Experimental Study on Supercritical CO_2 Enhanced Oil Recovery in Tight Reservoirs - Taking L Block as an Example

Abstract：

In order to solve the problem of fast decline in oil production and inability to maintain reservoir pressure in the L block of Cao She oilfield, a supercritical CO_2 injection and production experiment was conducted using a real rock core sample to explore the feasibility of using supercritical CO_2 flooding for enhanced oil recovery. The experiment was conducted on a long rock core sample after the reservoir had reached its decline stage. The effects of important operational parameters such as the number of flooding cycles, shut-in time, CO_2 injection volume, and adding surfactant flooding on enhancing oil recovery were studied. The results show that supercritical CO_2 flooding can effectively enhance oil recovery, with the best development effect in the first three flooding cycles, accounting for about 90% of the total oil recovery. There is a reasonable shut-in time for CO_2 flooding, and under certain conditions, prolonging the shut-in time can improve oil recovery to some extent. The oil recovery rate increases gradually with the increase of CO_2 injection volume. The oil recovery rate in the surfactant flooding experiment was 26.06%, which was 29.7% higher than the oil recovery rate in the flooding production experiment. Adding surfactant reduces the interfacial tension between oil and water and the starting pressure, improves the wetting properties of the reservoir rock, enhances the capillary imbibition and oil-water displacement ability of the matrix pore. The research results confirm the feasibility and huge application potential of injecting supercritical CO_2 for enhanced oil recovery, and can provide theoretical basis and technical support for the efficient development of the L block of Cao She oilfield.

Keywords：Tight oil reservoir; supercritical CO_2; production enhancement experiment; capillary suction agent; enhanced oil recovery.

Introduction

In recent years, tight oil has become a low-reservoir-rich unconventional oil resource after shale gas. At present, the initial development of tight oil is mainly based on horizontal wells with large-scale volume fracturing, and the production of depleted tight oil has the development characteristics of high initial production, fast decline in mid-term production, and low overall recovery rate. How to further supplement the reservoir energy and achieve secondary oil production after the depletion of tight oil has become an important problem facing the improvement of tight oil development. CO_2 injection as an efficient development method for further enhancing oil recovery after the depletion of tight oil has the advantage of effectively storing CO_2 while improving oil recovery. It can achieve economic benefits and environmental protection, and is increasingly being valued by the industry. CO_2 injection flooding mainly exhibits non-Newtonian flow characteristics, and CO_2 and oil have interactive effects, making the flow pattern very complex. In 1991, foreign researchers integrated field data, in-house experiments, and numerical simulations to demonstrate the feasibility of CO_2 injection in improving light oil reservoir recovery; in 2013, Hawthorne et al. pointed out that CO_2 injection is an important means of tight oil development, and the scale of the mesh network is a key factor affecting the injection effect; in 2016, Pu et al. studied the effects of shut-in time, injection and production cycle, and production pressure differential on CO_2 injection by conducting in-house column core experiments; in 2020, Wu Mei'e optimized the water injection, well pattern adjustment, and fracturing process continuously, and formed a horizontal well and vertical well mixed three-dimensional water injection development technology, effectively improving the water injection development effect of volcanic rock oil reservoirbelowbelow[1-5].

Through analyzing the previous research findings, it was found that the predecessors mainly optimized the development of tight oil reservoirs through water injection, numerical simulation technology, and horizontal well application[6-8], while the study on enhanced oil recovery using supercritical CO_2 in tight oil reservoirs was less.

The research area is located in the L block of Cao She Oilfield, with porosity ranging from 6.17% to 18.7%, permeability ranging from 1 to 4.50 mD, classified as medium-low porosity and very low permeability reservoir. The oil layer depth in the middle is 1670m, the original reservoir formation temperature is 78.5-104.52°C, the measured formation pressure is 26.45-37.2 MPa, the reservoir is of medium water sensitivity, and after depletion-type and water injection development, water intrusion is serious, and the wave of influence coefficient is low. The development effect is not ideal. The CO_2 injection and production method can effectively maintain the pressure of the tight oil reservoir, reduce the viscosity of crude oil, improve the flow channels in the reservoir, and further improve the recovery rate of tight oil. Therefore, taking the representative oil sample and core from the L block of Cao She Oilfield as the research object, based on the supercritical CO_2 long core injection and production experimental study, the research analyzed the degree of production, the oil replacement rate, etc. of the supercritical CO_2 injection and production, further explored the injection and production mechanism of tight oil with supercritical CO_2, the addition of imbibition agent imbibition injection and production, the number of injection and production cycles, the shut-in time, and the injection amount of CO_2, to provide theoretical basis and technical support for the efficient development design of CO_2 injection in tight oil reservoirs. The research results show that the CO_2 injection and production development method has great feasibility and application potential for improving the recovery rate of the block's tight oil reservoir.

1. Experimental materials, instruments, and methods

1.1 Experimental Materials

The live oil used in this experiment was the ground degassed crude oil from L block laboratory compound oil sample. The sample was the crude oil from Caocai oilfield after dehydration and degassing, with an original in-situ density of 0.8791 g/cm^3; crude oil viscosity of 5.14 mPa.s; and a wax content of 21.5-24.74%. The permeability-enhancing agent used in the experiment was the HI30 type nanopermeability-enhancing agent developed by Yangtze University, mainly composed of nonionic surfactants and nanometer silica particles.

The experimental conditions were determined based on the geological temperature and pressure of the study area block. According to the data of L block, the oil layer depth in the middle is 1670 m, the geological pressure is 26.49 MPa, the pressure coefficient is 1.25, the saturation pressure is 24.22 MPa, the reservoir pressure difference is 1.48 MPa, the geological temperature is 80.2 °C, and the oil volume coefficient is 1.326. The minimum miscible pressure of CO_2 is 22.11 MPa; the water sample was prepared according to the properties of the formation water, with a total mineralization of 10708.8 mg/l and a water type of $NaHCO_3$; the formation dissolved gas was mixed; CO_2 gas cylinder (99%); a real rock core from the reservoir was used, consisting of 16 rock cores combined.

1.2 Experimental Plan and Test Procedure

1.2.1 Experimental Plan

According to the Bral law, the natural core samples were sequentially combined to form a long core model. Under the original reservoir conditions, the long core was saturated with oil and the initial oil saturation and bound water saturation were measured. Based on the operating parameters of the experimental design, the long core supercritical CO_2 injection experiment was conducted. During the injection stage, a certain amount of CO_2 gas was injected into the rock core at the designed injection rate[9-10]. During the shut-in stage, the shut-in time was 24h and 48h during the experiment. During the production stage, the decline development was carried out at a pressure drop rate of 25 kPa / min. The reservoir pressure was depleted to the saturation pressure level, and CO_2 was injected to 30 MPa. After shutting in for 24 and 48 hours at 30 MPa, the well was released to the saturation pressure and the process was repeated for four cycles of injection and production.

In order to ensure the accuracy of the long core-flooding experiment, the core used in the experiment was taken from the same large outcrop, and the experimental conditions were the same. Because the pore volume of the long core is small, the corresponding oil production is also relatively small, the oil production data obtained by traditional measurement methods has a large error. Therefore, this paper uses the weighting method to calculate the recovery rate of the flooding, that is, the core is weighed before and after the experiment, and the produced oil volume is calculated by the difference in weight[11]. The long core experiment plan is shown in Table 1, and the experimental device is shown in Figure 1.

Table 1 Long Basalt Core Injection Test Schedule

Experiment Number	Core size /cm		Permeability /$10^{-3}\mu m^2$	Porosity / %	Irreducible Water saturation /%	Oil saturation /%	Injection type	Well-soaking time /h	Recovery degree /%
	Diameter	Length							
1#	2.5	30.25	2.44	19.43	49.80	50.2	Injecting CO_2	24.00	20.08
2#	2.5	30.25	2.56	18.37	48.30	51.7	Injecting CO_2 and permeability enhancers	24.00	26.06
3#	2.5	30.24	2.67	17.82	48.60	51.4	Injecting CO_2	48.00	24.15

The supercritical CO_2 high-temperature high-pressure experimental system (see Figure 1) mainly consists of:

Core model, high-temperature and high-pressure core flow evaluation system, temperature collection and control system, choke valve, intermediate container, core holder, pressure sensor, backpressure valve, oil, gas, and water separation and measurement device, and constant pressure and constant flow pump, etc. Among them, the high-temperature and high-pressure core flow evaluation system is a sealed rectangular steel container on one side of which the end door can be opened, which, when combined with the temperature collection and control system and the overburden pump, can provide the core model with a high-temperature and high-pressure external environment; the oil, gas, and water separation and measurement device is used to record the liquid separation record at the outlet end; the choke valve is used for the control of the production speed during development[12].

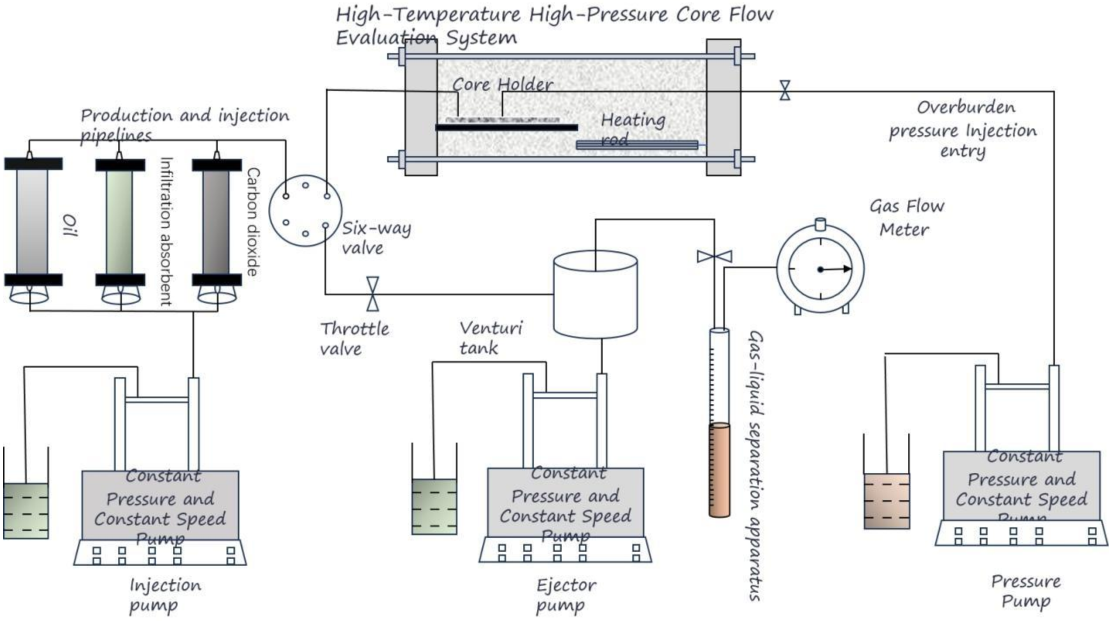

Figure 1 Schematic diagram of the high-temperature high-pressure core flow evaluation system

Figure 1 is a schematic diagram of the high-temperature high-pressure core flow evaluation system.

1.2.2 Test Procedure

1)Connect the experimental system according to the supercritical CO_2 high-temperature high-pressure flow diagram, and test the entire system for pressure to ensure its air-tightness. Then, place the experimental fluid samples in the piston container and place them together in a constant temperature oven set to the reservoir temperature. Preheat the fluid samples.

2)Saturate the long core. After the long core is evacuated, fill it with reservoir water and accurately measure the saturated water volume.

3)Establish bound water. Drive the reservoir water out of the long core with ground surface degassed crude oil, and accurately measure the discharged water volume, which is the original oil volume.

4)Establish the original oil saturation. Drive the ground surface degassed crude oil out of the long core with the compound activated oil.

5)Exhaustion experiment. After saturating the activated oil, the pressure is stabilized at the original reservoir pressure, and the exhaustion experiment is conducted by lowering the pressure at the outlet end. The post-exhaustion pressure is maintained at the saturation pressure level, which is set to 240 MPa in this experiment, and the oil and gas production rates are determined.

6)CO_2 flooding experiment. After the exhaustion experiment, the outlet end is injected with CO_2 at a constant pressure of 30 MPa for the first round. After the pressure stabilizes, the injection volume is recorded. The well is shut in for 24 and 48 hours after the injection, and production is carried out until the saturation pressure of about 240 MPa is reached. Then, the second, third, and fourth flooding experiments are conducted, and the oil and gas production rates in each round are accurately recorded to calculate the gas oil ratio and recovery rate.

7) CO_2 Injection and Absorption Pilot Test. After the depletion test, the exit end is injected with a constant pressure of 30 MPa for the first round of CO_2 and absorption agent injection. After the pressure stabilizes, the injection volume is recorded, and the well is shut in for 24 and 48 hours before being opened for production to a saturation pressure of about 24 MPa. Then, second, third, and fourth cycles of injection and absorption are carried out, and the oil and gas production volumes for each cycle are accurately recorded to calculate the gas oil ratio and recovery rate[13-15].

2. Results and Analysis

2.1 The experimental results

Through three dense oil tight rock core CO_2 injection studies, the effects of different operational parameters on development performance were comprehensively analyzed. As shown in Table 2 and 3, the recovery rate of the absorption agent injection experiment was 26.06%, which was 29.7% higher than the recovery rate of the injection oil experiment. After adding the absorption agent, the interfacial tension between oil and water was reduced, the initiation pressure was lowered, the rock wettability was improved, the permeability oil-water replacement ability of the matrix was enhanced, and the absorption effect was strengthened. As shown in Table 1 and 2, the CO_2 injection development method can obtain better development performance in dense oil development. Under certain conditions, extending the seal time to a certain extent can improve the recovery rate to some extent.

2.1.1 CO_2 Injection Test - 24-hour Results of Shut-in Well

The results of supercritical CO_2 flooding experiment under 24-hour seal-off condition are shown in Table 4. From the results in Table 4, it can be seen that the recovery rate was only 1.41% when the original reservoir pressure of 26.85 MPa declined to the saturation pressure of about 24 MPa. After four rounds of CO_2 flooding, the first round recovery rate was 10.26%, the second round was 5.12%, the third round was 2.59%, and the fourth round was 0.70%, with a total recovery rate of 20.08%. The contribution rate of the first, second, and third rounds of flooding to the total recovery rate was 89.50%.

Table 2 CO_2 Injection Test Results (Sealed Well for 24 Hours)

Experimental process	**Inlet pressure /MPa**	**Export pressure /MPa**	**CO_2 injection quantity /HCPV**	**oil mass /g**	**Gas flow /mL**	**Gasoline ratio / （ $m^3 \cdot m^{-3}$）**	**Recovery degree /%**
Exhaustion	26.85	26.65	-	0	0	0	0

	24.48	24.32	-	0.204	20	98	1.41
First round swallow	30.00	30.00	0.302	-	-	-	-
First round of vomit	24.33	24.25	-	1.482	320	216	11.67
Second round of swallow	30.00	30.00	0.386	-	-	-	-
Second round of vomit	24.46	24.38	-	0.742	440	593	16.79
Third round Swallow	30.00	30.00	0.421	-	-	-	-
Third round of vomit	24.36	24.33	-	0.376	800	2128	19.38
Fourth round of swallow	30.00	30.00	0.443	-	-	-	-
Fourth round of vomit	24.59	24.34	-	0.102	560	5490	20.08

2.1.2 The results of the 24-hour CO_2 injection and production test using a long-core of granite rock

The results of the supercritical CO_2 injection and recovery experiment under the condition of sealing the well for 24 hours are shown in Table 5. From the results in Table 5, it can be seen that the recovery rate was only 1.60% when the original reservoir pressure of 26.74 MPa declined to the saturation pressure of about 24 MPa. After four rounds of CO_2 injection and recovery, the first round of injection recovery rate was 13.52%, the second round was 6.79%, the third round was 3.31%, and the fourth round was 0.82%. The total recovery rate was 26.06%, and the contribution rate of the first, second, and third rounds of injection and recovery to the total recovery rate was 90.72%.

Table 3 CO_2 Injection and Depletion Test Results (After 24 Hours of Sealing the Well)

Experimental process	Inlet pressure /MPa	Export pressure /MPa	CO_2 injection quantity /HCPV	oil mass /g	Gas flow /mL	Gasoline ratio / （$m^3 \cdot m^{-3}$）	Recovery degree /%
Exhaustion	26.74	26.61	-	0	0	0	0
	24.50	24.36	-	0.226	50	221	1.60
First round swallow	30.00	30.00	0.302	-	-	-	-
First round of vomit	24.36	24.24	-	1.906	550	289	15.14
Second round of swallow	30.00	30.00	0.386	-	-	-	-
Second round of vomit	24.52	24.39	-	0.958	850	887	21.93
Third round	30.00	30.00	0.421	-	-	-	-

Swallow							
Third round of vomit	24.45	24.30	-	0.467	940	2013	25.24
Fourth round of swallow	30.00	30.00	0.443	-	-	-	-
Fourth round of vomit	24.54	24.40	-	0.116	780	6724	26.06

2.1.2 The results of the 48-hour CO_2 injection experiment with a long-core sandstone sample

The experimental results of supercritical CO_2 flooding under the condition of sealing well for 48 hours are shown in Table 5. From the results in Table 5, it can be seen that the recovery rate was only 1.68% when the original reservoir pressure of 26.74 MPa declined to the saturation pressure of about 24 MPa. After four rounds of CO_2 flooding, the first round of flooding had a recovery rate of 12.27%, the second round had a recovery rate of 6.07%, the third round had a recovery rate of 3.21%, and the fourth round had a recovery rate of 0.92%. The total recovery rate was 24.15%, and the contribution rate of the first, second, and third rounds of flooding to the total recovery rate was 89.24%.

Table 4 CO_2 Injection Test Results (Sealed Well for 48 Hours)

Experimental process	**Inlet pressure**	**Export pressure**	**CO_2 injection quantity**	**oil mass**	**Gas flow /mL**	**Gasoline ratio / ($m^3 \cdot m^{-3}$)**	**Recovery degree**

	/MPa	/MPa	/HCPV	/g			/%
Exhaustion	26.74	26.61	-	0	0	0	0
	24.55	24.36	-	0.229	30	131	1.68
First round swallow	30.00	30.00	0.302	-	-	-	-
First round of vomit	24.36	24.24	-	1.668	430	258	13.95
Second round of swallow	30.00	30.00	0.386	-	-	-	-
Second round of vomit	24.52	24.39	-	0.825	600	727	20.02
Third round Swallow	30.00	30.00	0.421	-	-	-	-
Third round of vomit	24.45	24.30	-	0.434	860	1981	23.23
Fourth round of swallow	30.00	30.00	0.443	-	-	-	-
Fourth round of vomit	24.54	24.40	-	0.126	640	5079	24.15

2.2 Discussion and Analysis

2.2.1 Effect of Imbibition Agents on Recovery Rates

The results of the impact of injecting surfactant on recovery rate are shown in Figure 2, where the recovery rate of surfactant-enhanced waterflooding is 26.06%. The recovery rate of CO_2-enhanced waterflooding was increased by 29.7% compared to the simple CO_2-enhanced waterflooding. From Figure 2, it can be seen that the water cut of the simple CO_2-enhanced waterflooding increased with the increase of the flooding cycle, and then decreased. The water cut of the surfactant-enhanced waterflooding decreased with the increase of the flooding cycle, and then increased, and the cumulative water cut reached 7.9% after the 4th flooding cycle, exceeding the water cut of the simple waterflooding. As the surfactant is continuously injected, it lowers the interfacial tension of the emulsified oil while increasing the reservoir pressure, thereby improving the CO_2-enhanced waterflooding capacity. This confirms that surfactant-enhanced waterflooding can appropriately lower the oil-water interfacial tension, improve the rock wettability to a more water-wet state, and cause the pervasive imbibition displacement of oil in the core under the capillary force, thereby increasing the amount of oil that can flow in the rock[16]. At the same time, the decrease in interfacial tension also reduces the resistance to oil droplet migration, enhances the ability to pass through the throat, which is also a beneficial factor.

In tight oil reservoirs, injected water flows through the fractures and cannot form sufficient pressure difference with the matrix, making it difficult for the oil in the matrix to be improved by percolation. Surfactant-enhanced oil recovery through wetting reversal displaces oil, which can significantly improve the recovery rate of the matrix in low pressure difference conditions, making it an effective method for the development of tight oil reservoirs.

The experimental results indicate that under certain conditions, the process of imbibition and expulsion can reduce the interfacial tension between oil and water appropriately, increase the rate of oil replacement, effectively supplement the energy of the reservoir, and increase the amount of oil that can flow in the rock, which can significantly enhance the recovery rate of tight oil.

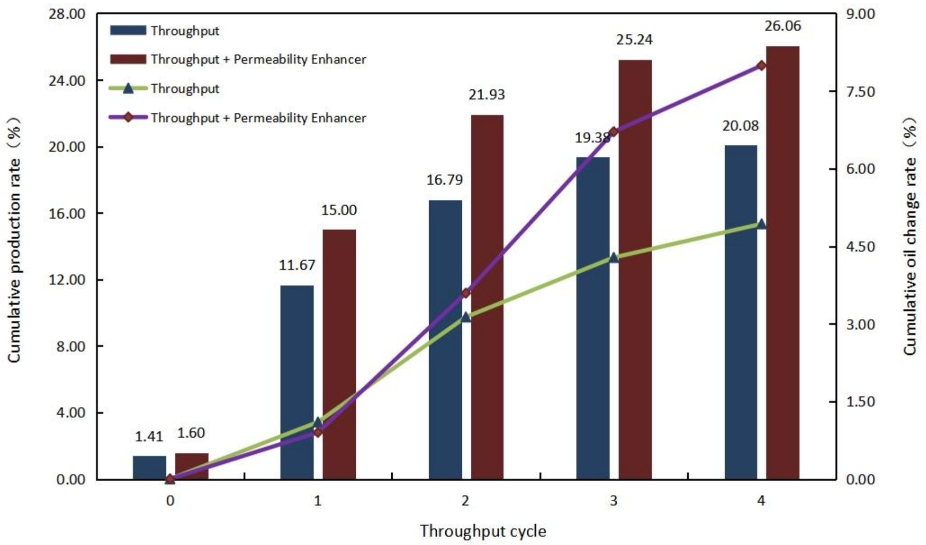

Figure 2 shows the effect of surfactants on recovery rate.

2.2.2 Impact of Throughput Cycles on Recovery Rate

The impact of production cycles on recovery rate is shown in Figure 3. As can be seen from Figure 3, the first production cycle has the highest recovery rate, reaching about half of the total recovery rate, while the fourth production cycle has a very low recovery rate. After the depletion phase is completed, injecting supercritical CO_2 can compensate for the energy of the reservoir to some extent, but the recovery rate of CO_2 injection production gradually decreases as the number of production cycles increases.

Firstly, as CO_2 injection continues, its effective compensation rate for the reservoir energy becomes lower and lower; secondly, after the first two injection rounds, most of the produced oil comes from larger pores and near the production end, while oil in microscopic pores and throats has not been produced or has only a small amount produced, making it difficult to produce oil in the third and fourth rounds, with a low recovery rate; finally, as CO_2 dissolves in crude oil, it can extract light components from it. With the increase of injection rounds, a large amount of light components in crude oil are extracted, so the content of light components in residual oil gradually decreases, thereby reducing the extraction effect of CO_2 and lowering the recovery rate[17-20].

The experimental results show that the round-by-round recovery rate after each injection round continues to decline, and the CO_2 flooding oil extraction effect is poor after more than 3 rounds.

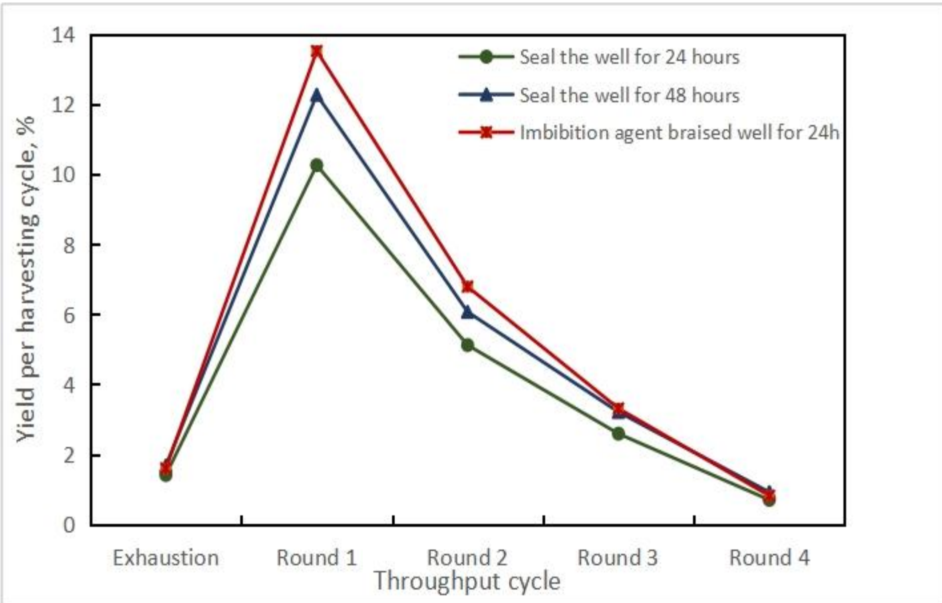

Figure 3 Impact of production cycle on recovery rate

2.2.3 The effect of sealing time on recovery rate

The influence of sealing time on recovery rate is shown in Figure 4. As can be seen from Figure 4, the total recovery rate for sealing for 24 hours is 20.08%, and the total recovery rate for sealing for 48 hours is 24.15%, an increase of 20.3% over sealing for 24 hours. This shows that under certain conditions, the influence of sealing time on recovery rate is significant, and the recovery rate increases as the sealing time is prolonged. This is because, in the early stage of sealing, extending the sealing time can enable CO_2 to dissolve more fully into the crude oil, making it easier for CO_2 to fully exert its swelling, reducing viscosity, and extracting oil functions, thereby improving the efficiency of CO_2 injection.

The experimental results show that under certain conditions, sealing time is positively correlated with recovery rate.

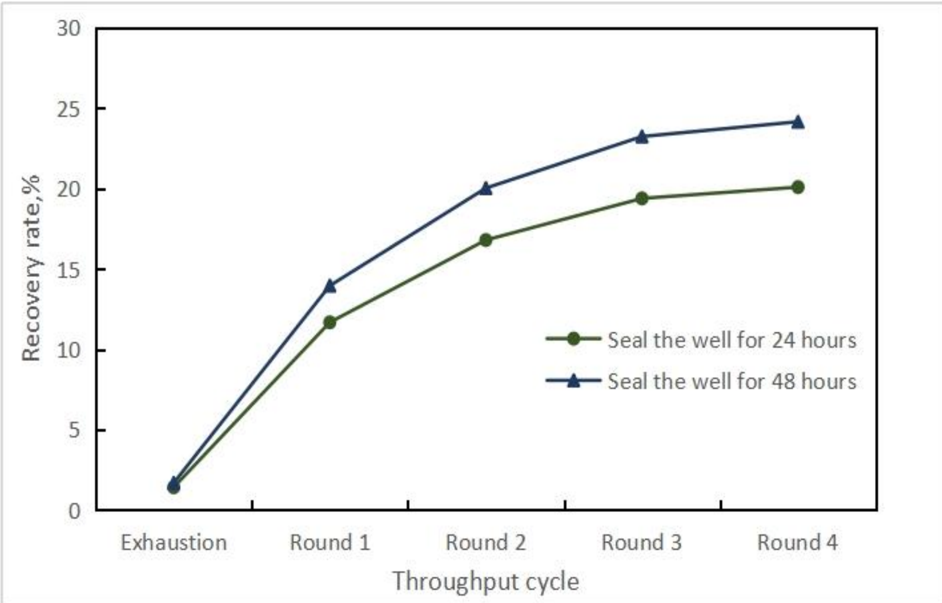

Figure 4 shows the impact of production rate on throughput per cycle.

2.2.4 The Impact of CO_2 Injection Rate on Oil Recovery

The injection of CO_2 has a significant impact on the production performance. Using the experimental data from schemes 1-3 in Table 1, the relationship curve between recovery rate and CO_2 injection volume was calculated and plotted in Figure 5, showing that as the CO_2 injection volume increases, the recovery rate gradually increases. When the CO_2 injection volume reaches 0.421 HCPV, the increase in recovery rate is relatively small. When the CO_2 injection volume reaches 0.443 HCPV, the recovery rate continues to increase, but the increase is very small and can be ignored. This is because, at low CO_2 injection volumes, the dissolution, expansion, reduction in viscosity, and extraction mechanisms of CO_2 improve the recovery rate of crude oil significantly. As crude oil is continuously produced, the remaining oil content gradually decreases, and subsequent injection of CO_2 cannot be fully utilized[21];

The experimental results show that the injection of CO_2 is also an important factor affecting the recovery rate, and the recovery rate increases as the CO_2 injection volume increases. After the CO_2 injection volume exceeds a certain level, the increase in recovery rate gradually slows down.

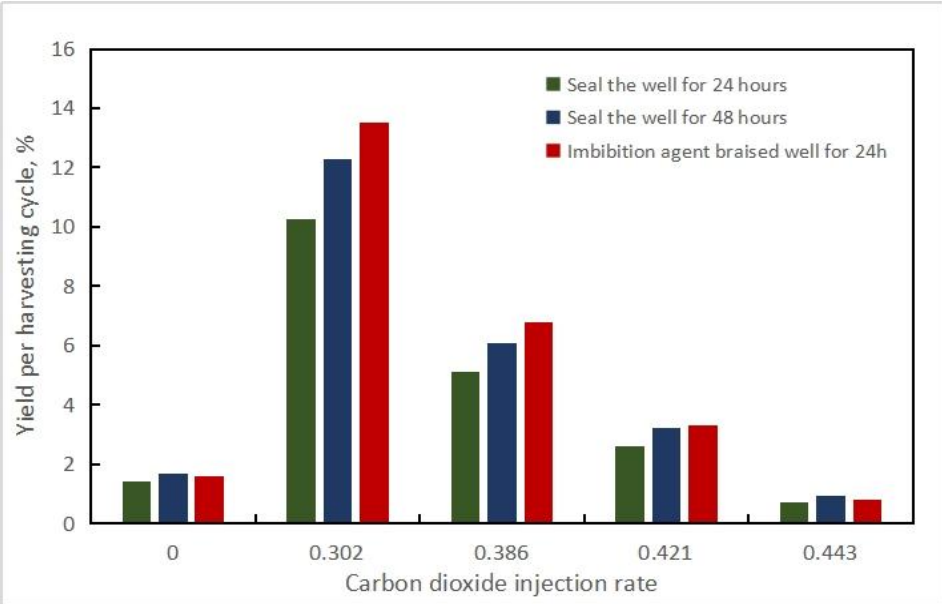

Figure 5 Impact of CO_2 Injection Rate on Oil Recovery Rate

3 Conclusion

1) The imbibition displacement experiment had a recovery rate of 26.06%, which was 29.7% higher than the CO_2 displacement experiment. Imbibition displacement can appropriately lower the oil-water interfacial tension and initiation pressure, increase the oil recovery rate, and achieve an accumulated oil recovery rate of 7.9% after the 4th displacement cycle, resulting in an increase in the amount of oil that can flow in the reservoir. As the imbibition agent is continuously injected, the emulsified oil lowers the oil-water interfacial tension while increasing the reservoir pressure, improving the CO_2 displacement ability and significantly increasing the oil recovery rate.

2) Supercritical CO_2 displacement can effectively improve the recovery rate of tight oil, with the best development effect achieved in the first 3 displacement cycles, accounting for about 90% of the total recovery rate. However, the incremental recovery rate of each displacement cycle decreases gradually, and the displacement oil recovery effect is poor after more than 3 displacement cycles.

3) The duration of sealing the well has a significant impact on the recovery rate, and there is a reasonable sealing time for CO_2 injection development. Under certain conditions, extending the sealing time to a certain extent can improve the recovery rate to some extent.

4) The injection volume of CO_2 has a significant impact on the enhanced oil recovery effect. As the injection volume of CO_2 increases, it leads to a decrease in crude oil viscosity, an increase in volumetric coefficient and dissolved gasoline ratio, which is beneficial to crude oil extraction. The enhanced oil recovery rate therefore increases with the increase of CO_2 injection volume. However, when the injection volume of CO_2 reaches a certain level, the increase in enhanced oil recovery rate becomes obvious after the CO_2 injection volume exceeds 0.421 HCPV and reaches 0.443 HCPV, so an appropriate CO_2 injection volume can greatly improve the recovery rate.

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