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An experimental study on enhanced oil recovery utilizing nanoparticle ferrofluid through the application of a magnetic field

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ABSTRACT

Enhanced oil recovery (EOR) is a significant target in oil engineering, and in this regard nanoparticle suspension flooding remains a challenging task. Therefore, in this study, suitable magnetic nanoparticles were synthesized for injection into a porous medium and then characterized. In addition, the utility of the synthesized nanoparticles for EOR with and without the application of a magnetic field was studied through a core flooding experiment. The oil recovery increased when a magnetic field was applied in comparison to without such an application owing to a better distribution and the utility of the magnetic nanoparticles in creating a column toward the direction of the magnetic field in the pore channels, which acts like a piston and can sweep the oil and thereby increase production.

Introduction

The emergence of nanoparticles (NPs) has increased the diversity of various industries owing to their extremely favorable sizes, which vary from 1 to 100 nm [1,2]. In the oil and gas industry, practical applications of nanotechnology have been specifically confirmed in both the upstream sector, such as in nano-drilling fluids, and in the refining and petrochemical processes [3–5]. Depending on the type of NPs used, the dominant mechanisms in improving oil production include a reduction in oil viscosity, decrease in interfacial tension, and alteration of the wettability [6–9]. The most commonly utilized NPs are spherical fumed silica particles, which can be made hydrophilic by forming stable oil-in-water emulsions, or hydrophobic by yielding water-in-oil emulsions [10–12]. These types of nanofluids are made by dispersing NPs in a solvent, which can be distilled water, brine, oil, or toluene, and should be distinguished from micellar solutions (also called nanofluids), which are commonly formed by dissolving a surfactant during the aqueous phase [13–15]. Studying several types of polysilicon NPs during a core flood experiment, Onyekonwu and Ogolo [16] determined the dominant advantage of employing hydrophobic and lipophilic particles, and neutrally wet particles, during enhanced oil recovery (EOR) for water-wet formation, while restricting lipophobic and hydrophilic type particles to oil-wet formations [16]. Further, an experimental investigation into the EOR mechanism and performance of a silica-based water-wet rock system using a charge-stabilized silica nanofluid revealed a reduction of the residual oil saturation from about 50% to 20%, corresponding to an NP content of as low as 0.1%. The authors implied that the change from strongly water-wet to a neutrally wet condition is a promising mechanism that can significantly improve the oil recovery in water-wet sandstone reservoirs [17].

The application of TiO_2 nanoparticles was introduced for sandstone oil-wet cores to improve heavy oil recovery [18]. Although there have been no observed changes in water viscosity regardless of the NP concentration, the use of such anatase and amorphous particles can improve the recovery factor from 49% to 80%, essentially induced through a change in the wettability of the surface. In addition, an extensive application of synthesized NPs as adsorbents and catalysts has been proven to have potential in enhancing heavy oil upgrade and recovery [19]. Thus, the presence of NPs inside a porous medium while providing appropriate

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reaction conditions will result in a significant quality enhancement in all three phases: liquid, gas, and solid.

Among the various kinds of NPs used for improving oil production, iron oxide NPs have also been regarded as a good candidate. Based on the experiment results of Ogolo et al. for various types of NP flooding, Fe_2O_3 NPs appear to provide a good recovery factor when dispersed in distilled water; however, the oil recovered by means of NP application has been next to nothing when using artificial brine as an agent, and the situation is even worse when the agent applied is ethanol [20]. The reason for this is related to the stability of NP dispersion, in that iron oxide NPs will be unstable and more quickly sediment in the presence of salt. However, using distilled water is absolutely impossible in practical applications, and a modification of the method employing iron oxide NPs should be carried out in the future. Understanding that surfactants can prevent the particles in a ferrofluid from clumping together, an ideal study by Kothari achieved an expected improvement in the sweeping efficiency when employing a ferrofluid to support the surfactant flooding as compared to using a surfactant alone [21]. The authors also stated that this type of combination has a favorable application for a viscous reservoir fluid compared to the conventional range of viscosity oils utilized in surfactant flooding.

Compared to other types of nanofluids, ferrofluids are substantially sensitive to magnets, and can act as a magneto-rheological fluid in which certain properties such as the apparent viscosity, yield stress, and storage modulus change after applying a magnetic field [22]. In the absence of an applied magnetic field, ferrofluids exhibit Newtonian behavior [23], but after applying a magnetic field, dispersed magnetic NPs can create a column in the direction of the externally applied magnetic field [24], drastically increasing the above-mentioned properties. Presumably, after applying a magnetic field during ferrofluid flooding in an oil reservoir, a column structure is formed in the pore channels and acts as a piston in the porous medium, thereby improving the sweeping efficiency and increasing the oil recovery. There have been some recent reports on applying a magnetic field in an oil reservoir [25–27], and the present study is an attempt to clarify the influence of a magnetic field on the EOR performance by means of magnetite NP flooding for two types of oil, light and heavy. As the first step, magnetite NPs were synthesized through a proper method with regard to the real scale criteria, and were characterized as suitable for injection through a porous medium. For the second step, the sedimentation ratio and wettability alteration were monitored, and finally, the application of the synthesized NPs for EOR purposes was studied during a core flooding experiment with and without the use of a magnetic field. The results technically clarified the influence of a magnetic field on the oil sweeping efficiency when injecting a magnetite ferrofluid. In particular, because this work was carried out using both light and heavy oil, the range of application of this idea is promising given that it is particularly beneficial to future works.

Experimental

Materials

To prepare the magnetic NPs, magnetite was synthesized with slight modifications based on a previously reported method [28]: Briefly, 1 mmol of citric acid trisodium salt dehydrate ($C_6H_5Na_3O_7.2H_2O$ Sigma-Aldrich Co., Ltd. USA), 4 mmol of NaOH (Merck Co., Ltd. Germany), and 2 mmol of $NaNO_3$ (Daejung Chemical & Metals CO., Ltd. Korea) were dissolved in 19 mL of distilled water and heated to almost 100 °C. Then, 1 mL of a 2 M $FeSO_4.7H_2O$ (Yukuri Pure Chemicals CO., Ltd, Japan) solution was added while the temperature was kept constant for 1 h, then cooled to room temperature naturally, and separated by a magnet followed by washing several times with distilled water. This synthesis is a one-step, inexpensive, and facile method, and has a real-scale performance capability [29]. To fully understand the effects of the proposed method for a wide range of oils, two different types of dead oil were considered during the core flooding processes, one from Kuwait (KWT) and the other from the van Gogh (VGH) field in Australia, as shown in Table 1. Clearly, these two types of oil have a remarkable difference, that is, a viscosity of lower than 17 cp for KWT oil, and higher than 355 cp for VGH oil. In other words, these oil samples can represent conventional light and heavy oil categories. NaCl (Daejung Chemical & Metals Co., Ltd, Korea) was used to make a brine solution for water flooding through the core experiment, as well as connate water.

Table 1
Properties of two crude oil samples used in the experiments.

Oil type	KWT	VGH
Gravity (API)	30.6	17.1
Viscosity at 71 °C (cp)	16.24	355.5
Pour point (°C)	−20.0	−17.5
Nitrogen (mg/kg)	1229	1836
Salt content (lb/1000 STB)	3.3	7.5
Total acid (mg KOH/g)	0.21	1.55

Characterization

The surface morphology of the magnetite was investigated using both transmission electron microscopy (TEM) (Philips CM200) and scanning electron microscopy (SEM) (S-4300, Hitachi, Japan), whereas the particle size distribution was monitored using a particle size analyzer (particle analyzer, ELS-Z, Otsuka, Japan). A Turbiscan lab expert system MA2000 (Formulation, France) was used to measure the light transmission through the suspension of NPs to indicate the stability of the suspension. The gas permeability of the core samples was measured using a steady-state gas permeameter (Gasperm, Vinci Technologies, France).

Core preparation

The core samples used for the flooding process are Berea sandstone cores with the same designed form in terms of length and diameter (Table 2). The basic properties of the porous medium, including the porosity and permeability, were measured before conducting the official flooding processes. An artificial 42,000 ppm salinity solution was made by dissolving NaCl in deionized water to create the original brine in the cores. After completely drying in an oven for 40 h at 104 °C, the gas permeability of each core was investigated using a gas perimeter, and the cores were then placed in a sealed tank with the available brine to be saturated for 48 h with the support of a vacuum machine. The use of a vacuum pump is strongly encouraged to ensure 100% brine saturation. During the saturation process, the porosity was also measured by considering both the wet and dry weights. Measurements of the liquid permeability were afterward taken using a core-flooding device. Even when the cores had been entirely saturated with brine, this permeability measurement step conducted by injecting the same brine at a reasonable flow rate made the initial brine saturation strongly robust and dismissed any air in the porous medium. For each core, crude oil in a separate accumulator was injected right after finishing the measurement at 0.05 ml/min until no more water effluent was observed. The initial water and oil saturation were then calculated based on the recorded effluent volumes. However, it is worth mentioning that because this study investigated two types of oil, four cores were equally divided to deal with the different oil types. Next, KWT light oil was injected

Table 2
Properties of Berea sandstone cores used for flooding experiments.

Core name	Length (mm)	Diameter (mm)	Porosity (%)	Gas permeability (mD)	Liquid permeability (mD)
A	93.1	37.95	18.94	141	60
B	92.2	37.95	18.80	134	79
C	89.6	38.0	19.08	139	77
E	92.0	38.0	21.51	150	82

into cores A and E, whereas cores B and C represented heavy oil reservoirs with VGH crude oil. After completing the oil injection processes, the cores were aged for 2 weeks before taking any further steps in order to simulate the rock-fluid condition similarly as found in a reservoir. All procedures were conducted at ambient temperature (25 °C). As shown in Table 2, the four cores showed relatively uniform porous characteristics, with a similar porosity of around 20% and pore volumes of around 20 ml, which indicated their adequate to carry out further processes for the purposes of comparison and evaluation. In terms of permeability, although core E had a higher permeable capacity than the other cores, this did not influence the results of the NP flooding for EOR because the incremental oil recovery was not proportional to the increase in permeability [30].

Results and discussion

Nanoparticle properties

A spherical morphology is the best morphology suitable for a porous medium because of easy transport through rock [31,32], easy detachment, and high mobility [33]. Fig. 1 shows both SEM and TEM images of synthesized NPs, the spherical morphology of which makes them suitable for injecting through the core samples. Fig. 2 shows both the intensity and volume distribution modes of the NPs, the sizes of which are all smaller than 80 nm, satisfying the desirable size required for injection into a porous medium. Clearly, this size is much smaller than the micro-sized pore throats inside the porous medium of common sandstone, which has a higher porosity of around 20% and liquid permeability greater than 60 mD [34]. In a dispersing medium, smaller sized NPs will be more favorable in terms of the stability of the suspension as a result of a higher charge density and larger electrostatic repulsive forces among the particles [35,36].

Nanoparticle ferrofluid precipitation

The precipitation speed can be easily recognized visually through the change in turbidity of the NPs dispersed in brine and physically depending on the concentration of NPs and the soluble salt content. A simple test was carried out to visually observe the sedimentation speed of various NP weight percentages in solutions with and without salinity. In particular, as NPs are dispersed in artificial brine with a specific concentration of NaCl, the stability will certainly decrease, inducing a larger scale of NP agglomeration (causing precipitation thereafter) [37]. A salt concentration was made from a 5000 ppm solution for all cases; in fact, this salinity was also used later to design the injected fluid during the core flooding experiment. The records of eight samples in total at the start and after 10 min are shown in Fig. 3. First, with the existing salt, it was easy to recognize the much faster precipitation of 4 wt% and 5 wt% ferrofluids after 10 min, as compared to the others, through the obvious settlement of NPs at the bottom. For cases of 3 wt%–0.05 wt%, an obvious change in turbidity was only recognizable at the upper parts of the jars, and a large density of NPs remained mainly suspended in the brine. The turbidity level was certainly higher in the ferrofluid with a lower NP concentration. Second, there was virtually no difference in turbidity of the 2 wt% NPs dispersed in water without any existing NaCl after 10 min. This absolutely affirms the negative impact of salinity in a NP ferrofluid even at a low concentration.

To fully understand the trend of sedimentation ratio versus time, the precipitation profile of 0.8 wt% NPs dispersed in 5000 ppm salinity brine was fully recorded in a Turbiscan device for a 34 h period. The observed profile of sedimentation is shown in Fig. 4. As can be seen in the figure, for a specific NP content, the sedimentation occurred simultaneously and rapidly under static conditions for nearly 162 min, and thereafter dropped more slightly; the settlement rate was virtually zero after 16 h corresponding with approximately 17% of the original NPs having been settled. This result evidently reveals the threshold of NP precipitation in a specifically low salinity fluid, which is particularly important in the design and maintenance of NP dispersion during the injection process. A longer duration of stability and lower magnitude of sedimentation are definitely preferable for preparing and processing a flooding; however, a sufficient amount of NPs also needs to be guaranteed to effectively improve the EOR performance.

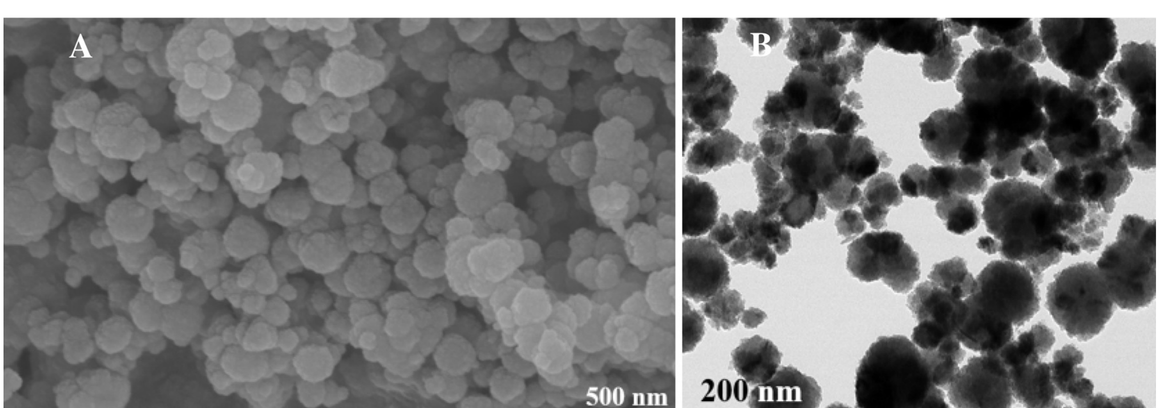

Fig. 1. (A) SEM and (B) TEM images of synthesized NPs.

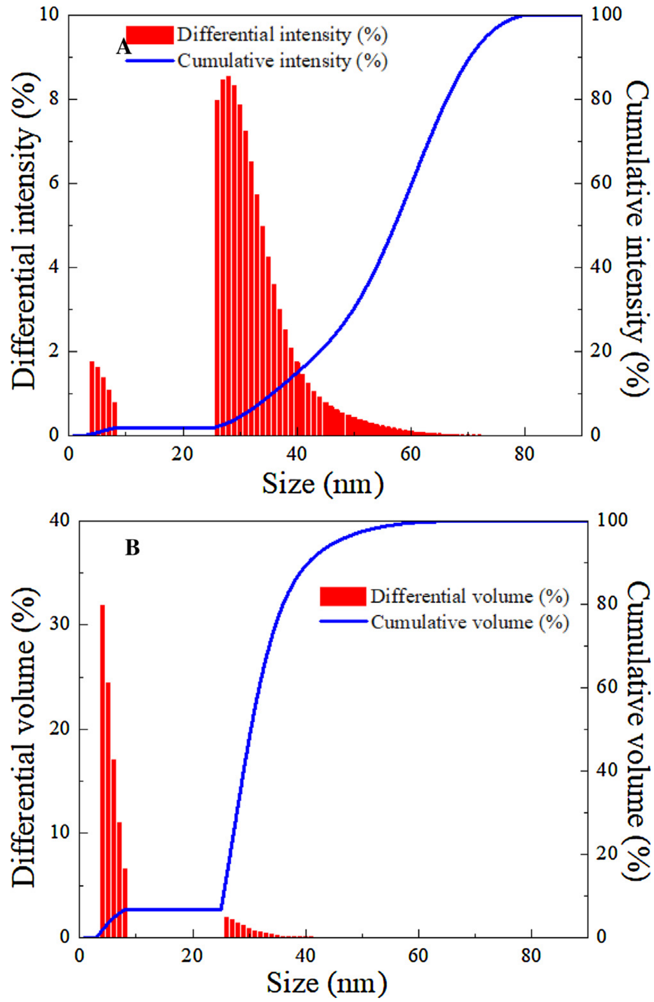

Fig. 2. NP size distribution: (A) intensity and (B) volume modes.

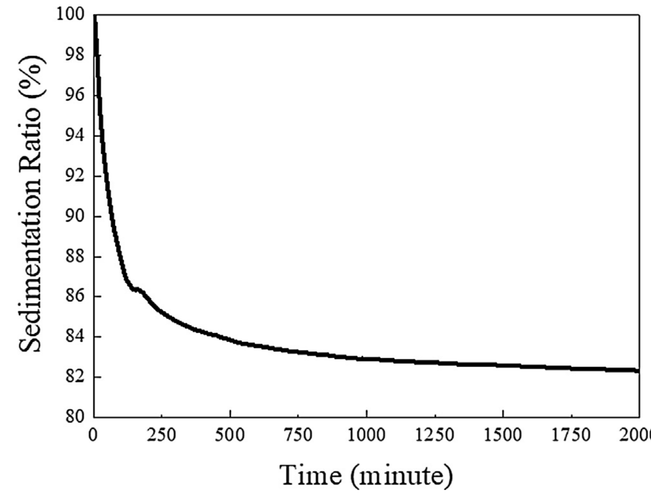

Fig. 4. Sedimentation ratio versus time for a 0.8 wt% NP in 5,000 ppm salinity brine.

Alteration of wettability using nanoparticles

The wettability of a rock system is a critical factor in determining the flow capacity of a reservoir, which should be preferentially considered, particularly when the wetting condition is likely to be changed owing to the effect of a surface-active agent [38–41]. Fundamentally, a neutral wetting condition is preferable compared to either oil-wet or water-wet rock, and a water-wet rock surface is definitely more favorable than an oil-wet system [42–44]. Various types of NPs have been previously identified as excellent agents in transforming the wetting characteristics into the expected conditions, thereby assisting in improving the oil sweeping efficiency; in particular, this mechanism is likely the main dynamic factor in enhanced oil recovery for several different rock-fluid systems [45–48]. In this study, both types of crude oil were examined to partially understand the magnitude of wettability alteration owing to the existence of NPs in an aqueous phase. Fundamentally, the contact angle between a liquid phase and a solid phase in a tertiary medium was consistently used to evaluate the wettability of the rock. For the same types of sandstone, an oil droplet was kept in a highly saline brine solution (42,000 ppm NaCl) beneath a horizontal sandstone surface for 30 min, and the contact angle between this droplet and the solid phase was then measured using a camera. A schematic of the contact angle measurements is shown in Fig. 5.

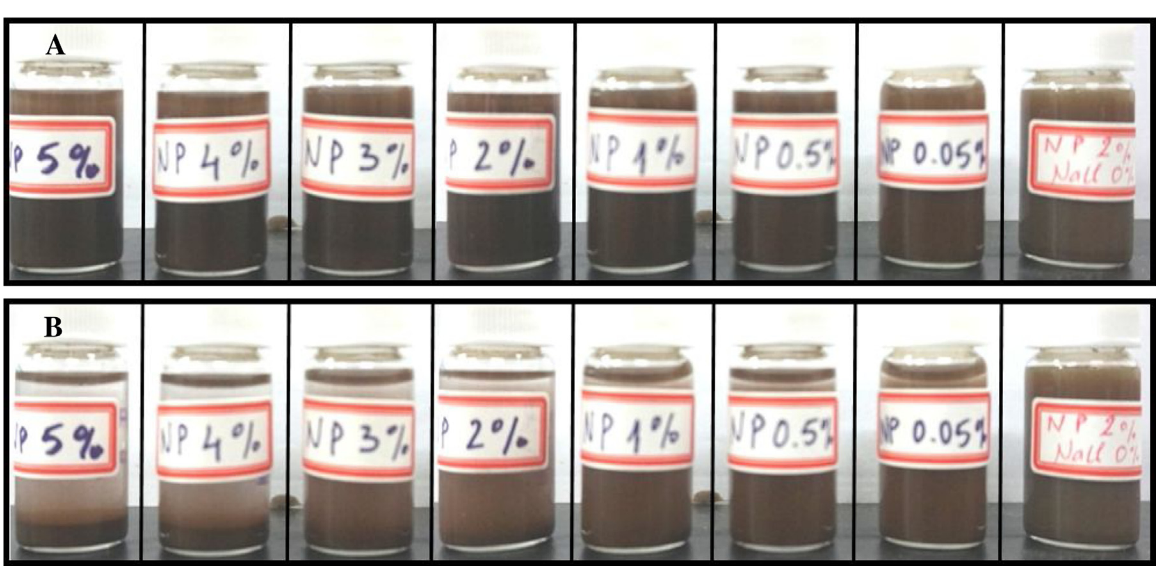

Fig. 3. Real turbidity records of different NP ferrofluids after: (A) 0 and (B) 10 min.

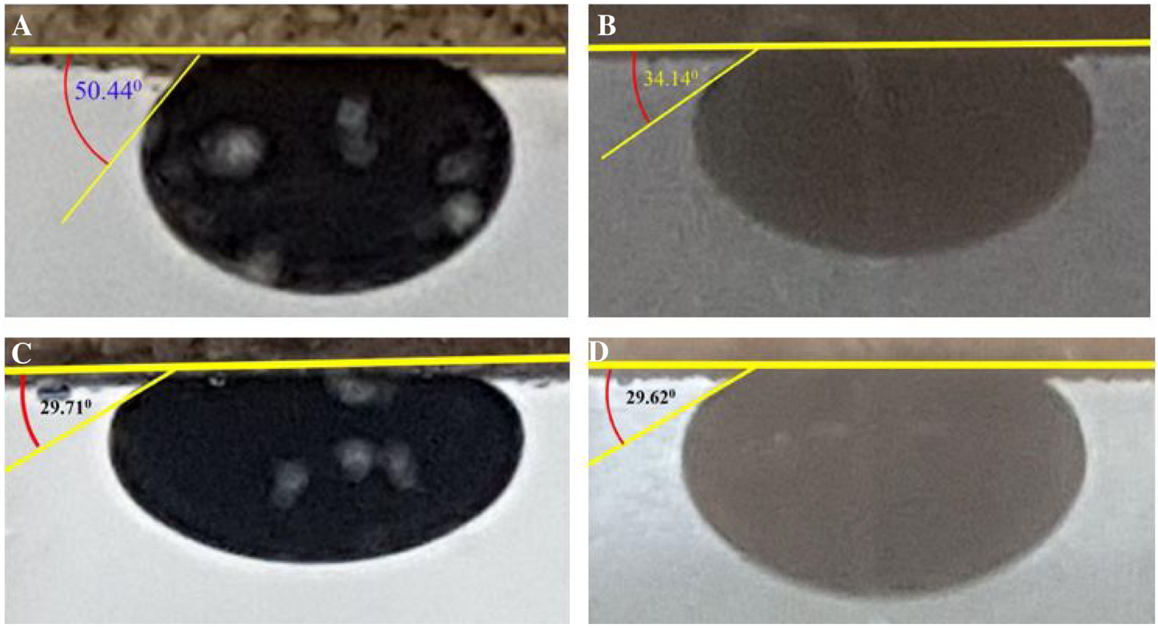

Fig. 5. Contact angle measurements for crude oils in high salinity brine: (A) KWT oil, no NP dispersion, (B) KWT oil, with NP dispersion, (C) VGH oil, no NP dispersion, and (D) VGH oil, with NP dispersion.

The results indicate a significant difference between the two oil types with regard to the change in contact angle. First, it is clear that this examined sandstone was originally a water-wet system, as expressed through a contact angle of lower than 90° for both types of crude oils, i.e., 50.44° and 29.71° for light and heavy oils, respectively. Second, with the existence of NP dispersion in the same environment, a dramatic reduction in the contact angle between KWT oil and the solid surface by approximately 16° was observed, whereas the angle appeared to be constant for the VGH oil. These visualized results imply an insignificant impact of NPs on a rock-fluid system with heavy oil. Although a short oil submergence time seems to be unsuitable because most heavy oil reservoirs are oil-wet, this conclusion is still acceptable when considering the contact period between the oil blobs and the injected fluid in a porous medium. In terms of light oil, the above observation definitely confirms the wettability alteration mechanism owing to the structural disjoining pressure at the wedge film created by the layer arrangement of NPs. This type of mechanism apparently makes the rock system more strongly water-wet for light oil, whereas the high viscosity can be considered as an explanation of the ineffectiveness of this mechanism for VGH heavy oil. In other words, compared to a heavy oil rock system, a change in wettability to strongly water-wet, and an improvement in fluid flow mobility, are essential mechanisms for potentially enhancing the oil production in a conventional light oil reservoir when NPs are employed, specifically magnetite NPs used in the present study.

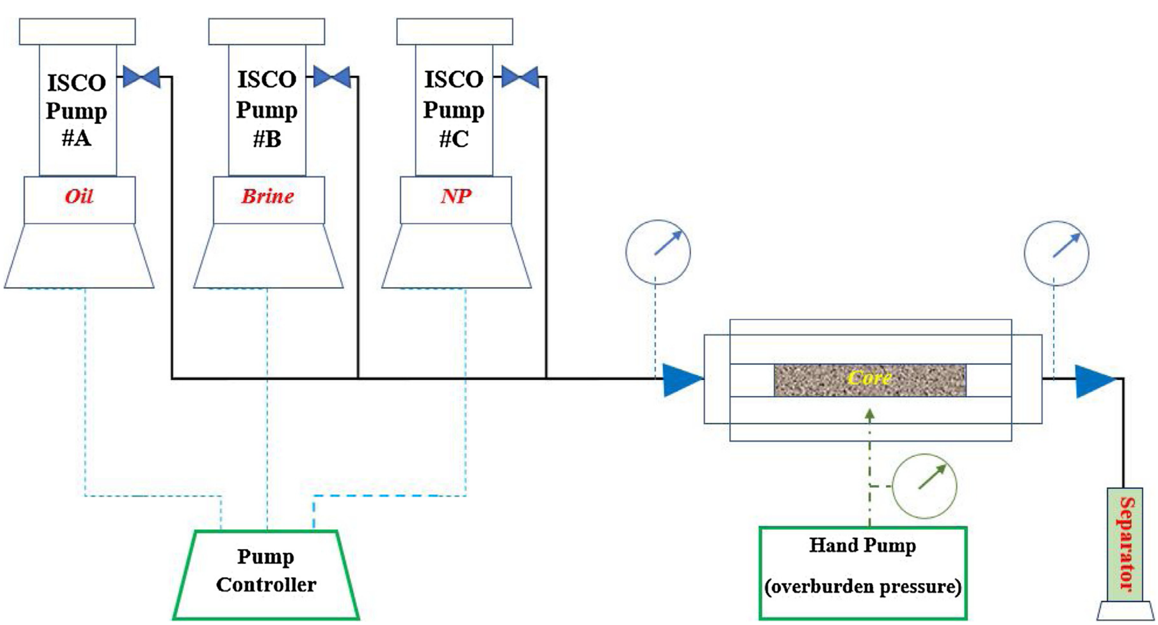

Fig. 6. Schematic of the facilities used for core flooding processes.

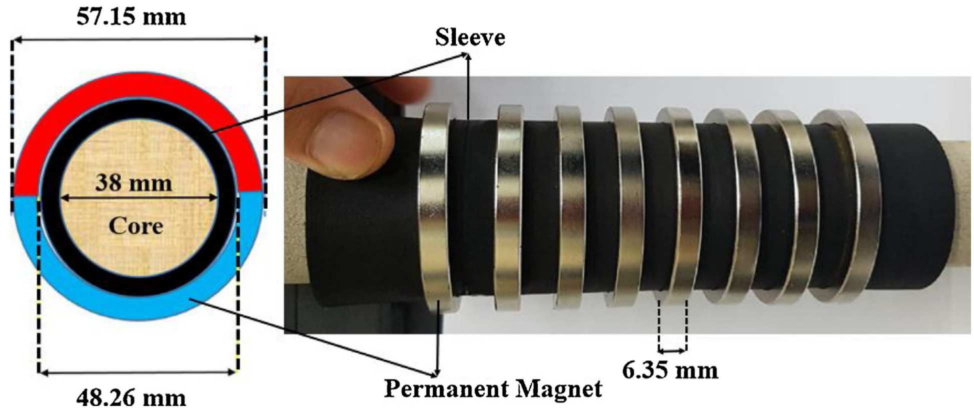

Fig. 7. The sleeve equipped with eight permanent ring magnets.

Core flood experiment

Core flooding experiments were carried out using a common setup [49,50] coupled with three pumps to deal with three kinds of fluid, respectively, which were electronically managed using a pump controller and a simple effluent separator, as shown in Fig. 6. An overburden pressure of 6 MPa was simultaneously applied during each flooding process to simulate the high-pressure environment around the cores and avoid fluid leakage from the sleeve.

To apply a magnetic field, a total of eight permanent ring magnets were attached alongside the core sleeve to create a uniform magnetic strength throughout the core. An image of this type of sleeve is shown clearly in Fig. 7. All of the ring magnets were N40 grade neodymium type magnets made in the USA (pull force of 29.06 lb). To increase the precision and accuracy, a permanent magnet instead of an electromagnet was used. The temperature during the use of the permanent magnet could be kept constant, but using an electromagnet increased the temperature and affected the results owing to a decrease in viscosity.

The four cores were equally divided to be flooded under non-magnet and magnet schemes for both light and heavy crude oil. Following that, cores E and C were prepared to examine the effects of the magnetic field, whereas a conventional flooding scheme was applied for cores A and B. The flooding experiments on oil recovery were carried out similarly for all four cores using the following steps:

- Water flooding: Synthesized brine (42,000 ppm NaCl) was first injected to recover oil until no more oil was produced at the effluent.
- Ferro fluid flooding: A 0.5 pore volume (PV) slug of 0.8 wt% NPs dispersed in low salinity brine (5000 ppm NaCl) was injected after the first water flood at the same injection rate.
- Post-flush water flooding: Finally, the synthesized brine was continually injected until there was no more oil production observed at the effluent.

A constant injection rate of 0.1 ml/min was applied during all core flooding experiments. The use of a ferrofluid for oil recovery was confirmed based on the flooding performances of all four cores, for both conventional injection and the application of a magnetic field. Based on the investigation into different cores for the same category of oil, the oil recovery efficiency was assessed using two recovery factors:

$$RF_1 = \frac{V_p \times 100}{V_{OOIP}}(\%), \tag{1}$$

$$RF_2 = \frac{V_{p.NP} \times 100}{V_{OIP.W}}(\%), \tag{2}$$

where RF_1 expressed a general recovery factor with respect to the original oil volume in the core prior to flooding, and RF_2 represents the efficiency of NP flooding after a pre-flush water injection. Following that, V_p and V_{OOIP} are the cumulative oil produced and the original oil volumes, respectively, whereas $V_{OIP.W}$ is the remaining amount of oil in the core after the first water flooding, and $V_{p.NP}$ is the oil produced through the use NPs and post-flush water injections.

The results of the flooding experiments for cores A and E as candidate light oil reservoirs are shown in Fig. 8. It was principally affirmed that the use of NPs remarkably enhanced the oil production after ineffective water flooding. In detail, the pre-flush water injection only recovered 55.62% of OOIP in core A after injecting 1.5 PV of brine, whereas this RF_1 value of core E was 63.38% after an injection of approximately 1.3 PV. In both cores, no additional oil was observed during the NP injection, whereas oil was observed within 1 PV of ultimate post-flush water flooding, with an increment in RF_1 of 15.38% for core A and 16.2% for core E. In terms of the oil recovery efficiency after water flooding, utilization of the ring magnets supports an RF_2 of 44.23%, which is 10.33% higher than the case without applying a magnet. This result undoubtedly describes the absolutely positive effect of the magnetic field in EOR when a NP ferrofluid is employed after water flooding.

This expected outcome can be explained based on the noticeable improvement in the sweeping efficiency, which has been demonstrated as the dominant macroscopic mechanism for enhancing oil production [51–54]. If the injection rate is reasonably designed, the NPs will neither agglomerate nor flow in a unique vector, and alternatively, the magnetic forces will drive the particles to flow uniformly in the core, and the oil will thereafter be displaced more thoroughly as a consequence as compared to the case of a conventional core flooding operation. In addition, magnetite NPs create a columnar structure in the direction of the applied magnetic field, and this column moves through the pores toward the production well owing to the pressure of the post flush water flooding. This column operates like a piston and sweeps the oil from the pore channels, thereby increasing the oil production. With this mechanism, the sweeping efficiency, and consequently the oil recovery, increase. Further, because the nano-sized particles are intrinsically partially retained in the core, the residual resistant factor, which is determined as the permeability impairment level, is also expected to be higher owing to the effect

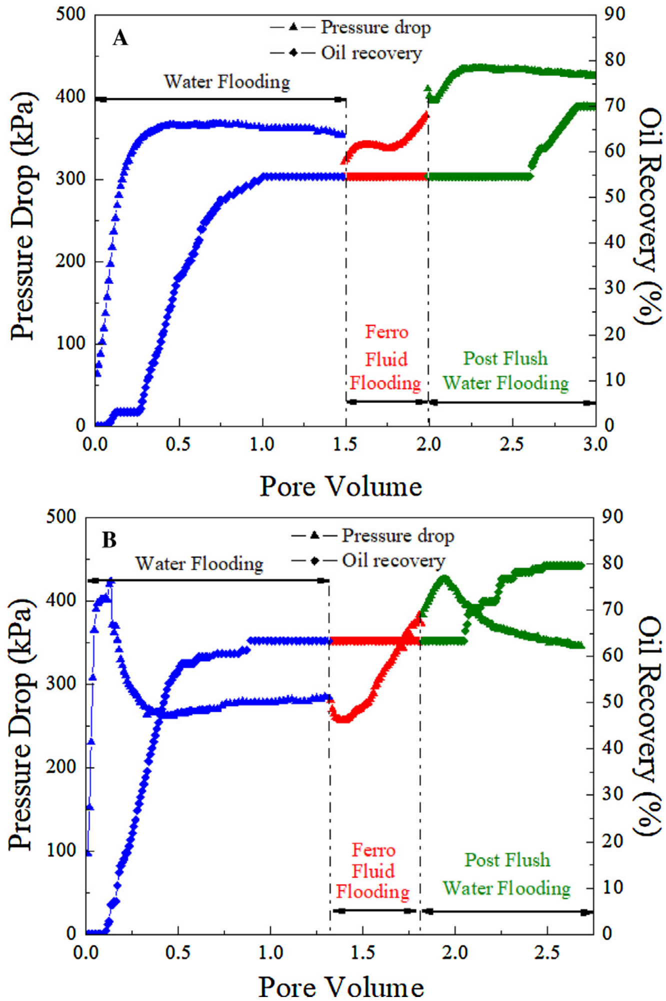

Fig. 8. Core flooding performances for KWT oil: (A) core A, no magnetic field and (B) Core E, applied magnetic field.

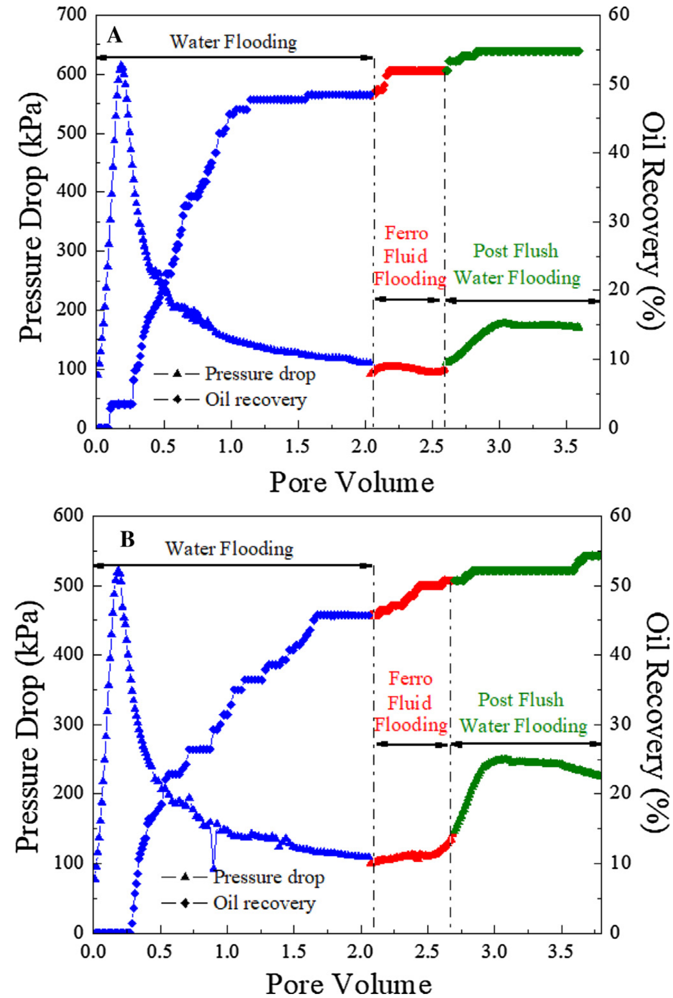

Fig. 9. Core flooding performances for VGH oil: (A) core B, no magnetic field and (B) core C, applied magnetic field.

of the magnetic power, which induces a higher distribution of NPs in the core. The resistant factor (R_{rf}) is defined as [55]:

$$R_{rf} = \frac{K_b}{K_a} = \frac{\Delta P_a}{\Delta P_b}, \quad (3)$$

where K_b and K_a are the permeability of the rock system before and after injecting NPs, respectively, corresponding to pressure drops ΔP_b and ΔP_a, respectively. Considering the stabilized pressure drop before and after NP flooding, the results in Fig. 8 show a slight difference in terms of the residual resistant factors, with about 1.20 for core A, and nearly 1.27 for core E. This insignificant deviation probably shows the thoroughly swept profile induced by the final 1 PV slug of the brine injection, which is highly efficient even under the effect of a magnetic scheme.

The aforementioned measurement of the contact angle between the VGH heavy oil and Berea sandstone surface presumably indicates the unsuitable exertion that occurs when using NPs to enhance heavy oil recovery under the rock wettability alteration mechanism. However, owing to the fact that the viscosity of the injected fluid will absolutely increase by the addition of the NPs, in addition to the possible improvement in particle flow in the core and in the mentioned columnar structure through the application of a magnetic field, such conclusion also needs to be determined for highly viscous crude oil reservoirs. Similar to a light oil type, an examination was carried out in two different cores. The results of core flooding for this heavy oil are described in Fig. 9.

As Fig. 9 shows, a resulting oil production at the effluent was observed as soon as the NP injection began after around 2 PV of water flooding, and this profile continued until the end of the entire process. The oil recovery for this heavy oil is slightly lower than that of KWT light oil, with an RF_1 of 48.42% after pre-water flooding, and a 6.32% increase in oil produced through NP injection, corresponding with a recovery factor RF_2 of 12.24% induced by the addition of the NPs. For core C, the application of a magnet did not remarkably enhance the heavy oil production, with an increase of 8.57% OOIP induced through NP flooding, corresponding to an efficiency of 15.79% (RF_2) after the initial water flooding process. In other words, the utilization of ring magnets only resulted in an additional improvement of 2.25% in RF_1 and 3.55% in RF_2 with respect to the case of core B. These results certainly affirm the actual enhancement of heavy oil recovery when employing nano-sized particles. Although it has been proven that a ferrofluid does not drastically change the wetting conditions, an increase in viscosity and a possible improvement in the flow-paths of the injected fluids caused by the accumulation of NPs in a porous medium, as well as the columnar structure made when applying a magnetic field, are critical factors helping to improve the oil extraction from the pores. Clearly, the particles were retained more easily in comparison with the light oil case because the heavy oil blobs are much less moveable, and as a consequence, the amount of particles distributed in the pores was greater than that in low viscous crude oil. Indeed, the permeability impairment, which is represented by the resistance factor, of cores B and C was higher than for both cores A and E, with R_{rf} of 1.46 and 2.17 for cores B and C, respectively. In particular, the higher R_{rf} of core C implies the higher magnitude of NPs retained in the porous medium induced by the power of the applied magnet. On one hand, this mechanism mitigates an oil-bypassing scheme, which supports the fluid flow profile in the medium and thereby improves the sweeping efficiency. On the other hand, because the injected fluid is not sufficiently supportive to make highly viscous oil moveable, the magnetic strength is more likely to cause the larger decrease in permeability as a consequence. This implication apparently explains the lesser effect of the magnetic field in improving heavy oil production as compared to light oil. Flooding using a ferrofluid with higher weight percent of magnetite NPs, or applying a magnetic field with higher strength, may lead to a more stable column in the direction of the applied magnetic field and cause a better sweeping efficiency in the case of heavy oil.

A new method was briefly introduced to EOR using an NP ferrofluid with the application of a magnetic field for both kinds of crude oil. Although the experiments were carried out in a small number of cores, and the facilities were too simple to completely understand the mechanisms behind the applied processes, the results substantially indicate the potential enhancement of oil production through the use of NPs and magnetic strength for both light and heavy oil. However, the method should be modified in future research for better application to actual oil fields, and in particular, the enhancement of heavy oil recovery should be increased further for greater feasibility in terms of technical and/or economic aspects.

Conclusions

Owing to the reduction of new oil field exploration and increasing demand for oil, EOR techniques are significant targets in the area of oil engineering. Among a number of methods for EOR, nanofluid flooding remains a challenging issue, and there are many unknown aspects to this method. In this study, ferrofluid flooding through core samples was studied with and without the application of a magnetic field for two kinds of oil. To obtain this goal, magnetite NPs were synthesized using a facile method that can be applicable in industry at a large scale; these NPs were then characterized with regard to the morphology and size, and studied to consider the sedimentation ratio suitable for injection into a porous medium. Using an NP ferrofluid made using synthesized magnetite, a short test of its ability to alter the wettability for Berea sandstone was briefly conducted to confirm the surface-active mechanism that is particularly vital for the EOR process. The results of the contact angle measurements definitely affirm the capacity of magnetite NP dispersion in changing the rock wetting condition from water-wet to more strongly water-wet with respect to light oil, whereas this mechanism is not really noticeable for heavy crude oil. In other words, this mechanism is a promising reason for the improved crude oil production in conventional oil reservoirs in comparison with highly viscous oil reservoirs. The results of core flooding experiments reveal the potential of applying a magnetic field to EOR using an NP ferrofluid; however, the efficiency was evaluated as more significant for a core containing light oil than for a core containing heavy oil. The mechanism behind this enhancement was adequately judged to be an upgrade in the NP distribution in the core, as well as the columnar structure created in the pore channels when applying a uniform magnetic field; however, the effect is insufficient to make the viscous oil moveable. In the other words, ferrofluid flooding in the absence of an applied magnetic field can increase the oil recovery owing to the wettability alteration and better sweeping efficiency, and when applying a magnetic field, this capability increases owing to the generation of a columnar structure that sweeps the oil more efficiently and promotes the distribution of NPs throughout the entire core, thereby postponing a breakthrough. Although the proposed method provided the expected outcomes and conclusions, because it has only just emerged for testing, modification should be attempted in future flooding experiments, including an increase in the number of cores, the types of rock systems applied, and in particular, determining measures to for practical application in actual oil fields.

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