EVALUATION OF POLYMER ALTERNATING WATERFLOODING IN MULTILAYERED HETEROGENEOUS WATERFLOODED RESERVOIR

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Georesources and Petroleum Engineering
Department of Mining and Petroleum Engineering
Faculty of Engineering
Chulalongkorn University
Academic Year 2016

การประเมินการฉีดอัดสารโพลิเมอร์สลับการฉีดอัดน้ำในแหล่งกักเก็บแบบวิวิธภัณฑ์หลายชั้นที่ผ่านการฉีดอัดน้ำแล้ว

นายวรุตม์ ตันเจริญ

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมทรัพยากรธรณีและปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
ปีการศึกษา 2559

Thesis Title	EVALUATION OF POLYMER ALTERNATING WATERFLOODING IN MULTILAYERED HETEROGENEOUS WATERFLOODED RESERVOIR
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Field of Study	Georesources and Petroleum Engineering
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วรุตม์ ตันเจริญ : การประเมินการฉีดอัดสารโพลิเมอร์สลับการฉีดอัดน้ำในแหล่งกักเก็บแบบวิวิธภัณฑ์หลายชั้นที่ผ่านการฉีดอัดน้ำแล้ว (EVALUATION OF POLYMER ALTERNATING WATERFLOODING IN MULTILAYERED HETEROGENEOUS WATERFLOODED RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: อ. ดร.ฟ้าลั่น ศรีสุริยชัย, 108 หน้า.

การฉีดอัดสารโพลิเมอร์มีการใช้อย่างแพร่หลายเพื่อเพิ่มปริมาณการผลิตน้ำมันเนื่องจากสารโพลิเมอร์สามารถเพิ่มความสามารถในการกวาดน้ำมันและทำให้โปรไฟล์การฉีดอัดราบเรียบมากขึ้น อย่างไรก็ตามการฉีดอัดสารโพลิเมอร์นั้นมีความยากลำบากเนื่องจากความหนืดของสารฉีดอัดค่อนข้างสูง จึงควรฉีดอัดก้อนน้ำก่อนและระหว่างการฉีดอัดก้อนโพลิเมอร์เพื่อเพิ่มความง่ายของการฉีดอัดสารที่มีความหนืดลงในหลุม

แบบจำลองเชิงตัวเลขถูกใช้เพื่อกำหนดตัวแปรในการดำเนินงานที่เหมาะสมที่สุดซึ่งทำให้สามารถผลิตน้ำมันได้สูงสุด จากผลการศึกษาพบว่าควรฉีดอัดน้ำก่อนสารโพลิเมอร์จนกว่าน้ำจะถูกผลิตเนื่องจากไม่เพียงแค่น้ำจะช่วยเพิ่มประสิทธิภาพการฉีดอัดสารโพลิเมอร์ด้วยการชะล้างน้ำมันบริเวณรอบหลุมออกไป แต่ยังทำให้แน่ใจว่าหลุมฉีดอัดและหลุมผลิตมีการเชื่อมต่อกัน ขนาดก้อนน้ำที่เล็กที่สุดระหว่างสารโพลิเมอร์ซึ่งคิดเป็น 5 เปอร์เซ็นต์ของขนาดก้อนโพลิเมอร์ซึ่งเพียงพอที่จะเพิ่มประสิทธิภาพการฉีดอัดสารโพลิเมอร์ และควรเลือกใช้ก้อนน้ำขนาดเล็กเนื่องจากก้อนน้ำขนาดใหญ่จะทำให้เสียเวลาในการฉีดอัดก้อนโพลิเมอร์ถัดไป อย่างไรก็ตามขนาดของก้อนน้ำขึ้นอยู่กับระดับการคายสารโพลิเมอร์ โดยเมื่อระดับการคายสารโพลิเมอร์ต่ำลง ขนาดของก้อนน้ำควรมีขนาดเพิ่มขึ้น การเรียงลำดับความเข้มข้นของสารโพลิเมอร์ไม่ได้แสดงผลดีที่มีนัยยะสำคัญเนื่องจากความไม่สมดุลระหว่างประสิทธิภาพการฉีดอัดสารโพลิเมอร์และประสิทธิภาพการแทนที่น้ำมัน จำนวนรอบของการฉีดอัดน้ำและสารโพลิเมอร์ที่เหมาะสมขึ้นกับความเข้มข้นของสารโพลิเมอร์ โดยจำนวนรอบของการฉีดอัดน้ำและสารโพลิเมอร์ที่มากขึ้นควรใช้กับความเข้มข้นของสารโพลิเมอร์สูง ในการศึกษานี้จำนวนรอบของการฉีดอัดน้ำและสารโพลิเมอร์สามรอบให้ปริมาณการผลิตน้ำมันมากกว่าหนึ่งรอบในทุกความเข้มข้นของสารโพลิเมอร์ ปัจจัยความต้านทานโพลิเมอร์มีอำนาจเหนือประสิทธิภาพการฉีดอัดสารโพลิเมอร์เมื่อใช้ความเข้มข้นของสารโพลิเมอร์ต่ำ การผลิตน้ำมันจะเพิ่มขึ้นเมื่อปัจจัยความต้านทานโพลิเมอร์เพิ่มขึ้น การฉีดอัดสารโพลิเมอร์แบบหลายก้อนให้ผลดีกว่าเมื่อเทียบกับก้อนเดี่ยวในทุกช่วงของดรรชนีวิวิธพันธ์ เมื่อการเรียงลำดับของการจัดเรียงตะกอนเป็นแบบการจัดเรียงตะกอนหยาบด้านบน ในทางตรงข้ามการจัดเรียงตะกอนหยาบด้านล่างซึ่งได้ประโยชน์ในเรื่องประสิทธิภาพการฉีดอัดสารโพลิเมอร์จากโซนที่มีค่าความสามารถในการซึมผ่านสูงด้านล่างของแหล่งกักเก็บอยู่แล้วประกอบกับผลจากแรงโน้มถ่วง ทำให้การฉีดอัดสารโพลิเมอร์แบบหลายก้อนไม่ให้ผลดีกว่าแบบก้อนเดี่ยว

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
สาขาวิชา	วิศวกรรมทรัพยากรธรณีและปิโตรเลียม	ลายมือชื่อ อ.ที่ปรึกษาหลัก	....
ปีการศึกษา	2559		

5871218321 : MAJOR GEORESOURCES AND PETROLEUM ENGINEERING
KEYWORDS: POLYMER FLOODING / POLYMER INJECTIVITY / CONCENTRATION SORTING / NUMBER OF ALTERNATIVE CYCLES

WARUT TUNCHAROEN: EVALUATION OF POLYMER ALTERNATING WATERFLOODING IN MULTILAYERED HETEROGENEOUS WATERFLOODED RESERVOIR. ADVISOR: FALAN SRISURIYACHAI, Ph.D., 108 pp.

Polymer flooding is widely implemented to improve oil recovery since it can increase sweep efficiency and smoothen reservoir profile. However, polymer solution is somewhat difficult to be injected due to high viscosity thus, water slug is recommended to be injected before and during polymer injection in order to increase an ease of injecting this viscous fluid into the wellbore.

Numerical simulation is performed to determine the most appropriate operating parameters to maximize oil recovery. Firstly, pre-flushed water should be injected until water breakthrough since not only it can increase polymer injectivity by flushing the oil around wellbore away, but also it ensures the connectivity between injector and producer. The smallest alternating water slug size which is 5 percent of polymer slug size is sufficient to increase injectivity of polymer slug and should be selected since large water slug setbacks time to inject the following polymer slug; however, slug size of alternating water is dependent on polymer desorption degree; with less degree of polymer desorption, slug size of alternating water should be increased. Concentration sorting does not show any significant benefit due to imbalance between polymer injectivity and displacement efficiency. Number of appropriate alternating water slug depends on polymer concentration; more alternative cycles should be implemented in case of high polymer concentration. In this study, three alternative cycles provide higher oil recovery than single-slug polymer in every polymer concentration. Residual resistance factor (RRF) dominates polymer injectivity when using low polymer concentration; oil production increases as RRF increases. Lastly, multi-slug polymer flooding yields better results compared to single-slug in all range of heterogeneity index when depositional sequence is coarsening upward. Oppositely, fining upward sequence has already obtained the benefit in terms of polymer injectivity from high permeability zone at the bottom of reservoir together with gravitational effects, consequently, multi-slug polymer flooding does not yield benefit over single-slug.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
Field of Study:	Georesources and Petroleum Engineering		
Academic Year:	2016		

ACKNOWLEDGEMENTS

I would like to express my sincere gratitude to Dr. Falan Srisuriyachai, my thesis advisor who has guided me to think, analyze and write in a professional way from the beginning. The door to his office was always open whenever I had a question about my thesis. More importantly, he has gradually inspired me to be more dedicated and optimistic. Without his valuable support, this thesis would not have been as it is.

I will be always be indebted to all instructors in Department of Mining and Petroleum Engineering, Chulalongkorn University who have contributed to my academic development in Petroleum Engineering study over two years. They have inspired me with passion, vision and future.

I would like to thank Chevron Thailand Exploration and Production, Ltd. for providing financial support for this study.

I must acknowledge MPE class of 2015 classmates for being together through thick and thin over two years, sharing useful advices for my thesis and making two years of study memorable.

Finally, I would like to express my deepest gratitude to my family, especially my mom and dad who has always stood by me in times of need and for their moral support, encouragement and blessings. This thesis is dedicated to you.

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LIST OF ABBREVIATIONS

BHP	Bottomhole pressure
DPR	Disproportionate permeability reduction
EOR	Enhanced oil recovery
HPAM	Hydrolyzed polyacrylamide polymer
XG	Xanthan gum polymer
IPV	Inaccessible pore volume
KRGCL	Relative permeability to gas at 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
MW	Molecular weight
PAM	Polyacrylamide
PV	Pore volume
PVT	Pressure – volume – temperature
RF	Resistance factor
RRF	Residual resistance factor
SCAL	Special core analysis
SCGON	Connate gas saturation
SWCON	Connate water 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
STW	Surface water rate
WCUT	Watercut

NOMENCLATURES

λ_p	Mobility of polymer
λ_o	Mobility of oil
λ_w	Mobility of water
ϕ	Porosity
μ_g	Gas viscosity
μ_o	Oil viscosity
μ_w	Water viscosity
B_g	Formation volume factor of gas
B_o	Formation volume factor of oil
B_w	Formation volume factor of water
C_m	Cumulative storage capacity
c_w	Water compressibility
h_i	Thickness of layer i
k_h	Horizontal permeability
k_i	Permeability of layer i
k_{ro}	Relative permeability to oil
k_{rw}	Relative permeability to water
L_k	Lorenz coefficient
M	Mobility ratio
P_{FF}	Fracture pressure
P_{ref}	Reference pressure
R_s	Solution gas-oil ratio
η_r	Relative viscosity
η	Viscosity of polymer solution
η_s	Viscosity of pure solvent

CHAPTER 1
INTRODUCTION

1.1 Background

In last few decades, the consumption of crude oil has continuously increased worldwide. Oil companies as major exporters had tendency to produce more crude oil to meet that high demand. Many oil companies have attempted to develop new techniques to extend production life of the reservoir they have partially produced. Waterflooding used to be a common technique to increase the amount of oil owing to its simplicity and cost-effectiveness. To illustrate, the water is injected into a well then it will force the oil toward adjacent production well. However, waterflooding has one major problem which happens when water bypasses the oil due to unfavorable mobility of water compared to that of oil. Water will flow with so-called “fingering” characteristic that greatly reduces volumetric sweep efficiency, leaving some amounts of oil non-displaced. Another problem happens when water flows through reservoir layers with different permeabilities called multilayered reservoir. Water tends to flow through the layers with comparatively high permeability first and thus, leaving oil in the lower-permeability layers non-displaced.

Later, Enhanced Oil Recovery (EOR) was introduced to solve these problems. Enhanced Oil Recovery is the implementation of various methods to increase the amount of oil from the reservoir by injecting substances into reservoir to create displacement mechanisms. Chemical Enhanced Oil Recovery (CEOR) is considered as one of the primary EOR technique for light to medium oil reservoir. This technique is performed by injecting chemicals that have abilities to improve oil recovery, including surfactant, alkaline, and the most concerned in this study, polymer substances. Basically, polymer is used in EOR to increase viscosity of injected water. This causes reduction of mobility of water, turning mobility ratio of the process to become more favorable and hence, more oil can be displaced without leaving untouched zones. It is desirable to replace waterflooding with polymer flooding, especially in the multi-layered reservoir containing several layers with different characteristics including porosity, capillary pressure and permeability which is a major concern in this study. Polymer solution is prepared and injected into the well instead of solely water. One benefit of polymer over water is that it creates more viscous fluid. Thus, when polymer solution is injected into the reservoir, polymer solution with higher viscous force will sweep more oil to the production well comparing to conventional waterflooding. Another benefit of polymer solution is that certain types of polymer tend to be adsorbed onto rock surface which results in reduction of the flow area of water, causing reduction of relative permeability to water and as a consequence, sweep efficiency is increased and more oil is produced.

However, the injection of polymer solution into a well still has a drawback. A major problem is its low injectivity as the desired injection rate is scarcely achieved when high polymer concentration is used in large slug size. If production rate is not balanced with injection rate then, the depletion of reservoir pressure can be accelerated. Subsequently, solution gas is liberated from the oil and effective permeability is reduced. Moreover, high adsorption of polymer onto rock surface could yield adverse effect on high reduction of flow ability. Therefore, water should be injected in between to increase the injectivity of polymer, as a consequence, water would result in desorption of polymer on the rock surface which yields more ease for injecting the following polymer slugs.

In this study, **STARS®** commercialized by **Computer Modelling Group Ltd. (CMG)** is selected to perform numerical simulation. Initially, reservoir model is constructed to create multilayered reservoir model in this study. Also, different operating parameters, including polymer slug size, polymer concentration and water slug size are observed and adjusted to yield the appropriate operating parameters as stated in the objective of this study.

1.2 Objectives

1. To identify appropriate operating parameters for polymer alternating waterflooding, including polymer slug size, polymer concentration, polymer injection starting time, and alternative injection cycles.

2. To investigate the effect of reservoir heterogeneity and type of depositional sequence on polymer alternating waterflooding.

1.3 Thesis Outline

This thesis contains six chapters as follows:

Chapter 1 provides a background of polymer flooding, objectives and methodology of this study.

Chapter 2 provides summary of literature reviews related to this study.

Chapter 3 provides important theories of polymer flooding which are the essential concepts for this study.

Chapter 4 provides the details of reservoir model which are used in the study, including rock and fluid properties and production constraints.

Chapter 5 provides reservoir simulation results and discussion among the results in aspects of operating parameters.

Chapter 6 provides conclusions of this work and recommendations for future works.

CHAPTER 2
LITERATURE REVIEW

2.1 Polymer Flooding in Multilayered Reservoir

Zhang et al. [1] conducted a numerical simulation to determine proper polymer injection concentration for individual heterogeneous reservoir layer. He noticed that simple polymer injection concentration cannot provide satisfactory results as the target zones in Daqing oilfield changed from Class I reservoir to Class II reservoir. For geological characteristics, second type of reservoir had much more difference in permeability distribution, also had bigger permeability variation coefficient (V_k) than first type of reservoir. In aspect of production characteristics, Class II reservoir had wider range of injection pressure distribution among well points and wider range of polymer volume among well groups. To increase the production, novel design method of injection concentration of polymer flooding was initialized; first, reservoir layers with different permeabilities required different polymer injection concentration – layer with permeability of $200\text{x}10^3$ μm^2 was suitable for concentration of 1200 mg/L, meanwhile, layer of $600\text{x}10^3$ μm^2 was compatible with concentration higher than 2400 mg/L. After adjusting injection concentration for individual well, injection pressure distribution was more balanced, development degree of low permeability layers was improved, polymer breakthrough time could be handled and more oil production was achieved with lower watercut.

Wang et al. [2] provided three key factors for successful polymer flooding in Daqing oilfield. First, “Zone Management before Polymer Flooding”, certain types of wells (e.g., well that had initial polymer injection pressure less than average, well that had high permeability differential from adjacent well) might need profile modification (i.e., gel treatment) before polymer flooding. Simulation result showed that oil recovery could be enhanced up to 2-4% original oil in place (OOIP). Moreover, applying separate layer injection to the well where the permeability differential was 2.5 and flooded until reaching 98% watercut also helped enhancing OOIP by 2.04%. Second, “Optimization of The Polymer Injection Formula”, *polymer* *viscosity*; for medium molecular weight polymer (12-16 million Daltons), viscosity of 40 mPa·s was recommended and for high molecular weight polymer (17-25 million Daltons), 50 mPa·s viscosity was sufficient to overcome the unfavorable mobility ratio, *polymer molecular weight (*MW*)*; viscosity would increase as MW increased and consequently, oil recovery enhanced but when MW was higher at some points, it would exhibit permeability reduction (i.e., resistance factor and residual resistance factor) Thus, appropriate MW must be concerned, *polymer solution concentration*; high concentration of polymer leaded to the reduction of watercut and less requirement for polymer volume, *polymer volume*; numerical simulation of Daqing oilfield showed that polymer injection should be stopped and switched to water injection when watercut reached 92-94%, *injection rate*; when injection rate increased, reservoir pressure near injectors increased, on the contrary, reservoir pressure near producers decreased. Hence, injection rate must be concerned to stabilize the reservoir pressure, moreover, lower injection rate caused watercut to increase more slowly and injection rate should be maintained under 0.16 PV/year to maximize the oil production in well spacing of 250 meters in Daqing oilfield. Third, "Individual Production and Injection Rate Allocation", for example, high injection rate should be applied to wells with high mobile oil saturation, low injection rate for wells near faults, and injection and production rate should be balanced.

Panthangkool and Srisuriyachai [3] studied operating parameters that affected the effectiveness of polymer flooding. They investigated two parameters, including, viscosity and injection rate of polymer solution. Several cases for polymer flooding were studied through reservoir simulator with waterflooding as a base case. For cases that solely polymer was injected, viscosity of polymer was too high that could reduce the injectivity and resulted in low oil production rate. Thus, pre-flushed water was injected to extend the production period and from the study, injecting 0.15 PV of pre-flushed water slug size and 0.20 PV of polymer slug size yielded highest oil recovery factor (RF) among other cases. For cases that polymer concentration and slug size were adjustable, the results showed that using concentration of 0.6225 lb/STB (the lowest) along with 0.225 PV polymer slug size (the largest) provided highest RF and lowest water production, plus, it was recommended that high polymer concentration should not be applied to reservoir with high heterogeneity. For polymer injection variation, it was implied that high injection rate was suitable for low heterogeneous reservoir while low injection rate should be used in case that heterogeneity was more than 0.4. For double-slug polymer injection, comparing with single-slug polymer injection, double slug provided slightly less RF as alternating water size got bigger but this method should further be applied if highly viscous polymer concentration was required.

Meybodi et al. [4] identified the effect of heterogeneity of multilayered reservoir by performing an experiment using five-spot glass microbial. Five patterns with different pore structures were embedded onto glass plate to create a pore space then the second glass plate was drilled at either end to provide an inlet and outlet holes. Before performing the experiment, optimum operating parameters (i.e., flow rate 0.0006 cm^3/min, water salinity 200,000 ppm, polymer molecular weight $12x10^6$ g/mol, and polymer concentration 300 ppm) were obtained through water injection process. Laboratory experiment showed that oil recovery was strongly affected by heterogeneity near injector thus, injection port selection was considered as an important parameter. Another experiment was conducted to identify effect from layer orientation. Combinations of three layers with different inclination angle at 0, 45, 90 degrees were used. Results showed that the highest oil recovery was obtained when inclination angle was 90 degrees; water or polymer was injected from high permeability to low permeability. This resulted from spreading of water or polymer through high permeability layer and wider front contacting to large fraction of pore space.

Peihui and Haibo [5] performed laboratory experiment to identify the effect of alternative polymer injection comparing to single-slug injection in aspects of overcoming profile reverse and ineffective polymer circulation in high permeability layer. Two scenarios were designed; single-slug injection was performed to inject only one polymer slug as a base case, alternative injection was accomplished by injecting alternative polymer slugs of high viscosity and low viscosity; more cycles, less polymer viscosity. Results showed that using 5 alternative cycles (0.056 PV each) provided highest oil recovery of 26% while single-slug injection provided only 23.1%. Moreover, alternative slug injection could reduce polymer usage by 25%. Injecting polymer more than 5 slugs caused each slug to be too small and it was not effective to increase oil recovery. Displacement mechanism of both kinds of injection was also studied. For single-slug injection, polymer preferred to enter through high permeability zone at early period of injection and with increment of displacement resistance factor, polymer started to enter low permeability zone instead, making fluid absorption profile improved. With continuous polymer injection, low permeability zone showed higher increase rate of resistance factor. Finally, fluid absorption would be decreased. This phenomenon was known as "profile reverse" which was unfavorable to polymer injection process. For alternative injection, polymer slug with higher viscosity entered high permeability zone first which enforced lower viscosity slug to enter low permeability zone. This could reduce mobility difference between two zones and consequently, inhibiting profile reverse behavior in low permeability zone. Furthermore, alternative injection was applied in 4 pilot test blocks in Daqing oilfield, starting from April 2011 to December 2012 to verify feasibility of this method and the technique provided satisfactory results; Incremental oil recovery increased while polymer powder dosage decreased.

2.2 Polymer Retention Mechanisms

Szabo et al. [6] focused on polymer retention mechanism in porous media by experimental studies using C-14 tagged HPAM in unconsolidated sand and sandstone. A set of static and dynamic experiments was devised with low level of polymer adsorption by using silica sand with a small surface-area. It was found that mechanical entrapment played a dominant role in low surface area sands, while in medium permeability, high surface-area Barea core, polymer retention mechanism by polymer adsorption was more dominant than mechanical entrapment.

Al-Sharji et al. [7] investigated mechanism of polymer entanglement to water-wet and oil-wet rock in both single-phase flow and two-phase flow conditions.

Basically, in oil-wet rock, polymer entanglement provided no significant change in oil and water effective permeability while in water-wet rock, polymer would obstruct the flow path of water while oil remained inside larger pores which reduced relative permeability to water while produced minimum reduction in relative permeability to oil. This phenomenon was known as Disproportionate Permeability Reduction (DPR). For single-phase flow, in a water-wet model, polymer solution (CPAM) was injected for 4 hours, pressure was observed to be slowly increased and an accumulation of polymer was found mostly on crevices (grain-grain contact), curvature of grains, and pore throats which effectively reduced flow area of water and increased flow resistance. Moreover, polymer layers were increased when polymer solution was injected at higher rates. In oil-wet case, no pressure drop and visually change in micromodel was observed. For two-phase flow, linear relationship between pressure drop and flow rate was acquired, in a water-wet model, as flow rate changed, pressure drop kept increasing with slope more than one, on the other hand, the plot of pressure drop and flow rate displayed slope equal to one, implying no permeability change in case of oil-wet rock.

Dawson et al. [8] studied about Inaccessible Pore Volume (IPV) in polymer flooding (the remainder of pore volume where polymer cannot get in) by performing three experimental polymer floods with varying amount of adsorption. The experimental floods were accomplished in three steps; initial solution, a bank of different solution and final solution using Polyacrylamide and salt. Three experiments included Flood 1 which was a frontal movement without adsorption. The core was pre-treated by polymer concentration higher than polymer bank before to eliminate adsorption effect and it was discovered that with the absence of adsorption, polymer moved through porous media faster than a tracer, Flood 2 which included both IPV and adsorption effects, IPV was found to be slightly larger than polymer adsorption, and Flood 3 of which polymer adsorption was made to dominate IPV, the laboratory data resulted in an error because polymer breakout curve would provide inaccurate values unless IPV effect was considered.

Dominguez [9] performed experiments to investigate the polymer retention mechanism and other fluid properties in porous media. High-molecular weight HPAM was used to flood the 86-mD Teflon core. The result showed that polymer retention was 10-21 μg/g mostly from mechanical entrapment as polymer retained in Teflon core was found to be larger than polymer adsorption on Teflon powder due to low adsorption on Teflon surface thus, mechanical entrapment dominated other mechanisms. Moreover, rate of mechanical entrapment was a function of polymer concentration; as polymer concentration decreased, more time was required to reach injected concentration and then the rate was reduced. Hydrodynamic force from the change in flow rate also affected polymer retention; polymer was retained as velocity increased, on the other hand, polymer was expelled when velocity decreased. Furthermore, IPV was found to be 19% of total pore volume and resistance factor ranged from 2-10 for 100-500 ppm of polymer in 2% NaCl which was 2-3 times lower than what was reported for natural porous media where polymer was also retained by polymer adsorption.

Ogunberu [10] investigated reduction of effective permeability to water under flow-induced polymer adsorption by using Alcoflood 935 (anionic polymer) to flood sand packs. He proposed that with increasing shear rate, permeability reduction mechanism would change from static to flow-induced adsorption necessitating a sharp increase in adsorbed polymer layer. Plus, anionic polymer could adsorb onto the surface of porous media, showing that ionic property of polymer would not affect the ability to reduce effective permeability to water if the polymer was hydrophilic.

From all chosen literatures, it is obvious that polymer flooding is one of the EOR method which is implemented to field operation. Two main topics relating to polymer flooding are emphasized; polymer flooding in multilayered reservoir and polymer retention mechanisms. However, only one literature about alternative polymer injection was presented without various parameters adjustment due to laboratory limitation; therefore, the study of polymer alternating water flooding in multilayered reservoir is conducted by numerical simulation to provide broader and more specific details on operating parameters and different scenarios.

CHAPTER 3
THEORY AND CONCEPT

3.1 Waterflooding

Waterflooding is a secondary recovery method to enhance the oil production rate to be more than simply using natural drive mechanism or so-called primary recovery. The concept of waterflooding is to inject the water into the injection well. As a consequence, water will sweep displaced oil to adjacent production well and oil can be produced. Selecting waterflooding technique to improve oil recovery yields benefits in aspect of availability, simplicity and cost-effectiveness. However, injecting water into the reservoir can lead to early breakthrough effect that can leave large amount of oil non-displaced as water has tendency to flow only through high permeability layer which causes oil in low permeability layer to be un-swept by water. Consequently, several enhanced oil recovery methods are introduced to overcome this so-called fingering effect including polymer flooding.

3.2 Polymer Flooding

Polymer is a substance formed by a large chain of many repeating units. It is created by "polymerization" of many small molecules called monomers. Since it has varieties of these monomers, polymer has wide range of properties and functions. Two main structures of polymer are backbone; which is responsible for polymer stability and side chain; which contributes water solubility to polymer. Generally, two types of polymer are used to perform polymer injection, which are Xanthan Gum and partially Hydrolyzed Polyacrylamide (HPAM).

1. Xanthan Gum: this type of polymer is a polysaccharide formed from polymerization of saccharide molecules. It originates from the bacterial fermentation of Glucose, Mannose and Glucuronic acid leaving debris to be removed before the polymer is injected. From the structure of Xanthan Gum illustrated in Figure 3.1, it is obvious that Xanthan Gum has –O- in the backbone which causes Xanthan Gum to have relatively lower thermal stability and be more susceptible to thermal degradation at high temperature. Xanthan Gum structure also consists of $–COO^-$ in hydrophilic group which indicates a good viscosifier, negative charges on $–COO^-$ have repulsion against negative ions on sandstone surface so Xanthan has less adsorption onto it but it has less chemical stability. Moreover, Xanthan Gum has more complex and rigid branches than HPAM, thus, it is insensitive to formation brine and has higher resistance to mechanical shear degradation. But since Xanthan Gum is a biopolymer, it is susceptible to biodegradation when introduced into reservoir.

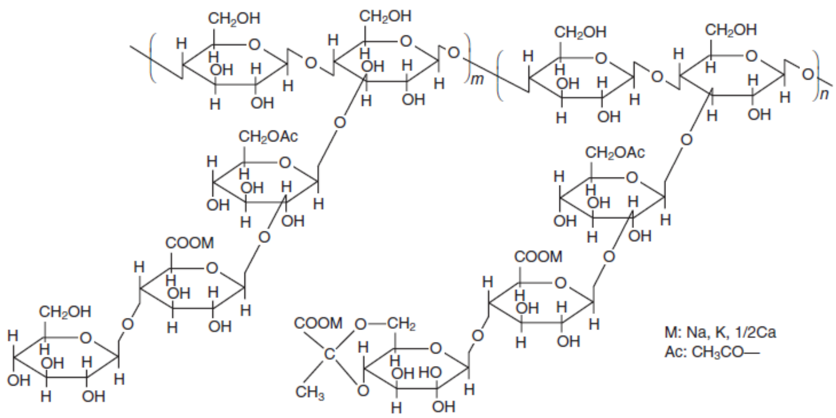


Figure 3.1 Xanthan Gum structure [11]

2. Polyacrylamide: this type of polymer is a polymer formed from the polymerization of acrylamide which is obtained by the hydration of acrylonitrile. Pure polyacrylamide is slightly positive charged and tends to be adsorbed onto rock surface, especially sandstone which has negative charges on its surface. This possibly reduces its potential to increase the viscosity to injected water. Hence, pure polyacrylamide has undergone partial hydrolysis to increase water solubility by reacting polyacrylamide with base such as sodium, potassium hydroxide or sodium carbonate, converting amide groups ($CONH_2$) to carboxyl groups ($-COO^-$) scattering along the backbone chain and becomes a partially Hydrolyzed Polyacrylamide (HPAM). From HPAM structure depicted in Figure 3.2, Carbon chain in the backbone brings good thermal stability and less susceptible to thermal degradation at high temperature but when HPAM is introduced into formation with high salinity or hardness, the repulsion of chain links is greatly decreased which reduces the potential of viscosity enhancement to polymer. HPAM also has ability to exhibit permanent permeability reduction which causes permeability contrast in reservoir with heterogeneity to reduce. In addition, HPAM is much cheaper than Xanthan Gum, thus, HPAM has become the most widely used polymer in EOR application these days.

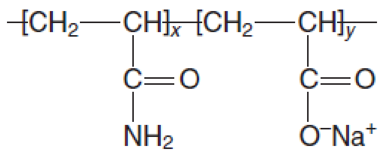


Figure 3.2 Molecular structure of Hydrolyzed Polyacrylamide (HPAM) [11]

Polymer flooding is considered as an enhanced oil recovery method to improve oil recovery factor. Polymer solution is injected into the well to sweep the oil to production well and more oil can be achieved. Typically, polymer has two major characteristics affecting the increment of oil production; first, polymer has more viscosity comparing to water, when it is mixed with water, it tends to increase the viscosity of water. This reduces the mobility ratio between water as a displacing fluid and oil as a displaced fluid and converge mobility ratio to favorable condition which is when mobility ratio is less than one. Second, polymer tends to adsorb onto rock surface, thus, water has difficulty traveling through pore spaces causing relative permeability to water to decline and turning mobility ratio to a favorable condition also.

Mobility ratio can be obtained from the following equation:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{ro}}{\mu_o}} \tag{3.1}$$

when,

M = Mobility ratio

λ_w = Mobility of water

λ_o = Mobility of oil

k_{rw} = Relative permeability to water

μ_w = Viscosity of water

k_{ro} = Relative permeability to oil

μ_o = Viscosity of oil

Mobility ratio implies relative speed between two fluids. In case of unfavorable condition (*M*>1), water travels faster than oil and tends to breakthrough first, on the other hand, oil travels faster than water in case of favorable condition (*M*<1).

3.3 Properties of Polymer

3.3.1 Rheology

Rheology is the study of flow and deformation of fluid. There are three rheological models namely Newtonian Fluid Model, Bingham Plastic Model and Power Law Model. Viscosity is one of the rheology defined as a resistance of the fluid to flow. Viscosity can be classified into 4 types which are Dynamic, Kinematic, Apparent and Relative viscosity which is an important factor to test the polymer solution. Relative viscosity is a ratio between viscosity of the polymer solution and viscosity of the pure solvent as shown in the following equation:

$$\eta_r = \frac{\eta}{\eta_s} \tag{3.2}$$

when,

η_r = Relative viscosity

η = Viscosity of polymer solution

η_s = Viscosity of pure solvent

One of the most important parameter that affects viscosity is molecular weight. The viscosity tends to increase as the molecular weight of polymer increases; therefore, types of polymer used to mix with water need to be carefully concerned.

3.3.2 Relative Permeability Reduction

Apart from increasing the viscosity of water, polymer solution also has effect on relative permeability reduction of water without affecting the relative permeability of oil. Considering mobility ratio equation, when relative permeability of water decreases, mobility ratio tends to decrease and converge to be a favorable condition (*M*<1). This occurs only in water-wet rock which has a characteristic that water is likely to occupy the smaller pores while oil occupies the center of pores which covers a larger area. When polymer is injected as a polymer solution, polymer itself will be adsorbed onto rock surface, reducing the available flow area of water at the smaller pore spaces while oil is nearly unaffected by the polymer entanglement. The phenomenon where water permeability is reducing while producing minimum reduction in the oil permeability is known as *Disproportionate Permeability Reduction (DPU).*

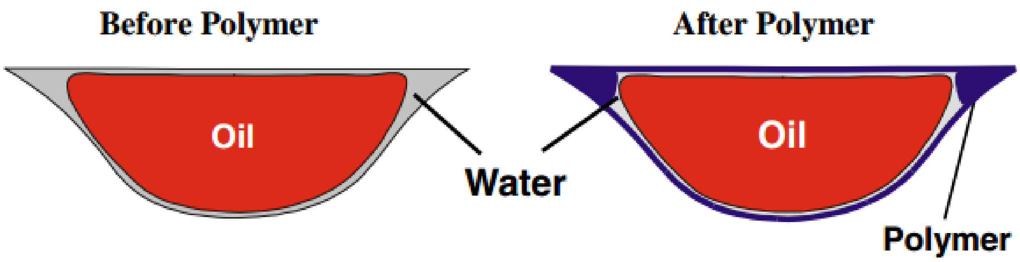


Figure 3.3 *Schematic illustration of a pore cross-section showing the water, oil and polymer distribution* [7]

There are two main measures in permeable media flow which are Resistance Factor (RF) and Residual Resistance Factor (RRF)

1. **Resistance Factor (RF):** a relative pressure drop caused by polymer flooding and waterflooding. By using Darcy's Law, this term can be written as a mobility ratio between water and polymer as follows:

$$RF = \frac{\Delta P_{polymer}}{\Delta P_{water}} = \frac{\lambda_{water}}{\lambda_{polymer}} \tag{3.3}$$

2. **Residual Resistance Factor (RRF):** a ratio between relative permeability to water and water after polymer flooding, also known as "Permeability Reduction" (i.e. at 100% adsorption, RRF=3 means relative permeability to water will reduce 3 times its original value).

$$RRF = \frac{k_{rw,\ before\ polymer\ flooding}}{k_{rw,\ after\ polymer\ flooding}} \tag{3.4}$$

In general, the most common measure of permeability reduction is *RRF* which can be affected by many parameters, including polymer type, molecular weight, degree of hydrolysis, shear rate and permeable media pore structure.

3.4 Polymer Flow Behavior in Porous Media

3.4.1 Inaccessible Pore Volume (IPV)

IPV happens for several reasons; first, when larger polymer molecule is introduced into reservoir and cannot flow through smaller pore space of rock. The volume of uninvaded pore space is known as Inaccessible Pore Volume *(*IPV*).* Another reason is from *"Wall Exclusion Effect"* as polymer molecule occupies center of a narrow pore space and polymer molecule near pore wall has lower viscosity, causing an apparent fluid slip [12]. Factors that affect IPV include polymer molecular weight, permeability-porosity of rock and pore size distribution. In addition, polymer can be affected by the combination of adsorption and IPV as illustrated in Figure 3.4.

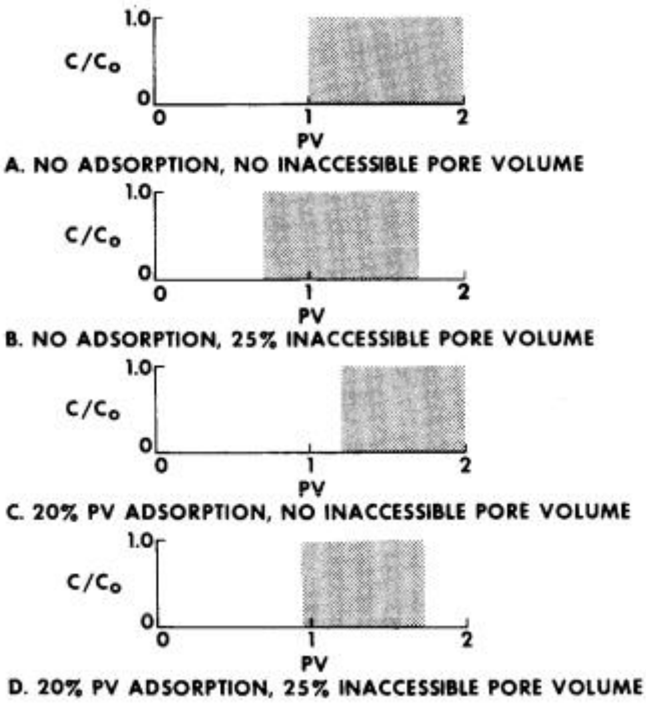


Figure 3.4 *Ideal Polymer Breakout Curves when bank size = 1.0 PV* [8]

IPV causes the polymer slug to breakthrough early and the breakout curve is shifted forward due to the amount of unflooded pore volume. However, adsorption effect tends to delay the front edge of polymer slug without having effect on the back edge which reduces the polymer size; thus, IPV together with adsorption effect produce smaller polymer size and simultaneously, shift the breakout curve forward [8].

3.4.2 Polymer Retention

Polymer retention consists of three main mechanisms, including polymer adsorption, mechanical entrapment and hydrodynamic retention. Figure 3.5 illustrates three types of polymer retention mechanisms.

1. Polymer Adsorption: the charge interaction between polymer and rock surface causes polymer molecule to be adsorbed onto surface of rock. Thus, some part of polymer mass will be removed from bulk polymer solution in this interaction. Polymer adsorption depends upon surface area of rock exposed to polymer solution.

2. Mechanical Entrapment: this mechanism contributes a major part of polymer retention. It usually occurs in low-permeability formation. Since polymer is flexible, when it is trapped in a pore channel, a fluid can still flow through a polymer chain and brings even more polymer into a channel, resulting in accumulation of polymer in a channel.

3. Hydrodynamic Retention: this mechanism is similar to Mechanical Entrapment except that trapped polymer molecule can be released when fluid does not flow through pore channel anymore [9].

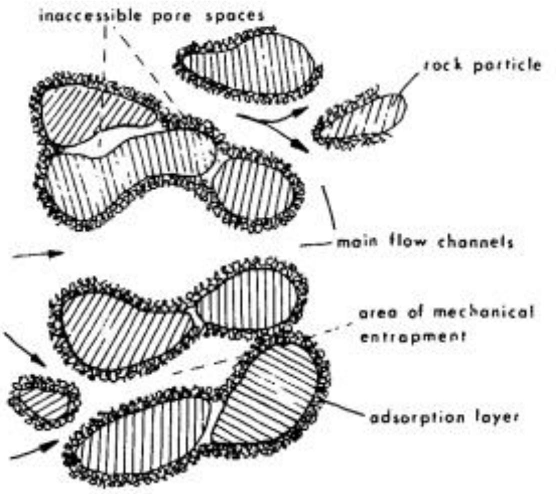


Figure 3.5 *Schematics of Polymer Retention in porous media* [9]

3.5 Polymer Injectivity

Polymer injectivity is defined as a polymer injection rate over pressure drop between the bottom-hole flowing pressure and some reference pressure. It is a critical factor to concern for every polymer flooding project in aspect of economic potential; therefore, single-well injectivity tests are usually performed before polymer flooding.

Injectivity of polymer can be limited by these following factors:

1. Mobility Ratio (*M*): as depicted in Figure 3.6 in case that M=1, the polymer injectivity remains constant throughout the process. If M<1, the injectivity decreases as the volume of reservoir swept increases because it is harder for polymer to flow and it reaches the lowest corresponding to injectivity at residual oil saturation. When M>1, injectivity increases as swept area increases since polymer has less resistance to flow.

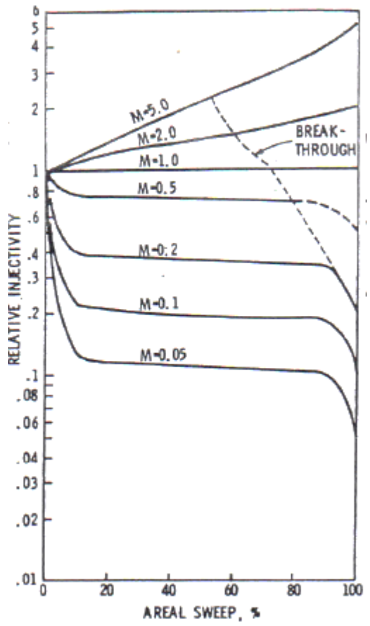


Figure 3.6 *Correlation of relative injectivity with areal sweep efficiencies at selected mobility ratios for miscible displacement in a five-spot pattern* [11]

2. Polymer Concentration: as the polymer concentration increases above critical polymer concentration, the polymer viscosity increases drastically with concentration, hence, the injectivity decreases and the oil production is delayed [13].

3. Polymer Size Distribution: in practice, polymer molecules used for field application have sizes as shown in Figure 3.7; some of them may have larger sizes than rock-pore size and polymer molecules are trapped at pore throat which reduces polymer injectivity.

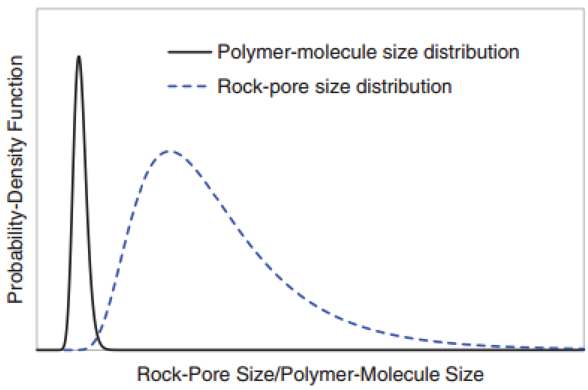


Figure 3.7 *Polymer-molecule size and rock-pore size distributions* [14]

4. Rheology of Polymer: HPAM polymer solution exhibits shear-thickening behavior at very high flow rates around wellbore [14] that is as shear rate increases, viscosity of polymer solution decreases and prone to increase the injectivity of polymer.

5. Mechanical Degradation: this occurs when injecting polymer under high velocity flows. HPAM is the most susceptible under normal operating condition [12]. The absence of face plugging the viscous nature of polymer solution causes injectivity to reduce [13].

6. Other Parameters: apart from statement above, there are several factors that can affect the polymer injectivity such as water salinity, well spacing, injection pattern, contamination of polymer solution, pressure drop, temperature, polymer retention and mechanical entrapment.

3.6 Reservoir Heterogeneity

Reservoir Heterogeneity is defined as the variation of rock properties, including thickness, porosity, permeability, etc. in different locations within the reservoir. One of the significant rock properties is permeability of rock. Combination of permeability can be classified into Parallel Layer and Serial Layer.

1. Parallel Layer: a case when fluid flows perpendicular to the layer of reservoirs with different permeabilities. For both linear and radial flow, the average permeability can be obtained from following equation:

$$k=\frac{\sum_{j=1}^{n} k_j h_j}{\sum_{j=1}^{n} h_j} \tag{3.5}$$

Figure 3.8 describes denotes for calculating the average permeability for reservoir containing many layers with different permeability for both linear and radial flow systems.

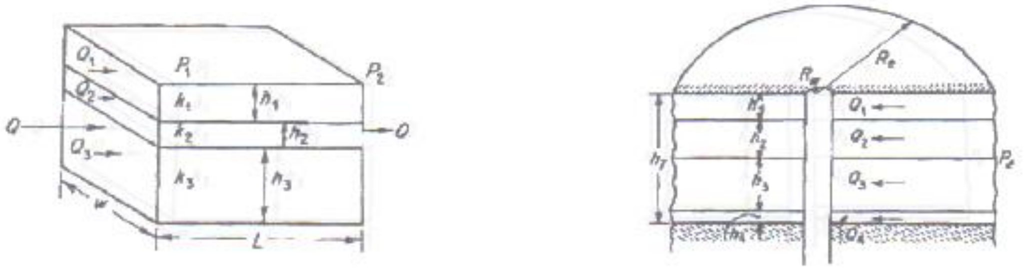


Figure 3.8 *Combination of reservoir layers in parallel induced by linear flow (left), radial flow (right)* [15]

2. Serial Layer: a case when fluid flow through reservoir layers connected in series. For linear flow, the average permeability can be written as follows:

$$k=\frac{L}{\sum_{j=1}^{n}\frac{L_j}{k_j}} \tag{3.6}$$

For radial flow, the equation becomes:

$$k=\frac{\log\frac{r_e}{r_w}}{\sum_{j=1}^{n}\frac{\log\frac{r_j}{r_{j-1}}}{k_j}} \tag{3.7}$$

Figure 3.9 illustrates flow in series for both linear and radial flows.

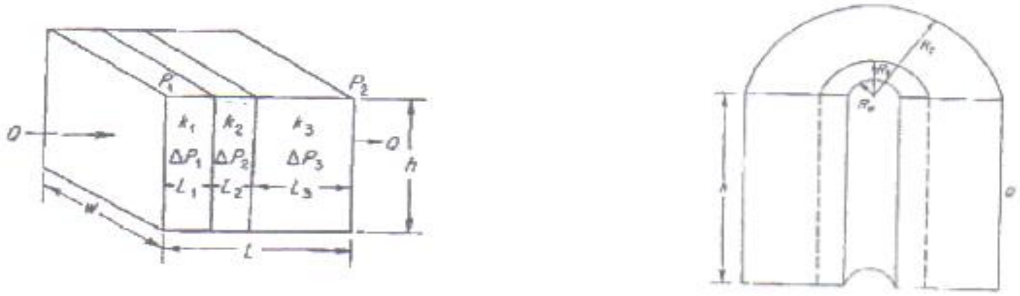


Figure 3.9 *Combination of reservoir layers in parallel induced by linear flow (left), radial flow (right)* [15]

Moreover, the heterogeneity of reservoir can be quantified by two methods including *Lorenz Coefficient* and *Coefficient of Variation*.

1. Lorenz Coefficient: this method is used to calculate the heterogeneity of layered reservoir. Lorenz coefficent (L_k) can be acquired from Figure 3.10 by ratio of area no.1 and area no.2. If L_k is close to zero, reservoir is considered to be a uniform permeability distribution.

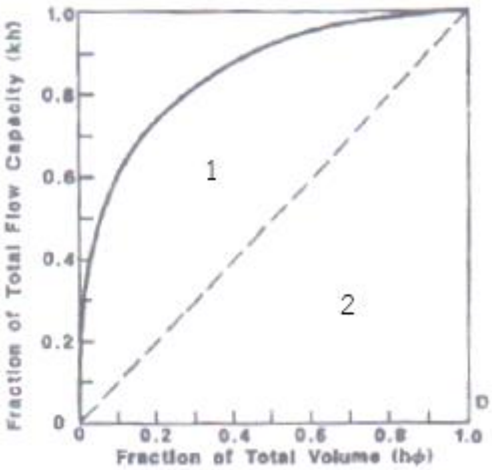


Figure 3.10 *Flow Capacity Distribution*

2. Coefficient of Variation: use log-normal distribution of permeability to acquire coefficient of permeability variation (V_k) as follows:

$$V_k = \frac{S}{k_{avg}} \tag{3.8}$$

where S is a standard deviation of permeability can be statistically obtained from:

$$S = \sqrt{\frac{\Sigma(k - k_{avg})^2}{n}} \tag{3.9}$$

and k_{avg} is an average permeability of reservoir obtained from:

$$k_{avg} = \frac{\Sigma k}{n} \tag{3.10}$$

Figure 3.11, V_k can be graphically determined by following equation:

$$V_k = \frac{k_{avg} - k_{84.1}}{k_{avg}} \tag{3.11}$$

where $k_{84.1}$ is a permeability at percentile 84.1 of cumulative sample.

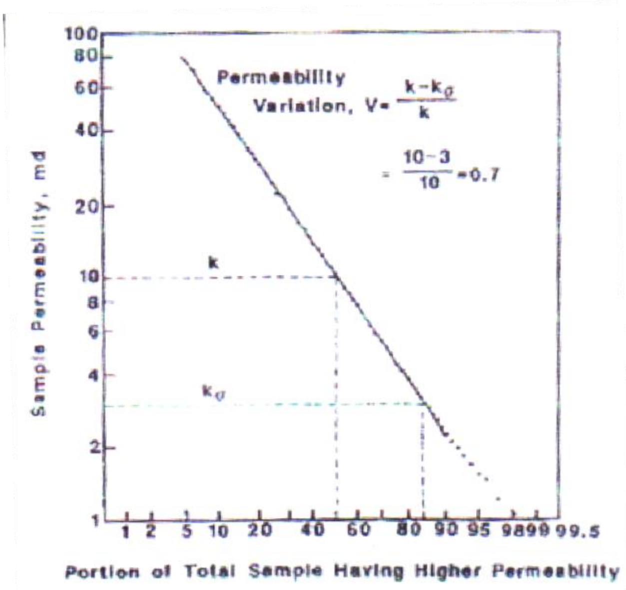


Figure 3.11 *Log normal permeability distribution* [15]

CHAPTER 4
RESERVOIR SIMULATION MODEL

To investigate the effect of polymer alternating waterflooding in multilayered heterogeneous reservoir, reservoir model is constructed using STARS© by Computer Modeling Group (CMG) as a numerical simulator. The reservoir has two wells, including injection well and production well. A quarter five-spot injection pattern is used in this study. This chapter provides details about reservoir model, including Grid Section, Reservoir Heterogeneity, PVT Properties, Petrophysical Properties, Polymer Properties, Well Specification and Production Constraints. In addition, thesis methodology is revealed in the last part of this chapter.

4.1 Grid Section

Reservoir simulation model is generated using Cartesian grid model. A number of grid blocks in i, j and k direction are 33, 33, and 9 blocks, respectively with the block width of 20 ft. for both i and j direction and 12 ft. for k direction. Injection well and production well are located on the edges of reservoir diagonally. Heterogeneous reservoir is constructed with Lorenz coefficient 0.2, 0.24 and 0.275 with permeability order from the highest to the lowest values (coarsening upward sequence) and the lowest to the highest (fining upward sequence). Porosity for the whole reservoir is kept constant at 20 percent. Summary of reservoir properties for static model is shown in Table 4.1 and Figure 4.1 illustrates 3-D reservoir model.

Table 4.1 Reservoir physical parameters for static model

Parameters	Values	Unit
Grid dimension	33x33x9	Block
Grid size	20x20x12	Ft.
Top of reservoir	7,000	Ft.
Effective porosity (ϕ)	20	%
Average horizontal permeability (k_H)	230	mD
Average vertical permeability (k_V)	230 ($k_V = k_H$)	mD
Initial water saturation (S_{wi})	20	%
Reference pressure at datum depth	3,445	psia
Reservoir temperature	182	$^{\circ}$F

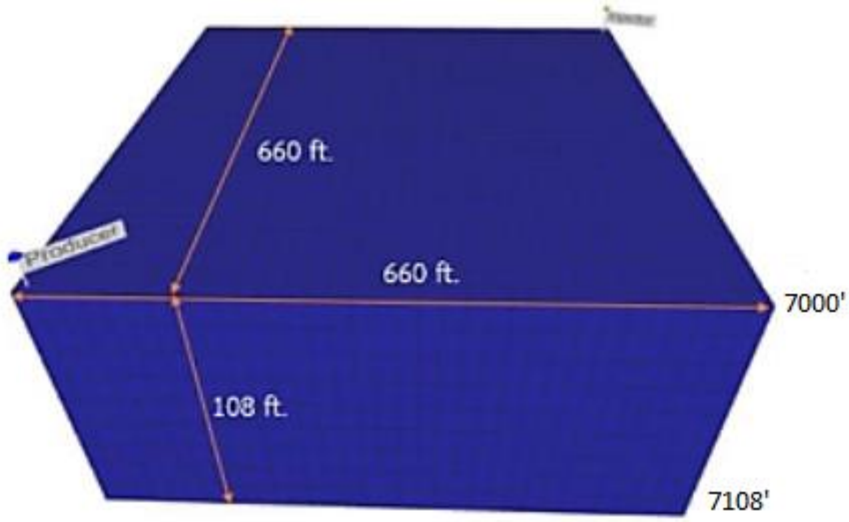


Figure 4.1 Dimension of static model and well location

4.2 Reservoir Heterogeneity

Heterogeneous reservoir is used in this study. Reservoir heterogeneity can be quantified by using *Lorenz coefficient* (L_k). Typical values for reservoir heterogeneity are from 0.2 to 0.3 thus, three values of heterogeneity which are 0.2, 0.24 and 0.275 are selected.

To calculate for the reservoir heterogeneity, permeability, porosity and reservoir thickness are required. Reservoir heterogeneity can be obtained from the ratio of the area between the curve and straight line and the triangular area from the plot which consists of fraction of cumulative porosity multiplied by reservoir thickness as x-axis and fraction of permeability multiplied by reservoir thickness as y-axis.

The permeability values for three L_k values are shown in Table 4.2.

Table 4.2 *Permeability values for different Lorenz coefficient*

Layer	k of L_k=0.2 (mD)	k of L_k=0.24 (mD)	k of L_k=0.275 (mD)
1	300	300	300
2	267	296	299
3	254	285	298
4	244	264	297
5	200	200	200
6	196	165	199
7	145	117	86
8	134	113	61
9	60	60	60

4.3 Pressure - Volume - Temperature (PVT) Properties

One of the properties which is important to run numerical simulation precisely is PVT data since it exhibits fluid characteristic inside the reservoir. Black Oil PVT is selected in this study. The correlations for PVT data are selected manually and properly based on fluid property assumption as shown in Table 4.3.

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

Input parameters for PVT properties are also required. Oil in this reservoir is medium oil with oil gravity 20°API and specific gas gravity 0.85. Reservoir temperature gradient of 0.017°F/ft and reservoir pressure gradient of 0.49 psi/ft are used in this study. Gas-oil ratio of 50 ft^3/bbl is assumed due to less gas dissolved in oil. Using bubble point pressure–solution gas-oil ratio correlation [15], bubble point pressure is found to be at 416 psi. Table 4.4 summarizes all the input parameters.

Table 4.4 *Input parameters for PVT data*

Parameter	Value	Unit
Oil Gravity	20	°API
Gas Gravity	0.85	SG
Bubble Point Pressure	416	psi
Reservoir Temperature	182	°F
Reservoir Pressure	3445	psi
Surface Temperature	62.33	°F
Surface Pressure	14.7	psi

Afterwards, the simulator will generate PVT data as a function of pressure or temperature as shown in figures below.

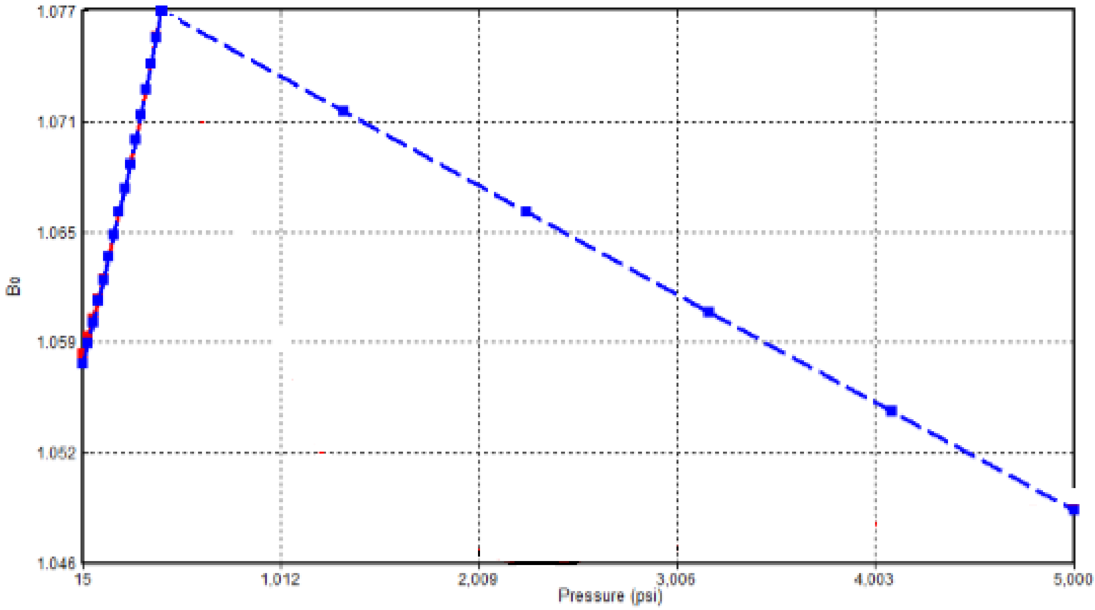


Figure 4.2 *Oil formation volume factor (B_o) as a function of pressure*

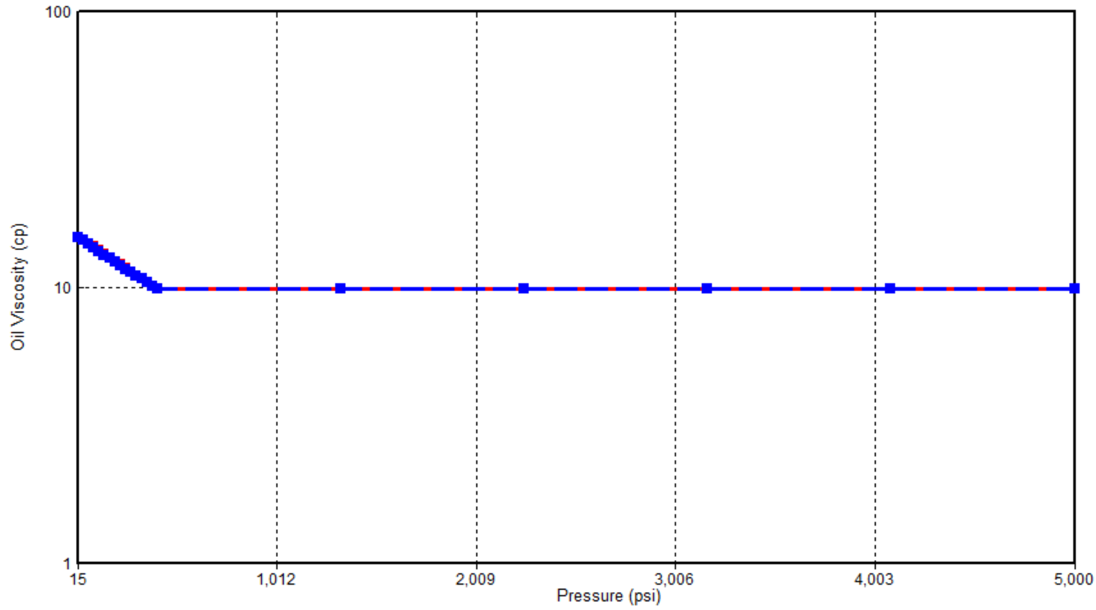


Figure 4.3 *Oil viscosity (μ_o) as a function of pressure*

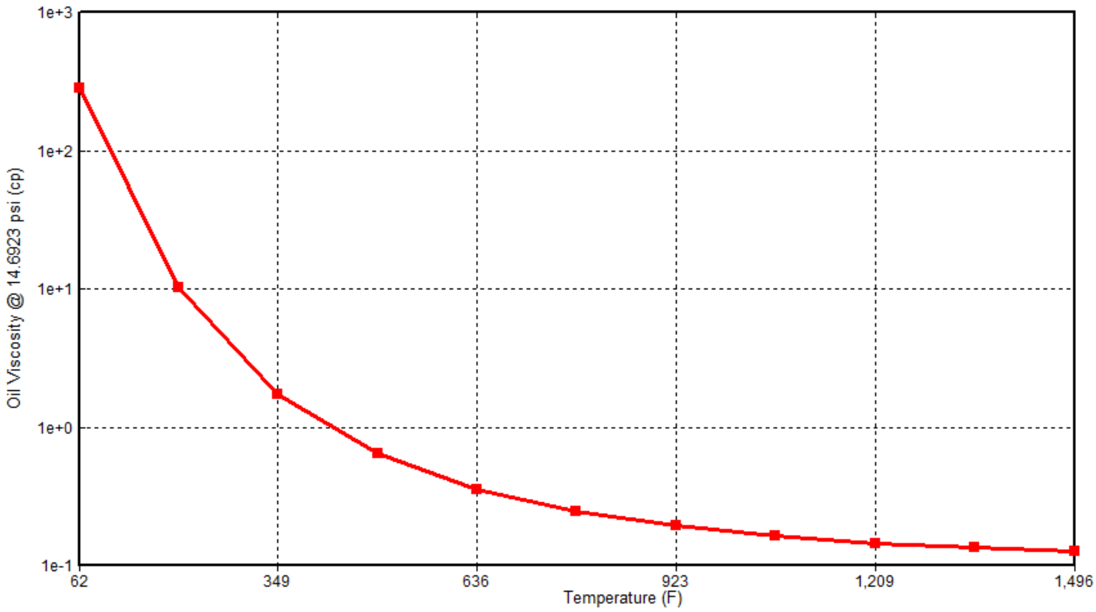


Figure 4.4 *Oil viscosity* (μ_o) *as a function of temperature*

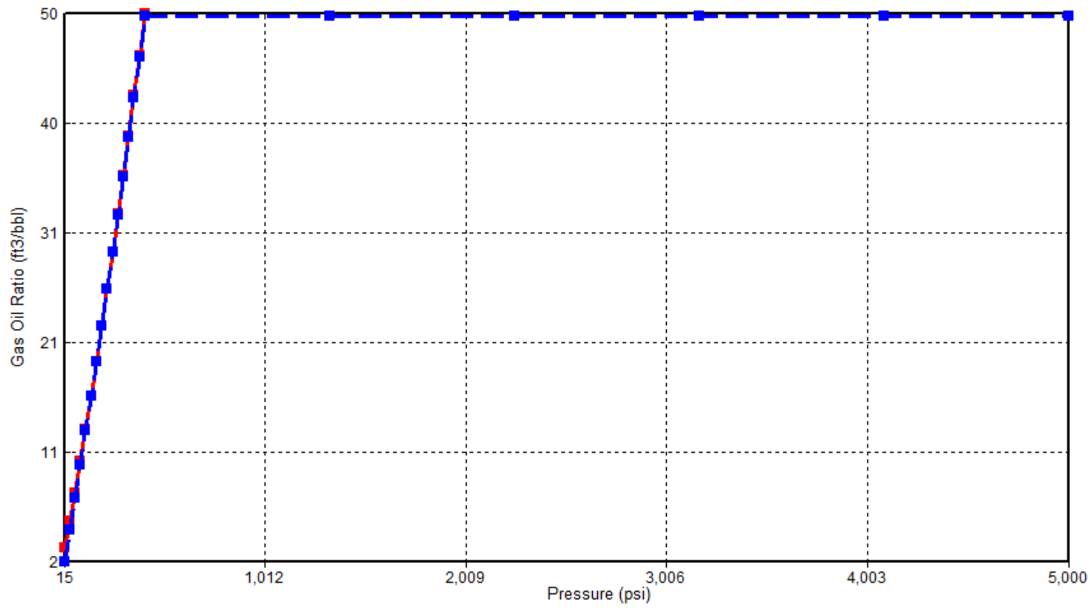


Figure 4.5 *Gas-oil ratio* (R_s) *as a function of pressure*

For the formation water properties, fresh water is assumed in this study with low salinity at 1,000 ppm to prevent salinity effect on residual resistance factor and polymer flooding process. Other properties are shown in Table 4.5.

Table 4.5 *PVT properties of formation water*

Parameter	Value	Unit
Reference Pressure	3,445	psi
Formation Volume Factor	1.02	rb/stb
Compressibility	2.98×10^{-6}	1/psi
Viscosity at Reference Pressure	0.36	cP
Water Salinity	1,000	ppm
Water Phase Density at Reference Pressure	61.17	lb/ft^3

Finally, formation volume factor of gas which relates during gas expansion on the surface is also displayed in Figure 4.6.

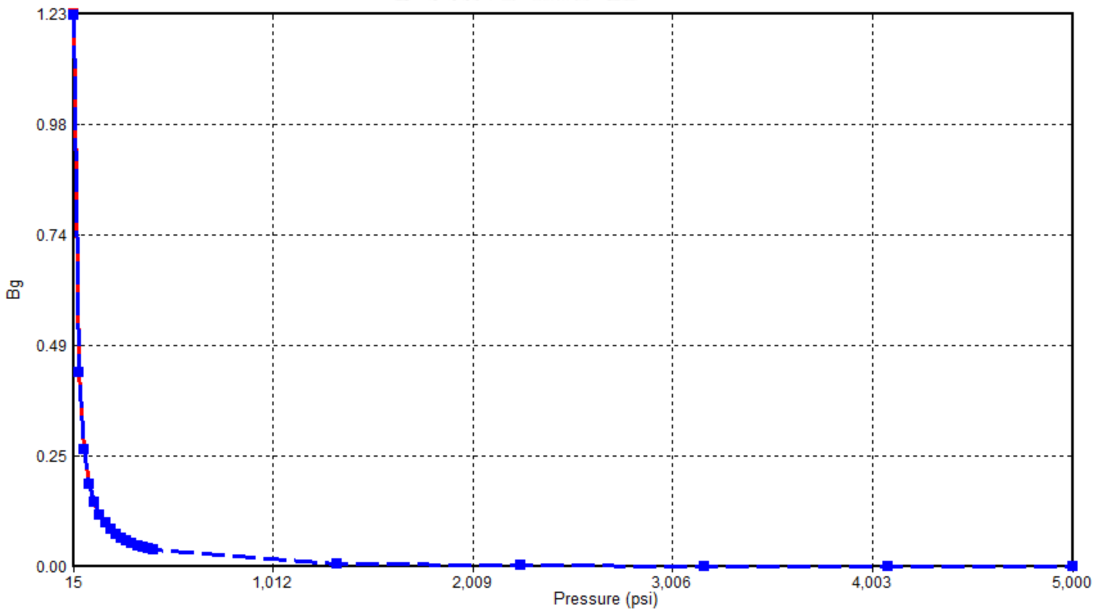


Figure 4.6 *Formation volume factor of gas (B_g) as a function of pressure*

4.4 Petrophysical Properties

Another important property before running the simulation is petrophysical property which is the interaction between rock and fluid inside reservoir. Method for evaluating three-phase relative permeability set is Stone's second model while Corey's correlation is used for evaluating two-phase permeability set, therefore oil-water permeability system and gas-liquid permeability system are generated using Corey's correlation. Rock wettability is water wet and residual oil saturation is set to be 0.25 which is appropriate to apply Enhanced Oil Recovery (EOR) method. Other input data for petrophysical properties are shown in Table 4.6.

Table 4.6 *Input data for petrophysical properties*

Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.25
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.25
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - kro at Connate Water	0.7
KRWIRO - krw at Irreducible Oil	0.3
KRGCL - krg at Connate Liquid	0.7
Exponent for Calculating krw from KRWIRO	2
Exponent for Calculating krow from KROCW	2
Exponent for Calculating krog from KROGCG	3
Exponent for Calculating krg from KRGCL	3

Moreover, three-phase relative permeability is shown in Figure 4.7 while two-phase relative permeability systems between oil-water and gas-liquid are shown in Figure 4.8 and Figure 4.9 respectively.

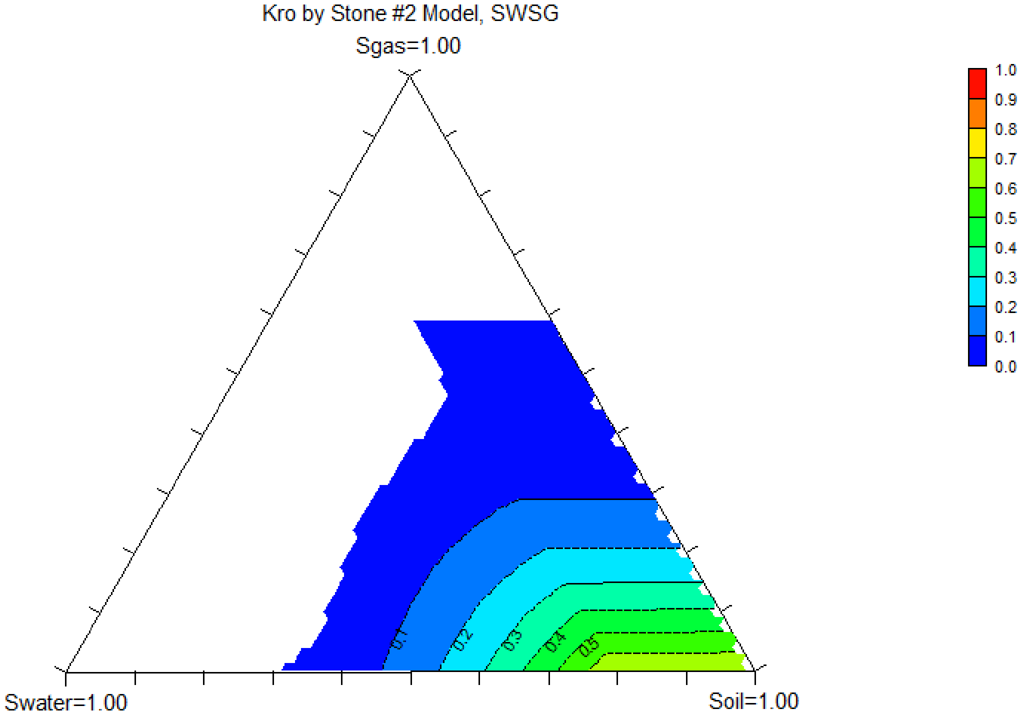


Figure 4.7 *Three phase permeability system*

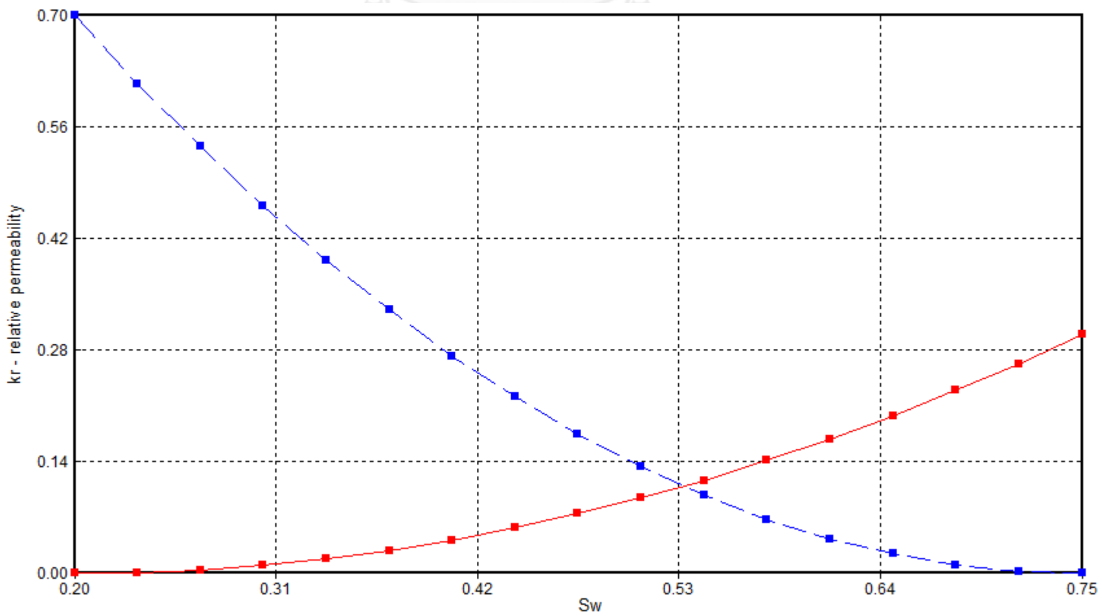


Figure 4.8 *Two phase relative permeability of oil-water*

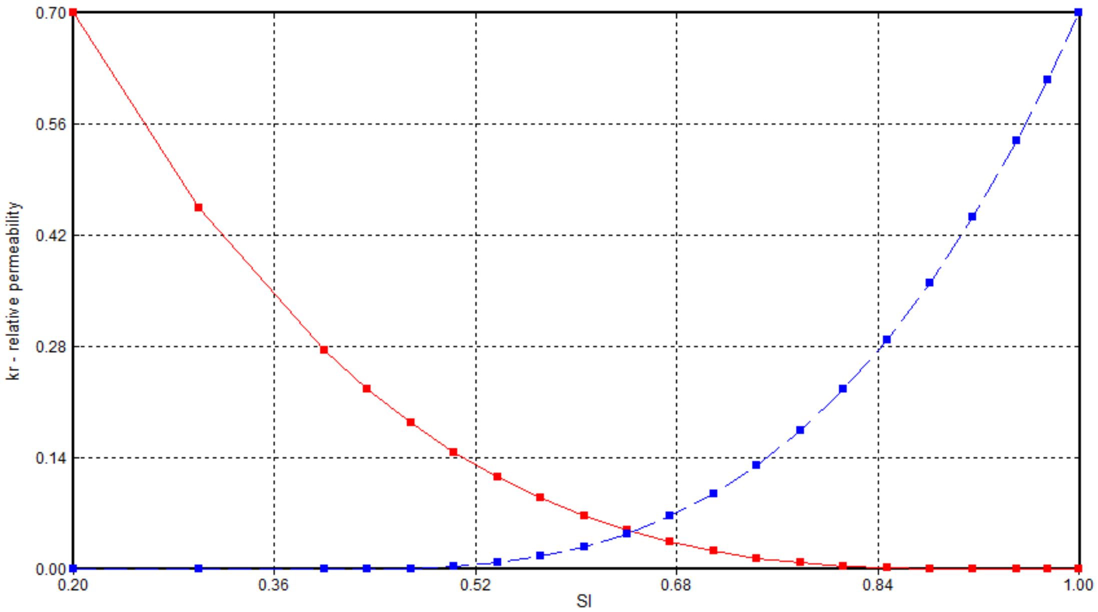


Figure 4.9 *Two phase relative permeability of gas-liquid*

4.5 Polymer Properties

In polymer flooding study, Hydrolized Polyacrylamide (HPAM) polymer named Flopaam 3330S is selected as it can exhibit polymer adsorption property. It has molecular weight of 8,000 million with degree of hydrolysis ranging between 25-30%. Polymer resistance factor is 2 and Inaccessible Pore Volume (IPV) is 20%. Polymer slug sizes are 0.2, 0.25 and 0.3 PV and polymer concentration values are 1,250, 1,000 and 833 ppm. Polymer degradation and polymer half-life are negligible in this study. Other polymer properties are summarized in Table 4.7.

Table 4.7 *Polymer viscosity at different polymer concentration*

Polymer Concentration (%wt.)	Viscosity (cP)
0	0.36
0.05	2.73
0.1	7.46
0.2	27.34
0.3	80.79

Since HPAM polymer can exhibit polymer adsorption on rock surface, polymer adsorption data is taken from Flopaam 3330S data as shown in Table 4.8 also, polymer desorption level is assumed to be 60% as shown in Table 4.9.

Table 4.8 *Polymer adsorption at different polymer concentration*

Polymer Concentration (%wt.)	Polymer Adsorption (mg/100 gm rock)
0	0
0.1	1.32
0.25	3.29
0.5	6.58

Table 4.9 *Maximum adsorption capacity and residual adsorption level*

Parameter	Value (lbmol/ft^3)
Maximum Adsorption Capacity (ADMAXT)	5.44×10^{-6}
Residual Adsorption Level (ADRT)	1.36×10^{-7}

4.6 Well Specification and Production Constraints

Wellbore radius for this study is 0.25 ft. for both production well and injection well. Full-to-base perforation is performed over 108 ft. interval. Two wells are located on the other side of reservoir diagonally.

Surface injection and production rate are equally set at 800 bbl/d in order to minimize reservoir pressure depletion. Minimum bottomhole pressure for the production well is 420 psi (above the bubble point pressure at 416 psi) which can ensure a single-phase oil production. Production will be terminated when watercut reaches 90%. For the injection well, maximum bottomhole pressure is limited to 4,700 psi due to the fracture pressure calculated using Eaton correlation [16] at 4,743 psi. The summary of production constraints is shown in Table 4.10 and Table 4.11.

Table 4.10 *Production well constraints*

Parameter	Limit/Mode	Value	Unit
Surface Liquid Rate, STL	Max	800	bbl/day
Bottomhole Pressure, BHP	Min	420	psi
Watercut, WCUT	-	0.9	-

Table 4.11 *Injection well constraints*

Parameter	Limit/Mode	Value	Unit
Surface Liquid Rate, STW	Max	800	bbl/day
Bottomhole Pressure, BHP	Max	4,700	psi

4.7 Methodology

All the steps to evaluate the performance of alternative polymer injection are shown in this section also, followed by the flowchart summarizing the thesis methodology shown in Figure .

1. Construct a coarsening upward heterogeneous model with Lorenz Coefficient (L_k) of 0.2.

2. Perform waterflooding from the start of oil production to be a reference for other polymer flooding cases.

3. Perform single-slug polymer flooding with three different polymer concentration (1,250 ppm/ 0.2 PV, 1,000 ppm/ 0.25 PV and 833 ppm/ 0.3 PV). Determine the best case by varying the operating parameter as follows:

❖ Polymer Injection Starting Time

- First day of production = 0 PV,
- Water volume = 0.02 PV (25% of water breakthrough),
- Water volume = 0.05 PV (50% of water breakthrough),
- At water breakthrough = 0.11 PV,
- At 25% watercut = 0.14 PV,
- At 50% watercut = 0.20 PV.

4. Perform polymer alternating waterflooding with three different polymer concentration (1,250 ppm/ 0.2 PV, 1,000 ppm/ 0.25 PV and 833 ppm/ 0.3 PV) by selecting the best polymer injection starting time from previous case and compare the results with single-slug polymer injection. Keep the same injected polymer mass while varying the following operating parameters:

- ❖ Alternating water slug size
  - First day of production = 0 PV
  - Water volume = 0.02 PV (25% of water breakthrough)
  - Water volume = 0.05 PV (50% of water breakthrough)
  - At water breakthrough = 0.11 PV
  - At 25% watercut = 0.14 PV
  - At 50% watercut = 0.20 PV
- ❖ Concentration sorting (using the best alternating water slug size)
  - Descending order (high to low)
  - Ascending order (low to high)
- ❖ Number of alternative cycles
  - 1 cycle
  - 2 cycles
  - 3 cycles
  - 4 cycles
  - 5 cycles

5. Perform polymer alternating waterflooding by selecting representative operating parameters from previous step to study the effect of the parameter as follows:

❖ Residual Resistance Factor (RRF)

- RRF=1.5,
- RRF=2 (default),
- RRF=2.5.

❖ Reservoir Heterogeneity

- Coarsening upward: single-slug vs. the best from previous cases,
- Fining upward: single-slug vs. the best from previous cases.

6. Compare and analyze the results obtained from polymer alternating water injection using outcome parameters such as oil recovery factor, oil production rate, and production time.

7. Conclude new findings based on thesis objectives and provide recommendation for further polymer flooding study.

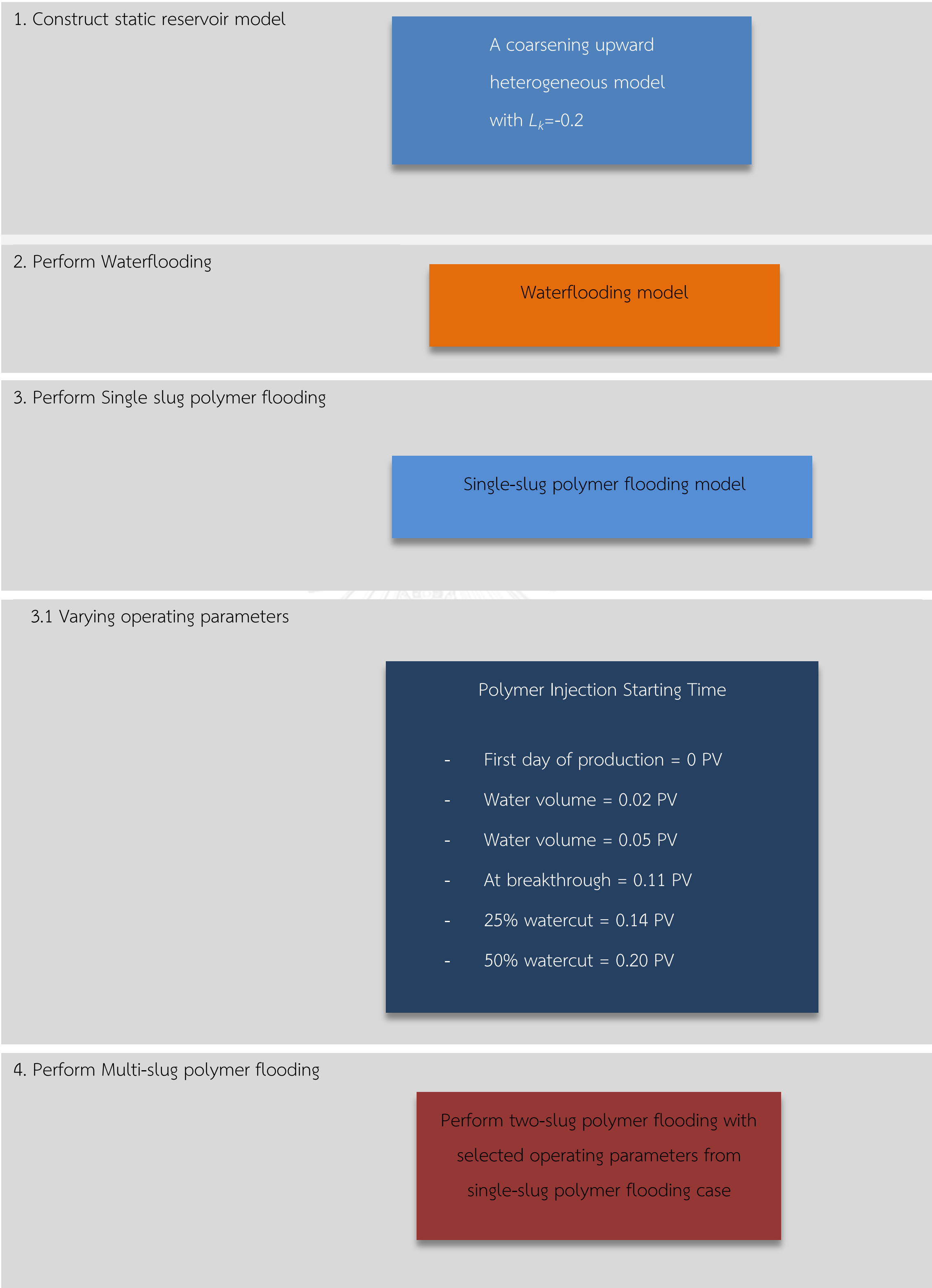


Figure 4.10 Summary of flowchart of thesis methodology

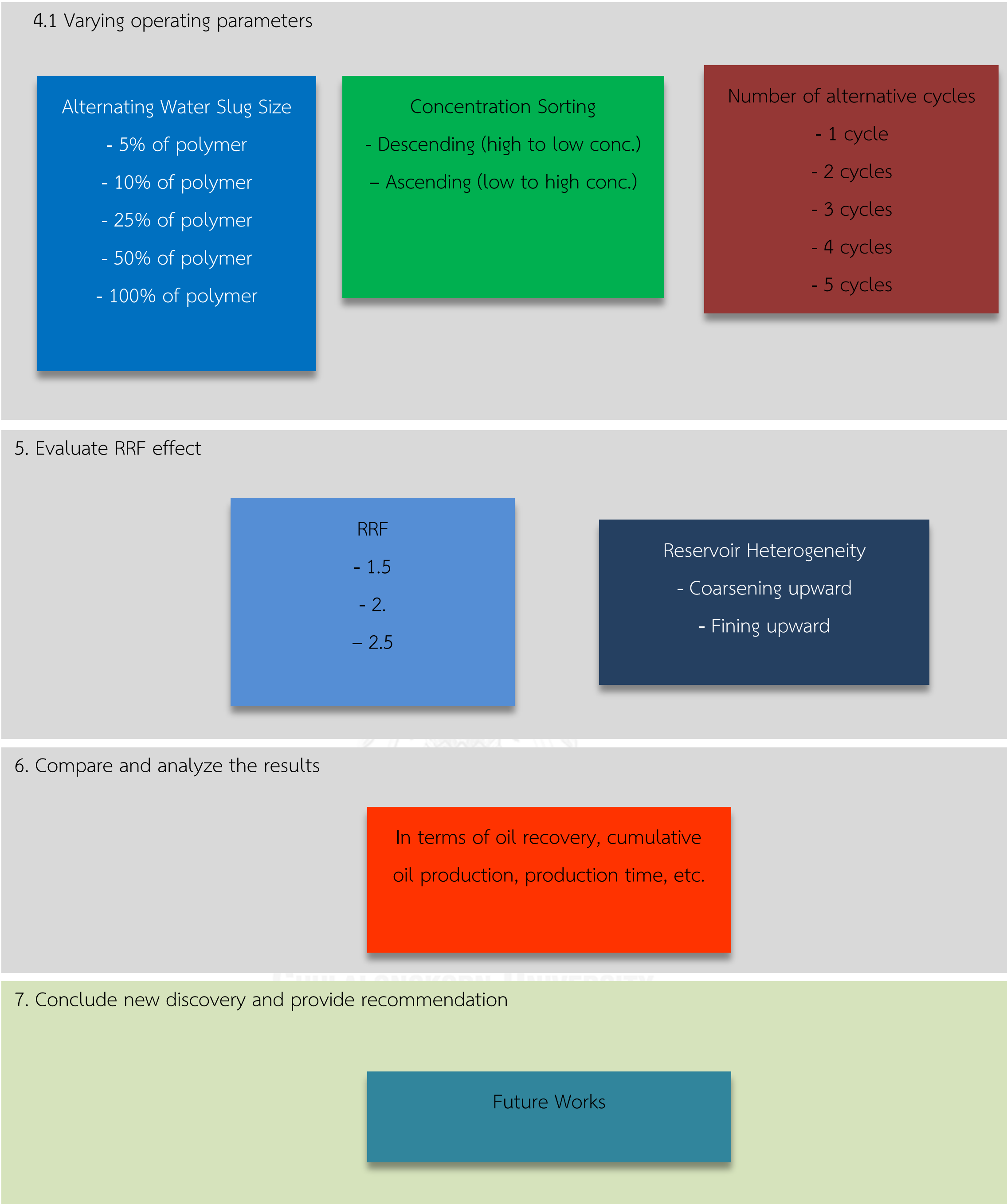


Figure 4.10 Summary of flowchart of thesis methodology (continued)

CHAPTER 5
RESULTS AND DISCUSSION

After static reservoir model with reservoir heterogeneity of 0.2 is constructed, waterflooding is performed as a reference case. Subsequently, single-slug polymer flooding is performed to determine the benefit over waterflooding. Polymer injection starting time is an operating parameter obtained from single-slug polymer flooding. Afterwards, multi-slug polymer flooding is performed to determine alternating water slug size, concentration sorting and number of alternative cycles while keeping the same polymer mass for all cases. Lastly, the effect of residual resistance factor and reservoir heterogeneity are also included in this section. In this chapter, it can be subdivided into seven sub-sections as follows:

5.1 Waterflooding

5.2 Effect of Polymer Injection Starting Time

5.3 Effect of Alternating Water Slug Size

5.4 Effect of Concentration Sorting

5.5 Effect of Number of Alternative Cycles

5.6 Effect of Residual Resistance Factor

5.7 Effect of Reservoir Heterogeneity

5.1 Waterflooding

Waterflooding is a conventional oil recovery method performed by injecting water into the reservoir to maintain reservoir pressure. Waterflooding will be used as a reference before performing single-slug polymer flooding and multi-slug polymer flooding. Waterflooding is performed from the first day of production until 90 percent watercut constraint is attained. The water injection rate, oil rate, watercut, bottomhole pressure and water saturation profile are detected with the final results.

Figure 5.1 illustrates water injection rate during waterflooding process. It can be observed that water injection rate can reach a desired rate of 800 bbl/d from the start of production until it reaches 90 percent watercut constraint.

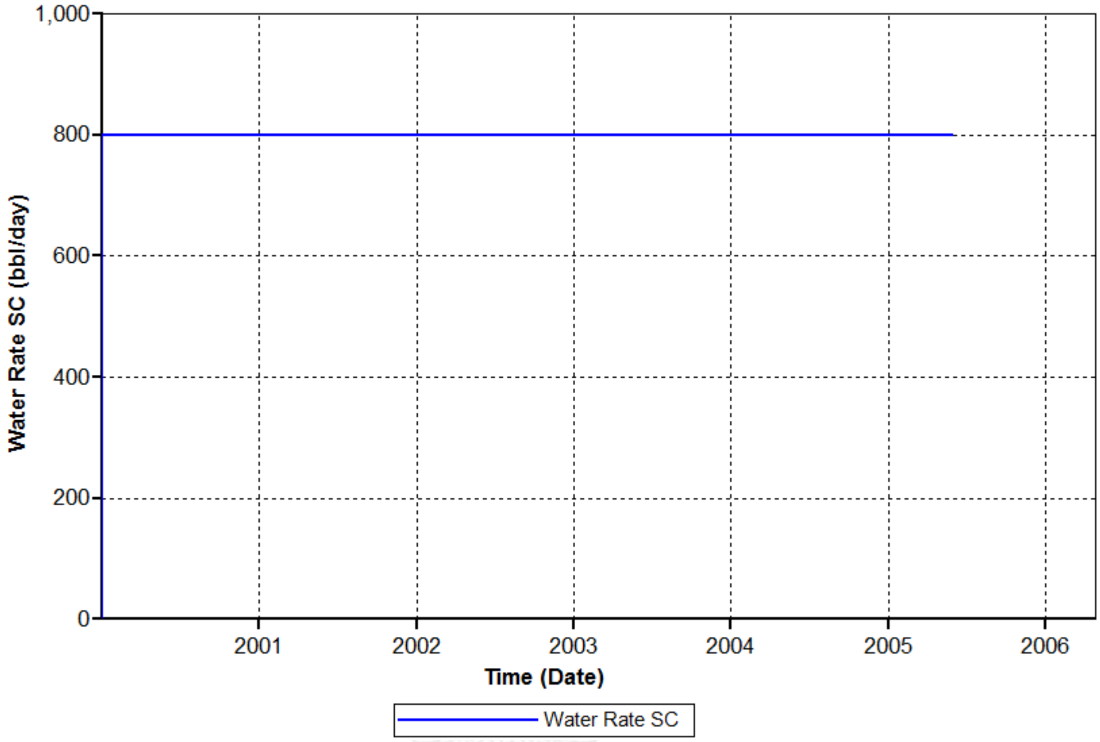


Figure 5.1 *Plot of water injection rate as a function of time of waterflooding in coarsening upward reservoir model with* L_k*=0.2*

Figure 5.2 shows that water starts to breakthrough at the 8th month of production due to high injection rate of 800 bbl/d. In accordance with watercut data, at the early time before breakthrough, pressure support from waterflooding can maintain oil rate at 800 STB/d. Later, after water breakthrough, oil rate drops rapidly due to the increment of water rate at production well.

Finally, oil production is terminated in mid-2005 due to watercut constraint with the final results summarized in Table 5.1.

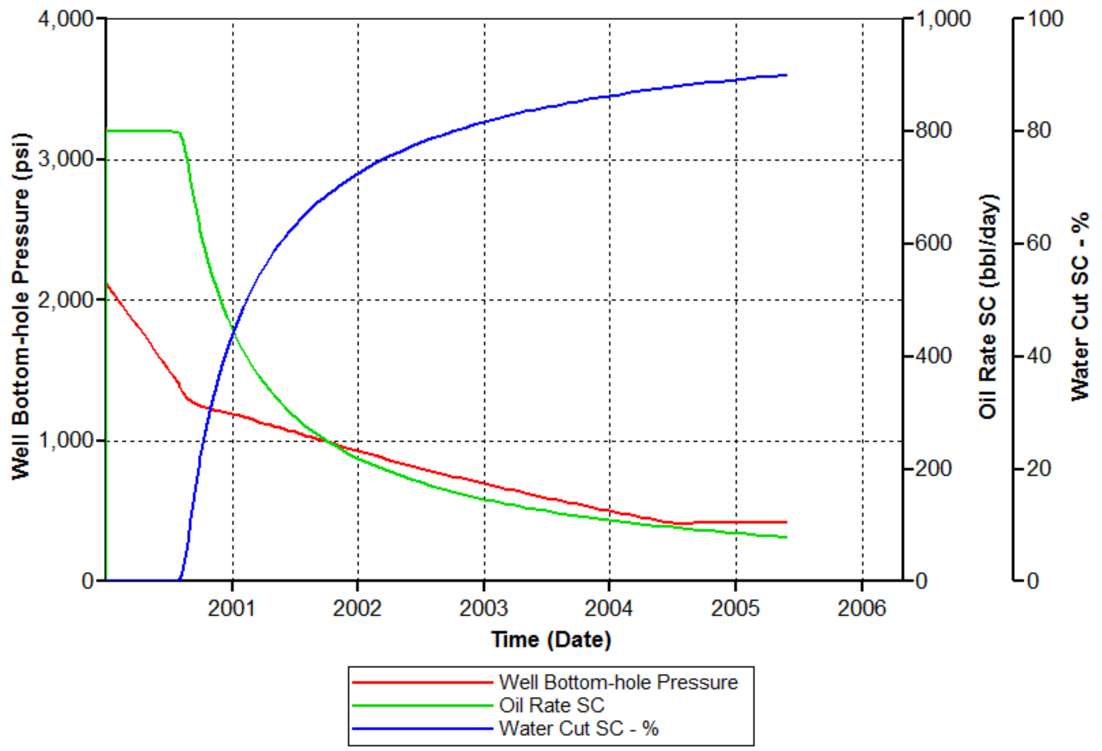


Figure 5.2 *Plot of bottomhole pressure, watercut and oil production rate at producer as a function of time of waterflooding in coarsening upward reservoir model with* L_k*=0.2*

Table 5.1 Summary of simulation outcomes from waterflooding in coarsening upward reservoir model with L_k*=0.2*

Parameters	Value	Unit
Oil Recovery Factor	41.55	%
Cumulative Oil Production	526,437	STB
Cumulative Water Production	1,055,032	bbl
Total Production Time	1,978	days

Figure 5.3 depicts water saturation profile at the time when water breakthrough for this waterflooding case, showing that water tends to reach production well at the upper layers of reservoir which have higher permeability values compared to deeper zone, leaving large amount of oil un-swept as known as

overriding characteristic. Thus, due to low oil recovery and early water breakthrough, polymer flooding is applied to improve the oil recovery process.

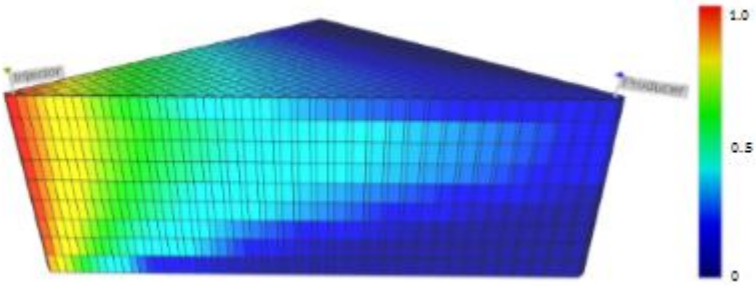


Figure 5.3 *Water saturation profile at water breakthrough of waterflooding in coarsening upward reservoir model with L_k=0.2*

5.2 Effect of Polymer Injection Starting Time

Before injecting polymer slug into injection well, pre-flushed water is injected in order to increase injectivity of polymer. Originally, reservoir is considered as a tank full of oil which is somewhat difficult to inject any liquid with high viscosity in. Water is injected first due to its flow ability to displace certain amount of oil around injector. After part of oil is removed, polymer can be easily injected. To determine effects of pre-flushed water, polymer slug sizes of 0.2, 0.24 and 0.275 PV are used together with polymer concentration of 1,250, 1,000 and 833 ppm respectively. Amount of water used is varied from no pre-flushed water, water volume = 0.02 PV (25% of water breakthrough), water volume = 0.05 PV (50% of water breakthrough), at water breakthrough = 0.11 PV, at 25% watercut = 0.14 PV and at 50% watercut = 0.20 PV. All the previously mentioned cases are illustrated in Figure 5.4.

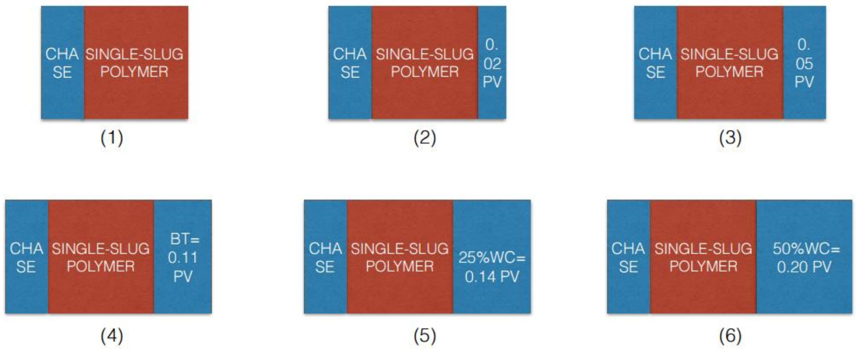


Figure 5.4 *Illustration of single-slug polymer flooding with different polymer injection starting time*

Table 5.2 and Figure 5.5 show the results in table and graphical forms from different polymer injection starting time, respectively.

Table 5.2 *Summary of oil recovery factors and total production time from different polymer injection starting times in coarsening upward reservoir model with L_k=0.2*

Cases	1,250 ppm		1,000 ppm		833 ppm	
	RF (%)	Time (days)	RF (%)	Time (days)	RF (%)	Time (days)
No Pre-flushed Water	51.38	1,735	52.34	1,552	52.58	1,400
Water volume = 0.02 PV	51.64	1,796	52.34	1,582	52.74	1,492
Water volume = 0.05 PV	51.60	1,827	52.27	1,613	52.83	1,521
Breakthrough = 0.11 PV	51.56	1,886	52.39	1,705	52.95	1,643
At 25% watercut = 0.14 PV	51.70	1,947	52.39	1,735	52.99	1,674
At 50% watercut = 0.20 PV	51.69	2,039	52.63	1,858	52.97	1,796

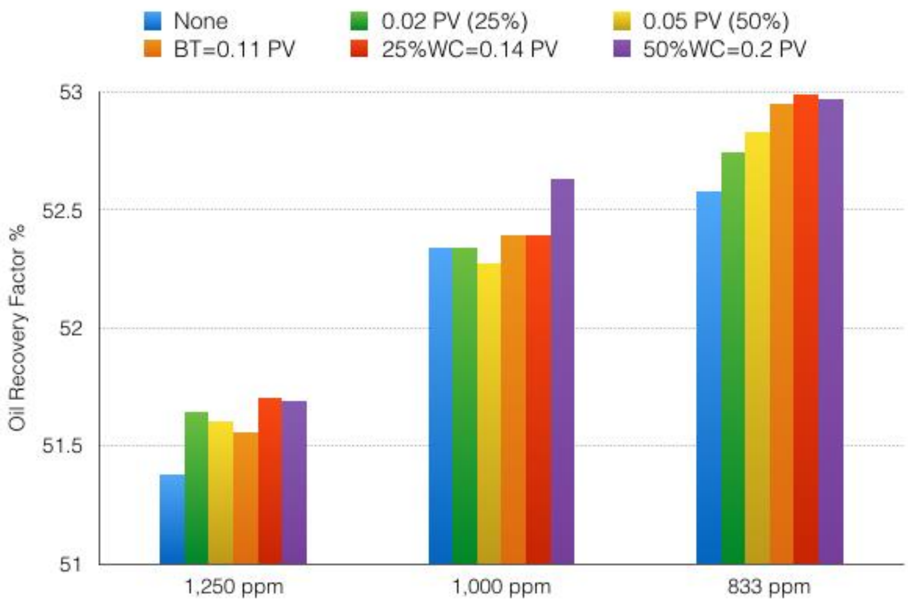


Figure 5.5 *Oil recovery factors obtained from different polymer injection starting time in coarsening upward reservoir model with L_k=0.2*

From the results of 1,250 ppm-polymer in single-slug, to inject pre-flushed water 25%, 50% before breakthrough, at breakthrough, 25% and 50% watercut provide similar values of oil recovery factor. They range from 51.56% to 51.7% with total production time from 1,796 to 2,039 days. While injecting polymer without pre-flushed water provides the lowest oil recovery of 52.38% with 1,735 days of production.

From the results of 1,000 ppm single-slug polymer cases, it can be seen that to inject pre-flushed water until 50% watercut yields the highest oil recovery of 52.63% with the longest production time of 1,858 days while other cases provide not much different oil recovery, ranging from 52.27% to 52.39% with the production time from 1,552 to 1,735 days.

From the results of 833 ppm single-slug polymer cases, it can be seen that three cases where pre-flushed water is injected until breakthrough, 25 percent watercut and 50 percent watercut provide similar oil recovery of 52.95%, 52.99% and 52.97%, respectively with total production time of 1,643 days, 1,674 days and 1,796 days, respectively. The lowest oil recovery is still obtained from the case with no pre-flushed water, yielding 52.58% oil recovery with 1,400 days of production.

From the trend among three different polymer concentrations, it can be seen that using the least concentration of 833 ppm provides the highest oil recovery among other cases (1,000 ppm and 1,250 ppm) also with the shortest production time.

It is summarized that using pre-flushed water from 0.02 to 0.2 PV provides slightly better oil recovery than no pre-flushed water since single-slug polymer itself has high viscosity which causes difficulty to be injected. Injecting pre-flushed water helps increasing injectivity of polymer by removing oil around wellbore towards production well which can possibly reduce oil saturation around injection well. As a consequence, polymer can be injected more easily. This mechanism is illustrated in Figure 5.6.

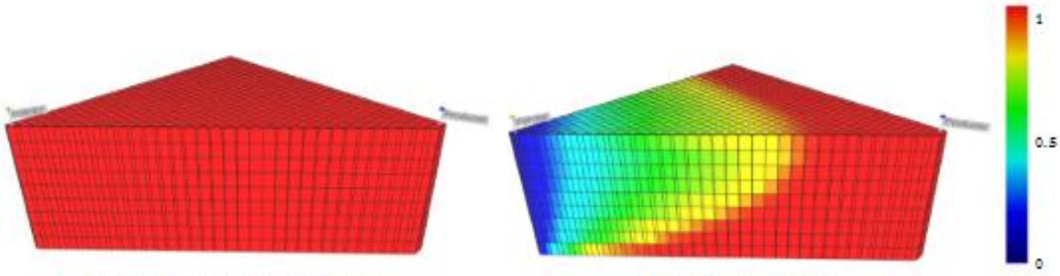


Figure 5.6 *Oil saturation profiles at the first day of production (left) and after 6 months (right) from coarsening upward reservoir model with L_k=0.2 using polymer concentration 833 ppm*

To maximize the benefit from pre-flushed water, the amount of water injected has to be balanced between polymer injectivity and time consumed. Too much pre-flushed water results in high polymer injectivity but also delays the time to inject polymer which can extend total production time. Actual liquid injection rates from different time to start injecting polymer are shown in Figure 5.7, implying that polymer injection rate has difficulty reaching 800 bbl/d as desired at early time when no pre-flushed water (red) is injected, while polymer injection rate slightly drops below 800 bbl/d for a short period of time when water volume of 0.02 PV (blue) is pre-injected, whereas to inject polymer with pre-flushed water until breakthrough (green) or 50 percent watercut (magenta), injectivity for both cases are very high that can reach 800 bbl/d throughout injection period.

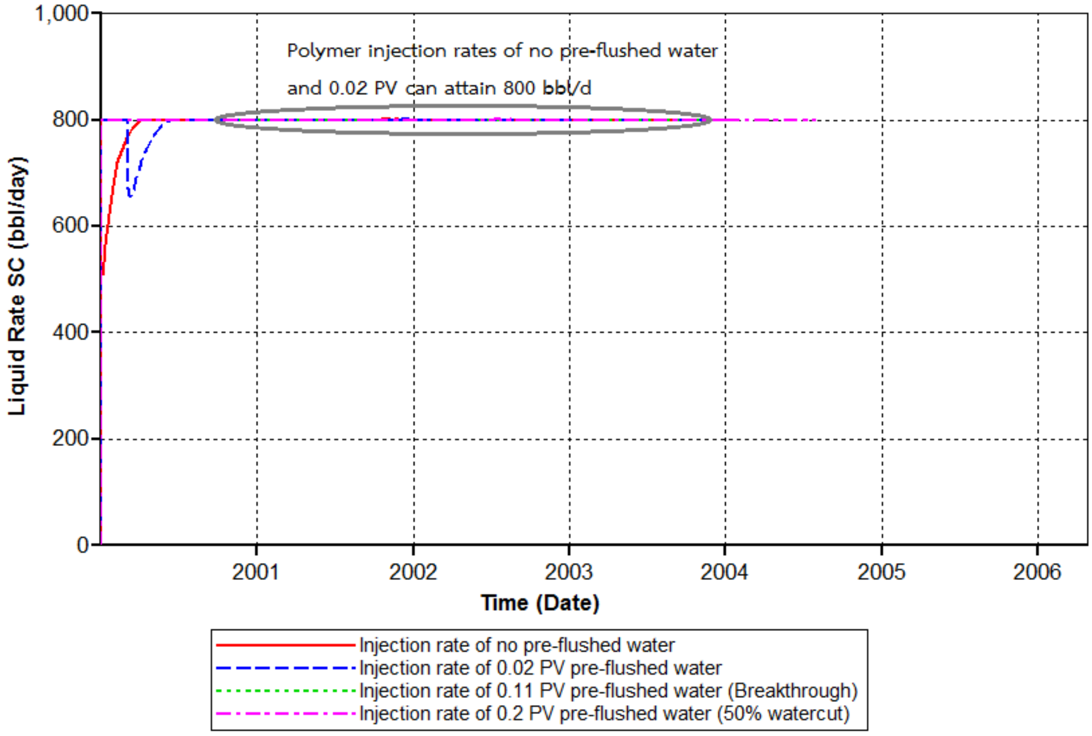


Figure 5.7 *Liquid injection rates of different polymer injection starting time using 833 ppm polymer in coarsening upward reservoir model with L_k=0.2*

The plot of oil production rates in Figure 5.8 shows that oil rates of every case can be maintained at 800 bbl/d before water breakthrough. After that, oil rates start to decline. Firstly, oil rates in both no pre-flushed water (red) and 0.02 PV pre-flushed water (blue) cases slightly drop below 800 bbl/d but they are still much higher than two latter cases. This is because polymer exhibits earlier oil displacement effect due to earlier polymer injection. At late time, chasing water is injected afterward as can be seen from a sharp drop of the oil rates.

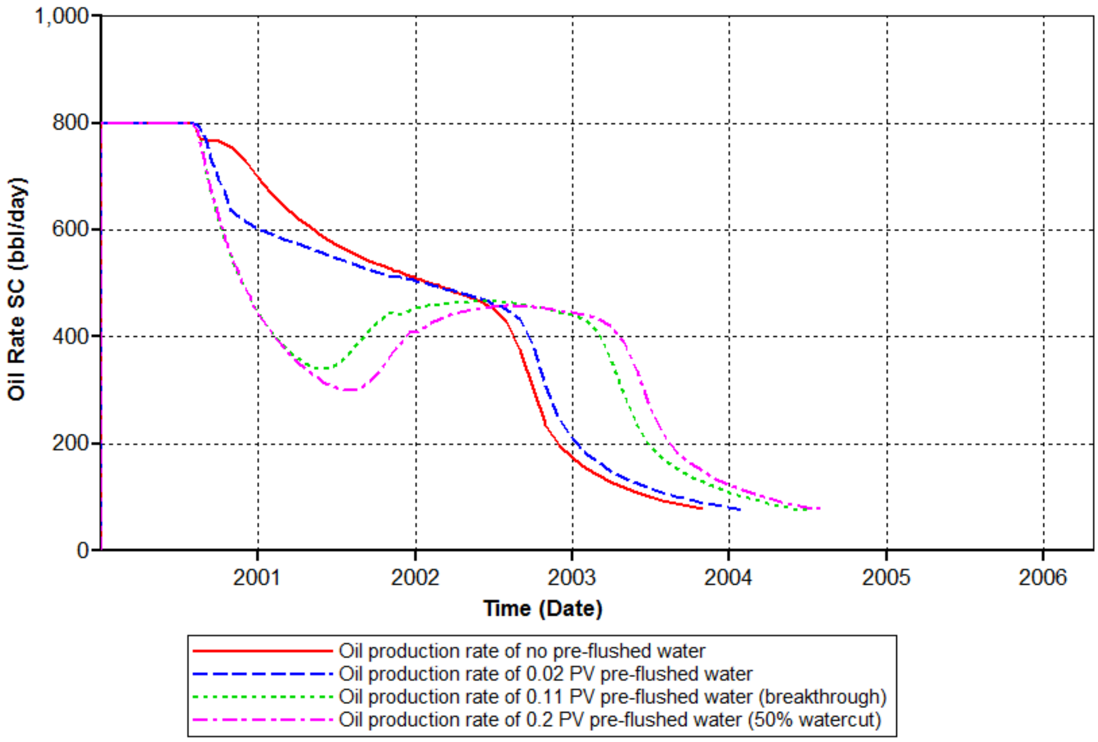


Figure 5.8 *Oil production rates of different polymer injection starting times using 833 ppm polymer in coarsening upward reservoir model with* L_k*=0.2*

In conclusion, selecting any amount of pre-flushed water provides not much different oil recovery. However, in case where pre-flushed water is not injected until water is produced at production well, the connectivity between injection and production well may not be verified. On the other hand, if pre-flushed water is injected after breakthrough, time during oil production will be extensively spent. Thus, injecting pre-flushed water until water breakthrough (0.11 PV) is recommended and is selected to be a representative for other operating parameter studies.

5.3 Effect of Alternating Water Slug Size

Instead of injecting a whole polymer slug into the reservoir, polymer slug is split into half and small slug of water is inserted in between in order to increase the injectivity of the second polymer slug. Another benefit of using alternating water is that after the first polymer slug is adsorbed onto rock surface, this alternating water can dissolve the polymer on rock surface which can possibly induce more polymer from the second slug to adsorb onto it due to the polymer retention mechanism. Alternating water slug size is varied from the smallest one of 5% of polymer size, 10%, 25%, 50% and the same size as polymer size while maintaining the same polymer mass as shown in Figure 5.9.

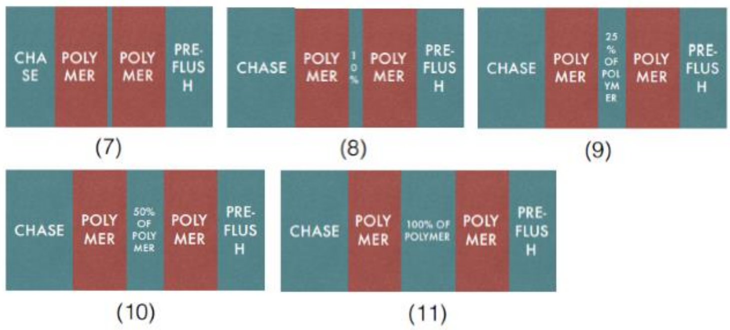


Figure 5.9 *Illustration of two-slug polymer flooding with different sizes of alternating water*

Table 5.3 and Figure 5.10 show results; including oil recovery factor and total production time from different cases with different sizes of alternating water slug.

Table 5.3 *Summary of oil recovery factors and total production time from different sizes of alternating water slug in coarsening upward reservoir model with L_k=0.2*

Cases	1,250 ppm		1,000 ppm		833 ppm	
	RF (%)	Time (days)	RF (%)	Time (days)	RF (%)	Time (days)
Water : Polymer = 5%	51.71	1,886	52.61	1,705	52.97	1,643
Water : Polymer = 10%	51.92	1,886	52.47	1,674	52.83	1,613
Water : Polymer = 25%	51.7	1,858	52.19	1,674	52.48	1,643
Water : Polymer = 50%	51.49	1,858	52.02	1,735	52.07	1,705
Water : Polymer = 100%	51.24	1,917	51.91	1,796	51.94	1,827

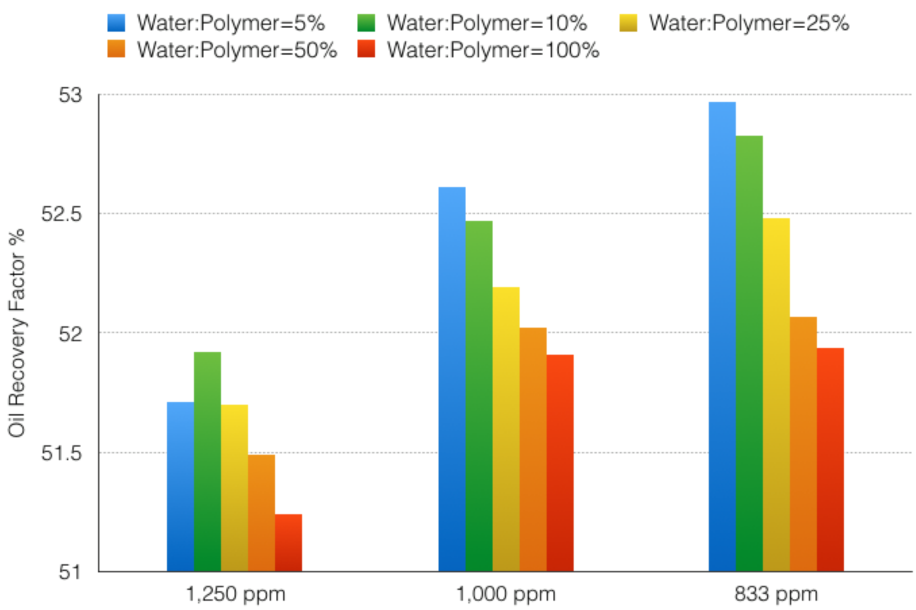


Figure 5.10 *Oil recovery factors obtained from different sizes of alternating water slug in coarsening upward reservoir model with L_k=0.2*

From results obtained from cases using polymer concentration of 1,250 ppm, it can be seen that to select alternating water of 5 percent of polymer slug size provides the second highest oil recovery of 51.71% while the highest oil recovery happens when 10 percent of polymer slug size is used, providing oil recovery of 51.92% while total production time is 1,886 days for both cases. Oil recovery is the lowest when alternating water slug size is as same as polymer size, providing only 51.24% with the longest production period of 1,917 days. Comparing to single-slug polymer flooding case, two-slug polymer flooding with the smallest alternating water slug size provides 0.15% more oil recovery (51.71% and 51.56%) while using 10% of polymer slug provides 0.36% more oil recovery (51.92% and 51.56%). Both cases share the same production time of 1,886 days.

Reducing polymer concentration to 1,000 ppm, results reveal that to select alternating water of 5 percent of polymer size provides the highest oil recovery of 52.61% with the production time of 1,705 days and oil recovery seems to drop with increasing alternating water slug size. In case where alternating water has the same size as polymer slug, oil recovery is 51.91% which is the lowest oil recovery among all cases. Comparing to single-slug polymer flooding case, two-slug polymer flooding with the smallest alternating water slug size provides 0.22% more oil recovery (52.61% and 52.39%) with the same production time of 1,705 days.

For the least polymer concentration of 833 ppm, it can be seen that to select alternating water of 5 percent of polymer size provides the highest oil recovery of 52.97% with total production time of 1,643 days while injecting too large alternating water slug, oil recovery strikingly drops. In case where alternating water is the same size as polymer slug, oil recovery is 51.94% which is the lowest one. Comparing to single-slug polymer flooding case, two-slug polymer flooding with the smallest alternating water slug size provides 0.02% more oil recovery (52.97% and 52.95%) with the same production time of 1,643 days.

From the trend among three different polymer concentrations, it can be seen that using the least polymer concentration of 833 ppm provides the highest oil recovery among other cases (1,000 ppm and 1,250 ppm) and also with the shortest production time.

It can be observed that the smallest alternating water slug size provides the best results with usage of 1,000 and 833 ppm-polymer and provides the second highest oil recovery when 1,250 ppm-polymer is used. Oppositely, using the largest alternating water slug size provides the lowest oil recovery in every case. This can be explained that since the highest polymer concentration of 1,250 ppm comes together with the lowest polymer injectivity, more amount of water is required in order to increase the second polymer injectivity. From Figure 5.11, increasing volume of alternating water from 5 to 10 percent of polymer slug, second-slug polymer injection rate (gray circle) from 10 percent (blue) overcomes that of 5 percent (red). Consequently, it results in higher oil production rate after some period of time (orange circle). For 1,000 ppm, even though large water slug can increase the injection rate of following polymer slug slightly below the desired rate (800 STB/d), time spent during water slug injection is much longer. Meanwhile, polymer injectivity from both cases is not significantly different as shown in Figure 5.12 and especially, in 833 ppm, all polymer injection rates are in line with each other as depicted in Figure 5.13 This setbacks time to inject another polymer slug.

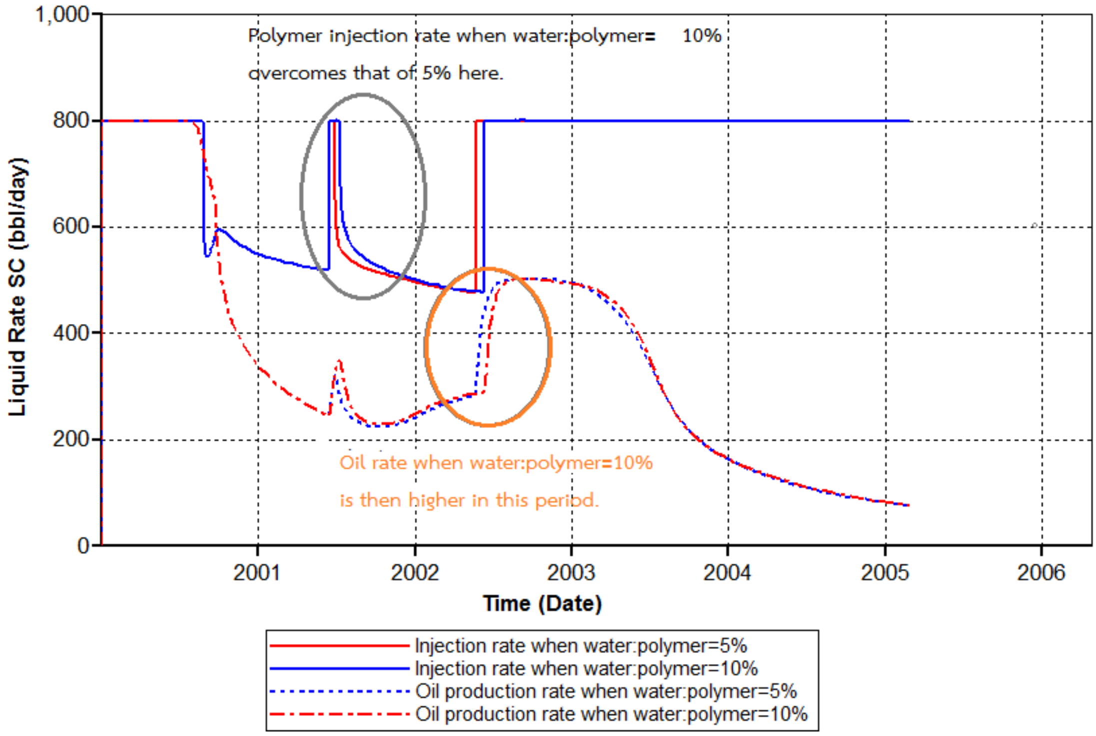


Figure 5.11 *Liquid injection rates and oil production rates of different sizes of alternating water slug size (5 and 10 percent) using 1,250 ppm polymer in coarsening upward reservoir model with* L_k*=0.2*

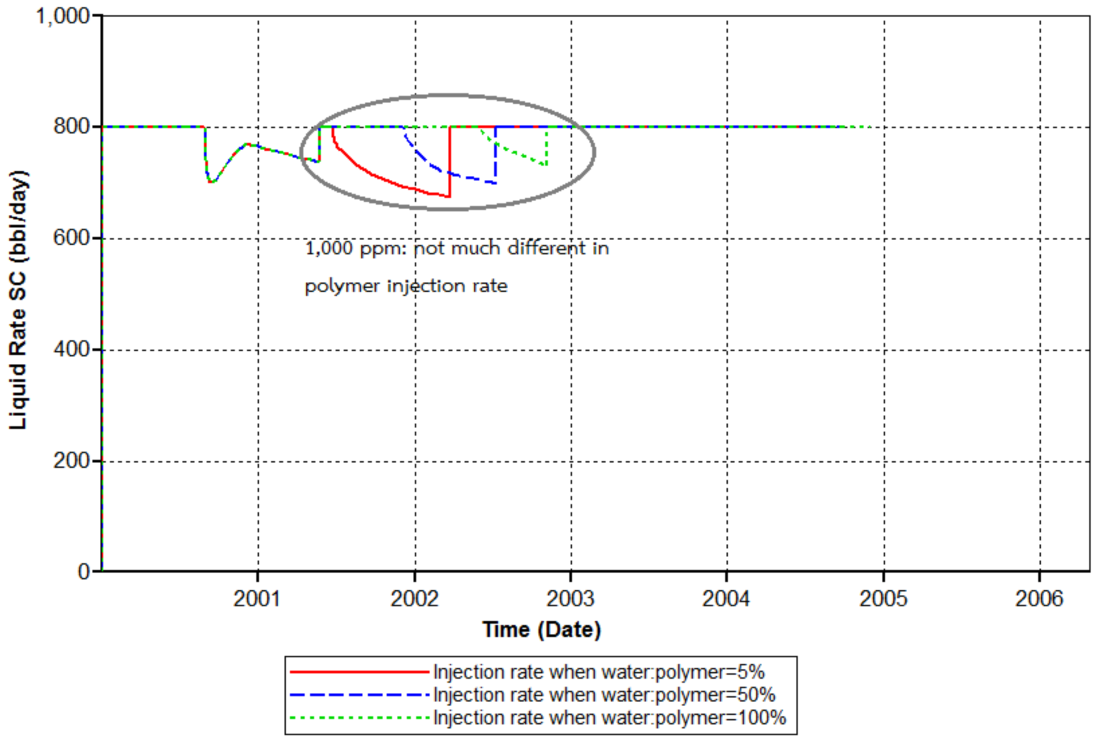


Figure 5.12 *Liquid injection rates of different sizes of alternating water slug size using 1,000 ppm polymer in coarsening upward reservoir model with* L_k*=0.2*

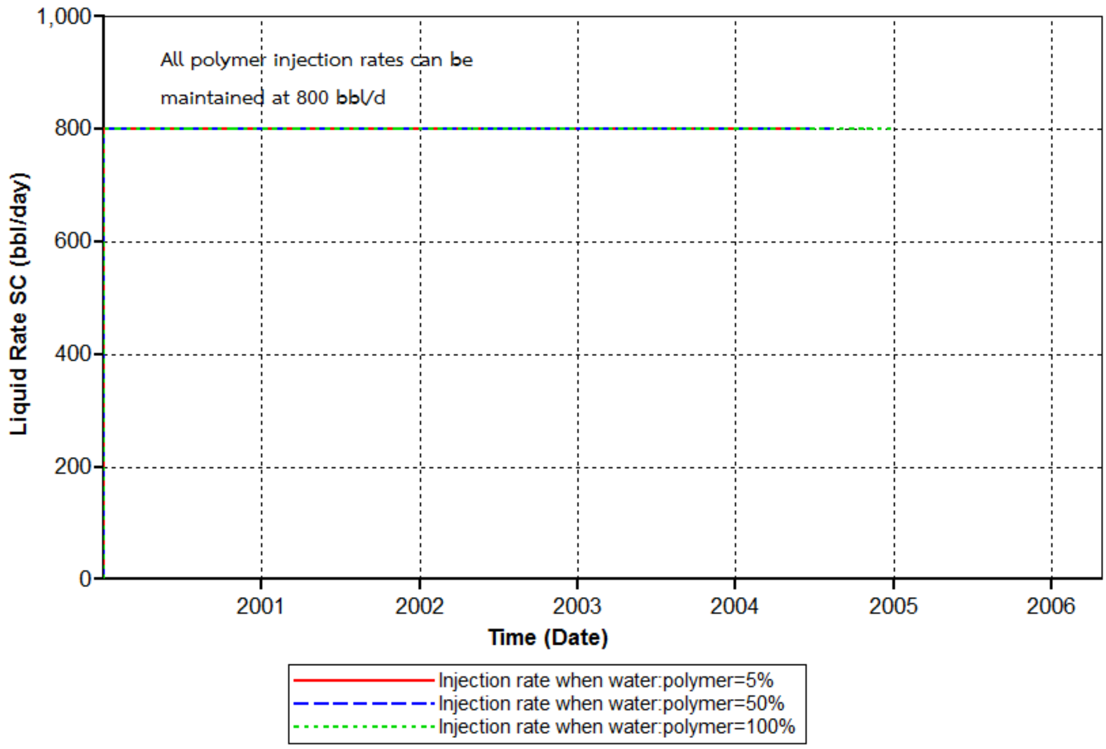


Figure 5.13 *Liquid injection rates of different sizes of alternating water slug size using 833 ppm polymer in coarsening upward reservoir model with* L_k*=0.2*

In this study, polymer desorption level is set at 60 percent. Small amount of alternating water is sufficient to desorb the previously adsorbed polymer from rock surface. This can be explained using the results from Table 5.4 and Figure 5.14; three desorption levels, including 80%, 60% (default level) and 10% are simulated using the same polymer concentration of 1,000 ppm. Final results show that when desorption level is set to the highest of 80%, much more oil recovery difference between using water/polymer ratio of 5 percent and 10 percent is observed. Since polymer on surface of rock can be easily desorbed, using less amount of water then shows greater benefit. Meanwhile, when the lowest desorption level of 10 percent is assumed, oil recovery factor from water slug size of 10 percent is slightly more than that of 5 percent case, implying that more volume of alternating water is required to desorb residual polymer away from rock surface.

Table 5.4 *Summary of oil recovery factors and total production time from different polymer desorption levels using 1,000 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

Cases	Desorption 80%		Desorption 60%		Desorption 10%	
	RF (%)	Time (days)	RF (%)	Time (days)	RF (%)	Time (days)
Water : Polymer = 5%	54.46	1,521	52.61	1,705	52.48	1,705
Water : Polymer = 10%	52.29	1,613	52.47	1,674	52.5	1,705
Water : Polymer = 25%	52.04	1,643	52.19	1,674	52.16	1,674
Water : Polymer = 50%	51.59	1,674	52.02	1,735	51.86	1,735
Water : Polymer = 100%	51.6	1,766	51.91	1,796	51.62	1,827

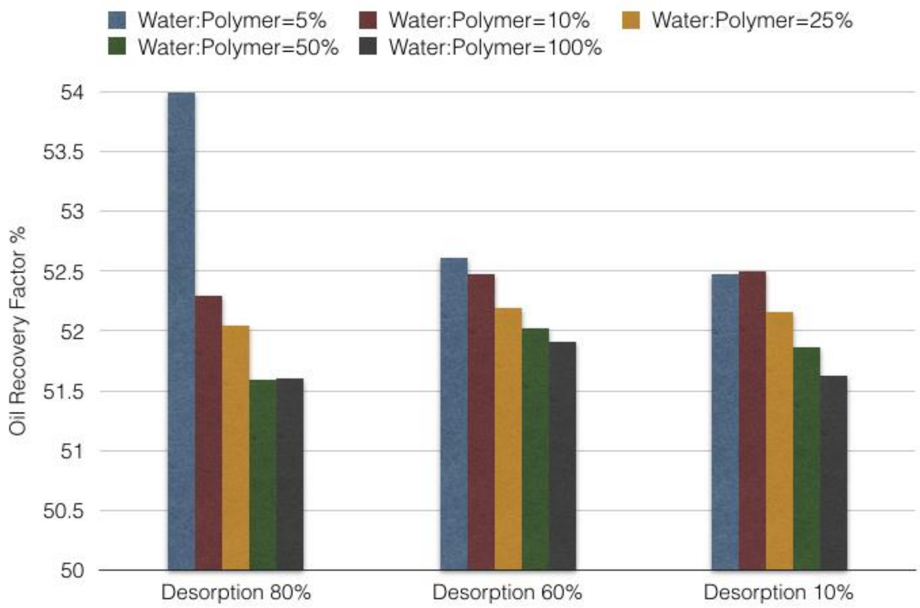


Figure 5.14 *Oil recovery factors obtained from different desorption levels in coarsening upward reservoir model with* L_k*=0.2*

In summary, alternating water slug size is very dependent on polymer desorption level. Based on desorption level of 60 percent, alternating water slug size of 5 percent of polymer slug size is appropriate to be a representative value for other operating parameter studies. Since this amount of water yields the highest oil recovery in both 1,000 and 833 ppm cases and the second highest oil recovery in 1,250 ppm-polymer due to the provided reason.

5.4 Effect of Concentration Sorting

For two-slug polymer flooding explained in previous section, concentration of each polymer slug is fixed as same as that of bulk polymer slug. This section will focus on the effect of concentration order of two-slug polymer flooding both in descending (high concentration followed by low concentration) and ascending (low concentration followed by high concentration) order while keeping the same polymer mass as shown in Figure 5.15.

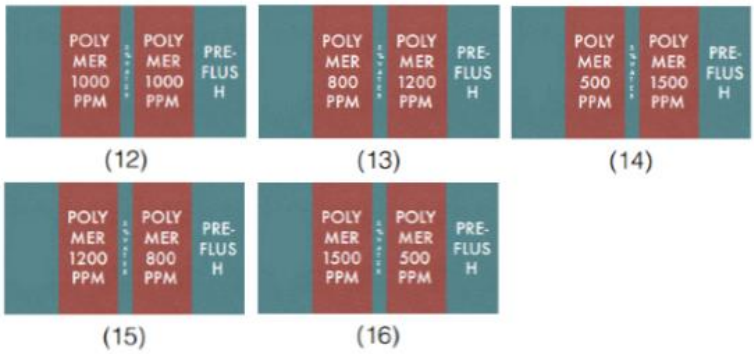


Figure 5.15 *Illustration of two-slug polymer flooding with different concentration sorting (example of 1,000 ppm-polymer is shown)*

Table 5.5 and Figure 5.16 show the results in table and graphical forms from different concentration sorting, respectively.

Table 5.5 *Summary of oil recovery factors and total production time from different concentration sorting in coarsening upward reservoir model with L_k=0.2*

Cases	1,250 ppm		1,000 ppm		833 ppm	
	RF (%)	Time (days)	RF (%)	Time (days)	RF (%)	Time (days)
Constant concentration	51.71	1886	52.61	1705	52.97	1643
Descending order (first slug increased by 20%)	51.93	1,886	52.71	1,735	53.42	1,643
Descending order (first slug increased by 50%)	51	2,039	51.82	1,858	52.32	1,735
Ascending order (first slug decreased by 20%)	51.03	1,886	51.64	1,766	52.05	1,674
Ascending order (first slug decreased by 50%)	50.34	2,100	50.49	1,978	50.75	1,917

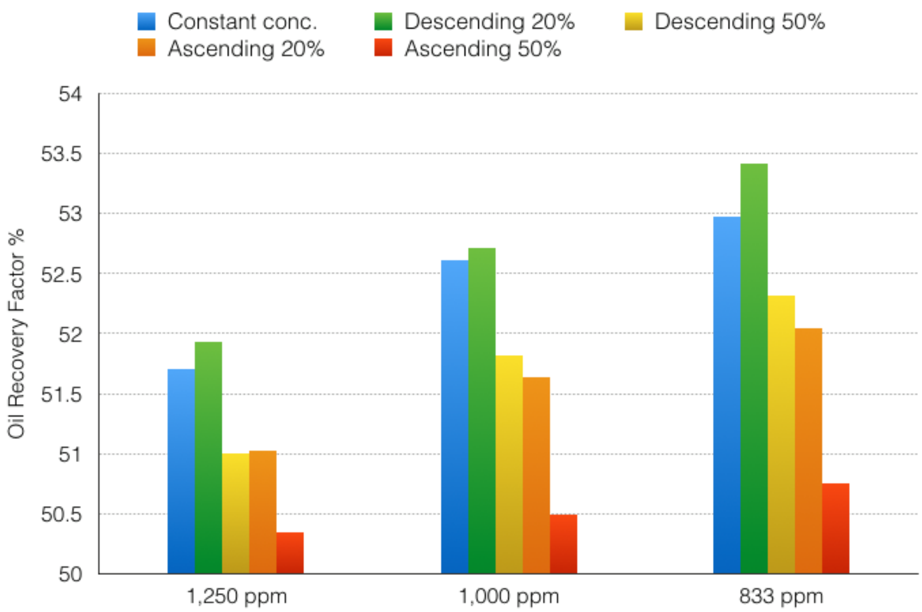


Figure 5.16 *Oil recovery factors obtained from different concentration sorting in L_k=0.2 coarsening upward reservoir*

Among the first five cases of 1,250 ppm, to select descending order where polymer concentration of first slug is increased by 20 percent (green bar) provides the highest oil recovery of 51.93% with 1,886 days of production while the lowest oil recovery happens when ascending order where polymer concentration of first slug is decreased by 50 percent (red bar) is performed, providing oil recovery of 50.34% and lasting 2,100 days of production. However, comparing to constant concentration (blue bar), the former case does not provide significant improvement in oil recovery, only 0.22% ahead (51.93% and 51.71%) with the same production time of 1,886 days.

In 1,000 ppm cases, to use descending order where polymer concentration of first slug is increased by 20 percent (green bar) provides the maximum oil recovery of 52.71% together with 1,735 days of production. In contrast, the lowest oil recovery is when ascending order where polymer concentration of first slug is decreased by 50 percent (red bar) is used, providing oil recovery of 50.49% together with the longest production time of 1,978 days. Nevertheless, comparing to constant concentration for both polymer slugs (blue bar), the first case just provides 0.1% more oil recovery (52.71% and 52.61%) while production time is 30 days longer (1,735 days and 1705 days).

Lastly in 833 ppm cases, just like in previous cases, to select descending order where polymer concentration of first slug is increased by 20 percent (green bar) provides the highest oil recovery of 53.42% with 1,643 days of production, on the other hand, ascending order where polymer concentration of first slug is decreased by 50 percent (red bar) provides the lowest oil recovery of 50.75% with 1,917 days of production. This concentration shows the biggest difference when comparing to constant concentration (blue bar) with 0.45% oil recovery increment (53.42% and 52.97%) with the same total production time of 1,643 days.

From the trend among three different polymer concentrations, it can be seen that using the least concentration of 833 ppm provides the highest oil recovery among other cases (1,000 ppm and 1,250 ppm), also with the shortest production time.

One thing in common for every case is that using ascending order where polymer concentration of first slug is reduced by 50 percent (red bar) provides the least oil recovery and the longest production time. This can be explained that since permeability variation in reservoir heterogeneity of 0.2 (in this case) is low, in other words, permeability of each reservoir layer is not much different from each other which allows high-concentration polymer to flow through as can be seen from polymer viscosity profile in Figure 5.17; first-slug polymer fronts of both descending order and ascending order cases are at about the same location after 19 months of production. Thus, using ascending order does not provide much benefit in terms of polymer injectivity while oil displacement effect is less due to lower polymer concentration. This is also confirmed by a plot of liquid injection rates in Figure 5.18; polymer injection rates in descending order slightly drops below 800 bbl/d in the first polymer slug (gray circle), subsequently, the rate can attain 800 bbl/d in the second polymer slug while polymer injection rate drops tremendously in ascending order, resulting in much less oil recovery.

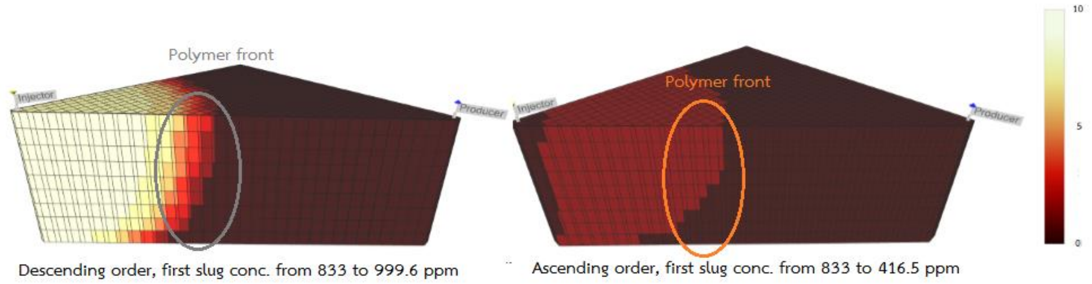


Figure 5.17 *Polymer viscosity profiles of descending order and ascending order using 833 ppm-polymer in coarsening upward sequence with* L_k*=0.2 after 19 months of production*

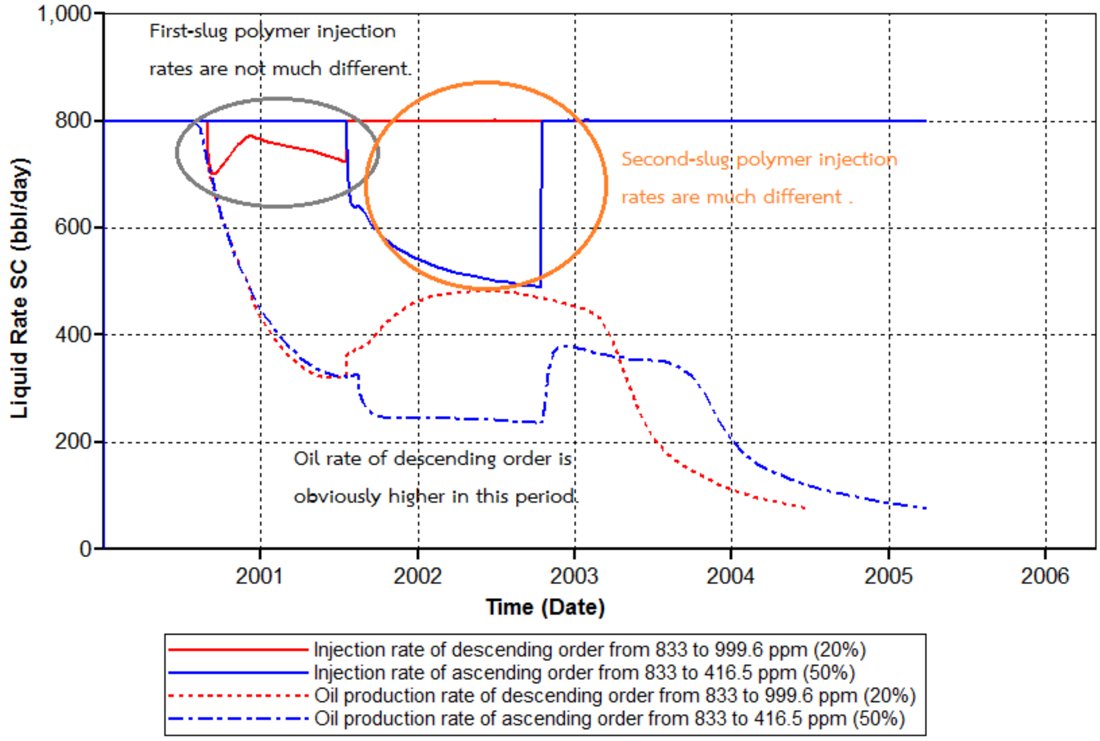


Figure 5.18 *Liquid injection rates of different concentration sorting using 833 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

Also, it can be observed that since polymer concentration of 833 ppm is the smallest value, increasing to certain number does not reduce polymer injectivity that much while gaining benefit from oil displacement efficiency. Thus, the most oil recovery improvement when ascending order is used instead of descending order can be observed in 833 ppm-polymer as shown earlier in the results. In other polymer concentrations (1,250 and 1,000 ppm), after they are increased by 20 percent, polymer injection rates reduce more due to higher polymer concentration as can be noticed from Figure 5.19 and Figure 5.20 and thus, the oil recovery difference between descending (green bar) and ascending (red bar) order cases decreases as polymer concentration increases.

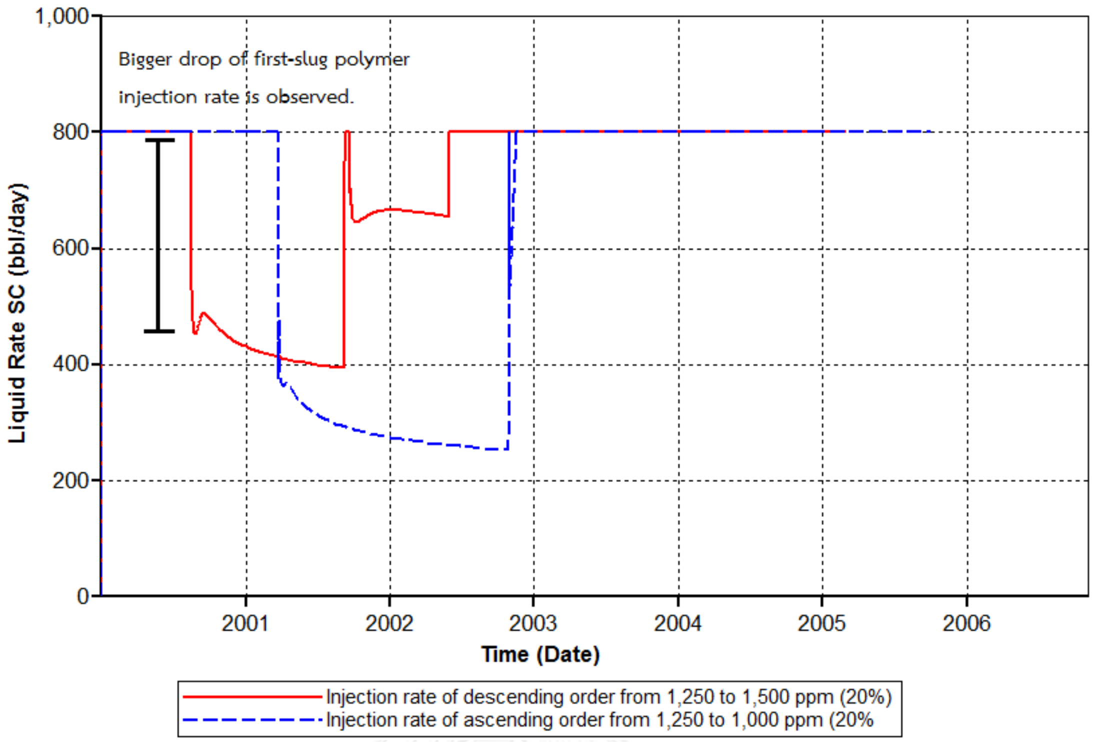


Figure 5.19 *Liquid injection rates of different concentration sorting using 1,250 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

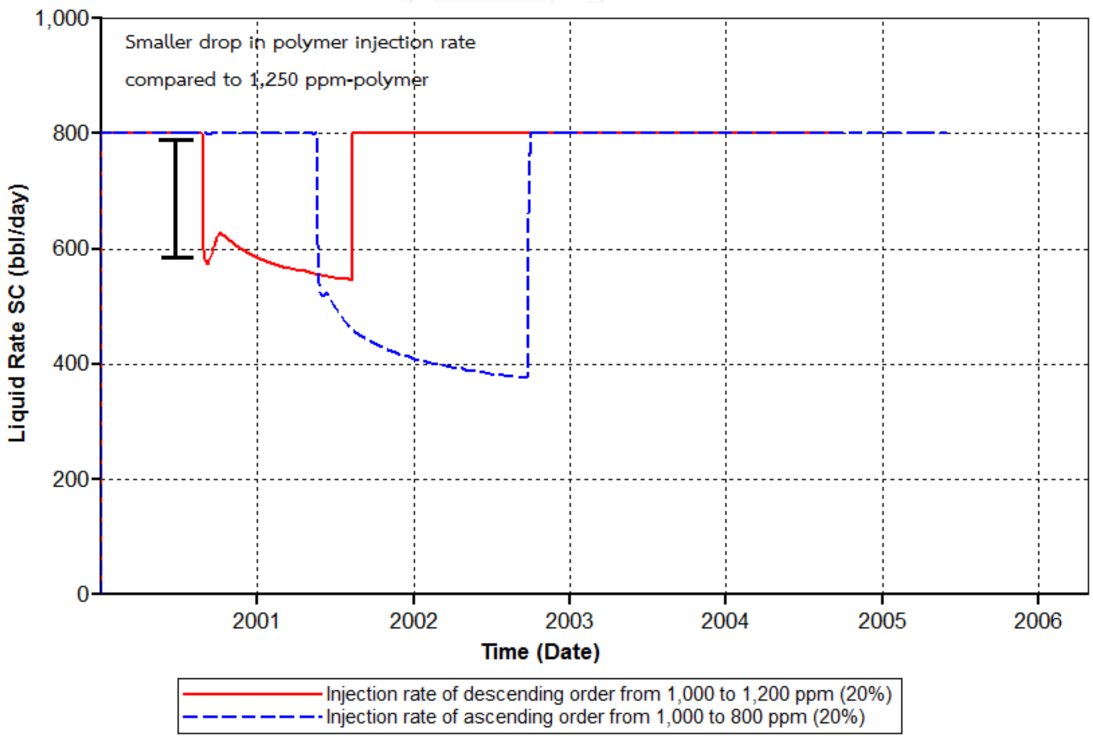


Figure 5.20 *Liquid injection rates of different concentration sorting using 1,000 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

Nevertheless, comparing between ascending order (green bar) and constant polymer concentration (blue bar), results in terms of oil recovery are not significantly different. This is because in case where same polymer concentration is used (red), both the first and the second polymer injection rates are balancing at high level due to moderate polymer injectivity (between that of descending and ascending order). It can be seen from the plots of injection rates (solid line) of 1,250, 1,000 and 833 ppm-polymer in Figure 5.21, Figure 5.22 and Figure 5.23 respectively. Polymer injection rates can be maintained at moderate level for both polymer slugs, resulting in not much different oil rate (dash line) comparing to using ascending order.

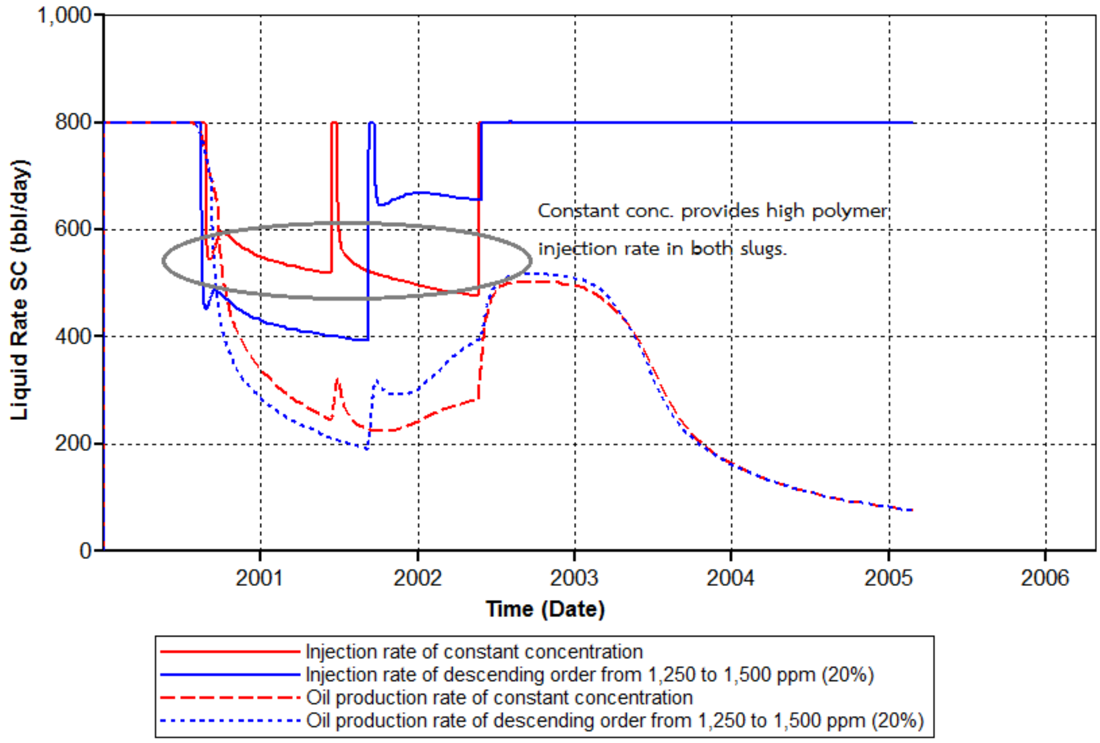


Figure 5.21 *Liquid injection rates and oil production rates of different concentration sorting using 1,250 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

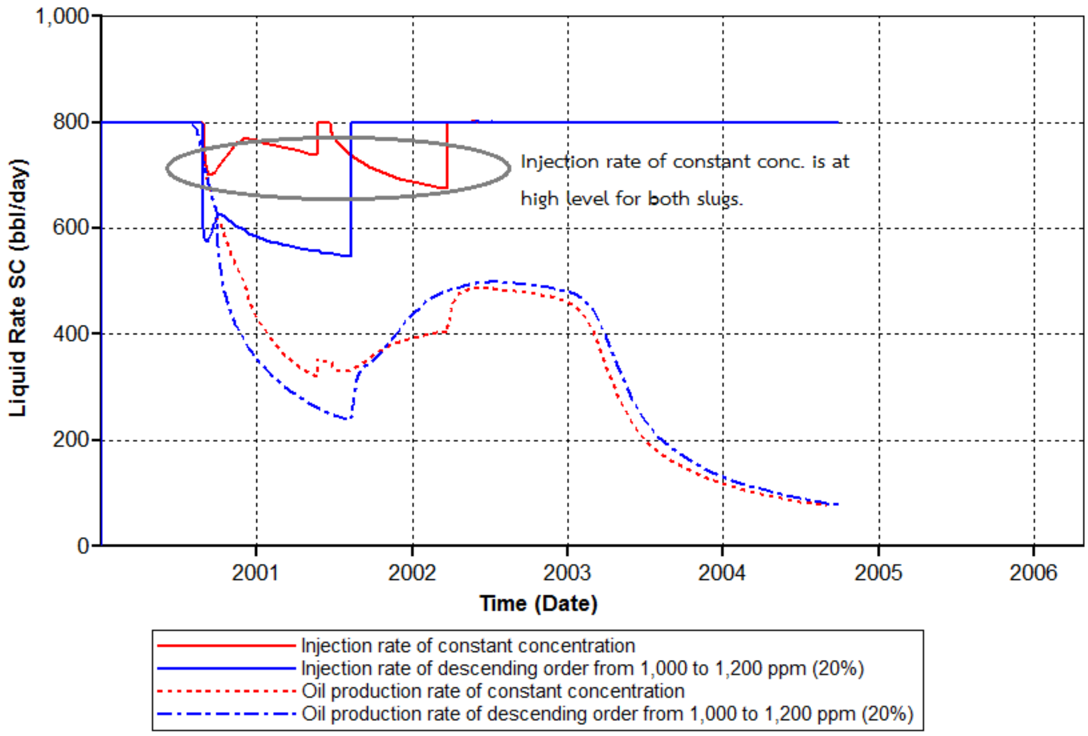


Figure 5.22 *Liquid injection rates and oil production rates of different concentration sorting using 1,000 ppm-polymer in coarsening upward reservoir model with L_k=0.2*

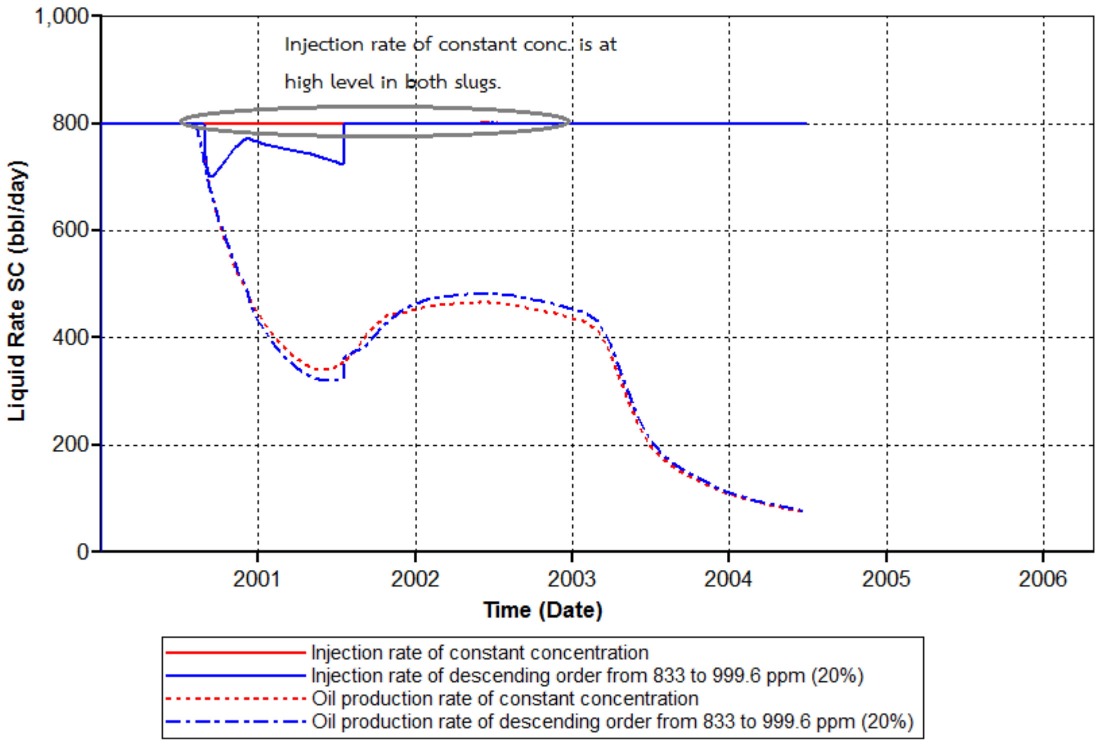


Figure 5.23 *Liquid injection rates and oil production rates of different concentration sorting using 833 ppm-polymer in coarsening upward reservoir model with L_k=0.2*

In conclusion, concentration sorting provides no significant oil production improvement either with descending or ascending order. Therefore, constant polymer concentration is selected as a representative case for other operating parameter studies due to the evidence provided in this section.

5.5 Effect of Number of Alternative Cycles

Since a bulk polymer slug can be separated into several smaller slugs with water slug in between to increase polymer injectivity, the exact number of polymer slugs which provides the best result will be investigated in this section. A number of alternative cycles starting from 1 to 5 cycles as recommended by previous literature [5] are simulated with the same polymer mass and bulk polymer slug is separated equally as illustrated in Figure 5.24.

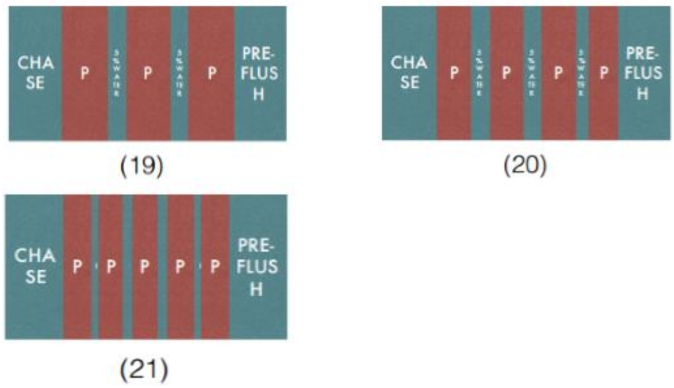


Figure 5.24 *Illustration of polymer alternating waterflooding with 3 cycles (19), 4 cycles (20), 5 cycles (21)*

Table 5.6 and Figure 5.25 show the results in table and graph forms from different numbers of alternative cycles respectively.

Table 5.6 *Summary of oil recovery factors and total production time from different number of alternative cycles in coarsening upward reservoir model with L_k=0.2*

Cases	1,250 ppm		1,000 ppm		833 ppm	
	RF (%)	Time (days)	RF (%)	Time (days)	RF (%)	Time (days)
1 cycle (single-slug)	51.56	1,886	52.39	1,705	52.95	1,643
2 cycles (two-slug)	51.71	1,886	52.80	1,705	52.98	1,643
3 cycles	52.34	1,886	52.69	1,705	52.95	1,613
4 cycles	52.3	1,886	52.77	1,705	53.18	1,643
5 cycles	52.28	1,886	52.69	1,705	53.04	1,613

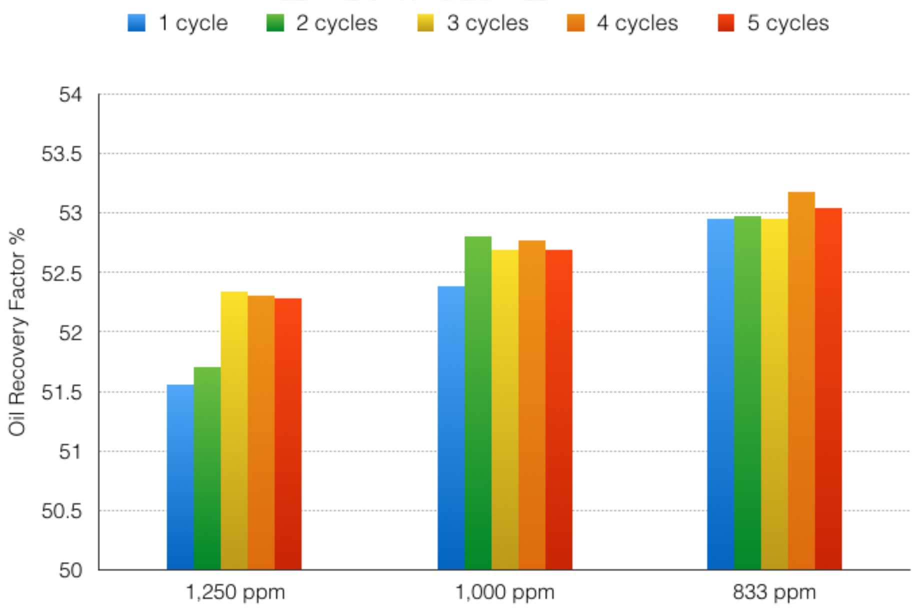


Figure 5.25 *Oil recovery factors obtained from different numbers of alternative cycles in coarsening upward reservoir model with L_k=0.2*

From the results of 1,250 ppm cases, it can be observed that to select either three, four or five cycles provides very similar oil recovery of 52.34%, 52.3% and 52.28% respectively also, with the same production time of 1,886 days. The oil recovery difference between 3-5 cycles and 1-2 cycles can be clearly observed. Comparing to two-slug polymer, the most oil recovery obtained from three alternative cycles is 0.63% more (52.34% and 51.71%) while the production time is 1,886 days for both cases.

The results of 1,000 ppm cases show that to use two alternative cycles provides the highest oil recovery of 52.8% with 1,705 days of production while using from three to five alternative cycles provides not much different oil recovery from using two alternative cycles, ranging from 52.69% to 52.77% with the same production time of 1,705 days. However, these four cases still provide distinguishably higher oil production compared to single-slug polymer which provides only 52.39% oil recovery. Comparing to two-slug polymer flooding case, using three or five cycles provides 0.11% less oil recovery (52.69% and 52.80%) with the same production time of 1,705 days while using four alternative cycles provides 0.03% less oil recovery (52.77% and 52.8%) with the same production time of 1,705 days also.

Lastly, in 833 ppm cases, it can be seen that to select four alternative cycles provides the highest oil recovery of 53.18% with 1,643 days of production while the oil recovery for other cases clusters, ranging from 52.95% to 53.04%. Comparing to two-slug polymer flooding case, the highest oil recovery from four alternative cycles is 0.21% more (53.18% and 52.97%) while production time is the same at 1,643 days.

The trend from three different polymer concentrations shows that the lowest concentration of 833 ppm provides the highest oil recovery among other cases (1,000 ppm and 1,250 ppm) with the shortest production time also.

From the results, it can be observed that for the highest polymer concentration of 1,250 ppm, using less alternative cycles (1-2 cycles) also provides apparently less oil recovery compared to using more alternative cycles (3-5 cycles). The obvious difference is when changing from 2 to 3 cycles. This can be clarified that since the highest concentration comes together with the highest polymer viscosity, using less alternative cycles (equivalent to using high polymer mass in each slug) possibly reduces polymer injectivity. It is displayed in Figure 5.26 that using single-slug polymer (red) lowers down the polymer injection rate from 800 bbl/d to less than 600 bbl/d during 0.2 PV polymer injection time. While using three alternative cycles (green), a small alternating water inserted in between polymer slugs tends to smoothen the following polymer injection rate not to drop rapidly compared to single-slug (red) and two-slug (blue). This results in an increment in oil rate as shown in Figure 5.27; oil rates from all three cases are almost the same lines but there are small humps of oil rate from four-slug over other lines which finally leads to higher oil recovery.

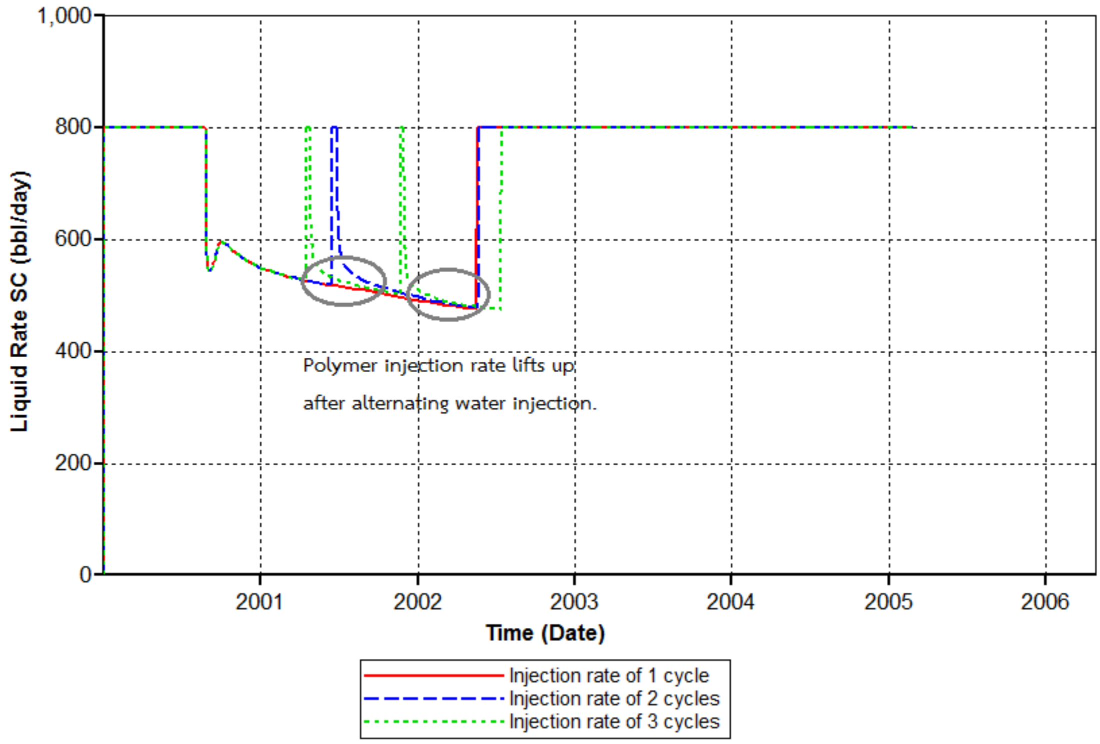


Figure 5.26 *Liquid injection rates of different number of alternative cycles using 1,250 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

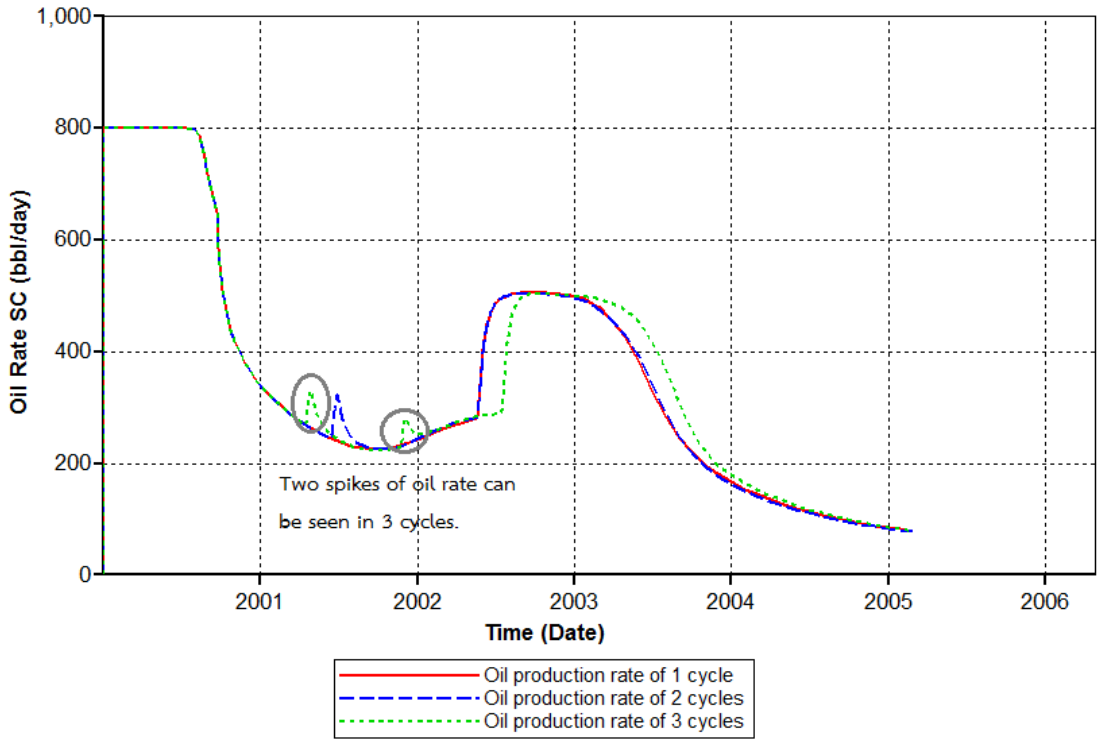


Figure 5.27 *Oil production rates of different number of alternative cycles using 1,250 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

From moderate polymer concentration of 1,000 ppm, using more than one cycle all provides similar oil recovery factors and noticeably higher than that of single-slug. Since concentration of 1,000 ppm is less than the maximum of 1,250 ppm, polymer injection rates are increased. It can be analyzed from Figure 5.28 that the minimum polymer injection rate is about 700 bbl/d which is higher than 500 bbl/d in 1,250 ppm cases. As a consequence, less alternative cycles (more polymer mass in each slug) can be used. Polymer injection rates for both two-slug (blue) and three-slug (green) overcome that of single-slug (red) right after alternating water injection. Finally, it results in more oil production as can be seen from the humps of oil production rate in Figure 5.29.

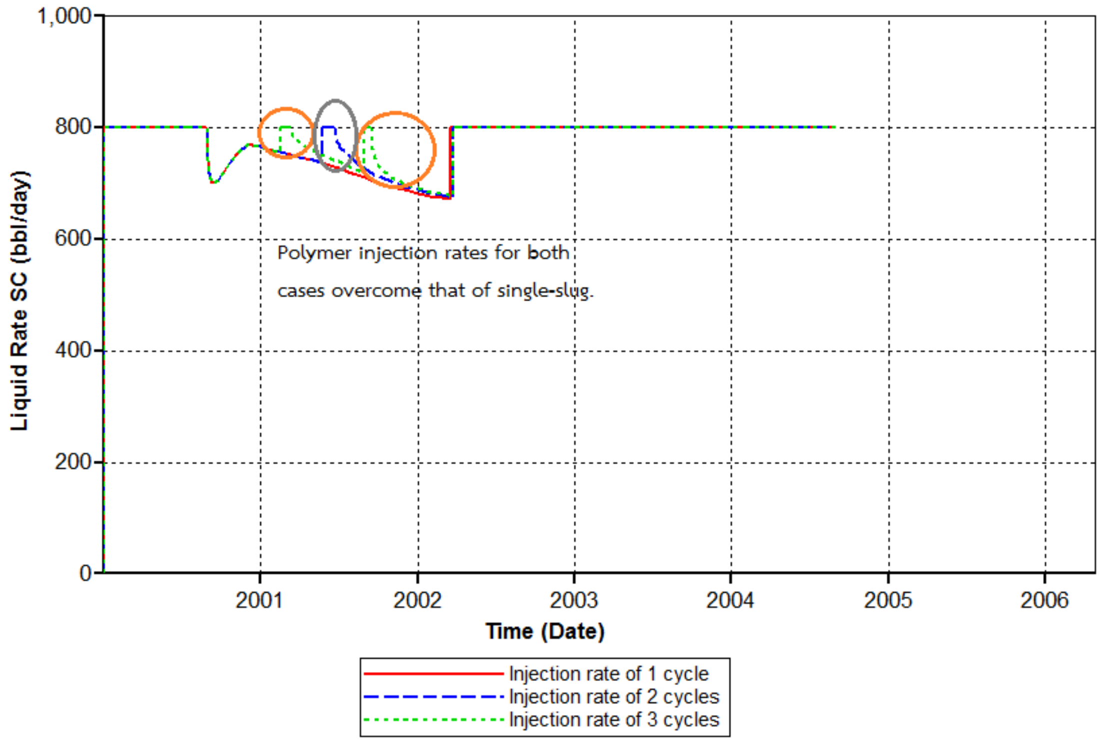


Figure 5.28 *Liquid injection rates of different number of alternative cycles using 1,000 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

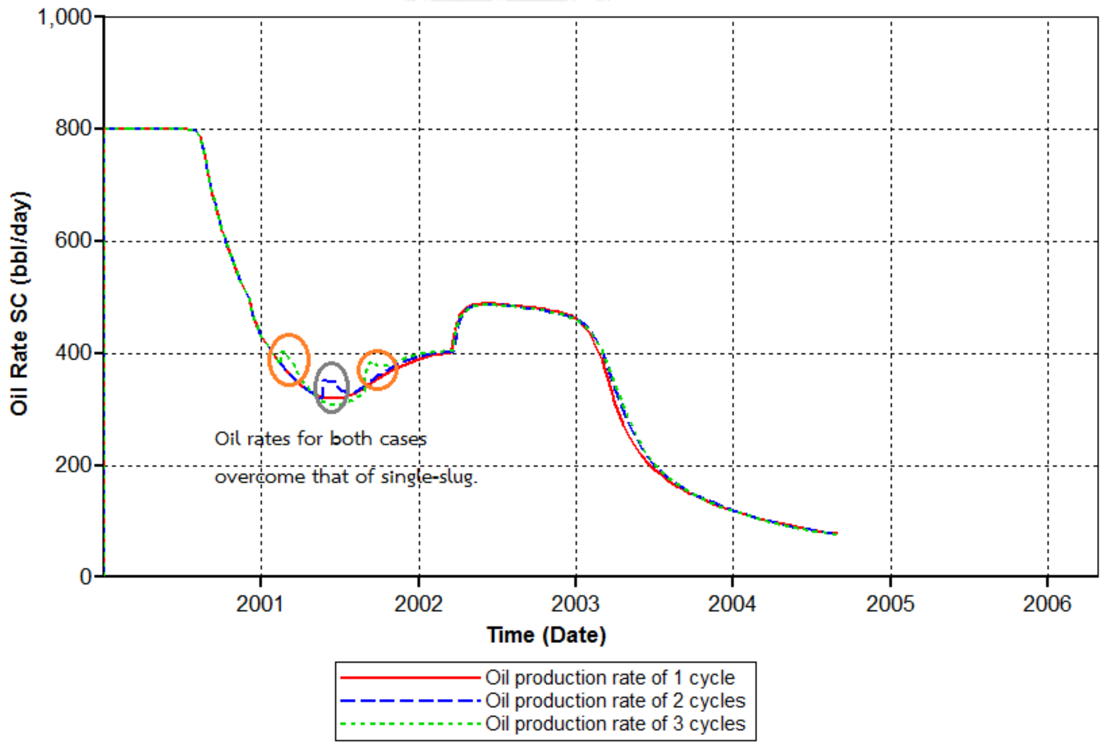


Figure 5.29 *Oil production rates of different number of alternative cycles using 1,000 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

Finally, due to the least polymer concentration of 833 ppm, using either 1 (red), 3 (blue) or 4 (green) alternative cycles, all polymer injection rates can reach 800 bbl/d as desired as seen in Figure 5.30. Consequently, the oil production rates from all cases shown in Figure 5.31 are about the same. Therefore, any number of alternative cycles can be selected in this polymer concentration.

To sum up, number of alternative cycles mainly depends on polymer concentration. Three-slug polymer flooding is selected as a representative case for further numerical simulation since this number provides the highest oil recovery in 1,250 ppm, in the range of 2-5 cycles in 1,000 ppm and any number of alternative cycles can be selected in the least polymer concentration of 833 ppm.

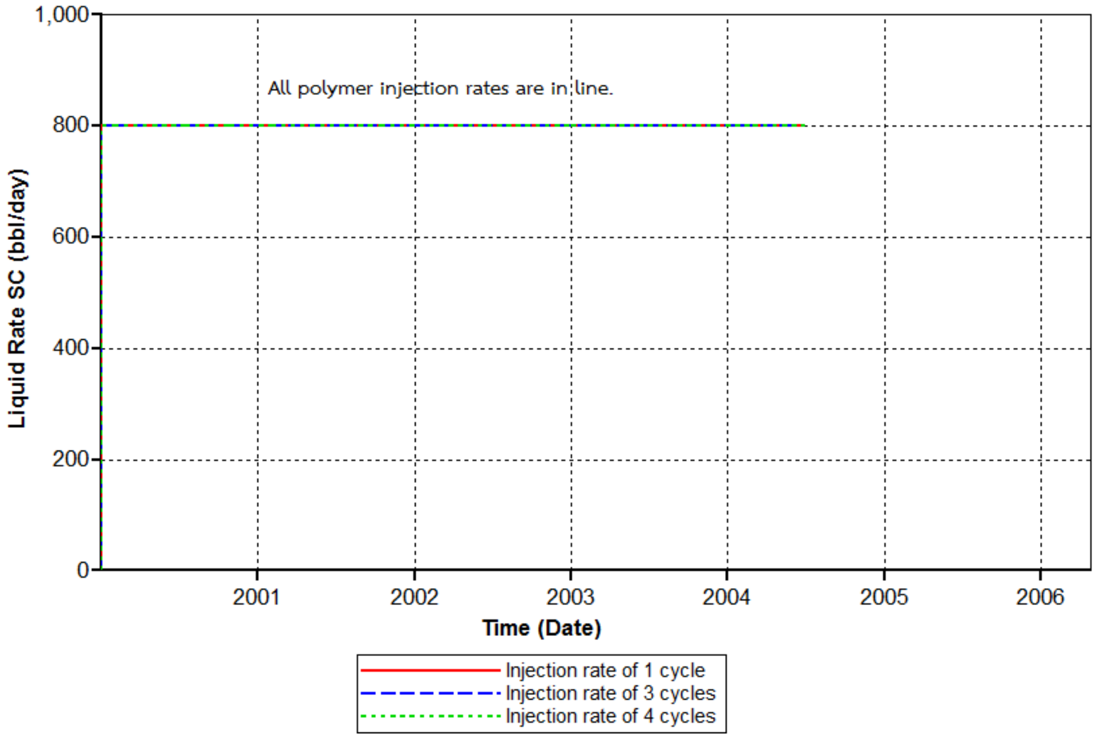


Figure 5.30 *Liquid injection rates of different number of alternative cycles using 833 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

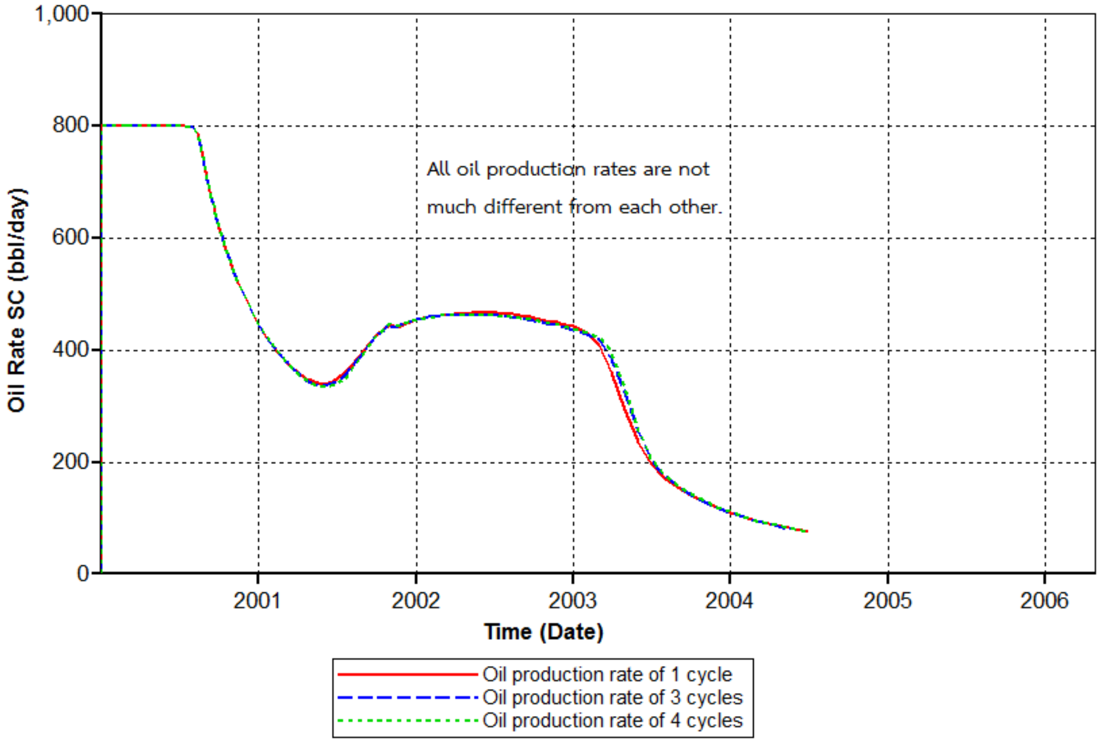
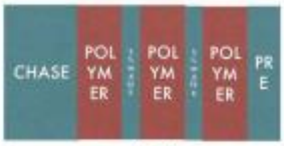


Figure 5.31 *Oil production rates of different number of alternative cycles using 833 ppm-polymer in coarsening upward reservoir model with* L_k*=0.2*

5.6 Effect of Residual Resistance Factor

Residual resistance factor (RRF) is one of the important polymer properties that affect oil production tremendously since RRF implies how much relative permeability to water is reduced from the original value which controls the mobility ratio of the process. In this section, the most appropriate operating parameters from section 5.2 to 5.5 are selected to evaluate the effect of RRF which are pre-flushed water until breakthrough, alternating water slug size of 5 percent of polymer size, constant polymer concentration and three-slug polymer as illustrated in Figure 5.32.



(22)

Figure 5.32 *Illustration of polymer alternating waterflooding with different residual resistance factor: coarsening upward using three-slug polymer flooding (22)*

Firstly, the oil recovery factors and production time are summarized in table form in Table 5.7, followed by oil recovery comparison in graph shown in Figure 5.33.

Table 5.7 *Summary of oil recovery factors and total production time from different residual resistance factors in coarsening upward reservoir model with L_k=0.2*

Cases	1,250 ppm		1,000 ppm		833 ppm	
	RF (%)	Time (days)	RF (%)	Time (days)	RF (%)	Time (days)
RRF=1.5	53.48	1,766	52.28	1,613	51.61	1,582
RRF=2 (default)	52.34	1,886	52.69	1,705	52.95	1,613
RRF=2.5	51.68	2,008	52.18	1,796	54.06	1,674

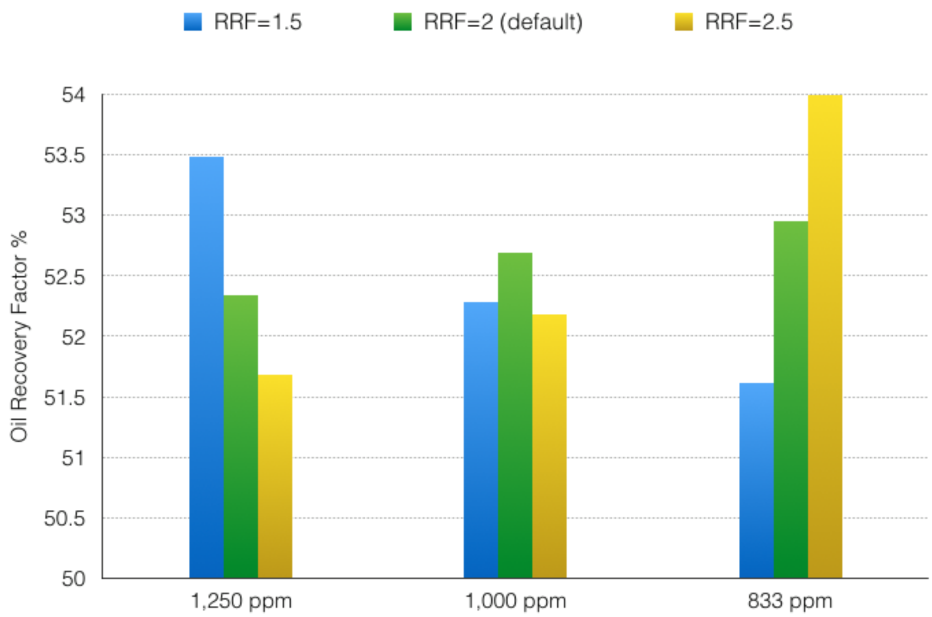


Figure 5.33 *Oil recovery factors obtained from different residual resistance factors in coarsening upward reservoir model with* L_k*=0.2*

From the results obtained from 1,250 ppm polymer, it can be seen that the most oil recovery of 53.48% with 1,766 days of production is obtained from the case where RRF is 1.5 which is the least RRF, after that, oil recovery seems to decrease as RRF increases. Comparing to the RRF baseline of 2, this case provides 1.14% more oil recovery (53.48% and 52.34%) and 120 days earlier in production time (1,766 and 1,866 days) too.

In 1,000 ppm cases, using three alternative cycles in RRF=2 (default) provides the highest oil recovery of 52.69% with 1,705 days of production. Oil recovery factors in all cases are not much different comparing to both 1,250 ppm and 833 ppm cases.

Lastly, in the least polymer concentration of 833 ppm, the opposite results from that of 1,250 ppm are observed; the highest oil recovery is obtained from the highest RRF of 2.5 case which yields oil recovery of as high as 54.06% with 1,674 days of production while the lowest one is from the least RRF of 1.5 which provides oil recovery of 51.61% with 1.582 days of production.

The trend shows that 833 ppm case provides the highest oil recovery among other cases (1,250 and 1,000 ppm) and the shortest production time also.

From the results, this can be explained that since polymer concentration of 1,250 ppm is quite high that leads to the tremendous reduction in polymer injectivity. Moreover, if RRF is 2.5, it causes the most relative permeability to water reduction that results in lowering of injectivity also. Combining these reasons together, oil recovery is the lowest in case of RRF is 2.5. While in case of RRF is 1.5, even though the mobility control is not as good as in RRF is 2.5 due to lower permeability reduction; however, the injectivity is much higher which provides an ease to inject polymer solution into a well, resulting in higher oil recovery. Figure 5.34 shows a plot of injection rates, implying that all polymer injection rates are parallel due to same production schedules but when RRF has the lowest value of 1.5 (green), polymer injection rate is remarkably higher than both RRF=2 (red) and RRF=2.5 (blue) which results in obviously higher in oil rate at middle time as shown in Figure 5.35. Finally, RRF=1.5 exhibits the highest oil recovery as seen earlier from the results.

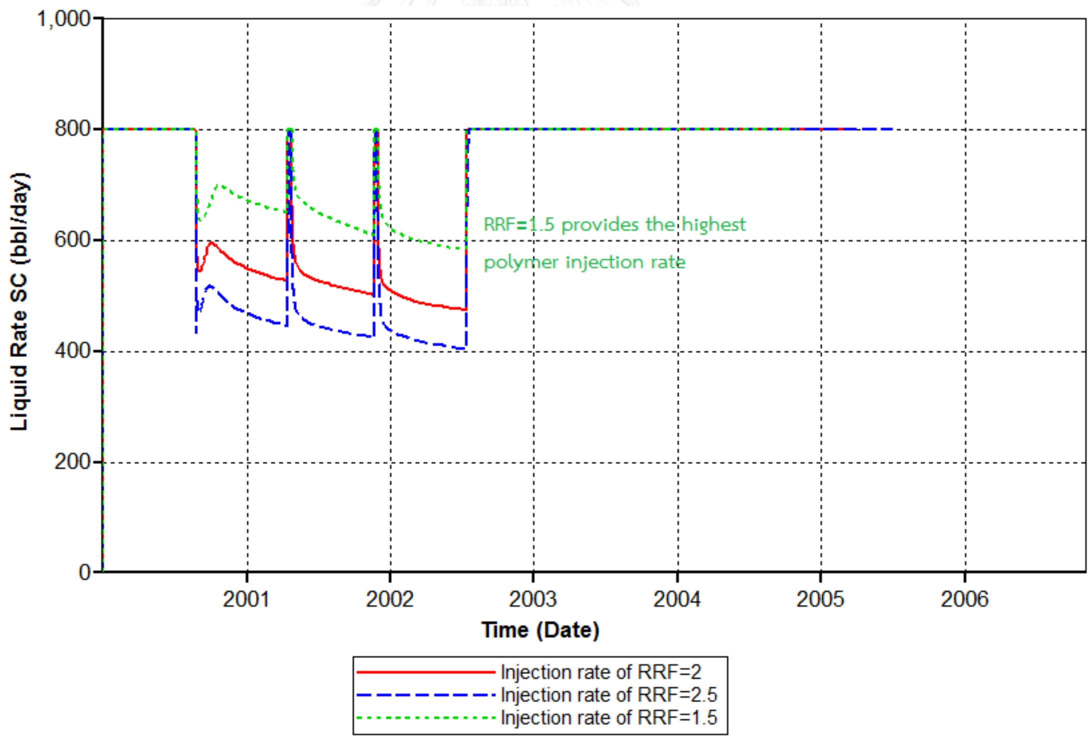


Figure 5.34 *Liquid injection rates of different residual resistance factors using 1,250 ppm polymer in coarsening upward reservoir model with* L_k*=0.2*

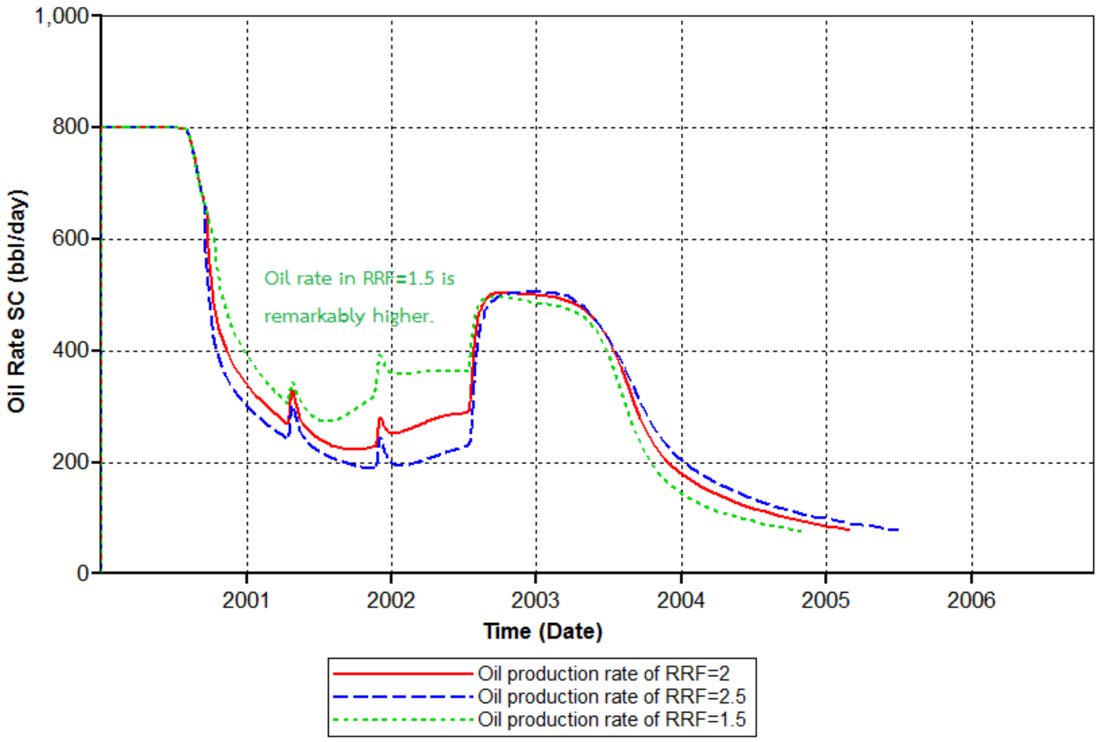


Figure 5.35 *Oil production rates of different residual resistance factors using 1,250 ppm polymer in coarsening upward reservoir model with* L_k*=0.2*

In 1,000 ppm cases, since polymer concentration is moderate, to balance between polymer injectivity and relative permeability reduction is more preferable and thus, RRF=2 provides the highest oil recovery as can be seen from Figure 5.36; polymer injection rate of RRF=2 (red) is at the high level between those of RRF=1.5 (green) and 2.5 (blue) while oil production rate in Figure 5.37 shows that RRF=2 also provides moderate oil rate which is not much different from others, resulting in similar oil recovery results.

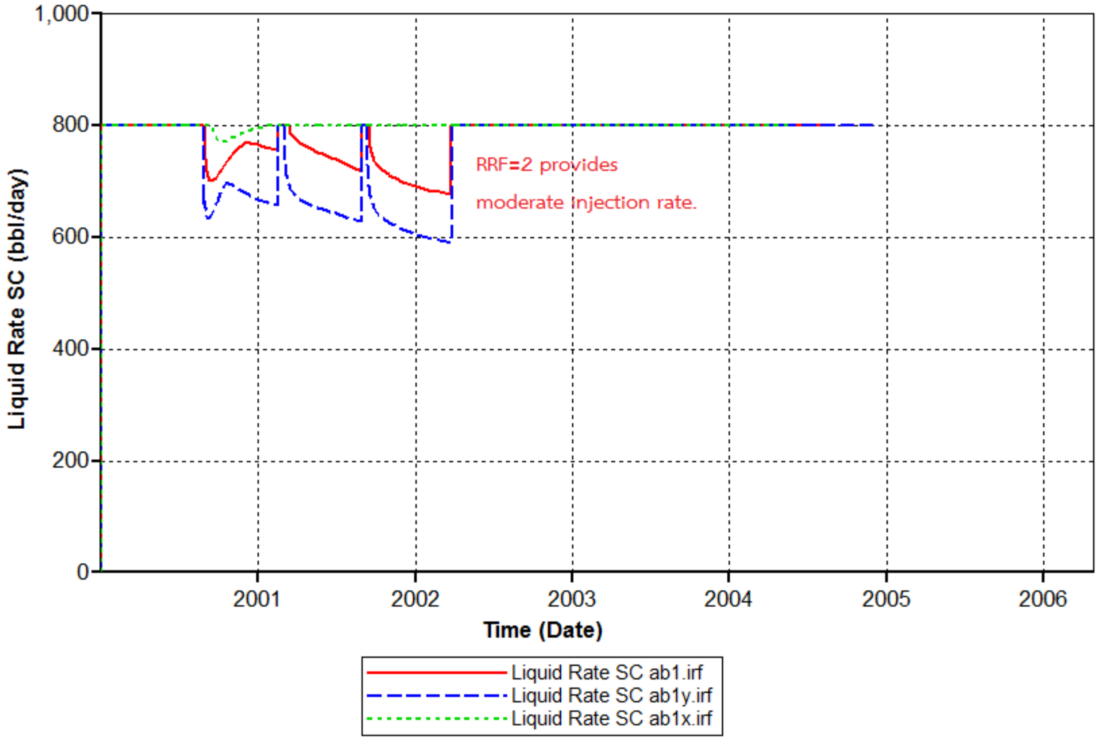


Figure 5.36 *Liquid injection rates of different residual resistance factors using 1,000 ppm polymer in coarsening upward reservoir model with* L_k*=0.2*

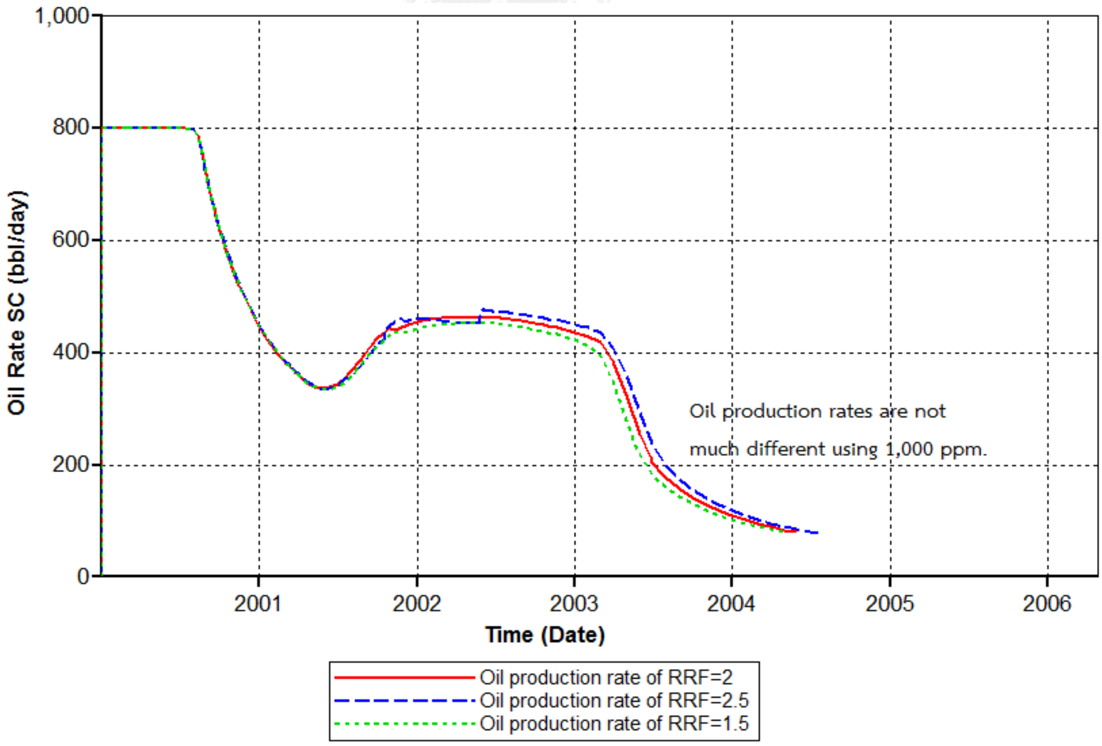


Figure 5.37 *Oil production rates of different residual resistance factors using 1,000 ppm polymer in coarsening upward reservoir model with* L_k*=0.2*

Lastly, in 833 ppm cases, it shows opposite results from those of 1,250 ppm cases since polymer concentration of 833 ppm is very low, when applying polymer flooding in the lowest RRF of 2.5, there is no problem with the injectivity while relative permeability to water is reduced the most so, it gains benefit from mobility control mechanism while in lowest RRF of 1.5, permeability is only slightly reduced which is not favorable comparing to RRF of 2.5. A plot of liquid injection rates in Figure 5.38 shows that even though liquid injection rate from RRF=2.5 (blue) cannot reach 800 bbl/d like in both RRF=1.5 (green) and RRF=2 (red), it just slightly drops from 800 bbl/d due to more relative permeability reduction, oil rate from this case is somewhat higher as shown in Figure 5.39, resulting in higher oil recovery.

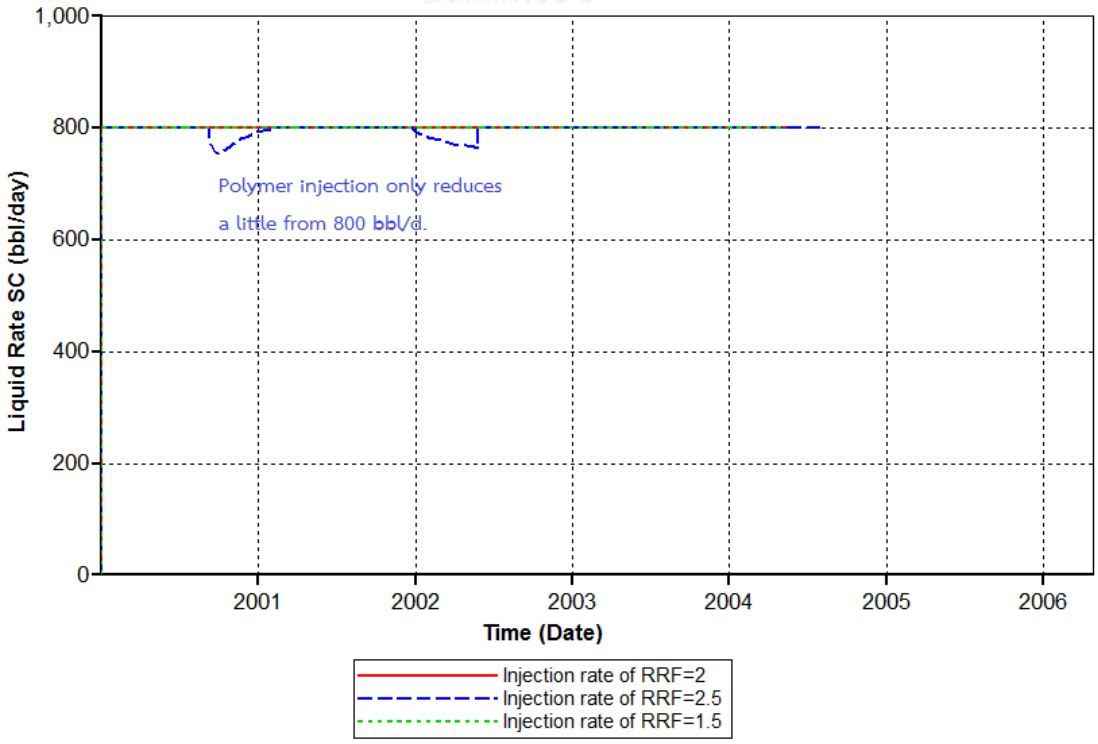


Figure 5.38 *Liquid injection rates of different residual resistance factors using 833 ppm polymer in coarsening upward reservoir model with* L_k*=0.2 with RRF of: 1.5 (green), 2 (red) and 2.5 (blue)*

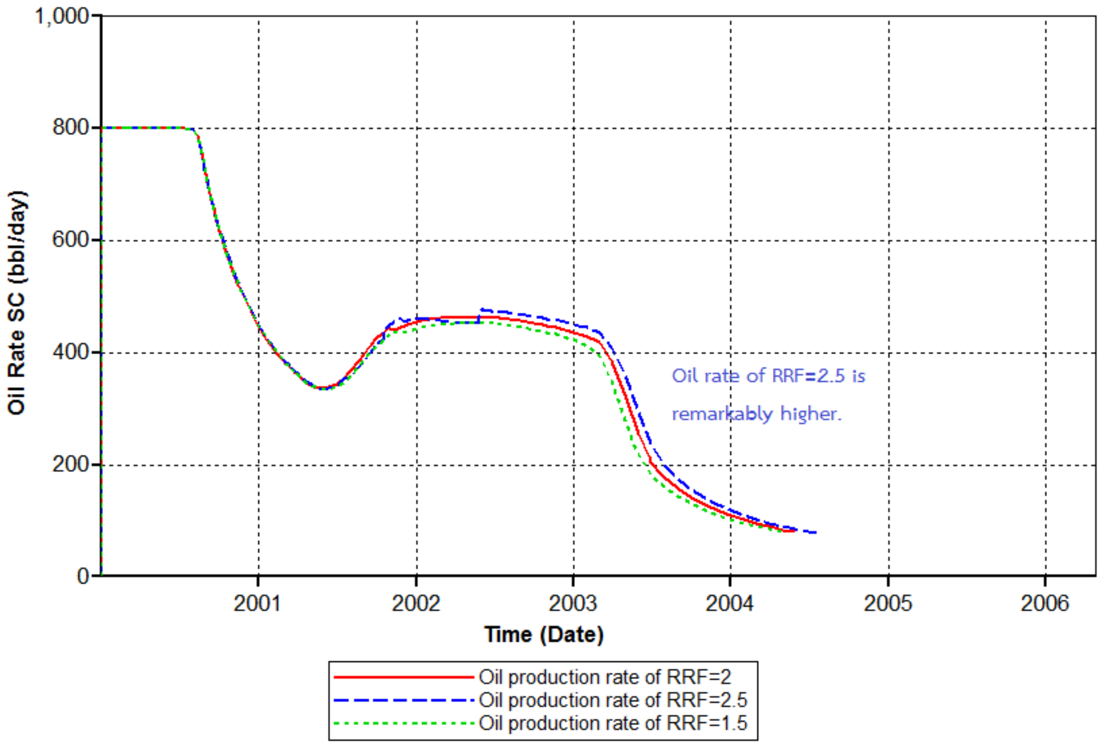


Figure 5.39 *Oil production rates of different residual resistance factors using 833 ppm polymer in coarsening upward reservoir model with* L_k*=0.2 with RRF of: 1.5 (green), 2 (red) and 2.5 (blue)*

In conclusion, residual resistance factor (RRF) affects oil recovery massively, especially, in low polymer concentration since it does not affect much on polymer injectivity. While polymer with the highest RRF also has the most relative permeability to water reduction, making it the most favorable condition to produce the oil. Finally, it results in the highest oil production. Meanwhile, in higher polymer concentration, the polymer injectivity has to be compensated with RRF because polymer is more difficult to be injected while the least RRF provides the smallest relative permeability reduction. As a result, polymer can be injected with the highest injection rate, resulting in the most oil production.

5.7 Effect of Reservoir Heterogeneity

From operating parameter studies in previous sections, it can be concluded that using three-slug polymer flooding with constant polymer concentration provides the best scenario for oil production, providing that reservoir has coarsening upward permeability sequence with *Lorenz Coefficient* (L_k) of 0.2. In this section, different reservoir heterogeneities, including L_k=0.2 (default), 0.24 and 0.275 and different sedimentary structures, including coarsening upward and fining upward are investigated. Comparison between single-slug and three-slug polymer in each reservoir heterogeneity will be discussed here as follows:

(A) Coarsening Upward with *Lorenz Coefficient* (L_k) of 0.2

(B) Coarsening Upward with *Lorenz Coefficient* (L_k) of 0.24

(C) Coarsening Upward with *Lorenz Coefficient* (L_k) of 0.275

(D) Fining Upward with *Lorenz Coefficient* (L_k) of 0.2

(E) Fining Upward with *Lorenz Coefficient* (L_k) of 0.24

(F) Fining Upward with *Lorenz Coefficient* (L_k) of 0.275

Table 5.8 shows the results from different reservoir heterogeneities in both oil recovery and production time while oil recovery in graph is shown in Figure 5.40.

Table 5.8 *Summary of oil recovery factors and total production time of single-slug and three-slug polymer from different reservoir heterogeneities and sedimentary structures*

Cases	No. of slug	1,250 ppm		1,000 ppm		833 ppm	
		RF (%)	Time (days)	RF (%)	Time (days)	RF (%)	Time (days)
(A)Coarsening, L_k=0.2	Single-slug	51.56	1,886	52.39	1,705	52.95	1,643
	Three-slug	52.34	1,886	52.69	1,705	52.95	1,613
(B)Coarsening, L_k=0.24	Single-slug	50.31	1,858	47.74	1,582	48.22	1,521
	Three-slug	50.45	1,827	47.86	1,582	48.52	1,492
(C)Coarsening, L_k=0.275	Single-slug	53.14	1,796	53.04	1,521	51.79	1,382
	Three-slug	53.28	1,796	53.66	1,613	52.05	1,521
(D)Fining, L_k=0.2	Single-slug	47.14	1,873	48.29	1,658	49.08	1,529
	Three-slug	47.08	1,858	48.03	1,643	48.79	1,552
(E)Fining, L_k=0.24	Single-slug	49.65	1,766	47.70	1,796	47.82	1,492
	Three-slug	49.28	1,796	47.59	1,492	47.69	1,461
(F)Fining, L_k=0.275	Single-slug	49.22	1,674	49.01	1,492	47.10	1,369
	Three-slug	48.97	1,796	48.85	1538	46.87	1,389

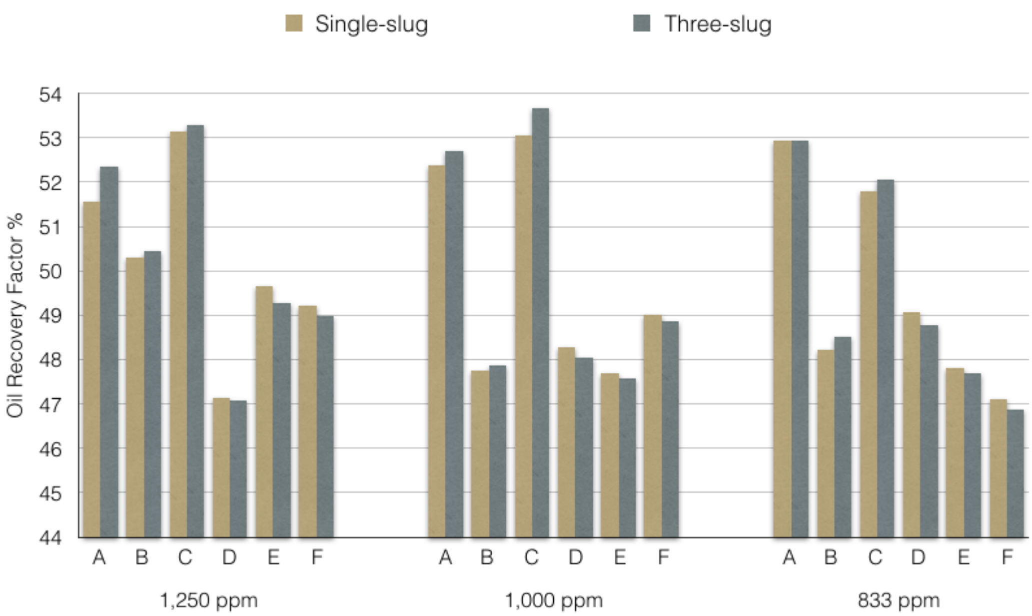


Figure 5.40 *Oil recovery factors obtained from single-slug and three-slug polymer from different reservoir heterogeneities and sedimentary structures*

From the results of the highest polymer concentration of 1,250 ppm, it can be observed that for coarsening upward, L_k=0.275 provides the highest oil recovery of 53.14% with 1,796 days of production in single-slug and 53.28% with the same production time in three-slug. Meanwhile, for fining upward, L_k=0.24 provides the highest oil recovery of 49.65% with 1,766 days of production in single-slug and 49.28% oil recovery with 1,796 days of production in three-slug.

In 1,000 ppm-polymer, same trend can be observed in coarsening upward; L_k=0.275 provides the highest oil recovery of 53.04% with 1,521 days in single-slug and 53.66% with 1,613 days in three-slug. In fining upward, L_k=0.275 provides the highest oil recovery of 49.01% with 1,492 days of production in single-slug and 48.85% with 1,538 days in three-slug.

Lastly, from the results of 833 ppm, for coarsening upward, L_k=0.2 gives the highest oil recovery of 52.95% in both single and three-slug polymer but single-slug takes 30 days longer (1,643 and 1,613 days). For fining upward, L_k=0.2 gives the highest one of 49.08% with 1,529 days in single-slug and 48.79% with 1,552 days in three-slug.

After changing the reservoir heterogeneity, the trend of oil recovery obtained from each heterogeneity is not much different; oil recovery factors in coarsening upward are remarkably higher than in fining upward and using three-slug helps improving oil production only in coarsening upward while worsens oil production in fining upward cases.

For coarsening upward, it can be observed that the highest *Lorenz Coefficient* (L_k) of 0.275 provides even higher oil recovery than L_k of 0.2 and 0.24 in both 1,250 and 1,000 ppm-polymer. This can be explained that even though permeability distribution is not good in L_k of 0.275 comparing to that of 0.2 and 0.24 but due to the permeability set-up for L_k of 0.275. Permeability values close to 300 mD (300, 299, 298, 297 mD) are in the first four reservoir layers which are the highest values. Thus, both 1,250 and 1,000 ppm-polymer which come together with high viscosity can easily flow through this high permeability channel. This can be seen in Figure 5.41. Polymer can flow through upper reservoir more (more light blue area covered) in L_k=0.275 for both concentration, resulting in higher oil rate as shown in Figure 5.42 and Figure 5.43.

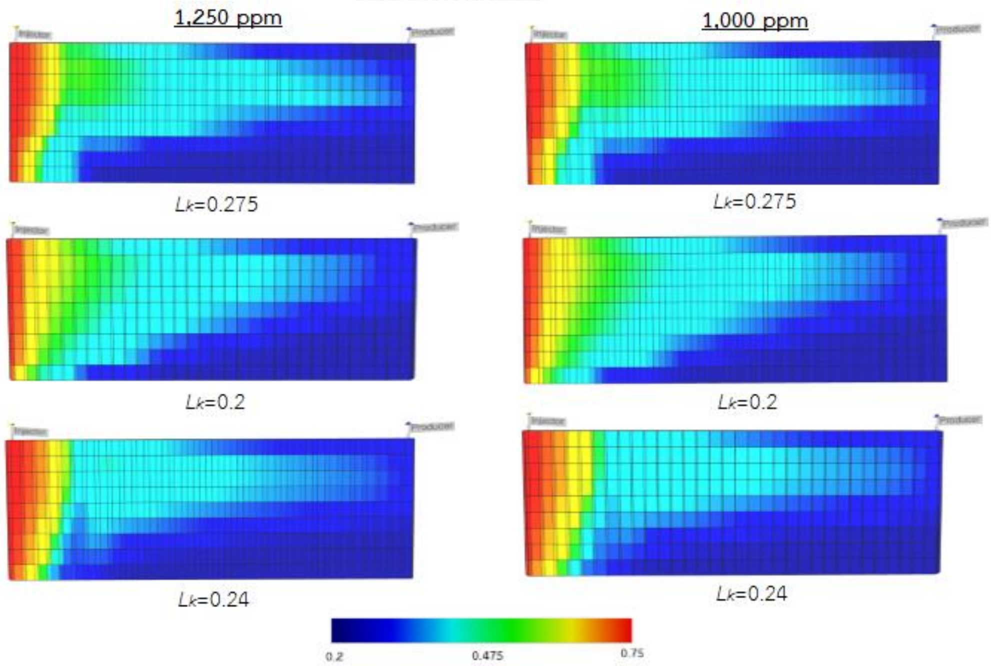


Figure 5.41 *Water saturation profiles of 1,250 and 1,000 ppm single-slug polymer in different reservoir heterogeneities (coarsening upward) after 9 months of production*

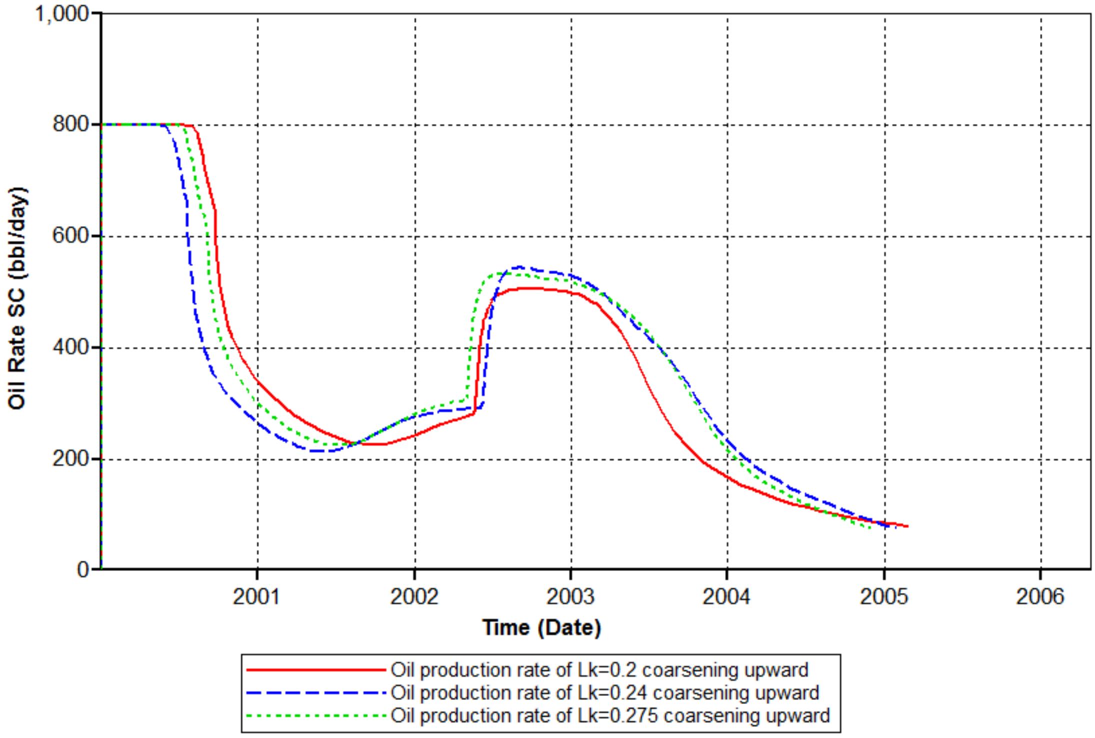


Figure 5.42 *Oil production rates of different reservoir heterogeneities (coarsening upward) using 1,250 ppm single-slug polymer*

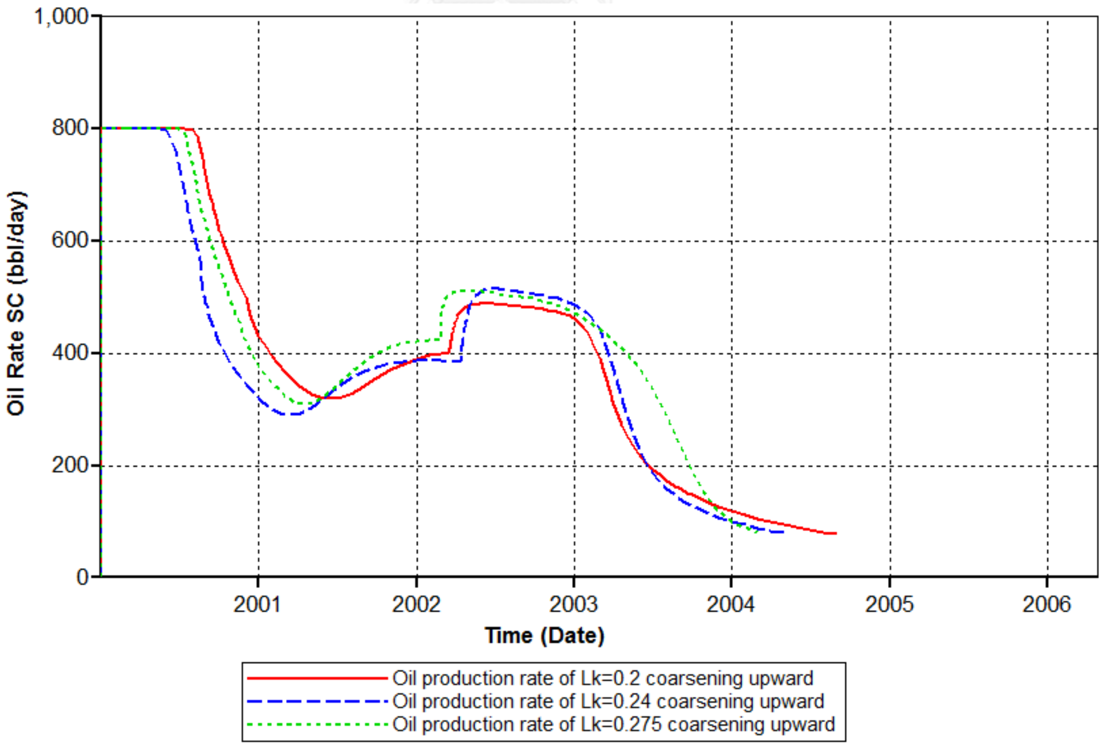


Figure 5.43 *Oil production rates of different reservoir heterogeneities (coarsening upward) using 1,000 ppm single-slug polymer*

While for the least polymer concentration of 833 ppm, polymer itself has no problem about low injectivity; it can spread into most of reservoir zone so, in L_k=0.2 which provides the best permeability distribution, polymer can travel into the reservoir and cover the most area as can be seen in Figure 5.44, resulting in the highest oil rate shown in Figure 5.45.

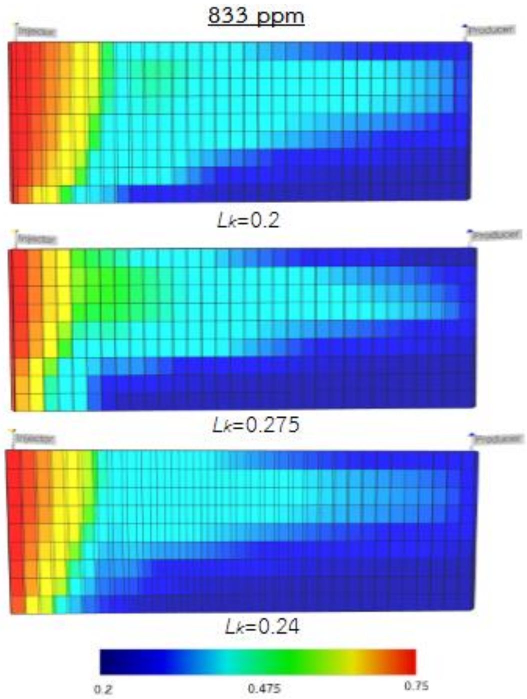


Figure 5.44 *Water saturation profiles of 833 ppm single-slug polymer in different reservoir heterogeneities (coarsening upward) after 9 months of production*

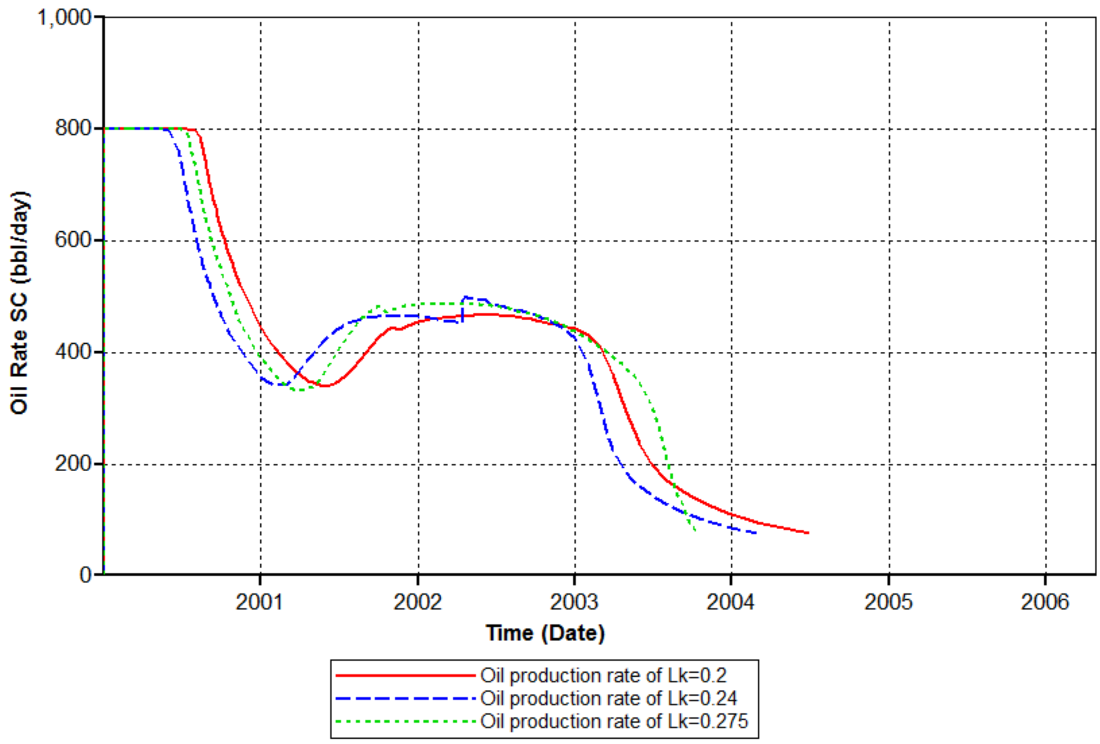


Figure 5.45 *Oil production rates of different reservoir heterogeneities (coarsening upward) using 833 ppm single-slug polymer*

For fining upward, the results can be summarized that in 1,250 ppm, *Lorenz Coefficient* (L_k) of 0.24 provides the best oil recovery but not significantly different from that of 0.275. This can be clarified that since fining upward reservoir has low permeability on top and high permeability at the bottom. It is difficult for high-concentration polymer to flow through upper reservoir. Polymer then falls down due to gravity and flows through lower reservoir only. As a consequence, the reservoirs with high heterogeneities at bottom such as L_k=0.24 (264, 285, 296, 300 mD) or L_k=0.275 (297, 298, 299, 300 mD) tend to permit more flow of polymer. This is shown in water saturation profiles in Figure 5.46, resulting in more oil production rate depicted in Figure 5.47.

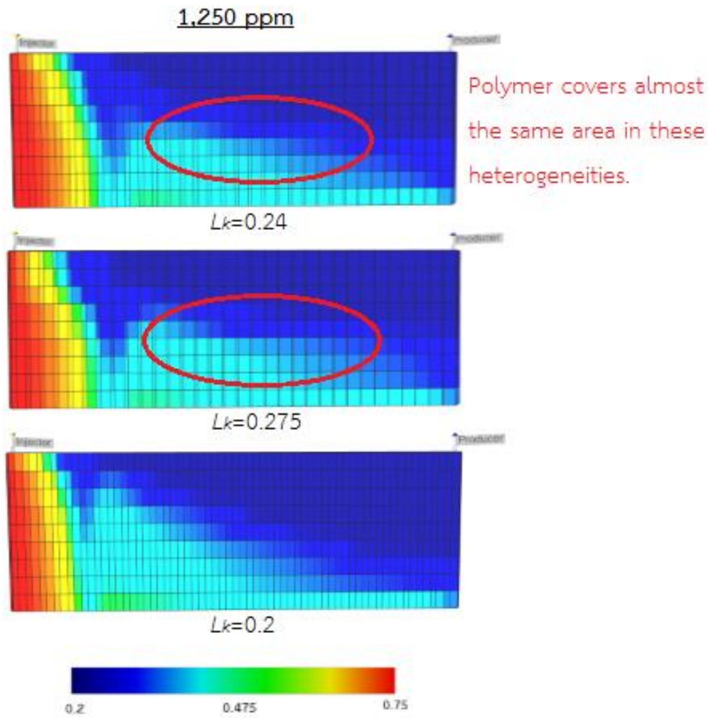


Figure 5.46 *Water saturation profiles of 1,250 ppm single-slug polymer in different reservoir heterogeneities (fining upward) after 9 months of production*

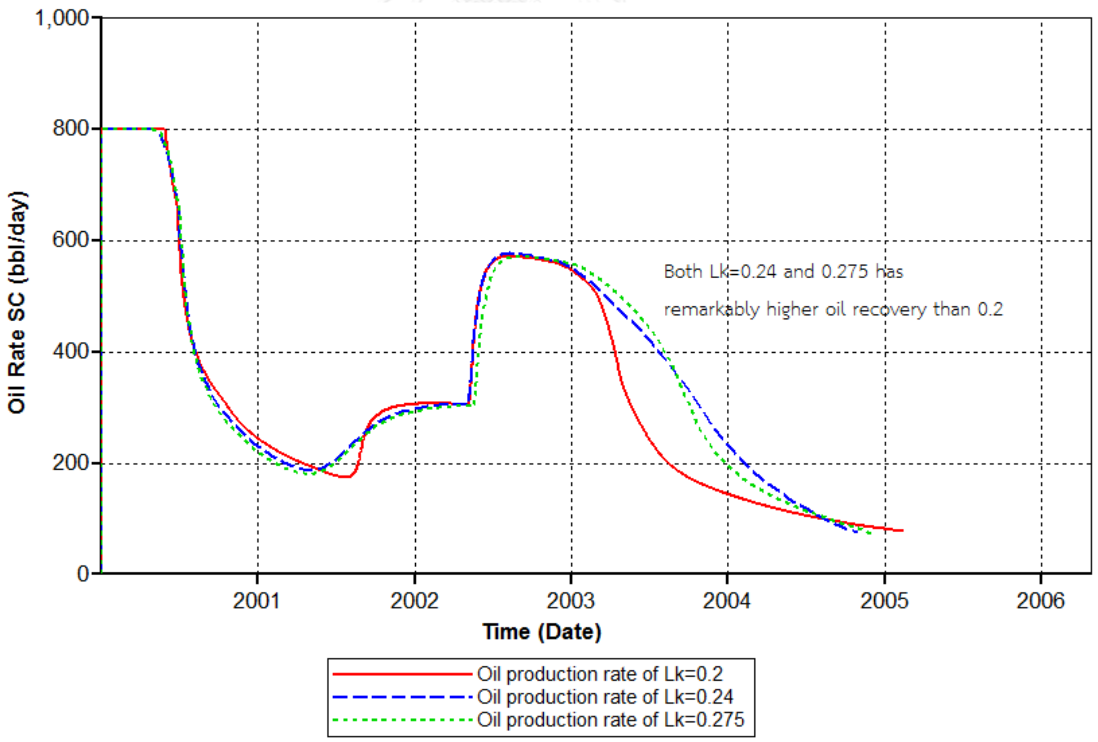


Figure 5.47 *Oil production rates of different reservoir heterogeneities (fining upward) using 1,250 ppm single-slug polymer*

In 1,000 ppm, L_k=0.275 shows superior result in terms of oil recovery than those in 0.2 and 0.24, same reason can be applied here; since polymer can flow better in high permeability channel at the bottom of reservoir in L_k=0.275 due to higher permeability values stated earlier, more polymer can get in as shown in Figure 5.48, creating more oil displacement efficiency which results in more oil rate as seen in Figure 5.49.

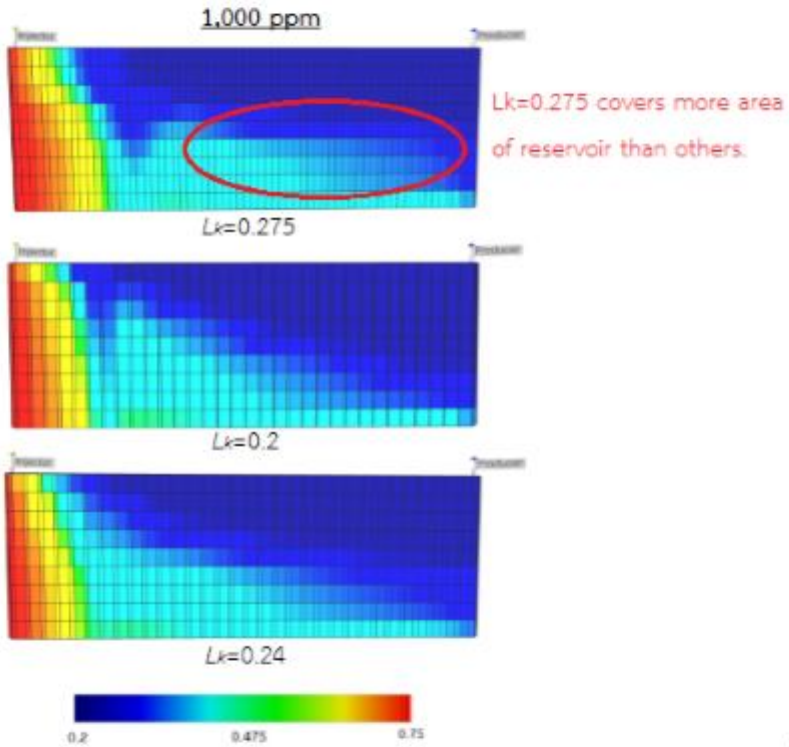


Figure 5.48 *Water saturation profiles of 1,000 ppm single-slug polymer in different reservoir heterogeneities (fining upward) after 9 months of production*

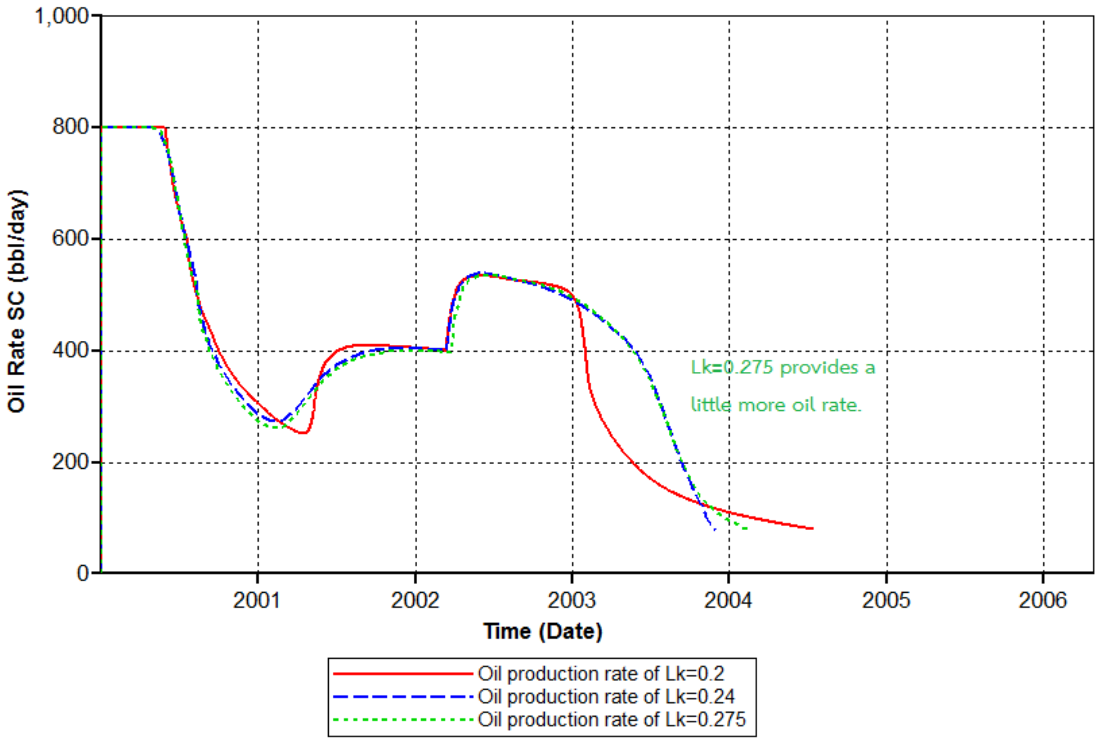


Figure 5.49 *Oil production rates of different reservoir heterogeneities (fining upward) using 1,000 ppm single-slug polymer*

Lastly, in the least concentration of 833 ppm, since polymer can flow through both high and low permeability channel due to low viscosity. Reservoir with L_k=0.2 which has the least heterogeneity permits the polymer to flow to each reservoir layer equally. This can be seen from the cross-section of reservoir in Figure 5.50. Meanwhile, the reservoirs with L_k=0.24 and 0.275 which have more heterogeneity tends to impede the flow of polymer into reservoir channels. According to this, more polymer that can get into reservoir in L_k=0.2 exhibits more oil displacement efficiency. Consequently, results in higher oil production rate as depicted in Figure 5.51.

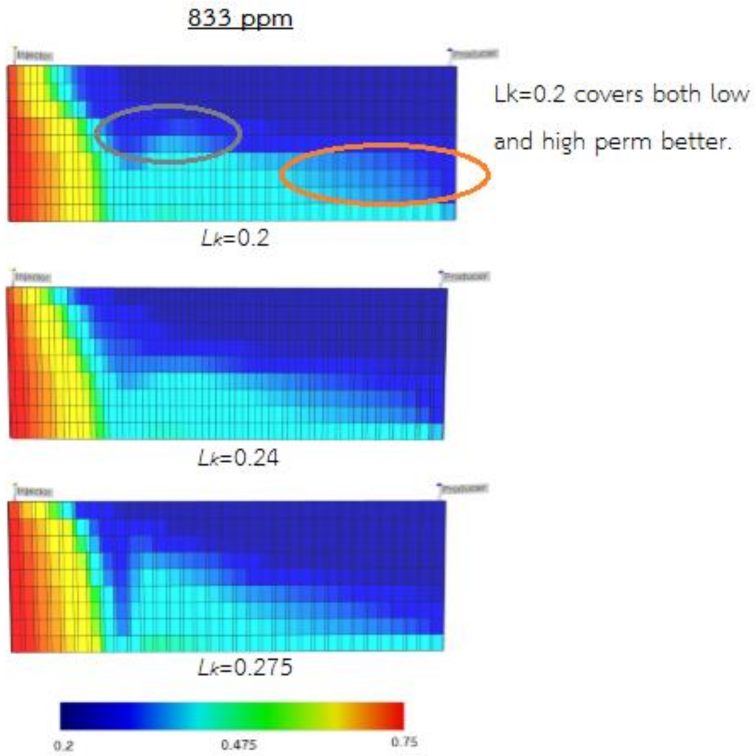


Figure 5.50 *Water saturation profiles of 833 ppm single-slug polymer in different reservoir heterogeneities (fining upward) after 9 months of production*

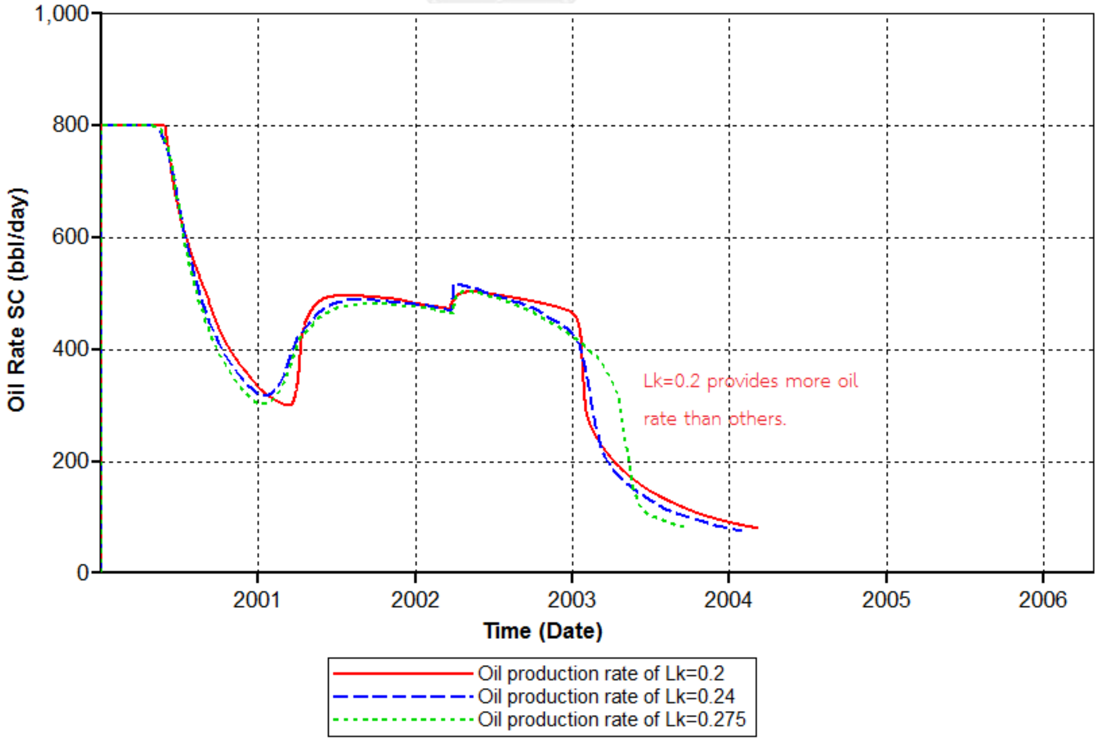


Figure 5.51 *Oil production rates of different reservoir heterogeneities (fining upward) using 833 ppm single-slug polymer*

Another aspect observed from the results is that using single-slug polymer provides slightly better oil recovery in all fining upward cases. This can be explained that since in fining upward sequence, low permeability is on top of reservoir while high permeability is at the bottom, alternating water has difficulty flowing through upper zone and falls down due to gravity, thus, water has less ability to help increasing polymer injectivity. The evidence from Figure 5.52 shows that after injecting alternating water for a while, polymer injection rate of fining upward increases. However it is much less than that of coarsening upward. Thus, this proves that alternating water has less polymer injectivity improvement in fining upward. In conclusion, the whole polymer slug should be injected after pre-flushed water. Since polymer injectivity is not much different from using three-slug polymer. This is shown in Figure 5.53. With single-slug usage, oil displacement mechanism occurs earlier than in three-slug which results in slightly higher oil rate as shown in Figure 5.54.

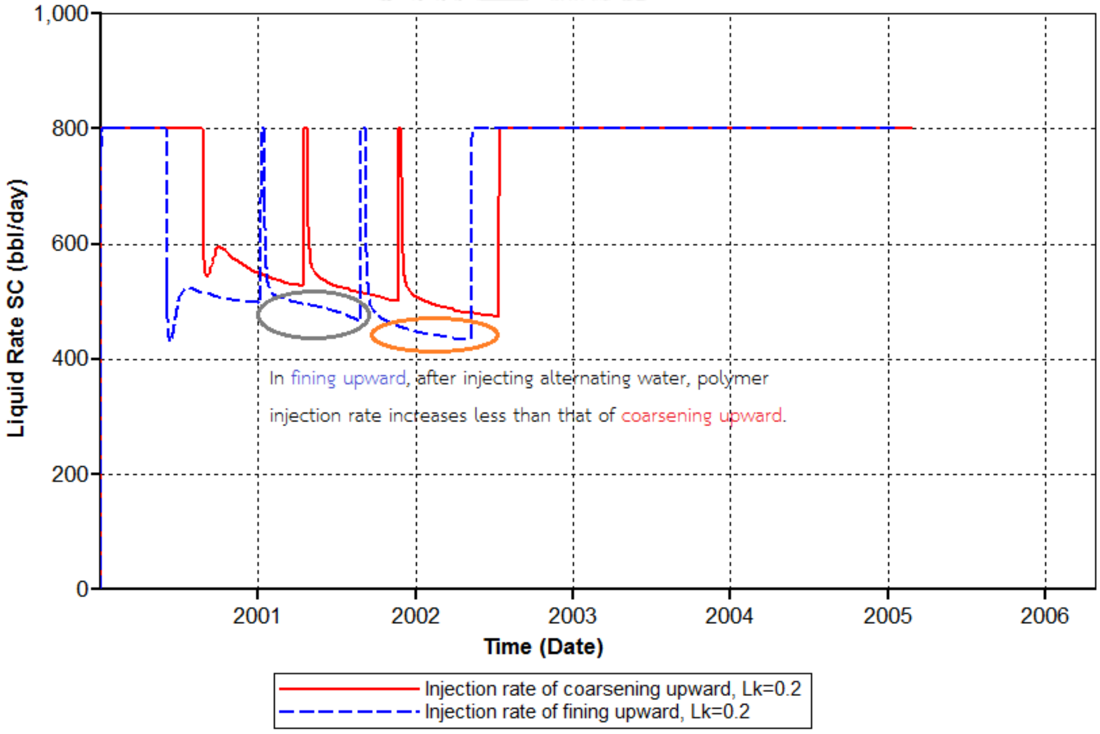


Figure 5.52 *Liquid injection rates of different sedimentary structures using 1,250 ppm three-slug polymer*

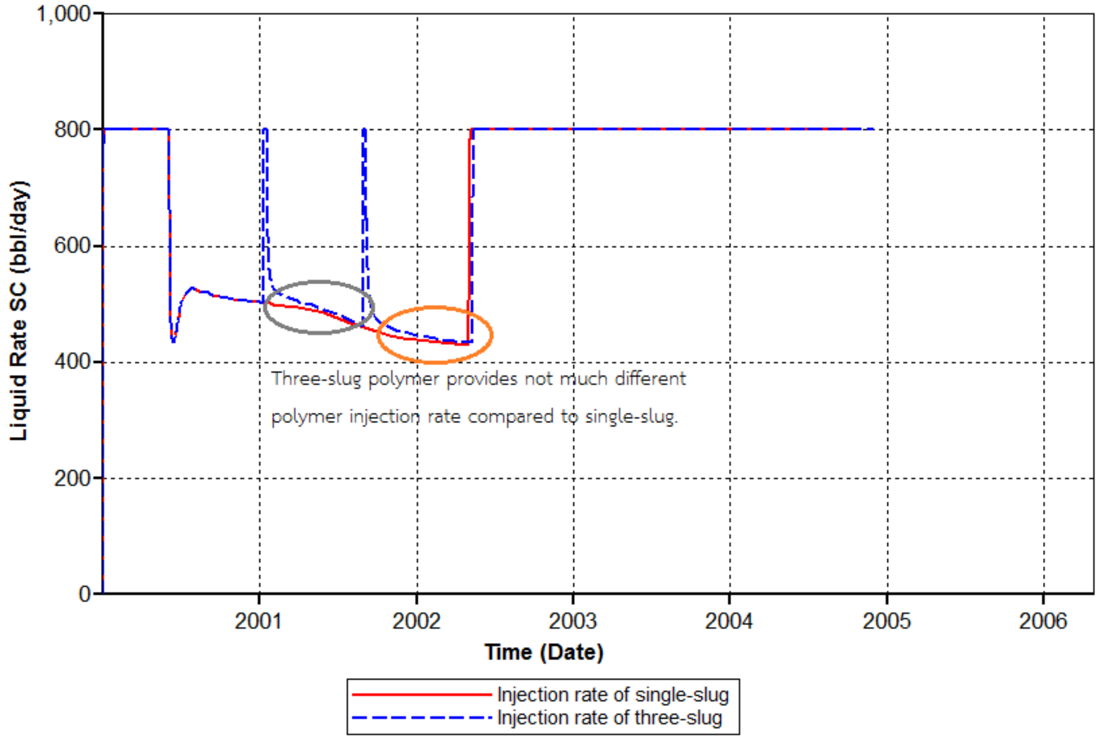


Figure 5.53 *Liquid injection rates of different number of alternative cycles in* L_k*=0.24 fining upward using 1,250 ppm three-slug polymer*

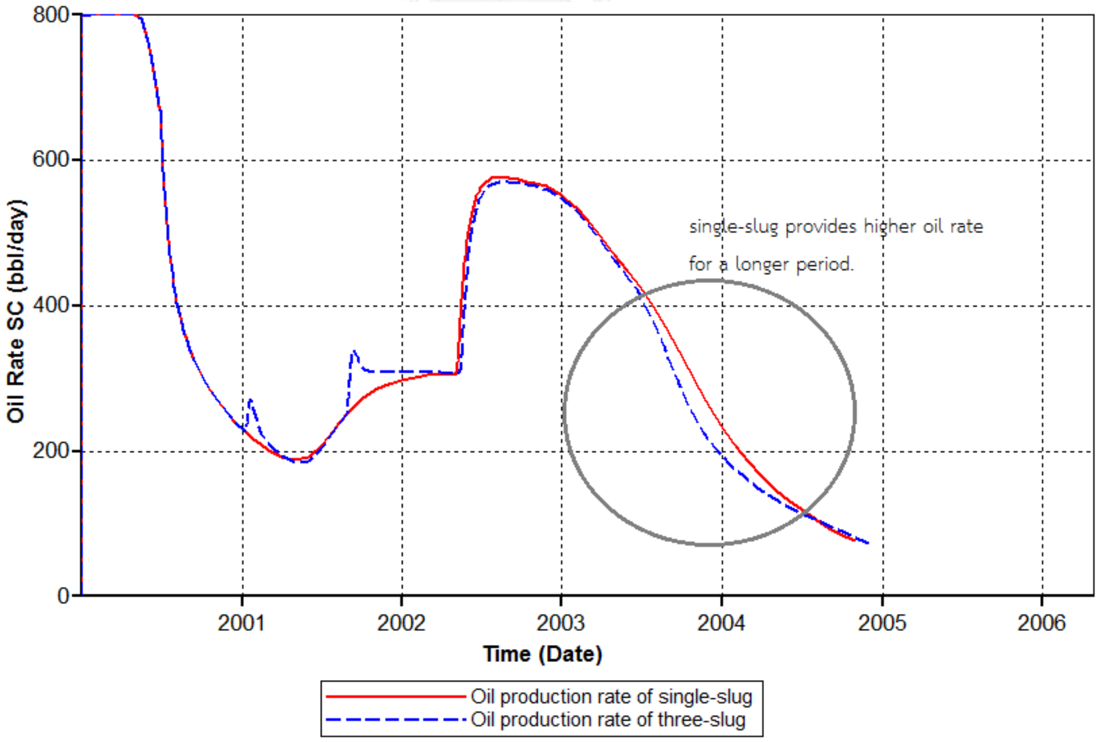


Figure 5.54 *Oil production rates of different number of alternative cycles in* L_k*=0.24 fining upward using 1,250 ppm three-slug polymer*

To sum up, coarsening upward is more favorable for three-slug polymer rather than single-slug polymer since using three cycles provides less polymer mass in each polymer slug which is more effortless to flow through pore space of rock, in addition, alternating water slugs between polymer slugs also help increasing the following polymer injectivity. Combining these effects together, three cycles provide more oil recovery in coarsening upward, on the other hand, in fining upward, due to the structure which does not permit the fluid to flow through upper reservoir easily, alternating water inserted has less efficiency to increase polymer injectivity due to gravitational force, thus, using single-slug polymer provides more oil recovery in fining upward.

CHAPTER 6
CONCLUSION AND RECOMMENDATION

This chapter concludes the results from numerical simulation from previous chapter together with the recommendation to improve the further study.

6.1 Conclusion

1. Pre-flushed water is suggested to be injected before polymer flooding process since it can increase the injectivity of following polymer slug. However, the amount of water required is insignificant as the oil recovery factors are not much different when volume of pre-flushed water is varied. Thus, the best practice is to inject pre-flushed water until breakthrough since the connectivity between injection and production wells can be verified. Afterwards, polymer flooding can be implemented.

2. To use alternating water slug size of 5 percent of polymer slug provides the best oil recovery for most of the cases since using more than 5 percent exhibits only limited improvement in polymer injectivity, while causing the delay of injecting polymer which, in turn, retards oil displacement mechanism. Nevertheless, the size of alternating water is very dependent on polymer desorption level. In case where desorption level is lower than the value used in this study (60 percent), much water will be required.

3. Concentration sorting both in ascending and descending order does not show significant improvement on oil recovery comparing to constant polymer concentration. Using constant concentration provides moderate polymer injection rate (between those of ascending and descending order) for both polymer slugs. As a result, it brings about similar oil recovery compared to that of ascending order.

4. Number of alternative cycles is dependent on polymer concentration; for 1,250 ppm, three-slug polymer provides the highest oil recovery since two alternating water slugs between polymer slugs are sufficient to increase polymer injectivity. While for 1,000 ppm, using between 2 to 5 cycles provides not much different in oil recovery, lastly, any number of alternative cycles can be selected in 833 ppm. As a

consequence, using three alternative cycles is recommended for all polymer concentration since it is a configuration that provides high oil production in all polymer concentration.

5. Residual resistance factor (RRF) strongly affects oil recovery by multi-slug polymer flooding. High polymer concentration can be used when RRF is low since small value of RRF results in small adsorption of polymer around injection well and small reduction of relative permeability to water which, in turn, polymer injectivity is maintained. Oppositely, small polymer concentration should be applied when RRF is high. As polymer viscosity is lower in this case, reduction of relative permeability can compensate the viscosity function to maintain the favorable condition of mobility ratio.

6. Multi-slug polymer flooding yields benefit in heterogeneous reservoir with depositional sequence as coarsening upward. Injectivity of low permeable zone at the bottom of reservoir can be improved with using alternating water slug. All range of heterogeneity index in this study response the same pattern. However, in fining upward sequence, multi-slug polymer injection does not yield benefit compared to single-slug. High permeability zone at the bottom of reservoir together with effect from gravity already favors the injectivity of polymer solution.

6.2 Recommendation

1. This study assumes some of the polymer behaviors to simplify the numerical simulation—e.g. neglecting the effect of shear thinning behavior (polymer viscosity is independent from shear rate), temperature and time have no effect on polymer. These may not represent the real polymer behaviors. So, it is recommended to include these parameters in the future study.

2. Specific values are used as input parameters for this study. These can provide only deterministic output values. Therefore, it is recommended that stochastic input parameters should be used instead in order to cover wider range of reservoir parameters. In addition, two or more numerical simulators is more preferable for the further study. Since the results can be crosschecked, bringing about more accurate final results.

3. Since these results are obtained from the simulation, laboratory experiment may be performed in order to verify the simulation results and if possible, this technique can be implemented in pilot test of oil field.

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Appendix A
RESERVOIR MODEL CONSTRUCTION

All parameters used to construct the reservoir model are shown in this section. 6 subsections include reservoir properties, pressure-volume-temperature (PVT) properties, rock-fluid properties, numerical and well & recurrent.

Simulation Settings

Parameters	Values
Simulator	STARS
Working units	Field
Porosity	Single Porosity

1. Reservoir Properties

1.1 Cartesian Grid

Parameters	Values
Grid type	Cartesian
K direction	Down
Number of grid box (I, J and K direction)	33 x 33 x 9
Block width (I direction)	33 x 20
Block width (J direction)	33 x 20

1.2 Array Properties

Parameters	Values
Grid top at layer 1	7,000
Grid thickness (ft.)	12
Porosity	0.2
Permeability I (mD)	Varied in each layer
Permeability J, K (mD).	Equal to Permeability I
Water mole fraction	1

2. Components

2.1 PVT Correlation

Parameters	Option	Values
Reservoir temperature		182°F
Generate data up to max. pressure of		5,000 psi
Bubble point pressure calculation	From R_s=50	416 psi
Oil density at STC (14.7 psia, 60°F)	Stock tank oil gravity (°API)	20
Gas density at STC (14.7 psia, 60°F)	Gas gravity (Air=1)	0.85
Oil properties (Bubble point, R_s, B_o) correlations	Standing	
Oil compressibility correlation	Glaso	
Dead oil viscosity correlation	Ng and Egbogah	
Live oil viscosity correlation	Beggs and Robinson	
Gas critical properties correlation	Standing	
Set/update value of reservoir temperature, fluid density in data set		Available

2.2 Water Properties Using Correlation

Parameters	Values
Reservoir temperature (TRES)	182°F
Reference pressure (REFPW)	3,445 psi
Water bubble point pressure	-
Water salinity (ppm)	1,000
Set/update value of reservoir temperature, fluid density in data set	Available

3. Rock-Fluid Properties

3.1 Rock Type Properties

Parameters	Values
Rock wettability	Water wet
Method for evaluating 3-phase relative permeability	Stone II

3.2 Relative Permeability Table

Parameters	Values
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.25
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.25
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05

KROCW - k_{ro} at Connate Water	0.7
KRWIRO - k_{rw} at Irreducible Oil	0.3
KRGCL - k_{rg} at Connate Liquid	0.7
Exponent for Calculating k_{rw} from KRWIRO	2
Exponent for Calculating k_{row} from KROCW	2
Exponent for Calculating k_{rog} from KROGCG	3
Exponent for Calculating k_{rg} from KRGCL	3

4. Initial Conditions

Parameters	Values
Vertical equilibrium calculation method	Depth-Average-Capillary
Reference pressure (REFPRES)	3,445 psi
Reference depth (REFDEPTH)	7,000 ft.
Water-oil contact depth (DWOC)	7,000 ft.

5. Numerical

Parameters	Values
First time step size after well change (DTWELL)	0.001
Isothermal option (ISOTHERM)	On
Linear solver iterations (ITERMAX)	200

6. Well & Recurrent

6.1 Injector

Type: INJECTOR MOBWEIGHT IMPLICIT

6.1.1 Perforation

Parameters	Values
Well radius (ft.)	0.25
Perforation start (I, J and K direction)	1 33 1
Perforation end (I, J and K direction)	1 33 9

6.1.2 Constraints

Constraint	Parameters	Limit/Mode	Values	Unit	ACTION
OPERATE	Surface liquid rate, STW	Max	800	bbl/d	CONT
OPERATE	Bottomhole pressure, BHP	Max	4,700	psi	CONT

6.2 Producer

Type: PRODUCER

6.2.1 Perforation

Parameters	Values
Well radius (ft.)	0.25
Perforation start (I, J and K direction)	33 1 1
Perforation end (I, J and K direction)	33 1 9

6.2.2 Constraints

Constraint	Parameters	Limit/Mode	Values	Unit	ACTION
OPERATE	Surface liquid rate, STL	Max	800	bbl/d	CONT
OPERATE	Bottomhole pressure, BHP	Min	420	psi	CONT

MONITOR	Water-cut, WCUT	0.9	STOP

Appendix B
POLYMER FLOODING MODEL CONSTRUCTION

The input parameters for polymer flooding model construction are shown in this section. It consists of 7 subsections, including process wizard, detail of polymer flood model, adsorption setting, viscosity setting, component molecular weight, adsorption components, injection fluid at injector.

1. Process Wizard

Parameters	Option
Process	Alkaline, surfactant, foam, and/or polymer model
Model	Polymer flood

2. Detail of Polymer Flood Model

Parameters	Values
Polymer is adsorbed onto the reservoir rock	Valid
Polymer resistance factor	Varied
Accessible pore volume for polymer adsorption	0.8
Polymer quantity decrease with time	Invalid
Rock type	Sandstone
Rock density (gm/cm^3)	2.65

3. Adsorption Setting

Polymer Concentration (%wt.)	Polymer Adsorption (mg/100gm rock)
0	0
0.1	1.3164
0.25	3.2909
0.5	6.5818

4. Viscosity Setting

Polymer Concentration (%wt.)	Viscosity (cP)
0	0.356894
0.05	2.7342832
0.1	7.457136
0.2	27.342832
0.3	80.78564

5. Component Molecular Weight

Component	MW (lb/lbmole)
Water	18
Polymer	8000
Dead_oil	426.9
Soln_gas	20.279

6. Adsorption Components

Composition dependence; Independent of temperature

6.1. Isotherm Adsorption Table

Mole Fraction	Adsorbed Moles per Unit Pore Volume (lbmole/ft3)
0	0
2.82E-06	1.16E-06

6.2. Rock Dependent Parameters

Parameters	Values
Maximum adsorption capacity (ADMAXT)	5.44E-06
Residual adsorption level (ADRT)	1.36E-07

7. Injection Fluid at Injector

Polymer Concentration	**1,250 ppm**	**1,000 ppm**	**833 ppm**
Component	Mole fraction	Mole fraction	Mole fraction
Water	0.99999718	0.99999775	0.99999812
Polymer	2.8184E-06	2.2542E-06	1.8774E-06
Dead_oil	0	0	0
Soln_gas	0	0	0

VITA

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