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A comprehensive model to analyze the engineering factors for effective CO_2 storage in shale gas reservoirs

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ABSTRACT

CO_2 huff-n-puff has proven to be an effective method for enhanced gas recovery (EGR). However, the current huff-and-puff simulation model must consider the comprehensive flow mechanism crucial for accurate reservoir and huff-n-puff simulation. Besides, the feasibility of effective CO_2 storage by huff-n-puff in shale gas reservoirs is still being determined. Therefore, to improve this situation, this paper establishes a comprehensive CO_2 huff-n-puff model, and the engineering factors for huff-and-puff and storage effects are evaluated. This meaningful work provides theoretical support for promoting CO_2 to improve gas recovery and storage in shale reservoirs.

Keywords: CCUS, CO_2 huff-n-puff, shale gas, EGR, MRST

1. INTRODUCTION

CO_2 huff-n-puff has been proven to be an effective method to improve EGR [1]. In addition, considering the storage capacity and existing infrastructure, injecting CO_2 into shale gas reservoirs is a feasible option for the geological storage of CO_2.

Adsorption/desorption [2], diffusion [3], stress sensitivity [4], dissolution [5] and SRV [6] are all important for the simulation of CO_2 huff-n-puff in shale gas reservoirs. The current huff-and-puff simulation model needs to consider the comprehensive flow mechanism, which is very important for accurate reservoir and huff-and-puff simulation. Therefore, this paper establishes a fully coupled model of the matrix, natural fracture, and hydraulic fracture improved on the MATLAB Reservoir Simulation Toolbox (MRST) (Lie, 2019) [7], which considers multiple mechanisms, including adsorption/desorption, diffusion, stress sensitivity of fracture, dissolution, and SRV.

Some scholars have also reported that higher CO_2 production is a significant problem in the huff-n-puff [8]. On the contrary, Fathi and Akkutlu [3] simulated the CO_2 huff-n-puff process, the results show that 90% of the injected CO_2 is stored. The inconsistency of the simulation results is related to the model's accuracy and the production system. Therefore, based on the comprehensive model established, this paper further evaluates the feasibility of effectively storing CO_2 by CO_2 huff-n-puff in shale gas reservoirs.

Finally, most of the CO_2 huff-n-puff simulations of shale gas reservoirs only focus on the influence of some parameters on the huff-n-puff effect. However, only a few people comprehensively study the influence of engineering parameters, including huff-n-puff system and fracture parameters. To improve this situation, after introducing the comprehensive model in detail, we continue to study the huff-n-puff and storage effects of different huff-n-puff systems and fracture parameters. This meaningful work provides theoretical support for promoting CO_2 to improve gas recovery and storage in shale reservoirs.

2. RESERVOIR MODEL DESCRIPTION

2.1 Physical model

Fig. 1a shows the physical model. The model includes matrix pores, natural fractures, and hydraulic fractures.

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There is a 5-stage fracturing MFHW in the reservoir, and there are 15 hydraulic fractures in 3 clusters of each stage. In addition, there are 56 natural fractures. After multiple hydraulic fractures and fracture networks are formed by hydraulic fracturing technology in shale reservoirs, the fracture network with medium conductivity is SRV, the pink area in Fig. 1a. The area not influenced by fracturing is unstimulated reservoir volume (USRV).

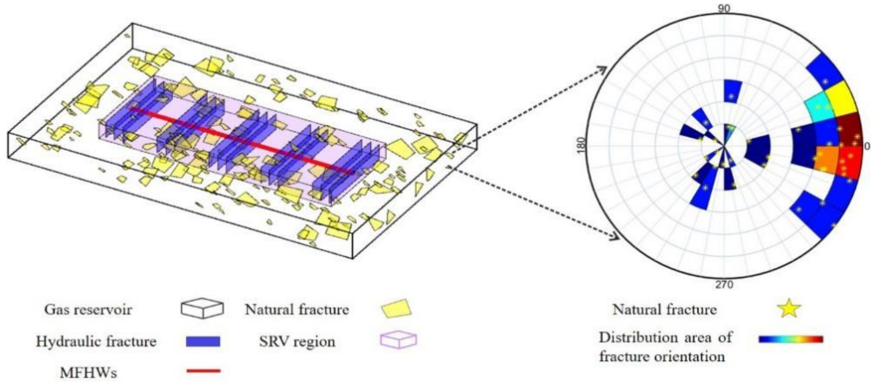

Fig. 1 (a): the physical model；(b) the variation in the orientation of natural fracture.

2.2 Theory

Adsorption/desorption

Multi-component gas mixtures usually use the Langmuir isotherm, as follows:

$$\rho_s^i = \rho_{sL}^i \frac{y_i \frac{p}{p_L^i}}{1+\sum_{j=1}^{n} y_j \frac{p}{p_L^i}} \tag{1}$$

Where, ρ_s^i is the adsorbed gas density of each component, ρ_{sL}^i is the maximum adsorbed gas density for each element, and the unit is kg/m^3. The variable p represents the reservoir pressure, and p_L^i is the Langmuir equilibrium pressure of each component in MPa. The superscript and subscript i and j refer to each hydrocarbon component. y_i is the mole fraction of component i in the vapor phase.

Diffusion

After considering the multiphase, tortuous path, and solid matrix in porous media, the modified form of Fick diffusion is as follows:

$$J_\alpha^i = -\frac{\phi S_\alpha}{\tau_\alpha} D_\alpha^i \nabla(\rho_\alpha X_\alpha^i) \tag{2}$$

The product $\rho_\alpha X_\alpha^i$ is the mass concentration of the component. D_α^i is the diffusion coefficient of the component, m^2/s； ϕ is the porosity, and τ_α is the tortuosity.

Dissolution

The dissolution of CO_2 in water in shale reservoir cannot be ignored. In this paper, the dissolution of CH_4 and CO_2 in water is considered by using Henry's law. The solubility x_c can be calculated by the following equation:

$$f_c = x_c \cdot H_c \tag{3}$$

$$H_c = H_c^* \exp\left[V_c^\infty \left(p - p^*\right)/RT\right]$$

(4)

Where, f_c is the fugacity coefficient; x_c is the solubility; H_c is the Henry coefficient; H_c^* is the Henry coefficient at temperature T and reference pressure p^*; V_c^∞ is the partial molar volume of CO_2 at infinite dilution; R is the molar gas constant.

Stress sensitivity of fracture

It is necessary to study the stress sensitivity of fractures because fractures tend to close with the decrease of formation pressure in the production process. The model proposed by Gangi is used to explain the variation of fracture permeability with pressure and confining pressure. The Gangi model is as follows:

$$K_f = K_0 \left[1 - \left(\frac{\sigma_c - \alpha_B p}{\sigma_1}\right)^m\right]^3 \tag{5}$$

Where, α_B is Biot's constant, σ_c is the confining stress, σ_1 is the maximum effective stress that closes the fracture completely, K_0 is the permeability at zero confining stress, and m is the constant related to the fracture surface roughness.

3. *DISCUSSION*

3.1 Effect of different huff-n-puff schemes

3.1.1 Huff-n-puff cycles

Table 1. Basic parameters for the calculation based on this proposed model.

Parameters	Value	Parameters	Value
Cartesian reservoir grid (i,j,k)	40×25×5	Hydraulic fracture number, N_H	15
Initial pressure, p_i (MPa)	12	Hydraulic fracture length, L_H (m)	160
Wellbore pressure, p_{wf} (MPa)	5	Hydraulic fracture spacing, S_H (m)	120
Reservoir temperature, T(K)	348.15	Hydraulic fracture height, H_F (m)	60
Reservoir thickness, h (m)	100	Matrix permeability, k_m (mD)	0.01
Huff-n-puff cycles, N_r	15	Hydraulic fracture permeability, k_H (mD)	1000
CO_2 injection time, t_{inj} (d)	180	Natural fracture permeability (SRV), k_{h1} (mD)	500
Soaking time, t_s (d)	180	Natural fracture permeability (USRV), k_{h2} (mD)	100
CO_2 injection rate, V_{inj} (m^3/s)	1	Natural fracture number, N_f	56
Production time per cycle, t_p (d)	180	Porosity of matrix, φ_m	0.1

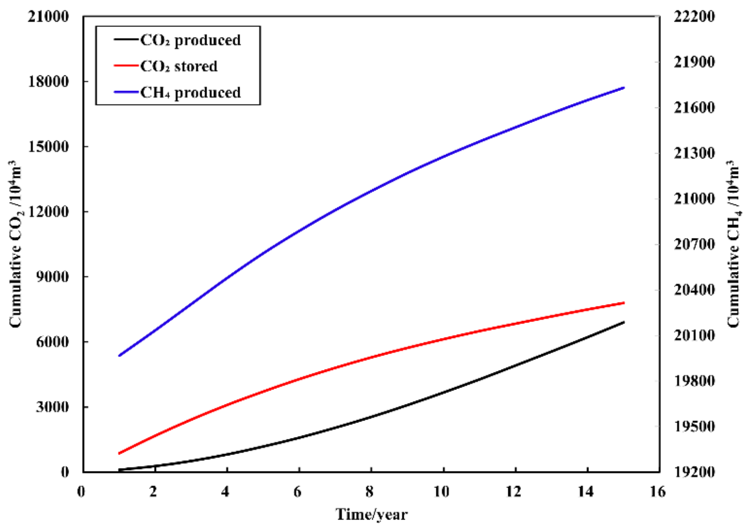

Fig. 2. Changes of cumulative gas production and storage characteristics during different huff-n-puff cycle.

Table 1 shows the basic parameters of CO_2 huff-n-puff simulation in the shale gas reservoir. Meng et al. [9] study shows that huff-n-puff in the later production stage can effectively improve gas recovery. Therefore, we set CO_2 huff-n-puff to start 30 years after depletion production.

In applying CO_2 huff-n-puff in shale gas reservoirs, the huff-n-puff cycle is an important parameter that needs to be carefully considered. The huff-n-puff up to 15 cycles were simulated. As shown in Table 1, each cycle includes 180 days of injection, 180 days of socking, and 180 days of production. Fig. 2 shows the cumulative gas production and storage characteristics changes during different huff-n-puff cycles. Among them, the blue curve is the cumulative gas production of methane, the red curve is the storage volume of CO_2, and the black curve is the production volume of CO_2. It can be seen that the cumulative gas production increases with the increase of huff-n-puff cycles, but the increasing trend slows down gradually. Compared with one huff-n-puff cycle, the cumulative gas production of 15 huff-n-puff cycles increased by 8.84%, with an average increase of 0.63% per cycle. According to the analysis of the storage effect, the storage volume and production volume of CO_2 increased with the increase of huff-n-puff cycles. With the pressure deficit in the formation, CO_2 is more likely to be stored in the formation. In this paper, the sum of the storage and production volumes is always equal to the injection volume of CO_2. The ratio of storage volume to injection volume is defined as the storage factor of CO_2. The results show that the storage factor can reach 0.53 when there are 15 huff-n-puff cycles. Facts have proved that CO_2 huff-n-puff can effectively store part of CO_2.

Fig. 3 shows the change in the mole fraction of CO_2 in different stages of the reservoir during CO_2 huff-n-puff. Among them, red indicates a high mole fraction, while blue indicates a low one. It can be seen that with the increase of huff-n-puff cycles, the mole fraction of area and SRV formed after fracturing. In addition, some areas are where the 'yellow bright spots' are affected by natural fractures. As seen in Fig. 3, more natural fractures are communicated with the increase of cycles. Fig. 3 illustrates the importance of hydraulic fracturing and SRV

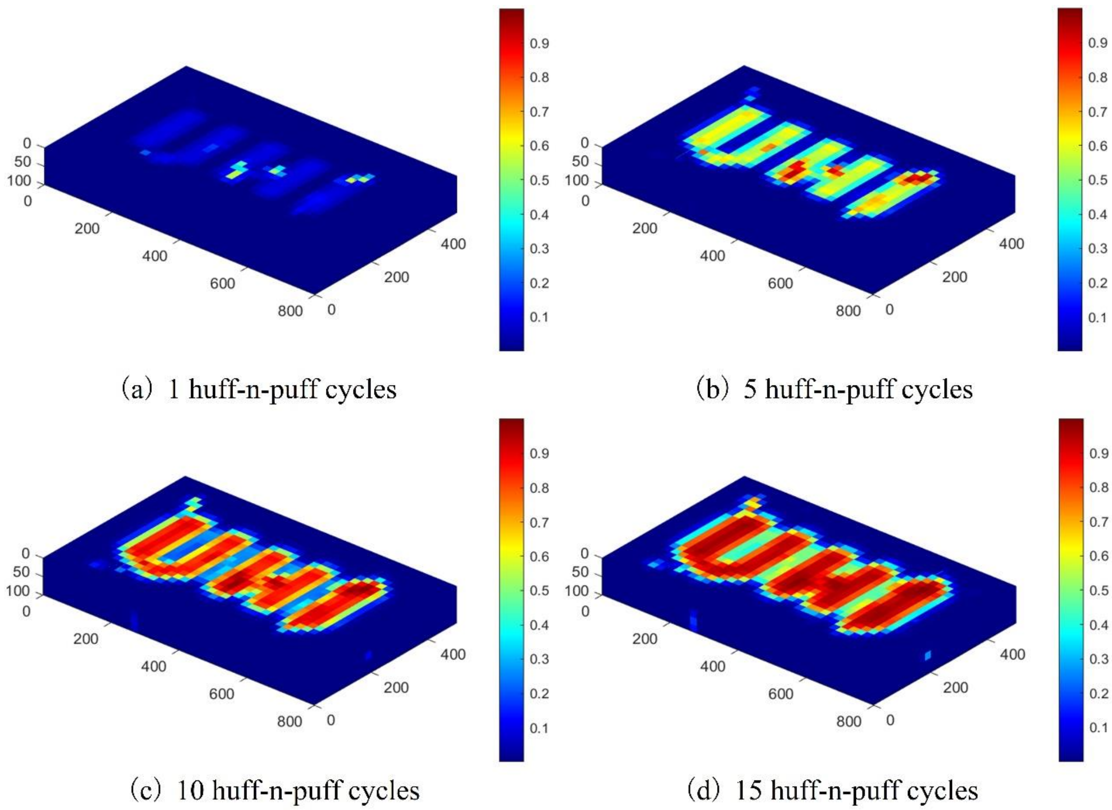

Fig. 3. Change of CO_2 mole fraction distribution at different huff-n-puff cycle.

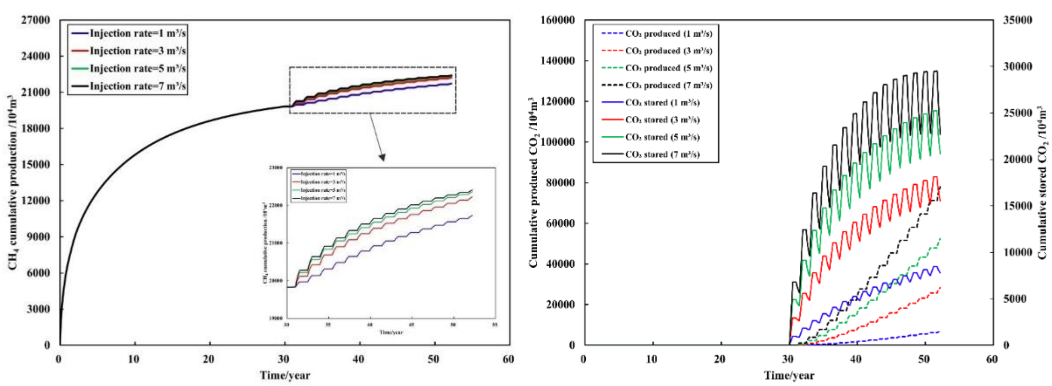

Fig. 4. Changes in cumulative gas production (left), production volume and storage volume of CO_2 (right) during different injection rates.

CO_2 near the fracturing well increases significantly and approaches 1. The intuitive change in Fig. 3 is that the red area is getting larger and darker. The mole fraction of CO_2 in 15 huff-n-puff cycles is much higher than in 1 huff-n-puff cycle. In addition, the area near the injection well can be divided into five areas with high mole fraction, corresponding to the number of fracturing segments of the well, which is determined by the high permeability during CO_2 huff-n-puff.

3.1.2 Injection rate

The left figure in Fig. 4 reports the change of cumulative gas production during different injection rates. It can be seen that the cumulative gas production increases with the increase of CO_2 injection rate, but the increase gradually decreases. Compared with the injection rate of $1m^3/s$, the cumulative gas production of

$7 m^3/s$ increased by 3.11%. We also compared the cumulative gas production only during the huff-n-puff stage (30 years later). The results show that compared with the injection rate of $1 m^3/s$, the cumulative gas production of $7 m^3/s$ increases by 35.37% during the huff-n-puff stage. Because the higher the injection rate is, the more CO_2 is injected, which increases the pressurization effect and competitive adsorption effect. However, too high an injection rate may push the methane near the well to the depth of the formation, so the increase of cumulative gas production will begin to slow down.

The blue, red, green, and black curves on the right of Fig. 4 are CO_2 production volume (dotted line) and storage volume (solid line) with different CO_2 injection rates during huff-n-puff, respectively. It shows that the storage volume and production volume of CO_2 increase with the increase in injection rate. However, the analysis of the storage factor shows that when the injection rate increases from $1 m^3/s$ to $7 m^3/s$, the storage factor decreases from 0.53 to 0.23. Nearly 77% of the CO_2 is reproduced at high injection rates, which is the same as the results of Kim et al [5]. The CO_2 injection volume should be optimized according to the storage capacity of the actual reservoir. It is worth mentioning that by adjusting the huff-n-puff scheme, the storage factor of 180 days injected under $1 m^3/s$ (169.71 t/d) can reach 0.58, which means that most of the CO_2 huff-n-puff schemes are effective for CO_2 storage.

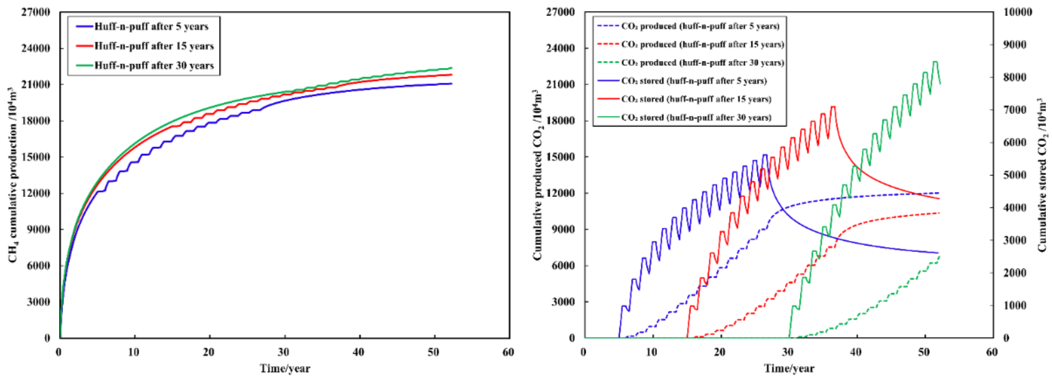

Fig. 5. Changes in cumulative gas production (left), production volume and storage volume of CO_2 (right) during different huff-n-puff opportunities.

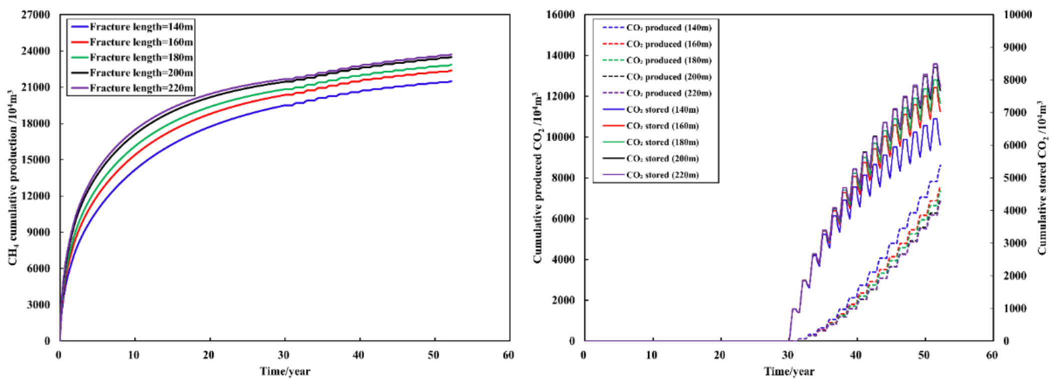

Fig. 6. Changes in cumulative gas production (left), production volume and storage volume of CO_2 (right) during different

3.1.3 Huff-n-puff opportunity

The left figure in Fig. 5 reports the cumulative gas production at different huff-n-puff opportunities. The cumulative gas production increased by 6.18% when the start time of injection changed from 5 years to 30 years. Because the huff-n-puff starts late, the formation pressure is relatively low, and the more obvious the CO_2 pressurization effect is, the greater the production pressure difference is. The results are consistent with those of Meng et al. [9].

The blue, red, and green curves on the right of Fig. 5 are CO_2 production volume (dotted line) and storage volume (solid line) at different huff-n-puff opportunities, respectively. It shows that the storage volume of CO_2 increases while the production volume decreases. Compared with 15 years, the storage volume of 30 years increased by 198.95%, and the production volume decreased by 42.61%. The storage factor of 30 years has increased from 0.18 to 0.53 compared with 15 years. The results shows that the late timing of huff-n-puff can improve recovery and help realize the storage of CO_2 during huff-n-puff.

3.2 Effect of hydraulic fracture length

The left figure in Fig. 6 reports the cumulative gas production at different hydraulic fracture lengths. The results show that the length of hydraulic fracture has a significant effect on cumulative gas production in both the depleted production stage and the huff-n-puff stage. During the total production stage, cumulative gas production increased by 10.31% when the fracture length increased from 140m to 220m. Analysis of different stages found that cumulative gas production increased by 11.09% in the depletion stage (30 years ago) and 2.58% in the huff-n-puff stage (30 years later). Longer hydraulic fractures should be created as high permeability channels, and hydraulic fractures should intersect with the natural fractures of the reservoir as far as possible.

The blue, red, green, black, and pink curves on the right of Fig. 6 are CO_2 production volume (dotted line) and storage volume (solid line) at different hydraulic fracture lengths, respectively. It shows that with the increase in crack length, the storage volume of CO_2 increases while the production volume decreases. The stored volume of the fracture length of 220m is 29.89% higher than that of 140m, and the production volume is 20.59% lower. The analysis of the storage factor shows that the storage factor increases from 0.45 to 0.59 when the fracture length increases from 140m to 220m. The results of huff-n-puff and storage show that the larger fracture length can improve recovery and help realize the storage of CO_2 during huff-n-puff.

4. CONCLUSIONS

The conclusions are as follows:

(1) By adjusting the huff-n-puff scheme, the storage factor of 180 days injected under $1m^3/s$ (169.71 t/d) can reach 0.58, which means that most of the CO_2 huff-n-puff schemes are effective for CO_2 storage. Among them, the ratio of storage volume to injection volume is defined as the storage factor of CO_2

(2) For the huff-n-puff scheme, higher injection can improve the shale gas recovery but will lower the CO_2 storage factor; the later huff-n-puff time can improve the recovery and help to achieve the storage of CO_2 during huff-n-puff.

(3) For fracture parameters, increasing the length of hydraulic fractures can improve recovery and help store more CO_2 during huff-n-puff.

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