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CO₂ plume evolution in the saline aquifer under various injection operations for CCS

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Abstract. Carbon capture and storage (CCS) projects inject large amounts of CO₂ into deep saline aquifers or depleted oil and gas reservoirs. This operation requires a leakage risk analysis for the injected CO₂. The subsurface flow of CO₂ at the injection formation is dependent on injection operations. This study proposes a method to combine a wellbore flow model and an analytical solution to the CO₂ plume to investigate the influence of the injection temperature, pressure, and rate on the interface evolution between the CO₂ and the brine. Using the wellbore flow model, the proposed method estimates the volume injection rate at the bottom hole under different injection parameters. Then it illustrates the effects of injection operations on the CO₂ plume and its maximum radius at the interface between the caprock and formation. The results provide an estimation of the plume radius under different injection rate and duration that would help field operators manage leakage risks.

1. Introduction

Carbon capture and storage (CCS) has been recognized as a primary technology to reduce greenhouse gas emissions to the atmosphere [1]. Injecting the captured CO₂ into the deep saline aquifer or depleted oil and gas reservoir through wells is mature in the petroleum industry. However, the public concern remains on the leakage risk of the stored CO₂. This risk is highly related to the injection operation and subsurface flow of the injected CO₂. Therefore, understanding deeply of the relationship between the flow of CO₂ and the injection operation would help manage the risk for CCS.

A large number of researchers have paid their attention to the displacement of the brine by the injected CO₂ [2]. They characterize the subsurface movement of CO₂ to estimate the disposal area. Nevertheless, there is little research on the influence of the injection operation on the CO₂ flow in the sequestration formation. This work combines a wellbore flow model and an analytical solution to the CO₂ plume in the reservoir to investigate the effects of injection temperature, pressure, and rate on the CO₂ subsurface flow. The wellbore flow model provides the volume injection rate at the bottom hole, which determines the area of the plume. The proposed method is conducive to control leaky risk during CCS.



2. Modelling for CO₂ injection and its subsurface flow

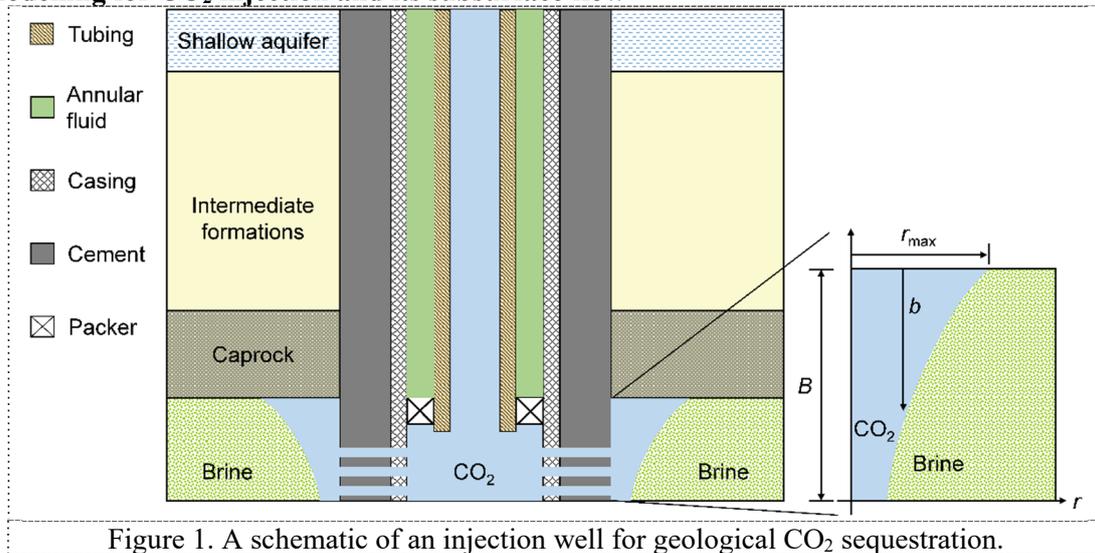


Figure 1. A schematic of an injection well for geological CO₂ sequestration.

Generally, wells serve as delivery channels to inject CO₂ into saline aquifers, as shown in Figure 1. A typical injection well contains a tubing and multiple barriers, including the casing, packers, annular fluid, and the cement sheath. Millions of tons of CO₂ flow into the wellbore under the controlled injection pressure, temperature, and rate at the wellhead. The injected CO₂ would displace the brine at the target reservoir (its thickness is B) and expand laterally. Nordbotten et al. [4] demonstrated that the interface separating the CO₂ and the resident brine is very sharp under the assumption of strong buoyant segregation (See Figure 1). This interface is often referred to as the CO₂ plume, whose thickness is depicted as $b(r,t)$ with r and t representing the radial distance from the wellbore and injection time, respectively.

2.1. Wellbore flow with heat transfer

The subsurface flow in the saline aquifer of the injected CO₂ is highly dependent on the pressure at the bottom hole and the fluid properties. A wellbore flow model would provide this valuable information. In this work, we assume a pure liquid CO₂ flow in a steady state. This assumption is often valid in deep wells with high injection pressure. Since wells are often several kilometers long, we consider a one-dimensional flow. Flowing these simplifications, the governing equations for the wellbore flow of CO₂ are [3]:

$$\begin{cases} \frac{dv_f}{ds} = -\frac{v_f}{\rho_f} \frac{d\rho_f}{ds} \\ \frac{dp_f}{ds} = -\rho_f v_f \frac{dv_f}{ds} + \rho_f g \cos \theta - f_w \\ \frac{dT_f}{ds} = C_{Jf} \frac{dp_f}{ds} + \frac{1}{c_{pf}} \left(-v_f \frac{dv_f}{ds} + g \cos \theta - \frac{f_w}{\rho_f} - \frac{q}{\rho_f v_f} \right) \end{cases} \quad (1)$$

where T_f , p_f , and v_f are the temperature, pressure, and velocity of CO₂, s and θ represent the depth and deviation angle of the wellbore, respectively, ρ_f and c_{pf} are the fluid density and specific heat at constant pressure, respectively, C_{Jf} is the Joule-Thomson coefficient, f_w is the friction between the fluid and the tubing wall, and q denotes the heat flux (per unit control volume) transferred from the formation to CO₂. Eq. (1) is complete to solve the concerned fluid temperature, pressure, and velocity. The remained terms are friction and heat transfer. f_w can be expressed as [3]:

$$f_w = f \frac{\rho_f v_f^2}{4r_{ti}} \quad (2)$$

where r_{ti} is the inner radius of the tubing, and the coefficient f is related to the flow pattern [3]:

$$f = \begin{cases} \frac{64}{\text{Re}}, & \text{Re} \leq 2400 \\ \left(\frac{1}{2 \ln \left[\frac{\varepsilon}{3.7r_{ti}} - \frac{5.02}{\text{Re}} \ln \left(\frac{\varepsilon}{3.7r_{ti}} + \frac{13}{\text{Re}} \right) \right]} \right)^2, & \text{Re} > 2400 \end{cases} \quad (3)$$

where $\text{Re} = 2\rho_f v_f r_{ti} / \mu_f$ is the Reynolds number, μ_f is the viscosity of CO_2 , and ε is the absolute roughness of the tubing inner surface. During injection, heat transfer occurs between the fluid and the formation, which can be estimated as [3]:

$$q = \frac{2U_{\text{tot}}}{r_{ti}} (T_f - T_{ei}) \quad (4)$$

where U_{tot} is the total heat transfer coefficient based on the tubing inner surface, and T_{ei} represents the initial temperature of the formation. Using the fluid temperature, pressure, and velocity at the wellhead as the boundary and initial conditions, Eqs. (1)-(4) can be solved by the finite difference method to provide the temperature and pressure profiles along the well.

2.2. CO_2 plume in the saline

A multiphase flow occurs as the injection CO_2 moves into the formation to displace the brine. Usually, the CO_2 at the bottom hole is a supercritical fluid, which is much less dense and less viscous than the brine. Nordbotten et al. [4] proposed some assumptions that the buoyant separation due to density difference is very strong, the capillary transition zone is small compared to the formation thickness, and the density and viscosity of both CO_2 and brine are uniform within a single formation. Under these formations, they showed that the interface between the CO_2 and brine is very sharp as a plume and derived an analytical solution to the plume thickness [4]:

$$\frac{b(r,t)}{B} = \frac{1}{\lambda_c - \lambda_w} \left(\sqrt{\frac{\lambda_c \lambda_w V(t)}{\phi \pi B r^2}} - \lambda_w \right) \quad (5)$$

where λ_c and λ_w are the mobility of the CO_2 and brine, respectively, ϕ is the porosity of the target formation, and V is the total injected volume of CO_2 [4]:

$$V(t) = \int Q dt \quad (6)$$

where Q is the volume injection rate at the bottom hole, and the integral time covers the whole injection duration.

As described by Eq. (1), the temperature and pressure of CO_2 at the bottom hole are determined by injection parameters that means the volume injection rate is dependent on the injection temperature, pressure, rate, and duration. Combining Eq. (5) the investigation on the influence of injection parameters on the CO_2 plume is available. Additionally, Eq. (5) also provides an estimation for the maximum radius of the plume [4]:

$$r_{\max} = \sqrt{\frac{\lambda_c Q t}{\phi \pi \lambda_w B}} \quad (7)$$

Based on Eq. (7), we can evaluate the leakage risk of the stored CO₂.

3. Results and discussions

In this section, we present a parametric study to illustrate the influence of injection parameters on the CO₂ plume. We first present the volume injection rate at the bottom hole under different injection operations, and then we show the CO₂ plume evolution and its maximum radius. The relevant parameters about the wellbore geometry and materials' properties can be extracted from [3] and [4].

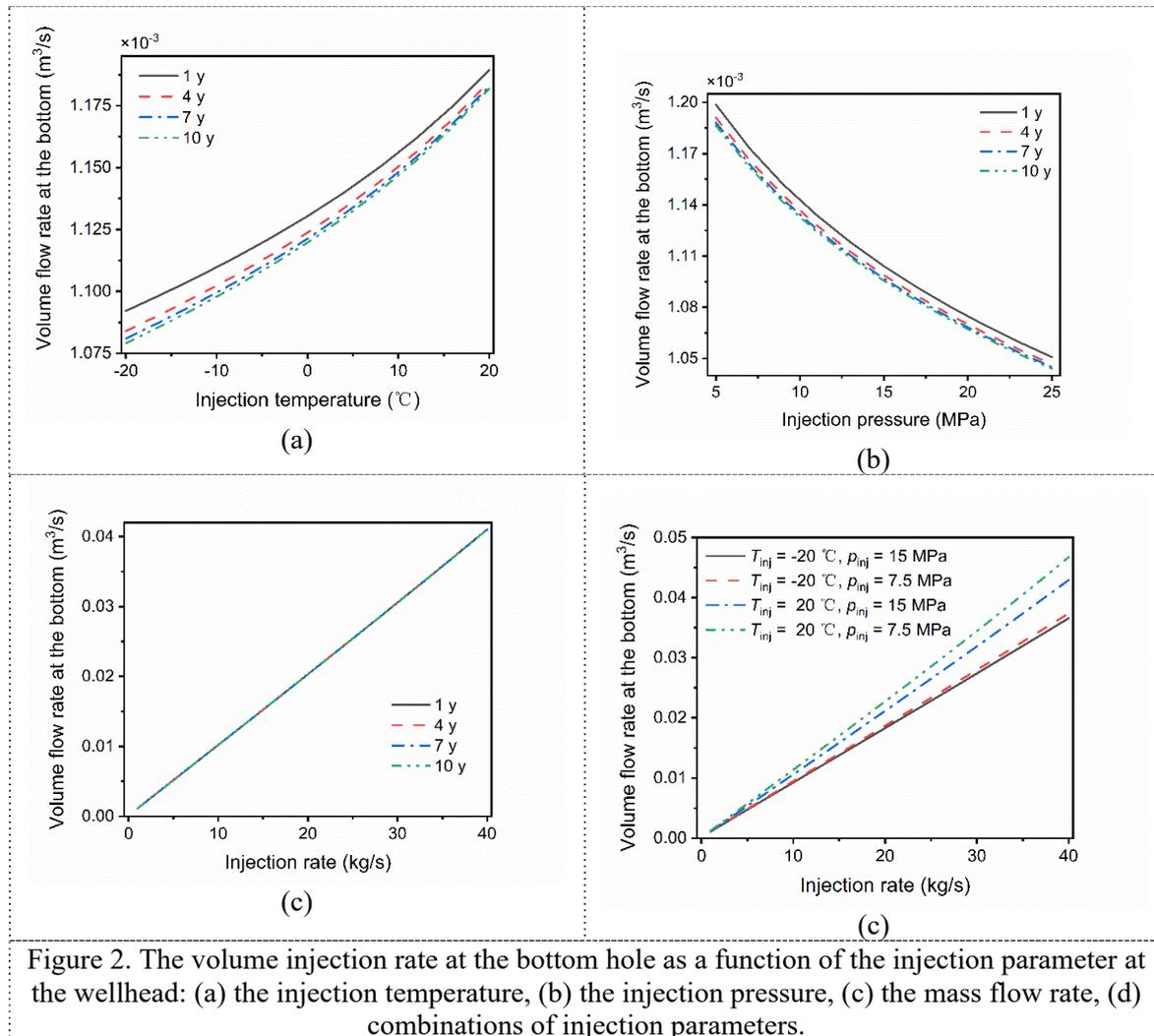


Figure 2. The volume injection rate at the bottom hole as a function of the injection parameter at the wellhead: (a) the injection temperature, (b) the injection pressure, (c) the mass flow rate, (d) combinations of injection parameters.

Figure 2 shows the volume injection rate at the bottom hole for different injection duration under various injection temperature, pressure, and rate. It exhibits that the volume rate increases (Figure 2(a)) with the injection temperature but decreases (Figure 2(b)) with the injection pressure. The injected fluid would occupy more space with higher temperatures and lower pressure that leads to a greater volume rate. Figure 2(c) indicates that the volume injection rate rises linearly with the mass flow rate at the wellhead, and it is independent of the injection duration. To illustrate the aggravating impact of injection parameters, Figure 2(d) plots the volume injection rate under combined injection temperatures, pressure, and rates. A combination of high injection temperatures and low injection

pressure produces a steep slope at which the injection volume rate increases with the mass flow rate. Figure 2 also shows that the mass flow rate has the most impact on the volume flow rate, while the injection temperature and pressure's effect is trivial.

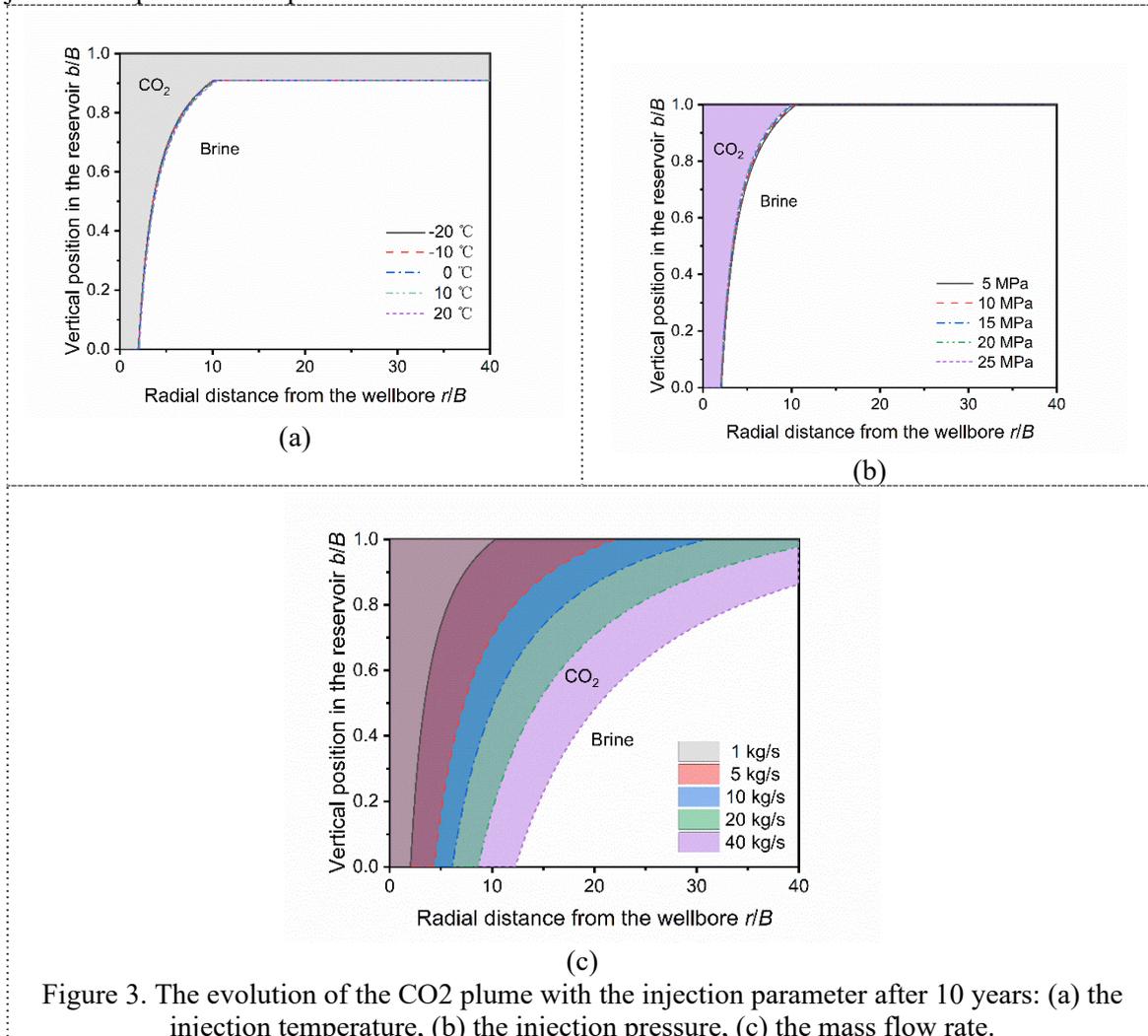


Figure 3. The evolution of the CO₂ plume with the injection parameter after 10 years: (a) the injection temperature, (b) the injection pressure, (c) the mass flow rate.

Consistent with the influence of injection parameters on the volume rate at the bottom, the interfaces between the CO₂ and brine nearly coincide under different injection temperatures and pressures (10 years of injection), as shown in Figures 3(a) and 3(b). Under fast mass flow rates, the plume spreads to a large extent in the reservoir (Figure 3(c)).

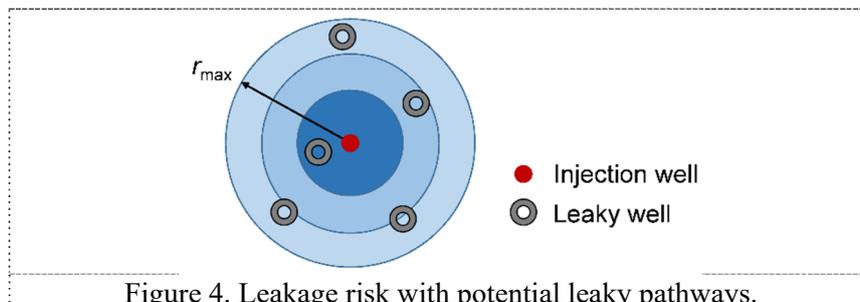


Figure 4. Leakage risk with potential leaky pathways.

It is widely recognized that the existent wells, either active or abandoned, are the primary potential leaky pathways for the stored CO₂, as shown in Figure 4. Eq. (7) estimates the maximum radius of the

CO₂ plume, from which we can adjust the injection parameter to control the plume. It also provides a reference to manage well distribution and remediation. Figure 5 illustrates the maximum radius of the CO₂ plume under different combinations of injection rate and duration for low injection temperature and high injection pressure (Figure 5(a)) and high injection temperature and low injection pressure (Figure 5(b)). It helps the field operator to choose appropriate injection rate and duration to constrain the CO₂ plume under a safe limit.

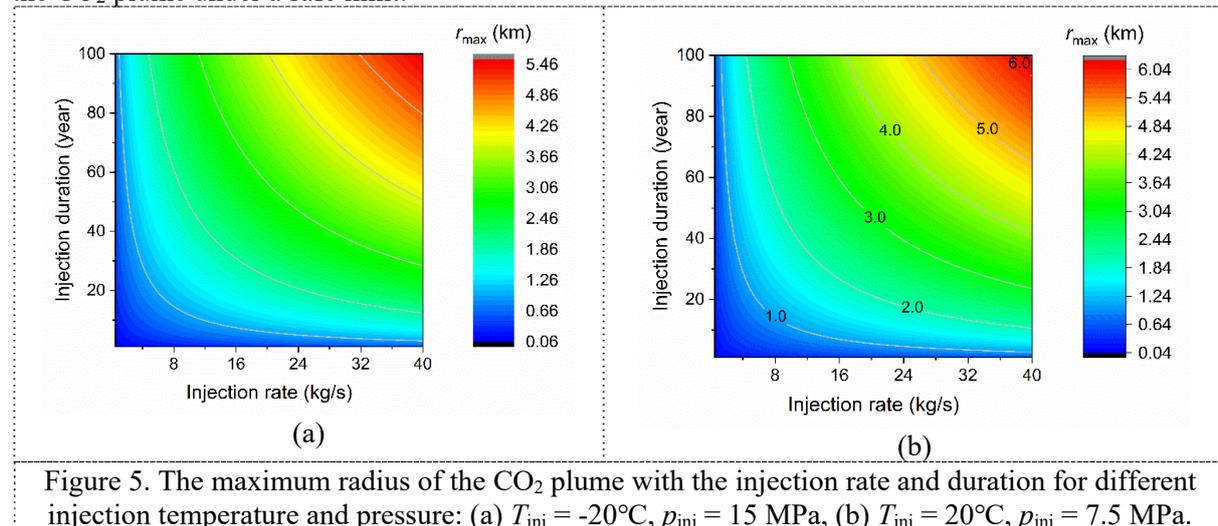


Figure 5. The maximum radius of the CO₂ plume with the injection rate and duration for different injection temperature and pressure: (a) $T_{\text{inj}} = -20^{\circ}\text{C}$, $p_{\text{inj}} = 15 \text{ MPa}$, (b) $T_{\text{inj}} = 20^{\circ}\text{C}$, $p_{\text{inj}} = 7.5 \text{ MPa}$.

4. Conclusions

This study reveals the effects of injection parameters on the CO₂ plume during CCS projects. Results show that the flow mass rate is the most influential factor in the plume. High injection temperatures, low injection pressure, and fast injection rates would enlarge the plume. This work also provides an estimation of the maximum radius of the plume that can help engineers control the leakage risk by adjusting injection parameters.

Acknowledgments

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