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FULL PAPER

# Using new surfactants in EOR process for new cases to lower the oil water interfacial tension

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In summary, NPs help in reducing the IFT either alone or in combination with surfactants. Moreover, NPs can also reduce the adsorption of surfactants on reservoir rock surface. However, additional experimental work is required to understand the underlying mechanism of improvement in interfacial properties using NPs. Mainly, experimental studies that have been carried out in this field dealt with determining the optimum NPs concentrations corresponding to minimum IFT. However, there is a lack of information on surfactant-NPs interactions. In addition, there is limited data on the interfacial behavior of surfactants with NPs other than silica. There is a huge potential for further investigation in this area, for example, how interfacial properties are altered if oil is changed from light to heavy or surfactants are changed from cationic to nonionic, zwitterionic or anionic, and so on.

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## Introduction

The process of oil recovery is divided into three main phases including primary, secondary and tertiary phases. In the petroleum industry, the primary and secondary phases are referred to as the conventional methods of oil extraction. On the other hand, the tertiary phase is referred to as enhanced oil recovery (EOR). The primary recovery produces less than 30% of original-oil-in-place (OOIP) through natural flow and artificial lift. Initially, crude oil naturally flows out of a reservoir due to its own pressure. Several mechanisms are involved in this process including solution-gas drive (important in heavy-oil reservoirs) (He *et al.*, 2019), gas-cap drive (Rezaei *et al.*, 2020b), water drive (Tayari *et al.*, 2018), rock and liquid expansion (Agi *et al.*, 2018, Gyan *et al.*, 2019) and gravity drainage (Aljuboori *et al.*, 2019). In many cases, the primary recovery is supported by a combination of these driving mechanisms (1-3). Continuous oil extraction causes the pressure gradient to drop in the reservoir and hence oil production rates decrease, in accordance with Darcy's law. To achieve higher rates of oil production, the drawdown pressure is usually increased by lowering the bottom-hole pressure (BHP) in the production well. This is accomplished by applying artificial lift, which compensates for the reduction in energy supplied by natural drive mechanisms after years of oil production (4-6). There are several artificial lift systems that have been used worldwide. Examples of these systems include hydraulic jet pumping, gas lift, plunger lift, beam pumping, hydraulic piston pumping and others. The selection of an artificial lift system depends on determining factors including downhole pressure /temperature, fluid properties, completion type and hole characteristics. The factors also include well location, operating and service personnel, surface climate, available power sources, economics and others (5).

Once primary oil recovery is no more feasible, secondary oil recovery is implemented to drive additional crude oil out of the reservoir using pressure maintenance techniques such as waterflooding and gas injection (7). In waterflooding, water is injected into a reservoir using a number of injection wells to maintain the pressure. The displaced oil is collected and produced using a number of production wells. However, water injection does not extract all the oil from the reservoir for two main reasons. Firstly, due to reservoir heterogeneities, water may flow in highly permeable pathways that exist between injection wells and production wells. This leaves several regions of the reservoir unswept by the waterflood. Secondly, oil ganglia surrounded by water are trapped within the small interstices of the rock matrix due to oil–water surface tension preventing oil from flowing (7). As indicated in Table 1, significant quantities of crude oil remain unrecovered following the primary and secondary phases of oil recovery. For this reason, a tertiary recovery phase, also known as EOR, has been introduced to boost the recovery from oil reservoirs. EOR involves a variety of operations such as chemical flooding (8), gas injection (2), microbial recovery (3) and thermal recovery (5). Figure 1 presents the main methods of EOR. By altering the wettability of the reservoir to preferentially water-wet (by the addition of surfactants or other chemicals), one can enhance the rate of oil recovery and reduce the amount of macroscopic bypassing.

*Goal of this study*

The main functions of surfactants are to reduce interfacial tension and wettability alteration [3]. Surfactant EOR mechanisms are discussed separately according to these two functions.

The core studied in these experiments is a carbonate sample (mainly limestone with a small amount of dolomite and trace amounts of quartz and clays) that obtained from Bangestan oil group. This core was cleaned and aged in crude oil for long enough time before flooding by aqueous phase. The aqueous phase in this project was distilled water or diluted surfactant solutions. Wettability alteration mechanism targets more on carbonate reservoirs. Carbonates are more likely oil-wet [7,8]. As the rock becomes more water-wet, water imbibition is enhanced and the residual oil saturation is reduced. In natural fractured carbonate reservoirs, surfactant injection changes the matrix to more water-wet. Then water can imbibe from fractures into matrix blocks to displace oil out. The relative permeability models and capillary pressure models resulting from wettability alteration were proposed by References [9] and [10]. Sheng [7] compared the effects of different mechanisms in oil recovery related to surfactant EOR. Particularly, the effects of wettability alteration and IFT reduction were compared. His numerical simulation results show that wettability alteration plays important roles when IFT is high, and it is effective in the early time. IFT plays very important roles with or without wettability alteration and is effective during the EOR entire process.

*Aqueous phase*

Distilled water was used as the aqueous phase for contact angle and flooding tests [10].

*Reservoir rock samples*

The rock samples used in this project consist of a core plug and several solid surfaces named as pellets (Figures 1 and 2). These are all from carbonate Bangestan group in south-west of Iran. Figure 1 shows the core plug and pellet surfaces [2].

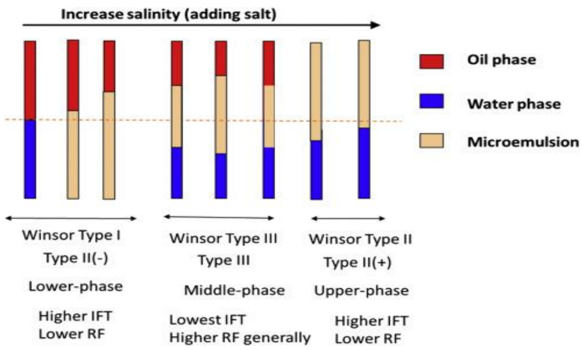


**FIGURE 1** Carbonate core plug and pellets (22)

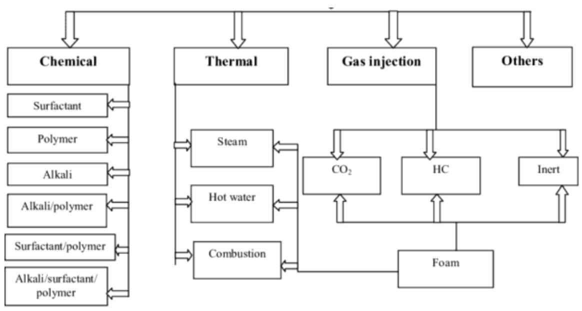


**FIGURE 2** Simplified classification of EOR methods

The properties of these solvents are shown in Table 1.

**TABLE 1** Cleaning solvents specifications

| Cleaning Solvent | Boiling point | Density |
|---|---|---|
| Toluene | 115.1 °C | 0.951 g/cm$^3$ |
| Methanol | 55.6 °C | 0.801 g/cm$^3$ |

## Experimental setup

Addition of surfactant in injection brine will cause emulsification of oil in water. In EOR, the microemulsion is a stable translucent micellar solution of oil and water. Types of microemulsion and salinity effect on phase behavior will determine the potential surfactant formulation for EOR processes. The purpose of the phase behavior test is to determine the chemical formulation for a specific application. In practice, the range of salinity is studied to find the relative surfactant solubility in brine and oil. Optimum salinity is targeted for EOR formulation, where the surfactant is equally soluble in oil and brine, which results in the lowest IFT between oil and brine (Figure 3).

However, a study on modified phase behavior test also can be done for a fixed salinity application, and more hydrophilic and more hydrophobic surfactants are mixed in different ratios to produce under optimum, optimum, and over optimum conditions similar to salinity scan [11-13]. For a fixed water salinity application, such as seawater application as the injection water, modified phase behavior test can be done to determine optimum surfactant formulation for a typical field condition (i.e., fixed water salinity). The present study focused on fixed salinity, where seawater is used as brine for surfactant mixture. The optimum ratio of the main surfactant (AEC) and co-surfactant (APG) is identified based on modified phase behavior.

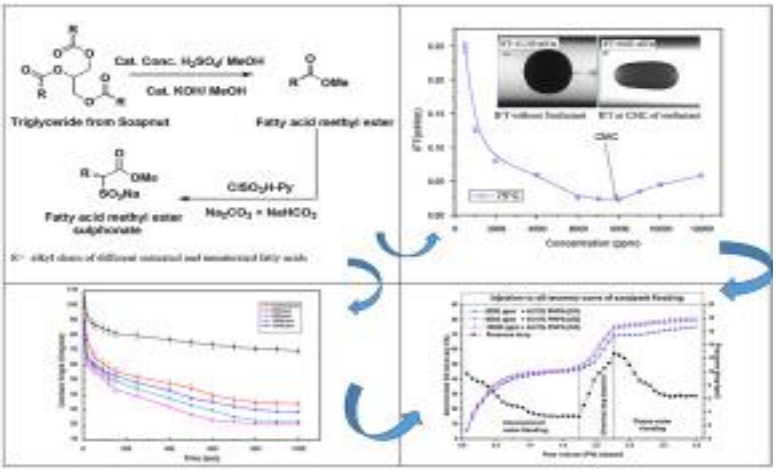


**FIGURE 3** Bio-based surfactant for enhanced oil recovery

*The high potential of surfactant-based flooding*

The high potential of surfactant-based flooding has been demonstrated in favorable conditions, such as at low temperature and soft brines. However, there are a very limited number of surfactants available that can be applied under harsh conditions of high temperature (> 100 °C) and high salinity/hardness. Sulfate's surfactant can improve surfactant tolerance to high salinities. However, they are subjected to hydrolysis at high temperature because it has sulfur-to-oxygen bond. Sulfonate surfactants such as olefin sulfonates and alkyl benzene sulfonates are stable at high temperature but sensitive to divalent ions [14-17]. Sulfonates are stable at high temperatures because they have sulfur-to-carbon bond, which is not easily subjected to hydrolysis.

At high temperature, the performance of surfactant-based flooding can be drastically decreased due to the instability of the applied surfactant. Chemically and the thermally stable surfactant is required to be identified, and its performance is mandatory to be evaluated for chemical EOR applications. Chemical stability is whether the surfactant molecule degrades under specified targeted condition, whereas solubility is whether surfactant dissolved and does not precipitate in the solution [18-21]. The addition of co-solvent or co-surfactant enables the surfactant solution to be prepared with a concentrated brine solution, even at high divalent cations concentration [22]. The biggest impediment to the use of a thermally stable surfactant in chemical EOR is the very poor solubility and compatibility of these surfactants in water containing high divalent cations such as calcium and magnesium, especially at high temperature where the solubility and compatibility are drastically reduced. Thus, this study is meant to identify workable surfactant formulation at harsh field conditions and also to find a co-surfactant and an optimum ratio for blending surfactant system that can improve the selected surfactant's compatibility with brine, chemically and thermally stable [21-23].

*Pendant Drop Apparatus*

Esmaeilzadeh *et al*. studied the impact of $ZrO_2$ on interfacial properties of anionic surfactant. They found that NPs augment the surface activity of the anionic surfactant and lower the IFT between water and oil [24]. Joonaki and Ghanaatian investigated the effect of aluminum oxide, iron oxide, and silicon oxide on the IFT and found that increasing the concentration of NPs reduced the IFT. Silicon oxide was more efficient in reducing the interfacial tension between water and oil [25]. Zargartalebi et al. investigated the effect of fumed silicon oxide NPs on the efficiency of surfactant in reducing the interfacial tension [26-29].

The concentration of NPs and surfactant is the most important parameter affecting the IFT. Zargartalebi *et al.* used partially hydrophobic silicon oxide and fumed silicon oxide to investigate the effect on IFT in the presence of surfactant [30-35]. They observed that, at lower surfactant concentrations, added NPs reduce the IFT. However, at higher concentrations, IFT increased due to the addition of NPs. It can be attributed to the electrostatic repulsive interactions between NPs and the anionic surfactant that promotes the diffusion of the surfactant towards the interface

Bulk Fluid refers to the fluid where the droplet is released. For example, water droplet is released in the atmosphere. Air is the bulk fluid. Drop Fluid refers to nature of the fluid of the droplet. For example, water droplet released in the atmosphere. Water is the drop fluid [36-39].

The VIT 6000 consists of following components:

- Two Manual pumps equipped with gauges for monitoring pump pressure
- Visual cell equipped with sapphire glasses can tolerate high pressure
- PT-100 thermometer for monitoring the temperature of the system
- A vibration-free base.
- A 700-bar pressure transmitter and an indicator for monitoring the pressure
- Spare parts, tools [40-46].

## Conclusion

Son *et al.* evaluated the $SiO_2$ NPs and polyvinyl alcohol (PVA) stabilized emulsion. Emulsion with a low concentration of PVA and a high concentration of $SiO_2$ NPs had greater stability and vice versa. Furthermore, the addition of salts efficiently stabilized the emulsion droplets without any significant coalescence and contributed to approximately 4% more oil recovery than what is achieved in the absence of emulsion system. Maghzi *et al.* studied the effects of dispersed $SiO_2$ NPs in water at different concentrations. The increase in the concentration of NPs increased the oil recovery. Also, the ultimate efficiency achieved for $SiO_2$ NPs flooding was higher compared to distilled water flooding. The increases in concentration from 0.1% to 0.3% cause the additional oil recovery to reach up to 16%. However, an optimum concentration of NPs is required to achieve the maximum recovery. In summary, an optimal concentration of NPs should be determined to have a maximum recovery. Higher concentrations of NPs have no significant effect on the recovery factor that can increase the cost.

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