Polymer screening for high temperature and high salinity at Carbonate Reservoirs

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Originality Statement

I, Zhandos Askar.., hereby declare that this submission is my own work and to the best of my knowledge it contains no materials previously published or written by another person, or substantial proportions of material which have been accepted for the award of any other degree or diploma at Nazarbayev University or any other educational institution, except where due acknowledgement is made in the thesis.

Any contribution made to the research by others, with whom I have worked at NU or elsewhere is explicitly acknowledged in the thesis.

I also declare that the intellectual content of this thesis is the product of my own work, except to the extent that assistance from others in the project's design and conception or in style, presentation and linguistic expression is acknowledged.

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ABSTRACT

Polymer flooding is one of the most promising EOR technique used in heterogeneous carbonate reservoirs; however, high temperature and high salinity (HTHS) conditions (120^0 C and 256000 ppm) restrict the full potential of a chemical. The conventional polymers are vulnerable to chemical degradation, mechanical degradation, as well as injectivity problems. The objective of the paper is to analyze the behavior of three different types of partially hydrolyzed polyacrylamide (HPAM) base polymers to select for HTHS carbonate reservoirs.

The laboratory work was conducted on three newly developed HPAM base polymers to find an appropriate candidate suitable for harsh reservoir conditions. The potential polymer must provide proper rheology at lower polymer concentration, have excellent thermal and mechanical stability, and allow good injectivity. The first step in the investigation was a rheometric analysis for each HPAM at various concentrations and temperatures. Further, the anaerobic thermal stability test at 80^0 C was conducted, and the results of viscosity were recorded for 2 months. Then, the polymer that met rheological criteria was studied for the injectivity test. During polymer flooding, the unsteady-state technique was carried out on carbonate reservoir cores with a permeability range between 10 – 100mD. The experiment included the injection of polymers at different concentrations after formation water flooding. Additionally, resistance factor, residual resistance factor and insitu rheology were investigated.

The rheometric analysis showed that at relatively low concentrations, two of the polymers exhibited diminished properties at HTHS conditions. Despite the high shear-thinning effect, SAV10 XV provided excellent viscosity value at low concentration. The thermal stability test showed that polymer could maintain 75% of its initial properties after a long period. Furthermore, the coreflooding introduced a higher resistance factor when 3000ppm was injected, whereas at 2000 ppm and 1000ppm RF was lower. The study also showed shear thinning and thickening behaviors at low and high injection rates respectively. Polymer enabled reduction of the mobility ratio; therefore, HPAM injection assisted in increasing oil production after water flooding.

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1. Introduction

By 2010, hydrocarbon energy supply constituted over 85% of world energy, consuming 87 million barrels per day. That energy consumptions will demand exploration of new oilfields if only the primary recovery mechanism is implemented. Approximately 10 billion barrels out of 32 billion barrels of oil produced is from carbonate reservoirs. According to Montaron, the proven reserves in carbonate reservoirs will supply 80 years of production. The current energy consumption increase over the next decades requires a sophisticated solution to overcome the deficiency of fossil fuel products. There are also several reasons why the Enhanced Oil Recovery (EOR) is important in petroleum engineering:

- Limited oilfield discoveries
- Recently found discoveries are probably located in offshore, deep offshore or local areas.
- Infeasibility of unconventional reservoirs (Montaron, 2008)

Oil recovery can be defined in terms of the production life phases: primary, secondary and tertiary. The primary mechanism is a function of the natural drive mechanism in the reservoir. Internal energy can recover hydrocarbons, not requiring an injection of any fluids or applying heat. The mechanism involves rock and fluid expansion, solution gas drive, aquifer, gas cap drive, and gravity drainage. Secondary recovery includes injection of external fluids like water or gas, which serves in keeping high pressure inside the reservoir. Tertiary recovery is the recovery conducted after secondary recovery, in which special chemicals, miscible gases, and thermal energy are exerted (Sheng, 2016). There were many arguments about the use of polymer; some say it is supplementary to waterflooding, while others claim that it refers to tertiary recovery. Regardless of etymology, polymer flooding is an excellent EOR method, which enhances the mobility ratio between displacing and displaced fluids, therefore increases the sweep efficiency (Donaldson, 1989).

Waterflood technology is a commonly used method to improve oil recovery. Despite, the successful accomplishments, the method also faces poor sweep efficiency. Since the early sixties, the use of water-soluble polymer has been used, and up to now, this method is assumed to be one of the most promising types of enhanced oil recovery. During the past 40 years, new polymer forms have been introduced to develop the flooding operation. Plenty of pilot and field tests had been conducted in the USA between 1970 and 1980 (Saboorian-Jooybari, Dejam & Chen, 2016, Jewett and Schurz, 1970; Chang, 1978; Manning et al.,1983; Needham and Doe, 1987; Du and Guan, 2004; Manrique et al., 2010) Many types of research are working on development projects related to polymers and EOR processes, producing more complex and sophisticated polymers (Donaldson, 1989).

The function of a polymer is to maintain the appropriate viscosity of the injecting fluid. With infeasibility of changing displaced fluid parameters (heat injection, chemical additives), injecting fluid control, e.g. by increasing viscosity with polymer, is an effective option (Jenings R, 1971). The higher viscosity fluid decreases viscous fingering; thus, early water-breakthrough can be eliminated. The mobility control also stabilizes and homogenizes the fluid front and significantly improves the sweep efficiency (De Simoni et al., 2018). The polymer solution affects rock and fluid interaction. Carbonate reservoirs have high permeable zones and most of the injected brine flows through them. The permeability of rock reduces due to adsorption, therefore, subsequent water injected is forced to flow through unswept region and improves sweep efficiency(Sheng et al., 2015).

The drawback of the polymer flood is due to the instability of chemicals at extreme reservoir conditions. Most of the HPAM solutions suffer from chemical, mechanical and, in rare cases, biological degradations, losing effectiveness in the formation. There were plenty of polymers advised to use at temperature up to 80^{o} C; however, reservoirs can achieve up to 120^{0} C influencing negatively on viscoelastic properties. (Sharma et al., 2013).

The paper will analyze various factors of decreasing the quality of polymer in the laboratory, such as temperature, shear rate, concentration and mechanical degradation at a high shear rate for a long period. These tests are performed by rheometer and with additional tools such as mixer and oven. After testing all three types of polymers, the injectivity test is conducted, in which rock and fluent interaction, as well as insitu rheology, are studied.

2. Problem definition

The polymer flooding is an excellent tool in terms of increasing sweep efficiency; however, injected fluid remains in the reservoir for a long period. The conventional HPAM polymers and Xanthan have successful field experiences; however, after some time, they start to lose viscoelastic properties (Quadri, 2015., Davison et al, 1982). The polymers are sensitive to high temperatures and high salinity. Consequently, the polymers degrade and precipitate. Monovalent and, especially, divalent ions shield the carboxyl group of the polymer molecule, decreasing the repulsive force between the molecular groups. On the other hand, increasing temperature increases the hydrolysis of a solution, further increasing the amount of carboxyl group. Consequently, the polymer becomes sensitive to the hardness of brine, and at higher salinity, precipitation may occur (Abbas et al., 2013). Based on this nature of Polymer, this EOR technique was recommended for low salinity and low-temperature reservoirs (Vermolen et al., 2011). Apart from those reservoir characteristics, HPAM frequently faces mechanical degradation, in which long molecular chain breaks due to high shear stress in high shear rate regions, particularly near wellbore region. Additionally, the pore size variation creates rapid changes in velocity, which negatively affect viscosity (Sheng, 2011). In carbonate reservoirs, HPAM polymers have a significant adsorption level. Also, heterogeneous carbonate reservoirs have low-permeable zones, through which large molecular chains cannot flow.

3. Literature review

3.1 Polymer products

The etymology of polymer comes from the Greek word "polys" and "meros", which means many parts. In chemistry, this term defines a chemical species with a distinct molecule bonded similarly, forming a pattern of monomers. The polymer is divided into several groups: homopolymer (single monomer) and a dimer (2 monomers), trimer, etc. The difference between high molecular chain and polymer is that polymer has repeating units, and molecular weight varies between 8 to 200 moles per gram. (Clark, 1984).

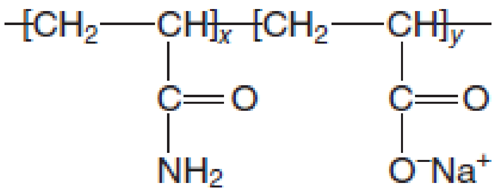
Most commonly used polymers are synthetic (HPAM, PAM) and biopolymers (xanthan gum), whereas natural polymers (guar gum, sodium carboxymethyl cellulose, and hydroxyl ethyl cellulose) are rare in use at the manufacturing. The table below represents general parameters for each type of polymers:

Table 1. Polymer parameters. Retrieved: Zhao, 1991.

Structure	Parameter	Polymer name
Oxygen ion in the backbone	Huge likelihood of thermal instability, thermal degradation at relatively high	Polyoxyethylene, and most of the natural polymers

	temperature, stability under 80^o C.	
Carbon chain in the backbone	High thermal stability, up to 110^o C.	HPAM, PAM, Sodium polyacrylate
Carboxyl group in hydrophilic	Excellent viscosifier, adsorption might occur on carbonate reservoirs due to attraction force between positive and negative ions, precipitation in the presence of divalent elements, significant chemical instability.	HPAM, biopolymers, sodium alginate.
Hydroxide or – CONH$_2$ in hydrophilic group	Excellent chemical stability, no precipitation occurs, less viscosifying effect due to low repulsive force between chain links, low adsorption in carbonate rocks.	Polyvinyl, PAM, HPAM.

Based on the characteristic table, the HPAM meets most of the criteria; thus, it is a widely used polymer in EOR applications (Manrique, 2007). The polyacrylamide is derived from polymerization of the acrylamide monomer. Polyacrylamide itself tends to get adsorbed on the mineral surface. However, during hydrolysis, some part of polyacrylamide changes into carboxylate groups with a negative ion in the backbone, which leads to a reduction of adsorption. The Hydrolyzed Polyacrylamide is represented below:



$$-[CH_2-CH(C(=O)NH_2)]_x-[CH_2-CH(C(=O)O^-Na^+)]_y-$$

Figure 1 , HPAM structure

Figure 1, HPAM structure in carbonate reservoir

The hydrolysis degree is the fraction of the carboxyl group, and the range constitutes from 15% to 35% in production. Negative ion in the backbone is strongly dependent on hydrolysis, which further affects the rheological behavior of the polymer solution. The negative ions repulse each other, creating higher viscosity. However, the presence of any electrolyte decreases the viscosity, since the positive charges shield the backbone of HPAM. In some applications, polyacrylamide (PAM) with very low hydrolysis is used. (Sheng, 2011). Polyacrylamide is generally anionic, but cationic or nonionic are also available, however used on rare occasions. (Green and Willhite, 1998). PAM-derived polymers used in EOR include hydrophobically associating polymers (Wang et al., 2006) and salinity-tolerant polyacrylamide (KYPAM) (Xie et al., 2008). Hydrophobically associative polymers consist of acrylamides (water-soluble monomers) and a moderate amount of hydrophobic (water-insoluble) monomers. In KYPAM, the HPAM side has both hydrophobic and hydrophilic groups. The hydrophilic groups create repulsive forces between each other, which leads to forming comb shape in the side chains, stretching flexible chains. Therefore, KYPAM has a higher viscosity than conventional HPAM viscosity in saline water (Sheng, 2015). Currently, new research is developing HPAM capable of working at HTHS conditions (Gailard et al. 2014). The development includes an upgrade of HPAM by a combination of different monomers such as N-vinyl-Pyrrolidone (NVP) or Acrylomido-tert-butyl-Sylfonate (ATBS) to the backbone chain. Researchers report that adding these monomers significantly improves polymer resistance against ionic components in brine, as well as thermal degradation. (Gailard et al. 2015).

3.2 Mechanism of polymer flooding.

Water is not able to displace oil from the reservoir completely, since both fluids are immiscible. The irreducible water and residual oil saturation (ROS) can be depicted on a curve to represent the relationship. However, even a huge amount of injected water cannot decrease the oil saturation below ROS. The polymer flooding technique involves adding a viscosifying chemical into displacing fluid. The mobility in the swept zone can be decreased, depending on the type of polymer used. Despite that the technique does not affect ROS, it dramatically minimizes the volume of injected fluid (Chang, 1978), (Sheng, 2015), (Nedham R et al., 1978). There are three possible ways of implementing polymer flooding technology: a. Effect of polymer on fractional flow, b. Maintaining proper mobility ratio, c. Redirection of water from the zone that has been swept.

Fractional flow is one of the popular methods of analyzing the fluid displacement front in an immiscible displacement process. The flow mechanism in the reservoir which reaches ROS is dependent on relative permeability relationships of displacing and displaced fluids. Using Darcy law to water pushing the oil with constant front can be used to find the fractional flow of oil:

$$f_o = \frac{1}{1+\mu_o k_w/\mu_w k_o} \qquad \text{...(1)}$$

Based on this equation, reduction of the ratio $\mu_o k_w/\mu_w k_o$ will enhance the rate of oil recovery, so that fractional flow of oil is increased. That can be achieved by increasing the viscosity of water by adding polymer into water or reduction of relative permeability of water because of retention onto a rock. The fractional flow effect is more important in the initial steps of waterflooding in which saturation of oil is high, hence, relative permeability is not low at that time. In the case of high oil viscosity, the fractional flow of water will be significantly higher, therefore, early water breakthrough and high watercut are expected. This term is called viscous fingering and can be explained in terms of fractional flow where injected fluid moves faster than producing oil because of high permeable layers. Finally, there will be a significant area untouched by water (Abdullah et al., 2017).

Field experiences show that reservoirs are impossible to be swept uniformly. The previous equation describing the equation of fractional flow can be expressed in terms of mobility ratio.

$$f_w = \frac{1}{1+1/M} \qquad \text{.. (2)}$$

More explicitly, mobility can be expressed in terms of the mathematical model, in which the effective permeability is labeled as k, the viscosity by μ, and mobility λ.

$$\lambda = \frac{k}{\mu} \qquad \text{...(3)}$$

In the equation, permeability can be expressed in relative permeability, so that for each of water phase, oil and displacing fluid relative permeabilities are used for determining mobility value. In general cases, one mobile fluid bypasses another fluid. To create piston-like movement so that aerial sweep efficiency increases, mobility in the upstream fluid is supposed to be equal or less than the displaced fluid in the downstream:

$$\lambda_u \leq \lambda_d \tag{4}$$

The mobility ratio term is used more frequently than comparison, which is expressed as a ratio of the displacing fluid mobility by displaced fluid mobility:

$$M = \frac{\lambda u}{\lambda d} \tag{5}$$

Where u and d are upstream and downstream respectively. The favorable mobility ratio is equal to or less than 1. Therefore, viscous fingering is observed in the cases when M > 1 (Craig, 1971). In polymer flooding, injecting fluids sweep several fluids ahead (water and oil).

On this occasion, total mobility of displacing fluids and displaced fluids supposed to be taken into account, and total mobility of displacing fluid should be less than total fluids ahead (Dyes, 1954):

$$M = \frac{\sum(\lambda n)u}{\sum(\lambda n)d} \leq 1 \tag{6}$$

However, several mobile saturations (gas, oil, and water) cannot be found in fluid displacement, whereas mobility is a function of fluid saturation. Therefore, total mobility is multivalued, and only the mobility using endpoint relative permeabilities is used unambiguously. Nedham (1978) states that mobility control will have great potential when oil saturation is high (oil relative permeability high), inferring that polymer flooding should be started immediately after primary production.

Two advantages of polymer flooding were discussed previously: faster oil displacement by improved fractional, flow increased aerial sweep efficiency by mobility control. Carbonate reservoirs have fractures; therefore, water predominantly enters high permeable zones. The polymer can create flow resistance in the high permeable zone by permeability reduction and viscosity increase. As a result, subsequent water injection will redistribute through a less permeable zone. When the water-oil ratio (WOR) is very high, fluid diversion is much preferred rather than fractional flow or a mobility control mechanism. If the polymer can attain its properties for a long period, the permeability reduction is long-lasting, thus flow diversion is conducted effectively.

3.3 The viscosity of polymer solution

1. Salinity and concentration effect

HPAM viscosity is extremely sensitive to monovalent or divalent elements in solution. When HPAM is hydrolyzed in the water, the $-COO^-$ groups push away each other, increasing hydrodynamic volume, hence viscofying the solution. Meanwhile, salts dissipate in the water, creating free ions. Furthermore, the monovalent salt neutralizes the backbone chain, therefore, repelling reduces considerably. The divalent salts, such as $MgCl_2$, have a much more detrimental effect on the viscosity. In the case of very high hydrolysis, a sharp decrease in viscosity was observed or even precipitation. At moderate hydrolysis, the solution viscosity decreases to some level, reaching a minimal point and stabilizing (Kamal,M.S, 2015).

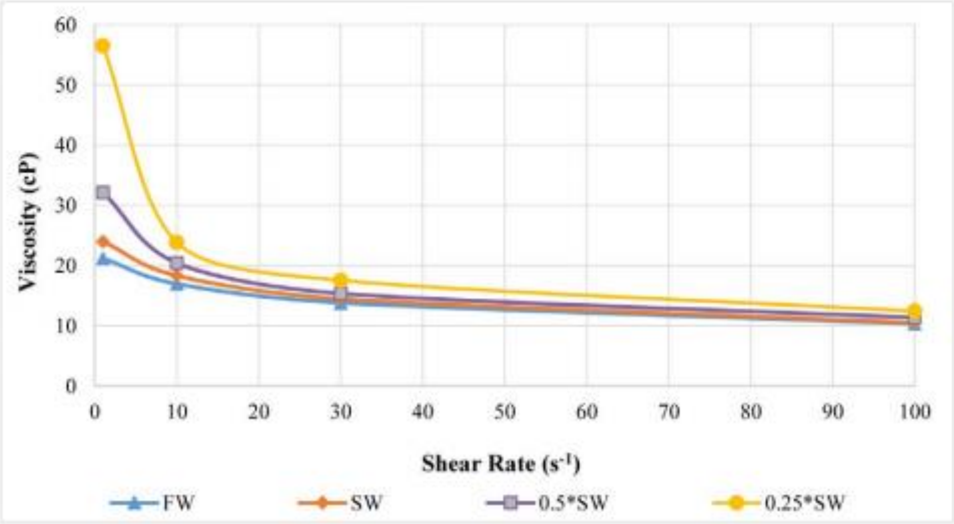


Figure 2. Viscosity vs Shear rate relationship. (Retrieved: Alfazazi, 2018)

In figure 2, viscosity with formation water and seawater at different salinity concentrations was investigated. The salinity detrimental effect on viscosity is justified. The higher the concentration of ions, the viscosity value becomes lower.

Apparently, the concentration of polymer directly increases the viscosity of the solution; however, it is not feasible to use a big amount of HPAM. Jae Jung (2012) introduced the experiment on HPAM concentration, and the results are depicted below:

Table 2. Concentration and viscosity representation

Concentration	Viscosity at low shear rate (cP)
1500 ppm	11.5
3000 ppm	58.0
5000 ppm	370.0
8000 ppm	3950.0

2. pH impact

HPAM is composed of two groups: carboxyl and amino, placed at the backbone chain. The carboxyl group is dependent on pH-sensitive rheological properties. At some pH conditions, the carboxyl group can exchange protons to dissolve salt in solution. In the case of very high pH content, the carboxyl groups split into small atoms, creating negatively charged ions, further forming electrostatic repulsion. In the case of lower pH, the carboxyl group transfers a proton to the hydrogen ion, so that any charged ions do not appear. Hence, neutral carboxyl groups at polymer chains do not create repulsion, which means viscosity of solution will not increase (Dang, C, 2011).

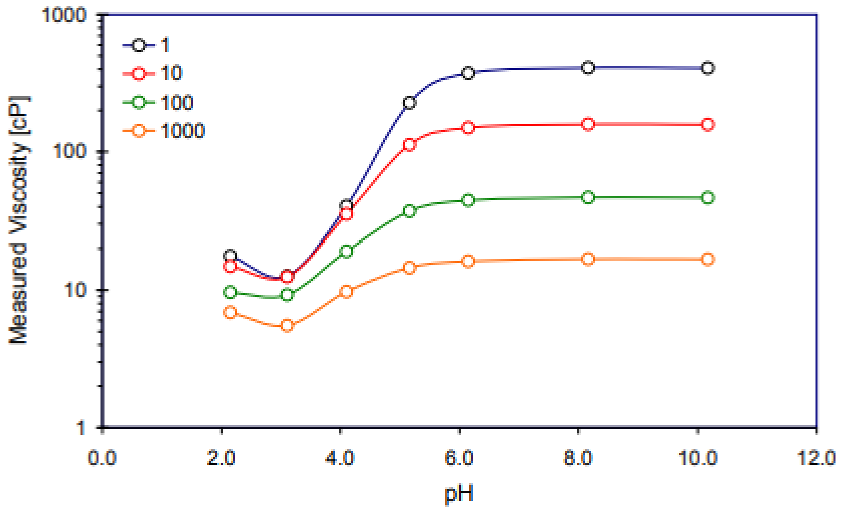


Figure 3. Viscosity of 0.5% Flopaam 3330S in 0.5% NaCl solution (Retrieved: David B.Levitt)

The pH relation with viscosity is described by the transition zone, in which the sharp change in viscosity is depicted. From figure 3, in the vicinity of pH 3, viscosity starts to increase, becoming Newtonian fluid after 6 pH. These observations justify the statement mentioned above: low pH (in this case less than 3 pH) proton number in an excessive amount which leads to a decrease in viscosity. On the other hand, high pH contributes to viscosity increase until the maximum point, since the proton exchange with carboxyl and dissolved salt creates negatively charged particles at the polymer chain backbone (Levit.D, 2008).

3. Temperature effect.

The temperature has a significant effect on viscosity at different shear rates. At relatively low shear, the temperature relation with viscosity can be described by the Arrhenius equation (Sheng, 2011):

$$\mu = A_p \exp\left(\frac{E_A}{RT}\right) \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(7)$$

A_p – frequency factor,

E_A – activity energy of the solution

R – gas constant

T – temperature

According to the equation, the temperature increase will contribute to viscosity change at a rapid rate. The reason for this behavior is the enhancing of polymer molecules activity, which reduces the resistance of fluid interaction. Hence, viscosity is decreased as the resistance between fluids is lowering. Each polymer has a distinct activity energy value, which may also change by temperature. HPAM becomes more sensitive if the temperature is higher than 35^{o}, which corresponds to E_a change (Luo, 2006).

Some types of polyacrylamides are not thermally stable for a long time. High temperature contributes to the hydrolyzing amide group, increasing the carboxyl group. Therefore, rheological properties alteration is observed, as well as the chemical stability of the solution. The direct relationship between temperature and hydrolysis can be used to benefit sweep efficiency and the injectivity of the solution. For instance, for low-temperature reservoirs solution at elevated temperature0 is preferred, whereas, for high-temperature reservoirs, a low hydrolyzed solution will satisfy polymer flooding (Gao C, 2013).

4. Shear rate effect

A polymer solution, characterized as a pseudoplastic fluid, and reduction of viscosity by shear is described by power low:

$$\mu = K\,{}^{\backprime}\Upsilon\text{^}(n-1) \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(8)$$

$\mu - viscosity$

$K - flow\ constant$

${}^{\backprime}\Upsilon - shear\ rate$

N varies from 0.7 to 0.4

For a Newtonian fluid, n = 1, K is constant, therefore viscosity value becomes constant. However, at a very high shear rate, the solution behavior is much different than these equations. Some laboratory works determined that the shear-thickening effect is observed at a very high shear rate, hence, the power low does not satisfy at these conditions (Sorbie, 1991). On the other hand, when shear stress reaches zero, yield stress does not allow viscosity to become zero. Power law behavior is observed at intermediate flow conditions, and the transition of flow behavior is dependent only on solution type, reservoir conditions, polymer concentration and temperature (Ward J., 1981).

A fluid flow behavior may be expressed in terms of Carreau equation (Carreau, 1997, Bird 1977)

$$\mu_p = \mu_\infty + (\mu_0 + \mu_\infty)(1 + (\lambda\Upsilon)^2)^\wedge(n-1)/2 \text{ ....(9)}$$

μ_p - viscosity at a particular shear rate, μ_∞ - infinite viscosity at an upper Newtonian plateau, μ_0 – zero shear rate viscosity at lower Newtonian plateau respectively. In a moderate shear rate, the equation is similar to power low. Figure 2 satisfies the Carreau equation, showing the shear thinning region with power low.

There is a different type of flow – elongational or extensional, where fluid stretch induces viscosity increase. Fluid flow through a series of different pore regions at high velocity induces dilatant behavior. In order to characterize dilatant behavior, the term stretch rate is used to depict the elongation of a polymer chain. However, the stretch rate is difficult to compute, thus shear rate dependence is suggested in the investigation of viscoelastic properties of HPAM solution (Delshad et al., 2008). Shear thickening is the result of a viscoelastic intrinsic property of HPAM, where the polymer has a flexible coil structure in solution. The viscosity is the strong function of flow rate: lower velocity allows the solution to relax during movement from one contraction to another. On this occasion, shear-thinning with power-law is depicted. The time required to relax the polymer configuration is called relaxation time, which is found by special rheometers. When the average time between 2 pore throats is less than relaxation time, polymer conformation preserves elongation. This physical phenomenon leads to an increase in apparent viscosity. However, shear thickening properties are observed in porous material flow, therefore rheological measurements cannot explain these features, requiring to use oscillation flow meter. (Green and Willhite, 1998).

3.4 Stability of HPAM solution

1. Chemical stability

Chemical degradation represents the breaking of polymer molecules at both long and short time scales. Immediate decrease of viscosity is generally due to contaminant attack, while long-term instability is due to hydrolysis. Chemical stability is a function of external element reduction and control of hydrolysis. Both of these mechanisms are explained further.

Oxidation-Reduction

A tiny amount of oxygen in the polymer solution significantly alters HPAM solution properties. At low temperatures, oxidative degradation is not observed or negligible. Temperature elevation leads to a dramatic decrease in viscosity. Yang (1985) suggested that viscosity is a function of oxygen, temperature and other ionic chemicals. However, the oxygen content of the solution had a significant impact, which was justified by the aging of the polymer at different oxygen contents. Before the observation of oxygen impact, the instability was considered to be a function of hydrolysis. This was completely wrong, as similar polymer in anaerobic conditions and elevated temperatures showed different results (Han et al, 2006).

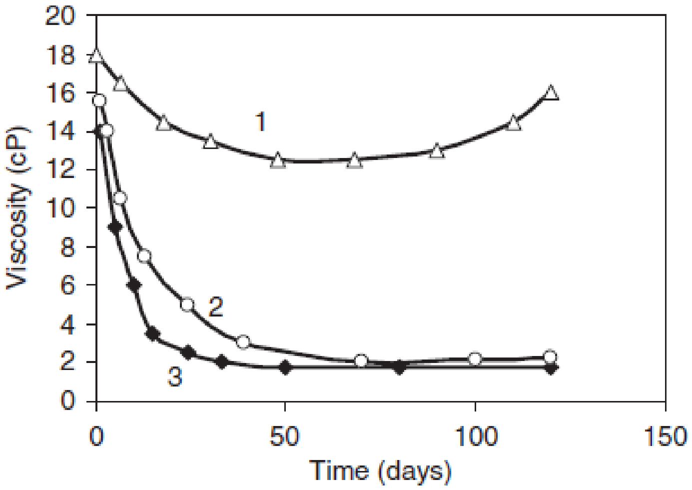


Figure 4. Aging of viscosity at: 1 – negligible oxygen, 2 – air, 3 - oxygen

In Daquing, huge amounts of oxygen were mixed in solution, fortunately, fluid injection had not been faced with oxygen degradation problems. Serigh and SKjevak (2014) said that Daquing sand in the reservoir successfully consumed the oxygen in a short moving distance. Based on this example. It can be stated that oxygen in the reservoir is not sufficient to degrade the injected polymer.

Divalent effect

In the solution with salinity, the viscosity of polyacrylamide increases as hydrolysis of the solution proceeds. However, divalent cations have a tremendous impact on the solution rheology. The highly hydrolyzed solution creates a huge hydrodynamic volume, however, the carboxyl group reacts with divalent atoms. The reaction between them forms gels or precipitation and decreases the viscosity (Johnson S, 2010). According to Ryles (1988), HPAM solutions were stable at hydrolyzation of 60 mol%. When hydrolyzation was increased to 80 mol%, the viscosity dropped twice from the initial value. Furthermore, polyacrylamide is sensitive to Mg^{2+} in the same way as Ca^{2+}, but to smaller degree. The divalent cations make a bond with electrolyte anions at the polymer chain. Since charge and polarizability are much higher than with monovalent cations, polymer contracts even smaller (Hernandez et al, 2018).

Effect of Iron ions

The most detrimental element, ferrous iron, can dramatically drop viscosity. In the case where both oxygen and Fe^{+2} are present, a chain reaction is conducted: redox couples and cycles (Pye 1967, Shupe 1981, Seright 2014). If oxygen is not present in the solution, ferrous iron has no damaging effect on viscosity. The chain reaction dramatically decreases viscosity, since the carboxyl group will go into reaction, while ferrous ions act as a catalyst of the mechanism. Seright (2015) states that 30-ppm of Fe^{+2} with 8000-ppb Oxygen content decreased the viscosity of HPAM up to 67 % in one week at a constant 90^{0} C.

2. Mechanical stability

Mechanical degradation is concerned about the breaking of the molecular chain of the polymer due to the high flow rate and mechanical stresses applied to the solution. Generally, these effects are observed at a high flow rate, long flow distance, and low permeability regions. In low permeability regions, pore throat radius is very small, therefore the high-stress region is created. In the situation, the polymer chain might get broken, so that viscosity drop occurs. The polymer break is related to molecular weight, larger molecules suffer from high shearing and elongational stresses (Sorbie et al., 1991). After rupture of high molecular chain, redistribution of molecules leads to viscosity fluctuation. Also, the term critical molecular weight is used to determine the value of weight after which no mechanical degradation occurs (Dupas, 2013).

Mechanical degradation of the polymer solution is characterized by the screen factor, which is performed by a simple tool called screen viscometer. The device consists of several 100-mesh screens, and the pump maintains pressure drops across screens. The screen factor is the response of viscoelastic property, which can withstand sudden elongational deformation and normal stress. Castor et al, 1981 states that in porous media the flow corresponds to fluid behavior in convergent-divergent channels. Induced stress has a significant impact on the polymer solution, therefore, the screen factor has a better function of mechanical degradation rather than viscosity. However, the interstitial velocity in porous media is relatively smaller than the flow in the screen viscometer. Thus, the screen factor is suggested to use as a qualitative method in the characterization of fluid performance.

3.5 Rock and fluid interaction.

The reservoir is a complex structure of rock and mineral fragments cemented randomly in a three-dimensional network. The flow regime of high-molecular polymer needs much effort to be determined. HPAM is a flexible molecule, behaving coil-like shape. In the reservoir, the fluid suffers from both shear and elongational flow regions, which are complex to assess. In a steady-state experiment, HPAM solutions show shear-thinning properties, where apparent viscosity decreases with a shear rate increase. The pressure and velocity relation cannot be described properly in terms of Darcy's equation. Additionally, pressure drop caused by shear thickening effect and permeability decrease is difficult to be explained mathematically. The huge frictional resistance, caused by the increase of viscosity and permeability reduction of the fluid is presented as "resistance factor", which composes the ratio of mobility water to the mobility of polymer solution (Pye, 1964):

$$RF = \frac{\lambda_w}{\lambda_p} = \frac{k_w/\mu_w}{k_p/\mu_p} \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(11)$$

λ *is mobility if each fluid, which is equal to the ratio of permeability to viscosity*

The in-situ effect of polymer on enhancing mobility ratio is generally characterized by RF, showing apparent viscosity. The apparent viscosity might be in 2 ways: the chemical effective in-situ viscosity and reduction in permeability due to the adsorption of polymer onto the reservoir surface. Shortly, RF shows a decrease in the mobility of chemical solutions relative to water.

The residual resistance factor (RRF) corresponds to the identification of permeability reduction. RRF is measured by finding the ratio of water mobility before and after chemical contact. If the water was injected at a similar flow rate, RRF form can be expressed as follows (Sorbie, 1991):

$$RFF = \frac{\lambda_w}{\lambda'_w} = k_w/k'_w \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(12)$$

where k'_w and λ'_w after polymer solution contact.

The effective in-situ viscosity of the solution is the viscosity of polymer flowing inside the core or reservoir, in which permeability reduction is taken into account. The combination of RF and RFF enables to have effective viscosity mathematical representation:

$$\mu_{eff} = \mu_w \frac{RF}{RRF} \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(13)$$

Alsofi A. et. al. conducted an experiment of pressure drop profile for polymer flooding was conducted. The parameters such as RF, RFF, and effective viscosities are determined based on laboratory results. According to data, higher resistance mostly occurred at low permeability cores. However, there was no inter-dependency between flow velocity and resistance factor. The flow rate increase for low permeability samples showed an increase in resistance, while for high permeable core sample resistance decreased. For residual resistance, mechanical entrapment was observed, since RRF decreased with the flow rate increase. On the other hand, low polymer retention was indicated in high permeable zones, which indicates a big pore size. Both resistances being high means that there is face or pore plugging, as polymer hydrodynamic radius is too big to flow through small pore regions. However, high resistance polymer can be used to plug more permeable zones (Carcoana, 1992).

Table 3. RF and RFF tests, Retrieved: Alsofi A. et. al, 2018.

Core	Air perm	Flow rate	Velocity	Rf	RRf	Effective viscosity
1	338	0.5	7.3	30.3	3.26	3.89
		1	14.6	30.8	3.18	4.05
		2	29.3	32.6	3.17	4.30
		3	43.9	34.1	3.18	4.48
		4	58.6	36.8	2.98	5.17
2	1644	2	30.7	19.9	2.01	4.15
		3	46.1	19.8	1.93	4.29
		4	61.5	19.8	1.91	4.33
		5	76.9	19.5	1.87	4.36
		6	92.2	19.6	1.85	4.44
3	45.2	0.5	8.2	99.1	23.29	1.78
		1	16.3	106.8	18.93	2.36

		2	32.6	118.1	14.44	3.42
		3	48.9	123.1	12.56	4.10
		4	65.2	134.2	11.78	4.76

Injectivity

In polymer flooding, the effectiveness of the method is directly measured with incremental oil recovery. The dependency between flow rate and pressure drop is essential to be determined. A general term used for expression of injectivity is :

$$I = {}^{q}/_{\Delta p} \qquad \text{...} (14)$$

In which q – flow rate in bbl/day, and Δq stand for pressure drop. In an ideal situation, a high flow rate is achieved at a given pressure drop, but applied pressure never exceeds the fracture pressure of the reservoir formation. For polyacrylamides, the viscoelastic properties have a significant impact on injectivity calculation.

The pressure drop pattern has two divisions: near and at a great distance from the wellbore. The near region has extreme pressure drop, which induces significant viscoelastic properties of the HPAM solution. On the other hand, the far region has a radial flow profile, as well as a low shear rate. These conditions do not provide noticeable mechanical degradation and other types of polymer instabilities (Donaldson, 1989).

Injectivity of the polymer solution is strongly dependent on rheology, and the latter is the function of concentration, brine composition, temperature, and viscoelastic properties. Also, polymer retention has detrimental effects on oil recovery, where polymer concentration decreases due to adsorbed chemicals onto the rock surface (Huh, 1985). Polymer chemistry is another important parameter for a proper polymer flood. The high molecular weight polymers can get trapped at small pore throats or can be constricted by adsorbed polymers, leading to slight injectivity loss over time. Shear thickening of HPAM solutions is also a significant factor in difficulties of injectivity, where at high shear rate polymer chain is not able to reorient to pass through narrow pore throats (Kaminsky, 2007).

4. Objectives of the thesis

Polymer flooding has great potential to increase oil recovery from a heterogeneous carbonate reservoir; however, high temperatures and high salinity conditions are some of the most difficult obstacles to successful implementation of the chemical EOR method. Currently, many commercial polymers are candiates for flooding purposes, and to choose a chemical for a particular case becomes an important problem. This paper aims to screen the best polymer for HTHS conditions based on the following parameters:

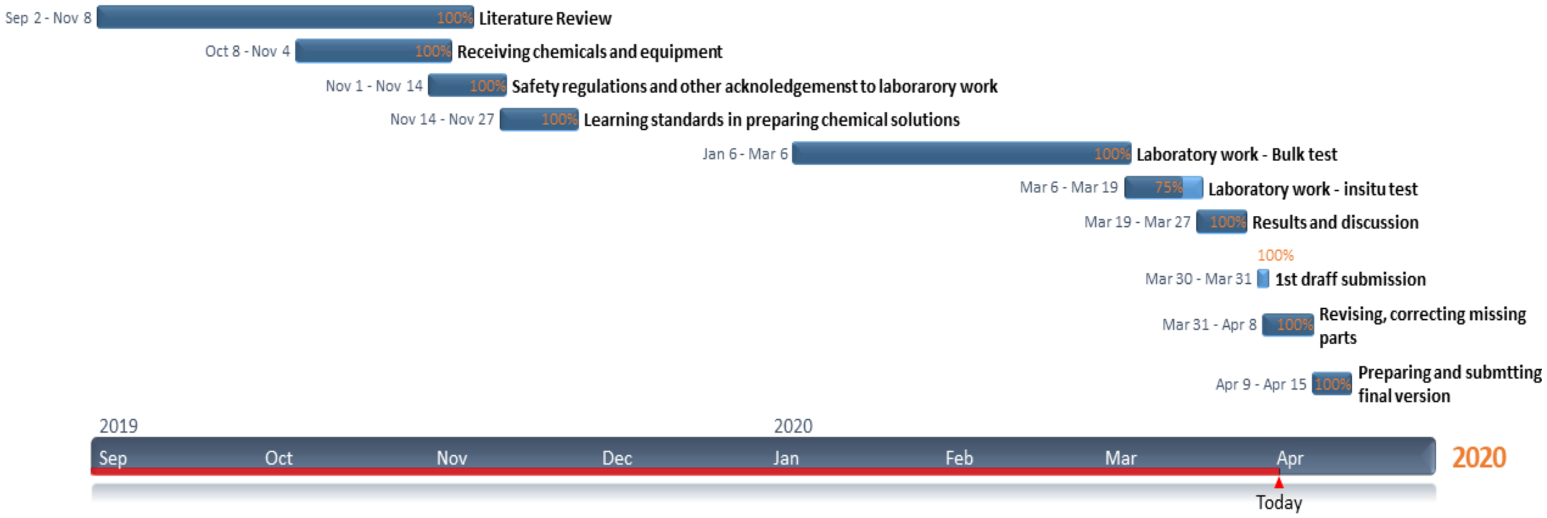
- Rheology of the polymer at various shear rates. The polymer should have a shear thinning effect with viscosity reduction
- The viscosity of polymer at various concentrations. The candidate chemical is suggested to have high viscosity at a low concentration level.
- The viscosity of polymer as a function of temperature
- Long-term thermal stability
- Mechanical degradation - viscosity drop due to high shear stress.
- Rock and fluid interaction – analyzing rheology, injectivity during flow through porous media

5. Project Plan

a. Project schedule

Below Gannt Chart is presented. It was developed to ensure that the project will be delivered on time.

Figure 5. Thesis schedule



b. Resource requirements

The necessary resources for project completion are identified and listed.

Table 4. Required resources

Device/material	Function
Laptop or PC	My own laptop or PC from computer lab is used to conduct the research
Chemicals	Salts, distilled water, polymer
Consumables	Filter paper, glass and etc
Equipment	Rheometer, oven, coreflooding equipment and etc
Access to the internet	To download essential materials related to my thesis

6. Methodology

6.1 Solution preparation

Polymer and brine solutions are made with distilled water, since external elements will mislead to wrong outcomes. Since the project concerns high salinity reservoir conditions, the following salt conditions were used to make a brine solution. After thorough mixing on a magnetic stirrer, the brine filtered through filter paper.

Monovalent	NaCl	208.74 g/l
Divalent	Mg$Cl_2 6H_2O$	37.26g/l

Table 5. Ionizing agents

The polymers used in this experiment were terpolymers, which are composed of N-Vinyl-Pyrrolidone (NVP). The NVP-HPAM polymers (SAV 10, SAV10|19, SAV10 XV) can withstand high temperature and salinity. The procedure for preparing the solution was following the API standard (API 1990). The polymer solution was made in a brine base. While maintaining constant stirring, the polymer powder was added steadily in order to eliminate the occurrence of agglomeration. After a necessary amount of powder was poured, the solution is stored in an oxygen-free condition. The amount of polymer poured into brine solution depends on how much concentration is required for experiment. For instance, to mix 3000 ppm solution, 6 gram of polymer is added into 200 ml brine. Subsequently, the container is covered by a polyethylene sheet to disallow oxygen damage. The stirring rate was 600-700 rpm in the beginning to create a vortex of around 30% of solution height at rest, afterwards decreasing to 200 rpm avoid mechanical degradation. The mixing time takes around three hours, after the polymer is left for a night to have a homogenous solution. The polymer solution can be diluted if less concentration is required, a highly concentrated solution is recommended for preparation. Additionally. Solution can be kept up to 2 weeks at room temperature and placed away from direct sunlight.

6.2 Bulk rheology

The rheological behavior of the polymer was measured by a Modular Compact Rheometer 302 Series provided by Anton Paar. The tool is equipped with an EC-motor and is purposed for a different type of measurement tasks. Temperature adjustment and sample-specific accessories can be modified to desired testing conditions. Electrical and mechanical components are integrated on a single control panel, which makes equipment comfortably used. It is advised to use Concentric Cylinder systems to investigate the temperature, concentration and shear rate effects on viscosity, since it can maintain a high and easily adjustable temperature. The measuring liquid is placed in annulus of the rotational cylinder and container cylinder. The liquid resist against rotation of cylinder creating drag force. That force is measured by motor since it can measure torque required to rotate the cylinder. Finally, torque is converted to shear stress. The shear stress and shear rate are further used to calculate viscosity of fluid. Also, concentric cylinder is recommended for moderate viscosity solutions, whereas polymer solution has viscosity between 150 cP to 3 cP.

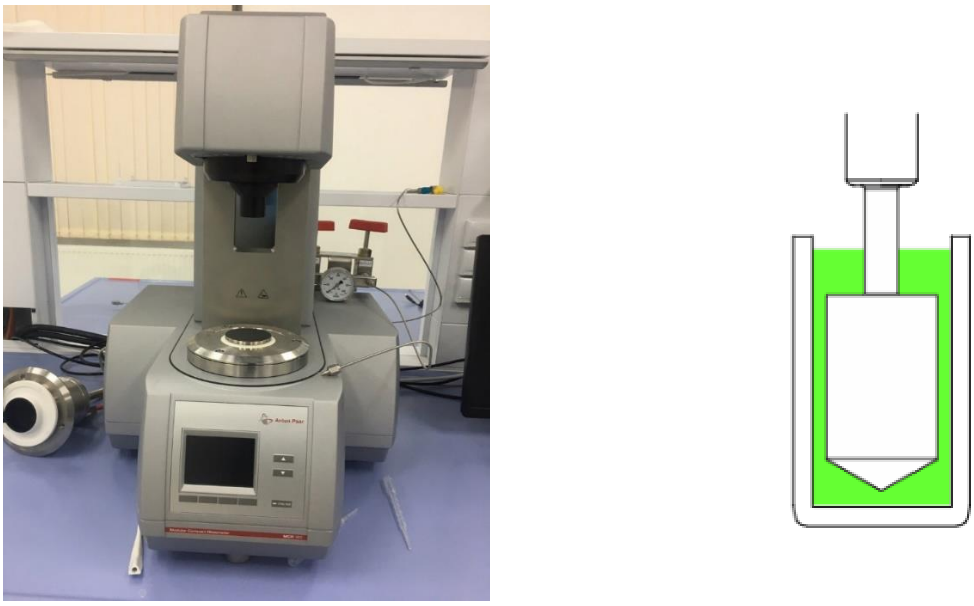


Figure 6. Rheometer and sample loading accessory.

The study of rheological properties began from room temperature at incremental shear rates. The temperature steps were gradual, since we aimed to find a strong relation between thermal and viscosity values. Additionally, all three polymer products were measured at various concentration levels, from 1000ppm to 3000ppm. The temperature also increased from 25^0 C to 80^0 C, with 10^0 C step increments.

6.3 Long term thermal stability

Long term stability was conducted on the best candidate polymer solution after studying rheology. The solution made on a high salinity brine base was placed into an oven at 80^0 C. The test provides polymer degradation over a long period. It precisely shows the effect of temperature on the viscosity over time. In order to avoid high hydrolysis, the oxygen-free condition was maintained. The ferrous iron is also detrimental when oxygen is free to a solution, therefore, the solution was distributed into small covered test tubes. The tubes were stored in an oven, and viscosity of aged solution was measured during thermal stability test. The viscosity measurement was conducted at 25^0 C and at a shear rate from 1 $s^{=1}$ to $100s^{-1}$.

Figure 7. Oven and sample

6.4 Mechanical degradation

Molecular breakdown is caused by high flow rate and rapid change of velocity when pore size varies. This degradation can be induced by a blender which causes the mechanical breakdown of the HPAM's long molecular chain. The Hamilton Beach Overhead mixer was used to pre-shear solution. All candidate polymers were separately tested by stirring at rotational velocity of 29400 rpm. The polymer samples were blended for 30 minutes with interruption each 5 minutes to take a small portion of polymer. After, small portion was measured to identify rheological behavior. The rheological test was conducted on rheometer at room temperature. The experiment was proceeded until rheological behaviors of the sample were stable, so that the least possible viscosity value could be found.

6.5 Rock and fluid interaction

Based on previous studies, the polymer with the highest quality was chosen from three candidate chemicals. The SAV10 XV met all previous set criteria: higher viscosity at low concentration, thermal stability and mechanical stability, hence, further its interaction with core was studied. Before injectivity took place, routine core analysis was conducted to find gas porosity, air permeability, and porous volume. Subsequently, the core was placed into core saturator for a night, so that the sample pore space was fully occupied with brine solution. All measured data are recorded below in the table.

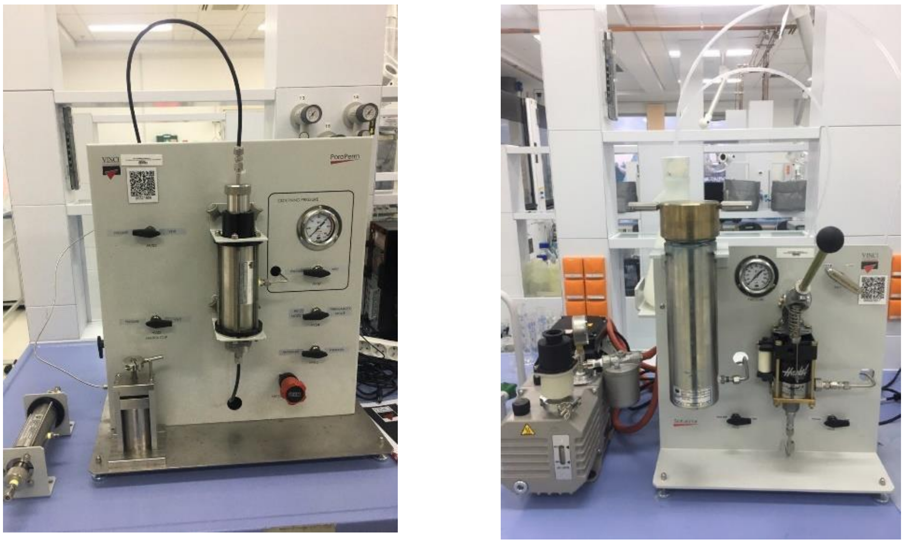


Figure (8) Porosity measurement and Core Saturator

Table 6. Routine core analysis

Properties	**Value**
Name	Indiana Sandstone
Length (mm)	73.37
Diameter(mm)	38.30
Porosity	19.03%
Permeability (Gas)	60mD

The core sample was saturated with brine under vacuum, then it was mounted into Vinci Autoflood Coreflood System. Before inserting core to proceed injectivity test, equipment was cleaned with distilled water and dried. The pumps and transducer systems were checked and filled with liquids to be tested. After the core holder was rebuilt, the dead volume was measured. Generally, the dead volume is measured before shipment, but it is recommended to check again. The next step is to apply confining pressure using a pressure regulator setting between 200psi to 300 psi. The injection pump creates pressure in the core holder. The flow rate can be monitored either on the control unit or on the pump screen.

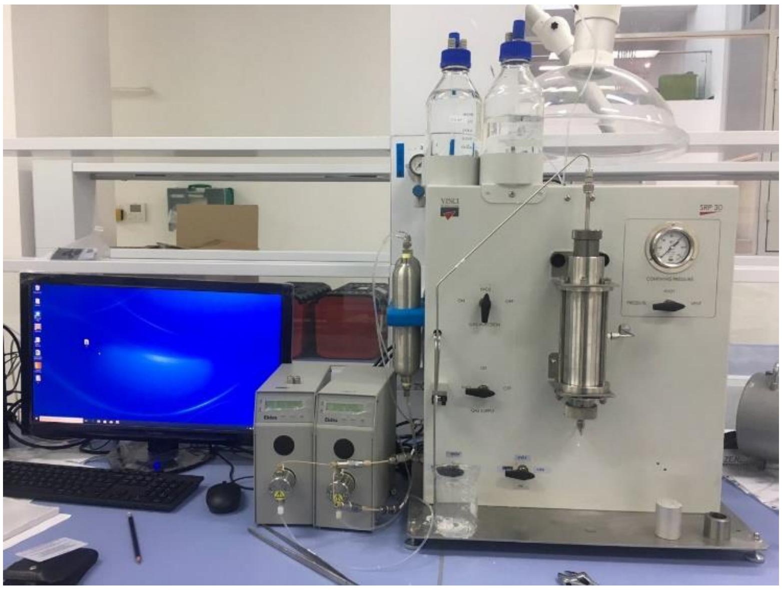


Figure 9. Coreflooding equipment

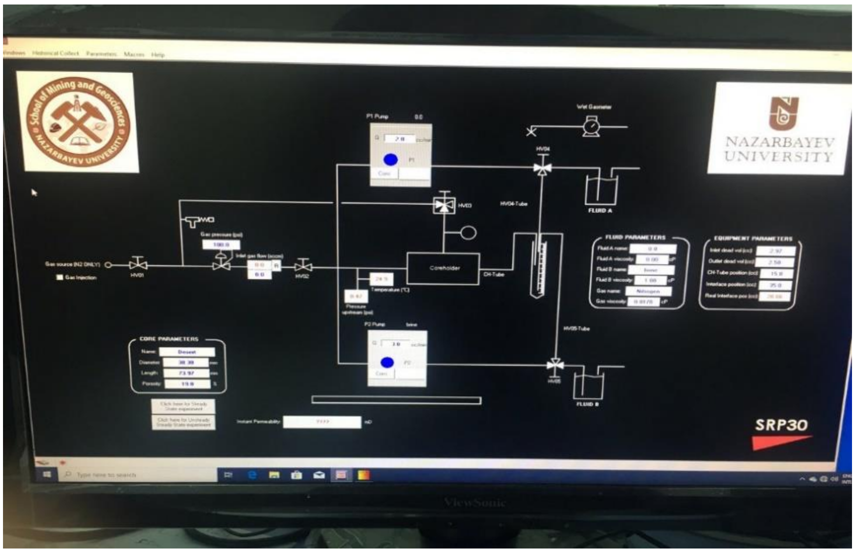


Figure 10. PID of coreflooding system

In the beginning, the brine solution was injected, and the pressure drop was recorded at different shear rates. The coreflooding equipment worked at room temperature (25^0 C) on a steady-state flow condition. HPAM SAV 10 XV at 3000 ppm concentration was injected at rate 0.1, 0.5, 1, 2 cc/min with 10 pore volume on each flow rate. The huge amount of injection allows reaching stable pressure, since these values are used to calculate the resistance factor. Resistance factor is a coefficient of polymer resistance to flow compared to the mobility of water (Pye, 1964):

$$RF = \Delta P_{polymer} / \Delta P_{water} \quad \text{(14)}$$

Mechanical degradation was also analyzed during the coreflooding procedure. The effluent was taken at different injection rates to find a relation between flow rate and viscosity. Additionally, recorded values were compared with previous mechanical degradation tests as quantitative work.

7. Results

Bulk test - Effect of shear rate

The polymer solution is non-Newtonian fluid, since its viscosity nature is not constant with shear rate change. The rheological behavior is unstable for low viscous polymer solutions at an interval between 1 s^{-1} and 10^{-1} s^{-1}, but increasing shear rate viscosity deviation starts to decrease. Additionally, HPAM, at some point, has a tendency of viscosity reduction with the shear rate increase. This region is generally shear thinning according to various papers, and it is stated that all HPAM have these inherent properties (Seright et al, 2011), (Levit et al, 2008), (Araujo et al, 2019). The shear-thinning effect is favorable for polymer flooding since the near-wellbore region has a high shear rate and less pressure is required to inject the fluid. For bulk reservoir volume the shear rate decreases at far distance from injection well, hence viscosity increases creating an adequate mobility ratio (Sheng. 2011), (Quadri et al, 2015).

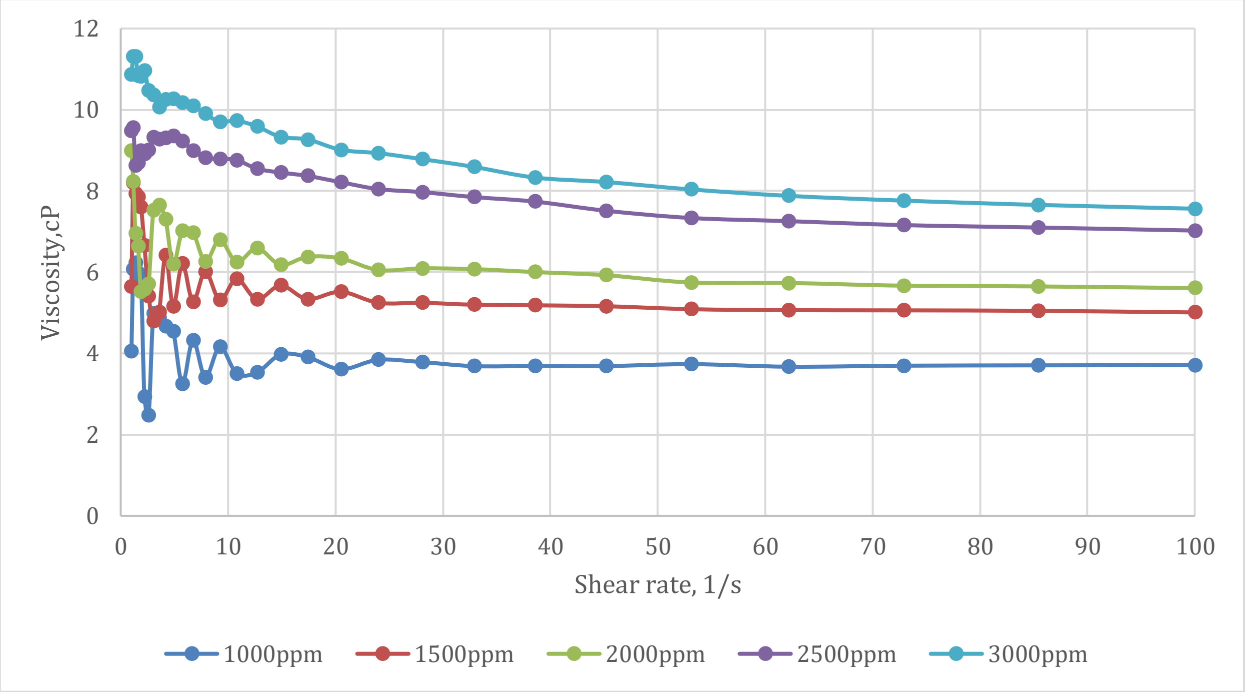


Figure 11, Viscosity vs shear rate of SAV10 at 25^0 C

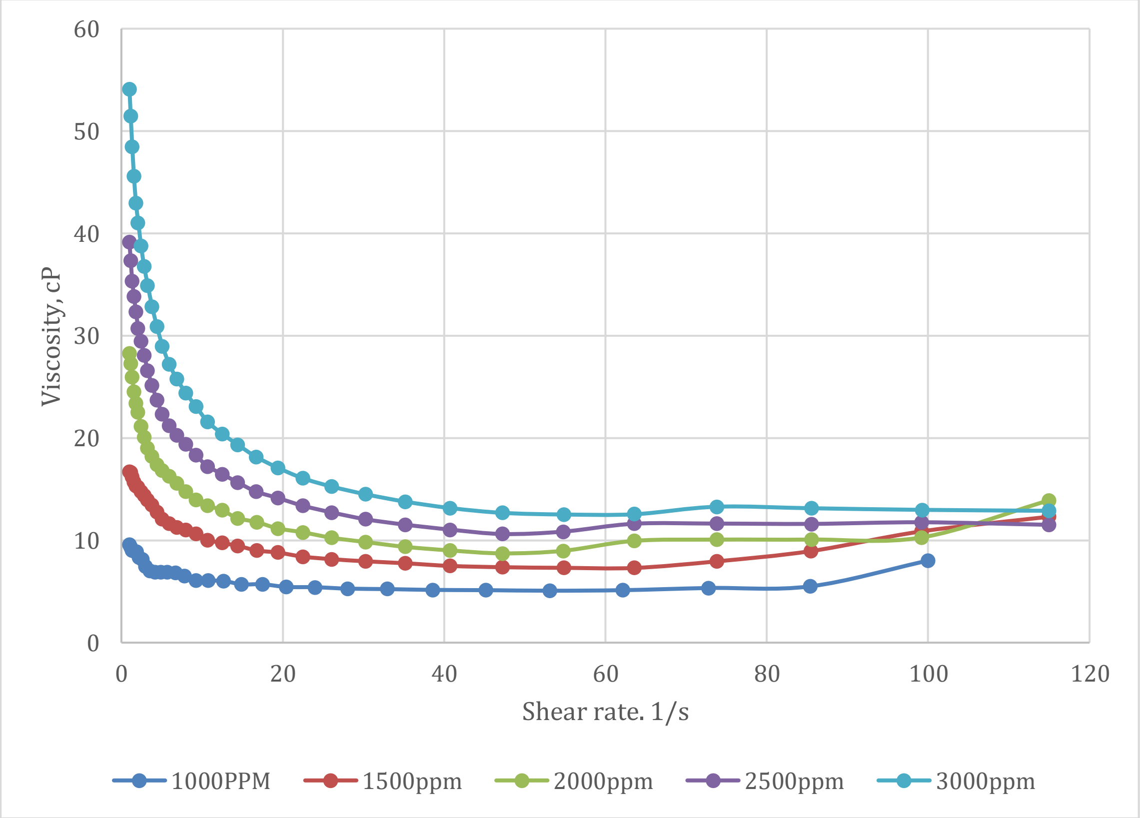


Figure 12, Viscosity vs shear rate of SAV10 XV at 25^0 C

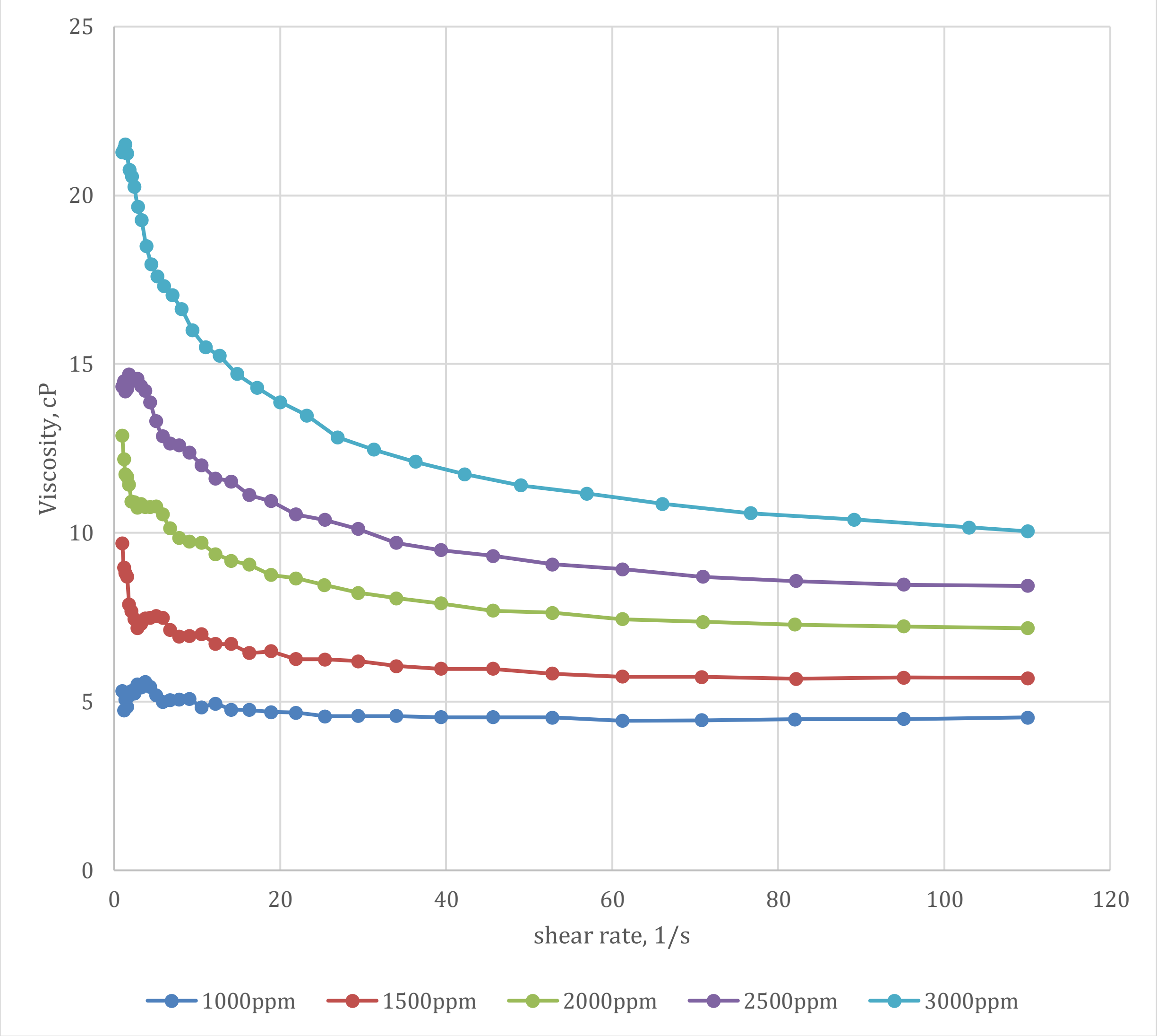


Figure 13, Viscosity vs shear rate of SAV 10|19 at 25^0 C

As expected, higher concentration creates greater viscosity, as more polymer molecular chains are present in the solution thus increasing hydrodynamic volume and therefore resulting in higher viscosity. . All three polymers showed shear thinning behavior, due to aligning of polymer chains upon exposure to shear (Samanta et al, 2010). There was shear thickening effect also observed with SAV10 XV at concentrations of 1000 ppm and 1500 ppm between 80 s^{-1} and 100 s^{-1} shear rates. Significant research has been performed on analyzing shear-thickening behavior of polymer, since injectivity problems are unwanted during injection (Ballard et al, 1988), (Xu et al, 2010).

Effect of temperature.

Candidate polymers were studied for rheological properties at 80^0 C to find the effect of temperature. Various concentrations (1000 ppm, 1500 ppm, 2000 ppm, 2500 ppm, and 3000 ppm) and different temperature values were investigated as variable factors on viscosity. Comparing with room temperature conditions, at high-temperature, significant viscosity drop was observed.

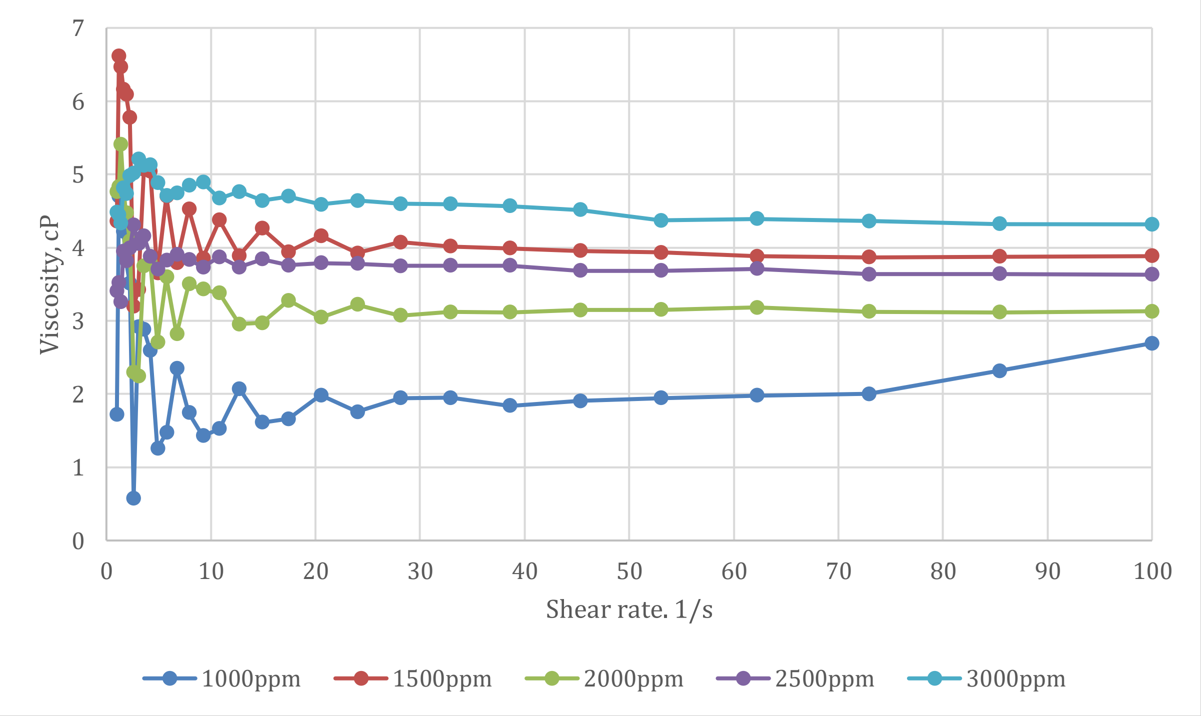


Figure 14, Viscosity vs shear rate of SAV10 at 80^o C

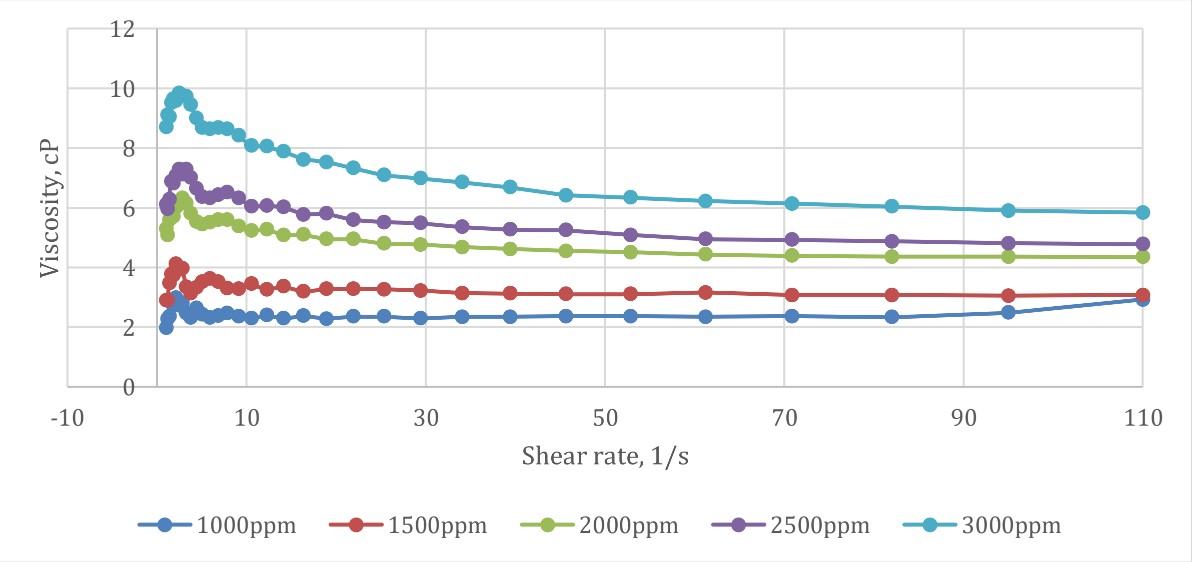


Figure 15, Viscosity vs shear rate of SAV10|19 at 80^{0} C

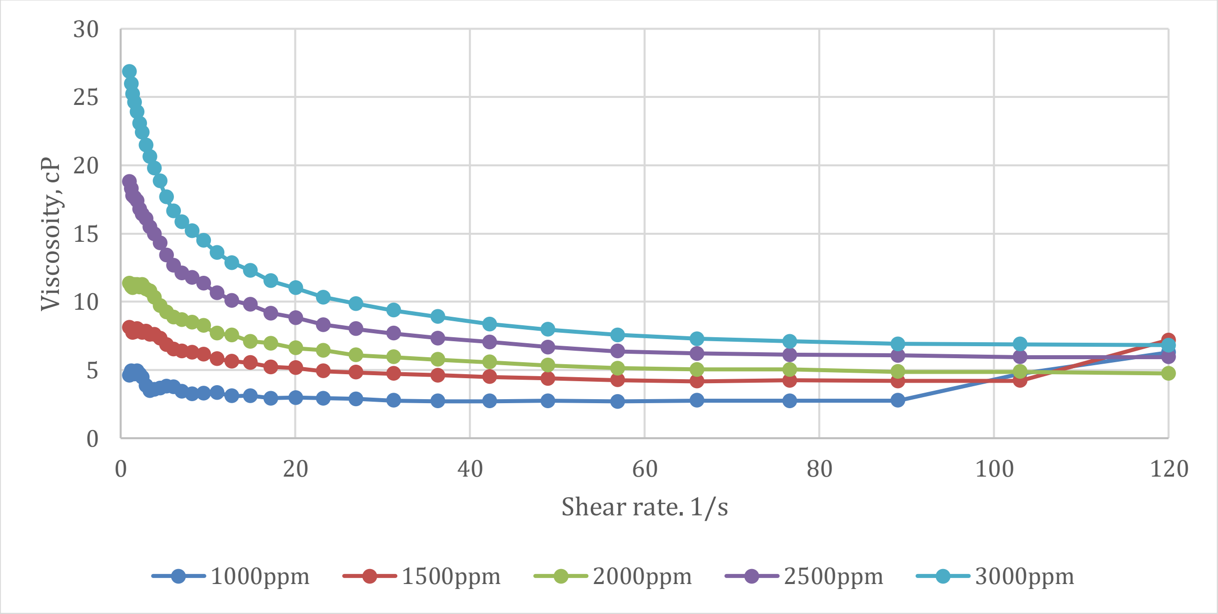


Figure 16, Viscosity vs shear rate of SAV10XV at 80^{o} C

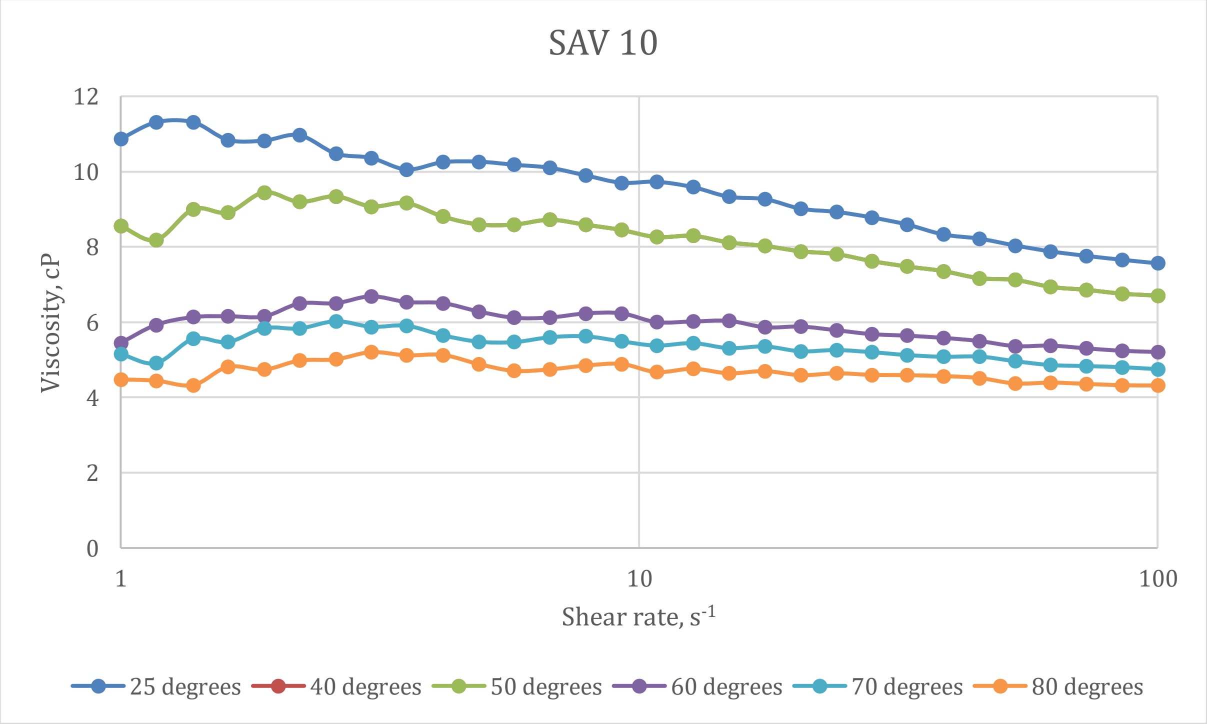


Figure 17, Viscosity vs shear rate of SAV 10 3000ppm at different temperature

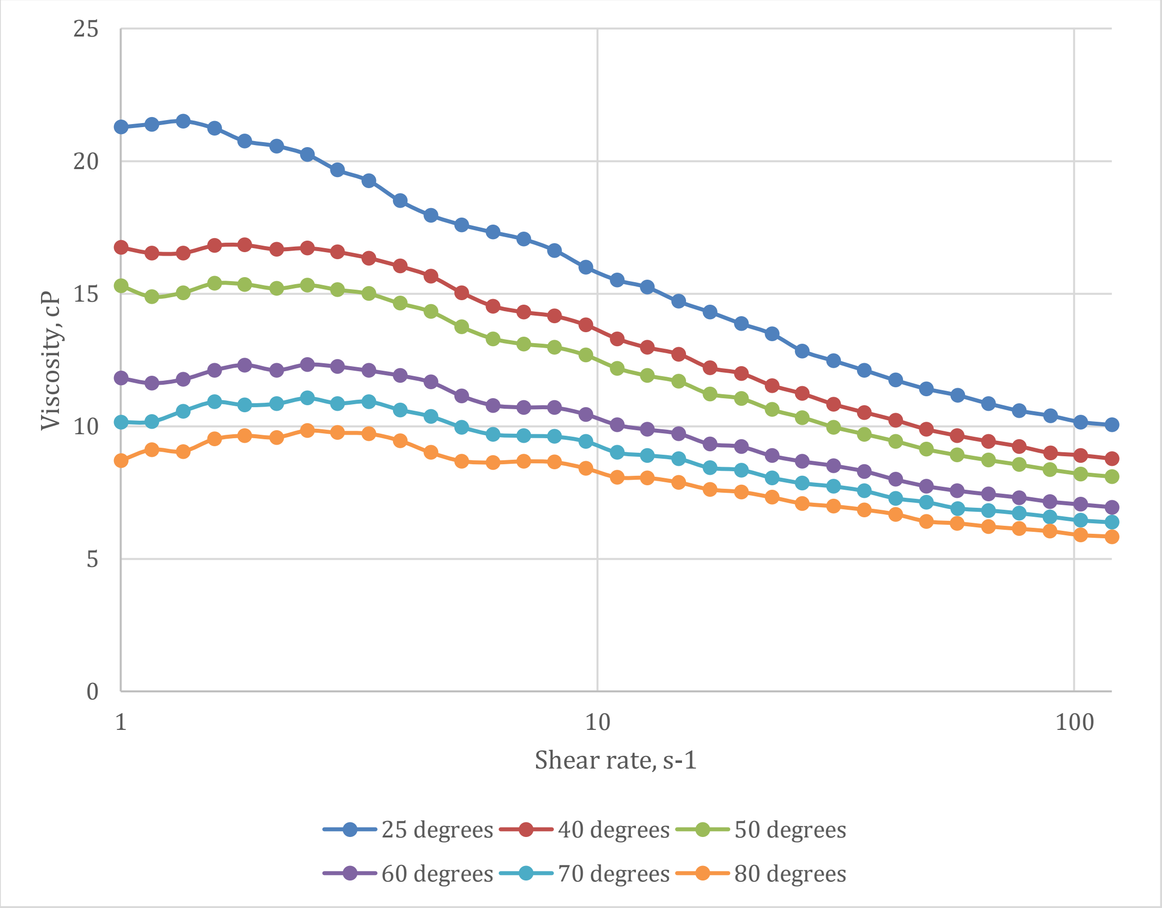


Figure 18, Viscosity vs shear rate of SAV 10|19 3000ppm at different temperature

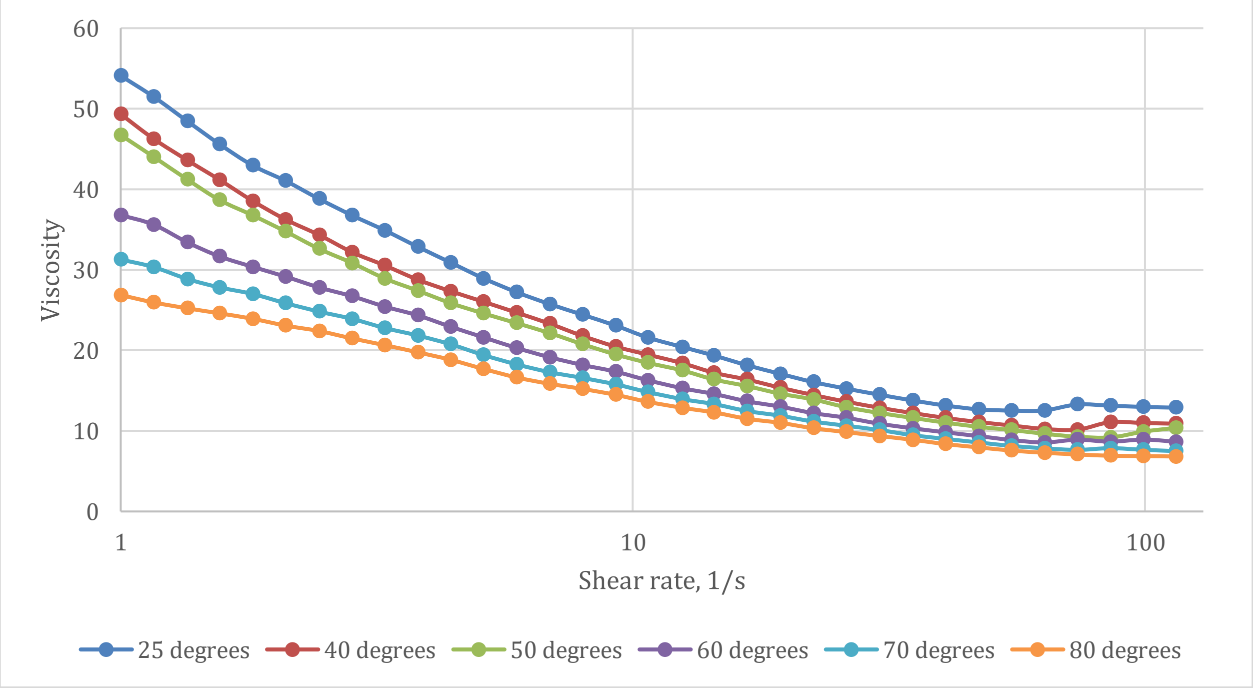


Figure 19, Viscosity vs shear rate of SAV 10 XV 3000ppm at different temperature

At all concentrations, polymer viscosity showed a significant reduction in viscosity with temperature rise. The temperature accelerates the average speed of molecules in a liquid, and neighboring molecules are in contact more frequently. Temperature rise also causes high hydrolyzation, which increases the carboxyl group on the backbone of polymer, creating electrostatic force. However, these polymers are viscosity dominant, since high temperatures worsened polymer solution by reducing viscosity. Additionally, the rate of viscosity reduction decreased with shear rate increase. This common behavior was observed by Nouri et al (2011), Samanta et al (2013), Alfazazi et al (2018), which indicates that polymer solution has a sophisticated relation with temperature as shown by the Arrhenious equation. According to figures 17, 18 and 19, SAV 10 XV has shown comparatively less viscosity loss with temperature increase. The rheological test provides that a 3000 ppm solution is advised to proceed for further tests. If the concentration is less than 3000 ppm, the proper mobility ratio will not be achieved during the polymer flooding process.

Long term stability

Laboratory thermal stability is a helpful tool to design effective polymer flood. The viscosity retention is key at reservoir conditions, since the flooding lasts for several months. Polymer thermally degrades at extreme temperatures, which leads to viscosity reduction. Synthetic polymers along with NVP can withstand up to 120^0 C, since modification can help to decrease the breaking of the acrylic backbone (Masalmeh et al, 2019). SAV 10 XV at 3000ppm was prepared in a brine base to fulfill long term temperature stability tests. The solution was distributed into small beakers closed with stopper, after they were placed into an oven at 80^0 C. Each day a sample was taken out from the oven one by one for following measurements. The sample was left for a rest until the temperature stabilizes with the surrounding condition in order to conduct a rheological test. The long-term thermal stability test carried out for 45 days, and its results are given as follows:

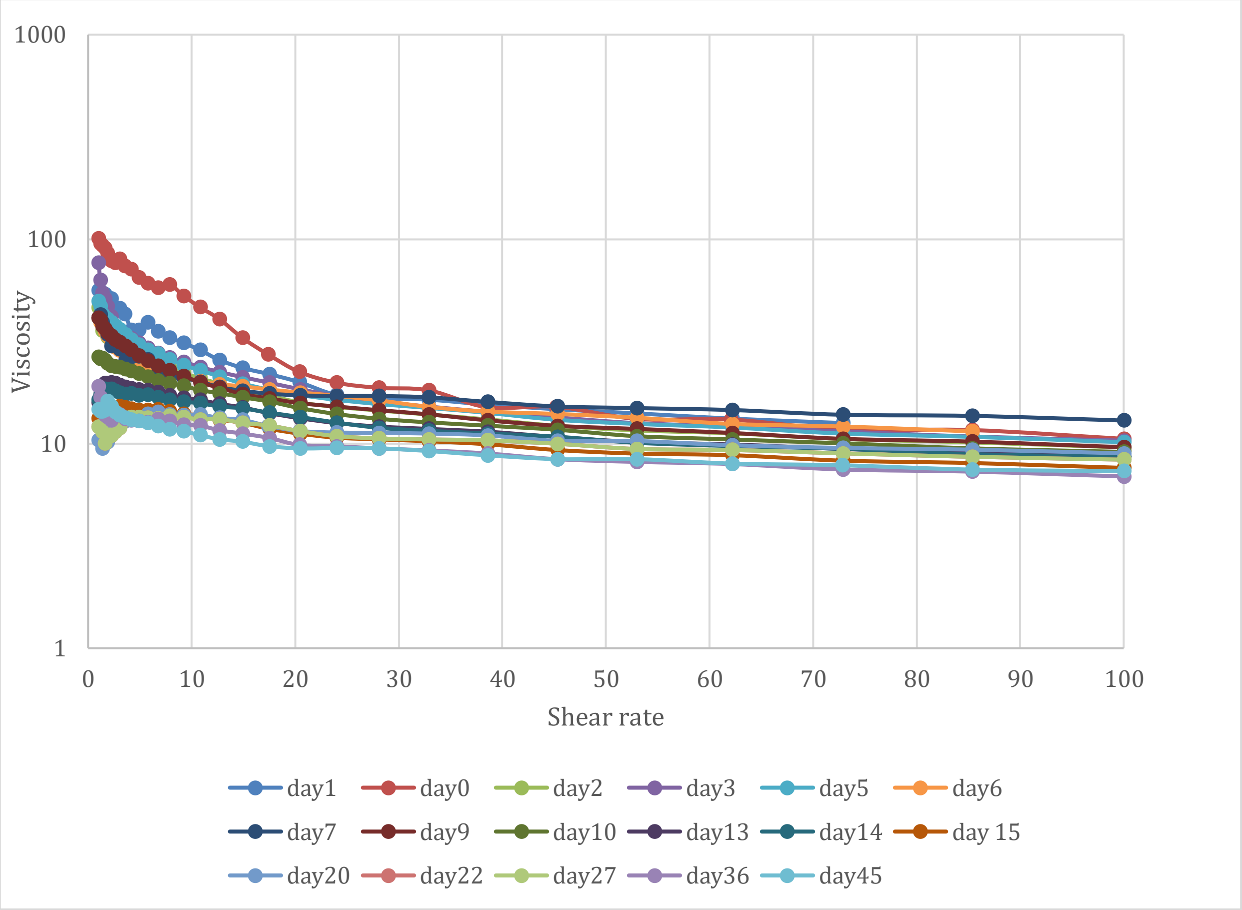


Figure 20, Viscosity vs shear rate of SAV 10 XV 3000 ppm during 45 days

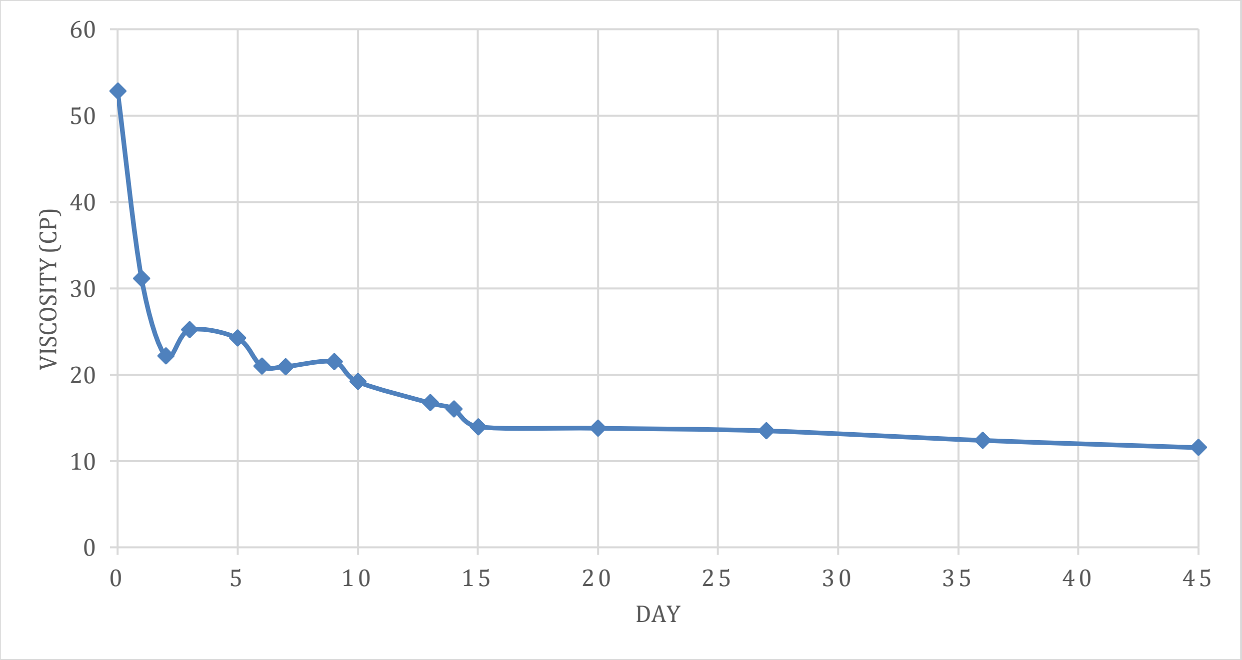


Figure 21, SAV 10 XV long term stability at 80^0 c (at $9s^{-1}$ shear rate)

The first 15 days showed irregular falling and rising in viscosity because of late hydration of polymer solution (Sorbie et al, 1991), (Alfazazi et al, 2018). Similar results were obtained in previous studies (Zhu et al, 2013; Choi et al, 2014). Starting from 20 days, viscosity decreased steadily, showing stable values. The viscosity loss is generally caused by molecular weight reduction due to free-radical induced scission of the acrylic backbone over the ageing period (Levit at al, 2008; Grollman, 1982). The SAV 10 XV at 3000 ppm is quite stable at high temperatures, which satisfies target reservoir conditions.

Mechanical degradation

Shear flow includes rotational and extensional flow inducing polymer coil stretch in the direction of flow. The flowing through porous media, valves and other different geometries causes extensional acceleration of the fluid. As a result, polymer chains are extensionally stretched (Jauenne et al, 2018). Three candidate polymers were stirred in a blender to study mechanical degradation. High angular velocity in the blender causes tangential and normal velocity so that elongation of the coil can be achieved. The rheology of pre-sheared solutions at 25^0 C is depicted below.

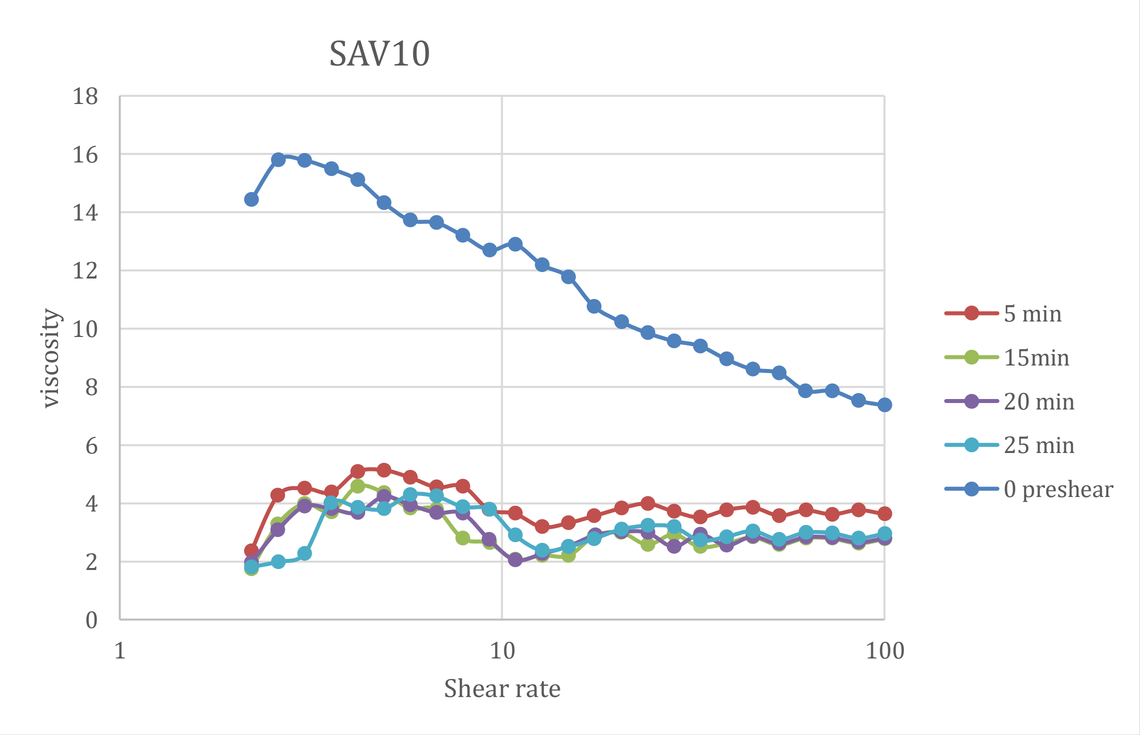


Figure 22, Viscosity of SAV 10 at 3000ppm after Mechanical degradation

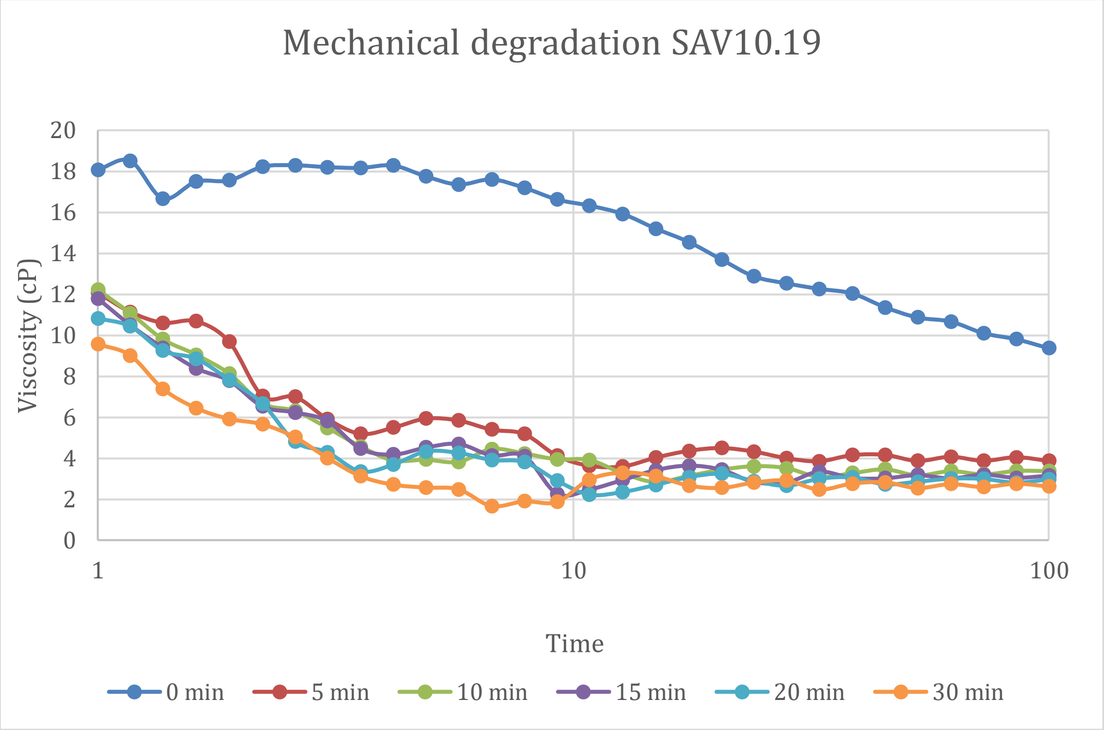


Figure 23, Viscosity of SAV 10.19 at 3000ppm after Mechanical degradation

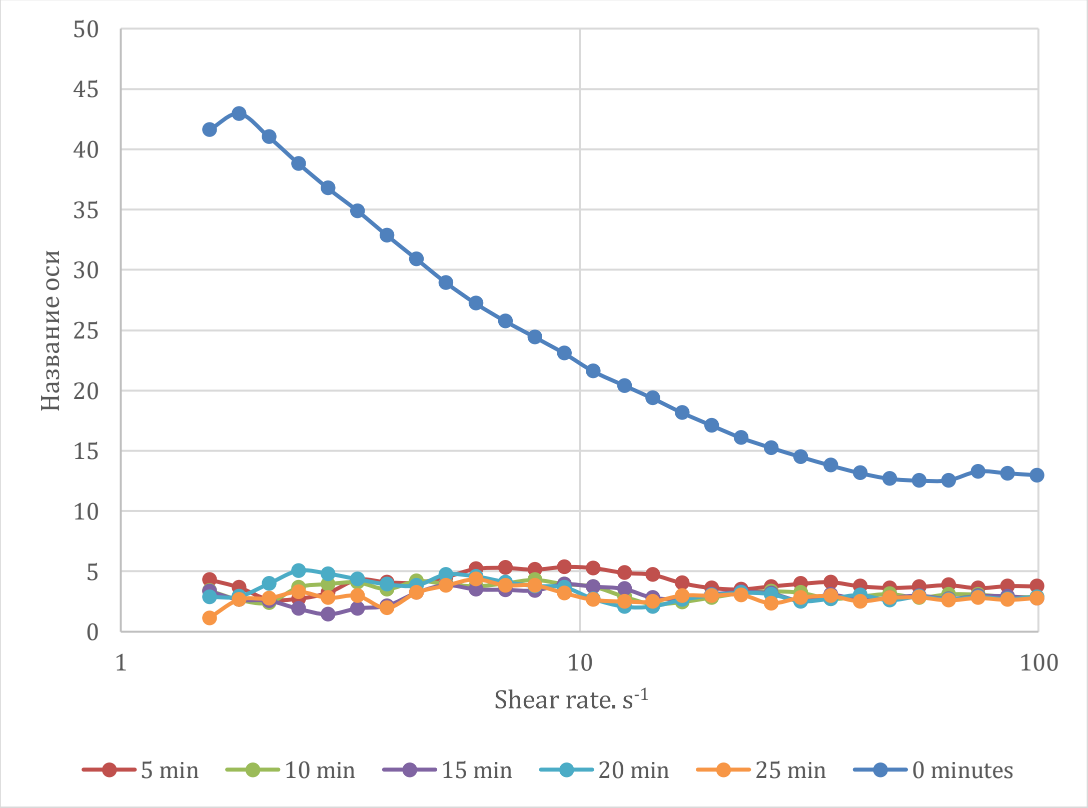


Figure 24, Viscosity of SAV 10 XV at 3000ppm after Mechanical degradation

According to De Gennes (1974), a polymer molecular chain suffers a sudden coil-stretch transition if the strain rate is greater than the inverse of relaxation time of a randomly taken polymer chain. If the time taken by polymer to take original shape is more than the relaxation time, the molecular chain will suffer from mechanical degradation. The relaxation time is strongly dependent on frictional contact of molecules and solvent, which are affected by the molecular shape, solution interaction, and viscosity. Since the chain starts to dilate, hydrodynamic force applied through friction increases. As a result, the chain ruptures at a critical strain rate (Jouene et al, 2018). Standard results of degradational experiments performed in the laboratory blender are depicted in figures 22. 23 and 24. SAV 10 19 has shown power-law functionality during the viscosity and shear rate test. The remaining two polymers had unchanged viscosity values with some fluctuations. The variation of viscosity value is caused by non-equally distributed molecules of a ruptured chain. The polymer solution reached its minimal molecular weight of chain afterwhich no further degradation was observed. SAV 10|19 and SAV 10 XV introduced desired values of viscosity for the following polymer flooding test.

Injectivity test

The injectivity test was aimed to analyze rock and fluid interaction during polymer flow through porous media. SAV10 XV showed great results on previous tests, being capable of performing at high temperature and high salinity conditions. The brine was injected to find differential pressure at different rates, and polymer at 3000 ppm was subsequently injected at different flow rates. At each flowrate, a corresponding resistance factor was found, which is a measure of polymer resistance to flow compared with water’s mobility. To have a complete picture of retention of polymer to rock, 40 pore volumes of solution in total was injected. Figure 25 shows the differential pressure versus volume injected during the whole experiment. High differential pressure is due to a high flow rate and reduction of effective permeability.

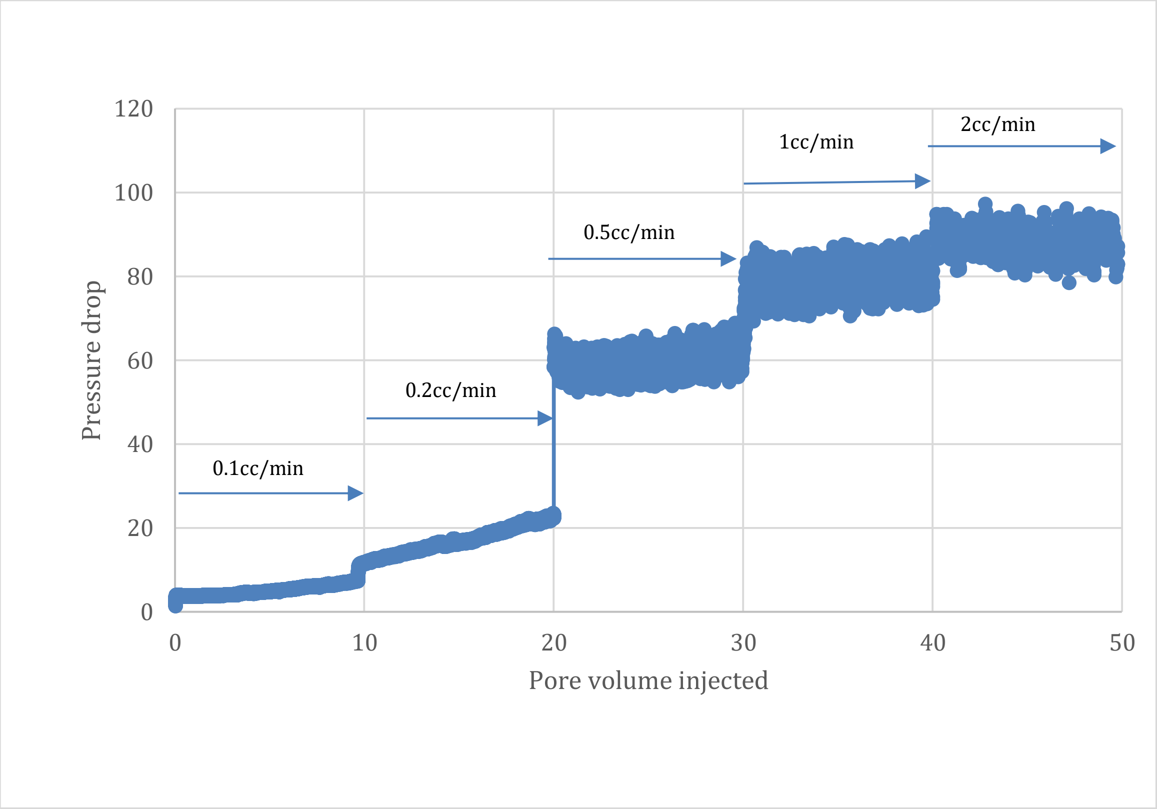


Figure 25, Injection of 3000ppm HPAM at a various flow rate

From figure 25, it was observed that differential pressure increased at a constant flow rate. This permeability reduction is due to the retention of polymer. Furthermore, RF was calculated, and its value decreases with increasing flow rate. It shows that RF is strongly-dependent upon the viscosity of polymer and permeability of porous medium. Therefore, one of the reasons for RF reduction is due to the shear-thinning nature of the polymer.

Brine injection

Flow rate (q, cc/min)	Pressure drop (dp, psi)
0,1	2,5
0,2	4,2
0,5	8,3
1	12,6
2	21,5
5	36,5

Polymer injection

Flow rate (q, cc/min)	Pressure drop (dp, psi)	RF
0,1	24	9,04
0,2	35	8,333333
0,5	60	7,228916
1	80	6,349206
2	90	4,186047

Table 7. Pressure drop vs flow rate and RF

Mechanical degradation after core-flooding

In-situ rheology is a major topic to study during polymer screening, since viscosity drop of solution cannot maintain effective chemical flooding. The core geometry has a complex structure, in which flow is not only shear, it contains converging and diverging regions. A rapid velocity change flowing from pore to pore causes significant mechanical degradation. These factors show the importance of analyzing viscosity reduction induced by mechanical degradation. The effluent of the polymer at different flow rates was taken to measure the rheological behavior of the polymer.

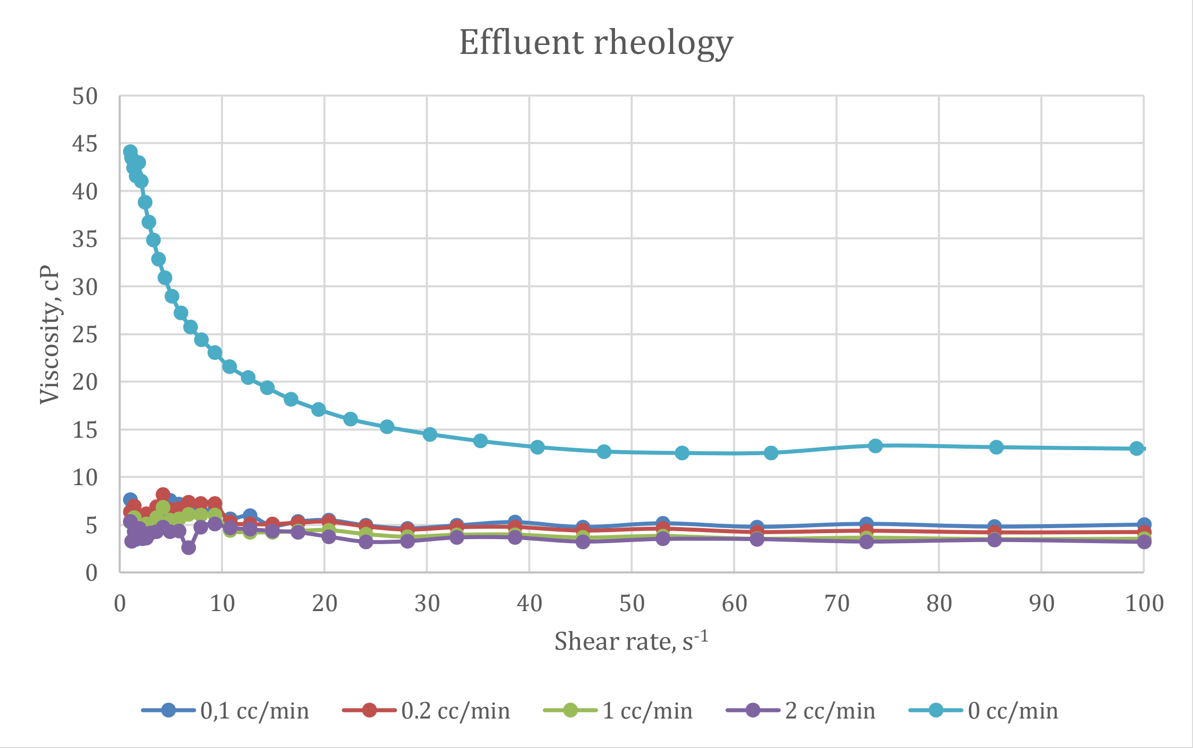


Figure 26, SAV 10 XV at 3000ppm effluent rheology

The results of the rheological behavior of effluent samples taken at different flow rates are depicted on figure 26. Both mechanical degradation tests, core flooding and experimental blender have shown similar results in terms of viscosity reduction. The viscosity of the solution decreased significantly compared with the initial values. The rheology of effluent had Newtonian fluid behavior with some fluctuations, while the polymer solution has power-law flowing nature. Generally, HPAM solutions degraded until minimal viscosity point, after which no viscosity loss is observed.

8. Conclusions and Recommendations

The paper was aimed to screen three HPAM base polymers: SAV 10, SAV 10|19 and SAV10 XV, to select a chemical for HTHS carbonate reservoirs. The reservoir conditions have extremely high salinity, 300000 ppm of both monovalent and divalent salts. The polymers were investigated for rheological behavior at different conditions, long-term thermal stability and mechanical degradation. Additionally, the core-flooding test was conducted at high pressure and room temperature conditions. The laboratory work provided the following conclusions:

- All candidates exhibited shear-thinning behaviors. SAV 10 XV at 1000 ppm and 1500 ppm showed shear thickening behavior at high shear rates. This flow nature justifies HPAM flow behavior based on previous work done on polymer flooding. At a similar concentration, SAV10 XV had higher viscosity at all temperatures and shear rate.
- The mechanical test helped to provide how the polymer solution loses viscous properties. The test showed that SAV 10 XV is quite resistive against mechanical degradation.
- After fulfilling previous laboratory work, SAV 10 XV was examined for thermal stability over 45 days. The polymer solution at 3000 ppm concentration retained 75% of its initial viscosity, which meets the criterion for further polymer flooding studies.
- The injectivity test shows that SAV 10 XV at low flow rate RF is higher comparing with the high flow rate. The reason for this mechanism is due to shear thinning nature of the polymer.

The research is recommended to continue in order to complete the injectivity test. The post-flush has not conducted, thus residual resistance factor was not calculated. The research is planned to be continued after lockdown.

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