USING LINEAR ALKYL BENZENE SULFONATE TO REDUCE INTERFACIAL TENSION OF CRUDE OIL

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การใช้สารอัลคิลเชิงเส้นของเบนซีนซัลโฟเนต
เพื่อลดแรงตึงผิวของน้ำมันดิบ

นายพิพัฒน์ พิพัฒน์พงศานนท์

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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ปีการศึกษา 2554

USING LINEAR ALKYL BENZENE SULFONATE

TO REDUCE INTERFACIAL TENSION

OF CRUDE OIL

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

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พิพัฒน์ พิพัฒน์พงศานนท์ : การใช้สารอัลคิลเชิงเส้นของเบนซีนซัลโฟเนต เพื่อลดแรงตึงผิวของน้ำมันดิบ (USING LINEAR ALKYL BENZENE SULFONATE TO REDUCE INTERFACIAL TENSION OF CRUDE OIL) อาจารย์ที่ปรึกษา : อาจารย์ ดร.อัฆพรรค์ วรรณโกมล, 127 หน้า.

การวิจัยนี้มีจุดมุ่งหมายเพื่อศึกษาการลดค่าแรงตึงผิวของน้ำมันดิบ โดยการเติมสารละลายลดแรงตึงผิวลงในน้ำมันดิบ สารอัลคิลเชิงเส้นของเบนซีนซัลโฟเนตถูกเลือกมาใช้เป็นสารเติมแต่งเพื่อลดแรงตึงผิวในงานวิจัยครั้งนี้ ผลกระทบอันเนื่องมาจากความเข้มข้นของสารอัลคิลเชิงเส้นของเบนซีนซัลโฟเนตที่ความเข้มข้นร้อยละ 5 10 และ 15 โดยปริมาตร และอุณหภูมิในช่วง 40 ถึง 90 องศาเซลเซียส ระหว่างสารละลายอัลคิลเชิงเส้นของเบนซีนซัลโฟเนตและน้ำมันดิบ จากแหล่งน้ำมันสันทรายซึ่งตั้งอยู่ที่แอ่งฝาง จะถูกทำการวัดค่าโดยวิธีใช้วงแหวนและแผ่นวัดค่าความตึงผิวตามมาตรฐานของ ASTM D971-99 โปรแกรม Eclipse 100 จะถูกนำมาใช้เพื่อทำการคำนวณอัตราการผลิตและผลตอบแทนทางเศรษฐศาสตร์ จากผลการศึกษาที่ได้พบว่า ค่าแรงตึงผิวลดลงได้มากที่สุดถึงร้อยละ 20 เมื่อมีการเติมสารละลายอัลคิลเชิงเส้นของเบนซีนซัลโฟเนตที่มีความเข้มข้นร้อยละ 10 โดยปริมาตรให้กับตัวอย่างน้ำมันดิบในการจำลองแหล่งกักเก็บ โดยการอัดสารลดแรงตึงผิวที่เตรียมไว้เพื่อช่วยในการผลิตพบว่าประสิทธิภาพการผลิตน้ำมันสูงสุดคิดเป็นร้อยละ 25.33 ซึ่งได้มาจากวิธีการอัดสารลดแรงตึงผิวนี้ที่มีความเข้มข้นร้อยละ 15 โดยปริมาตรที่อัตราการอัด 200 บาร์เรลต่อวัน ในส่วนของการประเมินทางเศรษฐศาสตร์พบว่าเมื่ออัตราดอกเบี้ยเงินกู้ (Discount Rate) เท่ากับร้อยละ 8 มูลค่าปัจจุบันสุทธิ (NPV) ที่สูงที่สุดมีมูลค่าเท่ากับ 9,479,412 ดอลล่าสหรัฐ ซึ่งได้จากวิธีการอัดสารละลายอัลคิลเชิงเส้นของเบนซีนซัลโฟเนตในอัตราการอัด 200 บาร์เรลต่อวัน ที่ความเข้มข้นของสารละลายร้อยละ 5 โดยปริมาตร ในขณะที่อัตราผลตอบแทนภายใน (IRR) ที่สูงที่สุดเท่ากับร้อยละ 31.96 ได้จากวิธีการอัดสารละลายอัลคิลเชิงเส้นของเบนซีนซัลโฟเนตในอัตราการอัด 100 บาร์เรลต่อวัน ที่ความเข้มข้นของสารละลายร้อยละ 5 โดยปริมาตร

สาขาวิชา เทคโนโลยีธรณี ลายมือชื่อนักศึกษา___________________________

ปีการศึกษา 2554 ลายมือชื่ออาจารย์ที่ปรึกษา________________________

PIPAT PIPATPONGSANON : USING LINEAR ALKYL BENZENE SULFONATE TO REDUCE INTERFACIAL TENSION OF CRUDE OIL. THESIS ADVISOR : AKKHAPUN WANNAKOMOL, Ph.D., 127 PP.

LINEAR ALKYL BENZENE SULFONATE/INTERFACIAL TENSION/ SURFACTANT/CRUDE OIL/FANG' OIL FIELDS

This research aimed to study the reduction of interfacial tension (IFT) by adding the surfactant solution into crude oil. Linear Alkyl Benzene Sulfonate (LAS) was selected to use as IFT reducing additive in this research. The effect of LAS concentration (5%, 10%, and 15% of concentration by volume) and temperature (40^{o}C - 90^{o}C) on IFT between LAS solution and crude oil from Sansai oil field located in Fang basin were measured by Ring and Plate Method based on ASTM D971-99 standard. In term of production rate and economics return calculation, Eclipse 100 program was applied for these purposes. As a result, it was found that the maximum of 20% crude oil IFT reducing occurred after adding LAS solution at 10% by volume at 70^{o}C to crude oil sample. In reservoir simulation with prepared surfactant solution injection, the highest oil recovery efficiency of 25.33% was from the 200 bbl/day surfactant solution injection rate model at concentration of 15% by volume. In economic evaluation with 8% discount rate, the highest net present value of 9,479,412 US$ was from 200 bbl/day surfactant solution injection rate model at concentration of 5% by volume. While the highest internal rate of return of 31.96% was from 100 bbl/day surfactant solution injection rate model at concentration of 5% by volume.

School of Geotechnology　　　　Student's Signature________________________

Academic Year 2011　　　　Advisor's Signature________________________

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ABBREVIATIONS

bbl	=	barrel
bbl/day	=	barrel per day
bbl/month	=	barrel per month
bbl/year	=	barrel per year
bbl/STB	=	barrel per stock tank barrel
Bcf	=	Billion cubic feet
Bcfd	=	Billion cubic feet per day
BOD	=	oil barrel per day
BTU	=	British thermal unit
cc	=	cubic centimeter
^{o}C	=	degree Celsius
dynes/cm	=	dynes/centimeter
$^{o}F/100$ ft	=	fahrenheit degree per 100 feet
ft^3/SCF	=	cubic foot per standard cubic foot
g/l	=	gram per liter
g/cc	=	gram per cubic centimeter
L/kg	=	liter per kilogram
mN/m	=	millinewton per meter
mm	=	millimeter
mg/kg bw/day	=	milligram per kilogram bodyweight per day

ABBREVIATIONS (Continued)

mg/m^3	=	milligram per cubic meter
Ma	=	Million ages
Mcf/bbl	=	Thousand cubic feet per barrel
mD	=	milli Darcy
MMbbl	=	Million barrels
MMcf	=	Million cubic feet
MMcfd	=	Million cubic feet per day
MMcf/month	=	Million cubic feet per month
MMcf/year	=	Million cubic feet per year
MMSTB	=	Million stock tank barrel
MMUS$	=	Million US$
MMUS$/km	=	Million US$ per kilometer
MMUS$/well	=	Million US$ per well
Pa	=	Pascal
ppg	=	pound per gallon
ppm	=	part per million
psi	=	pound square inch
SCF/STB	=	standard cubic foot per stock tank barrel
US$/bbl	=	US$ per barrel
US$/kg	=	US$ per kilogram
US$/MMBTU	=	US$ per Million British thermal unit
US$/MMcf	=	US$ per Million cubic feet

ABBREVIATIONS (Continued)

FGIP	=	Gas in place
FWIP	=	Water in place
FOIP	=	Oil in place
FGPT	=	Gas production total
FOPT	=	Oil production total
FWPT	=	Water production total
FGPR	=	Gas production rate
FOPR	=	Oil production rate
FWPR	=	Water production rate
FGOR	=	Gas oil ratio
FWCT	=	Water cut
FPR	=	Reservoir pressure
FOE	=	Oil efficiency
FTIRSUR	=	Surfactant injection rate
FTITSUR	=	Surfactant injection total

CHAPTER I

INTRODUCTION

1.1 Rationale and background

Secondary oil recovery methods have been developed and applied to many reservoirs around the world. The waterflooding is the widespread method caused from low cost, availability and well known. This method help to improve oil recovery compared to primary production. However, some wells can be produced only one-third of residual oil after primary production and left the two-third behind. To solve this problem, the Enhance oil recovery (EOR) is the applicable method. Surfactant flood is one kind of EOR that has been employed for more than 40 years in particular of USA in depleted oil reservoirs after waterflooding. This technology has been increasing interest and develops in many countries because of the high oil price. There are many of researches for finding the new agents to bring the residual oil up from the reservoir. But almost agents that used in flood process have hazard to the environment and very expensive. Thus, chemical flood is the process that is unattractive in some countries. However, chemical flood is still needed for some oil reservoirs.

Due to its properties that can reduce crude oil interfacial tension, soluble in water, inexpensive and affable with environment so this research selected LAS as an IFT reducing agent to study. The expected result of this study is that this surfactant would reduce crude oil IFT and can be an alternative IFT reducing agent to use in flooding process in the future.

1.2 Research objectives

The main objectives of this research are (1) to study the physical properties of crude oil mixed with LAS solution, (2) to study the effect of temperature and mixing ratio on interfacial tension and rheological properties of crude oil and surfactant solution, (3) to compare oil recovery efficiency between waterflooding process with and without adding LAS solution by simulation, and (4) to evaluate economics return from using LAS as crude oil IFT reducing agent.

1.3 Research methodology

1.3.1 Literature review

Relevant literatures were searched, reviewed, summarized and documented. The summary of the literature review were given in the thesis which included description and measurement of IFT, the classification and the use of surfactant to reduce IFT of crude oil, and specification of LAS substance that used in this research. The sources of information were from text book, journals, technical reports, and conference papers.

1.3.2 Experiments

Section 1:

1) Prepared LAS solution in the ratios between LAS and water at 5%, 10%, and 15% by volume respectively.

2) Mixed LAS solution and crude oil sample in 30 cc. glass cups in pre-defined ratios. Stir the compound until they dissolved into the solvent and then cooled down to room temperature.

3) Measured IFT of crude oil at range of temperature 40^{o}C - 90 ^{o}C.

Section 2:

Run waterflooding test in Eclipse E100 reservoir simulation program by using the optimum data from previous section.

1.3.3 Petroleum economics

The petroleum economics of the hydrocarbon resource from the Eclipse E100 program was evaluated. The results of cash flow analysis were studied and analyzed to determine the base case from Internal Rate of Return (IRR) and Net Present Value (NPV).

1.3.4 Thesis writing and presentation

All research activities, methods, and results of experimental and petroleum economics evaluation were fully documented and complied with the thesis. Finally, the thesis would be submitted at the end of the research.

1.4 Scope and limitations of the study

This research aimed to study interfacial tension of crude oil and surfactant solution when the surfactant concentration and temperature were changed. IFT test was a static test by ignoring influence of high pressure and salinity in the open system. The study of IFT and modified water viscosity were limited only in laboratory scale. IFT of LAS solution and crude oil were measured by Du-Nouy Ring method and Wilhelmy Plate method with KRUSS K10ST Tension Meter based on ASTM D971-99 standard. Modified water viscosity test was measured by Haake-Viscometer550. Crude oil samples used in this study were only from Fang Basin, Chiang-Mai, Thailand. Eclipse E100 program was used to run reservoir simulation test for oil recovery prediction. The simulation Model used in this study simulated from Sansai oil field, Fang basin, Chiang-Mai, Thailand. The other input parameters included surfactant adsorption of reservoir rock, emulsification, and displacement efficiency of surfactant were negligible.

1.5 Thesis contents

Chapter I introduced the study by describing the rationale and background, research objectives, research methodology, scope and limitations. **Chapter II** summarized results of the literature review. **Chapter III** described the method of this study. **Chapter IV** analyzed the results and the discussions from experimental which were laboratory works, reservoir simulation testing and petroleum economic evaluation. **Chapter V** reported the conclusions and gave some recommendations for future studies.

CHAPTER II

LITERATURE REVIEW

2.1 Introduction

This chapter is comprised of literature review of Sansai oil field located in Fang basin, Chiang Mai Province, Thailand. The description and measurement of IFT, the classification and use of surfactant to reduce crude oil IFT and the description of Linear Alkyl Benzene Sulfonate (LAS) and its harzard to human health or environment.

2.2 Description and measurement of Interfacial Tension (IFT)

The term of surface tension is reserved for the specific case in which the surface is between a liquid and its vapor or air. If the surface is between two different liquid and a solid the term interfacial tension (IFT) is used. IFT between water and pure hydrocarbon are about 30-50 dynes/cm at room temperature (Green and Willhite, 1998).

There are several methods to measure IFT as follows:

American Society of Testing Material (ASTM) recommends standard test methods for IFT following by D971-99 standardize.

2.2.1 The Du Nouy ring method

The universally accepted technique for measuring interfacial tension is by the Du Nouy ring which is a precise geometry made of Pt-Ir. International standards for both the liquid/gas and liquid/liquid interface, from a range of industries e.g. electrical insulation & electronics, water & environmental, rubber and surfactants, are based on this technique. The methods for cleaning the ring are described in these standards but it should be noted that new health and safety rules might preclude their use. Depending on the test material, water or a ‘legal’ solvent should be used to remove the test liquid from the surface followed by an acetone rinse and a final clean water rinse before flaming to red heat. The measurement requires the ring to be wetted by the liquid and then pulled it through the interface while measuring the force exerted on the ring. The ring must sit square and parallel to the interface as failure to do so will result in errors in the measurements. The maximum force of the vertical constituent is directly proportional to the surface tension as illustrated in figure 2.1 (Carole Moules, Camtel Ltd., 2002).

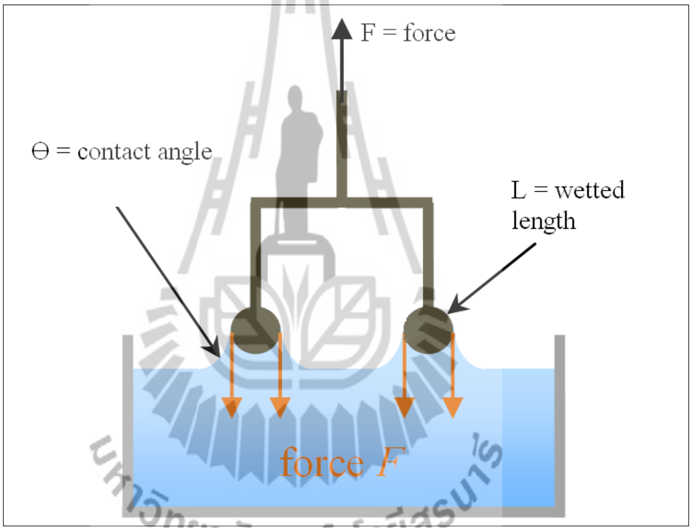

Figure 2.1 Du Nouy Ring methods (after http://www.ipc.uni-stuttgart.de).

$$\sigma = \frac{F\max - Fv}{L\cos\theta} \tag{2.1}$$

Where σ = surface or interfacial tension

Fmax = maximum force

Fv = weight of volume of liquid lifted

L = wetted length

θ = contact angle

The contact angle Θ decreases as the extension increases and has the value 0^o at the point of maximum force; this means that the term $\cos\Theta$ has the value 1.

2.2.2 Wilhelmy plate method

A detection plate made of platinum or glass is used in this method. When the bottom of a vertically oriented detection plate makes contact with a liquid surface, the liquid wets the plate surface upward and meniscus is created. At this moment, the surface area of the liquid is expanded and surface tension tends to contract the surface area as a counteraction, and immerse the plate downward as illustrated in figure 2.2.

This method determines surface tension by measuring the force bringing the plate downward via a counter balance. Surface Tension is a force for each length, and is calculated in relation to the perimeter of plate (double the plate's thickness and width) corrected for buoyancy caused by immersing the plate (Kyowa Interface Science CO., Ltd., 2007).

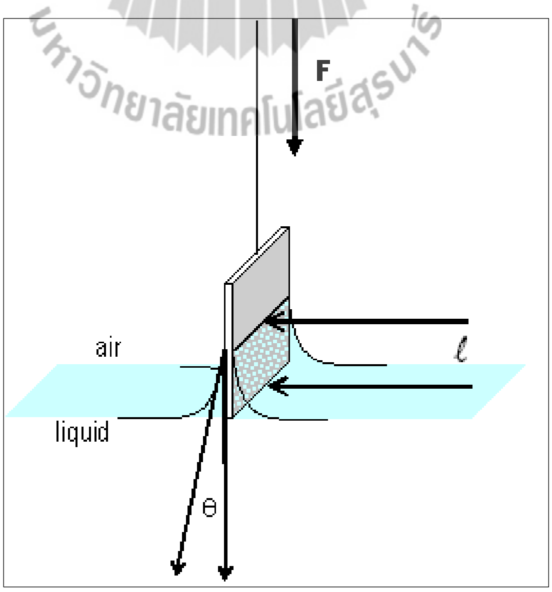

Figure 2.2 Wilhelmy plate method (after Holmberg, K., 2002).

$$\ell = \frac{F}{L\cos\theta} \quad (2.2)$$

Where ℓ = surface or interfacial tension (mN/m)

L = wetted perimeter (2w+2d) of Wilhelmy plate (mm)

Θ = the contact angle between the liquid phase and the plate (^{o})

F = force (mN/m)

2.2.3 Spinning drop method

This technique relies on the fact that gravitational acceleration has little effect on the shape of a fluid drop suspended in a liquid, when drop and the liquid are contained in a horizontal tube spun about its longitudinal axis. At low rotational velocities, the fluid drop will take on an ellipsoidal shape, but when a velocity is sufficiently large, it will become cylindrical. Under this latter condition, the radius of the cylindrical drop is determined by the interfacial tension, the density difference between the drop and the surrounding fluid, and the rotational velocity of the drop (Drelich, J. *et. al*., 2002).

This method is particularly suited to the measurement of very low interfacial tensions. A drop of liquid A is placed in a tube filled with liquid B, which has a higher density than A. On spinning the tube as shown in Figure 2.2 the drop of A moves to the axis of the tube and with increasing velocity of rotation, w, the drop becomes ellipsoidal and finally an elongated cylinder. Rotational velocities of about 20,000 rpm may be used as illustrated in figure 2.3. Consider an element of the cylinder of volume V. The centrifugal force on it is $w^2r^2\Delta\rho/2$. Integrating for a cylinder of length l is $\pi\omega^2\Delta\rho r_0^4 1/4$, and the interfacial free energy is $2\pi r_0 l\sigma$. The total energy, E, is thus

$$E = \frac{\omega^2\Delta p r_o^2 V}{A} + \frac{2V\sigma}{r_o} \quad (2.3)$$

Since V = πr_0^2 l. Putting $dE/dr_0 = 0$ we obtain

$$\sigma = \frac{\omega^2 \Delta p r_o^2}{A} \qquad (2.4)$$

Values of interfacial tension as low as 10^{-3} mN/m can be measured readily and accurately. Precision bore tubing must be used and the apparatus constructed with precision. Account must be taken for the lens effect produced by the outer fluid.

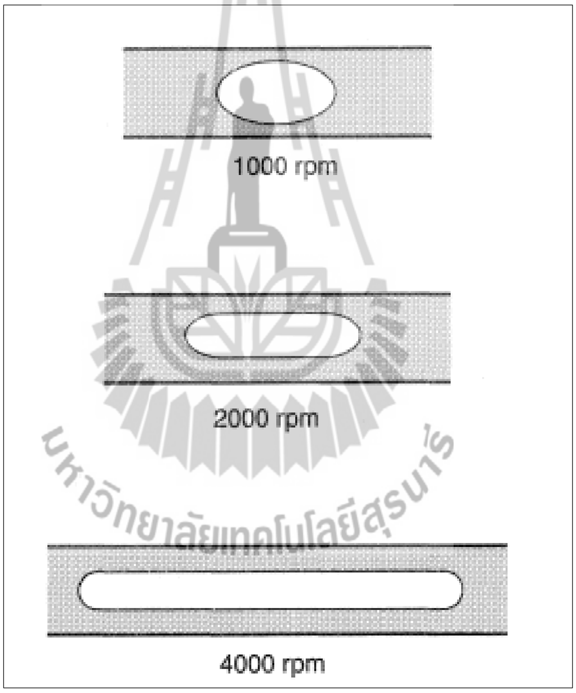

Figure 2.3 Spinning drop method (after http://www.thermopedia.com).

2.3 Classification and Use of Surfactant to reduce IFT

Surfactants are classified according to the ionic nature of the head group as anionic, cationic, nonionic and zwitterionic. Anionic and nonionic have been used as surfactants in EOR processes. Anionic surfactants have been the most widely used because they have good surfactant properties, are relatively stable, exhibit low adsorption on reservoir rock, and can manufactured economically. Nonionics have used primarily as cosurfactant to improve the behavior of surfactant systems. Nonionic are much more tolerant of high-salinity brine, but their surface-active properties (reduction of IFT) are not generally as good as anionic. Cationics are not use because they adsorb strongly on reservoir rock.

The most common surfactants used in micellar/polymer flooding are sulfonated hydrocarbon. The term "crude oil sulfonates" refers to the product when a crude oil is sulfonated after it has been topped. Petroleum sulfonates are sulfonates produced when an intermediate-molecular-weight refinery stream sulfonated, while "synthetic sulfonates" are the product when a relative pure organic compound is sulfonate. Crude oil and petroleum sulfonates have been use for low salinity application (< 2 to 3 wt.% NaCl). These surfactants have been widely use because they are effective at attaining low IFT, relatively inexpensive, and reported to be chemically stable (Green and Willhite, 1998).

Hong Chen *et al*. (2004) investigated IFT between oil solutions of cationic gemini surfactants. It is found that gemini surfactant are more effective and efficient than corresponding conventional surfactants in reducing IFT and can lower the tension of kerosene-water interface to ultra-low at very low concentration without other additives. The additional of salt results in more effectiveness of surfactant in reducing the tension of kerosene-water interface and showed that gemini surfactant has synergism with salt. The experiment use crude oil from Zhongyuan oil field of China.

Stefan Iglauer *et al*. (2009) investigated four different types of surfactants for effectiveness in tertiary oil recovery (TOR). They used basic screening analysis, which included IFT measurements, adsorption measurements and phase behavior studies. Performance in terms of EOR means that the surfactant generates a low IFT and shows low adsorption on the reservoir rock material. Surfactants are a) di-tridecyl sulfosuccinic acid ester, b) coconut diethanolamide; c) alkylpolygycosides, and d) alkyl propoxy sulfate sodium salts were tested on for enhanced oil recovery used coreflood tests on Berea Sandstone. Due to reductions of IFT led to significant additional incremental oil recovery for 40% TOR, 15% TOR, 75% TOR and 35-50% TOR, respectively.

2.4 Linear Alkyl Benzene Sulfonate (LAS)

LAS are synthetic anionic surfactant that been introduced in the 1960 as more biodegradable replacements for highly branched alkyl benzene sulfonate. LAS are nonvolatile compounds produced by Alkylation and Sulfonation of benzene, International Journal of Analytical Chemistry (2009).

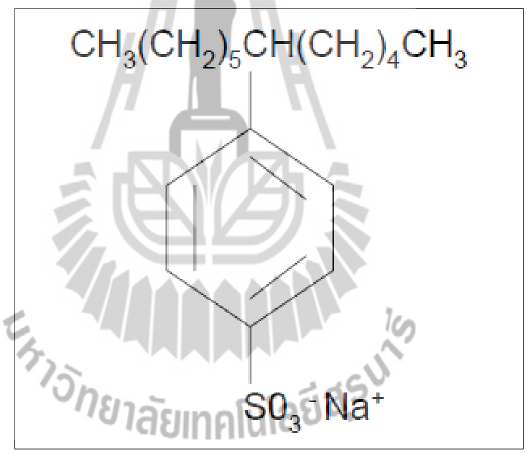

Figure 2.4 Chemical structure of Linear Alkyl Benzene Sulfonate in Dishwashing Liquid (SIDS Initial Assessment Report for 20th SIAM, 2005).

2.4.1 Category identification and justification

The LAS molecule contains an aromatic ring sulfonated at the para position and attached to a linear alkyl chain at any position except the terminal carbons. The alkyl carbon chain typically has 10 to 14 carbon atoms and the linearity of the alkyl chains ranges from 87 to 98%. While commercial LAS consists of more than 20 individual components, the ratio of the various homologs and isomers, representing different alkyl chain lengths and aromatic ring positions along the linear alkyl chain, is relatively constant in currently produced products, with the weighted average carbon number of the alkyl chain based on production volume per region between 11.7-11.8. LAS are supported as a category because of the close consistency of the mixtures, their commercial uses, fate, and health and environmental effects. LAS is the primary cleaning agent used in many laundry detergents and cleaners at concentrations up to 25% in consumer products, and up to 30% in commercial products, with the exception of one reported product at 45% in concentrated solid form that is mechanically dispensed into diluted solution for dishwashing.

2.4.2 Human health

Substantial data exist for mammalian toxicity. The available data indicate that LAS exhibits slight acute toxicity. Oral LD50 values for rats range from 1,080 to 1,980 mg/kg bw. Oral LD50 values for mice are 2,160 and 2,250 mg/kg bw for males and females, respectively. The rat dermal LD50 value was greater than 2,000 mg/kg bw. The oral and dermal acute toxicity data for LAS generally indicate low hazard potential when all studies are considered together. Acute inhalation toxicity data indicate that LAS is moderately toxic, with mortality occurring at respirable particle concentrations of 310 mg/m^3 (MMAD = 2.5 microns). In a series of studies on rabbits, LAS was not irritating to the skin or eyes at low concentrations (0.5-2.5%), moderately irritating at 5% by volume, and more severely irritating at higher (about 50%) concentrations. In studies that included rinsing, eye irritation effects diminished with rinsing after 30 seconds of exposure and were slight with rinsing after 4 seconds of exposure. In a low volume eye test (LVET) using a 35% by volume LAS solution, rabbits experienced moderate irritation that was completely reversible by day 35 (Note that the maximum concentration of LAS is 25% in consumer products and normally less than 30% in commercial products.). Accidental eye exposure in 231 manufacturing employee incidents and 284 consumer incidents established that eye irritation effects of exposure during manufacturing and use of products containing LAS and other surfactants are moderate, transient and reversible. In 15 repeated dose studies with rats, mice, and monkeys exposed to LAS via oral and dermal routes, LOAELs ranged from 115 to 750 mg/kg bw/day. The corresponding NOAELs ranged from 40 to 250 mg/kg bw/day. Effects commonly observed included suppressed body weight gain, diarrhea, and increases in relative liver weight, differences in enzymatic and serum-biochemical parameters, and mild degeneration and desquamation of the tubular epithelium in the kidneys. In four well-designed *in vitro* bacterial (*Salmonella*) mutagenicity studies, LAS shows no evidence of mutagenicity either with or without S9 metabolic activation. LAS showed no evidence of causing increased cell transformation in an *in vitro* cell transformation assay. In *in vivo* studies, no significant differences in chromosome aberrations were seen when mice were given either oral doses up to 800 mg/kg bw/day or dietary doses up to 1170 mg/kg bw/day. In a mouse micronucleus study, LAS did not induce a clastogenic effect. Rats given dietary doses up to 450 mg/kg bw/day also showed no significant differences in chromosome aberrations. Collectively, these data support that LAS is not genotoxic. The highest dose tested in four carcinogenicity studies with rats was 300 mg/kg bw/day. In the most documented study, rats were administered up to 250 mg LAS/kg body weight/day in the diet for two years. Results of this study indicate no gross or histopathological evidence of a carcinogenic effect. No evidence of tumorigenesis was observed in any of the carcinogenicity studies. While the quality and focus of the studies precludes a definitive assessment, the results of the genetic toxicology and rodent bioassay studies collectively provide strong weightof-evidence support that LAS is not genotoxic and is not a rodent carcinogen. Similarly, no evidence of reproductive or fertility effects was observed in any of the three available reproductive toxicity studies in which rats were given dietary doses over three to four generations. NOAELs from these reproductive studies ranged from 70 to 350 mg/kg bw/day, which were the highest doses tested. In 17 developmental toxicity studies, effects such as embryo death or deformities, and litter loss were most often observed only at maternally toxic doses and were associated with the irritation effects of LAS on skin or the gastrointestinal tract. No decreases in litter size, no changes in litter parameters, no malformations or significant differences in skeletal defects were observed at oral doses up to 780 mg/kg bw/day in rats and at dermal doses of 500 mg/kg bw/day in mice and 90 mg/kg bw/day in rabbits. All of the studies included in the dossier are considered reliable, but all with limitations. The results are consistent with each other and these data are used in a weight-of-evidence approach. Based on these considerations, the highest NOAEL value below the lowest LOAEL from all of the mammalian toxicity studies is the most appropriate. Therefore, the NOAEL is 85 mg/kg bw/day. This value comes from a rat drinking water, 9-month repeated dose toxicity study. The lowest LOAEL (115 mg/kg/day) was associated with increased weight of the cecum and slight degeneration of the renal tubules.

2.4.3 Environment

Pure LAS is a solid at ambient temperatures with a melting point of 198.5°C. The boiling point for LAS could not be determined experimentally due to decomposition beginning at 444°C. LAS has a low vapor pressure (calculated as 3-5 x 10-13 Pa). LAS is water soluble, with a critical micelle concentration (CMC) value of 0.1 g/L and forms a clear solution in water at concentrations up to 250 g/L. Although it is impossible to accurate measure an octanol-water partition coefficient for surface-active agents like LAS, an octanol-water partition coefficient of log 3.32 has been calculated for C11.6 LAS. Kd values for LAS in activated sludge and sediment increased with increasing alkyl chain length of LAS homologues with Kd values for C12 LAS of 3210 L/kg in activated sludge and 330 L/kg in river sediment.

In activated sludge, sorption and desorption equilibriam for LAS were achieved very rapidly, and comparison of the extent of sorption and biodegradation shows that the absorbed fraction as well as the soluble fraction of LAS is available for biodegradation. Based on Fugacity III modeling results using the most relevant input parameters, more than 99% of the residual (nonbiodegraded) fraction of LAS distribute to the soil. LAS does not undergo significant degradation by abiotic mechanisms under environmentally relevant conditions as photolyzable and hydrolyzable groups are absent from the chemical structure (SIDS Initial Assessment Report for 20th SIAM, 2005).

2.5 Fang' Oil Fields

Nopparat Settakul (2009) studied and summarized geology and petroleum system of Fang basin as follows. Fang basin is the oldest oilfield in Thailand and still producing oil. Local inhabitants found the first oil seepage on the ground surface in the dense jungle over a hundred years ago. Pioneer explorers from different government sectors involved in oil exploration and production but are still far away from being economically viable have investigated the oilfield. When the Defense Energy Department (DED) took responsibility for the site in 1956, a new era of modern technologies of geological survey, 3-D seismic survey, and directional drilling wells have been applied. From a gallon to a thousand barrels of oil, daily production has significantly increased. The oil discovery in Fang basin encourages further activities in petroleum exploration both onshore and offshore in Thailand.

The Fang' oil fields are located in Fang intermontane basin, Northern Thailand. Fang basin is approximately 150 km north of Chiang Mai or 850 km from Bangkok, the capital of Thailand. The surface area is approximately 600 km^2 (W 12 × L 50 km), probably the smallest intermontane basin in which petroleum has been discovered in the country. The basin lies NE-SW with an elongated shape and is surrounded by older formations of rocks from Cambrian and Igneous rocks to more recent sediments. The highest peak is around 2,000 m and the basin is about 450 m above mean sea level.

2.5.1 Geologic setting

The Fang basin is approximately 25-40 million years old and with layers in the Oligocene period. It is as deep as 10,000 ft in the deepest part of the basin. The lithologic assemblage is related to an episode of extension. Rifting started over 20 million years ago when the thick sequences of lacustrine sediments were deposited during the Miocene period. This sequence is called Maesod formation. Subsequent tectonic activity resulted in the deposition of thick sequences of coarse alluvial sediments that unconformably overlay the lacustrine sequences. This tectonic activity may be broadly related to changes in tectonic stress patterns caused by the progressive Indo-Eurasian collision. The coarse clastics are termed of Maefang formation and possibly span the latter Miocene to the Pliocene-Pleistocene period.

2.5.2 Subsurface structure

Fang basin is divided into 3 extensional sub-basins as interpreted from gravity and seismic surveys. These sub-basins are postulated by firstorder Riedel shear faults. The Riedel shears are clearly visible on satellite images cutting across Pre-Tertiary basements surrounding the Fang basin. These shears result from left lateral shear coupled with movement that initiated the basin. Within the subbasins, there occurs a swarm of cross-basin faults which are parallel with the Riedel shears; these are interpreted as coincident second order Riedel shears. The interpretation is based partly on the extensive network of seismic profiles across the Huai Ngu subbasin.

2.5.3 Subsurface lithostratigraphy

From the geological data, there are 2 major formations from the upper zone of Mae Fang formation to lower zones of Mae Sod formation as follows:

Mae Fang formation (Quaternary+Recent)

The post-rift of Mae Fang formation overlies discordantly above the Mae-Sod formation. The thickness of the Mae Fang formation from the surface varies from 1,000-1,800 ft. The minimum thickness is found on top of the Mae-Soon structure. The thickness will increase down dip from the crest of the structure. Mae Fang formation is mainly composed of coarse clastic sediments of soil, lateritic sands, loose sands, gravels, cobbles and pebbles, carbonized woods and clay on the top and towards the basin edge. Sizes of sands vary from coarse to very coarse grains, roundness from angular to subangular, poorly sorted and interbedded with reddish clays. While down dip towards the central basin clay-shale and arkosic sandstone are interbedded. This formation overlies discordantly with the Mae Sod formation. The Mae Fang formation shows energetic alluvial and fluvial deposits.

Mae Sod formation (Middle Tertiary)

The Mae Sod formation is composed of brown to gray shale, yellowish mudstone generally interbedded with sand and sandstone with a series of channels of sand paleodelta and fluvial sand. Basal conglomerate lies unconformity with Pre-Tertiary rocks and continues with sequences of lacustrine shale and mudstone. The color of the sediments indicates a reducing environment in the central, deeper part of the basin while an oxidizing environment develops in the shallow part of basin. Organic shale in the central part of the basin plays an important role as a potential source of rocks. The upper part of the Tertiary sediments is interbedded with 4 packages of sand which are important reservoir rocks in the Fang basin. Only 2 packages of sands have been proven to be producing sands. The sand thickness varies from 1-10 m. The thickness of the Mae Sod formation varies from the margin of the basin towards the centre of the basin. At the Mae-Soon structure, the thickness is approximately 3,500 ft or total thickness (Mae Fang+Mae Sod formation)

5,000 ft from the surface. Seismic interpretations indicate that the thickest part of the Mae Sod formation might reach up to 8,000 ft at the deepest part of the basin.

Basement (Pre-Tertiary)

The age of the basement of the Fang basin ranges from Mesozoic continental clastics to Cambrian marine clastics.

Environment of deposition

The Mae Sod Formation was laid down following initial basin rifting in the later Oligocene or early Miocene periods. Sands and shale alternate in the lower part of the formation indicating a fluvial to shallow lacustrine environment of deposition. A 75-100 ft lignite seam indicating a change in environment to swamps and peat bogs for a period caps this lower sequence. The upper portion of the Mae Sod is dominated by organic rich shale with minor sandstone beds occurring, especially in the lower part of the upper section. This lithology indicates a lacustrine dominated environment following the deposition of the peat. The Mae Sod formation is then overlain by the coarse clastic dominated Mae Fang formation, returning to a more fluvial tile dominated environment. The Mae Fang is not considered a viable rock source because of its dominant sandy lithology and shallow, immature depth of burial. The above description is based on the Fang basin but appears to be a valid generalization for most of the Thai Cenozoic intermontane basins.

2.5.4 Petroleum system

Petroleum source rocks

Source or potential source samples can be found from both outcrops and cores. Oil seepage can be seen near the edge of the basin. The oil found in the Fang basin is most likely from lacustrine shales found in the Mae Sod formation. The geochemical analysis of potential source rocks has been done by using cores and cuttings from selected wells of Mae-Soon and Sansai reservoirs. The analysis indicated very interesting results.

Total organic carbons (TOC) are very abundant between 1.12-2.67% with a maximum of 3.03%. Extraction soluble organic matter (EOM) is as high as 1,646 ppm. Kerogen type III is approximately 20-25%, indicative of a lacustrine paleo-environment. The maturation scale indicates that the top oil window should start below 4,000 ft. While the core indicates that maturation starts from 7,750 ft. Mean vitrinite reflectance (RO%) from core analysis is only 0.44% at 3,000 ft which is lower than the ideal level of maturation of RO 0.5-1.2% and with a temperature (Tmax) of 437-470°C in the Fang basin. Therefore, the most favorable source rocks are the Mae Sod shales that are within and below the oil window.

Migration

The current producing pay intervals are above the mature source rocks. This indicates the migration of fluids at certain distances from the source rocks to charge the oil reservoirs above. The contributing factors in the migration path from the depths are fractures and faults along permeable rocks during compaction and compression in the late Tertiary period. From the size of the basin and location of reservoirs and production zones the distance of migration is short. After oil generation, oil might migrate in different directions around to the potential traps. Evidence supporting this statement comes from biodegradation of oil being found at a very shallow depth in Chaiprakarn and Pongnok reservoirs, both sides of the basin, suggesting migration routes from the depths.

Oil reservoirs

Within the Fang basin, all productions come from the Mae Sod formation. The current producing reservoirs are distributed into widespread sections of the sorted sands and coarse clastics in some cases.

Reservoir distribution

Generally, interbedded sand and sandstones in the upper zones of the Mae Sod formation are dominant reservoir rocks in the Mae-Soon reservoir and others. The sand member that gives the lowest production includes 4 layers of sand. The thickness of each sand layer varies from 5-45 ft. The depth of this sand is about 2,386-2,487 ft that is the main producer of wells. The thickest part of this sand is in a North-South direction. Porosity decreases towards the margin of the reservoir. The sand member gives the highest production includes 5 sands, 5-15 ft in thickness for each sand, with a total thickness of about 55 ft. The depth is about 2,160-2,255 ft. Most of the old wells are from this sand 2,300 ft in depth. The thickness of the sand varies from place to place. The trend in thickness North-South is 55 ft and decreasing to 10-15 ft at the edge of reservoir.

Reservoir properties

Cores analysis from some wells shows interesting results of porosity up to 25%, permeability higher than 200 milliDarcy (mD), some loose clastics as high as 2,000-3,000 mD found in the well IF 26 (Table 2.1).

Table 2.1 Reservoir properties (after Settakul, N., 2009).

Well	Depth (ft)	Permeability (md)	Porosity (%) (abs)	Fluid saturation (%)		Density (g/cc)
				Oil (Sor)	Water (Sw)	
BS-110	2,755.0	231	25.7	6.1	54.4	2.67
IF-26-1	2,581.1	2,390	25.4	17.5	33.0	2.65
IF-26-2	2,587.1	3,440	26.7	20.5	34.7	2.64

Fluid properties

Physical properties of oil from Mae-Soon, Pongnok and Lankrabreau are quite similar with a very high content of paraffin wax up to 18%.

Table 2.2 Fluid properties (after Settakul, N., 2009).

Properties	Chiprakarn crude	Mae-Soon crude	Pongnok crude	Lankrabreau crude
API gravity	16.40	30.8	37.6	38.2
Pour point	65 °F	95 °F	92 °F	90 °F
Sulphur (%)	0.28	0.18	016	0.5
Paraffin wax(%wt)	-	18	18.62	14.5-20
Specific gravity	0.957	0.872	0.873	0.675-0.85
Color	Brownish black	Brownish black	Brownish black	Brownish black

Seals

Due to the interbedded sand/shale nature of the Mae Sod formation, the sands are effectively sealed from each other in a vertical sense by the thick, intervening shale. In the upper part of the Mae Sod, the shale to sand ratio is higher than the lower section. Many of reservoir sands appear to be lateraling continuous over larger distances, allowing for lengthy up dip migration pathways. Up dip structural seals are formed by both stratigraphic and faulting mechanisms.

Traps

Combinations of structural and stratigraphic traps are very important at the Mae-Soon reservoir in the Fang basin. Traps or plays in the Fang basin will reflect its evolution during much of its history as a continental interior subsidence. Traps will thus exclusively involve tension faults as well as unconformities caused by uplift and erosional systems.

Proven traps

Structural traps of rollover anticlines originate from growth faulting and compaction on the Pre-Tertiary basement. The anticlinal axis consists of a NNW-SSE trending conforming to the basin N-S trending, dipping 5-10° around the crest. Major faults are characterized by a listric geometry, which has resulted in the formation of a rollover structure in the hanging wall of the fault. The major fault identified from seismic interpretations is in the NE-SW direction and dipping 85°W. The fault is characteristic of a trust and strike slip fault. The western block has moved along the strike south about 150 ft and vertical displacement is about 250 ft. Minor faults are found associated with the Mae-Soon and Nongyao reservoirs. Combination traps of up dip truncation and lithostratigraphic pinchout from porous rocks to impermeable rocks have been proved to exist in Sansai, Pongnok, and Banthi reservoirs along the eastern trend of the Fang basin. In Chaiprakarn, some leakage of oil, probably uplift of the basin and erosion exposed crude oil near the surface and this degraded oil may have provided an effective trap

Potential traps

These traps might be formed under unconformities in the Pre-Tertiary basement. Synrift sediments forming potential anticlines drape drape anticline during the initial rifting. Paleogeomorphogic traps of burial Pre-Tertiary limestone or sandstones would form a good quality reservoir under unconformity.

2.5.5 Exploration history

Exploration

Oil was first found in the Fang basin over a hundred years ago when local inhabitants discovered oil seepage on the ground in the dense jungle. They believed it to be magic oil and used the oil as an ointment for skin infections. The Lord of Chiang Mai ordered a shallow well to be built called the “Lord’s Well”. Today, there is a memorial well called “Boh Tonkam”

In 1921, General Pra Kampangphet Akkarayothin (HM), the Director General of the Royal State Railway Department and a US geologist, Mr. Wallace Lee conducted a geological survey and drilled 2 shallow wells with a steam engine drilling rig in 1922 but these wells were dry and abandoned.

Drilling

Over 240 wells have been recorded since the first drilling well started in the Fang basin over 40 years ago. The wells are from different locations. Now only 5 locations are producing oil and 2 fields have been abandoned.

Production

The total production from the Fang basin is approximately 9 million barrels (MMBbl) from the following 7 reservoirs since early 1960 to the present day. I. Chaiprakarn reservoir (abandoned 1984), II. Mae-Soon reservoir, III. Pongnok reservoir (abandoned 1985), IV. Sansai reservoir, V. Nongyao reservoir, VI. Sanjang reservoir, and VII. Banthi reservoir. The latest Banthi reservoir was discovered from 3-D seismic interpretation in 2001. A total of 7 wells were drilled, 3 wells were directional wells. Five wells are producing at a rate of 150 BOD.

Reserve estimation

The Mae-Soon reservoir has produced 7 MMbbl since 1963. Production started from 100 barrel per day up to nearly 1,000 barrels per day at the peak of production

Table 2.3 Reserve Estimation of Fang’ oil fields (after Settakul, N., 2009).

Field	Probable(MMbbl)	Proven (MMbbl)	Recoverable(MMbbl)
Mae-Soon	23.0-30.0	10.0-15.0	8.00
Sansai	20.0	7.0	3.00
Nongyao	5.0	3.0	2.00
Samjang	5.0	1.5	0.75
Pongnok	6.0	3.0	1.50
Banthi	8.0	3.0	1.50
Chiprakarn	4.5	1.5	1.00

CHAPTER III

RESEARCH METHODOLOGY

3.1 Introduction

This research aimed to study interfacial tension between crude oil and LAS solution when surfactant concentration and temperature were changed. This chapter is divided into 3 sections, (I) Experimental that is consisted of IFT test and modified water viscosity test which required by simulation program and this section is also shown the obtainable data of Fang' oil fields from previous study. (II) Simulation models that used in Reservoir Simulation program to predict oil recovery by simulated surfactant flooding test, and (III) Economic evaluation.

3.2 Experiments

Materials

Crude oil samples that used in this study were from Fang' oil fields which provided by Northern Petroleum Development Center, Defence Energy Department, Fang, Chiang Mai province, Thailand.

Methods

3.2.1 IFT test

IFT of LAS solution and crude oil were measured by Wilhelmy Plate Method and Du Nouy Ring method with KRUSS K10ST Tension Meter illustrated in figure 3.1. This instrument has range of result 1-999 dyne/cm and range of temperature 0-100^{o}C.

IFT test processes were as follows:

- Prepared LAS solution in ratios between LAS and water of 5%, 10%, and 15% by volume.
- Mixed LAS solution and crude oil sample in 30 cc glass cups with the ratios of 5%, 10%, and 15% by volume, respectively. Stir the compound until they were dissolved into the solvent and then cooled down to room temperature. The mixed solution was immiscible and clearly separated into surfactant solution and crude oil.
- Measured IFT of crude oil at range of temperature 40-90^{o}C. This was because at the temperature below 40^{o}C crude oil samples were became a wax which could not be measured.

Phase behavior in the measuring cup from the experiment illustrated in figure 3.1, oil phase was on the top of system and clearly separated from surfactant solution phase which was below.

3.2.2 Modified water viscosity test

Modified viscosities of water after adding surfactant are measured by HAAKE-Viscometer550 illustrated in figure 3.2.

Test processes were as follows:

- Prepared LAS solution in the ratios of 5%, 10%, and 15% by volume.
- Measured modified viscosity of water at range of temperature 40-90^{o}C.

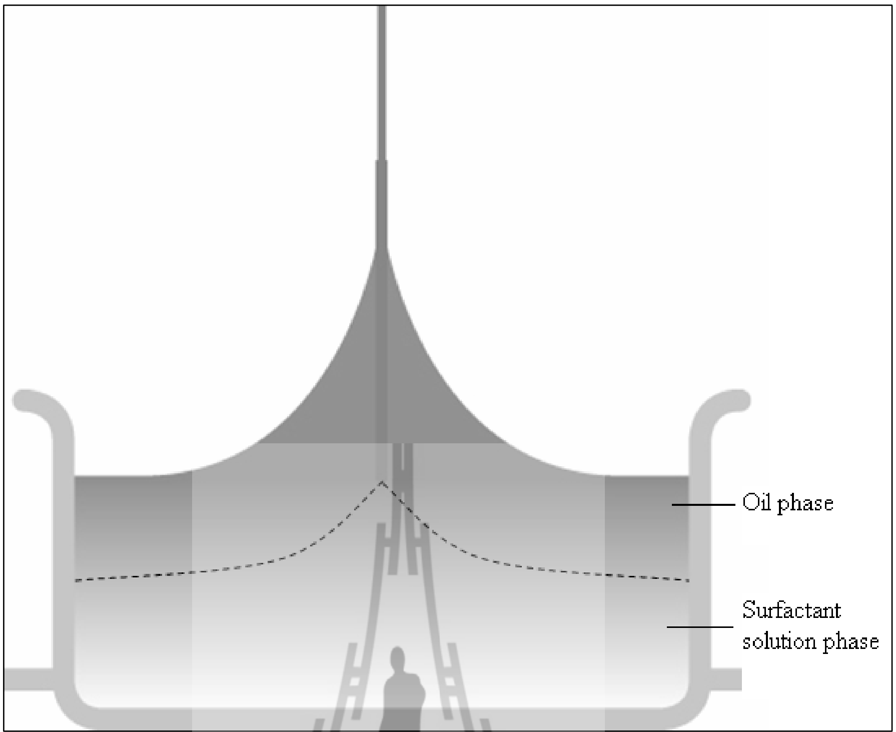

Figure 3.1 Phase behavior of the system from the experiment.

Figure 3.2 Kruss tension meter K10ST.

Figure 3.3 Haake - Viscometer550.

3.2.3 Obtainable data from previous study

Required data that need in reservoir simulation program were collected and adapted from works of Chumkratoke, C., (2004) which were composed of 4 sections.

1. Gas properties
2. Crude oil properties
3. Water properties
4. Reservoir rock properties

See appendix A for obtainable data

3.3 Reservoir simulation program

This study was run surfactant flood test compared with water flood test in reservoir simulation program. The reservoir conditions used in simulator were adapted from previous study of Chumkratoke, C., (2004).

3.3.1 Reservoir model input parameters

The reservoir simulation model is required the input data which had been showed in previous section that can be divided into

1. Grid Section

Grid section is required the porosity, permeability, depth, and thickness for each layer in Fang' oil fields. Porosity and permeability in this section were set into x, y, z for each layer.

2. PVT Section

PVT section is required fluid properties data that variable with pressure such as IFT of crude oil, fluid viscosity, fluid density, fluid formation volume factor, solution gas-oil ratio, modified water viscosity, etc.

3. SCAL Section

SCAL section is required rock properties which were set in the table as relative permeability versus fluid saturation data. This section was used the information to defined transition zone and flow condition of each phase to another phases.

4. Initialization Section

Initialization section is defined the initial condition of reservoir simulation. Simulator used this information to calculate the initial hydrostatic pressure gradient for each zone in reservoir model and allocated initial saturation for each phase in every grid cell. The required data were datum depth, pressure at datum depth, water-oil contact depth, and bubble point pressure at datum depth.

5. Schedule Section

This section is defined the data of producing well and injection well which required well and completion locations, production and injection rate, skin factor, well radius, well control and etc.

3.3.2 Flood pattern design

According to surfactant flood process, reservoir need to be injected by fresh water as a preflush sometimes used to change rock or fluid properties. Then the surfactant slug is injected to mix with the oil and change its properties, decreasing the interfacial tension and viscosity or changing rock wettability these effects mobilized more oil. Fresh water is injected at last as drive water.

Surfactant flooding pattern in this study relied on the reservoir structure, drainage area, number of well, production and injection activity. The summary of surfactant flooding pattern design, production and injection rate, and concentration of surfactant solution used in each model are showed in table 3.31

Table 3.1 Cases description.

Case name	Surfactant concentration	Water/Surfactant inj. description	Initial oil production (bbl/d/well)	Water/Surfactant solution inj. (bbl/d/well)
Water flood base case	-	Water injection after 13^{th} year	200	200
inj100_ case1	5% by vol	Fresh water inj. 2^{nd} year	100	100
		Surfactant inj. at 3^{rd} year		100
		Fresh water inj. 9^{th} year		100
inj100_ case2	10% by vol	Fresh water inj. 2^{nd} year	100	100
		Surfactant inj. at 3^{rd} year		100
		Fresh water inj. 9^{th} year		100
inj100_ case3	15% by vol	Fresh water inj. 2^{nd} year	100	100
		Surfactant inj. at 3^{rd} year		100
		Fresh water inj. 9^{th} year		100

Table 3.1 Cases description (continued).

Case name	Surfactant concentration	Water/Surfactant inj. description	Initial oil production (bbl/d/well)	Water/Surfactant solution inj. (bbl/d/well)
inj200_ case1	5% by vol	Fresh water inj. 2nd year	200	200
		Surfactant inj. at 3rd year		200
		Fresh water inj. 9th year		200
inj200_ case2	10% by vol	Fresh water inj. 2nd year	200	200
		Surfactant inj. at 3rd year		200
		Fresh water inj. 9th year		200
inj200_ case3	15% by vol	Fresh water inj. 2nd year	200	200
		Surfactant inj. at 3rd year		200
		Fresh water inj. 9th year		200
inj300_ case1	5% by vol	Fresh water inj. 2nd year	300	300
		Surfactant inj. at 3rd year		300
		Fresh water inj. 9th year		300
inj300_ case2	10% by vol	Fresh water inj. 2nd year	300	300
		Surfactant inj. at 3rd year		300
		Fresh water inj. 9th year		300
inj300_ case3	15% by vol	Fresh water inj. 2nd year	300	300
		Surfactant inj. at 3rd year		300
		Fresh water inj. 9th year		300

These cases had the same number of production well and injection well, location in simulator, and well activity as showed in table 3.32.

Table 3.2 Wells description.

Year	Well Name	Location	Well Activity	Injecting/Producing Phase
1	S3	(6,8)	Producer	Oil
2	INJ1	(7,13)	Injector	Fresh Water
3	INJ1	(7,13)	Injector	Surfactant Solution
5	S6	(12,17)	Producer	Oil
8	S10	(6,11)	Producer	Oil
9	INJ1	(7,13)	Injector	Fresh Water
10	S11	(11,10)	Producer	Oil

Note: Life time of these cases is limited at 20 years

3.4 Economic evaluation

The objective of this chapter is to determine economic evaluation from the simulation results of surfactant flood compare with the water flood. The parameters that used in cash flow analysis were as follows:

3.4.1 Basic assumptions

a.	Oil price (US$)	80
b.	Income tax (%)	50
c.	Escalation factor (%)	2
d.	Discount rate (%)	8
e.	Tangible cost (%)	20
f.	Intangible cost (%)	80
g.	Depreciation of tangible cost (%)	20
h.	Sliding scale royalty	
	Production level (bbl/day)	Rate (%)
	0-2000	5.00
	2,000-5,000	6.25
	5,000-10,000	10.00
	10,000-20,000	12.50
	>20,000	15.00
i.	Reserve size (MMSTB)	<10,000,000

3.4.2 Other assumptions

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

b. Increasing rate of capital expenditure comes from the price increasing of machinery and equipment used in oil industries, and given to two percent year.

c. Discount rate of money is 8.00 percent (Bank of Thailand, August 2011).

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

e. LAS cost is 1,300 US$/ton (after http://www.phoenixdo4u.com, August 2011).

f. The others expense used in cash flow analysis were showed in the table 3.33.

Table 3.3 Expenditure cost details in cash flow analysis.

Expenditure cost detail	Price
Concession	0.25 MMUS$
Geological and geophysical survey	0.5 MMUS$
Production facility	0.75 MMUS$
Drilling & completion production well	1.5 MMUS$
Drilling exploration & appraisal well	1 MMUS$
Facility costs of water injection well	0.05 MMUS$
Facility costs of surfactant injection well	0.062 MMUS$
Maintenance costs of water injection well	0.03 MMUS$
Maintenance costs of surfactant injection well	0.05 MMUS$
Cost of surfactant	1.3 US$/kg
Abandonment cost	0.0125 MMUS$
Operation cost of production	20 US$/bbl
Operation cost of water injection	0.5 US$/bbl
Operation cost of surfactant injection	1 US$/bbl

CHAPTER IV

RESULTS AND DISCUSSIONS

4.1 Introduction

This chapter presents the results and some discussions from previous chapters it was separated into 3 parts consisted of (I) experimental, laboratory results and discussions including IFT tested and modified water viscosity tested, (II) reservoir simulation results and discussions, and (III) economic evaluation results and discussions, respectively.

4.2 Experimental results and discussions

4.2.1 Interfacial Tension of crude oil

Measured IFT of crude oil without adding surfactant solution was showed in table 4.1 and measured crude oil IFT with adding surfactant solution at 5%, 10%, and 15% by volume concentration were showed in table 4.2 through table 4.4 respectively. IFT of crude oil with and without adding surfactant solution at selected ratio was illustrated in figure 4.1.

Table 4.1 Crude oil IFT from laboratory without adding surfactant solution.

Temperature (^{o}C)	IFT (dynes/cm)
40	31.87
50	27.27
60	26.73
70	26.53
80	26.03
90	25.47

Table 4.2 Crude oil IFT from laboratory with surfactant solution of 5% by volume LAS concentration.

Temperature (^{o}C)	IFT (dynes/cm)
40	29.97
50	27.6
60	27.43
70	26.8
80	26.5
90	26.2

Table 4.3 Crude oil IFT from laboratory with surfactant solution of 10% by volume LAS concentration.

Temperature (^{o}C)	IFT (dynes/cm)
40	29.1
50	21.8
60	21.4
70	21.1
80	21.47
90	21.3

Table 4.4 Crude oil IFT from laboratory with surfactant solution of 15% by volume LAS concentration.

Temperature (^{o}C)	IFT (dynes/cm)
40	27.9
50	26.6
60	25.6
70	26.53
80	26.47
90	26.37

From figure 4.1 at 40 ^{o}C IFT of crude oil at 0% by volume concentration was 31.87 dynes/cm. When a surfactant was added to solvent at 5% concentration, the dissolved surfactant molecules were dispersed as monomers. As the concentration of surfactant increased to 10% by volume concentration, the molecules tended to aggregate. Above a specific concentration called the critical micelle concentration (CMC), further addition of surfactant to 15% by volume results in the formation of micelle. The concentration of surfactant as monomers essentially increased above the CMC. It could be concluded that surfactant added at concentration above the CMC resulted in formation of additional micelles.

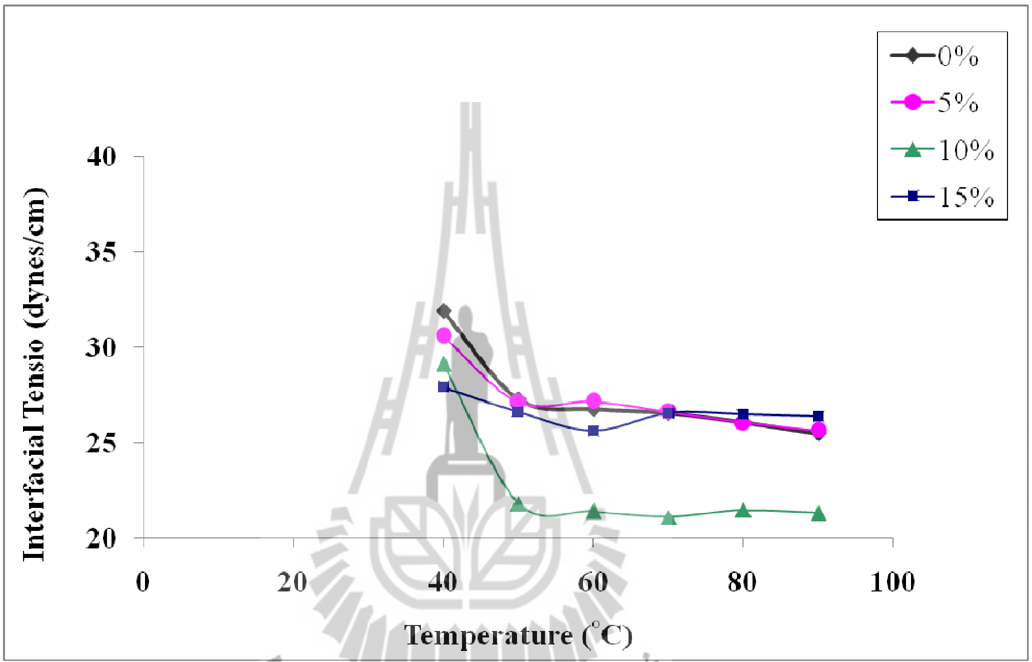

Figure 4.1 IFT of crude oil with and without adding surfactant solution at selected ratio.

4.2.2 Modified water viscosity

Modified water viscosity is the viscosity of water that dissolved with surfactant at any concentration as the function of temperature which required by simulation program. According to the scope and limitation of this study, modified water viscosity was measured by ignoring high pressure. Modified water viscosity are showed in table 4.1.

Table 4.5 Modified water viscosity at 40°C and 70°C.

Concentration (%)	Modified water viscosity (centipoises)	
	@40°C	**@70**°C
5	1.12	4.28
10	1.96	9.56
15	5.02	20.1

In general, when the temperature is increased, viscosity of water is decreased. However, as noticed from table 4.1, when added more surfactant solution concentration this affected in the increasing in viscosity. This was because the addition of surfactant into the water would be resulted in higher concentration of the solution. Another reason was from experimental that was operated in the open system. Therefore, at high temperature, water in surfactant solution could be evaporated from the system.

4.3 Reservoir simulation results and discussions

From previous chapter, total 10 flooding cases included one water flood base case and 9 surfactant flood cases were tested to observe and to compare the production efficiency to find the best case giving the highest recovery efficiency. The reservoir simulation results in each case was depicted as the oil recovery efficiency profile, fluid in place profile, cumulative fluids production profile, fluids production rate profile, gas-oil ratio water-cut and pressure profile, surfactant injection rate and total surfactant injection, and perspective view at the end of project life time from reservoir simulation program, respectively.

4.3.1 Model water flood base case results

Water flood base case results are showed in figure 4.2 through figure 4.6.

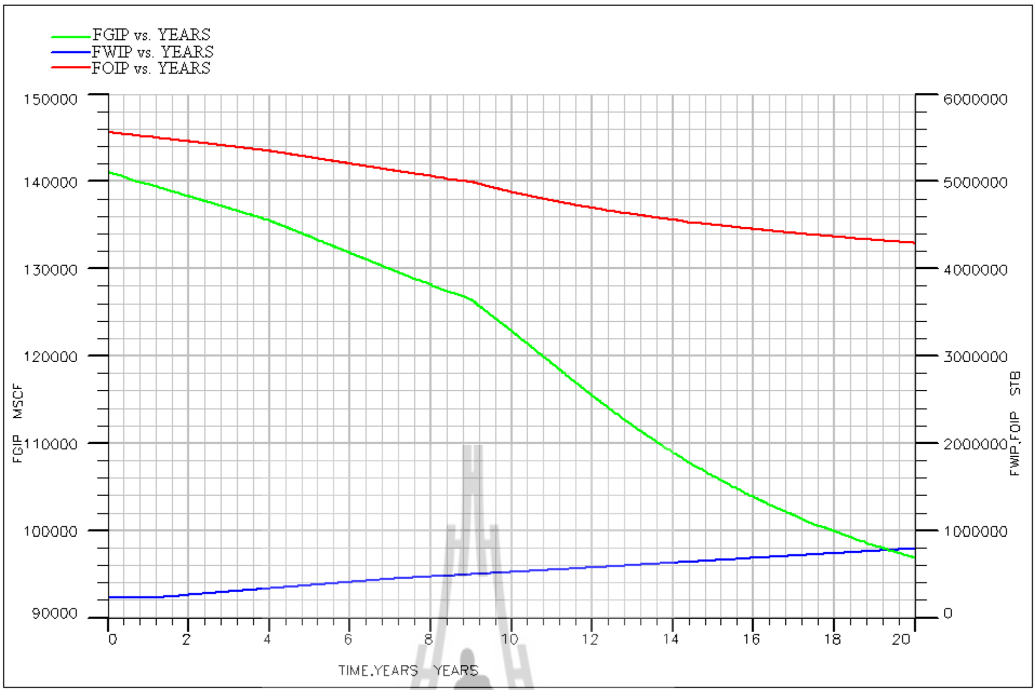

Figure 4.2 Fluids in place profiles vs. time of water flood base case.

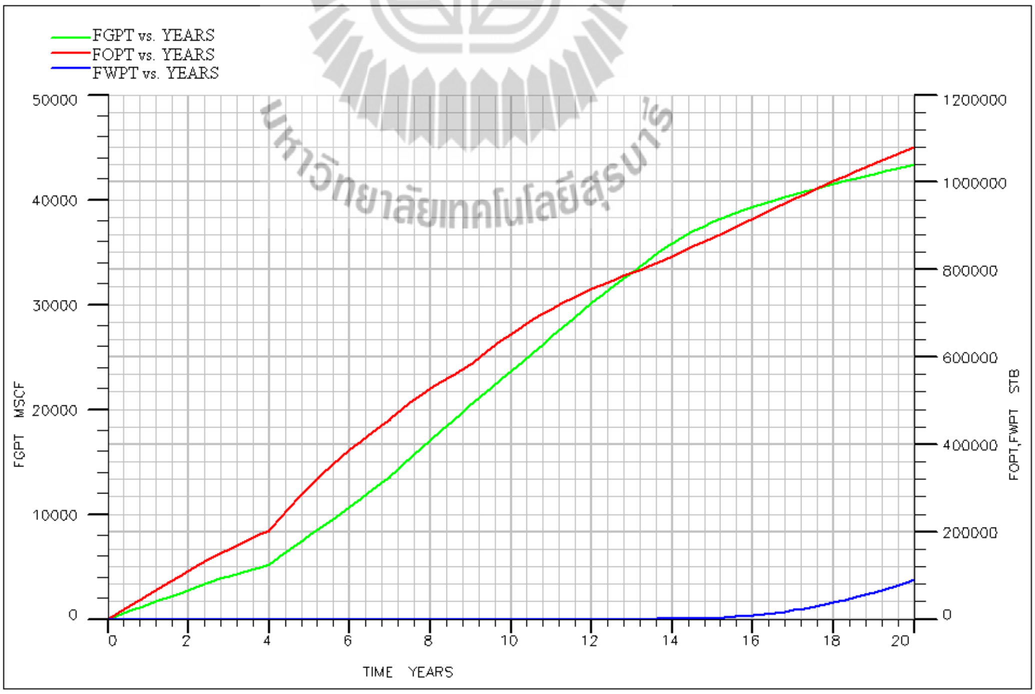

Figure 4.3 Cumulative fluids production profiles vs. time of water flood base case.

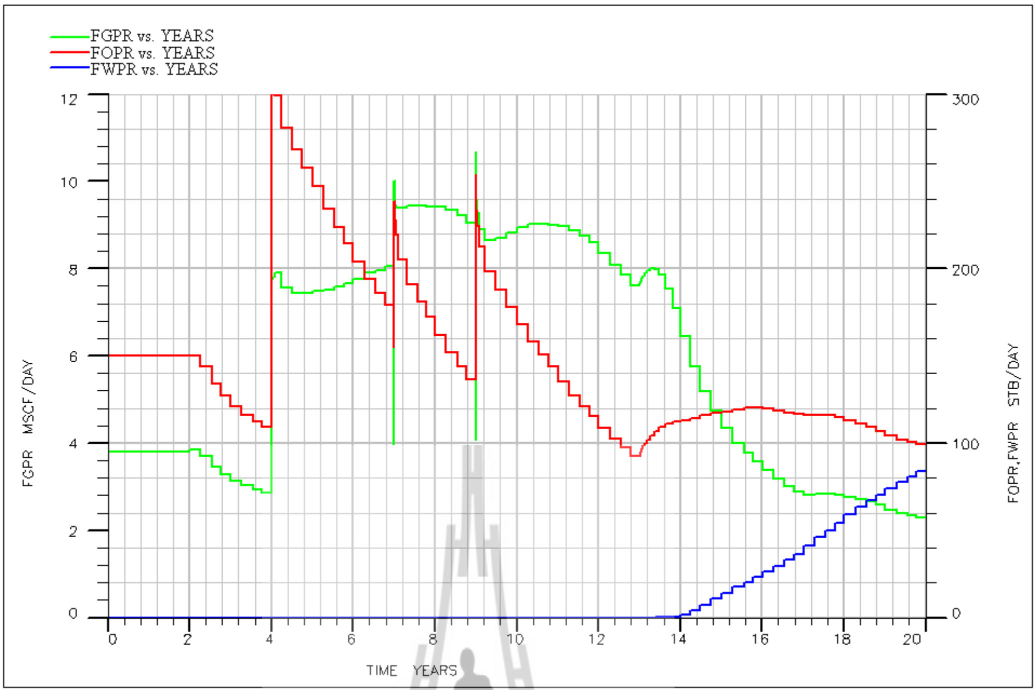

Figure 4.4 Fluids production rate profiles vs. time of water flood base case.

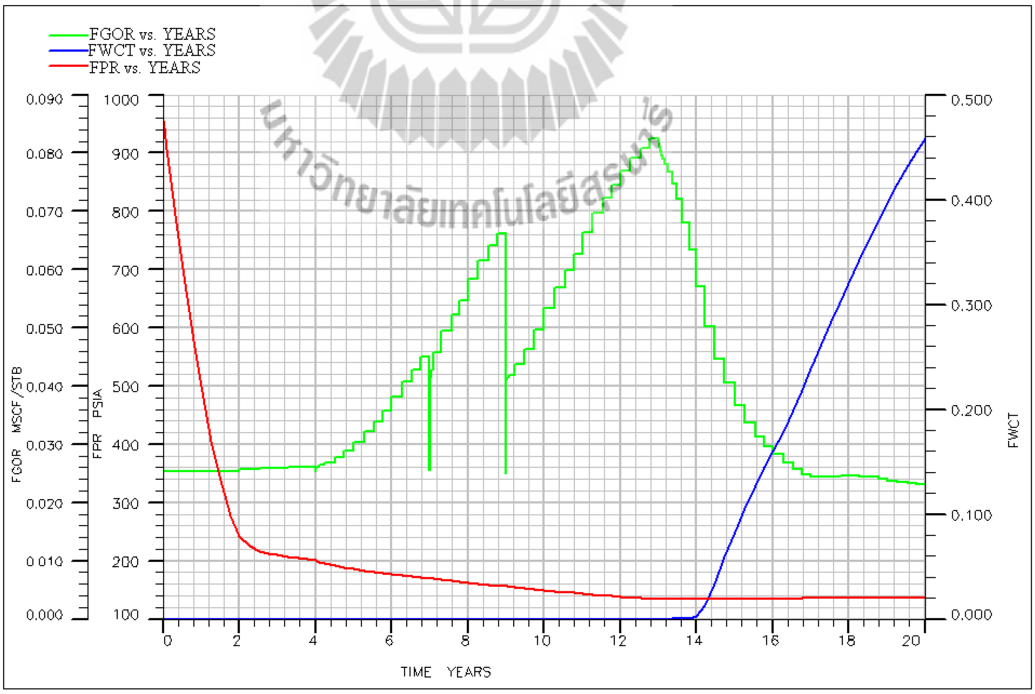

Figure 4.5 GOR, Water cut, and Pressure vs. time of water flood base case.

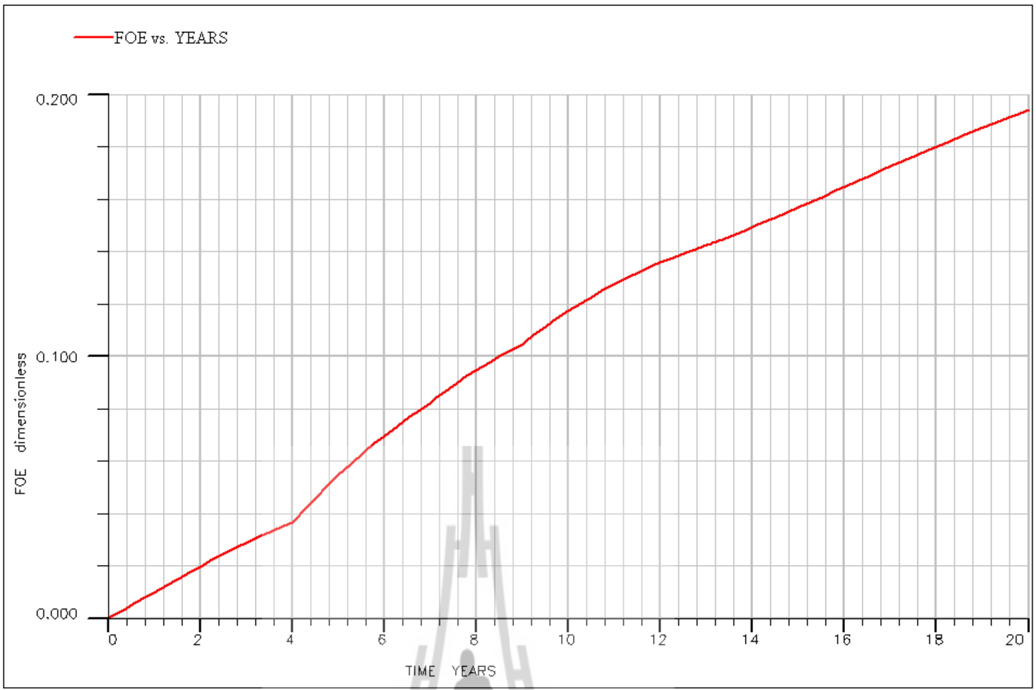

Figure 4.6 Recovery efficiency of oil vs. time of water flood base case.

4.3.2 Model inj100_case1 results

Model inj100_case1 is the surfactant flood at the injection rate 100 bbl/day with 5% by volume concentration and the simulation results are showed in figure 4.7 through figure 4.12.

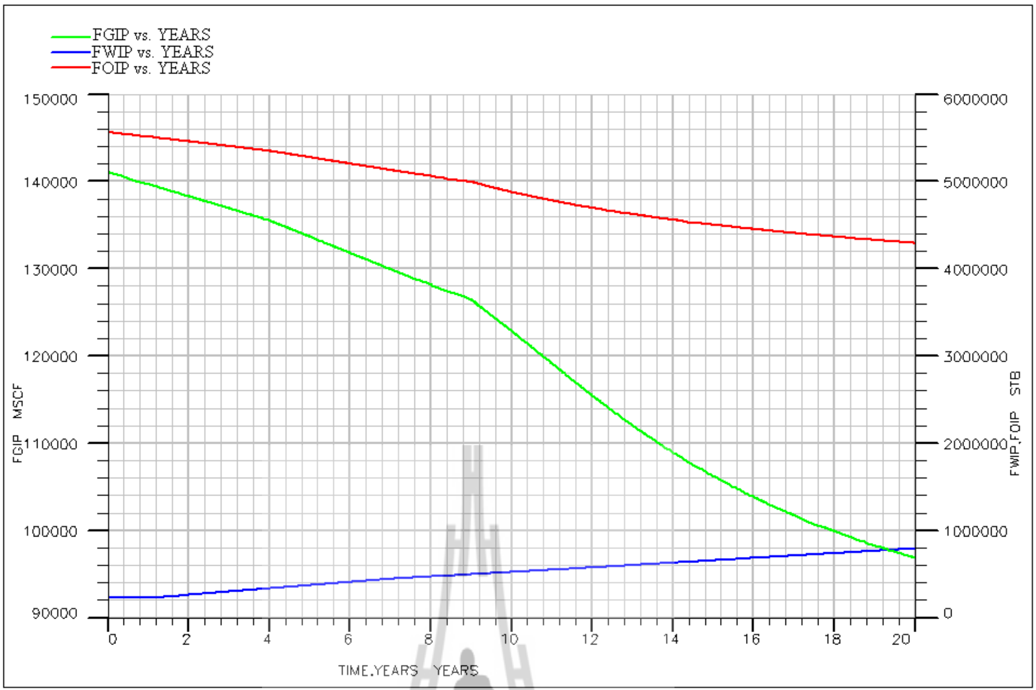

Figure 4.7 Fluids in place profiles vs. time of model inj100_case1.

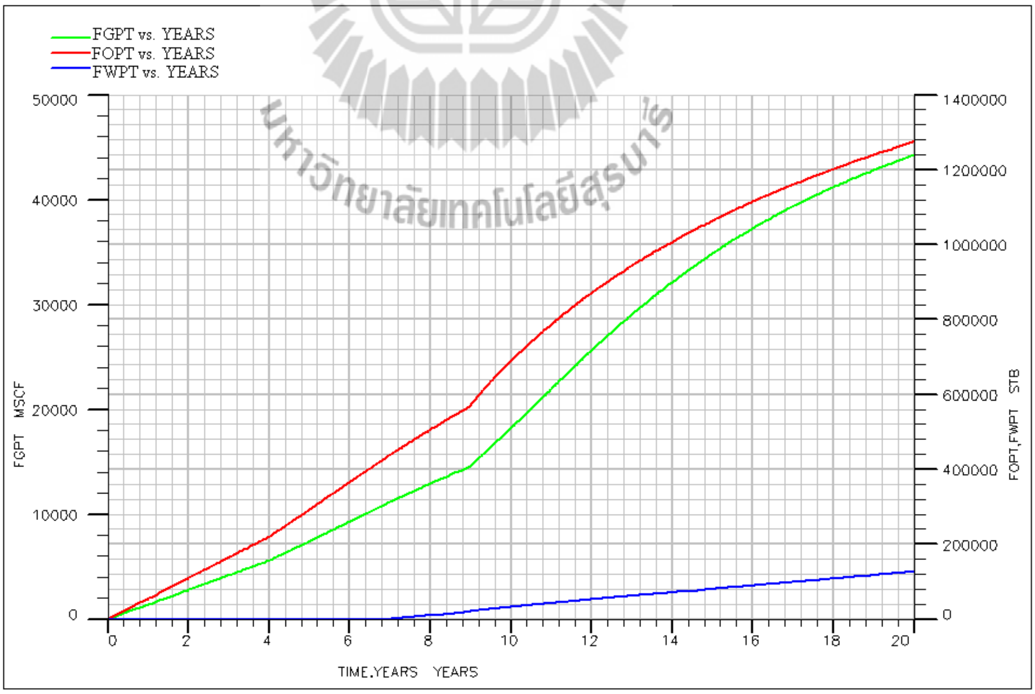

Figure 4.8 Cumulative fluids production profiles vs. time of model inj100_case1.

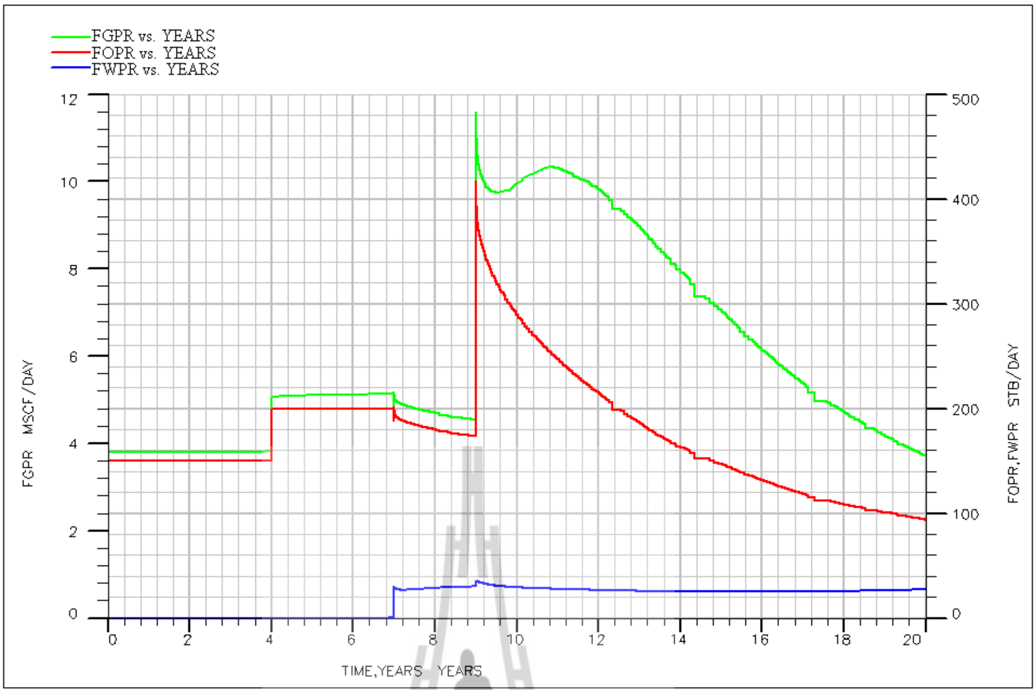

Figure 4.9 Fluids production rate profiles vs. time of model inj100_case1.

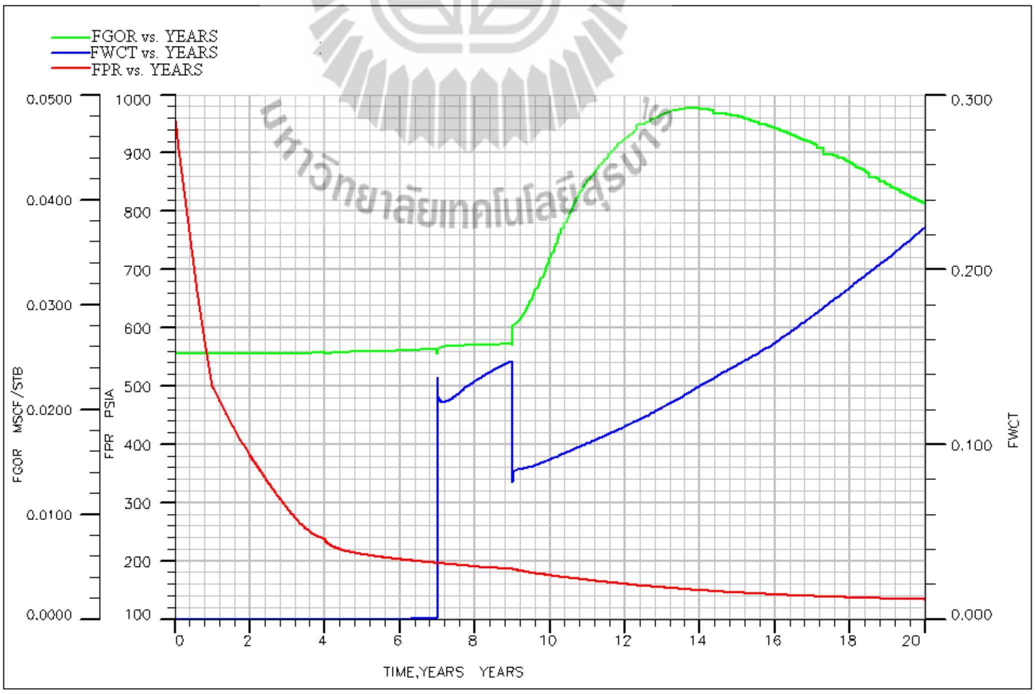

Figure 4.10 GOR, Water cut, and Pressure vs. time of model inj100_case1.

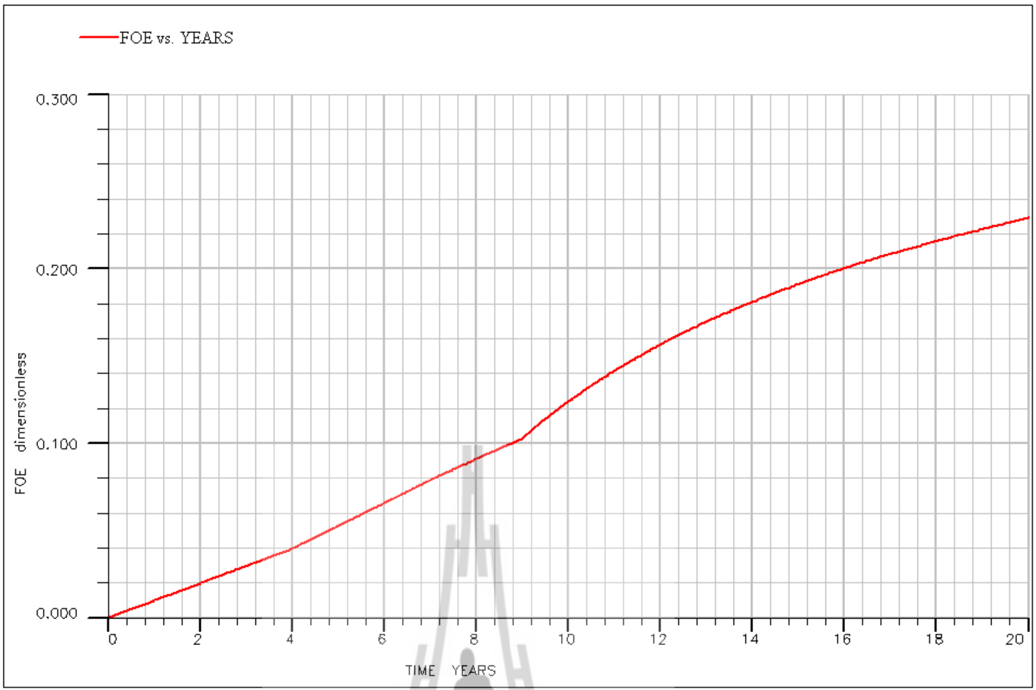

Figure 4.11 Recovery efficiency of oil vs. time of model inj100_case1.

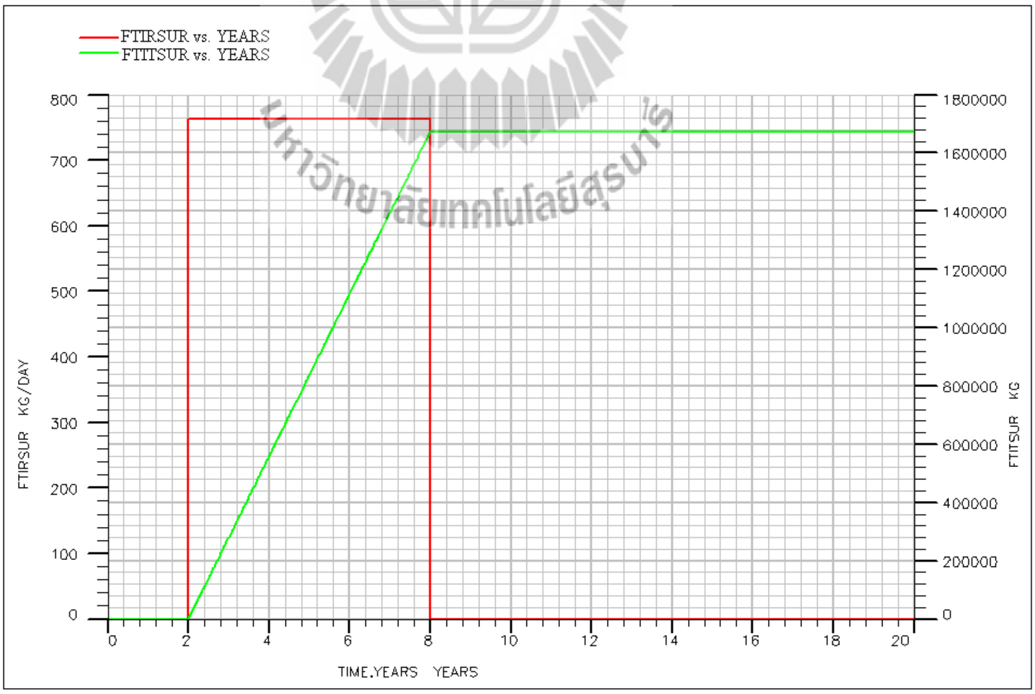

Figure 4.12 FTITSUR and FTIRSUR profiles vs. time of model inj100_case1.

4.3.3 Model inj100_case2 results

Model inj100_case2 is the surfactant flood at the injection rate 100 bbl/day with 10% by volume concentration and the simulation results are showed in figure 4.13 through figure 4.18.

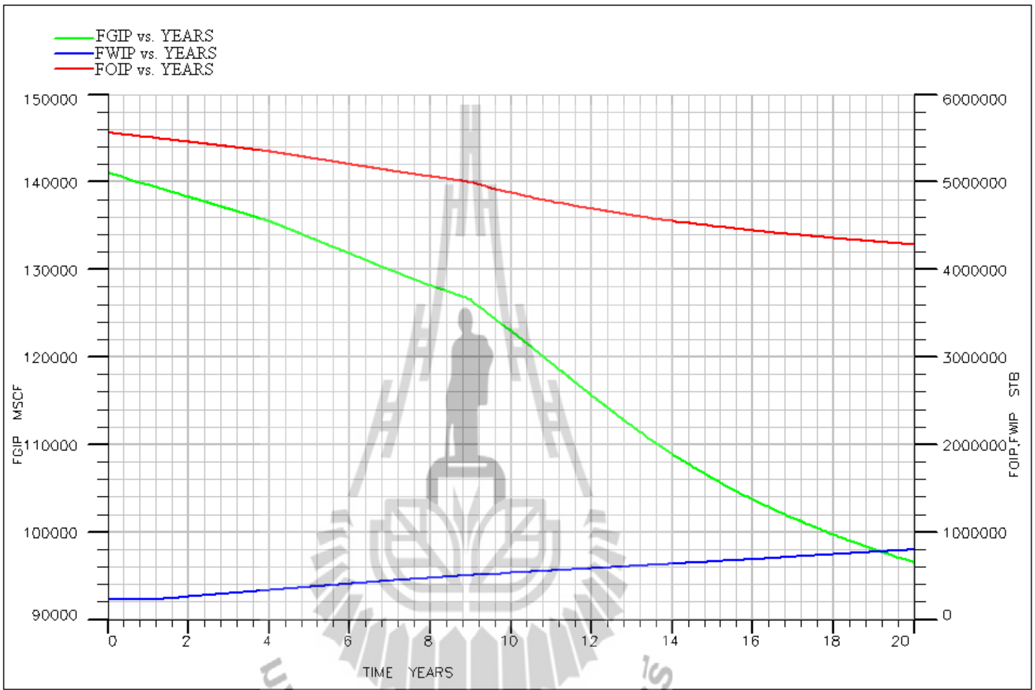

Figure 4.13 Fluids in place profiles vs. time of model inj100_case2.

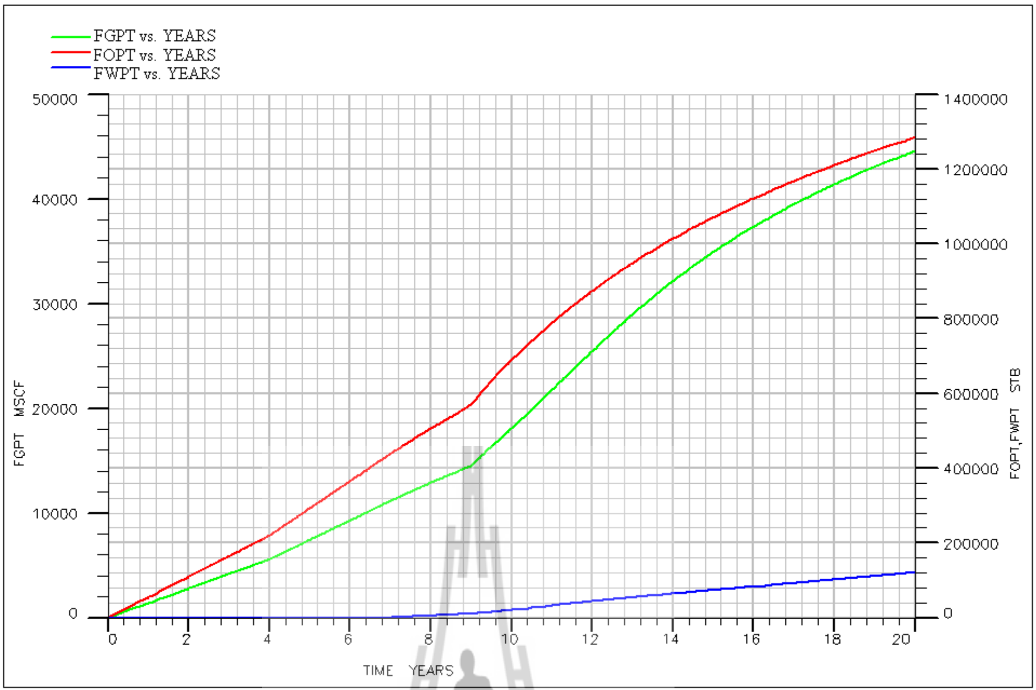

Figure 4.14 Cumulative fluids production profiles vs. time of model inj100_case2.

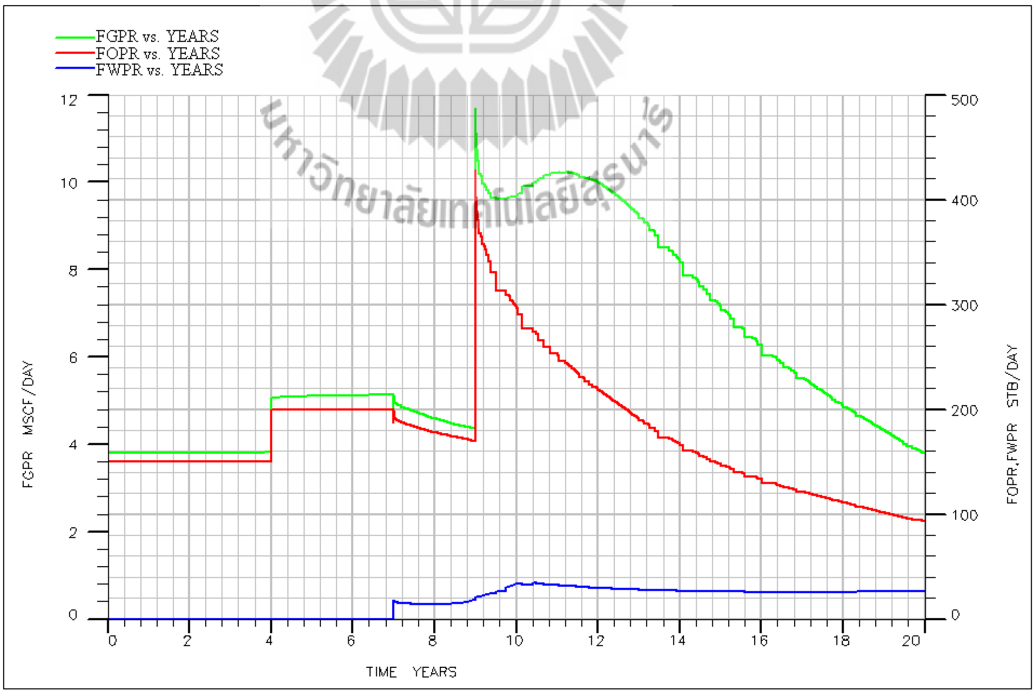

Figure 4.15 Fluids production rate profiles vs. time of model inj100_case2.

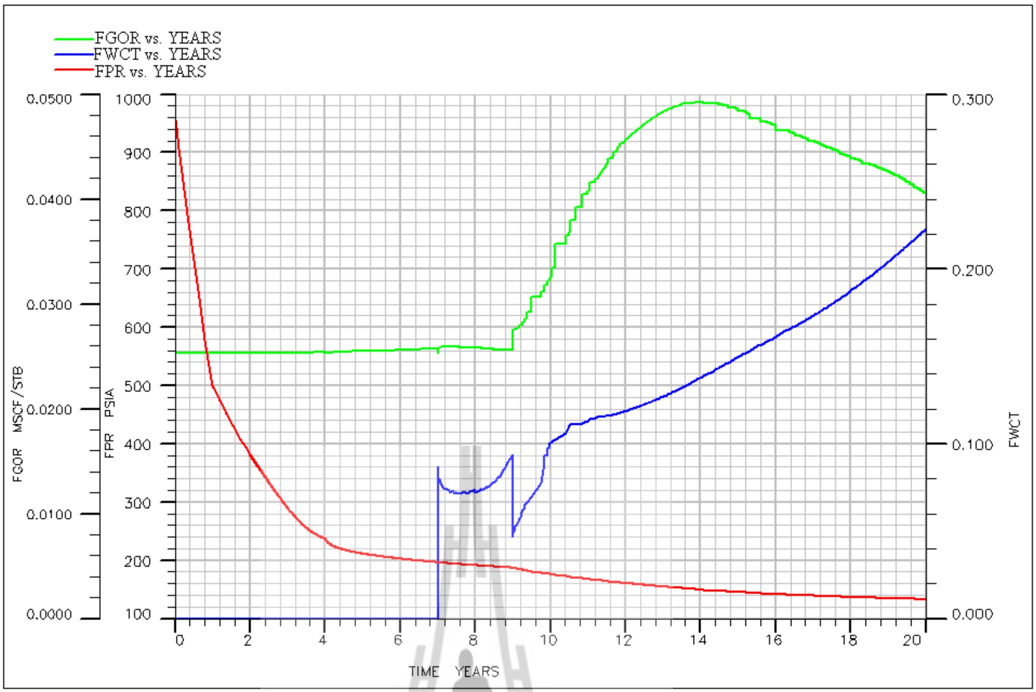

Figure 4.16 GOR, Water cut, and Pressure vs. time of model inj100_case2.

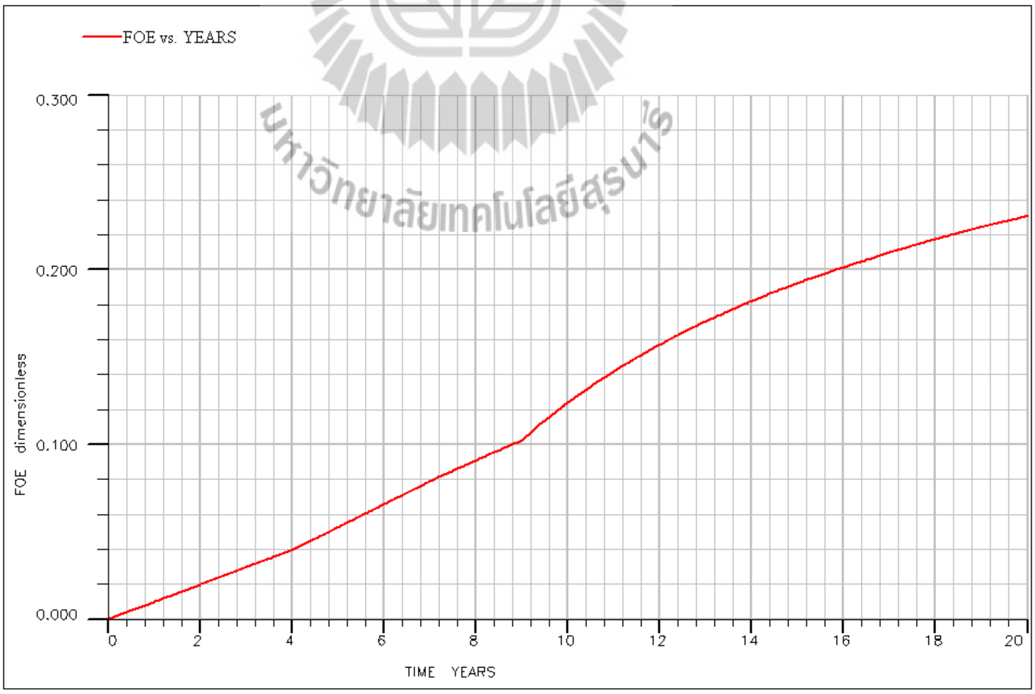

Figure 4.17 Recovery efficiency of oil vs. time of model inj100_case2.

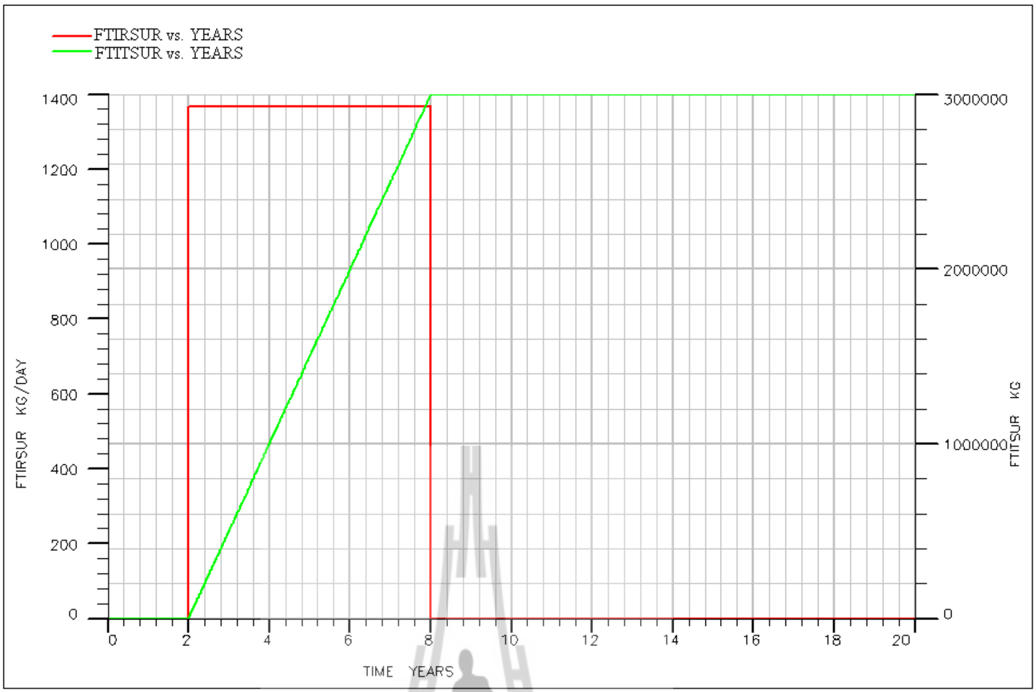

Figure 4.18 FTITSUR and FTIRSUR profiles vs. time of model inj100_case2.

4.3.4 Model inj100_case3 results

Model inj100_case3 is the surfactant flood at the injection rate 100 bbl/day with 15% by volume concentration and the simulation results are showed in figure 4.19 through figure 4.24.

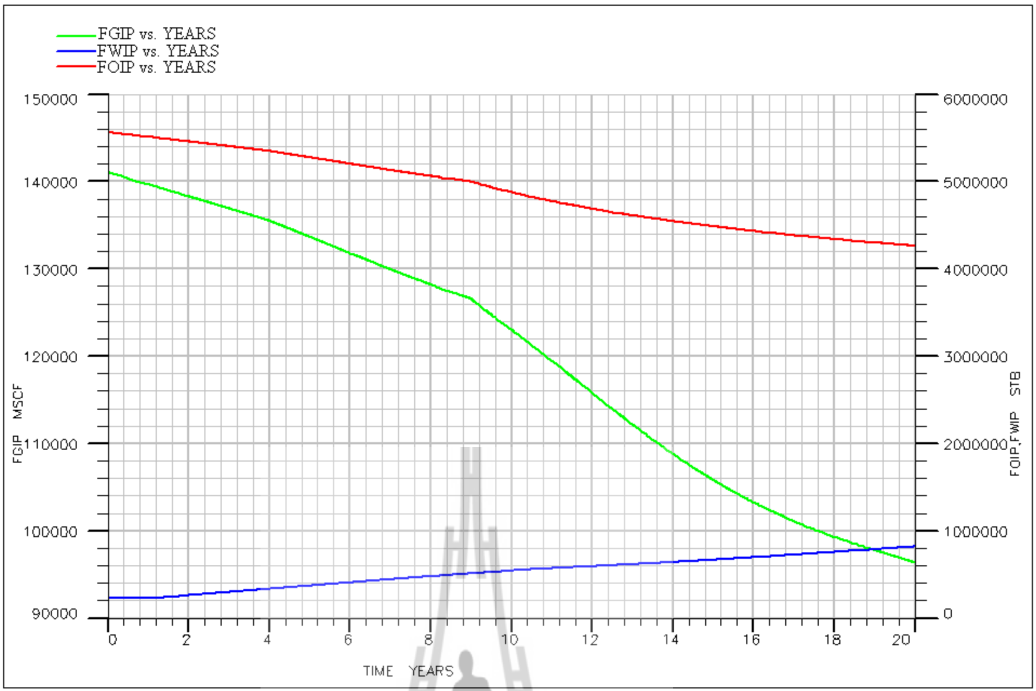

Figure 4.19 Fluids in place profiles vs. time of model inj100_case3.

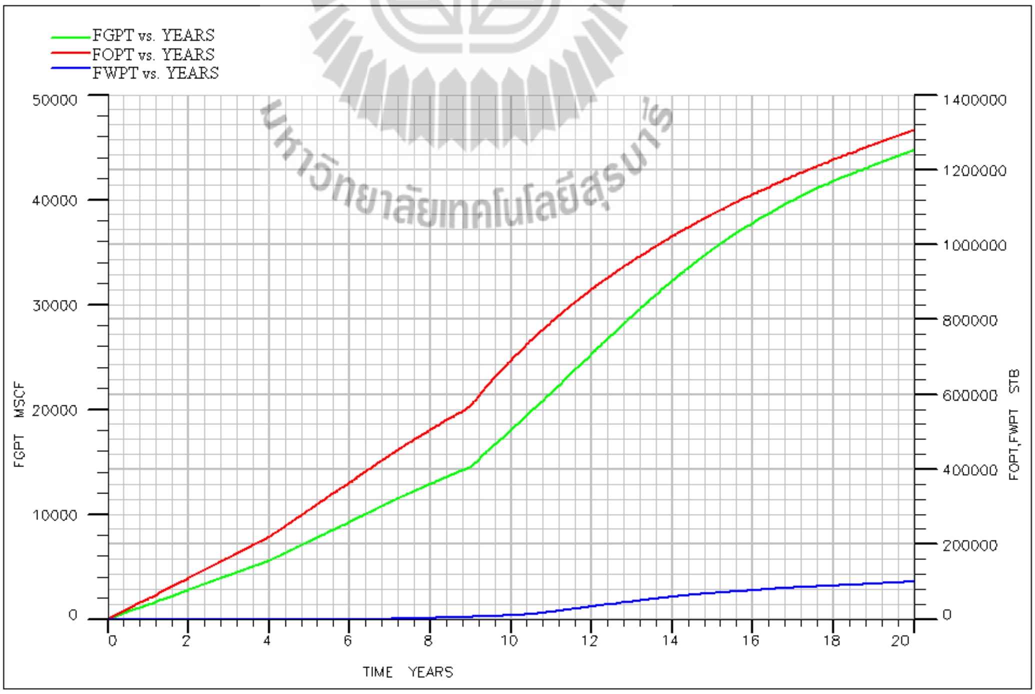

Figure 4.20 Cumulative fluids production profiles vs. time of model inj100_case3.

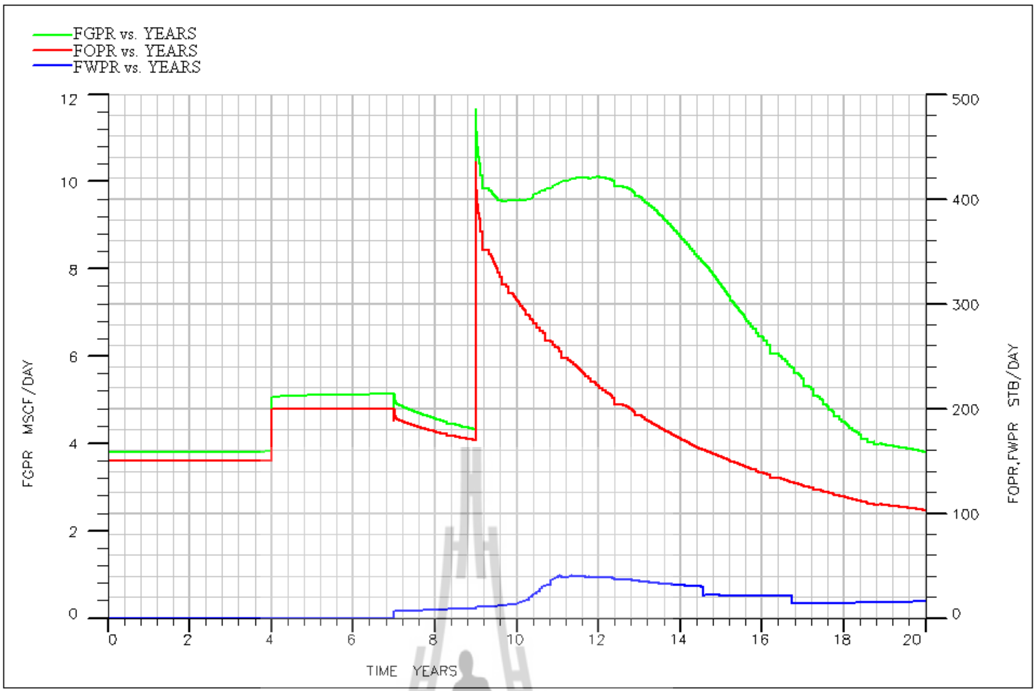

Figure 4.21 Fluids production rate profiles vs. time of model inj100_case3.

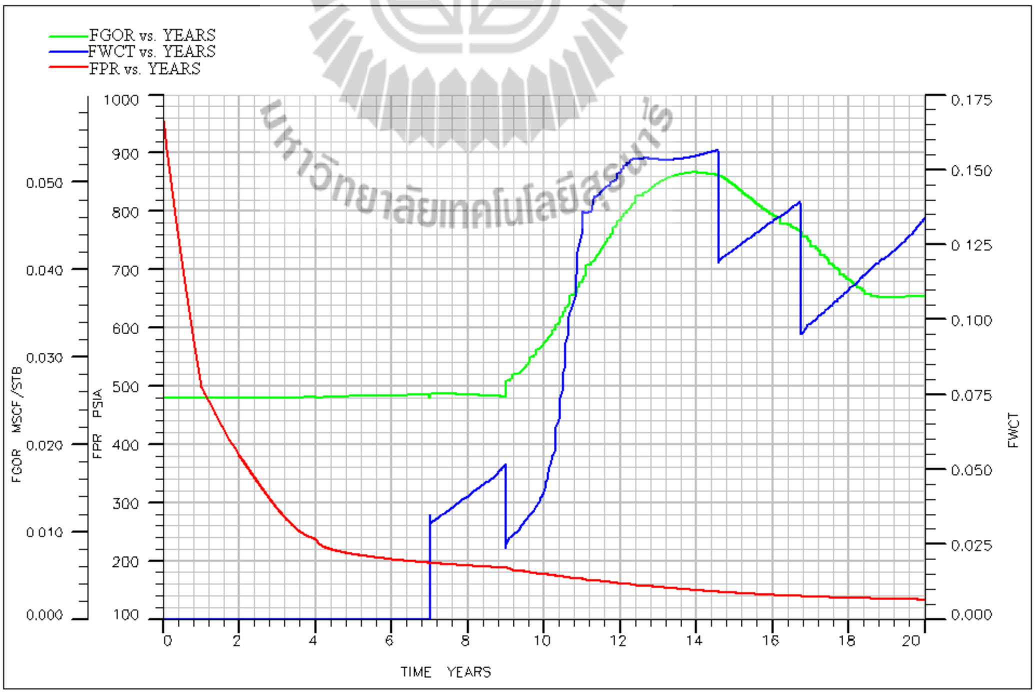

Figure 4.22 GOR, Water cut, and Pressure vs. time of model inj100_case3.

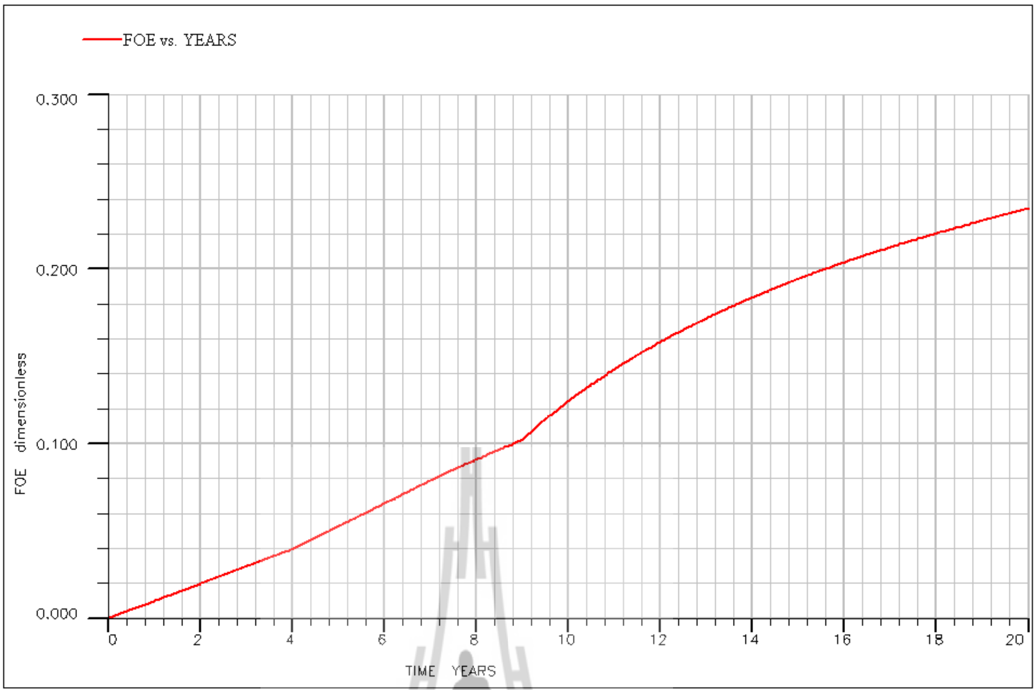

Figure 4.23 Recovery efficiency of oil vs. time of model inj100_case3.

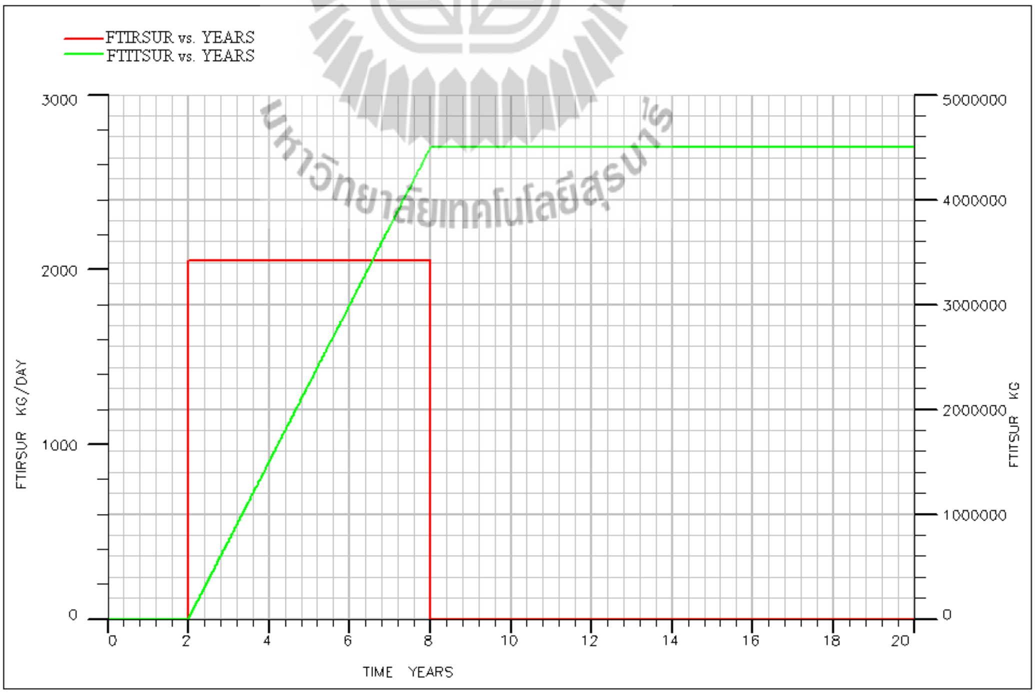

Figure 4.24 FTITSUR and FTIRSUR profiles vs. time of model inj100_case3**.**

4.3.5 Model inj200_case1 results

Model inj200_case1 is the surfactant flood at the injection rate 200 bbl/day with 5% by volume concentration and the simulation results are showed in figure 4.25 through figure 4.30.

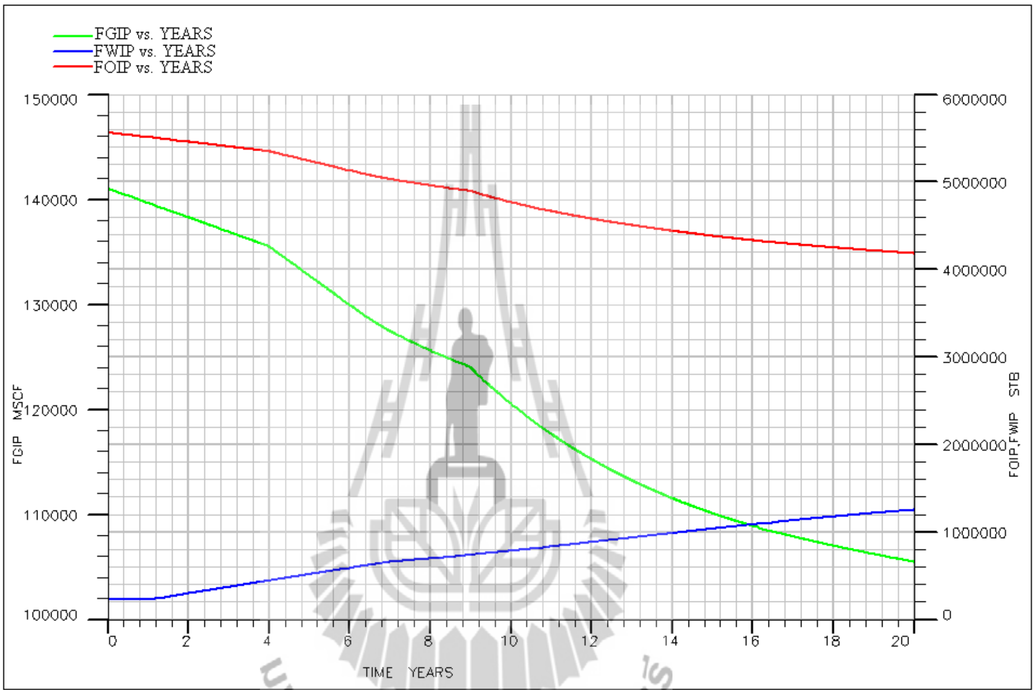

Figure 4.25 Fluids in place profiles vs. time of model inj200_case1.

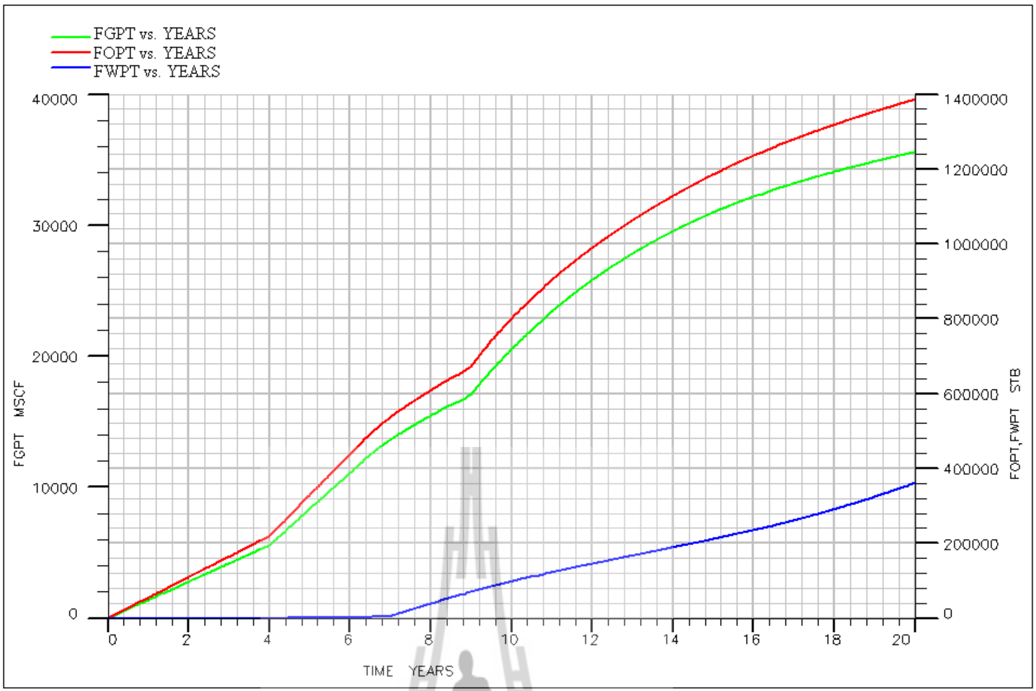

Figure 4.26 Cumulative fluids production profiles vs. time of model inj200_case1.

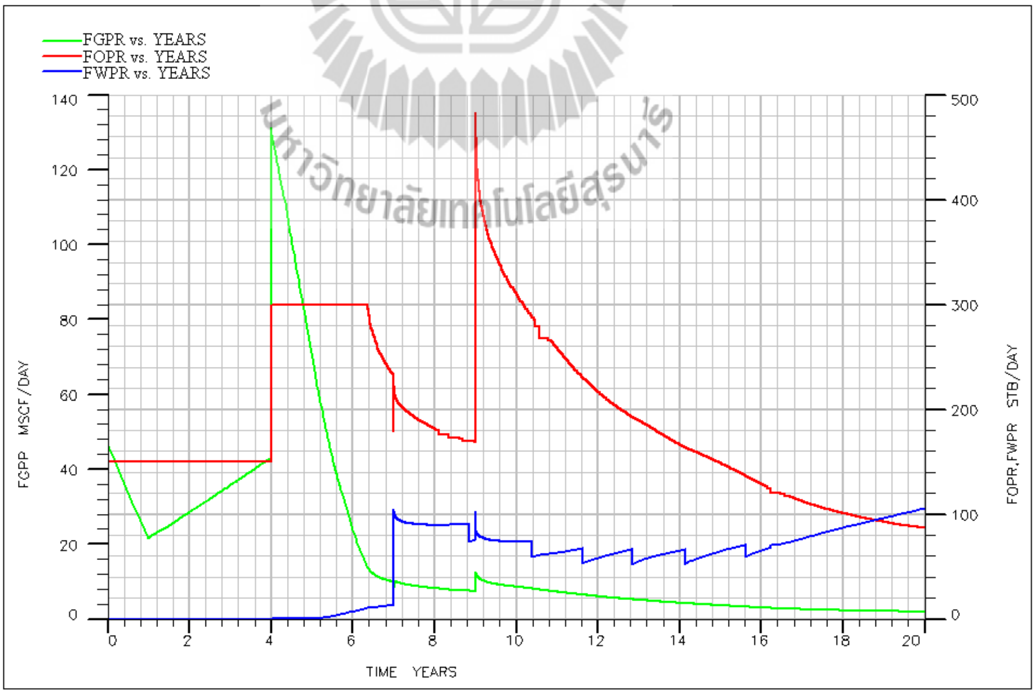

Figure 4.27 Fluids production rate profiles vs. time of model inj200_case1.

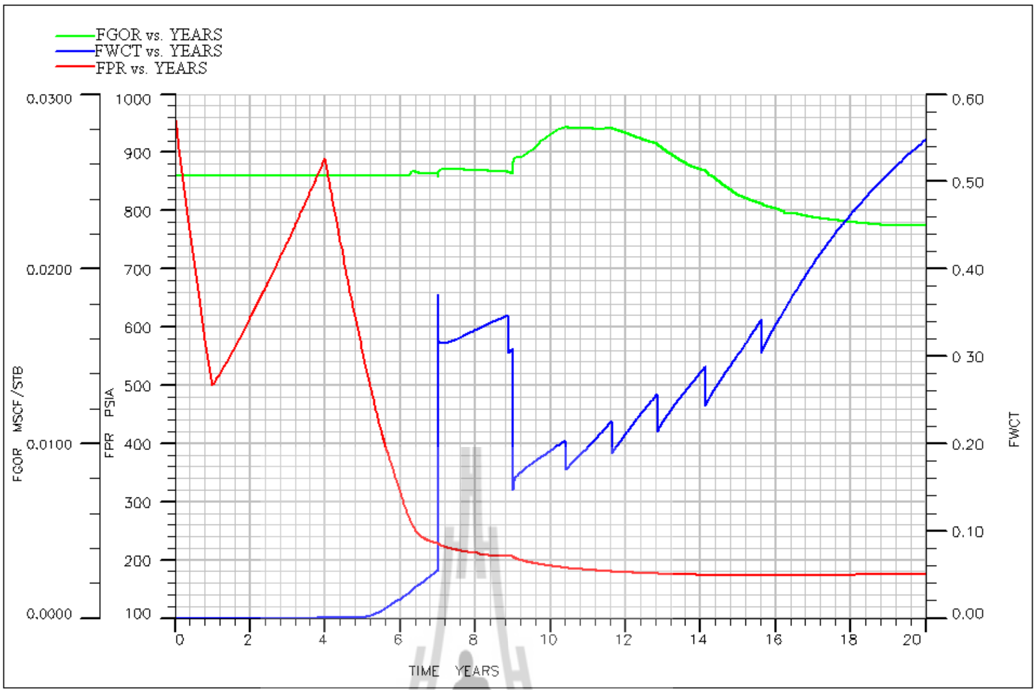

Figure 4.28 GOR, Water cut, and Pressure vs. time of model inj200_case1.

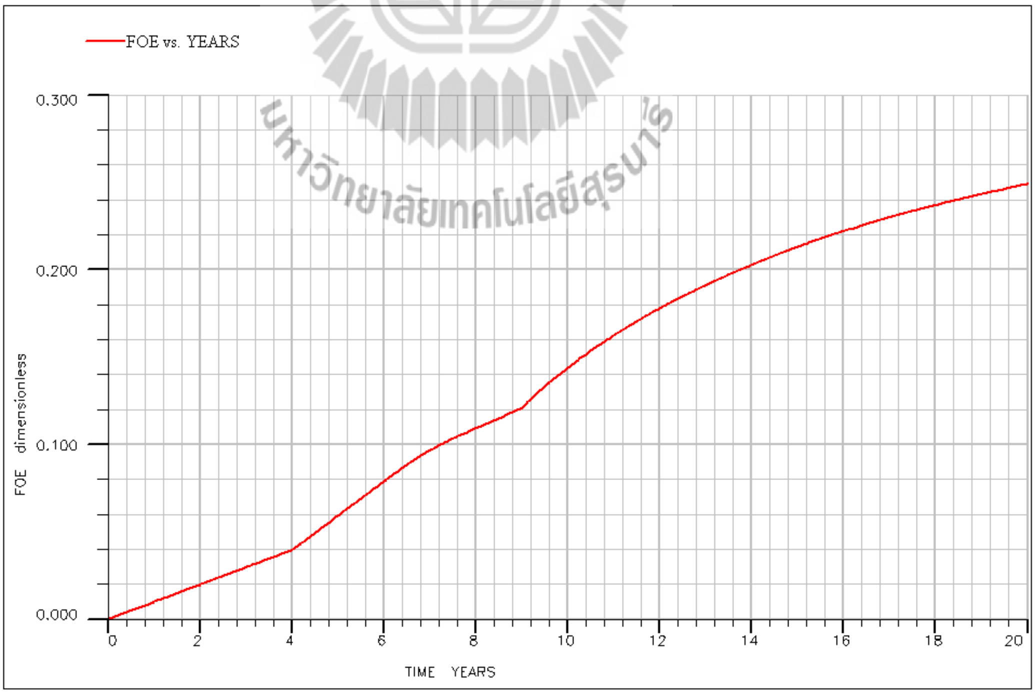

Figure 4.29 Recovery efficiency of oil vs. time of model inj200_case1.

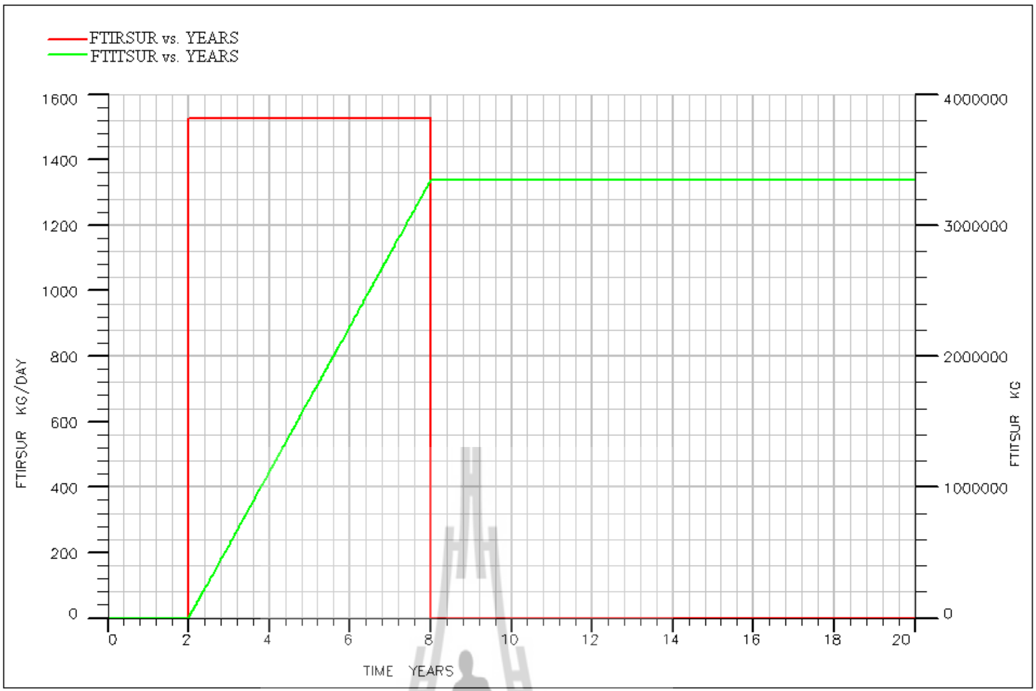

Figure 4.30 FTITSUR and FTIRSUR profiles vs. time of model inj200_case1.

4.3.6 Model inj200_case2 results

Model inj200_case2 is the surfactant flood at the injection rate 200 bbl/day with 10% by volume concentration and the simulation results are showed in figure 4.31 through figure 4.36.

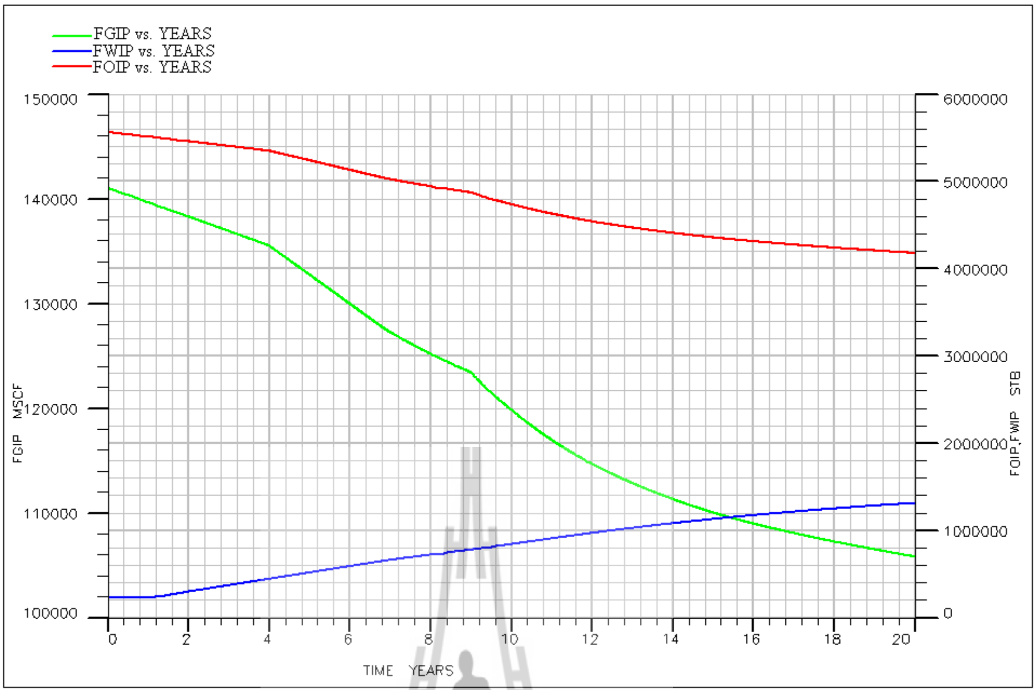

Figure 4.31 Fluids in place profiles vs. time of model inj200_case2.

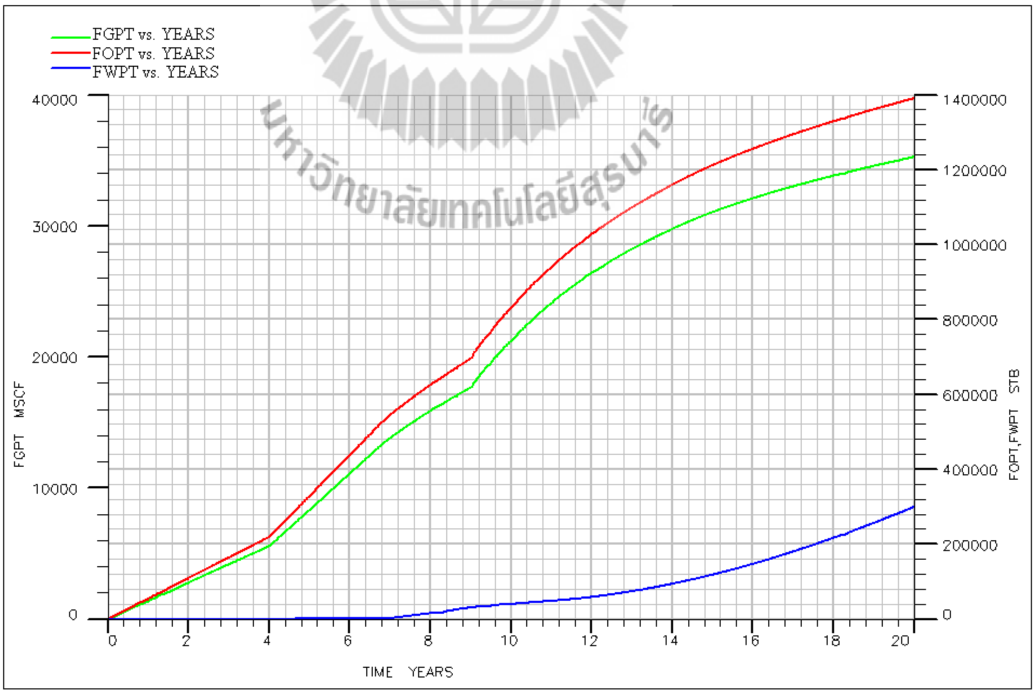

Figure 4.32 Cumulative fluids production profiles vs. time of model inj200_case2.

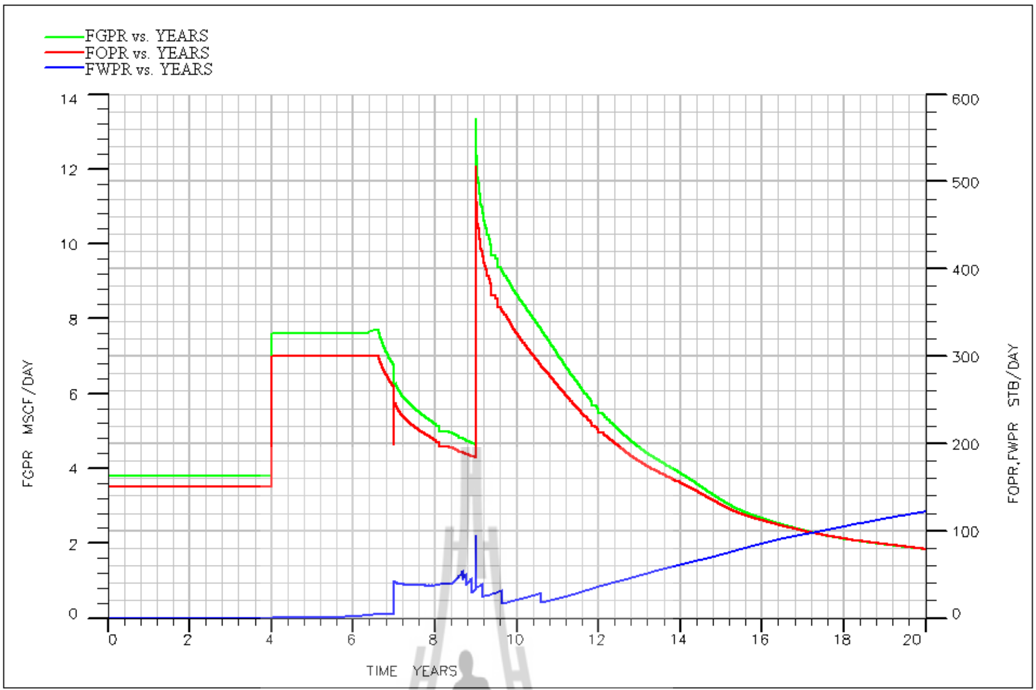

Figure 4.33 Fluids production rate profiles vs. time of model inj200_case2.

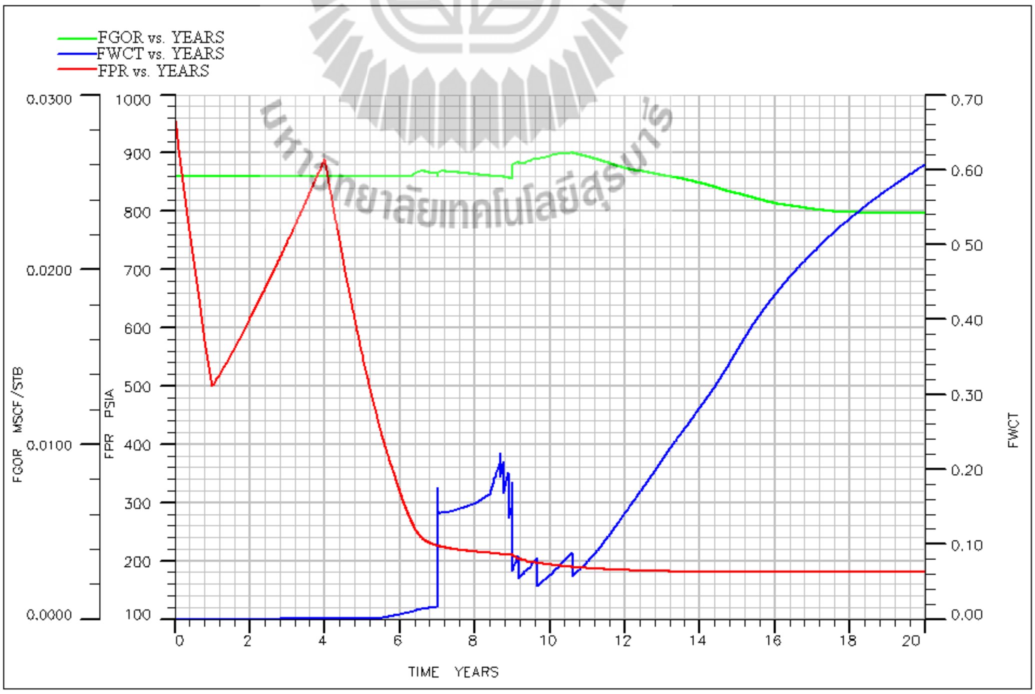

Figure 4.34 GOR, Water cut, and Pressure vs. time of model inj200_case2.

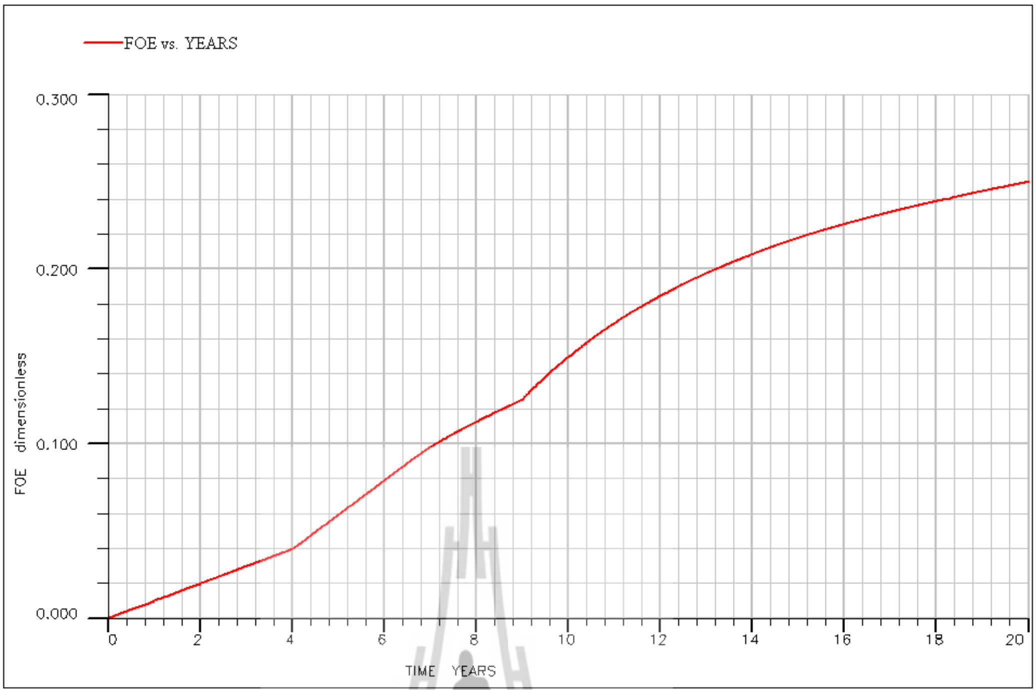

Figure 4.35 Recovery efficiency of oil vs. time of model inj200_case2.

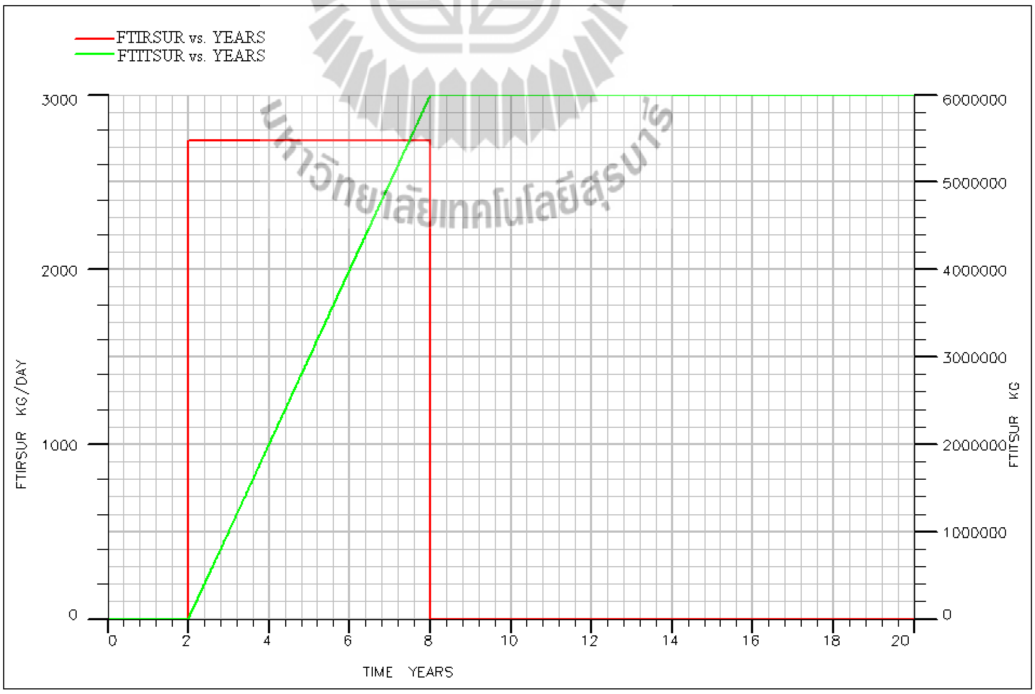

Figure 4.36 FTITSUR and FTIRSUR profiles vs. time of model inj200_case2.

4.3.7 Model inj200_case3 results

Model inj200_case3 is the surfactant flood at the injection rate 200 bbl/day with 15% by volume concentration and the simulation results are showed in figure 4.37 through figure 4.42.

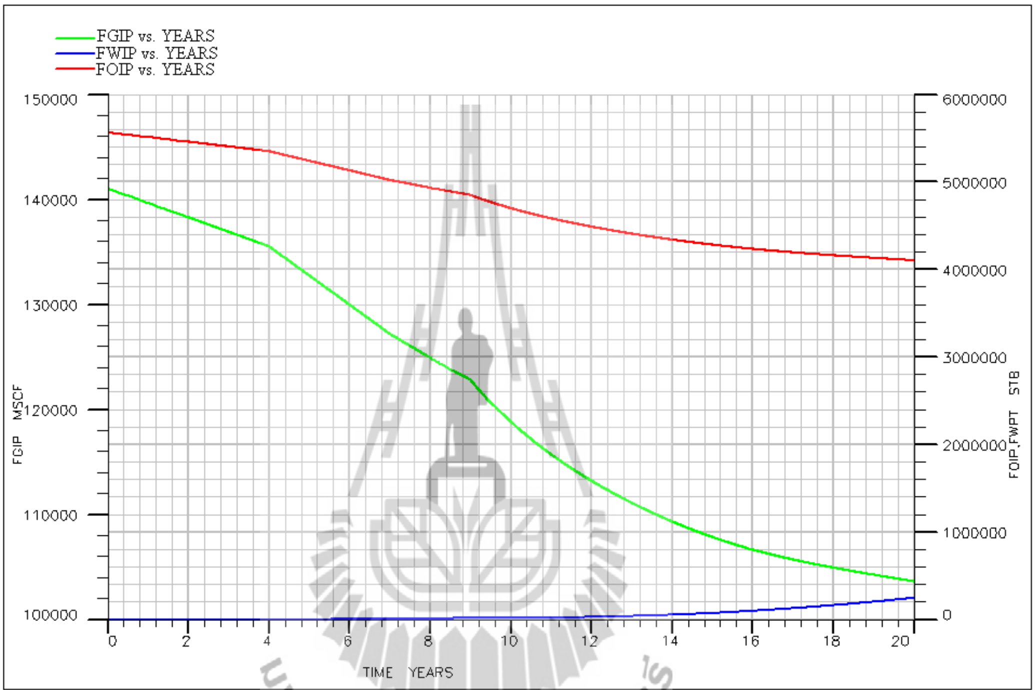

Figure 4.37 Fluids in place profiles vs. time of model inj200_case3.

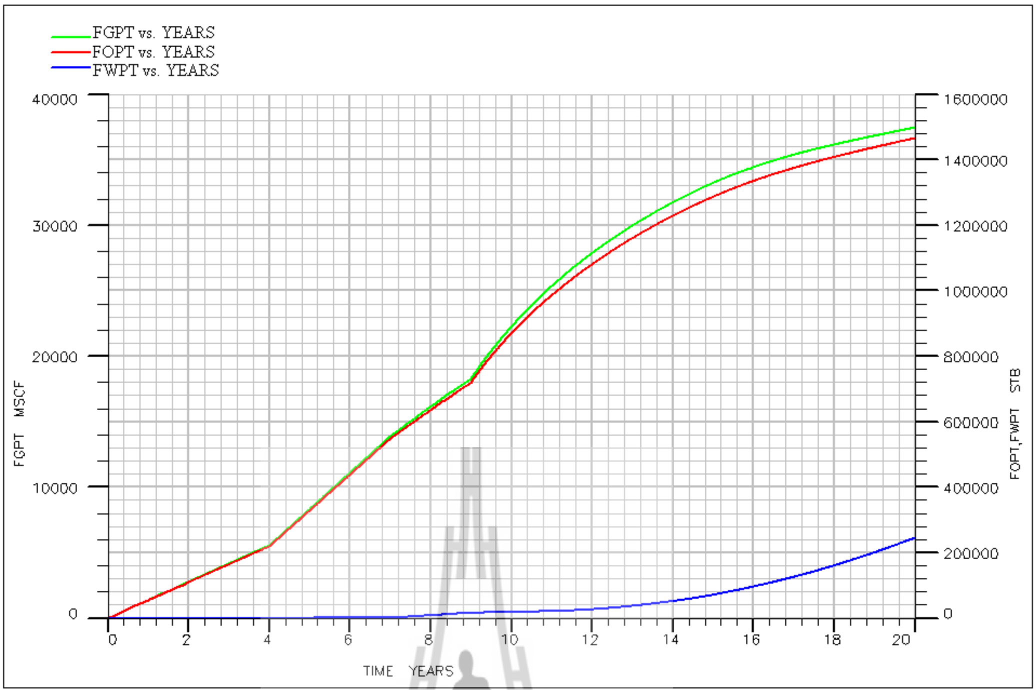

Figure 4.38 Cumulative fluids production profiles vs. time of model inj200_case3.

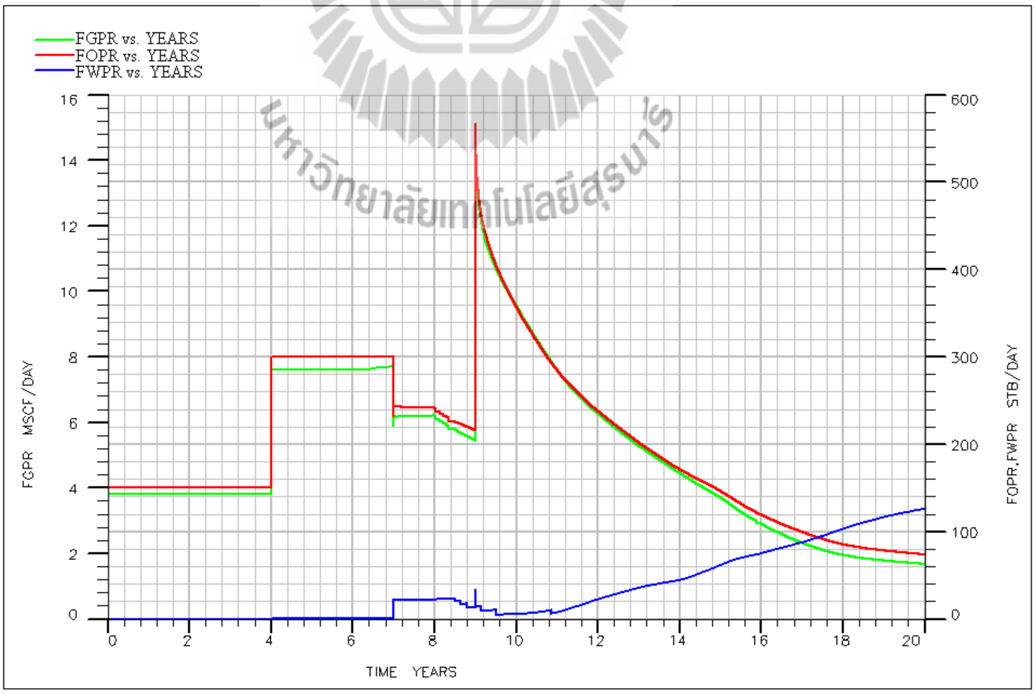

Figure 4.39 Fluids production rate profiles vs. time of model inj200_case3.

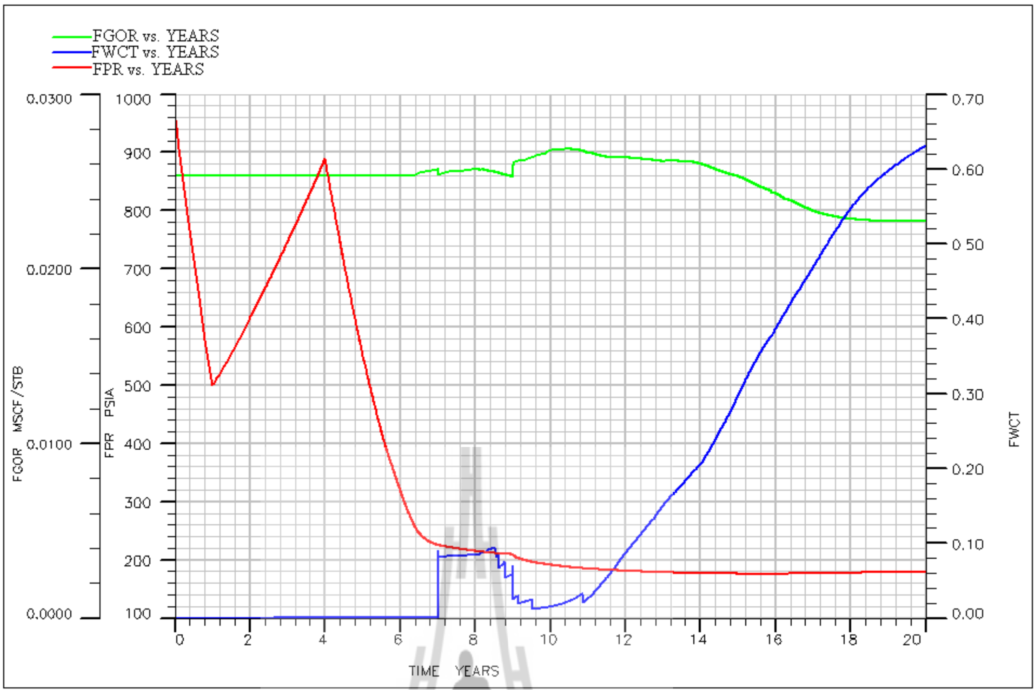

Figure 4.40 GOR, Water cut, and Pressure vs. time of model inj200_case3.

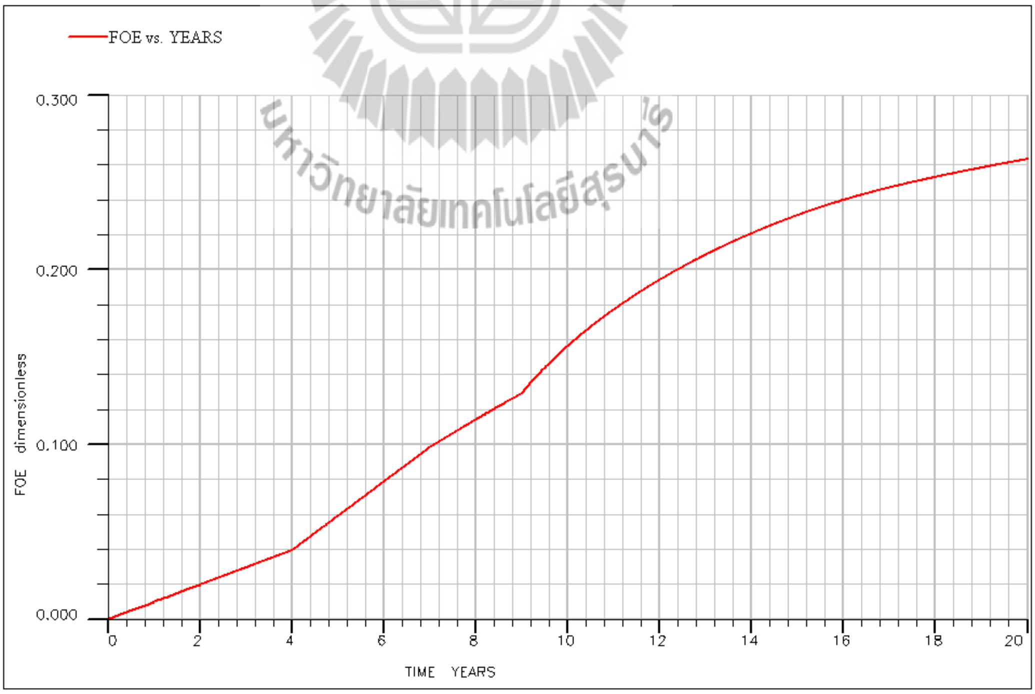

Figure 4.41 Recovery efficiency of oil vs. time of model inj200_case3.

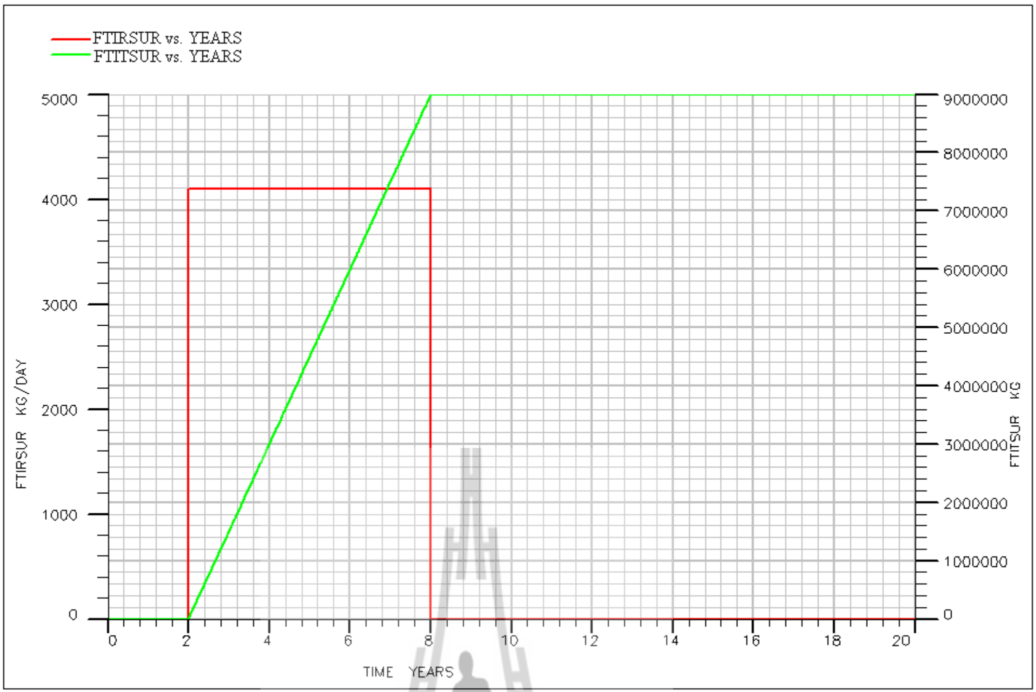

Figure 4.42 FTITSUR and FTIRSUR profiles vs. time of model inj200_case3.

4.3.8 Model inj300_case1 results

Model inj300_case1 is the surfactant flood at the injection rate 300 bbl/day with 5% by volume concentration and the simulation results are showed in figure 4.43 through figure 4.48.

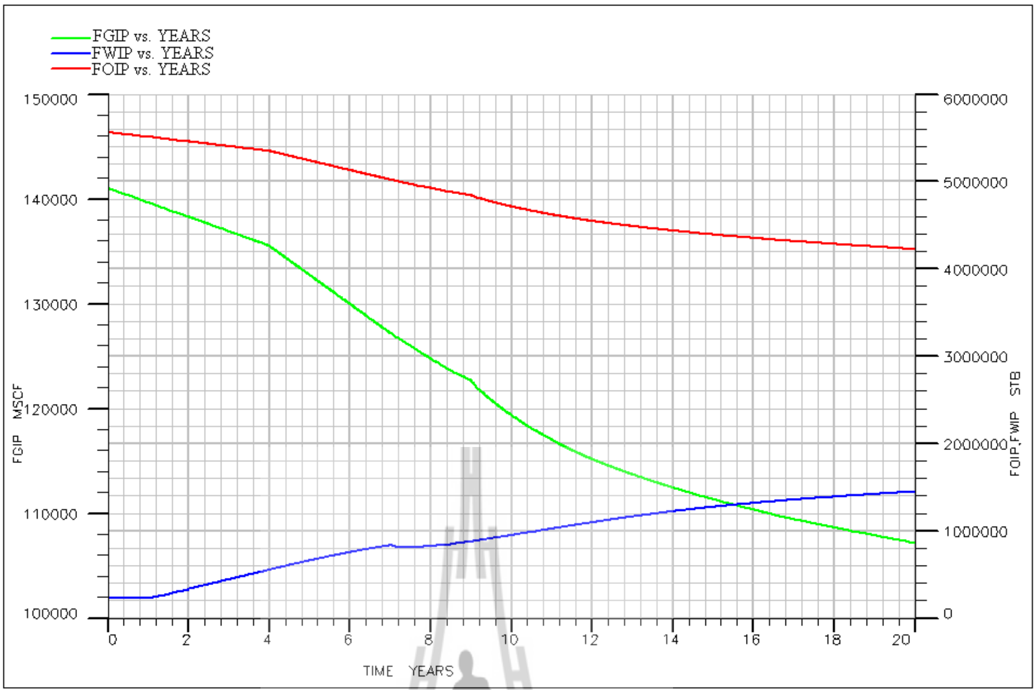

Figure 4.43 Fluids in place profiles vs. time of model inj300_case1.

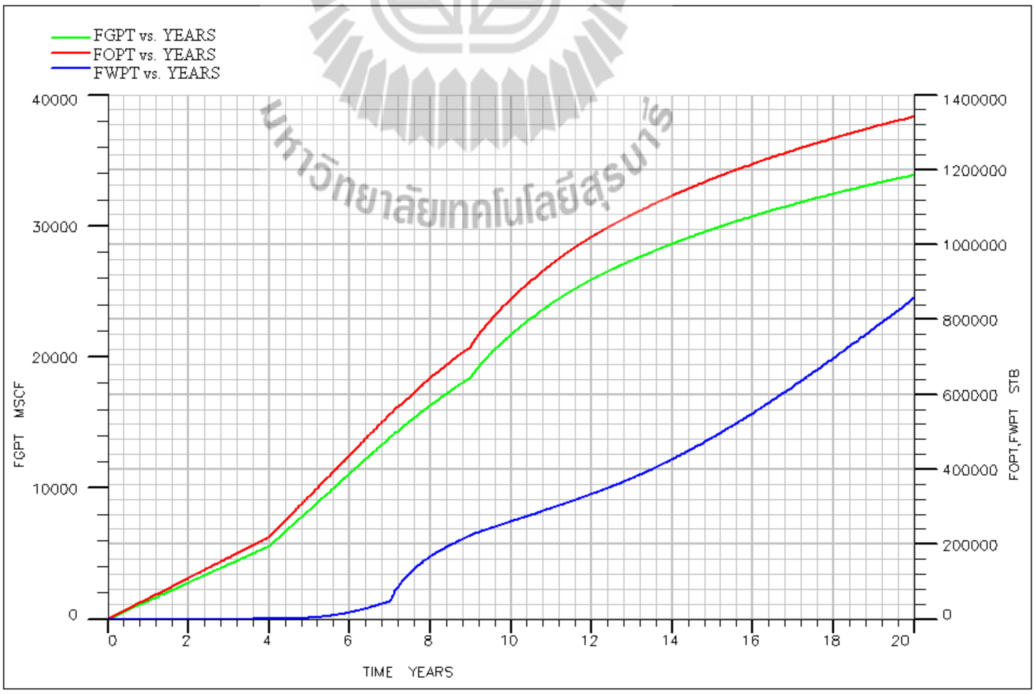

Figure 4.44 Cumulative fluids production profiles vs. time of model inj300_case1.

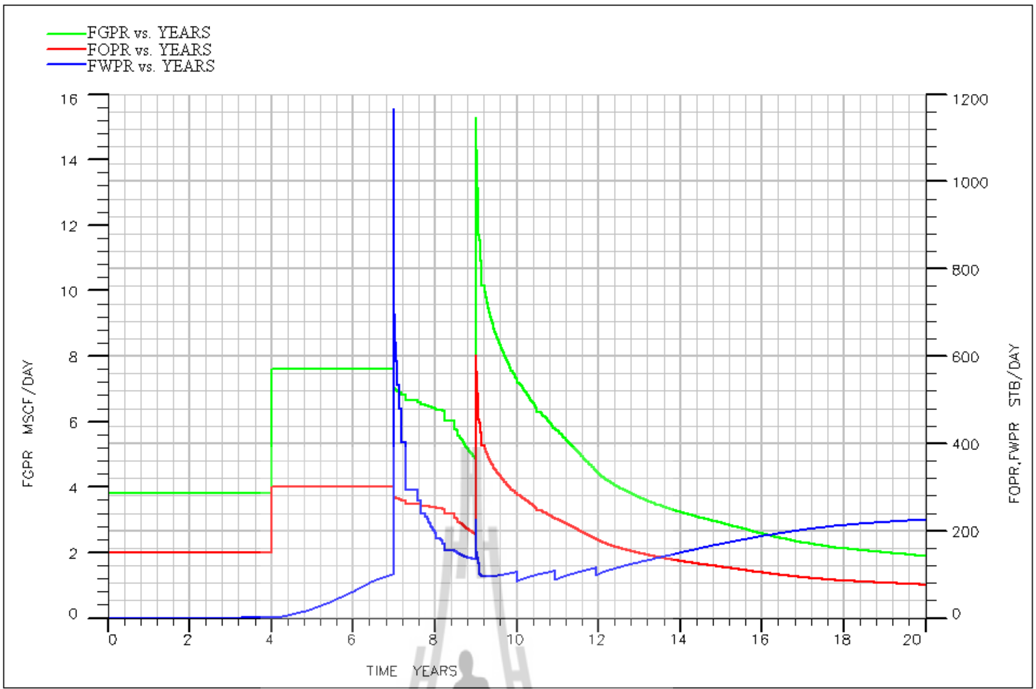

Figure 4.45 Fluids production rate profiles vs. time of model inj300_case1.

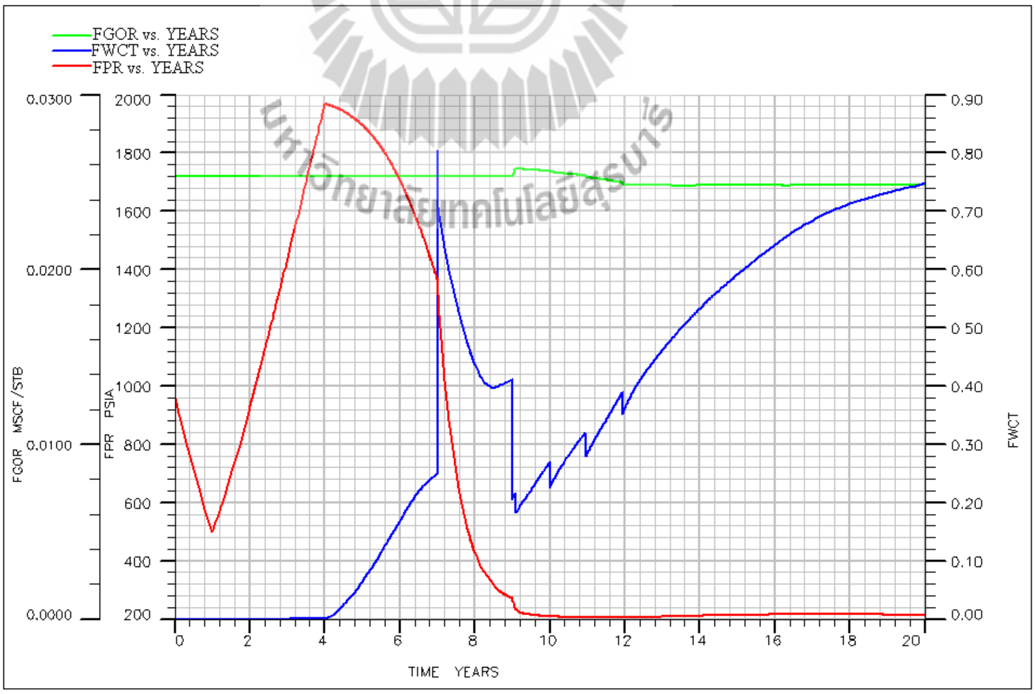

Figure 4.46 GOR, Water cut, and Pressure vs. time of model inj300_case1.

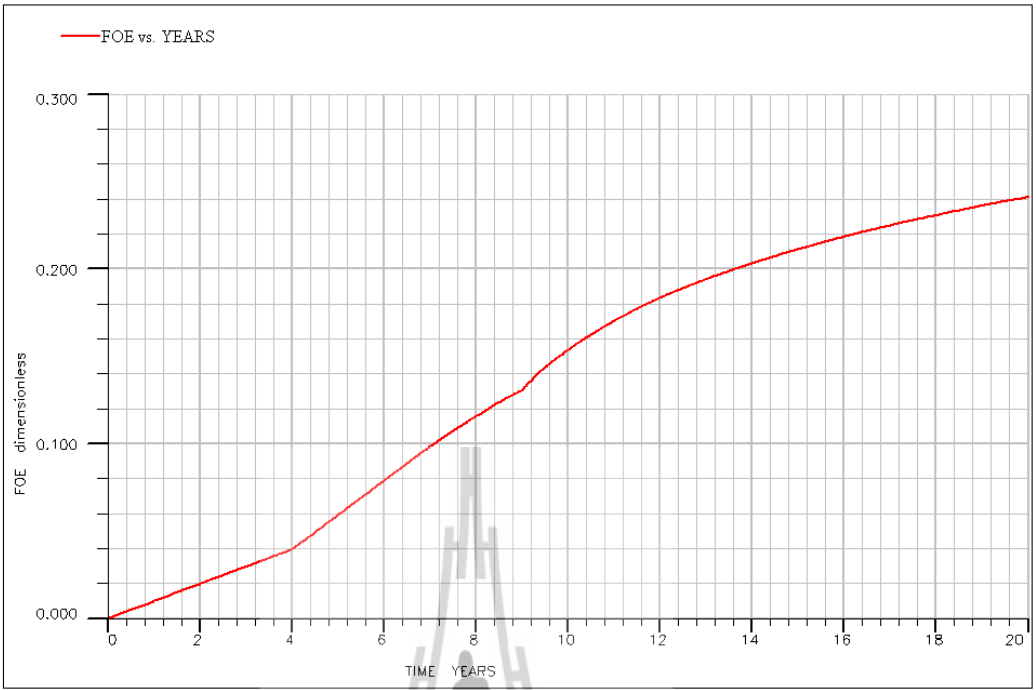

Figure 4.47 Recovery efficiency of oil vs. time of model inj300_case1.

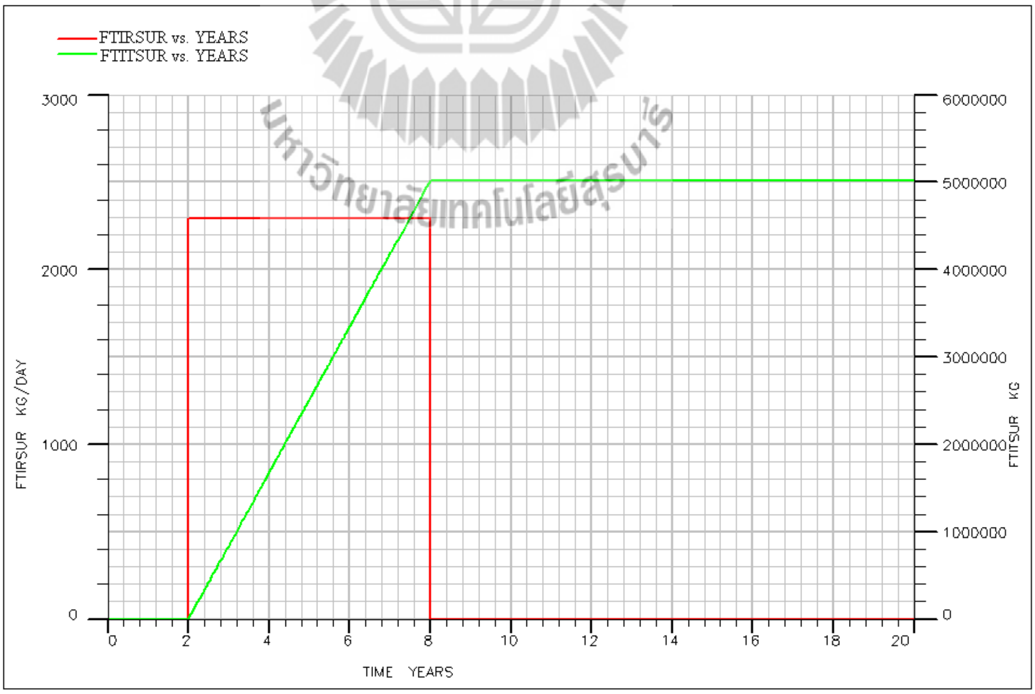

Figure 4.48 FTITSUR and FTIRSUR profiles vs. time of model inj300_case1.

4.3.9 Model inj300_case2 results

Model inj300_case2 is the surfactant flood at the injection rate 300 bbl/day with 10% by volume concentration and the simulation results are showed in figure 4.49 through figure 4.55.

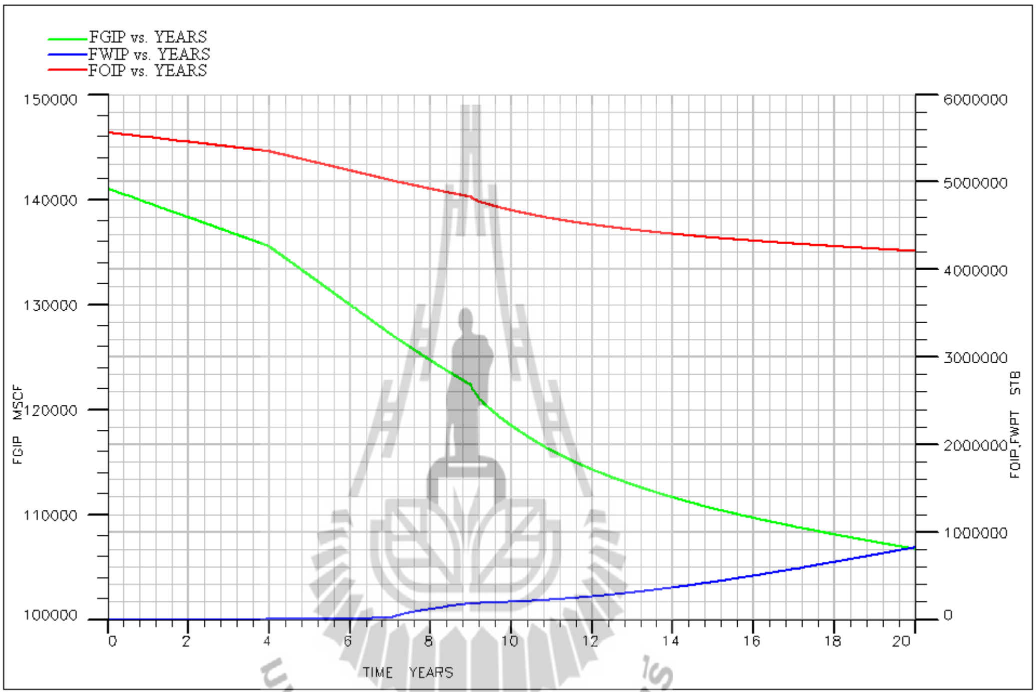

Figure 4.49 Fluids in place profiles vs. time of model inj300_case2.

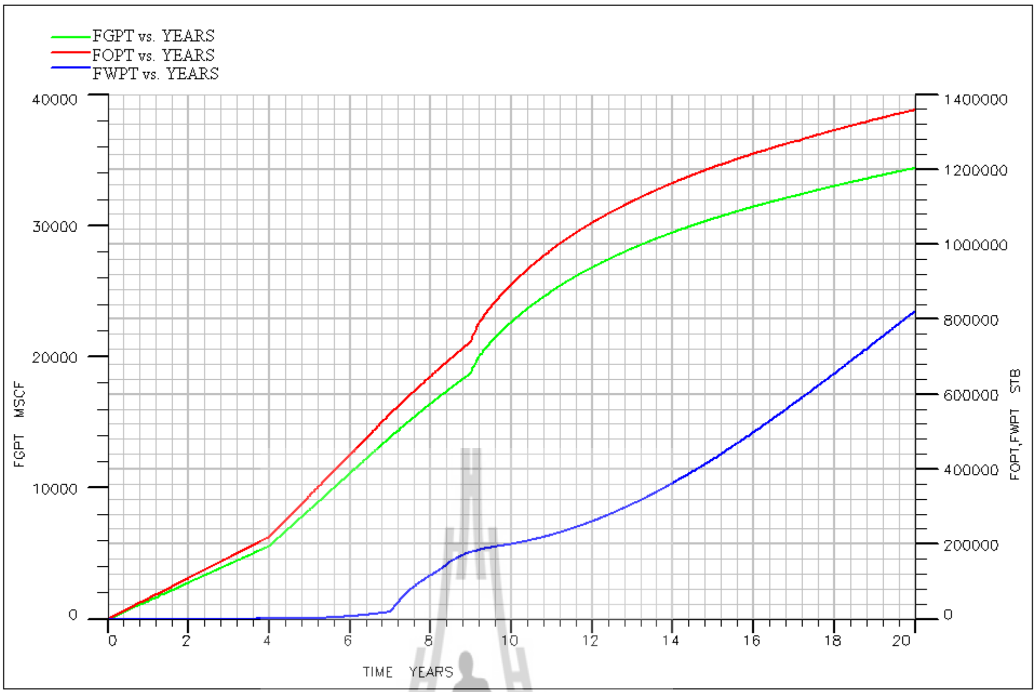

Figure 4.50 Cumulative fluids production profiles vs. time of model inj300_case2.

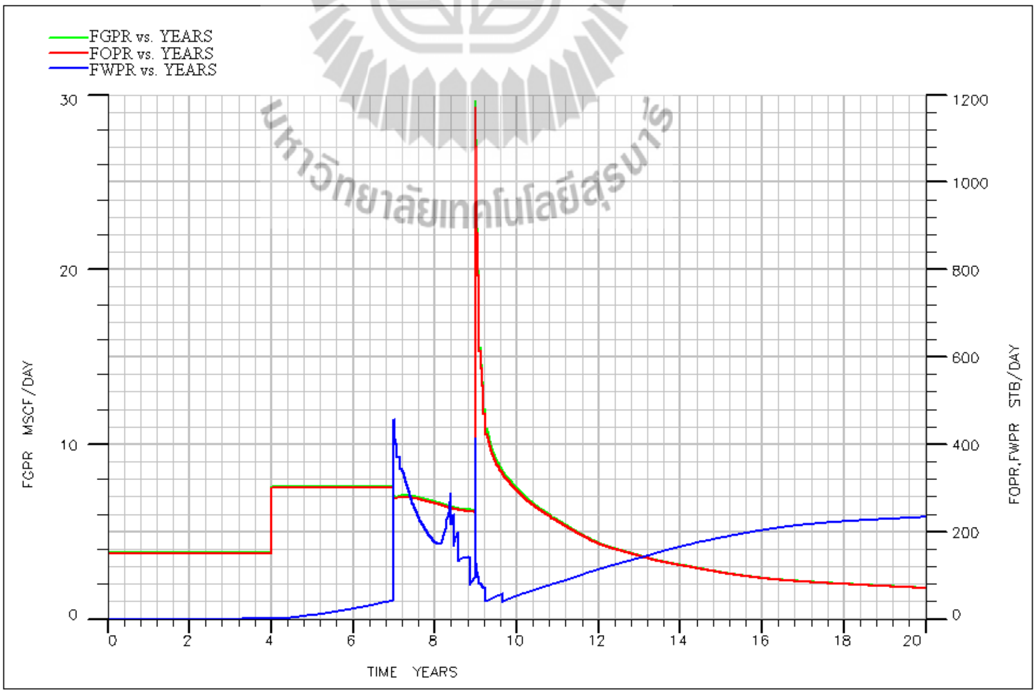

Figure 4.51 Fluids production rate profiles vs. time of model inj300_case2.

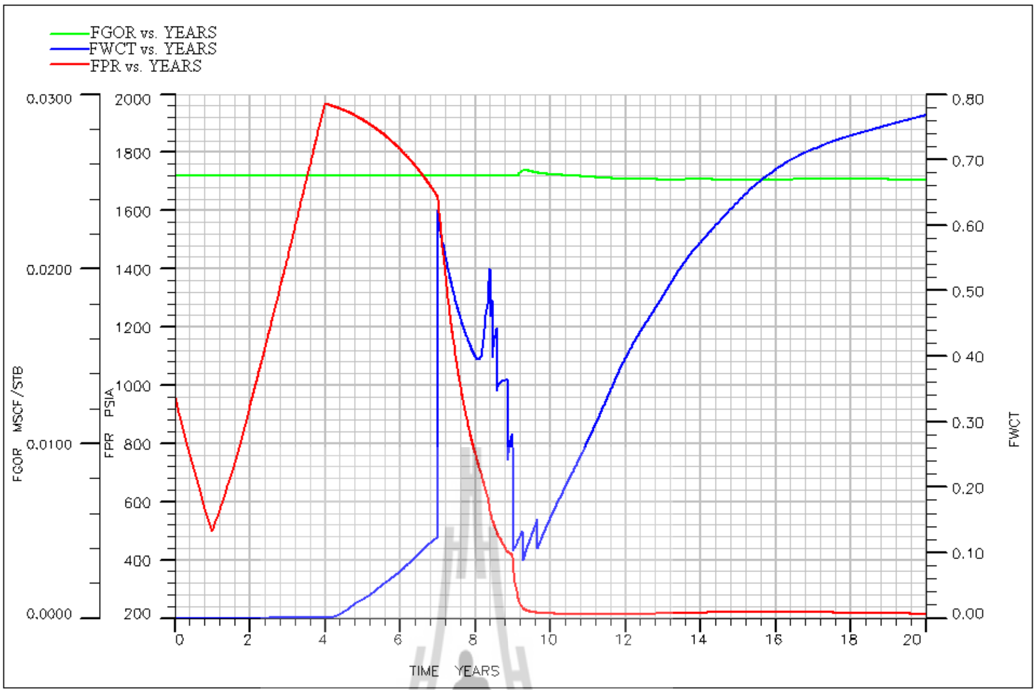

Figure 4.52 GOR, Water cut, and Pressure vs. time of model inj300_case2.

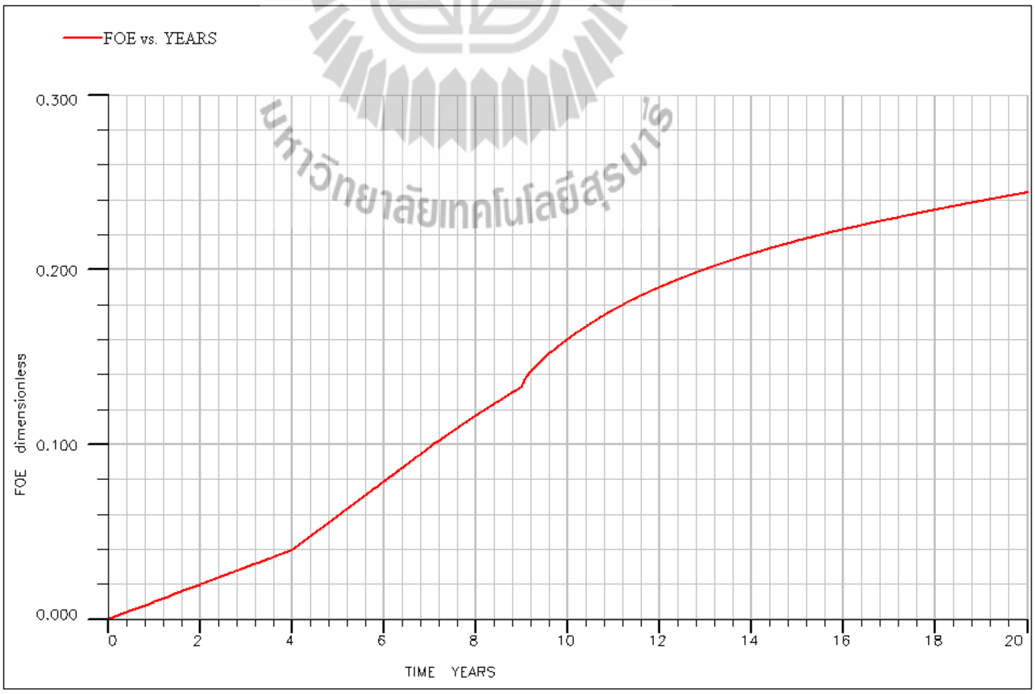

Figure 4.53 Recovery efficiency of oil vs. time of model inj300_case2.

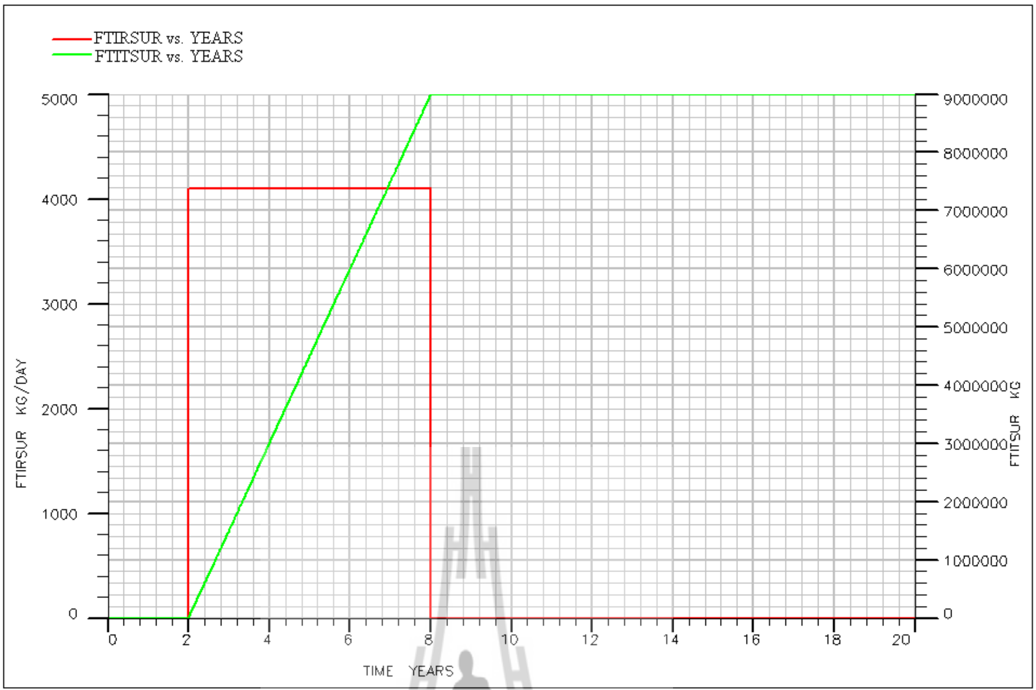

Figure 4.54 FTITSUR and FTIRSUR profiles vs. time of model inj300_case3

4.3.10 Model inj300_case3 results

Model inj300_case3 is the surfactant flood at the injection rate 300 bbl/day with 15% by volume concentration and the simulation results are showed in figure 4.55 through figure 4.60.

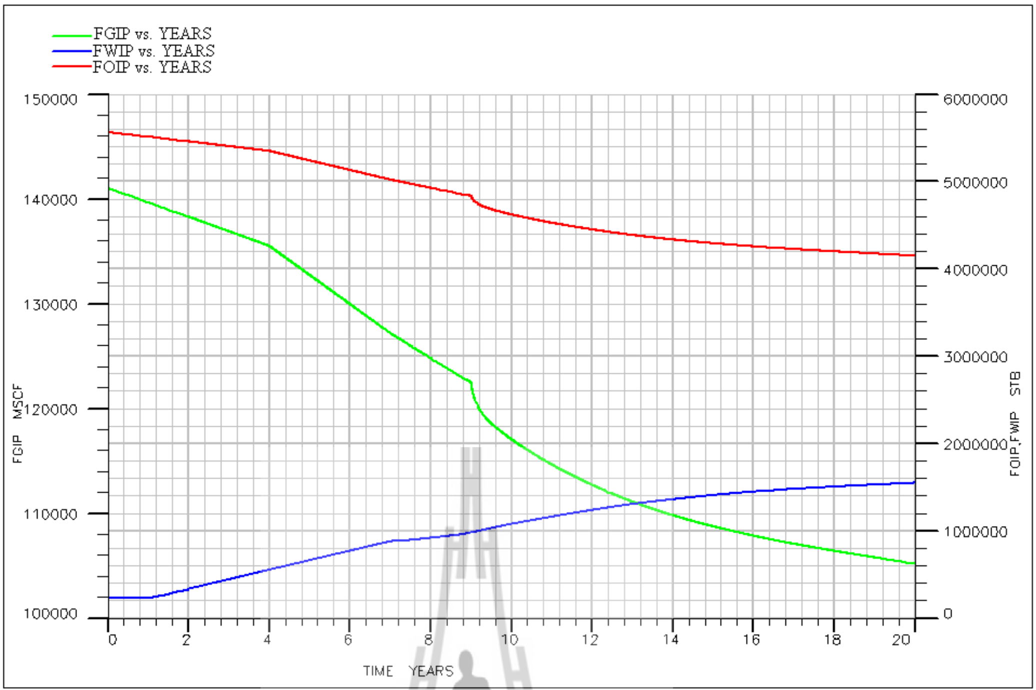

Figure 4.55 Fluids in place profiles vs. time of model inj300_case3.

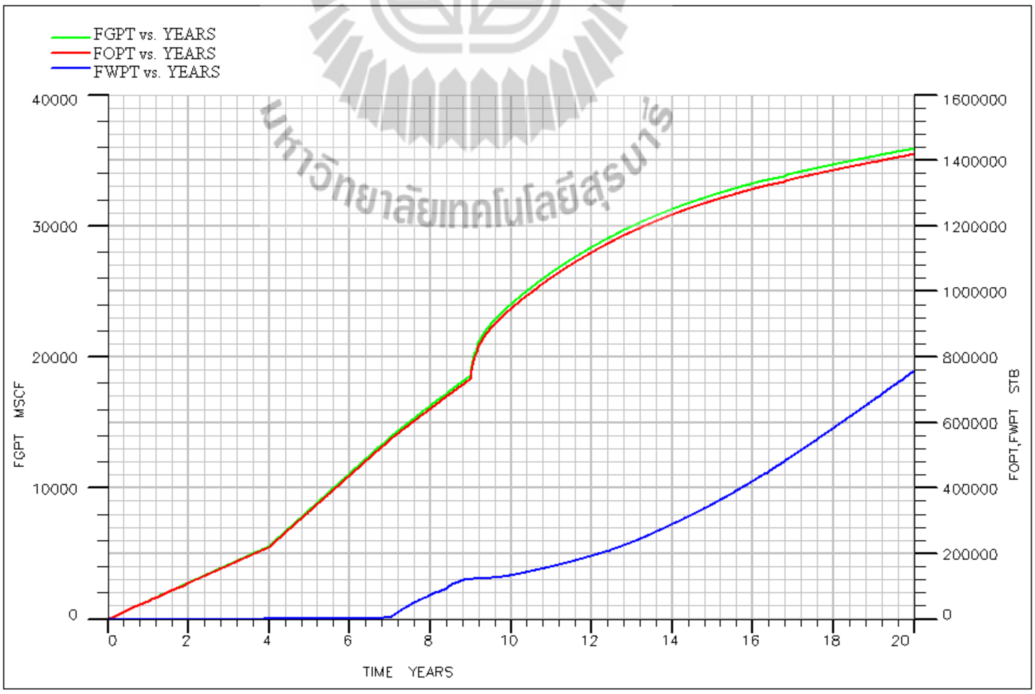

Figure 4.56 Cumulative fluids production profiles vs. time of model inj300_case3.

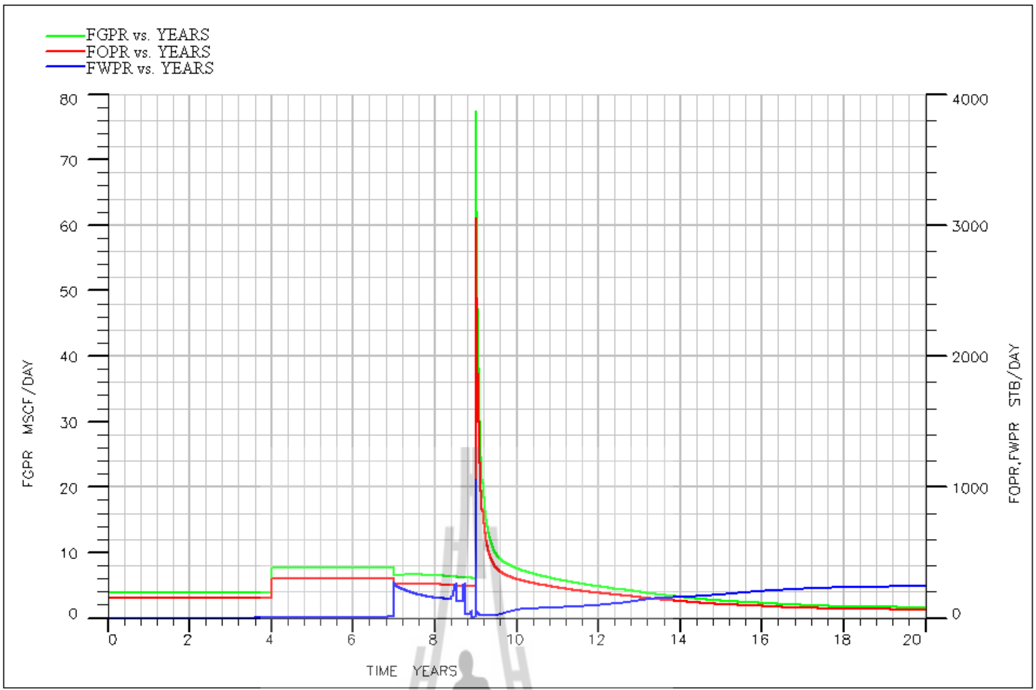

Figure 4.57 Fluids production rate profiles vs. time of model inj300_case3.

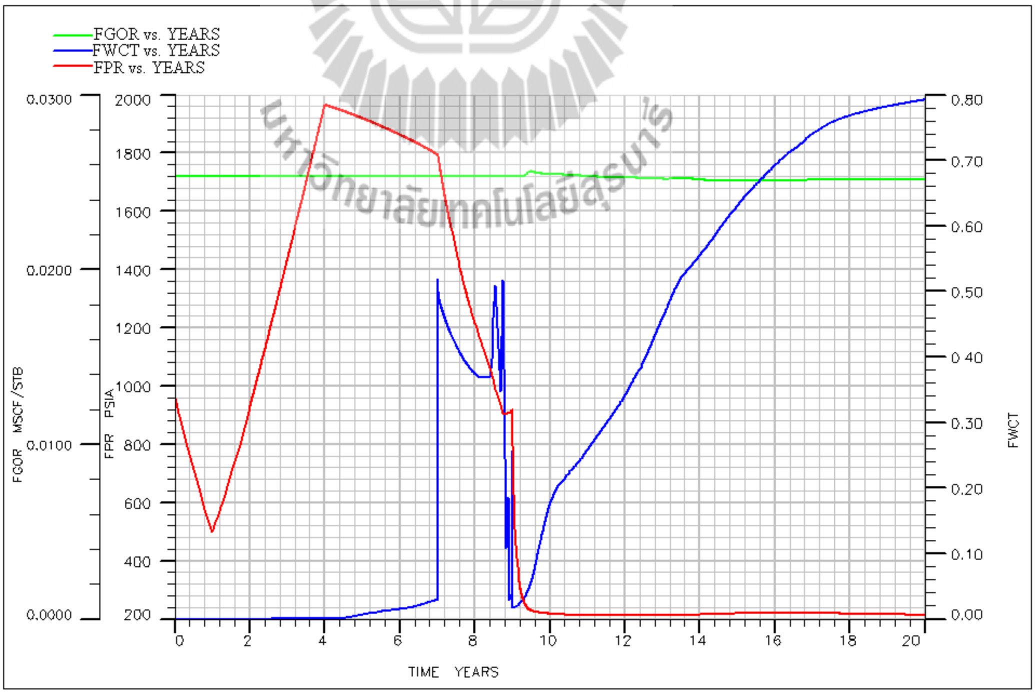

Figure 4.58 GOR, Water cut, and Pressure vs. time of model inj300_case3.

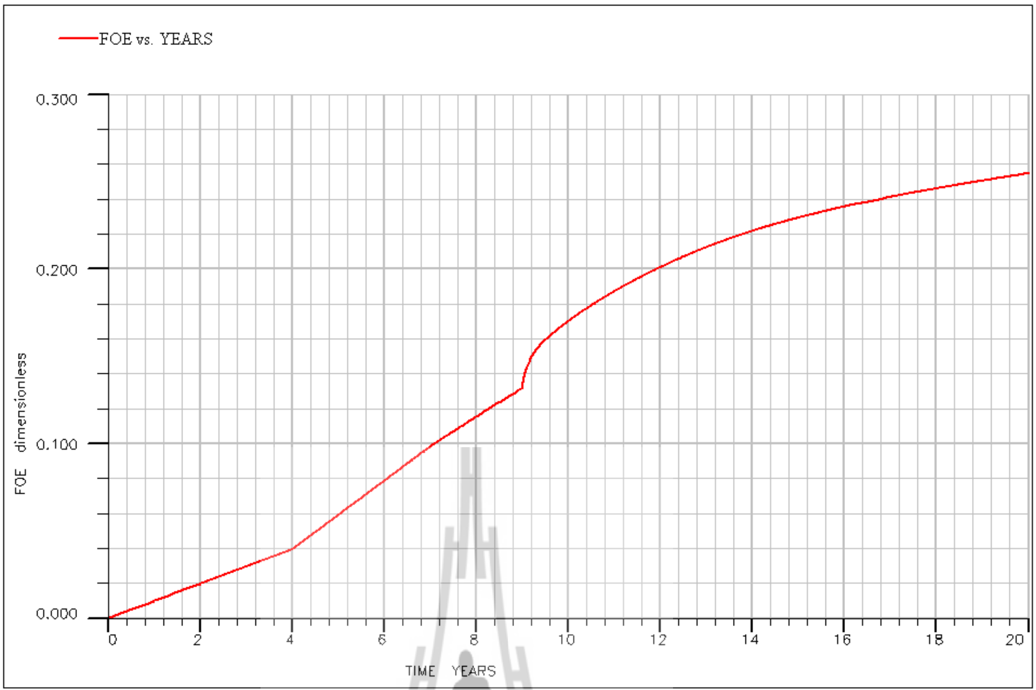

Figure 4.59 Recovery efficiency of oil vs. time of model inj300_case3.

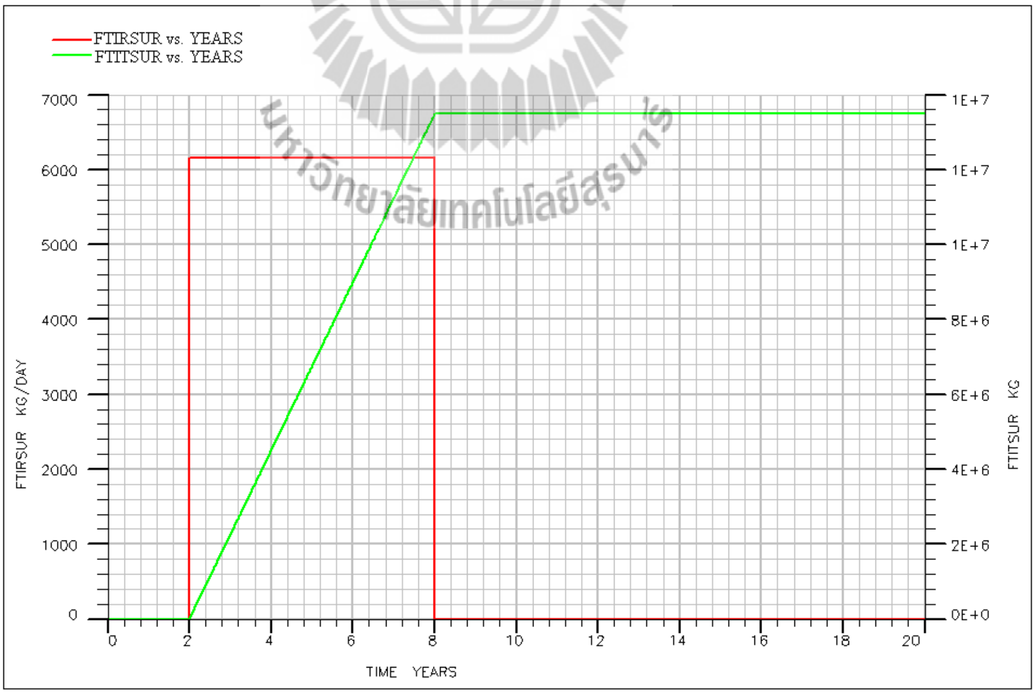

Figure 4.60 FTITSUR and FTIRSUR profiles vs. time of model inj300_case3.

Table 4.2 presents oil recovery efficiency for each case from reservoir simulation. It could be concluded that the highest recovery efficiency was 26.33% in case of inj200_case3 at 15% by volume concentration and the lowest recovery efficiency was 19.4% in case of water flood base case. Considered for each case at injection rate 100, 200, and 300 bbl/day, when the IFT and modified water viscosity was increased, the oil recovery was also increased. It is also noticeable from table 4.2 that after injection rate was over 200 bbl/d, the oil recovery efficiency percent was not so different. This might be resulted from the limitations and assumptions of input parameters of reservoir simulation model.

Table 4.6 Oil recovery efficiency.

Case name	Concentration (%)	Oil Recovery Efficiency (%)
Water flood base case	-	19.4
Inj100_case1	5	23.01
Inj100_case2	10	23.22
Inj100_case3	15	23.88
Inj200_case1	5	24.9
Inj200_case2	10	24.99
Inj200_case3	15	26.33
Inj300_case1	5	24.13
Inj300_case2	10	24.41
Inj300_case3	15	25.48

4.4 Economic evaluation results

The economic analysis were calculated and analyzed by using Microsoft Office Spreadsheet. The economic result of water flood base case is showed in table 4.3. Table 4.4 through table 4.6 are showed economic results of surfactant flood cases for injection rate at 100 bbl/day 5%, 10%, and 15% by volume concentrations respectively. Table 4.7 through table 4.9 are showed economic results of surfactant flood cases for injection rate at 200 bbl/day 5%, 10%, and 15% by volume concentrations. The last economic results of surfactant flood cases for injection rate at 300 bbl/day 5%, 10%, and 15% by volume concentrations are showed in table 4.10 through table 4.12. Internal rate of return (IRR) and Net present value (NPV) for each case are also illustrated in each table.

Table 4.7 Cash flow summary of water flood base case.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,750	4.380	0.000	1.185	0.219	0.000	2.866	1.950
6	54,750	4.380	0.000	1.209	0.219	1.421	1.421	0.895
7	51,057	4.085	0.000	1.150	0.204	1.310	1.310	0.764
8	41,960	3.357	0.000	0.964	0.168	1.057	1.057	0.571
9	100,928	8.074	1.750	2.365	0.404	2.053	2.053	1.027
10	84,255	6.740	0.000	2.014	0.337	2.195	2.195	1.017
11	70,015	5.601	0.000	1.707	0.280	1.807	1.807	0.775
12	69,669	5.574	1.750	1.732	0.279	1.126	1.126	0.447
13	54,456	4.357	0.000	1.381	0.218	1.324	1.324	0.487
14	71,036	5.683	1.750	1.838	0.284	1.070	1.070	0.364
15	57,008	4.561	0.000	1.504	0.228	1.304	1.304	0.411
16	45,770	3.662	0.000	1.232	0.183	1.013	1.013	0.296
17	36,699	2.936	0.000	1.008	0.147	0.836	0.836	0.226
18	38,883	3.111	0.050	1.182	0.156	0.727	0.727	0.182
19	42,108	3.369	0.000	1.298	0.168	0.846	0.846	0.196
20	43,567	3.485	0.000	1.366	0.174	0.867	0.867	0.186
21	43,157	3.453	0.000	1.381	0.173	0.844	0.844	0.168
22	42,211	3.377	0.000	1.380	0.169	0.809	0.809	0.149
23	40,309	3.225	0.000	1.349	0.161	0.857	0.857	0.146
24	37,111	2.969	0.000	1.275	0.148	0.773	0.773	0.122
Total	**1,079,699**	**86.376**	**8.800**	**28.522**	**4.319**	**22.240**	**22.045**	**7.963**
						IRR	41.93%	31.42%
						PIR	2.505	0.905

Table 4.8 Cash flow summary of surfactant flood model inj100_case1.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,900	4.392	0.000	1.189	0.220	0.000	2.874	1.956
6	54,750	4.380	0.075	1.262	0.219	1.382	1.382	0.871
7	54,750	4.380	0.362	1.282	0.219	1.197	1.197	0.699
8	54,750	4.380	0.362	1.308	0.219	1.184	1.184	0.640
9	107,612	8.609	2.112	2.573	0.430	2.016	2.016	1.008
10	95,290	7.623	0.362	2.330	0.381	2.269	2.269	1.051
11	87,267	6.981	0.362	2.181	0.349	2.045	2.045	0.877
12	76,631	6.130	2.112	1.960	0.307	1.096	1.096	0.435
13	67,494	5.400	0.000	1.773	0.270	1.623	1.623	0.597
14	113,904	9.112	1.750	3.009	0.456	2.114	2.114	0.720
15	83,127	6.650	0.000	2.257	0.333	1.920	1.920	0.605
16	74,220	5.938	0.000	2.063	0.297	1.679	1.679	0.490
17	63,753	5.100	0.000	1.817	0.255	1.459	1.459	0.394
18	55,073	4.406	0.000	1.610	0.220	1.233	1.233	0.309
19	48,875	3.910	0.000	1.465	0.196	1.125	1.125	0.261
20	44,329	3.546	0.000	1.362	0.177	1.004	1.004	0.215
21	40,395	3.232	0.000	1.272	0.162	0.899	0.899	0.179
22	37,083	2.967	0.000	1.197	0.148	0.811	0.811	0.149
23	34,226	2.738	0.000	1.133	0.137	0.734	0.734	0.125
24	32,478	2.598	0.000	1.100	0.130	0.684	0.684	0.108
Total	**1,280,907**	**102.473**	**10.997**	**34.142**	**5.124**	**26.473**	**26.287**	**9.271**
						IRR	42.52%	31.96%
						PIR	2.390	0.843

Table 4.9 Cash flow summary of surfactant flood model inj100_case2.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,900	4.392	0.000	1.189	0.220	0.000	2.874	1.956
6	54,750	4.380	0.075	1.262	0.219	1.382	1.382	0.871
7	54,750	4.380	0.649	1.294	0.219	1.048	1.048	0.611
8	54,750	4.380	0.649	1.320	0.219	1.035	1.035	0.559
9	107,659	8.613	2.399	2.587	0.431	1.867	1.867	0.934
10	95,310	7.625	0.649	2.343	0.381	2.120	2.120	0.982
11	87,502	7.000	0.649	2.200	0.350	1.901	1.901	0.815
12	78,005	6.240	2.399	2.007	0.312	0.981	0.981	0.390
13	70,378	5.630	0.000	1.846	0.282	1.696	1.696	0.624
14	115,187	9.215	1.750	3.043	0.461	2.146	2.146	0.731
15	87,013	6.961	0.000	2.360	0.348	2.017	2.017	0.636
16	75,050	6.004	0.000	2.085	0.300	1.699	1.699	0.496
17	64,226	5.138	0.000	1.830	0.257	1.471	1.471	0.398
18	55,593	4.447	0.000	1.624	0.222	1.245	1.245	0.312
19	48,851	3.908	0.000	1.464	0.195	1.124	1.124	0.260
20	43,675	3.494	0.000	1.343	0.175	0.988	0.988	0.212
21	40,309	3.225	0.000	1.270	0.161	0.897	0.897	0.178
22	37,265	2.981	0.000	1.203	0.149	0.815	0.815	0.150
23	34,874	2.790	0.000	1.153	0.139	0.749	0.749	0.128
24	32,596	2.608	0.000	1.104	0.130	0.687	0.687	0.108
Total	**1,292,641**	**103.411**	**12.717**	**34.527**	**5.171**	**25.867**	**25.680**	**8.932**
						IRR	41.42%	30.95%
						PIR	2.019	0.702

Table 4.10 Cash flow summary of surfactant flood model inj100_case3.

Year	**Cash flow summary**							**Discount cash flow (NPV@8%)**
					Government take			
	Oil production total (bbl/year)	**Gross revenue (MMUS$)**	**CAPEX (MMUS$)**	**OPEX (MMUS$)**	**Royalty (MMUS$)**	**Income tax (MMUS$)**	**Annual cash flow (MMUS$)**	
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,900	4.392	0.000	1.189	0.220	0.000	2.874	1.956
6	54,750	4.380	0.000	1.262	0.219	1.394	1.394	0.879
7	54,750	4.380	0.973	1.301	0.219	0.888	0.888	0.518
8	54,750	4.380	0.973	1.327	0.219	0.875	0.875	0.473
9	107,654	8.612	2.723	2.594	0.431	1.707	1.707	0.854
10	95,373	7.630	0.973	2.352	0.381	1.962	1.962	0.909
11	87,688	7.015	0.973	2.212	0.351	1.740	1.740	0.746
12	78,963	6.317	2.723	2.039	0.316	0.840	0.840	0.333
13	71,422	5.714	0.000	1.873	0.286	1.723	1.723	0.633
14	119,571	9.566	1.750	3.156	0.478	2.256	2.256	0.768
15	88,960	7.117	0.000	2.411	0.356	2.065	2.065	0.651
16	77,702	6.216	0.000	2.156	0.311	1.764	1.764	0.515
17	67,285	5.383	0.000	1.914	0.269	1.545	1.545	0.418
18	58,946	4.716	0.125	1.718	0.236	1.315	1.315	0.329
19	52,311	4.185	0.000	1.563	0.209	1.201	1.201	0.278
20	47,805	3.824	0.000	1.463	0.191	1.080	1.080	0.232
21	43,789	3.503	0.000	1.373	0.175	0.972	0.972	0.193
22	39,978	3.198	0.000	1.285	0.160	0.872	0.872	0.160
23	37,304	2.984	0.000	1.228	0.149	0.804	0.804	0.137
24	35,193	2.815	0.000	1.186	0.141	0.744	0.744	0.117
Total	**1,329,092**	**106.327**	**14.714**	**35.602**	**5.316**	**25.747**	**25.561**	**8.683**
						IRR	40.26%	29.87%
						PIR	1.737	0.590

Table 4.11 Cash flow summary of surfactant flood model inj200_case1.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,750	4.380	0.000	1.185	0.219	0.000	2.866	1.950
6	54,900	4.392	0.075	1.286	0.220	1.376	1.376	0.867
7	54,750	4.380	0.724	1.312	0.219	1.001	1.001	0.584
8	54,750	4.380	0.724	1.338	0.219	0.988	0.988	0.534
9	109,500	8.760	2.474	2.648	0.438	1.869	1.869	0.935
10	109,500	8.760	0.724	2.701	0.438	2.442	2.442	1.131
11	99,428	7.954	0.724	2.509	0.398	2.161	2.161	0.927
12	70,788	5.663	2.474	1.847	0.283	0.749	0.749	0.298
13	63,251	5.060	0.000	1.689	0.253	1.504	1.504	0.553
14	129,198	10.336	1.750	3.429	0.517	2.485	2.485	0.846
15	102,858	8.229	0.000	2.802	0.411	2.398	2.398	0.756
16	86,076	6.886	0.000	2.406	0.344	1.958	1.958	0.571
17	73,568	5.885	0.000	2.111	0.294	1.685	1.685	0.455
18	64,969	5.197	0.000	1.913	0.260	1.458	1.458	0.365
19	57,346	4.588	0.000	1.733	0.229	1.313	1.313	0.304
20	50,547	4.044	0.000	1.570	0.202	1.136	1.136	0.244
21	43,447	3.476	0.000	1.390	0.174	0.956	0.956	0.190
22	38,679	3.094	0.000	1.273	0.155	0.833	0.833	0.153
23	35,278	2.822	0.000	1.194	0.141	0.744	0.744	0.127
24	32,595	2.608	0.000	1.133	0.130	0.672	0.672	0.106
Total	**1,386,177**	**110.894**	**13.170**	**37.469**	**5.545**	**27.728**	**27.533**	**9.479**
						IRR	41.66%	31.17%
						PIR	2.091	0.720

Table 4.12 Cash flow summary of surfactant flood model inj200_case2.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,750	4.380	0.000	1.185	0.219	0.000	2.866	1.950
6	54,900	4.392	0.075	1.286	0.220	1.376	1.376	0.867
7	54,750	4.380	1.298	1.313	0.219	0.714	0.714	0.417
8	54,750	4.380	1.298	1.339	0.219	0.701	0.701	0.379
9	109,500	8.760	3.048	2.649	0.438	1.582	1.582	0.791
10	109,500	8.760	1.298	2.702	0.438	2.155	2.155	0.998
11	106,871	8.550	1.298	2.692	0.427	2.066	2.066	0.886
12	80,495	6.440	3.048	2.090	0.322	0.710	0.710	0.282
13	70,199	5.616	0.000	1.865	0.281	1.680	1.680	0.618
14	136,722	10.938	1.750	3.623	0.547	2.674	2.674	0.910
15	107,914	8.633	0.000	2.936	0.432	2.523	2.523	0.795
16	87,441	6.995	0.000	2.443	0.350	1.991	1.991	0.581
17	71,681	5.735	0.000	2.059	0.287	1.639	1.639	0.443
18	60,890	4.871	0.000	1.798	0.244	1.360	1.360	0.340
19	51,911	4.153	0.000	1.578	0.208	1.184	1.184	0.274
20	43,580	3.486	0.000	1.367	0.174	0.973	0.973	0.209
21	38,501	3.080	0.000	1.243	0.154	0.842	0.842	0.167
22	34,655	2.772	0.000	1.151	0.139	0.741	0.741	0.136
23	32,003	2.560	0.000	1.092	0.128	0.670	0.670	0.114
24	29,778	2.382	0.000	1.044	0.119	0.610	0.610	0.096
Total	**1,390,790**	**111.263**	**16.610**	**37.455**	**5.563**	**26.190**	**25.996**	**8.838**
						IRR	39.72%	29.37%
						PIR	1.565	0.532

Table 4.13 Cash flow summary of surfactant flood model inj200_case3.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,750	4.380	0.000	1.185	0.219	0.000	2.866	1.950
6	54,900	4.392	0.075	1.286	0.220	1.376	1.376	0.867
7	54,750	4.380	1.946	1.327	0.219	0.383	0.383	0.223
8	54,750	4.380	1.946	1.353	0.219	0.369	0.369	0.200
9	109,500	8.760	3.696	2.663	0.438	1.250	1.250	0.625
10	109,500	8.760	1.946	2.717	0.438	1.823	1.823	0.845
11	109,800	8.784	1.946	2.778	0.439	1.810	1.810	0.776
12	88,317	7.065	3.696	2.300	0.353	0.578	0.578	0.230
13	82,584	6.607	0.000	2.179	0.330	1.994	1.994	0.733
14	151,729	12.138	1.750	4.012	0.607	3.050	3.050	1.038
15	116,079	9.286	0.000	3.151	0.464	2.725	2.725	0.859
16	94,676	7.574	0.000	2.638	0.379	2.169	2.169	0.633
17	79,964	6.397	0.000	2.287	0.320	1.840	1.840	0.497
18	67,803	5.424	0.000	1.992	0.271	1.526	1.526	0.382
19	57,981	4.639	0.000	1.751	0.232	1.328	1.328	0.308
20	48,057	3.845	0.000	1.497	0.192	1.078	1.078	0.231
21	39,796	3.184	0.000	1.282	0.159	0.872	0.872	0.173
22	33,327	2.666	0.000	1.111	0.133	0.711	0.711	0.131
23	29,596	2.368	0.000	1.018	0.118	0.616	0.616	0.105
24	27,654	2.212	0.000	0.977	0.111	0.562	0.562	0.089
Total	**1,465,511**	**117.241**	**20.503**	**39.504**	**5.862**	**26.059**	**25.864**	**8.478**
						IRR	37.42%	27.24%
						PIR	1.262	0.414

Table 4.14 Cash flow summary of surfactant flood model inj300_case1.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,900	4.392	0.000	1.189	0.220	0.000	2.874	1.956
6	54,750	4.380	0.075	1.303	0.219	1.362	1.362	0.858
7	54,750	4.380	1.086	1.304	0.219	0.824	0.824	0.481
8	54,750	4.380	1.086	1.330	0.219	0.811	0.811	0.438
9	109,500	8.760	2.836	2.640	0.438	1.692	1.692	0.846
10	109,500	8.760	1.086	2.692	0.438	2.265	2.265	1.049
11	109,800	8.784	1.086	2.753	0.439	2.253	2.253	0.966
12	95,790	7.663	2.836	2.460	0.383	1.212	1.212	0.481
13	82,386	6.591	0.000	2.197	0.330	1.977	1.977	0.727
14	129,508	10.361	1.750	3.460	0.518	2.481	2.481	0.845
15	91,898	7.352	0.000	2.537	0.368	2.114	2.114	0.666
16	73,539	5.883	0.000	2.094	0.294	1.638	1.638	0.478
17	59,638	4.771	0.000	1.754	0.239	1.334	1.334	0.361
18	51,078	4.086	0.000	1.549	0.204	1.111	1.111	0.278
19	43,840	3.507	0.000	1.373	0.175	0.979	0.979	0.227
20	40,245	3.220	0.000	1.296	0.161	0.881	0.881	0.189
21	35,728	2.858	0.000	1.188	0.143	0.764	0.764	0.152
22	32,406	2.592	0.000	1.111	0.130	0.676	0.676	0.124
23	30,332	2.427	0.000	1.069	0.121	0.618	0.618	0.105
24	28,533	2.283	0.000	1.034	0.114	0.567	0.567	0.089
Total	**1,342,871**	**107.430**	**15.342**	**36.331**	**5.371**	**25.560**	**25.374**	**8.901**
						IRR	40.73%	30.30%
						PIR	1.654	0.580

Table 4.15 Cash flow summary of surfactant flood model inj300_case2.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,900	4.392	0.000	1.189	0.220	0.000	2.874	1.956
6	54,750	4.380	0.075	1.303	0.219	1.362	1.362	0.858
7	54,750	4.380	1.946	1.402	0.219	0.345	0.345	0.201
8	54,750	4.380	1.946	1.430	0.219	0.331	0.331	0.179
9	109,500	8.760	3.696	2.742	0.438	1.211	1.211	0.606
10	109,500	8.760	1.946	2.797	0.438	1.783	1.783	0.826
11	109,800	8.784	1.946	2.860	0.439	1.769	1.769	0.759
12	100,050	8.004	3.696	2.675	0.400	0.836	0.836	0.332
13	92,143	7.371	0.000	2.445	0.369	2.224	2.224	0.818
14	152,760	12.221	1.750	4.062	0.611	3.064	3.064	1.043
15	92,824	7.426	0.000	2.561	0.371	2.137	2.137	0.674
16	71,762	5.741	0.000	2.046	0.287	1.594	1.594	0.465
17	57,444	4.595	0.000	1.693	0.230	1.281	1.281	0.346
18	49,165	3.933	0.000	1.496	0.197	1.065	1.065	0.267
19	41,022	3.282	0.000	1.293	0.164	0.912	0.912	0.211
20	36,145	2.892	0.000	1.177	0.145	0.785	0.785	0.168
21	32,419	2.594	0.000	1.089	0.130	0.687	0.687	0.137
22	30,058	2.405	0.000	1.040	0.120	0.622	0.622	0.114
23	28,304	2.264	0.000	1.006	0.113	0.572	0.572	0.097
24	26,512	2.121	0.000	0.970	0.106	0.523	0.523	0.082
Total	**1,358,556**	**108.684**	**20.503**	**37.274**	**5.434**	**23.105**	**22.919**	**7.723**
						IRR	36.96%	26.82%
						PIR	1.118	0.377

Table 4.16 Cash flow summary of surfactant flood model inj300_case3.

Year	Cash flow summary							Discount cash flow (NPV@8%)
	Oil production total (bbl/year)	Gross revenue (MMUS$)	CAPEX (MMUS$)	OPEX (MMUS$)	Government take		Annual cash flow (MMUS$)	
					Royalty (MMUS$)	Income tax (MMUS$)		
1	0.000	0.000	0.250	0.000	0.000	0.000	-0.250	-0.231
2	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.429
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	1.750	0.000	0.000	0.000	-1.310	-0.963
5	54,900	4.392	0.000	1.189	0.220	0.000	2.874	1.956
6	54,750	4.380	0.075	1.303	0.219	1.362	1.362	0.858
7	54,750	4.380	2.920	1.318	0.219	0.000	-0.199	-0.116
8	54,750	4.380	2.920	1.344	0.219	0.000	-0.225	-0.122
9	109,500	8.760	4.670	2.654	0.438	0.768	0.768	0.384
10	109,500	8.760	2.920	2.707	0.438	1.341	1.341	0.621
11	109,800	8.784	2.920	2.769	0.439	1.328	1.328	0.570
12	94,797	7.584	4.670	2.451	0.379	0.262	0.262	0.104
13	90,868	7.269	0.000	2.412	0.363	2.192	2.192	0.806
14	213,746	17.100	1.750	5.640	0.855	4.593	4.593	1.564
15	95,109	7.609	0.000	2.622	0.380	2.193	2.193	0.691
16	76,515	6.121	0.000	2.174	0.306	1.711	1.711	0.499
17	63,677	5.094	0.000	1.865	0.255	1.432	1.432	0.387
18	51,844	4.147	0.000	1.571	0.207	1.130	1.130	0.283
19	42,021	3.362	0.000	1.321	0.168	0.936	0.936	0.217
20	35,580	2.846	0.000	1.160	0.142	0.772	0.772	0.166
21	30,541	2.443	0.000	1.034	0.122	0.644	0.644	0.128
22	27,025	2.162	0.000	0.948	0.108	0.553	0.553	0.102
23	24,799	1.984	0.000	0.898	0.099	0.493	0.493	0.084
24	23,706	1.896	0.000	0.881	0.095	0.460	0.460	0.073
Total	**1,418,177**	**113.454**	**26.342**	**38.259**	**5.673**	**22.171**	**21.560**	**6.838**
						IRR	32.79%	22.95%
						PIR	0.818	0.260

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Introduction

This chapter is divided into 2 parts which are conclusions and recommendations. In conclusions part, it presents the conclusion from three main parts (I) experimental and laboratory results including IFT and modified viscosity test, (II) reservoir simulation results, and (III) economic evaluation results, respectively. In recommendation part, it comprises of some recommendations for the future study.

5.2 Conclusions

5.2.1 Experiments

a. IFT test

IFT of crude oil measured at 40^{o}C at 0%, 5%, 10%, and 15% by volume LAS concentration was 31.87, 29.96, 29.1, and 27.9 dynes/cm respectively. After elevating temperature to 70^{o}C, the IFT of crude oil at 0%, 5%, 10%, and 15% LAS concentration was decreased to 26.53, 26.8, 21.1, and 26.53 dynes/cm, respectively. Therefore, it could be concluded that the changing in crude oil IFT might be resulted from the concentration and temperature of the solutions were changed.

b. Modified water viscosity

Unlike IFT of crude oil, viscosity of modified water tended to increase with temperature increasing. Results from measurement stated that the viscosity of water at 40^{o}C with 0%, 5%, 10%, and 15% by volume LAS concentration was 0.653, 1.12, 1.96, and 5.02 cp, respectively. However, when the temperature of solution was elevated to

70°C, the viscosity of water was changed to 0.4, 4.28, 9.56, and 20.1 cp, respectively.

5.2.2 Reservoir simulation

This section presents results from reservoir simulation which separated to oil recovery efficiency and oil production in figure 5.1 and figure 5.2. For figure 5.1 was showed oil recovery efficiency in comparison between water flood and surfactant flood in each case. Figure 5.2 was showed oil production in comparison between water flood and surfactant flood.

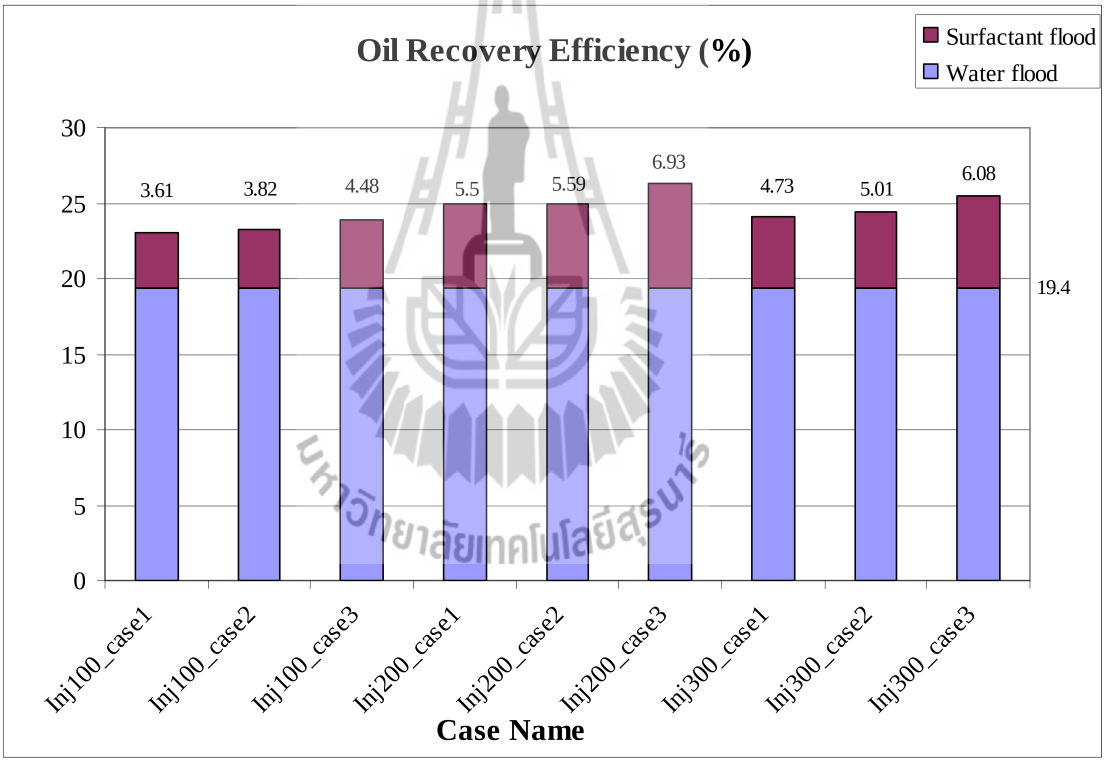

Figure 5.1 Oil recovery efficiency comparisons.

Oil recovery efficiency of water flood base case was 19.4%. In case of 100 bbl/day surfactant injection rate at 5%, 10%, and 15% by volume LAS concentration, oil recovery efficiency were higher than water flood base case 3.61%, 3.82%, and 4.48% respectively. In case of 200 bbl/day surfactant injection rate at 5%, 10%, and 15% by volume LAS concentration, oil recovery efficiency were higher than water flood base case

5.5%, 5.59%, and 6.93% respectively. In case of 300 bbl/day surfactant injection rate at 5%, 10%, and 15% by volume LAS concentration, oil recovery efficiency were higher than water flood base case 4.73%, 5.01%, and 6.08% respectively.

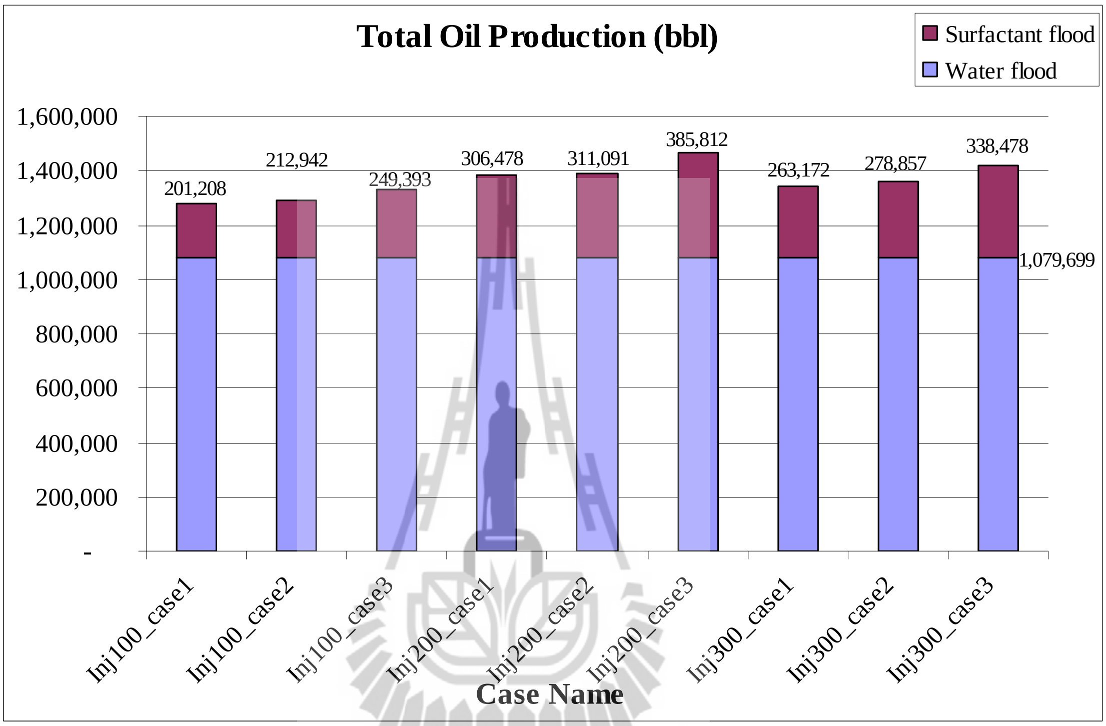

Figure 5.2 Total oil production comparisons.

Total oil production of water flood base case was 1,079,699 bbl. In case of 100 bbl/day surfactant injection rates at 5%, 10%, and 15% by volume LAS concentration, total oil production total were higher than water flood base case 201,208 bbl, 212,942 bbl, and 249,393 bbl respectively. In case of 200 bbl/day surfactant injection rates at 5%, 10%, and 15% by volume LAS concentration, total oil production were higher than water flood base case 306,478 bbl, 311,091 bbl, and 385,812 bbl respectively. In case of 300 bbl/day surfactant injection rates at 5%, 10%, and 15% by volume LAS concentration, total oil production were higher than water flood base case 263,172 bbl, 278,857 bbl, and 338,478 bbl respectively.

5.2.3 Economic evaluation

This section presents results from economic evaluations in term of NPV and IRR as illustrated in figure 5.3 through figure 5.4.

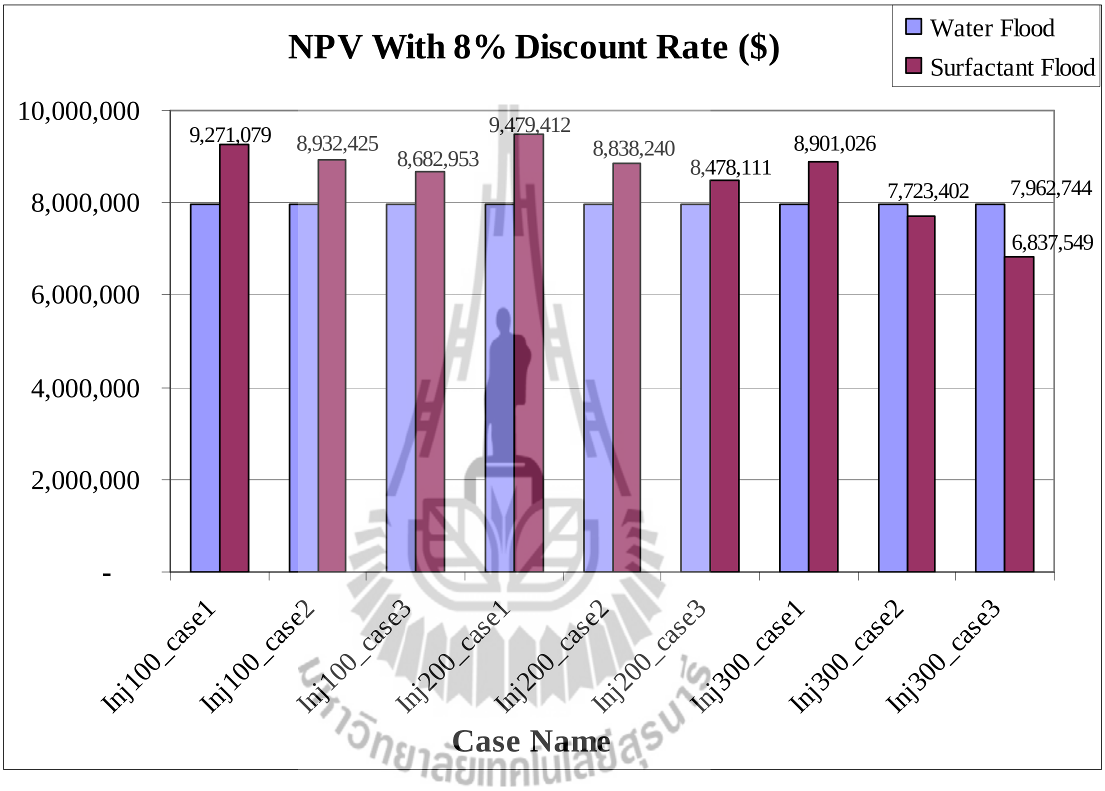

Figure 5.3 NPV with 8% discount rate.

Net present value (NPV) with 8% discount rate of water flood base case was 7,962,744 US$. In case of 100 bbl/day surfactant injection rates at 5%, 10%, and 15% by volume LAS concentration, NPV with 8% discount rate were higher than water flood base case 1,308,335 US$, 969,681 US$, and 720.209 US$ respectively. In case of 200 bbl/day surfactant injection rates at 5%, 10%, and 15% by volume LAS concentration, NPV with 8% discount rate were higher than water flood base case 1,516,668 US$, 875,496 US$, and 515,367 US$ respectively. In case of 300 bbl/day surfactant injection rates at 5% by volume LAS concentration NPV with 8% discount rate was higher than water flood case

938,282 US$. But at 10%, and 15% by volume LAS concentration, NPV with 8% discount rate were lower than water flood case 239,343 US$ and 1,125,195 US$ respectively.

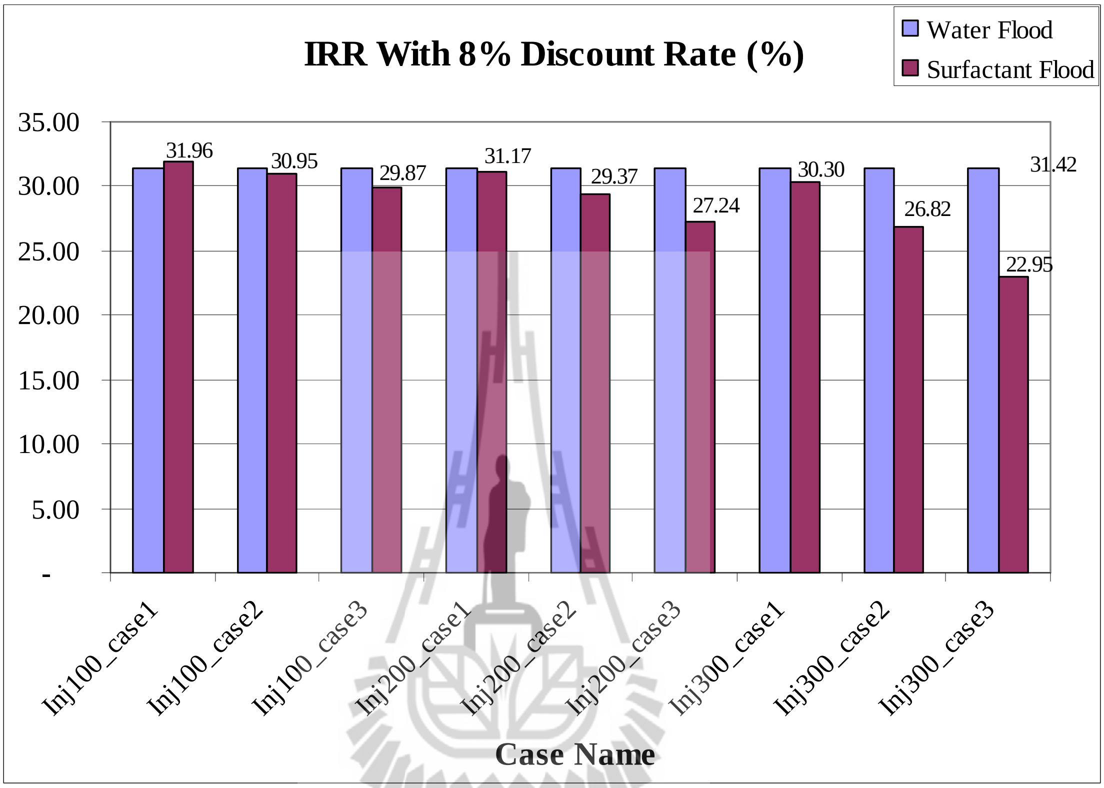

Figure 5.4 IRR with 8% discount rate.

Internal rate of return (IRR) with 8% discount rate of water flood base case was 31.42%. Only injection rate 100 bbl/day 5% LAS concentration case IRR was higher than water flood base case 0.54%. The other cases at 10% and 15% by volume LAS concentration IRR were lower than water flood base case 0.47% and 1.55% respectively. In case of 200 bbl/day surfactant injection rates at 5%, 10%, and 15% by volume LAS concentration, IRR with 8% discount rate were lower than water flood base case 0.25%, 2.05%, and 4.18% respectively. In case of 300 bbl/day surfactant injection rates at 5%, 10%, and 15% by volume LAS concentration, IRR with 8% discount rate were lower than water flood base case 1.12%, 4.6%, and 8.47% respectively.

Therefore, it could be concluded that the surfactant flood would give higher economic returns than those of water flood case only when the injected fluid had 5% by volume LAS concentration and the injection rate was not over than 100 bbl/day.

5.3 Recommendations

The uncertainties and adequacies of the research investigation and experiments lead to recommendation for further study as follows.

- The spinning drop tension method should be used to measure the IFT of crude oil because this method has more resolution than ring and plate methods.
- In reservoir simulation, the input parameters included surfactant adsorption of reservoir rock, emulsification, and displacement efficiency of surfactant should be performed.
- For economic evaluation part, oil price should be up to date because it plays an important role in NPV, IRR, and PIR predicting accuracy.

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APPENDIX A

OBTAINABLE DATA

Gas Properties

1. Gas composition

Table A.1 Gas properties of Sansai oil field (after Chumkratoke, C., 2004).

Gas composition	**Content (%)**
Gas Oxygen (O_2)	0.5162
Gas Nitrogen (N_2)	5.1077
Gas Methane (CH_4)	79.7008
Gas Carbon Dioxide (CO_2)	3.2131
Gas Ethane (C_2H_6)	2.7744
Gas Hydrogen (H_2)	1.6287
Gas Hydrogen Sulfide (H_2S)	7.0591
Total	100

Table A.2 Gas properties of Mae-Soon oil field (after Chumkratoke, C., 2004).

Gas composition	**Content (%)**
Gas Oxygen (O_2)	0.2578
Gas Nitrogen (N_2)	4.1915
Gas Methane (CH_4)	36.829
Gas Carbon Dioxide (CO_2)	3.218
Gas Ethane (C_2H_6)	18.4014
Gas Hydrogen (H_2)	3.8361
Gas Hydrogen Sulfide (H_2S)	33.2662
Total	100

2. Compressibility factor (z)

Table A.3 Compressibility factor of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	**Compressibility factor (z)**
950	0.939
400	0.971

Table A.4 Compressibility factor of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	**Compressibility factor (z)**
900	0.86
300	0.959

3. Gas formation volume factors (B_g)

Table A.5 Gas formation volume factors of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Gas formation volume factors (ft^3/SCF)
950	0.0176
400	0.0432

Table A.6 Gas formation volume factors of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	**Gas formation volume factors (ft^3/SCF)**
900	0.017
300	0.05693

4. Gas viscosity (μ_g)

Table A.7 Gas viscosity of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	**Gas viscosity (cp)**
950	0.014
400	0.0135

Table A.8 Gas viscosity of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	**Gas viscosity (cp)**
900	0.0148
300	0.0136

5. Gas isothermal compressibility (C_g)

Table A.9 Gas isothermal compressibility at initial reservoir pressure (after Chumkratoke, C., 2004).

Oil field	**Gas isothermal compressibility (psi^{-1})**
Sansai	131.2×10^{-5}
Mae-Soon	132.67×10^{-5}

Crude Oil Properties

1. Density of crude oil (ρ_o)

Table A.10 Density of Crude Oil (after Chumkratoke, C., 2004).

Oil field	(g/cc)	(lb/ft^3)	(lb/gallon)
Mae-Soon	0.85	53	7.1
Banthi	0.89	56	7.4
Nongyao	0.84	52.3	7
Sansai	0.86	54	7.2

2. Specific gravity of crude oil (γ_o)

Table A.11 Specific gravity of crude oil (after Chumkratoke, C., 2004).

Oil Field	(^{o}API)
Mae-Soon	0.85
Banthi	0.89
Nongyao	0.84
Sansai	0.86

3. API gravity (^{o}API)

Table A.12 API gravity of crude oil (after Chumkratoke, C., 2004).

Oil field	(^{o}API)
Mae-Soon	35.1
Banthi	-
Nongyao	37.75
Sansai	34

4. Oil viscosity (μ_o)

Table A.13 Dynamic viscosity of crude oil (after Chumkratoke, C., 2004).

Oil field	Oil viscosity (cp)
Mae-Soon	12
Banthi	11.2
Nongyao	12
Sansai	20.1

5. Solution gas-oil ratio (R_S)

Table A.14 Solution gas-oil ratio of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	R_S (SCF/STB)
950	165.01
400	58.237
200	25.279

Table A.15 Solution gas-oil ratio of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	R_S (SCF/STB)
900	215.05
300	57.29
150	24.87

6. Oil isothermal compressibility (C_o)

Table A.16 Oil isothermal compressibility of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Oil isothermal compressibility (psi^{-1})
950	1.337×10^{-5}
400	3.174×10^{-5}

Table A.17 Oil isothermal compressibility of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Oil isothermal compressibility (psi^{-1})
900	1.132×10^{-5}
300	$3.395\ 10^{-5}$

7. Oil formation volume factor (B_o)

Table A.18 Oil formation volume factor of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Oil formation volume factor (bbl/STB)
950	1.035
400	1.040
200	1.055

Table A.19 Oil formation volume factor of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Oil formation volume factor (bbl/STB)
900	1.041
300	1.049
150	1.061

Water Properties

1. Water salinity

Table A.20 Water resistivity and water salinity of Sansai oil field and Mae-Soon oil field (after Chumkratoke, C., 2004).

Oil field	Temperature (^{o}F)	Resistivity (Ωm)	NaCl concentration		
			(ppm)	(grain/gal)	(gram/lit)
Sansai	85	5.92	780	45	0.7704
Mae-Soon	85	2.98	1600	96	1.64352

2. Water formation volume factor (B_w)

Table A.21 Water formation volume factor of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Water formation volume factor (bbl/STB)
950	1.02677
400	1.0283
200	1.0284

Table A.22 Water formation volume factor of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Water formation volume factor (bbl/STB)
900	1.0280
300	1.0284
150	1.0285

3. Water isothermal compressibility (C_w)

Table A.23 Water isothermal compressibility of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Water isothermal compressibility (psi^{-1})
950	3.134×10^{-6}
400	3.171×10^{-6}
200	3.186×10^{-6}

Table A.24 Water Formation volume factor of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Water isothermal compressibility (psi^{-1})
900	3.133×10^{-6}
300	3.175×10^{-6}
150	$3.185\ 10^{-6}$

4. Water viscosity (μ_w)

Table A.25 Water viscosity of Sansai oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Water viscosity (centipoises)
950	0.375
400	0.366
200	0.363

Table A.26 Water viscosity of Mae-Soon oil field (after Chumkratoke, C., 2004).

Reservoir pressure (psi)	Water viscosity (centipoises)
900	0.3907
300	0.381
150	0.378

Reservoir Rock Properties

1. Rock porosity (ø)

Table A.27 Rock porosity of Fang' oil fields (after Chumkratoke, C., 2004).

Oil field	Porosity (%)
Sansai	18-33
Mae-Soon	25-29
Banthi	20-25
Nongyao	18-28

2. Rock permeability

Rock permeability of Fang' oil fields are showed in table 3.28.

Table A.28 Rock permeability of Fang' oil fields (after Chumkratoke, C., 2004).

Oil field	Permeability (md)
Sansai	24-329
Mae-Soon	20-300
Banthi	200-300
Nongyao	18-500

3. Fluid saturation

Table A.29 Fluid Saturation of Fang' oil fields (after Chumkratoke, C., 2004).

Oil field	Saturation (%)
Sansai	20-80
Mae-Soon	17-35
Banthi	10-50
Nongyao	58-64

4. Rock isothermal compressibility (C_f)

Table A.30 Rock isothermal compressibility in Fang' oil fields (after Chumkratoke, C., 2004).

Oil field	Isothermal compressibility (psi^{-1})
Sansai	20-80
Mae-Soon	17-35
Banthi	10-50
Nongyao	58-64

APPENDIX B

RESERVOIR SIMULATION RAW DATA

Table B.1 Oil production and surfactant solution injection data of surfactant flood model name case1_inj100.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.0098358	150	54900	0	0	100
2	0.0196715	150	109650	763.1382	763.25405	100
3	0.0295355	150	164400	763.1382	279350.99	100
4	0.0393716	150	219150	763.1382	557938.75	100
5	0.058704	277.94586	326762.47	763.1382	836526.45	100
6	0.0758223	248.37828	422052.28	763.1382	1115114.2	100
7	0.0914993	229.3075	509319.13	763.1382	1394465.2	100
8	0.1052658	196.27614	585950.25	763.1382	1673052.9	100
9	0.1173908	177.94757	653444.63	0	1673052.9	100
10	0.1369803	264.74704	767348.69	0	1673052.9	100
11	0.1527863	220.74127	850475.44	0	1673052.9	100
12	0.1661195	188.52888	924695	0	1673052.9	100
13	0.1775723	162.53169	988447.63	0	1673052.9	100
14	0.1874659	141.67505	1043520.6	0	1673052.9	100
15	0.1962461	127.16184	1092395.9	0	1673052.9	100
16	0.2042096	115.9796	1136724.9	0	1673052.9	100
17	0.2114663	106.01073	1177120	0	1673052.9	100
18	0.218128	97.502464	1214202.9	0	1673052.9	100
19	0.2242765	91.220329	1248428.8	0	1673052.9	100
20	0.2301109	86.918732	1280906.5	0	1673052.9	100

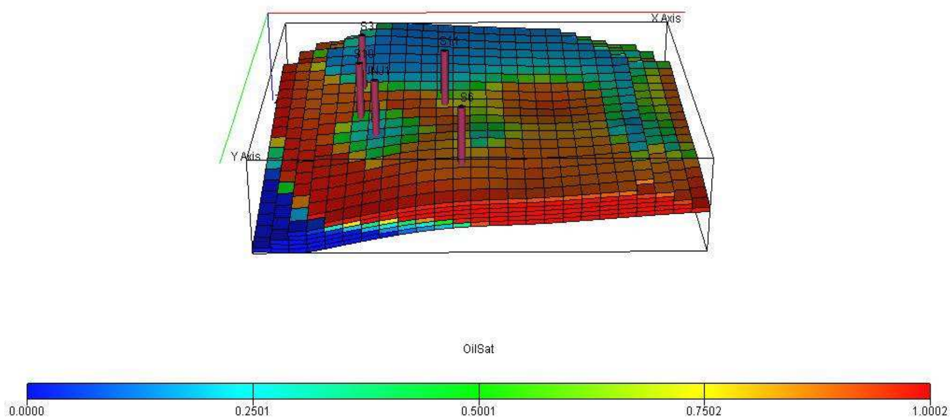

Figure B.1 3-D reservoir model of case1_inj100 at the end of production period.

Table B.2 Oil production and surfactant solution injection data of surfactant flood model name case2_inj100.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.009836	150	54900	0	0	100
2	0.019671	150	109650	0	0	100
3	0.029536	150	164400	1367.2893	500503.86	100
4	0.039372	150	219150	1367.2893	999640.26	100
5	0.058713	277.76495	326809.22	1367.2893	1498776.6	100
6	0.075834	248.46866	422118.97	1367.2893	2014533	100
7	0.091554	230.95084	509620.88	1367.2893	2498416.7	100
8	0.105567	201.703	587625.69	1367.2893	2997553.2	100
9	0.11821	185.41527	658004	0	0	100
10	0.138406	272.38522	773190.75	0	0	100
11	0.154534	224.17259	860203.44	0	0	100
12	0.168017	190.10422	935253.06	0	0	100
13	0.179554	164.47528	999478.56	0	0	100
14	0.189541	143.18335	1055071.6	0	0	100
15	0.198317	126.1338	1103922.8	0	0	100
16	0.206163	114.74178	1147597.3	0	0	100
17	0.213404	105.92898	1187906.6	0	0	100
18	0.220099	98.413193	1225171.1	0	0	100
19	0.226364	92.566788	1260044.8	0	0	100
20	0.232219	86.229332	1292641	0	0	100

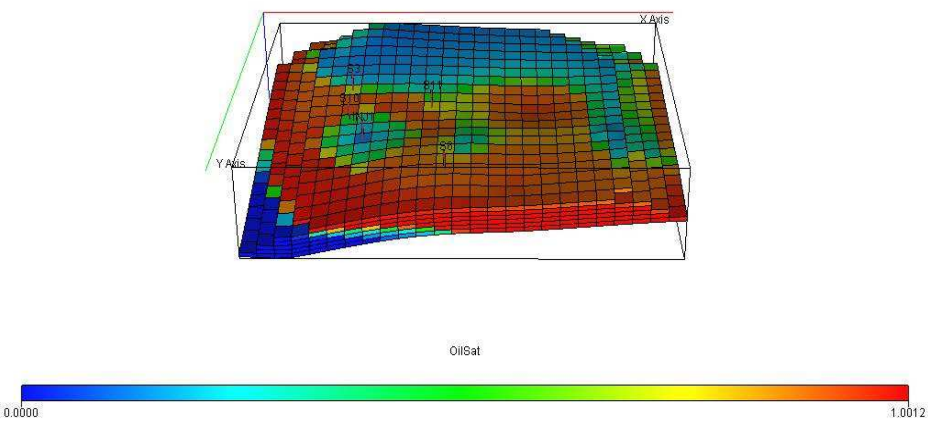

Figure B.2 3-D reservoir model of case2_inj100 at the end of production period.

Table B.3 Oil production and surfactant solution injection data of surfactant flood model name case3_inj100.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.009836	150	54900	0	0	100
2	0.019671	150	109650	0	0	100
3	0.029536	150	164400	2050.9341	750755.82	100
4	0.039372	150	219150	2050.9341	1499460.5	100
5	0.058712	277.89935	326803.66	2050.9341	2248165.1	100
6	0.075845	248.85858	422176.72	2050.9341	2996869.6	100
7	0.091598	231.67853	509865.12	2050.9341	3747625.6	100
8	0.105783	204.61707	588827.75	2050.9341	4496330.1	100
9	0.118613	189.22858	660249.31	0	4496330.1	100
10	0.139304	281.41077	779820.06	0	4496330.1	100
11	0.156075	233.37685	868780.13	0	4496330.1	100
12	0.169972	199.07022	946481.81	0	4496330.1	100
13	0.182121	171.96619	1013766.4	0	4496330.1	100
14	0.19271	151.93669	1072712	0	4496330.1	100
15	0.202108	137.23865	1125023.3	0	4496330.1	100
16	0.210696	125.96106	1172827.8	0	4496330.1	100
17	0.21848	114.7	1216616.5	0	4496330.1	100
18	0.225699	105.0971	1256594.4	0	4496330.1	100
19	0.232445	99.521591	1293898.8	0	4496330.1	100
20	0.238767	93.242805	1329091.8	0	4496330.1	100

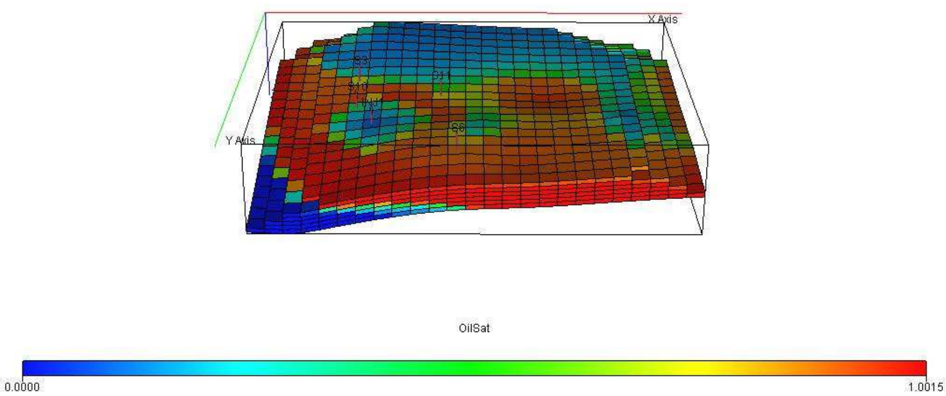

Figure B.3 3-D reservoir model of case3_inj100 at the end of production period.

Table B.4 Oil production and surfactant solution injection data of surfactant flood model name case1_inj200.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.009836	150	54750	0	0	0
2	0.019672	150	109650	0	1526.5081	200
3	0.029537	150	164400	1526.2764	558701.98	200
4	0.039375	150	219150	1526.2764	1115877.5	200
5	0.059048	300	328650	1526.2764	1673052.9	200
6	0.078721	300	438150	1526.2764	2230228.4	200
7	0.096582	232.86678	537578.06	1526.2764	2788930.4	200
8	0.109299	181.62619	608366.31	1526.2764	3346105.8	200
9	0.120662	169.01862	671617.06	0	3346105.8	200
10	0.143872	310.5582	800815.38	0	3346105.8	200
11	0.16235	258.56204	903673.31	0	3346105.8	200
12	0.177681	217.11562	989749.25	0	3346105.8	200
13	0.190924	189.30333	1063317.1	0	3346105.8	200
14	0.202596	166.38675	1128285.6	0	3346105.8	200
15	0.213002	148.6017	1185631.1	0	3346105.8	200
16	0.221972	128.74915	1236178.5	0	3346105.8	200
17	0.22989	112.04826	1279625	0	3346105.8	200
18	0.236839	100.89437	1318304.4	0	3346105.8	200
19	0.243093	92.671303	1353582.3	0	3346105.8	200
20	0.249032	86.613708	1386176.9	0	3346105.8	200

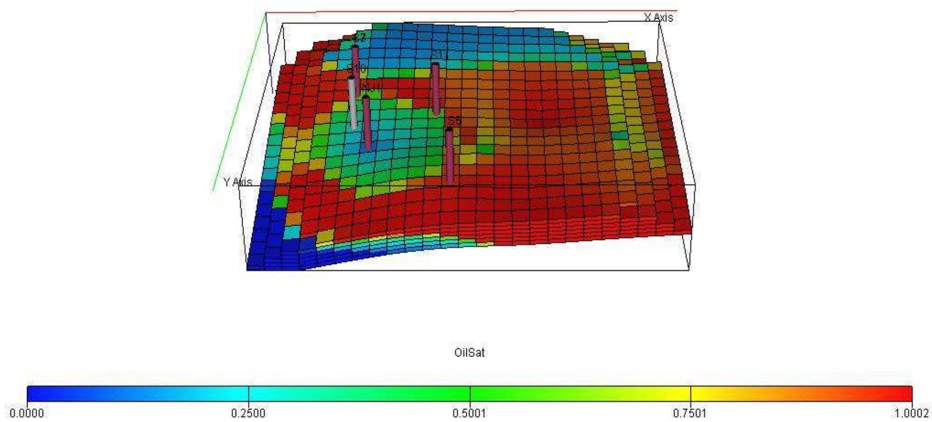

Figure B.4 3-D reservoir model of case1_inj200 at the end of production period.

Table B.5 Oil production and surfactant solution injection data of surfactant flood model name case2_inj200.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.009836	150	54750	0	0	200
2	0.019672	150	109650	0	0	200
3	0.029536	150	164400	2734.5785	1001007.7	200
4	0.039374	150	219150	2734.5785	1999280.5	200
5	0.059048	300	328650	2734.5785	2997553.2	200
6	0.078722	300	438150	2734.5785	3995825.9	200
7	0.097924	263.95016	545020.69	2734.5785	4990622.9	200
8	0.11229	203.98965	625515.69	2734.5785	5995106.4	200
9	0.124921	184.12984	695714.25	0	5995106.4	200
10	0.149557	326.44925	832436.25	0	5995106.4	200
11	0.168716	266.96921	940350.44	0	5995106.4	200
12	0.184651	216.42319	1027791.1	0	5995106.4	200
13	0.197433	179.50668	1099472.4	0	5995106.4	200
14	0.208348	155.23058	1160362.3	0	5995106.4	200
15	0.217698	129.59857	1212272.9	0	5995106.4	200
16	0.225555	111.79623	1255852.4	0	5995106.4	200
17	0.232465	99.891434	1294353.8	0	5995106.4	200
18	0.238764	90.876244	1329008.9	0	5995106.4	200
19	0.244443	84.545135	1361011.5	0	5995106.4	200
20	0.249863	78.889229	1390789.6	0	5995106.4	200

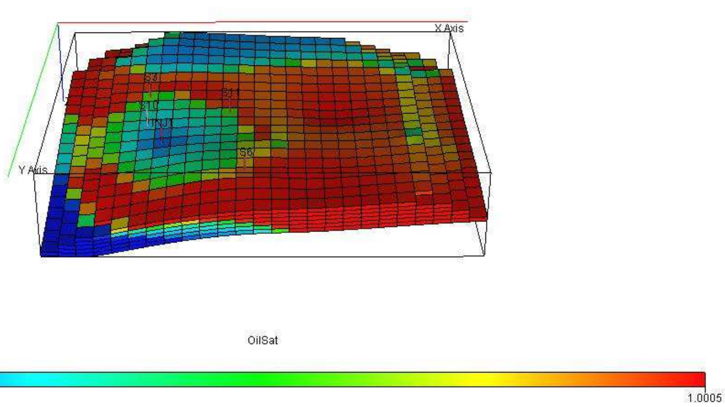

Figure B.5 3-D reservoir model of case2_inj200 at the end of production period.

Table B.6 Oil production and surfactant solution injection data of surfactant flood model name case3_inj200.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.009836	150	54750	0	0	200
2	0.019672	150	109650	4101.8683	0	200
3	0.029535	150	164400	4101.8683	1501511.6	200
4	0.039372	150	219150	4101.8683	2998921	200
5	0.059048	300	328650	4101.8683	4493248.9	200
6	0.07867	300	438150	4101.8683	5989979.4	200
7	0.098354	300	547950	4101.8683	7488612.3	200
8	0.114317	240.83913	636266.56	0	8983886	200
9	0.129078	215.42461	718850.19	0	8992660.3	200
10	0.156247	357.43753	870578.75	0	8992660.3	200
11	0.177121	285.07938	986657.69	0	8992660.3	200
12	0.194166	237.7627	1081333.9	0	8992660.3	200
13	0.208507	201.94402	1161297.6	0	8992660.3	200
14	0.220723	171.2914	1229100.4	0	8992660.3	200
15	0.231152	146.25868	1287081.8	0	8992660.3	200
16	0.239777	119.21666	1335138.5	0	8992660.3	200
17	0.246908	99.419891	1374934.9	0	8992660.3	200
18	0.252907	85.328125	1408261.6	0	8992660.3	200
19	0.258321	78.217346	1437857.3	0	8992660.3	200
20	0.263289	73.530838	1465510.9	0	8992660.3	200

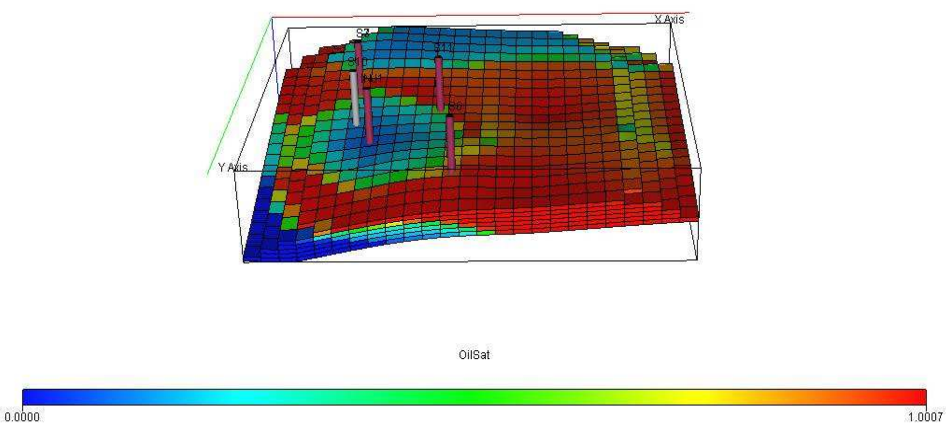

Figure B.6 3-D reservoir model of case3_inj200 at the end of production period.

Table B.7 Oil production and surfactant solution injection data of surfactant flood model name case1_inj300.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.0098358	150	54900	0	0	300
2	0.0196714	150	109650	0	0	300
3	0.0295369	150	164400	2289.4146	838052.96	300
4	0.0393748	150	219150	2289.4146	1673816.2	300
5	0.0590456	300	328650	2289.4146	2527613.1	300
6	0.078716	300	438150	2289.4146	3356394.2	300
7	0.098374	300	547950	2289.4146	4183395.4	300
8	0.1155652	252.68234	643740.31	2289.4146	5019158.8	300
9	0.1304525	192.49661	726126.31	0	5019158.8	300
10	0.1536248	284.60696	855634.19	0	5019158.8	300
11	0.1701303	226.03178	947532.06	0	5019158.8	300
12	0.1833664	178.04404	1021071.5	0	5019158.8	300
13	0.1940068	148.56641	1080709	0	5019158.8	300
14	0.2031003	130.35136	1131786.9	0	5019158.8	300
15	0.2112105	117.00247	1175627.3	0	5019158.8	300
16	0.218441	104.06034	1215872.1	0	5019158.8	300
17	0.2248596	92.988533	1251600.3	0	5019158.8	300
18	0.230681	85.552261	1284005.9	0	5019158.8	300
19	0.23613	80.527	1314337.8	0	5019158.8	300
20	0.2412558	76.156898	1342870.9	0	5019158.8	300

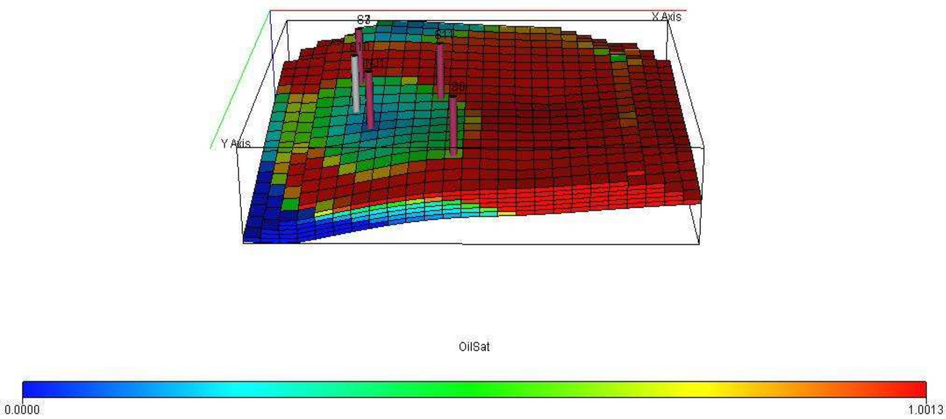

Figure B.7 3-D reservoir model of case1_inj300 at the end of production period.

Table B.8 Oil production and surfactant solution injection data of surfactant flood model name case2_inj300.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.009836	150	54900	0	0	300
2	0.019671	150	109650	0	0	300
3	0.029539	150	164400	4101.8678	1501511.6	300
4	0.039377	150	219150	4101.8678	2998920.8	300
5	0.059048	300	328650	4101.8678	4512025.3	300
6	0.078719	300	438150	4101.8678	6019345	300
7	0.098444	300	547950	4101.8678	7495250.7	300
8	0.116339	264.53485	647999.94	4101.8678	8992659.3	300
9	0.132975	244.75549	740142.56	0	8992659.3	300
10	0.160208	295.11594	892902.44	0	8992659.3	300
11	0.176999	224.01474	985726.62	0	8992659.3	300
12	0.189897	172.81271	1057488.8	0	8992659.3	300
13	0.200307	144.18349	1114932.3	0	8992659.3	300
14	0.208989	122.97942	1164097	0	8992659.3	300
15	0.216509	106.2863	1205118.8	0	8992659.3	300
16	0.223002	93.193802	1241263.4	0	8992659.3	300
17	0.228826	85.35778	1273682.6	0	8992659.3	300
18	0.234226	79.786896	1303740.1	0	8992659.3	300
19	0.23931	74.951828	1332043.8	0	8992659.3	300
20	0.244073	70.520302	1358555.8	0	8992659.3	300

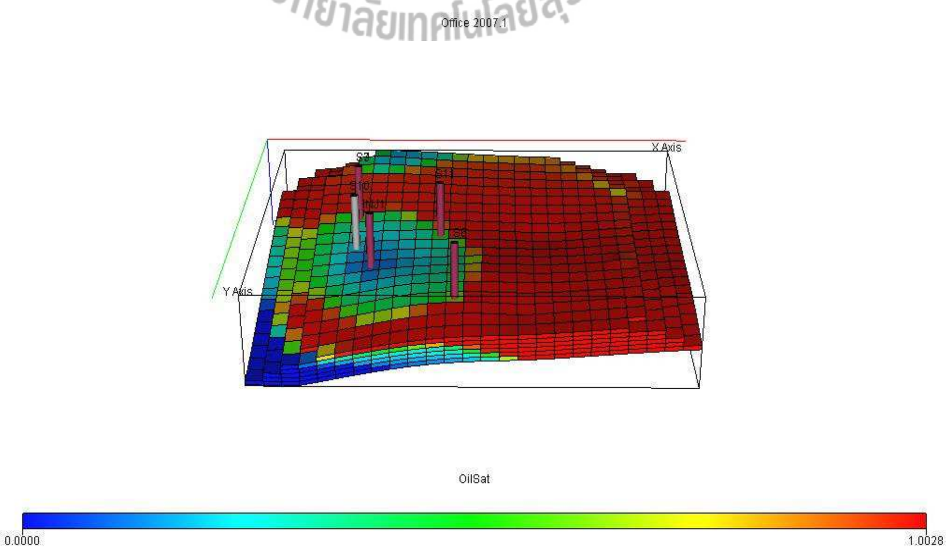

Figure B.8 3-D reservoir model of case2_inj300 at the end of production period.

Table B.9 Oil production and surfactant solution injection data of surfactant flood model name case3_inj300.

TIME (YEARS)	FOE	FOPR (STB/DAY)	FOPT (STB)	FTIRSUR (KG/DAY)	FTITSUR (KG)	FWIR (STB/DAY)
0	0	0	0	0	0	0
1	0.0098358	150	54900	0	0	300
2	0.0196714	150	109650	0	0	300
3	0.0295372	150	164400	6152.8022	2252267.6	300
4	0.0393755	150	219150	6152.8022	4498381.3	300
5	0.0590465	300	328650	6152.8022	6768409.3	300
6	0.0787176	300	438150	6152.8022	9014934.4	300
7	0.0984422	300	547950	6152.8022	11242877	300
8	0.1153881	257.56668	642746.69	6152.8022	13488990	300
9	0.131715	3054.4275	733614.31	0	13488990	300
10	0.1700362	295.97589	947360.75	0	13488990	300
11	0.1871705	231.8898	1042470.1	0	13488990	300
12	0.2009268	190.84727	1118985.3	0	13488990	300
13	0.2124052	157.84482	1182661.9	0	13488990	300
14	0.2217103	127.77355	1234505.4	0	13488990	300
15	0.2292754	104.82251	1276526.5	0	13488990	300
16	0.2356643	90.893356	1312106.9	0	13488990	300
17	0.241164	78.137009	1342648	0	13488990	300
18	0.2460041	70.326904	1369672.6	0	13488990	300
19	0.2504807	66.498512	1394471.3	0	13488990	300
20	0.2547798	63.591602	1418177.3	0	13488990	300

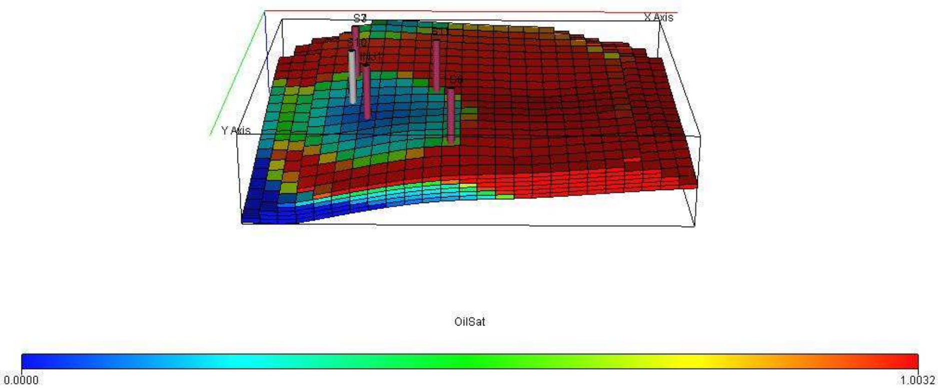

Figure B.9 3-D reservoir model of case3_inj300 at the end of production period.

APPENDIX C

CASH FLOW TABLE

Table C.1 The cash flow table of model case1_inj100.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well		Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($)		Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
												New injection well	Previous production well				INTANG	TANG				
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,900	150	54,750.00	150.00	4,392,000	219,600	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,750	150	54,750.00	-	4,380,000	219,000	1.1041				0	0	1	36,500	0	0	0	0	0	12,500	0	62,000
3	54,750	150	51,056.77	3,693.23	4,380,000	219,000	1.1262				0	0	0	0	278,545	362,109	0	0	0	0	0	0
4	54,750	150	41,960.07	12,789.93	4,380,000	219,000	1.1487				0	0	0	0	278,545	362,109	0	0	0	0	0	0
5	107,612	295	100,928.16	6,684.31	8,608,998	430,450	1.1717				1	0	0	0	278,545	362,109	1,200,000	300,000	250,000	0	0	0
6	95,290	261	84,254.84	11,034.97	7,623,185	381,159	1.1951				0	0	0	0	278,545	362,109	0	0	0	0	0	0
7	87,267	239	70,014.85	17,252.00	6,981,348	349,067	1.2190				0	0	0	0	278,545	362,109	0	0	0	0	0	0
8	76,631	210	69,669.06	6,962.06	6,130,490	306,524	1.2434				1	0	0	0	278,545	362,109	1,200,000	300,000	250,000	0	0	0
9	67,494	185	54,456.31	13,038.07	5,399,550	269,978	1.2682				0	0	0	36,500	0	0	0	0	0	0	0	0
10	113,904	312	71,036.25	42,867.81	9,112,325	455,616	1.2936				1	0	0	36,500	0	0	1,200,000	300,000	250,000	0	0	0
11	83,127	228	57,008.00	26,118.75	6,650,140	332,507	1.3195				0	0	0	36,500	0	0	0	0	0	0	0	0
12	74,220	203	45,770.32	28,449.24	5,937,565	296,878	1.3459				0	0	0	36,500	0	0	0	0	0	0	0	0
13	63,753	175	36,698.68	27,053.95	5,100,210	255,011	1.3728				0	0	0	36,500	0	0	0	0	0	0	0	0
14	55,073	151	38,882.88	16,190.09	4,405,838	220,292	1.4002				0	0	0	36,500	0	0	0	0	0	0	0	0
15	48,875	134	42,107.87	6,767.43	3,910,024	195,501	1.4282				0	0	0	36,500	0	0	0	0	0	0	0	0
16	44,329	121	43,566.82	762.18	3,546,320	177,316	1.4568				0	0	0	36,500	0	0	0	0	0	0	0	0
17	40,395	111	43,157.06	- 2,761.96	3,231,608	161,580	1.4859				0	0	0	36,500	0	0	0	0	0	0	0	0
18	37,083	102	42,210.86	- 5,127.96	2,966,632	148,332	1.5157				0	0	0	36,500	0	0	0	0	0	0	0	0
19	34,226	94	40,309.30	- 6,083.40	2,738,072	136,904	1.5460				0	0	0	36,500	0	0	0	0	0	0	0	0
20	32,478	89	37,110.70	- 4,633.00	2,598,216	129,911	1.5769				0	0	0	36,500	0	0	0	0	0	0	0	0
	1,280,907			201,207.70	102,472,520	5,123,626		250,000	500,000	1,000,000	4	0	1	474,500	1,671,273	2,172,654	4,800,000	1,200,000	1,000,000	12,500	0	62,000

Table C.1 The cash flow table of model case1_inj100 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1st year	2nd year	3rd year	4th year	5th year	6th year	7th year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil								
																		1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,188,511	0	0	0	0	1,518,111	2,873,889	-186,111	0	2,873,889	0.681	1,955,921	-460,951
		122,400					122,400	1,208,968	33,122	0	20,149	0	1,616,140	2,763,860	2,577,749	1,381,930	1,381,930	0.630	870,850	409,899
			122,400				122,400	1,233,148	0	11,262	0	37,765	1,985,684	2,394,316	4,972,065	1,197,158	1,197,158	0.583	698,530	1,108,429
				122,400			122,400	1,257,811	0	11,487	0	38,521	2,011,327	2,368,673	7,340,738	1,184,336	1,184,336	0.540	639,860	1,748,289
					12,400		12,400	2,521,703	0	11,717	0	39,291	4,577,670	4,031,328	11,372,065	2,015,664	2,015,664	0.500	1,008,334	2,756,623
						12,400	12,400	2,277,603	0	11,951	0	40,077	3,085,299	4,537,886	15,909,951	2,268,943	2,268,943	0.463	1,050,960	3,807,582
0	0	0	0	0	0	0	0	2,127,556	0	12,190	0	40,879	2,891,801	4,089,547	19,999,498	2,044,774	2,044,774	0.429	876,968	4,684,551
110,000	0	0	0	0	0	0	110,000	1,905,623	0	12,434	0	41,696	3,938,387	2,192,103	22,191,601	1,096,051	1,096,051	0.397	435,257	5,119,808
0	110,000	0	0	0	0	0	110,000	1,711,984	38,047	0	23,145	0	2,153,154	3,246,396	25,437,997	1,623,198	1,623,198	0.368	596,847	5,716,654
110,000	0	110,000	0	0	0	0	220,000	2,946,941	38,808	0	23,608	0	4,884,974	4,227,351	29,665,348	2,113,676	2,113,676	0.340	719,624	6,436,279
0	110,000	0	110,000	0	0	0	220,000	2,193,680	39,584	0	24,080	0	2,809,851	3,840,289	33,505,637	1,920,144	1,920,144	0.315	605,310	7,041,588
0	0	110,000	0	110,000	0	0	220,000	1,997,795	40,376	0	24,562	0	2,579,612	3,357,953	36,863,590	1,678,977	1,678,977	0.292	490,077	7,531,665
0	0	0	110,000	0	110,000	0	110,000	1,750,374	41,184	0	25,053	0	2,181,621	2,918,589	39,782,179	1,459,294	1,459,294	0.270	394,402	7,926,067
0	0	0	0	110,000	0	110,000	110,000	1,542,309	42,007	0	25,554	0	1,940,163	2,465,675	42,247,854	1,232,837	1,232,837	0.250	308,516	8,234,584
0	0	0	0	0	110,000	0	0	1,396,119	42,847	0	26,065	0	1,660,533	2,249,491	44,497,345	1,124,745	1,124,745	0.232	260,617	8,495,201
0	0	0	0	0	0	110,000	0	1,291,580	43,704	0	26,587	0	1,539,187	2,007,133	46,504,478	1,003,567	1,003,567	0.215	215,313	8,710,514
0	0	0	0	0	0	0	0	1,200,500	44,578	0	27,119	0	1,433,777	1,797,831	48,302,309	898,915	898,915	0.199	178,575	8,889,089
0	0	0	0	0	0	0	0	1,124,106	45,470	0	27,661	0	1,345,569	1,621,063	49,923,372	810,532	810,532	0.184	149,090	9,038,179
0	0	0	0	0	0	0	0	1,058,251	46,379	0	28,214	0	1,269,748	1,468,324	51,391,696	734,162	734,162	0.170	125,039	9,163,218
0	0	0	0	0	0	0	0	1,024,281	47,307	0	28,778	0	1,230,277	1,367,939	52,759,635	683,969	683,969	0.158	107,862	9,271,079
							1,712,000	32,958,843	543,416	71,040	330,578	238,229	49,712,885	52,759,635		26,472,873	26,286,762		9,271,079	
																IRR	42.52%		31.96%	
																PIR	2.390		0.843	

Table C.2 The cash flow table of model case2_inj100.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well		Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($)		Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
												New injection well	Previous production well				INTANG	TANG				
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,900	150	54,750.00	150.00	4,392,000	219,600	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,750	150	54,750.00	-	4,380,000	219,000	1.1041				0	0	1	36,500	0	0	0	0	0	12,500	0	62,000
3	54,750	150	46,492.21	8,257.79	4,380,000	219,000	1.1262				0	0	0	0	499,061	648,779	0	0	0	0	0	0
4	54,750	150	39,870.03	14,879.97	4,380,000	219,000	1.1487				0	0	0	0	499,061	648,779	0	0	0	0	0	0
5	107,659	295	93,986.64	13,672.58	8,612,738	430,637	1.1717				1	0	0	0	499,061	648,779	1,200,000	300,000	250,000	0	0	0
6	95,310	261	78,176.21	17,133.54	7,624,780	381,239	1.1951				0	0	0	0	499,061	648,779	0	0	0	0	0	0
7	87,502	240	65,267.00	22,234.91	7,000,153	350,008	1.2190				0	0	0	0	499,061	648,779	0	0	0	0	0	0
8	78,005	214	62,852.16	15,152.65	6,240,385	312,019	1.2434				1	0	0	0	499,061	648,779	1,200,000	300,000	250,000	0	0	0
9	70,378	193	49,889.54	20,488.77	5,630,265	281,513	1.2682				0	0	0	36,500	0	0	0	0	0	0	0	0
10	115,187	316	64,850.58	50,336.17	9,214,940	460,747	1.2936				1	0	0	36,500	0	0	1,200,000	300,000	250,000	0	0	0
11	87,013	238	52,382.91	34,629.78	6,961,015	348,051	1.3195				0	0	0	36,500	0	0	0	0	0	0	0	0
12	75,050	206	42,087.85	32,961.77	6,003,970	300,198	1.3459				0	0	0	36,500	0	0	0	0	0	0	0	0
13	64,226	176	33,716.48	30,509.02	5,138,040	256,902	1.3728				0	0	0	36,500	0	0	0	0	0	0	0	0
14	55,593	152	40,866.23	14,726.81	4,447,443	222,372	1.4002				0	0	0	36,500	0	0	0	0	0	0	0	0
15	48,851	134	42,709.54	6,141.66	3,908,096	195,405	1.4282				0	0	0	36,500	0	0	0	0	0	0	0	0
16	43,675	120	43,927.19	- 252.69	3,493,960	174,698	1.4568				0	0	0	36,500	0	0	0	0	0	0	0	0
17	40,309	110	42,494.11	- 2,184.81	3,224,744	161,237	1.4859				0	0	0	36,500	0	0	0	0	0	0	0	0
18	37,265	102	41,855.09	- 4,590.59	2,981,160	149,058	1.5157				0	0	0	36,500	0	0	0	0	0	0	0	0
19	34,874	96	39,025.94	- 4,152.24	2,789,896	139,495	1.5460				0	0	0	36,500	0	0	0	0	0	0	0	0
20	32,596	89	36,158.28	- 3,562.08	2,607,696	130,385	1.5769				0	0	0	36,500	0	0	0	0	0	0	0	0
	1,292,641			266,532.99	103,411,280	5,170,564		250,000	500,000	1,000,000	4	0	1	474,500	2,994,364	3,892,673	4,800,000	1,200,000	1,000,000	12,500	0	62,000

Table C.2 The cash flow table of model case2_inj100 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1st year	2nd year	3rd year	4th year	5th year	6th year	7th year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil								
																		1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,188,511	0	0	0	0	1,518,111	2,873,889	-186,111	0	2,873,889	0.681	1,955,921	-460,951
		122,400					122,400	1,208,968	33,122	0	20,149	0	1,616,140	2,763,860	2,577,749	1,381,930	1,381,930	0.630	870,850	409,899
			122,400				122,400	1,233,148	0	11,262	0	50,027	2,284,615	2,095,385	4,673,134	1,047,693	1,047,693	0.583	611,319	1,021,217
				122,400			122,400	1,257,811	0	11,487	0	51,027	2,310,504	2,069,496	6,742,631	1,034,748	1,034,748	0.540	559,042	1,580,260
					12,400		12,400	2,522,799	0	11,717	0	52,048	4,878,379	3,734,359	10,476,990	1,867,180	1,867,180	0.500	934,055	2,514,314
						12,400	12,400	2,278,079	0	11,951	0	53,089	3,385,537	4,239,243	14,716,233	2,119,622	2,119,622	0.463	981,795	3,496,109
0	0	0	0	0	0	0	0	2,133,287	0	12,190	0	54,150	3,198,414	3,801,739	18,517,972	1,900,870	1,900,870	0.429	815,250	4,311,360
110,000	0	0	0	0	0	0	110,000	1,939,784	0	12,434	0	55,233	4,278,249	1,962,136	20,480,108	981,068	981,068	0.397	389,596	4,700,955
0	110,000	0	0	0	0	0	110,000	1,785,134	38,047	0	23,145	0	2,237,840	3,392,425	23,872,533	1,696,212	1,696,212	0.368	623,694	5,324,649
110,000	0	110,000	0	0	0	0	220,000	2,980,127	38,808	0	23,608	0	4,923,290	4,291,650	28,164,183	2,145,825	2,145,825	0.340	730,570	6,055,219
0	110,000	0	110,000	0	0	0	220,000	2,296,228	39,584	0	24,080	0	2,927,944	4,033,072	32,197,254	2,016,536	2,016,536	0.315	635,696	6,690,915
0	0	110,000	0	110,000	0	0	220,000	2,020,138	40,376	0	24,562	0	2,605,275	3,398,695	35,595,949	1,699,347	1,699,347	0.292	496,023	7,186,938
0	0	0	110,000	0	110,000	0	110,000	1,763,357	41,184	0	25,053	0	2,196,496	2,941,544	38,537,493	1,470,772	1,470,772	0.270	397,504	7,584,442
0	0	0	0	110,000	0	110,000	110,000	1,556,874	42,007	0	25,554	0	1,956,807	2,490,636	41,028,129	1,245,318	1,245,318	0.250	311,640	7,896,082
0	0	0	0	0	110,000	0	0	1,395,431	42,847	0	26,065	0	1,659,749	2,248,347	43,276,477	1,124,174	1,124,174	0.232	260,485	8,156,566
0	0	0	0	0	0	110,000	0	1,272,510	43,704	0	26,587	0	1,517,499	1,976,461	45,252,937	988,230	988,230	0.215	212,023	8,368,590
0	0	0	0	0	0	0	0	1,197,950	44,578	0	27,119	0	1,430,884	1,793,860	47,046,797	896,930	896,930	0.199	178,180	8,546,770
0	0	0	0	0	0	0	0	1,129,611	45,470	0	27,661	0	1,351,800	1,629,360	48,676,157	814,680	814,680	0.184	149,853	8,696,623
0	0	0	0	0	0	0	0	1,078,281	46,379	0	28,214	0	1,292,369	1,497,527	50,173,684	748,764	748,764	0.170	127,526	8,824,148
0	0	0	0	0	0	0	0	1,028,018	47,307	0	28,778	0	1,234,489	1,373,207	51,546,892	686,604	686,604	0.158	108,277	8,932,425
							1,712,000	33,266,045	543,416	71,040	330,578	315,574	51,864,388	51,546,892		25,866,501	25,680,391		8,932,425	
																IRR	41.42%		30.95%	
																PIR	2.019		0.702	

Table C.3 The cash flow table of model case3_inj100.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well		Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($)		Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
												New injection well	Previous production well				INTANG	TANG				
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,900	150	54,750.00	150.00	4,392,000	219,600	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,750	150	54,750.00	-	4,380,000	219,000	1.1041				0	0	0	36,500	0	0	0	0	0	0	0	0
3	54,750	150	46,492.21	8,257.79	4,380,000	219,000	1.1262				0	0	0	0	748,591	973,168	0	0	0	0	0	0
4	54,750	150	39,870.03	14,879.97	4,380,000	219,000	1.1487				0	0	0	0	748,591	973,168	0	0	0	0	0	0
5	107,654	295	93,986.64	13,667.02	8,612,293	430,615	1.1717				1	0	0	0	748,591	973,168	1,200,000	300,000	250,000	0	0	0
6	95,373	261	78,176.21	17,196.85	7,629,845	381,492	1.1951				0	0	0	0	748,591	973,168	0	0	0	0	0	0
7	87,688	240	65,267.00	22,421.40	7,015,072	350,754	1.2190				0	0	0	0	748,591	973,168	0	0	0	0	0	0
8	78,963	216	62,852.16	16,110.47	6,317,010	315,851	1.2434				1	0	0	0	748,591	973,168	1,200,000	300,000	250,000	0	0	0
9	71,422	196	49,889.54	21,532.02	5,713,725	285,686	1.2682				0	0	0	36,500	0	0	0	0	0	0	0	0
10	119,571	328	64,850.58	54,720.17	9,565,660	478,283	1.2936				1	0	0	36,500	0	0	1,200,000	300,000	250,000	0	0	0
11	88,960	244	52,382.91	36,577.16	7,116,806	355,840	1.3195				0	0	0	36,500	0	0	0	0	0	0	0	0
12	77,702	213	42,087.85	35,613.83	6,216,134	310,807	1.3459				0	0	0	36,500	0	0	0	0	0	0	0	0
13	67,285	184	33,716.48	33,568.11	5,382,767	269,138	1.3728				0	0	0	36,500	0	0	0	0	0	0	0	0
14	58,946	161	40,866.23	18,079.37	4,715,648	235,782	1.4002				0	0	1	36,500	0	0	0	0	0	12,500	50,000	62,000
15	52,311	143	42,709.54	9,601.76	4,184,904	209,245	1.4282				0	0	0	36,500	0	0	0	0	0	0	0	0
16	47,805	131	43,927.19	3,877.31	3,824,360	191,218	1.4568				0	0	0	36,500	0	0	0	0	0	0	0	0
17	43,789	120	42,494.11	1,294.59	3,503,096	175,155	1.4859				0	0	0	36,500	0	0	0	0	0	0	0	0
18	39,978	110	41,855.09	- 1,877.19	3,198,232	159,912	1.5157				0	0	0	36,500	0	0	0	0	0	0	0	0
19	37,304	102	39,025.94	- 1,721.54	2,984,352	149,218	1.5460				0	0	0	36,500	0	0	0	0	0	0	0	0
20	35,193	96	36,158.28	- 965.28	2,815,440	140,772	1.5769				0	0	0	36,500	0	0	0	0	0	0	0	0
	1,329,092			302,983.79	106,327,344	5,316,367		250,000	500,000	1,000,000	4	0	1	474,500	4,491,546	5,839,009	4,800,000	1,200,000	1,000,000	12,500	50,000	62,000

Table C.3 The cash flow table of model case3_inj100 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1st year	2nd year	3rd year	4th year	5th year	6th year	7th year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil								
																		1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,188,511	0	0	0	0	1,518,111	2,873,889	-186,111	0	2,873,889	0.681	1,955,921	-460,951
		110,000					110,000	1,208,968	33,122	0	20,149	0	1,591,240	2,788,760	2,602,649	1,394,380	1,394,380	0.630	878,696	417,744
			110,000				110,000	1,233,148	0	11,262	0	56,868	2,603,446	1,776,554	4,379,203	888,277	888,277	0.583	518,301	936,046
				110,000			110,000	1,257,811	0	11,487	0	58,006	2,629,471	1,750,529	6,129,732	875,264	875,264	0.540	472,878	1,408,924
					0		0	2,522,668	0	11,717	0	59,166	5,197,334	3,414,959	9,544,691	1,707,480	1,707,480	0.500	854,165	2,263,089
						0	0	2,279,593	0	11,951	0	60,349	3,706,553	3,923,292	13,467,983	1,961,646	1,961,646	0.463	908,622	3,171,710
0	0	0	0	0	0	0	0	2,137,833	0	12,190	0	61,556	3,535,501	3,479,571	16,947,554	1,739,785	1,739,785	0.429	746,164	3,917,874
110,000	0	0	0	0	0	0	110,000	1,963,602	0	12,434	0	62,787	4,637,842	1,679,169	18,626,723	839,584	839,584	0.397	333,411	4,251,285
0	110,000	0	0	0	0	0	110,000	1,811,596	38,047	0	23,145	0	2,268,475	3,445,250	22,071,972	1,722,625	1,722,625	0.368	633,406	4,884,690
110,000	0	110,000	0	0	0	0	220,000	3,093,550	38,808	0	23,608	0	5,054,250	4,511,410	26,583,382	2,255,705	2,255,705	0.340	767,980	5,652,670
0	110,000	0	110,000	0	0	0	220,000	2,347,618	39,584	0	24,080	0	2,987,124	4,129,682	30,713,064	2,064,841	2,064,841	0.315	650,924	6,303,594
0	0	110,000	0	110,000	0	0	220,000	2,091,525	40,376	0	24,562	0	2,687,269	3,528,865	34,241,929	1,764,432	1,764,432	0.292	515,021	6,818,615
0	0	0	110,000	0	110,000	0	110,000	1,847,346	41,184	0	25,053	0	2,292,722	3,090,045	37,331,975	1,545,023	1,545,023	0.270	417,572	7,236,187
10,000	0	0	0	110,000	0	110,000	120,000	1,650,761	42,007	0	25,554	0	2,086,605	2,629,043	39,961,017	1,314,521	1,314,521	0.250	328,958	7,565,145
0	10,000	0	0	0	110,000	0	10,000	1,494,268	42,847	0	26,065	0	1,782,426	2,402,478	42,363,495	1,201,239	1,201,239	0.232	278,342	7,843,486
0	0	10,000	0	0	0	110,000	10,000	1,392,843	43,704	0	26,587	0	1,664,352	2,160,008	44,523,503	1,080,004	1,080,004	0.215	231,713	8,075,199
0	0	0	10,000	0	0	0	10,000	1,301,354	44,578	0	27,119	0	1,558,206	1,944,890	46,468,393	972,445	972,445	0.199	193,182	8,268,381
0	0	0	0	10,000	0	0	10,000	1,211,863	45,470	0	27,661	0	1,454,906	1,743,326	48,211,720	871,663	871,663	0.184	160,334	8,428,715
0	0	0	0	0	10,000	0	0	1,153,437	46,379	0	28,214	0	1,377,248	1,607,104	49,818,824	803,552	803,552	0.170	136,857	8,565,572
0	0	0	0	0	0	10,000	0	1,109,916	47,307	0	28,778	0	1,326,774	1,488,666	51,307,490	744,333	744,333	0.158	117,381	8,682,953
							1,700,000	34,298,213	543,416	71,040	330,578	358,731	55,019,854	51,307,490		25,746,800	25,560,690		8,682,953	
																IRR	40.26%		29.87%	
																PIR	1.737		0.590	

Table C.4 The cash flow table of model case1_inj200.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well		Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($)		Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
												New injection well	Previous production well				INTANG	TANG				
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,750	150	54,750.00	-	4,380,000	219,000	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,900	150	54,750.00	150.00	4,392,000	219,600	1.1041				0	0	1	73,000	0	0	0	0	0	12,500	0	62,000
3	54,750	150	46,492.21	8,257.79	4,380,000	219,000	1.1262				0	0	0	0	557,091	724,218	0	0	0	0	0	0
4	54,750	150	39,870.03	14,879.97	4,380,000	219,000	1.1487				0	0	0	0	557,091	724,218	0	0	0	0	0	0
5	109,500	300	93,986.64	15,513.36	8,760,000	438,000	1.1717				1	0	0	0	557,091	724,218	1,200,000	300,000	250,000	0	0	0
6	109,500	300	78,176.21	31,323.79	8,760,000	438,000	1.1951				0	0	0	0	557,091	724,218	0	0	0	0	0	0
7	99,428	272	65,267.00	34,161.06	7,954,245	397,712	1.2190				0	0	0	0	557,091	724,218	0	0	0	0	0	0
8	70,788	194	62,852.16	7,936.09	5,663,060	283,153	1.2434				1	0	0	0	557,091	724,218	1,200,000	300,000	250,000	0	0	0
9	63,251	173	49,889.54	13,361.21	5,060,060	253,003	1.2682				0	0	0	73,000	0	0	0	0	0	0	0	0
10	129,198	354	64,850.58	64,347.74	10,335,866	516,793	1.2936				1	0	0	73,000	0	0	1,200,000	300,000	250,000	0	0	0
11	102,858	282	52,382.91	50,475.02	8,228,634	411,432	1.3195				0	0	0	73,000	0	0	0	0	0	0	0	0
12	86,076	236	42,087.85	43,988.09	6,886,075	344,304	1.3459				0	0	0	73,000	0	0	0	0	0	0	0	0
13	73,568	202	33,716.48	39,851.37	5,885,428	294,271	1.3728				0	0	0	73,000	0	0	0	0	0	0	0	0
14	64,969	178	40,866.23	24,102.27	5,197,480	259,874	1.4002				0	0	0	73,000	0	0	0	0	0	0	0	0
15	57,346	157	42,709.54	14,635.96	4,587,640	229,382	1.4282				0	0	0	73,000	0	0	0	0	0	0	0	0
16	50,547	138	43,927.19	6,620.21	4,043,792	202,190	1.4568				0	0	0	73,000	0	0	0	0	0	0	0	0
17	43,447	119	42,494.11	952.39	3,475,720	173,786	1.4859				0	0	0	73,000	0	0	0	0	0	0	0	0
18	38,679	106	41,855.09	- 3,175.69	3,094,352	154,718	1.5157				0	0	0	73,000	0	0	0	0	0	0	0	0
19	35,278	97	39,025.94	- 3,748.04	2,822,232	141,112	1.5460				0	0	0	73,000	0	0	0	0	0	0	0	0
20	32,595	89	36,158.28	- 3,563.68	2,607,568	130,378	1.5769				0	0	0	73,000	0	0	0	0	0	0	0	0
	1,386,177			360,068.89	110,894,152	5,544,708		250,000	500,000	1,000,000	4	0	1	949,000	3,342,545	4,345,309	4,800,000	1,200,000	1,000,000	12,500	0	62,000

Table C.4 The cash flow table of model case1_inj200 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1^{st} year	2^{nd} year	3^{rd} year	4^{th} year	5^{th} year	6^{th} year	7^{th} year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil						1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,185,263	0	0	0	0	1,514,263	2,865,737	-194,263	0	2,865,737	0.681	1,950,372	-466,500
		122,400					122,400	1,212,281	33,122	0	40,299	0	1,640,202	2,751,798	2,557,535	1,375,899	1,375,899	0.630	867,050	400,550
			122,400				122,400	1,233,148	0	11,262	0	67,583	2,377,610	2,002,390	4,559,924	1,001,195	1,001,195	0.583	584,188	984,737
				122,400			122,400	1,257,811	0	11,487	0	68,934	2,403,850	1,976,150	6,536,074	988,075	988,075	0.540	533,826	1,518,564
					12,400		12,400	2,565,934	0	11,717	0	70,313	5,022,582	3,737,418	10,273,492	1,868,709	1,868,709	0.500	934,820	2,453,383
						12,400	12,400	2,617,253	0	11,951	0	71,719	3,875,541	4,884,459	15,157,951	2,442,229	2,442,229	0.463	1,131,225	3,584,608
0	0	0	0	0	0	0	0	2,424,045	0	12,190	0	73,154	3,631,319	4,322,926	19,480,877	2,161,463	2,161,463	0.429	927,014	4,511,622
110,000	0	0	0	0	0	0	110,000	1,760,326	0	12,434	0	74,617	4,164,747	1,498,313	20,979,190	749,156	749,156	0.397	297,500	4,809,123
0	110,000	0	0	0	0	0	110,000	1,604,345	38,047	0	46,291	0	2,051,686	3,008,374	23,987,564	1,504,187	1,504,187	0.368	553,086	5,362,209
110,000	0	110,000	0	0	0	0	220,000	3,342,636	38,808	0	47,217	0	5,365,454	4,970,411	28,957,975	2,485,206	2,485,206	0.340	846,116	6,208,325
0	110,000	0	110,000	0	0	0	220,000	2,714,377	39,584	0	48,161	0	3,433,554	4,795,080	33,753,055	2,397,540	2,397,540	0.315	755,805	6,964,130
0	0	110,000	0	110,000	0	0	220,000	2,316,938	40,376	0	49,124	0	2,970,742	3,915,334	37,668,389	1,957,667	1,957,667	0.292	571,424	7,535,554
0	0	0	110,000	0	110,000	0	110,000	2,019,858	41,184	0	50,107	0	2,515,420	3,370,008	41,038,397	1,685,004	1,685,004	0.270	455,404	7,990,958
0	0	0	0	110,000	0	110,000	110,000	1,819,432	42,007	0	51,109	0	2,282,422	2,915,058	43,953,456	1,457,529	1,457,529	0.250	364,745	8,355,703
0	0	0	0	0	110,000	0	0	1,638,070	42,847	0	52,131	0	1,962,430	2,625,210	46,578,665	1,312,605	1,312,605	0.232	304,146	8,659,850
0	0	0	0	0	0	110,000	0	1,472,760	43,704	0	53,174	0	1,771,828	2,271,964	48,850,630	1,135,982	1,135,982	0.215	243,723	8,903,573
0	0	0	0	0	0	0	0	1,291,184	44,578	0	54,237	0	1,563,786	1,911,934	50,762,564	955,967	955,967	0.199	189,908	9,093,481
0	0	0	0	0	0	0	0	1,172,501	45,470	0	55,322	0	1,428,011	1,666,341	52,428,905	833,171	833,171	0.184	153,254	9,246,735
0	0	0	0	0	0	0	0	1,090,778	46,379	0	56,428	0	1,334,698	1,487,534	53,916,439	743,767	743,767	0.170	126,675	9,373,410
0	0	0	0	0	0	0	0	1,027,968	47,307	0	57,557	0	1,263,210	1,344,358	55,260,797	672,179	672,179	0.158	106,002	9,479,412
							1,712,000	35,766,908	543,416	71,040	661,156	426,320	55,633,355	55,260,797		27,727,530	27,533,267		9,479,412	
																IRR	41.66%		31.17%	
																PIR	2.091		0.720	

Table C.5 The cash flow table of model case2_inj200.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well: New injection well	No. of water injection or surfactant injection well: Previous production well	Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($): INTANG	Drilling and completion costs of production well ($): TANG	Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,750	150	54,750.00	-	4,380,000	219,000	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,900	150	54,750.00	150.00	4,392,000	219,600	1.1041				0	0	1	73,000	0	0	0	0	0	12,500	0	62,000
3	54,750	150	46,492.21	8,257.79	4,380,000	219,000	1.1262				0	0	0	0	998,121	1,297,557	0	0	0	0	0	0
4	54,750	150	39,870.03	14,879.97	4,380,000	219,000	1.1487				0	0	0	0	998,121	1,297,557	0	0	0	0	0	0
5	109,500	300	93,986.64	15,513.36	8,760,000	438,000	1.1717				1	0	0	0	998,121	1,297,557	1,200,000	300,000	250,000	0	0	0
6	109,500	300	78,176.21	31,323.79	8,760,000	438,000	1.1951				0	0	0	0	998,121	1,297,557	0	0	0	0	0	0
7	106,871	293	65,267.00	41,603.69	8,549,655	427,483	1.2190				0	0	0	0	998,121	1,297,557	0	0	0	0	0	0
8	80,495	221	62,852.16	17,642.84	6,439,600	321,980	1.2434				1	0	0	0	998,121	1,297,557	1,200,000	300,000	250,000	0	0	0
9	70,199	192	49,889.54	20,309.02	5,615,885	280,794	1.2682				0	0	0	73,000	0	0	0	0	0	0	0	0
10	136,722	375	64,850.58	71,871.42	10,937,760	546,888	1.2936				1	0	0	73,000	0	0	1,200,000	300,000	250,000	0	0	0
11	107,914	296	52,382.91	55,531.28	8,633,135	431,657	1.3195				0	0	0	73,000	0	0	0	0	0	0	0	0
12	87,441	240	42,087.85	45,352.81	6,995,253	349,763	1.3459				0	0	0	73,000	0	0	0	0	0	0	0	0
13	71,681	196	33,716.48	37,964.82	5,734,504	286,725	1.3728				0	0	0	73,000	0	0	0	0	0	0	0	0
14	60,890	167	40,866.23	20,023.67	4,871,192	243,560	1.4002				0	0	0	73,000	0	0	0	0	0	0	0	0
15	51,911	142	42,709.54	9,201.06	4,152,848	207,642	1.4282				0	0	0	73,000	0	0	0	0	0	0	0	0
16	43,580	119	43,927.19	- 347.69	3,486,360	174,318	1.4568				0	0	0	73,000	0	0	0	0	0	0	0	0
17	38,501	105	42,494.11	- 3,992.71	3,080,112	154,006	1.4859				0	0	0	73,000	0	0	0	0	0	0	0	0
18	34,655	95	41,855.09	- 7,199.99	2,772,408	138,620	1.5157				0	0	0	73,000	0	0	0	0	0	0	0	0
19	32,003	88	39,025.94	- 7,023.34	2,560,208	128,010	1.5460				0	0	0	73,000	0	0	0	0	0	0	0	0
20	29,778	82	36,158.28	- 6,380.18	2,382,248	119,112	1.5769				0	0	0	73,000	0	0	0	0	0	0	0	0
	1,390,790		1,026,108.01	364,681.59	111,263,168	5,563,158		250,000	500,000	1,000,000	4	0	1	949,000	5,988,727	7,785,345	4,800,000	1,200,000	1,000,000	12,500	0	62,000

Table C.5 The cash flow table of model case2_inj200 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1st year	2nd year	3rd year	4th year	5th year	6th year	7th year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil						1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,185,263	0	0	0	0	1,514,263	2,865,737	-194,263	0	2,865,737	0.681	1,950,372	-466,500
		122,400					122,400	1,212,281	33,122	0	40,299	0	1,640,202	2,751,798	2,557,535	1,375,899	1,375,899	0.630	867,050	400,550
			122,400				122,400	1,233,148	0	11,262	0	68,448	2,951,815	1,428,185	3,985,719	714,092	714,092	0.583	416,666	817,216
				122,400			122,400	1,257,811	0	11,487	0	69,817	2,978,073	1,401,927	5,387,647	700,964	700,964	0.540	378,709	1,195,925
					12,400		12,400	2,565,934	0	11,717	0	71,214	5,596,822	3,163,178	8,550,825	1,581,589	1,581,589	0.500	791,188	1,987,113
						12,400	12,400	2,617,253	0	11,951	0	72,638	4,449,799	4,310,201	12,861,026	2,155,100	2,155,100	0.463	998,228	2,985,341
0	0	0	0	0	0	0	0	2,605,495	0	12,190	0	74,091	4,416,817	4,132,839	16,993,864	2,066,419	2,066,419	0.429	886,252	3,871,593
110,000	0	0	0	0	0	0	110,000	2,001,708	0	12,434	0	75,573	5,019,252	1,420,348	18,414,212	710,174	710,174	0.397	282,020	4,153,613
0	110,000	0	0	0	0	0	110,000	1,780,575	38,047	0	46,291	0	2,255,707	3,360,178	21,774,390	1,680,089	1,680,089	0.368	617,765	4,771,378
110,000	0	110,000	0	0	0	0	220,000	3,537,290	38,808	0	47,217	0	5,590,203	5,347,557	27,121,947	2,673,779	2,673,779	0.340	910,317	5,681,696
0	110,000	0	110,000	0	0	0	220,000	2,847,810	39,584	0	48,161	0	3,587,212	5,045,923	32,167,871	2,522,962	2,522,962	0.315	795,343	6,477,038
0	0	110,000	0	110,000	0	0	220,000	2,353,672	40,376	0	49,124	0	3,012,935	3,982,318	36,150,188	1,991,159	1,991,159	0.292	581,200	7,058,239
0	0	0	110,000	0	110,000	0	110,000	1,968,061	41,184	0	50,107	0	2,456,077	3,278,427	39,428,615	1,639,214	1,639,214	0.270	443,029	7,501,267
0	0	0	0	110,000	0	110,000	110,000	1,705,211	42,007	0	51,109	0	2,151,887	2,719,305	42,147,921	1,359,653	1,359,653	0.250	340,252	7,841,519
0	0	0	0	0	110,000	0	0	1,482,822	42,847	0	52,131	0	1,785,443	2,367,405	44,515,325	1,183,702	1,183,702	0.232	274,278	8,115,797
0	0	0	0	0	0	110,000	0	1,269,742	43,704	0	53,174	0	1,540,938	1,945,422	46,460,747	972,711	972,711	0.215	208,693	8,324,491
0	0	0	0	0	0	0	0	1,144,221	44,578	0	54,237	0	1,397,042	1,683,070	48,143,817	841,535	841,535	0.199	167,176	8,491,666
0	0	0	0	0	0	0	0	1,050,511	45,470	0	55,322	0	1,289,924	1,482,484	49,626,302	741,242	741,242	0.184	136,344	8,628,011
0	0	0	0	0	0	0	0	989,507	46,379	0	56,428	0	1,220,325	1,339,883	50,966,184	669,941	669,941	0.170	114,101	8,742,112
0	0	0	0	0	0	0	0	939,141	47,307	0	57,557	0	1,163,117	1,219,131	52,185,315	609,565	609,565	0.158	96,128	8,838,240
							1,712,000	35,747,458	543,416	71,040	661,156	431,781	59,077,853	52,185,315		26,189,789	25,995,526		8,838,240	
																IRR	39.72%		29.37%	
																PIR	1.565		0.532	

Table C.6 The cash flow table of model case3_inj200.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well		Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($)		Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
												New injection well	Previous production well				INTANG	TANG				
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,750	150	54,750.00	-	4,380,000	219,000	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,900	150	54,750.00	150.00	4,392,000	219,600	1.1041				0	0	1	73,000	0	0	0	0	0	12,500	0	62,000
3	54,750	150	46,492.21	8,257.79	4,380,000	219,000	1.1262				0	0	0	0	1,497,182	1,946,337	0	0	0	0	0	0
4	54,750	150	39,870.03	14,879.97	4,380,000	219,000	1.1487				0	0	0	0	1,497,182	1,946,337	0	0	0	0	0	0
5	109,500	300	93,986.64	15,513.36	8,760,000	438,000	1.1717				1	0	0	0	1,497,182	1,946,337	1,200,000	300,000	250,000	0	0	0
6	109,500	300	78,176.21	31,323.79	8,760,000	438,000	1.1951				0	0	0	0	1,497,182	1,946,337	0	0	0	0	0	0
7	109,800	301	65,267.00	44,533.00	8,784,000	439,200	1.2190				0	0	0	0	1,497,182	1,946,337	0	0	0	0	0	0
8	88,317	242	62,852.16	25,464.40	7,065,325	353,266	1.2434				1	0	0	0	1,497,182	1,946,337	1,200,000	300,000	250,000	0	0	0
9	82,584	226	49,889.54	32,694.09	6,606,690	330,335	1.2682				0	0	0	73,000	0	0	0	0	0	0	0	0
10	151,729	416	64,850.58	86,877.98	12,138,285	606,914	1.2936				1	0	0	73,000	0	0	1,200,000	300,000	250,000	0	0	0
11	116,079	318	52,382.91	63,696.03	9,286,315	464,316	1.3195				0	0	0	73,000	0	0	0	0	0	0	0	0
12	94,676	259	42,087.85	52,588.36	7,574,097	378,705	1.3459				0	0	0	73,000	0	0	0	0	0	0	0	0
13	79,964	219	33,716.48	46,247.22	6,397,096	319,855	1.3728				0	0	0	73,000	0	0	0	0	0	0	0	0
14	67,803	186	40,866.23	26,936.57	5,424,224	271,211	1.4002				0	0	0	73,000	0	0	0	0	0	0	0	0
15	57,981	159	42,709.54	15,271.86	4,638,512	231,926	1.4282				0	0	0	73,000	0	0	0	0	0	0	0	0
16	48,057	132	43,927.19	4,129.51	3,844,536	192,227	1.4568				0	0	0	73,000	0	0	0	0	0	0	0	0
17	39,796	109	42,494.11	- 2,697.71	3,183,712	159,186	1.4859				0	0	0	73,000	0	0	0	0	0	0	0	0
18	33,327	91	41,855.09	- 8,528.39	2,666,136	133,307	1.5157				0	0	0	73,000	0	0	0	0	0	0	0	0
19	29,596	81	39,025.94	- 9,430.24	2,367,656	118,383	1.5460				0	0	0	73,000	0	0	0	0	0	0	0	0
20	27,654	76	36,158.28	- 8,504.68	2,212,288	110,614	1.5769				0	0	0	73,000	0	0	0	0	0	0	0	0
	1,465,511		1,026,108.01	439,402.89	117,240,872	5,862,044		250,000	500,000	1,000,000	4	0	1	949,000	8,983,092	11,678,019	4,800,000	1,200,000	1,000,000	12,500	0	62,000

Table C.6 The cash flow table of model case3_inj200 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1^{st} year	2^{nd} year	3^{rd} year	4^{th} year	5^{th} year	6^{th} year	7^{th} year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil								
																		1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,185,263	0	0	0	0	1,514,263	2,865,737	-194,263	0	2,865,737	0.681	1,950,372	-466,500
		122,400					122,400	1,212,281	33,122	0	40,299	0	1,640,202	2,751,798	2,557,535	1,375,899	1,375,899	0.630	867,050	400,550
			122,400				122,400	1,233,148	0	11,262	0	82,473	3,614,619	765,381	3,322,916	382,690	382,690	0.583	223,296	623,846
				122,400			122,400	1,257,811	0	11,487	0	84,123	3,641,157	738,843	4,061,759	369,422	369,422	0.540	199,587	823,433
					12,400		12,400	2,565,934	0	11,717	0	85,805	6,260,192	2,499,808	6,561,566	1,249,904	1,249,904	0.500	625,263	1,448,696
						12,400	12,400	2,617,253	0	11,951	0	87,521	5,113,461	3,646,539	10,208,105	1,823,269	1,823,269	0.463	844,526	2,293,223
0	0	0	0	0	0	0	0	2,676,912	0	12,190	0	89,272	5,163,910	3,620,090	13,828,195	1,810,045	1,810,045	0.429	776,297	3,069,520
110,000	0	0	0	0	0	0	110,000	2,196,211	0	12,434	0	91,057	5,909,304	1,156,020	14,984,216	578,010	578,010	0.397	229,536	3,299,056
0	110,000	0	0	0	0	0	110,000	2,094,720	38,047	0	46,291	0	2,619,393	3,987,298	18,971,513	1,993,649	1,993,649	0.368	733,061	4,032,116
110,000	0	110,000	0	0	0	0	220,000	3,925,541	38,808	0	47,217	0	6,038,481	6,099,804	25,071,318	3,049,902	3,049,902	0.340	1,038,373	5,070,489
0	110,000	0	110,000	0	0	0	220,000	3,063,274	39,584	0	48,161	0	3,835,335	5,450,980	30,522,298	2,725,490	2,725,490	0.315	859,188	5,929,677
0	0	110,000	0	110,000	0	0	220,000	2,548,434	40,376	0	49,124	0	3,236,639	4,337,457	34,859,755	2,168,729	2,168,729	0.292	633,031	6,562,708
0	0	0	110,000	0	110,000	0	110,000	2,195,460	41,184	0	50,107	0	2,716,606	3,680,490	38,540,246	1,840,245	1,840,245	0.270	497,361	7,060,070
0	0	0	0	110,000	0	110,000	110,000	1,898,806	42,007	0	51,109	0	2,373,133	3,051,091	41,591,337	1,525,545	1,525,545	0.250	381,766	7,441,836
0	0	0	0	0	110,000	0	0	1,656,234	42,847	0	52,131	0	1,983,138	2,655,374	44,246,710	1,327,687	1,327,687	0.232	307,641	7,749,477
0	0	0	0	0	0	110,000	0	1,400,191	43,704	0	53,174	0	1,689,295	2,155,241	46,401,951	1,077,620	1,077,620	0.215	231,201	7,980,678
0	0	0	0	0	0	0	0	1,182,707	44,578	0	54,237	0	1,440,708	1,743,004	48,144,955	871,502	871,502	0.199	173,129	8,153,807
0	0	0	0	0	0	0	0	1,010,243	45,470	0	55,322	0	1,244,342	1,421,794	49,566,749	710,897	710,897	0.184	130,763	8,284,570
0	0	0	0	0	0	0	0	915,087	46,379	0	56,428	0	1,136,277	1,231,379	50,798,127	615,689	615,689	0.170	104,861	8,389,431
0	0	0	0	0	0	0	0	872,139	47,307	0	57,557	0	1,087,617	1,124,671	51,922,798	562,335	562,335	0.158	88,680	8,478,111
							1,712,000	37,707,649	543,416	71,040	661,156	520,251	65,318,074	51,922,798		26,058,531	25,864,268		8,478,111	
																IRR	37.42%		27.24%	
																PIR	1.262		0.414	

Table C.7 The cash flow table of model case1_inj300.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well		Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($)		Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
												New injection well	Previous production well				INTANG	TANG				
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,900	150	54,750.00	150.00	4,392,000	219,600	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,750	150	54,750.00	-	4,380,000	219,000	1.1041				0	0	1	109,500	0	0	0	0	0	12,500	0	62,000
3	54,750	150	46,492.21	8,257.79	4,380,000	219,000	1.1262				0	0	0	0	835,636	1,086,327	0	0	0	0	0	0
4	54,750	150	39,870.03	14,879.97	4,380,000	219,000	1.1487				0	0	0	0	835,636	1,086,327	0	0	0	0	0	0
5	109,500	300	93,986.64	15,513.36	8,760,000	438,000	1.1717				1	0	0	0	835,636	1,086,327	1,200,000	300,000	250,000	0	0	0
6	109,500	300	78,176.21	31,323.79	8,760,000	438,000	1.1951				0	0	0	0	835,636	1,086,327	0	0	0	0	0	0
7	109,800	301	65,267.00	44,533.00	8,784,000	439,200	1.2190				0	0	0	0	835,636	1,086,327	0	0	0	0	0	0
8	95,790	262	62,852.16	32,938.15	7,663,225	383,161	1.2434				1	0	0	0	835,636	1,086,327	1,200,000	300,000	250,000	0	0	0
9	82,386	226	49,889.54	32,496.46	6,590,880	329,544	1.2682				0	0	0	109,500	0	0	0	0	0	0	0	0
10	129,508	355	64,850.58	64,657.30	10,360,630	518,032	1.2936				1	0	0	109,500	0	0	1,200,000	300,000	250,000	0	0	0
11	91,898	252	52,382.91	39,514.96	7,351,830	367,591	1.3195				0	0	0	109,500	0	0	0	0	0	0	0	0
12	73,539	201	42,087.85	31,451.59	5,883,155	294,158	1.3459				0	0	0	109,500	0	0	0	0	0	0	0	0
13	59,638	163	33,716.48	25,921.02	4,771,000	238,550	1.3728				0	0	0	109,500	0	0	0	0	0	0	0	0
14	51,078	140	40,866.23	10,211.67	4,086,232	204,312	1.4002				0	0	0	109,500	0	0	0	0	0	0	0	0
15	43,840	120	42,709.54	1,130.86	3,507,232	175,362	1.4282				0	0	0	109,500	0	0	0	0	0	0	0	0
16	40,245	110	43,927.19	- 3,682.39	3,219,584	160,979	1.4568				0	0	0	109,500	0	0	0	0	0	0	0	0
17	35,728	98	42,494.11	- 6,765.91	2,858,256	142,913	1.4859				0	0	0	109,500	0	0	0	0	0	0	0	0
18	32,406	89	41,855.09	- 9,449.49	2,592,448	129,622	1.5157				0	0	0	109,500	0	0	0	0	0	0	0	0
19	30,332	83	39,025.94	- 8,694.04	2,426,552	121,328	1.5460				0	0	0	109,500	0	0	0	0	0	0	0	0
20	28,533	78	36,158.28	- 7,625.18	2,282,648	114,132	1.5769				0	0	0	109,500	0	0	0	0	0	0	0	0
	1,342,871			316,762.89	107,429,672	5,371,484		250,000	500,000	1,000,000	4	0	1	1,423,500	5,013,818	6,517,963	4,800,000	1,200,000	1,000,000	12,500	0	62,000

Table C.7 The cash flow table of model case1_inj300 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1st year	2nd year	3rd year	4th year	5th year	6th year	7th year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil								
																		1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,188,511	0	0	0	0	1,518,111	2,873,889	-186,111	0	2,873,889	0.681	1,955,921	-460,951
		122,400					122,400	1,208,968	33,122	0	60,448	0	1,656,439	2,723,561	2,537,450	1,361,780	1,361,780	0.630	858,153	397,201
			122,400				122,400	1,233,148	0	11,262	0	59,454	2,731,591	1,648,409	4,185,859	824,204	824,204	0.583	480,915	878,117
				122,400			122,400	1,257,811	0	11,487	0	60,643	2,757,668	1,622,332	5,808,191	811,166	811,166	0.540	438,248	1,316,364
					12,400		12,400	2,565,934	0	11,717	0	61,856	5,376,234	3,383,766	9,191,956	1,691,883	1,691,883	0.500	846,363	2,162,727
						12,400	12,400	2,617,253	0	11,951	0	63,093	4,229,024	4,530,976	13,722,932	2,265,488	2,265,488	0.463	1,049,359	3,212,086
0	0	0	0	0	0	0	0	2,676,912	0	12,190	0	64,355	4,278,984	4,505,016	18,227,948	2,252,508	2,252,508	0.429	966,062	4,178,148
110,000	0	0	0	0	0	0	110,000	2,382,064	0	12,434	0	65,642	5,239,629	2,423,596	20,651,544	1,211,798	1,211,798	0.397	481,222	4,659,370
0	110,000	0	0	0	0	0	110,000	2,089,707	38,047	0	69,436	0	2,636,735	3,954,145	24,605,689	1,977,073	1,977,073	0.368	726,965	5,386,335
110,000	0	110,000	0	0	0	0	220,000	3,350,645	38,808	0	70,825	0	5,398,310	4,962,321	29,568,009	2,481,160	2,481,160	0.340	844,738	6,231,074
0	110,000	0	110,000	0	0	0	220,000	2,425,146	39,584	0	72,241	0	3,124,563	4,227,267	33,795,276	2,113,633	2,113,633	0.315	666,305	6,897,379
0	0	110,000	0	110,000	0	0	220,000	1,979,488	40,376	0	73,686	0	2,607,708	3,275,447	37,070,723	1,637,724	1,637,724	0.292	478,036	7,375,415
0	0	0	110,000	0	110,000	0	110,000	1,637,390	41,184	0	75,160	0	2,102,284	2,668,716	39,739,439	1,334,358	1,334,358	0.270	360,636	7,736,051
0	0	0	0	110,000	0	110,000	110,000	1,430,428	42,007	0	76,663	0	1,863,410	2,222,822	41,962,261	1,111,411	1,111,411	0.250	278,130	8,014,180
0	0	0	0	0	110,000	0	0	1,252,298	42,847	0	78,196	0	1,548,703	1,958,529	43,920,790	979,264	979,264	0.232	226,907	8,241,087
0	0	0	0	0	0	110,000	0	1,172,581	43,704	0	79,760	0	1,457,025	1,762,559	45,683,349	881,279	881,279	0.215	189,077	8,430,164
0	0	0	0	0	0	0	0	1,061,805	44,578	0	81,356	0	1,330,651	1,527,605	47,210,953	763,802	763,802	0.199	151,734	8,581,898
0	0	0	0	0	0	0	0	982,322	45,470	0	82,983	0	1,240,397	1,352,051	48,563,005	676,026	676,026	0.184	124,349	8,706,247
0	0	0	0	0	0	0	0	937,850	46,379	0	84,642	0	1,190,199	1,236,353	49,799,357	618,176	618,176	0.170	105,285	8,811,531
0	0	0	0	0	0	0	0	899,876	47,307	0	86,335	0	1,147,651	1,134,997	50,934,354	567,498	567,498	0.158	89,494	8,901,026
							1,712,000	34,350,136	543,416	71,040	991,733	375,046	56,495,318	50,934,354		25,560,232	25,374,122		8,901,026	
																IRR	40.73%		30.30%	
																PIR	1.654		0.580	

Table C.8 The cash flow table of model case2_inj300.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well: New injection well	No. of water injection or surfactant injection well: Previous production well	Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($): INTANG	Drilling and completion costs of production well ($): TANG	Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,900	150	54,750.00	150.00	4,392,000	219,600	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,750	150	54,750.00	-	4,380,000	219,000	1.1041				0	0	1	109,500	0	0	0	0	0	12,500	0	62,000
3	54,750	150	46,492.21	8,257.79	4,380,000	219,000	1.1262				0	0	0	109,500	1,497,182	1,946,336	0	0	0	0	0	0
4	54,750	150	39,870.03	14,879.97	4,380,000	219,000	1.1487				0	0	0	109,500	1,497,182	1,946,336	0	0	0	0	0	0
5	109,500	300	93,986.64	15,513.36	8,760,000	438,000	1.1717				1	0	0	109,500	1,497,182	1,946,336	1,200,000	300,000	250,000	0	0	0
6	109,500	300	78,176.21	31,323.79	8,760,000	438,000	1.1951				0	0	0	109,500	1,497,182	1,946,336	0	0	0	0	0	0
7	109,800	301	65,267.00	44,533.00	8,784,000	439,200	1.2190				0	0	0	109,500	1,497,182	1,946,336	0	0	0	0	0	0
8	100,050	274	62,852.16	37,197.78	8,003,995	400,200	1.2434				1	0	0	109,500	1,497,182	1,946,336	1,200,000	300,000	250,000	0	0	0
9	92,143	252	49,889.54	42,253.08	7,371,410	368,570	1.2682				0	0	0	109,500	0	0	0	0	0	0	0	0
10	152,760	419	64,850.58	87,909.30	12,220,790	611,040	1.2936				1	0	0	109,500	0	0	1,200,000	300,000	250,000	0	0	0
11	92,824	254	52,382.91	40,441.27	7,425,934	371,297	1.3195				0	0	0	109,500	0	0	0	0	0	0	0	0
12	71,762	197	42,087.85	29,674.33	5,740,974	287,049	1.3459				0	0	0	109,500	0	0	0	0	0	0	0	0
13	57,444	157	33,716.48	23,727.02	4,595,480	229,774	1.3728				0	0	0	109,500	0	0	0	0	0	0	0	0
14	49,165	135	40,866.23	8,298.47	3,933,176	196,659	1.4002				0	0	0	109,500	0	0	0	0	0	0	0	0
15	41,022	112	42,709.54	- 1,687.74	3,281,744	164,087	1.4282				0	0	0	109,500	0	0	0	0	0	0	0	0
16	36,145	99	43,927.19	- 7,782.59	2,891,568	144,578	1.4568				0	0	0	109,500	0	0	0	0	0	0	0	0
17	32,419	89	42,494.11	- 10,074.91	2,593,536	129,677	1.4859				0	0	0	109,500	0	0	0	0	0	0	0	0
18	30,058	82	41,855.09	- 11,797.59	2,404,600	120,230	1.5157				0	0	0	109,500	0	0	0	0	0	0	0	0
19	28,304	78	39,025.94	- 10,722.24	2,264,296	113,215	1.5460				0	0	0	109,500	0	0	0	0	0	0	0	0
20	26,512	73	36,158.28	- 9,646.28	2,120,960	106,048	1.5769				0	0	0	109,500	0	0	0	0	0	0	0	0
	1,358,556		1,026,108.01	332,447.79	108,684,464	5,434,223		250,000	500,000	1,000,000	4	0	1	2,080,500	8,983,090	11,678,018	4,800,000	1,200,000	1,000,000	12,500	0	62,000

Table C.8 The cash flow table of model case2_inj300 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1st year	2nd year	3rd year	4th year	5th year	6th year	7th year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil								
																		1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,188,511	0	0	0	0	1,518,111	2,873,889	-186,111	0	2,873,889	0.681	1,955,921	-460,951
		122,400					122,400	1,208,968	33,122	0	60,448	0	1,656,439	2,723,561	2,537,450	1,361,780	1,361,780	0.630	858,153	397,201
			122,400				122,400	1,233,148	33,785	11,262	61,657	62,398	3,689,986	690,014	3,227,464	345,007	345,007	0.583	201,308	598,509
				122,400			122,400	1,257,811	34,461	11,487	62,891	63,646	3,718,031	661,969	3,889,432	330,984	330,984	0.540	178,821	777,330
					12,400		12,400	2,565,934	35,150	11,717	64,148	64,919	6,338,604	2,421,396	6,310,828	1,210,698	1,210,698	0.500	605,650	1,382,980
						12,400	12,400	2,617,253	35,853	11,951	65,431	66,218	5,193,442	3,566,558	9,877,386	1,783,279	1,783,279	0.463	826,003	2,208,984
0	0	0	0	0	0	0	0	2,676,912	36,570	12,190	66,740	67,542	5,245,490	3,538,510	13,415,897	1,769,255	1,769,255	0.429	758,803	2,967,787
110,000	0	0	0	0	0	0	110,000	2,487,990	37,301	12,434	68,075	68,893	6,331,229	1,672,766	15,088,663	836,383	836,383	0.397	332,139	3,299,926
0	110,000	0	0	0	0	0	110,000	2,337,182	38,047	0	69,436	0	2,923,236	4,448,173	19,536,836	2,224,087	2,224,087	0.368	817,792	4,117,718
110,000	0	110,000	0	0	0	0	220,000	3,952,224	38,808	0	70,825	0	6,092,897	6,127,894	25,664,730	3,063,947	3,063,947	0.340	1,043,155	5,160,873
0	110,000	0	110,000	0	0	0	220,000	2,449,591	39,584	0	72,241	0	3,152,713	4,273,221	29,937,951	2,136,611	2,136,611	0.315	673,549	5,834,421
0	0	110,000	0	110,000	0	0	220,000	1,931,649	40,376	0	73,686	0	2,552,760	3,188,214	33,126,165	1,594,107	1,594,107	0.292	465,305	6,299,726
0	0	0	110,000	0	110,000	0	110,000	1,577,152	41,184	0	75,160	0	2,033,270	2,562,210	35,688,376	1,281,105	1,281,105	0.270	346,243	6,645,969
0	0	0	0	110,000	0	110,000	110,000	1,376,849	42,007	0	76,663	0	1,802,178	2,130,998	37,819,373	1,065,499	1,065,499	0.250	266,640	6,912,609
0	0	0	0	0	110,000	0	0	1,171,785	42,847	0	78,196	0	1,456,916	1,824,828	39,644,202	912,414	912,414	0.232	211,417	7,124,026
0	0	0	0	0	0	110,000	0	1,053,117	43,704	0	79,760	0	1,321,160	1,570,408	41,214,609	785,204	785,204	0.215	168,464	7,292,490
0	0	0	0	0	0	0	0	963,465	44,578	0	81,356	0	1,219,075	1,374,461	42,589,070	687,230	687,230	0.199	136,522	7,429,013
0	0	0	0	0	0	0	0	911,143	45,470	0	82,983	0	1,159,826	1,244,774	43,833,844	622,387	622,387	0.184	114,482	7,543,495
0	0	0	0	0	0	0	0	875,139	46,379	0	84,642	0	1,119,375	1,144,921	44,978,765	572,460	572,460	0.170	97,499	7,640,994
0	0	0	0	0	0	0	0	836,135	47,307	0	86,335	0	1,075,825	1,045,135	46,023,900	522,567	522,567	0.158	82,409	7,723,402
							1,712,000	34,671,957	756,535	71,040	1,380,676	393,616	62,660,564	46,023,900		23,105,005	22,918,895		7,723,402	
																IRR	36.96%		26.82%	
																PIR	1.118		0.377	

Table C.9 The cash flow table of model case3_inj300.

Year	Oil production total (bbl/year)	Oil production total (bbl/day)	Oil production total from water injection (bbl/year) *Base case	Incremental oil from surfactant injection (bbl/year)	Income ($)	Royalty sliding scal ($)	2% Escal Factor	Concession ($)	Geological and geophysical surveys ($)	Exploration wells ($)	No. of Production well	No. of water injection or surfactant injection well		Water injection rate (bbl/year)	Surfactant injection rate (kg/year)	Cost of surfactant ($) 1.3 $/kg	Drilling and completion costs of production well ($)		Facility cost of production well ($) 250,000$/well	Abandonment cost ($) 12,500$/well	Facility cost of water injection well ($) 50,000$/well	Cost of storage and mixing facility for surfactant injection well ($) 62,000$/well
												New injection well	Previous production well				INTANG	TANG				
							1.0000	250,000														
							1.0200		500,000													
							1.0404			1,000,000												
0	0	0	-	-	0	0	1.0612				1	0	0	0	0	0	1,200,000	300,000	250,000	0	0	0
1	54,900	150	54,750.00	150.00	4,392,000	219,600	1.0824				0	0	0	0	0	0	0	0	0	0	0	0
2	54,750	150	54,750.00	-	4,380,000	219,000	1.1041				0	0	1	109,500	0	0	0	0	0	12,500	0	62,000
3	54,750	150	46,492.21	8,257.79	4,380,000	219,000	1.1262				0	0	0	0	2,245,773	2,919,505	0	0	0	0	0	0
4	54,750	150	39,870.03	14,879.97	4,380,000	219,000	1.1487				0	0	0	0	2,245,773	2,919,505	0	0	0	0	0	0
5	109,500	300	93,986.64	15,513.36	8,760,000	438,000	1.1717				1	0	0	0	2,245,773	2,919,505	1,200,000	300,000	250,000	0	0	0
6	109,500	300	78,176.21	31,323.79	8,760,000	438,000	1.1951				0	0	0	0	2,245,773	2,919,505	0	0	0	0	0	0
7	109,800	301	65,267.00	44,533.00	8,784,000	439,200	1.2190				0	0	0	0	2,245,773	2,919,505	0	0	0	0	0	0
8	94,797	260	62,852.16	31,944.53	7,583,735	379,187	1.2434				1	0	0	0	2,245,773	2,919,505	1,200,000	300,000	250,000	0	0	0
9	90,868	249	49,889.54	40,978.08	7,269,410	363,470	1.2682				0	0	0	109,500	0	0	0	0	0	0	0	0
10	213,746	586	64,850.58	148,895.86	17,099,715	854,986	1.2936				1	0	0	109,500	0	0	1,200,000	300,000	250,000	0	0	0
11	95,109	261	52,382.91	42,726.44	7,608,748	380,437	1.3195				0	0	0	109,500	0	0	0	0	0	0	0	0
12	76,515	210	42,087.85	34,427.35	6,121,216	306,061	1.3459				0	0	0	109,500	0	0	0	0	0	0	0	0
13	63,677	174	33,716.48	29,960.12	5,094,128	254,706	1.3728				0	0	0	109,500	0	0	0	0	0	0	0	0
14	51,844	142	40,866.23	10,977.27	4,147,480	207,374	1.4002				0	0	0	109,500	0	0	0	0	0	0	0	0
15	42,021	115	42,709.54	- 688.44	3,361,688	168,084	1.4282				0	0	0	109,500	0	0	0	0	0	0	0	0
16	35,580	97	43,927.19	- 8,346.79	2,846,432	142,322	1.4568				0	0	0	109,500	0	0	0	0	0	0	0	0
17	30,541	84	42,494.11	- 11,953.01	2,443,288	122,164	1.4859				0	0	0	109,500	0	0	0	0	0	0	0	0
18	27,025	74	41,855.09	- 14,830.49	2,161,968	108,098	1.5157				0	0	0	109,500	0	0	0	0	0	0	0	0
19	24,799	68	39,025.94	- 14,227.24	1,983,896	99,195	1.5460				0	0	0	109,500	0	0	0	0	0	0	0	0
20	23,706	65	36,158.28	- 12,452.28	1,896,480	94,824	1.5769				0	0	0	109,500	0	0	0	0	0	0	0	0
	1,418,177		1,026,108.01	392,069.29	113,454,184	5,672,709		250,000	500,000	1,000,000	4	0	1	1,423,500	13,474,637	17,517,028	4,800,000	1,200,000	1,000,000	12,500	0	62,000

Table C.9 The cash flow table of model case3_inj300 (Continued).

Depreciation (20%) Tangible Expense ($)								Operation cost of production well	Maintenance cost of water injection facility	Maintenance cost of surfactant injection facility	Operation cost of water injection	Operation cost of surfactant injection	Total allow expense ($)	Taxable income ($)	Cumulative taxable income ($)	Income tax ($)	Annual cash flow ($)	8.0% DISC FACTOR	Discounted cash flow ($)	Cumulative discounted cash flow ($)
1st year	2nd year	3rd year	4th year	5th year	6th year	7th year	Total	20$/bbl	30,000$/year	10,000$/year	0.5$/1 bbl of water	1$/1 bbl of increment oil								
																		1.000		
													250,000	-250,000	-250,000	0	-250,000	0.926	-231,481	-231,481
													500,000	-500,000	-750,000	0	-500,000	0.857	-428,669	-660,151
													1,000,000	-1,000,000	-1,750,000	0	-1,000,000	0.794	-793,832	-1,453,983
110,000							110,000	0	0	0	0	0	1,310,000	-1,310,000	-3,060,000	0	-1,310,000	0.735	-962,889	-2,416,872
	110,000						110,000	1,188,511	0	0	0	0	1,518,111	2,873,889	-186,111	0	2,873,889	0.681	1,955,921	-460,951
		122,400					122,400	1,208,968	33,122	0	60,448	0	1,656,439	2,723,561	2,537,450	1,361,780	1,361,780	0.630	858,153	397,201
			122,400				122,400	1,233,148	0	11,262	0	73,589	4,578,903	-198,903	2,338,547	0	-198,903	0.583	-116,058	281,143
				122,400			122,400	1,257,811	0	11,487	0	75,061	4,605,263	-225,263	2,113,284	0	-225,263	0.540	-121,703	159,441
					12,400		12,400	2,565,934	0	11,717	0	76,562	7,224,117	1,535,883	3,649,167	767,941	767,941	0.500	384,162	543,603
						12,400	12,400	2,617,253	0	11,951	0	78,093	6,077,201	2,682,799	6,331,965	1,341,399	1,341,399	0.463	621,327	1,164,930
0	0	0	0	0	0	0	0	2,676,912	0	12,190	0	79,655	6,127,461	2,656,539	8,988,504	1,328,269	1,328,269	0.429	569,672	1,734,602
110,000	0	0	0	0	0	0	110,000	2,357,355	0	12,434	0	81,248	7,059,729	524,007	9,512,511	262,003	262,003	0.397	104,045	1,838,647
0	110,000	0	0	0	0	0	110,000	2,304,842	38,047	0	69,436	0	2,885,796	4,383,613	13,896,124	2,191,807	2,191,807	0.368	805,923	2,644,570
110,000	0	110,000	0	0	0	0	220,000	5,530,076	38,808	0	70,825	0	7,914,695	9,185,020	23,081,144	4,592,510	4,592,510	0.340	1,563,571	4,208,140
0	110,000	0	110,000	0	0	0	220,000	2,509,895	39,584	0	72,241	0	3,222,159	4,386,589	27,467,733	2,193,295	2,193,295	0.315	691,418	4,899,558
0	0	110,000	0	110,000	0	0	220,000	2,059,588	40,376	0	73,686	0	2,699,711	3,421,505	30,889,238	1,710,753	1,710,753	0.292	499,352	5,398,911
0	0	0	110,000	0	110,000	0	110,000	1,748,287	41,184	0	75,160	0	2,229,337	2,864,791	33,754,030	1,432,396	1,432,396	0.270	387,132	5,786,043
0	0	0	0	110,000	0	110,000	110,000	1,451,868	42,007	0	76,663	0	1,887,913	2,259,567	36,013,597	1,129,784	1,129,784	0.250	282,727	6,068,770
0	0	0	0	0	110,000	0	0	1,200,330	42,847	0	78,196	0	1,489,458	1,872,230	37,885,827	936,115	936,115	0.232	216,909	6,285,679
0	0	0	0	0	0	110,000	0	1,036,678	43,704	0	79,760	0	1,302,465	1,543,967	39,429,795	771,984	771,984	0.215	165,628	6,451,307
0	0	0	0	0	0	0	0	907,649	44,578	0	81,356	0	1,155,748	1,287,540	40,717,335	643,770	643,770	0.199	127,889	6,579,196
0	0	0	0	0	0	0	0	819,206	45,470	0	82,983	0	1,055,757	1,106,211	41,823,546	553,106	553,106	0.184	101,739	6,680,934
0	0	0	0	0	0	0	0	766,766	46,379	0	84,642	0	996,982	986,914	42,810,460	493,457	493,457	0.170	84,043	6,764,977
0	0	0	0	0	0	0	0	747,639	47,307	0	86,335	0	976,106	920,374	43,730,834	460,187	460,187	0.158	72,571	6,837,549
							1,712,000	36,188,716	543,416	71,040	991,733	464,208	69,723,350	43,730,834		22,170,555	21,560,279		6,837,549	
																IRR	32.79%		22.95%	
																PIR	0.818		0.260	

BIOGRAPHY

Mr. Pipat Pipatpongsanon was born on March 3, 1983 in Surin province, Thailand. He received his Bachelor’s Degree in Engineering (Transportation) from Suranaree University of Technology (SUT) in 2006. During Bachelor’s Degree he worked in Civil Research Unit (CRU) at SUT as a part time student. After graduation, he has been employed under the position of Sales Engineer by the office of Onvalla Co., Ltd., Thailand. From 2008 to 2011, he studied for his Master’s Degree of Engineering at School of Geotechnology, Institute of Engineering at SUT with the major in Petroleum Technology.