24th ABCM International Congress of Mechanical Engineering
December 3-8, 2017, Curitiba, PR, Brazil

COBEM-2017-0896
FLOW RATE EFFECT ON POLYMER REVERSIBLE RETENTION IN SANDSTONE

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Abstract. *Polymer enhanced oil recovery (EOR) is beneficial to the economics of oil recovery projects because it reduces produced and injected water and anticipates oil recovery. However, the added polymer mass represents an extra cost to the EOR project. Polymer retention mechanisms strip polymer from the solution as the front advances through the reservoir. Therefore, polymer retention measurement is necessary to evaluate the economic feasibility of a polymer flooding project. During the development of an oil field, changes in injection strategy, well conditions or inclusion of new wells can modify the flow rate conditions throughout the reservoir. These changes in flow rate can release trapped polymer or influence the retention of more polymer. This non-permanent retention is named reversible retention. The objective of this paper is to investigate the flow rate influence in the reversible retention of a terpolymer in sandstone and to do that we use a modified version of the double polymer bank method in the experiments. Four different flow rates are evaluated (between 0.4cm^3/min and 1.0cm^3/min) in both increasing and decreasing fashions. A UV-spectrophotometer measured the polymer concentration in the effluents. The results show that this retention phenomenon is closely related to the flow rate, due to hydrodynamic effects. The results demonstrate higher reversibility for increasing flow rates when compared with the decreasing flow rate ones. Additionally, the reversible retention increases as the flow rates increments. The reversible retention of polymer in our experiments ranged from 5μg/g to 24.4μg/g. These results are consistent with other literature data.*

Keywords: *Polymer Flooding, Polymer Retention, Reversible Retention, Hydrodynamic Retention, Flow Rate Effect.*

1. INTRODUCTION

In oil recovery, the mobility ratio (M) between the injected fluid and oil is an important factor, especially for heavy crudes. Mobility is defined as the ratio between effective permeability to the fluid and its viscosity. Conventional waterflooding can be inefficient at oil recovery because of its high mobility (Sorbie, 1991). The addition of polymer to the injection water enhances the oil recovery because polymer increases the viscosity of displacing fluid, and reduces its effective permeability. Due to these characteristics, polymer enhanced oil recovery (EOR) increases volumetric sweep efficiencies and anticipates oil recovery when compared to waterflooding. Successful polymer flooding field pilots have been reported as early as 1960's (Pye, 1964), but it is still a very promising technique nowadays for heavy oil recovery (Delamaide, 2014).

Polymer retention (Γ) refers to any process that removes polymer from the injection water. If retention is acting, the polymer concentration in the injected water decreases and the viscosity of the displacing fluid deteriorates (Littmann, 1988). Due to this, Sorbie (1991) defines polymer retention as a key factor to determine the success of a polymer EOR field project.

There are three mechanisms of polymer retention: adsorption, mechanical entrapment, and hydrodynamic retention. According to Zhang and Seright (2014), adsorption is the adhesion of polymer to the rock surface, and it is instantaneous and irreversible. As Huh *et al*. (1990) report, the mechanical entrapment is a filtration mechanism that retains polymer irreversibly depending on the polymer molecular size and the pore size. Polymer is hydrodynamically retained in regions of stagnated flow and, according to Zhang and Seright (2015), this type of retention is closely related to the fluid flow rate and completely reversible. If mechanical entrapment occurs in a field project, severe injection problems will surface. Therefore the injection fluid is always designed to avoid this kind of retention. However, adsorption and hydrodynamic retention will always act during polymer flow in a porous medium. According to Sorbie (1991), adsorption is the major component of polymer retention. Nevertheless, Ferreira and Moreno (2017) highlighted that significant hydrodynamic retention could act even in highly permeable systems (~5μm^2).

In a field implementation of polymer EOR, the polymeric solution is subject to a plethora of different flow rates or apparent velocity (flow rate divided by the area open to flow). Near injection and production wells, the flow rate is high, while far from those wells, low flow rates are established. More than that, changes in injection strategy, well conditions or infill drilling can modify the fluid velocities conditions throughout the reservoir. These changes in flow rate can release trapped polymer or influence the retention of more polymer since reversible retention is closely related to the fluid velocity.

Few works that deal with polymer hydrodynamic retention are available, but the literature (Idahosa *et al*., 2016; Zhang and Seright, 2015) on this matter only measures this reversible retention with experiments in which the flow rate increases.

This work aims to investigate if the direction in which the flow rate changes (increasing or decreasing) plays a role in reversible retention estimation. We do this investigation through a core-flooding experiment.

2. MATERIALS AND METHODS

2.1 Fluids

We used two fluids in our experiment, a brine, and a polymeric solution. Both fluids were of high salinity and hardness, including six different ions, and the polymeric solution had polymer dissolved in it. The polymer we used was a high molecular weight ($M_w \approx 15x10^6$) polyacrylamide co-polymerized with acrylate and acrylamide-tert-butyl sulfonate (ATBS, also known as 2-acrylamido-2-methylpropane sulfonic acid – AMPS). The acrylate improves the viscosity of the polymer solution, and the ATBS increases the ability of the solution to maintain its viscosity under high salinity and temperature conditions. The solvent of both fluids was deionized water. Table 1 summarizes the concentration of every solute in each fluid.

Table 1. Solute concentrations on the fluids used in the experiment.

	Polymer ppm (1)	NaCl kg/m³ (2)	$CaCl_2 \cdot 2H_2O$ kg/m³ (2)	$MgCl_2 \cdot 6H_2O$ kg/m³ (2)	Na_2SO_4 kg/m³ (2)	KCl kg/m³ (2)
Brine	0	43300	5000	3150	650	300
Polymeric Solution	1250	86600	10000	6300	1300	600

(1) kg of solute per million of kg of solvent; (2) mass of solute per volume of solution.

All the salts were supplied by Sigma-Aldrich and were of reagent quality. The polymer was provided in powder form by SNF Floerger and was considered to have 100% of active polymer material.

The salts were dissolved in the deionized water in volumetric flasks at a room with controlled temperature. Dissolution of salts was aided by an ultrasonic stirrer to ensure that no solid material remained undissolved. The polymeric solution was made in two steps: first, a stock solution of 5000ppm was prepared, and then the stock solution was diluted to the target concentration (1250ppm). We prepared the stock solution as follows: 1) put the water with dissolved salts in a beaker and adjusted a magnetic stirrer in order to form a vortex of about 75% of the fluid height; 2) carefully add polymer in the shoulder of the vortex within one minute; 3) slow the rotation until the vortex is about 10% of the height; 4) after three hours of slow stirring, turn off the stirrer; 5) let it rest overnight; 6) if any fish eyes were present, we discarded the solution and started over.

Table 2 summarizes the main characteristics of the fluids we used in our experiment.

Table 2. Characteristics of the fluids used in the experiment.

		Brine	Polymeric Solution
Density	kg/m³	1034	1066
pH	-	5.7	5.4
Viscosity at $7.8s^{-1}$ (1)	mPa·s	1.103	8.830
Ionic Strength	mol/m³	$0.907x10^{-3}$	$1.814x10^{-3}$

(1) Polymeric solutions are shear-dependent non-Newtonian fluids.

2.2 Rock sample

We used sandstone samples of the Botucatu formation (Paraná basin, PR, Brazil). According to Cardoso and Balaban (2015), Botucatu sandstone is very similar to Berea sandstone and is adequate to experiments involving core-flood studies.

The core was cylindrical, with dimensions of 64.2mm of length and 37.7mm of diameter, it weighted 128.7g. The permeability and porosity of the core were 1.295μm² and 31%, respectively. The porosity was measured by a gas porosimeter and the permeability by water, with the aid of a syringe pump and high precision pressure sensors. The permeability was measured after polymer had flooded the core. Another Botucatu sample of similar characteristics was used as a filter for the polymeric solution.

2.3 Core-flooding

Figure 1 presents an illustration of the experimental apparatus.

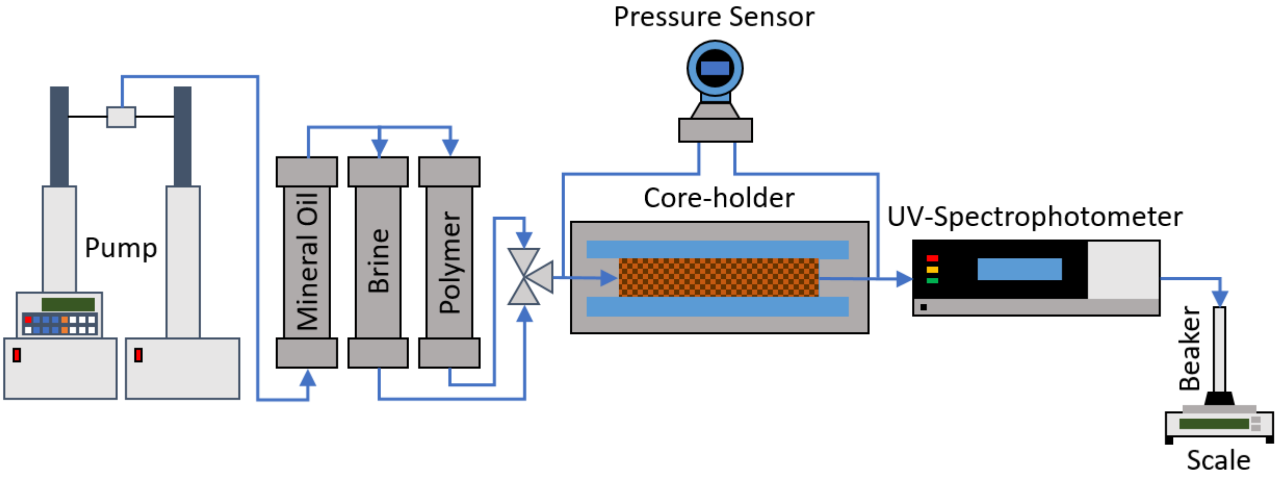

Figure 1. Schematics of the experimental apparatus.

An ISCO syringe pump injects distilled water in the mineral oil accumulator, the oil then displaces either brine or polymeric solution. A 3/2way valve selects the fluid to be injected in the sample that is confined in the core-holder. After the fluid exits the core-holder, it passes through an UV-spectrophotometer and is produced in a fractioned beaker, which is positioned on top of a scale.

The sole purpose of the mineral oil is to act as a displacing fluid, and the core only had contact with water phase fluids. The UV-spectrophotometer measures the polymer concentration in the solution. The fractioned beaker and the scale measure volume and mass, respectively. A high precision pressure sensor is used to monitor the pressure drop across the core-holder.

This setup can be used to measure other properties relevant to polymer EOR, as demonstrated by Ferreira and Moreno (2017).

The experiment reported in this paper consisted in alternating injection of polymer and brine at four different flow rates. The flow rates were evaluated in descending (first half) and ascending (second half) fashions, such as illustrated in Figure 2.

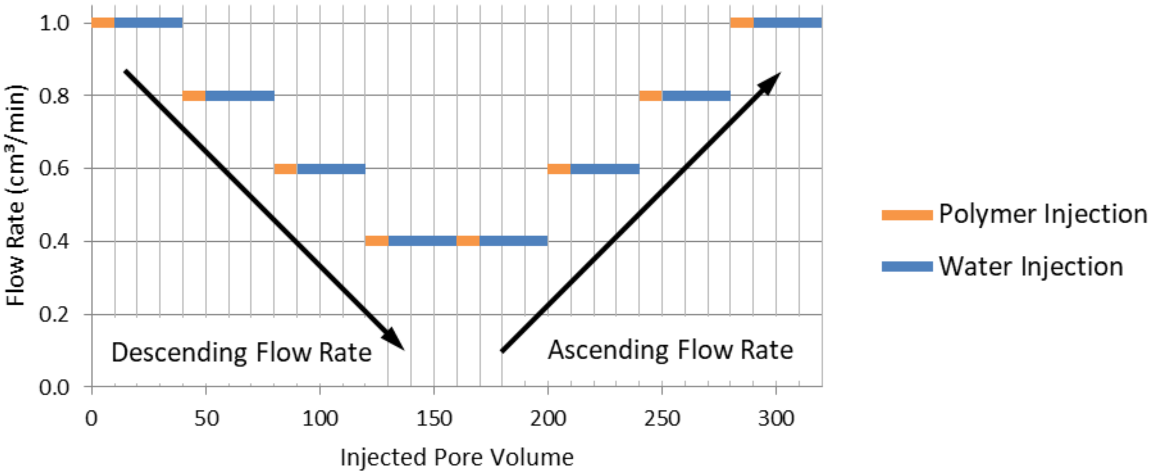

Figure 2. Core-flooding injection flow rate sequence (1cm³/min=1.667x10^{-8}m³/s).

Every polymer slug had a size of 10 pore volumes (PV), and every brine slug a size of 30PV. The size of the polymer bank was chosen to guarantee that the concentration of polymer in the production fluids was the same as the injected by the end of the polymer injection. The brine slug was larger than the polymer one because the brine has a lower viscosity than polymer, which leads to an unstable advance front. With 30PV we made sure that the polymer concentration in the production fluids was at zero by the end of the brine injection. By the end of every fluid injection, the pressure drop and polymer concentration indicated that the system was at steady state regime for at least 2PV.

We carried out the test in a controlled environment of 23ºC and with confining pressure of 900psi.

2.3.1 Measurement of retention

Lotsch *et al.* (1985) introduced a method to estimate polymer retention in core flooding experiments based on the difference between two polymer production curves. This procedure is named the double polymer bank method. The double polymer bank process is considered to be the best way to determine polymer retention (Idahosa *et al.*, 2016; Zhang and Seright, 2014; Ferreira and Moreno 2017). Ferreira and Moreno (2017) demonstrated that this method is preferable over those proposed by Dominguez and Willhite (1977) and Dawson and Lantz (1972).

The double polymer bank method needs at least two polymer production curves separated by a brine slug to estimate retention. We will call those, base curve and target curve. The base curve is assumed to be the polymer production curve to which no retention is associated, while the target curve represents the polymer production curve associated with retention. The polymer retention is dependent on the area between the target curve and the base one, as well as on polymer concentration, slug size, and rock sample dry mass. For our case, the base curve was chosen to be the ones of 0.4cm³/min (ascending and descending), and the target curves were those of 1.0, 0.8, and 0.6m³/min. The base curve for the descending flow rate retention calculations was the 4th polymer injection, while the 5th polymer injection was the baseline for the ascending flow rate. We chose the base curves to be those of the lowest flow rate, among the ones tested, because hydrodynamic retention increases for higher flow rates (Idahosa *et al.*, 2016; Zhang and Seright, 2015; Ferreira and Moreno 2017).

Classically, the retention measurement is done considering the front-end of the production curves (Hughes *et al.*, 1990; Idahosa *et al.*, 2016; Osterloh and Law, 1998; Zhang and Seright, 2014). However for this paper, we used the back-end of the curves, as exemplified by Figure 3.

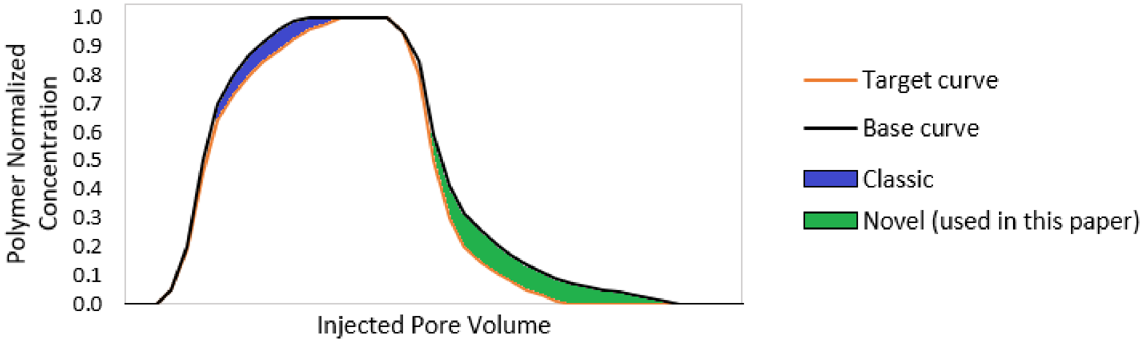

Figure 3. Novel (proposed in this work) and classic methods of utilizing the double polymer bank method to estimate polymer retention in porous media.

At first glance, there are not many differences in the methods. The differences arise in the fact that the shape of the front-end is different from the form of the back-end. The brine displacement by polymer is stable (M<1), therefore no viscous fingering take place. On the other hand, polymer displacement by brine is unstable (M>1), which results in the formation of viscous fingers and an early breakthrough of brine. After the brine breakthrough, the polymer production decreases slowly, which results in extended periods of low polymer concentration production. According to Zhang and Seright (2015), this condition can lead to very inaccurate retention estimates if the polymer concentration measurement is not accurate. Under proper conditions, UV-spectrophotometry is a superior way to accurately measure polymer concentration when compared to chemical (Allison *et al.*, 1987; API, 1990; Scoggins and Miller, 1979; Teixeira, 2005; Thomas *et al.*, 2013), rheological (Manichand and Seright, 2014; Moradi, 2011; Zhang and Seright, 2014) or gravimetric (Chisholm *et al.*, 2009; Mezzomo *et al.*, 2002) methods. Aghamir-baha (2014) reports that this method is capable of detecting polyacrylamides in concentrations as low as 0.01ppm. Therefore, we were able to successfully estimate the polymer concentration in the back-end of the curve.

By using the back-end of the production curve, we measured how much polymer left the porous media. The difference in polymer mass between the base and the target curves is the amount that stayed inside the porous medium for the flow rate of the target curve, i.e., the retained polymer.

3. RESULTS AND DISCUSSION

Figure 4 shows the polymer production curves for the ascending flow rate cases of 0.4cm³/min and 1.0cm³/min. The value of ten injected pore volumes (PV) marks the moment when the polymer injection ends, and the brine injection starts.

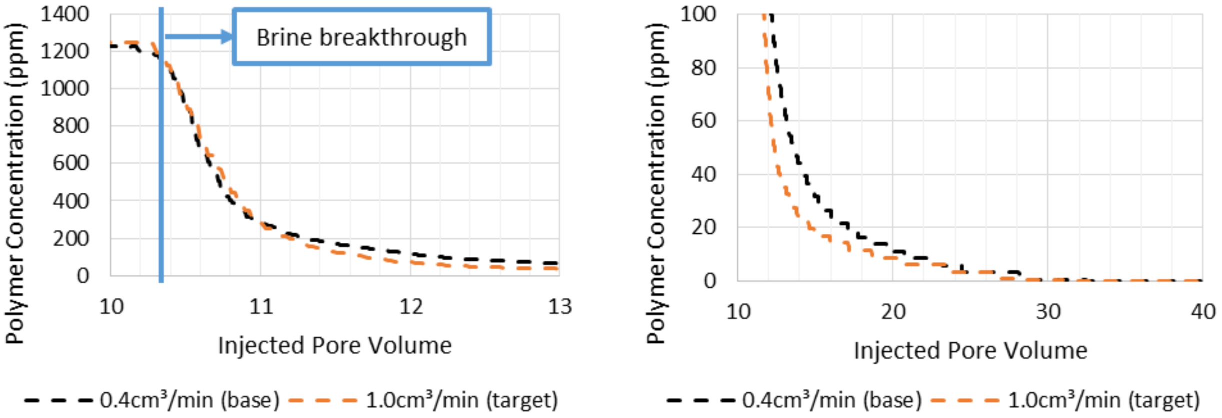

Figure 4. Back-end of polymer production curves during the start of brine injection for the ascending flow rate cases of 0.4cm³/min (base curve) and 1.0cm³/min (one of the target curves).

In Figure 4, one can see that polymer concentration starts to decrease around 10.4 injected PV. Considering that brine injection starts at ten injected PV, the brine breakthrough (i.e., when produced polymer concentration starts to decrease) occurs before one PV of brine is injected, indicating the formation of viscous fingers. After brine breaks through, the polymer concentration decreases rapidly from 1250ppm to around 100ppm within 12.5 injected PV. After that fast decline, the polymer concentration keeps slowly falling until it reaches zero at around 30 injected PV. One can also observe in Figure 4, that the differences between the base and target curves are small, indicating that little retention took place. The trend illustrated in Figure 4 is the same for all injections, as can be seen in Figure 5.

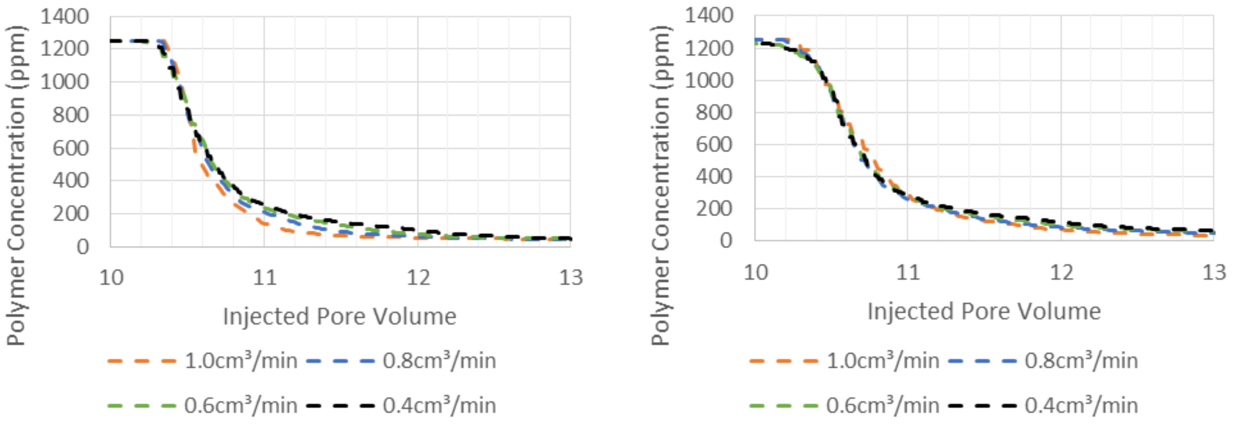

Figure 5. Polymer production curves for the descending flow rate (left) and ascending flow rate (right) cases.

Figure 6 illustrates the reversible retention results. The values are expressed in µg of polymer per g of rock, for both descending and ascending cases. Keep in mind that since our experiment is linear (i.e., area open to flow does not change), the trends observed for flow rates can be extended for apparent velocities.

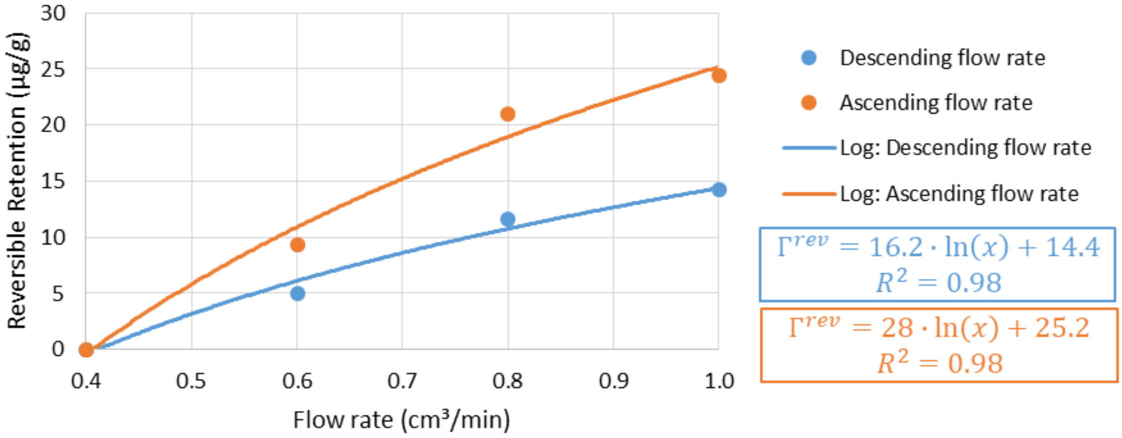

Figure 6. Polymer experimental reversible retention results for both descending (blue) and ascending (orange) flow rate cases and logarithm data fit.

In Figure 6, we can see that higher flow rates result in higher reversible retention. A logarithm curve fitted our data very nicely, achieving a coefficient of determination (R^2) of 98%. This data fitting indicates that hydrodynamic retention increases more substantially when flow rates are incremented from low values and, for high flow rates, a plateau should be reached. To understand the physical phenomenon that leads to this observation let us consider that a porous medium has various polymer hydrodynamic retention sites. Each site starts trapping (or retaining) polymer at a given flow rate, which we will name trap point. Each trap point has a specific flow rate associated with it, which may or may not be the same as other retention sites. Our results indicate that the majority of sites have a trap point in low flow rates. Additionally, under very high flow rates, all trapping sites will be fulfilled, and no additional hydrodynamic retention will take place.

Another notable result in Figure 6 is that the hydrodynamic retention for the case of ascending flow rate was higher than the case of descending flow rate. The ascending flow rate retention values were, on average, 80% greater than those for descending flow rates. This result indicates that the trap point is not solely a function of the flow rate, but also of the direction of the flow rate change (i.e., if the flow rate increases or decreases from its previous value). The direction of flow rate change should be a concern for future studies on polymer hydrodynamic retention.

In field applications of polymer EOR, there are a series of injector and producer wells. The apparent velocity of the fluids is high near the wells and low far from them, as discussed above. The difference between injector and producer wells is that the fluid is decelerating near an injector and accelerating near a producer. Since our results indicate that the reversible retention for increasing apparent velocities is higher than for decreasing ones, we expect more polymer to be trapped hydrodynamically near producers than injectors. This is an interesting result because production of polymers is undesirable since the production water needs to be treated on the surface. An analysis of the residual resistance factor with regard to hydrodynamic retention needs to be performed to evaluate if the polymer trapped near producers will represent an appreciable loss in productivity. Additionally, our results indicate that changes in flow rate can lead to additional polymer loss, especially in the zones of low flow rate (i.e., far from wells).

Figure 7 shows where our work stands amongst recent literature on polymer reversible retention.

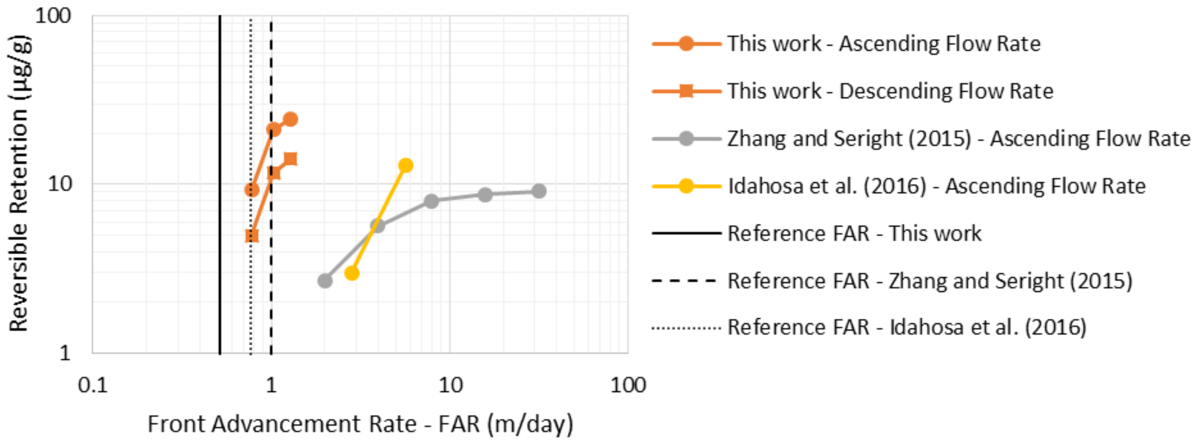

Figure 7. Literature on experimental evaluation of polymer hydrodynamic retention by the double polymer bank method (1m/day=1.157x10^{-5}m/s).

The front advancement rate (FAR) is the division of the volumetric flow rate by the area open to flow, which is also known as apparent or Darcy velocity. We plotted the results of Figure 7 against the FAR to normalize the data for experiments that used cores of different areas open to flow than ours.

Zhang and Seright (2015) used a consolidated Dundee sandstone core of permeability and porosity measured at 1.875μm² and 24.1%, respectively. They injected a polymeric solution composed of 500ppm of HPAM (SNF Flopaam 3230S) in a 2% NaCl brine.

Idahosa *et al.* (2016) carried out their experiment in sandpacks of 0.344μm² permeability and 37.2% porosity. They used a polymeric solution made of 500ppm of HPAM (SNF Flopaam 3630S) in 3.2% TDS brine.

In Figure 7, we can see that Zhang and Seright (2015) results tend to a plateau of retention. Idahosa *et al.* (2016) data include only two points, so no trend is observed besides the correspondence between higher FAR and higher reversible retention. Both results corroborate to our experimental observations and our theory for the physical phenomena.

We can see in Figure 7 that the reference FAR for each experiment is different. This means that the base curve for retention determination was obtained at distinct flow rates. The reference FAR was 0.99m/day for Zhang and Seright (2015), 0.76 for Idahosa *et al.* (2016), and 0.52 for our experiment. The double-polymer bank method estimates the retention relative to this base curve, i.e., the retained polymer correspondent to the flow rate of the base curve is considered zero and the value determined for the target curve is incremental to that. Considering the maximum FAR used by each author, Zhang and Seright (2015) measured 9.1μg/g retention at 31.7m/day, Idahosa *et al.* (2016) measured 12.9μg/g retention at 5.7m/day, and we measured 24.4μg/g retention at 1.3m/day (ascending flow rate). Therefore, we can see that, for higher reference FAR, retention measurements were lower. This corroborates with our theory that most hydrodynamic retention sites have a trap point in low flow rates.

We can estimate Zhang and Seright (2015) and Idahosa *et al.* (2016) results for our reference FAR. To do that, we need to calculate the retention of their base curve in relation to our base curve, which can be done by using the model presented in Figure 6 for the ascending flow rate case. Table 3 and Figure 8 summarize the results when we make this projection.

Table 3. Projected reversible retention at reference FAR (base curve) for current literature works on polymer hydrodynamic retention.

Author	Reference FAR	Projected Retention at Reference FAR
-	m/day [(1)]	μg/g
This work	0.52	0.0
Zhang and Seright (2015)	0.99	18.4
Idahosa *et al.* (2016)	0.76	10.9

[(1)] 1m/day=1.157x10^{-5}m/s

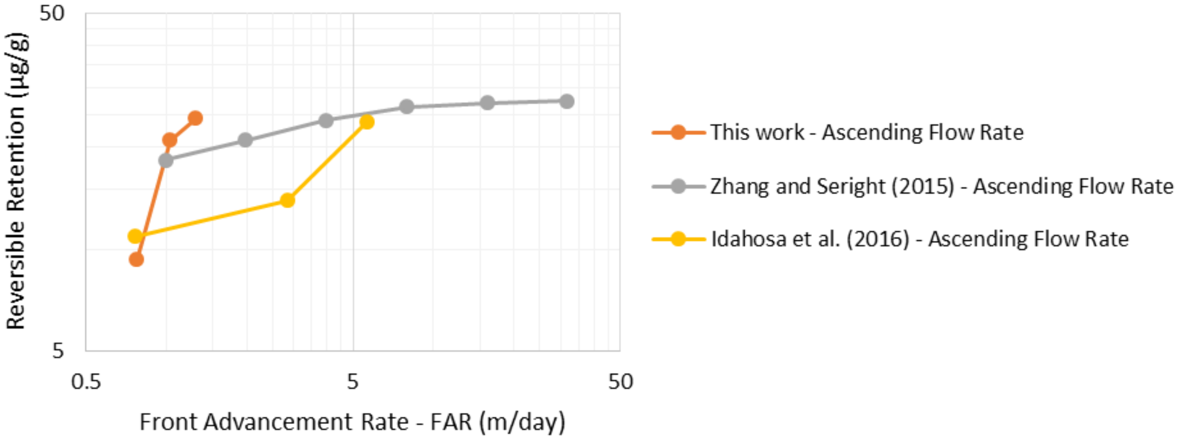

Figure 8. Projected reversible retention considering the reference FAR as the same as our experiment - ascending flow rate experiments (1m/day=1.157x10^{-5}m/s).

When we project the results of Zhang and Seright (2015) and Idahosa *et al.* (2016) to our reference FAR, we can see in Figure 8 that all the results have the same order of magnitude. The retention at 2.8m/day in Idahosa *et al.* (2016) seem to be an outlier. The analysis of Figure 8 strengthen the hypothesis of trap point discussed above and consolidates the proposed methodology.

4. CONCLUSIONS

In this paper, we investigated the hydrodynamic retention (reversible retention) of a polyacrylamide in porous media. We examined whether the direction of the injection flow rate change plays a role in reversible retention estimation. We have done this evaluation by performing a core-flooding experiment and using a modified methodology based on Lotsch *et al.* (1985). The main conclusions are:

1. The modified method (based on Lotsch et al., 1985) was successfully used to estimate reversible retention of polymer in porous media, yielding consistent results with recent literature;
2. Polymer displacement by brine is unstable and leads to early breakthrough of brine;
3. Reversible retention of polyacrylamides increases as flow rate increases;
4. Polyacrylamide hydrodynamic retention increases more substantially when low flow rates are incremented when compared to flow rate increase from high values. The field implication of this conclusion is that one can expect more hydrodynamic retention close to a producer, then around an injector;
5. The reversible retention seems to reach a plateau at high flow rates;
6. Polymer reversible retention is a relative measurement, and its value is very dependent on the base polymer production curve;
7. Our work suggests that reversible retention is dependent on the direction in which the flow rate changes (low-to-high or high-to-low). The flow rate change scheme should be a concern for future works on polymer hydrodynamic retention.

5. ACKNOWLEDGEMENTS

The authors would like to thank the Laboratory of Oil Reservoirs (LABORE) at Unicamp, the Brazilian National Agency of Petroleum Natural Gas and Biofuel (ANP), PRH-ANP, and the Coordination for the Improvement of Higher Education Personnel (CAPES).

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