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Original Paper

Investigation of influence factors on CO_2 flowback characteristics and optimization of flowback parameters during CO_2 dry fracturing in tight gas reservoirs

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A B S T R A C T

CO_2 dry fracturing is a promising alternative method to water fracturing in tight gas reservoirs, especially in water-scarce areas such as the Loess Plateau. The CO_2 flowback efficiency is a critical factor that affects the final gas production effect. However, there have been few studies focusing on the flowback characteristics after CO_2 dry fracturing. In this study, an extensive core-to-field scale study was conducted to investigate CO_2 flowback characteristics and CH_4 production behavior. Firstly, to investigate the impact of core properties and production conditions on CO_2 flowback, a series of laboratory experiments at the core scale were conducted. Then, the key factors affecting the flowback were analyzed using the grey correlation method based on field data. Finally, taking the construction parameters of Well S60 as an example, a dual-permeability model was used to characterize the different seepage fields in the matrix and fracture for tight gas reservoirs. The production parameters after CO_2 dry fracturing were then optimized. Experimental results demonstrate that CO_2 dry fracturing is more effective than slickwater fracturing, with a 9.2% increase in CH_4 recovery. The increase in core permeability plays a positive role in improving CH_4 production and CO_2 flowback. The soaking process is mainly affected by CO_2 diffusion, and the soaking time should be controlled within 12 h. Increasing the flowback pressure gradient results in a significant increase in both CH_4 recovery and CO_2 flowback efficiency. While, an increase in CO_2 injection is not conducive to CH_4 production and CO_2 flowback. Based on the experimental and field data, the important factors affecting flowback and production were comprehensively and effectively discussed. The results show that permeability is the most important factor, followed by porosity and effective thickness. Considering flowback efficiency and the influence of proppant reflux, the injection volume should be the minimum volume that meets the requirements for generating fractures. The soaking time should be short which is 1 day in this study, and the optimal bottom hole flowback pressure should be set at 10 MPa. This study aims to improve the understanding of CO_2 dry fracturing in tight gas reservoirs and provide valuable insights for optimizing the process parameters.

1. Introduction

Tight gas reservoirs represent a potential component of a vast global energy source that could last for decades (Li et al., 2020; Zou et al., 2018a). Hydraulic fracturing has substantially increased gas production in tight gas reservoirs, helping generate economical production in recent years (Chen et al., 2021; Li et al., 2015; Liang, 2022; Molenaar et al., 2022). While hydraulic fracturing has been successfully applied to unconventional reservoirs, its limitations are clear. During hydraulic fracturing, aqueous fracturing fluid containing chemical additives and a propping agent is injected into reservoirs under high pressures, one of the main concerns is that it

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may adversely impact the environment (Brittingham et al., 2014; Gallegos et al., 2015; Mauter et al., 2014; Vidic et al., 2013). An important key to understanding the environmental impact of hydraulic fracturing is the amount of water and chemical solutions used in the process. It is estimated that each well consumes approximately 20,000 tons of water and about 200 tons of chemicals solutions (Clark et al., 2013; Gallegos et al., 2015; Goodwin et al., 2014; Michalski and Ficek, 2016; Nicot et al., 2014; Scanlon et al., 2014). Between 30% and 90% of the injected material is unrecyclable and remains trapped underground (Clark et al., 2013; Lester et al., 2015). Flowback water and trapped water contain non-degradable chemicals, such as acids, heavy metals and high-molecular polymers, which potentially threaten the freshwater resources and the underground ecology (Michalski and Ficek, 2016; Stringfellow et al., 2017). In addition, for low permeability gas reservoirs, formation damage from the injection of water-based fracturing fluids is the most common cause of reduced productivity. These damage mechanisms are predominantly due to the water-blocking effect in tight formations caused by high capillary pressure and the presence of water-sensitive clays (Bennion, 2002; Shen et al., 2018).

While water-based fracturing fluids still play an important and indispensable role in fracturing treatments, their potential environmental hazards and waste of water resources have encouraged the development of waterless fracturing technologies (Kalam et al., 2021; Tian et al., 2023). Among them, CO_2 fracturing has received increasing attention and is considered as a potential solution to the current environmental problems caused by the water-based fracturing fluids (Middleton et al., 2015; Zhou et al., 2019). The properties of CO_2 and its strong interaction with the host rock lead to unique fracturing advantages. (1) Dissolution of minerals by CO_2-rock interaction can increase porosity and permeability (Jia et al., 2018; Peng et al., 2022; Zou et al., 2018b). (2) Exposure to CO_2 can weaken the rock matrix fabric, reducing the breakdown pressure (Ao et al., 2017; Wu et al., 2022; Yang et al., 2022). (3) The ultra-low viscosity of CO_2 can facilitate fracture propagation (Li and Zhang, 2019; Zhou et al., 2018). (4) Competitive adsorption between CO_2 and CH_4 can enhance gas recovery (Omari et al., 2022). In addition, compared to water-based fracturing, CO_2 dry fracturing technology is a non-water fracturing technique, which has the advantages such as stabilizing clay minerals, eliminating water locking, and improving environmental performance (Middleton et al., 2015; Wilkins et al., 2016; Xu et al., 2022).

Although the effectiveness of CO_2 fracturing is now recognized (Jiang et al., 2018; Ma et al., 2021; Wang and He, 2017), as an essential part in the fracturing process, the flowback of fracturing fluid will directly affect the performance of the fracturing. In recent years, a number of scholars have studied the flowback of fractured fluids in tight gas reservoirs from three perspectives: laboratory core experiments, theoretical models, and numerical simulations. On the experimental side, studies mainly focus on formation damage, imbibition of fracturing fluid in the matrix reservoir, and its retention in the fracture system. Yan et al. (2015) studied gas production impairment due to spontaneous migration of fracturing fluid into a shale gas formation through core flooding experiments, and in their experiments, shut-in time is considered to be the crucial factor, the results demonstrate a slight decrease in regained permeabilities with longer shut-in times. The results of Dutta et al. (2014) also show that fracturing fluid flowback can have an impact on gas production, and fluid flowback is affected by permeability, capillarity, and heterogeneities. Numerous scholars have suggested that an important cause of fluid retention in fractured formations is spontaneous percolation due to strong capillary forces generated by dense reservoirs (Hu et al., 2020). Ge et al. (2015) and Zhou et al. (2016) performed imbibition experiments with fracturing fluid and found that it caused the expansion of clay minerals and reduced matrix permeability. The spontaneous imbibition of fracturing fluid is considered to be one of the significant reasons for the low flowback efficiency of fracturing fluid. And the experimental results of Zhou et al. (2022) indicate that microfractures may be induced under imbibition replacement, leading to continuous micro-stimulation of the shale gas reservoir. Zhang et al. (2019) measured the fluid trapped in rough fractures using an improved conductivity apparatus, the effects of different factors including fracture aperture, surface roughness, tortuosity, and matrix imbibition on fluid retention were analyzed. The results showed that secondary fractures and microcracks played an important role in the retention of fracturing fluid. In terms of theoretical models, as the flowback process in gas reservoir is mainly a two-phase flow, many scholars have developed two-phase flow models to simulate the flowback process of water-based fracturing fluid based on the flowback mechanism of tight reservoir. They have focused on studying the influencing factors and prediction models of flowback (Abbasi et al., 2014; Ezulike and Dehghanpour, 2014; Xu et al., 2016). Since numerical solutions and mesh discretizations of flowback mathematical models are usually complicated, several authors have studied the flowback process in gas reservoirs through numerical simulations (Kanfar and Clarkson, 2016; Shen et al., 2016).

Previous studies mainly focused on flowback mechanism and production dynamics properties of water-based fracturing fluids in tight gas wells. CO_2 is a promising non-aqueous fracturing fluid that can avoid the problems associated with water-based fracturing operations. In general, rapid clean-up after a CO_2 fracturing stimulation is one of its main advantages, avoiding formation damage such as water locking. However, those previous investigations did not have the experimental data to illustrate the flowback behavior after CO_2 fracturing. In addition, different operation constraints have different impacts on CO_2 fracturing flowback, and there are few relevant studies. Overall, it is still inadequate for the investigation of CO_2 fracturing in tight gas reservoirs, especially the analysis of influencing factors and optimization of flowback after CO_2 fracturing. In this paper, multiple core-field scale studies were conducted to study the flowback behavior after CO_2 fracturing. First, a series of core experiments were conducted to investigate the effects of core properties and production conditions on CO_2 flowback. Then, based on the field data, the key factors affecting the flowback effect of tight gas reservoirs are studied. Finally, the key parameters in the flowback process were optimized by establishing a numerical model that matched the field parameters. Through the research presented in this paper, we hope to provide a theoretical and experimental basis for the efficient application of CO_2 fracturing in tight gas reservoirs.

2. Experiment

2.1. Samples

A total of 7 core samples used in this study were collected from Changqing tight gas reservoirs. Fig. 1(a) shows the cylindrical samples used in flooding experiments, which had a diameter of 3.8 cm and a length of 8 cm. Prior to flooding experiments, these samples underwent porosity and permeability tests. Table 1 presents the basic physical parameters of these samples.

2.2. Experimental apparatus and procedure

The flowback experiment was conducted to study the total gas production per unit pressure, and the flowback of CO_2 was measured. The test device is depicted in Fig. 2. The system consisted

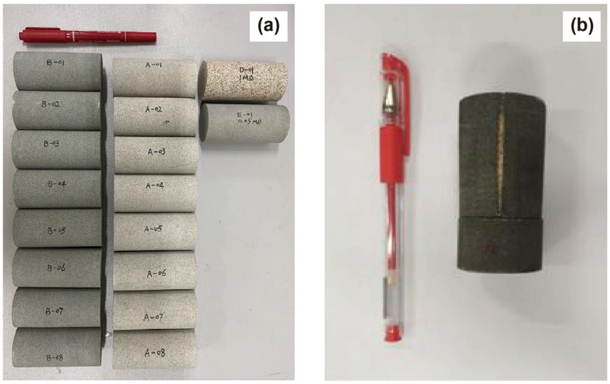

Fig. 1. Core samples from the Changqing tight gas reservoirs. (**a**) Cylindrical samples; (**b**) To create an artificial fracture, split and fill the core with 40–70 mesh sand.

of a data collection system, a pressure sensing system, a back pressure pump, a core holding unit, an intermediate container, a high pressure syringe pump, a gas collection system, and other auxiliary equipment.

The procedures of flowback tests are as follows: (1) Split the core and fill the fracture with a mixture of 40–70 mesh sand and AB glue to simulate an artificial fracture, as illustrated in Fig. 1(b). (2) Test the porosity of the artificially fractured cores as follows: the dry cores are saturated with water, the weight and dimension are measured before and after saturation. Porosity is determined by calculating the percentage of the water-filled volume to the total sample volume. And then the cores are dried again. (3) Place the core into the core holder, the irreducible water saturation is achieved through steam flooding: drive water vapor to the core at a constant rate, and record the core weight every 5 min. Stop the saturation when the water saturation reaches about 30%, and maintain the formation conditions (80 °C, 20 MPa) for 72 h to simulate reservoir aging. (4) Saturated with methane as follows: Keep the experimental temperature at 80 °C to simulate the formation conditions, and then saturate the core with methane to 20 MPa. (5) Inject CO_2 into the core until a certain pressure is reached (different pressure reflects different volume of CO_2 injection), then stop CO_2 injection and allow for a soaking period. (6) Decrease the pressure of the core holding unit to match the pressure set by the back pressure pump. CO_2 and methane generated during the experiment are separated using saturated sodium hydroxide solution. The gas generated is firstly passed through the saturated sodium hydroxide solution to quantify the amount of CO_2, and then the remaining gas is collected to determine the amount of produced methane. (7) Analyze the experimental data and calculate the efficiency of CO_2 flowback.

To study the effects of soaking time, flowback pressure gradient, and CO_2 injection volume on the gas production, a series of experiments were conducted with varying parameters, as detailed in Table 2. For slickwater flowback experiments, the same procedure described above was followed, except for the use of slickwater instead of injected CO_2.

3. Analysis of influencing factors based on field data

Various parameters, including sand thickness, effective thickness, porosity, permeability, formation pressure, flowback efficiency, and production data, were collected and analyzed for 37 wells in the tight gas demonstration area. To comprehensively and effectively analyze the key factors affecting the flowback and stimulation, we selected typical factors for a single-factor correlation analysis. Then, the grey correlation method was used to calculate the grey correlation between these factors. The ranking of each influencing factor was determined by the correlation weight between the influencing factors and flowback efficiency. Finally, the key controlling factors affecting the flowback were obtained.

Table 1
Properties of the cores used in this study.

Core No.	Length, mm	Diameter, mm	Permeability, mD	Porosity, %	Density, g/cm^3
B-01	80	38	0.41	8.5	2.79
B-02	80	38	0.45	8.8	2.85
B-03	80	38	0.46	9.2	2.92
B-04	80	38	0.42	7.5	2.78
A-08	80	38	0.1	7.8	2.84
D-01	80	38	1	9.5	2.89
E–01	80	38	0.05	8.7	2.89

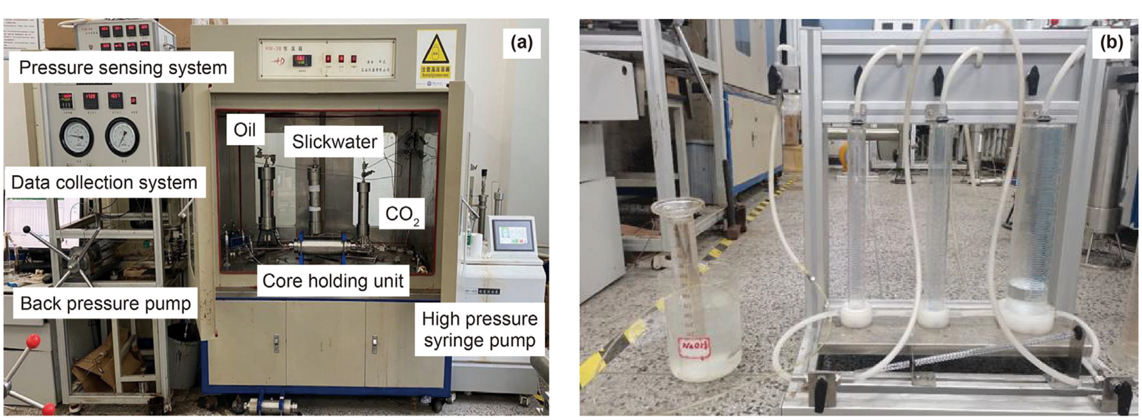

Fig. 2. Physical simulation system for CO_2 fracturing flowback. (**a**) Diagram of experimental equipment for CO_2 fracturing flowback; (**b**) Device for collecting total gas production and filtering CO_2 with saturated sodium hydroxide solution.

Table 2
Experimental design scheme for the flowback experiment.

No.	Fluid	Research factor	Permeability, mD	Pressure at the end of injection, MPa	Soaking time, h	Flowback pressure gradient, MPa
1	CO_2	Permeability	1	25	6	10
2			0.5			
3			0.1			
4			0.05			
5		Flowback time	0.5	25	2	15
6					6	
7					12	
8					18	
9					24	
10		CO_2 injection volume	0.5	22.5	6	15
11				25		
12				27.5		
13				30		
14		Flowback pressure gradient	0.5	25	2612	5
15						10
16						15
17						20
18	Slickwater	Control experiment	0.5	25	6	10
19					24	10
20					6	15

4. Numerical modeling

The commercial reservoir simulator GEM from Computer Modelling Group (CMG) was used to simulate the behavior of hydrocarbon reservoirs. The dual-permeability model is used to characterize the different seepage fields in the matrix and fracture, since it uses one cell to represent the fracture and one cell to represent the matrix in each fracture network block. At the same time, the grid is logarithmically spaced from the center of the artificial fracture, which can accurately simulate the multiphase unsteady flow from matrix to fracture and from matrix to artificial fracture, as demonstrated in Fig. 3(a). Simply put, the LS-LR-DK (logarithmically spaced, locally refined, and dual permeability) model is used to simulate vertical well fracturing, which is able to accurately capture the physics of the fluid flow in fractured tight reservoirs. During the simulation, CO_2 was injected at a high displacement rate of 2 m^3/min to decrease the bottom hole temperature to the critical temperature of CO_2, ensuring that the CO_2 was liquid and allowing the reservoir to be fractured.

And a typical multi-stage fracturing model for a vertical well was established by referencing the S60 well in the Changqing Oilfield, as shown in Fig. 3(b). The grid is divided into 20 × 61 × 1, the effective thickness of the gas reservoir is 5 m, and the structural top depth is 2239 m. Other model-input parameters are shown in Table 3. In the numerical simulation part, the key parameters affecting the CO_2 dry fracturing flowback were optimized.

5. Results and discussion

5.1. Experimental studies

Cores B-01 to B-04 were split and filled with sand, the porosity and saturated steam mass were measured. The pore volume and water saturation of the cores were then calculated. The results are shown in Table 4.

5.1.1. Flowback effects of slickwater fracturing

The slickwater fracturing flowback experiments in Table 2 (No. 18–No. 20) were carried out with B-03 core. Slickwater flowback experiments were conducted for soaking times of 6 and 24 h, respectively, with different flowback pressure gradients (5, 10, 15, 20 MPa). The results are shown in Fig. 4. The experimental results indicate that higher flowback pressure gradients lead to significant increases in both CH_4 recovery and slickwater flowback efficiency. This is because the increase in flowback pressure gradient results in a higher gas flow rate. At the same time, the slickwater can overcome the larger resistance caused by the capillary force and start to flow, achieving a high CH_4 recovery and a high slickwater flowback

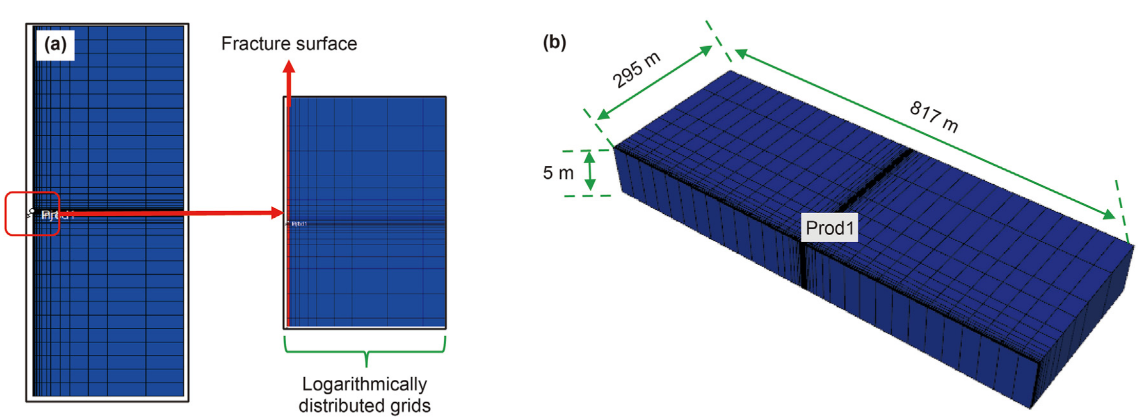

Fig. 3. Numerical simulation model. (**a**) Dual-permeability model of grid logarithmically spaced; (**b**) Schematic of the model size.

Table 3
Basic parameters of CO_2 dry fracturing flowback model for a tight gas reservoir.

Parameter	Value	Parameter	Value
Grid	20 × 61 × 1	Matrix permeability, mD	0.44
Effective thickness, m	5	Natural fracure permeability, mD	13
Formation pressure, MPa	22.4	Natural fracture spacing, m	0.231
Formation temperature, °C	75	Artificial fracture width, m	0.15
Matrix porosity, %	9.17	Artificial fracture permeability, mD	1000
Fracture porosity, %	0.9	Secondary fracture permeability, mD	40

Table 4
Properties of the cores after being split and filled with sand.

Core No.	Dry weight, g	Wet weight, g	The mass of saturated water vapor, g	The mass of saturated water, g	Mass of water, g	Porosity, %	Water saturation, %
B-01	195.83	204.88	198.47	9.05	2.64	10	29
B-02	197.22	206.49	200.26	9.27	3.04	10	33
B-03	195.77	204.88	198.65	9.11	2.88	10	32
B-04	207.84	215.83	210.55	7.99	2.71	9	34

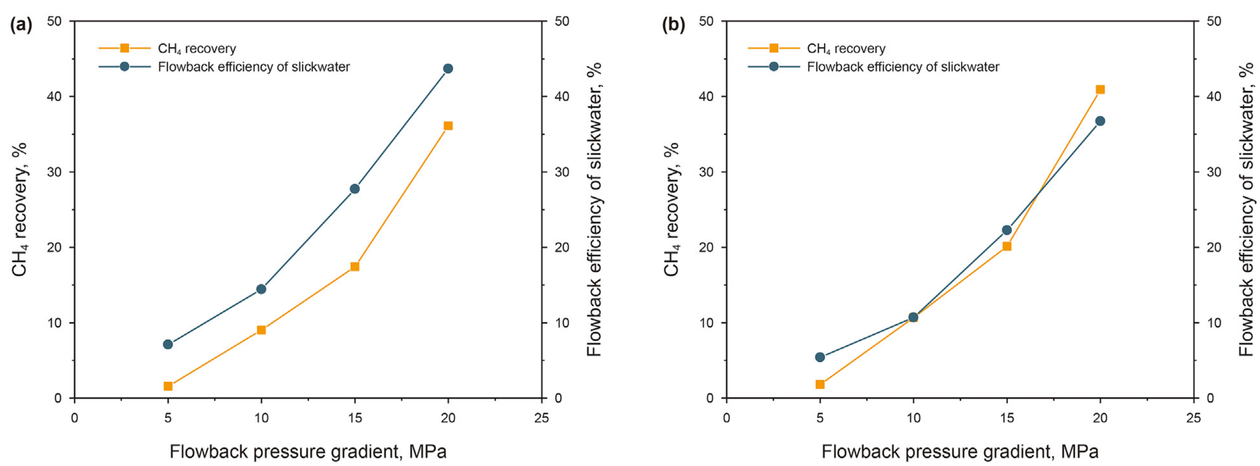

Fig. 4. CH_4 recovery and flowback efficiency of slickwater fracturing under different flowback pressure gradients. (**a**) Soaking for 6 h; (**b**) Soaking for 24 h.

efficiency. The same trend has been shown in previous research (Liang et al., 2021). However, the reservoir pressure would deplete rapidly as the flowback pressure gradient increased. Therefore, increasing production pressure gradient is not recommended.

By comparing Fig. 4(a) and (b), it can be seen that soaking for 24 h had a higher oil recovery than 6 h. However, it corresponded to a lower flowback efficiency of slickwater. With the increase in soaking time at a pressure gradient of 15 MPa, the CH_4 recovery increased from 17.43% to 20.11%, while the flowback efficiency of slickwater decreased from 27.73% to 22.26%. The main reason is that the injected water gradually enters the matrix during soaking, displacing more CH_4 from the matrix into the fracture, thus increasing the CH_4 recovery and decreasing the flowback efficiency of slickwater. The observations in this study are consistent with those found in previous studies (Liang et al., 2021), as even with an increase in the soaking time, the slickwater remained blocked in the pores of the formation matrix.

5.1.2. Flowback effects of CO_2 fracturing

The CO_2 fracturing flowback experiments were performed using core B-03 (No. 14–No. 17 in Table 2). After soaking for 6 h, CO_2 dry fracturing flowback experiments were conducted at different flowback pressure gradients (5, 10, 15, 20 MPa), and the results are shown in Fig. 5(a). Fig. 5(a) shows that increasing the flowback pressure gradient results in a more efficient CH_4 recovery. When the flowback pressure gradients are 5, 10, 15, and 20 MPa, the CH_4 recovery are 2.91%, 18.21%, 39.78%, and 68.79%, respectively.

For comparison, Fig. 5(b) includes data from slickwater and CO_2 fracturing flowback experiments, indicating a rapid clean-up after a CO_2 fracturing treatment. Under a flowback pressure gradient of 10 MPa, CO_2 dry fracturing resulted in a 9.2% increase in CH_4 recovery compared to slickwater fracturing. Additionally, the flowback efficiency of fracturing fluids increased significantly from 14.43% to 67.74% compared to slickwater fracturing. This is because under the imbibition led by capillary forces, the slickwater is easy to permeate into the core, which is difficult to flow back and increases the flow resistance of gas. CO_2 dry fracturing can effectively solve these problems and improve gas reservoir recovery. Our results are similar to those of previous studies, showing that CO_2 fracturing is more effective than slickwater fracturing (Xia et al., 2022), and this study extends upon previous research by investigating the flowback of CO_2 fracturing in gas reservoirs.

5.1.3. Effect of core permeability on CO_2 dry fracturing flowback

Cores D-01, B-03, A-08, and E–01 were used for CO_2 fracturing flowback tests, respectively. The experimental conditions were as follows: CO_2 was injected into the system until the pressure reached 25 MPa, followed by a 6 h soaking period, and then production with a flowback pressure gradient of 10 MPa. Fig. 6(a) shows the variation of CH_4 recovery with different permeability. The results indicate that higher core permeability leads to better gas recovery. As the core permeability decreases, gas flow

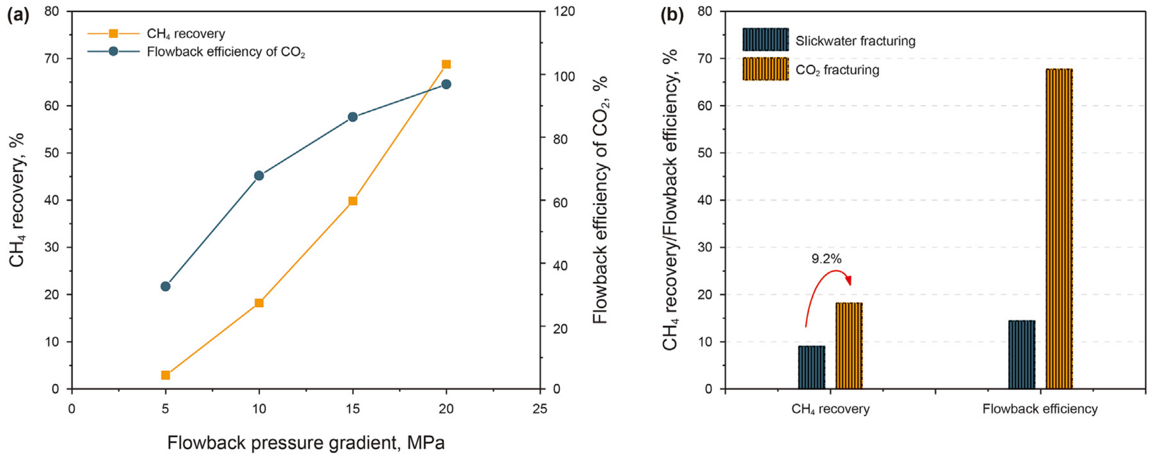

Fig. 5. CH_4 recovery and flowback efficiency of CO_2 fracturing. (**a**) CH_4 recovery and flowback efficiency of CO_2 fracturing under different flowback pressure gradients; (**b**) Comparison of flowback performance between slickwater fracturing and CO_2 fracturing.

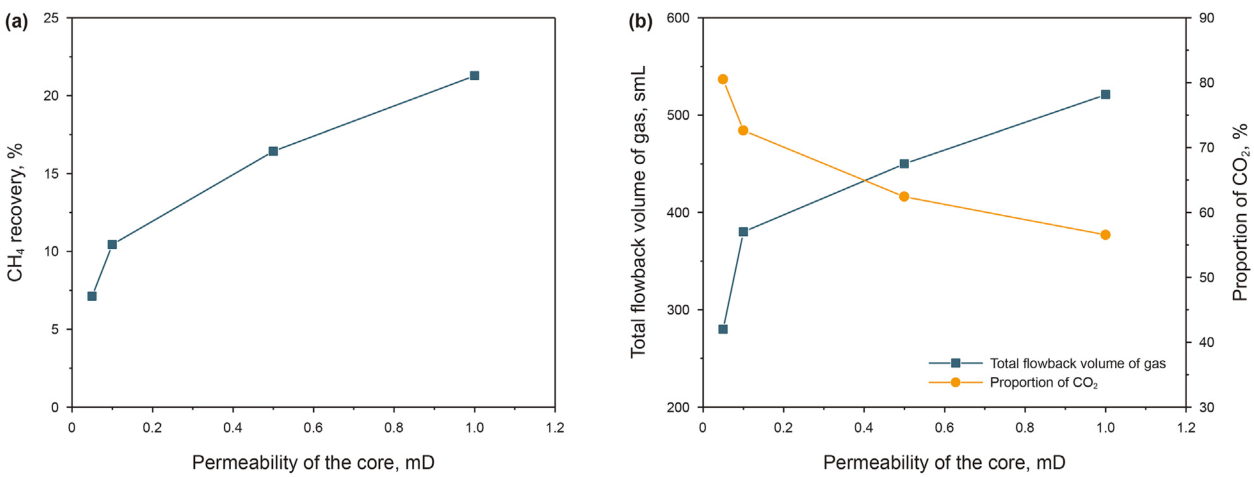

Fig. 6. CO_2 flowback characteristics and CH_4 production behavior under different core permeability. (**a**) CH_4 recovery of CO_2 fracturing; (**b**) Flowback gas volume of CO_2 fracturing.

resistance increases, resulting in poor development effect. Fig. 6(b) is a plot of gas flowback volume versus core permeability. As the permeability increases, a higher gas flowback volume is recorded, and the proportion of CO_2 in the gas decreases. When the core properties are poor, it is difficult for CO_2 to enter the core and replace CH_4, and CO_2 accounts for the majority of the total flowback gas.

5.1.4. *Effect of flowback pressure gradient on CO_2 dry fracturing flowback*

The CO_2 fracturing flowback experiment at different flowback pressure gradients was carried out using core B-01. The experimental conditions were as follows: CO_2 was injected into the system until the pressure reached 25 MPa, then the sample was soaked for 6 h before production at different flowback pressure gradients. As shown in Fig. 5(a), increasing the flowback pressure gradient results in a significant increase in both CH_4 recovery and CO_2 flowback efficiency. A small flowback pressure gradient (5 MPa) results in a low recovery of CH_4 (2.91%). With the increase in flowback pressure gradient, the CH_4 recovery increased rapidly and showed an exponential trend. The CO_2 flowback efficiency shows an increasing trend with pressure, but the rate of increase slows down at high pressures, and the flowback gradually reaches equilibrium. Overall, it is better to control a flowback pressure gradient of above 10–15 MPa.

Fig. 7 depicts the relationship between gas flowback volume and flowback pressure gradient. The total flowback gas volume increases linearly with the flowback pressure gradient, and the

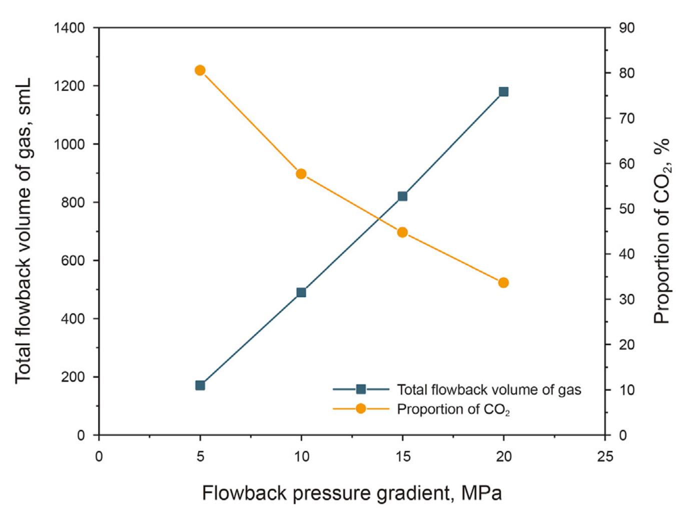

Fig. 7. The flowback gas volume of CO_2 fracturing under different flowback pressure gradients (Soaking for 6 h).

proportion of CO_2 in the flowback gas decreases rapidly. Due to its higher viscosity compared to methane, CO_2 takes a certain amount of time to enter the matrix. When the flowback pressure gradient is low, the gas in the fractures will flow back first, and the produced gas will be dominated by CO_2. As the flowback progresses, a large amount of natural gas is produced, causing the CO_2 content in the produced gas to plummet and the recovery of CH_4 to increase rapidly.

In addition, we conducted experiments to investigate the effect of flowback pressure gradient on oil recovery and flowback efficiency at other soaking times (2 and 12 h) using cores B-02 and B-03. The results, shown in Fig. 8, indicate that the flowback pressure gradient has a consistent effect on CH_4 recovery and CO_2 flowback across different soaking times. Higher pressure gradients are found to be more favorable for gas production, and the flowback efficiency of CO_2 also increases gradually with increasing pressure gradient. At low pressure gradients, most of the produced gas is CO_2. However, as continuous production under high pressure gradients, the output of natural gas gradually increases while CO_2 continues to diffuse into the matrix, replacing CH_4 and resulting in partial CO_2 retention. As a result, the CO_2 flowback efficiency no longer rises rapidly and essentially reaches equilibrium. Similarly, it is recommended to control the flowback pressure gradient above 10–15 MPa for better stimulation effect. All of these experimental results demonstrate that CO_2 fracturing has a more favorable flowback performance, allowing fracturing fluids to be recovered during the later stages of fracturing and minimizing formation damage (Middleton et al., 2015).

5.1.5. Effect of flowback timing on CO_2 dry fracturing flowback

To ensure that CO_2 can fully enter the matrix and displace CH_4, it is necessary to study the timing of flowback. To achieve a more efficient gas recovery in a shorter time, cores B-01, B-02, and B-03 were used to study the effect of different soaking times on CO_2 fracturing flowback. The experimental conditions were as follows: CO_2 was injected into the system until it reached a pressure of 25 MPa, followed by soaking for different times. Production was then carried out with a flowback pressure gradient of 15 MPa, the experimental results are shown in Fig. 9. The results indicate that the CH_4 recovery and total flowback gas volume initially increase with increasing soaking time, but then decrease, reaching a maximum recovery within 12 h. Longer soaking time results in a greater displacement of CH_4 by CO_2, but it also affected by reduced permeability due to fracture closure. The results also demonstrate that increasing the soaking time leads to a decrease in CO_2 flowback efficiency, primarily due to the continuous diffusion of CO_2 into the matrix. Based on these findings, it is recommended that flowback time should be controlled within 12 h.

5.1.6. Effect of injection volume on CO_2 dry fracturing flowback

Cores B-01, B-02, and B-04 were used to study the effect of CO_2 injection volume on CO_2 fracturing flowback. The experimental

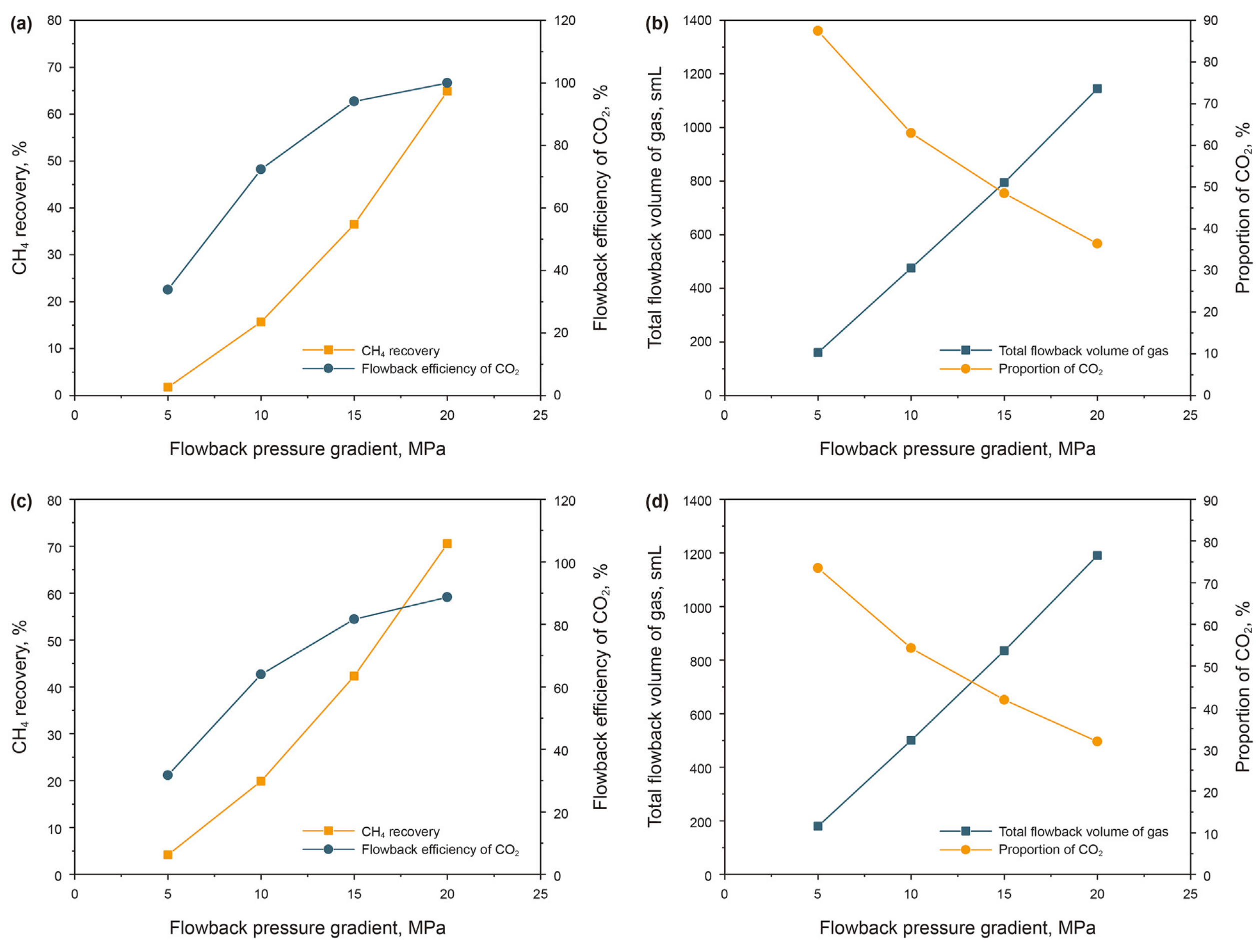

Fig. 8. CO_2 flowback characteristics and CH_4 production behavior under different flowback pressure gradients. (**a**) CH_4 recovery and flowback efficiency of CO_2 fracturing (soaking for 2 h); (**b**) Flowback gas volume of CO_2 fracturing (soaking for 2 h); (**c**) CH_4 recovery and flowback efficiency of CO_2 fracturing (soaking for 12 h); (**d**) Flowback gas volume of CO_2 fracturing (soaking for 12 h).

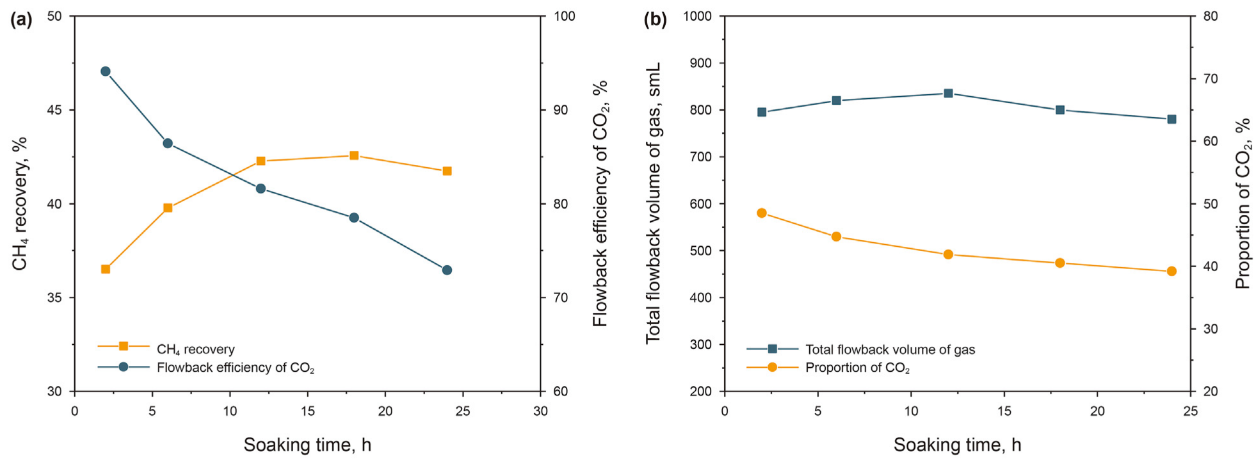

Fig. 9. CO_2 flowback characteristics and CH_4 production behavior under different soaking times. (**a**) CH_4 recovery and flowback efficiency of CO_2 fracturing; (**b**) Flowback gas volume of CO_2 fracturing.

conditions were as follows: Firstly, CO_2 was injected to achieve different system pressures (22.5, 25, 27.5, and 30 MPa, which represent injection volume of 186, 424, 602 and 742 smL, respectively). The samples were then soaked for 6 h before production was carried out at a flowback pressure gradient of 15 MPa. The experimental results are shown in Fig. 10. As the injection volume of CO_2 raised from 186 to 742 smL, the total gas flowback volume increased from 630 to 925 smL, and the proportion of CO_2 in the flowback gas increased from 26.33% to 60.97%. The system pressure gradually built up as more CO_2 was injected, and the gas expansion capability under high pressure became stronger, resulting in higher gas output and a greater CO_2 proportion in the flowback gas. As the proportion of CO_2 increased in the flowback gas, the proportion of CH_4 decreased, leading to a reduction in CH_4 recovery. Additionally, the proportion of CO_2 trapped in the core increased, causing a decrease in CO_2 flowback efficiency.

5.2. Analysis results of field data

5.2.1. Single factor analysis

Single factor correlation analysis was used to analyze the positive and negative correlation between fracturing fluid flowback efficiency and various parameters such as sand thickness, effective thickness, porosity, permeability and formation pressure. Data from 37 typical gas wells were collected for analysis.

(1) The relationship between sand thickness and flowback efficiency

Sand is an effective reservoir space for oil and gas, but there is no direct correlation between sand thickness and oil thickness in the reservoir. According to a single factor analysis of sand thickness and flowback efficiency collected from 37 wells, as shown in Fig. 11(a), there is no strong positive or negative correlation between sand thickness and fracture fluid flowback efficiency.

(2) The relationship between effective thickness and flowback efficiency

The effective thickness directly reflects the volume of oil and gas contained in the reservoir, and the effective thickness and its distribution range on the plane are important factors that affect the oil discharge area of a single well. Additionally, effective thickness is an important parameter that affects perforation position and fracturing construction, and is one of the main bases for fracturing well selection and evaluation. According to the single factor analysis of effective thickness and flowback efficiency collected from 37 wells, as shown in Fig. 11(b), it can be concluded that there is a good

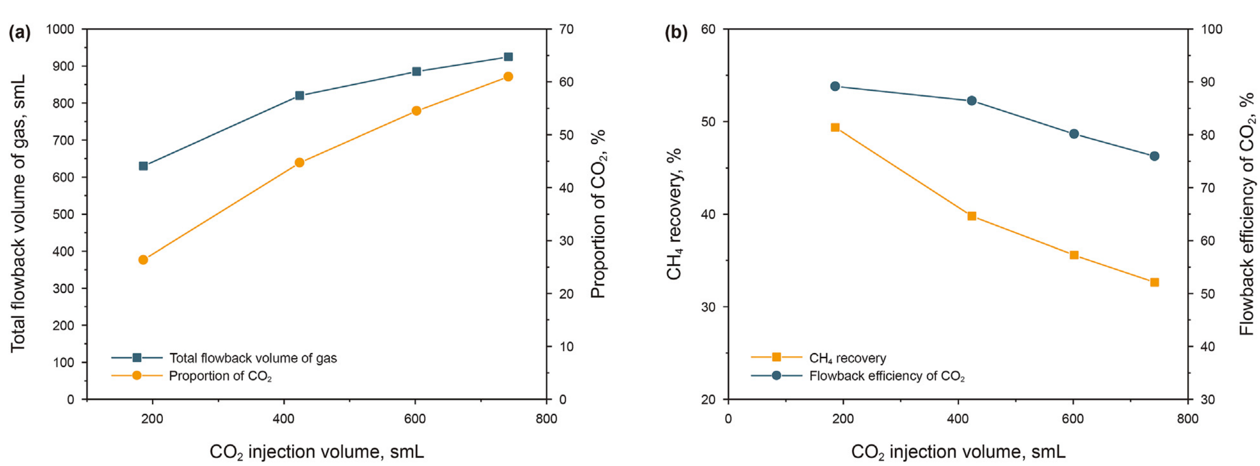

Fig. 10. CO_2 flowback characteristics and CH_4 production behavior under different CO_2 injection volume. (**a**) Flowback gas volume of CO_2 fracturing; (**b**) CH_4 recovery and flowback efficiency of CO_2 fracturing.

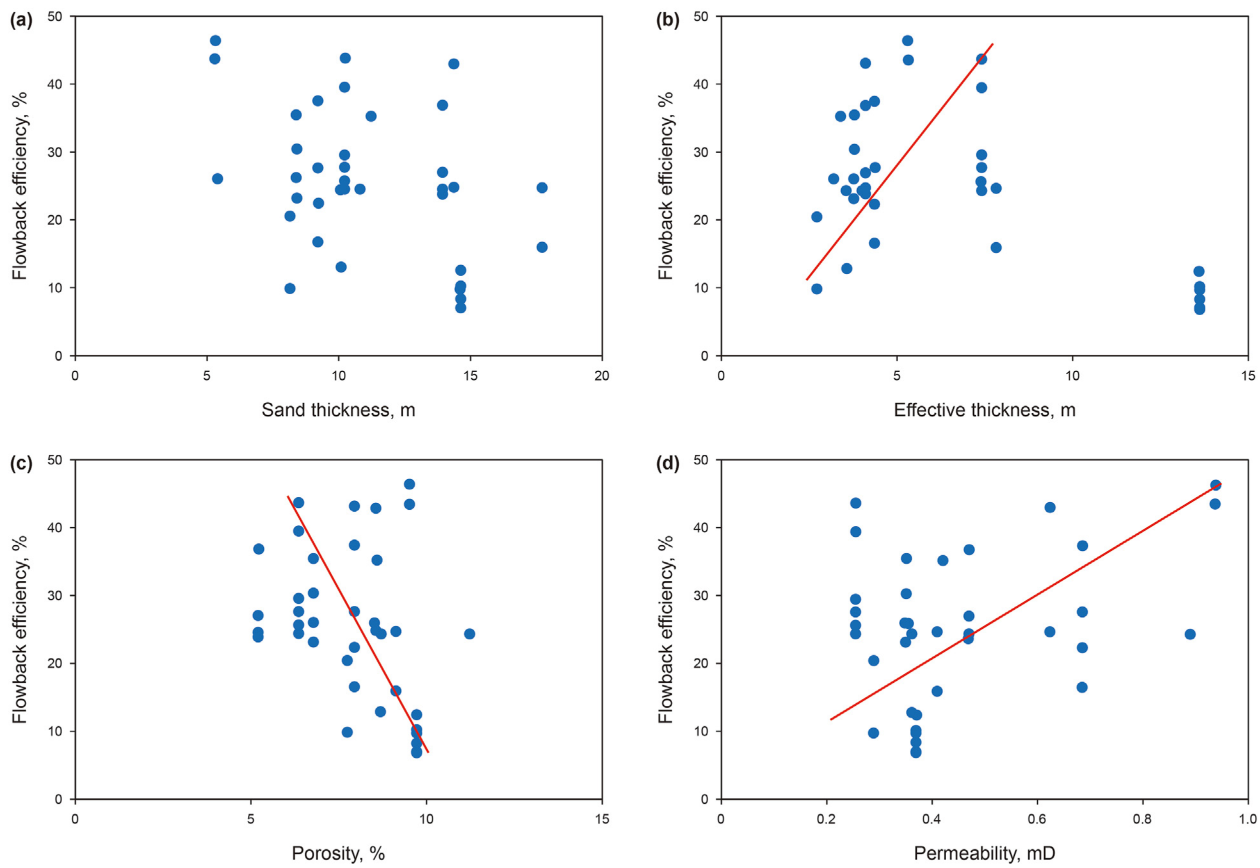

Fig. 11. Correlation analysis. (**a**) Sand thickness; (**b**) Effective thickness; (**c**) Porosity; (**d**) Permeability.

positive correlation between effective thickness and fracturing fluid flowback efficiency.

(3) The relationship between porosity and flowback efficiency

Porosity reflects the ability of a reservoir to store fluids. Based on a single factor analysis of statistical porosity and flowback efficiency of 37 wells, as shown in Fig. 11(c), it can be concluded that there is a certain negative correlation between porosity and fracturing fluid flowback efficiency, with porosity mainly distributed between 5% and 10%. As porosity increases, fracturing fluid flowback efficiency decreases.

(4) The relationship between permeability and flowback efficiency

Reservoir permeability is one of the main parameters that affect the production dynamics of oil and gas wells. It represents the flow capacity of reservoir fluids in porous media, directly affects fluid loss in the fracturing process, and is closely related to the formation and extension of fractures, ultimately affecting the stimulation effect. Based on a single factor analysis of statistical permeability and flowback efficiency of 37 wells, as shown in Fig. 11(d), it can be concluded that there is a positive correlation between permeability and fracturing fluid flowback efficiency.

(5) The relationship between formation pressure and flowback efficiency

Formation pressure reflects the initial production capacity of the reservoir. The higher the initial formation pressure, the larger the production pressure gradient at the same bottom hole pressure after opening the well, which may result in higher flowback efficiency of fracturing fluid. However, based on a single factor analysis of formation pressure and flowback efficiency, as shown in Fig. 12, no clear linear relationship was found between formation pressure and flowback efficiency.

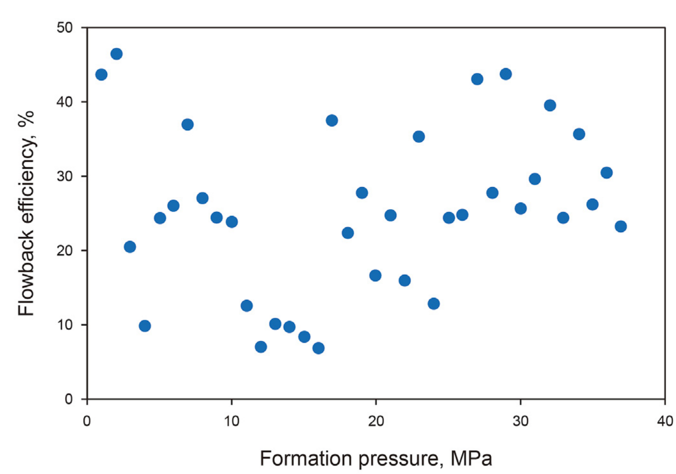

Fig. 12. Correlation analysis between formation pressure and fracturing fluid flowback efficiency.

Table 5
The sorting results of influencing factors.

Influencing factor	Flowback efficiency	
	Grey relational degree	Sorting
Sand thickness	0.629351	5
Effective thickness	0.653611	3
Porosity	0.702879	2
Permeability	0.722466	1
Formation pressure	0.638474	4

5.2.2. Sorting results of influencing factors

The correlation analysis from a single factor can result in mainly positive and negative correlations. However, the single factor analysis method is limited in its ability to fully explain the specific degree of influence and correlation between each influencing parameter and the flowback efficiency. To address this limitation, we employed the grey correlation method to calculate the degree of grey correlation for the five factors. The results were then sorted to determine their relative importance ranking. Table 5 displays the sorting results, which indicate that permeability is the most important factor, followed by porosity and effective thickness.

5.3. Numerical simulation results

5.3.1. Analysis of injection, soaking and production process of CO_2 dry fracturing

To analyze CO_2 migration and pressure changes during CO_2 dry fracturing injection, soaking and flowback in tight gas reservoirs, we conducted numerical simulations using the S60 well as an example. Liquid CO_2 was injected at a rate of 3 m^3/min, with a total injection volume of approximately 350 m^3. After soaking for 19 h, the well was opened, and the pressure and CO_2 concentration distribution were analyzed. Fig. 13(a) and (b) display the pressure and CO_2 concentration distributions at the end of CO_2 injection, respectively. During the CO_2 injection process, the formation pressure reached a maximum of about 40 MP, which was consistent with the field fracturing construction data. As CO_2 was injected, the pressure increased rapidly near the vertical well, and the CO_2 concentration was enriched in the area surrounding the well.

Fig. 13(c) and (d) illustrate the changes in the pressure field and CO_2 concentration field during the soaking process. As the shut-in time increased, the high pressure caused by CO_2 near the injection well gradually diffused to the depth of the formation, resulting in a gradual increase in the average formation pressure. Additionally, the range of CO_2 spread further expanded due to the effects of diffusion during the shut-in period.

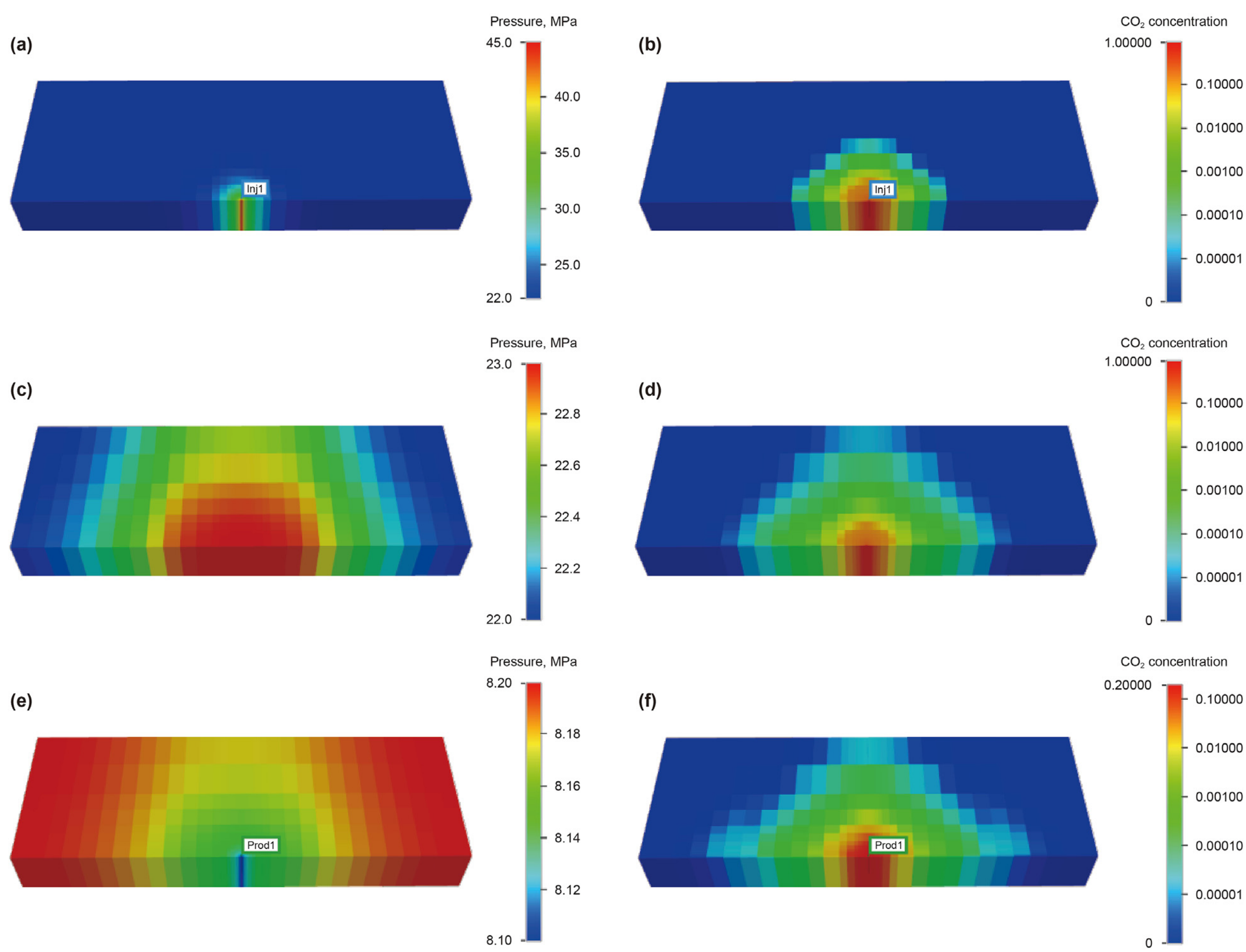

Fig. 13. CO_2 concentration and pressure distribution map. (**a**) Pressure distribution at the end of CO_2 injection (2 h); (**b**) CO_2 concentration distribution at the end of CO_2 injection (2 h); (**c**) Pressure distribution at the end of soaking (21 h); (**d**) CO_2 concentration distribution at the end of soaking (21 h); (**e**) Pressure distribution at the end of flowback (3 years); (**f**) CO_2 concentration distribution at the end of flowback (3 years).

The changes of pressure field and CO_2 concentration field in the flowback process are depicted in Fig. 13(e) and (f). During the initial stage of well opening, CO_2 near the fractured well quickly flowed back, driven by the pressure gradient, and quickly achieved the maximum stable flowback efficiency. In the later stage of flowback, the returned material mainly consisted of natural gas with a small amount of water production.

5.3.2. Influence of flowback pressure gradient on flowback efficiency

By changing the bottom hole flow pressure, the influence of flowback pressure gradient on CO_2 flowback efficiency was studied. We conducted numerical simulations with varying bottom hole flow pressures (4–12 MPa). The results are shown in Fig. 14. The cumulative gas and water production increased approximately linearly with the increase in production pressure gradient. The CO_2 flowback efficiency rose as well, and the flowback efficiency reached 90% when the bottom hole pressure was 10 MPa. However, as the pressure gradient continued to increase to a certain value (bottom hole pressure less than 6 MPa), the flowback efficiency no longer improved significantly with the flowback pressure gradient. Considering the simulation results and flowback efficiency as well as the critical flow rate of proppant, the optimal bottom hole pressure of 10 MPa was selected.

5.3.3. Influence of soaking time on flowback efficiency

We conducted numerical simulations to study the CO_2 flowback under different soaking times ranging from 1 day to 45 days, and the results are shown in Fig. 15. As the soaking time increased from 1 day to 45 days, the CO_2 flowback efficiency gradually decreased. This is because more CO_2 enters the deep formation due to diffusion, resulting in a decrease in CO_2 flowback. Meanwhile, the cumulative water production at the surface gradually increased, and a large amount of produced water accumulated in the main fractures,

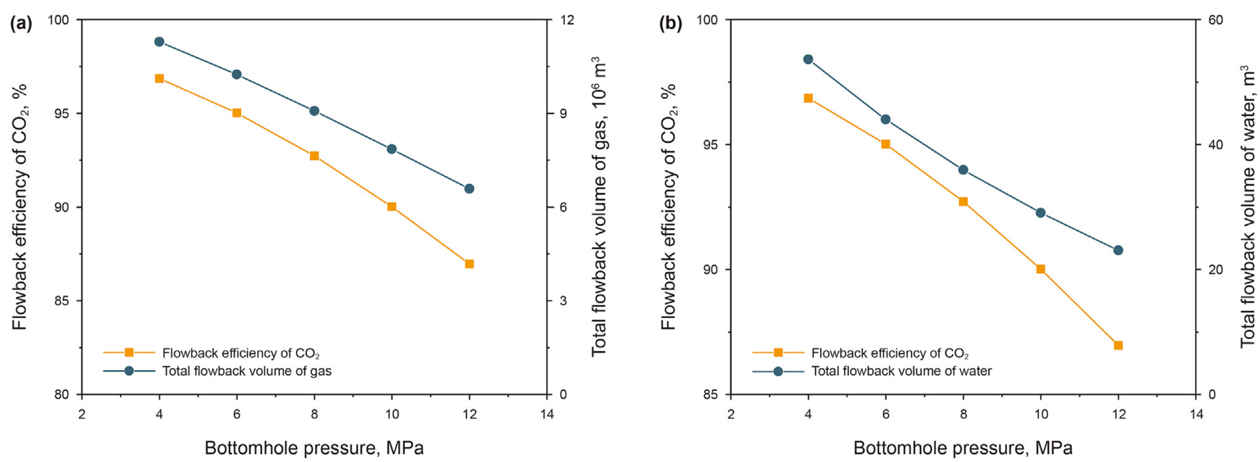

Fig. 14. Cumulative gas/water production and CO_2 flowback efficiency under different bottom hole pressures (production 3 years). (**a**) Cumulative gas production and CO_2 flowback efficiency; (**b**) Cumulative water production and CO_2 flowback efficiency.

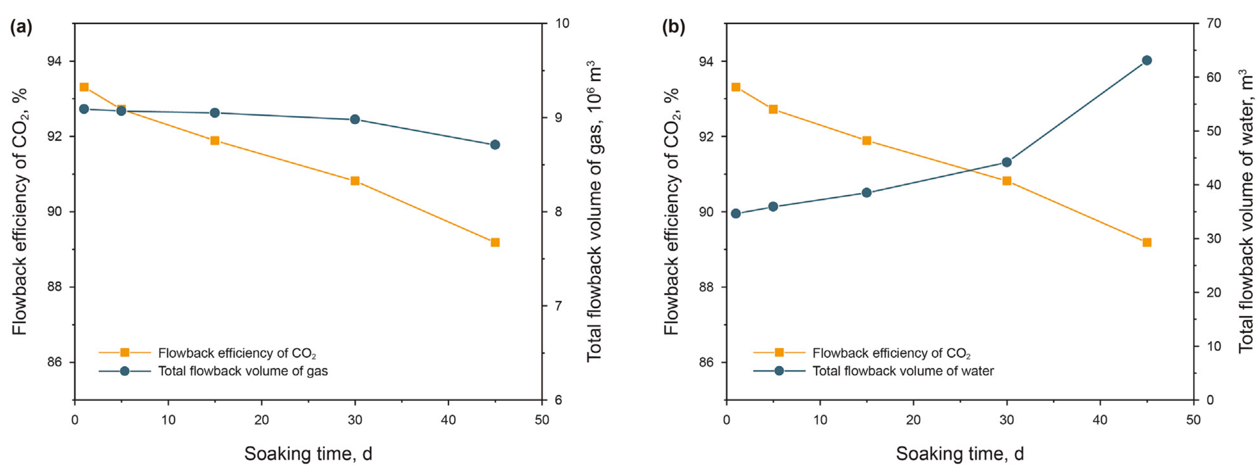

Fig. 15. Cumulative gas/water production and CO_2 flowback efficiency under different soaking time (production 3 years). (**a**) Cumulative gas production and CO_2 flowback efficiency; (**b**) Cumulative water production and CO_2 flowback efficiency.

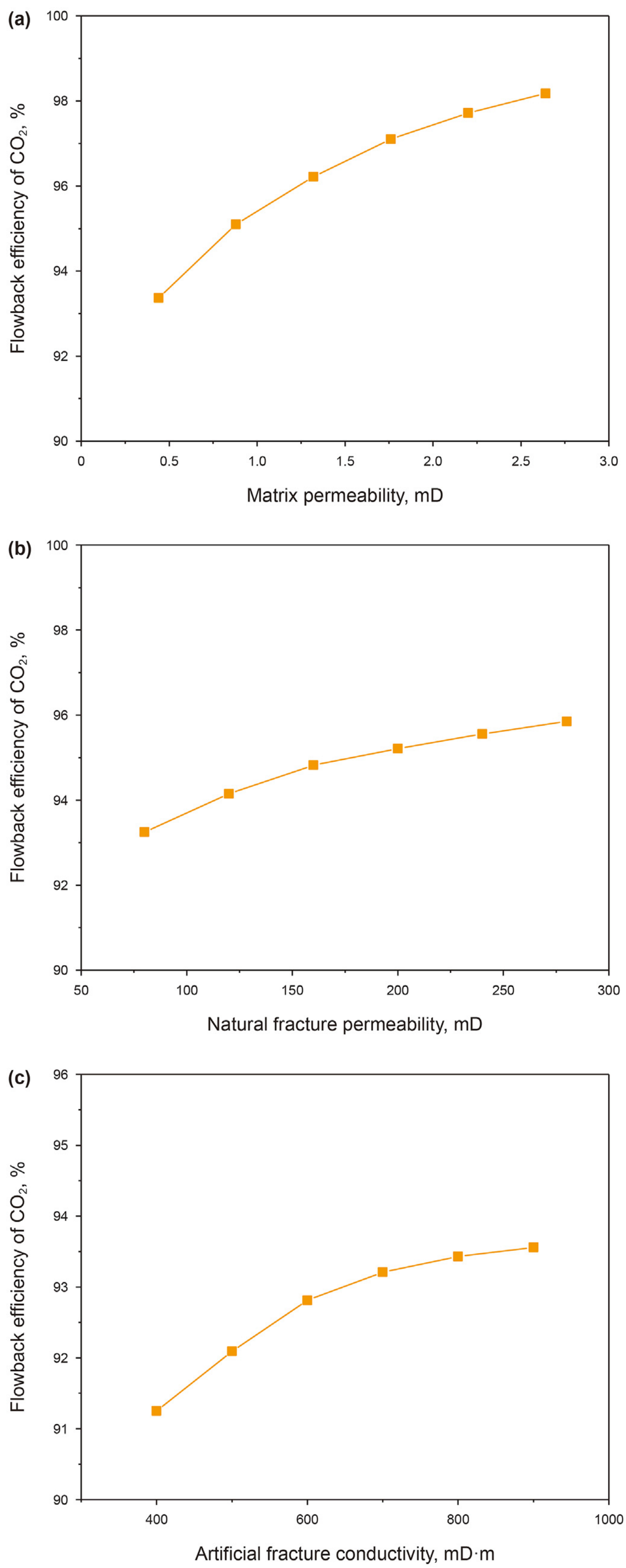

Fig. 16. (**a**) CO_2 flowback efficiency under different matrix permeabilities; (**b**) CO_2 flowback efficiency under different natural fracture permeabilities; (**c**) CO_2 flowback efficiency under different artificial fracture conductivities.

leading to a decrease in the cumulative gas production. When the soaking time was more than 30 days, the cumulative gas production was significantly reduced, indicating that the stimulation was less effective. Considering the simulation results and flowback efficiency, the optimal soaking time was 1 day.

5.3.4. Influence of permeability on flowback efficiency

Numerical simulations were conducted to investigate the CO_2 flowback under different matrix permeabilities, natural fracture permeabilities, and artificial fracture conductivities. The results are shown in Fig. 16. The results indicate that as the matrix permeability improved from 0.44 to 2.64 mD, the CO_2 flowback efficiency increased from 93.37% to 98.18%. Similarly, an increase in natural fracture permeability led to a higher CO_2 flowback efficiency, but the improvement plateaued as the fractures developed to a certain extent. Furthermore, a higher conductivity of the main fracture facilitated the flowback of CO_2, which in turn reduced the amount of CO_2 that diffused through the secondary fracture to the formation. Consequently, there was a gradual increase in the flowback efficiency.

5.3.5. Influence of CO_2 injection volume on flowback efficiency

Five numerical simulation studies were conducted with different CO_2 injection volumes (200–800 m^3). The results are shown in Fig. 17. As the CO_2 injection volume increased from 200 to 800 m^3, the CO_2 flowback efficiency decreased from 94.82% to 89.71%. This can be attributed to the increased retention of CO_2 in the formation due to diffusion, leading to a lower flowback efficiency. While gas production increased linearly with injection volume, the increase was mainly observed for CO_2, and there was little improvement in CH_4 production or water production. Considering the simulation results, flowback efficiency and injection cost, the injection volume should be the lowest volume that meets the requirements of fracture-making.

6. Conclusions

In this paper, the fundamental studies of CO_2 flowback and CH_4 production after CO_2 fracturing from the aspects of laboratory experiment and simulation were conducted. Several parameters closely related to production were discussed, such as CH_4 recovery, CO_2 flowback efficiency, and pressure distribution. The study results indicate that compared with conventional hydraulic fracturing, CO_2 fracturing has obvious advantages and application prospect. The experimental results demonstrate that CO_2 fracturing has a more favorable flowback performance, allowing fracturing fluids to be recovered during the later stages of fracturing and minimizing formation damage. However, the flowback efficiency of CO_2 is also affected by permeability, flowback pressure gradient, soaking time, and gas injection volume. Considering the simulation effect, flowback efficiency and proppant reflux, the injection volume should be the lowest volume that meets the requirements of fracture-making, the soaking time is 1 day, and the optimal bottom hole flowback pressure is 10 MPa. The study further verifies the application prospect and the possibility of CO_2 dry fracturing.

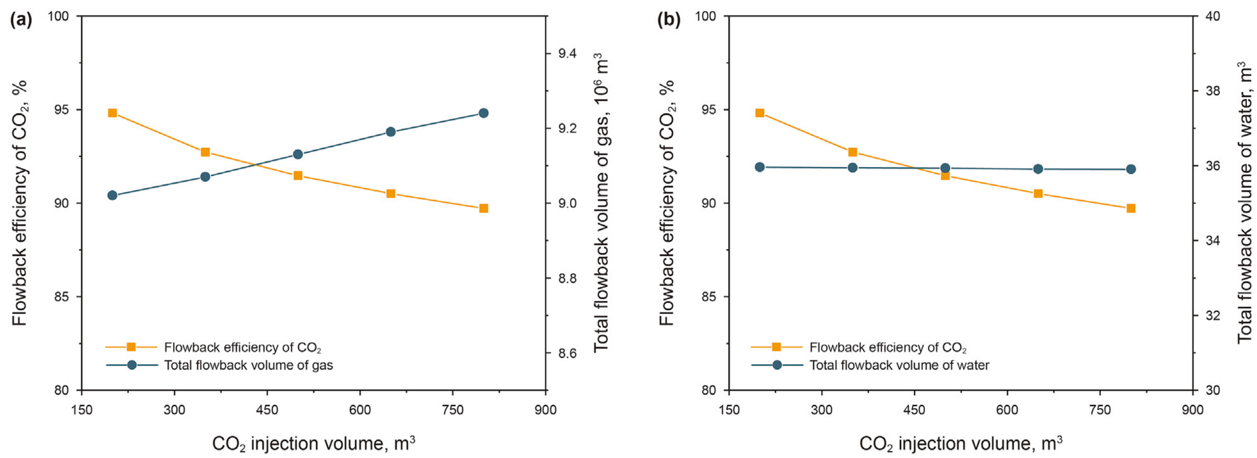

Fig. 17. Cumulative gas/water production and CO_2 flowback efficiency under different CO_2 injection volumes (production 3 years). (**a**) Cumulative gas production and CO_2 flowback efficiency; (**b**) Cumulative water production and CO_2 flowback efficiency.

Declaration of interest statement

The authors declare that there are no competing interests.

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