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Study on imbibition during the CO_2 enhanced oil recovery in fractured tight sandstone reservoirs

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Abstract:
CO_2 enhanced oil recovery (CO_2-EOR) is a key technology for improving the oil recovery of fractured tight reservoirs, and imbibition has been recognized as an important mechanism for oil recovery in low-permeability reservoirs. To clarify the imbibition role and influencing factors during the CO_2-EOR process in fractured tight oil reservoirs and also improve the EOR mechanism, a high-temperature and high-pressure CO_2 imbibition experiment was performed based on the nuclear magnetic resonance technology. The results show that high pressure and high permeability are beneficial to imbibition efficiency. The salinity of the imbibition fluid is not very sensitive to the imbibition recovery. In addition, the CO_2 increases the imbibition speed and can also significantly improve the production rate and oil recovery. It is beneficial to increase the CO_2 concentration to shorten the imbibition equilibrium time and enhance oil recovery. According to the results of the nuclear magnetic resonance study, although the nanopore can provide a greater imbibition force, the oil flow resistance is also larger, but CO_2 can reduce the flow resistance of oil and be conducive to oil production in smaller pores. The inclusion of imbibition into the research category of CO_2-EOR mechanism will be more in line with field practice and more scientific in fractured tight reservoirs, thus providing theoretical support for the development and improvement of the CO_2-EOR technology.

1. Introduction

With the continuous progress of the exploration and development technology, tight oil resources account for an increasing proportion of newly proved reserves, and their efficient development has become a focus of global attention (EIA, 2013; Yu and Miocevic, 2013; Luo et al., 2022; Zou et al., 2015; BP Group, 2018). Tight oil reservoirs are usually characterized by low porosity, low permeability, low original formation pressure, and natural microfracture development. Artificial fracturing is usually required to produce industrial oil flow. Therefore, a complex seepage system consisting of matrix, natural micro-fracture, and artificial fracture can be formed in the development process of tight oil. It is usually characterized by high starting pressure, poor injection-production response, and low water flooding recovery (Kabir et al., 2011; Shen et al., 2019; Wu et al., 2019; Zhu et al., 2019).

It is believed that the crude oil in tight reservoir matrix flows into fractures mainly by imbibition. Thus, imbibition is considered an important mechanism in the production process (Mattax and Kyte, 1962; Birdsell et al., 2015; Wang et al., 2017, 2019; Liu et al., 2022; Saafan et al., 2022; Karimova et al., 2023). As early as the middle of the 20^{th} century, some countries began to study and apply imbibition in oil exploitation (Graham and Richardson, 1959). With the large-scale development of tight oil reservoirs, the role of imbibition in the oil recovery has been significantly considered, and related research has gradually increased. Martic et al. (2002), Hatiboglu and Babadagli (2008), Salam and Wang (2022), Yao

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Table 1. Compositional analysis result of the reservoir brine.

Composition	Na^+	$SO_4{}^{2-}$	$Ca_2{}^+$	$Mg_2{}^+$	Cl^-	$HCO_3{}^-$
Concentration (mg/L)	25,315	122	4,906	496	48,839	385

et al. (2021) and Li et al. (2022) studied the principle and influencing factors of spontaneous imbibition through static experiments at normal temperature and pressure. It is believed that capillary force is the main driving force of imbibition and that rock wettability and interfacial tension are the main factors affecting imbibition. Javaheri et al. (2018), Yassin et al. (2018), Cheng et al. (2022), and Zhou et al. (2022) studied the influence of wettability on imbibition. The results showed that spontaneous imbibition does not occur in oil-wet rocks and that the stronger the hydrophilicity of rocks, the lower the interfacial tension, the greater the imbibition, the faster the imbibition speed, and the higher the recovery. Gu et al. (2017) and Yang et al. (2019) discovered that imbibition is significantly affected by reservoir permeability, where relatively high permeability often results in higher imbibition recovery. In addition, it was found that higher temperature, lower oil viscosity, and lower formation water salinity are beneficial for improving imbibition recovery (Høgnesen et al., 2006; Cai et al., 2020; Ding et al., 2022). To be closer to an actual reservoir environment, Wang et al. (2020), Yang et al. (2020), and Liang et al. (2021) successively performed dynamic imbibition experiments under reservoir temperature and pressure, evaluated and analyzed imbibition displacement effects under different water injection methods, and concluded that moderate and mild water injection should be conducive to more complete imbibition. Thus, the important contribution of imbibition to tight oil displacement was clarified.

With the application of the nuclear magnetic resonance (NMR) technology in oil and gas research, the micro displacement mechanism of imbibition has been gradually clarified. Jiang et al. (2018), Cheng et al. (2019), Liu and Sheng (2020), and Dou et al. (2021) studied the microscopic influence mechanism of the reservoir physical properties on imbibition through NMR experiments, and they found that imbibition mainly occurs in small and medium pores and that large pores have a weak imbibition effect, which further confirms that imbibition is an important mechanism for oil recovery in low-permeability or tight reservoirs. In order to further strengthen the oil recovery effect, Hou et al. (2015), Meng et al. (2018), and Sun et al. (2021) studied the effects of fracturing fluids and surfactants on imbibition from the perspective of changing rock wettability and interfacial tension.

CO_2 gas is a kind of good displacement media due to its miscibility with crude oil. CO_2 enhanced oil recovery (CO_2-EOR) has become an important EOR technology for fractured tight oil reservoirs (Bai et al., 2021; Pu et al., 2021; Zhu et al., 2021). At present, relevant studies on the CO_2-EOR mechanism in tight oil reservoirs are still limited to the interactions between CO_2 and crude oil, ignoring the imbibition of water phases and the influence of CO_2 on imbibition. For fractured tight reservoirs, a large amount of injected water in fractures has undergone imbibition displacement with crude oil in the stage of water fracturing and early water flooding before CO_2-EOR (Cai, 2021). Thus, it is not scientific to study the imbibition and CO_2 displacement separately.

The Chang 4+5 reservoir in Ordos Basin is a typical fractured tight sandstone reservoir with an average permeability of 0.46 mD and very developed structural micro-fractures. The reservoir was waterflooded in 2008 and CO_2-EOR was applied in 2015. At present, the study of CO_2 enhancement mechanism is limited to the miscibility between crude oil and CO_2, and does not consider the imbibition that has occurred in the reservoir for 7 years before gas injection. This study was performed to fully reveal the influence of CO_2 on previous imbibition and the mechanism of CO_2-EOR in fractured tight reservoir, so as to promote the maturity and perfection of CO_2-EOR technology.

2. Experiment

2.1 Materials

The core samples and crude oil (with a viscosity of 2.3 mPa·s at 60 °C) used in the experiment were obtained from the Chang 4+5 tight sandstone reservoir in the Shanbei area in the Ordos basin, and the experiment water was prepared according to the mineral composition of the formation water (with a salinity of 80,063 mg/L and viscosity of 0.924 mPa·s, Table 1) in the study area. The purity of CO_2 gas was 99.99%.

2.2 Design

The temperature and pressure of the experiment were selected according to the reservoir conditions (13 MPa, 60 °C).To clarify the influencing factors and imbibition rules with the participation of CO_2, under the condition of constant CO_2 concentration (0.4 mol/L), three factors, pressure, injected water salinity, and permeability, were changed to set up three levels of an L9 (3^3) orthogonal test (Table 2). Then, under the following conditions, another experiment was conducted, and the T_2 spectrum was collected: a CO_2 concentration of 0.3 mol/L, a salinity of 80.06 g/L, and a permeability of 1.5. Afterward, the obtained T_2 spectrum was compared with the spectrum of the fifth experiment to study the influence of the CO_2 concentration on imbibition and the microscopic displacement mechanism.

2.3 Procedures

The experimental process is shown in Fig. 1. Unlike the previous spontaneous imbibition experimental process, the experimental process was performed in an air bath to simulate the reservoir temperature, and the imbibition pressure was controlled by a back pressure valve to ensure a high-pressure environment. After the imbibition process, the liquid around

Table 2. Basic physical parameters of the rock samples and the orthogonal experiment.

No.	Cores			Influencing factors		
	Length (cm)	Diameter (cm)	Porosity (%)	Permeability (mD)	Pressure (MPa)	Salinity (g/L)
1	5.026	2.504	16.89	4.962	8	0
2	5.367	2.479	16.54	5.126	13	40.03
3	4.887	2.512	17.12	5.314	20	80.06
4	4.988	2.505	14.16	1.558	8	40.03
5	5.216	2.519	14.65	1.526	13	80.06
6	5.316	2.521	15.87	1.354	20	0
7	4.825	2.504	12.35	0.426	8	80.06
8	5.012	2.498	12.15	0.508	13	0
9	5.264	2.515	11.98	0.518	20	40.03

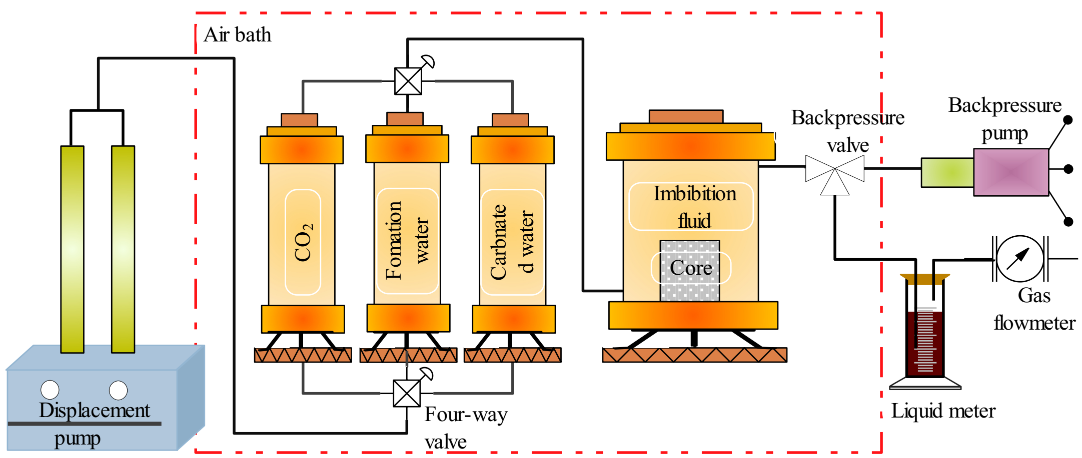

Fig. 1. Flow chart of the imbibition device under high temperature and high pressure.

the core in the container was extracted to a gas-liquid separator under the control of back pressure, and the imbibition fluid and crude oil were separated and measured.

The experimental steps are as follows:

1) The rock sample was saturated with formation water using a vacuum.
2) A $MnCl_2$ solution was used to saturate the cores in the conventional displacement process to shield the nuclear magnetic signal of water.
3) Step 2 was used to test the T_2 NMR spectra of the saturated crude oil in the above-mentioned rock sample under the initial state.
4) The core tested in step 3 was placed in an imbibition container, as shown in Fig. 1. Then, nitrogen was injected into the container and pressurized to the experimental pressure. The prepared formation water was injected into the container, and nitrogen was discharged from the top of the container until water was found at the top.
5) A certain amount of CO_2 was injected into the container at constant pressure to form the CO_2 gas cap. The imbibition oil was discharged from the sampling valve until no more oil was produced, and the experimental data at each sampling moment was recorded.
6) After the imbibition experiment, the core was taken out to test the T_2 spectrum.
7) Steps 1 to 6 were repeated to obtain data for different design experiments.

3. Test results

3.1 Imbibition characteristics

As seen in Fig. 2, the nine experiments all showed the following characteristics. 1) The initial oil production rate is high, and the recovery increases rapidly with time. 2) With the increase in the imbibition time, the production rate gradually decreases, and the oil recovery gradually becomes stable. This result is similar to the results of the conventional imbibition experiments without the participation of CO_2. In addition, within the permeability range of this study (0.4-5.4 md), the imbibition time to reach equilibrium is shortened with the increase in permeability, indicating that high permeability is conducive to imbibition. This analysis shows that initial imbibition mainly occurs in the core surface under the action of capillary force and that the oil-water displacement efficiency

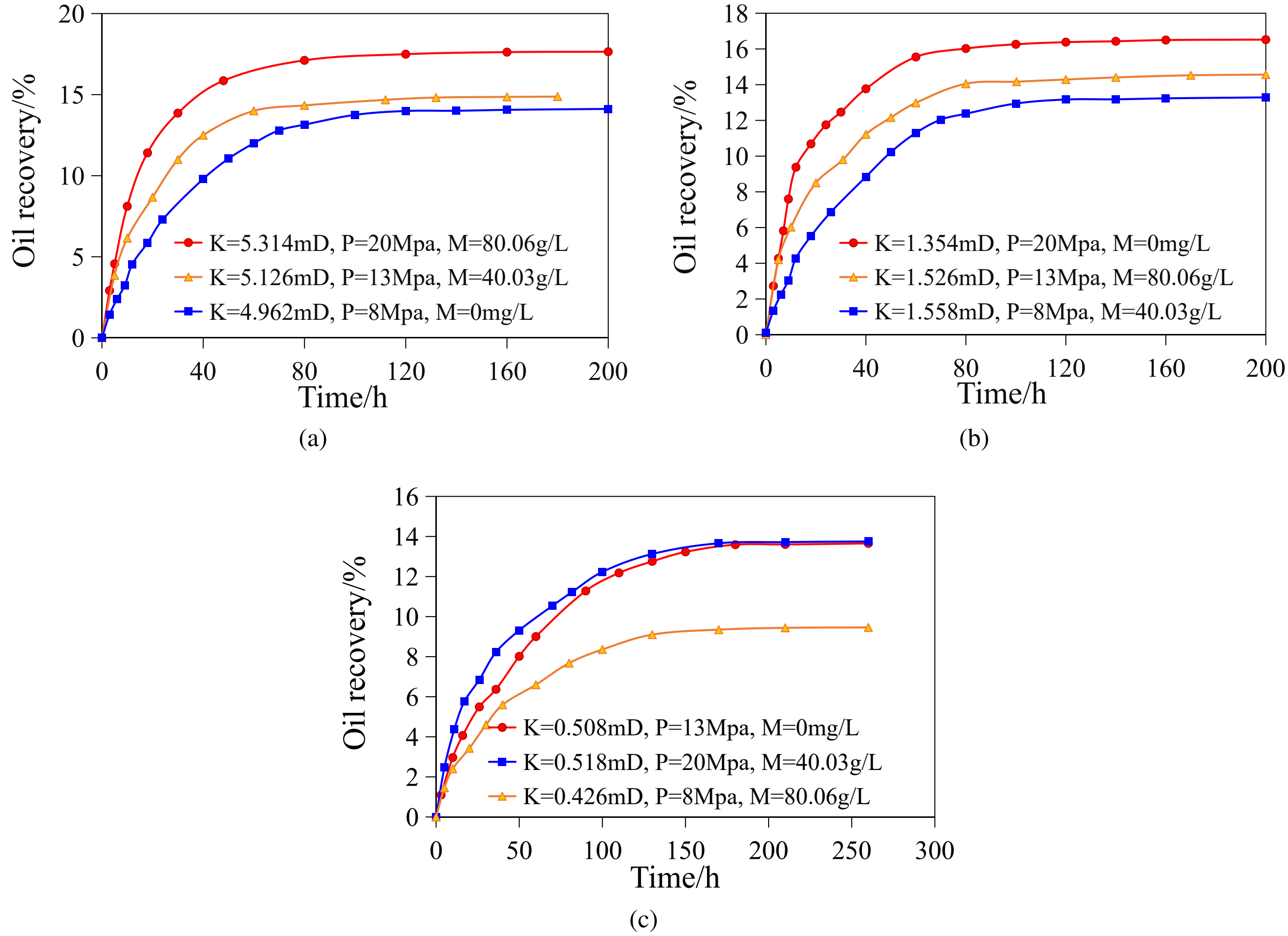

Fig. 2. Orthogonal experiment results of L9 (3^3). (a), (b), (c) represent the first, second, third group of cores respectively.

is high. However, in the later stage of imbibition experiment, the core surface formed oil droplets, resulting in a boundary effect, and, at the same time, the Jamin effect began to appear, thus increasing the difficulty of crude oil recovery in the core.

To clarify the influence degree of each factor on imbibition with the participation of CO_2, the imbibition recovery under each factor was calculated using the orthogonal experiment results, and a sensitivity analysis was performed. The results are shown in Tables 3 and 4 and Fig. 3.

The sensitivity analysis results showed that pressure is the most sensitive factor affecting imbibition recovery. Permeability is second only to pressure; however, it also has a significant effect. Nevertheless, the salinity of the imbibition fluid is not very sensitive to the impact of the imbibition recovery.

Fig. 3 shows a positive correlation between imbibition recovery and pressure. The higher the pressure, the faster the imbibition speed, and the higher the recovery. The analysis shows that these results are mainly because with the increase in pressure, the solubility of CO_2 in the formation water increases, and the acidity of the formation water increases, which not only reduces the oil-water interfacial tension (Fig. 4) and imbibition resistance but also enhances the ability to improve the wettability of rocks, making them more hydrophilic and strengthening the power of imbibition. The reason for the enhanced hydrophilicity is that the low pH value of carbonated water causes the quartz surface in sandstone to change from electrically neutral silanol groups to electrically positive silanol groups. In addition, pressure improves the diffusion and dissolution of CO_2 in crude oil, enabling more CO_2 interaction with oil at a faster speed. Thus, it is conducive to reducing the oil viscosity and seepage resistance and increasing the oil expansion coefficient and discharge energy.

The results of the sensitivity analysis showed that the lower the permeability of the core, the slower the imbibition rate and the lower the recovery. The analysis showed that permeability has both advantages and disadvantages for imbibition recovery. On the one hand, the lower the permeability of the core, the smaller the pore radius, and the larger the capillary force, which is one of the main driving forces of spontaneous imbibition. Therefore, a lower permeability can produce a larger driving force for imbibition. On the other hand, the lower the permeability, the greater the viscous forces caused by the decrease in the capillary radius. Moreover, the increase in the viscous forces caused by the decrease in the capillary radius is often greater than the increase in the capillary force, which has a stronger inhibition effect on spontaneous

Table 3. Orthogonal experimental results.

No.	Influence factors			Recovery (%)
	Permeability (mD)	Pressure (Mpa)	Salinity (g/L)	
1	4.962	8	0	14.12
2	5.126	13	40.03	14.88
3	5.314	20	80.06	17.65
4	1.558	8	40.03	13.29
5	1.526	13	80.06	14.56
6	1.354	20	0.00	16.52
7	0.426	8	80.06	9.46
8	0.508	13	0.00	13.65
9	0.518	20	40.03	13.75

Table 4. Sensitivity analysis of recovery.

Variable	Characteristic value of recovery			
Permeability	Recovery (%)	Level 1 at about 5 mD	Level 2 at about 1.5 mD	Level 3 at about 0.5 mD
	Each	14.12, 14.88, 17.65	13.29, 14.56, 16.52	9.46, 13.65, 13.75
	Sum	46.65	44.37	36.86
	Average	15.55	14.79	12.29
Pressure	Recovery (%)	Level 1 at about 8 MPa	Level 2 at about 13 MPa	Level 3 at about 20 MPa
	Each	14.12, 13.29, 9.46	14.88, 14.56, 13.65	17.65, 16.52, 13.75
	Sum	36.87	43.09	47.92
	Aveage	12.29	14.36	15.97
Salinity	Recovery (%)	Level 1 at about 0 g/L	Level 2 at about 40 g/L	Level 3 at about 80 g/L
	Each	14.12, 16.52, 13.65	14.88, 13.29, 13.75	17.65, 14.56, 9.46
	Sum	44.29	41.92	41.67
	Aveage	14.76	13.97	13.89

imbibition. Meanwhile, a lower permeability of the tight core is usually accompanied by an increase in heterogeneity, which also results in a decrease in imbibition recovery. In addition, permeability reduction hinders the diffusion of CO_2 in the core and reduces the rate of CO_2 mass transfer into the oil phase, thus weakening the ability of CO_2 to improve the imbibition rate. Therefore, for tight reservoirs, the lower the core permeability, the slower the imbibition rate, and the lower the imbibition recovery.

These experimental results show that the influence of salinity on imbibition is the same as that of the single-phase imbibition experiment. When the salinity is low, the salinity factor has a great influence on the imbibition displacement efficiency. However, when the salinity is higher than 40 g/L, its influence is no longer obvious. The analysis shows that this is mainly because the dissolution of CO_2 in formation water has little influence on salinity and does not significantly affect imbibition by significantly changing salinity.

3.2 CO_2 effect on imbibition

The curves of the recovery and oil production rate of the two experimental groups of the pure formation water imbibition and formation water imbibition with 0.3 mol/L CO_2 are shown in Fig. 5. The figure clearly shows that the addition of CO_2 greatly change the oil recovery rate. The ultimate recovery of the pure formation water imbibition was only 8.93%, while that of CO_2 could reach 13.72%, an increase of nearly 5%. In addition, it was noted that the peak of the oil production rate after CO_2 addiction appeared later; however, it was far beyond the peak of the pure formation water imbibition. Besides, the oil production rate of the former was always higher than that of the latter, except for the first few hours. By comparing the above experimental results (yellow curve in Fig. 2(b) and red curve in Fig. 5(a)), it was also found that the imbibition equilibrium time was extended to a cer-

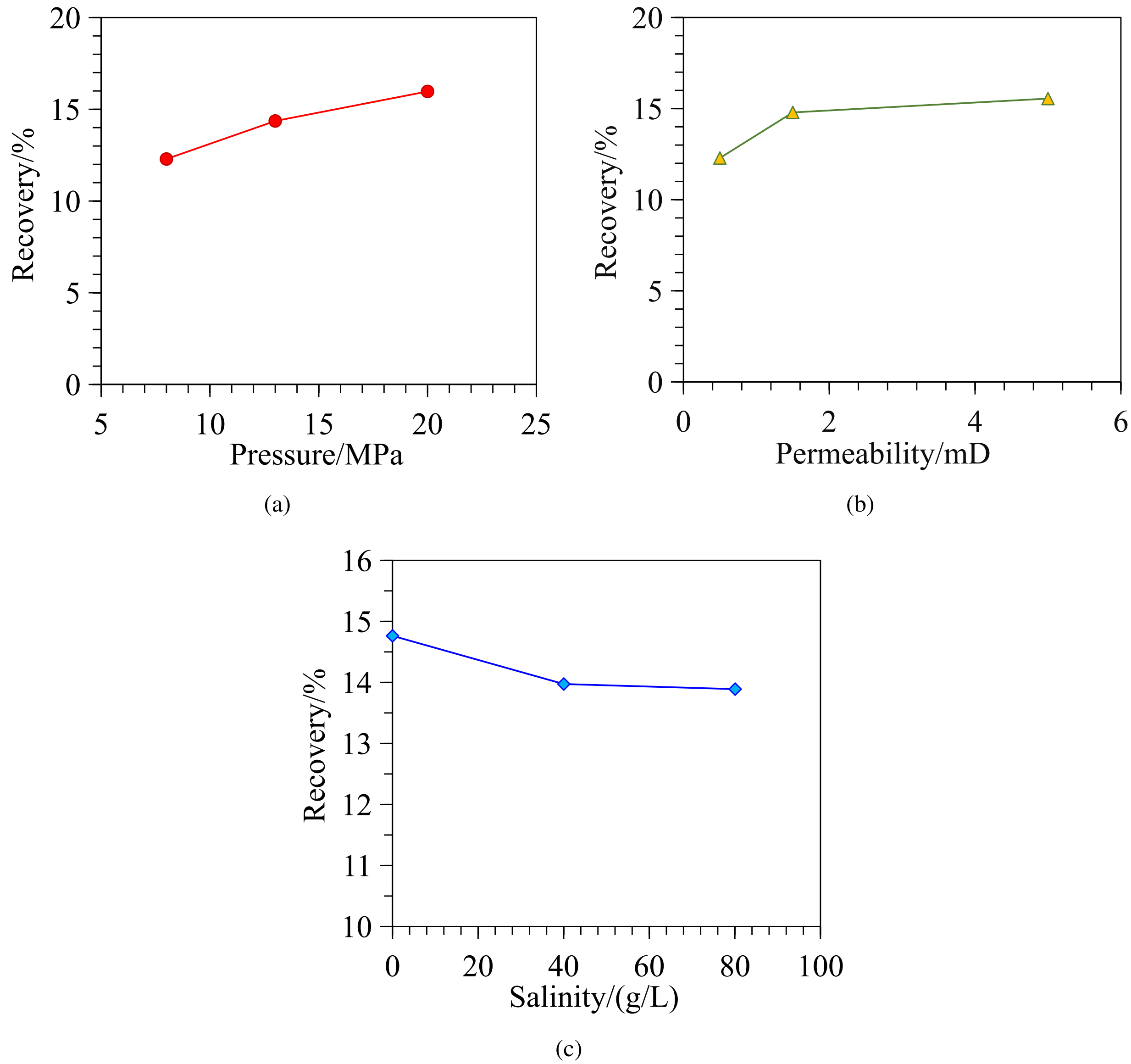

Fig. 3. Orthogonal experiment results of L9 (3^3). (a), (b), (c) represent the first, second, third group of cores respectively.

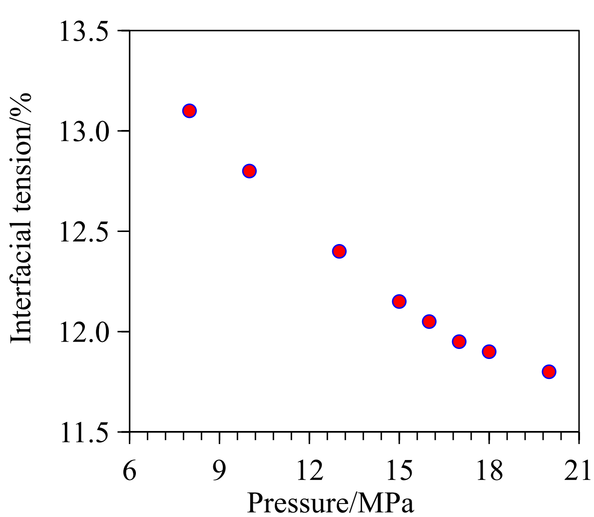

Fig. 4. Oil-water interfacial tension after dissolving CO_2.

tain extent when the CO_2 concentration was reduced from 0.4 mol/L to 0.3 mol/L, and the recovery rate was slightly decreased (from 14.56% to 13.72%). With the increase in the CO_2 concentration, the oil production rate was improved.

It takes time and processing for CO_2 and formation water to form carbonated water, change rock wettability, and reduce the oil-water interfacial tension, which makes the difference between the two groups of experiments not obvious at the initial imbibition stage. Thus the advantage of CO_2 injection in the early time was not reflected. In addition, in the early stage of imbibition, due to the adsorption of free CO_2 on the rock surface, the resistance of the oil flowback increased to a certain extent and even appeared not to be beneficial for oil recovery. With the gradual change in rock wettability, the interfacial tension of oil and water gradually decreased, and the imbibition power was improved. Moreover, due to the continuous increase in the CO_2 dissolved in crude oil by diffusion, the crude oil's

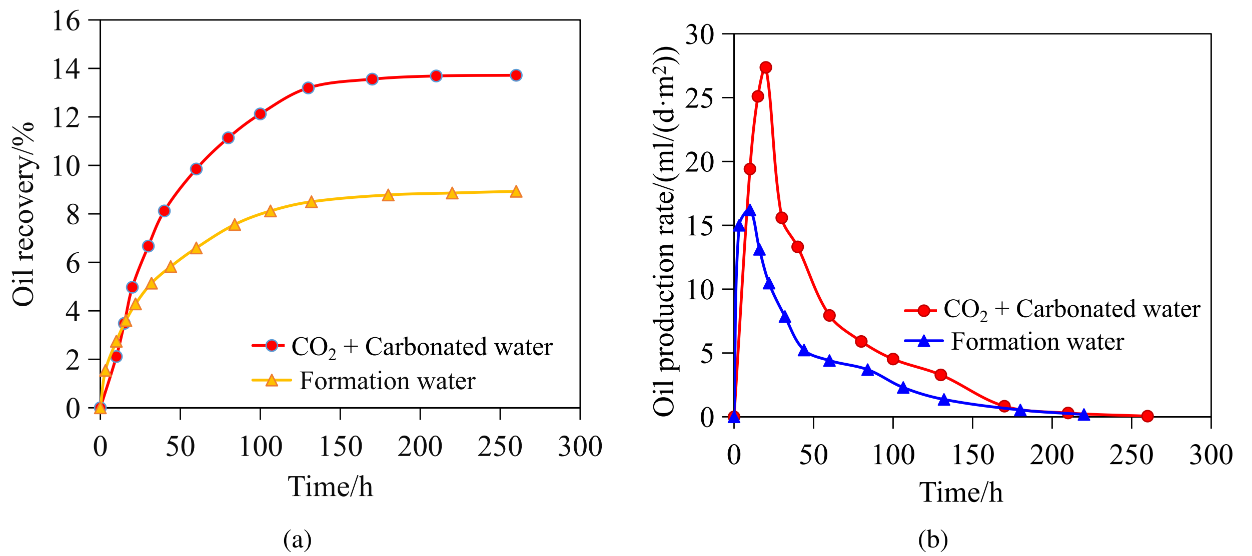

Fig. 5. Production dynamic comparison curves of different imbibition media. (a) Oil recovery and (b) oil production rate.

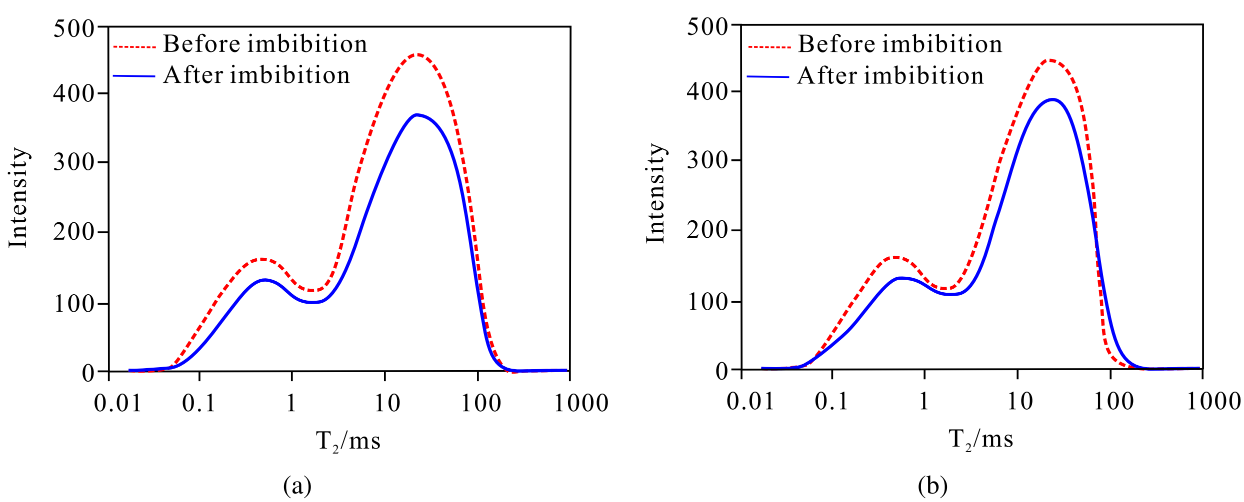

Fig. 6. NMR T_2 spectrum distribution before and after imbibition with different fluids. (a) Formation water and (b) CO_2 + Carbonated water.

viscosity decreased, the seepage resistance decreased, and the expansion energy increased. The synergistic effects of several mechanisms made the oil production rate rapidly increase, producing the phenomenon that the peak oil production rate appeared late but still much higher than the formation water imbibition, permitting the dual effects of CO_2 flooding and carbonated water imbibition. The crude oil in the larger pores was first produced in both groups in the early stage of the experiment. As the CO_2 concentration increased gradually in small pores by diffusion, oil was effectively produced in the small pores, thus significantly contributing to oil recovery.

3.3 Microscopic mechanism of oil production

To further study the microscopic mechanism of the CO_2 influence on imbibition, the NMR T_2 spectrum distribution of different imbibition fluids before and after imbibition was monitored, and the results were compared, as shown in Fig. 6.

The variation in the NMR T_2 spectrum amplitude with the relaxation time indicates the distribution of movable oil in pores of different sizes. The results show that the T_2 spectrum of the two groups of imbibition experiments presents a bimodal shape and that the right peak is higher, indicating that the crude oil was distributed in pores of different sizes and that it mainly existed in the large pore spaces. After imbibition, the T_2 spectrum in pores of different radius decreased to a certain extent, indicating that crude oil can be produced in different pore sizes.

To further distinguish the mobilized pore spaces and study the microscopic mechanism of oil mobilization during imbibition, the imbibition recovery efficiency under different pore throat radius distribution was counted. The crude oil mobiliz-

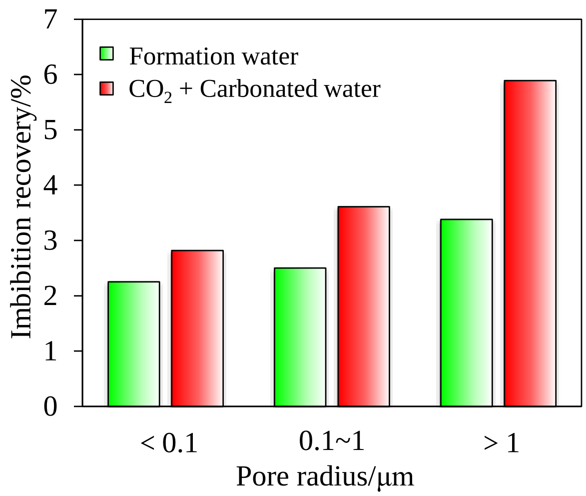

Fig. 7. Oil mobilization in different pore-throats after imbibition.

ation in different pores was statistically analyzed, and the results are shown in Fig. 7.

As shown in Fig. 7, the oil in the pores of different radii was mobilized in both experiments; however, the mobilization degree was different. The imbibition effect in the micron pores of both groups was the most significant, and the contribution to oil production was the largest, with imbibition recovery of 3.35% and 5.92%, respectively. The mobilization degree of formation water to crude oil in the nanopores and submicron pores was similar, and the mobilization degree of carbonate water to crude oil in the micropores was obviously higher than that in the nanopores. The addition of CO_2 improved the mobilization of crude oil in different pore; however, the best mobilization was in the micron pores. According to a comprehensive analysis, the reason for the above differences is mainly that CO_2 injection reduces the adhesion work between the crude oil and the pore walls. Moreover, the fluid flow resistance in the large pores is relatively small, and this part of the crude oil is easier to recover.

4. Conclusions

1) Imbibition plays an active and obvious synergic role in the CO_2 displacement in fractured tight sandstone reservoirs, which is important for the research on the CO_2 EOR mechanism.
2) Pressure and permeability are important factors affecting imbibition in the CO_2 displacement in fractured tight reservoirs, followed by salinity of imbibition fluid. The higher the pressure, the higher the imbibition efficiency, and the higher the oil recovery. The lower the permeability, the lower the imbibition speed and efficiency, and the lower the oil recovery. However the salinity of the imbibition fluid is not very sensitive to the impact of the imbibition recovery.
3) CO_2 injection improves the imbibition speed and efficiency of formation water and can significantly enhance the production rate and recovery of oil. The increase in the CO_2 concentration is beneficial with regard to shortening the imbibition equilibrium time and enhancing oil recovery. Therefore, CO_2 concentration is a key factors with regard to parameter optimization.
4) Nanopores can provide greater capillary forces and facilitate imbibition. However, the resistance of oil flow is also large, which makes oil fluidity poor. On the contrary, imbibition power in micrometer pore is weak, but the oil fluidity is good, and more crude oil can be produced. Compared with formation water imbibition, CO_2 injection is conducive to oil production in smaller pores and throats.

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Conflict of interest

The authors declare no competing interest.

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