Carbon Sequestration and Flow Behavior in Tight Reservoirs using CO_2-Energized Fracturing

Introduction

Geological CO_2 storage has become an important approach for supporting low-carbon energy development and reducing carbon emissions associated with fossil-energy utilization (Bashir et al. 2024). Meanwhile, tight and shale oil reservoirs have become important targets for hydrocarbon supply. Owing to their ultra-low porosity and permeability, the commercial development of these reservoirs strongly depends on large-scale hydraulic fracturing (Zhao et al. 2020). However, conventional water-based fracturing is commonly associated with high water consumption, fluid backflow, and limited pressure maintenance, which restrict its application in low-pressure and strongly heterogeneous continental shale oil reservoirs (Middleton et al. 2015).

CO_2 energized fracturing provides a potential CCUS-EOR route by using CO_2 as an energized working fluid during reservoir stimulation (Meng et al. 2025). This technology combines CO_2-based stimulation with water-based hydraulic fracturing and can be classified into pre-pad and post-pad schemes according to the injection sequence of CO_2 relative to the water-based fracturing fluid (Han et al. 2024). During fracturing and subsequent production, injected CO_2 can contribute to fracture-network development, reservoir pressure support, oil recovery enhancement, and geological CO_2 storage (Middleton et al. 2015). Field applications in Chinese shale oil reservoirs have demonstrated the feasibility of integrating CO_2 fracturing with carbon storage at the reservoir scale (Shi et al. 2023).

Previous studies have mainly focused on CO_2 storage in flooding, huff-n-puff, and other displacement-based recovery processes, with emphasis on storage capacity, trapping mechanisms, and recovery performance (Sambo et al. 2023). In contrast, the coupled reservoir pressure increment-sequestration response during CO_2 energized fracturing remains insufficiently quantified, especially during the injection-shut-in-production process. To address this gap, a compositional simulation model was established to evaluate the effects of CO_2 injection mass and shut-in time on reservoir pressure increment and CO_2 sequestration in shale oil reservoirs.

Method and Theory

A compositional numerical model was developed to describe the coupled reservoir pressure increment-sequestration response during CO_2 energized fracturing in a field-scale shale oil reservoir. The model was constructed under representative high-temperature and high-pressure conditions, with hydraulic-fracture geometry constrained by microseismic monitoring data. Local grid refinement was applied around the fractures to capture preferential flow and fracture-matrix mass exchange during the injection-shut-in-production process. Basic reservoir parameters were set according to field conditions, including a reservoir depth of 2584.9 m, initial pressure of 32 MPa, temperature of 112 °C, porosity of 0.10, and permeability of 0.03 mD (Meng et al. 2025). The model was formulated based on compositional mass conservation and multiphase flow in the fracture-matrix system. CO_2 phase behavior, component transport, diffusion, adsorption, geochemical reactions, and fracture-matrix exchange were incorporated to describe pressure propagation, CO_2 transport, and storage in the fracture-matrix system. CO_2 sequestration was quantified by the mass balance among injected CO_2, produced CO_2, and CO_2 retained in the reservoir after production. Reservoir pressure increment was evaluated from CO_2-induced pressure buildup and redistribution. The reservoir pressure increment area was defined as the region where reservoir pressure exceeded the initial pressure, while the reservoir pressure increment coefficient represented the average pressure enhancement intensity within this region. The injection-shut-in-production workflow and parameter-response framework are shown in Fig. 1.

***Table 1** . Simulation scheme*

Variable	Unit	Levels	Fixed condition
CO_2 injection mass	t/stage	15, 45, 75, 105, 135	Shut-in time = 0 d
Shut-in time	d	0, 5, 10, 20, 30	CO_2 injection mass = 75 t/stage

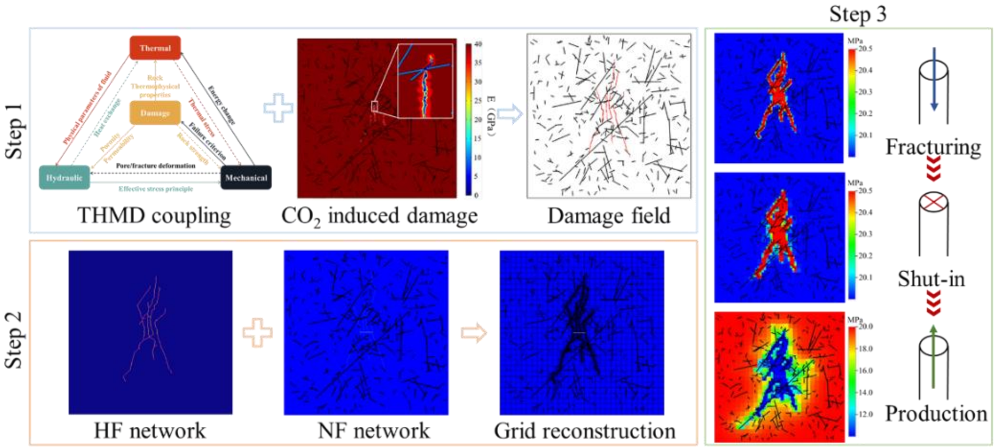

Figure 1 *. Numerical workflow for evaluating reservoir pressure increment and CO_2 sequestration during CO_2 energized fracturing.*

Results and Discussion

With the nominal single-stage CO_2 injection mass fixed at 75 t/stage, prolonging the shut-in time from 0 d to 30 d promoted pressure redistribution and expanded the pressure-affected region (Fig. 2a). The cumulative CO_2 production curves show that a longer shut-in time reduced CO_2 back-production during the production stage (Fig. 2b). At the end of production, cumulative CO_2 production decreased from 675.4 t to 639.6 t, while the CO_2 sequestration ratio increased from 80.6% to 81.6% (Fig. 2c). Meanwhile, the pressure increment area increased from 1.37×10^6 m^2 to 1.44×10^6 m^2, whereas the pressure increment coefficient slightly decreased from 1.144 to 1.114 (Fig. 2d). This indicates that shut-in-induced pressure redistribution enlarged the pressure-affected region but reduced the average pressure enhancement intensity. The adsorbed CO_2 mass also increased with shut-in time (Fig. 2e), reaching 335.0 t after 30 d compared with 318.4 t without shut-in. Correspondingly, the total stored CO_2 increased from 2799.6 t to 2835.4 t, and the adsorbed CO_2 proportion rose from 11.4% to 11.8% (Fig. 2f). These results indicate that shut-in time moderately improves CO_2 sequestration by promoting pressure diffusion and matrix adsorption.

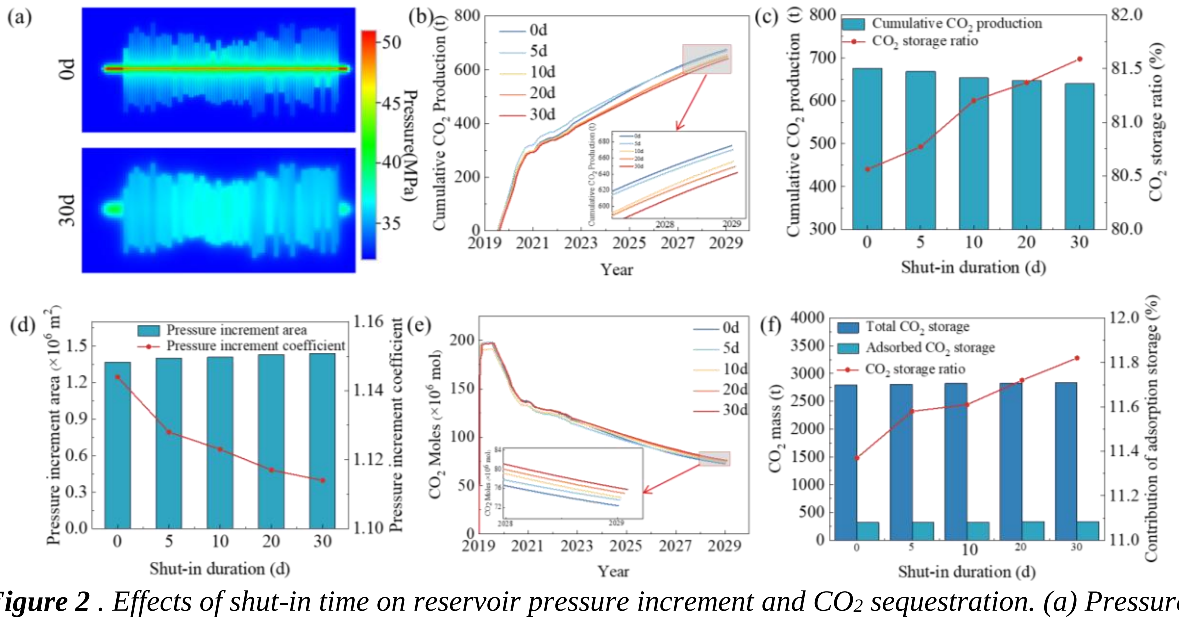

Figure 2 *. Effects of shut-in time on reservoir pressure increment and CO_2 sequestration. (a) Pressure distribution under different shut-in times; (b) cumulative CO_2 production; (c) cumulative CO_2 production and sequestration ratio; (d) pressure increment area and coefficient; (e) adsorbed CO_2 mass; (f) adsorbed CO_2 mass and its proportion in total stored CO_2.*

With the shut-in time fixed at 0 d, increasing the nominal single-stage CO_2 injection mass from 15 t/stage to 135 t/stage strongly affected both CO_2 production and sequestration behavior. The cumulative CO_2 production curves show that a larger injection mass resulted in greater CO_2 back-production during the production stage (Fig. 3b). At the end of production, cumulative CO_2 production increased from 154.0 t to 950.1 t, while the total stored CO_2 increased from 541.1 t to 5305.0 t. The corresponding CO_2 sequestration ratio increased from 77.8% to 84.8% (Fig. 3c), indicating that increasing CO_2 supply enhanced the well-scale storage capacity despite greater back-production. Meanwhile, the pressure increment area increased from 1.29×10^6 m^2 to 1.38×10^6 m^2, and the pressure increment coefficient increased slightly from 1.138 to 1.148 (Fig. 3d), suggesting that CO_2 injection mass improved both the spatial extent and average pressure enhancement intensity. The adsorbed CO_2 mass also increased markedly with increasing injection mass (Fig. 3e), reaching 826.5 t at 135 t/stage compared with 44.4 t at 15 t/stage. Correspondingly, the ratio of adsorbed CO_2 to total stored CO_2 increased from 8.2% to 15.6% (Fig. 3f). These results suggest that CO_2 injection mass is the dominant control on the sequestration scale and also increases the contribution of adsorbed CO_2 to total storage.

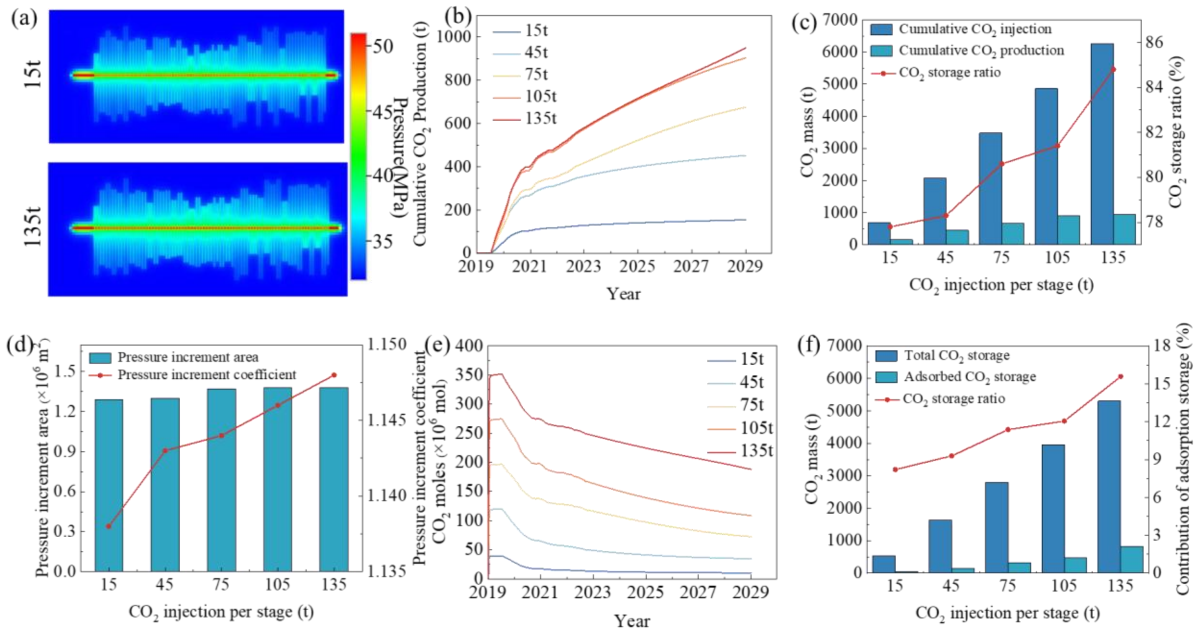

***Figure 3** . Effects of CO_2 injection mass on reservoir pressure increment and CO_2 sequestration. (a) Pressure distribution under different injection-mass levels; (b) cumulative CO_2 production; (c) cumulative CO_2 production and sequestration ratio; (d) pressure increment area and coefficient; (e) adsorbed CO_2 mass; (f) adsorbed CO_2 mass and its proportion in total stored CO_2.*

Overall, CO_2 injection mass primarily controlled CO_2 supply to the fracture-matrix system, thereby increasing total stored CO_2 and the adsorption contribution. However, the limited growth of the pressure increment area at high injection-mass levels indicates that pressure propagation was constrained by fracture geometry and matrix permeability. In contrast, shut-in time mainly promoted post-injection pressure redistribution and fracture-matrix CO_2 transfer, reducing back-production and moderately improving sequestration. Therefore, CO_2 injection mass and shut-in time regulate different aspects of the reservoir pressure increment-sequestration response.

Conclusions

A multiphase compositional model was established to investigate reservoir pressure increment and carbon sequestration during CO_2 energized fracturing in shale oil reservoirs. The results show that CO_2 injection mass and shut-in time exert distinct controls on the reservoir pressure increment-sequestration response. Increasing the nominal single-stage CO_2 injection mass from 15 t/stage to 135 t/stage mainly enlarged the well-scale sequestration capacity, with total stored CO_2 increasing from 541.1 t to 5305.0

t and adsorbed CO_2 increasing from 44.4 t to 826.5 t. In comparison, prolonging shut-in time mainly promoted pressure redistribution and matrix-scale CO_2 sequestration, reducing cumulative CO_2 production from 675.4 t to 639.6 t and increasing the sequestration ratio from 80.6% to 81.6%. The opposite variation between the pressure increment area and coefficient further indicates that an expanded pressure-affected region does not necessarily correspond to stronger average pressure enhancement intensity. These findings highlight the need for a joint evaluation of pressure maintenance and CO_2 sequestration during CO_2 energized fracturing, providing a quantitative basis for optimizing CCUS-oriented CO_2 energized fracturing designs in shale oil reservoirs.

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