NTNU – Trondheim
Norwegian University of
Science and Technology

An evaluation of the combination of EOR technologies based on applied reservoir simulation

Marte Herud

Master of Science in Engineering and ICT
Submission date: June 2012
Supervisor: Jon Kleppe, IPT

Norwegian University of Science and Technology
Department of Petroleum Engineering and Applied Geophysics

Abstract

This master thesis investigates a combination of two different chemical EOR methods: 1) polymer flooding and 2) deep profile control. The combination of these EOR methods are simulated by the use of ECLIPSE100 on a simplified synthetic 3D model (500m x 500m x 36m). A 4 meter thick high permeability layer with a permeability of 2000 mD is sandwiched between two low permeability layers of 100 mD. For most of the simulations, the oil viscosity was 30 cp. After 30 years of production, polymer flooding as a mobility control yielded an additional recovery of 6.7% of STOOIP. The combination of mobility control and deep profile control almost doubled the effect and gave additional recovery of 11.3% of STOOIP. Sensitivity studies showed that the effect of deep profile control is highly dependent on the extension of the partly blocked zone. The larger the blocking zone, the higher recovery by deep profile control. Saturation plots showed that polymer flooding advances the water front in the low permeable layers while profile control recover additional oil around the blocked area inside the low permeable formation. The two methods have a dual advantage and produce additional oil that is complementary to each other. In this master thesis it has been shown that the concept of combined polymer flooding and profile control is a highly promising combined recovery method, and a method that should be considered when evaluating a development scheme.

Sammendrag

Denne masteroppgaven har undersøkt en kombinasjon av to ulike måter å anvende den kjemiske EOR-metoden polymerflømming: 1) mobilitetskontroll og 2) dyp profilkontroll. Kombinasjonen av disse to EOR metodene har blitt simulert ved hjelp av ECLIPSE100 på en syntetisk 3D modell (500m x 500m x 36m). Et 4 meter tykt høypermeabilitetslag med en permeabilitet på 2000 mD er klemt mellom to lavpermeabilitetslag på 100 mD, med en oljeviskositet på 30 cp. Etter 30 år med produksjon, oppnådde polymerflømming som mobilitetskontroll en økt utvinning på 6,7% av STOOIP. Kombinasjonen av mobilitetskontroll og dyp profilkontroll doblet nesten effekten og ga en økt utvinning på 11,3% av STOOIP. En sensitivitetsstudie viste at effekten til dyp profilkontroll er svært avhengig av utstrekningen til den blokkerte sonen. Jo større blokkert sone, jo høyere økt utvinning. Plott over oljemetningen viste at polymerflømming fremmer vannfronten i de lavpermeable lagene, mens profilkontrollen øker utvinningen rundt det blokkerte området i den lavpermeable formasjonen. De to metodene har dobbelt effekt og produserer mer olje som er komplimenterende til hverandre. I denne masteroppgaven har det blitt vist at konseptet med kombinert polymerflømming og profilkontroll er svært lovende som en kombinert utvinningsmetode, og en metode som bør bli vurdert når en vurderer en utbyggingsplan.

Preface

This Master Thesis was carried out at the Norwegian University of Science and Technology (NTNU), the spring of 2012. The Master Thesis is a cooperation between the Department of Petroleum Engineering and Applied Geophysics at NTNU and Statoil ASA, Rotvoll. It is an extension of my project proposal [1], autumn 2011. The problem has been investigated on behalf of Statoil ASA.

Supervisors have been Professor Jon Kleppe at NTNU, Erik Skjetne, Varunendra Pratap Singh, Vegard Kippe and Arild Moen at Statoil ASA.

I wish to address a great thanks to my supervisors for guidance and availability during the project period. Meetings and personal communication have been helpful for the development of this report.

Trondheim - 10th of June, 2012

Marte Herud

Nomenclature

A – Area

E_R – Recovery Efficiency

E_D – Displacement Efficiency

E_M – Mobilization Efficiency

E_A – Areal Sweep Efficiency

E_V – Vertical Sweep Efficiency

f_w – Fractional Flow

F_{kr} – Permeability Reduction Factor

g – Gravity

k – Absolute Permeability

k_{rw} – Relative Water Permeability

k_{ro} – Relative Oil Permeability

k_w – Effective Water Permeability

k_o – Effective Oil Permeability

k_p – Effective Polymer Permeability

M – Mobility Ratio

P – Pressure

P_w – Water Pressure

P_o – Oil Pressure

Q_w – Water Production Rate

Q_o – Oil Production Rate

Q_T	–	Total Production Rate
S_w	–	Water Saturation
S_o	–	Oil Saturation
t	–	Time
v	–	Velocity
V_b	–	Bulk Volume
γ	–	Shear Rate
λ	–	Mobility
μ_w	–	Water Viscosity
μ_o	–	Oil Viscosity
ρ	–	Density
θ	–	Shear Stress
ϕ	–	Porosity
ρ_w	–	Water Density

Glossary

CAPEX	–	Capital Expenditures
EOR	–	Enhanced Oil Recovery
HPAM	–	Hydrolyzed Polyacrylamides
IOR	–	Improved Oil Recovery
NPD	–	The Norwegian Petroleum Directorate
NPV	–	Net Present Value
NTNU	–	Norwegian University of Science & Technology
OPEX	–	Operational Expenditures
R&D	–	Research & Development
SPE	–	The Society of Petroleum Engineers
STOOIP	–	Stock Tank Original Oil In Place

Table of Contents

List of Figures

List of Tables

1. Introduction

The energy consumption in the world is growing at a faster rate every year due to an increased quality of life. At the same time the population grow, which means that the energy demand will increase even more. The energy consumption is expected to grow 53% from 2008 to 2035 [2], see figure 1. Today, fossil fuels provide more than 85% of the world's energy needs [2]. Even though there is an increasing interest in renewable energy, it will take time to replace all the energy that the fossil fuels provide. This gives an increasing pressure on oil and gas supplies. To meet the requirement of the much-needed energy supply, better methods and better technology will be needed to be able to create solutions.

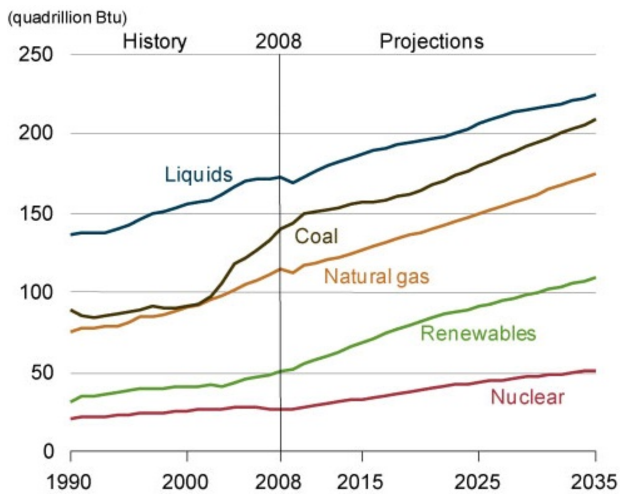

Figure 1: The World's Energy Consumption by Fuel [2]

In 2011 the SPE R&D Committee shared that one of the five Grand Challenges within R&D is increasing recovery factor [13]. Increase the recovery in the mature fields is a major concern since most of the current oil production comes from these. Normally the expenses are higher when trying to produce unconventional reservoirs, than increasing the recovery factor at existing fields by the use of Enhanced Oil Recovery (EOR) methods.

Many of the oil fields at the Norwegian continental shelf are reaching their economic limit due to a high water-cut. EOR is going to play a key role to meet the energy demand in years to come. The oil production at the Norwegian continental shelf today, is half of what it was in 2001 [5]. There is a decline in new oil discoveries, which means that the oil industry needs to seek after oil at unexplored and unconventional areas. New discoveries cannot be guaranteed. 2011 will probably be the first year since 1997 that can prove larger explored resources than produced resources [5]. Optimism in the oil industry and an increase in oil price may turn projects that have been assumed unprofitable, profitable. Historically, pilot projects have created large values in Norway.

The master thesis is an extension of a project proposal, showing that a combination of two EOR methods may increase the recovery factor.

2. Enhanced Oil Recovery

2.1. The Recovery Phases

The recovery factor expresses the amount of recovered petroleum as a percentage of the total petroleum initially in place. Enhanced Oil Recovery (EOR) may increase the recovery factor. The producing life of a reservoir has traditionally been divided into three distinct recovery phases: *primary*, *secondary* and *tertiary*, which describes them chronological.

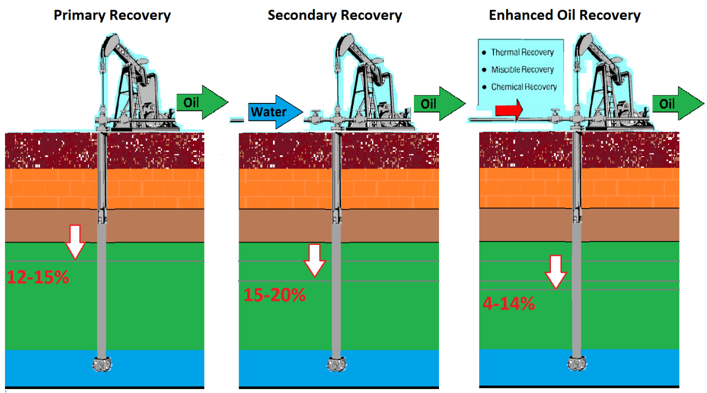

Figure 2: The Recovery Phases [3]

The *primary* phase includes all production that is driven by the displacement energy that is naturally in the reservoir, typically gasdrive, waterdrive or gravity drainage.

The *secondary* recovery phase is applied to increase the recovery factor. That is when fluids are injected, which normally includes water flooding, gas injection and pressure maintenance. It is mainly done to increase the pressure or the volumetric sweep efficiency in the reservoir.

The *tertiary* recovery is the recovery phase after secondary recovery and is often used as a synonym to EOR. However, EOR methods today may be applied at any stage in the reservoir development.

2.2. EOR

Enhanced oil recovery is when gases, chemicals or thermal energy is injected into the reservoir, and normally does not include pressure maintenance. It is applied after less risky production methods. Polymer flooding is one of the chemical EOR methods. EOR is sometimes called Improved Oil Recovery (IOR), but IOR includes both EOR and other methods like reservoir characterization, infill drilling, reservoir management etc. It is important to be aware of that EOR is not restricted to a particular phase, and is thus not equal to tertiary recovery.

2.2.1. The Objective

Most of the mature fields are having challenges with high water-cut and inefficient water flooding, generally caused by permeability variations in contiguous zones. Permeability variations can be caused by faults, fractures, compositional differences in the rock or by the recovery operations themselves. Water flooding may increase the heterogeneity in the reservoir due to fines migration, mineral dissolution etc. Since oil and water are immiscible, they will not completely displace each other in a reservoir. In China it has been estimated that about 65-77% of remaining oil is left in unswept areas and only 23-35% of remaining oil is confined to the water flooded area [14]. To compensate for this, it is often beneficial to alter the reservoir permeability to a more uniform permeability, in order to increase sweep efficiency and enhance the displacement efficiency compared to water flooding. There is a decline in new discoveries, so increasing the oil recovery in the mature fields becomes more and more important. EOR projects will only be successful in cases with a poor performing water flood and with a maximum contact between the reservoir and the fluid injected. The success of polymer flooding increases as the oil viscosity and/or the reservoir heterogeneity increases [15]. However, polymer flooding will only be profitable in reservoirs having a high residual oil saturation and an ineffective water flood.

2.2.2. The Economical Challenges

Applications of EOR methods are highly influenced by the oil price. When the oil price is low, oil companies are forced to reduce operating costs and thus less willing to take risks. A reduction of costs due to unnecessary water production will be desirable, which may turn EOR to a risk worth taking. In figure 3, a typical oil production profile with the plateau rate (A) can be seen. The time deciding whether to perform EOR or not before reaching the economic limit (B), and the two different results with EOR (D) and without EOR (C) at time X.

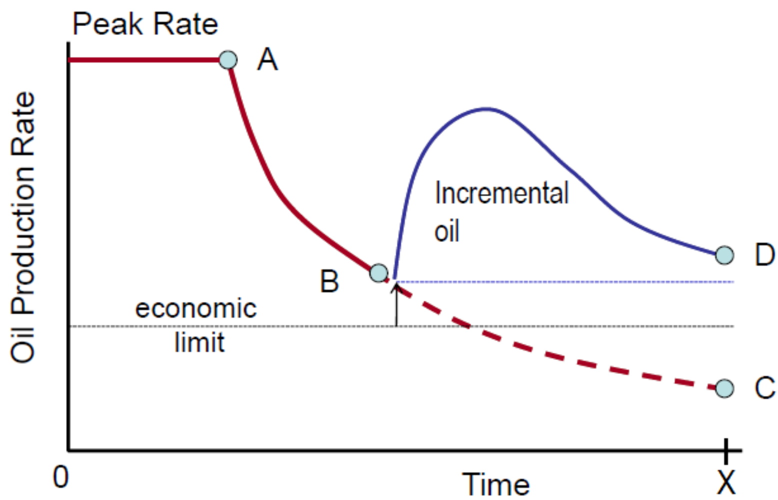

Figure 3: Incremental Oil Recovery [4]

Compared to the 1960s and 1970s, now there are polymers with a much higher quality and to a much lower price relative to crude oil. In the early 1970s the oil price was 3USD/bbl while polymer cost about USD 3/kg. Now the polymer costs about the same, while the oil price is around 100USD/bbl [15]. Due to high oil prices and major advances in the technology, the likelihood of applying chemical EOR have increased considerably the last few years.

2.3. EOR at the Norwegian Shelf

In 2002 Norway was ranked as the third largest exporter of oil in the world, while in 2010 Norway was ranked as the seventh. Since the peak in 2001, a decline can be observed in the amount of produced oil, see figure 4. The petroleum industry accounts for a quarter of the governments revenue and are having more than 200 000 people employed [5]. This gives the Norwegian oil industry a lot of responsibility.

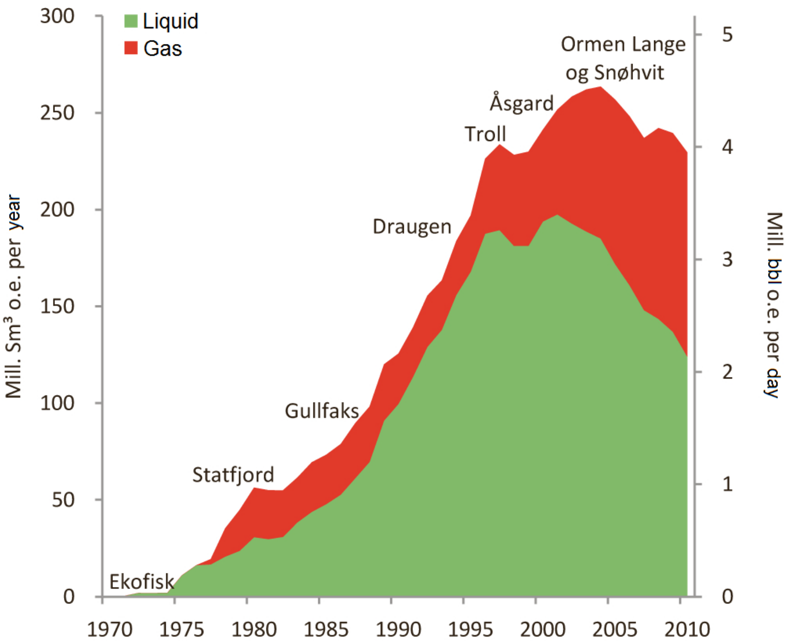

Figure 4: Historical Petroleum Production at the Norwegian Continental Shelf [5]

There is also a decline in new discoveries, except for this year. 2011 will probably be the first year since 1997 that can prove larger explored resources than produced resources [5]. New discoveries are important for the potential of producing the more challenging existing recoverable resources. They create large values which can be used in research and to increase the recovery factor in the mature fields.

The reservoir properties are good at the Norwegian shelf, which gives a higher recovery factor compared to other countries. As a result, the Norwegian industry does not necessarily need to focus on the use of EOR. However, an increase in today's recovery will contribute to large values to the Norwegian society. In 2010 less than 40% of the expected recoverable resources were recovered. [5]

Norway is known for being a pioneer, developing new technology in the oil industry. In 2005, 63% of all reported EOR field applications were at the Norwegian continental shelf [16]. Projects like SPOR, RUTH and PROFIT were started to focus on improved oil recovery and advanced technology [17]. However, advanced injection methods like polymer flooding accounts for only 3.3% of the planned increase in resources, according to the Norwegian Petroleum Directorate (NPD). About a quarter of today's reserves will not be producible using conventional methods, and there will be necessary to use EOR [5].

3. Principles of EOR methods

There are mechanisms the different EOR methods are trying to overcome. What mechanisms polymer flooding is trying to overcome are explained further.

3.1. Principles of Polymer Flooding

3.1.1. Volumetric Sweep Efficiency

$$E_R = E_D * E_M * E_A * E_V \tag{1}$$

E_R, or the overall recovery efficiency is a function of the recovery factor [3]. It is calculated by multiplying the displacement efficiency, E_D, mobilization efficiency, E_M, areal sweep efficiency, E_A, and the vertical sweep efficiency, E_V. Displacement efficiency is the fraction of the produced oil volume to the maximum oil recovered. Mobilization efficiency is the fraction of the maximum oil recovered to the stock tank original oil in place (STOOIP). Sweep efficiency covers both the vertical and areal sweep efficiency by multiplying E_A and E_V, and refers to the fraction of the volume swept by flooding fluid to the volume of STOOIP. This increases with increasing injection volume and it decreases with increasing mobility ratio. The sweep efficiency also depends on the well pattern, gravity segregation and reservoir heterogeneity. A high level of heterogeneity reduces the sweep efficiency during flooding.

3.1.2. Early Water Breakthrough

Early water breakthrough usually occurs in two cases: Due to heterogeneity in the reservoir or fractures causing high-permeability zones, or due to the mobility difference between the displacing fluid and displaced fluid where the displacing fluid tends to bypass the displaced fluid [18]. When breakthrough occurs, water will start to

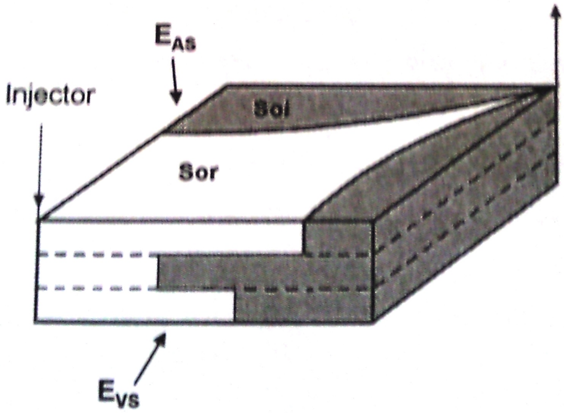

Figure 5: Areal, E_{AS}, vs Vertical Sweep Efficiency, E_{VS} [3]

be produced, and the oil production rate will immediately decrease considerably. The water production is measured by the ratio of water produced compared to the total volume of liquid produced, called *water-cut*. A polymer solution with a higher viscosity than water may result in a later breakthrough, see figure 6.

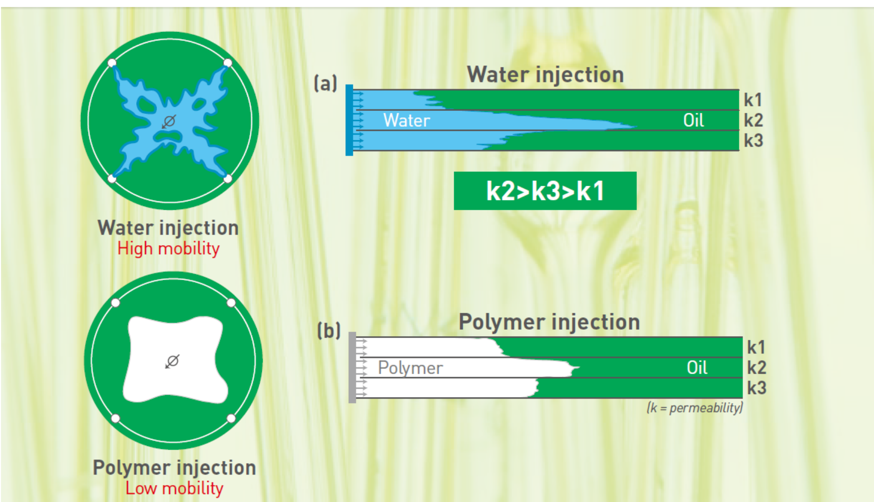

Figure 6: Early Water Breakthrough [6]

3.1.3. Mobility Ratio

Mobility ratio is defined as:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{(k_w/\mu_w)}{(k_o/\mu_o)} \quad (2)$$

where λ, μ, and k is mobility, viscosity and effective permeability respectively. Mobility ratio is mobility of displacing phase divided by mobility of displaced phase, so when producing oil by water flooding, oil will be the *displaced phase* while water will be the *displacing phase*.

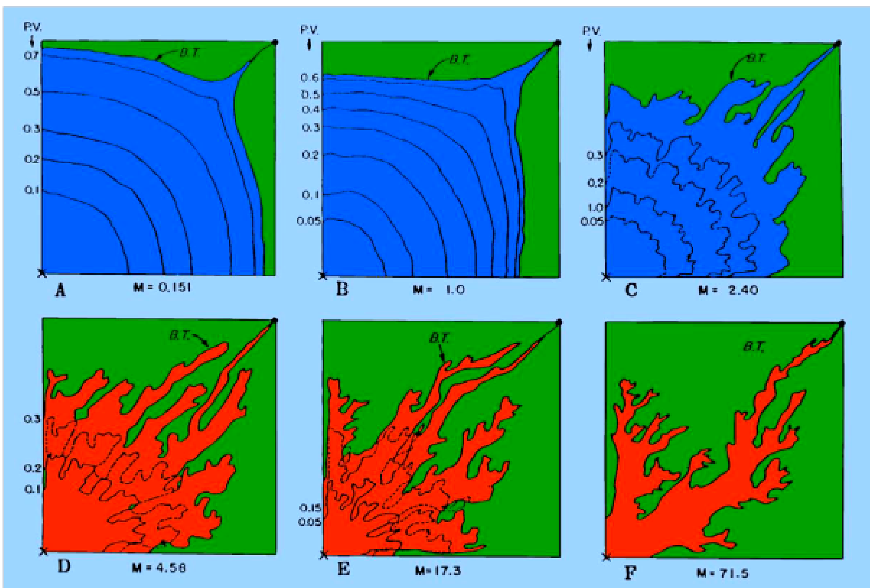

Figure 7: Effects of different mobility ratio [3]

Achieving a favorable mobility ratio, M, is one of the most important concepts in any EOR method. A favorable M can be achieved by increasing the viscosity of the displacing fluid by injecting chemicals, or reducing the viscosity of the displaced fluid by heat. Normally the mobility is controlled by injecting chemicals, like polymers. That is much more feasible than reducing the viscosity of the displaced fluid, which will not be feasible at offshore fields due to loss of heat. Reducing the relative permeability to the displacing fluid may also be achievable. Figure 7 shows different effects of different mobility ratios, where blue represents water, green represents oil and red is representing gas. Polymer flooding is only applied as a mobility control in situations with an unfavorable mobility ratio, M. That is generally when M>5 [12]. The oil recovered before breakthrough decreases as M increases. When the mobility ratio between the oil and water phase is unfavorable, an instability may develop in the fluid displacement process and lead to viscous fingering as seen in figure 7. This leads to decreased sweep efficiency.

3.1.4. Fractional Flow

Increased fractional flow of oil will improve the oil recovery factor. Fractional flow describes the ratio between the rate of produced water, q_w, and rate of total production, q_T, normally oil and water, q_o+q_w. The rate is defined by Darcy's law, see equation 3, for a two-phase flow. It is calculated by the relative mobility multiplied by the absolute permeability, kk_r/μ, multiplied by the area, A, and the change of pressure in x-direction, $\partial p/\partial x$.

Figure 8 shows the fractional flow curve for three viscosity ratios, measured in fractional flow, f_w, by water saturation, S_w. The tangent to the fractional flow curve has a start point at S_{wi}, initial water saturation, and an end point at $\bar{S_w}$, average saturation behind the shock front. The water saturation at the water front, S_{wf}, is where the fractional flow curve and tangent curve intersect. It can be seen that the displacement efficiency increases with decreasing viscosity ratio, hence mobility ratio. This will be further explained in the next section.

$$f_w = \frac{q_w}{q_T} = \frac{q_w}{q_w + q_o} \tag{3}$$

$$q_w = \frac{kk_{rw}A}{\mu_w}\frac{\partial p_w}{\partial x}\,,\ q_o = \frac{kk_{ro}A}{\mu_o}\frac{\partial p_o}{\partial x}$$

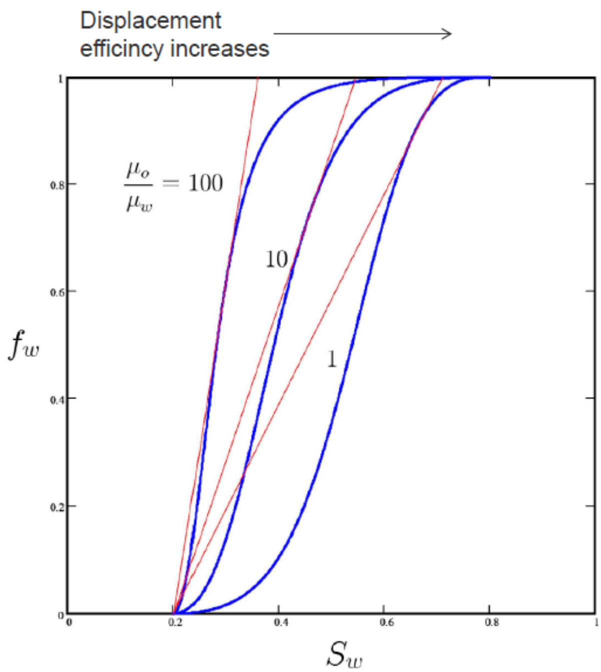

Figure 8: Fractional Flow Curves [3]

3.1.5. Buckley & Leverett

The one-dimensional Buckley & Leverett equation, equation 4, is a basic equation for describing immiscible displacement and explains how a saturation shock front develops, see figure 9. It says that the velocity of the water saturation is directly proportional to the derivative of the fractional flow equation evaluated for that water saturation [8]. After breakthrough, the Buckley & Leverett equation predicts a low water saturation shock front, see figure 9, with a considerable 'tailing' period of oil and water production [12].

$$v_{s_w} = \frac{dx}{dt}|_{S_w} = \frac{q_T}{A\phi}(\frac{df_w}{dS_w})|_{S_w} \tag{4}$$

v_{Sw} or dx/dt describes the velocity of the water front, or change of distance in water saturation by the change in time. The larger velo-

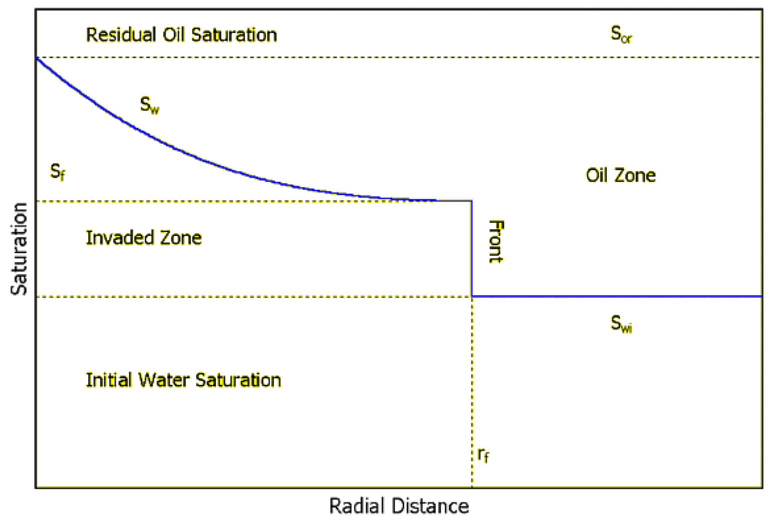

Figure 9: Schematic Saturation Profile describing Buckley-Leverett Displacement Concept [3]

city the water front has, the earlier breakthrough. This can be calculated by the total flow rate, q_T, over the cross sectional area, A, multiplied pore volume, ϕ, multiplied the change in fractional flow, f_w in water saturation, S_w.

The form of the fractional flow curve indicates what displacement efficiency that can be expected. The more to the right, the more efficient and piston like the displacement of oil is. When injecting a polymer solution, the fraction flow curve is shifted to the right and displaces more oil than water alone. The further the fractional flow curve is shifted to the right, the greater the shock front that develops during polymer displacement. This accelerates the oil displacement [19].

3.2. Polymer Flow Behavior in Porous Media

Polymers are chemicals that may be added to the water phase in order increase the viscosity of the water and create a more favorable mobility ratio. They are long chains of molecules with a repeating basic block, and have a large range of physical properties which makes them extremely useful. The polymers should be water-soluble and have the property of "uncoil" in water to be able to raise the viscosity [6]. Due to all the physical properties of polymers, some challenges may occur during application.

3.2.1. Polymer Rheology

Newtonian fluids are fluids where the flow rate varies linearly with the pressure gradient, like water. This means that the viscosity is independent of flow rate. Polymers are non-newtonian fluids and behaves like a pseudoplastic fluid, and thereby strongly sensitive to shear stress, see figure 10. The apparent viscosity, μ, decreases with an increasing rate, γ, of shear stress, τ, see equation 5. This is called a shear thinning effect. The shear thinning effect at high velocities is favorable during injection. However, when the polymer is injected the aim is that the viscosity of the injected fluid increases.

$$\mu = \frac{\tau}{\gamma} \tag{5}$$

3.2.2. Degradation

All types of degradation affects the macromolecules, which leads to a decreasing viscosity. You have three types of degradation; *chemical*, *mechanical* and *biological* degradation.

Chemical degradation is when the molecules break down or reduce the viscosity due to attacks by contaminants like oxygen and iron, or by hydrolysis. The extent of chemical degradation increases with increasing temperature and increasing oxygen content [7].

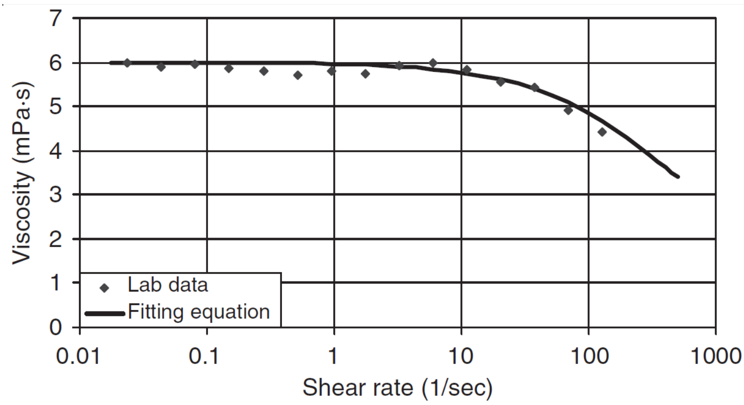

Figure 10: The Effect of different Shear Rates on Polymer Viscosity [7]

Mechanical degradation occurs when the polymer molecules are exposed to mechanical stresses due to high velocity flow. That might result in a breakdown of molecules. Higher flow rate, longer flow distance, and lower permeability makes the stress larger and results in increasing degradation. Mechanical degradation is predominantly expected to happen in the top side facility.

Biological degradation occurs when bacteria attacks the polymer molecules during storage or in the reservoir.

ECLIPSE 100 does not support degradation and will therefore not affect the simulation. However, it is important to keep in mind that it might occur in a real application.

3.2.3. Retention

Retention is of fundamental importance in EOR operations and describes the mechanisms which results in loss of polymers. In field applications this includes *adsorption* and *mechanical trapping*. Retention is considered to be irreversible, which means that it does not decrease with decreasing polymer concentration.

Mechanical trapping refers to when larger molecules becomes lodged in narrow flow channels and occurs mainly in low-permeability formations since it depends on the pore size distribution [7]. This blocking of channels leads to a buildup of materials close to the well and well plugging. A buildup is undesirable, and is the reason for why a certain permeability is required in reservoirs applying polymer flooding.

Adsorption is the interaction between the polymer molecules and the solid surface. In addition to loss of polymers, this may also result in an additional resistance to flow. Adsorption depends on the surface area, and is the only mechanism that removes the polymer from the solution [7].

3.2.4. Permeability Reduction

When a polymer solution is flowing through a reservoir, the permeability will decrease due to retention. It is considered irreversible and defined by the permeability reduction factor, F_{kr}, rock permeability when water flows, k_w, and permeability when aqueous polymer solution flows, k_p [7]. See appendix A for further information.

$$F_{kr} = \frac{k_w}{k_p} \tag{6}$$

In the polymer model, the permeability reduction to polymer is assumed to be proportional to the amount of polymer lost to the rock material due to adsorption. The injected polymer reduces the permeability of the rock to water permanently. Experimentally, it is found that only a very small change occurs to the hydrocarbon relative permeability, and the ECLIPSE 100 model assumes that the change is negligible.

3.2.5. Inacessible Pore Volume

Inaccessible pore volume is when the pores are smaller than the size of the polymer molecules which prevent them to flow through. As the inaccessible pore space to the polymer increases, the effective polymer fluid velocity also increases which leads to an earlier breakthrough of polymer.

3.2.6. Temperature

The polymers are sensitive to high temperatures, and high temperatures may lead to a chemical degradation of the polymer. The degradation due to temperature will be neglected due to moderate temperatures in the reservoir.

3.2.7. Salinity

The presence of salinity and divalent is critical when it comes to polymer flooding. Improving their behavior in the presence of salt is a major focus of research [6]. Salinity affects the viscosity of the polymer negatively, which can be quite critical. The presence of divalents may also affect the polymers viscosity, but it depends on the type of polymer used. For instance, hydrolyzed polyacrylamides (HPAM), see chapter 4.1, interact strongly with divalent metal cations such as Ca^{2+} and Mg^{2+} [7], see figure 11 and 12. All degradation mechanisms are also dependent on salinity.

In this simulation model, clear water will be injected, which means that the salinity challenge is neglected.

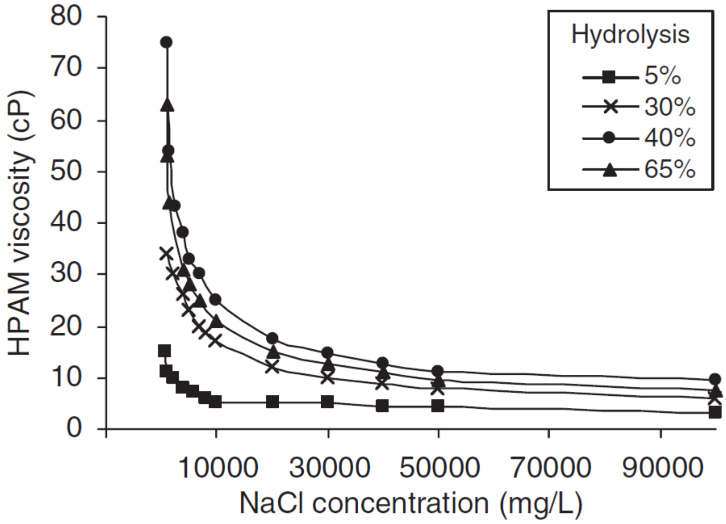

Figure 11: The Effect of Salinity on Polymer Viscosity [7]

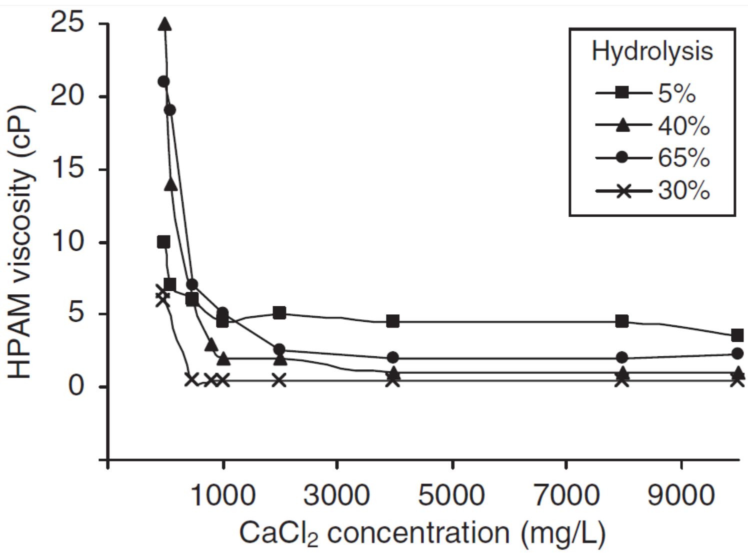

Figure 12: The Effect of Divalent on Polymer Viscosity [7]

4. Combination of EOR methods

In this thesis a combination of two EOR methods will be evaluated. A literature study was carried out in order to see the potential of the combined effect of polymer flooding and conformance control [1]. As a continuation a comparative simulation study has been carried out to evaluate the effectiveness of chemical EOR methods compared to a waterflooding in terms of incremental oil production and Net Present Value (NPV). This is an extension of the work done in the project proposal, in order to support the simulation model with theory. In order to understand the combination of the methods, each of the methods will be described in detail.

EOR activity in general has experienced an increasing interest since 2008, and polymer flooding is still the most important chemical EOR method [20]. Polymer flooding has become an important method again mainly thanks to China and its massive application where a 12% increase of recovery has been reported [21]. Since the 1980s, the focus on polymer flooding has moved from the US to China, from mainly onshore to offshore applications. Even though chemical methods have had recent advantages and a decrease in costs, they are sensitive to the change in oil price. One of the major challenges with polymer flooding is the response time and profitability, so a high OPEX and CAPEX in the first years must be taken into account.

4.1. Types of Polymer

The mostly used polymers fall into two generic classes: Polymers that are produced *synthetic* like polyacrylamides, and *biopolymers* like polysaccharides.

4.1.1. Polyacrylamides

The properties of the synthetic polymers depend on their molecular weight and their degree of hydrolysis. The higher molecular weight the polymer has, the more viscous it is. Polyacrylamide has a linear chain molecular structure which makes it flow easily through tortuous porous space in the rock. It is negatively charged, which accounts for many of its physical properties [8]. Hydrolyzed polyacrylamide (HPAM) have undergone partial hydrolysis in order to reduce the level of adsorption on rock surfaces, and is the most widely used polymer in EOR applications [7]. If the hydrolysis is too large it will be sensitive to salinity and the viscosity will be reduced, but if it is too small it will not be water soluble due to its large molecular weight. Compared to polysaccharides, it can provide a higher residual resistance and it is less expensive and thus more used. Microbial attack can be a serious problem and biocides need to be used in these situations[22]. HPAM has been used extensively with a great success in China's Daqing field [7].

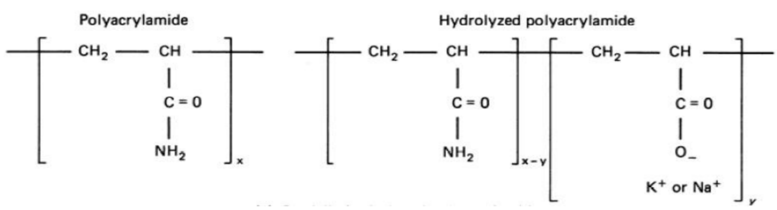

Figure 13: Molecular Structure of Hydrolyzed Polyacrylamide [8]

4.1.2. Polysaccharides

The molecular structure of the biopolymers gives the molecules a great stiffness [22]. They are less sensitive to salinity and mechanical degradation than synthetic polymers, but has a less viscosifying power than polyacrylamides in fresh water [23]. Biodegration by enzymes might occur which usually results in a viscosity decrease. They are normally used when there are no fresh water available for flooding due to their resistance to salinity [7].

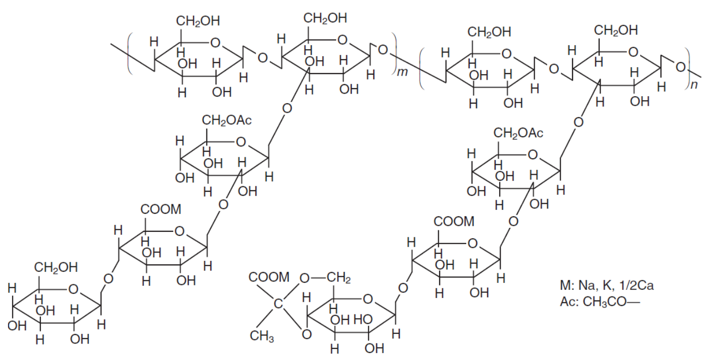

Figure 14: Molecular Structure of Xanthan Gum [7]

4.2. Mobility Control

Polymer flooding is normally used as a mobility control. When injecting water in a reservoir, oil is left behind because it is trapped by capillary forces, called residual oil, or because it has been bypassed. Early water breakthrough and high water-cut lead to decreased oil production, see figure 15. Polymer flooding is trying to reduce the amount of bypassed oil, not the residual oil, by creating a more favorable mobility ratio in typically reservoirs containing viscous oil. Polymer flooding is normally injected after a continuous water flooding, either as a slug with following water flooding, or as a continuous flooding. Polymers does not reduce the recovery factor significantly in swept zones since it does not affect the existing capillary forces and interfacial tension [22]. However, by improving the mobility ratio, it improves the oil recovery by increasing the volume of the reservoir contacted [24], see figure 16. Polymer flooding is applied by adding polymer to the waterflood to increase the viscosity, hence decrease its mobility. Thereby called a mobility control agent.

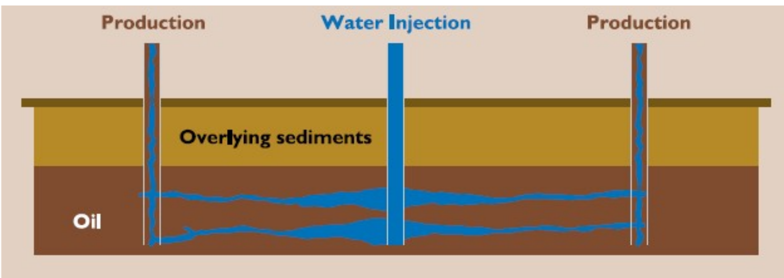

Figure 15: Waterflooding Without Polymer [9]

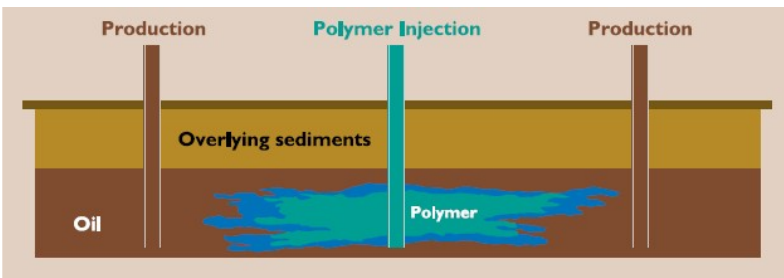

Figure 16: Waterflooding With Polymer [9]

4.3. Deep Profile Control

Another way applying polymer is conformance control. The main purpose of conformance control is to reduce the permeability of the rock to water in the water producing areas. Injected fluid preferentially enters high permeable layers with a high water saturation. This results in early breakthrough and large scale by-passing of reservoir oil. In order to create a more uniform reservoir and increase the volumetric sweep efficiency, the permeability needs to be reduced in the high permeability, watered-out zones. By injecting a gel blockage in these layers, a higher sweep efficiency can be seen. Applying blocking agents often results in a lower water injection thereby a lower water production, which reduces the operating costs. It might not increase the oil recovery, but the production time will decrease [25]. In figure 17 the differences in water flooding with (right) and without (left) conformance control can be seen.

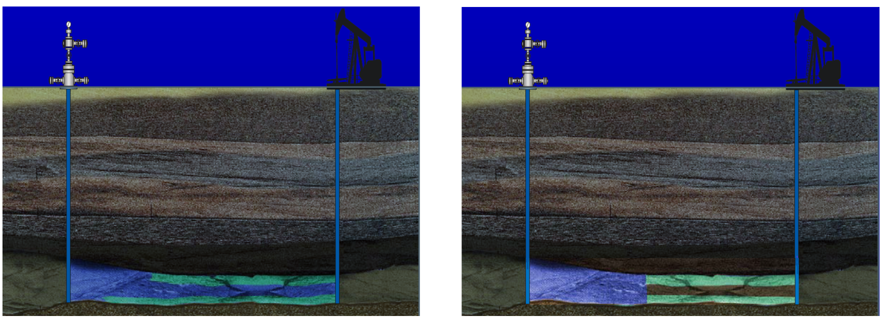

Figure 17: The Effect of Conformance Control [10]

Chemical conformance control needs to possess some preferred characteristics [26],[27]:

1: The solutions need to be low viscosity fluids prior to gelation, so they can be pumped easy

2: The chemical and physical properties must sustain at the bottom hole treating temperature

3: Must clean up rapidly and completely when the well is put back on production

4: Must not cause permanent damage to the formation

5: Must be compatible with treating fluids

Deep profile control is when the blockage is placed deep into the reservoir. It can be a challenge to perform deep profile control and hit right target deep into the reservoir. Because polymers sometimes have a tendency to turn into a gel too early, or adsorption may occur. To avoid this, polymers are usually injected at a high concentration, a so called bulk injection mode. It is shown that the blocking effectiveness is proportional to the slug size [28], however a higher concentration will increase the cost. This thesis will focus on deep profile control where conformance control is applied in selected zones deep into the reservoir.

The thesis will be optimistic when it comes to deep profile control and assume that:

1: The activation of the blockage material happened instantaneously

2: Permeability was only reduced where it was planned

3: The permeability reduction was permanent

4.4. The Combination Method

In China they have started applying a new technology where they combine chemical-based profile control with other EOR methods. It is now recognized as a potentially important EOR method [29]. After performing water flooding for a long period, problems occur due to heterogeneity. Polymer flooding cannot be applied efficiently in reservoirs having a high heterogeneity due to early breakthrough in high-permeability channels, hence a poor sweep efficiency [30]. To some extent the degree of success of a polymer flood increases with increasing heterogeneity in the reservoir. However, when the level of reservoir heterogeneity is so severe due to existing fractures and high-permeability layers, other solutions need to be put in action.

One solution is to place a gel blockage in order to reduce the permeability in fractures and high-permeability layers before applying a polymer flood, called the combination method. The idea is that the displacing fluid follows the high permeability layers (high k) with a high water saturation until it reaches the blockage. The displacing fluid will then be diverted into the layers with lower permeability (low k) and a high oil saturation, see figure 18. Oil displaced from the less-permeable layers can then crossflow into the high-permeable layers, where it flows more rapidly to the production well [11]. This will improve the water injection pressure and less polymer will be needed. Such a method will probably also result in an accelerated production rate and a higher oil recovery than polymer flooding alone. However, it is a complicated process due to complex mechanisms and numerous influence factors [31] which makes it a challenge to simulate.

4.4.1. Field experiences

The combination method has not been tested extensively yet. However, a pilot test in the Beixi block of Lamadian area in Daqing Oil Field in China can report successful results. Daqing Oil Field is the largest oil field in China and the field that accounts for most of the world's polymer driven oil production [30]. In 2004 there were 31 commercial-scale polymer flooding projects in Daqing Oil Field, with

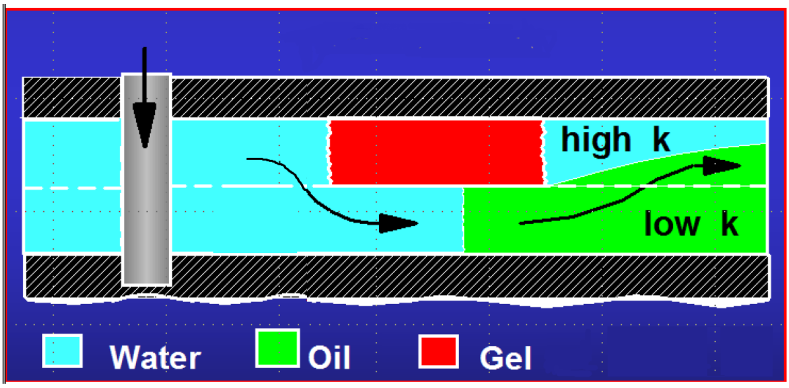

Figure 18: The Concept of the Combination Method [11]

2,427 injection wells and 2,916 production wells implemented in a total area of 274 km^2 [32]. After many years of production and water flooding, channels had formed due to a severe heterogeneity in the vertical direction. In some areas the polymer broke-through along high permeable layers and was produced too early, and could not perform efficient. The high permeable layers adsorbed as much as 46.7% of the total water injected. In order to improve the production efficiency, profile control was applied before the polymer flooding. After injecting a gel, an increase in adsorbed water in medium-low permability layers could be seen, and an increase in oil recovery. A thickness of 57.4 meters which had not been water injected before profile control, showed water injection after the profile control. A large decrease in injected water, and also a decrease in the amount of injected polymer was reported. The experimental results showed that the water-cut in polymer flooding may decrease as much as 16.2% after profile control [30].

5. Reservoir Simulation

5.1. Background Information

Reservoir simulation softwares are very powerful tools used to perform basic reservoir analysis. Models can be created and represent fluid flow through a reservoir [33]. The performance and pressure of the reservoir can be studied and the ultimate recovery methods of hydrocarbons can be determined. A simulation model is typically created before developing a new field.

In a reservoir simulation model, the model is subdivided into gridblocks. The total volume, porosity and saturation in the model is computed by the information from each gridblocks bulk volume (see equation 7), porosity and saturation at each time step [34].

$$V_B = x\Delta y\Delta z\Delta \tag{7}$$

The different reservoir simulators can be subdivided into four different main groups [33]:

- Black oil: Fluid flow
- Compositional: Fluid flow and phase compositional flow
- Thermal: Fluid flow, heat flow
- Chemical: Fluid flow, mass transport due to dispersion, adsorption and partitioning

The black oil simulator is the mostly used one, and more than 90% of all simulation studies can be performed with the black oil simulator [33]. In this thesis ECLIPSE 100 is used as a reservoir simulation software. ECLIPSE 100 is a general purpose black oil simulator with gas condensate options, written in FORTRAN [35]. It is a fully-implicit, three phase, three dimensional reservoir model made in the Cartesian coordinate system. Each cell have six neighboring cells which allows flow between all the gridblocks.

Models can be made very complicated and almost describe the reservoir precisely. An accurately presented model seems more trustworthy than a simpler model to many. Although, many claim that the time and effort used on creating the model as the geologist and geophysics would like to see it, hardly add any end effect [33]. The goal should be to make it as simple as possible, and at the same time be able to calculate the well history and pressure data with small errors. Complicated models are only more time consuming. But of course, gathering correct data is the most important factor in reservoir simulation. To base the simulation on incorrect data will make an incorrect model. However, even early reservoir models based on weak reservoir data and hardly any historical data, can create information that describe optimal well and field development strategy.

This list shows the minimal data required for a typical study [33] :

- Geological maps
- Net and gross sand thicknesses
- Oil and gas gravities
- Initial gas/oil ratio or condensate yield
- Reservoir temperature and pressure
- Initial water saturation
- Gas/oil and oil/water contacts
- Separator conditions
- Production and pressure information
- Flowing wellhead or bottomhole pressures at economic limit

Reservoir simulation is the most useful tool available for reservoir engineers. It is the only one that integrates physics, mathematics, reservoir engineering and computer programming and bring them togheter.

5.2. The Reservoir Model

In order to obtain a better understanding of the EOR mechanisms, a numerical simulation method will be a powerful tool. A synthetic reservoir model has been created to perform a reservoir simulation. The reservoir model is not a copy of any real field, but all the data that have been used are representative for oil fields at the Norwegian continental shelf. A simple reservoir model will give simpler and clearer solutions which are easier to evaluate. It will also give results and conclusions with a much lower uncertainty than a real field would have. ECLIPSE 100 is not applicable for simulating the combination method in practical large-scale oilfield cases because of its intrinsic limitations [29], and is therefore simulated on a synthetic model. Some main limitations on simulation softwares due to the combination method are as follows [29]:

- Most of them are two-phase models, not considering the influence of the vapor phase; thus have a big problem in conjunction with previous water flooding.

- Excessive simplicities exist in the description of combination method, especially in the description of in-situ gelation process and its property.

- Few simulators can effectively and practically simulate primary production, water flooding, polymer flooding, profile control and any combination of above processes by one simulator without conjunction problems.

A conceptual heterogeneous 2D model, see figure 20, has been created in order to better understand the processes. Two vertical wells, one injector and one producer, were placed in each end of the model. A more comprehensive conceptual 3D model, see figure 21, with a vertical well placed in each corner were also created. Different scenarios were created for each of the models, and evaluated. Both the wells are perforated in all layers.

5.2.1. Properties

The reservoir model is a one-quarter of a five spot pattern. It is a 25x25x36 grid model (500x500x36meter), with an injection well and a production well located at opposite corners. It is a very fine model, in order to see all the effects that occurs in the model during production. Each of the 36 layers are 1 meter thick, and the reservoir depth is set to 1700 meters. The porosity is set to 33 % and is uniform throughout the whole model. Horizontal permeabilities (k_H) were set to 2000mD in the mid-layers, layer 17-20, and 100 mD in the others, see figure 19. The vertical permeability were set to 0.1*k_H.

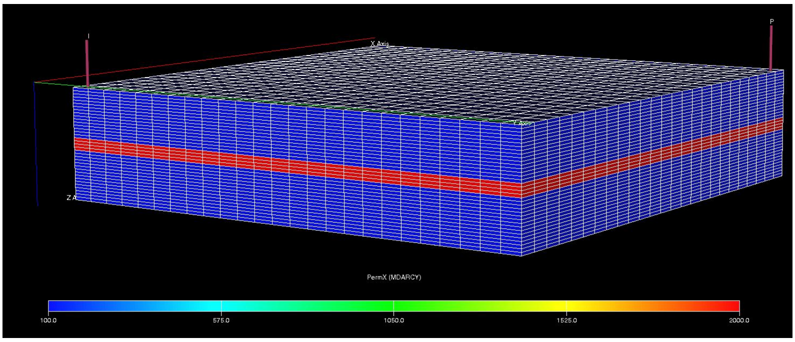

Figure 19: The Permeability Distribution

The model contains only two fluids for the simplicity; water and oil. Gas in reservoir models often makes it harder to understand the development of the production of the field. The water-oil contact is 300 meters below the reservoir, so the aquifer will not have any influence on the production. The oil in the model has a moderate viscosity. Table 1 summarizes the properties of the model.

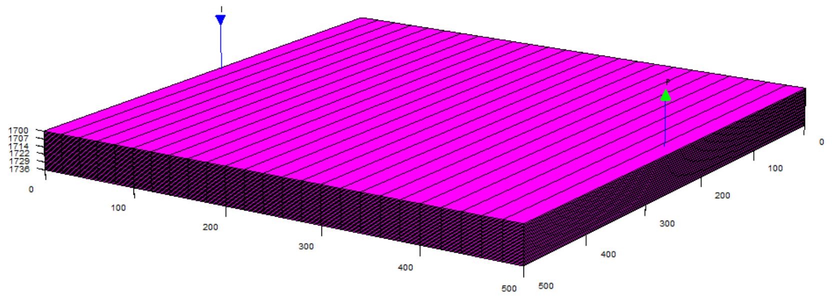

Figure 20: The 2D Model

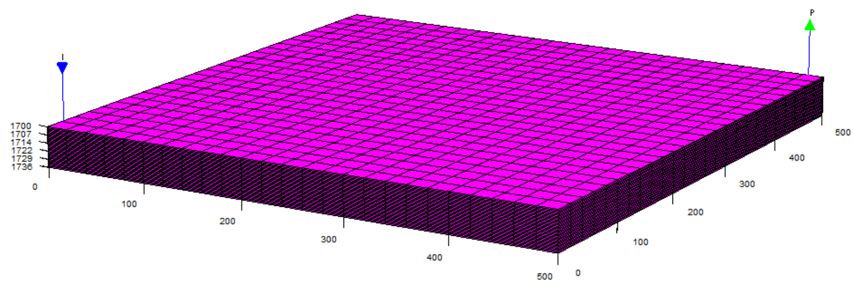

Figure 21: The 3D Model

5.3. The Polymer Model

The polymer model in ECLIPSE 100 uses a fully implicit five-component model (oil, water, gas, brine, polymer). Only three phases will be used in this thesis (oil, water, polymer). The polymer model in ECLIPSE 100 is very simplified when it comes to chemistry. The polymer flow in the model is assumed to have no influence on the flow of the oil, for instance. However, in a screening phase the polymer model can give a good idea on what results that can be expected when applying a polymer flood.

The polymer model properties have been given by Vegard Kippe and Varunendra Pratap Singh, Statoil ASA. A full description can be found in Appendix D.

5.3.1. Fluid Properties

The relative permeability curves are given as straight lines for water and oil. The irreducible water saturation and oil saturation are both set to 0.15. The oil viscosity is set to 10 and 30 cp.

The viscosity terms in the fluid flow equations in ECLIPSE100 contain the effects of a change in the viscosity of the aqueous phase due to the presence of polymer and salt in the solution. For the equation, see Appendix A.

Property	Value	Unit
Size	500x500x36	meter
STOOIP	14.749	M bbl
Reservoir Depth	1700	meter
Reservoir Thickness	36	meter
Initial Pressure	170	bar
Porosity	0.33	fraction
Permeability	100 and 2000	mD
Initial Oil Saturation	0.85	fraction
Oil Viscosity	10 and 30	cp

Table 1: Reservoir Model Properties

6. Screening

Screening is a process carried out after a reservoir is discovered, and the screening criteria are important in order to make a development scheme. The screening phase includes a set of rules which makes it easier deciding whether the reservoir is suitable for polymer flooding or not. It is important to be aware of that the screening criteria only should be used as a guidance, and not be fully trusted. When it comes to screening criteria for polymer flooding, it is important to identify if the reservoir has a poor sweep efficiency due to high oil viscosity or too large scale of heterogeneity.

Before choosing a polymer there are different parameters that should be evaluated:

1: Industrial availability

2: Performance as viscosifier

3: Polymer stability

4: Polymer price

5: Timing

6: Risk [36]

Some of the screening criteria are not up to date anymore. Successful field results have shown that the permeability can be all the way down to 5mD [15], and the oil viscosity may be as high as 500 cp and even higher. The water injectivity may also be as high as before polymer flooding was started. Near well fracturing can also be applied which will lead to higher pressure gradients within the reservoir, hence displace more oil.

Table 2 is a summary of reservoir screening criteria that have been listed in the book 'Polymer - Improved Oil Recovery' [12].

Screening criterion	**Viscosity control polymer flood**	**Heterogeneity control polymer flood**	**Comment**
Oil Viscosity	Usually 5<cp<30cp Max 70cp	Usually 0.4<cp<10cp Max 20cp	Symptom in both cases is early water breakthrough and low sweep efficiency.
Level of large-scale heterogeneity–layering or channels	Low - formation should be as homogeneous as possible	Some heterogeneity $4<k_{hi}/k_{av}<30$	For heterogeneity control, less severe contrast does not require polymer and more severe is too high for normal polymer.
Absolute permeability	Min. approximate 20 mD No max.		To avoid excessive polymer retention.
Temperature	Lower temperatures best Best<80°C Max. about 95°C		Polymers degrade at higher temperatures.
Water injectivity	Should be good preferably with some spare injection capacity Fracing may help		If there are problems with water, they will be worse for polymer.
Aquifer/oil/ water contact	Injection not deep in aquifer or far below oil/water contact		Additional retention losses in transport to oil leg.
Clays	Should generally be low		Tend to give high polymer retention.
Injection brine salinity/ hardness	Not critical but may determine which polymers can be used		High salinity/hardness -> biopolymer Lower salinity/hardness -> HPAM
Operating conditions (i) Chemical + fluid (ii) Logistics	No major problems with: e.g. O_2, Fe, biodegradation, H_2S, additive incompatibility e.g. polymer storage, mixing and injection equipment		Such problems may be technically soluble but they may rule out the polymer flood on economic grounds.

Table 2: Screening Criteria [12]

7. The Simulation Scenarios

The objective of the simulation is to find the optimized scenario for the combination method. Water flooding is an obvious comparative scenario in order to see the success factor. The chemical EOR methods, deep profile control and polymer flooding, are also compared separately. The universal technical success of an EOR method is the recovery factor. When it comes to polymer flooding it is the incremental oil recovered over water flooding. A Net Present Value (NPV) calculation has been carried out in order to determine the best approach for the synthetic model.

Different cases have been investigated. All the cases have been run for two different oil viscosities, 10 cp and 30 cp, in order to see the effect of that. At the Norwegian shelf, the oil viscosity is quite low in general. However, 30 cp will hopefully give some interesting results when it comes to the combination method. All cases have been run with restrictions on rate and a combination of rate and bottom hole pressure. The results that will be presented will only have a constraint on rate, due to the simplicity. The bottom hole pressure is therefore assumed not to cause any problems.

All cases starts at the 1st of January 2012 and ends 1st of January 2042.

7.1. Water Flooding

This is the base case. Water is injected from the start date throughout the whole production. Due to heterogeneity and moderate viscous oil in the model, viscous fingering probably will occur. Oil saturation will decrease rapidly in the high permeability layers compared to the less permeable layers.

7.2. Deep Profile Control

Due to the level of heterogeneity in the model, deep profile control is applied. The effect of this EOR method separately will be compared to the performance in combination with a following continuous polymer flood. The profile control is simulated by reducing the absolute permeability in certain blocks across the model. The relative permeability will not change by doing it this way. Water-chanelling in the reservoir model will be detected by injecting a tracer. The concentration of tracer describes the pattern of the water flood, and where the permeability should be reduced. This is where the blocking will be placed. Different cases have been simulated in order to find the best location for blocking, the extension of blocking needed, and the degree of permeability reduction. The displacing fluid will follow the easiest way which are the high permeability layers. When the permeability is reduced in these layers the displacing fluid will hopefully be diverted into the oil bearing layers and displace it, hence increase the sweep efficiency and oil recovery in these layers.

A profile control is difficult to simulate in ECLIPSE 100. In this thesis the process will be simplified. Water flooding is started at day 1 and tracer is injected when the water cut has reached 80% which is the 1st of January, 2019. After 10 days injecting a batch of tracer, water is injected the following 90 days. The concentration of tracer will indicate the location of the highest water saturation, hence the lowest oil saturation. These are the layers where the permeability will be reduced.

In order to simulate deep profile control, the permeability is reduced with 50%, 70% and 90% in certain blocks across the model. Both the location and the extent of the permeability reduction has been varied. At figure 22 the different cases can be seen. 1) 50% permeability reduction (green=1000mD), 3) 90% permeability reduction (blue=200mD), 2) 90% permeability reduction closer to the injection well, 4) permeability reduction over an extended area. Model 3) and 4) differs with 20 meters of blocking and 80 meters of blocking. Some of these cases have only been run in combination with polymer flooding as mobility control.

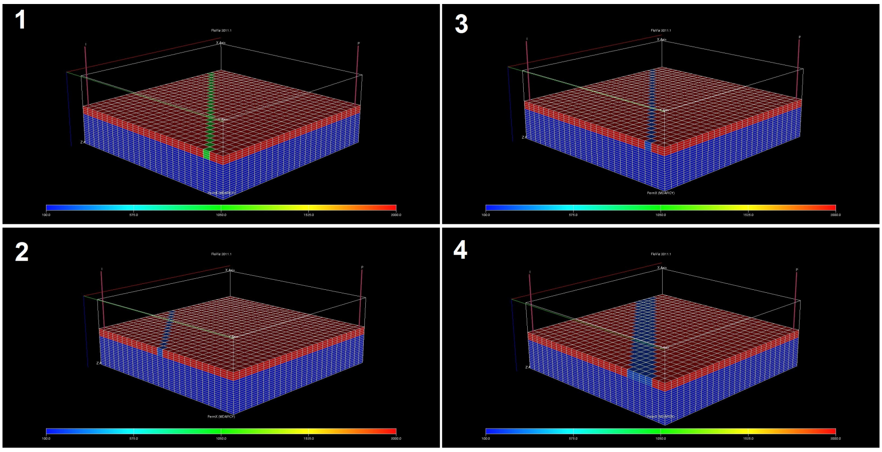

Figure 22: The Different Permeability Reductions

7.3. Polymer Flooding

Polymer flooding will be compared to the profile control and the combination method. Different cases have been chosen in order to see the effect of time of injection, and polymer concentration injected with respect to oil recovery. The polymer injection will be simulated as a continuously flood, and not as a slug injection with following water injection. Slug injection is not supposed to be as effective as a continuously injection due to viscous fingering and water breakthrough in the polymer phase. Injecting polymers for a long period has been underestimated due to limitations in reservoir simulation. Large grid blocks are needed when reservoirs are simulated. The fingering that occurs in the viscous polymer as water tries to displace it, will be underestimated if not small grid blocks are used [15].

In one of the cases, polymer is injected after 100 days of water injection. Polymer in the water face will create a more favorable oil-water mobility ratio and hopefully reduce the water-cut. The oil saturation will probably decrease more in the low permeability layers compared with water flooding. However, the oil saturation will probably still be quite high in some of the layers due to the degree of heterogeneity.

For the other case, the time of injection is chosen to be when the water-cut has reached 80%, and hence more representative for how a real case would have been. Normally water flooding is applied as long as it is economical, before other more risky and expensive methods are implemented. However, polymer flooding is often more effective when applied as a secondary recovery than a tertiary [23]. All these cases have been run, using a polymer concentration of 0.7 kg/m^3. Cases have also been run where the concentration is set to 0.5 kg/m^3.

7.4. Combination Method

The combination method is applied by first performing a deep profile control. When the permeability reduction is applied, polymer is injected continuously throughout the whole production. The combination method has the dual advantage of both improve the mobility ratio and creating a more uniform reservoir. Not only will deep profile control increase the sweep efficiency, hence the oil recovery, it will probably also reduce the amount of injected displacing fluid and produced displacing fluid. The combination method will not be possible to simulate correctly by using ECLIPSE 100, see chapter 5.2, and will therefore be simplified.

The combination method has been simulated with three different permeability reductions; 50%, 70% and 90%. Also a reduction on the permeability concentration from 0.7 kg/m^3 to 0.5 kg/m^3, an extended area of permeability reduction, a decrease in the distance between the injection well and location of the permeability reduction has been simulated.

Net present value will decide which case that turn out as the best one.

A summary of all the scenarios are listed in table 3.

No.	Scenario	Short Version
1	Water Flooding	WF
2	Polymer Flooding after 100 days of WF	PF
3	Profile Control, 50% reduction	Div50
4	Profile Control, 70% reduction	Div70
5	Profile Control, 90% reduction	Div90
6	Polymer Flooding at time of water-cut=80%	PF-Late
7	PF with reduced polymer concentration	PF-05
8	PF-Late with reduced polymer concentration	PF-Late05
9	Combination Method, 50% reduction	Comb50
10	Combination Method, 70% reduction	Comb70
11	Combination Method, 90% reduction	Comb90
12	Comb90 with reduced polymer concentration	Comb90-05
13	Comb90 with blocking over an extended area	Comb90Larger
14	Comb90 closer to the injection well	Comb90Closer

Table 3: The Different Scenarios

8. Simulation Results

All the simulation scenarios were carried out using ECLIPSE 100. The 2D model and the 3D model were evaluated for all cases, both for an oil viscosity of 10 cp and 30 cp. As expected, the highest potential for the combination method occurs when the oil viscosity is high. Due to the similarity in the results obtained at different viscosities, the results achieved by 30 cp viscosity only will be evaluated. In order to compare the different scenarios, the increase in oil recovery over water flooding will be compared, see figure 23. The comparison of the profile control cases and the combination cases can be found in Appendix B. The oil recovery achieved by water flooding is 22.98%.

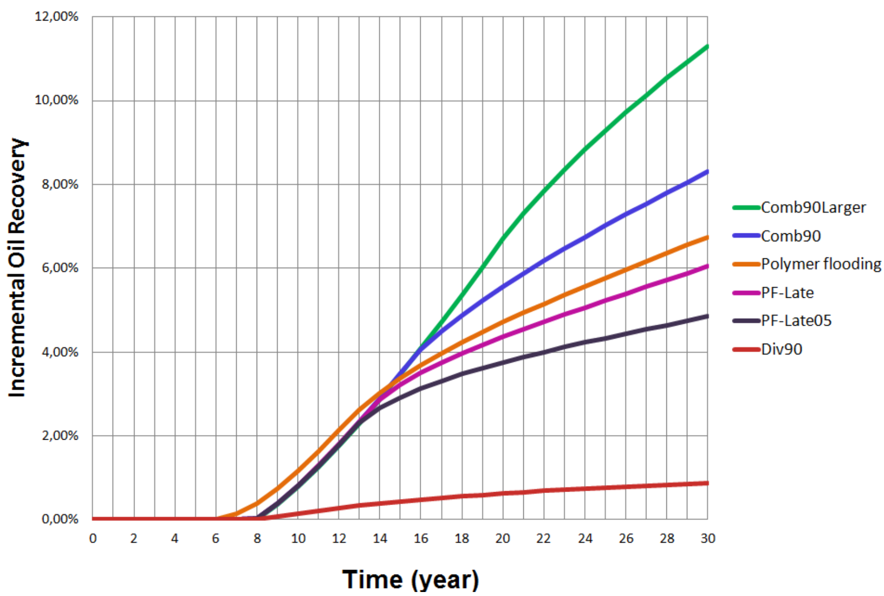

Figure 23: The Increase in Oil Recovery over Water Flooding

Figure 27 shows how the distribution of oil saturation differs in the different scenarios at a certain date in one of the high permeable layers. The combination case and profile control case shows how the water divergence affects the displacement and sweep efficiency. Behind the water front or the polymer front, the oil saturation has almost reached its residual oil saturation across the whole model. But the oil saturation on the other side of the blocking is at least 5% higher, even though it is just about 20 meters away. This implies that the displacing fluid displaces the oil from the lower permeable layers with a higher oil saturation. Figure 24 shows how the profile control affects the distribution of oil saturation. The oil saturation will be quite low in front of the blocking due to an increase in pressure due to the permeability reduction. Behind the blocking the oil saturation will be higher due to all the oil that is diverted from the low permeability layers into the mid-layers.

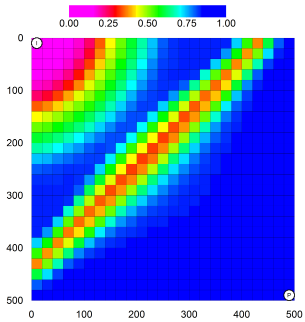

Figure 24: The Effect of Profile Control in Oil Saturation

A large difference between the water flooding case and the polymer flooding case can also be observed. The polymer flooding case displaces the oil with a much higher sweep efficiency. In figure 25 it can be seen that the water flooding case is much more affected by gravity forces, which results in a higher water saturation in the bottom layers. As seen in the Buckley-Leverett equation, equation 4, the larger velocity the front has, the earlier breakthrough. Due to the viscosity polymer possess, polymer will flow much slower than water and break through at a later time.

8.1. Deep Profile Control

The deep profile control cases are identical to base case until watercut reaches 80%, 11th of April, 2019. The tracer concentration was injected at the 1st of January 2019 and continous water flooding for 90 days was started the 11th of January. The tracer concentration was mainly detected in the high permeability layers, as expected. Hence the permeability was reduced in certain blocks across the model in layer 17-20, see figure 25. From 11th of April 2019 where the deep profile control is applied, a small increase in rate and oil production can be seen, see figure 28 and 23. 50% decrease in permeability hardly increased the recovery factor at all. Until the end of production, the 1st of January 2042, a permeability reduction of 50% resulted in an increase in oil recovery by 0.085%. A permeability reduction of 70% neither increased the recovery significantly. However, a permeability reduction of 90% had a potential of increased oil recovery. The permeability was reduced from 2000mD to 200mD, hence it will enhance a more uniform reservoir due to the permeability of 100mD in the lower permeable layers. A permeability reduction of 90% increased the oil recovery by 0.863%. Neither of the cases reduced the water-cut or increased the bottom hole pressure in the injection well noticeably, which explains the low increase in oil recovery.

8.2. Polymer Flooding

Fast improvements were achieved in cumulative oil production when applying polymer flooding as a mobility control compared to water flooding, see figure 28 and 23. A large increase in bottom hole pressure can be observed in both wells immediately after the start of injection, hence a large increase in oil rate, see figure 28. The water-cut decreased when applying polymer flooding, see figure 29. The case where polymer is injected after 100 days, PF-Late, shows a higher oil recovery than the case where polymer is injected at the 11th of April 2019, PF. However, a longer time of injection will require larger amounts of expensive polymers. Reducing the concentration of polymer resulted in a decrease in oil recovery and an increase in water production compared to PF and PF-Late. PF-05 and PF-Late05 resulted in an increase of 5.199% and 4.848% in oil recovery respectively, compared to WF. The NPV values will show which method that gives the best result. Case PF resulted in an increase in oil recovery of 6,745%, while PF-Late resulted in an increase of 6.050% in oil recovery.

8.3. Combination Method

The highest potential in cumulative oil production was observed when applying the combination method, see figure 28 and 23. Different locations of the permeability reduction was tried in order to observe how it affected the results. The blocks chosen are about 325 meters to 460 meters away from the injector. A decrease in distance between the injector and the blocking did not affect the production at all. However, an increased area of blocking increased the oil recovery significantly. As could be observed when applying profile control, the highest increase in recovery factor was achieved by the combination method with a permeability reduction of 90%. The combination method with a permeability reduction of 70% gives a lower oil recovery than the continous polymer flooding case. However, the permeability reduction and delayed time of injection requires less amounts of polymer and reduces the water-cut. It might result in a higher NPV and hence be a better solution.

The combination method with a permeability reduction of 50% resulted in an increase of 6.223% in oil recovery, and a reduction of 70% resulted in an increase of 6.649%. Comb90 had an increase of 8.301% compared to water flooding. The highest increase in oil recovery was achieved by the case Comb90Larger with an extended area of reduced permeability. Comb90Larger resulted in an increase of 11.304% compared to water flooding. This is an increase of 4.559% compared to PF, 5.254% compared PF-Late, and an increase of 3.003% compared to combination method without an increase in area, Comb90. The bottom hole pressure increased significantly in both wells at the time of application. The pressure in the injection well stays at 130 bar throughout the whole production. A significant decrease in water-cut could also be observed in the combination cases compared to water flooding, see figure 29. A decrease in water-cut of almost 20% can be seen at the 1st of January 2021, comparing Comb90 and WF. The increase in bottom hole pressure and decrease in water-cut explains the high increase in oil recovery. A decrease in water-cut also affects the economy positively.

A summary of the increased oil recovery over water flooding at the end of production can be seen in table 4.

As can be seen in figure 25, the gravity force has a large impact on the water flooding case, and a high water saturation can bee seen in the bottom layers. A large effect of the water divergence can be seen in the combination method, and oil is displaced from the lower permeable layers by the polymer flood due to the blocking in the mid-layers. The effect of extended blocking explains the increase in oil recovery over the Comb90 case, see figure 26.

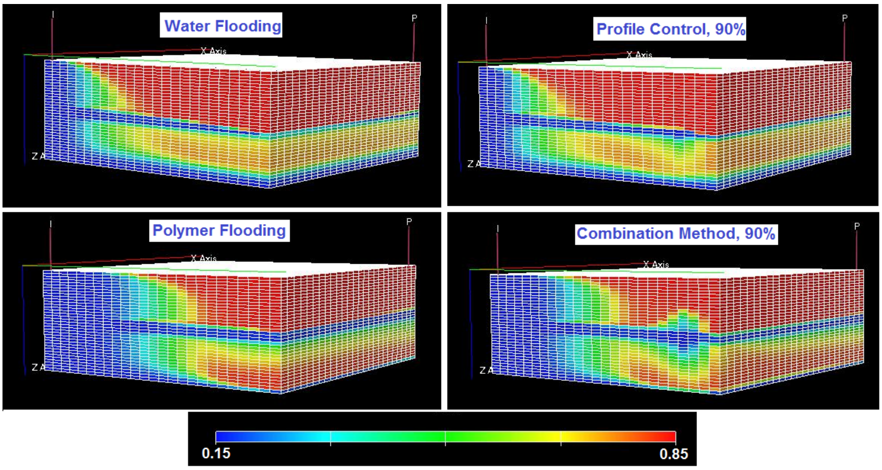

Figure 25: A Comparison of Oil Saturation at the 1st of January, 2043

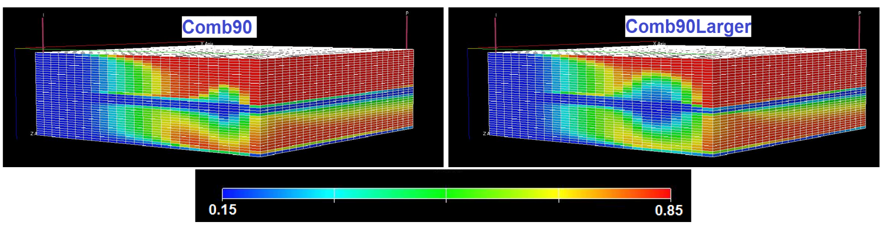

Figure 26: A Comparison of Oil Saturation at the 1st of January, 2043

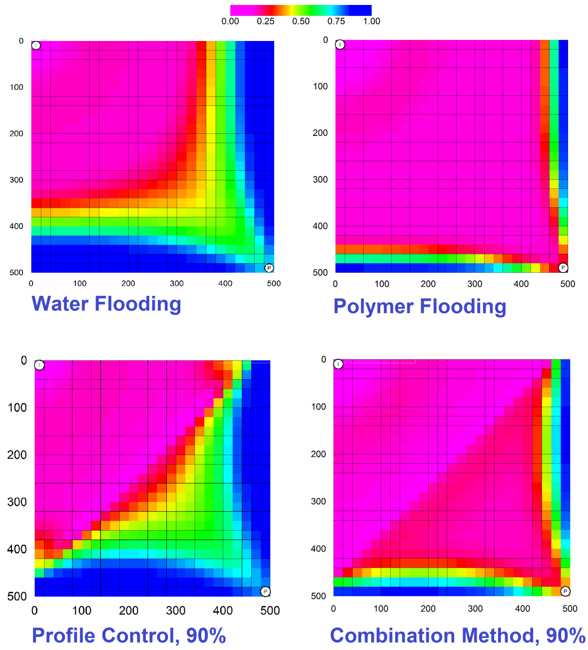

Figure 27: Comparison of Distribution of Oil Saturation in Layer 19, the 1st of January, 2025

Scenario	Results
Div50	0.085%
Div70	0.228%
Div90	0.863%
PF-Late05	4.848%
PF-Late	6.050%
Comb50	6.223%
Comb70	6.649%
Comb90-05	6.723%
PF	6.745%
Comb90	8.301%
Comb90-Larger	11.304%

Table 4: Increase in Oil Recovery at the 1st of January, 2042

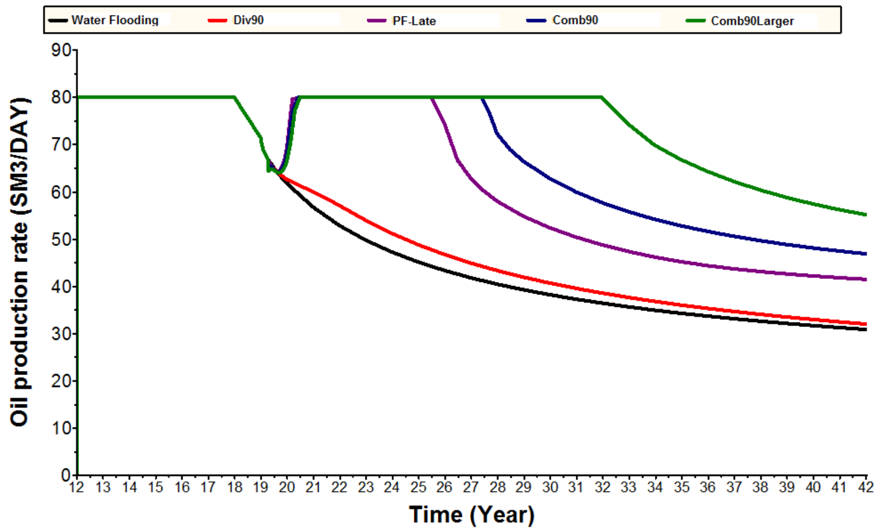

Figure 28: Comparison of Oil Production Rate

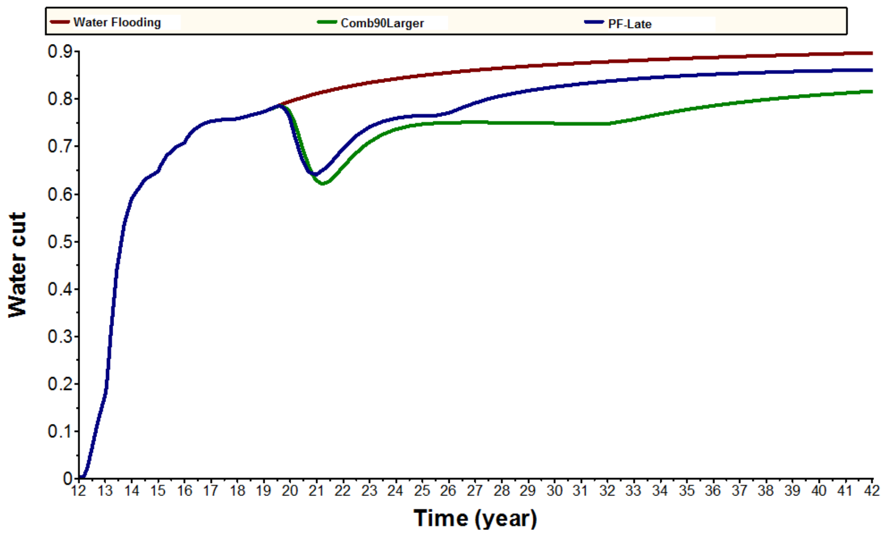

Figure 29: Comparison of Water-Cut

8.4. Economy

Even if a method gives a high increase in oil recovery, it is always the economy that decides which approach to choose. A simple Net Present Value (NPV) calculation was performed in order to evaluate the results for the different cases. A NPV evaluation can be used as a guideline in order to decide which projects to accept or reject.

$$NPV = \sum_{t=0}^{t-n} \frac{C_t}{(1+i)^t} \tag{8}$$

Capital Expenditures (CAPEX) and Operational Expenditures (OPEX) due to deep profile application, CAPEX and OPEX due to polymer flooding, oil price, and discount rate are taken into account. It is assumed to be a continuation on an ongoing field project, so the CAPEX and OPEX are covering the changes on the facilites needed for chemical operations. The polymer price of 10 USD/kg is covering all OPEX for polymer flooding and will therefore be higher than the polymer price as a raw material. The NPV has not been calculated for the scenarios with a permeability reduction of 50% and 70% due to the small increase in oil recovery. The NPV calculations are not the increase over water flooding, but the absolute numbers. The cost due to production of water and polymer will not be taken into account. For the Comb90Larger case, the expenses due to profile control has been added by 1/3 to the Comb90 case due to larger amounts of chemicals needed for the blocking. All the rates used are given by Varunendra Pratap Singh and Erik Skjetne, Statoil ASA, and summarized in table 5. The uncertainties due to rates are high, and any changes will affect the results to quite a great extent. A sensitivity analysis due to changes in rates will not be carried out.

The OPEX and CAPEX values for polymer flooding are assuming a full field size that may have more than hundred wells. All the cases have been run with only two wells, one injection and one production well, which will affect the NPV. Chemical methods will not be economical to carry out on a small field due to high CAPEX and OPEX. Naturally, the waterflooding case will be the most economic case when evaluating the different scenarios on such a small field. In order to do a more realistic evaluation, there has been performed an upscaling of the model to a total of 60 wells instead of 2. An upscaling will not change the OPEX and CAPEX for polymer flooding, however the expenses due to profile control will increase due to larger amounts of chemicals needed. It has been assumed that the oil production and polymer injection will increase by 30 times.

The NPV results can be found in table 6. A more detailed NPV calculation can be found in appendix C.

Cost	Unit	Value
Discount Rate		0.08
Oil Price	USD/bbl	100
OPEX, Polymer Flooding	USD/kg	10
CAPEX, Polymer Flooding	USD	200 000 000
CAPEX+OPEX, Profile Control	USD	60 000 000
OPEX, PF, Upscaled Model	USD/kg	10
CAPEX, PF, Upscaled Model	USD	200 000 000
CAPEX+OPEX, Prof. Control, Upscaled Mod.	USD	700 000 000

Table 5: The Rates

Scenario	NPV, $1M
Water Flooding (WF)	156.3
Div90	104.6
PF-Late	62.1
PF-Late05	59.4
Polymer Flooding (PF)	-6.1
Comb90	34.1
Comb90-Larger	31.8
Water Flooding, Upscaled Model	4690.0
Div90, Upscaled Model	4342.3
Comb90-Larger, Upscaled Model	5156.3

Table 6: NPV Values for the Different Cases

9. Discussion

"The world is changing. Some look back and some look forward. Some look at the challenges of ramping up enhanced oil recovery (EOR) in the past and some look at the opportunities for doing so now", Gary A. Pope, JPT, July 2011. This is an advice that should be taken seriously. Especially after showing an increase in oil recovery of more than 11% by the use of an enhanced oil recovery method, the combination method.

9.1. The Results

The fact that all the results are based on the use of a synthetic model needs to be considered. Due to the complexity of the combination method, a lot of simplifications have been made. The challenges due to shear effects, degradation, retention, salinity and temperature are simplified in this thesis due to the limitations in the simulation software. Naturally this will affect the results of the simulation, and probably be different to a real case. As mentioned in chapter 5.2, new simulators have been created in order to simulate this method as correct as possible. However, the results achieved show the same tendency as many other papers have reported [29], [32], [11] and seems therefore quite trustworthy. The synthetic model is much smaller than a real reservoir, having a much higher stock tank original oil in place (STOOIP). Hence a smaller increase in oil recovery would still have contributed to large values.

Deep profile control alone did not increase the oil recovery considerably. However, an even greater level of heterogeneity in the reservoir probably will increase the production. By reducing the permeability with 50%, the permeability still will be as high as 1000mD which is considerably higher than the 100mD in the low permeability layers. Hardly any of the displacing fluid was diverted into the layers with lower permability which explains the low increase in oil recovery. The bottom hole pressure for the injection well neither increased noticeable. By reducing the permeability with 90%, an increase of almost 1% in oil recovery was observed. In a real case it will be more costly the higher degree of permeability reduction, due to larger amounts of chemicals needed. This thesis is assuming the same cost for all of the profile control cases, except the extended one, since they will not differ that much in cost. The profile control will probably not last as long as expected in this thesis, and a decrease in production may occur after some years.

Applying polymer flooding will create a more favorable mobility ratio which increases the sweep efficiency, lower the viscous fingering and contribute to an increased oil recovery. A large increase in sweep efficiency can be seen in figure 27 and 25. The large decrease in water-cut favors polymer flooding due to restrictions and rules on water production, which increases the production costs. A smaller decrease in water-cut can be seen by decreasing the concentration of polymer. The adsorption of polymer is almost absent in all cases. When it comes to production of polymer, that is negative. However, polymer can be recycled which lower the costs, and the relative permeability will not change. Applying polymer flooding resulted in a large increase in bottom hole pressure in both wells immediately after the start of injection, compared to water flooding. This is because there are no constraints on bottom hole pressure and only a constraint on rate. The bottom hole pressure in the injection well stays quite high, about 130 bar, throughout the whole production, and maintain a favorable pressure difference between the wells. The bottom hole pressure increased to about 600 bar in the injection well for a short time, in order to maintain the given rate. This will be a challenge to achieve, and will require pumps. Wells that can bear such pressures are also more expensive to design, and will be unfavorable. A decrease in injection rate will be necessary in a real case.

Combining deep profile control and polymer flooding resulted in the highest increase in oil recovery. As seen in the cases with profile control and polymer flooding without combining them, less permeability reduction (Comb50, Comb70) and a decrease in polymer concentration resulted in a decrease in oil recovery. Neither did it increase the NPV. When decreasing the distance between the blocking and the injection well, no change in results could be observed. The blocking had the same effect when applying it closer to the injection well, hence displaced the same amount of oil from the low permeable oil bearing layers. Due to the high permeability in the mid layers, the effect in time will not differ and thereby give the same result. Sensitivity studies showed that the effect of deep profile control is highly dependent on the extension of the partly blocked zone. The larger blocking zone, the higher recovery by deep profile control. A 90% decrease in permeability and an extended area of blocking, Comb90Larger, resulted in the highest increase of all of the methods. The combination method performed surprisingly good compared to polymer flooding alone. Due to the low increase in production when applying deep profile control, such an increase in recovery was not expected. Saturation plots, see figure 25, 26 and 27, showed that polymer flooding advances the water front in the low permeable layers while profile control recover additional oil around the blocked area inside the low permeable formation. The two methods have a dual advantage and produce additional oil that is complementary to each other. However, the application of profile control is very simplified. Neglecting all the challenges that might occur will favor the combination method. A profile control will probably never last as long as it has been pretended in this case, and a decrease in production after time will probably be seen.

None of the scenarios resulted in an increased NPV over water flooding when calculating it for the synthetic model, having two wells only. Due to high Capital Expenditures (CAPEX) and Operational Expenditures (OPEX) when applying chemical methods, a certain STOOIP will be needed. The upscaling of the model created a more realistic situation, and more realistic numbers. When increasing the number of wells, the combination of polymer flooding and profile control turned out as the best solution, giving the highest NPV number. Almost an increase of $500 million over water flooding. Larger fields with higher STOOIP and more wells will easier withstand the high CAPEX and OPEX due to chemical methods, and will not be as sensitive to a high increase in oil recovery as smaller fields. These positive NPV numbers in addition to an increase of more than 11% in oil recovery were even more optimistic than expected. It has been shown that the concept of combined polymer flooding and profile control is a highly promising combined recovery method, and a method that should be considered when evaluating a development scheme.

9.2. The Potential and Opportunities for EOR in Norway

In 2011 large oil fields were discovered at the Norwegian continental shelf. A significant increase in oil price has also been seen the last years. This gives an optimism in the Norwegian oil industry and more resources can be used in research and pilot testing. The current status is that in many cases it is cheaper to start up new fields abroad than trying to increase the recovery factor in Norwegian fields. However, many cases is also showing that it is more economic to increase the oil recovery at mature fields than starting up unconventional fields. The Minister of Petroleum and Energy in Norway, Ola Borten Moe, said during a meeting at Petoro[1] : "In a time where we focus on new discoveries, it is even more important to focus on increased recovery at existing fields".

Implementing chemical EOR methods at the Norwegian continental shelf has been downgraded due to the complexity offshore. The use of polymers onshore may be qualified as a mature EOR technique, but only a few projects have been implemented offshore. Compared to onshore activities they are much more dependent on surface facilities and environmental regulations, and not only by the lithology. A larger well spacing at offshore fields than onshore has also been evaluated as a challenge. The reason for this concern is that it may be harder to inject the polymers deep into the reservoir. In the Daqing Oil Field they experienced that they actually had an improved oil recovery at larger well spacing, within a limit of course. That had to do with the heterogeneity in the reservoir, and the polymer's ability to create a more uniform reservoir. Due to the heterogeneity that is normally present in the reservoirs at the Norwegian shelf, well spacing might probably not be a challenge [32]. Norway is also world leading when it comes to knowledge on well technology. The Dalia Field in Angola is an offshore field showing that the challenge due to salinity can be solved by using the right polymer [36]. Another issue is the treatment of the produced fluid that are containing polymer. In the beginning of the injection the polymer concentration will

[1] A Norwegian state-owned company which manages Norway's portfolio of licenses for petroleum on the Norwegian continental shelf.

be maintained very low. The concentration will increase with time, and it is therefore important to try to reduce the amount of produced water using profile control for instance. Transporting and storage of polymer is another issue. The space is limited on offshore installations, but polymer flooding does not require complex and additional surface facilities and thus a suitable method for offshore operations. Polymers can be delivered in a liquid emulsion, water solution or as a solid powder. Powder polymer supply is achievable for offshore fields either with a bulk carrier or using containers.

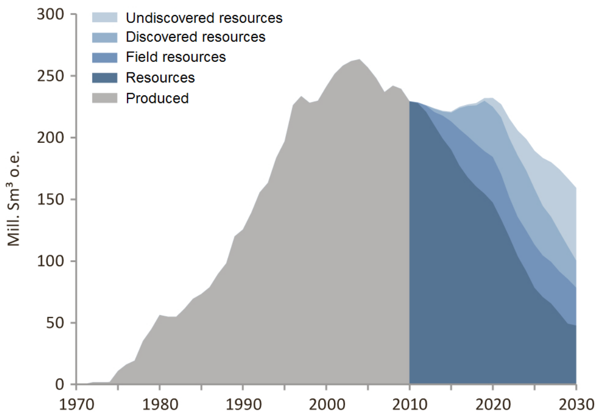

Figure 30: The Oil Reserves at the Norwegian Continental Shelf[5]

The undiscovered resources are decreasing, see figure 30. There will come a time where there are no more new fields to put into production, using the conventional methods. Increasing the recovery factor in mature fields will be essential, and EOR methods will be necessary. When this time comes, Norway may be in a leading position if a lot of new experiments, research and pilot projects are started already now. What we know is that EOR works. However, many of the existing enhanced oil recovery methods will not be economical at the Norwegian shelf the way they perform today. The challenge is to make them more stable, effective and profitable. The high oil price is a good opportunity doing so. If Norway can come up with solutions that are more effective than the ones already existing, this will make a major change. China is an ideal example showing that investing in research may contribute large values.

10. Conclusion

- The combination of polymer flooding and deep profile control is a highly promising combined recovery method.
- The combination of polymer flooding and deep profile control increased the oil recovery of STOIIP with 11.3% over water flooding.
- The combination of polymer flooding and deep profile control increased the oil recovery of STOIIP with more than 4% over traditional polymer flooding.
- When applying the combination method, the effect of the deep profile control is highly dependent on the extension of the blocking zone. The oil recovery of STOIIP increased by 3%, just by extending the blocking zone.
- The combination method showed an increase of almost $500 million in NPV compared to water flooding, giving a NPV of $5156 million for the combination method.

References

[1] Marte Herud. A Literature Review on Polymer Flooding. Technical report, NTNU, 2011.

[2] United States Energy Information Administration. International Energy Outlook 2011, September 2011. http://205.254.135.24/forecasts/ieo/.

[3] Professor Val Pinczewski at UNSW. Notes from "Reservoir Engineering" class at UNSW, June 2011.

[4] Professor Yildray Cinar at UNSW. Notes from "EOR and EGR" class at UNSW, June 2011.

[5] The Norwegian Petroleum Directorate. Status og utfordringer paa norsk sokkel, October 2011. http://www.npd.no/Publikasjoner/Ressursrapporter/2011.

[6] Total E&P. EOR Maximizing Recovery Factors, December 2011. http://www.total.com/MEDIAS/MEDIAS_INFOS/3404/EN /TOTAL-EORbis-GB2.pdf.

[7] James Sheng. *Modern Chemical Enhanced Oil Recovery*. Gulf Professional Publishing, 2011.

[8] Larry W. Lake. *Enhanced Oil Recovery*. Prentice Hall, 1989.

[9] Petroleum Development Oman. Polymer Flooding, 2011. http://www.pdo.co.om/pdoweb/tabid/278/Default.aspx.

[10] TIORCO. Improved Oil Recovery Technologies for the Illinois Basin, September 2010. http://www.inoga.org/archive/2010/OilRecovery -MikeLantz.pdf.

[11] Olatokunbo O. Akanni R. S. Seright, Guoyin Zhang and Dongmei Wang. A Comparison of Polymer Flooding With In-Depth Profile Modification, Paper SPE146087. Technical report, SPE, New Mexico Tech, University of Dakota, 2011.

[12] D. Phil K. S. Sorbie. *Polymer - Improved Oil Recovery*. CRC Press, 1991.

[13] SPE. The Five R&D Grand Challenges Plus One, May 2011. `http://www.spe.org/jpt/print/archives/2011/05/12RDChallenges.pdf`.

[14] Y. Liu et al. Application and Development of Chemical-Based Conformance Control Treatments in China Oil Fields, Paper SPE 99641. Technical report, SPE, PetroChine, California Inst. of Technology, 2006.

[15] The Society of Petroleum Engineers. Journal of Petroleum Technology, July 2011. `http://editiondigital.net/publication/?i=72970&p=67`.

[16] A.R. Awan et al. A Survey of North Sea Enhanced-Oil-Recovery Projects Initiated During the Years 1975-2005,Paper SPE99546. Technical report, SPE, NTNU, 2008.

[17] S.Njaa. Improved Oil Recovery - The Norwegian Case, SPE Paper 26173. Technical report, Norwegian Petroleum Directorate, 1994.

[18] Wei Wang et al. Application of a Novel Polymer System in Chemical Enhanced Oil Recovery, July 2002. `http://www.springerlink.com/content/kvfx1prn3klr06dh/`.

[19] Alain-Yves Huc. *Heavy Crude Oils - From Geology to Upgrading An Overview*. Energies nouvelles Publications, 2011.

[20] E. Manrique et al. EOR: Current Status and Opportunities, Paper SPE 130113. Technical report, SPE, University of Wyoming, 2010.

[21] P. Zitha et al SPE. Increasing Hydrocarbon Recovery Factors, November 2011. `http://www.spe.org/industry/docs/recoveryfactors.pdf`.

[22] Aurel Carcoana. *Applied Enhanced Oil Recovery*. Prentice-Hall, 1992.

[23] Peter H. Doe Riley B. Needham. Polymer Flooding Review Paper SPE 17140. Technical report, SPE,Phillips Petroleum Co, 1987.

[24] R.T. Johansen. *Improved Oil Recovery*. Interstate Oil Compact Commission, 1983.

[25] S.M. Smith S. R. Clark, M.J. Pirrs. Design and Application of an Alkaline-Surfactant-Polymer Recovery System for the West Kiehl Field, Paper SPE 17538. Technical report, Teton Oil and Gas Corporation, Surtek, Inc, Pacific Hunt Oil, -.

[26] Martin Navratil et al. Diverting Agents for Sweep Improvements in Flooding Operations - Laboratory Studies, Paper SPE 10621. Technical report, SPE, The Borden Company, 1982.

[27] Abdulaziz Al-Harbi et al. Associative Polymer Usage as Stimulation Diversion System for Multilayered Reservoirs, Paper SPE 136914. Technical report, SPE, Bandar Al-Malki, Saudi Aramco, Halliburton, 2010.

[28] M.S Mitchell Martin Navratil, Mojmir Sovak. Formation Blocking Agents: Applicability in Water- and Steamflooding, Paper SPE 12006. Technical report, SPE, Borden Chemical Div., 1983.

[29] Yuan Shiyi et al. Numerical imulator for the Combination Process of Profile Control and Polymer, Paper SPE 64792. Technical report, SPE, CNOOC, 2011.

[30] Y.Yang H. Liu, J.Wang and F.Wang. A New Method for Profile Control With Compund Ion Gel Before Polymer Flooding, Paper SPE 93359. Technical report, Daqing Oilfield Co. Ltd., 2005.

[31] Baojun Bai Yuzhang Liu and Yefei Wang. Applied Technologies and Prospects of Conformance Control Treatments in China. Technical report, Research Institute of Petroleum Exploration and Development, Missouri University of Science and Technology, Petroleum University of China, 2010.

[32] Wang Demin et all. Experiences Learned after Production more than 300 million Barrels of Oil by Polymer Flooding in Daqing

Oil Field, Paper SPE 77693. Technical report, SPE, Daqing Oil Company Limited, 2002.

[33] James L. Buchwalter Abdus Satter, Ghulam M. Iqbal. *Practical Enhanced Reservoir Engineering*. PennWell, 2008.

[34] John R. Fanchi. *Principles of Applied Reservoir Simulation*. Elsevier, 2006.

[35] Schlumberger. Eclipse technical description manual, 2011.1, 2011.

[36] D. Morel et al. Polymer Injection in Deep Offshore Field: The Daila Angola Case, Paper SPE 116672. Technical report, SPE, Total E&P, Total Petrochemicals France, 2008.

A. The Polymer Model

A.1. Polymer Model in Eclipse

To activate the polymer flood model in Eclipse 100, the keyword POLYMER is needed in the RUNSPEC section. In the PROPS section PLYVISC, PLYROCK, PLYADS, TLMIXPAR, PLYMAX need to be specified. Since the standard brine is used, the concentration of polymer and salt injected is specified in the SCHEDULE section by the keyword WPOLYMER.

Different keywords needs to be added in the PROPS section.

A.1.1. PLYVISC

Describes the increased viscosity of water due to the added concentration of polymer in the injected water.

A.1.2. PLYROCK

Specifies the rock properties. The adsorption index is set to 2, and no polymer desorption may occur.

A.1.3. PLYADS

Describes the adsorption of polymer by the rock formation.

A.1.4. TLMIXPAR

Can only be used in runs where either MISCIBLE, SOLVENT or POLYMER are activated. Specifies the mixing parameter for viscosity calculation (1- fully mixed).

A.1.5. PLYMAX

The maximum polymer and salt concentrations that are to be used in the mixing parameter calculation of the fluid component viscosities.

Shear thinning: neglected. No PLYSHEAR. Viscosity reduction due to local velocity.

A.2. The Black Oil Equations

Since the polymer solution is assumed to have no influence on the flow of the hydrocarbons, the black oil equations used in the model are as follows:

$$\frac{d}{dt}\left(\frac{VS_w}{B_rB_w}\right) = \sum\left[\frac{Tk_{rw}}{B_w\mu_{w\,eff}R_k}\left(\delta P_w - \rho_w g D_z\right)\right] + Q_w \qquad (9)$$

$$\frac{d}{dt}\left(\frac{V^*S_wC_p}{B_rB_w}\right)+\frac{d}{dt}\left(V\rho_rC_p^a\frac{1-\phi}{\phi}\right) = \sum\left[\frac{Tk_{rw}}{B_w\mu_{p\,eff}R_k}(\delta P_w - \rho_w g D_z)\right]C_p+Q_wC_p \qquad (10)$$

$$V^* = V(1-S_{dpv}) \qquad (11)$$

S_{dpv}	–	dead pore space within each grid cell
C_p^a	–	polymer adsorption concentration
ρ_r	–	mass density of the rock formation
R_k	–	relative permeability reduction factor for the aqueous phase due to polymer retention
C_p, C_n	–	polymer and salt concentration
μ_{aeff}	–	effective viscosity of the water (a=w), polymer (a=p) and salt (a=s)
D_z	–	cell center depth
B_r, B_w	–	rock and water formation volumes
T	–	transmissibility
V	–	pore block volume

The model assumes that the density and formation volume factor of the aqueous phase are independent of the polymer and salt concentrations. The polymer solution, reservoir brine and the injected water are represented in the model as miscible components in the aqueous phase, where the degree of mixing is specified through the viscosity terms in the conservation equations [35]

A.3. Fluid Viscosities

Effective viscosity values in the model are calculated using Todd-Longstaff technique as follows[35].

$$\mu_{p,eff} = \mu_m(C_p)^{\omega}\mu_p^{1-\omega} \tag{12}$$

ω is the Todd-Longstaff mixing parameter. It can be set to 0 or 1. It is set to 1 in this model which means that the polymer solution and water are fully mixed.

A.4. Pemeability Reduction

In order to compute the reduction in rock permeability the residual resistance factor (RRF) has to be specified. The actual resistance factor can then be calculated [35]:

$$R_k = 1.0 + (RRF - 1.0)\frac{C_p^a}{C_p^a max} \tag{13}$$

C$_p^a$ is the concentration of adsorbed polymer, and C$_p^a max$ is the maximum adsorbed concentration. The RRF is the 2nd argument in PLYROCK. C$_p^a max$ is the 5th argument, see PLYROCK in appendix D.

A.5. Shear Thinning

ECLIPSE 100 assumes that the shear thinning rate is proportional to the flow viscosity, see chapter 3.2.1. In a synthetic simple model as have been used in this thesis, that assumption will cover the effects. However, this is a simplification and some shear thinning effects will be neglected in large field models.

The reduction in the polymer viscosity is assumed to be reversible as a function of the water velocity and is calculated as [35]: The reduction in viscosity of the polymer solution is assumed to be reversible as a function of the water velocity. The resulting shear viscosity of the polymer solution is calculated as:

$$\mu_{sh} = \mu_{w,eff}\left[\frac{1 + (P - 1)M}{P}\right] \tag{14}$$

μ_{sh} – the shear viscosity of the polymer solution (water+polymer)

$\mu_{w,eff}$ – the effective water viscosity

P – the viscosity multiplier assuming no shear effect, see PLYVSIC in appendix D

M – the shear thinning multiplier, see PLYSHEAR in appendix D

B. Comparison of Increased Oil Recovery

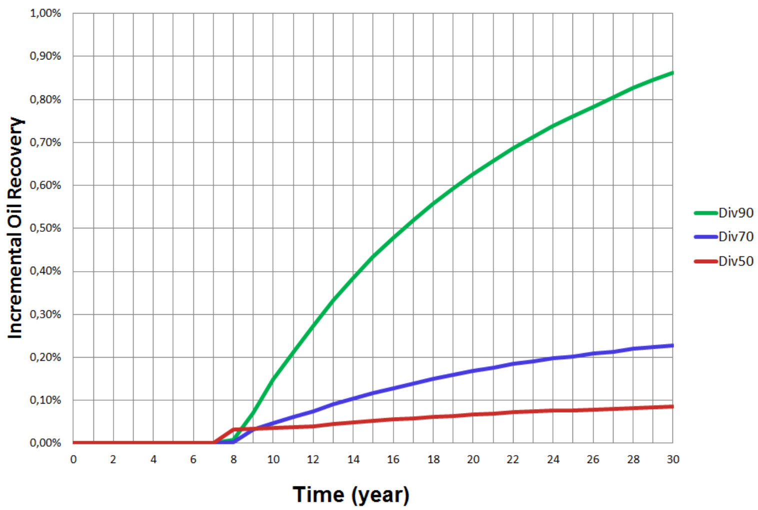

Figure 31: A Comparison of the Profile Control Cases

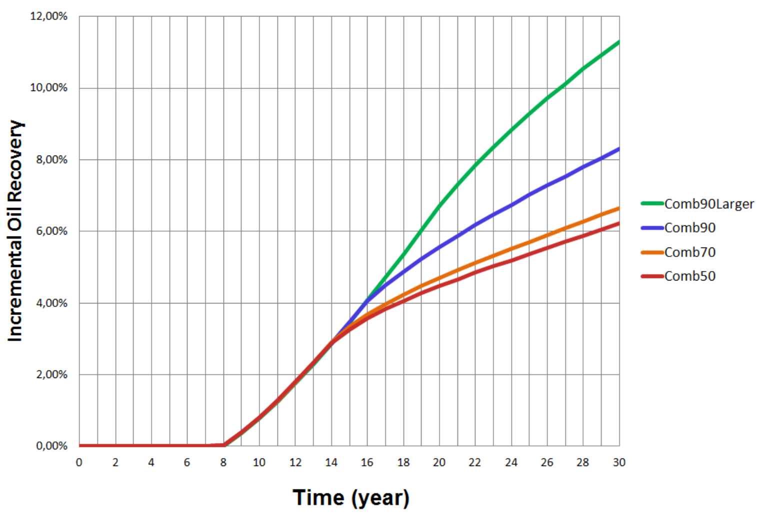

Figure 32: A Comparison of the Combination Cases

C. Economy Calculations

The detailed NPV calculations are attached.

These are the values used in the calculations.

Cost	Unit	Value
Discount Rate		0.08
Oil Price	USD/bbl	100
OPEX, Polymer Flooding	USD/kg	10
CAPEX, Polymer Flooding	USD	200 000 000
CAPEX+OPEX, Profile Control	USD	60 000 000
OPEX, PF, Upscaled Model	USD/kg	10
CAPEX, PF, Upscaled Model	USD	200 000 000
CAPEX+OPEX, Prof. Control, Upscaled Mod.	USD	700 000 000

Table 7: The Rates

	WF			Div90		
	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative
	m3	m3	USD	m3	m3	USD
2013	29280	-	$17 052 376	29280	-	$ -38 503 180
2014	29200		$32 798 473	29200		$ -22 757 083
2015	29200		$47 378 192	29200		$ -8 177 363
2016	29200		$60 877 932	29200		$ 5 322 377
2017	29280		$73 411 938	29280		$ 17 856 382
2018	29200		$84 985 789	29200		$ 29 430 233
2019	26085		$94 559 209	26085,3		$ 39 003 654
2020	23525		$102 553 449	23701,1		$ 47 057 736
2021	20719		$109 072 560	22197,7		$ 54 042 178
2022	19301		$114 695 800	21121,9		$ 60 195 831
2023	18173		$119 598 242	19709,4		$ 65 512 623
2024	17298		$123 918 760	18696,5		$ 70 182 580
2025	16482		$127 730 704	17866,7		$ 74 314 701
2026	15831		$131 120 725	17062,1		$ 77 968 440
2027	15269		$134 148 279	16405,3		$ 81 221 301
2028	14779		$136 861 682	15829,6		$ 84 127 513
2029	14386		$139 307 250	15360,5		$ 86 738 707
2030	13963		$141 505 069	14863,8		$ 89 078 298
2031	13619		$143 489 951	14455,2		$ 91 185 035
2032	13309		$145 285 890	14085		$ 93 085 760
2033	13061		$146 917 908	13785,8		$ 94 808 305
2034	12768		$148 395 092	13442,3		$ 96 363 513
2035	12530		$149 737 380	13162,4		$ 97 773 537
2036	12313		$150 958 685	12905,5		$ 99 053 632
2037	12143		$152 073 965	12668,5		$ 100 217 139
2038	11922		$153 087 813	12448,7		$ 101 275 768
2039	11747		$154 012 742	12243,6		$ 102 239 831
2040	11582		$154 857 142	12084,2		$ 103 120 860
2041	11427		$155 628 551	11870,9		$ 103 922 229
2042	11281		**$156 333 687**	11700,8		**$ 104 653 604**

Figure 33: NPV, Div 90

	WF			Polymer Flooding			Polymer Flooding 05		
	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative
	m3	m3	USD	m3	m3	USD	m3	m3	USD
2013	29280	-	$17 052 376	29280	14896	$ -168 270 735	29280	10640	$ -168 231 328
2014	29200		$32 798 473	29200	51100	$ -152 962 739	29200	36500	$ -152 798 160
2015	29200		$47 378 192	29200	51100	$ -138 788 667	29200	36500	$ -138 508 189
2016	29200		$60 877 932	29200	63875	$ -125 758 428	29200	45625	$ -125 343 806
2017	29280		$73 411 938	29280	76860	$ -113 747 518	29280	54900	$ -113 183 441
2018	29200		$84 985 789	29200	76650	$ -102 656 692	29200	54750	$ -101 954 608
2019	26085		$94 559 209	29200	76650	$ -92 387 409	29200	54750	$ -91 557 540
2020	23525		$102 553 449	29280	76860	$ -82 852 762	29280	54900	$ -81 904 250
2021	20719		$109 072 560	29200	76650	$ -74 048 506	29200	54750	$ -72 990 440
2022	19301		$114 695 800	29200	76650	$ -65 896 418	29200	54750	$ -64 736 912
2023	18173		$119 598 242	29200	76650	$ -58 348 188	29200	54750	$ -57 094 757
2024	17298		$123 918 760	29280	76860	$ -51 339 938	26487	54900	$ -50 696 878
2025	16482		$127 730 704	27910	76650	$ -45 166 823	24113	54750	$ -45 321 504
2026	15831		$131 120 725	25164	76650	$ -40 039 142	22503	54750	$ -40 689 034
2027	15269		$134 148 279	23495	76650	$ -35 622 141	21164	54750	$ -36 665 168
2028	14779		$136 861 682	22153	76650	$ -31 778 800	20040	54750	$ -33 145 690
2029	14386		$139 307 250	21092	76860	$ -28 400 963	19150	54900	$ -30 038 766
2030	13963		$141 505 069	20104	76650	$ -25 428 355	18310	54750	$ -27 293 686
2031	13619		$143 489 951	19337	76650	$ -22 787 682	17651	54750	$ -24 848 120
2032	13309		$145 285 890	18711	76650	$ -20 427 184	17096	54750	$ -22 658 481
2033	13061		$146 917 908	18244	76860	$ -18 300 233	16669	54900	$ -20 684 727
2034	12768		$148 395 092	17765	76650	$ -16 385 900	16219	54750	$ -18 909 022
2035	12530		$149 737 380	17403	76650	$ -14 652 138	15867	54750	$ -17 302 527
2036	12313		$150 958 685	17094	76650	$ -13 077 492	15558	54750	$ -15 845 710
2037	12143		$152 073 965	16870	76860	$ -11 640 329	15324	54900	$ -14 518 507
2038	11922		$153 087 813	16587	76650	$ -10 333 439	15035	54750	$ -13 313 981
2039	11747		$154 012 742	16374	76650	$ -9 140 088	14811	54750	$ -12 216 277
2040	11582		$154 857 142	16181	76650	$ -8 049 212	14608	54750	$ -11 214 728
2041	11427		$155 628 551	16004	76650	$ -7 051 117	14420	54750	$ -10 300 039
2042	11281		**$156 333 687**	15839	76650	**$ -6 137 237**	14246	54750	**$ -9 464 000**

Figure 34: NPV, Polymer Flooding

	WF			PF-Late			PF-Late05		
	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative
	m3	m3	USD	m3	m3	USD	m3	m3	USD
2013	29280	-	$17 052 376	29280		$ 17 052 376	29280		$ 17 052 376
2014	29200		$32 798 473	29200		$ 32 798 473	29200		$ 32 798 473
2015	29200		$47 378 192	29200		$ 47 378 192	29200		$ 47 378 192
2016	29200		$60 877 932	29200		$ 60 877 932	29200		$ 60 877 932
2017	29280		$73 411 938	29280		$ 73 411 938	29280		$ 73 411 938
2018	29200		$84 985 789	29200		$ 84 985 789	29200		$ 84 985 789
2019	26085		$94 559 209	26085	210	$ -22 140 095	26085		$ -22 138 870
2020	23525		$102 553 449	24216	55440	$ -14 210 736	24215	39750	$ -14 124 946
2021	20719		$109 072 560	29250	76860	$ -5 391 893	29112	54900	$ -5 239 544
2022	19301		$114 695 800	29200	76650	$ 2 760 196	29200	54750	$ 3 013 984
2023	18173		$119 598 242	29200	76650	$ 10 308 426	29200	54750	$ 10 656 139
2024	17298		$123 918 760	29200	76650	$ 17 297 528	29200	54750	$ 17 732 209
2025	16482		$127 730 704	29280	76860	$ 23 786 648	28731	54900	$ 24 175 060
2026	15831		$131 120 725	28185	76650	$ 29 561 278	24115	54750	$ 29 152 644
2027	15269		$134 148 279	23652	76650	$ 34 009 369	21259	54750	$ 33 195 207
2028	14779		$136 861 682	21579	76650	$ 37 747 346	19754	54750	$ 36 662 159
2029	14386		$139 307 250	20082	76860	$ 40 953 438	18674	54900	$ 39 688 200
2030	13963		$141 505 069	19137	76650	$ 43 773 885	17748	54750	$ 42 344 789
2031	13619		$143 489 951	18414	76650	$ 46 279 951	17050	54750	$ 44 702 807
2032	13309		$145 285 890	17809	76650	$ 48 518 753	16474	54750	$ 46 808 414
2033	13061		$146 917 908	17345	76860	$ 50 533 299	16031	54900	$ 48 702 400
2034	12768		$148 395 092	16868	76650	$ 52 343 854	15572	54750	$ 50 403 273
2035	12530		$149 737 380	16509	76650	$ 53 981 846	15213	54750	$ 51 939 730
2036	12313		$150 958 685	16211	76650	$ 55 468 907	14900	54750	$ 53 331 329
2037	12143		$152 073 965	15962	76650	$ 56 822 937	14626	54750	$ 54 594 645
2038	11922		$153 087 813	15752	76650	$ 58 058 803	14384	54750	$ 55 743 820
2039	11747		$154 012 742	15572	76650	$ 59 188 988	14171	54750	$ 56 791 122
2040	11582		$154 857 142	15457	76860	$ 60 226 851	14020	54900	$ 57 749 671
2041	11427		$155 628 551	15277	76650	$ 61 175 855	13813	54750	$ 58 623 390
2042	11281		**$156 333 687**	15152	76650	**$ 62 046 755**	13660	54750	**$ 59 422 844**

Figure 35: NPV, PF-Late

	WF			Comb90			Comb90Larger		
	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative
	m3	m3	USD	m3	m3	USD	m3	m3	USD
2013	29280	-	$17 052 376	29280		$ 17 052 376	29280		$ 17 052 376
2014	29200		$32 798 473	29200		$ 32 798 473	29200		$ 32 798 473
2015	29200		$47 378 192	29200		$ 47 378 192	29200		$ 47 378 192
2016	29200		$60 877 932	29200		$ 60 877 932	29200		$ 60 877 932
2017	29280		$73 411 938	29280		$ 73 411 938	29280		$ 73 411 938
2018	29200		$84 985 789	29200		$ 84 985 789	29200		$ 84 985 789
2019	26085		$94 559 209	26085	210	$ -57 149 519	26085		$ -68 818 101
2020	23525		$102 553 449	24104	55440	$ -49 258 219	23937	39750	$ -60 898 545
2021	20719		$109 072 560	29052	76860	$ -40 501 613	28618	54900	$ -52 168 673
2022	19301		$114 695 800	29200	76650	$ -32 349 525	29200	54750	$ -43 915 145
2023	18173		$119 598 242	29200	76650	$ -24 801 295	29200	54750	$ -36 272 990
2024	17298		$123 918 760	29200	76650	$ -17 812 193	29200	54750	$ -29 196 920
2025	16482		$127 730 704	29280	76860	$ -11 323 072	29280	54900	$ -22 627 053
2026	15831		$131 120 725	29200	76650	$ -5 331 044	29200	54750	$ -16 560 464
2027	15269		$134 148 279	29200	76650	$ 217 130	29200	54750	$ -10 943 252
2028	14779		$136 861 682	28047	76650	$ 5 142 572	29200	54750	$ -5 742 129
2029	14386		$139 307 250	24789	76860	$ 9 148 809	29280	54900	$ -913 081
2030	13963		$141 505 069	22947	76650	$ 12 568 832	29200	54750	$ 3 546 043
2031	13619		$143 489 951	21905	76650	$ 15 583 641	29200	54750	$ 7 674 862
2032	13309		$145 285 890	21067	76650	$ 18 262 059	29200	54750	$ 11 497 842
2033	13061		$146 917 908	20429	76860	$ 20 661 953	27205	54900	$ 14 788 014
2034	12768		$148 395 092	19790	76650	$ 22 810 557	25511	54750	$ 17 638 839
2035	12530		$149 737 380	19290	76650	$ 24 746 400	24400	54750	$ 20 159 433
2036	12313		$150 958 685	18856	76650	$ 26 495 818	23489	54750	$ 22 402 984
2037	12143		$152 073 965	18477	76650	$ 28 080 851	22720	54750	$ 24 409 673
2038	11922		$153 087 813	18143	76650	$ 29 520 079	22059	54750	$ 26 211 559
2039	11747		$154 012 742	17846	76650	$ 30 829 336	21485	54750	$ 27 834 775
2040	11582		$154 857 142	17628	76860	$ 32 025 444	21040	54900	$ 29 305 127
2041	11427		$155 628 551	17341	76650	$ 33 113 789	20543	54750	$ 30 633 148
2042	11281		**$156 333 687**	17125	76650	**$ 34 108 052**	20157	54750	**$ 31 838 694**

Figure 36: NPV, Comb90 and Comb90Larger

	WF, 60wells			Comb90Larger, 60wells			Div90		
	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative	Production	Injection	NPV cumulative
	m3	m3	USD	m3	m3	USD	m3	m3	USD
2013	878400		$ 511 571 276	878400		$ 511 571 276	878400	-	$ 456 015 720
2014	876000		$ 983 954 184	876000		$ 983 954 184	876000		$ 928 398 628
2015	876000		$ 1 421 345 765	876000		$ 1 421 345 765	876000		$ 1 365 790 209
2016	876000		$ 1 826 337 969	876000		$ 1 826 337 969	876000		$ 1 770 782 414
2017	878400		$ 2 202 358 129	878400		$ 2 202 358 129	878400		$ 2 146 802 574
2018	876000		$ 2 549 573 668	876000		$ 2 549 573 668	876000		$ 2 494 018 113
2019	782559		$ 2 836 776 278	782559		$ 2 136 587 804	782559		$ 2 372 777 446
2020	705750		$ 3 076 603 470	718116	1192500	$ 2 374 174 488	711033		$ 2 614 399 901
2021	621564		$ 3 272 176 801	858534	1647000	$ 2 636 070 649	665931		$ 2 823 933 182
2022	579039		$ 3 440 873 988	876000	1642499	$ 2 883 676 485	633657		$ 3 008 542 773
2023	545202		$ 3 587 947 245	876000	1642500	$ 3 112 941 146	591282		$ 3 168 046 534
2024	518925		$ 3 717 562 795	876000	1642500	$ 3 325 223 239	560895		$ 3 308 145 227
2025	494469		$ 3 831 921 131	878400	1647000	$ 3 522 319 246	536001		$ 3 432 108 878
2026	474918		$ 3 933 621 759	876000	1642500	$ 3 704 316 926	511863		$ 3 541 721 039
2027	458070		$ 4 024 448 368	876000	1642500	$ 3 872 833 296	492159		$ 3 639 306 851
2028	443382		$ 4 105 850 457	876000	1642500	$ 4 028 866 971	474888		$ 3 726 493 239
2029	431586		$ 4 179 217 511	878400	1647000	$ 4 173 738 421	460815		$ 3 804 829 050
2030	418893		$ 4 245 152 067	876000	1642500	$ 4 307 512 148	445914		$ 3 875 016 763
2031	408573		$ 4 304 698 519	876000	1642500	$ 4 431 376 711	433656		$ 3 938 218 874
2032	399255		$ 4 358 576 689	876000	1642500	$ 4 546 066 120	422550		$ 3 995 240 628
2033	391839		$ 4 407 537 248	816138	1647000	$ 4 644 771 279	413574		$ 4 046 916 992
2034	383037		$ 4 451 852 752	765339	1642500	$ 4 730 296 027	403269		$ 4 093 573 238
2035	375903		$ 4 492 121 395	731997	1642500	$ 4 805 913 844	394872		$ 4 135 873 937
2036	369384		$ 4 528 760 556	704676	1642500	$ 4 873 220 374	387165		$ 4 174 276 794
2037	364302		$ 4 562 218 962	681591	1642500	$ 4 933 421 050	380055		$ 4 209 181 995
2038	357663		$ 4 592 634 392	661779	1642500	$ 4 987 477 618	373461		$ 4 240 940 876
2039	352398		$ 4 620 382 260	644559	1642500	$ 5 036 174 090	367308		$ 4 269 862 760
2040	347454		$ 4 645 714 275	631206	1647000	$ 5 080 284 666	362526		$ 4 296 293 637
2041	342813		$ 4 668 856 545	616284	1642500	$ 5 120 125 282	356127		$ 4 320 334 695
2042	338430		**$ 4 690 010 607**	604716	1642500	**$ 5 156 291 667**	351024		**$ 4 342 275 963**

Figure 37: NPV, WF and Comb90Larger with 60 wells

D. Data Files

The data file written for the water flooding case, and the combination case with a permeability reduction of 90% is attached. The RESTART file used in the Comb90 file is not attached, but will be exactly the same as the WF data file.

```
RUNSPEC
TITLE
3D - WATER INJECTION

DIMENS
   25   25    36  /

OIL

WATER

METRIC

SAVE
/

TRACERS
    0    1    0    0  'NODIFF' /

TABDIMS
    1    1   50    2    2   20 /

REGDIMS
    2    1    0    0 /

WELLDIMS
    2    36    1    2 /

START
   1 'JAN' 2012  /

NSTACK
    150 /

UNIFOUT

UNIFIN


GRID
=============================================================
INIT
EQUALS
      'DX'    20       /
      'DY'    20       /
      'PORO'  0.33     /

      'DZ'    1        1  25  1  25  1  1  /
      'PERMX' 100      /
      'PERMZ' 10       /
      'MULTZ' 1.0      /
      'TOPS'  1700.0   /
```

```
      'DZ'    1        1  25  1  25  2  16  /
      'PERMX' 100      /
      'PERMZ' 10       /
      'MULTZ' 1.0      /

      'DZ'    1        1  25  1  25  17  20  /
      'PERMX' 2000     /
      'PERMZ' 200      /
      'MULTZ' 1.0      /

      'DZ'    1        1  25  1  25  21  36  /
      'PERMX' 100      /
      'PERMZ' 10       /

/

COPY
      'PERMX'    'PERMY'   1  25  1  25  1  36  /

/

RPTGRID
-- Report Levels for Grid Section Data
--
'PORO'
'PORV'
 /

PROPS
===============================================================

SWFN
    0.15   .0    .0
    0.85  0.50   .0

/

SOF2
    0.15   .0
    0.85  1.0
/

PVTW
 1700  1.0  4.03E-05  0.5  0.0 /

PVCDO
  230  1.06 6.65E-05  30   192.E-05 /

ROCK
 4000.0    .30E-05 /
```

```
DENSITY
 600.0000  1000.0000 /

TRACER
 'IW1' 'WAT' /
/

RPTPROPS
'TRACER'
 /

REGIONS    ========================================================

--FIPNUM
--  10*10*2 /

SOLUTION
==============================================================

EQUIL
1700  170  2000  0   0   0   0   0   0  /

TVDPFIW1
1500   0.0
1800   0.0  /

RPTSOL
-- Initialisation Print Output
'RESTART=1' 'FIP=2' 'PBLK' 'SALT' 'RK' 'FIPPLY=2' /

SUMMARY
==============================================================

RUNSUM

EXCEL
SEPARATE

FWCT
FOPR
FWIR
FWPR
FOIP
FPR
FOE
FWIR
FWIT
FOPT
WBHP
 I
 P /
```

```
WGOR
 P /

RPTSMRY
 1 /

SCHEDULE
=============================================================

RPTSCHED
'PRES' 'SWAT' 'RESTART=1' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2'
'WELSPECS'
'NEWTON=2' 'PBLK' 'SALT' 'RK' 'FIPSALT=2' /

TUNING
1 365 0.1 0.15 3 0.3 0.1 1.25 0.75 /
0.1 0.001 1E-7 0.0001
10 0.01 1E-6 0.001 0.001 /
12 1 150 1 8 8 4*1E6 /

WELSPECS
'I'  'G'   1  1  1700  'WAT'  0.0  'STD'  'SHUT'  'NO'  /
'P'  'G'  25 25  1700  'OIL'  0.0  'STD'  'SHUT'  'NO'  /
/

COMPDAT
'I'   1   1   1  36 'OPEN'   0  .0   0.15 /
'P'  25  25   1  36 'OPEN'   0  .0   0.15 /
/

WCONPROD
'P' 'OPEN' 'ORAT' 80.0 /
/

WCONINJE
'I' 'WAT' 'OPEN' 'RATE' 80.0 /
/

WTRACER
'I' 'IW1' 0.0 /
/

TSTEP
1*366 /

-- 1 year, 150

WCONINJE
'I' 'WAT' 'OPEN' 'RATE' 200.0 /
/

TSTEP
```

```
2*365 /

---2  years, 180

WCONINJE
'I' 'WAT' 'OPEN' 'RATE' 250.0 /
/
TSTEP
1*365 /

-- 3  years, 250

WCONINJE
'I' 'WAT' 'OPEN' 'RATE' 300.0 /
/

--2016
TSTEP
1*366/
TSTEP
2*365/

WTRACER
'I' 'IW1' 100.0 /
/

TSTEP
1*10/

WTRACER
'I' 'IW1' 0.0 /
/

TSTEP
1*90/


--END OF RESTART FILE
--2020

TSTEP
1*266/
TSTEP
3*365/

TSTEP
1*366/
TSTEP
3*365/

--2028
TSTEP
```

```
1*366/
TSTEP
3*365/
--2032

TSTEP
1*366/
TSTEP
3*365/

--2036
TSTEP
1*366/
TSTEP
3*365/

--2040

TSTEP
1*366/
TSTEP
3*365/
--2044
END
```

```
RUNSPEC
TITLE
3D - COMBINATION METHOD, 90% blocking, Comb90

DIMENS
   25   25    36  /

OIL

WATER

POLYMER

METRIC

SAVE
/

TRACERS
    0    1    0    0  'NODIFF' /

TABDIMS
    1    1   50    5    2   20 /

REGDIMS
    2    1    0    0 /

WELLDIMS
    2    36    1    2 /

START
   1 'JAN' 2012  /

NSTACK
   100 /

UNIFOUT

UNIFIN


GRID
==============================================================
INIT
EQUALS
      'DX'    20        /
      'DY'    20        /
      'PORO'  0.33      /

      'DZ'    1         1  25  1  25  1  1  /
      'PERMX' 100       /
      'PERMZ' 10        /
```

```
      'MULTZ' 1.0      /
      'TOPS'  1700.0   /

      'DZ'    1        1  25  1  25  2  16  /
      'PERMX' 100      /
      'PERMZ' 10       /
      'MULTZ' 1.0      /

      'DZ'    1        1  25  1  25  17  20  /
      'PERMX' 2000     /
      'PERMZ' 200      /
      'MULTZ' 1.0      /

      'DZ'    1        1  25  1  25  21  36  /
      'PERMX' 100      /
      'PERMZ' 10       /

/

COPY
      'PERMX'    'PERMY'   1  25  1  25  1  36  /

/

RPTGRID
-- Report Levels for Grid Section Data
--
'PORO'
'PORV'
 /

MULTIPLY
 PERMX 0.1   23  23  1 1  17 20 /
 PERMX 0.1   22  22  2 2  17 20 /
 PERMX 0.1   21  21  3 3  17 20 /
 PERMX 0.1   20  20  4 4  17 20 /
 PERMX 0.1   19  19  5 5  17 20 /
 PERMX 0.1   18  18  6 6  17 20 /
 PERMX 0.1   17  17  7 7  17 20 /
 PERMX 0.1   16  16  8 8  17 20 /
 PERMX 0.1   15  15  9 9  17 20 /
 PERMX 0.1   14  14  10 10  17 20 /
 PERMX 0.1   13  13  11 11  17 20 /
 PERMX 0.1   12  12  12 12  17 20 /
 PERMX 0.1   11  11  13 13  17 20 /
 PERMX 0.1   10  10  14 14  17 20 /
 PERMX 0.1    9   9  15 15  17 20 /
 PERMX 0.1    8   8  16 16  17 20 /
 PERMX 0.1    7   7  17 17  17 20 /
 PERMX 0.1    6   6  18 18  17 20 /
 PERMX 0.1    5   5  19 19  17 20 /
 PERMX 0.1    4   4  20 20  17 20 /
```

```
 PERMX 0.1     3   3  21 21  17 20 /
 PERMX 0.1     2   2  22 22  17 20 /
 PERMX 0.1     1   1  23 23  17 20 /

 PERMY 0.1   23  23  1 1  17 20 /
 PERMY 0.1   22  22  2 2  17 20 /
 PERMY 0.1   21  21  3 3  17 20 /
 PERMY 0.1   20  20  4 4  17 20 /
 PERMY 0.1   19  19  5 5  17 20 /
 PERMY 0.1   18  18  6 6  17 20 /
 PERMY 0.1   17  17  7 7  17 20 /
 PERMY 0.1   16  16  8 8  17 20 /
 PERMY 0.1   15  15  9 9  17 20 /
 PERMY 0.1   14  14  10 10  17 20 /
 PERMY 0.1   13  13  11 11  17 20 /
 PERMY 0.1   12  12  12 12  17 20 /
 PERMY 0.1   11  11  13 13  17 20 /
 PERMY 0.1   10  10  14 14  17 20 /
 PERMY 0.1    9   9  15 15  17 20 /
 PERMY 0.1    8   8  16 16  17 20 /
 PERMY 0.1    7   7  17 17  17 20 /
 PERMY 0.1    6   6  18 18  17 20 /
 PERMY 0.1    5   5  19 19  17 20 /
 PERMY 0.1    4   4  20 20  17 20 /
 PERMY 0.1    3   3  21 21  17 20 /
 PERMY 0.1    2   2  22 22  17 20 /
 PERMY 0.1    1   1  23 23  17 20 /
/

PROPS
==============================================================

SWFN
    0.15   .0    .0
    0.85  0.50   .0

/

SOF2
    0.15   .0
    0.85  1.0
/

PVTW
 1700  1.0  4.03E-05  0.5  0.0 /

PVCDO
  230  1.06 6.65E-05  30   192.E-05 /

ROCK
 4000.0    .30E-05 /
```

```
DENSITY
 600.0000  1000.0000 /

TRACER
 'IW1' 'WAT' /
/

RPTPROPS
'TRACER'
 /

-----POLYMER KEYWORDS

PLYVISC
--   kg/m3  water viscosity multiplier
     0.0      1.0
     0.5      3.5
     1.0      6.4
     1.5     12.4
     2.0     24.7 /

PLYROCK
-- dead       residual   mass dens. adsorpt  max adsorpt
-- pore space resistance kg/m3               kg/kg
   0.199        1.3      2650.0      2        0.00002 /

PLYADS
-- conc  adsorb-conc
 0.000   0.000000
 0.250      0.000011
 0.500      0.000015
 0.750      0.000017
 1.000      0.000018
 1.250      0.000019
 1.500      0.000019
 1.750      0.000020
 2.000      0.000020 /


TLMIXPAR
-- mixing parameter
   1.0 /

PLYMAX
-- max poly conc  salt concentration
-- kg/sm3         kg/sm3
   2.0            0.0 /

RPTPROPS
-- PROPS Reporting Options
--
'PLYVISC'
```

```
/

REGIONS    ==========================================================

--FIPNUM
--  10*10*2 /

--MISCNUM
--100*1 /

--RPTREGS
-- Controls on output from regions section
--
--'MISCNUM'
--/

SOLUTION
================================================================

RESTART
 'RESTART' 9 /
-- RESTART FILE CREATED

--EQUIL
--1700  170  3000  0   0   0   0   0   0  /

--TVDPFIW1
--1500   0.0
--1800   0.0  /

--RPTSOL
-- Initialisation Print Output
--'RESTART=1' 'FIP=2' 'PBLK' 'SALT' 'RK' 'FIPPLY=2' /

SUMMARY
================================================================

RUNSUM

EXCEL
SEPARATE

FWCT
FOPR
FWIR
FWPR
FOIP
FPR
FOE
FCPR
FCPT
FCIR
```

```
FCIT
FCIP
FCAD
FWIR
FWIT
FOPT
WBHP
 I
 P /

WGOR
 P /

RPTSMRY
 1 /

SCHEDULE
==============================================================

RPTSCHED
'PRES' 'SWAT' 'RESTART=1' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2'
'WELSPECS'
'NEWTON=2' 'PBLK' 'SALT' 'RK' 'FIPSALT=2' /

TUNING
1 365 0.1 0.15 3 0.3 0.1 1.25 0.75 /
0.1 0.001 1E-7 0.0001
10 0.01 1E-6 0.001 0.001 /
12 1 100 1 8 8 4*1E6 /

WELSPECS
'I'  'G'   1  1  1700  'WAT'  0.0  'STD'  'SHUT'  'NO'  /
'P'  'G'  25 25  1700  'OIL'  0.0  'STD'  'SHUT'  'NO'  /
/

COMPDAT
'I'   1   1   1  36 'OPEN'   0  .0   0.15 /
'P'  25  25   1  36 'OPEN'   0  .0   0.15 /
/



WPOLYMER
--well  poly conc  salt conc
--name  kg/sm3
 'I'    0.7         0.0 /
 /

TSTEP
1*265/
--2020
```

```
TSTEP
1*366/
TSTEP
3*365/

TSTEP
1*366/
TSTEP
3*365/
--2028

TSTEP
1*366/
TSTEP
3*365/

--2032
TSTEP
1*366/
TSTEP
3*365/

--2036

TSTEP
3*365/
TSTEP
1*366/
TSTEP
3*365/
--2043
END
```