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CO_2-Low Interfacial Tension Viscoelastic Fluid Synergistic Flooding in Tight Reservoirs

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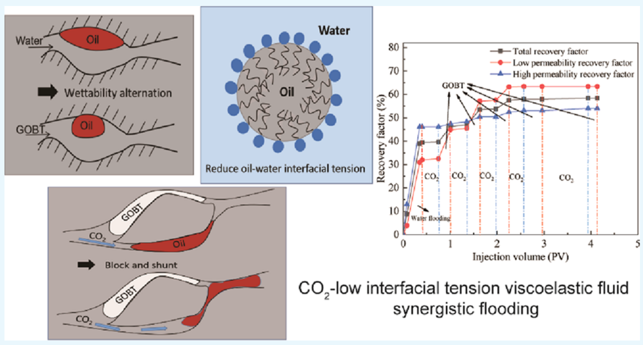
ABSTRACT: Tight oil reservoirs have poor physical properties, insufficient formation energy, and low natural productivity. CO_2 flooding is an important technical mean that enhances the oil recovery of dense reservoirs and achieves effective CO_2 sequestration, but strong heterogeneity of the tight oil reservoir usually results in gas channeling and poor enhanced oil recovery effect. The existing methods to prevent gas channeling are mainly to use the small-molecule amine system and the polymer gel system to plug fracture and high permeability channels. The small-molecular amine system has low flash points and pollutes the environment and the polymer gel has poor injectivity and great damage to the formation, which limit their large-scale application. Therefore, a new viewpoint of CO_2-low interfacial tension viscoelastic fluid synergistic flooding for enhanced oil recovery in a tight oil reservoir was made. The performance of low interfacial tension viscoelastic fluid (GOBT) was studied. The injectivity and oil displacement effect of CO_2-GOBT synergistic flooding were evaluated, and the mechanism of CO_2-GOBT synergistic flooding was discussed. The experimental results showed that 0.4% GOBT is a low interfacial tension viscoelastic fluid, which has strong adaptability to the salinity water of tight oil reservoirs (6788−80,000 mg/L), good viscosity stability at different pHs, excellent capacity to emulsify crude oil, and the ability to improve reservoir water wettability. CO_2 alternating 0.4% GOBT flooding has good injection ability in cores (K_a = 0.249 mD), and injecting 0.4% GOBT can effectively increase the injection pressure of subsequent CO_2 flooding. CO_2 alternating 0.4% GOBT flooding can effectively improve water flooding recovery in tight sandstone reservoirs, which is better than CO_2 flooding and 0.4% GOBT flooding in both homogeneous and heterogeneous conditions. The mechanisms of CO_2 alternating 0.4% GOBT flooding to enhance the oil recovery include that GOBT and CO_2 foam block high permeability layers, shunt and sweep low permeability layers, and GOBT emulsify and wash oil. CO_2 partially dissolving in GOBT synergistically enhances the core water wettability, which improves GOBT injectability, emulsification, and stripping ability to residual oil.



CO_2-low interfacial tension viscoelastic fluid synergistic flooding

1. INTRODUCTION

Tight oil reservoir is characterized by low porosity, low permeability, conspicuous interface effect between fluid and rock, and poor reservoir fluid mobility,[1−4] and injecting gas,[5−7] active water,[8−10] and low salinity water[11] are effective methods to improve its oil recovery. The gas injection can replenish reservoir energy, reduce oil viscosity, expand crude oil, and improve oil mobility;[12] this is the main choice for the development of tight reservoirs. CO_2 flooding is the most ideal way, which can realize underground storage to effectively reduce carbon emissions and has good economic and social benefits.[13−18] However, the existence of fractures and large pore channels easily leads to gas channeling during CO_2 injection, which limits the swept volume of CO_2 flooding and enhanced oil recovery (EOR) effect.[19,20] Hence, scholars have explored water alternating gas, foam, and gel technologies to regulate and control cracks, delay gas channeling, and improve the aspirating profile.[21] The strong heterogeneity or high permeability grade difference in the tight oil reservoir more easily leads to ineffective water−gas alternating injection, and the remaining oil in the low permeability layer cannot be started.[22] CO_2 foam flooding has a better EOR effect than water alternating gas flooding, and microbubble is more stable, but CO_2 foam can only meet the plugging and shunting requirements of heterogeneous cores with low permeability, micron-size cracks (40−83 μm), and

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permeability grade difference below 30.[23−26] Natural polymers (starch, cellulose) and synthetic polymer gels have good plugging performance in tight fractured reservoirs (≥0.1 mD), but there are some deficiencies in the fracture width adaptability (0.08−0.65 mm), higher viscosity of the initial injection fluid, and long gel reaction time (6−20 h) in the reservoir.[27−30] Surfactants can be adsorbed on solid−liquid, liquid−liquid, and gas−liquid interfaces to change the wettability of the reservoir rock surface, reduce the interfacial tension between oil and water, emulsify crude oil, and form foam to improve the oil recovery.[31−33] In particular, viscoelastic surfactant or viscoelastic fluid flooding has a function similar to the combination flooding of the surfactant and the polymer, and good injectivity due to the small molecular weight of the surfactant can improve the water injection sweep volume and displacement efficiency and enhance the oil recovery by 10−20% and is an attractive new technology for EOR.[34−37] However, the existing viscoelastic fluid displacement system is complex and has the possibility of chromatographic separation. It is more important that there is no literature report on viscoelastic fluid flooding and CO_2-viscoelastic fluid synergy flooding in enhancing the oil recovery in tight reservoirs.[38−46] Hence, it is necessary to research CO_2-low interfacial tension viscoelastic fluid synergistic flooding in tight reservoirs according to the deficiency of existing CO_2 flooding technology and the excellent performance of low interfacial tension viscoelastic fluid flooding. The synergistic displacement oil of CO_2 and low interfacial tension viscoelastic fluid can be carried out by injecting CO_2 and low interfacial tension viscoelastic fluid into the reservoir alternately at a smaller slug size, so as to realize the synergistic effect of CO_2 and viscoelastic fluid flooding with low interfacial tension to improve tight oil recovery.

In this paper, the CO_2 and low interfacial tension viscoelastic fluid synergistic oil displacement effect and mechanism were studied by rheological properties, interfacial activity, wettability tests, and core flooding experiments. The injectivity and cooperative displacing oil effect of CO_2 and the low interfacial tension viscoelastic fluid (GOBT) in tight reservoir cores were systematically studied, which enriched the EOR technology and theory of heterogeneous tight reservoirs.

2. RESULTS AND DISCUSSION

2.1. Performance of GOBT. *2.1.1. Basic Performance and Influencing Factors of GOBT. 2.1.1.1. Basic Performance.* The basic properties of GOBT with different concentrations are shown in Table 1. As shown in Table 1, the viscosity of GOBT

Table 1. Basic Performance Parameters of GOBT with Different Concentrations (47.2 °C)

concentration/%	viscosity/mPa·s	tan δ	IFT/(10^{-2} mN/m)
0.1	1.21		2.71
0.2	2.65	0.8652	2.56
0.3	2.96	0.6561	2.44
0.4	3.42	0.5992	2.31

gradually increased with an increase in GOBT concentration, but the interfacial tension and tan δ values decreased, which indicates that the interfacial activity and elasticity enhanced. When the GOBT concentration was 0.4%, its viscosity reached 3.42 mPa·s at a reservoir temperature of 47.2 °C which is the approximate crude oil viscosity of the oil reservoir (3.4 mPa·s), tan δ = 0.5992 < 1, and the oil−water interfacial tension of 0.4% GOBT was 2.31×10^{-2} mN/m which is in the low interfacial tension range. Thus, 0.4% GOBT is indeed a low interfacial tension viscoelastic fluid, and the mobility ratio with the formation crude oil is close to 1. That means 0.4% GOBT had good mobility adjustment ability when injected into heterogeneous tight oil reservoirs and had the potential for preventing CO_2 gas channeling.

2.1.1.2. Influencing Factors. The effect of salinity on the basic performance of 0.4% GOBT is shown in Figures 1, 2 and

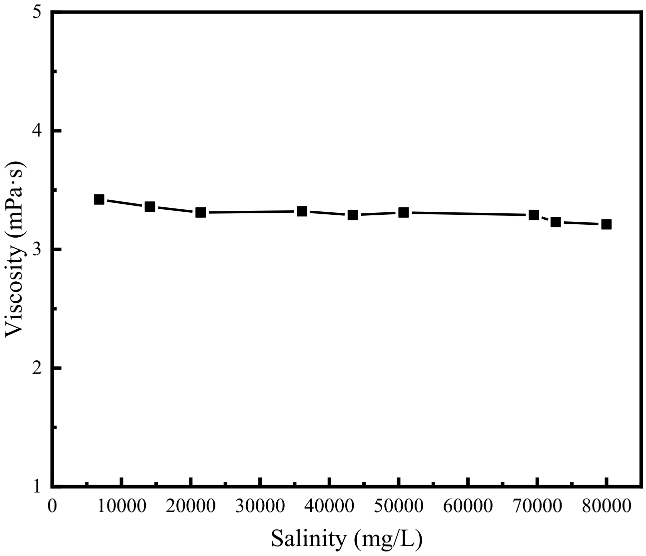

Figure 1. Effect of salinity on the viscosity of 0.4% GOBT at 47.2 °C.

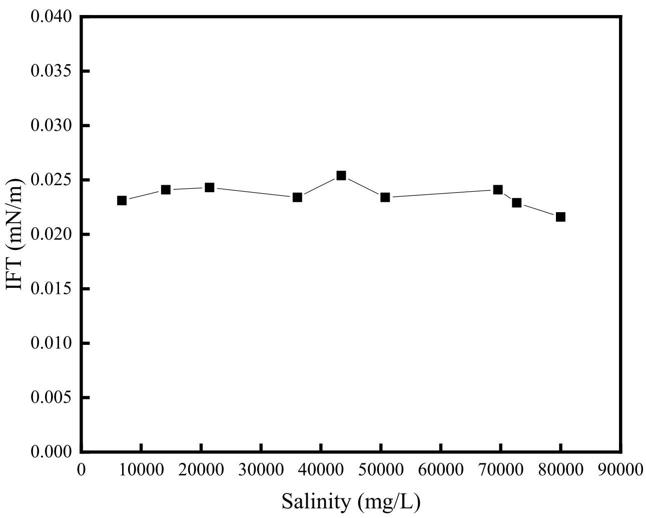

Figure 2. Effect of salinity on the interfacial tension between 0.4% GOBT and crude oil at 47.2 °C.

Table 2. As can be seen from Figure 1, the viscosity of 0.4% GOBT decreased slightly with the increase of salinity, and the reduction rate was less than 6.1%. This illustrated that the change of salinity had little effect on the viscosity of 0.4% GOBT. As shown in Figure 2, when the salinity is increased from 6788 to 80,000 mg/L, the interfacial tension between 0.4% GOBT and crude oil has little change (2.16−2.54 × 10^{-2} mN/m) and always remains in the low interfacial tension range (10^{-2} mN/m). According to the data in Table 2, the tan δ value of 0.4%

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Table 2. Effect of Salinity on the Viscoelasticity of 0.4% GOBT at 47.2 °C

salinity/mg·L^{-1}	tan δ	elasticity or viscosity
6788	0.5992	elasticity
10,000	0.5348	elasticity
20,000	0.7127	elasticity
40,000	0.6904	elasticity
60,000	0.4976	elasticity
80,000	0.8831	elasticity

GOBT fluctuated with the increase of salinity but was always less than 1.

In other words, GOBT always belongs to a viscoelastic fluid that is mainly elastic in the range of experimental salinity. In summary, the salinity had a slight effect on the viscosity, interfacial activity, and viscoelasticity of 0.4% GOBT, indicating that GOBT has good salinity (6788−80,000 mg/L) adaptability.

The effect of CO_2 dissolving in 0.4% GOBT on its pH value and viscosity was investigated. The experimental results are shown in Table 3. It can be seen from Table 3 that under the pressure of 0.1MPa, as the time of CO_2 dissolving in the GOBT increases, the pH value of GOBT gradually decreased from 8.5 and stabilized at 5.4, but the viscosity only shows a downward trend. This phenomenon indicated that CO_2 dissolves in GOBT and reduces the pH value, resulting in a slight decrease in viscosity. The in-depth analysis found that the viscosity of 0.4% GOBT was mildly affected by pH, and the viscosity reduction rate was only 6.7%.

Table 3. Effect of CO_2 Dissolution Time in 0.4% GOBT on Its pH and Viscosity

time/s	pH	viscosity/mPa·s^{-1}
0	8.5	3.42
30	6.2	3.36
60	5.7	3.23
90	5.4	3.21
120	5.4	3.19

2.1.2. Other Performance of GOBT. 2.1.2.1. Effect of GOBT on the Wettability of the Reservoir Core. The test results of the water and oil contact angles of the reservoir core are shown in Figure 3. The water phase wetting angle on the core surface decreased from 45° to 8.4°, meaning the core became more hydrophilic. Inversely, the oil phase wetting angle on the core surface increased from 17.9° to 24.2°, that is, the core soaked by 0.4% GOBT becomes relatively less lipophilic. In a word, the core became more hydrophilic after soaking with 0.4% GOBT. In other words, when injecting 0.4% GOBT into the tight reservoir, the surface of pore media changed to more hydrophilic and the adhesion force of pore surface to oil is reduced, which will be beneficial to the injection of viscoelastic fluid and the start-up and stripping of residual oil in pores, as well as the improvement of the recovery degree.[47−49]

2.1.2.2. Emulsifying Performance of GOBT. The dehydration rate is listed in Table 4. With the increase of the emulsion standing time, the dehydration rate of the emulsion gradually increased under different oil−water ratios (from 3:7 to 1:1 and 7:3), but the growth rate of the dehydration rate was obviously different. For example, with the increase of the oil−water ratio, the water separation rate increased from 0 to 6.67% and finally reached 42.8% after the emulsion stood for 5 min, which

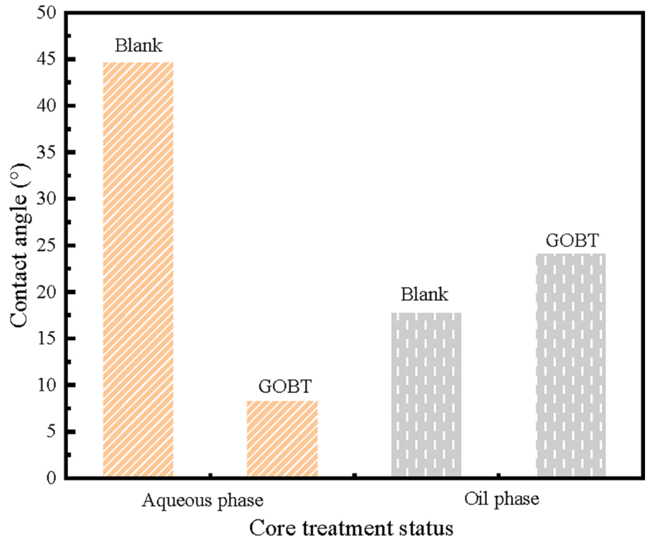

Figure 3. Changes of water-phase and oil-phase contact angles in different core treatment status.

Table 4. Emulsification of GOBT to Crude Oil (47.2 °C)

	dehydration rate/%		
time/min	oil: 0.4% GOBT = 3:7	oil: 0.4% GOBT = 1:1	oil: 0.4% GOBT = 7:3
0	0	0	0
5	0	6.67	42.8
10	0	13.3	66.7
15	11.1	26.6	76.2
20	22.2	40	80.9
60	22.2	60	88.1

illustrated that GOBT has an emulsifying effect on crude oil, but the emulsion stability is obviously affected by the oil−water ratio. A high oil−water ratio is not conducive to the emulsification of oil−water by GOBT and emulsion stability, such as 7:3. This phenomenon was attributed to the presence of the unique micellar structure of GOBT and surface hydrophilic groups.[50] The GOBT is similar to a hydrophilic emulsifier and tends to form oil-in-water emulsions. On the contrary, a high oil−water ratio (>50%) is easier to form water-in-oil emulsions, so emulsion formation is more difficult and unstable.

2.2. CO_2-GOBT Alternating Injectivity Experiment. The permeability of the tight oil reservoir core selected for the injection experiment was 0.249 mD, and the experimental results are shown in Figure 4. First, CO_2 was injected steadily at a low injection pressure, and then 0.4% GOBT viscoelastic fluid was injected until the injection pressure gradually increased to 3.01 MPa and stays stable; finally, CO_2 was injected again, and the final injection pressure stabilized at 2.58 MPa, indicating that CO_2 alternating 0.4% GOBT flooding has good injectability and the stable pressure can be reached at different injection stages. In addition, it is known from the change of CO_2 injection pressure before and after the injection of 0.4% GOBT that the GOBT not only has good injection performance in tight reservoirs but also can effectively plug the pore throat and improve the sweep ability of subsequent CO_2 flooding.

2.3. Effect of CO_2-GOBT Synergistic Flooding. *2.3.1. Homogeneous Core Flooding.* The CO_2 flooding, 0.3PV 0.4% GOBT flooding and subsequent water flooding, and CO_2 alternating 0.4% GOBT flooding (0.3PV alternating four cycles)

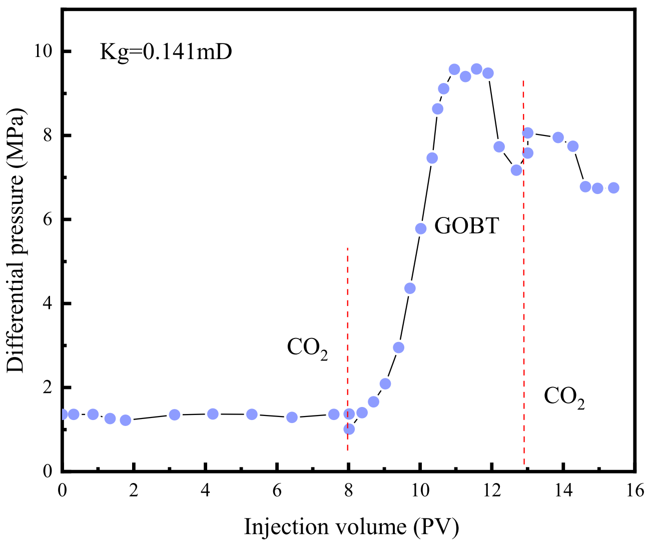

Figure 4. Alternate injectivity curves of CO_2/0.4% GOBT in tight reservoir cores.

were conducted at 47.2 °C after water flooding reached 90% water cut. The EOR results of three different displacement methods are shown in Figure 5 and Table 5. The results indicated that continuous CO_2 flooding can only increase the recovery by 2.21%. Injecting 0.3PV 0.4% GOBT and continuing water flooding improved the oil recovery by 3.77%, which was 1.56% higher than that of CO_2 flooding, indicating that 0.4% GOBT does have a certain oil washing ability. Although CO_2 alternating 0.4% GOBT flooding was only implemented in four cycles, the recovery of CO_2 alternating 0.4% GOBT flooding (0.3PV alternating) increased by 4.41%, which was 2.2 and 0.64% higher than those of CO_2 flooding and 0.4% GOBT flooding, respectively, and this implied that CO_2 alternating 0.4% GOBT flooding exhibited a good synergistic effect.

2.3.2. Heterogeneous Core Flooding. The high and low permeability dual-pipe flooding experiments were implemented using a tight reservoir core with a permeability range of 4.3. The oil displacement effect of CO_2 flooding, 0.3PV 0.4% GOBT flooding and subsequent water flooding, and CO_2 alternating 0.4% GOBT flooding (0.3PV alternating) was studied after water flooding to 90%. The relationship between the recovery rate and the injected volume is shown in Figure 6 and the experimental results are shown in Table 6.

As can be seen from the data in Figure 6 and Table 6, the effect of continuous CO_2 flooding was poorer. The recovery efficiency of the low permeability layer only increased by 0.56%, and even that of the high permeability layer only increased by 1.16%. While injecting 0.3PV 0.4% GOBT and continuing water flooding significantly improved the oil recovery, the low permeability layer and high permeability layer recovery increased, respectively, by 20.99 and 13.88%, which indicated that GOBT can indeed seal the high permeability layer and can effectively increase the swept volume so that the subsequent waterflood can be obviously diverted to the low permeability layer, which greatly improves the recovery ratio of the low permeability layer. Meanwhile, there is still an obvious plugging and oil washing effect in the high permeability layer, which further increased the recovery efficiency by nearly 14%. CO_2 alternating GOBT flooding (0.3PV alternating five cycles) enhanced the oil recovery more effectively compared with CO_2 flooding and GOBT flooding, the CO_2 sweep volume and

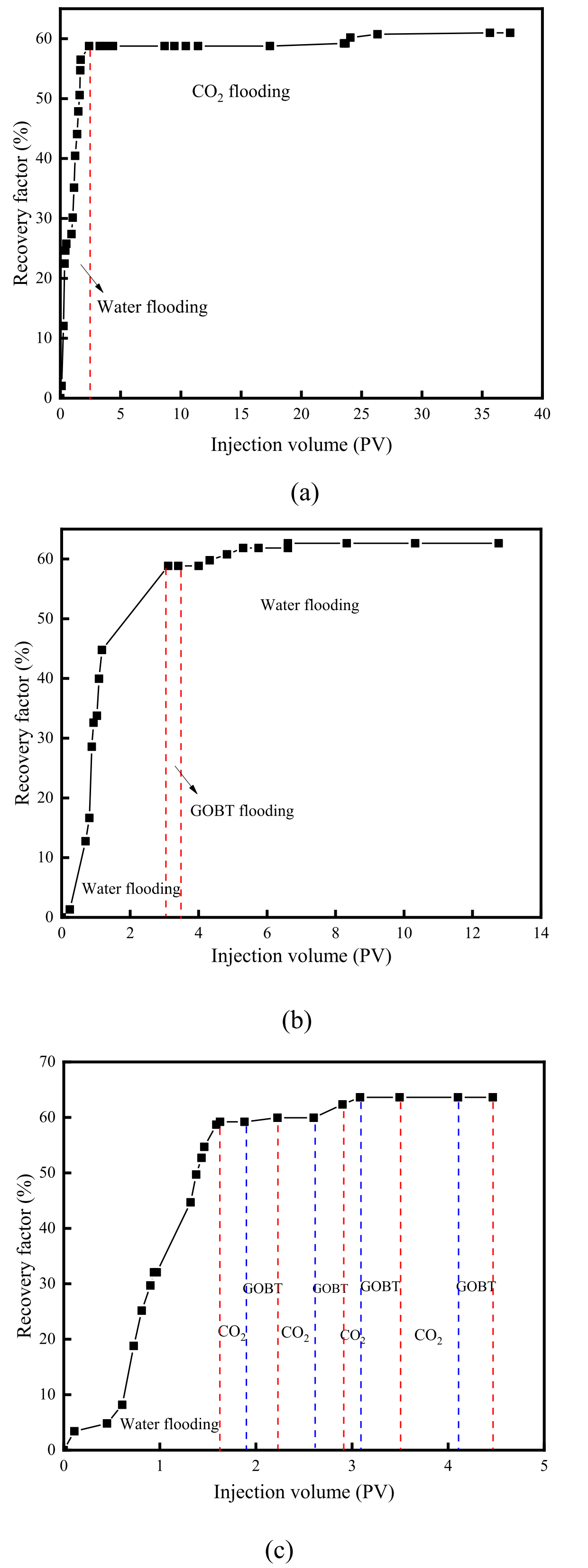

Figure 5. Recovery factor effect of different displacement modes for homogeneous cores. (a) Oil displacement effect of CO_2 flooding after water flooding. (b) Oil displacement effect of 0.3PV 0.4% GOBT flooding and subsequent water flooding after water flooding. (c) Oil displacement effect of CO_2 alternating 0.4% GOBT flooding (0.3PV alternating) after water flooding.

Table 5. Oil Displacement Effect of Different Displacement Modes on Homogeneous Cores

number	K_g/mD	Φ/%	S_{wi}/%	water flooding recovery/%	total recovery/%	enhanced oil recovery/%	displacement modes
1	0.30	9.6	32.2	58.76	60.97	2.21	CO_2 flooding
2	0.26	11.6	35.9	58.83	62.60	3.77	0.3PV 0.4% GOBT flooding and subsequent water flooding
3	0.27	10.8	33.4	59.20	63.61	4.41	CO_2 alternating 0.4% GOBT flooding (0.3PV alternating)

shunting effect obviously increased, the recovery efficiency of the low permeability layer increased by 31.41%, and the high permeability layer was blocked more effectively. The seepage oil washing ability of the high permeability layer decreased in the subsequent CO_2 flooding, and the recovery rate was only 7.93%.

In conclusion, for heterogeneous tight reservoirs, CO_2 and 0.4% GOBT alternate flooding really have a good synergistic oil flooding effect, which can better seal the high permeability layer and improve the sweep ability of CO_2 in the low permeability layer and significantly enhance the oil recovery.

2.4. Mechanism of CO_2-GOBT Synergistic Oil Displacement. *2.4.1. Plugging the High Permeability Layer and Starting-Up the Low Permeability Layer by Shunting.* As can be seen from Figure 7, under the same permeability grade difference (4.3), CO_2 mainly flowed through the high permeability layer in CO_2 flooding, with a shunt rate of 99.55%. By injecting 0.3PV 0.4% GOBT and subsequent waterflooding, the high permeability layer was effectively sealed, and the shunt index of the high permeability layer decreased to 94.15%. While the CO_2 alternating 0.4% GOBT flooding had a better plugging effect, the shunt rate of the high permeability layer decreased to 86.93%.

The results showed that the plugging of CO_2 alternating 0.4% GOBT flooding is more effective than 0.3PV 0.4% GOBT alternating water flooding. This phenomenon was ascribed to the formation of CO_2 foam during the CO_2 alternating GOBT flooding process, which strengthened the plugging effect of the high permeability layer. Table 7 describes that there was obvious foam in the produced liquid of the alternate flooding containing CO_2 under the same permeability grade difference and the same alternate flooding slug size and period. Besides, alternating flooding containing CO_2 had a better plugging effect for high permeability layers and could start the low permeability layer more efficiently to enhance the oil recovery. For example, the recovery of CO_2 alternating 0.4% GOBT flooding in the high permeability layer was significantly lower than that of the 0.4% GOBT alternating water flooding, but the total recovery of CO_2 alternating 0.4% GOBT flooding was nearly 1% higher than that of the 0.4% GOBT alternating water flooding.

2.4.2. Low Interfacial Tension and Emulsifying and Washing Oil Effect. According to the data in Table 1, the GOBT belongs to low interfacial tension (10^{-2} mN/m) viscoelastic fluid and is mainly elastic (tan δ < 1) at a concentration of 0.2−0.4% and has the ability to emulsify and start the residual oil (IFT < 2.7×10^{-2} mN/m). The data in Table 4 indicate that 0.4% GOBT could emulsify different proportions of oil and water (3:7−7:3), the stability of emulsion was closely related to the oil content, that is, the emulsion with low oil content had good stability, and the dehydration rate in 1 h was only 22.2%. Meanwhile, the oil displacement experiment also proved that there was an obvious oil washing effect in both single-pipe homogeneous core flooding and dual-pipe parallel heterogeneous core flooding. As shown in Table 5, 0.3PV 0.4% GOBT flooding and subsequent water flooding were conducted after single-pipe homogeneous core water flooding until water cut reached 98%, and the recovery ratio only increased by 3.77%. According to Table 6, 0.3PV 0.4% GOBT flooding could effectively block the high permeability layer and increase the recovery rate of the low permeability layer by 20.99% after parallel dual-pipe heterogeneous core water flooding; meanwhile, the recovery rate of the high permeability layer increased by 13.88% based on 56.48% of water flooding recovery due to the GOBT entering into the high permeability layer.

2.4.3. Wettability Change and Improved GOBT Injectibility and the Ability to Emulsify and Peel off Residual Oil. The cores of tight reservoirs were treated by CO_2 aqueous solution, GOBT, and CO_2-GOBT. The contact angles of the core water phase and oil phase are measured and presented in Figure 8. As shown in Figure 8, the CO_2 aqueous solution reduces the hydrophilicity of the core, the core was more inclined to be oil-wet, and the oil-phase contact angle was only 12.1°. The GOBT and CO_2-GOBT enhanced the hydrophilicity of the core, the effect of CO_2/GOBT was more obvious, and the water-phase contact angle was only 7.4°, which was conducive to injection of GOBT and CO_2-GOBT and could significantly reduce the injection pressure of displacement fluid. In addition, GOBT is beneficial to emulsification and stripping of remaining oil and to improve the recovery of residual oil in the high permeability layer.

3. CONCLUSIONS

(1) 0.4% GOBT is a low interfacial tension viscoelastic fluid, which was highly adaptable to salinity water in tight oil reservoirs, exhibited good viscosity stability at different pHs, and also possessed the ability to emulsify crude oil and improve the water wettability of the reservoir.

(2) The CO_2 alternating 0.4% GOBT flooding has good injectability, the stable pressure can be reached at different injection stages, and the injection pressure of subsequent CO_2 flooding increased significantly after injecting 0.4% GOBT, which reflected good injectivity and plugged the pore throat effect of GOBT.

(3) The single-tube core flooding experiment showed that CO_2 flooding, 0.3PV 0.4% GOBT flooding and subsequent water flooding, and CO_2 alternating 0.4% GOBT flooding increased recovery by 2.21, 3.77, and 4.41%, respectively, after water flooding reached 90% water cut, which indicated that 0.4% GOBT does have a certain oil washing ability and CO_2-0.4% GOBT alternate flooding also exhibited a good synergistic effect.

(4) The parallel two-tube core heterogeneous oil displacement experiment indicated that CO_2 alternating 0.4% GOBT flooding can more effectively plug the high permeability layer than 0.4% GOBT flooding, and enhancing the recovery (31.41%) of the low permeability layer was better than that of CO_2 flooding (0.56%) and

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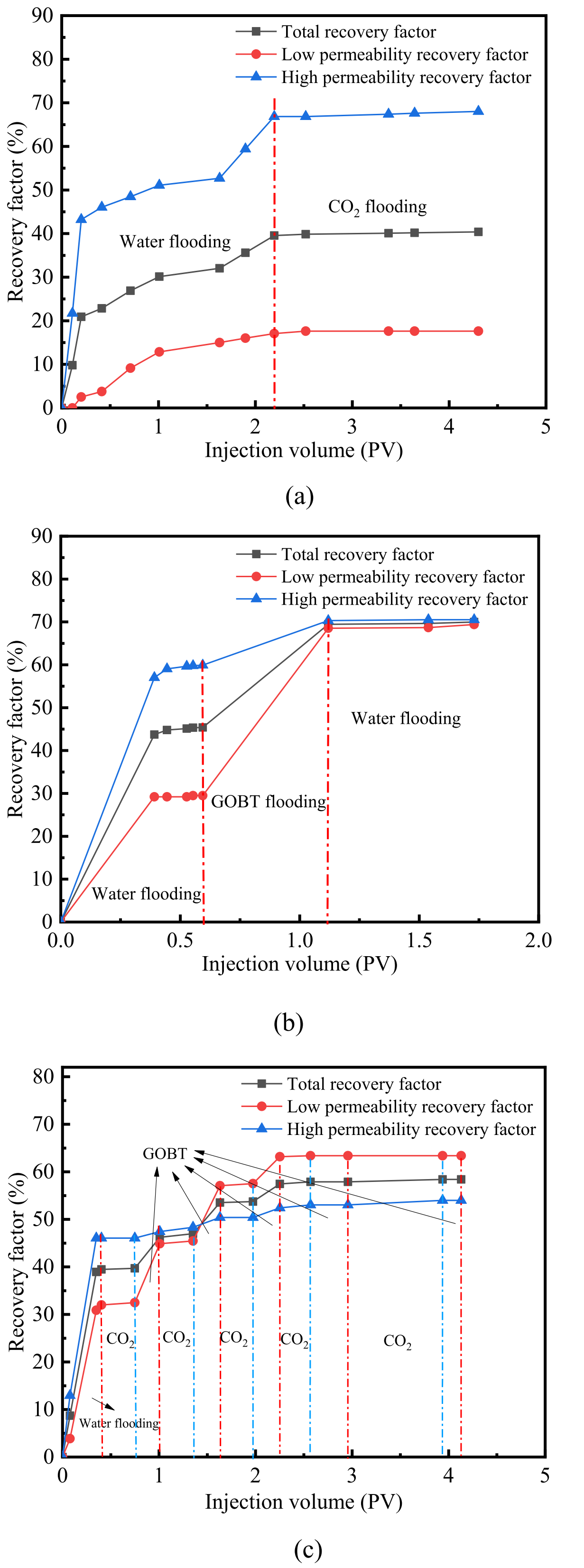

Figure 6. Recovery factor effect of different displacement modes for heterogeneous cores. (a) Oil displacement effect of CO_2 flooding after water flooding. (b) Oil displacement effect of 0.4% GOBT flooding and subsequent water flooding after water flooding. (c) Oil displacement effect of CO_2 alternating 0.4% GOBT flooding (0.3PV alternating) after water flooding.

0.4% GOBT + water flooding (20.99%) and really had a good synergistic oil flooding effect.

(5) The mechanism of CO_2 alternating 0.4% GOBT flooding to enhance the oil recovery includes that GOBT and CO_2 foam block high permeability layers, shunt and sweep low-permeability layers, and GOBT emulsify and wash oil. CO_2 partially dissolving in GOBT synergistically enhances the reservoir core hydrophilicity, which improves GOBT injectability, emulsification, and stripping ability to residual oil.

4. MATERIALS AND METHODS

4.1. Materials. NaCl, KCl, $CaCl_2$, Na_2SO_4, $MgCl_2$, $NaHCO_3$, and Na_2CO_3 were purchased from Aladdin Biochemical Technology Co., Ltd, Shanghai, China. Low interfacial tension viscoelastic fluid (GOBT) was provided by the School of Petroleum Engineering, Yangtze University. The oil used for the test is a live oil prepared from dehydrated reservoir crude oil with a viscosity of 3.4 mPa·s (47.2 °C). The experimental cores are reservoir cores (K_g = 0.141−0.81 mD).

4.2. Methods. *4.2.1. Fluid Preparation. 4.2.1.1. Injection Water Preparation.* Injection water was prepared by weighing 0.6152 g of NaCl, 9.5664 g of Na_2SO_4, 0.4521 g of $NaHCO_3$, 1.7493 g of $CaCl_2$, 1.1533 g of $MgCl_2 \cdot 6H_2O$, and 0.0397 g of KCl and putting them into pure water successively and stirring until completely dissolved. Simulated injection water with a salinity of 6788 mg/L was held in a 2 L volumetric flask for use, and the ionic composition of injected water is shown in Table 8.

4.2.1.2. Formation Water Preparation. Formation water was prepared by weighing 34.9698 g of NaCl, 1.9345 g of Na_2SO_4, 0.2732 g of $NaHCO_3$, 102.3120 g of $CaCl_2$, 1.1910 g of $MgCl_2 \cdot 6H_2O$, and 19.3195 g of KCl and putting them into pure water successively and stirring until completely dissolved. Simulated formation water with a salinity of 80,000 mg/L was held in a 2 L volumetric flask for use, and the ionic composition of formation water is shown in Table 9.

4.2.1.3. GOBT Preparation. The required amount of GOBT was added to the injection water (6788 mg/L), stirring continuously for 2 h until completely dissolved. GOBT with a concentration of 0.1, 0.2, 0.3, and 0.4% were prepared and left for 2 h for use.

4.2.1.4. 0.4% GOBT with Different Salinity Preparation. 0.4% GOBT was prepared by diluting the prepared formation water (80,000 mg/L) with pure water to the required salinity.

4.2.2. Rheological Properties Test. 4.2.2.1. Viscosity Measurements. The viscosity measurements were conducted by a DV-2T Brook-field viscometer. The viscosities of the fluid at a shear rate of 7 s^{-1} were recorded at 47.2 °C. The viscosity test error was about 0.005 mPa·s.

4.2.2.2. Viscoelasticity Measurements. The stress scanning for GOBT was conducted by a MCR301 interfacial rheometer at 47.2 °C. The change of modulus with the angular frequency was investigated. The storage modulus G' and the loss modulus G'' were determined, and the loss factor tanδ was calculated by the eq 1. In this equation, G' and G'' are, respectively, the storage modulus and loss modulus. δ is the phase angle, which represents the phase difference between shear stress and shear strain, and when $\tan \delta < 1$, the fluid is mainly elastic; when $\tan \delta > 1$, the fluid is mainly viscous.

$$\tan \delta = \frac{G''}{G'} \quad (1)$$

Table 6. Oil Displacement Effect of Different Displacement Modes for Heterogeneous Cores

displacement modes	number	K_g/mD	Φ/%	S_{wi}/%	water flooding recovery/% low	water flooding recovery/% high	water flooding recovery/% total	enhanced oil recovery/% low	enhanced oil recovery/% high	enhanced oil recovery/% total
CO_2 flooding	4	0.19	12.5	35.2	17.06	66.86	39.55	0.56	1.16	0.83
	5	0.81	11.9	31.5						
0.3PV 0.4% GOBT flooding and subsequent water flooding	6	0.25	10.2	33.9	17.70	56.48	40.11	20.99	13.88	16.89
	7	1.01	9.4	31.1						
CO_2 alternating 0.4% GOBT flooding (0.3PV alternating)	8	0.17	12.3	37.6	31.99	46.06	39.46	31.41	7.93	18.95
	9	0.75	13.9	30.0						

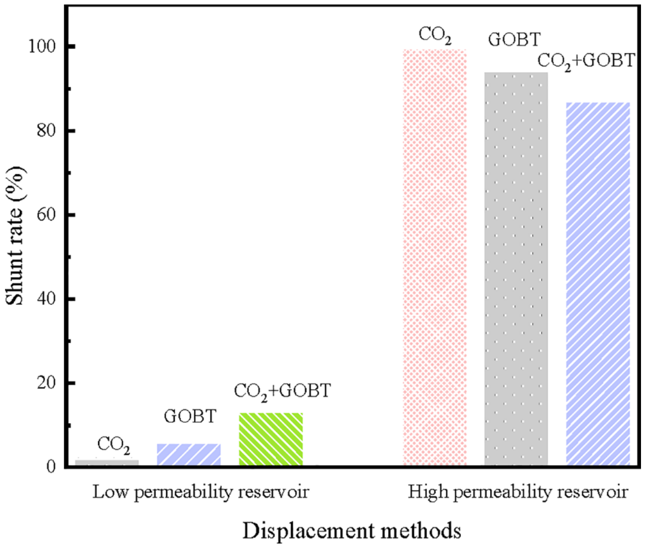

Figure 7. Relationship between the plugging effect and shunt rate of displacement fluid.

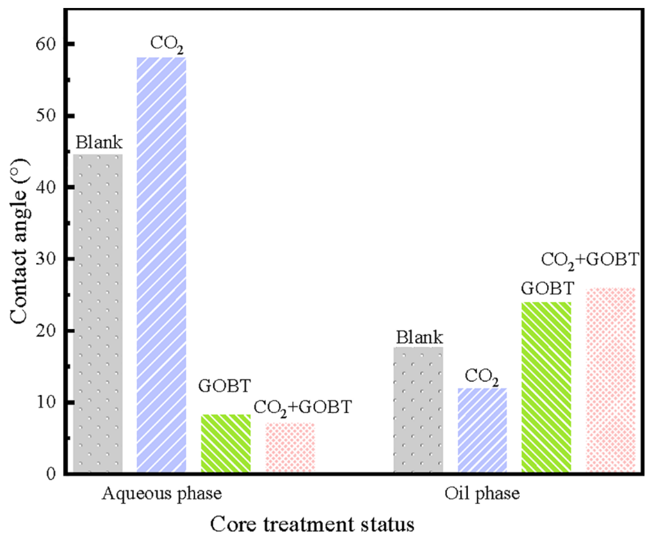

Figure 8. Change of water-phase and oil-phase contact angles of the reservoir core treated with different fluids.

4.2.3. Interfacial Tension Tests. The interfacial tension between GOBT with different salinities and dehydrated crude oil was measured by a TX500C spin drop interfacial tensiometer at a speed of 5000 rpm and 47.2 °C.

4.2.4. Wettability Measurements. Reservoir cores were washed and dried and cut into thin sections with the same diameter and thickness. The core thin sections were placed in CO_2 water solution, GOBT, and CO_2-GOBT for 6 h, and then the core thin sections were taken out and dried naturally. The contact angle (θ) on the surface of the core thin section was measured by an OCA 50 automatic contact angle measuring instrument, and the wettability was characterized by changes in the contact angle (θ).

4.2.5. Emulsifying Property Tests. The GOBT and dehydrated crude oil were mixed according to a certain oil—water ratio and then vibrated up and down 100 times to make the two phases mix evenly. Then, the emulsion was left standing at 47.2 °C, and the volume of precipitated water was observed and recorded. The dehydration rate of the emulsion was calculated by the ratio of the precipitated water volume to the initial GOBT volume to indicate the emulsifying capacity of GOBT on crude oil.

4.2.6. CO_2-Low Interfacial Tension Viscoelastic Fluid (GOBT) Alternating Injectivity Experiment. The alternating injectivity experiment of CO_2-GOBT was conducted to investigate the alternating injectivity of CO_2-GOBT under 0.249 mD and 47.2 °C.

4.2.7. Oil Displacement Performance. 4.2.7.1. Homogeneous Model Oil Displacement Experiments. The CO_2 flooding, GOBT flooding, and CO_2-GOBT synergistic flooding were conducted on the core by constant pressure displacement at 47.2 °C to compare the oil displacement efficiency.

4.2.7.2. Heterogeneous Model Oil Displacement Experiments. The CO_2 flooding, GOBT flooding, and CO_2-GOBT synergistic flooding were conducted by constant pressure displacement, simulating the formation heterogeneity at 47.2 °C to compare the oil displacement efficiency. The three groups

Table 7. Effects of Foam on Plugging the High Permeability Layer and EOR of the Low Permeability Layer

number	K_g/mD	Φ/%	S_{wi}/%	water flooding recovery/% low	water flooding recovery/% high	water flooding recovery/% total	enhanced oil recovery/% low	enhanced oil recovery/% high	enhanced oil recovery/% total	displacement modes	phenomenon
10	2.5	9.5	51.1	17.27	56.47	39.93	21.42	13.89	17.07	0.4% GOBT alternating water flooding (0.3PV alternating)	no foam
11	10.0	9.4	53.4								
12	0.17	12.3	37.6	31.99	46.06	39.46	31.18	6.35	18.00	CO_2 alternating 0.4% GOBT flooding (0.3PV alternating)	foam
13	0.75	13.9	30.0								

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Table 8. Ionic Composition of Injected Water ($mg \cdot L^{-1}$)

ionic composition/$mg \cdot L^{-1}$						
Na^+, K^+	Ca^{2+}	Mg^{2+}	Cl^-	SO_4^{2-}	HCO_3^-	salinity/$mg \cdot L^{-1}$
1695	349.74	75.01	1033.48	3470.9	164.1	6788

Table 9. Ionic Composition of Formation Water ($mg \cdot L^{-1}$)

ionic composition/$mg \cdot L^{-1}$						
Na^+, K^+	Ca^{2+}	Mg^{2+}	Cl^-	SO_4^{2-}	HCO_3^-	salinity/$mg \cdot L^{-1}$
10183	19148	71	49233	654	99	80,000

of dual-tube cores are 0.81 mD/0.189 mD, 1.01 mD/0.25 mD, and 0.745 mD/0.172 mD, with a grade difference of 4.3.

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Notes

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