

Fracture Development and Pressure Behaviour during Water and Polymer Injections in Saturated Unconsolidated Sand

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Abstract: Polymer flooding which is an EOR technique using water viscosified with soluble polymers is an important EOR method in heavy oil reservoirs, where field studies showed a recovery up to 59%. However, accurate assessment of injectivity of viscous polymer solutions can give major challenges. The objective of this study is to experimentally investigate the water and polymer injectivities in an unconsolidated sand pack saturated either with brine or with heavy oil, subject to confining axial and radial stresses in the range of those encountered in reservoirs. In particular we are interested in the typical reservoir conditions under which failure/hydraulic fracturing of the sample occurs. We also intend to investigate the effect that hydraulic fracture will have on polymer injectivity. The injection experiments were conducted in a biaxial pressure vessel containing a porous medium, in which flow rates can be controlled and pressures can be measured. Data from rheological measurements and a single-phase water flood experiment carried out in this study were utilised for understanding and comparing the injectivity results for polymer flood experiments. The outcome of experimental analysis showed that the viscous nature of the polymer solution and the viscosity of the oil are the main causes for the loss in injectivity compared to a water flood. A change in confining pressure does not influence the injectivity. However, it does affect the occurrence of fracturing. It was found that fracturing occurred at a pressure drop of 4.3 times the minimum confining pressure and caused injectivity to rise. Pressure data obtained from the water flood experiments was fitted with prediction models that describe pressure behaviour during injection in a porous medium. Fitting resulted in a value for permeability of the porous medium and was used in prediction models that describe a polymer flood. Polymer flood data gave a best fit when polymer with a constant average viscosity was assumed to have displaced all saturation fluid. The rheology showed that the polymer solution has shear thickening behaviour, making a non-Newtonian model that only considers shear thinning invalid. A displacement model, which describes the displacement of water by a polymer solution with constant viscosity made clear that retention effects are highest close to the wellbore and decrease when polymer is further invaded in the porous medium.

I. INTRODUCTION

Hydrocarbons will remain the primary source of energy for the next few decades based on current status of technology. Energy supply to sustain world economies requires developing additional crude oil reserves. For some areas, this additional development will be in the form of exploration and drilling, but for most oil-producing areas it will very likely be sustained by applying enhanced oil recovery (EOR). High energy demand and depletion of light oils, made interest in production of heavy oil grow (Gao, 2011).

Conventional oilfields are typically developed in three main phases: primary, secondary and tertiary recovery. Primary recovery relies on natural drive mechanisms such as solution gas, water influx, gas cap drive or gravity drainage. Secondary recovery refers to techniques, such as gas or water injection, whose purpose, in part, is to maintain reservoir pressure. Tertiary recovery is any technique applied after secondary recovery. Enhanced oil recovery is oil production by injection of materials not normally present in the reservoir. The definition does not restrict EOR to a particular phase (primary, secondary or tertiary) in the producing life of a reservoir. According to a survey (Kootungal, 2010), thermal methods such as steam flood and hot water flood are successful strategies for producing heavy oil. However, these methods are not suitable for thin layers and deep reservoirs. A non-thermal recovery method gives the outcome.

Based on past experiences, polymer flood is recommended for oil viscosity less than 100 cP under reservoir temperature, and sandstone reservoir with oil saturation higher than 30 %, reservoir permeability greater than 20 mD, net thickness more than 3 m, and reservoir temperature less than 90 °C (Lake et al., 1992; Alkaleef and Zaid, 2007; Gao and Towler, 2011).

The basic principle of polymer flooding consists of adding polymer to the water in order to increase its viscosity. The resulting decrease in water mobility and lower mobility ratio between the drive (displacing) fluid and to be displaced oil, increases the volumetric sweep efficiency of the injected fluid substantially. Irreducible oil saturation does not decrease although the remaining oil saturation does approach S_{or} , which is assumed to be practically the same for both water flooding and polymer flooding. In order for polymer flooding in heavy oil to be effective, the concentration of the polymer solution must be beyond a threshold value.

Injection rate is also of influence on the oil recovery. High injection rates can cause viscous fingering, but will give a higher sweep efficiency in the end. The larger recovery efficiency is the basis for the economic success of polymer flooding. According to Lake (1992), a polymer flood is expected to be economic when the water flooding mobility ratio is between 1 and 50, the reservoir heterogeneity is high (Dykstra-Parson coefficient of 0.75), or a combination of these two occurs.

Another aspect of polymer flooding which needs to be taken into consideration is the increase in pore pressure. When pore pressure exceeds the confining pressure, the rock will fracture and polymers will flow through the fracture, losing sweep efficiency.

Zhou and others (2010) conducted several injectivity experiments using honey injection with different viscosities in an unconsolidated sand. The results showed failure occurs when injection pressure was 2.5 to 3 times the minimum

confining pressure. Honey was used instead of polymers to preserve the Newtonian character of the injection fluid.

Meng (2010) conducted hydraulic fracturing tests, in which he used viscous Newtonian fluid and cross-linked (or X-linked) gel as injection fluid. He applied tri-axial loadings on a porous medium (Colton sandstone, Pierre Bleue limestone and Felsler sandstone) that were varied to relate fracture occurrence with the in-situ stresses. The results showed a fracture pressure of 2.5 to 4 times higher than the minimum confining pressure.

Little research has been devoted to pressure build-up phenomena with polymer injection in porous media. When water-soluble, high molecular weight polymers like hydrolysed polyacrylamide (HPAM) are used for EOR, polymer retention retards propagation into the formation. Consequently, high polymer retention can substantially delay oil displacement and recovery (Zhang and Seright, 2013).

The rheology of a polymer is characterized by a viscosity increase or decrease depending on shear rate effects. The shear rate effects become clear when the polymer solution has a constant concentration and viscosity is measured at varying shear rates.

The focus of this study is to investigate the water and polymer injectivities in an unconsolidated sand pack saturated either with brine or with heavy oil, subject to confining axial and radial stresses in the range of those encountered in reservoirs. In particular we are interested in the typical reservoir conditions under which failure/hydraulic fracturing of the sample occurs. We also intend to investigate the effect that hydraulic fracture will have on polymer injection and pressure behavior in the reservoir during both injectivities.

II. METHODOLOGY

A. Physical Model

The purpose of this research is to investigate pressure behavior and the injectivity of polymer in the context of polymer flooding compared to water-flooding in unconsolidated heavy oil reservoirs. Let us consider a cylindrical homogenous and isotropic porous medium with radius R_c and height H , having porosity ϕ and permeability k , with well-rounded sand grains of diameter d_g . Three models will be considered to match the experiments conducted in this study. The first model is water injection in a water saturated porous medium (WIW). The second model is polymer solution of concentration c_p , injected into a water saturated porous medium (PIW). The final model is the same polymer solution of concentration c_p injected in an oil saturated porous medium (PIO). Fluids are injected in the porous medium at constant flow rate Q . The analysis is restricted to incompressible, non-inertial and isothermal flows. For the remainder of the work the following assumptions will be considered.

- Polymer degradation by chemical, mechanical, thermal and bacterial means is not considered and chromatographic separation in porous medium is neglected.
- No chemical reactions between polymer, rock and formation brine.
- No mass transfer between the stagnant and flowing regions of the fluid.
- The polymer adsorption onto the rock surface is instantaneous and mixing zone between the water and polymer fronts is negligible.

- The density (ρ) of aqueous phase is constant, i.e. polymer does not change the density of aqueous phase.

Another major assumption, made in this study, concerns the flow profile. As a consequence of the experimental set-up, flow in the BHS has spherical symmetry. Therefore, the analysis of the flow problems outline above, should honour the spherical symmetry.

B. Governing Equations

The above flow problem can be described formulating and solving a system of equations describing polymer flow in porous media. We are interested in the pressure behaviour during the water-flood and polymer flood for different flow rates. We will describe how bottom-hole flowing well pressure varies as a function of time.

The governing partial differential equation for flow in porous media is called the diffusivity equation. The diffusivity equation for a compressible liquid is given as:

$$\frac{1}{r} \frac{\partial}{\partial r} \left[\frac{k\rho}{\mu} r \frac{\partial P}{\partial r} \right] = \phi c \rho \frac{\partial P}{\partial t} \quad (2.1)$$

where r is the radial distance from the injection point and c is the compressibility.

Depending on conditions of the reservoir model and type of injection experiments, the partial diffusivity equation is solved to describe the transient, semi-steady state and steady state regime for Newtonian fluids. The flow regimes are explained with the analytical solution for each injection model, namely the water injection in a water saturated core, polymer injection in a water saturated core and polymer injection in an oil saturated core.

For every type of experiment, the initial conditions are the same. Prior to injection, the bottom-hole flowing well pressure (P_{wf}) is equal to the initial pressure (P_i). Therefore, the initial condition is given by:

$$P_{wf}(t=0) = p_i \quad \text{for } r = R_w$$

$$P(t=0) = p_i \quad \text{for } R_w < r < R_e$$

In the experimental results the moment when injection is started is assumed as $t = 0$. The initiation of injection will always be after a few seconds after the measurement has started.

Initially, the pressure response can be described using a transient solution of the diffusivity equation. It is assumed during this period that the pressure response at the wellbore is not affected by the drainage boundary of the well and vice versa. This is frequently referred to as the infinite reservoir case since, during the transient flow period, the reservoir appears to be infinite in extent. The condition for transient state is:

$$\frac{\partial P}{\partial t} = f(r, t)$$

The bottom-hole flowing well pressure for transient state during injection with injection rate ' Q ' is described with (Chaudry, 2004).

$$P_{wf} = P_i + \frac{Q\mu}{4\pi k H} \left[\ln \left(\frac{4kt}{\gamma \phi c R_w^2} \right) \right] \quad (2.2)$$

Eventually, stabilised flow conditions will prevail, which means that the boundary affects the pressure and is considered as solid "brick wall", which prevents the flow of fluid out of

the radial cell. This corresponds to the semi-steady state condition.

$$\frac{\partial P}{\partial r} = 0 \quad \text{at } r = R_e$$

If the well is injecting at a constant flow rate, then the rate of change of wellbore pressure with respect to time is constant. The cell pressure will increase in such a way that,

$$\frac{\partial P}{\partial r} = \frac{Q}{c\pi R_e H \phi}$$

The bottom-hole flowing well pressure for semi-steady state during injection is described with (Chaudry, 2004).

$$P_{wf} = P_i + \frac{Q\mu}{2\pi kH} \left[\frac{1}{2} \ln \left(\frac{4A}{\gamma c_A R_w^2} \right) + 2\pi \left(\frac{kt}{\phi \mu c_A} \right) \right] \quad (2.3)$$

Where $\gamma=1.781$ and $c_A=31.6$

Reservoirs with injection wells can reach true steady-state condition when total injection rate is equal to total production rate. This condition is present when the reservoir model has an open boundary and therefore,

$$P(r, t) = \text{constant and } \frac{\partial P}{\partial t} = 0$$

The bottom-hole flowing well pressure for steady state during injection is described with (Chaudry, 2004).

$$P_{wf} = P_i + \frac{Q\mu}{2\pi kH} \left[\ln \left(\frac{R_e}{R_w} \right) \right] \quad (2.4)$$

Polymers behave non-Newtonian and retention effects cause permeability reduction. Equation (2.5) describes the bottom-hole flowing pressure and takes the shear thinning and permeability reduction R_k into consideration (Lake, 1992).

$$P_{wf} = P_i + \left(\frac{Q}{2\pi H} \right)^{n_{pl}} \frac{H_{pl} R_k}{k_w (1-n_{pl})} \left(R_e^{1-n_{pl}} - R_w^{1-n_{pl}} \right) \quad (2.5)$$

C. Additional Equations

(a) Permeability Reduction

During polymer injection in a porous medium, retention of the polymer molecules takes place leading to a reduction of permeability. Permeability reduction manifests itself through increase in pressure drop. Permeability reduction is only one of three measures in permeable media flow (Lake, 1992). The resistance factor F_R is the ratio of the mobility of brine to that of a single-phase polymer solution flowing under the same conditions.

$$F_R = \frac{\lambda_w}{\lambda_p} = \left(\frac{k_w}{\mu_w} \right) \cdot \left(\frac{\mu_p}{k_p} \right) \quad (2.6)$$

For constant flow rate, F_R is the inverse ratio of pressure drop; for constant pressure drop, F_R is the ratio of flow rates. F_R is an indication of the total mobility lowering contribution of a polymer. To describe the permeability reduction effect alone, a permeability reduction factor R_k is defined as:

$$F_R = \frac{k_w}{k_p} = \frac{\mu_w}{\mu_p} F_R \quad (2.7)$$

A final definition is the residual resistance factor R_{RF} , which is the mobility of a brine/water solution before and after polymer injection.

$$R_{RF} = \frac{\lambda_w}{\lambda_{wa}} \quad (2.8)$$

where λ_{wa} is the mobility of the brine/water after contact with polymer.

(b) Mobilities

The mobilities are given by

$$\lambda_p = \frac{k_p}{\mu_{p,eff}} \quad (2.9)$$

$$\lambda_w = \frac{k_w}{\mu_{w,eff}} \quad (2.10)$$

where $\mu_{p,eff}$ and $\mu_{w,eff}$ are the effective viscosities of water and the polymer solution.

A way to determine the efficiency is by means of mobility ratio M . The mobility ratio is calculated by,

$$M = \frac{\lambda_{ing}}{\lambda_{ed}} = \frac{k_{ing}/\mu_{ing}}{k_{ed}/\mu_{ed}} \quad (2.11)$$

where the subscripts “ing” and “ed” stand for the displacing fluid and the displaced fluid respectively.

Mobility reduction R_m is an indication of loss of injectivity during polymer injection. It takes into account the pressure drop due to viscosity and adsorption of polymer to the rock. It is defined as:

$$R_m = \frac{\Delta P_p}{\Delta P_b} \quad (2.12)$$

where ΔP_p is the pressure drop during polymer injection and ΔP_b pressure drop for brine prior to polymer injection.

(c) Injectivity

The injectivity of a well is defined as (Lake, 1992).

$$I = \frac{Q}{\Delta P} \quad (2.13)$$

where, Q is the volumetric injection rate into the well, and ΔP is the pressure drop between the bottom-hole flowing pressure and some reference pressure, i.e. the initial pore pressure.

Injectivity is preferred to be high, meaning high injection rates and low pressure drop. High flow rates lead to increased sweep efficiency. Another useful measure is the relative injectivity,

$$I_r = \frac{I}{I_w} \quad (2.14)$$

where, I_w the water injectivity in ml/min/bar. I_r can be used to visualize more easily the injectivity decline to be anticipated when injecting polymer. Both I and I_r are functions of time, but the long-time limit of I_r for a Newtonian polymer solution is simply the viscosity ratio if skin effects are small.

D. Analytical Solutions

Two analytical solutions were considered, which are the displacement of water or oil by a polymer solution. The first solution takes the non-Newtonian behaviour into account and the second solution assumes the polymer has a constant average viscosity. The three experimental models are explained with the analytical solution considering the assumptions.

The flow model is solved for a well, of radius R_w , in a horizontal, homogeneous and circular drainage area of radius R_e . The pressures at R_e and R_w are P_i and P_{wf} , respectively. P_i is constant (steady-state flow), but P_{wf} can vary with time.

The fluids flowing in the reservoir are single aqueous phase, at residual oil or water saturation, which are both incompressible with pressure-independent rheological properties.

The volumetric injection rate is defined as:

$$Q = 2\pi r H u_r \quad (2.15)$$

where u_r is the Darcy velocity, which is used in shear rate calculations.

During injection there is a polymer-water or polymer-oil front depending on the experimental model. The region $R_w < r < R_p$ accounts for the polymer which has displaced the water (or oil) from the well (R_w) to a certain point in the reservoir (R_p), the polymer-water front. In the region $R_p < r < R_e$ accounts for the water or oil that is displaced by the polymer to the polymer-water front (R_p) and reaches to the end of the reservoir (R_e).

The pressure drop during polymer injection with non-Newtonian effects is defined as:

$$P_{wf} - P_i = \left(\frac{Q}{2\pi H} \right)^{n_{pl}} \frac{H_{pl} R_k}{(1-n_{pl})k_w} (R_p^{1-n_{pl}} - R_w^{1-n_{pl}}) + \frac{Q\mu_f}{2\pi k_f H} \left[\ln \left(\frac{R_e}{R_p} \right) \right] \quad (2.16)$$

The first term on the right-hand side of equation (2.16) gives the pressure drop of the polymer region ($R_w < r < R_p$) and takes into account the non-Newtonian effect and the permeability reduction effect. The second term gives the pressure behaviour of the water region ($R_p < r < R_e$).

If the polymer viscosity μ_p is taken as a constant value, the model for pressure drop is defined as:

$$P_{wf} - P_i = \frac{Q\mu_p}{2\pi k_p H} \left(\ln \left(\frac{R_p}{R_w} \right) \right) + \frac{Q\mu_f}{2\pi k_f H} \left(\ln \left(\frac{R_e}{R_p} \right) \right) \quad (2.17)$$

The first term on the right side of equation (2.17) gives the pressure drop of the polymer region ($R_w < r < R_p$). The second term gives the pressure drop of the water or oil region ($R_p < r < R_e$).

In both equation (2.16) and (2.17), μ_p is the viscosity of the saturation fluid of the porous medium (water or oil), k_p is the polymer permeability, k_f is the permeability of the saturation fluid phase (water or oil) and R_p is the radial distance of the injected polymer front. If μ_p is equal to μ_f , it becomes a single phase steady state flow model as in equation (2.4).

The viscosity of the polymer, μ_p , is estimated for different shear rates. Once the shear rates are calculated at each radial distance of the polymer solution, the viscosity can be determined from Figure 2.1. Viscosities for shear rates higher than 1000 s⁻¹ are estimated using a relation between shear thinning and shear thickening slopes obtained from measured data found by Zitha (2001). The estimated viscosities will help to justify the non-Newtonian model with shear thinning effects and the model with a constant polymer viscosity.

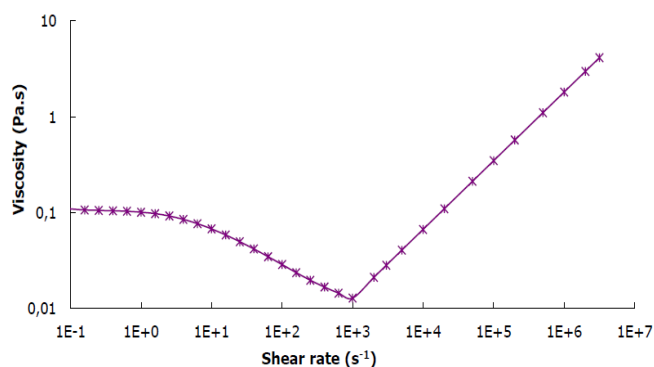


Figure 2.1: Viscosity versus shear rate of AN905 HPAM with a concentration of 5000 ppm and salinity of 0 g/L NaCl. Newtonian plateau and shear thinning regime from rheometer

measurements. Shear thickening regime estimated from slope relations.

(a) Water injection into water saturated porous medium

The WIW model assumes a single phase liquid flow. The equations for each flow regime assume single phase liquid flow as well (equations 2.2, 2.3 and 2.4). So the flow equations give a good prediction of what is happening during the WIW experiments. Figure 2.2 shows the pressure drop versus time for each flow regime in the case of the WIW model. It can clearly be seen that the transient state pressure drop increases fast for short times and will reach a constant pressure drop if time is infinite. The semi-steady state pressure drop keeps increasing with a constant rate. Due to the effect of no outflow at the boundary, injected fluid will build up pressure. If the inflow is equal to the outflow, pressure drop will not increase but will stay constant and reach steady state flow as explained before. The experimental set-up in this study has an open boundary. Therefore, the water outflow will eventually be equal to the injection rate of water and flow will reach a steady state. It takes time to reach steady state flow, so transient state flow will describe the pressure drop increase before it reaches the steady state flow. Due to the small size of the porous medium, steady state flow will be reached in less than 3 seconds.

To estimate the permeability of the porous medium, the flow models are fitted with the experimental results. The flow model that fits best is used to determine the permeability.

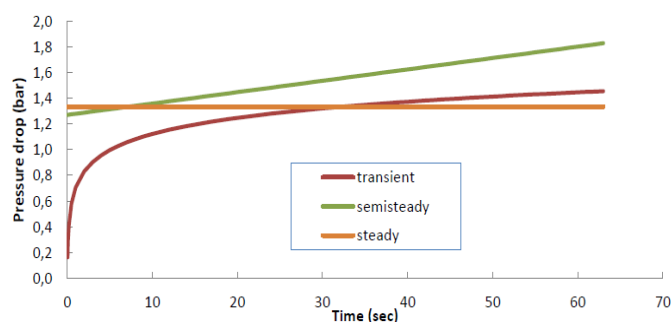
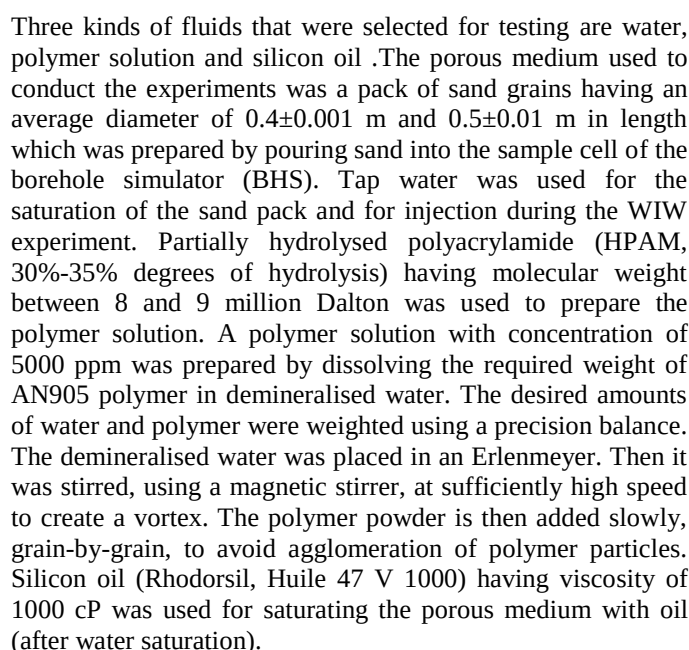


Figure 2.2: Transient state, semi-steady state and steady state pressure drop versus time for the WIW model. Flow rate, viscosity and permeability are constant.

(b) Polymer Injection into Water Saturated Porous Medium

The model for PIW is a pseudo-two-phase flow (assumed single phase flow) model where the polymer solution displaces the water. Both fluids are considered incompressible, injection rate is equal to outflow rate after some time, so eventually steady state flow conditions prevail. Given the size of the porous medium, the time to reach steady state will again be less than 3 seconds. Figure 2.3 shows the graphs corresponding to the analytical solutions for the displacement flow and the steady state flow where the polymer has already displaced all the water (equations 2.16, 2.17 and 2.4).

It is assumed that polymer (viscous fluid) displaces water (less viscous fluid) in a front like manner. The viscous polymer will create a higher pressure drop compared to the WIW model. The pressure drop increases over time, because low viscosity fluid is displaced by a higher viscosity fluid.



The porous sample was placed in a biaxial pressure vessel. The vessel can put the sample under axial and radial pressure to create reservoir conditions. Pressures vary between 0 bar and 100 bar in this experiment. The axial and radial pressures were

created by injecting silicon oil onto the rubber sleeve (radial) and on top of the filter (axial). Axial pressure should always be 10 bar higher than radial pressure to prevent leakage from radial pressure chamber into the axial pressure chamber on top of the sample. These oil pressure chambers are coloured purple as indicated in Figure 2.5.

When the porous sample is in place and the system is closed so no leakage can occur, the final procedure must be taken to prepare the injection experiment. This procedure is presented in Table 2.1. During each step the data acquisitions system is used to record pressure changes, axial displacement and outflow rates.

Table 2.1: Step by step procedure of preparing the BHS

Step	Title	Description	Parameters varied			
			Q (ml/min)	V _{fluid} (L)	P _{axial} (bar)	P _{radial} (bar)
1	Removal of air in porous medium	Evacuation and CO ₂ flushing				
2a	Water saturating	Inject water through bottom filter until it flows out from the top. Wait one hour.	100	27		
		Water flushing 4 times		1		
2b	Oil saturating	Inject oil through bottom filter until it flows out from the top. Wait two hours.	30	21		
		Oil flushing 4 times		1		
3	Increase axial and radial pressures	Make sure axial pressure is always 10 bar higher than radial pressure.				
		Record pressures and axial displacement				
		-Exp. 1 to 10			100	70
		-Exp. 11 and 12			50	30
4	Fill injection pipe	When saturated, open the bottom of the injection pipe				
		Saturation fluid flows in the pipe and displaces air out				
		Use ISCO pump to fill pipe with polymer for PIW and PIO experiment types. The polymer displaces saturation fluid back into sample				
5	Connect injection cell	The injection cell is connected to injection pipe via injection lines. The cell and lines must be filled with injection fluid.				
6	Pressurize fluids in injection lines	Use ISCO pump to put injection lines under the same pressure as the initial pore pressure in the sample				
7	Set MTS servo controller	Choose the right injection rates for each experiment.				
		Start data-acquisition				

III. RESULTS AND DISCUSSION

A. Results

Table 3.1 below gives an overview of the experiments with the injection rate, the injected volume, the confining pressures and the flowing well (injection) pressures during injection.

In the table below, we can see that 550 ml was not injected in three parts for Exps. 1, 2 and 3 (WIW). Here the flow rate was changed 2 times during the injection. Time to switch from one flow rate to another flow rate was 10 seconds. The same procedure was used in Exps. 8, 9 and 10 (PIW).

For the WIW, PIW and PIO experiments, observations will be discussed for the case of an injection rate of 600 ml/min. The

PIW experiments will be discussed for two confining pressures 100/70 bar and 50/30 bar (Exps. 10 and 11).

Further, injectivity will be discussed and the WIW injectivity was the base case for the relative injectivity.

(a) Water Injection in a Water Saturated Porous Medium

Figure 3.1 shows the pressure drop versus time over the radius of the BHS measured during water injection in a water saturated sand-pack at injection rate of 600 ml/min (Exp. 4). The injection rate (600 ml/min) was set at the start of the experiment, from the first moment the pressure starts to increase and lasts for 53 seconds.

Table 3.1: Summary of sample properties, experimental parameters and measured pressures. Experiment type WIW, PIW and PIO stands for water injection in a water saturated sample, polymer injection in a water saturated sample and polymer injection in an oil saturated sample, respectively.

Experiment	Type	Injection rate (ml/min)	Injected volume (ml)	Mass sand (kg)	Pore Volume (m^3)	ϕ (%)	k_w (Darcy)	P_{axial} (bar)	P_{radial} (bar)	$P_{injection}$ (bar)	P_{pore} (bar)	$P_{increase}$ (bar)
1	WIW	60	87	90.8	27.6	0.44	2.3	96	72	2.38	2.10	0.28
2	WIW	300	174	90.8	27.6	0.44	2.3	96	72	2.45	2.10	0.35
3	WIW	600	289	90.8	27.6	0.44	2.3	96	72	2.95	2.10	0.85
4	WIW	600	550	90.8	27.6	0.44	2.3	97	72	3.30	2.10	1.20
5	WIW	600	550	90.8	27.6	0.44	2.3	96	71	3.43	2.10	1.33
6	WIW	1200	550	90.8	27.6	0.44	2.3	100	74	4.35	2.10	2.25
7	WIW	1200	550	90.8	27.6	0.44	2.3	99	74	3.98	2.10	1.88
8	PIW	10	50	90.8	27.6	0.44	2.3	99	71	2.92	2.10	0.82
9	PIW	120	241	90.8	27.6	0.44	2.3	99	71	11.02	2.10	8.92
10	PIW	600	259	90.8	27.6	0.44	2.3	99	71	28.40	2.10	26.30
11	PIW	600	550	91.8	27.4	0.44	2.3	46	33	27.71	2.00	25.71
12	PIO	600	550	91.8	26.5	0.42	2.3	51	30	57.44	1.90	55.54

From 3 to 10 seconds the pressure seems to increase linearly. The data acquisition system records measurements every 0.1 seconds, but it does not show recorded measurements on the linear slope. The time of the beginning of the linear slope matches with the time when the balance, for water outflow measurements, sends a signal to the data acquisitions system. This can be seen in the graphs in Appendix H where water outflow is presented together with the pressure drop measurements. Communication between the balance and recording device causes a break in the recording of 7 seconds, hence the linear interpolation between measurements at 3 and 10 seconds respectively. After 10 seconds the pressure fluctuates between 0.9 bar and 1.5 bar with an average of approximately 1.2 bar. At 24 seconds there is another recording break, at 45 seconds there is a peak in the pressure drop, followed by another break in recording as explained above. After 55 seconds the injection stops and the pressure drop decreases almost immediately.

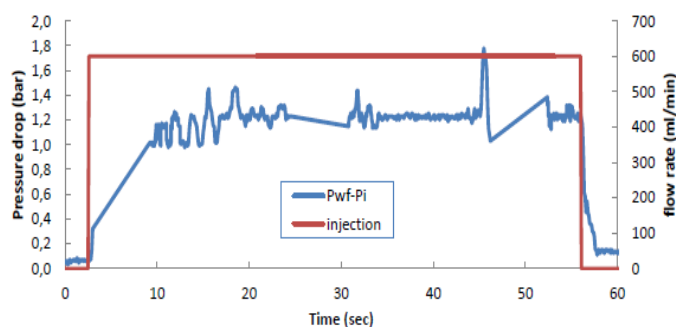


Figure 3.1: Exp. 4. Injection with $q=600$ ml/min. The pressuredrop (Pwf-Pi) and flow rate are presented versus time.

The experimental data from WIW Exps. 4 and 5 with an injection rate of 600 ml/min are presented against time in Figure 3.2. The data from the two experiments are similar which indicated reproducibility (within experimental error margins).

The main uncertainty for these water injection experiments is the permeability. Therefore the permeability was chosen as the fitting parameter for matching the model predictions of different flow regimes to the experimental data. As can be seen in Figure 3.2, the steady-state model gives a better fit to the measured data than the transient and semi steady state models. This supports the statement that the time to reach steady-state is short on account of the small dimensions of the samples

compared to the reservoir situation. Because of this observation, the rest of the discussion will be based on a steady-state flow assumption. The corresponding permeability was 2.3 ± 0.1 D. This value was also used as the absolute permeability for the analysis (model predictions, curve fitting) of the polymer injection experiments into the water- and oil-saturated sand-packs (Exp. 8 to 12). In these experiments the main uncertainties are the rheology, and retention of the polymer and the geo-mechanical properties of the sand-pack.

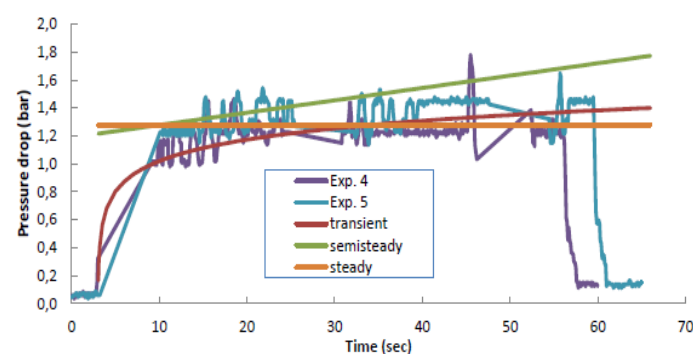


Figure 3.2: Pressure drop of Exp. 4 and 5 together with the transient, semi-steady and steady- state models for $q = 600$ ml and $k = 2.3$ Darcy are presented versus time.

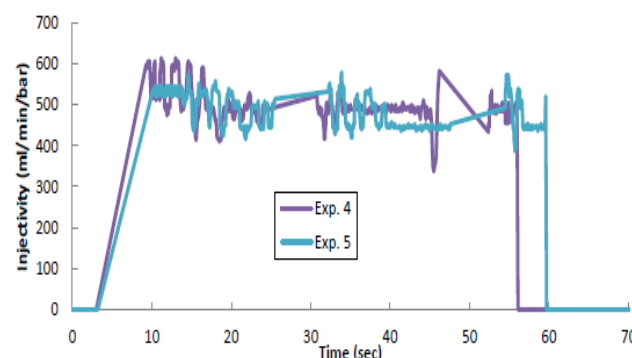


Figure 3.3: Injectivities of Experiments. 4 and 5.

Injectivity of the water flood for experiments 4 and 5 is presented in Figure 3.3. Injection starts at approximately 3 seconds. At this moment in time the injectivity is zero. After 10 seconds, the injectivity in Exp. 4 reached a value of 550 ± 5 ml/min/bar. From 10 to 20 seconds injectivity declined to a value of 490 ± 2 ml/min/bar, with fluctuations between 420 and 530 ml/min/bar. The reason for a higher injectivity around 10

seconds of injection and decline to an average value of 500 ml/min/bar is due an increasing pressure drop from zero pressure drop when injection is initiated, because when pressure drop is low, injectivity is high. The injectivity results for Exp. 5 show the same results as Exp. 4, only with a slightly lower value, starting from an injectivity of 530 ml/min/bar with a decline to a value of approximately 460 ml/min/bar with fluctuations between 420 and 570 ml/min/bar.

(b) Polymer Injection in a Water Saturated Porous Medium

Figure 3.4 shows the pressure drop obtained during polymer injection in a water saturated sample versus time, again for an injection rate of 600 ml/min (Exp. 10). The axial and radial pressures on the sample were 99 and 71 bar respectively. Injection starts after 10 seconds and lasts approximately 25 seconds. The pressure drop increases up to a value of 26 ± 2 bar. The pressure remains around this value with fairly large fluctuations between 21 and 32 bar. When injection stops, the pressure decreases steeply to the initial pore pressure P_i (0 bar pressure drop) in approximately 15 seconds.

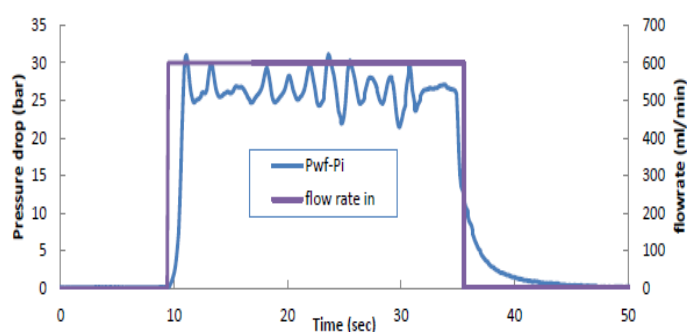


Figure 3.4: Exp. 10 (PIW) with $q=600$ ml/min. The pressure drop (Pwf-Pi) and flow rate in are presented versus time. Exp. 10 has a axial and radial pressure of 99 bar and 71 bar, respectively.

In Figure 3.5 results of a similar experiment (Exp. 11) as in Figure 3.4 are presented. Only in this injection experiment the confining pressure has been lowered to an axial pressure and radial pressure of 46 bar and 33 bar respectively. The pressure drop increase starts around 28 seconds and rises to 25 ± 2 bar, with fluctuations between 23 bar and 30 bar. After 80 seconds (52 seconds of injection), the injection stops and pressure drop decreases immediately and smoothens out to zero pressure drop in approximately 13 seconds.

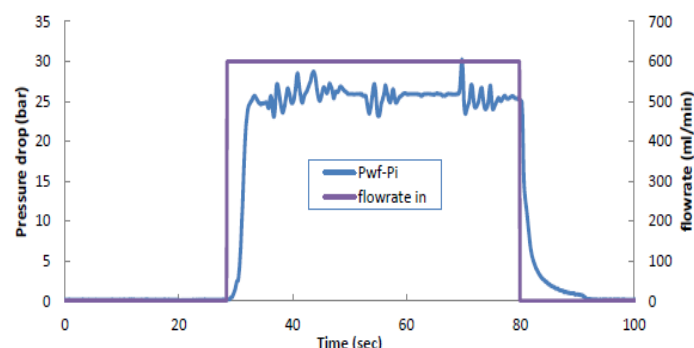


Figure 3.5: Exp. 11 (PIW) with $q=600$ ml/min. The pressure drop (Pwf-Pi), flow rate in are presented versus time. The experiment was performed with axial and radial pressure of 46 bar and 33 bar, respectively.

In Figure 3.6, pressure drop results of experiments 10 and 11 (PIW) are presented together versus time. Here it is visible, even though the confining pressure is different, the pressure drop of Exps. 10 and 11 is the same (i.e. the same within

experimental error margins). Although Exps. 10 and 11 are executed in different sand packs, we assume that any differences in the properties of these porous media are negligible for the purposes of these experiments.

Exp. 10 has a shorter injection time, because three injection rates were chosen during the injection of 550 ml (Exps. 8,9 and 10) as explained earlier.

The experimental data and PIW model prediction are shown together in Figure 3.6. Because the pressure drop takes on a stable value virtually immediately after the start of injection, the steady-state model gives the best fit. The viscosity that fits for this model is 20 cP, which is 20 times higher than the viscosity of water used in the WIW model, corresponding to a 20 times higher pressure drop. This viscosity was used as input for the displacement model with constant polymer viscosity. As explained, when the polymer has displaced all the water, the pressure drop will show the same result as the steady-state model where all the water is displaced.

In the non-Newtonian displacement model the polymer solution is assumed to be shear thinning. This means the polymer solution is shear thickening over the main part of the injection radius, with a viscosity of 134 cP at the wellbore and 12 cP at 13.5 cm, resulting in a higher predicted pressure drop than shown in Figure 3.6. Therefore, the non-Newtonian model is not valid for an injection rate of 600 ml/min or higher, causing the high shear rates. The rheology values of the PIW experiment are equal to the values of the PIO experiment, because injection rate and penetration depth are the same. Therefore the non-Newtonian model will also not be valid in the PIO model. The permeability reduction R_{ki} is assumed to be 1, because we have no data on retention. Retention does take place, therefore permeability was reduced and R_{ki} is in reality higher than 1, which results in higher pressure drop for both displacement models than Figure 3.6 shows.

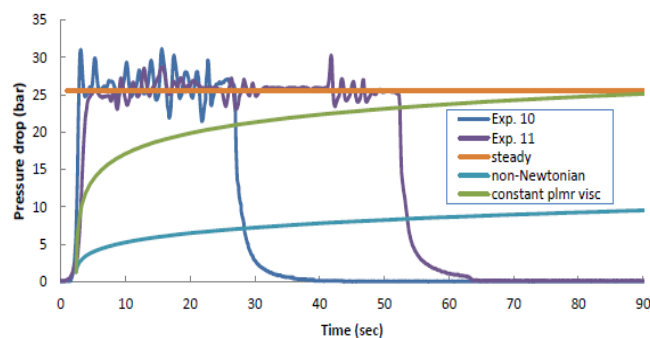


Figure 3.6: Exp. 10 and 11 (PIW) are presented together with the steady state, displacement non-Newtonian flow and displacement flow with constant polymer viscosity models for $q = 600$ ml, $k = 2.3$ Darcy and $\mu_p = 20$ cP. Exp. 10 has axial and radial confining pressure of 99 bar and 71 bar respectively. Exp. 11 has axial and radial confining pressure of 64 and 33 bar respectively.

To clarify the effects of permeability reduction on pressure drop, the displacement model with constant polymer viscosity is presented in Figure 3.7 versus time for R_{ki} higher than 1, meaning k_p is lower than 2.3 D. When R_{ki} is higher than 1, we can see that the curve has a steeper initial pressure drop. For $R_{k2.5}$ ($R_k = 2.5$) the modelled pressure drop matches the slope of initial experimental pressure drop, but will reach a pressure drop that is double the experimental pressure drop as time passes. If we look at $R_{k1.5}$ ($R_k = 1.5$) we see that this curve does not match the initial pressure drop increase as well as $R_{k2.5}$, but as time passes $R_{k1.5}$ matches with the experimental

data around 10 seconds. The $Rk1$ ($R_k=1$) curve matches with the data when all water is displaced by the polymer solution. A good match can be found when R_k is taken as a variable parameter that will decrease when time passes and the polymer has displaced more water. This means most retention effects occur at short time and close to the wellbore, causing R_k to be high. When time passes and the polymer solution invades further into the porous medium, retention effects decrease, decreasing R_k .

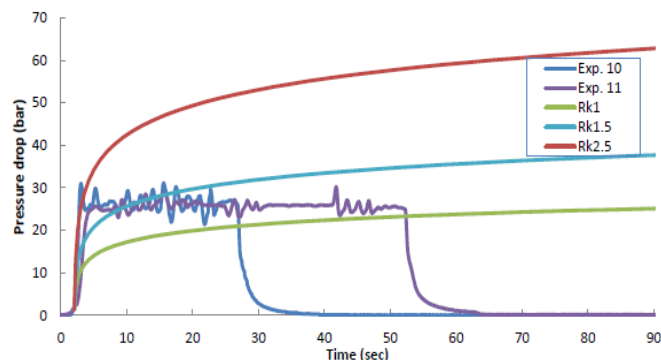


Figure 3.7: Exps. 10 and 11 data together with the modelled pressure drop of the displacement model with constant polymer viscosity. R_k is varied to show retention effects to show retention effects on pressure drop. $Rk1$ ($R_k=1$) $Rk1.5$ ($R_k=1.5$) and $Rk2.5$ ($R_k=2.5$).

Injectivity of the polymer flood is presented in Figure 3.8 for Exp. 10 and 11. The injectivities show peaks at the beginning and at the end of the injection. This is due to the same reason as mentioned for the injectivities from Exps. 4 and 5; a low pressure drop that quickly increases after injection is initiated. Both Exps. 10 and 11 stay around an average value of 23 ml/min/bar. Compared to the injectivities of Exps. 4 and 5, this value is approximately 20 times lower. This means pressure drop is 20 times higher. The difference in pressure drop compared to water injection experiment, is caused by the higher viscosity of the polymer solution and retention effects. According to equation (2.16) we can see both properties increase the pressure drop.

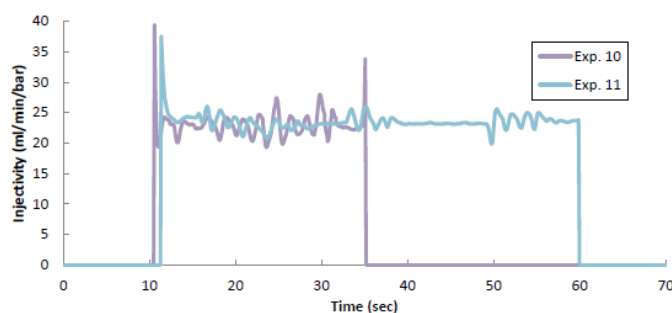


Figure 3.8: Injectivities of Experiments 10 and 11.

(c) Polymer Injection in an Oil Saturated Sample

In Figure 3.9, the result of Exp. 12, a polymer injection in an oil saturated sand (PIO) is shown. After 13 seconds the injection starts with an injection rate of 600 ml/min and continues for 52 seconds. When injection starts, the pressure increase is 130 ± 1 bar for nearly 1.0 s. After this peak in the pressure drop, the pressure drop decreases to 51 bar and takes on an average value of 55 bar with fluctuations between 51 bar and 58 bar. At 65 seconds the injection of the polymer stops and the pressure drop decreases exponentially until 120 seconds when it is back to zero bar pressure drop.

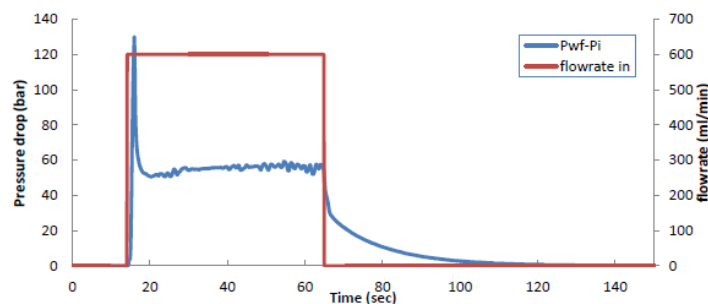


Figure 3.9: Exp. 12 (PIO) with $q=600$ ml/min. Polymer injection in an oil saturated sample. The pressure drop (Pwf-Pi), flow rate in are shown versus time. Exp. 12 has a axial and radial pressure of 51 bar and 30 bar, respectively.

The experimental data is compared with PIO model predictions in Figure 3.10. Because the pressure increase takes on a stable value almost directly after the start of injection, the single phase steady state model gives the best fit, with a viscosity of 43 cP. This is 43 times higher than the water viscosity. This corresponds with the pressure drop increase, which is also 43 times higher than the pressure drop of the WIW experiment. For the displacement model with a constant polymer solution viscosity, we take 43 cP. The curve will eventually reach stable pressure drop when all the oil has been displaced by the polymer. If displacement is has a shorter time constant, the model prediction would give a better fit as it reaches the stable pressure drop faster.

The displacement model with constant polymer viscosity has a very high initial pressure drop. The initial pressure drop for the displacement model is 1334 ± 1 bar. The initial pressure drop represent the pressure drop, when is no polymer present in the porous medium. So the fluid that provides the pressure drop is oil. The oil has a high viscosity of 1000 cP, therefore it causes more pressure drop compared to the viscous polymer. Both curves decrease, because the high viscosity oil is displaced by a lower viscosity polymer solution.

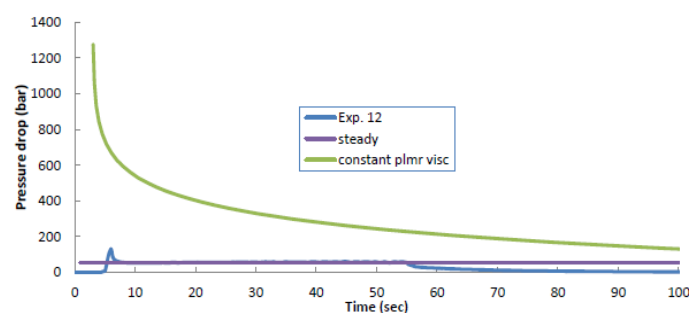


Figure 3.10: Exp. 12 (PIO) results versus time together with the single-phase steady state and the displacement with constant polymer viscosity models for $q = 600$ ml and $k = 2.3$ Darcy and polymer viscosity 43 cP.

To find an explanation for the peak pressure, we need to understand what happens when pressure drop reaches the high values predicted by the displacement model. As seen in earlier research done by Zhou (2010) and Meng (2010), were they studied fracture development for injecting high viscosity fluids in unconsolidated sands, the porous medium will develop fractures if the pressure drop is 2.5 to 4 times higher than the minimum confining pressure. The minimum confining radial pressure in Exps. 12 is 30 bar. So we can expect a fracture development when the pressure drop reaches a value between 75 and 120 bar. The peak pressure drop is 130 ± 1 bar, so a fracture did occur, but initiated at a higher pressure drop than was claimed by Zhou and Meng. In the fracture, permeability

will be higher creating a smaller pressure drop. The viscosity that fits with the peak in the steady state model is 100 cP (Figure 3.11). Fracture occurrence makes use of displacement model predictions invalid.

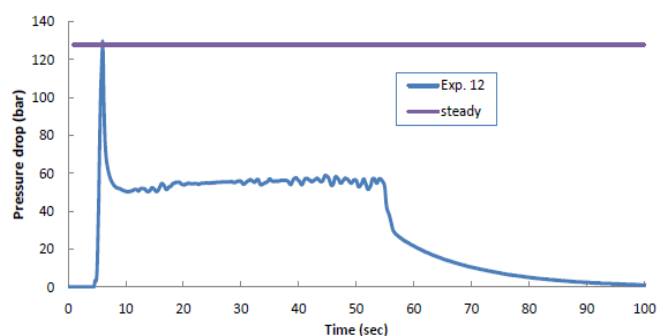


Figure 3.11: Exp. 12 (PIO) results versus time together with steady state model for $q = 600$ ml and $k = 2.3$ Darcy and polymer viscosity 100 cP.

The injectivity of Exp. 12 is presented in Figure 3.12. The first peak the graph shows is again due to the low pressure drop that increases very quickly right after injection starts. Right after the first high peak, we see a low peak. The low injectivity peak is the same as the peak from the pressure increase where the fracture developed. The peak injectivity has a value of around 5 ml/min/bar. Compared to the water flood case, this is 100 times smaller, meaning pressure drop was 100 times higher during injection of the polymer in an oil saturated sand pack. Compared to the polymer injection in a water saturated sand pack, the injectivity is 5 times smaller. This mean due to oil saturation, the pressure increase is 5 times higher.

After the low peak, the injectivity stays around 10 ml/min/bar. This is 50 times smaller than the water flood case and 2.5 times smaller than the polymer flood in water saturated sand pack case.

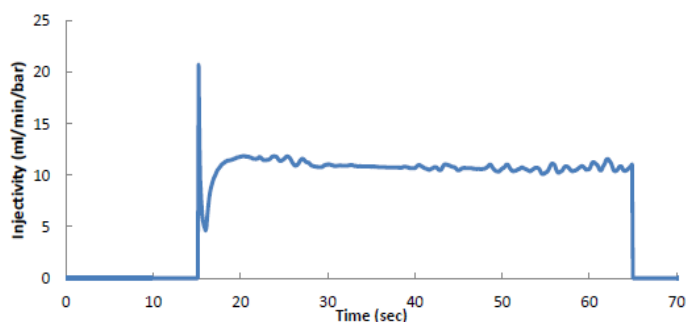


Figure 3.12: Injectivity of Exp. 12.

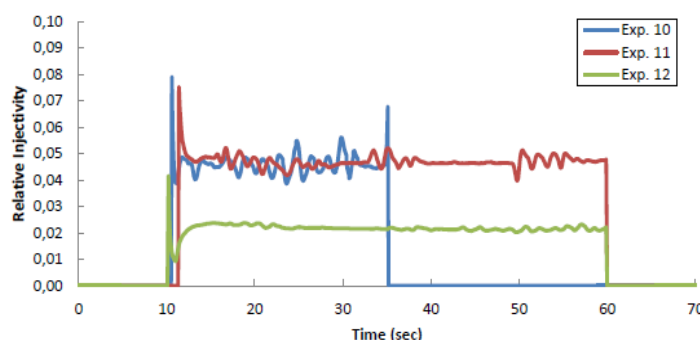


Figure 3.13: Relative injectivities of Exps. 10, 11 and 12 in relation to water injectivity.

An overview of the relation between water flood injectivities and the polymer flood injectivities is shown in Figure 3.13. The relation is the relative injectivity with respect to water

injectivity and indicates the decline to be anticipated when injecting polymer. So the injectivity of Exps. 10 and 11 is 0.05 times water injectivity and for Exp. 12 the injectivity is 0.02 times water injectivity.

B. Discussion

From the WIW experiments it was found that, flow can be adequately described by a steady-state model. Using the steady-state model, we found that a permeability of 2.3 ± 0.1 D gave the best fit. Assuming the preparation procedure is done the same way for each sand pack, the permeability for all the other experiments can be expected to be 2.3 ± 0.1 D. Pressure drop is very low for WIW experiments and thus gives a high injectivity of 500 ml/min/bar.

The PIW experiments with the injection rate of 600 ml/min were reproducible for different confining pressures. Therefore we can conclude that confining pressure has negligible influence on the pressure drop during a polymer flood. The pressure drop in PIW experiments was 20 times higher than the pressure drop in WIW experiments. This is related to the higher viscosity of the polymer solution compared to water. The expectation when injecting polymer is that pressure drop will increase over time as it displaces the water which has a lower viscosity. The two analytical solution models for displacement both show this expectation. The non-Newtonian displacement model was expected to give the best fit as it considers the rheology and retention of the polymer solution. The results, however, showed a stable pressure drop over time. The non-Newtonian model was found to not be valid for higher shear rates than 1000 s⁻¹. The shear thickening and retention effects have to be considered to give a good fit, although it will not fit as well as the steady state model that assumes all water has been displaced by the polymer solution. The displacement model with constant polymer viscosity will eventually give the same fit as the single phase steady state model, but does not reach the stable pressure drop quickly enough to fit the experimental results. When the retention effect is analysed, causing permeability reduction, it became clear that the displacement model fits when R_{ki} is high close to the wellbore and decreases when the polymer solution further invades the porous medium. The stable pressure drop fits best with the single phase steady state model when a viscosity of 20 cP is assumed, which is 20 times higher as the water viscosity. Therefore, in PIW experiment, the polymer flood can best be considered as a single phase steady state flow where the polymer solution with average viscosity of 20 cP has displaced all the water.

According to the injectivity comparison of WIW with PIW the pressure drop, when the polymer HPAM AN905 with a concentration of 5000 ppm is used for the polymer flood, will be 20 times higher than the pressure drop in a water flood, corresponding with increased viscosity.

The PIO model predicted a decrease in pressure drop when a displacement flow is considered, because a high viscosity oil is displaced by a lower viscosity polymer solution. The results of the PIO experiment, however, showed a peak pressure which was 4.3 times higher than the confining radial pressure. According to the work of Zhou and Meng this means a fracture has occurred, but at a higher pressure drop as was claimed. The peak pressure lasted only for 1.0 sec. After the 1.0 sec the pressure declined to a stable average value. As observed with PIO experiments, the steady state model showed the best fit to the measurements, and the best fit was found using a viscosity value of 43 cP. This is 43 times higher than viscosity of water and corresponds to the pressure drop, which is also

approximately 43 times higher than the pressure drop of the WIW experiment.

When the peak pressure was used to fit model predictions to observed data, a viscosity of 100 cP is required. The analytical solution model that considers displacement with constant polymer solution viscosity, gives a pressure drop that is significantly higher than the experimental data shows, due to the high oil viscosity. The predictions of high pressure drop explains why pressure has been able to reach the fracture pressure.

When the injectivities of the PIO experiment is compared with the WIW experiment, we see that the stable average pressure drop has an injectivity 50 times smaller than the water injectivity and the peak pressure drop has an injectivity 100 times smaller.

A way to see the relation between the water flood injectivity and polymer flood injectivity is by means of the relative injectivity. This work has showed that injectivity decline for PIW is 0.05, for PIO this decline is 0.02 and for the peak in PIO experiment this is 0.01. Injectivity is preferred to be high to give the best recovery results. The experiments clearly showed when injection fluid or displaced fluid have a higher viscosity than water, injectivity decreased. The occurrence of the fracture in the PIO experiment, however, increased injectivity during the experiment. If the fracture had not occurred the injectivity would reach even lower values than the peak injectivity showed.

We need not forget that assumptions are made to cover limitations of the experiment.

With the BHS set-up it is not possible to measure polymer retention effects such as mechanical entrapment or adsorption, which are known characteristics of HPAM.

The outflow of the flooding experiment is measured with a mass balance. The mass balance measurements are recorded by the data acquisition system. The limitation is that measurements are recorded every 20 seconds and not every 0.1 seconds. Outflow results cannot be used for comparison with the injection flow rate, especially for the short time interval of the experiment.

The pressure measured inside the sample is the pressure at the bottom of the of the injection pipe. Pressures inside the sample at different radii cannot be measured.

For the steady state model, radial cylindrical flow is assumed. Analysing the porous medium after the flooding experiment, showed that the fluid spreads in a spherical way. Not enough literature is present to model steady state spherical flow. Modelling cylindrical or spherical flow makes a difference for the flow rates inside the sample at different radii, this determines shear rates and thus viscosity for the polymer solution.

The injection cell can only inject 550 ml during one injection. 550 ml is not enough for the injection fluid to reach the borders of the set-up.

The permeability is determined by fitting the steady state model with the experimental results of the WIW experiments. Exps. 11 and 12 are both performed in new prepared porous medium. For these two porous media, the same permeability is assumed, which is potentially a false assumption.

CONCLUSION

Results of the experiments showed flooding experiments are reproducible, proving the reliability of the BHS set-up.

The injectivity of a water flood decreased when the polymer HPAM AN905 is added to create a solution of 5000 ppm. Displacing water, the injectivity decreases with a factor 20. When displacing oil of 1000 cP, the injectivity decreases with a factor 50. During displacement of oil, the resultant pressure drop over the sample was more than 2.5 to 4 times (4.3 times) higher than the confining radial pressure which initiated fracturing. This led to an increase in permeability and thus a lower pressure drop over the sample. Due to the fracture the injectivity doubled. So polymer flood decreases injectivity, but when a fracture develops it will increase to a stable value.

Predicting pressure behaviour for a polymer flood experiment is best approached using a single phase steady-state flow model that assumes all saturation fluid has been displaced. Although it remains unclear what viscosity should be considered for the injection fluid as it is a result of fitting the experiments and not an input value beforehand. The non-Newtonian model needs to consider permeability reduction, shear thickening effects and the actual spherical flow to give a good fit. Not enough data was collected for these parameters, therefore the model did not give a good fit. The displacement model with constant polymer viscosity made clear that retention is highest close to the wellbore and decreases when polymer is further invaded in the porous medium.

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