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# 1 **CO<sub>2</sub> Plume and Pressure Monitoring through Pressure Sensors above the** 2 **Caprock**

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## 8 **Abstract**

9 Commercial-scale development of CO<sub>2</sub> geological storage necessitates robust and real-time  
10 monitoring methods to track the injected CO<sub>2</sub> plume and provide assurance of CO<sub>2</sub> storage. Pressure  
11 monitoring above the injection zone is a method to detect potential CO<sub>2</sub> leaks into overlying  
12 formations. We present a generic CO<sub>2</sub> storage model with a single injector to predict pressure  
13 changes above the caprock due to both fast hydraulic communication and partially undrained loading,  
14 the latter often neglected in reservoir simulation. The simulation used a compositional simulator  
15 coupled with geomechanics to solve the poroelastic equations in the entire storage complex. The  
16 results show that changes of pore pressure above the caprock caused by partially undrained loading  
17 reach up to ~15 kPa within ~10 days followed by a gradual decay with time. This is about 1% of the  
18 pressure increase in the injection zone. Furthermore, the pressure changes above the caprock are  
19 closely related to the advance of the CO<sub>2</sub> plume. The results also include forward simulations  
20 considering the presence of: a fault either with high or low permeability, a poorly isolated abandoned  
21 well, a leaky injector, and a second injector. Fluid flow through high permeability paths across the  
22 caprock favors a ~one order of magnitude higher, yet more gradual pressure increase than the base  
23 case with a fully covering caprock. Pressure monitoring above the caprock is a feasible technology to

24 track the CO<sub>2</sub> plume, requires high precision pressure measurements, and must account for partially  
25 undrained poroelastic loading to interpret correctly measured pressure signals in the field.

26 **Keywords:** poroelasticity, CCUS, wellbore instrumentation, leaks, caprock integrity

## 27 1. Introduction

28 The successful development of carbon dioxide (CO<sub>2</sub>) geological storage necessitates robust and real-  
29 time monitoring methods to detect potential CO<sub>2</sub> leakage into overlying formations and provide  
30 assurance for permanent CO<sub>2</sub> trapping (Kim & Hosseini, 2015; Meckel et al., 2008). Most monitoring  
31 techniques are based on measurements on the surface and in the injection zone. On-surface  
32 monitoring (such as 4D seismic and InSAR mapping) can capture large geophysical features but is  
33 limited by high costs, laborious interpretation, difficulty to capture low CO<sub>2</sub> saturations, and a large  
34 attenuation of signals imposed by the overburden (Arts et al., 2004; Rutqvist et al., 2010). Monitoring  
35 in the injection zone (IZ) involves fluid sampling, rock analysis, and placement of sensors in the target  
36 formation, enables direct access to the zone of interest, and offers direct evidence for leak detection,  
37 but remains limited to a few observation wells and small sampling volumes (Ajo-Franklin et al., 2013;  
38 Hovorka et al., 2006; Zeidouni & Pooladi-Darvish, 2012b, 2012a).

39 Pressure monitoring above the injection zone (AIZ) is an alternative approach to monitor CO<sub>2</sub>  
40 injection and detect undesirable migration of fluids from the injection zone to overlying formations  
41 (Liebscher et al., 2013; Park et al., 2012; Wiese et al., 2013; Zhang et al., 2019). AIZ pressure  
42 monitoring can be done above the injection point but in the same storage formation, e.g. Decatur and  
43 Otway field cases (Bauer et al., 2016; Ennis-King et al., 2017), or above the caprock, e.g. Cranfield and  
44 Ketzin field cases (S. Hosseini et al., 2018; Wiese et al., 2013). AIZ pressure monitoring is relatively  
45 inexpensive, covers a wider area than the IZ monitoring, and has the potential to detect leaks into  
46 overlying formations if monitored above the caprock (S. Hosseini et al., 2018). This type of  
47 monitoring takes advantage of the pressure changes caused by injection with a pressure front moving

48 faster than the injected fluid (Rutqvist 2012). Significant work has been done to predict and identify  
49 leakages through abandoned wellbores due to direct hydraulic communication between the IZ and  
50 the AIZ through analytical models and numerical simulation (Cihan et al., 2013; González-Nicolás et  
51 al., 2015; Jung et al., 2013; Namhata et al., 2016; Sun & Durlofsky, 2019; Zhang et al., 2018).

52 Pore pressure increases above the caprock were thought to be zero in the absence of high  
53 permeability paths across the caprock or adjacent faults with high permeability. Thus, any deviation  
54 from the pressure baseline (expected to be constant) was considered as a result of high hydraulic  
55 communication that could become a potential leak if the high permeability path is reached by the CO<sub>2</sub>  
56 plume. However, recent pressure monitoring in the Cranfield CO<sub>2</sub> injection project indicates  
57 measurable changes of pore pressure above the caprock (~50 kPa) after two years of CO<sub>2</sub> injection  
58 with IZ pressure change reaching a maximum of ~8.8 MPa in the absence of leaks (Kim & Hosseini,  
59 2014; Tao et al., 2012). Analytical and numerical simulation work demonstrates that rock  
60 deformation above the injection zone can induce pressure changes in the absence of leaks through  
61 the caprock, by means of a poroelastic phenomenon known as “undrained loading” (Kim & Hosseini,  
62 2014; Zeidouni & Vilarrasa, 2016). Despite recent advances and numerical simulations, pressure  
63 monitoring above the caprock remains largely underutilized or misinterpreted because of a lack of  
64 (1) validation schemes, (2) discrimination between fast hydraulic communication and undrained  
65 loading, (3) thorough measurement of poromechanical properties of the AIZ, (4) thorough  
66 deployment of high-resolution sensors to capture subtle pressure changes (e.g., 1 kPa), (5) coupled  
67 poroelastic simulation beyond the injection zone for all CO<sub>2</sub> storage projects, (6) extension of existing  
68 models to two-phase fluid flow, (7) accurate prediction of absolute magnitude and transient pressure  
69 changes in the AIZ, and (8) evaluation of other leaking/sealing scenarios beyond just one leaky  
70 abandoned well (S. Hosseini et al., 2018; S. A. Hosseini, 2019; S. Hosseini & Alfi, 2016; Kim & Hosseini,  
71 2014; Mishra et al., 2014; Wiese et al., 2013; Zeidouni & Vilarrasa, 2016).

72 CO<sub>2</sub> injection and reservoir pressurization cause displacements and deformations far beyond the  
73 extent of the CO<sub>2</sub> plume (Rutqvist et al., 2010; Segall & Fitzgerald, 1998; Tang et al., 2021). Fluid  
74 injection and reservoir pressurization may result in ground surface uplift due to expansion of the  
75 reservoir caused by decreased effective stress. For example, InSAR data showed a surface uplift on  
76 the order of 5 mm per year in the In Salah Gas Project in Algeria (with a CO<sub>2</sub> injection rate of 0.5–1  
77 Mt/year) (Rutqvist et al., 2009, 2010). CO<sub>2</sub> injection and reservoir pressurization also causes rock  
78 deformation between the surface and the reservoir which may appear as a change of pore pressure  
79 in fluid-saturated rocks (Detournay & Cheng, 1988; Roussel & Agrawal, 2017; Segall & Fitzgerald,  
80 1998; Zeidouni & Vilarrasa, 2016). During a drained process, the application of an external stress  
81 induces volumetric strains without change of pore pressure. In contrast, pore pressure will increase  
82 in an undrained process when a (contraction) volumetric deformation is applied to a fluid-filled  
83 porous material (Cheng, 2016; Coussy, 2004). Hence, even in the absence of fast hydraulic  
84 communication between the injection zone and formations above the caprock, CO<sub>2</sub> (or any fluid)  
85 injection can modify the pore pressure above the caprock due to undrained loading.

86 In general, two mechanisms can contribute to pore pressure changes in porous media (1) advective  
87 fluid transport and (2) pore volume deformation. These coupled pore pressure diffusion and  
88 mechanical deformation processes are captured by the pressure  $P$  diffusivity equation for fluid flow  
89 coupled with poroelasticity with respect to time  $t$  (Cheng, 2016; Coussy, 2004; Detournay & Cheng,  
90 1993):

$$91 \quad \frac{\partial P}{\partial t} = \frac{kM^*}{\mu} \nabla^2 P - \alpha M^* \frac{\partial \varepsilon_V}{\partial t} \quad (1)$$

92 where  $k$  is the porous medium permeability,  $\mu$  is the fluid viscosity,  $\alpha$  is the Biot coefficient,  $\varepsilon_V$  is the  
93 bulk volumetric strain, and the Biot modulus  $M^*$  is

$$94 \quad M^* = \left( \frac{\phi_0}{K_f} + \frac{\alpha - \phi_0}{K_m} \right)^{-1} \quad (2)$$

95 where  $\phi_0$  is the initial rock porosity,  $K_f$  is the bulk modulus of the pore fluid, and  $K_m$  is the bulk  
 96 modulus of the rock matrix. Notice that Eq. 1 is the pressure diffusivity equation with total  
 97 compressibility ( $C_t = 1/M^*$ ), where the second term in the right-hand side captures the impact of  
 98 rock deformation on pressure changes. Reservoir simulation without geomechanical coupling (or  
 99 just one-way coupling) captures the first term on the right-hand side of Eq. 1 only.

100 For a linear elastic isotropic porous solid, the expected pore pressure change  $\Delta P$  under undrained  
 101 loading (no change in fluid mass within pore volume) is directly proportional to the imposed  
 102 volumetric strain (Coussy, 2004):

$$103 \quad \Delta P = -\alpha M^* \Delta \varepsilon_V \quad (3)$$

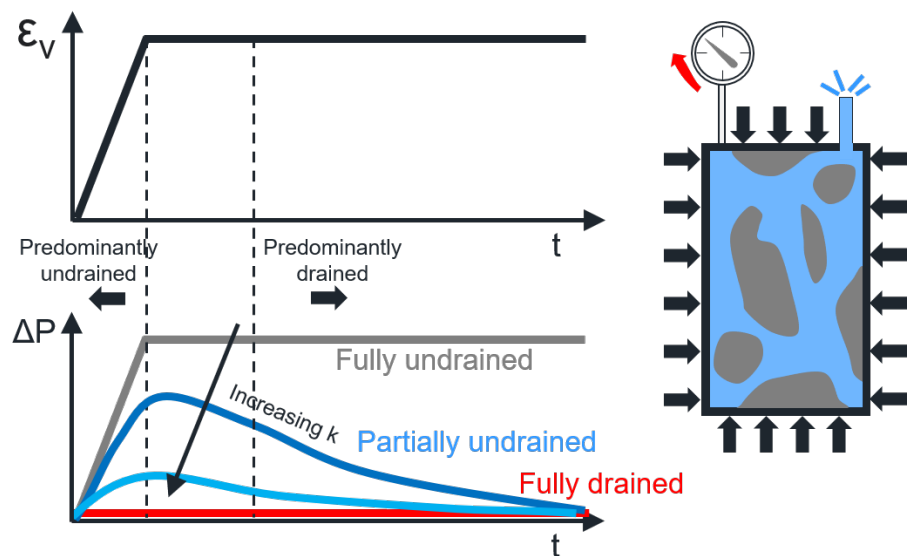
104 Thus, pore pressure change due to undrained loading depends on rock poroelastic properties, fluid  
 105 compressibility ( $K_f$ )<sup>-1</sup>, and volumetric strain. Decreases in pore volume lead to increases of pore  
 106 pressure, while increases in pore volume lead to decreases of pore pressure for fully or partially  
 107 undrained loading (Fig. 1).

108 Whether a process is undrained or drained depends on the rate of (strain) loading and the rate of  
 109 pore pressure diffusion. Perfect fluid containment is rare in natural environments, so most processes  
 110 can be generalized as partially undrained depending on the time interval of analysis. For example,  
 111 the characteristic time of pressure diffusion  $T_{ch}$  captures the time when  $\sim 2/3$  of the pore pressure is  
 112 dissipated from an initial undrained loading state (Cheng, 2016):

$$113 \quad T_{ch} = \frac{L^2}{D_h} \quad (4)$$

114 where  $L$  is the characteristic drainage length and  $D_h = \frac{kM^*}{\mu}$  is the hydraulic diffusivity. Higher  
 115 permeability and shorter characteristic distance of drainage decrease the characteristic pore  
 116 pressure diffusion time and the magnitude of pore pressure increase for partially undrained loading  
 117 of real sediments (Fig. 1). Thus, the partially undrained condition entails a smaller amount of pore

118 pressure variations than the fully undrained condition due to pressure dissipation. In fact, if the rate  
 119 of (strain) loading is lower than the rate of pore pressure diffusion, a porous medium may never  
 120 experience a pore pressure change due to pore volume reduction. Additional constitutive equations  
 121 for the multiphase fluid flow, the poroelastic solid, and coupled hydro-mechanical simulation are  
 122 available elsewhere (Cheng, 2016; Coussy, 2004; Prevost, 2013; Tran et al., 2009).



123  
 124 **Fig. 1.** Comparison among fully drained, partially undrained, and undrained conditions: the pore pressure  
 125 changes under the partially undrained condition are proportional to the imposed volumetric strain but also  
 126 depend on the hydraulic diffusivity of the porous medium.

127 The objective of this paper is to extend the current knowledge on pore-pressure monitoring above  
 128 the caprock, mostly limited to leakages due to hydraulic communication, and make evident the  
 129 impact of deformation-induced partially undrained loading. Such improvement is critical to establish  
 130 pore-pressure monitoring above the caprock as a new subsurface signal that can potentially track  
 131 the CO<sub>2</sub> plume, quantify hydraulic communication, detect possible leaks, and help ensure safe CO<sub>2</sub>  
 132 storage. The paper starts with a description of the compositional fluid flow model coupled with  
 133 geomechanics. We put special emphasis on examining the poroelastic response above the caprock by

134 analyzing the magnitude, evolution, and distribution of the pressure increase through forward  
135 modeling. The modeling work excludes pressure monitoring above the injection point but within the  
136 same storage formation, since such response is expected to be dominated by fluid advection. The  
137 analysis also discusses the possible configuration of pressure sensors regarding their position with  
138 respect to the injector, horizontally and vertically above the caprock. The discussion section  
139 considers the presence of various subsurface scenarios relevant to inverse analysis, including the  
140 presence of a poorly isolated injector wellbore, a leaky abandoned wellbore, a high-  
141 permeability/sealing fault, and two injectors.

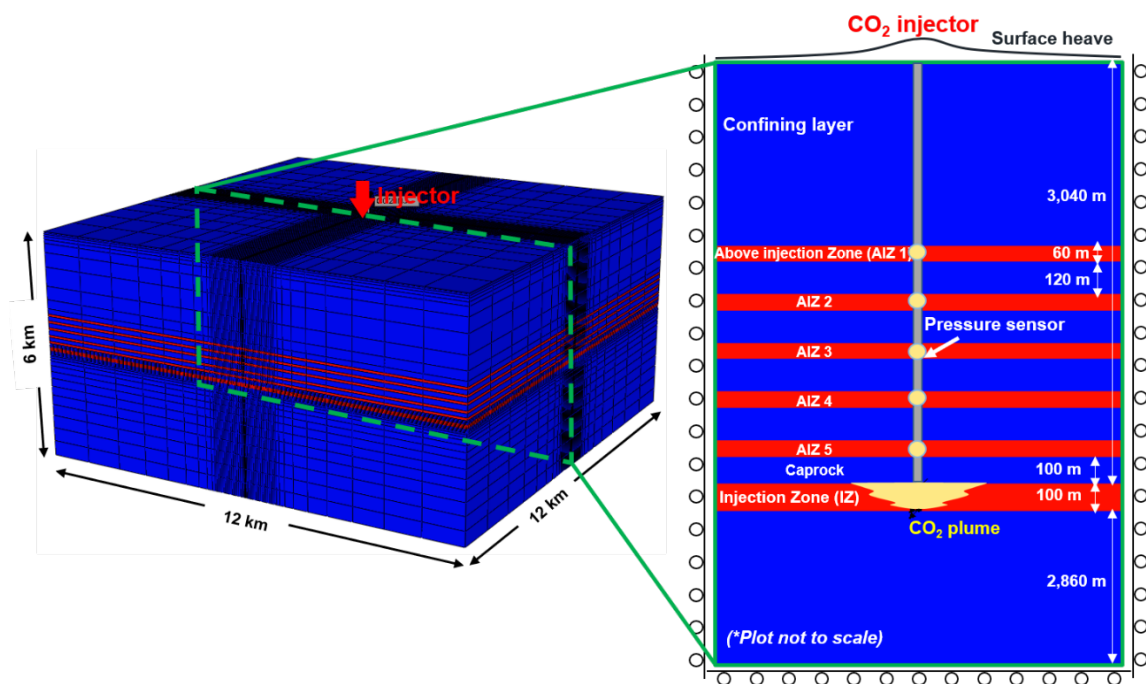
## 142 2. Methodology

143 We use a fluid-flow compositional model coupled with poroelasticity for the entire storage complex,  
144 including overburden and underburden layers, which are usually ignored in reservoir simulation. All  
145 the materials are assumed to be mechanically and hydraulically isotropic. The model is handled  
146 through the reservoir simulator CMG-GEM; details about the model formulation, coupling scheme,  
147 and validation are available elsewhere (Computer Modeling Group Ltd., 2013; Ryu et al., 2019; Tran  
148 et al., 2009). The storage complex extends 12 km by 12 km in the lateral direction (49 blocks by 49  
149 blocks) and 6 km in the vertical direction (48 blocks), totaling 115,248 grid blocks (Fig. 2). The grid  
150 size is gradually reduced from the reservoir boundary to the center of the injection point. The grid  
151 size ( $dx \times dy \times dz$ ) near the injector is  $6 \text{ m} \times 6 \text{ m} \times 20 \text{ m}$  with mesh refinement near the injection point.  
152 The mesh coarseness is a balance between accuracy and computing time/output file size. Two-way  
153 coupling with poroelasticity equations results in computational times much longer than fluid-flow  
154 simulation only (Prevost, 2013). Each coupled simulation takes about 64 CPU hours. The lateral  
155 extension is sufficiently large to avoid any mechanical boundary effects. The injection zone (IZ) is  
156 100 m thick located at 3,040 m of depth. The injection zone is fully overlain by a 100 m-thick caprock.  
157 The low-permeability caprock overlying the injection zone assures  $\text{CO}_2$  containment. The five layers



158 for pressure monitoring are above the caprock and are separated by shales with a thickness of 120  
 159 m. We name these layers AIZ 1 to AIZ 5 (above-injection-zone). Each AIZ layer has a thickness of 60  
 160 m. The IZ and AIZs have high permeability (300 mD) and are delimited by confining layers with low  
 161 permeability (100 nD). The storage complex geometry is inspired on shale-sand sequences in young  
 162 sedimentary basins, such as those in the Gulf of Mexico coast (Beckham, 2018).

163 The boundaries of the IZ and the AIZ monitoring layers (the edge of this storage complex) are set to  
 164 constant pressure. The top surface is free to move to capture surface heave due to strains induced in  
 165 the injection zone and overburden. Only vertical displacement is allowed for the lateral surfaces in  
 166 the storage complex. We simulate CO<sub>2</sub> injection at the reservoir center with a constant injection rate  
 167 of 1,008 tons of CO<sub>2</sub> per day (about 0.37 Mt/year). The injector is modeled as a source term in the IZ  
 168 with an equivalent radius of 0.1 m. The injection operation lasts for two years followed by one year  
 169 of shut-in. The yellow dots “along the injector” in Fig. 2 represent the hypothetical location of  
 170 pressure sensors vertically above the injection block, although the physical presence of the injector  
 171 is not modeled.



172

173 **Fig. 2.** Reservoir geometry and boundary conditions. CO<sub>2</sub> is injected into the injection zone (IZ) at the depth  
174 of 3,040 m. The injection zone is fully overlain by a 100-m low-permeability caprock followed by five above-  
175 injection-zone (AIZ) pressure monitoring layers - all above the caprock.

176 The capillary pressure and relative permeability properties for sand and shale are available in the  
177 Appendix 1. We assume isothermal conditions. The viscosity, mass density, compressibility, and  
178 mutual solubilities of CO<sub>2</sub> and brine are calculated by the compositional module of CMG-GEM with  
179 the corresponding calibrated equations of state; further details are available elsewhere (Jung et al.,  
180 2020; Singh & Wheeler, 2016). The poroelasticity equations are extended to two phases within the  
181 geomechanical module (Tran et al., 2004). We report liquid pressure (water) in all figures. The  
182 capillary pressure is neglected in effective stress poroelastic equations in CMG-GEM. This is a  
183 reasonable approximation for IZ and AIZ layers, since the capillary pressure is <1% of the in-situ  
184 stress. Notice that the partially undrained loading is only relevant above the caprock in brine-filled  
185 layers, so single-phase Eq. 2 still applies with  $K_f = K_{brine}$ . Other input parameters are listed in Table 1.  
186 The assigned values aim at simulating an ideal scenario of sand-shale sequences in the Gulf of Mexico  
187 Coast (Jung et al., 2018; Zheng & Espinoza, 2021). A validation of the reservoir simulation model and  
188 adopted solution mesh/time step is available in Appendix 2.

189 The motivation for building a simplified model is to directly observe and characterize pressure  
190 variations due to partially undrained loading induced by injection in a simple yet representative  
191 model. First, we show the results of an ideal caprock fully extending over the entire injection zone so  
192 pressure changes due to undrained loading can be isolated (Section 3). Then, we include possible  
193 high permeability paths to differentiate increases of pore pressure caused solely by partially  
194 undrained loading from fast hydraulic communication across the caprock (Section 4). The ideal  
195 settings serve to capture key features of pressure changes and offer possible interpretations for  
196 tracking CO<sub>2</sub> plume and monitoring subsurface leakages. A brief discussion for field cases is available  
197 in Section 5.

**Table 1.** Input parameters.

Property	Symbol	IZ/AIZ (sand)	Caprock (shale)
Initial porosity [-]	$\phi$	0.22	0.10
Permeability [mD]	$k$	300	0.0001
Young's modulus [GPa]	$E$	5	20
Poisson's ratio [-]	$\nu$	0.2	0.3
Bulk modulus* [GPa]	$K$	2.78	16.67
Biot coefficient** [-]	$\alpha$	0.92	0.54
Bulk modulus of brine [GPa]	$K_f$		2.2
Bulk modulus of rock matrix [GPa]	$K_m$		36

199

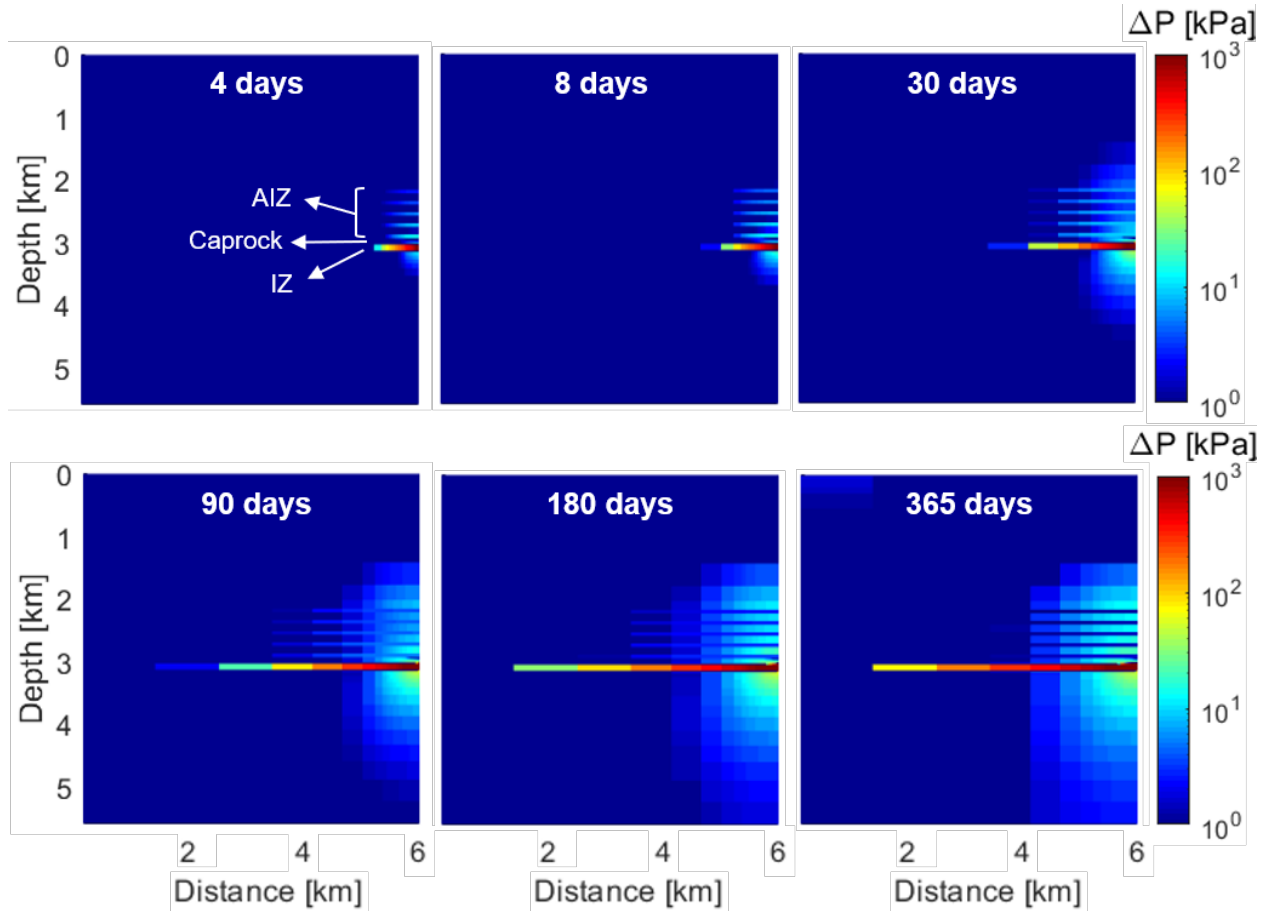
Notes: (\*)  $K = E/[3(1-2\nu)]$ , (\*\*)  $\alpha = 1 - K/K_m$ 

## 200 3. Results

### 201 3.1. Pressure increases above a fully covering caprock

202 Numerical simulations show that pressure buildup from CO<sub>2</sub> injection in the IZ causes pore pressure  
 203 changes in the storage complex, even outside the IZ, with a low permeability caprock that covers the  
 204 entire injection zone (Fig. 3). The changes outside the reservoir are a result of partially undrained  
 205 loading and, therefore, depend on space and time. For example, the affected region with  $\Delta P > 1$  kPa  
 206 extends to as far as 2 km away from the injector at  $t = 365$  days. The snapshots of pore pressure  
 207 change at various times demonstrate that the five AIZ permeable layers above the caprock respond  
 208 to CO<sub>2</sub> injection in the IZ.

209 The pore pressure in overlying shales also changes. The difference between pore-pressure changes  
 210 in sand (AIZ monitoring layers) and shale (caprock and other confining layers) is the result of their  
 211 distinct mechanical and hydraulic properties including bulk modulus and permeability. The sand,  
 212 with a lower bulk modulus, experiences a larger volumetric strain and thus a higher increase of  
 213 pressure than the shale (Eq. 3). The sand drains more quickly (less than 10 days in this simulation)  
 214 than the shale because of its larger hydraulic diffusivity (Eq. 4 and Fig. 3). As a result, the pressure  
 215 increase due to partially undrained loading in sand presents a short-term response ( $\sim 10$  days), while  
 216 the pressure increase in shale can persist for a relatively long time ( $> 100$  days) after injection starts.

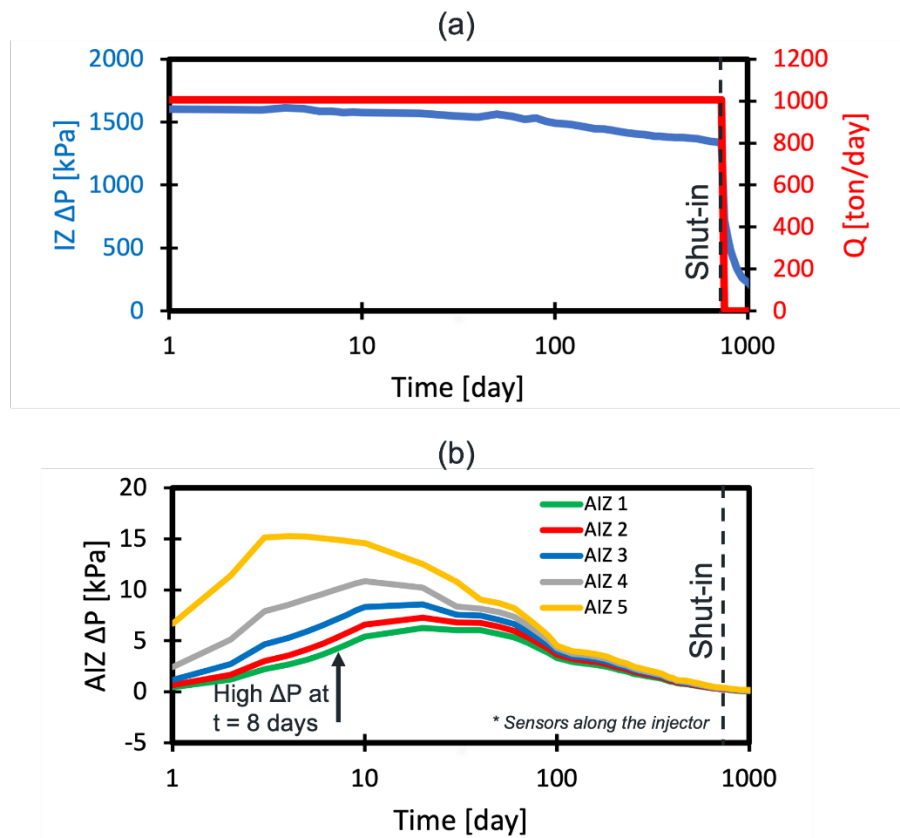


217

218 **Fig. 3.** Pore pressure changes in the CO<sub>2</sub> storage complex (half-domain cross-section shown because of  
 219 symmetry: injector located on the right boundary). CO<sub>2</sub> injection increases pressure in the injection zone  $\Delta P >$   
 220 1,000 kPa. Partially undrained loading induced by CO<sub>2</sub> injection causes changes of pore pressure  $\Delta P <$  20 kPa  
 221 outside the reservoir layer. Pore pressure in AIZ sand layers above the fully covering caprock increases in the  
 222 first 10 days to a peak value and then decreases with time. Pore pressure in shale exhibits more gradual and  
 223 long-lasting changes than in sands.

224 The temporal evolution of the injection rate, IZ pressure change  $\Delta P$ , and AIZ pressure change  $\Delta P$   
 225 during two years of injection and one year of shut-in are closely interrelated (Fig. 4). The IZ pressure  
 226 increases as much as 1,600 kPa and is followed by a gradual reduction until equilibrium to quasi-  
 227 steady-state conditions while injection lasts. Instead, the pore pressure in the AIZ (along the injector  
 228 and above the caprock) exhibits a transient response. The AIZ pressure increases in the first 10 days

229 and then decreases due to pressure dissipation despite continued injection. The pressure increase in  
 230 the five AIZ layers above the caprock is less than 5 kPa after 100 days of injection. For example, AIZ  
 231 5 (100 m above the IZ) exhibits an instantaneous response to CO<sub>2</sub> injection and fast pressure buildup  
 232 during the initial stage of injection. A gentle decrease of pressure with time follows after reaching a  
 233 peak (15 kPa) at  $t = 4$  days. The pressure in other distant AIZ layers exhibits a similar trend but with  
 234 a smaller amount of pressure variations and a delay in reaching the peak which increases with the  
 235 distance to the injector. Hence, AIZ pressure changes are time/location-dependent and monitoring  
 236 should focus on the initial stage of injection activities or during periods of changes of injection rate.



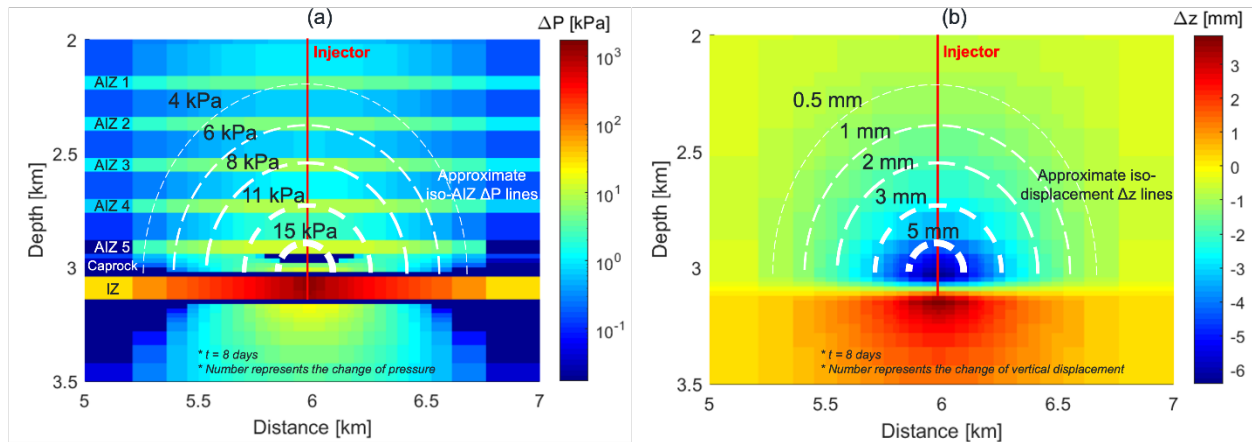
237

238 **Fig. 4.** CO<sub>2</sub> injection rate and pore pressure evolution with a fully covering caprock: (a) injection rate and  
 239 bottom-hole pressure increase in the injection zone (IZ); (b) pressure increase above the caprock due to  
 240 partially undrained loading in AIZ monitoring layers.

241 Fig. 5 shows pressure change and vertical displacement around the injector at  $t = 8$  days (when the  
242 maximum AIZ  $\Delta P$  occurs). The AIZ  $\Delta P$  is larger than 15 kPa within  $\sim 160$  m of the injection point (the  
243 distance here refers to the radial distance to the injection point). A strong  $\Delta P$  signal favors an easy  
244 and reliable interpretation of pressure monitoring above the caprock. The AIZ  $\Delta P$  decreases more  
245 quickly with increasing distance from the injector. The AIZ  $\Delta P$  is less than 4 kPa when the distance is  
246 larger than 880 m. The detection limit to pressure variations depends on: (1) pressure transducer  
247 resolution, usually about  $(\text{maximum pressure}) \times 10^{-6}$  (Santos & Silva, 2022), and (2) background  
248 electrical and mechanical noise. For example, the maximum pressure resolution possible for a  
249 transducer with  $10^{-6}$  resolution rated to 100 MPa is  $\sim 0.1$  kPa. However, other physical factors and  
250 analog to digital conversion may reduce the transducer detection limits. An analog to digital  
251 conversion at 16-bit results in a resolution of  $(\text{maximum pressure}) / (2^{16}) \sim (\text{maximum pressure}) \times$   
252  $10^{-5}$ , i.e. 1 kPa for a 100 MPa pressure transducer. The typical amplitude of background noise in  
253 standard subsurface pressure sensors is around 4 kPa (S. Hosseini et al., 2018; Wiese et al., 2013).  
254 Noise is the result of several natural and artificial phenomena such as changes in atmospheric  
255 pressure, ocean tides, surface precipitation, and pressure variations associated with measurement  
256 instruments and equipment operation. In our generic simulated case, 4 kPa-resolution pressure  
257 sensors could detect a pressure change larger than the background noise due to partially undrained  
258 loading only if installed closer than  $\sim 880$  m from the injection point. Higher precision pressure  
259 transducers and signal analysis could increase the range of reliable pressure monitoring.

260 The vertical displacement induced by  $\text{CO}_2$  injection is the highest closer to the injector ( $\sim 6$  mm at the  
261 caprock/reservoir interface), which is a result of the reduced effective vertical stress in the IZ. The  
262 uplift is higher than 5 mm at less than 160 m from the injection point. Fig. 5 highlights the potential  
263 of poroelastic monitoring when ground surface heave ( $\sim 0.3$  mm straight above injector in this case)  
264 is challenging or impossible to measure on the surface.

265

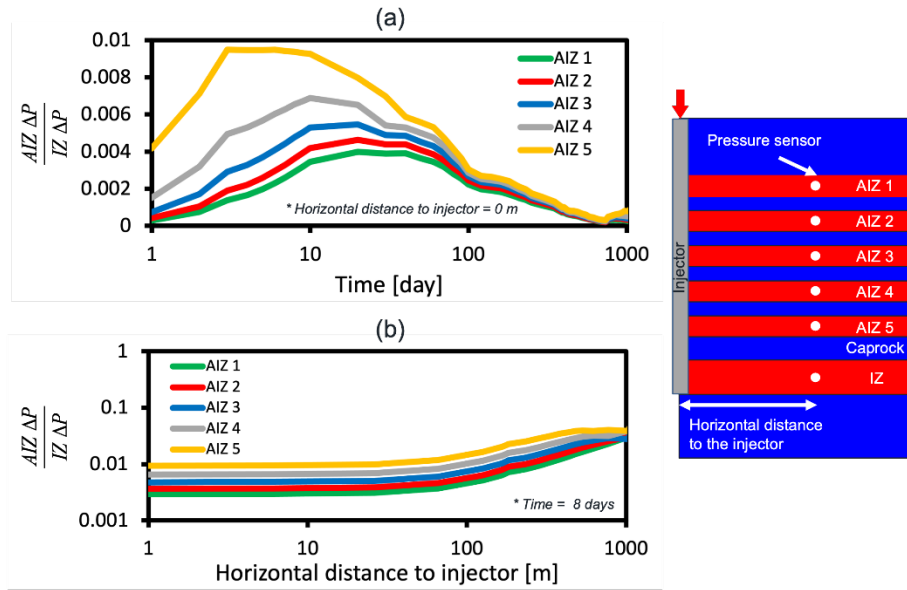


266

267 **Fig. 5.** Poroelastic response at  $t = 8$  days due to  $\text{CO}_2$  injection with a fully covering caprock: (a) pore pressure  
 268 changes in the storage complex and pressure fronts around the injector – notice the logarithmic scale; (b)  
 269 vertical displacement. Surface heave is negligible while pore pressure changes in permeable AIZ formations  
 270 above the caprock is in the order of  $\sim 10^{+1}$  kPa (iso- $\Delta P$  lines applicable to AIZ layers only).

271 **3.2. Relationship between pressure changes above the caprock and within the**  
 272 **reservoir**

273 The relationship between AIZ  $\Delta P$  (monitoring layers above the caprock) and IZ  $\Delta P$  enables the  
 274 estimation of the IZ pressure from measurements of pressure increases above the caprock. Let us  
 275 examine the ratio between AIZ  $\Delta P$  and IZ  $\Delta P$  along the injector and plot the results as a function of  
 276 time for the five AIZ permeable layers above the caprock (Fig. 6a). The ratio between AIZ  $\Delta P$  and IZ  
 277  $\Delta P$  reaches a peak (0.40%, 0.46%, 0.54%, 0.69%, and 0.95%) between 4 to 20 days and then  
 278 decreases with time. Thus, the pressure increase above the caprock can be as large as  $\sim 1\%$  of the IZ  
 279 pressure increase for this selected reservoir model with a fully covering caprock and the assumed  
 280 injection schedule.



281

282 **Fig. 6.** Relationship between pressure above the caprock AIZ  $\Delta P$  and IZ  $\Delta P$  after 8 days: (1) ratio between AIZ  
 283  $\Delta P$  and IZ  $\Delta P$  as a function of time (sampled points along the injector); (2) ratio between AIZ  $\Delta P$  and IZ  $\Delta P$  as a  
 284 function of horizontal distance to the injector. The maximum ratio is about 1% in the areas of interest.

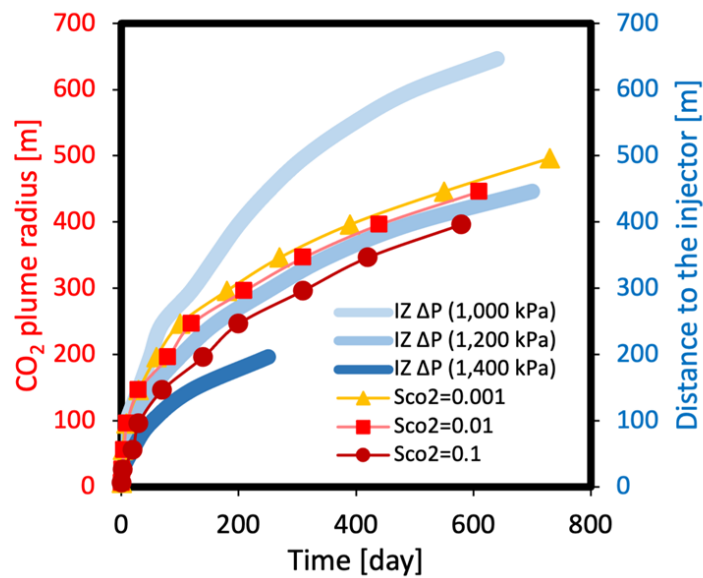
285 Fig. 6b shows the ratio AIZ  $\Delta P$ /IZ  $\Delta P$  for pairs located at the same horizontal distance from the  
 286 injector at  $t = 8$  days. The ratio AIZ  $\Delta P$ /IZ  $\Delta P$  is nearly constant within 100 m around the injector,  
 287 which indicates that this ratio does not rely much on the horizontal distance to the injector for five  
 288 AIZ monitoring layers. For a distance larger than 1000 m, the ratio between AIZ  $\Delta P$  and IZ  $\Delta P$  is  
 289 meaningless since the pressure variations in IZ and AIZ tend to be negligible.

### 290 3.3. Interpretation of AIZ $\Delta P$ /IZ $\Delta P$ ratio for plume migration

291 Fig. 6 demonstrates that the AIZ  $\Delta P$ /IZ  $\Delta P$  depends mainly on time (after injection) rather than  
 292 horizontal distance to the injector (particularly when the horizontal distance is less than 100 m).  
 293 Hence, variations of AIZ  $\Delta P$ /IZ  $\Delta P$  ratio can tell the evolution of the pressure front with time.  
 294 Furthermore, the IZ pressure front is related to the saturation front (Fig. 7). Near the injector, the  
 295 ratio AIZ  $\Delta P$ /IZ  $\Delta P$  is expected to increase, reach a maximum value, and decrease as a result of  $\text{CO}_2$   
 296 injection at constant rate (Fig. 6a). The increase of AIZ  $\Delta P$ /IZ  $\Delta P$  is caused by the pressurization of



297 the injection zone. The maximum AIZ  $\Delta P$ /IZ  $\Delta P$  depends mostly on the imposed rock deformation  
 298 and poroelastic properties (Eq. 3). The time for the maximum ratio AIZ  $\Delta P$ /IZ  $\Delta P$  occurs between 4  
 299 and 20 days in our model (Fig. 6a). The CO<sub>2</sub> plume is ~40 m away from the injector at the peak in AIZ  
 300 5 (4 days) and 96 m away at the peak in AIZ 1 (20 days) (Fig. 7). The AIZ  $\Delta P$ /IZ  $\Delta P$  decrease rate  
 301 depends on the hydraulic diffusivity of the AIZ. Values of AIZ  $\Delta P$ /IZ  $\Delta P$  cannot be larger than the peak  
 302 in the absence of a high permeability path between the IZ and AIZ layers above the caprock. IZ  $\Delta P$  can  
 303 be approximated from analytical solutions or reservoir simulations with known bottom-hole  
 304 pressure – See Appendix 2 (Avci, 1994; Benson & Doughty, 2006).



305  
 306 **Fig. 7.** CO<sub>2</sub> plume radius: the migration of CO<sub>2</sub> plume is tracked through CO<sub>2</sub> saturation. The 1,200 kPa  
 307 pressure front in the IZ moves simultaneously with the CO<sub>2</sub> plume for a constant injection rate.

## 308 4. Discussion: detection of subsurface high permeability paths

### 309 4.1. Presence of a high-permeability fault

310 The previous section highlights that pressure increases above the caprock are possible during CO<sub>2</sub>  
 311 injection in a reservoir in the absence of any high permeability paths connecting the injection zone  
 312 and permeable formations above the caprock. The cause is deformation of the rock and relatively fast

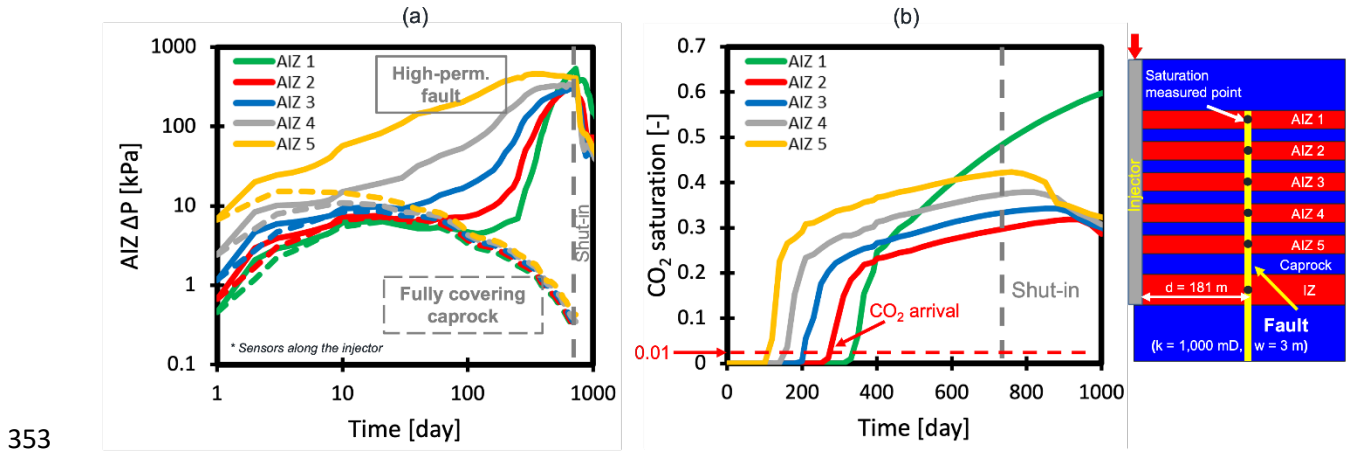
313 compression of the pore fluid. As an extension of our base case with a fully covering low-permeability  
314 caprock, let us consider the existence of a fault with high permeability and its influence on the AIZ  
315 pore pressure above the caprock. A high permeability fault is set at a distance of 181 m from the  
316 injector. The fault intersects all AIZ layers and shales in between spanning over 980 m of vertical  
317 length. We model the fault as a wall of grid blocks with a width of 3 m and volume-average  
318 permeability equal to 1,000 mD (Childs et al., 2007; Faulkner et al., 2010; Tao et al., 2012; Zheng &  
319 Espinoza, 2021b). Fig. 8a compares the pressure increase in five AIZ layers monitored along the  
320 injector and the base case.

321 The pressure increase in AIZ layers above the caprock with a fully covering caprock (base case) is the  
322 result of partially undrained loading. However, the AIZ pressure increase in the presence of a high-  
323 permeability fault is the result of the combined effects of direct and fast hydraulic communication,  
324 and partially undrained loading (Eq. 1). The key features in Fig. 8a include:

- 325 • The presence of a high permeability path favors more gradual increases of pore pressure to  
326 higher peak values in AIZ layers until injection shut-in (2 years) than the base case (Fig. 6).  
327 This additional and sustained pressure increase is the result of fluid communication between  
328 the IZ and the AIZ layers above the caprock through the fault.
- 329 • The pressure trends in the base and high-permeability fault cases overlap with each other in  
330 the first 10 days of CO<sub>2</sub> injection before the effects of partially undrained loading reaches the  
331 maximum value. After that, the pressure deviation between the two cases gradually becomes  
332 more and more significant. The AIZ  $\Delta P$  in presence of a high-permeability fault is one order  
333 of magnitude larger than the base case after one year of injection. Direct fluid communication,  
334 hence, increases AIZ pore pressure ten times more than partially undrained loading after 2  
335 years.

336 • The pressure buildup due to the hydraulic communication takes time. This is a function of the  
 337 hydraulic diffusivity of the reservoir rock and high permeability features across the caprock.  
 338 For example, it takes 26 days for achieving a pressure increase of 100 kPa in AIZ 5 (closest to  
 339 the injection point) and more than 160 days in the other AIZs for the same pressure imcrease.  
 340 Thus, more distant regions exhibit a longer delay in pore pressure increase. The time delay  
 341 in sensing the pressure increase at different monitoring points helps assess caprock integrity.

342 Pressure increase larger than expected by sole partially undrained unloading implies fluid transfer  
 343 (e.g. brine) across the caprock or a sealing fault, but does not necessarily mean a CO<sub>2</sub> leak. Let us also  
 344 monitor the evolution of CO<sub>2</sub> saturation along the fault. The negligible caprock dip (assumed in this  
 345 generic model) and buoyancy of bulk CO<sub>2</sub> leads to the rise of CO<sub>2</sub> through the fault and AIZ layers, and  
 346 thus the pressure in uppermost AIZ 1 is higher than the pressure in other AIZs after two years of CO<sub>2</sub>  
 347 injection. Here we define the CO<sub>2</sub> arrival at a specific AIZ when CO<sub>2</sub> saturation at the measured point  
 348 is higher than 0.01. The CO<sub>2</sub> arrival time for five AIZs is 100, 140, 200, 250, 310 days (Fig. 8b). Thus,  
 349 leakage detection through direct CO<sub>2</sub> saturation monitoring (e.g., through fluid sampling or neutron  
 350 and resistivity logs) requires at least several months. The AIZ pressure increase occurs much before  
 351 the change of CO<sub>2</sub> saturation and provides earlier warnings than compositional monitoring at a  
 352 potential observation well near the fault.



354 **Fig. 8.** Time evolution of pore pressure and CO<sub>2</sub> saturation above the caprock in the presence of a high-  
355 permeability fault: (a) pressure increase in five AIZ layers along the injector, including the base case with a  
356 fully covering caprock and the case with a high-permeability fault; (b) CO<sub>2</sub> saturation in five AIZ layers along  
357 the fault. A high-permeability fault results in steady and higher increases of pressure in AIZ layers above the  
358 caprock than in the base case.

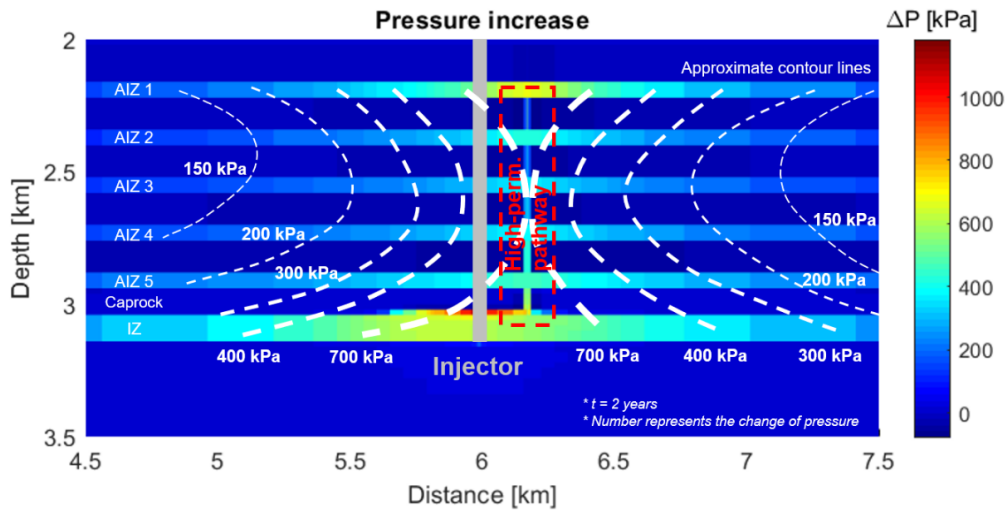
359 The CO<sub>2</sub> arrival time can also be approximated with analytical equations (See Appendix 2). For  
360 example, for steady-state single phase radial fluid flow the piston-like injection front radius  $R$  is a  
361 function of time  $t$ :

$$362 \quad R = \sqrt{\frac{Q_{eff}}{\pi h} t} \quad (5)$$

363 where  $Q_{eff}$  is the injection volumetric flow rate and  $h$  is the reservoir thickness. CO<sub>2</sub> injection in brine  
364 results in poor sweep efficiency, hence the injection rate can be modified to  $Q_{eff} = Q/\psi$ , where  $Q$  is the  
365 actual injection rate and  $\psi$  is the volume-time average sweep efficiency factor. Typical sweep  
366 efficiency factors for CO<sub>2</sub> in oil reservoirs range from 0.20 to 0.28 for 1 pore volume (Lake et al., 2019).  
367 Direct comparison of numerical simulations with Eq. 5 results in a reasonable approximation for the  
368 CO<sub>2</sub> plume radius as a function of time with  $\psi = 0.01$  to 0.015 (Fig. 7). The low value of  $\psi$  captures  
369 CO<sub>2</sub> high mobility, buoyancy and low solubility in water. Eq. 5 also predicts that CO<sub>2</sub> should arrive to  
370 the fault at  $R = 181$  m, at  $t = 71$ -107 days (with  $\psi = 0.01$  to 0.015) in agreement with the CO<sub>2</sub> arrival  
371 ( $S_{CO_2} = 0.01$ ) at AIZ 5 at  $t \sim 105$  days shown in Fig. 8b.

372 The pressure distribution shown in Fig. 9 is the result of a high-permeability fault (compare to the  
373 base case in Fig. 5a). The high-permeability path releases pressure from the injection zone and  
374 exhibits the highest AIZ  $\Delta P$  in each AIZ. The AIZ  $\Delta P$  decays with the increase of distance to the high-  
375 permeability fault. A rough estimation of the leakage location is possible through pressure  
376 monitoring and mapping above the caprock. In this case, the estimated location of the high-  
377 permeability path based on the perturbations of pore pressure is about 180 m away from the injector,

378 which coincides with the actual fault location (the fault location has the highest AIZ  $\Delta P$  in each  
 379 monitoring layer). An increase of the number of monitoring wells is expected to provide useful  
 380 information on the estimation of the extent of subsurface leakages (Zeidouni & Pooladi-Darvish,  
 381 2012b). The objective of this paper is to explore the pressure signals above the caprock for different  
 382 subsurface leakage scenarios through forward modeling (see also next subsections). Though, this  
 383 simple example could be extended into a formal inverse problem to detect high-permeability  
 384 pathways with unknown location and arbitrary geometry. Geostatistical data-space approaches and  
 385 deep-learning algorithms have been used to locate leaks through leaky wellbores considering  
 386 hydraulic communication only or simplified overburden mechanical models (Sun & Durlofsky, 2019;  
 387 Tang et al., 2021).



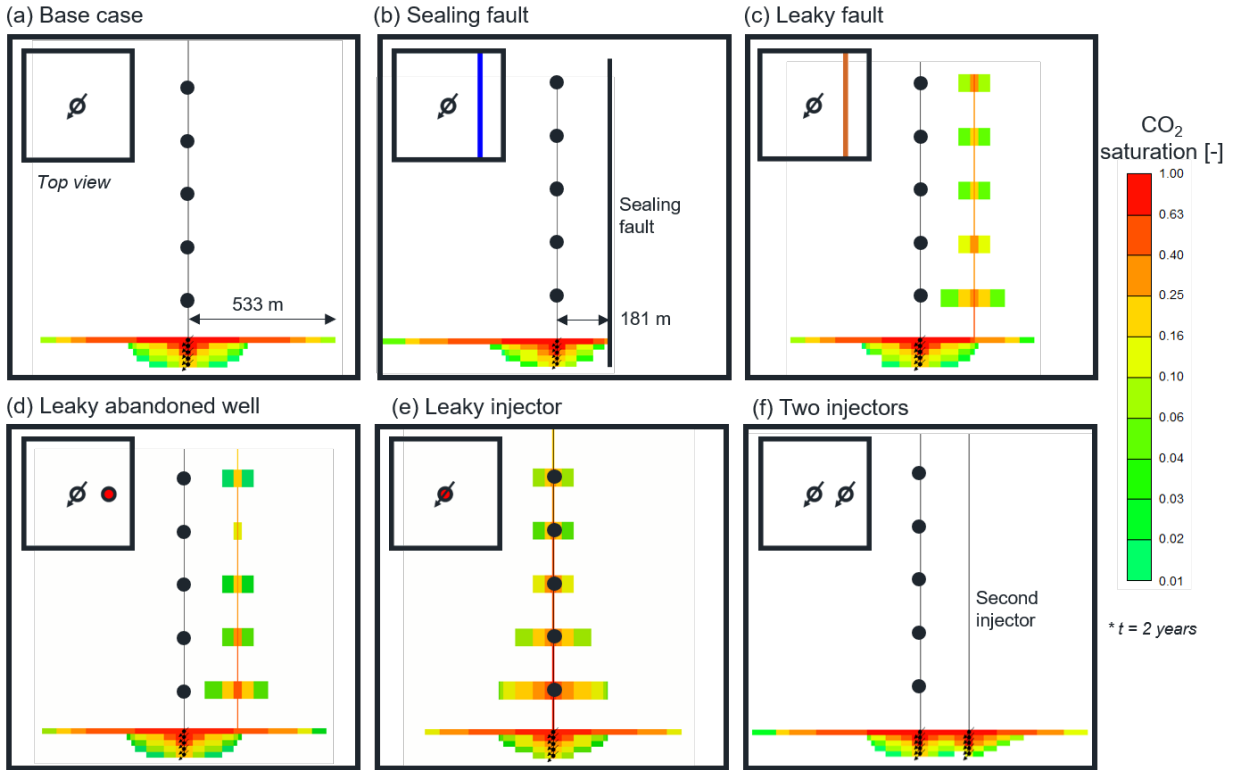
388 **Fig. 9.** Pressure change in permeable monitoring layers above the caprock in the presence of a high-  
 389 permeability fault. The red dashed box highlights the location of the estimated high-permeability path based  
 390 solely on the observed field pore pressure, which coincides with the location of the high-permeability fault.  
 391

392 **4.2. Other relevant scenarios**

393 In this section, we discuss the pressure increases above the caprock in other relevant subsurface  
 394 scenarios. Fig. 10 presents the distribution of CO<sub>2</sub> plume after two years of injection in six different

395 cases, including (a) base case with a low-permeability caprock covering all the injection zone, i.e., no  
396 fast hydraulic communication or leaks, (b) case with a sealing fault, (c) case with a leaky fault, (d)  
397 case with a leaky abandoned well, (e) case with a leaky injector, and (f) case with two injectors. The  
398 leaky fault, the sealing fault, the leaky abandoned well, and the second injector are placed at a  
399 distance of 181 m from the primary injector. The effective (volume average) permeability of all the  
400 leaky grid blocks is 1,000 mD with a thickness of 3 m. The fault permeability has three different values  
401 ( $k_{fault} = 10, 100, \text{ and } 1,000 \text{ mD}$ ) in the leaky fault case for a sensitivity test. The second injector starts  
402 after 1 year at the same rate of the first injector, up to 1008 ton/day, until the end of the simulation  
403 (2 years). Multiple wells are generally used to maximize the available storage space and increase  
404 spatial sweep efficiency (Lake et al., 2014; Sun & Durlofsky, 2019). Layer AIZ 1 is overlain by a thick  
405 fully covering secondary caprock. The black dots along the primary injector in Fig. 10 represent the  
406 location of pressure monitoring sensors.

407 The CO<sub>2</sub> plume radius is 533 m after 2-years in the base case (cut-off  $S_{CO_2}=1\%$  - Fig. 10a). The sealing  
408 fault inhibits CO<sub>2</sub> flow on one side and results in preferential CO<sub>2</sub> plume migration opposite to the  
409 fault location (Fig. 2b). The presence of leaks reduces the CO<sub>2</sub> plume reach in all leaky cases. High  
410 saturation around the leaky well of Fig. 10d in AIZ 5 to 3 is caused by proximity to the injected layer,  
411 while high saturation in AIZ 1 is caused by accumulation of CO<sub>2</sub> by buoyancy. AIZ 2 exhibits low  
412 saturation because is neither close to the injected layer nor the top layer. Case (d) has been studied  
413 previously with focus on pressure time-derivative analysis to discriminate the influence of partially  
414 undrained loading from hydraulic communication (Zeidouni & Vilarrasa, 2016). The CO<sub>2</sub> plume reach  
415 is the shortest (only 427 m) in the leaky injector case (Fig. 10e).



416

417 **Fig. 10.** Distribution of CO<sub>2</sub> plume after two years of CO<sub>2</sub> injection in different scenarios: (a) base case (no  
 418 leaks through the caprock); (b) case with a sealing fault; (c) case with a leaky fault; (d) case with a leaky  
 419 abandoned well; (e) case with a leaky injector; and (f) case with two injectors. The inserted plot at the top left  
 420 of each sub-figure represents the schematic top-view of each layout.

421 Fig. 11 shows the AIZ pressure increase for the different cases shown in Fig. 10. The presence of high  
 422 permeability pathways results in the AIZ pressure change in the range of 100 to 1,000 kPa, while  
 423 pressure increase due to partially undrained loading is characterized by lower values (in the order  
 424 of magnitude of 10 kPa). All cases with high-permeability pathways lead to eventual CO<sub>2</sub> leaks in our  
 425 ideal models with no caprock dip. Strong hydraulic communication with no CO<sub>2</sub> leaks could be  
 426 possible, for example, injecting CO<sub>2</sub> near the top of an anticline with a high-permeability fault  
 427 downdip not reached by the CO<sub>2</sub> plume.

428 The leaky injector has the most significant effect on pore pressure changes along the well compared  
 429 with other leaky scenarios. The leaky abandoned well is 181 m away from the injector and thus

430 exhibits a delay in pressure increase compared with the leaky injector case. The response for the  
431 leaky abandoned-well case overlaps with the response for the base case at the initial stage ( $t < 90$   
432 days), suggesting direct fluid flow has not yet arrived at the abandoned well and the primary reason  
433 for pressure change is due to partially undrained loading. Afterward, continuous hydraulic  
434 communication leads to faster and higher pressure increases.

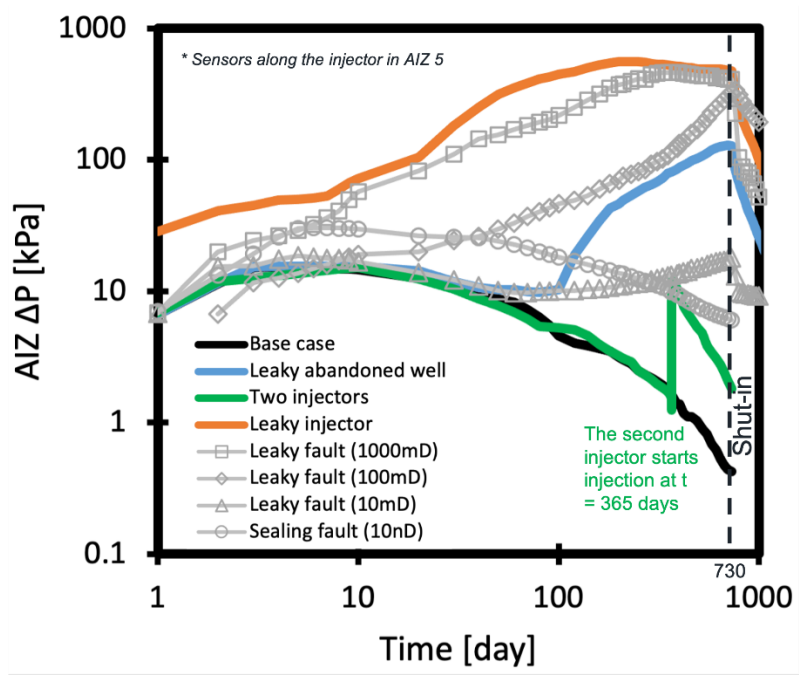
435 Variations in fault permeability can result in distinct responses in the AIZ. A permeable fault favors  
436 faster fluid communication and higher AIZ pressure increase than the fault with lower permeability.  
437 The pressure increase is one order of magnitude smaller for the case with  $k_{fault} = 10$  mD than for  $k_{fault}$   
438  $= 1,000$  mD. However, if the fault permeability is small enough to inhibit fluid flow (for example, 10  
439 nD), structural sealing will favor a stronger undrained loading above the reservoir and thus higher  
440 pressure increase above the caprock (as large as 30 kPa) than the base case with no sealing fault and  
441 no leaks.

442 The addition of the second injector after 1 year results in increases of  $\Delta P$  by 12 kPa in the first five  
443 following days, as a result of partially undrained loading caused by the injection process. The increase  
444 of pressure induced by undrained loading follows the principle of superposition (Roussel & Agrawal,  
445 2017), consistently with the assumed linear poroelastic behavior of the rocks. This increase is  
446 relatively small compared to changes caused by direct hydraulic communication, yet measurable.  
447 Understanding distinct features of pressure increase with or without leaks can help quantify caprock  
448 sealing and identify high permeability paths across the caprock.

449 The transient poroelastic response in the field depends on fluid injection rate and injection schedule.  
450 A large injection rate entails fast pressure buildup in the IZ and thus triggers a strong pressure  
451 response in the AIZ. For a given injected volume, a step-wise increase of injection rate will mitigate  
452 the pore pressure increase from partially undrained loading as increases of volumetric strain happen  
453 at the same time pore pressure dissipates in the AIZ. For example, the pressure ramp-up period



454 should be smaller than ~10 days in our base case to induce a noticeable peak and decay of the  
 455 pressure signal by partially undrained loading in the AIZ monitoring layers.



456

457 **Fig. 11.** Pore pressure increases above the caprock for different storage scenarios shown in Fig. 10. The fault  
 458 permeability varies from 10 nD to 1,000 mD. The effective permeability of leaky blocks in other leaky  
 459 scenarios is 1,000 mD.

460 Another possible scenario is a highly compartmentalized and relatively small reservoir. No-flow  
 461 boundary conditions have a direct impact on pressure in the injection zone and therefore in AIZ  
 462 layers. Typically, pressure gradients within the reservoir are small under compartmentalized  
 463 conditions and pressure can remain high over long periods of time after injection shut-in. Such  
 464 pressure response in the IZ would result in a less pronounced yet more enduring pressure increase  
 465 in the AIZ assuming a fully-covering caprock. The reservoir model used in this paper is sufficiently  
 466 large so that the difference between constant pressure or no-flow boundary condition (i.e.,  
 467 compartmentalized) is negligible on AIZ  $\Delta P$  for ~1008 ton/day injection rate over 2 years.

## 468 5. Comparison of generic simulation results with field data

469 There are four CO<sub>2</sub> injection field cases published so far that document pressure monitoring above  
470 the injection zone: Cranfield (USA), Ketzin (Germany), Otway (Australia), and Decatur (USA) (Bauer  
471 et al., 2016; Ennis-King et al., 2017; Kim & Hosseini, 2014; Wiese et al., 2013). The first two involve  
472 pressure monitoring above the caprock similar to the generic model simulated in this study. The last  
473 two measure pressure above the injection point but within the same injection unit, such that, thin  
474 low permeability layers exist between the injection point and the pressure sensors but there is no  
475 thick and continuous low-permeability caprock separating the pressure sensors from the injection  
476 point. We include these two most recent field cases in the following summary for the sake of  
477 completeness and comparison, although our model is meant to be compared with cases that measure  
478 pressure above the caprock.

- 479 • *Cranfield, United States, 2009-2011* (Kim & Hosseini, 2014; Tao et al., 2012): CO<sub>2</sub> was injected  
480 in a sandstone with a three-step rate schedule. Reservoir (IZ) pressure change reached a  
481 maximum of ~8.8 MPa after 250 days of injection. Pore pressure changes are available for  
482 two monitoring wells in permeable layers above a ~120 m-thick caprock. The pressure  
483 signal of wellbore 31F-2 (68 m down-dip) shows an initial increase of 50-150 kPa followed  
484 by a steady increase of 100 kPa, totaling AIZ  $\Delta P$ / IZ  $\Delta P$  ~ 0.028. The pressure signal of  
485 wellbore 31F-3 (132 m down-dip) shows spikes up to 50 kPa which coincide with changes  
486 of injection rate and rapid dissipation (5-20 days), totaling AIZ  $\Delta P$ / IZ  $\Delta P$  ~ 0.006. Using Fig.  
487 11 as a guide permits concluding the following: (1) the steady and relatively high pressure  
488 increase in well 31F-2 indicates that there might have been hydraulic communication  
489 through the caprock along this vertical well, and (2) relatively small pressure spikes indicate  
490 full caprock sealing along well 31F-3. None of these cases point necessarily to a CO<sub>2</sub> leak,  
491 since the wells are downdip the injection well and there is no field evidence of capillary

492 sealing breakthrough (Espinoza & Santamarina, 2017). Temperature variations along the  
493 wells might have also affected pressure readings (Lindeberg, 2011).

494 • *Ketzin, Germany, 2011-2012* (Wiese et al., 2013): CO<sub>2</sub> was injected in well Ktzi 201 for over  
495 8 months with a prescribed constant rate interrupted sporadically. Reservoir IZ bottom-hole  
496 pressure increased ~0.5 MPa. Monitoring well P300 measured pressure 215 m above  
497 injection zone and 120 m updip in the first permeable layer above the caprock. AIZ  
498 monitoring showed steady pressure increase reaching a maximum of 7.5 kPa, i.e., AIZ  $\Delta P$ / IZ  
499  $\Delta P \sim 0.015$ . The original paper does not offer conclusive proofs for the steady rise in  
500 pressure above the caprock and does not discard the possibility of strong hydraulic  
501 communication. In fact, there are faults ~2 km away from the injector and monitoring wells  
502 behind a dome. A cursory comparison with Fig. 11 indicates hydraulic communication likely  
503 through the faults since the monitoring well does not go through the caprock. A CO<sub>2</sub> leak is  
504 not a direct implication of hydraulic communication because the injection volume is small  
505 and the fault system is mostly behind a dome within the reservoir layer.

506 • *Decatur, United States, 2011-2014* (Bauer et al., 2016): CO<sub>2</sub> injection was performed at well  
507 CCS1 over nearly 3 years at a constant injection rate and close to the bottom of Mt. Simon  
508 Formation (sandstone with embedded thin shale layers). As a result, bottomhole pressure  
509 at the injector (IZ) changed within ~1 month up to 3.4 MPa at the depth of injection.  
510 Additional pressure monitoring above the injection depth but within the Mt. Simon  
511 Formation and below the Eau Claire Shale caprock registered steady increases of up to 0.35  
512 MPa in well VW1 within the Mt. Simon Sandstone. This is about 0.10 of the IZ  $\Delta P$ . The original  
513 paper concludes that there is good hydraulic communication between the injection and  
514 measured points in agreement with previous expectations and our numerical simulations  
515 (Fig. 11). Rapid hydraulic communication is likely due to discontinuities of thin shale layers

516 within the Mt. Simon Formation, which is capped by the Eau Claire shale and provides  
517 further assurance of CO<sub>2</sub> storage.

518 • *Otway, Australia, 2015-2016* (Ennis-King et al., 2017): CO<sub>2</sub> was injected in the Paarette A  
519 Formation with a target injection rate of ~150 tons/day for over 150 days with sporadic  
520 shut-ins at the CO2CRC Otway site in South-West Victoria, Australia. The bottom-hole  
521 pressure reached quickly IZ  $\Delta P = 0.2$  MPa after injection started or resumed. Pressure  
522 monitoring above the injection point exhibited gradual changes of up to 35 kPa well  
523 correlated with injection starting/resuming times. This is 0.175 of the pressure at the  
524 injection point. This strong hydraulic communication is not surprising since pressure  
525 changes are within the same permeable storage unit and under the caprock. In fact, CO<sub>2</sub>  
526 plume migration interpreted from time-lapse seismic suggests the presence of a  
527 transmissive fault ~300 m away from the injector (Dance et al., 2019).

## 528 6. Conclusions

529 This paper presents numerical simulation results of CO<sub>2</sub> injection and corresponding pore pressure  
530 changes above the caprock due to partially undrained loading and hydraulic communication, in views  
531 of CO<sub>2</sub> plume tracking and leak monitoring in CO<sub>2</sub> geological storage. The simplified model in this  
532 paper serves as an ideal case of pressure monitoring in a sand-shale sequence and aims at providing  
533 general trends, although each actual site possesses its own particularities and complexities that may  
534 impact those trends. Yet, the results shed light on the general characterization and validation of  
535 pressure signals above the caprock as a result of injection-induced poroelastic effects, provide rapid  
536 guidelines for analyses of field cases, and serve as validation to build specific models for a given field  
537 case geometry, rock properties, and injection schedule. The major conclusions of this paper are:

538 • Reduced effective stress at the reservoir/storage unit induced by CO<sub>2</sub> injection results in  
539 surface heave as well as rock deformation between the injection layer and the ground surface.

540 A pore pressure variation due to rock deformation and formation fluid compression may  
541 appear above the caprock as a result of partially undrained loading.

542 • The pore pressure increase induced by partially undrained loading above the caprock is non-  
543 negligible. The pressure increase is up to 1% of the injection zone (IZ) pressure increase for  
544 the chosen storage complex. Pressure increase above the caprock due to partially undrained  
545 loading is maximum when rapid changes of pressure occur in the IZ, such as in the initial  
546 stage of injection for a constant injection rate schedule, or when injection resumes after a  
547 shut-in period. Since the pressure in the injection zone is linked to the migration of the CO<sub>2</sub>  
548 plume, it is possible to use pressure changes above the caprock to track the migration of the  
549 CO<sub>2</sub> plume in the injection zone.

550 • High permeability paths across the caprock can increase pressure change above the caprock  
551 by one order of magnitude compared to the base case with a fully covering caprock (from  
552 ~15 kPa in the base case to 100-1,000 kPa). Such distinctive response is useful to discern  
553 pressure changes caused solely by rock compression from pressure changes caused by a high  
554 permeability path through the caprock.

555 • The comparison of generic trends with field cases suggest that: (1) Cranfield monitoring well  
556 31F-3 showed a pressure response above the caprock similar to our simulated base case with  
557 no fluid transfer across the caprock, (2) Ketzin monitoring well P300 showed a pressure  
558 change above the caprock compatible with fair hydraulic communication between the  
559 reservoir and the caprock, and (3) two other cases of monitoring above the injection point  
560 within the same injection zone show high hydraulic communication, as expected. A tailored  
561 simulation for each case is needed to confirm these cursory interpretations.

562 • Pressure monitoring above the caprock can be an effective technique to track the extent of  
563 the CO<sub>2</sub> plume, quantify hydraulic communication, detect potential leaks, and provide earlier

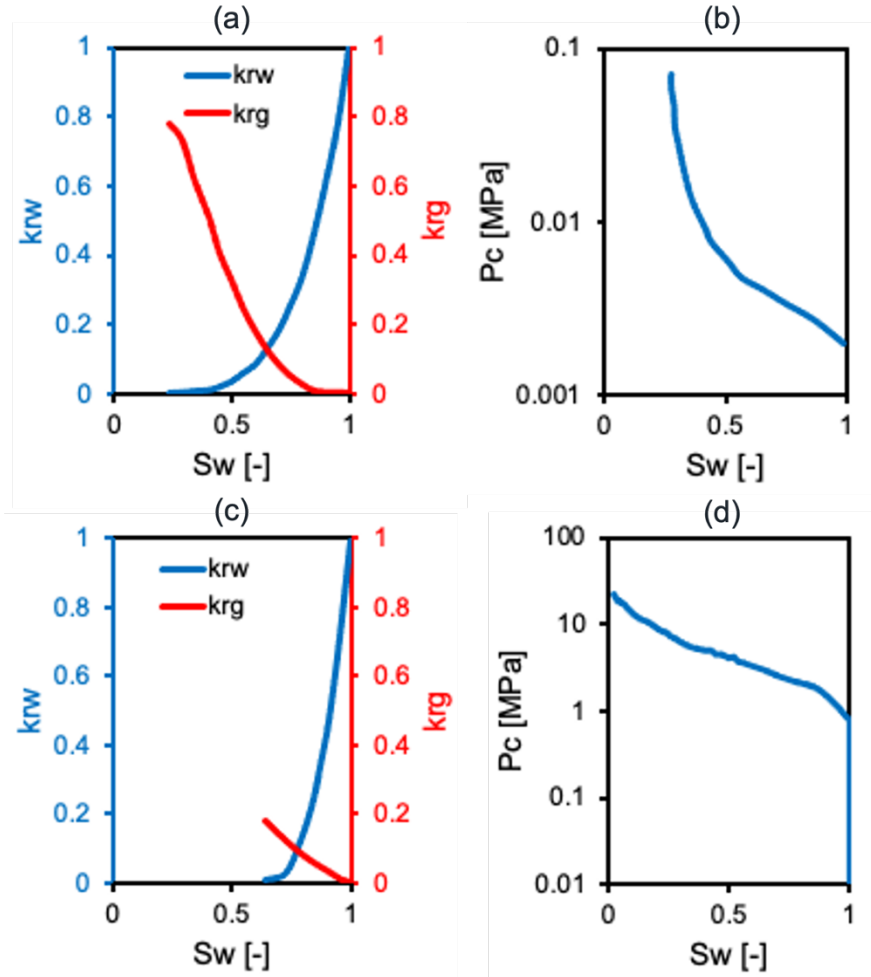
564 leak warnings than compositional fluid monitoring. Unexpected pressure increases above the  
565 caprock (higher than the range expected for partially undrained loading) are an indication of  
566 non-negligible hydraulic communication from the injection zone into overlying formations.

## 567 Acknowledgments

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570 the novelty of this paper and better explain the results.

## 571 Appendix 1: Capillary pressure and relative permeability

572 The capillary pressure in sand is converted from J-functions measured with an air-mercury system  
573 to a CO<sub>2</sub>-brine system. The relative permeability curve in sand is calculated through the Brooks-Corey  
574 drainage model (Jung et al., 2018) (Fig. A1a and Fig. A1b). The capillary pressure and the relative  
575 permeability for shale are adapted from the literature and shown in Fig. A1c and Fig. A1d (Bennion  
576 & Bachu, 2008; Ren et al., 2016).



577 **Fig. A1.** Capillary pressure and relative permeability in the model: sand (a) and (b); shale (c) and (d).  
578

579 **Appendix 2: Model validation**

580 We validated our numerical model against an analytical solution which combines mass balance for  
581 radial flow and multiphase Darcy's law (Benson & Doughty, 2006; Tsopele et al., 2022). The increase  
582 of pressure  $\Delta P$  in the injection zone (IZ) as a function of distance to the injector and time is

583 
$$\Delta P = \frac{Q\mu_{brine}}{4\pi kh} W + \frac{Q\mu_{CO_2}}{2\pi kh} \left( \ln \frac{r_f}{r_w} + \left( \frac{f_{CO_2}}{k_{rCO_2}} \Big|_{r_f} - 1 \right) \left( 1 - \frac{r_w}{r_f - r_w} \ln \frac{r_f}{r_w} \right) \right)$$

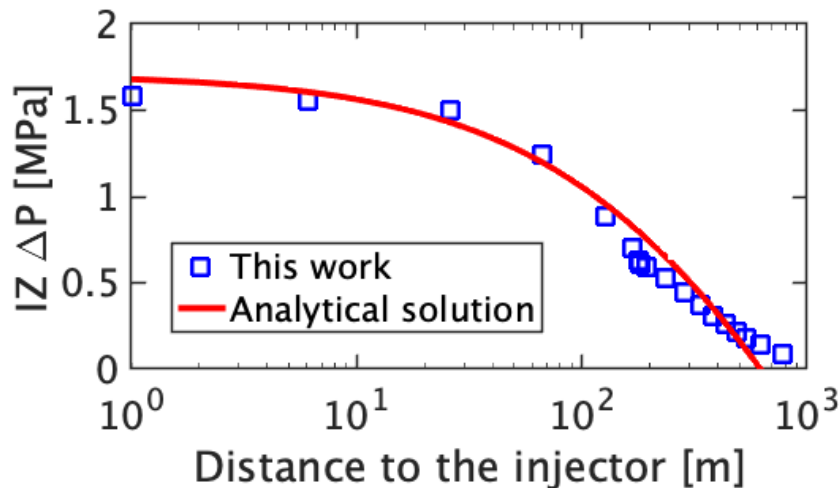
584 where

585 
$$W = -0.5772 - \ln(u_f)$$
  
586 
$$u_f = \frac{\phi\mu_{brine}C_t r_f^2}{4kt}$$

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$$r_f = \left( \frac{Qt}{\pi h \phi S_{CO_2}} \right)^{1/2}$$

Here  $Q$  is the injection rate ( $m^3/s$ ),  $t$  is the injection time ( $s$ ),  $\mu_{CO_2}$  is the  $CO_2$  viscosity ( $Pa \cdot s$ ),  $\mu_{brine}$  is the brine viscosity ( $Pa \cdot s$ ),  $k$  is the injection zone permeability ( $m^2$ ),  $h$  is the injection zone thickness ( $m$ ),  $\phi$  is the injection zone porosity,  $C_t$  is the injection zone compressibility ( $1/Pa$ ),  $r_w$  is the distance to the injector ( $m$ ). At the  $CO_2$  front,  $r_f$  is the radius of the  $CO_2$  front ( $m$ ) and  $S_{CO_2}$  is the average  $CO_2$  saturation at the  $CO_2$  front, which is indicated in Fig. 7a.  $f_{CO_2}$  is the  $CO_2$  fractional flow at the  $CO_2$  front, which is obtained through the Buckley-Leverett equation (Peters, 2012).  $k_{rCO_2}$  is the  $CO_2$  relative permeability at the  $CO_2$  front, which is calculated through the Corey-type equation as  $k_{rCO_2} = k_{rCO_2}^0 \left( \frac{S_{CO_2}}{1-S_{rb}} \right)^n$  (Burton et al., 2009), where  $S_{rb}$  is the irreducible brine saturation and  $k_{rCO_2}^0$  is the  $CO_2$  relative permeability at the irreducible brine saturation. The capillary pressure and the relative permeability information can be found in Fig. A1. Fig. A2 shows the IZ pressure increase obtained by the numerical model and mesh adopted in this paper compares well to the analytical solution.



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**Fig. A2.** Comparison of the numerical and the analytical solutions for pressure increase in the AIZ at time = 8 days.



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