Simulation Model Application to Predict the Effect of Salinity on Surfactant Adsorption and Retention in Alkali Surfactant Flooding

(Fenerapan Model Simulasi untuk Memprediksi Efek Kadar Garam Pada Pelekatan Dan Penahan Surfactan Dalam Injeksi Alkali Surfactan)

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Abstract
Modeling works of alkali surfactant injection are presented in this paper, in order to analysis the effect of salinity on surfactant adsorption and retention. Simulation model was validated using UTCHEM simulator. The simulation model was validated using laboratory experiment. From the laboratory experiment and modeling, it was found that surfactant retention, as well as surfactant adsorption, increased with the salinity. However they were not linearly related. The application of microemulsion Type III (salinity of 1.4% wt.) gave the optimum flooding. Although more surfactant was adsorbed and retained compared to microemulsion Type I (salinity of 1.4% wt.), it but yielded the highest recovery factor. The formation of microemulsion Type II (salinity of 2.0% wt.) should be avoided since it effectively caused surfactant loss due to surfactant adsorption and retention.

Keywords: Adsorption, Retention, Surfactant, Recovery Factor.

I. INTRODUCTION
Chemical flooding is one of the major enhanced oil recovery (EOR) techniques to produce a part of the remaining oil by controlling the mobility of the injecting fluid or interfacial tension (IFT) between oil and water. The effectiveness of chemical enhanced recovery processes depends on the delivery of injected chemical and water into reservoir to contact oil. Retention of chemical substances such as surfactant in porous media can be an important mechanism since it causes retardation and consumption of the surfactant. The retention is due to both adsorption onto solid surfaces, precipitation, and microemulsion trapping within dead-end and small pores. Many of the properties of surfactants are influenced by the electrolyte concentrations in the water. Divalent cations contained in formation water such as calcium and natrium ions are mainly important and can make significant differences in adsorption and precipitation (Hirasaki et al., 2011; Koukounis et al., 1983). Surfactant retention can be affected by surfactant structure, mineralogy, salinity, pH, Eh, microemulsion viscosity, crude oil, co-solvent, and mobility control among other variables (Solairaj et al., 2012; Tavassoli, 2016; Nelson, 1982). In a microemulsion flood, the injected fluid interacts with the reservoir brine, crude oil, and reservoir rock. Initially, the microemulsion fluid may be miscible with crude oil and reservoir brine. However, because of dilution and surfactant adsorption, the flood can degenerate to an immiscible displacement (Gupta and Trushenski, 1979).

Glover et al. (1979) suggested that phase trapping of microemulsion phase can significantly contribute to surfactant retention. They observed that retention increased linearly with salinity up to a certain salinity and then above that salinity almost all the surfactant injected was retained in
the core. Low salinity phase behavior is called Type I. In this kind of system, surfactant is partitioned predominantly into the aqueous phase. High salinity phase behavior is called Type II. In this kind of system, surfactant is partitioned predominantly into the oleic phase. When the oleic phase has a low oil concentration, the oil is said to be "swollen" by the surfactant and brine. While moderate salinity is called Type III. The salinity at which the middle phase has a WOR of unity is called optimal salinity because the lowest interfacial tensions (IFT) usually occur near this salinity, (Magzymov et al. 2016; Hirasaki et al., 1983; Tavassoli et al., 2016).

Phase behavior studies indicated type II microemulsion formed at that salinity and was the cause of high surfactant retention since type II microemulsion is trapped in the pores of the rock unless the capillary number is extremely high or unless it is displaced by a fluid with a lower salinity to reverse the phase behavior to type I. Novosad (1982) extended the study and devised a method to quantify the surfactant retained due to adsorption and unfavorable phase behavior (entrapment of immobile oil phase and surfactant precipitation due to divalent cations). He concluded that better-performing processes are usually accompanied by lower surfactant retention (but not vice versa) (Ghosh and Johns, 2014; Hirasaki, 1981; Khamaniri et al., 2015; Solairaj et al., 2012).

The objective of this research is to predict the effect of salinity on the performance of alkali surfactant flooding such as recovery factor, surfactant adsorption and retention.

II. METHOD

This study was accomplished by combining laboratory works with reservoir simulation. Berdasarkan pada percobaan alkali surfactant (AS) coreflooding was performed in the laboratory. Then a reservoir simulator software, UTCHEM, generated 1-D model refers to the laboratory condition. Before varying parameters to be analyzed, generated model needs to be validated to the experiment results. Lastly, number of grid and salinity of injected fluid were varied to further be examined. In addition, adsorption and oil recovery were also analyzed after parameter changes.

2.1. Laboratory Data

The data used in this study refer to the research of Ratna Widyaningsih (2014). In the research, Berea sandstone core was used in the experiment. The core was put in the oven to assure it was completely dry. The epoxy core holder was made with the side pressure tap for each core as shown in Figure 1. A leak test was performed, and vacuumed the core about one day. Then dry epoxy core weight was measured. After that it was submerged into the water while the valves were opened until the core was completely saturated. Eventually the wet weight core was measured to calculate the volume of fluid that filled the pores of the core. The same procedure was conducted for three other cores. The properties of the cores are given in Table 1.

![Figure 1. The Scheme of Coreflooding Instrument](image)

Table 1. Coreflooding parameters

| Parameter | Case I | Case II | Case III |
|-----------|--------|---------|----------|
| Length, cm | 28.5   | 28.4    | 28.45    |
| Diameter, cm | 3.7    | 3.7     | 3.7      |
| φ, fraction | 0.19   | 0.19    | 0.19     |
| Pore Volume, cc | 59     | 57      | 58       |
| ΔP, psi | 5.3    | 5.3     | 5.3      |
| k, mD | 93     | 90      | 90       |
| S_w, % | 70%    | 70%     | 68%      |
| V_{oil}, cc | 41.5   | 39.8    | 39.4     |
| k_{o,e} mD | 60.9   | 61      | 59       |
| S_{oil}, % | 33.05% | 34.74%  | 34.38%   |
| Salinity, ppm | 6,000  | 20,000  | 14,000   |

The injection scenarios for the first three cores were used to observe the surfactant retention in the different microemulsion types. In order to fulfill the conditions, the salinity of chemical solution injected was respectively set at 6000 ppm (Winsor Type I), 20000 ppm (Winsor Type II), and 14000 ppm (Winsor Type III).

The core flooding procedure was as follows. The epoxy core was saturated by brine 0.6 wt%, then oil flooding was conducted with very low flowrate. The next step was waterflooding where the flowrate was 3.4 cc/min. The salinity of water injection depended on the scenario mentioned above. After that 0.4 PV alkali surfactant (AS) solution was injected at flowrate of 0.23 cc/min. In addition, 1.6 PV brine with the same salinity as in water flooding at with the flowrate of 0.23 cc/min. The chemical concentration contained in the AS solution slug consisted of 0.196 % Na2CO3, 0.093% LAS, 0.166 % DOSS, and 0.205 % TEGBE. The coreflooding schemes are shown in
2.2. Simulation Model

The reservoir simulator software which was used in this study was UTCHEM. This software was chosen because the features matched the purpose of this study. UTCHEM, advanced processes compositional simulator, is able to simulate chemical flooding with salinity effect, the increase of water viscosity by polymer addition, and adsorption of chemical components. The model was operated in 1-D mode with variation of salinity and chemical concentration. The same procedure with coreflooding in laboratory was applied into UTCHEM simulator. Moreover, the core was assumed to have a cuboidal shape instead of cylindrical shape with the same volume and same cross-sectional area of the cylinder. In case of base case, the cuboid was divided into 11 equal blocks (11 x 0.1903 ft in length) in X-axis (N_x), 1 block (1 x 0.11 ft in width) in Y-axis (N_y), and 1 block (1 x 0.11 cm in height) in Z-axis (N_z). Additionally, injector and producer well were located in both ends of the model. All reservoir properties, component properties (oil, and chemical substances, and brine at salinity 6000 ppm), and wellbore characteristics were inputted into the software. The volume of AS slug was set to be 0.4 PV then followed by 1.6 PV chase brine at salinity 6000 ppm. After validating the model with coreflooding results, the salinity were varied (20000 ppm and 14000 ppm). Then the adsorption and retention of surfactant were analyzed.

III. RESULTS AND DISCUSSION

In order to predict the surfactant adsorbed and retained, UTCHEM simulator was applied. The validation of the simulation model is shown in Figure 2. The figure shows that the effluent to initial surfactant concentration ratio of the simulation result agrees with that of the experimental result. The figure shows that the effluent surfactant concentration reduced as salinity increased. In other words, the surfactant retention increased with salinity. In case of salinity 2% wt. the curve show that almost surfactant injected is retained in the core. As mentioned by Glover et al. (1979) and Solairaj et al. (2012) type II microemulsion formed at that salinity was the cause of high surfactant retention since type II microemulsion is trapped in the pores of the rock.

Figure 3 shows the estimation of adsorption during surfactant injection for various microemulsion types. It indicates that the surfactant adsorption increases with salinity. Another information obtained figure is the surfactant volume adsorbed tends to be constant after 0.5 PV surfactant solution is injected. Figure 4 shows the profile of surfactant retained during surfactant injection for various microemulsion types. The figure shows that volume of surfactant retained increases with salinity. However, in case of salinity 2% wt. the surfactant volume retained still increases linearly. It is noted here, that both surfactant adsorption and retention do not increase linearly with salinity.
along the range of surfactant concentration studied. Despite the coreflooding with salinity of 0.6% wt. produced a lower adsorption and retention of surfactant, but the displacement was not optimum since the microemulsion was less miscible with crude oil. However, the RF of this Type I microemulsion approached to that of Type III microemulsion at high surfactant concentrations. It could be concluded that the effect of salinity reduced as the surfactant concentration was increased. The core flooding with salinity of 2.0% wt. (Type II) gave moderate RF at low surfactant concentrations. However, this coreflooding type produced the lowest RF compared to others, since the effect of microemulsion trapping became larger.

The formation of microemulsion Type II (salinity of 2.0% wt.) should be avoided since it effectively causes surfactant loss due to adsorption and retention.

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IV. CONCLUSIONS
Based on the simulation results and analyses shown above, several conclusions are made as follows:
1. It was found that the surfactant adsorption, as well as surfactant retention, increases with the salinity. However they are not linearly related.
2. The application of microemulsion Type III (salinity of 1.4% wt.) gives the optimum flooding. Although more surfactant is adsorbed and retained compared to microemulsion Type I (salinity of 1.4% wt.), but it yields the highest oil recovery factor.
3. The formation of microemulsion Type II (salinity of 2.0% wt.) should be avoided since it effectively causes surfactant loss due to adsorption and retention.

Figure 4. Prediction of retained surfactant during injection at various salinity levels

Figure 5. Prediction of retained surfactant during injection at various salinity levels
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