Enhanced Oil Recovery by Surfactant Flooding with Considering Adsorption?Desorption of Surfactant

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https://doi.org/10.15017/4060112

出版情報：Kyushu University, 2019, 博士（工学）, 課程博士

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論 文 名　：　Enhanced Oil Recovery by Surfactant Flooding with Considering Adsorption-Desorption of Surfactant（界面活性剤の吸脱着を考慮した界面活性剤攻法による原油増進回収）

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論　文　内　容　の　要　旨

Even after primary and secondary oil recovery, a significant amount (in some cases more than 70%) of crude oil is still trapped within the micron pores of the bearing rock matrix. Chemical enhanced oil recovery (CEOR) using a surfactant, as a surface active agent, has been applied as an effective method to recover the residual oil by decreasing capillary forces and interfacial tension (IFT) between oil and aqueous phases in an oil reservoir. During the surfactant journey in the reservoir, it was not only dissolved in reservoir fluids but also adsorbed on internal surface of formation rocks. The surfactant loss is affected by reservoir rock and fluids conditions. This sets a challenge on surfactant-based CEOR in which the technique become less attractive economically. Some studies claimed the reversible surfactant adsorption, but they concluded that the desorption has no significant improvement in resources production. However, sufficient tests were not carried out on the effects of the surfactant desorption in the surfactant-based CEOR.

This research has focused on the adsorption and desorption of surfactant on reservoir rock surface and further investigated their effects on oil recovery. A field scale numerical simulation was developed after history-matching with the coreflooding-test result to develop a new combined method injection surfactant slug and moderate salinity chase water that achieved the highest oil recovery ratio.

This thesis consists of 5 chapters as follows:

Chapter 1 is the introductory chapter which addresses the importance of surfactant used in CEOR, mechanisms of surfactant flooding, surfactant adsorption and desorption and effects of surfactant concentration and formation-water salinity. The chapter further reviews the previous approaches of combined surfactant and low salinity water-flooding. From that regard, a problem formulation was presented to develop a scheme of the surfactant-based CEOR to resolve the mentioned issues.

Chapter 2 presents the measurement results of a popular anionic typed surfactant, sodium dodecylbenzene-sulfonate (SDBS), on the interface of oil/aqueous and rock/aqueous systems. One of the effects of SDBS water solution on oil properties, the IFT was measured by varying its concentration from 0.01 to 2 wt.%. It was found that IFT decreases with an increasing SDBS concentration, and possesses an optimal value at 0.1wt.%. Besides, the adsorption of SDBS onto the Berea sandstone was carried out at a targeted reservoir temperature of 45°C by shaking the mixture of SDBS water solution and the crushed sandstone (grain size; 140-450 μm) at a ratio of 10:1 for 24 hours. The SDBS adsorption was found to follow a Langmuir adsorption isotherm, the adsorption was saturated at 1 wt.% SDBS. The dynamic adsorption and desorption experiments were conducted by a flowing test of SDBS water solution through the Berea sandstone-core (4.5cm in diameter and 7.2cm in length). The results suggested that the SDBS adsorption isotherm was classified into four concentration regions I to IV. In region I where the attraction force is weak, the highest SDBS desorption rate up to 97% was measured. In the region II and III where the first layer of monomers is packed, the SDBS desorption decreased sharply to 41%. At the plateau adsorption in region IV, the desorption rate increased to 83% due to the weaker attraction force between monomer-tail portions. The effect of system salinity decreased the adsorption affinity between SDBS and the sandstone surface, but it followed the Langmuir adsorption isotherm in the tested salinity range.

Chapter 3 addresses the effects of salinity alteration of chase waterflooding on enhanced oil recovery at post surfactant flooding. The experiment was targeted to improve the effectiveness of surfactant flooding in a high saline formation-water. The waterflooding test was conducted using the core (4.5 cm in diameter, 7.23 cm in length) in a sequence that was first injected by high saline formation-water, followed by an SDBS slug at its critical micelle concentration (CMC) of 0.1 wt.% and injected chase water. The salinity of chase water was varied in several cases such as 0 (fresh water), 1, 3 and 5 wt.%-NaCl. In the combined method injecting SDBS slug and 1 wt.%-NaCl chase water (mild saline water), the highest oil recovery ratio of 56.2% was recorded and 11% in oil recovery ratio was improved compared with the conventional low salinity waterflooding (LSWF). The improvement is mainly owing to reducing IFT between oil and 1 wt.%-NaCl chase water injected, and also the chase water successfully prevented the dissolution of divalent cation of clay content within the core. In contrary, when the salinity of the chase water increased above 3 wt.%-NaCl, the desorption of SDBS was reduced with increasing the released rate of divalent cation, because the carrying cation reduced the effectiveness of desorbed SDBS. In the case of the chase waterflooding using fresh water (0 wt.%-NaCl), lower oil production was caused by the unbalanced distribution of surfactant monomers in oil and aqueous phases. Observations of the core surfaces after the waterflooding suggested that high saline chase water (≥ 3 wt.%-NaCl) leads to the precipitation of SDBS as sulfate salt after reacting with NaCl. As a result, the precipitates deposited and blocked flowing paths of oil droplets in the core. On the other hand, the chase water of 1 wt.%-NaCl mitigated the precipitation, which thereby restored the core permeability close to its initial one.

Chapter 4 presents the numerical simulation study of the combined method of surfactant and LSWF. Firstly, oil production of the waterflooding test was simulated by one-dimensional flow model including the Langmuir adsorption–desorption isotherm model and the IFT model, and later upgraded to a typical field-scale implementation model (150m×150m×50m, 80% oil saturation) using the simulator CMG-STARS^{TM}. In the one-directional flow model, the numerical modellings were successfully history matched with the waterflooding-test results incorporating the Corey exponent and capillary number. The sensitivity analysis of the chase water salinity and injection SDBS slug size was then conducted. The combined method of SDBS slug and low salinity chase water injection was further validated in a field scale model. It was also simulated that low saline water provided higher desorption rate of the adsorbed SDBS and the bank of desorbed SDBS advanced more extensively in the reservoir and induced IFT reduction in the contacted region, hence up to 2.1% of oil recovery has increased.

Chapter 5 is a summary and conclusion of major findings of present research including the research interest for the future study.