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Parameter Analysis of Polymer on Sandstone Reservoir in Indonesia: An Experimental Laboratory Study

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Abstract

Polymers are often used to increase oil recovery by improving sweeping efficiency. Screening was carried out as a first step in evaluating the test parameters of several polymers of the Hydrolized Polyacrylaamide (HPAM) type in fluid and sandstone reservoir rocks. The test was carried out using a reservoir fluid classified as light oil (35°API) and at a reservoir temperature (60°C).

There are 5 types of HPAM polymers, namely A1, F1, F2, F3 and P1. The test parameters carried out on these 5 types of polymer include compatibility test for formation water. The rheology polymer test includes concentration vs Tres, shear rate vs viscosity which aims to determine the type of polymer solution being tested is a non-Newtonian or pseudoplastic fluid group. Thermal stability test of polymer for 60 days to determine the stability of the polymer solution whether it is degraded or stable. Filtration testing with criteria FR value < 1.2, screen factor test and adsorption testing using the static method with a standard limit of adsorption value < 400 µg/gr and polymer injectivity test.

From these tests, scoring (range 0-100) was carried out to determine polymer candidates in polymer flooding testing. The F1 polymer candidate for the sandstone reservoir was obtained with a score of 82.25. From the results of the rheology test, the F1 polymer concentration was 2000 ppm. For thermal degradation for 60 days, the polymer F1 2000 ppm experienced a degradation of 15.5%. The results of the F1 2000 ppm polymer static adsorption test were 54.8 µg/gr. For the filtration ratio (FR) value of 1 and the injectivity test results (residual resistance factor / RRF) of 1.With the RRF = 1 value indicating rock permeability after injection of polymer F1 2000 ppm, it tends not to experience plugging due to injection of polymer solution

Keywords: Polymer, sandstone, rheology, injectivity

Introduction

The use of polymer solutions in the application of chemical EOR injection technology have a role in increasing oil recovery effort by improving oil mobility in porous media. The addition of the polymer solution is expected to increase the viscosity value of the displacement fluid so that it can form a "piston like" effect with the aim of increasing volumetric sweep efficiency of the light oil reservoir. (Sheng, 2010; Seright et al, 2008; Shah and Schechter, 1977)

The polymer screening and performance testing must be done before pilot scale implementation in the oil fields. The partially hydrolyzed polyacrylamide (HPAM) polymers were used in this study. There are several tests which have to be passed to make sure the HPAM polymer performance in reservoir condition meet the criteria which will improve the oil recovery of the mature fields. Several test which must be done were screening tests or rheology evaluation such as compatibility tests, viscosity vs. shear rate tests, thermal stability tests, filtration tests, and static adsorption tests. The injectivity tests and coreflooding test were also carried out to know the performance of the polymer injection into the native and/or synthetic core.

The purpose of this study is to investigate the performance of the HPAM polymer injection in increasing oil recovery in light oil reservoir.

Research Methodology

This research study begins to understand the rheological properties of the polymeric material and providing more insight about the adequacy of polymer HPAM from its behavior through porous media (reservoirs). HPAM concentration that were tested were at 500 – 3000 ppm. The material of HPAM was mixed in a injection water (see **Table 1** for injection water composition). The experiment consists of several tests conducted experimentally, started by testing compatibility, shear test, screen factor, filtration, adsorption, thermal degradation, scoring and injectivity (Poettman and Hause, 1978; Lemigas, 2008). All the tests were carried out at 60°C as the reservoir temperature.

- **Compatibility test**
  The solubility of HPAM with various concentrations were visually observed at both

room and 60°C temperature to investigate the phase solution, color changing, and precipitation.

- **Shear test**
  All the rheological experiments were performed on Brookfield DVIII with UL adaptor. For each test (viscosity vs concentration and viscosity vs shear rate), the polymer solutions were prepared with varying concentrations. Concentrations ranged from 500 – 3000 ppm of polymeric material in brine. The viscosity vs concentration of HPAM was measured using shear rate 7 rpm and the viscosity vs shear rate was measured using shear rate from 50 rpm to 250 rpm.
- **Screen Factor**
  Tests were carried out to determine the qualitative size of the polymer and to determine the viscoelastic behavior of the polymer solution (Sorbie, 1991). Viscoelastic is a characteristic that is viscous and elastic when it is deformed (Jouenne, S and Heurteux, 2017).
- **Filtration test**
  A filtration test was conducted to evaluate the polymer solution has free of aggregates which could lead to formation plugging. The measurement of filter test is pumped through 3 μm membrane with a differential pressure of 2 bars.
- **Adsorption test**
  The polymer solutions were prepared to conduct static adsorption test according to Recommended Practice (RP 63) using native core
- **Thermal degradation test**
  Tests were performed during 3 months at 60°C temperature under anaerobic conditions in sealed glass ampoules.
- **Injectivity test**
  HPAM injectivity test was run at concentration 2000 ppm, temperature of 60°C, and slow injection rates of 0.3 cc/min, 0.6 cc/min, and 1 cc/min.

Result and Discussion

Polymer screening on a laboratory scale is carried out to determine the characteristics of polymers in a reservoir. Recent popular material of polymer that assured to accommodate in oil fields is HPAM. HPAM has most often been used to achieve a more favorable mobility ratio and improve macroscopic sweep in chemical EOR by increasing viscosity of the water. When dissolved in fluid, the polymer solutions have a viscosity that depends on many aspects: concentration, molecular weight, temperature, and salinity (Lemigas, 2008). In this study, the investigation of polymer flood has been performed using sandstone reservoir.

The polymer compatibility test for injection water was carried out at room temperature and reservoir temperature of 60°C. The result of that test shown as **Table 2** which shown the good polymer solutions with clearly, no sediment for each of polymer concentrations

The rheological properties of the HPAM polymer solution were evaluated by measuring the apparent viscosity vs concentration and viscosity vs shear rate. This experiment is one of the most prominent screening of an injected chasing fluid during the chemical flooding process. **Figure 1** demonstrates variation shear rate from 7 rpm to 330 rpm was conducted on the viscosity of 1 concentrations each polymer at 60 °C temperature. This result presents HPAM is generally classified as a non-Newtonian fluid, because the viscosity changes when shear rate was applied. Thus, the type of fluid rheology is pseudo-plastic fluid. In this desired condition, pseudo-plastic fluid was known as shear thinning, in which viscosity decreases as shear rate increases.

The experiment result of viscosity vs concentration was demonstrated the viscosity increasing steadily with increasing polymer concentration at 60 °C temperature. This behavior greatly contributes to the shear thickening of the HPAM solution for when the polymer flows at a high shear rate in porous media.

Screen factor test was carried out to determine the quality of the polymer solution. Based on the results of the screen factor test shown in **Figure 2** concluded that higher polymer concentration indicates the polymer solution were long to flow. The equation were used to determine the screen factor (Sorbie, 1991) is:

$$SF = \frac{\mathrm{t(solution)\ (second)}}{\mathrm{t(solvent)\ (second)}}$$

The filtration test was performed to determine the polymer can flow through the rock pores and evaluating the effect of debris. **Figure 3** informs a volume plot graph against time of the polymer through the filter paper. Each of concentration solution was ensured that polymer hydration had been achieved. The value of the FR for F1 2000 ppm is 1, F2 2000 ppm is 1.2, F3 2500 ppm is 1.1, A1 1500 ppm is 1.02 and P1 2000 ppm is 1.29. This result rapidly indicates F1, F2, F3 and A1 are acceptable as it has no tendency to plug porous media in the reservoir because the requirement of the filtration ratio (FR) value was below 1.2. If the FR value's > 1.2 indicates an indication of polymer causing plugging in rock pores.

Static adsorption test is carried out using native core. Based on each polymer solution, the F1 polymer solution obtained has an adsorption value of 54.8 g/gr and can be seen for the distribution of adsorption on each polymer at **Figure 4**.

The laboratory thermal degradation test was conducted to investigate the remaining viscosity after aging as primary criteria chemicals EOR. F1 presented a good polymer candidate as it performed the remarkable viscosity decay during aging period at 60ºC temperature (see **Figure 5**). The viscosity of F1 2000 ppm maintains a constant value in the last 30 days, and the rest after 3 months of aging period, it increased slowly from 22 cP to 27 cP in the first 20 days. The viscosity of F2 2000 ppm maintains a constant value in the last 30 days, and the rest after 3 months of aging period, it decreases slowly from 20 cP to 14 cP with a viscosity retention percentage of 20%. Thus, more effective preparations should be developed to improve their thermal degradation.

Based on the results of thermal stability test, scoring is carried out on several test parameters and characteristics of the polymer. In Table 3 shows the F1 polymer has a score of 86.5 assuming the F1 polymer price is 3$/kg, the pore volume injected into the reservoir is 0.3.

To understand the performance of the polymer to the rocks, injectivity tests were carried out. The characteristic of the rocks that were used is sandstone native core plugs with permeability range of 1500 to 2500 mD and average porosity of 0.26.

The injectivity tests were carried out using step-up rate of 0.1, 0.3, 0.6 and 1 cc/min. The results of the polymer injectivity can be seen in **Figure 7**. Based on the test results, the polymer has Residual Resistance Factor (RRF) average value 1 (one) which means that the permeability of the core plugs after polymer injection were not changing as much after polymer injection.

Conclusion

The test results for all of the parameters are already meet the criteria for polymer screening as chemical EOR. Based on the polymer screening test and polymer performance test that have been done, polymer concentration (F1) of 2000 ppm is suitable for polymer injection with rule of thumb polymer viscosity should be four times higher than oil viscosity (6.988 cSt) which gives about 22.71 cP. Accordingly, then the conclusion obtained from this study is F1 2000 ppm was selected. F1 with concentration 2000 ppm was resistant in reservoir condition, it shown in thermal stability test (**Figure 5)**. Also the polymer concentration (F1) had the best score of the scoring parameters shown in **Table 3** which gives about 86.5 of 100**.** The results of injectivity test were indicated the rate of injectivity affected the RRF value. Based on these results, this polymer has potential to be implemented on the pilot scale on light oil reservoir.

References

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Table 1 Brine/water injection composition

Parameter	Result	
ANION		
Klorida	8748	mg/L
Bikarbonat	1970	mg/L
Sulfat	0.16	mg/L
Karbonat	98	mg/L
Hidroksida	0	mg/L
KATION		
Natrium	6150	mg/L
Kalsium	80.2	mg/L
Magnesium	134.2	mg/L
Ferum	0	mg/L
Barium	0	mg/L
Total Dissolve Solid	17550	mg/L

Table 2 Aqueous Stability Polymer

Polymer	Aqueous Stability
F1	Clear, no sediment
F2	Clear, no sediment
F3	Clear, no sediment
A1	Clear, no sediment
P1	Clear, no sediment

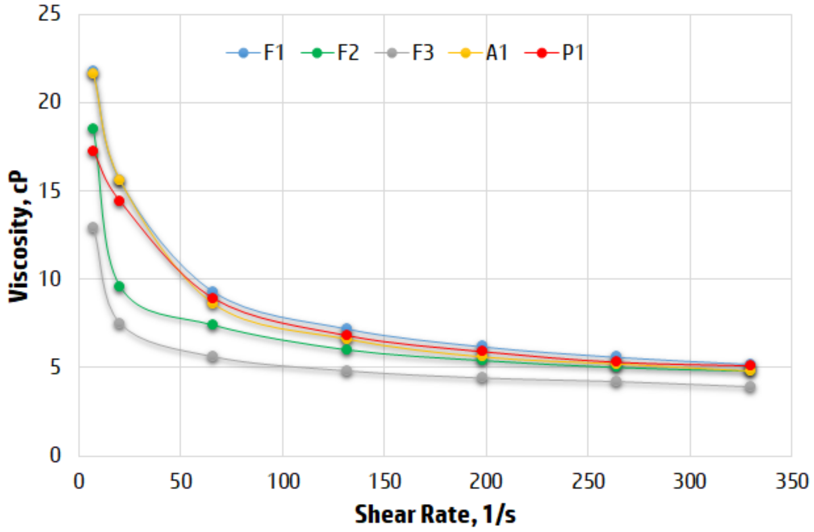

Figure 1 Effect of polymer on shear rate test results

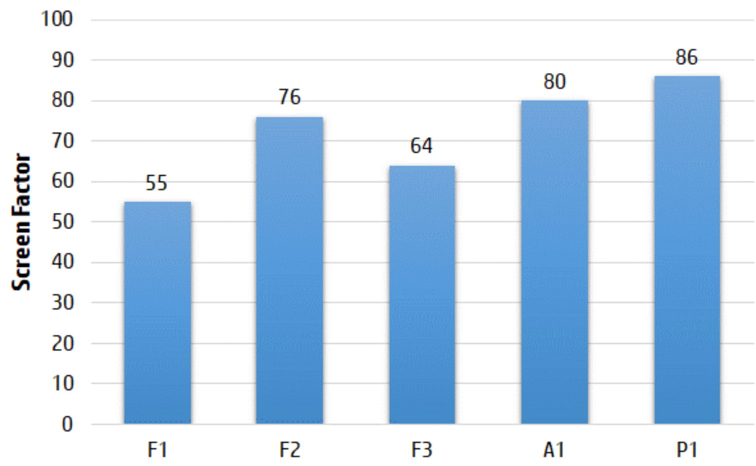

Figure 2 Screen factor test results

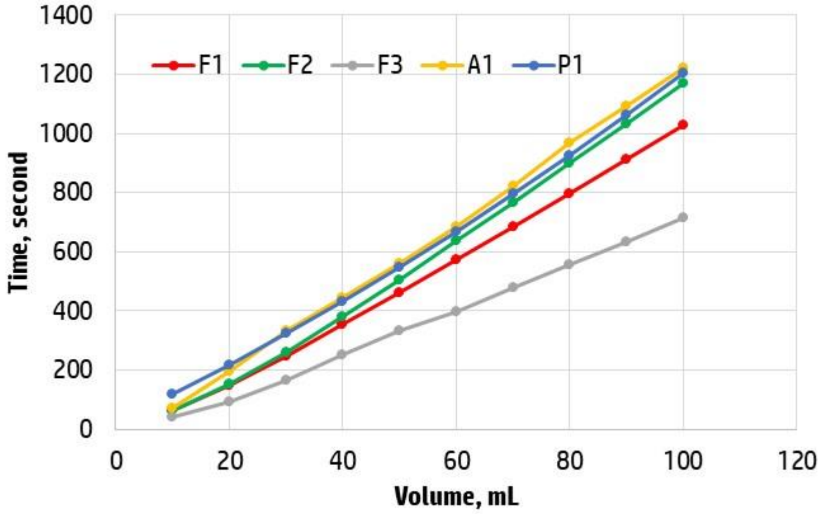

Figure 3 Filter test using 3 µm membrane results

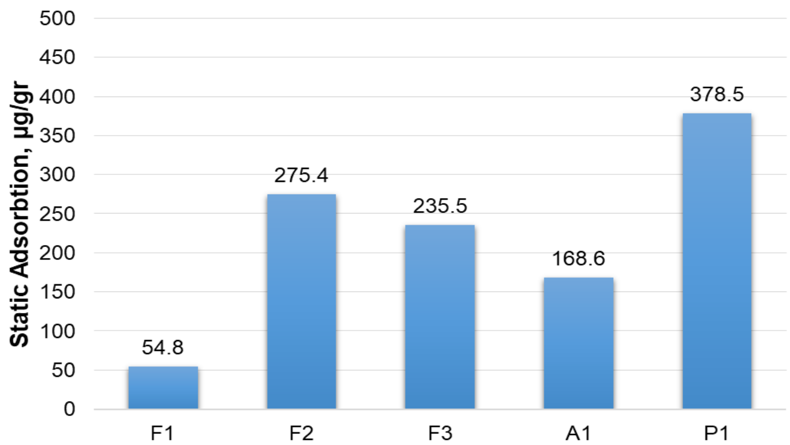

Figure 4 Adsorption static on native core results

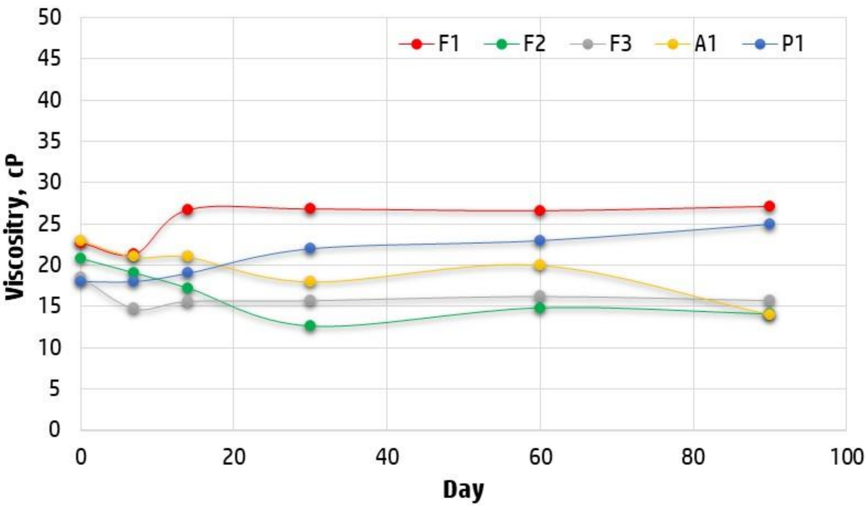

Figure 5 Thermal degradation test results

Table 3 Scoring parameter of polymer

PARAMETER	CATEGORY	SCORE	PERCENTAGE	F1 Test Result	F1 Score	F2 Test Result	F2 Score	F3 Test Result	F3 Score	A1 Test Result	A1 Score	P1 Test Result	P1 Score
Price (US$/kg)	< 3	20	20	3	15	3	15	3	15	4	10	4	10
	3 - 4		15										
	4 - 5		10										
	> 5		5										
PV Injected, PV	≤ 0.3	10	10	0.3	10	0.3	10	0.3	10	0.3	10	0.3	10
	0.3 - 0.5		7.5										
	0.5 - 0.8		5										
	> 0.8		2.5										
Concentration, %	≤ 0.15	15	15	0.2	12	0.25	9	0.2	12	0.15	15	0.2	12
	0.15 - 0.2		12										
	0.2 - 0.3		9										
	0.3 - 0.5		6										
	> 0.5		3										
Screen Factor	≤ 50	10	10	55	7.5	76	2.5	64	5	80	2.5	86	2.5
	50 - 60		7.5										
	60 - 75		5										
	75 - 100		2.5										
FR	<=1	10	10	1	10	1.2	5	1.1	7.5	1.02	10	1.29	5
	1.1 - 1.2		7.5										
	1.2 - 1.3		5										
	> 1.3		2.5										
Static Absorbtion, µg/g	< 100	10	10	54.8	10	275.4	6	235.3	6	167	8	378.5	4
	100 - 200		8										
	200 - 300		6										
	300 - 400		4										
	> 400		0										
Molecule Weight, Million Dalton	<10	10	10	8	10	12	8	20	4	15	6	15	6
	10 - 15		8										
	15 - 20		6										
	20 - 25		4										
	> 25		2										
Thermal Degradation (%)	0 - 10	15	15	15.5	12	14.05	12	16	12	38.6	9	35.6	9
	10 - 20		12										
	20 - 40		9										
	40 - 50		6										
	> 50		3										
		100			86.5		67.5		71.5		70.5		58.5

Table 4. Native core characteristic

Core	D (inch)	L (inch)	W (gr)	Φ	Ka (mD)
1	1.5	6.0	316.0	0.28	764.0

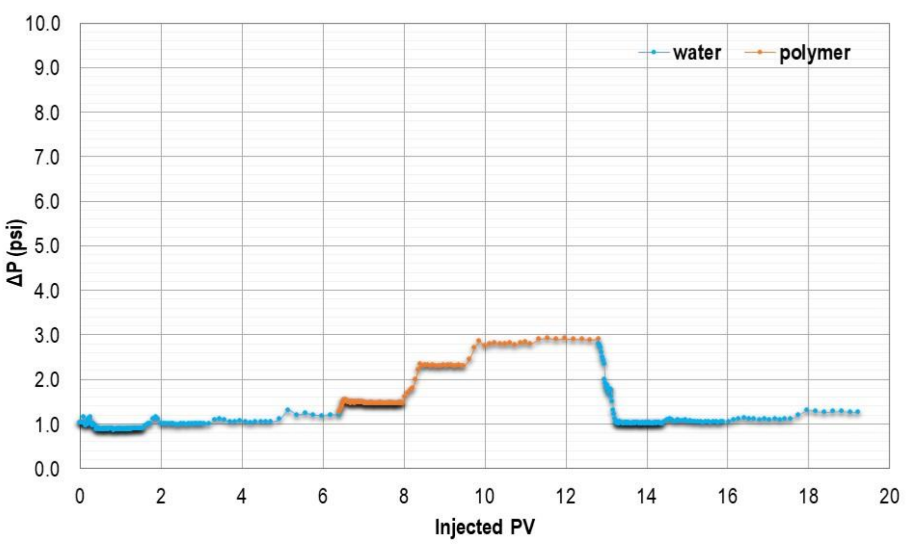

Figure 6. ΔP distribution vs injected pore volume

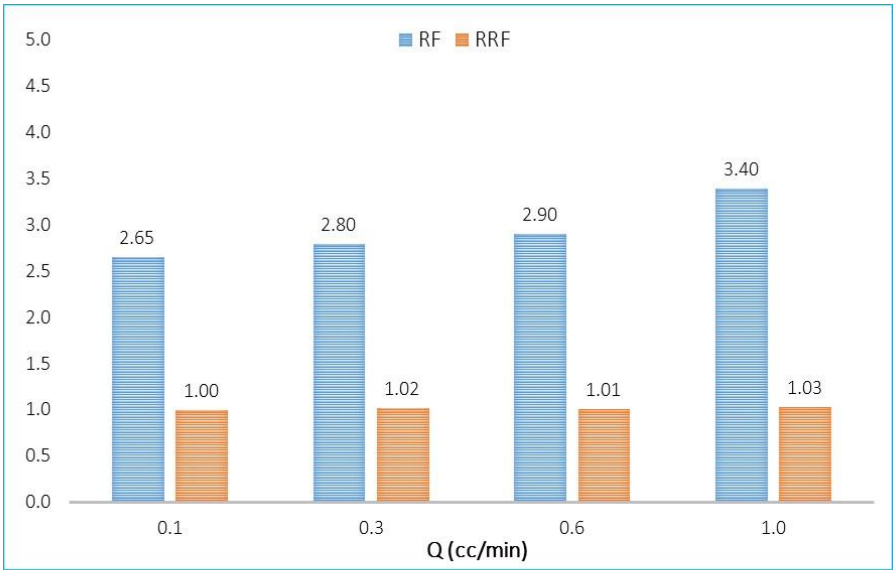

Figure 7. Injectivity test result (RF & RRF)