Assessment of Surfactant Flooding with Variations of Slug Injection Strategies in Waterflooded Reservoir

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การประเมินกระบวนการฉีดอัดสารลดแรงตึงผิวด้วยการเปลี่ยนกลยุทธ์การฉีดอัดในแหล่งกักเก็บที่ผ่านการฉีดอัดด้วยน้ำ

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อานันท์ ตันติอานนท์ : การประเมินกระบวนการฉีดอัดสารลดแรงตึงผิวด้วยการเปลี่ยนกลยุทธ์การฉีดอัดในแหล่งกักเก็บที่ผ่านการฉีดอัดด้วยน้ำ (Assessment of Surfactant Flooding with Variations of Slug Injection Strategies in Waterflooded Reservoir) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ฟ้าลั่น ศรีสุริยชัย, 133 หน้า.

การใช้สารลดแรงตึงผิวในแหล่งกักเก็บที่ผ่านกระบวนการฉีดอัดด้วยน้ำอาจส่งผลให้ลดประสิทธิภาพของสารลดแรงตึงผิวลงเนื่องจากจะก่อให้เกิดการเจือจางและการดูดซับของสารลดแรงตึงผิว อย่างไรก็ดีปัญหานี้มีความเป็นไปได้ที่จะสามารถแก้ไขได้โดยการใช้หลักการเปลี่ยนแปลงสมดุลยภาพระหว่างความเข้มข้นของสารลดแรงตึงผิว ด้วยเหตุนี้การศึกษานี้จึงมีวัตถุประสงค์เพื่อประเมินผลกระทบของการฉีดอัดสารลดแรงตึงผิวด้วยวิธีการจัดลำดับก้อนมวลของสารลดแรงตึงผิวในแหล่งกักเก็บที่ผ่านการฉีดอัดด้วยน้ำในการเพิ่มการผลิตน้ำมัน ตัวแปรเชิงปฏิบัติการของการฉีดอัดได้ถูกประเมินในขั้นต้นโดยทำการระบุผลของความเข้มข้นของสารลดแรงตึงผิว อัตราการฉีดอัด และเวลาในการเริ่มการฉีดอัดสารลดแรงตึงผิวภายหลังจากการฉีดอัดด้วยน้ำสำหรับการฉีดอัดแบบก้อนมวลสารเดียวและการฉีดอัดแบบก้อนมวลสารหลายก้อน ผลกระทบของตัวแปรของแหล่งกักเก็บที่เกี่ยวข้องกับความสามารถในการซึมผ่านสัมพัทธ์ต่อปริมาณน้ำมันที่ผลิตได้ ได้แก่ สัดส่วนของน้ำที่ไม่สามารถลดลงได้ และ ความสามารถในการซึมผ่านสัมพัทธ์ของน้ำมันที่จุดสุดท้าย ได้ถูกประเมินในลำดับต่อมา ประสิทธิภาพของกลยุทธ์การฉีดอัดสารลดแรงตึงผิวได้ถูกประเมินบนพื้นฐานของปริมาณน้ำมันที่ผลิตได้

ผลการศึกษาบ่งชี้ว่าการฉีดอัดสารลดแรงตึงผิวแบบก้อนมวลสารสองก้อนให้ผลของปริมาณน้ำมันที่ผลิตได้มากกว่าการฉีดอัดสารลดแรงตึงผิวแบบก้อนมวลสารเดียวเนื่องจากได้ผลประโยชน์จากการสังเวยสารลดแรงตึงผิวบางส่วนต่อการดูดซับและการคายตัวของสารลดแรงตึงผิวในภายหลัง การเลือกรูปแบบของวิธีการฉีดอัดสารลดแรงตึงผิวแบบก้อนมวลสารสองก้อนขึ้นอยู่กับความเข้มข้นของสารลดแรงตึงผิวแบบก้อนมวลสารเดียวอ้างอิงที่ถูกนำมาดัดแปลงแก้ไข ในขณะที่การเลือกระดับความต่างของความเข้มข้นของสารลดแรงตึงผิวระหว่างสองก้อนมวลสารจะขึ้นอยู่กับการจัดวางอัตราส่วนมวลสารของสารลดแรงตึงผิว การดัดแปลงแก้ไขการฉีดอัดสารลดแรงตึงผิวแบบก้อนมวลสารสองก้อนเป็นก้อนมวลสารสามก้อนไม่ช่วยเพิ่มปริมาณน้ำมันที่ผลิตได้ในการศึกษานี้ อย่างไรก็ดีปริมาณน้ำมันที่ผลิตได้ยังมากกว่าการฉีดอัดสารลดแรงตึงผิวแบบก้อนมวลสารเดียว

ตัวแปรเชิงปฏิบัติการมีผลกระทบต่อประสิทธิภาพในการผลิตน้ำมันดังนี้ ความเข้มข้นของสารลดแรงตึงผิวมีผลกระทบเล็กน้อยต่ออัตราการเปลี่ยนแปลงของปริมาณน้ำมันที่ผลิตได้ แต่ไม่มีผลต่อปริมาณน้ำมันสุทธิที่ผลิตได้ ปริมาณน้ำมันสุทธิที่ผลิตได้และอัตราการเปลี่ยนแปลงของปริมาณน้ำมันที่ผลิตได้มีความอ่อนไหวต่อการเปลี่ยนแปลงอัตราการฉีดอัดมาก เวลาในการเริ่มการฉีดอัดสารลดแรงตึงผิวไม่แสดงผลกระทบต่อปริมาณน้ำมันสุทธิที่ผลิตได้เพียงแค่การเริ่มการฉีดอัดสารลดแรงตึงผิวที่สัดส่วนการผลิตน้ำสูงจะเลื่อนการผลิตออกไปในภาพรวม ในส่วนของผลกระทบของคุณสมบัติของแหล่งกักเก็บ การเปลี่ยนแปลงของความสามารถในการซึมผ่านสัมพัทธ์ของน้ำมันที่จุดสุดท้าย มีความอ่อนไหวต่อประสิทธิภาพของการฉีดอัดสารลดแรงตึงผิวมากกว่าเมื่อเปรียบเทียบกับการเปลี่ยนแปลงของสัดส่วนของน้ำที่ไม่สามารถลดลงได้

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
สาขาวิชา	วิศวกรรมปิโตรเลียม	ลายมือชื่อ อ.ที่ปรึกษาหลัก	....
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KEYWORDS: SURFACTANT FLOODING / MULTI-SLUG GRADING/INJECTION STRATEGIES / SINGLE-SLUG / TWO-SLUG / THREE-SLUG

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Introduction of surfactant into waterflooded reservoir may cause the reduction in surfactant efficiency by means of surfactant dilution and adsorption. However, it is possible to overcome this issue by utilizing concept of equilibrium shifting between different surfactant concentrations. Therefore, this study aims to evaluate the effects of surfactant flooding with multi-slug grading in waterflooded reservoir on additional oil recovery. Flooding operating conditions are initially evaluated to identify effects of injected surfactant concentration, surfactant injection rate, and time to implement surfactant flooding after water pre-injection for single-slug injection and multi-slug injection. The effects on oil recovery of reservoir parameters related to interaction between surfactant and rock surface including changes of properties related to relative permeability curves, such as irreducible water saturation and endpoint relative permeability, are then evaluated. Performance of surfactant flooding strategy is evaluated based on oil recovery factor.

Simulated results indicate that two-slug surfactant injection yields better oil recovery than single-slug surfactant injection due to benefit of sacrificial adsorption or desorption process. Selection of type of two-slug injection strategy would depend on surfactant concentration of single-slug which is chosen to be modified; whereas, the selection of magnitude of concentration contrast between the two slugs would depend on placement of surfactant mass ratio. Modification of two-slug into three-slug injection does not show improvement in oil recovery in this study. However, additional oil recovery is observed to be better than single-slug surfactant injection.

Assessment of operating parameters implies impacts on oil recovery performance. Surfactant concentration slightly shows effects on rate of change in oil recovery, but not on final oil recovery. The final oil recovery as well as the rate of recovering is more sensitive to the change in surfactant injection rate. Increase in injection rate results in faster and higher oil recovery. Time to implement surfactant injection does not show much impact on final oil recovery. Implementing at higher watercut would just delay production as a whole. For the effects of reservoir properties, changes in endpoint relative permeability to oil is more sensitive to the performance of surfactant flooding when compared to changes in endpoint water saturation.

Department:	Mining and Petroleum Engineering	Student's Signature	....
Field of Study:	Petroleum Engineering	Advisor's Signature	....
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List of Abbreviations

A/S	Alkaline-Surfactant
A-H	Accretion-High Contrast
AASA	Alkyl Aryl Sulfonic Acid
A-L	Accretion-Low Contrast
ASP	Alkaline-Surfactant-Polymer
bbl	Barrel
bbl/day	Barrel Per Day
BHP	Bottomhole Pressure
Ca^{2+}	Calcium ion
cm^3	Cubic centimeter
CMC	Critical Micelle Concentration
CMG	Computer Modeling Group
Cont.	Continue
cP	CentiPoise
CTAB	Cationic Surfactant Hexadecyltrimethylammoniumbromide
DTWELL	First time step size after well change
DWOC	Water-oil contact depth
dyne/cm	Dyne per centimeter
EOR	Enhanced Oil Recovery
F0.5	For 0.5 wt.%
F0.75	For 0.75 wt.%
F1	For 1 wt.%
ft	Foot/Feet
g	Gram
g/ml	Gram per milliliter

GOR	Gas Oil Ratio
IFT	Interfacial Tension
ISOTHERM	Isothermal option
ITERMAX	Linear solver iteration
km	Kilometer
KRGCL	Relative permeability to gas at connate liquid saturation
KROCW	Relative permeability to oil at connate water saturation
KROGCG	Relative permeability to oil at connate gas saturation
KRWIRO	Relative permeability to water at irreducible oil saturation
lb/lbmole	Pound per mole
M^{2+}	Divalent ion
mD	Millidarcy
mg/100g	Milligram per hundred grams
mg/g	Milligram per gram
Mg^{2+}	Magnesium ion
ml	Milliliter
ml/min	Milliliter/Minutes
MMbbl	Million barrel
MR_2	Surfactant-divalent cation complex that precipitate in brine
MW	Molecular Weight
Na^+	Sodium ion
NaCl	Sodium Chloride
NaOH	Sodium Hydroxide
^oAPI	American Petroleum Institute Gravity
^oC	Degree Celsius
^oF	Degree Fahrenheit

OOIP	Original Oil In Place
pH	Potential of Hydrogen
ppm	Part per million
psia	Pound per square inch absolute
PV	Pore Volume
PVT	Pressure-Volume-Temperature
PZC	Point of Zero Charge
R^-	Anionic surfactant (petroleum sulfonate)
R-H	Reduction-High Contrast
REFDEPTH	Reference depth
REFPW	Reference pressure
RF	Recovery Factor
R-L	Reduction-Low Contrast
SCF/STB	Standard cubic feet per stock tank barrel
SDBS	Sodium Dodecyl Benzene Sulfonate
SDG	Two-Slug Surfactant Flooding
SGCON	Connate gas saturation
SGCRIT	Critical gas saturation
SL	Sodium Lignosulfonate
SOIRG	Irreducible oil saturation for gas-liquid table
SOIRW	Irreducible oil saturation for water-oil table
SORG	Residual oil saturation for gas-liquid table
SORW	Residual oil saturation for water-oil table
SSG	Single-Slug Surfactant Flooding
STL	Surface liquid rate
STO	Surface oil rate
STW	Surface water rate

SWCON	Connate water saturation
SWCRIT	Critical water saturation
TDS	Total Dissolve Solid
TRES	Reservoir temperature
WCUT	Watercut
WOC	Water-Oil Contact
wt.	By Weight

Nomenclatures

ϕ	Porosity
ϕ_{eff}	Effective porosity
μ_g	Gas viscosity
μ_w	Water viscosity
μ_o	Oil viscosity
μ	Viscosity of displacing fluid
v	Effective flow rate of displacing fluid
σ	Interfacial tension between displacing and displaced fluids
θ	Contact angle measured through the fluid with highest density
A	Area per surfactant molecule
Ad	Adsorption concentration
B_g	Gas formation volume factor
B_o	Oil formation volume factor
C_o	Initial concentration of surfactant
C_e	Surfactant concentration after adsorption
k_h	Horizontal permeability
k_v	Vertical permeability
k_{rg}	Relative permeability to gas
k_{rog}	Relative permeability to oil for gas-liquid system
k_{row}	Relative permeability to oil for water-oil system
k_{rw}	Relative permeability to water for water-oil system
M	Molecular weight of the surfactant
N_c	Capillary number
N_{cri}	Critical capillary number

p_b	Bubble point pressure
q	Flow rate per unit cross-sectional area
R_s	Solution gas-oil ratio
S_l	Liquid saturation
S_{or}	Residual oil saturation
S_w	Water saturation
S_{wc}	Connate water saturation
S_{wi}	Initial water saturation
V	Surfactant solution volume

Chapter 1
INTRODUCTION

1.1 Background

Oil recovery mechanism can be categorized into three stages: primary, secondary, and tertiary. In the early period of oil production, oil recovery is driven mainly by means of natural sources of energy presented initially inside the reservoir. These natural sources of energy include rock and fluid expansions, solution gas, water influx, gas cap, and gravity drainage. However, these natural sources of energy are diminished along with the hydrocarbons production. At certain time, presence energy is no longer sufficient to drive oil up to surface. In order to attain additional oil recovery and prolong oil production life, sufficient energy is required to supply reservoir to maintain reservoir pressure. The method of injecting external fluid into reservoir to maintain pressure is known as secondary recovery mechanism. The technique widely implemented is waterflooding since it is simple and does not require high cost for implementation. However, in many oil fields, large amount of remaining oil is still left behind after secondary recovery stage. This may be due to unfavorable wetting condition, which causes high capillary pressure, making external energy from secondary recovery to be insufficient. For this reason, tertiary recovery has been introduced to resolve these issues.

Tertiary recovery, also known as Enhanced Oil Recovery (EOR), is a process where external fluids that are absent in the reservoir are injected [1]. These fluids may physically and chemically interact with reservoir rock and fluids to generate a favorable condition for oil production. One of the widely used EOR techniques is chemical flooding. Nowadays, chemical flooding can be sub-categorized into alkali flooding, surfactant flooding, and polymer flooding. Combinations of these techniques are also possible as long as they are compatible to each other.

Alkali flooding is characterized by the ability to alternate wetting condition in the reservoir. Alkaline agents are also served as sacrificing material when performing alkali-surfactant flooding to prevent the loss to surfactant agent. Surfactant flooding is a technique performed to reduce interfacial tension at interface between two immiscible fluids. The reduction in IFT enables oil to emulsify into flowing aqueous phase in a form of small droplet or emulsion. This small form of droplet can pass easily through pore throats. Polymer flooding is performed to stabilize flood front by the means of increasing injectant viscosity and as a consequence, decreasing mobility ratio to a favorable value. This helps improving volumetric sweep efficiency.

In most oil fields, waterflood has been implemented after a certain period of production from natural depletion to prolong the production life. Posterior to waterflooding process, a large amount of oil is still remained behind. This remained oil is a target for EOR processes. However, introduction of surfactant into the waterflooded reservoir which has considerably high water saturation may cause the reduction of surfactant efficiency by mean of surfactant dilution and surfactant adsorption. Therefore, in order to maintain lowest IFT condition, extremely high concentration of surfactant is inevitable. This is a critical economical challenge for surfactant flooding process owing to the high cost of surfactant agent.

Though, it is possible to overcome this challenge by executing suitable injecting sequence. As illustrated in Figure 1.1, surfactant solution could be divided into multiple slugs with different surfactant concentrations, injection rates, and commencement dates. Several studies have observed that reduction in surfactant concentration slug can cause a shift in equilibrium, resulting in desorption of retaining active surfactant monomers. Therefore, it is possible to gain benefit from the change in equilibrium to achieve longer period of lowest IFT condition while maintaining the amount of surfactant use.

Hence, this study aims to evaluate the effects of surfactant flooding with multi-slug grading in waterflooded reservoir on the additional oil recovery. STARS reservoir simulation program, commercialized by Computer Modeling Group (CMG), is employed in this study to investigate the results. Flooding operating conditions are initially evaluated to identify effects of injected surfactant concentration, surfactant injection rate, and time to implement surfactant flooding after water pre-injection for single-slug injection and multi-slug injection. The effects of reservoir parameters related to relative permeability are also investigated. The interested parameters include changes of irreducible water saturation and endpoint relative permeability to oil. Performance of surfactant flooding strategy is evaluated based on oil recovery factor.

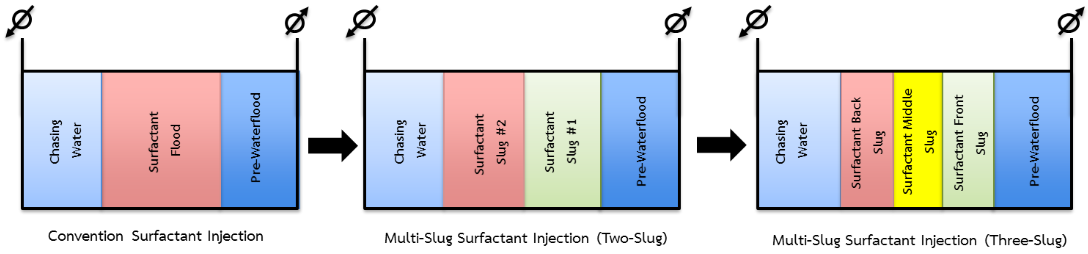


Figure 1.1: Multiple slug surfactant flooding development diagram

1.2 Objectives

1. To evaluate effectiveness of surfactant flooding process with multi-slug grading compared to conventional surfactant flooding in waterflooded reservoir.
2. To determine the effects of operating conditions of surfactant flooding with multi-slug grading in waterflooded reservoir, including surfactant concentration, surfactant injection rate, and time to implement surfactant injection after water pre-injection.
3. To determine the effects of reservoir parameters related to relative permeability curve, such as irreducible water saturation and endpoint relative permeability, on effectiveness of surfactant flooding with multi-slug grading in waterflooded reservoir.

1.3 Outline of Methodology

Research methodology is summarized in Figure 1.2. Detail descriptions of each step are explained in the last section of Chapter 4.

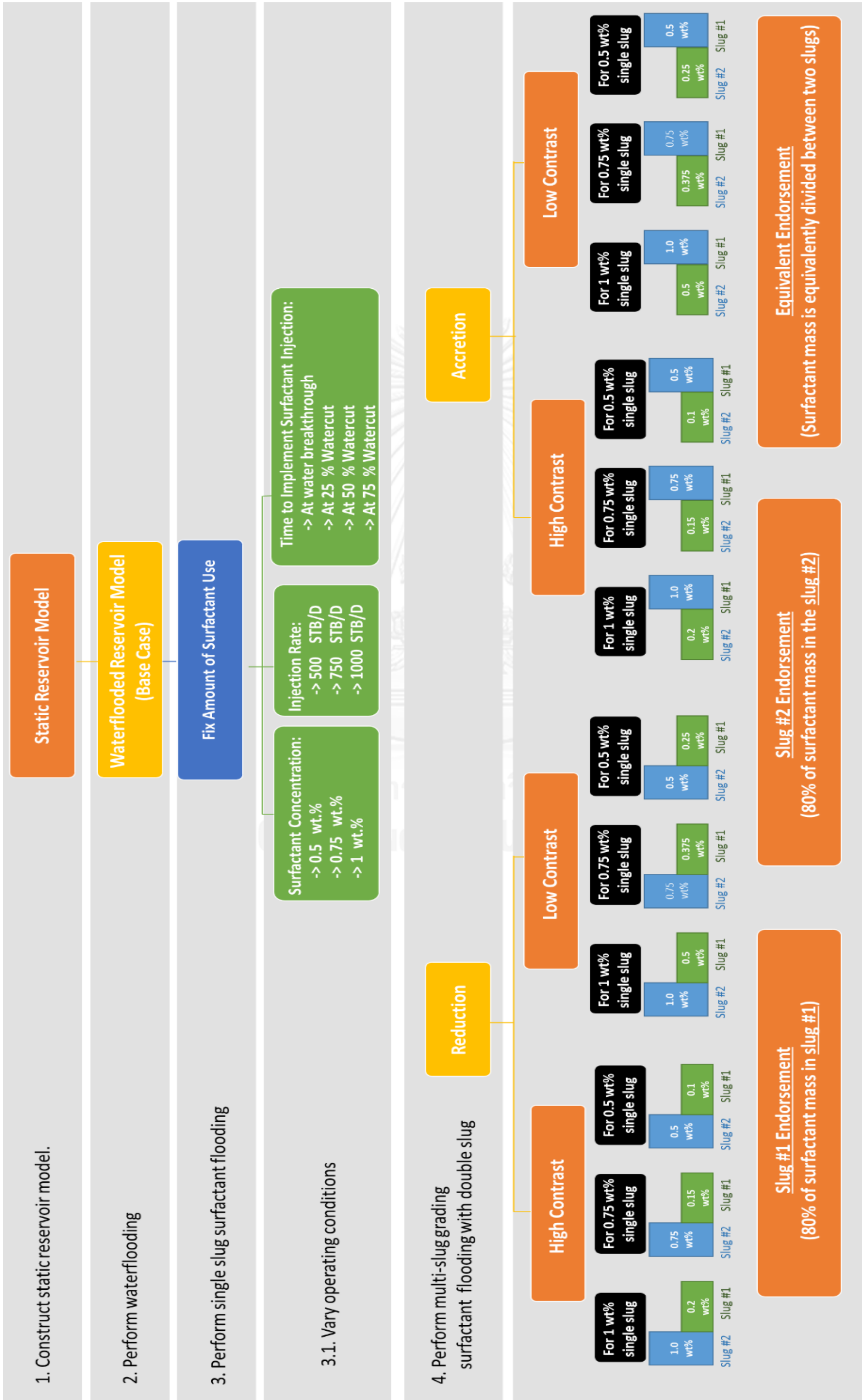


Figure 1.2: Summary of research methodology

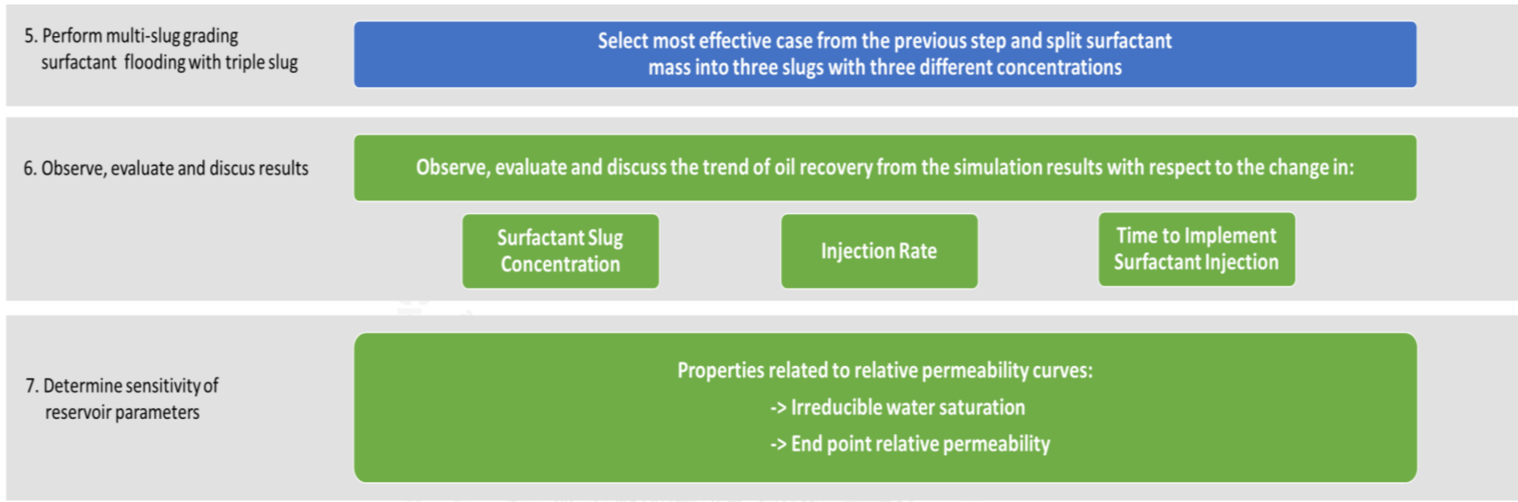


Figure 1.2: Summary of research methodology (continued)

1.4 Outline of Thesis

This thesis is composed of six chapters as follow:

Chapter 1 gives an introduction to the challenges for surfactant flooding process, and proposes the possible solutions as well as stating the objectives and methodology outline of this study.

Chapter 2 provides various literatures related to the study on adsorption and desorption of surfactant active monomers as well as enhancement options for surfactant flooding in waterflooded reservoirs.

Chapter 3 presents important concepts and theories related to oil recovery via surfactant flooding technique.

Chapter 4 provides details of reservoir simulation model construction in STARS reservoir simulation program commercialized via Computer Modeling Group (CMG). The details include reservoir segment, well and recurrent segment, as well as injected surfactant properties. In addition, research methodology is described in detail at the end of this chapter.

Chapter 5 emphasizes on results and discussions of reservoir simulation study. Effectiveness multi-slug grading and conventional flooding are compared. Moreover, effects of operating parameters, such as surfactant concentration, surfactant injection rate, and time of implementation, are assessed. Lastly, effect of reservoir parameters related to relative permeability curve is determined.

Chapter 6 gives conclusions and recommendations of this research.

Chapter 2
LITERATURE REVIEW

This chapter reviews various literatures related to effectiveness of surfactant flooding using the concept of adsorption and desorption of surfactant active monomers, as well as enhancement options for surfactant flooding in waterflooded reservoirs.

2.1 Adsorption and Desorption of Surfactant Active Monomers

Adsorption of active surfactant monomer at early period and desorption at late time play important roles in reducing IFT and making surfactant flooding process economically feasible. Several studies have indicated the potential exist in obtaining benefits from desorbed active surfactant monomer to improve the efficiency in IFT reduction and economics of surfactant flooding.

Somasundaran and Hanna [2] investigated adsorption-desorption of sulfonates by reservoir rock minerals in solution of various sulfonate concentrations. This study used the term “abstraction” alone to describe the process of adsorption and precipitation of surfactant onto mineral surface, and exclude the precipitation in the bulk solution. The experiments were conducted by changing surfactant concentrations in stepwise manner to examine the abstraction behavior of surfactant during micellar flooding process. The experimental results indicated that significant amount of sulfonate can be de-abstracted from the surface by diluted surfactant concentration solution. In other words, flushing the core with water subsequent to the advance of a surfactant slug can remove abstracted sulfonate from rock surface. However, degree of de-abstraction isotherm depends largely on how close the pre-diluted surfactant concentration to the abstraction maximum. When the maximum pre-dilution surfactant concentration is not too different from the abstraction isotherm, the dilution isotherm is found not to differ significantly from the abstraction isotherm. In other words, the degree of de-abstraction is similar to the degree of abstraction when maximum abstraction is reached by pre-dilution surfactant concentration.

Gogoi [3] investigated the effects of desorbed surfactant and alkali concentration in the extended waterflood on oil-water IFT reduction and oil recovery. Experiments were conducted to obtain the adsorption-desorption behavior of Sodium Lignosulfonate (SL), which is an anionic surfactant, on core samples during EOR of medium viscosity oil. Experimental results indicated a presence of both desorbed surfactant and NaOH in the extended waterflood. This helped reducing oil-water IFT and thereby releasing trapped oil. This desorbed surfactant lasted for a long period of waterflood. The concentration of desorbed surfactant in the extended waterflood was found to be very low but still an ultra-low IFT was obtained by using suitable alkali. Core flood results showed an additional recovery of around 7-10% of the initial oil in place was obtained by desorbed surfactant and alkali. Results indicated that by utilizing desorbed surfactant during the extended waterflood operation the efficiency and economics of surfactant flooding can be improved significantly.

Liu et al. [4] investigated the adsorption-desorption-related interfacial phenomena and their effects on oil recovery. The results of this work helped to verify possibility in improving efficiency and economics of surfactant flooding. The surfactant agent used in this work is alkyl-aryl sulfonic acid. The adsorption of surfactant in continuous injection process and adsorption-desorption of surfactant in slug injection process were investigated. In the case of adsorption of surfactant in a continuous injection test, it was found that the normalized surfactant concentration, which is the ratio between surfactant concentrations in effluent sample to the original surfactant concentration, reached 0.83 at about 15.5 PV fluid production and remained constant for another 6 PV. This is because the equilibrium monolayer adsorption had been reached. However, the continued constant loss of surfactant after 15.5 PV was the result of multi-layer adsorption. In case of adsorption-desorption of surfactant in a slug injection test where dilute surfactant is applied, the injected fluid was formation water containing 0.2 wt.% surfactant and 1.0 wt.% NaOH. 1.5 PV of A/S solution was injected in the slug injection test to simulate adsorption-desorption process. The results indicated that separation of surfactant from alkaline-surfactant solution occurred by adsorption first and then desorption during the flow through core sample. Surfactant concentration in the effluent sample was still increasing when alkaline concentration in the effluent samples reached its maximum. It was also observed that desorbed surfactant can be very effective in reducing the oil-water IFT if an appropriate alkali concentration is applied. Moreover, four coreflood tests were also carried out to assess the effect of desorbed surfactant on oil recovery (in extended waterflood). The comparison was made between performing extended waterflood and alkali slug injection after the injection of A/S slug. The results indicated that performing extended waterflood together with additional 1.0 wt.% NaOH after injecting A/S slug yielded much lower IFT with additional of 13% IOIP due to the desorption of surfactant agents.

Azam et al. [5] investigated adsorption of a novel synthesized anionic surfactant at various conditions on Berea sandstone. The anionic surfactant, which contains 16-18 carbons in a chain with branch in the middle and a sulfonate head group, was synthesized in the laboratory. The Critical Micelle Concentration (CMC) of surfactant and Point of Zero Charge (PZC) of Berea sandstone were determined in this study. Moreover, static adsorption experiments were performed to investigate the effect of pH, salinity and temperature on the surfactant adsorption. Based on the experimental results, CMC was found to be at 0.179 wt.% (1,790 ppm) and therefore, any addition of surfactant concentration beyond this point did not increase surfactant adsorption, but only increased micellization in solution. The PZC of Berea sandstone was found to be 8.0. Hence, at pH above 8.0, Berea rock sample carries negative surface charge; therefore, anionic surfactants will have a lower adsorption values due to repulsion forces between each other. To evaluate this effect, two different alkalis, which are sodium metaborate (pH 9.5) and sodium teraborate (pH 10.5), were used to adjust the pH of the rock sample. Surfactant appears to adsorb lesser onto Berea sandstone in the presence of sodium tetraborate (adsorption reduced to 0.28 mg/g) as compared to sodium metaborate (0.36 mg/g). For the effect of salinity on adsorption, the experimental results show that adsorption of anionic surfactant increases with an increase of salt concentration until 2 wt.% concentration. After this value, any increase in salinity did not significantly affect surfactant adsorption. Surfactant adsorption was increased to 1.29 and 1.56 mg/g by the addition of 1 and 2 wt.% NaCl, respectively. The addition of NaCl decreases the functional group electrostatic repulsion in the adsorbed layer. Hence, the electrical double layer can be compressed strongly by increasing the salt concentration. However, temperature had the reverse effect to salinity. The adsorption of surfactant is reduced with increasing temperature. This is due to the higher kinetic energy, leading to weaker force of interaction between surfactant and Berea sandstone and subsequently higher entropy.

2.2 Enhancement Options for Surfactant Flooding in Waterflooded Reservoirs

Berger and Lee [6] reported a new type of surfactant, Alkyl Aryl Sulfonic Acid (AASA), that can be used at a very low concentration yet yielding ultra-low IFT for sandstone and limestone formation. The synthesis of AASA was determined to be economically feasible and potentially used as a surfactant in enhanced oil recovery applications. These new types of surfactants offered several advantages in terms of injected surfactant concentration, salt tolerance and emulsion, corrosion, and scale reduction over traditional surfactant used in ASP and surfactant flood. Ultra-low concentration can be used to produce ultra-low IFT with or without the addition of alkali, depending on the type of reservoir rock. They were also tolerant to high TDS brines and divalent salts. This made pre-treatment of the brine an option instead of a necessity. Moreover, problems such as emulsion formation, scale, and corrosion were minimized because only low concentration of surfactant is needed and alkali is not required. Their versatility and effectiveness offered a tremendous economic advantage over conventional sulfonate surfactant.

Babadagli et al. [7] performed a laboratory feasibility study of diluted surfactant injection for the Yibal field in Oman. Twelve surfactants with different surfactant types (anionic, cationic, nonionic) and at various concentrations were used to investigate the effects on oil recovery in this study. To quantify the surfactant injection recovery as a tertiary method for waterflooded area, two sets of dynamic experiments were used: 1) surfactant injection after waterflooding; 2) surfactant injection without pre-waterflooding. The results were evaluated in terms of the final oil recovery. The injection of surfactant solution after waterflooding yielded additional recovery up to 7.4% of OOIP from the secondary waterflooding process, which the recovery was found to be 75.1% OOIP. Injection of surfactant as the secondary recovery yielded only 69.9% OOIP. Thus, surfactant injection as secondary recovery was not preferable and not recommended over waterflooding in terms of both cost and recovery. For the case of waterflooding succeed by surfactant injection, it was observed that the surfactant type and concentration were more pronounced than the previous flooding history (or the amount recovered by the waterflooding) when it came to tertiary recovery. However, in case of using surfactant solution as secondary recovery, sweep efficiency was more critical than the reduction in IFT. In other words, the addition of surfactant concentration did not yield more recovery than waterflooding, but surfactants with better penetration (lower adsorption) into formation did.

Pei et al.[8] investigated an effect of nano-particle on improving stability of emulsion in surfactant flooding in waterflooded heavy oil reservoir. In this study, oil-in-water emulsions were prepared using biodiesel and brine water as the oil and water phases. Cationic surfactant hexadecyltrimethylammoniumbromide (CTAB) with purity of 99% was used to make emulsion. Hydrophilic silica nanoparticles (NP20) with the primary particle diameter of 15 nm were used to stabilize the emulsion with the surfactant and thicken the emulsion system. Phase behavior tests and rheology studies were conducted. The results showed that the emulsion system stabilized by nanoparticle and surfactant shown to remain stable for several months, which indicates that the emulsion stability can significantly improve with addition of silica nanoparticle in a surfactant system. Moreover, the increased nanoparticle concentration narrowed the droplet size range by making the oil droplet even smaller, which indicates that the emulsion were oil-in-water type. The rheology study indicated the presence of nanoparticles can increase the viscosity of the displacing fluid to the desirable mobility. Coreflooding study was also conducted to evaluate the effectiveness of emulsion flooding for improved oil recovery. Flooding tests were conducted in cores with absolute permeability varied from 100 mD to 1,100 mD. 0.5 PV emulsion slugs were injected at the rate of 0.1 ml/min after the initial waterflooding. The result showed that emulsion stabilized by nanoparticle and surfactant had a better displacement performance than the emulsion stabilized by surfactant for all permeability range. The emulsion flooding with the extended waterflooding recovered 50% of OOIP. It was indicated that injection of nanoparticle surfactant stabilized emulsion can significantly increase mobility ratio and thus, leads to the improvement of tertiary oil recoveries.

From these literature reviews, it can be seen that surfactant agent not only adsorb onto but also desorb from rock surface with respect to the change in surfactant concentration in the system. Moreover, these desorbed surfactants could still promote a favorable ultra-low IFT condition. However, none of literatures have emphasized on injection strategy of multi-slug surfactant with different slug concentration, injection rate, and time to implement surfactant injection after water pre-injection. Hence, this study is performed to evaluate the effectiveness of surfactant flooding with multi-slug grading in waterflooded reservoir and also to determine the effects of injection strategy on oil recovery.

Chapter 3

THEORY AND CONCEPT

This chapter presents theories and concepts related to oil recovery mechanisms by means of surfactant flooding technique, which include principle of surfactant flooding, types of surfactants, principle of oil displacement, types of micro-emulsion, surfactant retention, and displacement mechanisms.

3.1 Principle of Surfactant Flooding

Surfactant flooding is one of the promising techniques to recover portion of remaining oil that could not be extracted by a long term waterflooding process due to high capillary pressure. A presence of surfactant agents helps overcoming this issue by means of reducing interfacial tension (IFT) between two immiscible fluids, which are oil and water. The accumulation of surfactant agents at the oil-brine interface leads to reduction in IFT until oil is detached from rock surface and suspended in solution in a form of emulsion or small oil droplet. In this form, oil droplet is capable of deforming, elongating, and overcoming capillary pressure at pore throat. This leads to an increase in oil recovery.

3.2 Types of Surfactants

Surfactant molecules compose of two major portions, which are hydrophilic head and lipophilic tail. The combination of the two parts is known as amphiphile. Hydrophilic head refers to the part of surfactant that interacts strongly with the polar molecule such as water, whereas, lipophilic tail refers to the part of surfactant that interacts strongly with non-polar molecule like oil. Typically, the lipophilic tail is a long chain of hydrocarbon with 8-18 carbon atoms, and hydrophilic head is a polar and ionic portion. The balance between hydrophilic head and lipophilic tail gives the characteristic of a surfactant to reside at the interface between crude oil and water in order to help lowering the interfacial tension.

Surfactant active monomer agent can be classified into four types each of which is different in the charge on ionic head portion as shown in Figure 3.1.

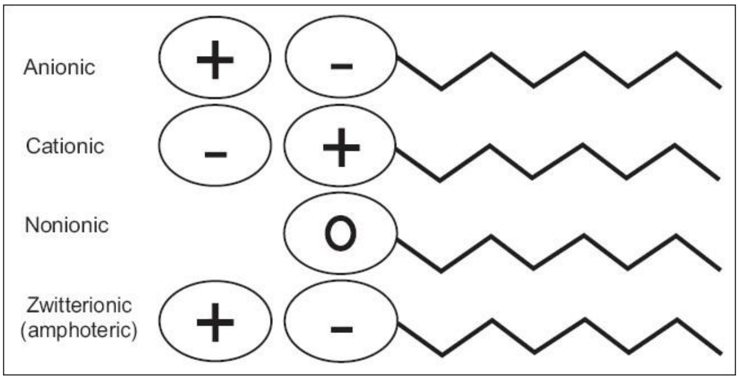


Figure 3.1: Four types of surfactant active monomer agent [9]

Anionic surfactants

Anionic surfactants are characterized by the negative charge on hydrophilic head. This type of surfactant exhibits low adsorption characteristic on the negatively charged surface like sandstone surface. They are stable and capable in reducing interfacial tension to an ultra-low condition. For this reason, anionic surfactants are considered as effective agent widely used for surfactant flooding. However, this type of surfactant is not suitable for positively charged reservoirs like carbonate reservoirs due to loss of surfactant via surface adsorption.

Cationic surfactants

Cationic surfactants are characterized by the positive charge on hydrophilic head. This type of surfactant exhibits low adsorption characteristic on the positively charged surface like on the carbonate rock. They are capable of changing wetting condition from oil-wet to water-wet, which is favorable condition for production. However, this type of surfactant is not suitable for sandstone reservoirs due to loss of surfactant via surface adsorption and this type of surfactant is still expensive compared to anionic surfactant.

Nonionic surfactants

Nonionic surfactants are characterized by the neutral charge on hydrophilic head. This type of surfactant exhibits good tolerance to a high salinity environment. However, the capability of nonionic surfactants to reduce interfacial tension is not as good as the anionic surfactants. Therefore, they are typically used as a co-surfactant to increase the salinity tolerant capability of anionic surfactant while maintaining the ability to reduce IFT to an ultra-low condition.

Amphoteric/Zwitterionic surfactants

Amphoteric surfactants are characterized by the mixture of charge properties on hydrophilic head, which can be nonionic-anionic, nonionic-cationic, or anionic-cationic. This type of surfactant exhibits high tolerance to high temperature and salinity, but the cost for this type surfactant is very expensive.

3.3 Principle of Oil Displacement by Surfactant Flooding

The ability of surfactant agents to reduce the IFT has been utilized to recover the capillary-trapped residual oil remaining after waterflooding process. The reduction in interfacial tension and the increase in viscosity of displacing fluid lead to lowering resistance to flow. This resistance to flow is defined by a capillary number, which is the ratio of viscous forces and local capillary forces [1]. This dimensionless term can be calculated using Equation (3.1):

$$N_c = \frac{v\mu}{\sigma} \tag{3.1}$$

where, v = effective flow rate of displacing fluid (m/s),

μ = viscosity of displacing fluid (mPa ▪s),

σ = interfacial tension between the displacing and displaced fluids (mN/m or dyne/cm).

In water-wet rocks, the capillary number can be expressed using Equation (3.2):

$$N_c = \frac{v\mu_w}{\sigma \cos\theta} \tag{3.2}$$

where, θ = contact angle measured through the fluid with highest density.

As a result of decreasing interfacial tension, capillary number increases, leading to lower residual oil saturation and increase in oil recovery, as shown in Figure 3.2.

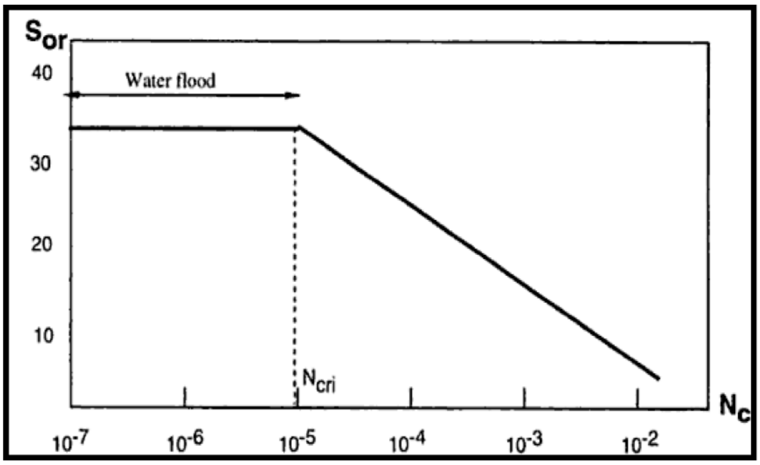
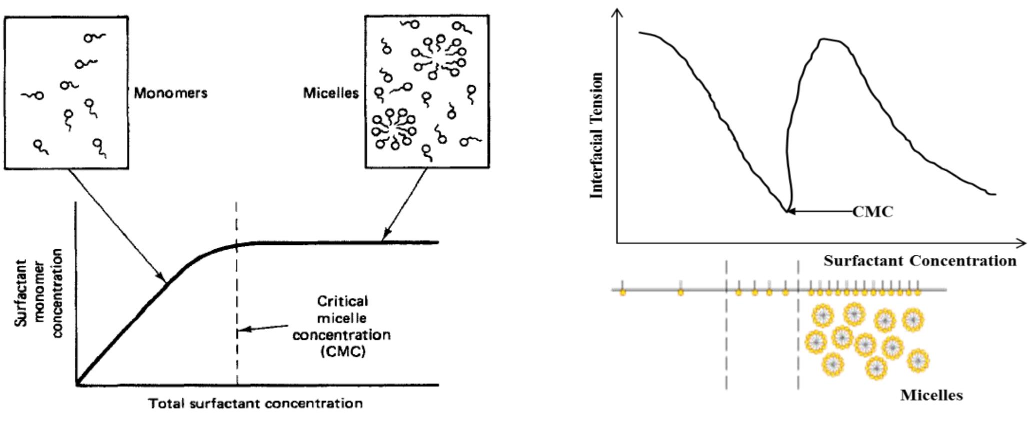


Figure 3.2: Capillary desaturation curve for a non-wetting phase [1]

In conventional waterflooding operations, capillary number is generally at or near the order of 10^{-6}. However, capillary number must be increased to at least 10^{-5} to improve oil recovery. In many cases, velocity and viscous of displacing fluid cannot be varied by order of 10^{2} or more. This is because too high injection velocity may create fracture in the formation and too high viscosity may cause difficulty in injection. Therefore, interfacial tension, which could be reduced to achieve such orders of magnitudes, is the only parameter that can be modified. With the right concentration of surfactant, the interfacial tension could be reduced down to the range of 10^{-3} to 10^{-4}.



(a) (b)

Figure 3.3: (a) Surfactant monomer concentration vs. total surfactant concentration, (b) Generic IFT value as a function of surfactant concentration[10]

Upon introduction of surfactants into the system, surfactant monomers accumulate at the interface, sticking its polar head portion into water phase and non-polar tail portion into oil phase. This configuration reduces the system free energy by reducing the energy of the interface and creating most stabilized configuration of surfactant monomers. Once the interface is fully covered by surfactant monomers, the surfactants start aggregating into micelles, which in turn further reduces the system free energy by decreasing the contact area of hydrophobic parts of the surfactant with water. The concentration of surfactant above which micelles are spontaneously formed is known as Critical Micelle Concentration (CMC). As shown in Figure 3.3(a), surfactant monomer concentration remains constant regardless of any increase in total surfactant concentration after CMC. In term of system free energy, Figure 3.3(b) indicates that the presence of surfactants causes reduction of interfacial tension. However, after CMC is reached, any further accretion of surfactant concentration will just increase the interfacial tension.

Micelle can be classified into two forms, which create different types of micro-emulsions. Oil-in-water micelles, or swollen micelles, have the tail groups at the center with the heads extending outward and water-in-oil micelles, or inverted swollen micelles, have the head groups at the center with the tails extending outward.

3.4 Types of Microemulsions

As illustrated in Figure 3.4, there are three different types of micro-emulsions, each of which is formed based on salinity of aqueous phase. At low brine salinity, surfactants exhibit a better solubility in aqueous than oil phase. Oil-in-water emulsion is formed at the center of the swollen micelles. This type of emulsion is known as Winsor type II (-). Type II indicates that there are two phases in the system, which are water and oil emulsions, and negative sign indicates that tie lines in ternary phase diagram have negative slope. At high brine salinity, surfactants exhibit a better solubility in oil than aqueous phase. The presence of excess sodium ions pushes surfactant monomers into oil phase, forming water-in-oil emulsion at the center of inverted swollen micelles. This type of emulsion is called Winsor type II (+). At intermediate salinity, there are three different phases formed in the system including excess oil and brine phases and micro-emulsion phase. Both swollen micelles and inverted swollen micelles can be found in this environment. As a result, residual oil and irreducible water are no longer presented in the formation. An ultra-low condition could be achieved at this range of optimum salinity environment, and relative permeabilities curve form a diagonal shape, which is the condition where two fluids flow like a single phase flow. This type of micro-emulsion is called Winsor type III.

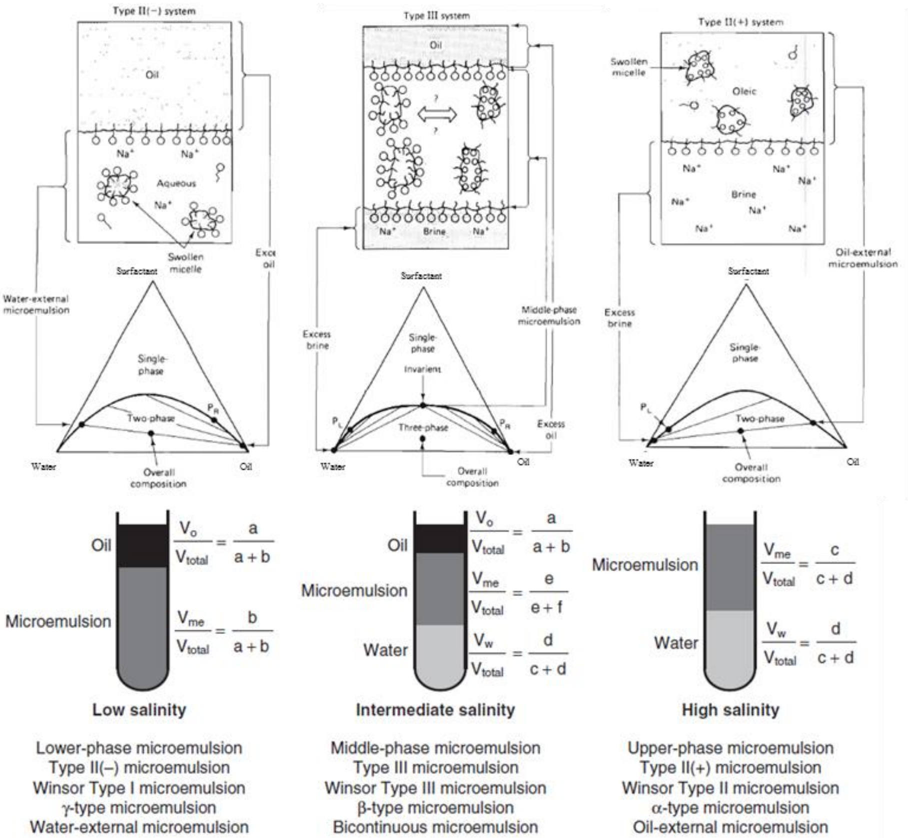
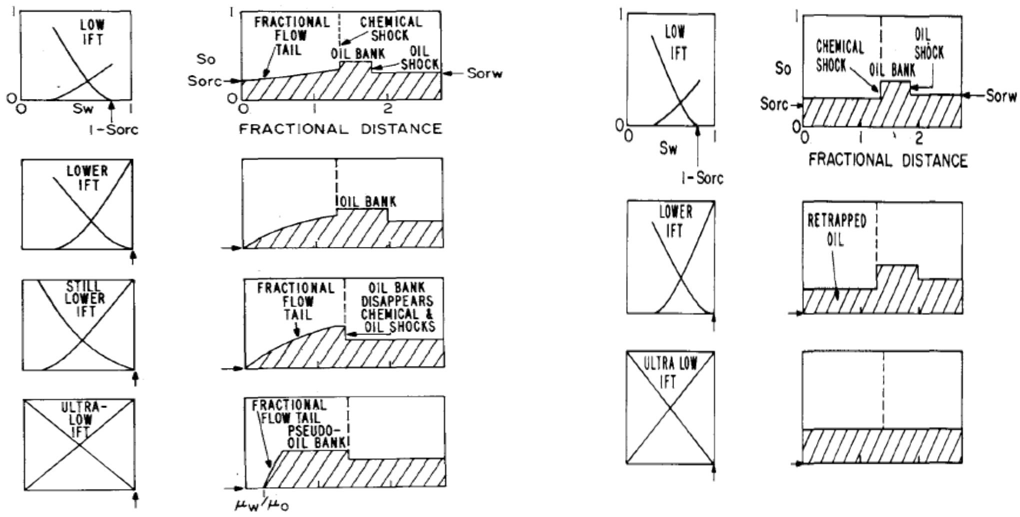


Figure 3.4: Three types of micro-emulsions and effects of salinity on phase behavior[1]

The formation of emulsions in the system, as the result of interfacial tension reduction, affects residual saturation, which directly changes relative permeabilities, as illustrated in Figure 3.5. Emulsions improve oil recovery by two mechanisms.



(a) (b)

Figure 3.5: Changes in relative permeability curves and oil saturation profile at different IFT: (a) emulsification and entrapment mechanism, (b) emulsification and entrainment mechanism [10]

The first mechanism is emulsification and entrainment, as shown in Figure 3.5(a). In this mechanism, residual oil undergoing mobilization is emulsified and entrained into the flowing surfactant solution. This improves displacement/microscopic efficiency of the system. At low IFT, oil bank is formed from the liberated oil emulsion. A shift of saturation gradient can be seen in the flooded zone. At lower IFT, relative permeability curve shifts to right side as a result of reduction in residual oil saturation, which may reach zero if perfect conditions are established. Flow ability of water at this condition is also improved. Oil and water have similar flow ability at this stage. At still lower IFT, connate water is displaced by the flowing mobile connate water from the previous stage and travels at the same speed with oil phase. Oil shock front and chemical shock front are overlapped in this stage. At ultra-low IFT condition, relative permeability curves form diagonal shape. Fluids in the system flow as one single phase at this condition. This is the most favorable condition where all fluids are displaced by injected chemical and pseudo oil bank is formed.

The second mechanism is emulsification and entrapment, as shown in Figure 3.5(b). In this mechanism, the emulsified oil is trapped again in the porous medium at downstream pore throats that are too small for the emulsion droplets to pass through. In term of macroscopic efficiency, this phenomenon improves the sweep efficiency and helps reducing viscous fingering effects.

3.5 Surfactant Retention

Surfactant retention, which is one of the most important variables that has to be minimized for successful commercial application of surfactant process, is the mechanism that concerns with adsorption, precipitation, degradation, and phase trapping of surfactants. Surfactant consumptions vary widely depending on surfactant structure, mineralogy or rock, salinity, pH, temperature, micro-emulsion viscosity, crude oil, co-solvent and mobility control among other variables. However, it is difficult to separate the surfactant losses from different mechanisms. Therefore, total surfactant loss is usually reported as surfactant retention without clearly specifying the losses from different mechanisms.

Rock solid may possess positively charged or negatively charged surface depending on mineralogy. Typically, at neutral pH, sandstone rock has negatively charged surface due to the presence of silica, whereas carbonate rock has positively charged surface owing to the presence of calcite and dolomite. As the surfactant comes into contact with the reservoir rock, the electrical interaction between rock solid surface and surfactant ions leads to the adsorption of surfactants onto the rock surface. Anionic surfactants possess negatively charged and therefore, tend to adsorb onto carbonate rock. On the other hand, cationic surfactants are adsorbed by sandstone surface due to the positively charged polar head. It was observed that maximum adsorption occurs near the CMC and surfactant adsorption will not increase when the CMC is reached. To prevent loss of surfactant due to adsorption, sacrificial agents, such as alkaline substances, can be used to reduce the surfactants consumption.

The solubility of surfactant decreases with increasing salinity. The presence of divalent ions, for example calcium ion (Ca^{2+}) and magnesium ion (Mg^{2+}), in formation brine causes the precipitation of surfactants. This precipitation process is a reversible process, as described by Equation (3.3). As surfactant concentration increases, the system undergoes precipitation-dissolution-reprecipitation mechanism. When surfactant concentration is below CMC, number of surfactant monomer in solution increases with an increase of surfactant concentration. As a result of ionization, Na^+ and R^- also increase linearly with surfactant concentration. Upon reaching CMC, divalent ions in brine formation react with R^- to generate MR_2 precipitation. Therefore, concentration of Ca^{2+} is reduced. This continues until the surfactant concentration reached CMC and all the Ca^{2+} in the solution has been consumed. Above CMC, precipitation of surfactant stops. The concentration of R^- decreases, as a result of micelle formation. The presence of micelle solubilizes existing MR_2 precipitates. An increase in micelle concentration from further addition of surfactant concentration dissolves more precipitate until certain limit. After surfactant concentration is increased above a limit, surfactant itself will precipitate because of its limited solubility and therefore reprecipitation reoccurs.

$$2R^- + M^{2+} \leftrightarrow MR_2 \downarrow \tag{3.3}$$

Where, R^- = Anionic surfactant (petroleum sulfonate),
M^{2+} = Divalent ion (Ca^{2+} or Mg^{2+}),
MR_2 = Surfactant-divalent cation complex that precipitate in brine.

Thermal degradation of surfactants happens through the hydrolytic desulfonation reaction, at which heat at elevated temperature causes the polar head of surfactant monomer to detach from its non-polar tail. As a result, the degraded surfactant no longer has ability to reduce interfacial tension. Most of the surfactants are tested to be stable at normal reservoir temperature, whereas the stability of the best sulfonates was marginally acceptable at a temperature of 200 °C.

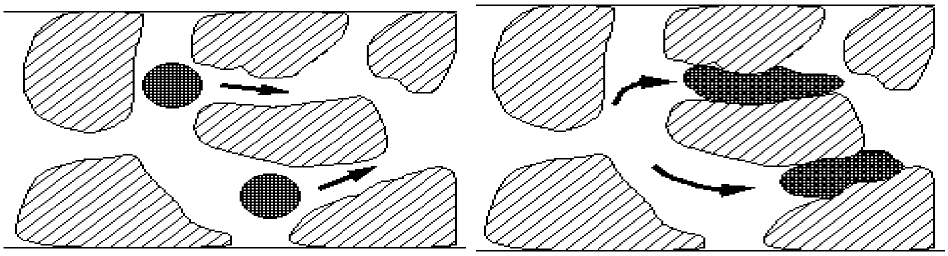


Figure 3.6: Deforming and elongating of oil drops through pores due to reduction in IFT

3.6 Displacement Mechanisms

In surfactant flooding, the process can be categorized into diluted surfactant flooding and micellar flooding. Discussion of the displacement mechanism may be made according to these two groups.

3.6.1 Displacement Mechanism in Diluted Surfactant Flooding

Diluted surfactant flooding is considered as immiscible displacement process in the field application. The oil droplets are emulsified because of the low interfacial tension and entrained in surfactant solution. These entrained oil droplets are carried forward and are pulled, as illustrated in Figure 3.6, to become long oil threads so that they can deform and pass through pore throats. The oil threads could be broken during flow. Once broken, they become small droplets and are emulsified. These small droplets flow downward and lodge at the next throats to be coalesced with other oil droplets. When the salinity is low, oil-in-water emulsions are formed. When salinity is high, water-in-oil emulsions are formed. These oil droplets are coalesced to form an oil bank ahead of the surfactant slug.

3.6.2 Displacement Mechanism in Micellar Surfactant Flooding

Micellar flooding is considered as miscible displacement process. As discussed earlier, depending on salinity and compositions, there are three types of micro-emulsions. The solubilization or swelling mechanism is related to the type of micro-emulsion. Solubilization corresponding to type II(-), similar to a vaporizing-gas drive. The emulsified oil droplets of this type are carried forward and are coalesced with oil ahead to form an oil bank. Swelling corresponds to type II(+), similar to a condensing-gas drive. Micro-emulsion of this type allows external oil to merge with residual oil to form an oil bank. In middle-phase micro-emulsion, due to the lowest IFT, oil and water can be solubilized in each other, and oil droplets can flow more easily through pore throats. Oil droplets move forward and merge with oil downstream to form an oil bank. Because of solubilization effect, water and oil volumes are expanded, leading to higher relative permeabilities and lower residual saturations. However, when relative permeability to water (k_{rw}) increases faster than relative permeability to oil (k_{ro}) with decreasing IFT, oil saturation in oil bank and oil recovery rate are deteriorated, if there is no viscosity alteration.

Chapter 4

RESERVOIR SIMULATION MODEL AND RESEARCH METHODOLOGY

This chapter provides specifications of reservoir simulation model used in this research. STARS reservoir simulation program, commercialized by Computer Modeling Group (CMG), is employed in this study to construct a simulated reservoir model as well as to investigate the results. Details of this reservoir simulation model can be divided into three main sections, which are reservoir section, well and recurrent section, and injected surfactant properties section. Thorough descriptions of each section are explained in this chapter.

4.1 Reservoir Section

In order to construct a simulated reservoir model, parameters such as, reservoir size, initial reservoir conditions, Pressure-Volume-Temperature (PVT) properties, rock and fluid properties, are inevitable. In addition, numerical controls must be specified for precise numerical calculation.

4.1.1 Reservoir Size, Properties, and Initial Condition

Reservoir simulation model is constructed in Cartesian coordinate as shown in Figure 4.1. The model is configured by 33 x 33 x 9 blocks (x, y and z directions) where each individual block has the size of 20 x 20 x 12 ft in x, y and z direction, respectively. This gives the total reservoir size of 660 x 660 x 108 ft in x, y and z, and the total of 9,801 grid blocks, which the total number does not exceed limitation of CMG academic license of 10,000 grid blocks. Therefore, total volume of this reservoir model is equal to 8.38 MMbbl.

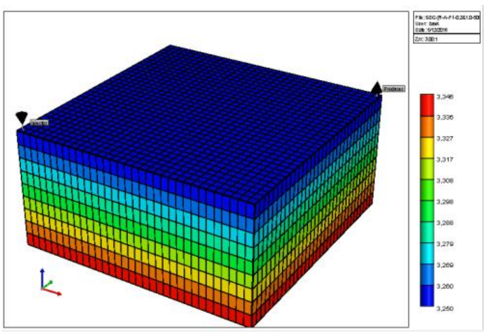


Figure 4.1: 3-D reservoir model constructed in STARS reservoir simulation program

The top of simulated reservoir model is located at depth of 3,250 ft with effective porosity of 20% along with horizontal permeability of 100 mD and vertical permeability of 10% of horizontal permeability. Initial water saturation is at 20%. Reference pressure and temperature at datum depth are determined from typical pressure and temperature gradients as shown in Figure 4.2 and Figure 4.3, respectively. Surface temperature is assumed to be at 77 ^{o}F. The pressure and temperature at datum are determined to be at 1,400 psia and 122 ^{o}F, accordingly.

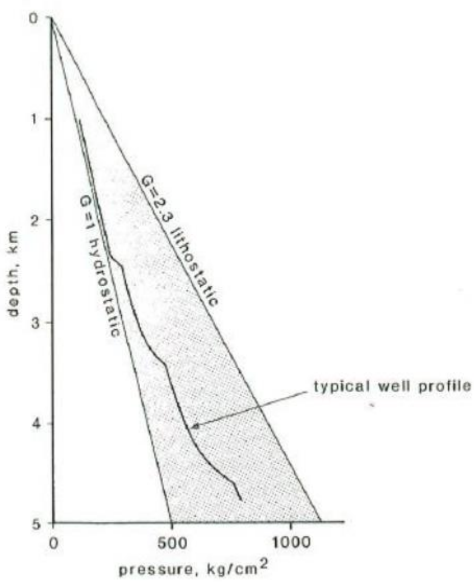


Figure 4.2: Typical hydrostatic pressure gradient[11]

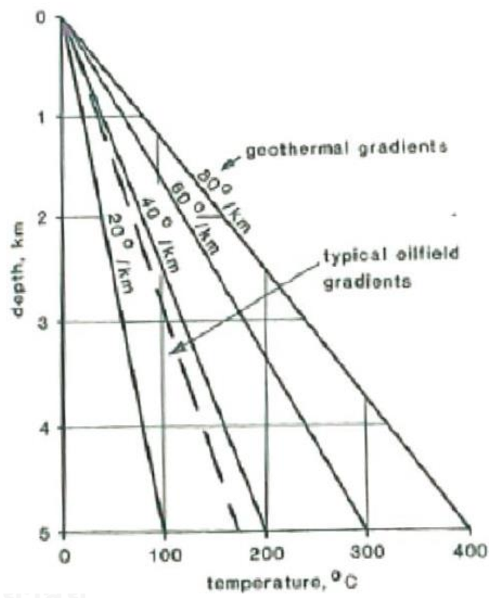


Figure 4.3: Typical geothermal gradient[11]

According to the reservoir size, effective porosity and initial water saturation, the total effective pore volume of this reservoir model is equivalent to 1.68 MMbbl and Original Oil In Place (OOIP) of 1.34 MMbbl. The reservoir model is constructed as a homogenous model. All essential reservoir data are listed and summarized in Table 4.1.

Table 4.1: Data for reservoir model [12-16]

Parameters	Values	Unit
Grid dimension	33 x 33 x 9	Block
Grid size	20 x 20 x 12	ft
Top of reservoir	3,250	ft
Effective porosity (ϕ)	20	%
Horizontal permeability (k_H)	100	mD
Vertical permeability (k_V)	$0.1k_H$	mD
Initial water saturation (S_{wi})	20	%
Reference pressure at datum depth	1,400	psia
Reservoir temperature	122	^{o}F
Oil gravity	30	^{o}API
Solution Gas Oil Ratio (R_s)	264	SCF/STB
Bubble Point Pressure (P_b)	1,350	psia
Total production time	20	years

4.1.2 Pressure-Volume-Temperature (PVT) Properties

PVT data of all the fluids presented in the reservoir model are generated from the correlations inside STARS reservoir simulation program, as summarized in Table 4.2. Two important PVT data are solution gas-oil ratio (R_s) and bubble point pressure (P_b). By defining the bubble point pressure, solution gas-oil ratio can be determined using Figure 4.4 at specified reservoir temperature, oil gravity, and gas gravity.

Values of input parameters necessary for PVT data generation by correlations in STARS reservoir simulation program are summarized in Table 4.3. The generated PVT data includes oil formation volume factor (B_o), gas formation volume factor (B_g), water formation volume factor (B_w), oil viscosity (μ_o), gas viscosity (μ_g), and water viscosity (μ_w). The generated PVT data as a function of pressure are illustrated in Figure 4.5 to Figure 4.11.

Table 4.2: Correlation types for generating each PVT data

Parameters	Correlation Types
Oil properties (P_b, R_s, B_o) correlations	Standing
Oil compressibilitycorrelation	Glaso
Dead oil viscosity correlation	Ng and Egbogah
Live oil viscosity correlation	Beggs and Robinson
Gas critical properties correlation	Standing

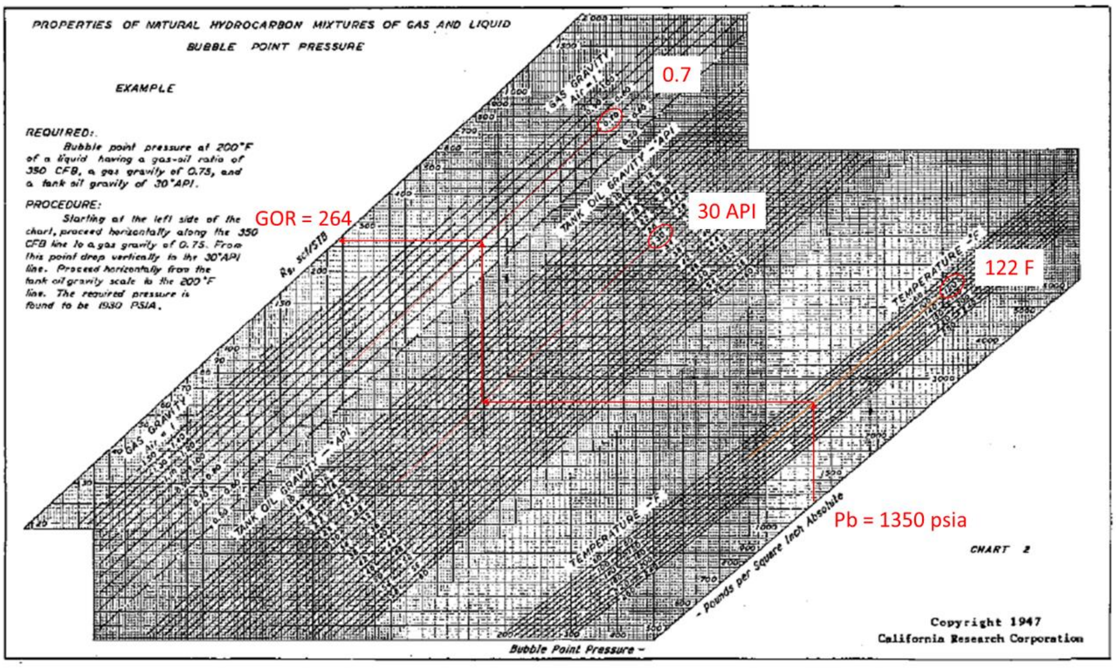


Figure 4.4: Correlation between bubble-point pressure and solution gas-oil ratio (Copyright 1947 Chevron Oil Field Research Co., with permission.) [16]

Table 4.3: Data for reservoir model[12-16]

Parameters	Values	Unit
Reservoir Temperature	122	°F
Oil Gravity	30	°API
Gas Gravity	0.7	-
Solution Gas Oil Ratio (R_s)	264	SCF/STB
Bubble Point Pressure (P_b)	1,350	psia
Reference Pressure	1,400	psia

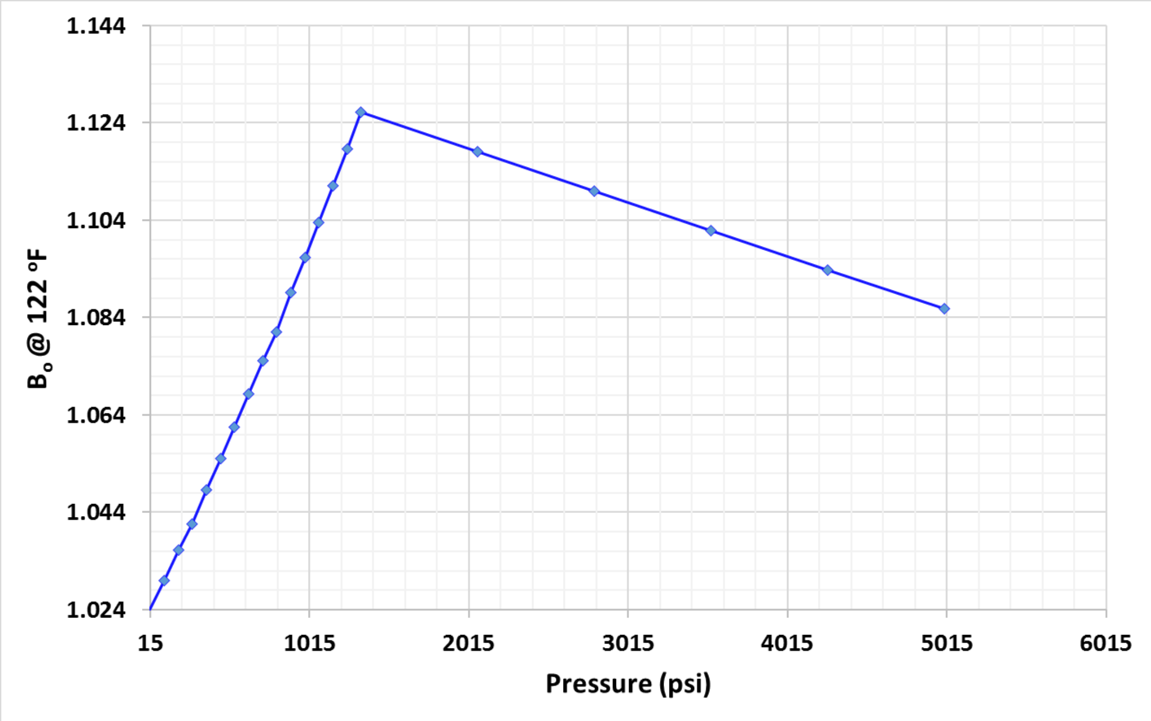


Figure 4.5: Oil formation volume factor (B_o) generated from correlation as a function of pressure

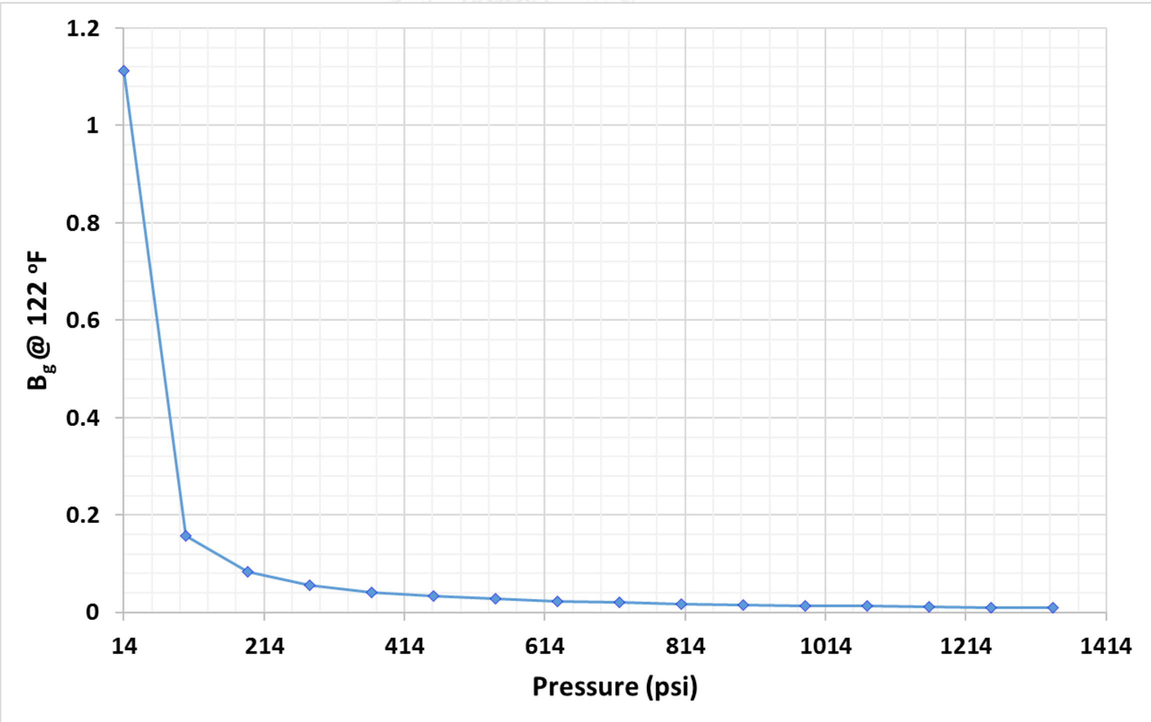


Figure 4.6: Gas formation volume factor (B_g) generated from correlation as a function of pressure

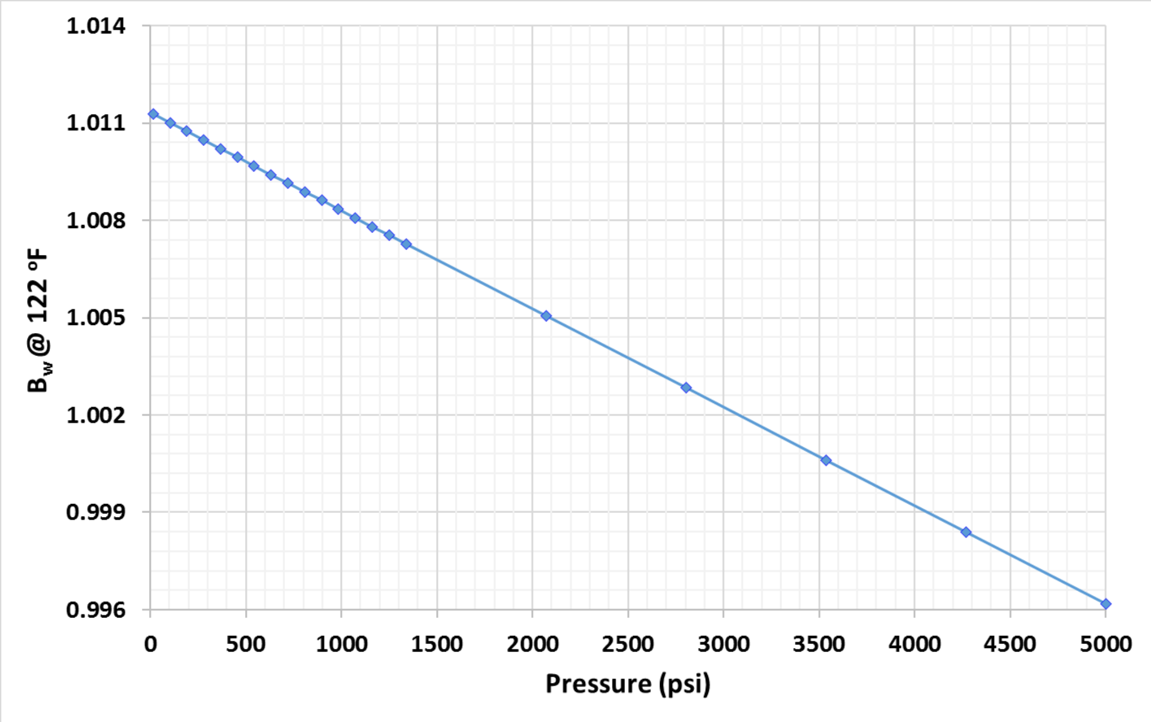


Figure 4.7: Water formation volume factor (B_w) generated from correlation as a function of pressure

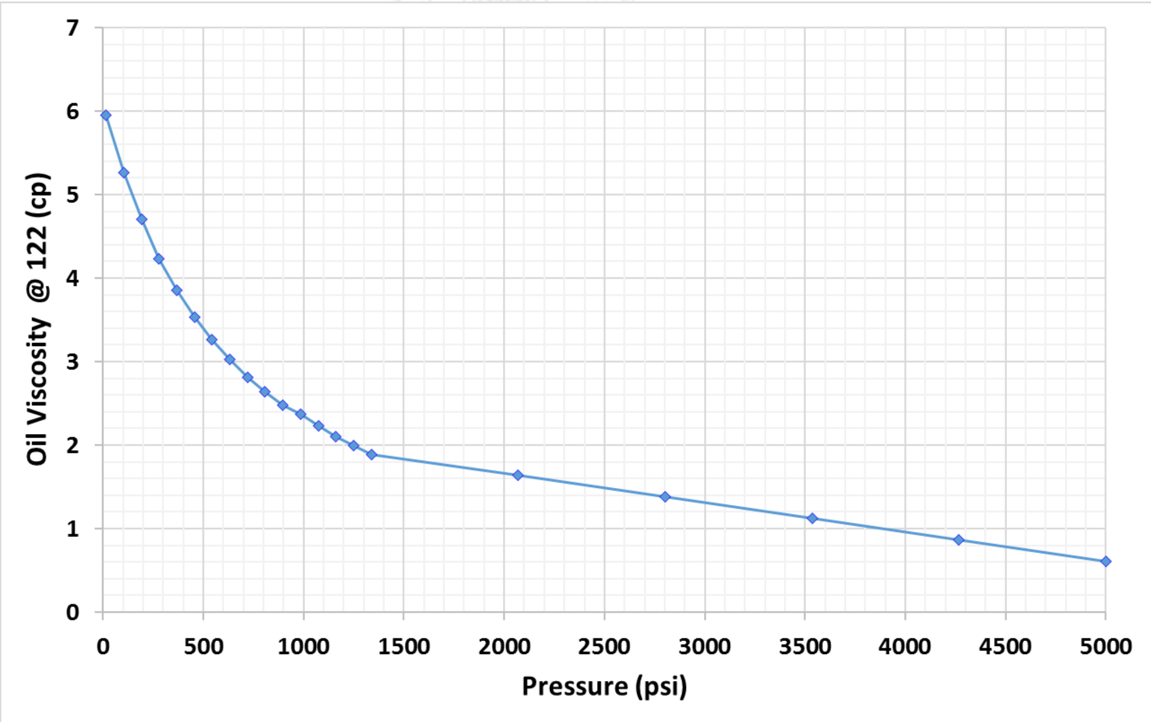


Figure 4.8: Oil viscosity (μ_o) generated from correlation as a function of pressure

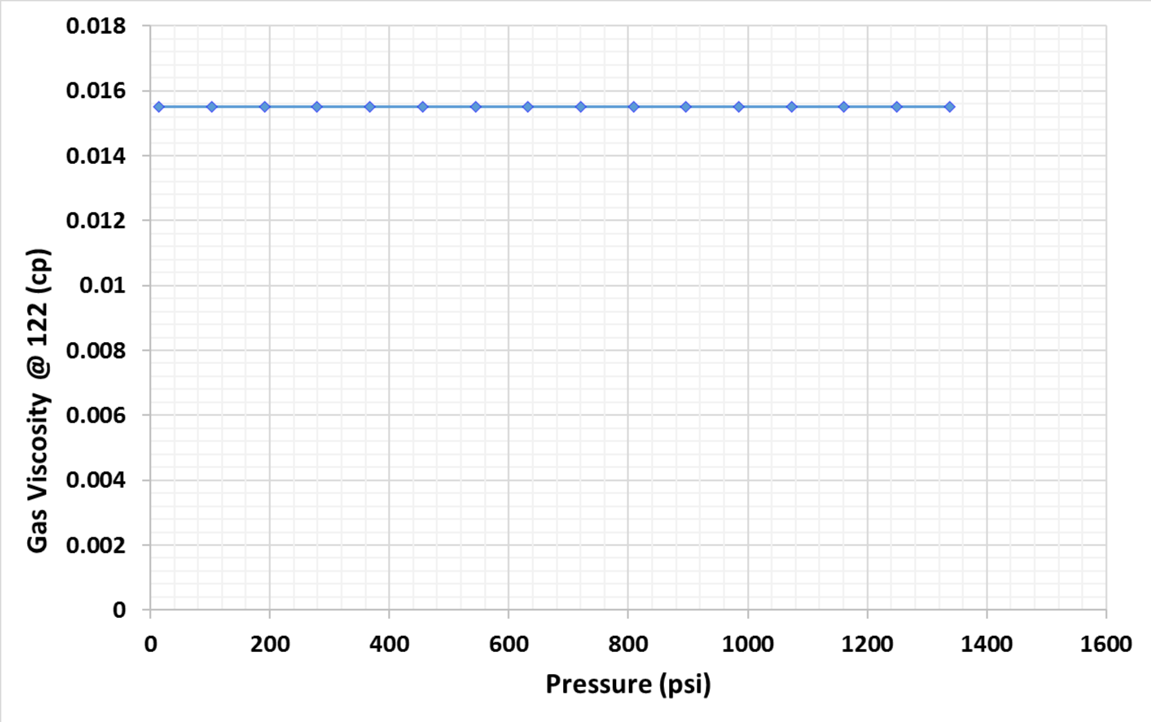


Figure 4.9: Gas viscosity (μ_g) generated from correlation as a function of pressure

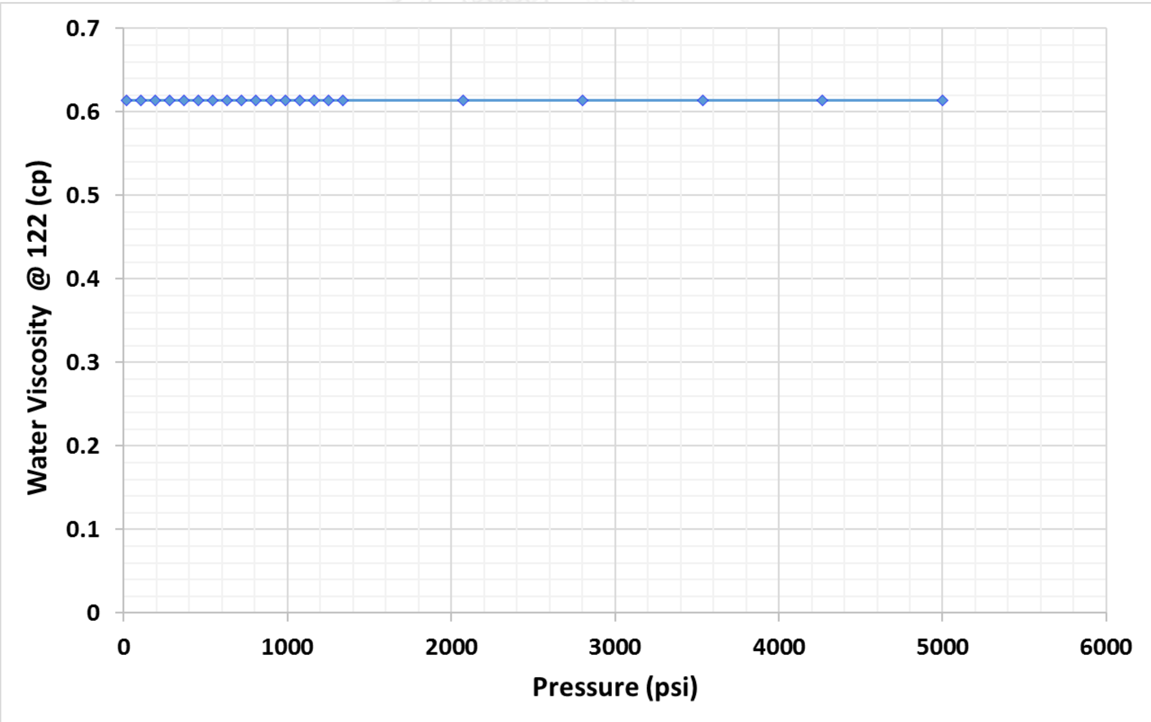


Figure 4.10: Water viscosity (μ_w) generated from correlation as a function of pressure

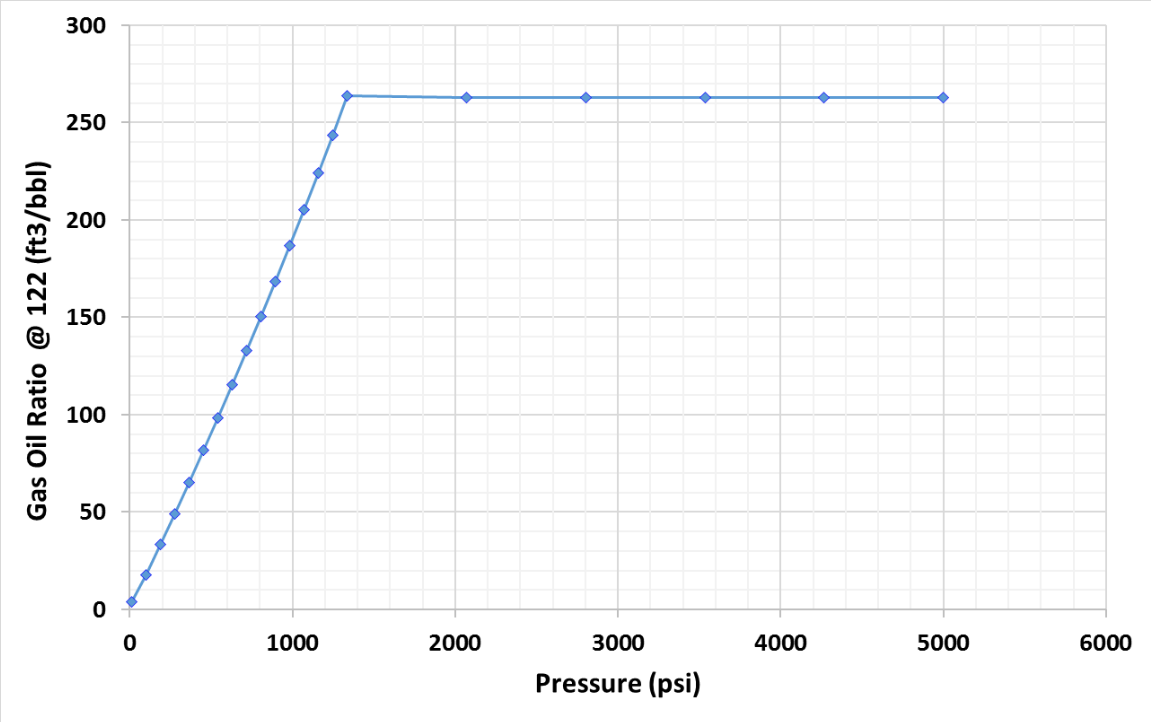


Figure 4.11: Gas-oil ratio (R_s) generated from correlation as a function of pressure

4.1.3 Rock and Fluid Properties or Special Core Analysis (SCAL) Properties

Relative permeability curves, wettability, and adsorption function are properties between rock and fluid inside the reservoir. In this work, sandstone formation is employed, and therefore wettability of rock formation is water-wet.

Initial relative permeability curve between rock and fluid system is then constructed based on water-wet condition by specifying the endpoint saturation as well as relative permeability values at irreducible water saturation and residual oil saturation. Corey's exponent value of 3 as suggested for well sorted consolidated sandstone is used. Stone's II model is employed as a method for evaluating 3-phase relative permeability to oil. Capillary number is set at value of 10^{-5}, which is a typical value where no chemical agent is presented inside the reservoir. Table 4.4 summarizes important information required to construct the initial relative permeability curves for this reservoir model.

It is important to note that for the waterflood models (base case models) there is only one interpolation set since there is no intervention in rock-fluid properties as for the case of surfactant flooding models in section 4.3. And this interpolation set is corresponding to initial relative permeability curves generated from information in Table 4.4. The initial relative permeability curves are plotted as shown in Figure 4.12.

Table 4.4: Relative permeability correlations for initial relative permeability curves

Rock Fluid Properties	
Rock Wettability	Water-Wet
Method for Evaluating 3-Phase Kro	Stone's II Model
Relative Permeability Correlations	
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.25
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.25
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.7
KRWIRO - Krw at Irreducible Oil	0.25
KRGCL - Krg at Connate Liquid	0.7
KROGCG - Krog at Connate Gas	-
Exponent for calculating Krw from KRWIRO	3
Exponent for calculating Krow from KROCW	3
Exponent for calculating Krog from KROGCG	3
Exponent for calculating Krg from KRGCL	3

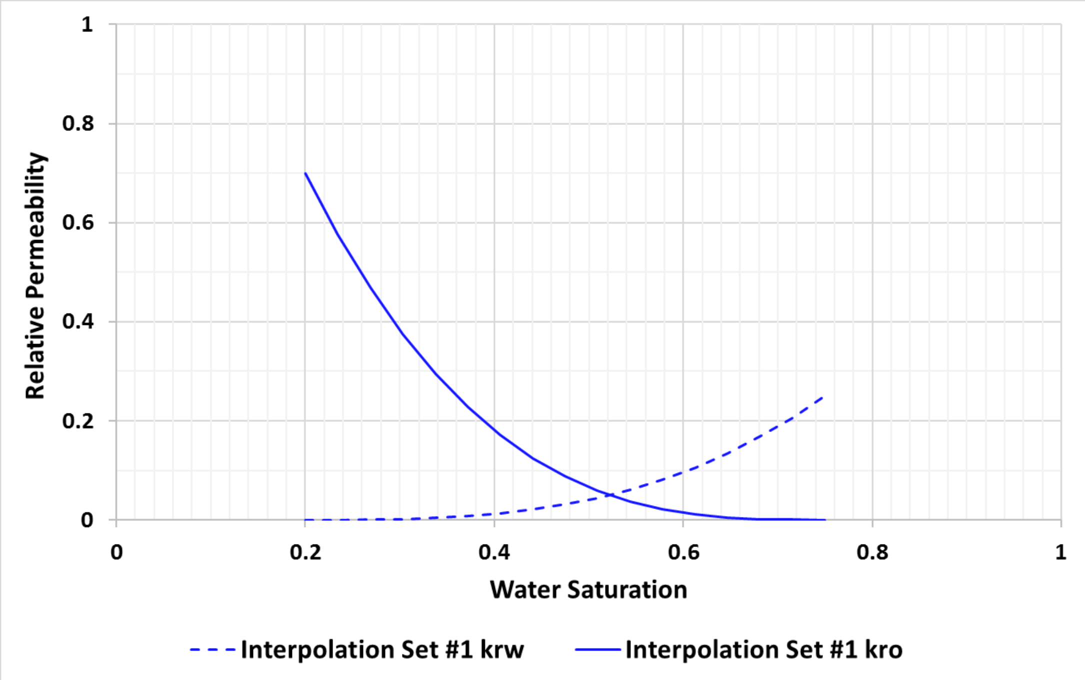


Figure 4.12: Initial relative permeability curves as a function of water saturation for the reservoir model

4.2 Well and Recurrent Model

This section describes well pattern, well location, well specifications, date of simulation, injected fluid and well constraints of both production and injection wells in this reservoir simulation model.

In this work, a quarter-five-spot well pattern is used where the production and injection well are placed at the opposite corners as shown in Figure 4.13. Both wells have identical specifications, where wellbore radius is set to be at 0.25 ft., and skin around the wellbore is assumed to be zero. Full-to-base perforation is employed in this work.

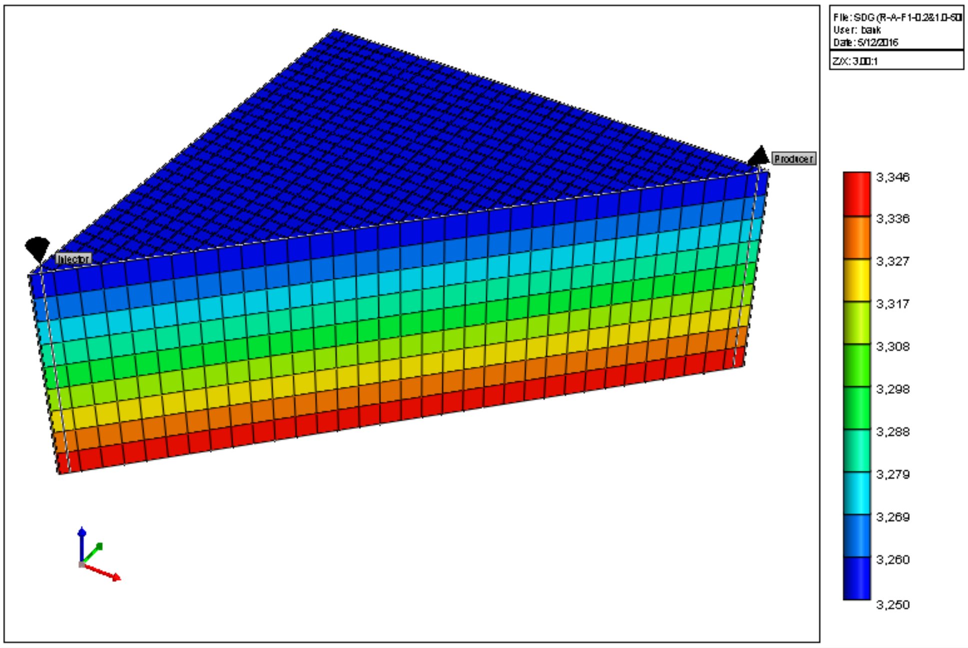


Figure 4.13: Cross-sectional image of 3-D reservoir model

Total simulation date is ranged for 20 years, and flooding operation starts from day one. During the simulation period, certain operation and monitoring are set as well constraints to control activity of the wells. Any violations on well constraints may terminate the reservoir simulation process.

For injection well, two operating parameters, which include bottomhole pressure and surface water injection rate, are set as well constraints. Injection well bottomhole pressure is limited to a maximum amount of 1,800 psi which is still below approximated formation fracture pressure in order to prevent undesired injectant leakage. Maximum surface water injection rate is varied according to a desired injection rate. Only in case of injection well, mole fraction of injected fluid must be specified in order to define type of injectant.

For production well, well constraints consist of two operating parameters including bottomhole pressure and surface liquid rate, and one monitoring parameter, which is watercut. First, production well bottomhole pressure is limited to a minimum value of 200 psi. Second, maximum liquid production rate is set to be equal to surface water injection rate. By maintaining voidage ratio equal to 1, reservoir pressure is sustained at certain value. Third, watercut is monitored to assure that the value does not exceed the limit of 95% to balance economic issue. Table 4.5 and Table 4.6 summarize well constraints of injection well and production well, respectively.

Table 4.5: Well constraints of injection well

Constraint	Parameters	Limit/Mode	Value	Unit	Action
Operate	Bottomhole pressure (BHP)	Max	1,800	psi	Cont.
Operate	Surface water rate (STW)	Max	Vary	bbl/day	Cont.

Table 4.6: Well constraints of production well

Constraint	Parameters	Limit/Mode	Value	Unit	Action
Operate	Bottomhole pressure (BHP)	Min	200	psi	Cont.
Operate	Surface liquid rate (STW)	Max	Vary	bbl/day	Cont.
Monitor	Watercut (WCUT)		0.95	fraction	Stop

4.3 Injected Surfactant Properties

4.3.1 Surfactant Concentration, Interfacial Tension, and Adsorption Values

Sodium Dodecylbenzenesulfonate, which is an anionic surfactant, is chosen as a surfactant agent in this study. Interfacial tension (IFT) values as a function of surfactant concentration are taken from related study and the values are summarized in Table 4.7. For surfactant adsorption values as a function of surfactant concentration, default values provided by STARS reservoir simulation program is employed. Table 4.8 summarizes values of adsorption as a function of surfactant concentration used in this study.

Table 4.7: Values of interfacial tension as a function of surfactant concentration[17]

Weight Surfactant (%)	Interfacial Tension (dynes/cm)
0	18.2
0.5	0.001
1	0.0001

Table 4.8: Values of adsorption as a function of surfactant concentration

Weight Surfactant (%)	Surfactant Adsorption (mg)/(100gm of rock)
0	0
1	27.5

4.3.2 Petrophysical Properties

For surfactant flooding models, four additional interpolation sets are constructed with different endpoint saturations, relative permeability values at irreducible water saturation and residual oil saturation, and Corey's exponent values as listed Table 4.9. The system is shifted from one to another interpolation set once the capillary number of the system reaches the defined value of each set as shown in Table 4.10. The changes in capillary number of the system are resulted from the alternation of system IFT from the intervention of rock and fluid properties by surfactant agent. Hence, it can be said that interpolation set is a function of capillary number, and capillary number is subsequently a function of IFT. Relative permeability curves for different interpolation sets as a function of water saturation is plotted in Figure 4.14.

Table 4.9: Relative permeability correlations for each interpolation set

Relative Permeability Correlations					
Interpolation Set	**1**	**2**	**3**	**4**	**5**
SWCON - Endpoint Saturation: Connate Water	0.2	0.2	0.2	0.2	0
SWCRIT - Endpoint Saturation: Critical Water	0.2	0.2	0.2	0.2	0
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.25	0.15	0.01	0	0
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.25	0.15	0.01	0	0
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0	0	0	0	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2	0.2	0.2	0.2	0
SGCON - Endpoint Saturation: Connate Gas	0	0	0	0	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05	0.05	0.05	0.05	0
KROCW - Kro at Connate Water	0.7	0.8	0.9	0.95	1
KRWIRO - Krw at Irreducible Oil	0.25	0.5	0.8	1	1
KRGCL - Krg at Connate Liquid	0.7	0.8	0.9	0.95	1
KROGCG - Krog at Connate Gas	-				
Exponent for calculating Krw from KRWIRO	3	2.5	2	1.5	1
Exponent for calculating Krow from KROCW	3	2.5	2	1.5	1
Exponent for calculating Krog from KROGCG	3	2.5	2	1.5	1
Exponent for calculating Krg from KRGCL	3	2.5	2	1.5	1

Table 4.10: Assigned ranges of capillary number for each interpolation set

Interpolation Set	Phase	Values
Set 1	Wetting Phase	-7<n≤-5
	Non-Wetting Phase	-7<n≤-5
Set 2	Wetting Phase	-5<n≤-4.5
	Non-Wetting Phase	-5<n≤-4.5
Set 3	Wetting Phase	-4.5<n≤-4.25
	Non-Wetting Phase	-4.5<n≤-4.25
Set 4	Wetting Phase	-4.25<n≤-4
	Non-Wetting Phase	-4.25<n≤-4
Set 5	Wetting Phase	-4<n≤-3.75
	Non-Wetting Phase	-4<n≤-3.75

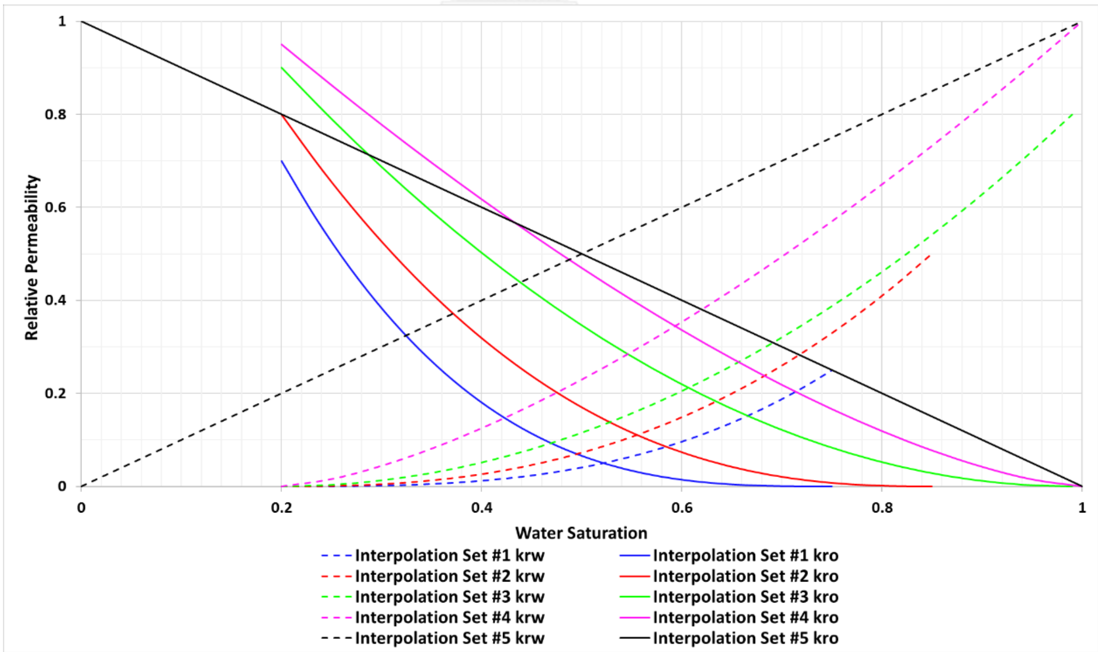


Figure 4.14: Relative permeability curves for different interpolation sets as a function of water saturation

4.4 Research Methodology

1. Construct reservoir simulation model using reservoir simulator together with data as explained in section 4.1 to section 4.3.

2. Perform waterflooding in constructed reservoir model using injection rate of 500, 750, 1,000 bbl/day with appropriate reservoir properties to obtain reference oil recovery values for each injection rate. These values are then used to compare with conventional surfactant flooding and multi-slug grading surfactant injection.

3. Perform surfactant flooding after water pre-injection in single-slug mode where the concentration of surfactant remains constant throughout the surfactant slug. Amount of surfactant used in all cases are fixed, and therefore slug sizes are changed accordingly to achieve desired surfactant concentration. The chosen operating conditions and their ranges of value that are investigated in this step are as follow:

   - Surfactant concentration: 0.5, 0.75, 1.0 wt.%
   - Injection rate: 500, 750, 1,000 bbl/day
   - Time to implement surfactant flooding after water pre-injection (through watercut at production well): at water breakthrough, 25%, 50%, 75%

   Surfactant concentration and injection rate are studied to investigate the effect of IFT reduction on oil recovery. Whilst, watercut percentage is used for the study of appropriate time to implement surfactant flooding after waterflood process. Full-factorial experimental design is utilized for the purpose of investigating effects of each factor, as well as the effects of interaction between factors on the response variable (oil recovery). Therefore, there will be totally 36 cases (3 x 3 x 4) needed to investigate in this stage.

4. Perform surfactant flooding in multi-slug grading mode with two-slug. In this stage, surfactant concentrations of slug #1 and #2 are varied to investigate the

effects of surfactant concentration reduction and accretion on oil recovery, while maintaining amount of surfactant used to be the same as in previous step for the purpose of comparing results between single-slug injection and multi-slug grading injection. Four injection strategies of two-slug surfactant flooding with three different mass ratios are investigated in this section. The four injection strategies include:

- Reduction-High contrast (R-H)
- Accretion-High contrast(A-H)
- Reduction-Low contrast (R-L)
- Accretion-Low contrast (A-L)

The following three different designs are investigated:

- Slug #1 endorsement (80% of surfactant mass is in the slug #1)
- Slug #2 endorsement (80% of surfactant mass is in the slug #2)
- Surfactant mass is divided equally between slug #1 and #2.

5. Perform surfactant flooding in multi-slug grading mode with three-slug. This step is performed as an extension of surfactant flooding with two-slug. Hence, the most favorable case for surfactant concentration reduction and accretion from the previous step are selected to perform three-slug mode. The operating conditions (i.e. injection rate and watercut percentage) of the selected case are fixed, whilst varying surfactant concentration and mass ratio of each slug.

6. Observe, evaluate and discuss the trend of oil recovery from the simulation results with respect to the change in surfactant slug concentration, injection rate, and time to implement surfactant injection after water pre-injection. Report the most effective injection strategy for surfactant flooding in waterflooded reservoir.

7. Determine effects of reservoir parameters on effectiveness of surfactant flooding. The interested parameters include properties related to relative permeability curves such as irreducible water saturation and endpoint relative permeability to oil.

Chapter 5

RESULTS AND DISCUSSION

In this study, evaluation of surfactant flooding process with multi-slug grading is performed to compare effectiveness of the process over conventional surfactant flooding in waterflooded reservoir. In multi-slug grading mode, surfactant is divided into two slugs (two-slug mode) or three slugs (three-slug mode) with each slug possessing different surfactant concentrations as illustrate in Figure 5.1. However, amount of surfactant used is kept constant for the purpose of making comparison. Moreover, effects of operating conditions on surfactant flooding in multi-slug grading mode are investigated. Operating parameters of interest consist of surfactant concentration, surfactant injection rate, and time to implement surfactant injection after water pre-injection. At the end of this study, effects of reservoir parameters related to relative permeability curve, such as irreducible water saturation and endpoint relative permeability to oil, on effectiveness of surfactant flooding with multi-slug grading in waterflooded reservoir are investigated.

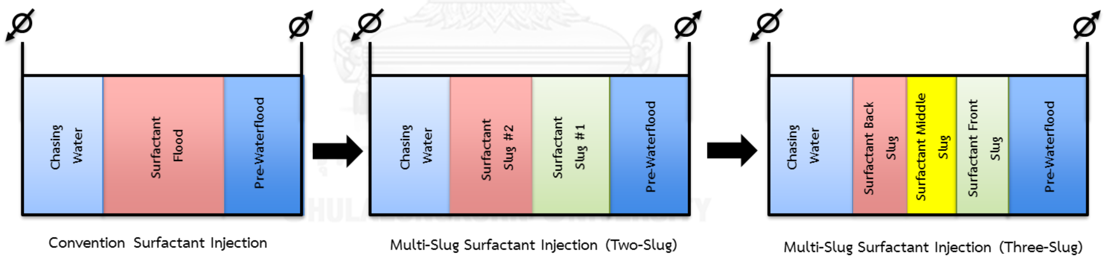


Figure 5.1: Development diagram of conventional surfactant injection into multi-slug surfactant injection (two-slug mode and three-slug mode)

5.1 Waterflooding Base Case

Waterflooding is performed first in the simulated reservoir model with three different injection rates (500, 750, 1,000 bbl/day). The process starts from the first day of production until one of the production constrains is attained. Simulated results are used as reference values to compare with conventional surfactant flooding and multi-slug grading surfactant flooding in following sections.

Figure 5.2 shows oil recovery factor obtained from three different injection rates as a function of time for waterflooding base case. The production rate is also varied to be as same as injection rate in order to keep voidage ratio equal to one. Final oil recovery factors and termination date for each injection rate of waterflooding base case are summarized in Table 5.1. The final oil recovery factors obtained by means of waterflooding at different injection rates show approximately the same value. However, termination date for the case of 500 bbl/day took 1 year longer than injection rate of 750 and 1,000 bbl/day.

According to Figure 5.3, oil production rate of 500 bbl/day can be maintained at desired plateau production rate for approximately two and a half years. A drastic reduction in oil production rate is observed due to water breakthrough as can be seen from remarkable increment of water production rate. The water production rate continues to increase, resulting in less amount of oil being produced. The process is then terminated when the watercut reaches the constraint of 95%.

For the case of 750 bbl/day injection rate, production rate can be maintained at plateau rate only for 3 months, as shown in Figure 5.4. This is because the actual injection rate is below production rate due to the limited injection pressure. Hence, reservoir pressure drops, and as a consequence oil production rate decreases. However, as water injection rate increases above oil production rate due to higher injectivity, average reservoir pressure tends to be stabilized. Oil production rate the drops again when water breakthrough the production well. For the case of 1,000 bbl/day, results are similar to the case of 750 bbl/day and are shown in Figure 5.5. However, no production plateau rate is observed at the early time as the injection well is switched to be controlled by maximum injection pressure to prevent undesired fracture from the first day of production due to too high production rate.

According to the results, total production period for waterflooding process lasts for 5-6 years and this yields oil recovery factor up to approximately 53%. This indicates that large amount of oil is still remained inside the reservoir as can be seen in Figure 5.6 to Figure 5.8.

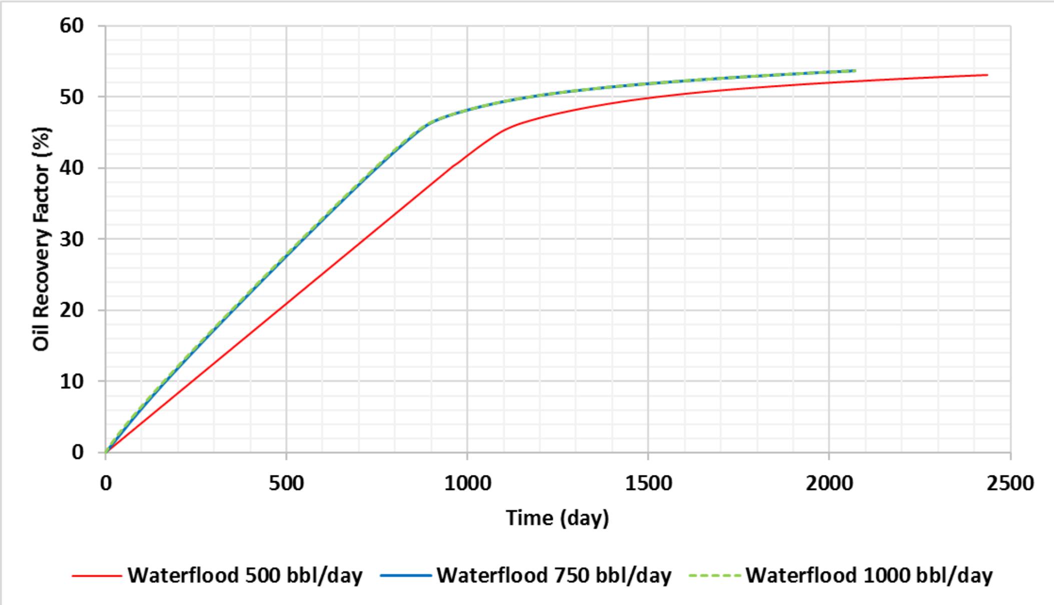


Figure 5.2: Oil recovery factors obtained from waterflooding at different injection rates as a function of time

Table 5.1: Summary of oil recovery factors and termination dates of each injection rate for waterflooding base case.

Case Number	Injection Rate (bbl/day)	Production Rate (bbl/day)	Final Oil Recovery Factor (%)	Termination Date (day)
1	500	500	53.13	2,435
2	750	750	53.69	2,070
3	1,000	1,000	53.66	2,070

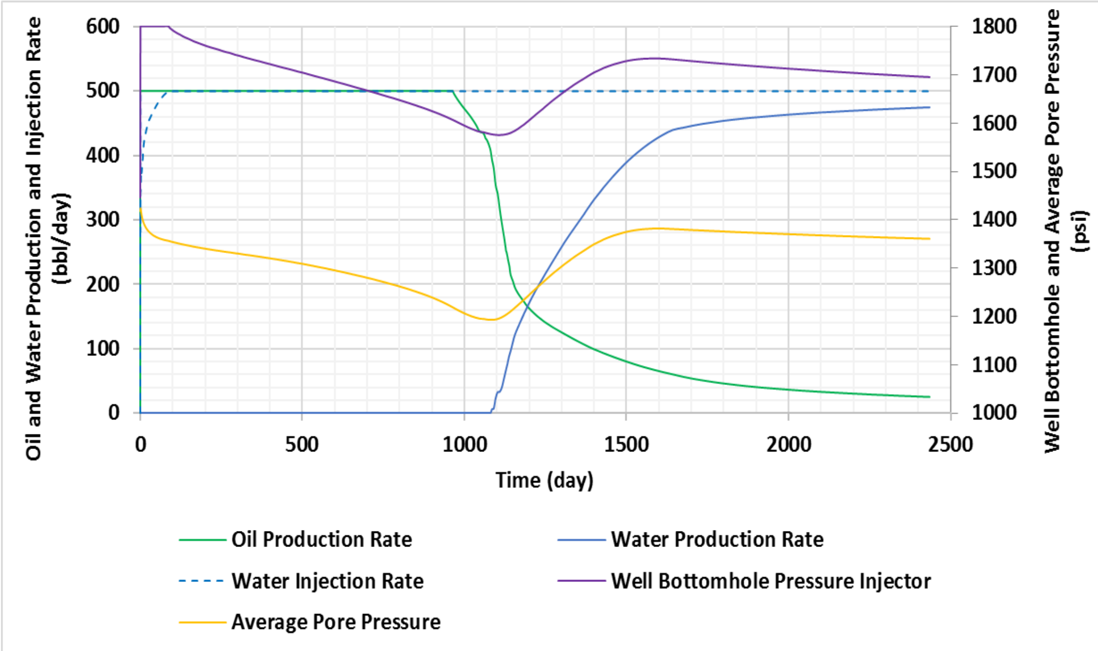


Figure 5.3: Production rates, injection rates, and average reservoir pressure of waterflooding with desired injection and production rates of 500 bbl/day as a function of time

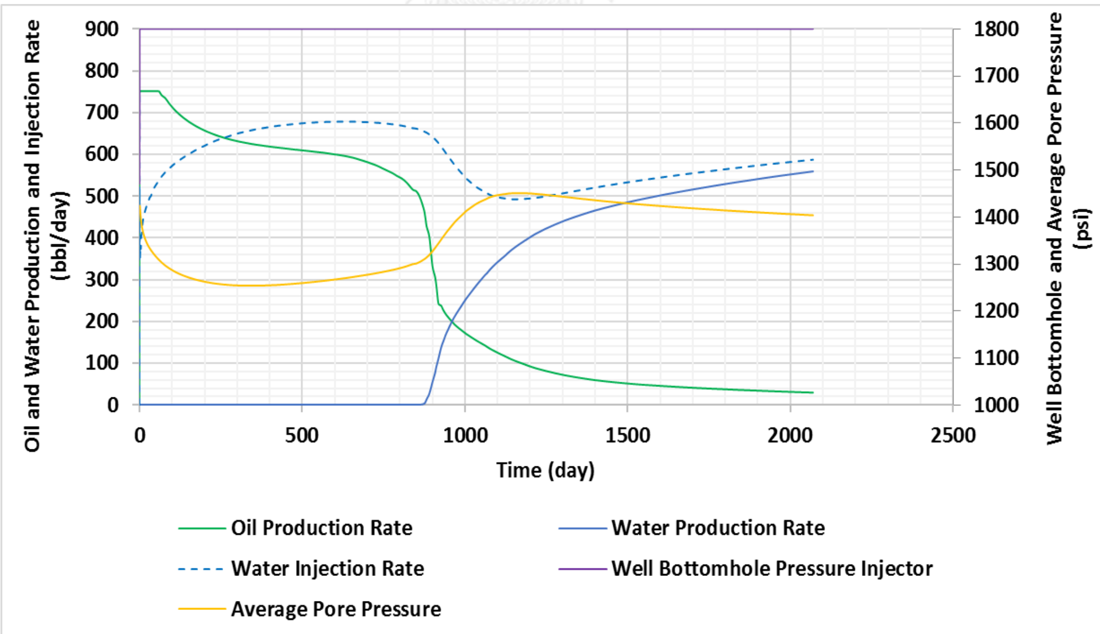


Figure 5.4: Production rates, injection rates, and average reservoir pressure of waterflooding with desired injection and production rates of 750 bbl/day as a function of time

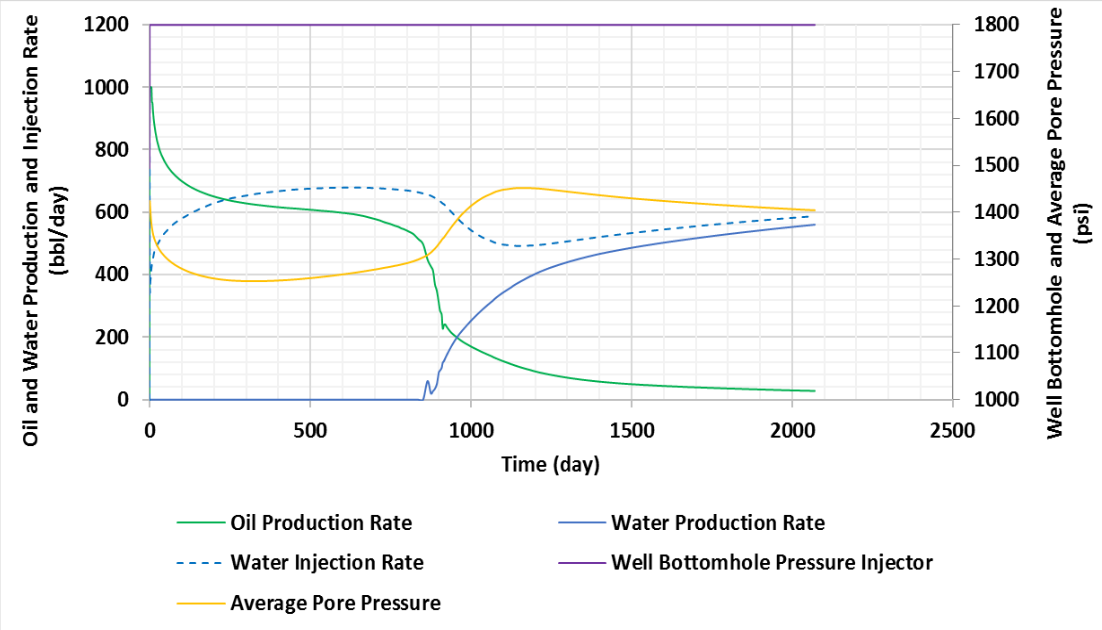


Figure 5.5: Production rates, injection rates, and average reservoir pressure of waterflooding with desired injection and production rates of 1,000 bbl/day as a function of time

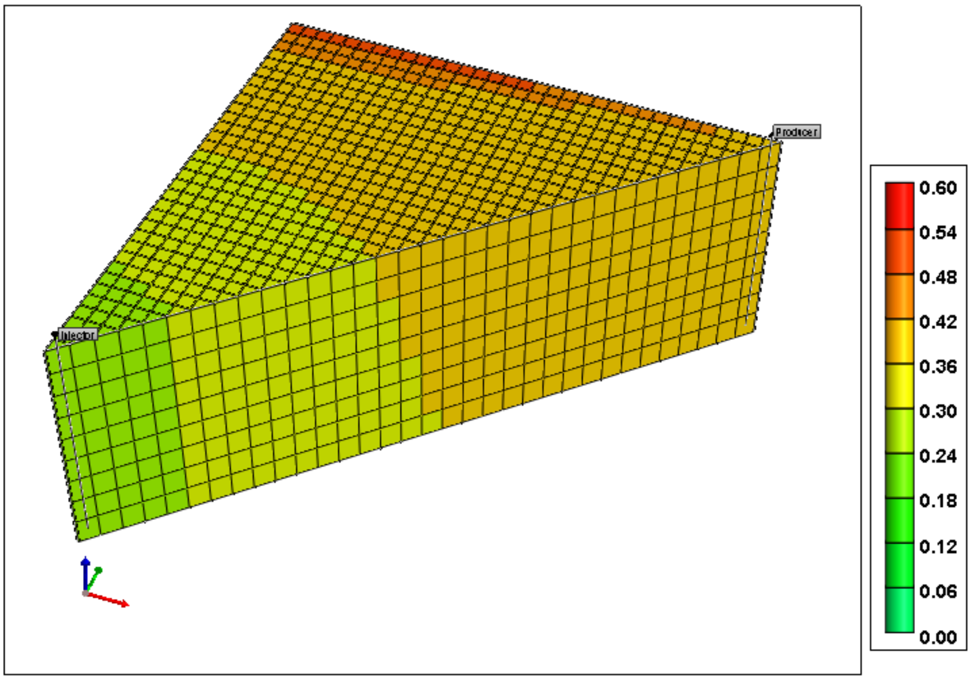


Figure 5.6: Oil saturation profile at the end of waterflooding with desired injection and production rates of 500 bbl/day

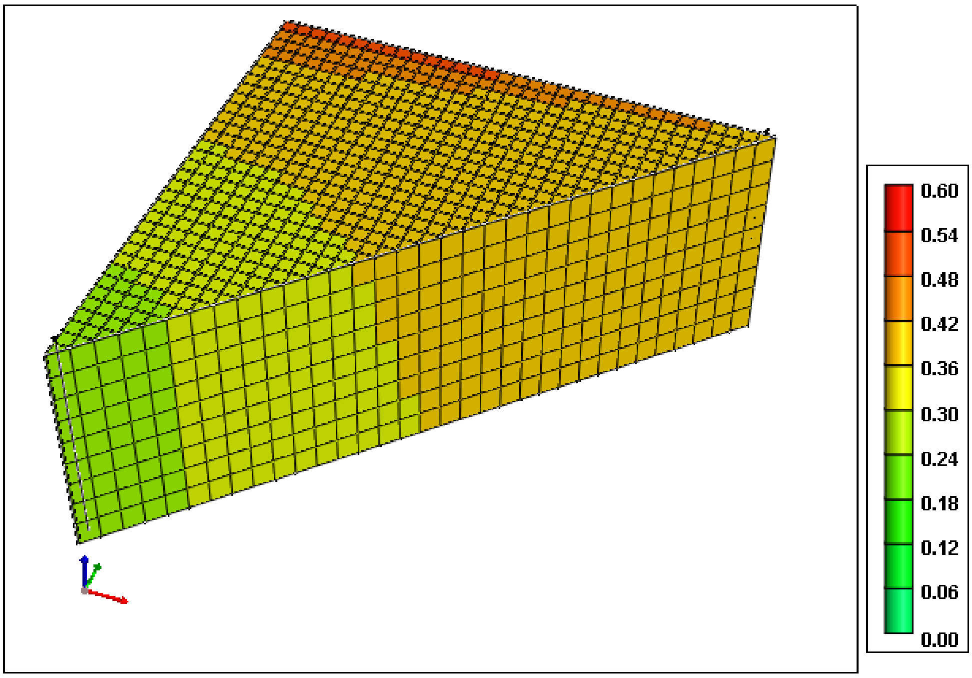


Figure 5.7: Oil saturation profile at the end of waterflooding with desired injection and production rates of 750 bbl/day

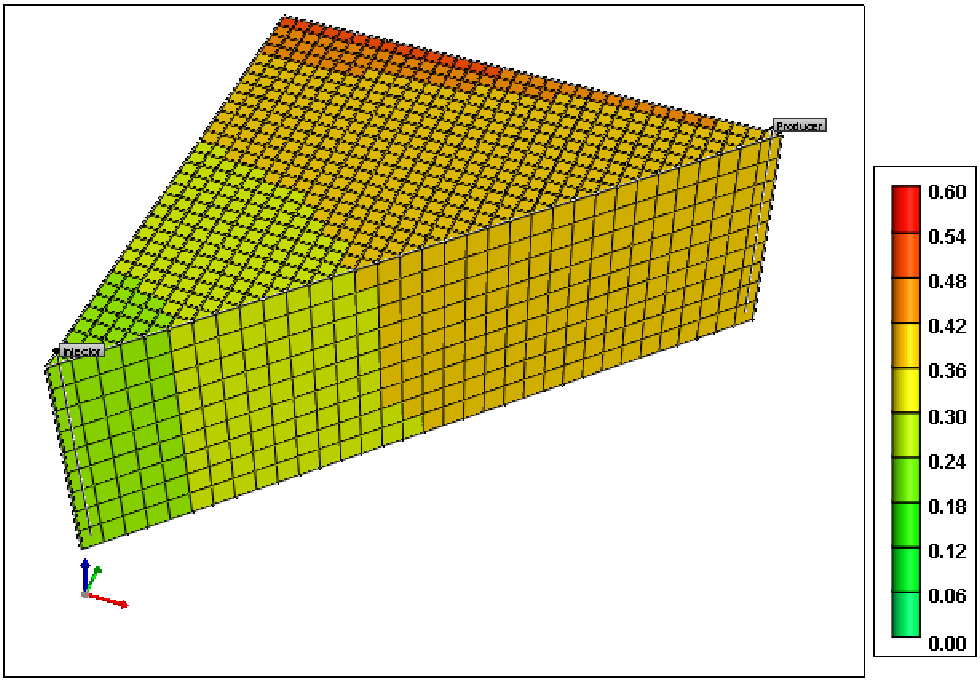


Figure 5.8: Oil saturation profile at the end of waterflooding with desired injection and production rates of 1,000 bbl/day

5.2 Single-Slug Surfactant Flooding

In this study, single-slug surfactant flooding is the first scenario used to evaluate effectiveness compared to waterflooding base case. Surfactant flooding in single-slug mode, where the concentration of surfactant remains constant throughout the surfactant slug, are performed in this section. Amount of surfactant used in all cases are fixed, and therefore slug sizes will be changed accordingly, to achieve desired surfactant concentration as illustrated in Figure 5.9. The amount of surfactant is fixed at the boundary condition of 1 wt.% and 0.25 PV slug size. This yields amount of surfactant equivalent to 666 tons. The study parameters of single-slug surfactant flooding consist of surfactant concentration, surfactant injection rate, and time to implement surfactant injection after water pre-injection.

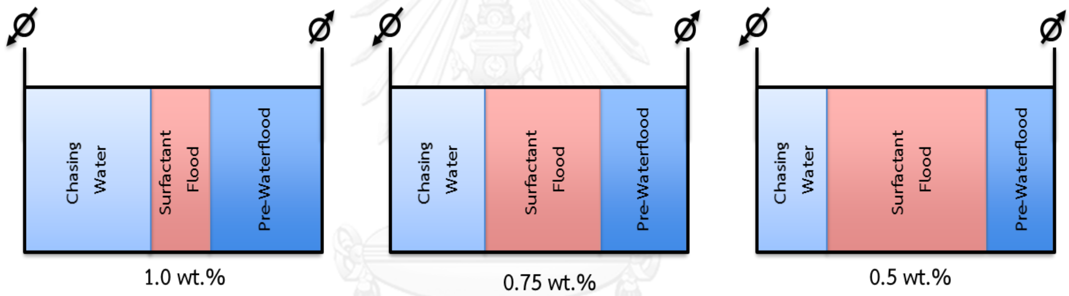


Figure 5.9: Variation of surfactant slug size as a function of surfactant concentration

Surfactant concentration and injection rate are studied to investigate the effect of IFT reduction on oil recovery. Whilst, watercut percentage is used in this study for the study of appropriate time to implement surfactant flooding after waterflood process.

Full-factorial experimental design is utilized for the purpose of investigating effects of each factor, as well as the effects of interactions between each parameter on the response variable (oil recovery). Therefore, there will be totally 36 cases (3x3x4) needed to investigate in this section.

5.2.1 Surfactant Concentration

In this section, effect of surfactant concentration is examined. Concentration of surfactant directly affects the reduction of IFT between oil and water phases. Figure 5.10, Figure 5.14, and Figure 5.16 show graphical results of oil recovery factor as a function of time of waterflooding process compared to surfactant flooding process at different surfactant concentration (0.5 wt.%, 0.75 wt.%, and 1.0 wt.%). Numerical results are summarized in Table 5.2 to Table 5.4. According to the result, oil recovery factor of surfactant flooding at any surfactant concentration yields greater value compared to waterflooding base case. The additional oil recovery due to surfactant flooding is approximately 22%. This indicates that the presence of surfactant agent gives benefits in term of additional oil recovery.

However, at any particular flow rate and time to implement surfactant flooding, changes in surfactant concentration does not yield much difference in term of final oil recovery. This is owing to the amount of surfactant used is fixed for all cases. Though, the differences in surfactant concentration result in different slug sizes for each case. Therefore, the different rates of oil production and oil recovery are observed.

Since amount of surfactant used is fixed, it is important to note that surfactant slug size is varied according to the slug concentration, and therefore the higher the concentration the smaller the slug size and vice versa. The differences in surfactant concentration and slug size help clarifying the reasons why each case has different oil production rate, but yet yields the final oil recovery of approximately the same value.

Figure 5.12 and Figure 5.13 show interfacial tension profile and surfactant adsorption profile of various surfactant concentrations at 500 bbl/day injection rate implemented at water breakthrough on day 1,827 and 2,830, respectively. According to the result, it can be observed that the system exhibits lower interfacial tension but greater adsorption with respect to the increase in surfactant concentration. Therefore, at high surfactant concentration (1.0 wt.%), greater amount of oil is liberated at the early time due to lower IFT, resulting in steeper slope on oil recovery factor curve and oil production rate curve. However, the system could not maintain the lowest IFT condition at late time due to loss of surfactant agent through adsorption, causing the reduction in surfactant concentration. Moreover, the system exhibits only small PV of low IFT condition due to a small surfactant slug size at 1.0 wt.% surfactant concentration. As a consequent, oil recovery curve and oil production rate curve are flatted at the late time. On the other hand, at low surfactant concentration (0.5 wt.%), the system only experiences middle ranges of IFT condition at the early time. Hence, oil recovery factor and oil production rate is lower than the case of higher concentration. However, since there is smaller loss of surfactant due to adsorption and larger PV of low IFT condition from a larger surfactant slug at late time, oil recovery factor and oil production rate is built up and catch up with the case of 1.0 wt.%.

Hence, it can be concluded in this section that surfactant concentration at fixed amount of surfactant use does not affect the final oil recovery but shows slight effect on rate of change of oil recovery factor and oil production.

Table 5.2: Oil recovery factors and termination dates of surfactant flooding implemented at water breakthrough with different surfactant concentration compared to oil recovery factors and termination date of waterflooding at fixed injection rate of 500 bbl/day

Case Number	Surfactant Concentration (wt.%)	Final Oil Recovery Factor	Termination Date
Waterflood	-	53.13	2,435
1	0.5	73.94	6,066
2	0.75	73.84	5,796
3	1.0	73.98	5,823

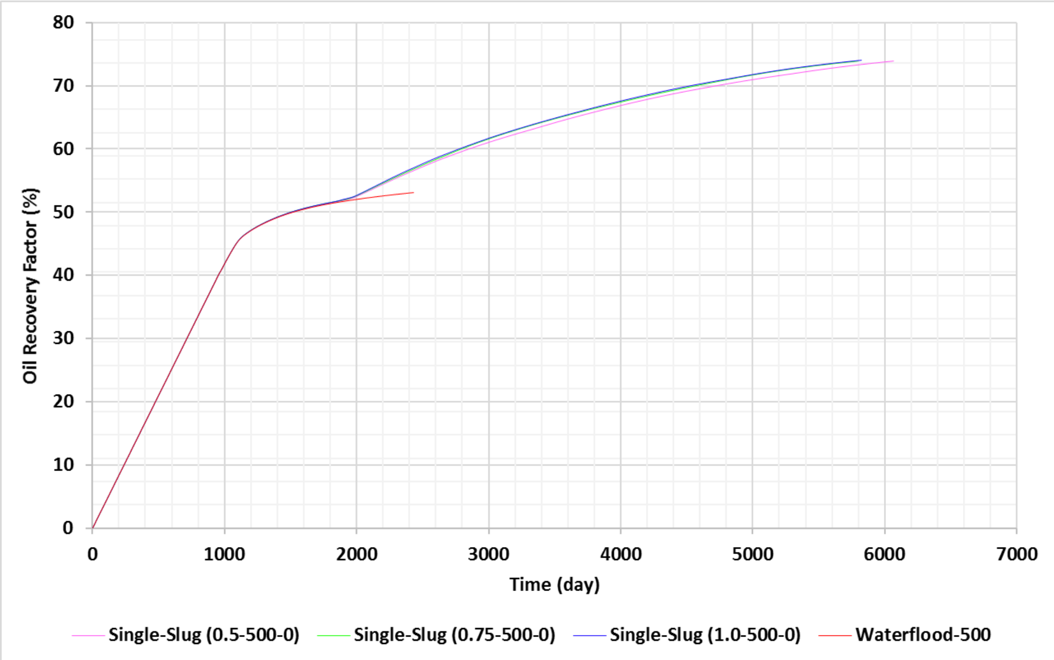


Figure 5.10: Oil recovery factors of surfactant flooding implemented at water breakthrough with different surfactant concentrations compared to oil recovery factors of waterflooding at fixed injection rate of 500 bbl/day as a function of time

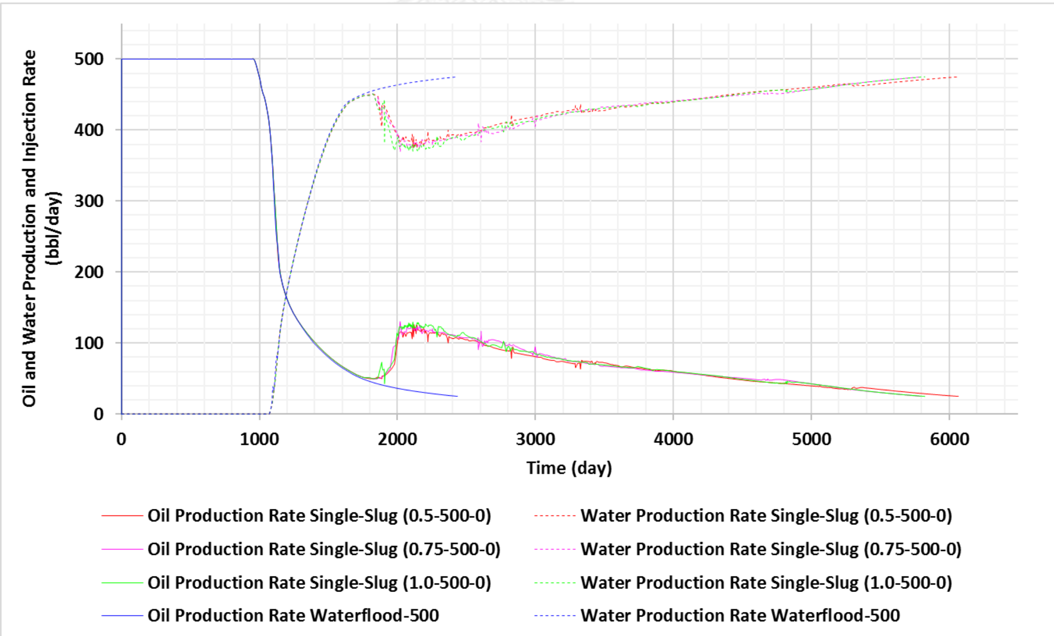


Figure 5.11: Oil and water production rates of surfactant flooding implemented at water breakthrough with different surfactant concentrations compared to oil and water production rates of waterflooding at fixed injection rate of 500 bbl/day

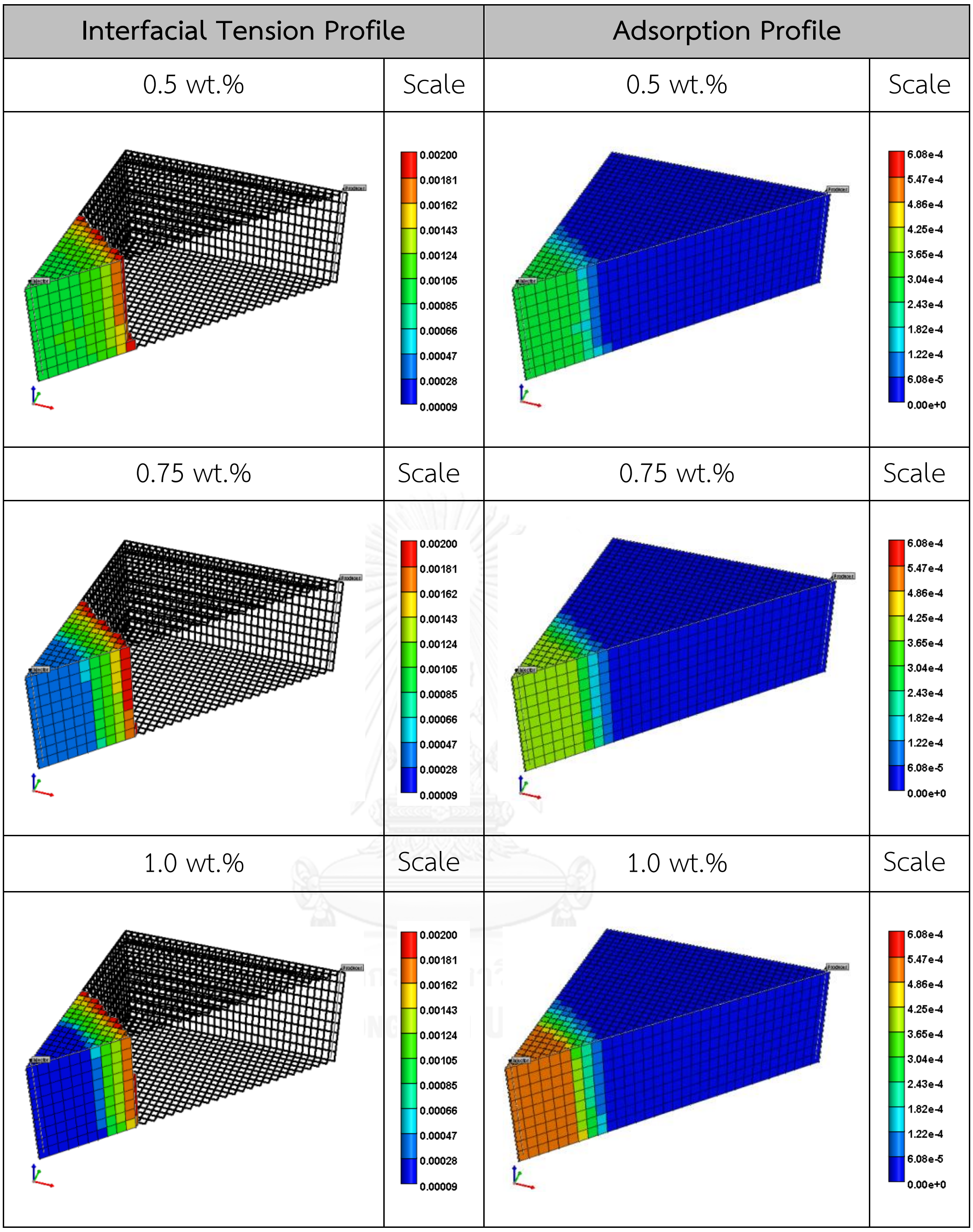


Figure 5.12: Interfacial tension profiles (left column) and adsorption profiles (right column) of surfactant flooding implemented at water breakthrough with different surfactant concentrations and fixed injection of 500 bbl/day (profiles are taken at day 1,827 during single-slug surfactant flooding)

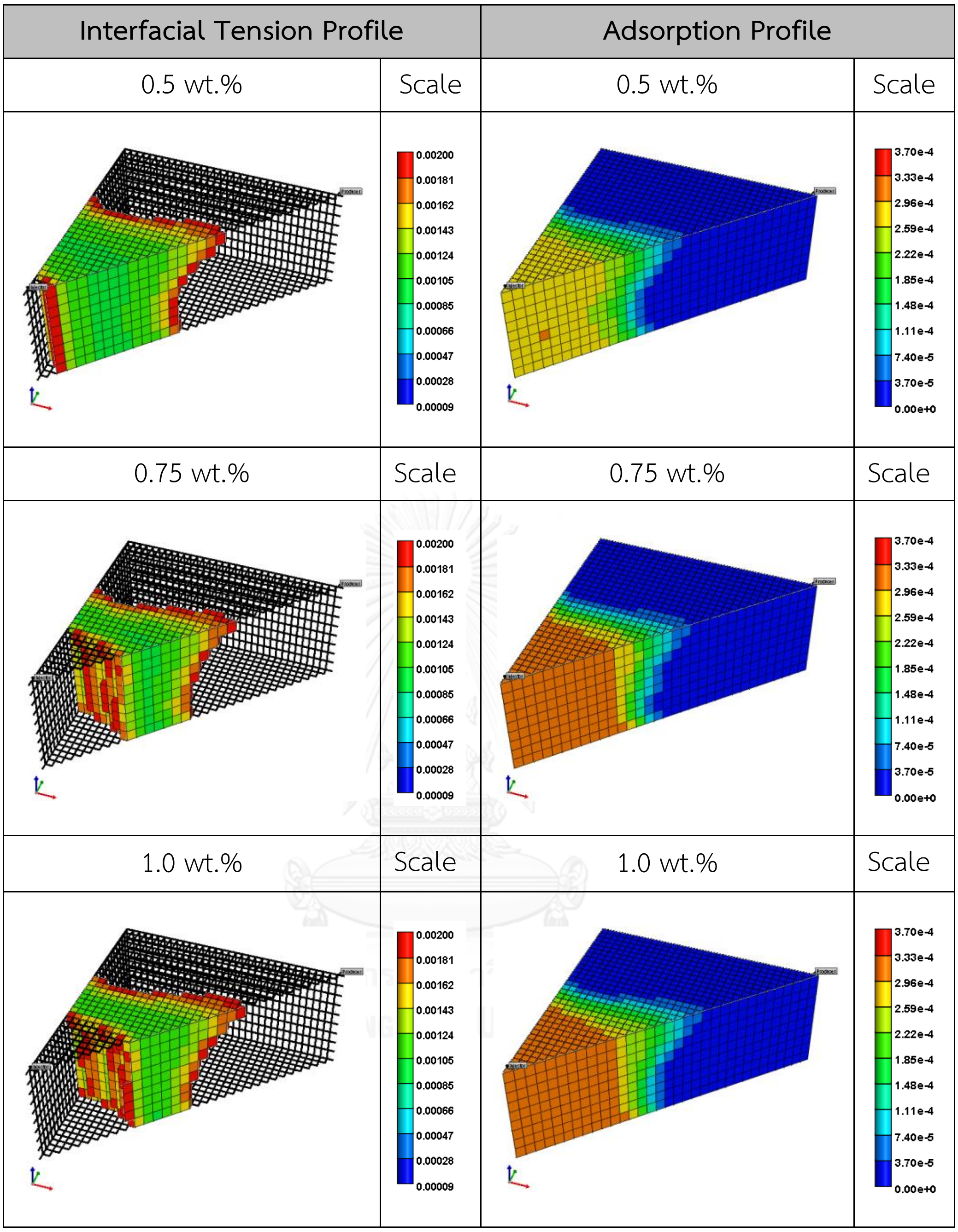


Figure 5.13: Interfacial tension profiles (left column) and adsorption profiles (right column) of surfactant flooding implemented at water breakthrough with different surfactant concentrations and fixed injection rate of 500 bbl/day (profiles are taken at day 2,830 after single-slug surfactant flooding)

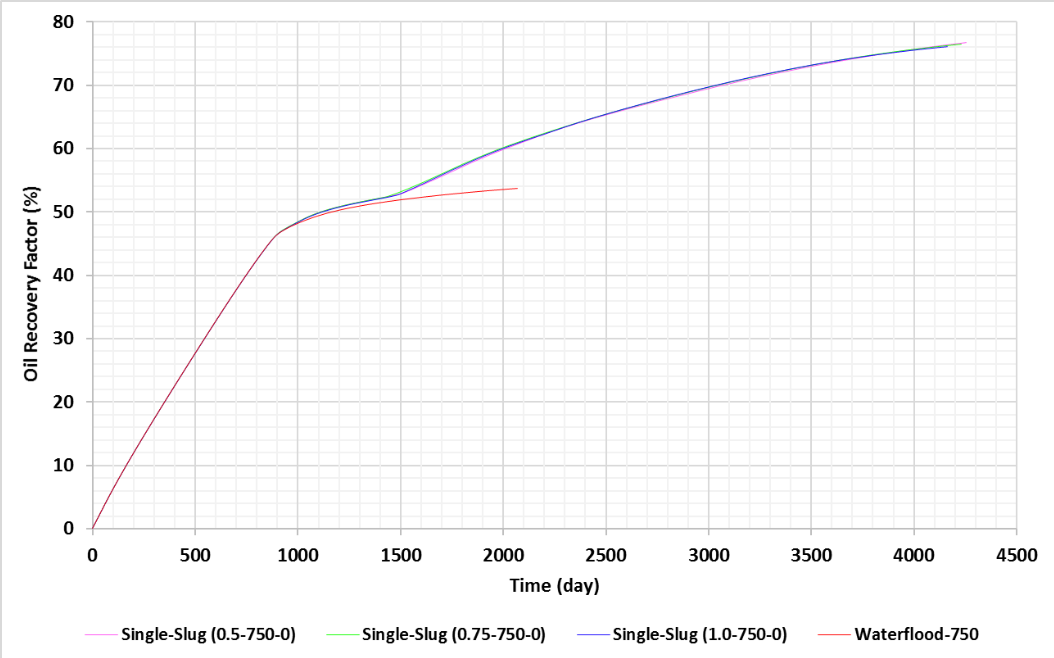


Figure 5.14: Oil recovery factors of surfactant flooding implemented at water breakthrough with different surfactant concentrations compared to oil recovery factors of waterflooding at fixed injection rate of 750 bbl/day as a function of time

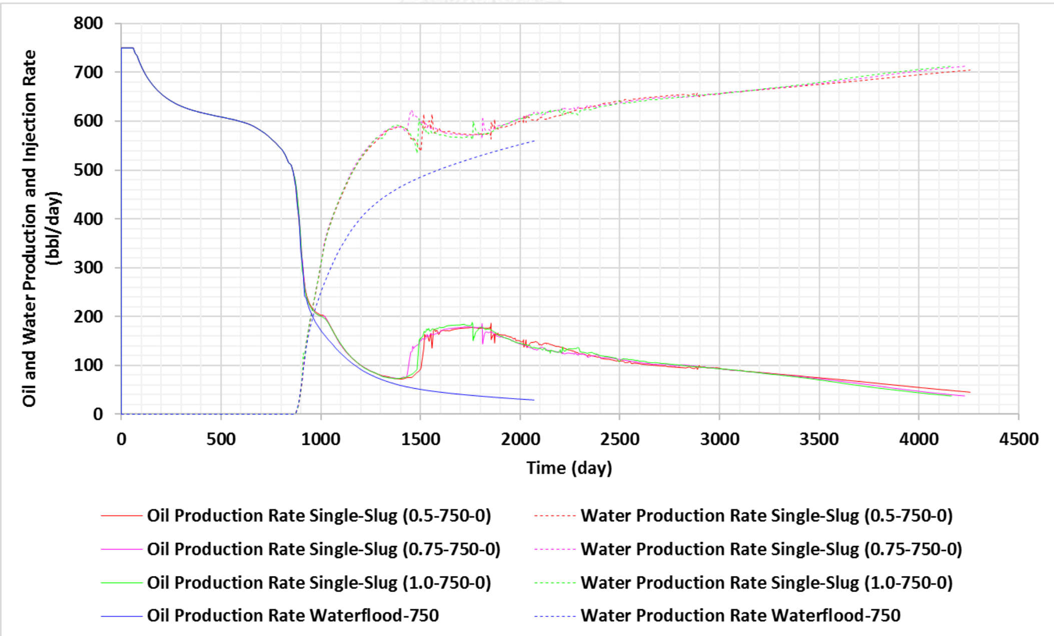


Figure 5.15: Oil and water production rates of surfactant flooding implemented at water breakthrough with different surfactant concentrations compared to oil and water production of waterflooding at fixed injection rate of 750 bbl/day

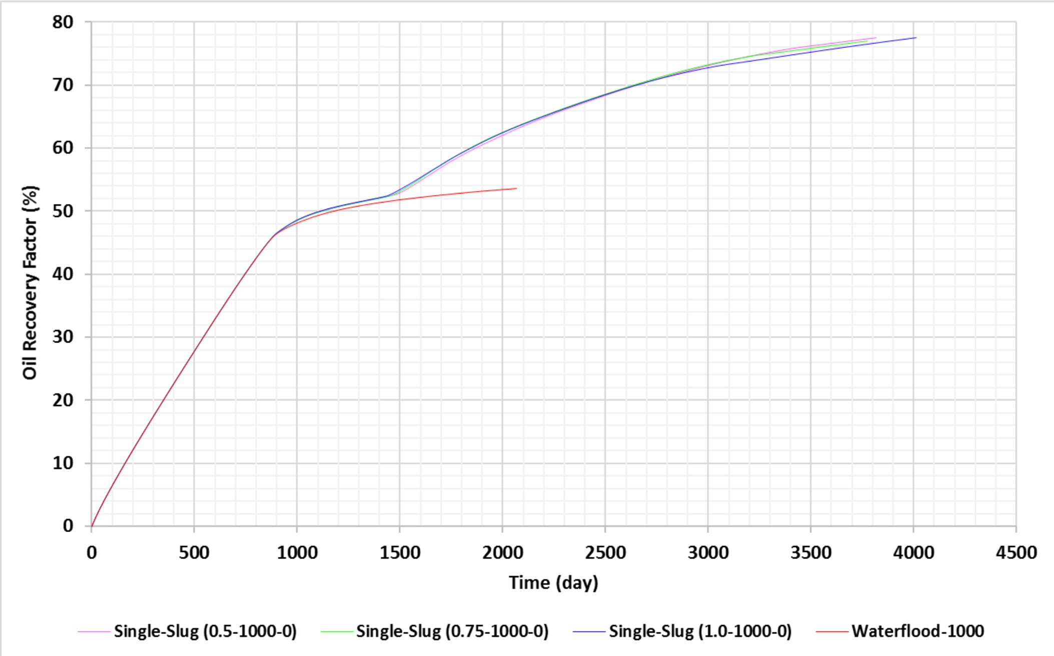


Figure 5.16: Oil recovery factors of surfactant flooding implemented at water breakthrough with different surfactant concentrations compared to oil recovery factors of waterflooding at fixed injection rate of 1,000 bbl/day

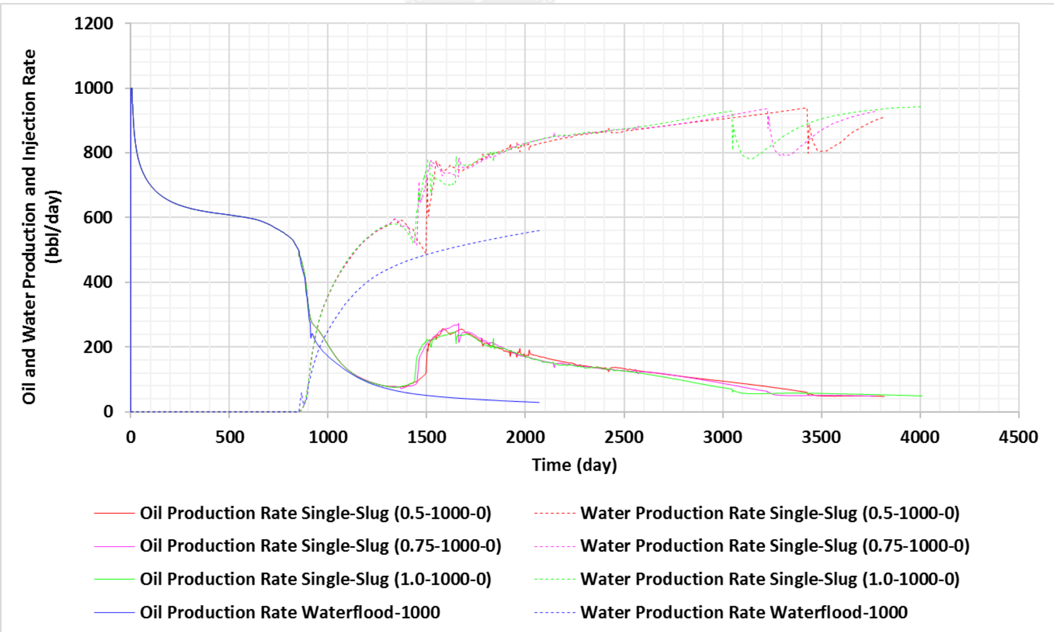


Figure 5.17: Oil and water production rates of surfactant flooding implemented at water breakthrough with different surfactant concentrations compared to oil and water production of waterflooding at fixed injection rate of 1,000 bbl/day

Table 5.3: Oil recovery factors and termination dates of surfactant flooding implemented at water breakthrough with different surfactant concentration compared to oil recovery factors and termination date of waterflooding at fixed injection rate of 750 bbl/day

Case Number	Surfactant Concentration (wt.%)	Final Oil Recovery Factor	Termination Date
Waterflood	-	53.69	2,070
1	0.5	76.64	4,256
2	0.75	76.44	4,229
3	1.0	76.16	4,164

Table 5.4: Oil recovery factors and termination dates of surfactant flooding implemented at water breakthrough with different surfactant concentration compared to oil recovery factors and termination date of waterflooding fixed injection rate of 1,000 bbl/day

Case Number	Surfactant Concentration (wt.%)	Final Oil Recovery Factor	Termination Date
Waterflood	-	53.66	2,070
1	0.5	77.60	3,819
2	0.75	77.05	3,773
3	1.0	77.48	4,012

5.2.2 Surfactant Injection Rate

In this section, effect of surfactant injection rate is studied. Oil recovery factors as a function of time from different surfactant injection rates are plotted from Figure 5.21 to Figure 5.23. According to the result, it can be observed that final oil recovery as well as the rate of recovering increases as surfactant injection rate increased. This phenomenon can be explained through the concept of surfactant retention time as well as the adsorption effect.

The effects of adsorption can be obviously seen at high surfactant concentration (1.0 wt.%) in Figure 5.18. At high injection rate (1,000 bbl/day), adsorption profile illustrates greater area of surfactant adsorption, indicating that the surfactant solution could reach and extract more residual oil in wider range. This is because at higher injection rate the contact time between surfactant solution and rock surface is diminished. Therefore, there is more non-adsorbed surfactant monomers, which plays a major role in recovering more residual oil, left to push forward. In case of low injection (500 bbl/day), higher oil saturation value is still remained at the bottom of the reservoir adjacent to the production well comparing to higher injection rate. This coincides with the adsorption profile which indicates the smaller range of adsorption.

However, at low surfactant concentration (0.5 wt.%) as shown in Figure 5.20, the effect of adsorption is lesser at lower surfactant injection rate (500 bbl/day) when compared to the same injection rate at higher concentration. This can be explained that lower surfactant concentration results in lower adsorption at the early time anyhow. Therefore, the adsorption is already lower regardless of the surfactant injection rate.

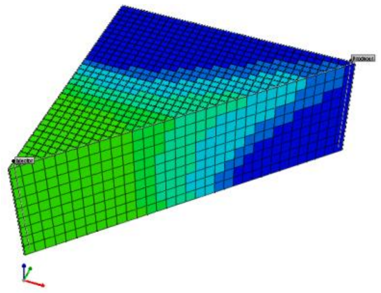
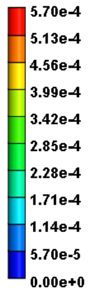
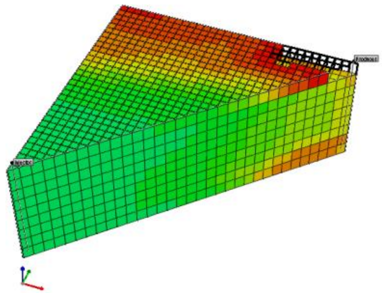
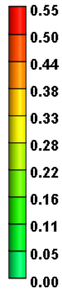
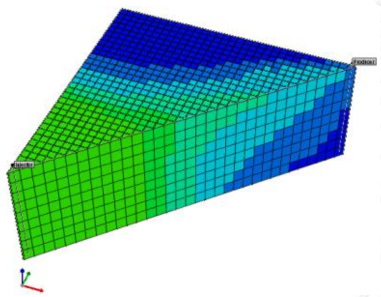
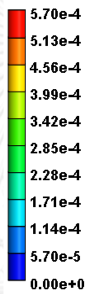
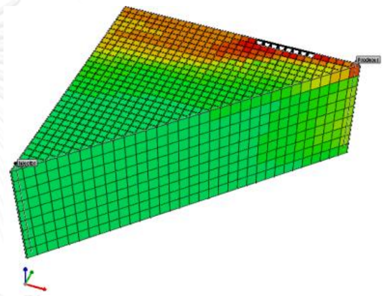
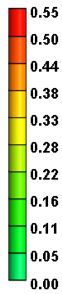
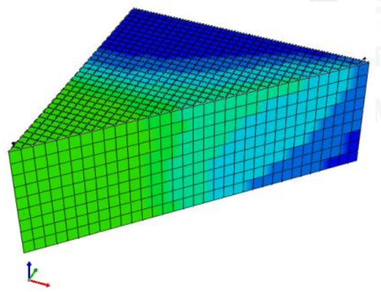
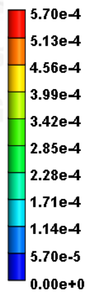
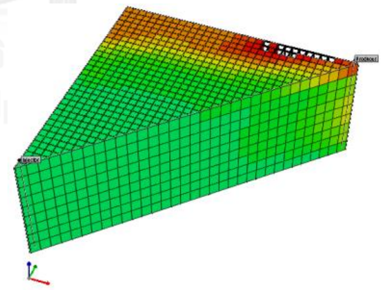
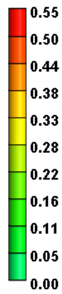
Adsorption Profile		Oil Saturation Profile	
500 bbl/day	Scale	500 bbl/day	Scale
			
750 bbl/day	Scale	750 bbl/day	Scale
			
1,000 bbl/day	Scale	1,000 bbl/day	Scale
			

Figure 5.18: Adsorption profiles (left column) and oil saturation profiles (right column) of 1.0 wt.% concentration surfactant flooding implemented at water breakthrough with different surfactant injection rates (profiles are taken at end of production life)

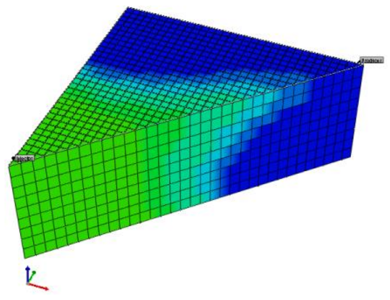
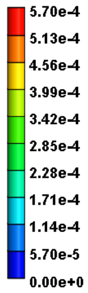
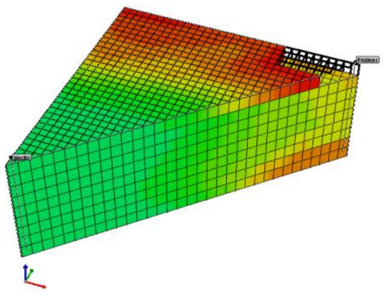
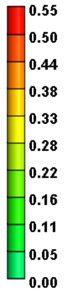
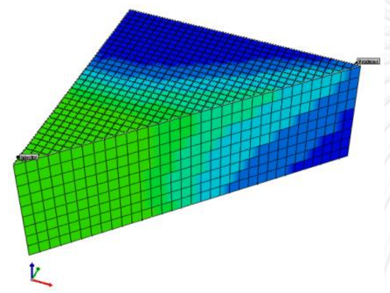
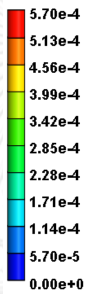
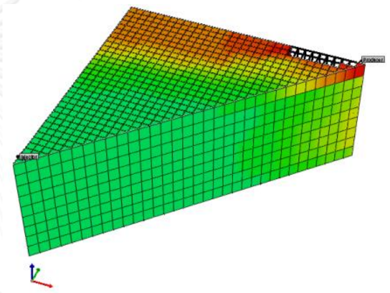
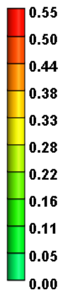
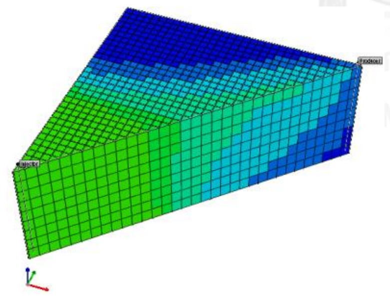
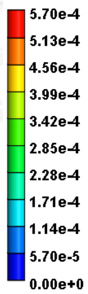
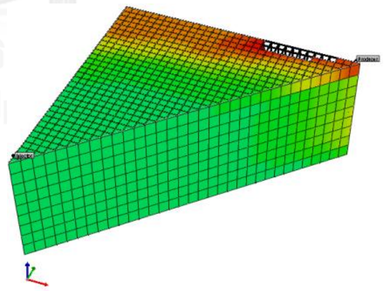
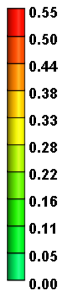
Adsorption Profile		Oil Saturation Profile	
500 bbl/day	Scale	500 bbl/day	Scale
			
750 bbl/day	Scale	750 bbl/day	Scale
			
1,000 bbl/day	Scale	1,000 bbl/day	Scale
			

Figure 5.19: Adsorption profiles (left column) and oil saturation profiles (right column) of 0.75 wt.% concentration surfactant flooding implemented at water breakthrough with different surfactant injection rates (profiles are taken at end of production life)

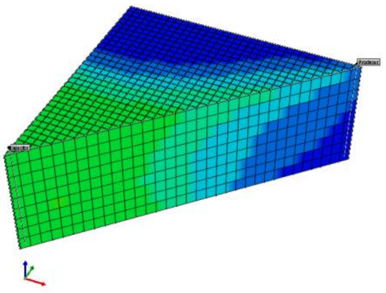
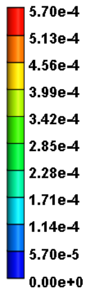
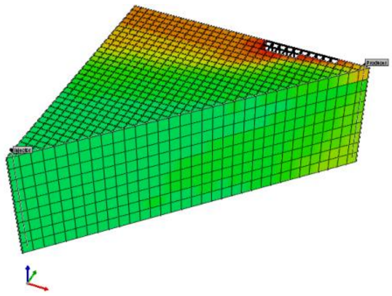
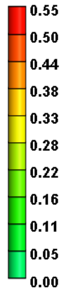
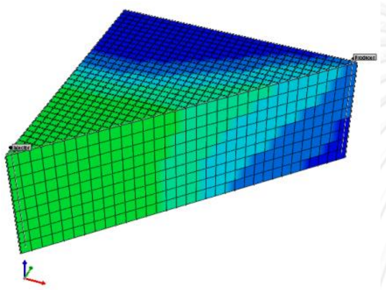
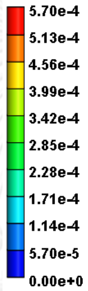
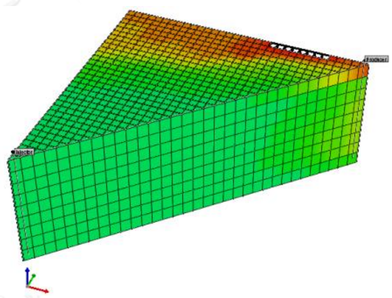
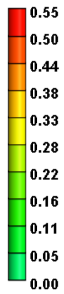
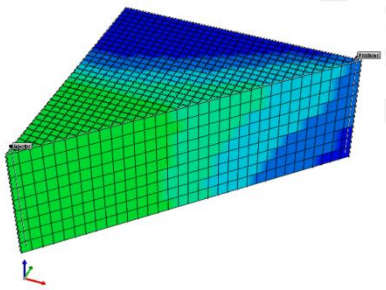
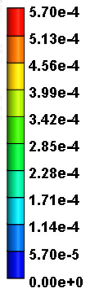
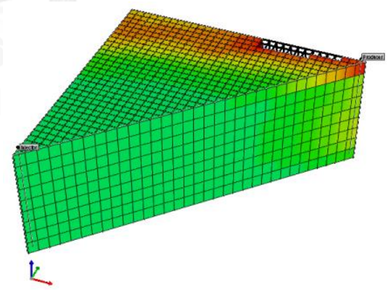
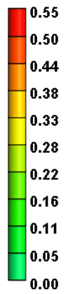
Adsorption Profile		Oil Saturation Profile	
500 bbl/day	Scale	500 bbl/day	Scale
			
750 bbl/day	Scale	750 bbl/day	Scale
			
1,000 bbl/day	Scale	1,000 bbl/day	Scale
			

Figure 5.20: Adsorption profiles (left column) and oil saturation profiles (right column) of 0.5 wt.% concentration surfactant flooding implemented at water breakthrough with different surfactant injection (profile are taken at end of production life)

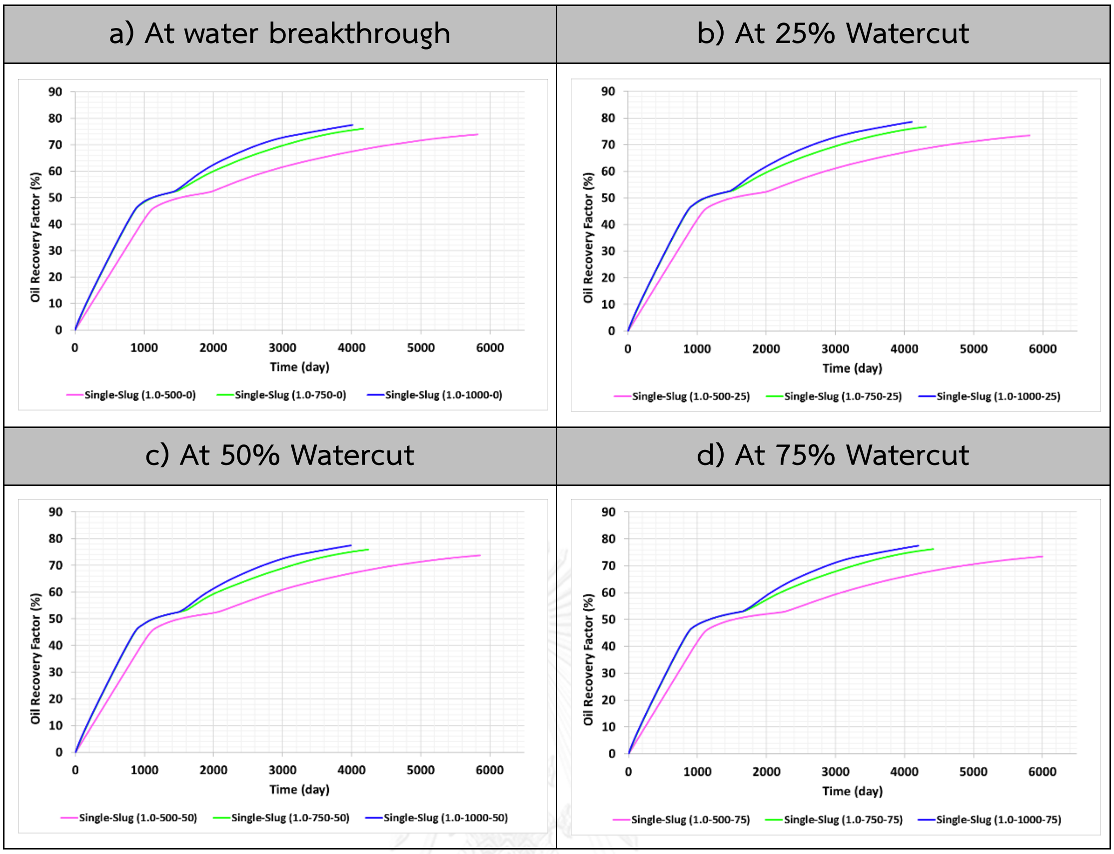
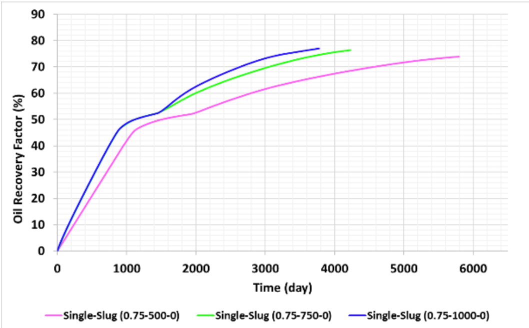
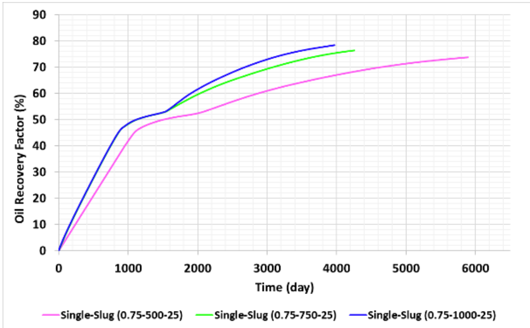


Figure 5.21: Oil recovery factors of 1.0 wt.% concentration surfactant flooding at various surfactant injection rates: a) surfactant flooding implemented at water breakthrough, b) surfactant flooding implemented at 25% watercut, c) surfactant flooding implemented at 50% watercut, d) surfactant flooding implemented at 75% watercut

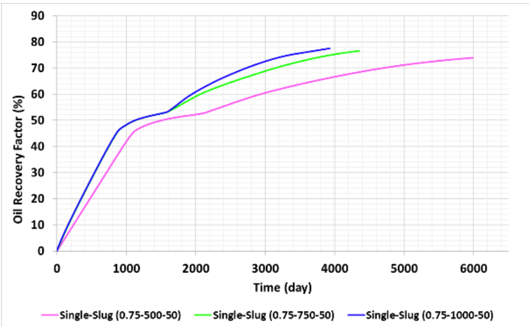
a) At water breakthrough



b) At 25% Watercut



c) At 50% Watercut



d) At 75% Watercut

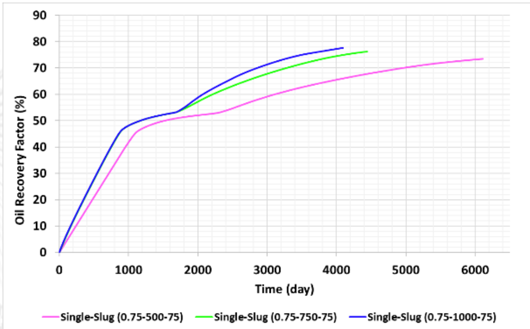


Figure 5.22: Oil recovery factors of 0.75 wt.% concentration surfactant flooding at various surfactant injection rates: a) surfactant flooding implemented at water breakthrough, b) surfactant flooding implemented at 25% watercut, c) surfactant flooding implemented at 50% watercut, d) surfactant flooding implemented at 75% watercut

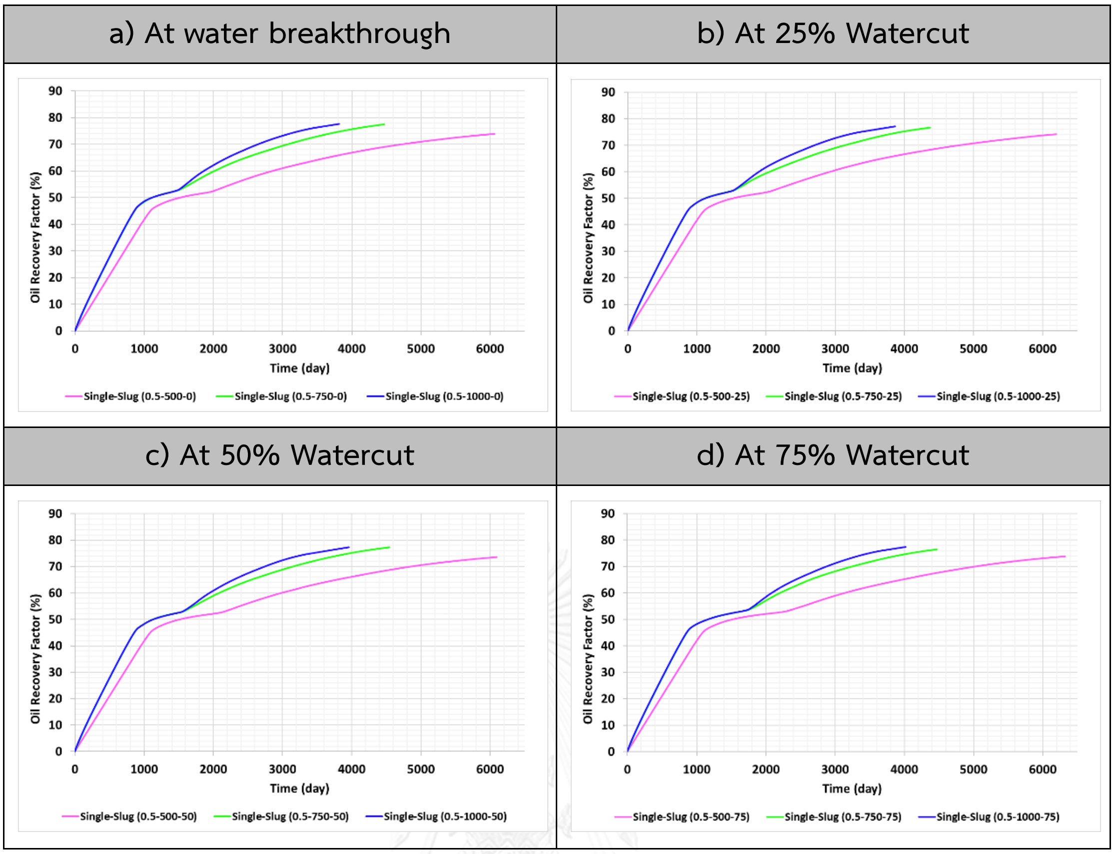


Figure 5.23: Oil recovery factors of 0.5 wt.% concentration surfactant flooding at various surfactant injection rates: a) surfactant flooding implemented at water breakthrough, b) surfactant flooding implemented at 25% watercut, c) surfactant flooding implemented at 50% watercut, d) surfactant flooding implemented at 75% watercut

5.2.3 Time to Implement Surfactant Injection after Water Pre-injection

Time to start implementation of surfactant flooding is indicated by watercut percentage observed at production well, which is set to be at water breakthrough, 25%, 50%, and 75%. Oil recovery factor as a function of time at different implementation times are plotted in Figure 5.24 to Figure 5.26. According to the results, it can be observed that choosing to commence surfactant flooding process at higher watercut percentage would only cause a delay in oil recovery.

As a common practice, recovering as much oil as possible at the earliest time is favorable in term of economics. Therefore, it is recommended to start surfactant flooding process as early as possible. Hence, in the next step, two-slug surfactant flooding is performed by taking into account only percentage watercut at water breakthrough and 25% as a criterion for implementing surfactant flooding process.

Another supporting reason for choosing to implement at water breakthrough and 25% watercut for the next step is on the dilution and adsorption effects. By observing the oil recovery factor values, it could be possible that starting surfactant flooding at late time for low surfactant concentration case would result in further dilution of surfactant slug. This is due to the higher water saturation inside the reservoir. Therefore, the system could not reach lower IFT. As a consequent, lower amount of oil is recovered. Hence, at lower surfactant concentration, it is better to commence surfactant flooding at earlier time. On the other hand, at high concentration, starting surfactant flooding at 25% watercut seems to yield the best result. At higher surfactant concentration, surfactant adsorption is also higher. Therefore, the presence of high water saturation would help to reduce the concentration, and subsequently lowering the loss of surfactant agent due to adsorption. However, too high water saturation would also reduce too much surfactant concentration, inhibiting the system to reach lowest IFT.

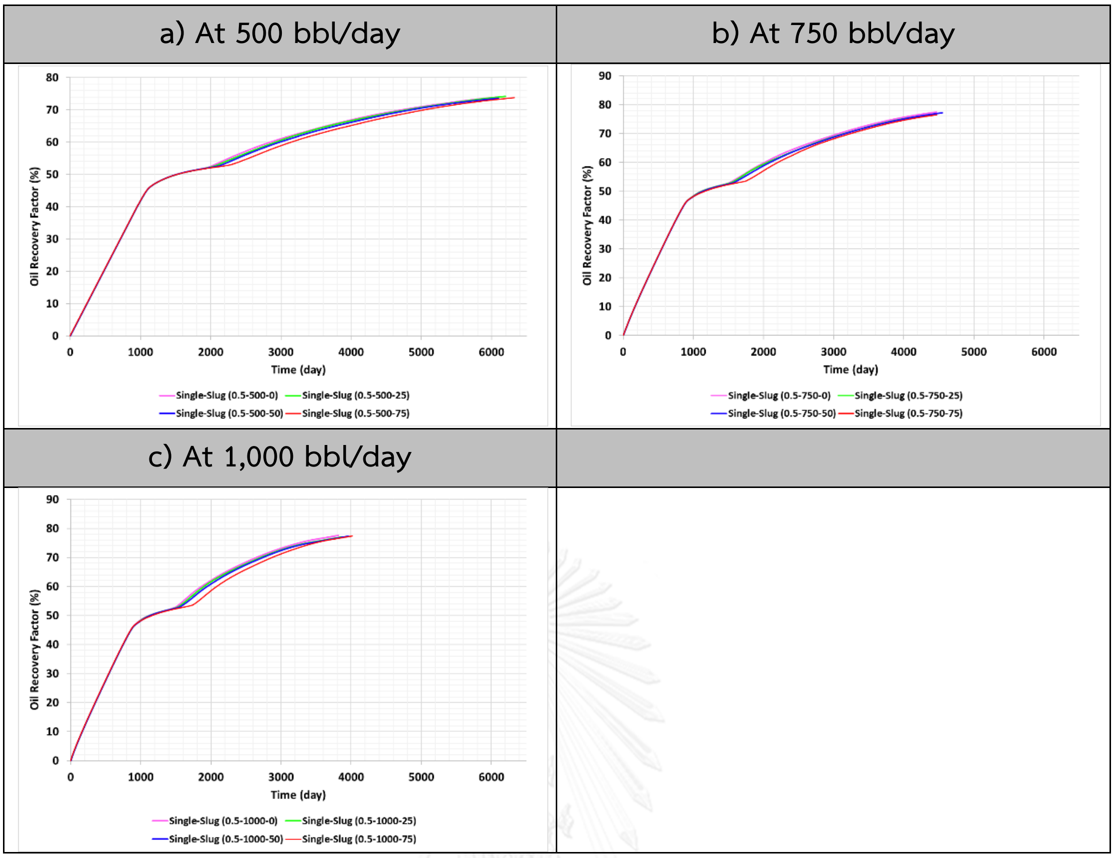
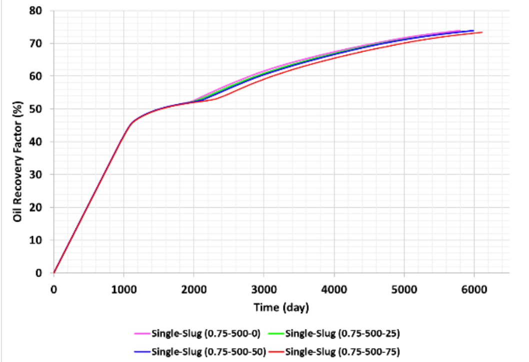


Figure 5.24: Oil recovery factors of 0.5 wt.% concentration surfactant flooding at various time of surfactant flooding implementation: a) surfactant flooding at 500 bbl/day injection rate, b) surfactant flooding at 750 bbl/day injection rate, c) surfactant flooding at 1,000 bbl/day injection

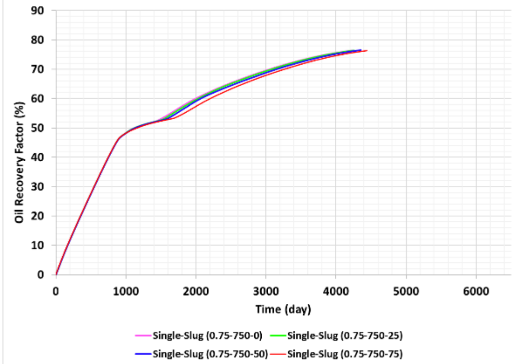
Table 5.5: Oil recovery factors and termination dates of 0.5 wt.% concentration surfactant flooding at various time of surfactant flooding implementation

	At water breakthrough		At 25% watercut		At 50% watercut		At 75% watercut	
	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)
500 bbl/day	73.94	6,067	74.22	6,095	73.59	6,198	73.79	6,321
750 bbl/day	77.41	4,467	76.56	4,370	77.24	4,546	76.45	4,468
1,000 bbl/day	77.60	3,819	77.14	3,865	77.33	3,957	77.35	4,018

a) At 500 bbl/day



b) At 750 bbl/day



c) At 1,000 bbl/day

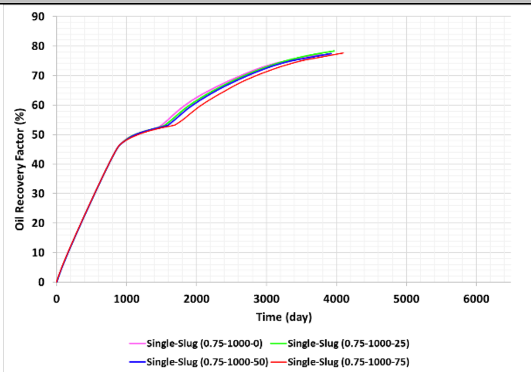


Figure 5.25: Oil recovery factors of 0.75 wt.% concentration surfactant flooding at various time of surfactant flooding implementation: a) surfactant flooding at 500 bbl/day injection rate, b) surfactant flooding at 750 bbl/day injection rate, c) surfactant flooding at 1,000 bbl/day injection

Table 5.6: Oil recovery factors and termination dates of 0.75 wt.% concentration surfactant flooding at various time of surfactant flooding implementation

	At water breakthrough		At 25% watercut		At 50% watercut		At 75% watercut	
	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)
500 bbl/day	73.85	5,796	73.70	5,895	73.85	5,988	73.43	6,112
750 bbl/day	76.44	4,229	76.38	4,257	76.53	4,352	76.30	4,440
1,000 bbl/day	77.05	3,773	78.37	3,970	77.40	3,926	77.64	4,095

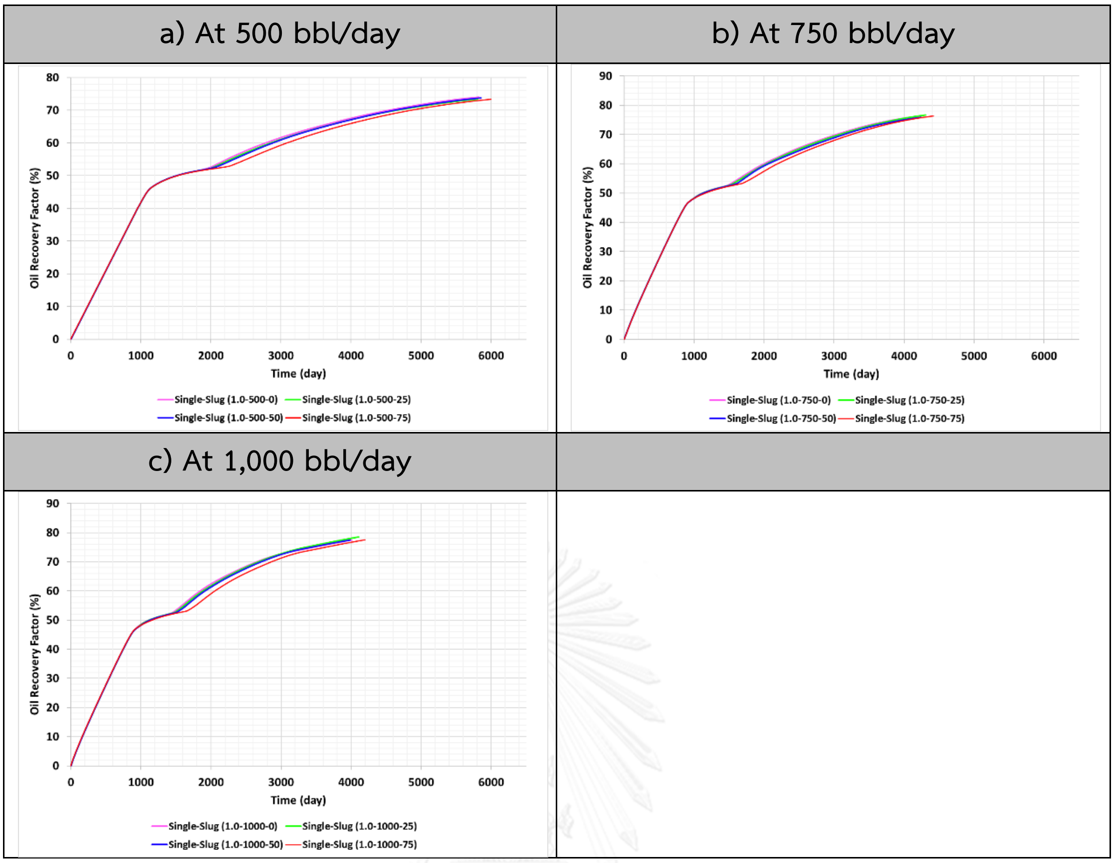


Figure 5.26: Oil recovery factors of 1.0 wt.% concentration surfactant flooding at various time of surfactant flooding implementation: a) surfactant flooding at 500 bbl/day injection rate, b) surfactant flooding at 750 bbl/day injection rate, c) surfactant flooding at 1,000 bbl/day injection

Table 5.7: Oil recovery factors and termination dates of 1.0 wt.% concentration surfactant flooding at various time of surfactant flooding implementation

	At water breakthrough		At 25% watercut		At 50% watercut		At 75% watercut	
	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)	Oil Recovery (%)	Termination Time (day)
500 bbl/day	73.98	5,824	73.42	5,813	73.72	5,856	73.41	5,996
750 bbl/day	76.16	4,164	76.70	4,307	75.91	4,239	76.30	4,419
1,000 bbl/day	77.48	4,012	78.51	4,108	77.46	3,990	77.48	4,199

5.3 Two-slug Surfactant Flooding

In this section, a single-slug surfactant solution is modified into two-slug mode with different surfactant concentrations, surfactant injection rates, and times to start implementation; while maintaining the total amount of surfactant used to be the same as in the case of single-slug surfactant flooding. This is performed to investigate the benefit of desorbed surfactant monomer due to the shift in equilibrium, as well as the benefit of sacrificial adsorption from surfactant monomer to achieve longer period of the lowest IFT condition.

Four injection strategies of two-slug surfactant flooding with three different mass ratios are investigated in this work. The descriptions of the four injection strategies are as following:

1. Reduction-High contrast (R-H)
   - Concentration of slug #1 is 20% of single-slug concentration
   - Concentration of slug #2 is equivalent to single-slug concentration
2. Reduction-Low contrast (R-L)
   - Concentration of slug #1 is 50% of single-slug concentration
   - Concentration of slug #2 is equivalent to single-slug concentration
3. Accretion-High contrast (A-H)
   - Concentration of slug #1 is equivalent to single-slug concentration
   - Concentration of slug #2 is 20% of single-slug concentration
4. Accretion-Low contrast (A-L)
   - Concentration of slug #1 is equivalent to single-slug concentration
   - Concentration of slug #2 is 50% of single-slug concentration

Table 5.8 summarizes the assigned concentration of the slug #1 and #2 of each injection strategies in two-slug surfactant flooding mode.

Table 5.8: Surfactant concentration of each slug in two-slug injection strategy

Single-Slug Concentration	Two-slug Concentration	R-H	R-L	A-H	A-L
1.0 wt.%	Slug #1 (wt.%)	0.20	0.50	1.00	1.00
	Slug #2 (wt.%)	1.00	1.00	0.20	0.50
0.75 wt.%	Slug #1 (wt.%)	0.15	0.375	0.75	0.75
	Slug #2 (wt.%)	0.75	0.75	0.15	0.375
0.5 wt.%	Slug #1 (wt.%)	0.10	0.25	0.50	0.50
	Slug #2 (wt.%)	0.50	0.50	0.10	0.25

Moreover, for each of the four injection strategies, three different designs are investigated as listed below. Table 5.9 illustrates the layout of the three designs for mass ratio.

1. Slug #1 endorsement (80:20)
   - 80% of surfactant mass is in slug #1 and 20% is in the slug #2
2. Slug #2 endorsement (20:80)
   - 80% of surfactant mass is in the slug #2 and 20% is in the slug #1
3. Equivalent endorsement (50:50)
   - Surfactant mass is divided equivalently in slug #1 and #2

Table 5.9: Illustration of the three surfactant mass ratio designs for the four injection strategies

R-H			R-L		
80:20	20:80	50:50	80:20	20:80	50:50
A-H			A-L		
80:20	20:80	50:50	80:20	20:80	50:50

According to the observations, there are two main mechanisms which allow surfactant flooding in two-slug surfactant flooding to yield higher oil recovery than single-slug surfactant flooding. The first mechanism is related to sacrificing of adsorption of the first slug surfactant monomer, causing lower adsorption of second slug surfactant monomers. As a result, the second slug can maintain its concentration and region of lowest IFT condition could be expanded. This mechanism is used to describe the oil recovery mechanism of injection strategy Type R-H and Type R-L. The second mechanism, which is used to describe the oil recovery mechanism of injection strategy Type A-H and Type A-L, is related to desorption of retained active surfactant monomer from the first surfactant slug. The desorbed surfactant monomer is then commingled with the second slug surfactant monomer and prolongs the lower IFT condition period at the late time.

The mechanism at which the system undergoes would depend on the influence of the following three main parameters: injection rate, surfactant slug concentration, and surfactant mass ratio.

First, increase in flow rate results in lesser contact time between rock and surfactant monomer, and therefore less adsorption for higher concentration solution is observed. For the effect of surfactant slug concentration, the higher the surfactant slug concentration, the higher the adsorption magnitude. For surfactant mass ratio, since the total mass of surfactant is kept constant and slug concentration is defined in this study, any change in amount of surfactant would only affect the surfactant slug size. That is, increase in amount of surfactant would only increase the size of the surfactant slug.

In term of production time, two phenomena can be observed based on the injection sequence, as shown in Figure 5.27 to Figure 5.29. The first phenomenon can be seen in injection strategy with Type R. For this type injection strategy, the increase in oil recovery due to effect of surfactant flooding tends to be slower than the case of single-slug surfactant flooding at the early time. This is owing to lowering of slug concentration of first slug in two-slug surfactant injection. Though, the rate of oil recovery could catch up with, or even go beyond oil recovery obtained from single-slug surfactant injection at the late time, and could further prolong the production period before production constrain is attained.

However, as the degree of contrast between two slugs change from high to low, the response of incremental oil recovery is faster. The second phenomenon can be observed in Type A injection strategy. For this type of injection strategy, increment of oil recovery is almost the same as the case of single-slug surfactant injection at the early period. This is because the front slug of two-slug injection mode has the same concentration as single-slug mode. Nevertheless, rate of oil recovery tends to drop below single-slug oil recovery, but production period could be maintained longer. This phenomenon can be observed in Figure 5.27 to Figure 5.29.

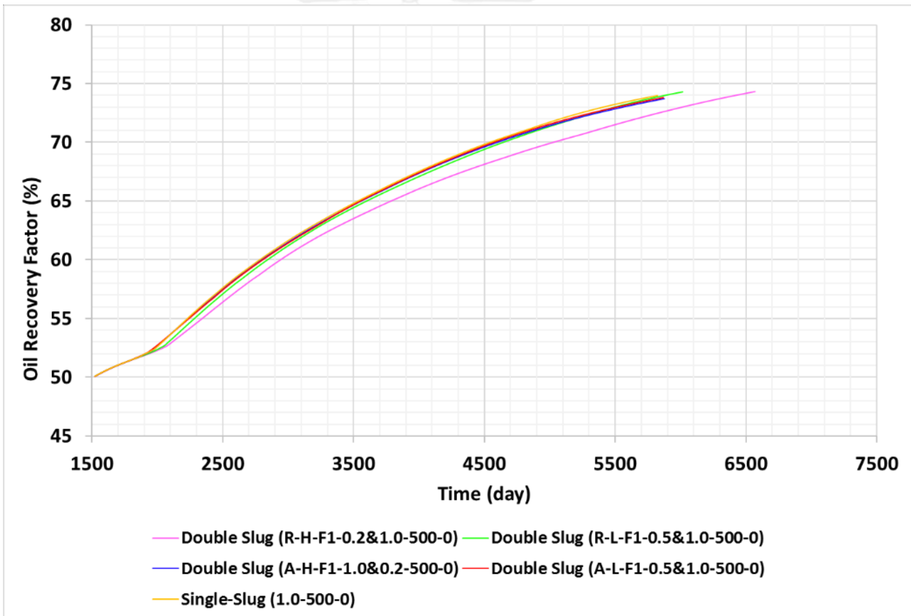


Figure 5.27: Oil recovery factors obtained from the four types of two-slug surfactant injection strategy (1.0 wt.% base and equivalent mass between two slugs) compared to 1.0 wt.% concentration single-slug injection implemented at water breakthrough with injection rate of 500 bbl/day

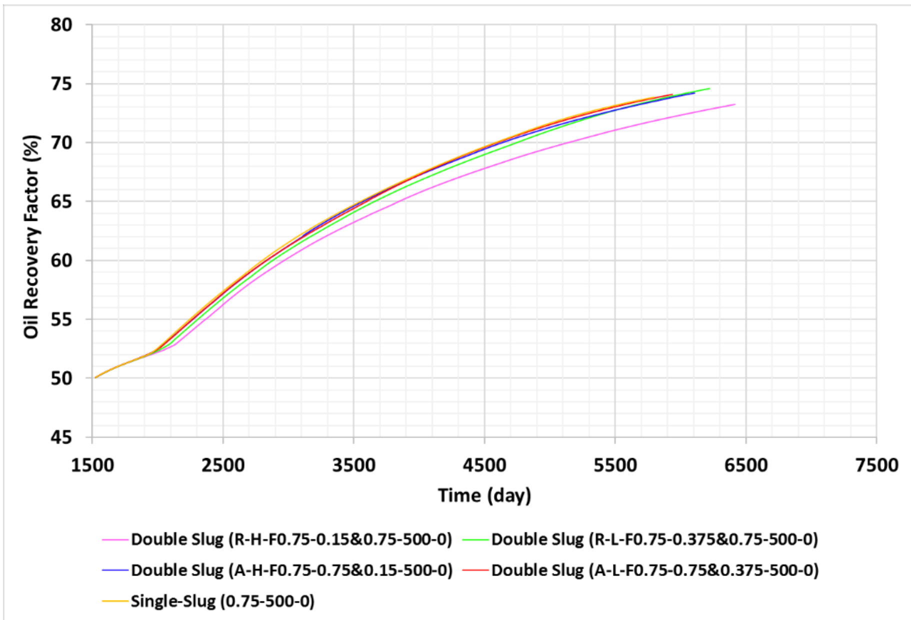


Figure 5.28: Oil recovery factors obtained from the four types of two-slug surfactant injection strategy (0.75 wt.% base and equivalent mass between two slugs) compared to 0.75 wt.% concentration single-slug injection implemented at water breakthrough with injection rate of 500 bbl/day

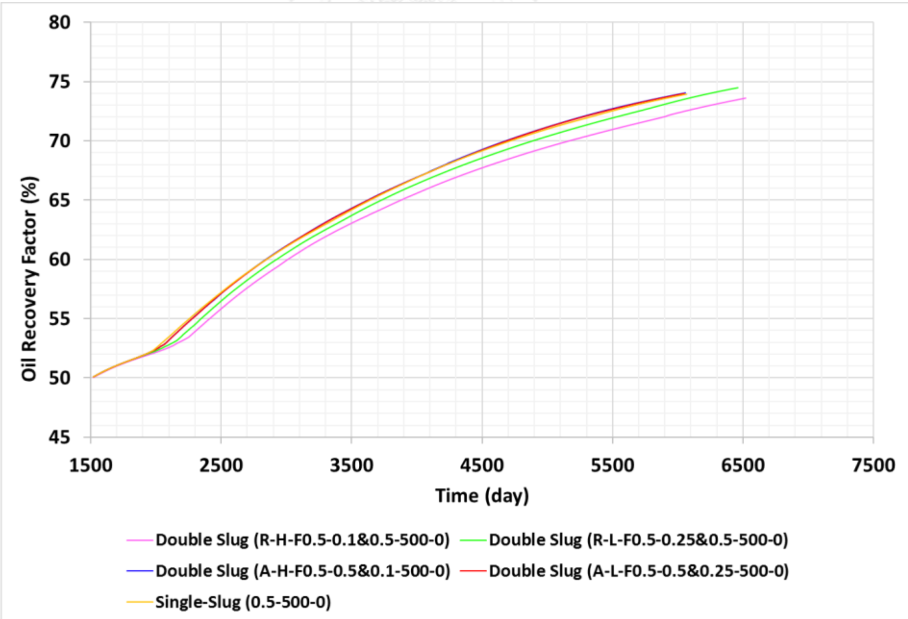


Figure 5.29: Oil recovery factors obtained from the four types of two-slug surfactant injection strategy (0.5 wt.% base and equivalent mass between two slugs) compared to 0.5 wt.% concentration single-slug injection implemented at water breakthrough with injection rate of 500 bbl/day

The influences of the four main parameters and the two additional oil recovery mechanisms mentioned earlier are used to explain the benefit of two-slug surfactant flooding over single-slug surfactant flooding in this study. Table 5.10 to Table 5.12 show oil recovery factors obtained from two-slug surfactant injection in percentage at different injection rates, times to implement surfactant flooding, mass ratios, and injection sequences based from single-slug concentrations of 1.0 wt.%, 0.75 wt.%, and 0.5 wt.%, respectively.

Table 5.10: Oil recovery factors of two-slug mode at different injection rate, time of surfactant implementation, mass ratio, and injection strategy for 1.0 wt.% single-slug concentration as a base

			Injection Rate, Watercut Percentage (bbl/day, %)					
			500, 0	500, 25	750, 0	750, 25	1000, 0	1000, 25
			Oil Recovery Factor of Single-Slug Mode (%)					
			73.98	73.42	76.16	76.7	77.48	78.51
Single-Slug Concentration	Injection Strategy	Mass Ratio	Oil Recovery Factor of Two-slug Mode (%)					
1.0 wt.%	R-H (0.2&1.0)	50:50	74.32	74.51	76.82	77.20	77.85	77.33
	R-L (0.5&1.0)		74.29	74.01	77.45	77.35	78.00	77.83
	A-H (1.0&0.2)		73.71	73.52	76.18	76.30	77.77	77.21
	A-L (1.0&0.5)		73.73	73.77	76.67	75.86	77.90	77.65
	R-H (0.2&1.0)	80:20	74.18	73.89	76.63	77.03	77.84	76.26
	R-L (0.5&1.0)		74.22	74.08	76.91	77.36	78.30	77.78
	A-H (1.0&0.2)		74.37	73.60	76.81	76.83	76.69	77.29
	A-L (1.0&0.5)		73.42	73.60	76.65	76.20	77.49	77.46
	R-H (0.2&1.0)	20:80	74.44	74.98	77.00	77.27	77.81	77.67
	R-L (0.5&1.0)		73.56	73.58	76.58	76.40	77.41	77.66
	A-H (1.0&0.2)		73.79	73.70	76.96	76.99	76.18	76.85
	A-L (1.0&0.5)		73.74	73.90	76.61	77.23	77.18	78.09

Table 5.11: Oil recovery factors of two-slug mode at different injection rate, time of surfactant implementation, mass ratio, and injection strategy for 0.75 wt.% single-slug concentration as a base

			Injection Rate, Watercut Percentage (bbl/day, %)					
			500, 0	**500, 25**	**750, 0**	**750, 25**	**1000, 0**	**1000, 25**
			Oil Recovery Factor of Single-Slug Mode (%)					
			73.848	73.7	76.44	76.378	77.05	78.372
Single-Slug Concentration	Injection Strategy	Mass Ratio	Oil Recovery Factor of Two-slug Mode (%)					
0.75 wt.%	R-H (0.15&0.75)	50:50	73.25	74.17	76.45	77.09	77.90	77.84
	R-L (0.375&0.75)		74.59	74.39	76.97	77.11	78.24	77.00
	A-H (0.75&0.15)		74.21	74.13	76.31	76.11	77.70	76.59
	A-L (0.75&0.375)		74.09	73.83	76.10	76.03	77.38	77.06
	R-H (0.15&0.75)	80:20	73.97	74.20	77.13	76.87	77.73	77.39
	R-L (0.375&0.75)		74.80	74.55	77.31	77.85	77.36	76.70
	A-H (0.75&0.15)		74.17	73.94	75.97	76.76	77.44	78.16
	A-L (0.75&0.375)		73.73	73.76	76.31	76.63	77.40	77.59
	R-H (0.15&0.75)	20:80	74.59	74.71	77.27	77.39	77.22	78.16
	R-L (0.375&0.75)		74.38	73.79	76.68	76.75	77.68	77.83
	A-H (0.75&0.15)		73.86	73.88	76.94	76.82	77.49	77.70
	A-L (0.75&0.375)		73.49	73.30	76.80	76.08	77.23	76.94

Table 5.12: Oil recovery factors of two-slug mode at different injection rate, time of surfactant implementation, mass ratio, and injection strategy for 0.5 wt.% single-slug concentration

			Injection Rate, Watercut Percentage (bbl/day, %)					
			500, 0	500, 25	750, 0	750, 25	1000, 0	1000, 25
			Oil Recovery Factor of Single-Slug Mode (%)					
			73.94	74.22	77.41	76.564	77.598	77.14
Single-Slug Concentration	Injection Strategy	Mass Ratio	Oil Recovery Factor of Two-slug Mode (%)					
0.5 wt.%	R-H (0.1&0.5)	50:50	73.60	73.76	76.84	76.31	77.11	77.48
	R-L (0.25&0.5)		74.48	74.08	76.72	77.40	77.27	77.72
	A-H (0.5&0.1)		-	-	76.63	76.60	77.77	77.47
	A-L (0.5&0.25)		74.01	74.43	76.31	76.43	77.85	77.16
	R-H (0.1&0.5)	80:20	-	-	-	-	-	-
	R-L (0.25&0.5)		74.44	74.14	76.72	77.39	77.47	77.33
	A-H (0.5&0.1)		74.62	73.58	76.68	77.64	76.77	76.69
	A-L (0.5&0.25)		74.31	73.87	76.61	76.72	77.01	78.01
	R-H (0.1&0.5)	20:80	75.12	73.71	77.35	76.80	77.06	78.00
	R-L (0.25&0.5)		74.67	74.03	76.76	77.17	77.15	77.59
	A-H (0.5&0.1)		-	-	-	-	-	-
	A-L (0.5&0.25)		74.36	73.10	77.20	76.48	77.26	77.18

* Blank cells refer to the case that terminate because production constraint has been met before finishing surfactant injection.

Degrees of improvement in term of oil recovery factor from two-slug surfactant flooding compared to single-slug surfactant flooding are calculated by Equation (5.1). Table 5.13 to Table 5.15 summarize degree of improvement for each case.

$$\begin{matrix} Oil\ recovery \\ improvement\ percentage \end{matrix} = \frac{\left(RF_{double\ slug} - RF_{single\ slug}\right)}{\left(RF_{single\ slug}\right)} \times 100 \qquad (5.1)$$

Table 5.13: Oil recovery improvement percentage between two-slug mode and single-slug mode with 1.0 wt.% concentration as a base

Single-Slug Concentration	Injection Strategy	Mass Ratio	500, 0	500, 25	750, 0	750, 25	1000, 0	1000, 25
			Percentage Improvement of Oil Recovery of Two-slug Mode Over Single-Slug Mode (%)					
1.0 wt.%	R-H (0.2&1.0)	50:50	0.45	1.48	0.87	0.65	0.48	-1.50
	R-L (0.5&1.0)		0.42	0.80	1.70	0.85	0.67	-0.87
	A-H (1.0&0.2)		-0.36	0.14	0.03	-0.52	0.37	-1.66
	A-L (1.0&0.5)		-0.34	0.48	0.67	-1.10	0.54	-1.10
	R-H (0.2&1.0)	80:20	0.27	0.64	0.62	0.43	0.46	-2.87
	R-L (0.5&1.0)		0.32	0.90	0.99	0.86	1.06	-0.93
	A-H (1.0&0.2)		0.53	0.25	0.86	0.17	-1.02	-1.55
	A-L (1.0&0.5)		-0.76	0.25	0.65	-0.65	0.02	-1.34
	R-H (0.2&1.0)	20:80	0.62	2.12	1.11	0.74	0.43	-1.07
	R-L (0.5&1.0)		-0.56	0.22	0.56	-0.39	-0.09	-1.08
	A-H (1.0&0.2)		-0.26	0.38	1.05	0.38	-1.68	-2.11
	A-L (1.0&0.5)		-0.32	0.65	0.59	0.69	-0.39	-0.53

Note: column headers are Injection Rate, Watercut Percentage (bbl/day, %).

Table 5.14: Oil recovery improvement percentage between two-slug mode and single-slug mode with 0.75 wt.% concentration as a base

Single-Slug Concentration	Injection Strategy	Mass Ratio	500, 0	500, 25	750, 0	750, 25	1000, 0	1000, 25
			Percentage Improvement of Oil Recovery of Two-slug Mode Over Single-Slug Mode (%)					
0.75 wt.%	R-H (0.15&0.75)	50:50	-0.82	0.63	0.01	0.94	1.10	-0.69
	R-L (0.375&0.75)		1.00	0.94	0.68	0.96	1.54	-1.75
	A-H (0.75&0.15)		0.48	0.59	-0.17	-0.35	0.84	-2.28
	A-L (0.75&0.375)		0.32	0.18	-0.45	-0.45	0.43	-1.67
	R-H (0.15&0.75)	80:20	0.17	0.68	0.89	0.64	0.88	-1.26
	R-L (0.375&0.75)		1.28	1.15	1.13	1.93	0.40	-2.13
	A-H (0.75&0.15)		0.43	0.33	-0.62	0.50	0.50	-0.27
	A-L (0.75&0.375)		-0.16	0.08	-0.17	0.32	0.45	-0.99
	R-H (0.15&0.75)	20:80	1.00	1.37	1.08	1.32	0.22	-0.28
	R-L (0.375&0.75)		0.72	0.12	0.31	0.48	0.81	-0.69
	A-H (0.75&0.15)		0.01	0.24	0.65	0.58	0.57	-0.86
	A-L (0.75&0.375)		-0.49	-0.55	0.47	-0.39	0.23	-1.83

Table 5.15: Oil recovery improvement percentage between two-slug mode and single-slug mode with 0.5 wt.% as a base

			Injection Rate, Watercut Percentage (bbl/day, %)					
			500, 0	500, 25	750, 0	750, 25	1000, 0	1000, 25
Single-Slug Concentration	Injection Strategy	Mass Ratio	Percentage Improvement of Oil Recovery of Two-slug Mode Over Single-Slug Mode (%)					
0.5 wt.%	R-H (0.1&0.5)	50:50	-0.46	-0.62	-0.74	-0.33	-0.63	0.45
	R-L (0.25&0.5)		0.73	-0.18	-0.90	1.09	-0.42	0.75
	A-H (0.5&0.1)		-	-	-1.01	0.05	0.22	0.43
	A-L (0.5&0.25)		0.09	0.28	-1.42	-0.17	0.33	0.03
	R-H (0.1&0.5)	80:20	-	-	-	-	-	-
	R-L (0.25&0.5)		0.68	-0.11	-0.89	1.08	-0.16	0.25
	A-H (0.5&0.1)		0.92	-0.87	-0.94	1.40	-1.07	-0.58
	A-L (0.5&0.25)		0.50	-0.47	-1.03	0.20	-0.76	1.13
	R-H (0.1&0.5)	20:80	1.60	-0.69	-0.07	0.30	-0.69	1.11
	R-L (0.25&0.5)		0.99	-0.26	-0.84	0.79	-0.58	0.58
	A-H (0.5&0.1)		-	-	-	-	-	-
	A-L (0.5&0.25)		0.57	-1.51	-0.27	-0.11	-0.43	0.05

* Blank cells refer to the case that terminate because production constraint has been met before finishing surfactant injection.

According to the percentage of oil recovery improvement for each single-slug concentration in Table 5.13 to Table 5.15, the injection strategy that yields the best improvement at different mass ratios, flow rates, times of surfactant implementation and single-slug reference concentration are listed in Table 5.16

Table 5.16: Summary of recommended injection strategy

Mass Ratio	Injection Rate	Time to Implement	Recommended Injection Strategy		
			For 1.0 wt.%	For 0.75 wt.%	For 0.5 wt.%
20:80	low	low	R-H	R-H	R-H
	low	high	R-H	R-H	-
	mid	low	R-H	R-H	-
	mid	high	R-H	R-H	R-L
	high	low	R-H	R-L	-
	high	high	-	-	R-H
80:20	low	low	A-H	R-L	A-H
	low	high	R-L	R-L	-
	mid	low	R-L	R-L	-
	mid	high	R-L	R-L	A-H
	high	low	R-L	R-H	-
	high	high	-	-	A-L
50:50	low	low	R-H	R-L	R-L
	low	high	R-H	R-L	A-L
	mid	low	R-L	R-L	-
	mid	high	R-L	R-L	R-L
	high	low	R-L	R-L	A-L
	high	high	-	-	R-L

* Blank cell refers to the case that double-slug surfactant flooding shows no benefit over single-slug surfactant flooding.

* Injection rate: low = 500 bbl/day, mid = 750 bbl/day, high = 1,000 bbl/day

* Time to implement: low = at water breakthrough, high = at 25% watercut

5.3.1 Two-slug Surfactant Flooding based on 1.0 wt.% Single-Slug

According to the results in Table 5.16, at high surfactant concentration (1.0 wt.%), regardless of the injection rate and watercut percentage, performing Type R injection strategy is more preferable. This is because degree of adsorption of the slug #2 solution, which has higher concentration, is alleviated by sacrificial adsorption from the slug #1 surfactant monomers.

As can be seen in Figure 5.30, Type A injection strategy at the early time near the injector shows high adsorption profile. This adsorption is solely contributed from the surfactant monomer in 1.0 wt.% slug solution, whereas in case of Type R injection strategy, only part of surfactant monomers inside 1.0 wt.% are being adsorbed onto the rock surface to reach the maximum adsorption. Figure 5.31 shows adsorption profile of Type R injection strategy. At the first day of slug #2 surfactant injection, adsorption profiles of Type R-L and Type R-H have shown adsorption in green scale and light blue scale, respectively. Once the slug #2 surfactant injection has finished, the adsorption profile near wellbore increases to red scale for both cases. This indicates that the amount of surfactant monomer that is adsorbed and changes the scale from green and light blue into red scale is contributed from surfactant monomer inside slug #2. And therefore, there is lesser amount of surfactant from 1.0 wt.% being adsorbed compared to Type A injection strategy.

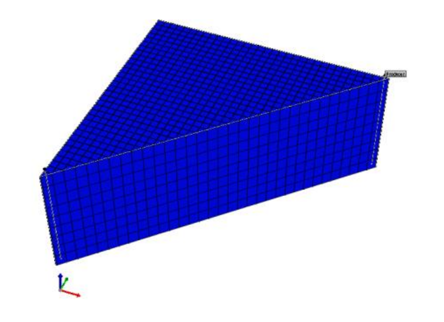
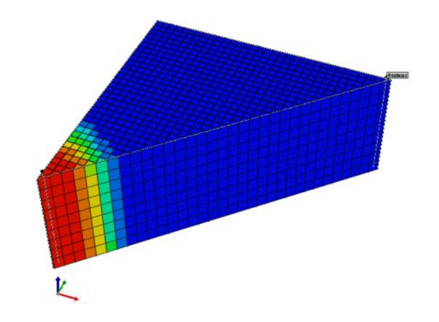
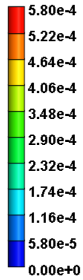
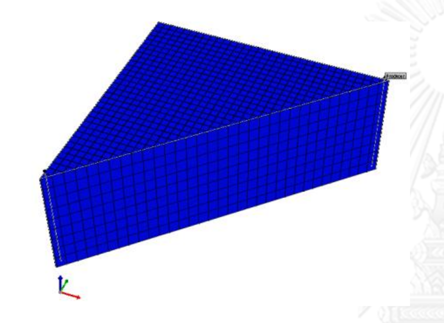
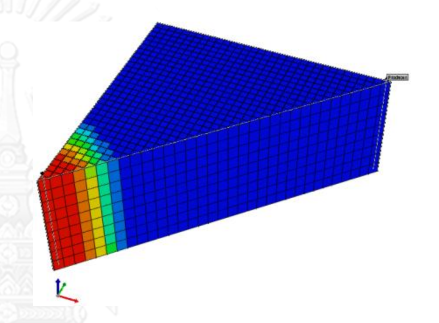
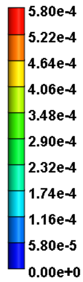
<table>
<tr><th colspan="3">Adsorption Profile of Type A-L(1.0&0.5)</th></tr>
<tr><td>End of water flooding</td><td>End of slug #1 injection</td><td>Scale</td></tr>
<tr><td></td><td></td><td>
</td></tr>
<tr><th colspan="3">Adsorption Profile of Type A-H(1.0&0.2)</th></tr>
<tr><td>End of water flooding</td><td>End of slug #1 injection</td><td>Scale</td></tr>
<tr><td></td><td></td><td>
</td></tr>
</table>

Figure 5.30: Adsorption profiles of Type A-L (1.0&0.5) and Type A-H (1.0&0.2) injection strategy (1.0 wt.% base and equivalent mass between two slugs) implemented at water breakthrough with injection rate of 500 bbl/day. Two periods including end of waterflooding process and end of slug #1 injection

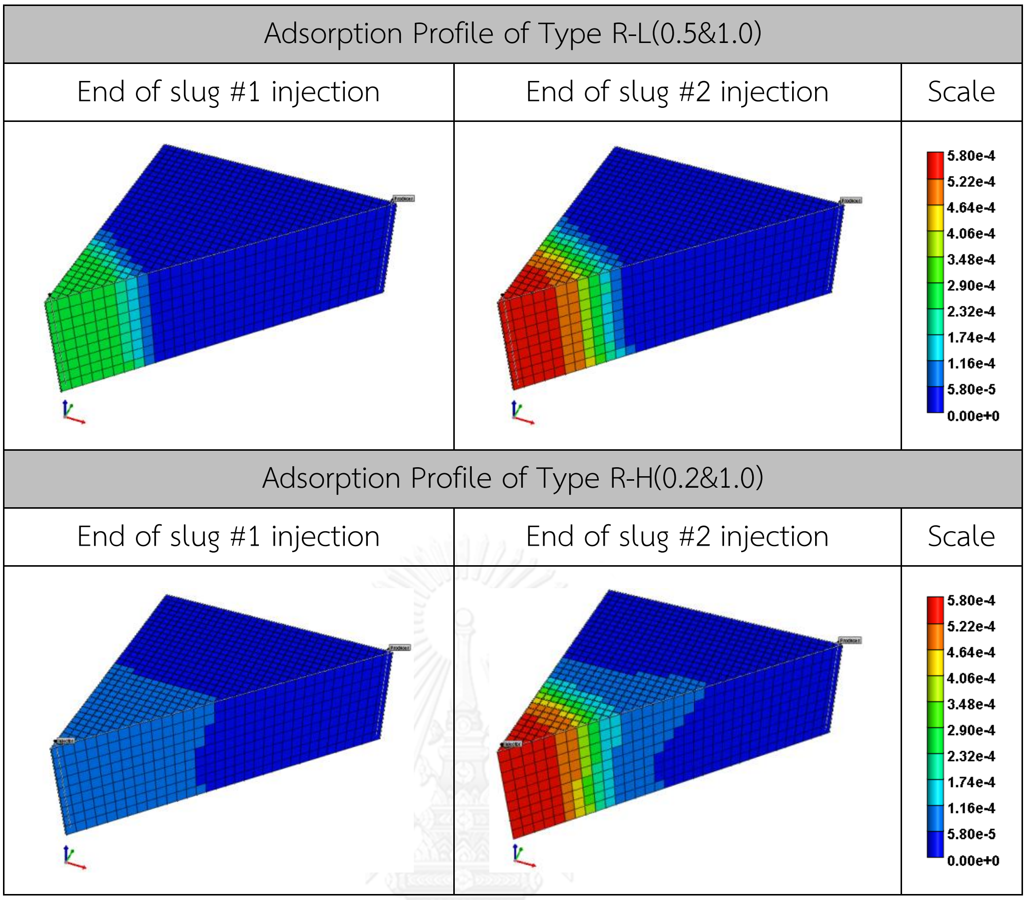


Figure 5.31: Adsorption profiles of Type R-L (0.5&1.0) and Type R-H (0.2&1.0) injection strategy (1.0 wt.% base and equivalent mass between two slugs) implemented at water breakthrough with injection rate of 500 bbl/day. Two periods including end of slug #1 Injection and end of slug #2 injection

Hence, in term of areas at which the lowest IFT condition could be established, Type R injection strategy could expand larger area of the lowest IFT condition up to 63 blocks, as shown in Figure 5.32, whereas Type A injection strategy could expand the lowest IFT condition up to 36 blocks, as illustrated in Figure 5.33. Moreover, Type R injection strategy also show wider area of low IFT condition than single-slug surfactant injection, which is shown in Figure 5.34. This is the reason why Type R injection strategy yields better oil recovery.

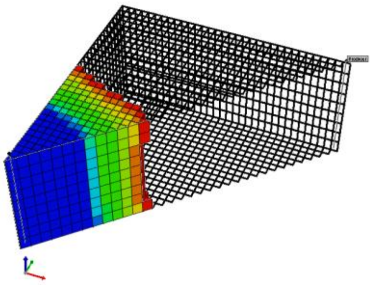
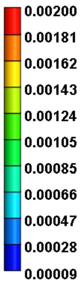
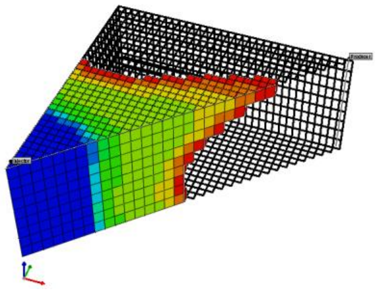
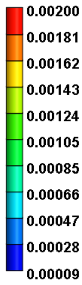
Interfacial Tension Profile			
R-L(0.5&1.0)	Scale	R-H(0.2&1.0)	Scale
			

Figure 5.32: Interfacial tension profiles of Type R-L (0.5&1.0) and Type R-H (0.2&1.0) injection strategy (1.0 wt.% base and equivalent mass between two slugs) implemented at water breakthrough with injection rate of 500 bbl/day (Profiles are taken at the end of slug #2 injection)

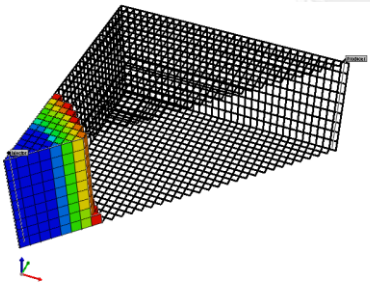
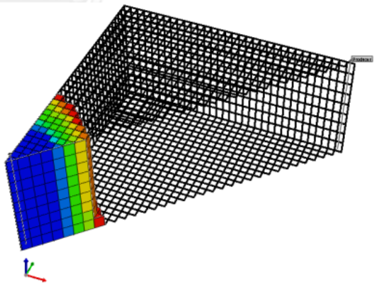
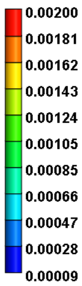
Interfacial Tension Profile			
A-L(1.0&0.5)	Scale	A-H(1.0&0.2)	Scale
			

Figure 5.33: Interfacial tension profiles of Type A-L (1.0&0.5) and Type A-H (1.0&0.2) injection strategy (1.0 wt.% base and equivalent mass between two slugs) implemented at water breakthrough with injection rate of 500 bbl/day (Profiles are taken at the end of slug #1 injection)

Interfacial Tension Profile

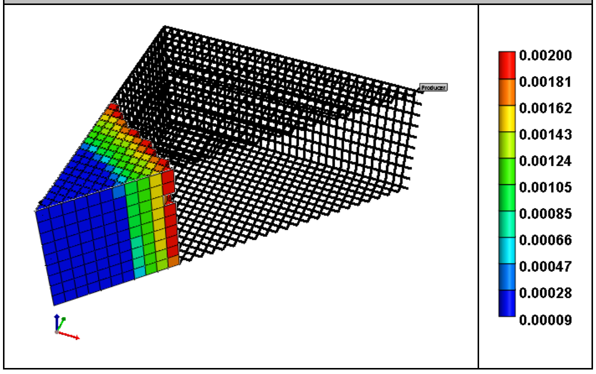


Figure 5.34: Interfacial tension profile of 1.0 wt.% concentration single-slug surfactant injection implemented at water breakthrough with injection rate of 500 bbl/day (Profile is taken at the end of surfactant injection)

Due to low injection rate, low water cut, and high surfactant concentration, which promote extremely high adsorption of surfactant, performing Type A injection strategy could yield a better oil recovery improvement percentage over other injection strategies at mass ratio of 80:20. This is due to the desorption mechanism. According to Figure 5.35, it can be seen that the adsorbed surfactant monomers are detached from the rock surface resulting in lower adsorption at the end of slug #2 injection. Moreover, due to a higher contrast between slug #1 and slug #2 for Type A-H injection strategy, there are high magnitude of desorption than Type A-L. Hence, this indicates that there would be more surfactant monomer desorbed in Type A-H than in case of Type A-L. These desorbed surfactant monomers are then commingled with the surfactant monomers in slug #2 solution and would lead to lower IFT condition at the later stage.

The effect of desorbed surfactant monomers can be observed in Figure 5.36. IFT profile of Type A-H reveals two-color region (dark green and yellow) of IFT. The dark green zone indicates that the adsorbed surfactant monomers have been desorbed and commingled with slug #2 surfactant solution of 0.2 wt.%, causing concentration of surfactant solution at the front side of slug to be higher. Hence, IFT is lower than the back side of slug.

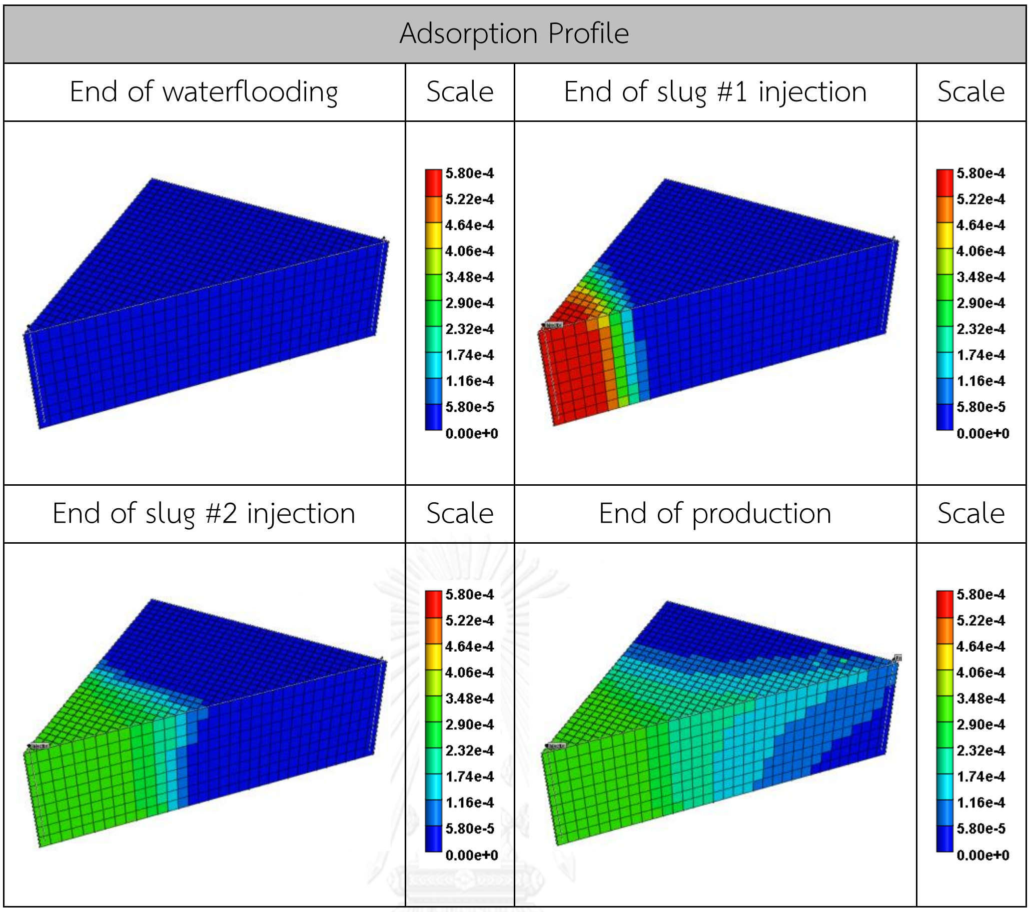


Figure 5.35: Adsorption profiles at four different periods of Type A-H (1.0&0.2) injection strategy (1.0 wt.% base and mass ratio of 80:20) implemented at water breakthrough with injection rate of 500 bbl/day

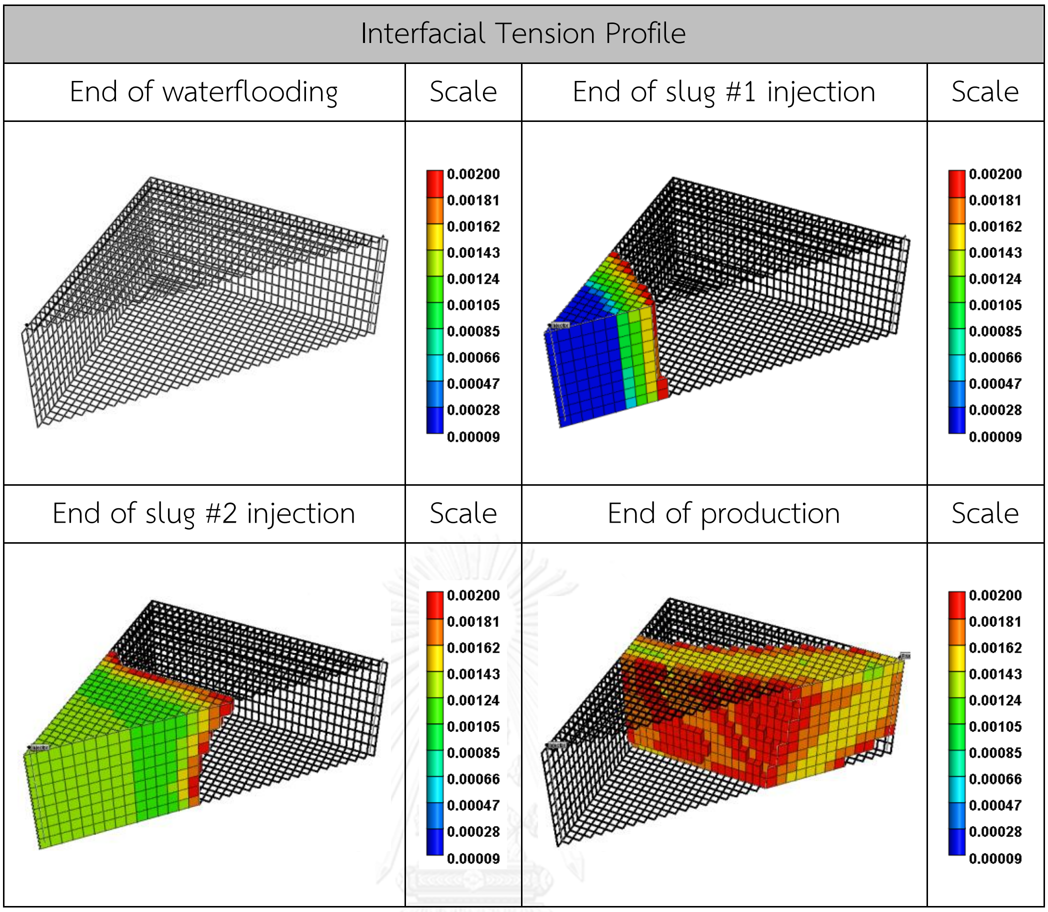


Figure 5.36: Interfacial tension profiles at four different periods of Type A-H (1.0&0.2) injection strategy (1.0 wt.% base and mass ratio of 80:20) implemented at water breakthrough with injection rate of 500 bbl/day

One of the observations is on oil recovery at injection rate of 1,000 bbl/day and watercut percentage of 25% which yields negative oil recovery improvement percentage in all cases, regardless of mass ratio and injection strategy. The reason why two-slug surfactant injection shows lower oil recovery factor than single-slug surfactant injection could possibly be explained through the effect of injection rate and time of surfactant flooding implementation. Since the principle of improving oil recovery from two-slug surfactant flooding is mainly due to the adsorption and desorption of retained surfactant monomer, at high injection rate, the degree of adsorption is lower than other injection rate. Therefore, the benefit of two-slug injection is impeded. Performing two-slug surfactant injection would only further decrease the slug size of high concentration slug, leading to smaller area where the lowest IFT condition could be established. Figure 5.37 shows that lowest IFT of two-slug could be maintained up to only 4 blocks; whereas, single-slug could maintain the lowest IFT up to 7 blocks, as shown in Figure 5.38. Moreover, high watercut percentage would further dilute the concentration of slug with lower concentration. Hence, lower oil recovery for two-slug injection is observed with these conditions. This effect can also be observed in case of 0.75 wt.% as base as well.

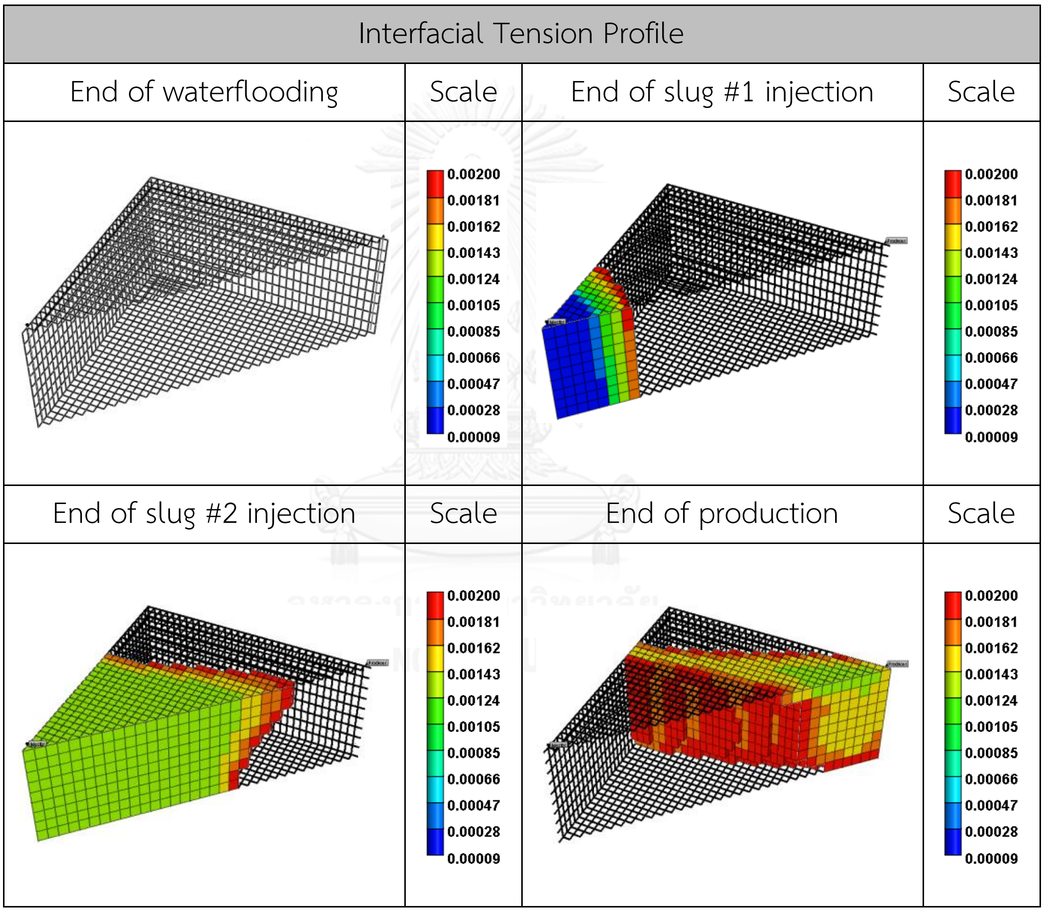


Figure 5.37: Interfacial tension profiles at four different periods of Type A-H (1.0&0.2) injection strategy (1.0 wt.% base and equivalent mass between two slugs) implemented at 25% with injection rate of 1,000 bbl/day

<table>
<tr><th colspan="3">Interfacial Tension Profile</th></tr>
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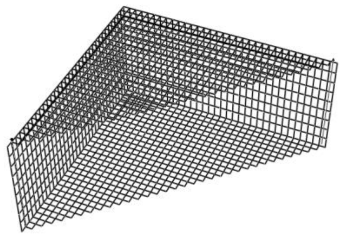
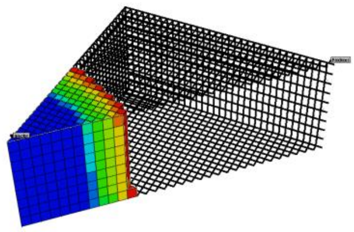
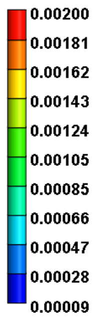
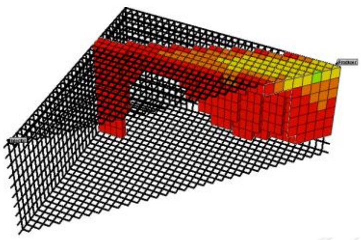
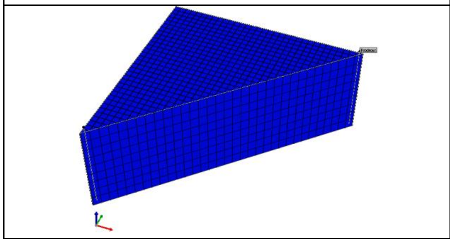
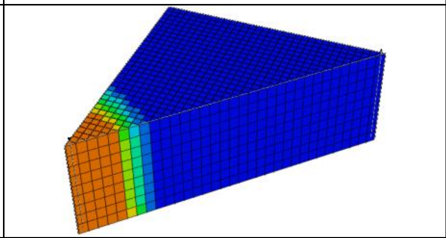
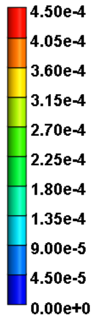
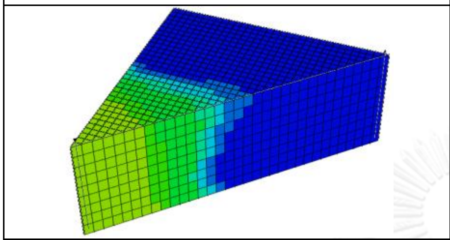
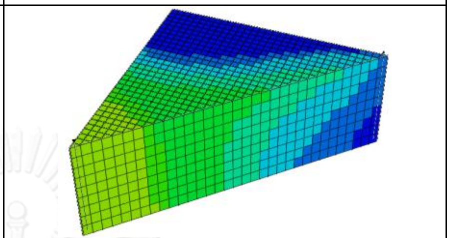
<tr><td></td><td></td><td rowspan="3"></td></tr>
<tr><td>End of production</td><td></td></tr>
<tr><td></td><td></td></tr>
</table>

Figure 5.38: Interfacial tension profiles at three different periods of 1.0 wt.% concentration single-slug surfactant injection implemented at 25% watercut with injection rate of 1000 bbl/day

5.3.2 Two-slug Surfactant Flooding based on 0.75 wt.% Single-Slug

At middle surfactant concentration (0.75 wt.%), results in Table 5.16 show that regardless of watercut percentage and injection rate, performing two-slug surfactant flooding with Type R injection strategy would yield better oil recovery improvement. The reason why Type A injection strategy is not suitable in this case is because the slug concentration of 0.75 wt.% still leads to too high adsorption. Though, even at high watercut percentage with the effect of dilution, but at low injection rate, the effect of adsorption could not be overcome. According to the adsorption profile of Type A injection strategy in Figure 5.39, high value of adsorption at early period is contributed solely from the slug #1 solution of Type A injection strategy, which has high surfactant concentration. Since the large amount of surfactant monomer has left surfactant solution, the concentration of the slug solution decreases and could generate a low IFT condition up to only 333 blocks, as shown in Figure 5.40. Hence, it is more preferable to perform Type R injection strategy.

In case of Type R injection strategy, the effect of adsorption of high concentration slug, which is the key component, is alleviated by the sacrificial adsorption. As can be observed in Figure 5.41, before the slug #2 of Type R injection strategy entered the reservoir, there is already some of surfactant monomers adsorbed on the rock surface. Once the slug #2 solution come in, there is only a few amount of surfactant monomer left the slug solution in order to fulfill the gap on the rock surface until the maximum adsorption is reached. Hence, Type R injection sequence could acquire larger area of low IFT up to 612 blocks, as shown in Figure 5.42.

Adsorption Profile of Type A-L(0.75&0.375)		
End of water flooding	End of slug #1 injection	Scale
		
End of slug #2 injection	End of poduction	
		

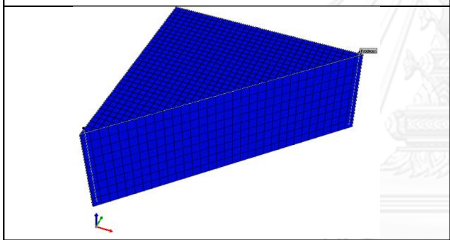
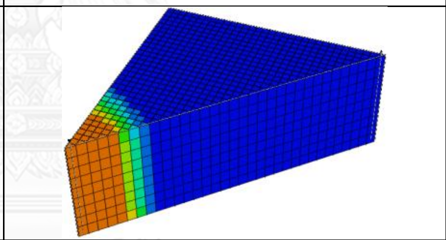
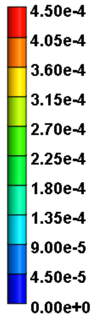
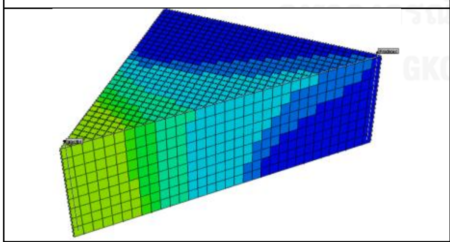
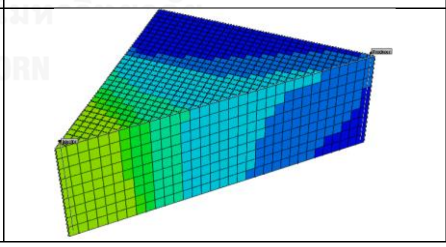
Adsorption Profile of Type A-H(0.75&0.15)		
End of water flooding	End of slug #1 injection	Scale
		
End of slug #2 injection	End of poduction	
		

Figure 5.39: Adsorption profiles at four different periods of Type A-L (0.75&0.375) and Type A-H (0.75&0.15) injection strategy (0.75 wt.% base and equivalent mass between two slugs) implemented at water breakthrough with injection rate of 500 bbl/day

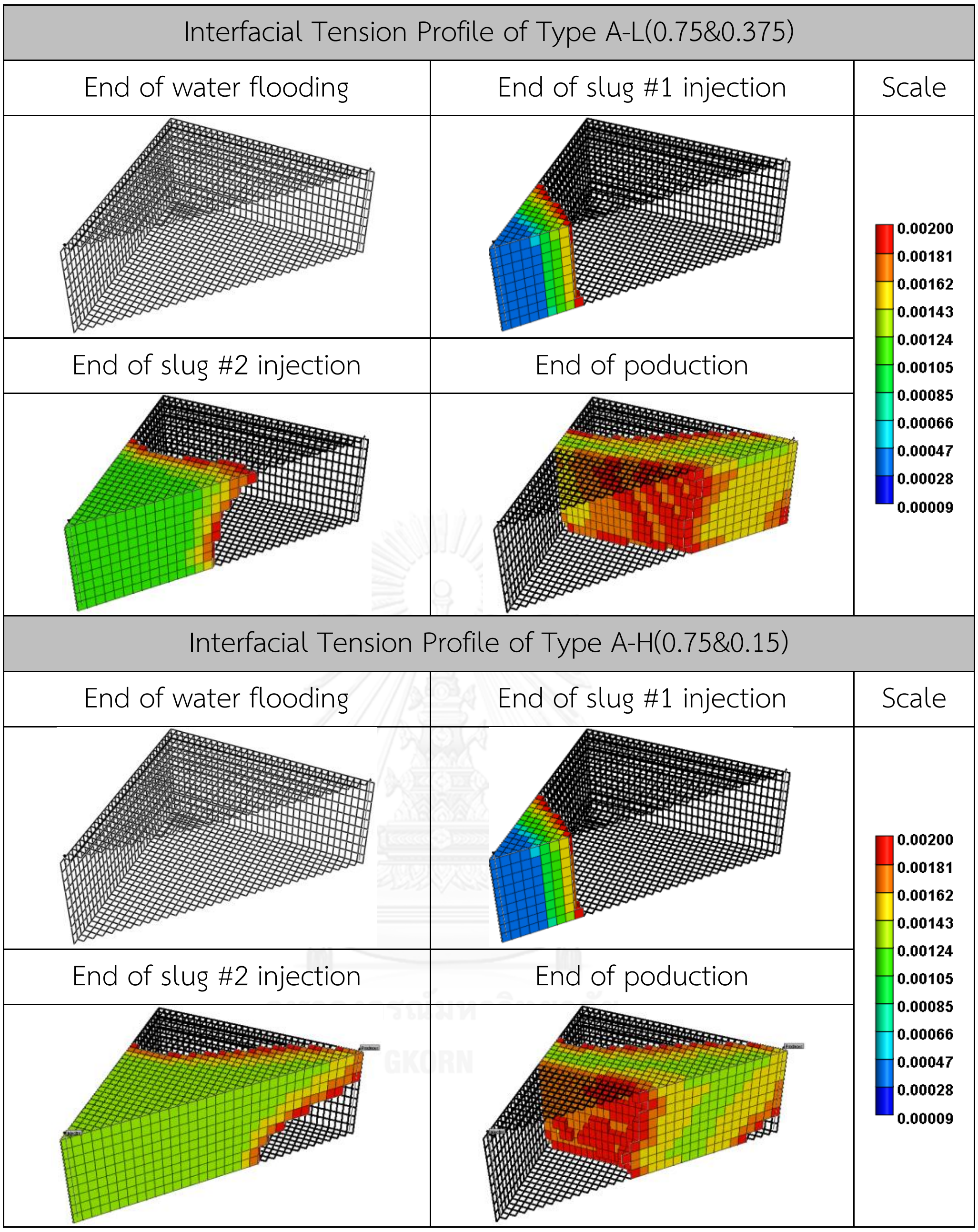


Figure 5.40: Interfacial tension profiles at four different periods of Type A-L (0.75&0.375) and Type A-H (0.75&0.15) injection strategy (0.75 wt.% base and equivalent mass between two slugs) implemented at water breakthrough with injection rate of 500 bbl/day

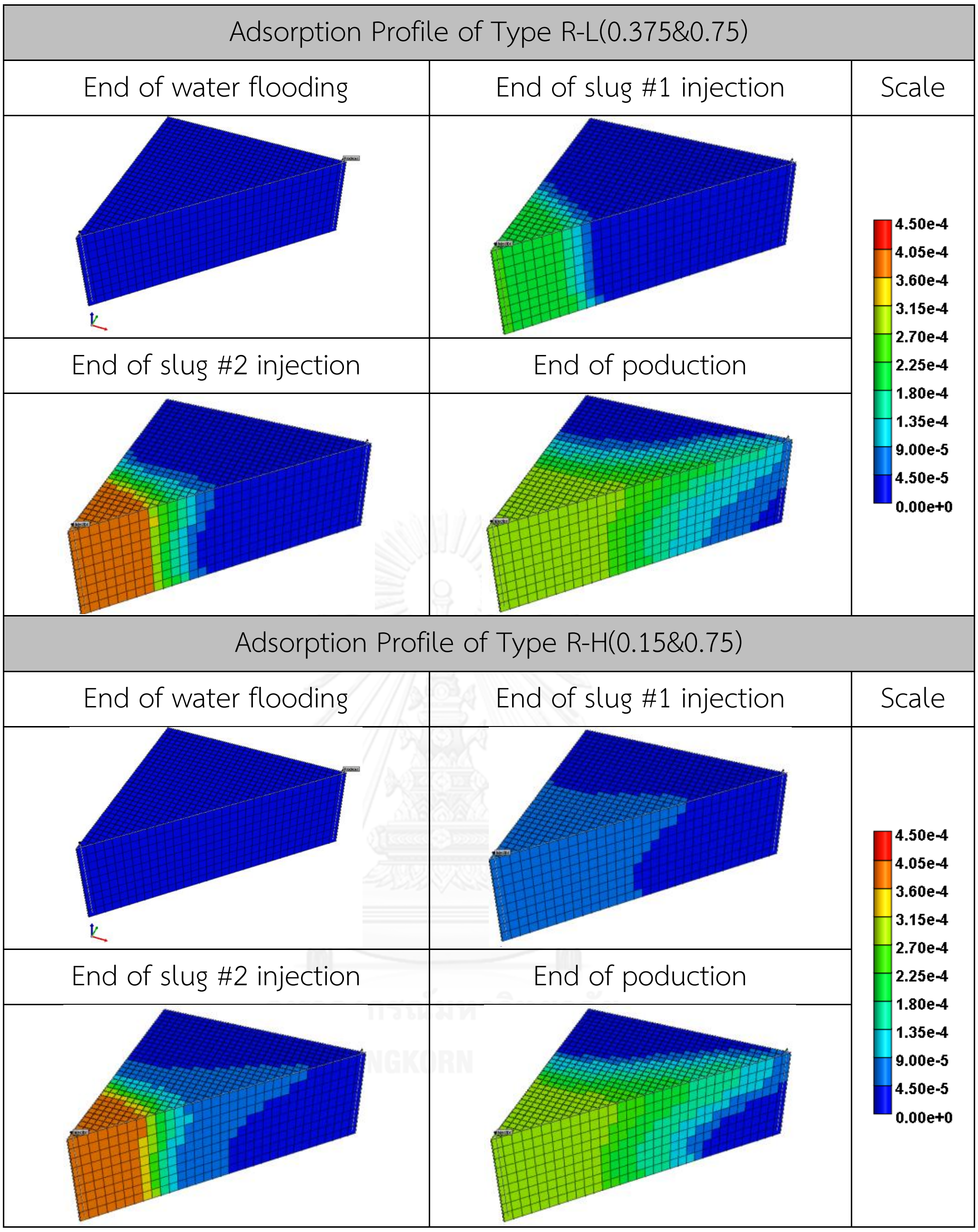


Figure 5.41: Adsorption profiles at four different periods of Type R-L (0.375&0.75) and Type R-H (0.15&0.75) injection strategy (0.75 wt.% base and equivalent mass between two slugs) implemented at water breakthrough with injection rate of 500 bbl/day

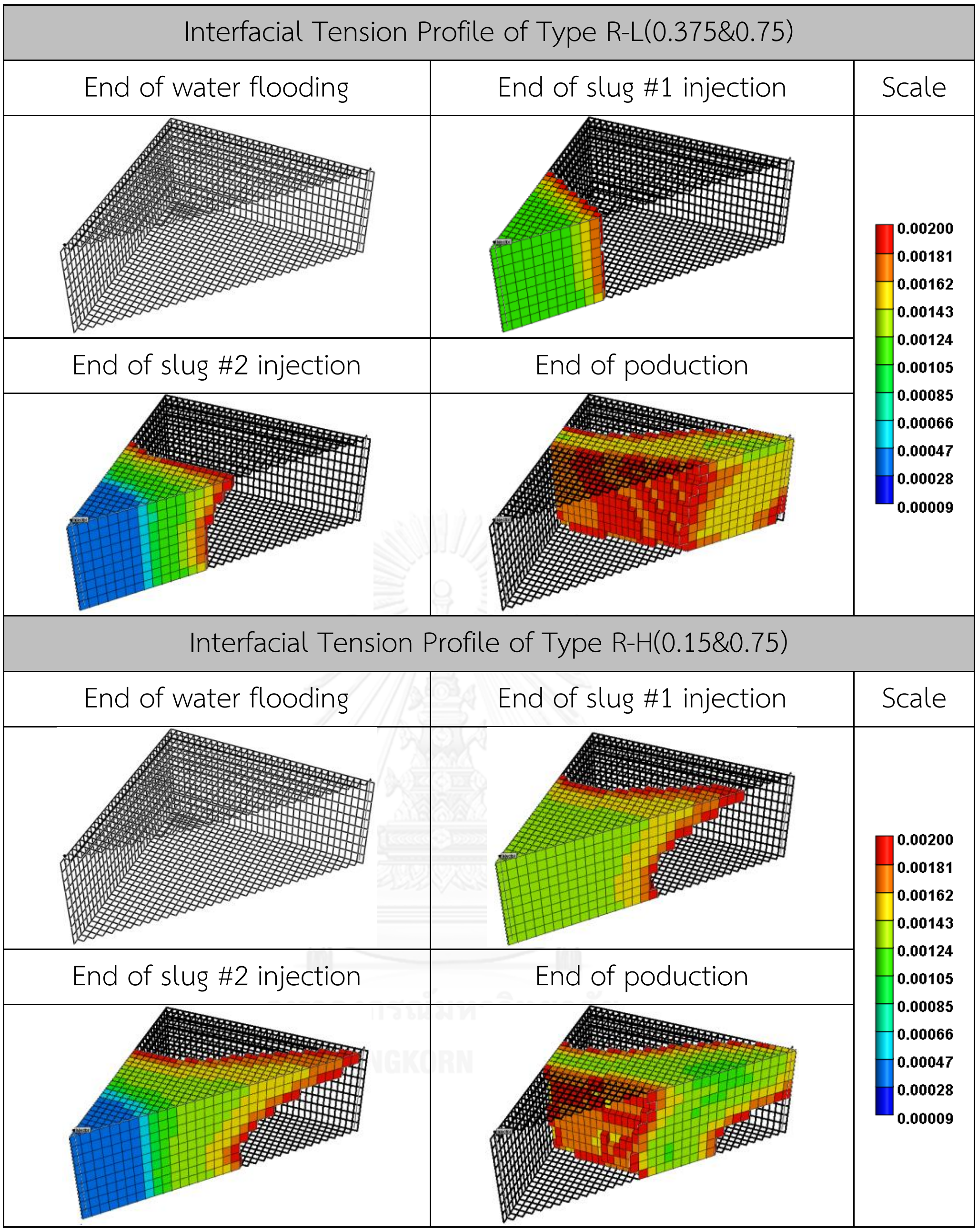


Figure 5.42: Interfacial tension profiles at four different periods of Type R-L (0.375&0.75) and Type R-H (0.15&0.75) injection strategy (0.75 wt.% base and equivalent mass between two slugs) implemented at water breakthrough with injection rate of 500 bbl/day

In case of mass ratio at 80:20, Type R-L injection strategy is better than single-slug surfactant flooding and other types of injection strategy because there is the effect of sacrificial surfactant which allow surfactant monomers in slug #2 be able to move further, and therefore lower IFT condition could be maintained for longer period. As can be seen in Figure 5.43, Type R-L injection strategy can maintain lower IFT condition (dark green area) at larger area when compared to other types of injection strategies as well as single-slug injection, as shown in Figure 5.44. As a result of prolonged lower IFT condition, Type R-L injection strategy could extend the production period longer than other types of injection sequence, which leads to higher oil recovery. Figure 5.45 shows oil production rate for the four types of injection strategy compared to 0.75 wt.% concentration single-slug injection.

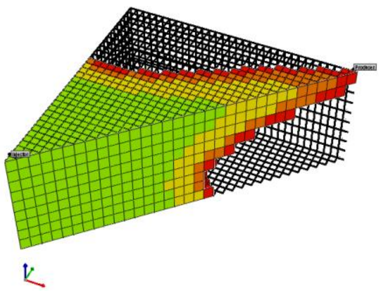
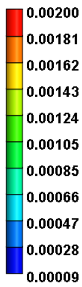
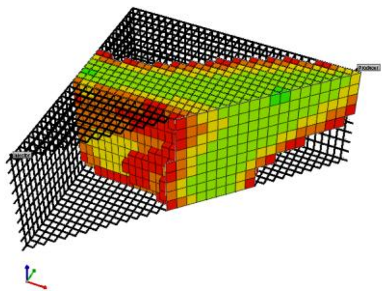
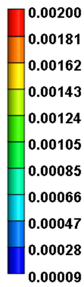
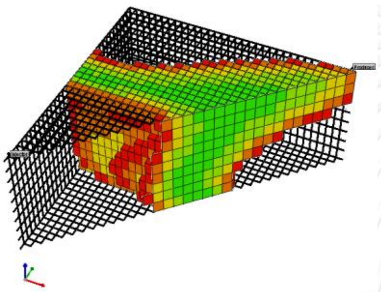
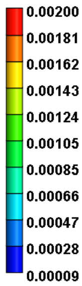
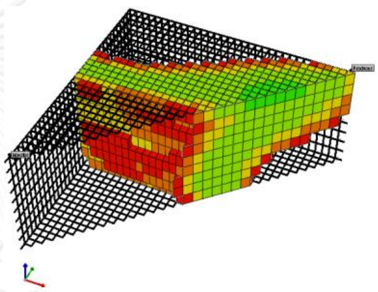
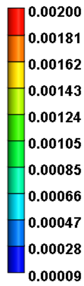
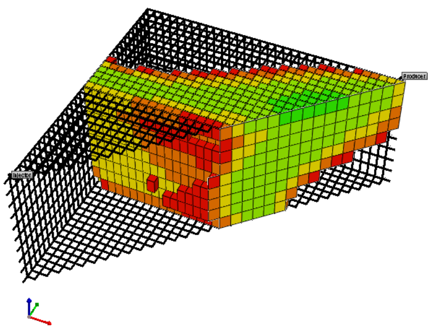
Interfacial Tension Profile			
R-H(0.15&0.75)	Scale	A-H(0.75&0.15)	Scale
			
R-L(0.375&0.75)	Scale	A-L(0.75&0.375)	Scale
			

Figure 5.43: Interfacial tension profiles of four different injections strategy (0.75 wt.% base and mass ratio of 80:20) implemented at water breakthrough with injection rate of 500 bbl/day (Profiles are taken during chasing waterflooding period)



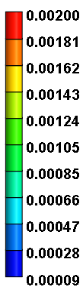


Figure 5.44: Interfacial tension profile of 0.75 wt.% concentration single-slug surfactant injection implemented at water breakthrough with injection rate of 500 bbl/day (Profile is taken during chasing waterflooding period)

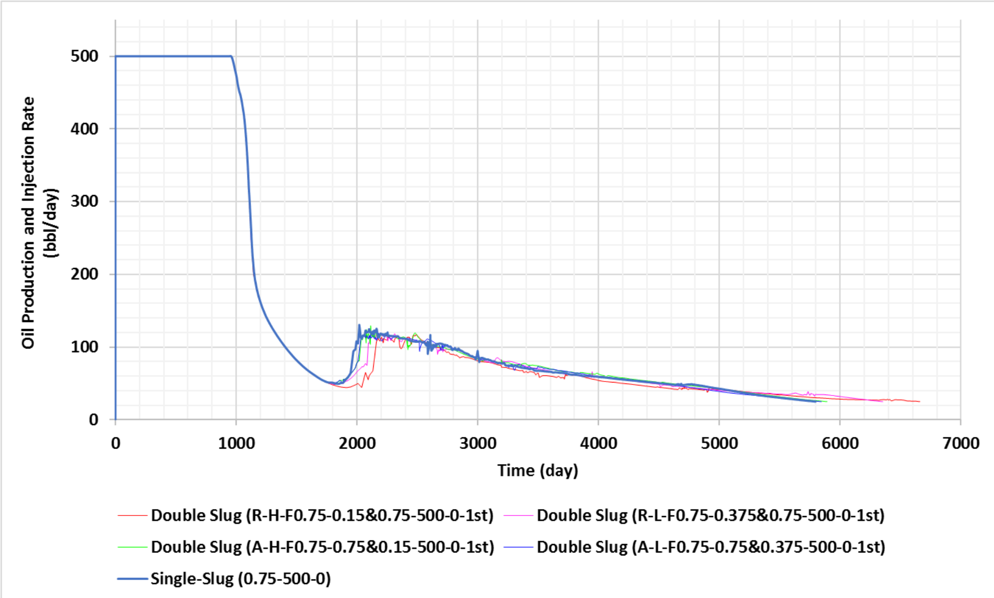


Figure 5.45: Oil production rates of four different injections strategy (0.75 wt.% base and mass ratio of 80:20) implemented at water breakthrough with injection rate of 500 bbl/day

The reason that Type A injection strategy shows better oil recovery than single-slug surfactant flooding is because it could maintain longer condition of lower IFT. Even though, the area at which the lowest IFT condition could be reached is larger for the case of single-slug surfactant, as illustrated in Figure 5.46 and Figure 5.47, at later time, two-slug surfactant flooding with Type A injection strategy could maintain the area of lower IFT condition larger than the case of single-slug surfactant flooding.

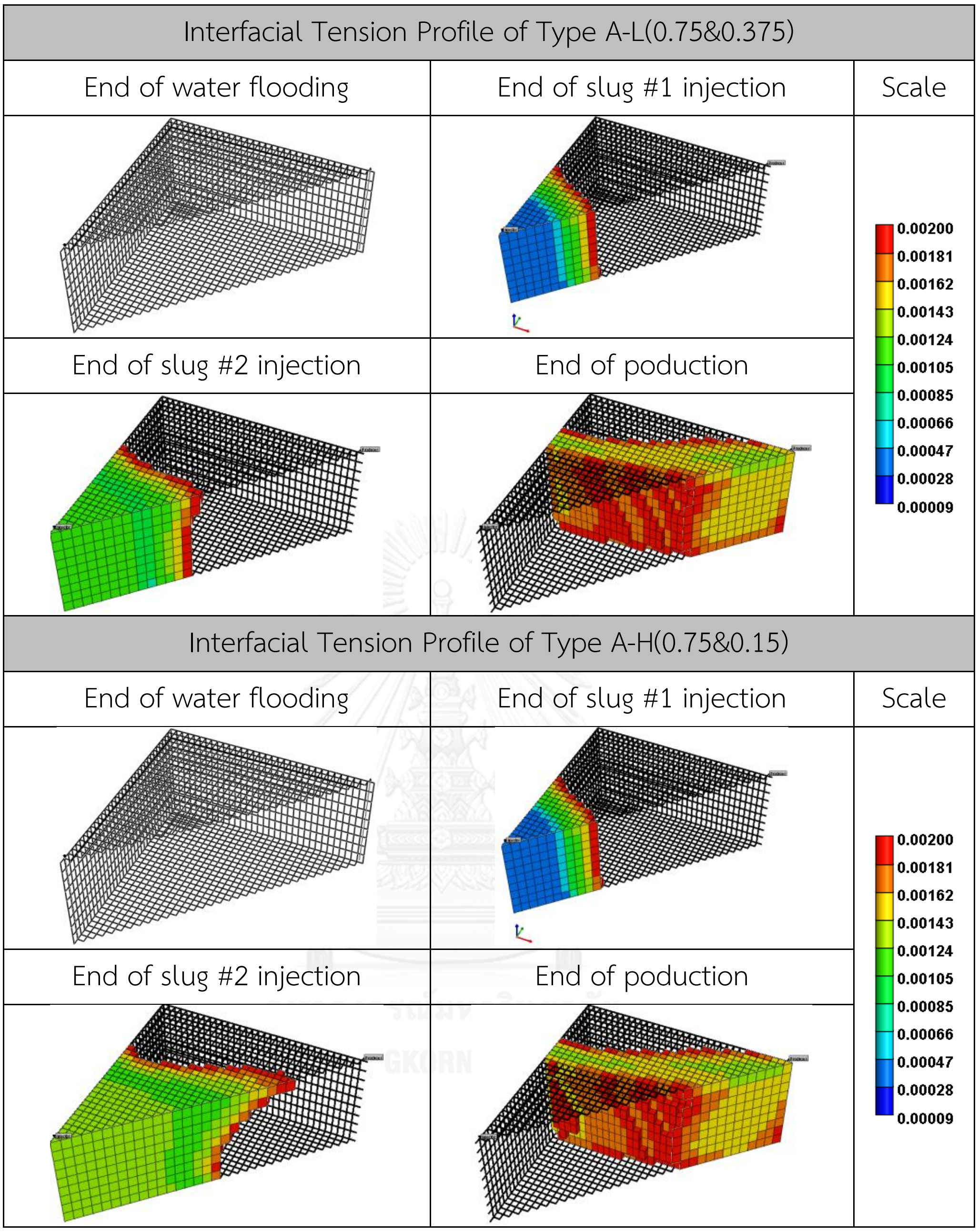


Figure 5.46: Interfacial tension profiles at four different periods of Type A-L (0.75&0.375) and Type A-H (0.75&0.15) injection strategy (0.75 wt.% base and mass ratio of 80:20) implemented at water breakthrough with injection rate of 500 bbl/day

<table>
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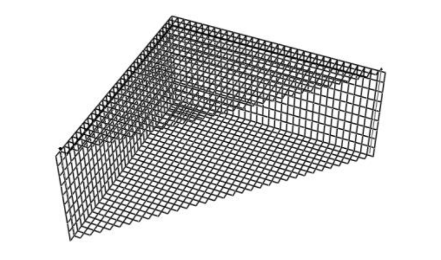
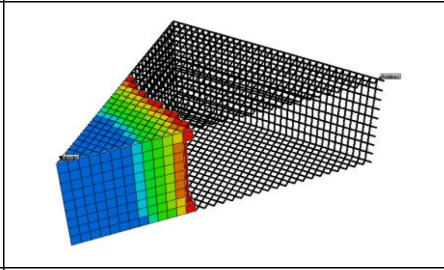
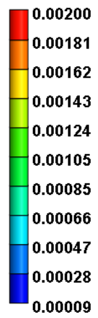
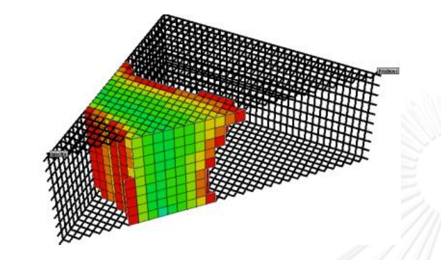
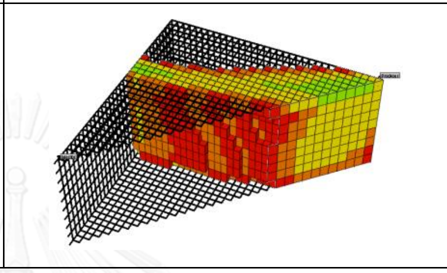
<tr><td></td><td></td><td rowspan="3"></td></tr>
<tr><td>During chasing waterflooding</td><td>End of production</td></tr>
<tr><td></td><td></td></tr>
</table>

Figure 5.47: Interfacial tension profiles at four different periods of 0.75 wt.% concentration single-slug surfactant injection implemented at water breakthrough with injection rate of 500 bbl/day

In case of mass ratio at 20:80, Type R-H is better because there are sacrificial surfactants that are adsorbed onto rock surface, which alleviates the degree of adsorption of the second slug. This allows larger area of the lowest IFT to be established. For single-slug surfactant flooding, the lowest IFT area could be reached up to only 7 blocks. However, for Type R-L and Type R-H injection sequence, the lowest IFT condition area could reach up to 8 blocks and 9 blocks, respectively. This can be observed in Figure 5.48 and Figure 5.49.

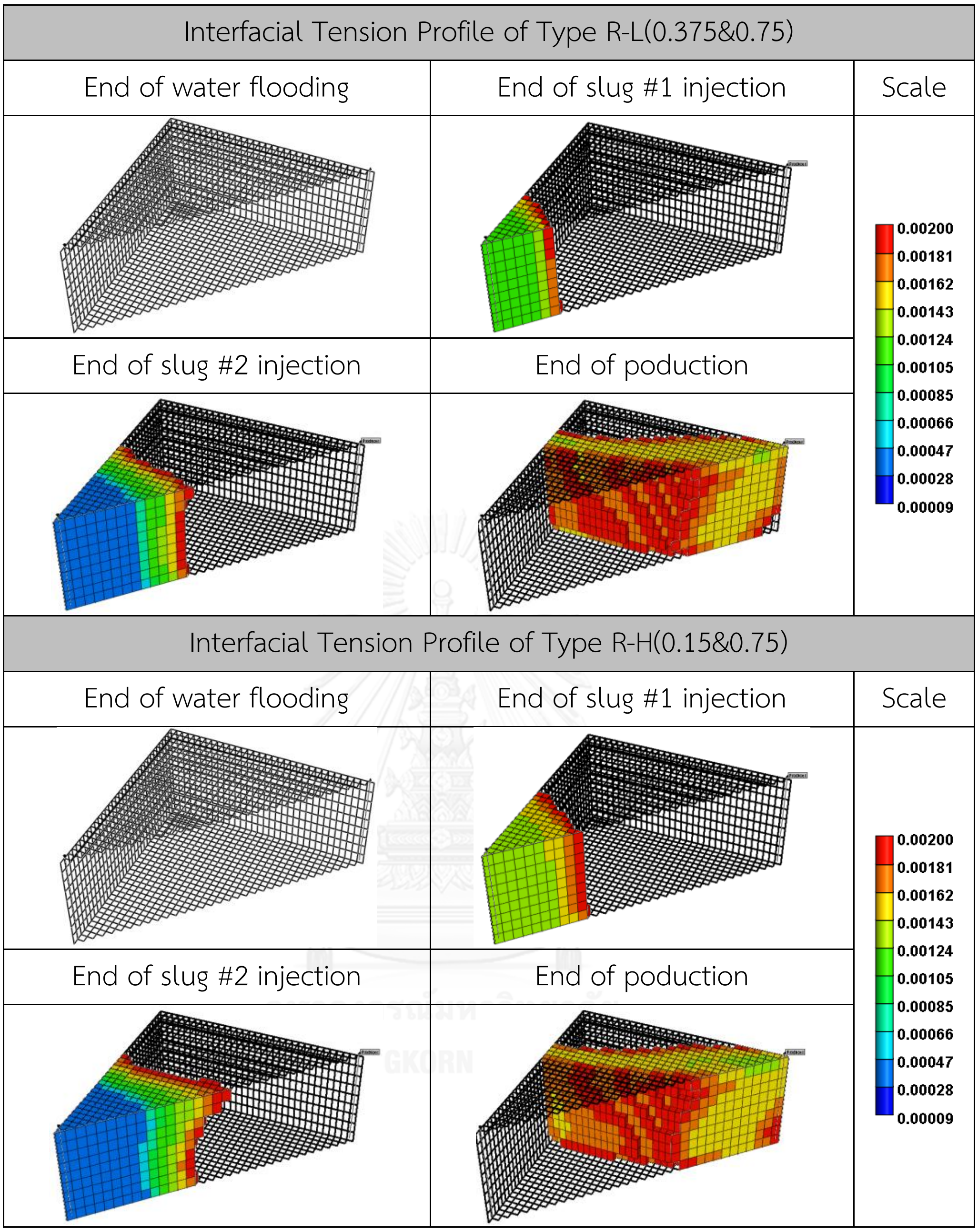


Figure 5.48: Interfacial tension profiles at four different periods of Type R-L(0.375&0.75) and Type R-H(0.15&0.75) injection strategy (0.75 wt.% base and mass ratio of 20:80) implemented at water breakthrough with injection rate of 500 bbl/day

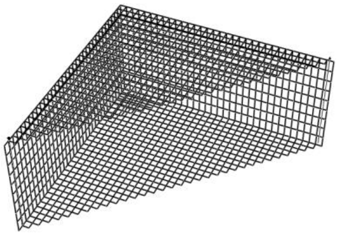
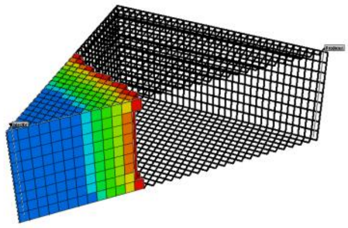
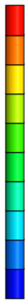
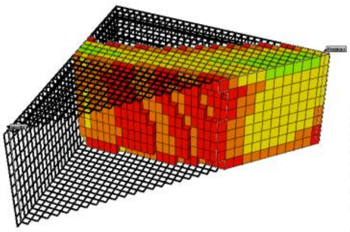
<table>
<tr><th colspan="3">Interfacial Tension Profile</th></tr>
<tr><td>End of water flooding</td><td>End of surfactant injection</td><td>Scale</td></tr>
<tr><td></td><td></td><td rowspan="3">
</td></tr>
<tr><td>End of production</td><td></td></tr>
<tr><td></td><td></td></tr>
</table>

Figure 5.49: Interfacial tension profiles at three different periods of 0.75 wt.% concentration single-slug surfactant injection implemented at water breakthrough with injection rate of 500 bbl/day

5.3.3 Two-slug Surfactant Flooding based on 0.5 wt.% Single-Slug

At low surfactant concentration (0.5wt%), the recommendation of which injection strategy should be performed can be separated very clearly by mass ratio. For mass ratio of 80:20, it is recommended to perform Type A injection strategy. Whereas, for mass ratio of 20:80, Type R injection strategy is more preferable. This indicates that majority of surfactant mass should be put in the slug with highest concentration when performing two-slug surfactant flooding with 0.5 wt.% single-slug as a base. This is because slug solution concentration of 0.1 wt.% and 0.25 wt.% may be too low to create low enough IFT condition. Though, surfactant monomers in these two concentrations can serve as sacrificial agent, which enhance 0.5 wt.% slug solution to generate low IFT condition. For this reason, the key player in reducing IFT value here is 0.5 wt.% slug solution. Note that slug solution concentration of 0.5 wt.% has concentration not as high as in case of 1.0 wt.% and 0.75 wt.%. Therefore, the magnitude of is also lower.

The magnitude of adsorption for 0.5 wt.% is found to be below the residual adsorption in this study. Therefore, regardless of injection strategy, no effect of desorption has been observed at this concentration. Hence, at mass ratio of 80:20, the reason why Type A-H injection strategy shows better improvement over single-slug surfactant flooding is mainly due to lower loss of surfactant monomers from adsorption and therefore wider area of adsorption (orange color) is observed, as illustrated in Figure 5.50. As a result, this prolongs plateau rate of oil production of Type A-H injection strategy to be longer than the case of single-slug surfactant injection. This leads the production period of Type A-H injection strategy to be nine months longer than single-slug surfactant injection. On the other hand, Type R-L injection strategy also shows better oil recovery improvement over single-slug surfactant flooding. This is due to the effects of sacrificial surfactant monomer from the lower concentration of the slug #1. Hence, when high concentration of the slug #2 enters, lesser amount of surfactant monomers is adsorbed. However, the improvement is not as much as Type A-H injection strategy because majority of surfactant mass is in the low concertation slug. However, at high injection (1,000 bbl/day), Type A-L injection strategy is more preferable. This could possibly be because at high flowrate the adsorption magnitude of 0.25 wt.% is reduced and therefore lower IFT could be reached by the greater amount of unabsorbed surfactant monomer in 0.25 wt.% slug solution.

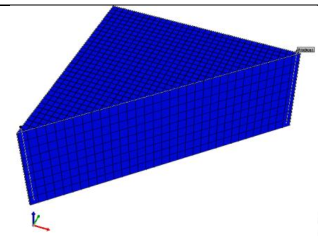
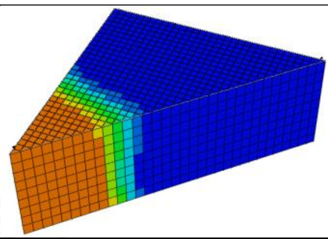
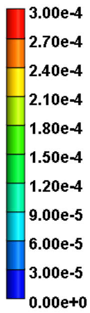
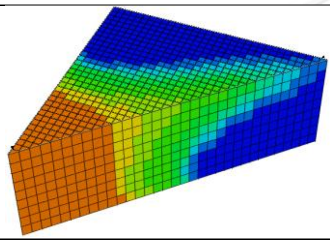
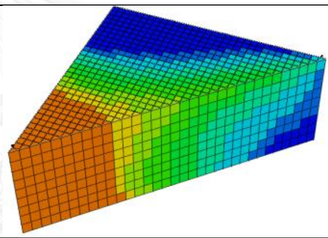
Adsorption Profile of Type A-H(0.5&0.1)		
End of water flooding	End of slug #1 injection	Scale
		
End of slug #2 injection	End of poduction	
		

Figure 5.50: Adsorption profiles at four different periods of Type A-H(0.5&0.1) injection strategy (0.5 wt.% base and mass ratio of 80:20) implemented at water breakthrough with injection rate of 500 bbl/day

At mass ratio of 20:80, the same principle is followed. As can be seen in Table 5.15, Type A injection strategy show lowest improvement of oil recovery compared to other type of injection strategy in two-slug mode at the same operating condition. Here, the benefit of sacrificial adsorption can be seen clearly. Greater amount of surfactant monomers is unabsorbed and could thoroughly reach out the reservoir in larger area. Hence, low IFT condition could be maintained for a longer period of time. This phenomenon can be observed in Figure 5.51 to Figure 5.52, which illustrate the adsorption profile and IFT profile at different periods in Type R-H injection strategy compared to single-slug surfactant injection. This result further support that 0.5 wt.% slug solution is still a key play and that the majority of surfactant mass should be located in highest concentration when performing two-slug surfactant flooding with

0.5 wt.% single-slug as a base. At the mass ratio of 50:50, there is no favor in amount of surfactant. Therefore, in order to see the improvement of oil recovery over single-slug surfactant flooding, concentration of the slug #1 and #2 should be similar. This is maintained longer period of lowest IFT condition.

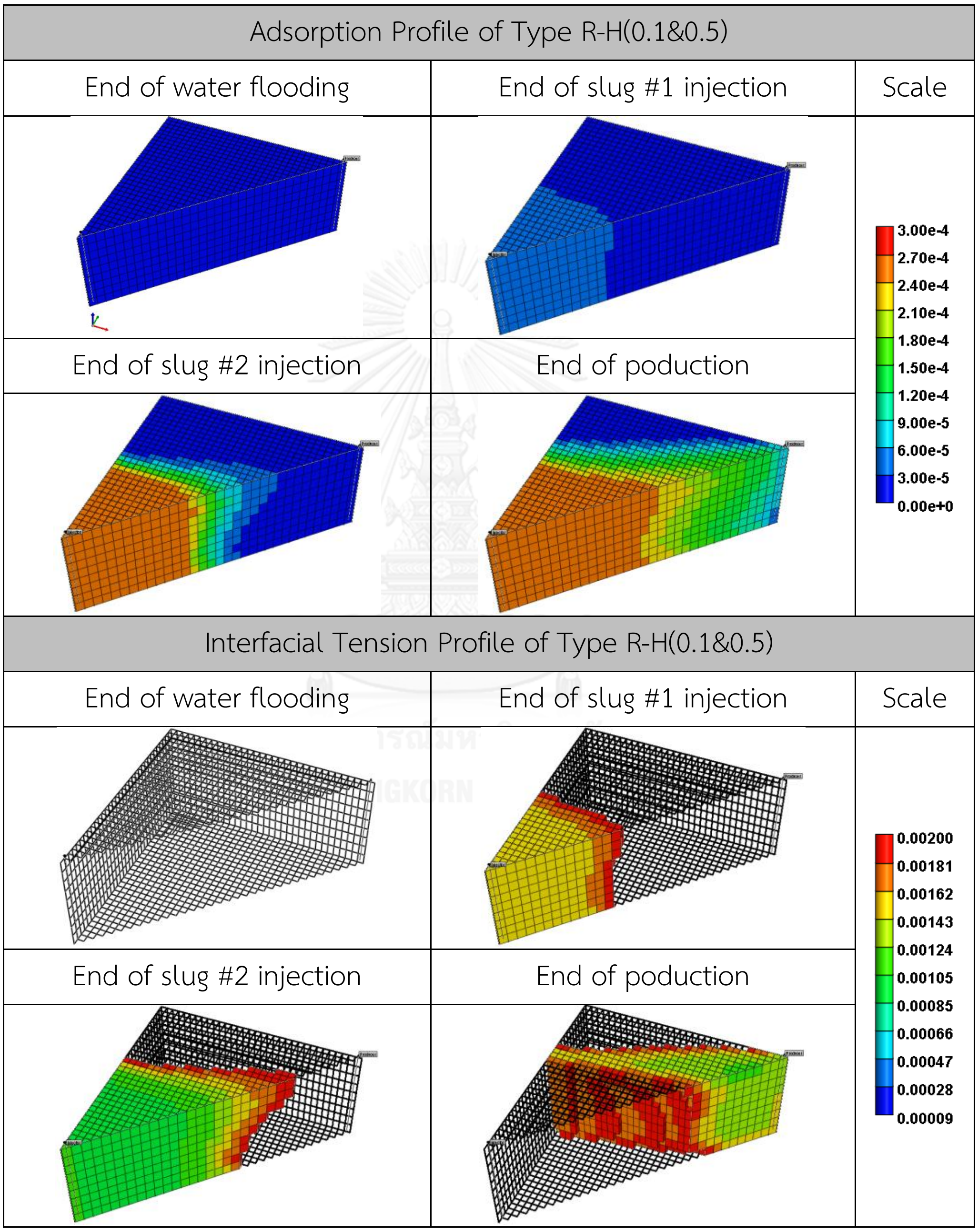


Figure 5.51: Adsorption profiles and interfacial tension profiles at four different periods of Type R-H(0.1&0.5) injection strategy (0.75 wt.% bas and mass ratio of 20:80) implemented at 25% watercut with injection rate of 1,000 bbl/day

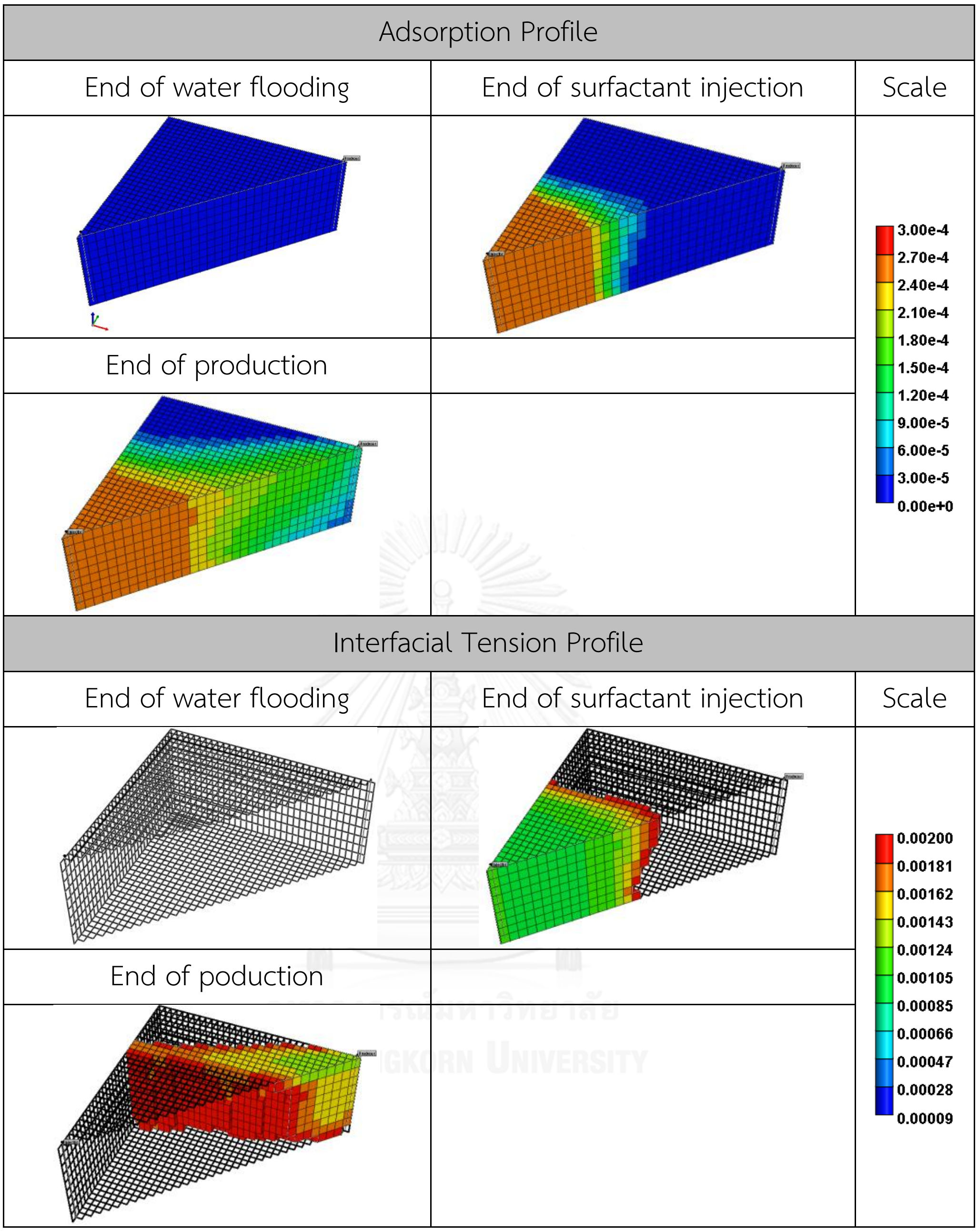


Figure 5.52: Adsorption profiles and interfacial tension profiles at three different periods of 0.5 wt.% concentration single-slug surfactant injection implemented at 25% watercut with 1,000 bbl/day

5.4 Three-slug Surfactant Flooding

In this section, two-slug surfactant solution is further divided into three-slug with different surfactant concentrations and mass ratios. However, other operating conditions, such as surfactant injection rate and time of implementation, are kept constant as the selected case to avoid other effects that may cause difficulty in interpretation.

Note that the case with high injection rate (1,000 bbl/d) for each surfactant concentration results in the highest oil recovery factor for the case of single-slug surfactant flooding. Therefore, in this section, cases from two-slug surfactant flooding that are selected to perform three-slug surfactant flooding are chosen from the case which yields the highest improvement of oil recovery at the condition of high inject rate. Slug concentration of the middle slug is set to be at half value between the concentration of the front slug and back slug. This is to keep the direction of slug concentration magnitude to be corresponding to the selected two-slug case. The mass ratio of the middle slug is taken from front slug for 20% and back slug for 20% in order to have consistence mass of middle slug. The middle slug solution is located in between front slug and back slug. Table 5.17 summarizes condition of three-slug surfactant flooding cases and illustrates the condition of two-slug cases that are chosen to be modified.

Table 5.17: Three-slug surfactant flooding cases setting

Single-Slug Concentration	Parameters	Two-slug Selected Cases	Three-slug Cases
For 1.0 wt.%	Injection Type	Type R-L(0.5&1.0)	(0.5&0.75&1.0) wt.%
	Mass Ratio	80:20	64:20:16
	Injection Rate	1,000	1,000
	Surfactant Implementation	At Water Breakthrough	At Water Breakthrough
For 0.75 wt.%	Injection Type	Type R-L(0.375&0.75)	(0.375&0.5625&0.75) wt.%
	Mass Ratio	50:50	40:20:40
	Injection Rate	1,000	1,000
	Surfactant Implementation	At Water Breakthrough	At Water Breakthrough
For 0.5 wt.%	Injection Type	Type A-L(0.5&0.25)	(0.5&0.375&0.25) wt.%
	Mass Ratio	80:20	64:20:16
	Injection Rate	1,000	1,000
	Surfactant Implementation	25	25

After running simulation, the simulated results of three-slug, for any single-slug concentration as a base case, do not show benefit over two-slug surfactant injection in term of oil recovery, yet the differences between the two types of injection are small even though performing three-slug surfactant flooding still give better results than performing single-slug surfactant flooding. Figure 5.53 shows the comparison of oil recovery factor between three different injection strategies (three-slug, two-slug, and single-slug) at different single-slug concentration base cases.

Improvement in oil recovery of three-slug surfactant flooding over single-slug surfactant flooding follows the same principle as in case of two-slug surfactant flooding. Therefore, three-slug surfactant flooding shows improvement in oil recovery as in two-slug surfactant flooding. However, the reason why three-slug surfactant flooding yields lower oil recovery than the case of two-slug surfactant flooding is because part of the surfactant mass has been taken from the highest concentration slug, causing the reduction in slug size of key component in generating the lowest IFT condition. Therefore, period at which low IFT condition could be maintained is slightly shorter than the case of two-slug injection. Hence, the results show slightly lower amount of oil recovery.

Table 5.18: Oil recovery factors of each injection

	Oil Recovery Factor (%)		
	Three-slug Surfactant Injection	Two-slug Surfactant Injection	Single-Slug Surfactant Injection
For 0.5 wt.%	77.94	78.01	77.13
For 0.75 wt.%	77.31	77.82	77.05
For 1.0 wt.%	77.54	78.30	77.47

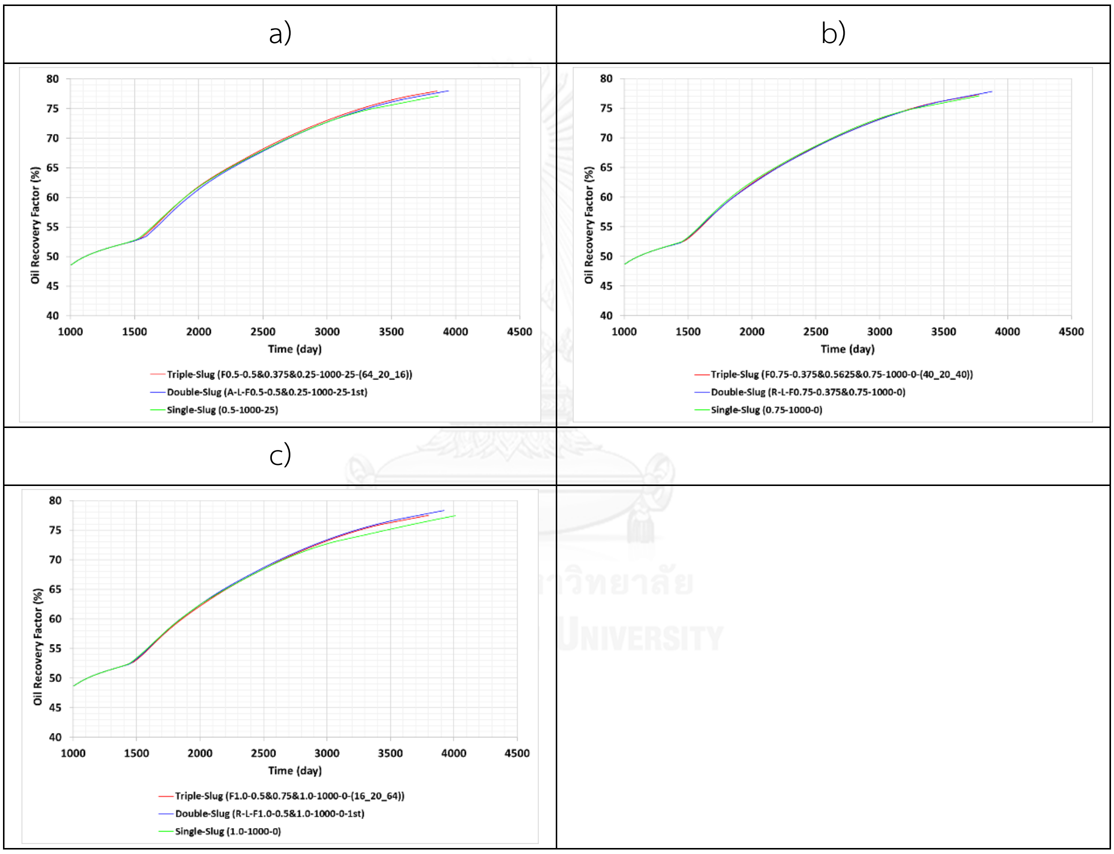


Figure 5.53: Oil recovery factors as a function of time at three different injection strategies (three-slug, two-slug, single-slug) for different base case concentration a) for0.5 wt.% as a single-slug base case concentration, b) for 0.75 wt.% as a single-slug base case concentration, c) for 1.0 wt.% as a single-slug base case concentration

5.5 Effects of Reservoir Properties Related to Relative Permeability Curves

In this section, effects of reservoir properties related to relative permeability curves on effectiveness of surfactant flooding with the selected injection strategy are determined. The properties that have been investigated include endpoint water saturation and endpoint relative permeability to oil.

For the investigation of endpoint water saturation, the values of relative permeability at irreducible water saturation for the first four interpolation sets are shifted from 20% to 15%. This is to investigate the effectiveness of the surfactant flooding process when the reservoir contains higher volume of displaceable oil. Figure 5.54 shows modified relative permeability curves for different interpolation sets as a function of water saturation.

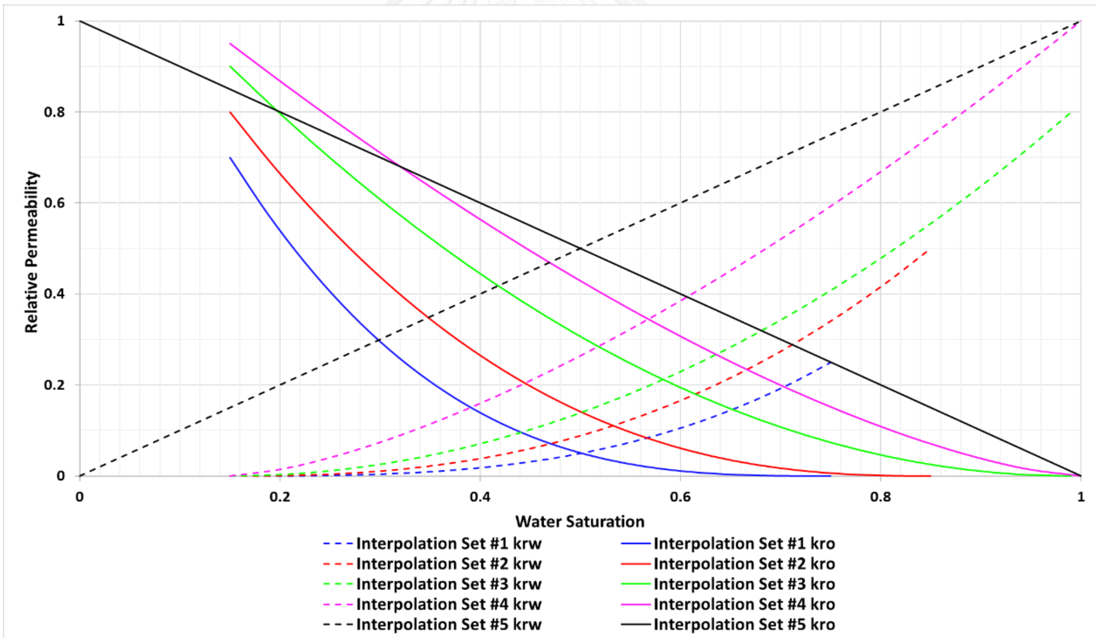


Figure 5.54: Modified irreducible water saturation endpoint of relative permeability curves at value of 0.15 for different interpolation sets as a function of water saturation

According to the result, changes in endpoint water saturation show no effects on injectivity of injected fluid, as indicated by overlapping curves of water injected cumulative. This is because there is no alternation in term of flow ability. However, since the displaceable volume of oil in the system has been altered, shifting of oil recovery can be observed and can be divided into two periods, which are period of waterflooding process and period of surfactant flooding. It is important to note that only relative permeability curve of Set 1 is being used during waterflooding period. At the period of waterflooding process, oil recovery factor of modified shows lower value than unmodified case, even though cumulative oil productions are the same in both cases. This is due to great amount of OOIP in modified case from the reduction in irreducible water saturation. During surfactant flooding process, oil recovery of modified irreducible water saturation slightly exceeds unmodified case. This is because greater amount of residual oil can be recovered by surfactant agents in modified irreducible water saturation case; hence, there is more displaceable oil to be produced. Moreover, at late time when there is high water saturation, there is no modification in relative permeability; hence, flow ability inside the system behaves similar to the unmodified case. Figure 5.55 and Figure 5.56 compare oil recovery factors, cumulative water injection, and cumulative oil production curves of modified and unmodified endpoint water saturation for single-slug and two-slug surfactant flooding.

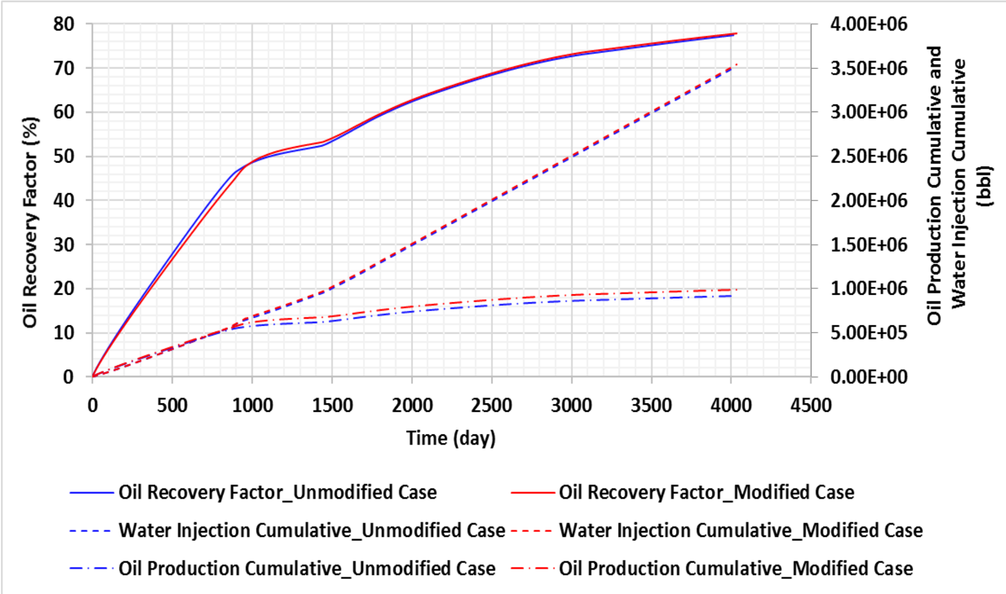


Figure 5.55: Oil recovery factor, cumulative water injection, and cumulative oil production curve as a function of time of modified endpoint water saturation case compared to unmodified case for 1.0 wt.% single-slug surfactant flooding implemented at water breakthrough with injection rate of 1,000 bbl/day

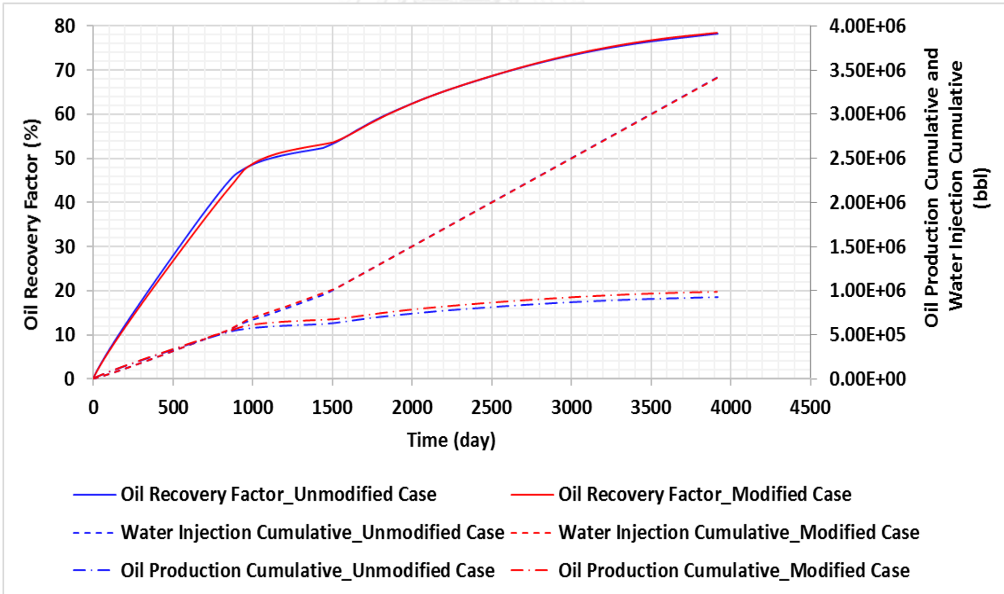


Figure 5.56: Oil recovery factor, cumulative water injection, and cumulative oil production curve as a function of time of modified endpoint water saturation case compared to unmodified case for Type R-L(0.5&1.0) two-slug surfactant flooding (1.0 wt.% as base and mass ratio of 80:20) implemented at water breakthrough with 1,000 bbl/day

For the investigation of endpoint relative permeability to oil, values of relative permeability to oil at connate water of interpolation Set 2 to Set 4 are set to be the same as in Set 1, which is at 70%. Variation in endpoint relative permeability is performed to determine effectiveness of surfactant flooding process when the reservoir has limited flow ability of oil. Figure 5.57 illustrates the modified relative permeability curves for different interpolation sets as a function of time.

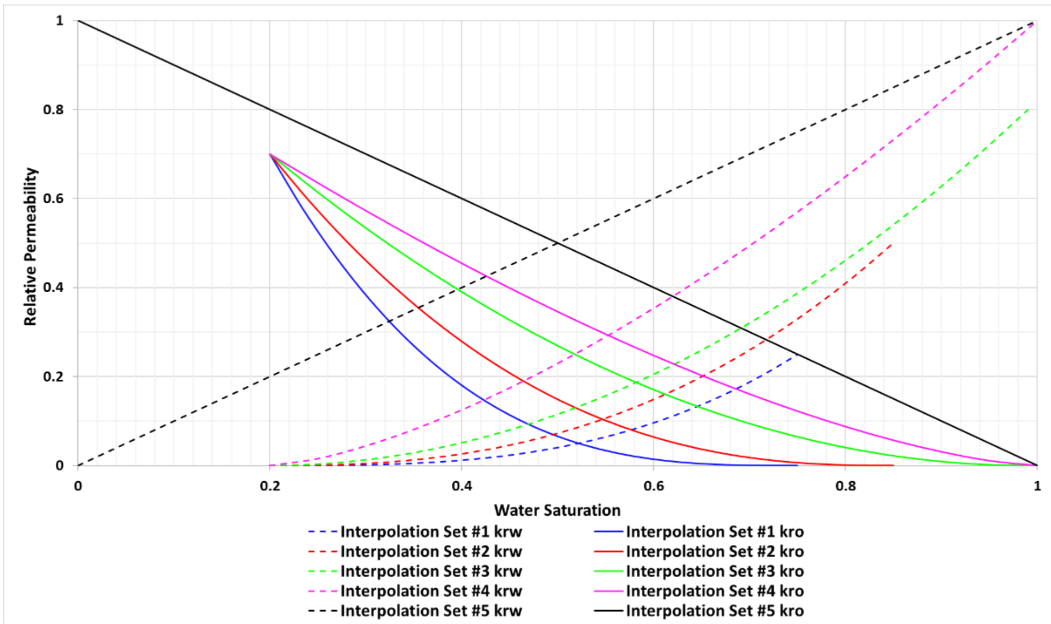


Figure 5.57: Modified endpoint of relative permeability to oil of relative permeability curves with fixed value of 0.7 for different interpolation sets as a function of water saturation

As a result, changes in endpoint relative permeability to oil show no effects on oil recovery and injectivity during waterflooding period. This is because during waterflooding period only relative permeability curve of Set 1 is being used for both modified endpoint relative permeability and unmodified cases. However, during period of surfactant injection, changes in endpoint relative permeability indicate significant effect on oil recovery and slight effect on injectivity, as shown in Figure 5.58 and Figure 5.59. This is because during surfactant flooding the system is shifted from one to another interpolation set; hence, the reduction in endpoint relative permeability leads to lower flow ability of oil during lower water saturation. As a result, larger amount of oil remains unrecovered. Moreover, high saturation of oil impedes flow ability of injected surfactant solution.

Hence, it can be concluded in this section that changes in endpoint relative permeability to oil is more sensitive to the performance of surfactant flooding with various injection strategies when compared to changes in endpoint irreducible water saturation.

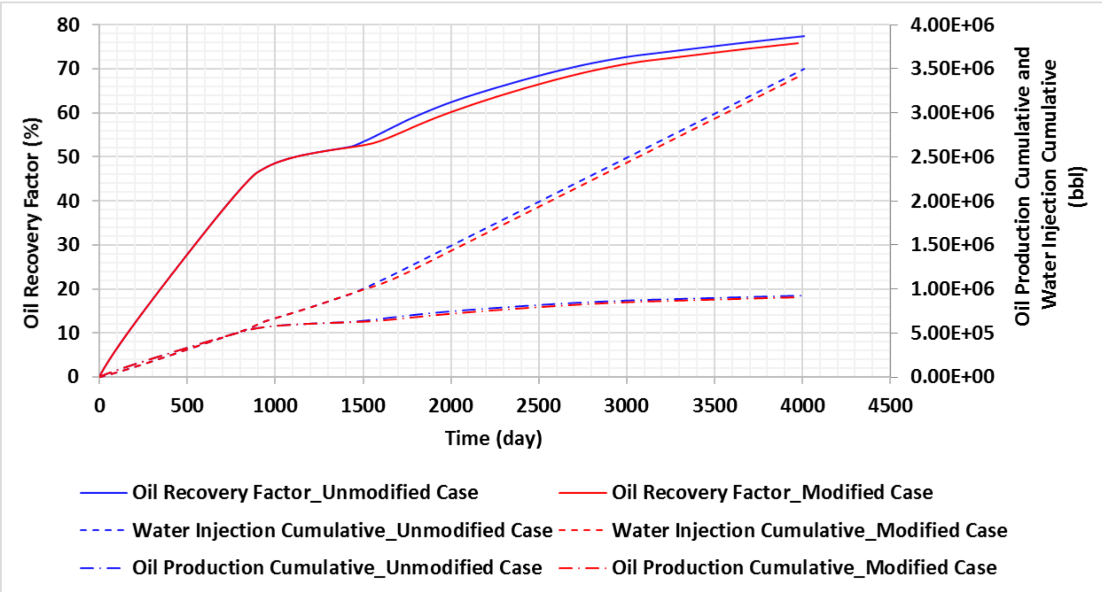


Figure 5.58: Oil recovery factor, cumulative water injection, and cumulative oil production curve as a function of time of modified endpoint relative permeability to oil case compared to unmodified case for 1.0 wt.% single-slug surfactant flooding implemented at water breakthrough with injection rate of 1,000 bbl/day

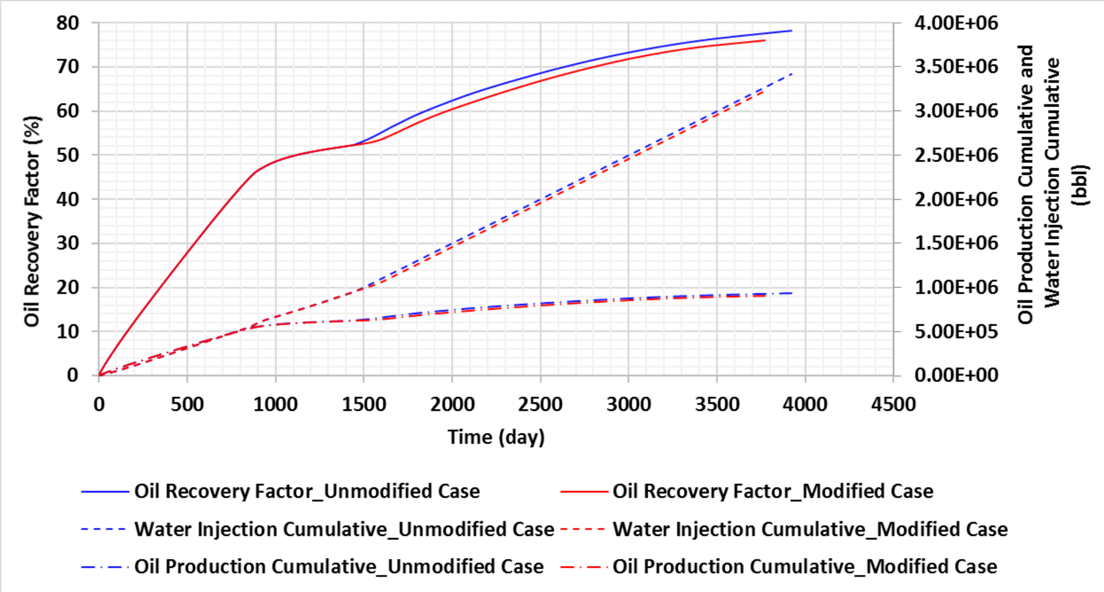


Figure 5.59: Oil recovery factors, cumulative water injection, and cumulative oil production curve as a function of time of modified endpoint relative permeability to oil case compared to unmodified case for Type R-L(0.5&1.0) two-slug surfactant flooding (1.0 wt.% as base case and mass ratio of 80:20) implemented at water breakthrough with 1,000 bbl/day

Chapter 6

CONCLUSIONS AND RECOMMENDATIONS

This chapter summarizes important points that have been observed in this study. This includes effects of operating parameters as well as type of slug injection strategies in multi-slug grading mode. These observations serve as a guideline for selecting suitable injection strategy in surfactant flooding process with multi-slug concentration grading at fixed surfactant mass. In addition, this chapter also provides several recommendations for future studies.

6.1 Conclusions

According to the observations in Chapter 5, the following conclusions are made:

1. According to the variation in surfactant slug concentration during single-slug surfactant flooding, surfactant slug concentration does not show significant effect on final oil recovery, but shows slight effects on rate of change of oil recovery and oil production rate.
2. For both single-slug and two-slug surfactant flooding, final oil recovery as well as the rate of recovering increase as surfactant injection rate is increased because of lower retention time that leads to lower surfactant adsorption.
3. Based on the investigation on time to implement surfactant flooding, commencing surfactant flooding process at higher watercut only results in a delay in oil recovery while final oil recovery is as same as commencing at other watercut values.
4. In two-slug surfactant flooding, there are two main mechanisms which two-slug surfactant flooding undergo to yield higher oil recovery than single-slug surfactant flooding. The first mechanism is related to sacrificial adsorption of the first-slug surfactant monomers. The second mechanism is related to description of retained surfactant monomers.

5. The mechanism at which system undergoes would depend on the influence three main parameters including surfactant injection rate, surfactant slug concentration, and surfactant mass ratio.
6. Selection of two-slug surfactant flooding injection strategy type (reduction in first slug concentration or Type R and reduction in second slug concentration or Type A) depends on concentration of reference single-slug, which is chosen to be modified. At high (1.0 wt.%) and middle (0.75 wt.%) concentrations, Type R injection strategy is preferred due to lower adsorption; whereas, at low (0.5 wt.%) concentration, type of injection strategy is clearly separated by mass ratio.
7. At high (1.0 wt.%) concentration and middle (0.75 wt.%) concentration, selection of two-slug surfactant flooding design (high contrast between each slug or Type R-H and A-H and low contrast between each slug or Type R-L and A-L depends on the chosen mass ratio. At 20:80 mass ratio, Type R-H injection strategy is preferred due to benefit of larger area of sacrificial adsorption allows establishment of larger area of the lowest IFT condition. At 80:20 Type R-L injection strategy is preferred due to greater amount of surfactant remains in the first slug, and therefore concentration of the first slug should not be too low or else adequate IFT condition could not be established.
8. At low (0.5 wt.%) concentration, selection of two-slug surfactant flooding injection strategy type (Type R or Type A) is differentiated by mass ratio. For mass ratio of 80:20, Type A injection strategy is recommended; whereas, Type R injection strategy is preferred for mass ratio of 20:80. This indicates that majority of surfactant mass should be put in the slug with higher concentration when performing two-slug surfactant flooding based on 0.5 wt.% single-slug.
9. Modification of two-slug into three-slug does not show benefit over two-slug surfactant injection in term of oil recovery for this specific setting, yet the differences between two types of injection are small. However, performing three-slug surfactant flooding still gives better results than performing single-slug surfactant flooding.

10. Two reservoir properties related to relative permeability curves, which are endpoint water saturation an endpoint relative permeability to oil, are investigated. According the results, changes in endpoint relative permeability to oil is more sensitive to the performance of surfactant flooding when compared to changes in endpoint water saturation.

6.2 Recommendations

This section provides recommendations and suggestions for future studies related modification of surfactant slug injection strategies in waterflooded reservoir.

1. Laboratory experiment on IFT, adsorption, desorption and relative permeability curves should be performed in order to obtain more precise result from the reservoir simulation.
2. Coreflood test on surfactant flooding with two-slug injection strategy should be performed comparing with single-slug injection strategy to determine the feasibility of the process.
3. Benefits of three-slug surfactant flooding should be further investigated.

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APPENDIX

APPENDIX A
CMG RESERVOIR SIMULATION MODEL CONSTRUCTION IN DETAIL

STARS reservoir simulation program, commercialized by Computer Modeling Group (CMG), is employed in this study to investigate the results. In order to create a base case reservoir model, required data are needed to be input into six main sections as followed: 1) reservoir properties, pressure-volume-temperature (PVT) properties, rock-fluid properties, and well & recurrent. All the numerical values used in this work are shown below.

Simulator Setting

Input Parameter	Value
Simulator	STARS
Working Units	Field
Porosity	Single porosity
Simulation start date	2000/01/01

1. Reservoir

1.1 Create Cartesian Grid

The reservoir is model is constructed by choosing “Create Cartesian Grid” wizard. The information used to construct the grid are listed below.

Input Parameter	Value	Unit
Grid Type	Cartesian	
K Direction	Down	
Number of Grid Blocks	33, 33, 9 (I, J, K, direction respectively)	Blocks
Block widths (I direction)	33×20	Ft
Block widths (J direction)	33×20	Ft

1.2 Array Properties

Input Parameter	Value	Unit
Grid Top at Layer 1	3,250	ft
Grid Thickness (whole grid)	12	ft
Porosity	0.2	fraction
Permeability I	100	mD
Permeability J (mD)	Equals I (equal)	mD
Permeability k (mD)	Equal I*0.1	mD
Water Mole Fraction	1	

2. Components

2.1 PVT Using Correlation

Input Parameter	Option	Value	Unit
Reservoir temperature		122	^oF
Generate data up to max. pressure of		5,000	psi
Bubble point pressure calculation	Generate from GOR value	264	SCF/STB
Oil density at STC (14.7 psia, 60^{o}F)	Stock tank oil gravity (API)	30	API
Gas density at STC (14.7 psia, 60^{o}F)	Gas gravity (Air = 1)	0.7	fraction
Oil properties (Bubble point, Rs, Bo) correlation	Standing*		
Oil compressibility correlation	Glaso*		
Dead oil viscosity correlation	Ng and Egbogah*		
Live oil viscosity correlation	Beggs and Robinson*		
Gas critical properties correlation	Standing*		
Set/Update Value of Reservoir Temperature, Fluid Densities in Dataset		✓	

*Refers to default of simulator

2.2 Water properties using correlation

Input Parameter	Value	Unit
Reservoir temperature (TRES)	122	°F
Reference pressure (REFPW)	1,400	psi
Water bubble point pressure	-	-
Water salinity	10,000	ppm
Undersaturated Co	1E-05	1/psi
Set/Update Value of Reservoir Temperature, Fluid Densities in Dataset	✓	

Note: Water bubble point pressure is left to be blank for the default value of water.

3. Rock-Fluid

The input parameter in this section is used as preliminary data before using Process Wizard for chemical flooding in Appendix B.

3.1 Rock Type Properties

Input Parameter	Value
Use Interpolation Sets	No
Rock wettability	Water wet
Method for evaluating 3-phase KRO	Stone’s second model

3.2 Relative Permeability

3.2.1 Relative Permeability Endpoint Input

Input Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.25
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.25
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.7
KRWIRO - Krw at Irreducible Oil	0.25
KRGCL - Krg at Connate Liquid	0.7
KROGCG - Krog at Connate Gas	-
Exponent for calculating Krw from KRWIRO	3
Exponent for calculating Krow from KROCW	3
Exponent for calculating Krog from KROGCG	3
Exponent for calculating Krg from KRGCL	3

3.2.2 Generated Relative Permeability Curve Data

Water-Oil Table

S_w	K_{rw}	K_{row}
0.2	0	0.7
0.234375	6.10352e-005	0.576782
0.26875	0.000488281	0.468945
0.303125	0.00164795	0.375464
0.3375	0.00390625	0.295312
0.371875	0.00762939	0.227466
0.40625	0.0131836	0.170898
0.440625	0.0209351	0.124585
0.475	0.03125	0.0875
0.509375	0.0444946	0.0586182
0.54375	0.0610352	0.0369141
0.578125	0.0812378	0.0213623
0.6125	0.105469	0.0109375
0.646875	0.134094	0.00461426
0.68125	0.16748	0.00136719
0.715625	0.205994	0.000170898
0.75	0.25	0

Liquid-Gas Table (Liquid Saturation)

S_l	K_{rg}	K_{rog}
0.2	0.7	0
0.3	0.455674	0
0.4	0.276059	0
0.434375	0.227466	0.000131635
0.46875	0.184938	0.00105308
0.503125	0.148072	0.00355415
0.5375	0.116463	0.00842466
0.571875	0.0897058	0.0164544
0.60625	0.0673973	0.0284332
0.640625	0.0491326	0.0451509
0.675	0.0345074	0.0673973
0.709375	0.0231173	0.0959621
0.74375	0.0145578	0.131635
0.778125	0.00842466	0.175207
0.8125	0.00431343	0.227466
0.846875	0.00181973	0.289203
0.88125	0.000539178	0.361207
0.915625	6.73973e-005	0.444269
0.95	0	0.539178
0.975	0	0.616095
1	0	0.7

4. Initial Condition

Input Parameter	Value	Unit
Vertical Equilibrium Calculation Methods	Depth-Average Capillary-Gravity Method	
Reference pressure (REFPW)	1,400	psi
Reference Depth (REFDEPTH)	3,250	ft
Water-Oil Contact Depth (DWOC)	3,358	ft

5. Numerical

Input Parameter	Value
First Time Step Size after Well Change (DTWELL)	0.001
Isothermal Option (ISOTHERM)	ON
Linear Solver Iteration (ITERMAX)	300

6. Wells and Recurrent

6.1 Date

Input Parameter	Value	Unit
Range of Date	241	months

6.2 Injection Well

6.2.1 Perforations

Input Parameter	Value	Unit
Radius	0.25	ft
Perforation start	1, 33, 1	
Perforation end	1, 33,9	

6.2.2 Well Events

ID & Type	Value
Name:	Injector
Type:	Injector Mobweight implicit

Constraint	Parameter	Limit/Mode	Value	Action
OPERATE	BHP bottom hole pressure	MAX	1,800 psi	CONT
OPERATE	STW surface water rate	MAX	Vary	CONT

6.3 Production Well

6.3.1 Perforations

Input Parameter	Value	Unit
Radius	0.25	ft
Perforation start	33, 1, 1	
Perforation end	33, 1, 9	

6.3.2 Well Events

ID & Type	Value
Name:	Producer
Type:	Producer

Constraint	Parameter	Limit/Mode	Value	Action
OPERATE	STL surface liquid rate	MAX	Vary	CONT
OPERATE	BHP bottomhole pressure	MIN	200 psi	CONT
MONITOR	WCUT water-cut		0.95	STOP
MONITOR	STO surface oil rate	MIN	25 bbl/day	STOP

APPENDIX B
CMG RESERVOIR SIMULATION MODEL CONSTRUCTION WITH SURFACTANT IN DETAIL

Surfactant model is constructed by Process Wizard in STARS simulation program. All the numerical values used in this work are shown below.

1. Process Wizard

1.1 Choose Process

Input Parameter	Value
Process	Alkaline, surfactant, foam, and/or polymer model
Model	Surfactant flood (add 1 component)

1.2 Input Specific Data

Input Parameter	Value	Unit
Use reversible partitioning of surfactant into oil	✓	
Use irreversible partitioning of surfactant into oil	×	
Number of relative perm. Sets for interpolation	5	sets
Use adsorption for surfactant	✓	
Rock type for conversion of adsorption values (gm rock to PV)	Sandstone	
Rock Density	2.65	gm/cm3

1.3 Component Selection

Input Parameter	Value
Add new component for surfactant	✓

1.4 Set Rock Fluid Regions

1.5 Set Interfacial Tension Values

Weight % Surfactant	Interfacial Tension (dyne/cm)
0	18.2
0.5	0.001
1	0.0001

1.6 Set Adsorption Values

Weight % Surfactant	Surfactant Adsorption (mg/100gm rock)
0	0
1	27.5

2. Rock-Fluid

2.1 Relative Permeability Endpoint Input of Interpolation Set 1

Input Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.25
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.25
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.7
KRWIRO - Krw at Irreducible Oil	0.25
KRGCL - Krg at Connate Liquid	0.7
KROGCG - Krog at Connate Gas	-
Exponent for calculating Krw from KRWIRO	3
Exponent for calculating Krow from KROCW	3
Exponent for calculating Krog from KROGCG	3
Exponent for calculating Krg from KRGCL	3

Interpolation Set Parameters	Value
Wetting Phase	-5
Non-Wetting Phase	-5

2.2 Relative Permeability Endpoint Input of Interpolation Set 2

Input Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.15
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.15
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.8
KRWIRO - Krw at Irreducible Oil	0.5
KRGCL - Krg at Connate Liquid	0.8
KROGCG - Krog at Connate Gas	-
Exponent for calculating Krw from KRWIRO	2.5
Exponent for calculating Krow from KROCW	2.5
Exponent for calculating Krog from KROGCG	2.5
Exponent for calculating Krg from KRGCL	2.5

Interpolation Set Parameters	Value
Wetting Phase	-4.5
Non-Wetting Phase	-4.5

2.3 Relative Permeability Endpoint Input of Interpolation Set 3

Input Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.01
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.01
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.9
KRWIRO - Krw at Irreducible Oil	0.8
KRGCL - Krg at Connate Liquid	0.9
KROGCG - Krog at Connate Gas	-
Exponent for calculating Krw from KRWIRO	2
Exponent for calculating Krow from KROCW	2
Exponent for calculating Krog from KROGCG	2
Exponent for calculating Krg from KRGCL	2

Interpolation Set Parameters	Value
Wetting Phase	-4.25
Non-Wetting Phase	-4.25

2.4 Relative Permeability Endpoint Input of Interpolation Set 4

Input Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.95
KRWIRO - Krw at Irreducible Oil	1
KRGCL - Krg at Connate Liquid	0.95
KROGCG - Krog at Connate Gas	-
Exponent for calculating Krw from KRWIRO	1.5
Exponent for calculating Krow from KROCW	1.5
Exponent for calculating Krog from KROGCG	1.5
Exponent for calculating Krg from KRGCL	1.5

Interpolation Set Parameters	Value
Wetting Phase	**-4**
Non-Wetting Phase	**-4**

2.5 Relative Permeability Endpoint Input of Interpolation Set 5

Input Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0
SWCRIT - Endpoint Saturation: Critical Water	0
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0
KROCW - Kro at Connate Water	1
KRWIRO - Krw at Irreducible Oil	1
KRGCL - Krg at Connate Liquid	1
KROGCG - Krog at Connate Gas	
Exponent for calculating Krw from KRWIRO	1
Exponent for calculating Krow from KROCW	1
Exponent for calculating Krog from KROGCG	1
Exponent for calculating Krg from KRGCL	1

Interpolation Set Parameters	Value
Wetting Phase	-3.75
Non-Wetting Phase	-3.75

2.6 Adsorption Components

Input Parameter	Value	Unit
Maximum adsorption capacity	0.000607787	lbmole/ft3
Residual adsorption level (50%)	0.000303894	lbmole/ft3

VITA

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