Eurasian Chem.-Technol. J. 26 (2024) 245–252

https://doi.org/10.18321.ectj1648

Laboratory Testing of Polymer Flooding by Hydrolyzed Poly(acrylamide) in High Salinity Conditions

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Article info

Received:
12 August 2024

Received in revised form:
10 September 2024

Accepted:
16 October 2024

Keywords:
Polymer flooding
Oil recovery
Sand pack
High salinity

Abstract

This study investigates the efficacy of high molecular weight hydrolyzed polyacrylamide (HPAM) solutions in enhancing oil recovery under high salinity conditions. The viscosity values of 0.25 wt.% HPAM solutions in 250 g·L^{-1} brine with high content of divalent cations (Ca and Mg) were found to range from 11.5 to 12.6 cP for both 10% and 30% hydrolysis polymers. The displacement of 420-cP oil from sand pack models showed that injecting 3 pore volumes (PVs) of polymer solutions significantly increased the oil recovery factor, with an increment of 16–28% after the injection of 1 PV of water. The results of fractional flow calculations, along with sand pack flooding experiments, suggest that the oil recovery factor measurements are most likely overestimated by roughly 10%. An explanation for this is the plugging of pores by high molecular weight polymers. In fact, as the molecular weight increased from low to medium high and super high, it required the assumption of a much higher viscosity to achieve a fit between fractional flow predictions and actual polymer flood results. These findings highlight the potential of high molecular weight HPAM solutions to enhance oil recovery in high salinity environments and underscore the importance of using both sand pack flooding experiments and fractional flow calculations for comparing different polymers.

1. Introduction

Enhanced Oil Recovery (EOR) methods have become increasingly vital in maximizing the extraction of oil from mature reservoirs [1–5]. Among the various EOR techniques, polymer flooding has garnered significant attention due to its potential to improve sweep efficiency [6–8]. In polymer flooding, the addition of polymers to the injected water increases the viscosity of the displacing fluid, improving the mobility ratio between the injected fluid and the oil. This leads to a more stable displacement front and reduces viscous fingering, ultimately enhancing oil recovery [9]. In heterogeneous (layered) reservoirs with cross-flow, increasing the polymer solution viscosity up to a certain value – determined by the initial mobility ratio and the permeability contrast between the layers – can result in a more uniform oil displacement front across all layers. This mechanism, where the displacement of mobile oil is enhanced by increasing the viscosity of the displacing phase, is what makes polymer flooding successful in many field trials under varying *in-situ* reservoir conditions. By adjusting the viscosity appropriately, the technology can mitigate the effects of reservoir heterogeneity, leading to more efficient oil recovery [10].

However, the application of polymer flooding in high salinity environments presents unique challenges [11–13]. High salinity brines can adversely affect the performance of polymers, particularly hydrolyzed polyacrylamides (HPAM) [14], which are commonly used in polymer flooding [15]. The presence of high concentrations of salts can lead to a sig-

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nificant reduction in viscosity due to suppressing the polyelectrolyte effect. This causes the need for polymers that can maintain their effectiveness in such harsh conditions [16].

This study focuses on evaluating the performance of high molecular weight hydrolyzed polyacrylamide (HPAM) solutions in high salinity environments. Specifically, the research aims to determine the viscosity behavior of HPAM solutions with varying degrees of hydrolysis in brine with a salt concentration of 250 $g \cdot L^{-1}$. The study examines the impact of polymer injection on oil recovery in a laboratory setting.

By exploring the relationship between polymer viscosity, salinity, and oil recovery, this study contributes to a better understanding of the suitability and efficiency of high molecular weight HPAM polymers with different hydrolysis degrees for EOR applications in challenging reservoir conditions.

2. Materials and methods

2.1 Polymers

Commercially available HPAM samples provided by SNF company (France) were used for the core/sand pack flooding experiments (Table 1). The hydrolysis degree of HPAM samples was between 10–30% and molecular weight varied from low (~ 5 000 000 Da) to super high (~ 20–30 000 000 Da). The accurate determination of polymer molecular weight (Mw) is often challenging due to several factors. First, precise measurement of Mw can be difficult to achieve consistently. Second, polymers typically exhibit a broad molecular weight distribution rather than a single, definitive value. As a result, while expressing polymer concentration in mol/L could be advantageous, the variability and uncertainty in Mw make this impractical. Therefore, it is preferable to describe polymers using terms like "low molecular weight" or "high molecular weight," which more accurately reflects the inherent variability and distribution of polymer sizes. This is also why weight percent (wt.%) is used instead of molarity ($mol \cdot L^{-1}$), as wt.% provides a more consistent and accurate representation of polymer concentration, given the variability in molecular weight.

The molecular weight and hydrolysis of HPAM significantly impact EOR performance. Higher molecular weight polymers increase solution viscosity and improve the mobility ratio, enhancing sweep efficiency in heterogeneous reservoirs. However, excessive molecular weight can hinder polymer

Table 1. List of commercial HPAM samples provided by SNF company (France) with different molecular weights and hydrolysis degree values

#	Polymer	Molecular weight	Degree of hydrolysis, %	Rotations per minute, (RPM)	Viscosity, cP	Average viscosity, cP
1	Flopam AN 910 X5896	Average	10	0.3	440 520 560	506.6
2	Flopam AN 910 SH GH 2279	Medium high	10	0.3	5280 5760 5780	5606.6
3	Flopam AN 910 VHM V5944	High	10	0.3	320 310 360	330
4	Flopaam 3230S GS 5181	Low	30	0.3	7390 7740 8000	7710
5	Flopaam 3430S GS 5175	Medium	30	0.3	5100 5420 5100	5206.6
6	Flopaam 3630S GS 5183	Super-high	30	0.3	17480 18080 17740	17766.6

propagation through porous media and cause pore plugging. Hydrolysis affects the conformation of polymer molecules and, as a result, has a significant effect on viscosity. Since hydrolysis also influences interactions with ions in saline solutions, excessively high hydrolysis can increase salinity sensitivity and reduce viscosity.

Table 1 presents a series of HPAM commercial samples utilized in the present study along with their corresponding viscosities, which were measured using a Brookfield LVT spindle #61 viscometer in distilled water at a concentration of 0.25 wt.%.

Polymer solutions used for sand pack flooding experiments were prepared by using brine with a salt concentration of 250 g·L^{-1}. The viscosity of the solutions was measured by Model 900 rotational viscometer (Ofite, USA).

2.2 Brine

For most experiments, a synthetic brine with a concentration of 250 g·L^{-1} was used to dissolve the polymer and conduct the flooding experiments. The chemical composition of brine is the following: 225 g·L^{-1} NaCl; 12.5 g·L^{-1} $CaCl_2$; 12.5 g·L^{-1} $MgCl_2$. Extra pure salts provided by TM MEDIA company were used in this study to prepare synthetic brine.

A salinity of 250 g·L^{-1} is classified as high salinity brine and is among the highest levels recorded in Kazakhstani oilfields. For example, Table 2 provides salinity measurements for various Kazakhstani oilfields obtained in the laboratory.

Table 2. Laboratory-measured salinity values for different Kazakhstani oilfields

Oil field	Salinity, g·L^{-1}
Uzen	15-60
Karazhanbas	26-30
Kenbay	140
Ayrankol	240-270

2.3 Oil

Karazhanbas oil (well #1913) with density and viscosity values of 0.93 g/cm^3 and 420 cP at 30 °C, respectively, was used in this work.

2.4 Sand pack model

A sand pack model with a diameter of 4.3 cm and a length of 8.6 cm was used to conduct polymer flooding experiments. The model was filled with sand from the Karazhanbas field. The sand was used as received, containing the resident oil and water.

Sand pack flooding experiments were conducted according to the following procedure:

1. Vacuuming the model;
2. Saturating the model with 250 g·L^{-1} synthetic brine to calculate pore volume;
3. Injecting 420 cP oil at 1 cm^3/min until irreducible water saturation is reached;
4. Injecting 1 pore volume of synthetic brine with a salt concentration of 250 g·L^{-1} at 0.3 cm^3/min to simulate water flooding conditions;
5. Injecting 3 pore volumes of 0.25 wt.% polymer solution at 0.3 cm^3/min in 250 g·L^{-1} synthetic brine to measure the incremental oil recovery factor.

All tests were conducted at 25 °C. The oil recovery drive fluids were injected at a flow rate of 0.3 cm^3/min, which corresponds to a linear Darcy velocity of 30 cm/day. This rate was chosen as it approximates the actual flow conditions observed at significant distances from the wellbore in real reservoir environments.

The sand packs exhibited a permeability of approximately 9.8 Darcy when fully saturated with brine and an oil permeability of around 15 Darcy at connate water saturation.

It should be noted that the results of additional oil recovery should be interpreted with caution. Similarly, the obtained recovery factor values must be used carefully when scaling up polymer flooding. It is evident that an experiment with the one-dimensional flow in a small core sample or sand pack allows for the recovery of significant oil volumes, reflecting the maximum displacement efficiency for the case of injecting an unlimited volume of polymer solution [17].

3. Results and discussion

3.1 Dynamic viscosity of the polymer solutions in high salinity brine

Determining the dynamic viscosity of polymer solutions is crucial in polymer flooding. The primary objective of polymer flooding is to improve the sweep efficiency by increasing the viscosity of the displacing fluid, reducing the mobility ratio between the injected water and the oil. By carefully measuring and adjusting the dynamic viscosity of the polymer solution, operators can optimize the fluid's flow properties to achieve a more uniform and effective displacement of oil.

However, if high salinity brine is the only option available for polymer flooding, achieving the target viscosity of the solution can be challenging. This is true for hydrolyzed polyacrylamide (HPAM), which reduces its viscosity due to the polyelectrolyte effect. In this study, brine with a salt concentration of 250 g·L^{-1} was purposefully utilized to assess the efficiency of HPAM under high salinity conditions.

Table 3 lists the dynamic viscosity values measured for 0.25 wt.% HPAM solutions in brine with a salt concentration of 250 g·L^{-1} at 30 °C.

As illustrated in Table 3, only the low molecular weight polymer failed to achieve a viscosity value exceeding 10 cP. The viscosity value of 2.86 cP is insufficient for most polymer flooding projects, where the target polymer viscosity is typically above 10 cP. This polymer would be disqualified from consideration. However, in this study, sand pack flooding tests were still conducted with this polymer due to its scientific research interest.

Table 3. Dynamic viscosity of different HPAMs in 250 g·L^{-1} brine. Polymer concentration – 0.25 wt.%

Molecular weight	Hydrolysis degree, %	Viscosity at 30 °C and 7.3 s^{-1}, cP
Medium high	10	11.75
Average	10	11.52
Low	30	2.86
Super high	30	12.63

3.2 Sand pack flooding tests

Experiment #1 – Injection of 2.86 cP polymer solution

Low molecular weight, 30% hydrolysis degree HPAM was used for this test. As seen from Fig. 1, in this test the injection of brine with a salt concentration of 250 g·L^{-1} allowed to displace around 35% of oil after 1 PV was injected into the model. If the water flooding had been continued, the oil recovery factor (ORF) would reach 50% after the injection of 4 PVs. However, switching to polymer flooding allowed to produce 66% of oil, as a result, the incremental oil recovery reached to 16%.

The results of this experiment show that even low viscosity (less than 5 cP) polymer solutions can achieve higher than 15% incremental oil recovery from a high permeability sand pack model.

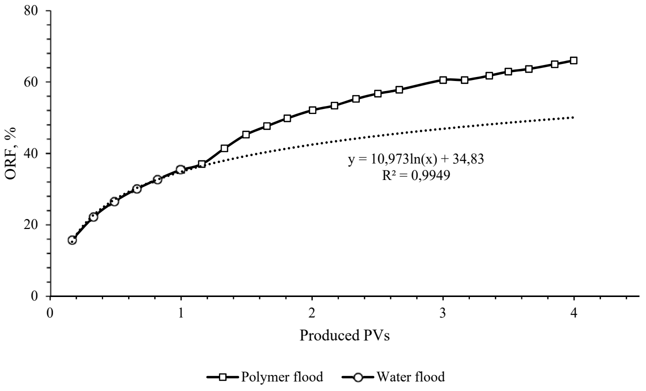

Fig. 1. Results of polymer flooding experiment by using 0.25 wt.% low molecular weight, 30% hydrolysis degree HPAM.

Experiment #2 – Injection of 11.75 cP polymer solution

Medium high molecular weight, 10% hydrolysis degree HPAM was used for this test. As seen in Fig. 2, in this test the injection of brine with a salt concentration of 250 g·L^{-1} allowed to displace around 30% of oil after 1 PV was injected into the model. If the water flooding had continued, the ORF would have reached 42.25% after the injection of 4 PVs. However, switching to polymer flooding allowed to produce 70.85% of oil, as a result, the incremental oil recovery reached 28.6%.

The higher oil recovery factor achieved in this experiment compared to the previous one can be attributed to the increase in polymer viscosity from 2.8 to 11.7 cP.

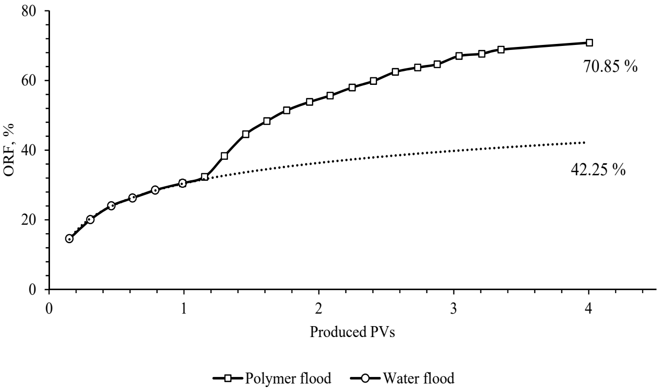

Fig. 2. Results of polymer flooding experiment by using 0.25 wt.% medium high molecular weight, 10% hydrolysis degree HPAM.

Experiment #3 – Injection of 12.63 cP polymer solution

Super high molecular weight, 30% hydrolysis degree HPAM was used for this test. As seen in Fig. 3, in this test the injection of brine with a salt concentration of 250 g·L^{-1} allowed to displace around 27% of oil after 1 PV was injected into the model. If the water flooding had been continued, the ORF would have reached 35.6% after the injection of 4 PVs.

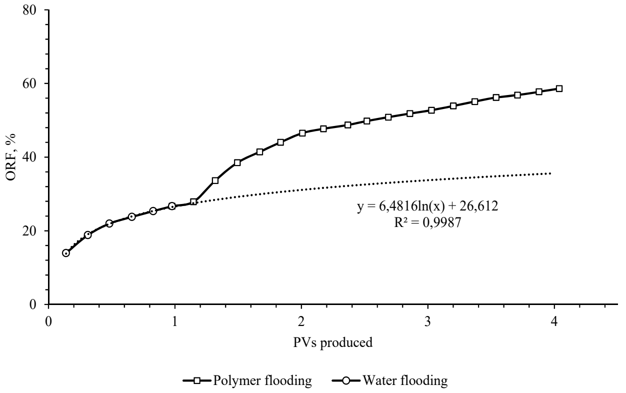

Fig. 3. Results of polymer flooding experiment by using 0.25 wt.% super high molecular weight, 30% hydrolysis degree HPAM.

However, switching to polymer flooding allowed to produce 58.6% of oil, as a result, the incremental oil recovery reached 23%.

This experiment shows that increasing the molecular weight of HPAM to what the manufacturer denotes as "super high", roughly corresponding to 20–30 mln Da, does not significantly influence the oil recovery factor in a linear sand pack flood.

The analysis of three experiments shows that injecting 1 PV of water resulted in recoveries ranging from 26 to 35%. This variation, despite using the same oil, can be explained by factors such as slight differences in sand pack packing, leading to variations in pore structure and permeability. Achieving uniform packing is inherently challenging, and small experimental errors or slight differences in sand properties, like wetting characteristics, may also have contributed to these discrepancies.

The experiments shown above demonstrate that in linear sand pack flooding even in brine with a salt concentration of 250 g·L^{-1} high molecular weight HPAMs can provide a notable oil recovery factor increment.

The water flood data from the Experiments #1-3 were fitted to Brooks-Corey equations [18]:

$$k_{rw} = k_{rwo}\left[\frac{S_w - S_{wi}}{1 - S_{or} - S_{wi}}\right]^{n_w}$$

$$k_{ro} = \left[\frac{1 - S_w - S_{or}}{1 - S_{or} - S_{wi}}\right]^{n_o}$$

where k_{rw} is relative permeability to water, k_{ro} is relative permeability to oil, S_w is water saturation, S_{wi} is initial water saturation, S_{or} is residual oil saturation, n_w and n_o are saturation exponents.

Table 4 lists a set of parameters that provided an adequate fit for experiments # 1-3. Figure 4 shows the relative permeability curves obtained by using Brooks-Corey equations with n_w and n_o equal to 2.5 and 4, respectively, for experiment #3. According to the lab measurements S_{wi} were equal to 0.093. S_{or} is assumed to be 0.37.

The relative permeability values shown in Fig. 4 were further used to calculate the fraction of water in the produced fluid volume by using the following fractional flow formula [18]:

$$f_w = \frac{1}{1 + \frac{k_{ro}}{\mu_0}\frac{\mu_w}{k_{rw}}}$$

As the next step, the number of PVs needed to be injected or produced to achieve a certain oil recovery factor can be easily calculated. Figures 5–7 compare the oil recovery factors calculated using this method with those actually observed in the laboratory.

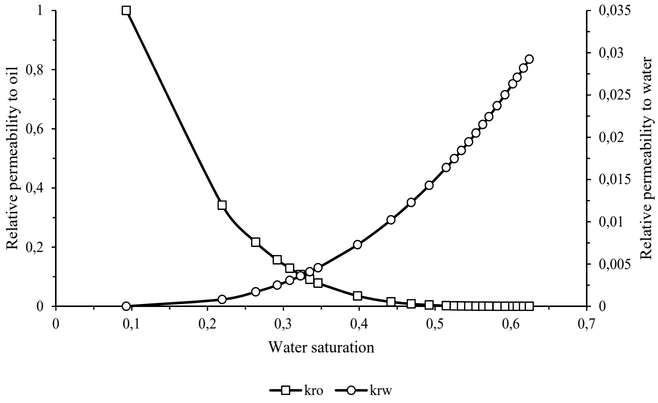

Fig. 4. Relative permeability curves obtained by using Brooks-Corey equations for experiment #3.

Table 4. Fitting parameters for fractional flow calculations

Experiment	Fluid	k_{rwo}	S_{wi}	S_{or}	n_w	n_o
#1	2.86 cP low MW HPAM	0.0291	0.1	0.3	2.5	1.85
#2	11.75 cP medium high MW HPAM	0.0298	0.2	0.23	2.5	4.2
#3	12.6 cP super high MW HPAM	0.0292	0.093	0.37	2.5	4

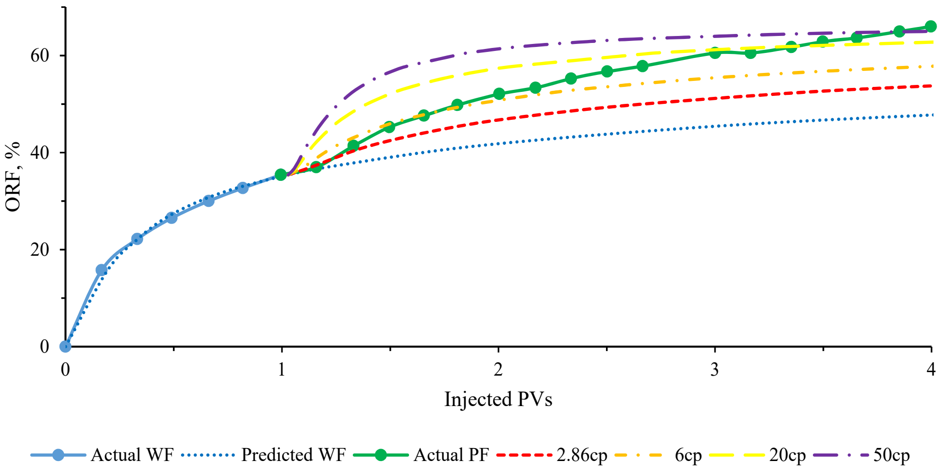

Fig. 5. Actual water and polymer floods versus fractional flow predictions for experiment #1 – 2.86 cP low molecular weight HPAM.

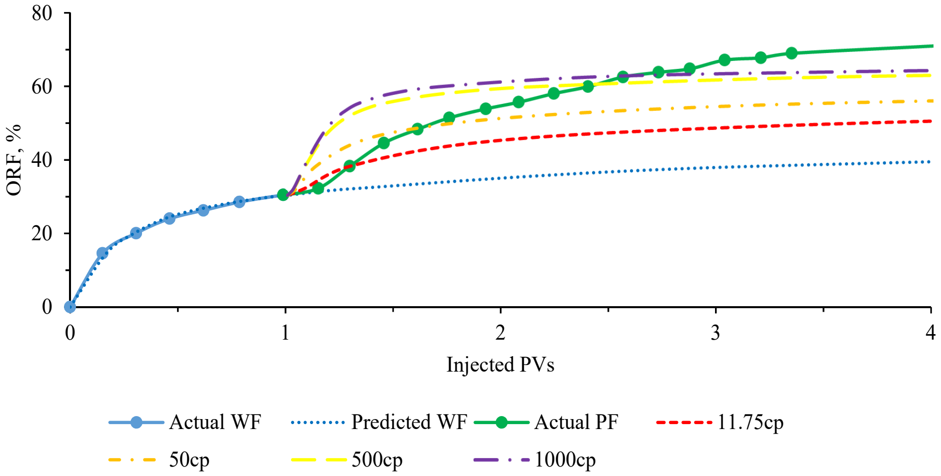

Fig. 6. Actual water and polymer floods versus fractional flow predictions for experiment #2 – 11.75 cP medium high molecular weight HPAM.

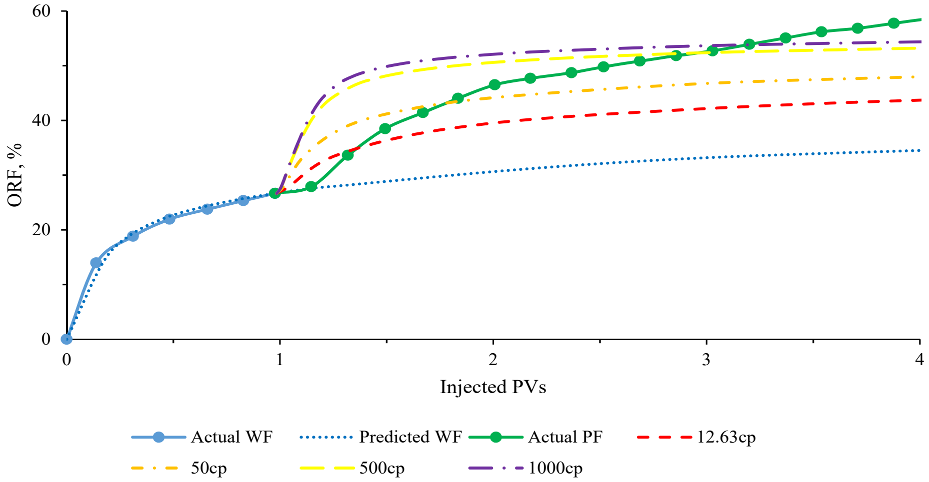

Fig. 7. Actual water and polymer floods versus fractional flow predictions for experiment #3 – 12.63 cP super high molecular weight HPAM.

For instance, Fig. 5 demonstrates that the polymer flooding results from the sand pack experiment using a 2.86 cP low molecular weight polymer solution significantly exceed the expected outcomes based on theoretical calculations (compare the green line with circles to the red dashed line). The same is true for the experiments conducted by using 11.75 cP medium high molecular weight polymer (Fig. 6) and 12.63 cP super high molecular weight polymer (Fig. 7) solutions.

The fact that the theoretical projections are below the actual polymer flood results (Figs. 5–7) can be explained by fluid-rock interactions which are not considered in the equations presented above. As seen in Fig. 5, matching the results of the 2.86 cP low molecular weight HPAM flooding requires the assumption of at least a 20 cP polymer solution. For medium, high, and super high molecular weight HPAM flooding, even the assumption of a 500 cP solution was insufficient to match the results of sand pack flooding experiments (Figs. 6–7 and Table 5).

Table 5. Comparison of polymer molecular weight, actual viscosity, and assumed viscosity for the fit by fractional flow calculations

Polymer molecular weight	Actual viscosity, cP	Viscosity required for adequate fit with fractional flow predictions, cP
Low	2.86	~20
Medium high	11.75	> 500
Very high	12.63	

This anomaly can be explained by the fact that higher molecular weight polymers provide resistance factors that are higher than those expected from viscosity measurements. This resistance factor effect is not expected to penetrate deep into the reservoir [18], and most likely increases with polymer molecular weight, as the high molecular weight component of polymer tends to plug pores. That is why for higher molecular weight polymers, as Table 5 shows, the assumption of much higher viscosity was required to fit the results of polymer floods by fractional flow calculations.

Considering the influence of the resistance factor effect on the outcome of the linear sand pack flooding experiment, it is important to compare different polymers not only by the actual ORF observed in lab conditions but also by the results of fractional flow calculations. The observed ORF in the lab can be overestimated due to fluid-rock interactions, highlighting the necessity of incorporating both methods for a more accurate assessment.

4. Conclusions

1. The viscosity values of 0.25 wt.% high molecular weight HPAM solutions in 250 g·L^{-1} brine ranged from 11.5 to 12.6 cP for both 10% and 30% hydrolysis degree polymers.
2. Injecting 3 PVs of HPAM solutions allowed an incremental increase in the oil recovery factor after the injection of 1 PV of water by 16–28%.
3. The assumption of much higher viscosity is required to achieve an adequate fit with fractional flow calculations for all experiments, especially those involving high molecular weight polymers. An explanation for this anomaly is the plugging of pores by high molecular weight components of polymer solutions, suggesting that the oil recovery factors from the linear sand pack flooding tests are most likely overestimated.
4. Another potential explanation for the observed anomaly is the reduction in permeability due to polymer filtration, which may be influenced by the very high salinity and hardness of the solution used. These conditions could potentially affect the solubility of the polymer. Future research should consider the possibility of solubility issues and explore their impact on permeability reduction and overall performance.

Acknowledgement

This work was funded by the Science Committee of the Ministry of Science and Higher Education of the Republic of Kazakhstan. Grant Number: AP09260574.

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