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**LONG-TERM THERMAL EFFECTS ON INJECTIVITY EVOLUTION
DURING CO₂ STORAGE**

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23 **ABSTRACT**

24 Carbon dioxide (CO₂) is likely to reach the bottom of injection wells at a colder temperature than
25 that of the storage formation, causing cooling of the rock. This cooling, together with
26 overpressure, tends to open up fractures, which may enhance injectivity. We investigate cooling
27 effects on injectivity enhancement by modeling the In Salah CO₂ storage site and a theoretical,
28 long-term injection case. We use stress-dependent permeability functions that predict an increase
29 in permeability as the effective stress acting normal to fractures decreases. Normal effective
30 stress can decrease either due to overpressure or cooling. We calibrate our In Salah model, which
31 includes a fracture zone perpendicular to the well, obtaining a good fitting with the injection
32 pressure measured at KB-502 and the rapid CO₂ breakthrough that occurred at the observation
33 well KB-5 located 2 km away from the injection well. CO₂ preferentially advances through the
34 fracture zone, which becomes two orders of magnitude more permeable than the rest of the
35 reservoir. Nevertheless, the effect of cooling on the long-term injectivity enhancement is limited
36 in pressure dominated storage sites, like at In Salah, because most of the permeability
37 enhancement is due to overpressure. However, thermal effects enhance injectivity in cooling
38 dominated storage sites, which may decrease the injection pressure by 20 %, saving a significant
39 amount of compression energy all over the duration of storage projects. Overall, our simulation
40 results show that cooling has the potential to enhance injectivity in fractured reservoirs.

41

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

43

44

45 **INTRODUCTION**

46 Carbon dioxide (CO₂) is likely to reach the bottom of the injection well at a colder temperature
47 than that of the storage formation. This temperature difference occurs because CO₂ does not

48thermally equilibrate with the geothermal gradient, especially at high flow rates of injection
49(Paterson et al., 2008). For example, the temperature difference between the temperature at
50which CO₂ entered the storage formation and the rock was of 55 °C at Cranfield, Mississippi
51(Kim and Hosseini, 2014) and of 45 °C at In Salah, Algeria (Bissell et al., 2011). Despite these
52large temperature differences, thermal effects have received little attention and only a few studies
53deal with them (Han et al., 2010; Singh et al., 2011; Goodarzi et al., 2012, 2015; Fang et al.,
542013; Bao et al., 2014; Vilarrasa, 2016; Vilarrasa and Rutqvist, 2017). In particular, the
55geomechanical effects of cold CO₂ injection on caprock stability have been investigated in a
56generic repository (Vilarrasa et al., 2013a; 2014; Kim and Hosseini, 2015) and at the In Salah
57storage site (Preisig and Prevost, 2011; Gor et al., 2013; Vilarrasa et al., 2015).

58Apart from the significant temperature difference, a substantial overpressure (around 10 MPa)
59caused relevant thermo-hydro-mechanical coupled effects at the In Salah storage site (Gemmer et
60al., 2012; Verdon et al., 2013; White et al., 2014; Rutqvist et al., 2016). A ground uplift of around
615 mm/yr was measured on top of the three horizontal injection wells using satellite geodetic data
62(Vasco et al., 2008; Mathieson et al., 2009; Onuma and Okhawa, 2009). Simulation results
63showed that such ground uplift rate could be reproduced by considering pressure increase and
64volumetric expansion of both the injection zone and the overlying caprock (Rutqvist et al.,
652010). This uplift rate would require the caprock permeability to be two orders of magnitude
66higher than the initially estimated value from core samples (Rutqvist et al., 2010). Furthermore, a
67double lobe uplift pattern appeared on top of KB-502 injection well, which was explained by the
68opening of a fracture zone at depth (Vasco et al., 2010). The opening of this fracture zone might
69have induced some microseismic events (Oye et al., 2013), but no felt seismic event has been
70reported (IEAGHG, 2013; Stork et al., 2015; Verdon et al., 2015). A number of detailed analyses
71and modeling of this fracture zone opening and resulting surface uplift pattern have indicated

72that the fracture zone opening remained confined within the lowest few hundred meters of the
73900 m thick caprock, so the overall sealing capacity of the caprock was not compromised (Vasco
74et al., 2010; Rinaldi and Rutqvist, 2013).

75An event that deserves special attention is the CO₂ leakage that occurred through an existing well
76(KB-5), located 2 km away from the KB-502 injection well. After the leakage at KB-5 was
77detected around 2 years after injection started, the well was properly sealed to avoid further
78leakage (Ringrose et al., 2009). This rapid breakthrough probably occurred because of reservoir
79permeability enhancement caused by fracture opening as a result of overpressure and cooling
80induced by injection (Birkholzer et al., 2015). In a fractured reservoir, like that at In Salah, both
81overpressure, which expands fractures, and cooling, which contracts the matrix, open up
82fractures (de Simone et al., 2013) and thus, injectivity is expected to increase.

83The aim of this study is to investigate the role of thermal contraction of the rock on permeability
84enhancement. To this end, we perform coupled thermo-hydro-mechanical simulations of cold
85CO₂ injection modeling the In Salah storage site. First, we analyze the cooling front advance in a
86fractured reservoir by modeling a single fracture surrounded by rock matrix. Next, we simulate
87injection at the In Salah storage site using an equivalent continuum model to account for
88fractures and considering reactivation and opening of the fracture zone, providing a preferential
89flow path for the injected CO₂. In particular, we calibrate our model to reproduce the injection
90pressure measured at KB-502 and the CO₂ breakthrough at the observation well KB-5. Finally,
91we study the role of induced thermal stresses on injectivity enhancement for both In Salah and a
92theoretical, long-term injection case.

93

94 **METHODS**

95 **Thermo-hydro-mechanical mathematical model**

96 We consider both CO₂ injection in thermal equilibrium with the storage formation and injection
97 of CO₂ that is colder than the storage formation. Injection of cold CO₂ in a deep confined saline
98 formation induces coupled thermo-hydro-mechanical processes that may affect reservoir
99 injectivity. Thus, mass conservation of each phase, energy balance and momentum balance have
100 to be solved to account for these couplings. Mass conservation of these two partially miscible
101 fluids can be written as (Bear, 1972)

$$102 \frac{\partial(\phi S_{\alpha} \rho_{\alpha})}{\partial t} + \nabla \cdot (\rho_{\alpha} \mathbf{q}_{\alpha}) = r_{\alpha}, \quad \alpha = c, w, \quad (1)$$

103 where ϕ [L³ L⁻³] is porosity, S_{α} [-] is saturation of the α -phase, ρ_{α} [M L⁻³] is density of the α -
104 phase, t [T] is time, $\mathbf{q}_{\alpha}$ [L³ L⁻² T⁻¹] is the volumetric flux, r_{α} [M L⁻³ T⁻¹] is the phase change term
105 (i.e., CO₂ dissolution into water and water evaporation into CO₂) (Spycher and Pruess, 2005) and
106 α is either CO₂-rich phase, c , or aqueous phase, w .

107 Momentum conservation for the CO₂-rich and the aqueous phases is given by Darcy's law

$$108 \mathbf{q}_{\alpha} = - \frac{\kappa \kappa_{r\alpha}}{\mu_{\alpha}} (\nabla P_{\alpha} + \rho_{\alpha} g \nabla z), \quad \alpha = c, w, \quad (2)$$

109 where κ [L²] is intrinsic permeability, $\kappa_{r\alpha}$ [-] is the α -phase relative permeability, μ_{α} [M L⁻¹ T⁻¹]
110¹] is viscosity of α -phase, P_{α} [M L⁻¹ T⁻²] is the α -phase pressure, g [L T⁻²] is gravity and z [L]
111 is the vertical coordinate.

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

$$113 \frac{\partial((1-\phi)\rho_s h_s + \phi\rho_w S_w h_w + \phi\rho_c S_c h_c)}{\partial t} - \phi S_c \frac{DP_c}{Dt} + \nabla \cdot (-\lambda \nabla T + \rho_w h_w \mathbf{q}_w + \rho_c h_c \mathbf{q}_c) = 0, \quad (3)$$

where ρ_s [M L⁻³] is solid density, h_α [L² T⁻²] is enthalpy of α -phase ($\alpha = c, w, s$; s for solid),
 λ [M L T⁻³ Θ] is thermal conductivity of the geological media and T [Θ] 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

$$\nabla \cdot \boldsymbol{\sigma} + \mathbf{b} = \mathbf{0}, \quad (4)$$

where $\boldsymbol{\sigma}$ [M L⁻¹ T⁻²] is the stress tensor and $\mathbf{b}$ [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),

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

where $\boldsymbol{\varepsilon}$ [L L⁻¹] is the strain tensor, $\sigma_m = \text{tr}(\boldsymbol{\sigma})/3$ [M L⁻¹ T⁻²] is the mean stress, $\text{tr}(\boldsymbol{\sigma})$ [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, ν [-] is Poisson ratio and α_T [Θ^{-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, ε_v [L L⁻¹], reads

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

where σ'_m [M L⁻¹ T⁻²] is the mean effective stress. Combining Equations (5) and (6), the effective
 stress, $\boldsymbol{\sigma}'$ [M L⁻¹ T⁻²], changes yield

$$\sigma' = K\varepsilon_v \mathbf{I} + 2G \mathbf{e} - \frac{\varepsilon_v}{3} \mathbf{I} + 3K\alpha_T \Delta T \mathbf{I}. \quad (7)$$

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)

$$\frac{\kappa_{hm}}{\kappa_i} = \left(\frac{b}{b_i} \right)^3 = \left(\frac{\gamma_s + \gamma_t e^{\frac{\sigma'_{n,i}}{K_{t,f}}}}{\gamma_s + \gamma_t e^{\frac{\sigma'_{n,i}}{K_{t,f}}}} \right)^3, \quad (8)$$

where b [L] and b_i [L] are the current and initial fracture apertures, respectively, and

κ_{hm} [L²] and κ_i [L²] are the permeability at the current and initial stress state, respectively. $K_{t,f}$

155 $[M L^{-1} T^{-2}]$ refers to the bulk modulus of the reservoir fractures, and $\sigma'_n [M L^{-1} T^{-2}]$ and $\sigma'_{n,i} [M$
156 $L^{-1} T^{-2}]$ are the current and initial normal effective stress acting on the fracture, respectively
157 (Rinaldi et al., 2014a). $\gamma_e [L^3 L^{-3}]$ and $\gamma_t [L^3 L^{-3}]$ represent the unstressed volume fraction for the
158 hard and soft parts of a body rock, respectively (Liu and Rutqvist, 2013).

159 We further assume permeability changes due to fracture zone reactivation. In comparison to the
160 fix permeability increase proposed by Rinaldi et al. (2016), here if fracture reactivation occurs,
161 the permeability may follow a similar stress-dependent permeability curve as that of Equation
162 (8), but with different K_{tf} , γ_e , and γ_t (Figure 1). To calculate fracture reactivation, we consider the
163 Mohr-Coulomb failure criterion, which in terms of the maximum, $\sigma'_1 [M L^{-1} T^{-2}]$, and minimum,
164 $\sigma'_3 [M L^{-1} T^{-2}]$, principal effective stresses reads

$$165 f = \sigma'_1 - \frac{1 + \sin \varphi}{1 - \sin \varphi} \sigma'_3, \quad (9)$$

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

168 **Modeling of In Salah, Algeria**

169 Fracture model

170 We firstly model non-isothermal two-phase flow, with no mechanical coupling, in a single
171 fracture (Figure 2) in order to analyze the effect of fractures on the fluid pressure and
172 temperature distributions. Such model is needed to assess the validity (i.e., if the pressure and
173 temperature distributions could be affected by preferential flow through fractures) of a porous
174 media model that does not explicitly include fractures. Due to symmetry, the model includes half
175 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 CO₂ injection on injectivity, we model the injection of CO₂ 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 km², 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 CO₂ 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

200stress is 45.5 MPa (perpendicular to the horizontal injection well) and the minimum horizontal
201stress is 28.6 MPa (parallel to the well) (Morris et al., 2011). Injection takes place in a 1000 m
202injection well, which is centered in the model. The injection rate closely follows the actual
203injection rate of 0.3 Mt/yr at KB-502 (Rinaldi and Rutqvist, 2013). CO₂ is injected 45 °C colder
204than the storage formation, which corresponds to the actual injection temperature at In Salah
205(Bissell et al., 2011).

206The storage formation at In Salah is characterized by a set of fractures perpendicular to the
207minimum principal stress, i.e., perpendicular to the horizontal injection well (Iding and Ringrose,
2082010). The fracture aperture has been estimated to range from 10⁻⁴ m to 10⁻³ m and the spacing
209from 0.2 m to 1.0 m (Iding and Ringrose, 2010). Our reservoir model includes these data in the
210calculation of the permeability (Equation (8)), but fractures are not explicitly included in the
211model.

212We consider that the higher fracture density within the fracture zone yields a lower stiffness and
213a higher permeability. To determine the material properties of both the fracture zone and the rest
214of the reservoir, we calibrate the model to fit the temporal evolution of bottomhole pressure at
215KB-502 and the breakthrough of CO₂ after about 2 years from the beginning of injection at point
216P6. P6 is placed 2 km away from the well and around 100 m away from the center of the fracture
217zone (see Figure 3), which corresponds to the approximate position of well KB-5 at In Salah.

218In Salah model calibration

219Since no real measurements of the bottomhole pressure were carried out during active operation,
220we calculate the bottomhole pressure from the wellhead pressure and the injection rate
221measurements by using the code T2Well (Pan et al., 2011). Given the uncertainties in this
222calculation, we assume that an error of 2 MPa on the computed pressure may exist. The
223parameters that are calibrated are the (i) initial permeability, (ii) the parameter $K_{t,f}$, (iii) the

224 volume fractions γ_e and γ_t , and (iv) the friction angle for both the reservoir and fracture zone. The
225 volume fraction of the hard part of the body rock γ_e is assumed to change from 0.001 to 0.2647
226 and the volume fraction of the soft part of the body rock γ_t from 0.7353 to 0.999, with the
227 restriction that $\gamma_e + \gamma_t = 1$. For the calibration, real measurement of injection rates at In Salah
228 were used as input for the model (Rinaldi et al., 2016)

229 The model is calibrated by matching the pressure at the KB-502 injection well and by obtaining
230 CO₂ breakthrough at well KB-5 around 2 years after the start of injection. Data matching is
231 performed with the code iTOUGH2-PEST with TOUGH-FLAC (Rinaldi et al., 2015a; 2016).
232 This approach takes advantage of the iTOUGH2 capabilities (Finsterle, 2004) for inverse
233 analysis of a forward model through the PEST protocol (Finsterle and Zhang, 2011). Coupled
234 fluid flow and geomechanics simulations are carried out using TOUGH-FLAC (Rutqvist, 2011).
235 TOUGH-FLAC combines the multiphase, multicomponent fluid flow and heat transport
236 simulator TOUGH2 (Pruess et al., 2011) and the geomechanical simulator FLAC^{3D} (ITASCA,
237 2009). TOUGH2 uses in these simulations the equation of state ECO2N, which accounts for
238 mixtures of water, NaCl and CO₂, as well as dissolution of CO₂ into water (Pruess, 2005).
239 TOUGH-FLAC has been applied to several problems of CO₂ injection in deep saline formation
240 implying deformation and two-phase flow under isothermal (e.g., Rinaldi et al., 2014b, 2015b)
241 and non-isothermal conditions (Rutqvist et al., 2011).

242 Modeling of thermal effects for In Salah reservoir

243 Once the model is calibrated for the initial injection period, which lasted for around 2 years, at
244 injection well KB-502 at In Salah, we perform generic simulations to study the hypothetical
245 thermal effects that could have occurred for a long-term CO₂ injection at a constant mass flow
246 rate of 0.3 Mt/yr maintained during 30 years. This injection rate is similar to the one injected at

247In Salah and induces a fluid pressure that is very close to fracturing conditions through the entire
248injection period. We run a base case using the same properties as the calibrated model, injecting
249CO₂ at 50 °C. Then, to investigate the effect of thermo-mechanical induced stresses (the third
250term on the right-hand side of Equation (7)) on injectivity, we run a case in isothermal
251conditions. Furthermore, since induced thermal stresses are proportional to the stiffness of the
252rock, we run two additional simulations of CO₂ injection at 50 °C, in which the stiffness of the
253fracture zone is increased by a factor of 5 and 10.

254Modeling of thermal effect for a generic, high permeable reservoir

255Finally, we model a case with a homogeneous high reservoir permeability ($k = 10^{-13}$ m² in the
256fracture zone and the rest of the reservoir) and with a Young's modulus equal to 10 GPa in the
257whole model, so that pressure buildup is low and the changes in injectivity are induced mainly
258by cooling.

259

260RESULTS

261Fracture model

262Figure 4 shows the temperature distribution with distance to the injection well after 3 days of
263CO₂ injection at 50 °C in a model that includes one fracture and 0.5 m of rock matrix. The
264temperature profile and temperature front shows a negligible difference between the fracture and
265the rock matrix. In spite of the fact that CO₂ advances slightly more rapidly through the fracture
266due to its higher permeability, the relatively high permeability of the rock matrix allows
267homogenizing the cooling front and there is no preferential advance through the fracture. This
268homogeneous front is observed for the models that consider a fracture spacing of 0.2 m and 1.0

269m. For the model with smaller fracture spacing, i.e., 0.2 m, no temperature difference is observed
270in the direction perpendicular to the fracture. For the model with larger fracture spacing, i.e., 1.0
271m, a slight difference of 0.01 °C is observed between the temperature at the fracture and the
272temperature at a midpoint between two fractures, i.e., 0.5 m away from the fracture inside the
273rock matrix. This verification validates the assumption of modeling the reservoir at In Salah,
274which is fractured with fractures perpendicular to the injection well, as an equivalent porous
275media in which fractures do not need to be explicitly included in the model.

276In Salah reservoir model calibration

277Figure 5 shows the simulated pressure resulting from the calibration of CO₂ injection at well KB-
278502 at In Salah. We achieved a reasonable fit during active injection phase, with a bottomhole
279pressure that follows the measured pressure evolution. Nevertheless, pressure drop is lower in
280our model than in the measurements after shut-in, which is likely due to the fact that our
281injection well model does not account for the vertical part of the well, so it does not simulate
282processes such as phase transition that may occur after shut-in. Thus, the error of the computed
283bottomhole pressure from the wellhead pressure measurements may entail a larger error after
284shut-in than during the injection phase, which could explain the mismatch. Table 2 lists the
285calibrated parameters and their values.

286To reproduce not only the pressure evolution, but also the CO₂ breakthrough at well KB-5 (point
287P6 in our model), the resulting permeability within the fracture zone is much larger than in the
288rest of the reservoir. Figure 6 displays the stress-dependent permeability functions of both the
289fracture zone and the rest of the reservoir, including the permeability enhancement upon fracture
290reactivation. Fault or fracture zone reactivation may cause shear slip of numerous fractures,
291which open up due to shear dilatancy, and thereby enhance the overall fracture zone permeability
292(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 $2 \cdot 10^{-14} \text{ m}^2$, 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°C , is due to CO_2 dissolution into the brine.

318 **Thermal effects on injectivity at In Salah**

319 Figure 8 shows the evolution of the liquid saturation at several points when injecting CO₂ at 50
320 °C for 30 years using the same material properties as in the calibrated model. Simulation results
321 indicate a rapid desaturation of the whole fracture zone. Actually, CO₂ reaches the limit of the
322 fracture zone (point P5) in half a year. For a continuous CO₂ injection rate of 0.3 Mt/yr, CO₂
323 breakthrough at point P6, which corresponds to the location of well KB-5, occurs after 1.36 years
324 from the start of injection. In contrast, CO₂ advances much slower in the rest of the reservoir.
325 CO₂ reaches point P4, which is placed 250 m away from the injection well outside the fracture
326 zone, after 3.2 years. CO₂ saturation remains practically constant at every point in the longer-
327 term, until the end of the injection at 30 years.

328 Figure 9 displays the temperature evolution at the same points as in Figure 8 when injecting CO₂
329 at 50 °C for 30 years. Cooling takes place rapidly within the fracture zone. Point P1, which is the
330 closest observation point to the injection well, quickly reacts to the cold injection, with a
331 temperature decrease of about 20 °C in less than one year. After this rapid temperature drop, the
332 reactivation of the fracture zone enhances its permeability, reducing fluid pressure, which
333 induces an incoming flow of warmer fluid from the surrounding rock that causes a little increase
334 in temperature at about 1 year, only to keep decreasing as the cold injection continues (Figure 8,
335 blue solid line). Point P3, placed 250 m away from the injection well inside the fracture zone,
336 starts to cool down after around 0.3 years and progressively cools down for 20 years, when the
337 injection temperature is almost reached. The cooling front reaches the limit of the fracture zone
338 (point P5), placed 2.5 km away from the injection well, after around 6 years. However, far away
339 from the injection well, the magnitude of the cooling is smaller than around the injection well.
340 On the other hand, outside of the fracture zone, cooling is limited to the vicinity of the injection

341well. For example, temperature drops only 5 °C at point P2, which is located 10 m away from the
342injection well.

343This calculated distribution of cooling indicates that, around well KB-502 at In Salah, thermo-
344mechanical effects may be restricted mainly to the fracture zone and therefore have little effect
345on the rest of the reservoir. Table 3 quantifies, at point P3, placed 250 m away from the injection
346well in the fracture zone, the maximum change in the effective stress normal to fractures, which
347are oriented perpendicular to the well for all the considered cases. This include the base case with
348the material parameters calibrated against CO₂ injection at well KB-502, an isothermal case, and
349two cases with a stiffer fracture zone. Additionally, Table 3 includes the ratio of the maximum
350permeability reached during injection to the initial permeability and the maximum overpressure.
351The smallest change in the effective stress normal to the fractures occurs in the isothermal case.
352The smaller the changes in effective stress normal to the fractures, the less the fractures open.
353Thus, under isothermal conditions, the permeability increase is the smallest and therefore,
354overpressure is the highest. In contrast, for a cold injection, the changes in effective stress normal
355to the fractures become larger due to more substantial cooling-induced stresses. As a result,
356permeability increases more, enhancing injectivity and inducing a lower overpressure. Increasing
357the stiffness of the fracture zone has the effect of increasing the cooling-induced normal stress
358reduction, resulting then in a larger permeability ratio and smaller overpressure.

359In the cases analyzed here, the injection pressure is high and rapidly reaches the fracturing
360conditions. Hence, given the small differences in normal stress changes, the effect of cooling-
361induced stresses is not very large in magnitude because fractures reactivate at the early stage of
362injection, which causes stress redistribution that limits the effect of the induced cooling stress
363reduction.

364Thermal 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.

385

386 **DISCUSSION AND CONCLUSIONS**

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

396 The presence of the fracture zone has a great influence on the CO₂ plume and cooling front
397 evolution (Figure 7). CO₂ preferentially advances through the fracture zone, which becomes two
398 orders of magnitude more permeable than the rest of the reservoir (Figure 6). The slower flow
399 through the reservoir outside of the fracture zone is due to its lower permeability, but more
400 importantly, due to the fact that most of the CO₂ is injected through the fracture zone. Actually,
401 flow rate is not uniformly distributed along wells and will tend to preferentially enter into the
402 storage formation through the zones with the lowest resistance to flow (Rinaldi and Rutqvist,
403 2013; Vilarrasa et al., 2013b; Chen et al., 2014). This preferential flow also restricts the cooling
404 advance to the fracture zone, which causes a positive feedback for preferential flow as
405 permeability in the fracture zone will be enhanced by cooling. On the other hand, since zones
406 with higher permeability may have a higher fracture density than less permeable zones, the
407 higher fracture density may lead to a softer rock and therefore, induced thermal stresses may
408 become relatively small. However, the temperature difference in CO₂ storage projects may be
409 large (recall the 45 °C difference at In Salah or the 55 °C difference at Cranfield), so even for

410relatively soft rocks, which may have Young's modulus in the order of 1 GPa, the induced
411thermal stresses may still become significant.

412To assess the effect of cooling on injectivity, we perform long-term simulations injecting CO₂ at
41350 °C at a constant mass flow rate of 0.3 Mt/yr during 30 years. In these simulations, in which
414we use the calibrated material parameters, pressure buildup is high and approaches the fracturing
415pressure. We compared cold CO₂ with a case of CO₂ injection in thermal equilibrium with the
416storage formation, and two extra cases in which we consider a stiffer fracture zone. Simulation
417results indicate that cooling has the potential to increase injectivity. However, due to the high
418injection pressure at In Salah, which was close to the fracturing pressure and even exceeded it
419within the reservoir at some periods of time (Rutqvist, 2012; Oye et al., 2013), fracture
420reactivation mainly happened due to overpressure. Thus, the effect of cooling was limited in the
421pressure dominated simulations.

422On the other hand, cooling has a larger effect on injectivity when overpressure is low. Since
423cooling causes a thermal stress reduction, large temperature differences and/or stiff rocks may
424lead to large effective stress reduction that could yield shear failure conditions. In such cases,
425permeability would be enhanced, especially in the direction perpendicular to shear, due to the
426roughness of fractures (Yeo et al., 1998; Mallikamas and Rajaram, 2005; Vilarrasa et al., 2011;
427Rutqvist, 2015). The increase in injectivity induced by cooling may decrease the injection
428pressure by 20 % (Figure 11). Data from several injection sites will be required to generalize the
429actual amount of injectivity increase induced by cooling, but this study suggests that there is
430potential to save a significant amount of compression energy all over the duration of injection
431projects. Similar observations of injectivity enhancement have been observed in fractured
432geothermal 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.

443

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643**TABLES**

644

645Table 1. Properties of the rocks considered in the fracture model of In Salah, Algeria.

Property	Fracture	Rock matrix
Intrinsic permeability, k (m ²)	10^{-12}	$1.3 \cdot 10^{-14}$
Relative water permeability, k_{rw} (-)	S_w^3	$S_w^{5.25}$
Relative CO ₂ permeability, k_{rc} (-)	S_c^3	$S_c^{3.5}$
Gas entry pressure, p_0 (MPa)	0.01	0.1
van Genuchten shape parameter m (-)	0.8	0.7
Residual liquid saturation, S_{rw} (-)	0.05	0.31
Porosity (-)	0.5	0.17
Thermal conductivity of geologic media, λ (W/m/K)	2.0	2.0
Solid specific heat capacity, c_p (J/kg/K)	900	900
Bulk thermal expansion coefficient, α_T (°C ⁻¹)	10^{-5}	10^{-5}

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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 $\gamma_e + \gamma_t = 1$).

Property	Rock	Fracture zone
Initial intrinsic permeability, k (m ²)	$10^{-14.09 \pm 0.13}$ ($8.1 \cdot 10^{-15}$)	$10^{-13.0 \pm 0.2}$ ($9.5 \cdot 10^{-14}$)
Bulk modulus reservoir fractures, $K_{t,f}$ (MPa)	3.5 ± 1.2	3.1 ± 1.4
Hard unstressed volume fraction, γ_e (-)	$0.2647 - 0.2$	$0.2647 - 0.001$
Soft unstressed volume fraction, γ_t (-)	$0.7353 - 0.8$	$0.7353 - 0.999$
Friction angle, φ (-)	26.6 ± 1.2	28 ± 1.3
Young's modulus, E (GPa)	10	1
Poisson ratio, ν (-)	0.3	0.3

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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, $\kappa_{\max}/\kappa_i$, and the maximum overpressure, ΔP , reached during injection at points P3 (250 m away from the injection well inside the fracture zone), for all the considered cases.

Case	$\Delta\sigma'_n$ (MPa)	$\kappa_{\max}/\kappa_i$ (-)	ΔP (MPa)
Base case	-6.50	582	11.46
Isothermal	-6.41	533	11.53
Stiffer fracture zone (factor 5)	-6.74	735	11.42
Stiffer fracture zone (factor 10)	-6.80	783	11.41

689FIGURES

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692Figure 1. Stress-dependent permeability functions, including permeability changes upon fracture
693reactivation.

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699 Figure 2. Schematic representation of the model including half of a single fracture and the rock

700 matrix between two adjacent fractures. Note that the fracture has been enlarged in order to

701 visualize it.

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712 Figure 3. (a) Schematic representation of the model setup, including initial and boundary
713 conditions of the reservoir model around the KB-502 injection horizontal well (red line) at
714 In Salah and (b) position of the monitoring points used in the model. P6 corresponds to the
715 approximate position of vertical well KB-5.

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718Figure 4. Temperature distribution after 3 days of injection in the model considering a single
 719 fracture and the rock matrix around the fracture. The temperature front has a negligible
 720 difference between the fracture and the rock matrix, so the modeling of the In Salah
 721 reservoir, which is fractured, as an equivalent porous media is valid.

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724 Figure 5. (a) Resulting pressure for the calibrated model compared to measured bottomhole
 725 pressure at KB-502 injection well. (b) Temperature and (c) liquid saturation at the six
 726 monitoring points as a function of time. While solid lines represent monitoring points
 727 within the fracture zone, dashed lines correspond to monitoring points in the reservoir
 728 (Figure 3). The cyan dotted line is the KB-5 monitoring point.

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731 Figure 6. Stress-dependent permeability functions of the fracture zone and the rest of the
732 reservoir, including the permeability enhancement upon fracture reactivation. The
733 permeability evolution with time of points P1 to P3 is also indicated as the effective stress
734 normal to fractures decreases due to overpressure and cooling.

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737 Figure 7. (a) Pressure, (b) liquid saturation and (c) temperature distribution after 2 years of cold

738 CO₂ injection.

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743 Figure 8. Liquid saturation evolution for CO₂ injection at 50 °C during 30 years at several
 744 observation points. While solid lines represent monitoring points within the fracture zone,
 745 dashed lines correspond to monitoring points in the reservoir (Figure 3). The cyan dotted
 746 line is the KB-5 monitoring point.

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 749 Figure 9. Temperature evolution at several observation points when injecting CO₂ at 50 °C
 750 during 30 years. While solid lines represent monitoring points within the fracture zone,
 751 dashed lines correspond to monitoring points in the reservoir (Figure 3). The cyan dotted
 752 line is the KB-5 monitoring point.

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755 Figure 10. Stress-dependent permeability functions of the high permeable homogeneous models

756 when injecting CO₂ at 50 °C and at 95 °C during 30 years at observation point P1.

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761 Figure 11. Overpressure evolution (a) at the injection well at point P0 and (b) at point P1 for CO₂

762 injection 45 °C colder than the storage formation (blue line) and in thermal equilibrium

763 with the storage formation (red line) in a high permeable homogeneous reservoir. The

764 sharp drop in overpressure when injecting cold CO₂ is due to permeability and injectivity

765 enhancement induced by thermal stress reduction.

766

767

768 Figure 12. Minimum effective stress evolution at point P1 for CO₂ injection 45 °C colder than the
 769 storage formation and in thermal equilibrium with the storage formation in a high
 770 permeable homogeneous reservoir. The difference between the two effective stresses is the
 771 induced thermal stress, which is proportional to the temperature reduction indicated for the
 772 case of the cold CO₂ injection.