EVALUATION OF STEAM-FOAM FLOODING IN MULTI-LAYERED HETEROGENEOUS RESERVOIR

Mr. Chakkit Kekina

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Thesis Advisor	Falan Srisuriyachai, Ph.D.

Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

....Dean of the Faculty of Engineering

(Associate Professor Supot Teachavorasinskun, D.Eng.)

THESIS COMMITTEE

....Chairman

(Assistant Professor Jirawat Chewaroungroaj, Ph.D.)

....Thesis Advisor

(Falan Srisuriyachai, Ph.D.)

....Examiner

(Kittiphong Jongkittinarukorn, Ph.D.)

....External Examiner

(Monrawee Pancharoen, Ph.D.)

จักรกริช เกกินะ : การประเมินการฉีดอัดโฟมไอน้ำในแหล่งกักเก็บน้ำมันแบบวิวิธพันธ์หลายชั้น (EVALUATION OF STEAM-FOAM FLOODING IN MULTI-LAYERED HETEROGENEOUS RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: อ. ดร.ฟ้าลั่น ศรีสุริยชัย, 113 หน้า.

การฉีดอัดไอน้ำเป็นหนึ่งในเทคนิคการเพิ่มการผลิตน้ำมันที่ถูกเลือกใช้มากที่สุดกับน้ำมันหนัก ไอน้ำสามารถผลักน้ำมัน ช่วยรักษาแรงดันแหล่งกักเก็บและส่งความร้อนไปสู่น้ำมันส่งผลให้ความหนืดของน้ำมันลดลงทำให้น้ำมันไหลได้ อย่างไรก็ตามไอน้ำมีแนวโน้มที่จะไหลขึ้นด้านบนแหล่งกักเก็บเนื่องจากความหนาแน่นที่เบากว่าเมื่อเทียบกับน้ำมัน ปล่อยให้ส่วนล่างของแหล่งกักเก็บไม่ถูกผลิต ทำให้เกิดประสิทธิภาพในการกวาดแนวตั้งที่น้อย โฟมไอน้ำช่วยเพิ่มคุณสมบัติการไหลของไอน้ำโดยการสร้างความหนืดให้สูงขึ้นทำให้แนวการกวาดตามแนวตั้งดีขึ้น การศึกษานี้พยายามที่จะวิเคราะห์ผลกระทบของตัวแปรเชิงปฏิบัติการและความเป็นวิวิธพันธ์ของแหล่งกักเก็บ แบบจำลองพื้นฐานถูกสร้างขึ้นแบบเอกพันธ์ในตอนเริ่มต้น ตัวแปรเชิงปฏิบัติการที่ถูกเลือกในการศึกษานี้ได้แก่เสถียรภาพโฟม คุณภาพโฟม คุณภาพไอน้ำและอัตราการฉีดอัดไอน้ำ จากนั้นตัวแปรดังกล่าวที่ถูกเลือกจะถูกนำเข้าสู่แบบจำลองแบบวิวิธพันธ์ที่มีสัมประสิทธิ์ลอเรนซ์ที่แตกต่างกันเพื่อศึกษาผลของความเป็นวิวิธพันธ์ของแหล่งกักเก็บที่มีต่อกระบวนการผลิต

ผลการศึกษาแสดงให้เห็นว่าการฉีดอัดโฟมไอน้ำด้วยการปรับตัวแปรเชิงปฏิบัติการที่เหมาะสมจะให้ผลลัพธ์ที่เป็นประโยชน์เมื่อเทียบกับการฉีดอัดไอน้ำทั่วไป เนื่องจากมีการเพิ่มประสิทธิภาพการกวาดแนวตั้ง ในแง่ของตัวแปรเชิงปฏิบัติการ ครึ่งชีวิตของโฟมซึ่งเป็นตัวบ่งชี้ความเสถียรของโฟมควรอยู่ระหว่าง 0.25 ถึง 1 วันเพื่อหลีกเลี่ยงความยากในการฉีดอัดโฟมที่มีความเสถียรสูงและการไหลขึ้นด้านบนของไอน้ำในโฟมที่มีความเสถียรต่ำ โฟมคุณภาพสูงสามารถฉีดอัดได้ง่าย ไอน้ำควบแน่นมีแนวโน้มที่จะเคลื่อนตัวลงและปล่อยให้น้ำมันเหลือค้างอยู่ในชั้นบนของแหล่งกักเก็บ ในขณะที่โฟมคุณภาพต่ำที่มีปริมาณของสารละลายของสารลดแรงตึงผิวที่สูงกว่าทำงานได้คล้ายกับน้ำมากขึ้นและเคลื่อนที่ช้าลงซึ่งจะนำไปสู่ประสิทธิภาพการฉีดอัดที่ต่ำของหลุมฉีดอัด คุณภาพโฟมที่เหมาะสมจะอยู่ที่ประมาณ 0.90 ค่าคุณภาพไอน้ำที่แตกต่างกันไม่ส่งผลกระทบต่อการผลิตน้ำมัน แต่คุณภาพไอน้ำที่สูงขึ้นต้องใช้พลังงานมากขึ้นเพื่อเอาชนะความร้อนแฝงของไอน้ำ อัตราการฉีดไอน้ำที่สูงขึ้นทำให้การผลิตน้ำมันสูงขึ้น อย่างไรก็ตามน้ำถูกผลิตได้ไวกว่าซึ่งจะนำไปสู่อัตราส่วนการผลิตน้ำที่สูงรวดเร็วขึ้น ในแง่ของความเป็นวิวิธพันธ์ของแหล่งกักเก็บ แหล่งกักเก็บที่ตะกอนละเอียดด้านบนให้ผลลัพธ์ที่ดีกว่าแหล่งกักเก็บที่มีตะกอนหยาบด้านบน เนื่องจากความสามารถในการซึมผ่านที่ต่ำบริเวณด้านบนของแหล่งกักเก็บสามารถลดการไหลขึ้นด้านบนของไอน้ำซึ่งจะทำให้การกวาดตามแนวตั้งดีขึ้น นอกจากนี้ค่าสัมประสิทธิ์ลอเรนซ์ที่แตกต่างกันในช่วงปกติซึ่งมีค่าตั้งแต่ 0.20 ถึง 0.30 ไม่ก่อให้เกิดผลลัพธ์ที่แตกต่างอย่างมีนัยสำคัญในการฉีดอัดโฟมไอน้ำ

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ....

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5871203921 : MAJOR GEORESOURCES AND PETROLEUM ENGINEERING

KEYWORDS: STEAM-FOAM FLOODING / HETEROGENEOUS RESERVOIR / HEAVY OIL / STEAM OVERRIDING

CHAKKIT KEKINA: EVALUATION OF STEAM-FOAM FLOODING IN MULTI-LAYERED HETEROGENEOUS RESERVOIR. ADVISOR: FALAN SRISURIYACHAI, Ph.D., 113 pp.

Steamflooding, one of the Enhance Oil Recovery (EOR) techniques to perform with heavy oil, provides physical displacement, helps maintain reservoir pressure and delivers heat to oil, resulting in decreasing of oil viscosity and oil is readily to flow. However, steam tends to override the reservoir due to its lighter density compared to oil, leaving bottom part of reservoir non-displaced and therefore, causing poor vertical sweep efficiency. Steam-foam enhances flow properties of steam by creating higher viscosity displacing material, resulting in better sweeping. This study attempts to analyze effects of operational parameters and reservoir heterogeneity. A base case model is constructed as homogeneous model. Operating parameters including foam stability, foam quality, steam quality and steam injection rate are identified. Later, selected operating parameters are performed in various heterogeneity values quantified by Lorenz coefficient to observe effects of reservoir heterogeneity.

Simulation results indicate that steam-foam flooding with appropriate adjustment of operating parameters yields beneficial results compared to conventional steamflooding due to enhanced vertical sweeping front. In terms of operating parameters, optimum range of foam half-life which is an indicator for foam stability is suggested to be in between 0.25 and 1 day to avoid low fluid injectivity in foam with high stability and steam overriding in foam with low stability. In case of high foam quality, steam can be injected easily. Condensing steam tends to move downward and leaves certain amount of oil in shallow zone. Whereas low foam quality with higher portion of surfactant solution behaves closer to water and moves slower, leading to low injectivity of the injector. Optimum foam quality is found to be around 0.90. Different steam quality values do not significantly affect oil production but higher steam quality requires more energy to achieve latent heat of steam. Higher steam injection rate yields higher oil recovery which is desirable. However, water also breakthrough earlier, leading to high water-cut in earlier stage of production. In terms of reservoir heterogeneity, fining upward reservoir provides better results than coarsening upward reservoir because low permeability layers on top of reservoir can mitigate steam overriding, leading to better vertical sweeping profile. Moreover, different heterogeneous degree in typical range of Lorenz coefficient values from 0.20 to 0.30 does not provide significantly different results.

Department:	Mining and Petroleum Engineering	Student's Signature	....
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LIST OF ABBREVIATIONS

bbl	Barrel
bbl/day	Barrel Per Day
BHP	Bottomhole Pressure
CMG	Computer Modeling Group
cP	Centipoise
DTMAX	Max Time Step Size
DTMIN	Min Time Step Size
DTWELL	First time step size after well change
dyne/cm	Dyne per centimeter
EOR	Enhanced Oil Recovery
GOR	Gas Oil Ratio
ISOTHERM	Isothermal option
ITERMAX	Linear solver iteration
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
mD	Millidarcy
MW	Molecular Weight
°API	American Petroleum Institute Gravity
OOIP	Original Oil in Place
ppm	Part per million
psia	Pound per square inch absolute
PVT	Pressure-Volume-Temperature
RF	Recovery Factor
SCF/STB	Standard cubic feet per stock tank barrel
SGCON	Connate gas saturation

SGCRIT	Critical gas saturation
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
STL	Surface liquid rate
STO	Surface oil rate
STW	Surface water rate
STF	Surface total phase rate
SWCON	Connate water saturation
SWCRIT	Critical water saturation
WCUT	Watercut
wt.	By Weight

NOMENCLATURES

ϕ	Porosity
μ_g	Gas viscosity
μ_w	Water viscosity
μ_o	Oil viscosity
B_g	Gas formation volume factor\
B_o	Oil formation volume factor
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
p_b	Bubble point pressure
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

CHAPTER 1
INTRODUCTION

1.1. Background

Nowadays, heavy crude oil provides an interesting situation for the economics of petroleum development. The resources of heavy oil in the world are more than twice those of conventional light and medium crude oil. However, according to its high viscosity, the method to extract this type of oil is more difficult compared to those lighter oils. Thus, thermal recovery, one of Enhanced Oil Recovery (EOR) technique is usually implemented in reservoir with heavy oil. Steamflooding is nowadays one of the most chosen methods for real implementation due to effectiveness of the process. Recovery mechanisms of heavy crude oil by steamflooding are mainly related to changes of fluid properties and petrophysical properties that favor oil production. As steam is injected into the formation, first mechanism obtained is the physical displacement employing in a manner similar to waterflooding or immiscible gas flooding. As steam is gaseous phase and it helps maintain reservoir pressure, oil is pushed toward the production well. Not only providing pressure source, heat from steam is delivered to viscous oil through latent heat of vaporization. Viscosity of oil is substantially decreased and this results in improvement of flow ability of oil. Moreover, heat from steam is adequate to allow portions of heavy oil to vaporize in gaseous form. Condensation of this light ends results in upgrading of oil properties.

However, steamflooding also inherit with a major drawback. As steam is gaseous phase, steam tends to flow to the top section of reservoir, leaving bottom part of reservoir non-displaced. This eventually causes poor vertical sweep efficiency. In reservoir containing high vertical communication (high vertical permeability) and/or high permeability channel, steamflooding may result in unsatisfactory. In order to minimize this drawback of steamflooding, steam can turn into foam flooding as flow properties of foam are totally different from solely steam. Foam is generated by combining surfactant solution and steam together which can be performed at downhole condition. When surfactant solution is mixed with steam, a structure called lamella is created. Lamella which is thin film of water filled with surfactant monomer functions to capture steam inside its structure. As monomers of surfactant are packed inside lamella, this causes high strength of the total structure and the combination in total obtained higher viscosity compared to parental fluids. Due to this high viscosity of foam, displacement occurs in better vertical profile as steam overriding is mitigated. Surfactant can also reduce interfacial tension between oil and water, resulting in liberation of oil in a form of emulsion.

In general, the efficiency of steam-foam flooding is manageable by operational parameters such as fluid infection rate, foam quality, and foam stability. Moreover, there are also several uncontrollable factors that dictate effectiveness of the process such as variations of physical properties of reservoir rock including permeability, porosity, thickness, and a presence of faults and fractures. This so-called heterogeneity term is a major concern when performing several EOR techniques as expected results can be highly deviated. As creating foam may mitigate effects of reservoir heterogeneity, its effectiveness may be different in different degrees of heterogeneity. Therefore, evaluating the effects of heterogeneity is important and must be performed prior to implementation of steam-foam flooding in heterogeneous reservoirs.

In this study, the reservoir simulator STARS® commercialized by Computer Modeling Group Ltd. (CMG) is used as evaluation tool. An attempt is made to analyze effects of operational parameters and reservoir heterogeneity. A base case model is constructed as homogeneous model. It will be adjusted for optimal operational parameters including foam stability, foam quality, steam quality and steam injection rate. Later, selected operational parameters are various heterogeneity values to observe effects of heterogeneity. Heterogeneous reservoir models are created by varying reservoir permeability in ten layers to represent multi-layered sandstone reservoir. Lorenz coefficient is calculated for every model to quantify heterogeneity. Simulation outcomes which are oil recovery factor, cumulative water production, cumulative oil production, oil, gas and water production rates, injection well bottomhole pressure and cumulative injected pore volume of injectant are used for discussion and judgment of flooding performance. At the end of study, conclusion and new observations will be summarized.

1.2. Objectives

1. To identify appropriate values or ranges of operating parameters for steam-foam flooding, including foam stability, foam quality, steam quality and steam injection rate.

2. To investigate effect of heterogeneity on effectiveness of steam-foam flooding.

1.3. Outline of Methodology

1. Construct homogeneous model be means of reservoir simulation program (CMG STARS).

2. Perform steamflooding starting at day one to represent a base case for comparing with other steam-foam flooding cases.

3. Perform parameter-crossed steam-foam flooding by varying all of these operating parameters and evaluate effects of each parameter and its optimum range:

- Foam stability: 0.25, 1, 4 and 16 days,
- Foam quality: 0.80, 0.85, 0.90 and 0.95,
- Steam quality: 0.45, 0.60, 0.75 and 0.90,
- Steam injection rate: 40, 60, 80 and 100 bbl/day.

4. Select dominant parameters and their optimum ranges to perform in multilayered heterogeneous reservoir to study effects of reservoir heterogeneity including:

- Lorentz coefficient (L_k): 0.20, 0.25 and 0.30,
- Sedimentary structure: coarsening upward sequence and fining upward sequence.

5. Analyze the results obtained from steam-foam flooding using oil recovery factor, oil production rate, water production, etc.

6. Conclude new discovery based on thesis objectives and provide recommendations for further steam-foam flooding study.

1.4. Thesis Outline

This thesis contains six chapters as follows:

Chapter I provides motivation of the study, background of steam-foam flooding, objectives and methodology outline of this study.

Chapter II summarizes relevant literatures to this study

Chapter III provides essential concepts related to oil recovery mechanism by mean of steam-foam flooding process.

Chapter IV describes details of reservoir model used in this study including rock and fluid properties and production constraints. Additionally, details of the methodology are described at the end of this chapter.

Chapter V discusses the reservoir simulation results in aspects of operating parameters and reservoir heterogeneity.

Chapter VI concludes the outcomes obtained from this study and provides recommendation for future works.

CHAPTER 2
LITERATURE REVIEW

2.1. Application of Steam-foam Flooding

Steamflooding is known as the most suited method for heavy oil. Nevertheless, steam which is gas phase is not stabilized by gravity and this could turn the process to have poor vertical sweep efficiency as a result of gravity overlay in a thick sand and channeling in a layered formation with poor vertical communication between sand members. Steam-foam flooding does not provide only benefits transforming gas to a more viscous foam but it can also perform thermal recovery at the same time. Foam is a special kind of colloidal dispersion where gas is dispersed in a continuous liquid phase. The characteristics of foam can enhance oil recovery mechanism especially in preventing channeling and overlaying of gas flooding. Steam-foam flooding has been developed to improve these disadvantages and the followings are relevant researches.

Hirasaki [2] reviewed steam-foam flooding process and summarized its mechanisms in these following conclusions. Surfactants reduce steam mobility by stabilizing liquid lamellae that cause the steam to be a discontinuous phase. The propagation of surfactant is retarded by adsorption. In the case of ion exchange of divalent ions from clays, surfactant is also retarded by precipitation and partitioning into the oil. The rate of propagation of foam is also determined by the generation mechanisms including leave-behind, snap-off, and division, and the destruction mechanisms including condensation, evaporation, and coalescence. The reduced mobility of steam-foam increases the pressure gradient in the steam-swept region to displace heated oil and to divert steam to the unheated interval. Therefore, according to these benefits, steam-foam flooding can improve sweep efficiency and hence enhance oil recovery.

Patzek [3] studied and compared the results of several steam-foam flooding pilots in the States. In all cases, steam injection pressure was increased significantly and the cumulative-oil/steam ratio (COSR) was also increased, relative to the preceding steamflooding. All early production responses resulted in higher oil cuts and less vented steam but several late production responses obtained high oil cut. Vertical and areal sweep efficiencies by steam-foam were also increased. In thick reservoirs containing fine layers, foam can divert steam to the otherwise by-passed layers. Conversely, it is less obvious that steam-foam should be used in massive and dipping sands that are dominated by gravity drainage. In a flat and moderately thick reservoir, gravity drainage occurred slowly and it is difficult to recirculate the overlain steam. Therefore, this kind of reservoir should be considered if steam-foam can exploit a reservoir effectively and economically.

2.2. Factors to improve steam-foam flooding

Keijzer et al. [4] conducted a laboratory study on steam-foam flooding to investigate a means to reduce steam mobility in steamflooding. The results indicated that formulation of surfactants was not necessarily effective at temperature over 200 °C or 392 °F. However, long-chain alkylaryl sulphonates, which is thermally stable, exhibited an excellent capability of reducing steam mobility at elevated temperature. The performance of steam-foam flooding with these surfactants was studied in core-flow experiments at steam injection temperature to represent steam operations in the Tia Juana field, Venezuela. The surfactant molecular weight and concentration were selected to be main parameters for reducing steam mobility. The obtained laboratory results indicated that the mobility reduction was controlled mainly by steam temperature, steam quality, surfactant type and concentration. Steam-foam flooding was feasible to reduce effective permeability to steam, to plug depleted layers, to divert the injected steam into non-producing sands and hence, to enhance oil production.

Cuenca et al. [5] developed high pressure and high temperature screening tools to evaluate dynamical properties of the foam in porous media. Benchmark formulations based on classical Alpha Olefin Sulfonate (AOS), Alkyl Aryl Sulfonate (AAS) were characterized and compared to optimized formulations. Surfactant formulations were designed to provide enhanced bulk viscosity. These formulations were intended to compensate a strong decrement of water viscosity with temperature and expected to enhance steam-foam lifetime and in turn to provide a better steam mobility. Since steam foam is highly sensitive to possible temperature gradients, an optimized experimental setup was developed to evaluate high temperature foam half-life obtained with standard and enhanced viscosity formulations. These outcomes were coupled with rheology and mobility reduction evaluation in sand pack experiments to evaluate the results. The results indicated that both foam stability and Mobility Reduction Factor (MRF) are improved with the use of optimized formulations. The viscosity of formulations seemed to impact on steam-foam stability as well as gas mobility reduction. Foam quality and foam stability played important role as well. The most effective optimized formulation was AOS medium alkyl chain length with medium alkyl chain length foam boosters which possessed the longest half-life time in a presence of oil at temperature of 200 °C (392 °F) and pressure of 30 bar (435 psi). These results open new perspectives for steam additives development, based on foam boosters. The high MRF values achieved with these formulations should improve steam utilization in a reservoir.

Mohammadi [6] performed reservoir simulations, using a prototype model of a section of Midway Sunset Field in California, to study effect of gravity on surfactant and steam by evaluating results among various steam and foam selective injection strategies at different formation intervals. The results indicated that, in a thick multi-zone formation, by injecting foam in top portion of the formation and injecting steam near the bottom, production response can be accelerated over bottom injection alone. This consequence was believed with the behavior of the surfactant draining down into the lower steam zone, resulting in foam generation in the inter-zone gravity override regions. Practically, this technique can be implemented by multiple completion methods, simultaneous injection through tubing and annulus, or use of two adjacent wells for steam and steam-foam injection. Although the results were obtained from specific reservoir, the concept can be extended to other types of structures since the underlying principal deals with optimum placement of the surfactant for correcting gravity override.

Mohammadi and McCollum [7] conducted several experiments of chemical additives to study increment of oil recovery in steam-flooded reservoirs with severe channeling conditions. A series of screening tests was conducted in Guadalupe reservoir conditions for evaluation of the Resistance Factor (RF) and oil recovery abilities of each chemical. Alpha Olefin Sulfonate (AOS), Alkyl Aryl Sulfonate (AAS), and a formulated Alkyl Toluene Sulfonate (ATS) performed in favorable results and were selected for a series of field injectivity tests. AOS, AAS, and ATS were injected, each into an injection well to record their injection wellhead pressures, used for determination of mobility improvement. Additionally, semi-log plot of wellhead pressure as a function of time was a straight line with slope proportionated to the apparent viscosity. The results showed that ATS yielded the highest apparent viscosity. Therefore, ATS was selected to be performed in several testing and monitoring program. The results showed that, in the absence of divalent ions, sulfonated components of ATS were quite stable under reservoir conditions in a steam-flooding. The high pH component of ATS was consumed by the reservoir rock, resulting in deterioration of its effectiveness as a foaming agent. Overall, ATS was found to improve steam mobility and resulted in incremental oil production. Selecting appropriate properties of foaming agent for simulations was also importance. As ATS can yield effective results, the properties of ATS were selected to be used as simulating properties of foaming agent in this study.

Hutchinson et al. [8] performed several experiments of steam-foam flooding in a one-dimensional sand pack with about 12% residual oil saturation. In the presence of residual oil, co-injection of surfactant with steam failed to generate foam in the model, while the same procedure generated strong foam in sand pack without oil. However, in a presence of residual oil, the results showed that foam can be generated by slug injection, injecting surfactant as a liquid slug ahead of the steam. This was probably caused by increment of mixing phases since the steam had to flow through each surfactant slug after each slug injection. In this procedure, about 5 %PV at 1.0 wt% concentration was the minimum slug size required to generate foam. Nevertheless, above this limit, increasing in slug size or in concentration showed only small effect. Moreover, in first few slugs, pressure responses were quite small because of surfactant losses. As these losses could fill up the thief zone, surfactant losses from the following slugs were reduced and hence, improved the pressure response.

According to these literature reviews, it can be noticed that several operating parameters was evaluated. However, selecting the most dominant operating parameter should be emphasized and would help the operating design to be effective. Moreover, the effect of heterogeneities to steam-foam flooding has not been yet evaluated. Hence, in this study, several operating parameters will be applied by varying values in the simulations and then results are compared to select the dominant parameter as well as appropriate values. Effects of heterogeneity are also evaluated to identify the limitation of condition for performing steam-foam flooding in heterogeneous reservoir.

CHAPTER 3
THEORY AND CONCEPT

3.1. Steamflooding

Steamflooding is nowadays one of the most selected Enhance Oil Recovery (EOR) techniques to perform with heavy oil. Recovery mechanisms of heavy crude oil by steamflooding are mainly related to changes of fluid properties and petrophysical properties that favor oil production. As steam is injected into the formation, first mechanism obtained is the physical displacement employing in a manner similar to waterflooding or immiscible gas flooding. As steam is gaseous phase and it helps maintain reservoir pressure, oil is pushed toward the production well. Not only providing pressure source, heat from steam is delivered to viscous oil through latent heat of vaporization. Viscosity of oil is substantially decreased and this results in improvement of flow ability of oil. Moreover, heat from steam is adequate to allow portions of heavy oil to vaporize in gaseous form [9] [10]. Condensation of this light ends results in upgrading of oil properties. As steam is gaseous phase, steam tends to flow to the top section of reservoir, leaving bottom part of reservoir non-displaced This phenomenon is so-called steam overriding and it eventually causes poor vertical sweep efficiency. In order to minimize this drawback of steamflooding, steam can turn into foam flooding as flow properties of foam are totally different from solely steam.

3.2. Steam-Foam Flooding

Steam-foam is generated by combining surfactant solution and steam together which can be performed at downhole condition. When surfactant solution is mixed with steam, a structure called lamella is created. Lamella which is thin film of water filled with surfactant monomer functions to capture steam inside its structure. As monomers of surfactant are packed inside lamella, this causes high strength of the total structure and the combination in total obtained higher viscosity compared to parental fluids. Due to this high viscosity of foam, displacement occurs in better vertical profile as steam overriding is mitigated [11]. Surfactant can also reduce interfacial tension between oil and water, resulting in liberation of oil in a form of emulsion.

3.3. Fundamental of Foam and Applications

3.3.1. Definition of Foams

Foams are a special kind of colloidal dispersion where gas is dispersed in a continuous liquid phase. The dispersed phase is sometimes referred to as the internal (disperse) phase, and the continuous phase as the external phase. Figure 3.1 shows the general foam structure contained between the bottom of the bulk liquid and the upper side of bulk gas. Within the magnified region, the gas phase is separated from the thin liquid-film, by a two-dimensional interface. A sharp dividing surface does not exist between gas and liquid properties. Dictated by mathematical convenience, the physical behavior of this interfacial region is approximated by a two-dimensional surface phase (the Gibbs surface). A lamella is defined as the region that encompasses the thin film, the two interfaces on either side of the thin film, and part of the junction to other lamellae. The connection of three lamellae, at an angle of 120°, is referred to the Plateau border. Because Figure 3.1 represents only a two-dimensional slice, the Plateau border extends perpendicularly, out of the page.

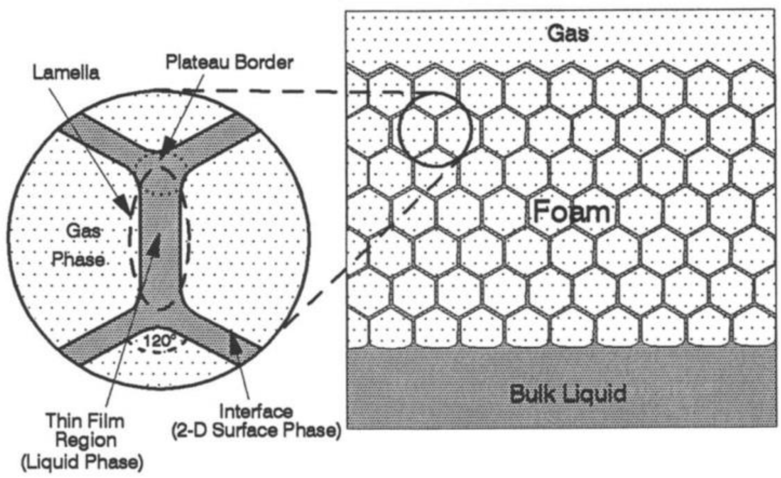

Figure 3.1 The general foam structure [1]

3.3.2. Surfactant

The surfactant has a key role in generation and stability of the foam in porous media. It affects the interfacial forces between the gas and liquid. The proper surfactant should have the following properties: can generate ample, lasting foam at the reservoir conditions, should have low adsorption and decomposition losses, should increase the sweep efficiency and the oil recovery, in addition it should be commercially available and inexpensive. Once the porous medium is pre-saturated with a surfactant solution, foam is readily formed during displacing the liquid phase by the gas phase. Foam coalescence forces are inversely proportional to surfactant concentration; thus the foam weakens and the displacement efficiency decreases as the surfactant concentration decreases. In the higher surfactant concentration, the size of foam bubbles inside porous media slightly decreases and the lower velocity is required to create foam. Adsorption of the surfactant on the reservoir rock decreases with increasing the temperatures ranging from 50 ^{o}C to 150 ^{o}C and reduces the surfactant concentration in the injected fluid.

3.3.3. Foam Stability

The stability of foam is determined by a number of factors in order to withstand foam collapsing or breakdown. Half-life time, the time required to decrease half of foam volume, is the parameter used to evaluate foam stability. Foam stability can be reduced by gravity drainage of liquid occurring in low viscous liquid. Increasing surface viscosity of foam can be enhanced by adding some additives such as gellants or cross-linker compounds. Thinning of foam is the phenomenon decreasing foam stability. It can be caused by capillary pressure, the difference of pressure between interfaces at plateau boarder. Moreover, Marangoni effect, the movement of liquid from low to high tension regions in the film, provides thinning resistance against liquid film and helps stabilizing foam system. Increment of temperature strongly decreases foam stability due to higher rate of coalescence of foam bubbles. High salinity decreases foam stability by obstructing foam from surfactant layer at surface. At high pressure, surface viscosity obtains higher strength which helps maintaining foam stability. However, foam stability is utilized differently in different flooding; high foam stability is suitable for immiscible flooding, whereas in miscible flooding, foam stability should be kept at appropriate value to optimize both effects of miscibility of liberating gas and mobility controlling.

3.3.4. Foam Formation

Foam formation and consist of three mechanisms which are snap-off, lamella division and leave-behind. Figure 3.2 illustrates foam formation consisting snap-off, lamella division and leave behind structures.

Snap-off

This mechanism occurs when a bubble enters in a narrow section of a pore and separate into two bubbles. This phenomenon dominates foam generating process and helps to increase discontinuity of gas

Lamella division

This mechanism increases number of lamellae or bubbles. It can be existed when a moving lamella encounters a branch in the flow path, and then splits into two. Lamella division is thought to be the primary foam-generation mechanism in steady gas-liquid flow.

Leave-behind

This mechanism also occurs during invasion of a gas phase to a porous medium saturated with a liquid phase. Foams generated solely by leave-behind give approximately a five-fold reduction in steady-state gas permeability, whereas discontinuous-gas foam created by snap-off resulted in several hundred-fold reduction in gas mobility. This indicates that the strength of foam is affected by the dominant mechanism of foam generation.

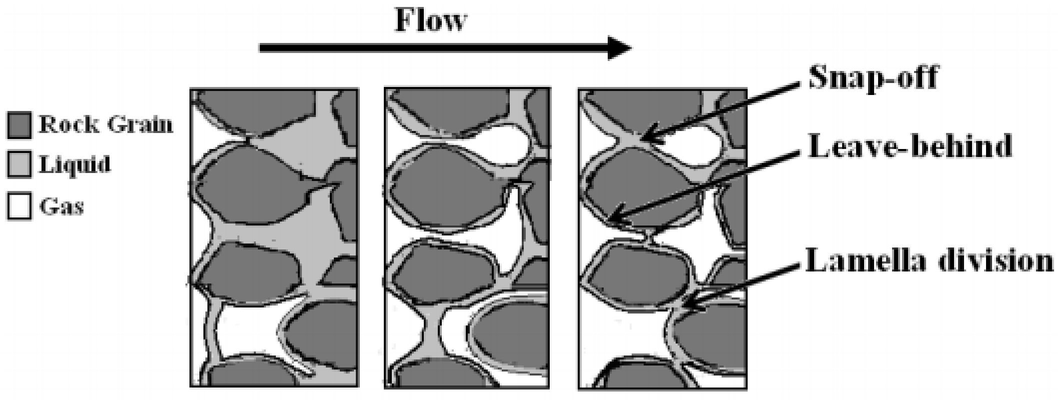

Figure 3.2 Foam formation consisting snap-off, leave-behind and lamella division [1]

3.3.5. Foam dynamics in porous media

For gas-liquid flow in porous media without foam, the gas phase resides in the center of the large pores, occupying the main paths of flow, while the liquid phase fills the small pores and coats walls of the large pores. Existence of foam affects this diffusivity mechanism. The gas phase in foam will be trapped by films of the liquid lamellae. As a result, the gas velocity decreases and gas and liquid phases will move together at the same velocity if a case of stable foam has been achieved. This section briefs mechanisms of generating, stability, and flow regimes of foam in porous media.

3.3.6. Foam - Oil Interaction

Foam stability is influenced by the presence of oil. When a drop of oil comes into contact with the gas-liquid interface, the oil may form a bead on the surface or it may spread and form a film. If the oil has a strong affinity for the new phase, it will seek to maximize its contact (interfacial area) and form a film. A liquid with much weaker affinity may form into a bead Oil can weaken or even destroy foam since oil has an impact on the lamella stability resulting in a change in foam rheology. Foam stability in the presence of oil is described by many parameters; the use of entering and spreading coefficients is one technique to describe the effect of oil on foam. The entering and spreading coefficients describe the behavior of oil droplets in presence of water and gas. The entering coefficient (E) measures whether the oil droplet can enter the interface between gas and water and the spreading coefficient (S) measures whether the oil droplet is likely to spontaneously spread between gas and water phases. Both the entering and the spreading coefficients can be derived thermodynamically in equation 3.1 and 3.2:

$$E = \gamma_{GS} + \gamma_{OS} - \gamma_{OG} \quad (3.1),$$

$$S = \gamma_{GS} - \gamma_{OS} - \gamma_{OG} \quad (3.2),$$

where the surface tension between the aqueous solution and the gas phase is given by γ_{GS}, γ_{OS} is the interfacial tension of the aqueous solution and the oil phase and lastly γ_{OG} gives the interfacial tension between the oil and the gas phase. These tensions are presented in Figure 3.3. Oil has a detrimental effect on foam when both entering and spreading occur, that is when E and S are positive. When no entering occurs; or entering but no spreading, oil has no or little effect on foam stability.

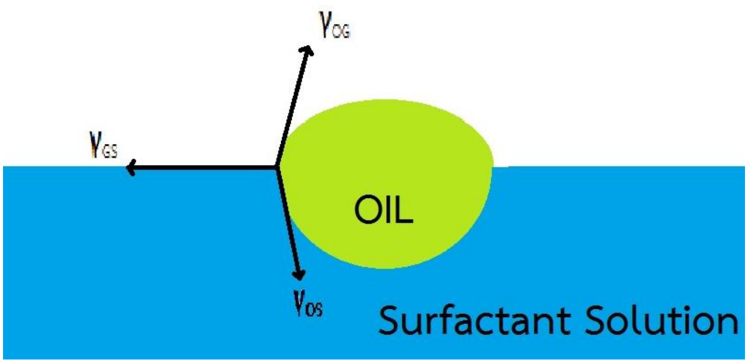

Figure 3.3 Surface tension diagram of oil droplet and surfactant

3.3.7. Steam-Foam Mechanism

Steamflooding is a method of extracting heavy crude oil as steamflooding can perform two mechanisms to improve the amount of oil recovered. The first mechanism is the physical displacement employing in a manner similar to waterflooding or immiscible gas flooding, in which oil is pushed toward the production well. The second mechanism is to heat viscous oil to elevated temperature and to thereby decrease its viscosity so that it flows easier through the formation toward the production well. However, steamflooding, which is not stabilized by gravity, obtains a poor vertical sweep efficiency as a result of gravity overlay in a thick sand with vertical communication and/or channeling in a layered formation with poor vertical communication between sand members. In order to minimize drawbacks of steamflooding, steam-foam flooding, the combination between surfactant and steamflooding, was developed [12]. Surfactant can reduce surface tension of liquid and then reduces the work needed to create foam. Thus, foam can be produced more in this flooding. The foam can reduce the mobility of the steam and hence, increases the pressure gradient in the steam-swept region to displace the heated oil better and to divert steam to the unheated interval.

3.3.8. Foam Modeling Concepts

In order to model foam simulation, many factors below are needed to be considered to provide appropriate flow behaviors of foam.

Foam Quality

Foam is made up of liquid and gas and so its flow behavior is between liquid and gas properties. Foam quality or foaminess or foamability is a ratio of gas volume per total foam volume, which is the sum of gas and surfactant solution volume.

Foam density

Foam density is required to be corrected in order to provide proper gravity model. It can be calculated as a function of foam quality and falls in between gas and surfactant density. As foam contains larger amount of gas compared to surfactant solution, foam density is then closer to gas density.

Foam degradation

Foam degradation is a function of time, oil saturation and capillary pressure. The higher value of oil saturation can cause the faster foam degradation. However, high resistant foaming agents, which can withstand high oil saturation, are available nowadays.

Foam regeneration

Foam can be in-situ created by injecting gas and surfactant solution at surface conditions with an aid of snap-off and lamella division mechanisms. Hence, pre-generation of foam is not required at surface.

Surfactant adsorption

Surfactant can be adsorbed by reservoir rock. In the simulator, the adsorption models are based on Langmuir Isotherm and empirical Freundlich model. Laboratory data is required in order to utilize this option. In general, EOR process, anionic surfactants are widely used as they can exhibit low adsorption property in negative charged rock surface including sandstone.

3.3.9. Foam Reaction

In STARS commercialized by CMG, foam reaction is used to represent foam regeneration and foam degradation models. Gas and liquid are injected separately from surface and foam is in-situ created in reservoir. In Table 3.1, reaction 5 and 6 represent foam regeneration models. Reaction 1, 2, 3, 4, 9 and 10 represent foam degradation models. Reaction 7 represents a model of blockage purpose of trapped lamella. Reaction 8 represents a model of flow diversion to limit the creation of trapped lamella.

Table 3.1 Reaction in foam model by STAR program commercialized by CMG

Reactions			
1	Lamella	$\longrightarrow$	Water + Surfactant
2	Foam Gas	$\longrightarrow$	Steam
3	Lamella + Oil	$\longrightarrow$	Water + Surfactant + Oil
4	Foam Gas + Oil	$\longrightarrow$	Steam + Oil
5	Water + Surfactant + Steam	$\longrightarrow$	Lamella + Steam
6	Lamella + Steam	$\longrightarrow$	Lamella + Foam Gas
7	Lamella	$\longrightarrow$	Trapped Lamella
8	Lamella + Trapped Lamella	$\longrightarrow$	Lamella
9	Trapped Lamella	$\longrightarrow$	Water + Surfactant
10	Trapped Lamella + Oil	$\longrightarrow$	Water + Surfactant + Oil

3.4. Reservoir Heterogeneity

All reservoirs are characterized by a sum of matrix and fluids properties. They are evaluated by a complex investigation consisting of core sampling analysis, geological, geophysical and hydrodynamic investigation and production data. These properties can be constant for the whole field when reservoir is a homogenous one, or these properties can be variable and reservoir is a heterogeneous one. Lorenz coefficient is statistical method for determination of reservoir heterogeneity. For calculation, the Lorenz coefficient necessary requires porosity, permeability and thickness of the reservoir. Number of values has to be adequate and has a uniform distribution on the field for a statistical calculation

3.4.1. Average Permeability

Weighted-Average Permeability

This averaging method is shown in equation 3.3 to calculate the average permeability of parallel layers with different permeabilities as shown in Figure 3.4.

$$k=\frac{\sum_{j=1}^{n} k_j h_j}{\sum_{j=1}^{n} h_j} \tag{3.3}$$

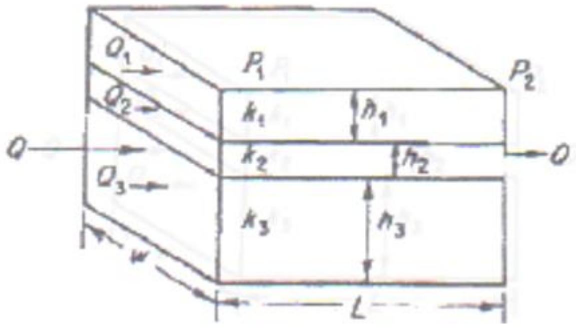

Figure 3.4 Linear flow through parallel layers [9]

Harmonic-Average Permeability

This averaging method is performed based on equation 3.4 to calculate the average permeability of serial layers with different permeabilities as shown in Figure 3.5.

$$k=\frac{L}{\sum_{j=1}^{n}\frac{L_j}{k_j}} \tag{3.4}$$

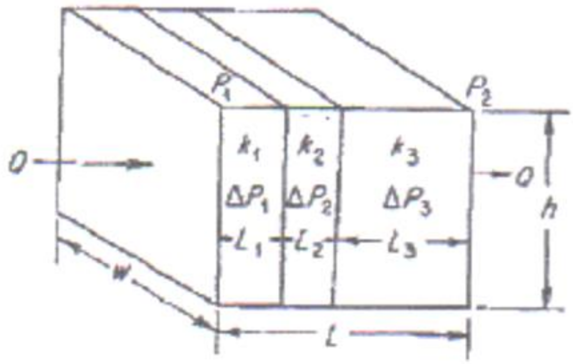

Figure 3.5 Linear flow through serial layers [9]

3.4.2. Lorenz Coefficient

The Lorenz Coefficient is a static measure of heterogeneity considering static porosity and permeability of stratified reservoir. Figure 3.6 is a graph used to calculate the Lorenz Coefficient. To construct this graph, properties of reservoir layers are arranged in tabular form in order of constantly decrementing values of permeability. Next, calculate fractional storage capacity (C_n) and Fractional flow capacity (F_n) in each layer using equation 3.5 and 3.6 respectively. Eventually, calculate area A_1 and A_2 using trapezoidal rule and then apply them into equation 3.7 to calculate Lorenz coefficient:

$$F_n = \frac{\sum_{j=1}^{n} k_j h_j}{\sum_{j=1}^{N} k_j h_j} \quad (3.5),$$

$$C_n = \frac{\sum_{j=1}^{n} \emptyset_j h_j}{\sum_{j=1}^{N} \emptyset_j h_j} \quad (3.6),$$

$$Lorenz\ Coefficient = \frac{A_1}{A_2} \quad (3.7),$$

where

N is number of total layers,

n is number of each layer, n= 1, 2, 3, ..., N,

k_j is absolute permeability,

$\emptyset_j$ is absolute porosity and

h_j is net pay thickness.

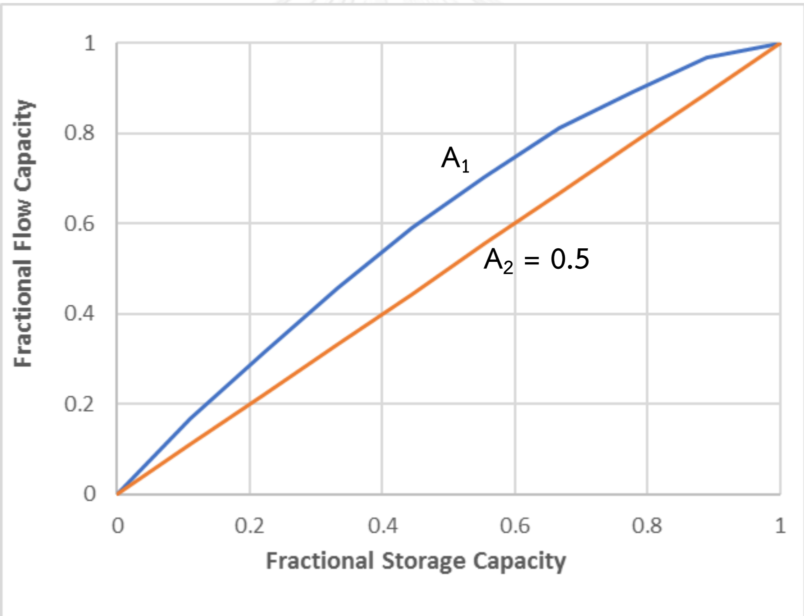

Figure 3.6 Plot of fractional flow capacity against fractional flow capacity, illustrating Lorenz curve

In homogeneous reservoir, the curve of fractional flow capacity against fractional flow capacity is linear, leading to zero Lorenz Coefficient. In heterogeneous reservoir, more difference in permeability makes the curve of fractional flow capacity against fractional flow capacity gain more deviation from the linear curve, resulting in higher Lorenz Coefficient. Typical range of Lorenz Coefficient is between 0.20 and 0.30.

3.4.3. Sediment Structure

Sediment structure can be differentiated into coarsening upward sequence and fining upward sequence. Coarsening upward reservoir is a reservoir with high permeability at top part of reservoir and low permeability at bottom part of reservoir. Therefore, fluid can travel in upper part faster than lower part and then helps gas to override the reservoir. Contrarily, fining upward reservoir is a reservoir with high permeability at bottom part of reservoir and low permeability at top part of reservoir. Hence, fluid can travel in upper part slower than lower part. This kind of situation assists mitigating fluid overriding especially in gas flooding process.

CHAPTER 4
RESERVOIR SIMULATION MODEL

This chapter describes details of reservoir model used in this study. The reservoir model is constructed by using STARS® commercialized by Computer Modeling Group Ltd. (*CMG*) as a numerical simulator to develop simulation study of steam-foam flooding process. The simulation consists of four main sections including reservoir physical properties, Pressure-Volume-Temperature (PVT) properties, rock and fluid properties and well specification and production constrains. Furthermore, details of the methodology are described at the end of this chapter.

4.1. Reservoir Physical Properties

Reservoir simulation model is generated using Cartesian coordinates to represent a quarter 5-spot flood pattern. Table 4.1 summarizes the size of reservoir and the important reservoir properties.

Table 4.1 Reservoir Properties

Parameters	Values	Unit
Grid dimension	30x30x10	Block
Grid size	15x15x10	ft
Top of reservoir	1,500	ft
Effective porosity (ϕ)	0.25	
Horizontal permeability (k_H)	1,000	mD
Vertical permeability (k_V)	$0.1k_H$	mD

Moreover, to study effect of reservoir heterogeneity, permeability of the reservoir is varied into different value in each layer by maintaining equivalent weighted-average horizontal permeability. Lorenz coefficient (L_k) is used to quantify degree of reservoir heterogeneity consisting of 0.20, 0.25 and 0.30. Sediment structure is differentiated into coarsening upward sequence and fining upward sequence. Coarsening upward reservoir is a reservoir with high permeability at top part of reservoir and low permeability at bottom part of reservoir. Contrarily, fining upward reservoir is a reservoir with high permeability at bottom part of reservoir and low permeability at top part of reservoir. Table 4.2 shows horizontal permeability in each layer of different reservoir heterogeneities used in this study.

Table 4.2 Permeability data in each layer in reservoir containing different heterogeneities

	Horizontal permeability (mD)						
	Homogeneous	Heterogeneous					
		Coarsening upward			Fining upward		
Lorenz coefficient (L_k)	0.00	0.20	0.25	0.30	0.20	0.25	0.30
Layer 1 (Top)	1,000	1,526	1,658	1,789	474	342	211
Layer 2	1,000	1,421	1,526	1,632	579	474	368
Layer 3	1,000	1,316	1,395	1,474	684	605	526
Layer 4	1,000	1,211	1,263	1,316	789	737	684
Layer 5	1,000	1,105	1,132	1,158	895	868	842
Layer 6	1,000	895	868	842	1,105	1,132	1,158
Layer 7	1,000	789	737	684	1,211	1,263	1,316
Layer 8	1,000	684	605	526	1,316	1,395	1,474
Layer 9	1,000	579	474	368	1,421	1,526	1,632
Layer 10 (Bottom)	1,000	474	342	211	1,526	1,658	1,789
Average	1,000	1,000	1,000	1,000	1,000	1,000	1,000

4.2. Pressure - Volume - Temperature (PVT) Properties

PVT data is one of the most important reservoir properties to specify reservoir model. In this study, Black Oil PVT is selected to construct reservoir model. Table 4.3 summarizes correlations used to generate PVT data of all the fluids.

Table 4.3 Summary of correlations for PVT data

Parameter	Correlation
Oil properties (P_b, R_s, B_o) and gas critical properties	Standing
Oil compressibility	Glaso
Dead oil viscosity	Ng and Egbogah
Live oil viscosity	Beggs and Robinson
Gas critical properties correlation	Standing

The required PVT properties are shown in Table 4.4. To represent heavy oil, oil gravity of 15°API and specific gas gravity of 0.85 are selected. Reservoir temperature and pressure are calculated at average depth of reservoir with temperature gradient of 0.017°F/ft and pressure gradient of 0.49 psi/ft respectively. Gas-oil ratio of 45 ft^3/bbl is selected to represent small amount of solution gas dissolved in oil as selected oil in this study is heavy oil. Bubble point pressure is considered using bubble point pressure–solution gas-oil ratio correlation to be around 200 psi.

Table 4.4 Input parameters for PVT data

Parameter	Value	Unit
Oil gravity	15	°API
Gas gravity	0.85	
Gas-oil ratio	45	ft^3/bbl
Reservoir temperature	88.7	°F
Reservoir pressure	774.2	psi
Surface temperature	62.3	°F
Surface pressure	14.7	psi
Bubble point pressure	197	psi

The correlations of PVT data versus pressure or temperature generated by STARS® are shown in Figure 4.1 to Figure 4.8. The 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).

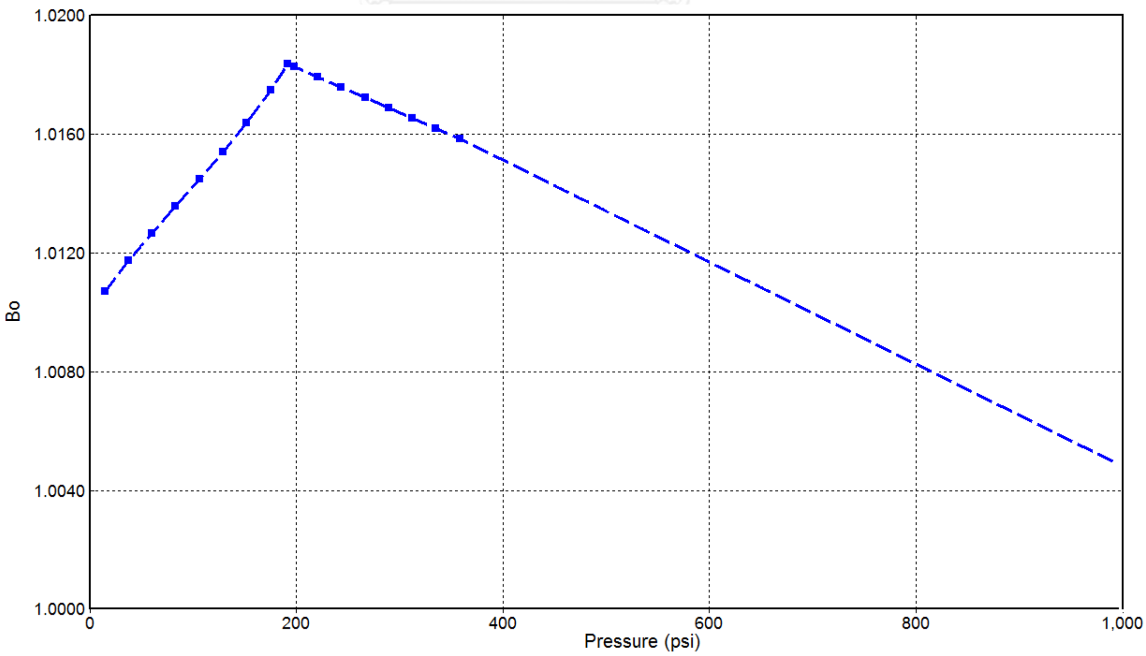

Figure 4.1 Oil formation volume factor (B_o) as a function of pressure

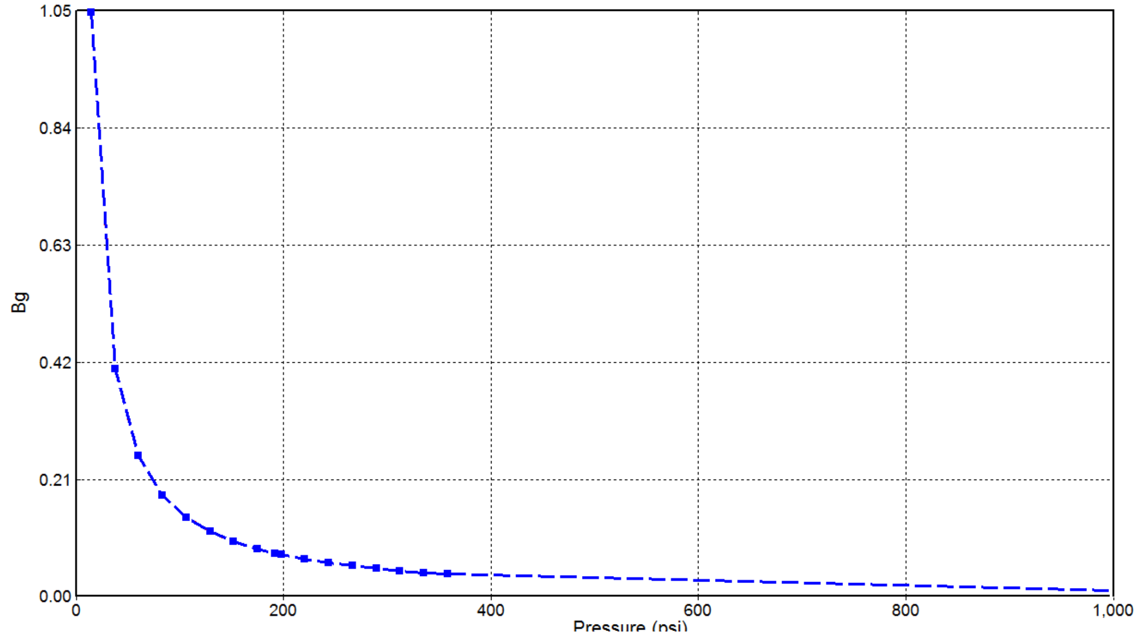

Figure 4.2 Gas formation volume factor (B_g) as a function of pressure

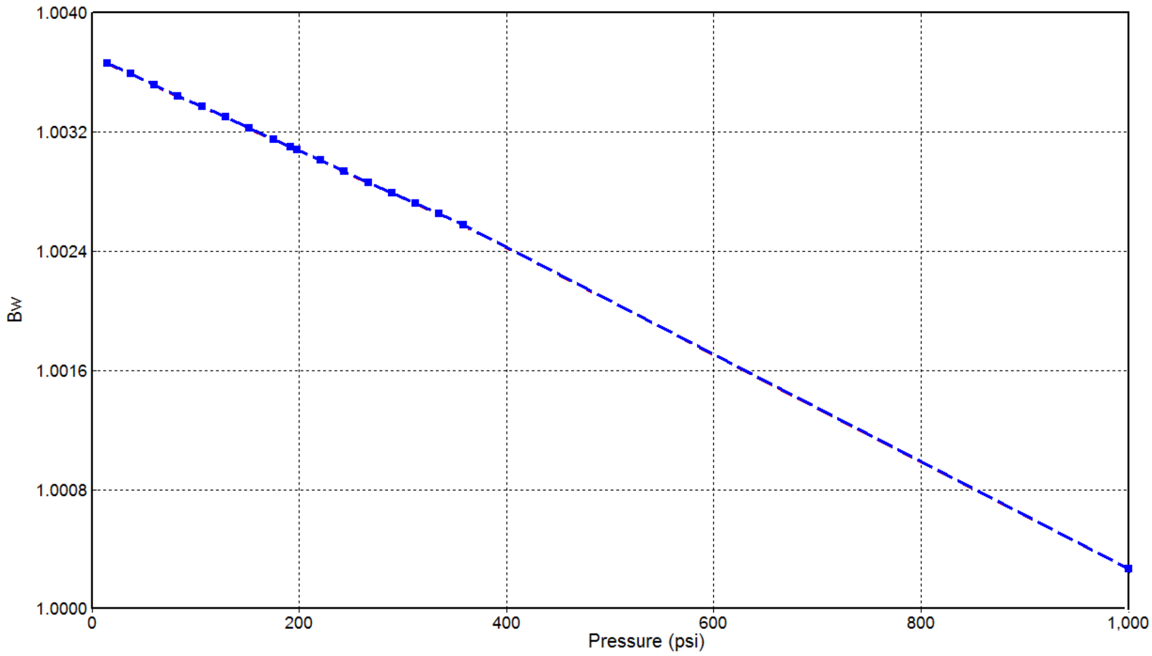

Figure 4.3 Water formation volume factor (B_w) as a function of pressure

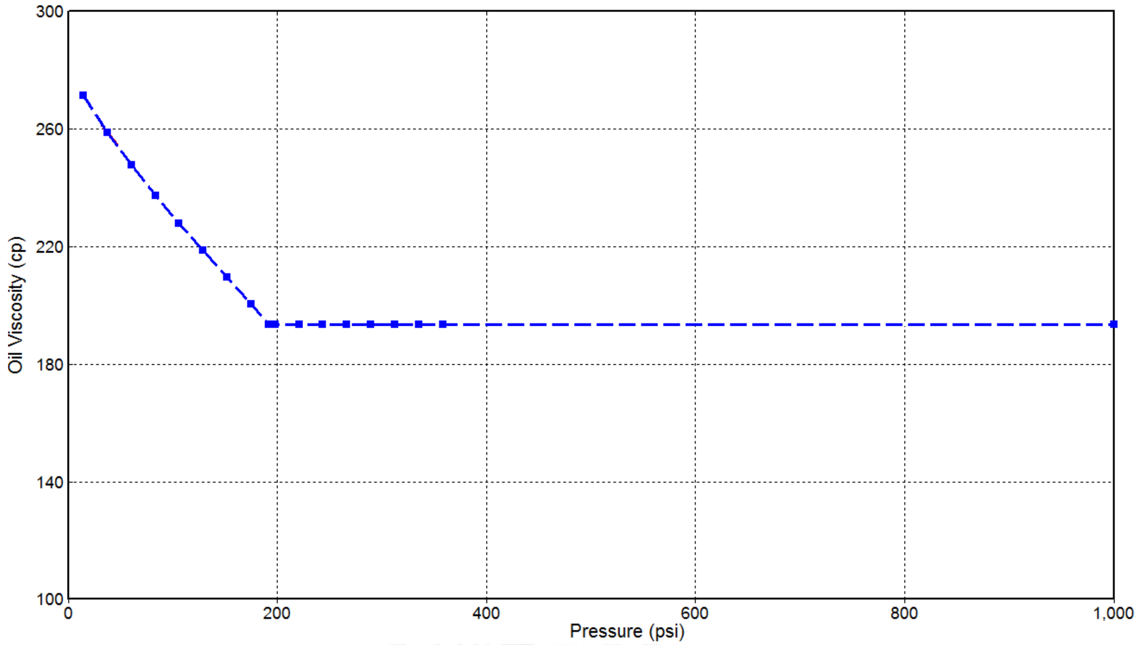

Figure 4.4 Oil viscosity (μ_o) as a function of pressure

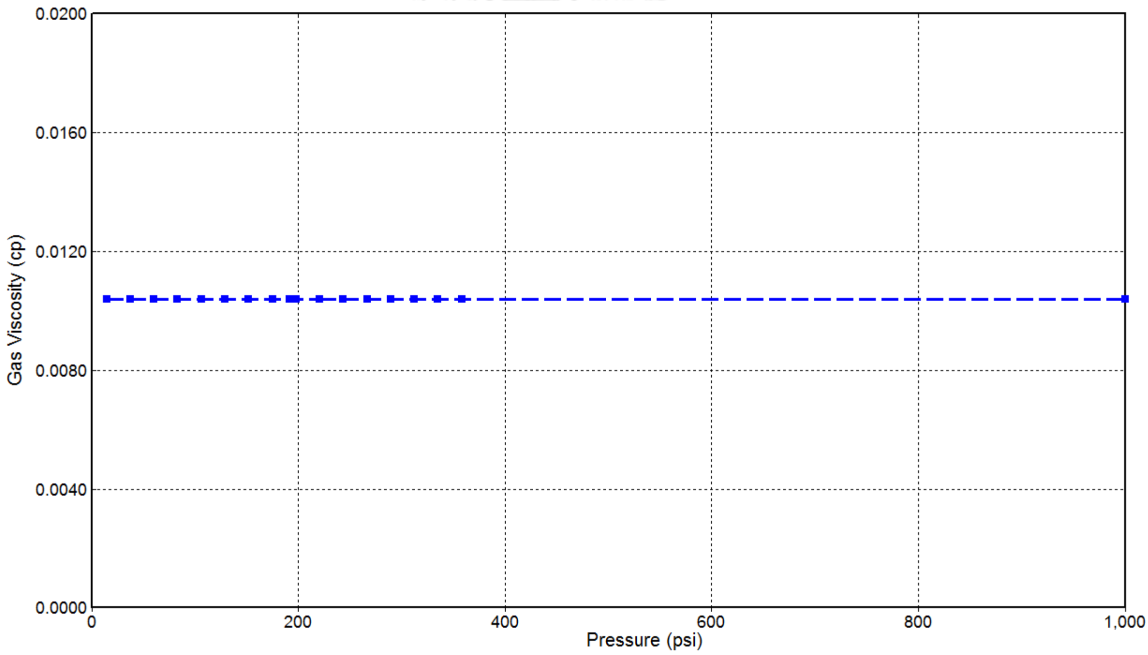

Figure 4.5 Gas viscosity (μ_g) as a function of pressure

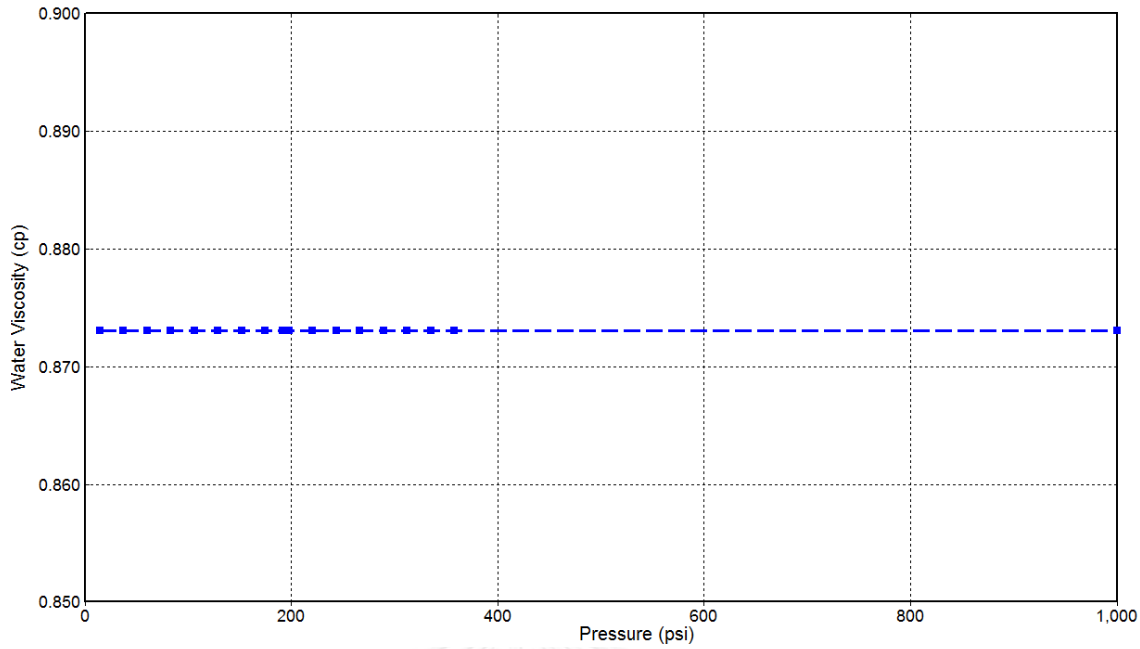

Figure 4.6 Water viscosity (μ_w) as a function of pressure

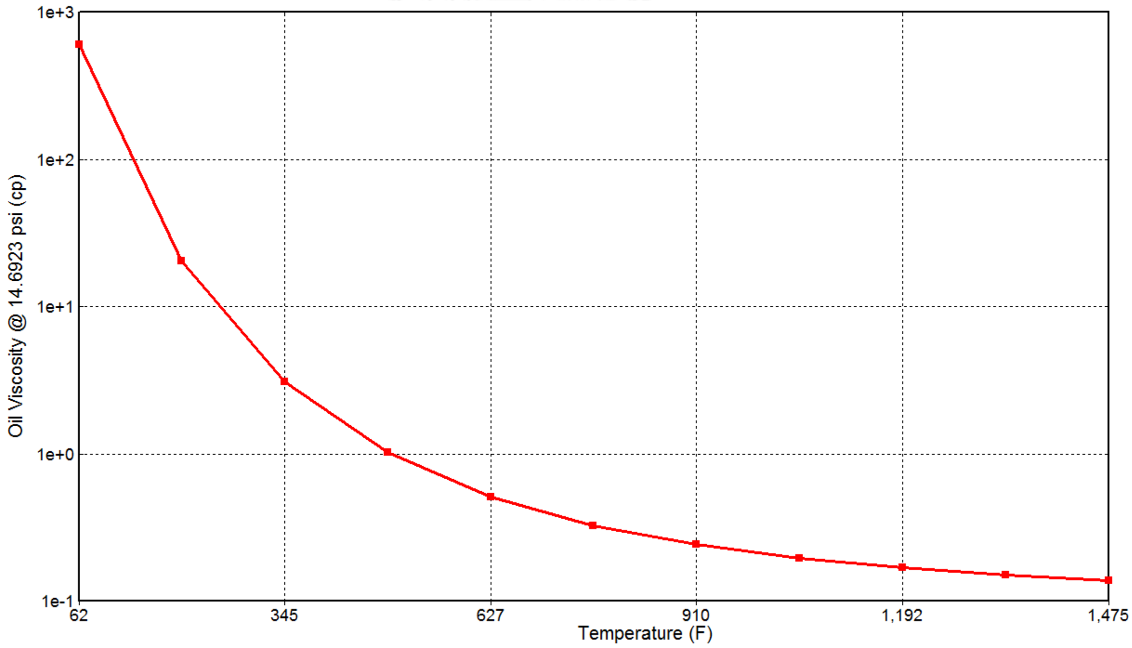

Figure 4.7 Oil viscosity (μ_o) as a function of temperature

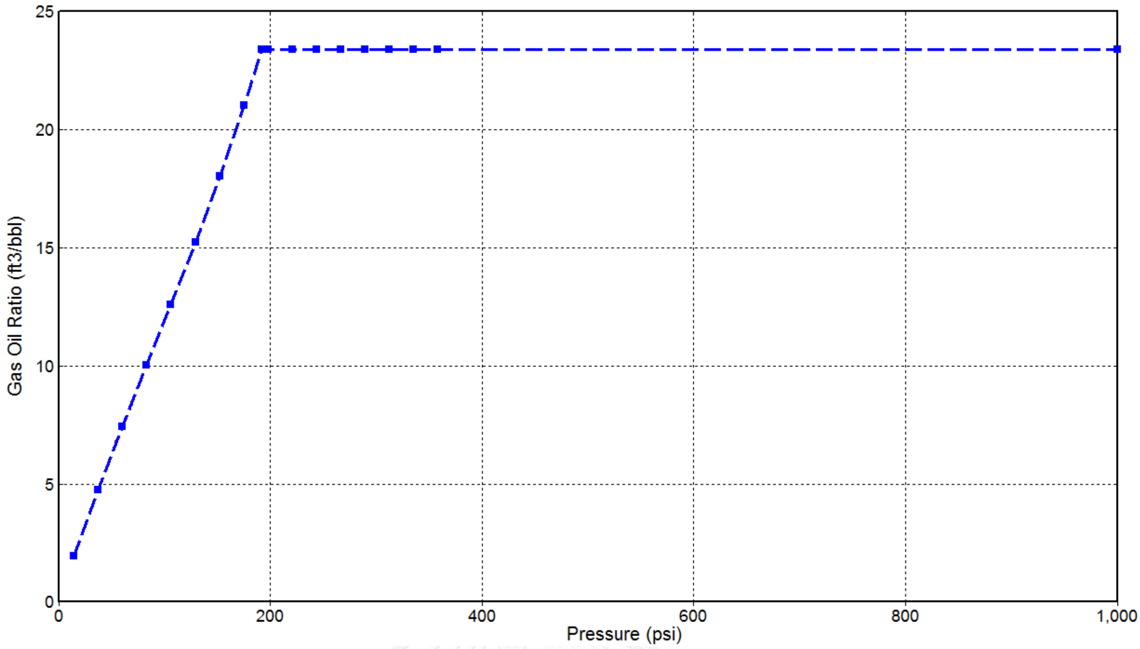

Figure 4.8 Gas-oil ratio (R_s) as a function of pressure

4.3. Rock and Fluid Properties

In this study, Stone's II model [13] is selected to generate relative permeability of three-phase system. The parameters used to create relative permeability system are shown in Table 4.5, whereas Table 4.6 and Table 4.7, shows the values of water-oil and gas-liquid relative permeability respectively. Two-phase relative permeability systems between oil-water, gas-liquid and three-phase relative permeability are illustrated in Figure 4.9, 4.10 and 4.11 respectively.

Table 4.5 Input data for petrophysical properties

Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.28
SWCRIT - Endpoint Saturation: Critical Water	0.28
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.24
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.24
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0.05
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.1
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.15
KROCW - k_{ro} at Connate Water	0.41
KRWIRO - k_{rw} at Irreducible Oil	0.13
KRGCL - k_{rg} at Connate Liquid	0.6
Exponent for Calculating k_{rw} from KRWIRO	3
Exponent for Calculating k_{row} from KROCW	3
Exponent for Calculating k_{rog} from KROGCG	3
Exponent for Calculating k_{rg} from KRGCL	3

Table 4.6 Relative permeabilities to water and to oil as functions of water saturation

Water saturation (S_w)	Relative perm. to water (k_{rw})	Relative perm. to oil (k_{row})
0.28	0.0000	0.4100
0.31	0.0000	0.3378
0.34	0.0003	0.2747
0.37	0.0009	0.2199
0.4	0.0020	0.1730
0.43	0.0040	0.1332
0.46	0.0069	0.1001
0.49	0.0109	0.0730
0.52	0.0163	0.0513
0.55	0.0231	0.0343
0.58	0.0317	0.0216
0.61	0.0422	0.0125
0.64	0.0548	0.0064
0.67	0.0697	0.0027
0.7	0.0871	0.0008
0.73	0.1071	0.0001
0.76	0.1300	0.0000

Table 4.7 Relative permeabilities to gas and to liquid as functions of liquid saturation

Liquid saturation (S_l)	Relative perm. to gas (k_{rg})	Relative perm. to liquid (k_{rog})
0.33	0.6000	0.0000
0.36	0.5176	0.0000
0.38	0.4430	0.0000
0.41	0.3650	0.0000
0.44	0.2968	0.0003
0.47	0.2376	0.0012
0.50	0.1869	0.0028
0.53	0.1440	0.0055
0.56	0.1082	0.0094
0.59	0.0789	0.0150
0.62	0.0554	0.0223
0.64	0.0371	0.0318
0.67	0.0234	0.0436
0.70	0.0135	0.0580
0.73	0.0069	0.0754
0.76	0.0029	0.0958
0.79	0.0009	0.1197
0.82	0.0001	0.1472
0.85	0.0000	0.1786
0.93	0.0000	0.2785
1.00	0.0000	0.4100

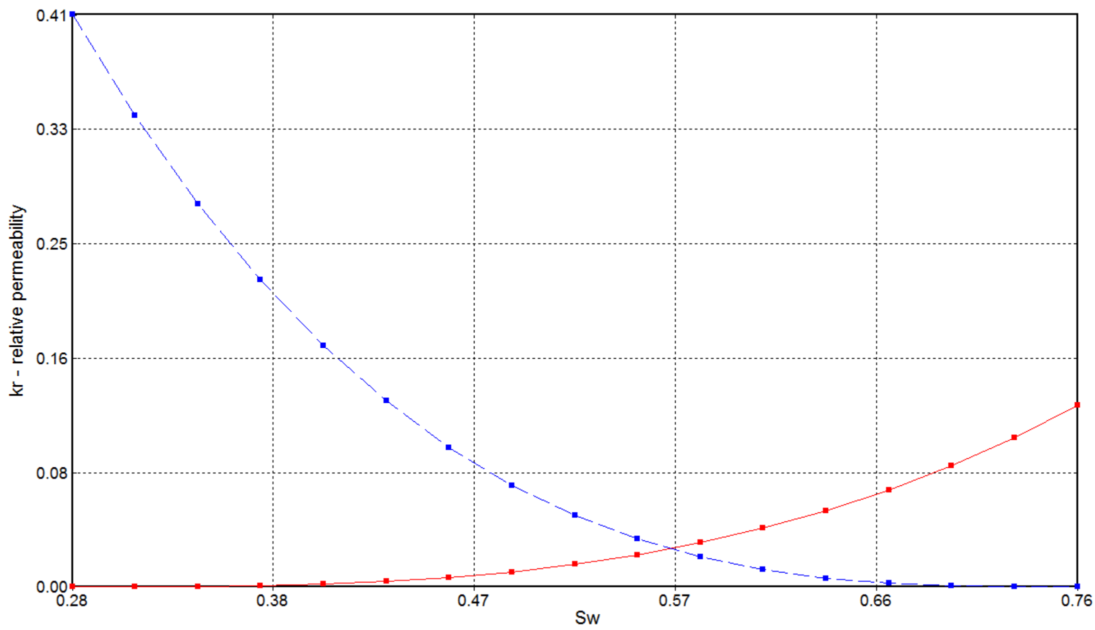

Figure 4.9 Two phase relative permeability of gas-liquid as functions of liquid saturation

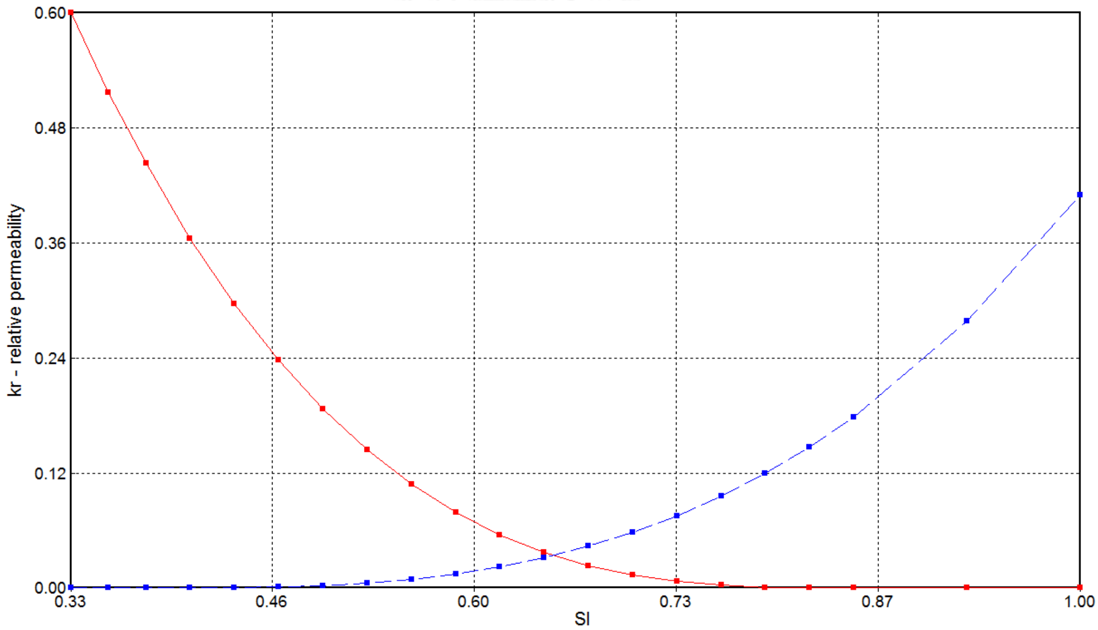

Figure 4.10 Two phase relative permeability of oil-water as functions of water saturation

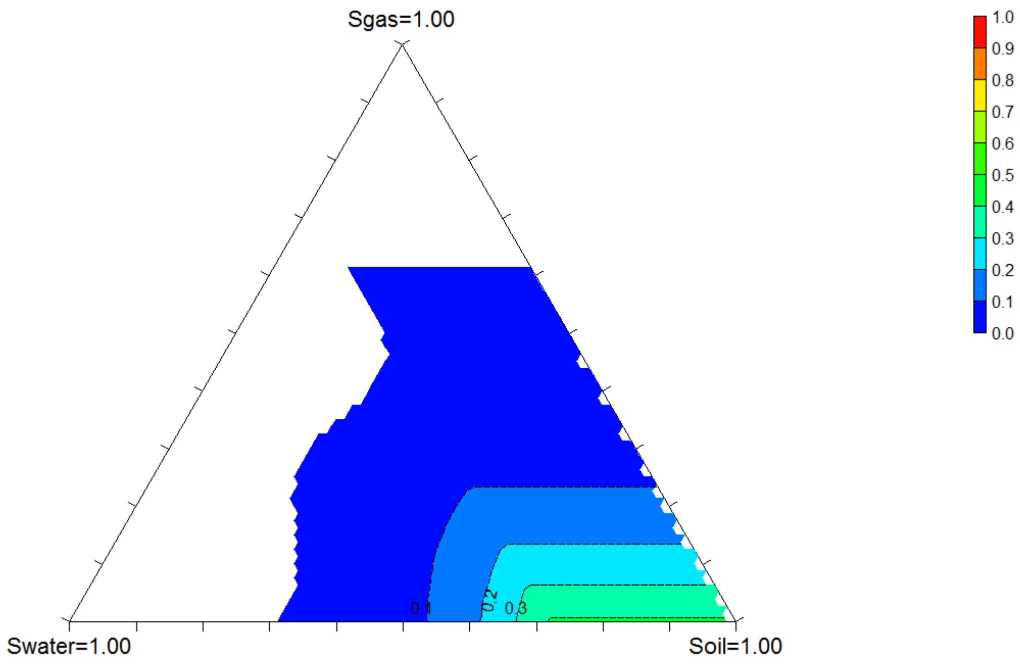

Figure 4.11 Three-phase relative permeability system constructed from Stone II model

4.4. Well Specification and Production Constraints

The injection well and production well are diagonally located at the corners of the reservoir to represent a quarter 5-spot flooding pattern. Both wells have the same size of wellbore radius of 3 inches and are fully perforated in all layers of reservoir. Figure 4.12 illustrates 3-dimentional view of reservoir model including locations of injection and production wells.

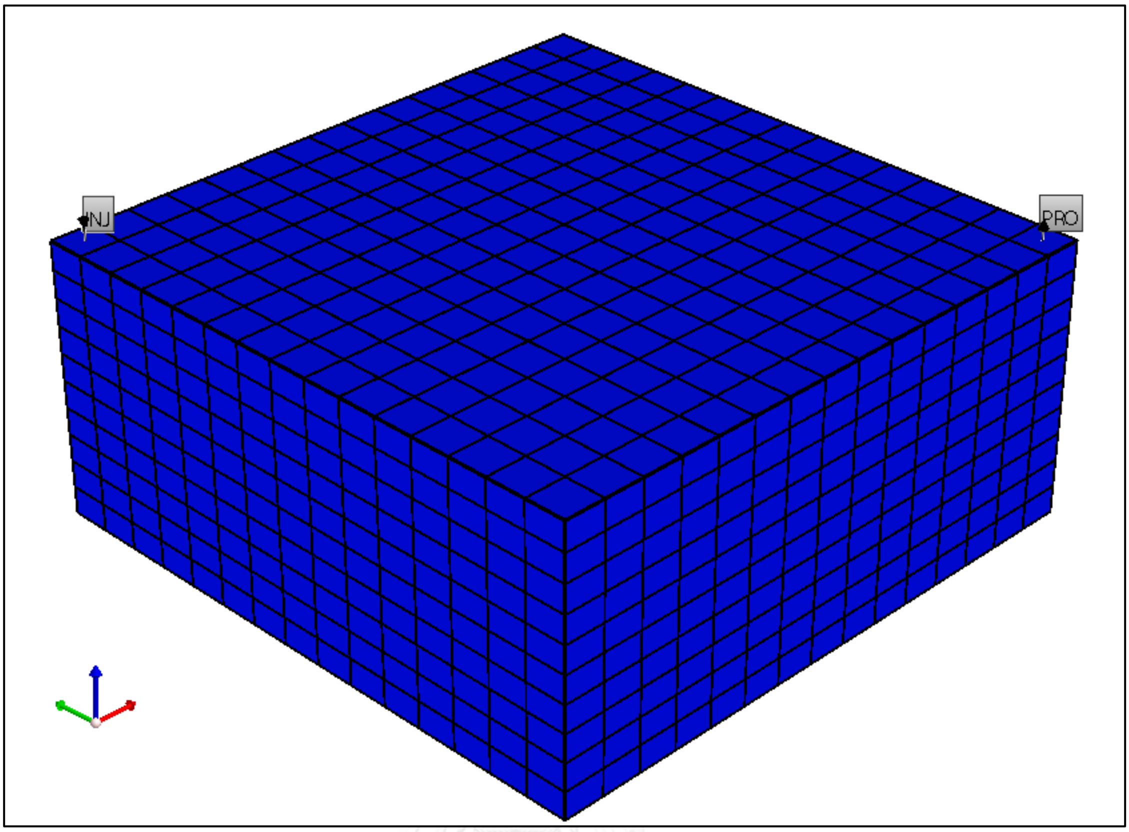

Figure 4.12 Three-dimensional view of the reservoir model

To classify foam qualities in injection well, mole fractions of water, surfactant and steam are justified and shown in Table 4.8. Moreover, Table 4.9 shows maximum surface total phase injection rate in different foam quality and maximum steam injection rate. Injection well and production well constraints are summarized in Table 4.10.

Table 4.8 Mole fractions of foam components (water, surfactant and steam) in different foam qualities

	Mole fraction			
	0.8	0.85	0.9	0.95
Water	0.68598	0.60679	0.49296	0.31545
Surfactant	0.00079	0.00070	0.00057	0.00036
Steam	0.31323	0.39252	0.50647	0.68419

Table 4.9 Maximum total phase injection rate in different foam qualities and maximum steam injection rate

Maximum total phase injection rate, bbl/day					
Mole fraction		0.8	0.85	0.9	0.95
Maximum steam injection rate, bbl/day	40	128.0	102.1	79.1	58.5
	60	192.1	153.2	118.7	87.8
	80	256.1	204.3	158.3	117.1
	100	320.1	255.4	197.8	146.3

Table 4.10 Injection well and production well constraints

Injection well			
Parameter	**Limit/Mode**	**Value**	**Unit**
Bottomhole pressure, BHP	Max	950	psi
Surface total phase rate, STF	Max	varied by Table 4.9	bbl/day
Production well			
Parameter	**Limit/Mode**	**Value**	**Unit**
Bottomhole pressure, BHP	Min	200	psi
Watercut, WCUT	-	0.95	-
Surface oil rate, STO	Min	10	bbl/day

4.5. Thesis Methodology

The evaluation of steam-foam injection is shown in these following steps and summarized by the flowchart in Figure 4.13.

1. Using reservoir simulation program, STARS® commercialized by Computer Modeling Group Ltd. (CMG), to construct homogeneous mode.

2. Perform steamflooding starting at day one to be a base case for steam-foam flooding cases. In both steamflooding and steam-foam flooding, steam injection rates are varied to 60, 80 and 100 bbl/day while keeping other parameters constant. Then, compare the results and conclude the benefit of steam-foam flooding over steamflooding.

3. Perform steam-foam flooding starting at day one by varying four operating parameters, consisting foam stability, foam quality, steam quality and steam injection rate. Foam stability is represented by foam half-life and varied among 0.25, 1, 4 and 16 days. Foam quality is varied among 80, 85, 90 and 95 percent. Steam quality is varied among 45, 60, 75 and 90 percent. Steam injection rate is varied among 40, 60, 80 and 100 bbl/day. All parameters are crossed each other, resulting in 4 x 4 x 4 x 4 = 256 simulations. After that, evaluate the results and discuss the effects of each parameters.

4. Select two dominant parameters and their optimum ranges to perform in multilayered heterogeneous reservoir to study effects of reservoir heterogeneity. Reservoir heterogeneity is divided into two sediment structures consisting of coarsening upward sequence and fining upward sequence. Each sediment structure is differentiated into Lorenz coefficient of 0.20, 0.25 and 0.30. All parameters are crossed each other. Observe the obtained results and evaluate the effects of reservoir heterogeneity.

5. The evaluations of the results obtained from steam-foam flooding are based on oil recovery factor, oil production rate, water production, steam injection rate and bottomhole pressure. 3-dimensional illustrations of ternary phase saturation and oil saturation are also used to assist the evaluations.

6. Conclude new findings based on thesis objectives and provide recommendations for further steam-foam flooding study.

Figure 4.13 Flowchart summarizing thesis methodology

CHAPTER 5
RESULTS AND DISCUSSION

In this study, steamflooding process is performed as a base case. Results of steamflooding are used as references to compare with results from steam-foam flooding in terms oil recovery factor and water production. Homogeneous model is constructed to identify appropriate operational parameters including foam stability, foam quality, steam quality and steam injection rate. Later, selected operational parameters are performed in various heterogeneity values to observe effects of reservoir heterogeneity. This chapter consists of following sub-sections:

5.1. Comparison between Steamflooding and Steam-Foam Flooding Results,

5.2. Effects of Operational Parameters, and

5.3. Effects of Reservoir Heterogeneity.

5.1. Comparison between Steamflooding and Steam-Foam Flooding Results

5.1.1. Steamflooding Results

Steamflooding is performed as base case, starting at day one in the simulation. The results of steamflooding are used as references for steam-foam flooding cases. Oil recovery factor, steam injection rate, oil and water production, bottomhole pressure of injectors and producers are described in Figure 5.2 to Figure 5.5. respectively with various injection rates. After investigation, the results can be used to compare with mechanism of steam-foam flooding process in 5.1.2.

In this thesis, steam injection rate is one of the studied operational parameters. Injection rate of steamflooding process is varied to 60, 80 and 100 bbl/day (equivalent to liquid volume) to investigate their behavior.

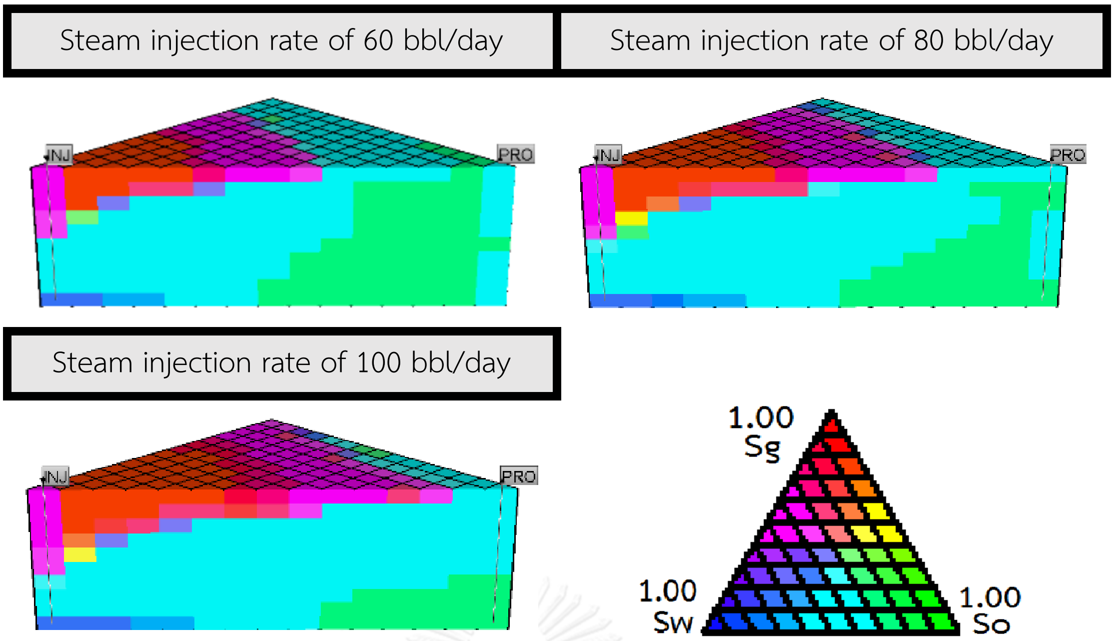

Figure 5.1 Cross-sectional side view of ternary phase saturation profiles at the 6^{th} production year using different steam injection rates of steamflooding

Figure 5.1 illustrates 3-dimensional results of ternary phase saturation profiles at the 6^{th} production year with different steam injection rates of steamflooding. It can be observed that injected steam tends to move upward leaving oil un-swept in the lower layers. This phenomenon is called steam overriding. Higher steam injection rate provides faster flooding front resulting in steam overriding breakthrough. Steam overriding can be improved with steam-foam flooding which is explained in section 5.1.2: Steam-Foam Flooding Results.

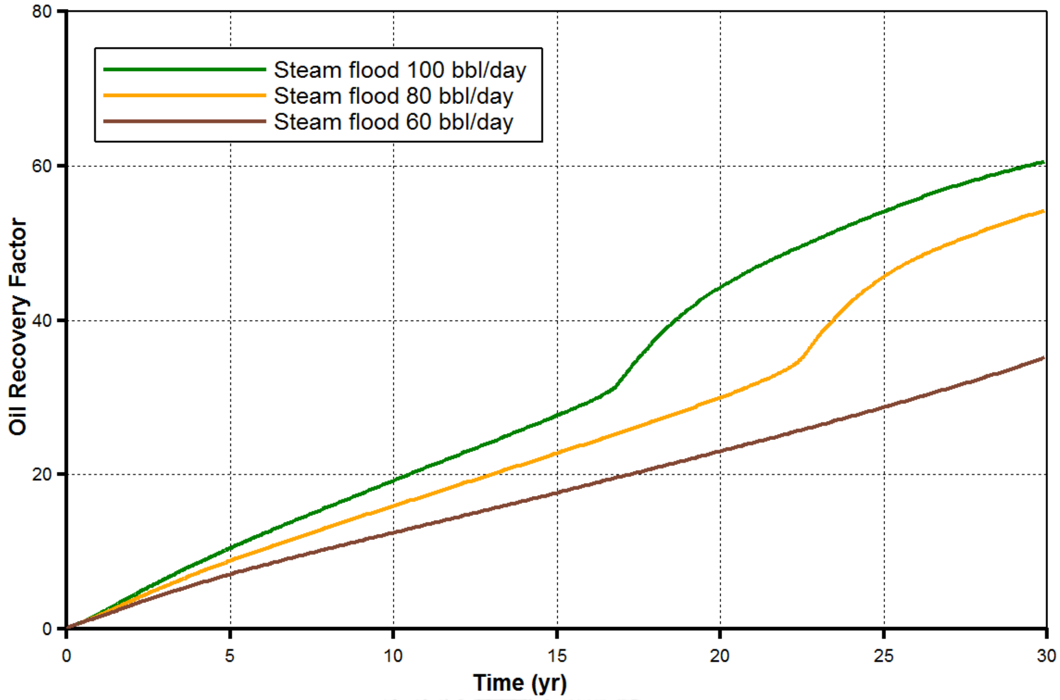

Figure 5.2 Oil recovery factors obtained from steamflooding using various steam injection rates as a function of time

Figure 5.2 illustrates oil recovery factors obtained from three different steam injection rates. It can be observed that steam injection rate of 100 bbl/day can yield the highest oil recovery factor. Injection rate of 100 bbl/day and 80 bbl/day rapidly increase oil recovery factor in about 17th and 23rd of production year respectively. This is due to steam breakthrough which can sweep large amount of oil through the producer. However, overriding steam breakthrough can cause disadvantage to steamflooding process as steam tends to flow to the top section of reservoir due to its lighter density compared to oil, leaving bottom part of reservoir non-displaced. This effect cannot be observed in the results from steam injection rate of 60 bbl/day as steam does not reach breakthrough yet.

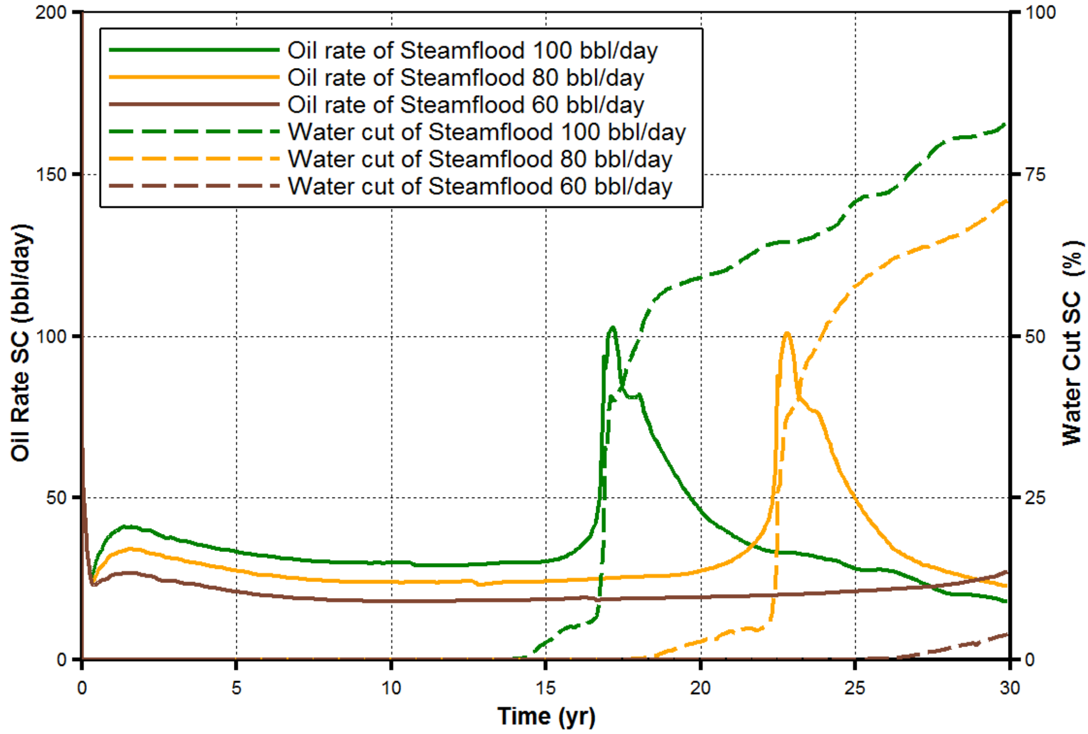

Figure 5.3 Oil production rates and water cut obtained from steamflooding using various steam injection rates as a function of time

Figure 5.3 shows oil production rates and water cut obtained from steamflooding using different steam injection rates. It can be observed that oil production rate can be steady maintained until steam breakthrough. Once steam breakthrough, large amount of oil is swept through the producer resulting in rapidly increment of oil production rate. After that, oil production rate is gradually decreased due to increment of water cut. Comparing between steam injection rate of 100 bbl/day and 80 bbl/day, it can be obviously observed that, higher steam injection rate accelerates increment of water volume into the system.

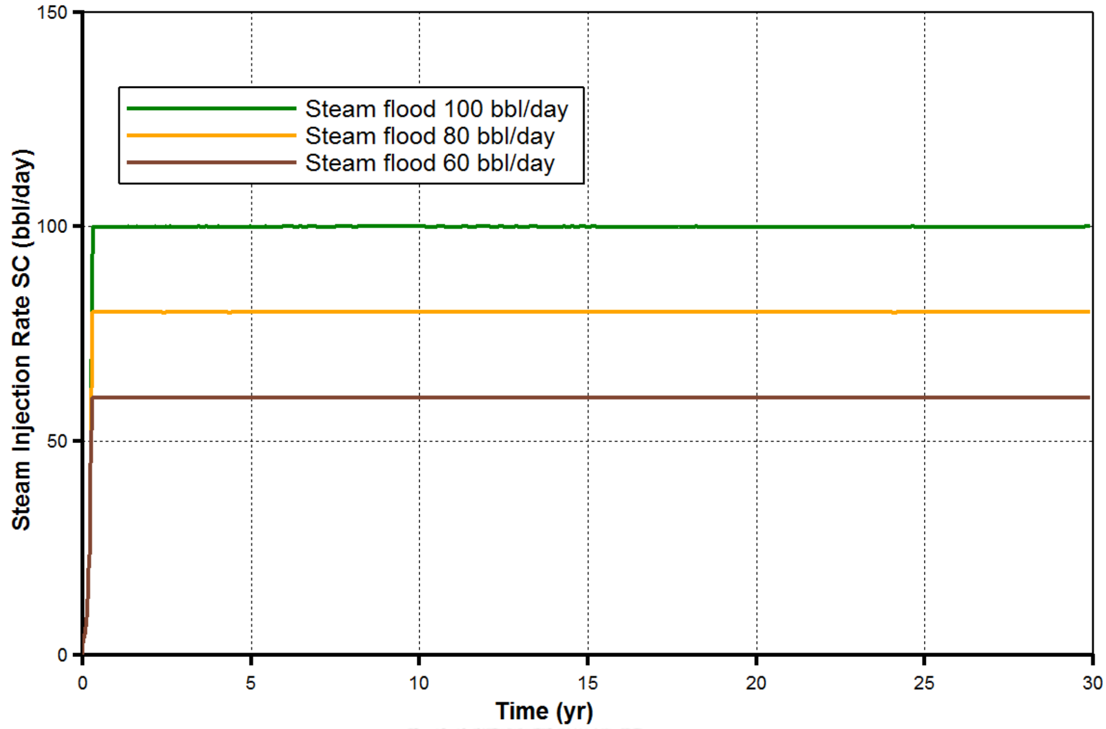

Figure 5.4 Actual steam injection rates of steamflooding using various steam injection rates as a function of time

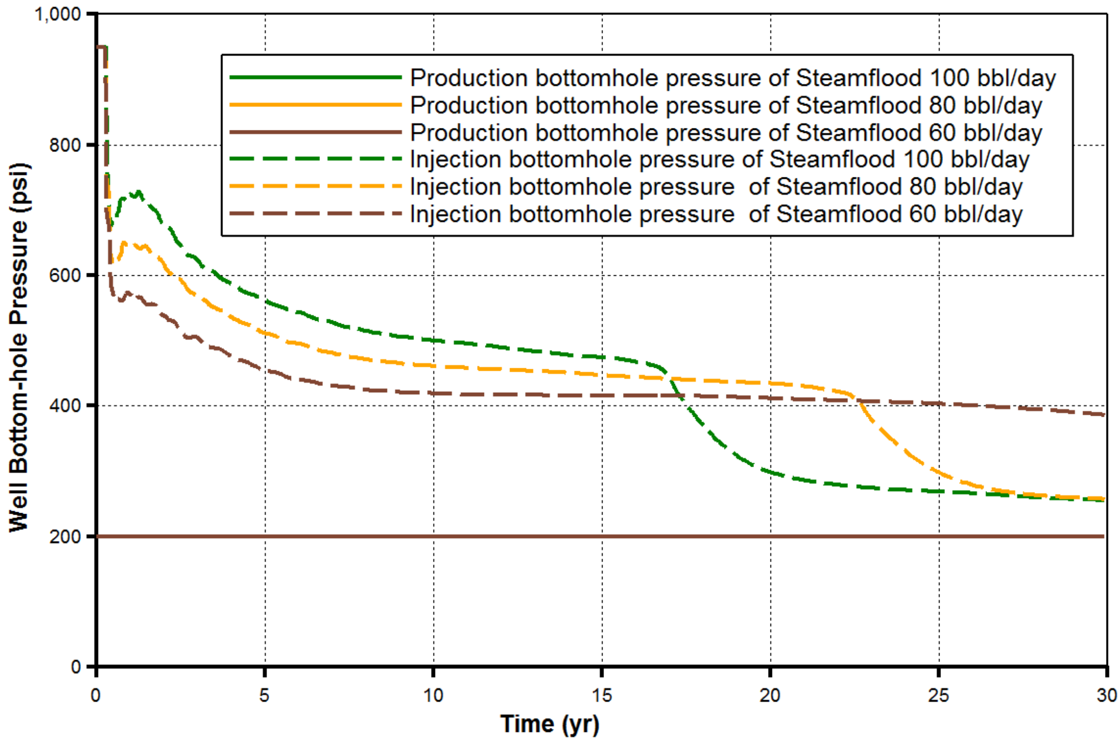

Figure 5.5 Bottomhole pressure of production and injection wells from steamflooding using various steam injection rates as a function of time

Figure 5.4 and Figure 5.5 illustrate actual steam injection rates and bottomhole pressures (of both injection and production wells as a function of time, respectively. As steam injection rate can be attained at the desire value, bottomhole pressure of injector need to be adjusted. For all three cases, bottomhole pressure of injector is reduced during all production time as steam can be injected easier once steam travels and sweeps oil through the reservoir. With steam injection rates of 80 and 100 bbl/day, once steam breakthroughs, bottomhole pressure of injector rapidly drops because steam flow much easier leading to increment of fluid injectivity. Bottomhole pressure of producer can be maintained at desire pressure as production rate does not reach the production constraints.

From this section, steamflooding yields oil recovery factors 35 to 60% with various steam injection rate. The higher steam injection rate yields higher oil recovery factor. Moreover, once steam breakthroughs, large amount of oil swept by steam arrives the producer, leading to rapid increment of oil production rate as well as oil recovery factor.

5.1.2. Steam-Foam Flooding Results

In this section, results from steam-foam flooding cases with various steam injection rates are compared with steamflooding cases to describe mechanism of steam-foam flooding process. Steam-foam is injected from the first day of production. To demonstrate mechanism of steam-foam flooding process, foam with foam quality of 0.95, foam half-life of 0.25 day and surfactant concentration of 0.5%wt are selected to be performed.

Figure 5.6 and Figure 5.7 illustrate cross-sectional side view of ternary phase saturation profiles with different steam injection rates of steamflooding and steam-foam flooding at the 5th and 16th production year respectively. At the 5th production year, it is noticeable that, in steam-foam flooding process, flooding fluid can maintain much better vertical sweeping front due to the benefit of the foam. However, underrunning fluid, consisting of surfactant solution and condensing steam, also exists. This situation causes starting of water production as mentioned in previous section. At the 16th production year, steam overriding can be seen in both steamflooding and steam-foam flooding process. This is because, when the foam travels that far, major amount of foam decays and liberates into steam. Therefore, the flooding fluid behaves more similar to steam. As flooding fluid overriding and underrunning are obtained, certain oil is left at the middle of the reservoir. This problem can be resolved by choosing appropriate foam in order to provide vertical sweeping front.

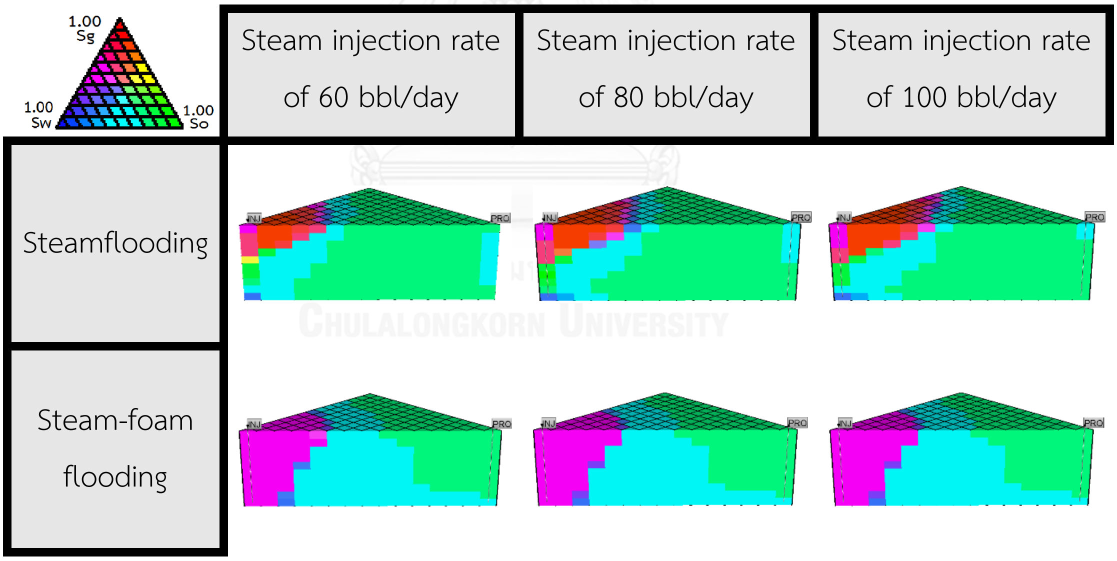

Figure 5.6 Cross-sectional side view of ternary phase saturation profiles at the 5th production year using different steam injection rates of steamflooding and steam-foam flooding

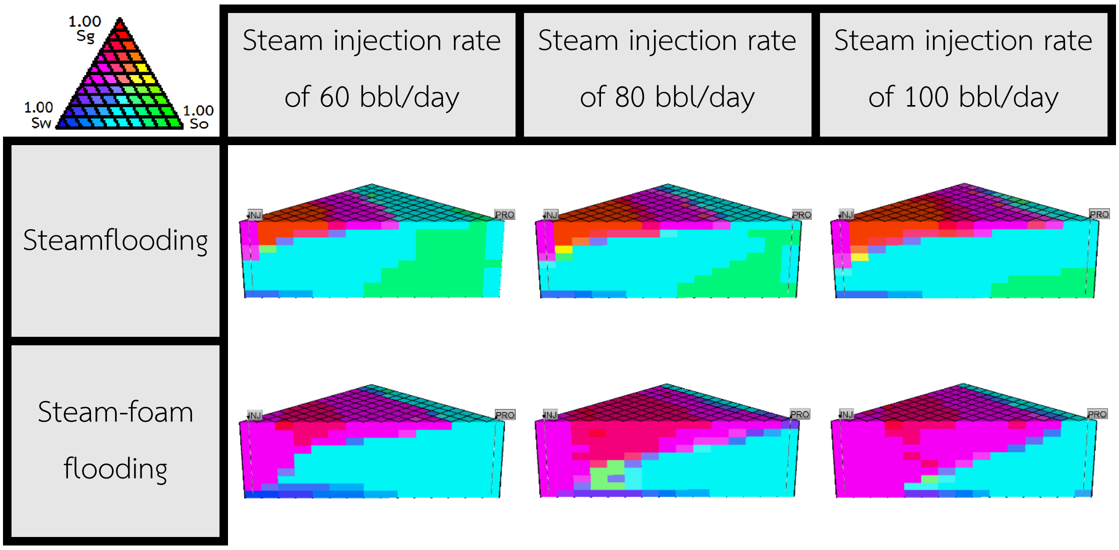

Figure 5.7 Cross-sectional side view of ternary phase saturation profiles at the 16th production year using different steam injection rates of steamflooding and steam-foam flooding

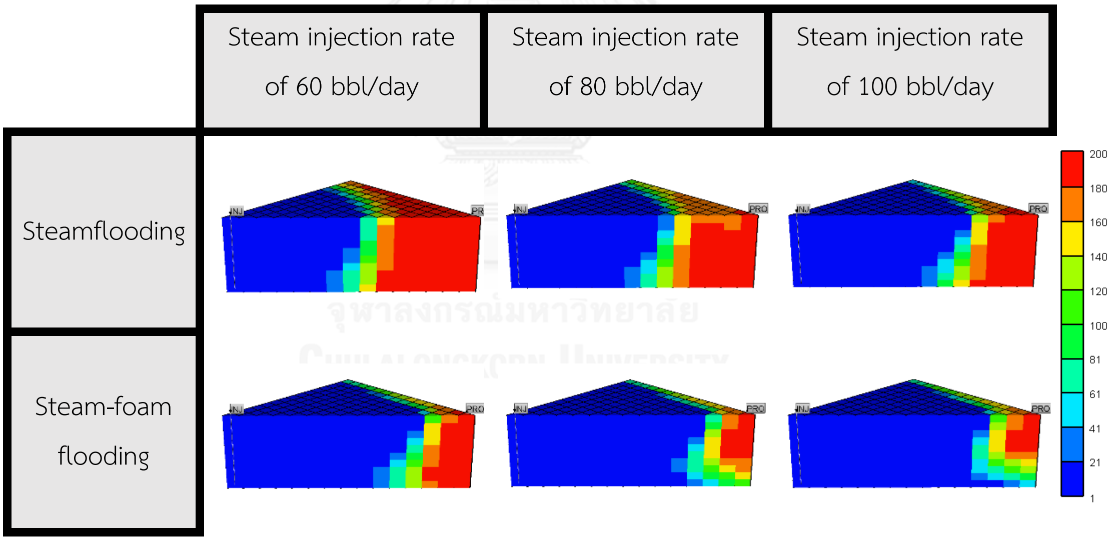

Figure 5.8 Cross-sectional side view of oil viscosity profiles at the 16th production year using different steam injection rates of steamflooding and steam-foam flooding

Figure 5.8 shows cross-sectional side view of oil viscosity profiles with different steam injection rates of steamflooding and steam-foam flooding at the 16th production year. The viscosity profiles can be used to identify hot oil bank as oil viscosity deceases when it is heated. This hot oil bank is swept by flooding fluid and breakthroughs the producer few time before flooding fluid breakthroughs. The oil bank breakthrough provides rapid increment of oil production rate at that time and later, flooding fluid breakthrough also causes rapid decrement of oil production rate as shown in Figure 5.10 to Figure 5.12. Furthermore, amount of hot oil bank determines slope and peak of oil production rate profile in that period; higher amount of hot oil bank provides higher slope and peak.

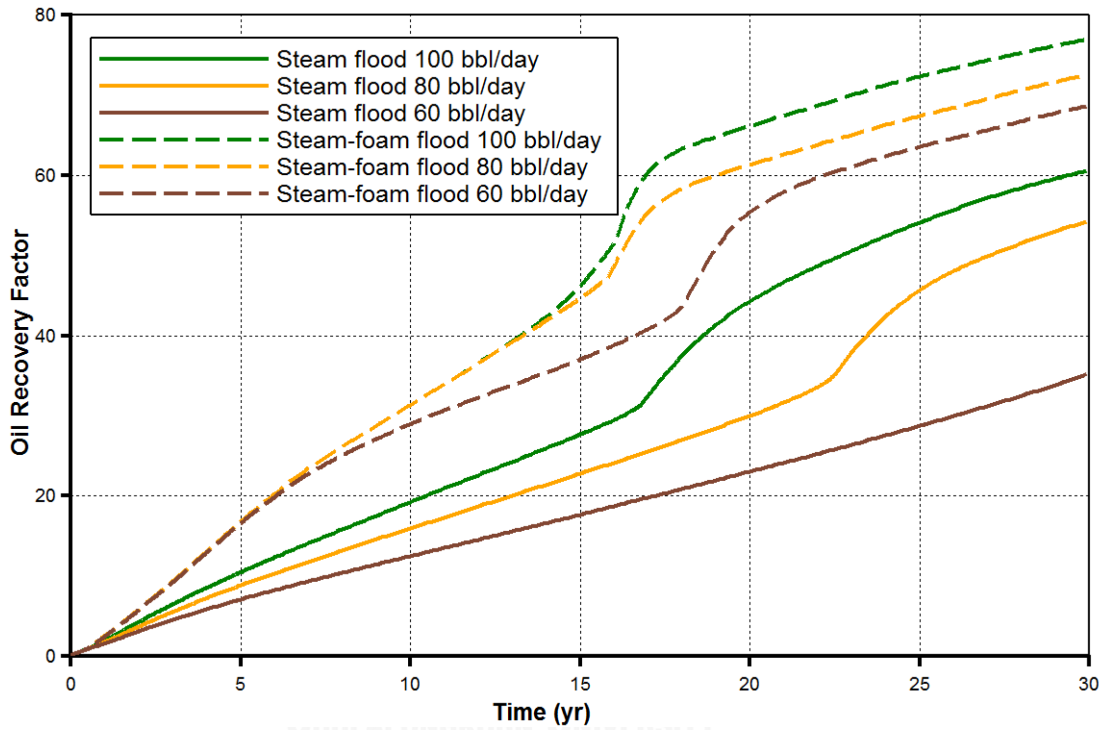

Figure 5.9 Oil recovery factors obtained from steam-foam flooding using various steam injection rates as a function of time in comparison with steamflooding

Figure 5.9 illustrates comparisons of oil recovery factor between steam-foam flooding process and steamflooding process at different injection rates. Steam-foam flooding process provides similar oil recovery profile compared to steamflooding process but yielding higher oil recovery. Steam-foam travels better in both vertical and horizontal directions than steam which only prefers to travel vertically due to its lower density. The higher oil recovery by steam-foam is due to maintaining vertical sweeping profile compared to steamflooding front. This phenomenon leads to improvement of vertical sweep efficiency by steam-foam flooding.

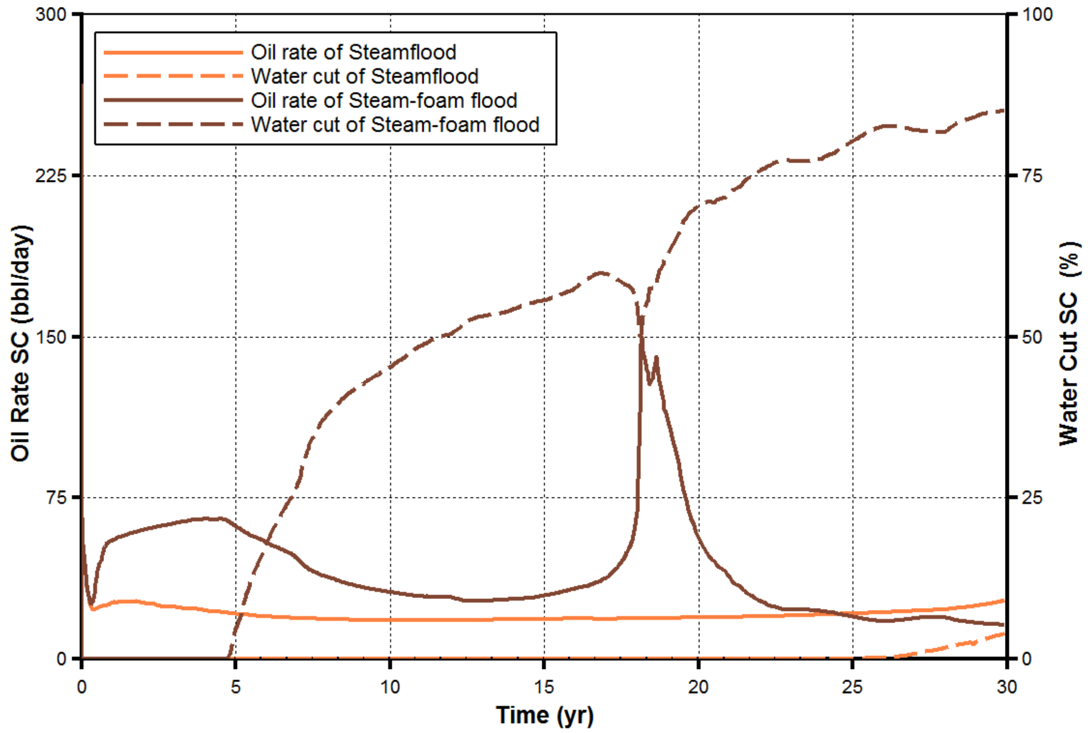

Figure 5.10 Oil production rates and water cut of steam-foam flooding in comparison with steamflooding with steam injection rates of 60 bbl/day as a function of time

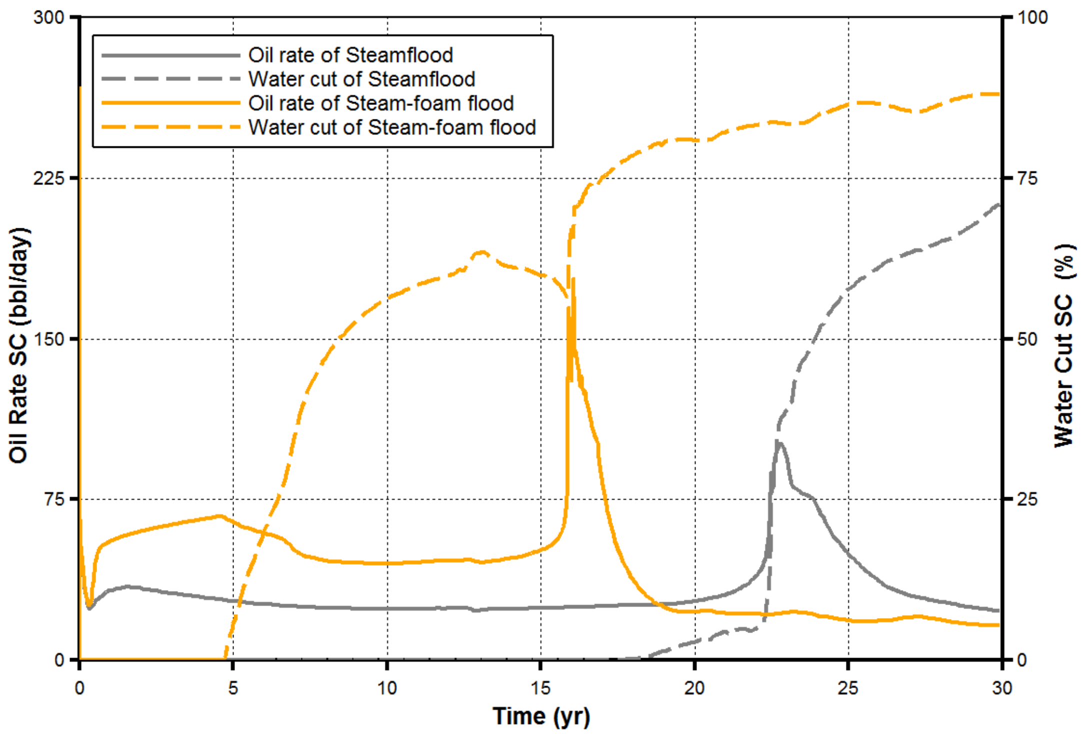

Figure 5.11 Oil production rates and water cut of steam-foam flooding in comparison with steamflooding with steam injection rates of 80 bbl/day as a function of time

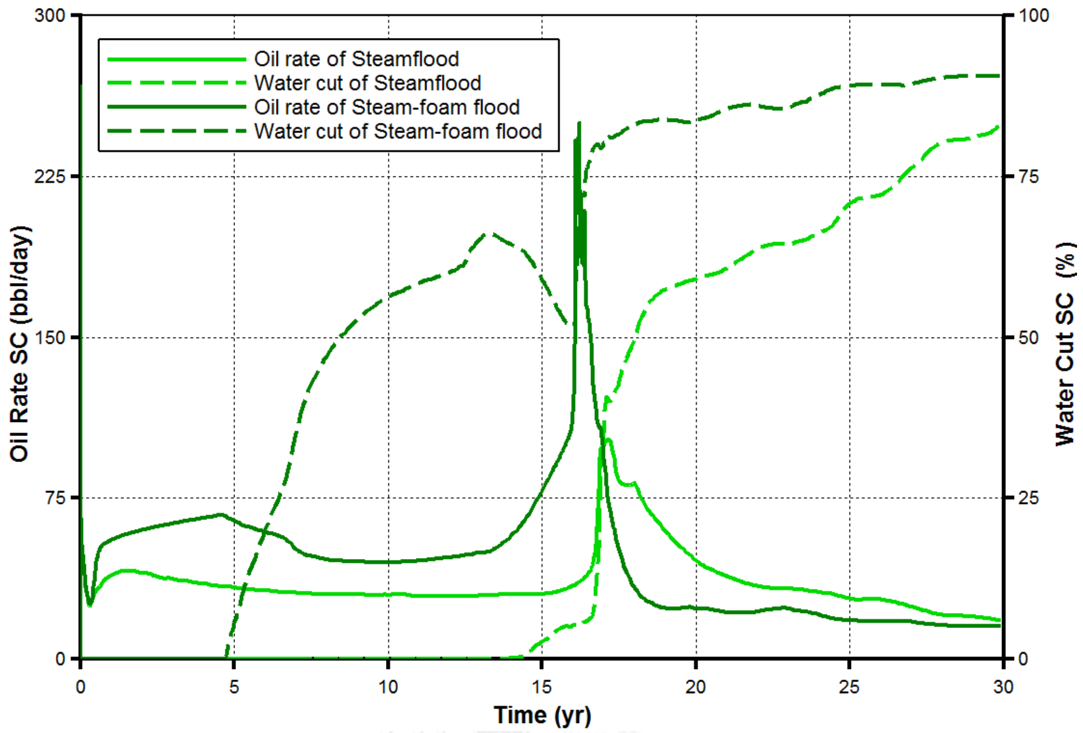

Figure 5.12 Oil production rates and water cut of steam-foam flooding in comparison with steamflooding with steam injection rates of 100 bbl/day as a function of time

Figure 5.10 to Figure 5.12 show oil production rate and water cut of steam-foam flooding process in comparison with steamflooding process with steam injection rates of 60, 80 and 100 bbl/day, respectively. It can be observed that the most obvious difference between steam-foam flooding and steam flooding process is the water cut profile. The water cut profile of steam-foam flooding process has two main periods. Considering steam-foam flooding process with steam injection rate of 100 bbl/day in Figure 5.12, the starting of the first period is at the 5th production year which water cut starts to exist and gradually increases. This is caused by injection fluid underrunning breakthrough consisting of surfactant solution and condensing steam. Later, in the 13th production year, steam-foam can deliver hot oil bank through the producer, resulting in water cut gradually declining. The starting of the second period is at 16th production year which water cut rapidly increases. This is caused by steam overriding breakthrough which is liberated from foam decaying. In term of oil production rate, in first 5 production years, oil production rate can be about double times comparing to steamflooding process. This is the result of the improvement in vertical sweep efficiency. After injection fluid underrunning breakthrough at the 5th production year, oil production rate slowly declines and can be maintained steady rate until hot oil bank breakthroughs the producer. Oil production rate rapidly increases after hot oil bank breakthrough and immediately declines due to steam overring breakthrough in 16th production year. This situation also provides the jump in oil recovery factor in Figure 5.9. After taking the benefit of hot oil bank breakthrough, oil production rate reduces into one-half comparing to first half production period and maintains steady rate till the end of production time.

Comparing among different steam injection rates, it definitely shows that higher steam injection rate delivers higher oil production rate. However, higher production rate also causes earlier steam overriding breakthrough which provides higher water production and might reach earlier water cut limit.

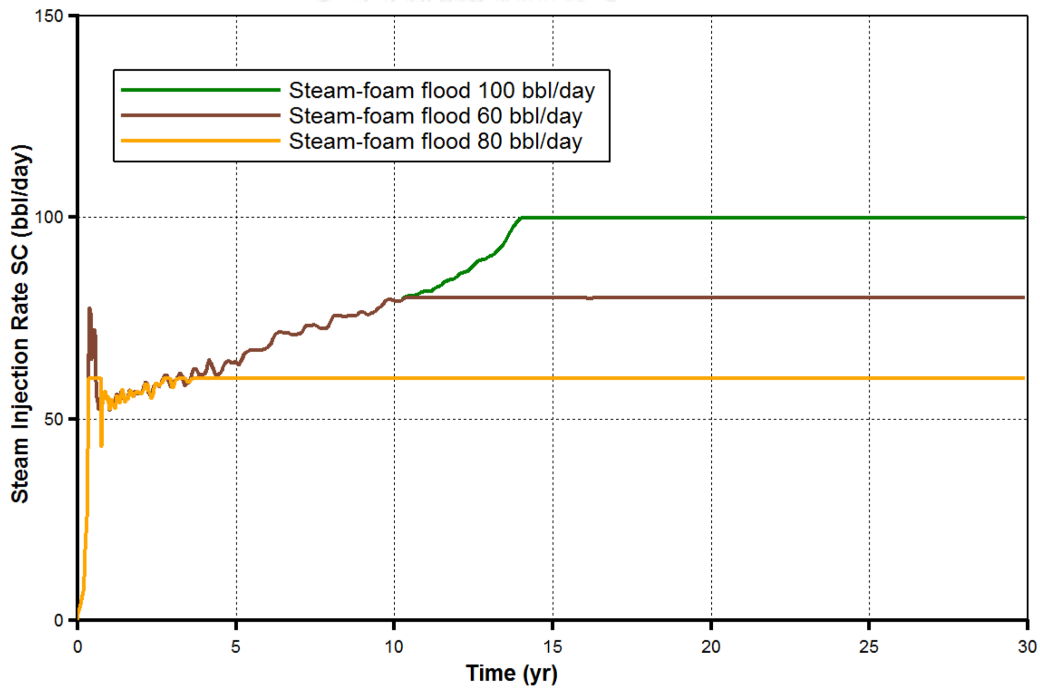

Figure 5.13 Steam injection rates of steam-foam flooding using various steam injection rates as a function of time

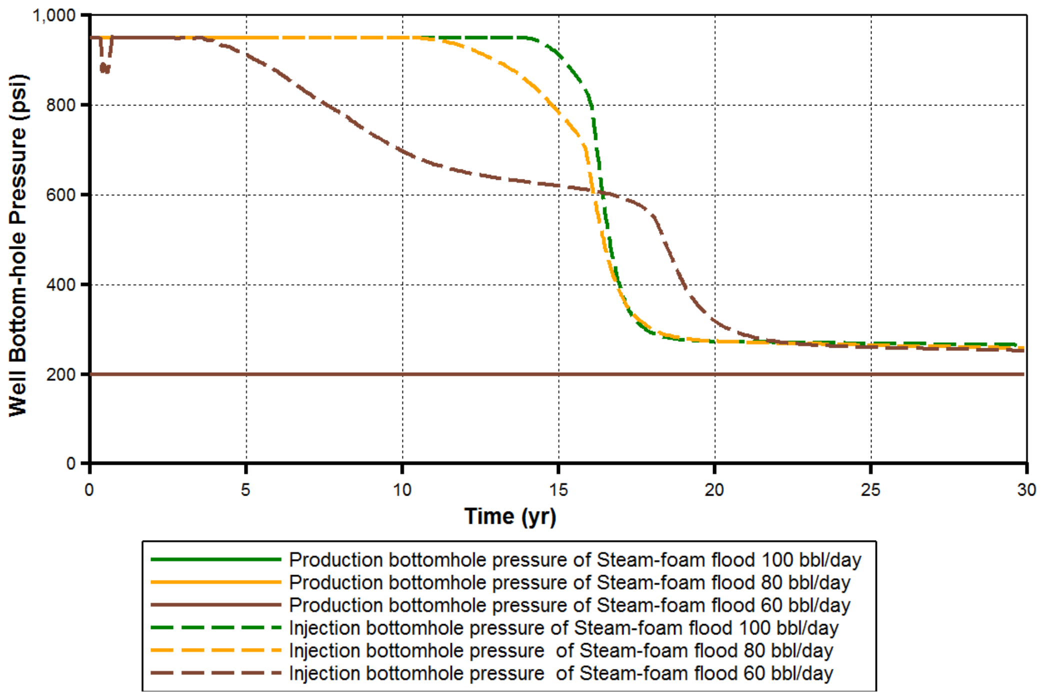

Figure 5.14 Bottomhole pressures of producer and injector of steam-foam flooding using various steam injection rates as a function of time

Figure 5.13 and Figure 5.14 depict actual steam injection rate and bottomhole pressures for steam-foam flooding as a function of time respectively. In fact, steam cannot reach the setting rate since the first day of production. This is because large foam portion remains nearby injection well, leading to lowering of fluid injectivity. In initial production period, due to low fluid injectivity, bottomhole pressure of injector is attained the desire value. Once steam can attain the setting rate, due to increment in fluid injectivity, bottomhole pressure of injector is reduced. Bottomhole pressure of injector is rapidly reduced again once steam breakthrough the producer because the injected fluid can travel easier. Bottomhole pressure of producer can be maintained at desired pressure as production rate does not reach the production constraints.

From this section, steam-foam flooding process can yield much higher oil recovery than steamflooding process. Vertical sweeping front are improved due to higher viscosity enhanced by foaming. However, steam overring still occurs in middle phase of production time. This can be improved by selecting appropriate foam properties which is evaluated in next few sections.

5.2. Effects of Operating Parameters

The simulation cases are constructed to study effects of four operating parameters consisting foam stability, foam quality, steam quality and steam injection rate. Foam stability is represented by foam half-life and varied among 0.25, 1, 4 and 16 days. Foam quality is varied among 80, 85, 90 and 95 percent. Steam quality is varied among 45, 60, 75 and 90 percent. Steam injection rate is varied among 40, 60, 80 and 100 bbl/day. All parameters are crossed each other, resulting in 4 x 4 x 4 x 4 = 256 simulation cases, in order to observe effects across each parameter.

Figure 5.15 shows oil recovery factors of each simulation, which are arranged by crossing foam half-life and foam quality into a 4x4-block matrix. Each matrix is fixed by steam quality and steam injection rate and then each matrix is crossed again. This figure can illustrate mainly effects of foam half-life and foam quality and yet roughly show effect of steam quality and steam injection rate. Oil recovery factors are commonly high in higher steam injection rate. However, steam quality does not much affect the results. The matrix, fixing steam quality of 0.60 and steam injection rate of 80 bbl/day, is selected to be investigated effects of foam stability and foam quality. First, foam quality is selected at 0.90 to evaluate effects of foam stability in section 5.2.1. Thereafter, foam half-life is selected at 1 day to evaluate effects of foam quality in section 5.2.2.

Note: Those abbreviations in Figure 5.15 are stand for these following meaning;

FH: Foam half-life

FQ: Foam quality

SQ: Steam quality

SR: Steam injection rate

SQ45 SR100	FQ80	FQ85	FQ90	FQ95
FH16	48	45	45	45
FH4	58	56	61	76
FH1	75	77	84	82
FH0.25	71	73	80	73

SQ60 SR100	FQ80	FQ85	FQ90	FQ95
FH16	48	45	45	45
FH4	57	56	61	75
FH1	76	77	84	82
FH0.25	72	73	81	74

SQ75 SR100	FQ80	FQ85	FQ90	FQ95
FH16	48	46	46	46
FH4	58	56	62	77
FH1	77	78	85	81
FH0.25	72	73	82	76

SQ90 SR100	FQ80	FQ85	FQ90	FQ95
FH16	50	48	48	49
FH4	61	59	67	83
FH1	77	79	86	82
FH0.25	73	73	82	77

SQ45 SR80	FQ80	FQ85	FQ90	FQ95
FH16	48	45	45	45
FH4	58	56	61	76
FH1	76	77	83	79
FH0.25	72	73	79	69

SQ60 SR80	FQ80	FQ85	FQ90	FQ95
FH16	48	45	45	45
FH4	57	56	61	75
FH1	76	78	84	81
FH0.25	72	73	80	71

SQ75 SR80	FQ80	FQ85	FQ90	FQ95
FH16	48	46	46	46
FH4	58	56	62	76
FH1	77	78	84	81
FH0.25	73	73	81	72

SQ90 SR80	FQ80	FQ85	FQ90	FQ95
FH16	50	48	48	49
FH4	61	59	67	83
FH1	77	77	83	77
FH0.25	73	73	81	73

SQ45 SR60	FQ80	FQ85	FQ90	FQ95
FH16	48	45	45	45
FH4	58	56	61	73
FH1	76	75	80	72
FH0.25	72	73	72	62

SQ60 SR60	FQ80	FQ85	FQ90	FQ95
FH16	48	45	45	45
FH4	57	56	61	74
FH1	76	74	77	76
FH0.25	72	73	74	65

SQ75 SR60	FQ80	FQ85	FQ90	FQ95
FH16	48	46	46	46
FH4	58	56	62	77
FH1	74	74	78	78
FH0.25	73	73	76	67

SQ90 SR60	FQ80	FQ85	FQ90	FQ95
FH16	50	48	48	49
FH4	61	59	67	83
FH1	73	74	82	80
FH0.25	72	73	78	69

SQ45 SR40	FQ80	FQ85	FQ90	FQ95
FH16	48	45	45	45
FH4	58	56	61	61
FH1	70	71	73	49
FH0.25	69	67	61	38

SQ60 SR40	FQ80	FQ85	FQ90	FQ95
FH16	48	45	45	45
FH4	57	56	61	66
FH1	69	70	77	54
FH0.25	70	68	65	41

SQ75 SR40	FQ80	FQ85	FQ90	FQ95
FH16	48	46	46	46
FH4	58	56	62	70
FH1	70	70	78	62
FH0.25	70	69	66	45

SQ90 SR40	FQ80	FQ85	FQ90	FQ95
FH16	50	48	48	49
FH4	61	59	68	76
FH1	71	70	79	72
FH0.25	69	69	67	56

Figure 5.15 Oil recovery factors from cross-over operating parameters

5.2.1. Effects of foam stability

Foam stability can be expressed in term of foam half-life. Figure 5.16 shows oil recovery factors of steam-foam flooding process with different foam half-life. Steam quality of 0.60, steam injection rate of 80 bbl/day and foam quality of 0.90 are selected to investigate effects of foam stability. With appropriate foam half-life, oil production can be significantly enhanced. Those reasons of these phenomena are interpreted in this section.

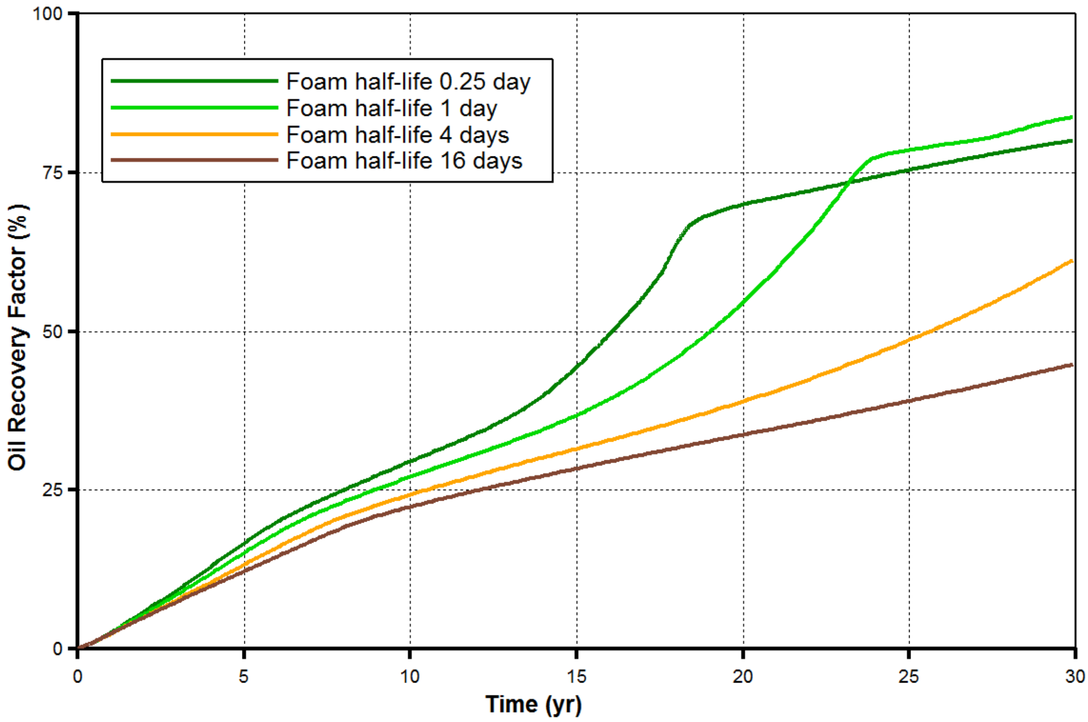

Figure 5.16 Oil recovery factors obtained from steam-foam flooding with different foam half-life values as a function of time

From the figure, steam-foam flooding processes with foam half-life of 0.25 and 1 day can yield favorable results. In the first 20 production years, the process with foam half-life of 0.25 tends to yield the highest result but the process with foam half-life of 1 day can overtake in the late production time. This is because the process with foam half-life of 1 day obtains better vertical sweeping profile as shown in Figure 5.17. The processes with higher foam half-life of 4 and 16 days cannot recover much oil.

This is because high stability foam slowly collapses and hence, large foam portion remains nearby injection well, leading to lowering of fluid injectivity as shown in Figure 5.18.

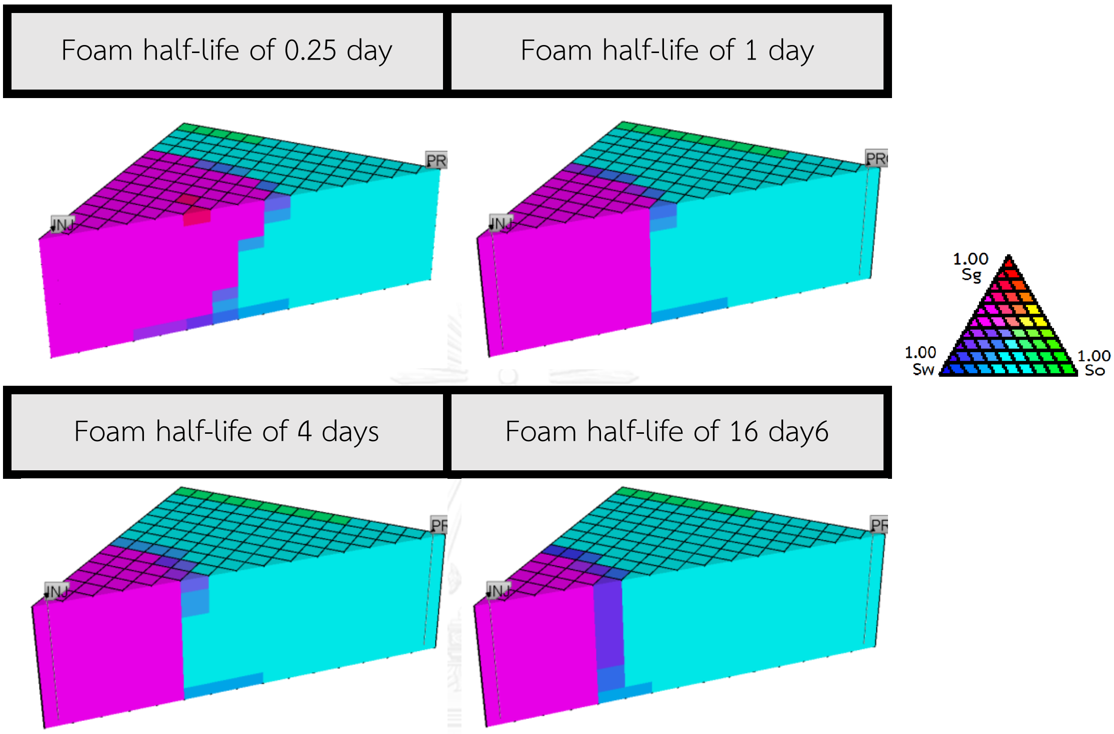

Figure 5.17 Cross-sectional views of ternary phase saturation profiles at the 15th production year with different foam half-life values of steam-foam flooding

Figure 5.17 illustrates ternary phase saturation profiles with different foam half-life values. Low stability foam, with foam half-life of 0.25 day, collapses into steam and surfactant solution quickly. Injected foam then behaves like original fluids: gas tends to cause steam overriding whereas surfactant solution underrunning to bottom zone, leaving certain amount of oil behind. The higher stability foam, with foam half-life of 1 day, can maintain longer foam behavior and therefore, maintain better vertical sweeping profile. Then, the foam with half-life of 1 day can sweep more amount of oil through the producer and overtake the foam with 0.25 day in late production time as shown in Figure 5.16. Too high stability foam, with foam half-life values of 4 and 16 days, result in low injectivity problem that make the flooding front travels slower.

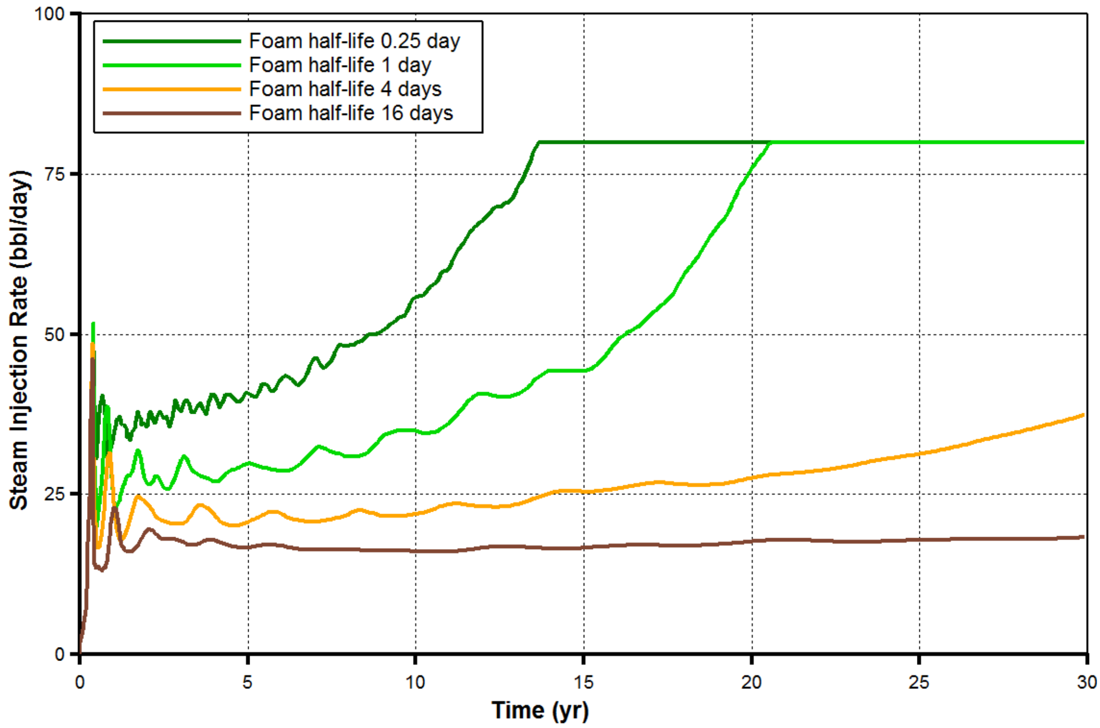

Figure 5.18 Actual steam injection rate of steam-foam flooding with different foam half-life values as a function of time

Figure 5.18 shows actual steam injection rates with different foam half-life values. The figure confirms that high stability foam with foam half-life of 4 and 16 days cause low fluid injectivity problem which leads low recovery.

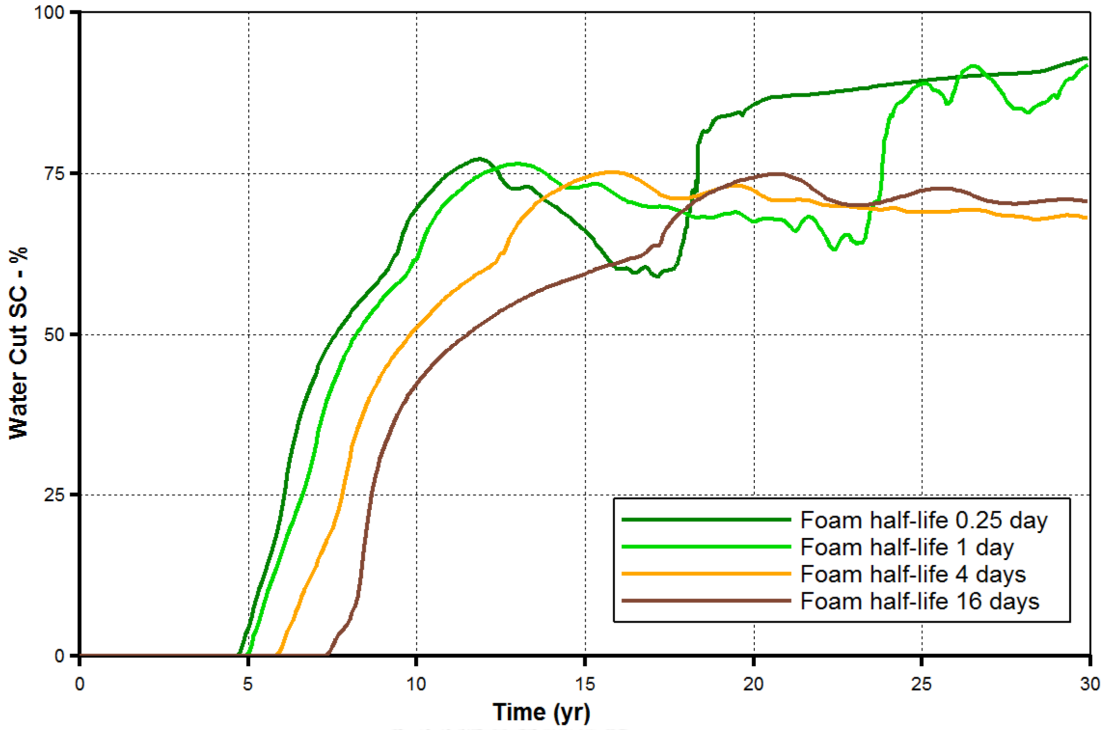

Figure 5.19 Water-cut of steam-foam flooding with different foam half-life values as a function of time

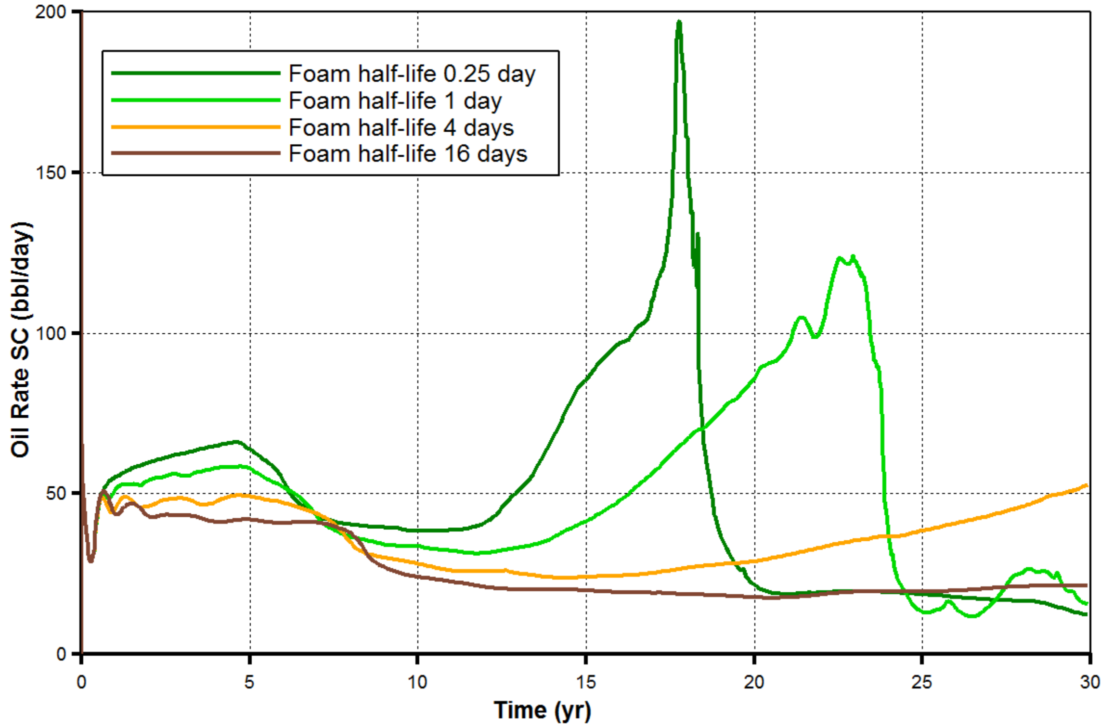

Figure 5.20 Oil production rates of steam-foam flooding with different foam half-life values as a function of time

Figure 5.19 and Figure 5.20 illustrate water-cut and oil production rate respectively. According to Figure 5.20, as lower foam stability has higher fluid injectivity, it provides higher rate at early production period. However, it also causes earlier flooding fluid underrunning breakthrough as shown in Figure 5.19. Low stability foam, with half-life of 0.25 day, provides earliest hot oil bank breakthrough at the 12th production year. Foam with half-life of 1 day, provides later hot oil bank breakthrough at 14th production year but obtain larger amount of oil. This is because it has better vertical sweeping front which can sweep more oil through the producer. Moreover, in foam with half-life of 0.25 day, the third increment of oil production rate can be noticed. This is because the foam is soft and hence steam can easily liberate from the foam. This steam overrides the reservoir and also condenses down to lower zone, therefore helps sweeping more oil through the producer. Nevertheless, steam overriding breakthrough also causes high water production. Steam overriding breakthrough in foam with half-life of 4 and 16 days cannot be noticed as high stability foam hardly allows steam to liberate.

From this section, selecting appropriate foam half-life value provides favorable result. Foam with high stability slowly collapses and hence, large foam portion remains near injection well, leading to lowering of fluid injectivity. In contrast, foam with low stability collapses into steam and surfactant solution quickly. Injected fluids then behave like original fluids: gas tends to cause steam overriding and consecutively leaves oil in lower section of reservoir. Optimum range of foam half-life which is an indicator for foam stability is suggested to be in between 0.25 and 1 day for this study.

5.2.2. Effects of foam quality

In this section, steam-foam flooding processes with different foam quality are evaluated. Steam quality of 0.60, steam injection rate of 80 bbl/day and foam half-life of 1 day are selected to be performed. The results of oil recovery, as shown in Figure 5.21, do not show much the differences between the processes with foam quality of 0.80 and 0.85. The process with foam quality of 0.95 can recover the largest amount of oil in the first 23 production years but be overtaken by the process with foam quality of 0.90 after that. The descriptions for those results are mentioned in this section.

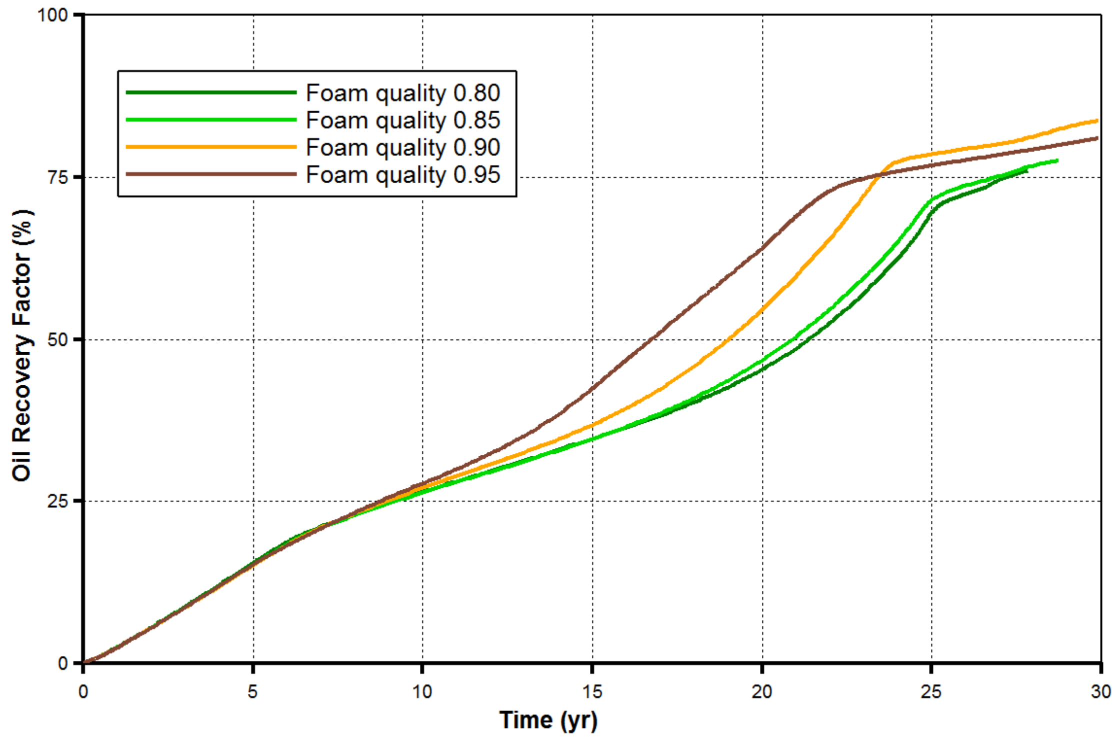

Figure 5.21 Oil recovery factor obtained from steam-foam flooding with different foam quality values as a function of time

In Figure 5.22, cross-sectional views of oil saturation profiles at the 10th production year are selected to illustrate early breakthrough by water underrunning problem. In the process with foam quality of 0.95, due to higher carried heat, more amount of steam is injected into the reservoir and part of steam condenses into water and moves downward, resulting in early breakthrough from water underrunning problem, and leaving certain amount of oil in shallow zone. This makes the process with 0.90 foam quality can produce more oil in later period. In the processes with foam quality of 0.80 and 0.85 which contain higher portion of surfactant solution, the foam behaves closer to water and therefore, travels slower, leading to low injectivity at injector and low oil production rate as shown in Figure 5.23 and Figure 5.25.

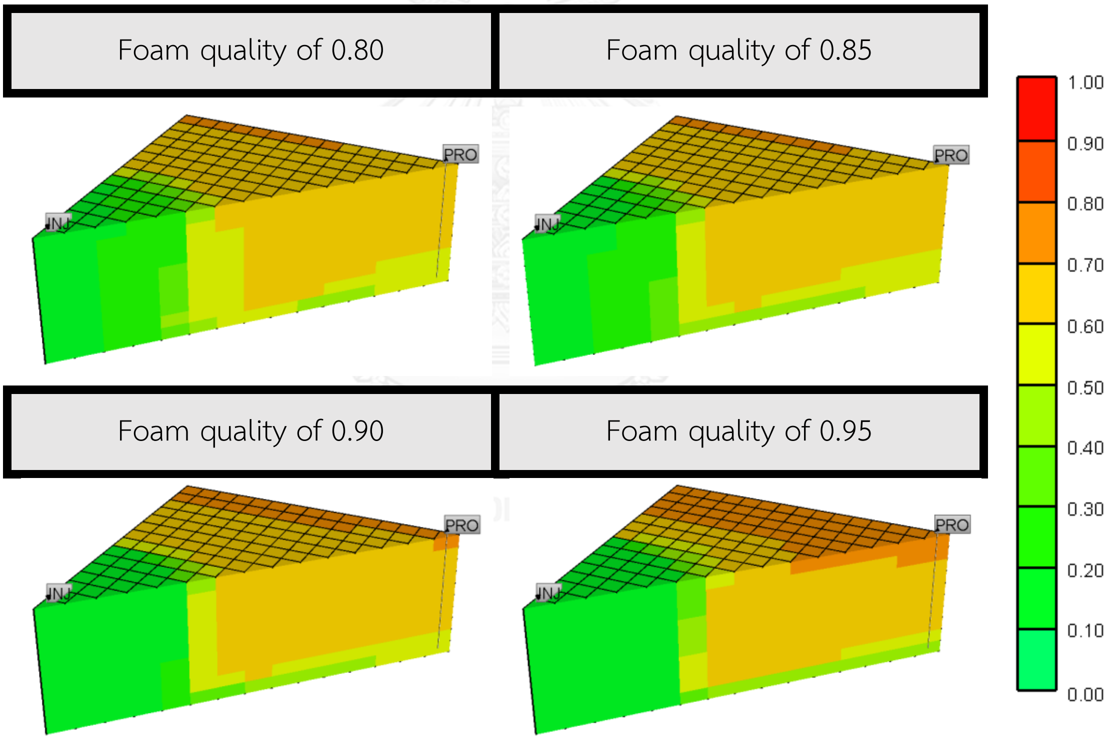

Figure 5.22 Cross-sectional views of oil saturation profiles at the 10th production year with different foam quality values of steam-foam flooding

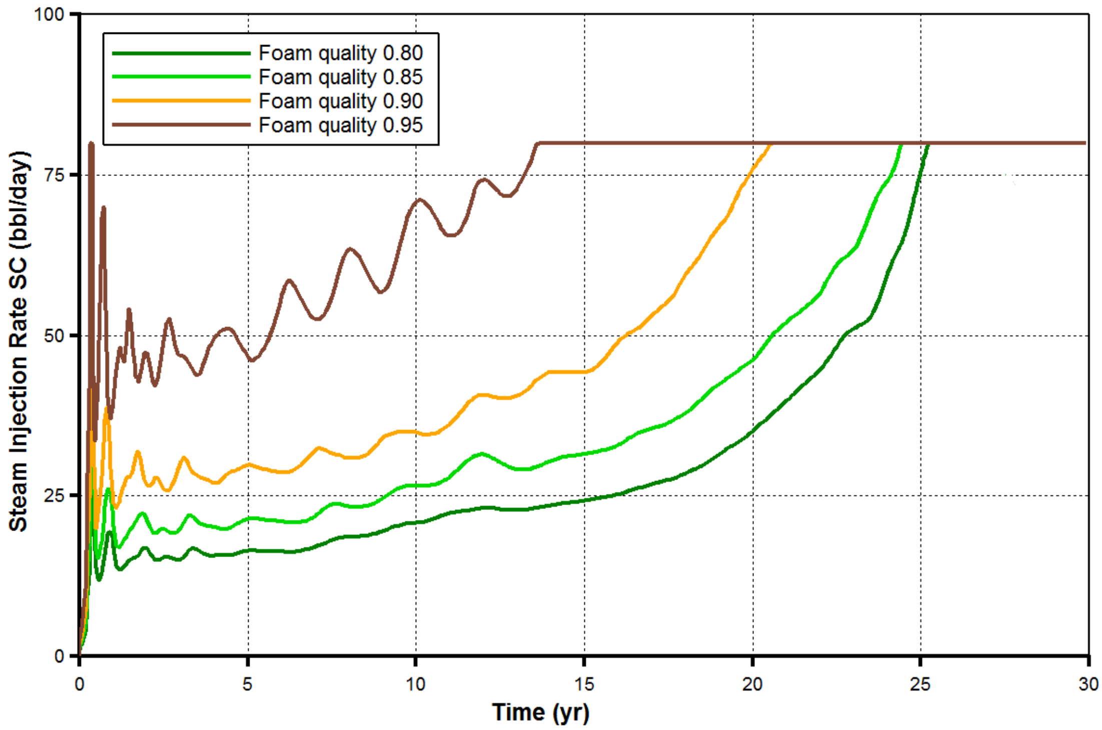

Figure 5.23 Actual steam injection rate of steam-foam flooding with different foam quality values as a function of time

Figure 5.23 can mention a problem of low injectivity at the injector in low foam quality process. The processes with low foam quality, such as 0.80 and 0.85, containing higher portion of surfactant solution, the foam behaves closer to water and hence travels slower. Larger amount of foam maintains near the injector and resist injection of the foam.

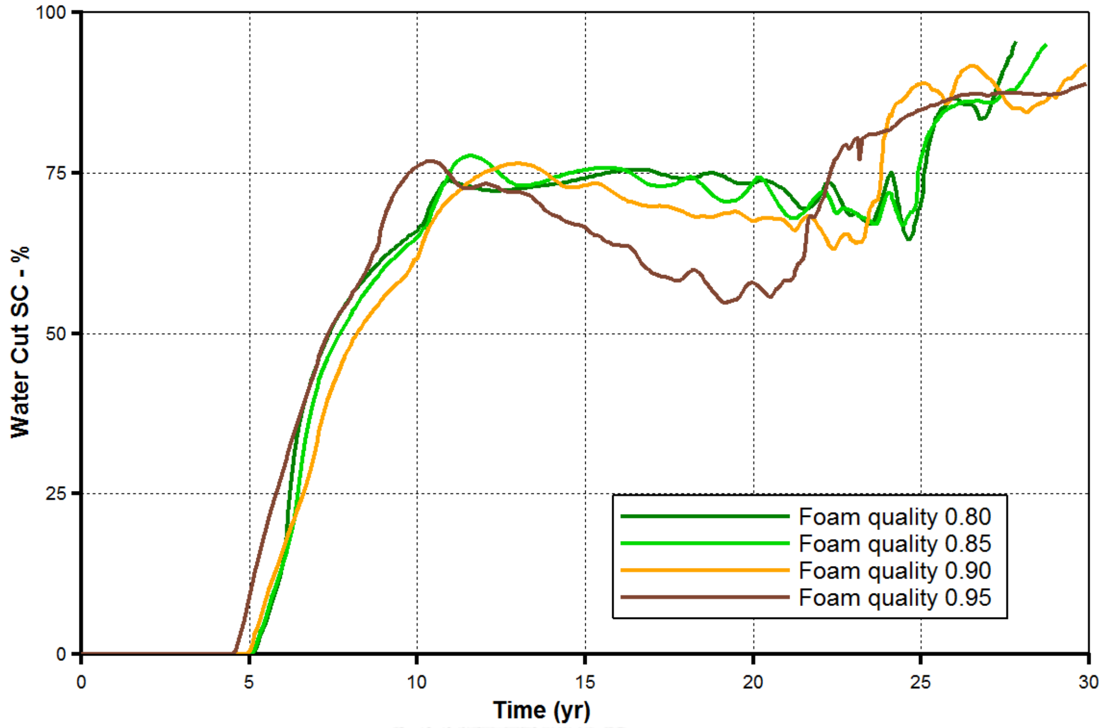

Figure 5.24 Water-cut of steam-foam flooding with different foam quality values as a function of time

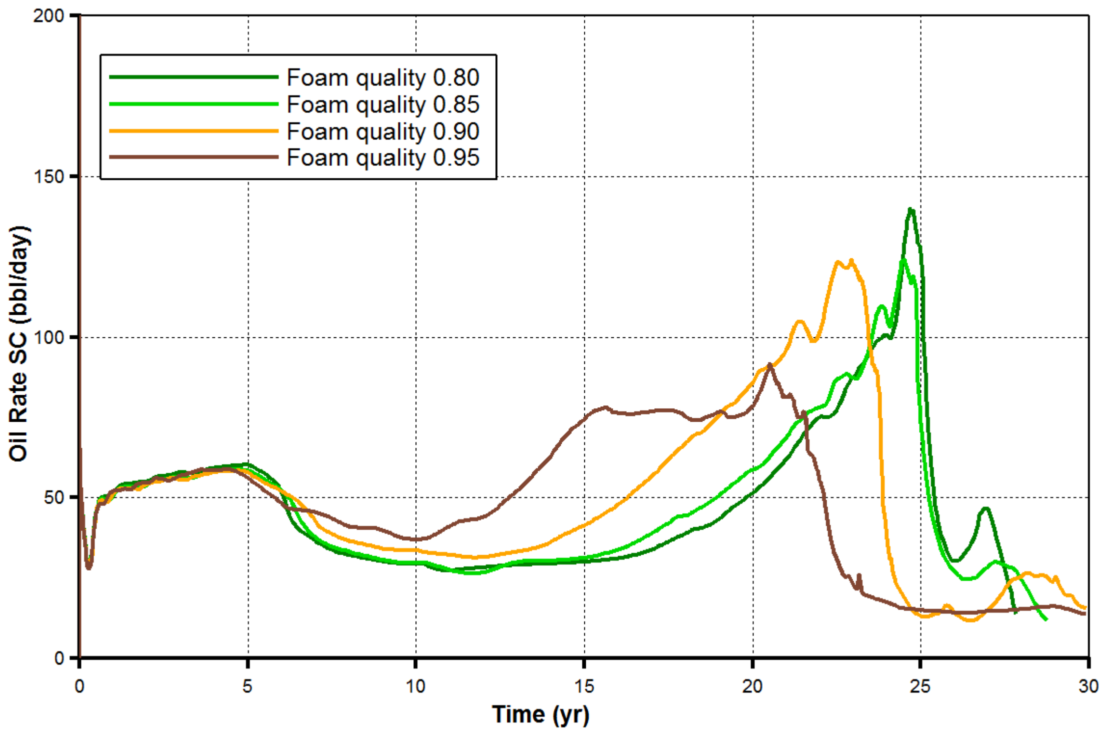

Figure 5.25 Oil production rates of steam-foam flooding with different foam quality values as a function of time

Figure 5.24 shows that underrunning water breakthroughs the producer in almost the same time at the 5^{th} production year in all cases. In the higher foam quality of 0.90 and 0.95, overriding steam breakthroughs the producer earlier due to higher amount of steam. However, these two high foam quality cases do not reach water-cut constraint. In contrast, the lower foam quality of 0.80 and 0.85 face high water-cut and reach the limit early. This is because those cases contain larger amount of surfactant solution. From Figure 5.25, in the process with foam quality of 0.95, hot oil bank breakthroughs at the producer very early in the 10^{th} production year. This makes the profit in the early period that oil can be produced in high rate. However, the process with foam quality of 0.90 can surpass in amount of oil recovery in late production time due to better vertical sweep efficiency that can be noticed in Figure 5.22.

From this section, in high foam quality, due to higher carrying heat, steam can be injected with an ease and high amount of steam is injected into reservoir. Condensing steam tends to move downward and leaves certain amount of oil in shallow zone, resulting in low vertical sweep efficiency. Whereas low foam quality with higher portion of surfactant solution behaves closer to water and moves slower, leading to low injectivity of the injector.

5.2.3. Effects of steam quality

This section shows effect of different steam quality on steam-foam flooding processes. Steam injection rate of 80 bbl/day is selected to be performed. According to section 5.2.1 and 5.2.2, appropriate foam half-life of 1 day and foam quality of 0.90 are utilized. In the aspect of oil recovery, as shown in Figure 5.26, the results cannot show significant difference as any steam quality chosen in this study delivers sufficient heat for oil recovery mechanism through reduction of oil viscosity. Another aspect presenting in this section is energy consumption.

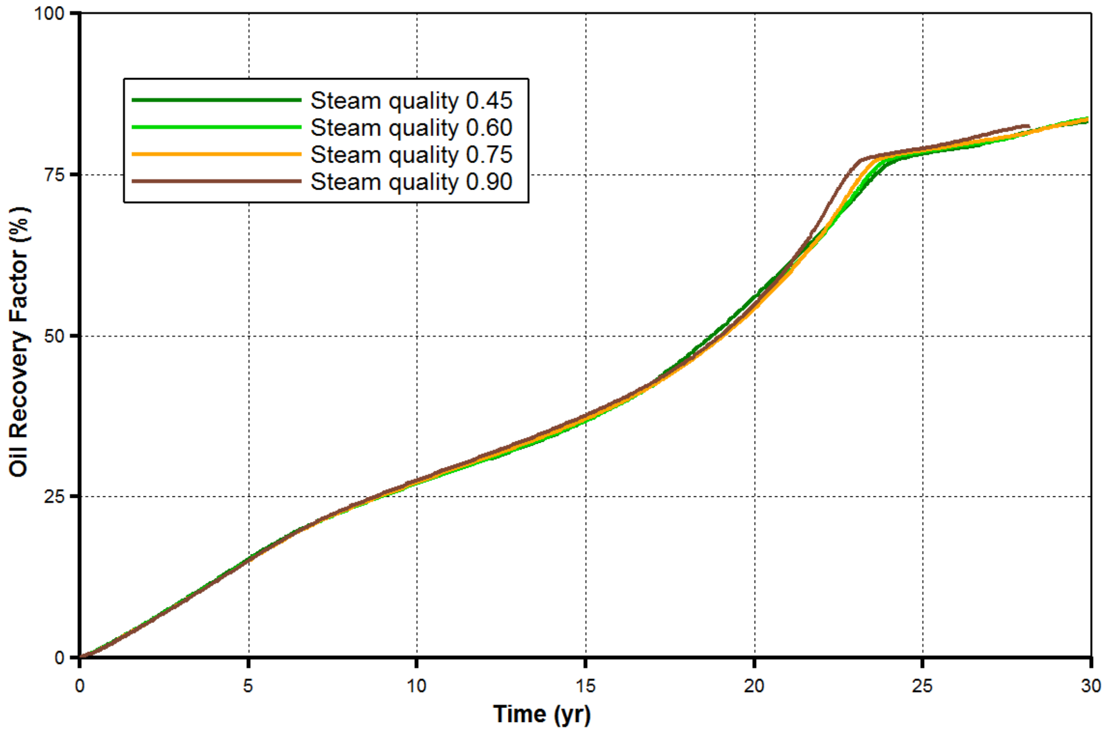

Figure 5.26 Oil recovery factors obtained from steam-foam flooding with different steam quality values as a function of time

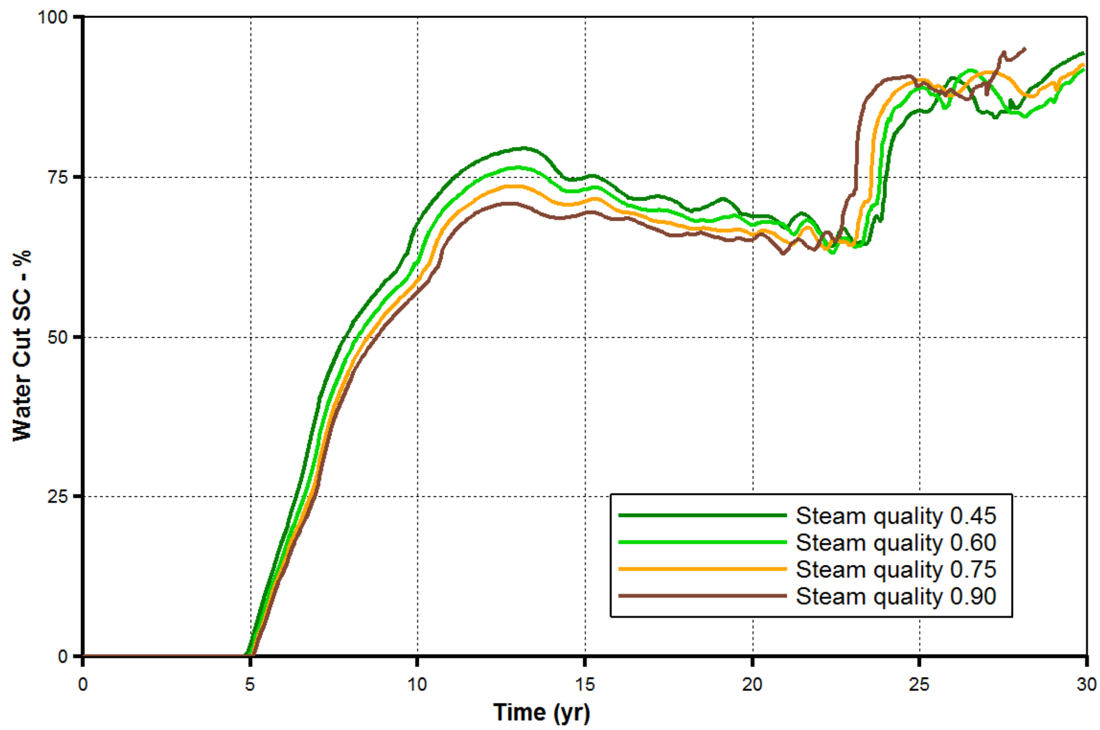

Figure 5.27 Water-cut of steam-foam flooding with different steam quality values as a function of time

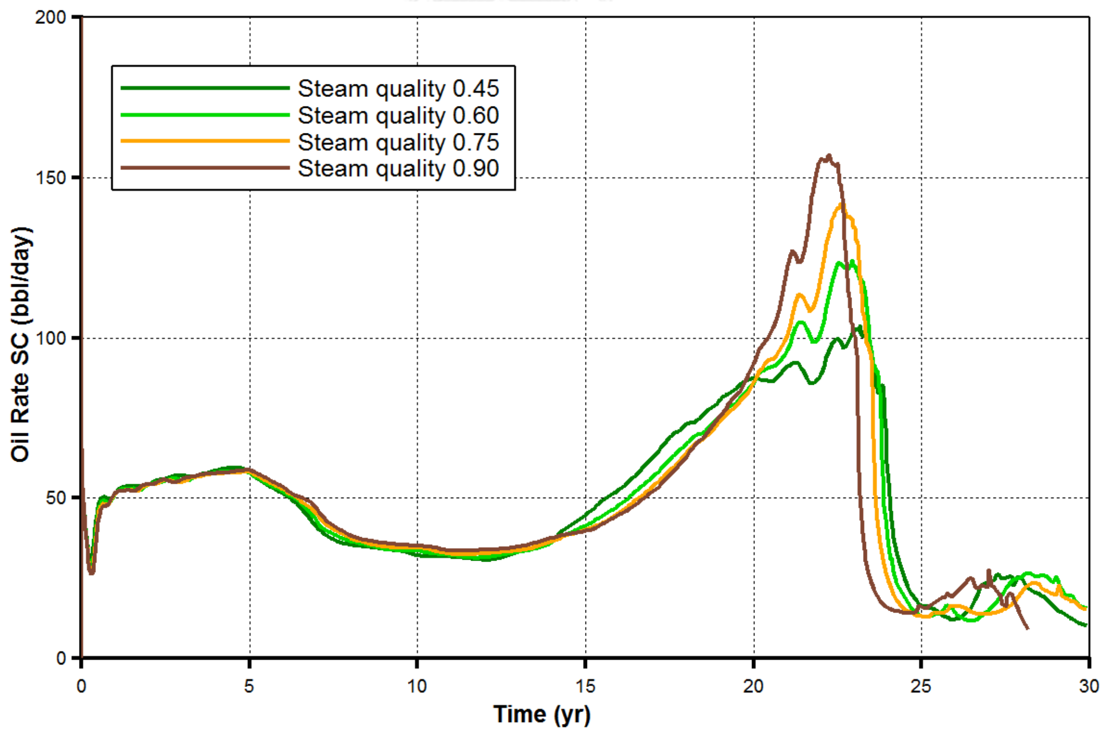

Figure 5.28 Oil production rate of steam-foam flooding with different steam quality values as a function of time

Figure 5.27 and Figure 5.28 illustrate water-cut and oil production rate at the producer respectively. Although the results of oil recovery behave similarly, water-cut and oil production rate profile are different. In term of water-cut, after flooding fluid underrunning breakthrough at the 5th production year, foam with lower steam quality yields higher water-cut due to higher liquid portion of steam. In contrast, in aspect of steam overriding breakthrough, foam with higher steam quality breakthroughs the producer earlier and causes higher water-cut. This issue leads to water-cut constraint limit in foam with steam quality of 0.95. In early production period, oil production rate does not differentiate. Foam with low steam quality of 0.45 can sweep hot oil bank through the producer earlier and produce longer due to late overring steam breakthrough. However, although foam with low steam quality of 0.45 can produce hot oil bank with longer period, it does not gain bigger oil recovery.

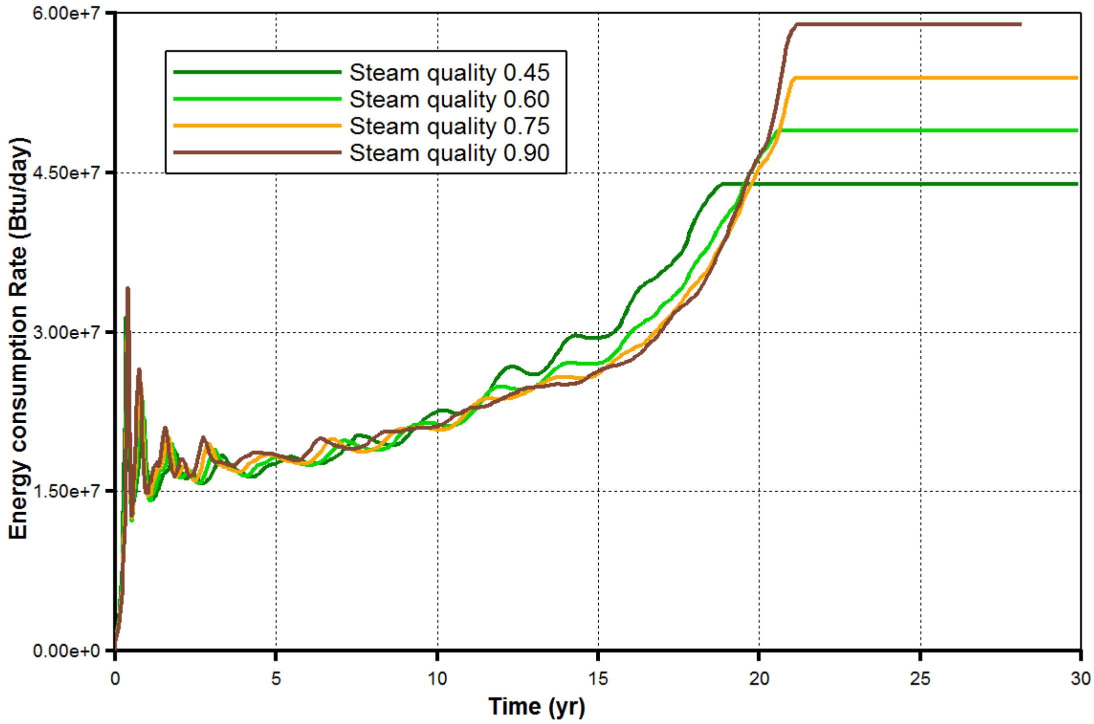

Figure 5.29 Energy consumption rates of steam-foam flooding with different steam quality values as a function of time

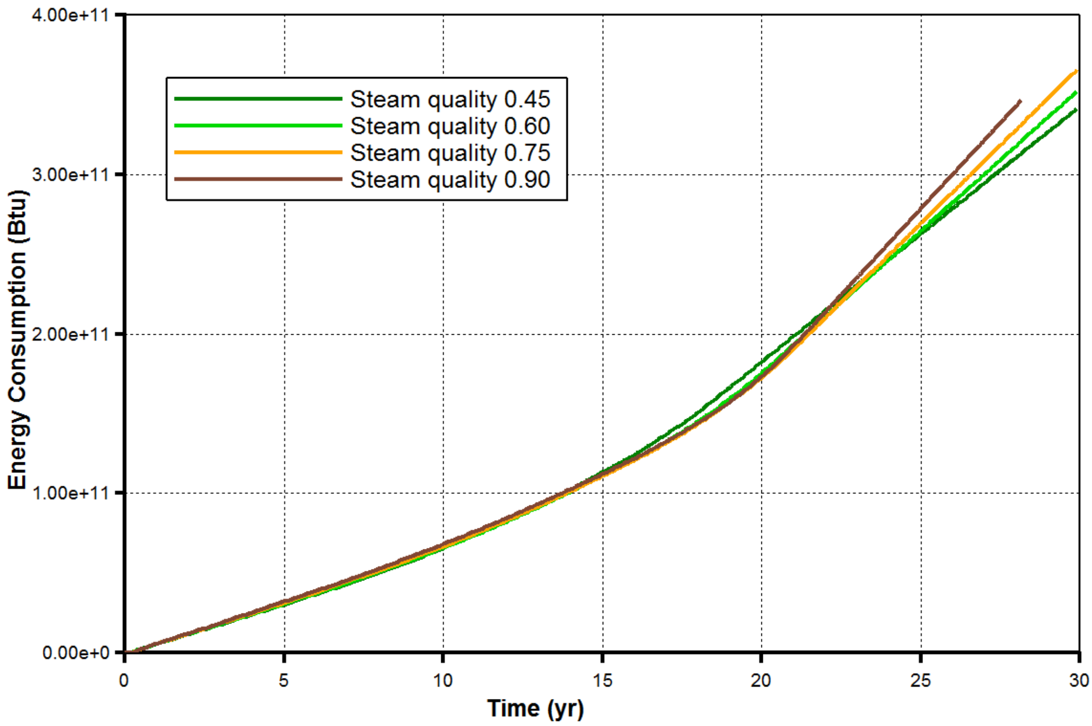

Figure 5.30 Cumulative energy consumption of steam-foam flooding with different steam quality values as a function of time

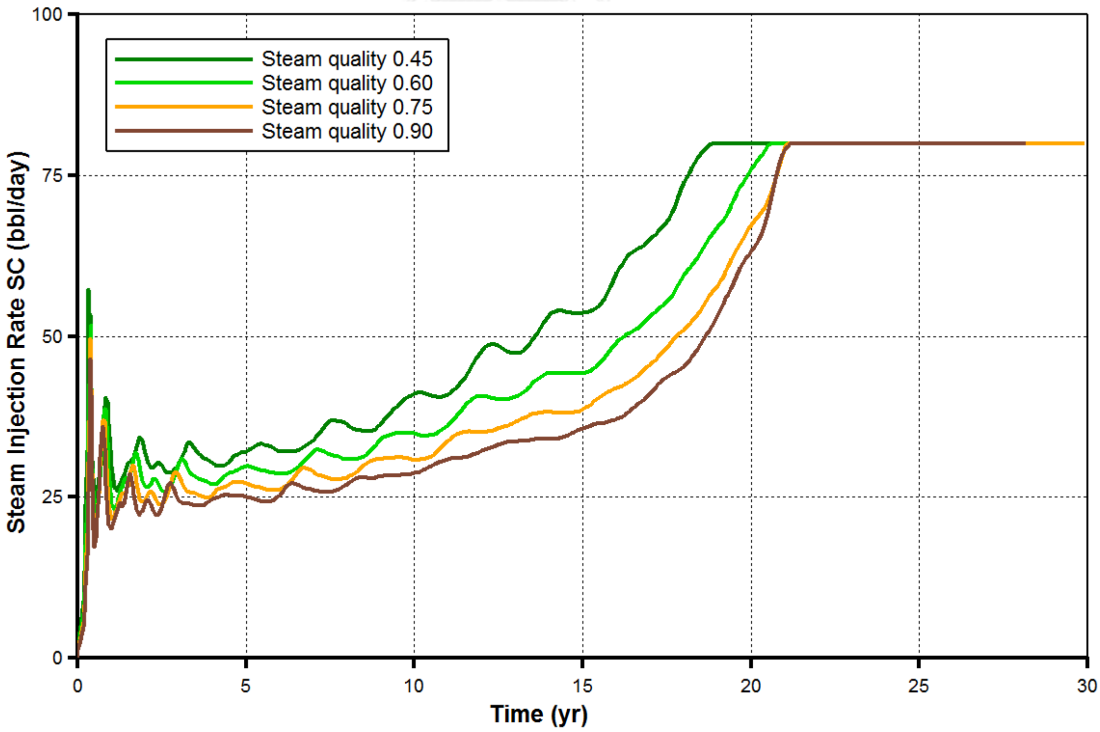

Figure 5.31 Actual steam injection rates of steam-foam flooding with different steam quality values as a function of time

Figure 5.29 to Figure 5.31 illustrate energy consumption rate, cumulative energy consumption and actual steam injection rate of the injector respectively. From Figure 5.29 and Figure 5.30, foam with higher steam quality, containing higher portion of steam, consumes higher energy because it need more energy to achieve latent heat of steam. From Figure 5.31, foam with lower steam quality can perform better injectivity. To quantify the amount of energy consumption utilized per a barrel of steam, energy consumption rate is divided by steam injection rate. The value in each data point provides the same product as shown in Table 5.1. It confirms that steam with higher quality consumes higher energy. Therefore, steam with low foam quality is worth in term of energy consumption.

Table 5.1 Energy consumption per a barrel of steam

	Steam quality of 0.45	Steam quality of 0.60	Steam quality of 0.75	Steam quality of 0.90
Energy consumption per barrel of steam (btu/bbl)	5.49×10^5	6.12×10^5	6.74×10^5	7.37×10^5

From this section, different steam quality values do not significantly affect oil production as any steam quality chosen in this study delivers sufficient heat for oil recovery mechanism through reduction of oil viscosity. However, higher steam quality, due to higher steam portion, requires more energy to achieve latent heat of steam.

5.2.4. Effects of steam injection rate

This section describes effect of different steam injection rate on steam-foam flooding processes. In fact, the actual steam injection rate in some cases cannot attain at the setting value from the starting. This is because huge amount of strong foam still locates near the injector and resists the injection. For this section, soft foam with foam half-life of 0.25 day and foam quality of 0.95 is selected because foam with foam half-life of 1 day and foam quality of 0.90 cannot attain the setting rate from initial period due to low injectivity. This soft foam truly illustrates the effect of different steam injection rate.

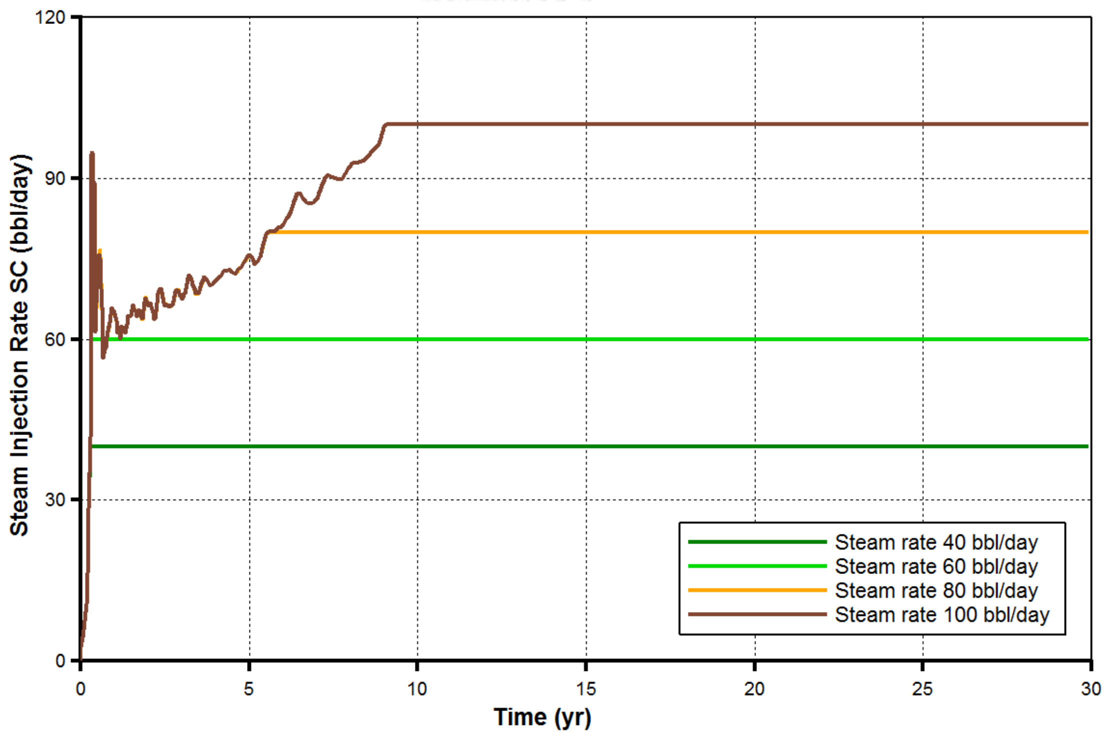

Figure 5.32 Actual steam injection rates of steam-foam flooding with different steam injection rates as a function of time

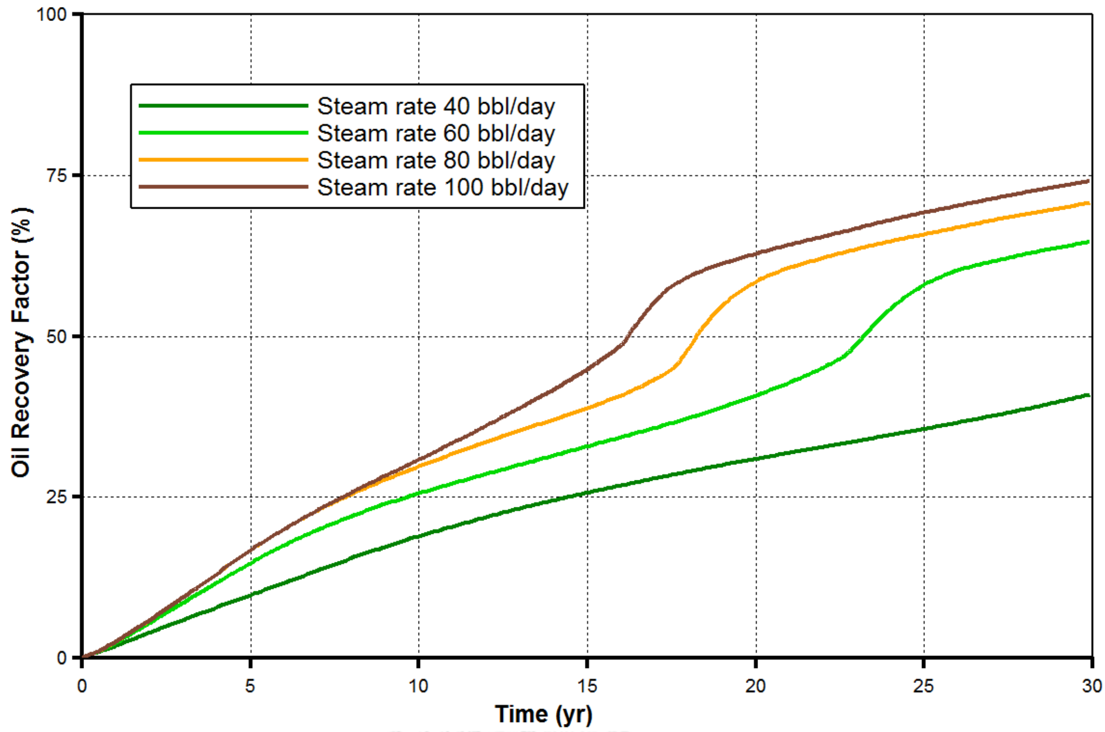

Figure 5.33 Oil recovery factors obtained from steam-foam flooding with different steam injection rates as a function of time

Figure 5.33 shows the results of oil recovery factor with different steam injection rates. In low steam injection rate of 40 bbl/day, foam cannot yet breakthrough at the producer, providing very small oil recovery factor. In higher steam injection rate of 60, 80 and 100 bbl/day, the effect of steam overriding breakthrough can be seen and provides huge gaining oil recovery factor.

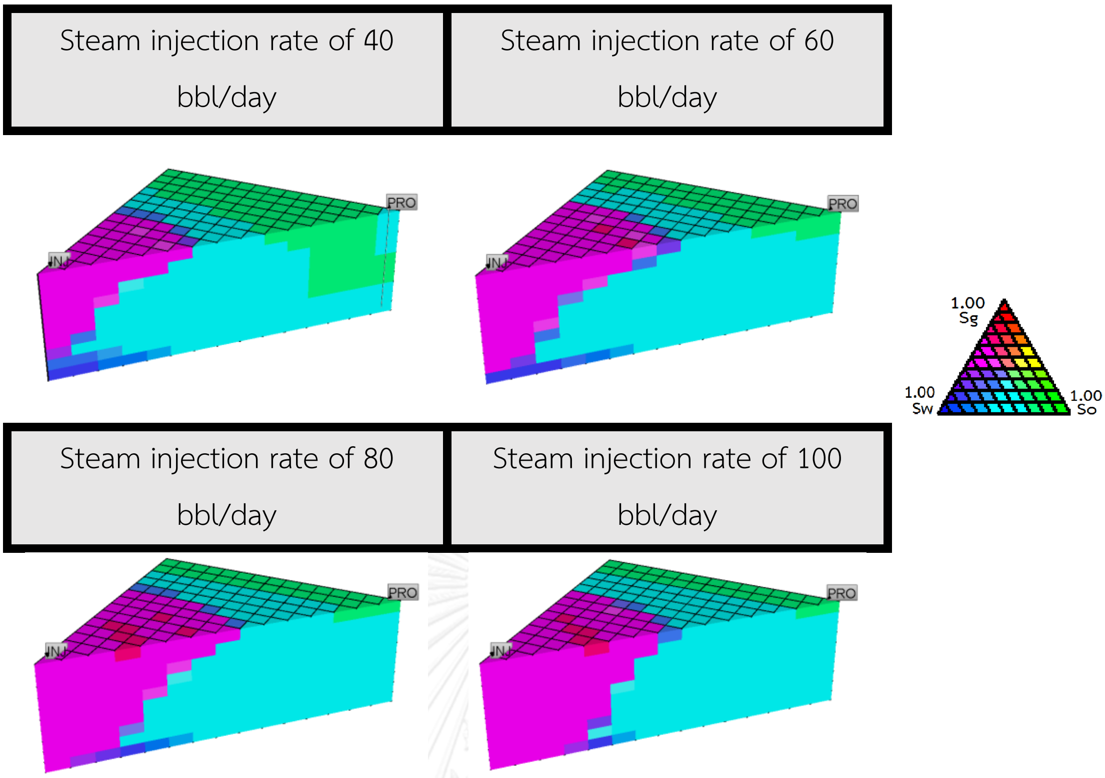

Figure 5.34 Cross-sectional views of ternary phase saturation profiles at the 10th production year with different steam injection rates of steam-foam

Figure 5.34 shows cross-sectional views of ternary phase saturation profiles. This can illustrate that foam with higher steam injection rate does not only provide higher flooding speed but also can maintain better flooding front. This is because, in foam with higher steam injection rate, newer foam can substitute collapsing foam faster. In contrast, in foam with lower steam injection rate, foam collapses into steam and surfactant solution faster. The steam overrides the reservoir and surfactant solution underruns the reservoir. This causes unsuitable flooding front capable of leaving certain amount of oil in lower section of reservoir.

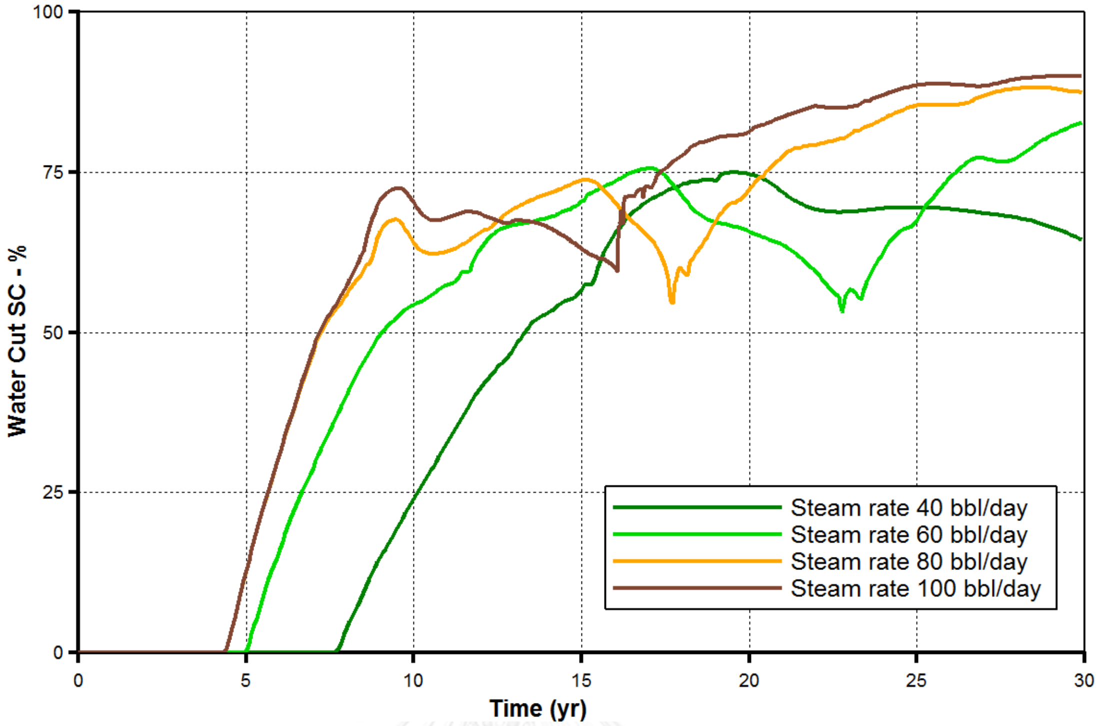

Figure 5.35 Water-cut of steam-foam flooding with different steam injection rates as a function of time

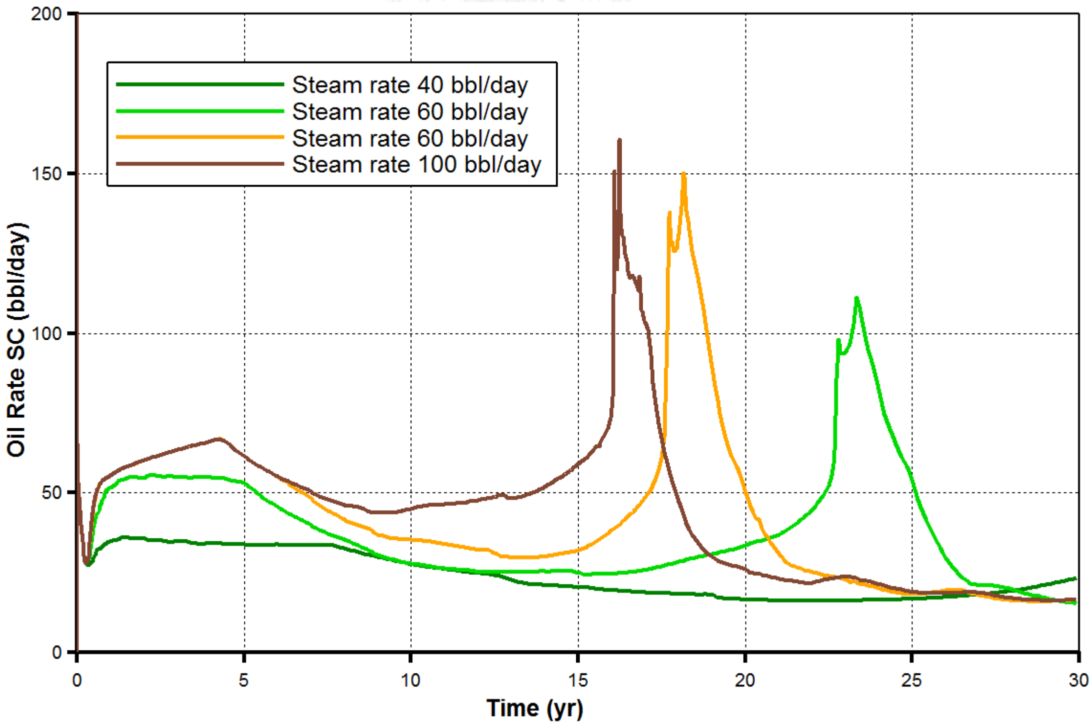

Figure 5.36 Oil production rates of steam-foam flooding with different steam injection rates as a function of time

Figure 5.35 and Figure 5.36 show water-cut and oil production rate of steam foam flooding respectively. The results reveals that, although higher steam injection rate provides higher oil production rate, it also causes higher and faster rise of water-cut. This high water-cut can reach water-cut constraint and terminates the production in some cases.

From this section, higher steam injection rate yields higher oil recovery which is desirable. However, water also breakthrough earlier, leading to high water-cut in earlier stage of production.

5.3. Effects of reservoir heterogeneities

In this section, effect of different reservoir heterogeneities is investigated. For preliminary, oil recovery factor for all cross-over of foam half-life, foam quality and reservoir heterogeneity case are collected and presented in Figure 5.37. From previous section, foam stability and foam quality dominate the results of steam-foam flooding. Therefore, three effective values of foam half-life of 0.25, 1, and 4 days and three effective values of foam quality of 0.85, 0.90 and 0.95 are performed with various reservoir heterogeneities. Steam quality and steam injection rate are fixed at 0.45 and 60 bbl/day respectively. Reservoir heterogeneities are divided into two sedimentary structures consisting of coarsening upward sequence and fining upward sequence. Each sedimentary structure is differentiated into Lorenz coefficient of 0.20, 0.25 and 0.30. Homogeneous reservoir is also included in the figure.

Note: Those abbreviations in Figure 5.37 are stand for these following meaning;

FH: Foam half-life

FQ: Foam quality

C: Coarsening upward sequence

F: Fining upward sequence

0.30C	68	71	66	0.30C	66	71	67	0.30C	61	63	71
0.25C	69	72	65	0.25C	69	73	67	0.25C	58	60	68
0.20C	69	71	63	0.20C	71	74	68	0.20C	55	59	68
0	73	76	67	0	74	78	78	0	56	62	77
0.20F	77	82	75	0.20F	79	82	77	0.20F	65	70	80
0.25F	76	82	76	0.25F	79	82	77	0.25F	67	72	80
0.30F	76	81	76	0.30F	78	81	77	0.30F	70	74	80
FH0.25	FQ85	FQ90	FQ95	FH1	FQ85	FQ90	FQ95	FH4	FQ85	FQ90	FQ95

Figure 5.37 Oil recovery factors obtained from cross-over foam half-life, foam quality and reservoir heterogeneity

Figure 5.37 obviously mentions that sedimentary structure of the reservoir provides different results of oil recovery in steam-foam flooding. Fining upward reservoir improves oil recovery whereas coarsening upward reservoir worsens the results. To demonstrate effect of different reservoir heterogeneities, the row with foam half-life of 1 day and foam quality of 0.90 is selected.

5.3.1. Effects of sedimentary structures

This section describes the results of reservoirs with different sedimentary structures. Figure 5.38 shows cross-sectional views of ternary phase saturation profiles at the 15th production year of homogeneous, coarsening upward and fining upward reservoirs respectively. The results performed by foam with half-life of 1 day in the red frame in Figure 5.37 are selected to be interpreted. Lorenz coefficient of 0.25 is chosen for coarsening upward and fining upward reservoirs. Coarsening upward reservoir, which consists of high permeability on upper layers, worsens the flooding by accelerating steam overriding as steam travels faster in the upper layers. Contrarily, fining upward reservoir, which obtain low permeability in upper layer, improves the flooding by resisting steam overriding as the flooding fluid tends to move down to the lower layer which obtain high reservoir permeability.

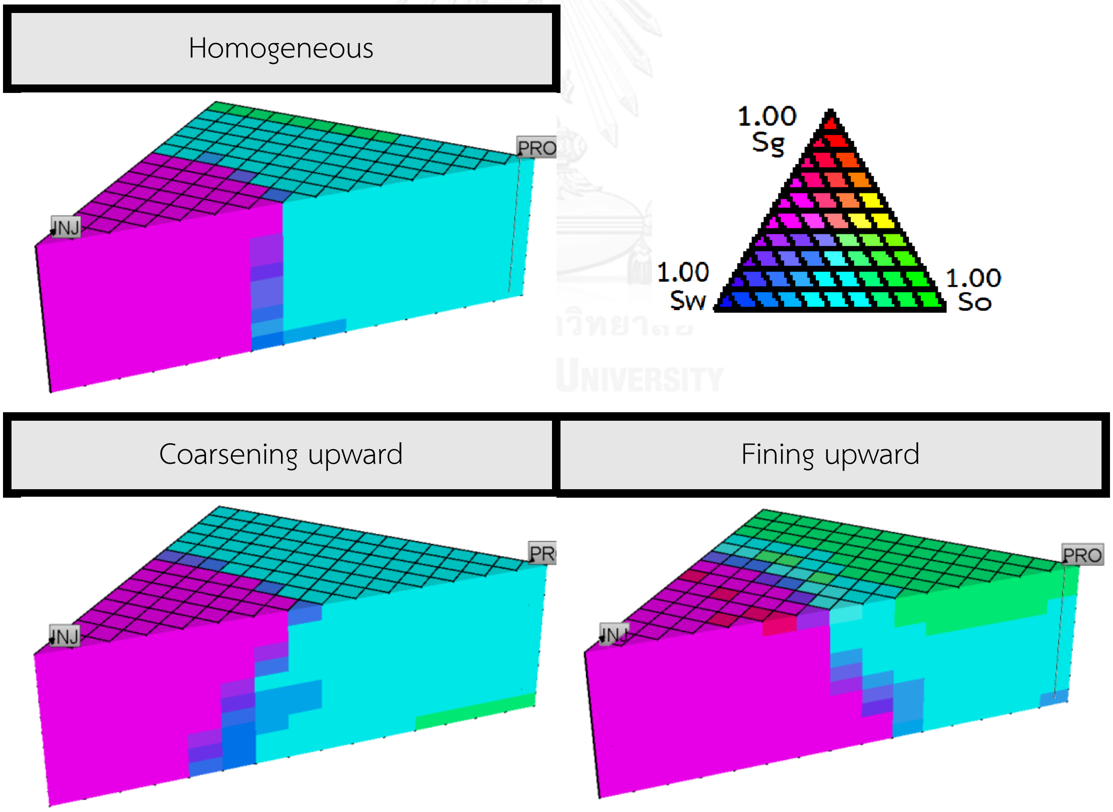

Figure 5.38 Cross-sectional views of ternary phase saturation profiles at the 15th production year with different sediment structures of steam-foam flooding

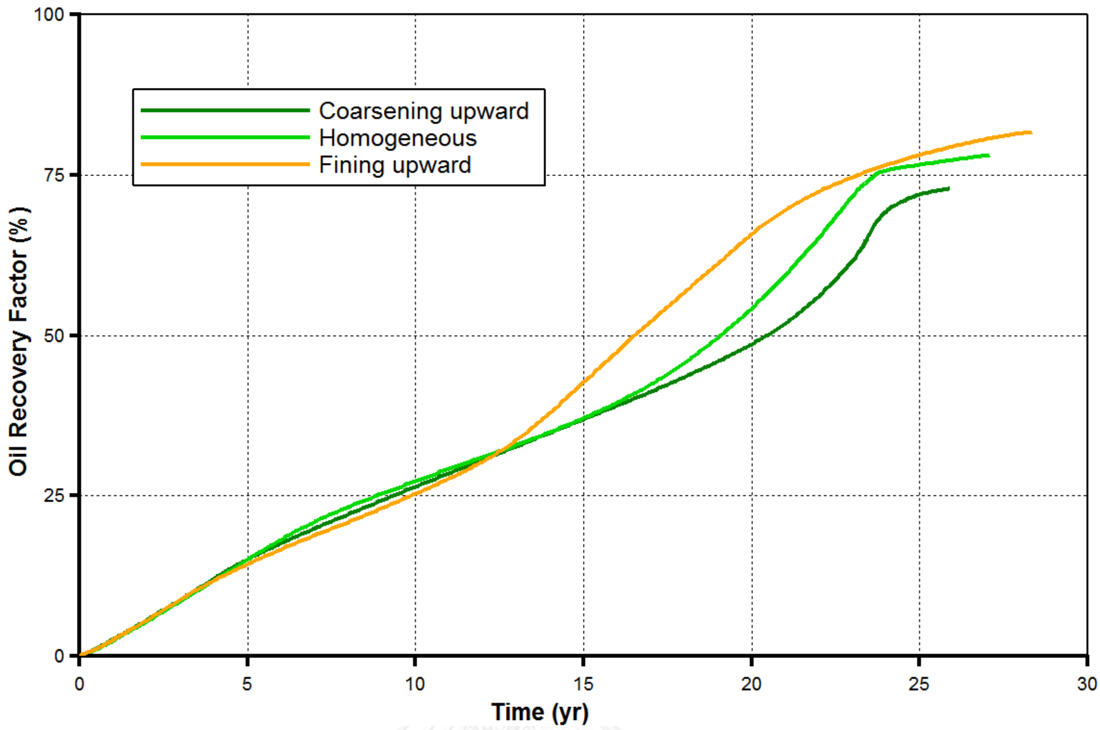

Figure 5.39 Oil recovery factors obtained from steam-foam flooding in different sediment structures as a function of time

Figure 5.39 shows oil recovery factor with different sediment structures. The results show that, oil recovery is improved in fining upward reservoir but worsened in coarsening upward reservoir. In fining upward reservoir, oil recovery is improved due to better sweeping profile as prior mentioned. In coarsening upward reservoir, oil recovery lowers due to steam overriding which leave some oil in the reservoir. Moreover, this steam overriding yet causes high water cut leading to early end production in 26th production year.

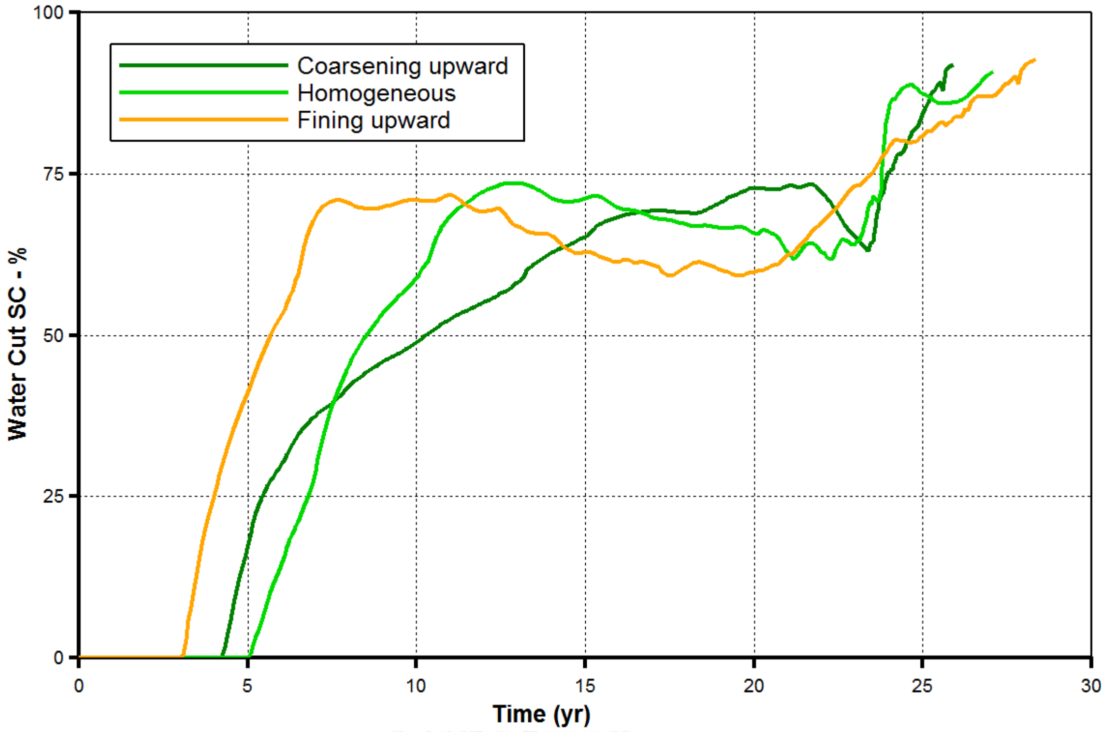

Figure 5.40 Water-cut of steam-foam flooding in different sedimentary structures as a function of time

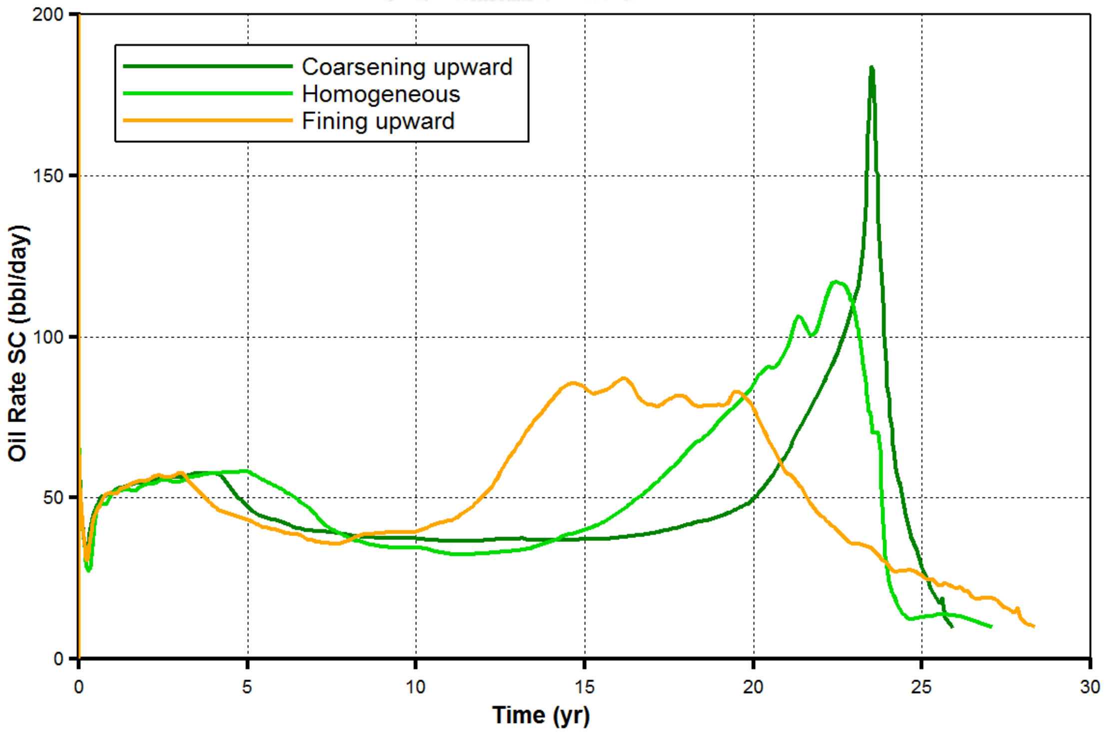

Figure 5.41 Oil production rates of steam-foam flooding in different sedimentary structures as a function of time

Figure 5.40 and Figure 5.41 show water cut and oil production rate with different sedimentary structures respectively. In fining upward reservoir, water underrunning breakthroughs earlier due to higher reservoir permeability in lower layers. This leads to low oil production rate in early production time. Oil production rate increases after hot oil bank breakthrough in the 8^{th} production year with larger amount of oil comparing to the others. After the foam breakthroughs at the producer, oil production rate gradually declines. On the other hand, oil production rate in coarsening upward reservoir immediately declines due to steam overriding breakthrough. Moreover, this steam overriding breakthrough leads to high water cut problem and hence, terminates the production by reaching oil production rate constraint.

Form this section, fining upward reservoir shows better responds by steam-foam flooding as low permeability layers on top of reservoir can mitigate steam overriding. Therefore, sweeping front travels in better vertical profile and hence, sweep more oil through the producer.

5.3.2. Effects of heterogeneous degree on coarsening upward reservoir

5.3.2.1. Effects by performing low to moderate foam stability

This section describes effect of different heterogeneous degree on coarsening upward reservoir. From previous section, with foam half-life of 1 day, the coarsening upward reservoir is less suitable to be flooded by steam-foam than fining upward and homogeneous reservoir. As the results performed by foam with half-life of 0.25 and 1 day are consistent, the results performed by foam with half-life of 1 day in the red frame in Figure 5.37 are selected to be interpreted. This section divides coarsening upward reservoir into three heterogeneous degrees with Lorenz coefficients of 0.20, 0.25 and 0.30, which are in a normal range, to observe their differences.

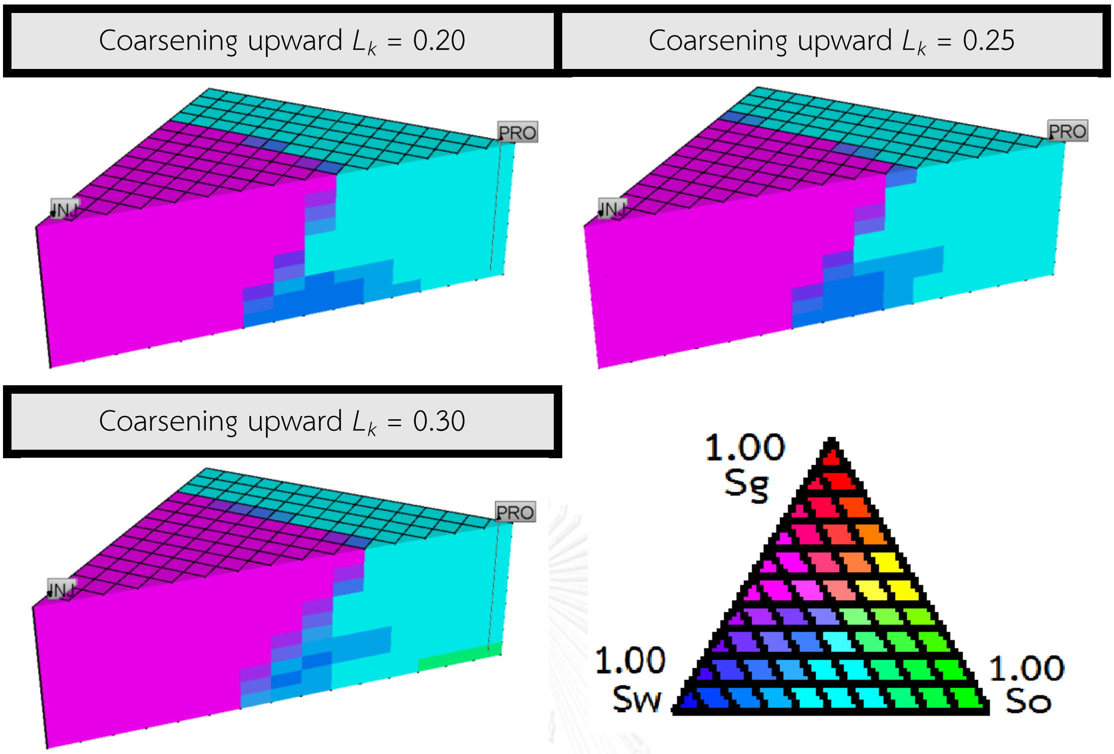

Figure 5.42 Cross-sectional views of ternary phase saturation profiles at the 20th production year with different Lorenz coefficient values on coarsening upward reservoir of steam-foam flooding by foam with half-life of 1 day

Figure 5.42 shows cross-sectional views of ternary phase saturation profiles at the 20th production year for each heterogeneous degree. As flooding fluid can travel faster in upper layers due to higher permeability, the reservoir with higher heterogeneous degree provides worse overriding flooding front. This inappropriate flooding front leaves oil un-flooded in the reservoir leading to low oil recovery as shown in Figure 5.43.

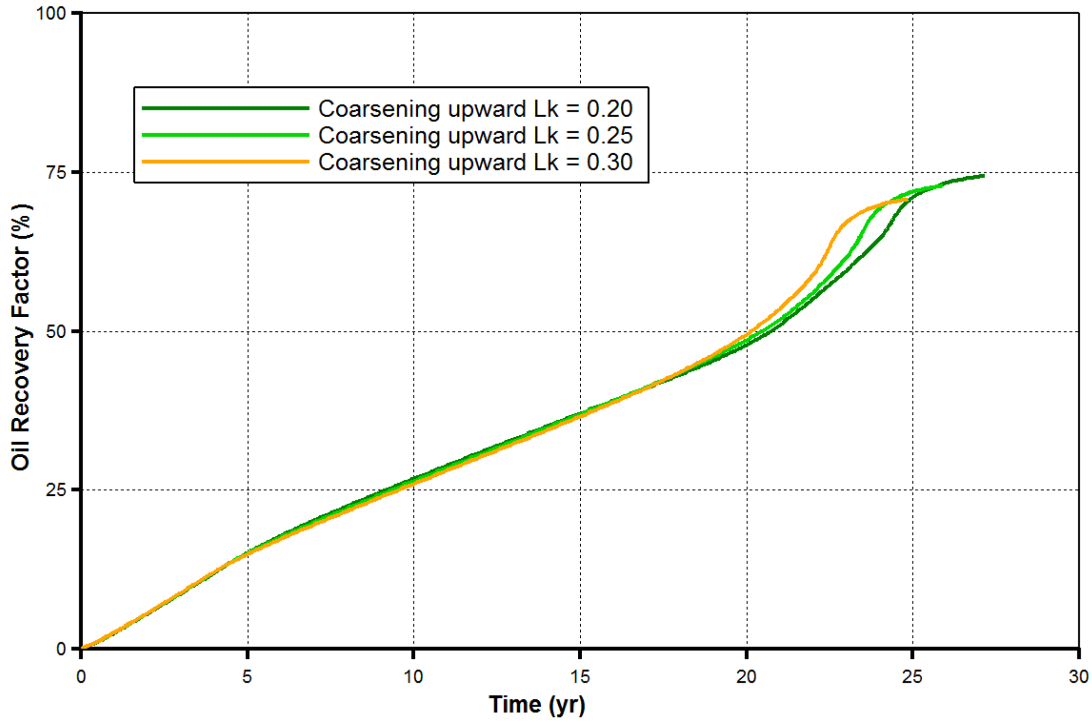

Figure 5.43 Oil recovery factors obtained from steam-foam flooding by foam with half-life of 1 day with different Lorenz coefficient values on coarsening upward

Oil recovery factor of each heterogeneous degree is presented in Figure 5.43. There are not much different results before the 18th production year. The difference will be noticeable after that year due to hot oil bank breakthrough. Every heterogeneous degree is terminated before expected time at the 30th production year due to reaching the limit of oil production rate constraint.

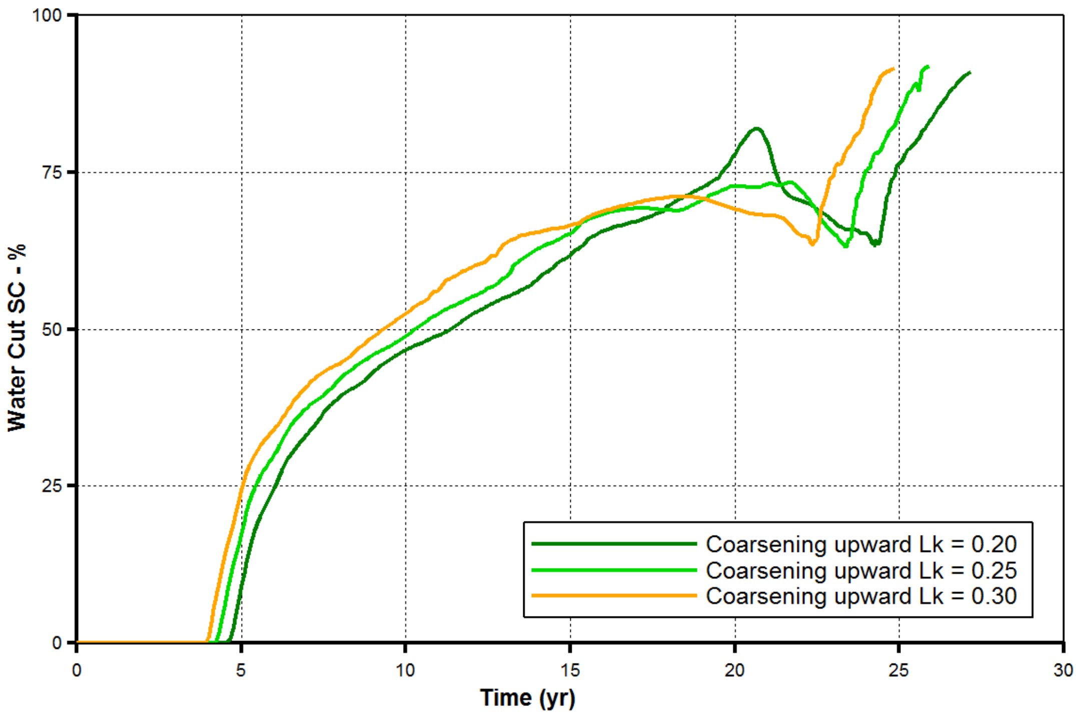

Figure 5.44 Water-cut of steam-foam flooding by foam with half-life of 1 day with different Lorenz coefficient values on coarsening upward reservoir as a function of time

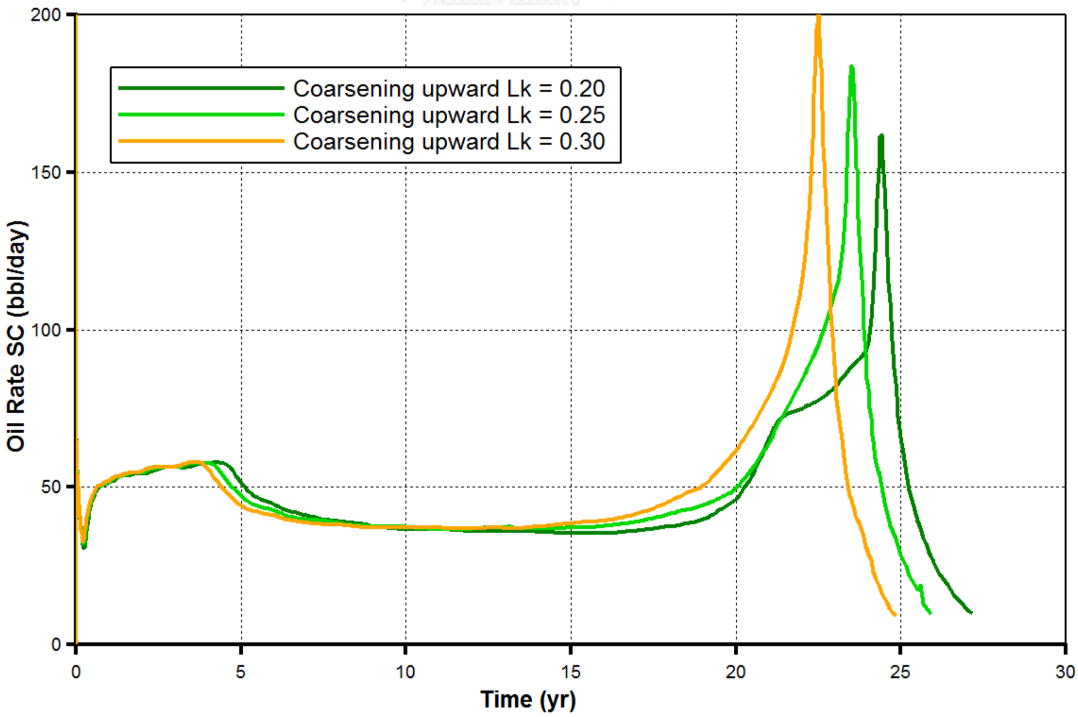

Figure 5.45 Oil production rates of steam-foam flooding by foam with half-life of 1 day with different Lorenz coefficient values on coarsening upward reservoir as a function of time

Figure 5.44 and Figure 5.45 illustrate water-cut and oil production rate of each heterogeneous degree respectively. Figure 5.44 shows that condensing steam and surfactant solution can breakthrough slightly earlier in higher heterogeneous degree. This provides slightly lower oil production rate in early production period as shown in Figure 5.45. In heterogeneous degree with Lorenz coefficient of 0.30, due to high permeability in upper layers, hot oil bank breakthroughs the producer earlier than the others. After that, steam also breakthroughs earlier and then oil production rate immediately drops due to immediately rising in water-cut. This high water production leads to reaching oil production rate constraint very fast just in the 25th production year. The heterogeneous degree with Lorenz coefficient of 0.20 can recover the highest amount of oil due to appropriate flooding front. Moreover, oil production can longer maintain above the constraint.

From this section, in coarsening upward reservoir, the higher heterogeneous degree causes the worse oil recovery. Because the flooding fluid attempts to travel in upper layers having higher permeability resulting in overriding flooding front which leaves some oil behind in the reservoir and high water production.

5.3.2.2. Effects by performing high foam stability

As the results performed by foam with half-life of 4 day are inconsistent with the others, these results of coarsening upward reservoir in the brown frame in Figure 5.37 are separately interpreted in this section. Figure 5.46 shows cross-sectional views of ternary phase saturation profiles at the 20th production year for each heterogeneous degree. The results show similar tendency as the results performed by foam with half-life of 1 day. However, flooding front travels much slower due to low injectivity.

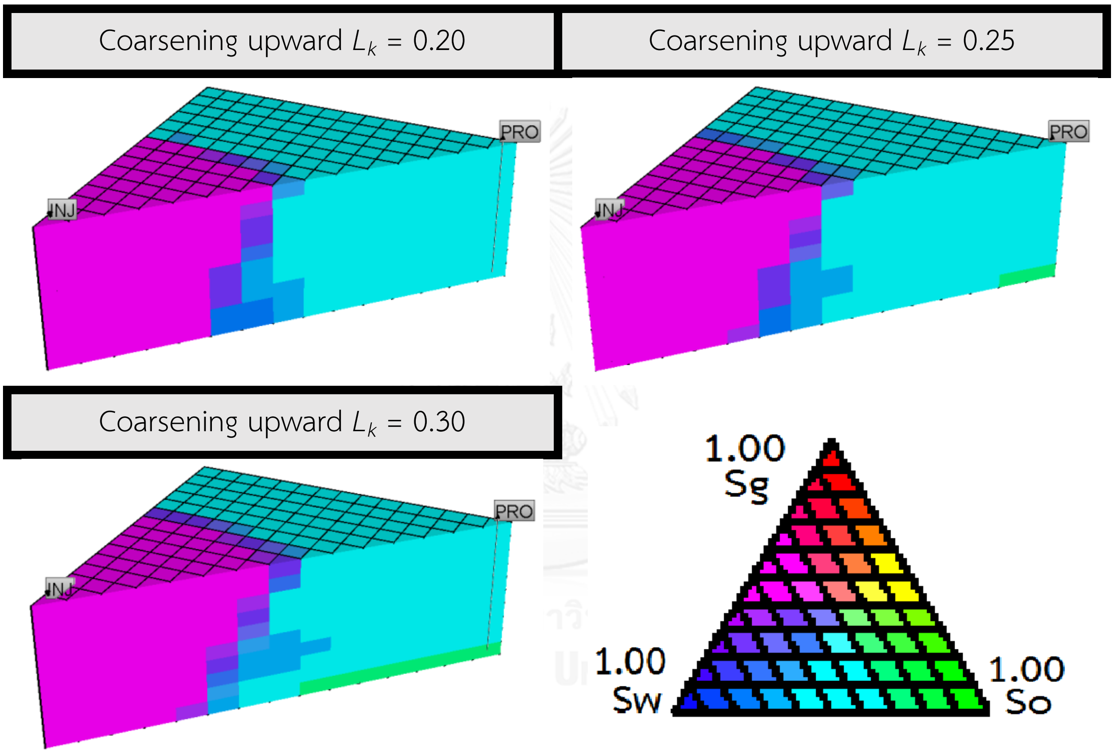

Figure 5.46 Cross-sectional views of ternary phase saturation profiles at the 20th production year with different Lorenz coefficient values on coarsening upward reservoir of steam-foam flooding by foam with half-life of 4 day

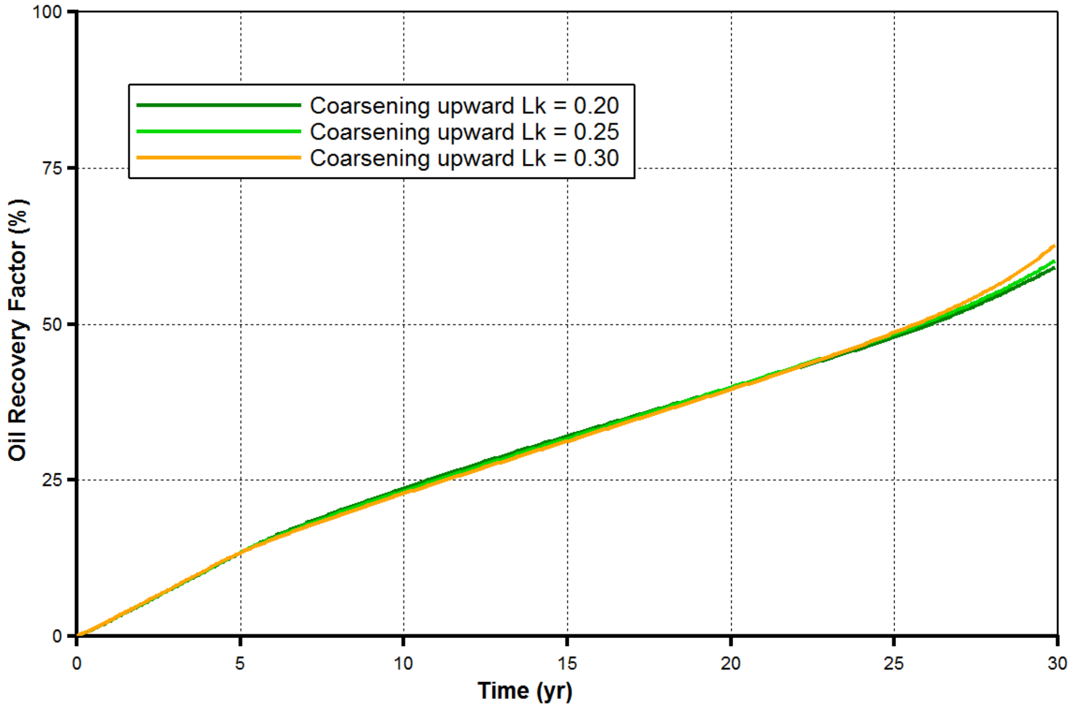

Figure 5.47 Oil recovery factors obtained from steam-foam flooding by foam with half-life of 4 day with different Lorenz coefficient values on coarsening upward

Figure 5.47 shows oil recovery factors obtained from steam-foam flooding by foam with half-life of 4 day. The results show different outcome comparing to the results performed by foam with half-life of 1 day as oil can be recovered with the highest amount in the reservoir with Lorenz Coefficient of 0.30. This is because the flooding front travels slowly and steam does not yet breakthrough the producer. Once the steam breakthrough the producer, water production would rapidly increase and terminate the production earlier than the other two reservoirs having the same behavior as results performed by foam with half-life of 1 day.

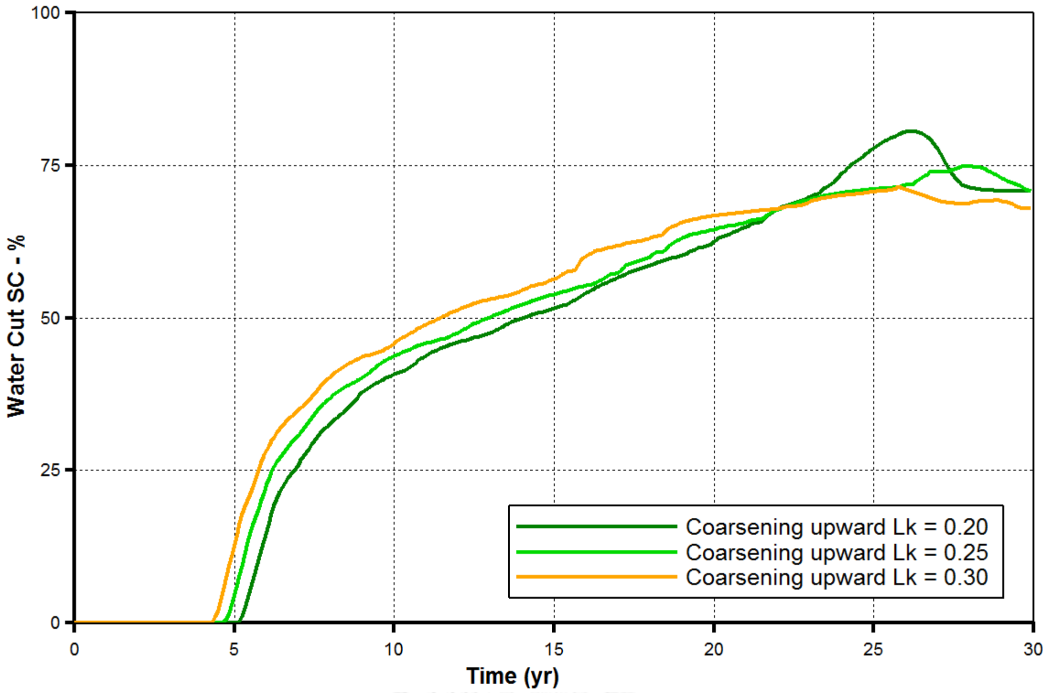

Figure 5.48 Water-cut of steam-foam flooding by foam with half-life of 4 day with different Lorenz coefficient values on coarsening upward reservoir as a function of time

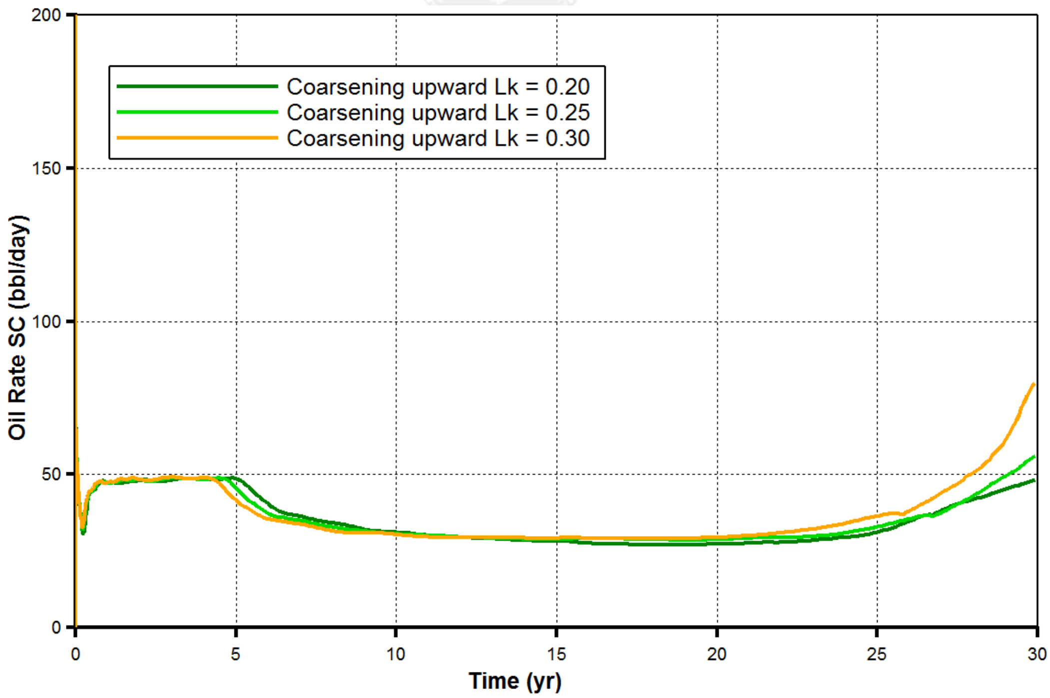

Figure 5.49 Oil production rates of steam-foam flooding by foam with half-life of 4 day with different Lorenz coefficient values on coarsening upward reservoir as a function of time

Figure 5.48 and Figure 5.49 show water-cut and oil production rates of steam-foam flooding by foam with half-life of 4 day respectively. Figure 5.48 confirms that steam does not breakthrough the producer yet. In Figure 5.49, in reservoir with Lorenz Coefficient of 0.30, oil production rate rises up faster than the others in late period. This is because hot oil bank breakthroughs the producer earlier than the others due faster traveling in high permeability layers in upper zone.

5.3.3. Effects of heterogeneous degree on fining upward reservoir

5.3.3.1. Effects by performing low to moderate foam stability

From section 5.3.1, the fining upward reservoir can be recovered the most amount of oil by steam-foam flooding comparing to coarsening upward and homogeneous reservoir. In this section, to investigate behaviors of different heterogeneous degree of fining upward reservoir, the reservoir is divided into three heterogeneous degrees with Lorenz coefficient values of 0.20, 0.25 and 0.30, which are in a normal range. As the results performed by foam with half-life of 0.25 and 1 day are consistent, the results performed by foam with half-life of 1 day in the red frame in Figure 5.37 are selected to be interpreted.

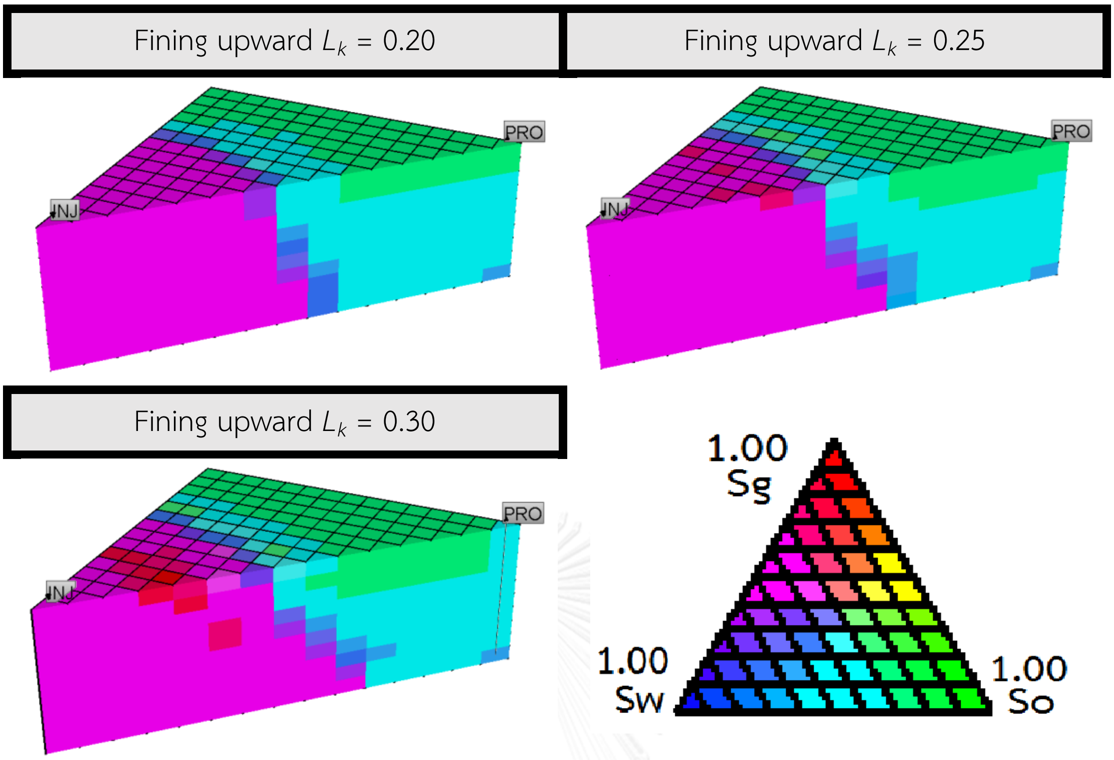

Figure 5.50 Cross-sectional views of ternary phase saturation profiles at the 20th production year with different Lorenz coefficient values on fining upward reservoir of steam-foam flooding by foam with half-life of 1 day

Figure 5.50 shows cross-section views of ternary phase saturation profiles at the 20th production year with different Lorenz coefficient values. The results show only a slight difference in flooding front profiles. In the reservoir with Lorenz coefficient of 0.30, due to higher permeability in lower layers, flooding fluid travels faster in the lower layers, leading to slightly faster underrunning breakthrough.

Figure 5.51 presents oil recovery factor of different heterogeneous degrees. The results look very similar and can yield similar oil recovery factor around 81-82 percent which is very favorable. The difference can be observed is that reservoir with high heterogeneous degree can recover more amount of oil between the 12^{th} and 22^{nd} production year but also terminates the production earlier.

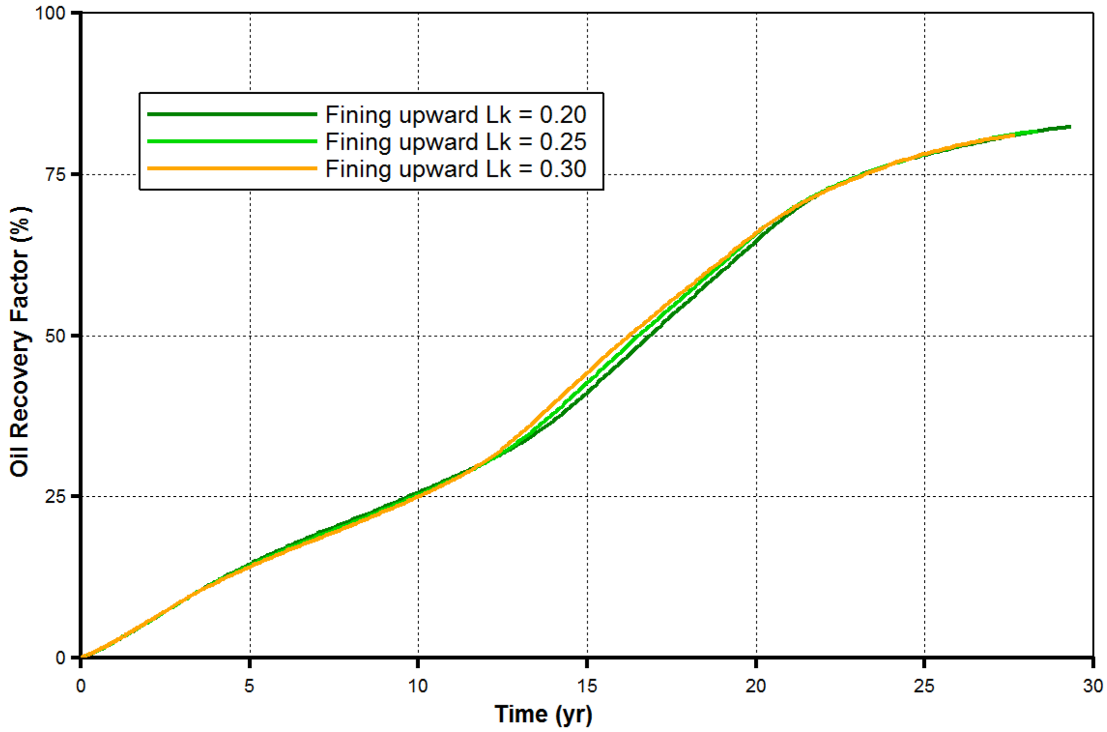

Figure 5.51 Oil recovery factors obtained from steam-foam flooding by foam with half-life of 1 day with different Lorenz coefficient values on fining upward reservoir as a function of time

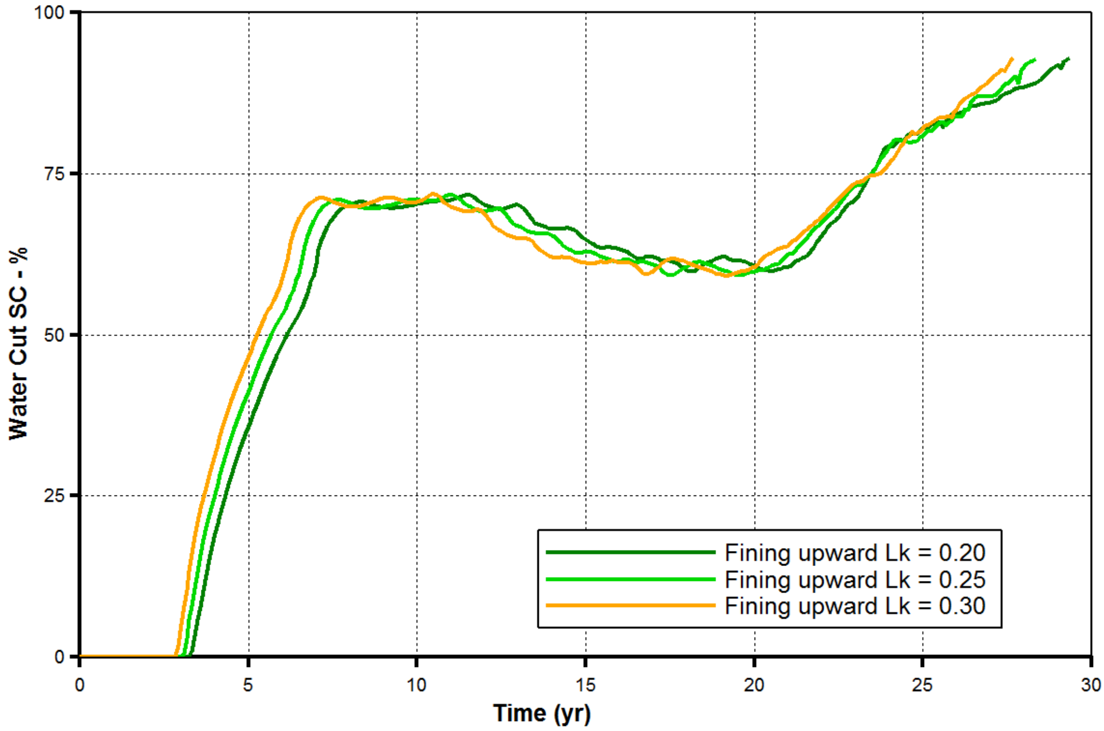

Figure 5.52 Water-cut of steam-foam flooding by foam with half-life of 1 day with different Lorenz coefficient values on fining upward reservoir as a function of time

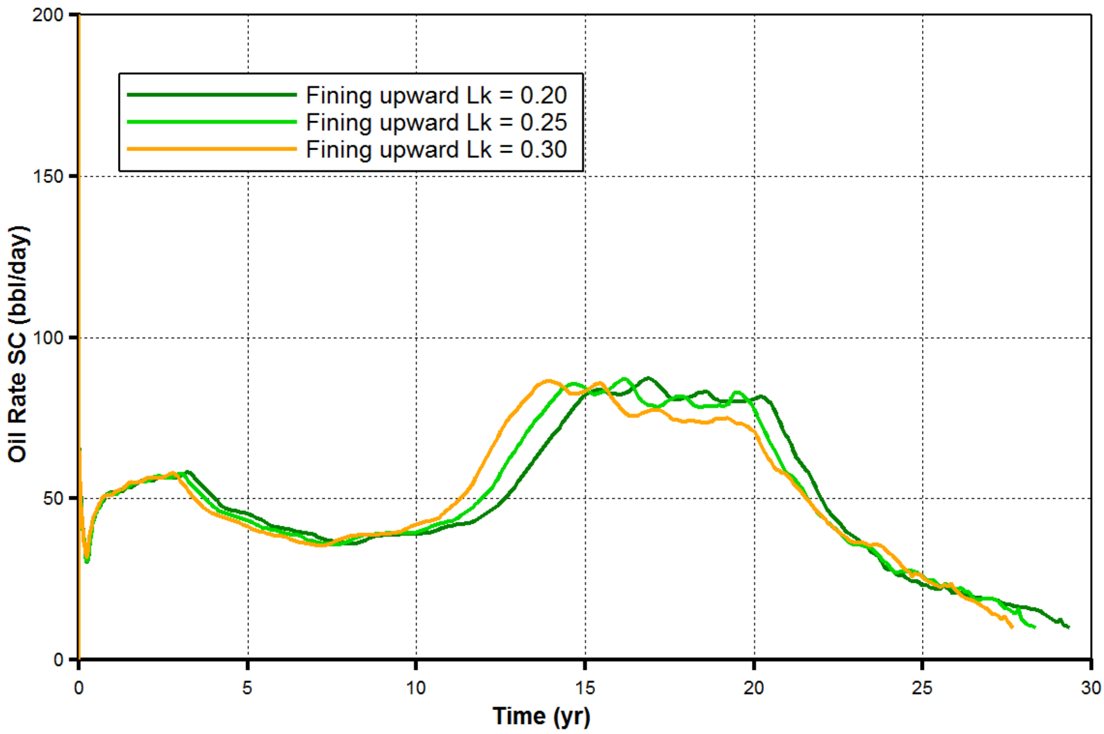

Figure 5.53 Oil production rates of steam-foam flooding by foam with half-life of 1 day with different Lorenz coefficient values on fining upward reservoir as a function of time

Figure 5.52 and Figure 5.53 depict results of water-cut and oil production rate of each heterogeneous degree respectively. From Figure 5.52, in reservoir with Lorenz coefficient of 0.30, flooding fluid underrunning breakthroughs the producer slightly earlier than the others due to high permeability in the lower layers. The three profiles look similar but the reservoir with Lorenz coefficient of 0.30 advances all flooding steps and reaches the limit of oil production rate constraint earlier. Figure 5.53 confirms that all the profiles are not much different. Hot oil bank can breakthrough at the producer earlier in reservoir with Lorenz coefficient of 0.30 but steam also overriding earlier. This leads the production produce high amount of water.

From this section, in fining upward reservoir, different heterogeneous degree in typical range of Lorenz coefficient values from 0.20 to 0.30 does not provide significant adverse result. However, in reservoir with high heterogeneous degree, water-cut rises up faster.

5.3.3.2. Effects by performing high foam stability

As the results performed by foam with half-life of 4 day are inconsistent with the others, these results of fining upward reservoir in the brown frame in Figure 5.37 are separately interpreted in this section. Figure 5.54 shows cross-section views of ternary phase saturation profiles at the 20th production year with different Lorenz coefficient values. The results show only a slight difference in flooding front profiles.

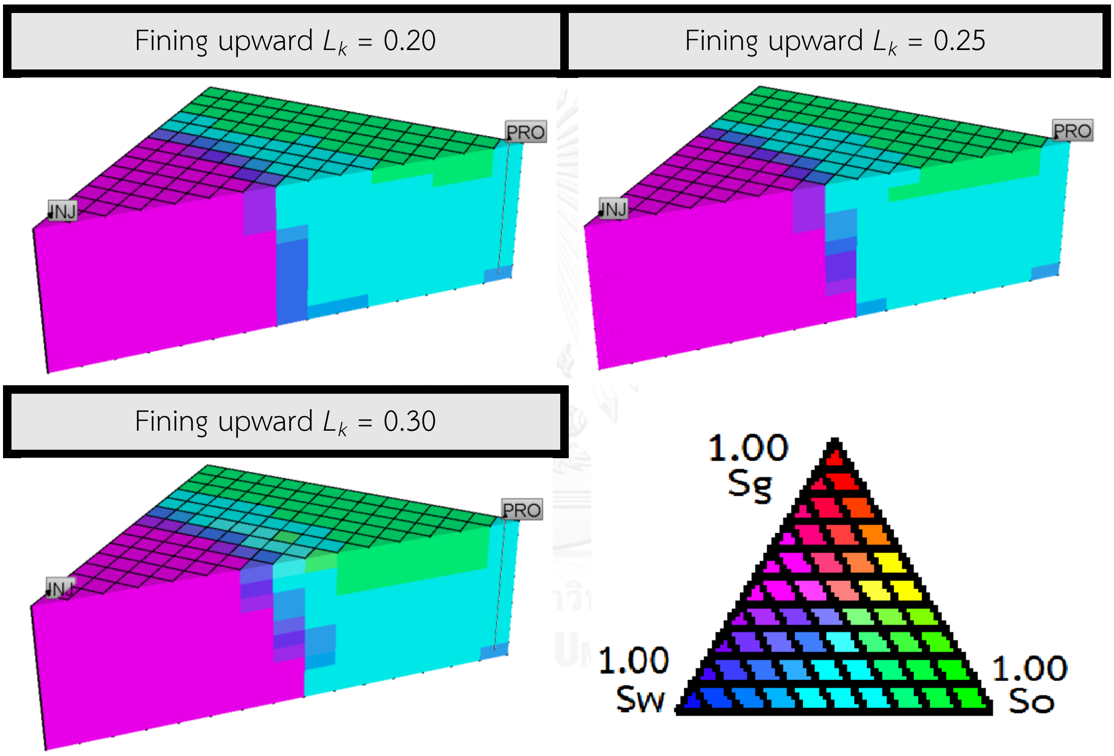

Figure 5.54 Cross-sectional views of ternary phase saturation profiles at the 20th production year with different Lorenz coefficient values on fining upward reservoir of steam-foam flooding by foam with half-life of 4 day

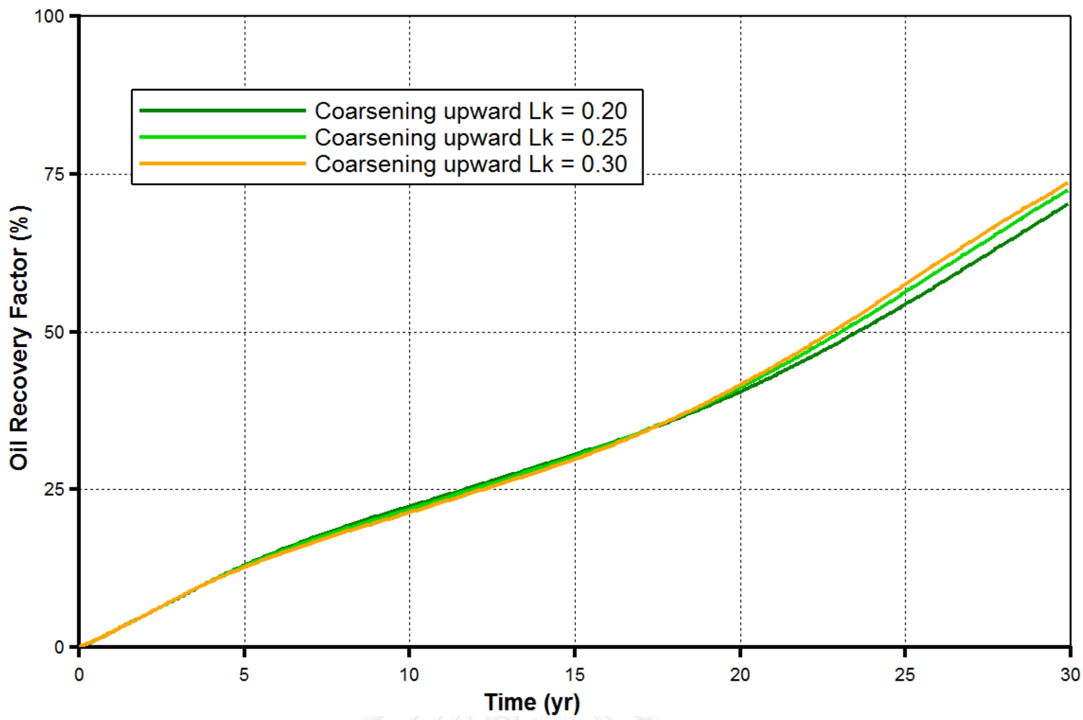

Figure 5.55 Oil recovery factors obtained from steam-foam flooding by foam with half-life of 4 day with different Lorenz coefficient values on fining upward reservoir as a function of time

Figure 5.55 shows oil recovery factors obtained from steam-foam flooding by foam with half-life of 4 day. The results show similar tendency to the results performed by foam with half-life of 1 day. The difference is the flooding front travels slowly and steam does not yet breakthrough the producer due to low injectivity. Once the steam breakthrough the producer, the results would behave in the same way as the results performed by foam with half-life of 1 day. In reservoir with Lorenz Coefficient of 0.30, it can yield the highest oil recovery due to faster traveling of hot oil bank in high permeability layer in lower zone.

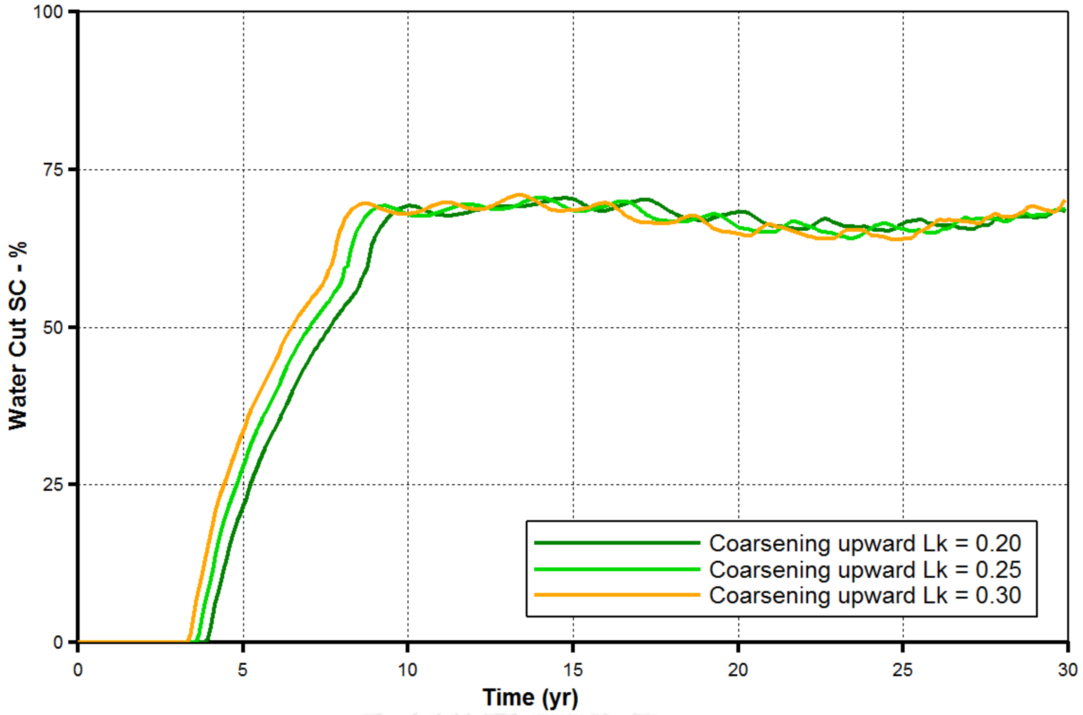

Figure 5.56 Water-cut of steam-foam flooding by foam with half-life of 4 day with different Lorenz coefficient values on fining upward reservoir as a function of time

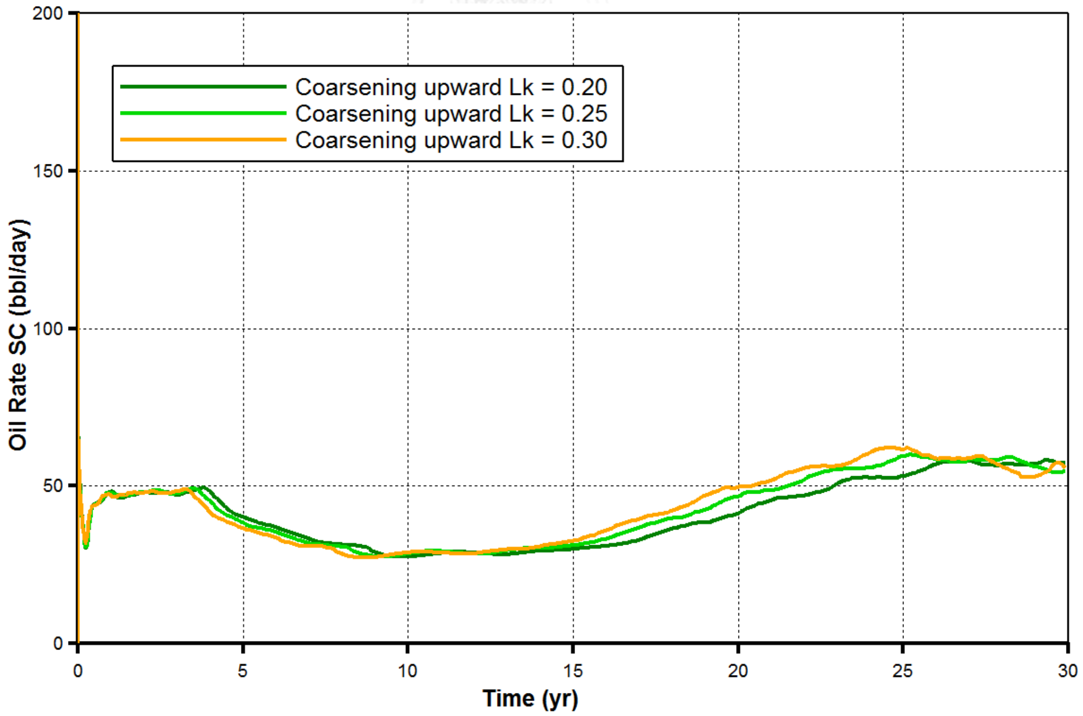

Figure 5.57 Oil production rates of steam-foam flooding by foam with half-life of 4 day with different Lorenz coefficient values on fining upward reservoir as a function of time

Figure 5.56 and Figure 5.57 show water-cut and oil production rates of steam-foam flooding by foam with half-life of 4 day respectively. Figure 5.56 indicates that steam does not breakthrough the producer yet. Figure 5.57, confirms that, in reservoir with Lorenz Coefficient of 0.30, hot oil bank travels and breakthrough the producer faster than the others due to high permeability layers in lower zone.

From section 5.3.2.2 and 5.3.3.2, the behavior of the flooding by high foam stability shows similar tendency to the flooding by low to moderate foam stability. The difference is lower speed of flooding front due to lower injectivity.

CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

In this section, conclusions are made based on discussion of steam-foam flooding in previous chapter. Recommendations for further study are stated at the end.

6.1. Conclusions

1. Due to enhanced viscosity by foam, vertical sweeping efficiency is improved. Then, steam-foam flooding process can yield significantly higher oil recovery compared to steamflooding process.
2. Foam with high stability slowly collapses and hence, large foam portion remains nearby injection well, leading to lowering fluid injectivity. In contrast, foam with low stability collapses into steam and surfactant solution quickly. Injected fluids then behave like original fluids: gas tends to cause steam overriding and consecutively leaves oil in lower section of reservoir. Optimum range of foam half-life which is an indicator for foam stability is suggested to be in between 0.25 and 1 day for this study.
3. In high foam quality, due to higher carrying heat, steam can be injected with an ease and high amount of steam is injected into reservoir. Condensing steam tends to move downward and leaves certain amount of oil in shallow zone, resulting in low vertical sweep efficiency. Whereas low foam quality with higher portion of surfactant solution behaves closer to water and moves slower, leading to low injectivity at the injector. Optimum foam quality is suggested to be around 0.90.
4. Different steam quality values do not significantly affect oil production as any steam quality chosen in this study delivers sufficient heat for oil recovery mechanism through reduction of oil viscosity. However, higher steam quality,

due to higher steam portion, requires more energy to achieve latent heat of steam. Optimum steam quality is suggested to be around 0.60.

5. Higher steam injection rate yields higher oil recovery which is desirable. However, water also breakthrough earlier, leading to high water-cut in earlier stage of production.
6. Fining upward reservoir provides better responds by steam-foam flooding than coarsening upward reservoir. Because low permeability layers on top of reservoir can mitigate steam overriding. Therefore, sweeping front travels in better vertical profile and hence, sweep more oil through the producer.
7. In coarsening upward reservoir, higher heterogeneous degree causes worse oil recovery. Because the flooding fluid attempts to travel in upper layers which possess higher permeability, resulting in overriding flood front and leaving some oil behind in the reservoir.
8. In fining upward reservoir, different heterogeneous degrees in typical range of Lorenz coefficient values from 0.20 to 0.30 does not provide significant adverse result. However, in reservoir with higher heterogeneous degree, water-cut rises up faster.

6.2. Recommendations

The following useful recommendations are suggested for further study of steam-foam flooding.

1. Laboratory experiment on foam properties including IFT, viscosity and relative permeability curves should be performed to obtain more precise result from the reservoir simulation.
2. Benefits of multi-zone injection including steam and surfactant solution separately injection should be further investigated.

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APPENDIX

CONSTRUCTION OF RESERVOIR MODEL

This appendix provides the mean of constructing a reservoir model including rock and fluid properties by using STARS reservoir simulation program, commercialized by Computer Modeling Group (CMG). The simulation requires six main sections including reservoir properties, pressure-volume-temperature (PVT) properties, rock-fluid properties, initial condition, numerical and well & recurrent.

In starting, the simulator need to be set by these following setting.

Simulator	STARS
Working units	FIELD
Porosity	Single porosity
Simulation start date	1/1/2000

1. **Reservoir**

Reservoir-Grid initialization

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

Grid Type	Cartesian
K Direction	Down
Number of Grid Blocks (I x j x k)	30 x 30 x 10
Block widths (I direction)	30 × 15
Block widths (J direction)	30 × 15

Reservoir-Array properties

Parameter	Value	Unit
Grid Top at Layer 1	1,500	ft
Grid Thickness (whole grid)	10	ft
Porosity	0.25	
Permeability I	1000	mD
Permeability J (mD)	Equals I (equal)	mD
Permeability k (mD)	Equal I*0.1	mD
Water Mole Fraction	1	

Note that the permeabilities are for homogenous reservoir. Permeabilities for heterogeneous reservoir need to be adjust.

2. Components

PVT using correlation

Parameter	Option	Value
Reservoir temperature		88.7 °F
Generate data up to max. pressure of		4,000 psi
Bubble point pressure calculation	Generate from GOR value	45 SCF/STB
Oil density at STC (14.7 psia, 60oF)	Stock tank oil gravity (API)	15 °API
Gas density at STC (14.7 psia, 60oF)	Gas gravity (Air = 1)	0.85
Oil properties (Bubble point, Rs, Bo)	Standing	
Oil compressibility correlation	Glaso	
Dead oil viscosity correlation	Ng and Egbogah	
Live oil viscosity correlation	Beggs and Robinson	
Gas critical properties correlation	Standing	

Water properties using correlation

Parameter	Value
Reservoir temperature (TRES)	150 °F
Reference pressure (REFPW)	774.2 psi
Water bubble point pressure	-
Water salinity	1,000 ppm
Undersaturated Co	1.5E-05 psi-1

3. **Rock fluid properties**

Generate using below table in simulator

Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.28
SWCRIT - Endpoint Saturation: Critical Water	0.28
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.24
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.24
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0.05
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.1
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.15
KROCW - k_{ro} at Connate Water	0.41
KRWIRO - k_{rw} at Irreducible Oil	0.13
KRGCL - k_{rg} at Connate Liquid	0.6
Exponent for Calculating k_{rw} from KRWIRO	3
Exponent for Calculating k_{row} from KROCW	3
Exponent for Calculating k_{rog} from KROGCG	3
Exponent for Calculating k_{rg} from KRGCL	3

For performing steam-foam flooding, process wizard is used as an aiding tool t set foam properties. The setup is described in this following step.

1. Process selection

   Process: Alkaline, surfactant, foam, and/or polymer model

2. Model selection

   Model: Foam flood with foam model (add 4 components)

Select Options	
Use N2 gas to generate foam	Yes
Weight percent surfactant used to generate the foam	0.5
Include IFT reduction effects from the surfactant	Yes
Foam half life (days)	1
Foam-in-oil life (days)	0.5
Trapped foam half life (days)	500
Trapped Foam-in-oil half life (days)	10
Number of relative sets for interpolation	2
Use apsorption for surfactant	Yes
Rock type for conversion of apsorption values	Sandstone
Rock Density, gm/cm3	2.65
Krg Reduction due to strong foam	0.35
Krw Reduction due to strong foam	0.02

Note that N2 gas needs to be selected first and it will be corrected to be steam afterward.

3. Component selection

Select Options	
Add new component for surfactant	Yes
Add new component for Foam_gas	Yes
Add new component for Lamellae	Yes
Add new component for N2	Yes
Add new component for Trapped lamellae	Yes

4. Rock fluid region setting

Foam	
Rock fluid Region Number 1	
Rock fluid Region Number 2	Yes
IFT reduction	
Rock fluid Region Number 1	Yes
Rock fluid Region Number 2	

5. Interfacial Tension values

Weight% Surfactant	Interfacial Tension, (dyne/cm)
0	18.2
0.05	0.5
0.1	0.028
0.2	0.028
0.4	0.0057
0.6	0.00121
0.8	0.00037
1	0.5

6. Steam correction

Steam is corrected by changing N2 in Component and Phase Properties by these following steps.

- In Component definition tab, select N2, click Add/Edit a Component and edit these parameters.

Component name	Steam
Reference phase	Aqueous
Critical pressure	3200 psi
Critical temperature	700 °F
Molecular weight	18.015 lb/lbmole

- Select Foam_Gas, click Add/Edit a Component and edit Molecular weight into 18.015 lb/lbmole.
- In Densities tab, correct Foam_gas and Steam by these values.

	Foam_gas	Stream
Density	0.0697009	62.2511
Liquid compressibility	3.15E-06	3.15E-06
1st thermal expansion coeff	0.000138731	0.000138731

- In Liquid phase viscosities tab, correct all Steam's parameters with the same values of the Water.

4. Initial condition

Reference pressure - 774.2 psi

Reference depth - 1550 ft

5. Numerical

Input Parameter	Value
Time step Control Keywords	
Max Number of Timesteps (MAXSTEPS)	99999
Max Time Step Size (DTMAX)	1e+020 day
Min Time Step Size (DTMIN)	1e-008 day
First Time Step Size after Well Change (DTWELL)	0.001 day
Solution Method Keywords	
Isothermal Option (ISOTHERM)	OFF
Model Formulation	SXY
Under-Relaxation Option (UNRELAX)	-1
Upstream Calculation Option (UPSTREAM)	NLEVEL
Maximum Newton Iterations (NEWTONCYC)	20
Maximum Time Step Cuts (NCUTS)	20

6. Well and Recurrent

6.1. Injector

The injector is located at the corner of the reservoir and perforated all 10 layers.

Well Definition

Name	INJ
Type	INJECTOR MOBWEIGHT EXPLICIT
Group	None

Constraint Definition

Parameter	Limit/Mode	Value	Unit
Bottomhole pressure, BHP	Max	950	psi
Surface total phase rate, STF	Max	118.7	bbl/day

Note that this demonstrated surface total phase rate is for steam injection rate of 80 bbl/day with. For other injections, surface total phase rate need to be adjusted.

Injected Fluid

Component	Mole fraction
Water	0.49296
Surfactant	0.00057
Foam_Gas	0.0
Steam	0.50647
Dead_Oil	0.0
Soln_Gas	0.0
Total	1.0

Note that these mole fraction are accustomed for foam quality of 0.90. With other foam quality values, mole fractions need to be adjusted. Temperature is set at 572 °F. Steam quality is varied. Pressure is set at 950 psi.

6.2. Producer

Well Definition

Name	PRO
Type	PRODUCER
Group	None

Constraint Definition

Parameter	Limit/Mode	Value	Unit
Bottomhole pressure, BHP	Min	200	psi
Watercut, WCUT	-	0.95	-
Surface Water Rate, STW	Max	500	bbl/day
Surface oil rate, STO	Min	10	bbl/day

Simulation dates

01/01/2000	Start
31/12/2030	Stop

VITA

Mr. Chakkit Kekina was born on September 3rd, 1991 in Sukhothai, Thailand. He received his Bachelor degree in Mechanical Engineering from Faculty of Engineering, Chalulongkorn University in 2014. After graduation, he started to work as a design engineer at Honda R&D Asia Pacific Company Limited. He continued his study in the Master's Degree program in Georesources and Petroleum Engineering at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University since the academic year 2015. During his study, he obtained a scholarship granted by PTT Exploration and Production Public Company Limited.