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Phase behavior and interfacial tension evaluation of a newly designed surfactant on heavy oil displacement efficiency; effects of salinity, wettability, and capillary pressure

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ABSTRACT

This work aims to discuss the results of wide ranges of laboratory investigations to evaluate the performance of a newly-formulated surfactant for heavy oil reservoirs in order to improve the microscopic sweep efficiency after water flooding processes. In the first part, the specific behavior of the formulated surfactant including its salinity tolerance, interfacial tension, and optimum performance window was determined. Then, the application of surfactant solutions in real sandstone reservoir rocks was assessed for both oil-wet and water-wet cases. Besides, the effect of changing the capillary and viscous forces and interfacial tension on the residual phase saturations were characterized. According to the results, the newly formulated surfactant provides middle phase micro-emulsion and low IFT value (i.e., about 0.01 mN/m) in a salinity window around 150,000 ppm which indicates its proper performance at high salinity ranges. Both the relative volume and solubilization ratios demonstrate the proper values to be applied for real case applications. Monitoring the differential pressure response and the effluent states in both water-wet and oil-wet Berea sandstone cores represent an incremental residual heavy oil production after water flooding through the formation of the emulsified oil droplets in the effluent solutions by chemical slug flooding. Plotting the capillary desaturation curves for both wetting and non-wetting phases through different capillary numbers demonstrate a normal variation trend for the non-wetting phase (approximately a semi-log relationship), while the wetting phase is greatly affected by the capillary end effect and relative permeability variations in the porous medium. This useful information could be extended for the other similar cases of chemically enhanced heavy oil recovery processes.

1. Introduction

A proper chemical composition is able to reduce the remaining crude oil in place after primary and secondary oil recovery stages by providing suitable phase behavior of the liquid systems and acceptable micro-emulsion state which could be confirmed by performing standard laboratory tests [1,2]. The transition state of the micro-emulsions that contains oil, water, and surfactant/alkali is mostly referred to the classification proposed by Winsor [3]. According to this classification, Winsor type I (oil in water solution), type II (water in oil solution), and type III (a bi-continuous phase as a middle phase with both excess oil and water phases) are the most acceptable types of micro-emulsion. Several parameters have been reported in the literature with the ability to transform micro-emulsion of Winsor type I to type III and type II (or in opposite direction) to find the proper solution salinity and desired ion concentrations [2–7]. The most widely used surfactants as the chemical agents nominated for chemically enhanced oil recovery contain two functional groups i.e., hydrophilic and hydrophobic parts; among them, sulfonate and sulfate based anionic surfactants are commonly used. It is widely accepted that as the length of the hydrophobic part increases, higher salinity tolerant surfactant could be obtained and the solution affinity to the oil phase increases [5]. Liu et al. [8] have also reported that the mixture of the surfactants would be able to tolerate hash reservoirs condition with high salinity concentration compared to single surfactant component solution. According to their results considering chemicals with intermediate groups connecting the hydrophobic parts to the hydrophilic sections, raises the droplet stability in the micro-emulsion state and provides more stable interfaces.

Oil–water displacement behavior is greatly affected by introducing surfactants into the mixture as they reduce the oil–water interfacial tension (IFT). Surfactants are also known for their effects

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Table 1
Core plugs properties of the Berea sandstone samples.

Plug	Length, cm	Diameter, cm	Porosity (%)	Liquid permeability, (md)	PV, cc
A	5.1	3.8	20	101.5	11.5
B	5.5	3.8	19.5	122.6	12.5
C	7.7	3.8	16	123.8	14
D	6.8	3.8	19.5	105.2	15

to alter the fundamental forces in the porous media like viscous forces, capillary effects, and the relative movement of the phases which are very dependent to the nature of the grain surface wettability. Capillary number is defined as the ratio of the viscous to capillary forces; the simplest form to represent this dimensionless number is as $N_c = \mu\nu/\sigma$ (μ: displacing fluid viscosity, ν: displacing fluid velocity, and σ: fluids interfacial tension). Capillary desaturation curve (CDC) demonstrates how the residual wetting and non-wetting phases saturations are decreased as the capillary number is increased in a porous medium [9]. The residual liquid phase starts to decrease as the capillary number approaches the critical capillary number, $(N_c)_c$, and this trend continues until a maximum value, which is called the maximum capillary number, $(N_c)_{\max}$, is attained. Relatively high value of capillary number around 10^{-7} is reported for traditional waterflooding process [9], therefore higher values of capillary number should be achieved to reduce the residual oil phase saturation during any chemically modified water flooding process. Compared to other parameters in the capillary number, the interfacial tension could be considerably altered by introducing surfactant/alkali into the injecting solution to achieve the highest capillary number thus the lowest residual oil saturation. This terminology have been adapted by many researchers; for example $(N_c)_c$ and $(N_c)_{\max}$ were mentioned as the mobilization and the prevention of entrapment indicators, respectively, by Morrow and Songkran [11], while, the term of total desaturation capillary number was used by Lake [10] for $(N_c)_{\max}$.

Besides, the effects of the capillary numbers and the injection flow rates on oil–water relative permeabilities (K_r) have been reported by Kalaydjian [12]. Three different regimes were proposed by changing the flow rates: capillary driven displacement, a balance between capillary and viscous forces, and the dominant viscous force regime. It was concluded that K_r and P_c are functions of the flow rate which means higher injection rate brings higher K_r and P_c. Bartley and Ruth [13] studied the effects of other parameters such as medium absolute permeability, fluids viscosity and the pressure drop on Kr. Their results confirmed the leading effect of medium absolute permeability on K_r for the two phases flow in porous media. Lefebvre du Prey [14] reported that the K_r value increases considerably for both the wetting phases in an oil-wet media. The relative permeability variation with N_c was also supported by other researchers like Bardon and Longeron [15], Amaefule and Handy [16], and Harbert [17] which confirms that K_r is a function of IFT, flow rate, absolute permeability and the fluids viscosity. On the other hand, the results of a series of steady state core flooding experiments by Fulcher et al. [18] in water-wet sand stone rocks indicated that the water relative permeability was increased by N_c, however, the trend was not clear for the oil phase. They reported that IFT and viscosity rather than the P_c are the affecting parameters on oil and water K_r. According to most of the previous published papers [19–23], the value of the critical capillary number was not considerably affected by different approaches mentioned here.

In this work, the following criteria would be covered to evaluate the performance of a new surfactant formula for heavy oil production enhancement in sand stone oil reservoirs: (i) the surfactant solution salinity tolerance will be presented while its concentration increases, (ii) the best performance solution region for the surfactant would be found, (iii) interfacial tension variation of the chemical mixtures–crude oil would be determined when salinity value and surfactant concentration are varying, (iv) core flooding experiments would be carried out to evaluate the displacement extent of the provided chemicals, (v) the wetting affinity of the porous media would altered from water-wet to oil-wet during core flooding experiments, (vi) the order of capillary number will be changed by modifying the interfacial tension value and the injection velocity to find out the order of residual phase saturations during the nominated chemical flooding, and finally (vii) the behavior of CDC plots would be discussed after wetting and non-wetting phase displacements.

2. Experimental work

2.1. Materials

After initial assessments, a newly designed anionic surfactant was formulated as a mixture of sulfonic acid, nonylphenol 10 mol ethoxylated, triethanol amine, and isobutanol. The new surfactant formula was designed to have high saline formation water tolerance, proper dispersion tendency, and high reservoir temperature endurance. Different types of the chemicals with certain quantities were mixed to improve the dissolution degree of the mixture and provide a more dispersive material; isobutanol was considered in the formula as a mutual solvent. The overall mixture was known to have a proper solubility behavior without forming any gels or liquid crystals. A detailed description of its physicochemical properties could be found in Dehghan et al. [24]. Sodium chloride salt was prepared by MERCK for brine preparation.

After initial screening of available crude oils from different reservoirs, a heavy crude oil sample from one of the Iranian oil reservoirs was selected. It has API degree of 19 (ASTM D1298) and kinematic viscosity of 350 cp (ASTM D445) at 25 °C. Its asphaltene content was approximately 14% (SARA analysis) and its acid

Table 2
Plan for chemical injection in the Berea sandstone plugs.

Injection mode	Sequence	Injected fluid	Composition	
Continuous	Initial oil flood	Crude oil (4 PV)	As mentioned in Section 2.1	
Continuous (initial flood)	Water flood	Brine	NaCl	4–15 wt%
Slug	Chemical injection	Surfactant slug (0.3 PV)	Brine containing 0.2 wt% surfactant	
Continuous (final flood)	Water flood	Brine	NaCl	4–15 wt%
Flow rate			0.15 cc/min	