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LONG-TERM THERMAL EFFECTS ON INJECTIVITY EVOLUTION DURING CO₂ STORAGE

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**ABSTRACT**

Carbon dioxide (CO\textsubscript{2}) is likely to reach the bottom of injection wells at a colder temperature than that of the storage formation, causing cooling of the rock. This cooling, together with overpressure, tends to open up fractures, which may enhance injectivity. We investigate cooling effects on injectivity enhancement by modeling the In Salah CO\textsubscript{2} storage site and a theoretical, long-term injection case. We use stress-dependent permeability functions that predict an increase in permeability as the effective stress acting normal to fractures decreases. Normal effective stress can decrease either due to overpressure or cooling. We calibrate our In Salah model, which includes a fracture zone perpendicular to the well, obtaining a good fitting with the injection pressure measured at KB-502 and the rapid CO\textsubscript{2} breakthrough that occurred at the observation well KB-5 located 2 km away from the injection well. CO\textsubscript{2} preferentially advances through the fracture zone, which becomes two orders of magnitude more permeable than the rest of the reservoir. Nevertheless, the effect of cooling on the long-term injectivity enhancement is limited in pressure dominated storage sites, like at In Salah, because most of the permeability enhancement is due to overpressure. However, thermal effects enhance injectivity in cooling dominated storage sites, which may decrease the injection pressure by 20 %, saving a significant amount of compression energy all over the duration of storage projects. Overall, our simulation results show that cooling has the potential to enhance injectivity in fractured reservoirs.

**Keywords:** cooling; fracture aperture; permeability increase; thermo-hydro-mechanical coupling
INTRODUCTION

Carbon dioxide (CO\textsubscript{2}) is likely to reach the bottom of the injection well at a colder temperature than that of the storage formation. This temperature difference occurs because CO\textsubscript{2} does not thermally equilibrate with the geothermal gradient, especially at high flow rates of injection (Paterson et al., 2008). For example, the temperature difference between the temperature at which CO\textsubscript{2} entered the storage formation and the rock was of 55 °C at Cranfield, Mississippi (Kim and Hosseini, 2014) and of 45 °C at In Salah, Algeria (Bissell et al., 2011). Despite these large temperature differences, thermal effects have received little attention and only a few studies deal with them (Han et al., 2010; Singh et al., 2011; Goodarzi et al., 2012, 2015; Fang et al., 2013; Bao et al., 2014; Vilarrasa, 2016; Vilarrasa and Rutqvist, 2017). In particular, the geomechanical effects of cold CO\textsubscript{2} injection on caprock stability have been investigated in a generic repository (Vilarrasa et al., 2013a; 2014; Kim and Hosseini, 2015) and at the In Salah storage site (Preisig and Prevost, 2011; Gor et al., 2013; Vilarrasa et al., 2015).

Apart from the significant temperature difference, a substantial overpressure (around 10 MPa) caused relevant thermo-hydro-mechanical coupled effects at the In Salah storage site (Gemmer et al., 2012; Verdon et al., 2013; White et al., 2014; Rutqvist et al., 2016). A ground uplift of around 5 mm/yr was measured on top of the three horizontal injection wells using satellite geodetic data (Vasco et al., 2008; Mathieson et al., 2009; Onuma and Okhawa, 2009). Simulation results showed that such ground uplift rate could be reproduced by considering pressure increase and volumetric expansion of both the injection zone and the overlying caprock (Rutqvist et al., 2010). This uplift rate would require the caprock permeability to be two orders of magnitude higher than the initially estimated value from core samples (Rutqvist et al., 2010). Furthermore, a double lobe uplift pattern appeared on top of KB-502 injection well, which was explained by the opening of a fracture zone at depth (Vasco et al., 2010). The opening of this fracture zone might
have induced some microseismic events (Oye et al., 2013), but no felt seismic event has been reported (IEA GHG, 2013; Stork et al., 2015; Verdon et al., 2015). A number of detailed analyses and modeling of this fracture zone opening and resulting surface uplift pattern have indicated that the fracture zone opening remained confined within the lowest few hundred meters of the 900 m thick caprock, so the overall sealing capacity of the caprock was not compromised (Vasco et al., 2010; Rinaldi and Rutqvist, 2013).

An event that deserves special attention is the CO₂ leakage that occurred through an existing well (KB-5), located 2 km away from the KB-502 injection well. After the leakage at KB-5 was detected around 2 years after injection started, the well was properly sealed to avoid further leakage (Ringrose et al., 2009). This rapid breakthrough probably occurred because of reservoir permeability enhancement caused by fracture opening as a result of overpressure and cooling induced by injection (Birkholzer et al., 2015). In a fractured reservoir, like that at In Salah, both overpressure, which expands fractures, and cooling, which contracts the matrix, open up fractures (de Simone et al., 2013) and thus, injectivity is expected to increase.

The aim of this study is to investigate the role of thermal contraction of the rock on permeability enhancement. To this end, we perform coupled thermo-hydro-mechanical simulations of cold CO₂ injection modeling the In Salah storage site. First, we analyze the cooling front advance in a fractured reservoir by modeling a single fracture surrounded by rock matrix. Next, we simulate injection at the In Salah storage site using an equivalent continuum model to account for fractures and considering reactivation and opening of the fracture zone, providing a preferential flow path for the injected CO₂. In particular, we calibrate our model to reproduce the injection pressure measured at KB-502 and the CO₂ breakthrough at the observation well KB-5. Finally, we study the role of induced thermal stresses on injectivity enhancement for both In Salah and a theoretical, long-term injection case.
METHODS

Thermo-hydro-mechanical mathematical model

We consider both CO$_2$ injection in thermal equilibrium with the storage formation and injection of CO$_2$ that is colder than the storage formation. Injection of cold CO$_2$ in a deep confined saline formation induces coupled thermo-hydro-mechanical processes that may affect reservoir injectivity. Thus, mass conservation of each phase, energy balance and momentum balance have to be solved to account for these couplings. Mass conservation of these two partially miscible fluids can be written as (Bear, 1972)

$$\frac{\partial (q_{\alpha} S_{\alpha} \rho_{\alpha})}{\partial t} + \nabla \cdot (\rho_{\alpha} q_{\alpha}) = r_{\alpha}, \quad \alpha = c, w,$$

(1)

where $\phi$ [L$^3$ L$^{-3}$] is porosity, $S_{\alpha}$ [-] is saturation of the $\alpha$-phase, $\rho_{\alpha}$ [M L$^{-3}$] is density of the $\alpha$-phase, $t$ [T] is time, $q_{\alpha}$ [L$^3$ L$^{-2}$ T$^{-1}$] is the volumetric flux, $r_{\alpha}$ [M L$^{-3}$ T$^{-1}$] is the phase change term (i.e., CO$_2$ dissolution into water and water evaporation into CO$_2$) (Spycher and Pruess, 2005) and $\alpha$ is either CO$_2$-rich phase, $c$, or aqueous phase, $w$.

Momentum conservation for the CO$_2$-rich and the aqueous phases is given by Darcy’s law

$$q_{\alpha} = -\frac{KK_{\alpha}}{\mu_{\alpha}} (\nabla P_{\alpha} + \rho_{\alpha} g \nabla z), \quad \alpha = c, w,$$

(2)

where $\kappa$ [L$^2$] is intrinsic permeability, $K_{\alpha}$ [-] is the $\alpha$-phase relative permeability, $\mu_{\alpha}$ [M L$^{-1}$ T$^{-1}$] is viscosity of $\alpha$-phase, $P_{\alpha}$ [M L$^{-1}$ T$^{-2}$] is the $\alpha$-phase pressure, $g$ [L T$^{-2}$] is gravity and $z$ [L] is the vertical coordinate.

Energy conservation can be written as (e.g., Nield and Bejan, 2006)

$$\frac{\partial ((1-\phi) \rho_h h + \phi \rho_w S_w h + \phi \rho_c S_c h)}{\partial t} - \phi S_r \frac{DP}{Dt} + \nabla \cdot (-k \nabla T + \rho_w h_w q_w + \rho_c h_c q_c) = 0,$$

(3)
where $\rho_s$ [M L$^{-3}$] is solid density, $h_\alpha$ [L$^2$ T$^{-2}$] is enthalpy of $\alpha$-phase ($\alpha = c, w, s$; $s$ for solid), $\lambda$ [M L T$^{-3}$ $\Theta$] is thermal conductivity of the geological media and $T$ [$\Theta$] is temperature. We assume thermal equilibrium of all phases at every point.

Neglecting inertial terms, the momentum balance of the solid phase is reduced to the equilibrium of stresses

$$\nabla \cdot \sigma + b = 0, \quad (4)$$

where $\sigma$ [M L$^{-1}$ T$^{-2}$] is the stress tensor and $b$ [M L$^{-2}$ T$^{-2}$] is the body forces vector.

We assume linear thermoelasticity in porous media to include the effect of changes in fluid pressure and temperature on rock strain. Elastic strain is a function of total stress, overpressure and temperature (Segall and Fitzgerald, 1998),

$$\varepsilon = \frac{1}{2G} \sigma - \left( \frac{1}{2G} - \frac{1}{3K} \right) \sigma_m \mathbf{I} - \frac{1}{3K} \Delta P \mathbf{I} - \alpha_r \Delta T \mathbf{I}, \quad (5)$$

where $\varepsilon$ [L L$^{-1}$] is the strain tensor, $\sigma_m = tr(\sigma)$ [M L$^{-1}$ T$^{-2}$] is the mean stress, $tr(\sigma)$ [M L$^{-1}$ T$^{-2}$] is the trace of the stress tensor, $\mathbf{I}$ [ ] is the identity matrix, $P$ [M L$^{-1}$ T$^{-2}$] is fluid pressure, $K = E/(3(1-2\nu))$ [M L$^{-1}$ T$^{-2}$] is the bulk modulus, $G = E/(2(1+\nu))$ [M L$^{-1}$ T$^{-2}$] is the shear modulus, $E$ [M L$^{-1}$ T$^{-2}$] is the Young’s modulus, $\nu$ [ ] is Poisson ratio and $\alpha_r$ [$\Theta^{-1}$] is the linear thermal expansion coefficient of the porous medium. We adopt the sign criterion of geomechanics, i.e., stress and strain are positive in compression and negative in extension.

The volumetric strain, $\varepsilon_v$ [L L$^{-1}$], reads

$$\varepsilon_v = \frac{\sigma'_m}{K} - 3\alpha_r \Delta T, \quad (6)$$

where $\sigma'_m$ [M L$^{-1}$ T$^{-2}$] is the mean effective stress. Combining Equations (5) and (6), the effective stress, $\sigma'$ [M L$^{-1}$ T$^{-2}$], changes yield
\[ \sigma' = K \varepsilon I + 2G \left( \varepsilon - \frac{\varepsilon^2}{3} I \right) + 3K \alpha_\gamma \Delta T I . \] (7)

These effective stress changes induce changes in fracture aperture and consequently, in permeability and capillarity (Rutqvist et al., 2002; Rutqvist, 2015).

**Stress-dependent permeability**

We assume that fracture aperture depends on the normal effective stress acting on the fracture according to an exponential relation (Liu et al., 2013; Liu and Rutqvist, 2013). We adopt the conceptual model initially proposed by Liu et al. (2009), which divides fractured geological media into a soft and a hard part. The soft part represents the response of a medium to small stress, and it follows a “natural” or “true” strain formulation in Hooke’s law. The hard part represents the rock response to large stress, following a so-called “engineering” strain relationship for the Hooke’s law. Liu et al. (2013) verified this model by comparison to experimental data on fracture closure as a function of stress. Liu and Rutqvist (2013) extended such formulation to a dual continuum model (i.e., accounting for fractures and rock matrix, both represented with soft and hard part). Assuming that most deformation occurs at cracks or fractures and that it is poorly affected at large stress, together with the assumption that the cubic law holds valid (Witherspoon et al., 1980), permeability change can then be evaluated accounting for the initial state of stress as (Rinaldi et al., 2014a)

\[ \frac{\kappa_{hm}}{\kappa_i} = \left( \frac{b}{b_i} \right)^3 \left( \frac{x_{n_i}^0 + x_{n_i}^f + x_{n_i}^f}{x_{n_i}^0 + x_{n_i}^f + x_{n_i}^f} \right)^3 , \] (8)

where \( b \) [L] and \( b_i \) [L] are the current and initial fracture apertures, respectively, and \( \kappa_{hm} \) [L\(^2\)] and \( \kappa_i \) [L\(^2\)] are the permeability at the current and initial stress state, respectively. \( K_{nf} \) [M L\(^{-1}\) T\(^{-2}\)] refers to the bulk modulus of the reservoir fractures, and \( \sigma_{nf} \) [M L\(^{-1}\) T\(^{-2}\)] and \( \sigma_{nf,i} \) [M
L^{-1} \ T^{-2}] are the current and initial normal effective stress acting on the fracture, respectively (Rinaldi et al., 2014a). $\gamma_e [L^3 \ L^{-3}]$ and $\gamma_t [L^3 \ L^{-3}]$ represent the unstressed volume fraction for the hard and soft parts of a body rock, respectively (Liu and Rutqvist, 2013).

We further assume permeability changes due to fracture zone reactivation. In comparison to the fix permeability increase proposed by Rinaldi et al. (2016), here if fracture reactivation occurs, the permeability may follow a similar stress-dependent permeability curve as that of Equation (8), but with different $K_{zf}, \gamma_e$, and $\gamma_t$ (Figure 1). To calculate fracture reactivation, we consider the Mohr-Coulomb failure criterion, which in terms of the maximum, $\sigma'_1 [M \ L^{-1} \ T^{-2}]$, and minimum, $\sigma'_3 [M \ L^{-1} \ T^{-2}]$, principal effective stresses reads

$$ f = \sigma'_1 - \frac{1 + \sin \phi}{1 - \sin \phi} \sigma'_3, \quad (9) $$

where $\phi [-]$ is the friction angle. If reactivation occurs, i.e., $f = 0$, permeability is enhanced (Figure 1).

**Modeling of In Salah, Algeria**

**Fracture model**

We firstly model non-isothermal two-phase flow, with no mechanical coupling, in a single fracture (Figure 2) in order to analyze the effect of fractures on the fluid pressure and temperature distributions. Such model is needed to assess the validity (i.e., if the pressure and temperature distributions could be affected by preferential flow through fractures) of a porous media model that does not explicitly include fractures. Due to symmetry, the model includes half of the fracture and half of the rock matrix between two consecutive fractures. We consider two models, one for the minimum spacing of 0.2 m (the model is 0.1 m wide) and another one for the maximum spacing of 1.0 m (the model is 0.5 m wide) of the fracture spacing at In Salah (Iding and Ringrose, 2010). We consider that the aperture of the fracture equals $10^{-3}$ m, which is within
the range of fracture aperture at In Salah (Iding and Ringrose, 2010). The length of the model is 500 m. We impose a constant pressure and temperature at the boundaries coinciding with the injection well and at the outer boundary. While we prescribe the pressure at 30 MPa and the temperature at 50 °C at the injection well, we maintain the initial conditions at the outer boundary, i.e., a pressure of 18 MPa and a temperature of 95 °C. Table 1 includes the hydro-thermal properties of the fracture and the rock matrix. The capillary functions of the rock matrix fit the retention curve and relative permeability curves measurements performed on the reservoir rock of In Salah, which were presented by Shi et al. (2012).

**In Salah model**

Then, to investigate the effect of cold CO$_2$ injection on injectivity, we model the injection of CO$_2$ through well KB-502 at In Salah, Algeria. Since we aim to study how thermo-hydro-mechanical effects induce changes in injectivity, we focus on the storage formation. We model a 2D horizontal section of the storage formation under plane strain conditions, which is representative of the central section of the storage formation. The model extends 76x76 km$^2$, with open flow boundary conditions and no displacement perpendicular to the outer boundaries (Figure 3). The model includes a fracture zone that extends 3500 m in the direction perpendicular to the injection well and that has a width of 80 m (Figure 3) (Rinaldi and Rutqvist, 2013; Rucci et al., 2013). Injection induced pressure inflation and opening of this fracture zone caused the double lobe uplift observed on the surface at In Salah (Vasco et al., 2010) and is thought to have enabled the rapid CO$_2$ breakthrough observed at well KB-5 (Ringrose et al., 2009). The initial fluid pressure is 18.0 MPa, the temperature 95 °C, the vertical stress is 40.5 MPa, the maximum horizontal stress is 45.5 MPa (perpendicular to the horizontal injection well) and the minimum horizontal stress is 28.6 MPa (parallel to the well) (Morris et al., 2011). Injection takes places in a 1000 m injection well, which is centered in the model. The injection rate closely follows the actual
injection rate of 0.3 Mt/yr at KB-502 (Rinaldi and Rutqvist, 2013). CO₂ is injected 45 °C colder than the storage formation, which corresponds to the actual injection temperature at In Salah (Bissell et al., 2011).

The storage formation at In Salah is characterized by a set of fractures perpendicular to the minimum principal stress, i.e., perpendicular to the horizontal injection well (Iding and Ringrose, 2010). The fracture aperture has been estimated to range from 10^{-4} m to 10^{-3} m and the spacing from 0.2 m to 1.0 m (Iding and Ringrose, 2010). Our reservoir model includes these data in the calculation of the permeability (Equation (8)), but fractures are not explicitly included in the model.

We consider that the higher fracture density within the fracture zone yields a lower stiffness and a higher permeability. To determine the material properties of both the fracture zone and the rest of the reservoir, we calibrate the model to fit the temporal evolution of bottomhole pressure at KB-502 and the breakthrough of CO₂ after about 2 years from the beginning of injection at point P6. P6 is placed 2 km away from the well and around 100 m away from the center of the fracture zone (see Figure 3), which corresponds to the approximate position of well KB-5 at In Salah.

**In Salah model calibration**

Since no real measurements of the bottomhole pressure were carried out during active operation, we calculate the bottomhole pressure from the wellhead pressure and the injection rate measurements by using the code T2Well (Pan et al., 2011). Given the uncertainties in this calculation, we assume that an error of 2 MPa on the computed pressure may exist. The parameters that are calibrated are the (i) initial permeability, (ii) the parameter $K_{t,f}$, (iii) the volume fractions $\gamma_e$ and $\gamma_t$, and (iv) the friction angle for both the reservoir and fracture zone. The volume fraction of the hard part of the body rock $\gamma_e$ is assumed to change from 0.01 to 0.2647 and the volume fraction of the soft part of the body rock $\gamma_t$ from 0.7353 to 0.999, with the
restriction that \( \gamma_e + \gamma_r = 1 \). For the calibration, real measurement of injection rates at In Salah were used as input for the model (Rinaldi et al., 2016).

The model is calibrated by matching the pressure at the KB-502 injection well and by obtaining CO\(_2\) breakthrough at well KB-5 around 2 years after the start of injection. Data matching is performed with the code iTOUGH2-PEST with TOUGH-FLAC (Rinaldi et al., 2015a; 2016). This approach takes advantage of the iTOUGH2 capabilities (Finsterle, 2004) for inverse analysis of a forward model through the PEST protocol (Finsterle and Zhang, 2011). Coupled fluid flow and geomechanics simulations are carried out using TOUGH-FLAC (Rutqvist, 2011). TOUGH-FLAC combines the multiphase, multicomponent fluid flow and heat transport simulator TOUGH2 (Pruess et al., 2011) and the geomechanical simulator FLAC\(^3\)D (ITASCA, 2009). TOUGH2 uses in these simulations the equation of state ECO\(_2\)N, which accounts for mixtures of water, NaCl and CO\(_2\), as well as dissolution of CO\(_2\) into water (Pruess, 2005). TOUGH-FLAC has been applied to several problems of CO\(_2\) injection in deep saline formation implying deformation and two-phase flow under isothermal (e.g., Rinaldi et al., 2014b, 2015b) and non-isothermal conditions (Rutqvist et al., 2011).

**Modeling of thermal effects for In Salah reservoir**

Once the model is calibrated for the initial injection period, which lasted for around 2 years, at injection well KB-502 at In Salah, we perform generic simulations to study the hypothetical thermal effects that could have occurred for a long-term CO\(_2\) injection at a constant mass flow rate of 0.3 Mt/yr maintained during 30 years. This injection rate is similar to the one injected at In Salah and induces a fluid pressure that is very close to fracturing conditions through the entire injection period. We run a base case using the same properties as the calibrated model, injecting CO\(_2\) at 50 °C. Then, to investigate the effect of thermo-mechanical induced stresses (the third term on the right-hand side of Equation (7)) on injectivity, we run a case in isothermal
conditions. Furthermore, since induced thermal stresses are proportional to the stiffness of the rock, we run two additional simulations of CO$_2$ injection at 50 °C, in which the stiffness of the fracture zone is increased by a factor of 5 and 10.

Modeling of thermal effect for a generic, high permeable reservoir

Finally, we model a case with a homogeneous high reservoir permeability ($\kappa = 10^{-13}$ m$^2$ in the fracture zone and the rest of the reservoir) and with a Young’s modulus equal to 10 GPa in the whole model, so that pressure buildup is low and the changes in injectivity are induced mainly by cooling.

RESULTS

Fracture model

Figure 4 shows the temperature distribution with distance to the injection well after 3 days of CO$_2$ injection at 50 °C in a model that includes one fracture and 0.5 m of rock matrix. The temperature profile and temperature front shows a negligible difference between the fracture and the rock matrix. In spite of the fact that CO$_2$ advances slightly more rapidly through the fracture due to its higher permeability, the relatively high permeability of the rock matrix allows homogenizing the cooling front and there is no preferential advance through the fracture. This homogeneous front is observed for the models that consider a fracture spacing of 0.2 m and 1.0 m. For the model with smaller fracture spacing, i.e., 0.2 m, no temperature difference is observed in the direction perpendicular to the fracture. For the model with larger fracture spacing, i.e., 1.0 m, a slight difference of 0.01 °C is observed between the temperature at the fracture and the temperature at a midpoint between two fractures, i.e., 0.5 m away from the fracture inside the rock matrix. This verification validates the assumption of modeling the reservoir at In Salah,
which is fractured with fractures perpendicular to the injection well, as an equivalent porous media in which fractures do not need to be explicitly included in the model.

**In Salah reservoir model calibration**

Figure 5 shows the simulated pressure resulting from the calibration of CO$_2$ injection at well KB-502 at In Salah. We achieved a reasonable fit during active injection phase, with a bottomhole pressure that follows the measured pressure evolution. Nevertheless, pressure drop is lower in our model than in the measurements after shut-in, which is likely due to the fact that our injection well model does not account for the vertical part of the well, so it does not simulate processes such as phase transition that may occur after shut-in. Thus, the error of the computed bottomhole pressure from the wellhead pressure measurements may entail a larger error after shut-in than during the injection phase, which could explain the mismatch. Table 2 lists the calibrated parameters and their values.

To reproduce not only the pressure evolution, but also the CO$_2$ breakthrough at well KB-5 (point P6 in our model), the resulting permeability within the fracture zone is much larger than in the rest of the reservoir. Figure 6 displays the stress-dependent permeability functions of both the fracture zone and the rest of the reservoir, including the permeability enhancement upon fracture reactivation. Fault or fracture zone reactivation may cause shear slip of numerous fractures, which open up due to shear dilatancy, and thereby enhance the overall fracture zone permeability (Yeo et al., 1998; Mallikamas and Rajaram, 2005; Vilarrasa et al., 2011; Rutqvist, 2015). The permeability evolution at points P1 to P4 (see Figure 3 for the location of the points) is also plotted. Permeability increases as the effective stress normal to the fractures decreases as a result of overpressure and cooling. Permeability increases up to two orders of magnitude in the fracture zone, reaching values as high as $10^{-11}$ m$^2$. In contrast, the permeability in the rest of the reservoir increases up to $2\cdot10^{-14}$ m$^2$, i.e., just by a factor of three, which is in accordance with previous
estimates of permeability increase at In Salah (Rinaldi and Rutqvist, 2013; Liu and Rutqvist, 2013).

This permeability contrast between the fracture zone and the rest of the reservoir causes a preferential advance of CO$_2$ through the fracture zone (Figure 7b). The CO$_2$ plume reaches point P3 (located 250 m away from the injection well inside the fracture zone) in 1 month and point P5 (located 2500 m away from the injection well inside the fracture zone) in around 1 year (Figure 5c). This rapid advance of the CO$_2$ plume within the fracture zone results in CO$_2$ breakthrough at well KB-5 2.3 years after the start of injection. The time of the breakthrough is within the temporal scale at which CO$_2$ breakthrough was observed in the field (Ringrose et al., 2009). In contrast, CO$_2$ advances much slower outside the fracture zone. Actually, CO$_2$ does not reach point P2, which is placed only 250 m away from the injection well outside the fracture zone.

Figure 5 shows that the cooling front advances much behind than the CO$_2$ front. Due to the limited advance of CO$_2$ outside of the fracture zone, cooling is small in this region (see the slight decrease in temperature that occurs in point P2, which is located just 10 m away from the injection well). The higher permeability of the fracture zone permits a larger advance of the cooling front, not only in extension, but also in magnitude. Figure 7c displays the spatial distribution of temperature after 2 years of injection, showing that it mainly advances through the fracture zone, but significantly behind the CO$_2$ front (Figure 7b). Figure 7c also shows a zone of slightly increased temperature that coincides with the CO$_2$ plume. This small temperature increase, which is lower than 1 ºC, is due to CO$_2$ dissolution into the brine.

**Thermal effects on injectivity at In Salah**

Figure 8 shows the evolution of the liquid saturation at several points when injecting CO$_2$ at 50 ºC for 30 years using the same material properties as in the calibrated model. Simulation results indicate a rapid desaturation of the whole fracture zone. Actually, CO$_2$ reaches the limit of the
fracture zone (point P5) in half a year. For a continuous CO$_2$ injection rate of 0.3 Mt/yr, CO$_2$ breakthrough at point P6, which corresponds to the location of well KB-5, occurs after 1.36 years from the start of injection. In contrast, CO$_2$ advances much slower in the rest of the reservoir. CO$_2$ reaches point P4, which is placed 250 m away from the injection well outside the fracture zone, after 3.2 years. CO$_2$ saturation remains practically constant at every point in the longer-term, until the end of the injection at 30 years.

Figure 9 displays the temperature evolution at the same points as in Figure 8 when injecting CO$_2$ at 50 °C for 30 years. Cooling takes place rapidly within the fracture zone. Point P1, which is the closest observation point to the injection well, quickly reacts to the cold injection, with a temperature decrease of about 20 °C in less than one year. After this rapid temperature drop, the reactivation of the fracture zone enhances its permeability, reducing fluid pressure, which induces an incoming flow of warmer fluid from the surrounding rock that causes a little increase in temperature at about 1 year, only to keep decreasing as the cold injection continues (Figure 8, blue solid line). Point P3, placed 250 m away from the injection well inside the fracture zone, starts to cool down after around 0.3 years and progressively cools down for 20 years, when the injection temperature is almost reached. The cooling front reaches the limit of the fracture zone (point P5), placed 2.5 km away from the injection well, after around 6 years. However, far away from the injection well, the magnitude of the cooling is smaller than around the injection well. On the other hand, outside of the fracture zone, cooling is limited to the vicinity of the injection well. For example, temperature drops only 5 °C at point P2, which is located 10 m away from the injection well.

This calculated distribution of cooling indicates that, around well KB-502 at In Salah, thermomechanical effects may be restricted mainly to the fracture zone and therefore have little effect on the rest of the reservoir. Table 3 quantifies, at point P3, placed 250 m away from the injection
well in the fracture zone, the maximum change in the effective stress normal to fractures, which are oriented perpendicular to the well for all the considered cases. This include the base case with the material parameters calibrated against CO₂ injection at well KB-502, an isothermal case, and two cases with a stiffer fracture zone. Additionally, Table 3 includes the ratio of the maximum permeability reached during injection to the initial permeability and the maximum overpressure. The smallest change in the effective stress normal to the fractures occurs in the isothermal case. The smaller the changes in effective stress normal to the fractures, the less the fractures open. Thus, under isothermal conditions, the permeability increase is the smallest and therefore, overpressure is the highest. In contrast, for a cold injection, the changes in effective stress normal to the fractures become larger due to more substantial cooling-induced stresses. As a result, permeability increases more, enhancing injectivity and inducing a lower overpressure. Increasing the stiffness of the fracture zone has the effect of increasing the cooling-induced normal stress reduction, resulting then in a larger permeability ratio and smaller overpressure.

In the cases analyzed here, the injection pressure is high and rapidly reaches the fracturing conditions. Hence, given the small differences in normal stress changes, the effect of cooling-induced stresses is not very large in magnitude because fractures reactivate at the early stage of injection, which causes stress redistribution that limits the effect of the induced cooling stress reduction.

**Thermal effects on injectivity at a generic reservoir**

On the other hand, for the cases in which overpressure is low, i.e., in the homogeneous high permeability models, the effective stress reduction normal to the fractures is initially low and thus, fracture reactivation does not occur due to pressure buildup. However, the effective stress normal to the fractures subsequently decreases due to the induced thermal stresses in the region affected by cooling. As a result, for cooling dominated (instead of pressure dominated) injection
scenarios, permeability enhancement due to cooling can be of a factor of three (Figure 10). Note that reactivation, and thus permeability enhancement, only occurs for the case in which CO₂ is injected cold. This permeability enhancement has a clear effect on the required injection pressure to inject a prescribed CO₂ mass flow rate.

Figure 11 displays the overpressure evolution at the injection well and in the reservoir 10 m away from the well for CO₂ injection in thermal equilibrium with the storage formation and at 45 °C colder than the storage formation. In the reservoir, overpressure is similar despite the higher permeability induced by cooling (Figure 11b). However, the difference becomes significant in the injection well (Figure 11a). Initially, injection pressure builds up slightly more rapidly for the case of cold CO₂ injection due to the higher viscosity of CO₂ for decreasing temperatures. However, after 50 days, the induced thermal stresses are high enough to induce fracture reactivation (Figure 12), which enhances permeability (recall Figure 10). As a result, injection pressure drops more than 1 MPa, which represents around a 20 % of the overpressure. Thus, cold CO₂ injection in cooling dominated injection cases leads to an injectivity enhancement that may give rise to a significant reduction of the injection pressure.
DISCUSSION AND CONCLUSIONS

We have calibrated a model of In Salah using the injection data of well KB-502 and the breakthrough time of CO₂ at the well KB-5, obtaining a good fitting. We included a fracture zone perpendicular to the well that caused the double lobe uplift pattern on the ground surface and through which CO₂ rapidly advances, leading to the rapid breakthrough at KB-5. We use a stress-dependent permeability function that predicts an increase in permeability as the effective stress acting normal to the fracture zone decreases. Normal effective stress can decrease either due to overpressure or cooling. Furthermore, we assume that the stress-dependent permeability function can jump to a more permeable function upon reactivation of the fracture zone.

The presence of the fracture zone has a great influence on the CO₂ plume and cooling front evolution (Figure 7). CO₂ preferentially advances through the fracture zone, which becomes two orders of magnitude more permeable than the rest of the reservoir (Figure 6). The slower flow through the reservoir outside of the fracture zone is due to its lower permeability, but more importantly, due to the fact that most of the CO₂ is injected through the fracture zone. Actually, flow rate is not uniformly distributed along wells and will tend to preferentially enter into the storage formation through the zones with the lowest resistance to flow (Rinaldi and Rutqvist, 2013; Vilarrasa et al., 2013b; Chen et al., 2014). This preferential flow also restricts the cooling advance to the fracture zone, which causes a positive feedback for preferential flow as permeability in the fracture zone will be enhanced by cooling. On the other hand, since zones with higher permeability may have a higher fracture density than less permeable zones, the higher fracture density may lead to a softer rock and therefore, induced thermal stresses may become relatively small. However, the temperature difference in CO₂ storage projects may be large (recall the 45 °C difference at In Salah or the 55 °C difference at Cranfield), so even for
relatively soft rocks, which may have Young’s modulus in the order of 1 GPa, the induced thermal stresses may still become significant.

To assess the effect of cooling on injectivity, we perform long-term simulations injecting CO₂ at 50 °C at a constant mass flow rate of 0.3 Mt/yr during 30 years. In these simulations, in which we use the calibrated material parameters, pressure buildup is high and approaches the fracturing pressure. We compared cold CO₂ with a case of CO₂ injection in thermal equilibrium with the storage formation, and two extra cases in which we consider a stiffer fracture zone. Simulation results indicate that cooling has the potential to increase injectivity. However, due to the high injection pressure at In Salah, which was close to the fracturing pressure and even exceeded it within the reservoir at some periods of time (Rutqvist, 2012; Oye et al., 2013), fracture reactivation mainly happened due to overpressure. Thus, the effect of cooling was limited in the pressure dominated simulations.

On the other hand, cooling has a larger effect on injectivity when overpressure is low. Since cooling causes a thermal stress reduction, large temperature differences and/or stiff rocks may lead to large effective stress reduction that could yield shear failure conditions. In such cases, permeability would be enhanced, especially in the direction perpendicular to shear, due to the roughness of fractures (Yeo et al., 1998; Mallikamas and Rajaram, 2005; Vilarrasa et al., 2011; Rutqvist, 2015). The increase in injectivity induced by cooling may decrease the injection pressure by 20 % (Figure 11). Data from several injection sites will be required to generalize the actual amount of injectivity increase induced by cooling, but this study suggests that there is potential to save a significant amount of compression energy all over the duration of injection projects. Similar observations of injectivity enhancement have been observed in fractured geothermal reservoirs as a result of strong cooling (e.g., Koh et al., 2011; Jeanne et al., 2015).
Overall, our simulation results show that cooling has the potential to enhance injectivity in fractured reservoirs. While in pressure dominated storage sites, like In Salah, most of the permeability enhancement will be due to overpressure, thermal effects will enhance injectivity in cooling dominated storage sites. Cooling dominated injection scenarios are most likely to occur than pressure dominated ones because regulators will, in most cases, limit overpressure below the fracturing pressure to avoid damaging the caprock sealing capacity. Coupled thermo-hydro-mechanical studies should be performed case specifically to assess caprock stability. If the induced thermal stresses do not compromise the caprock integrity and sealing capacity, cooling will be beneficial for CO₂ storage purposes due to the induced permeability and injectivity enhancement.

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TABLES

Table 1. Properties of the rocks considered in the fracture model of In Salah, Algeria.

<table>
<thead>
<tr>
<th>Property</th>
<th>Fracture</th>
<th>Rock matrix</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intrinsic permeability, $k$ (m$^2$)</td>
<td>$10^{-12}$</td>
<td>$1.3 \cdot 10^{-14}$</td>
</tr>
<tr>
<td>Relative water permeability, $k_{rw}$ (-)</td>
<td>$S_u^3$</td>
<td>$S_u^{5.25}$</td>
</tr>
<tr>
<td>Relative CO$<em>2$ permeability, $k</em>{rc}$ (-)</td>
<td>$S_i^3$</td>
<td>$S_i^{3.5}$</td>
</tr>
<tr>
<td>Gas entry pressure, $p_0$ (MPa)</td>
<td>0.01</td>
<td>0.1</td>
</tr>
<tr>
<td>van Genuchten shape parameter $m$ (-)</td>
<td>0.8</td>
<td>0.7</td>
</tr>
<tr>
<td>Residual liquid saturation, $S_w$ (-)</td>
<td>0.05</td>
<td>0.31</td>
</tr>
<tr>
<td>Porosity (-)</td>
<td>0.5</td>
<td>0.17</td>
</tr>
<tr>
<td>Thermal conductivity of geologic media, $\lambda$ (W/m/K)</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>Solid specific heat capacity, $c_p$ (J/kg/K)</td>
<td>900</td>
<td>900</td>
</tr>
<tr>
<td>Bulk thermal expansion coefficient, $\alpha_T$ ($^\circ$C$^{-1}$)</td>
<td>$10^{-5}$</td>
<td>$10^{-5}$</td>
</tr>
</tbody>
</table>
Table 2. Properties of the calibrated reservoir model of In Salah, Algeria. The first and second values of volume fractions correspond to before and after reactivation, respectively (note that $\gamma_e + \gamma_t = 1$.

<table>
<thead>
<tr>
<th>Property</th>
<th>Rock</th>
<th>Fracture zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial intrinsic permeability, $k$ (m$^2$)</td>
<td>$10^{-14.09\pm0.13} (8.1\cdot10^{-15})$</td>
<td>$10^{-13.0\pm0.2} (9.5\cdot10^{-14})$</td>
</tr>
<tr>
<td>Bulk modulus reservoir fractures, $K_{ef}$ (MPa)</td>
<td>3.5$\pm1.2$</td>
<td>3.1$\pm1.4$</td>
</tr>
<tr>
<td>Hard unstressed volume fraction, $\gamma_e$ (-)</td>
<td>0.2647 – 0.2</td>
<td>0.2647 – 0.001</td>
</tr>
<tr>
<td>Soft unstressed volume fraction, $\gamma_t$ (-)</td>
<td>0.7353 – 0.8</td>
<td>0.7353 – 0.999</td>
</tr>
<tr>
<td>Friction angle, $\phi$ (-)</td>
<td>26.6 $\pm1.2$</td>
<td>28$\pm1.3$</td>
</tr>
<tr>
<td>Young’s modulus, $E$ (GPa)</td>
<td>10</td>
<td>1</td>
</tr>
<tr>
<td>Poisson ratio, $\nu$ (-)</td>
<td>0.3</td>
<td>0.3</td>
</tr>
</tbody>
</table>
Table 3. Maximum change in the effective stress normal to the fractures at In Salah, $\Delta \sigma'_n$, ratio of the maximum permeability to the initial permeability, $\kappa_{\text{max}} / \kappa_i$, and the maximum overpressure, $\Delta P$, reached during injection at points P3 (250 m away from the injection well inside the fracture zone), for all the considered cases.

<table>
<thead>
<tr>
<th>Case</th>
<th>$\Delta \sigma'_n$ (MPa)</th>
<th>$\kappa_{\text{max}} / \kappa_i$ (-)</th>
<th>$\Delta P$ (MPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>-6.50</td>
<td>582</td>
<td>11.46</td>
</tr>
<tr>
<td>Isothermal</td>
<td>-6.41</td>
<td>533</td>
<td>11.53</td>
</tr>
<tr>
<td>Stiffer fracture zone (factor 5)</td>
<td>-6.74</td>
<td>735</td>
<td>11.42</td>
</tr>
<tr>
<td>Stiffer fracture zone (factor 10)</td>
<td>-6.80</td>
<td>783</td>
<td>11.41</td>
</tr>
</tbody>
</table>
Figure 1. Stress-dependent permeability functions, including permeability changes upon fracture reactivation.
Figure 2. Schematic representation of the model including half of a single fracture and the rock matrix between two adjacent fractures. Note that the fracture has been enlarged in order to visualize it.
Figure 3. (a) Schematic representation of the model setup, including initial and boundary conditions of the reservoir model around the KB-502 injection horizontal well (red line) at In Salah and (b) position of the monitoring points used in the model. P6 corresponds to the approximate position of vertical well KB-5.
Figure 4. Temperature distribution after 3 days of injection in the model considering a single fracture and the rock matrix around the fracture. The temperature front has a negligible difference between the fracture and the rock matrix, so the modeling of the In Salah reservoir, which is fractured, as an equivalent porous media is valid.
Figure 5. (a) Resulting pressure for the calibrated model compared to measured bottomhole pressure at KB-502 injection well. (b) Temperature and (c) liquid saturation at the six monitoring points as a function of time. While solid lines represent monitoring points within the fracture zone, dashed lines correspond to monitoring points in the reservoir (Figure 3). The cyan dotted line is the KB-5 monitoring point.
Figure 6. Stress-dependent permeability functions of the fracture zone and the rest of the reservoir, including the permeability enhancement upon fracture reactivation. The permeability evolution with time of points P1 to P3 is also indicated as the effective stress normal to fractures decreases due to overpressure and cooling.
Figure 7. (a) Pressure, (b) liquid saturation and (c) temperature distribution after 2 years of cold CO$_2$ injection.
Figure 8. Liquid saturation evolution for CO₂ injection at 50 °C during 30 years at several observation points. While solid lines represent monitoring points within the fracture zone, dashed lines correspond to monitoring points in the reservoir (Figure 3). The cyan dotted line is the KB-5 monitoring point.
Figure 9. Temperature evolution at several observation points when injecting CO$_2$ at 50 °C during 30 years. While solid lines represent monitoring points within the fracture zone, dashed lines correspond to monitoring points in the reservoir (Figure 3). The cyan dotted line is the KB-5 monitoring point.
Figure 10. Stress-dependent permeability functions of the high permeable homogeneous models when injecting CO$_2$ at 50 °C and at 95 °C during 30 years at observation point P1.
Figure 11. Overpressure evolution (a) at the injection well at point P0 and (b) at point P1 for CO₂ injection 45 °C colder than the storage formation (blue line) and in thermal equilibrium with the storage formation (red line) in a high permeable homogeneous reservoir. The sharp drop in overpressure when injecting cold CO₂ is due to permeability and injectivity enhancement induced by thermal stress reduction.
Figure 12. Minimum effective stress evolution at point P1 for CO₂ injection 45 ºC colder than the storage formation and in thermal equilibrium with the storage formation in a high permeable homogeneous reservoir. The difference between the two effective stresses is the induced thermal stress, which is proportional to the temperature reduction indicated for the case of the cold CO₂ injection.