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Effect of *in-situ* stress alterations on flow through faults and fractures in the cap rock

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Abstract

Cap-rock integrity is of paramount importance during injection and subsequent long-term storage of CO_2 in the subsurface. Pre-existing (natural) and man-induced fractures in the cap rock represent potential flow paths out of the storage formation. In this study, a first-order semi-analytical model of flow through a vertical fracture penetrating cap rock is constructed taking the stress-dependent fracture permeability into account. The model is then applied to study the effects of *in-situ* stress normal to fracture on the flow rate through the fracture. The flow rate increases nonlinearly with the reservoir pressure, which is due to a combined effect of nonlinear fracture deformation law and the cubic law governing the flow rate.

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Keywords: geomechanics; coupled model; fracture; permeability; leakage; cap rock; CO_2

1. Introduction

Cap-rock integrity is of paramount importance during injection of CO_2 and during subsequent long-term storage of CO_2 in the subsurface. Fractures and faults in the cap rock represent potential flow paths for CO_2 migration out of the storage formation. Pre-existing sealing fractures and faults may open and thereby become hydraulically conductive if the compressive normal stress acting on the fracture plane is reduced during injection or during subsequent lifetime of the storage site.

Stress changes leading to fracture opening can be caused by natural geological processes, but may also result from the stress re-distribution accompanying the injection of CO_2 into the reservoir [1, 2]. For instance, injection

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into a reservoir is known to increase the total horizontal stresses in the reservoir and to reduce the total (and effective) horizontal stresses in the overburden (Fig. 1) [3]. Such stress alteration will lead to dilation, and possibly the opening of pre-existing, natural vertical fractures that often exist in siliciclastic (shales, claystone) and evaporitic (anhydrite) cap rocks. Fracture reopening will increase the permeability of the overlying formation, which may allow CO_2 to migrate upwards through the cap rock. For example, at the In Salah CO_2 injection project in Algeria, CO_2 injection in well KB-502 caused tensile opening of an existing fracture zone in the caprock and upward migration of the injected CO_2 into the lower part of the caprock [4, 5]. Another type of fractures that may create flow paths through the cap rock are fractures in the near-well area. Since a wellbore serves as a stress concentrator, alterations of *in-situ* stresses caused by injection are likely to be amplified in the vicinity of the well. Such amplified stresses may induce new fractures or activate the already existing ones, enabling upward migration of CO_2 across the cap rock.

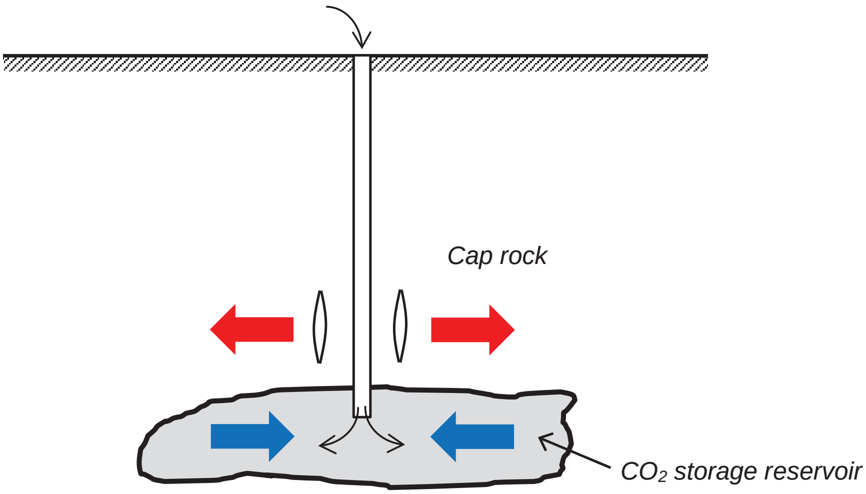


Fig. 1. Schematic view of vertical fracture opening in the cap rock caused by CO_2 injection into the underlying reservoir. Blue arrows indicate increase of horizontal total stresses in the reservoir (stresses becoming more compressive). Red arrows indicate decrease of horizontal total stresses in the overburden (stresses becoming less compressive). Aperture of pre-existing, natural vertical fractures in the overburden is likely to increase as a result of these stress changes. This will increase the permeability of the cap rock.

In this study, we focus on the effect of a single, individual vertical fracture in the cap rock on leakage from a CO_2 storage reservoir. The effect of an individual vertical fracture on CO_2 leakage was previously addressed in refs. [6, 7]. However, geomechanical effects were neglected in those earlier studies, and only the hydraulic problem was treated. In reality, the permeability of a fracture (and thus the flow through the fracture) depends on the effective normal stress acting on the fracture plane and given by:

$$\sigma_n' = \sigma_n - p \tag{1}$$

where σ_n' is the effective normal stress; σ_n is the total normal stress; p is the fluid pressure inside the fracture. It is assumed in Eq. (1) that the Biot effective stress coefficient for the fracture deformation is equal to one, which is a common assumption for fractures in geomechanics. When the effective normal stress increases, either due to an increase in the *in-situ* horizontal stress or due to a reduction in the fluid pressure, the fracture closes, and its permeability decreases. Conversely, when the effective normal stress decreases, e.g. due to a fluid pressure increase caused by fluid injection or due to a reduction in the *in-situ* horizontal stresses, the fracture opens up, and its permeability increases. The decrease in the permeability in the former case and the increase in the latter are typically nonlinear: it takes more effort to close the fracture as its aperture becomes smaller since more asperities come into contact, and the normal stiffness of the fracture increases.

Consider a vertical fracture (a "joint") penetrating the cap rock from the reservoir to an upper aquifer. In reality, it can be an isolated fracture, a fracture network or a pre-existing fault. For the sake of simplicity, the case of an isolated fracture is considered in this study. During CO_2 injection, the fluid pressure front might eventually reach the fracture, and the fluid pressure in the fracture will increase. This will induce the flow (of CO_2 or brine) in the fracture in the vertical direction unless the fracture is completely closed and thus has zero permeability (this may happen e.g. if the fracture is filled with gouge or is mineralized). At the same time, the fracture might start opening as the pressure increases along the fracture height. This will increase the fracture permeability. Therefore, we are dealing here with a two-way coupled problem: The fracture aperture affects the fluid flow, and the fluid pressure affects the fracture aperture. The coupling strength depends on the fracture properties, in particular the normal stiffness.

As the CO_2 injection proceeds, the horizontal *in-situ* stresses in the cap rock may eventually decrease. This will further increase the fracture permeability and thus the leakage rate.

Fractures may have different orientation. Even in the same fracture set, the fracture orientations may slightly vary. Thus, the normal stress acting on each vertical fracture is different unless the horizontal *in-situ* stresses are isotropic. Moreover, different normal stresses may act on different parts of the same fracture if the fracture surface is not a perfect plane. These considerations suggest that the total normal stress plays a crucial role in determining the fracture permeability.

The objective of this study was to investigate the effect of a single vertical fracture in the cap rock on the integrity of a CO_2 storage site. To this end, we construct a simple semi-analytical model in Section 2 that can be used to estimate the leakage flow rate as a function of the reservoir pressure. The model is then applied to demonstrate the effect of *in-situ* stresses on the leakage flow rate in Section 3. The paper concludes with a discussion and recommendations on CO_2 storage site selection and pressure management that would take into account geomechanical effects and stress-dependent fracture permeability.

2. Semi-analytical model of leakage through a vertical fracture

The geometry of the model is shown in Fig. 2. The fracture height and length are equal to H and L, respectively. The fracture width is equal to w and can be different at different vertical locations. However, the fracture width is assumed to be the same at all points located at the same depth, i.e. at a given z.

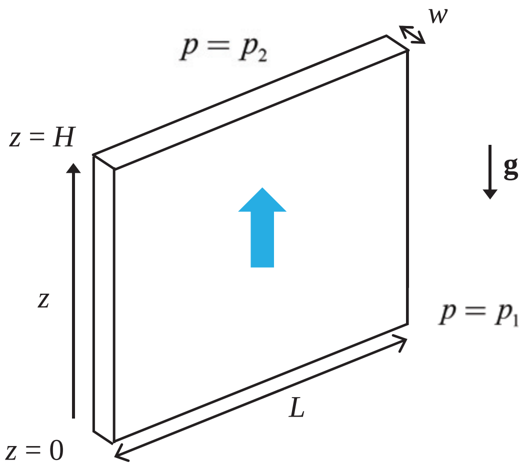


Fig. 2. Geometry of the vertical fracture in the cap rock. Blue arrow indicates the direction of flow (upwards). Fracture width, height, and horizontal length are denoted by w, H, and L, respectively.

There are many correlations between the normal stress and the fracture permeability available in the literature. For instance, the following correlation was reported for shale in ref. [8]:

$$k = k_0 \exp\left(-C'\sigma_n'\right) \tag{2}$$

where C' is a fitting parameter, equal to e.g. 0.27 for Kimmeridge shale [8]; k_0 is the permeability of a fracture at zero effective normal stress. Two examples of k *vs.* σ_n' dependency are shown in Fig. 3 for two different values of C'.

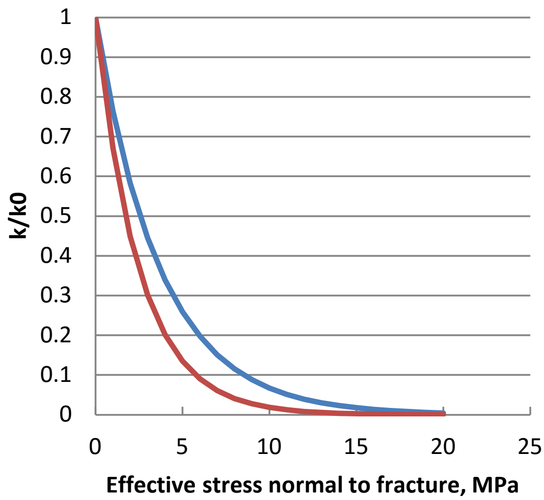


Fig. 3. Fracture permeability *vs*. effective normal stress for C' = 0.27 (blue) and C' = 0.4 (red), according to Eq. (2).

Assuming single-phase flow (e.g. CO_2 dissolved in brine), the superficial fluid velocity in the fracture along the vertical direction is given by:

$$v = -\frac{w^2}{12\mu}\frac{d}{dz}\left(p + \rho_f g z\right) \tag{3}$$

where ρ_f and μ are the density and the dynamic viscosity of the fluid, respectively; g is the acceleration of gravity; z is the vertical coordinate (Fig. 2). The aperture, w, in Eq. (3) should be hydraulic rather than mechanical aperture. In this model, we make no distinction between the two, thereby implying that the mechanical and hydraulic apertures are equal. Since the fracture is assumed to have the same aperture at all locations at a given z, the horizontal components of the superficial fluid velocity are equal to zero at all locations inside the fracture.

We assume that the fracture permeability can be approximated *locally* with Eq. (2). For a Newtonian fluid, the local fracture permeability is given by $w^2/12$. Thus, the aperture is given by:

$$w = w_0 \exp\left(-C'\sigma_n' / 2\right) \tag{4}$$

where w_0 is the aperture at zero effective normal stress. Assume that the horizontal *in-situ* stress acting normal to the fracture plane is a linear function of depth:

$$\sigma_n = \sigma_0 - \beta\rho_b g z \tag{5}$$

where σ_0 is the horizontal *in-situ* stress at the bottom of the fracture (z = 0); ρ_b is the bulk density of the rock; β is a dimensionless coefficient. In extensional tectonic regime, e.g. in stable intercontinental areas, β<1. In compressional stress environment, e.g. in tectonically active areas, β>1. Substituting Eqs. (4) and (5) into Eq. (3) yields the following pressure equation for steady-state flow in the fracture:

$$\frac{dp}{dz} + \rho_f g = -\frac{12\mu Q}{L w_0^3} \exp\left[C\left(\sigma_0 - \beta\rho_b g z - p\right)\right] \tag{6}$$

where Q is the flow rate through the fracture (m^3/s), and $C = 3C'/2$.

After introducing dimensionless pressure, flow rate, z-coordinate, σ_0, rock bulk weight, and fluid bulk weight as follows:

$$\begin{aligned} \tilde{p} &= \frac{p}{\rho_f g H}\ , \\ \tilde{Q} &= \frac{12\mu Q}{L\rho_f g w_0^3}\ , \\ \tilde{z} &= z/H\ , \\ \tilde{\sigma}_0 &= C\sigma_0\ , \\ \tilde{\gamma}_b &= C\beta\rho_b g H\ , \\ \tilde{\gamma}_f &= C\rho_f g H\ , \end{aligned} \tag{7}$$

the pressure equation reduces to:

$$\frac{d\tilde{p}}{d\tilde{z}} + \tilde{Q}\exp\left(\tilde{\sigma}_0 - \tilde{\gamma}_b\tilde{z} - \tilde{\gamma}_f\tilde{p}\right) + 1 = 0 \tag{8}$$

As a boundary condition, we specify pressure, p_2, at the top of the fracture (Fig. 2):

$$\tilde{p} = \tilde{p}_2 \quad \text{at} \quad \tilde{z} = 1 \tag{9}$$

3. Effect of *in-situ* stresses on leakage flow rate

We now perform computations for different flow rates, Q, and different *in-situ* stress values at the fracture bottom, σ_0. The dimensional input parameters for the simulations are listed in Table 1. Dimensionless parameters derived from Table 1 using Eqs. (7) are listed in Table 2. Table 2 demonstrates how the number of parameters has been reduced by non-dimensionalization.

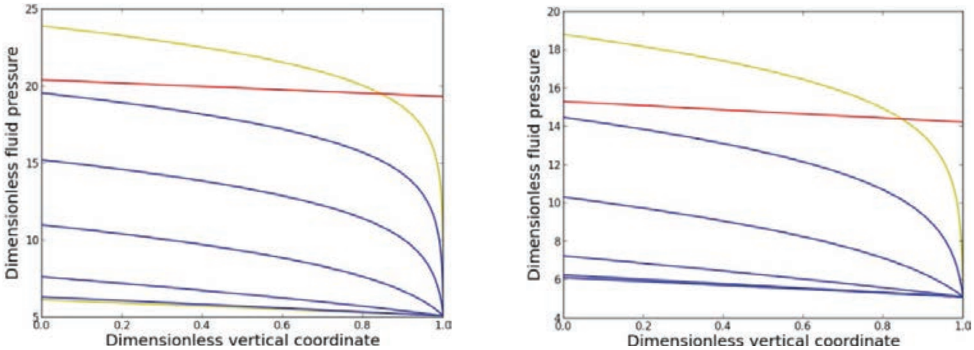
Eq. (8) with the boundary condition given by Eq. (9) was solved numerically using the spatial discretization step $\Delta\tilde{z} = 10^{-4}$. Computations were performed for a wide range of flow rates and for two values of the *in-situ* stress at the fracture bottom (see Tables 1 and 2).

The results in form of pressure curves at different flow rates are presented in Figure 4 for two values of the dimensionless horizontal *in-situ* stress: $\tilde{\sigma}_0 = 10.8$ (Figure 4a) and $\tilde{\sigma}_0 = 8.1$ (Figure 4b). The red lines in Figure 4 represent the fracture reopening pressure. Fracture reopening occurs when the fluid pressure in the fracture is equal to the total normal stress, $p = \sigma_n$. In dimensionless parameters, the fracture reopening is thus given by:

$$\tilde{p} = \frac{\tilde{\sigma}_0 - \tilde{\gamma}_b \tilde{z}}{\tilde{\gamma}_f} \tag{10}$$

As evident from Figure 4, the pressure stays below the fracture reopening pressure at all flow rates except the highest one.

Flow rate through the fracture increases nonlinearly with the fluid pressure applied at the fracture bottom. This nonlinearity is a combined result of two mechanisms: the nonlinear fracture deformation law [Eq. (4)] and the "cubic law" describing the dependency of the flow rate on the local fracture aperture [Eq. (3)]. According to Eq. (4), the fracture aperture increases faster as the effective stress becomes smaller, i.e. as the pressure increases and the fracture opens up. According to the "cubic law" [9, 10], the flow rate is proportional to w^3 [*cf*. Eq. (3)]. Thus, both mechanisms result in the flow rate increasing more rapidly as the pressure in the reservoir builds up.



a *b*

Fig. 4. Dimensionless fluid pressure in the fracture as a function of depth at different leakage rates. The red line shows the fracture reopening pressure. The top yellow line corresponds to $\tilde{Q} = 12.2$. The bottom yellow curve corresponds to $\tilde{Q} = 1.22 \cdot 10^{-5}$. The blue curves correspond, in ascending order, to $\tilde{Q} = 1.22 \cdot 10^{-4}$, $1.22 \cdot 10^{-3}$, $1.22 \cdot 10^{-2}$, $1.22 \cdot 10^{-1}$, 1.22 . The dimensionless horizontal *in-situ* total stress, $\tilde{\sigma}_0$, is equal to 10.8 (a) or 8.1 (b). The bottom yellow line is indistinguishable from the bottom blue line in (b).

Table 1. Dimensional input parameters for semi-analytical simulations.

Dimensional parameter	Value
C, Pa^{-1}	$0.27 \cdot 10^{-6}$
β	0.4
ρ_b, kg/m^3	2700
ρ_f, kg/m^3	1000
g, m/s^2	9.8
H, m	200
L, m	100
μ, Pa·s	0.001
w_0, m	0.001

p_2, Pa	$10 \cdot 10^6$
σ_0, Pa	$40 \cdot 10^6$; $30 \cdot 10^6$
Q, m^3/s	10^{-6}..1

Table 2. Dimensionless input parameters for semi-analytical simulations; based on Table 1 and Eqs. (7).

Dimensionless parameter	Value
$\tilde{\gamma}_b = C\beta\rho_b gH$	0.572
$\tilde{\gamma}_f = C\rho_f gH$	0.529
$\tilde{p}_2 = p_2 / (\rho_f gH)$	5.102
$\tilde{Q} = 12\mu Q / (L\rho_f g w_0^3)$	$1.22 \cdot 10^{-5}$..12.2
$\tilde{\sigma}_0 = C\sigma_0$	10.8; 8.1

4. Discussion and conclusion

The semi-analytical model constructed in Section 2 is a simple and fast computational tool that enables risk assessment of leakage through a vertical fracture in the cap rock caused by pressure increase in the reservoir. Computations presented in Section 3 demonstrate that the nonlinear fracture deformation may lead to a rapid increase of the fracture permeability and thus the leakage rate when the fluid pressure front propagates upwards in the fracture. It is therefore important to characterize fractures present or suspected in the cap rock. *In-situ* investigation of fracture properties at CO_2 storage sites is, in practice, difficult or impossible. Numerical simulations of fracture deformation and flow under stress can therefore be used, as explicated in another recent publication from the MiReCOL project, ref. [11].

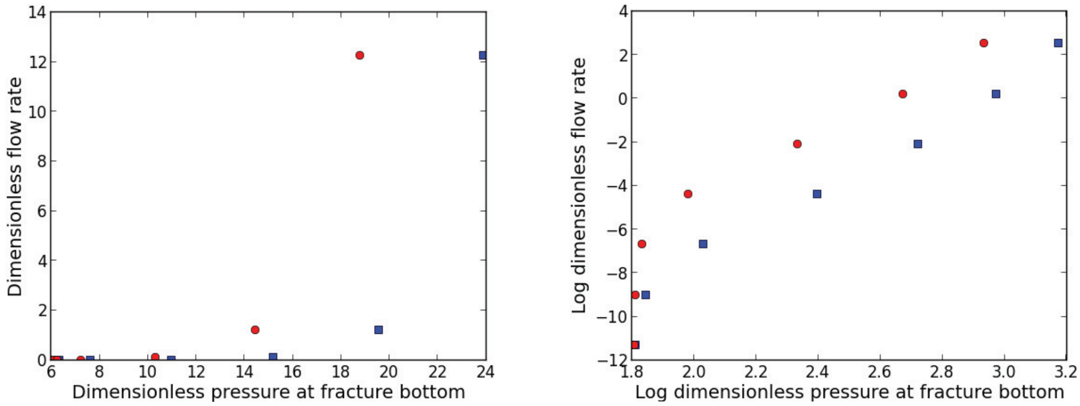


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Fig. 5. Dimensionless flow rate through the fracture as a function of fluid pressure at the bottom of the fracture (the "reservoir pressure") for $\tilde{\sigma}_0 = 10.8$ (blue squares) and $\tilde{\sigma}_0 = 8.1$ (red circles) in linear-linear (a) and log-log (b) coordinates.

The *in-situ* stress normal to fracture is or paramount importance for predicting leakage through vertical fractures, as Fig. 5 shows. Therefore, *in-situ* stress measurements are crucial for risk assessment of leakage in CO_2 storage sites. Such measurements can be performed by means of extended leakoff tests, breakout analysis, deformation rate analysis, etc. Fractures can have different orientations in the cap rock. The fractures normal to the minimum horizontal stress have the lowest reopening pressure and thus are most prone to leakage, other parameters being equal.

The variation of the fracture reopening pressure with the fracture orientation lead recently one of the authors to introduce two new concepts in drilling-related geomechanics: the *spectrum* of fracture reopening pressures and the *spectrum* of lost-circulation pressures [12, 13]. These are to replace the commonly used (e.g., in drilling) *fracture reopening pressure* and *lost-circulation pressure*. The analyses presented in this paper demonstrate that the knowledge of the fracture reopening pressure spectrum is essential for leakage risk assessment in CO_2 storage projects, too.

Nonlinearity of the leakage rate as a function of the reservoir pressure evident in Figure 5 suggests that the role of monitoring becomes even more important as the injection proceeds. Increasing the reservoir pressure by 1 bar at a later stage of injection is likely to have a larger impact on the leakage risk than the same increase at the beginning of injection.

The semi-analytical model of leakage through a vertical fracture in the cap rock developed in this study allows a quick estimation of the leakage potential without the need for a complicated and time-consuming coupled reservoir simulation. The model enables first-order estimates of the leakage rate. Based on this initial assessment, more detailed, site-specific numerical models (e.g. coupled reservoir-geomechanical models) can be developed.

Such detailed coupled simulations are indeed required for assessment of long-term effects of CO_2 injection on the stress field and, thus, on the fracture permeability. Such effects are due to the *stress path*, i.e. the change of the total *in-situ* stresses in the reservoir and in the cap rock caused by the pore pressure variation in the reservoir [14]. During CO_2 injection, the total horizontal stresses in the reservoir increase, while the total horizontal stresses in the cap rock slightly decrease. This will increase the permeability of the vertical fractures penetrating the cap rock, as evident from Fig. 5 (compare the red and the blue data points).

The importance of fracture characterization in the cap rock of a CO_2 storage site is obvious from our analysis. Fracture properties are crucial for application of even the simplest models, such as the semi-analytical model introduced in Section 2. In particular, not only fracture permeabilities, but also fracture aperture, orientation, morphology, and stress-displacement behaviour should be characterized by field and laboratory measurements as accurately as possible. This will improve the overall risk assessment of CO_2 storage sites in both short-term and long-term perspectives.

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