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ORIGINAL ARTICLE

Implications of chemical agents and nanofluids coupled with carbon dioxide to improve oil recovery factor

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Abstract
In this study, we experimentally investigated the effects of chemically enhanced oil recovery methods containing hydrolyzed polyacrylamide (HPAM), surfactant–hydrolyzed polyacrylamide (SHPAM), surfactant nanofluids (SNF), that is, coupled with carbon dioxide (CO_2) and water chase injection to measure enhanced oil recovery methods in a sandstone reservoir. To proceed with the experiments, we performed four flooding tests at the simulated reservoir temperature of 70 °C. The sand packs were saturated with oil to establish the irreducible water saturation (Swr). Then, the fluid flow in sand packs remained undistributed for about 5 days to obtain the 1.5 pore volume (PV). We observed that the pressure drop had small fluctuations when there was waterflooding (until 1.5 PV), and after injecting the chemical agents, the pressure drop had a sharp rise. It is indicated that the chemical solution has implemented higher pressure drops (significant energy efficiency) to displace the oil instead of water. The maximum oil recovery factor was about 53% and 59% when HPAM and SHPAM solution displaced oil after waterflooding, respectively; however, it is observed that water chase flooding recovered about 8% and 14% of remaining oil in place while CO_2 has increased only 3% and 5%, respectively. SNF solution can provide more oil recovery factors. It is about 72% (SNF with 0.5 wt%) and 67% (SNF with 1 wt%). We observed that water chase flooding recovered about 20% of oil in place while CO_2 increased by only 8%. It was concluded that the SNF solution with 0.5 wt% tends to adhere to the water–CO_2 and causes to improve oil recovery factor after SNF injection. Therefore, SNF is the optimum enhanced oil recovery method among other chemical agents. On the other hand, with the decrease in CO_2 flow rate and increase in silica nanoparticles slug size, pressure drop has started to decrease in higher pore volume injections, indicating that larger volumes of CO_2 can be stored in sand packs. However, by increasing the CO_2 flow rate and decreasing silica nanoparticles slug size, CO_2 can escape easily from the sand pack.

Keywords Oil recovery · Sandstone reservoirs · Silica nanoparticles · CO_2 flow rate · Slug size

Introduction

Sandstone reservoirs are very different from carbonate reservoirs. If diagenesis in carbonate reservoirs is very important in the distribution and evolution of cavities, the main factor controlling geometry and heterogeneity in sandstone reservoirs is the facies changes and sedimentary environment (Morad et al. 2010; Yıldız and Yılmaz 2020; Zhang et al. 2020). In other words, sedimentary models directly correlate with static reservoir models. This reservoir rock is spread to deep sea sands in alluvial cone environments on land. The world's most essential sandstone reservoirs have developed in deltaic environments, where large volumes of sand are transported by channels and spread in crater ridges (Adepehin et al. 2019; Heidsiek et al. 2020). Due to the silicate mineralogical nature of the particles (quartz, feldspar, rock fragments, and clay minerals) and the youngness of many sandstone reservoirs, diagenesis does not

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affect them (Zhao et al. 2021; Dong et al. 2021; Qiao et al. 2020). Unlike carbonate reservoirs, cavities in sandstone reservoirs are not very diverse. Intergranular pores are the primary type of porosity in sandstone reservoirs. Sometimes, feldspar particles and crushed stone may be dissolved during diagenesis, creating mold porosity. Porosity and permeability in sandstone reservoirs depend on particle size, porosity, type, and amount of clay. Sandstone with kaolinite cement is more permeable than types with illite cement (Li et al. 2020; Miall 1988).

Due to the importance of carbon storage for geothermal applications and the re-injection of CO_2 for further enhanced oil recovery methods, it is essential to increase the carbon storage capacity in subsurface formations (Wu and Li 2020; Buscheck et al. 2016; Feng et al. 2014; Li et al. 2016; Davarpanah and Mirshekari 2019). Furthermore, the CO_2 released into the atmosphere might harm human lives (Norhasyima and Mahlia 2018; Xu et al. 2014). One vital role of CO_2 in EOR processes is to reduce the residual oil viscosity, which can help mobilize more feasibly and improve the oil recovery factor. The poor performance of CO_2 injection can provide gravity segregation and viscous fingering corresponding to the lower density and viscosity of the gas phase. *In situ* foam generation during CO_2 injection can solve viscous fingering and gravity segregation issues (Hill et al. 2020; Wei et al. 2015; Marbun et al. 2021).

On the other hand, *in situ* foams can reduce the formation damage and improve oil recovery by trapping CO_2. This phenomenon can be essential in carbon storage capacity too. One of the drawbacks of foams is the instability issue which may be kinetically and thermodynamically (Shabib-Asl et al. 2019). Adding polymer solution can increase the fluid viscosity, preventing gas mobilization. Due to the surfactants' effectiveness in reducing the interfacial tension (IFT) (Pan et al. 2020), they can provide more oil recovery factors than the polymer solution (Rognmo et al. 2020; Sun et al. 2019; Alcorn et al. 2020; Davarpanah 2020).

However, having said this, we experimentally investigated the effects of chemically enhanced oil recovery methods containing hydrolyzed polyacrylamide (HPAM), surfactant–hydrolyzed polyacrylamide (SHPAM), and surfactant nanofluids (SNF), coupled with carbon dioxide (CO_2) and water chase injection to measure and select the optimum enhanced oil recovery methods in a sandstone reservoir. To proceed with the experiments, we performed four flooding tests at the simulated reservoir temperature of 70 °C.

Materials and experimental procedure

Materials

Chemical agents

To prepare the chemical agents used for this experiment, foams were generated with a sodium lauryl sulfate (SDS) surfactant with a purity of 95%, and the nanoparticles were extracted from liquid tetraethylorthosilicate (Zarei and Nasiri 2021) with a purity of 98.9%. To obtain the polymer solution for experiments, we added 2 gr. of HPAM in 1 L of distilled water, which was placed in a magnetic stirrer at 150 RPM for 12 h to ensure that the solution had a stable vortex. Then, we added the SDS to the polymer solution at 300 RPM for 1 h to make the SHPAM. This procedure was also repeated for surfactant nanofluids (henceforth, SNF) preparation by adding SDS to silica nanoparticles.

Crude oil

The crude oil characteristics are described in Table 1.

Synthetic brine

We provided the synthesized brine according to formation brine properties for more accurate results. The synthesized brine mainly consisted of NaCl, with a purity of 99.8%. For preparing all chemical agents, we used desalinated water for better results and fewer environmental impacts.

Sand pack preparation

To perform the experiments, we pre-washed the initial sands from the Tarim Basin in China with toluene, and then, they were dried for 72 h at 220 °C to remove any impurities. The sand particle sizes range between 15 and 35 (±5) nm. It mainly consisted of quartz with 94% and chlorite and kaolinite with weight percent of 4% and 2%, respectively. Finally, we artificially synthesized sand pack to proceed with the flooding experiments.

Table 1 Crude oil characteristics from the Tarim Basin in China

Parameter	Value (unit)
Viscosity at 70 °C	2.94 mPa.s
Density at 70 °C	0.925 (gm/cc)
Aromatics	3.25%
Resins	9.84%
Asphaltenes	15.42%
Other components	71.49%

Experiments

To hold the prepared sand packs for oil recovery experiments, we used a stainless steel holder that can be replaced for each experiment (see Fig. 1). We continuously injected water into the sand pack held in the core holder to measure permeability and porosity to be fully saturated. The porosity varied from 7.29 to 13.15%, while the permeability ranged from 0.022 to 0.35 mD. Crude oil with a flow rate of 0.02 cm3/min was injected through core samples to measure the connate water saturation. The point where there was no water production was called connate water saturation (Swc≈39.75–42.35%). Then, the following steps were done sequentially to measure the oil recovery factor.

1- We used HPAM as a polymer solution to measure the oil recovery factor, and how the pressure drop profile can be varied. HPAM solution has more pressure drop than water due to its viscosity and density.
2- In the second step, we used a surfactant–HPAM (SHPAM) solution to measure the oil recovery factor, and how the pressure drop profile can be varied.
3- To compare the effect of SNF solution on the oil recovery factor with the previous injectivity scenarios, we performed a core flooding test and observed the differences in the produced oil.
4- Here, we used SNF (with 0.5 wt%) to control the CO_2 mobility as generated *in situ* foam by this surfactant can decrease the CO_2 breakthrough and subsequent CO_2 storage capacity in subsurface formations.
5- To optimize the CO_2 flow rate, we investigated 25–75-mL/hr flow rates and measured pressure drop accordingly.

Results and discussion

We performed four flooding tests at the simulated reservoir temperature of 70 °C. The porosity and permeability of the sand packs were measured 25–31% and 526–583 mD respectively. To establish the irreducible water saturation (S_{wr}), the sand packs were saturated with oil for a period, and then, the sand packs remained undistributed (without any fluid flow) for about 5 days to obtain the 1.5 pore volume (henceforth, PV) injected. Then, we performed the flooding experiments with chemical agents and measured the pressure drop profile and oil recovery factor.

Polymer solution

During the injection of invading fluids to recover the oil from the end of sand packs, there is a natural resistance between the artificial sand pack (as the consolidated porous medium) and the fluids to move through the pores and pore throats. It depends on the viscosity and density of the invaded (injected) fluid. Here, we used HPAM as a polymer solution to measure the oil recovery factor, and how the pressure drop profile can be varied. HPAM solution has more pressure drop than water due to its viscosity and density. It has corresponded to the more required energy to displace the HPAM solution through a porous medium, and subsequently, the pressure drop has risen dramatically.

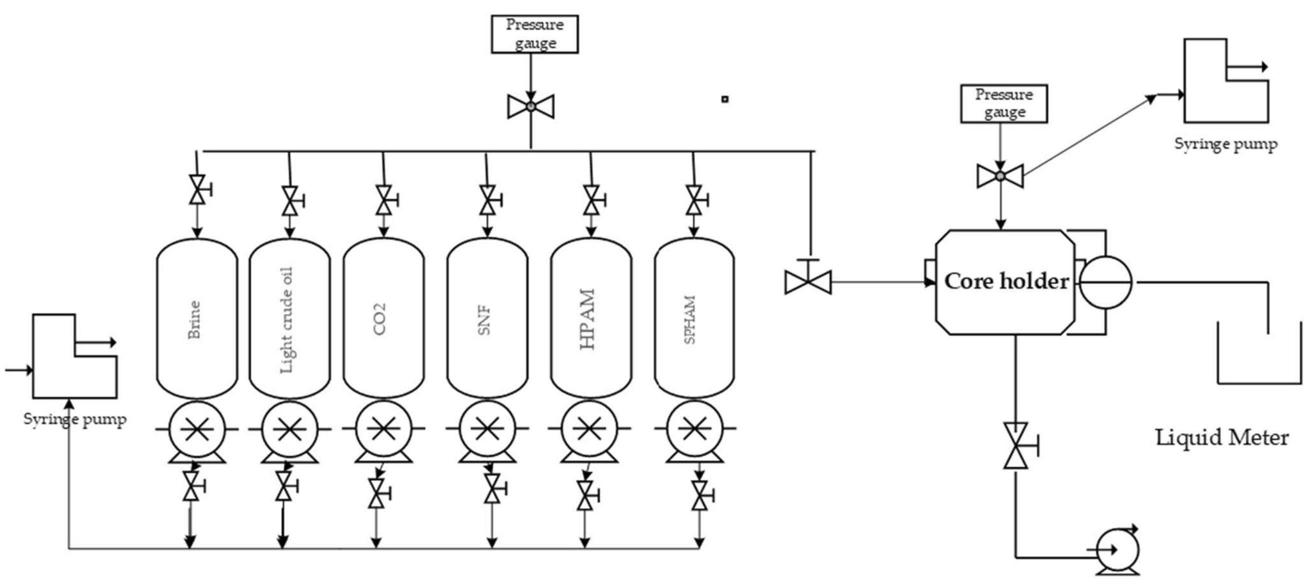

Fig. 1 Schematic of flooding experimental setup

As shown in Fig. 2, the pressure drop had small fluctuations when there was waterflooding (until 1.5 PV). After injecting the HPAM solution, the pressure drop (red line) had a sharp increase (around 52 psi) in just 0.5 PV, which indicated that the HPAM solution had implemented higher pressure drops (significant energy efficiency) to displace the oil instead of water. Figure 2 shows that the maximum oil recovery factor was about 53% (green line) when the HPAM solution displaced oil after waterflooding. To investigate the efficiency of carbon dioxide (CO_2) and water chase injection, we injected both as separate injectivity scenarios after oil recovery was stabilized after the HPAM solution. We observed that water chase flooding recovered about 8% of oil in place while CO_2 increased by only 3%. It was concluded that the HPAM solution could control the CO_2 solubility in crude oil and cause to improve the oil recovery factor after HPAM injection, which was found by Yang et al. 2005.

Surfactant–HPAM solution

Here, we used a surfactant–HPAM (SHPAM) solution to measure the oil recovery factor, and how the pressure drop profile can be varied. As shown in Fig. 3, the pressure drop had small fluctuations when there was waterflooding (until 1.5 PV), and after injecting the SHPAM solution, the pressure drop (black line) increased slightly (around 48 psi) to just 0.5 PV; however, as the SHPAM solution was covered a broader area in sand pack. It has led to more pressure drop than HPAM solution as it needs higher efficiency to displace the oil phase. Due to the surfactants' effectiveness in reducing the interfacial tension (IFT), in comparison with HPAM solution, it can provide more oil recovery factor. It is about 59% which is about 7% more than the HPAM solution. We observed that water chase flooding recovered about 14% of the remaining oil in place while CO_2 has increased only 5%. It was concluded that the SHPAM solution could control the CO_2 solubility in crude oil and cause to improve the oil recovery factor after SHPAM injection. It can be witnessed

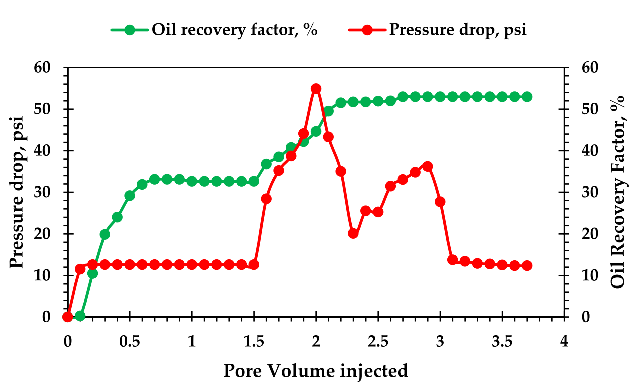

Fig. 2 Effect of HPAM solution after waterflooding on the pressure drop and oil recovery factor

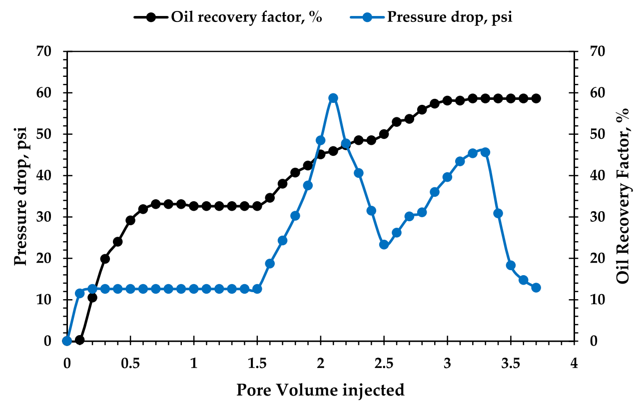

Fig. 3 Effect of SHPAM solution after waterflooding on the pressure drop and oil recovery factor

that SHPAM coupled with CO_2 and water chasing, can provide better sweep efficiency than the HPAM solution.

SNF solution

Here, we used (SNF) solution to measure the oil recovery factor, and how the pressure drop profile can be varied. As shown in Fig. 4 (0.5 wt%) and Fig. 5 (1 wt%), the pressure drop had small fluctuations when there was waterflooding (until 1.5 PV). After injecting the SNF solution for two different solutions, the pressure drop (purple line) increased sharply (around 80 psi for SNF with 0.5 wt%) in just 0.5 PV; however, as the SNF solution (presence of silica nanoparticles and surfactants) was covered a broader area in sand pack. It has led to more pressure drop than SNF solution as it needs higher efficiency to displace the oil phase. Due to the effectiveness of surfactants in reducing the interfacial tension (IFT) and silica nanoparticles in the reduction of wettability alternation and disjoining pressure, compared

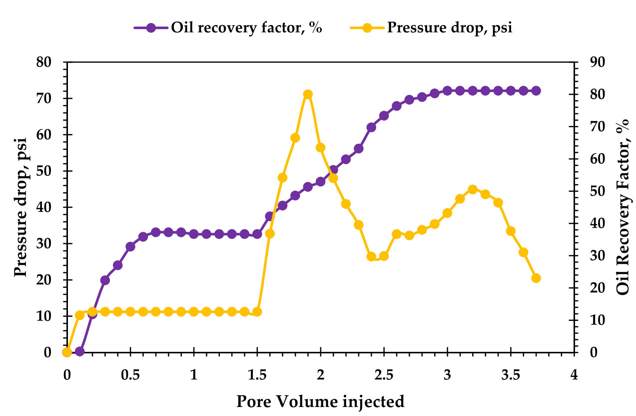

Fig. 4 Effect of SNF (0.5 wt%) solution after waterflooding on the pressure drop and oil recovery factor

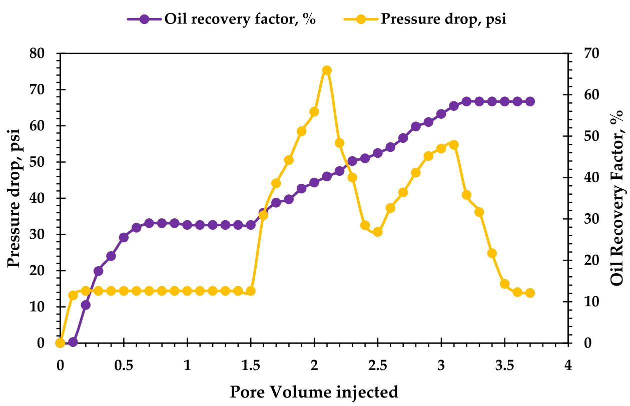

Fig. 5 Effect of SNF (1 wt%) solution after waterflooding on the pressure drop and oil recovery factor

with HPAM and SHPAM solutions, it can provide more oil recovery factors. It is about 72% (SNF with 0.5 wt%) and 67% (SNF with 1 wt%). We observed that water chase flooding recovered about 20% of oil in place while CO_2 increased by only 8%. It was concluded that the SNF solution with 0.5 wt% tends to adhere to the water–CO2 and causes to improve oil recovery factor after SNF injection.

Effect of CO_2 flow rate

To optimize the CO_2 flow rate, we investigated 25–75-mL/hr flow rates and measured pressure drop accordingly. As shown in Fig. 6, by the decrease in CO2 flow rate, pressure drop has started to decrease in higher pore volume injections, indicating that larger volumes of CO_2 can be stored in sand packs. However, with the increased CO2 flow rate, CO2 can easily escape from the sand pack. Therefore, 25-mL/hr CO_2 flow rate was the optimum flow rate as it can help to decrease the pressure drop in higher pore injection volumes of SNF.

Silica nanoparticle slug size effect

Here, we investigated the effect of silica nanoparticle slug sizes (0.5 PV and 1 PV) on the pressure drop during the SNF injection and the optimum CO_2 flow of 25 mL/hr. As shown in Fig. 7, by the increase in slug sizes, pressure drop has started to decrease in higher pore volume injections, indicating that larger volumes of CO_2 can be stored in sand packs. However, with the decrease in slug sizes, CO_2 can escape easily from the sand pack. Therefore, 1 PV of slug sizes was the optimum as it can help decrease the pressure drop in higher pore injection volumes of SNF.

Conclusions

Here, we set aside the different chemically enhanced oil recovery (EOR) methods coupled with CO_2 and water chase injection to select the optimum EOR methods to improve oil recovery. The main notable features of this study are as follows:

- The pressure drop had small fluctuations when there was waterflooding (until 1.5 PV), and after injecting the HPAM solution, the pressure drop had a sharp increase (around 52 psi) in just 0.5 PV, which indicated that the HPAM solution had implemented higher pressure drops (significant energy efficiency) to displace the oil instead of water.
- The maximum oil recovery factor was 53% when the HPAM solution displaced oil after waterflooding.
- It is observed that water chase flooding recovered about 8% of remained oil in place while CO_2 has increased by only 3%.
- Due to the effectiveness of surfactants in reducing the interfacial tension (IFT) and silica nanoparticles in the reduction of wettability alternation and disjoining pres-

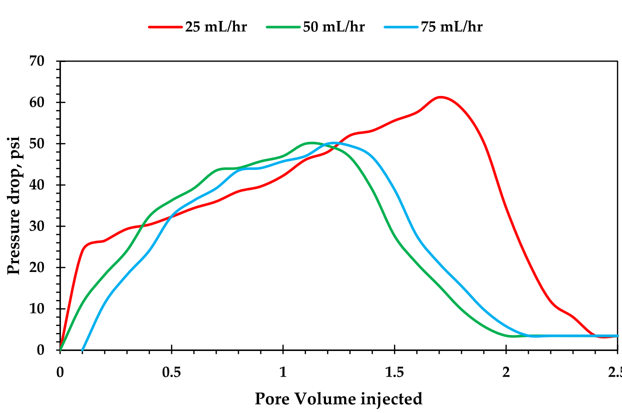

Fig. 6 Effect of CO_2 flow rate on the pressure drop

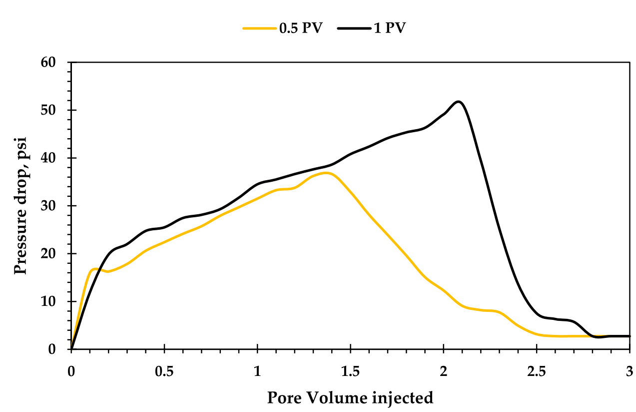

Fig. 7 Effect of silica nanoparticle slug size on the pressure drop

sure, compared with HPAM and SHPAM solutions, it can provide more oil recovery factors. It is about 72% (SNF with 0.5 wt%) and 67% (SNF with 1 wt%).

- SNF solution can provide more oil recovery factors. It is about 72% (SNF with 0.5 wt%) and 67% (SNF with 1 wt%). We observed that water chase flooding recovered about 20% of oil in place while CO_2 increased by only 8%. It was concluded that the SNF solution with 0.5 wt% tends to adhere to the water–CO_2 and causes to improve oil recovery factor after SNF injection.
- With the decrease in CO_2 flow rate and increase in silica nanoparticles slug size, pressure drop has started to decrease in higher pore volume injections, indicating that larger volumes of CO_2 can be stored in sand packs. However, by increasing the CO_2 flow rate and decreasing silica nanoparticles slug size, CO_2 can escape easily from the sand pack.

Author Contributions All authors have made the same contribution and reviewed the paper.

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Data availability The data can be shared upon request to the corresponding author.

Declarations

Conflicts of interest The authors declare no conflict of interest.

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