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Enhanced oil displacement by nanofluid's structural disjoining pressure in model fractured porous media

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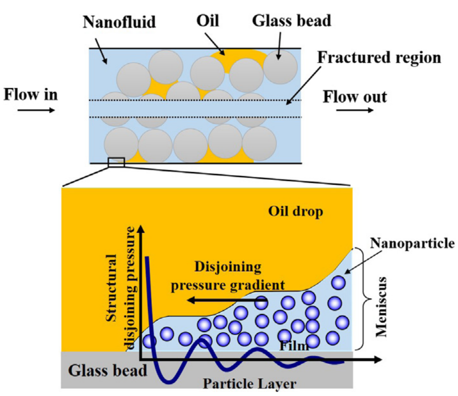
GRAPHICAL ABSTRACT



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ABSTRACT

Nanofluids for improved oil recovery has been demonstrated through laboratory corefloods. Despite numerous experimental studies, little is known about the efficacy of nanofluids in fractured systems. Here, we present studies of nanofluid injection in fractured porous media (both water-wet and oil-wet) formed by sintering borosilicate glass-beads around a dissolvable substrate. The fracture inside the porous medium is characterized and visualized using a high resolution X-ray microtomography. Based on a simple displacement theory, the nanofluid injection is conducted at a rate where structural disjoining pressure driven oil recovery is operational. An additional 23.8% oil was displaced using nanofluid after brine injection with an overall recovery efficiency of 90.4% provided the matrix was in its native wettability state. But only 6% additional oil was displaced by nanofluid following brine injection when the bead-pack was rendered oil-wet. Nanofluids appear to be a good candidate for enhanced oil recovery (EOR) in fractured water-wet to weakly water-wet media but not necessarily for strongly oil-wet systems. Our laboratory studies enable us to understand limitations of nanofluids for improving oil recovery in fractured media.

1. Introduction

Over 20% of the world's oil reservoirs are naturally fractured [1] while over 60% of the world's remaining oil lies trapped in fractured reservoirs [2]. Some of these reservoirs are wetted by oil,

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and are known to retain oil in the matrix leading to inefficient production [3]. Excessive hydraulic conductivity within fractures over that of the rock matrix contributes to injected fluid bypassing much of the matrix, resulting in very low oil recovery. Many improved recovery methods such as thermal recovery [4–6], chemical flooding [2,7,8], miscible and CO_2-foam flooding [9,10] have been considered. Ideally, however, without altering the wettability of the matrix, fractured systems suffer from poor contact of the displacing agents. The oil recovery mechanism in fractured reservoirs is reviewed and discussed by Fernø [11].

Nanofluids have recently been proposed as EOR (enhanced oil recovery) agents. Compared to traditional chemical methods, nanofluids are inexpensive, efficient, and environmentally friendly [12]. Researchers have observed positive results for ultimate oil recovery with nanofluid injection in core samples [13–21].

The mechanism of nanofluid-EOR is not fully understood. Two classical mechanisms have been suggested in the literature: interfacial tension reduction [14,22] and wettability alteration caused by nanoparticles' deposition or adsorption [13,23].

Wasan and Nikolov [24] found that the structural disjoining pressure caused by ordered layering of nanoparticles at oil/-nanofluid/solid three-phase contact region was the cause of wettability alteration (Fig. 1). Subsequent studies [25–31] clearly show that the nanofluid's structural disjoining pressure accelerates oil displacement from solid substrates compared to conventional liquids without nanoparticles. Two distinct contact lines were observed during the separation of oil droplets from a solid surface after nanofluid introduction: an outer one (between the oil, solid and water film) driven by capillarity and an inner one (between the oil, solid and mixed oil/water film) driven by structural disjoining pressure. Furthermore, the rate of inner contact line movement is much slower than that of the outer contact line [27]. The outer contact line forms first and ceases to advance once force balance is attained at the three-phase contact line, subsequent to which structural forces drive the inner contact line movement. Our previous study [18] clearly shows that improved oil recovery due to nanofluid is effective when the characteristic time for nanofluid advection inside the bead-pack is larger than that for nanofluid film formation, necessary for detachment of oil from the solid surface.

Although a number of results from laboratory tests have validated the use of nanofluids for EOR, their utilization for fractured media has not been studied. In particular the efficacy of nanofluids in poorly water-wetting fractured systems has not been demonstrated. For the purpose of evaluating tertiary recovery by nanofluids, we developed a method to embed a fracture within a sintered bead-pack. The technique of building such packs is outlined below. To facilitate observation of tertiary oil mobilization and displacement, nanofluid injection rate was chosen to enable structural disjoining pressure mechanism. The final goal of our study was to identify the limitations on the use of nanofluid in fractured porous media with respect to wettability.

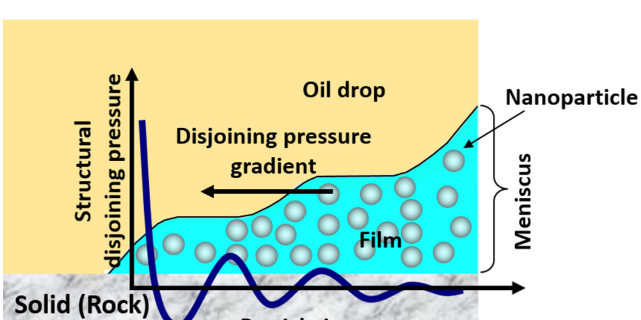

Fig. 1. Schematic presentation of mechanism of oil drop displacement driven by nanofluid structural disjoining pressure: Ordered layering of nanoparticles leads to disjoining pressure gradient and drives oil displacement.

Although mildly sintered bead-packs tend to have permeabilities ranging on the high side of what is prevalent in hydrocarbon reservoirs, visible systems afford observations that are only indirectly obtained in real systems, often in multi-pore length scale resolution. Furthermore, success in model systems is almost a prerequisite for use in consolidated sands and carbonates, i.e., a failure in high permeability synthetic media is usually sufficient for ascertaining efficacy.

2. Materials

2.1. Oil

Oil used in this study is an immersion liquid from Cargille Laboratories (NJ, USA). Properties of the Cargille immersion liquid are given in Table 1. A small amount (100 ppm) of Oil Red EGN dye (Aldrich Chemical Co., Milwaukee, WI) was added to the oil sample to increase visual contrast for observational ease.

2.2. Brine solution

Brine was prepared by dissolving sodium chloride (NaCl, Fisher Scientific, USA) in deionized (DI) water. The concentration of NaCl was 0.25 wt% of solution. The solution density is 0.99 ± 0.01 g mL^{-1} with a pH of 6.5 ± 0.5 at 22 °C and 1 atm pressure. The viscosity of the solution is 1.022 mPa s at 20 °C.

2.3. Polymeric nanofluid

Most reservoir environments are at high temperature, pressure, and salinity. Nanofluids, such as silica nanoparticle dispersions agglomerate in such environments. But polyethylene glycol 8000 (Fisher Scientific, USA) dispersed in brine is relatively stable with respect to dissolved electrolytes or temperature. This suspension is akin to a deformable nano-particle suspension, and we call it a polymeric nanofluid (patent applied). In order to enhance the effect of the structural disjoining pressure on the oil recovery process, the nanofluid composition was selected based on a multistep process [30,32]. The size and polydispersity of the polymeric nanofluid in brine were characterized through dynamic light scattering (Malvern Instruments, UK). At 25 °C, the average diameter is 9.5 ± 0.5 nm, with a polydispersity of 8–12%. The concentration of the nanofluid used in this study is 0.277 wt% or 10 vol% calculated based on the molar concentration of the polymer [33]. The density of nanofluid is 1.00 ± 0.01 g mL^{-1} with a pH = 6.5 ± 0.5 at 22 °C at 1 atm pressure and the viscosity of nanofluid is 1.097 mPa s at 20 °C.

2.4. Interfacial tension measurement

The classical method of drop-shape analysis was used to calculate the interfacial tension of oil/brine and oil/polymeric nanofluid

Table 1
Oil properties (25 °C, 1 atm pressure).

Property	Value
Density, g mL^{-1}	0.854
Viscosity, Pa s	0.0181
Surface tension, mN m^{-1}	29.4
Refractive index	1.474