# Simulation Study of In-Situ Polymer Rheology in a Radial Flow Experiment

Master Thesis in Petroleum Technology - Reservoir Chemistry

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# Abstract

The global energy demand is continuously growing, and even though renewable energy sources are becoming increasingly important, oil remains the leading energy fuel to this date, accounting for one third of the consumption. [1] This indicates that the demand for oil will still be an important energy source in the years to come. The majority of the conventional fields have already been produced, which means that the industry is moving over into a new phase of more complex oil recovery methods. [2] The amount of heavy oil resources worldwide is estimated to 3.396 billion barrels, and these reservoirs demand more complex recovery methods to be successful. These unconventional recovery methods are expensive and face technological challenges. [3]

Enhanced oil recovery methods are a necessity to optimize the production of heavy oils, and polymer flooding is one of the most widely used EOR methods for unconventional reservoirs. [2] Polymer flooding is an especially efficient recovery method for heterogeneous reservoirs or heavy crude oil reservoirs with an unfavorable mobility ratio between the oil and the displacing fluid. The aim of this recovery method is to increase the macroscopic sweep efficiency by increasing the viscosity of the injection fluid, and hereby make the mobility ratio more favorable to avoid viscous fingering. Polymers can additionally be used to plug of high permeability zones in a reservoir. [4] On the other hand, polymer flooding faces multiple challenges concerning field applications, in example low injectivity, degradation, retention, and the potentially high expenses. [4]

Polymer injectivity is an important factor to study, because better understanding may increase the implementation of polymer flooding for EOR. The majority of injectivity studies found in literature today are performed in linear cores, but the flow in a radial core may have great differences from a linear core flood. The most important difference is that linear core floods are performed under steady-state conditions, while radial core floods are under an unsteady-state pressure regime. [5] In actual field operations, the latter situation is most common and thereby most relevant to study. Experiments in radial cores exert radial flow and are generally better replicates for fluid flow in field operations.

Viscosity measurements of synthetic polymers obtained from viscometers has shown to differ from the apparent viscosity in porous media because of its viscoelastic behavior and the elongational flow. This implies that the in-situ polymer rheology is important to investigate further in order to minimize the uncertainties concerning polymer flooding in enhanced oil recovery (EOR) operations. Linear core experiments may overestimate the shear thickening behavior, which in turn can lead to an underestimated polymer injectivity. [5] This will certainly affect the economical calculations for the EOR-project and may lead to polymer flooding being disposed as an efficient recovery method for the project.

The experiment in this thesis was performed at the Centre for Integrated Petroleum Research (CIPR) with the objective of analyzing the in-situ rheology of partially hydrolyzed polyacrylamide (HPAM) by history matching the pressure data collected from fluid flow experiments in a radial core sample. The experimental data, which made the basis for this thesis, was collected from water- and polymer flooding experiments in a radial Bentheimer disc. Automatic history matching was performed to find the permeability field and to estimate the in-situ polymer rheology. The in-situ rheology was estimated for four HPAM solutions with different polymer concentrations, to investigate how the concentration affects the rheological behavior. Analysis of the individual pressure ports additionally contributed to the fluid flow characterization.

The tool used to do the history matching was MRST by SINTEF by using the Ensemble Kalman Filter (EnKF), developed at the University of Bergen. The results showed a permeability change in the core sample during the experiment. Both shear thinning and shear thickening behavior was observed for the polymer solutions. There was observed both rate and concentration dependency of the rheological behavior. A distinct shear thickening behavior at the higher injection rates was observed, which is consistent with the existing literature, where this behavior is assigned to the viscoelasticity of HPAM. [10] Significant shear thinning behavior was observed for the polymer solutions of the highest concentrations. The onset of shear thickening showed shifting towards higher velocities for increasing injection rates. The bulk and in-situ viscosity had similar tangential lines, although different viscosity values.

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# Nomenclature

# Variables

A	Area	[m <sup>2</sup> ]
С	Concentration	[-]
C*	Critical overlap concentration	[-]
dP	Differential pressure	[kPA]
dP/dr	Pressure drop over radius r	[Pa/m]
dP/dx	Pressure drop per unit length	[Pa/m]
Dvx/dy	Shear rate	[s <sup>-1</sup> ]
E <sub>A</sub>	Areal sweep efficiency	[-]
E <sub>D</sub>	Microscopic displacement efficiency	[-]
E <sub>R</sub>	Expected recovery factor	[-]
Ev	Vertical sweep efficiency	[-]
E <sub>vol</sub>	Volumetric sweep efficiency	[-]
F <sub>VP</sub>	Pore volume polymer solution injected	[fraction]
h	Thickness of the core sample	[m]
1	Injectivity	[-]
ls	Ionic strength	[-]
К	Absolute permeability	[D], [m <sup>2</sup> ]
К	Power law constant	[-]
k <sub>e</sub>	Effective permeability	[m <sup>2</sup> ]
k <sub>r</sub>	Relative permeability	[-]
k <sup>°</sup>	End point relative permeability	[-]
L	Length	[m]
Μ	Mobility ratio	[-]
m	Molar concentration	[mol/m <sup>3</sup> ]
M0	End point mobility ratio	[-]
n	Power law exponent	[-]
N <sub>De</sub>	Deborah number	[-]
N <sub>vc</sub>	Capillary number	[-]
Р	Pressure	[Pa], [bar]
r	Radius of the core sample	[m]
r	Radial position	[m]
R	Retention	[-]
R <sub>F</sub>	Resistance factor	[-]
R <sub>RF</sub>	Residual resistance factor	[-]
R <sub>k</sub>	Permeability reduction factor	[-]
R <sup>2</sup>	Root-mean-square	[-]
S	Saturation	[fraction]
t <sub>e</sub>	Relaxation time	[s]
u	Darcy velocity	[m/s]
Vb	Bulk volume	[m <sup>3</sup> ]
Vm	Matrix volume	[m <sup>3</sup> ]
Vp	Pore volume	[m <sup>3</sup> ]
Vp,abs	Total volume of voids	[m <sup>3</sup> ]

Vp,eff	Volume of interconnected pores	[m <sup>3</sup> ]
Q	Flow rate	[m <sup>3</sup> /s]
q	Injection rate	[m <sup>3</sup> /s]
х	Length	[m]
Z	Ionic valence	[-]
$\alpha'$	Pore structure constant	[-]
Δ	Difference	[-]
$\eta_{app}$	Apparent viscosity	[cP]
Ϋ́	Shear rate	[s⁻¹]
$\phi$	Porosity	[%],[fraction]
μ	Viscosity	[cP]
$\langle v \rangle$	Average pore velocity	[m/s]
σ	Interfacial tension	[]
τ	Applied shear stress	[Pa]
τ	Relaxation constant	[s]
λ	Mobility	[m <sup>2</sup> /Pa·s]
Ė	Stretching rate	[s <sup>-1</sup> ]
ρ	density	[]

### Subscripts

A	Areal
Abs	Absolute
b	Bulk
С	critical
D	Microscopic
D	Displacing
d	Displaced fluid
e	Outer boundary
eff	effective
g	Gas
i	Component
max	Maximum shear thickening
0	Oil
р	polymer
pm	Effective shear rate
ps	Polymer solution
r	Relative
r	rock
res	Residual
ro	Residual oil
rw	Residual water
R	Recovery
tot	Total
V	Vertical
vol	Volumetric
W	Water

W	Well
0	Zero shear rate
∞	Infinite shear rate

### Abbreviations

BT	Water breakthrough
CF	Capillary forces
CIPR	Center for Integrated Petroleum Research
DCD	Capillary desaturation curve
EnKF	Ensemble Kalman Filter
EOR	Enhanced oil recovery
FW	Fractional wet
HPAM	Partially hydrolyzed polyacrylamide
IPV	Inaccessible pore volume
MATLAB	Matric laboratory
MRST	MATLAB Reservoir Simulation Toolbox
MWD	Molecular weight distribution
MWL	Mixed wet large
MWS	Mixed wet small
PAM	Polyacrylamide
ррт	Parts per million
PV	Pore volume
VF	Viscous forces

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# 1. Introduction

The world energy demand is continuously growing, and is estimated by the U.S. Energy Information Administration to increase from 575 quadrillion British thermal units (Btu) in 2015 to 736 quadrillion Btu in 2040. While renewable energy sources are becoming more important, fossil fuels will still be an important energy resource in 2040 and is estimated to account for 77% of the energy use [6]. Fossil fuels are still considered as the dominant energy source [1], and this implies that the demand for more efficient and environmental friendly production is growing. Since oil is a non-renewable energy source, the reserves are limited and with most of the light oil produced, the heavy oil is left to recover to meet the energy demand. Heavy crude oil reservoirs challenge the current technology and the old ways of thinking, as they are more complex to recover than the conventional oil reservoirs. These reservoirs normally have a low recovery efficiency of 10-20 %, and this brings the need for enhanced oil recovery (EOR) techniques to perform successful recoveries. [7].

Primary recovery is based on the compressional energy of the reservoir, which force the oil to the producer and leads to a pressure drop [8]. This method usually recovers only 5-15% of the oil reserves. Secondary recovery methods are used for pressure maintenance in the reservoir and use other drive mechanisms to bring the oil to the surface. The most common secondary recovery method is waterflooding, and the recovery is usually between 20-50% [9]. Both primary and secondary recovery methods leave great amounts of crude oil in the reservoirs, and in some heterogeneous reservoirs as much as 70% of the oil may be left behind [8]. With the increasing global energy demand, it is important to exploit all the potentials of these reserves.

Enhanced oil recovery (EOR) methods are used to change the chemical and physical properties of the reservoir rock or the injecting fluid [3]. These methods are capable of recovering up to 80% of the reserves [9], and are usually applied in fields that are hard to produce considering high oil viscosity or strong capillary forces. The three most commonly used primary EOR techniques are thermal-, chemical- and gas injection [11]. Making new wells have been cheaper than using EOR to increase the recovery from existing wells, but when the demand for oil and the oil prize increases, the more expensive recovery methods are becoming more viable [9].

One of the most common chemical EOR methods is polymer flooding, and the recovery technique has been applied for over 40 years [12]. Polymer is added to the injection fluid to increase its viscosity to make the mobility ratio between the injecting fluid and the crude oil more favorable. This will result in less viscous fingering and a more stable displacement. Polymer flooding is usually the preferred recovery method when the oil viscosity is high or the reservoir is heterogeneous [4]. Synthetic polymers are most commonly applied, because they have relatively low costs and good viscofying effect. Polymer flooding also has some limitations such as retention, degradation and polymer rheology [13]. The rheological behavior of synthetic polymers is very uncertain, as the viscosity values tend to deviate from bulk- and in-situ measurements. Synthetic polymers tend to show a viscoelastic behavior, which means that they have increased viscosity at the injection well, since this is where the velocity is at its peak. Consequently, this will affect the injection pressure and well injectivity. Polymer in-situ rheology remains an uncertain science, and is thereby important to investigate further.

Current literature declares that in linear core floods, degradation of polymer happens at high flow rates, and that this significant degree of shear thickening leads to high injection pressures. In contrast to this, in radial core experiments, it is proved to be a great reduction in differential pressure in comparison with linear core experiments. This states that there is a significant difference between polymer floods in linear and radial core experiments. One reason for this difference is that the radial injections go through transient and semi-transient pressure regimes, while linear floods are exerted at steady state conditions [5]. In this thesis, the polymer in-situ rheology will be investigated by history matching a laboratory experiment in a radial core sample.

Following the oil crisis from 2014, the oil price per barrel has become remarkably lower than in 2013. This means that the more expensive production methods, like chemical flooding, are not prioritized because it provides low profit [13]. Therefore, it is important to optimize the recovery methods, and possibly lower the costs by making the production more efficient. Simulation tools make it possible to build models of the reservoirs and use these models to test different production scenarios before deciding what method will be most efficient. The use of these tools can help making the most efficient choice for the specified

reservoirs and can possibly help cutting the production costs. The simulation tool used for this thesis was MRST (MATLAB) by SINTEF. History matches of pressure data from a radial core flow experiment were performed to investigate the rheological behavior of HPAM during radial flow with altering polymer concentration.

### 2. Basic theory

This section serves the purpose to introduce some of the basic theory that is relevant to fully understand this thesis.

Primary recovery methods, such as pressure depletion, have low recovery factors because of the gradual and rapid pressure decrease in the reservoir. This pressure drop will result in a pressure below the bubble point, and thereby gas will be dissolved from the oil and create a solution gas drive. A natural water drive normally isn't sufficient enough to maintain the pressure in the reservoir, and water injection is therefore a very common pressure support for these reservoirs. Waterflooding using seawater is the most frequently used secondary recovery method in the North Sea because of its low costs, high efficiency and accessibility. This method prevents solution gas from developing, and increases the total recovery. Nevertheless, waterflooding does not always yield a good recovery, because of reservoir heterogeneity, problems related to the well siting and spacing between the wells, and an unfavorable mobility ratio between the injection water and the displaced fluids. These factors lead to low volumetric sweep efficiency, while other factors, such as the displacement efficiency of water, may lead to low microscopic sweep efficiency [4].

The expected recovery factor,  $E_R$  is defined as;

$$E_R = \frac{N_p}{N} = E_D \cdot E_{Vol} = E_D \cdot E_A \cdot E_V$$
(2.1)

where  $N_p$  is oil produced, N is Standard oil originally in place (STOOIP),  $E_D$  is the microscopic displacement efficiency,  $E_{Vol}$  is the volumetric displacement efficiency,  $E_A$  is the areal sweep efficiency and  $E_V$  is the vertical sweep efficiency. These parameters are defined in equation 2.2-5 below.

$$E_D = \frac{Volume \ oil \ displaced}{Volume \ oil \ contacted} \tag{2.2}$$

$$E_{Vol} = \frac{Volume \ oil \ contacted}{Volume \ oil \ in \ place}$$
(2.3)

$$E_A = \frac{Area \ contacted \ by \ water}{Total \ area}$$
(2.4)

$$E_V = \frac{Cross-sectional\ area\ contacted\ by\ water}{Total\ cross-section\ area}$$
(2.5)



Figure 2.1: Schematic of the sweep efficiency (From Skauge and Skarestad (2014) [14]).

Large amounts of oil are usually left in the reservoir after a water flood because of either capillary forces trapping the oil or because the oil gets bypassed by the water. There are high probabilities that the oil will be bypassed if there are significant heterogeneities in the reservoir or if there is an unfavorable mobility ratio between the water and the oil [8]. This problem is illustrated in figure 2.1 above. The less viscous water may finger into the oil and ensure an inefficient areal sweep of the reservoir. This is called viscous fingering, and the oil that is left bypassed is the target for polymer flooding. [8]

Tertiary recovery methods aim to increase the volumetric sweep efficiency and to enhance the microscopic sweep efficiency by, in example, modifying the mobility ratio, reducing the capillary forces or by plugging high-permeability zones. Polymer flooding is a tertiary recovery method that improves the macroscopic sweep efficiency by increasing the viscosity of the injection fluid, and thereby making the mobility ratio between the injection fluid and the displaced fluid more favorable. There have been some discussions about whether polymer flooding also can contribute to improved microscopic sweep efficiency, and the research of Wang et al. (2001) and Huh and Pope (2008) showed that the viscoelastic behavior of HPAM can decrease the residual oil saturation [15].

#### 2.1 EOR

Enhanced oil recovery (EOR) is describing a group of technologies that can improve the recovery from existing oil reservoirs significantly. To have a successful EOR project, it is necessary to plan the project in detail based on the oil properties, the reservoir conditions and the availability of possible injectants. When planning an EOR project, and evaluating which technique is most suitable for the specified case, the reservoir is characterized, the engineering design parameters are determined and pilots or field tests are run if found necessary. The ultimate project driver is the economics, because the production should of course be profitable. [13]

To get an overlook on the profitability of the project, simulation models are great tools and will reduce the probability of unsuccessful recovery projects. The models will estimate the performance when given reservoir data and recovery method. After the ideal simulator is selected, all the necessary data are collected and history matched. The performance is then predicted and sensitivity studies of the model are conducted. Simulation models need to be updated with new information when gained because they can not take account what they do not know. The best way to discover unknown important information is to compare the results from the model with the actual results.

The EOR method is chosen based on what process needs to be improved, if it is the sweep efficiency or the displacement efficiency. Polymer flooding and thermal methods improve the sweep efficiency by overcoming reservoir heterogeneities or unfavorable mobility ratios. Chemical flooding, miscible or immiscible gas flooding, or microbial processes improve the displacement efficiency by overcoming the capillary forces [13].

It is necessary to understand the basic petrophysical and fluid properties to get a good understanding of the mechanisms behind EOR techniques. The following sections will include the most important properties for understanding the mechanisms behind this thesis.

#### 2.2 Petrophysical properties

#### 2.2.1 Porosity

The porosity of a rock is a dimensionless parameter, and is defined as the void part of the bulk volume not occupied by grains and cement [6]. This parameter is directly linked to the fluid volume present in a reservoir, and is described as;

$$\phi = \frac{V_p}{V_b} \cdot 100\% = \frac{V_b - V_m}{V_b} \cdot 100\%$$
(2.6)

Where  $V_b$  is the bulk volume,  $V_p$  is the pore volume and  $V_m$  is the matrix volume. The effective porosity is the ratio of the total volume of interconnected pores to the bulk volume of the rock sample;

$$\phi_{eff} = \frac{V_{p,eff}}{V_b} \tag{2.7}$$

Where  $V_{p,eff}$  is the volume of the interconnected pores. These are the pores that are able to hold and transmit fluids. The pores that are not interconnected with the others are accounted for in the residual porosity, which is defined as the ratio of the isolated pores to the bulk volume:

$$\phi_{res} = \frac{V_{p,abs} - V_{p,eff}}{V_b} \tag{2.7}$$

Where  $V_{p,abs}$  is the total volume of the voids in the rock. The isolated pores do not contribute to fluid flow through the rock sample. Absolute porosity is defined as the ratio of the total void volume to the bulk volume of the rock, and can be expressed as the sum of the effective and the residual porosity:

$$\phi_{abs} = \frac{V_{p,abs}}{V_b} = \phi_{eff} + \phi_{res}$$
(2.8)

The porosity is dependent on multiple factors, such as rock type, grain size range, shape and distribution, cementation, weathering and composition of the clay minerals. [4]

#### 2.2.2 Permeability

Permeability of a porous medium is the mediums capability to transmit fluids through its network of interconnected pores [4]. The parameter is thereby dependent on the effective porosity of the medium. Three types of permeability can be described; absolute, effective and relative permeability.

The permeability can be treated as a constant for the porous medium if there is only one fluid flowing through it. This is the absolute permeability and the constant is not dependent on the fluid type or flow rate. For a linear horizontal flow of an incompressible fluid in a porous media, the permeability is described with this generalized form of the Darcy Equation;

$$Q = -A\frac{\kappa}{\mu}\frac{dP}{dx}$$
(2.9)

Where Q is the flow rate, A is the cross-sectional area of the porous media sample, K is the absolute permeability,  $\mu$  is the viscosity of the fluid and  $\frac{dP}{dx}$  is the pressure drop per unit length. The negative sign indicates that the pressure gradient is negative, as the pressure decreases in the flow direction. Figure 2.2 below illustrates the parameters in the Darcy equation.



Figure 2.2: Illustration of the components of the Darcy equation. (Inspired by Zolotukhin, A.B. and J.R. Ursin (2000)
[4])

The unit used for permeability is usually Darcy (D) in the oil industry, and is defined as

$$1 Darcy = \frac{1 \frac{cm^3}{sec} \cdot 1cP}{1 cm^2 \cdot 1 \frac{atm}{cm}} = 0.98692 \cdot 10^{-8} cm^2 = 0.98692 \cdot 10^{-12} m^2$$
(2.10)

Darcy velocity, u, is defined as the volumetric injection rate per unit cross-sectional area of the rock sample;

$$u = \frac{Q}{A} \tag{2.11}$$

This value is related to the average pore velocity,  $\langle v \rangle$ ;

$$\langle v \rangle = \frac{u}{\phi} = \frac{Q}{A\phi} \tag{2.12}$$

where  $\phi$  is the porosity, Q is the flow rate and A is the cross-sectional area. [4]

#### 2.2.2.1 Effective and Relative Permeability

The effective permeability is defined as the permeability to one particular fluid when there is more than one incompressible fluid present in the medium. This permeability is very dependent on the fluids relative saturations, and will be drastically reduced when other fluids interferes with the flow. In addition to the fluid saturations, the effective permeability will depend strongly on the wettability of the porous media. One can express the effective permeability as;

$$k_{e,i} = \mu_i \frac{x}{A} \frac{Q_i}{\Delta P_i} \tag{2.13}$$

 $k_e$  is the effective permeability of fluid I, x is the length of the porous media, and *i* denotes the fluid. This equation is derived from the general Darcy Equation (2.9) expressed in the section above.

Relative permeability is the ratio of the porous mediums effective permeability of one fluid and the absolute permeability of the porous media;

$$k_{r,i} = \frac{k_{e,i}}{\kappa} \tag{2.14}$$

where  $k_r$  is the relative permeability and *i* denotes the fluid. The relative permeability is important for the study of flow in a reservoir, as it relates one fluids flow to the presence of other fluids. Relative permeability curves are plotted as a function of saturations, usually the saturation of the wetting fluid. The relative permeability is dependent on the displacement process, and thereby can have different values for the same saturations. The difference in the relative permeability for the imbibition- and the drainage process in the same system is referred to as hysteresis. [4]

#### 2.2.2.2 Darcy's law for radial flow in a cylindrical disc

The experiment used in this thesis was exerted in a radial disc, with the inlet placed in the center and the outlet at the outer boundary of the disc. This means that the Darcy equation for a linear horizontal flow expressed above cannot be used in this situation. Thus it is necessary to adapt the Darcy equation to a radial flow;

$$Q = -\frac{KA}{\mu}\frac{dP}{dr} = -\frac{2\pi\hbar K}{\mu}r\frac{dP}{dr}$$
(2.15)

$$Q \int_{r_w}^{r_e} \frac{dr}{r} = -\frac{2\pi hK}{\mu} \int_{p_w}^{p_e} dP$$
 (2.16)

$$p_e = p_w + \frac{\mu Q}{2\pi h K} \ln \frac{r_w}{r_e} \tag{2.17}$$

$$\Delta P = -\frac{\mu Q}{2\pi h K} ln \frac{r_w}{r_e}$$
(2.18)

Where Q is the flow rate, K is the permeability, A is the cross sectional area (A= $2\pi rh$ ), h is the thickness of the disc,  $p_e$  is the pressure at the outer boundary,  $p_w$  is the pressure at the injection well,  $r_e$  is the radius at the outer boundary and  $r_w$  is the injection well radius.  $\Delta P$  is the differential pressure from the injection well to the producer (outer boundary). This equation can be used to calculate the permeability values at the different radiuses between the injection well ( $r_w$ ) and the outer boundary ( $r_e$ ), when the pressure drop over the sample is known. Figure 2.3 shows a sketch of a radial model that conducts this type of flow.



Figure 2.3: Illustration of a radial model with inlet in the center and flow propagating towards the outer boundary of the disc. Modified from Lien, J. (2004) [16].

By deriving the Darcy equation the same way as for a one-phase flow, the equation for a two-phase flow in a radial disc can be expressed as;

$$\Delta P = -\frac{\mu Q}{2\pi h k_{e,i}} ln \frac{r_w}{r_e}$$
(2.19)

where  $k_{e,i}$  is used instead of the absolute permeability in the equation for a one-phase flow. [16]

#### 2.2.3 Saturation

While the porosity defines the fraction of the rock that is able to hold fluids, the saturation defines the amount of fluid that is actually present in the rock. The saturation is a dimensionless parameter defined as the pore volume occupied by a fluid relative to the total pore volume;

$$S_i = \frac{V_i}{V_p}, i = w, o, g$$
 (2.20)

Where  $V_i$  is the volume occupied by a particular fluid phase i and  $V_p$  is the total pore volume. The sum of all the individual fluid saturations should be equal to 1;

$$\sum_{1}^{n} S_{i} = S_{w} + S_{o} + S_{g} = 1$$
(2.21)

If there are two or more fluids present in the reservoir, the distribution of the fluids are dependent on the wettability of the reservoir rock. The saturation can have big variations over the reservoir, and can also vary over time and during production. Some fluids can be trapped and left behind in the reservoir after production, and the saturation of these fluids at this point is called the residual saturation [4].

#### 2.2.3.1 Residual oil saturation

When the production is finished, there will always remain some oil in the reservoir, which is called residual oil. The residual oil saturation can be defined as the fraction of the total pore volume that contains residual oil. The oil is left behind because it is trapped by capillary forces, and is disconnected from the rest of the oil [8] Two scenarios can describe this trapping, and these are shown in the pore-doublet- and snap-off model illustrated in figure 2.4 and 2.5 below.



Figure 2.4: Illustration of trapping in a pore doublet model. From Skarestad, M. and A. Skauge (2015) [14].

In the pore-doublet model, the oil is bypassed by water in the pore with less capillary forces, which means the pore with less radius.



Figure 2.5: Illustration of trapping in a snap-off model. (Skarestad, M. and A. Skauge (2015) [14]

In the snap-off model, the oil phase snaps off and portions of oil are left in the middle of the pores with the water flowing around them. [14]

#### 2.2.3.2 Capillary Number and the Capillary Desaturation Curve (CDC)

The capillary number,  $N_{vc}$ , is a dimensionless parameter defined as the relation between the viscous and capillary forces between the displacing and the displaced fluid;

$$N_{\nu c} = \frac{VF}{CF} = \frac{u\mu}{\sigma} \tag{2.22}$$

where u and  $\mu$  s the Darcy velocity and the viscosity of the displacing fluid, and  $\sigma$  is the interfacial tension between the two fluids.

Research has shown that the capillary number could be related to the residual oil saturation, and the relationship between these two is presented as a Capillary Desaturation Curve (CDC). Figure 2.6 below shows an example of a CDC.



Figure 2.6: A general capillary desaturation curve (CDC) for both wetting and non-wetting fluids. [17]

For low capillary numbers the residual oil saturation can be considered constant. After the capillary number reaches a certain point, called the critical capillary number,  $(N_{vc})_c$ , the curve bends and the residual oil saturation decreases. To get a significant reduction in the residual oil saturation, it is necessary to increase the capillary number by several orders of magnitude. The curve shows that a normal water flood can only increase the capillary number to some degree, and that the residual oil saturation will be reduced only to some extent.

To increase the capillary number further than a normal waterflooding can do, the viscous forces can be increased or the capillary forces can be reduced. An increase in the viscous force is achieved by either applying a higher injection velocity or by increasing the viscosity of the displacing fluid. The injection velocity is usually increased to the maximum in field experiments and is limited because of the fracturing risk, but the viscosity can easily be increased by adding polymers to the displacing fluid. The capillary forces are decreased by

reducing the interfacial tension between the fluids, which can be done by applying surfactants to the injecting fluid. Surfactants can decrease the interfacial tension by several orders, and can thereby efficiently decrease the residual oil saturation. [14]

The residual oil saturation is not expected to decrease sufficiently by applying a polymer flood, because of the possibility for injectivity problems when using more viscous polymer solutions. Therefore, the viscosity will not be increased enough to increase the capillary number by great magnitudes.

#### 2.2.4 Wettability

Wettability is described as a fluids ability to spread on a solid. The contact angle of the fluids at the surface can be used to determine the wettability condition in a system. A system can be strongly water-wet, oil-wet, neutral-wet or something in between these. The wetting is not necessarily the same over the whole system, and these can be separated in Mixed Wet Large (MWL), Mixed Wet Small (MWS) and Fractional Wet (FW) systems. In a MWL-system, the oil-wet parts are in the larger pores, while in a MWS-system, the oil-wet parts are in the smaller pores. Both large and small pores can be oil-wet in a FW-system. [18]

The wettability will affect the relative permeability of a system, mostly because it controls the location and distribution of the fluids in the porous media. If a system gets more waterwet, the crossing point of the oil and water relative permeability curves will move to the right and the endpoint relative permeability of water will decrease. The end point relative permeability of water will be higher for an imbibition than for drainage in a water-wet system, because of trapped oil in the middle of the pores after an imbibition. The oil will force the water to flow around it. This is also why the endpoint relative permeability of oil will be higher than for water for an imbibition process in a water-wet system. The flow will move more easily in the middle of the pores, where oil will be located in this type of system. Obviously, it will be the opposite way for an oil-wet system.

The capillary pressure depends on the radius of the interface curvature between the fluids, and this curvature is dependent on the wettability. A change in wetting will change the radius and thereby the capillary pressure. A strongly wetted system will spontaneously imbibe the wetting fluid. [18]

#### 2.3 Fluid properties

#### 2.3.1 Viscosity

Viscosity is a parameter that defines the internal resistance of a fluid to shear [3]. It also refers to the "thickness" of the fluid, as the "thicker" the fluid is, the higher viscosity it has [10]. Fluids that have a constant viscosity, that is independent of the shears stress, are called Newtonian fluids, and their viscosity can be described with the Newton model;

$$\tau = \mu \frac{dv_x}{dy} \tag{2.23}$$

where  $\tau$  is the applied shear stress,  $\mu$  is the fluid viscosity and  $\frac{dv_x}{dy}$  is the shear rate. Even though the viscosity of Newtonian fluids does not vary with shear stress, it does however vary with the fluid temperature, especially the viscosity of oil [4]. The relationship above holds for a lot of materials, here included most of the low molecular weight fluids [19], but the majority of fluids that are relevant for well simulations are non-Newtonian and thereby more complex. These fluids have a viscosity value that is a function of the shear rate [8]. While water and oil are Newtonian fluids, polymer solutions with sufficient polymer concentrations are defined as non-Newtonian fluids [4].

There are multiple types of non-Newtonian fluids, in example dilatant-, pseudoplastic- and Bingham fluids, which are shown in figure 2.7 below [8]. The most important fluids for well simulations are pseudoplastic, viscoelastic and Bingham fluids. Polymer solutions are generally viscoelastic, but they may be treated as pseudoplastics under steady shear conditions. Pseudoplastic and viscoelastic fluids are distinguished by the presence of normal stress effects in the viscoelastic fluids [19].

For viscoelastic fluids the stress at a given time depends on the strain history [8]. Pseudoplastic fluids show decreasing viscosity with increasing shear rate, while dilatant fluids show increasing viscosity with increasing shear rate. Bingham fluids behave like solid materials up until a critical shear stress, where the fluid starts flowing.



Figure 2.7: The relation of shear stress and shear rate for different types of non-Newtonian fluids. From Sorbie, K.S. (1991) [8].

There are multiple units for the viscosity, but in this thesis centipoise is used, which is defined as;

$$1000 \ cP = 1 \ Pa \cdot s = 1 \frac{N \cdot s}{m^2} \tag{2.24}$$

#### 2.3.2 Mobility

The mobility is a very central parameter considering fluid flow in a reservoir, and is defined as the ratio of the relative permeability and the viscosity of the fluid;

$$\lambda_i = \frac{k_i}{\mu_i} \tag{2.25}$$

where  $\lambda$  is the mobility, k is the relative permeability,  $\mu$  is the viscosity, and the subscript i refers to the fluid type [20]. The mobility is especially important for understanding the basic concepts behind polymer flooding.

The ratio between the mobility of the injected and the displaced fluid is referred to as the mobility ratio, M. For a displacement of oil by water, the mobility ratio is defined as;

$$M_{wo} = \frac{\lambda_{w,or}}{\lambda_{o,rw}} = \frac{k_{rD}}{\mu_D} S_D \frac{\mu_d}{k_{rd}} S_d$$
(2.26)

where  $\lambda_{w,or}$  is the mobility of water at residual oil saturation,  $\lambda_{o,rw}$  is the mobility of oil at residual water saturation,  $k_r$  is the relative permeability,  $\mu$  is the viscosity, and S is the average saturation of the specified fluid. D and d denotes the displacing fluid and the displaced fluid respectively.

The mobility ratio is an important parameter concerning secondary recovery methods, as it has a great impact on the recovery efficiency by defining the one fluids ability to displace the other [20]. The displacement will be inefficient and uneven if the mobility ratio is greater than one. On the other hand, the displacement process is more piston-like and thereby more efficient if the mobility ratio is less or equal to one [21]. Volumetric sweep efficiency is generally increased when the mobility ratio is reduced, and in reservoirs with great variations in the permeability, mobility ratios below unity are often an advantage.

The mobility ratio can be adjusted by changes in the relative permeabilities and/or changes in the fluid viscosity. Most mobility control processes involve addition of chemicals to the injection fluid. These chemicals are primarily polymers when the injection fluid is water. [4]

The end point mobility ratio describes the stability of the displacement front, and can be expressed as;

$$M^{0} = \frac{\lambda_{w}}{\lambda_{o}} = \frac{k_{rw}^{0}}{k_{ro}^{0}} \cdot \frac{\mu_{o}}{\mu_{w}}$$
(2.27)

where  $M^0$  is the end point mobility ratio,  $\lambda_w$  and  $\lambda_o$  is the mobility of the water and oil respectively,  $k_{rw}^0$  and  $k_{ro}^0$  is the end point relative permeability of water and oil respectively and  $\mu_o$  and  $\mu_w$  is the viscosity of oil and water respectively. The end point mobility ratio affects the microscopic displacement efficiency in a very significant degree because of its influence on the water breakthrough [14]. Three scenarios are usually used to explain the behavior of the front, and these are illustrated in figure 2.8 below.



Figure 2.8: Illustration of three possible behaviors of the displacement front depending on the end point mobility ratio. From Skarestad, M. and A. Skauge (2014) [14].

Water breakthrough will occur at an early stage of the displacement process for the higher end point mobility ratio values ( $M^0 - 10$ ). This will result in a long tail production of oil after the breakthrough. Intermediate values ( $M^0 - 1$ ) will result in a later water breakthrough and a shorter tail production. For smaller values of the end point mobility ratio ( $M^0 - 0.1$ ), the water breakthrough will occur significantly later in the displacement process, and this scenario is the most desirable one [14].

Even though the mobility ratio is as desired, the microscopic displacement efficiency is limited by the amount of residual oil in the porous media. This microscopic displacement efficiency,  $E_D^{\infty}$ , can be calculated with this formula;

$$E_D^{\infty} = 1 - \frac{S_{orw}}{S_{oi}} \tag{2.28}$$

where  $S_{orw}$  is the oil saturation at residual water saturation and  $S_{oi}$  is the initial oil saturation [14]. In the experiment used for this thesis there is only residual oil left in the porous media, which means the microscopic displacement efficiency will be equal to zero.

#### 2.3.3 Flow regimes

There are mainly three categories of flow regimes in a porous media; steady state, semisteady state and the transient period. The steady state and the transient periods are the ones that are relevant for this thesis, and will be the only ones discussed in this section. Steady state flow means that there is a constant pressure everywhere in the reservoir. This type of flow can occur in the drainage area of the well if the pressure at the boundary is held constant during production at a constant rate [22]. The pressure will be independent on both time and radial position in the well. Steady state flow occurs when the reservoir pressure is maintained by in example waterflooding or a strong aquifer. This state can be hard to keep up because the production rate may not always be constant. [23]

The transient period, or the unsteady state, is defined as the period where a pressure change in the well region reaches the outer boundary. The pressure in the well drops when the production start, and this will cause the pressure in the rest of the reservoir to change. This means that the pressure drop will be a function of the time and the radial position in the reservoir, in contrast to a steady state.

When the pressure disturbance reaches the outer boundary, there are two possible outcomes. The pressure regime can reach a semi-steady state where the pressure will drop, or a steady state if the pressure is maintained by water injection. [24]

# 3. Polymer flooding

Polymer flooding is one of the most frequently used EOR-techniques, aiming to increase the volumetric sweep efficiency and/or improve the recovery rate. The technique is a chemical injection and involves adding polymers to the injection brine to increase the viscosity of the injection fluid and thereby decrease its mobility. By changing the mobility of the injecting fluid, the mobility ratio between the injection fluid and the crude oil will be improved, which in turn will give a more ideal displacement front [4]. For reservoirs with a high adverse mobility ratio, polymer flooding will lead to an improvement of the macroscopic sweep efficiency. In addition to mobility control, polymers can also be used to plug off high permeability zones, and thereby improve the total recovery. Polymer flooding will be especially favorable in heterogeneous reservoirs or reservoirs with viscous oil. Small concentrations of polymer will increase the viscosity of aqueous solutions very significantly, which makes polymers very useful for EOR implementations.

Since polymer flooding is one of the more expensive EOR methods, the low oil prizes make the technique less attractive. This makes it very important to perform careful calculations of the productivity to evaluate if the process is economically viable, and how the recovery method will be most successful. Polymer flooding is shown to have greatest effect if it is applied early in the waterflooding, when the oil saturation is relatively high [25], which indicates that EOR methods should be taken account for early in the recovery method evaluation. Polymers with high molecular weight or salt-resistant polymers that withstands high temperatures are making polymer flooding more economical [26], and can contribute to increase the viability.

For the polymer to be successful in EOR implementations, it is important that it remains stable at the reservoir conditions and in contact with the reservoir brine during the timeframe of the polymer flooding. Therefore, it is necessary to have knowledge about the polymer characteristics and behavior to optimize the polymer flood. In the following pages some of the most important characteristics, behavioral patterns and restrictions will be accounted for.
The polymer rheology is observed to be different in a porous media than in a capillary flow, because it is influenced by the strain history and the pore structure geometry. The rheological behavior is important concerning the injectivity and the displacement pressure gradients, and it is thereby of interest to understand the in-situ rheology. This subject is not investigated widely enough at this point to fully understand the polymer flow through a porous media, so it is important to study the in-situ rheology for different scenarios to be able to estimate the productivity of polymer flooding [27]. In this thesis the in-situ rheological behavior of HPAM will be studied for polymer solutions of different concentrations at different injection rates in a radial flow experiment.

### 3.1 Polymers

Polymers are long chains of molecules that have the ability to change the viscosity and mobility of fluids. Biopolymers like cellulose or proteins have high viscosity, high tolerance of salt and mechanical degradation and are environmental friendly, but on the other side they are expensive, have limited production capacity and low tolerance of bacteria. Synthetic polymer like polyethylene and polyamide have high viscosity, are relatively cheap and have high production capacity. On the other hand, synthetic polymers are not stable at high salinity, they are environmentally challenging and have low tolerance for mechanical degradation. Polymers are tailored to fit the reservoir conditions, and it is very important to use the polymers with the best fit, especially considering salinity and temperature, in order to optimize the recovery.

The most common polymer types for chemical EOR implementations are biopolymers like Xanthan and synthetic polymers like polyacrylamide (PAM) or partially hydrolyzed polyacrylamide (HPAM) [4]. Synthetic polymers are more extensively used in field experiments than biopolymers, and especially PAM and HPAM. The polymer used for this experiment was partially hydrolyzed polyacrylamide (HPAM), and this type will therefore be the only polymer discussed further in this thesis.

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#### 3.1.1 HPAM

HPAM is extensively used in polymer flooding because of its low production costs and its rheological properties. The historical reason for HPAM to be used in field operations, from the 1960's, is that it was already widely used in other industries, in particular the paper industry [8]. Studies of HPAM have mainly been exerted in linear cores, and recent research suggests that there are significant differences in polymer flow behavior in linear and radial models [5].

#### 3.1.1.1 Molecular structure

The polymer flow behavior, retention, adsorption and stability are all connected to the molecular structure of the polymer, and therefore it is important to have knowledge about it. HPAM is a synthetic polymer with acrylamide monomers. The chain is randomly coiled and the coil stricture of the polymer is flexible when added in aqueous solutions [8]. Figure 3.1 below shows a schematic of the PAM- and HPAM-molecule.



Figure 3.1: Sketch of the structure of a Polyacrylamide and a Partially Hydrolyzed Polyacrylamide. From Sorbie, K.S (1991)
[8]

The polyacrylamide molecule is partially hydrolyzed to some degree, which implies that some of the amide groups are converted to carboxyl groups. These carboxyl groups makes the backbone chain of the HPAM polymer negatively charged, which has a great impact on the rheological properties of the polymer solution. At low salinities, the polymer will stretch out because of repulsion between the negative charges. This will make each molecule take bigger space in the solution, and thereby the viscosity will increase. Research has shown that the relative viscosity decreases with increasing degree of hydrolysis [28].

The degree of hydrolysis will have an impact on the water solubility, chain extension, sensitivity, retention and viscosity of the solution [8], and the hydrolysis can be tailored to optimize the polymer properties for the specific case. For HPAM used in polymer flooding, a degree of hydrolysis in between 30-35% is most common [4]. HPAM will not be soluble in water if the degree of hydrolysis is too small, and the polymer will be too sensitive to salinity and hardness if the degree of hydrolysis is too high. Increasing temperatures in the reservoir will continue the hydrolysis [8], and therefore it is important to carefully calculate the right amount of hydrolysis for the polymer to have an optimal performance.

The mobility of polymer solutions containing HPAM is reduced because of both increasing viscosity of the solution and reduced permeability of the porous media because of polymer retention [28].

#### 3.1.1.2 Molecular weight

Polyacrylamides that are used in EOR processes typically have an average molecular weight in the range 2-10 x  $10^6$ . They also tend to have a wide molecular weight distribution (MWD). Research has also shown that the MDW have a significantly long high molecular weight tail that can be up to 40 x  $10^6$ . For a polyacrylamide polymer with molecular weight of 4 x  $10^6$ that has been hydrolyzed to a degree of 30%, one fully extended molecule in a great solvent would have a diameter in the range of 7-25 Å and be longer than 10  $\mu$ m. [8].

Studies have shown that for solutions with the same polymer concentration, the viscosity and shear dependence will increase with the molecular weight. This will theoretically imply that usage of small amounts of polymer with high molecular weight will be an economic advantage in contrast to using a great amount of polymer with low molecular weight to obtain the most favorable viscosity [21].

The ionic strength,  $I_s$ , is defined as;

$$I_s = \frac{1}{2} \sum m_i z_i^2 \tag{3.1}$$

where  $m_i$  is the molar concentration and  $z_i$  is the ionic valence of ion i.

The ionic strength is a function of the ionic concentration, and from equation 3.1 above, it is obvious that the ionic strength will increase with increasing ion valence. Monovalent ions like Na<sup>+</sup> will result in increasing ionic strength with the molarity. Divalent ions like Ca<sup>2+</sup> on the other hand, will have a non-linear increase in the ionic strength when increasing the concentration. [8]

### 3.2 Rheology

Rheology is the study of the flow behavior of non-Newtonian fluids [8], and can be described as deformation and flow of materials in response to applied stress. Polymers rheological properties in dilute solutions make them useful for EOR implementations. Aqueous solutions containing polyacrylamides often exhibit non-Newtonian behavior, which indicates that the viscosity is dependent on the shear rate.

The viscosity of polymer solutions normally decreases with increasing shear rate, and this behavior is called shear thinning. The viscosity decrease occurs because the molecules reduce the internal friction by aligning themselves with the flow direction. Shear thinning behavior is often expressed by the power law-model;

$$\mu = K\dot{\gamma}^{(n-1)} \tag{3.2}$$

where  $\mu$  is the viscosity, *K* is the power-law constant, n is the power-law exponent and  $\dot{\gamma}$  is the shear rate [28].

At very low and very high shear rates, polymer solutions tend to behave like Newtonian fluids, with constant viscosity. Meanwhile, in the intermediate shear rates, they tend to behave as pseudo-plastics that obey the power law concerning the dependency of their viscosity on the shear rate [4]. The Carreau model can be used to describe the behavior of polymer solutions within a wide range of shear rates, and the Carreau equation is expressed as;

$$\frac{\mu - \mu_{\infty}}{\mu_0 - \mu_{\infty}} = \left[1 + (\tau \dot{\gamma})^2\right]^{(n-1)/2}$$
(3.3)

where  $\mu$  is the viscosity,  $\mu_{\infty}$  is the viscosity of the infinite shear rate,  $\mu_0$  is the viscosity of the zero shear rate,  $\tau$  is the relaxation constant,  $\dot{\gamma}$  is the shear rate and n is the power law exponent (n < 1). Figure 3.1 shows a comparison of the Carreau model and the power law model for the viscosity of polymers. This model describes the behavior of polymer solutions at pure shear flows where the shear rate,  $\dot{\gamma}$ , is orthogonal to the flow direction.



Figure 3.2: Carreau model and power law model for the viscosity of Polymers. From Sorbie, K. S. (1991) [8].

It is evident from figure 3.2 that at low shear rates, the macromolecules does not have a significant conformation change, therefore the viscosity is constant and the flow exerts a Newtonian behavior.

At increasing shear rates, the macromolecules are starting to deform and gradually orient themselves in the flow direction. This causes a reduction in the viscosity, and exerts a power law behavior. This is the shear thinning flow regime. At the higher shear rates, the macromolecules are oriented with the flow direction, and the viscosity is lowered but constant. The flow then exerts a Newtonian behavior again. [4] HPAM shows viscoelastic and extensional viscosity effects, and the behavior of the polymer flow based on these characteristics will be discussed in the following sections.

The onset of shear thickening for HPAM flowing through a porous media can be defined by the Deborah number,  $N_{De}$ ;

$$N_{De} = \frac{\text{Liquid relaxation time}}{\text{Characteristic time for fluid flow}} = \frac{t_e}{(1/\dot{\epsilon})} = t_e \dot{\epsilon}$$
(3.4)

where  $t_e$  is the relaxation time and  $\dot{\varepsilon}$  is the characteristic stretching rate in the porous media. The elongational time for fluid flow is defined as the inverse of  $\dot{\varepsilon}$ . The resistance of flow increases significantly when the Deborah number is above a critical value, ~0.5, because of increasing extensional viscosity. [8]

#### 3.2.1 Effect of salinity

The rheology of polymer solutions may be affected by the salinity of the brine and the divalent ions, and the largest effects are observed for polyacrylamides. [5] HPAM will have a strong viscofying effect in brines of low salinity, because of the electrostatic repulsion between the carboxylate groups. Oppositely, high salinity will lead to a reduction of the repulsive forces, and cause a lower viscofying effect. Divalent ions like Mg<sup>2+</sup> and Ca<sup>2+</sup> will especially lead to a significant reduction in HPAM-viscosity. [8] Figure 3.3 shows the difference between polymer coils in high and low salinities.



Figure 3.3: Effect of salinity on the polymer molecules. From Sorbie, K.S. (1991) [8].

## 3.2.2 Effect of pH and temperature

Variations in pH can have similar effects on the polymer viscosity as the salinity. The polymer chain will be neutral at low pH values and there will be less expansion of the chain because of the electrostatic effects. The viscosity is observed to decrease by a factor by 4 when the pH goes from 9.8 to 4. This effect will be greatest in solutions with low salinity. The polymer chain will be completely charged at high pH values [8].

Nouri et al. (1971) showed that the viscosity of polymer solutions and the shear dependence will decrease with increasing temperatures [21], while Smith, F.W. (1970) stated that increasing temperature has little effect on the water mobility reduction [29].

# 3.3 In-situ rheology

In-situ rheology is the rheological behavior of non-Newtonian polymer solutions as they are flowing through a porous media [8]. It is of great interest to compare the in-situ rheology to the bulk rheology of a polymer solution, because these rheological behaviors are shown to deviate from each other. The in-situ rheology is very important to consider when applying a polymer flood because it will have a great impact on the injectivity and the sweep efficiency. [8]

The bulk rheology of HPAM is, as mentioned, dependent on the molecular structure of the polymer. Not surprisingly, the molecular structure will also have an effect on the in-situ rheology. In addition to this, the porous media is also an important factor. A flow through a porous media will naturally be more tortuous than flow in a rheometer [8]. In a porous media, the polymer chains are pulled and contracted as the pore sizes changes throughout

the flow pathway. The apparent viscosity will increase as the shear rate is increased. This is referred to as shear-thickening viscosity behavior. HPAM is described as shear thickening in porous media, but not in rheological measurements [30]. Shear thinning can be observed for HPAM solutions in a porous media if the salinity is low, the polymer concentration is sufficiently high and if the flow rates are low. The level of shear thinning will be very little or nonexistent under EOR compared to the shear thickening at the high flow rates [31].

The macroscopic rheology of polymer solutions in a porous media is referred to as the apparent viscosity. For non-Newtonian fluids, the in-situ apparent viscosity,  $\eta_{app}$ , can be found by rearranging the Darcy equation;

$$\eta_{app} = \frac{kA\Delta P}{QL} \tag{3.5}$$

In this case,  $\Delta P$  will usually not be a linear function of the flow rate, Q. Polymer retention may lead to a reduced effective permeability, k, so it is of importance to assure if the pressure drop is a result of the viscous effect of the polymer solution or to some degree a result of retention resulting in pore blocking and permeability reduction. If the pressure drop is affected by retention, the apparent viscosity will be overestimated, but if there is no permeability reduction of the porous media, rheograms of apparent viscosity versus the flow rate can be made. Retention will be described more in detail in a later section. [8]

The polymer rheology has a significant effect on both injectivity and sweep efficiency in a porous media under EOR implementations. HPAM has shown shear-thinning behavior at low velocities for fluid flow in porous media [31]. This means that the viscosity will decrease as the velocity and shear rate increase. Simultaneously, HPAM is extensively proved to have a shear thickening behavior for high injection rates, where the resistance factor increases with increasing flow velocity. This behavior can be addressed to the viscoelasticity of the polymer molecules during flow through a porous media. Although polymer flooding is assumed to improve the macroscopic sweep only, the viscoelastic behavior is shown to lower the residual saturation of oil [15], and hereby the microscopic sweep.

HPAM solutions are observed to undergo mechanical degradation during injection into a porous media, which will reduce the polymers efficiency regarding mobility control. This will

also have an effect on the viscoelastic behavior. Research has shown that the maximum resistance factor is dependent on the permeability in addition to the Deborah number. It has been proposed that this is because of the reduced importance on mechanical degradation after the polymer has been exposed to shear. After the polymer has been mechanically degraded, the original polymer solution parameters are changed and the initial ones are no longer valid.

Equation 3.6 below is a commonly used equation that relates the shear rate to the flux and the properties of the porous media for a two-phase flow;

$$\dot{\gamma}_{pm} = \alpha' \frac{4u}{\sqrt{8k_{e,i}\phi}} \tag{3.6}$$

where  $\dot{\gamma}_{pm}$  is the effective shear rate,  $\alpha'$  is a parameter describing the pore structure, u is the Darcy velocity,  $k_{e,i}$  is the effective permeability of fluid I, and  $\phi$  is the porosity of the porous media. [8]

Polymer floods are normally applied with concentrations of 200-4000 ppm. This span is called the semi-dilute regime, and these concentration values indicate that the molecules will be interacting. The dilute and semi-dilute regime is separated by the critical overlap concentration,  $C^*$ . For concentrations above this value, the polymer molecules will overlap and there is possibility for polymer aggregation and entanglement. A typical shear viscosity curve for HPAM bulk solution will look like the curve in figure 3.4.



Figure 3.4: A typical shear viscosity curve for HPAM [5].

For a HPAM solution in porous media, the curve is very different. The expansion and contraction of polymer molecules because of the porous media structure can result in a steep increase in the shear-thickening behavior.

### 3.3.1 Inaccessible Pore Volume

Polymer molecules are often large relative to some of the pores in the porous media, and therefore the polymers do not have access to all the pores that are filled with brine. This pore space is referred to as the inaccessible pore volume (IPV). The amount of inaccessible PV is dependent on the polymer type and the type of porous media, and can be as small as 1-2% or up to 25-30% [28].

The inaccessible pore volume results in different velocities for the water bank and the polymer slug, because the pore space is not accessible to the large polymer molecules. Since less of the rock surface is in contact with the polymer because of the IPV, the amount of polymer adsorbed by the porous media will be less. [25]

#### 3.3.2 Apparent Slip Effect

Molecular surface exclusion is believed to cause what is called the apparent slip effect, which follows from entropic exclusion of polymer molecules on the surface of the pores. This will increase the velocity of the polymer flow, and the phenomenon is illustrated in figure 3,5 below.



Figure 3.5: Capillary tube illustrating the apparent slip effect. From Sorbie, K.S. (1991) [8].

Figure 3.5 shows the depleted layer in a capillary tube, and the polymer concentration profile. The thickness of the depleted layer is in the range of the molecular size.

The in-situ viscosity will be reduced because of the apparent slip effect, and the propagation through the porous media will accelerate. The more similar the pore size and the polymer molecular size, the higher significance this effect will have. The polymer molecules will be restricted close to the wall, while it can rotate freely in the bulk of the fluids. This will cause an entropic drive force to migrate particles from the wall site. [8].

## 3.4 Degradation

During a polymer flood it is preferable that the polymer properties are not degraded. This includes any process that will break down the molecular structure of the polymer and by this reduce the molecular weight [8]. If this happens, the polymers effect on the viscosity may be reduced. Polymer degradation is detected by lowered viscosity of the polymer solution over time [28]. Polyacrylamide is stable at up to 90°C at normal salinity levels, and up to 62°C at normal seawater salinities. This characteristic restricts the use of PAM and HPAM in offshore operations [4]. There are three main degradations considered in oil recovery; Chemical, biological and mechanical degradation, which will be discussed in this section [8].

#### 3.4.1 Chemical and biological degradation

Chemical degradation includes several degradation processes, in example thermal oxidation, hydrolysis and free radical substitution. Polyacrylamides are susceptible to oxidative attacks by the dissolved oxygen in the injected water. In compliance with chemical reaction kinetics, the degradation rate will increase with increasing temperatures. By reducing the oxygen concentration in the injection water or the brine, this type of degradation can be prevented [28]. Research has shown that Polyacrylamide can be stable at quite high temperatures, measured up to 90°C in absence of Oxygen and divalent ions [28]. Usually the other types of degradation are of bigger concern during a polymer flooding.

Biological degradation refers to breakdown of macromolecules by bacteria in the reservoir or during storage. This will only have a big effect on the polymer at low temperatures or in absence of effective biocides in the reservoir. It is perceived that synthetic HPAM is less exposed to bacterial attacks in the low-temperature regimes than biopolymers, but there are little data to prove this. Biodices like formaldehyde are successfully used to prevent biological degradation [8].

#### 3.4.2 Mechanical degradation

Because PAM has an elastic behavior, the polymer will easily be mechanically degraded by high shear rates in a porous media [28]. The degree of mechanical degradation is shown to correlate with the pressure gradient as the degradation increases when the pressure gradient increases [28]. In order to achieve a successful polymer flood it is important that the polymer is shear-stable under the injection conditions. A mechanical degradation will break down the large molecules to smaller ones, which will change the molecular weight distribution. In such case, the resistance factor will decrease. This could in turn reduce the viscosity of the solution. Even though the polymer is shear damaged, it can still have satisfactory properties for the flooding [8].

Most of the mechanical degradation will happen near the well because of the high flow rate at the inlet and the high pressure. After this point, the flow rate and pressure will decrease and there will be less significant degradation of polymer molecules. [28]

During flooding with HPAM solutions, a greater pressure drop than expected may occur at the well site. This phenomenon is referred to as the entrance pressure drop, and is defined

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as the difference between the observed injection pressure and the deviating pressure drop [32]. The entrance pressure drop can be related to the mechanical degradation, and the pressure drop is equal to zero until the flow rate is high enough for mechanical degradation to take place. After this point, the entrance pressure drop and the degree of degradation will increase with increasing flow rate. The injectivity of HPAM in porous media is affected by the existence of an entrance pressure drop. [33]

## 3.5 Retention

Retention is described as the mechanisms that reduce the mean velocity of the polymer molecules during their flow through a porous media [4]. Primarily, retention of polymer is caused by adsorption on the surface or by mechanical entrapment in small pores relative to the polymer molecule size, but retention can also be caused by a local accumulation of polymer (hydrodynamic retention) [28]. Retention of polymer will lead to a decrease in the polymer concentration of the solution, and in the velocity of the front, which will result in a reduction in the efficiency. Polymer entrapment and dilution of polymer solution results in decreased mobility control in remote areas. On the other hand, retention may result in lowered permeability of the porous media, and this may contribute to better recovery. Overall the general effect tends to be reduced oil recovery. Vela, S. et al (1976) concluded that the polymer retention will increase with decreasing permeability [34]. Generally, retention of polymer in EOR implementations is considered irreversible and instantaneous. [28]

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Figure 3.6: The three types of polymer retention in a porous media. Illustration inspired by sketch from Zolotukhin, A.B. and J.R. Ursin (2000) [4].

To calculate the amount of polymer that is required to achieve a successful polymer flood, this mass balance equation can be used;

Or this equation;

$$V_b \phi F_{VP} \rho_{ps} C_p = V_b (1 - \phi) \rho_r R_p \tag{3.8}$$

Where  $V_b$  is the bulk volume of the porous media,  $\phi$  is the porosity,  $F_{VP}$  is the pore volume polymer solution injected,  $\rho_{ps}$  is the density of the polymer solution,  $C_p$  is the polymer concentration,  $\rho_r$  is the rock density and  $R_p$  is the retention of polymer. [4]

The degree of polymer retention is dependent on the polymer type, the molecular properties of the solution, the solvent condition and the characteristics of the solid surface. The degree of hydrolysis of HPAM will have an effect on the retention. HPAM have high molecular weight and extended chains, which makes it likely that retention of this polymer type is irreversible. This is because of the assumption that not all of the chain will detach from the surface simultaneously [35].

#### 3.5.1 Surface adsorption

Surface adsorption refers to all interaction between the polymer molecules and the solid surface of the porous media. The molecules are attached to the surface because of physical adsorption. Generally, the larger surface areas available, the higher levels of surface adsorption are observed. The polymer molecules adjacent to the pore walls will have a zero flow rate, and thereby reduce the polymer solution flow through the porous media. Polymer adsorption is a very important subject when determining if a polymer flooding is economically viable. [8]

#### 3.5.2 Mechanical entrapment

Mechanical entrapment occurs when the pore channels are to narrow for all the polymer chains to continue the flow trough the porous media. The porous media is an interconnected network of pores and pore throats that give the solution many alternate flow paths from inlet to outlet. When molecules are trapped in smaller pores, the overall flow will be reduced because these pores will be blocked for fluid flow. This type of retention is most common in low-permeability zones with smaller pores. Mechanical entrapment can either occur by polymers with large molecular weight relative to the pore size, or by concentration blocking of polymers with low molecular weight. Studies have shown that the mechanical entrapment is dependent on the polymer concentration. The degree of mechanical entrapment in the core will be highest at the inlet and decrease towards the outer boundary.

The most important consequences of mechanical entrapment are reduced polymer concentration of the flow, and reduced permeability of the porous media. The media can be completely blocked if the entrapment is sufficient enough. [8]

### 3.5.3 Hydrodynamic retention

Hydrodynamic retention of polymer molecules can be hard to define but occurs when polymer molecules falls out of the flow and stagnates in a porous media [8]. This may happen when the flow rate is suddenly increased after a period of constant flow rate. Increasing polymer retention with increasing flow rate is observed for polyacrylamide when

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measuring the polymer concentration before and after a polymer flood. This makes it possible to conclude that more polymer molecules are lost for polymer flooding with higher flow rates [36]. According to Zhang, G. and R.S. Seright (2015), the loss of polymer is increasing more sharply with rate in the low-permeability zones than in the high-permeability zones. The report also stated that this type of retention is reversible in almost every case, and that it affects the polymer flow in a limited degree. [37]

## 3.6 Mobility and permeability reduction

Polymer solutions resistance to flow and their ability to reduce the permeability of a porous media causes mobility reduction. Some factors needs to be defined to describe this reduction;

Resistance factor  $(R_F)$  is defined as the ratio between the water mobility  $(\lambda_w)$  and the polymer solution mobility  $(\lambda_p)$  at the residual oil saturation. When this equation is combined with the definitions of mobility (equation 2.25), this relation is obtained;

$$R_F = \frac{\lambda_w}{\lambda_p} = \frac{k_{e,w}\mu_p}{k_{e,p}\mu_w}$$
(3.9)

where  $k_e$  is the effective permeability,  $\mu$  is the viscosity, and w and p denotes water and polymer solution respectively. [39] The  $R_F$  values show the same trend as the apparent viscosity when plotted against the injection rate. [40]

Permeability reduction factor  $(R_k)$  is the flow resistance caused by the permeability reduction, and is defined as the ratio between the water permeability  $(k_w)$  and the polymer permeability  $(k_p)$ ;

$$R_k = \frac{k_w}{k_p} = \frac{\mu_w}{\mu_p} R_F \tag{3.10}$$

Polymer retention contributes to the reduction of the permeability of the rock and depends on polymer type, the retained amount, pore-size distribution and polymer size relative to pore size [28]. The permeability reduction is measured by flooding polymer through the porous media before displacing the polymer with brine afterwards. The permeability of the final brine can be calculated and compared to the permeability before the polymer flood. It can be convenient to express the permeability reduction based on the initial brine permeability, which is done by the residual resistance factor [28]. The residual resistance factor ( $R_{RF}$ ) is a measure of the polymer induced permeability reduction, and is defined as;

$$R_{RF} = \frac{\lambda_w}{\lambda_{wa}} = \frac{k_w}{k_{wa}} \approx \frac{k_w}{k_p}$$
(3.11)

where  $k_w$  is the water permeability measured before the polymer flooding, and  $k_{wa}$  is the water permeability after the polymer flooding. The residual resistance factor will increase when the permeability of the porous media decreases or when the molecular weight increases. [40]

## 3.7 Polymer concentration

The concentration of polymer molecules in a solution will influence on the interaction between the molecules. As previously mentioned, higher molecular weight will increase the viscosity of the solution, and in the same way will the viscosity increase with the concentration of polymer. [38]

There are three proposed concentration regimes called dilute, semi-dilute and concentrated. Where the concentrations are lowest in the dilute regime and highest in the concentrated regime. In the dilute regime the polymers have space to move freely, and aggregation and entanglement will not happen here. In a semi-dilute regime, the possibility of aggregation and entanglement is present, because the radii of the polymer molecules may overlap. For a concentrated regime, the solution is called a viscoelastic solid, as the molecules will overlap and create a network structure. The three regions and the polymer interactions are illustrated in figure 3.7.



Figure 3.7: The three different concentration regimes. From Zhang, G. and R.S. Seright, [38]

# 4. Injectivity

Understanding polymer injectivity is crucial for successful polymer EOR implementation. In radial cores, injectivity experiments show a significant reduction in differential pressure compared to linear cores. So there is a remarkable difference between radial and linear polymer flow. Radial injections go through transient (unsteady state) and semi-transient pressure regimes. When using polymers to increase the viscosity of the injection water, the injectivity is likely to be reduced.

The injectivity is possible to calculate by using this formula;

$$I = \frac{q}{\Delta P} \tag{4.1}$$

where *I* is the injectivity, *q* is the injection rate and  $\Delta P$  is the pressure drop in the injection well.

Theoretically, the rheological behavior of polymer may negatively affect the well injectivity. Since the velocity and pressure is highest at the well, a shear thickening polymer solution will be very viscous at this section of the reservoir, and may create an excessive pressure buildup or cause low maximum injection rates [28]. However, the well injectivity is observed to be high in the well-area and seem to be little affected by the shear thickening characteristic of HPAM [15]. Yiwei, Ma. And M.W. McClure showed that the shear thickening induces a fracture at the well bore, which prevents shear thickening and hereby also the injectivity loss. [15].

# 5. Problems with polymer flooding

Polymer adsorption is generally irreversible, and the polymer will therefore cause permanent formation damage. Oil that is left in the reservoir after a polymer flood will be more difficult to retrieve by other recovery techniques because of the permeability reduction the polymer adsorption has caused [30].

Reduced permeability and increased viscosity may lead to low polymer injectivity. Polymer stabilizes the water/oil emulsions, and this is a problem when trying to reuse the produced water.

# 6. Previous research

The rheological behavior of polymers has been studied for multiple years, and yet the in-situ behavior is not fully understood. This section mentions some of the discoveries made of the subject throughout the years.

Pye, D. J. (1964) stated that for water soluble polymers containing acrylamide, the viscosity values measured in the formation deviates significantly from the viscometer values. This deviation was quantified as the resistance factor, R, which was defined as the ratio of the brine mobility to the polymer solution mobility at residual oil saturation. It was assumed that the permeability was constant, and that there was no permanent permeability loss during the polymer flood. These polymers viscosity deviation from the viscometer values was later known as viscoelastic behavior. Increasing flow rates showed increasing viscosities, and this was addressed to the rock properties. The study concluded that this viscofying effect would give increased oil recoveries, and lower production costs because of the low polymer concentrations needed to improve the water-oil mobility ratio. [39]

Following the research of Pye, the viscofying effects of HPAM became a subject of interest, and in 1970, Smith, F.W. found that the viscosity will increase with the velocity. [29] Seright, R.S. et al. (2009) observed that HPAM solutions exerted Newtonian behavior at low to intermediate fluxes, and that the solutions showed pseudodilatant behavior for the intermediate to high fluxes. [33] In 2010, Seright R.S. et al. concluded that shear thinning behavior could be observed for HPAM solutions in porous media if the solutions were fresh, injected in short cores with low permeability or if the solutions had low salinity levels. However, the shear thinning would be almost non-existent compared to the degree of shear thickening at the high flow rates. [31]

Hatzignatiou, D.G. et al. (2015) stated that the viscosity of polymer solutions will increase with the polymer concentration, and that the viscosity may decrease in presence of high salinities, under high temperatures or if the solution is exposed to oxygen. They also stated

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that the rate of viscosity decrease could be described by the power law model, and that the power law exponent, n, is a rheological characteristic of the specified polymer. [41]

Hatzignatiou, D.G. et al. (2013) reported that the polymer adsorption and oil recovery is greatly affected by the wettability of the porous media. The polymer will not coat the rock surface in an oil-wet media, and this leads the water mobility to be reduced to a great extent in regions with low oil saturations in a oil-wet media in comparison with a water-wet media. This effect was suggested to improve the recovery. Skauge, A. et al. (2012) stated that viscous fingers will contribute to better recovery in a non-water wet media with viscous oil, by transporting the oil through the channels during a tertiary polymer flood. [50] Broseta, D. et al. (1995) reported that the presence of residual oil in a water-wet media will increase the polymer adsorption and retention of HPAM, and that this effect is addressed to the oil working as an extra surface for the polymer to adhere to. [40]

A recent study at the Centre for Integrated Petroleum Research (CiPR) at the University of Bergen by Skauge, T. et al (2016) showed that the onset of shear thickening will increase with increasing injection rates in experiments with radial flow. They also concluded that the shear thickening region would be longer in comparison with the lower rates. [5] Zamani, N. et al. (2015) concluded that the onset of shear thickening will depend on the rock type, the permeability, tortuosity and the polymer properties. It was suggested that the onset will vary for different positions in the media, and this will make the onset vary with the injection rate. [42]

Jacobsen, J.G. (2017) reported that the effect of the polymer concentration on the HPAM rheology was to increase the absolute viscosity and the shear thinning-slope, and that this could be addressed to the increased amount of high molecular weight species. [43]

# 7. Simulation tools

Simulation models are important tools when determining what recovery method would be the best fit for the specific reservoir. By implementing known parameters describing the porous media, the fluids present in the reservoir and the processes involved for an EOR method, the tools can be used to estimate the expected production. By testing different

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recovery methods in the model, the most productive method can be chosen without unnecessary and expensive testing in the field. Field operations can be irreversible, and may permanently weaken the productivity more than it helps the total recovery. [30] By using simulation tools to estimate the economical profit, the more expensive EOR methods can be viable for field projects. [13]

The simulation tool used to history match the experiment in this thesis was MRST (MATLAB) by SINTEF. MRST was used for automatic history matching with the Ensemble Kalman Filter (EnKF). In this section, a brief introduction of the simulation tool will be presented.

Automatic history matching is very useful to speed up the history matching, as the conventional method is very time consuming where the parameters are changed one by one. In addition, manual history matching depends greatly on the experience of the engineer who interprets the data. Automatic history matching should only be used as a tool and not as a replacement for reasonable interpretations by experienced scientists and engineers. [44]

### 7.1 MRST, MATLAB

MATLAB stands for matrix laboratory and is developed by the MathWorks. The software is designed for engineers and scientists, and can be used in multiple different ways. In example MATLAB can be used for modeling, simulation, data analysis and development of algorithms. [45] MATLAB has been evolved with the help form multiple users, and contains a broad specter of "toolboxes" that extends the applications of MATLAB. [42]

The MATLAB Reservoir Simulation Toolbox (MRST) is developed by SINTEF and is an open source software that can be used in a variety of ways. The toolbox aims to make the process from basic testing to validation of more realistic problems more efficient. It contains multiple mathematic models, computational methods, plotting tool and others to be able to perform simulations of fluid flow in a porous media. [46] Reservoir simulators evaluate and predict how the fluids in a hydrocarbon reservoir will behave by using numerical models of the petrophysical properties. Their main purpose is to optimize the recovery of hydrocarbon reservoirs by evaluate all the data available for the specified case. [46]

The Ensemble Kalman Filter (EnKF) was used in this thesis to do automatic history matching in MATLAB. This is a workflow tool developed by the University of Bergen (UiB) as an add-on to MATLAB, and was introduced by Evensen (1994). The EnKF uses a Monte Carlo approach where it uses ensemble random values from a distribution to approximate the state distribution. The ensembles are updated until the simulated values give satisfactory matches with the experimental data. [47] The tool has a broad specter of applications, but in this section only a summary of the approaches used in this thesis will be included. Detailed descriptions of other possible applications of the EnKF can be found in Evensen (2003) [48].

#### 7.1.1 Waterflooding

The rock properties of the experimental core sample and the injection rates are inputs in the MATLAB script, while the permeability is the only tuning parameter. The differential pressure is estimated by MRST by using Darcy's law for a two-phase flow in radial geometry (equation 2.18), which was described in section 2.2.2.2. The permeability of the core was assumed heterogeneous, because a homogeneous permeability gave unsatisfactory history matches of the pressure data. The permeability field was divided into three regions,  $K_1$ ,  $K_2$  and  $K_3$ . The two boundaries between the regions were defined as  $r_1$ , the outer boundary of region 1, and  $r_3$ , the inner boundary of region 3. This means that the history matching was managed by a total of five parameters.

MRST gives  $r_1$  and  $r_3$  as fractions of the total radius while the permeabilities are given in mD. For each of the five variables, maximum and minimum values are stated in the script. The number of ensembles, iterations and the size of the experimental errors are chosen and the Ensemble Kalman Filter simulates the best history match in the range of these numerically. The inputs can be changed if the result is unsatisfactory. Below is some descriptions of the code words in the script.

n\_ens is the number of ensembles per iteration performed. This means that for each iteration, the simulator chooses this amount of values from the total range specified in the script.

er\_var is the experimental error and expresses the uncertainty of the given experimental data. If the experimental error value is high, the simulator have greater freedom in creating the best match.

n\_region is the amount of permeability regions chosen for the disk.

Aim denotes the type of aim the simulation has. In example for the waterflooding the aim is to find the permeability, so the code for this process will be "Permeability\_field", and for the polymer flooding the code will be "in\_situ\_rheology".

When the simulation is done, MRST provides one plot of the experimental data with the simulated curve, one plot of all the iterations and one distribution chart. The distribution chart shows if the maximum and/or minimum values need to be altered. Below is an example of a distribution chart provided from MRST after the history matching of the final water injection at 2.5 ml/min.



Figure 7.1: The distribution chart for the final water injection at 2.5 ml/min.

Figure 7.1 shows the distribution chart obtained from MRST after the history match of the final water injection at 2.5 ml/min. The lighter colored bars are representing the randomly selected ensemble members that MRST initially chose from the given interval. The darker

colored bars are the ensemble members from the narrowed interval after all the iterations are finished. The tallest bar is referring to the value that gave the best history match.

From the laboratory experiment, pressure data was given for both an initial water injection and a final water injection, which was performed after the polymer floods. The absolute permeability of the core sample was estimated for both water injections to compare the permeability fields before and after the polymer flooding.



Figure 7.2: Initial waterflooding at 25 ml/min.

Figure 7.2 above illustrates the history match of the initial water flood, where the red points are the experimental data and the green line is the simulated pressure curve. The black curve in the first figure is the estimated curve before the EnKF filter was run. The history matching of the final water injection was performed in the exact way as the initial water injection.

### 7.1.2 Polymer flooding

In addition to the input used for the water flood matching, the permeability is used as input in the script for the history matching of the polymer flooding. The objective of this history matching is to find the in-situ rheology for the polymer flooding, and the tuning parameters in this case are the parameters from the extended Carreau equation;

The Carreau equation (3.3) is adjusted to take into account both shear thinning and shear thinning in the extended Carreau model, which can be expressed as;

$$\eta(\dot{y}) = \eta_{\infty} + (\eta_0 - \eta_{\infty}) \left[1 + (\lambda_1 \dot{y})^2\right]^{\frac{n_1 - 1}{2}} + \eta_{max} \left[1 - e^{(-(\lambda_2 \dot{y})^{n_2 - 1}}\right]$$
(7.1)

where  $\eta(\dot{y})$  is the apparent viscosity as a function of the shear rate  $(\dot{y})$ ,  $\eta_{\infty}$ ,  $\eta_0$  and  $\eta_{max}$  are the apparent viscosities at infinite shear rate, zero shear rate and maximum shear rate respectively,  $\lambda_1$  and  $\lambda_2$  are the polymer specific empirical constants including the molecule relaxation time, and  $n_1$  and  $n_2$  are the power law indexes.

 $n_1$  represents the shear thinning behavior and  $n_2$  describes the shear thickening behavior. The range of  $\lambda_1$  and  $\lambda_2$  are unknowns while  $n_1$  should be below 1 and  $n_2$  should be below 2.5 to avoid instability. [10]

MRST produce four plots after the simulation is done, where one is a plot of the experimental data and the simulated curve, one plot is of the rheological curve, one plot is of all the iterations and the last one is a distribution chart.



Figure 7.3: The rheology curve obtained from MRST after history matching of the polymer flooding of the 1000 ppm polymer solution at 2 ml/min.

Figure 7.3 shows the rheological curve obtained from the history matching of the polymer flooding of the solution with polymer concentration of 1000 ppm at the injection rate of 2 ml/min. The curve follows from the extended Carreau equation (7.1).

# 8. Experimental data

The TOTAL disc 2 experiment was performed in a water wet radial Bentheimer disc with a diameter of 29.95 cm, wellbore radius of 0.325 cm and thickness of 1.996. The porosity had been measured to 24.67% and the permeability was estimated to be 2188.6 mD by using the Darcy equation and the differential pressure measured over the core during an initial water flood. The disc had 11 pressure ports placed at different radiuses, including the injection well and the outer boundary of the disc. Figure 8.1 shows a picture of the disc.



Figure 8.1: The radial core with mounted pressure ports, injector and producer. (From the experimental data excel sheet)

Total disc 2	Value	
Diameter [cm]	29.95	
Wellbore radius [cm]	0.325	
Thickness [cm]	1.996	
Pore volume [ml]	346.89	
Porosity [%]	24.67	
Kabs [mD]	2188.6	
Ko [mD]	520.9	
Swi [Fraction]	0.15	

## Table 8.1: Disc properties

Pressure port	Distance [cm]		
P1 (Inlet)	0.325		
P2	0.8		
P3	1.2		
P4	1.7		
P5	2.4		
P6	3.5		
P7	5		
P8	7		
P9	10		
P10	14.5		
P_Out	14.975		

#### Table 8.2: Pressure port placements.

Table 8.1 and 8.2 presents the disc properties and the placement of the pressure ports respectively. The fluid properties for the injection water, oil and the polymer solutions are found in table 8.3.

As mentioned, the experiment started with an initial waterflooding. Afterwards, the disc was saturated with oil until it achieved irreducible water saturation, S<sub>wi</sub>, which was calculated to be 0.15. Waterflooding was performed to produce the oil, and the S<sub>or</sub> ended up at 0.58. Then a polymer flood was performed for enhanced oil recovery, and lowered the S<sub>or</sub> to 0.36 in total. After this, water was injected before polymer solutions of four different concentrations were injected in the disc to estimate the rheological behavior of the solutions. Then a final brine injection was performed.

TOTAL disc 2	WI, Initial	Polymer solution 1	Polymer solution 2	Polymer solution 3	Polymer Solution 4	WI, Final
Brine viscosity [cP]	1.02	1.02	1.02	1.02	1.02	1.02
Oil viscosity [cP]	105	105	105	105	105	105
Polymer concentration [ppm]	-	1000	700	400	100	-
Injection rate interval [ml/min]	0 – 25	0 – 2.5	0 – 2.5	0 – 2.5	0 – 2.5	0 – 2.5
Temperature [°C]	22	22	22	22	22	22

#### Table 8.3: Fluid properties.

The experimental data included calculations of the permeability values of the core sample before the core was saturated with oil and after the production by water flooding. These permeability values were used to compare with the permeability fields obtained by history matching and are found in table 8.4.

Table 8.4: Experimental values for permeability.

Experimental values	Initial water flood	Secondary water injection
Permeability [mD]	2188	33

All the experimental data from the processes mentioned above was available, and the differential pressures from the initial water injection, the polymer floods with different polymer concentrations and the final brine injection were used for history matching in this thesis, together with the disc- and fluid properties. In addition, the experimentally measured bulk viscosity was used to compare with the rheological behavior found from the simulations.

# 9. Results

In this thesis the initial and final water injections and four polymer floods with varying polymer concentration from the TOTAL disc 2 experiment were history matched by using MRST (MATLAB). The permeability field values were tested by applying different uses of the Darcy equation for radial flow (2.18). The pressure ports were evaluated and investigated for apparent rheological behavior. The rheology curves were studied based on both flow rate and concentration, in addition to being compared to the bulk viscosity. A summary of the results will follow in section 9.3, while a conclusion of the results will be presented in section 10.

# 9.1 Waterflooding

The absolute permeability was found from history matching both the pressure data obtained from the first water injection, and from the final water injection. The reason for this was to see if the permeability of the core changed during the experiment. The permeability field obtained from the final brine injection proved that the permeability was significantly lower after the experiment than before. By examining the permeability value calculated in the experimental data after the second water flood, it was apparent that the permeability had changed before the core was exposed to the polymer, since the permeability after polymer flooding was almost identical to the one before polymer flooding. This indicates that the Residual resistance factor ( $R_{RF}$ ) of this experiment is equal to one.

Both permeability fields obtained were used to history match the polymer injection, but only the permeability field obtained from the final brine injection gave satisfactory matches. This verified that the permeability must have been changed before the polymer injection.

In addition to the history matching, the permeability values were calculated by three other methods. These methods are referred to as the slope method, the Darcy method and the analytical method, where all the calculations were made from using the Darcy equation for flow in a radial model in three different ways. In the slope method, the plots of the differential pressure against the injection rate for each pressure port were used to find the slope of the line, and these values were replacing  $\frac{\Delta p}{\rho}$  in the Darcy equation. In the Darcy

method, the permeability values for each of the pressure ports were calculated by applying the Darcy equation directly on the pressure data. In the analytical method the permeability was the variable, and was changed to fit the experimental data. A comparison of these calculation methods and the experimental values is presented in section 9.1.6.

### 9.1.1 History matching of the Initial water injection

Below, in figure 9.1-3, are the history matches of the pressure data from the initial water injection, for the injection rates of 25, 15 and 5 ml/min.



Figure 9.1: History match of the pressure data from the initial water injection at 25 ml/min by using MRST.

Figure 9.1 above shows the history match of the initial water injection for the highest injection rate (25 ml/min). The green line is the simulated curve by MRST and the red points are the experimental pressure data. The simulated curve hits most of the pressure points, and the few "outliers" have very small deviations from the trend. The permeability field obtained for this match is listed in table 9.1 below.

Position (cm)	Distance (cm)	K(mD)	Average K (mD)
0.325 – 0.733	0.408	449	
0.733 – 14.389	13.656	2306	2168
14.389 – 14.975	0.586	160	

Table 9.1: The permeability field obtained for the initial water injection at 25 ml/min.

The permeability field obtained from the match of the initial water injection at 25 ml/min was used for the four other rates performed for the initial water injection, and the obtained history matches were quite satisfactory. This indicated that the permeability field obtained appeared to be constant and independent on the flow rate, which was assumed based on the theory of absolute permeability (ref. section 2.2.2). The permeability field found for the highest rate was therefore used for all the other rates of the flooding, since the experimental pressure points have lower uncertainty for higher pressures.

In Figure 9.2 below is the history match of the water injection at 15 ml/min, and the experimental data shows few and small deviations from the simulated curve.



Figure 9.2: History match of the pressure data from the initial water injection at 15 ml/min by using MRST.

Figure 9.3 shows the history match of the initial water injection at 5 ml/min when using the permeability field obtained from the highest injection rate. This match is not as good as for

the other rates, but since these pressure data points are from the injection with the lowest rate, the pressures are also the lowest. This makes these data points the most uncertain ones compared to the pressure data from the higher injection rates. The simulated curve still seems to go through half of the points, and the deviations from the curve seem to be equally weighted.

The history matches for the rest of the injection rates are found in Appendix B.



Figure 9.3: History match of the pressure data from the initial water injection at 5 ml/min by using MRST.

# 9.1.2 History matching of the final water injection

A second permeability field was found by performing a history match of the pressure data from the final water injection. Some of the differential pressure points created a plateau in the plots for the final water injection. This plateau creates issues for MRST when trying to history match the data, and it would have been a very time consuming procedure to obtain satisfactory results for all the flow rates. Figure 9.4 shows the history match obtained when including all the differential pressure data for the injection rate of 2.5 ml/min.



Figure 9.4: History match of the pressure data from the final water injection at 2.5 ml/min by using MRST, including all the pressure data.

The three plateau-pressure points (from pressure port P2-P4) were removed from the experimental data set when the history match was performed in MRST to avoid errors in the simulation. It was concluded that the curve would have to pass through these points anyways to fit the rest of the pressure data, and that removing them would thereby be a better solution than to "create" one point to represent all of them. After removing these three data points, the history match was run once again. Figure 9.5 below show the history match without the plateau-points.



Figure 9.5: History match of the pressure data from the final water injection at 2.5 ml/min by using MRST, excluding the pressure data from pressure port P1-P3.

The pressure data from pressure port 9 proved to be an outlier for all of the flow rates, by constantly deviating from the almost linear trend. Therefore, it was decided to exclude this point as well, since the pressure port was placed in the outer region of the core sample, with relatively low pressure compared to the pressure ports closer to the well, and hereby higher uncertainties. A total of four pressure port data points were remover from the experimental data when history matching the final brine injection.

Below, in figure 9.6-8, are the matches performed for the final water injection at 2.5, 1 and 0.05 ml/min respectively. The history matches of the remaining rates are found in Appendix B.



Figure 9.6: History match of the final water injection at 2.5 ml/min.

The history match of the final water injection at 2.5 ml/min was quite good, and the experimental data showed only small deviations from the simulated curve. The knee in the simulated curve indicates a region change with different permeability value, as the permeability field is divided into three regions as mentioned in section 7.1.1. This will be an overall trend for all the polymer flood matches.


Figure 9.7: History match of the final water injection at 1 ml/min.



Figure 9.8: History match of the final water injection at 0.05 ml/min.

Both figure 9.7 and 9.8 shows satisfactory history matched for the injection rates of 1 and 0.05 ml/min. The rest of the injection rates show similar history matches.

The permeability values found for all the rates are listed in table 9.2 below. In contrast to the history matching of the initial water injection, the permeability values varied slightly for each of the rates. The absolute permeability is defined as a constant value describing the porous media when a single phase is flowing through the formation, and is independent on the injection rate. This is proved not to be the case for the final brine injection, which indicates that there may be more than one fluid phase flowing in the media. [3]

Injection rate	<b>K</b> <sub>1</sub> [mD]	<b>K<sub>2</sub></b> [mD]	<b>K</b> ₃ [mD]	<b>r</b> <sub>1</sub> [fraction]	$\mathbf{r}_3$ [fraction]
2.5	58	15	235	0.26	0.96
2	67	14	278	0.24	0.96
1.7	62	14	580	0.27	0.97
1.5	69	16	359	0.24	0.97
1.2	53	14	402	0.31	0.89
1	59	16	619	0.28	0.95
0.7	65	19	812	0.29	0.94
0.5	56	18	505	0.34	0.91
0.3	58	19	295	0.32	0.89
0.1	72	19	245	0.39	0.83
0.05	69	17	439	0.51	0.80

Table 9.2: Permeability field values obtained from history matching of the final water injection, for all the injection rates.

It was decided to use the permeability field found for the highest injection rate when history matching the polymer floods, as these values was believed to be most trustworthy because of the high pressures. This permeability field is presented in table 9.3. The regions are converted from fractions of the total radius to exact position in the core sample.

Table 9.3: The permeability field found for the final brine injection at 2.5 ml/
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Position (cm)	Distance (cm)	K(mD)	Average K (mD)
0.325 – 3.809	3.484	58	
3.809 - 14.389	10.58	15	34
14.389 – 14.975	0.586	235	

#### 9.1.3 Pressure port reliability for the initial water injection

To investigate how reliable the pressure data from each of the pressure ports were, the differential pressure data was plotted against the injection rates for all the pressure ports for both the initial and the final water injection.



Figure 9.9: Differential pressure from the initial water injection plotted against injection rate for pressure port 1.

From the plot in figure 9.9 above, it is evident that the points are following a linear trend. This is the case for all the pressure ports with almost insignificant deviations. The one point that had the biggest deviation was in the plot for pressure port 10, as shown in figure 9.10 below.



Figure 9.10: Differential pressures from the initial water injection plotted against the injection rates for pressure port 10.

As seen from the  $R^2$  value, the trendline good fit with the data points, even if there are tiny deviations from the trend. This indicates that the pressure port can be considered reliable.

The Darcy equation for radial flow (Equation 2.18) was utilized to calculate the permeability value at each of the pressure ports, by using the slope of the trendline through the points. These values are presented in table 9.4 and the permeability distribution is presented in figure 9.11.

Pressure port	Permeability [mD]
P1	1291
P2	2012
P3	2063
P4	1860
P5	1755
P6	1714
P7	1724
P8	1615
Р9	1340
P10	305
Average	1568

 Table 9.4: Permeability values for each of the pressure ports calculated by using the slope of the plots of differential pressure versus injection rate, initial water injection



Figure 9.11: Permeability distribution for each pressure port for the initial water injection

# 9.1.4 Pressure port reliability for the final water injection

The plot of differential pressure over the injection rate for the final water injection is shown for pressure port 1 in figure 9.12.



Figure 9.12: The differential pressures from the final water injection plotted against the injection rates for pressure port 1.

Similarly as for the initial water saturation, the data point follows a linear trend with only small deviations. The most significant deviations for this flooding are found for pressure port 10, as shown in figure 9.13 below. Pressure port 10 is the one that has the lowest differential pressure, and is thereby the most uncertain port relative to the others. Similarly as for the initial water injection the R<sup>2</sup> value is still close to 1, and the pressure port can be considered reliable.



Figure 9.13: The differential pressures from the final water injection plotted against the injection rates for pressure port 10

Pressure port	Permeability [mD]
P1	24
P2	34
P3	29
P4	25
P5	21
P6	20
P7	19
P8	18
P9	12
P10	40
Average	24

 Table 9.5: Permeability values for each of the pressure ports calculated by using the slope of the plots of differential pressure versus injection rate, final water injection

The diagram of the permeability values for the final water flood is shown in figure 9.14 below, and the values are remarkably lower, as mentioned earlier when the permeability fields were found by simulation in MRST. Only pressure point 10 marks out as a port that does not follow the same downsizing trend as the other ports, whereas the permeability value for this port is way higher than for the others. This indicates that the placement of



pressure port 10 has been less affected by the injection processes than the other pressure ports have.

Figure 9.14: Permeability distribution for each pressure port for the initial water injection.

# 9.1.5 Permeability calculated for each pressure port by the Darcy equation

The permeability value for each of the ten pressure ports was calculated by using the Darcy equation for radial flow (equation 2.18) directly, by using the experimental pressure data. The permeability values for the initial water flood are listed in table 9.6 and the permeability values for the final water injection are listed in table 9.7.

Pressure port	Permeability [mD]
P1	1233
P2	1977
Р3	2067
P4	1866
P5	1832
P6	2203
P7	1743
P8	2153
Р9	1005
P10	153
Average	1626

 Table 9.6: Permeability values calculated from the experimental data for the initial water injection, for each of the pressure ports.

Pressure port	Permeability [mD]
P1	28
P2	45
P3	36
P4	31
Р5	26
P6	25
P7	23
P8	22
Р9	16
P10	35
Average	29

# Table 9.7: Permeability values calculated from the experimental data for the initial water injection, for each of the pressure ports.

The permeability values for each of the ports are generally higher when using this calculation method in comparison with the slope method. It is suggested that this difference may come from the alignment of the trendline.

# 9.1.6 Comparison of the different permeability calculation methods

Table 9.8 presents an overview of the different permeability values obtained in this thesis for the initial water injection, both the experimental value and all the calculated values.

Calculation method	Permeability [mD]
Experimental method (lab)	2189
Slope method	1568
Darcy method	1626
Simulated method	2168
Analytical method	1850

Table 9.8: Permeability values calculated for the initial water injection

Figure 9.15 and 9.16 show the experimental pressure data for the initial water injection plotted against the distance of the pressure ports and the injection rates respectively for the 15 ml/min injection and for pressure port 5. The plots include all the curves representing each of the permeability values calculated by the different methods.



Figure 9.15: Comparison of the different permeability values for the initial water injection at 15 ml/min by plotting the differential pressure against the distance of the pressure ports.

From figure 9.15 above, it is evident that all the permeability values are close to the experimental data, but none of them makes a perfect fit. The initial pressure value is not reached by any of the curves, and the data from pressure ports 8 and 9 are not even close to being matched by the curves. If the best match is based on the pressure ports in between these, the analytical method seem to give the best match, by actually going through some of the points.



Figure 9.16: Comparison of the different permeability values for the initial water injection for pressure port 5 by plotting the differential pressure against the injection rates.

Similarly as for the plot of the differential pressure versus the distance, the analytical method seems to give the best approximation to the experimental data in figure 9.16 above.

Table 9.9 presents an overview of the permeability values obtained in this thesis for the final water injection, including the experimental value from the laboratory sheet and the different calculated values.

Calculation method	Permeability [mD]
Experimental method (lab)	33
Slope method	24
Darcy method	29
Simulated method	34
Analytical method	23

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rable 5.5. renneabilit	y values (	alculated	ior the	mai	vvacci	injection

Figure 9.17 and 9.18 show the experimental data for the final water injection plotted against the distance of the pressure ports and the injection rates respectively, for the 1,5 ml/min injection and for pressure port 5. The figures include the curves representing each of the permeability values calculated by the different methods.



Figure 9.17: Comparison of the different permeability values for the final water injection at 1.5 ml/min by plotting the differential pressure against the distance of the pressure ports.

Similarly as for the initial water injection, the analytical method seem to give the best match of the experimental data, in addition to the slope method, which gives almost the same curve. Figure 9.18 below confirms that the analytical method gives a better match with the experimental data.



Figure 9.18: Comparison of the different permeability values for the final water injection for pressure port 5 by plotting the differential pressure against the injection rates.

Since the different calculation methods give very different permeability values, it is evident that the permeability is dependent on the perspective of the calculations. The values obtained when considering the whole porous media in one are clearly different from the values obtained when calculating for different independent points of the reservoir. This could be expected since the porous media is heterogeneous.

# 9.2 Polymer flooding

Below in figure 9.19 is the history match of the polymer flood at flow rate 2.5 ml/min using the permeability field estimated from the initial water flood. It is obvious that this permeability field must be wrong for the time of this process because the curve will not fit the trend of the pressure data, as the pressure almost show a constant decline. After a significant amount of simulations this was the most satisfactory match, which made it clear that it would not be possible to get a great match with the permeability field found for the initial water injection.



Figure 9.19: History matching of the polymer flooding of the 1000 ppm polymer solution at flow rate 2.5 ml/min, using the permeability field from the initial waterflooding.

Below in figure 9.20 is the history match of the pressure data provided for the highest flow rate at 2.5 ml/min when using the permeability field found from the final brine injection. The red points are the pressure data and the green line is the simulated pressure curve. It is clear to see that this permeability field suits better as there are only small deviations from the simulated curve. The matches for the 700, 400 and 100 ppm polymer solutions for 2.5 ml/min are shown in figure 9.21-23.



Figure 9.20: History match of the polymer flooding of the 1000 ppm solution at flow rate 2.5 ml/min, by using the permeability field from the final brine injection.



Figure 9.21: History match of the polymer flooding of the 700 ppm solution at flow rate 2.5 ml/min, by using the permeability field from the final brine injection.



Figure 9.22: History match of the polymer flooding of the 400 ppm solution at flow rate 2.5 ml/min, by using the permeability field from the final brine injection.



Figure 9.23: History match of the polymer flooding of the 100 ppm solution at flow rate 2.5 ml/min, by using the permeability field from the final brine injection.

The best history matches were obtained for the three solutions with the highest concentrations, although the matches were somewhat poor for the lowest injection rates. The 100 ppm polymer solution on the other hand, gave poor matches for all the rates, with the match of the 2,5 ml/min injection being the most satisfactory one. The matches only gets less satisfactory with decreasing flow rate.

#### 9.2.1 Rheology curves

For the lowest concentrations, 400 and 100 ppm, the solutions show Newtonian behavior at the lower rates. The solution of 100 ppm shows an almost Newtonian for all the rates, but considering that the history matches of this solution were quite poor, it is hard to conclude what exact behavior this solution exerts by analyzing these results only.

The higher concentrations, 700 and 1000 ppm, show both shear thickening and shear thinning at the higher rates, and less shear thickening for decreasing rates. The 1000 ppm-solution is clearly show higher degree of shear thinning than the rest of the solutions.



Figure 9.24: The rheology curves for the solution with polymer concentration of 1000 ppm.

Figure 9.24 above show the rheology curves for all the flow rates run for the solution with the highest polymer concentration. Even though the rheology curves are slightly different depending on the flow rate, they tend to show somewhat similar trends. There is no consequent change with rate, but one can say that the solution gets less shear thickening with decreasing flow rate. In addition to this, the shear thinning behavior of the solution seems to be somewhat the same, independent on the flow rate. The onset of the shear thickening regime seems to move towards lower velocities with decreasing flow rate.



Figure 9.25: The simulated Carreau curves for all the flow rates run for the polymer solution with polymer concentration of 700 ppm

The case for the solution with polymer concentration of 700 ppm in figure 9.25 is similar to the one for the 1000 ppm-solution. The rheology curves show both shear thickening and shear thinning for all the flow rates except the two lowest ones at 0.1 and 0.05 ml/min. These two flow rates only show a shear thinning behavior for the solution. In the same way as for the 1000 ppm-solution, the onset of the shear thickening seem to shift towards lower velocities with decreasing flow rates. The 700 ppm solution show stronger shear thickening behavior than shear thinning behavior, whilst the 1000 ppm-solution show stronger degree of shear thinning behavior.



Figure 9.26: The simulated Carreau curves for all the flow rates run for the polymer solution with polymer concentration of 400 ppm.

The solution with polymer concentration of 400 ppm in figure 9.26 show significantly greater shear thickening behavior than shear thinning behavior for the intermediate to high flow rates. The lowest rates does not show signs of shear thickening at all, while approximately all flow rates show vague signs of shear thinning behavior. The shear thinning regimes show low resistance factors that are close to the water viscosity. Also in this case it is possible to say that the onset of the shear thickening regime shifts towards lower velocities with decreasing flow rate.



Figure 9.27: The rheology curves for the solution with polymer concentration of 100 ppm.

Figure 9.27 above shows the rheology curves for all the flow rates run for the solution with the lowest polymer concentration. The curves are remarkably different from the 1000 and 700 ppm solution, as there are no signs of shear thinning at all. Even though the curves for the highest flow rates show signs of shear thickening, the viscosity values are very low and about the same as the water viscosity for all the rates. When considering the uncertainties in the pressure ports, the shear thickening may be regarded as insignificant and the solution may be referred to as Newtonian.

When comparing all four solutions with different polymer concentrations, it is evident that the shear thinning behavior decreases significantly with concentration. The shear thickening behavior is present for all the concentrations at the intermediate to high flow rates, although the behavior can be viewed as insignificant for the lowest polymer concentration. The shear thickening behavior of the solutions does not seem to be as much affected by the reduced concentration as the shear thinning behavior is.

Below are some plots comparing the rheology curves for some of the flow rates. Plots for all of the flow rates are found in Appendix C. For the flow rate of 1.2 ml/min there were no data available for the solution with polymer concentration of 400 ppm.



Figure 9.28: Rheology curves for all four concentrations at injection rate 2.5 ml/min.

Figrue 9.28 shows a clear trend of decreasing shear thinning behavior with concentration, while the shear thickening behavior is more varying for the different injection rates. By comparing these plots for all flow rates, it is evident that the shear thinning behavior is most significant for the highest flow rate. It is also clear that the viscosity of the lowest concentration is basically constant for all flow rates and that the solution exerts Newtonian flow behavior. The slope of the shear thickening regime for the 400 ppm solution is steeper than for the 700 ppm-solution at 2.5 ml/min, but not for the rest of the flow rates. The 700 ppm solution has a steeper shear-thickening slope than all the other concentrations for the intermediate to high flow rates, except the highest flow rate, as mentioned.

The two highest concentrations show both shear thinning and shear thickening flow behavior for the intermediate to high flow rates, and only shear thinning behavior for the lowest flow rates. The 400 ppm-solution show shear thickening behavior for all the flow rates except the lowest one at 0.05 ml/min. The solution shows shear thinning at the highest flow rate and to some degree at some of the intermediate to low flow rates.



Figure 9.29: Rheology curves for all four concentrations at injection rate 1 ml/min



Figure 9.30: Rheology curves for all four concentrations at injection rate 0.05 ml/min.

From figure 9.30 above, it is evident that the polymer solutions only show shear thinning behavior and no shear thickening behavior at the lowest flow rate.

#### 9.2.2 Onset of shear thickening

The onset of shear thickening was plotted against the injection rate for all the polymer solutions to investigate how the onset shifts with the rate. It is a general trend of the onset of shear thickening to shift towards higher flow velocities with increasing injection rates, although there are some deviations. The plots for the 700 and 100 ppm polymer solutions show an almost linear trend of increasing onset with increasing injection rate, while the 1000 and 400 ppm polymer solutions show more varying trends. The intermediate to high flow rates for the 1000 ppm solution almost show a linear trend, while the three lowest rates showing shear thickening have onset values deviating from this trend. For the 400 ppm solution, the trend is more altering with both increasing and decreasing onset values with increasing rate.



Figure 9.31: Onset of shear thickening plotted against injection rate for the 1000 ppm polymer solution.



Figure 9.32: Onset of shear thickening plotted against injection rate for the 700 ppm polymer solution.



Figure 9.33: Onset of shear thickening plotted against injection rate for the 400 ppm polymer solution.



Figure 9.34: Onset of shear thickening plotted against injection rate for the 100 ppm polymer solution.

#### 9.2.3 Pressure ports

The differential pressures were plotted against the injection rates for the polymer floods to investigate if there data showed signs of shear thickening or shear thinning behavior for all the polymer solutions. As mentioned in section 2.3.1 and shown in figure 2.6, the fluid shows shear thickening behavior if the line curves upwards and shear thinning behavior if the line curves downwards. A line was drawn from the first points that showed a linear trend, and it was observed how the rest of the points acted relative to this line. Figure 9.36 shows how the curving of the trend will decide if the polymer at the specified pressure port shows shear thinning or shear thickening behavior.



Figure 9.35: Illustration of what the curvature of the pressure plots against injection rate will say about the rheological behavior.

If the experimental pressure data points curves upwards from the linear line, the fluid shows signs of shear thickening behavior at that pressure port, while the fluid show shear thinning behavior if it curves downwards from the linear line. Figure 9.37-9.40 below shows the differential pressure versus injection rate for all four polymer solutions at pressure port 1. The pressure points at the lowest injection rates were not weighed too much, as these carries the greatest insecurities concerning the low pressure values.



Figure 9.36: Differential pressure plotted against injection rate for pressure port 1 for the 1000 ppm polymer solution.







Figure 9.38: Differential pressure plotted against injection rate for pressure port 1 for the 400 ppm polymer solution.





The plots above of the three solutions with the highest concentration show signs of shear thickening behavior by curving upwards for the highest injection rates. The 100 ppm polymer solution showed a linear trend and can be considered Newtonian at pressure port. For the pressure ports placed further away from the injection well, the lowest concentration showed vague signs of shear thinning behavior. This behavior can be seen in figure 9.41 and 9.42, and this means that even though the rheology curves for the solution with polymer concentration of 100 ppm showed no signs of shear thinning behavior, these plots show that the solution actually show signs of shear thinning at some of the pressure ports. This difference in behavioral pattern could be because the porous media is considered, as a whole during the history match, or because of the fact that the history matches of this solution was quite poor.



Figure 9.40: Differential pressure plotted against injection rate for pressure port 5 for the 100 ppm polymer solution.





### 9.2.4 Bulk vs. in-situ viscosity

The bulk viscosity had been measured in the laboratory, and the shear thinning behavior was compared to the estimated in-situ viscosity. The shear rate was converted to Darcy velocity by using equation 3.7.  $\alpha'$  was altered to get the best match with the curve, but there war no great match to get from it. .  $\alpha'$  in the cases for figure xx and xx are equal to 1. Instead, the power law index, n, was calculated for bot the rheology curves. Since the in-situ rheology consisted of multiple curves, one of the rates, 1,7 ml/min, was chosen for the comparison. The power law indexes calculated are listed in table 9.10 below. Only the polymer solutions of 700 and 1000 ppm were compared, since these were the only ones with distinct shear thinning behavior.

#### Table 9.10: Bulk vs in-situ viscosity

	700 ppm	1000 ppm
Bulk rheology curve	-2,93·10 <sup>5</sup>	-3,41·10 <sup>5</sup>
In-situ rheology curve	-7,65·10 <sup>5</sup>	-3,74·10 <sup>5</sup>



Figure 9.42: Bulk vs. in-situ viscosity for the 1000 ppm solution.





# 9.3 Results summary

The aim of this thesis was to investigate the in-situ rheological behavior of HPAM-solutions with different polymer concentrations in a radial core flood experiment. Based on the TOTAL disc 2 experiment, history matches were performed to estimate the permeability field and the rheological behavior of the polymer in the porous media. The simulation tool MRST was used to perform automatic history matches of the differential pressures from the initial water injection, the polymer floods and the final water injection. Additional calculations were made to investigate the results. The usual permeability of Bentheimer sandstone varies between 0.52 and 3.02 Darcy [49], which means that all the estimated initial permeabilities are realistic for the porous media.

The Darcy equation was used in different ways to estimate the permeability, and it was obvious that it did matter how the equation was used, since the permeability values obtained were all different. The average permeability of the core depends on if the porous media is considered as a whole, or if the permeability values are found for different positions in the media. The permeability field found for the final brine injection was almost identical to the one calculated experimentally for the secondary water injection. This indicates that the residual resistance factor is equal to one, and that there is no permeability reduction because of polymer adsorption.

A significant permeability reduction was observed between the initial and final water injection. The average permeability for the core found by the initial water injection was estimated to be 2168 mD while the average permeability for the core found by the final water injection was estimated to be only 34 mD. This decrease in permeability may to some degree be addressed to the residual oil that is left in the porous media, but with this drastic decrease in permeability it is likely for the core to have been damaged and that some of the flow paths have been blocked.

The permeability field estimated for the final water injection was used to simulate the polymer flooding and estimate the rheology curves for the polymer solutions of four different concentrations. The polymer solution with concentration of 1000 ppm both showed significant shear thinning and shear thickening behavior, while the shear thinning regime was more dominant. The onset of shear thickening seemed to be shifting towards higher velocities for increasing injection rates for the intermediate to low fluxes, while the

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lowest rates showing shear thickening deviated somewhat from the trend. When compared to the bulk viscosity for the same concentration, the polymers showed the same shear thinning behavior, with similar power law indexes, but the in-situ viscosities were remarkably lower than the bulk viscosities.

The polymer solution of 700 ppm also showed significant shear thinning and shear thickening behavior. In contrast to the 1000 ppm solution, the shear thickening regime was more dominating for this polymer solution. The onset of shear thickening showed a clear linear trend with higher onset values for higher injection rates. When compared to the bulk viscosity for the same concentration, it was evident that shear thinning behaviors did not follow the same exact trend. The shear thinning of the in-situ rheology curve was steeper than for the bulk rheology. In addition, the viscosity values were relatively much lower for the in-situ estimations.

The polymer solution of 400 ppm showed slight signs of shear thinning, for all of the injection rates, but the shear thickening behavior was more dominant for this solution. The shift of onset of shear thickening was very variable compared to the other polymer solutions

Close to Newtonian behavior was observed for the 100 ppm polymer solution, as the highest viscosity values were very close to the water viscosity. By examining the pressure data for each of the pressure ports, there were slight signs of shear thinning behavior at some of the ports. The onset of shear thickening seemed to be linearly shifting towards higher flow velocities with increasing injection rate.

The history matches of the polymer floods showed great compliance for the three highest polymer concentrations, while the matches for the polymer solution with concentration of 100 ppm were unsatisfactory. This could possibly be explained by the low concentration.

# 10. Conclusion

The results obtained in this simulation study were consistent with the theory mentioned earlier in the thesis. The polymer solutions showed increasing viscosity with increasing rate, as Hatzignatiou, D.G. et al. (2015) [40] stated in their research. In addition to this, it was observed higher degree of shear thinning with increasing concentration, as stated by

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Jacobsen, J.G. (2017) [43]. This effect has been suggested to occur because of increasing molecular weight.

Skauge, T. et al (2016) stated that the onset of shear thickening will shift towards higher velocities for increasing fluxes [5], which was observed in the results of this thesis to some degree. The 700 and 100 ppm solutions showed a clear shift towards higher velocities at increasing injection rates. The 1000 ppm solution showed an almost linear trend for the intermediate to high injection rates, while the 400 ppm solution showed more variable shift in the onset of shear thickening.

The study of the rheological behavior of four HPAM polymer solutions with different concentrations showed that the shear thinning behavior of HPAM decreases with concentration, while the shear thickening behavior seems less affected by the concentration. On the other hand, the shear thinning rheological behavior seems to be almost independent on rate in contrast to the shear thickening behavior, which decreases with decreasing flow rate.

The shear thinning behavior was clearly most significant for the highest flow rates. The 700 and 1000 ppm polymer solutions showed both shear thinning and shear thickening behavior, but at the rate decreased, the shear thickening behavior was reduced until only shear thinning behavior was left for the two lowest flow rates. It may be concluded that the shear thinning behavior is most dependent on the concentration, while the shear thickening behavior is most dependent on the flow rate.

In-situ polymer rheology is a complex subject that is of great importance to gain better knowledge of, concerning polymer injectivity and implementation of polymer flooding as enhanced oil recovery. The viscoelastic characteristics of polymers will increase the viscosity near the well bore and cause low injectivity. In the same time, the viscoelastic behavior of polymer solutions makes them very suitable for mobility control and more efficient recovery. Therefore, better knowledge could make it possible to take advantage of the positive aspects of polymer flooding. Fluid flow through radial models are better replicates for fluid flow in real field projects, and should definitely be more extensively investigated. [5]

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# 11. Further work

Obviously, the rheological properties of polymer solutions in porous media are not yet fully understood, so there is a need for expanded research concerning this subject. A wider range of concentrations, molecular weight, polymer types, rock types and wettability preference should be of interest.

Based on the result from this thesis, it would be natural to continue this investigation by upscaling the simulation model to reservoir scale to test the rheology behavior over a larger area, to make the situation more realistic for a field experiment. This would imply higher injection rates and thereby higher pressure regimes.

It would be interesting to compare the in-situ rheological behavior of HPAM for porous media of different wettability preferences to investigate the effect it would have on the retention, adsorption and degradation of the polymer, as the literature is divided on this subject.
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# A. Appendix A

## A.1 Experimental data

## A.1.1 Initial water injection

Radius	0,325	0,8	1,2	1,7	2,4	3,5	5	7	10	14,5	14,975
Rate	D1	D2	D3	D/I	D5	D6	D7	DQ	DQ	P10	P Out
	r 1 [mahau]	r 2 [mahau]	r J [mahau]	r <del></del> facheal	r J [mahau]	ru [mahau]	r 7 [mahau]	ro [mahau]	r J [unhau]	F 10 [mahau]	r_out
[mi/min]	[mbar]	[mbar]	[mbar]	[mbar]	[mbar]	[mbar]	[mbar]	[mbar]	[mbar]	[mbar]	[mbar]
0	0	0	0	0	0	0	0	0	0	0	0
5	25,07	11,34	9,58	9,10	8,09	4,63	5,70	3,04	5,03	4,00	1,42
10	44,74	24,29	20,00	19,16	16,50	12,62	11,68	8,15	8,83	6,45	3,10
15	68,01	36,12	31,03	29,42	26,34	20,55	18,32	13,72	13,60	9,36	5,30
20	90,12	48,22	41,69	39,43	36,21	27,97	25,60	19,61	18,05	13,12	8,15
25	116,75	61,83	53,21	51,60	46,51	38,54	33,04	25,94	23,23	16,75	11,36

#### Table A.1: Experimental data for the initial water flood.

### A.1.2 Final water injection

Radius	0,325	0,8	1,2	1,7	2,4	3,5	5	7	10	14,5	14,975
[cm]											
Rate	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P_Out
[ml/min]	[mbar]	[mbar]	[mbar]	[mbar]							
0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
0,05	8,98	2,59	3,45	3,36	3,59	2,93	2,47	1,70	1,20	0,15	0,04
0,10	16,92	6,78	7,96	7,55	7,97	6,43	5,55	3,98	2,78	0,25	0,07
0,30	51,21	24,95	26,48	26,42	26,25	21,78	17,44	13,17	9,88	0,63	0,22
0,50	89,46	42,97	45,90	45,90	46,74	37,43	31,17	22,61	17,21	1,28	0,65
0,70	127,06	69,37	71,09	70,83	71,36	59,11	48,58	36,30	27,02	1,86	1,00
1,00	188,02	105,48	106,06	105,85	107,01	88,10	72,03	53,32	40,87	2,32	1,20
1,20	236,19	130,20	132,69	133,16	134,92	110,67	90,94	67,36	51,10	2,66	1,29
1,50	304,14	168,82	171,27	170,84	172,89	142,71	116,42	86,91	64,45	3,16	1,46
1,70	352,60	194,46	195,52	195,26	198,14	163,13	133,98	98 <i>,</i> 95	74,20	3,48	1,64
2,00	421,90	231,04	232,99	232,63	235,55	194,48	158,32	117,29	88,33	4,18	1,87
2,50	547,76	291,50	294,01	294,03	297,92	245,89	199,38	147,12	111,10	5,15	2,24

#### Table A.2: Experimental data for the final water flood.

#### A.1.3 Polymer floods

#### A.1.3.1 1000 ppm

Radius [cm]	0,325	0,8	1,2	1,7	2,4	3,5	5	7	10	14,5	14,975
Rate [ml/min]	P1 [mbar]	P2 [mbar]	P3 [mbar]	P4 [mbar]	P5 [mbar]	P6 [mbar]	P7 [mbar]	P8 [mbar]	P9 [mbar]	P10 [mbar]	P_Out [mbar]
0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
0,05	32,15	23,24	24,57	24,28	24,41	21,85	16,77	12,08	9,84	0,88	0,52
0,10	62,86	45,64	46,76	47,06	47,78	41,07	34,18	23,97	19,10	1,72	1,27
0,30	197,60	128,02	130,54	129,96	131,76	114,61	95,08	67,42	51,40	4,10	2,40
0,50	330,20	203,61	205,25	204,84	207,88	181,38	150,18	106,65	80,37	6,07	3,41
0,70	464,05	278,99	280,57	280,37	284,30	245,73	204,32	144,79	110,20	7,69	4,24
1,00	672,31	393,18	396,21	395,42	401,25	345,58	286,44	202,41	153,57	10,10	5,40
1,20	806,91	471,19	472,42	471,92	478,67	408,76	338,93	238,33	180,61	11,47	6,12
1,50	1030,94	600,22	600,89	600,60	608,96	517,31	426,94	298,16	226,77	13,90	7,21
1,70	1175,13	685,49	687,37	686,52	695,42	587,74	484,76	335,94	256,62	15,37	7,89
2,00	1401,35	824,34	824,91	824,81	835,18	700,90	575,70	396,02	304,29	17,32	8,85
2,50	1809,47	1075,21	1075,42	1075,53	982,94	903,39	736,01	497,26	388,12	21,46	10,37

Table A.3: Experimental data for the 1000 ppm polymer flood.

#### A.1.3.2 700 ppm

Radius [cm]	0,325	0,8	1,2	1,7	2,4	3,5	5	7	10	14,5	14,975
Rate [ml/min ]	P1 [mbar]	P2 [mbar]	P3 [mbar]	P4 [mbar]	P5 [mbar]	P6 [mbar]	P7 [mbar]	P8 [mbar]	P9 [mbar]	P10 [mbar ]	P_Out [mbar]
0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
0,05	21,60	15,81	17,36	16,40	17,84	15,59	12,58	8,87	7,58	1,42	1,06
0,10	44,04	29,48	31,23	31,19	31,73	27,82	23,00	16,00	13,29	1,58	1,10
0,30	149,54	88,92	89,29	89,48	90,83	78,57	64,95	46,94	35,55	3,12	2,00
0,50	260,06	140,52	144,10	143,31	146,35	126,26	104,55	75,15	57,58	4,86	3,00
0,70	374,31	199,36	199,88	198,78	202,21	174,19	143,84	102,81	78,37	6,05	3,60
1,00	547,83	283,75	284,55	284,58	289,20	246,12	204,26	144,60	110,84	7,73	4,29
1,20	665,11	338,91	340,13	339,90	344,49	292,68	242,07	171,76	130,53	8,87	4,85
1,50	852,67	435,64	437,23	436,45	442,81	372,32	307,60	216,73	164,62	10,94	5,70
1,70	969,82	494,31	498,21	497,70	505,29	422,66	348,48	243,73	187,21	12,02	6,02
2,00	1150,34	590,88	593,93	593,47	602,29	499,60	409,84	284,43	219,34	13,77	6,72
2,50	1491,97	775,77	778,88	777,43	788,49	646,13	527,21	358,98	281,06	16,90	7,92

#### Table A.4: Experimental data for the 700 ppm polymer flood.

### A.1.3.3 400 ppm

r	0,00	0,80	1,20	1,70	2,40	3,50	5,00	7,00	10,00	14,50	14,975
rate	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P_Out
0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
0,05	17,10	10,83	9,67	10,33	9,28	8,47	7,13	5,27	3,71	0,10	0,05
0,10	35,34	21,45	19,31	20,31	18,96	16,81	14,19	10,48	7,68	0,21	0,11
0,30	121,59	60,77	57,59	58,31	57,91	50,25	41,18	30,12	23,32	1,42	0,53
0,50	211,82	96,43	96,23	96,19	96,56	82,85	68,17	50,24	37,66	2,35	1,02
0,70	305,28	137,79	135,05	135,08	136,32	116,23	96,36	69,44	52,63	3,04	1,33
1,00	443,51	196,08	196,31	196,35	197,78	167,23	138,31	100,00	75,76	4,17	1,98
1,50	690,53	304,99	304,83	305,12	308,84	256,93	211,25	151,64	115,35	5,95	2,74
1,70	788,40	350,72	350,47	350,44	354,85	293,30	240,87	171,47	131,18	6,78	3,02
2,00	936,49	420,47	419,42	418,98	424,50	349,24	286,31	202,00	154,87	7,87	3,42
2,50	1201,17	544,38	544,91	544,48	551,18	448,40	365,22	253,08	196,93	9,90	4,16

#### Table A.5: Experimental data for the 400 ppm polymer flood.

#### A.1.3.4 100 ppm

#### Table A.6: Experimental data for the 100 ppm polymer flood.

r	0,00	0,80	1,20	1,70	2,40	3,50	5,00	7,00	10,00	14,50	14,975
rate	P1	P2	P3	P4	P5	P6	P7	P8	Р9	P10	P_Out
0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
0,05	7,85	3,88	4,52	4,98	4,98	3,79	3,04	2,17	1,70	0,10	0,00
0,10	18,33	9,65	9,77	10,30	10,52	8,52	7,13	5,25	3,79	0,10	0,08
0,30	69,98	34,13	34,52	33,27	34,91	29,44	23,03	17,98	13,80	0,86	0,60
0,50	136,10	59,63	59,40	60,00	60,96	51,14	41,79	30,55	24,15	1,35	0,87
0,70	198,98	85,93	86,82	85,94	87,52	73,85	59,90	44,24	34,03	1,82	1,07
1,00	297,44	128,38	128,29	127,12	129,91	109,39	89,31	65,31	49,60	2,36	1,32
1,20	361,63	158,39	157,31	157,62	160,10	133,49	108,73	79,14	61,06	2,67	1,39
1,50	460,25	201,91	202,79	203,02	205,89	171,16	140,22	102,26	77,80	3,61	1,78
1,70	524,77	233,43	233,06	232,25	235,86	196,00	159,75	115,90	88,39	4,18	1,94
2,00	614,96	276,29	276,89	276,26	280,39	232,19	189,67	137,00	104,86	4,90	2,19
2,50	777,45	356,04	355,49	355,32	360,32	295,64	240,31	171,57	132,86	6,05	2,59

## B. Appendix B

## B.1 Simulated results

#### B.1.1 Initial water injection

The red points are the experimental data, the black line is the initial permeability distribution and the green line is the simulated pressure curve after EnKf.





Radius [m]



Figure B.3: Initial water injection 15 ml/min



Figure B.4: Initial water injection, 10 ml/min



Figure B.5: Initial water injection 5 ml/min

#### B.1.2 Final water injection

The red points are the experimental data, the black line is the initial permeability distribution and the green line is the simulated pressure curve after EnKF.



Figure B.6: Final water injection, 2.5 ml/min



Figure B.7: Final water injection, 2 ml/min



Figure B.8: Final water injection, 1.7 ml/min



Figure B.9: Final water injection, 1.5 ml/min



Figure B.10: Final water injection, 1.2 ml/min



Figure B.11: Final water injection, 1 ml/min



Figure B.12: Final water injection, 0.7 ml/min



Figure B.13: Final water injection,, 0.5 ml/min



Figure B.14: Final water injection,, 0.3 ml/min



Figure B.15: Final water injection, 0.1 ml/min



Figure B.16: Final water injection, 0.05 ml/min

### B.1.3 Polymer flooding

#### B.1.3.1 1000 ppm



Figure B.17: History match of the flooding of the 1000 ppm solution at 2.5 ml/min.







Figure B.19: History match of the flooding of the 1000 ppm solution at 1.7 ml/min.



Figure B.20: History match of the flooding of the 1000 ppm solution at 1.5 ml/min.



Figure B.21: History match of the flooding of the 1000 ppm solution at 1.2 ml/min.



Figure B.22: History match of the flooding of the 1000 ppm solution at 1 ml/min.



Figure B.23: History match of the flooding of the 1000 ppm solution at 0.7 ml/min.



Figure B.24: History match of the flooding of the 1000 ppm solution at 0.5 ml/min.



Figure B.25: History match of the flooding of the 1000 ppm solution at 0.3 ml/min.



Figure B.26: History match of the flooding of the 1000 ppm solution at 0.1 ml/min.



Figure B.27: History match of the flooding of the 1000 ppm solution at 0.05 ml/min.

#### B.1.3.2 700 ppm



Figure B.28: History match of the flooding of the 700 ppm solution at 2.5 ml/min.



Figure B.29: History match of the flooding of the 700 ppm solution at 2 ml/min.



Figure B.30: History match of the flooding of the 700 ppm solution at 1.7 ml/min.



Figure B.31: History match of the flooding of the 700 ppm solution at 1.5 ml/min.



Figure B.32: History match of the flooding of the 700 ppm solution at 1.2 ml/min.



Figure B.33: History match of the flooding of the 700 ppm solution at 1 ml/min.



Figure B.34: History match of the flooding of the 700 ppm solution at 0.7 ml/min.



Figure B.35: History match of the flooding of the 700 ppm solution at 0.5 ml/min.



Figure B.36: History match of the flooding of the 700 ppm solution at 0.3 ml/min.



Figure B.37: History match of the flooding of the 700 ppm solution at 0.1 ml/min.



Figure B.38: History match of the flooding of the 700 ppm solution at 0.05 ml/min.

#### B.1.3.3 400 ppm



Figure B.39: History match of the flooding of the 400 ppm solution at 2.5 ml/min.



Figure B.40: History match of the flooding of the 400 ppm solution at 2 ml/min.



Figure B.41: History match of the flooding of the 400 ppm solution at 1.7 ml/min.



Figure B.42: History match of the flooding of the 400 ppm solution at 1.5 ml/min.



Figure B.43: History match of the flooding of the 400 ppm solution at 1 ml/min.



Figure B.44: History match of the flooding of the 400 ppm solution at 0.7 ml/min.



Figure B.45: History match of the flooding of the 400 ppm solution at 0.5 ml/min.



Figure B.46: History match of the flooding of the 400 ppm solution at 0.3 ml/min.



Figure B.47: History match of the flooding of the 400 ppm solution at 0.1 ml/min.



Figure B.48: History match of the flooding of the 400 ppm solution at 0.05 ml/min.

#### B.1.3.4 100 ppm



Figure B.49: History match of the flooding of the 100 ppm solution at 2.5 ml/min



Figure B.50: History match of the flooding of the 100 ppm solution at 2 ml/min.



Figure B.51: History match of the flooding of the 100 ppm solution at 1.7 ml/min.



Figure B.52: History match of the flooding of the 100 ppm solution at 1.5 ml/min.



Figure B.53: History match of the flooding of the 100 ppm solution at 1.2 ml/min.



Figure B.54: History match of the flooding of the 100 ppm solution at 1 ml/min.



Figure B.55: History match of the flooding of the 100 ppm solution at 0.7 ml/min.



Figure B.56: History match of the flooding of the 100 ppm solution at 0.5 ml/min.


Figure B.57: History match of the flooding of the 100 ppm solution at 0.3 ml/min.



Figure B.58: History match of the flooding of the 100 ppm solution at 0.1 ml/min.



Figure B.59: History match of the flooding of the 100 ppm solution at 0.05 ml/min.

## C. Appendix C

## C.1 Rheology curves

The following figures the rheology curves for the four polymer solutions plotted for the same injection rates. There is one plot per injection rate, to show how the curves vary with concentration for all the rates.



Figure 0.1: Rheology curves for all polymer concentrations at injection rate 2.5 ml/min.



Figure 0.2: Rheology curves for all polymer concentrations at injection rate 2 ml/min.



Figure 0.3: Rheology curves for all polymer concentrations at injection rate 1.7 ml/min.



Figure 0.4: Rheology curves for all polymer concentrations at injection rate 1.5 ml/min.







Figure 0.6: Rheology curves for all polymer concentrations at injection rate 1 ml/min.



Figure 0.7: Rheology curves for all polymer concentrations at injection rate 0.7 ml/min.



Figure 0.8: Rheology curves for all polymer concentrations at injection rate 0.5 ml/min.



Figure 0.9: Rheology curves for all polymer concentrations at injection rate 0.3 ml/min.



Figure 0.10: Rheology curves for all polymer concentrations at injection rate 0.1 ml/min.



