Experimental Study on Gas Injection for Ultra Deep and High-Pressure Fractured-Vuggy Carbonate Oil Reservoirs

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Abstract

In the development of ultra-deep fractured-vuggy carbonate reservoirs, normally only few wells were drilled and hydraulically fractured to create channels connecting the large vugs. Production decline at early stages due to rapid pressure decline appears to be the main problem, and water and gas injection via huff-and-puff mode can be applied to maintain oil production. For the targeted reservoir (6,000-7,500 meter depth) in the Northwest China, nitrogen injection has shown good IOR (improved oil recovery) response. In this study, injection of CO_2 and methane rich natural gas with different injection-production modes was studied in the laboratory. The laboratory techniques are using a specially designed experimental set-up with multiple cavities connected by small channels to simulate the fractured-vuggy carbonate reservoir. The physical model was designed based on the characteristics of the fractured-vuggy carbonate reservoir and similarity theory, to investigate the influencing factors and the mechanisms of oil recovery of gas injection. Gas huff-and-puff experiments were conducted using three different injection-production modes, including vertical model with injection well at top and production well at the bottom, vertical model with injection and production wells at the bottom, and horizontal model with injection and production wells at the same end, under pressure up to 65 MPa. The minimum miscible pressure (MMP) of CO_2 and natural gas with the crude oil were measured through a slim-tube test. The effects of gravity stabilization and miscibility on oil production were analyzed. The experimental results show that the MMP of CO_2 of the targeted oil is 30.1 MPa, and over MMP of 47.6 MPa for the methane-rich natural gas, and the IOR performance of the methane-rich natural gas is better than that of CO_2 at ultra-high pressure conditions. It indicates that the action of gravity stabilized oil displacement can be the most important mechanism in the development of high pressure fractured-vuggy reservoirs for gas injection, overshadowing the miscibility effect of CO_2 for high pressure applications. The results of the study can provide important guidelines for designing gas injection process in ultra-high pressure fractured-vuggy carbonate reservoirs.

Introduction

Many Ordovician type and naturally fractured-vuggy carbonate reservoirs have been explored, such as in the Tahe oilfield of Northwest China, which are buried deeply (6000-7500 m) and with ultra high-pressure (60-75 MPa). The permeability of the reservoir rock matrix is extremely low, ranging from 0.1 to 1 mD, and oil and gas are stored in natural fractures and small and large vugs (Du et al. 2011; Xu et al. 2010; Zheng et al. 2010). Hydraulic fracturing has been applied to create connections among the vugs and production wells, natural and man-made fractures (up to millimeter size opening) and vugs (up to meter size diameter) are the main flow channels of fluids and primary hydrocarbon storage spaces respectively (Chen et al. 2005; Corbett et al. 2010; Yousef et al. 2014).

In the early stage of oil production, the fractured-vuggy carbonate reservoirs of Tahe oilfield mainly depended on natural energy for exploitation (Camacho-Velazquez et al. 2002; Chen et al. 2005). Later, the mode of artificial

DOI: 10.14800/IOGR.1250

Received June 1, 2023; revised July 1, 2023; accepted July 17, 2023.
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water injection was implemented to supplement the energy for production. Due to the extremely high heterogeneity of the reservoirs and incomplete well pattern, the effect of water injection gradually becomes minor and negligible with the increase of water injection cycle (Li et al. 2013; Pratap et al. 1997; Rivas-Gomez et al. 2001; Rong et al. 2016). There is a lot of remaining oil still in the reservoir after water injection (Jing et al. 2012; Rezaei et al. 2013; Wang et al. 2016). The production of this remaining oil is a major challenge in the development process, and there is need to explore new enhance oil recovery methods (Farhadinia et al. 2011; Shakiba et al. 2016), including gas injection, and nitrogen injection has shown good IOR (improved oil recovery) response (Su et al. 2017a Yuan et al. 2015; Yue et al. 2018).

In recent years, many researchers have designed and built physical experimental models to simulate the fractured-cavity carbonate reservoir in order to reveal the mechanism and influencing factors of water and gas injection for enhanced oil recovery. Most of the studies were conducted by generating specific physical models which were usually in regular structure or fixed special distribution (Cruz-Hernandez et al. 2001; Li et al. 2008; Li et al. 2009; Wang et al. 2011). However, the distribution and connection of fractures and caves (or vugs) could not reflect correctly by these simple physical models (Su et al. 2017b).

In this study, the buried depth of the target fractured-vuggy reservoir in Tahe oilfield is between 5,210-6,020 m, in which a lot of large vugs have been identified by various geological, geophysics and well logging techniques (Tian et al. 2019). Based on the characteristics of the fractured-vuggy reservoir and the similarity theory, an experimental model with multiple cavities connected by small channels is innovatively designed and built to simulate the fractured-vuggy reservoir. CO_2 and natural gas huff-and-puff experiments were conducted under the reservoir conditions with different injection-production modes. PVT and MMP experiments were also performed to facilitate the IOR mechanism analysis with different types of injection gas in terms of miscibility, gas driving, and gravity stabilization effects.

Experimental arrangements

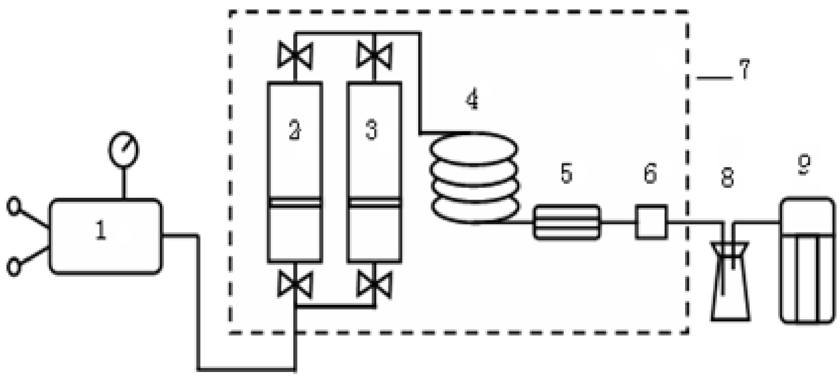
Materials. The average surface density and viscosity of the oil in targeted reservoir are 0.8744 g/cm^3 and 13.83 mPa·s, respectively, which is a light-medium conventional crude oil with medium sulfur and high wax content. The oil sample used in the experiment was prepared by dead oil and natural gas in the laboratory according to a gas-oil ratio of 66 m^3/m^3. The basic physical parameters of the crude oil are shown in **Table 1**.

Table 1—The basic physical properties of simulated oil

Parameters	Value
Formation temperature, °C	130
Formation pressure, MPa	40-65
Saturation pressure (Pb), MPa	16.5
Formation oil volume factor (Bo@130 °C, 40 MPa)	1.14
Solution gas-oil ratio (GOR), m^3/t	63-73
Formation oil density, g/cm^3	0.848
Surface oil density (@ 20 °C, 0.101MPa), g/cm^3	0. 91
Surface oil viscosity (@20 °C, 0. 101 MPa), mPa·s	78. 47
Formation oil density at saturation pressure (@130 °C), g/cm^3	0. 827
Formation oil viscosity at saturation pressure (@130 °C), mPa·s	2. 654

The gases used for injection include CO_2 (purity 99.9%) and a natural gas (C_1-93.30%, C_2-4.94%, C_3-1.34%, and CO_2-0.4%), which were prepared and supplied by Qingdao Tianyuan Gas Company. The water sample was prepared according to the analysis results of formation water with a salinity of 15×10^4 ppm. The crude oil components and related physical properties under experimental conditions are listed in **Tables 1** and **2**.

CO_2 and natural gas MMP experiments. MMP is the threshold pressure at which gas and oil achieve miscibility in-situ at a constant temperature. It is an important parameter for designing miscible displacement and predicting miscible state. The main parameters affecting miscibility are the injection gas composition, reservoir fluid composition, and reservoir temperature. Slim-tube test is the widely accepted experimental technique for determining MMP in the petroleum industry. Experiments were carried out using a conventional high-pressure PVT analyzer to test the physical properties of the reservoir crude oil (the maximum working pressure of the equipment was 70 MPa and the temperature was 150°C). The flow chart of the slim tube test device is based on the conventional standard experimental procedure, as shown in **Figure 1**. The main parameters of the slim tube test device is shown in Table 2.



1. Displacement pump, 2. Formation oil, 3. Injection gas, 4. Slim tube model, 5. Observation window, 6. Back pressure valve, 7. Thermostat box, 8. Separation bottle, 9. Gas meter

Figure 1—The schematic diagram of slim displacement experiment apparatus.

Table 2—The parameters of the slim tube model.

Main parameter	Value
Temperature resistance, °C	180
Pressure resistance, MPa	70
Length, m	12
Inner diameter, mm	14
Filler glass beads, mesh	80 mesh, 120 mesh (each 50%)
Pore volume, cm^3	65
Porosity, %	51.73
Permeability, D	5

Firstly, the MMP of crude oil was predicted by commercial simulation software, according to crude oil composition and reservoir temperature. On the basis of predicted MMP values, five displacement pressure points were set appropriately above and below the miscible pressure, and then slim tube miscibility pressure test was carried out. A certain amount of petroleum ether was injected into the slim tube for cleaning and dried with nitrogen, and then saturated with the oil sample. CO_2 and natural gas was injected at a rate of 0.3 mL/min to displace the crude oil. The volume of the crude oil was measured during the displacement process, and the gas injection was stopped until 1.2 pore volume gas injected or no longer oil produced.

According to the software predicted results of MMP, the slim tube test for two types of gases (CO_2/natural gas) under 5 different displacement pressures were carried out separately. The experimental temperature was held constant at 130 °C. It is generally believed that when the ultimate recovery is greater than 90%, the displacement pressure is the minimum miscible pressure of the gas and crude oil. The results of the MMP experiment can be seen in **Figures 2** and **3**.

According to the miscibility determination criterion of the slim tube experiment, it was determined that the MMP of CO_2 and formation oil is 30.1 MPa, and the MMP of natural gas and formation oil is 47.6 MPa. CO_2 obtains miscibility more easily than natural gas under reservoir condition.

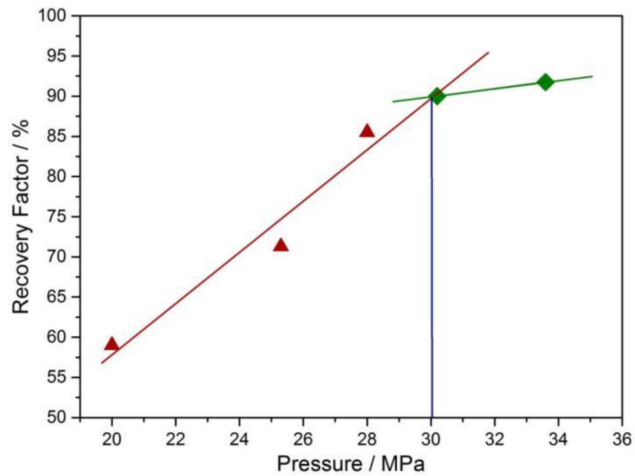


Figure 2—Result of the slim tube test for determining CO_2 MMP.

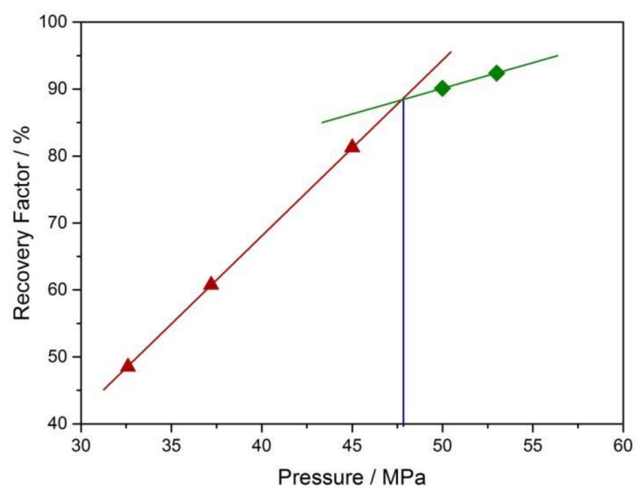


Figure 3—Result of the slim tube test for determining natural gas MMP.

The Fractured-cavity Models and Experimental Set-up. The physical simulation experiment is an important research method for optimizing the gas injection parameters, injection medium, and evaluating the effects of gas injection. Following parameters are taken into consideration for experimental study.

Similarity Criteria. A fractured-cavity physical model was designed based on the fracture-vuggy reservoir characteristics and similarity theory, and an experimental study was conducted. The experimental model construction is according to similar criterion to define the experimental conditions and the characteristics of the model, creating the more significant experimental model results to the actual fracture-vuggy reservoir.

Considering the vug is the main storage space in fractured-vuggy reservoirs, in the process of experimental model design, it is not necessary to satisfy multiple similar criterions at the same time. The similar criterion design is emphasis on the fluid flow in the vug (Haibo et al. 2014). At this point, the viscous force shows negligible effect, while the gravity differentiation plays a vital role due to the smaller seepage area of fractured-vuggy reservoirs. Hence, the similar design is mainly based on the relation between gravity and pressure, oil production rate, and injection flow rate (Su et al. 2017b). According to similar theory, when the similarity coefficient is 1, the field parameters and model parameters are similar. The similarity coefficient can be calculated by the ratio of field parameters to model parameters.

To ensure the rationality of the model, the geometric similarity, kinematic similarity, and dynamic similarity analysis of the model were carried out by dimensional analysis, see **Table 3**.

Table 3—Similarity criteria group of fracture cavity type reservoir.

Kinematic similarity	Dynamic similarity	Geometric similarity
$\pi_1 = Q/\rho v L^2$	$\pi_3 = p/\rho v^2$	$\pi_6 = V_{vug}/L^3$
$\pi_2 = tv/L$	$\pi_4 = gL/v^2$	$\pi_7 = K_f/L^2$
	$\pi_5 = \mu/\rho v L$	$\pi_8 = r_w/L$
		$\pi_9 = x_f/L$
		$\pi_{10} = \varphi_v$
		$\pi_{11} = \varphi_f$

The characteristic parameters of the fracture-cavity model mainly consider the filling of the gravel in the cave, and the number of fractures connecting caves. We have regrouped main similarity criterions to meet the need of experimental research, see **Table 4**, which can reflect the fractured-vuggy reservoir characteristics.

Table 4—Similarity criterion group of the physical model and stimulation experiment.

Serial number	Similarity criterion	Physical meaning	Source	Satisfaction condition
1	$V_{vug}/K_f x_f$	Ratio of cavity volume to fracture conductivity	$\pi_6/\pi_7\pi_9$	Geometric similarity
2	$Q_t/(\varphi_v + \varphi_f)\rho L^3$	Injection rate	$\pi_1\pi_2/(\pi_{10} + \pi_{11})$	Kinematic similarity
3	$p/\rho g L$	Injection pressure / gravity	π_3/π_4	Dynamic similarity
4	$\mu/\rho v L$	Viscous force / inertial force	π_5	Dynamic similarity
5	v^2/gL	Inertial force / gravity	$1/\pi_4$	Dynamic similarity

According to the similarity criteria of physical model huff-and-puff experiment, the main parameters of simulation were determined by actual reservoir parameters, as shown in **Table 5**.

Table 5—Physical model parameter values.

Parameters	Fracture aperture, mm	Fracture permeability, μm^2	Cavern volume, m^3	Cavern diameter, m	Flow time, d	Filling degree, %	Injection rate, m^3/d
Actual reservoir	0.1-5.0	$1\text{-}10^6$	0.004-10000	0.2-30	1-10	0-100	30-150
Physical model	3	2-20	0.0006-0.002	0.0765	0.05-0.5	100	0.1-0.5*
Similarity coefficient	1-1.6	$0.05\text{-}5\times10^5$	$0.50\text{-}2\times10^6$	2.6-392	2-200	0-1	$200\text{-}2\times10^5$

*The unit is mL/min

Designing and Description of Multiple-cavity Model.To investigate the mechanism of CO_2 and natural gas huff-and-puff, a physical model with multiple cavities connected by small channels was designed by using the similarity theory. Inside the model, two metal pistons were used to separate the high-pressure vessel into three cavities (simulated karst caves), each piston had three holes which connected the chambers (simulated fractures) as shown in **Figure 4**, and the chambers were filled with carbonate fragments (stones), as shown in **Figure 5**.

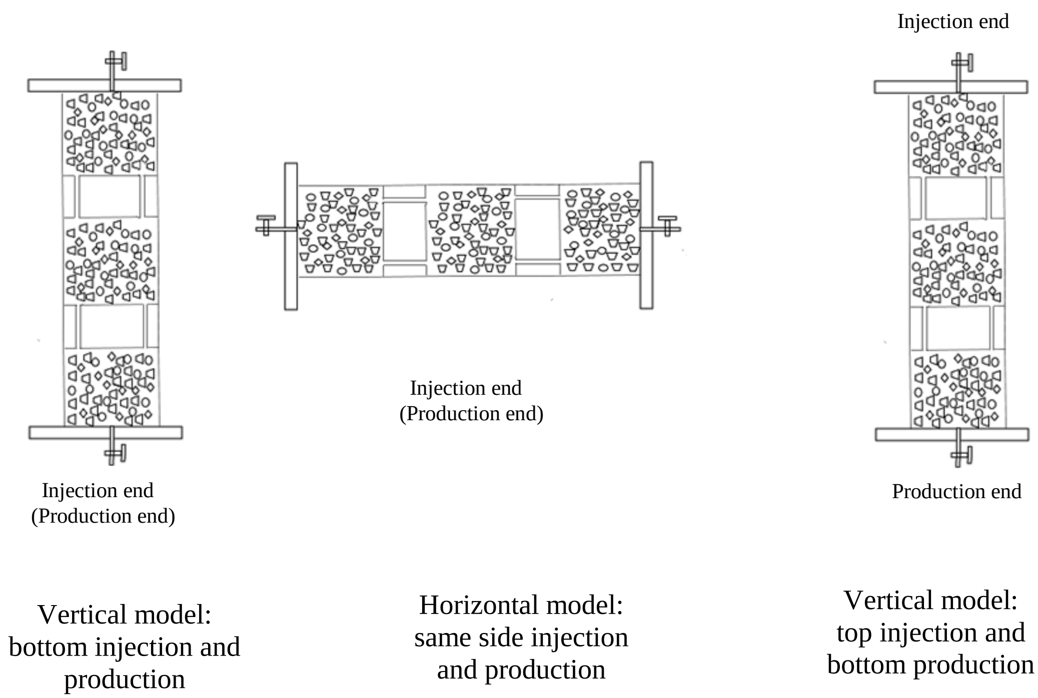
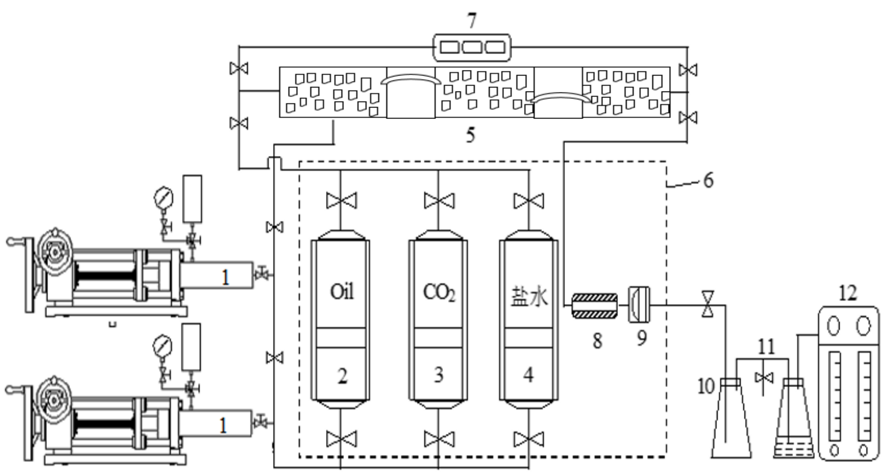


Figure 4—Different injection-production well modes in CO_2/Natural gas huff-and-puff experiment.

Figure 5—Experimental model tube and carbonate stone fillings.

The main design parameters of the model are as follows: the inner height is 40 cm, the inner diameter is 7.65 cm, the effective height is 27.5 cm (except the thickness of the piston), the diameter of connecting hole of the piston is 3 mm, the model is filled with carbonate rock fragments of 0.5-1.0 cm, the pressure is 70 MPa, and the temperature is 150 °C. The model can be adjusted to any angle of injection and production according to simulation requirements under experimental conditions.

The schematic flow chart of the experimental device is mainly composed of physical model system, displacement system, temperature control system, back-pressure control system, data monitoring system, metering system and a number of pipelines and valves, as shown in **Figure 6**.



1. Displacement pump; 2. Formation oil container; 3. CO_2/ natural gas container; 4. Brine container; 5. Rotatable fracture-cave sand filled model; 6. Thermostatic oven; 7. Pressure sensor; 8. Observation window; 9. Back pressure valve; 10.Separation bottle; 11.Sampling port; 12. Gas meter.

Figure 6—The schematic diagram of CO_2 /natural gas huff-and-puff experimental apparatus.

Experimental Procedures. The experimental process in multiple fracture-cavity model include seven steps:

(1) Experimental model approach: The fracture-cavity model was filled with carbonate rock pieces, and placed vertically/horizontally into the thermostatic displacement device.

(2) Water injection: The water was injected from the bottom of the model to measure the porosity, and the model pressure was controlled to 18 MPa.

(3) Oil injection: The oil was injected from the topside of the model to displace the saturated water until no more water flow from the outlet end, and then the irreducible water as well as initial oil saturation was measured. The temperature of the experimental model was kept constant at 130 °C, and pressure was controlled to 18 MPa.

(4) Gas injection: The CO_2/natural gas was injected into the model until it reaches the required pressure of 65 MPa.

(5) Soaking: The model temperature was maintained at formation temperature (130 °C), and injection valve was closed to allow the injected gas to soak and stabilized the pressure inside the model.

(6) Oil production: The outlet valve was opened to produce oil and gas under back pressure control. The volume of the produced gas/oil and the pressure difference at that point were measured and when the pressure reached to 18 MPa, production was stopped.

(7) Second huff-and-puff cycle: During the second cycle of huff-and-puff, the gas was re-injected into the model to the same pressure value (65 MPa), and the above experimental process was repeated until the ultimate huff-and-puff cycle reached. Total 6 cycles of CO_2 and natural gas huff-and-puff for vertical model with injection and production wells at the bottom and horizontal model with injection and production wells at the same end, and 1 cycle for vertical model with injection well at top and production well at the bottom were carried out. The experimental results were compared and analyzed to select the optimal injection gas and injection-production well mode. Related data and estimations (for example, OOIP, S_{wi}, and pore volume) for each experiment are presented in **Table 6**.

Table 6—The experimental conditions of the gas injection huff-and-puff and preliminary calculations.

Model measurement parameters	Value	Model measurement parameters	Value
Pore volume, mL	675	Temperature, ° C	130
Saturated oil volume, mL	606	Gas injection pressure interval, MPa	18-65
Porosity, %	53.43	Gas injection rate, $mL.min^{-1}$	0.1
Oil saturation, %	89.78	Soaking time, min	To stable pressure

Experimental results and discussions

CO_2 Huff-and-Puff under Different Injection-Production Modes. The main EOR mechanisms of CO_2 huff-and-puff are: a) oil swelling; b) hydrocarbon extraction by CO_2; c) viscosity reduction; d) solution gas drive. For CO_2 injection experiments, six huff-and-puff cycles for bottom injection and production, and horizontal same-end injection and production were carried out. The recovery factor (RF) for each set of huff-and-puff experiment was defined as the cumulative oil production divided by the OOIP (original oil in places) corresponding to that particular experiment. The incremental recovery factor for each cycle was defined as the produced oil for that specific cycle divided by the OOIP. The experimental results of six cycles of CO_2 bottom injection and production, and horizontal same-end injection and production in terms of incremental recovery factor and oil exchange rate are compared in **Figures 7** and **8**. It was inferred that the effect of bottom injection and production was similar to that of horizontal same-end injection and production.

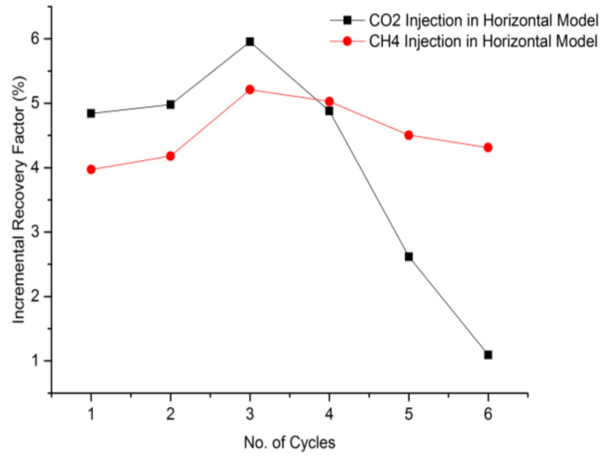


Figure 7—Incremental recovery factor of CO_2 and natural gas huff-and-puff experiment in horizontal model with injection and production at the same end.

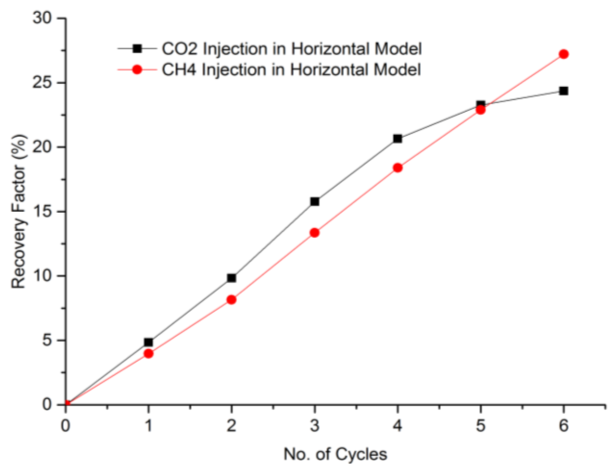


Figure 8—Recovery factor of CO_2 and natural gas huff-and-puff experiment in horizontal model with injection and production at the same end.

According to the CO_2 and oil MMP analysis, CO_2 was miscible with crude oil under experimental conditions. The solubility and swelling coefficient of CO_2 in crude oil was high, whereas the density of CO_2 was close to crude oil under high pressure conditions. The migration and diffusion rate of CO_2 in crude oil was low because most of the injected CO_2 accumulated at the injection-end or in the cavity near the injection-end. It was difficult to move or flow towards the upper part or other "karst cavities" connected through fractures and developed the mechanism of gravity stabilized oil displacement. The production mechanism for bottom injection and production, and horizontal same-end injection and production was mainly relied on elastic energy produced by oil swelling. Most of the injected CO_2 produced along with crude oil, resulted in faster energy release, and hence lower oil exchange ratio and overall oil production. It was observed that the water was also produced during production process of bottom injection and production well mode. During the soaking period, the water moved to the bottom of the model due to gravity difference.

For top injection and bottom production well mode, one cycle of CO_2 huff-and-puff was carried out. During the injection period, the injected CO_2 was completely dissolved in crude oil at high pressures, and swelling elastic energy caused oil to flow towards production well, as shown in **Figure 9**. But when the pressure decreased less than MMP of CO_2 and oil (30.1 MPa), the gas separated from the crude oil, and moved to the upper part showing gravity stable displacement effect, resulted in increased oil production and exchange ratio.

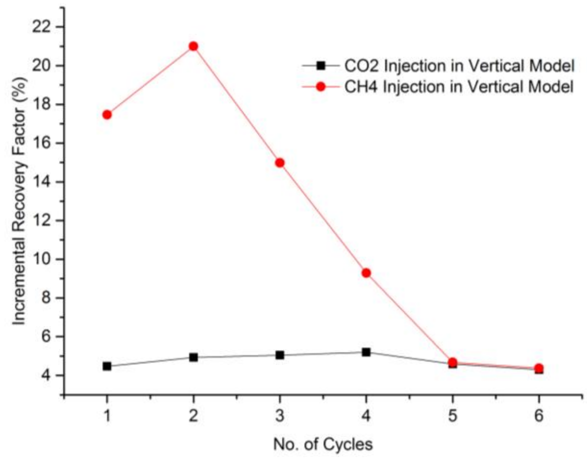


Figure 9—Incremental recovery factor of CO_2 and natural gas huff-and-puff experiment in vertical model with injection and production at the bottom of the model.

For natural gas injection experiments, six cycles of huff-and-puff for bottom injection and production, and horizontal same-end injection and production were carried out. The RF obtained by CO_2 and natural gas huff-and-puff are shown in **Figure 10**.

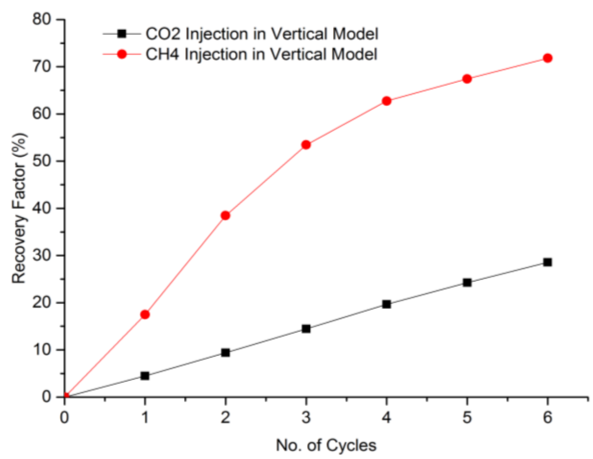


Figure 10—Recovery factor of CO_2 and natural gas huff-and-puff experiment in vertical model with injection and production at the bottom of the model

The experimental results of natural gas indicate that the bottom injection and production well mode has better effect than horizontal same-end injection and production well mode. The production mechanism for horizontal same-end injection and production was mainly depended on liberation of elastic energy. During the injection process, natural gas was accumulated near the injection-end resulted in increasing internal pressure of the model. At early stages of production, when the pressure was high (50-65 MPa), natural gas was miscible with crude oil and considerable amount of gas was produced with oil. Due to which oil exchange ratio and the recovery rate maintained a linear trend. However, at the lower pressure range (<50 MPa), the natural gas separated from the oil and migrated to the upper part of the cavity near injection-end. The placement of the model in horizontal direction leads to the natural gas accumulation close to the production end which causes gas channeling effect. After the gas breakthrough, the oil exchange ratio and recovery rate decreased sharply.

For bottom injection and production well mode, natural gas was in near miscible or immiscible state with crude oil at high pressure conditions. Since the density of natural gas was much less than the density of crude oil and the mass transfer of natural gas was faster in crude oil. Hence, natural gas migrated to the upper part of the model during the process of injection and well soaking. During preliminary stage, oil production was mainly based on liberation of elastic energy produced due to oil swelling. As the model pressure decreased below MMP of natural gas and crude oil (47.6 MPa), the gas separated from crude oil and moved to the upper part of the model and formed the gas cap drive effect, resulted in a significant increase in oil production.

The comparison of comprehensive experimental results by CO_2 and natural gas are shown in **Table 7**. The experimental results indicate that the top injection and bottom production mode has better effect than the other two modes.

Table 7—The effect comparison for CO_2 and natural gas huff-and-puff under different injection-production patterns.

	Horizontal model-Same end injection production		Vertical model-Lower injection lower production	
	CO_2 huff-and-puff	Natural gas huff-and- puff	CO_2 huff-and-puff	Natural gas huff-and-puff
Average one-cycle oil production, mL	24.60	27.47	28.82	72.52
Average one-cycle oil exchange rate, g/g	0.198	0.348	0.212	0.961
Average single cycle recovery, %	4.06	4.53	4.75	11.97
Ultimate recovery factor, %	24.36	27.20	28.53	71.80

Conclusions

In this study, the performance of CO_2 and natural gas huff-and-puff in deep and high pressure fractured-vuggy carbonate reservoirs was investigated. A specially designed physical model with multiple fractured-cavity has been used to simulate the oil displacement and fluid flow process in different injection-production modes. The following conclusions can be drawn.

1. The slim tube experiment shows that CO_2 and the methane rich natural gas both can achieve miscible state with the oil under the reservoir conditions of the targeted block in Tahe Oilfield. The MMP for CO_2 is 30.1 MPa, and 47.6 MPa for the natural gas, so the capacity of miscibility of CO_2 is much higher than that of the natural gas, in which CO_2 has very high solubility in oil that can make the produced fluid containing more CO_2 than oil, reducing the gas/oil exchange ratio and economics
2. The experimental results indicate that, when the multi-cavity model was in vertical position, gas injection can significantly improve oil recovery in the ultra-high pressure fractured-vuggy reservoirs, and top gas injection and bottom production (either using CO_2 or natural gas) has better IOR response than the huff-and-puff process with injection-production at the bottom end, and much better than that when the model was in horizontal position and injection-production at the same ends. That indicates that gravity stabilization is important for the high-pressure fractured-vuggy reservoir.
3. For the huff-and-puff process and when the vugs are vertically located, the IOR performance of methane rich natural gas is much better than that of CO_2 at ultra high pressure conditions that mean gravity stabilization can overshadow the miscibility effect that can prevail at low pressure conditions.
4. For the targeted fractured-vuggy reservoir at ultra high pressure conditions, gas injection with lean gases (such as, nitrogen, methane, and methane rich natural gas) in a huff-and-puff mode is recommended for a gravity stabilized operation and for pressure maintenance, and CO_2 is not a suitable injectant at this high pressure condition.

Nomenclatures

IOR	=	improve oil recovery
MMP	=	minimum miscibility pressure
HSEIP	=	horizontal same-end injection and production
VBIBP	=	vertical bottom injection and bottom production
VTIBP	=	vertical top injection and bottom production

Conflicting Interests

The author(s) declare that they have no Conflicting interests.

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