PROCEEDINGS
JOINT CONVENTION BANDUNG (JCB) 2021
November 23rd – 25th 2021

Investigation of Polymer Flood Performance in Light Oil Reservoir: Laboratory Case Study

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Abstract

The use of polymer solutions in the application of chemical EOR injection technology has 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 the volumetric sweep efficiency of the light oil reservoir.

The polymer used in this study was HPAM with using 3 concentrations, namely 500 ppm, 1000 ppm, and 1500 ppm conducted at temperature of 70 °C. The rheology test of the polymer included concentration vs temperature, and shear rate vs viscosity. Thermal stability testing of polymer for 7, 14, 30, 60, and 90 days at 70 °C was done to determine the stability of the polymer solution. Filtration testing was conducted with the criteria of FR <1.2. The static adsorption test has been done with the standard limit of adsorption value <400 µg / gr. Polymer injectivity test using 3 variations of injection rates and coreflooding test were conducted to determine the reduction of Sor in reservoirs due to polymer displacement.

From the polymer testing stage, it was found that HPAM polymers at 3 concentrations were compatible with the injection. This is indicated with the clear solution for 3 concentrations at room temperature and at 70 °C. The rheology test results showed that the polymer solution with 3 concentrations was decreased in viscosity with the addition of the shear rate value. In the thermal stability test, the viscosity value of the HPAM with 500 ppm was relatively constant. The value of the FR for HPAM 500 ppm is 1.1, HPAM 1000 ppm is 1.07 and HPAM is 1500 ppm is 1.03. The results of the static adsorption test showed the lowest HPAM value of 500 ppm was 156 µg/gr. In the injectivity test results, the resistance residual factor (RRF) values at injection rates of 0.3, 0.6, and 1 cc/min were 0.8, 1.04, and 1.12. With the RRF value close to 1, indicating that after injection of 500 ppm of HPAM tended to not experience plugging. Polymer flooding shows the oil recovery factor (RF) of water injection is 39% OOIP, and RF after polymer injection with 0.35 PV with flush water is 13.5% OOIP or 22% Sor.

By knowing the behavior of HPAM polymer with various concentration to be used for chemical EOR injection, it could provide advantages for future implementation in the light oil reservoir in Indonesia.

Keywords: filtration, injectivity, light oil, polymer flooding, rheology.

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) polymer 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, 1000 and 1500 ppm. The material of HPAM was mixed in a brine water that has a designated salinity of roughly 2800 ppm (see **Table 1** for brine water composition). The experiment consists of several tests, started by testing compatibility, shear test, filtration, adsorption, thermal degradation, injectivity, and coreflooding (Poettman and Hause, 1978; Lemigas, 2008). All the tests were carried out at 70°C as the light oil reservoir temperature.

- **Compatibility test**
  The solubility of HPAM with various concentrations were visually observed at both room and 70 °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 ppm to 1500 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.
- **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).
- **Thermal degradation test**
  Tests were performed during 3 months at 70 °C temperature under anaerobic conditions in sealed glass ampoules.
- **Injectivity test**
  HPAM injectivity test was run at concentration 500 ppm, temperature of 70 °C, and slow injection rates of 0.3 cc/min, 0.6 cc/min, and 1 cc/min.
- **Coreflooding test**
  During the flooding experiment, the injection rate of the displacing fluids was controlled at 0.3 cc/min with polymer injection 0.35 PV.

Result and Discussion

Polymer flooding is intentionally conducted to reduce relative permeability of water in the reservoir, therefore can improve the production of oil, as well as to enlarge the swept volume of the 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 light crude oil. The characteristic of light crude oil has been shown in **Table 2**. Based on the result, the °API of crude oil was approaching 28 and this has to do with designing the compatible of HPAM type. Besides, the water analysis demonstrates roughly 2800 ppm salinity brine.

The compatibility of the polymer solution was first conducted at both room and 70 °C temperature. This presents in **Figure 1**, with the good result of the clear phase solution, the color of the solution was not changing, and no precipitation, which is essential to obtain distinctly sufficient chemicals.

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 2** demonstrates variation shear rate from 50 rpm to 250 rpm was conducted on the viscosity of 3 concentrations polymer at 70 °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 70 °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.

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 with 3 concentrations. Each of concentration solution was ensured that polymer hydration had been achieved. The value of the FR for HPAM 500 ppm is 1.1, HPAM 1000 ppm is 1.07, and HPAM 1500 ppm is 1.03. This result rapidly indicates HPAM 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.

The thermal degradation test was conducted during 3 months at 70 °C temperature to investigate the remaining viscosity of HPAM. The result is presented in **Figure 4**. The viscosity of 500 ppm maintains a constant value in the last 30 days, and the rest after 3 months of aging period, it decreases slowly from 10 cP to 7 cP with a viscosity retention percentage of 30%. Comparatively, the remaining viscosity of the two concentrations left was demonstrated at 1000 ppm and 1500 ppm with increasing the number viscosity due to the changing of the colloidal system solution, likely through hydrolysis reaction. Thus, more effective preparations should be developed to improve their thermal degradation.

To understand the performance of the polymer to the rocks, injectivity and coreflooding 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 0.3, 0.6 and 1 cc/min for every concentration of polymer solution. The results of the polymer injectivity can be seen in **Figure 5**. From the test results, the polymer has Residual Resistance Factor (RRF) value near to 1 (one) which means that the permeability of the core plugs after polymer injection were not changing as much and also indicates plugging did not happen after polymer injection.

From coreflooding test result, recovery factor (RF) after waterflood is at 7.2 cc or 38.7 % (OOIP) and Sor after waterflood is at 11.4 cc (61.3% OOIP). With injecting 0.35 PV polymer, recovery of oil is at 2.4 cc or 13% OOIP. This result shows that by injecting polymer after waterflood, additional oil recovery can be gained about 13.5% OOIP or about 22% ROIP **(see Figure 6).**

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 of 1000 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 26 cP and from coreflood result which gives about 22% ROIP. From these results, this polymer has potential to be implemented on the pilot scale on light oil reservoir.

References

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Acknowledgements

Thank you to the Exploitation Department in R&D Center for Oil and Gas Technology “LEMIGAS” for the technical and non-technical supports for this research.

Table 1 Brine water composition

	Unit	Result
ANION		
Chloride	mg/L	709.06
Bicarbonate	mg/L	1037.31
Sulfate	mg/L	0.07
Carbonate	mg/L	120.02
Hydroxide	mg/L	0.00
KATION		
Sodium	mg/L	891.1
Calcium	mg/L	20.04
Magnesium	mg/L	15.19
Iron	mg/L	0.00
Barium	mg/L	0.00
Total Dissolve Solid	mg/L	2792.81
pH		8.71

Table 2 Characteristic of light crude oil

Determination	**Unit**	**Result**	**Method**
Density at 15◦C	g/cm3	0.8792	ASTM D. 5002
◦API Gravity	-	27.5588	ASTM D. 5002
Kin. Viscosity at 70◦C	cSt	6.9884	ASTM D. 445
Pour Point	◦C	45	ASTM S. 5853
Asphaltene	%wt	0.374	IP. 143
Total Acid Number	mg KOH/g	0.0156	ASTM D. 664
Saturated	%wt	52.20	Column Chromatography
Aromatic	%wt	16.04	Column Chromatography

Figure 1
Compatibility polymer solution at room temperature (a) and 70 °C (b)

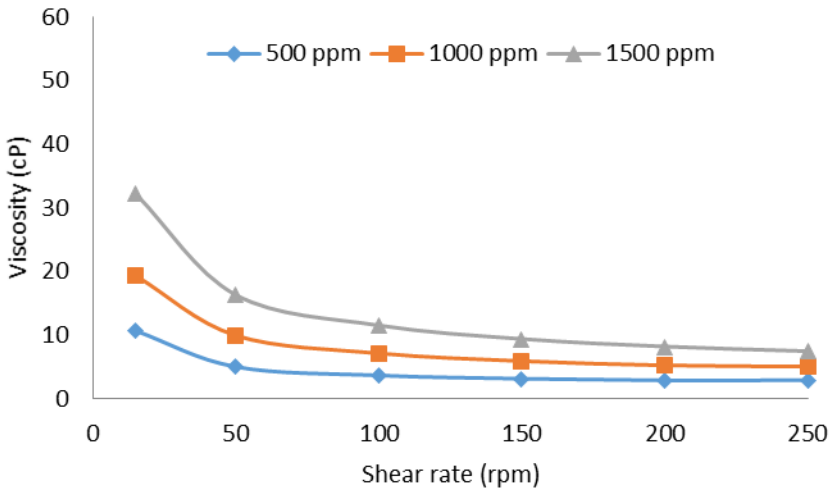

Figure 2
Effect of polymer on shear rate test results

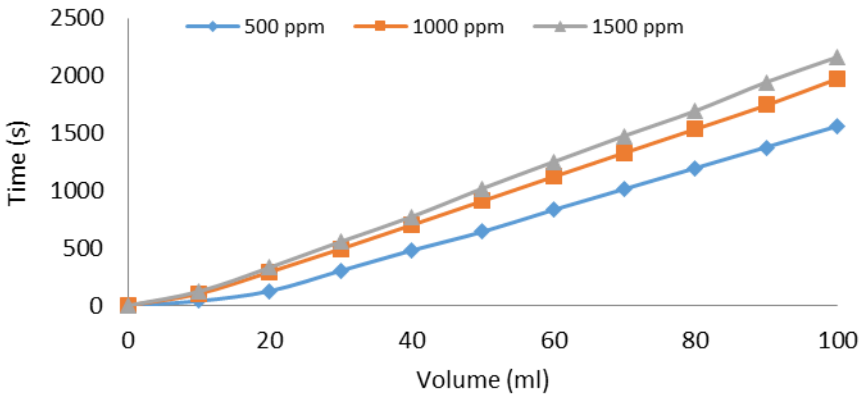

Figure 3
Filter test using 3 µm membrane results

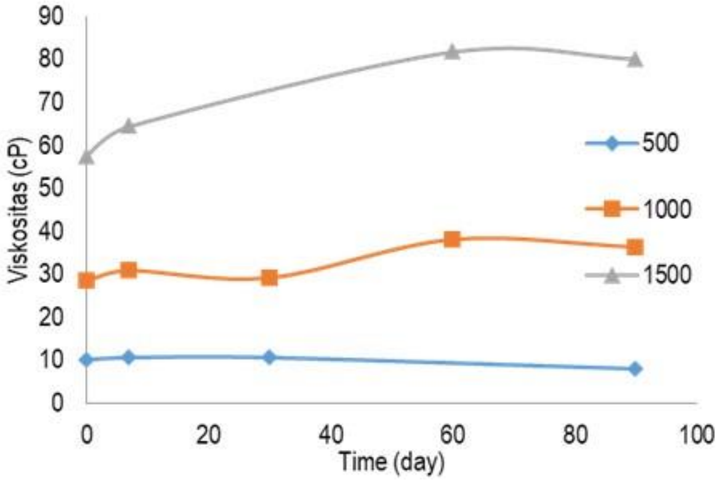

Figure 4
Thermal degradation test results

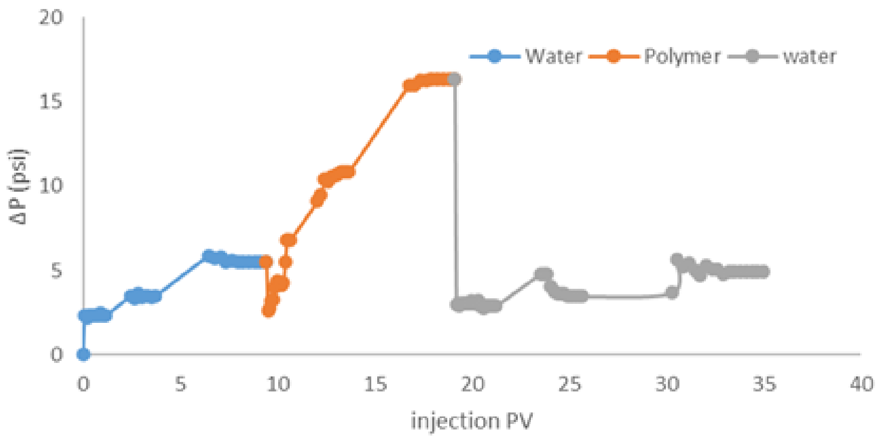

Figure 5
Injectivity test results

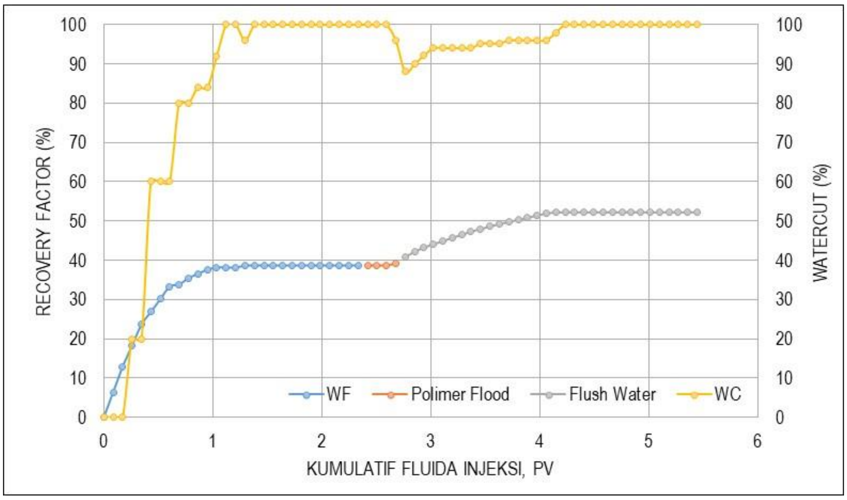

Figure 6
Coreflooding test results