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From characteristics to performance: a laboratory study of surfactant-polymer for CEOR

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Abstract

Together with signs of renaissance, Oil and Gas sector faces serious challenges in both finding new reserves and sustaining production. Aside from the exploration, arresting production decline from existing wells seems more visible shortly.

Enhanced oil recovery (EOR) is the major focus in Indonesia where the majority of oil fields are on the declining stage. "K" field in South Sumatera is one amongst others that are included as the priority of EOR development which aims to sustain the production. After the screening process, chemical injection is the most feasible method to be implemented. Surfactant-polymer is considered effective in both lowering interfacial tension (IFT) and improving sweep efficiency.

Laboratory measurements were conducted to test numerous formulations of surfactants ranging from the concentration of 0.05% to 1 %. The best surfactant is then selected to be tested in a surfactant-polymer solution using a polymer with a concentration of 500 ppm to 2000 ppm. The interfacial tension between oil and surfactant-polymer was measured to understand the performance of formulations. The rheological test was performed to measure the viscosity of formulations. The thermal stability of surfactant-polymer at reservoir temperature (60^{o}C) was also observed in a certain period. To ascertain selected formulations' capability on producing incremental oil, the coreflood experiment was carried out. The high percentage of recovered residual oil (%Sor) is the key parameter indicating successful chemical injection.

This paper describes the process of selecting the most favorable surfactant-polymer formulation that can serve as a reference to mature oil fields in Indonesia. In particular, it demonstrates the necessity of formulating the right concentration of surfactant and polymer to yield a stable formulation.

Introduction

Chemical EOR is one of the processes carried out to improve oil recovery mainly by injecting chemical systems that contain surface-active agents. In the process, surfactant injection is usually followed by the addition of aqueous solution as a displacing fluid. Polymer solutions are usually added to the aqueous solution as a mobility control agent [1].

The addition of the surfactant solution will reduce the interfacial tension between crude oil and formation water, decrease the capillary force and will cause the oil to become mobile. With the injection of polymer and chase water, oil bank will be swept efficiently and will significantly increase oil recovery [2].

The addition of polymer increases the viscosity of the injected water and reduce the permeability of the porous media to reduce the mobility ratio between displacing fluid and displaced fluid [3]. That mechanism then reduces viscous fingering and improves sweep efficiency [4].

In this study, the research begins by selecting the best surfactant concentration to be mixed with the polymer. The coreflooding is then carried out to determine the additional oil recovery that can be obtained.

Research Methodology

This study consists of several experiments conducted on surfactant and surfactant-polymer solutions. Firstly, experiments on palm oil-based surfactant solutions (Oleyl Glycerine PEG-400) were carried out to select the most favorable surfactant solution. After that, the selected surfactant was formulated into surfactant-polymer solutions by mixing the surfactant with polymer (FP3630S). The SP solution then injected into a core to determine the additional oil recovery. Below is the order of experiments carried out in the laboratory.

1) Screening of surfactant solutions

This screening was done to select the best surfactant concentration based on its visual compatibility and interfacial tension value. Solutions at the surfactant concentration of 0.05%, 0.1%, 0.3%, 0.5%, and 1% were tested for its compatibility to assess the solubility of the surfactant and injection water used visually. After that, the interfacial tension measurement was conducted to determine the optimal concentration of surfactant used using the spinning drop interfacial tensiometer. The selected solution then tested for its thermal stability to see the effect of temperature on the

interfacial tension value at the reservoir temperature (60°C) for 90 days (Day-0, day-7, day-14, day-30, day-60, day-90). Finally, the spontaneous imbibition test was performed to assess the ability of the selected surfactant solution to produce oil under static condition.

2) Screening of surfactant-polymer solutions

The surfactant solution that has been selected through the screening of surfactant was then formulated with polymer at concentrations of 500 ppm, 1000 ppm, 1500 ppm, and 2000 ppm to form surfactant-polymer solution (SP). Firstly, the compatibility test was carried out to see the solution's solubility. After that, the interfacial tension value of each solution was measured to select solutions that fit the required criteria. Finally, the thermal stability test was performed to assess the stability of the SP solution under the reservoir temperature (60°C) for 90 days (Day-0, day-7, day-14, day-30, day-60, day-90).

3) Surfactant-polymer coreflooding

The previously tested surfactant-polymer solution then injected into the Berea core. Firstly, the core used was measured, weighed, vacuumed, water-saturated and inserted into the core holder before it was saturated with oil and flooded. After the core was saturated, the water injection process was carried out to simulate the process of water flooding. Finally, the selected surfactant-polymer solution was injected to determine incremental oil recovery.

Result and Discussion

This laboratory study was conducted using K field reservoir fluids which characteristics can be seen in Table 1 below.

Table 1: K field reservoir fluid characteristics

Parameter	Value
Ca^{++}	80.16 ppm
Mg^{++}	133.68 ppm
Cl^{-}/ Salinity	8745.07/ 17048.99 ppm
Injct. Water Viscosity	1.1 Cp
Injct. Water Density	1.0196 gr/cc
API°	33.8
Oil Viscosity	2.98 Cp
Oil Density	0.8557

It can be seen that some of the limitations raised by Taber et al. (1997) are met, namely the content of divalent ions (Ca^{++} and Mg^{++}) below 500 ppm and the salinity below 20,000 ppm [5]. Based on the chemical injection selection criteria by Aladasani and Bai (2010), the type of formation that is recommended for chemical injection is sandstone with intermediate oil [6].

1) Surfactant solutions screening result

The surfactant used was formulated into concentrations of 0.05%, 0.1%, 0.3%, 0.5% and 1%. Those solutions were tested for their compatibility and measured to determine their interfacial tension. Figure 1 and Table 2 show the result of the compatibility test carried out on five surfactant solutions. Based on the compatibility test, the addition of surfactant concentration affects the visual compatibility which results in the range of compatibility ranging from clear to milky. The solution is considered stable if the surfactant and water used dissolve perfectly [7], [8].

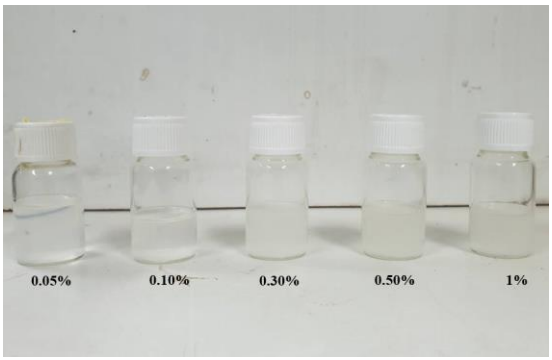

Figure 1: Visual compatibility of five surfactant concentrations

Table 2 below is the range of compatibility based on visual interpretation.

Table 2: Compatibility range of surfactant solutions

Conc.	Compatibility
0.05%	Clear, soluble
0.10%	Clear, soluble
0.30%	Slightly Milky, soluble
0.50%	Slightly Milky, soluble
1%	Milky, precipitate

After the compatibility test, the research was then continued with the interfacial tension measurement. As shown in Table 3, the lowest interfacial tension value is obtained through the use of 0.3% surfactant concentration. The addition of surfactant concentration above 0.3% results on the increase of interfacial tension value which means that the addition of surfactant concentration after its critical concentration does not affect the interfacial tension value obtained. Through those tests, the surfactant solution at the concentration of 0.3% is chosen for use in further tests.

Table 3: Interfacial tension value of five surfactant concentrations

Concentration	IFT (dyne/cm)
0.05%	5.11E-01
0.10%	1.34E-02
0.30%	2.08E-03
0.50%	1.85E-02
1%	4.53E-02

The thermal stability test was carried out within a measurement period of three months (Day-0,7,14,30,60,90) at the reservoir temperature (60ºC) using the selected 0.3% surfactant solution. As shown in Table 4, the measured surfactant solution gives stable values below 1.00E-02 dyne/cm for the measurement in three months.

Table 4: Thermal stability test result on 0.3% surfactant solution

Day	IFT (dyne/cm)
0	2.08E-03
7	2.16E-03
14	2.74E-03
30	4.87E-03
60	1.08E-03
90	3.63E-03

The spontaneous imbibition test was carried out at 60ºC using formation water and 0.3% surfactant solution. Figure 2 shows the result of oil recovery in which the formation water and surfactant solution produce 11.31% and 78.07% oil respectively. Through the result of spontaneous imbibition, it can be concluded that the 0.3% surfactant solution can produce oil under static condition.

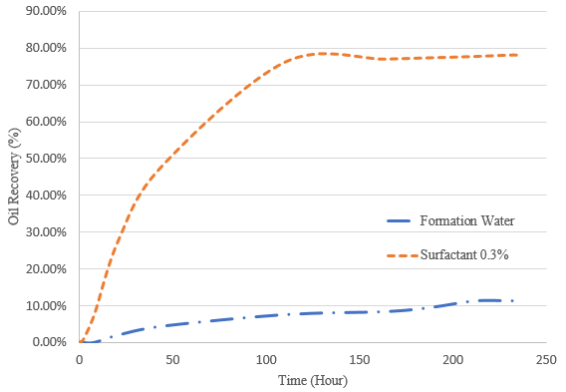

Figure 2: The result of spontaneous imbibition on 0.3% surfactant solution and formation water

2) Surfactant-polymer screening result

The polymer product used in this research is polyacrylamide (FP3630S). The surfactant at a concentration of 0.3% was formulated with polymer at concentrations of 500 ppm, 1000

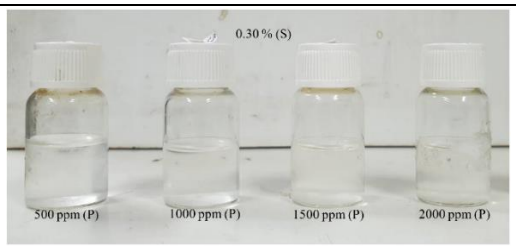

Figure 3: Visual compatibility of four surfactant-polymer (SP) solutions

Table 5 below is the range of compatibility based on visual interpretation.

Table 5: Compatibility range of SP solutions

	Surfactant Conc.
Polymer Conc.	0.30%
500 ppm	Slightly Milky
1000 ppm	Slightly Milky
1500 ppm	Slightly Milky
2000 ppm	Slightly Milky

ppm, 1500 ppm, and 2000 ppm to form four surfactant-polymer solutions. The compatibility test of the surfactant-polymer solution was conducted to determine the effect of polymer concentration addition on the compatibility of the surfactant-polymer solution. Figure 3 and Table 5 above show the result of the compatibility test of SP solutions where the addition of polymer concentrations (500 ppm – 2000 ppm) does not affect the appearance of solutions.

Table 6: Interfacial tension and viscosity measurement result on four surfactant-polymer solutions

Polymer Conc.	Surfactant Conc. 0.30%	
	IFT (dyne/cm)	Viscosity (cp)
500 ppm (SP 1)	3.95E-03	3.81
1000 ppm (SP 2)	5.36E-03	6.89
1500 ppm (SP 3)	5.16E-02	12.23
2000 ppm (SP 4)	9.80E-02	19.68

Table 7: Thermal stability test result on selected surfactant-polymer solution (0.3% S + 1000 ppm P)

	0.3% S + 1000 ppm P	
Day	IFT (dyne/cm)	Viscosity (Cp)
0	5.36E-03	7.25
7	3.57E-03	5.71
14	5.60E-03	4.33
30	4.86E-03	9.28
60	2.55E-03	7.39
90	2.10E-03	7.05

Table 6 above shows the interfacial tension and viscosity of measured surfactant-polymer solutions. The measurement of SP 1 and SP 2 result on the interfacial tension value below 1.00E-02 dyne/cm while SP 3 and SP 4 has the value above 1.00E-02 dyne/cm. As seen in Table 6, the addition of polymer concentration increases the viscosity of solutions gradually. The SP chosen for use in subsequent study is SP2 where the solution has an interfacial tension value below 1.00E-02 dyne/cm and a viscosity value above the formation water and oil. Although the SP1 solution also has a viscosity above water and oil viscosity, the solution chosen is SP2 because it is based on consideration of possible polymer degradation.

Through the thermal stability test of the surfactant-polymer solution, the stability of the SP solution can be assessed. As shown in table 7, The SP 2 solution has a stable interfacial tension value below 1.00E-02 dyne/cm and fluctuating viscosity but remains above the viscosity of water and oil.

3) Surfactant-polymer coreflooding result

After the surfactant-polymer screening, SP2 solution is chosen to be used in coreflooding. Figure 4 illustrates the process of coreflooding which has been carried out where the process was started by water injection and followed by the injection of 1 %PV surfactant-polymer solution. The process was then closed with chase water injection.

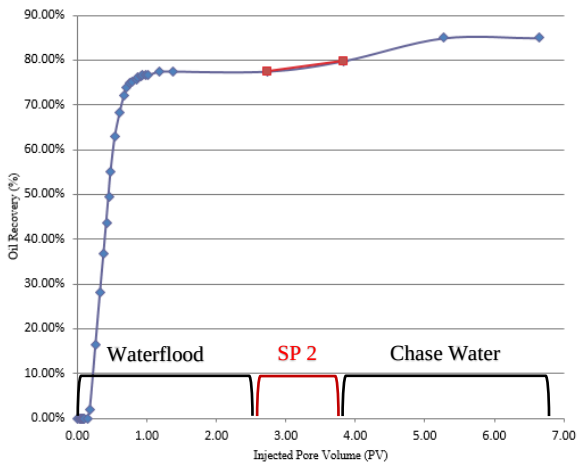

Figure 4: The result of surfactant-polymer (0.3% S + 1000 ppm P) core flooding

Table 8: Core properties and flooding result

PV (cc)	39.48
IOIP (cc)	21.8
Soi	0.5521
RF Waterflood (%Soi)	77.52
Sor	0.2248
RF SP (%Soi/ %Sor)	7.43/ 33.06

Table 8 shows the result of coreflooding in which the water injection yields 77.52 %Soi oil recovery or as much as 16.9 cc of oil. After that, the SP injection results in an incremental oil recovery of 7.43 %Soi/ 33.06 %Sor or as much as 1.62 cc of oil.

Conclusion

The main objective of this research is to study the performance of surfactant-polymer solutions. In this study, a surfactant-polymer solution with a surfactant concentration of 0.3% and a polymer of 1000 ppm (SP2) has been selected and its ability to produce incremental oil has been demonstrated by the coreflooding process. It can be concluded that the SP2 solution can produce incremental oil with the oil recovery of 33.06 %Sor and this result indicates that the solution has a fairly good performance so it is recommended for further studies. It should be noted that this research is far from perfect and needs to be added with several tests such as Filtration test, adsorption test, and flooding scheme optimization.

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