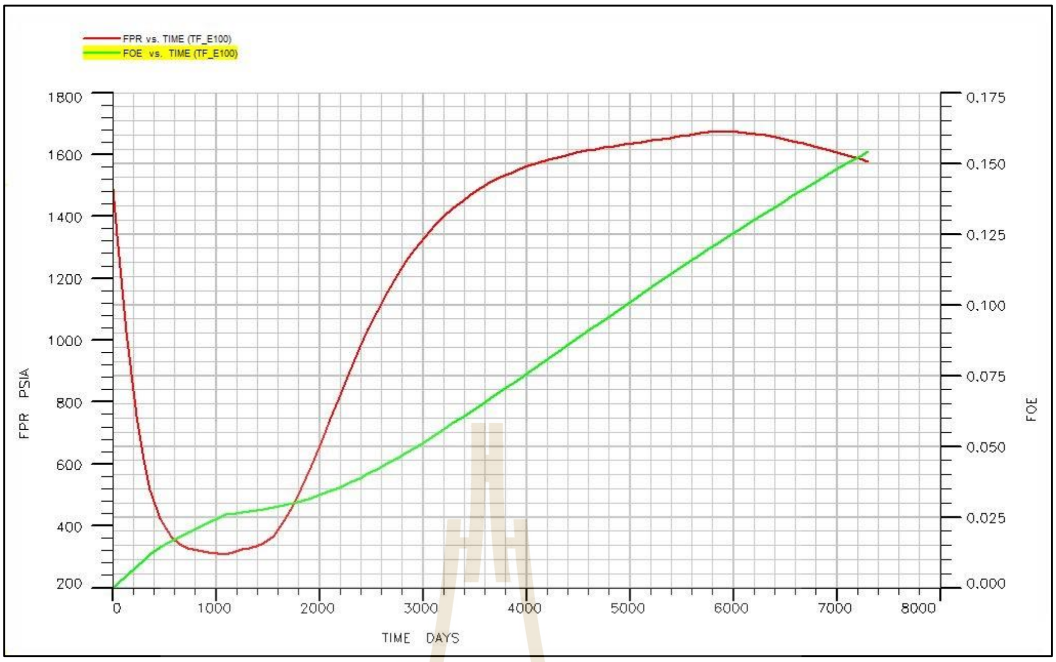


Figure 4.66 Field pressure and oil recovery efficiency vs. time of model case 15.

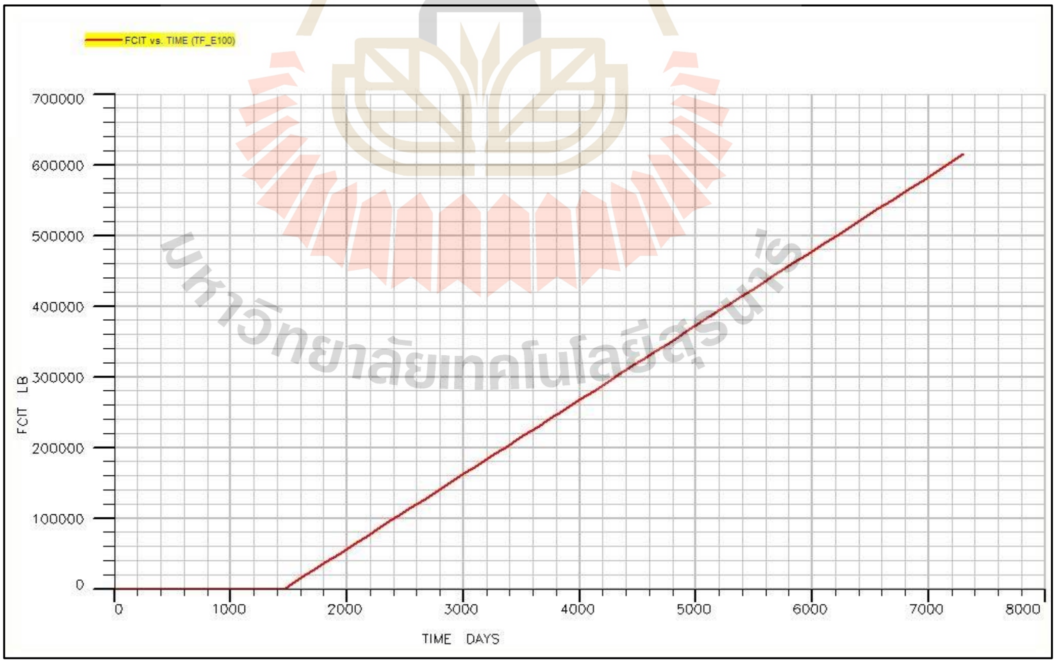


Figure 4.67 Field polymer injection total vs. time of model case 15.

### 4.1.16 Result of Model Case 16

Model Case 16 employs the direct line drive pattern and water injection method in the fourth year, and polymer injection method in the fifth year. The production period is 20 years. The production is commenced in 4 production wells at the initial oil production rate of 150 bbl/d/well. After 4 years, 2 production wells are converted to start water injection at the water and polymer injection rate of 250 bbl/d/well. The remaining production wells are produced at the rate of 300 bbl/d/well. The simulation results are shown in Figures 4.68 – 4.72:

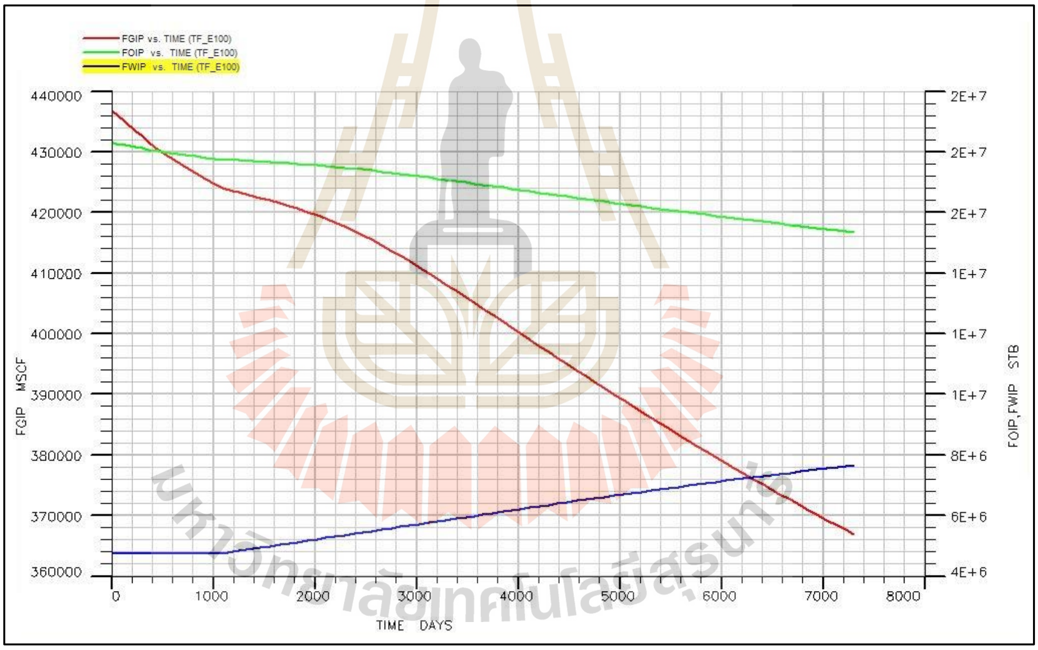


Figure 4.68 Fluid in place profile vs. time of model case 16.

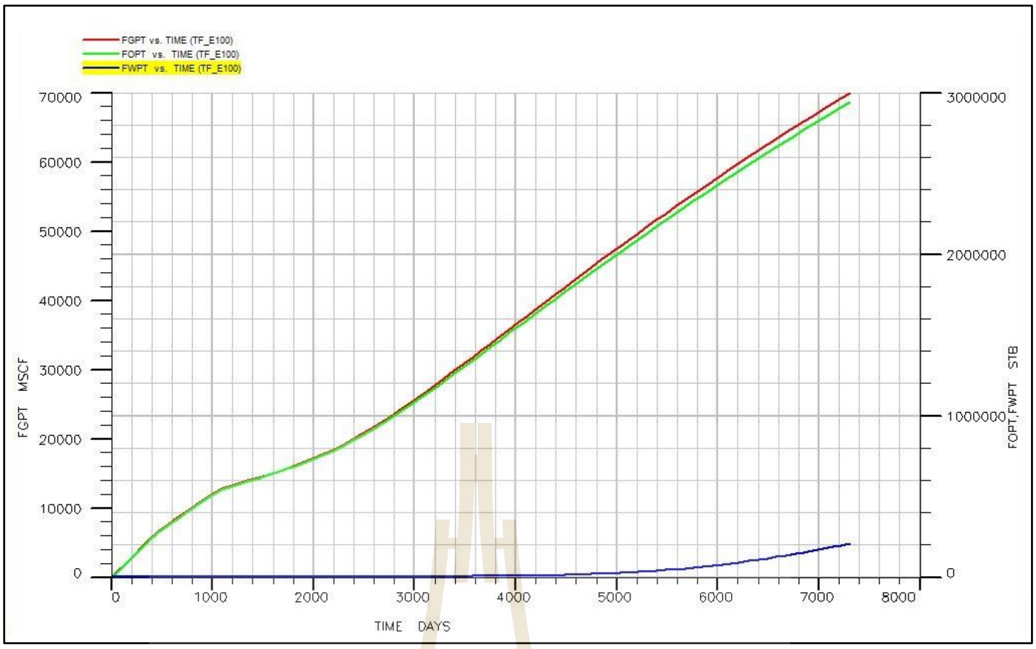


Figure 4.69 Cumulative fluids production profile vs. time of model case 16.

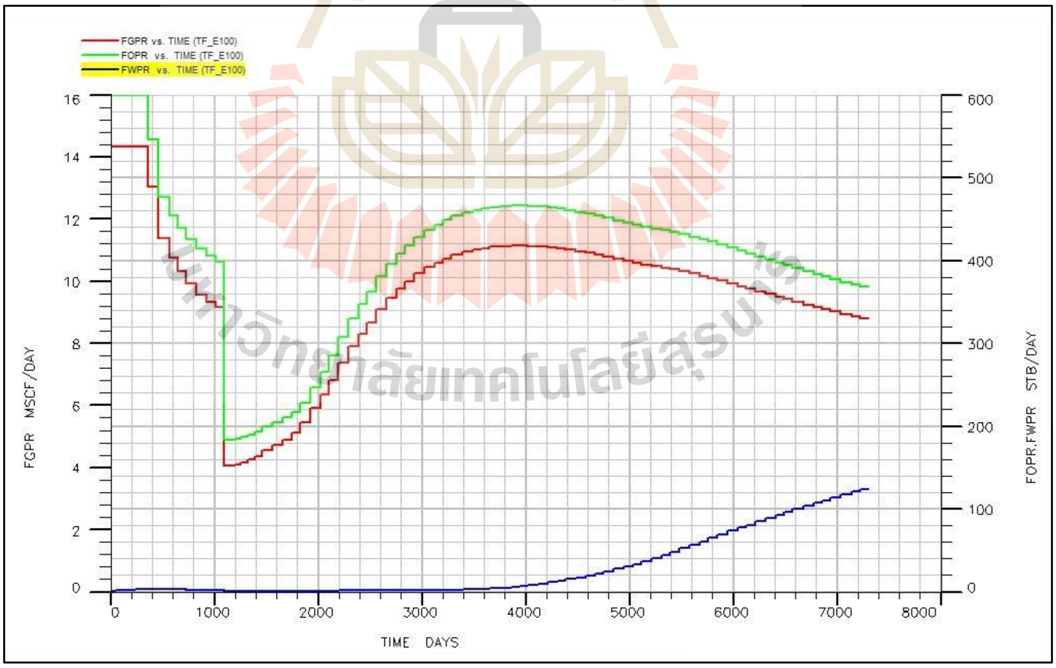


Figure 4.70 Fluids production rate profile vs. time of model case 16.

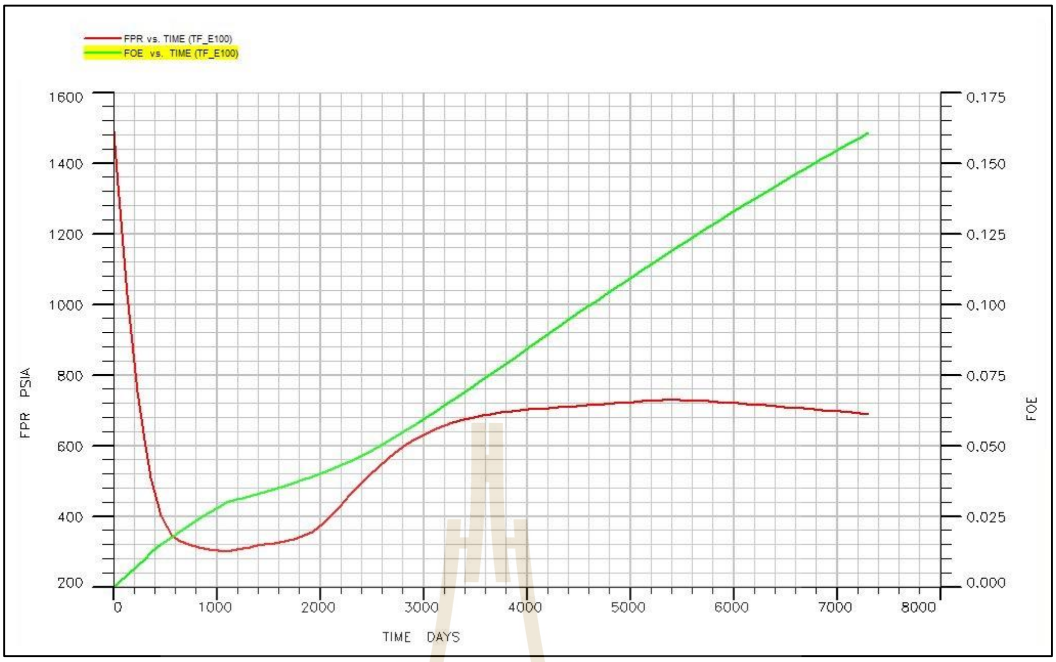


Figure 4.71 Field pressure and oil recovery efficiency vs. time of model case 16.

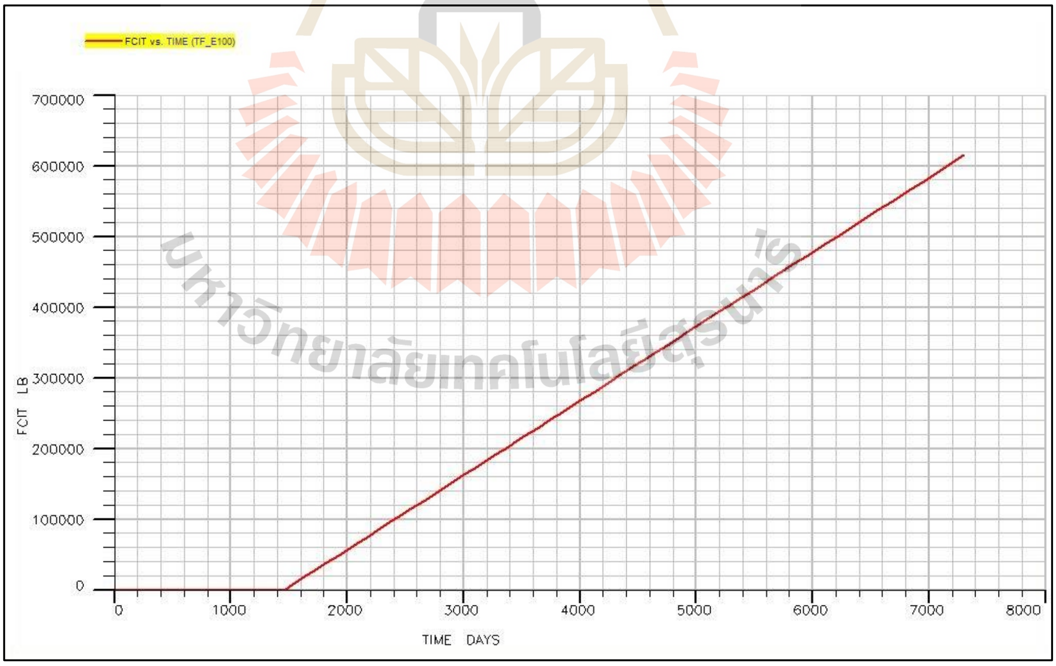


Figure 4.72 Field polymer injection total vs. time of model case 16.

## 4.2 Summary of oil recovery results

The reserved size of reservoir is 18,291,244 bbl. Summary of oil recovery results are shown in Table 4.2.

Table 4.2 Summary of oil recovery results.

| Case study | Flood pattern | Type of fluid to inject | Year to inject | Product rate (bbl) | Inject rate (bbl) | Cum. Oil Production (MMbbl) | Amount of polymer to inject (ton) | RF (%) |
|---|---|---|---|---|---|---|---|---|
| 1 | Staggered line | No inject | - | 600 | 0 | 1.697 | - | 6.43 |
| 2 | Direct line | No inject | - | 600 | 0 | 2.031 | - | 11.11 |
| 3 | Staggered line | Water | 1st | 600 | 500 | 2.856 | - | 15.61 |
| 4 | Direct line | Water | 1st | 600 | 500 | 2.980 | - | 16.29 |
| 5 | Staggered line | Water | 3rd | 600 | 500 | 2.695 | - | 14.74 |
| 6 | Direct line | Water | 3rd | 600 | 500 | 2.820 | - | 15.42 |
| 7 | Staggered line | Water | 5th | 600 | 500 | 2.495 | - | 13.64 |
| 8 | Direct line | Water | 5th | 600 | 500 | 2.630 | - | 14.37 |
| 9 | Staggered line | Polymer | 1st | 600 | 500 | 3.196 | 730 | 17.47 |
| 10 | Direct line | Polymer | 1st | 600 | 500 | 3.300 | 730 | 18.04 |
| 11 | Staggered line | Polymer | 2rd | 600 | 500 | 3.081 | 691 | 16.84 |
| 12 | Direct line | Polymer | 2rd | 600 | 500 | 3.189 | 691 | 17.43 |
| 13 | Staggered line | Polymer | 3th | 600 | 500 | 2.955 | 653 | 16.16 |
| 14 | Direct line | Polymer | 3th | 600 | 500 | 3.067 | 653 | 16.77 |
| 15 | Staggered line | Polymer | 4th | 600 | 500 | 2.822 | 615 | 15.43 |
| 16 | Direct line | Polymer | 4th | 600 | 500 | 2.939 | 615 | 16.07 |

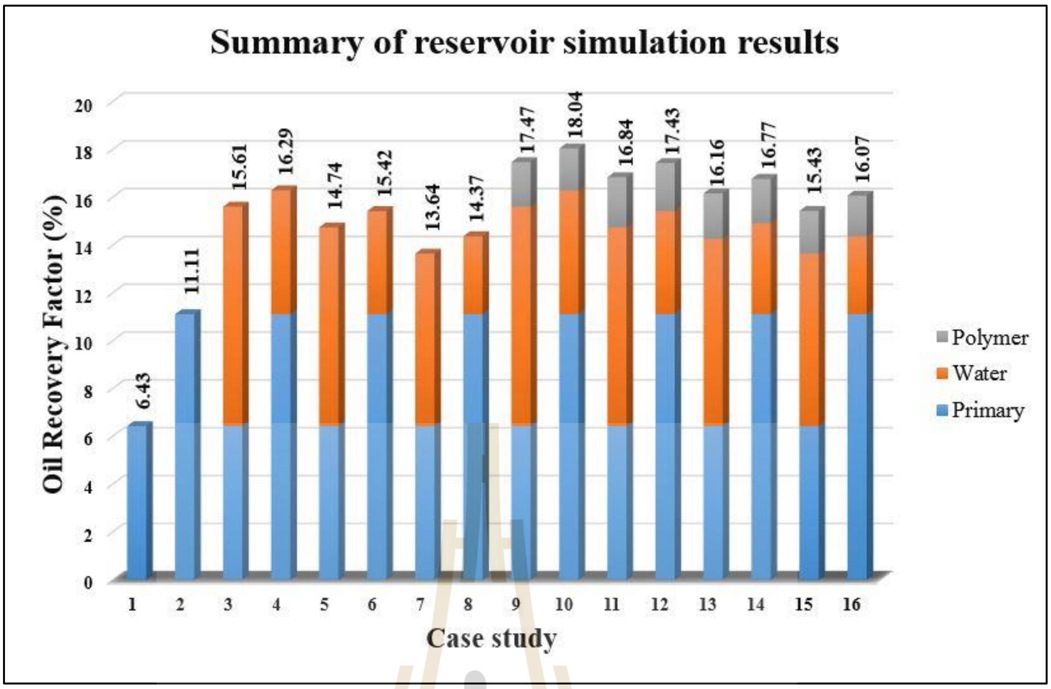


Figure 4.73 Oil recovery factor of reservoir simulations

# CHAPTER V

# ECONOMIC ANALYSIS

## 5.1 Objectives

Objectives of this chapter are to (1) determine economic parameters which are used to analyze project investment possibility and (2) compare all case studies to find the most cost effective (optimization) for Phitsanulok Basin. The parameters comprise of net present value (NPV), profit investment ratio (PIR), and internal rate of return (IRR).

## 5.2 Exploration and production schedule

The exploration and production period are in line with the Petroleum Acts "Thailand III". The duration is divided into 4 years of exploration and 20 years of production. The work plan of the project are summarized as follow.

1st year: Petroleum concession

2nd year: Geological and geophysical survey

3rd year: Drill exploration well

4th year: Drill development well and prepare to start production plan

5th year: Starting the production plan

## 5.3 Economic assumption

### 5.3.1 Basic assumptions

| | | |
|---|---|---|
| a. | Oil price (US$/bbl) | 50 and 80 |
| b. | Income tax (%) | 50 |
| c. | Escalation factor (%) | 2 |
| d. | Discount rate (%) | 10.0 |
| e. | Tangible cost (%) | 20 |
| f. | Intangible cost (%) | 80 |
| g. | Depreciation of tangible cost (%) | 20 |
| i. | Sliding scale royalty | |
| | Production level (b/d) | 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 |

### 5.3.2 Other assumptions

a. The oil price is constant over the production period.

b. Increasing rate of capital expenditure comes from the raising prices of machineries and equipment used in oil industries at 2% per year.

c. Operation cost is escalated by 2 % per year.

d. The expense used in cash flow analysis is list in Table 5.1.

Table 5.1 Cash flow expenditures

| Expenditures | For All Case Studies |
|---|---|
| Concession (MMUS$) | 0.5 |
| Geological and geophysical survey (MMUS$) | 2 |
| Production facility (MMUS$) | 20 |
| Drilling and completion production well (MMUS$/well) | 2 |
| Drilling and completion injection well (MMUS$/well) | 1.5 |
| Drilling exploration & appraisal well (MMUS$) | 1 |
| Facility costs of water injection well (US$/well) | 63,500 |
| Facility costs of polymer injection well (US$/well) | 65,000 |
| Maintenance costs of water injection well (US$/year) | 42,500 |
| Maintenance costs of polymer injection well (US$/year) | 42,500 |
| Cost of polymer including transportation (US$/kg) | 5 |
| Abandonment cost (US$) | 12,500 |
| Operating costs of production well (US$/bbl) | 20 |
| Operating cost of water injection (US$/bbl) | 0.5 |
| Operational cost of polymer Injection (US$/bbl incremental of oil) | 1.0 |

## 5.4 Table of cash flow summary

The economic analysis is calculated and analyzed by the Microsoft Excels spreadsheet. The economic summary results of all case studies are illustrated in Tables C.1-C.32. These table display undiscounted IRR and PIR at the end of annual cash flow column and discounted value at the end of discount cash flow column. The IRR, PIR and NPV summary of all case studies are illustrated in Table 5.2 and 5.3.

Table 5.2 Cash flow summary at 10% Discount, Oil Price = 50$

| Case study | Type of fluid to inject | Year to inject | Oil Recovery Factor (%) | IRR Undiscounted (%) | PIR Undiscounted (Fraction) | IRR (10.0%Disc) (%) | PIR (10.0%Disc) (Fraction) | NPV (10.0%Disc) (MMUS$) |
|---|---|---|---|---|---|---|---|---|
| 1 | No inject | - | 6.43 | -2.22 | -0.106 | -11.11 | -0.234 | -6.910 |
| 2 | No inject | - | 11.11 | -0.12 | -0.006 | -9.20 | -0.198 | -6.239 |
| 3 | Water | 1st | 15.61 | 5.65 | 0.374 | -3.96 | -0.109 | -2.792 |
| 4 | Water | 1st | 16.29 | 8.33 | 0.449 | -1.52 | -0.035 | -0.962 |
| 5 | Water | 3rd | 14.74 | 1.71 | 0.117 | -7.54 | -0.210 | -6.220 |
| 6 | Water | 3rd | 15.42 | 2.31 | 0.146 | -6.99 | -0.181 | -5.730 |
| 7 | Water | 5th | 13.64 | 1.27 | 0.087 | -7.93 | -0.213 | -6.357 |
| 8 | Water | 5th | 14.37 | 2.07 | 0.127 | -7.21 | -0.178 | -5.669 |
| 9 | Polymer | 1st | 17.47 | 7.96 | 0.469 | -1.85 | -0.044 | -1.235 |
| 10 | Polymer | 1st | 18.04 | 8.50 | 0.456 | -1.37 | -0.030 | -0.905 |
| 11 | Polymer | 2rd | 16.84 | 3.01 | 0.197 | -6.35 | -0.168 | -5.319 |
| 12 | Polymer | 2rd | 17.43 | 3.59 | 0.217 | -5.83 | -0.145 | -4.898 |
| 13 | Polymer | 3th | 16.16 | 1.97 | 0.133 | -7.30 | -0.196 | -6.216 |
| 14 | Polymer | 3th | 16.77 | 2.29 | 0.145 | -7.01 | -0.181 | -6.095 |
| 15 | Polymer | 4th | 15.43 | 1.51 | 0.102 | -7.71 | -0.204 | -6.466 |
| 16 | Polymer | 4th | 16.07 | 1.89 | 0.120 | -7.37 | -0.187 | -6.298 |

Table 5.3 Cash flow summary at 10% Discount, Oil Price = 80$

| Case study | Type of fluid to inject | Year to inject | Oil Recovery Factor (%) | IRR Undiscounted (%) | PIR Undiscounted (Fraction) | IRR (10.0%Disc) (%) | PIR (10.0%Disc) (Fraction) | NPV (10.0%Disc) (MMUS$) |
|---|---|---|---|---|---|---|---|---|
| 1 | No inject | - | 6.43 | 18.54 | 0.878 | 7.77 | 0.155 | 4.569 |
| 2 | No inject | - | 11.11 | 20.46 | 1.038 | 9.51 | 0.204 | 6.430 |
| 3 | Water | 1st | 15.61 | 26.41 | 2.054 | 14.92 | 0.451 | 11.565 |
| 4 | Water | 1st | 16.29 | 34.62 | 2.099 | 22.38 | 0.545 | 15.072 |
| 5 | Water | 3rd | 14.74 | 20.27 | 1.588 | 9.33 | 0.271 | 8.040 |
| 6 | Water | 3rd | 15.42 | 23.64 | 0.117 | 12.40 | 0.320 | 10.119 |
| 7 | Water | 5th | 13.64 | 19.04 | 1.444 | 8.22 | 0.222 | 6.600 |
| 8 | Water | 5th | 14.37 | 22.49 | 1.456 | 11.35 | 0.268 | 8.520 |
| 9 | Polymer | 1st | 17.47 | 30.66 | 2.200 | 18.78 | 0.507 | 14.110 |
| 10 | Polymer | 1st | 18.04 | 34.54 | 2.137 | 22.31 | 0.534 | 15.928 |
| 11 | Polymer | 2rd | 16.84 | 23.24 | 1.758 | 12.03 | 0.337 | 10.684 |
| 12 | Polymer | 2rd | 17.43 | 23.86 | 1.691 | 12.60 | 0.339 | 11.426 |
| 13 | Polymer | 3th | 16.16 | 20.47 | 1.624 | 9.52 | 0.271 | 8.614 |
| 14 | Polymer | 3th | 16.77 | 21.59 | 1.597 | 10.53 | 0.289 | 9.737 |
| 15 | Polymer | 4th | 15.43 | 19.18 | 1.517 | 8.34 | 0.232 | 7.325 |
| 16 | Polymer | 4th | 16.07 | 20.19 | 1.495 | 9.27 | 0.248 | 8.346 |

## 5.5 Economic Analysis

Economic analysis in this study base on the constant oil price rates of 50 and 80 $/bbl and the discounted rate of 10.0%. At the oil price rate of 50$/bbl, the IRRs result of all case studies range from -11.11 to -1.37%, while the PIRs range from -0.234 to -0.030

fraction. The best case of this study is Case 10 of which employs the polymer flooding method in the direct line drive pattern in the first year of injection. Its best NPV is -0.905 MMUS$. Summary of the economic results of all case studies are shown in Figures 5.2-5.4.

At the oil price rate of 80$/bbl, the IRRs range from 7.77 to 22.38%, and the PIRs range from 0.155-0.545 fraction. The best case of this study is Case 10 of which employs the polymer flooding method in the direct line drive pattern in the first year of injection. Its best NPV is 15.928 MMUS$. Summary of the economic results of all case studies are shown in Figures 5.5-5.7.

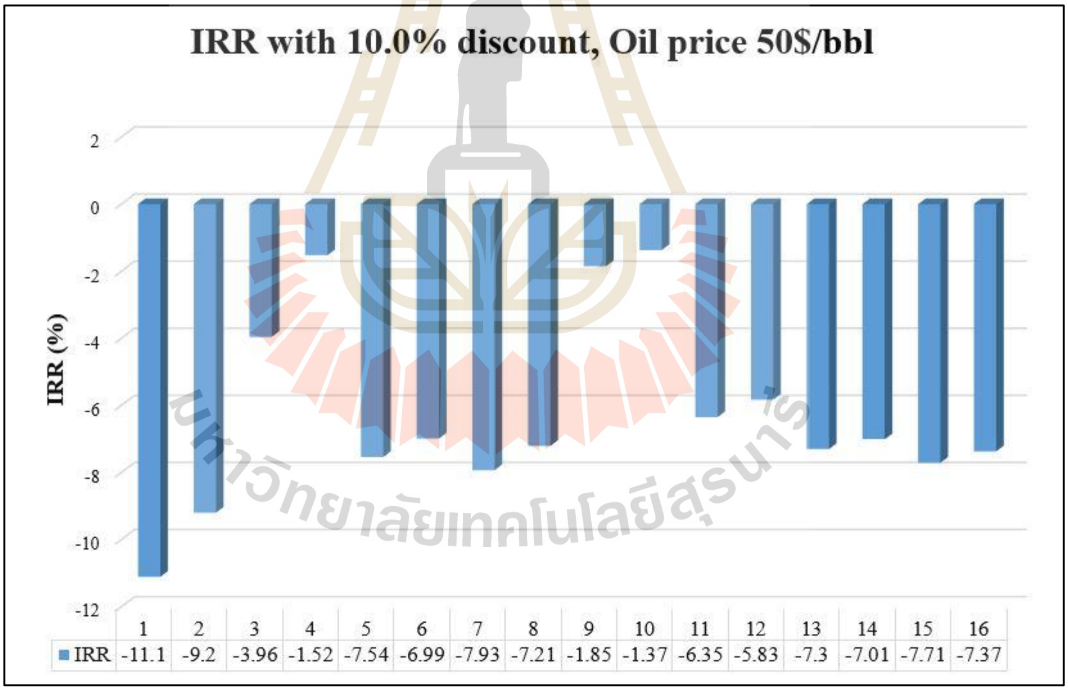


Figure 5.1 Summary of IRR Results, Oil price 50$/bbl.

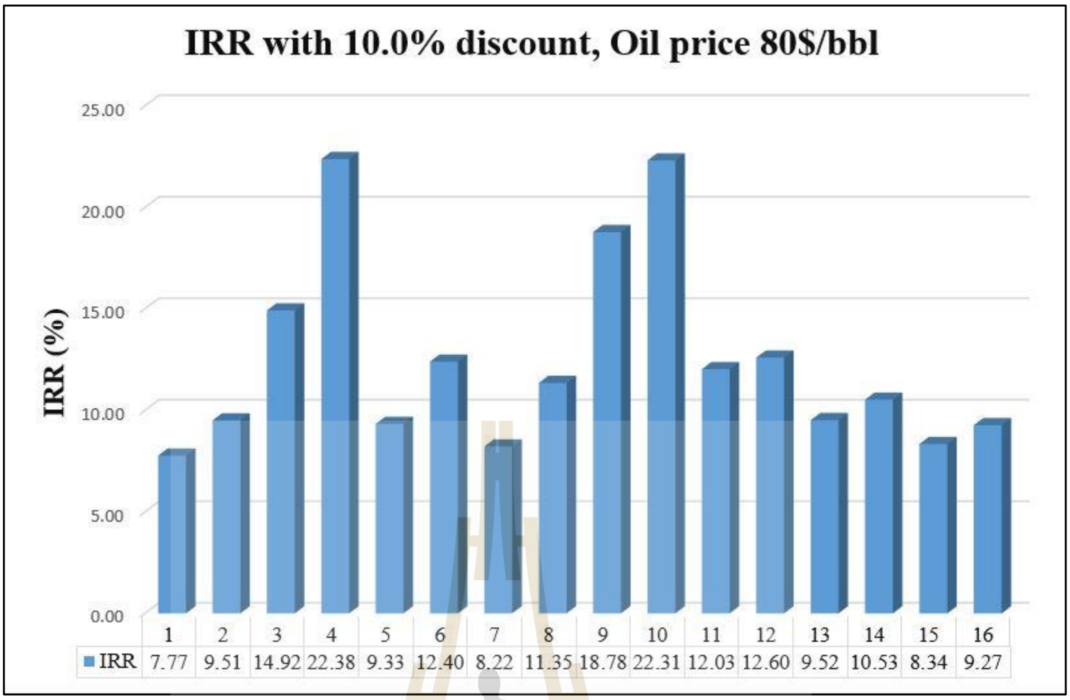


Figure 5.2 Summary of IRR Results, Oil price 80$/bbl.

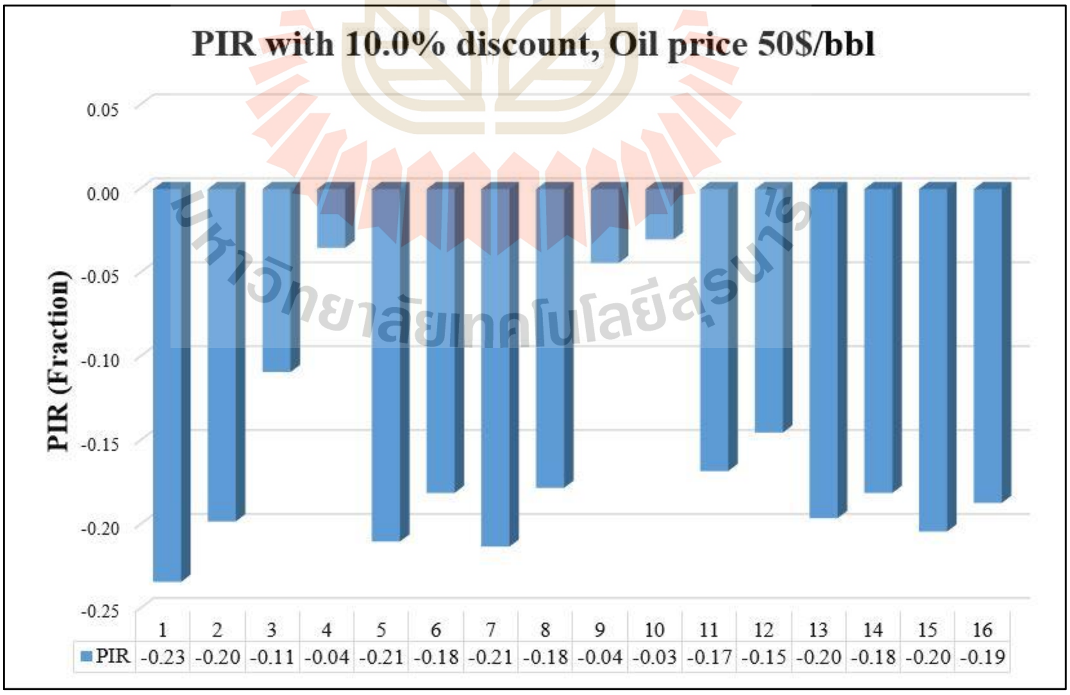


Figure 5.3 Summary of PIR Results, Oil price 50$/bbl.

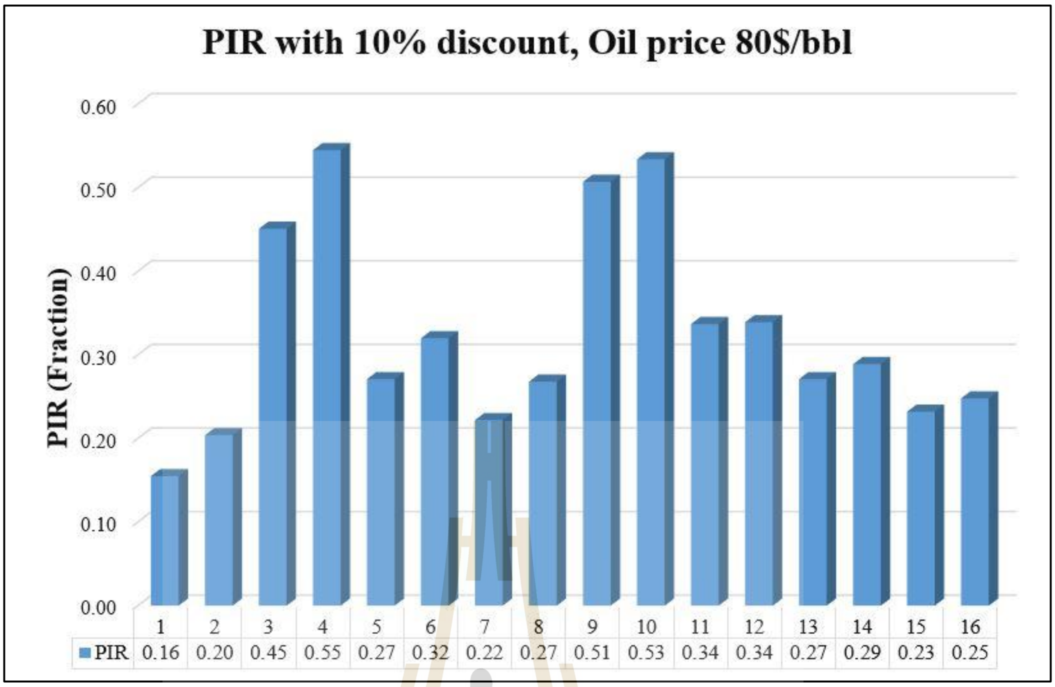


Figure 5.4 Summary of PIR Results, Oil price 80$/bbl.

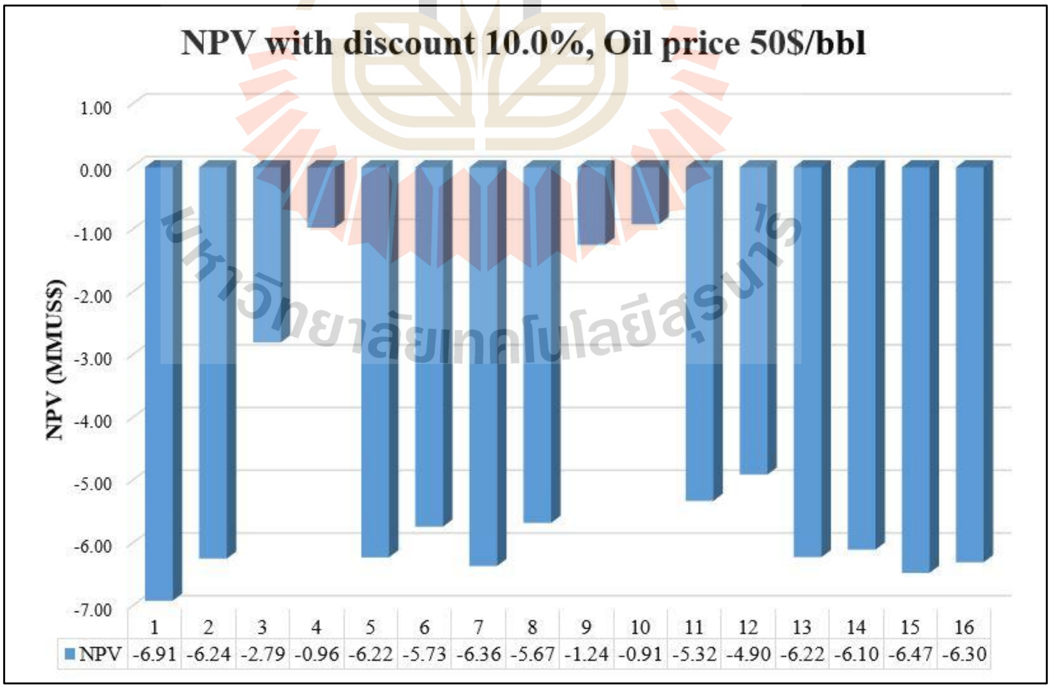


Figure 5.5 Summary of NPV Results, Oil price 50$/bbl.

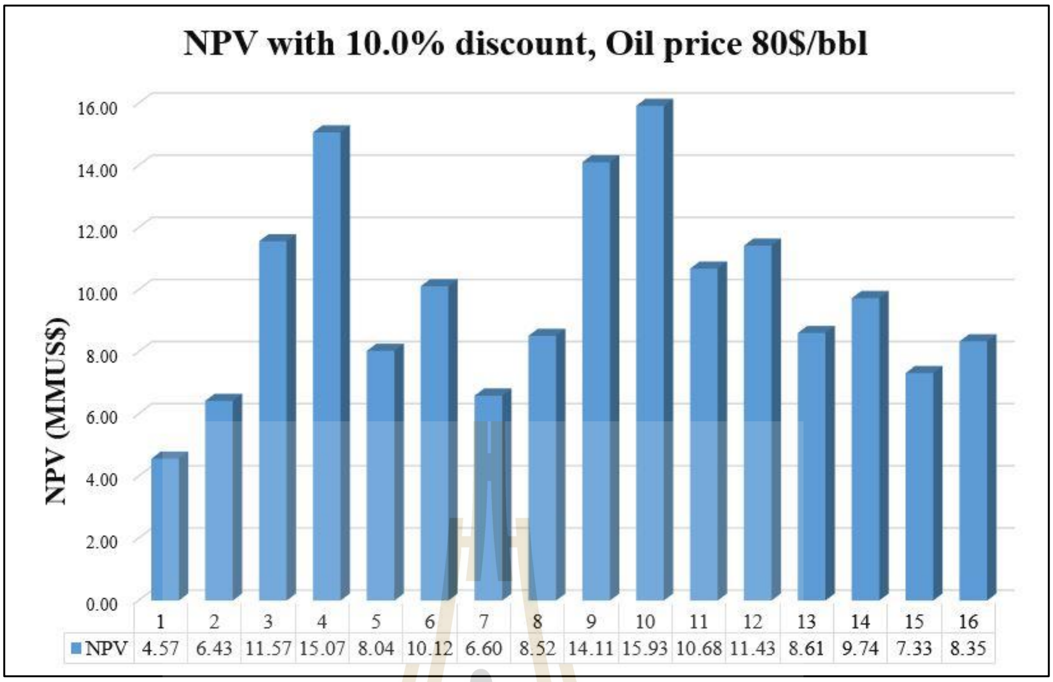


Figure 5.6 Summary of NPV Results, Oil price 80$/bbl.

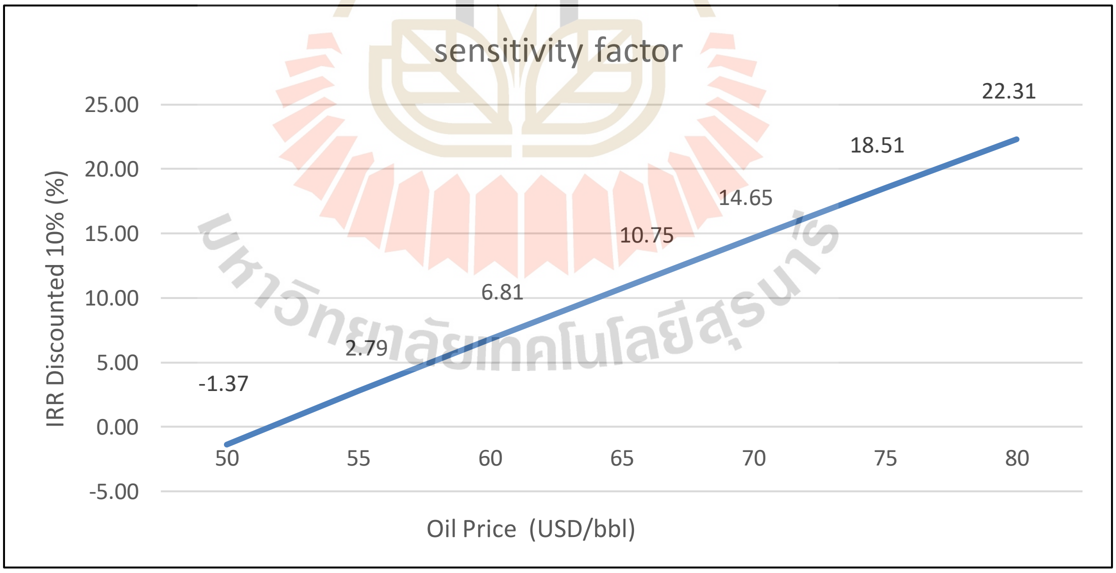


Figure 5.7 Sensitivity factor of polymer flood in Pru Kathiam oil field

# CHAPTER VI

# CONCLUSIONS AND DISCUSSIONS

## 6.1 Introduction

Economic evaluation of water and polymer flooding simulation module of oil field in Phitsanulok Basin is discussed in this chapter including variations that affect reliability of the study, obstacles and suggestions for future studies.

## 6.2 Conclusions of Case Study Results

The recovery factor of primary production in this reservoir model is low. The effect of water and polymer flooding method increase reservoir pressure and oil recovery. The advantage of polymer solution is to improve the swept coefficient and volumetric sweep efficiency, while decrease the mobility ratio.

The study focuses on monocline structure style with 6 layers, using reservoir and fluid data from Pru Kathiam oil field. The reserved size of reservoir is around 18.29 MMBBL. The porosity ranges from 20% to 30%, and the permeability varies from 1 to 500 md. The study uses reservoir simulation to evaluate 16 case studies for oil recovery with two patterns – staggered line and direct line drive. All cases have the same total production rate of 600 bbl/day, and production life time of 20 years. Cases 3 to 16 have an injection rate of 500 bbl/d. The XCD polymer (Xanthan gum) with concentration of 600 ppm is used in these simulations. According to the result, polymer flooding has higher recovery efficiency potential comparing to waterflooding method.

Case 1 and 2 show that oil recovery from natural flow (no water or polymer injection) can produce 6.43 and 11.11% of oil in place. Case 3 to 8 show the application of waterflooding in both straggled line and direct line patterns in the first, third and fifth years. The recoveries increase to 15.61%, 16.29%, 14.74%, 15.42%, 13.64%, and 14.37% respectively. Case 9 to 16 show the application of polymer flooding in both straggled line and direct line patterns in the first, second, third and fourth years. The recoveries increase to 17.47%, 18.04%, 16.84%, 17.43%, and 16.16% 16.77%, 15.43% and 16.07% respectively. Summary of reservoir simulation results are shown in Figure 4.3 and Table 4.2.

## 6.3 Economic Analysis

Economic analysis in this study base on the constant oil price rates of 50 and 80 $/bbl and the discounted rate of 10.0%. At the oil price rate of 50$/bbl, the IRRs result of all case studies range from -11.11 to -1.37%, while the PIRs range from -0.234 to -0.030 fraction. The best case of this study is Case 10 of which employs the polymer flooding method in the direct line drive pattern in the first year of injection. Its best NPV is -0.905 MMUS$. Summary of the economic results of all case studies are shown in Figures 5.2-5.4.

At the oil price rate of 80$/bbl, the IRRs range from 7.77 to 22.38%, and the PIRs range from 0.155-0.545 fraction. The best case of this study is Case 10 of which employs the polymer flooding method in the direct line drive pattern in the first year of injection. Its best NPV is 15.928 MMUS$. Summary of the economic results of all case studies are shown in Figures 5.5-5.7.

## 6.4 Discussions

1) The reservoir simulation results indicate that the polymer flooding technique has the most potential in increasing oil recovery efficiency of Pru Kathiam oil field in Phitsanulok Basin comparing to the natural flow and waterflooding techniques.

2) The best case of this study is Case 10 of which employs polymer flooding technique in the direct line drive pattern in the first year of injection. (2 production wells and 2 injection wells). The case provides the best oil recovery and values of economics. The summary of oil recovery factor and NPV result is 18.04%. At the oil price rate of 50$/bbl, the NPV is -0.905 MMUS$. At the oil price rate of 80$/bbl, the NPV is 15.928 MMUS$.

3) It is found that the development of this reservoir by waterflooding and polymer techniques has the economic worthiness at the oil of up to 51.61$/bbl

4) For all cases, in the first year of injection, water and polymer flooding are the best techniques in improving efficiency of oil recovery and economic values. But in the real field operation, it is unlikely that the operation can take place in the first year because water and polymer flooding projects require at least 3 to 5 years in collecting data of reservoir properties and history of production rates.

5) History matching should be compared to the real field and the reservoir simulation because it is crucial in producing more accurate results. The study also finds that the more reservoir properties data obtained, the more accurate the results are. However, production rates are not included in this study due to the inaccessibility of the data.

6) Polymer flooding in Phitsanulok basin studying by Jutikarn Kanarak. Oil gravity is 39.4 API. Recovery factor is 28.72%-48.48%. Polymer flooding in U-thong oil field studying by Theeradech Thongsumrit. Problem of this reservoir is low pressure after primary production. The residual oil left in the reservoir. Oil gravity is 33.0 API and recovery factor is 44.19%-55.03%. Waterflooding and polymer flooding in Phitsanulok basin studying by Krissada Yoosumdangkit. The result of this study, Recovery factor by waterflooding is 13.64-16.29% and recovery factor by polymer flooding is 15.43-18.04%.

7) Reliability of simulation result depends on confidential of rock and fluid properties data collected from the oil field.

8) For future study, the locations of production and injection wells can be changed to five spot, seven spot, and nine spot, and peripheral flood patterns in order to find oil recovery efficiency and economic values for heavy oil in Phitsanulok basin. It is suggested that the researchers should have sufficient understanding of program application (ECLIPSE and Surfer) in order to input data into the simulations and produce highly accurate results.

# REFERENCES

Bal, A.A., Burgisser, H.M., Harris, D.K., Herber, M.A., Rigby, S.M., Winkler, F.J., and Thumprasertwong, S. (1992). **The Tertiary Phitsanulok Lacustrine Basin, onshore Thailand. In Proceedings of the Geologic Resources of Thailand: Potential for future development** (pp.247-258). Bangkok, Thailand: Department of Mineral Resources.

Bill, D.B., and Kenneth, E.A., (1992**). Modern Petroleum**, Third Edition.

Bradley, H.B. (1987). **Petroleum engineering handbook. Society of Petroleum Engineers**.

Burri, P. (1989). **Hydrocarbon Potential of Tertiary Intermontane Basin of Thialand. In Proceeding of the International Symposium on Intermontane Basins**: Geology and Resources (pp.2-13). Chiang Mai, Thailand:

Don, W.G., and Willhite G.P. (1998). **Enhanced Oil Recovery**, SPE Textbook Series, Volume 6.

Du, Y., Guan, L. (2004) **Field-scale polymer flooding: lessons learnt and experiences gained during past 40 years**. In: SPE 91787 presented at SPE international petroleum conference, Mexico, 7–9 Nov 2004

Wakefield, L. L. (1983**). An introduction to the Geology of the Phitsanulok Basin**. In Conference on Geology and Mineral Resources (pp.19-28). Bangkok, Thailand.

Gerding, M. (1986). **Fundamental of petroleum.** Texas: Petroleum Extension Service.

Heavy Oil (2012). **Paper IPTC 14753**, International Petroleum Technology Conference 2011, Bangkok, Thailand, February 7 -9 (2012)

Jayasekera, A.J. and Goodyear, S.G. (2000). "**The Development of Heavy Oil Fields in the United Kingdom Continental Shelf: Past, Present, and Future**", SPE Res. Eval. &Eng., 3 (5), October 2000, p 371 – 379.

Kanarak, J. (2011). **Enhanced oil recovery with polymer flooding for oil field in Phitsanulok Basin**. M.S. thesis, Suranaree University of Technology, Thailand.

Kumar, M., Hoang, V., Satik, C. and Rojas, D.H. (2005) "**High Mobility Ratio WaterFlood Performance Prediction: Challenges and New Insights**", SPE 97671, SPE International Improved Oil Recovery Conference, Kuala Lumpur, Malaysia.

Maheshwari, Y.K. (2011). **A comparative simulation study of chemical EOR methodologies (Alkaline, Surfactant and/or Polymer) applied to Norne field E-Segment**. M.S. thesis, Department of Petroleum Engineering and Applied Geophysics.

Mildred G. (1986). **Fundamentals of Petroleum**, Texas: Petroleum Extension Service.

Miller, K.A.(2006) **"Improving the State of the Art of Western Canadian Heavy Oil Waterflood Technology",** Journal of Canadian Petroleum Technology, 54 (4), p 7 – 11.

Noianusontigul, K. (2008). **Numerical simulation by eclipse on polymer injection in the Benchamas oilfield as an EOR method using the high-performance computing cluster**. M.S. thesis, Asian Institute of Technology, Thailand.

O'Leary, J., and Hill, G.S. (1989). **Tertiary basin development in the Southern central Nicholls plains, Thailand.** In: Thanasuthipitak, T., Ounchanum, P. (Eds.), **Proceedings of the International Symposium on Intermontane Basins.** Geology & Resources, Chiang Mai, Thailand.

Rattanapranudej, S. (2004). **Improving Oil Recovery by Water Flooding in Suphan Buri Basin of Thailand**, M.S. thesis, Suranaree University of Technology, Thailand

Schlumberger Oilfield glossary, (2009). XRD & XRF. [Online] Available at http://www.glossary.oilfield.slb.com/search.cfm

Schlumberger. (2003). **ECLIPSE technical description**. Reservoir Simulation Software. Licensed and Supported by GeoQuest.

Sirisawadwattana, J, Sriyanong, P, Itthisawatpan, K, Opdal, S T and Ketmalee, T. (2012). **The Comparative Study of Thermal and Chemical EOR in Unconsolidated Siliciclastic Reservoir Containing Medium Heavy Oil**, Paper IPTC 14753, International Petroleum Technology Conference 2011, Bangkok, Thailand, February 7 -9 (2012).

Smith, G.E. (1992) "**Waterflooding Heavy Oils**", SPE 24367, SPE Rocky Mountain Regional Meeting, Casper, Wyoming, May 18 – 21.

Thai Shall Exploration & Production Co, Ltd. (2004).: **"Pru Krathiam Feasibility Screening Report"**

Willhite, G.P. (1986). **Waterflooding**, SPE Textbook Series, Volume 3, Richardson, TX.

Win, T. N., (2007). **Correlation Between Chemical Composition of Mudrock and Well log Data in the Suphan Buri basin, Thailand,** M.S. Thesis, Chiang Mai University.

Wongsirasawad, L. (2002) **"20 Successful Years of Sirikit Oilfield"** Thailand Petroleum Conference 2002, Bangkok.

# APPENDIX A

# SIMULATION DATA

Table A.1 PVTO (The Oil Properties).

| Rs (Mscf /stb) | Pbub (psia) | FVF (rb /stb) | Visc (cp) |
|---|---|---|---|
| 0.00063 | 14.70000 | 1.06883 | 9.47292 |
| | 145.50526 | 1.05593 | 9.68094 |
| | 300.00000 | 1.05519 | 10.12457 |
| | 407.11579 | 1.05500 | 10.51385 |
| | 537.92105 | 1.05488 | 11.06619 |
| | 668.72632 | 1.05480 | 11.69783 |
| | 799.53158 | 1.05475 | 12.40692 |
| | 930.33684 | 1.05471 | 13.19387 |
| | 1061.14210 | 1.05469 | 14.06044 |
| | 1191.94740 | 1.05466 | 15.00934 |
| | 1322.75260 | 1.05465 | 16.04398 |
| | 1453.55790 | 1.05463 | 17.16826 |
| | 1584.36320 | 1.05462 | 18.38655 |
| | 1715.16840 | 1.05461 | 19.70356 |
| | 1800.00000 | 1.05461 | 20.61281 |
| | 1976.77890 | 1.05459 | 22.65405 |
| | 2107.58420 | 1.05459 | 24.29832 |
| | 2238.38950 | 1.05458 | 26.06281 |
| | 2369.19470 | 1.05458 | 27.95339 |
| | 2500.00000 | 1.05457 | 29.97608 |
| 0.00999 | 145.50526 | 1.07259 | 8.64731 |
| | 300.00000 | 1.06490 | 8.78645 |
| | 407.11579 | 1.06300 | 8.93117 |
| | 537.92105 | 1.06171 | 9.14963 |
| | 668.72632 | 1.06092 | 9.40776 |
| | 799.53158 | 1.06040 | 9.70160 |
| | 930.33684 | 1.06002 | 10.02873 |
| | 1061.14210 | 1.05973 | 10.38768 |
| | 1191.94740 | 1.05951 | 10.77753 |
| | 1322.75260 | 1.05933 | 11.19781 |
| | 1453.55790 | 1.05918 | 11.64831 |
| | 1584.36320 | 1.05906 | 12.12903 |
| | 1715.16840 | 1.05896 | 12.64012 |
| | 1800.00000 | 1.05890 | 12.98793 |
| | 1976.77890 | 1.05879 | 13.75455 |
| | 2107.58420 | 1.05872 | 14.35866 |
| | 2238.38950 | 1.05866 | 14.99460 |
| | 2369.19470 | 1.05861 | 15.66286 |
| | 2500.00000 | 1.05856 | 16.36395 |

Table A.1 PVTO (The Oil Properties). (Continued)

| Rs (Mscf /stb) | Pbub (psia) | FVF (rb /stb) | Visc (cp) |
|---|---|---|---|
| 0.023881 | 300.00000 | 1.07821 | 7.65033 |
| | 407.11579 | 1.07406 | 7.72402 |
| | 537.92105 | 1.07124 | 7.84572 |
| | 668.72632 | 1.06952 | 7.99687 |
| | 799.53158 | 1.06837 | 8.17383 |
| | 930.33684 | 1.06755 | 8.37422 |
| | 1061.14210 | 1.06692 | 8.59640 |
| | 1191.94740 | 1.06644 | 8.83926 |
| | 1322.75260 | 1.06605 | 9.10197 |
| | 1453.55790 | 1.06573 | 9.38400 |
| | 1584.36320 | 1.06546 | 9.68493 |
| | 1715.16840 | 1.06524 | 10.00452 |
| | 1800.00000 | 1.06511 | 10.22168 |
| | 1976.77890 | 1.06487 | 10.69907 |
| | 2107.58420 | 1.06473 | 11.07390 |
| | 2238.38950 | 1.06460 | 11.46707 |
| | 2369.19470 | 1.06448 | 11.87863 |
| | 2500.00000 | 1.06438 | 12.30861 |

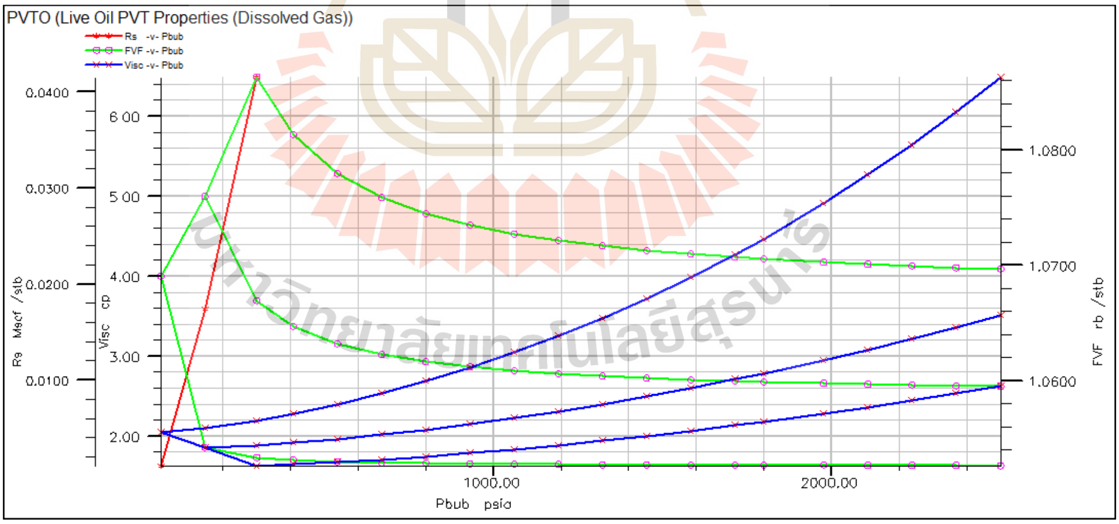


Figure A.1 Graph shows relationship of bubble-point pressure, (Pbub) VS oil formation volume factor, (FVF) and solution gas-oil ratio, (Rs).

Table A.2 PVDG (The Dry Gas PVT Property).

| Pressure (psia) | FVF (rb /Mscf) | Visc (cp) |
|---|---|---|
| 14.700000 | 225.764090 | 0.013055 |
| 145.505260 | 22.519860 | 0.013135 |
| 300.000000 | 10.762904 | 0.013280 |
| 407.115790 | 7.852413 | 0.013403 |
| 537.921050 | 5.872899 | 0.013577 |
| 668.726320 | 4.670348 | 0.013773 |
| 799.531580 | 3.863628 | 0.013993 |
| 930.336840 | 3.285965 | 0.014235 |
| 1061.142100 | 2.852823 | 0.014499 |
| 1191.947400 | 2.516775 | 0.014785 |
| 1322.752600 | 2.249151 | 0.015092 |
| 1453.557900 | 2.031597 | 0.015420 |
| 1584.363200 | 1.851809 | 0.015769 |
| 1715.168400 | 1.701223 | 0.016137 |
| 1800.000000 | 1.616198 | 0.016386 |
| 1976.778900 | 1.464670 | 0.016928 |
| 2107.584200 | 1.370734 | 0.017348 |
| 2238.389500 | 1.289237 | 0.017782 |
| 2369.194700 | 1.218103 | 0.018229 |
| 2500.000000 | 1.155675 | 0.018685 |

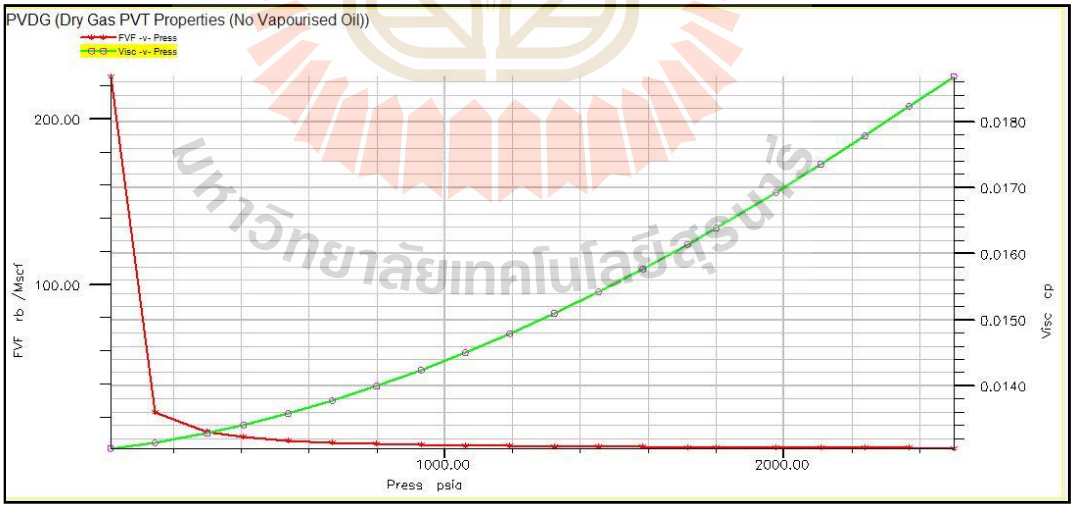


Figure A.2 Graph shows relationship of pressure VS gas formation volume factor and gas viscosity.

# APPENDIX B

# POLYMER DATA

## Data of polymer solution for injection

According to Kanarak (2011), Data is collected from the result of laboratory testing on polymer properties. The experiment is to examine the polymer properties at high temperature. The tests that were carried out are:

1. Heat-resistance of polymer
2. Screen factor of polymer

The polymer properties to be determined are:

1. Viscosity versus concentration of polymer solution with changed temperature.
2. Screen factor versus concentration of polymer solution with changed temperature.

The testing was carried out at different polymer concentrations: 600, 1,200, 1,800, 2,400 and 3,000 ppm, dissolved both with the freshwater and brine.

## Testing results for polymer properties

According to Thang (2005)**,** the measurement parameters of XCD polymer solution at the different concentrations before and after heating are presented in Table B1. The viscosity and screen factor versus concentration with changed temperature. The test of polymer solution have considerable loss of viscosity (plastic and apparent viscosity) and screen factor after heated polymer up to 150º C in the different times. Especially in the polymer samples with low concentration (600 ppm), the capability of increased viscosity and screen factor were almost lost. The problem from high polymer concentration is that it will increase cost which will reduce economic efficiency.

The capability to maintain plastic viscosity versus the concentration after heating up XCD polymer solution to 150ºC is presented in Figure 3.1 and 3.2. According to the figure, when polymer concentration increased to between 500-2,000 ppm, viscosity increase rapidly. After that, viscosity increased slowly.

In the environment of brine, XCD polymer has a good salt-resistance. The tests with brine solution of 4% NaCl showed that they still maintained the parameters of viscosity, screen factor after heated polymer up to 130ºC.

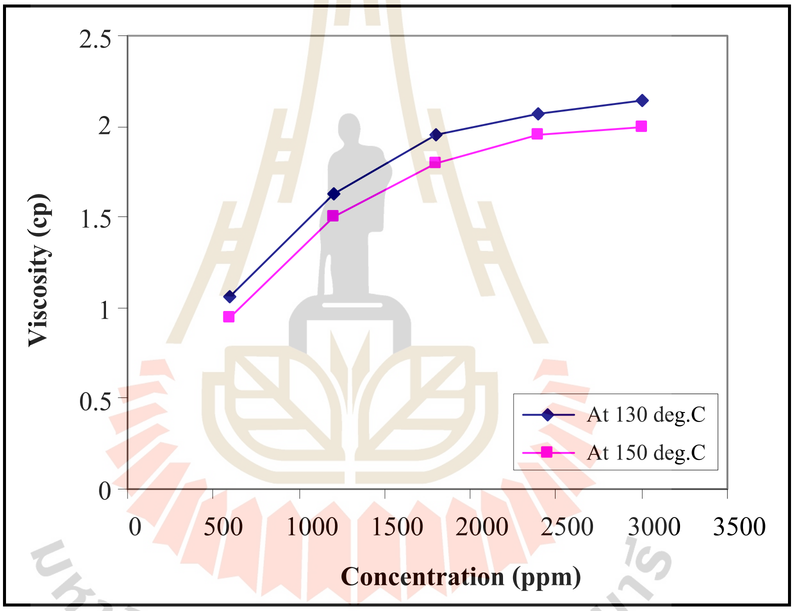


Figure B.1 The viscosity versus concentration of polymer solution

(After Thang, 2005)

Table B.1 Results of test for polymer properties (After Thang, 2005)

| No | Polymer | Conc. ppm | Before heating | | | | | | Heating temp, ºC | Heating time, h | After heating | | | | | Viscosity through capilar,μa | Screen factor | | Remark |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Temp. ºC | PH | $V_{300}$ | $V_{600}$ | μP | μa | | | Temp. ºC | PH | $V_{300}$ | $V_{600}$ | μP | | Before heating | After Heating | |
| 1 | XCD | 600 | 28.5 | 8 | 5 | 7 | 2 | 3.5 | 130 | 7 | 26.0 | 8 | 3 | 4 | 1 | - | 1.9 | 1.1 | |
| 2 | XCD | 600 | 28.5 | 8 | 5 | 7 | 2 | 3.5 | 150 | 7 | 26.0 | 8 | 3 | 4 | 1 | - | 1.9 | 1 | |
| 3 | XCD | 1200 | 28.5 | 8 | 7 | 9 | 2 | 4.5 | 130 | 7 | 28.0 | 8 | 3 | 4.5 | 1.5 | - | 2.2 | 1.1 | |
| 4 | XCD | 1200 | 28.5 | 8 | 7 | 9 | 2 | 4.5 | 150 | 7 | 30.0 | 8 | 3 | 4.5 | 1.5 | - | 2.2 | 1.1 | |
| 5 | XCD | 1800 | 30.0 | 8 | 8 | 12 | 4 | 6 | 130 | 7 | 30.0 | 8 | 4 | 6 | 2 | 1.0 | 2.6 | 1.3 | |
| 6 | XCD | 1800 | 30.0 | 8 | 8 | 12 | 4 | 6 | 150 | 7 | 30.0 | 8 | 3 | 4.5 | 1.5 | 1.0 | 2.6 | 1.3 | |
| 7 | XCD | 2400 | 30.5 | 8 | 10 | 14 | 4 | 7 | 130 | 7 | 30.5 | 8 | 4 | 6 | 2 | 1.1 | 4.5 | 1.4 | |
| 8 | XCD | 2400 | 30.5 | 8 | 10 | 14 | 4 | 7 | 150 | 7 | 30.5 | 8 | 3 | 5 | 2 | 1.0 | 4.5 | 1.3 | |
| 9 | XCD | 3000 | 30.5 | 8 | 12 | 17 | 5 | 8.5 | 130 | 7 | 30.5 | 8 | 5 | 7 | 2 | 1.7 | 11.4 | 1.5 | |
| 10 | XCD | 3000 | 30.5 | 8 | 12 | 17 | 5 | 8.5 | 150 | 7 | 30.5 | 8 | 3 | 5 | 2 | 1.4 | 11.4 | 1.4 | |
| 11 | XCD | 3000 | 26.0 | 8 | 15 | 20 | 5 | 9.8 | 130 | 7 | 26.0 | 8 | 4 | 6 | 2 | - | - | - | Brine |
| 12 | XCD | 3000 | 26.0 | 8 | 15 | 20 | 5 | 9.8 | 150 | 7 | 26.0 | 8 | 3.5 | 5.5 | 2 | - | - | - | Brine |

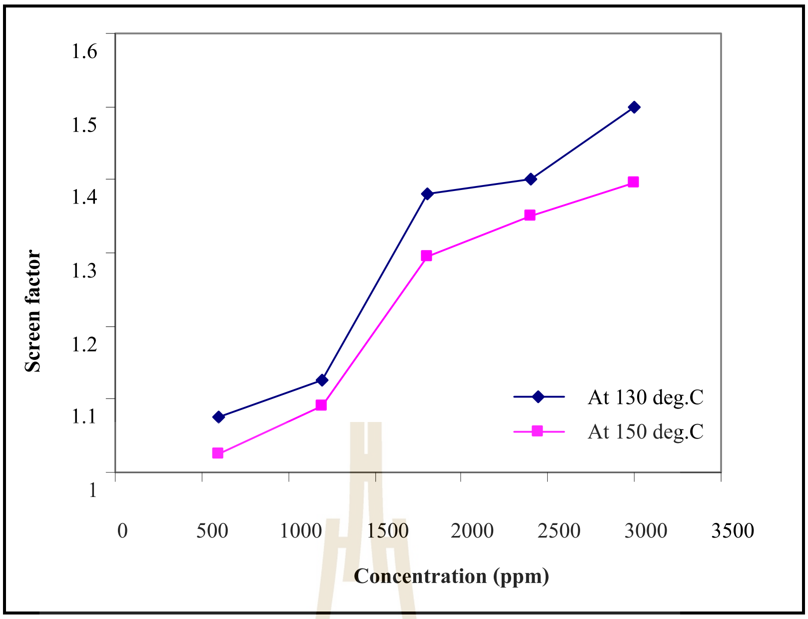


Figure B.2 The screen factor versus concentration of polymer solution (After Thang 2005)

With low concentration, XCD polymer fails to maintain viscosity, screen factor in a long time when polymer was heated up to 130-150ºC. It is clear that the definition of limitation of the heat resistance for polymers still depends on the purpose of using it in the enhanced oil recovery technique. If the polymer are used for the purpose of well treatment or making gel, then the above solutions can be satisfied up to 150ºC or more than that.

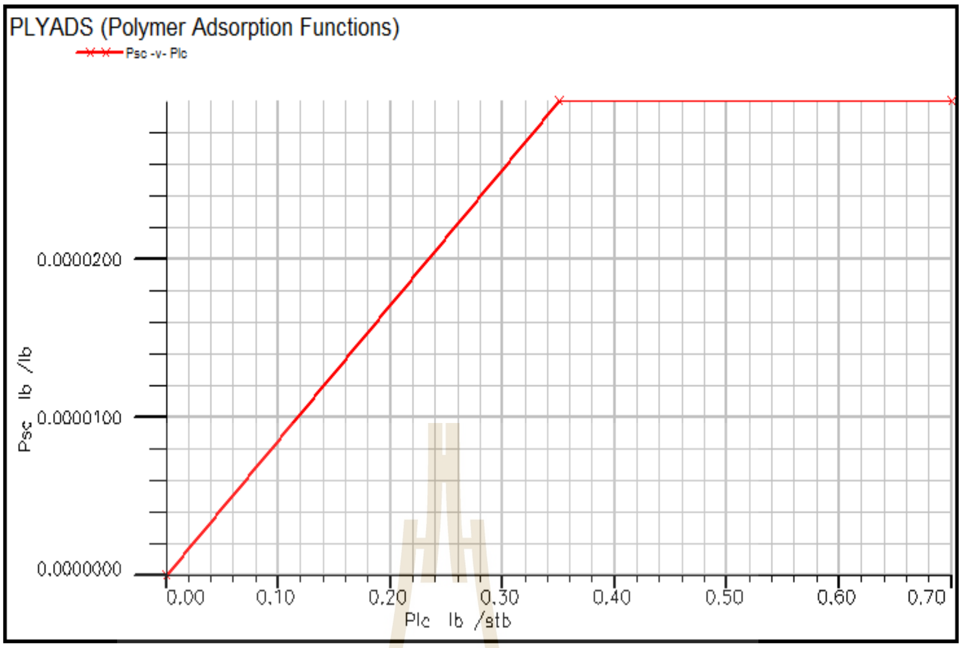


Figure B.3 Polymer adsorption function graph display result

from Suphan Buri basin input data section

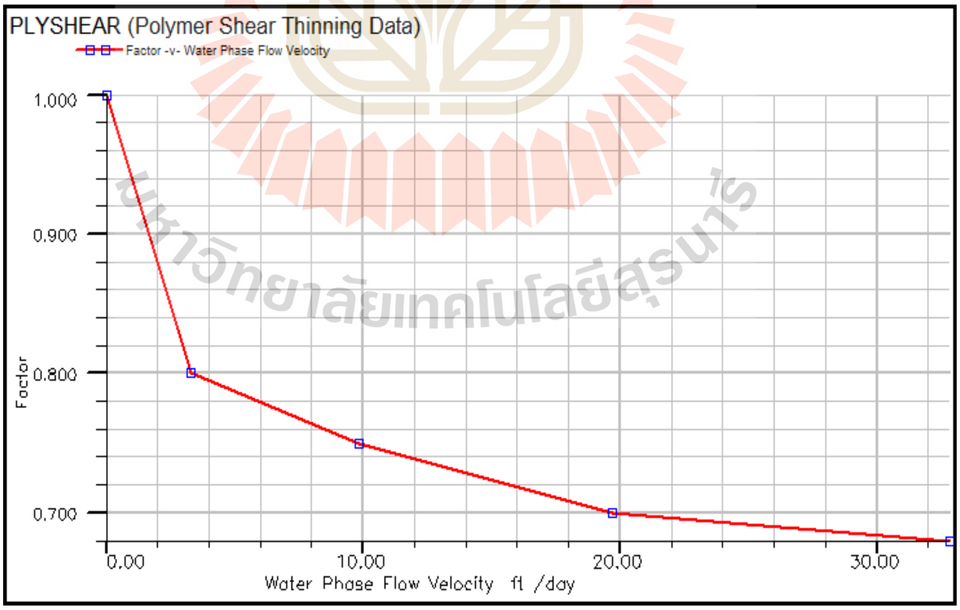


Figure B.4 Polymer shear thinning data graph display result

from Suphan Buri basin input data section

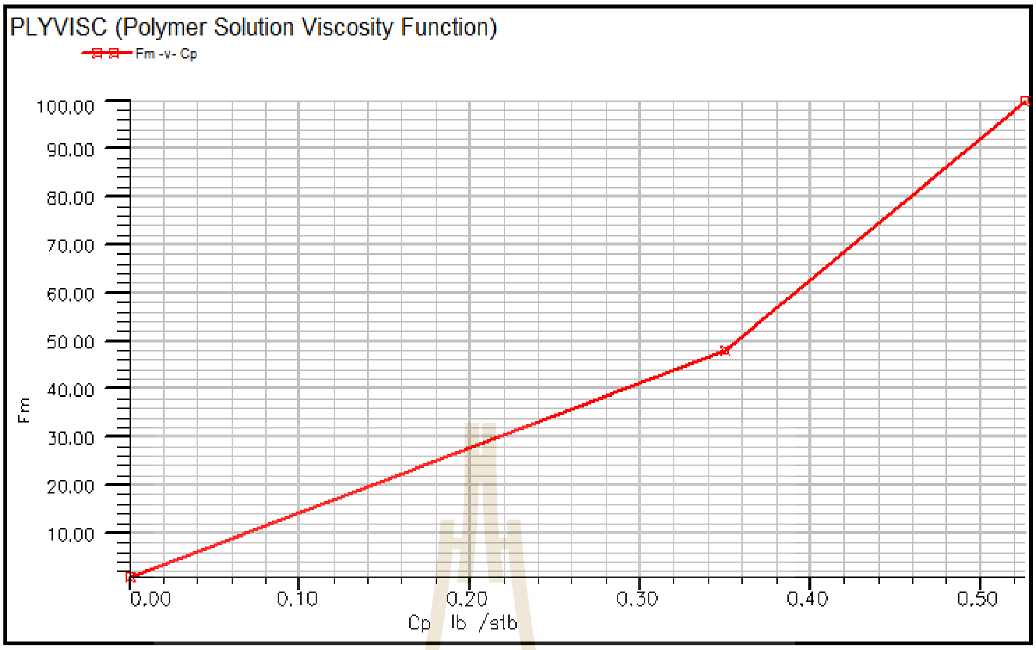


Figure B.5 Polymer solution viscosity function graph display result from Suphan Buri basin input data section

# APPENDIX C

# CASH FLOW SUMMARY

## Table of cash flow summary

The economic analysis is calculated and analyzed by the Microsoft Excels spreadsheet. The economic summary results of all case studies are illustrated in Tables C.1-C.32. Tables C.1-C.32 display undiscounted IRR and PIR at the end of annual cash flow column and discounted value at the end of discount cash flow column. The IRR, PIR and NPV summary of all case studies are illustrated in Table C.33 and C.34.

Table C.1 Cash flow summary of case 1. Recovery Factor = 6.43%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,195 | 10.760 | 0.000 | 4.659 | 0.538 | 0.000 | 1.323 | 0.822 |
| 6 | 140,276 | 7.014 | 0.000 | 3.098 | 0.351 | 0.000 | -0.674 | -0.381 |
| 7 | 116,062 | 5.803 | 0.000 | 2.614 | 0.290 | 0.000 | -1.341 | -0.688 |
| 8 | 107,942 | 5.397 | 0.000 | 2.480 | 0.270 | 0.000 | -1.593 | -0.743 |
| 9 | 102,000 | 5.100 | 0.000 | 2.390 | 0.255 | 1.227 | 1.227 | 0.521 |
| 10 | 97,283 | 4.864 | 0.000 | 2.325 | 0.243 | 1.148 | 1.148 | 0.443 |
| 11 | 92,909 | 4.645 | 0.000 | 2.265 | 0.232 | 1.074 | 1.074 | 0.376 |
| 12 | 88,835 | 4.442 | 0.000 | 2.209 | 0.222 | 1.005 | 1.005 | 0.320 |
| 13 | 84,839 | 4.242 | 0.000 | 2.152 | 0.212 | 0.939 | 0.939 | 0.272 |
| 14 | 80,960 | 4.048 | 0.000 | 2.095 | 0.202 | 0.875 | 0.875 | 0.231 |
| 15 | 77,238 | 3.862 | 0.000 | 2.038 | 0.193 | 0.815 | 0.815 | 0.195 |
| 16 | 73,096 | 3.655 | 0.000 | 1.968 | 0.183 | 0.752 | 0.752 | 0.164 |
| 17 | 69,015 | 3.451 | 0.000 | 1.895 | 0.173 | 0.692 | 0.692 | 0.137 |
| 18 | 64,804 | 3.240 | 0.000 | 1.815 | 0.162 | 0.632 | 0.632 | 0.114 |
| 19 | 59,926 | 2.996 | 0.000 | 1.712 | 0.150 | 0.567 | 0.567 | 0.093 |
| 20 | 55,010 | 2.751 | 0.000 | 1.603 | 0.138 | 0.505 | 0.505 | 0.075 |
| 21 | 49,878 | 2.494 | 0.000 | 1.482 | 0.125 | 0.443 | 0.443 | 0.060 |
| 22 | 44,842 | 2.242 | 0.000 | 1.359 | 0.112 | 0.385 | 0.385 | 0.047 |
| 23 | 40,288 | 2.014 | 0.000 | 1.246 | 0.101 | 0.334 | 0.334 | 0.037 |
| 24 | 36,335 | 1.817 | 0.000 | 1.146 | 0.091 | 0.290 | 0.290 | 0.029 |
| Total | 1,696,733 | 84.837 | 29.500 | 42.550 | 4.242 | 11.685 | -3.140 | -6.910 |
| | | | | | | IRR | -2.22% | -11.11% |
| | | | | | | PIR | -0.106 | -0.234 |

Table C.2 Cash flow summary of case 2. Recovery Factor = 11.11%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 219,600 | 10.980 | 0.000 | 4.754 | 0.549 | 0.000 | 1.357 | 0.843 |
| 6 | 174,488 | 8.724 | 0.000 | 3.853 | 0.436 | 0.058 | 0.058 | 0.033 |
| 7 | 147,987 | 7.399 | 0.000 | 3.333 | 0.370 | 0.000 | -0.624 | -0.320 |
| 8 | 136,656 | 6.833 | 0.000 | 3.139 | 0.342 | 0.000 | -0.968 | -0.452 |
| 9 | 128,234 | 6.412 | 0.000 | 3.005 | 0.321 | 1.543 | 1.543 | 0.654 |
| 10 | 121,476 | 6.074 | 0.000 | 2.903 | 0.304 | 1.433 | 1.433 | 0.553 |
| 11 | 115,916 | 5.796 | 0.000 | 2.826 | 0.290 | 1.340 | 1.340 | 0.470 |
| 12 | 111,202 | 5.560 | 0.000 | 2.765 | 0.278 | 1.258 | 1.258 | 0.401 |
| 13 | 106,633 | 5.332 | 0.000 | 2.705 | 0.267 | 1.180 | 1.180 | 0.342 |
| 14 | 101,718 | 5.086 | 0.000 | 2.632 | 0.254 | 1.100 | 1.100 | 0.290 |
| 15 | 96,003 | 4.800 | 0.000 | 2.533 | 0.240 | 1.013 | 1.013 | 0.243 |
| 16 | 89,826 | 4.491 | 0.000 | 2.418 | 0.225 | 0.924 | 0.924 | 0.201 |
| 17 | 83,289 | 4.164 | 0.000 | 2.287 | 0.208 | 0.835 | 0.835 | 0.165 |
| 18 | 76,529 | 3.826 | 0.000 | 2.143 | 0.191 | 0.746 | 0.746 | 0.134 |
| 19 | 69,601 | 3.480 | 0.000 | 1.988 | 0.174 | 0.659 | 0.659 | 0.108 |
| 20 | 62,681 | 3.134 | 0.000 | 1.826 | 0.157 | 0.576 | 0.576 | 0.086 |
| 21 | 56,040 | 2.802 | 0.000 | 1.665 | 0.140 | 0.498 | 0.498 | 0.067 |
| 22 | 49,847 | 2.492 | 0.000 | 1.511 | 0.125 | 0.428 | 0.428 | 0.053 |
| 23 | 44,243 | 2.212 | 0.000 | 1.368 | 0.111 | 0.367 | 0.367 | 0.041 |
| 24 | 39,352 | 1.968 | 0.000 | 1.241 | 0.098 | 0.314 | 0.314 | 0.032 |
| Total | 2,031,321 | 101.566 | 31.500 | 50.897 | 5.078 | 14.273 | -0.182 | -6.239 |
| | | | | | | IRR | -0.12% | -9.20% |
| | | | | | | PIR | -0.006 | -0.198 |

Table C.3 Cash flow summary of case 3. Recovery Factor = 15.61%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 22.131 | 0.000 | 0.000 | 0.000 | -5.706 | -3.897 |
| 5 | 164,664 | 8.233 | 0.000 | 6.284 | 0.412 | 0.000 | -2.568 | -1.595 |
| 6 | 168,771 | 8.439 | 0.000 | 3.874 | 0.422 | 0.018 | 0.018 | 0.010 |
| 7 | 171,660 | 8.583 | 0.000 | 4.017 | 0.429 | 0.015 | 0.015 | 0.008 |
| 8 | 172,718 | 8.636 | 0.000 | 4.122 | 0.432 | 0.000 | -0.024 | -0.011 |
| 9 | 173,609 | 8.680 | 0.000 | 4.225 | 0.434 | 2.011 | 2.011 | 0.853 |
| 10 | 173,740 | 8.687 | 0.000 | 4.312 | 0.434 | 1.970 | 1.970 | 0.760 |
| 11 | 172,714 | 8.636 | 0.000 | 4.373 | 0.432 | 1.916 | 1.916 | 0.671 |
| 12 | 167,437 | 8.372 | 0.000 | 4.326 | 0.419 | 1.814 | 1.814 | 0.578 |
| 13 | 159,329 | 7.966 | 0.000 | 4.202 | 0.398 | 1.683 | 1.683 | 0.488 |
| 14 | 153,239 | 7.662 | 0.000 | 4.121 | 0.383 | 1.579 | 1.579 | 0.416 |
| 15 | 146,285 | 7.314 | 0.000 | 4.013 | 0.366 | 1.468 | 1.468 | 0.351 |
| 16 | 137,685 | 6.884 | 0.000 | 3.855 | 0.344 | 1.342 | 1.342 | 0.292 |
| 17 | 130,530 | 6.527 | 0.000 | 3.730 | 0.326 | 1.235 | 1.235 | 0.244 |
| 18 | 125,020 | 6.251 | 0.000 | 3.644 | 0.313 | 1.147 | 1.147 | 0.206 |
| 19 | 119,448 | 5.972 | 0.000 | 3.553 | 0.299 | 1.060 | 1.060 | 0.173 |
| 20 | 113,307 | 5.665 | 0.000 | 3.441 | 0.283 | 0.971 | 0.971 | 0.144 |
| 21 | 107,983 | 5.399 | 0.000 | 3.348 | 0.270 | 0.890 | 0.890 | 0.120 |
| 22 | 103,296 | 5.165 | 0.000 | 3.270 | 0.258 | 0.818 | 0.818 | 0.101 |
| 23 | 99,117 | 4.956 | 0.000 | 3.203 | 0.248 | 0.752 | 0.752 | 0.084 |
| 24 | 95,576 | 4.779 | 0.000 | 3.154 | 0.239 | 0.693 | 0.693 | 0.070 |
| Total | 2,856,125 | 142.806 | 25.631 | 79.067 | 7.140 | 21.383 | 9.585 | -2.792 |
| | | | | | | IRR | 5.65% | -3.96% |
| | | | | | | PIR | 0.374 | -0.109 |

Table C.4 Cash flow summary of case 4. Recovery Factor = 16.29%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 24.131 | 0.000 | 0.000 | 0.000 | -7.386 | -5.045 |
| 5 | 219,600 | 10.980 | 0.000 | 4.899 | 0.549 | 0.000 | 1.346 | 0.836 |
| 6 | 219,600 | 10.980 | 0.000 | 4.997 | 0.549 | 0.624 | 0.624 | 0.352 |
| 7 | 207,702 | 10.385 | 0.000 | 4.829 | 0.519 | 0.425 | 0.425 | 0.218 |
| 8 | 189,110 | 9.455 | 0.000 | 4.498 | 0.473 | 0.149 | 0.149 | 0.070 |
| 9 | 180,542 | 9.027 | 0.000 | 4.388 | 0.451 | 2.094 | 2.094 | 0.888 |
| 10 | 175,097 | 8.755 | 0.000 | 4.345 | 0.438 | 1.986 | 1.986 | 0.766 |
| 11 | 169,424 | 8.471 | 0.000 | 4.294 | 0.424 | 1.877 | 1.877 | 0.658 |
| 12 | 163,291 | 8.165 | 0.000 | 4.227 | 0.408 | 1.765 | 1.765 | 0.562 |
| 13 | 158,102 | 7.905 | 0.000 | 4.180 | 0.395 | 1.665 | 1.665 | 0.482 |
| 14 | 151,268 | 7.563 | 0.000 | 4.087 | 0.378 | 1.549 | 1.549 | 0.408 |
| 15 | 143,286 | 7.164 | 0.000 | 3.958 | 0.358 | 1.424 | 1.424 | 0.341 |
| 16 | 135,564 | 6.778 | 0.000 | 3.829 | 0.339 | 1.305 | 1.305 | 0.284 |
| 17 | 128,207 | 6.410 | 0.000 | 3.704 | 0.321 | 1.193 | 1.193 | 0.236 |
| 18 | 121,578 | 6.079 | 0.000 | 3.592 | 0.304 | 1.091 | 1.091 | 0.196 |
| 19 | 115,653 | 5.783 | 0.000 | 3.495 | 0.289 | 0.999 | 0.999 | 0.163 |
| 20 | 109,943 | 5.497 | 0.000 | 3.399 | 0.275 | 0.912 | 0.912 | 0.136 |
| 21 | 104,559 | 5.228 | 0.000 | 3.307 | 0.261 | 0.830 | 0.830 | 0.112 |
| 22 | 99,742 | 4.987 | 0.000 | 3.227 | 0.249 | 0.756 | 0.756 | 0.093 |
| 23 | 95,522 | 4.776 | 0.000 | 3.161 | 0.239 | 0.688 | 0.688 | 0.077 |
| 24 | 91,780 | 4.589 | 0.000 | 3.106 | 0.229 | 0.627 | 0.627 | 0.064 |
| Total | 2,979,568 | 148.978 | 27.631 | 79.522 | 7.449 | 21.959 | 12.418 | -0.962 |
| | | | | | | IRR | 8.33% | -1.52% |
| | | | | | | PIR | 0.449 | -0.035 |

Table C.5 Cash flow summary of case 5. Recovery Factor = 14.74%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,195 | 10.760 | 0.000 | 4.659 | 0.538 | 0.000 | 1.323 | 0.822 |
| 6 | 140,276 | 7.014 | 0.000 | 3.098 | 0.351 | 0.000 | -0.674 | -0.381 |
| 7 | 46,629 | 2.331 | 0.156 | 1.201 | 0.117 | 0.000 | -3.277 | -1.682 |
| 8 | 79,362 | 3.968 | 0.000 | 1.977 | 0.198 | 0.000 | -2.474 | -1.154 |
| 9 | 113,583 | 5.679 | 0.000 | 2.819 | 0.284 | 1.275 | 1.275 | 0.541 |
| 10 | 137,933 | 6.897 | 0.000 | 3.457 | 0.345 | 1.534 | 1.534 | 0.592 |
| 11 | 152,635 | 7.632 | 0.000 | 3.885 | 0.382 | 1.683 | 1.683 | 0.590 |
| 12 | 161,219 | 8.061 | 0.000 | 4.176 | 0.403 | 1.741 | 1.741 | 0.555 |
| 13 | 165,709 | 8.285 | 0.000 | 4.373 | 0.414 | 1.749 | 1.749 | 0.507 |
| 14 | 165,964 | 8.298 | 0.000 | 4.467 | 0.415 | 1.708 | 1.708 | 0.450 |
| 15 | 160,937 | 8.047 | 0.000 | 4.424 | 0.402 | 1.610 | 1.610 | 0.385 |
| 16 | 154,827 | 7.741 | 0.000 | 4.348 | 0.387 | 1.503 | 1.503 | 0.327 |
| 17 | 148,770 | 7.438 | 0.000 | 4.269 | 0.372 | 1.399 | 1.399 | 0.277 |
| 18 | 140,870 | 7.044 | 0.000 | 4.133 | 0.352 | 1.279 | 1.279 | 0.230 |
| 19 | 133,010 | 6.650 | 0.000 | 3.991 | 0.333 | 1.164 | 1.164 | 0.190 |
| 20 | 127,205 | 6.360 | 0.000 | 3.901 | 0.318 | 1.070 | 1.070 | 0.159 |
| 21 | 121,349 | 6.067 | 0.000 | 3.805 | 0.303 | 0.979 | 0.979 | 0.132 |
| 22 | 115,367 | 5.768 | 0.000 | 3.700 | 0.288 | 0.890 | 0.890 | 0.109 |
| 23 | 109,768 | 5.488 | 0.000 | 3.601 | 0.274 | 0.806 | 0.806 | 0.090 |
| 24 | 104,798 | 5.240 | 0.000 | 3.516 | 0.262 | 0.731 | 0.731 | 0.074 |
| Total | 2,695,407 | 134.770 | 29.656 | 73.799 | 6.739 | 21.123 | 3.480 | -6.220 |
| | | | | | | IRR | 1.71% | -7.54% |
| | | | | | | PIR | 0.117 | -0.210 |

Table C.6 Cash flow summary of case 6. Recovery Factor = 15.42%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 267,729 | 13.386 | 0.000 | 5.796 | 0.669 | 0.000 | 2.601 | 1.615 |
| 6 | 163,516 | 8.176 | 0.000 | 3.611 | 0.409 | 0.000 | -0.164 | -0.092 |
| 7 | 74,451 | 3.723 | 0.156 | 1.828 | 0.186 | 0.000 | -2.662 | -1.366 |
| 8 | 93,515 | 4.676 | 0.000 | 2.302 | 0.234 | 0.000 | -2.206 | -1.029 |
| 9 | 124,128 | 6.206 | 0.000 | 3.066 | 0.310 | 1.402 | 1.402 | 0.595 |
| 10 | 147,545 | 7.377 | 0.000 | 3.687 | 0.369 | 1.648 | 1.648 | 0.635 |
| 11 | 161,220 | 8.061 | 0.000 | 4.094 | 0.403 | 1.782 | 1.782 | 0.625 |
| 12 | 167,253 | 8.363 | 0.000 | 4.326 | 0.418 | 1.809 | 1.809 | 0.577 |
| 13 | 167,482 | 8.374 | 0.000 | 4.418 | 0.419 | 1.769 | 1.769 | 0.512 |
| 14 | 163,822 | 8.191 | 0.000 | 4.412 | 0.410 | 1.685 | 1.685 | 0.444 |
| 15 | 159,473 | 7.974 | 0.000 | 4.385 | 0.399 | 1.595 | 1.595 | 0.382 |
| 16 | 153,869 | 7.693 | 0.000 | 4.322 | 0.385 | 1.493 | 1.493 | 0.325 |
| 17 | 146,233 | 7.312 | 0.000 | 4.199 | 0.366 | 1.374 | 1.374 | 0.272 |
| 18 | 138,373 | 6.919 | 0.000 | 4.063 | 0.346 | 1.255 | 1.255 | 0.226 |
| 19 | 130,829 | 6.541 | 0.000 | 3.928 | 0.327 | 1.143 | 1.143 | 0.187 |
| 20 | 123,739 | 6.187 | 0.000 | 3.800 | 0.309 | 1.039 | 1.039 | 0.154 |
| 21 | 117,615 | 5.881 | 0.000 | 3.694 | 0.294 | 0.946 | 0.946 | 0.128 |
| 22 | 111,790 | 5.589 | 0.000 | 3.592 | 0.279 | 0.859 | 0.859 | 0.106 |
| 23 | 106,209 | 5.310 | 0.000 | 3.491 | 0.266 | 0.777 | 0.777 | 0.087 |
| 24 | 101,143 | 5.057 | 0.000 | 3.401 | 0.253 | 0.702 | 0.702 | 0.071 |
| Total | 2,819,931 | 140.997 | 31.656 | 76.415 | 7.050 | 21.277 | 4.625 | -5.730 |
| | | | | | | IRR | 2.31% | -6.99% |
| | | | | | | PIR | 0.146 | -0.181 |

Table C.7 Cash flow summary of case 7. Recovery Factor = 13.64%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,195 | 10.760 | 0.000 | 4.659 | 0.538 | 0.000 | 1.323 | 0.822 |
| 6 | 140,276 | 7.014 | 0.000 | 3.098 | 0.351 | 0.000 | -0.674 | -0.381 |
| 7 | 116,062 | 5.803 | 0.000 | 2.614 | 0.290 | 0.000 | -1.341 | -0.688 |
| 8 | 107,942 | 5.397 | 0.000 | 2.480 | 0.270 | 0.000 | -1.593 | -0.743 |
| 9 | 30,465 | 1.523 | 0.286 | 0.871 | 0.076 | 0.276 | 0.276 | 0.117 |
| 10 | 36,313 | 1.816 | 0.000 | 1.028 | 0.091 | 0.348 | 0.348 | 0.134 |
| 11 | 60,103 | 3.005 | 0.000 | 1.629 | 0.150 | 0.613 | 0.613 | 0.215 |
| 12 | 94,736 | 4.737 | 0.000 | 2.522 | 0.237 | 0.989 | 0.989 | 0.315 |
| 13 | 125,268 | 6.263 | 0.000 | 3.347 | 0.313 | 1.301 | 1.301 | 0.377 |
| 14 | 144,908 | 7.245 | 0.000 | 3.922 | 0.362 | 1.480 | 1.480 | 0.390 |
| 15 | 156,238 | 7.812 | 0.000 | 4.300 | 0.391 | 1.561 | 1.561 | 0.374 |
| 16 | 161,310 | 8.065 | 0.000 | 4.522 | 0.403 | 1.570 | 1.570 | 0.342 |
| 17 | 159,799 | 7.990 | 0.000 | 4.571 | 0.399 | 1.510 | 1.510 | 0.299 |
| 18 | 154,372 | 7.719 | 0.000 | 4.511 | 0.386 | 1.411 | 1.411 | 0.254 |
| 19 | 149,472 | 7.474 | 0.000 | 4.461 | 0.374 | 1.319 | 1.319 | 0.216 |
| 20 | 142,082 | 7.104 | 0.000 | 4.335 | 0.355 | 1.207 | 1.207 | 0.179 |
| 21 | 134,158 | 6.708 | 0.000 | 4.186 | 0.335 | 1.093 | 1.093 | 0.148 |
| 22 | 128,084 | 6.404 | 0.000 | 4.086 | 0.320 | 0.999 | 0.999 | 0.123 |
| 23 | 122,313 | 6.116 | 0.000 | 3.989 | 0.306 | 0.910 | 0.910 | 0.102 |
| 24 | 116,247 | 5.812 | 0.000 | 3.878 | 0.291 | 0.822 | 0.822 | 0.083 |
| Total | 2,495,344 | 124.767 | 29.786 | 69.009 | 6.238 | 17.410 | 2.585 | -6.357 |
| | | | | | | IRR | 1.27% | -7.93% |
| | | | | | | PIR | 0.087 | -0.213 |

Table C.8 Cash flow summary of case 8. Recovery Factor = 14.37%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 267,729 | 13.386 | 0.000 | 5.796 | 0.669 | 0.000 | 2.601 | 1.615 |
| 6 | 163,516 | 8.176 | 0.000 | 3.611 | 0.409 | 0.000 | -0.164 | -0.092 |
| 7 | 144,778 | 7.239 | 0.000 | 3.261 | 0.362 | 0.000 | -0.704 | -0.361 |
| 8 | 134,429 | 6.721 | 0.000 | 3.088 | 0.336 | 0.000 | -1.023 | -0.477 |
| 9 | 59,356 | 2.968 | 0.286 | 1.548 | 0.148 | 0.623 | 0.623 | 0.264 |
| 10 | 63,192 | 3.160 | 0.000 | 1.671 | 0.158 | 0.666 | 0.666 | 0.257 |
| 11 | 69,831 | 3.492 | 0.000 | 1.866 | 0.175 | 0.726 | 0.726 | 0.254 |
| 12 | 84,946 | 4.247 | 0.000 | 2.279 | 0.212 | 0.878 | 0.878 | 0.280 |
| 13 | 113,092 | 5.655 | 0.000 | 3.038 | 0.283 | 1.167 | 1.167 | 0.338 |
| 14 | 137,080 | 6.854 | 0.000 | 3.720 | 0.343 | 1.396 | 1.396 | 0.368 |
| 15 | 151,776 | 7.589 | 0.000 | 4.182 | 0.379 | 1.514 | 1.514 | 0.362 |
| 16 | 156,423 | 7.821 | 0.000 | 4.391 | 0.391 | 1.520 | 1.520 | 0.331 |
| 17 | 156,201 | 7.810 | 0.000 | 4.473 | 0.391 | 1.473 | 1.473 | 0.292 |
| 18 | 153,172 | 7.659 | 0.000 | 4.477 | 0.383 | 1.399 | 1.399 | 0.252 |
| 19 | 146,732 | 7.337 | 0.000 | 4.383 | 0.367 | 1.293 | 1.293 | 0.211 |
| 20 | 139,322 | 6.966 | 0.000 | 4.255 | 0.348 | 1.182 | 1.182 | 0.176 |
| 21 | 131,961 | 6.598 | 0.000 | 4.121 | 0.330 | 1.074 | 1.074 | 0.145 |
| 22 | 124,803 | 6.240 | 0.000 | 3.986 | 0.312 | 0.971 | 0.971 | 0.119 |
| 23 | 118,591 | 5.930 | 0.000 | 3.874 | 0.296 | 0.880 | 0.880 | 0.098 |
| 24 | 112,827 | 5.641 | 0.000 | 3.770 | 0.282 | 0.795 | 0.795 | 0.081 |
| Total | 2,629,755 | 131.488 | 31.786 | 71.788 | 6.574 | 17.555 | 4.045 | -5.669 |
| | | | | | | IRR | 2.07% | -7.21% |
| | | | | | | PIR | 0.127 | -0.178 |

Table C.9 Cash flow summary of case 9. Recovery Factor = 17.47%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 22.131 | 0.000 | 0.000 | 0.000 | -5.706 | -3.897 |
| 5 | 166,332 | 8.317 | 0.000 | 3.746 | 0.416 | 0.000 | 0.049 | 0.030 |
| 6 | 169,192 | 8.460 | 0.115 | 3.950 | 0.423 | 0.000 | -0.135 | -0.076 |
| 7 | 172,044 | 8.602 | 0.115 | 4.094 | 0.430 | 0.000 | -0.143 | -0.073 |
| 8 | 173,727 | 8.686 | 0.115 | 4.214 | 0.434 | 0.000 | -0.184 | -0.086 |
| 9 | 174,022 | 8.701 | 0.115 | 4.305 | 0.435 | 1.923 | 1.923 | 0.815 |
| 10 | 174,503 | 8.725 | 0.115 | 4.403 | 0.436 | 1.885 | 1.885 | 0.727 |
| 11 | 174,726 | 8.736 | 0.115 | 4.496 | 0.437 | 1.844 | 1.844 | 0.646 |
| 12 | 175,038 | 8.752 | 0.115 | 4.595 | 0.438 | 1.802 | 1.802 | 0.574 |
| 13 | 173,668 | 8.683 | 0.115 | 4.651 | 0.434 | 1.741 | 1.741 | 0.504 |
| 14 | 171,472 | 8.574 | 0.115 | 4.687 | 0.429 | 1.671 | 1.671 | 0.440 |
| 15 | 167,457 | 8.373 | 0.115 | 4.675 | 0.419 | 1.582 | 1.582 | 0.379 |
| 16 | 162,491 | 8.125 | 0.115 | 4.636 | 0.406 | 1.484 | 1.484 | 0.323 |
| 17 | 157,805 | 7.890 | 0.115 | 4.599 | 0.395 | 1.391 | 1.391 | 0.275 |
| 18 | 154,016 | 7.701 | 0.115 | 4.585 | 0.385 | 1.308 | 1.308 | 0.235 |
| 19 | 149,335 | 7.467 | 0.115 | 4.543 | 0.373 | 1.218 | 1.218 | 0.199 |
| 20 | 144,897 | 7.245 | 0.115 | 4.505 | 0.362 | 1.131 | 1.131 | 0.168 |
| 21 | 139,812 | 6.991 | 0.115 | 4.444 | 0.350 | 1.041 | 1.041 | 0.141 |
| 22 | 135,476 | 6.774 | 0.115 | 4.401 | 0.339 | 0.959 | 0.959 | 0.118 |
| 23 | 131,661 | 6.583 | 0.115 | 4.371 | 0.329 | 0.884 | 0.884 | 0.099 |
| 24 | 128,424 | 6.421 | 0.115 | 4.357 | 0.321 | 0.814 | 0.814 | 0.083 |
| Total | 3,196,097 | 159.805 | 27.820 | 88.257 | 7.990 | 22.678 | 13.059 | -1.235 |
| | | | | | | IRR | 7.96% | -1.85% |
| | | | | | | PIR | 0.469 | -0.044 |

Table C.10 Cash flow summary of case 10. Recovery Factor = 18.04%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 24.131 | 0.000 | 0.000 | 0.000 | -7.386 | -5.045 |
| 5 | 219,000 | 10.950 | 0.000 | 4.886 | 0.548 | 0.000 | 1.331 | 0.826 |
| 6 | 219,000 | 10.950 | 0.115 | 5.049 | 0.548 | 0.526 | 0.526 | 0.297 |
| 7 | 209,347 | 10.467 | 0.115 | 4.933 | 0.523 | 0.355 | 0.355 | 0.182 |
| 8 | 190,271 | 9.514 | 0.115 | 4.593 | 0.476 | 0.071 | 0.071 | 0.033 |
| 9 | 181,183 | 9.059 | 0.115 | 4.472 | 0.453 | 2.010 | 2.010 | 0.852 |
| 10 | 177,163 | 8.858 | 0.115 | 4.465 | 0.443 | 1.917 | 1.917 | 0.739 |
| 11 | 174,700 | 8.735 | 0.115 | 4.495 | 0.437 | 1.844 | 1.844 | 0.646 |
| 12 | 172,707 | 8.635 | 0.115 | 4.535 | 0.432 | 1.776 | 1.776 | 0.566 |
| 13 | 169,109 | 8.455 | 0.115 | 4.534 | 0.423 | 1.692 | 1.692 | 0.490 |
| 14 | 165,401 | 8.270 | 0.115 | 4.529 | 0.414 | 1.606 | 1.606 | 0.423 |
| 15 | 161,357 | 8.068 | 0.115 | 4.513 | 0.403 | 1.518 | 1.518 | 0.363 |
| 16 | 158,422 | 7.921 | 0.115 | 4.525 | 0.396 | 1.442 | 1.442 | 0.314 |
| 17 | 153,679 | 7.684 | 0.115 | 4.484 | 0.384 | 1.350 | 1.350 | 0.267 |
| 18 | 148,736 | 7.437 | 0.115 | 4.436 | 0.372 | 1.257 | 1.257 | 0.226 |
| 19 | 143,740 | 7.187 | 0.115 | 4.382 | 0.359 | 1.165 | 1.165 | 0.191 |
| 20 | 139,348 | 6.967 | 0.115 | 4.342 | 0.348 | 1.081 | 1.081 | 0.161 |
| 21 | 134,681 | 6.734 | 0.115 | 4.289 | 0.337 | 0.996 | 0.996 | 0.135 |
| 22 | 130,680 | 6.534 | 0.115 | 4.254 | 0.327 | 0.919 | 0.919 | 0.113 |
| 23 | 127,165 | 6.358 | 0.115 | 4.230 | 0.318 | 0.847 | 0.847 | 0.095 |
| 24 | 123,993 | 6.200 | 0.115 | 4.215 | 0.310 | 0.779 | 0.779 | 0.079 |
| Total | 3,299,680 | 164.984 | 29.820 | 90.162 | 8.249 | 23.154 | 13.599 | -0.905 |
| | | | | | | IRR | 8.50% | -1.37% |
| | | | | | | PIR | 0.456 | -0.030 |

Table C.11 Cash flow summary of case 11. Recovery Factor = 16.84%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,043 | 10.752 | 0.000 | 4.655 | 0.538 | 0.000 | 1.319 | 0.819 |
| 6 | 83,190 | 4.160 | 0.000 | 1.985 | 0.208 | 0.000 | -2.273 | -1.283 |
| 7 | 117,201 | 5.860 | 0.271 | 2.862 | 0.293 | 0.000 | -1.702 | -0.873 |
| 8 | 141,221 | 7.061 | 0.115 | 3.472 | 0.353 | 0.000 | -1.145 | -0.534 |
| 9 | 154,357 | 7.718 | 0.115 | 3.849 | 0.386 | 1.671 | 1.671 | 0.709 |
| 10 | 162,340 | 8.117 | 0.115 | 4.116 | 0.406 | 1.727 | 1.727 | 0.666 |
| 11 | 167,154 | 8.358 | 0.115 | 4.316 | 0.418 | 1.754 | 1.754 | 0.615 |
| 12 | 170,552 | 8.528 | 0.115 | 4.487 | 0.426 | 1.749 | 1.749 | 0.557 |
| 13 | 171,785 | 8.589 | 0.115 | 4.608 | 0.429 | 1.718 | 1.718 | 0.498 |
| 14 | 172,374 | 8.619 | 0.115 | 4.715 | 0.431 | 1.679 | 1.679 | 0.442 |
| 15 | 171,519 | 8.576 | 0.115 | 4.787 | 0.429 | 1.622 | 1.622 | 0.388 |
| 16 | 169,104 | 8.455 | 0.115 | 4.818 | 0.423 | 1.549 | 1.549 | 0.337 |
| 17 | 163,814 | 8.191 | 0.115 | 4.769 | 0.410 | 1.449 | 1.449 | 0.287 |
| 18 | 158,868 | 7.943 | 0.115 | 4.726 | 0.397 | 1.353 | 1.353 | 0.243 |
| 19 | 155,362 | 7.768 | 0.115 | 4.720 | 0.388 | 1.272 | 1.272 | 0.208 |
| 20 | 151,199 | 7.560 | 0.115 | 4.694 | 0.378 | 1.186 | 1.186 | 0.176 |
| 21 | 145,830 | 7.292 | 0.115 | 4.628 | 0.365 | 1.092 | 1.092 | 0.148 |
| 22 | 140,975 | 7.049 | 0.115 | 4.573 | 0.352 | 1.004 | 1.004 | 0.123 |
| 23 | 136,370 | 6.819 | 0.115 | 4.522 | 0.341 | 0.920 | 0.920 | 0.103 |
| 24 | 132,713 | 6.636 | 0.115 | 4.498 | 0.332 | 0.845 | 0.845 | 0.086 |
| Total | 3,080,970 | 154.048 | 31.730 | 85.801 | 7.702 | 22.591 | 6.250 | -5.319 |
| | | | | | | IRR | 3.01% | -6.35% |
| | | | | | | PIR | 0.197 | -0.168 |

Table C.12 Cash flow summary of case 12. Recovery Factor = 17.43%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 219,000 | 10.950 | 0.000 | 4.741 | 0.548 | 0.000 | 1.341 | 0.833 |
| 6 | 138,179 | 6.909 | 0.000 | 3.199 | 0.345 | 0.000 | -0.955 | -0.539 |
| 7 | 156,213 | 7.811 | 0.271 | 3.740 | 0.391 | 0.000 | -0.806 | -0.414 |
| 8 | 167,282 | 8.364 | 0.115 | 4.069 | 0.418 | 0.000 | -0.585 | -0.273 |
| 9 | 171,071 | 8.554 | 0.115 | 4.239 | 0.428 | 1.873 | 1.873 | 0.794 |
| 10 | 173,028 | 8.651 | 0.115 | 4.371 | 0.433 | 1.853 | 1.853 | 0.715 |
| 11 | 173,757 | 8.688 | 0.115 | 4.476 | 0.434 | 1.831 | 1.831 | 0.642 |
| 12 | 174,067 | 8.703 | 0.115 | 4.574 | 0.435 | 1.790 | 1.790 | 0.570 |
| 13 | 172,378 | 8.619 | 0.115 | 4.622 | 0.431 | 1.725 | 1.725 | 0.500 |
| 14 | 169,960 | 8.498 | 0.115 | 4.652 | 0.425 | 1.653 | 1.653 | 0.435 |
| 15 | 166,586 | 8.329 | 0.115 | 4.656 | 0.416 | 1.571 | 1.571 | 0.376 |
| 16 | 162,995 | 8.150 | 0.115 | 4.653 | 0.407 | 1.487 | 1.487 | 0.324 |
| 17 | 159,027 | 7.951 | 0.115 | 4.636 | 0.398 | 1.401 | 1.401 | 0.277 |
| 18 | 154,984 | 7.749 | 0.115 | 4.616 | 0.387 | 1.315 | 1.315 | 0.237 |
| 19 | 150,013 | 7.501 | 0.115 | 4.566 | 0.375 | 1.222 | 1.222 | 0.200 |
| 20 | 145,283 | 7.264 | 0.115 | 4.520 | 0.363 | 1.133 | 1.133 | 0.168 |
| 21 | 139,927 | 6.996 | 0.115 | 4.451 | 0.350 | 1.040 | 1.040 | 0.141 |
| 22 | 135,456 | 6.773 | 0.115 | 4.404 | 0.339 | 0.957 | 0.957 | 0.118 |
| 23 | 131,321 | 6.566 | 0.115 | 4.364 | 0.328 | 0.879 | 0.879 | 0.098 |
| 24 | 128,040 | 6.402 | 0.115 | 4.349 | 0.320 | 0.809 | 0.809 | 0.082 |
| Total | 3,188,568 | 159.428 | 33.730 | 87.897 | 7.971 | 22.541 | 7.315 | -4.898 |
| | | | | | | IRR | 3.59% | -5.83% |
| | | | | | | PIR | 0.217 | -0.145 |

Table C.13 Cash flow summary of case 13. Recovery Factor = 16.16%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,043 | 10.752 | 0.000 | 4.655 | 0.538 | 0.000 | 1.319 | 0.819 |
| 6 | 141,475 | 7.074 | 0.000 | 3.124 | 0.354 | 0.000 | -0.644 | -0.363 |
| 7 | 47,403 | 2.370 | 0.000 | 1.218 | 0.119 | 0.000 | -3.207 | -1.646 |
| 8 | 79,471 | 3.974 | 0.115 | 2.046 | 0.199 | 0.000 | -2.627 | -1.225 |
| 9 | 113,898 | 5.695 | 0.401 | 2.893 | 0.285 | 1.188 | 1.188 | 0.504 |
| 10 | 138,021 | 6.901 | 0.115 | 3.528 | 0.345 | 1.457 | 1.457 | 0.562 |
| 11 | 152,601 | 7.630 | 0.115 | 3.954 | 0.382 | 1.590 | 1.590 | 0.557 |
| 12 | 161,672 | 8.084 | 0.115 | 4.259 | 0.404 | 1.653 | 1.653 | 0.527 |
| 13 | 166,410 | 8.321 | 0.115 | 4.464 | 0.416 | 1.663 | 1.663 | 0.482 |
| 14 | 169,497 | 8.475 | 0.115 | 4.633 | 0.424 | 1.651 | 1.651 | 0.435 |
| 15 | 171,091 | 8.555 | 0.115 | 4.768 | 0.428 | 1.622 | 1.622 | 0.388 |
| 16 | 171,544 | 8.577 | 0.115 | 4.876 | 0.429 | 1.579 | 1.579 | 0.344 |
| 17 | 168,982 | 8.449 | 0.115 | 4.902 | 0.422 | 1.505 | 1.505 | 0.298 |
| 18 | 164,648 | 8.232 | 0.115 | 4.879 | 0.412 | 1.413 | 1.413 | 0.254 |
| 19 | 159,527 | 7.976 | 0.115 | 4.830 | 0.399 | 1.316 | 1.316 | 0.215 |
| 20 | 156,490 | 7.824 | 0.115 | 4.839 | 0.391 | 1.239 | 1.239 | 0.184 |
| 21 | 151,611 | 7.581 | 0.115 | 4.790 | 0.379 | 1.148 | 1.148 | 0.155 |
| 22 | 146,609 | 7.330 | 0.115 | 4.734 | 0.367 | 1.057 | 1.057 | 0.130 |
| 23 | 141,660 | 7.083 | 0.115 | 4.676 | 0.354 | 0.969 | 0.969 | 0.108 |
| 24 | 137,306 | 6.865 | 0.115 | 4.633 | 0.343 | 0.887 | 0.887 | 0.090 |
| Total | 2,954,957 | 147.748 | 31.745 | 82.702 | 7.387 | 21.936 | 4.238 | -6.216 |
| | | | | | | IRR | 1.97% | -7.30% |
| | | | | | | PIR | 0.133 | -0.196 |

Table C.14 Cash flow summary of case 14. Recovery Factor = 16.77%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 219,000 | 10.950 | 0.000 | 4.741 | 0.548 | 0.000 | 1.341 | 0.833 |
| 6 | 176,003 | 8.800 | 0.000 | 3.886 | 0.440 | 0.077 | 0.077 | 0.043 |
| 7 | 80,393 | 4.020 | 0.000 | 1.961 | 0.201 | 0.000 | -2.463 | -1.264 |
| 8 | 105,578 | 5.279 | 0.115 | 2.645 | 0.264 | 0.000 | -2.065 | -0.964 |
| 9 | 133,529 | 6.676 | 0.401 | 3.353 | 0.334 | 1.425 | 1.425 | 0.604 |
| 10 | 153,265 | 7.663 | 0.115 | 3.891 | 0.383 | 1.637 | 1.637 | 0.631 |
| 11 | 164,228 | 8.211 | 0.115 | 4.236 | 0.411 | 1.725 | 1.725 | 0.604 |
| 12 | 170,149 | 8.507 | 0.115 | 4.469 | 0.425 | 1.749 | 1.749 | 0.557 |
| 13 | 171,886 | 8.594 | 0.115 | 4.602 | 0.430 | 1.724 | 1.724 | 0.499 |
| 14 | 171,901 | 8.595 | 0.115 | 4.694 | 0.430 | 1.678 | 1.678 | 0.442 |
| 15 | 170,126 | 8.506 | 0.115 | 4.741 | 0.425 | 1.612 | 1.612 | 0.386 |
| 16 | 167,513 | 8.376 | 0.115 | 4.766 | 0.419 | 1.538 | 1.538 | 0.335 |
| 17 | 163,126 | 8.156 | 0.115 | 4.741 | 0.408 | 1.446 | 1.446 | 0.286 |
| 18 | 159,555 | 7.978 | 0.115 | 4.735 | 0.399 | 1.364 | 1.364 | 0.245 |
| 19 | 155,653 | 7.783 | 0.115 | 4.719 | 0.389 | 1.280 | 1.280 | 0.209 |
| 20 | 151,105 | 7.555 | 0.115 | 4.681 | 0.378 | 1.191 | 1.191 | 0.177 |
| 21 | 145,508 | 7.275 | 0.115 | 4.608 | 0.364 | 1.094 | 1.094 | 0.148 |
| 22 | 140,461 | 7.023 | 0.115 | 4.547 | 0.351 | 1.005 | 1.005 | 0.123 |
| 23 | 135,887 | 6.794 | 0.115 | 4.496 | 0.340 | 0.921 | 0.921 | 0.103 |
| 24 | 132,035 | 6.602 | 0.115 | 4.465 | 0.330 | 0.845 | 0.845 | 0.086 |
| Total | 3,066,901 | 153.345 | 33.745 | 84.979 | 7.667 | 22.311 | 4.904 | -6.095 |
| | | | | | | IRR | 2.29% | -7.01% |
| | | | | | | PIR | 0.145 | -0.181 |

Table C.15 Cash flow summary of case 15. Recovery Factor = 15.43, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,043 | 10.752 | 0.000 | 4.655 | 0.538 | 0.000 | 1.319 | 0.819 |
| 6 | 141,475 | 7.074 | 0.000 | 3.124 | 0.354 | 0.000 | -0.644 | -0.363 |
| 7 | 117,924 | 5.896 | 0.000 | 2.656 | 0.295 | 0.000 | -1.295 | -0.664 |
| 8 | 35,649 | 1.782 | 0.000 | 0.973 | 0.089 | 0.000 | -3.520 | -1.642 |
| 9 | 51,909 | 2.595 | 0.401 | 1.447 | 0.130 | 0.439 | 0.439 | 0.186 |
| 10 | 85,226 | 4.261 | 0.115 | 2.272 | 0.213 | 0.831 | 0.831 | 0.320 |
| 11 | 118,091 | 5.905 | 0.115 | 3.119 | 0.295 | 1.188 | 1.188 | 0.416 |
| 12 | 140,988 | 7.049 | 0.115 | 3.751 | 0.352 | 1.415 | 1.415 | 0.451 |
| 13 | 154,081 | 7.704 | 0.115 | 4.158 | 0.385 | 1.523 | 1.523 | 0.441 |
| 14 | 162,051 | 8.103 | 0.115 | 4.447 | 0.405 | 1.568 | 1.568 | 0.413 |
| 15 | 166,812 | 8.341 | 0.115 | 4.662 | 0.417 | 1.573 | 1.573 | 0.377 |
| 16 | 169,944 | 8.497 | 0.115 | 4.840 | 0.425 | 1.559 | 1.559 | 0.339 |
| 17 | 170,287 | 8.514 | 0.115 | 4.945 | 0.426 | 1.514 | 1.514 | 0.300 |
| 18 | 168,843 | 8.442 | 0.115 | 5.004 | 0.422 | 1.451 | 1.451 | 0.261 |
| 19 | 164,986 | 8.249 | 0.115 | 4.994 | 0.412 | 1.364 | 1.364 | 0.223 |
| 20 | 160,353 | 8.018 | 0.115 | 4.959 | 0.401 | 1.271 | 1.271 | 0.189 |
| 21 | 156,455 | 7.823 | 0.115 | 4.942 | 0.391 | 1.187 | 1.187 | 0.160 |
| 22 | 152,117 | 7.606 | 0.115 | 4.909 | 0.380 | 1.101 | 1.101 | 0.135 |
| 23 | 147,086 | 7.354 | 0.115 | 4.852 | 0.368 | 1.010 | 1.010 | 0.113 |
| 24 | 142,463 | 7.123 | 0.115 | 4.804 | 0.356 | 0.924 | 0.924 | 0.094 |
| Total | 2,821,782 | 141.089 | 31.629 | 79.511 | 7.054 | 19.917 | 3.238 | -6.466 |
| | | | | | | IRR | 1.51% | -7.71% |
| | | | | | | PIR | 0.102 | -0.204 |

Table C.16 Cash flow summary of case 16. Recovery Factor = 16.07%, Oil Price = 50$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 219,000 | 10.950 | 0.000 | 4.741 | 0.548 | 0.000 | 1.341 | 0.833 |
| 6 | 176,003 | 8.800 | 0.000 | 3.886 | 0.440 | 0.077 | 0.077 | 0.043 |
| 7 | 150,185 | 7.509 | 0.000 | 3.383 | 0.375 | 0.000 | -0.569 | -0.292 |
| 8 | 68,500 | 3.425 | 0.000 | 1.728 | 0.171 | 0.000 | -2.794 | -1.303 |
| 9 | 75,593 | 3.780 | 0.401 | 2.000 | 0.189 | 0.725 | 0.725 | 0.307 |
| 10 | 92,905 | 4.645 | 0.115 | 2.454 | 0.232 | 0.922 | 0.922 | 0.355 |
| 11 | 122,299 | 6.115 | 0.115 | 3.220 | 0.306 | 1.237 | 1.237 | 0.434 |
| 12 | 146,176 | 7.309 | 0.115 | 3.879 | 0.365 | 1.475 | 1.475 | 0.470 |
| 13 | 160,144 | 8.007 | 0.115 | 4.310 | 0.400 | 1.591 | 1.591 | 0.461 |
| 14 | 167,308 | 8.365 | 0.115 | 4.582 | 0.418 | 1.625 | 1.625 | 0.428 |
| 15 | 169,929 | 8.496 | 0.115 | 4.742 | 0.425 | 1.607 | 1.607 | 0.385 |
| 16 | 169,904 | 8.495 | 0.115 | 4.837 | 0.425 | 1.559 | 1.559 | 0.339 |
| 17 | 166,958 | 8.348 | 0.115 | 4.852 | 0.417 | 1.481 | 1.481 | 0.293 |
| 18 | 163,294 | 8.165 | 0.115 | 4.847 | 0.408 | 1.397 | 1.397 | 0.251 |
| 19 | 159,777 | 7.989 | 0.115 | 4.843 | 0.399 | 1.315 | 1.315 | 0.215 |
| 20 | 156,429 | 7.821 | 0.115 | 4.843 | 0.391 | 1.236 | 1.236 | 0.184 |
| 21 | 151,078 | 7.554 | 0.115 | 4.780 | 0.378 | 1.140 | 1.140 | 0.154 |
| 22 | 145,869 | 7.293 | 0.115 | 4.718 | 0.365 | 1.048 | 1.048 | 0.129 |
| 23 | 140,771 | 7.039 | 0.115 | 4.655 | 0.352 | 0.958 | 0.958 | 0.107 |
| 24 | 136,502 | 6.825 | 0.115 | 4.614 | 0.341 | 0.877 | 0.877 | 0.089 |
| Total | 2,938,622 | 146.931 | 33.629 | 81.915 | 7.347 | 20.271 | 4.030 | -6.298 |
| | | | | | | IRR | 1.89% | -7.37% |
| | | | | | | PIR | 0.120 | -0.187 |

Table C.17 Cash flow summary of case 1. Recovery Factor = 6.43%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,195 | 17.216 | 0.000 | 4.659 | 0.861 | 0.000 | 7.456 | 4.630 |
| 6 | 140,276 | 11.222 | 0.000 | 3.098 | 0.561 | 1.662 | 1.662 | 0.938 |
| 7 | 116,062 | 9.285 | 0.000 | 2.614 | 0.464 | 0.983 | 0.983 | 0.505 |
| 8 | 107,942 | 8.635 | 0.000 | 2.480 | 0.432 | 0.742 | 0.742 | 0.346 |
| 9 | 102,000 | 8.160 | 0.000 | 2.390 | 0.408 | 2.681 | 2.681 | 1.137 |
| 10 | 97,283 | 7.783 | 0.000 | 2.325 | 0.389 | 2.534 | 2.534 | 0.977 |
| 11 | 92,909 | 7.433 | 0.000 | 2.265 | 0.372 | 2.398 | 2.398 | 0.840 |
| 12 | 88,835 | 7.107 | 0.000 | 2.209 | 0.355 | 2.271 | 2.271 | 0.724 |
| 13 | 84,839 | 6.787 | 0.000 | 2.152 | 0.339 | 2.148 | 2.148 | 0.622 |
| 14 | 80,960 | 6.477 | 0.000 | 2.095 | 0.324 | 2.029 | 2.029 | 0.534 |
| 15 | 77,238 | 6.179 | 0.000 | 2.038 | 0.309 | 1.916 | 1.916 | 0.459 |
| 16 | 73,096 | 5.848 | 0.000 | 1.968 | 0.292 | 1.794 | 1.794 | 0.390 |
| 17 | 69,015 | 5.521 | 0.000 | 1.895 | 0.276 | 1.675 | 1.675 | 0.331 |
| 18 | 64,804 | 5.184 | 0.000 | 1.815 | 0.259 | 1.555 | 1.555 | 0.280 |
| 19 | 59,926 | 4.794 | 0.000 | 1.712 | 0.240 | 1.421 | 1.421 | 0.232 |
| 20 | 55,010 | 4.401 | 0.000 | 1.603 | 0.220 | 1.289 | 1.289 | 0.192 |
| 21 | 49,878 | 3.990 | 0.000 | 1.482 | 0.200 | 1.154 | 1.154 | 0.156 |
| 22 | 44,842 | 3.587 | 0.000 | 1.359 | 0.179 | 1.024 | 1.024 | 0.126 |
| 23 | 40,288 | 3.223 | 0.000 | 1.246 | 0.161 | 0.908 | 0.908 | 0.101 |
| 24 | 36,335 | 2.907 | 0.000 | 1.146 | 0.145 | 0.808 | 0.808 | 0.082 |
| Total | 1,696,733 | 135.739 | 29.500 | 42.550 | 6.787 | 30.993 | 25.909 | 4.569 |
| | | | | | | IRR | 18.54% | 7.77% |
| | | | | | | PIR | 0.878 | 0.155 |

Table C.18 Cash flow summary of case 2. Recovery Factor = 11.11%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 219,600 | 17.568 | 0.000 | 4.754 | 0.878 | 0.000 | 7.616 | 4.729 |
| 6 | 174,488 | 13.959 | 0.000 | 3.853 | 0.698 | 2.544 | 2.544 | 1.436 |
| 7 | 147,987 | 11.839 | 0.000 | 3.333 | 0.592 | 1.797 | 1.797 | 0.922 |
| 8 | 136,656 | 10.932 | 0.000 | 3.139 | 0.547 | 1.463 | 1.463 | 0.683 |
| 9 | 128,234 | 10.259 | 0.000 | 3.005 | 0.513 | 3.370 | 3.370 | 1.429 |
| 10 | 121,476 | 9.718 | 0.000 | 2.903 | 0.486 | 3.164 | 3.164 | 1.220 |
| 11 | 115,916 | 9.273 | 0.000 | 2.826 | 0.464 | 2.992 | 2.992 | 1.049 |
| 12 | 111,202 | 8.896 | 0.000 | 2.765 | 0.445 | 2.843 | 2.843 | 0.906 |
| 13 | 106,633 | 8.531 | 0.000 | 2.705 | 0.427 | 2.700 | 2.700 | 0.782 |
| 14 | 101,718 | 8.137 | 0.000 | 2.632 | 0.407 | 2.549 | 2.549 | 0.671 |
| 15 | 96,003 | 7.680 | 0.000 | 2.533 | 0.384 | 2.381 | 2.381 | 0.570 |
| 16 | 89,826 | 7.186 | 0.000 | 2.418 | 0.359 | 2.204 | 2.204 | 0.480 |
| 17 | 83,289 | 6.663 | 0.000 | 2.287 | 0.333 | 2.022 | 2.022 | 0.400 |
| 18 | 76,529 | 6.122 | 0.000 | 2.143 | 0.306 | 1.837 | 1.837 | 0.330 |
| 19 | 69,601 | 5.568 | 0.000 | 1.988 | 0.278 | 1.651 | 1.651 | 0.270 |
| 20 | 62,681 | 5.014 | 0.000 | 1.826 | 0.251 | 1.469 | 1.469 | 0.218 |
| 21 | 56,040 | 4.483 | 0.000 | 1.665 | 0.224 | 1.297 | 1.297 | 0.175 |
| 22 | 49,847 | 3.988 | 0.000 | 1.511 | 0.199 | 1.139 | 1.139 | 0.140 |
| 23 | 44,243 | 3.539 | 0.000 | 1.368 | 0.177 | 0.997 | 0.997 | 0.111 |
| 24 | 39,352 | 3.148 | 0.000 | 1.241 | 0.157 | 0.875 | 0.875 | 0.089 |
| Total | 2,031,321 | 162.506 | 31.500 | 50.897 | 8.125 | 39.294 | 32.689 | 6.430 |
| | | | | | | IRR | 20.46% | 9.51% |
| | | | | | | PIR | 1.038 | 0.204 |

Table C.19 Cash flow summary of case 3. Recovery Factor = 15.61%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 22.131 | 0.000 | 0.000 | 0.000 | -5.706 | -3.897 |
| 5 | 164,664 | 13.173 | 0.000 | 6.284 | 0.659 | 0.000 | 2.125 | 1.319 |
| 6 | 168,771 | 13.502 | 0.000 | 3.874 | 0.675 | 2.423 | 2.423 | 1.368 |
| 7 | 171,660 | 13.733 | 0.000 | 4.017 | 0.687 | 2.461 | 2.461 | 1.263 |
| 8 | 172,718 | 13.817 | 0.000 | 4.122 | 0.691 | 2.449 | 2.449 | 1.143 |
| 9 | 173,609 | 13.889 | 0.000 | 4.225 | 0.694 | 4.485 | 4.485 | 1.902 |
| 10 | 173,740 | 13.899 | 0.000 | 4.312 | 0.695 | 4.446 | 4.446 | 1.714 |
| 11 | 172,714 | 13.817 | 0.000 | 4.373 | 0.691 | 4.377 | 4.377 | 1.534 |
| 12 | 167,437 | 13.395 | 0.000 | 4.326 | 0.670 | 4.200 | 4.200 | 1.338 |
| 13 | 159,329 | 12.746 | 0.000 | 4.202 | 0.637 | 3.954 | 3.954 | 1.145 |
| 14 | 153,239 | 12.259 | 0.000 | 4.121 | 0.613 | 3.763 | 3.763 | 0.991 |
| 15 | 146,285 | 11.703 | 0.000 | 4.013 | 0.585 | 3.552 | 3.552 | 0.850 |
| 16 | 137,685 | 11.015 | 0.000 | 3.855 | 0.551 | 3.304 | 3.304 | 0.719 |
| 17 | 130,530 | 10.442 | 0.000 | 3.730 | 0.522 | 3.095 | 3.095 | 0.612 |
| 18 | 125,020 | 10.002 | 0.000 | 3.644 | 0.500 | 2.929 | 2.929 | 0.527 |
| 19 | 119,448 | 9.556 | 0.000 | 3.553 | 0.478 | 2.763 | 2.763 | 0.452 |
| 20 | 113,307 | 9.065 | 0.000 | 3.441 | 0.453 | 2.585 | 2.585 | 0.384 |
| 21 | 107,983 | 8.639 | 0.000 | 3.348 | 0.432 | 2.429 | 2.429 | 0.328 |
| 22 | 103,296 | 8.264 | 0.000 | 3.270 | 0.413 | 2.290 | 2.290 | 0.281 |
| 23 | 99,117 | 7.929 | 0.000 | 3.203 | 0.396 | 2.165 | 2.165 | 0.242 |
| 24 | 95,576 | 7.646 | 0.000 | 3.154 | 0.382 | 2.055 | 2.055 | 0.209 |
| Total | 2,856,125 | 228.490 | 25.631 | 79.067 | 11.425 | 59.725 | 52.643 | 11.565 |
| | | | | | | IRR | 26.41% | 14.92% |
| | | | | | | PIR | 2.054 | 0.451 |

Table C.20 Cash flow summary of case 4. Recovery Factor = 16.29%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 24.131 | 0.000 | 0.000 | 0.000 | -7.386 | -5.045 |
| 5 | 219,600 | 17.568 | 0.000 | 4.899 | 0.878 | 0.000 | 7.604 | 4.722 |
| 6 | 219,600 | 17.568 | 0.000 | 4.997 | 0.878 | 3.753 | 3.753 | 2.119 |
| 7 | 207,702 | 16.616 | 0.000 | 4.829 | 0.831 | 3.385 | 3.385 | 1.737 |
| 8 | 189,110 | 15.129 | 0.000 | 4.498 | 0.756 | 2.844 | 2.844 | 1.327 |
| 9 | 180,542 | 14.443 | 0.000 | 4.388 | 0.722 | 4.667 | 4.667 | 1.979 |
| 10 | 175,097 | 14.008 | 0.000 | 4.345 | 0.700 | 4.481 | 4.481 | 1.728 |
| 11 | 169,424 | 13.554 | 0.000 | 4.294 | 0.678 | 4.291 | 4.291 | 1.504 |
| 12 | 163,291 | 13.063 | 0.000 | 4.227 | 0.653 | 4.091 | 4.091 | 1.304 |
| 13 | 158,102 | 12.648 | 0.000 | 4.180 | 0.632 | 3.918 | 3.918 | 1.135 |
| 14 | 151,268 | 12.101 | 0.000 | 4.087 | 0.605 | 3.705 | 3.705 | 0.976 |
| 15 | 143,286 | 11.463 | 0.000 | 3.958 | 0.573 | 3.466 | 3.466 | 0.830 |
| 16 | 135,564 | 10.845 | 0.000 | 3.829 | 0.542 | 3.237 | 3.237 | 0.704 |
| 17 | 128,207 | 10.257 | 0.000 | 3.704 | 0.513 | 3.020 | 3.020 | 0.597 |
| 18 | 121,578 | 9.726 | 0.000 | 3.592 | 0.486 | 2.824 | 2.824 | 0.508 |
| 19 | 115,653 | 9.252 | 0.000 | 3.495 | 0.463 | 2.647 | 2.647 | 0.433 |
| 20 | 109,943 | 8.795 | 0.000 | 3.399 | 0.440 | 2.479 | 2.479 | 0.368 |
| 21 | 104,559 | 8.365 | 0.000 | 3.307 | 0.418 | 2.320 | 2.320 | 0.314 |
| 22 | 99,742 | 7.979 | 0.000 | 3.227 | 0.399 | 2.177 | 2.177 | 0.267 |
| 23 | 95,522 | 7.642 | 0.000 | 3.161 | 0.382 | 2.049 | 2.049 | 0.229 |
| 24 | 91,780 | 7.342 | 0.000 | 3.106 | 0.367 | 1.935 | 1.935 | 0.196 |
| Total | 2,979,568 | 238.365 | 27.631 | 79.522 | 11.918 | 61.288 | 58.006 | 15.072 |
| | | | | | | IRR | 34.62% | 22.38% |
| | | | | | | PIR | 2.099 | 0.545 |

Table C.21 Cash flow summary of case 5. Recovery Factor = 14.74%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,195 | 17.216 | 0.000 | 4.659 | 0.861 | 0.000 | 7.456 | 4.630 |
| 6 | 140,276 | 11.222 | 0.000 | 3.098 | 0.561 | 1.662 | 1.662 | 0.938 |
| 7 | 46,629 | 3.730 | 0.156 | 1.201 | 0.187 | 0.000 | -1.948 | -1.000 |
| 8 | 79,362 | 6.349 | 0.000 | 1.977 | 0.317 | 0.000 | -0.212 | -0.099 |
| 9 | 113,583 | 9.087 | 0.000 | 2.819 | 0.454 | 2.894 | 2.894 | 1.227 |
| 10 | 137,933 | 11.035 | 0.000 | 3.457 | 0.552 | 3.500 | 3.500 | 1.349 |
| 11 | 152,635 | 12.211 | 0.000 | 3.885 | 0.611 | 3.858 | 3.858 | 1.352 |
| 12 | 161,219 | 12.898 | 0.000 | 4.176 | 0.645 | 4.038 | 4.038 | 1.287 |
| 13 | 165,709 | 13.257 | 0.000 | 4.373 | 0.663 | 4.110 | 4.110 | 1.191 |
| 14 | 165,964 | 13.277 | 0.000 | 4.467 | 0.664 | 4.073 | 4.073 | 1.073 |
| 15 | 160,937 | 12.875 | 0.000 | 4.424 | 0.644 | 3.904 | 3.904 | 0.935 |
| 16 | 154,827 | 12.386 | 0.000 | 4.348 | 0.619 | 3.709 | 3.709 | 0.807 |
| 17 | 148,770 | 11.902 | 0.000 | 4.269 | 0.595 | 3.519 | 3.519 | 0.696 |
| 18 | 140,870 | 11.270 | 0.000 | 4.133 | 0.563 | 3.287 | 3.287 | 0.591 |
| 19 | 133,010 | 10.641 | 0.000 | 3.991 | 0.532 | 3.059 | 3.059 | 0.500 |
| 20 | 127,205 | 10.176 | 0.000 | 3.901 | 0.509 | 2.883 | 2.883 | 0.429 |
| 21 | 121,349 | 9.708 | 0.000 | 3.805 | 0.485 | 2.709 | 2.709 | 0.366 |
| 22 | 115,367 | 9.229 | 0.000 | 3.700 | 0.461 | 2.534 | 2.534 | 0.311 |
| 23 | 109,768 | 8.781 | 0.000 | 3.601 | 0.439 | 2.371 | 2.371 | 0.265 |
| 24 | 104,798 | 8.384 | 0.000 | 3.516 | 0.419 | 2.224 | 2.224 | 0.226 |
| Total | 2,695,407 | 215.633 | 29.656 | 73.799 | 10.782 | 54.333 | 47.089 | 8.040 |
| | | | | | | IRR | 20.27% | 9.33% |
| | | | | | | PIR | 1.588 | 0.271 |

Table C.22 Cash flow summary of case 6. Recovery Factor = 15.42%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 267,729 | 21.418 | 0.000 | 5.796 | 1.071 | 0.000 | 10.231 | 6.353 |
| 6 | 163,516 | 13.081 | 0.000 | 3.611 | 0.654 | 2.248 | 2.248 | 1.269 |
| 7 | 74,451 | 5.956 | 0.156 | 1.828 | 0.298 | 0.000 | -0.541 | -0.277 |
| 8 | 93,515 | 7.481 | 0.000 | 2.302 | 0.374 | 0.229 | 0.229 | 0.107 |
| 9 | 124,128 | 9.930 | 0.000 | 3.066 | 0.497 | 3.171 | 3.171 | 1.345 |
| 10 | 147,545 | 11.804 | 0.000 | 3.687 | 0.590 | 3.750 | 3.750 | 1.446 |
| 11 | 161,220 | 12.898 | 0.000 | 4.094 | 0.645 | 4.079 | 4.079 | 1.430 |
| 12 | 167,253 | 13.380 | 0.000 | 4.326 | 0.669 | 4.193 | 4.193 | 1.336 |
| 13 | 167,482 | 13.399 | 0.000 | 4.418 | 0.670 | 4.155 | 4.155 | 1.204 |
| 14 | 163,822 | 13.106 | 0.000 | 4.412 | 0.655 | 4.019 | 4.019 | 1.058 |
| 15 | 159,473 | 12.758 | 0.000 | 4.385 | 0.638 | 3.867 | 3.867 | 0.926 |
| 16 | 153,869 | 12.310 | 0.000 | 4.322 | 0.615 | 3.686 | 3.686 | 0.802 |
| 17 | 146,233 | 11.699 | 0.000 | 4.199 | 0.585 | 3.457 | 3.457 | 0.684 |
| 18 | 138,373 | 11.070 | 0.000 | 4.063 | 0.553 | 3.227 | 3.227 | 0.580 |
| 19 | 130,829 | 10.466 | 0.000 | 3.928 | 0.523 | 3.007 | 3.007 | 0.492 |
| 20 | 123,739 | 9.899 | 0.000 | 3.800 | 0.495 | 2.802 | 2.802 | 0.416 |
| 21 | 117,615 | 9.409 | 0.000 | 3.694 | 0.470 | 2.622 | 2.622 | 0.354 |
| 22 | 111,790 | 8.943 | 0.000 | 3.592 | 0.447 | 2.452 | 2.452 | 0.301 |
| 23 | 106,209 | 8.497 | 0.000 | 3.491 | 0.425 | 2.290 | 2.290 | 0.256 |
| 24 | 101,143 | 8.091 | 0.000 | 3.401 | 0.405 | 2.143 | 2.143 | 0.218 |
| Total | 2,819,931 | 225.594 | 31.656 | 76.415 | 11.280 | 55.400 | 50.870 | 10.119 |
| | | | | | | IRR | 23.64% | 12.40% |
| | | | | | | PIR | 1.607 | 0.320 |

Table C.23 Cash flow summary of case 7. Recovery Factor = 13.64%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,195 | 17.216 | 0.000 | 4.659 | 0.861 | 0.000 | 7.456 | 4.630 |
| 6 | 140,276 | 11.222 | 0.000 | 3.098 | 0.561 | 1.662 | 1.662 | 0.938 |
| 7 | 116,062 | 9.285 | 0.000 | 2.614 | 0.464 | 0.983 | 0.983 | 0.505 |
| 8 | 107,942 | 8.635 | 0.000 | 2.480 | 0.432 | 0.742 | 0.742 | 0.346 |
| 9 | 30,465 | 2.437 | 0.286 | 0.871 | 0.122 | 0.710 | 0.710 | 0.301 |
| 10 | 36,313 | 2.905 | 0.000 | 1.028 | 0.145 | 0.866 | 0.866 | 0.334 |
| 11 | 60,103 | 4.808 | 0.000 | 1.629 | 0.240 | 1.470 | 1.470 | 0.515 |
| 12 | 94,736 | 7.579 | 0.000 | 2.522 | 0.379 | 2.339 | 2.339 | 0.745 |
| 13 | 125,268 | 10.021 | 0.000 | 3.347 | 0.501 | 3.087 | 3.087 | 0.894 |
| 14 | 144,908 | 11.593 | 0.000 | 3.922 | 0.580 | 3.545 | 3.545 | 0.934 |
| 15 | 156,238 | 12.499 | 0.000 | 4.300 | 0.625 | 3.787 | 3.787 | 0.907 |
| 16 | 161,310 | 12.905 | 0.000 | 4.522 | 0.645 | 3.869 | 3.869 | 0.842 |
| 17 | 159,799 | 12.784 | 0.000 | 4.571 | 0.639 | 3.787 | 3.787 | 0.749 |
| 18 | 154,372 | 12.350 | 0.000 | 4.511 | 0.617 | 3.611 | 3.611 | 0.649 |
| 19 | 149,472 | 11.958 | 0.000 | 4.461 | 0.598 | 3.449 | 3.449 | 0.564 |
| 20 | 142,082 | 11.367 | 0.000 | 4.335 | 0.568 | 3.232 | 3.232 | 0.480 |
| 21 | 134,158 | 10.733 | 0.000 | 4.186 | 0.537 | 3.005 | 3.005 | 0.406 |
| 22 | 128,084 | 10.247 | 0.000 | 4.086 | 0.512 | 2.824 | 2.824 | 0.347 |
| 23 | 122,313 | 9.785 | 0.000 | 3.989 | 0.489 | 2.653 | 2.653 | 0.296 |
| 24 | 116,247 | 9.300 | 0.000 | 3.878 | 0.465 | 2.479 | 2.479 | 0.252 |
| Total | 2,495,344 | 199.628 | 29.786 | 69.009 | 9.981 | 48.098 | 43.014 | 6.600 |
| | | | | | | IRR | 19.04% | 8.22% |
| | | | | | | PIR | 1.444 | 0.222 |

Table C.24 Cash flow summary of case 8. Recovery Factor = 14.37%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 267,729 | 21.418 | 0.000 | 5.796 | 1.071 | 0.000 | 10.231 | 6.353 |
| 6 | 163,516 | 13.081 | 0.000 | 3.611 | 0.654 | 2.248 | 2.248 | 1.269 |
| 7 | 144,778 | 11.582 | 0.000 | 3.261 | 0.579 | 1.711 | 1.711 | 0.878 |
| 8 | 134,429 | 10.754 | 0.000 | 3.088 | 0.538 | 1.404 | 1.404 | 0.655 |
| 9 | 59,356 | 4.749 | 0.286 | 1.548 | 0.237 | 1.469 | 1.469 | 0.623 |
| 10 | 63,192 | 5.055 | 0.000 | 1.671 | 0.253 | 1.566 | 1.566 | 0.604 |
| 11 | 69,831 | 5.586 | 0.000 | 1.866 | 0.279 | 1.721 | 1.721 | 0.603 |
| 12 | 84,946 | 6.796 | 0.000 | 2.279 | 0.340 | 2.088 | 2.088 | 0.665 |
| 13 | 113,092 | 9.047 | 0.000 | 3.038 | 0.452 | 2.778 | 2.778 | 0.805 |
| 14 | 137,080 | 10.966 | 0.000 | 3.720 | 0.548 | 3.349 | 3.349 | 0.882 |
| 15 | 151,776 | 12.142 | 0.000 | 4.182 | 0.607 | 3.676 | 3.676 | 0.880 |
| 16 | 156,423 | 12.514 | 0.000 | 4.391 | 0.626 | 3.749 | 3.749 | 0.816 |
| 17 | 156,201 | 12.496 | 0.000 | 4.473 | 0.625 | 3.699 | 3.699 | 0.732 |
| 18 | 153,172 | 12.254 | 0.000 | 4.477 | 0.613 | 3.582 | 3.582 | 0.644 |
| 19 | 146,732 | 11.739 | 0.000 | 4.383 | 0.587 | 3.384 | 3.384 | 0.553 |
| 20 | 139,322 | 11.146 | 0.000 | 4.255 | 0.557 | 3.167 | 3.167 | 0.471 |
| 21 | 131,961 | 10.557 | 0.000 | 4.121 | 0.528 | 2.954 | 2.954 | 0.399 |
| 22 | 124,803 | 9.984 | 0.000 | 3.986 | 0.499 | 2.749 | 2.749 | 0.338 |
| 23 | 118,591 | 9.487 | 0.000 | 3.874 | 0.474 | 2.569 | 2.569 | 0.287 |
| 24 | 112,827 | 9.026 | 0.000 | 3.770 | 0.451 | 2.403 | 2.403 | 0.244 |
| Total | 2,629,755 | 210.380 | 31.786 | 71.788 | 10.519 | 50.268 | 46.280 | 8.520 |
| | | | | | | IRR | 22.49% | 11.35% |
| | | | | | | PIR | 1.456 | 0.268 |

Table C.25 Cash flow summary of case 9. Recovery Factor = 17.47%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 22.131 | 0.000 | 0.000 | 0.000 | -5.706 | -3.897 |
| 5 | 166,332 | 13.307 | 0.000 | 3.746 | 0.665 | 0.000 | 4.789 | 2.974 |
| 6 | 169,192 | 13.535 | 0.115 | 3.950 | 0.677 | 2.343 | 2.343 | 1.323 |
| 7 | 172,044 | 13.764 | 0.115 | 4.094 | 0.688 | 2.380 | 2.380 | 1.221 |
| 8 | 173,727 | 13.898 | 0.115 | 4.214 | 0.695 | 2.384 | 2.384 | 1.112 |
| 9 | 174,022 | 13.922 | 0.115 | 4.305 | 0.696 | 4.403 | 4.403 | 1.867 |
| 10 | 174,503 | 13.960 | 0.115 | 4.403 | 0.698 | 4.372 | 4.372 | 1.686 |
| 11 | 174,726 | 13.978 | 0.115 | 4.496 | 0.699 | 4.334 | 4.334 | 1.519 |
| 12 | 175,038 | 14.003 | 0.115 | 4.595 | 0.700 | 4.296 | 4.296 | 1.369 |
| 13 | 173,668 | 13.893 | 0.115 | 4.651 | 0.695 | 4.216 | 4.216 | 1.221 |
| 14 | 171,472 | 13.718 | 0.115 | 4.687 | 0.686 | 4.115 | 4.115 | 1.084 |
| 15 | 167,457 | 13.397 | 0.115 | 4.675 | 0.670 | 3.968 | 3.968 | 0.950 |
| 16 | 162,491 | 12.999 | 0.115 | 4.636 | 0.650 | 3.799 | 3.799 | 0.827 |
| 17 | 157,805 | 12.624 | 0.115 | 4.599 | 0.631 | 3.639 | 3.639 | 0.720 |
| 18 | 154,016 | 12.321 | 0.115 | 4.585 | 0.616 | 3.503 | 3.503 | 0.630 |
| 19 | 149,335 | 11.947 | 0.115 | 4.543 | 0.597 | 3.346 | 3.346 | 0.547 |
| 20 | 144,897 | 11.592 | 0.115 | 4.505 | 0.580 | 3.196 | 3.196 | 0.475 |
| 21 | 139,812 | 11.185 | 0.115 | 4.444 | 0.559 | 3.034 | 3.034 | 0.410 |
| 22 | 135,476 | 10.838 | 0.115 | 4.401 | 0.542 | 2.890 | 2.890 | 0.355 |
| 23 | 131,661 | 10.533 | 0.115 | 4.371 | 0.527 | 2.760 | 2.760 | 0.308 |
| 24 | 128,424 | 10.274 | 0.115 | 4.357 | 0.514 | 2.644 | 2.644 | 0.268 |
| Total | 3,196,097 | 255.688 | 27.820 | 88.257 | 12.784 | 65.621 | 61.205 | 14.110 |
| | | | | | | IRR | 30.66% | 18.78% |
| | | | | | | PIR | 2.200 | 0.507 |

Table C.26 Cash flow summary of case 10. Recovery Factor = 18.04%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 24.131 | 0.000 | 0.000 | 0.000 | -7.386 | -5.045 |
| 5 | 219,000 | 17.520 | 0.000 | 4.886 | 0.876 | 0.000 | 7.572 | 4.702 |
| 6 | 219,000 | 17.520 | 0.115 | 5.049 | 0.876 | 3.647 | 3.647 | 2.059 |
| 7 | 209,347 | 16.748 | 0.115 | 4.933 | 0.837 | 3.338 | 3.338 | 1.713 |
| 8 | 190,271 | 15.222 | 0.115 | 4.593 | 0.761 | 2.783 | 2.783 | 1.298 |
| 9 | 181,183 | 14.495 | 0.115 | 4.472 | 0.725 | 4.591 | 4.591 | 1.947 |
| 10 | 177,163 | 14.173 | 0.115 | 4.465 | 0.709 | 4.442 | 4.442 | 1.713 |
| 11 | 174,700 | 13.976 | 0.115 | 4.495 | 0.699 | 4.334 | 4.334 | 1.519 |
| 12 | 172,707 | 13.817 | 0.115 | 4.535 | 0.691 | 4.238 | 4.238 | 1.350 |
| 13 | 169,109 | 13.529 | 0.115 | 4.534 | 0.676 | 4.101 | 4.101 | 1.188 |
| 14 | 165,401 | 13.232 | 0.115 | 4.529 | 0.662 | 3.963 | 3.963 | 1.044 |
| 15 | 161,357 | 12.909 | 0.115 | 4.513 | 0.645 | 3.818 | 3.818 | 0.914 |
| 16 | 158,422 | 12.674 | 0.115 | 4.525 | 0.634 | 3.700 | 3.700 | 0.805 |
| 17 | 153,679 | 12.294 | 0.115 | 4.484 | 0.615 | 3.540 | 3.540 | 0.700 |
| 18 | 148,736 | 11.899 | 0.115 | 4.436 | 0.595 | 3.377 | 3.377 | 0.607 |
| 19 | 143,740 | 11.499 | 0.115 | 4.382 | 0.575 | 3.214 | 3.214 | 0.525 |
| 20 | 139,348 | 11.148 | 0.115 | 4.342 | 0.557 | 3.067 | 3.067 | 0.456 |
| 21 | 134,681 | 10.774 | 0.115 | 4.289 | 0.539 | 2.916 | 2.916 | 0.394 |
| 22 | 130,680 | 10.454 | 0.115 | 4.254 | 0.523 | 2.781 | 2.781 | 0.342 |
| 23 | 127,165 | 10.173 | 0.115 | 4.230 | 0.509 | 2.659 | 2.659 | 0.297 |
| 24 | 123,993 | 9.919 | 0.115 | 4.215 | 0.496 | 2.546 | 2.546 | 0.259 |
| Total | 3,299,680 | 263.974 | 29.820 | 90.162 | 13.199 | 67.054 | 63.740 | 15.928 |
| | | | | | | IRR | 34.54% | 22.31% |
| | | | | | | PIR | 2.137 | 0.534 |

Table C.27 Cash flow summary of case 11. Recovery Factor = 16.84%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,043 | 17.203 | 0.000 | 4.655 | 0.860 | 0.000 | 7.448 | 4.625 |
| 6 | 83,190 | 6.655 | 0.000 | 1.985 | 0.333 | 0.049 | 0.049 | 0.028 |
| 7 | 117,201 | 9.376 | 0.271 | 2.862 | 0.469 | 0.819 | 0.819 | 0.420 |
| 8 | 141,221 | 11.298 | 0.115 | 3.472 | 0.565 | 1.440 | 1.440 | 0.672 |
| 9 | 154,357 | 12.349 | 0.115 | 3.849 | 0.617 | 3.871 | 3.871 | 1.642 |
| 10 | 162,340 | 12.987 | 0.115 | 4.116 | 0.649 | 4.040 | 4.040 | 1.558 |
| 11 | 167,154 | 13.372 | 0.115 | 4.316 | 0.669 | 4.136 | 4.136 | 1.450 |
| 12 | 170,552 | 13.644 | 0.115 | 4.487 | 0.682 | 4.180 | 4.180 | 1.332 |
| 13 | 171,785 | 13.743 | 0.115 | 4.608 | 0.687 | 4.166 | 4.166 | 1.207 |
| 14 | 172,374 | 13.790 | 0.115 | 4.715 | 0.689 | 4.135 | 4.135 | 1.089 |
| 15 | 171,519 | 13.722 | 0.115 | 4.787 | 0.686 | 4.067 | 4.067 | 0.974 |
| 16 | 169,104 | 13.528 | 0.115 | 4.818 | 0.676 | 3.959 | 3.959 | 0.862 |
| 17 | 163,814 | 13.105 | 0.115 | 4.769 | 0.655 | 3.783 | 3.783 | 0.748 |
| 18 | 158,868 | 12.709 | 0.115 | 4.726 | 0.635 | 3.616 | 3.616 | 0.650 |
| 19 | 155,362 | 12.429 | 0.115 | 4.720 | 0.621 | 3.486 | 3.486 | 0.570 |
| 20 | 151,199 | 12.096 | 0.115 | 4.694 | 0.605 | 3.341 | 3.341 | 0.497 |
| 21 | 145,830 | 11.666 | 0.115 | 4.628 | 0.583 | 3.170 | 3.170 | 0.428 |
| 22 | 140,975 | 11.278 | 0.115 | 4.573 | 0.564 | 3.013 | 3.013 | 0.370 |
| 23 | 136,370 | 10.910 | 0.115 | 4.522 | 0.545 | 2.863 | 2.863 | 0.320 |
| 24 | 132,713 | 10.617 | 0.115 | 4.498 | 0.531 | 2.737 | 2.737 | 0.278 |
| Total | 3,080,970 | 246.478 | 31.730 | 85.801 | 12.324 | 60.871 | 55.779 | 10.684 |
| | | | | | | IRR | 23.24% | 12.03% |
| | | | | | | PIR | 1.758 | 0.337 |

Table C.28 Cash flow summary of case 12. Recovery Factor = 17.43%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 219,000 | 17.520 | 0.000 | 4.741 | 0.876 | 0.000 | 7.583 | 4.708 |
| 6 | 138,179 | 11.054 | 0.000 | 3.199 | 0.553 | 1.491 | 1.491 | 0.842 |
| 7 | 156,213 | 12.497 | 0.271 | 3.740 | 0.625 | 1.823 | 1.823 | 0.935 |
| 8 | 167,282 | 13.383 | 0.115 | 4.069 | 0.669 | 2.091 | 2.091 | 0.976 |
| 9 | 171,071 | 13.686 | 0.115 | 4.239 | 0.684 | 4.310 | 4.310 | 1.828 |
| 10 | 173,028 | 13.842 | 0.115 | 4.371 | 0.692 | 4.319 | 4.319 | 1.665 |
| 11 | 173,757 | 13.901 | 0.115 | 4.476 | 0.695 | 4.307 | 4.307 | 1.510 |
| 12 | 174,067 | 13.925 | 0.115 | 4.574 | 0.696 | 4.270 | 4.270 | 1.361 |
| 13 | 172,378 | 13.790 | 0.115 | 4.622 | 0.690 | 4.182 | 4.182 | 1.211 |
| 14 | 169,960 | 13.597 | 0.115 | 4.652 | 0.680 | 4.075 | 4.075 | 1.073 |
| 15 | 166,586 | 13.327 | 0.115 | 4.656 | 0.666 | 3.945 | 3.945 | 0.944 |
| 16 | 162,995 | 13.040 | 0.115 | 4.653 | 0.652 | 3.810 | 3.810 | 0.829 |
| 17 | 159,027 | 12.722 | 0.115 | 4.636 | 0.636 | 3.667 | 3.667 | 0.726 |
| 18 | 154,984 | 12.399 | 0.115 | 4.616 | 0.620 | 3.524 | 3.524 | 0.634 |
| 19 | 150,013 | 12.001 | 0.115 | 4.566 | 0.600 | 3.360 | 3.360 | 0.549 |
| 20 | 145,283 | 11.623 | 0.115 | 4.520 | 0.581 | 3.203 | 3.203 | 0.476 |
| 21 | 139,927 | 11.194 | 0.115 | 4.451 | 0.560 | 3.034 | 3.034 | 0.410 |
| 22 | 135,456 | 10.836 | 0.115 | 4.404 | 0.542 | 2.888 | 2.888 | 0.355 |
| 23 | 131,321 | 10.506 | 0.115 | 4.364 | 0.525 | 2.750 | 2.750 | 0.307 |
| 24 | 128,040 | 10.243 | 0.115 | 4.349 | 0.512 | 2.633 | 2.633 | 0.267 |
| Total | 3,188,568 | 255.085 | 33.730 | 87.897 | 12.754 | 63.684 | 57.047 | 11.426 |
| | | | | | | IRR | 23.86% | 12.60% |
| | | | | | | PIR | 1.691 | 0.339 |

Table C.29 Cash flow summary of case 13. Recovery Factor = 16.16%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,043 | 17.203 | 0.000 | 4.655 | 0.860 | 0.000 | 7.448 | 4.625 |
| 6 | 141,475 | 11.318 | 0.000 | 3.124 | 0.566 | 1.694 | 1.694 | 0.956 |
| 7 | 47,403 | 3.792 | 0.000 | 1.218 | 0.190 | 0.000 | -1.856 | -0.952 |
| 8 | 79,471 | 6.358 | 0.115 | 2.046 | 0.318 | 0.000 | -0.362 | -0.169 |
| 9 | 113,898 | 9.112 | 0.401 | 2.893 | 0.456 | 2.811 | 2.811 | 1.192 |
| 10 | 138,021 | 11.042 | 0.115 | 3.528 | 0.552 | 3.423 | 3.423 | 1.320 |
| 11 | 152,601 | 12.208 | 0.115 | 3.954 | 0.610 | 3.764 | 3.764 | 1.319 |
| 12 | 161,672 | 12.934 | 0.115 | 4.259 | 0.647 | 3.956 | 3.956 | 1.261 |
| 13 | 166,410 | 13.313 | 0.115 | 4.464 | 0.666 | 4.034 | 4.034 | 1.169 |
| 14 | 169,497 | 13.560 | 0.115 | 4.633 | 0.678 | 4.067 | 4.067 | 1.071 |
| 15 | 171,091 | 13.687 | 0.115 | 4.768 | 0.684 | 4.060 | 4.060 | 0.972 |
| 16 | 171,544 | 13.723 | 0.115 | 4.876 | 0.686 | 4.023 | 4.023 | 0.876 |
| 17 | 168,982 | 13.519 | 0.115 | 4.902 | 0.676 | 3.913 | 3.913 | 0.774 |
| 18 | 164,648 | 13.172 | 0.115 | 4.879 | 0.659 | 3.759 | 3.759 | 0.676 |
| 19 | 159,527 | 12.762 | 0.115 | 4.830 | 0.638 | 3.589 | 3.589 | 0.587 |
| 20 | 156,490 | 12.519 | 0.115 | 4.839 | 0.626 | 3.469 | 3.469 | 0.516 |
| 21 | 151,611 | 12.129 | 0.115 | 4.790 | 0.606 | 3.309 | 3.309 | 0.447 |
| 22 | 146,609 | 11.729 | 0.115 | 4.734 | 0.586 | 3.146 | 3.146 | 0.387 |
| 23 | 141,660 | 11.333 | 0.115 | 4.676 | 0.567 | 2.987 | 2.987 | 0.334 |
| 24 | 137,306 | 10.984 | 0.115 | 4.633 | 0.549 | 2.843 | 2.843 | 0.289 |
| Total | 2,954,957 | 236.397 | 31.745 | 82.702 | 11.820 | 58.850 | 51.540 | 8.614 |
| | | | | | | IRR | 20.47% | 9.52% |
| | | | | | | PIR | 1.624 | 0.271 |

Table C.30 Cash flow summary of case 14. Recovery Factor = 16.77%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 219,000 | 17.520 | 0.000 | 4.741 | 0.876 | 0.000 | 7.583 | 4.708 |
| 6 | 176,003 | 14.080 | 0.000 | 3.886 | 0.704 | 2.585 | 2.585 | 1.459 |
| 7 | 80,393 | 6.431 | 0.000 | 1.961 | 0.322 | 0.000 | -0.171 | -0.088 |
| 8 | 105,578 | 8.446 | 0.115 | 2.645 | 0.422 | 0.472 | 0.472 | 0.220 |
| 9 | 133,529 | 10.682 | 0.401 | 3.353 | 0.534 | 3.328 | 3.328 | 1.411 |
| 10 | 153,265 | 12.261 | 0.115 | 3.891 | 0.613 | 3.821 | 3.821 | 1.473 |
| 11 | 164,228 | 13.138 | 0.115 | 4.236 | 0.657 | 4.065 | 4.065 | 1.425 |
| 12 | 170,149 | 13.612 | 0.115 | 4.469 | 0.681 | 4.174 | 4.174 | 1.330 |
| 13 | 171,886 | 13.751 | 0.115 | 4.602 | 0.688 | 4.173 | 4.173 | 1.209 |
| 14 | 171,901 | 13.752 | 0.115 | 4.694 | 0.688 | 4.128 | 4.128 | 1.087 |
| 15 | 170,126 | 13.610 | 0.115 | 4.741 | 0.681 | 4.037 | 4.037 | 0.966 |
| 16 | 167,513 | 13.401 | 0.115 | 4.766 | 0.670 | 3.925 | 3.925 | 0.854 |
| 17 | 163,126 | 13.050 | 0.115 | 4.741 | 0.653 | 3.771 | 3.771 | 0.746 |
| 18 | 159,555 | 12.764 | 0.115 | 4.735 | 0.638 | 3.638 | 3.638 | 0.654 |
| 19 | 155,653 | 12.452 | 0.115 | 4.719 | 0.623 | 3.498 | 3.498 | 0.572 |
| 20 | 151,105 | 12.088 | 0.115 | 4.681 | 0.604 | 3.344 | 3.344 | 0.497 |
| 21 | 145,508 | 11.641 | 0.115 | 4.608 | 0.582 | 3.168 | 3.168 | 0.428 |
| 22 | 140,461 | 11.237 | 0.115 | 4.547 | 0.562 | 3.006 | 3.006 | 0.369 |
| 23 | 135,887 | 10.871 | 0.115 | 4.496 | 0.544 | 2.858 | 2.858 | 0.319 |
| 24 | 132,035 | 10.563 | 0.115 | 4.465 | 0.528 | 2.727 | 2.727 | 0.277 |
| Total | 3,066,901 | 245.352 | 33.745 | 84.979 | 12.268 | 60.715 | 53.907 | 9.737 |
| | | | | | | IRR | 21.59% | 10.53% |
| | | | | | | PIR | 1.597 | 0.289 |

Table C.31 Cash flow summary of case 15. Recovery Factor = 15.43%, Oil Price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 26.000 | 0.000 | 0.000 | 0.000 | -9.040 | -6.174 |
| 5 | 215,043 | 17.203 | 0.000 | 4.655 | 0.860 | 0.000 | 7.448 | 4.625 |
| 6 | 141,475 | 11.318 | 0.000 | 3.124 | 0.566 | 1.694 | 1.694 | 0.956 |
| 7 | 117,924 | 9.434 | 0.000 | 2.656 | 0.472 | 1.033 | 1.033 | 0.530 |
| 8 | 35,649 | 2.852 | 0.000 | 0.973 | 0.143 | 0.000 | -2.504 | -1.168 |
| 9 | 51,909 | 4.153 | 0.401 | 1.447 | 0.208 | 1.179 | 1.179 | 0.500 |
| 10 | 85,226 | 6.818 | 0.115 | 2.272 | 0.341 | 2.045 | 2.045 | 0.788 |
| 11 | 118,091 | 9.447 | 0.115 | 3.119 | 0.472 | 2.870 | 2.870 | 1.006 |
| 12 | 140,988 | 11.279 | 0.115 | 3.751 | 0.564 | 3.424 | 3.424 | 1.091 |
| 13 | 154,081 | 12.327 | 0.115 | 4.158 | 0.616 | 3.719 | 3.719 | 1.077 |
| 14 | 162,051 | 12.964 | 0.115 | 4.447 | 0.648 | 3.877 | 3.877 | 1.021 |
| 15 | 166,812 | 13.345 | 0.115 | 4.662 | 0.667 | 3.950 | 3.950 | 0.946 |
| 16 | 169,944 | 13.596 | 0.115 | 4.840 | 0.680 | 3.980 | 3.980 | 0.866 |
| 17 | 170,287 | 13.623 | 0.115 | 4.945 | 0.681 | 3.941 | 3.941 | 0.780 |
| 18 | 168,843 | 13.507 | 0.115 | 5.004 | 0.675 | 3.857 | 3.857 | 0.694 |
| 19 | 164,986 | 13.199 | 0.115 | 4.994 | 0.660 | 3.715 | 3.715 | 0.607 |
| 20 | 160,353 | 12.828 | 0.115 | 4.959 | 0.641 | 3.556 | 3.556 | 0.529 |
| 21 | 156,455 | 12.516 | 0.115 | 4.942 | 0.626 | 3.417 | 3.417 | 0.462 |
| 22 | 152,117 | 12.169 | 0.115 | 4.909 | 0.608 | 3.268 | 3.268 | 0.401 |
| 23 | 147,086 | 11.767 | 0.115 | 4.852 | 0.588 | 3.106 | 3.106 | 0.347 |
| 24 | 142,463 | 11.397 | 0.115 | 4.804 | 0.570 | 2.954 | 2.954 | 0.300 |
| Total | 2,821,782 | 225.743 | 31.629 | 79.511 | 11.287 | 55.586 | 47.990 | 7.325 |
| | | | | | | IRR | 19.18% | 8.34% |
| | | | | | | PIR | 1.517 | 0.232 |

Table C.32 Cash flow summary of case 16. Recovery Factor = 16.07%, Oil price = 80$

| Year | Cash flow summary | | | | | | | Discount cash flow (NPV@10.0%) |
|---|---|---|---|---|---|---|---|---|
| | Oil production total | Gross revenue | CAPEX | OPEX | Government take | | Annual cash flow | |
| | | | | | Royalty | Inc. tax | | |
| | (bbl/year) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) | (MMUS$) |
| 1 | 0.000 | 0.000 | 0.500 | 0.000 | 0.000 | 0.000 | -0.500 | -0.455 |
| 2 | 0.000 | 0.000 | 2.000 | 0.000 | 0.000 | 0.000 | -2.000 | -1.653 |
| 3 | 0.000 | 0.000 | 1.000 | 0.000 | 0.000 | 0.000 | -1.000 | -0.751 |
| 4 | 0.000 | 0.000 | 28.000 | 0.000 | 0.000 | 0.000 | -10.720 | -7.322 |
| 5 | 219,000 | 17.520 | 0.000 | 4.741 | 0.876 | 0.000 | 7.583 | 4.708 |
| 6 | 176,003 | 14.080 | 0.000 | 3.886 | 0.704 | 2.585 | 2.585 | 1.459 |
| 7 | 150,185 | 12.015 | 0.000 | 3.383 | 0.601 | 1.856 | 1.856 | 0.952 |
| 8 | 68,500 | 5.480 | 0.000 | 1.728 | 0.274 | 0.000 | -0.842 | -0.393 |
| 9 | 75,593 | 6.047 | 0.401 | 2.000 | 0.302 | 1.802 | 1.802 | 0.764 |
| 10 | 92,905 | 7.432 | 0.115 | 2.454 | 0.372 | 2.246 | 2.246 | 0.866 |
| 11 | 122,299 | 9.784 | 0.115 | 3.220 | 0.489 | 2.980 | 2.980 | 1.044 |
| 12 | 146,176 | 11.694 | 0.115 | 3.879 | 0.585 | 3.558 | 3.558 | 1.134 |
| 13 | 160,144 | 12.812 | 0.115 | 4.310 | 0.641 | 3.873 | 3.873 | 1.122 |
| 14 | 167,308 | 13.385 | 0.115 | 4.582 | 0.669 | 4.009 | 4.009 | 1.056 |
| 15 | 169,929 | 13.594 | 0.115 | 4.742 | 0.680 | 4.029 | 4.029 | 0.964 |
| 16 | 169,904 | 13.592 | 0.115 | 4.837 | 0.680 | 3.980 | 3.980 | 0.866 |
| 17 | 166,958 | 13.357 | 0.115 | 4.852 | 0.668 | 3.861 | 3.861 | 0.764 |
| 18 | 163,294 | 13.064 | 0.115 | 4.847 | 0.653 | 3.724 | 3.724 | 0.670 |
| 19 | 159,777 | 12.782 | 0.115 | 4.843 | 0.639 | 3.592 | 3.592 | 0.587 |
| 20 | 156,429 | 12.514 | 0.115 | 4.843 | 0.626 | 3.465 | 3.465 | 0.515 |
| 21 | 151,078 | 12.086 | 0.115 | 4.780 | 0.604 | 3.293 | 3.293 | 0.445 |
| 22 | 145,869 | 11.670 | 0.115 | 4.718 | 0.583 | 3.126 | 3.126 | 0.384 |
| 23 | 140,771 | 11.262 | 0.115 | 4.655 | 0.563 | 2.964 | 2.964 | 0.331 |
| 24 | 136,502 | 10.920 | 0.115 | 4.614 | 0.546 | 2.822 | 2.822 | 0.287 |
| Total | 2,938,622 | 235.090 | 33.629 | 81.915 | 11.754 | 57.765 | 50.286 | 8.346 |
| | | | | | | IRR | 20.19% | 9.27% |
| | | | | | | PIR | 1.495 | 0.248 |

Table C.33 Cash flow summary at 10% Discount, Oil Price = 50$

| Case study | Type of fluid to inject | Year to inject | Oil Recovery Factor (%) | IRR Undiscounted (%) | PIR Undiscounted (Fraction) | IRR (10.0%Disc) (%) | PIR (10.0%Disc) (Fraction) | NPV (10.0%Disc) (MMUS$) |
|---|---|---|---|---|---|---|---|---|
| 1 | No inject | - | 6.43 | -2.22 | -0.106 | -11.11 | -0.234 | -6.910 |
| 2 | No inject | - | 11.11 | -0.12 | -0.006 | -9.20 | -0.198 | -6.239 |
| 3 | Water | 1st | 15.61 | 5.65 | 0.374 | -3.96 | -0.109 | -2.792 |
| 4 | Water | 1st | 16.29 | 8.33 | 0.449 | -1.52 | -0.035 | -0.962 |
| 5 | Water | 3rd | 14.74 | 1.71 | 0.117 | -7.54 | -0.210 | -6.220 |
| 6 | Water | 3rd | 15.42 | 2.31 | 0.146 | -6.99 | -0.181 | -5.730 |
| 7 | Water | 5th | 13.64 | 1.27 | 0.087 | -7.93 | -0.213 | -6.357 |
| 8 | Water | 5th | 14.37 | 2.07 | 0.127 | -7.21 | -0.178 | -5.669 |
| 9 | Polymer | 1st | 17.47 | 7.96 | 0.469 | -1.85 | -0.044 | -1.235 |
| 10 | Polymer | 1st | 18.04 | 8.50 | 0.456 | -1.37 | -0.030 | -0.905 |
| 11 | Polymer | 2rd | 16.84 | 3.01 | 0.197 | -6.35 | -0.168 | -5.319 |
| 12 | Polymer | 2rd | 17.43 | 3.59 | 0.217 | -5.83 | -0.145 | -4.898 |
| 13 | Polymer | 3th | 16.16 | 1.97 | 0.133 | -7.30 | -0.196 | -6.216 |
| 14 | Polymer | 3th | 16.77 | 2.29 | 0.145 | -7.01 | -0.181 | -6.095 |
| 15 | Polymer | 4th | 15.43 | 1.51 | 0.102 | -7.71 | -0.204 | -6.466 |
| 16 | Polymer | 4th | 16.07 | 1.89 | 0.120 | -7.37 | -0.187 | -6.298 |

Table C.34 Cash flow summary at 10% Discount, Oil Price = 80$

| Case study | Type of fluid to inject | Year to inject | Oil Recovery Factor (%) | IRR Undiscounted (%) | PIR Undiscounted (Fraction) | IRR (10.0%Disc) (%) | PIR (10.0%Disc) (Fraction) | NPV (10.0%Disc) (MMUS$) |
|---|---|---|---|---|---|---|---|---|
| 1 | No inject | - | 6.43 | 18.54 | 0.878 | 7.77 | 0.155 | 4.569 |
| 2 | No inject | - | 11.11 | 20.46 | 1.038 | 9.51 | 0.204 | 6.430 |
| 3 | Water | 1st | 15.61 | 26.41 | 2.054 | 14.92 | 0.451 | 11.565 |
| 4 | Water | 1st | 16.29 | 34.62 | 2.099 | 22.38 | 0.545 | 15.072 |
| 5 | Water | 3rd | 14.74 | 20.27 | 1.588 | 9.33 | 0.271 | 8.040 |
| 6 | Water | 3rd | 15.42 | 23.64 | 0.117 | 12.40 | 0.320 | 10.119 |
| 7 | Water | 5th | 13.64 | 19.04 | 1.444 | 8.22 | 0.222 | 6.600 |
| 8 | Water | 5th | 14.37 | 22.49 | 1.456 | 11.35 | 0.268 | 8.520 |
| 9 | Polymer | 1st | 17.47 | 30.66 | 2.200 | 18.78 | 0.507 | 14.110 |
| 10 | Polymer | 1st | 18.04 | 34.54 | 2.137 | 22.31 | 0.534 | 15.928 |
| 11 | Polymer | 2rd | 16.84 | 23.24 | 1.758 | 12.03 | 0.337 | 10.684 |
| 12 | Polymer | 2rd | 17.43 | 23.86 | 1.691 | 12.60 | 0.339 | 11.426 |
| 13 | Polymer | 3th | 16.16 | 20.47 | 1.624 | 9.52 | 0.271 | 8.614 |
| 14 | Polymer | 3th | 16.77 | 21.59 | 1.597 | 10.53 | 0.289 | 9.737 |
| 15 | Polymer | 4th | 15.43 | 19.18 | 1.517 | 8.34 | 0.232 | 7.325 |
| 16 | Polymer | 4th | 16.07 | 20.19 | 1.495 | 9.27 | 0.248 | 8.346 |

# BIOGRAPHY

Mr. Krissada Yoosumdangkit was born on the 12th of November 1986 in Nakhon Ratchasima. Graduated from Rajsima Wittayalai School in 2004, he continued to pursue a bachelor's degree at Suranaree University of Technology (SUT). In 2009, he earned his degree in Transportation Engineering and continued to work for Practika Co, Ltd, until 2011.

From 2011-2016, he has studied for master's degree in the School of Geotechnology, Institute of Engineering at SUT with the major in Petroleum Engineering.