Evaluation of Sequential Polymer Flooding in Multi-layered Heterogeneous Reservoir

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การฉีดอัดสารโพลิเมอร์เป็นเทคนิคที่รู้จักกันอย่างแพร่หลายสำหรับควบคุมอัตราส่วนความสามารถในการเคลื่อนที่ซึ่งเป็นผลมาจากการเพิ่มความหนืดของสารฉีดอัดและการลดความสามารถในการซึมผ่านประสิทธิผลของน้ำ ก่อให้เกิดการปรับปรุงความสามารถในการกวาดน้ำมันและการควบคุมโปรไฟล์การฉีดอัดในแนวตั้ง

การศึกษานี้มุ่งเน้นไปยังผลกระทบของการฉีดอัดโพลิเมอร์แบบลำดับและปัจจัยความต้านทานโพลิเมอร์ที่มีต่อแหล่งกักเก็บแบบวิวิธพันธ์หลายชั้น ประสิทธิภาพของการฉีดอัดโพลิเมอร์แบบลำดับถูกกระทำโดยการเปรียบเทียบผลจากการฉีดอัดโพลิเมอร์แบบก้อนเดี่ยว

ในการศึกษานี้ การฉีดอัดน้ำก่อนสารโพลิเมอร์ไม่มีความจำเป็นเนื่องจากการดูดซับของสารโพลิเมอร์จะก่อให้เกิดก้อนน้ำที่ทำหน้าที่คล้ายน้ำก่อนการฉีดอัด สารโพลิเมอร์ที่มีความเข้มข้นสูง และก้อนโพลิเมอร์ขนาดใหญ่มีแนวโน้มจะให้ผลดี อย่างไรก็ดี ก้อนโพลิเมอร์ที่มีขนาดใหญ่จนเกินไปอาจก่อให้เกิดผลที่ไม่เป็นที่น่าพอใจในมุมมองทางเศรษฐศาสตร์

ผลดีจากการฉีดอัดโพลิเมอร์แบบลำดับคือ ช่วยลดเวลาในการผลิตและยังช่วยลดปริมาณน้ำจากการผลิตที่จะเกิดขึ้น เพื่อออกแบบแผนการฉีดอัดสารละลายโพลิเมอร์แบบลำดับ ก้อนโพลิเมอร์แรกควรจะมีความเข้มข้นมากและมีขนาดมวลใหญ่เพื่อที่จะรักษาเสถียรภาพของการแทนที่ การลดความเข้มข้นของสารโพลิเมอร์ระหว่างก้อนอย่างรวดเร็วจะต้องให้ความสำคัญต่อขนาดก้อนโพลิเมอร์แรกเป็นอย่างมากเมื่อเปรียบเทียบกับการลดความเข้มข้นอย่างช้า ๆ การฉีดอัดโพลิเมอร์แบบลำดับให้ประสิทธิภาพที่ดียิ่งขึ้นในกรณีที่ปัจจัยความต้านทานโพลิเมอร์มีค่ามาก ปริมาณน้ำมันที่ผลิตสามารถผลิตได้เพิ่มมากขึ้นจากแผนการฉีดอัดอย่างเหมาะสมที่สุด อย่างไรก็ดีการฉีดอัดโพลิเมอร์แบบลำดับมีความเหมาะสมกับแหล่งกักเก็บที่มีค่าสัมประสิทธิ์วิวิธพันธ์ต่ำ เนื่องจากแหล่งกักเก็บที่มีค่าสัมประสิทธิ์วิวิธพันธ์สูงมีแนวโน้มที่จะลดประสิทธิภาพของกระบวนการซึ่งเป็นผลมาจากการกระจายตัวของค่าความสามารถในการซึมผ่านที่แย่

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Polymer flooding is a well-known technique used for controlling mobility ratio from both viscosity enhancement and reduction of effective permeability to water, leading to improvement of sweep efficiency as well as wellbore profile.

This study emphasizes on effect of sequential polymer flooding together with residual resistance factor on multi-layered heterogeneous reservoir. Effectiveness of sequential polymer flooding is evaluated by comparing results with single-slug polymer flooding. In this study, pre-flushed water is not required since polymer adsorption results in water slug functioning as pre-flushed water. High polymer concentration and large slug size tend to yield favorable results. However, too large slug size could result in unsatisfactory in economic point of view.

Benefit of sequential polymer flooding is shortening total production period and reducing total water production. To design sequential polymer flooding scheme, first polymer slug should be high in polymer concentration and large in slug size to maintain stability of displacement. High contrast in reduction of concentration results in more concern on first slug size compared to low contrast in reduction of concentration. Sequential polymer flooding is even more effective in case of high value of residual resistance factor. Increment of oil recovery can be obtained from optimal scheme. However, sequential polymer flooding is more suitable with low heterogeneity reservoir since high heterogeneity tends to decrease it effectiveness due to poor permeability distribution.

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Figure 5.76 Oil saturation profile of low permeability zone (8th layer) at the end of production of triple-slug sequential polymer with residual resistance factor of 1.5 with different degree of heterogeneity (a) L_k = 0.2 (b) L_k = 0.24 and (c) L_k = 0.275 132

List of abbreviations

$\mu g/gm$	Microgram per gram
^{o}API	American petroleum institute gravity
bbl/day	Barrel per day
BHP	Bottomhole pressure
CMG	Computer Modeling Group
cP	Centipoise
mD	Millidarcy
DPR	Disproportionate permeability reduction
EOR	Enhance oil reocvery
F or ^{o}F	Degree Fahrenheit
HAP	Hydrophobic associating polymer
HPAM	Hydrolyzed polyacrylamide
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
KRWIRO	Relative permeability to water at irreducible oil saturation
MW	Molecular weight
PAM	Polyacrylamide
ppm	Part per million
PV	Pore volume
PVT	Pressure-volume-temperature
SCAL	Special core analysis
SCGON	Connate gas saturation
SGCRIT	Critical gas saturation
SOIRG	Irreducible oil saturation for Gas-Liquid table
SOIRW	Irreducible oil saturation for Water-Oil table
SORG	Residual oil saturation for Gas-Liquid table

SORW	Residual oil saturation for Water-Oil table
STL	Surface liquid rate
STW	Surface water rate
SWCON	Connate water saturation
WCUT	Water cut
w/w	Weight by weight
XG	Xanthan gum

Nomenclatures

λ_p	Mobility of polymer slug
λ_o	Mobility of oil
λ_w	Mobility of water
λ_w	Mobility of brine
$\emptyset$	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
F_m	Cumulative flow capacity
H_m	Cumulative thickness
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_k	Permeability reduction factor
R_{RF}	Residual resistance factor
R_s	Solution gas-oil ratio
υ	Poisson's ratio

CHAPTER I

INTRODUCTION

1.1 Background

Due to rapid increment in demand of oil and highly depletion of newly discovered oil reserve in past few decades, Enhance Oil Recovery (EOR) has been more considered as a solution to increase production efficiency of existing reservoirs. Among various types of EOR method, polymer flooding is one that is widely used due to its suitability for board range of reservoir properties and conditions. Theoretically, polymer flooding is performed to improve mobility of injected fluid when displaced fluid is non-uniformly swept by waterflooding. Volumetric sweep efficiency is generally improved after the process.

Heterogeneous reservoir is found as one target matched for polymer flooding. Heterogeneous reservoir is defined as a reservoir containing variety of reservoir properties in both horizontal and vertical directions. Heterogeneity of permeability is one of the most concerned factors, leading to difficulty in recovery prediction. In several cases, extremely low sweep efficiency than expected could happen due to heterogeneous anomaly. Polymer flooding is an EOR method that is proved to be suitable for heterogeneous reservoir. Higher in viscosity of polymer solution compared to saline water reduces mobility of displacing fluid to the comparable range of displaced oil and hence, displacement mechanism is conducted with improved viscous force, enhancing sweep efficiency. Not only increasing in viscosity that can improve sweep efficiency, adsorption of polymer in porous media also enhances sweep efficiency by reducing relative permeability to water, decreasing mobility ratio of the process to a more favorable condition. Reduction of relative permeability to water can be quantified as residual resistance factor which is a ratio of relative permeability to water before to after performing polymer flooding. Both viscosity and adsorption of polymer are controlled by polymer concentration and type of polymer.

In practical, polymer solution is not injected as a solely concentration, most of polymer flooding processes are designed with decreasing concentration as more pore volume has been injected to attenuate viscosity contrast with chasing water to overcome mixing problem of polymer slug and chasing water (quick dilution of polymer solution) as well as to maintain injectivity of polymer slug. One of objectives of this study is to investigate effects of residual resistance factor on sequential polymer flooding process in heterogeneous reservoir model together with selection of operational parameters.

STARS® simulation program commercialized by **Computer Modeling Group Ltd. (CMG)** is used as investigation tool for this study. A heterogeneous reservoir model will be constructed with variation of permeability as layers. First, permeability is varied in order from maximum value at top layer and decreased with depth. A case representing medium value of heterogeneity (quantified by Lorenz coefficient) is chosen as initialized model. Selection of operational parameters is firstly performed on initialized model to identify pre-flushed water slug size, polymer solution slug size and polymer concentration with various residual resistance factors. Selected cases are modified to create sequential polymer flooding with various value of residual resistance factor as well as reservoir heterogeneity. Eventually, effects of sequential polymer flooding on multi-layered heterogeneous reservoir are observed. Oil recovery factor under selected production constrains is a major criterion used to judge effectiveness of the process. Moreover, oil recovered per mass unit of polymer consumed, total water production and total production period are also used to assist judging process of cases.

1.2 Objectives

1. To determine operating parameters for sequential polymer flooding including pre-injected water slug size, polymer solution slug size, polymer concentration and degree of concentration reduction between polymer slugs in multi-layered heterogeneous reservoir.

2. To study effects of residual resistance factor on sequential polymer flooding in multi-layered heterogeneous reservoir.
3. To study effects of reservoir heterogeneity on sequential polymer flooding in multi-layered heterogeneous reservoir.

1.3 Outline of Methodology

1. Construct reservoir model with various heterogeneity values having coarsening upward sequence (high permeability on top of the model) and perform waterflooding process. The obtained simulation outcome data are used as references to compared with those obtained from polymer flooding.
2. Perform single-slug polymer flooding to all generated models with different operating parameters to select an operating parameters that meet requirement at various residual resistance factor. At this step selected operating parameters for each reservoir model with different heterogeneity values are obtained. Operating parameter are:
   - Pre-injected water slug size
   - Polymer slug size
   - Polymer concentration
3. Modify polymer flooding with selected operating parameters from previous step into double-slug and triple slug sequential polymer flooding. In this step, different scheme of flooding is performed to study effects of polymer concentration reduction between polymer slugs.
4. Analyze and discuss the simulation outcomes for each study parameters
5. Summarize the most suitable operating parameters and suggest appropriate production scheme for polymer flooding.

1.4 Thesis Outline

This thesis consist of six chapters as follow:

Chapter I introduces background of polymer flooding, objectives and methodology of this study.

Chapter II summarizes previous literatures that related to this study.

Chapter III reviews significant concepts related to polymer flooding and heterogeneous reservoir.

Chapter IV describes details of reservoir model construction, rock and fluid properties and production constrains.

Chapter V presents reservoir simulation results and discusses interest parameters. The results of obtained from polymer flooding with single slug and sequential slugs are compared and summarized.

Chapter VI provides conclusions and recommendations for further study.

CHAPTER II

LITERATURE REVIEW

2.1 Polymer Adsorption Mechanism during Polymer Flooding Process

Zaltoun et al. [1] designed two new polyacrylamide flooding processes for water control in production well without inducing any risk of plugging by cross-linkers. The idea of these two processes was that polymer should shrink in injection process and swell during production phase. The first process was performed by using Hydrolyzed Polyacrylamide (HPAM) coiled molecule that shrink in a presence of salt and swell in soften brine. The second process was performed using Polyacrylamide (PAM) as adsorbed polymer and used swelling agent instead of salinity gradient. The experimental results on sand and sandstone core showed an improvement on reduction of relative permeability to water while relative permeability to oil was not significantly affected in the first process and even more outstanding improvement in the second process due to nonionic nature of PAM compared to anionic HPAM, causing higher adsorption by PAM. The result of laboratory was confirmed by treatment of well VA-48 in the Cerville-Velaine field. This well was treated by the first process and water production was greatly reduced compared to neighboring wells.

Al-Sharji et al. [2] presented a mechanistic study of polymer adsorption for both single and two phase flow on Disproportionate Permeability Reduction (DPR) by performing experiment in a glass micro model with video recorder on both oil-wet and water-wet surface. In single phase flow, the result showed that under the water-wet condition, polymers was formed and built up in crevices between grains. This entanglement of polymer reduced the flow area of water, causing significantly reduction in relative permeability to water in water-wet surface, whereas in oil-wet condition, polymer layers was not formed on surface grain and relative permeabilities to oil and water are mostly the same. In two-phase flow of water-wet surface, water flowed through film along pore wall and in small pores, water was forced to flow through adsorbed polymer layers and oil patch and therefore, relative permeability to water was reduced while oil that flowed in the center of larger pores was nearly unaffected.

Ogunberu and Asghari [3] investigated effects of flow-induced polymer adsorption on reduction of permeability to water. The experimental result showed that polymer adsorption thickness was increased as shear rate increased and at above critical shear rate which is between 400-500 s^{-1}, static adsorption changed to flow-induced adsorption which had a sharp increase in adsorbed polymer layers. Further experiment also showed that allowing a residence time slightly improved residual resistance factor of polymer under static adsorption and greatly improved under flow-induced adsorption especially in low injection rate. However, flow-induced adsorption was limited by increasing of polymer concentration and low permeability media.

2.2 Polymer Flooding in Heterogeneous Reservoirs

Leiting et al. [4] studied feasibility of improving residual resistance factor of polymer flooding to apply with heavy oil reservoirs. These studies were divided into two sections. The first section investigated effects of properties of different polymer solutions on mobility control. Two types of polymer which were Hydrolyzed Polyacrylamide (HPAM 3830) and Hydrophobic Associating Polymer (HAP 0312) were selected in this study. The result showed that HAP 0312 was superior in mobility control even molecular weight of HAP 0312 is lower than that of HPAM 3830. HAP 0312 was adsorbed onto rock surface at higher degree compared to HPAM 3830. The second section was performed to study effects of residual resistance factor on oil recovery by using a numerical simulation. Simulation results showed that increment of oil recovery was remarkably as residual resistance factor increased at the same viscosity of polymer solutions while increment of oil recovery were slowed down as viscosity of polymer solution increased. They concluded that effective mobility control in heavy oil can be achieved by simultaneously increasing polymer viscosity and residual resistance factor. Polymer viscosity requirement can be decreased with effective polymer that yielded good residual resistance factor.

Deng et al. [5] reported a successful case of combined technique of high strength in-depth profile modification with ultra-high molecular weight polymer flooding in H2II zone in Xiaermen oilfield where oil viscosity was relatively high and formation was unconsolidated, contained severe permeability heterogeneity and also a large channel. The treatment process was performed by conducting in-depth profile modification with high strength modifier PAB to adjust the flow profile and then injecting ultra-high molecular weight polymer solution prepared by produced water to solve the problem of lacking in fresh water. Profile control treatments were performed between polymer intervals to ensure that polymer will not flow into channel. After injecting 0.164 PV of polymer solution, oil recovery was increased by 2.52% and according to this result, incremental of oil recovery by this treatment process was predicted up to 10%.

Wang et al. [6] identified key parameters of project design for polymer flooding based on twelve years of experience in Daqing oil field. To optimize oil recovery, under some circumstances, in-depth profile modification should be performed before implementing polymer flooding to control flow profile especially for the formation containing severe channeling. Moreover, polymer formulas should be designed as followed; choosing of the highest practical MW polymer to minimize volume of polymers required and not too large to allow polymer flowing through reservoir rock without plugging; varying polymer concentrations during injection phase depending on response of individual well; and considering change of salinity and temperature due to season while slug size and injection rate were depended on water and well spacing of individual well.

Meybodi et al. [7] conducted five-spot glass micro-model test to investigate effect of heterogeneity of layered reservoirs on polymer flooding. The experiment was performed on micro-model that was initially saturated with crude oil and varied flow rate, water salinity, polymer type and concentrations. Three different pore structures combined with different layers orientations were considered to designing of five different micro-models with strongly water-wet condition. The experimental result showed that areal sweep efficiency strongly depended on local heterogeneity near the injection zone. Thus, location of injection well was identified as an important factor for oil recovery. For the effect of layer orientation, when injection port was located in high permeable zone, oil recovery increased with an increase of layer orientation degree and for zero degree orientation, polymer flooding did not result in different in oil recovery compared to waterflooding. Additionally, oil recovery from polymer flooding increased with an increase of layer inclination angle.

Wassamuth et al. [8] presented associative polymers which were more suitable than commercial HPAM used to recover heavy oil. The experiment was performed in two geometric dual-permeability cores to compare effects of associative polymer with commercial HPAM. The result of laboratory scale test was also introduced to field scale simulation to investigate effects of associative polymers. The experimental and simulation results showed that at the same concentration, associative polymers generated more suitable in-situ apparent viscosity than commercial HPAM without significant retention or plugging. Moreover, resistance factor of associative polymers were far greater than HPAM. These effects contributed to incremental oil recovery with less polymer solution injected as well as can be used as diverted or blocking purpose in high permeability zone.

Panthangkul and Srisuriyachai [9] performed a multi-layered heterogeneous reservoir simulation to investigate effects of viscosity and injection rate of polymer solution and after that, double-slug mode of polymer injection was also studied. Degree of heterogeneity was represented by Lorenz coefficient. According to simulation result, polymer flooding should be injected after pre-flushed water in order to increase injectivity of polymer solution. Polymer concentration should not be too high as injectivity had to be maintained, whereas too low polymer concentration would yield a poor oil recovery due to unsuitable mobility ratio. High polymer injection rate provided benefit only in small value of Lorenz coefficient while small injection rate was more favorable in highly heterogeneous reservoirs. Injecting polymer in double-slug mode did not yield any benefit due to low injectivity.

According to the chosen literatures, polymer flooding is considered as an effective technique to control mobility ratio of displacing fluid. Polymer flooding has been implemented worldwide. However, only a few literatures have emphasized on an effect sequential polymer flooding which would be theoretically suitable in field operation combine with effect of residual resistance factor. Hence, this study is performed to provide an insight idea of how to select operating conditions as well as describe in detail of benefit of this technique.

CHAPTER III

THEORY AND CONCEPT

3.1 Polymer Flooding

Polymer flooding is an EOR technique performed by adding high molecular-weight, water soluble polymer into injected water to improve sweep efficiency by decreasing mobility ratio of flooded water. Mobility ratio is defined as a mobility of the displacing phase to the mobility of the displaced phase as shown in equation 3.1). Benefits of adding polymer are enhancing viscosity of displacing fluid and reducing relative permeability to water of formation with small effect on relative permeability to oil or to gas which is a result from polymer retention and consecutively reduce mobility ratio to a favor condition.

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k_{rw}}{\mu_w}\frac{\mu_o}{k_{ro}} \qquad 3.1),$$

where

λ_w = mobility of water

λ_o = mobility of oil

k_{rw} = relative permeability to water

k_{ro} = relative permeability to oil

μ_w = water viscosity

μ_o = oil viscosity

There are two commonly used group of polymers nowadays which are:

1. Polyacrylamide (PAM) is the most widely used synthetic polymer. Polyacrylamide is generated by polymerization of acrylamide monomer. Average molecular weight of PAM can be varied from 0.5 to 30 million Daltons. Due to slightly positively charged of PAM, this type of polymer tends to be adsorbed onto rock surface, making polyacrylamide not a good viscosity enhancing agent. Thus, polyacrylamide is slightly modified to partially Hydrolyzed polyacrylamide (HPAM) through hydrolysis, converting some amide groups (NH_2) along backbone chain to anionic (negatively charged) carboxyl groups (COO^-). Degree of hydrolysis is a fraction

of amide groups that are converted to carboxyl groups and this term also affects water solubility, salinity sensitivity, viscosity and retention.

2. Xanthan gum (XG) is the most widely used biopolymer. Xanthan is produced from fermentation process caused by bacterium called Xanthomonascampestris. Bacterial fermentation process usually leaves substantial debris in products which have to be removed before injecting into the reservoirs. Molecular weight of XG is varied around 1 to 5 million Daltons.

Both HPAM and XG yield high viscosity with just small amount. Both of them can be supplied as solid (dry powder) or liquid (solution or emulsion) forms. In the past, dry powder was widely used in oil field due to shipping and storage with small cost compared to solution form. However, using dry powder to prepare polymer solution may result in a formation of "fish eye" where dry powder is encapsulated in viscous layers and surrounded by water. Nowadays, both of them are supplied in liquid form with concentration range of 35 to 50%w/w instead of dry powder to prevent this problem. Figure 3.1 illustrates molecular structures of HPAM and Xanthan biopolymer [10].

Each polymer possesses advantages and significant disadvantages over another. In a presence of divalent ions ($Ca^{2+}$and Mg^{2+}), HPAM yields relatively low apparent viscosity compared to XG at the same concentration and moreover, HPAM can be mechanically degraded due to shearing effect while XG is mechanically stable. However, xanthan gum is also more expensive and has potential to plug pores and extensional viscosity of semi rigid XG molecule is less than the flexible HPAM. Both HPAM and XG are moderately tolerant to high reservoir temperature. However, thermal degradation usually aggravates in a presence of oxygen. Other factors such as high pH and presence of metal ion also decrease thermal stability of both polymers. Biological degradation can occur with HPAM and more serious with XG. Thus, biocide such as formaldehyde and several alcohols are commonly used to stabilize HPAM and XG solutions. Oxidation is considered as a serious degradation for both HPAM and XG, causing by dissolved oxygen in injected water. Oxidation can be occurred even in a small reaction rate due to high residence time in the reservoir and aggravated when temperature is increased. Thus, oxygen scavengers are usually added to prevent polymer oxidation.

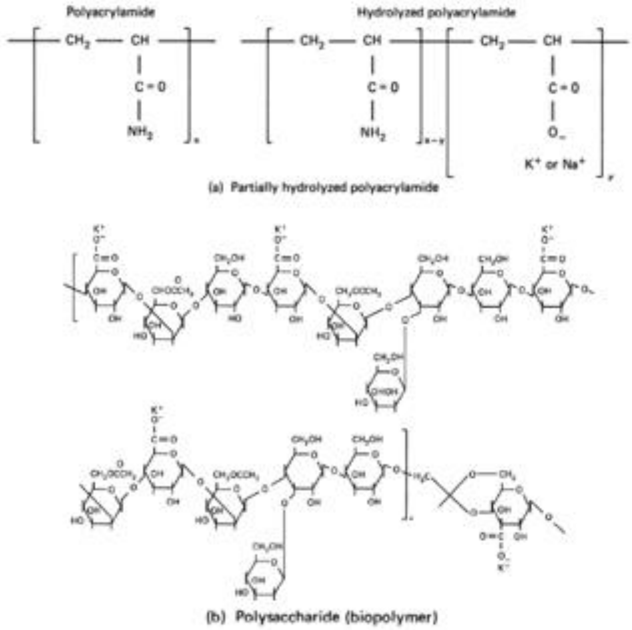


Figure 3.1 Molecular structure of a) synthetic polymer (HPAM) and b) Xanthan biopolymer (Polysaccharide) [10]

To perform polymer flooding in cost effective way, polymer concentration is reduced while more pore volume of solution is injected as depicted in Figure 3.2. After sufficient polymer solution is injected, water is injected to chase previously injected polymer slug. Polymer flooding does not lower residual oil saturation. It improves oil recovery over waterflooding by increasing contacted reservoir volume. Polymer flooding should be performed in early stage when mobile oil is still high (more than 10% pore volume). Polymer flooding is usually implemented in reservoir having tendency of viscous fingering or channeling problems together with heterogeneous reservoirs. Injected water during waterflooding will flow through the high permeability layers resulting in early water breakthrough and consecutively low sweep efficiency. However, polymer flooding does not yield significant improvement on oil recovery in homogeneous reservoirs containing low viscous oil or reservoirs having high water saturation at the beginning [11].

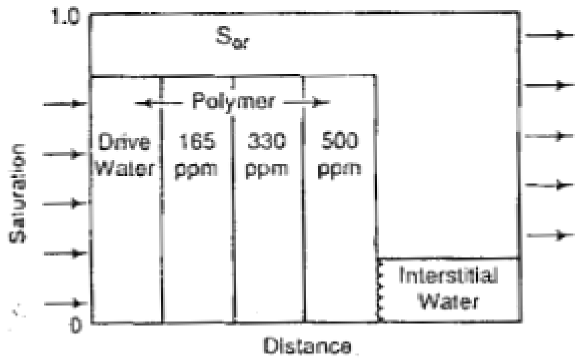


Figure 3.2 Injection schedule for a continuous polymer flooding [12]

Polymer flooding can be implemented in [12] both sandstone and carbonate reservoirs possessing both water-wet and oil-wet conditions. Water-wet sandstone is more favorable to perform polymer flooding due to less plugging tendency caused by polymer adsorption. Changing in relative permeability in oil-wet is insignificant. Porosity of reservoirs rock must be medium to high to assure a good storage capacity. Low permeability formation should be avoided because it would require high injection pressure and actual injection rate might be too low. Reservoir temperature should not be more than 200°F for HPAM and 180°F for XG to prevent thermal degradation. Thus, deep formation is not a good candidate. Maximum oil viscosity for polymer flooding implementation is around 150 cP. Polymer with higher viscosity is required for very viscous oil and this might cause a tremendously low injectivity. By the way, oil viscosity should not be too low that makes other EOR methods to be preferable.

3.2 Characteristics of Polymer Flooding

3.2.1 Rheology

Viscosity enhancement is one of the major functions of polymer in EOR method. As concentration of polymer increases, viscosity of polymer solution is increased. In addition, at a given flow velocity or shear rate, and polymer concentration, an apparent viscosity and mobility reduction increases as Molecular Weight (MW) of polymer increases. To optimize mobility reduction and minimize polymer volume used, proper MW of polymer should be chosen [6].

At low shear rate, apparent viscosity of polymer solutions is independent from shear rate. This behavior of polymer solution makes it recognized as Newtonian fluid. However, at higher shear rate, polymer solution turns to Non-Newtonian fluid as an apparent viscosity of polymer solution decreases with an increment of shear rate as shown in Figure 3.3. This behavior of fluid is so-called pseudo-plastic or shear-thinning. Shear thinning behavior of polymer solution is caused by alignment of polymer molecules, shearing to reduce internal friction. Nevertheless, this viscosity reduction is reversible if polymer molecule is not thermal degraded. This behavior is favorable for polymer flooding implementation because when polymer solution flows through perforation holes which are small is size, viscosity of polymer solution is decreased, resulting in greater injectivity and as a consequence, desired mobility ratio can be achieved due to reduction of viscosity.

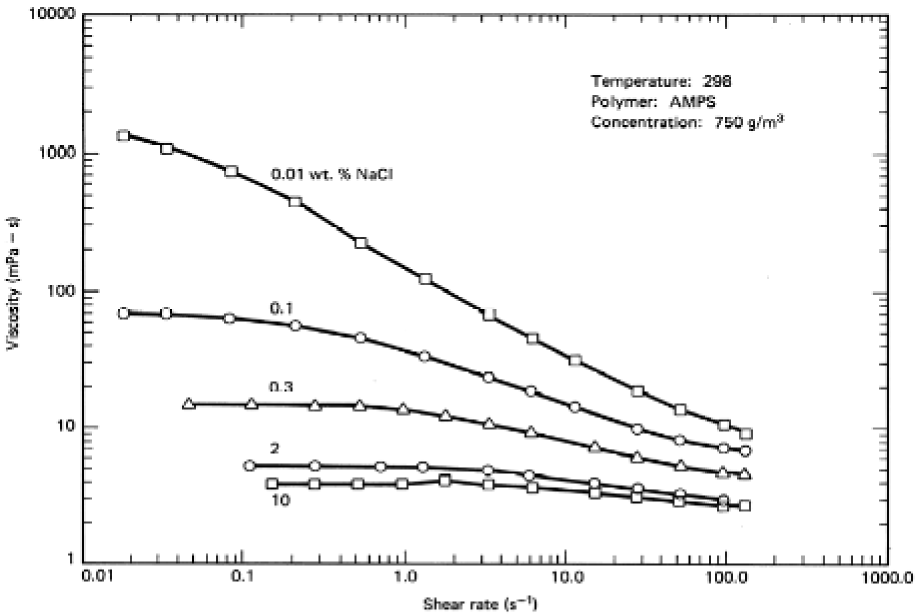


Figure 3.3 Viscosity of polymer solutions with different salinities as a function of shear rate [10]

For HPAM, rheology behavior is also affected by salinity and divalent ions. At low salinity, negative charges repel each other along backbone chain. This repellant stretches molecule of polymer and hence, polymers occupy more space in solution, increasing apparent viscosity. In a presence of divalent ions, negative charges of polymer molecules are interacted; reducing repulsion and thus, extension is reduced. In contrast, XG molecules which are more stiffed resulted from semi rigid rod structure, extension is less and therefore XG is insensitive to salinity or divalent ions.

3.2.2 Reduction of Relative Permeability

Adsorption of polymer on rock surface causes reduction of relative permeability to water with no significant effect on relative permeability to oil or gas. This phenomenon is known as Disproportionate Permeability Reduction (DPR) which occurs only in water-wet rock. Polymer is adsorbed onto rock surface and this reduces available flow area of water while oil that occupies in the middle of pore space is nearly unaffected as shown in Figure 3.4. Permeability reduction depends on polymer types for example, adsorption of XG and permeability reduction are relatively small compared to HPAM. Moreover, molecular weight, shear rate, degree of hydrolysis and pore structure also control permeability reduction as well.

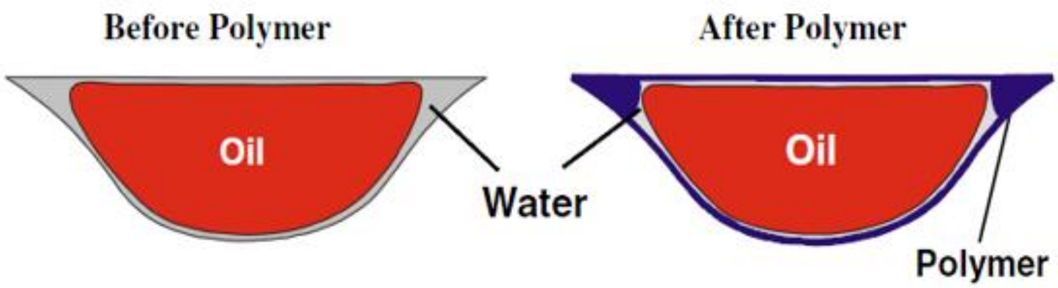


Figure 3.4 Illustration of permeability reduction mechanism [2]

Permeability reduction is usually measured as a term of permeability reduction factor (R_k) which is a ratio of relative permeability to brine before and after polymer injection.

$$R_k = \frac{k_{rw,before\ polymer\ injection}}{k_{rw,after\ polymer\ injection}} \qquad 3.2),$$

or the term of residual resistance factor (R_{RF}) which is a ratio of mobility of brine solution before and after polymer injection.

$$R_{RF} = \frac{\lambda_{brine\ ,before\ polymer\ injection}}{\lambda_{brine\ ,after\ polymer\ injection}} \qquad 3.3),$$

Both permeability reduction factor and residual resistance factor are usually determined by ratio of pressure drop from water injection in core flooding test at after and before injection polymer solution at the same injection rate. Figure 3.5 demonstrates effects of relative permeability reduction on pressure drop by plotting pressure drops of water injection before and after injection of polymer solution in x and y axis, respectively. From the figure, for oil-wet condition possessing the same relative permeability to water, pressure drops before and after polymer injection are almost the same. In contrast, pressure drop after polymer injection in case of water-wet condition is higher than pressure drop before polymer injection. The ratio of pressure drops after and before polymer injection represents permeability reduction factor whereas residual resistance factor can be calculated from this ratio at the end point saturation (irreducible water saturation).

Figure 3.6 shows an example of effect of polymer adsorption on relative permeability curve of Berea sandstone with water-wet condition using commercial polymer solution. From this figure, relative permeability to oil is almost unaffected from polymer adsorption, whereas relative permeability to water is greatly reduced around 90 percent of original value.

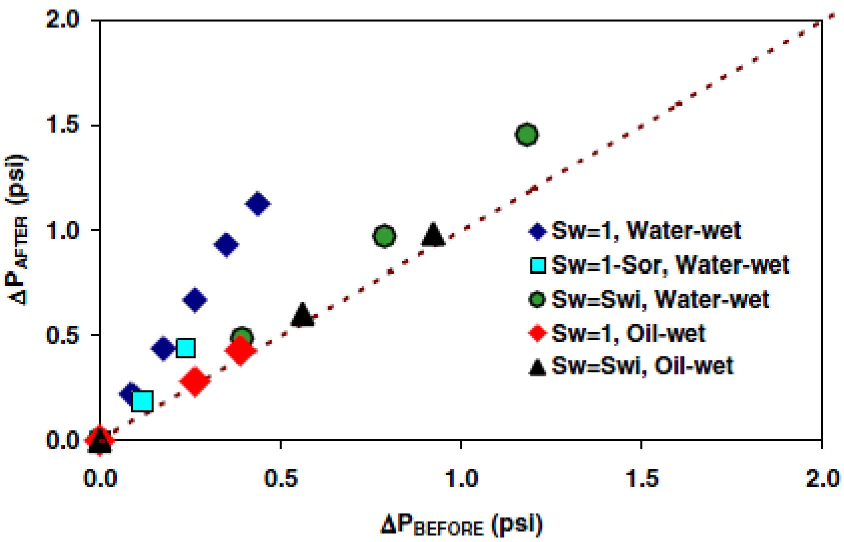


Figure 3.5 Pressure drop from injection process before and after polymer injection of water-wet and oil-wet condition [2]

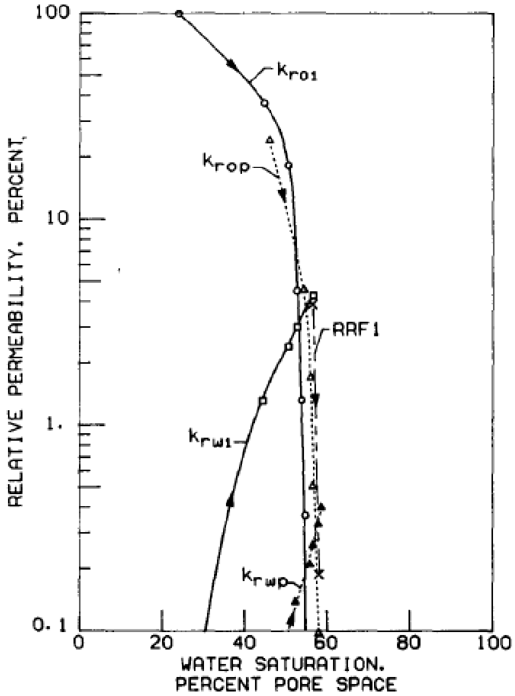


Figure 3.6 Relative permeability to oil and to water before and after contact with commercial polymer solution (Dow pusher 1000^{TM}) [13]

3.2.3 Polymer Retention

When polymer solution flows through formation, there is a measurable amount of polymer retention in the formation. Polymer retention is caused by interaction between porous media and polymer molecules which can be categorized into three main mechanisms including polymer adsorption, mechanical entrapment and hydrodynamic retention [11] as illustrated in Figure 3.7. Hydrodynamic retention is defined as a phenomenon that polymer molecules are temporary trapped in stagnant flow regions by hydrodynamic drag forces. However, when the flow is stopped, these molecules will diffuse out into main flow, so hydrodynamic retention is considered as a reversible retention process and does not contribute to a field-scale of polymer flooding.

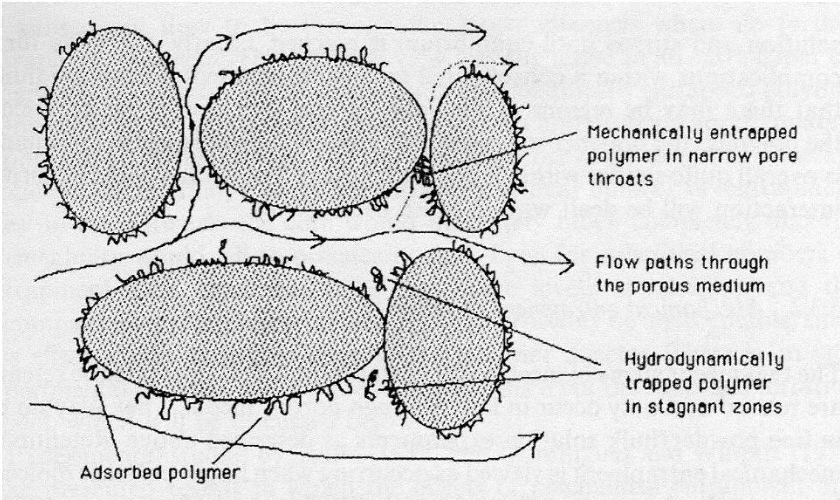


Figure 3.7 Schematic diagram of polymer retention mechanism in porous media [11]

Mechanical entrapment occurs when large molecule of polymer flows through a pore with large opening but cannot leave due to a smaller opening on exit side. Mechanical entrapment strongly depends on polymer molecular size and reservoir pore structure. Retention of polymer molecules in low permeability reservoirs is large due to excessive mechanical entrapment of polymer molecules in small pore throats, resulting in reduction of effectiveness in polymer flooding process. Mechanical entrapment is considered as a primary lose for XG whereas it does not cause reduction of relative permeability to water.

Polymer adsorption is caused by difference in charge property between polymer molecule and rock surface. This interaction causes polymer molecules to be bound onto rock surface, mainly by physical interaction (van der Waal's and hydrogen bonding) and adsorption is considered as irreversible process. Polymer adsorption is considered as a primary lose for HPAM. In the absence of mechanical entrapment, polymer adsorption is directly proportional to polymer concentration at low concentration. Polymer adsorption can occur in most reservoir rocks, especially carbonate one which is positively charged in nature. Adsorbed polymer can be considered as a loss of polymer concentration or as an additional resistance to flow if adsorption takes place in proper range.

3.2.4 Inaccessible Pore Volume

Inaccessible Pore Volume (IPV) is defined as a fraction of pore space that does not allow polymer molecules to flow through due to relatively large molecular size. IPV has been observed for all types of porous media for both HPAM and XG and it can be increased with increment of polymer molecular weight, reduction in permeability and characteristic of porous media. IPV can reach up to 30 percent in severe case. The bank of water from polymer solution that loses polymer mass from adsorption process and the bank of water preceding polymer slug will be reduced by the amount of IPV. Polymer response will be seen at production wells sooner as a result of IPV forces polymer molecule to flow only through larger pore, offsetting lagging effect caused by polymer adsorption as demonstrated by polymer concentration after polymer solution in injected shown in Figure 3.8

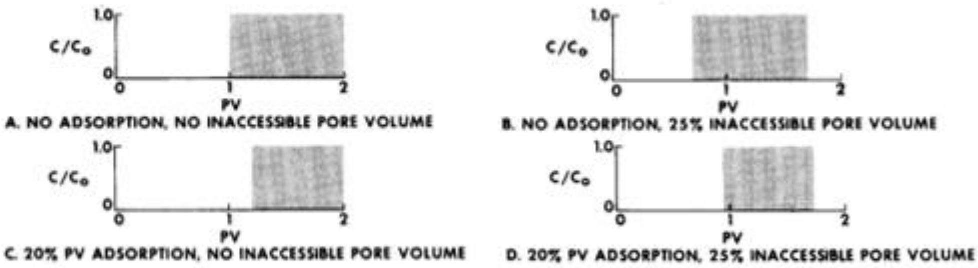


Figure 3.8 Ideal polymer break out curve, polymer bank size = 1.0 PV [14]

3.3 Reservoir Heterogeneity

Reservoir heterogeneity is defined as a variation in reservoir properties in the spatial location including porosity, saturation, thickness, fault and fracture, wettability, rock characteristics, rock facies and especially permeability which is an important factor affecting sweep efficiency and oil recovery. Heterogeneity of reservoirs depends upon depositional environments and subsequent events such as cementation, compaction and dolomitization [15]. Homogeneous reservoir is considered as an ideal reservoir. However, most reservoirs contain varying degree of heterogeneity. There are essentially two types of heterogeneity which are vertical heterogeneity and areal heterogeneity.

Variation in permeability is mostly used as parameter that is responsible for degree of heterogeneity. Heterogeneity is quantitatively expressed as a term of coefficient. Formation possessing uniformity of properties results in coefficient close to zero. On the other hand, formation that has coefficient close to unity is identified as a maximum variation of properties through formation. There are several methods used to quantify degree of heterogeneity such as the coefficient of variation, Dykstra-Parsons coefficient or so-called coefficient of permeability variation [16] and Lorenz coefficient. In this study, Lorenz coefficient suggested by Schmalz and Rahme is chosen due to its simplicity and accuracy for multi-layered heterogeneous reservoirs that is mainly emphasized in this study. In order to determine Lorenz coefficient, permeability values are arranged in descending order form the maximum (positioned at top) to the minimum (positioned at bottom). Lorenz curve is obtained from plotting between cumulative flow capacity (*F_m*), in y- axis, and cumulative thickness (*H_m*), in x- axis as shown in Figure 3.9, where

$$F_m = \frac{\sum_{i=1}^{n} k_i h_i}{\sum_{i=1}^{N} k_i h_i} \qquad 3.4)$$

and

$$H_m = \frac{\sum_{i=1}^{n} h_i}{\sum_{i=1}^{N} h_i} \qquad 3.5)$$

Lorenz coefficient is calculated from area under Lorenz curve but above the straight line divided by the area under the straight line. Lorenz coefficient can vary from zero, for ideally homogeneous reservoir, to unity, for completely heterogeneous reservoir. Lorenz coefficient can be modified by including porosity in the calculation. The term cumulative storage capacity (*C_m*) is used instead of cumulative thickness to be more precise and the data must be ordered according to the ratio of permeability to porosity.

$$C_m = \frac{\sum_{i=1}^{n} \emptyset_i h_i}{\sum_{i=1}^{N} \emptyset_i h_i} \qquad 3.6)$$

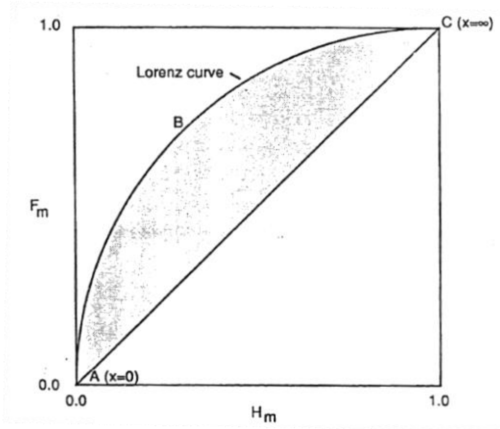


Figure 3.9 Flow capacity distribution representing Lorenz curve [14]

CHAPTER IV

RESERVOIR SIMULATION MODEL

In order to investigate performance of polymer flooding in multi-layered heterogeneous reservoir, reservoir model is constructed using reservoir simulator **STARS®** commercialized by **Computer Modeling Group Ltd. (CMG).** The reservoir model is constructed to simulate a quarter five-spot flood pattern. This chapter describes fundamental of model construction including grid section, reservoir heterogeneity construction, PVT properties, petrophysical properties, well specification and production constrains. The last section of this chapter summarizes thesis methodology.

4.1 Grid Section

The reservoir model with dimension of 660×660×108 ft in x, y and z directions is constructed based on appropriate range of well space for polymer flooding in field cases. Number of grid and grid size in x, y and z directions are 33, 33, 9 and 20, 20, 12 ft, respectively. The reservoir model is constructed by using Cartesian grid type with square pattern. Injector and producer are located diagonally on two corners of the model. Figure 4.1 illustrates 3-D dimension of reservoir model and location of injector and producer. Porosity of 0.2 is assigned in all layers while permeability in each layer are different from the largest value in topmost layer to smallest value in bottommost. This appearance represents coarsening upward heterogeneous reservoir. Summary of reservoir properties for physical model are shown in Table 4.1 including magnitude of permeability values which are possibly related to porosity of 0.3.

Table 4.1 Reservoir properties for physical model

Parameters	Values	Unit
Grid dimension	33 × 33 × 9	Block
Grid size	20 × 20 × 12	ft
Porosity	20	%
Horizontal permeability	Varied in each layers	mD
Vertical permeability	Equal to 0.1 k_h	mD
Average permeability	200	mD
Minimum permeability	60	mD
Maximum permeability	300	mD
Top of reservoir	3,280	ft
Initial pressure at datum depth	1,622	psia
Reservoir temperature	118.94	^{o}F

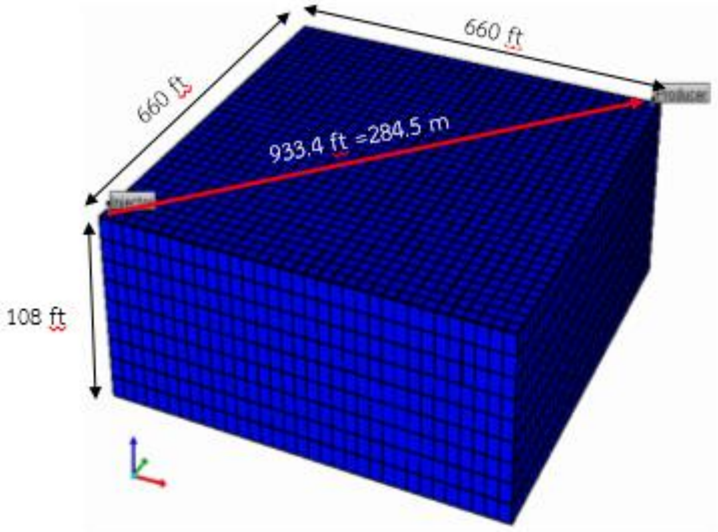


Figure 4.1 Dimension of reservoir model and location of injector and producer

4.2 Reservoir Heterogeneity Construction

In this study, variation of permeability is chosen to represent degree of heterogeneity. Lorenz coefficient (L_k) is used to quantify reservoir heterogeneity due to its simplicity and accuracy for multi-layered heterogeneous reservoir. In order to calculate Lorenz coefficient, permeability in all layers are ordered in descending direction from the largest to the smallest value. Lorenz curve is obtained from plotting between cumulative flow capacity (F_m), on y-axis, and cumulative Storage capacity (C_m) on x-axis, where

$$F_m = \frac{\sum_{i=1}^{n} k_i h_i}{\sum_{i=1}^{N} k_i h_i} \qquad 4.1),$$

$$C_m = \frac{\sum_{i=1}^{n} \emptyset_i h_i}{\sum_{i=1}^{N} \emptyset_i h_i} \qquad 4.2).$$

Lorenz coefficient is then calculated from a ratio of area curve above straight line over area below straight line. Magnitude of Lorenz coefficient can vary from zero to unity. Homogeneous reservoir is represented by straight line which is depicted in Figure 4.2. The greater deviation of any line from this straight line indicates higher heterogeneity of the reservoir. Three models with variation of permeability are constructed with Lorenz coefficients ranging from 0.2 to 0.275 and to be comparable among cases, maximum, minimum, average and median of permeability are kept constant in all three cases. Table 4.2 summarizes permeability value in each layer for three models with different Lorenz coefficient and Figure 4.3 illustrates all three Lorenz curve for three models with different heterogeneities.

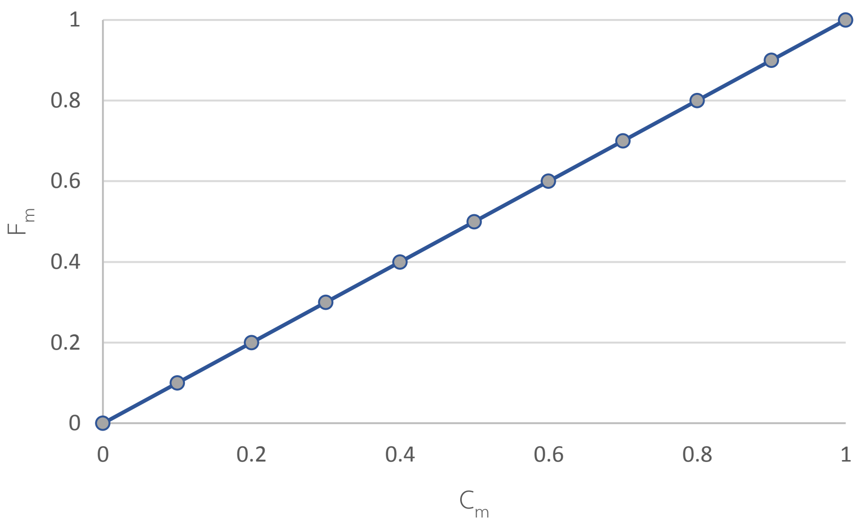


Figure 4.2 Flow capacity distribution for homogeneous reservoir

Table 4.2 Permeability values in each layer for reservoir with different Lorenz coefficients

Layer	k_h of L_k 0.20	k_h of L_k 0.24	k_h of L_k 0.275
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

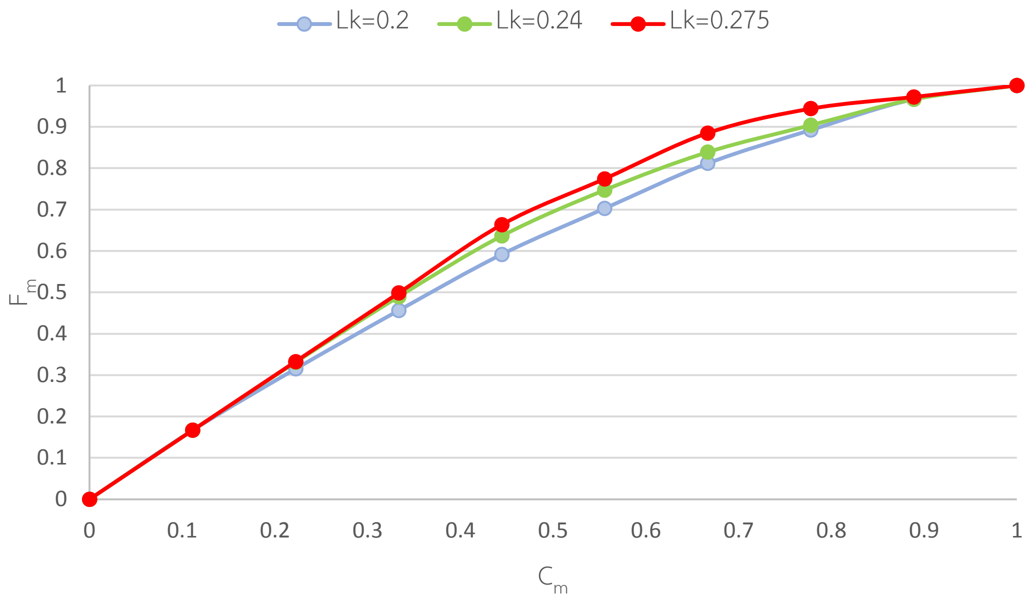


Figure 4.3 Summary of flow capacity distribution for reservoir models with different Lorenz coefficients

4.3 Pressure-Volume-Temperature (PVT) Properties

The PVT properties of reservoir fluid are generated by several correlations provided by CMG simulator which is summarized in Table 4.3 and parameters used for initial input in this study are summarized in the Table 4.4. Figure 4.4 to Figure 4.7 illustrate generated PVT properties which are formation volume factor (B_o) as a function of pressure, oil viscosity as a function of pressure, oil viscosity as a function of temperature and gas-oil ratio as a function of pressure, respectively. For those properties that are function with pressure, blue color line is used in this study which is for STAR program (the red color line is for IMEX program).

Table 4.3 Summary of correlations used to generate PVT functions

Parameters	Correlation
Oil properties (Pb, Rs, Bo) and gas critical properties	Standing
Oil compressibility	Glaso
Dead oil viscosity	Ng and Egbogah
Live oil viscosity	Beggs and Robison

Table 4.4 Input parameters for to generate PVT functions

Parameters	value	Unit
Oil gravity	20	°API
Gas gravity	0.7	-
bubblepoint pressure	1150	psi
Reservoir Temperature	118.94	°F
Reservoir pressure	1622	psi
Surface temperature	62.33	°F
Surface pressure	14.7	psi

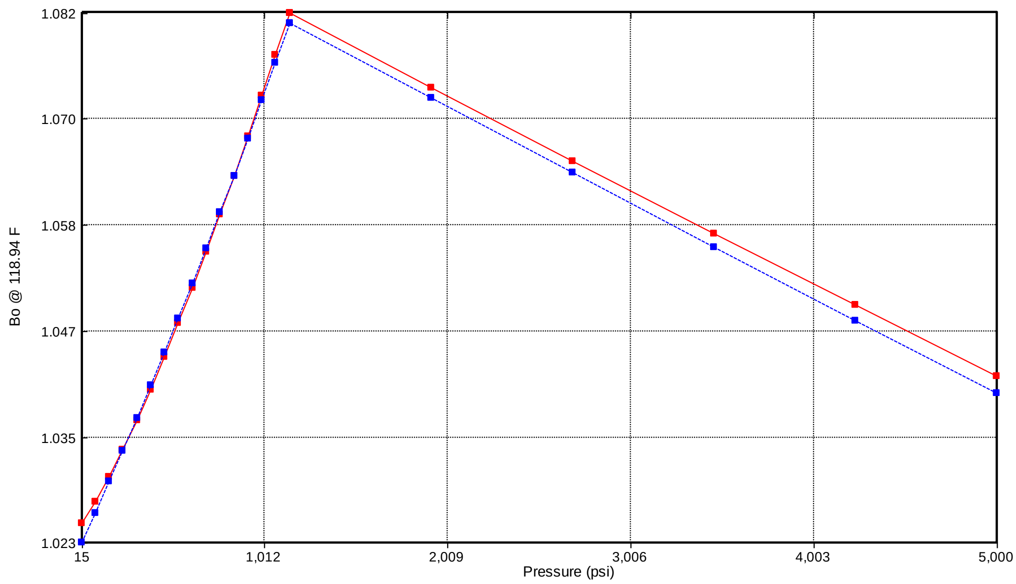


Figure 4.4 Oil formation volume factor (B_o) as a function of pressure

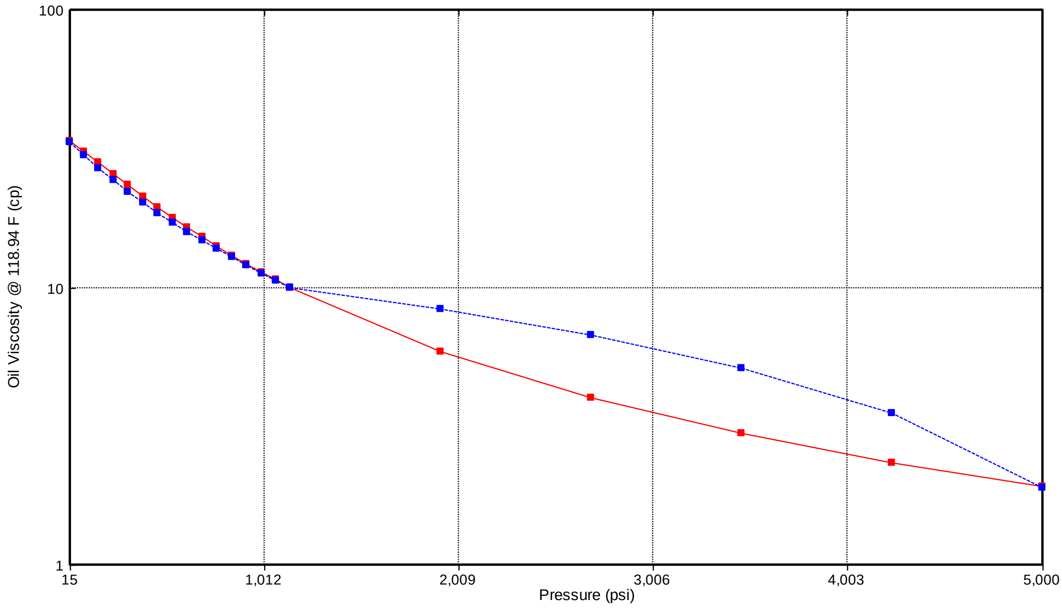


Figure 4.5 Oil viscosity (μ_o) as a function of pressure

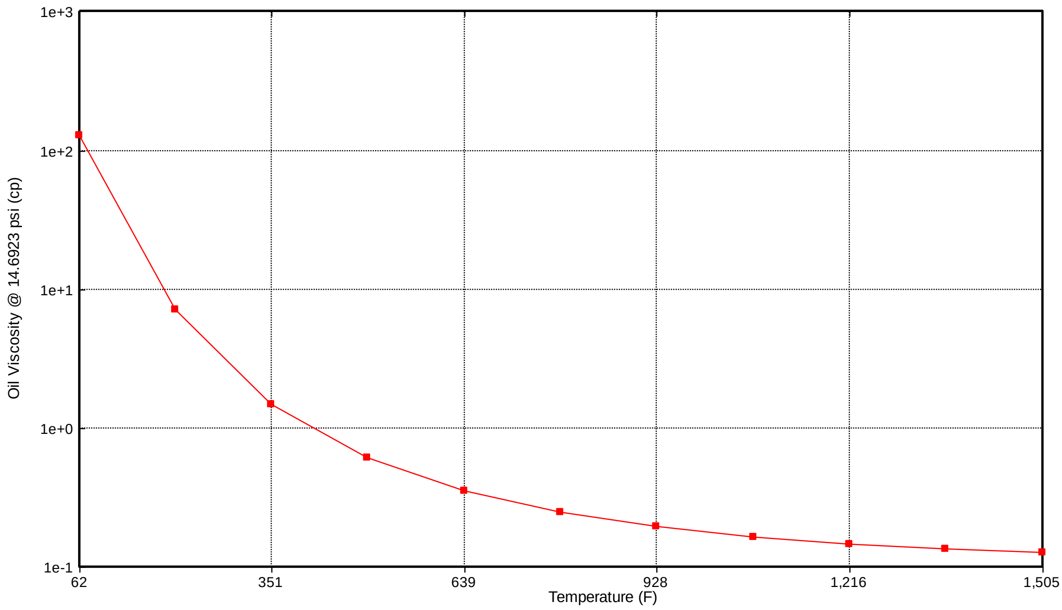


Figure 4.6 Oil viscosity (μ_o) as a function of temperature

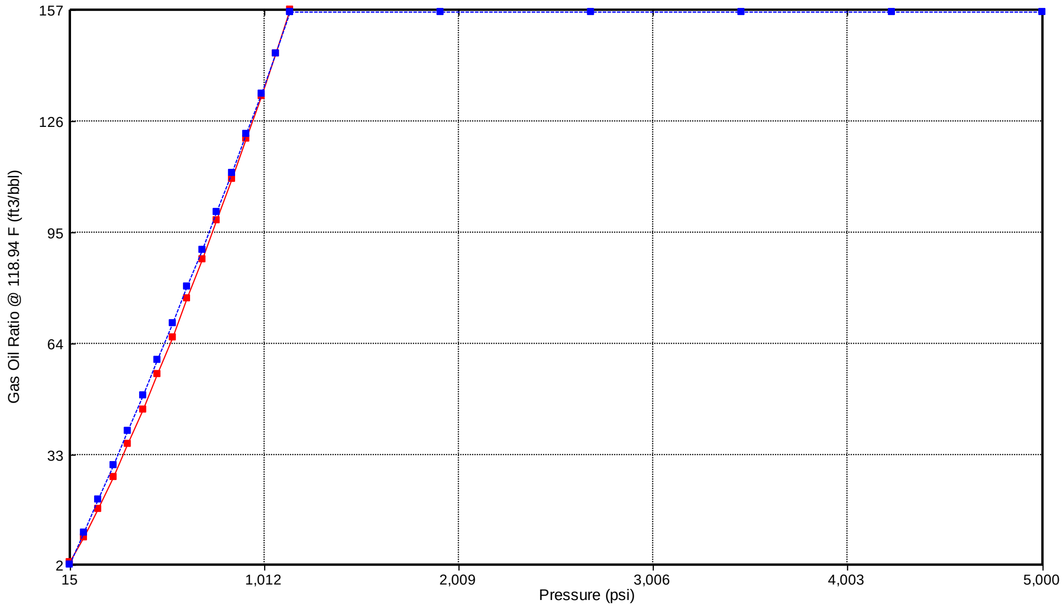


Figure 4.7 Gas/Oil ratio (R_s) as a function of pressure

This study excludes an effect of salinity disturbance on polymer solution to clearly present an effect of residual resistance factor and sequential scheme of polymer flooding. It can be assumed that salinity of formation water is not as high as it could cause chemical instability. PVT properties of formation water are shown in Table 4.5

Table 4.5 PVT properties of formation water

Property	value	unit
Referenc pressure (P_{ref})	1622	psi
Formation Volume Factor (B_W)	1.00562	rb/stb
Compressibility (C_W)	3.01×10^{-6}	psi^{-1}
Viscosity (μ_w)	0.621428	cP
Water salinity	0	ppm

Dry gas is absent from the start of flooding process. However, since injectivity of polymer is quite low compared to water, gas is liberated adjacent to the production well due to rapid decline of reservoir pressure. Formation volume factor of dry gas (B_g) and gas viscosity (μ_g) are illustrated in Figure 4.8 and Figure 4.9 respectively.

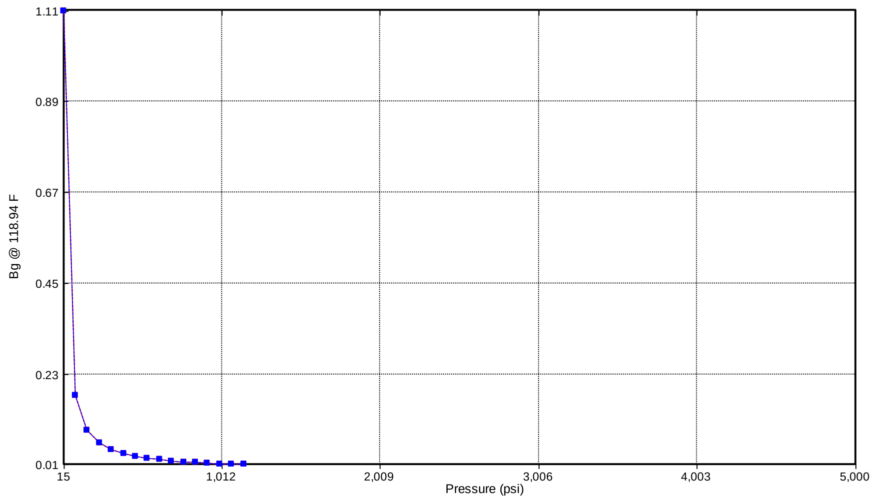


Figure 4.8 Formation volume factor of dry gas (B_g) as a function of pressure

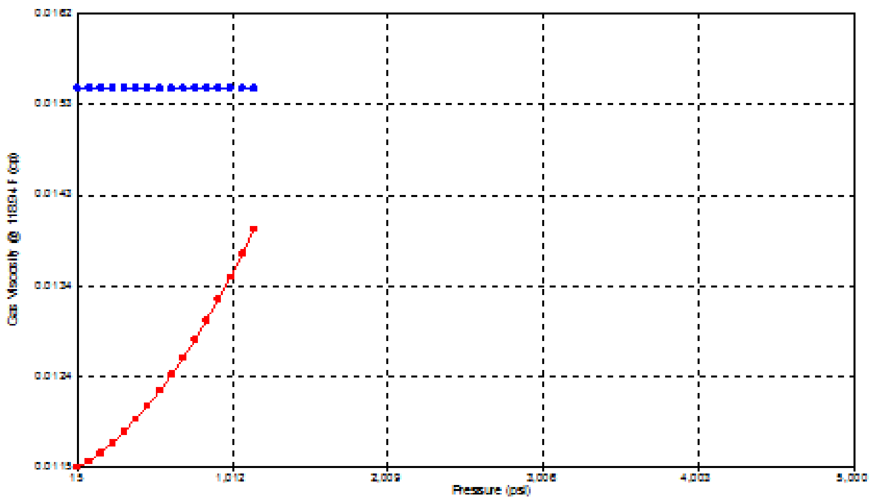


Figure 4.9 Gas viscosity (μ_g) as a function of pressure

4.4 Petrophysical Properties

Since oil, gas and water can be found in any location of reservoir, three-phase permeability is created from Stone II model, constructed from oil-water permeability system and gas-liquid permeability system. Corey's correlation is used to generate two-phase relative permeability to theoretically match water-wet condition. Input data required for generating relative permeability curves is summarized in the Table 4.66. Figure 4.10 and 4.11 illustrate oil-water and gas-liquid relative permeability systems, respectively.

Table 4.6 Summary of input data used for generating relative permeability curves

Parameters	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 - 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

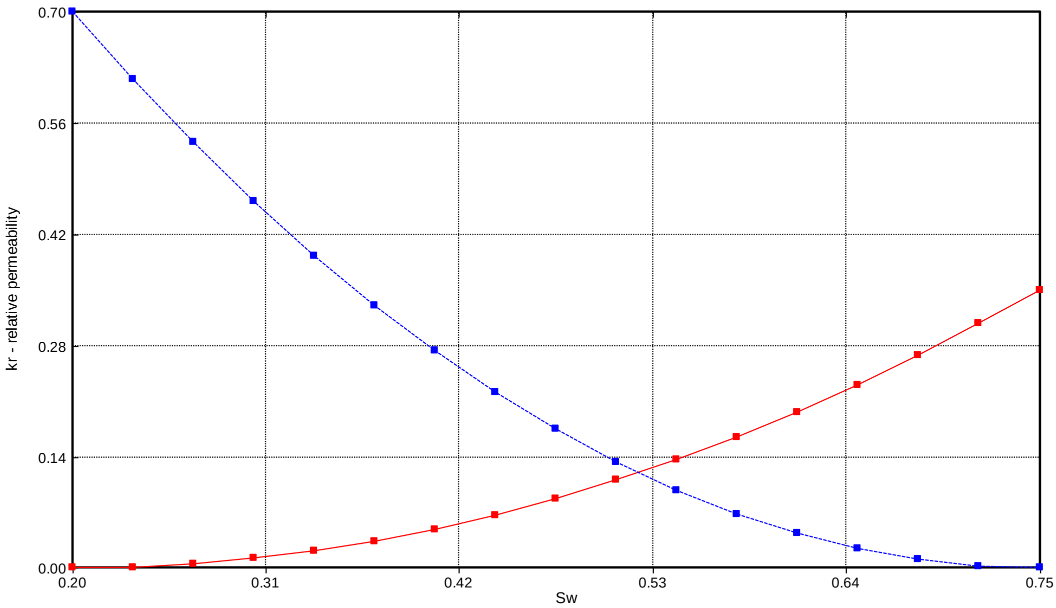


Figure 4.10 Relative permeability of oil-water system as a function of water saturation

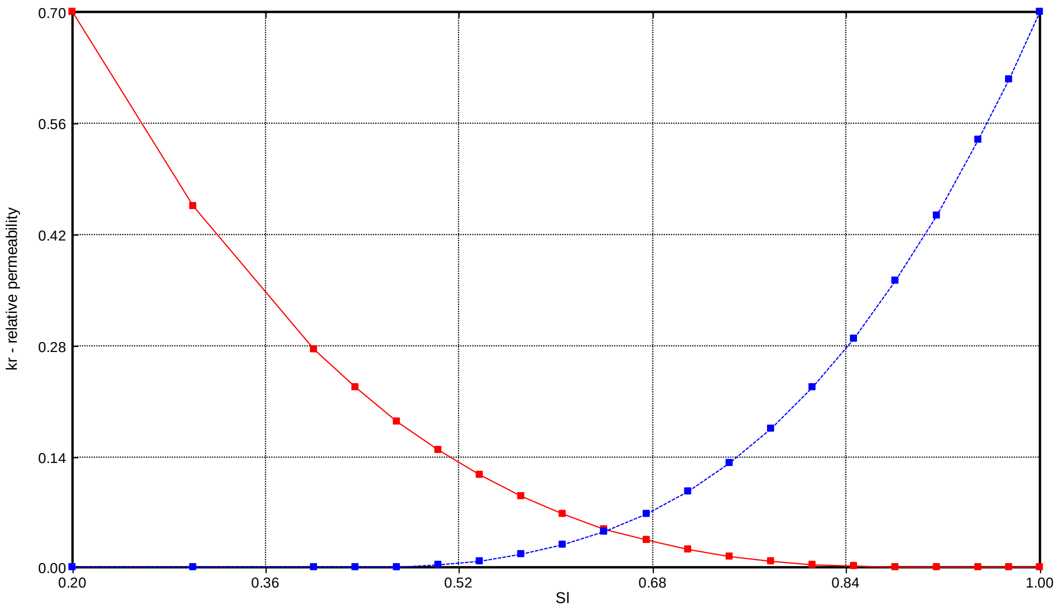


Figure 4.11 Relative permeability of gas-liquid system as a function of liquid saturation

4.5 Polymer Properties

In this study, polymer properties are based on commercial hydrolyzed polyacrylamide polymer (HPAM) called Flopaam 3330S. Flopaam 3330S has a moderate molecular weight of 8 million Daltons with degree of hydrolyzation ranging in between 25 and 30%. Apparent viscosity of polymer solution can be calculated by multiplying water viscosity to viscosity multiplier shown in Table 4.7 which is an exponential function of polymer concentration as illustrated in Figure 4.12. Inaccessible pore volume is assumed to be constant of 15 percent which is a typical value of this polymer molecular size. Since temperature is not too high to cause polymer degradation, polymer half-life is therefore neglected in this study.

Table 4.7 Viscosity multiplier and apparent viscosity as a function of polymer concentration [17]

Polymer concentration, (% wt)	Viscosity multiplier	Viscosity (cp)
0	0	0.621428
0.05	4.4	2.7342832
0.1	12	7.457136
0.2	44	27.342832
0.3	130	80.78564

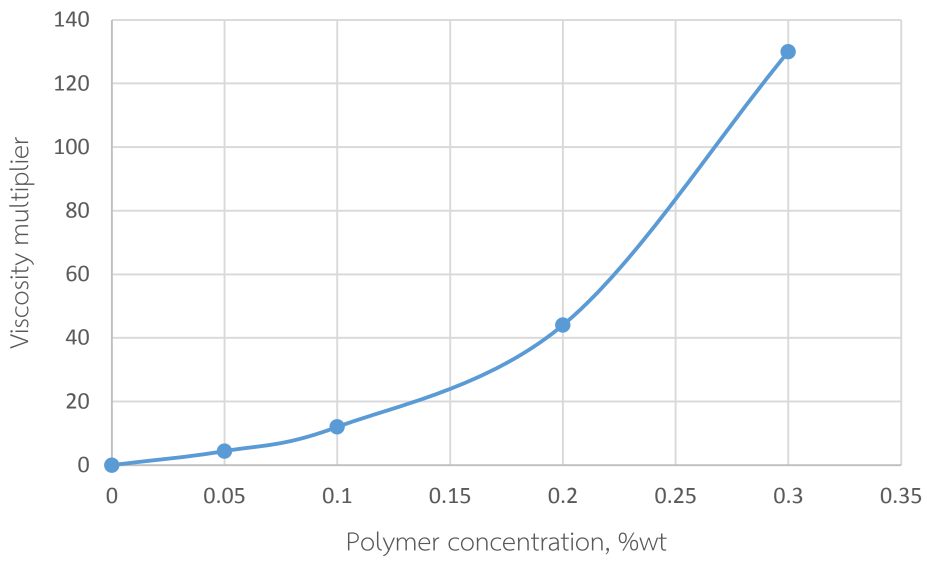


Figure 4.12 Relation of viscosity multiplier as a function of polymer concentration

Polymer adsorption is considered as irreversible process. Polymer adsorption function is summarized in Table 4.8. At low concentration, polymer adsorption is proportional to polymer concentration. Since polymer adsorption is not performed in this study, adsorption function is based on relevant literature in which adsorption of Floppam 3330S was experimented under various conditions

Table 4.8 *Viscosity multiplier and apparent viscosity as a function of polymer concentration [18]*

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

4.6 Well Specification & Injection and Production Constrains

In this study, wellbore radius of producer and injector are both 0.25 ft which is corresponded to bit diameter of 6 inches. Injector and producer are diagonally located at the corners of reservoir model and both are fully perforated throughout reservoir thickness. Limitations for injector are maximum surface liquid injection rate that corresponds to maximum surface liquid production rate and maximum bottomhole pressure which corresponds to fracture pressure calculated by Ben-Eaton equation [19] where

$$\frac{P_{FF}}{D} = \frac{\nu}{1-\nu}\left(\frac{\sigma_{ob}}{D} - \frac{P_F}{D}\right) + \frac{P_F}{D} \qquad 4.3)$$

where

$\frac{P_{FF}}{D}$	=	Fraction pressure gradient, psi/ft
$\frac{\sigma_{ob}}{D}$	=	Overburden pressure gradient, psi/ft
$\frac{P_F}{D}$	=	Reservoir pressure gradient, psi/ft
ν	=	Poisson's ratio

Typical overburden and Poisson's ratio are used [20] to calculate fracture pressure gradient in this study. Constraints for producer are minimum bottomhole pressure and maximum surface liquid production rate and economic constraints are minimum surface oil rate and water cut. Simulation is automatically terminated if any economic constrains is reached or total production period reaches the concession period of 30 years. All constrains for producer and injector are summarized in Figure 4.9 and Figure 4.10, respectively.

Table 4.9 Well constrains for producer

Parameter	Limit/Mode	Value	Unit
surface liquid rate, STL	Max	400	bbl/day
bottomhole pressure, BHP	Min	200	psi
water-cut, WCUT		0.9	
surface oil rate, STO	MIn	25	bbl/day

Table 4.10 Well constrains for injector

Parameter	Limit/Mode	Value	Unit
surface liquid rate, STW	Max	400	bbl/day
bottomhole pressure, BHP	Max	2,100	psi

4.7 Thesis Methodology

Thesis methodology is described in this section. At the end of this section, flowchart summarizing all steps in this study is shown in Figure 4.13.

1. Construct heterogeneous reservoir models with different Lorenz coefficients of 0.20, 0.24 and 0.275 with coarsening upward sequence.
2. Perform waterflooding process on three different Lorenz coefficient models to obtain simulation data and use them as references to compare with single slug polymer flooding and sequential polymer flooding.
3. Perform single slug polymer flooding to all generated models with different operating parameters as well as various residual resistant factors (R_{RF} equals to 1.5, 2, and 2.5) to select operating parameters that meet requirements. The major criteria to selecting operating parameters are oil recovery factor, oil recovered per polymer consumed, water production and total production period, respectively. Selected operating parameters in this study are:
    - Pre-injected water slug size (0.00, 0.04, and 0.08 PV)
    - Polymer slug size (0.2, 0.25, and 0.3 PV)
    - Polymer concentration (500, 750, and 1,000 ppm),
4. Perform a sequential polymer flooding with different schemes of concentration profile to select the best scheme for different residual resistant factors that meets requirement for. In this step, amount of polymer used in sequential flooding scheme is kept equal to amount of

polymer used in the best single slug scheme to be able to compare between sequential polymer flooding and single slug polymer flooding.

5. Compare and analyze simulation outcomes between single-slug polymer flooding with sequential polymer flooding for production performance.
6. Conclude new findings based on thesis objectives and provide recommendations for further study.

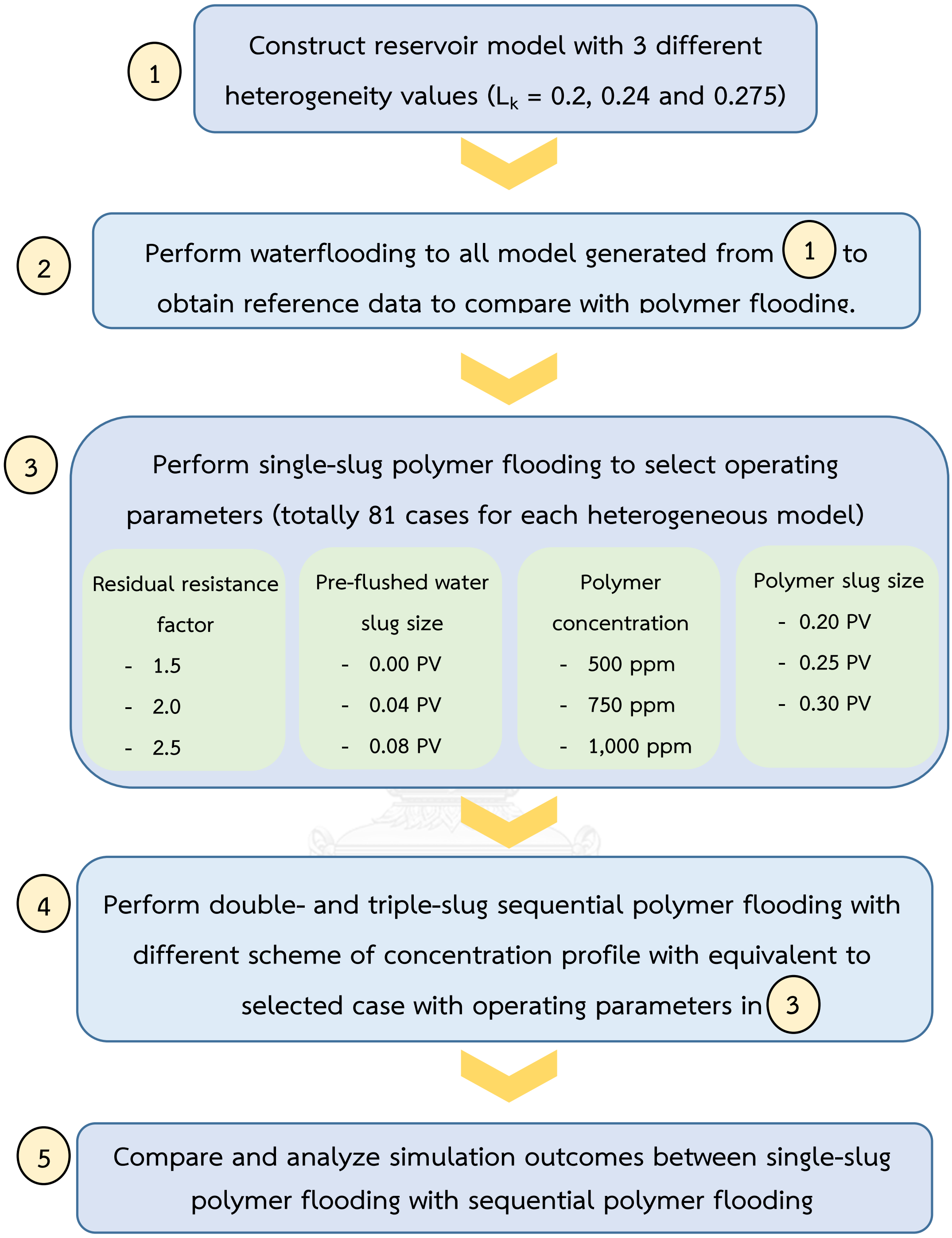


Figure 4.13 Methodology diagram in this study

CHAPTER V

SIMULATION RESULTS AND DISCUSSION

Once multi-layered heterogeneous reservoir models are constructed with different Lorenz coefficients, waterflooding is performed as a reference case. After that, selection of operating parameters for single-slug polymer flooding including pre-flushed water, polymer concentration and polymer slug size, is performed on every model with different value of residual resistance factor. Thereafter, to investigate effects of sequential polymer flooding, double-slug and triple-slug sequential polymer flooding are performed by controlling amount of polymer used as in case of single-slug polymer flooding. In this chapter, discussion and analyze of all simulation results are performed by subdividing into five sections which are:

5.1 Comparison between waterflooding and polymer flooding,

5.2 Selection of single-slug polymer flooding base case,

5.3 Double slug sequential polymer flooding,

5.4 Triple slug sequential polymer flooding,

5.5 Effect of reservoir heterogeneity.

5.1 Comparison of Waterflooding and Polymer Flooding.

5.1.1 Waterflooding

Waterflooding is simulated as a reference case to compare results with all simulation cases. In this section, result from model with Lorenz coefficient of 0.2 is used for explanation. Waterflooding is performed from the first day of production until one of production constrains is reached. Water injection rate, oil and water production rates, bottomhole pressure of production well, oil recovery factor and cumulative water production are illustrated in Figure 5.1 to Figure 5.4. Water saturation profile showing arrival of water breakthrough is depicted in Figure 5.5.

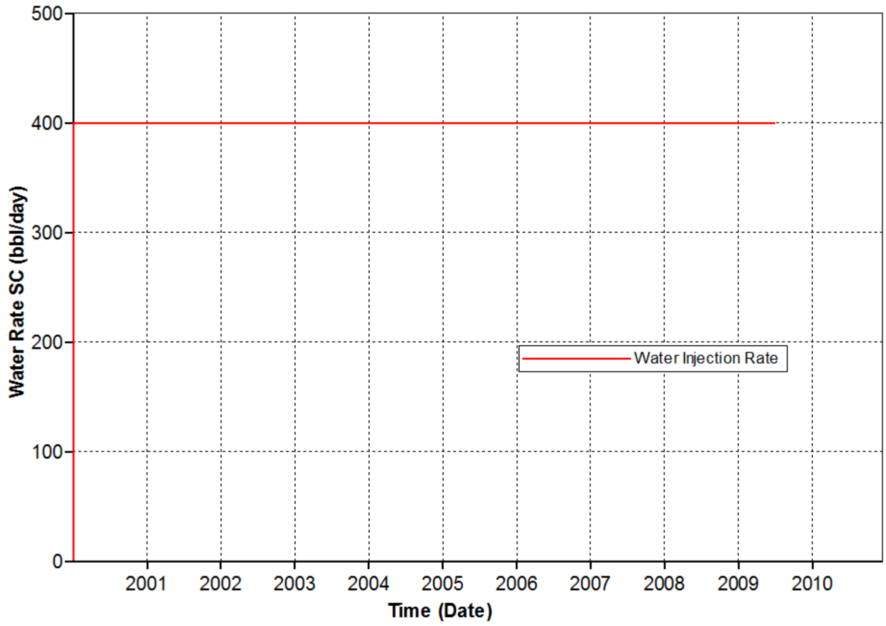


Figure 5.1 Water injection rate of waterflooding case as a function of time

Figure 5.1 illustrates actually water injection rate at injection well. The figure shows that, injection rate reaches 400 bbl/day which is the desired rate from the first day of injection.

Figure 5.2 depicts oil and water production rates obtained from waterflooding process. In early stage of production, oil production rate can be maintained at desired rate of 400 bbl/day for eight months. After that, oil rate starts to decline due to insufficient pressure support from injection well. Oil production rate starts to remarkably decrease around one and half year after starting of production due to water breakthrough as can be seen from abrupt increment of water production rate at the same time. Water production rate continues to increase, resulting in less amount of oil being produced. Production is then terminated once watercut reaches a constraint of 0.9.

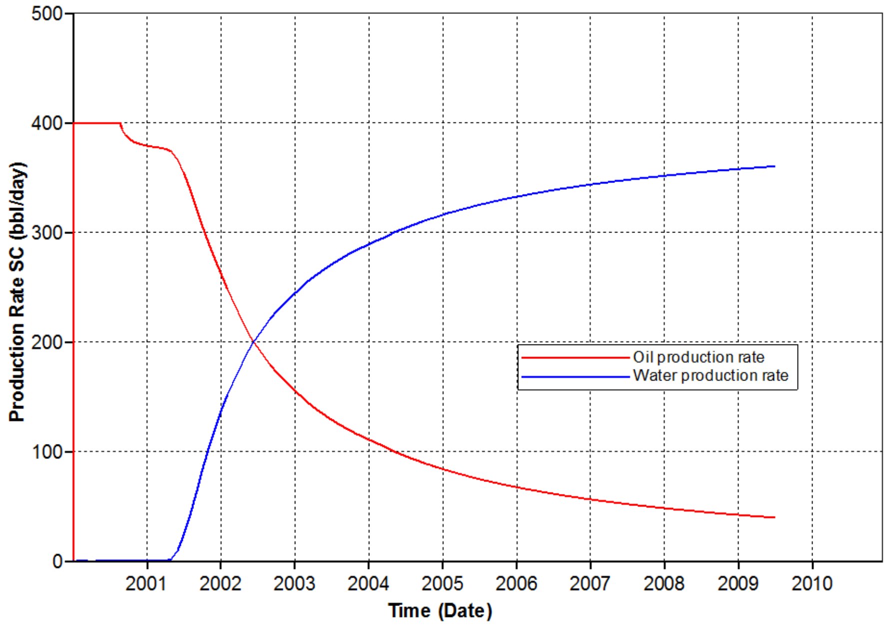


Figure 5.2 Oil and water production rate of waterflooding case as a function of time

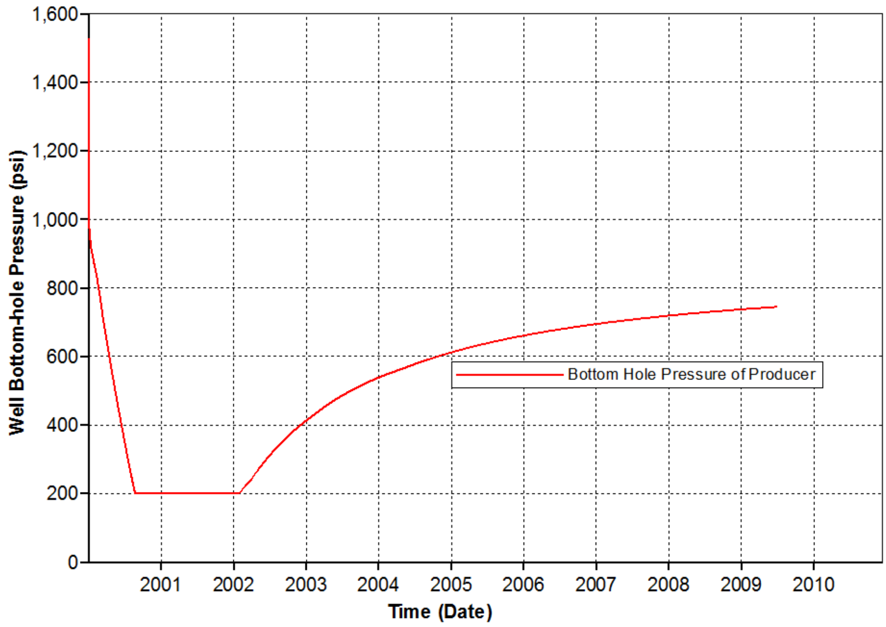


Figure 5.3 Bottomhole pressure of production well of waterflooding case as a function of time

As explained in Figure 5.2 that there is a period where production well suffers from insufficient support from injected water, the evidence is illustrated in Figure 5.3. Bottomhole pressure at production well is reduced to maintain constant production rate due to insufficient reservoir pressure. Nevertheless, bottomhole pressure cannot be lower than 200 psi which is related to production design of the well. Hence, there is period where bottomhole pressure is constant at this minimum value. Once effect from injected water arrives to production well, reservoir pressure is raised and this results in increment of bottomhole pressure to attain desired production rate.

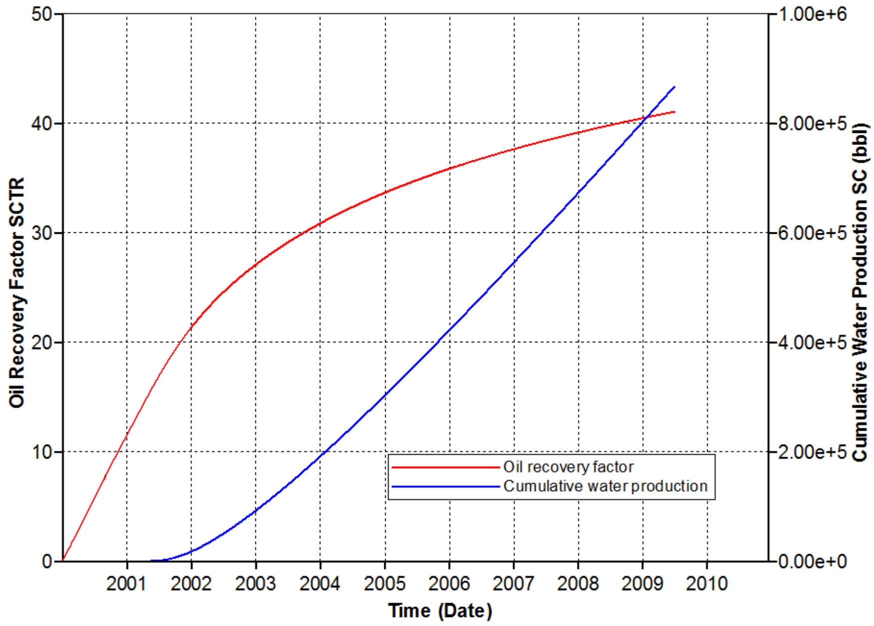


Figure 5.4 Oil recovery factor and cumulative water production of waterflooding case as a function of time

With total production period of 9.5 years, waterflooding process yields recovery factor of 41.06% with total water production of 867.8 Mbbl as illustrated in Figure 5.4. Figure 5.5 shows arrival of water at water breakthrough using water saturation profile. From the figure, early breakthrough of water occurs in upper layer (light blue color) where absolute permeability is the highest. It can be expected that more than half of oil, that is not produced, remains in the bottom layers due to low permeability at the bottom locations.

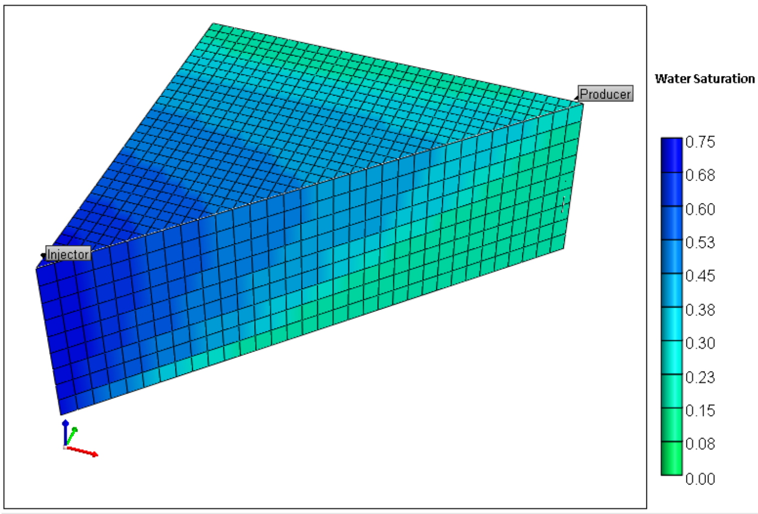


Figure 5.5 Water saturation profile at period of water breakthrough (top layer) in waterflooding case.

5.1.2 Polymer Flooding

After waterflooding is performed in previous section, single-slug polymer flooding is first studied to evaluate an effectiveness of single-slug polymer in comparison with waterflooding. In order to illustrate mechanism of single-slug polymer flooding, simulation is performed on the same heterogeneous model with L_k of 0.20. The example case utilizes polymer concentration and polymer slug size of 750 ppm and 0.25 pore volume (PV). The case contains no pre-flushed water and maximum residual resistance factor is 2. Production constraints are as same as waterflooding case and termination of production occurs when one of production constrains is attained.

At this concentration, viscosity multiplier equals to 7.267 whereas relative permeability to water for polymer flooding case is less than 1.75 times compared to waterflooding case for whole range of saturation as a result of polymer adsorption. The reason that reduction of relative permeability does not equal to 2 as desired residual resistance factor value is explained in section 5.2.2. Combining with mobility ratio equation shown in section 3.1, mobility ratio of polymer flooding case is less than waterflooding cases of about 12.7 times, resulting in more favorable for displacement mechanism. Calculation of mobility ratio for waterflooding over polymer flooding case is illustrated in this section.

$$\frac{M_{waterflooding}}{M_{polymer\ flooding}} = \frac{\lambda_w}{\lambda_o} \times \frac{\lambda_o}{\lambda_{wp}} = \frac{\lambda_w}{\lambda_{wp}}$$

$$= \frac{k_{rw}}{\mu_w} \times \frac{\mu_{wp}}{k_{rwp}}$$

$$= \frac{k_{rw}}{\mu_w} \times \frac{7.267\mu_w}{\frac{1}{1.75}k_{rw}} = 12.72$$

However, this calculation is based on two assumptions which are 1) polymer viscosity is constant and 2) reduction of relative permeability to water is constant. In fact, polymer viscosity is decreased due to adsorption process whereas reduction of relative permeability to water in the model is not uniform due to adsorption process as well.

Figure 5.6 represents actual injection rate of polymer solution as a function of time. From the figure, it can be observed that desired rate of 400 bbl/day cannot be obtained due to high viscosity of polymer solution compared to water. Moreover, in a presence of polymer solution, polymer adsorption causes reduction of effective permeability. Both of the reasons result in low injectivity of polymer solution. However, after 0.25 PV of polymer solution is injected, water can be injected as chasing fluid at the desired rate.

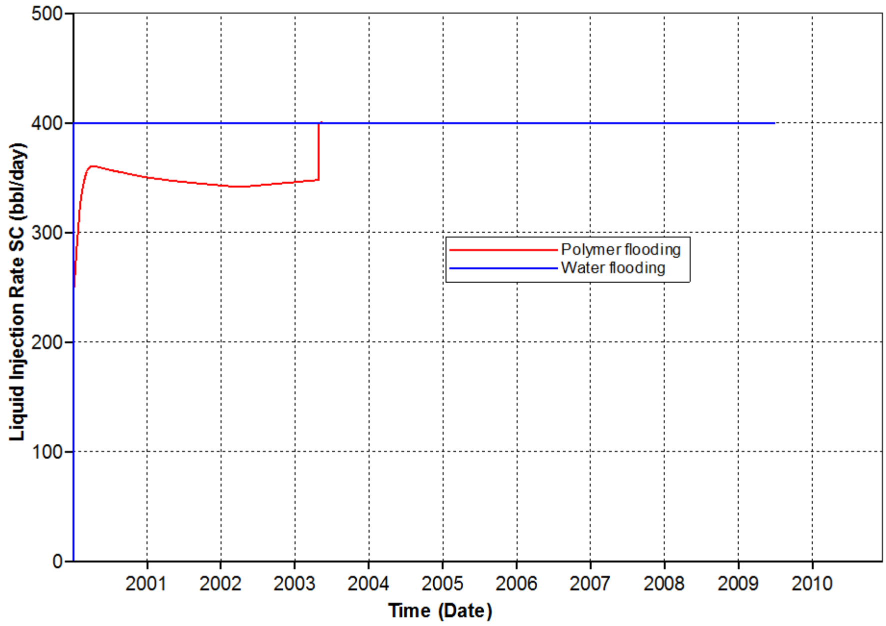


Figure 5.6 Comparison of liquid injection rate between polymer flooding base case and waterflooding

Figure 5.7 illustrated oil and water production rates from polymer flooding case. In early stage, oil production rate of single-slug polymer flooding declines earlier compared to waterflooding case due to slower pressure support from injected fluid caused by low injectivity of polymer solution. As similar as waterflooding case, evidence is observed from bottomhole pressure of production well shown in Figure 5.8 but minimum bottomhole pressure is maintained for longer time in polymer flooding case due to much slower pressure effect from injected fluid. However, more favorable mobility ratio provided by polymer solution which is effects of high viscosity of polymer solution and reduction of water relative permeability helps to delay water breakthrough. Declination of oil production rate is also reduced compared to waterflooding case as water breakthrough problem is mitigated.

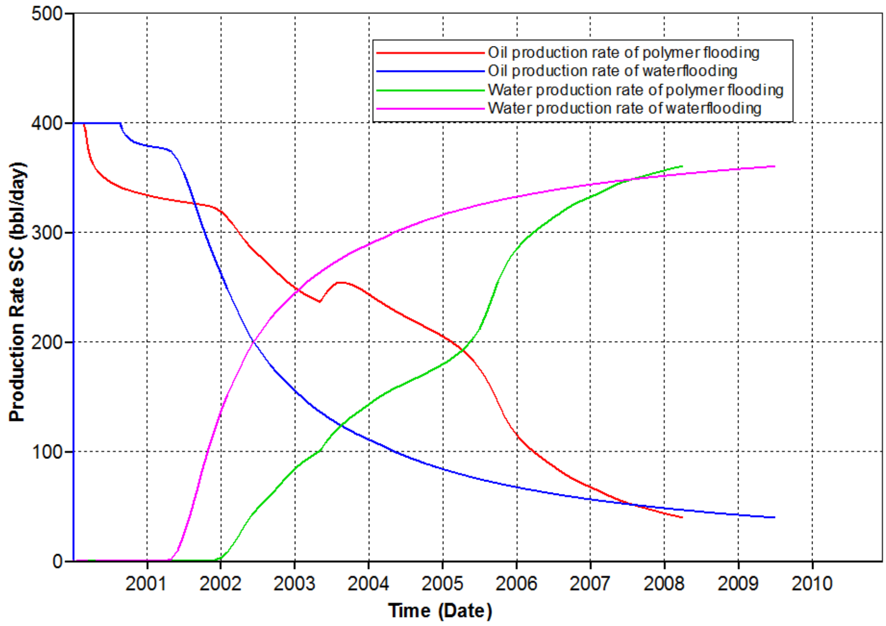


Figure 5.7 Comparison of oil and water production rates between polymer flooding and waterflooding

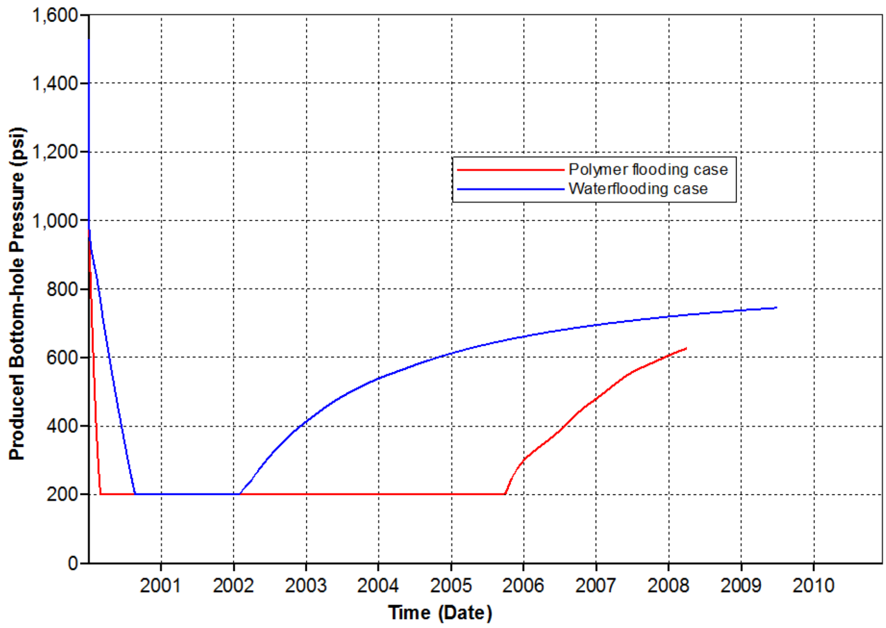


Figure 5.8 Comparison of bottomhole pressure of production well between polymer flooding and waterflooding

In case of polymer flooding, first water breakthrough reaching production well comes from polymer solution that gradually loses polymer mass due to polymer adsorption on to the surface rock. Consequently, this polymer solution becomes water.

Figure 5.9a demonstrates polymer adsorption profile which represents location where polymer exists since polymer adsorption is a function of polymer concentration. This figure shows that at that time polymer does not travel far from injection well. In contrast, Figure 5.9b illustrates oil saturation profile at the same day. It can be seen that oil saturation remarkably decreases at the location where there is polymer. Nevertheless, adsorption of polymer tends to decrease at the flood front which can be explained from reduction in concentration. Oil saturation profile also shows that part of oil in top layers of reservoir is also displaced from displacing fluid. Together with explanation earlier, reduction of polymer concentration turns polymer solution into water and this water can travel much faster than polymer solution. Therefore, this water from polymer adsorption tends to breakthrough earlier than the rest of polymer back.

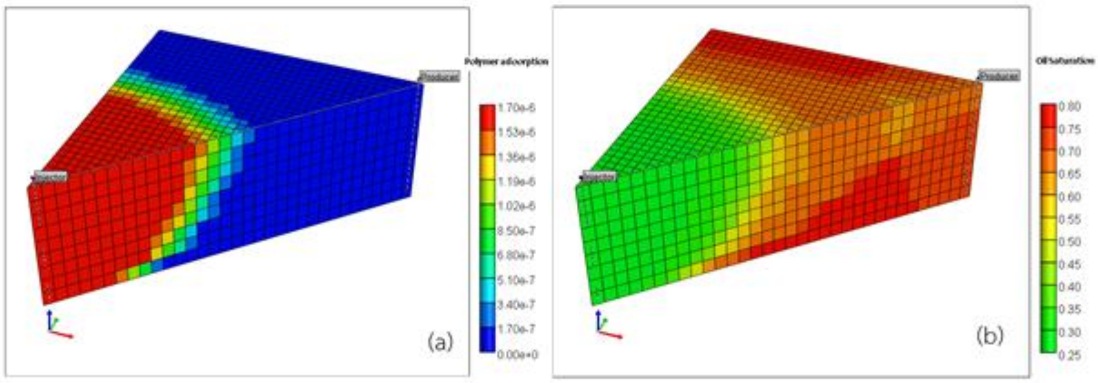


Figure 5.9 a) Polymer adsorption profile and b) oil saturation profile of polymer flooding case at the day of water breakthrough

After water breakthrough oil production rate from polymer flooding case continues to decrease. It can be noticed from Figure 5.7 that oil rate starts to increase again. This can be explained from polymer adsorption profile and oil saturation profile that after water which used to be part of polymer solution breakthrough, oil is left behind since this water results in unfavorable mobility ratio. The following polymer slug therefore, can sweep this remaining oil; forming second high oil saturation bank. Peak of oil rate is caused by arrival of remaining oil supported by pressure support from chasing water. Arrival of remaining oil can be noticed in Figure 5.9b where two high oil saturation banks are separated by low oil saturation bank which is moving water left from polymer adsorption. Water production rate of polymer flooding base case gradually increases until polymer solution and chasing water sweep in high permeability layer and produced, resulting in sharply increment of water production at later period.

With total production period of 8.2 years, example of polymer flooding process yields recovery factor of 51.1 % with total water production of 477.2 Mbbl as illustrated in Figure 5.10. It can be obviously observed that polymer flooding yields much higher oil recovery factor, produces less water and previously mentioned high recovery factor is obtained within shorter period. Figure 5.11 (a) and (b) and Figure 5.12 (a) and (b) compare oil saturation profiles at the last day of production obtained between waterflooding and polymer flooding case. These figures remarkably show that the use of polymer solution can greatly improve both areal sweep efficiency and vertical sweep efficiency.

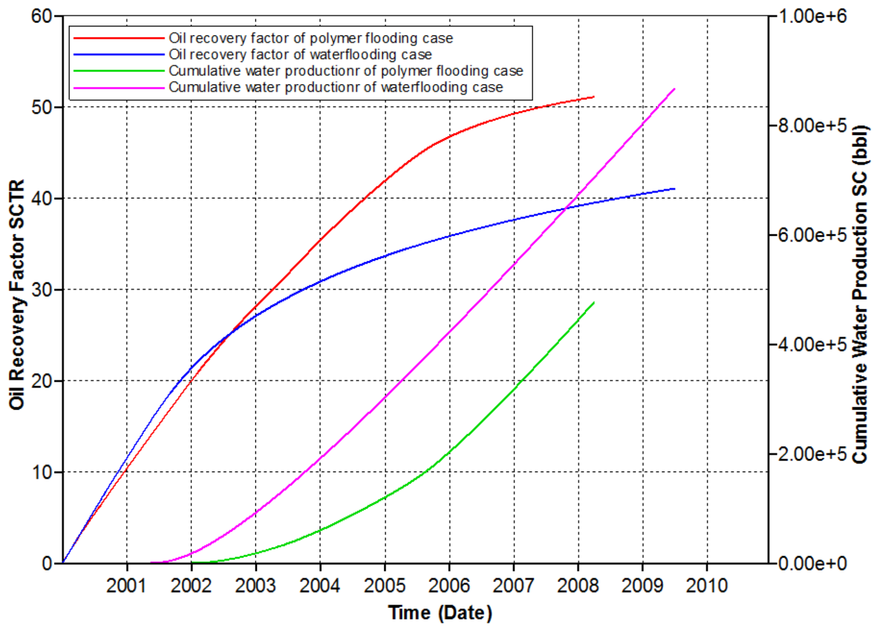


Figure 5.10 Comparison of oil recovery factor between polymer flooding case and waterflooding case as a function of time

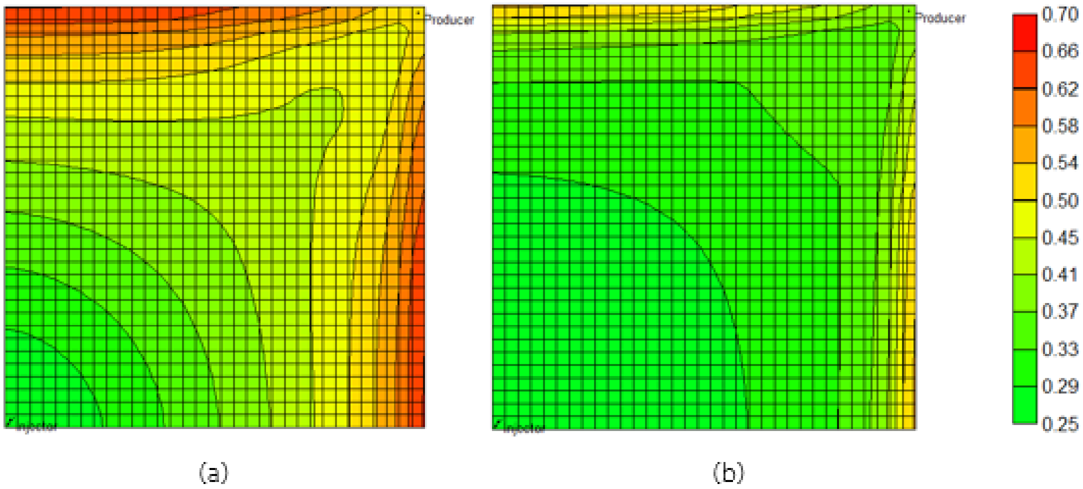


Figure 5.11 Oil saturation profile from top view of a) waterflooding case and b) polymer flooding case at the end of production

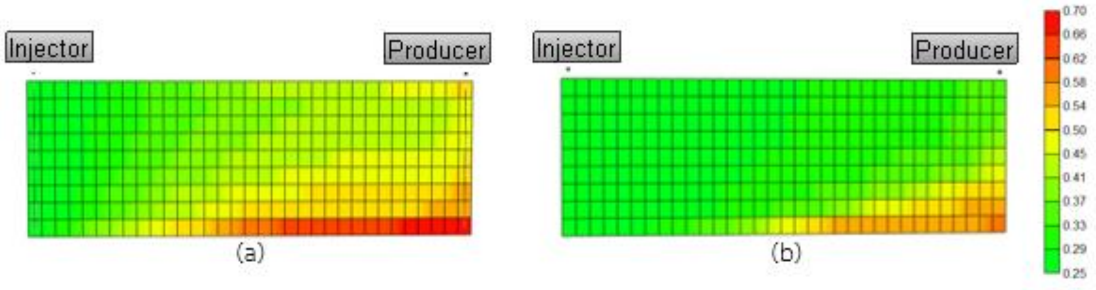


Figure 5.12 Oil saturation profile from side view of a) waterflooding case and b) polymer flooding case at the end of production

Nevertheless, this result does not include effects of shear thinning behavior of polymer solution. In fact, viscosity of polymer solution is aggravated when polymer solution is subjected to a high shear rate during the injection process, especially in the area adjacent to the injector where polymer solution is forced to penetrate through formation with high velocity. This high velocity happens only in high permeability zone locating on top of reservoir. However, this phenomenon would not have much effect on oil recovery factor in because when polymer solution travels far from injector, polymer solution will travel at lower velocity as it is distributed throughout the formation. Since, polymer solution is not thermal degraded yet, viscosity is recoverable, returning to high viscosity as original desired value. Then, favorable mobility is still attained in the area far from an injector. Therefore, effect of shear-rate-dependent viscosity is only an increase of injectivity of polymer solution which should result in shortening production period. However, this does not have much effect on an oil recovery factor at the end of production.

5.2 Selection of Single-slug Polymer Flooding Base Case

To evaluate effectiveness of sequential polymer flooding, single-slug polymer flooding is firstly performed to select operating parameters including pre-flushed water slug size, polymer concentration and polymer slug size for different residual resistance factor (usually related to different degree of adsorption). The selection of base case needs to satisfy all judging criteria. In this study, oil recovery factor is a major concerned and hence it is first considered. Without doubt, amount of additional oil recovery per polymer consumed (bbl/ton) cannot be neglected. This reflects to efficiency of the process and it is a second consideration. Water production and total production period are also included. Oil recovery factor, water production and total production period are direct simulation outcomes, whereas, amount of additional oil recovery per polymer consumed is a processed data, calculated by amount of additional oil produced compared to waterflooding base case. In this section, effects of each operating parameter are firstly discussed to evaluate their effects on production performance. After that, all cases are scored based on judging criteria. Only one case that meets the most criteria for each designed residual resistance factor are selected. All study cases are summarized in Table 5.1

5.2.1 Effect of Pre-flushed Water Slug Size

In order to increase injectivity of polymer solution, a slug of pre-flushed water is pre-injected prior to polymer slug. Slug size of pre-flushed water is varied based on water breakthrough time from zero PV (no pre-flushed water) to 0.08 PV. Thereafter, polymer solution with different concentrations and slug sizes are injected and chased by water again. This section emphasizes on effect of pre-flushed water on performance of single-slug polymer flooding.

First, actual injection rate of polymer slug size of 0.25PV, residual resistance factor of 2.0 and various concentrations of 500, 750 and 1,000 ppm are illustrated in

Figure 5.13 to Figure 5.15, respectively. Each figure shows actual injection rates as a function of production time for different pre-flushed water slugs. The results show that in case of having pre-flushed water, polymer solution can be injected at higher rate than the case without polymer solution. Pre-flushed water displaces part of high oil around injector, pushing oil toward producer. Once oil saturation around the wellbore is reduced, polymer can be easily injected. However, the benefit is more obvious when polymer solution cannot be injected at the desired rate such as in case of polymer concentrations of 750 and 1,000 ppm as shown in Figure 5.14 and Figure 5.15 while in case of polymer concentration of 500 ppm, existing of pre-flushed water slug does not show much benefit as can be seen in Figure 5.13

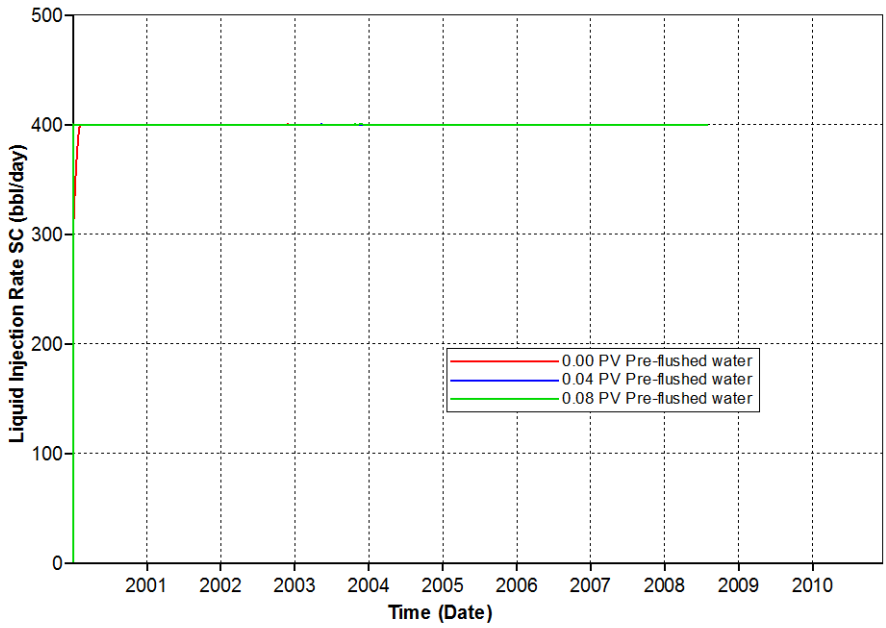


Figure 5.13 Actual liquid injection rates of different pre-flushed water slug sizes for polymer concentration of 500 ppm

Table 5.1 Summary of operating conditions (27 cases for each residual resistance factor)

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)
0	0.2	500
		750
		1,000
	0.25	500
		750
		1,000
	0.3	500
		750
		1,000
0.04	0.2	500
		750
		1,000
	0.25	500
		750
		1,000
	0.3	500
		750
		1,000
0.08	0.2	500
		750
		1,000
	0.25	500
		750
		1,000
	0.3	500
		750
		1,000

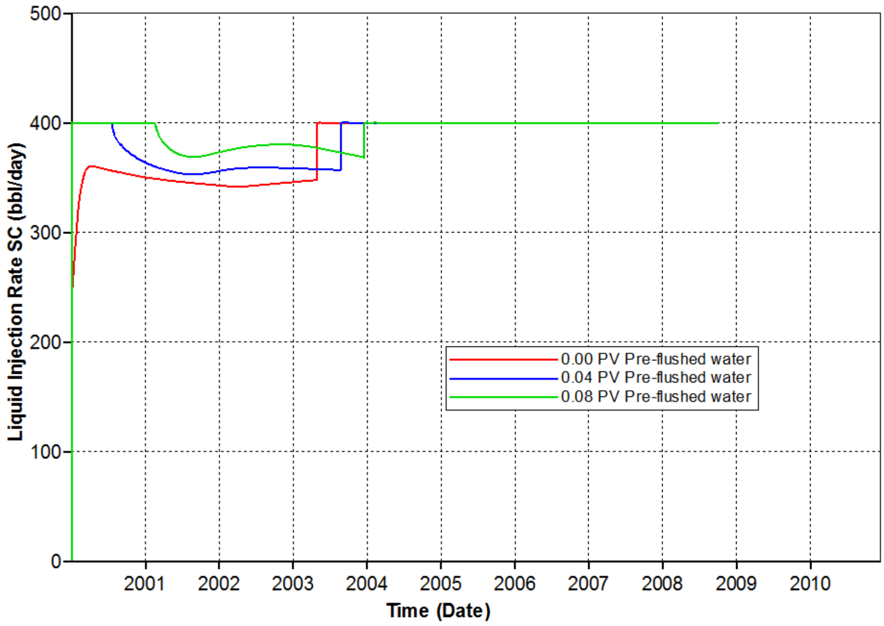


Figure 5.14 Actual liquid injection rates of different pre-flushed water slug sizes for polymer concentration of 750 ppm

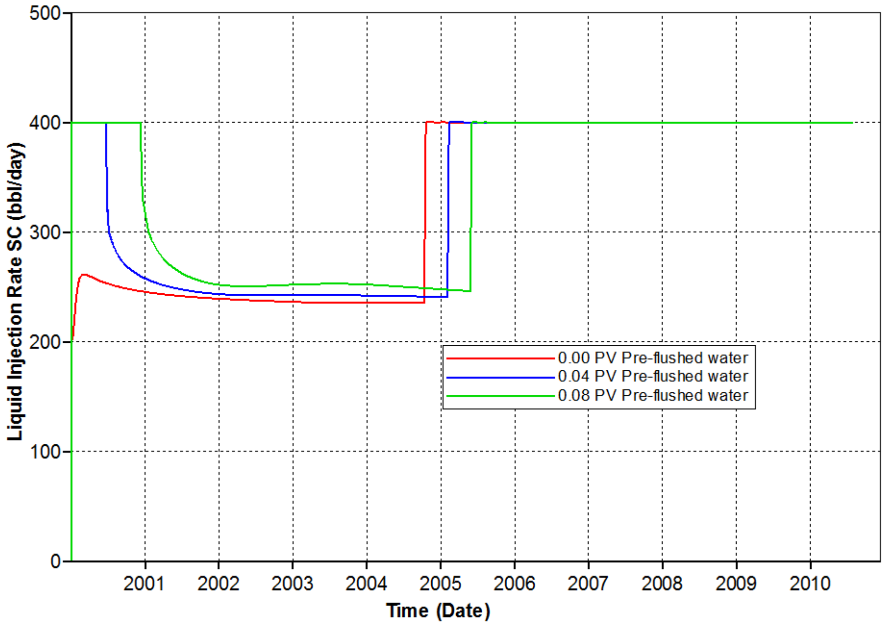


Figure 5.15 Actual liquid injection rates of different pre-flushed water slug sizes for polymer concentration of 1,000 ppm

Since liquid injection rates are varies from case to case, liquid production rate is surely affected. Figure 5.16 to Figure 5.18 demonstrate oil production rates obtained from polymer flooding with different pre-flushed water slug sizes for polymer concentrations of 500, 750 and 1,000, respectively.

Since polymer concentration of 500 ppm can be easily injected in both cases, with and without pre-flushed water, oil production rates can be maintained at desired rate for almost the same period as can be observed from Figure 5.16. Consecutive reduction of oil production rate is due to breakthrough of water. Case with larger pre-flushed water slug sizes corresponds to early reduction of oil rate but the effect of polymer slug comes later.

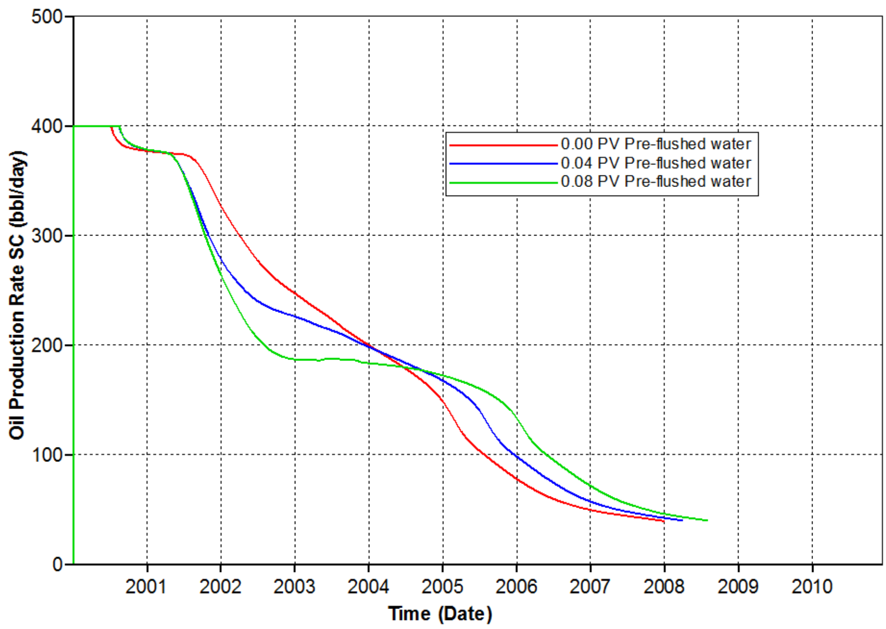


Figure 5.16 Oil production rates of different pre-flushed water slug sizes for polymer concentration of 500 ppm

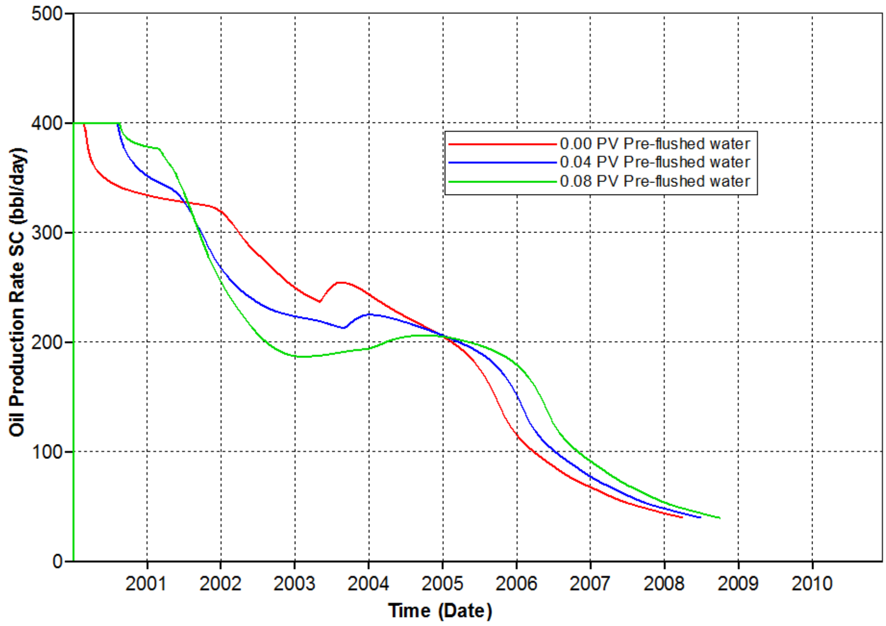


Figure 5.17 Oil production rates of different pre-flushed water slug sizes for polymer concentration of 750 ppm

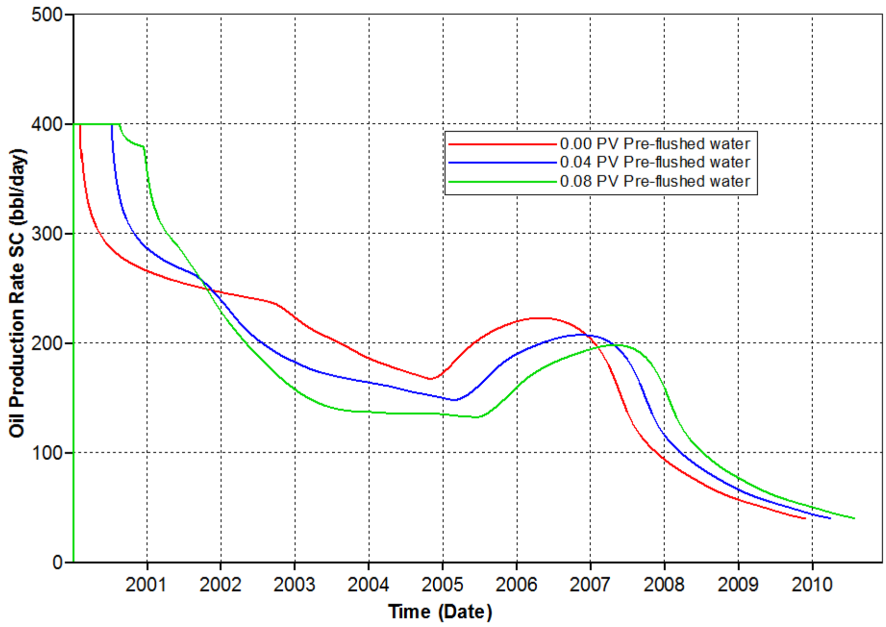


Figure 5.18 Oil production rates of different pre-flushed water slug sizes for polymer concentration of 1,000 ppm

Because of high injectivity of water in early stage of water injection, oil production rate of polymer flooding of cases with pre-flushed water with polymer concentration of 750 and 1,000 ppm are higher than cases without pre-flushed water cases as can be noticed in Figure 5.17 and Figure 5.18. However, in later stage, oil production rate in case without pre-flushed water is much higher due to arrival of remaining oil that cannot be swept by water but is flushed by polymer solution.

Nevertheless, differences in oil recovery between cases with and without pre-flushed water are insignificant since oil that is left from pre-flushed water is still displaced by polymer slug. And since production period is maintained without interruption of termination, removable oil is therefore flushed out. Oil recovery factors of all scenarios are summarized in Figure 5.16.

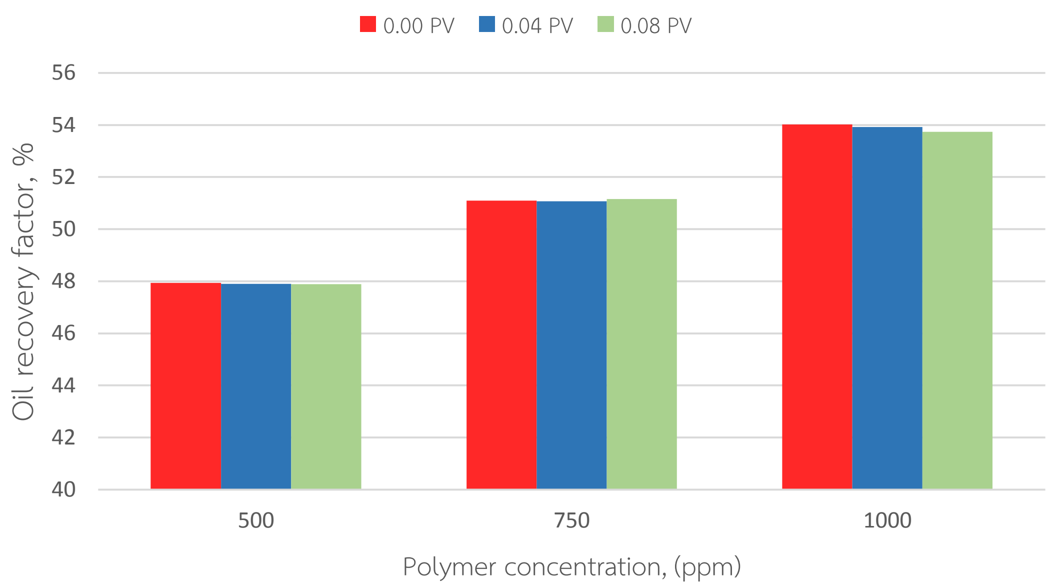


Figure 5.19 Summary of oil recovery factors obtained from polymer flooding with concentration of 500, 750 and 1,000 ppm with different pre-flushed water slug sizes

Presence of pre-flushed water slug causes an early water breakthrough as same as waterflooding. Oppositely, polymer solution can delay water breakthrough as illustrated in Figure 5.20 to Figure 5.22. In addition, total production period in case of polymer flooding with pre-flushed water is extended due to time during pre-flushed water process. Longer production time leads to higher water production. Total water production of polymer flooding with polymer slug size of 0.25 PV, residual resistance factor 2.0 for three different concentrations and different pre-flushed water slug sizes are summarized in Figure 5.23

As can be expected, increasing of pre-flushed water slug size results in increment of water production rate as can be seen from a hump of green lines in Figure 5.20 to Figure 5.22. Additional amount of water results in high water production while oil recovery is almost the same.

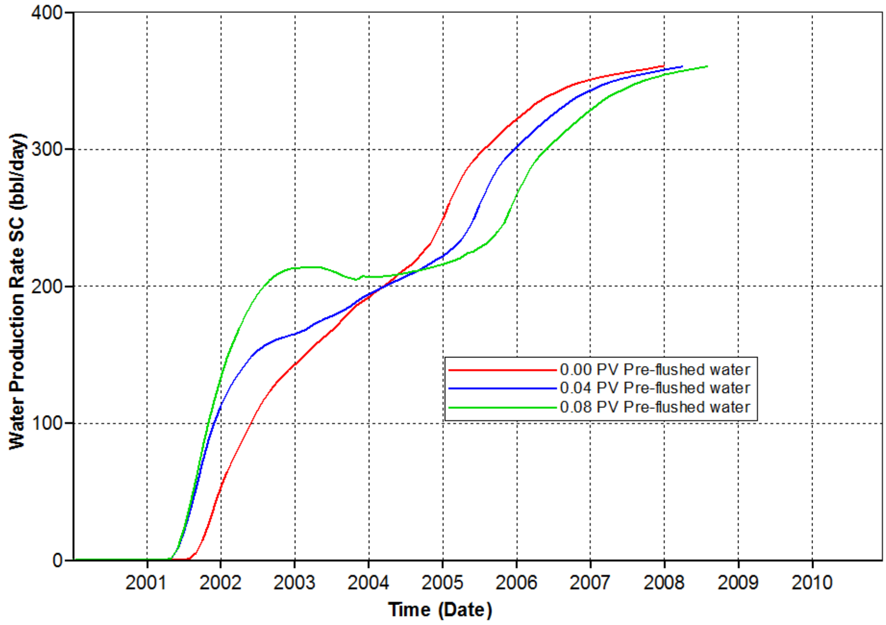


Figure 5.20 Water production rates of different pre-flushed water slug sizes for polymer concentration of 500 ppm

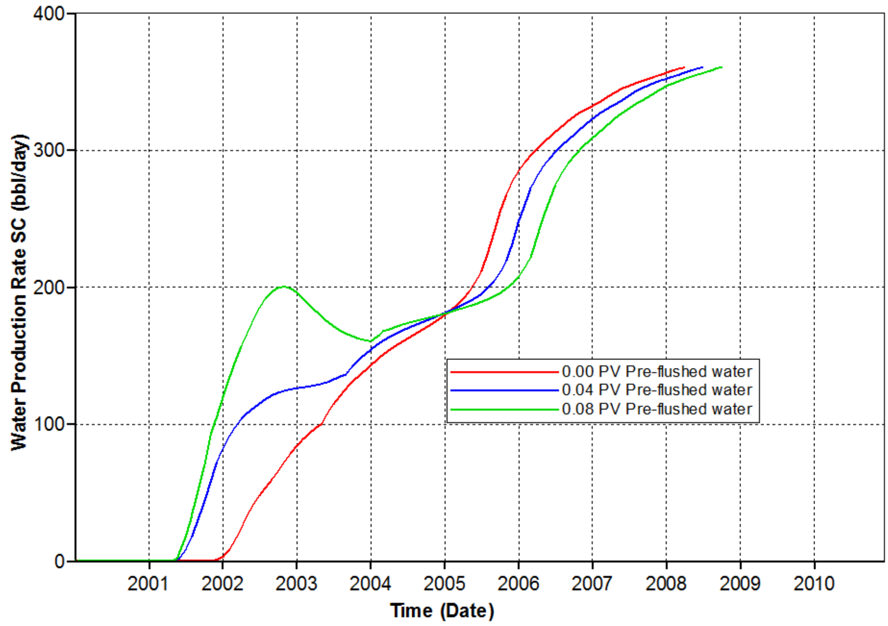


Figure 5.21 Water production rates of different pre-flushed water slug sizes for polymer concentration of 750 ppm

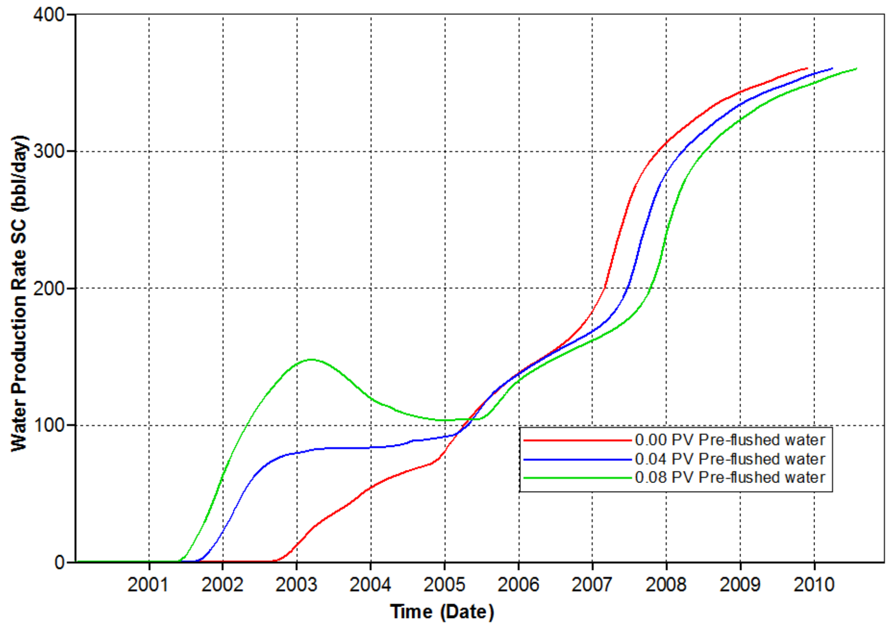


Figure 5.22 Water production rates of different pre-flushed water slug sizes for polymer concentration of 1,000 ppm

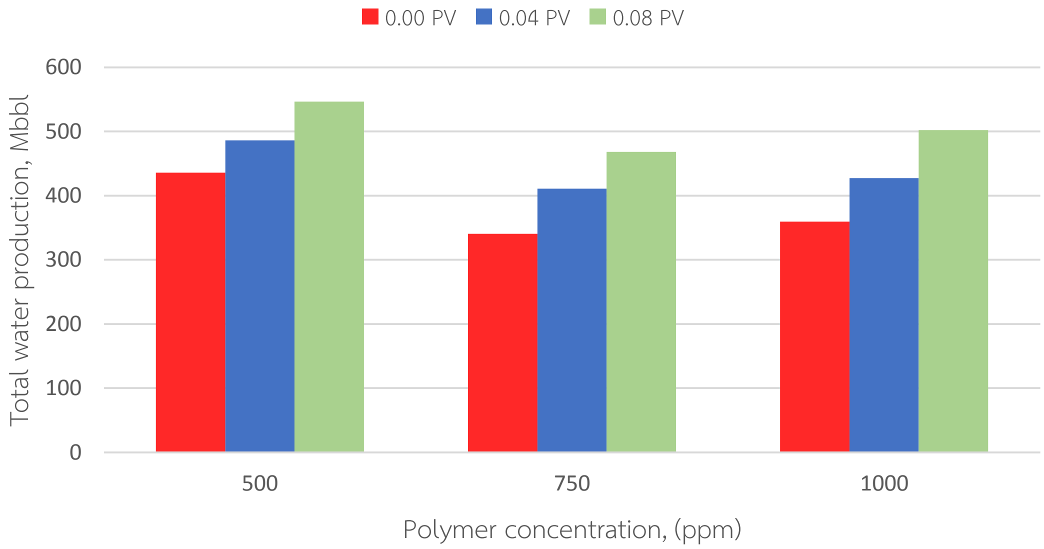


Figure 5.23 Summary of total water production obtained from polymer flooding with concentration of 500, 750 and 1,000 ppm with different pre-flushed water slug sizes

In this section, it can be obviously seen that presence of pre-flushed polymer slug does not yield much benefit on oil recovery factor. The only benefit is to increase polymer injectivity for when high polymer concentration is required for viscous oil. In this study, the maximum concentration of polymer used is 1,000 ppm and even this concentration cannot be injected at the desired rate at injection well, production still can maintain above economic limitation.

As explain in section 5.1, high polymer concentration also obtains benefit from polymer adsorption. After adsorption, part of polymer solution turns into water with much less viscosity. This water acts as pre-flushed water that can partially sweep viscous oil. Therefore, pre-flushed water slug is not required in this study also due to high water production and longer production period.

5.2.2 Effect of Polymer Concentration

Polymer concentration is one of the designed parameters in this study. Polymer concentration is critical parameters since it changes mobility ratio of displaced fluid by directly control viscosity of polymer solution and affects to amount of adsorbed polymer which is related to residual resistance factor and reduction of relative permeability to water. To compare cases that consumed different amount of polymer, additional oil recovery per polymer consumed is considered as a criterion to compare performance among cases. In this section, pre-flushed water slug size and polymer solution slug size are kept constant at 0.00 PV and 0.25 PV, respectively. Polymer concentrations are varied from 500 to 1,000 to investigate its effect. Figure 5.24 to Figure 5.26 illustrate effects of polymer concentrations on actual liquid injection rate at producers for polymer solution with residual resistance factors of 1.5, 2.0 and 2.5, respectively.

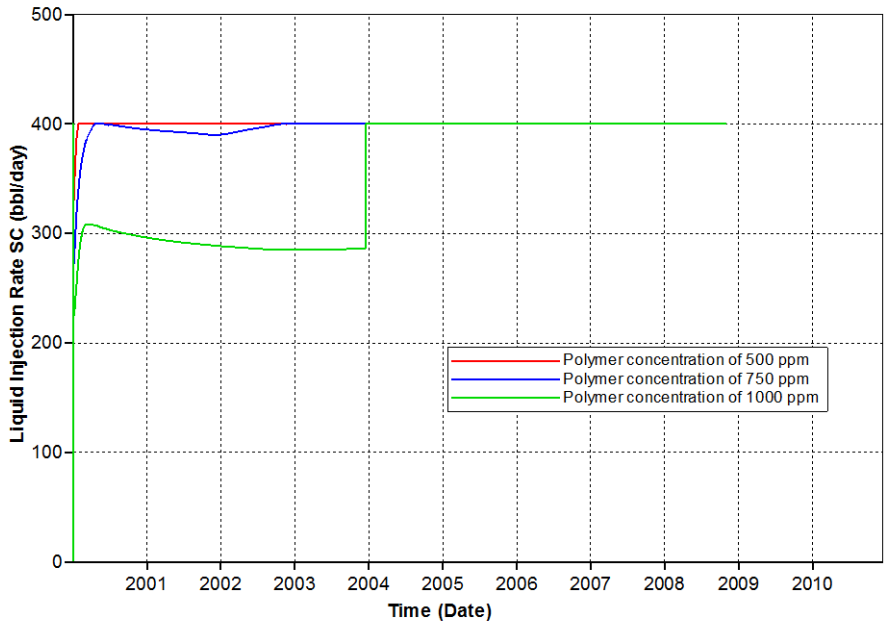


Figure 5.24 Actual liquid injection rates of different polymer concentrations for polymer solution with residual resistance factor of 1.5

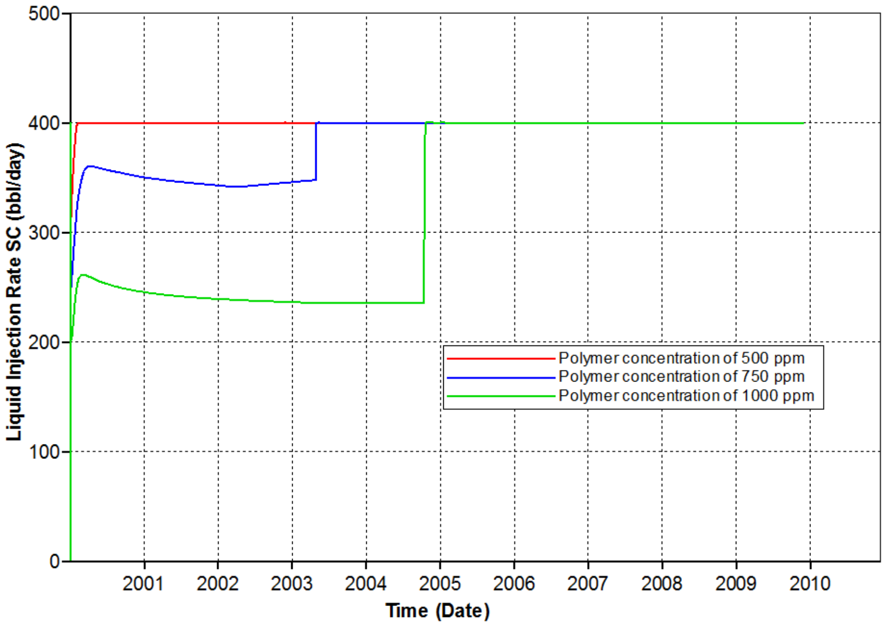


Figure 5.25 Actual liquid injection rates of different polymer concentrations for polymer solution with residual resistance factor of 2.0

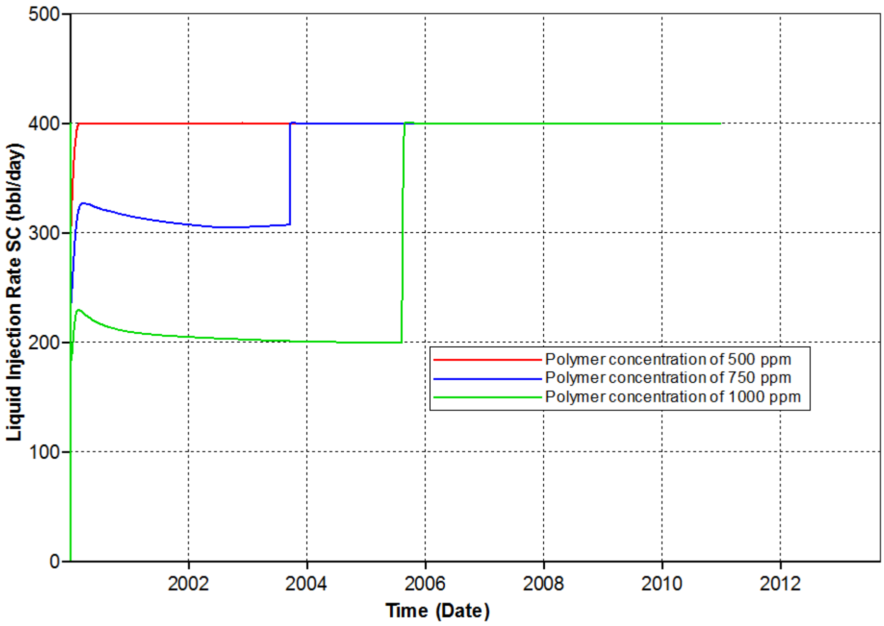


Figure 5.26 Actual liquid injection rates of different polymer concentrations for polymer solution with residual resistance factor of 2.5

According to Figure 5.24 to Figure 5.26, it is obvious that polymer concentration is critical parameter that controls injectivity of polymer solution. Increasing polymer concentration results in higher viscosity of polymer solution. Since polymer adsorption is directly proportional to polymer concentration, higher amount of polymer adsorbed on the rock surface is also increased with polymer concentration. This effect leads to reduction of effective permeability to water which can be related to residual resistant factor as demonstrated in Figure 5.27, dark blue color represents the highest residual resistance factor or the highest reduction of effective permeability to water while light blue and green are lesser degrees, respectively.

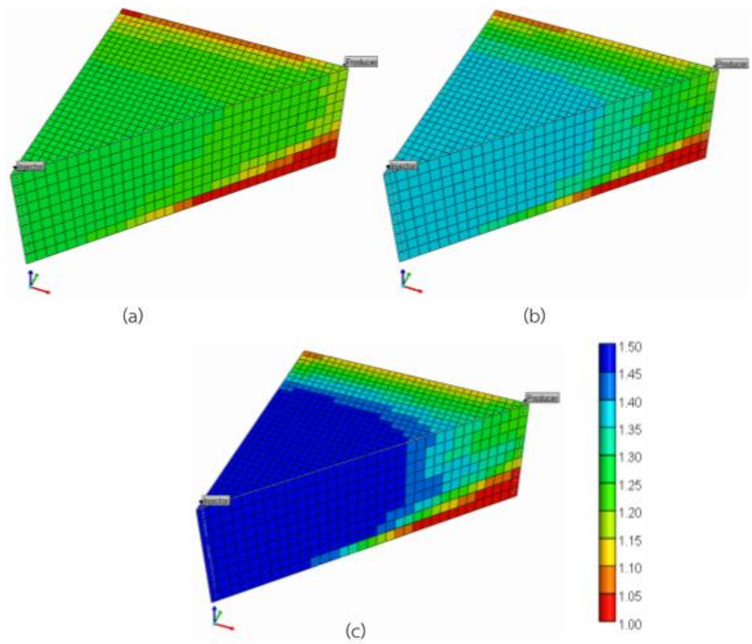


Figure 5.27 Residual resistance factor profile at the end of production (a) polymer concentration of 500 ppm, (b) polymer concentration of 750 ppm and (c) polymer concentration of 1,000 ppm

Even though high polymer concentration intrinsically comes with disadvantage of low injectivity, improvement of mobility ratio and effective permeability to water yield benefit on oil recovery. Figure 5.28 to Figure 5.30 show oil production rates as a function of time of different polymer concentrations for polymer solution with residual resistance factor of 1.5, 2.0 and 2.5, respectively.

At the start of production, oil rate is related to injectivity of fluid as being discussed in previous section. In cases of polymer concentration of 1,000 ppm in every residual resistance factor, increment of oil production rate in later stage is a result from arrival of remaining oil which is swept from favorable displacement conditions including appropriate viscosity ratio (between displacing and displaced fluids and reduction of effective permeability to water). For the cases of polymer concentration of 750 ppm, remaining oil is well swept only with residual resistance factor of 2.0 and 2.5, meaning that higher reduction of effective permeability to water can compensate loss of viscosity (in case that polymer concentration is not too high). None of peak oil rate is observed in case of polymer concentration of 500 ppm for any residual resistance factor.

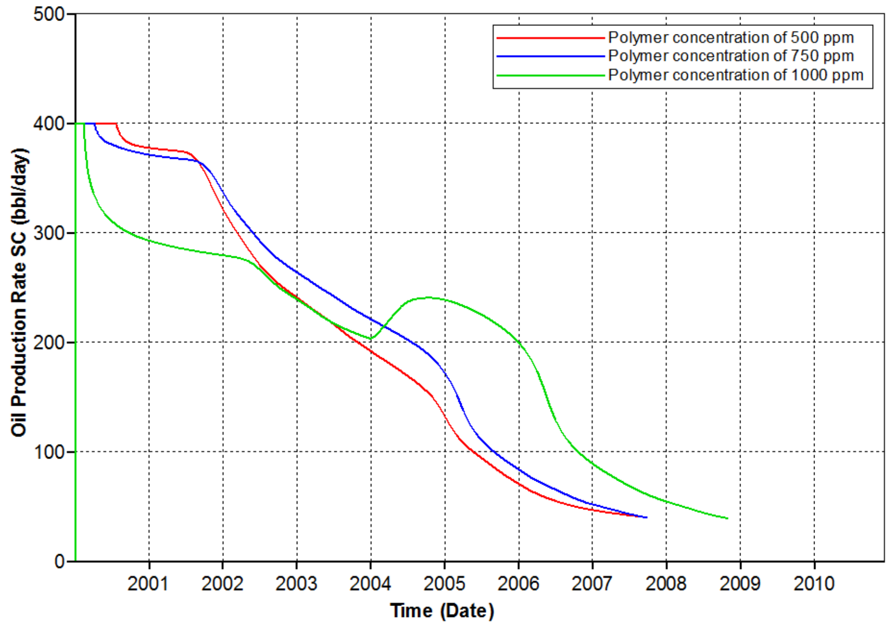


Figure 5.28 Oil production rates of different polymer concentrations for polymer solution with residual resistance factor of 1.5

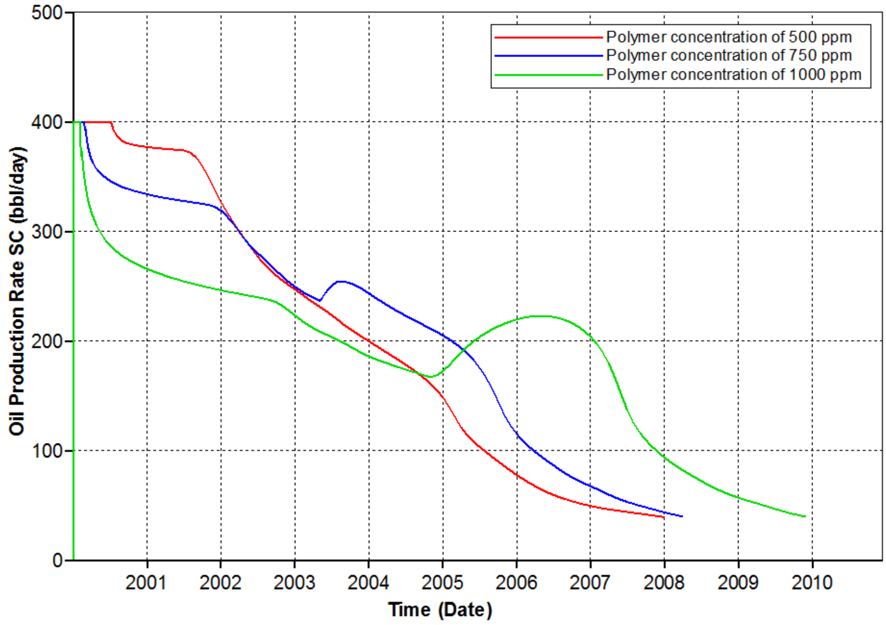


Figure 5.29 Oil production rates of different polymer concentrations for polymer solution with residual resistance factor of 2.0

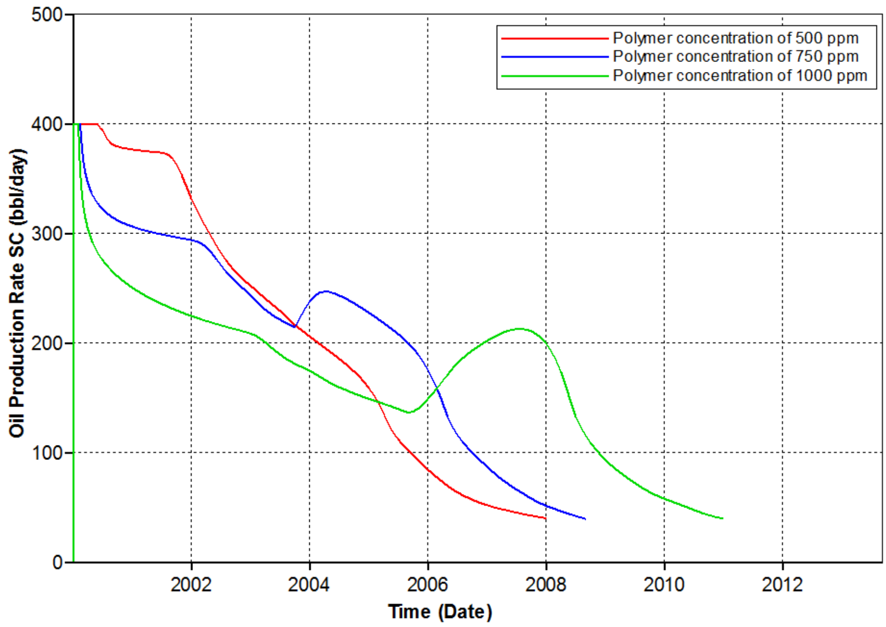


Figure 5.30 Oil production rates of different polymer concentrations for polymer solution with residual resistance factor of 2.5

Oil recovery factors of all cases in the study of polymer concentration are summarized in Figure 5.31. From figure, concentration of 1,000 ppm yields the highest oil recovery factor among all cases. As explained previously, higher concentration of polymer increases viscosity of injectant. This leads to higher viscous force to displace more fluid. Moreover, favorable condition is attained and effects of heterogeneity are mitigated, resulting in higher oil recovery from lower permeable zone.

However, when consider amount of additional oil recovered per polymer consumed which is illustrated in Figure 5.32, effectiveness of lower polymer concentration cases is better than high polymer concentration.

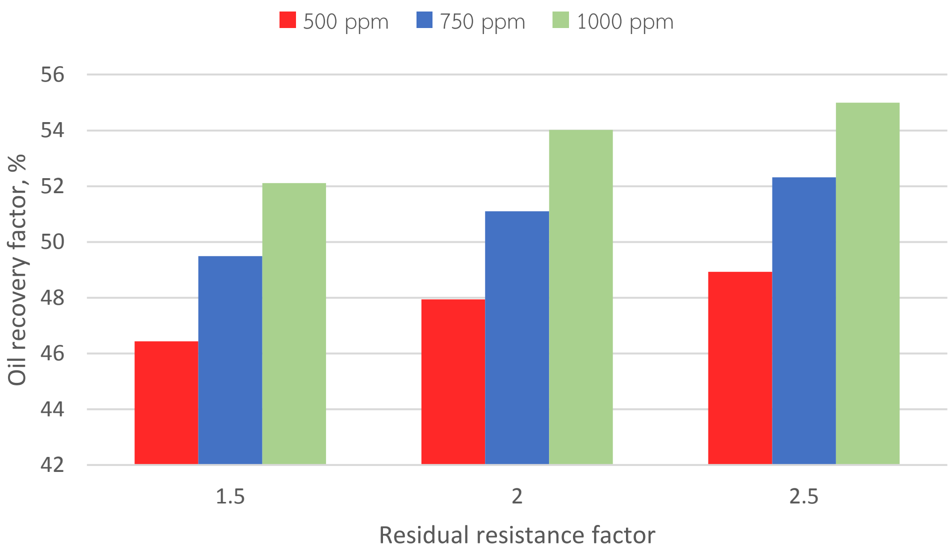


Figure 5.31 Summary of oil recovery factors obtained residual resistance factors of 1.5, 2.0 and 2.5 with different polymer concentrations

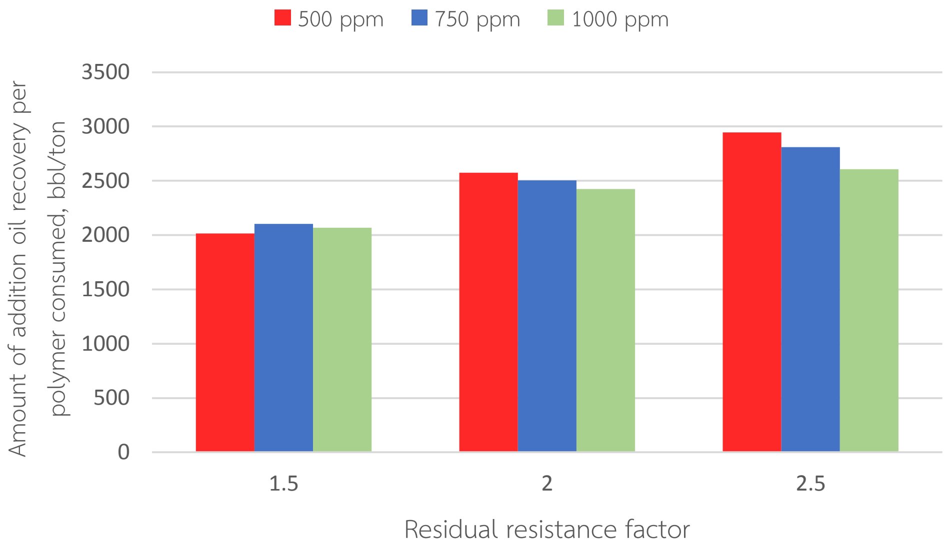


Figure 5.32 Summary of oil recovery factors obtained residual resistance factors of 1.5, 2.0 and 2.5 with different polymer concentrations

Water production is another concerning parameter in this study. Figure 5.33 summarized total water production from cases in the study of polymer concentrations. From the figure, high polymer concentration tends to yields smaller water production. Polymer concentration of 1,000 ppm causes the latest water breakthrough and consequently the smallest total water production. This result is due to the most favorable mobility ratio among other cases. However, in case of residual resistance of 2.5, total water production of the case of polymer with concentration of 1,000 ppm is higher than the case of 750 ppm. This can be explained that due to extremely low injectivity, total production period is longer than the cases of 750 ppm and hence, total water production is increased.

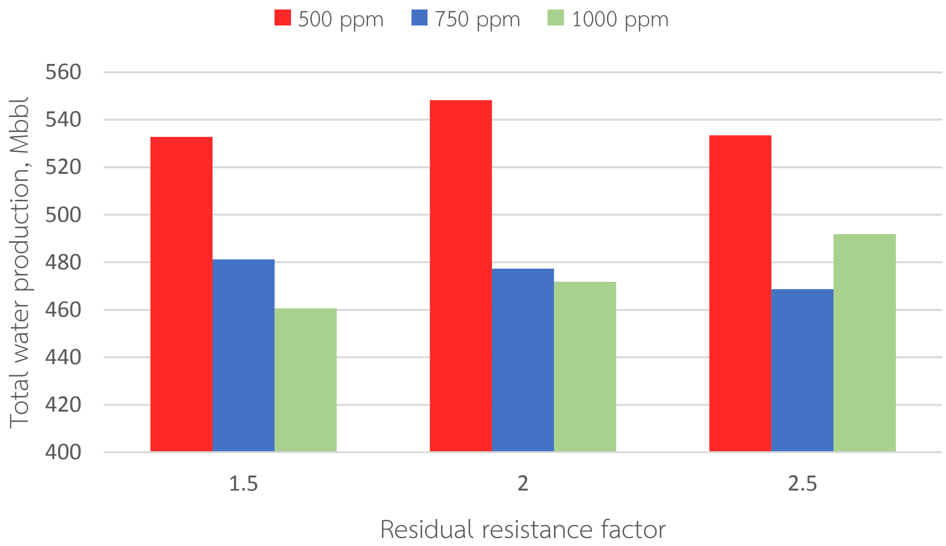


Figure 5.33 Summary of total water production of polymer flooding with maximum resistance factor of 1.5, 2.0 and 2.5 at different polymer concentration

The effect of polymer concentration is very obvious in this study. Higher concentration tends to yield benefit from both increasing of viscosity of injectant and reduction of effective permeability to water. Both effects result in favorability of mobility ratio that consecutively yields high oil recovery and retarding water production. Nevertheless, incremental of oil might not meet requirement in terms of economic point of view. Effects of polymer concentration are partly linked to effects of residual resistance factor which will be explained in section 5.2.4.

5.2.3 Effect of Polymer Slug Size

In order to perform polymer flooding in the cost effective way, polymer solution is not injected into the reservoir until the end of production but it is injected for certain slug size and chased by water. In this section, in order to evaluate effects of polymer slug size, maximum resistance factor and pre-flushed water are kept constant at 2.0 and 0 PV, respectively. Slug size of polymer solution are varied between 0.2 and 0.3 PV and after the desired amount of polymer is injected, chasing water slug is injected until the end of production.

Oil recovery factor and total water production with different of polymer slug size are summarized in Figure 5.34 and Figure 5.35, respectively. From the figures, it is obvious that large polymer slug yields better result compared to small polymer slug size when compare at the same polymer concentration in term of high oil recovery factor and lower total water production.

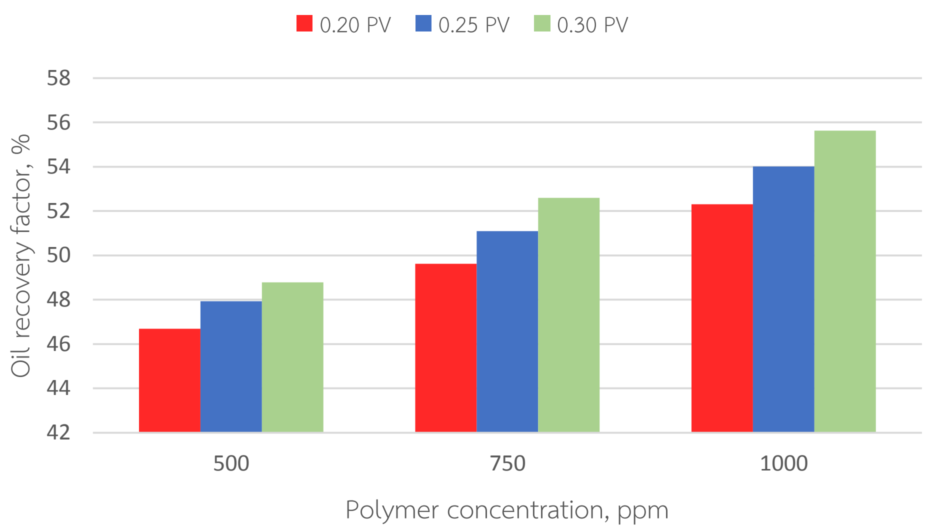


Figure 5.34 Summary of oil recovery factors of polymer flooding with polymer concentration of 500, 750 and 1,000 ppm at different polymer slug sizes

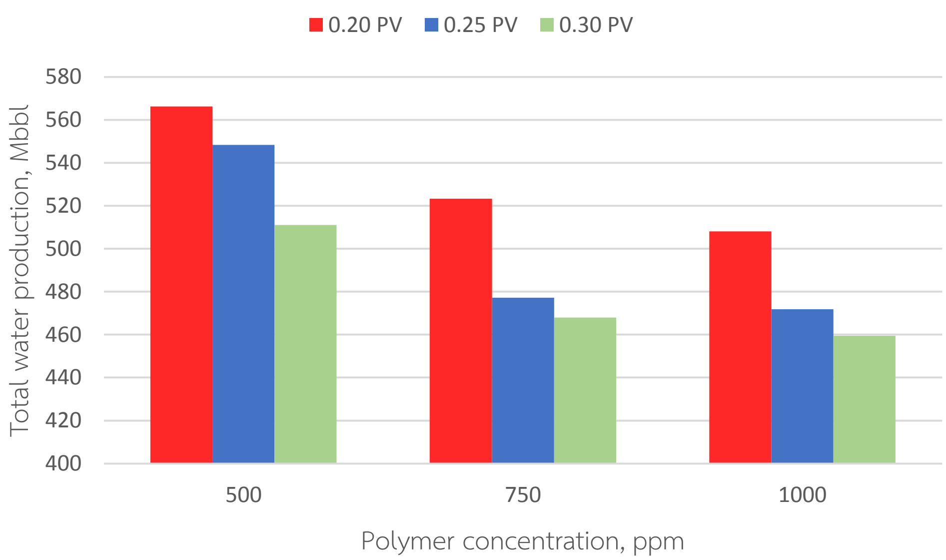


Figure 5.35 Summary of total water productions of polymer flooding with polymer concentration of 500, 750 and 1,000 ppm at different polymer slug sizes

Larger polymer slug size comes with higher amount of polymer. This means that there is adequate polymer mass to maintain high viscosity injectant as well as adsorbed polymer to reduce effective permeability to water. This occurrence allows high concentration of polymer solution to displace considerable amount of oil near the boundary of reservoir model as illustrated in Figure 5.36

Figure 5.36a shows that high amount of oil is still left near reservoir boundary at the end of production, while in Figure 5.36 and Figure 5.36 injecting larger polymer slug size can recover high amount of oil and hence less amount of oil is remained in this area. However, benefit of smaller polymer solution slug size over larger polymer solution slug size is the greater amount of oil recovered per polymer consumed as summarized in Figure 5.37

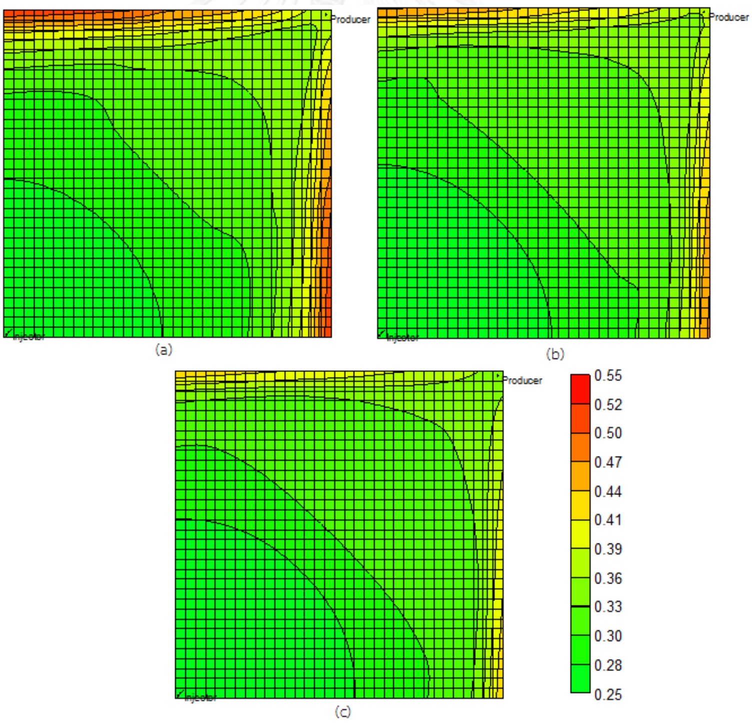


Figure 5.36 Oil saturation profile in the uppermost layer at the end of production in case of polymer concentration of 1,000 ppm (a) polymer solution slug 0.2 PV (b) polymer solution slug 0.25 PV and (c) polymer solution slug 0.3 PV

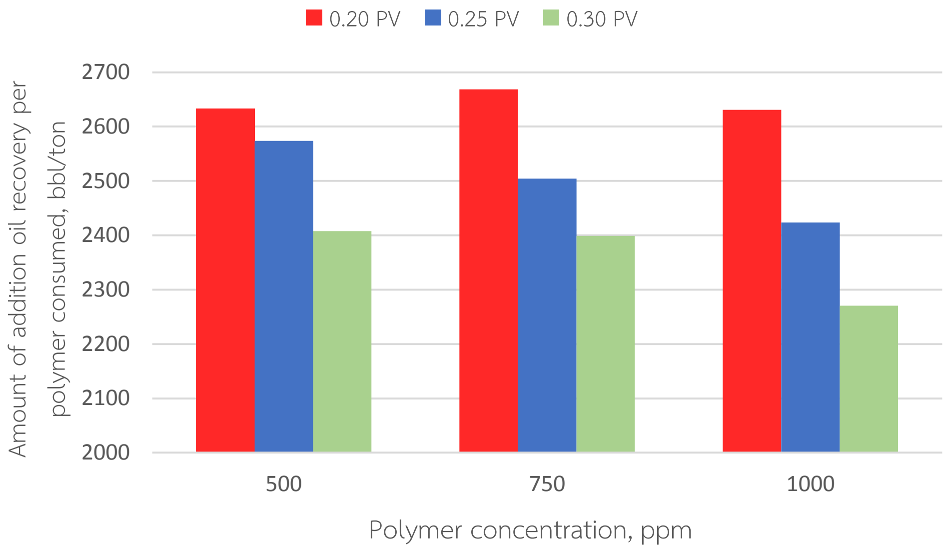


Figure 5.37 Summary of additional oil recovered per polymer consumed of polymer flooding with polymer concentration of 500, 750 and 1,000 ppm at different polymer slug sizes

From simulation results in this section, it can be seen that increasing of polymer slug size always increases oil recovery factor. This is due to increment of polymer mass that results in adequate polymer to maintain viscosity of injected fluid as well as adsorbed polymer onto rock surface to improve effective permeability to water. However, increasing of polymer mass also comes with less additional oil recovered per polymer consumed.

Among all cases, considering constant polymer mass, two cases that can be used to compare are polymer concentration of 500 ppm with slug size of 0.3 and polymer concentration of 750 with slug size of 0.2. In terms of oil recovery factor and total water production, high polymer concentration with smaller slug size tends to yield better result compared to small polymer concentration with larger slug size.

5.2.4 Effect of Residual Resistance Factor

Residual resistance factor is defined as ratio of permeability before and after polymer injected. Theoretically, residual resistance factor depends on amount of polymer adsorbed onto rock surface which is related to polymer and rock types. In this study, it is assumed that residual resistance factor can be varied by several triggering mechanisms while it can maintain the same of viscosity enhancement effect. Polymer concentration of 1,000 ppm is selected to investigate effects of residual resistance factor due to polymer concentration of 1,000 ppm can yield the desired residual resistance factor and polymer solution is injected from the first day of production (no pre-flushed water).

Oil recovery factor and additional oil recovered per polymer consumed of all cases are summarized in Figure 5.38 and Figure 5.39, respectively. According to these results, increment of residual resistance factor improves oil recovery factor and additional oil recovered per polymer consumed for the same size of polymer solution slug. As explained in section 5.2.2, mobility ratio of displacing fluid is improved from both increment of viscosity of polymer solution and reduction of effective permeability to water. Although mobility ratio of polymer solution with higher residual resistance factor is improved, total production period of polymer solution with higher residual resistance factor are much longer due to its poor injectivity (polymer solution permeates slowly), causing higher total water production compared to cases of lower residual resistance factor as shown in Figure 5.40. From these figures, it can be seen that larger slug size results in characteristics as explained in section 5.2.3.

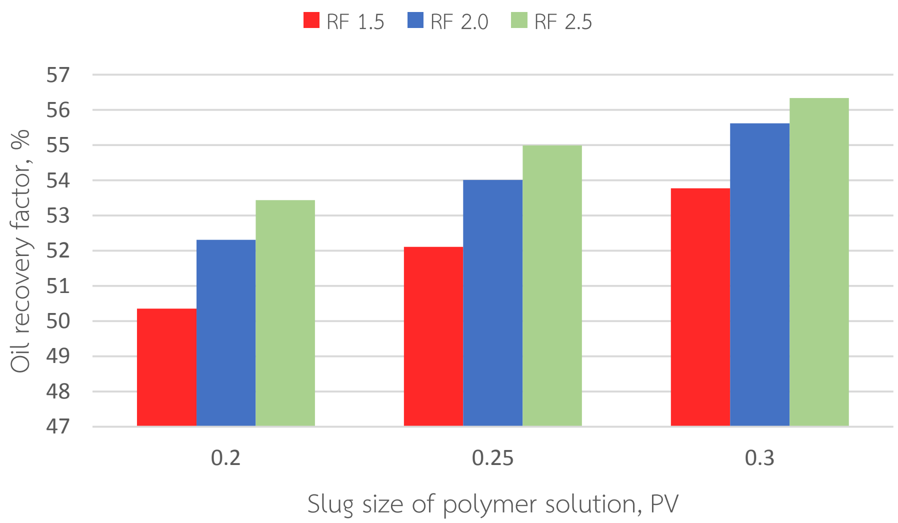


Figure 5.38 Summary of oil recovery factors of polymer flooding with polymer slug size of 0.2, 0.25 and 0.3 PV at different residual resistance factors

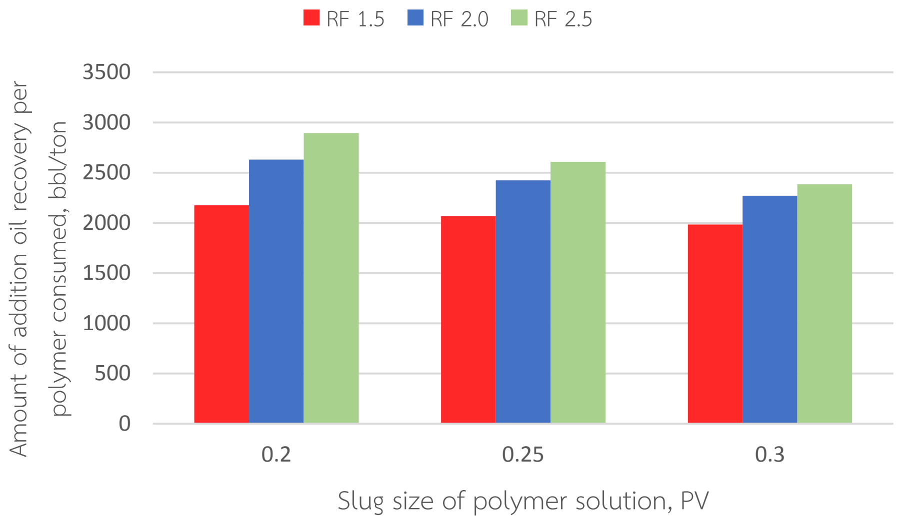


Figure 5.39 Summary of additional oil recovered per polymer consumed of polymer flooding with polymer slug size of 0.2, 0.25 and 0.3 PV at different residual resistance factors

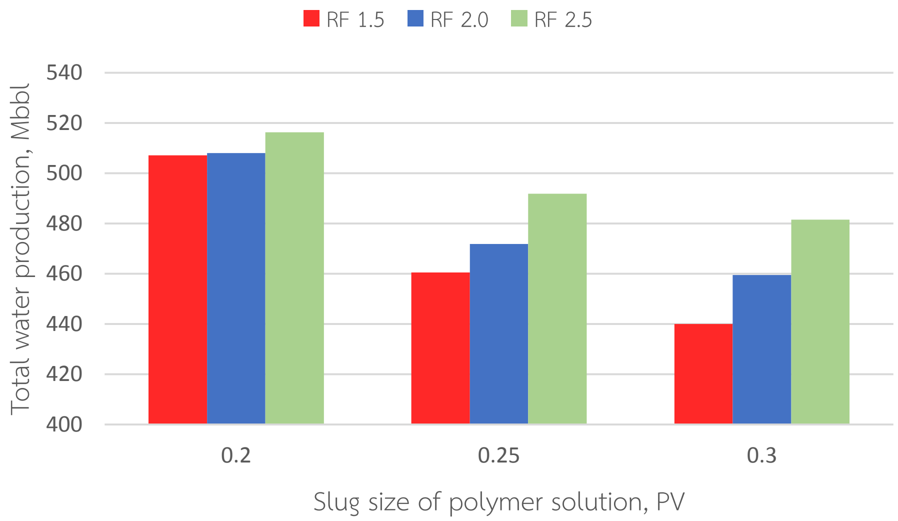


Figure 5.40 Summary of total water production of polymer flooding with polymer solution slug size of 0.2, 0.25, 0.3 PV at different residual resistance factor

From Figure 5.37 it can be observed that polymer slug size affects total water production, compared among the same residual resistance factor. As polymer slug size is larger, sweep efficiency is much better and hence, high amount of remaining oil is produced. After that water starts breaking through at higher water production rate due to less oil remained. This results short period water production and hence decreases total amount of water produced.

In summary, residual resistance factor has a great impact on effectiveness of polymer flooding process. Higher residual resistance factor tends to yield better oil recovery from the effect of improving mobility ratio. However, high residual resistant factor could result in low injectivity, causing displacement mechanism to occur slowly that could turn into high total water production.

5.2.5 Selection of Single-slug Polymer Flooding Base Case Scheme

In this study, all operating parameters which are pre-flushed water slug size, polymer concentration, polymer solution slug size and residual resistance factor are cross-combined and this yields totally 81 simulation cases. Simulation outcomes of all cases are summarized in Table 5.2 to Table 5.4, where each table is summarized for one residual resistance factor.

To select single-slug polymer flooding base case for further study, oil recovery, additional oil recovered per polymer consumed, total water production and production time are used to compare among each case. However, it still difficult to judge the effectiveness from just one parameter since several aspects can be considered from different point of views. Thereafter, to be able to include all simulation outcomes in judgment, all outcomes are scored with different weighing fraction based on their priorities and the case with the highest total score is selected for the following process.

Oil recovery factor is the major criterion in this study as it is typically represents for an income of the project. In this study, oil recovery factor contributes for 55% of total score. However, not only oil recovery factor is considered. Effectiveness of injected polymer must be considered as well. Additional oil recovered per constant mass of polymer is hence, selected a second criterion. Since there are cases with different amount of polymer consumption, this criterion is required as higher amount of polymer increases costs of investment. Additional oil recovered per polymer consumed contributes for 20% of total score in this study. Higher values of these two parameters represent favorable score.

In addition, produced water is nowadays one of the most concerns. In several countries, disposal of water to opened water is prohibited. Water reinjection together with several treatments is therefore considered as costly process. So, total amount of water production is considered as third important criterion with contribution of 15% of total score. Last, higher rate of oil production is always better. Hence, total production period is chosen as the last criterion, contributing for 10% of total score. For these two values, the smaller are more desirable.

Table 5.2 Summary of simulation outcomes for polymer solution with residual resistance factor of 1.5

Pre-flushed water (PV)	Polymer slug size (PV)	Polymer concentration (ppm)	Total Production time (days)	Total water production (Mbbl)	RF, %	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,861	559.93	45.40	2,030.3
		750	2,891	526.24	48.10	2,194.5
		1,000	3,196	507.16	50.36	2,174.0
	0.25	500	2,830	532.70	46.44	2,014.3
		750	2,830	481.14	49.49	2,103.4
		1,000	3,227	460.58	52.11	2,067.2
	0.3	500	2,800	507.81	47.34	1,958.7
		750	2,861	472.46	50.93	2,052.3
		1,000	3,319	440.08	53.77	1,982.4
0.04	0.2	500	2,982	610.61	45.50	2,078.3
		750	2,982	573.57	48.04	2,176.7
		1,000	3,288	560.15	50.37	2,176.8
	0.25	500	2,982	594.19	46.64	2,090.0
		750	2,953	540.49	49.52	2,109.7
		1,000	3,347	526.17	52.23	2,089.0
	0.3	500	2,922	558.73	47.40	1,978.4
		750	2,982	531.71	50.90	2,046.5
		1,000	3,439	507.76	53.86	1,995.8
0.08	0.2	500	3,104	660.95	45.59	2,120.0
		750	3,104	624.48	48.07	2,187.0
		1,000	3,408	622.90	50.54	2,218.3
	0.25	500	3,074	634.18	46.58	2,064.4
		750	3,074	591.51	49.48	2,100.4
		1,000	3,469	593.42	52.36	2,115.1
	0.3	500	3,043	609.17	47.41	1,979.7
		750	3,104	582.94	50.84	2,033.8
		1,000	3,592	588.53	54.05	2,024.7

Table 5.3 Summary of simulation outcomes for polymer solution with residual resistance factor of 2.0

Pre-flushed water (PV)	Polymer slug size (PV)	Polymer concentration (ppm)	Total production time (days)	Total water production (Mbbl)	RF, %	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,922	566.19	46.69	2,632.7
		750	3,043	523.32	49.62	2,668.7
		1,000	3,500	508.05	52.31	2,630.6
	0.25	500	2,922	548.25	47.94	2,573.6
		750	3,013	477.24	51.10	2,504.1
		1,000	3,622	471.82	54.01	2,423.8
	0.3	500	2,861	511.07	48.78	2,407.6
		750	3,074	467.98	52.60	2,399.2
		1,000	3,804	459.46	55.62	2,270.6
0.04	0.2	500	3,043	616.98	46.77	2,673.5
		750	3,135	579.13	49.61	2,667.2
		1,000	3,622	573.04	52.27	2,621.8
	0.25	500	3,013	588.48	47.89	2,557.3
		750	3,104	535.94	51.07	2,497.0
		1,000	3,743	540.00	53.92	2,405.6
	0.3	500	2,982	562.52	48.78	2,408.4
		750	3,135	517.80	52.44	2,365.5
		1,000	3,926	531.35	55.47	2,246.6
0.08	0.2	500	3,166	667.91	46.86	2,711.5
		750	3,196	623.16	49.57	2,654.6
		1,000	3,743	638.20	52.17	2,598.6
	0.25	500	3,135	639.79	47.89	2,556.7
		750	3,196	593.86	51.15	2,517.5
		1,000	3,865	611.20	53.74	2,372.7
	0.3	500	3,104	613.67	48.78	2,406.1
		750	3,227	577.05	52.55	2,388.2
		1,000	4,049	604.40	55.30	2,219.7

Table 5.4 Summary of simulation outcomes for polymer solution with residual resistance factor of 2.5

Pre-flushed water (PV)	Polymer slug size (PV)	Polymer concentration (ppm)	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,953	563.40	47.73	3,120.8
		750	3,166	516.09	50.78	3,030.8
		1,000	3,804	516.34	53.44	2,894.7
	0.25	500	2,922	533.46	48.93	2,944.5
		750	3,166	468.74	52.32	2,808.4
		1,000	4,018	491.88	55.00	2,607.6
	0.3	500	2,891	506.29	49.91	2,759.4
		750	3,227	446.73	53.76	2,640.7
		1,000	4,261	481.55	56.34	2,382.7
0.04	0.2	500	3,074	614.92	47.80	3,151.6
		750	3,257	570.65	50.77	3,026.8
		1,000	3,957	600.24	53.10	2,816.6
	0.25	500	3,043	585.14	48.96	2,956.8
		750	3,257	525.81	52.31	2,807.6
		1,000	4,138	562.48	54.82	2,574.7
	0.3	500	3,013	559.01	49.87	2,747.9
		750	3,347	515.67	53.87	2,664.1
		1,000	4,352	542.66	56.03	2,333.5
0.08	0.2	500	3,196	665.62	47.84	3,172.0
		750	3,347	622.88	50.86	3,056.3
		1,000	4,049	653.88	52.89	2,767.5
	0.25	500	3,135	609.75	49.83	3,281.1
		750	3,378	592.79	52.49	2,852.4
		1,000	4,261	634.79	54.48	2,510.6
	0.3	500	3,196	647.36	49.02	2,481.1
		750	3,469	585.64	54.02	2,693.2
		1,000	4,474	620.63	55.69	2,281.0

From Table 5.2 to Table 5.4 raw data are processed by using judgment function. Maximum oil recovery and maximum additional oil recovered per polymer consumed in each table are used as denominator for other values with the same residual resistance factor. This results in fraction for the whole case except the maximum value itself will obtain 1.0. For total water production and production period, the minimum values are used as numerator where other values are denominator. This also results in fraction for the whole case except the minimum value itself will obtain 1.0.

Fractions of each simulation outcome are multiplied by weighting number (percent contribution) and the summation is made. Table 5.5 to Table 5.7 summarize process data from cases using polymer solution with residual resistance factors of 1.5, 2.0 and 2.5, respectively. The summary of judgment function is shown below.

$$Oil\ recovery\ score = \frac{Oil\ recovery\ of\ case\ i}{Maximum\ \ oil\ recovery} \times 55\% \qquad 5.1)$$

$$Polymer\ eff.\ score = \frac{Oil\ recovery\ per\ polymer\ consumed\ of\ case\ i}{Maximum\ oil\ recovery\ per\ polymer\ consumed} \times 20\% \qquad 5.2)$$

$$Water\ production\ score = \frac{Minimum\ total\ water\ production}{Total\ water\ production\ of\ case\ i} \times 15\% \qquad 5.3)$$

$$Total\ production\ time\ score = \frac{Minimum\ total\ production\ period}{Total\ production\ period\ of\ case\ i} \times 10\% \qquad 5.4)$$

From Tables 5.5 and 5.6, for residual resistance factor of 1.5 and 2.0, polymer concentration of 1,000 ppm with polymer solution slug size 0.30 PV and without pre-flushed water yields the highest total score among other cases. But, polymer concentration of 750 ppm with polymer solution slug size 0.30 PV and without pre-flushed water yields highest total score in case of residual resistance factor of 2.5 (as highlighted by yellow color). The case of 1,000 ppm with residual resistance factor losses the score to 750 ppm from long total production period and high amount of produced water due to low injectivity from permeability reduction that is caused by polymer adsorption.

However, a case of 1,000 ppm single-slug polymer flooding with slug size of 0.3 PV and no pre-flushed water is chosen as base case since these conditions yields best total score for most residual resistance factor. Moreover, this selection will result in comparable results of sequential polymer flooding across different residual resistance factor since the whole cases will consume the same amount of polymer.

Table 5.5 Summary of processed data and judging score from polymer solution residual resistance factor of 1.5

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Total production time Score	Water production score	Polymer efficiency score	Recovery score	Total score
0	0.2	500	9.79	11.79	18.31	46.20	86.08
		750	9.69	12.54	19.79	48.95	90.96
		1,000	8.76	13.02	19.60	51.24	92.62
	0.25	500	9.89	12.39	18.16	47.26	87.71
		750	9.89	13.72	18.96	50.36	92.94
		1,000	8.68	14.33	18.64	53.03	94.67
	0.3	500	10.00	13.00	17.66	48.18	88.83
		750	9.79	13.97	18.50	51.83	94.09
		1,000	8.44	15.00	17.87	54.72	96.03
0.04	0.2	500	9.39	10.81	18.74	46.31	85.24
		750	9.39	11.51	19.62	48.89	89.41
		1,000	8.52	11.78	19.63	51.26	91.18
	0.25	500	9.39	11.11	18.84	47.47	86.81
		750	9.48	12.21	19.02	50.39	91.11
		1,000	8.37	12.55	18.83	53.15	92.89
	0.3	500	9.58	11.81	17.84	48.24	87.47
		750	9.39	12.42	18.45	51.80	92.06
		1,000	8.14	13.00	17.99	54.81	93.95
0.08	0.2	500	9.02	9.99	19.11	46.40	84.52
		750	9.02	10.57	19.72	48.92	88.23
		1,000	8.22	10.60	20.00	51.44	90.25
	0.25	500	9.11	10.41	18.61	47.40	85.53
		750	9.11	11.16	18.94	50.35	89.56
		1,000	8.07	11.12	19.07	53.29	91.55
	0.3	500	9.20	10.84	17.85	48.24	86.13
		750	9.02	11.32	18.34	51.74	90.42
		1,000	7.80	11.22	18.26	55.00	92.27

Table 5.6 Summary of processed data and judging score from polymer solution residual resistance factor of 2.0

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Total production time Score	Water production score	Polymer efficiency score	Recovery score	Total score
0	0.2	500	9.79	12.17	19.42	46.16	87.55
		750	9.40	13.17	19.68	49.06	91.32
		1,000	8.17	13.57	19.40	51.72	92.86
	0.25	500	9.79	12.57	18.98	47.40	88.74
		750	9.50	14.44	18.47	50.52	92.93
		1,000	7.90	14.61	17.88	53.41	93.79
	0.3	500	10.00	13.49	17.76	48.23	89.48
		750	9.31	14.73	17.70	52.01	93.74
		1,000	7.52	15.00	16.75	55.00	94.27
0.04	0.2	500	9.40	11.17	19.72	46.25	86.54
		750	9.13	11.90	19.67	49.06	89.76
		1,000	7.90	12.03	19.34	51.68	90.95
	0.25	500	9.50	11.71	18.86	47.36	87.43
		750	9.22	12.86	18.42	50.50	90.99
		1,000	7.64	12.76	17.74	53.31	91.46
	0.3	500	9.59	12.25	17.76	48.24	87.85
		750	9.13	13.31	17.45	51.85	91.73
		1,000	7.29	12.97	16.57	54.85	91.68
0.08	0.2	500	9.04	10.32	20.00	46.33	85.69
		750	8.95	11.06	19.58	49.02	88.61
		1,000	7.64	10.80	19.17	51.59	89.20
	0.25	500	9.13	10.77	18.86	47.36	86.11
		750	8.95	11.61	18.57	50.58	89.70
		1,000	7.40	11.28	17.50	53.14	89.32
	0.3	500	9.22	11.23	17.75	48.23	86.42
		750	8.87	11.94	17.61	51.96	90.38
		1,000	7.07	11.40	16.37	54.68	89.52

Table 5.7 Summary of processed data and judging score from polymer solution residual resistance factor of 2.5

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Total production time Score	Water production score	Polymer efficiency score	Recovery score	Total score
0	0.2	500	9.79	11.89	19.02	46.59	87.30
		750	9.13	12.98	18.47	49.57	90.16
		1,000	7.60	12.98	17.65	52.16	90.39
	0.25	500	9.89	12.56	17.95	47.76	88.17
		750	9.13	14.30	17.12	51.07	91.62
		1,000	7.20	13.62	15.89	53.69	90.40
	0.3	500	10.00	13.24	16.82	48.72	88.78
		750	8.96	15.00	16.10	52.48	92.54
		1,000	6.78	13.92	14.52	55.00	90.22
0.04	0.2	500	9.40	10.90	19.21	46.66	86.17
		750	8.88	11.74	18.45	49.56	88.63
		1,000	7.31	11.16	17.17	51.84	87.48
	0.25	500	9.50	11.45	18.02	47.79	86.77
		750	8.88	12.74	17.11	51.07	89.80
		1,000	6.99	11.91	15.69	53.52	88.11
	0.3	500	9.60	11.99	16.75	48.68	87.02
		750	8.64	12.99	16.24	52.59	90.46
		1,000	6.64	12.35	14.22	54.69	87.91
0.08	0.2	500	9.05	10.07	19.34	46.70	85.15
		750	8.64	10.76	18.63	49.65	87.67
		1,000	7.14	10.25	16.87	51.63	85.89
	0.25	500	9.22	10.99	20.00	48.64	88.85
		750	8.56	11.30	17.39	51.24	88.49
		1,000	6.78	10.56	15.30	53.18	85.83
	0.3	500	9.05	10.35	15.12	47.85	82.37
		750	8.33	11.44	16.42	52.73	88.92
		1,000	6.46	10.80	13.90	54.36	85.53

5.3 Double-slug Sequential Polymer Flooding

Theoretically, polymer solution is injected for certain period and chased by water slug as explained in section 5.2.3. Once water injection is begun, injected water tries to displace polymer solution slug with unfavorable mobility ratio. Different from viscous fingering occurred from unfavorable of mobility ratio of oil and aqueous phase, unfavorable mobility ratio creates fingering water profile between interface of water and polymer slug since both slugs are the same phase. Due to large contrast in polymer concentration, viscosity is greatly reduced at this junction between polymer and chased water slugs. Therefore, concept of sequential polymer flooding is applied to attenuate reduction of viscosity of polymer solution slug and at the same time to improve injectivity of polymer solution.

After single-slug polymer flooding base case selected is selected from previous section, the case is modified into double-slug sequential polymer flooding to investigate effectiveness of this technique based on theory explained previously. Double-slug sequential polymer flooding is designed by maintaining amount of polymer used as same to in case of single-slug polymer flooding base case.

According to simulation outcomes in previous section, polymer concentration of 1,000 ppm is selected to represent first polymer for two main reasons. First, polymer concentration of 1,000 ppm can effectively control mobility ratio at flood front, resulting in larger amount of oil to be swept. Second, reason high amount of polymer will be adsorbed onto rock surface as there is still large area available for adsorption. After concentration of first polymer slug is selected, slug size of first polymer slug is varied in between 0.1 to 0.2 PV. Chosen of concentration of second polymer slug is varied only 500 and 750 ppm to evaluate effects of different degree of concentration reduction. Slug size of second slug therefore depends on the mass of polymer remained from the first slug. The same criteria as in single-slug polymer flooding are used to compare effectiveness of double-slug sequential polymer flooding except amount of addition of oil recovered per polymer consumed since all schemes consumed the same amount of polymer. Details of all flooding schemes in double-slug polymer flooding are summarized in Table 5.8. Prefix A, B, and C represent cases of polymer solution with residual resistance factors of 1.5, 2.0 and 2.5, respectively.

Table 5.8 Summary of every double-slug sequential polymer scheme

Scheme no.	Residual resistance factor	Slug size of first slug (PV)	Concentration of second slug (ppm)	Slug size of second slug (PV)
A1	1.5	0.1	750	0.2667
A2	1.5	0.1	500	0.4
A3	1.5	0.15	750	0.20
A4	1.5	0.15	500	0.30
A5	1.5	0.2	750	0.1333
A6	1.5	0.2	500	0.20
B1	2.0	0.1	750	0.2667
B2	2.0	0.1	500	0.4
B3	2.0	0.15	750	0.20
B4	2.0	0.15	500	0.30
B5	2.0	0.2	750	0.1333
B6	2.0	0.2	500	0.20
C1	2.5	0.1	750	0.2667
C2	2.5	0.1	500	0.4
C3	2.5	0.15	750	0.20
C4	2.5	0.15	500	0.30
C5	2.5	0.2	750	0.1333
C6	2.5	0.2	500	0.20

5.3.1 Comparison of Single-Slug and Double-slug Sequential Polymer Flooding

In this section, effect of double-slug sequential polymer flooding is firstly discussed. Results from schemes A1, B1 and C1 of double-slug sequential polymer flooding are compared to cases with the same residual resistance factor of single-slug polymer flooding base case from section 5.2.

Injection rate and average reservoir pressure are first compared and illustrated in Figure 5.41 to Figure 5.43 , for three different resistance factors. From these figures, once second polymer slug is injected, actual injection rate is sharply increased due to reduction of viscosity of second slug. Average reservoir pressure in early stage in case of double-slug sequential polymer flooding is hence increased as a result of higher injection rate of second slug as demonstrated in these figures. In case of high residual resistance factor, increment of average reservoir pressure is not as much as low residual resistance factor due to high adsorption of polymer in first slug, resulting in reduction of effective permeability to water as discuss in section 5.2.4. Consequently, second slug cannot be injected easily. Increment of average reservoir pressure of both single and double- sequential polymer slug in later stage is caused by pressure support from chased water.

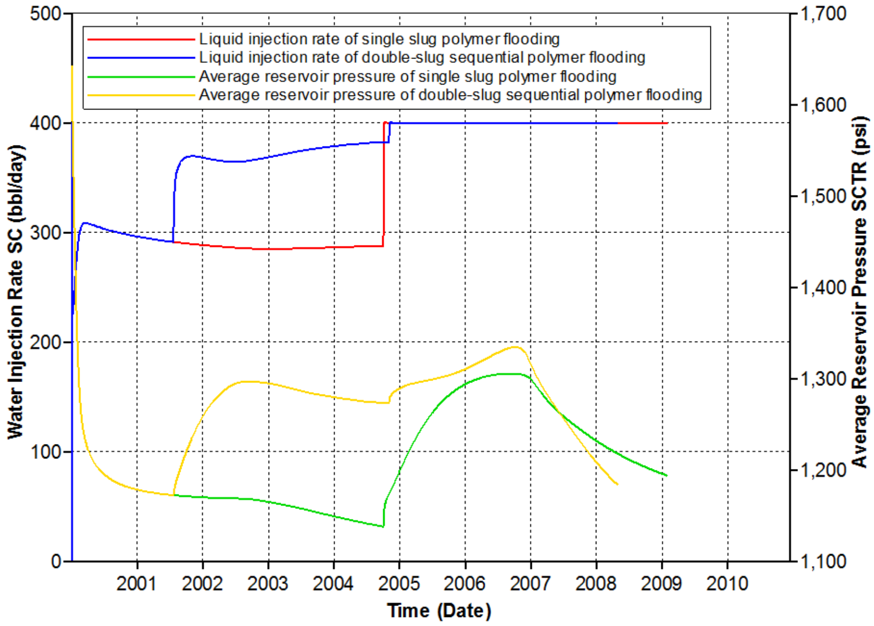


Figure 5.41 Actual injection rates and average reservoir pressures as a function of time of single-slug and double-slug sequential polymer flooding for residual resistance factor of 1.5

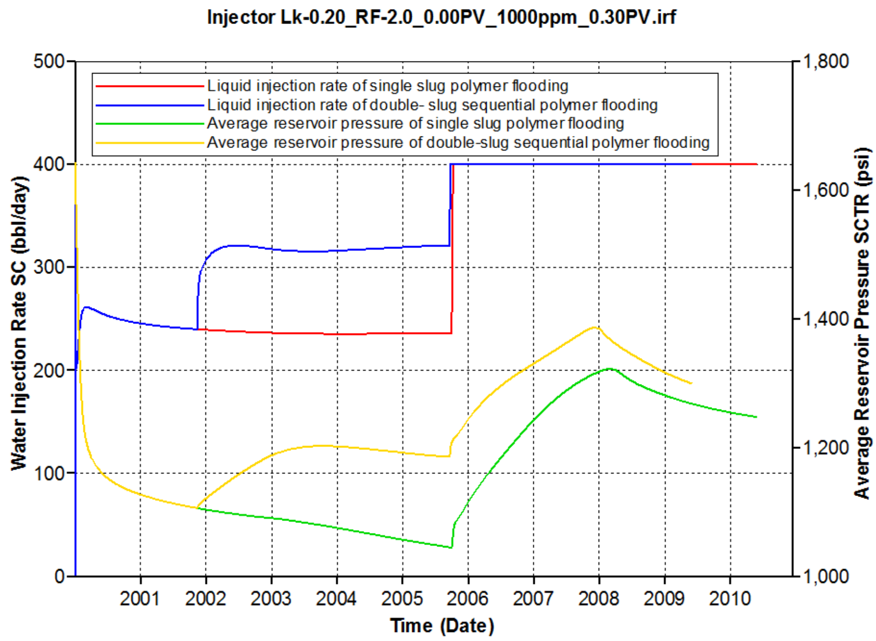


Figure 5.42 Actual injection rates and average reservoir pressures as a function of time of single-slug and double-slug sequential polymer flooding for residual resistance factor of 2.0

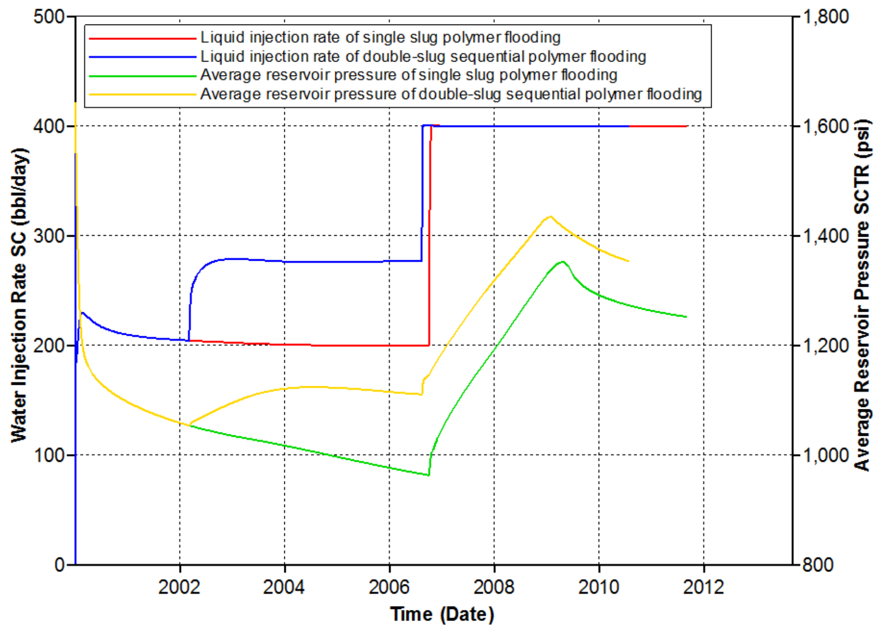


Figure 5.43 Actual injection rates and average reservoir pressures as a function of time of single-slug and double-slug sequential polymer flooding for residual resistance factor of 2.5

Since average reservoir pressure is improved in case double-slug sequential polymer flooding compared to single-slug polymer flooding, effects on oil production rate is therefore obviously seen. Oil production rates from the case of single-slug and double-slug sequential polymer flooding are illustrated in Figure 5.44 to Figure 5.46 for different three residual resistance factors.

In case of residual resistance factor of 1.5, oil production rate of double-slug is increased after short period after declining rate due to supporting pressure from second slug with high injectivity as can be seen in Figure 5.44. However, increment of oil production rate is clearly observed only once and there is no clear second peak of oil rate. Major part of oil is recovered from both pressure support from higher injectivity and sweep efficiency of two polymer slugs. However, higher pressure support from chasing water cannot increase oil rate due to poor residual resistance factor of previously injected polymer solutions (both 1,000 and 750 having residual resistance factor of 1.5). The increment of oil rate is more obvious in single-slug case since reservoir pressure is raised at late time when most of recoverable oil is not produced yet.

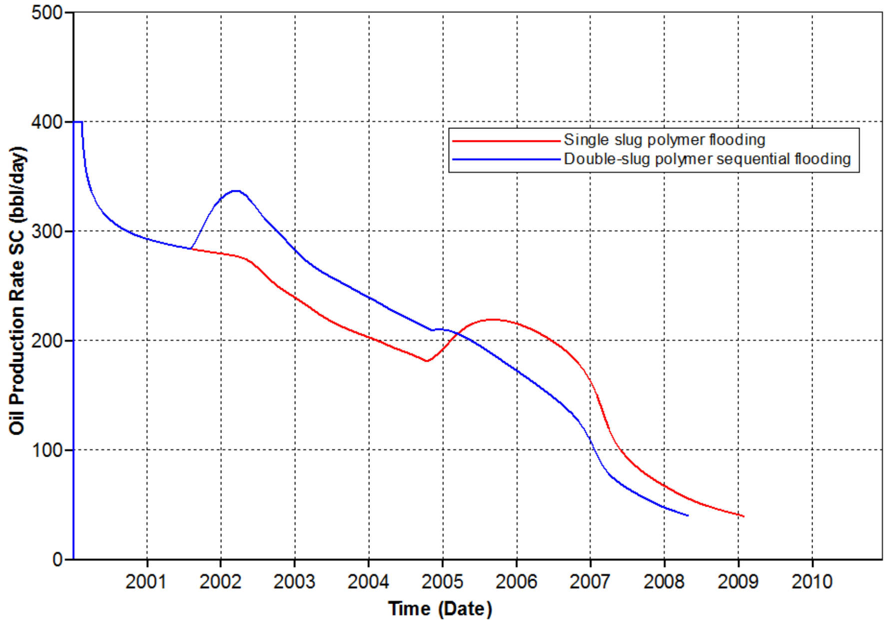


Figure 5.44 Oil production rates of single-slug and double-slug sequential polymer flooding for polymer solution with residual resistance factor of 1.5

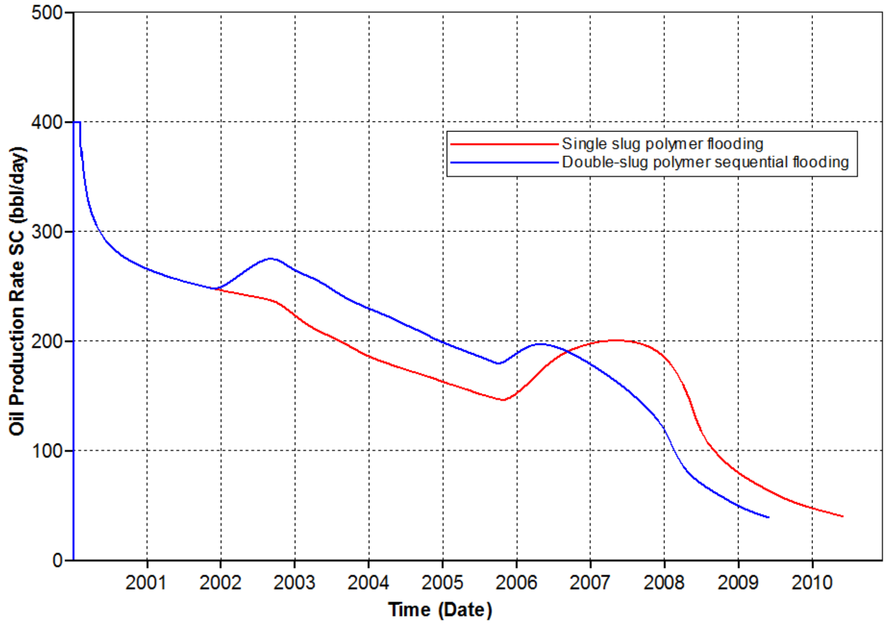


Figure 5.45 Oil production rates of single-slug and double-slug sequential polymer flooding for polymer solution with residual resistance factor of 2.0

On the contrary, residual resistance factors of 2.0 and 2.5 show increment of oil production rate twice, first in early stage and second in late period as illustrated in Figure 5.45 and Figure 5.46, respectively. In these two cases, second oil production rate is due to both increment of reservoir pressure and improving of mobility ratio due to high value of residual resistance factor.

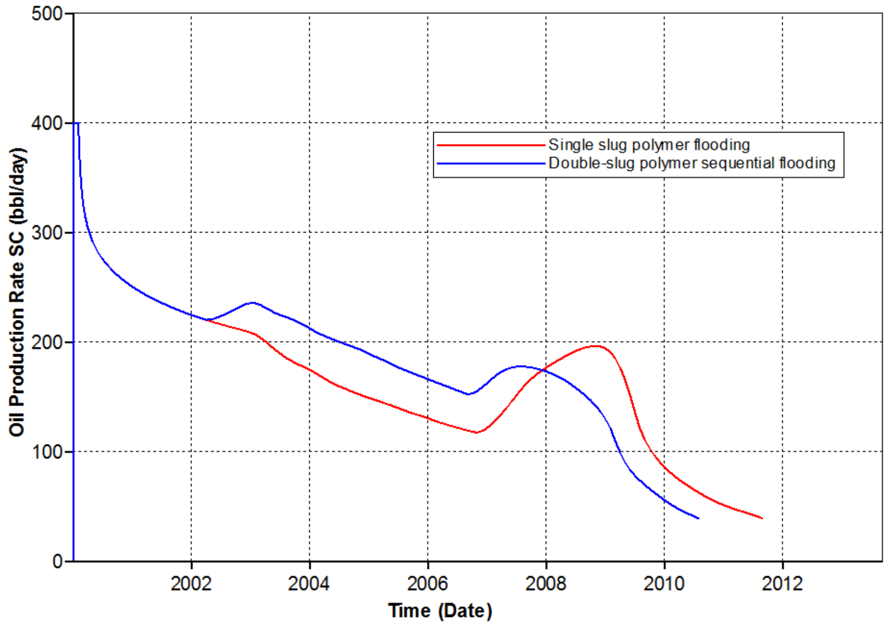


Figure 5.46 Oil production rates of single-slug and double-slug sequential polymer flooding for polymer solution with residual resistance factor of 2.5

Similar to the phenomenon previously discussed in section 5.2.3, large polymer slug size allows polymer solution to displace oil left near the reservoir boundary in high permeability layer effectively. Therefore, single-slug polymer flooding having larger slug size with 1,000 ppm can displace oil near the boundary in high permeability layer better than case of double-slug sequential polymer flooding as illustrated by oil saturation profile in high permeability layer (top layer) in 5.47a and b. However, in double-slug sequential polymer flooding, higher amount of oil in low permeability layer is produced in higher amount compared to single-slug polymer flooding as illustrated by oil saturation profile in low permeability layer (8^{th} layer) in 5.48a and b.

In double-slug sequential polymer flooding, polymer slug in low permeability layer travels faster than in case of single-slug polymer flooding due to improvement of injectivity. Gradually reduction in concentration results in better injectivity while stable displacement is not disturbed. Abruptly change in concentration by chasing high concentration polymer slug with water results in instable displacement due to rapid decrease of viscosity of first polymer slug from mixing process. Chasing high concentration polymer slug with lower polymer concentration slug can mitigate this effect. This phenomenon allows double-slug sequential polymer flooding to recover oil in both high and low permeability layers effectively.

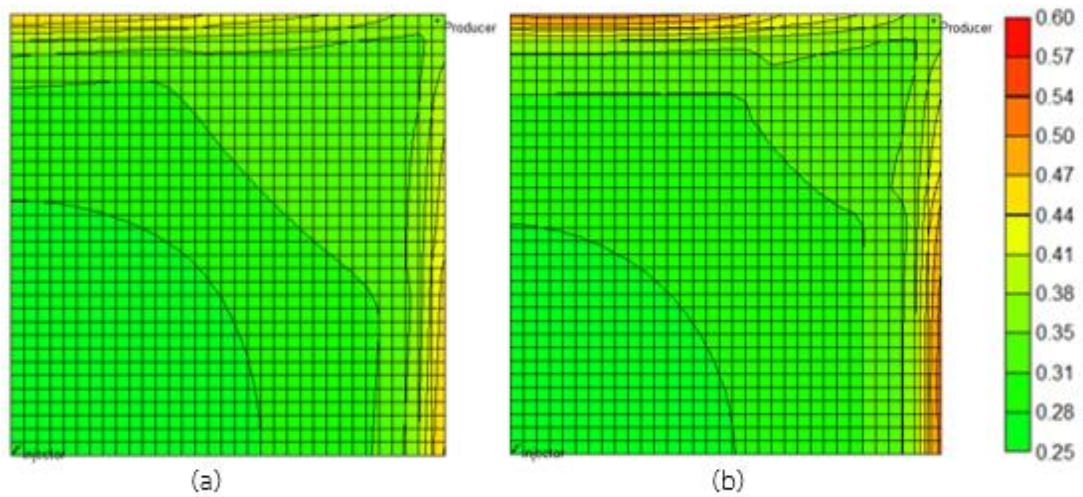


Figure 5.47 Oil saturation profile of high permeability layer (top layer) of a) single-slug polymer flooding and b) double-slug sequential polymer

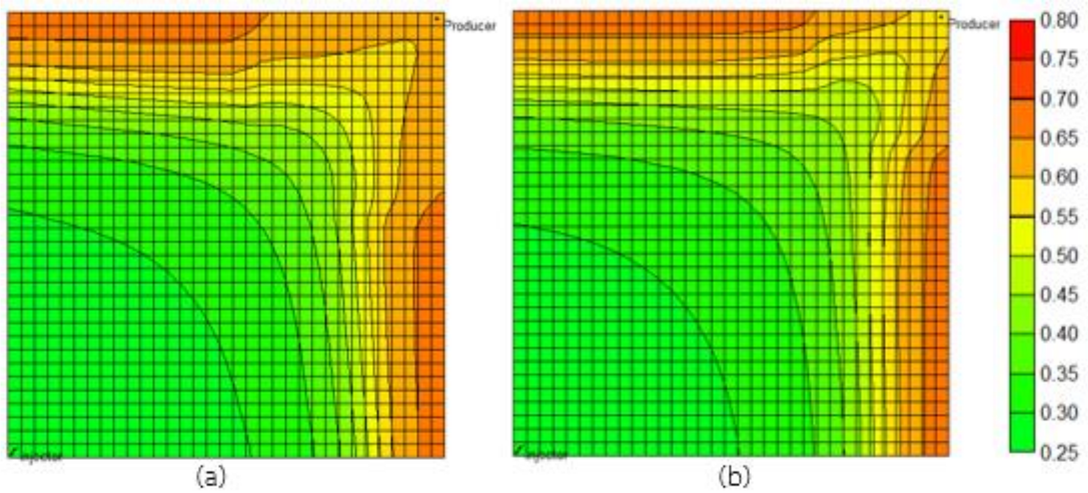


Figure 5.48 Oil saturation profile of low permeability layer (8^{th} layer) of a) single-slug polymer flooding and b) double-slug sequential polymer

Oil recovery factors obtained from both single-slug and double-slug sequential polymer flooding with different residual resistance factors are summarized in Figure 5.49 From the figure, double-slug sequential polymer flooding yields slightly lower oil recovery factor compared to single-slug polymer flooding in case of residual resistance factor of 1.5. Even though increasing oil production in low permeability layer is obtained from higher injectivity when polymer concentration is reduced, decreasing of viscosity occurs due to mixing, resulting in less stable displacement. Together with small residual resistance factor value, sweep efficiency is impoverished. Of course, improvement in oil recovery is observed with an increase of residual resistance factor. Injectivity may be not as high as case of residual resistance factor of 1.5, but reduction of effective permeability to water is higher, improving sweep efficiency. This occurrence results in less instable displacement in high permeability layers meanwhile benefits from injectivity improvement is obtained in low permeability layers. Double-slug sequential polymer flooding therefore yields much higher recovery factor compared to single-slug when residual resistance factor is as high as 2.5.

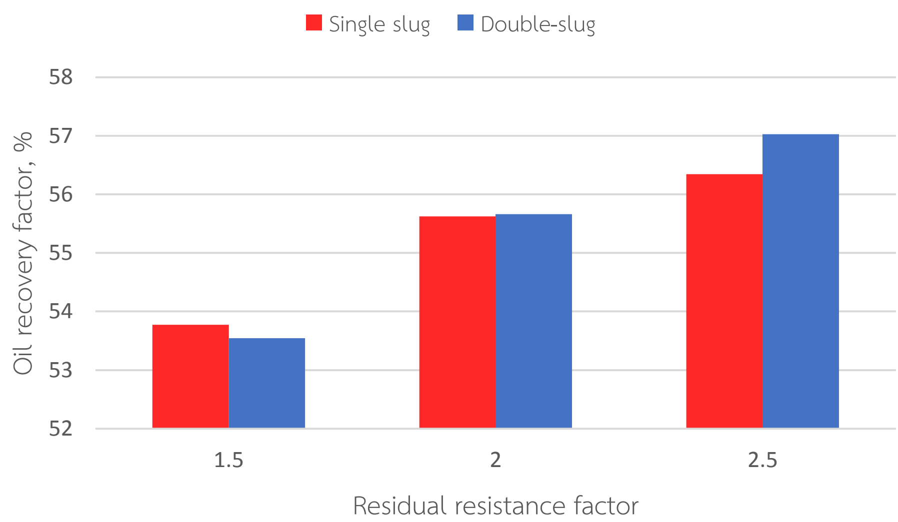


Figure 5.49 Comparison of oil recovery factor between single-slug and double-slug sequential polymer flooding for polymer solutions with different residual resistance factors

Comparison of total production period and total water production of single and double-slug sequential polymer flooding are illustrated in Figure 5.50 and Figure 5.51, respectively.

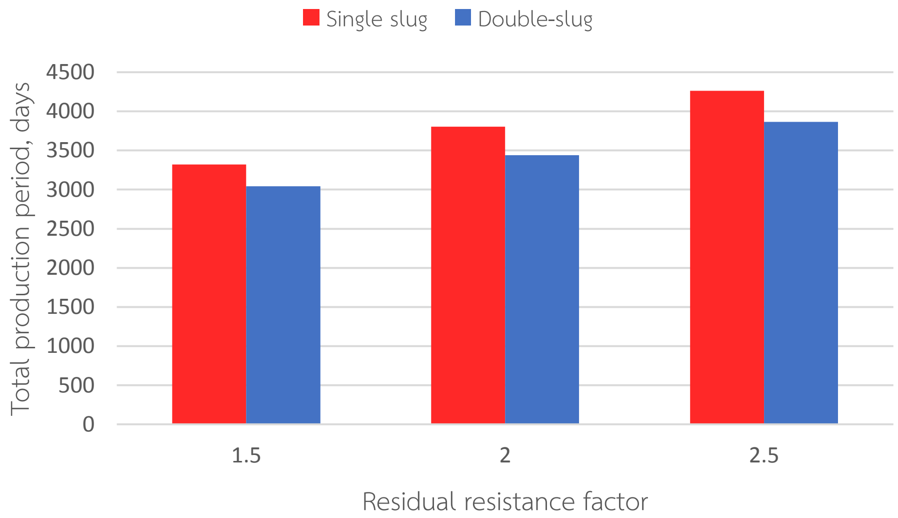


Figure 5.50 Comparison of total production period between single-slug and double-slug sequential polymer flooding for polymer solutions with different residual resistance factors

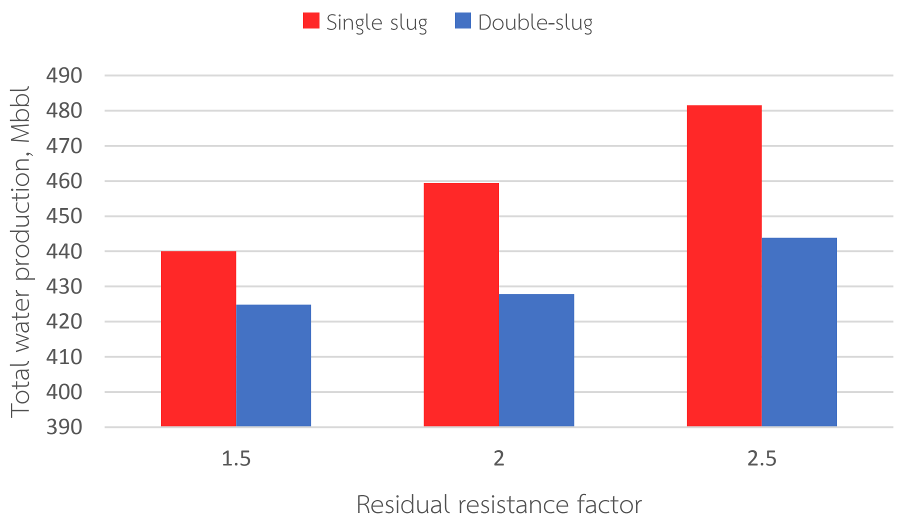


Figure 5.51 Comparison of total water production between single-slug and double-slug sequential polymer flooding for polymer solutions with different residual resistance factors

From these figures, double-slug sequential polymer flooding can shorten total production period by improving polymer injectivity. Oil slug, polymer slug and chasing water slug therefore, travel at higher velocity. Hence, total water production is much reduced compared to single-slug polymer flooding. These benefits are clearly observed in every residual resistance factor.

From simulation results, it is remarkable that benefits of double-slug sequential polymer flooding over single-slug are shortening total production period and reducing total water production. Oil production rate is raised from early stage with greater pressure support. Benefit of double-slug sequential polymer flooding on oil recovery is observed when residual resistance factor is high. However, effect of concentration of second polymer slug and slug size of first polymer slug are not yet included. Following section will describe effects of these two parameters.

5.3.2 Effect of Slug Partitioning with Fixed First Slug Size

Once comparison between single-slug and double-slug sequential polymer flooding is performed, double-slug polymer flooding is modified into different schemes. Flooding schemes A2, B2 and C2 are compared with A1, B1, and C1 to investigate effects of slug partitioning with fixed first slug size. Comparison is made on the same residual resistance factor as well as among residual resistance factors.

First, oil production rates of scheme A1-2, B1-2 and C1-2 are illustrated in Figure 5.52 to Figure 5.54, respectively. Scheme with denote 1 represents a case having less difference in concentration between first and second polymer slugs (1,000 then followed by 750 ppm), whereas scheme with 2 represents a case with big difference in concentration between first and second polymer slugs (1,000 then followed by 500 ppm).

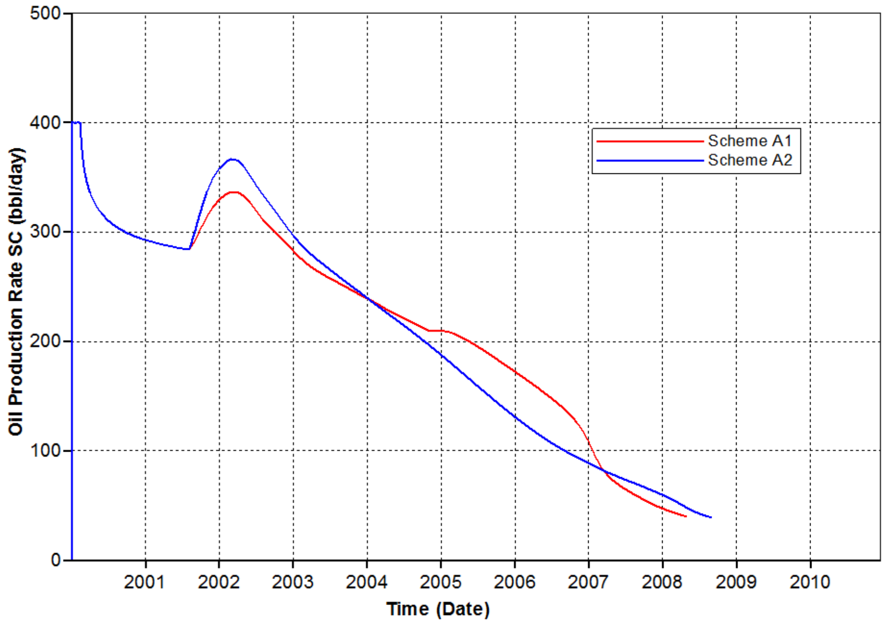


Figure 5.52 Oil production rates of double-slug sequential polymer flooding with different second slug concentrations for polymer solution with residual resistance factor of 1.5

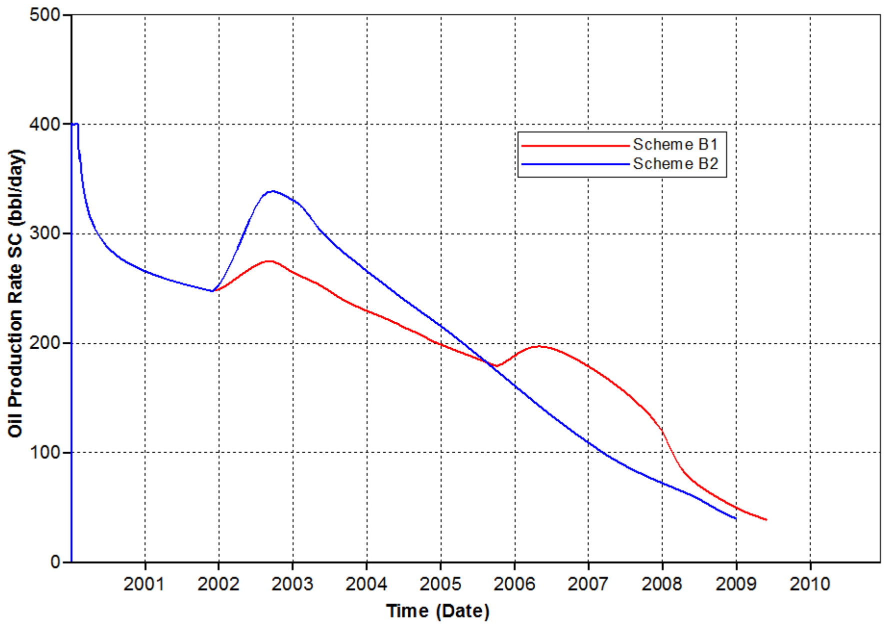


Figure 5.53 Oil production rates of double-slug sequential polymer flooding with different second slug concentrations for polymer solution with residual resistance factor of 2.0

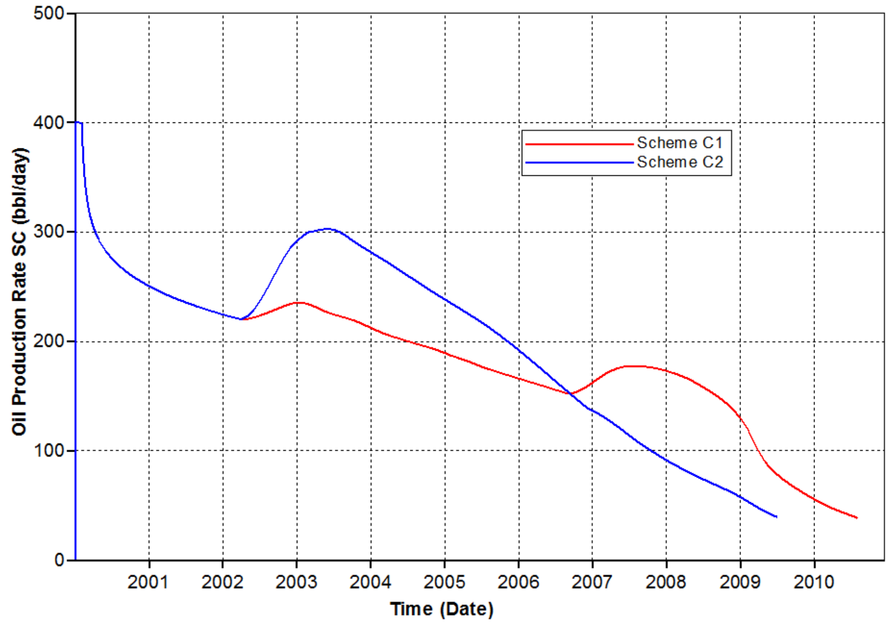


Figure 5.54 Oil production rates of double-slug sequential polymer flooding with different second slug concentrations for polymer solution with residual resistance factor of 2.5

From these three figures, it can be seen that increment of oil production rates in early stage occurs at the same time but result from scheme 2 (higher contrast of polymer concentration) is higher than scheme 1 as a result from better injectivity in every residual resistance factor. This difference is more obvious when residual resistance factor is higher. However, as can predict, second peak of oil rate is not observed in case of scheme 2 for every residual resistance factor. In addition, in later stage, oil production rate of scheme 2 declines faster than scheme 1 as a result of poorer sweep efficiency from less polymer concentration, resulting in low oil recovery factor as depicted in Figure 5.55

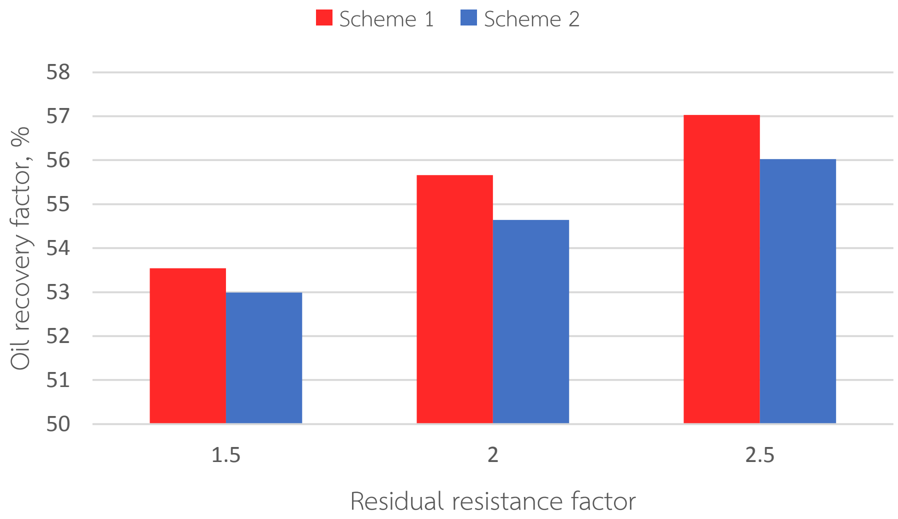


Figure 5.55 Comparison of oil recovery factor between low concentration and high concentration contrast in sequential polymer flooding for polymer solutions with different residual resistance factors

Since oil production rate is affected from slug partitioning, total production time is also affected. Figure 5.56 represents total production time of scheme 1 and 2 for different of residual resistance factors. From the figure, total production time of scheme 2 is shorter than scheme 1 for residual resistance factor of 2 and 2.5 as a result of oil production rate. As residual resistance factor increases polymer adsorption causes reduction of effective permeability to water, improving sweep efficiency. However, benefit from higher injectivity dominates, causing rapid termination. However, in case of residual resistance factor of 1.5, production time of scheme 2 is slightly longer than scheme 1 due to poorer sweep efficiency (both from concentration and residual resistance factor). Oil is therefore produced slowly, causing long period to terminate the process.

As polymer concentration is reduced, more amount of water is required to mix up with polymer for scheme 2. Total water production is always higher in these cases as illustrated in Figure 5.57.

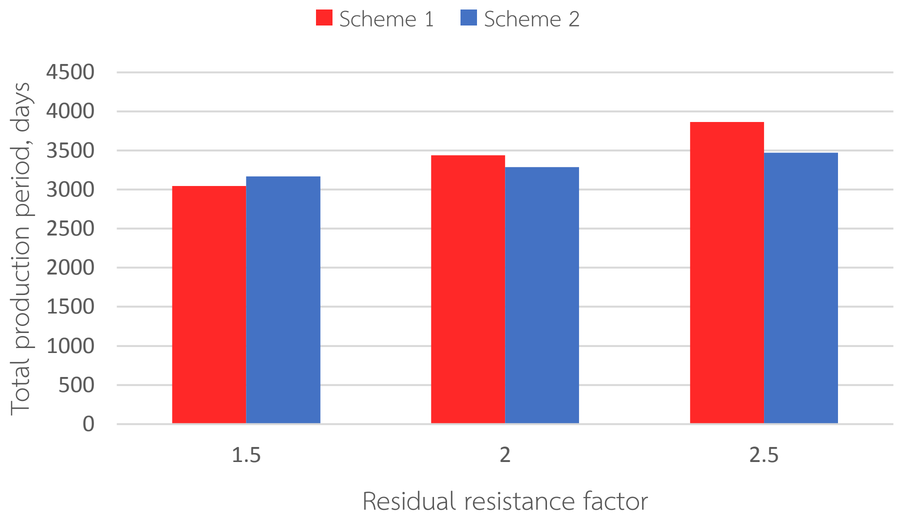


Figure 5.56 Comparison of total production period between low concentration and high concentration contrast in sequential polymer flooding for polymer solutions with different residual resistance factors

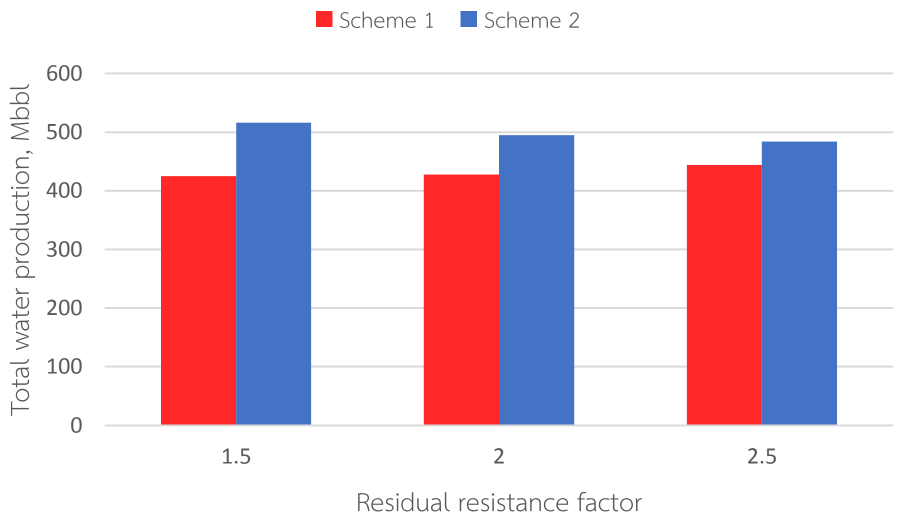


Figure 5.57 Comparison of total water production between low concentration and high concentration contrast in sequential polymer flooding for polymer solutions with different residual resistance factors

It can be seen that, high difference in concentration between first and second polymer slug results in poorer sweep efficiency as mixing of polymer concentrations can cause reduction of polymer viscosity. This leads instability of mobility control and so, lower oil recovery factor. Moreover, using of low concentration of second slug cannot avoid high amount of water production. The only benefit over using less contrast in polymer concentration is shortening production period which is observed only in case of high residual resistance factor (2 and 2.5).

5.3.3 Effect of Slug Partitioning with Various Slug Sizes and Polymer Concentrations

Effects of slug size of first polymer slug is evaluated by comparing scheme 1,3,5 (for low contrast of polymer concentration) and 2,4,6 (for high contrast of polymer concentration) for every residual resistance factor.

Comparison of schemes 2, 4 and 6 is firstly performed. Increment of oil production rate from different schemes are observed at different times as second polymer slug injection is started at different times perform at times as demonstrated in Figure 5.58 to 5.60. The results show that, increment of oil production rate of a case having larger first polymer slug size is less than a case that have smaller first slug size. The early injection of low polymer concentration results in abrupt change of oil rate when previous oil rate is still high. Nevertheless, large increment of oil production rate is also observed for case of larger first polymer slug. The benefit is different at different time for every residual resistance factor. It can be noticed from these three figures that magnitude of increment of oil rates of larger first slug size is more obvious in higher residual resistance factor. This could be explained that as residual resistance factor increases, large polymer slug size with higher concentration can sweep with favorable mobility ratio. A contrast of oil rates before and after injecting low concentration polymer slug is then remarkable.

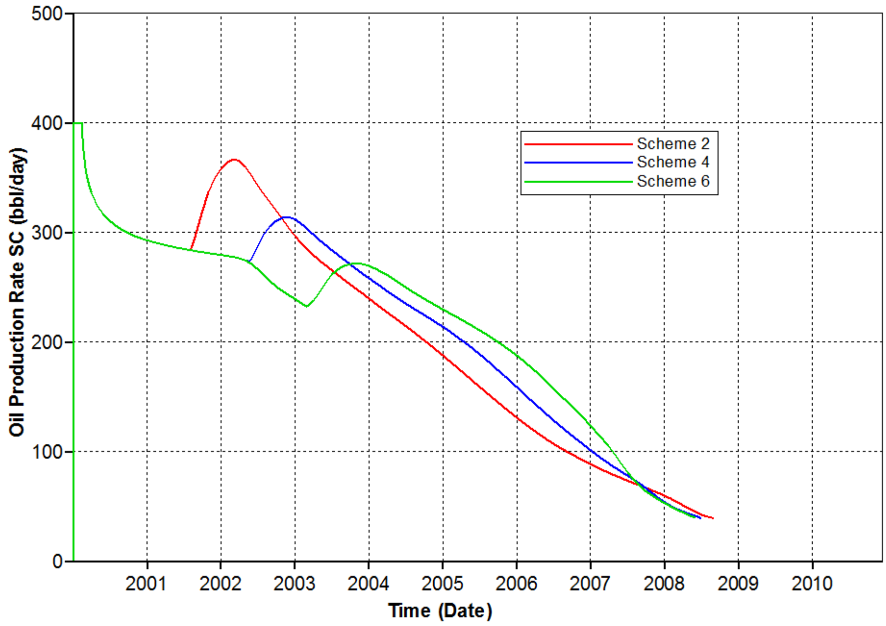


Figure 5.58 Oil production rates of double-slug sequential polymer flooding with different first polymer slug sizes and second slug with concentration of 500 ppm for polymer solution with residual resistance factor of 1.5

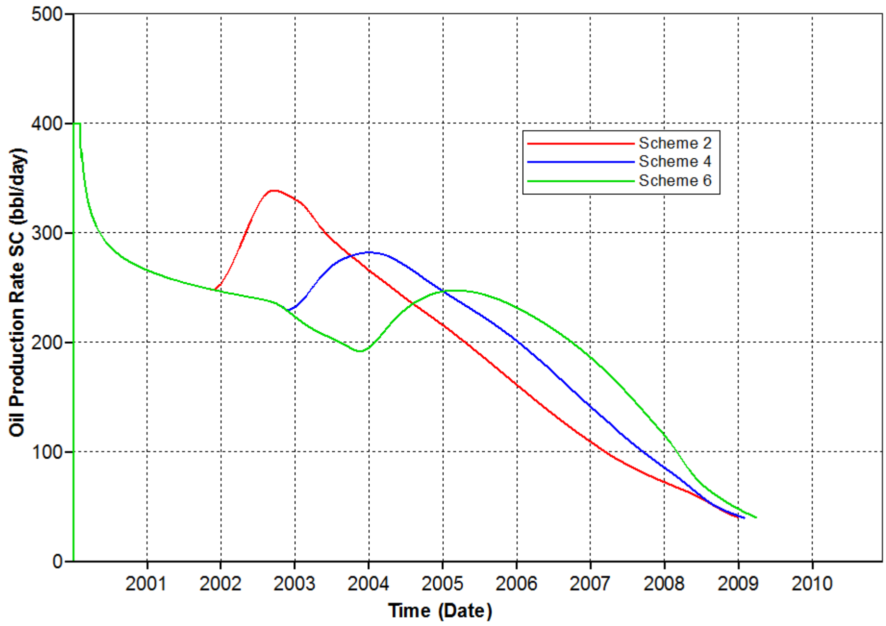


Figure 5.59 Oil production rates of double-slug sequential polymer flooding with different first polymer slug sizes and second slug with concentration of 500 ppm for polymer solution with residual resistance factor of 2.0

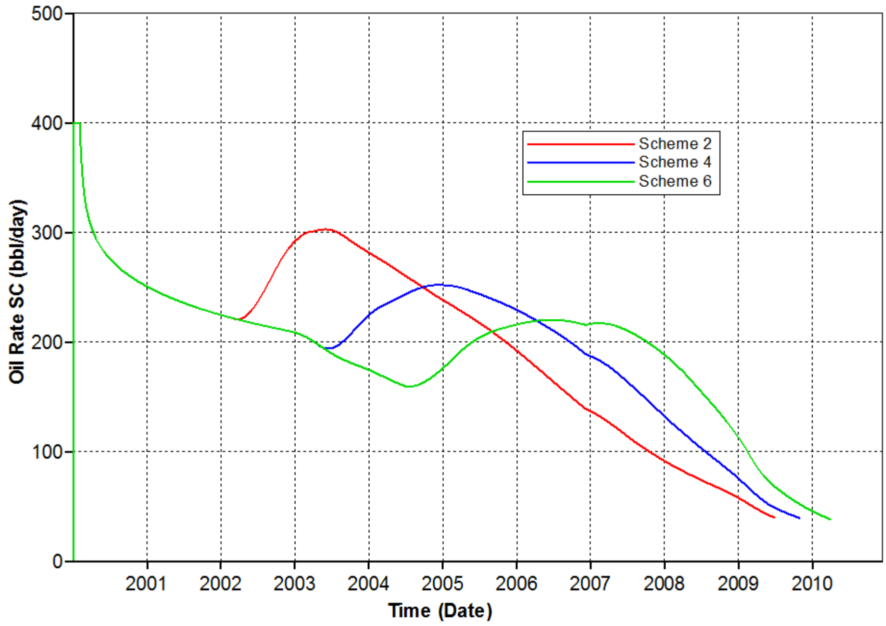


Figure 5.60 Oil production rates of double-slug sequential polymer flooding with different first polymer slug sizes and second slug with concentration of 500 ppm for polymer solution with residual resistance factor of 2.5

Oil recovery factors obtained from different slug sizes of first polymer slug followed by 500 ppm second slug is summarized in Figure 5.61. From this figure, it is obvious that larger size of first polymer slug yields better oil recovery factor compared to smaller size of polymer slug even slug size of second polymer slug is smaller. As explained in section 5.2.2, higher concentration of polymer can displace more fluid due to viscosity effect and reduction of effective permeability from polymer adsorption. Therefore, larger slug size of first polymer slug can displace more oil compared to smaller slug size of first polymer.

Since higher polymer concentration cannot be easily injected to the formation, using larger slug size of first polymer slug leads to longer total production period as summarized in Figure 5.65. However, in case of residual resistance factor of 1.5, similar to section 5.3.2, total production period of a case having larger first slug is shorter than a case having smaller first slug. Even though large high concentration slug can travel slowly, much improvement in injectivity with an assist of small residual resistance factor dominates effect from high viscosity of large slug, resulting in slightly shorter production period.

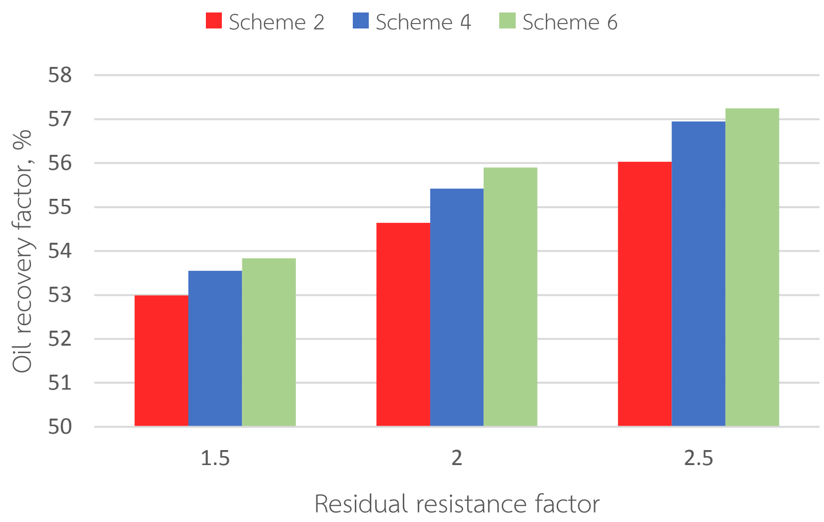


Figure 5.61 Comparison of oil recovery factor among different sizes of first polymer slug with second slug size of 500 ppm polymer concentration for polymer solutions with different residual resistance factors

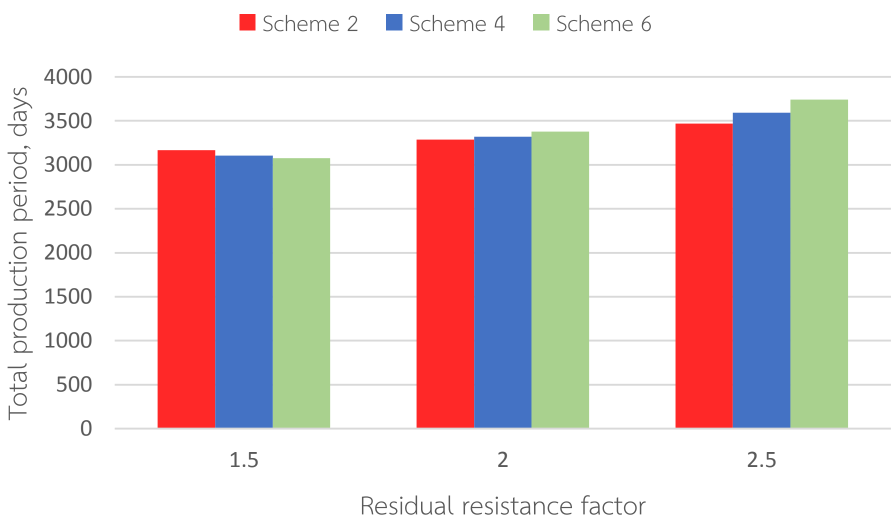


Figure 5.62 Comparison of total production time among different sizes of first polymer slug with second slug size of 500 ppm polymer concentration for polymer solutions with different residual resistance factors

Although larger slug size of first polymer slug leads to longer total production period in most cases, total water production of a case having larger slug size of first polymer slug is lower than a case having smaller slug size. Total water production of a case with larger slug size is decreased as a result from larger portion of high polymer concentration. Moreover, this high concentration of polymer slug allows polymer adsorption throughout in the reservoir, causing reduction of effective permeability to water as discussed in section 5.2.3

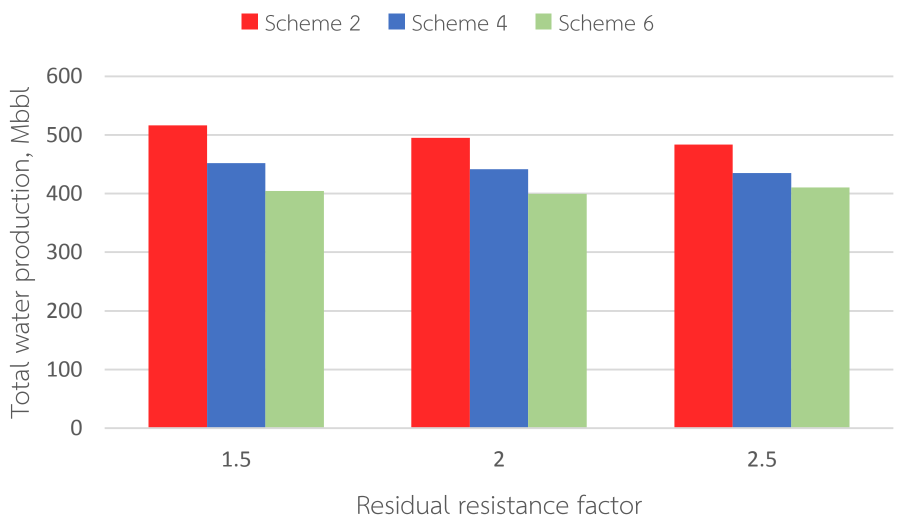


Figure 5.63 Summary of total water production of double-slug sequential polymer flooding with different size of first slug with second slug concentration of 500 ppm for different of residual resistance factor

Once comparison of schemes 2, 4 and 6 is performed, comparison of schemes 1, 3 and 5 is made to evaluate effects of first polymer slug size when there is small difference between concentration of first and second polymer slugs. The result show that effects of first polymer slug size on a scheme having small difference between concentration of first and second polymer slugs are quite similar to a case of large difference. Oil recovery factors are summarized in Figure 5.64. From the figure, difference in oil recovery factor is not obvious as in case of large difference of concentrations. However, there is no exactly the trend observed in this case. When contrast of polymer concentration is not high, the case with larger first slug may not obtain benefit from small improvement in injectivity that is traded with decrease in reduction of effective permeability, whereas in case of high resistance factor injectivity is not much improved. For resistance factor of 2.0, benefit of injectivity and reduction in permeability is still obtained from sequential flooding when first slug is large and polymer contrast is not much.

Figure 5.64 Comparison of oil recovery factor among different sizes of first polymer slug with second slug size of 750 ppm polymer concentration for polymer solutions with different residual resistance factors

Total production period is summarized in Figure 5.65. The results show that production period is always increased with larger slug size. The only difference of result in this section with the case of large contrast between two slugs is observed in case of residual resistance factor of 1.5. As polymer concentration is slightly modified in concentration, effect from viscosity still dominates injectivity improvement and hence, larger viscous slug results in longer production time.

Total water production is demonstrated in Figure 5.66. Increasing of slug size of polymer slug should decrease total water production. This trend can be observed in case of residual resistance factor of 1.5. However, for residual resistance factor of 2.0 and 2.5, similar trends cannot be observed. For residual resistance factor of 2.0, total water production is the highest in case that first slug is small. As concentration between two slugs is not much different together with an aid of high residual resistance factor, chasing water can be started almost the same day. That makes the case with higher amount of water which is the case B1 to produce maximum water. Nevertheless, total production period slightly increases with larger slug size, making the case B5 to increase amount of water production again. The same explanation is applied also for residual resistance factor of 2.5 but slightly longer production time of case C5 results in the highest water production over case C1.

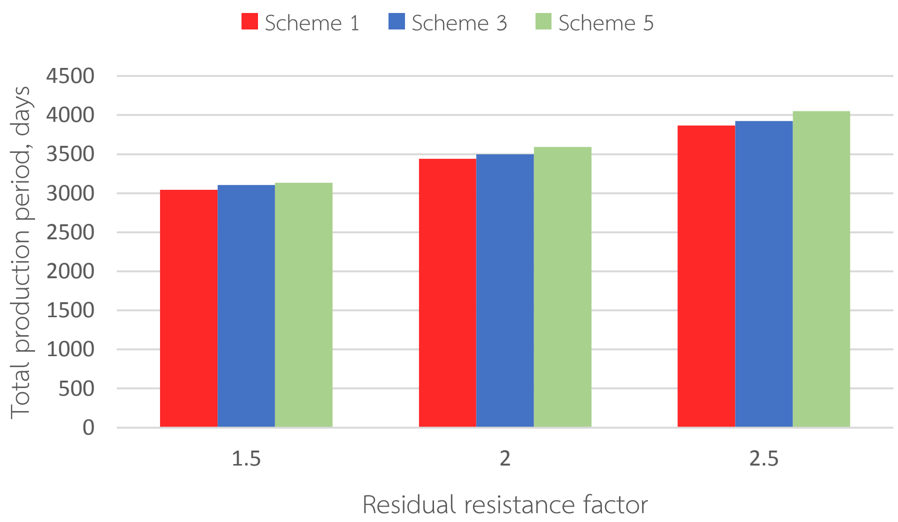


Figure 5.65 Comparison of total production period among different sizes of first polymer slug with second slug size of 750 ppm polymer concentration for polymer solutions with different residual resistance factors

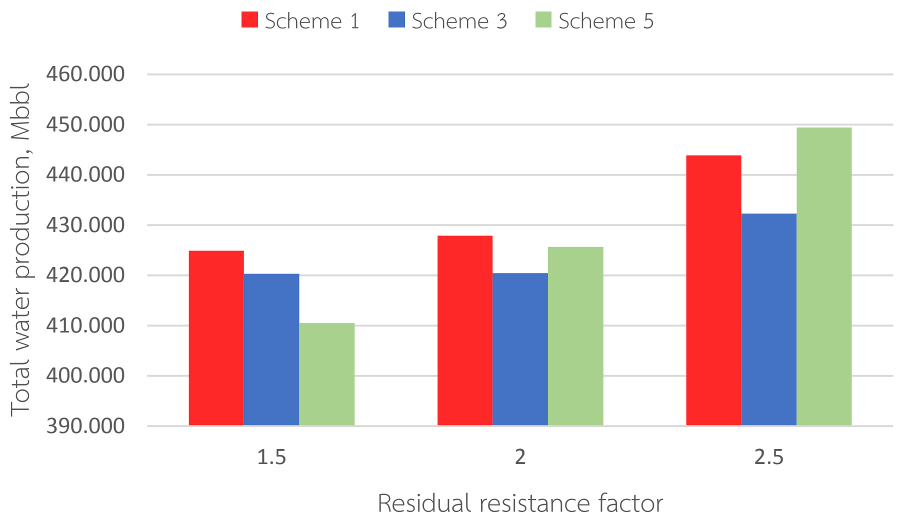


Figure 5.66 Comparison of total water production among different sizes of first polymer slug with second slug size of 750 ppm polymer concentration for polymer solutions with different residual resistance factors

In summary, slug size of first polymer slug has a greater impact especially when concentration of following slug is highly reduced compared to second slug. Even though benefit from higher injectivity is obtained, the rate of reduction in concentration in first slug cannot be avoided. Hence, first slug should be large to maintain its concentration from reduction of viscosity from polymer adsorption and mixing with second slug polymer. Tendency of oil recovery factor, total production period and total water production can be mostly predicted. For sequential polymer flooding with small reduction in polymer concentration, size of first slug only shows small impact on effectiveness of the process since both polymer slugs have closer properties compared to the case with high contrast. Trends of simulation outcomes maybe not as clear as case of high contrast.

5.3.4 Summary of Double-slug Sequential Polymer Flooding

In this study, effects of slug size of first polymer slug and concentration of second slug are studied together with effects of residual resistance factor. Simulation results of double-slug sequential polymer flooding in different schemes are summarized in Table 5.9 to Table 5.11 for residual resistance factors of 1.5, 2.0 and 2.5, respectively.

Favorable results which are high oil recovery factor, low total water production and low total production period can be obtained from an optimal scheme. The same judgment function of single-slug is used to determine the optimal scheme for double-slug sequent polymer flooding. Maximum value of oil recovery factor, maximum value polymer efficiency, minimum value water production and minimum value of total production period are obtained from best single-slug and these values are used in judgment function for double-slug cases to compare with original total score from single-slug polymer flooding. From the tables, Scheme no.6 yields the highest total score for all residual resistance factors.

From these results, it can be noticed that effect of slug size of first polymer slug dominates effect of concentration of second polymer slug. Therefore, slug size of first polymer slug should be large enough to maintain stability of displacement mechanism and concentration of second slug should not be too low to cause rapid reduction in stability of the first slug or not too high that improvement in injectivity will not occur.

It is also obvious that residual resistance factor is a critical parameter that determines effectiveness of double-slug sequential polymer flooding. In case of residual resistance factor of 1.5, benefits of double-slug sequential polymer flooding with optimal scheme over single-slug polymer flooding are shortening total production period and reducing water production. Higher in oil recovery factor can be obtained with optimal scheme with residual resistance factor of 2 and 2.5.

It can concluded that higher residual resistance factor of polymer solution is a favorable condition to perform double-slug sequential polymer flooding effectively.

Table 5.9 *Summary of simulation outcomes for double-slug sequential polymer flooding with residual resistance factor of 1.5*

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single-slug	3,319	440.08	53.77	96.03
A1	3,043	424.9	53.55	96.78
A2	3,166	516.35	52.99	92.32
A3	3,104	420.32	53.84	97.48
A4	3,104	451.95	53.55	95.68
A5	3,135	410.51	53.8	97.66
A6	3,074	404.25	53.84	98.19

Table 5.10 Summary of simulation outcomes for double-slug sequential polymer flooding with residual resistance factor of 2.0

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single-slug	3,804	459.46	55.62	94.27
B1	3,439	427.9	55.66	96.25
B2	3,288	495	54.64	92.27
B3	3,500	420.46	55.94	96.98
B4	3,319	441.51	55.42	95.54
B5	3,592	425.67	56.07	96.85
B6	3,378	399.75	55.9	98.05

Table 5.11 Summary of simulation outcomes for double-slug sequential polymer flooding with residual resistance factor of 2.5

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single-slug	4,261	481.55	56.34	90.22
C1	3,865	443.88	57.03	93.42
C2	3,469	483.9	56.03	91.10
C3	3,926	432.3	57.03	93.72
C4	3,592	434.87	56.95	94.15
C5	4,049	449.39	56.95	92.75
C6	3,743	410.41	57.25	95.32

5.4 Triple-Slug Sequential Polymer Flooding

As same as cases of double-slug sequential polymer flooding, triple-slug sequential polymer flooding is performed by keeping amount of polymer used to be equal to the case of single-slug polymer flooding base case.

According to simulation outcomes from previous section, effect of second polymer slug concentration is dominated by slug size of first slug in cases that polymer concentrations are much different (concentration of second slug of 500 ppm). Slug size of first polymer slug should be large enough to maintain stability of displacement mechanism and water controllability of polymer solution. Therefore, for case with big difference in concentrations, only scheme 6 is selected for modification into triple-slug. However, effect of first polymer slug size in case of small difference in concentrations is not obvious, so all schemes 1, 3, and 5 are selected to modify into triple-slug.

In this study, slug size of second polymer slug is varied from 0.1 to 0.2 PV based on selected scheme of double-slug sequential polymer flooding, whereas slug size of third polymer slug depends on how much polymer mass is remained from first and second slugs. Concentration of third polymer slug is kept constant at 250 and 500 ppm for cases of concentrations of second slug 500 and 750 ppm, respectively. The same criteria as single-slug polymer flooding are used for comparing effectiveness of triple-slug sequential polymer flooding except amount of addition oil recovery per polymer consume since all schemes consume the same amount of polymer. All schemes of triple-slug sequential polymer flooding are summarized in Table 5.12

Table 5.12 Summary of every triple-slug sequential polymer scheme

Scheme no.	Residual resistance factor	Slug size of first slug (PV)	Concentration of second slug (ppm)	Slug size of second slug (PV)	Concentration of third slug (ppm)	Slug size of third slug (PV)
A11	1.5	0.1	750	0.1	500	0.25
A12	1.5	0.1	750	0.15	500	0.175
A13	1.5	0.1	750	0.2	500	0.1
A31	1.5	0.15	750	0.1	500	0.15
A32	1.5	0.15	750	0.15	500	0.075
A51	1.5	0.2	750	0.1	500	0.05
A61	1.5	0.2	500	0.1	250	0.2
A62	1.5	0.2	500	0.15	250	0.1
B11	2.0	0.1	750	0.1	500	0.25
B12	2.0	0.1	750	0.15	500	0.175
B13	2.0	0.1	750	0.2	500	0.1
B31	2.0	0.15	750	0.1	500	0.15
B32	2.0	0.15	750	0.15	500	0.075
B51	2.0	0.2	750	0.1	500	0.05
B61	2.0	0.2	500	0.1	250	0.2
B62	2.0	0.2	500	0.15	250	0.1
C11	2.5	0.1	750	0.1	500	0.25
C12	2.5	0.1	750	0.15	500	0.175
C13	2.5	0.1	750	0.2	500	0.1
C31	2.5	0.15	750	0.1	500	0.15
C32	2.5	0.15	750	0.15	500	0.075
C51	2.5	0.2	750	0.1	500	0.05
C61	2.5	0.2	500	0.1	250	0.2
C62	2.5	0.2	500	0.15	250	0.1

Similar to explanation in double-slug sequential polymer flooding, triple-slug sequential polymer flooding can further improve injectivity of polymer solution, resulting in higher oil production rate during injection third-slug. However, in case of concentration of second slug of 500 ppm, triple-slug does not yield improvement of injectivity since polymer solution of 500 ppm can be already injected at the desired rate. In case of triple-slug sequential polymer flooding applied with residual resistance factors of 2.0 and 2.5, total production period is shortened compared double-slug sequential polymer flooding as a result of improvement on injectivity. However, in case of residual resistance factor of 1.5, total production period is as same as case of double-slug since improvement of injectivity is traded with poor sweep efficiency (both from reduction of viscosity and decrease in reduction of effective permeability to water).

With favorable mobility ratio, shortening of total production period comes together with reduction of total water production as can be seen in all cases of residual resistance factor of 2.5. However, in case of residual resistance factor of 2.0, although total production period is shorter, higher total water production is observed in one case which is a result from too small slug size of first and second polymer slug, causing poor reduction of effective permeability to water.

Simulation outcomes of triple-slug sequential polymer flooding in different schemes are summarized in to Table 5.15 for residual resistance factors of 1.5, 2.0 and 2.5, respectively.

Table 5.13 *Summary of simulation outcomes for double-slug and triple-slug sequential polymer flooding with residual resistance factor of 1.5*

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
A1	3,043	424.90	53.55	96.78
A11	3,074	454.33	53.59	95.79
A12	3,043	432.33	53.76	97.03
A13	3,013	416.01	53.67	97.51
A3	3,104	420.32	53.84	97.48
A31	3,043	406.13	53.86	98.27
A32	3,043	400.67	53.80	98.34
A5	3,135	410.51	53.80	97.66
A51	3,104	401.80	53.80	98.64
A6	3,074	404.25	53.84	98.19
A61	3,166	444.46	53.79	96.33
A62	3,074	404.83	53.84	98.16

Table 5.14 Summary of simulation outcomes for double-slug and triple-slug sequential polymer flooding with residual resistance factor of 2.0

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
B1	3,439	427.90	55.66	96.25
B11	3,288	442.41	55.45	95.66
B12	3,288	417.53	55.63	96.98
B13	3,319	408.39	55.62	97.24
B3	3,500	420.46	55.94	96.98
B31	3,347	401.31	55.93	98.13
B32	3,408	403.93	55.97	97.94
B5	3,592	425.67	56.07	96.85
B51	3,500	405.80	55.92	97.55
B6	3,378	399.75	55.90	98.05
B61	3,439	429.23	55.74	96.38
B62	3,378	400.25	55.90	98.02

Table 5.15 Summary of simulation outcomes for double-slug and triple-slug sequential polymer flooding with residual resistance factor of 2.5

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
C1	3,865	443.88	57.03	93.42
C11	3,561	432.19	57.02	94.46
C12	3,622	419.07	57.27	95.29
C13	3,684	414.46	57.10	94.99
C3	3,926	432.30	57.03	93.72
C31	3,712	407.58	57.33	95.65
C32	3,804	414.81	57.15	94.83
C5	4,049	449.39	56.95	92.75
C51	3,957	433.31	56.95	93.47
C6	3,743	410.41	57.25	95.32
C61	3,773	433.86	57.13	94.15
C62	3,712	402.91	57.22	95.63

In summary, benefit of triple-slug sequential polymer flooding over double-slug sequential polymer flooding is improvement of injectivity compared to double-slug. This benefit is observed only when second slug of polymer cannot attain the desired rate. Improvement of injectivity of triple-slug yields shorter total production time as well as total water production for residual resistance factor of 2.0 and 2.5. A slight increment of oil recovery factor is obtained with optimal scheme with residual resistance factor 2.5. These results further confirm from previous section that higher residual resistance factor of polymer solution is one concern for sequential polymer flooding effectively as discussed in section 5.3.4.

5.5 Effect of Reservoir Heterogeneity

Discussion over last sections is made on reservoir model with Lorenz coefficient value of 0.20. In this section, effect of reservoir heterogeneity is investigated through the study on reservoir with higher heterogeneity. Two models with variation of permeability are constructed with L_k of 0.24 and 0.275 and to be comparable among cases, higher heterogeneity models are constructed by keeping maximum permeability, average permeability, mean value permeability and minimum permeability for all three models.

Similarly, single-slug polymer flooding is first investigated for reservoir models with higher heterogeneity. After that, base case is selected, using the same criteria which are oil recovery factor, additional oil recovered per polymer consumed, total water production and production time with the same weighing fractions.

In this section, effects of heterogeneity on simulation outcomes of single-slug polymer flooding are firstly discussed. After that, the results obtained from different heterogeneous models, employing double-slug and triple-slug sequential models are compared.

5.5.1 Effect of Heterogeneity on Single-slug Polymer Flooding

Simulation outcomes of all cases for heterogeneous model with L_k of 0.24 are summarized in Table 5.16 to Table 5.18, and simulation outcomes of all cases for heterogeneous model with L_k of 0.275 are summarized in Table 5.19 to Table 5.21 where three tables for each reservoir heterogeneity value are for three different residual resistance factors of 1.5, 2.0 and 2.5.

From the tables, it can be observed that pre-flushed water slug still does not yield much benefit on oil recovery. Moreover, presence of pre-flushed water results in extension of total production period which consequently causes high total water production as same as in case of reservoir model with L_k =0.20. Higher polymer concentration tends to yield higher oil recovery factor due to more favorable mobility ratio, resulted from viscosity enhancement and reduction of effective permeability to water. In contrast to low heterogeneity model with low residual resistance factor, increment of polymer concentration meets requirements in terms of amount of additional oil recovery per polymer consumed since oil cannot well swept with low polymer concentration due to effect of permeability variation.

According to these simulation results, increment of polymer slug size increases oil recovery factor due to higher polymer mass that results in sufficient polymer quantity to maintain viscosity of polymer solution after adsorption of polymer onto rock surface. As same as low heterogeneity model, increment of polymer slug size also comes together with less amount of additional oil recovered per polymer mass consumed due to small amount of oil left at late time. Increment additional oil recovered per polymer consumed is still observed with an increase of residual resistance factor of polymer solution. However increment of residual resistance factor tends to yield lower injectivity and hence, resulting in longer total production time as well as higher total water production.

Total judgment scores of all cases based on criteria and weighing fractions for heterogeneous models with L_k of 0.24 and 0.275 are summarized in Table 5.22 and Table 5.23, respectively. From the table, similar to heterogeneity model with L_k =0.2, polymer concentration of 1,000 ppm with polymer slug size 0.30PV and without pre-flushed water yields the highest total score among all cases for residual resistance factors of 1.5 and 2.0. However, in case of the highest residual resistance factor of 2.5, polymer concentration of 1,000 ppm with polymer solution slug size 0.20 PV, without pre-flushed water and polymer concentration of 750 ppm with polymer solution slug size 0.30 PV, without pre-flushed water yields yield the highest total score in case of heterogeneous models with L_k of 0.24 and 0.275.

Table 5.16 Summary of simulation outcomes of heterogeneous model with L_k of 0.24 for polymer solution with residual resistance factor of 1.5

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Production time (days)	Total water production (bbl)	RF, %	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,738	534.55	43.49	1,582.2
		750	2,616	441.84	45.95	1,823.8
		1,000	2,800	366.26	48.62	1,991.9
	0.25	500	2,647	484.09	44.46	1,628.2
		750	2,616	416.83	47.67	1,886.3
		1,000	2,861	328.99	50.59	1,962.4
	0.3	500	2,647	469.50	45.51	1,686.1
		750	2,588	385.08	49.05	1,859.8
		1,000	3,013	325.30	52.63	1,953.1
0.04	0.2	500	2,830	573.30	43.60	1,634.0
		750	2,738	499.70	46.03	1,846.9
		1,000	2,891	420.08	48.65	1,999.1
	0.25	500	2,800	545.46	44.70	1,720.0
		750	2,708	463.75	47.66	1,885.9
		1,000	2,982	394.46	50.78	1,996.3
	0.3	500	2,800	531.09	45.71	1,748.7
		750	2,708	442.97	49.06	1,861.7
		1,000	3,135	396.51	52.68	1,960.7
0.08	0.2	500	2,953	623.20	43.71	1,687.7
		750	2,861	549.29	46.18	1,893.7
		1,000	3,013	484.98	48.77	2,026.6
	0.25	500	2,922	595.40	44.76	1,742.2
		750	2,861	525.43	47.79	1,917.9
		1,000	3,104	462.48	50.92	2,023.2
	0.3	500	2,922	581.12	45.76	1,762.3
		750	2,861	504.53	49.17	1,885.3
		1,000	3,257	466.76	52.77	1,974.3

Table 5.17 Summary of simulation outcomes of heterogeneous model with L_k of 0.24 for polymer solution with residual resistance factor of 2.0

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Production time (days)	Total water production (bbl)	RF, %	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,800	540.78	44.79	2,193.5
		750	2,800	448.71	47.63	2,347.1
		1,000	3,074	353.53	50.64	2,464.2
	0.25	500	2,738	499.29	45.93	2,179.6
		750	2,800	411.19	49.39	2,315.9
		1,000	3,288	345.68	52.88	2,389.8
	0.3	500	2,738	483.32	47.05	2,164.5
		750	2,830	388.88	50.90	2,243.8
		1,000	3,500	343.79	54.70	2,275.0
0.04	0.2	500	2,922	590.77	44.96	2,271.4
		750	2,891	505.04	47.70	2,369.6
		1,000	3,166	409.39	50.51	2,434.3
	0.25	500	2,891	561.04	46.15	2,263.2
		750	2,861	459.49	49.32	2,298.5
		1,000	3,378	404.90	52.76	2,366.9
	0.3	500	2,861	534.72	47.12	2,187.7
		750	2,922	449.63	50.92	2,248.1
		1,000	3,622	417.93	54.43	2,233.7
0.08	0.2	500	3,043	640.38	45.05	2,312.2
		750	2,982	559.44	47.80	2,400.9
		1,000	3,288	476.12	50.38	2,404.0
	0.25	500	3,013	611.31	46.17	2,270.9
		750	2,982	527.09	49.53	2,351.7
		1,000	3,500	475.53	52.54	2,326.7
	0.3	500	2,982	584.70	47.13	2,189.1
		750	3,013	508.12	51.01	2,266.3
		1,000	3,712	479.09	54.12	2,185.3

Table 5.18 Summary of simulation outcomes of heterogeneous model with L_k of 0.24 for polymer solution with residual resistance factor of 2.5

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Production time (days)	Total water production (bbl)	RF, %	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,891	558.77	46.07	2,792.1
		750	2,953	450.61	48.99	2,770.7
		1,000	3,347	349.47	51.75	2,722.5
	0.25	500	2,830	516.85	47.26	2,677.2
		750	2,953	399.91	50.74	2,654.1
		1,000	3,653	352.81	53.88	2,576.4
	0.3	500	2,769	478.12	48.22	2,530.9
		750	3,043	386.19	52.41	2,557.1
		1,000	3,926	353.24	55.23	2,357.6
0.04	0.2	500	2,982	598.82	46.09	2,797.3
		750	3,043	505.75	48.98	2,766.3
		1,000	3,469	417.42	51.55	2,677.2
	0.25	500	2,922	557.34	47.25	2,674.5
		750	3,043	457.66	50.72	2,646.8
		1,000	3,743	413.39	53.70	2,544.3
	0.3	500	2,891	530.19	48.24	2,536.0
		750	3,135	445.56	52.39	2,554.0
		1,000	4,049	428.38	55.04	2,328.8
0.08	0.2	500	3,135	660.15	46.27	2,882.0
		750	3,135	558.69	49.17	2,827.6
		1,000	3,592	488.37	51.25	2,606.3
	0.25	500	3,043	607.66	47.27	2,681.9
		750	3,166	524.79	51.02	2,722.0
		1,000	3,865	487.21	53.32	2,472.9
	0.3	500	3,013	580.61	48.26	2,541.6
		750	3,257	515.81	52.61	2,598.7
		1,000	4,169	503.88	54.90	2,306.7

Table 5.19 Summary of simulation outcomes of heterogeneous model with L_k of 0.275 for polymer solution with residual resistance factor of 1.5

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Production time (days)	Total water production (bbl)	RF, %	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,526	479.00	41.25	1,845.7
		750	2,404	380.30	44.12	2,126.9
		1,000	2,708	343.55	47.50	2,384.0
	0.25	500	2,496	436.33	43.41	2,286.6
		750	2,373	343.94	45.73	2,102.7
		1,000	2,861	338.96	49.72	2,323.5
	0.3	500	2,465	439.51	42.29	1,553.7
		750	2,465	355.25	47.51	2,121.5
		1,000	3,074	357.09	51.87	2,271.8
0.04	0.2	500	2,647	527.97	41.46	1,944.7
		750	2,496	427.31	44.10	2,119.9
		1,000	2,830	408.55	47.66	2,423.1
	0.25	500	2,616	499.49	42.56	1,965.7
		750	2,496	401.46	45.86	2,134.1
		1,000	2,982	406.83	49.84	2,346.3
	0.3	500	2,616	485.17	43.57	1,953.7
		750	2,588	413.12	47.59	2,137.6
		1,000	3,196	429.20	51.90	2,275.9
0.08	0.2	500	2,769	576.27	41.58	2,001.5
		750	2,647	485.85	44.37	2,204.8
		1,000	2,982	483.57	47.94	2,487.2
	0.25	500	2,769	559.43	42.74	2,033.3
		750	2,677	471.89	46.13	2,202.2
		1,000	3,135	485.65	50.12	2,397.0
	0.3	500	2,800	556.10	43.85	2,040.7
		750	2,769	484.10	47.78	2,177.7
		1,000	3,319	500.29	51.98	2,287.5

Table 5.20 Summary of simulation outcomes of heterogeneous model with L_k of 0.275 for polymer solution with residual resistance factor of 2.0

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Production time (days)	Total water production (bbl)	RF, %	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,616	494.60	42.67	2,509.6
		750	2,557	374.93	45.76	2,636.5
		1,000	3,074	364.45	49.76	2,912.6
	0.25	500	2,557	454.08	43.80	2,430.6
		750	2,588	347.44	47.69	2,591.2
		1,000	3,288	356.46	51.95	2,740.3
	0.3	500	2,557	438.37	44.90	2,368.3
		750	2,677	346.83	49.32	2,498.2
		1,000	3,561	377.08	53.80	2,572.5
0.04	0.2	500	2,738	544.39	42.85	2,595.4
		750	2,647	430.97	45.84	2,661.9
		1,000	3,166	420.60	49.60	2,874.9
	0.25	500	2,708	514.96	44.03	2,515.4
		750	2,677	405.88	47.69	2,590.7
		1,000	3,408	426.73	51.82	2,716.7
	0.3	500	2,708	499.19	45.11	2,435.2
		750	2,800	418.84	49.43	2,520.2
		1,000	3,684	451.37	53.58	2,537.0
0.08	0.2	500	2,861	593.38	42.99	2,658.8
		750	2,769	495.85	46.09	2,738.6
		1,000	3,319	499.40	49.55	2,863.7
	0.25	500	2,830	563.29	44.09	2,540.8
		750	2,769	462.72	47.83	2,625.4
		1,000	3,531	498.65	51.69	2,690.8
	0.3	500	2,861	558.55	45.27	2,485.1
		750	2,922	487.32	49.68	2,573.7
		1,000	3,773	512.98	53.26	2,487.7

Table 5.21 Summary of simulation outcomes of heterogeneous model with L_k of 0.275 for polymer solution with residual resistance factor of 2.5

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Production time (days)	Total water production (bbl)	RF, %	Amount of oil recovery per mass polymer consumed (bbl/tons)
0	0.2	500	2,677	501.72	43.84	3,059.6
		750	2,708	374.40	47.20	3,085.9
		1,000	3,378	382.26	50.84	3,166.4
	0.25	500	2,647	470.54	45.15	2,935.2
		750	2,769	345.67	49.12	2,947.5
		1,000	3,684	375.57	52.95	2,927.8
	0.3	500	2,616	442.73	46.20	2,772.7
		750	2,922	353.80	50.95	2,836.4
		1,000	4,018	394.78	54.58	2,693.1
0.04	0.2	500	2,830	563.43	44.10	3,179.0
		750	2,830	441.34	47.31	3,121.7
		1,000	3,469	429.66	50.53	3,093.2
	0.25	500	2,769	521.39	45.26	2,978.3
		750	2,861	403.35	49.17	2,960.4
		1,000	3,804	447.23	52.83	2,904.7
	0.3	500	2,738	493.66	46.29	2,801.4
		750	3,043	423.34	51.13	2,874.5
		1,000	4,108	460.97	54.23	2,639.7
0.08	0.2	500	2,953	612.53	44.22	3,233.7
		750	2,922	494.29	47.49	3,175.1
		1,000	3,592	499.11	50.35	3,052.0
	0.25	500	2,922	581.39	45.41	3,032.6
		750	2,982	470.19	49.42	3,023.2
		1,000	3,896	509.94	52.40	2,824.9
	0.3	500	2,861	542.84	46.32	2,811.7
		750	3,135	483.34	51.16	2,880.4
		1,000	4,199	526.07	54.00	2,602.9

As same as the case of reservoir with L_k =0.2, a case of polymer concentration of 1,000 ppm single-slug polymer flooding with slug size of 0.3 PV and no pre-flushed water is chosen as base case since these conditions yield the best score for most residual resistance factor. This selection also results in comparable results of sequential polymer flooding across different residual resistance factors since the amount of polymer consumed is the same for all cases.

Once base case of single-slug polymer flooding is selected, base case of each heterogeneity are compared to evaluate an effect of heterogeneity on production performance of single-slug polymer flooding. Oil recovery factors of all heterogeneity values are summarized in Figure 5.67. From the figure, it is obvious that increment of heterogeneity results in reduction of oil recovery factor. When heterogeneity is increased, both polymer and water slugs tend to displace oil in upper layers (layer 2nd-4th) due high permeability values, leaving abundant of oil non-displaced in low permeability zones (layer 6th-8th).

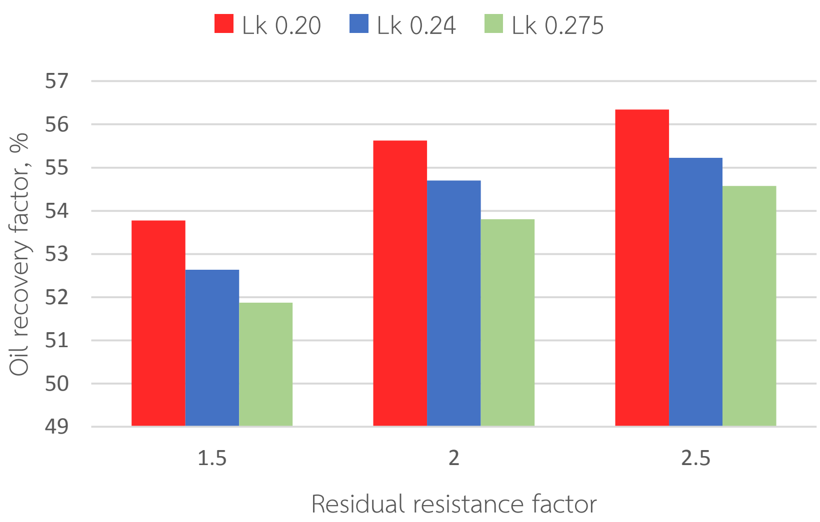


Figure 5.67 Comparison of oil recovery factor among different heterogeneities of single-slug polymer base case for polymer solutions with different residual resistance factors

Table 5.22 Summary of total judging score for heterogeneous model with L_k of 0.24 with different value of residual resistance factor

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Total score		
			RRF=1.5	RRF = 2.0	RRF = 2.5
0	0.2	500	79.52	82.16	84.22
		750	86.83	88.22	89.03
		1,000	92.90	94.42	93.70
	0.25	500	82.26	84.20	85.57
		750	89.90	90.78	91.44
		1,000	95.98	95.81	93.97
	0.3	500	84.25	85.54	86.55
		750	92.15	92.33	92.61
		1,000	97.72	96.29	93.25
0.04	0.2	500	79.22	81.74	83.35
		750	85.42	86.88	87.44
		1,000	91.01	91.80	90.46
	0.25	500	81.76	83.44	84.50
		750	88.37	89.04	89.43
		1,000	93.67	93.10	91.22
	0.3	500	83.33	84.35	85.10
		750	90.08	90.29	90.50
		1,000	94.82	92.76	90.05
0.08	0.2	500	78.81	81.11	82.85
		750	84.75	85.96	86.81
		1,000	89.48	89.33	87.57
	0.25	500	80.90	82.38	83.42
		750	87.07	87.86	88.43
		1,000	91.93	90.38	88.19
	0.3	500	82.34	83.16	83.91
		750	88.58	88.92	89.09
		1,000	92.88	90.30	87.73

Table 5.23 Summary of total judging score for heterogeneous model with L_k of 0.275 with different value of residual resistance factor

Pre-flushed water (PV)	Polymer slug (PV)	Polymer concentration (ppm)	Total score		
			RRF=1.5	RRF = 2.0	RRF = 2.5
0	0.2	500	79.01	81.37	83.21
		750	87.68	88.99	90.16
		1,000	93.71	93.72	92.13
	0.25	500	86.05	83.14	84.55
		750	90.80	91.63	92.18
		1,000	95.31	94.54	92.38
	0.3	500	78.99	84.24	85.41
		750	91.96	92.35	92.49
		1,000	95.80	93.87	91.30
0.04	0.2	500	78.57	80.76	82.55
		750	85.69	87.11	87.98
		1,000	91.35	91.14	89.66
	0.25	500	80.58	82.05	83.43
		750	88.47	89.14	89.86
		1,000	92.67	91.57	89.67
	0.3	500	81.87	82.92	84.03
		750	89.61	89.61	90.15
		1,000	93.06	90.88	88.60
0.08	0.2	500	77.91	80.14	81.88
		750	84.62	85.89	86.93
		1,000	89.71	88.69	87.29
	0.25	500	79.67	81.02	82.39
		750	86.68	87.63	88.30
		1,000	90.85	89.23	87.16
	0.3	500	80.87	81.82	82.76
		750	87.65	88.12	88.44
		1,000	91.20	88.67	86.60

Since polymer and water slugs tends to displace oil only in high permeability zones in case of high heterogeneity, total production time should be shorten with increase of heterogeneity as a result of high water cut. However, total production time of heterogeneous model with L_k of 0.24 is slightly shorter than total production time of heterogeneous model with L_k of 0.275. Viscosity profiles representing location of exist polymer slug are used to explain this irregular occurrence as demonstrated in Figure 5.68 to Figure 5.70. From these figures, blue and red slug represent high and low viscosity fluids which are polymer and water, respectively.

From Figure 5.68, movement of polymer solution slug is almost uniform as a result of favorable mobility condition but with different patterns for each model due to difference in permeability variation. At this point, movement of fluid is only controlled by mobility ratio of displacing fluid. None of irregular occurrence is observed. Figure 5.69 and Figure 5.70 demonstrate water viscosity profiles after inject chasing water for 2 year and at the end of production, respectively. From these figures, in case of heterogeneous model L_k = 0.2, most chasing water tends to move and breakthrough only in first and second layers as permeability of these two layers are much higher compared to other layers whereas large slug of polymer (blue and green colors) still cannot effectively displace in low permeability layers.

However, in case of heterogeneous model with L_k of 0.275, chasing water tends to move and breakthrough in third and fourth layers instead of first and second layers even these two layers possess higher permeability values. This phenomenon is due to gravity segregation that allows higher fluid to percolate down with an assist of high vertical permeability in these zones which are proportionate to high horizontal permeability. Combining with mostly uniform of horizontal permeability distribution of this model in these upper layers, effect of permeability variation is dominated by gravity segregation, resulting in irregular movement of fluid. Figure 5.69b) and Figure 5.70 demonstrate tonguing water due to gravity segregation which is balanced with permeability distribution, resulting in breakthrough of chasing water in high permeability layers at the same time. This occurrence results in attaining of water production constrain earlier in case of heterogeneous model with L_k of 0.24. Total production time of all base cases are summarized in Figure 5.71.

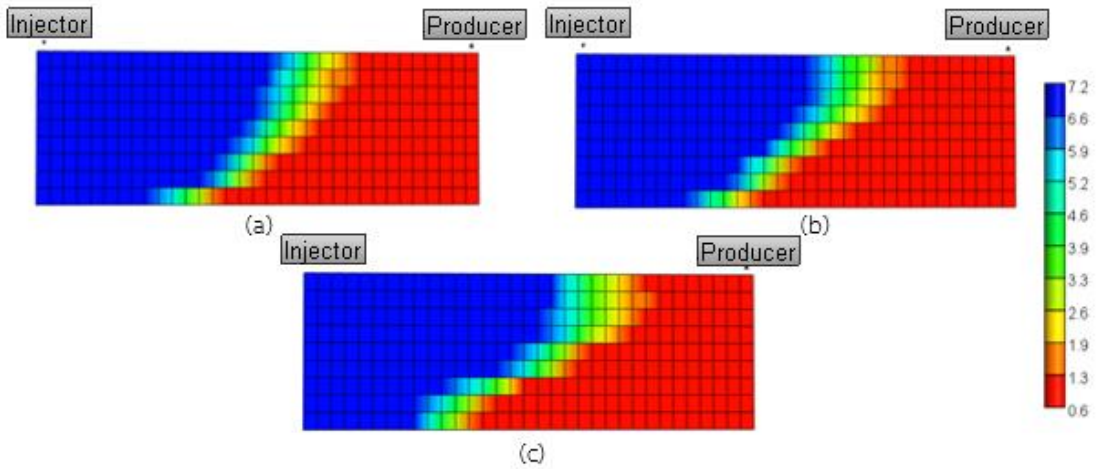


Figure 5.68 Water viscosity profile from side view at the day before inject chasing water in case of single-slug polymer flooding base case with residual resistance factor 1.5 (a) L_k = 0.2 (b) L_k = 0.24 and (c) L_k = 0.275

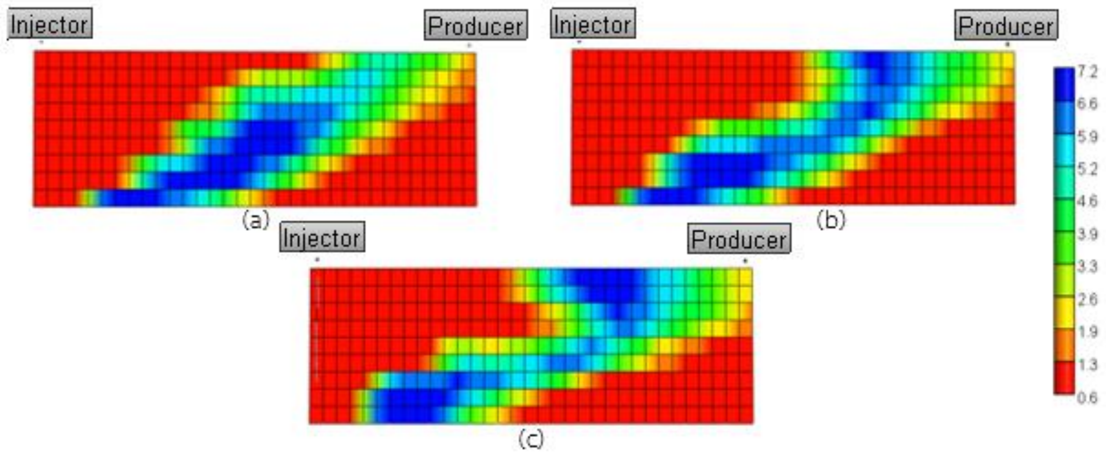


Figure 5.69 Water viscosity profile from side view after 2 year of chasing water injection water in case of single-slug polymer flooding base case with residual resistance factor 1.5 (a) L_k = 0.2 (b) L_k = 0.24 and (c) L_k = 0.275

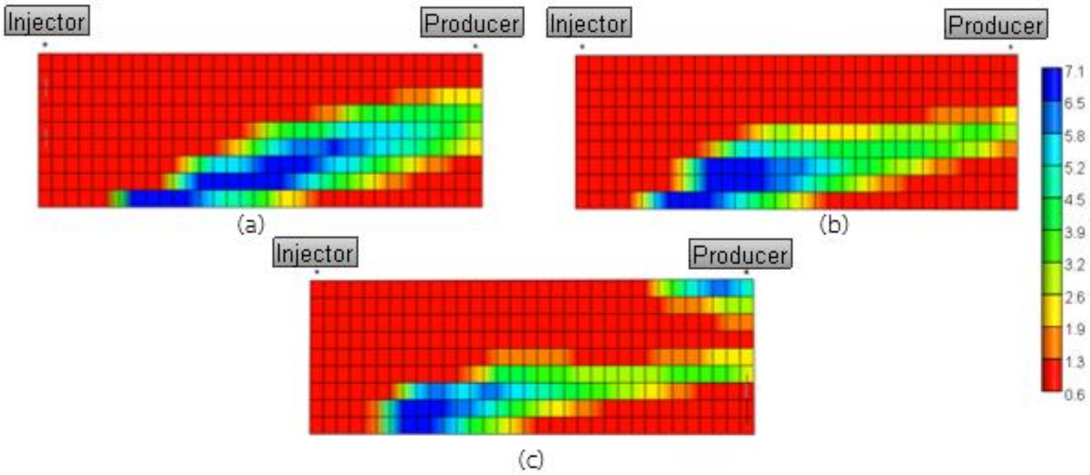


Figure 5.70 Water viscosity profile from side view at the end of production in case of single-slug polymer flooding base case with residual resistance factor 1.5 (a) L_k = 0.2 (b) L_k = 0.24 and (c) L_k = 0.275

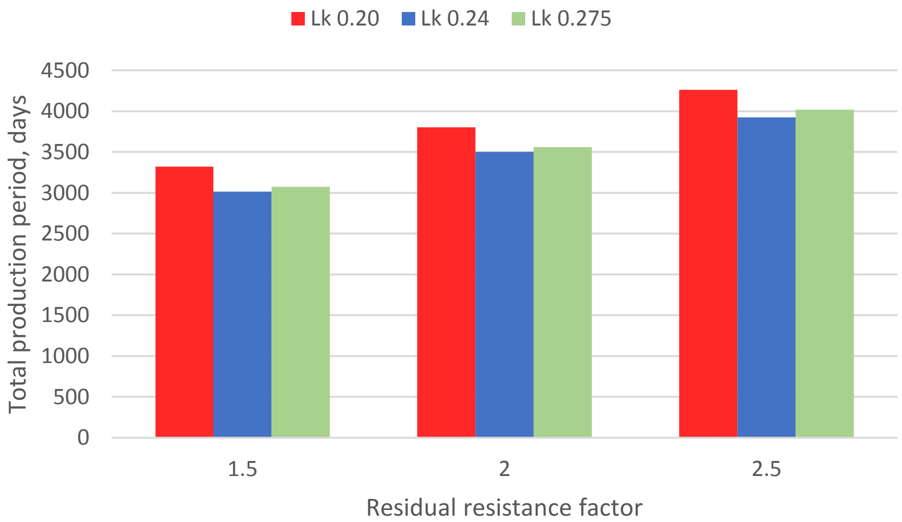


Figure 5.71 Comparison of total production period among different heterogeneity of single-slug polymer base case for polymer solutions with different residual resistance factors

Total water productions of all cases are summarized in Figure 5.72. From the figure, total water production of single-slug base case is related to total production period. As water production rate in later stage is high, extension of just small total production period can cause dramatically increase of total water production as discussed in section 5.3.

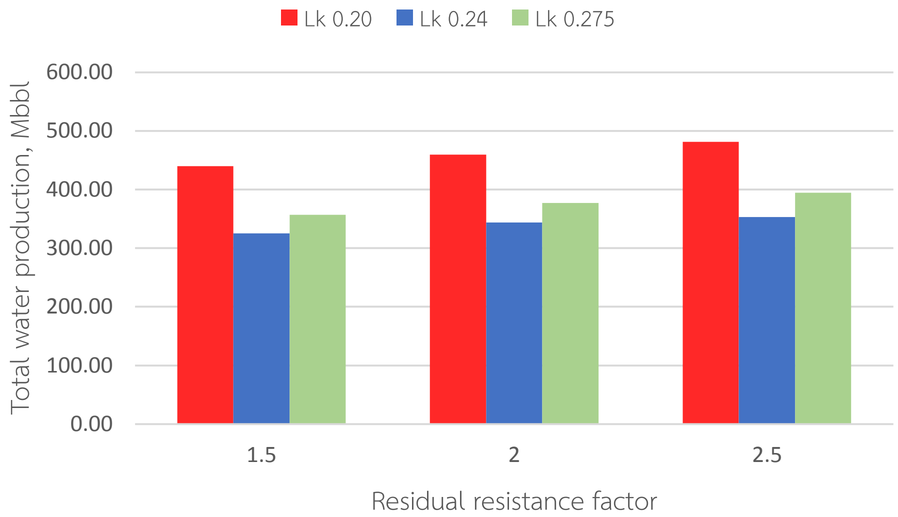


Figure 5.72 Comparison of total water production among different heterogeneity of single-slug polymer base case for polymer solutions with different residual resistance factors

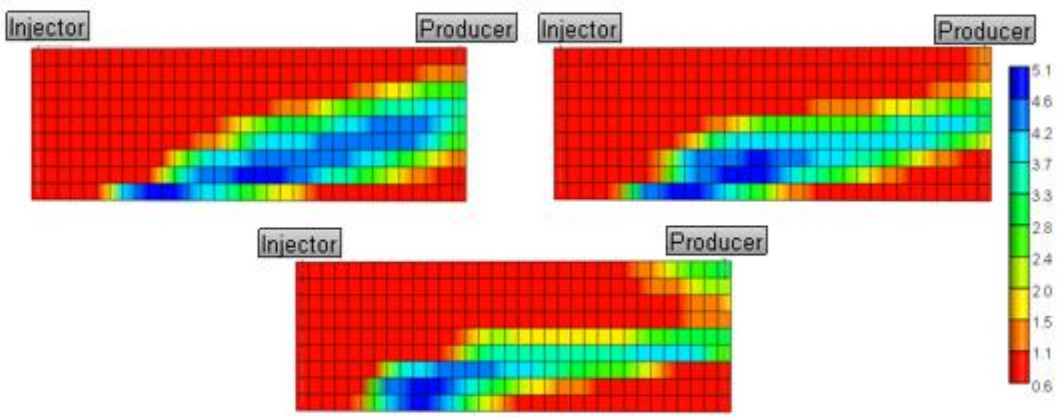
In summary, in case of higher heterogeneity, effects of operating parameters are similar to the case of reservoir model with L_k = 2.0. Oil from low permeability layers cannot be well-swept with low polymer concentration with low residual resistance factor in case of higher value of Lorenz coefficients. In case of the highest heterogeneity, gravity segregation dominates over permeability distribution, resulting in water breakthrough in middle zone.

5.5.2 Effect of Heterogeneity on Multi-slug Sequential Polymer Flooding

Effect of heterogeneity on multi-slug sequential polymer is performed by modifying single-slug polymer base case into double-slug and triple-slug sequential as in case of reservoir with Lorenz coefficient of 0.2. The same schemes of double-slug and triple-slug are summarized in Table 5.8 and Table 5.12, respectively.

Again, viscosity profiles at the end of production which is proportional to polymer concentration are used to explain effects of heterogeneity on effectiveness of double-slug and triple-slug sequential polymer flooding. Figure 5.73 and Figure 5.74

illustrate polymer concentration profiles of different heterogeneity models for double-slug and triple-slug, respectively.



(c)

Figure 5.73 Water viscosity profile from side view at the end of production in case of double-slug sequential polymer flooding base case with residual resistance factor 1.5 (a) L_k = 0.2 (b) L_k = 0.24 and (c) L_k = 0.275

From Figure 5.73, double-slug sequential polymer flooding tends to yield smoother viscosity profiles in all heterogeneity values compared to single-slug polymer flooding which is illustrated in Figure 5.70. Smoothening of viscosity profile can be as explained from step reduction of polymer concentration, causing less mixing behavior at the same time of injectivity improvement as discussed in section 5.3. As can predict, triple-slug yields even better profiles compared to double-slug as illustrated in Figure 5.74. Improvement of viscosity profile is more obvious when heterogeneity is increased due to larger variation of permeability compared to low heterogeneity.

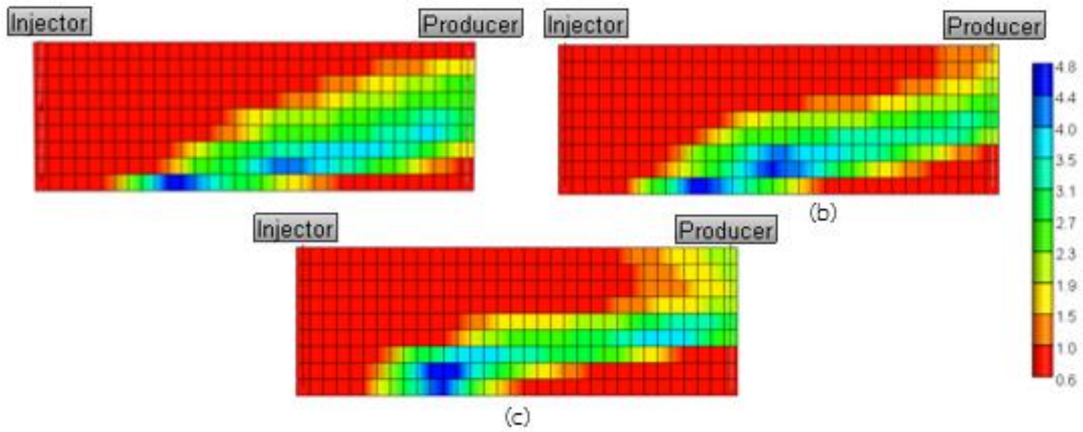


Figure 5.74 Water viscosity profile from side view at the end of production in case of triple-slug sequential polymer flooding base case with residual resistance factor 1.5 (a) L_k = 0.2 (b) L_k = 0.24 and (c) L_k = 0.275

Although benefit of multi-slug sequential polymer flooding in term of smoothening polymer distribution is shown to all ranges of heterogeneity, benefit of double-slug and triple-slug in terms of oil recovery is worse when heterogeneity is increased. Similar to the explanation in section 5.3.1, additional oil recovered from double-slug and triple-slug sequential polymer flooding is obtained from low permeability zones. Since permeability is not well distributed in whole reservoir, permeability values in low permeability zone are reduced in case of high heterogeneity. This causes less amount of oil to be displaced by polymer solution as demonstrated by oil saturation at the end of production depicted in Figure 5.75 and Figure 5.76, where both figures represent for double-slug and triple-slug sequential polymer flooding. This phenomenon results in lower addition oil recovered from double and triple-slug sequential polymer flooding in case of heterogeneous model with L_k of 0.24 with residual resistance factor of 2.5. In case of heterogeneous model with L_k 0.275, oil recovery is even less compared to single-slug for all schemes of double-slug and triple-slug.

However, benefit of multi-slug sequential polymer flooding over single-slug polymer flooding in terms of injectivitiy improvement and shortening of total production period is still applicable to all ranges of heterogeneity. Simulation outcomes for all cases of double-slug and triple-slug sequential polymer flooding of heterogeneous model with L_k of 0.24 and 0.275 for residual resistance of 1.5, 2.0 and 2.5 are summarized in Table 5.24 to Table 5.29.

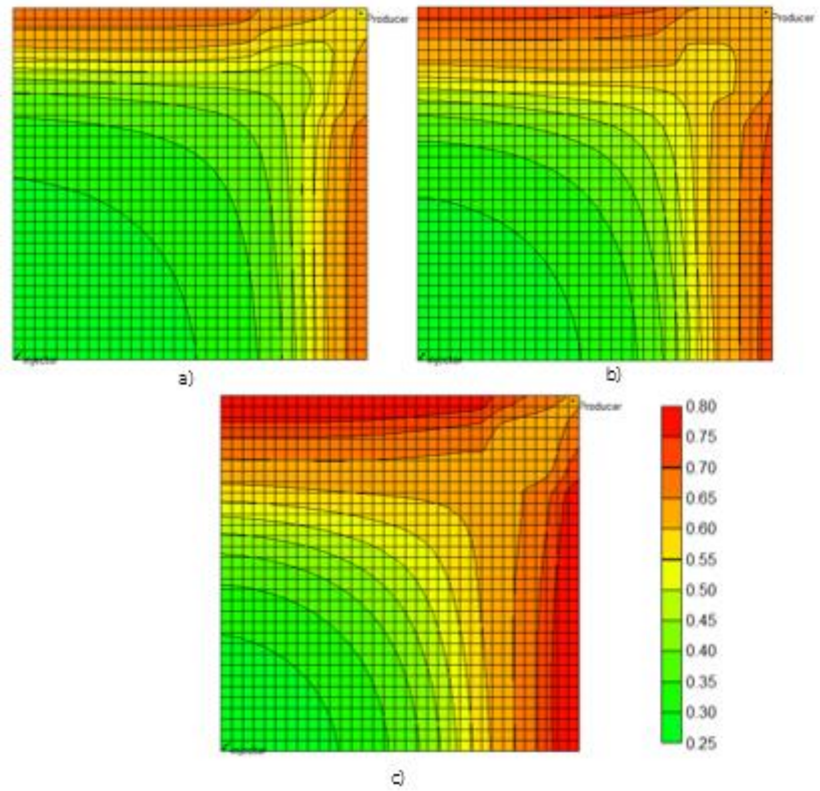


Figure 5.75 Oil saturation profile of low permeability zone (8th layer) at the end of production of double-slug sequential polymer with residual resistance factor of 1.5 with different degree of heterogeneity (a) L_k = 0.2 (b) L_k = 0.24 and (c) L_k = 0.275

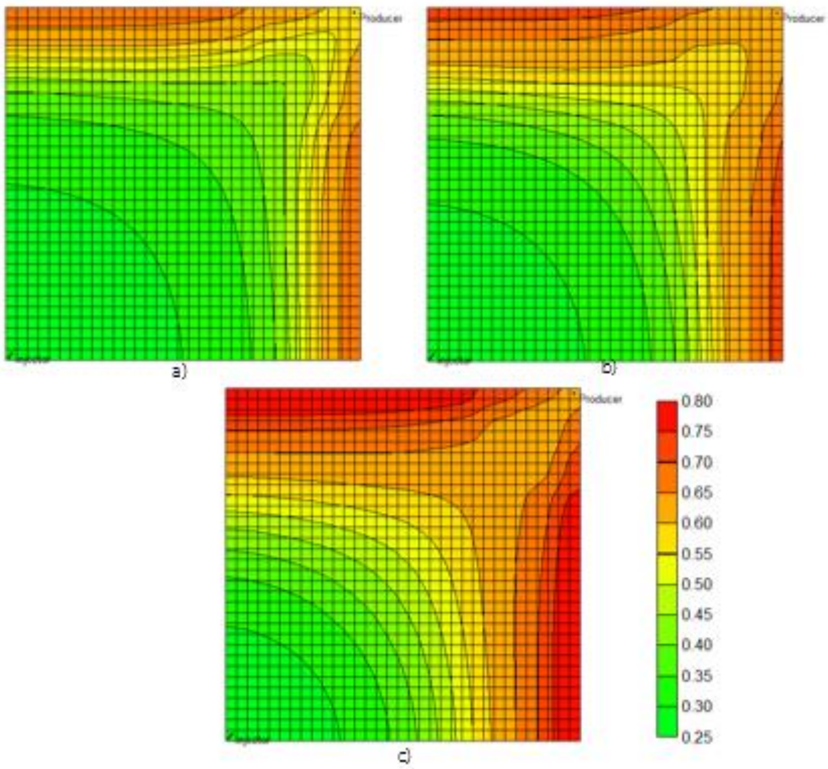


Figure 5.76 Oil saturation profile of low permeability zone (8th layer) at the end of production of triple-slug sequential polymer with residual resistance factor of 1.5 with different degree of heterogeneity (a) L_k = 0.2 (b) L_k = 0.24 and (c) L_k = 0.275

In summary, shortening of total production time is the only benefit of double-slug and triple-slug sequential polymer flooding over single-slug polymer flooding that functions in all heterogeneity values. Increment of heterogeneity tends to decrease amount of oil production in low permeability layers, resulting in reduction of oil recovery factor with double-slug and triple-slug sequential polymer flooding. In case of heterogeneous model with L_k 0.24, double-slug and triple-slug sequential polymer flooding can yield higher oil recovery factor with optimal scheme, whereas double-slug and triple-slug tend to yield lower oil recovery factor and higher total water production in case of heterogeneous model with L_k of 0.275. Therefore, it can be concluded that multi-slug sequential polymer flooding is the method that is suitable for reservoir with low heterogeneity.

Table 5.24 Summary of simulation outcomes from double-slug and triple-slug sequential polymer flooding with residual resistance factor of 1.5 for heterogeneous model with L_k of 0.24

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single slug	3,013	325.30	52.63	97.72
A1	2,861	368.85	52.08	94.98
A11	2,982	437.23	52.10	92.60
A12	2,922	404.05	52.22	94.00
A13	2,891	385.43	52.21	94.65
A2	3,166	532.64	51.77	89.24
A3	2,891	352.49	52.26	95.98
A31	2,922	377.01	52.33	95.16
A32	2,891	358.22	52.27	95.76
A4	3,043	446.79	52.09	92.15
A5	2,922	340.42	52.33	96.54
A51	2,922	345.73	52.28	96.20
A6	2,953	375.22	52.27	94.97
A61	3,104	436.32	52.34	92.90
A62	3,013	397.96	52.41	94.40

Table 5.25 Summary of simulation outcomes from double-slug and triple-slug sequential polymer flooding with residual resistance factor of 2.0 for heterogeneous model with L_k of 0.24

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single-slug	3,500	343.79	54.70	96.29
B1	3,257	368.43	54.32	95.01
B11	3,227	435.57	54.12	92.48
B12	3,196	397.35	54.30	94.10
B13	3,196	374.44	54.29	94.88
B2	3,319	521.37	53.61	89.14
B3	3,288	348.96	54.49	96.11
B31	3,227	369.69	54.52	95.49
B32	3,257	358.40	54.57	95.97
B4	3,257	435.07	54.02	92.19
B5	3,378	353.17	54.63	96.01
B51	3,347	357.29	54.55	95.75
B6	3,257	368.84	54.41	95.19
B61	3,408	430.77	54.48	92.97
B62	3,319	392.54	54.54	94.50

Table 5.26 Summary of simulation outcomes from double-slug and triple-slug sequential polymer flooding with residual resistance factor of 2.5 for heterogeneous model with L_k of 0.24

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single-slug	3,926	353.24	55.23	93.25
C1	3,684	382.81	55.75	93.66
C11	3,500	422.82	55.74	92.73
C12	3,531	396.83	55.97	93.95
C13	3,561	377.99	55.80	94.19
C2	3,500	507.33	55.00	89.14
C3	3,743	370.13	55.70	93.90
C31	3,592	374.72	55.93	94.51
C32	3,653	368.04	55.72	94.21
C4	3,531	426.75	55.58	92.22
C5	3,804	364.71	55.47	93.51
C51	3,743	363.12	55.41	93.58
C6	3,592	367.90	55.68	94.26
C61	3,712	425.54	55.74	92.21
C62	3,622	384.23	55.76	93.76

Table 5.27 Summary of simulation outcomes for double-slug and triple-slug sequential polymer flooding with residual resistance factor of 1.5 for heterogeneous model with L_k of 0.275

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single-slug	3,074	357.09	51.87	95.80
A1	2,830	372.93	50.70	93.12
A11	2,953	446.30	50.47	89.90
A12	2,891	411.26	50.65	91.49
A13	2,830	380.53	50.64	92.70
A2	3,135	542.72	50.01	86.23
A3	2,861	354.93	50.99	94.43
A31	2,861	371.00	50.80	93.33
A32	2,830	350.58	50.85	94.37
A4	3,013	453.90	50.51	89.61
A5	2,861	329.35	51.10	95.85
A51	2,819	319.88	50.89	95.96
A6	2,891	366.90	50.74	93.27
A61	2,982	406.74	50.59	91.25
A62	2,922	379.75	50.74	92.68

Table 5.28 Summary of simulation outcomes for double-slug and triple-slug sequential polymer flooding with residual resistance factor of 2.0 for heterogeneous model with L_k of 0.275

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single-slug	3,561	377.08	53.80	93.87
B1	3,257	380.89	53.12	92.97
B11	3,196	442.00	52.58	90.08
B12	3,166	402.91	52.81	91.79
B13	3,135	366.62	52.82	93.18
B2	3,288	530.78	51.90	86.46
B3	3,257	348.39	53.33	94.68
B31	3,166	361.35	53.07	93.82
B32	3,188	345.20	53.21	94.74
B4	3,227	441.27	52.52	89.90
B5	3,319	340.31	53.50	95.25
B51	3,227	323.50	53.17	95.57
B6	3,196	359.69	53.02	93.70
B61	3,288	400.72	52.84	91.62
B62	3,227	372.77	53.01	93.10

Table 5.29 Summary of simulation outcomes for double-slug and triple-slug sequential polymer flooding with residual resistance factor of 2.5 for heterogeneous model with L_k of 0.275

Scheme no.	Total production time (days)	Total water production (Mbbl)	Recovery factor (%)	Total score
Single-slug	4,018	394.78	54.58	91.30
C1	3,653	384.00	54.48	92.12
C11	3,469	425.99	54.25	90.72
C12	3,500	399.67	54.54	92.03
C13	3,500	368.74	54.37	92.79
C2	3,684	362.29	54.37	86.79
C3	3,684	362.29	54.37	92.66
C31	3,531	365.50	54.52	93.14
C32	3,553	342.94	54.32	93.63
C4	3,500	430.28	54.10	90.25
C5	3,743	352.36	54.33	92.87
C51	3,653	339.67	54.18	93.30
C6	3,531	358.80	54.30	92.97
C61	3,622	407.34	54.21	90.89
C62	3,561	376.34	54.34	92.32

CHAPTER VI

CONCLUSION AND RECOMMENDATION

In this chapter, the whole study is summarized into conclusions. Recommendations are also suggested for further studies.

6.1 Conclusion

1. Benefit of pre-flushed water to increase injectivity of polymer solution is insignificant in this study since adsorption of polymer causes a less polymer concentration slug that has a function similar to pre-flushed water slug. Pre-flushed water slug therefore, tends to increase total water production as well as production time.

2. Polymer solution with higher concentration tends to yield more favorable mobility condition that is affected from both viscosity enhancement and reduction of effective permeability due to polymer adsorption. However, too high concentration can cause poor injectivity and results in delay of a displacement mechanism. In this study, polymer concentration of 1,000 ppm is effective in most study cases.

3. Larger slug size of polymer solution corresponds to high amount of polymer mass that has ability to maintain viscosity of injected fluid as well as well as to be adsorbed onto rock surface to reduce effective permeability to water. With fixed polymer concentration, increment of polymer slug size increases oil recovery factor. However, slug size of polymer should be carefully designed because large slug size could cause less additional oil recovered per polymer consumed.

4. Residual resistance factor which is strongly dependent on polymer adsorption plays a major role in oil recovery mechanism of polymer flooding. Higher residual resistance factor favors oil recovery factor as favorability of mobility control is achieved due to reduction of effective

permeability to water. Increment of residual resistance factor improves effectiveness of polymer in terms of amount of additional oil recovered per polymer consumed.

5. Benefits of double-slug and triple-slug sequential polymer flooding over single-slug polymer flooding are shortening of total production period and reduction of total water production as well as increasing oil recovery factor when optimal scheme is applied in reservoir with low heterogeneity.

6. To design sequential polymer flooding, first polymer slug must be high in polymer concentration and large in slug size to maintain stability of displacement mechanism. Reduction of following polymer slugs can be performed in different ways. Large contrast in reduction of polymer concentration results in improvement of injectivity but more concern of first slug size to prevent high rate of reduction in polymer viscosity. Small contrast in reduction of polymer concentration returns less injectivity improvement but less concern of first slug size.

7. To perform sequential polymer flooding, polymer solution should possess high value of residual resistance factor to compensate with effects from reduction in polymer concentration that is traded off with increasing of injectivity improvement. In this study sequential polymer flooding using polymer solution that can yield residual resistance factor of 2.0 and 2.5 shows benefit over single-slug polymer flooding.

8. Benefit of triple-slug over double-slug polymer flooding is shortening production time. Moreover, reduction of polymer concentration in multi-step also helps to reduce polymer mixing effect between each slug that could cause instability of flooding mechanism. Oil displacement in lower permeable zone is improved.

9. Double-slug and triple-slug are more suitable in reservoir with low heterogeneity. Increment of reservoir heterogeneity tends to decrease

effectiveness as displacement in low permeability zone is more difficult due to poor permeability distribution.

6.2 Recommendation

1. Although salinity effect is neglected as an assumption of low reservoir salinity in this study, most reservoir brines can be considerably high. Therefore, further reservoir simulation study should be able to handle effects of salinity on polymer properties as well as divalent ions to obtain more accuracy results.
2. In this study, effect of shear thinning behavior is neglected, so viscosity of polymer solution is independent from the shear rate. Then, further study should include an effect of shear thinning behavior to obtain more accuracy results.
3. Due to lacking of laboratory data, polymer properties used in this study are taken from several literature reviews. Hence, laboratory study should be performed to obtain some important input data especially in PVT properties section and Rock-fluid properties section.
4. Construction of permeability model is performed with only coarsening upward sequence, difference sequence of permeability such as fining upward and random permeability should be thoroughly studied.

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APPENDIX

Appendix A

RESERVOIR MODEL CONSTRUCTION

In this study, CMG builder program with a selection of STARS, There are 6 section are required for the input of reservoir information which are, reservoir properties, pressure-volume-temperature (PVT) properties, rock-fluid properties, numerical and well & recurrent.

Simulator Setting

Parameters	Value
Simulator	STARS
Working Units	Field
Porosity	Single Porosity

1. Reservoir

1.1 Cartesian Grid

Parameters	Value
Grid type	Cartesian
K direction	Down
Number of grid box (I, j and k direction)	33 × 33 × 9
Block widths (I direction)	33 × 20
Block widths (J direction)	33 × 20

1.2 Array Properties

Parameters	Whole grid
Grid top at layer 1	3280
Grid thickness (ft)	12
porosity	0.2
Permeability I (mD)	Varied in each layers
Permeability J (mD)	Equal to Permeability I
Permeability J (mD)	Equal to Permeability I × 0.1
Water mole fraction	1

2. Components

2.1 PVT Correlation

Parameters	Option	Value
Reservoir temperature		140 F
Generate data up to max. pressure of		5000 psi
Bubble point pressure calculation	Value provided	1150 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)	0.7
Oil properties (Bubble point, Rs, Bo) correlations	Standing	
Oil compressibility correlation	Galso	
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	Value
Reservoir temperature (TRES)	118.94 F
Reference pressure (REFPW)	1622
Water bubble point pressure	-
Water salinity (ppm)	0
Set/update Value of Reservoir Temperature, fluid density in data set	available

3. Rock-fluid

3.1 Rock Type Properties

Parameters	Value
Rock wetteability	Water wet
Method for evaluate 3-phase relative permeability	Stone II

3.2 Relative Permeability Table

Parameters	**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

4. Initial Conditions

Parameters	Value
Vertical Equilibrium Calculation Method	Depth-Average-Capillary
Reference Pressure (REFPRES)	1622 psi
Reference Depth (REFDEPTH)	3280 ft
Water-Oil Contact Depth (DWOC)	3388 ft

5. Numerical

Parameters	Value
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 Perforations

Parameters	Value
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

6.2.2 Constrains

Constrain	Parameter	Limit/Mode	Value	Unit	ACTION
OPERATE	surface liquid rate, STW	Max	400	bbl/day	CONT
OPERATE	bottomhole pressure, BHP	Max	2100	psi	CONT

6.2 Producer

Type: PRODUCER

6.1.1 Perforations

Parameters	Value
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 Constrains

Constrain	Parameter	Limit/Mode	Value	Unit	Action
OPERATE	surface liquid rate, STL	Max	400	bbl/day	CONT
OPERATE	bottomhole pressure, BHP	Min	200	psi	CONT
MONITOR	water-cut, WCUT		0.9		STOP
MONITOR	surface oil rate, STO	MIn	25	bbl/day	STOP

Appendix B

POLYMER FLOODING MODEL CONSTRUCTION

Polymer model is constructed from Process Wizard in STARs simulator. The input data are summarized below;

1. Process Wizard

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

2. Detail of Polymer Flood Model

Parameters	Value
Polymer is adsorbed onto the reservoir rock	valid
Polymer resistance factor	varied
Accessible pore volume for polymer adsorption	0.85
Polymer quantity decrease with time	invalid
Rock type	Sandstone
Rock density (gm/cm3)	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 multiplier	Viscosity (cp)
0	0	0.621428
0.05	4.4	2.7342832
0.1	12	7.457136
0.2	44	27.342832
0.3	130	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
2.25E-06	9.27E-07

6.2 Rock Dependent Parameters

Parameters	Value
Maximum adsorption capacity (ADMAXT)	9.27e-007 lbmole/ft3
Residual adsorption level (ADRT)	9.27e-007 lbmole/ft3

Permeability reduction also often accompanies with adsorption, the simulator accounts for this by region dependent resistance factors RRF which allow correlation of local permeability with local adsorption levels. It is assumed that only single-phase flow paths are altered. Water phase relative permeability reduction for each grid block from equation

$$R_k = 1.0 + (RRF - 1.0) \times \frac{Amount\ of\ polymer\ adsorbed}{Maximum\ adsorption\ capacity}$$

7. Injection Fluid at Injector

Polymer concentration	250 ppm	500 ppm	750 ppm	1,000 ppm
Component	Mole fraction	Mole fraction	Mole fraction	Mole fraction
Water	0.999999437	0.999999	0.999998309	0.999998
Polymer	5.63265E-07	1.13E-06	1.69064E-06	2.25E-06
Dead_oil	0	0	0	0
Soln_gas	0	0	0	0

VITA

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