Advances in Geo-Energy Research

Vol. 9, No. 3, p. 152-155, 2023

Short communication

Effect of nanoparticles on phase behavior of surfactant-oil-water system: An application in multiphase flow system

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Keywords:
Phase Behavior
multiphase flow system
nanoparticle
surfactant

Cited as:
Yarveicy, H. Effect of nanoparticles on phase behavior of surfactant-oil-water system: An application in multiphase flow system. Advances in Geo-Energy Research, 2023, 9(3): 152-155.
https://doi.org/10.46690/ager.2023.09.03

Abstract:
This paper experimentally investigates how adding nanoparticles to Soloterra surfactant affects phase behavior and surfactant flooding. These experiments include three phases. In phase one, phase behavior tests are conducted on surfactant solutions to choose the compatible nanoparticle. Phase two entails measuring interfacial tension between the stable nanoparticle + surfactant solutions and hydrocarbon. In phase three, a series of micromodel flooding tests are conducted to experimentally study the possibility of enhancing oil recovery. A possible relationship between static phase behavior and dynamic fluid flow is studied to evaluate the effects of nanoparticles on surfactant solutions. The results of the phase behavior experiment show that Soloterra 964 is compatible with Al_2O_3 and Cu_2O. Moreover, the Soloterra 964 + copper oxide solution can help observe all three Winsor types. The interfacial tension test results show that adding nanoparticles to solutions leads to lower interfacial tension. The results of micromodel flooding experiments indicate that adding surfactant and nanoparticle to the injected solution leads to higher breakthrough time and oil recovery. In addition, type III flooding produced a less stable displacement pattern than types II- and II+.

1. Introduction

Surfactant flooding for increasing oil recovery has recently gained popularity (Xu et al., 2020; Zhu and Li, 2020; Chen et al., 2023). Adequate adsorption levels and low interfacial tension at low surfactant concentrations are crucial design criteria for optimizing chemical systems to recover oil trapped in petroleum reservoirs (Hama et al., 2023; Zhang et al., 2023).

One of the most crucial aspects of chemical flood design for enhanced oil recovery (EOR) is choosing a surfactant formulation that can mobilize oil without losing too much of it to adsorption and phase separation. Nowadays, it is routine practice in the oil and gas industry to screen surfactants and their formulations for low interfacial tension using phase behavior tests (Saboorian-Jooybari and Chen, 2023) because of the well-established association between the interfacial tension and microemulsion phase behavior.

Nanotechnology suggests a novel method for increasing oil recovery (Kazemzadeh et al., 2019; Shao et al., 2023). Nanoparticles apply to this process because of their valuable capabilities based on their unique features (Kister et al., 2018). These characteristics include active surfaces, high specific areas, and unusual chemical reactivity (Sun et al., 2017).

Surfactant adsorption onto reservoir rock presents a critical issue during surfactant flooding (Tavakkoli et al., 2022). Researchers recommend addressing this challenge by adding nanoparticles to zwitterionic surfactant solutions to improve oil recovery (Zhong et al., 2020). Also, hydrophilic nanoparticles are added to non-ionic surfactant to increase the surfactant efficiency to deal with the adsorption problem (Zhong et al., 2019). Furthermore, adding silica nanoparticles to Sodium Dodecyl Sulfate surfactant solutions reduces interfacial tension (Zargartalebi et al., 2015). Interfacial tension also decreases when mixing the amphoteric surfactant with nanoparticles

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Yandy Scientific Press

Received July 18, 2023; revised August 2, 2023; accepted August 14, 20213; available online August 17, 2023.

Table 1. Compatibility tests with deionized water versus 2.5% and 5% salinity solutions.

Surfactant	CMC (wt%)	Nanoparticle	2.5% salinity solution	5% salinity solution
Soloterra 963	0.19	Al_2O_3	Yes	No
Soloterra 964	0.23	Al_2O_3	Yes	Yes
Soloterra 982	0.26	Al_2O_3	No	No
Soloterra 983	0.31	Al_2O_3	No	No
Soloterra 963	0.19	Cu_2O	No	No
Soloterra 964	0.23	Cu_2O	Yes	Yes
Soloterra 982	0.26	Cu_2O	No	No
Soloterra 983	0.31	Cu_2O	No	No

(Rezaei et al., 2020).

Surfactant flooding is an EOR technique that targets the trapped oil by reducing the interfacial tension between the brine and oil (Cho et al., 2008; Deng et al., 2021). However, only a few studies have been conducted to determine the effect of nanoparticles on surfactant phase behavior and surfactant flooding. Moreover, few researchers have investigated a possible relationship between static phase behavior and dynamic fluid flow. This research conducts different sets of experiments to understand the possibility of microemulsion formation during nanoparticles and surfactant flooding. In addition, it investigates the feasibility of adding nanoparticles to Soloterra surfactant for EOR.

2. Materials and methods

1) Materials
Hydrocarbon of n-hexadecane and the salt of NaCl were sourced from Merck Co, and Sasol supplied Soloterra 963, Soloterra 964, Soloterra 982, and Soloterra 983. The study used Al_2O_3 and Cu_2O as nanoparticles. Fig. 1 demonstrates the chemical formula of Soloterra surfactants.
2) Phase behavior
The study entailed performing dynamic phase behavior testing on the surfactant-nanoparticle-oil-water phase behavior at different salinities typical of each Winsor type of behavior. Continuous images of the test tubes were taken using a digital camera while they were being aggressively shaken and left standing vertically.
3) Interfacial tension
A spinning drop tensiometer measured the interfacial tension. The holder for the sample is first filled with a surfactant solution of a known brine salinity, and then a solution drop is added. Measurements and readings are taken in the ambient environment for at least 40 minutes.
4) Micromodel setup
This study employed two-dimensional homogenous glass micromodels (Yarveicy and Haghtalab., 2018). Without any additional treatment, the micromodels this study used were water-wet.

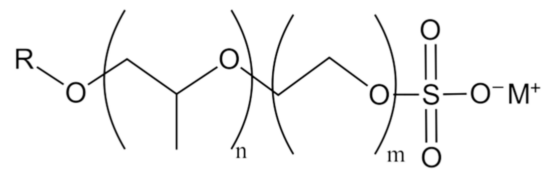

Fig. 1. chemical structure of Soloterra.

Table 2. Phase behavior tests at different salinities.

Solutions	0% Nacl	2.5% Nacl	5% Nacl
Soloterra 964 + Al_2O_3	II-	II-	III
Soloterra 964 + Cu_2O	II-	III	II

3. Results and discussion

3.1 Phase behavior

Phase behavior tests can aid in the understanding of the fundamental mechanism of microemulsion generation. As shown in Table 1, Critical micelle concentration (CMC) for all selected surfactants is measured. Table 1 also demonstrates the compatibility tests conducted with deionized water, 2.5% sodium chloride, and 5% sodium chloride water. On the other hand, Table 2 shows that surfactant-nanoparticle-oil-water phase behavior tests were made with equal amounts of water and oil for a range of salinities (0%-5% w/v). Specifically, variations in brine salinity affect the behavior of the surfactant-nanoparticle-oil-brine phase. Typically, the investigation should test a range of salinities before drawing any conclusions. It is possible to separate oil and EOR fluid of the same salinity by adding equal volumes of both to a tube, mixing them vigorously, and then letting them sit still (Puerto et al., 2012). Components (oil, water, and surfactant) split into distinct phases during equilibration, and the amount of a given part often characterizes the distinctive phase features. Also, as shown in Table 2, When water solubility is lager

Table 3. Interfacial tension between surfactant + nanoparticle solution and hydrocarbon.

Solution	Interfacial tension (mN/m)	
	In deionized water	In the 5% NaCl
Soloterra 963 + Al_2O_3	2.27 ± 0.001	0.42 ± 0.002
Soloterra 964 + Al_2O_3	2.64 ± 0.002	0.36 ± 0.001
Soloterra 982 + Al_2O_3	2.39 ± 0.003	0.28 ± 0.003
Soloterra 983 + Al_2O_3	2.24 ± 0.002	0.41 ± 0.002
Soloterra 964 + Cu_2O	2.33 ± 0.003	0.39 ± 0.002
Soloterra 964 + Cu_2O	2.54 ± 0.002	0.34 ± 0.002
Soloterra 964 + Cu_2O	2.28 ± 0.004	0.31 ± 0.002
Soloterra 964 + Cu_2O	2.19 ± 0.002	0.32 ± 0.002

Table 4. Hydrocarbon recovery at different micromodel flooding conditions.

Surfactant	Nanoparticle	Salinity	Breakthrough time	Recovery at breakthrough	Total recovery
NA	NA	0	1,270	27.04	31.125
Soloterra 964	NA	0	1,515	33.663	34.298
Soloterra 964	Al_2O_3	0	1,733	41.711	43.602
Soloterra 964	Al_2O_3	2.5	1,988	35.346	40.081
Soloterra 964	Al_2O_3	5	1,993	47.9034	48.385
Soloterra 964	Cu_2O	0	2,012	49.187	50.298
Soloterra 964	Cu_2O	2.5	2,888	51.002	54.834
Soloterra 964	Cu_2O	5	2,935	53.737	60.35

than that of oil, most of the microemulsion dissolves into the brine, a phenomenon known as Winsor type II- phase behavior. When water solubility is less than that of oil, the behavior corresponds to a Winsor type II+ where microemulsion is predominantly in the oil phase. According to Sim et al. (2014), when water solubility is the same as that of oil, an oil-and-brine microemulsion forms-a phenomenon known as Winsor type III.

The in-lab phase behavior testing confirmed that microemulsions remained stable for several weeks, which is consistent with the stability data. Table 3 indicates that adding surfactant and nanoparticle to the prepared solution leads to interfacial reduction. The results show that adding Soloterra 983 to solutions leads to higher interfacial tension reduction compared with other surfactants. Finally, the results of interfacial tension show that adding nanoparticle + surfactant to deionized water leads to higher interfacial tension reduction compared wth DI water.

3.2 Micromodel flooding

Using micromodels and a wide variety of surfactant solutions, numerous research groups have studied displacement patterns (Yang et al., 2021). A microfluidic method is used to investigate the processes of displacement that occur when using surfactant nanoparticles.

For type III surfactant flooding, oil recovery seemed to be maximized at lower flow rates. There appeared to be some stability in displacement at lower flow rates, but as the rate increased, the displacement became less stable, suggesting that oil recovery decreased. For type II+, a similar pattern emerged; however, the conclusions are not as concrete. Finally, the study indicates that type III flooding produced a less stable displacement pattern than types II+ and II-.

As Table 4 indicates, adding surfactant and nanoparticle to the injected solution leads to higher breakthrough time and oil recovery. Type II exhibits an increase in oil recovery with increasing Ca and a transition to a more stable displacement process. The results do not demonstrate a change from capillary fingering to steady displacement when a microemulsion displaces oil. Instead, with more Ca, the displacement changes to viscous fingering, bringing the results for types III and II+ into line with the situation of a $\nu < 1$ proportion of holes occupied by capillary fingering before the injected solution breaks through.

4. Conclusion

This study illustrates the effect of nanoparticles on phase behavior and multiphase flow of a surfactant-oil-water system. Moreover, this study suggests a methodology to select suitable nanoparticle and surfactant solutions for enhanced oil recovery.

The research drew the following conclusions:

1) Among all tested surfactants, Soloterra 964 is the only surfactant compatible with Al_2O_3 and Cu_2O.
2) Variations in brine salinity affect the phase behavior of the surfactant-nanoparticle-oil-brine phase. All three Winsor types are apparent with the Soloterra 964 + Cu_2O solution, but only type II- and type III are present with the Soloterra 964 + Al_2O_3 solution.
3) The Soloterra 964 + Cu_2O solution induces interfacial tension reduction and wettability change. Soloterra 964 concentration needs to be above CMC to be effective.
4) It is assumed so far that the surfactant + nanoparticle floods are in a state of local equilibrium, meaning that the microemulsion phase forms instantly upon contact between the surfactant and oil components. Therefore, the research investigated the displacement scenarios in which either water or microemulsion displaces oil.
5) Adding surfactant and nanoparticle to the injected solution leads to higher breakthrough time and oil recovery. The study revealed that type III flooding produced a less stable displacement pattern than types II+ and II-. These findings prompt further investigations concerning the impact of microemulsion production on displacement efficiency.

Conflict of interest

The authors declare no competing interest.

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