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SURFACTANTS EVALUATION FOR CHEMICAL FLOODING-ENHANCED OIL RECOVERY: COMPREHENSIVE SCREENING WITH LABORATORY TESTS

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Abstract

Laboratory tests using surfactants with several concentration and salinity variations have been carried out to determine the optimum performance of surfactants in increasing oil recovery. To meet the suitability of a surfactant, a comprehensive screening laboratory analysis is needed in its selection. In this test, each surfactant with concentrations of 0.1%, 0.3%, 0.5%, and 1%, respectively, was mixed with brine in the salinity range of 10,000 - 20,000 ppm. Seven tests were carried out in the selection process. The test analyses several parameters, namely compatibility, interfacial tension, thermal stability, phase behavior, filtration, and imbibition. The results of several tests from surfactant A, B, and C analysis showed that surfactant A obtained optimal results in testing interfacial tension with a concentration of 0.5% and salinity of 10,000 ppm. Then with thermal stability testing, stable interfacial tension results were obtained on surfactant A with a concentration of 0.3% and salinity of 10,000 ppm. As well as from spontaneous imbibition testing, the best recovery factor results were obtained with a value of 72.04% using type A surfactants with a concentration of 0.5 and salinity of 18,000 ppm. In this spontaneous imbibition test, it can be used as the final selection of surfactant with the optimum performance.

Keywords: Chemical enhanced oil recovery, Recovery factor, Surfactant screening

1. Introduction

Most of the fossil fuels consumed in Indonesia are sourced from crude oil. However, the increasing demand for crude oil is not accompanied by an increase in oil production. Since the year of 2000, oil production has decreased rapidly. Data and Information Centre of ESDM [1] stated, since national oil demand exceeds its supply capacity, Indonesia then became a net oil importing country in 2004. Furthermore, the share of imported oil (crude oil and fuel products) continues to increase due to production of national crude oil that continues to decline and there is no additional capacity refinery to produce fuel [1]. To meet the ever-increasing demand for oil, various efforts are believed to be able to rapidly increase oil production. Examples of such efforts are drilling new wells, infill drilling, well stimulation, and others.

The decline in oil production in Indonesia also shows the fact that most of the existing oil fields are mature fields. Declining production is the most characteristic of the mature field. Most of the existing mature fields are generated by primary recovery (internal energy is naturally present in the reservoir) and secondary recovery (injection of water or gas to maintain pressure). When these two methods are applied, there will always be a numerous amount of non-recoverable oil in the reservoir. This oil that cannot be produced is referred to as residual oil. Generally, residual oil is in the form of isolated or trapped oil. Enhanced Oil Recovery (EOR) procedure is the method that can produce this residual oil. In the EOR process, specific chemicals or gases are injected, and thermal energy is used to remove any remaining oil. By altering the fluid forces, the injected fluids increase overall oil displacement efficiency and mobilize and produce trapped oil [2]. In tertiary processes, mechanisms for higher recovery include interactions between injected fluid and oil, for instance, oil swelling, decreased oil viscosity, and changes in wettability are all consequences [3]. The most promising EOR approach is chemical EOR, which is non-thermal and has higher efficiency, is technically and economically feasible, and has affordable capital expenses. [4]. Chemical EOR (CEOR) involves the injection of a specific fluid that will improve the recovery of the oil with respect to its phase behaviour properties by lowering the interfacial tension, for example by using surfactants [5]. The two primary oil displacement methods in surfactant injection are lowering the interfacial tension (IFT) between the displacing fluid and the remaining oil and modifying reservoir wettability to more advantageous conditions [6].

In general, the chemicals used in CEOR are surfactants, polymers, and alkalis. The injection may consist of one type of chemical or a combination of them (Surfactant-Polymer or Alkaline-Surfactant-Polymer for example). The polymer in the chemical process is injected to increase the sweep efficiency (as a mobility control agent) [7]. Surfactant injection is another type of chemical EOR that works by lowering the IFT to an ultralow level and altering the wettability status of reservoir rocks [7]. Surfactants fall into four main categories: Zwitterionic, non-ionic, cationic, and anionic [8]. Surfactants have a molecular structure consisting of hydrophilic groups that have a strong ability to attract solvents and hydrophobic groups that have a very weak ability to attract solvents. Either lowering the interfacial tension (IFT) or emulsifying oil and water are two surfactant mechanisms utilized in the EOR process [7]. A change in wettability, an increase in sweep efficiency, or a decrease in interfacial tension (IFT) are all possible outcomes of the interaction between the surfactant and the rock-oil system [9-11].

This research aims to highlight the result of a comprehensive test of a specific surfactant. The tests are necessary to identify the best surfactant and brine concentration to be injected as well as the compatibility of the produced surfactant with the formation in the reservoir.

2. Surfactant Design

Comprehensive tests based on laboratory research were carried out to assess the performance of surfactant solutions. The equipment used in this laboratory study is the Anton Paar Densitymeter, IFT spinning drop, Membrane filter tester to test filtration, core flooding rig, which is a core flooding test tool to test the CEOR injection scheme, Memmert EM Convection Oven for heating crude oil samples, cores, and for testing of thermal stability and phase behavior. The materials used in the experiment consists of crude oil samples from Field X, formation water samples from Field X for surfactant solvents, and injection water samples from Field X for surfactant solvents, and surfactants A, B, C, as a screening test research object.

The study begins with the preparation of a surfactant solution by mixing the surfactant with synthetic water, and then after the surfactant is formulated, then proceed with testing some parameters. There are three types of surfactant solutions made with varying concentrations of 0.1%, 0.3%, 0.5% and 1% respectively. Variations of synthetic water are also made based on the salinity, namely 10,000, 17,500, 18,000 and 20,000 ppm. After the surfactant is made, then proceed with the screening tests of the surfactants. The compatibility test, the interfacial tension measurement (IFT), the thermal stability test, the phase behavior test, the filtration test, and the spontaneous imbibition test are all parts of the evaluation. Choosing the right type of surfactant is essential for solubility, chemical and thermal stability, and surfactant adsorption in challenging reservoir conditions [12].

Compatibility test is carried out by mixing the surfactant with formation water or injection water and then observing the changes that occur in the solution and it is expected to form a homogeneous solution. IFT test on a laboratory scale was carried out using spinning drop tensiometer equipment at a temperature setting of 60^0C according to field conditions. The next test is the thermal stability test. The test is carried out by dissolving the surfactant in formation water according to the concentration being tested. Then all samples were placed in the oven at the reservoir temperature. Observations were made at a certain period and then the IFT value was measured. Measurements were repeated on the 4th, 7th, 14th, and 21st days. Phase behavior test is conducted to analyse the type of phase formed when a surfactant is mixed with crude oil at reservoir temperature conditions.

The compatibility test aims to verify the solubility of the surfactant in formation aqueous. In this study, brine was used as the solvent, so the ideal surfactant formulation should be compatible with it. The non-soluble composition was determined if the surfactant solution exhibited cloudiness, phase separation, and precipitation. The surfactant's solubility and compatibility were also evaluated [13]. The compatibility of the brine and the surfactant is the first screening criteria of the laboratory test. This test is carried out to determine the suitability between the two phases in the form of clear, cloudy, hazy, or forming precipitation. It is expected that the surfactant solution can have clear compatibility.

Thermal stability test was conducted to investigate whether the surfactant that has the minimum IFT value could maintain its interfacial tension reduction capability or lose its ability at reservoir temperature. Thermal stability is essential at the surface and in the reservoir because surfactants are sensitive to temperature and salinity. The selection of foam-forming surfactants needs to be stable in the reservoir because each reservoir has its own temperature and salinity range [14]. Based on these results, surfactants that can maintain their IFT value can proceed to the next screening test which is phase behaviour test.

The goal of the phase behavior test is to investigate the forming process and determine the type of microemulsion by mixing a surfactant and oil solution. The test was carried out within seven days and observations were made. It is expected that a middle phase (microemulsion) will be formed or known as Winsor Type III. A good surfactant is indicated by the thickness of the microemulsion formed. Tests are carried out on surfactant samples that have passed the thermal stability test.

The filtration test was conducted to evaluate the stability of the surfactant when the surfactant solution flows through the membrane. The filtration test was carried out by flowing the surfactant solution through a 0.45-micron filter paper. A total of 550 cc of surfactant solution was prepared for each test. During the test, the time for each surfactant to flow through the filter paper was recorded. Spontaneous imbibition is a test to measure the performance of surfactants in increasing oil recovery. Spontaneous imbibition test was carried out by replacing the saturation of the wetting phase with the non-wetting phase in the core. The oil-saturated core is placed in an Amott cell filled with replacement fluid. In this study, three spontaneous imbibition tests were performed. In each test, brine and surfactant solutions were used as replacement fluids.

3. Compatibility Test

The results of the compatibility test are shown in Tables 1 to 3. It shows that the two surfactants, B and C, are soluble in salt water with some exceptions under conditions of high concentration-high salinity. On the other hand, surfactant A showed a hazy solution with brine at all salinities and concentrations.

Table 1. Compatibility test for surfactant A.

Concentration	Salinity			
	10.000 ppm	**17.500 ppm**	**18.000 ppm**	**20000 ppm**
	Results			
0.1%	Cloudy	Cloudy	Cloudy	Cloudy
0.3%	Cloudy	Cloudy	Cloudy	Hazy
0.5%	Cloudy	Cloudy	Cloudy	Hazy
1%	Cloudy	Cloudy	Cloudy	Hazy

Compatibility test results on surfactant A are shown in Table 1. From these results, almost all the tests obtained cloudy results, where the characteristics of the surfactants did not dissolve completely but were still within reasonable limits. These results were seen in all types of concentrations at salinity of 10.000 to 18.000 ppm. However, at concentration of 0.3% to 1% at salinity of 20,000 ppm, the results are in the form of hazy. The results show that the colour of the surfactant solution looks more unclear than cloudy. However, the solubility of surfactants is still within reasonable limits due to the absence of precipitation in the solution. Hence it can be ascertained that surfactant A can still be included in the next test.

The behavior of the surfactant-oil-water phase test is crucial for assessing the degree of oil extraction during the injection of the surfactant. Lower IFT between driving fluid and oil can be achieved through emulsification [15]. If the compatibility is cloudy, hazy, and precipitation, plugging tendencies are possible. Further testing with filtration tests is needed to mitigate this potential hazard.

Table 2. Compatibility test for surfactant B.

Concentration	**Salinity**			
	10.000 ppm	**17.500 ppm**	**18.000 ppm**	**20000 ppm**
	Results			
0.1%	Clear	Clear	Clear	Clear
0.3%	Clear	Clear	Clear	Clear
0.5%	Clear	Clear	Clear	Cloudy
1%	Clear	Clear	Clear	Hazy

Table 3 on the last surfactant sample shows that Surfactant C has a tendency similar to the characteristics of surfactant B where the overall results obtained are clear in all concentrations and salinities. Based on the results of the compatibility test in Tables 1 to 3, the results are in the clear category. The clear category compatibility means that the potential for plugging when the surfactant is injected into the reservoir is quite small and can provide maximum capability during the next filtration test.

Table 3. Compatibility test for surfactant C.

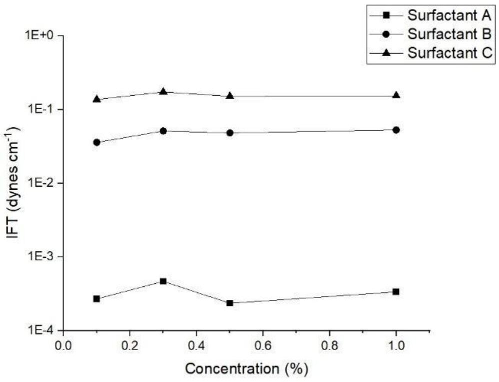
Concentration	**Salinity**			
	10.000 ppm	**17.500 ppm**	**18.000 ppm**	**20000 ppm**
	Results			
0.1%	Clear	Clear	Clear	Clear
0.3%	Clear	Clear	Clear	Clear
0.5%	Clear	Clear	Clear	Clear
1%	Clear	Clear	Clear	Clear

4. IFT Test

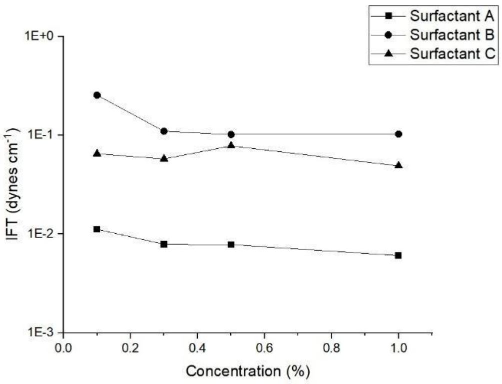
IFT measurements performed on surfactants A, B, and C showed that some samples had values of 10^{-3} (shown in Fig 1) as expected to increase the number of capillaries. Surfactant A with a salinity of 10000 ppm even achieves a very low IFT value of up to 10^{-4} which is a very good reduction for IFT. All surfactants with an IFT of 10^{-3} will proceed to the thermal stability test. Although surfactant C did not reach a value of 10^{-3}, it was decided to go through the next screening test because its IFT value at all concentrations was relatively close to 10^{-5}.

One of the most crucial screening parameters in this surfactant study is the Interfacial Tension (IFT) value. The main principle in CEOR, especially surfactant injection, is to reduce the interfacial tension between the surfactant and oil at the reservoir temperature with a specific minimum value of up to 10^{-3}. Reduction of IFT on surfactant flooding will increase the capillary number which will contribute to increased oil mobility. In the alkalinity process, the alkali is injected into the reservoir to produce in-situ surfactants and reduce the adsorption of surfactants and/or polymers [7]. The screening procedure can proceed to the subsequent test if the surfactant is successful in reducing the IFT number as anticipated. The molecular structure, temperature, salinity, and surfactant concentration in aqueous solutions all play a major role in determining the IFT values. When it comes to ultralow IFT, a high surfactant concentration is preferable to a low surfactant concentration [3].

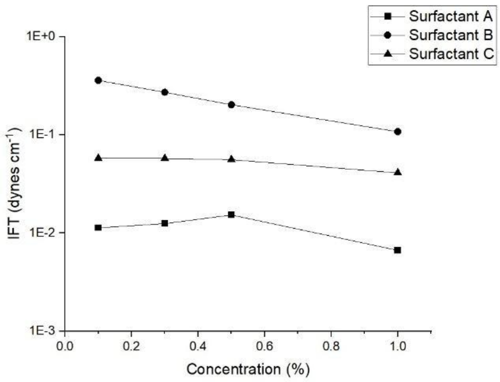
Under production conditions for tight oil reservoirs, the ultra-low oil-water IFT can create in-situ microemulsions and swiftly mobilize the invaded water in the matrix but cannot trigger capillary desaturation of the water phase [16].



(a) IFT at 60ºC for 10.000 ppm.



(b) IFT at 60ºC at 18.000 ppm.



(c) IFT at 60ºC at 20.000 ppm.

Fig. 1. IFT Test results for surfactant A, B and C.

5. Thermal Stability Test

Thermal stability results as depicted in Fig. 2. Surfactant A with concentration of 0.3% salinity at 10,000 ppm has the best result compared to other types of surfactants because on the first day until the 4th day it shows a down trend and then on the next day of measurement until the 14th day the surfactant was able to maintain IFT at 10^{-3}. Thermal stability is critical at the surface and in the reservoir conditions because surfactants are sensitive at temperature and salinity [17].

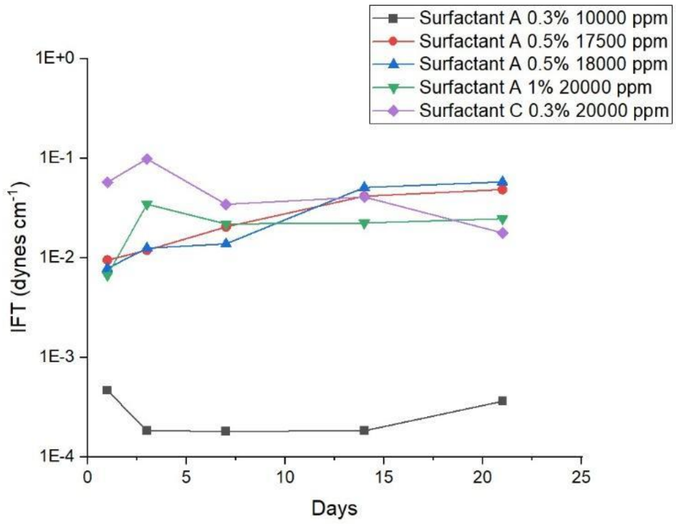


Fig. 2. Results of thermal stability test.

6. Phase Behavior Test

Analysis of the phase behavior test was carried out for 52 days, during which the surfactant samples were put in an oven at 60° C. Under these conditions, surfactants that have good performance will form a middle phase. Microemulsion phase behavior can change from Type I to Type III and then to Type II by increasing salinity at constant temperature and pressure [18, 19]. Type III is preferred for EOR applications due to its lowest IFT. Additionally, Type I and Type II are detrimental to an EOR process and to achieving ultra-low IFT with surfactant, respectively. Based on the results in Table 4, only Surfactant A 0.5% + Brine 18000 ppm formed a microemulsion or middle phase.

According to Healy and Read, the phase behavior of surfactant-brine-oil systems is an important factor in determining how well processes for oil recovery using microemulsions work [20]. The main way that microemulsions are made is by micelles in the oil and aqueous phases, which are highly dependent on temperature and salinity [3]. By reducing the IFT and promoting a miscible displacement, these microemulsions can enhance oil recovery from carbonate and sandstone reservoirs [20]. The concept of microemulsion phase behavior has a significant impact on the success of surfactant flooding. In 1948, Winsor proposed the most common classification for the phase behavior of microemulsions. He defined four different types of microemulsions [11].

Table 4. Results of phase behavior test.

Sample	Windsor Type	Microemulsion Thickness (cc)
Surfactant A 0.3% + Brine 10000 ppm	-	-
urfactant A 0.5% + Brine 17500 ppm	II	0.15
urfactant A 0.5% + Brine 18000 ppm	III	0.1
urfactant A 0.3% + Brine 20000 ppm	-	-
urfactant C 0.3% + Brine 20000 ppm	II	0.2

7. Filtration Test

Four surfactant solutions were formulated, they are Surfactant A 0.3% + Brine 20000 ppm, Surfactant A 1% + Brine 20000 ppm, Surfactant A 0.3% + 10000 ppm, and Surfactant C 0.3% + Brine 20000 ppm. Table 4 shows the results of those four filtration tests. It is expected that the surfactant solution has a filtration ratio lower than 1.2, because when the filtration ratio exceeds 1.2 there will be a tendency for pore clogging. All samples had a filtration ratio lower than 1.2 which was desired for the surfactant solution. There were only four filtration tests performed. For surfactant A 0.5% + Brine 18000 ppm no filtration test was carried out because it can be assumed from the results of the sample filtration test with 10000 ppm and 20000 ppm brine. The FR value must be below 1.2 since Surfactant A 1% + Brine 20000 ppm has an FR of 0.98 and Surfactant A 0.3% + Brine 10000 ppm has an FR of 1.05. As Teodora et.al. stated, surfactants suitable for use in EOR applications have FR of less than 1.2 [21].

8. Spontaneous Imbibition Test

Figure 3 depicts that the yield of surfactant oil is higher than that of water in each test. For the first test, surfactant A 1% + Brine 20000 ppm had a higher recovery factor than 20000 ppm brine. On the other hand, Surfactant A 0.3% + Brine 10.000 ppm shows the result is in greater recovery compared to baseline (10,000 ppm brine). The last sample surfactant A 0.5% + Brine 18000 ppm has the highest recovery factor of 76.21% compared to other surfactant solutions and its baseline (18000 ppm brine). The ability of the surfactant solution to recover oil in the reservoir rock is related to the function of the surfactant as an IFT reducer. Reducing the IFT of the oil-rock system will increase the mobility of the oil, thereby allowing the oil to flow freely to the production well.

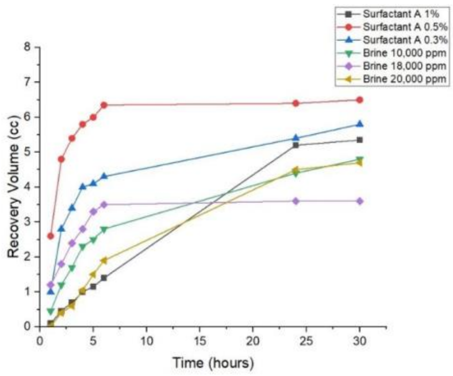


Fig. 3. Results of spontaneous imbibition test.

9. Conclusions

Based on the comprehensive test, it can be ascertained that Surfactant A is the best selection among other surfactants due to its performance. In terms of salinity, the three types of surfactants used can work optimally in the salinity range of 10,000-20,000 ppm. Overall, surfactant A 0.5% plus 18000 ppm brine is considered the best formulation because it can achieve ultra-low IFT values, form an intermediate phase (Winsor type III), produce the highest contact angle reduction, pass the filtration test, and have the largest recovery factor in spontaneous imbibition test. However, there is one parameter that needs to be considered if surfactant A is used at 18000 ppm salinity, it is the possibility of thermal degradation which causes a decrease in the IFT reduction performance of surfactant A.

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