EVALUATION OF POLYMER FLOODING IN MULTI-LAYERED HETEROGENEOUS RESERVOIR: THE STUDY OF VISCOSITY AND INJECTION RATE OF POLYMER SOLUTION

Ms. AniwanPanthangkool

A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
Faculty of Engineering
Chulalongkorn University
Academic Year 2012

การประเมินการแทนที่ด้วยพอลิเมอร์ในแหล่งกักเก็บแบบวิวิธพันธ์หลายชั้น : การศึกษาความหนืด
และอัตราการฉีดอัดของพอลิเมอร์

นางสาวอนิวรรณ พันธางกูร

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
ปีการศึกษา 2555

Thesis Title	EVALUATION OF POLYMER FLOODING IN MULTI-LAYERED HETEROGENEOUS RESERVOIR : THE STUDY OF VISCOSITY AND INJECTION RATE OF POLYMER SOLUTION.
By	Ms. AniwanPanthangkool
Field of Study	Petroleum Engineering
Thesis Advisor	FalanSrisuriyachai, Ph.D.
Thesis Co-advisor	KreangkraiManeeintr, Ph.D.

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

……………………...Dean of the Faculty of Engineering
(Associate Professor BoonsomLerdhirunwong, Dr.Ing.)

THESIS COMMITTEE

……………………….Chairman
(Associate Professor SarithdejPathanasethpong)

………………………Thesis Advisor
(FalanSrisuriyachai, Ph.D.)

………………………Thesis Co-advisor
(KreangkraiManeeintr , Ph.D.)

……………………....Examiner
(Assistant Professor SuwatAthichanagorn, Ph.D.)

………………………External Examiner
(WitsarutThungsunthomkhan, Ph.D.)

อนิวรรณ พันธางกูร : การประเมินการแทนที่ด้วยพอลิเมอร์ในแหล่งกักเก็บแบบวิวิธพันธ์หลายชั้น : การศึกษาความหนืดและอัตราการฉีดอัดของพอลิเมอร์. (EVALUATION OF POLYMER FLOODING IN MULTI-LAYERED HETEROGENEOUS RESERVOIR: THE STUDY OF VISCOSITY AND INJECTION RATE OF POLYMER SOLUTION) อ.ที่ปรึกษาวิทยานิพนธ์หลัก:ดร.ฟ้าลั่น ศรีสุริยชัย , อ.ที่ปรึกษาวิทยานิพนธ์ร่วม: ดร. เกรียงไกร มณีอินทร์, 108หน้า.

ในการฉีดอัดสารละลายโพลีเมอร์ อัตราส่วนความสามารถในการเคลื่อนที่ของของไหลลดลงอย่างมาก ทำให้เกิดการปรับปรุงประสิทธิภาพการกวาดน้ำมันในแนวระนาบและโพรไฟล์การฉีดอัดในแนวตั้ง รอบเวลาการผุดขึ้นของสารที่ถูกอัดฉีดในหลุมผลิตถูกยืดออกไปอย่างชัดเจน ดังนั้นเทคนิคดังกล่าวน่าจะเหมาะกับแหล่งกักเก็บน้ำมันไม่สม่ำเสมอแบบหลายชั้น

การศึกษานี้มุ่งเน้นไปที่ผลกระทบของความหนืดและอัตราการฉีดอัดของสารละลายโพลีเมอร์ที่มีต่อประสิทธิภาพของการฉีดอัด การยืนยันรูปแบบการฉีดอัดที่ดีที่สุดเป็นขั้นขั้นตอนแรกของการศึกษา หลังจากนั้น ความหนืด (ซึ่งถูกควบคุมโดยตรงจากความเข้มข้น) อัตราการฉีดอัดและการฉีดอัดแบบสองกลุ่มก้อน จึงถูกศึกษา ค่าความไม่สม่ำเสมอที่แตกต่างกันถูกเตรียมขึ้นจากค่าสัมประสิทธิ์ของลอเรนซ์ ในช่วง 0.25 ถึง 0.46

จากผลการศึกษาสามารถสรุปได้ว่า การฉีดอัดน้ำก่อนสารละลายโพลีเมอร์มีความจำเป็นเพื่อเพิ่มความสามารถในการฉีดอัด ขนาดกลุ่มก้อนของน้ำที่เหมาสมคือ 0.15 เท่าของรูพรุนทั้งหมด ในขณะที่ขนาดกลุ่มก้อนของสารละลายโพลีเมอร์ที่เหมาะสมคือ 0.20 เท่าของรูพรุนทั้งหมด การรวมกันของกลุ่มก้อนดังกล่าวช่วยให้เกิดประสิทธิภาพการผลิตสูงสุดภายในระยะเวลาอันสั้น การฉีดอัดกลุ่มก้อนขนาดใหญ่ของสารละลายโพลีเมอร์ที่ความเข้มข้นต่ำให้ผลดีกว่าการฉีดอัดกลุ่มก้อนขนาดเล็กที่ความเข้มข้นสูงเสมอ ความเข้มข้นที่สูงจนเกินไปจะทำให้การฉีดอัดเป็นไปได้ยาก ในขณะที่ความเข้มข้นต่ำจนเกินไปจะทำได้ผลผลิตน้ำมันต่ำอันเนื่องมาจากอัตราส่วนความสามารถในการเคลื่อนที่ของของไหลไม่เหมาะสม อัตราการฉีดอัดสูงให้ผลดีในแหล่งกักเก็บที่มีค่าความไม่สม่ำเสมอต่ำ ในขณะที่อัตราการฉีดอัดไม่มีผลต่อแหล่งกักเก็บที่มีค่าความไม่สม่ำเสมอสูงกว่า 0.40 การฉีดอัดแบบสองกลุ่มก้อนทำให้ความสามารถในการฉีดอัดลดลงซึ่งไม่เหมาะสมกับการศึกษานี้

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต..
สาขาวิชา วิศวกรรมปิโตรเลียม	ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก.............
ปีการศึกษา 2555	ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์ร่วม.............

5371610121: MAJOR PETROLEUM ENGINEERING
KEYWORDS:POLYMER FLOODING / HETEROGENEITY

ANIWAN PANTHANGKOOL:EVALUATION OF POLYMER FLOODING IN MULTI-LAYERED HETEROGENEOUS RESERVOIR: THE STUDY OF VISCOSITY AND INJECTION RATE OF POLYMER SOLUTION.ADVISOR: FALAN SRISURIYACHAI, Ph.D., CO-ADVISOR: KREANGKRAI MANEEINTR, Ph.D.,108pp.

In polymer flooding, mobility ratio is substantially reduced, improving areal sweep efficiency as well as wellbore profile. Breakthrough time is obviously extended. This technique seems to be suitable for heterogeneous reservoir.

This study emphasizes on effects of viscosity and injection rate of polymer solution on effectiveness of polymer flooding in reservoir containing certain range of heterogeneity. Optimization is performed first to verify injection scheme. After that, viscosity (related to polymer concentration), polymer injection rate, and double-slug injection mode are studied. Different heterogeneity is prepared by Lorenz coefficient to have value ranging from 0.25 to 0.46.

From the results, it can be concluded that pre-flushed water is required increase injectivitybefore polymer injection. The optimal pre-flushed water is 0.15PV, whereas optimal polymer slug size is 0.20 PV.This combination results in high oil recovery efficiency at short time of production. Injecting big slug of low polymer concentration yields better results than small slug of high polymer concentration. Too high polymer concentration results in low injectivity, whereas too low concentration of polymer yields low oil recovery due to improper mobility control.High polymer injection rate provides benefit on low heterogeneous reservoir, while injection rate does not show different on heterogeneity higher than 0.4.Double-slug injection results in low injectivity and is not recommended in this study.

Department Mining and Petroleum Engineering Student's Signature……......…..
Field of Study Petroleum Engineering Advisor's Signature…......……...
Academic Year 2012 Co-advisor's Signature…......…...

Acknowledgements

I would like to thank my thesis advisor Dr. FalanSrisuriyachai for his dedication to propagate knowledge in petroleum engineering field as well as precious supervision during this work. I also would like to express my sincere gratitude for his patience and encouragement. Moreover, my thanks also go out to Dr. KreangkraiManeeintr, my thesis co-advisor for hisknowledge supports.

I also would like to thank all faculty members in the Department of Mining and Petroleum Engineering who gave me all technical knowledge and supported me. I would like to thank the thesis committee members for their comments and recommendations to complete this thesis.

My thanks also go toSchlumberger Overseas S.A. for providing educational license of ECLIPSE®100 reservoir simulation software to the Department of Mining and Petroleum Engineering which was used in this study. I would like to thank Chevron Thailand Exploration and Production for providing financial support for this study.

I also give my special thankto Mr. NattaphonTemkiatviseswho provides me important advices on the simulation software that brought me a progressive of simulation work.

Finally, I appreciate all the supports from my family members, friends and classmates.

CONTENTS

Page

List of Tables

Page

Page

List of Figures

Page

Page

Page

Page

List of Abbreviations

API	American Petroleum Institute (viscosity unit)
BHP	Bottomhole pressure
cP	Centipoise
°C	Degree Celsius
EOR	Enhanced Oil Recovery
F or °F	Degree Fahrenheit
FVF	Formation Volume Factor
HPAM	Hydrolized polyacrylamide polymer
I	Injection well
MMSTB	Million stock tank barrel
mD	Millidarcy
OOIP	Original Oil In Place
P	Production well
PAM	Polyacrylamides
PAC	Polyacrylate copolymer
psia	Pound per square inch absolute
ppm	Part per million
PV	Pore Volume
PVP	Scleroglucan and Polyvinylpyrrolidones
PVT	Pressure-Volume-Temperature
rb/stb	Reservoir barrel per stock tank barrel
RF	Recovery Factor
SCAL	Special core analysis
SRAM	Secondary Recovery Analysis Model
stb/day	Stock-tank barrel per day
XG	Xanthan Gum
w/w	Weight by weight

Nomenclatures

ϕ	Porosity
μ	viscosity
C_n	Fractional storage capacity or fractional of total volume
h	Thickness
F_m	Multiplier to water viscosity
F_n	Fractional flow capacity
G	Gini's coefficient of concentration
j	Specific number of layer
k	Absolute permeability
k_r	Relative permeability
k_h	Horizontal permeability
k_{ro}	Relative permeability to oil (Oil/Water function)
k_{rw}	Relative permeability to water
L_k	Lorenz coefficient
M	Mobility
M_o	Mobility of oil
M_r	Relative mobility
M_w	Mobility of water
N	Total number of reservoir layers
P_{lc}	Concentration of polymer solution
P_{ref}	Reference pressure
P_{sc}	Concentration of polymer adsorbed by the rock formation
S_{wcr}	Critical water saturation
S_{wi}	Initial water saturation (connate water saturation)
S_{wmin}	Minimum water saturation (irreducible water saturation)
S_{orw}	Residual oil saturation (to water)

CHAPTER I

INTRODUCTION

1.1 Background

Nowadays, polymer flooding is more implemented worldwide comparing to other Enhanced Oil Recovery (EOR) techniques because of its suitability for broad range of reservoir petrophysical and fluid properties. The major goal of polymer injection is to reduce the mobility of injected displacing phase that consecutively improves the mobility ratio of fluid displacement mechanism and eventually increase volumetric sweep efficiency of displacement mechanism. A high concentration of polymer solution or gel formation (forming from polymer solution and gelling agent) are moreover used for controlling the wellbore profile in cases that high permeability streaks are present around the wellbore, causing a non-uniform flood front and consecutively resulting in low sweep efficiency. Polymer solution can also be injected as post-treatment slug following surface active agent slug (surfactant and alkali) or can be co-injected with surfactant and air to generate highly stable foam. In brief, polymer is mostly used to control the mobility of displacing phase.

In heterogeneous reservoir, the variation of petrophyscial properties (especially permeability) can result in a severe oil recovery factor. The heterogeneity of reservoir formation can be found in several ways such as directional permeability, areal permeability variations, and vertical permeability stratification. The application of polymer flooding in heterogeneous reservoir can result in a positive result because higher viscosity of polymer solution reduces the mobility of displacing phase and hence the displacement can be accomplished with a less irregular flood front. However, too high concentration could yield extremely high viscosity fluid and hence, difficulty in injection of fluid into a formation. Viscosity and injection rate of injected polymer solution are therefore considered as adjustable parameters that can mitigate the problem related to heterogeneity and injectivity of the reservoir. Prior to the field implementation of polymer flooding, several polymer solution properties including viscosity and also injection rate should be studied thoroughly and eventually optimized. In this study, the main scope will emphasize on both viscosity and injection rate of polymer solution, how they affect the oil recovery factor in heterogeneous reservoir models based on theory and simulation results.The additional study is performed on multiple slugs having the same injected volume of polymer solution but different in the volume alternated water slug.

ECLIPSE®100 simulation program commercialized by **GeoQuest Schlumberger** is chosen for this study. Reservoir models are constructed with the variation of permeability to illustrate the degree of heterogeneity. Vertical permeability stratification is modeled to represent the reservoir heterogeneityby keeping the same value of average permeability, maximum permeability, minimum permeability and median of data set. The variable parameters, viscosity (controlled by polymer concentration) and injection rate of polymer solution, are then applied to these heterogeneous models. Oil recovery factor at the end of production periodis used as judgment parameter for throughout the study. Other study parameters such as cumulative water production, field water cut, bottomhole pressure are used to accompany the discussion section.

1.2 Objectives

1. To study the effect of viscosity and injection rate of polymer solution in polymer flooding process in multi-layered heterogeneous reservoir.
2. To determine the optimum range of viscosity and injection rate of polymer solution in polymer flooding process in multi-layered heterogeneous reservoir.
3. To study the possibilityof applying multiple slugs polymer flooding in multi-layered heterogeneous reservoir.

1.3 Outline of methodology

1. Reviewseveral related researchesfor creation of the main idea of thesis.
2. Gather and verify all required data for reservoir simulation model.

3. Generate the heterogeneity contrast scheme approximately seven different values by keeping the same value of average and median absolute permeability.
4. Apply the polymer flooding to the base case model. At this step, the optimization of polymer flooding parameters which are slug size of pre-flushed water and slug size of polymersolution for medium heterogeneous reservoir is performed.
5. Simulate the model with variousstudy parametersto evaluate their effects on oil production performance. The study parameters include
   - Polymer injection rate
   - Chasing water slug size
   - Polymer Slug size
   - Polymer concentration
6. Analyze and compare results from simulation ofall study parameter schemes.
7. Summarize the optimum production strategy by polymer flooding for multi-layered heterogeneous reservoir.

1.4 Thesis outline

The thesis comprises of outline as followed:

Chapter IIsummarizespreviousevidencesofpolymer floodingin various study parameter including experimentlaboratory and simulation. Most of studies showed improvement of recovery factorbyusing polymer injection,

Chapter IIIreviews the significantconcepts of polymer floodingand reservoir heterogeneity whichare combined in this thesis,

Chapter IVdescribes the details of reservoir model constructed including reservoir rock, fluids and petrophysical properties,

Chapter Vdiscusses the obtained results of simulation including optimization of polymer flooding and the study of different design parameters influencingin recovery behavior, Chapter VIsummarizes the effectiveness of polymer recovery and effects of each study parameter in heterogeneous reservoir from reservoir simulation, including additional recommendations for furtherstudy.

1.5 Expected usefulness

This study emphasizes on reservoir simulation of heterogeneous reservoir consists of various value of heterogeneity. Certain range of viscosity (through polymer concentration) and injection rate of polymer solution are simulated on reservoir models in order to determine proper condition for polymer flooding implementation in heterogeneous reservoir. The obtained data will be useful as screening criteria for polymer flooding in this type of reservoir especially one with known heterogeneity value.

CHAPTER II

LITERATURE REVIEW

In this chapter,previousevidencesof polymer flooding in heterogeneous reservoirs with various design parameters are reviewed for both experimental and simulation aspects. Nevertheless, limited number of researches on polymer flooding in multi-layered heterogeneous reservoirs is performed due to other competitive methods and economical reasons. The following papers are examples.

The early study of polymer flooding in heterogeneous reservoir was performed byDavison and Mentzer[1]. They conducted a polymer flooding experiment in porous medium including thermal stability of various polymer solutions. The major aim was to find proper polymer solution for the North Sea reservoirs that contains high heterogeneity and high reservoir temperature. Waterflooding in the zones resulted in severe channeling of injection water, leading to an early water breakthrough into production wells. Another factor reducing efficiency is the common rise of the -oil/water contact, resulting in excessive quantity of water cut in the production wells. The thermal stability test of polymer and viscosifying potential showed that Scleroglucan and Polyvinylpyrrolidones (PVP) clearly have the best thermal stability. At the porous medium flow performance, the fraction of oil recovered at water breakthrough is much greater for polymer flooding with the more viscous oil compared to seawater flooding. Moreover,oil recovery obtained from polymer flooding is significantly higher than that obtained from seawater-floodeing for all model oils used.

From this experiment, investigators suggested that injecting polymer would delay water breakthrough, particularly for highly viscous oils and in oil-wet or mixed wettability porous media. Small-volume slugs of Scleroglucan solution should be used effectively for de-accelerating the flow rate through the high permeability path, helping to divert displacement mechanism into low permeability zones.

Over four years,Surkalo and Pitts[2] examined the effective of polymer flooding in the field having a high Dykstra-Parsons variation factor of about 0.85 and a mobility ratio of displacement mechanism is 2.5. The examination was focused on the design and performance of a vertical conformance by using Secondary Recovery Analysis Model (SRAM). The results showed that the primary recovery process was approximately 0.03 PV and the ultimate primary oil recovery was about 0.09 PV. But the total oil recovery as a result of primary recovery and polymer flooding was 0.31 PV. Thus, a vertical conformance provided by polymer flooding in this field recovered more oil than the use of waterflooding and less water is required for injection.

The new era of polymer flooding in heterogeneous reservoir started at the beginning of 21st century. Wankui et al. [3] investigated the various factors having great influence on polymer flooding field test. Daqing Oil Field is a well-known heterogeneous sandstone reservoir composed of fluvial-delta system. The polymer flooding test consisted of five-spot flood system with producer-injector spacing of about 250 m. Referring to the result of this test, the produced oil was gradually increased and the produced water was constantly reduced after polymer injection. Water is the oil displacement carrier and energy, therefore low water production means low reservoir energy consumption, which does not only yield economic return, but can also keep luxuriant productivity of oil wells. For factor concerning injectivity, flowing resistance was increased because of increasing the viscosity of injected water viscosity and retention of polymer in reservoir, and injection pressure was increased at the same injection rate. The injection pressure tended to be stabilized when a given pore volume was injected. However, the injection pressure decreased when polymer absorption in reservoir reached equilibrium point. The data of reservoir core before and after polymer injection indicated that polymer flooding does not only enlarge swept volume but also increase oil recovery.

Jiecheng et al. [4] studied the improvement of oil recovery by using polymer flooding in Daqing Oilfield. The field had been operated for more than ten years, and oil recovery in major reservoir, which has very high permeability and thickness, declined. With the enlargement of application of polymer flooding, the poor reservoir, which is the low permeability and thin reservoir, will be the main substitutable targets in the future. Comparing the characteristics of major and poor reservoir, such as connectivity and diversity between layers in vertical direction, it could be seen that the same technique cannot be use as the major reservoir, it is necessary to develop the specific technology for poor reservoir. The laboratory and field tests indicated that polymer flooding is feasible for poor reservoir. Combining with infilling well pattern, the oil recovery of polymer flooding for poor reservoir is more than 10% higher than waterflooding. To optimize polymer injection parameters in poor reservoir having high heterogeneity between inter-layer, inner-layers, and horizontal direction, the quantitative analysis was used.

Meybodi et al. [5] conducted the five-spot glass micro-model test for polymer flooding to simulate a polymer flooding in heterogeneity reservoir. The experiments were performed on saturated crude oil at varying conditions of flow rate, water salinity, polymer type and polymer concentration. Three different pore structures combined with different layer orientations are considered for experiment designing. The main interests of this study were on the heterogeneity of porous media and the layer orientations effects. Normally, most oil reservoirs are heterogeneous because of the wide variations in porosity, permeability, depositional environments, and their naturally fractured systems. These heterogeneities have effects on the oil recovery mechanism. According to the experiment, it can be noted that the vertical sweep efficiency is a function of reservoir characteristics alone, while areal sweep efficiency is a function of reservoir characteristics together with well locations. Adding suitable polymer solution to injected water would result in reduction of detrimental effect of permeability variations by decreasing the water/oil mobility ratio (increasing in water viscosity), diverting the injected water from zones that have been well swept, so that oil recovery is increased because of improving both the vertical and areal sweep efficiency. For the effect of layer orientation, the results confirmed that the highest oil recovery is obtained when the layers are perpendicular to the mean flow direction. Also, the oil recovery in polymer flooding increases with increment of layer inclination angle.

Xiaoqin and Wenting[6]individually designed for polymer concentration for single injection well, which needed relieving of the areal contradictory. The numerical simulation and the field practice were used as the method to design it. In this research, Daqing oilfield, which is a multilayer heterogeneous reservoir, represented a model. In the field site, after the polymer implementation, the breakthrough rate of polymer along high permeability zone is effectively controlled; meanwhile, development degree of low permeability reservoir is increased, which can greatly improve the displacement efficiency with higher oil production and in the same time water production is lowered.

Seright[7] mentioned the effect of viscosity on polymer flooding for two layers free cross flow model. At any given injection volume for free cross flow case, the highest increase in oil recovery occurred when increasing the polymer viscosity.

From the researches which were mentioned previously, they are good evident to confirm a positive effectiveness of polymer flooding on heterogeneity reservoir. Each study was accomplished in both laboratory experiment and field test to prove the advantage of polymer flooding that increase oil recovery factor.

Schneider and Owens [8] studied measurement of relative permeability to oil and water after several types of polymer were injected by steady-state procedures on 18 outcrop and formation core samples. Permeability of samples was varied from 50 to 1,200 md. Six polymer types were applied in both oil-wet and water-wet systems The results showed that polymer injection does not affect on increase of oil relative permeability. However, relative permeability to water was substantially reduced over entire saturation range for water-wet system. Polymer solution affected both relative permeability to oil and water in oil-wet system. Variation of relative permeability to oil was observed, while relative permeability to water was the same magnitude as measured in water-wet system. There was no obvious difference on relative permeability to oil and water when polymer type is varied.

Barrufet and Ali [9] determined modification of relative permeability to oil and water occurred by polymer adsorption in water-wet system by means of core flooding experiment. Starch based biopolymers which are abundant, cost effective and environmental friendly were used in this study. Alteration of relative permeability and capillary pressure curves showed the effectiveness in reducing water mobility both injection and production processes. After testing in core flooding system before and after polymer treatment, there was a significant declination in relative permeability to water due to polymer adsorption on pore surface. Moreover, they concluded that modification of relative permeability to oil and water was dependent on type of formation.

CHAPTER III

THEORY AND CONCEPT

This chapter reviews principle concept of oil recovery mechanism by polymer flooding and heterogeneity of reservoir formation which are combined in this study.

3.1 Principle of Polymer Flooding

Polymer flooding [10] is the EOR technique using water-soluble polymers to improve the sweep efficiency by reducing the mobility ratio at the flood front. Chemically, one polymer molecule is composed of a number of individual molecules that are linked in same manner. These individual molecules called “monomer” are usually associated in the pattern that repeats itself throughout the length of each polymer. Polymer can be calledhomopolymer when only one type of monomer is present, whereascopolymeris termed for polymerthat joins two different monomers.

The molecular weight of polymer is high but these large molecules can be soluble in water because of the hydrogen bonding between water molecule and the polymer’s polar side chains. In general, four types of polymer are used in EOR.

1) Polyacrylamides (PAM) is a synthetic anionic polymer. PAM is normally found as dry powder and can be dissolved in water. It is sometimes foundas emulsion gel as it is easier for preparing a solution compared to powder polymer.

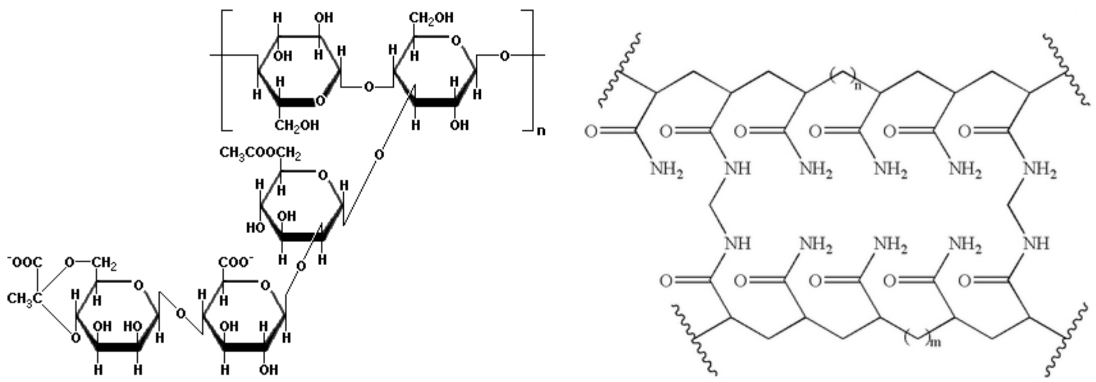
2) Xanthan gum (XG) is a natural anionic biopolymer. It is in general, found as dry powder and it is water soluble.

3) Cellulosic compounds are semi-synthetic polymer. It can be both non-ionic and anionic.

4) Polyacrylate copolymer (PAC) is anionic synthetic polymer. Commercially, it is found as dry powder and is water soluble.

PAM and XG are two commercial polymers used in EOR because they are stable in reservoir conditions and they also have high resistance to improper conditions. The molecule of PAM creates very strong hydrogen bond with water molecules when it is in contact with water.PAM can be soluble in water at the highest concentration of 35 %w/w. The PAM solution becomes more viscous when its concentration is raised. XG is a high-molecular-weight, natural carbohydrate. It is manufactured by bacterial fermentation process. XG has high thermal stability that means its viscosity decreases slightly when the temperature is raised. Therefore, this makes XG to become a preferred material in the EOR process. The molecular structures of PAM and XG are shown in Figure 3.1.

Both of PAM and XG yield high viscosities at relatively low concentrations. However, their viscosities are adversely affected by salinity and the presence of divalent ions which cause the difficulty in polymer hydration. The use of dry polymer powder to prepare polymer solution can result in the formation of *"fish-eyes"* (dry powder surrounded by wetted polymer) that could cause in many production problems. Nowadays, PAM and XG can be supplied in liquid form to prevent the formation of undesired particles.



a) Polyacrylamide b) Xanthan gum

Figure3.1 Molecular structures of commonly used polymers:
a) Polyacrylamide and b) Xanthan gum [11]

Usually, viscosity of polymer solution decreases as temperature increases. The loss of viscosity is reversible unless thermal degradation occurs. In the moderate reservoir temperature, the change of viscosity of PAM and XG is minimal.

A good polymer solution should integrally have mechanical, thermal, bacteriological, and chemical stabilities. PAM can be degraded due to mechanical sheer during the mixing step and moreover, it is less tolerant to the presence of divalent ions compared to XG. One of the disadvantages of XG is bacteriological problem. Therefore XG is always required bactericide to prevent bacteriological degradation[12].For the thermal stability, XG is not stable at the reservoir temperature above 230^{o}F[13].Anyway, in high temperature reservoir thermal stability additives such as thioures, isopropyl alcohol, nitrogen purges, sulfates, propylene glycol, formal aldehyde, and acetone can be mixed together with PAM and XG to prevent thermal degradation.

Polymer is normally used to alter the fractional flow characteristic of the water phase which displaces oil. The major function of polymer in EOR is to increase the viscosity of injected water and to reduce the relative permeability to water in the formation. Hence, the oil's relative flow is improved.

Mobility (M) is a measurement of the ease with which a fluid moves through a reservoir rock and it is expressed as

$M= k_r / \mu$(1)

wherek_r and μ are relative permeability in mDarcy and viscosity in cPoise, respectively.

Relative mobility (M_r) is the ratio of mobility of displacing fluid to mobility of displaced fluid. In the waterflood process, relative mobility is thus expressed as

$M_r= M_w / M_o$(2)

whereM_o and M_w are mobility of oil and water, respectively [10].

Polymer flooding is usually chosen for heterogeneous reservoir. Performing waterflooding in heterogeneous reservoir may result in flow through high permeability channels or natural fractures, causing viscous fingering and as a consequence, the flooding efficiency is low. Moreover, early breakthrough of injected water causes the problem to manage high quantity of produced water. Polymer solution reduces the mobility of injected phase. The flood front is smoother and therefore, the sweep efficiency is improved. Figure 3.2a and 3.2b demonstrate the areal and vertical sweep efficiency improvement by the use of polymer, respectively.

Polymer flooding is compatible with both sandstone and carbonate reservoirs. Sandstone is more favorable since polymers are anionic and therefore, injected polymer will not be adsorbed onto the negatively-changed surface. The reservoir temperature below200^{o}F is preferable in order to avoid the polymer degradation. Thus, the depth of should be less than 9700ft. Oil viscosity should be less than 100 cP because higher polymer concentration is needed for high oil viscosity to achieve the desired mobility control. The presence of clay in the reservoir formation causes the loss of polymer. Therefore, reservoir containing high amount of clay should be avoided.

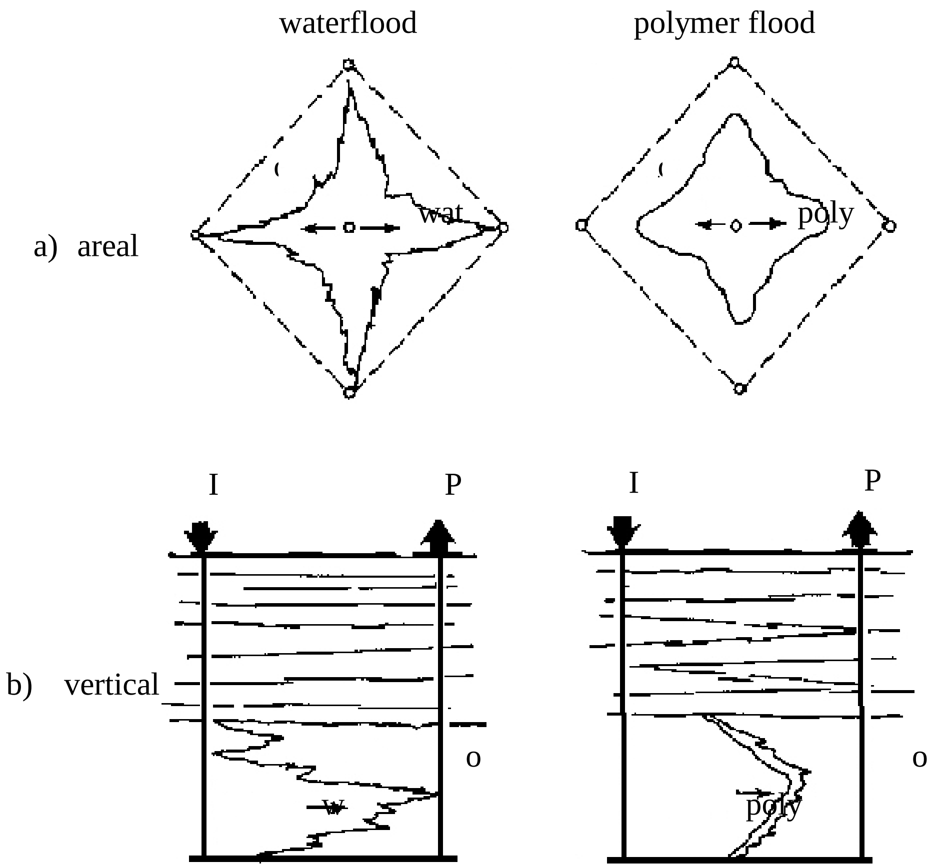


Figure3.2 Theareal and vertical sweep efficiency improvement by the use of polymer flooding: a) areal and b) vertical [11]

3.2 Property of polymer

It is important that injected polymer has to have three main properties which are easy to be injected into porous medium, able to build up viscous fluid at low concentration and do not cause deleterious problem to downhole environment.

However, viscosity of polymer plays the most important role in polymer flooding since it controls mobility of injected fluid and hence, improve volumetric efficiency. Since part of polymer molecule possesses charge property, polymer is therefore adsorbed onto rock surface due to charge property of rock surface. Polymer adsorption is one of the most important things to concern when polymer flooding is decided for implementation. As polymer is injected into porous medium, polymer tends to sweep into big pores since polymer molecule contains large chains. Viscous forces provided by polymer molecular however cannot overcome capillary pressure and therefore polymer cannot access into some pores. Following sections describe three important properties related to polymer injection which are polymer viscosity, polymer adsorption and dead pore volume due to polymer solution.

3.2.1 Polymer viscosity

As fluids are in contact with rock formation, there exists an interfacezone which each fluid will affectviscosityof others. Polymer substance diluted in water also has this property. Thus, effective polymer solution viscosity is determined by Todd-Longstaff technique to representvalue of polymer viscosity that is influenced by diluted water. Fully mixed polymer solution viscosity, which is function of polymer solution concentration, and viscosity of solution at the maximum polymer concentration areobligated for effective polymer solution viscosity calculation. The mixing parameter is used to indicate sensitivity of fluid mixture. Generally, it refers to injected polymer solution and water that segregate between each other or not [14].

Nevertheless, polymer viscosity cannot be maintained constant throughout polymer flooding process. Viscosity of polymer can be reduced by several effects including mechanical process, chemical process, thermal process and biological process [10]. By mechanical process, polymer solution loses viscosity through shear thinning effect. As shear rate increases, viscosity is substantially reduced as well. However, this reduction of viscosity is recoverable if polymer structure is not destroyed by thermal degradation. Several chemical reactions can affect polymer viscosity. Presence of some ions can remarkably increase viscosity ofpolymer solution. This reaction is useful to create gel from polymer through cross-linking. Reduction of viscosity by chemical reaction occurs when polymer solution precipitates with several salt ions in reservoir. This reaction results in ineffective molecules of polymer in solution and hence viscosity is drastically reduced. Thermal stability severely affects viscosity of polymer solution as well. Viscosity of polymer reduces as temperature is raised. Beyond certain temperature polymer loses thermal stability, resulting in breaking of polymer molecule (backbone and side-chain parts). In general, polymer flooding is performed in reservoir with temperature less than 200 ^{o}F to avoid permanent loss of viscosity. Biological degradation is also found in the use of polymer flooding. Especially xanthan gum, which is biological product, compulsorily requires to be used with biocide in order to prevent loss of viscosity due to biodegradation.

3.2.2 Polymer adsorption and resistance factor

Most injected polymer is absorbed by rock formation when it passes through rock surface due to different charge properties between rock surface and polymer molecule. Polyacrylamide is severely adsorbed in carbonate rock surface since molecule is negatively charge. Absorption can occur through physical interaction between molecule of polymer and rugose pore space. However, adsorption is expected sometimes when polymer is injected into reservoir. The term **resistance factor** referring to relative pressure drop caused by polymer solution which remains in porous medium is calculated to predict adsorption in different objective of polymer solution. When mobility control is expected throughout flooding process, pressure loss due to polymer or resistance factor should be minimal to maintain polymer viscosity throughout flooding process. On the contrary, high polymer adsorption or high resistance factor is expected to block high permeability channel and divert flow to low permeability zone in polymer-gel treatment. When polymer is adsorbed onto rock surface, relative permeability to water is slightly modified [8],[9].

3.2.3Dead pore volume

Inaccessible pore space by polymer solution is defined as a dead pore volume and it depends on type of rock type. This ineffective pore space affects on increasing polymer solution velocity to travel into formation which is faster than tracers in water.

Generally, dead pore space is smaller or equal to irreducible water saturation.That means, end point saturation of relative permeability curves is shifted and additional oil recovery can be obtained when polymer flooding is performed [14].

3.3 Reservoir heterogeneity

Heterogeneous formations comprise two or more non-communicating sand grain members, each possibly own different rock properties. The variation of rock properties is also caused by difference in depositional environment and/or segregation of differently sized of sediments into layers. The term heterogeneity in general refers to reservoir storage capacity and flow ability which are porosity and permeability, respectively. In sandstone reservoir, the development of properties is mostly accomplished by physical change. The properties strongly depend on nature of sediments, environment of deposition, and generally subsequent compaction and cementation. In a carbonate reservoir, on the other hand, the development of porosity and permeability is more complex, involving both physical and chemical changes. Carbonate porosity and permeability may be developed after consolidation or deposition through selective solution, replacement, recystallization, dolomitization, etc.

Reservoir heterogeneities can be mainly divided into three types: areal variations, vertical variations, and reservoir fractures[15]. It is obvious that reservoir may be non-uniform in all properties such as permeability, porosity, pore size distribution, wettability, connate water saturation and crude properties. **Areal variations** represent a type of reservoir heterogeneity in areal view. This type of heterogeneity includes dual porosity, vugs, mixed wettability, fractional wettability and series of permeability. The presence of these mentioned formation properties result in difficulty in prediction ofproduction behavior and ultimate oil recovery. **Vertical stratification** refers to layered reservoirs. Each layer possesses different properties especially porosity and absolute permeability. Several authors have suggested measuring the degree of stratification, lateral extent of shale breaks and continuity of zone of specific permeability in order to study this formation heterogeneity type.**Reservoir fracturesand directional permeability** are heterogeneities that have remarkably difference in property compared to the rest of reservoir portion. Extremely high permeability results in both advantage and disadvantage of this type of structure. The presence of fractures around the production well could stimulate the well productivity, whereas the presence of them in the entire reservoir formation causes the thief zone and consecutively high residual oil saturation remained.

3.4Quantitative Measurement of Heterogeneity

There are several methods to quantitatively determine the heterogeneity of reservoir. The term permeability variation mostly represents heterogeneity of formation and it is quantitatively expressed as a coefficient. Many petrophysicists have purposed methods to calculate this mentioned coefficient such as Schmalz-Rahme, Dykstra-Parson, and Warren-Price [16]. In this study, the **Lorenz coefficient** (L_k),purposed by Schmalz and Rahme, is chosen due to its simplicity for vertical stratification representing the heterogeneity of reservoir in this study. As mention in previous section, vertical stratification describes reservoir that contains many layers with different reservoir properties. Permeability which is one of the most important parameters affecting flow property and recovery factor is the parameter that is responsible for the value of heterogeneity.

Let the reservoir contains N layers and in each layer, j, possesses thickness h_j, porosity ϕ_j, and absolute permeability k_j. In order to determine the Lorenz coefficient due to the heterogeneity of absolute permeability, the values of permeability are then ordered from the maximum to the minimum. Two parameters are needed to be calculated: the fractional flow capacity (F_n) and the fractional storage capacity or fractional of total volume (C_n) and they can be determined from:

$$F_n = \frac{\sum_{j=1}^{j=n} k_j h_j}{\sum_{j=1}^{j=N} k_j h_j} \qquad (3),$$

$$C_n = \frac{\sum_{j=1}^{j=n} \phi_j h_j}{\sum_{j=1}^{j=N} \phi_j h_j} \qquad (4).$$

Calculating the cumulative F_n and $C_n$for the ordered layers, the plot can be constructed as shown in Figure 3.3. This plotis widely used to indicate the contrast in permeabilities in the total thickness, the greater contrast indicated by the increased divergence from a 45˚ line.

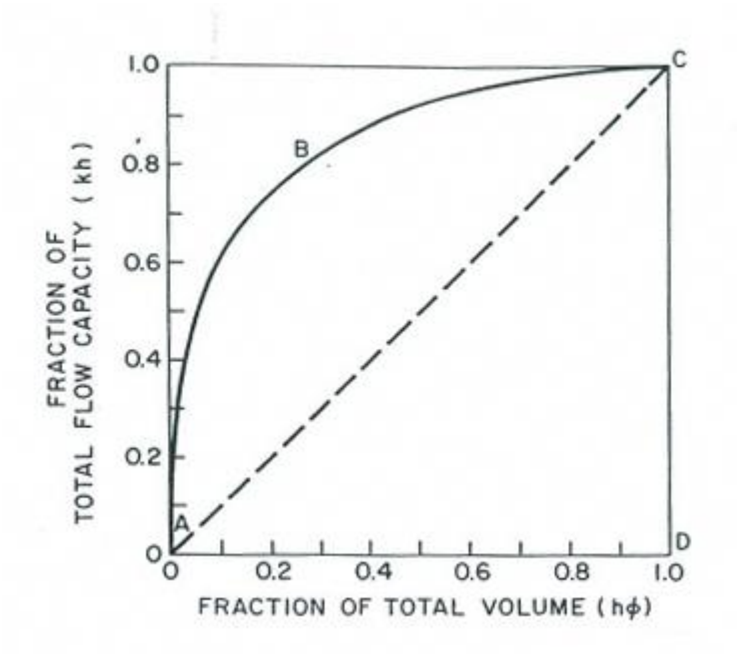


Figure 3.3: Flow capacity distribution, hypothetical reservoir [15]

Lorenz Coefficient (L_k) was conducted by Schmalz and Rahme in 1950. The value is the termed for characterizing the permeability distribution within the pay section. From Figure 3.3, they defined the Lorenz Coefficient of heterogeneity as:

$$\text{Lorenz Coefficient } (L_k) = \frac{\text{area } \overline{\text{ABCA}}}{\text{area } \overline{\text{ADCA}}} \quad (5).$$

The value of the Lorenz coefficient ranges from zero to unity, a uniform permeability reservoir having a Lorenz coefficient of zero [17].

Estimation of Lorenz coefficient requires evaluation of the area under the cumulative total flow capacity curve and the diagonal. This can be accomplished by simple algorithm such as the trapezoidal rule. Another approach can be performed is the use of relationship between Lorenz coefficient and Gini's coefficient of concentration. *G*. as the equation:

$$L_k = \frac{1}{2n} \frac{\sum_{i=0}^{n} \sum_{j=1}^{n} |ki - kj\,|}{\sum_{i=1}^{n} ki} \quad (6).$$

This method does not require ordering of the data and assumed that all permeabilities have equal probability. L_k is substantially negatively biased (greater than 5%) for small sample sizes ($n<40$) and heterogeneous distributions ($L_k>0.6$). Thus, using this method will understate the heterogeneity in the reservoir, but it is more precise than the Dykstra-Parsons method [18].

CHAPTER IV

RESERVOIR SIMULATIONAND METHODOLOGY

In order to study polymer injection in heterogeneous reservoir study, simulation is utilizedto describe reservoir characteristics. ECLIPSE®100 reservoir simulator equipped with a function of polymer flooding is chosen as a tool in this study. This chapter describes the model is constructed and emphasizeson important design properties of reservoir rock and fluid and also production parameters. The heterogeneous reservoir model is constructed as part of five-spot patternand details are shown in this chapter as well.

The reservoir model dimension is 1,000×1,000×100 ftwhere it is subdivided into 50×50×10 grid blocks in *x*, *y* and *z* direction, respectively. The grid size is therefore 20×20×10 ft for *x*, *y* and *z* direction. Both injection and production wells arediagonally located on the opposite corner of each other in model as shown Figures 4.1 and 4.2. From both figures, red color represents oil saturation, whereas blue color is water saturation. Different permeability in each layer is assigned into the mentioned model from the largest value on top to the smallest value at the bottom in order to represent coarsening upward sequence heterogeneous reservoir. However, average permeability, maximum permeability, minimum permeability and median of permeability data set are kept constant in order to make all cases comparable. Reservoir properties are summarized in Table 4.1.

Porosity is fixed at constant of 0.3 for every layer. The assumption is made here that each layer composes of different grain size that results in same value of porosity but different in permeability. This assumption favors the calculation of Original Oil In Place (OOIP).

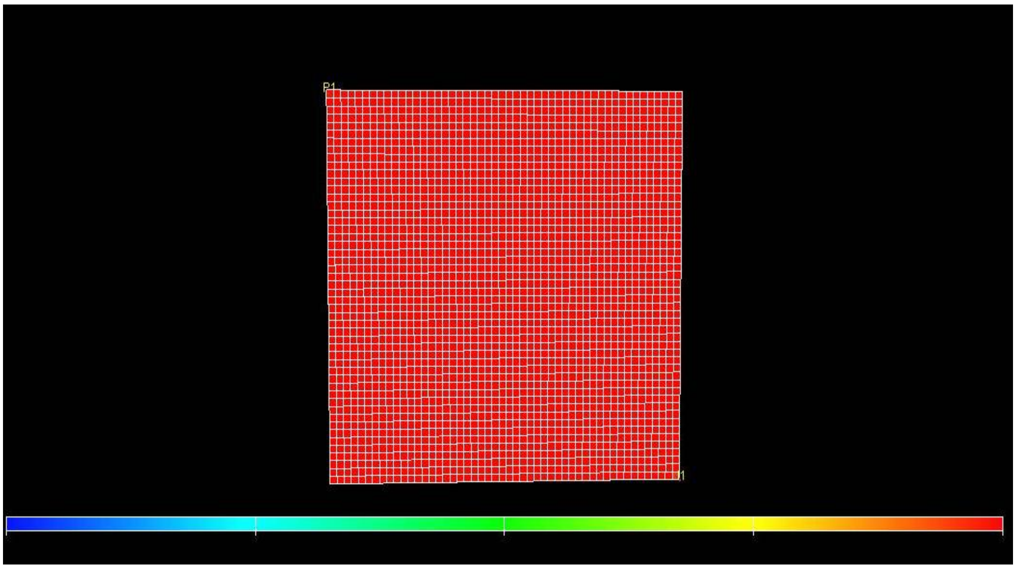


Figure 4.1 Top view of constructed reservoir model (red color represents oil saturation and blue color represents water saturation)

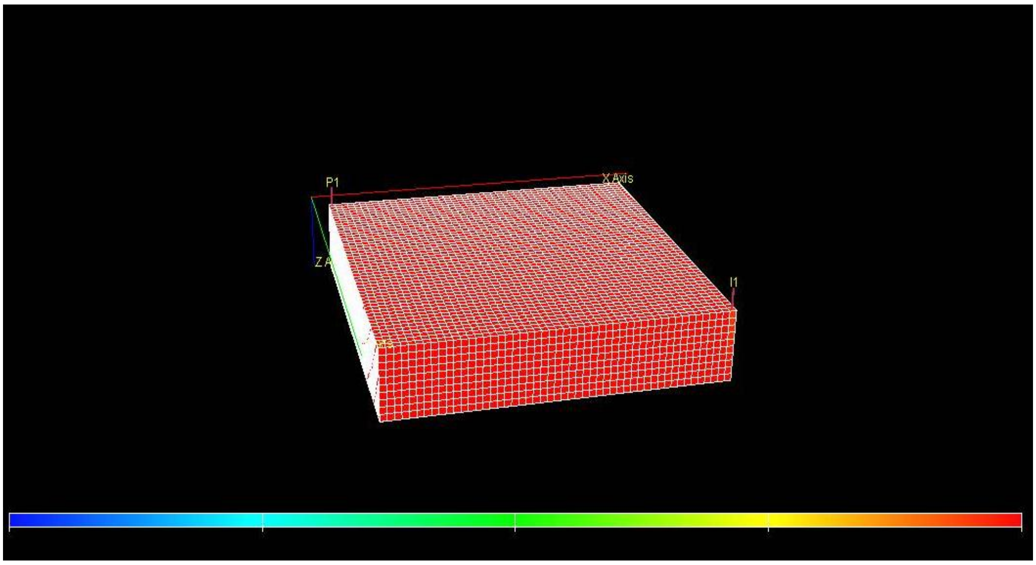


Figure 4.2 Three-dimensional reservoir model showing injection well as I1 and production well as P1(red color represents oil saturation and blue color represents water saturation)

Table 4.1 Reservoir dimensions and other required properties for reservoir simulation

Parameters	**Values**	**Unit**
Grid dimension	50×50×10	Block
Grid size	20×20×10	ft
Porosity	30	%
Horizontal permeability	Varied in each layer	mD
Vertical permeability	Equal to $0.1k_h$	mD
Average permeability	150	mD
Maximum permeability	300	mD
Minimum permeability	10	mD
Median of permeability data	150	mD
Datum depth	3,200	ft
Reservoir thickness	100	ft
OOIP	3.838	MMSTB

4.1Pressure-Volume-Temperature (PVT) properties

Reservoir and surface conditions are used to correlate fluid properties in ECLIPSE®100and parameters are summarized in Table 4.2. This reservoir model initially possesses saturated oil and characteristics (formation volume factor and viscosity) of dead oil changing as a function of reservoir pressure is plotted in Figure 4.3.

Table 4.2 Reservoir condition and surface properties input data

Parameters	**Values**	**Unit**
Oil gravity (stock tank condition)	17	°API
Gas gravity (seperator condition)	0.7	-
Bubble point pressure	500	psia
Salinity	0	fraction
Surface temperature	60	°F
Surface pressure	14.7	psia
Reservoir temperature	140	°F
Reservoir pressure	1430	psia
Rock type	Unconsolidated Sandstone	-

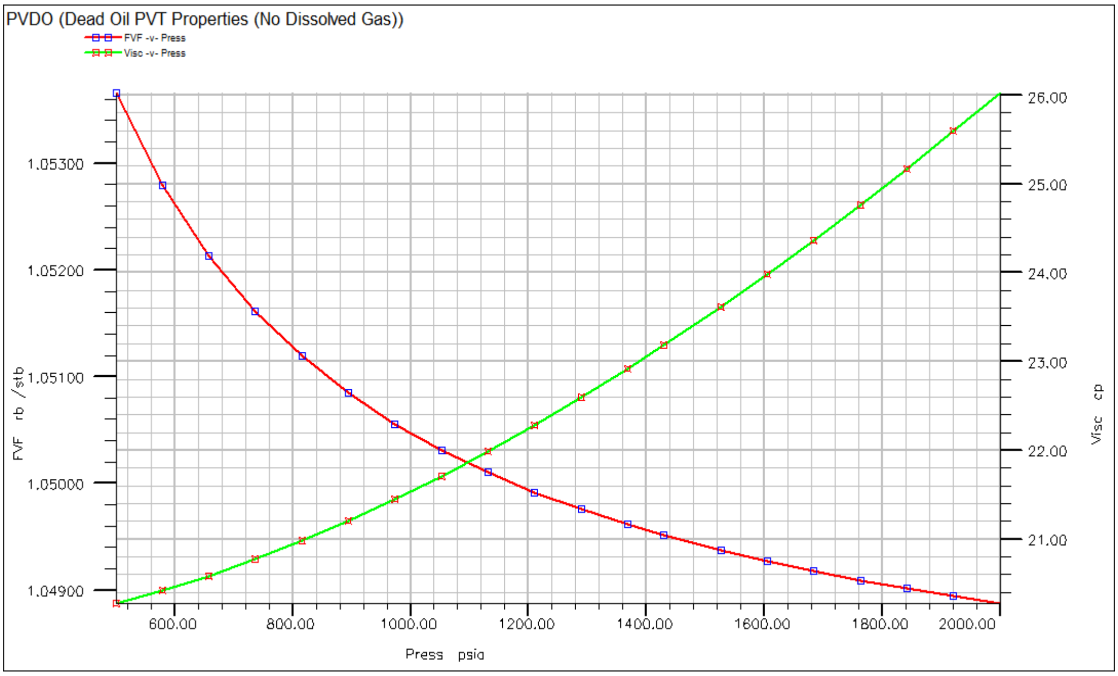


Figure 4.3 Dead oil propertiesincluding formation volume factor and viscosity (no dissolved gas) as a function of reservoir pressure

The correlation data expressed in Table 4.3 shows PVT properties of formation water and consecutively Table 4.4 summarizes fluid densities at surface condition.

Table 4.3 PVT Properties of formation water

Property	Value	Units
Reference pressure(P_{ref})	1,430	psia
Water FVF at P_{ref}	1.006538	rb/stb
Water compressibility	3.030644×10^{-6}	psi^{-1}
Water viscosity at P_{ref}	0.4634349	cP
Water viscosibility	1.011103×10^{-6}	psi^{-1}

Table 4.4 Density of reservoir fluids at surface condition

Property	Value	Units
Oil density	59.42659	lb/ft^3
Water density	62.42797	lb/ft^3
Gas density	0.04369958	lb/ft^3

4.2 Petrophysicalproperties

The Corey correlation is used to originate relative permeability curves due tolack of the real data. Important values required for constructing relative permeability curves by the mentioned correlation is summarized in Table 4.5. After that the calculated data are plotted as curves and are shown in Figure 4.4. However, it is assumed that there is no variation of relative permeability due to adsorption of polymer onto rock surface.

Table 4.5 Required data for relative permeability construction by Corey correlation

Parameters	**Values**
Corey oil exponent	2
S_{orw}	0.25
k_{ro}at S_{wmin}	1
Corey water exponent	2
S_{wmin}	0.2
S_{wcr}	0.2
S_{wi}	0.2
k_{rw}at S_{orw}	0.25
k_r (100% sat)	1

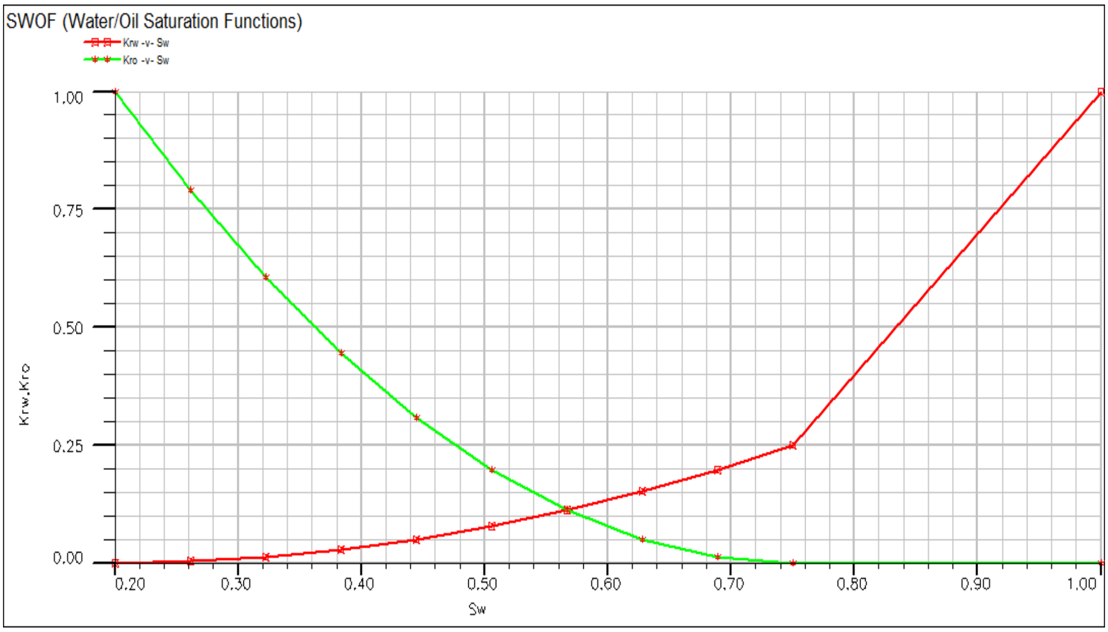


Figure4.4 Relative permeability to oil (green line)and to water (red line) as functions of water saturation

Polymer adsorption function is assumed about 1% of polymer concentration as shown in Figure 4.5. Noted that P_{sc} is concentration of polymer adsorbed by the rock formation (lb/lb) and P_{lc} is concentration of polymer solution (lb/STB). For other related parameters in polymer flooding such as inaccessible pore volume and mixing parameter are also assumed.

In this study, a commercial hydrolized polyacrylamide polymer (HPAM) called Flopaam 3330S represents the injected polymer. The apparent viscosity of this commercial polymer at standard conditions is summarized in Table 4.6. As a function of polymer flooding requirement, the PLYVISC keyword in ECLIPSE®100 or polymer solution viscosity function is a relationship between values of polymer concentration (C_p) and multiplier to water viscosity (F_m) as shown in Figure 4.6. The formation water viscosity is fixed at 0.469 cP. For example, if polymer concentration is 0.1751 lb/STB, the multiplier to water viscosity is 4.4 and hence, viscosity of polymer solution is 0.7704 cP.

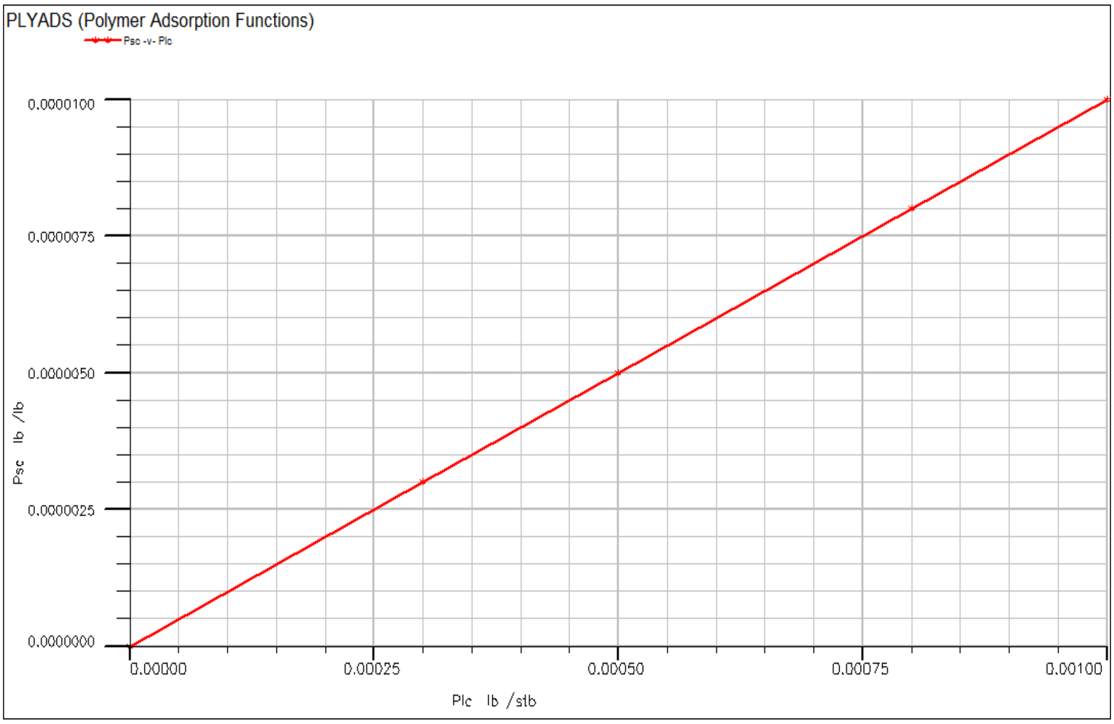


Figure4.5 Polymer adsorptionby reservoir rock as a function of polymer concentration

Table 4.6Apparent viscosity of Flopaam 3330S, a commercial HPAM polymer[14]

Polymer concentration		**Apparent viscosity (cP)**		F_m
ppm	**lb/STB**	**at 25°C**	**at 60°C**	
500	0.1751	4	2.06	4.4
1,000	0.3502	10	5.63	12
2,000	0.7004	40	20.64	44
3,000	1.0506	120	60.98	130

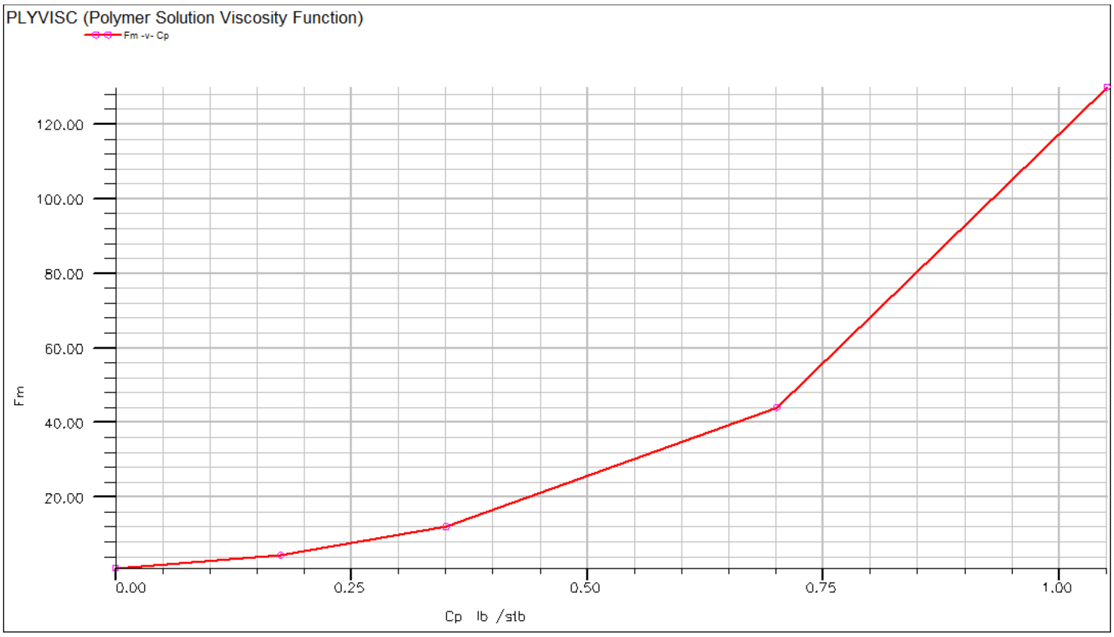


Figure 4.6 Relation between polymer concentration (C_p) and multiplier to water viscosity (F_m) used in the simulations

4.3 Well specification and production constraints

In this study, both injection and production wells are vertical and alsothe same well bore radius of 6-5/8 inches. For injection well, bottomholepressure is limited at 1,900 psia due to fracture constraint and the maximum injection rate is 1,000 STB/D. Other economic constraints such as maximum water cut, minimal oil rate for realistic production oil control are summarized in Table 4.7. In case that one constraint is reached any, the production is automatically shut in. All cases are simulated for total production period of 40 years to concordance with general concession of 30 plus 10 years of extension.

Table 4.7Production constraints for reservoir simulation

Parameter	Value	Units
Minimum oil production rate of production well	20	STB/D
Maximum water cut of each well	95	%
Fracturing pressure	2,250	psia
Maximum injection BHP	1,900	psia
Minimum production BHP	200	psia
Maximum injection rate	1,000	STB/D
Maximum liquid production rate	1,500	STB/D
Total production period	40	Years

4.4Thesis methodology

To achieve goals in this study, details of procedures are precisely described in this section. The study is basically based several previous studies as mentioned in literature reviews. After several important concepts are verified the following steps are taken place.

- Required data for reservoir simulation are gathered. In this step, seven different heterogeneity values of 0.25, 0.30, 0.34, 0.38, 0.40, 0.42 to 0.46 are also constructed and complete details are explained in section 4.5.
- Medium value of heterogeneity of 0.384 is initially selectedfor general base case to simulate waterflooding. After that comparison is made on applying solely polymer injection.
- Next step, optimization of polymer flooding parameters which are pre-flushed water and polymer slug size are performed. Total combination of 18 cases with varying both pre-flushed and polymer slug size, are selected. Liquid injection

rate, bottomhole pressure, polymer concentration are kept constant in all cases. At the end of this step the optimal case is identified and is used as polymer base case for the rest of study.

▪First design parameter, polymer concentration, is investigated. The interest isdivided into two differentstudies. One is emphasized on polymer flooding in variation of both polymer slug size and concentration to keep total mass of polymer constant. Another is emphasized only polymer concentration when slug size is fixed. Both interests are performed on four different scenarios over range of heterogeneity constructed.

▪Second design parameter is polymer injection rate. Simulation is performed on polymer flooding base case with four different injection rates over range of heterogeneity.

▪ Last, double-slug injection is studied in order to study its benefit by comparing with single-slug polymer injection. This step of study is performed by splitting single polymer slug as obtained from polymer flooding base case into two equal slugs by alternating water slug. Not only double-slug is studied but size of alternating water slug is varied as well. Again, selected scenarios are simulated on heterogeneous model.

▪Simulation result cases are discussed by using several simulation outcomes which are oil recovery factor, cumulative oil produced, water cut, cumulative water produced, liquid injection rate, liquid production rate, and dimensionless cumulative water injected.

4.5Construction of reservoir heterogeneity

In this study, the reservoir model is constructed as heterogeneous formation, having variation of permeability as an indicator of heterogeneity. The **Lorenz coefficient** (L_k),purposed by Schmalz and Rahme [15]is chosen in this study due to its simplicity and applicability for stratified reservoir formation. Ten layers of each model are expressed by difference permeability values, ordering form maximum to minimum. Seven models with variation of heterogeneity are constructed to have heterogeneity in the range of 0.25 to 0.46.Model construction is controlled bysome limitations which are equality of average permeability, maximum permeability, minimum permeability and median of permeability data set. Calculation of heterogeneity is consecutively explained in this section.

Let the model having$N$ layers with$j$ representing each layer, $h_j$is thickness,ϕ_j represents porosity and $k_j$is absolute permeability. The fractional flow capacity (F_n) and the fractional of total volume (C_n) are calculated in cumulative value for each layer

$$F_n = \frac{\sum_{j=1}^{j=n} k_j h_j}{\sum_{j=1}^{j=N} k_j h_j} \text{ , and } \quad C_n = \frac{\sum_{j=1}^{j=n} \phi_j h_j}{\sum_{j=1}^{j=N} \phi_j h_j} .$$

Then all ten cumulative values are plotted, havingthe fractional flow capacity (F_n) on y-axis and the fractional of total volume (C_n) on x-axis. The plot shown in Figure 4.7 represents a homogeneous model. However, when reservoir deviates from homogeneity, the greater deviation is indicated by an increase of divergence from a 45˚ line. In order to determine the Lorenz coefficient, different area between deviated curve and homogeneous curve are calculated and after that the different area is divided by area of homogeneous curve.

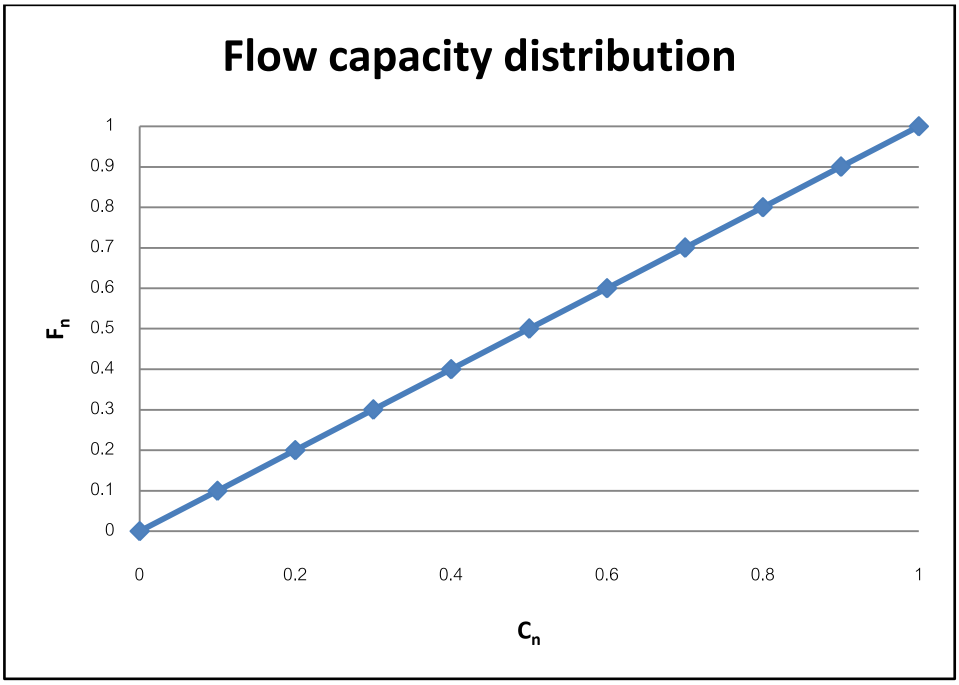


Figure 4.7 Flow capacity distribution of homogeneous model

Case no. 1 is constructed to haveL_k equal to 0.46. Aaverage permeability is150 mDarcy, maximum permeability is 300 mDarcy, minimum permeability is 10 mDarcyamdmedian is 150mDarcy. Table 4.8 summarizes cumulative values for calculation of heterogeneity and the curve is plotted in Figure 4.8.

Table 4.8 Cumulative values for Lorenz coefficient calculationof case 1 (L_k = 0.46)

layer	**k**	**h**	**kh**	**hϕ**	**cum. kh**	**cum. hϕ**	C_n**(X)**	F_n**(Y)**	**Area of each layer**
							0	0	
1	300	10	3,000	3	3,000	3	0.1	0.2	0.01
2	295	10	2,950	3	5,950	6	0.2	0.396667	0.029833
3	290	10	2,900	3	8,850	9	0.3	0.59	0.049333
4	262	10	2,620	3	11,470	12	0.4	0.764667	0.067733
5	260	10	2,600	3	14,070	15	0.5	0.938	0.085133
6	40	10	400	3	14,470	18	0.6	0.964667	0.095133
7	17	10	170	3	14,640	21	0.7	0.976	0.097033
8	15	10	150	3	14,790	24	0.8	0.986	0.0981
9	11	10	110	3	14,900	27	0.9	0.993333	0.098967
10	10	10	100	3	15,000	30	1	1	0.099667

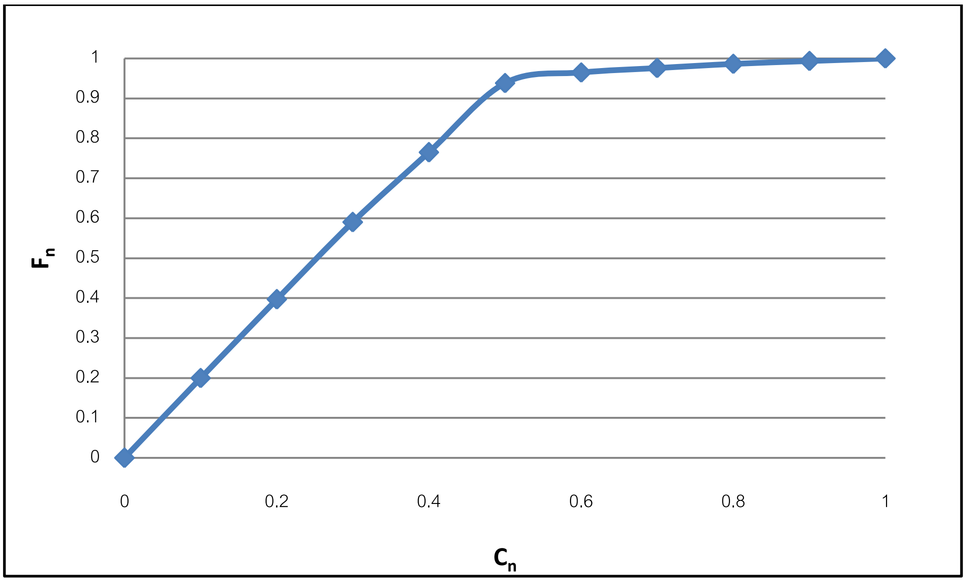


Figure 4.8 Flow capacity distribution of case 1 (L_k = 0.46)

The calculation of case no. 2 is similar to case no. 1 but the permeability in each later is slightly modified. $L_k$is 0.42 in this case.Table 4.9 summarizes cumulative values for calculation of heterogeneity and the curve is plotted in Figure 4.9.

Table 4.9 Cumulative values for Lorenz coefficient calculation of case 2 (L_k = 0.42)

layer	k	h	kh	hϕ	cum. kh	cum. hϕ	C_n(X)	F_n(Y)	Area of each layer
							0	0	
1	300	10	3,000	3	3,000	3	0.1	0.2	0.01
2	290	10	2,900	3	5,900	6	0.2	0.393333	0.029667
3	285	10	2,850	3	8,750	9	0.3	0.583333	0.048833
4	230	10	2,300	3	11,050	12	0.4	0.736667	0.066
5	170	10	1,700	3	12,750	15	0.5	0.85	0.079333
6	130	10	1,300	3	14,050	18	0.6	0.936667	0.089333
7	40	10	400	3	14,450	21	0.7	0.963333	0.095
8	25	10	250	3	14,700	24	0.8	0.98	0.097167
9	20	10	200	3	14,900	27	0.9	0.993333	0.098667
10	10	10	100	3	15,000	30	1	1	0.099667

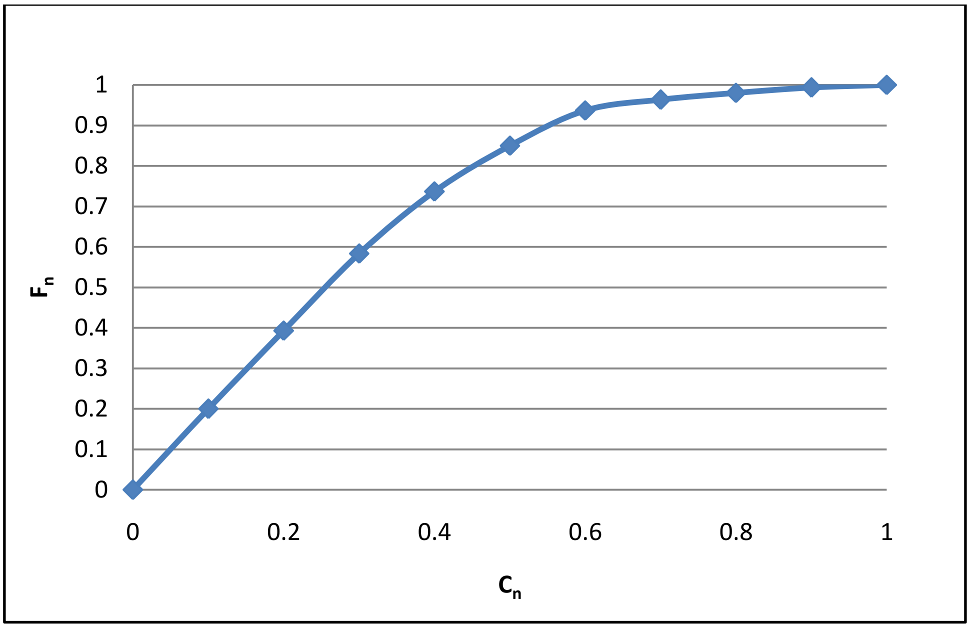


Figure 4.9Flow capacity distribution of case 2 (L_k = 0.42)

For the case no. 3, L_k is 0.40. Table 4.10 summarizes cumulative values for calculation of heterogeneity and the curve is plotted in Figure 4.10.

Table 4.10 Cumulative values for Lorenz coefficient calculation of case 3 (L_k = 0.40)

layer	**k**	**h**	**kh**	**hϕ**	**cum. kh**	**cum. hϕ**	***C_n*(X)**	***F_n*(Y)**	**Area of each layer**
							0	0	
1	300	10	3,000	3	3,000	3	0.1	0.2	0.01
2	275	10	2,750	3	5,750	6	0.2	0.383333	0.029167
3	265	10	2,650	3	8,400	9	0.3	0.56	0.047167
4	230	10	2,300	3	10,700	12	0.4	0.713333	0.063667
5	170	10	1,700	3	12,400	15	0.5	0.826667	0.077
6	130	10	1,300	3	13,700	18	0.6	0.913333	0.087
7	45	10	450	3	14,150	21	0.7	0.943333	0.092833
8	40	10	400	3	14,550	24	0.8	0.97	0.095667
9	35	10	350	3	14,900	27	0.9	0.993333	0.098167
10	10	10	100	3	15,000	30	1	1	0.099667

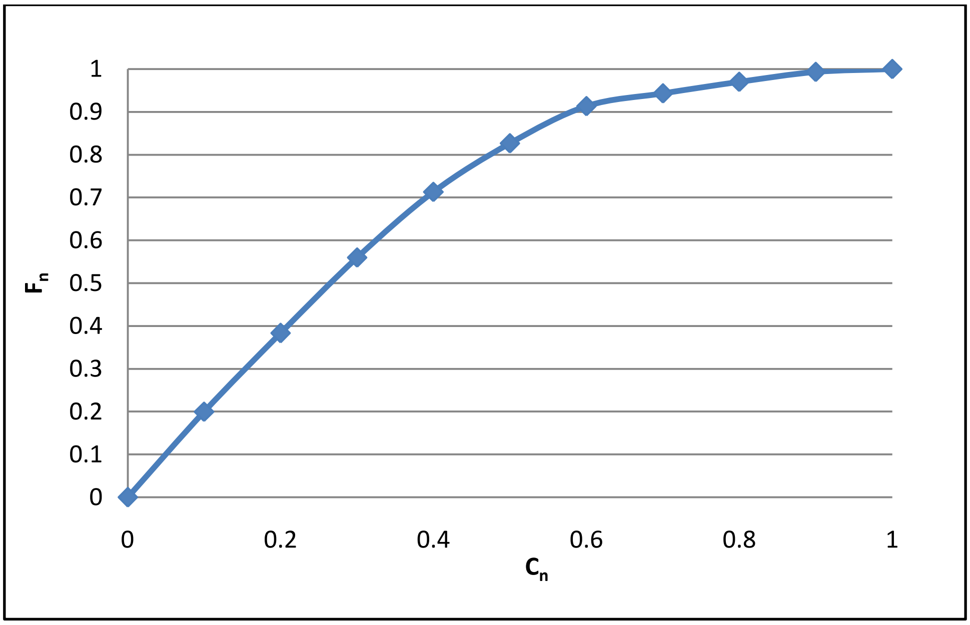


Figure 4.10 Flow capacity distribution case 3 (L_k = 0.40)

For the case no.4, L_k is 0.38. Table 4.1 summarizes cumulative values for calculation of heterogeneity and the curve is plotted in Figure 4.11.

Table 4.11 Cumulative values for Lorenz coefficient calculation of case 4 (L_k = 0.38)

layer	**k**	**h**	**kh**	**hϕ**	**cum. kh**	**cum. hϕ**	***C*$_n$(X)**	***F*$_n$(Y)**	**Area of each layer**
							0	0	
1	300	10	3,000	3	3,000	3	0.1	0.2	0.01
2	270	10	2,700	3	5,700	6	0.2	0.38	0.029
3	255	10	2,550	3	8,250	9	0.3	0.55	0.0465
4	220	10	2,200	3	10,450	12	0.4	0.696667	0.062333
5	155	10	1,550	3	12,000	15	0.5	0.8	0.074833
6	145	10	1,450	3	13,450	18	0.6	0.896667	0.084833
7	60	10	600	3	14,050	21	0.7	0.936667	0.091667
8	45	10	450	3	14,500	24	0.8	0.966667	0.095167
9	40	10	400	3	14,900	27	0.9	0.993333	0.098
10	10	10	100	3	15,000	30	1	1	0.099667

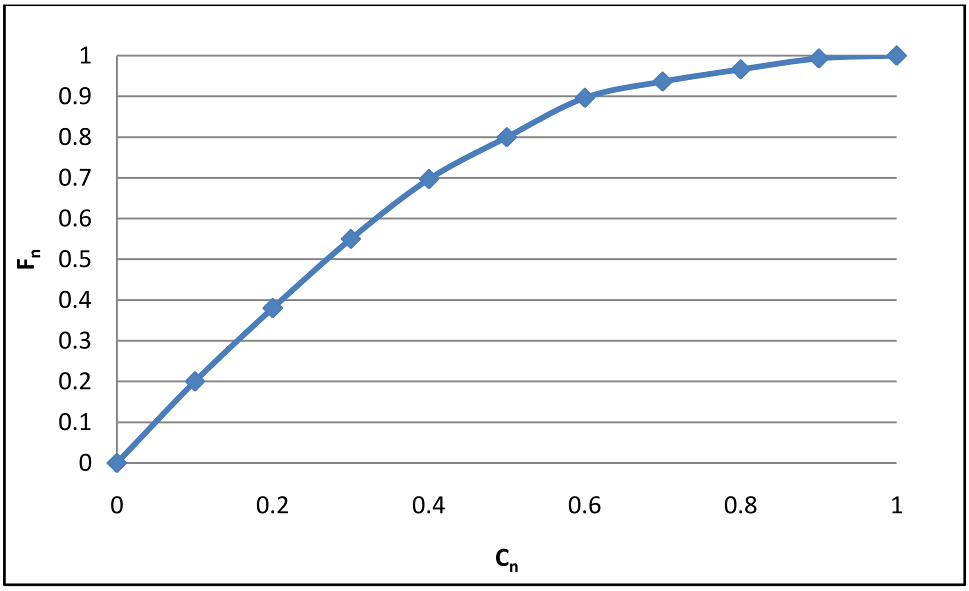


Figure 4.11Flow capacity distribution case 4 (L_k = 0.38)

For the case no.5, L_k is 0.34. Table 4.12 summarizes cumulative values for calculation of heterogeneity and the curve is plotted in Figure 4.12.

Table 4.12 Cumulative values for Lorenz coefficient calculation of case 5 (L_k = 0.34)

layer	k	h	kh	hϕ	cum. kh	cum. hϕ	C_n(X)	F_n(Y)	Area of each layer
							0	0	
1	300	10	3,000	3	3,000	3	0.1	0.2	0.01
2	260	10	2,600	3	5,600	6	0.2	0.373333	0.028667
3	220	10	2,200	3	7,800	9	0.3	0.52	0.044667
4	200	10	2,000	3	9,800	12	0.4	0.653333	0.058667
5	170	10	1,700	3	11,500	15	0.5	0.766667	0.071
6	130	10	1,300	3	12,800	18	0.6	0.853333	0.081
7	80	10	800	3	13,600	21	0.7	0.906667	0.088
8	70	10	700	3	14,300	24	0.8	0.953333	0.093
9	60	10	600	3	14,900	27	0.9	0.993333	0.097333
10	10	10	100	3	15,000	30	1	1	0.099667

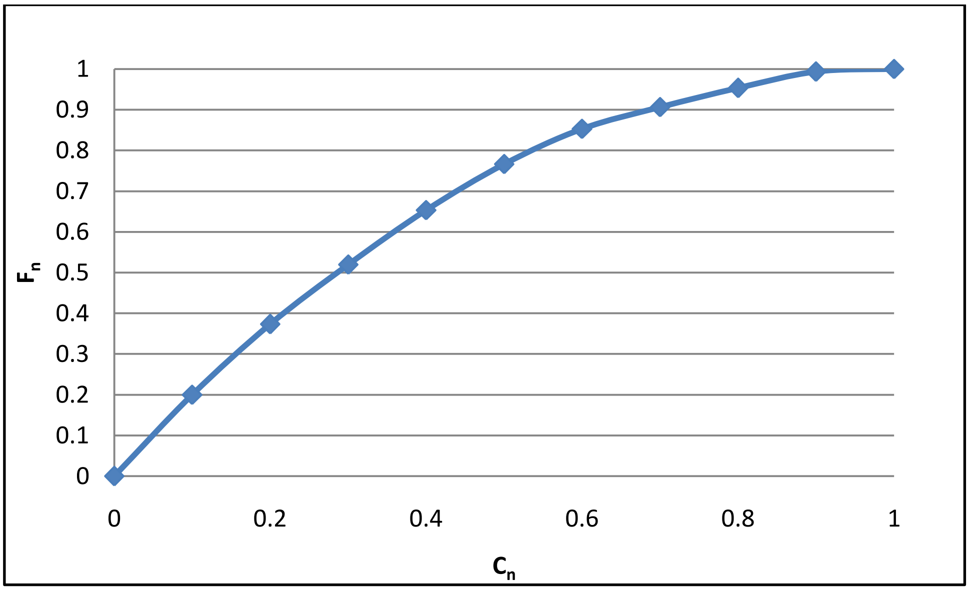


Figure 4.12 Flow capacity distribution case 5 (L_k = 0.34)

For the case no.6, L_k is 0.30. Table 4.13 summarizes cumulative values for calculation of heterogeneity and the curve is plotted in Figure 4.13.

Table 4.13 Cumulative values for Lorenz coefficient calculation of case 6 (L_k = 0.30)

layer	**k**	**h**	**kh**	**hϕ**	**cum. kh**	**cum. hϕ**	C_n**(X)**	F_n**(Y)**	**Area of each layer**
							0	0	
1	300	10	3,000	3	3,000	3	0.1	0.2	0.01
2	220	10	2,200	3	5,200	6	0.2	0.346667	0.027333
3	210	10	2,100	3	7,300	9	0.3	0.486667	0.041667
4	200	10	2,000	3	9,300	12	0.4	0.62	0.055333
5	155	10	1,550	3	10,850	15	0.5	0.723333	0.067167
6	145	10	1,450	3	12,300	18	0.6	0.82	0.077167
7	100	10	1,000	3	13,300	21	0.7	0.886667	0.085333
8	90	10	900	3	14,200	24	0.8	0.946667	0.091667
9	70	10	700	3	14,900	27	0.9	0.993333	0.097
10	10	10	100	3	15,000	30	1	1	0.099667

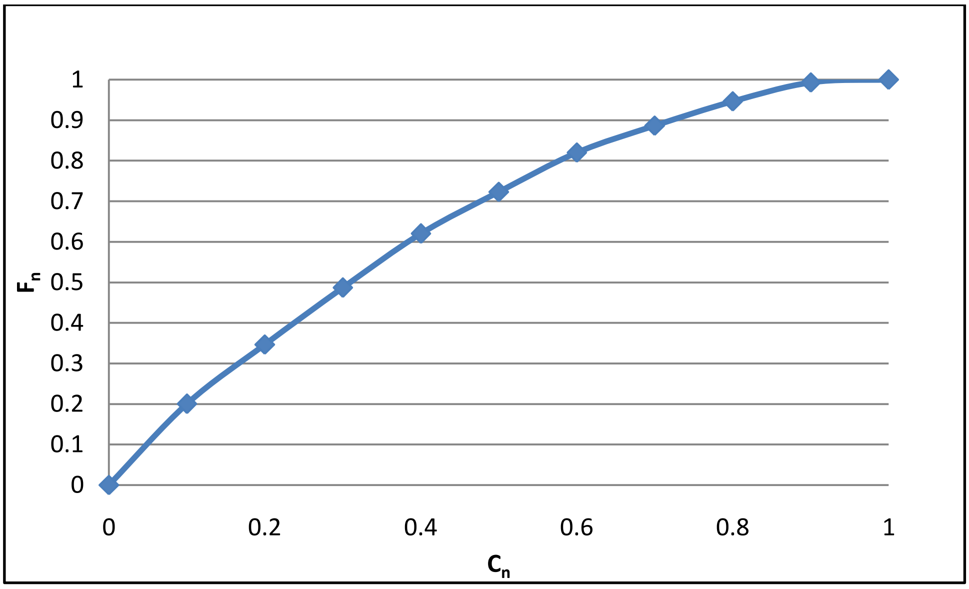


Figure 4.13 Flow capacity distribution case 6 (L_k = 0.30)

For the last case, the smallest $L_k$value of 0.25 represents heterogeneity of the reservoir. Table 4.14 summarizes cumulative values for calculation of heterogeneity and the curve is plotted in Figure 4.14.

Table 4.14 Cumulative values for Lorenz coefficient calculation of case 7 (L_k = 0.25)

layer	k	h	kh	hϕ	cum. kh	cum. hϕ	C_n(X)	F_n(Y)	Area of each layer
							0	0	
1	300	10	3,000	3	3,000	3	0.1	0.2	0.01
2	210	10	2,100	3	5,100	6	0.2	0.34	0.027
3	180	10	1,800	3	6,900	9	0.3	0.46	0.04
4	160	10	1,600	3	8,500	12	0.4	0.566667	0.051333
5	155	10	1,550	3	10,050	15	0.5	0.67	0.061833
6	145	10	1,450	3	11,500	18	0.6	0.766667	0.071833
7	125	10	1,250	3	12,750	21	0.7	0.85	0.080833
8	115	10	1,150	3	13,900	24	0.8	0.926667	0.088833
9	100	10	1,000	3	14,900	27	0.9	0.993333	0.096
10	10	10	100	3	15,000	30	1	1	0.099667

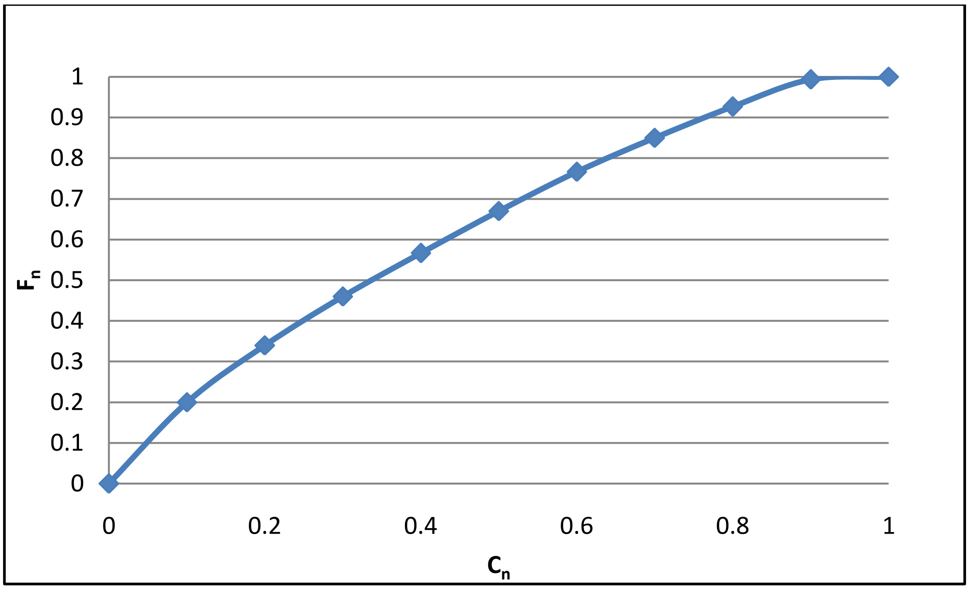


Figure 4.14 Flow capacity distribution case 7 (L_k =0.25)

Comparison of flow capacity distribution from case no. 1 to case no. 7 including distribution capacity of homogeneous model is illustrated in Figure 4.15.

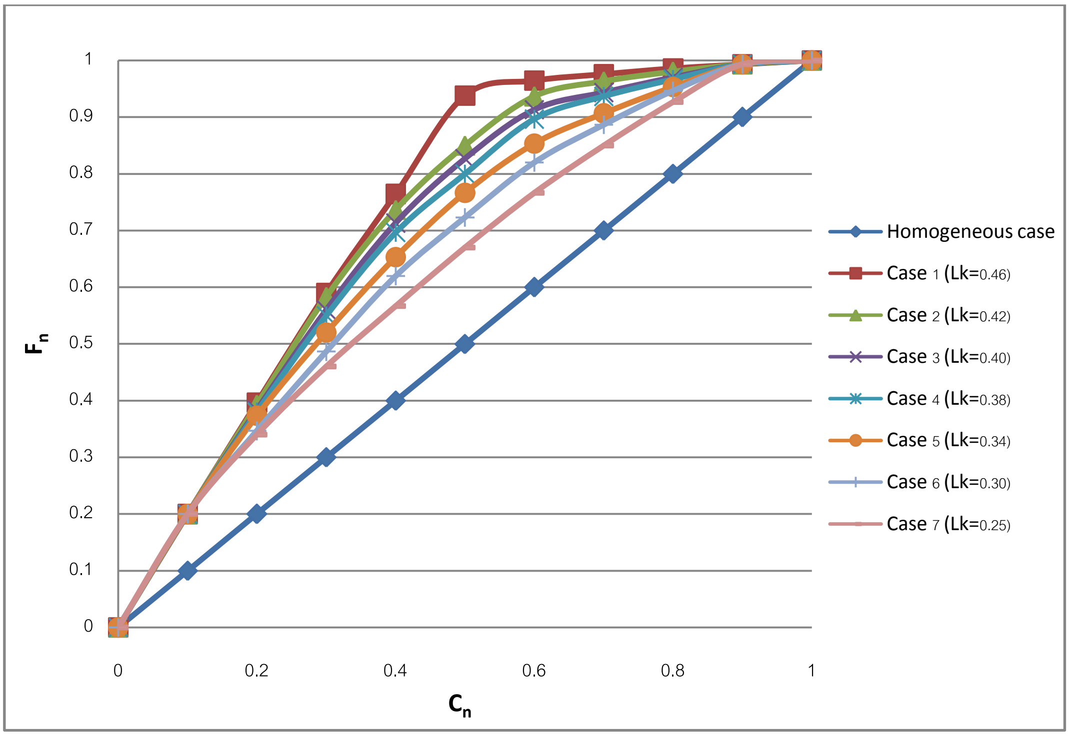


Figure 4.15 Summary of flow capacity distribution

Designed heterogeneity values are applied withpolymer flooding cases to study the sensitivity of all interest parameters. Results and discussions are described in next chapter.

CHAPTER V

OPTIMIZATION AND SENSITIVITY ANALYSIS

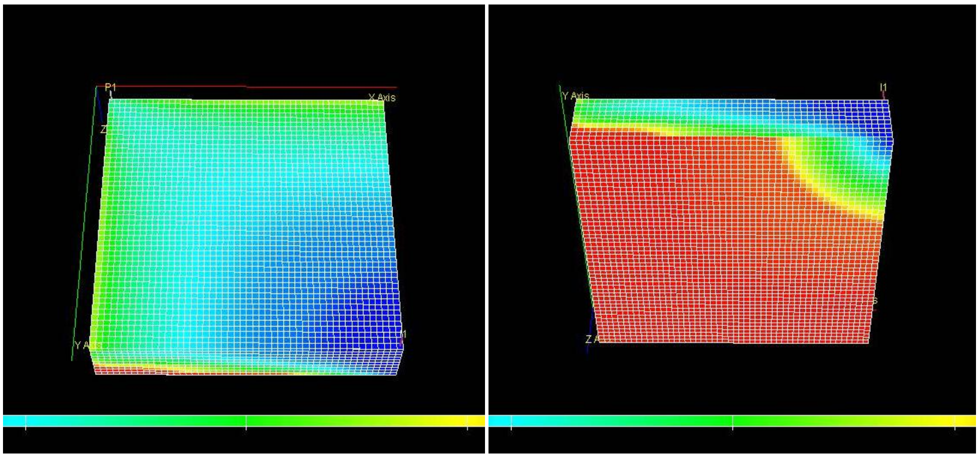
Referring to the mentioned objectives in introductionchapter which are to observe the effect of viscosity and injection rate on effectiveness of polymer flooding in multi-layered heterogeneous reservoir and to optimize the polymer injection scheme in heterogeneous formation, base case model is constructed to represent a blank test to use for comparison by applying only waterflooding onto the model. Optimization of polymer flooding is performed after in order to obtain the polymer flooding base case. At the end, selected parameters are studied in order to observe their sensitivities on polymer flooding in heterogeneous reservoir. The six study cases are:

1. Waterflooding base case,
2. Optimization of polymer flooding determination polymer flooding base caseincluding shear thinningeffect on production performance,
3. Effect of polymer concentrationand slug size,
4. Effect of polymer concentration,
5. Effect of injection rate of polymer solution,
6. Effect of multiple slug design.

5.1 Waterflooding base case

Basically, waterflooding is fundamental of model construction before moving further to next step. After model is completely built as described in chapter 4, waterflooding is performed from without primary recovery until one of the preset production constraints is reached. For waterflooding base case, middle value of heterogeneity with aL_k value of 0.38 is chosen for simulation at 1,000 STB/D water injection rate.

Figure 5.1 shows waterflooding base case model when production reaches producing limitations in both top and bottom views. Red color represents oil saturation, whereas blue color is water saturation. Figures 5.2 to 5.6 show reservoir simulation outcomes including water injection rate at injector, bottomhole pressures, water cut at producer, oil production rate and finally oil recovery factor.



(a) (b)

Figure 5.1 Oil saturation profile from waterflooding base case model from (a) top view and (b) bottom view at the end of production period(red color is oil saturation and blue color is water saturation)

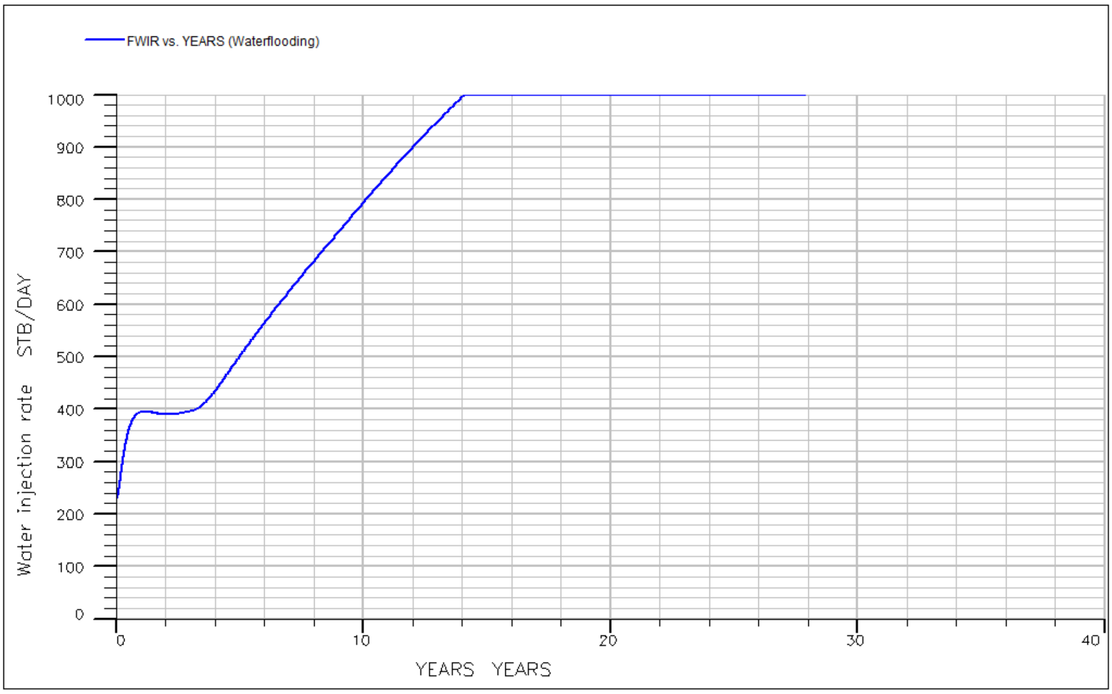


Figure 5.2 Water injection rate of waterflooding base case as a function of time

Figure 5.2 shows that injection rate increases with time due increment of water injectivity. The injection rate reaches maximum value as the well is switched to control by injection rate instead of bottomhole pressure. The bottomhole pressure is then dropped at around the year 14th as can be seen in Figure 5.3.

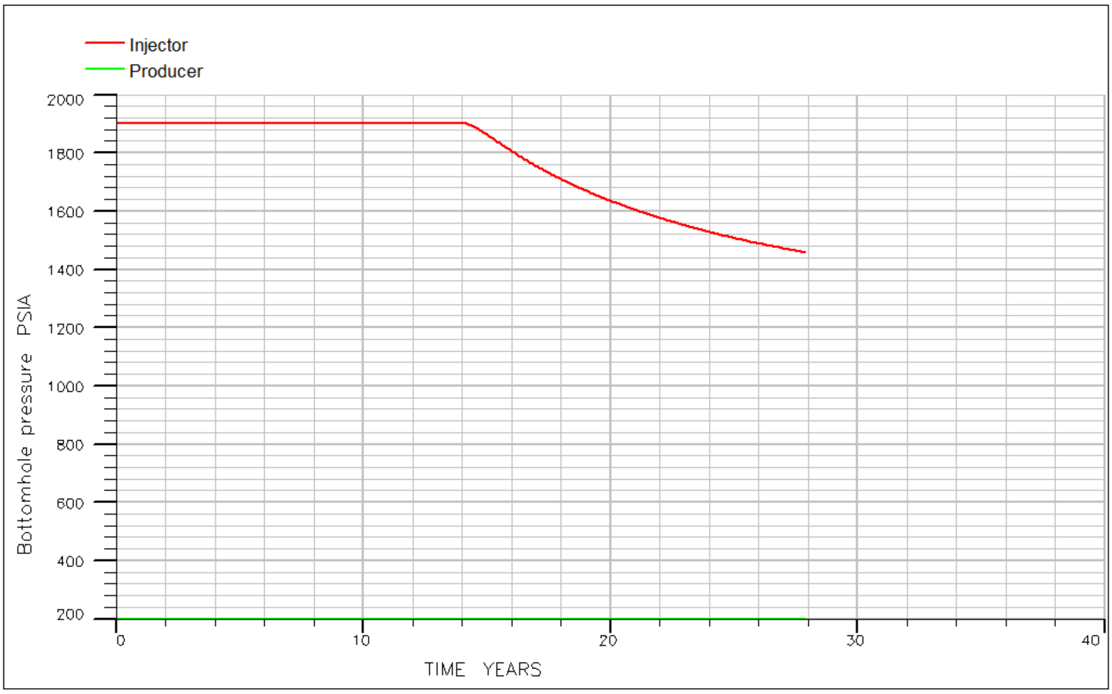


Figure 5.3 Bottomhole pressures of injector and producer of waterflooding base case as functions of time

Final water cut at producer is shown in Figure 5.4. At the beginning of production, connate water expands as pressure around producer decreases. Thus the expanded water yields slightly higher water saturation. As a result of water expansion, there is a small amount of water production before water breakthrough. . It can be obviously seen that at the 3rd year of production, water breakthrough occurs. The cause of early water breakthrough is from heterogeneity. When high permeability channel exists, water tends to flow through this channel, causing an arrival of water at producer after a few years of waterfloodingprocess.

Oil production rate and oil recovery factor of waterfloodingbase case are shown in Figures 5.5 and 5.6, respectively. In an early stage of production, oil production rate slightly drops although water is kept injected. Due to oil compressibility and viscous properties, oil requires certain period before pressure will effect on increasing production rate.

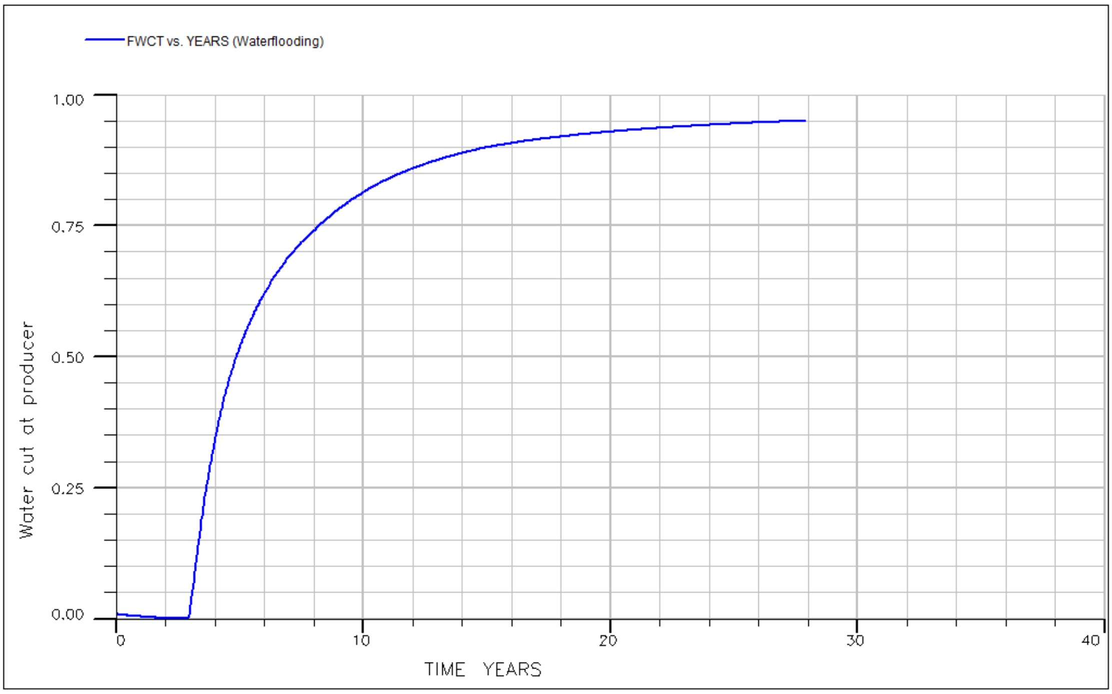


Figure 5.4 Water cut at producer as a function of time of waterflooding base case

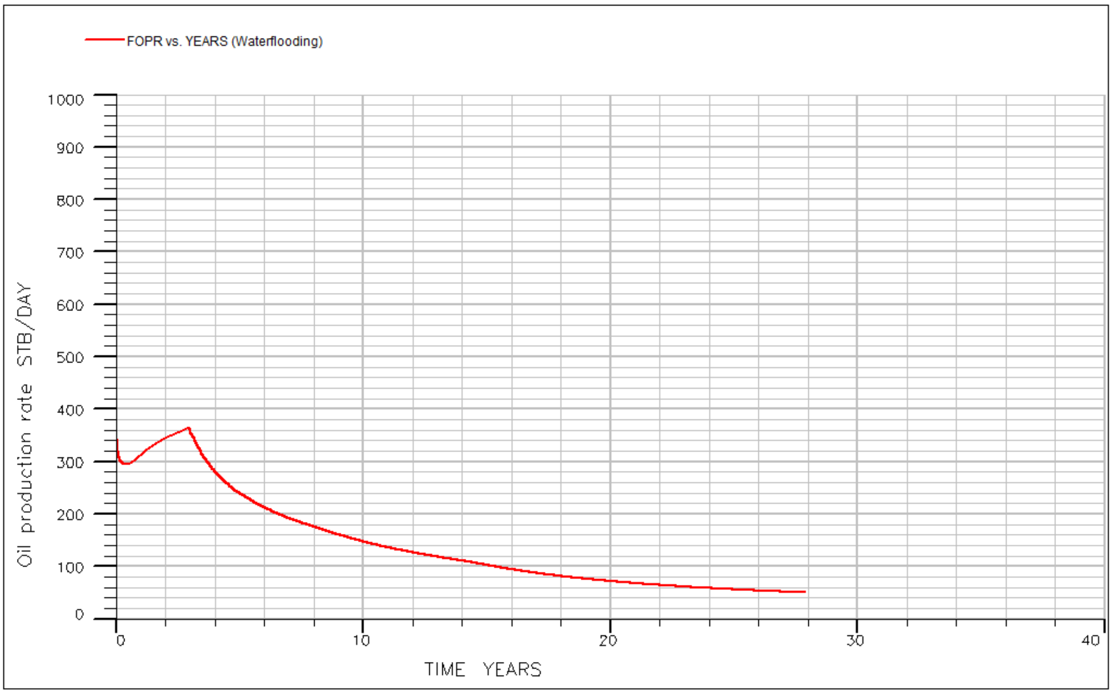


Figure 5.5 Oil production rate at producer as a function of time for waterflooding base case

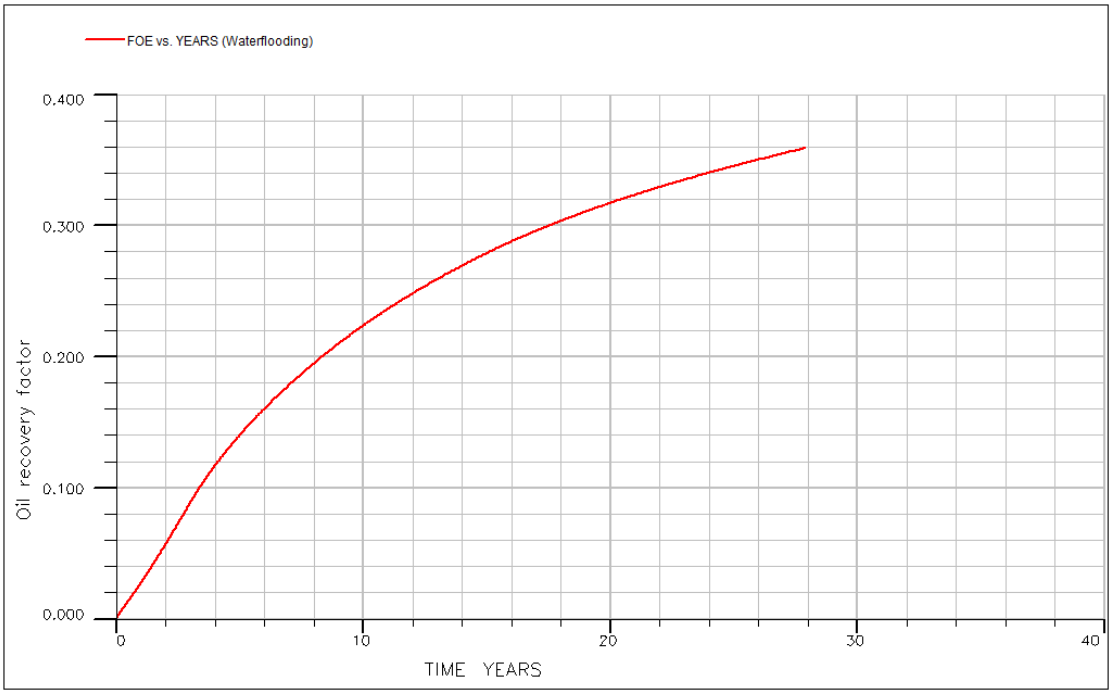


Figure 5.6 Oil recovery factor as a function of time for waterflooding base case

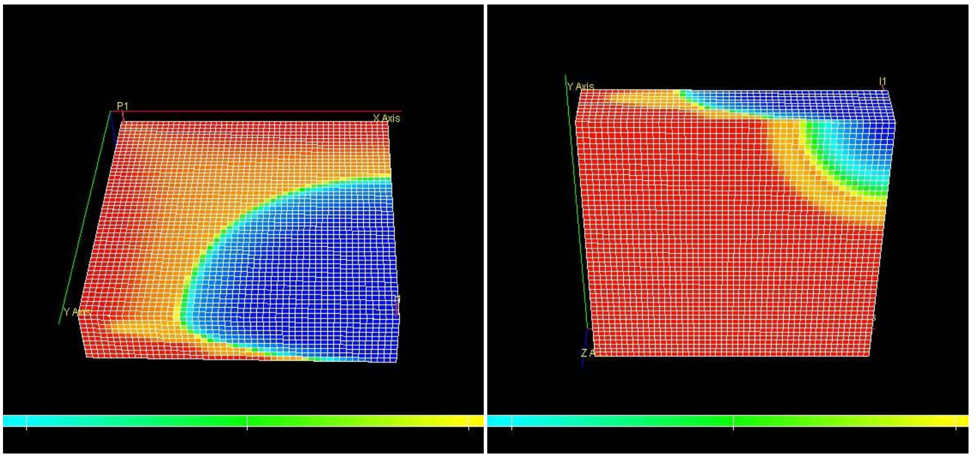
Oil production of waterflooding base case terminates at the year 28th because water cut reaches limitation of 95%. In summary, cumulative oil production is 1.46 MMSTB and oil recovery factor is approximately 36%.

5.2 Optimization of polymer flooding and determination of polymer flooding base case

After waterflooding base case is performed, polymer flooding is initially studied in order to achieve results based on objectives. Single slug polymer flooding is performed by the use of black oil simulator with additional option for polymer flooding as previously described in chapter 4.

A quarter of five-spot pattern and middle value of heterogeneity (L_k = 0.38) are also applied as same as waterflooding base case. The main goal of this section is to determine the optimized polymer flooding scheme. Concentration of polymer solution is initially fixed at 0.7004 lb/STB and maximum injection rate is at 1,000 STB/D. Solely polymer injection is performed first. Polymer solution is injected into reservoir from the beginning until production well is shut in due to any production limitation. The results are illustrated in Figures 5.7 to 5.14.

As seen in Figure 5.7, polymer flooding shows better mobility control and sweep efficiency compared to waterflooding base case (Figure 5.1). This can be seen from less variation in saturation compared from top to bottom layers.



(a) (b)

Figure 5.7 Oil saturation profile from solely polymer injection model from (a) top view and (b) bottom view at the end of production period (red color is oil saturation and blue color is water saturation)

At the end of production, oil recovery factor is as low as 22% and cumulative oil production is only 900,000 STB as observed from Figures 5.8 and 5.9, respectively.

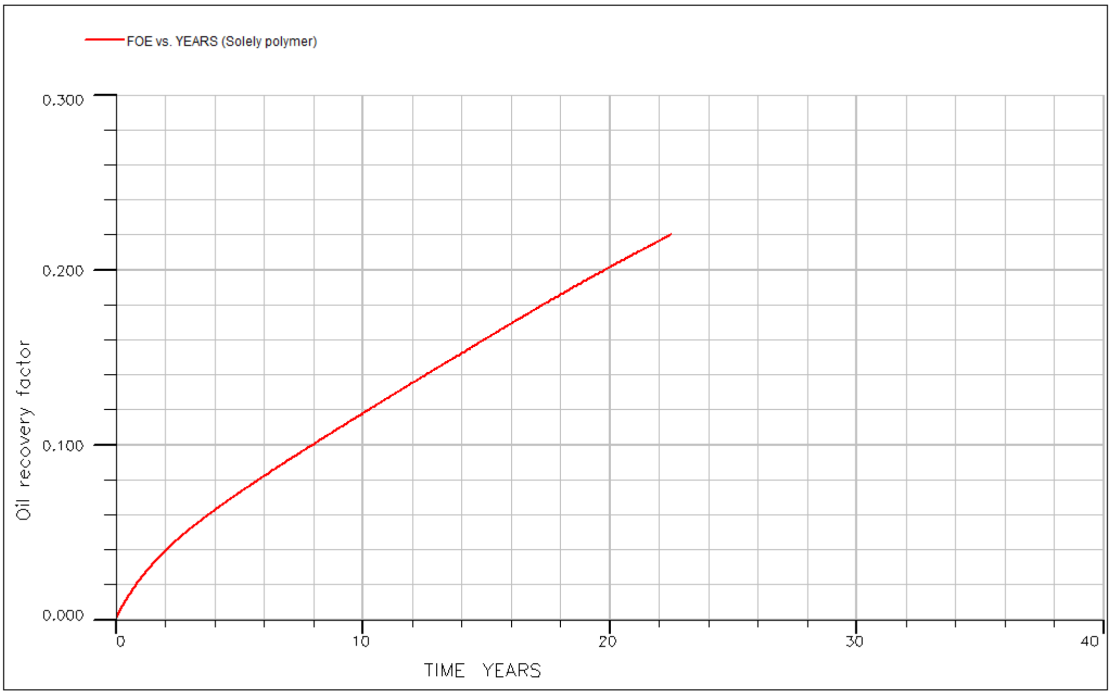


Figure 5.8 Oil recovery factor of solely polymer flooding case as a function of time

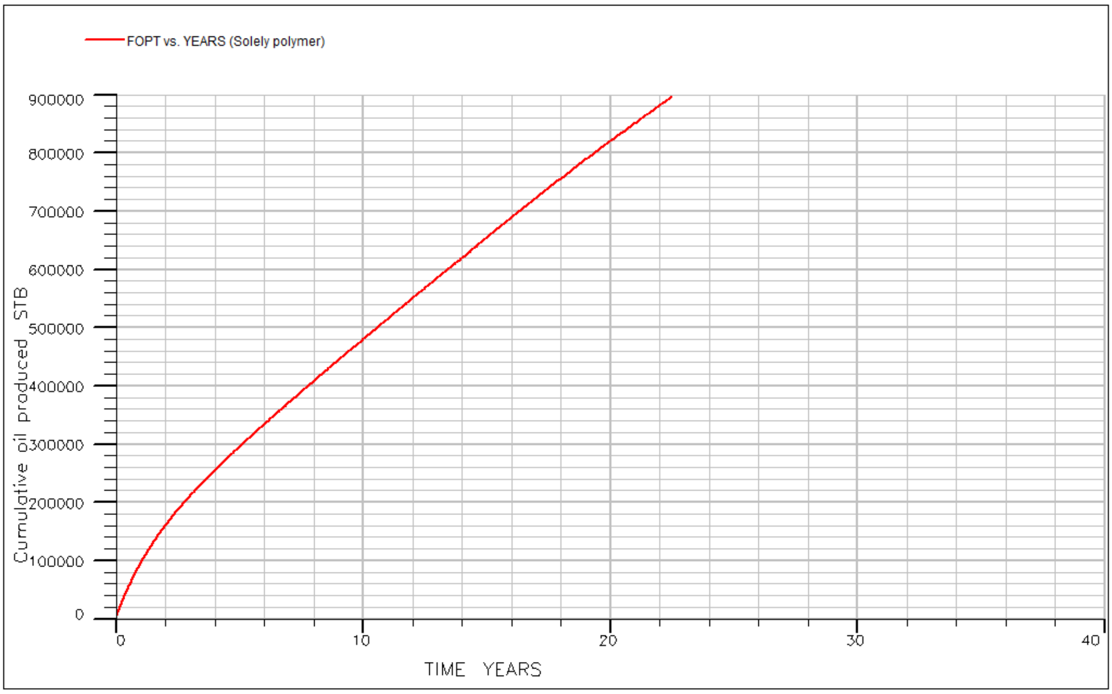


Figure 5.9 Cumulative oil produced of solely polymer flooding case as a function of time

Even though flood front movement in top layers is more advanced compared to the bottom ones due to higher permeability (Figures 5.7a and 5.7b), polymer flooding is able to extend water breakthrough time about 17 years as observed from water production rate at producer in Figure 5.10. Difference of water production between polymer flooding case and waterflooding case can be obviously seen also water cut at producer in Figure 5.11 (compared to Figure 5.4).

However, one problem often encountered in polymer injection is low injectivity. Injectivity is a function of both reservoir properties as operation parameters. Among all reservoir properties, viscosity of injectant is one of the most important that control this ability. Injectivity or an ease to inject a fluid into porous medium is basically low when viscosity is high. Therefore injectivity of solely polymer flooding is too low and this results in short period ofproduction due to low oil production rate as can be seen in Figure 5.12.

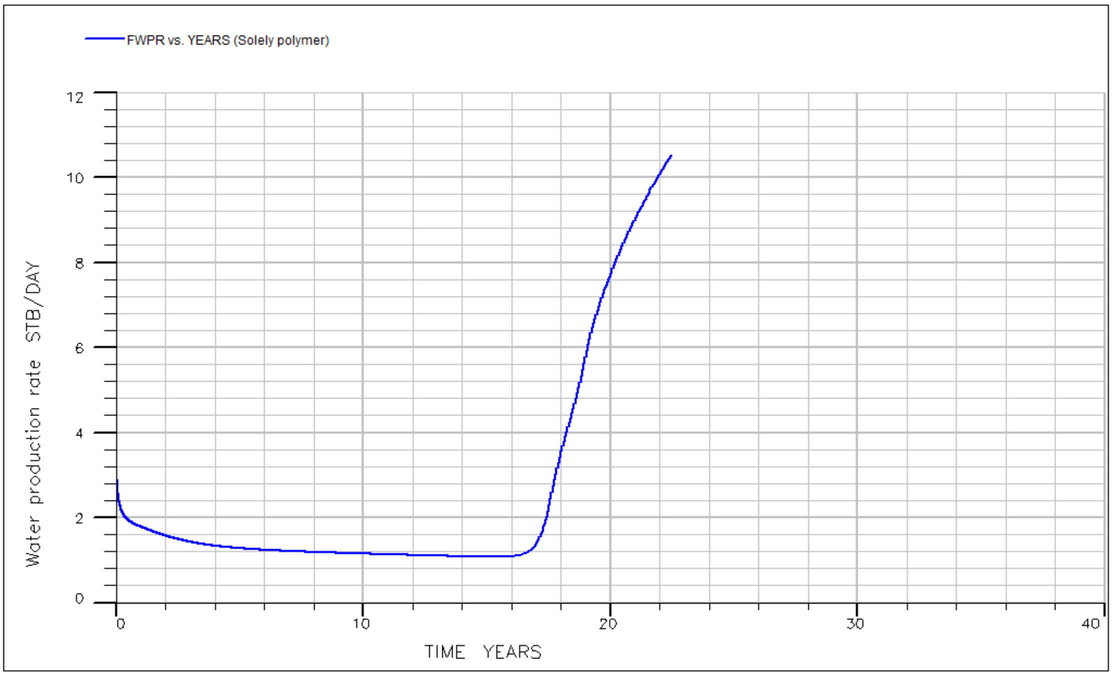


Figure 5.10 Water production rate of solely polymer flooding case as a function of time

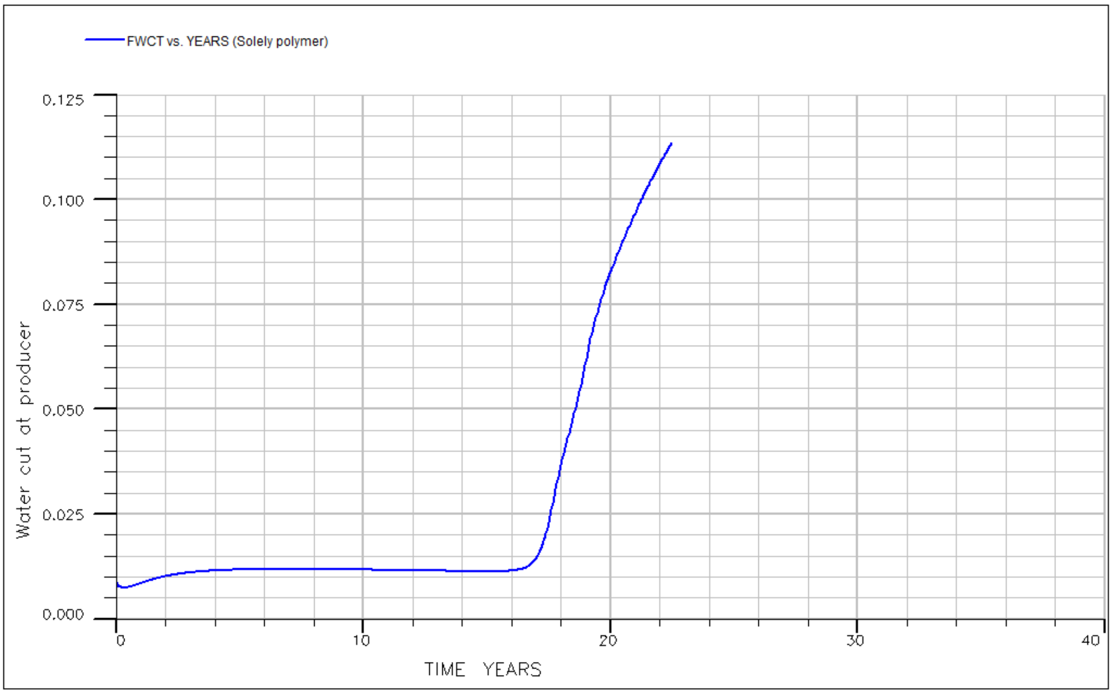


Figure 5.11 Water cut of solely polymer flooding case as a function of time

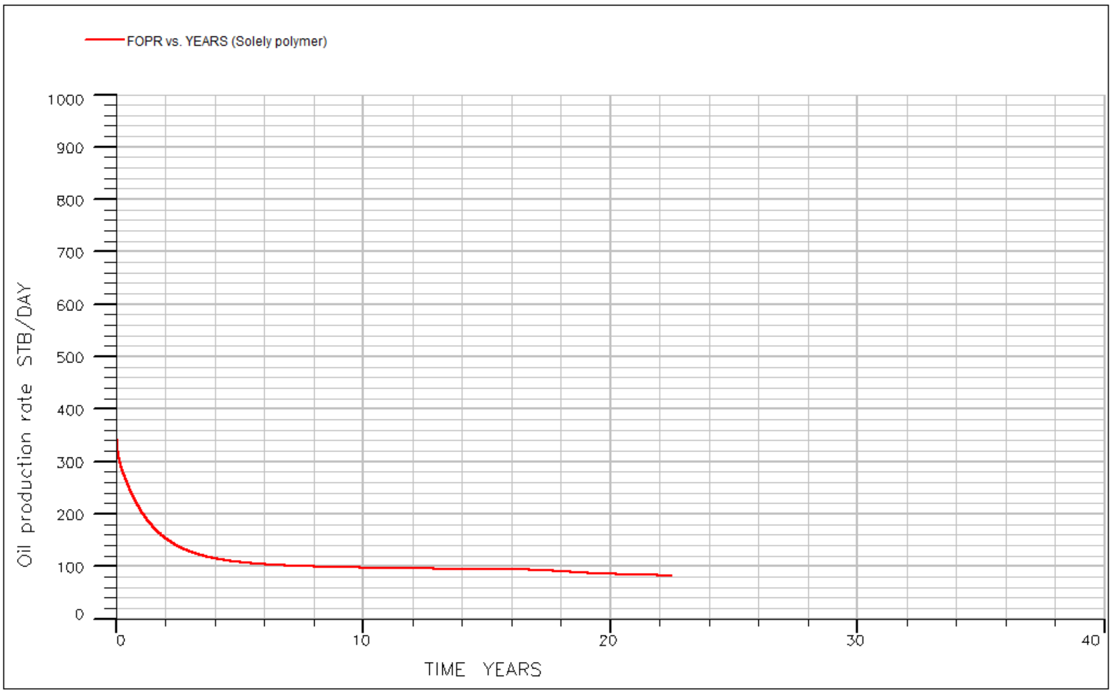


Figure 5.12 Oil production rate of solely polymer flooding case as a function of time

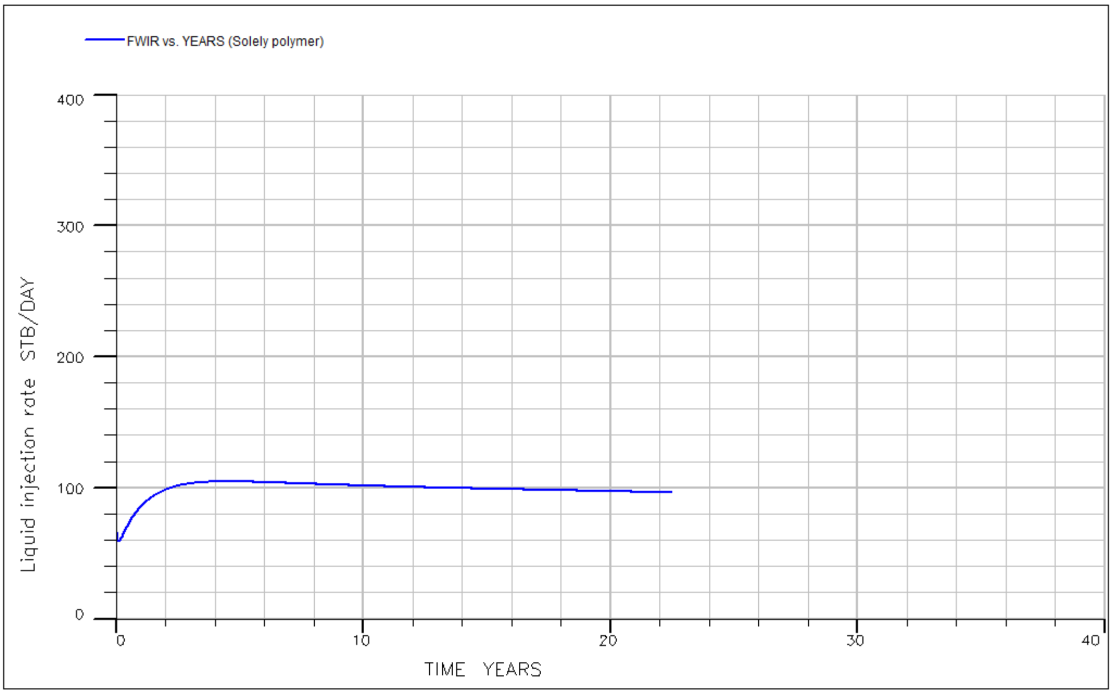


Figure 5.13 Polymer injection rate of solely polymer flooding case as a function of time

Figure 5.13 illustrates polymer injection rate that is relatively low compared to waterflooding. The injection rate slightly increases for short period at early stage and declines later before it stops. As described previously injectivity of polymer flooding is low and results in this declining. Termination of production in this case occurs without reaching any production constraint as seen fromFigure 5.14 where bottomhole pressure and injection rate of injection well are still at the pre-set value.The total production period is approximately 22 years and the process still leave a plenty amount of oil as seen from the polymer flood front that has not reached yet the production well.

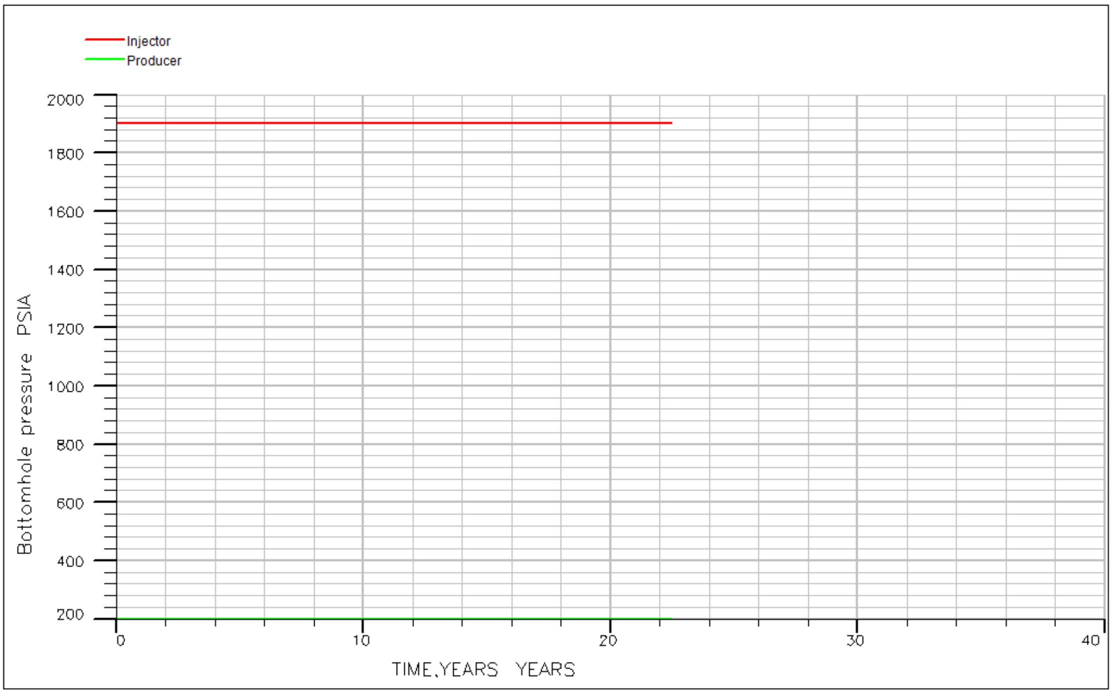
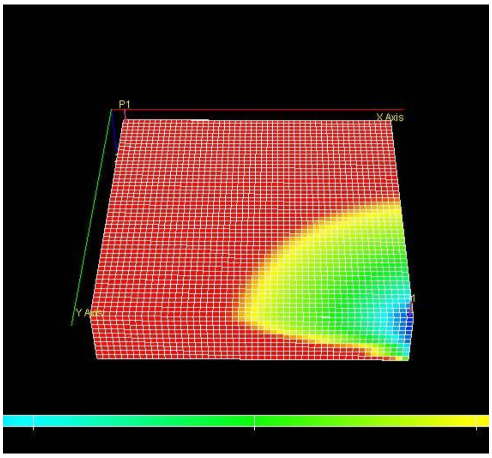
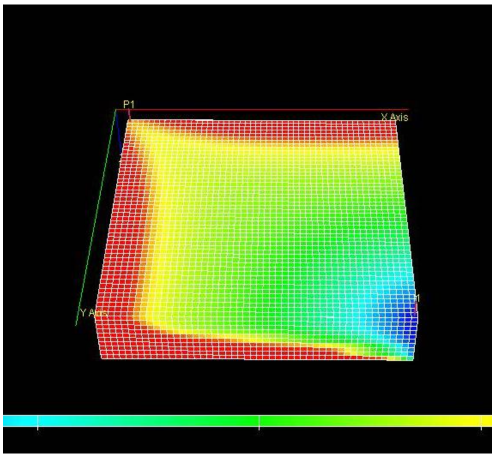


Figure 5.14 Bottomhole pressures of injector and producer of solely polymer flooding case as functions of time

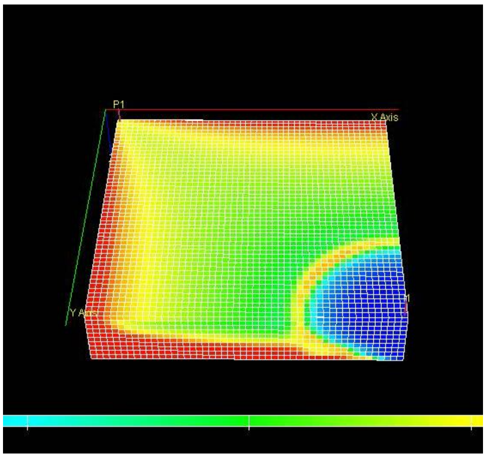
In order to increase injectivity of polymer solution, part of water is pre-injected. This water is so called pre-flushed water. Initially, 0.10 PV of pre-flushed water slug size is injected into reservoir and followed by polymer slug. This simulation isperformed with polymer solution concentration of 0.704 lb/STB atinjection rate of 1,000 STB/D. The chosen heterogeneity is the medium value of 0.384.The injection sequence is illustrated in Figures 5.15(a) to 5.15(d).



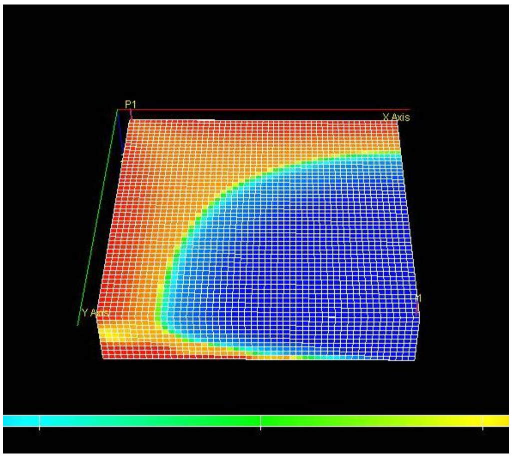
(a)



(b)



(c)



(d)

Figure 5.15 Oil saturation profile showing injection sequence of polymer flooding case including injection of 0.1PV pre-flushed slug (a) injection of pre-flushed, (b) beginning of polymer inject (c) oil bank formed by polymer slug, and (d) termination of production(red color is oil saturation and blue color is water saturation)

However, simulation cannot be completely performed through production limit of 40 years due to inadequate injectivity of combination between pre-flushed water and polymer slug. Figures 5.16 to 5.22 summarize simulation outcomes from the case where 0.1PV of pre-flushed water is injected and followed by polymer slug. Most production behaviors are similar to the case of solely polymer injection.

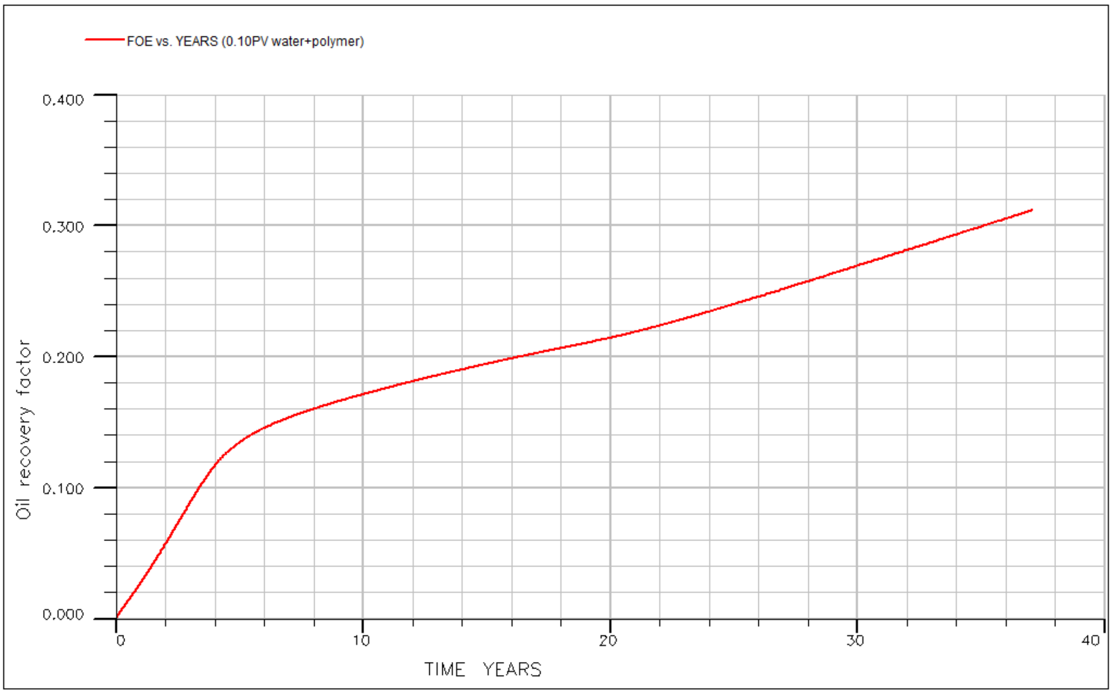


Figure 5.16 Oil recovery factor of the case 0.10 PV pre-flushed water slug size followed by polymer slug size as a function of time

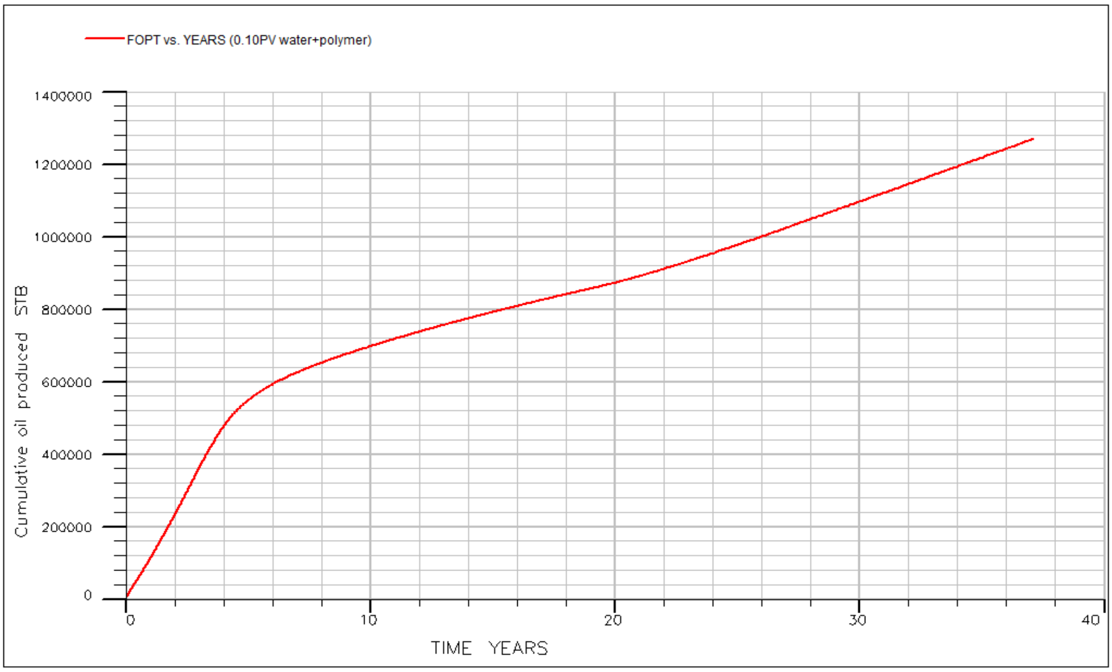


Figure 5.17 Cumulative oil produced of the case 0.10 PV pre-flushed water slug size followed by polymer slug size as a function of time

The trend of oil recovery factor and cumulative oil produced in Figure 5.16 and 5.17 shows better result at the starting pre-flushed period compared to the later stage. When polymer slug is injected, injectivity decreases, resulting in reduction of injection rate and oil production rate. Production appearance is similar to waterflooding base case in pre-flushed region and then change into solely polymer flooding. Cumulative oil produced trend changes again slightly before the year 19th which is the period that oil bank from polymer injection starts to arrive at producer. This can be confirmed by reduction of water production rate at coincidental period as seen in Figure 5.18 as well as field water cut in Figure 5.19. Figure 5.20 shows a slight increment of oil production rate at the year 19th which also confirms an arrival of oil bank.

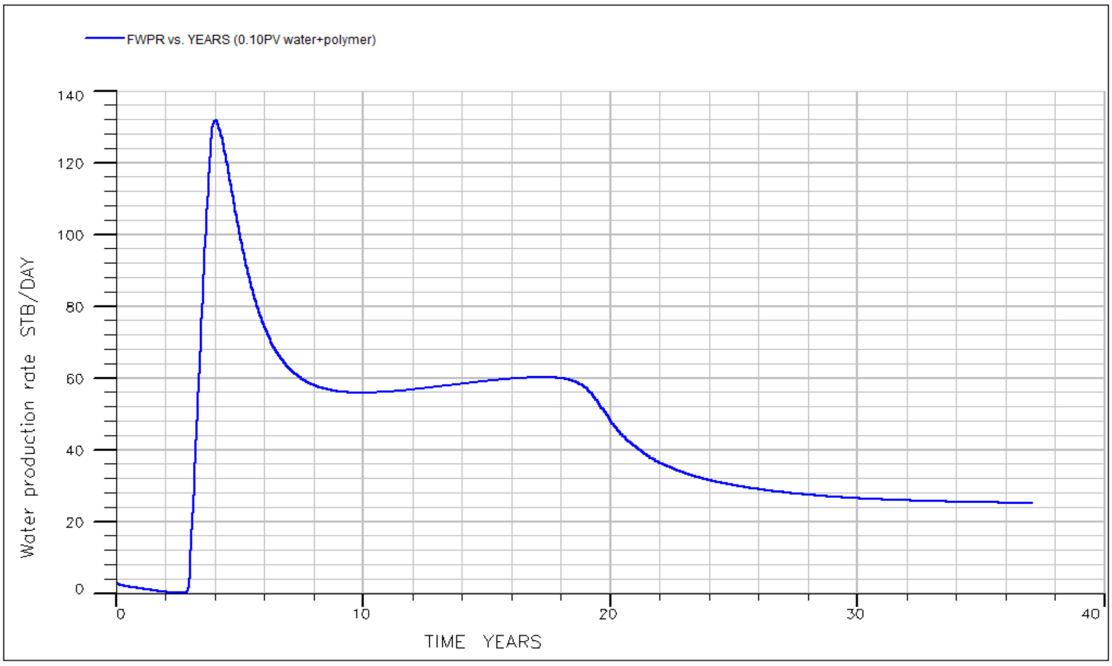


Figure 5.18 Water production rate of the case 0.10 PV pre-flushed water slug size followed by polymer slug size as a function of time

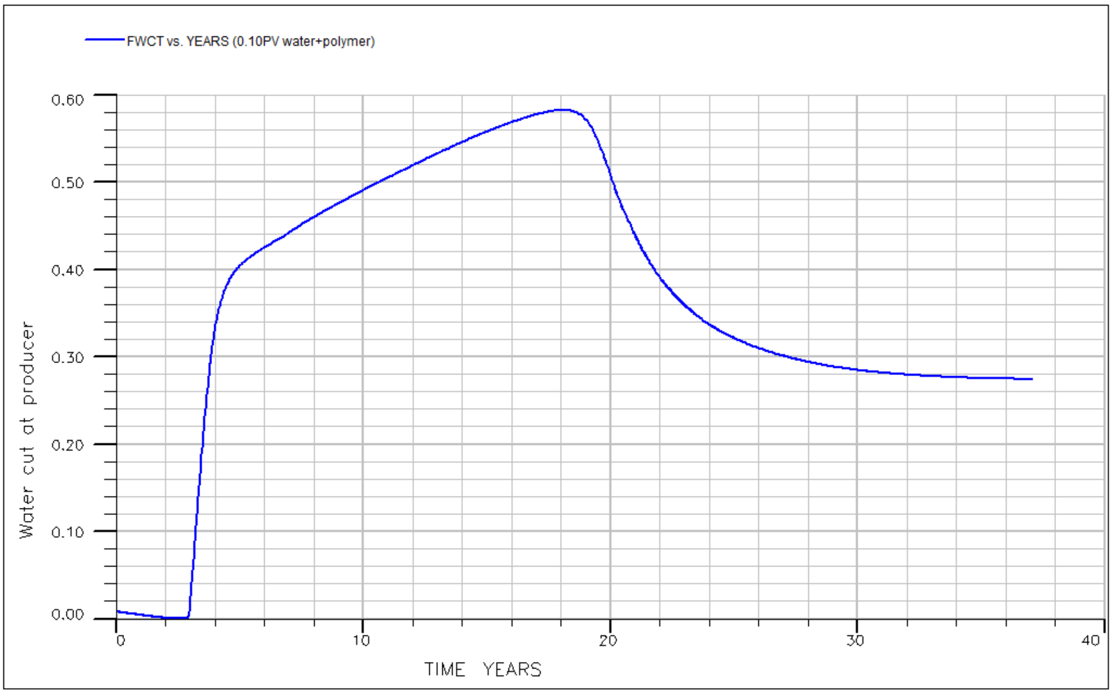


Figure 5.19 Water cut of the case 0.10 PV pre-flushed water slug size followed by polymer slug size as a function of time

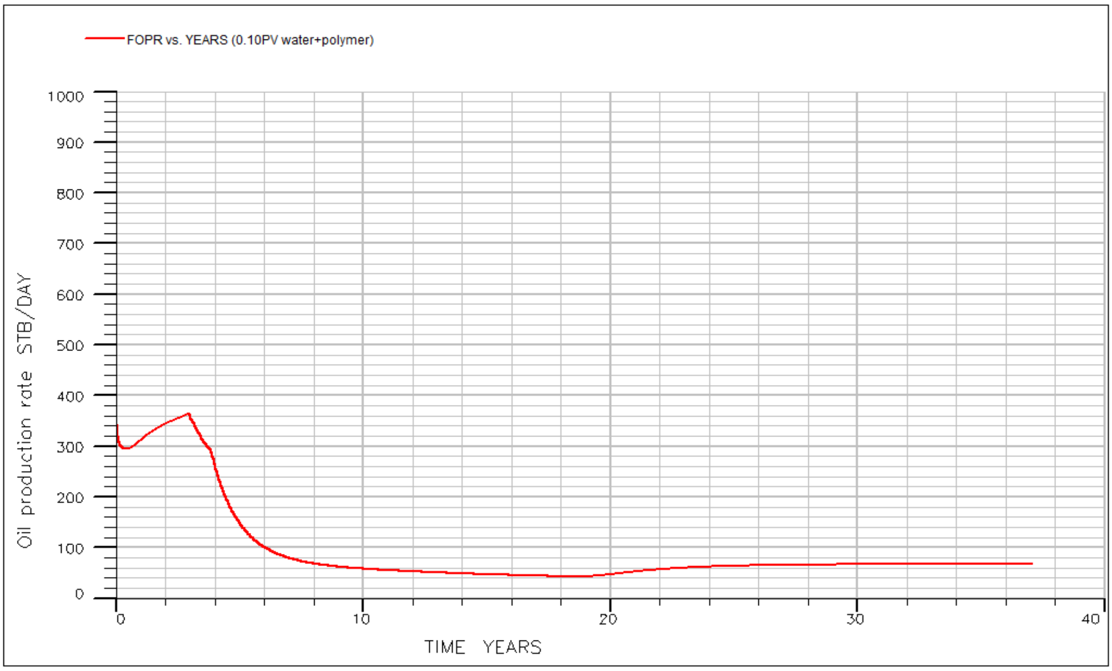


Figure 5.20 Oil production rate of the case 0.10 PV pre-flushed water slug size followed by polymer slug size as a function of time

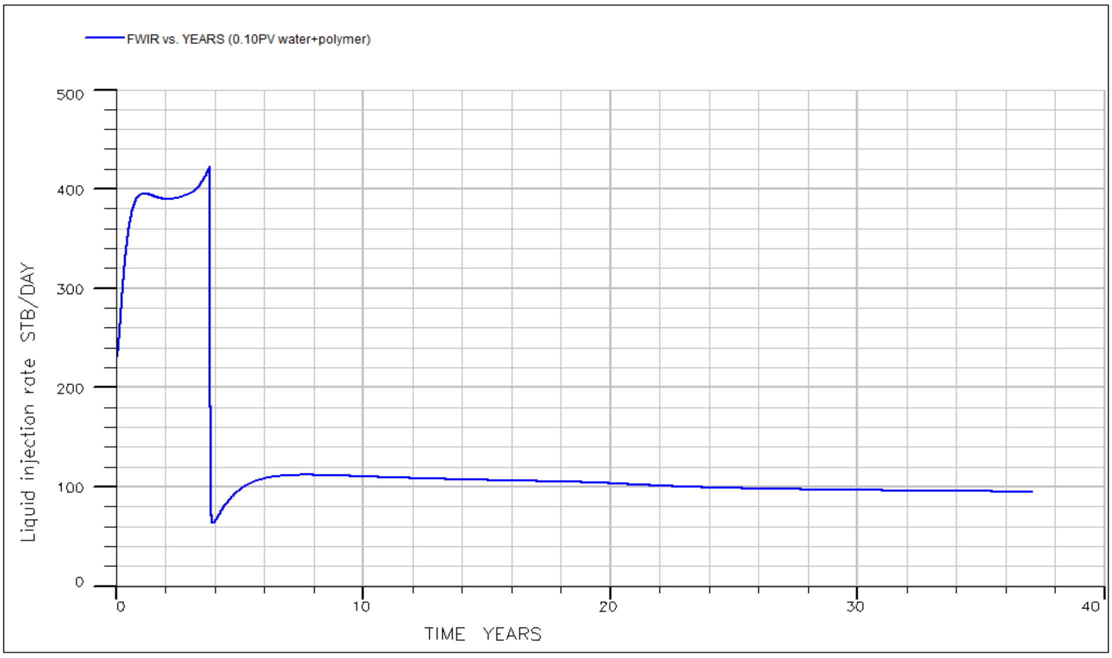


Figure 5.21 Water injection rate of the case 0.10 PV pre-flushed water slug size followed by polymer slug size as a function of time

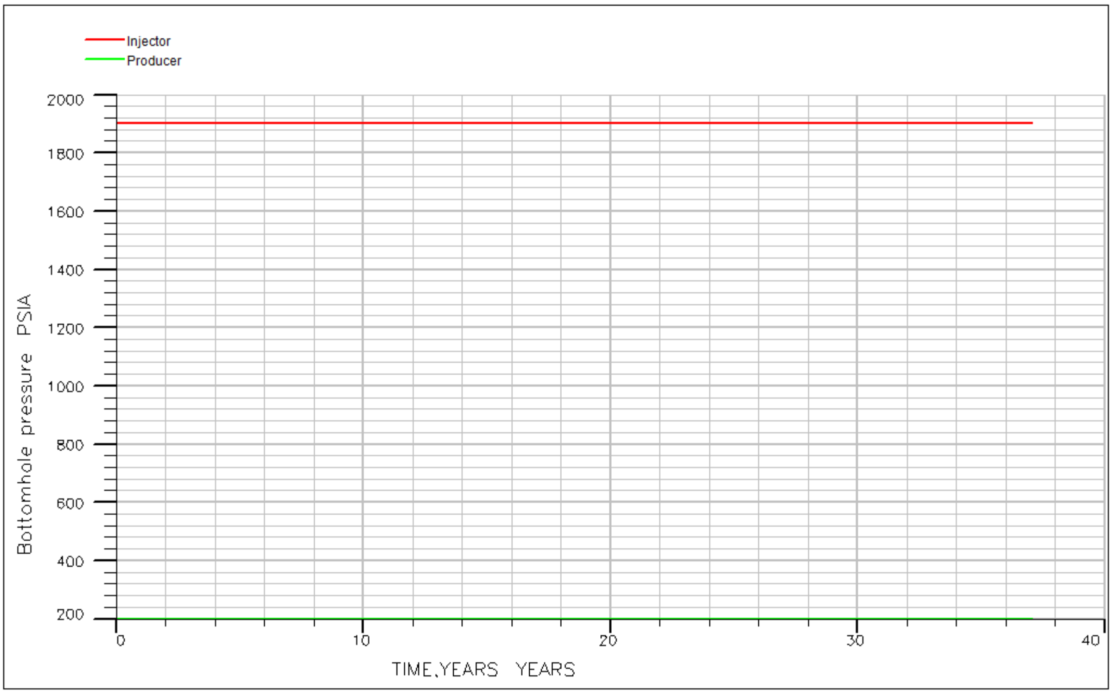


Figure 5.22 Bottomhole pressures of injector and producer of the case 0.10 PV pre-flushed water slug size followed polymer slug size as functions of time

Figure 5.21 shows that injection rate abruptly drops at the year 4^{th} which is starting period ofpolymer injection. Moreover, oil production rate during pre-flushed water injection is greater than during polymer injection period as can be seen from Figures 5.20. The injection well is also controlled at bottomhole pressure as shown in Figure 5.22 throughout 37 years of production period until the well shut in due to very low injectivity (low injection rate as seen from Figure 5.21). In summary, this production scheme yields totally 1.28 MMSTB cumulative oil produced which is equivalent to recovery factor of 0.31.

Injecting pre-flush slug shows an ability to extend production period as well as oil recovery factor compared to solely polymer injection. However, this initial pre-flushed slug of 0.1 PV is too small and hence values are selected at 0.15, 0.20, 0.25 and 0.30. Not only determination of pre-flushed water slug size, polymer slug size is optimized as well. In this study, polymer slug size is varied from 0.20 to 0.30 PV.

Together with variation of pre-flushed slug size, polymer slug is varied as well and the total 18 polymer flooding combination cases are generated and consecutively simulated in order to optimize both pre-flushed water and polymer injected slugs. Details of these 18 cases are summarized in Tables 5.1.

Table 5.1 Slug size of injected fluids of18 study cases for polymer flooding optimization

Case no.	**Pre-flushed water slug size**	**Polymer slug size**
1	0.15 PV	Until termination
2	0.15 PV	0.20 PV
3	0.15 PV	0.25 PV
4	0.15 PV	0.30 PV
5	0.20 PV	Until termination
6	0.20 PV	0.20 PV
7	0.20 PV	0.25 PV
8	0.20 PV	0.30 PV
9	0.25 PV	Until termination
10	0.25 PV	0.20 PV
11	0.25 PV	0.25 PV
12	0.25 PV	0.30 PV
13	0.30 PV	Until termination
14	0.30 PV	0.20 PV
15	0.30 PV	0.25PV
16	0.30 PV	0.30PV
17	0.15 PV	0.10 PV
18	0.15 PV	0.15 PV

From Table 5.1 cases no. 1, 5, 9, and 13 are simulated to identify when chasing water after polymer slug has to be performed. Therefore, polymer solution is kept injected until production is terminated. After that, the point there desired pore volume is reached can be identified and other cases can be performed at desired polymer slugs.

All cases are simulated with polymer solution concentration of 0.704 lb/STB at injection rate of 1,000 STB/D. The chosen heterogeneity is the medium value of 0.384.

However, in case of 0.30 PV of polymer slug size, total amount of fluid cannot be injected because the point where chasing water after polymer slug exceeds production period of 40 years. Thus, all cases remain only 14 instead of 18 and details are summarized inTables 5.2.

Table 5.2 Slug size of injected fluids for remaining 14 study cases for polymer flooding optimization

Case no.	**Pre-flushed water slug size**	**Polymer slug size**
1	0.15 PV	Until termination
2	0.15 PV	0.20 PV
3	0.15 PV	0.25 PV
4	0.20 PV	Until termination
5	0.20 PV	0.20 PV
6	0.20 PV	0.25 PV
7	0.25 PV	Until termination
8	0.25 PV	0.20 PV
9	0.25 PV	0.25 PV
10	0.30 PV	Until termination
11	0.30 PV	0.20 PV
12	0.30 PV	0.25PV
13	0.15 PV	0.10 PV
14	0.15 PV	0.15 PV

Again, all cases simulation cases are simulated with polymer concentration, injection rate, value of chosen heterogeneity and production period as same as mentioned for previous 18 cases.

Cases no. 1, 4, 7 and 10 are simulated to label as reference cases to determine injection point of polymer solution at different chasing water slug size as previously discussed. Then, results obtained from cases no. 2, 3,5,6,8,9,11 and 12 are illustrated in Figures 5.23 to 5.32.

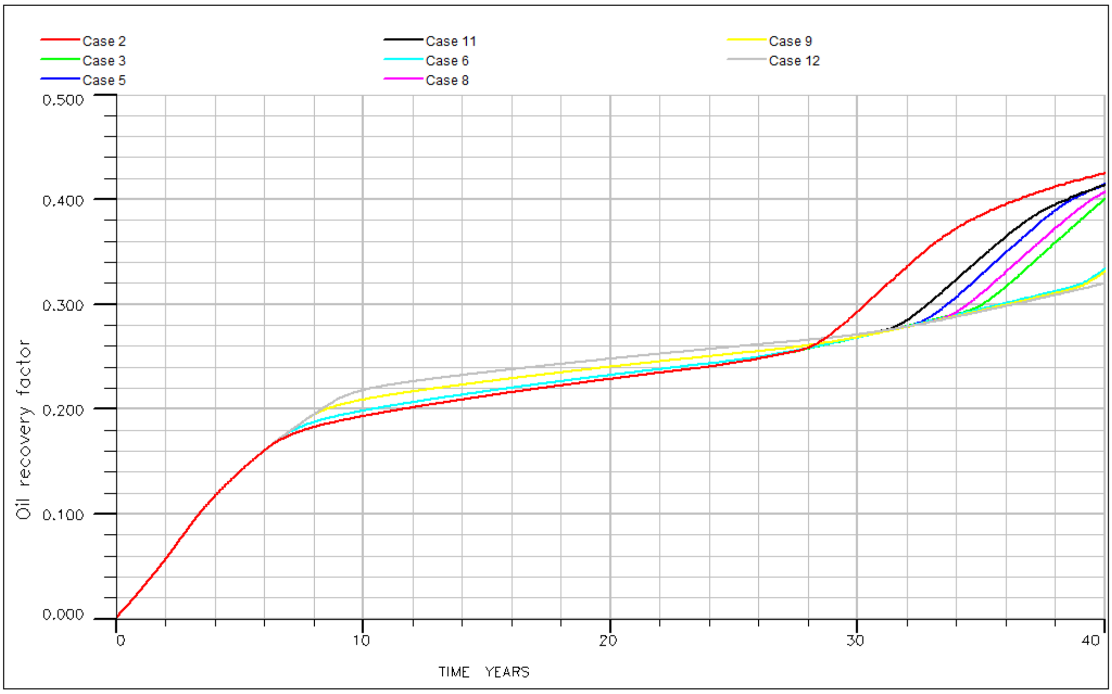


Figure 5.23 Oil recovery factors of polymer flooding cases 2, 3, 5, 6, 8, 9, 11 and 12 as functions of time

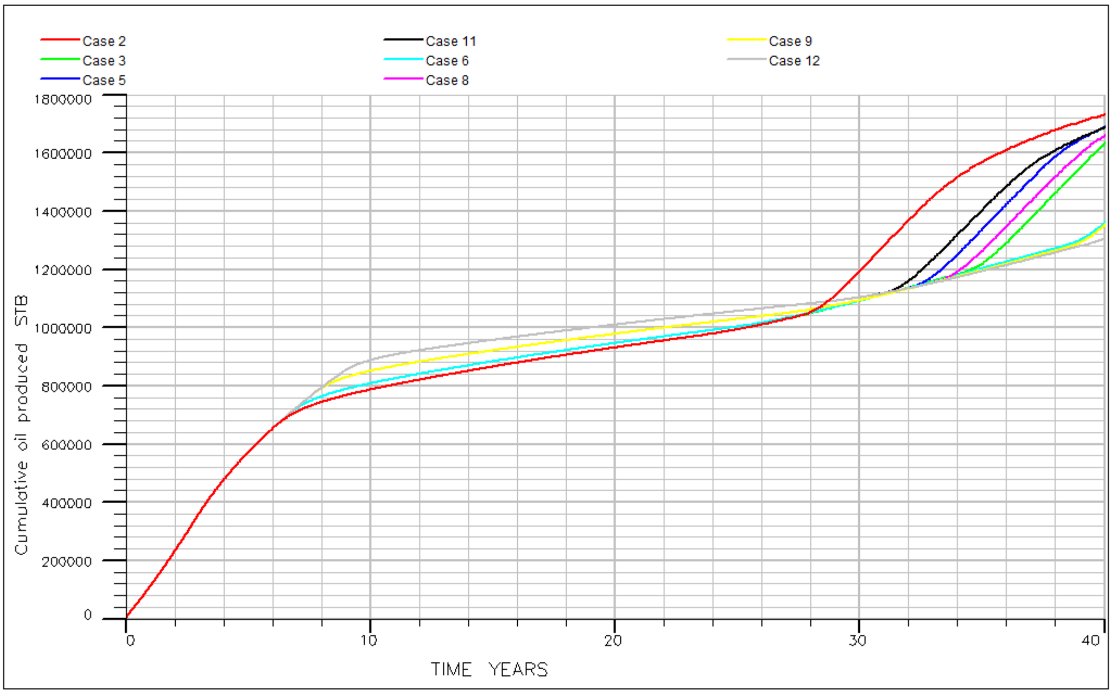


Figure 5.24 Cumulative oil productions of cases no. 2, 3, 5, 6, 8, 9, 11 and 12 as functions of time

All simulation cases reach total production period of 40 years.Figures 5.23 and 5.24 show thatoil recovery factoris improved by injecting of chasingwater instead of injecting continuously polymer slug. Comparing to waterflooding base case, total production period is much longer and total oil recovery factor is higher. Production period can be even longer than 40 years in all cases.

From Figures 5.25 and 5.26 water production rate and water cut evolve in production period. There is no water produced until water breakthrough as seen from first peaks around the 3rd year. After water production is raised for while, water production rate declines due to polymer is injected, resulting lowering of injection rate as well as production rate. Water production rate increases again after certain years of plateau rate due to polymer solution breakthrough. In cases no. 6, 9 and 12, it can be seen that bigger slug size retards all mentioned water production characteristics.

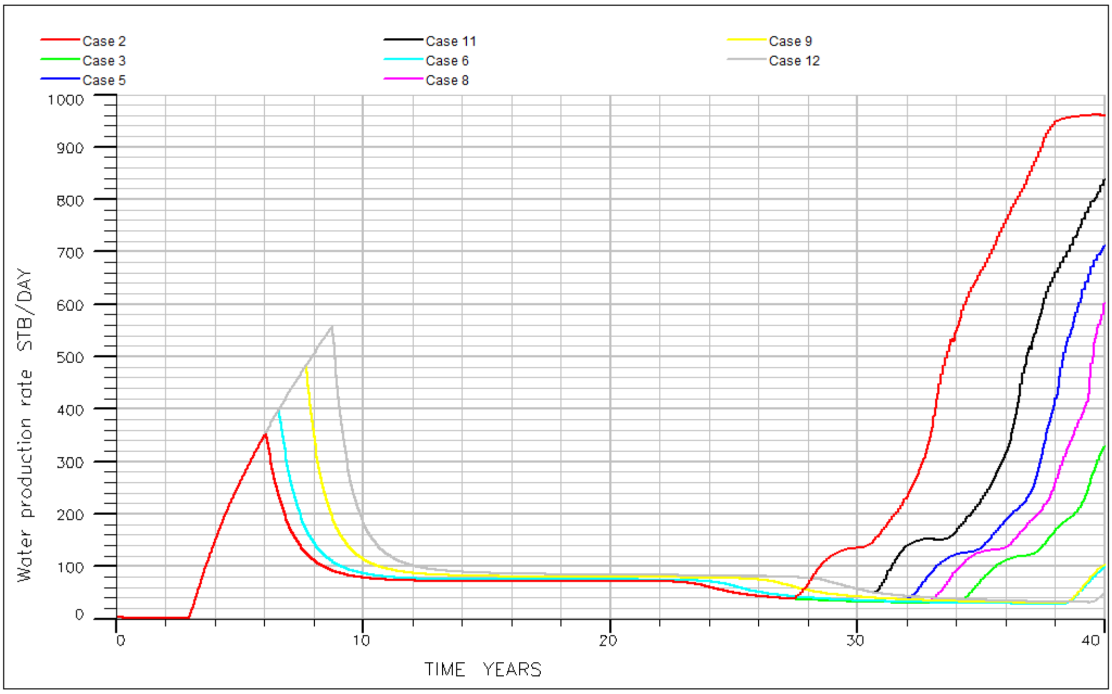


Figure 5.25 Water production rates of cases no. 2, 3, 5, 6, 8, 9, 11 and 12 as functions of time

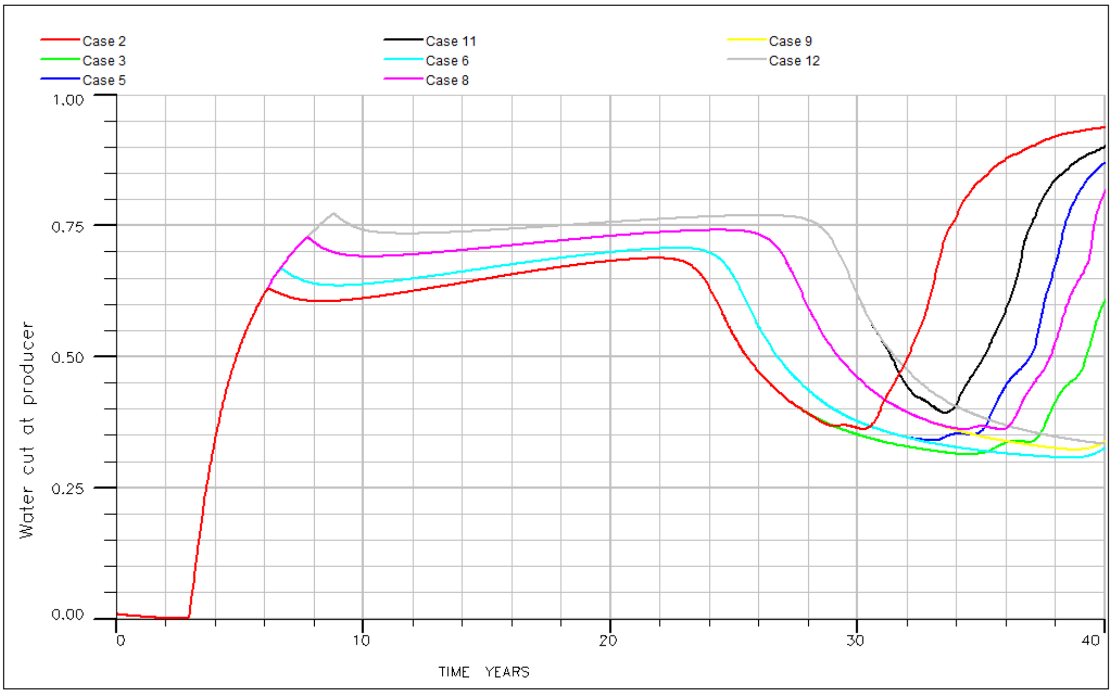


Figure 5.26 Water cut of cases no. 2, 3, 5, 6, 8, 9, 11 and 12 as function of time

Next step is to define the optimized case of polymer flooding. Figure 5.23 shows that case no.2 yields the highest cumulative oil recovery factor. Additionally, this case consumes the least amount of polymer solution of 0.2PV.

Even though, oil production and water injection rates in the beginning time of case no.2 early drop when comparing to other bigger pre-flushed water slug size cases in Figures 5.27 and 5.28, this optimal case becomes the fastest scheme to obtain the highest oil production rate and finally become the best production scheme for this study.

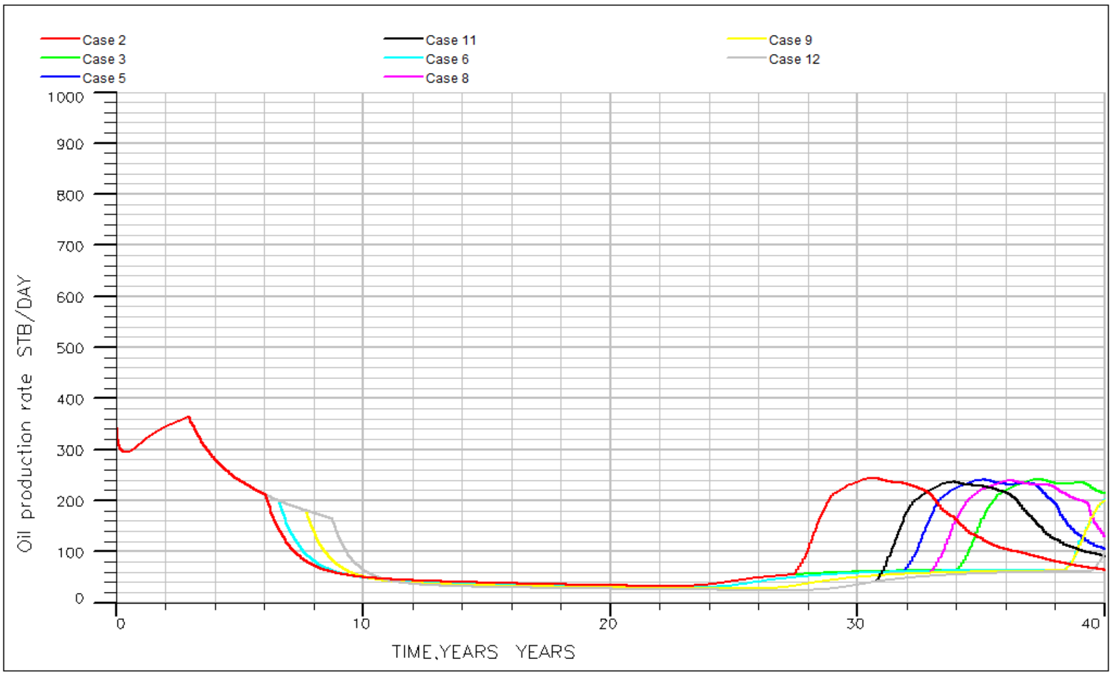


Figure 5.27 Oil production rates of cases no. 2, 3, 5, 6, 8, 9, 11 and 12 as functions of time

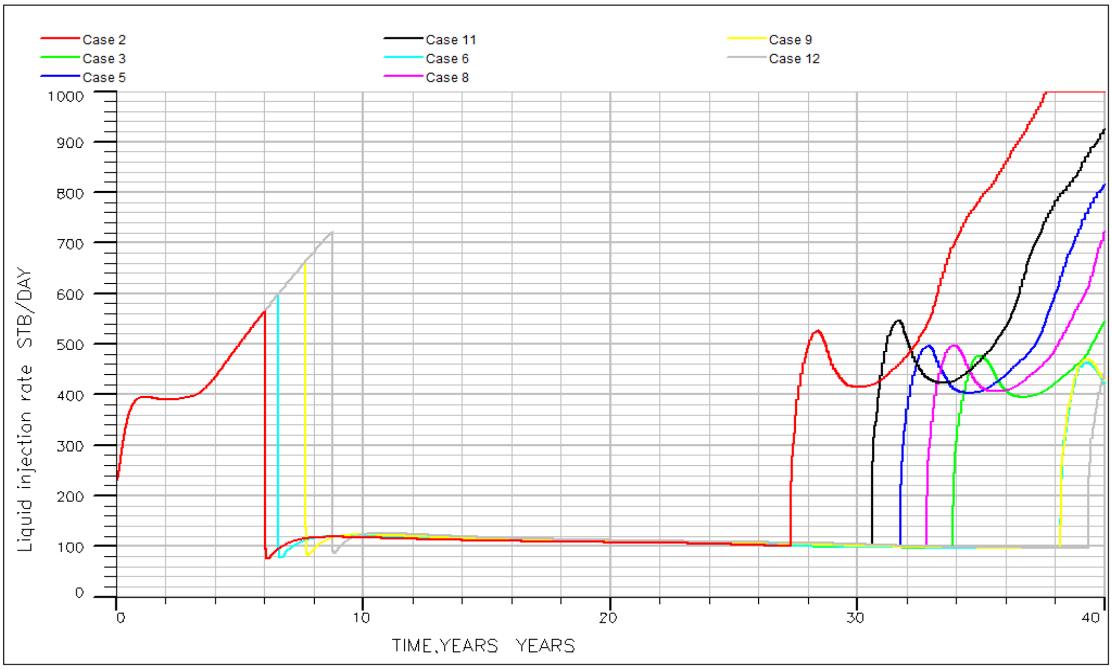


Figure 5.28 Water injection rates of cases no. 2, 3, 5, 6, 8, 9, 11 and 12 as functions of time

Nevertheless, the highest oil production of case no.2 also comes together with the highest cumulative water produced as well as the highest cumulative water injected as can be observed in Figures 5.29 and 5.30, respectively. In this study, water disposal and source of injected water are not considered. But this could turn case no.2 not to be the best case due to cost of water treatment and source of water management.

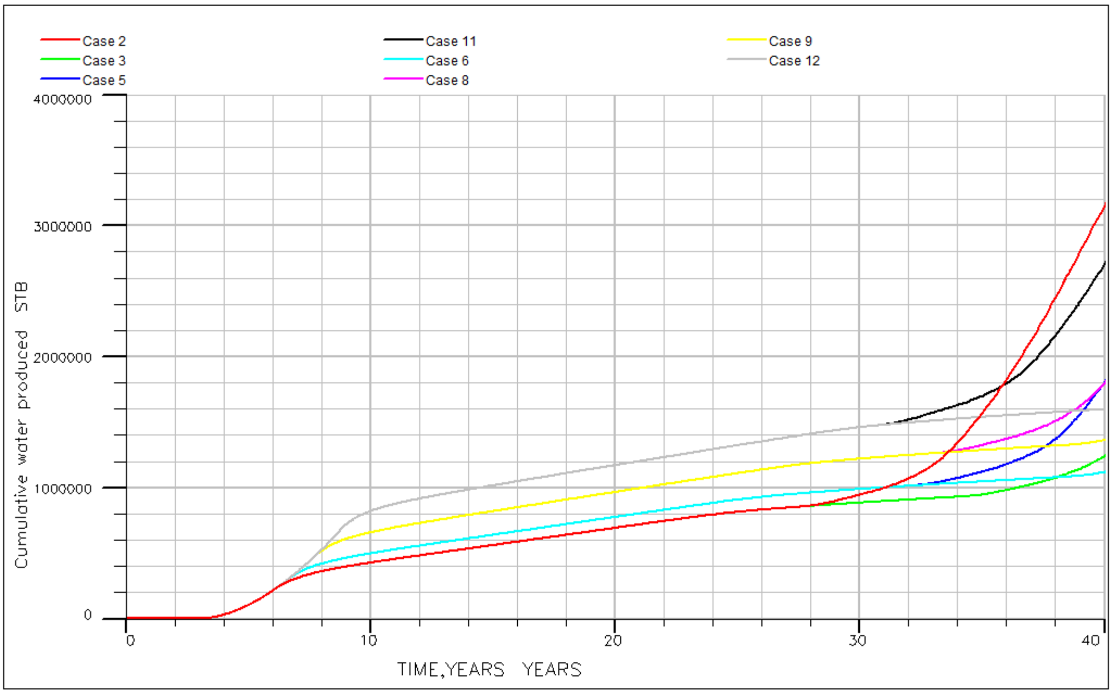


Figure 5.29 Cumulative water produced of cases no. 2, 3, 5, 6, 8, 9, 11 and 12 as functions of time

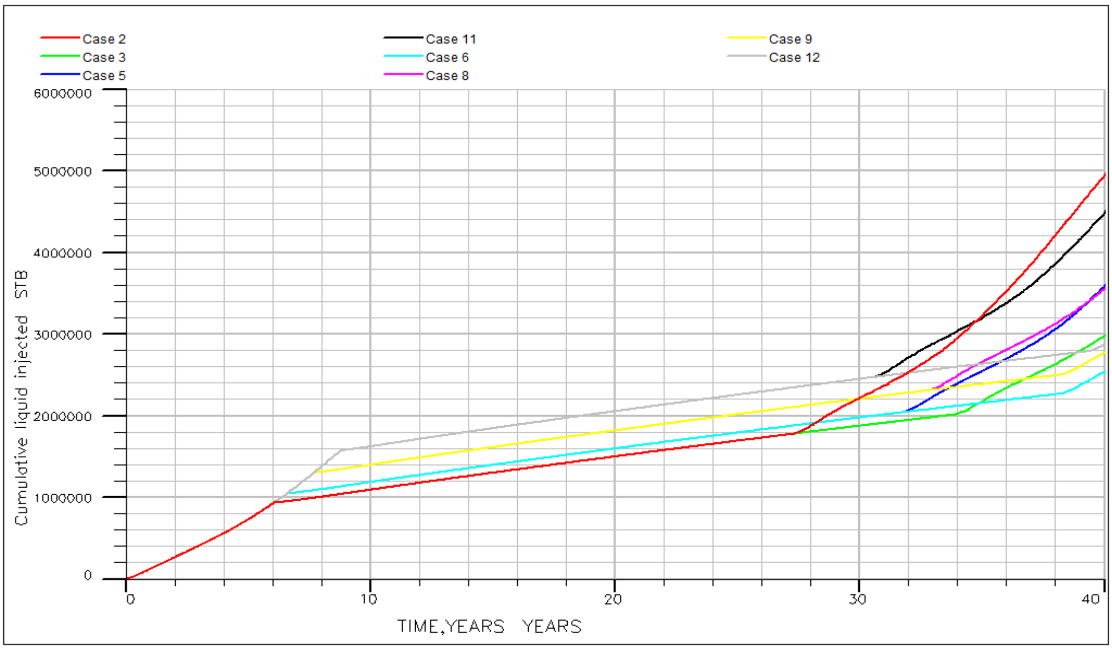


Figure 5.30 Cumulative liquid injected of case 2, 3, 5, 6, 8, 9, 11 and 12 as functions of time

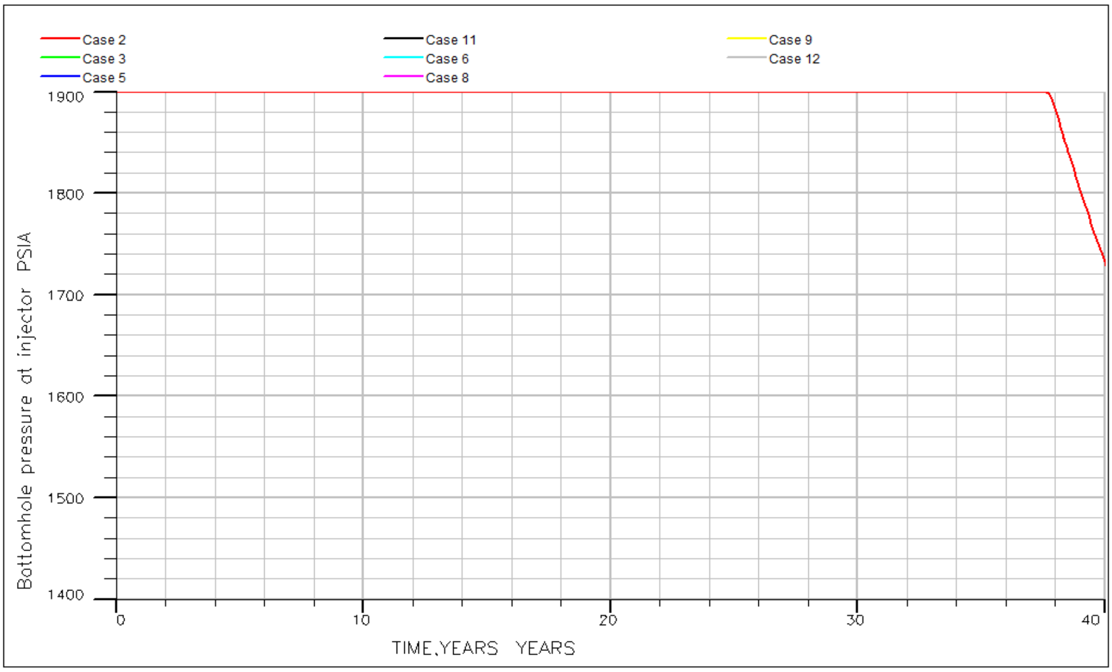


Figure 5.31 Bottomhole pressures of injector of cases no. 2, 3, 5, 6, 8, 9, 11 and 12 as functions of time

From Figure 5.31, case no.2 which is early concluded to be the best case shows that after the year 38thbottomhole pressure substantially decreases. This is a result from higher injectivity of chasing water that is performed earlier. Hence, injector is switched to control by injection rate instead of bottomhole pressure.

All the simulation outcomes total production period, dimensionless cumulative water injected, cumulative water produced, oil recovery factor, consumed polymer amount and incremental oil per volume of polymer are summarized in Table 5.3.

Table 5.3 Summary result of polymer flooding optimization

Case no.	**Production time (yr.)**	**Dimensionless cumulative water injected**	**Cumulative water produced (MSTB)**	**RF (%)**	**Polymer Used (MSTB)**	**Incremental oil per polymer used (STB/lb polymer)**
2	40	0.972	3,179	42.56%	1,024	2.28
3	40	0.585	1,253	40.20%	1,279	1.72
5	40	0.706	1,826	41.54%	1,024	2.22
6	40	0.498	1,121	33.55%	1,279	1.44
8	40	0.699	1,820	40.82%	1,024	2.19
9	40	0.544	1,365	33.34%	1,279	1.43
11	40	0.882	2,733	41.49%	1,024	2.22
12	40	0.564	1,601	32.13%	1,279	1.38

From summary shown in Table 5.3, case no. 2 yields the highest oil recovery factoras related to the highest dimensionless cumulative fluid injected.Moreover, ratio of total production oil to total amount of polymer consumed is as high as 1.60, the highest among all cases. For the next polymer flooding cases in this study, case no 2.with an operation design of 0.15 PV of pre-flushed water slug size followed by 0.20 PV of polymer solution slug size and followed by chasing water, represents a polymer flooding base case throughout the study. Three dimensional illustration of case no. 2 during the displacement mechanism is shown in Figure 5.32. Red color represents oil saturation, whereas blue color is water saturation.

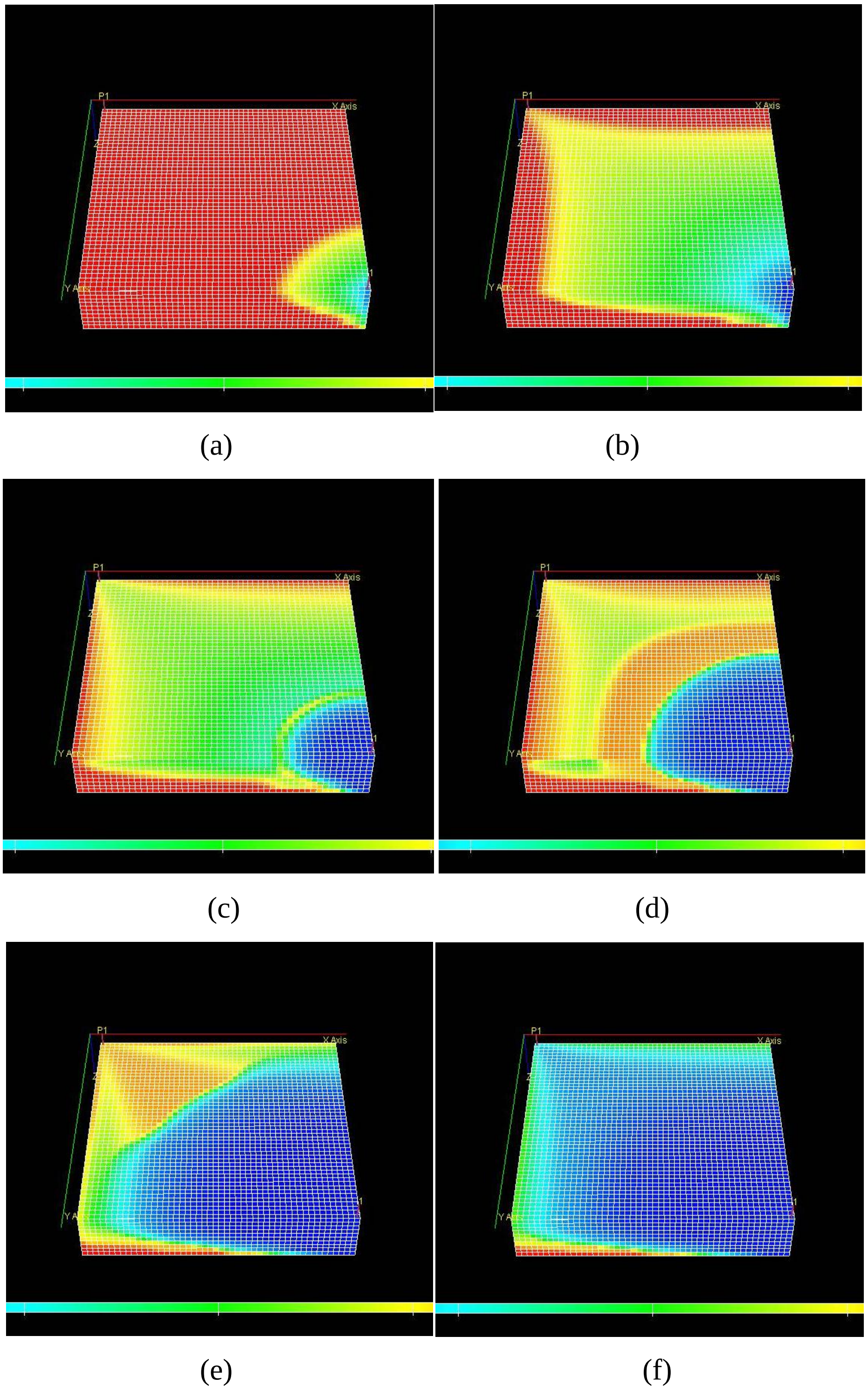


Figure 5.32 Oil saturation profile showing injection sequence of optimized polymer flooding base case (case no.2) (a) initial stage of pre-flushed water injection, (b) later stage of pre-flushed water injection 0.15PV of water is injected, (c) initial stage of polymer injection, (d) oil bank formed by polymer solution, (e) initial stage of chasing water injection and (f) termination of production

Cases no. 13 and 14 are simulated in order to prove that the polymer slug size should not be smaller than 0.20 PV. Both cases yields very high water cut and hence the limitation of 95% is reached early. This eventually results in a shut in of both cases before total production period of 40 years. Figures 5.33 to 5.35 illustrate production parameters of these two cases as functions of time.

From Figure 5.33 it can be seen that cases no. 13 and 14 cannot complete the production for a whole 40 years, terminating at year 32nd and 37th, respectively. Field oil recovery is relatively lower than case no.2 which is the optimized case.

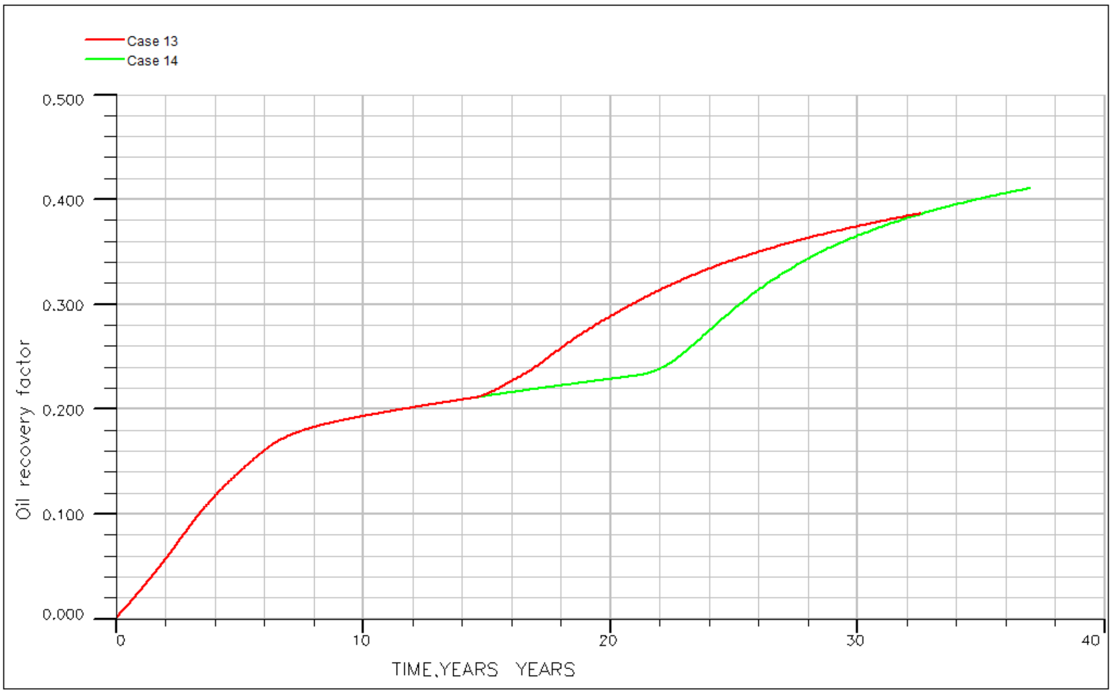


Figure 5.33 Oil recovery factors of cases no. 13 and 14 as functions of time

As mentioned before, these two cases are terminated due to high water production that is corresponding to reduction of oil production rate. Oil and water production rates of these two cases are illustrated in Figures 5.34 and 5.35, respectively.

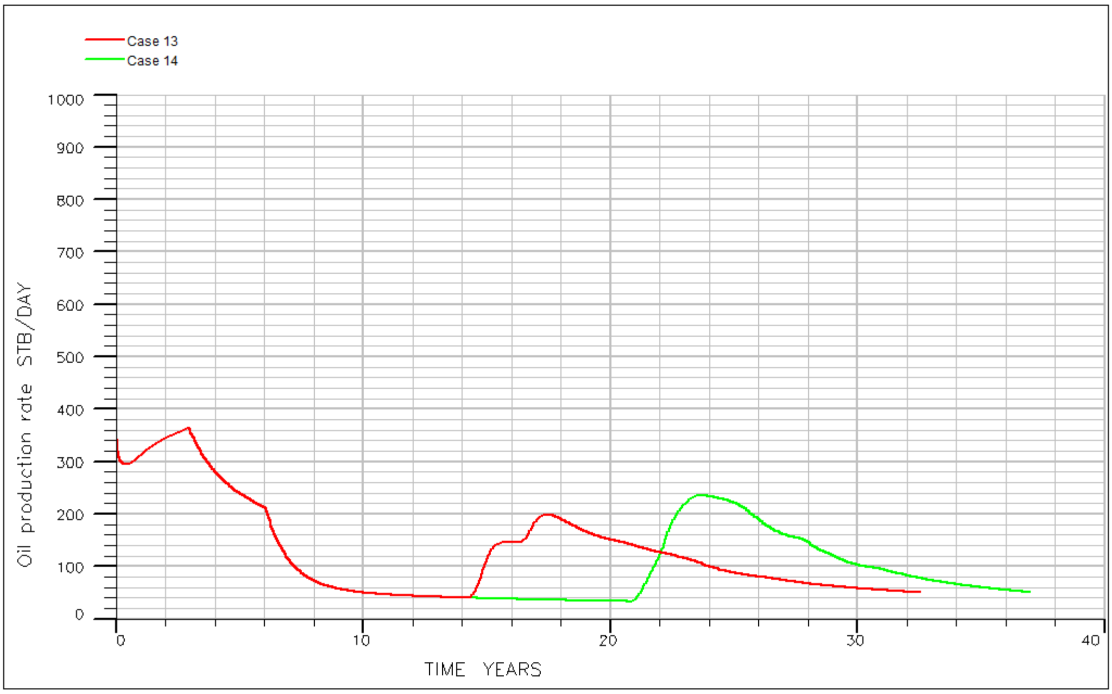


Figure 5.34 Oil production rates of cases no. 13 and 14 as functions of time

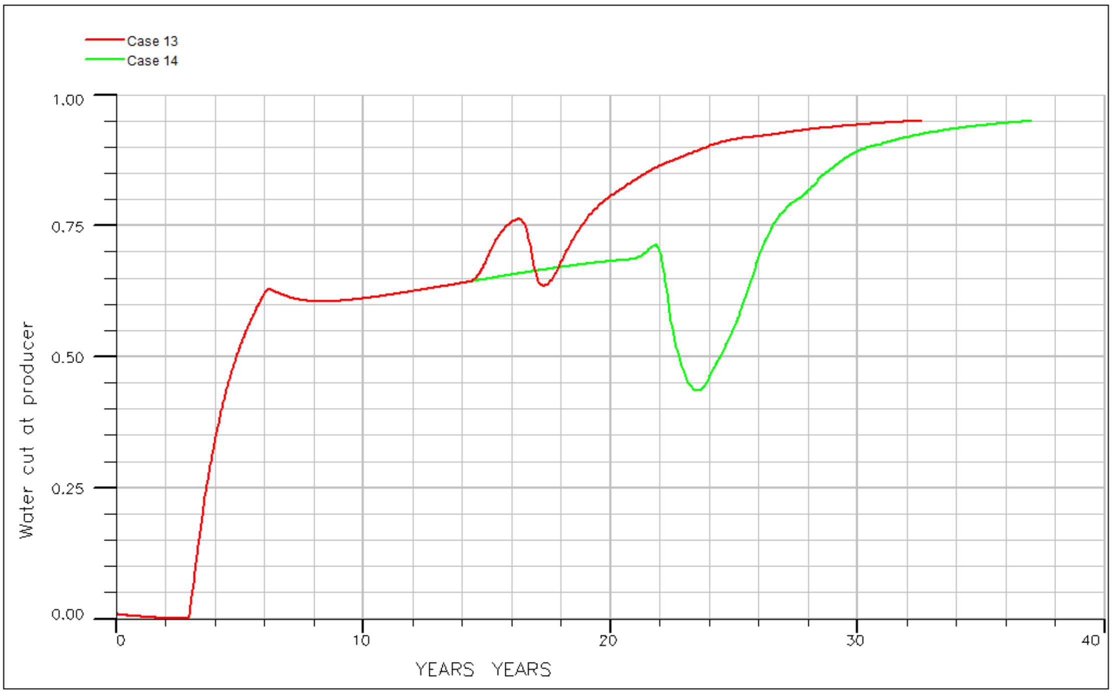


Figure 5.35 Water cut of cases no. 13 and 14 as functions of time

5.2.1 Effect of shear thinning on production performance

Polymer solution possesses one important property which is shear thinning. That is when polymer solution flows at different speed in porous medium, shearing with pores results in reduction of fluid viscosity. And since the injection rate of polymer solution is not constant due to the constraint at injection well, travel speed of polymer slug can be differentiated and could results in variation of viscosity of polymer. Table 5.4 summarizes shear thinning multiplier of selected polymer solution. The multiplier is basically multiplied to viscosity of polymer solution and results in differentiation when polymer travels at different speed.

Table 5.4 Shear thinning multiplier of Flopaam 3330S as a function of velocity [14]

Fluid velocity (ft/day)	**Shear thinning multiplier**
0	1
283.5	0.9999
2,834.6	0.9998
28,346.5	0.7
283,464.6	0.33
2834,645.7	0.18

Figures 5.36 to 5.39 illustrate comparisons between results obtained from simulations with and without shear thinning effect. These comparisons include oil recovery factor, cumulative oil produced, final water cut and cumulative water produced.

From these four figures, it is obvious that there is mostly no difference between cases including or not including shear thinning effect. This can be explained that fluid speed in the reservoir is low that this corresponds to the multiplier of about unit. Therefore, the effect of shear thinning is not included in the rest of reservoir simulation since there is no significant effect on effectiveness of polymer flooding in this study.

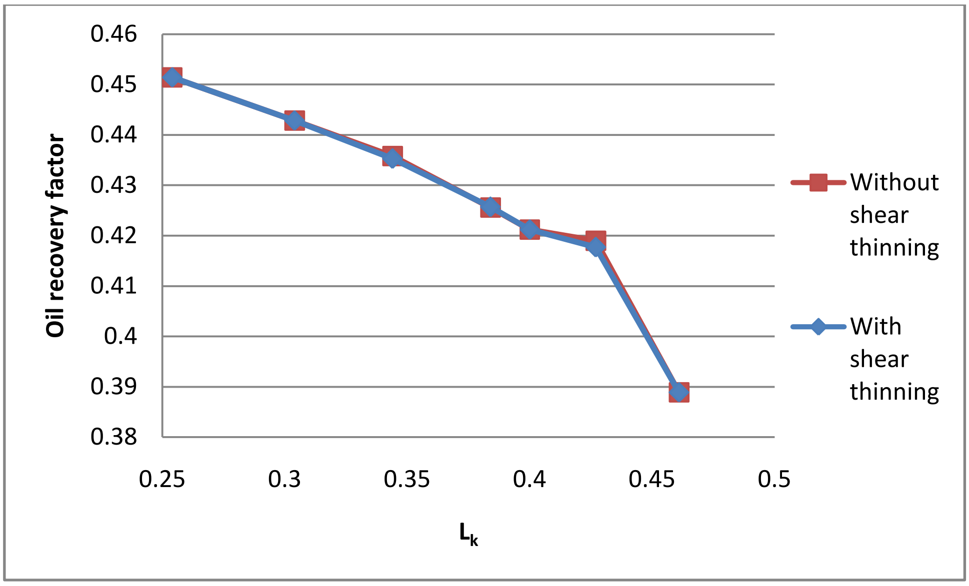


Figure 5.36Comparison of oil recovery factors obtained from with and without shear thinning effects as functions of heterogeneity

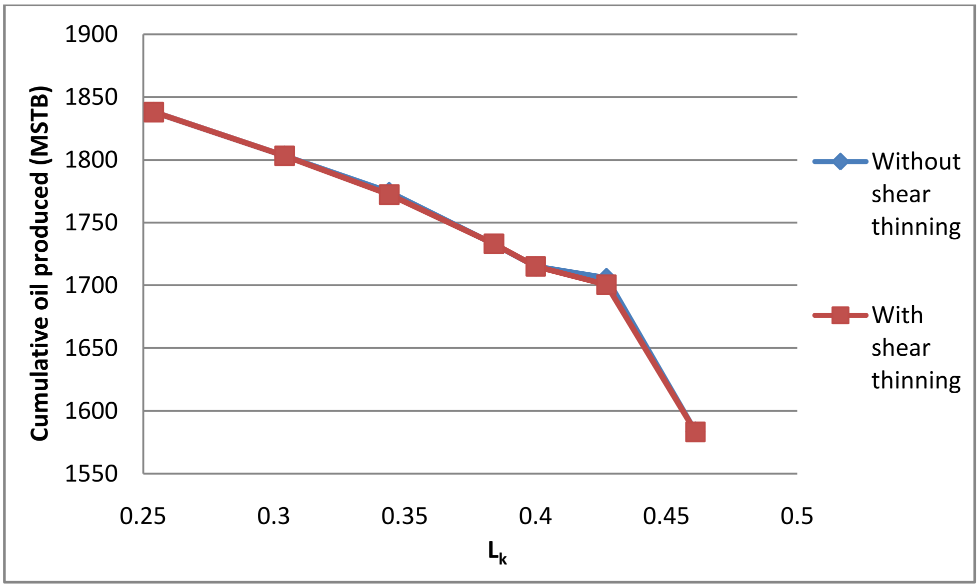


Figure 5.37 Comparison of cumulative oil produced obtained from with and without shear thinning effects as functions of heterogeneity

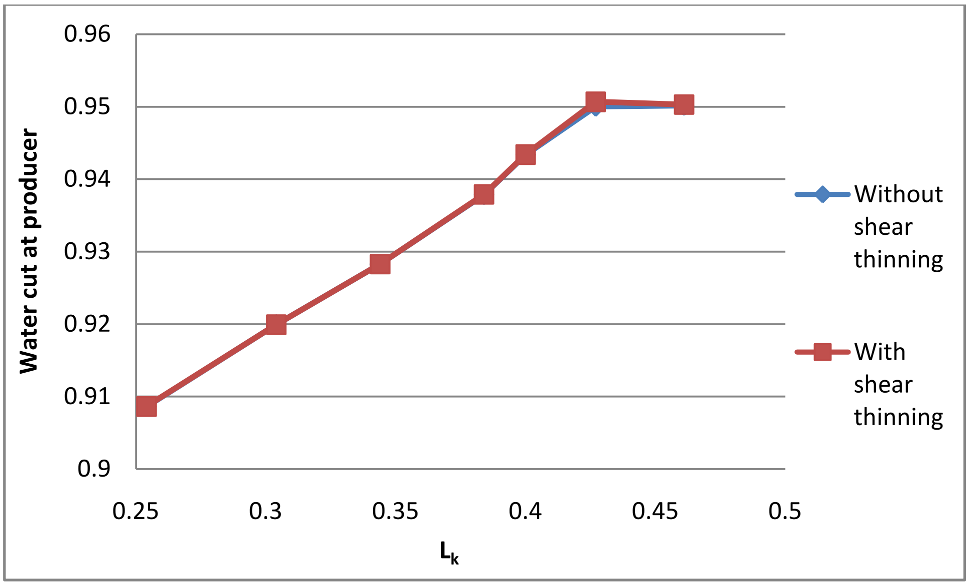


Figure 5.38 Comparison of water cut at producer obtained from with and without shear thinning effects as functions of heterogeneity

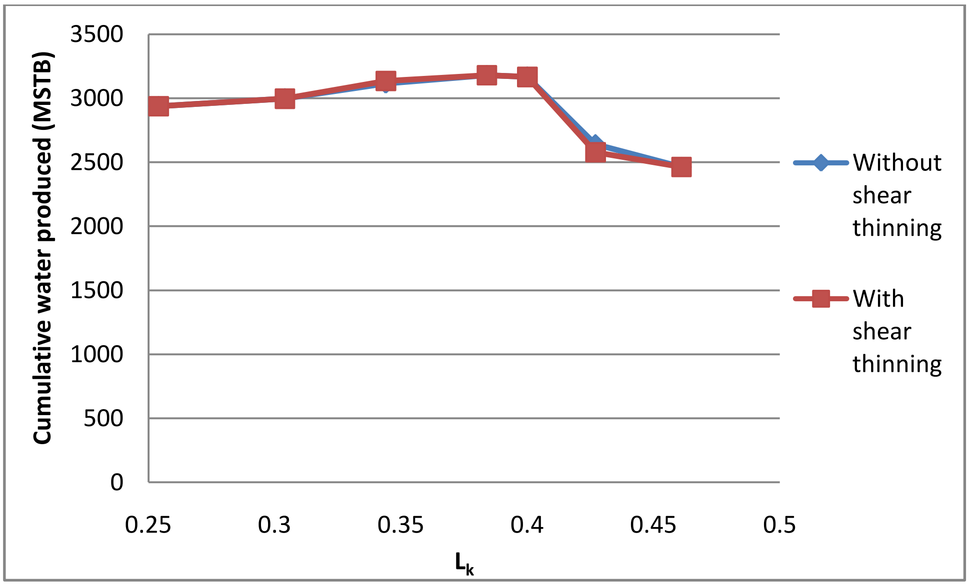


Figure 5.39 Comparison of cumulative water produced obtained from with and without shear thinning effects as functions of heterogeneity

5.3 Effect of polymer concentration and slug size

Investment value is used as a major criterion for making decision of any flied implementation. So this part of study demonstrates effect of polymer concentration when total mass of polymer is kept constant. Varying both two related parameters, polymer solution concentration and polymer solution slug size in order to provide the same polymer mass, is performed in this section. Four scenarios are created as shown in Table 5.5.

Table 5.5 Summary of polymer flooding scenarios in the study of effect of polymer concentration and slug size

Scenario no.	**Pre-flushed water slug size (PV)**	**Polymer slug size (PV)**	**Injection rate (STB/D)**	**Polymer concentration (lb/STB)**	**Running period assign (Yrs)**
1	0.150	0.150	1,000	0.9339	40
2	0.150	0.175	1,000	0.8004	40
3	0.150	0.200	1,000	0.7004	40
4	0.150	0.225	1,000	0.6225	40

All parameters and settings required for reservoir simulation are obtained from polymer flooding base case, which are 1,000 STB/D injection rate, 0.15 PV pre-flushed water slug size, and production duration of 40 years. Every scenario is simulated with variation of heterogeneity representing by Lorenz coefficient in a range from 0.25 to 0.46. Figures 5.40 to 5.43 demonstrate simulation outcomes which are field oil recovery factor, cumulative oil produced, water cut, and cumulative water produced as functions of heterogeneity, respectively.

From Figures 5.40 and 5.41 it can be inferred that at lower heterogeneity, both polymer concentration and polymer slug size slightly affect oil recovery factor and cumulative oil produced as can be seen from simulation outcomes at L_k of 0.25. Oil recovery factors vary in range of 0.44-0.45. However, when heterogeneity is higher, polymer concentration and polymer slug size tend to have more effect on effectiveness of polymer flooding. From the figures it can be seen that, the higher the heterogeneity, the lower the field oil recovery factor. High polymer concentration together with smaller slug size leads to low oil recovery factor and cumulative oil produced compared to the same polymer mass at lower concentration and bigger slug size.

It can be observed that when polymer solution concentration is high and smaller slug size is used, high value of heterogeneity of 0.45 yields very low field oil recovery around 0.2 or below. This can be explained that at high polymer concentration which is corresponded to highly viscous fluid, injected fluid is difficultly injected into formation. Therefore, simulation is terminated due to one of production constraints is reached.

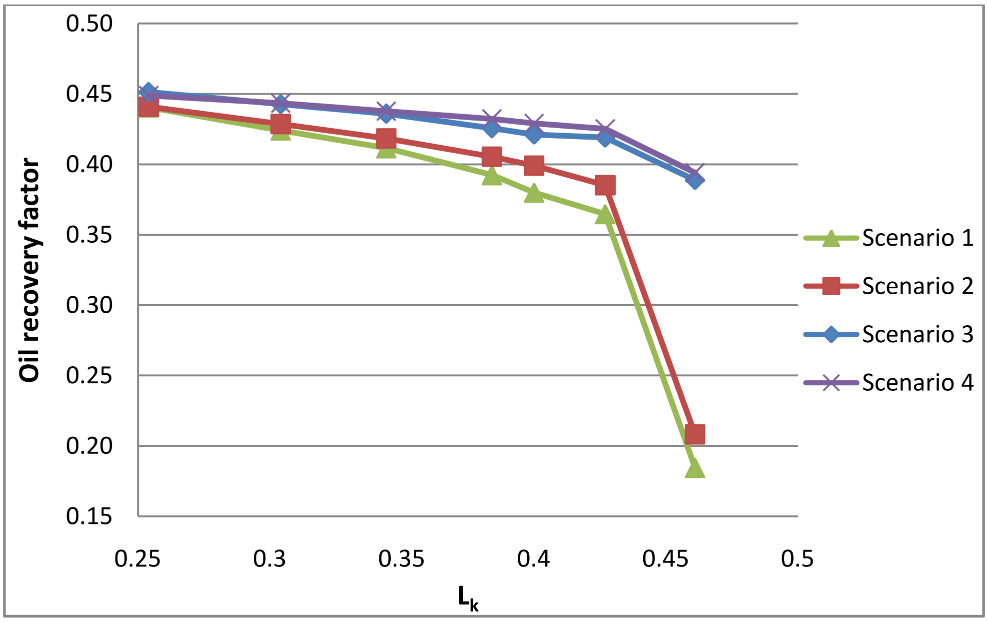


Figure 5.40 Relationship between oil recovery factor and reservoir heterogeneity in the study of effect of polymer concentration and slug size

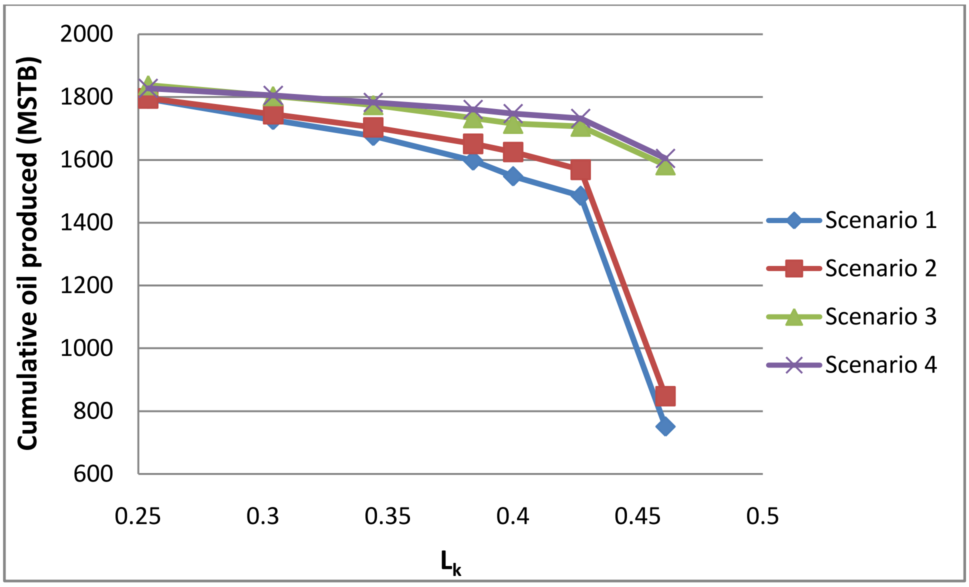


Figure 5.41 Relationship between cumulative oil produced and reservoir heterogeneity in the study of effect of polymer concentration and slug size

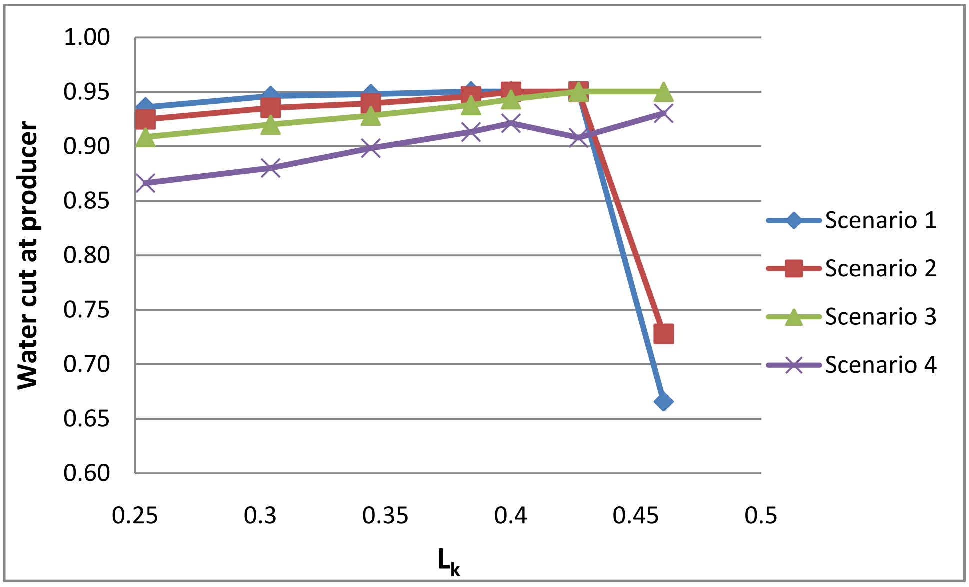


Figure 5.42 Relationship between water cut and reservoir heterogeneity in the study of effect of polymer concentration and slug size

From Figure 5.42, final water cut ratio at producer form most scenarios is higher than 0.9. However, it can be seen that at lower heterogeneity water cut is differentiated among each scenario. Lower water cut obtained by the smallest polymer solution concentration confirms the highest oil recovery factor as shown in Figure 5.40. When heterogeneity is higher, final water cut tends to converge to the preset constraint of 0.95. This could be explained by the preferential flow channel that results in an early water breakthrough and consequently higher water cut. Heterogeneity value higher than 0.4 results in high water cut in all scenarios.

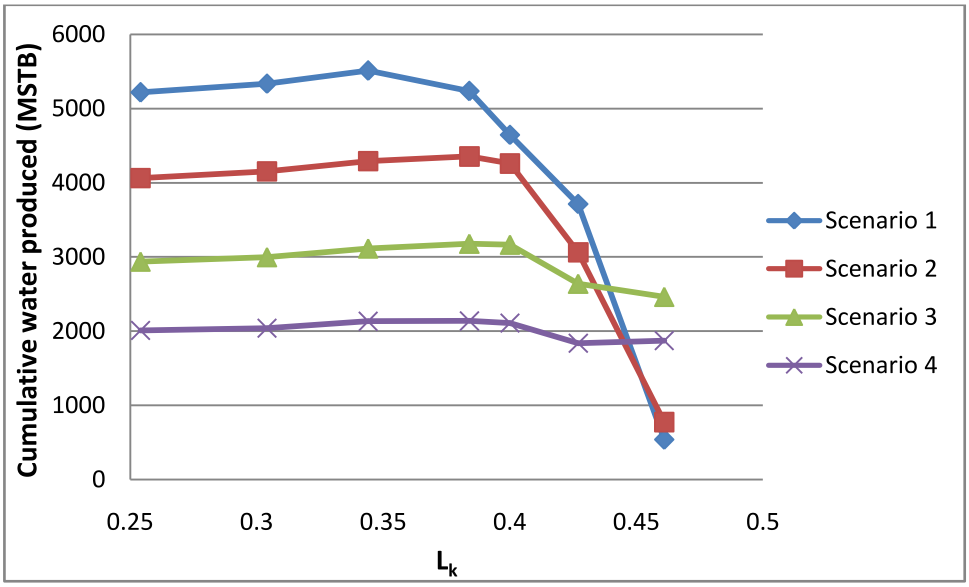


Figure 5.43 Relationship between total water production and reservoir heterogeneity in the study of effect of polymer concentration under economic limit

Cumulative water produced is one of the most important criteria for field implementation decision. High cumulative water produced comes together with water management planning including water treatment and water disposal. From Figure 5.43 lower polymer solution concentration yields less cumulative water produced compared to higher concentration polymer. At higher reservoir heterogeneity, the trend of cumulative water produced is declined. This could be explained that total flow ability only depends on flow from the high permeability channel. Both oil and water are then less produced when heterogeneity increases.

From previous discussion, low polymer solution concentration of 0.6225 lb/STB with a slug size of 0.225 PV is the best scenario since this provides the highest oil recovery and the least water production (as seen from cumulative water produced around 2,000 MSTB from Figure 5.6). This scenario is also adaptable for any range of heterogeneity in this study. Another conclusion can be made in this section is at higher heterogeneity, high concentration of polymer solution with small slug size is not recommended. Detailsof simulation result of all scenarios combined with different cases are summarized in Table 5.6.Cases A, B, C, D, E, F and G represent variation of heterogeneity values from 0.46, 0.42, 0.40, 0.38, 0.34, 0.30 and 0.25, respectively.

Table 5.6 Summary of simulation result in the study of effect of polymer concentration and slug size

Case no.	Production time (yr.)	RF (%)	Cumulative oil produced (MSTB)	Dimensionless cumulative water injected	Cumulative water produced (MSTB)
1A	13	18.44%	750.94	0.22	537
1B	35	36.48%	1,485.33	1.02	3,712
1C	37	38.00%	1,547.41	1.21	4,645
1D	39	39.24%	1,597.69	1.34	5,233
1E	40	41.15%	1,675.50	1.41	5,510
1F	40	42.41%	1,726.88	1.39	5,335
1G	40	44.05%	1,793.77	1.38	5,216
2A	23	20.82%	847.70	0.29	773
2B	37	38.52%	1,568.39	0.92	3,062
2C	39	39.91%	1,624.99	1.16	4,258
2D	40	40.54%	1,650.70	1.18	4,353
2E	40	41.84%	1,703.55	1.18	4,291
2F	40	42.87%	1,745.38	1.16	4,153
2G	40	44.10%	1,795.58	1.16	4,062
3A	40	38.89%	1,583.29	0.81	2,462
3B	40	41.90%	1,705.98	0.87	2,640
3C	40	42.12%	1,714.96	0.97	3,166
3D	40	42.56%	1,732.83	0.97	3,179
3E	40	43.58%	1,774.48	0.97	3,114
3F	40	44.29%	1,803.16	0.95	2,996
3G	40	45.14%	1,838.04	0.95	2,937
4A	40	39.41%	1,604.77	0.70	1,871
4B	40	42.53%	1,731.76	0.72	1,836
4C	40	42.91%	1,747.13	0.77	2,107
4D	40	43.24%	1,760.42	0.78	2,137
4E	40	43.78%	1,782.68	0.78	2,132
4F	40	44.34%	1,805.40	0.77	2,039
4G	40	44.89%	1,827.65	0.77	2,010

5.4 Effect of polymer concentration

Concentration of polymer solution is one of the designed parameters in this study since it directly controls polymer viscosity. Previous section is discussed on variation of both concentration and slug size. In this section, the study is emphasized only on polymer solution concentration by fixing the same injected volume or the same slug size. Similar to previous section, reservoir model is constructed as similar as the polymer base case, including 0.15 PV pre-flushed water slug size and 0.20 PV polymer slug size. Table 5.7 summarizes all simulated scenarios that are run with seven heterogeneity values. Figures 5.44 to 5.47 demonstrate simulation outcomes which are oil recovery factor, cumulative oil produced, water cut, and cumulative water produced as functions of heterogeneity, respectively.

Table 5.7 Summary of polymer flooding scenariosin the study of effect of polymer concentration

Scenarios no.	**Pre-flushed water slug size (PV)**	**Polymer slug size (PV)**	**Injection rate (STB/D)**	**Polymer concentration (lb/STB)**	**Running period assign (Yrs)**
1	0.15	0.20	1,000	1.0506	40
2	0.15	0.20	1,000	0.7004	40
3	0.15	0.20	1,000	0.5253	40
4	0.15	0.20	1,000	0.1751	40

According to Figures 5.44 and 5.45, the highest polymer concentration scenario obviously yields extremely low oil recovery factor in most heterogeneity values. Only the reservoir containing the lowest value of $L_k$can maintain high oil recovery factor. In overall it yields the lowest oil recovery when compared to others less polymer concentration scenarios. From scenarios no. 2 and 3, where polymer concentrations are moderate, it can be concluded that in low heterogeneity values oil recovery factors do not vary much to polymer concentration. Lower polymer concentration yields slightly greater amount of cumulative oil produced. Then, difference comes smaller until certain heterogeneity value.The last scenario where polymer concentration is relatively low shows a remarkable drop from moderate polymer concentrations. It can be inferred that, oil recovery factor is directly affected from polymer concentration. Too high concentration could result in low injectivity, whereas too low concentration could yield improper mobility ratio that consecutively causes less oil recovery factor.

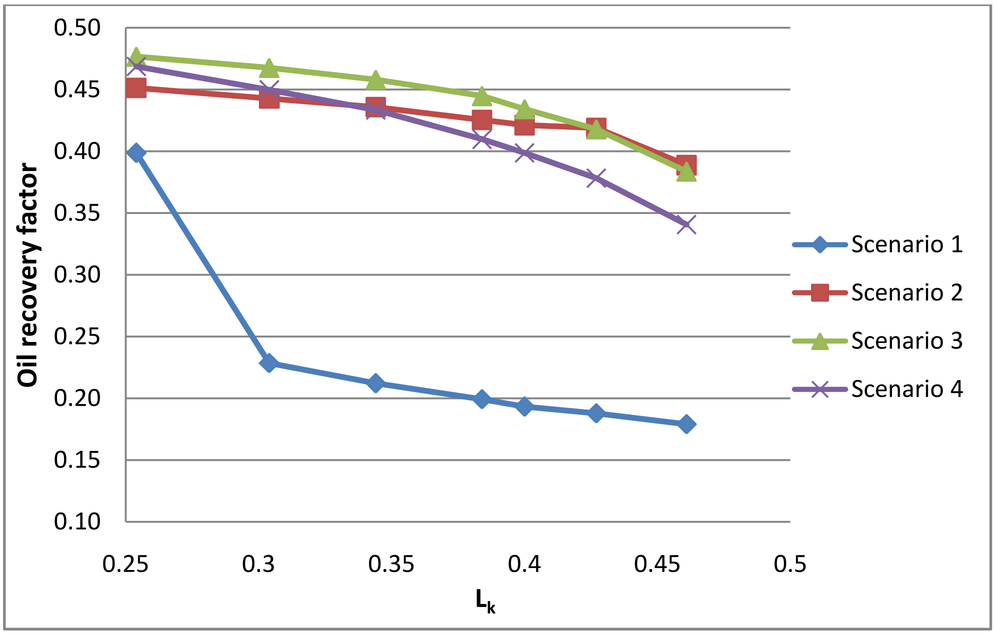


Figure 5.44 Relationship between oil recovery factors and reservoir heterogeneity in the study of effect of polymer concentration

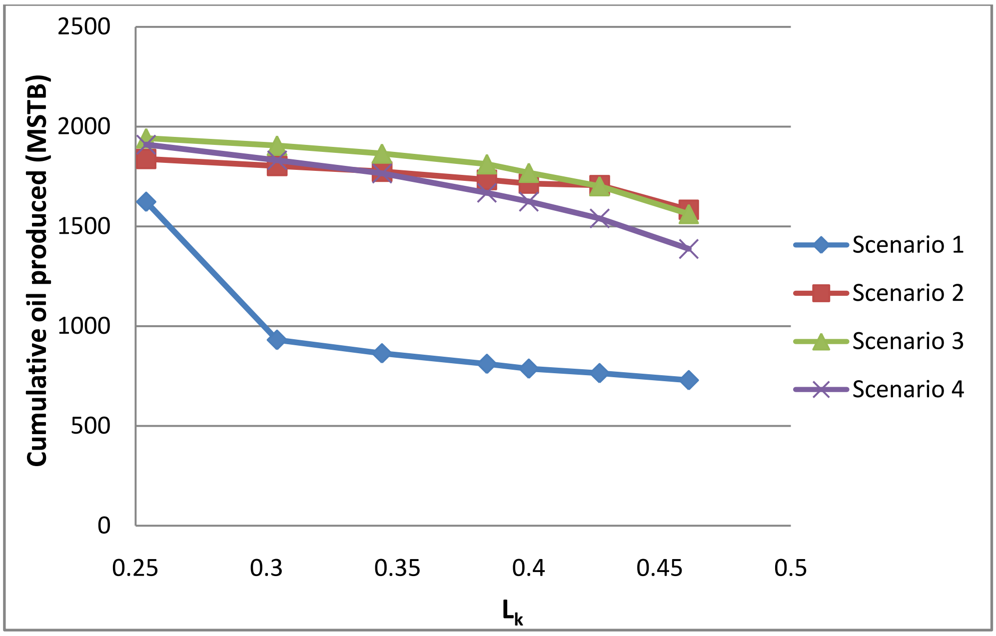


Figure 5.45 Relationship between cumulative oil produced and reservoir heterogeneity in the study of effect of polymer concentration

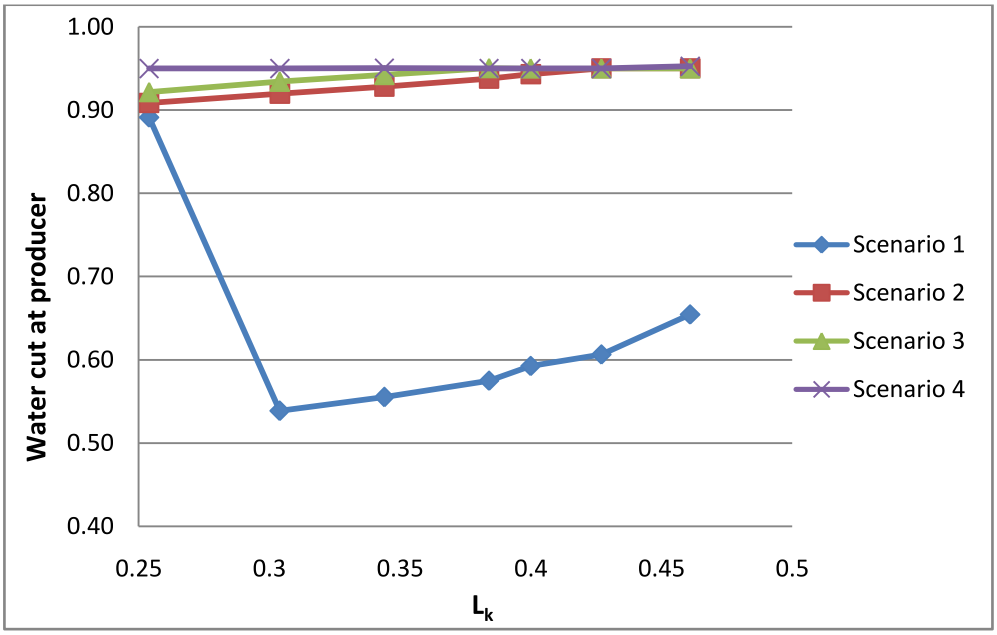


Figure 5.46 Relationship between water cut and reservoir heterogeneity in the study of effect of polymer concentration

Figures5.46 and 5.47 show that high polymer concentration yields very low water cut at termination as well as cumulative water produced. As previously discussed that production is terminated due to low injectivity and hence, oil rate reaches the preset production constraint before it goes through total production period. For remain scenarios, a slight variation of water cut is observed in low heterogeneity region. However, final water cut reaches the same value of 0.95 in higher heterogeneity range.

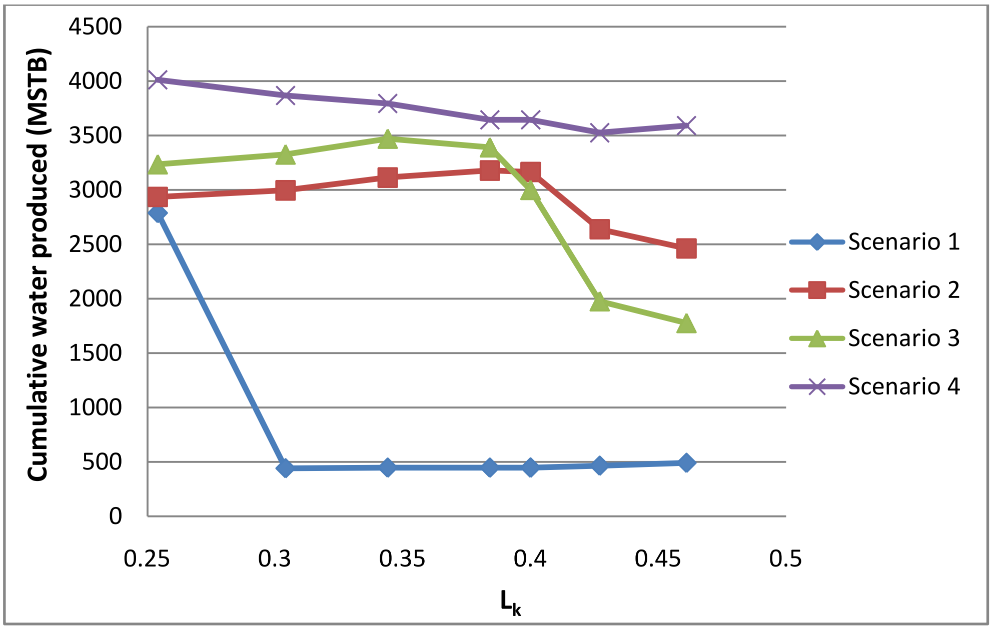


Figure 5.47 Relationship between cumulative water produced and reservoir heterogeneityin the study of effect of polymer concentration

Figure 5.47 shows that moderate polymer concentration scenarios provide similar trend in cumulative water produced as functions of reservoir heterogeneity. Reduction of water produced occurs at certain heterogeneity. At this point, cumulative water produced coincidentally reduces with cumulative oil produced. This could be a result from combination from high heterogeneity and low injectivity of polymer solution. Water produced obtained from the lowest polymer concentration tends to be more stable in the whole range of heterogeneity in this study. High injectivity is obtained in this case.

When polymer slug size is constant, too high polymer concentration is unsuitable for most heterogeneity. Homogeneity or small value heterogeneityare still valid for high polymer concentration. Moderate polymer concentration of 0.5253 lb/STB yields the best result. When heterogeneity is relative high, water produced is substantially reduced by the use of moderate polymer concentration that even makes this scenario becomes more favorable. The significant detailsof simulation results are summarized in Table 5.8. Again, letters A, B, C, D, E, F and G represent the variation of heterogeneity values from 0.46, 0.42, 0.40, 0.38, 0.34, 0.30 and 0.25, respectively.

Table 5.8 Summary of simulation result in the study of effect of polymer concentration

Case no.	Production time (yr.)	RF (%)	Cumulative oil produced (MSTB)	Dimensionless cumulative water injected	Cumulative water produced (MSTB)
1A	11	17.90%	728.81	0.21	491
1B	12	18.78%	764.70	0.21	465
1C	13	19.32%	786.57	0.21	447
1D	15	19.92%	811.13	0.22	448
1E	19	21.21%	863.60	0.23	447
1F	24	22.85%	930.20	0.24	442
1G	40	39.87%	1,623.22	0.88	2,788
2A	40	38.89%	1,583.29	0.81	2,462
2B	40	41.90%	1,705.98	0.87	2,640
2C	40	42.12%	1,714.96	0.97	3,166
2D	40	42.56%	1,732.83	0.97	3,179
2E	40	43.58%	1,774.48	0.97	3,114
2F	40	44.29%	1,803.16	0.95	2,996
2G	40	45.14%	1,838.04	0.95	2,937
3A	35	38.38%	1,562.76	0.67	1,777
3B	37	41.80%	1,701.96	0.54	1,222
3C	38	43.44%	1,768.63	0.94	3,001
3D	39	44.48%	1,811.25	1.03	3,392
3E	40	45.82%	1,865.57	1.06	3,471
3F	40	46.77%	1,904.40	1.04	3,326
3G	40	47.68%	1,941.49	1.03	3,237
4A	31	34.07%	1,387.14	0.99	3,592
4B	31	37.83%	1,540.41	1.01	3,526
4C	32	39.89%	1,624.09	1.05	3,645
4D	32	40.98%	1,668.59	1.06	3,645
4E	33	43.35%	1,764.97	1.10	3,795
4F	34	44.98%	1,831.51	1.13	3,868
4G	34	46.88%	1,908.99	1.18	4,012

5.5 Effect of polymer injection rate

Higher injection rate could yield positive result but it might adversely affect on polymer flooding efficiency for reservoir containing very high heterogeneity. Therefore, polymer injection rate becomes one of the most important study parameters. To study polymer injection rate, all scenarios are basically constructed with the same required parameters as in polymer flooding base case, including polymer concentration, pre-flushed water slug size, total polymer solution volume and production constraints. Every injection rate is performed with seven designed heterogeneity. Details of each simulation are shown in Table 5.9.

Table 5.9 Summary of polymer flooding cases in the study of effect of polymer injection rate

Scenario no.	**Pre-flushed water slug size (PV)**	**Polymer slug size (PV)**	**Injection rate (STB/D)**	**Polymer concentration (lb/STB)**	**Running period assign (Yrs)**
1	0.15	0.20	500	0.7004	40
2	0.15	0.20	750	0.7004	40
3	0.15	0.20	1,000	0.7004	40
4	0.15	0.20	1,250	0.7004	40

Figures 5.48 to 5.51 illustrate important simulation outcomes which are oil recovery factor, cumulative oil produced, water cutand cumulative water produced. From Figures 5.48 and 5.49, in the beginning small value of heterogeneity yields minimum oil recovery when combined with low polymer injection rate. Focusing on two maximum injection rates, which are 1,000 and 1,250 STB/D, cumulative oil produced as functions of time are completely overlaid. This means that, at lower heterogeneity injection rate of 1,000 is the optimized value. However, when heterogeneity increases until certain value, polymer injection rate does not affect on oil recovery factor. From the figures, it can be seen than heterogeneity above 0.4 is considerably a point where injection rates no more affecting oil recovery factor.

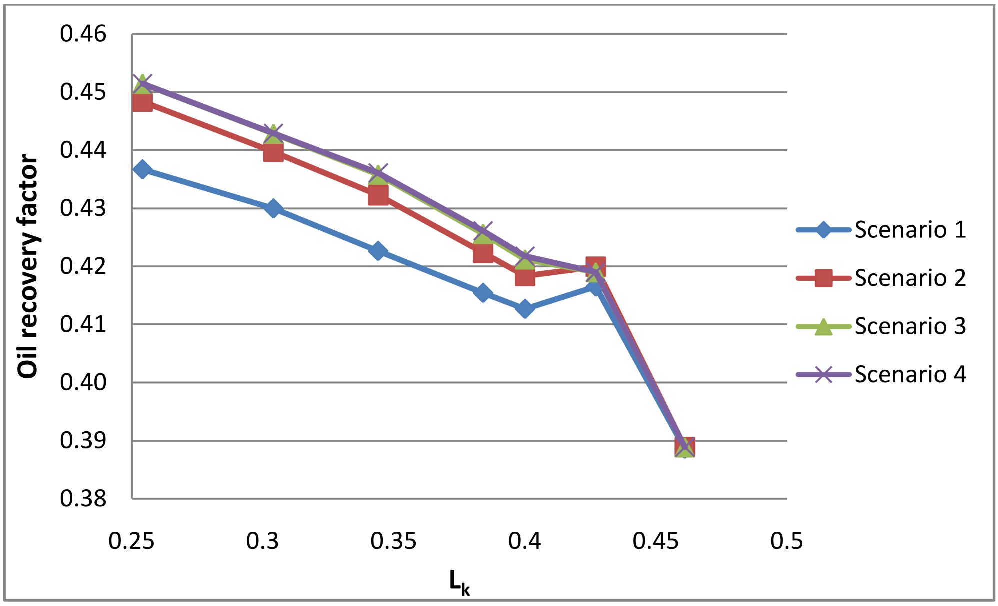


Figure 5.48 Relationship between oil recovery factors and reservoir heterogeneity in the study of effect ofpolymer injection rate

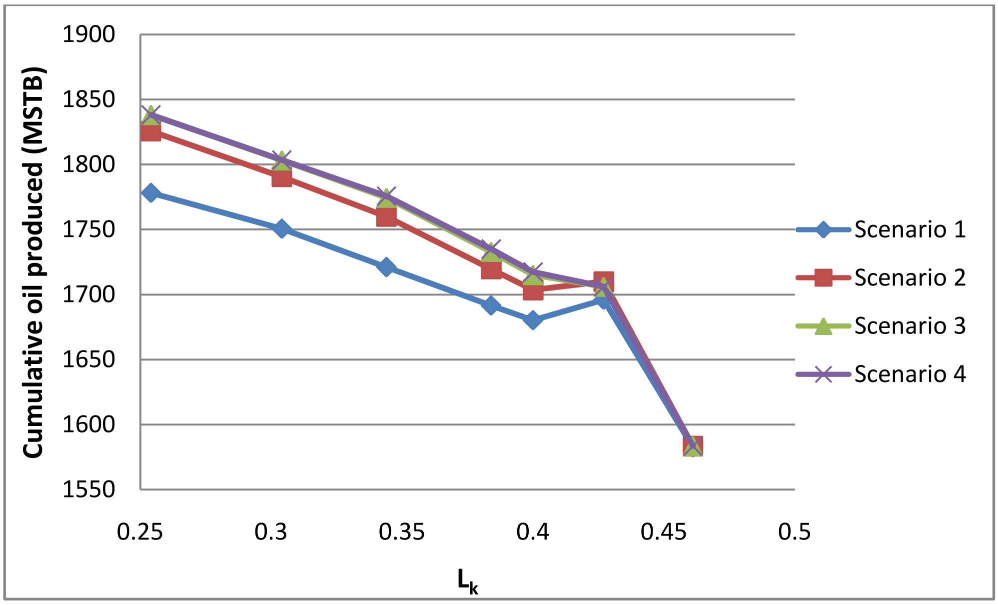


Figure 5.49 Relationship between cumulative oil produced and reservoir heterogeneity in the study of effect of polymer injection rate

However, when considering water produced, low injection rate tends to show better result as can be seen from Figures 5.50 and 5.51. At low reservoir heterogeneity, low injection rate yields oil recovery, but in the same time low water produced as well. At higher injection rate, total volume of injected liquid is higher, therefore, amount of produced water is higher as well. At the heterogeneity value above 0.4 all injection rates tend to yield high water cut at the end of production. That means polymer is difficultly injected into formation becauseinjectivity is low. Hence, polymer solution enters only in high permeability channels leaving most oil in low permeability zone. Polymer solution breakthrough then results in high water cut but low water produced.

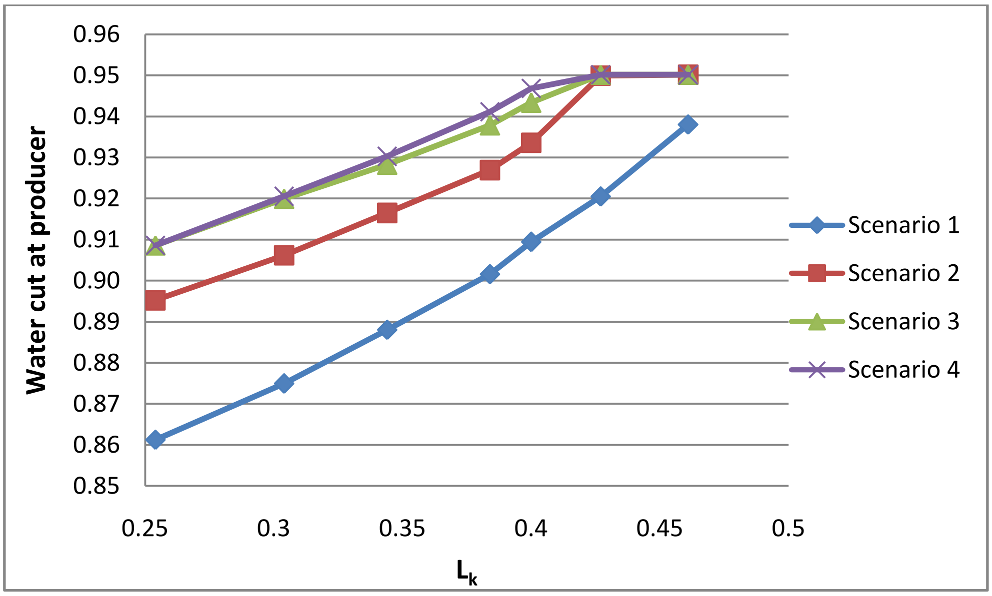


Figure 5.50Relationship between water cut and reservoir heterogeneity for the study of effect of polymer injection rate

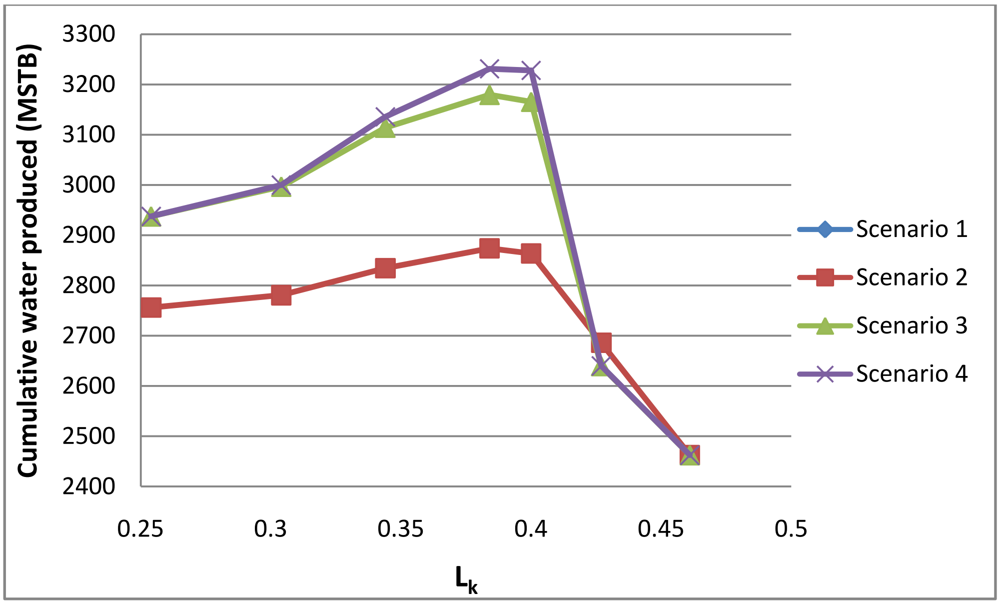


Figure 5.51 Relationship between cumulative water produced and reservoir heterogeneity for the study of effect of polymer injection rate

From the previous discussions, it can be concluded that higher polymer injection rate yields more advantage in less heterogeneous formation. However, the optimal injection rate exists which is 1,000 STB/D in this study. On the contrary, lower injection rate yields benefit in reservoir containing heterogeneity higher than 0.4 since the result compared to higher injection rate is not different. By the way the heterogeneity above 0.4 could cause difficulty in injecting polymer solution into selected reservoir model. If water produced is taken in consideration, higher injection rate is more punished since it causes higher water production. Summary of simulation result of each simulation caseis shown in Table 5.10.Letters A, B, C, D, E, F and G represent the variation of heterogeneity values from 0.46, 0.42, 0.40, 0.38, 0.34, 0.30 and 0.25, respectively.

Table 5.10 Summary of simulation result in the study of effect from polymer injection rate

Case no.	Production time (yr.)	RF (%)	Cumulative oil produced (MSTB)	Dimensionless cumulative water injected	Cumulative water produced (MSTB)
1A	40	38.86%	1,582.28	0.77	2,351
1B	40	41.65%	1,695.91	0.78	2,276
1C	40	41.27%	1,680.20	0.78	2,326
1D	40	41.54%	1,691.48	0.78	2,318
1E	40	42.26%	1,720.88	0.78	2,282
1F	40	42.99%	1,750.60	0.78	2,235
1G	40	43.67%	1,778.06	0.78	2,213
2A	38	38.89%	1,583.31	0.81	2,463
2B	40	41.99%	1,709.80	0.87	2,686
2C	40	41.84%	1,703.40	0.90	2,864
2D	40	42.23%	1,719.57	0.90	2,874
2E	40	43.22%	1,759.94	0.90	2,834
2F	40	43.97%	1,790.39	0.90	2,781
2G	40	44.84%	1,825.59	0.90	2,756
3A	40	38.89%	1,583.29	0.81	2,462
3B	40	41.90%	1,705.98	0.87	2,640
3C	40	42.12%	1,714.96	0.97	3,166
3D	40	42.56%	1,732.83	0.97	3,179
3E	40	43.58%	1,774.48	0.97	3,114
3F	40	44.29%	1,803.16	0.95	2,996
3G	40	45.14%	1,838.04	0.95	2,937
4A	38	38.89%	1,583.29	0.81	2,462
4B	39	41.90%	1,706.00	0.87	2,640
4C	40	42.17%	1,717.23	0.98	3,228
4D	40	42.61%	1,734.93	0.99	3,231
4E	40	43.61%	1,775.56	0.98	3,136
4F	40	44.29%	1,803.35	0.96	3,000
4G	40	45.14%	1,838.04	0.95	2,937

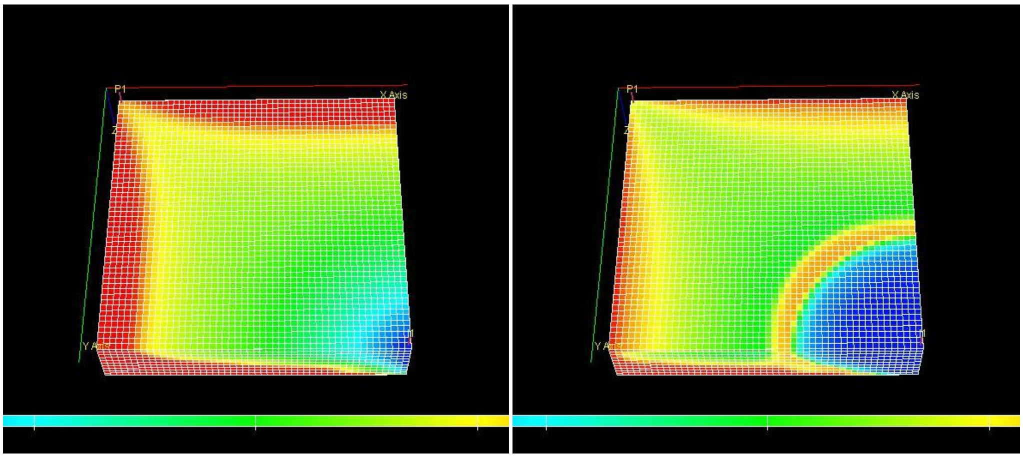
5.6 Effect of double-slug polymer injection

After defining the optimum polymer slug strategy for single-slug injection in chapter 5.2, objective of the study in this section is to compare the result obtained by single-slug base case to double-slug injection mode. A whole single polymer slug is divided into two equal slugs, alternating by chasing water. Polymer concentration, injection rate, and pre-flushed slug size are kept constant as the polymer flooding base case. The only variation in this section is the slug size of alternating which is varied from 0.05 PV to 0.10 PV. All variation scenarios are summarized in Table 5.11.

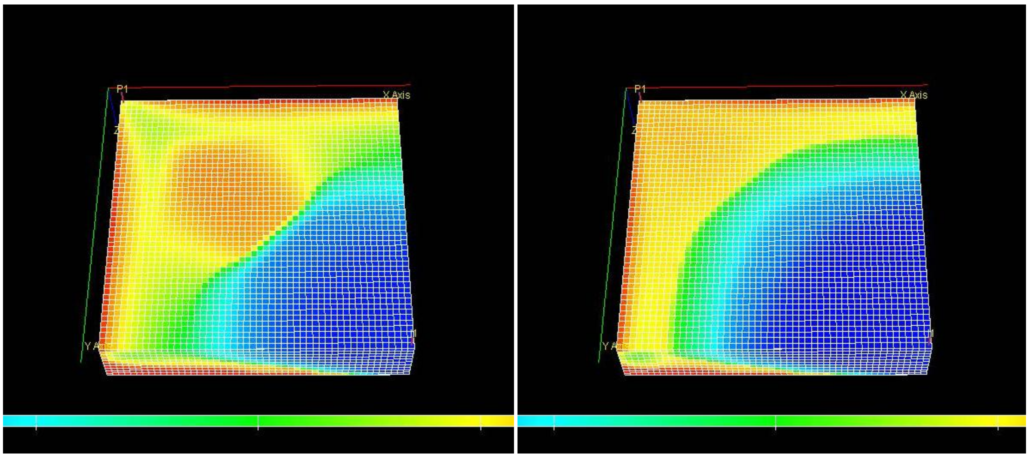
Table 5.11 Summary of polymer flooding scenarios in the study of effect of double-slug polymer injection

Scenario no.	Pre-flushed water slug size (PV)	1st Polymer slug size (PV)	Alternating water slug size (PV)	2nd Polymer slug size (PV)
1	0.150	0.200	0.000	0.000
2	0.150	0.100	0.050	0.100
3	0.150	0.100	0.075	0.100
4	0.150	0.100	0.100	0.100

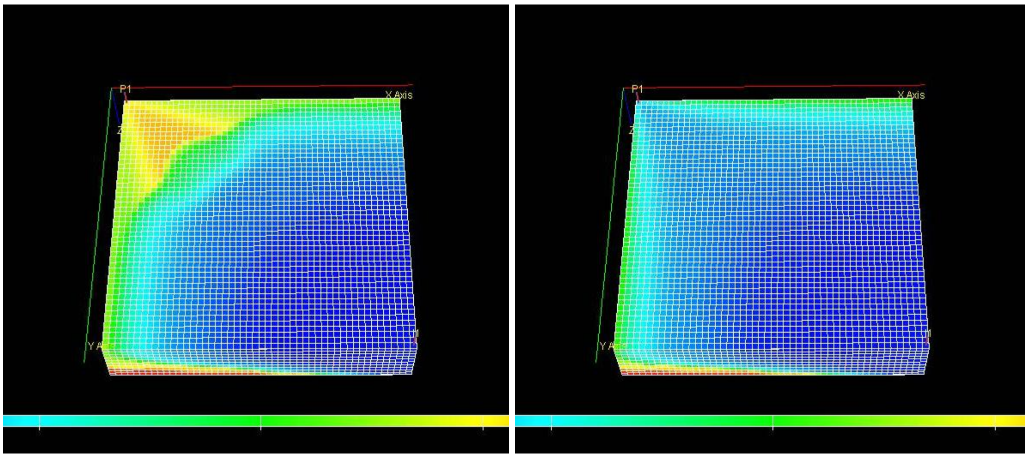
Injection sequence of double-slug polymer injection is illustrated in Figure 5.52. The figure shows different colors in terms of oil saturation. From Figure 5.52a, it can be seen that chasing water breakthroughs at producer through upper layer of reservoir where it is high permeability channel. Newly formed oil bank is obviously seen in Figure 5.52b when first slug of polymer is injectected. From Figure 5.52c to 5.52e injection of alternating water, second slug of polymer and chasing water cannot be recognized by color scale of oil saturation. At the end of production, most area of reservoir is displaced by injected fluid except lower part which is still red color in Figure 5.52f. This is a result from low permeability of bottom layer



(a) (b)



(c) (d)



(e) (f)

Figure 5.52 Oil saturation profile showing double-slug injection sequence (a) Pre-flushed water, (b) first polymer slug injection, (c) alternating water slug, (d) second polymer slug, (e), chasing water and (f) termination of production

Figures 5.53 to 5.56 illustrate simulation outcomes including oil recovery factor, cumulative oil produced, water cut and cumulative water produced.

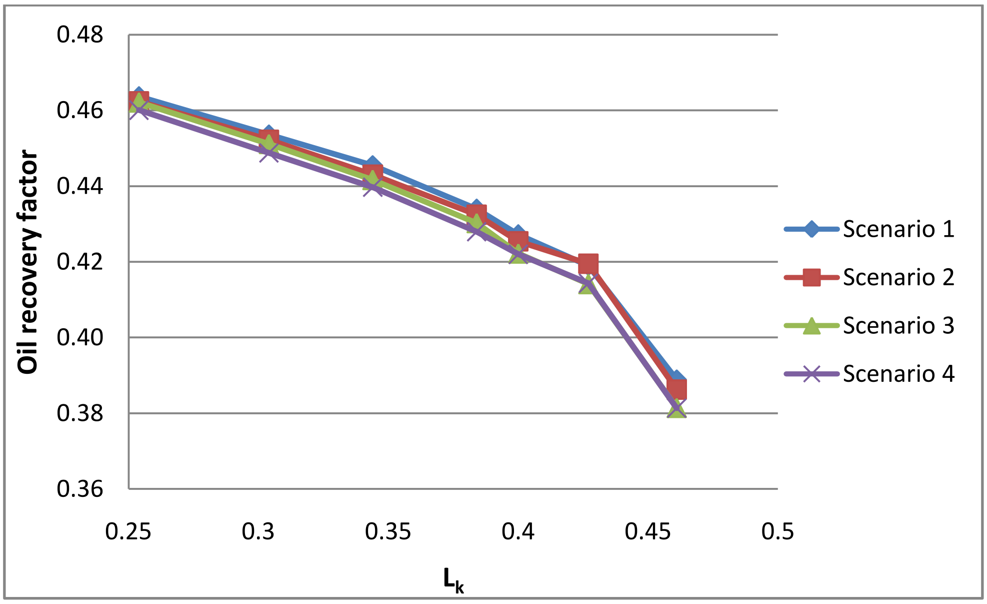


Figure 5.53 Relationship between oil recovery factor and reservoir heterogeneity in the study of effect of double-slug polymer injection

From Figures 5.53 and 5.54, trend of oil recovery factors and cumulative oil produced obtained from every scenario in all heterogeneities is mostly the same. However, single-slug polymer base case still yields the highest oil recovery factor. Alternating by water is performed to increase injectivity of polymer slug. When injection process is switched from alternating water to second polymer slug, there exists region of low injectivity again before injection rate reaches its maximum. Hence, oil recovery is slightly less especially when size of alternating water is getting bigger.

Injecting in double slugs should yield more benefit when highly viscous polymer is required to inject. The base case polymer concentration chosen for this study is probably at optimal condition, therefore dividing whole single-slug does not show any benefit.

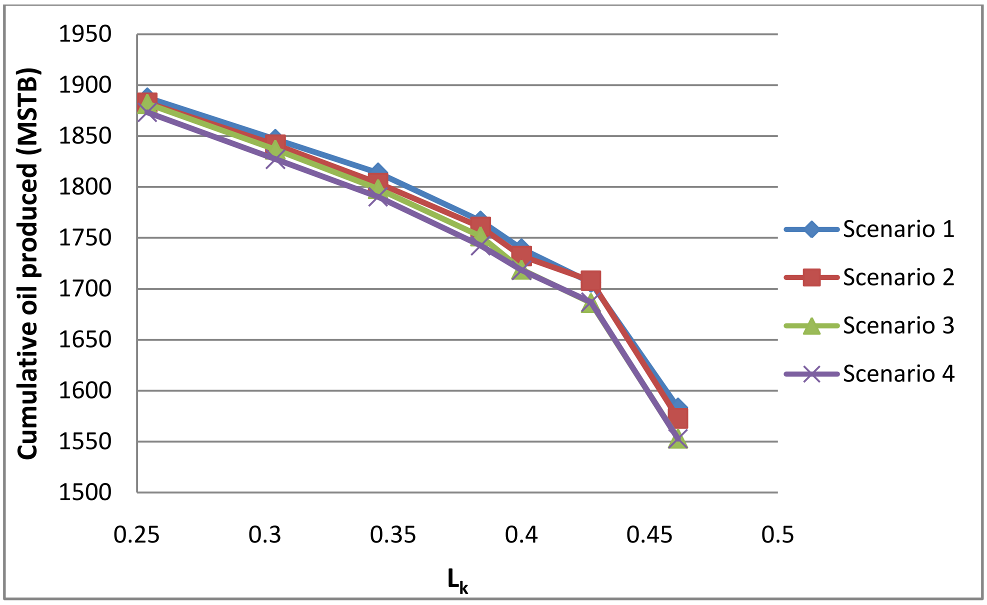


Figure 5.54 Relationship between cumulative oil produced and reservoir heterogeneity in the study of effect of double-slug polymer injection

From Figures 5.55 and 5.56, final water cut and cumulative water produced obtained from single-slug case are higher than other scenarios. As whole polymer slug is early injected, recoverable oil bank is produced earlier and hence higher production rate is achieved at production well. However, if water produced is sensitive and has to be accounted for consideration for polymer implementation, scenario no.2 where less water produced is obtained might represent the best scenario.

It can be concluded that at preset conditions of pre-flushed water, polymer concentration and polymer injection rate, injecting polymer in double-slug mode does not yield improvement in oil recovery compared to single-slug mode due to low injectivity during changing injected fluids. However, small benefit obtained from double-slug is lower water produced in low heterogeneity zone.

Similar to previous sections, higher value of heterogeneity than 4.0 results in high final water-cut which is caused by selective flow in high permeability channel. And since the flow ability is low, total liquid production is low as well for all polymer injection scenarios. Result from simulated cases is summarized in Table 5.12. Letters A, B, C, D, E, F and G represent the variation of heterogeneity values from 0.46, 0.42, 0.40, 0.38, 0.34, 0.30 and 0.25, respectively.

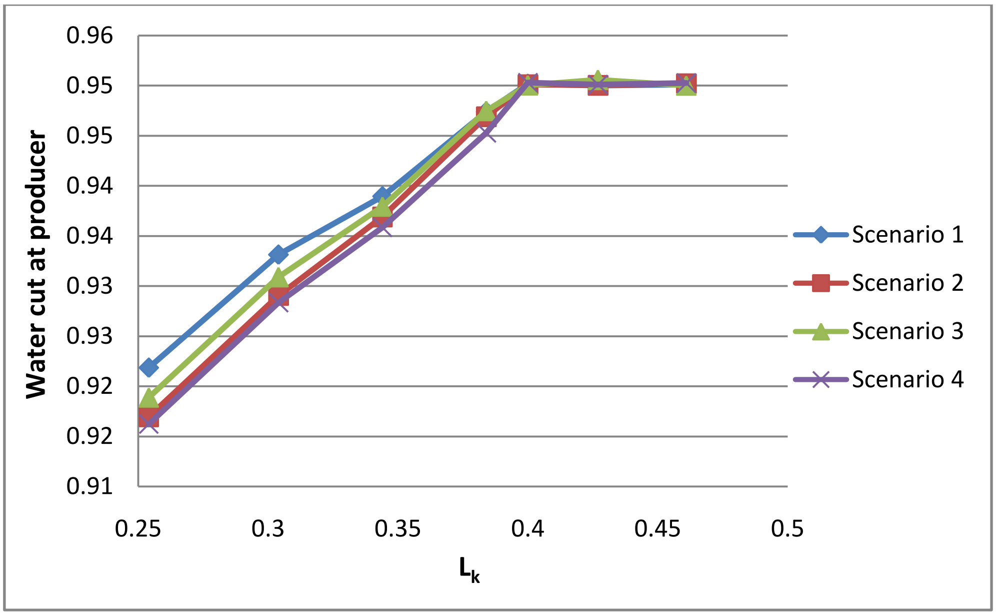


Figure 5.55 Relationship between water cut and reservoir heterogeneityin the study of effect of double-slug polymer injection

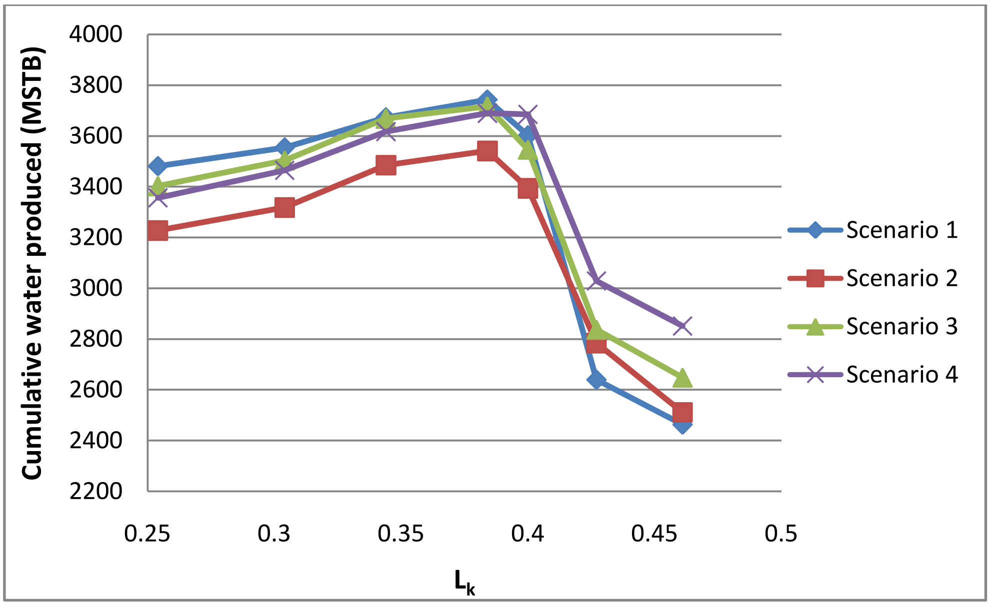


Figure 5.56 Relationship between cumulative water produced and reservoir heterogeneity in the study of effect of double-slug polymer injection

Table 5.12 Summary of simulation result in the study of effect of double-slug polymer injection

Case no.	Production time (yr.)	RF (%)	Cumulative oil produced (MSTB)	Dimensionless cumulative water injected	Cumulative water produced (MSTB)
1A	40	38.89%	1,583.29	0.81	2,462
1B	40	41.90%	1,705.98	0.87	2,640
1C	40	42.12%	1,714.96	0.97	3,166
1D	40	42.56%	1,732.83	0.97	3,179
1E	40	43.58%	1,774.48	0.97	3,114
1F	40	44.29%	1,803.16	0.95	2,996
1G	40	45.14%	1,838.04	0.95	2,937
2A	39	38.63%	1,572.76	0.82	2,511
2B	40	41.65%	1,695.75	0.85	2,579
2C	40	41.93%	1,707.23	0.92	2,953
2D	40	42.39%	1,725.89	0.93	2,975
2E	40	43.29%	1,762.82	0.93	2,927
2F	40	44.09%	1,795.10	0.91	2,768
2G	40	44.95%	1,830.07	0.90	2,701
3A	38	38.14%	1,553.10	0.84	2,648
3B	40	41.30%	1,681.61	0.89	2,757
3C	40	41.67%	1,696.76	0.96	3,150
3D	40	42.18%	1,717.32	0.96	3,150
3E	40	43.18%	1,758.10	0.97	3,110
3F	40	44.01%	1,791.84	0.94	2,950
3G	40	44.95%	1,830.06	0.94	2,869
4A	40	38.02%	1,548.20	0.86	2,768
4B	40	40.95%	1,667.42	0.88	2,746
4C	40	41.39%	1,685.28	0.95	3,113
4D	40	41.91%	1,706.39	0.96	3,123
4E	40	42.95%	1,748.78	0.96	3,060
4F	40	43.73%	1,780.69	0.94	2,917
4G	40	44.71%	1,820.30	0.93	2,834

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

This study emphasizes on simulation study of polymer flooding in reservoir containing heterogeneity. Several parameters such as polymer concentration, polymer slug size, chasing water slug size and polymer injection rate are investigated for their effects on effectiveness of polymer flooding in heterogeneous reservoir. ECLIPSE®100 reservoir simulator with special polymer flooding function is used as a tool for investigation. Hydrolyzed polyacrylamide (Flopaam 3330S), a commercial polymer, is chosen to represent polymer substance in this work. The reservoir model properties are based on previous study [18] and several recommendations for polymer flooding. The main objective is to evaluate effects of viscosity through polymer concentration and injection rate of polymer solution on polymer flooding multi-layered heterogeneous reservoir. In order to investigate effects of interest parameters optimized polymer flooding case is identified. The significant findings are summarized as following:

1. Polymer flooding should be injected after pre-flushed water in order to increase injectivity of polymer solution. Therefore, slug size of pre-flushed water plays an important role in optimizing flooding process.Moreover, slug size of polymer solution is also required to identify. In this study, pre-flushed water slug of 0.15PV followed by polymer slug of 0.20PV yields the highest oil recovery efficiency within short period of timethat consecutively results in less cumulative water produced.

2. When quantity of polymer is limited, preparing polymer solution at low concentration with high volume yields better results compared to high polymer concentration with small volume. This conclusion is valid for whole range of reservoir heterogeneity in this study.Polymer solution concentration of 0.6225 lb/STB with a slug size of 0.225 PV isthe best scenario in this study. At higher reservoir heterogeneity than 0.4 Lorenz

coefficient, high concentration of polymer solution with small slug size is strongly not recommended.

3. When polymer slug size is constant, polymer concentration directly affects oil recovery factor. Too low concentration could yield unsuitable mobility ratio that consecutively yields less oil recovery factor, while too high concentration results in low injectivity for most heterogeneity values. In this study, moderate polymer concentration of 0.5253 lb/STB yields the best result. When heterogeneity is high, water produced is substantially reduced by the use of moderate polymer concentration that even makes this concentration becomes more favorable.

4. Polymer injection rate is one of important parameters, for homogeneous reservoir, higher injection rate could yield positive result. But higher polymer injection rate provides advantage only in small value heterogeneity in heterogeneous formation. On the contrary, lower injection rate is more favorable in reservoir containing heterogeneity higher than 0.4. In summary, injection rate of 1,000 STB/D is an optimum value in this study.

5. Injecting polymer in double-slug mode does not show any benefit in this study due to low injectivity during changing injected fluids. However, small advantage obtained from dividing polymer slug is lower water produced.

Recommendations for future study are as following:

1. In this study the effect of salinity on polymer viscosity is not taken into account for polymer solution used. Generally, offshore oil field production should consider salinity on polymer solution as one of impacting parameter. Therefore future reservoir simulation in offshore oilfield should involve the effect of salinity on polymer flooding.

2. For more accuracy, laboratory test of polymer on core sample should be conducted to ensure input data is suitable for polymer flooding. Relative permeability of polymer solution – oil may be slightly altered from water-oil one.

3. The constructed heterogeneity emphasized on only certain range. Wider range of heterogeneity should be investigated.

4. Sequence of permeability value is only from high to from low top to bottom layer. Different in sequence should yield additional conclusion. The study in irregular sequence would represent more reality.

5. Porosity of reservoir rock in each layer is kept constant in order to make original oil in place equal for every model. However,porosity should be varied as a function of permeability to represent more corrected model based on theory.

REFERENCES

[1] Davison P., and Mentzer E.Polymer Flooding in North Sea Reservoirs.Paper SPE 9300(June 1982)

[2] Surkalo H., and Pitts M.J., Polyacrylamide. Vertical Conformance Process Improved Sweep Efficiency and Oil Recovery in The OK Field.Paper SPE 14115 presented at the SPE 1986 International Meeting on Petroleum Engineering held in Beijing, China(17-20 March 1986)

[3] Wankui G., Jiecheng C., and Chuanhong L. Commercial Pilot Test of Polymer Flooding in Daqing Oil Field.Paper SPE 59275 presented at the 2000 SPE/DOE Improved Oil Recovery Symposium held in Tulsa, Oklahoma(3-5 April 2000)

[4]Jiecheng C., Xinguang S., Wenguang B., and Jiangtao L. Cases Studies on Polymer Flooding for Poor Reservoir in Daqing Oilfield.Paper SPE 108661 presented at the 2007 SPE Asia Pacific Oil & Gas Conference and Exhibition held in Jakarta, Indonesia(30 October-1 November 2007)

[5]Meybodi E., Kharrat R., and Ghazanfari M.H. Effect of Heterogeneity of Layered Reservoirs on Polymer Flooding: An Experimental Approach Using Five-Spot Glass Micromodel.Paper SPE 113820 presented at the 2008 SPE Europec/EAGE Annual Conference and Exhibition held in Rome, Italy(9-12 June 2008)

[6] Xiaoqin Z., Wenting G., Xia L., Zhen L., Jing M., and Dongyang J. Novel Injecting Concentration Design Method for Polymer Flooding in Heterogeneous Reservoirs.Paper SPE 123404, presented at the 2009 SPE Asia Pacific Oil and Gas Conference and Exhibition held in Jakarta, Indonesia(4-6 August 2009)

[7]Seright R.S. Potential for Polymer Flooding Reservoirs with Viscous Oils.Paper SPE 129899 presented at the 2010 SPE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, USA(24-28 April 2010)

[8]Schneider, F.N., and Owens, W.W. Steady-State Measurement of Relative Permeability for Polymer/Oil Systems. SPE 9408 presented at the SPE 55th Annual Technical Conference and Exhibition held in Dallas, U.S.A (1980)

[9] Barrufet, M.A. and Ali, L. Modification of Relative Permeability Curves by Polymer Adsorption. SPE 27015 presented at Latin America/Caribbean PetroleumEngineering Conference held in Buenos Aires, Argentina (1994)

[10] Donaldson, E.C., Chilingarian, G.V., and Yen, T.F. Enhanced Oil Recovery, II: Processes and Operations. Developments in Petroleum Science Volume 17, Part B. Amsterdam: Elsevier Science Publishers B.V., 1989.

[11] FalanSrisuriyachai. Evaluation of Alkali Flooding Combined with Intermittent Flow in Carbonate Reservoir. Doctoral Dissertation, Department of Chemical, Mining and Environmental Engineering (DICMA), Faculty of Engineering, University of Bologna, 2008.

[12] Bragg, J.R., Maruca, S.D., Gale, L.S., Wernau, W.C., Bech, D., Goldman, I.M.,Laskin, A.I. and Naslund, L.A. Control of Xanthan Degrading Organisms in the Loudon Pilot.SPE 11989 presented at the SPE Meeting held in Houston, Texas,U.S.A (1983)

[13] Ash, S.G., Clarke-Sturman, A.J., Calvert, R. and Nisbet, T.M. Chemical stability of biopolymer solution.SPE 12085 presented at the SPE Meeting held in Houston, Texas, U.S.A (1983)

[14] TorpongYaowapa. Optimization of Polymer Flooding in Medium Viscosity Oil Reservoir.Master's Thesis, Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University, 2010.

[15] Craig Jr., F.F. The Reservoir Engineering Aspects of Waterflooding. Dallas, Texas: Millet the Printer, 1971.

[16] Tiab, D., and Donaldson, E.C.Petrophysics, Houston, Texas, U.S.A:Gulf publishing company, 1996.

[17] Craig, F.F.The Reservoir Engineering Aspect of Water flooding, Society of Petroleum Engineering of AIME,fourth printing, New York, U.S.A., 1993.

[18] Lake, L.W. and Jerry L. A Review of Heterogeneity Measures Used in Reservoir Characterization.Paper SPE 20156 SPE Journal(1989)

APPENDIX

APPENDIX

RESERVOIRMODELCONSTRUCTIONBY ECLIPSE®100SIMULATOR

To construct a reservoir model,providing required data into ECLIPSE 100 reservoir simulator. The model used in this study composes of 50 × 50 × 10 blocks in the x-, y- and z- directions.

1. Case Definition

Simulator	Black oil
Model dimension	Number of cells in the x-direction 50
	Number of cells in the y-direction 50
	Number of cells in the z-direction 10
Grid type	Cartesian
Geometry type	Block Centered
IORoptions	Polymer Flood Model
Solution type	Fully Implicit

2. Reservoir properties

<u>Gird</u>

X Permeability value	Varied from 300 to 10 md with constant average
Y Permeability value	Varied from 300 to 10 mdwith constant average
Z Permeability value	Varied from 30 to 1 mdwith constant average
Porosity	0.30
X Grid block sizes	20 ft
Y Grid block sizes	20 ft

Z Grid block sizes 10 ft

Depths of Top faces 3200 ft

3. PVT

Fluid densities at surface condition	Oil density	59.42659	lb/cu.ft
	Water density	62.42797	lb/cu.ft
	Gas density	0.04369958	lb/cu.ft
Water PVT properties	Reference pressure (Pref)	1430	psia
	Water FVF at Pref	1.006538	rb/stb
	Water compressibility	3.03E-06	/psi
	Water viscosity at Pref	0.4634349	cP
	Water viscosibility	1.01E-06	/psi
Rock properties	Reference pressure	1430	psia
	Rock compressibility	3.00E-05	psi-1
Polymer/Salt Concentrations	Polymer concentration	Based on each case	lb/stb
	Salt concentration	0	lb/stb

Dead oil PVT properties (No dissolved gas)

Pbub (psia)	FVF (rb /stb)	Visc (cp)
500	1.053662723	20.28112932
578.9473684	1.052791245	20.42125381
657.8947368	1.052129677	20.58542552
736.8421053	1.051610166	20.77170111
815.7894737	1.051191392	20.97850719
894.7368421	1.050846644	21.20457663
973.6842105	1.050557889	21.44887458
1052.631579	1.050312509	21.71054656
1131.578947	1.050101414	21.98888067
1210.526316	1.049917888	22.28327954
1289.473684	1.049756861	22.59323894
1368.421053	1.049614434	22.91833123
1430	1.04951427	23.18217229
1526.315789	1.049373826	23.61251115
1605.263158	1.049271289	23.98102141
1684.210526	1.049178373	24.36349446
1763.157895	1.049093785	24.75973371
1842.105263	1.049016454	25.1695698
1921.052632	1.048945483	25.59285657
2000	1.04888012	26.02946768

Polymer solution viscosity function

Cp (lb/stb)	Fm
0	1
0.1751	4.4
0.3502	12
0.7004	44
1.0506	130

4. SCAL

Water/oil saturation functions

Sw	Krw	Kro	Pc (psia)
0.2	0	1	0
0.26111111	0.00308642	0.79012346	0
0.32222222	0.012345679	0.60493827	0
0.38333333	0.027777778	0.44444444	0
0.44444444	0.049382716	0.30864198	0
0.50555556	0.077160494	0.19753086	0
0.56666667	0.11111111	0.11111111	0
0.62777778	0.15123457	0.049382716	0
0.68888889	0.19753086	0.012345679	0
0.75	0.25	0	0
1	1	0	0

Polymer adsorption functions

Plc (lb/stb)	Psc (lb/lb)
0	0
0.0003	3E-06
0.0005	5E-06
0.0008	8E-06
0.001	1E-05

Polymer rockproperties

Dead pore space	0.13	-
Residual resistance factor	1.2	-
Rock mass density	1880	lb/rb
Adsorption index	2	-
Maximum polymer adsorption value	0.0002	-

** Dead pore space is void where only one entry existsand fluid cannot flow through. Normally this value does not exceed value of irreducible water saturation.

5. Initialization

Equilibration data specification

Datum depth	3200 ft
Pressure at datum depth	1400 psia
WOC depth	10000 ft

6. Schedule

6.1 Production well

Well specification

Well name	P1
Group	G1
I location	1
J location	1
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	NO
PVT Property table	1
Density calculation	SEG

Well connection data

Well connection data	P1
K upper	1
K lower	10
Open/shut flag	OPEN
Well bore ID	0.510467 ft
Direction	Z

Production well control

Well	P1
Open/shut flag	OPEN
Control	LRAT
Liquid rate	1500 stb/day
BHP target	200 psia

Production well economic limits

Well	P1
Minimum oil rate	20
Maximum water cut	0.95
Workover procedure	WELL
End run	YES
Quantity for economic limit	RATE
Secondary workover procedure	NONE

6.2Injecttion well

Well specification

Well name	I1
Group	G2
I location	50
J location	50
Preferred phase	WATER
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

Injection well control

Well	I1
Injector type	WATER
Open/shut flag	OPEN
Control mode	RATE
Liquid surface rate	1000 stb/day
BHP target	1900 psia

Well connection data

Well connection data	I1
K upper	1
K lower	10
Open/shut flag	OPEN

Well bore ID	0.510467 ft
Direction	Z

Injection well polymwe/salt concentration

Well connection data	I1
Polymer concentration	based on each case study
Salt concentration	0

Vitae

Ms. AniwanPanthangkool was born on Mar 11th, 1986 in Bangkok, Thailand. She received her Bachelor degree in Civil Engineering from Faculty of Engineering, Chulalongkorn University in 2008. After graduation, she started her career in engineering industry as a structural designer for two years at Connell Wagner (Thailand). After that, she joins SCG Heim as a construction coordinator for three years up to present. She continues her study in the Master’s Degree program in Petroleum Engineering at the Department of Mining and Petroleum Engineering, Chulalongkorn University since the academic year 2010.