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Numerical Simulation and Parameter Sensitivity Analysis of CO_2 Flooding in Shale Gas Reservoir

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ABSTRACT

CO_2 flooding presents a promising methodology for enhancing shale gas recovery. To research its feasibility and evaluate the ability of CO_2 storage in the shale formations, we established a numerical simulation model of CO_2 flooding in shale gas reservoirs based on the embedded discrete fracture model (EDFM). The study analyzed the effects of reservoir properties, well spacing, injection pressure, and injection rate on the CO_2 flooding effectiveness in shale gas reservoirs. The CO_2 flooding model established in this study employs geological parameters derived from actual shale gas reservoir data, ensuring high levels of authenticity. The research results can provide a reference for oilfields to implement CO_2 flooding for enhanced shale gas recovery.

Keywords: Shale gas, CO_2 flooding, CO_2 storage

1. INTRODUCTION

Shale gas development relies on the complex fracture networks created by large-scale hydraulic fracturing, with depletion development being the primary approach [1-3]. Shale gas production exhibits high initial productivity followed by rapid decline, with adsorbed gas dominating in later stages. Currently, there remains a lack of effective methods to enhance shale gas recovery. As an important gas-drive technique, CO_2 flooding can effectively replenish formation energy [4]. Moreover, CO_2 has strong adsorptive ability and can replace the adsorbed CH_4 in the formation. Therefore, CO_2 flooding shows greater potential for improving shale gas recovery compared to conventional approaches.

The greenhouse effect caused by CO_2 has become a major climate challenge. During shale gas development, the complex fracture networks formed around the wellbore by hydraulic fracturing can provide underground storage space for CO_2. Meanwhile, shale's high density [5] and good sealing properties prevent CO_2 leakage, making it conducive to long-term CO_2 storage. Therefore, CO_2 flooding in shale gas reservoirs serves as a dual-purpose method that enhances shale gas recovery while effectively mitigating greenhouse gas emissions.

The recent years have witnessed extensive research in related field by scholars worldwide. The study of Lu et al indicates that injection of CO_2 can increase shale gas production [6]. In the experiment of Nurhandoko et al, the volume of released gas exhibited similar behavior to pressure accumulation phenomena, clearly indicating that the CO_2 released from shale was less than that of inert gases under the same conditions [7]. Wei et al discover that the effect of CO_2 displacement is different under different permeability conditions by simulation [8]. Zhang et al find that the gas adsorption capacities in shale are ranked as $SO_2 > CO_2 > NO > N_2 \approx CH_4 > CO$ within the pressure range of 0.5 – 30 MPa by injecting various gas components in the shale under real reservoir conditions[9]. Based on these studies, it can indicate that CO_2 flooding has the potential to enhance shale gas recovery. However, CO_2 flooding in shale gas reservoirs is still in the experimental stage. Current research on the effects of CO_2 injection parameters on shale gas production and CO_2 storage capacity is limited. Optimizing injection parameters is crucial for the practical implementation of CO_2 flooding in shale gas reservoirs. It needs to consider the variation patterns of shale gas production under different CO_2 injection parameters, so as to develop a gas injection strategy.

A shale gas reservoir CO_2 flooding model was established to investigate the impact of various parameters on shale gas production. The study systematically analyzed the effects of key reservoir properties (porosity and permeability) and engineering factors (well spacing, injection pressure, and injection

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rate) on shale gas yield. The research results can provide a reference for optimizing CO_2 flooding strategies in shale gas reservoirs.

2. BASIC PARAMETERS OF MODEL

The target block is located in the A shale gas reservoir, which has entered the full-scale development stage, with some well pads progressing into late-stage development. A shale gas reservoir is located in Sichuan Basin. The test results of porosity and permeability indicate that the permeability of the reservoir ranges from 0.045 to 0.00036mD, while the porosity varies from 0.0465-0.0603.

Table. 1 The porosity and permeability test results

Sample ID	POR	PERM, mD
1	4.77	3.6×10^{-4}
2	5.22	2.1×10^{-3}
3	5.79	8.3×10^{-4}
4	4.65	4.5×10^{-2}
5	5.11	6.4×10^{-3}
6	6.03	1.6×10^{-3}

Two wells in the target block were selected, and their basic parameters are shown in Table 2. The well length of these two wells are 2100m, and the half-length of fracture formed by hydraulic fracturing ranges from 120 to 150m.

Table. 2 Basic parameters of the target wells

Well	Well length, m	Number of fracture	Fracture half-length, m	Fracture conductivity, mD·m
W_1	2100	171	120-150	40
W_2	2100	80	120-150	40

The EDFM demonstrates advantages in terms of computational efficiency and high accuracy for fracture characterization [10], making it suitable for simulating complex fracture networks in shale gas reservoirs.

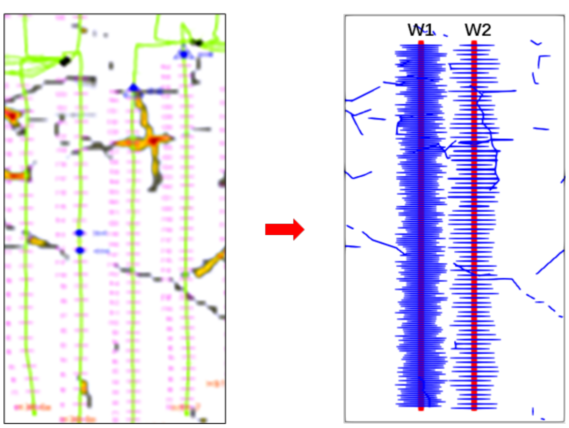


Fig. 1. Fracture model established based on EDFM

Table. 3 The components of shale gas

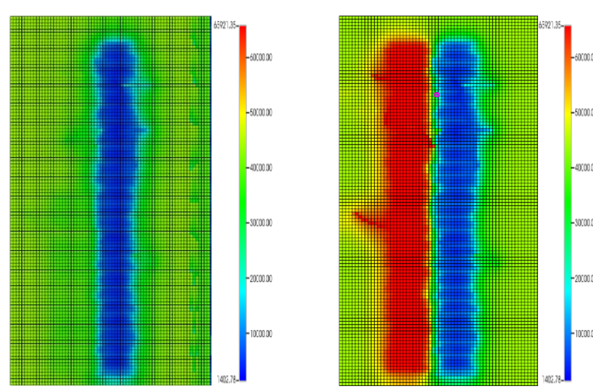
Component	Mole fraction, 10^{-2}
H_2	0.021
He	0.050
N_2	0.41
CO_2	0.52
H_2S	<0.01
CH_4	98.339
C_2	0.64
C_3	0.02

Therefore, an EDFM-based shale gas reservoir fracture model was established. To enhance the model realism, natural fracture distributions were based on seismic data (Fig. 1).

A components model was established based on the shale gas composition of target block (Table 3), and the adsorption of CH_4 and CO_2 in shale matrix is also considered.

3. CO_2 FLOODING MECHANISM IN SHALE GAS RESERVOIRS

Production simulation of shale gas was conducted using the established CO_2 flooding model. Well W1 was designated as an injection well, while Well W2 served as a production well. The distribution of formation pressure after 20 years of production without CO_2 injection and with CO_2 injection are shown in Fig. 2. The figure 2(a) is the pressure distribution without CO_2 injection, and 2(b) is the pressure distribution with CO_2 injection. It can find that the formation pressure is effectively supplemented when CO_2 flooding, and the degree of pressure drop

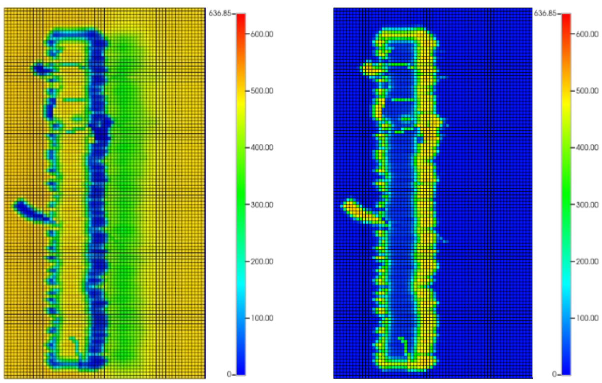


(a) Without CO_2 Injection (b) With CO_2 Injection

Fig. 2. Pressure distribution

around the production well is significantly reduced at the end of simulation period.

The distribution of adsorbed gas in the formation after 20 years of CO_2 flooding is shown in Fig. 3. The figure (a) shows the distribution of CH_4 in the formation. Significant reductions in adsorbed CH_4 content are observed in the interwell region (between W1 and W2), demonstrating the effectiveness of CO_2 in competitively displacing adsorbed CH_4. The figure (b) shows the distribution of adsorbed CO_2 in the formation. The adsorbed amount of CO_2 rises sharply around the injection well, especially in the region between the production well and the injection well. It fully indicates that during the CO_2 flooding process, CO_2 displaces the



(a) CH_4 (b) CO_2

Fig. 3. Gas adsorption distribution

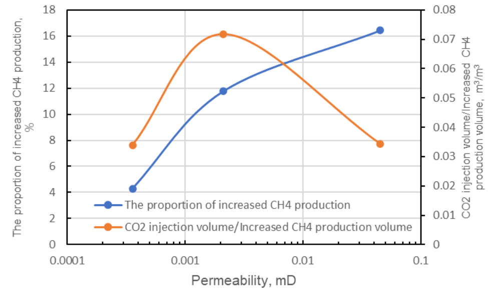
adsorbed CH_4 in the formation and drives it toward the production well, thus increasing the shale gas production. In addition, a large amount of CO_2 was retained in the formation by adsorption to realizing CO_2 storage.

4. SENSITIVITY ANALYSIS OF CO_2 FLOODING IN SHALE GAS RESERVOIRS

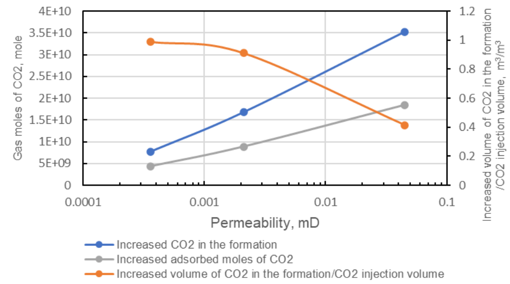
4.1 Physical properties of the shale gas reservoir

Based on the permeability distribution of target reservoir formation, the reservoirs is classified into three categories: 10^{-2} mD、 10^{-3}mD and 10^{-4}mD. Cores 1, 2, and 4 from Table 1 are selected to analyze the impact of reservoir physical properties on shale gas production with CO_2 flooding.

After 20 years of production, the simulation results are shown in Fig. 4. The figure (a) presents the increment of CH_4 and the gas exchange ratio under different physical properties. The figure (b) diaplays the CO_2 storage results under different reservoir physical properties. The results indicate that the injected CO_2 can spread to farther areas in reservoirs with a better reservoir physical property, thus displacing more CH_4. However, gas channeling is more prone to happen, which results in the output of CO_2 from the production well.



(a) The increase of CH_4



(b) CO_2 storage

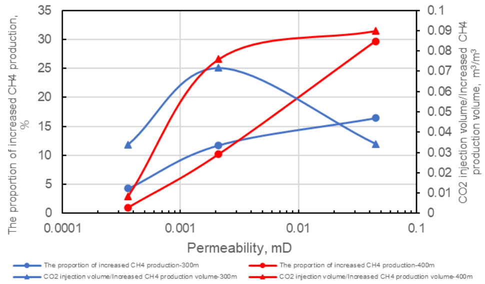
Fig. 4. CH_4 increment and CO_2 storage under different reservoir physical properties

Consequently, as reservoir basic physical property improve, the CH_4 production and CO_2 storage increased, the gas exchange ratio increased and then decreased, the CO_2 storage ratio decreased.

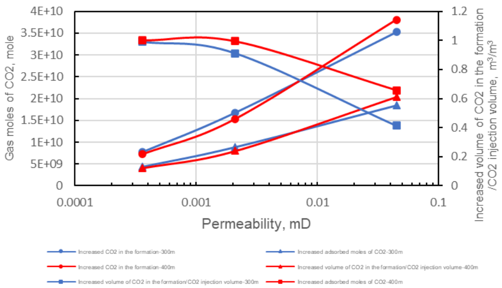
4.2 Well spacing

The well spacing was expanded by 100m under the three reservoir conditions. After 20 years of CO_2 flooding, the simulation results are shown in Fig. 5. As well spacing increases, the CH_4 production, gas exchange ratio, CO_2 storage and CO_2 storage ratio increased under the condition of good physical properties; the CH_4 production and gas exchange ratio decreased, while CO_2 storage and CO_2 storage ratio remain essentially unchanged under the condition of poor physical properties.

When the well spacings increase, it is more difficult for CO_2 to be produced from the production well. More CO_2 remains trapped in the formation under high permeability conditions. At the same time, the increased area between wells allows more CH_4 to be driven toward the production well. Under low permeability conditions, increasing well spacing prevents CO_2 from effectively reaching the production well, resulting in poor gas displacement efficiency. Therefore the effect of well spacing on shale gas production varies significantly under different permeability conditions.



(a) The increase of CH_4

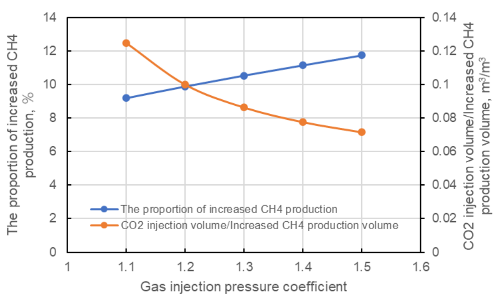


(b) CO_2 storage

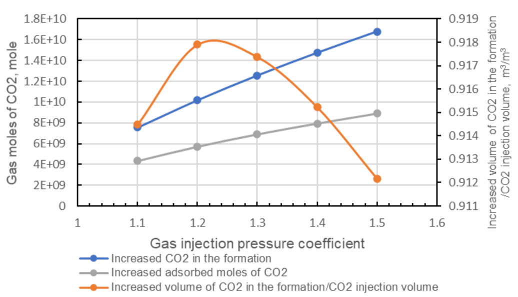
Fig. 5. CH_4 increment and CO_2 storage under different well spacings

4.3 *Injection pressure*

A sensitivity analysis of CO_2 injection pressure was carried out using the type 2 reservoir (2.1×10^{-3}mD) as an example. The injection pressure was set to be 1.1, 1.2, 1.3, 1.4, and 1.5 times of the original formation pressure, respectively. The simulation results after 20 years of production are shown in Fig. 6. As the injection pressure increased, the CH_4 production increased, the gas exchange ratio decreased, the CO_2 storage increased, and the CO_2 storage ratio first increased and then decreased.



(a) The increase of CH_4



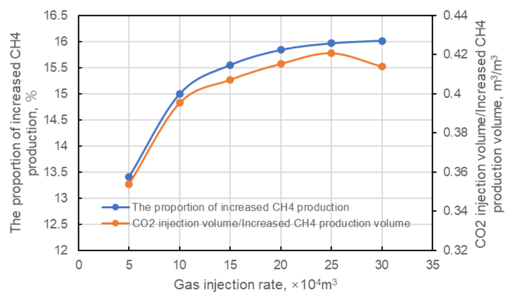
(b) CO_2 storage

Fig. 6. CH_4 increment and CO_2 storage under different CO_2 injection pressure

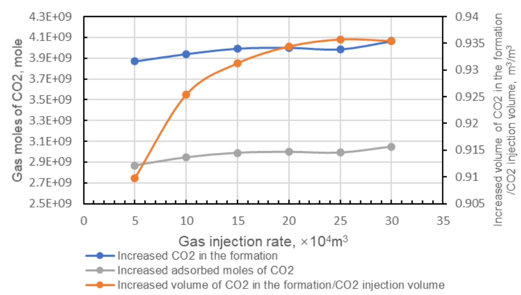
Higher CO_2 injection pressure expanded the CO_2 sweep area, displacing more CH_4 and thereby increasing both CH_4 production and CO_2 storage. However, the increase of pressure also made CO_2 more easily be produced from W2, leading to a decrease in the utilization ratio and storage ratio of CO_2.

4.4 *CO_2 injection rate*

To analyze the impact of CO_2 injection rate on shale gas production, the CO_2 injection rate was adjusted to 5, 10, 15, 20, 25, and 30 × 10^4 m^3/d while maintaining the maximum injection pressure constant. After 20 years of production, the simulation results are shown in Fig. 7. As the CO_2 injection rate increased, the CH_4 production, the gas exchange ratio, CO_2 storage and CO_2 storage ratio all increased.



(a) The increase of CH_4



(b) CO_2 storage

Fig. 7. CH_4 increment and CO_2 storage under different injection rate

As the injection rate increases, the bottomhole pressure of the injection well rises more rapidly, enhancing CO_2 adsorption capacity and displacing more CH_4. When the pressure rises to the maximum injection pressure, shale gas production stabilizes and shows minimal variation with further increases in injection rate.

5. CONCLUSIONS

To investigate the impact of injection-production parameters on shale gas production during CO_2 flooding, numerical simulations were conducted to analyze the variation trends in shale gas production associated with changes in reservoir properties, well spacing, injection pressure, and injection rate. The main conclusions are as follows:

(1) CO_2 flooding can significantly enhance shale gas production and achieve effective CO_2 storage.

(2) For shale gas reservoirs with good reservoir properties, CO_2 should be injected at large well spacing, while those with poor reservoir properties require small well spacing.

(3) During CO_2 gas flooding in shale gas reservoirs, injector pressure should not be excessively high to prevent CO_2 from being produced back through the production wells, which would compromise CO_2 storage efficiency.

(4) CO_2 injection rate should be maximized under the premise of avoiding gas channeling to optimize shale gas recovery.

DECLARATION OF INTEREST STATEMENT

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. All authors read and approved the final manuscript.

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