

Passive injection: A strategy for mitigating reservoir pressurization, induced seismicity and brine migration in geologic CO₂ storage



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ABSTRACT

Many technical, regulatory and public perception challenges remain to be addressed before large-scale deployment of CO₂ geologic storage becomes a reality. Two major risks associated with injection of CO₂ into the subsurface are the possibility of induced earthquakes compromising long-term seal integrity, and the displacement of saline brines resulting in contamination of shallow groundwater. Both induced seismicity and brine migration are caused by elevated pressures in the storage formation owing to the relative incompressibility of water.

Here, we describe a strategy, termed passive injection that can be used to inject large amounts of CO₂ in a storage formation with no increase, temporary or long-term, in reservoir pressure. Passive injection relies on the strategic placement of brine production wells to create negative pressure gradients that result in CO₂ entering the formation at ambient pressure. Injection occurs at the intersection of pressure-depth profiles for a surface-pressurized, low-density CO₂ column and a hydrostatic column of formation fluid. A multi-stage, square-ring well configuration is envisaged, in which brine production wells are repurposed for CO₂ injection upon CO₂ breakthrough, and the next concentric ring of production wells installed at a greater distance.

Numerical simulations of passive injection are presented using the coupled thermo-hydro-mechanical (THM), multi-fluid, multi-phase numerical simulator FEHM. We consider CO₂ injection into a 3 km-deep, closed reservoir over a period of 50 years, with up to four stages of injection and production depending on well-spacing and production pressures. Storage rates as high as 4 Mt yr⁻¹ at 70% utilization of the reservoir pore volume are achieved under optimum conditions. Long-term mass production of brine is approximately 1.7 times that of CO₂ sequestered. Geomechanical effects due to reservoir drawdown, cooling near injection wells, and surface subsidence are modeled. The risk of induced seismicity is quantified in terms of the Coulomb Failure Stress (CFS) for an optimally oriented fault in an extensional tectonic regime. Injection and production-induced changes in pressure and CFS confirm that, both during and at the conclusion of injection, (i) reservoir pressure is everywhere less than or equal to its initial value; and (ii) the risk of induced seismicity is everywhere reduced or unchanged. Thus, the primary risks of brine migration outside the primary reservoir and induced seismicity compromising seal integrity are neutralized.

Passive injection produces large quantities of brine, the treatment and disposal of which represents an additional economic burden to CO₂ geologic storage operations. Unless additional revenue streams or economies of scale can be leveraged, these costs are likely to limit the viability of the proposed scheme to only the most economically favorable sites.

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1. Introduction

Geological storage of carbon dioxide (GCS) emitted by large (>Mt yr⁻¹) coal or gas-fired power stations is one proposed method for mitigating rises in atmospheric greenhouse gases (IPCC, 2005). More than 90% of these emissions are accounted for by emitters producing less than 5 Mt yr⁻¹ of CO₂ (IEAGHG, 2002). The viability of emitter-specific GCS schemes depends on their ability to accommodate large volumes of CO₂ every year for several decades (Buscheck

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et al., 2012; Deng et al., 2012). Others have suggested that CCS operations should be larger still (10s to 100s of Mt yr⁻¹); such efforts would be cooperative in nature, accommodating multiple sources at a single sequestration site while leveraging economies of scale to reduce costs (Middleton et al., 2012).

To be effective in mitigating climate change, injected CO₂ must be retained for at least 1000 years (Shaffer, 2010). One of the potential mechanisms for CO₂ to escape the primary storage reservoir is through permeable pathways that transect the caprock, for example, a pre-existing, leaky fault zone (Keating et al., 2012) or a poorly plugged well. Recently, concerns have grown that such pathways might be created by the reactivation of uncharacterized, medium-sized faults (Zoback and Gorelick, 2012). The mechanism for inducing such earthquakes is generally an increase in pressure within the fault contributing to a reduction in the effective stress (Cappa and Rutqvist, 2011). Therefore, it will be necessary to perform comprehensive geomechanical site assessment and effectively manage reservoir overpressures to address these concerns.

Another risk associated with GCS is the environmental impacts of brine migration into shallow aquifers. Due to its incompressible nature, the area over which formation pressures are elevated can far exceed the actual area of the injected CO₂ (Pruess and Garcia, 2002). For instance, Birkholzer et al. (2009) showed a pressure rise of 1 MPa at 15 km distance from an injection well even though the CO₂ had traveled only 2 km. Oldenburg and Rinaldi (2011) modeled transport of saline brine within a vertical conduit and found that, for sufficient overpressurization, brine could migrate into an overlying freshwater aquifer, forming a dense, saline layer at the base. Thus, there is a credible concern that vertical connections, e.g., fault zones, open or leaking wells, could become potential sources of migration under overpressure, even if they are at significant distance from the injection site.

Hosseini and Nicot (2012) developed analytical models to assess improved storage capacity by brine extraction. They demonstrated a 30% increase in CO₂ storage over a scenario in which no brine production occurs. However, gains were more modest for reinjection strategies, i.e., where the produced brine was disposed of into a shallower aquifer. Active CO₂ reservoir management (ACRM) is a proposed pressure management scheme in which brine production wells are deployed in support of CO₂ injection to manage fluid overpressure within the reservoir (Buscheck et al., 2012; Elliot et al., 2013). There are numerous advantages, including the promotion of higher injection rates by reducing near-well pressure build up, reduction of brine migration and a lessened risk of induced seismicity; all these benefits are derived from the maintenance of lower reservoir pressures. However, ACRM comes with additional costs, including the drilling and operation of brine production wells, and the treatment and disposal of the brine produced. On a case-by-case basis, the cost of managing extracted water will depend on the amount of total dissolved solids (TDS), geographic proximity to reinjection formations (Harto and Veil, 2011), water scarcity and local environmental regulations (Breunig et al., 2013). Buscheck et al. (2012) provide an in-depth review of the various treatment options (estimates range from \$0.40 to \$2.30/ton of CO₂; Bourcier et al., 2011; Sullivan et al., 2012) and secondary uses for produced brine, e.g., as a coolant in a conventional power plant, a working fluid in an Enhanced Geothermal System (EGS). In contrast, an IEAGHG report (2012) analyzing several CCS and brine extraction case studies concluded that treatment costs are in some cases prohibitive (up to \$8.02/ton) and deep geological disposal may be preferable. They further suggest dissolution of CO₂ in any reinjected brine as a secondary mechanism for sequestration (IEAGHG, 2012; Pool et al., 2013).

Birkholzer et al. (2012) propose a scheme of Impact-driven pressure management, where brine extraction wells are operated in close proximity to sensitive features (e.g., a critically stressed fault)

to meet local performance targets. The advantage of this scheme is that it minimizes the quantity of extracted brine and associated treatment costs; however, the authors acknowledge that case-by-case considerations may require regional pressure management, for instance, where the locations of sensitive features are unknown or are broadly distributed, or where public acceptance, plume manipulation or monitoring considerations require reduction of the pressure-impacted area.

In these scenarios, costs can be partially offset by the market value of produced fresh-water, in the case of reverse-osmosis treatment of brine, or generated electricity, if an EGS system is successfully utilized. Breunig et al. (2013) consider more novel revenue streams, such as mineral extraction and biomass (algae and fish) production, and conclude that the net present value of extracted brine may in some circumstances be positive. However, perhaps the greatest, yet least well-constrained, cost-saving of ACRM is the reduction in likelihood of low-probability, high-impact events. For example, the total cost of an induced earthquake that irreversibly compromises a caprock seal includes the volume of CO₂ that is subsequently emitted, the loss of a sequestration location and all investment in its development, including geological characterization, permitting and infrastructure. Similarly, the cost of brine migration leading to aquifer contamination would be measured in terms of the remediation effort or the permanent loss of the groundwater resource (Bielicki et al., 2013; Pollak et al., 2013). Relatively mature studies of seawater intrusion into coastal aquifers, e.g., California, Florida, Netherlands, are a useful guide in this regard (Bear and Cheng, 1999).

Several engineering challenges facing CO₂ are directly linked to overpressurization within the reservoir. In many instances, some amount of reservoir pressurization below prescribed limits (e.g., fracture propagation or fault reactivation pressure) is permissible and does not lead to induced seismicity. For instance, Ellsworth (2013) report that 30,000 Class II wells are used in the US for wastewater disposal (associated with the shale gas industry), while only a few of these are correlated with increased rates of $M \geq 3$ seismicity. Nevertheless, in cases where seismicity did occur, it was both unexpected and had adverse economic and public perception impacts (e.g., Keranen et al., 2013; Kim, 2013). Such consequences are likely to be at least, if not more, undesirable within a GCS context.

Subsurface engineering is an inherently uncertain endeavor; medium-sized faults (particularly within the basement, e.g., Horton, 2012; Kim, 2013) can escape detection during site-characterization while imperfect quantification of failure parameters (e.g., fault friction, ambient stress) that inform operating pressure thresholds may contribute additional uncertainty. Unknown faults cannot be the target of impact-driven pressure management schemes (Birkholzer et al., 2012) and critical-crust adherents suggest that much of the continental interior is susceptible to induced earthquakes (Zoback and Gorelick, 2012). Both induced seismicity and brine migration are high-impact events that in an information-poor environment are difficult to forecast. In the event that such risks are deemed totally unacceptable to a GCS operation, one option would be to avoid the underlying physical cause – reservoir pressurization – while still achieving the CO₂ storage goal.

In this contribution, we outline a strategy for emplacement of large volumes of CO₂ into deep geological formations without any significant increase, temporary or long-term, in reservoir pressure. The strategy relies on brine production as the primary mechanism for driving CO₂ into the formation and is, in a sense, an extension of ACRM. However, unlike ACRM, brine production is the sole driver of fluid transport in the system; injection overpressure is not allowed to occur in the process. Injection operations are multi-staged, employing concentric rings of production wells to draw CO₂ from interior wells at formation pressure. In essence, the CO₂,

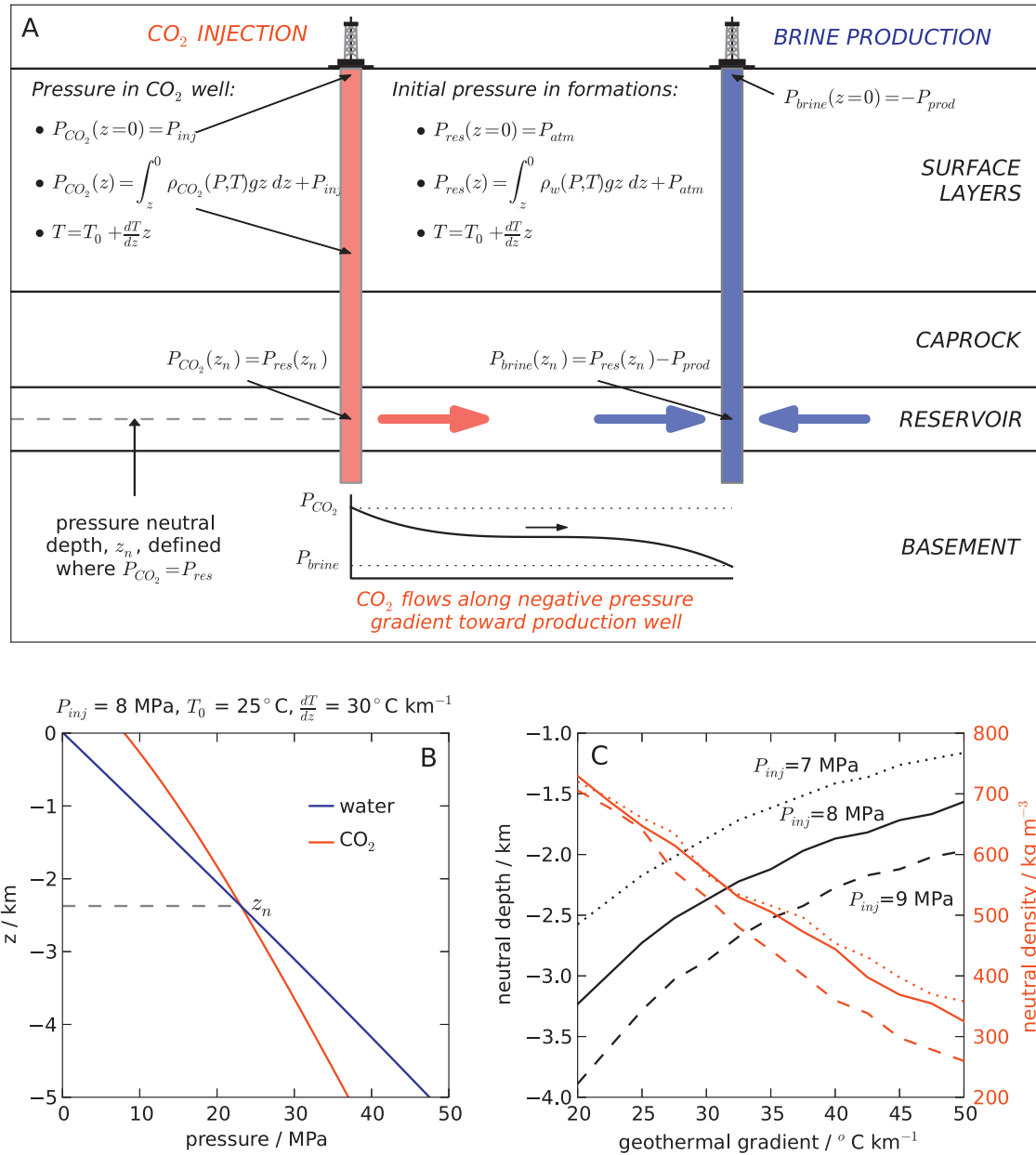


Fig. 1. (A) Schematic representation of passive injection via brine production in a two well system. Governing equations for pressure in the CO₂ injection well (P_{CO_2}) and initial formation pressure (P_{res}) are shown. A schematic of pressure variation along the profile between the injection and production wells is included at the bottom of the subfigure. (B) Pressure–depth curves for a column of formation water (blue) subject to atmospheric conditions at the surface, and a column of CO₂ (red) pressurized to 8 MPa at the surface. For a geothermal gradient of $30^\circ \text{C km}^{-1}$, the pressure neutral depth, z_n , is $\sim 2.3 \text{ km}$. (C) Dependence of z_n (black curves) and CO₂ density at z_n (red curves) on geothermal gradient for three surface pressurizations: 7 (dotted), 8 (solid) and 9 MPa (dashed). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of the article.)

rather than being pushed out of the injection well by overpressure, is drawn into the formation by underpressure resulting from brine production.

In support of this concept, we present numerical experiments conducted using the thermo-hydro-mechanical, multi-fluid, multi-phase simulator FEHM that demonstrate the feasibility of passive CO₂ injection at rates in excess of 1 Mt yr^{-1} . We explore operational and site characteristics that optimize injection while minimizing costs, including well spacing and scheduling, brine production pressure, geothermal gradient and aquifer compartmentalization. Finally, we provide an analysis of induced stresses, mechanical deformation and reservoir pressure throughout the injection operation. This supports the two main claims that: (i) formation pressures never exceed their initial value and therefore the possibility of brine migration and shallow aquifer contamination is

negligible; and (ii) the likelihood of fault reactivation, of particular concern in extensional environments, is reduced as a consequence of the brine production, thereby providing additional long-term CO₂ storage security.

2. Passive injection of CO₂

In this section, we outline a strategy for emplacing CO₂ in the subsurface without any increase in formation fluid pressure. Injection is termed passive, because CO₂ exits the injection well at the same pressure as the formation fluid.

At its core, passive injection relies on CO₂ flowing out of an injection well along a negative pressure gradient created by brine production. Fig. 1A shows schematically the CO₂ and brine flows envisaged for an idealized horizontal reservoir overlain by an

impermeable caprock. The injection and production wells are separated by some horizontal distance, r , and are assumed to be open within the reservoir. The production well is pumped such that the pressure inside the well at reservoir depth is some amount P_{prod} less than the initial formation pressure; as a consequence, brine flows toward the production well and is removed from the reservoir. With sufficient pumping, the underpressured region will expand outward from the production well and begin to influence flow in the vicinity of the injection well.

In a traditional injection operation, the pressure within the CO₂ well at reservoir depth is maintained at some amount higher than the formation pressure due to wellhead pressure (WHP) applied at the surface. Formation pressure near the well, which is initially hydrostatic, will increase as the CO₂ flows into the formation, displacing brine. In contrast, here we are considering the case where CO₂ in the well is at the same pressure as that initially in the formation. In the absence of any other pressure perturbations within the formation, there would be no pressure gradient at the injection well and CO₂ flow would be zero. However, due to ongoing brine production at a proximate location, formation pressure is less than its initial value; therefore, CO₂ flows from the well into the formation.

One potential drawback of this strategy is the negative changes in formation permeability that may be induced by production and pressure drawdown. For instance, several studies have documented permeability reduction in produced oil and gas reservoirs, attributed to poroelastic and inelastic deformation of the pores (Schutjens et al., 2004; Pettersen, 2010). However, in contrast to an oil production operation where the target reservoir depletion may exceed 50 MPa before abandonment (Schutjens et al., 2004), drawdowns considered here do not exceed 10 MPa. Furthermore, pressures are eventually recovered during CO₂ emplacement. Compiled oil and gas production data indicate a permeability reduction of no more than 10% associated with a drawdown of this magnitude (Schutjens et al., 2004; Pettersen, 2010). Consequently, pressure sensitivity of the permeability is not considered here, although may be significant if this strategy were extended to higher production pressures.

2.1. Neutral pressure depth

Passive injection requires the delivery of liquid or super-critical CO₂ to a specific depth (the formation) at a specific pressure (initial formation pressure). CO₂ pressure, P_{CO_2} , within the well depends on the weight of the fluid column above; typically, this is calculated by integrating the pressure and temperature dependent density, $\rho_{CO_2}(P, T)$, over the depth of the column, i.e.,

$$P_{CO_2}(z) = \int_z^0 \rho_{CO_2}(P_{CO_2}, T)gzdz + P_{inj}, \quad (1)$$

where g is the acceleration of gravity and P_{inj} is a constant pump pressure applied at the surface. Temperature is assumed to vary linearly with depth, i.e.,

$$T(z) = T_0 + \frac{dT}{dz}z, \quad (2)$$

where T_0 and dT/dz are the surface temperature and geothermal gradient, respectively. As ρ_{CO_2} is defined in terms of P_{CO_2} and T using a look-up table, the integral is evaluated iteratively. For $P_{inj} = 8$ MPa, $T_0 = 25^\circ\text{C}$, and $dT/dz = 30^\circ\text{C km}^{-1}$, Fig. 1B plots the pressure inside a column of CO₂ within the injection well (red curve).

Deploying similar arguments, the initial pressure of a column of formation water, P_{res} , is also derived, in this case assuming atmospheric pressure at the surface and using third order polynomial functions in P and T to calculate water temperature (Zyvoloski, 2007). For simplicity, the effects of salt concentration on density

have been neglected. The pressure of this column is also plotted in Fig. 1B (blue curve).

Fig. 1B shows that while CO₂ pressure is initially higher than in the formation – CO₂ must be compressed at the surface so that it can be injected as a liquid – due to its higher density, formation pressure eventually catches up and surpasses CO₂. We define the neutral pressure depth, z_n , where $P_{CO_2} = P_{res}$; this is the targeted injection depth.

For a given geothermal gradient and a target reservoir depth, the operator can exercise some control over z_n by varying surface pressurization of the CO₂. For example, increasing P_{inj} from 8 to 9 MPa, for a 30°C km^{-1} geothermal gradient, increases the neutral pressure depth by ~ 1 km (Fig. 1C). However, as the injection pressure must be at least large enough to liquefy the CO₂ at the surface, there exists an inherent lower limit on z_n , typically 2–3 km depending on surface temperature and geothermal gradient. At present, this requirement would rule out shallower storage formations. Furthermore, well completion costs increase with depth; for the 2–3 km deep wells proposed here, EPA (2010) estimate costs of \$3.5–4.5 million per well. For the temperature gradients considered here, CO₂ remains in a liquid form despite increasing temperature with depth.

The neutral pressure depth exists because of the density contrast between CO₂ and formation water. The rate at which P_{res} approaches P_{CO_2} depends on this contrast; the greater the difference, the shallower z_n . As CO₂ density is strongly temperature dependent, z_n is shallower at higher geothermal gradients (Fig. 1C). However, there is a tradeoff; shallower injection depths at higher geothermal gradients are accompanied by a lower density of the injected CO₂. Thus, the mass of CO₂ that can be stored in a given pore volume is reduced. Furthermore, buoyancy forces on the sequestered CO₂ are proportional to the density difference with the formation water; at higher geothermal gradients, these forces are greater.

The conclusions are consistent with those of Bachu (2003), who considered the importance of geothermal gradient in an analysis of the suitability of sedimentary basins in Canada for GCS. For a range of geothermal gradients (20 – 60°C km^{-1}) and surface temperatures (0 – 25°C), he showed that colder basins permitted higher CO₂ injection densities, resulting in greater storage efficiency and a reduced buoyant load on the overlying caprock.

Based on the arguments outlined in this section and the CO₂ phase behavior shown in Fig. 1B and C, we have proceeded to model the scenario of a cool basin (30°C km^{-1}) with a surface temperature of 25°C . Injection is to target a reservoir at 3 km depth; thus, CO₂ would need to be pressurized to ~ 8.7 MPa at the surface for z_n to coincide with the reservoir.

2.2. Well patterns

The second important component of passive CO₂ injection is the repurposing of brine production wells for CO₂ injection when breakthrough occurs; this is the concept of a multi-stage GCS operation. This may introduce an additional cost during well completion as the both brine production and CO₂ injection must be accommodated. The locations and scheduling of injection and production wells are flexible and would likely be both site and operation specific. However, in this pilot study, we restrict ourselves to a regular well pattern and investigate some of the general sensitivities of this scheme.

Fig. 2 shows schematically, in quarter-symmetry and map view, the distribution of injection and production wells for a four-stage passive injection operation. In the first stage, injection occurs into the lower left corner (center well), with brine production occurring some distance, r , away. This corresponds to a five-spot well pattern and an initially high ratio of production to injection wells (4:1).

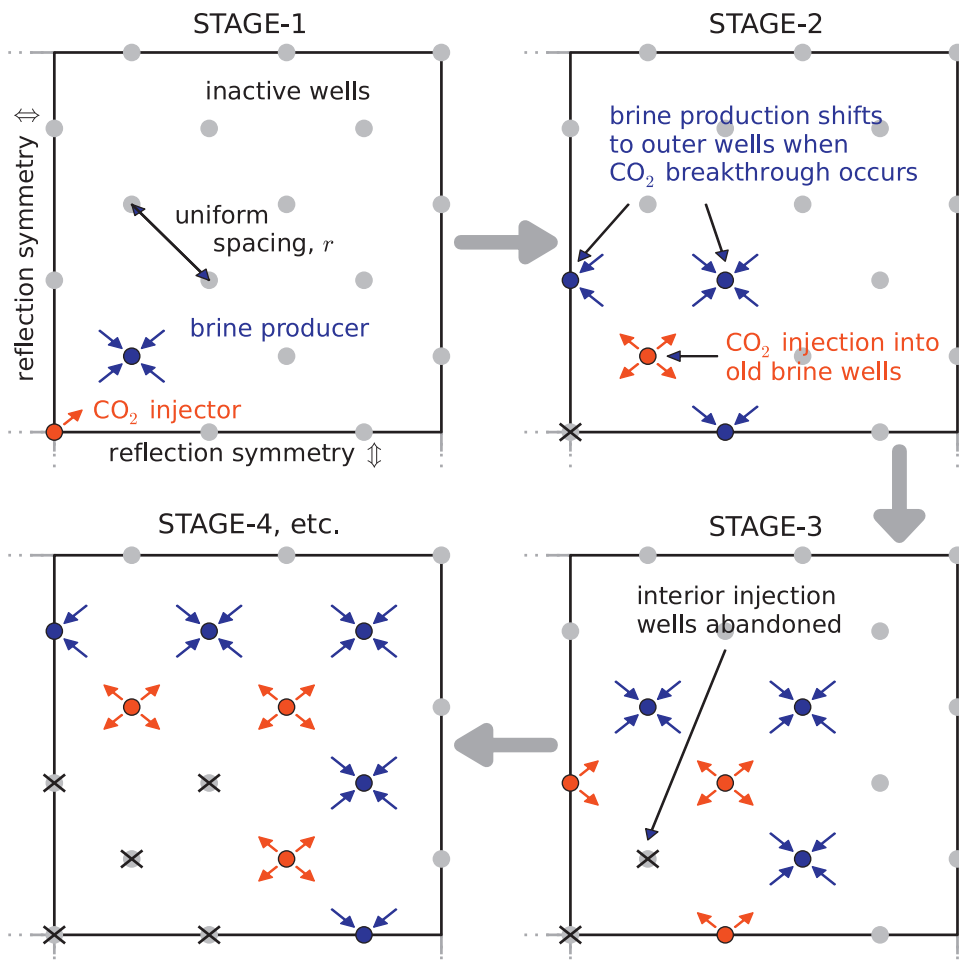


Fig. 2. Quarter-symmetry schematic representation of multi-stage, multi-well injection/production operation. A regular array of active CO₂ injectors (red), brine producers (blue) and inactive (gray) wells are shown. CO₂ migrates from the injection wells toward the pressure lows created by the brine producers. When a CO₂ breakthrough criterion is satisfied, a new stage begins, in which brine production shifts further out and old production wells are repurposed for injection. Interior injection wells are plugged and abandoned. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of the article.)

Injected CO₂ migrates toward and eventually appears at the production well. However, depending on the produced mixture of CO₂ and brine, it may still be economical to continue operation and simply separate the produced CO₂ for reinjection. Eventually however, the produced CO₂ fraction will be significant enough to satisfy a breakthrough criterion and warrant the next stage of injection; this would likely depend on the economics of CO₂ separation and reinjection. Here, we change stages when the instantaneous retention efficiency – defined as the net CO₂ retention rate divided by the injection rate – is 50%, i.e., for each ton of CO₂ injected, half a ton is co-produced with the brine.

While 50% CO₂ production may seem arbitrarily high, the decision to transition to the next stage of injection would ultimately be a financial one. If CO₂ injection targets are still being met, and if the costs of separation, transport and reinjection of the produced CO₂ are low compared to those associated with stage transition, e.g., drilling new production wells, repurposing existing production wells for injection, then continued operation at reduced efficiency may make fiscal sense. In Section 4.2.4, we compare results obtained for the relatively lenient 50% criterion versus a stricter 2% produced CO₂ cutoff. These end-member scenarios provide some bounds on the potential operating well schedules should such a strategy be pursued.

Each subsequent stage involves: (i) repurposing all brine production wells from the previous stage for passive CO₂ injection; (ii) developing a new set of production wells in staggered formation

that bound the injection wells; and (iii) plugging and abandoning old injection wells. For example, in moving from stage-1 to stage-2, (i) four brine production wells are repurposed for injection, (ii) eight new production wells are developed; and (iii) one old injection well is abandoned. The resulting ratio of production to injection wells decreases to 2:1. In moving from stage-2 to -3, and from -3 to -4, the ratio decreases further, to 1.5:1 and then to 1.33:1.

Continued use of early stage injection wells is not likely to significantly improve injection rates due to the obstructing pressure effects of later injection wells. As an alternative, an operator might consider injection of a portion of the extracted brine into these wells in an effort to reduce treatment costs and increase capillary trapping; however, such brine injection would contribute to reservoir pressurization that violates the zero-pressure-increase goal of passive injection. The incremental benefits of continued CO₂ injection into the abandoned interior wells are considered in Section 4.2.6.

3. Numerical simulations

The aim of this paper is to test the feasibility of the proposed injection strategy via computational modeling. In particular, we are concerned with the operational requirements, such as number of wells, land area, and pumping pressures, required for safe CO₂ storage at injection rates on the order of several Mt yr⁻¹ for fifty years. Numerical experiments are performed using the subsurface

flow, transport and geomechanical simulation code, Finite Element Heat and Mass transfer (FEHM; Zyvoloski, 2007). Model construction is described in Section 3.2, while a mesh sensitivity analysis is presented in Section 3.3.

3.1. Code description

FEHM solves heat and mass conservation equations for multi-phase, multi-fluid, unsaturated flow in porous media, coupled to non-linear elastic and plastic deformation. The heat and mass balance equations are solved using an efficient, node-centered control volume implementation, while stresses are computed on the corresponding finite element grid. Depending on the degree of coupling, the governing equations for stress and flow can be solved fully coupled or sequentially. In the simulations presented here, where stress perturbations are supplied by pressure and temperature changes, it is sufficient to perform a single stress solve at the end of a simulation or at desired time steps within, i.e., we use sequential coupling.

The primary coupling between flow and stress is thermal and poroelastic. Positive changes in fluid pressure cause an increase in rock compression via a Biot coefficient of 1, while decreases in temperature result in rock contraction via the coefficient of thermal expansion, here $3 \times 10^{-5} \text{ K}^{-1}$. In these simulations, induced stress changes are primarily poroelastic due to drawdown around production wells. Local cooling by the injected fluid contributes to a secondary stress perturbation.

In many codes, differential flow in mixtures of CO_2 and water are typically handled via user-defined relative permeability curves. Two commonly used relationships are the Brooks–Corey and van Genuchten curves (Pruess and Garcia, 2002; Keating et al., 2012). In contrast, here we use power-law curves of the form

$$k_w = \left(\frac{S - S_{\min}}{1 - S_{\min}} \right)^{n_w}, \quad k_{\text{CO}_2} = k_{\max} \left(\frac{1 - S}{1 - S_{\min}} \right)^{n_{\text{CO}_2}} \quad (3)$$

where S is the saturation of water, k_w and k_{CO_2} are the relative permeabilities of water and CO_2 , $S_{\min}$ is the irreducible saturation for water, $k_{\max}$ is the maximum relative permeability for CO_2 , and n_w and n_{CO_2} are exponents for the water and CO_2 curves, respectively. These curves are fitted to compiled experimental data for sandstones (Fig. 3; data from Bachu and Bennion, 2008; Perrin and Beson, 2010; Krevor et al., 2012; Berg et al., 2013); this avoids having to calibrate for Brooks–Corey or van Genuchten parameters while still providing a good match to observation. Based on these fits, we choose an irreducible water saturation of 0.2, a maximum CO_2 relative permeability 80% that of water, and exponents of 3.1 for both curves. These parameters are summarized in Table 1.

3.2. Model setup

Fig. 4A presents the computational grid, zonal assignments and boundary conditions necessary to simulate the simplified production/injection strategy outlined in Section 2 (Figs. 1A and 2). The computational domain is a cuboid that encompasses one quarter of the complete well field, extending 5 km on the horizontal edges. Increased horizontal refinement is supplied in the vicinity of injection and production wells with the number of refined regions depending on the number of stages in the injection operation; the importance of horizontal refinement around wells is discussed in Section 3.3. Vertical refinement is coarse except in the vicinity of the reservoir and caprock; the interface between these units is located at a depth of 3 km.

Both 100 m and 300 m thick reservoir and caprock units are stratigraphically horizontal, i.e., we do not consider buoyant CO_2 migration within an inclined reservoir (Buscheck et al., 2012). For dipping storage formations, buoyant migration of the CO_2 plume

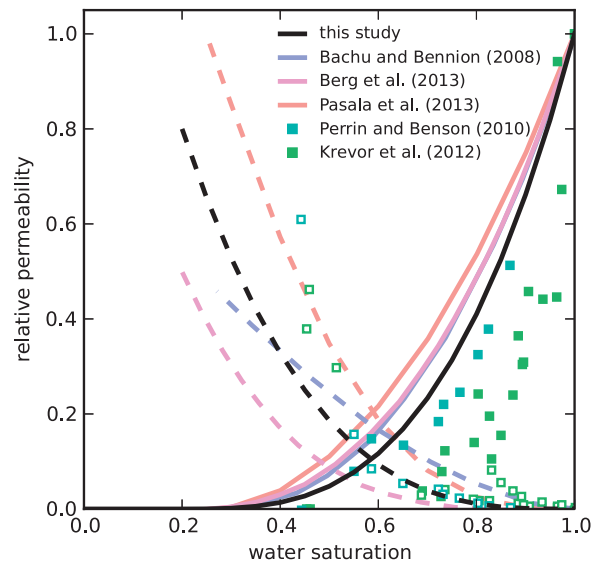


Fig. 3. Relative permeability curves for liquid CO_2 (black dashed line) and water (black solid) used in this study (from Dempsey et al., 2014). These curves are representative power-law functions fit to compiled experimental data and curves used by other studies (Bachu and Bennion, 2008; Perrin and Beson, 2010; Krevor et al., 2012; Berg et al., 2013; Pasala et al., 2013).

may necessitate higher production underpressures down-dip to counteract this tendency. Consistent with other studies (Rutqvist et al., 2010), homogeneous, isotropic permeabilities and porosities are assigned (Table 1). Assumptions of such homogeneity do not address issues of deleterious CO_2 fast pathways that would be

Table 1

Parameters used in the models and calculating Coulomb Failure Stresses. Bracketed parameters show values explored in sensitivity analysis.

Parameter	Value
<i>Operational</i>	
Injection depth	3 km
Production pressure	2, 5, 10 MPa
Injection pressure	0
Injection temperature	50 °C
Reservoir temperature	115 °C
Well spacing	0.2–2.4 km
<i>Material</i>	
Thermal conductivity	$3.0 \text{ W m}^{-1} \text{ K}^{-1}$
Density	2500 kg m^{-3}
Specific heat capacity	$1000 \text{ J m}^{-3} \text{ K}^{-1}$
<i>Permeability</i>	
Caprock	10^{-19} m^2
Reservoir	10^{-14} m^2
Basement	10^{-18} m^2
<i>Porosity</i>	
Caprock	0.01
Reservoir	0.1
Basement	0.01
<i>Young's modulus</i>	
Caprock	20 GPa
Reservoir	5 GPa
Basement	20 GPa
Poisson's ratio	0.25
Biot coupling	1.0
<i>Relative permeability (see Eq. (3))</i>	
Irreducible saturation, $S_{\min}$	0.2
Max. CO_2 rel. perm., $k_{\max}$	0.8
Fitted exponents, n_w and n_{CO_2}	3.1
<i>Coulomb Failure Stress (CFS)</i>	
Friction coefficient	0.65
Failure plane strike	Parallel to y-axis and σ_H .
Failure plane dip	60°

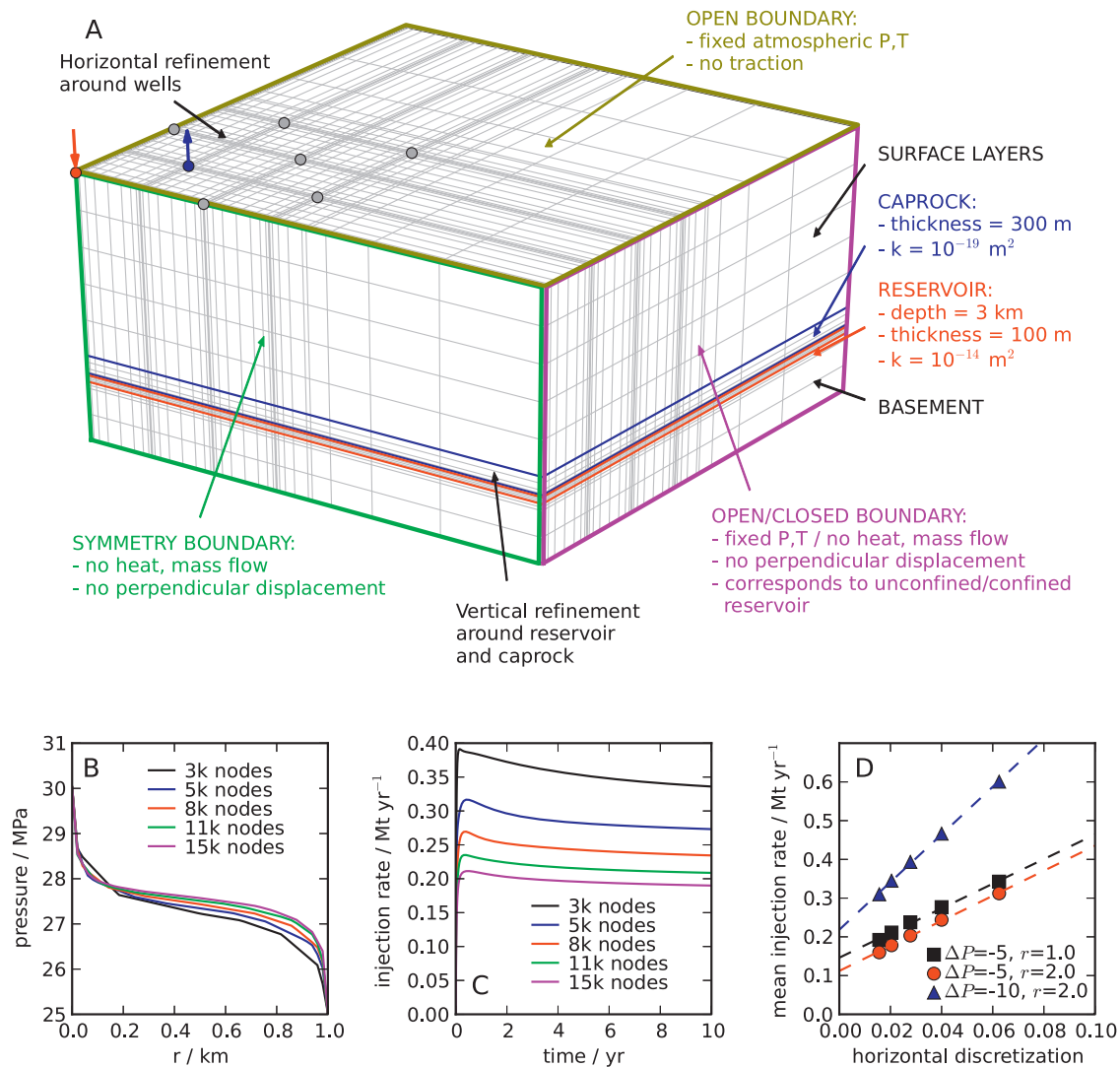


Fig. 4. (A) Overview of computational mesh, formation zones and properties, and boundary conditions for stage one of a three-stage injection scenario. Sensitivity of the pressure profile between injection ($r=0$) and production well ($r=1 \text{ km}$) (B) and attendant injected flow rate (C) to mesh resolution. (D) Convergence of flow rate with increasing resolution for three injection configurations: 5 MPa underpressure and 1.0 km well spacing (black squares, see also B and C); 5 MPa underpressure, 2.0 km spacing (red circles); 10 MPa underpressure, 2.0 km spacing (blue triangles). Flow rate at the medium resolution (used for subsequent simulations) is between 1.6 and 1.8 times the limiting flow rate in each case. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of the article.)

expected to form in formations with realistic permeability heterogeneity. However, given that formation homogeneity is likely to be desirable characteristic of potential storage sites, we have determined this issue to be outside the scope of the present study. The prescribed caprock permeability is sufficient to prevent vertical migration of CO_2 and we do not treat failure or leakage scenarios (Rutqvist and Tsang, 2002; Rutqvist et al., 2008). However, the implications for induced seismic risk are quantified and discussed (see Section 5.1).

Quarter spot symmetry is ensured by prescribing reflecting boundary conditions – no heat or mass flow, no perpendicular displacement, i.e., rollers – on two lateral boundaries. The other lateral boundaries are also closed to heat and mass transfer and are on rollers; physically, this corresponds to a laterally closed aquifer with no recharge. In Section 4.2.5, the second set of lateral boundaries are opened to consider the case of an open reservoir; this is achieved by allowing flow in or out of the boundary to maintain a fixed pressure. The upper boundary, which corresponds to the ground surface, is prescribed zero traction and maintained at atmospheric temperature (25°C) and pressure. The lower

boundary, at 4 km depth, is closed to heat and mass flow and is on rollers.

The model is initialized with vertical gradients in temperature and pressure in accordance with arguments outlined in Section 2.1, i.e., $dt/dz = 30^\circ\text{C km}^{-1}$ and pressure given by the weight of the overlying fluid column.

Two options are available for representing injection and production in the model: either (i) source/sink flow rates can be directly prescribed, with pressure in the control volume changing in response to the mass balance; or (ii) inlet and outlet flowing pressures are prescribed, in which case the source/sink flow rates are proportional to the difference between nodal and flowing pressure. In practice, this is equivalent to a well operator modifying injection and production rates to maintain a constant WHP.

Each approach has its own advantages and disadvantages; for instance, a fixed mass flow rate achieves (by definition) the desired sequestration targets but provides no control over formation pressures. This is unacceptable for passive injection, as precise engineering of pressure magnitude and gradient is central to achieving the objective of zero overpressure inside the reservoir.

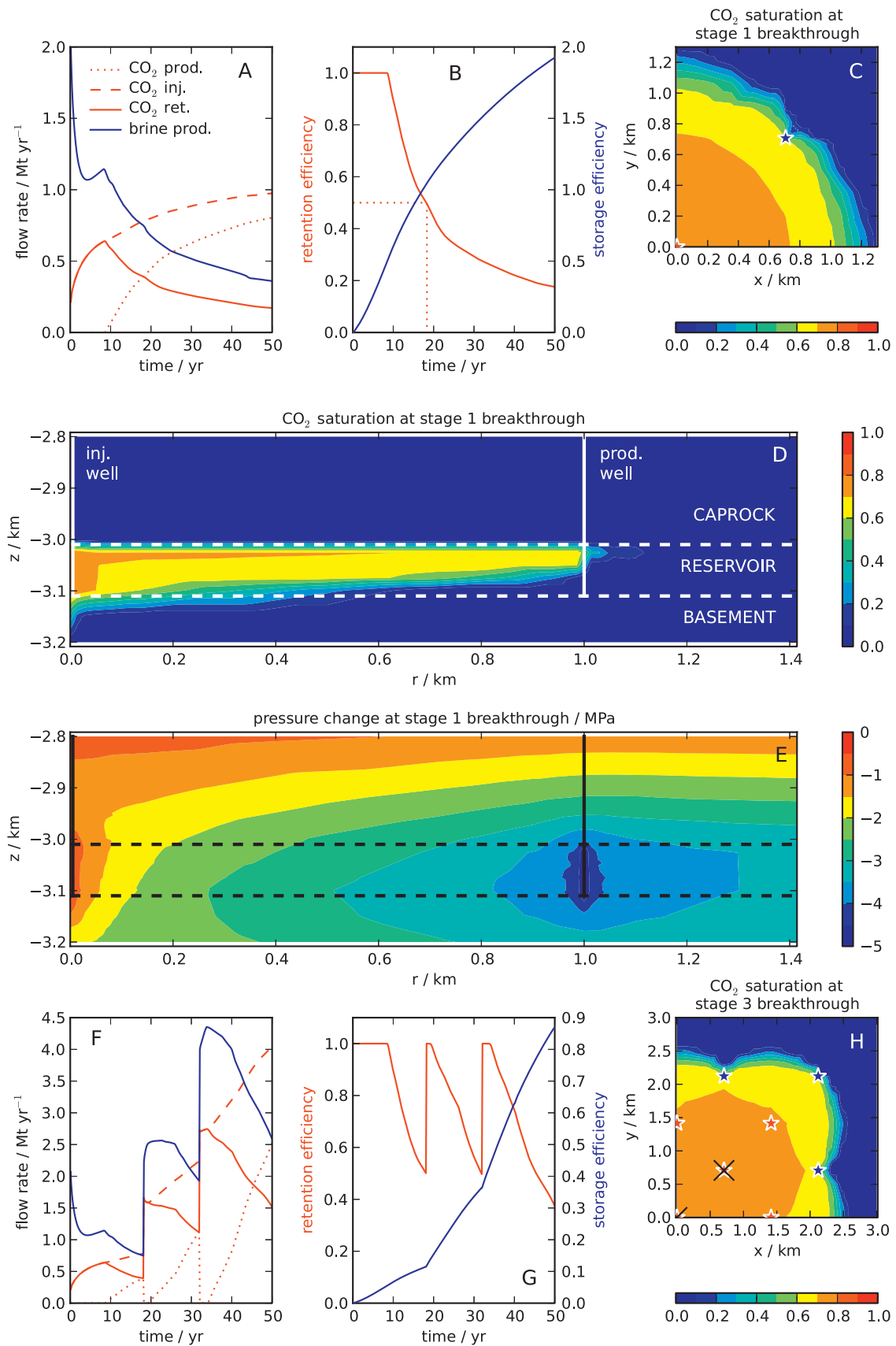


Fig. 5. Summary of a 50-year, single-stage, 1-km-spacing CO₂ injection scenario. (A) CO₂ injection (red dashed), production (dotted) and net retention (solid) rates, and brine production rate (blue). (B) Retention efficiency (red) and storage efficiency (blue) for the 50-year simulation. Here the breakthrough criterion is arbitrarily defined where the retention efficiency drops below 50%, in this case after ~18 years as indicated by the dotted red line. (C) Horizontal slice of CO₂ saturation at the top of the reservoir unit at the breakthrough time of 18 years. Production and injection wells are shown by a blue and red star, respectively. (D) Vertical slice of CO₂ saturation between the injection and production wells. (E) Accumulated fluid pressure change at the breakthrough time; note, negative values indicate a drop in fluid pressure from initial values. (F–H) As for

By operating fixed pressure injection and production we gain this control, at the cost of being unable to prescribe flow rates – the operational implications of this restriction are discussed in Section 4.1. Furthermore, unreasonably high injection and production rates occur at early time as pressures around the wells equilibrate with the imposed source term; however, these effects are quite transient and these anomalous mass transfers are small in comparison to total transfers over the length of a simulation.

Both injection and production wells are represented using fixed flowing pressures sources/sinks. All wells are assumed to be vertical and open within the reservoir, i.e., several source nodes are assigned per injection well.

3.3. Mesh sensitivity

Use of mass sources and sinks formulated in terms of a flowing-pressure creates sharp pressure gradients in the vicinity of injection and production wells. As mass flow is proportional to pressure gradient, a high mesh resolution is desired near well locations (Fig. 4A). A mesh sensitivity study was undertaken to establish a resolution that adequately represented near-well pressure and flow.

In this simplified scenario, there is a single injection well at the symmetry corner (center of the full well pattern) and production well at a distance of 1 km; this corresponds to the stage-1 injection pattern shown in Fig. 2. As we are concerned with mass flow rates, pure water is used in place of CO₂. This enables us to evaluate passive injection rates at higher mesh resolution.

Fig. 4B shows the gradual refinement of steady-state fluid pressure along a profile between the wells for increasing mesh resolution (incremental addition of two nodes between injector and producer up to a doubling of the coarsest mesh resolution). Near-well gradients are seen to sharpen, while pressure is relatively flat in between. Corresponding injection rates for a ten year period for the five meshes are given in Fig. 4C; injection decreases from 0.34 Mt yr⁻¹ for the coarsest mesh to 0.18 Mt yr⁻¹ for the finest. This is in response to flattening of the inter-well pressure gradient. When plotted against the horizontal discretization (Fig. 4D), mean injection rate trends linearly toward a limiting value of 0.15 Mt yr⁻¹ for an infinitesimally discretized domain. Mesh convergence for simulations with a larger well spacing and higher production pressure are also shown.

All remaining simulations described here were performed using medium resolution meshes (Fig. 4A). While for a single-stage mesh, i.e., the 8000 node grid used in the mesh sensitivity study, this is not difficult to simulate, adding additional stages requires more areas of horizontal refinement. Two-, three- and four-stage grids, all modeled here, have respectively, 17,000, 30,000, and 47,000 nodes at the medium resolution. Given the increased computational costs associated with simulating CO₂ mixtures and coupled stress, this resolution is regarded as adequate.

Accurate representation of CO₂ injection rates is a key outcome of this model. In Fig. 4D, we show that by using a medium resolution mesh we will overestimate this quantity in a given system. However, Fig. 4D also quantifies this overestimate; for the medium resolution mesh, this is between 60% and 80% depending on well-spacing and production pressure. This allows us to leverage the computational savings of low resolution meshes to perform a broader sensitivity study, while acknowledging that our results are likely to overestimate CO₂ injection rates and volumes by a factor on the order of 1.6–1.8. In future treatments, use of specific

well-modules embedded in the medium resolution mesh could yield improved estimates of injected and extracted flow rates.

4. Results

In our initial simulation, we consider a single-stage injection scenario, in which the central injection well is separated from the outer production wells by a distance of 1 km. Production wells are pumped at 5 MPa (i.e., a fixed pressure source 5 MPa less than the ambient value) for a period of 50 years, while a CO₂ source term, fixed to maintain initial formation pressure, represents the injection well. Results are summarized in Fig. 5A–E.

For this configuration, we find an initial CO₂ injection rate of 0.3 Mt yr⁻¹, rising to 0.6 Mt yr⁻¹ after ten years when CO₂ first reaches the production well. CO₂ injection continues to increase to 1.0 Mt yr⁻¹ by the end of fifty years; however, at this time, the well is producing almost as much CO₂ as is being injected. The reason for a steady rise in the CO₂ injection rate is that fluid being driven between injection and production wells, while initially water, is steadily being replaced by less viscous CO₂. Our primary interest is in the CO₂ retention rate, which we define here as the difference between the instantaneous injection and production rates. We consider only structural trapping and neglect the effects of CO₂ dissolution and subsequent mineral reactions that would sequester CO₂ permanently. Following the breakthrough of CO₂ at the production well, the retention rate exhibits an exponential decline. Nevertheless, by the end of the 50 year simulation, more than 16 Mt of CO₂ have been stored in the reservoir (Fig. 6A).

Brine production exhibits some similar trends to the CO₂ injection curve. At early times, brine production is high but declines rapidly as reservoir pressures are initially reduced. However, for a short period of time, this decline is reversed, gaining slightly in response to the emplacement of less viscous CO₂. When CO₂ breakthrough occurs, the brine production rate drops in concert with the CO₂ injection rate; this is because an ever increasing proportion of production is co-produced CO₂.

While initially CO₂ production is low and the CO₂ retention rate is appreciable, a point must eventually be reached where continued operation is no longer desirable; this is defined by the breakthrough criterion. In practice, this will be determined by economic drivers such as financial penalties for emitting the produced CO₂, infrastructure costs for separation and transport to a reinjection well, and the cost of drilling the next stage of wells. However, for the purposes of this study, we use an arbitrary breakthrough criterion based on the retention efficiency, which we define as the instantaneous retention rate divided by instantaneous injection rate. This is a useful measure of the current effectiveness of the GCS operation. In this simulation, a new stage is initiated when the retention efficiency drops below 0.5; for stage-1, this occurs after 18 years of injection (Fig. 5B). In these simulations, 0.5 represents one possible end-member for the amount of CO₂ co-production an operator might economically justified in tolerating.

Another metric of the effectiveness of the storage strategy is storage efficiency (SE), defined here in terms of the volume CO₂ stored in the section of the reservoir formation that is inside the perimeter of production wells. This is essentially the reservoir volume that has been exposed for storage by the passive injection method. If the perimeter of production wells bounds an area, *A*,

(A–C) but for the full three-stage injection operation, with stage changes after 18 and 35 years. Storage fraction in G is calculated for the reservoir volume laterally delineated by the square formed by the final set of production wells. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of the article.)

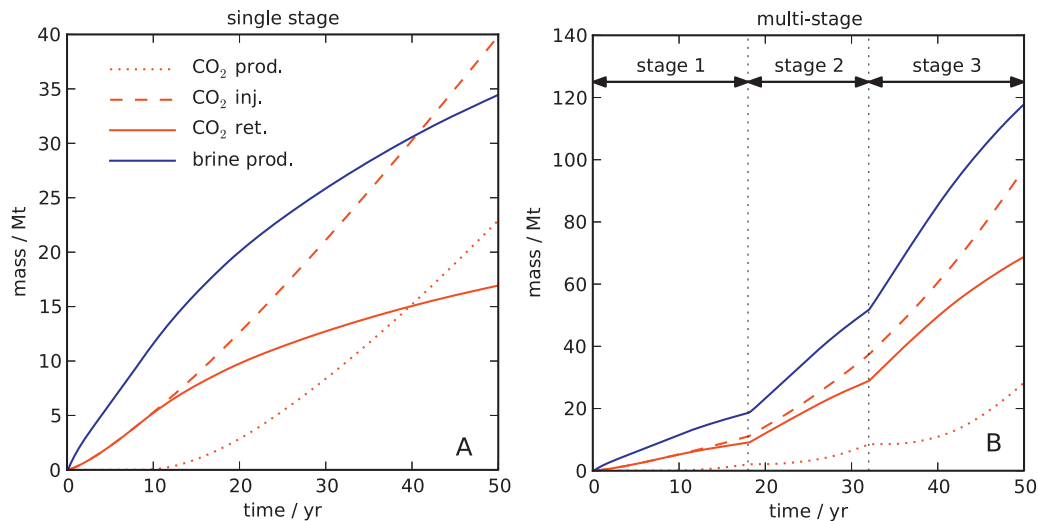


Fig. 6. Accumulated quantities of produced brine (blue) and injected (red dashed), produced (red dotted) and retained (red solid) CO₂ associated with the (A) single and (B) multi-stage injection flow rates in Fig. 5A and F, respectively. Black dotted lines demarcate stage transitions in B. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of the article.)

the height of the reservoir formation is h and the irreducible water saturation is S_{min} then SE is given by

$$SE = \frac{V_{CO_2}}{Ah(1 - S_{min})}, \quad (4)$$

where V_{CO_2} is the volume of CO₂ retained by the reservoir (injection minus production). This is similar to the definition of Birkholzer et al. (2009) except that we allow some inaccessible fraction of the pore space, corresponding to the irreducible saturation. If CO₂ migrates across the perimeter of production wells – as it generally does at later times – then SE may, somewhat unintuitively, exceed 1. However, as an approximate measure of reservoir utilization it is useful both as a guide for understanding the CO₂ sweep and, later, as a tool for comparison.

Storage efficiency is plotted in Fig. 5B. At early time, it increases linearly, but slows down as the front of injected CO₂ approaches the production wells. At the breakthrough time of 18 years, $SE \approx 1.0$. By the end of the simulation, SE is almost 2; this is because the front of injected CO₂ has extended significantly beyond the region horizontally demarcated by the production wells (Fig. 5C) but has also not uniformly filled the reservoir over its depth (the bottom of the reservoir is generally not accessed by the buoyant CO₂).

The distribution of CO₂ in the reservoir after 18 years is contoured in Fig. 5C and D. Buoyancy ensures that the emplaced CO₂ rises to the underside of the caprock; the maximum lateral extent of the CO₂ plume is therefore defined at the depth of the caprock-reservoir interface. Furthermore, while CO₂ is injected and brine is produced over a 100 m open-hole length spanning the thickness of the reservoir, buoyancy ensures that CO₂ is only produced from the top of the production well.

Changes in pressure within the reservoir and caprock are contoured in Fig. 5E after 18 years. These indicate that pressures near the injection well are largely unchanged from their original value. Pressures are increasingly depressed with proximity to the injection well, both within the reservoir and caprock. At large underpressure, the possibility of mechanical deformation around the well may need to be considered so as to avoid damage.

4.1. Multi-stage injection

Having established a breakthrough criterion, we now consider the proposed multi-stage injection (Fig. 2) in which the stage count is automatically iterated when the criterion is satisfied. For a well

spacing of 1 km and a production pressure of 5 MPa, transition to stage-2 occurs after 18 years (Fig. 5B) and to stage-3 after 27.5 years. Note that, because the breakthrough criterion is only assessed on a quarterly basis, in regions where retention efficiency is changing rapidly a new stage may not be initialized precisely at the breakthrough threshold.

Accompanying each stage transition is an increase in both the CO₂ retention and brine production rate in response to the increased well count. For instance, from stage-1 to stage-2, CO₂ retention exhibits a 5-fold increase from 0.3 to 1.5 Mt yr⁻¹. At the same time, brine production increases by more than a factor of 3 as eight new production wells are brought online in place of the four previously operating (and now repurposed for injection). At the beginning of stage-2, retention efficiency returns to 1 (Fig. 5G) – CO₂ is not immediately produced at the new production wells – but starts declining within a couple of years.

When the breakthrough criterion is once more satisfied, stage-3 commences. Again, the addition of eight injection wells and twelve production wells has a positive effect on both CO₂ retention and brine production. Retention efficiency, which is once more returned to 1, starts to decline after two years and is 0.3 by the end of the 50 year simulation. At the end of this time, storage efficiency within the 18 km² area demarcated by the production wells is a respectable 0.9. At later stages, migration of the CO₂ plume beyond this boundary is minimal (Fig. 5H). Total CO₂ retention in the simulated reservoir over the 50 year period is 68 Mt (Fig. 6B) – a more than fourfold increase over the single-stage simulation.

In practice, a GCS operation is more likely to be tasked with storing a steady stream of produced CO₂, rather than the evolving rate that is indicated in Fig. 5A and F. However, these hypothetical curves actually represent an upper limit on an injection rate that satisfies the pressure criteria of the passive injection strategy. If, for reasons of supply, the CO₂ injection rate were maintained below the hypothetical limit given in Fig. 5, the practical result would be development of an underpressured region around the injection well. This underpressure might be utilized as a buffer against future volatility in the CO₂ supply rate. Alternatively, as greater capacity is made available at later stages, the injection operation may accommodate additional CO₂ streams.

In the next section, we will show how the CO₂ injection rate depends on the brine production pressure. This suggests that injection rates may be further controlled by appropriate operation on the extraction side of the operation. For instance, reducing the

Table 2
Per-well CO₂ retention statistics for a four-stage operation with 10 MPa underpressure and 1 km well spacing. N_{inj} = number of operating injection wells, N_{prod} = number of operating production wells, N_{tot} = total number of operating wells. CO₂ ret. = average per-stage retention rate.

Stage	N_{inj}	N_{prod}	CO ₂ ret. [Mt yr ⁻¹]	CO ₂ ret./ N_{inj}	CO ₂ ret./ N_{prod}	CO ₂ ret./ N_{tot}
1	1	4	0.9	0.9	0.23	0.18
2	4	8	2.7	0.68	0.34	0.23
3	8	12	4.6	0.58	0.38	0.23
4	12	16	6.4	0.53	0.4	0.23

production pressure at each new stage could both stabilize the injection rate while increasing the time between stages.

4.2. Sensitivity analysis

In the previous section, we provided a general overview of the operation of multi-stage passive injection strategy. In this section, we investigate the sensitivity of CO₂ retention, brine production, and CO₂ breakthrough, to operational aspects of the injection. Multi-stage injection was simulated for well-spacings ranging from 200 m to 2.4 km in 200 m increments. For each well configuration, three production pressure scenarios were considered: 2, 5 and 10 MPa. All other parameters were held fixed, including the material parameters given in Table 1 and a breakthrough criterion of 0.5 retention efficiency (Fig. 5B).

4.2.1. Breakthrough time and stage transition

Stage-1 breakthrough times as a function of well spacing and production pressure are plotted in Fig. 7A. The model exhibits intuitive trends, with breakthrough occurring at earlier times when wells are spaced closer together or when pumped at higher pressures. Log-transformation of these data yields a linear relationship (Fig. 7B), suggesting breakthrough time has a power-law dependence on well-spacing, with the exponent ranging between 1.74 and 1.78.

Flow in the reservoir is approximately two-dimensional, being restricted to a stratigraphic unit with thickness much less than its horizontal extent. Thus, for an average injection rate, q , and neglecting the effects of partial saturation and vertical segregation of the fluid (Fig. 5C and D), one can write the position of the front of injected CO₂, r , as a function of time, t ,

$$hr^2(1 - S_{min}) = qt, \quad (5)$$

where h is the thickness of the reservoir and S_{min} is the irreducible saturation of water. The approximate r^2 dependence indicated by Fig. 7B is consistent with this picture.

The effect of the driving pressure gradient is also incorporated by noting that mean retention rates scale in proportion to brine production pressure, P_{prod} (Fig. 7E), i.e.,

$$q = CP_{prod}, \quad (6)$$

where C is a constant depending on formation permeability and intrinsic fluid properties, e.g., relative permeability, viscosity. Thus, Eq. (5) is rewritten

$$t = \frac{h(1 - S_{min})}{CP_{prod}} r^2, \quad (7)$$

where the coefficient of the r^2 term is given by the reciprocal transformation of the y-intercept of the regression curves in Fig. 7B – respectively, 41.3, 18.1 and 8.9 for the 2, 5 and 10 MPa pumping scenarios. The ratio of these terms, 1:0.44:0.22 is roughly consistent with the ratio of the inverses of P_{prod} , 1:0.4:0.2, suggesting the relationship given in Eq. (7) is fairly accurate.

Fig. 7C and D summarizes the dependence of successive breakthrough times on well spacing for a 10 MPa production pressure.

Log-transformation of these data indicates the r^2 dependence is preserved for successive stages; the fitted exponent ranges between 1.74 and 1.79. Furthermore, the breakthrough time for each successive stage is approximately constant, e.g., for 1 km spacing and a 10 MPa pumping pressure, breakthrough times are 9, 16, 23 and 30 years (Fig. 7C).

4.2.2. Retention rates

In general, both CO₂ injection and brine production rates scale linearly with the pressure difference driving flow in the system. For instance, during stage-1, doubling the production pressure from 5 to 10 MPa, doubles the flow rate from 0.35–0.5 to 0.7–1.0 Mt yr⁻¹, depending on well spacing (Fig. 7E). This suggests an avenue by which an operator might control the injection rate – by modifying brine extraction – to handle a fixed volumetric stream of CO₂. Impacts on injection operation life-time and efficiency, as well as the issue of time-delay between changes in production and injection flow rates will be addressed in future work.

The retention rate also exhibits a mildly positive relationship with well spacing; this is a modeling artifact introduced by decreasing discretization as wells are spaced further apart. The magnitude of this overestimate is constrained in Section 3.3 and, compared to other drivers of the retention rate, e.g., number of operating wells, the effect is relatively small. For instance, the mean retention rate per stage increases by ~ 1.8 Mt yr⁻¹ between stages 1 $\rightarrow$ 2, 2 $\rightarrow$ 3 and 3 $\rightarrow$ 4 (Table 2). Nevertheless, this behavior is a worthwhile reminder that flow rates are unavoidably influenced by the mesh discretization and that a 60% reduction should be applied to obtain a reasonable estimate.

Increased rates of retention must be weighed up against the costs of additional wells and pipeline each time a new stage is added. Taking the per-stage retention rate for the 10 MPa, 1-km spacing scenario, statistics for per-well retention rates – injection, production and total – for each stage are compiled in Table 2. These figures show that while the total retention rate increases from 0.9 to 6.4 Mt yr⁻¹, the mean retention per injection well decreases from 0.9 to 0.53 Mt yr⁻¹. On average, each injection well is less effective at later stages.

However, the effectiveness of the operation is better judged on a per-total-well basis, i.e., taking into account all operating infrastructure. Beyond stage-1, the per-well efficiency is relatively flat at 0.23 Mt yr⁻¹. This suggests that, if costs are balanced, three two-stage injection operations (12 wells per operation, 12 injection and 24 production wells, 36 wells total) are as effective as a single five-stage operations (16 injection and 20 production wells, 36 wells total).

However, when combined with cost estimates for various injection and production related activities, e.g., compression and transport of CO₂, production and treatment of brine, per-well statistics can help inform operational decision-making. For example, if the cost of operating a CO₂ injection well is low relative to a brine production well, then multi-stage operations would be preferred as these maximize the ratio of cheap injection wells to expensive production wells. If the opposite is true, then multiple two-stage operations would be favored.

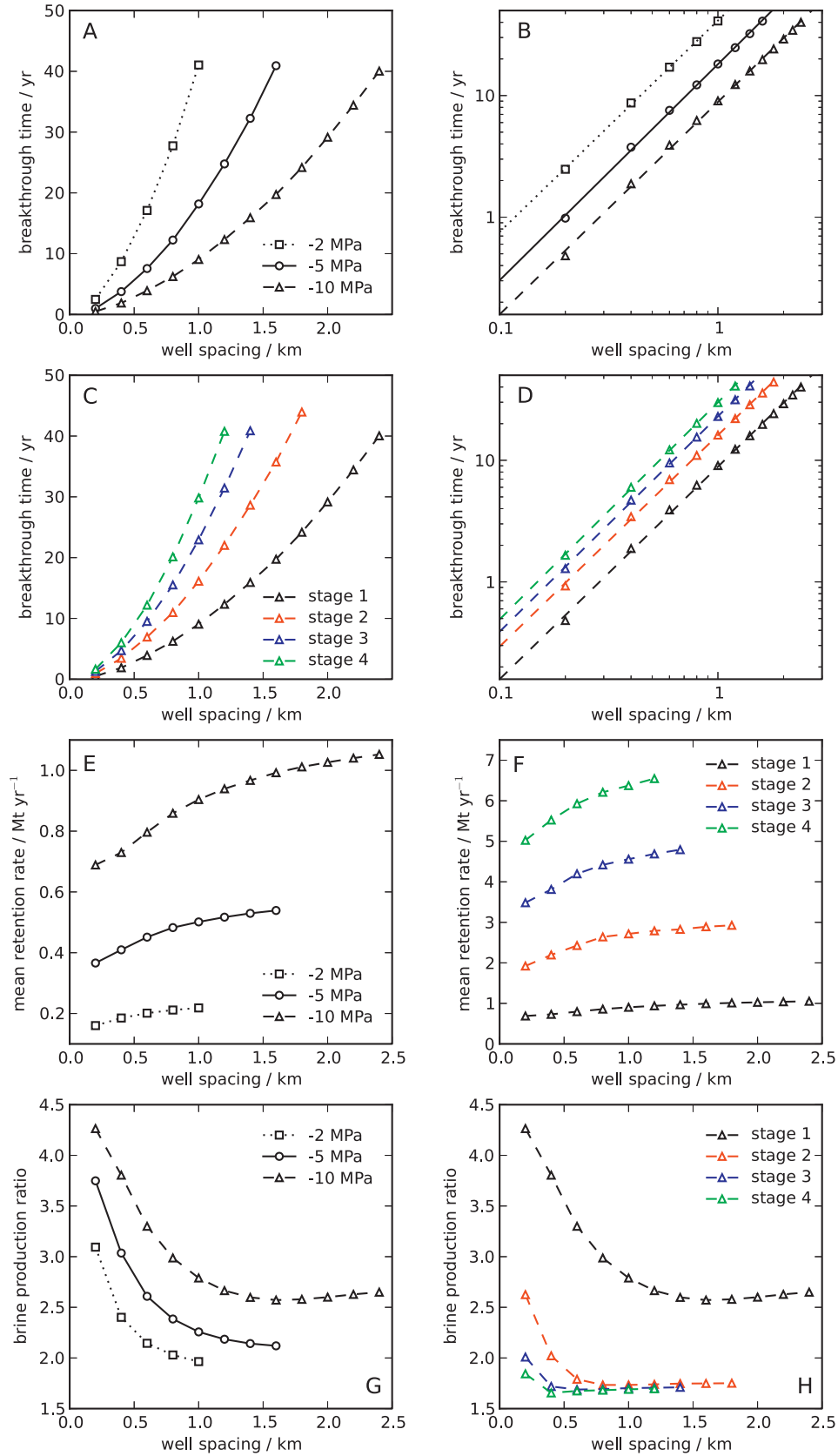


Fig. 7. Sensitivity of passive CO₂ injection to well spacing and production pressure. (A) CO₂ breakthrough time at different well spacings and pressures for a single-stage operation. Linear regression through the log-transformed data in B indicates power-law relationships with an exponent that varies between 1.75 and 1.84. (C) Breakthrough times for each stage of a four-stage operation. Again, log-transformation (D) indicates the relationship is a power-law with an exponent between 1.84 and 1.86. (E) Sensitivity of mean injection rate (E) and brine production ratio (G) to different well spacings and production pressures, and during different stages of a four-stage operation (F, H).

4.2.3. Brine production

One obvious drawback of passive injection is the production of large quantities of brine that will ultimately require treatment, and storage or discharge. Therefore, an important component of this study is an analysis of parameters that minimize the brine production ratio, defined as the mass of brine produced per ton of CO₂ sequestered.

Fig. 7G shows that brine production increases significantly at higher pumping pressures; this additional cost may have to be accepted if a target CO₂ retention rate is to be achieved (Fig. 7E). For increasing distance between wells, brine production drops and then stabilizes. This is partly a model artifact; outer production wells are spaced closer to the closed outer boundaries (representing a closed aquifer) and, in the period of time before breakthrough is achieved, are better able to drawdown the reservoir. If these boundaries were open, mass recharge would prevent drawdown and maintain high production rates. While certainly a boundary effect, this behavior is nevertheless illustrative of the advantages of utilizing closed aquifers with this storage method. In Section 4.2.5, we contrast with a scenario of injection into an open aquifer.

The brine production ratio also drops sharply with the transition from stage-1 to stage-2. This is due to the relatively sharp jump in the ratio of injection to production wells. In subsequent stages, the ratio remains relatively flat at 1.7 tons for brine produced for each ton of CO₂ sequestered.

It is worthwhile considering the amount of brine produced by passive injection in the context of brine production and disposal within the oil and gas sector. For the three-stage simulation shown in Fig. 5E–G, total brine production over the 50 year period is a little under 120 Mt, or an average of 2.4 Mt yr⁻¹. In a report by Clark and Veil (2009), brine extraction accompanying US oil production operations was approximately 20.4 billion bbl in 2007, or 3240 Mt (assuming a density 1000 kg m⁻³). About 58% of this was reinjected into formations to maintain pressure and improve recovery, an option that is not available in passive injection. However, much of the remainder, about 40% or 1300 Mt, was reinjected into other geological formations. Thus, the passive injection operation reported here generates for disposal an amount of brine approximately equal to 0.2% of that disposed by the oil and gas sector in 2007.

Clark and Veil (2009) also report, for onshore oil production, an average volumetric ratio of produced brine to oil of 7.6, i.e., 7.6 bbl of brine are extracted along with each bbl of oil. Allowing that 40% of this brine is disposed of in geological formations, the ratio of disposed brine to oil decreases to 3. For a typical oil density of 900 kg m⁻³, the corresponding mass ratio is 3.3. This latter statistic is analogous to the brine production ratio we report for passive injection, i.e., it is a measure of the quantity of brine that must be disposed of when either producing 1 kg of oil or disposing of 1 kg of CO₂ by passive injection. In this context, as a measure of operational efficiency, the particular ratios reported in Fig. 7G and H generally exceed the standards set by oil sector operations.

The cost of treating and disposing of produced brine is likely to be the most economically burdensome aspect of the passive injection method. Sullivan et al. (2013) provide cost estimates for a range of treatment and disposal methods, including injection into Class II wells, which would be the most likely disposal method. Their simulated cost estimates, when scaled to account for brine production ratios between 1.7 and 3, generally fall in a range of \$2.50–25.00 per ton of injected CO₂; clearly, at the higher end of the scale (where trucking costs dominate), the proposed scheme is economically prohibitive. Any practical application of passive injection would require favorable conditions for brine disposal, synergistic revenue streams (e.g., geothermal generation, mineral extraction; Breunig et al., 2013) or perhaps look to take advantage of economies of scale, e.g., shared pipeline infrastructure (Middleton et al., 2012).

4.2.4. Low-tolerance for CO₂ co-production

Separation of co-produced CO₂ is common practice during enhanced oil recovery (EOR) operations because the expense to acquire it is relatively high. Nevertheless, significant costs are associated with the separation of CO₂ from the miscible hydrocarbons and recompression for reuse (Jarell et al., 2002). In our case, while separation of CO₂ from immiscible brine is likely to be less expensive, an operator may nevertheless be unwilling to tolerate CO₂ co-production and reinjection. Depending on the penalties for emitting the co-produced CO₂, the breakthrough criterion may then be stricter and stage transition will occur at earlier times.

We consider a four-stage injection operation with 1-km spacing and 10 MPa production pressure and compare two breakthrough criteria: stage transition at (i) 50% and (ii) 98% retention efficiency. Fig. 8A and B illustrates long-term retention, brine production and storage efficiency for the two scenarios, with per-stage statistics summarized in Table 3.

The most significant difference is 45–50% reduction in the breakthrough time. A direct consequence of this is a requirement for more rapid construction of, and transition to, new stages, although this could be offset by increasing well spacing (Fig. 7A and C). The mean retention rate is slightly higher because the breakthrough criterion prevents operation at retention rates retarded by CO₂ co-production. The brine production ratio is not significantly affected.

Another drawback of this approach is less efficient usage of the pore volume. For the two scenarios, SE at a given stage transition is generally 30–50% lower when the stricter breakthrough criterion is applied. Due to buoyancy, CO₂ breakthrough at the production well is always at the top of reservoir; tolerance for some CO₂ production allows continued injection and retention within the under-utilized deeper sections of the reservoir.

4.2.5. Passive injection into an open aquifer

So far, by application of closed lateral boundary conditions, we have only considered injection into a laterally compartmentalized reservoir. Here, we consider the case of a larger reservoir in which assumption of lateral confinement is no longer valid and brine can flow across the boundaries in response to drawdown. In the simulation, this is implemented by replacing the 'no-flow' lateral boundary condition with one of fixed-pressure (set to initial formation pressure). The code maintains pressure at this boundary through the addition of mass; physically, this represents lateral recharge by brine outside the simulation domain. As in the previous section, we have simulated a four-stage operation with 1 km well spacing and 10 MPa production pressure; results are plotted in Fig. 8C and D and summarized in Table 3.

The most significant difference between the two scenarios is a much higher brine production at all stages for the open reservoir; this is reflected in an approximate doubling of the brine production ratio. Imposing a fixed-pressure boundary condition causes additional brine to enter the simulated reservoir in response to pressure drawdown around the production wells. This lateral recharge maintains higher pressures in the vicinity of the production wells and thus contributes to an elevated extraction rate.

At the same time, the retention rate is slightly lower; this is due to smaller pressure gradients that are maintained in the presence of the recharging boundaries. Breakthrough times are also slightly longer due to the reduced rate of CO₂ transport. Finally, storage efficiency is about 20–25% less for the open aquifer scenario.

Given all these drawbacks, there is a compelling argument that passive injection operations should target smaller, closed formations. In these formations, it is easier to cause a significant pressure drawdown to drive CO₂ flow while at the same time minimizing expensive brine production.

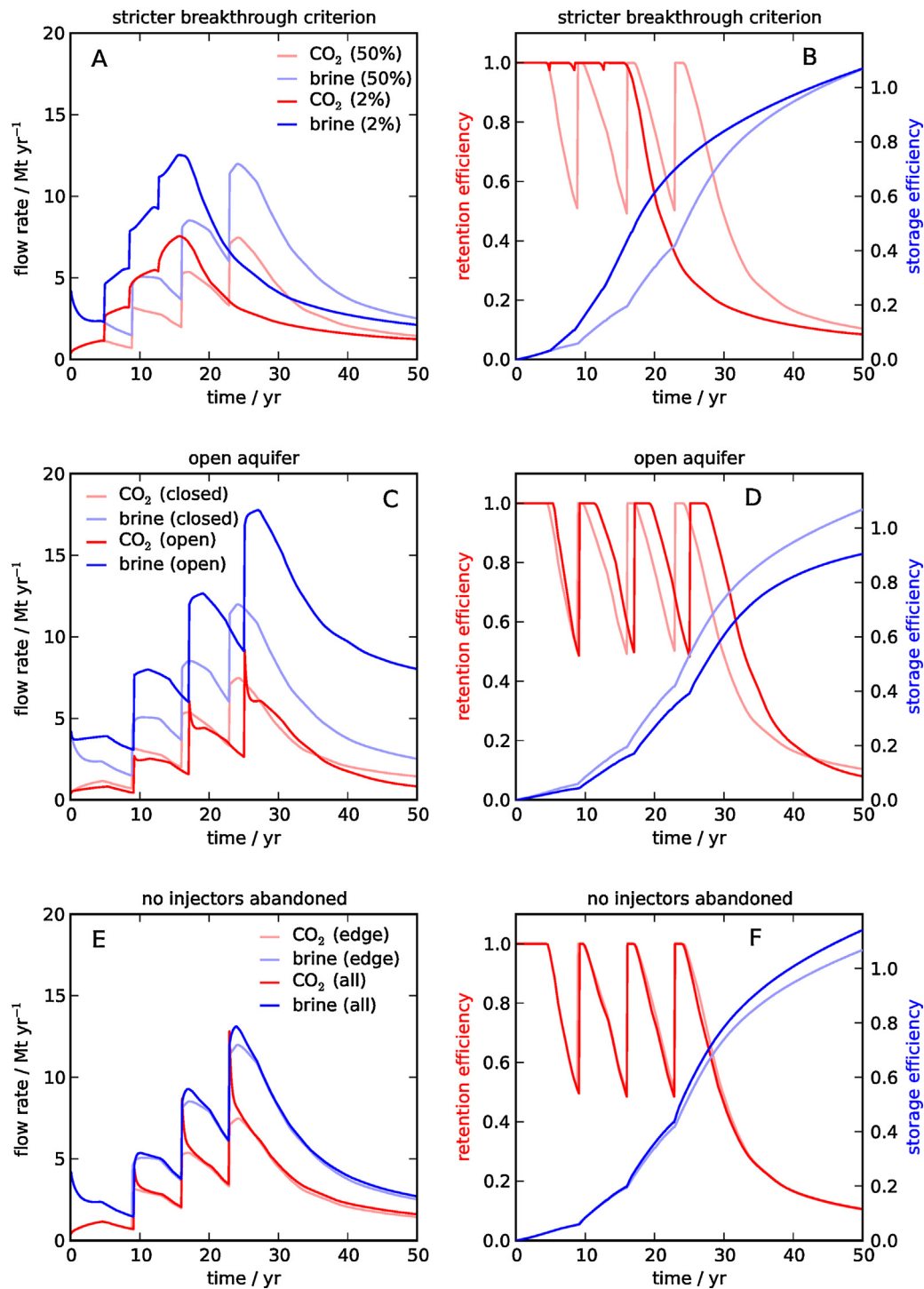


Fig. 8. (A) Comparison between CO₂ retention (red) and brine production (blue) rates for two breakthrough criteria: 50% (light-colored) and 2% produced CO₂ (dark-colored). These simulations consider four-stage injection into an open reservoir with 1-km well spacing at 10 MPa underpressure. (B) Comparison of retention (red) and storage efficiency (blue) for the two breakthrough criteria. (C and D) The same curves but this time considering open (light-colored) versus closed (dark-colored) aquifer conditions. A 50% produced CO₂ breakthrough criteria is used in this case. (E and F) As above, this time illustrating the scenario that interior injection wells are not abandoned (dark colored). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of the article.)

4.2.6. Continued operation of interior injection wells

When a stage transition occurs, sources and sinks within the reservoir are reconfigured and a new pressure distribution is created. Interior injection wells that experienced negative pressure gradients in the previous stage (responding with CO₂ flow) are now less influenced by the production wells. This is due to both

advancement of the production front to a greater distance as well as pressure support and shielding supplied by the new injection wells. Nevertheless, an argument could be made that, due to the substantial investment in drilling each well, interior injectors (the crossed wells in Fig. 2) should be preserved, even if the injection rate at each is somewhat lessened. However, the decision to continue

Table 3

Summary of breakthrough time, t_{br} , mean CO₂ retention rate and brine production ratio for simulations comparing the effect of hard versus soft breakthrough criteria and closed versus open reservoir conditions (see Fig. 7).

Stage	Benchmark			Stricter breakthrough criterion (Fig. 8A and B)			Open aquifer (Fig. 8C and D)		
	t_{br} [yr]	CO ₂ ret. [Mt yr ⁻¹]	Brine ratio	t_{br} [yr]	CO ₂ ret. [Mt yr ⁻¹]	Brine ratio	t_{br} [yr]	CO ₂ ret. [Mt yr ⁻¹]	Brine ratio
1	9	0.9	2.8	5	0.9	3.5	9	0.7	5.8
2	16	2.7	1.7	8	3.0	1.7	17	2.2	3.4
3	23	4.6	1.7	13	5.1	1.7	25	3.9	3.0
4	30	6.4	1.7	16	7.1	1.6	33	5.4	3.0

operating each well must be made on an ongoing basis, weighing up the costs of compression, maintenance, pipeline, etc., against CO₂ injected.

Fig. 8E and F presents CO₂ injection and brine production for the scenario where all interior injection wells remain in service for the duration of the operation. In general, the CO₂ retention rate is almost identical to the scenario in which these wells are retired; this indicates the benefits of maintaining interior wells are incremental at best. However, for a short time after the stage transition, the retention rate does remain slightly higher than if the interior injectors were abandoned. This is due to the finite time required for reservoir pressures to re-equilibrate to the new well configuration. Thus, it may be economic to maintain interior injectors for a short period of time – one or two years – after a stage transition.

5. Further considerations

So far, we have limited our discussion to a numerical demonstration of passive CO₂ injection and a sensitivity analysis of parameters that are potentially within an operator's control, e.g., assessment of temperature gradient and reservoir compartmentalization during site selection, well-spacing and production pressure, tolerance for CO₂ co-production. However, there are many other factors that are likely to affect the success of such a sequestration strategy.

Passive injection relies on CO₂ flowing along negative pressure gradients directed toward producing wells. If both an injection and production well intersect the same permeable feature, then a fast-pathway or short-circuit would be introduced to the system (IEAGHG, 2012). CO₂ breakthrough will then occur more rapidly, reducing the efficiency of the CO₂ sweep. Similar concerns exist in the creation and operation of Engineered Geothermal Systems (EGS), where uncontrolled well stimulation can lead to the creation of hydraulic fractures; fast-pathways that reduce sweep volume and create a thermal short-circuit. The risk of fast-pathways/short-circuiting can be minimized through comprehensive structural characterization, tracer testing and/or abandonment of jeopardized wells. In the future, techniques for the deployment of hardening, impermeable silica gels, currently being developed to increase sweep efficiency in EGS and ensure seal integrity in CCS (Ezzedine et al., 2012), might be applied to the problem of CO₂ short-circuits.

Another possibility for increasing the efficiency of a general GCS operation, is the use of novel well-track designs to take advantage of reservoir geometry and CO₂ buoyancy. For example, recent developments in directional drilling open up the possibility of horizontal injection wells that could parallel a sub-horizontal reservoir unit (Buscheck et al., 2012); the open-hole length of such well tracks are not limited by reservoir thickness. Furthermore, deployed in the concentric square-ring configuration considered here, these wells could substantially reduce the number of wells required at each stage. Several co-linear injection/production wells – point sources – could be replaced with a single horizontal well, i.e., a line source.

Buscheck et al. (2012) propose that for CO₂ injection into an inclined formation, production wells might be positioned

down-dip (below) from the CO₂ injectors so as to both relieve reservoir overpressure and to draw CO₂ in the opposite direction of its buoyant flow, thereby increasing the utilized reservoir volume. Fig. 5D shows that, for the injection strategies considered here, when CO₂ breakthrough occurs, it is typically at the top of a production well due to buoyant CO₂ migrating most rapidly along the underside of the caprock. It is possible that CO₂ breakthrough might be delayed through the use of horizontal production wells that parallel the base of the reservoir layer.

5.1. Implications for induced seismicity

The primary purpose of passive CO₂ injection is to mitigate some of the negative externalities associated with reservoir overpressurization, including induced seismicity and brine migration. The simulations detailed in Section 4 were performed using a fully coupled thermal-hydrological-mechanical simulator. Therefore, we are in a position to investigate induced stress changes due to injection and their implications for mechanical failure.

Induced stresses in the model are generated by either temperature or pressure changes. In our model, the only source of thermal stress is by the injection of cool 50 °C liquid CO₂ into a reservoir the 115 °C reservoir. This implies that CO₂ in the well is not in thermal equilibrium with the geothermal gradient, an assumption made in calculating the pressure neutral depth in Section 2.1. A more robust approach would be to use a wellbore model that accounts for conductive heat exchange with the formation (e.g., Vilarrasa et al., 2013).

Induced cooling is local to the wellbore, extending ~200 m away, and results in thermal contraction. Providing that borehole image analysis indicates that the injection zone is not a large fault or fracture, reactivation of significant features by thermal stressing is unlikely. However, shear failure could be induced on smaller, well-oriented fractures; as noted by Vilarrasa et al. (2013), this could lead to a rise in injectivity of the well.

Of greater concern is the elevation of pore pressure within a fault that contributes to its reactivation (Cappa and Rutqvist, 2011; Zoback and Gorelick, 2012). However, as shown in Fig. 5E, at the conclusion of injection, all pressures within the reservoir are less than ambient. Indeed, neglecting the small increase due to buoyancy, the passive injection strategy permits no mechanism at all for increases in pressure.

While generally regarded as the primary risk, elevated fluid pressure within a fault is not the only way to trigger an earthquake. Flexure or subsidence of adjacent formations responding to reservoir pressurization can indirectly modify their internal stresses, which may reinforce or work against the tectonic load (Hangx et al., 2010; Dempsey et al., 2014). Therefore, we seek a metric for the induced seismic hazard due to given changes in stress and fluid pressure; for this, we use the change in Coulomb Failure Stress, ΔCFS . The Coulomb Failure Stress is a measure of the proximity of a fault to failure for given stress and pressure state,

$$\Delta CFS = \Delta |\tau| - \mu(\Delta \sigma_n - \Delta p_f), \quad (8)$$

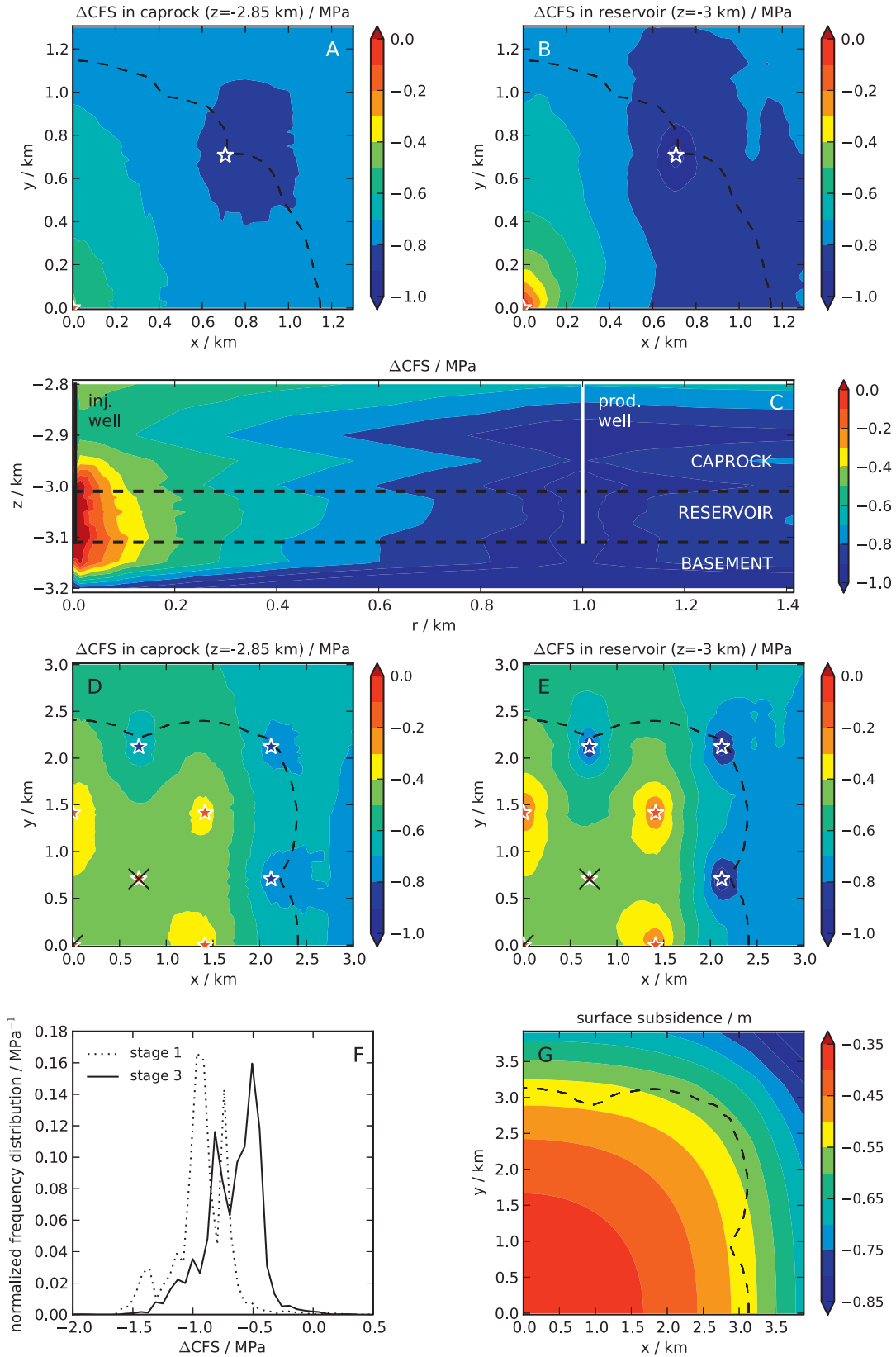


Fig. 9. (A–C) Summary of the induced seismic threat for the injection scenario presented in Fig. 5A–E. (A) Contours of ΔCFS for a horizontal slice through the caprock, calculated assuming a 60° dipping fault in an extensional tectonic regime. The black dashed line marks the horizontal extent of injected CO_2 . (B) Contours of ΔCFS for a horizontal slice at the top of the reservoir. (C) Vertical slice of ΔCFS passing through the production and injection well. Relevant rock types and wells are plotted. (D–G) Summary of the induced seismic threat for the injection scenario presented in Fig. 5F–H. Horizontal slices of ΔCFS in the caprock (D) and top of the reservoir (E). (F) Normalized frequency distribution for the distribution of ΔCFS between 2.5 and 3.5 km depth (500 m either side of the reservoir) at the end of stage-1 (dotted) and stage 3 (solid). (G) Contours of surface subsidence at the end of stage-3 (50 years).

where τ and σ_n are the shear and normal stress on the fault, and μ is the coefficient of friction. A positive value for ΔCFS , caused by induced changes in stress or pressure, indicates that the likelihood of fault failure has increased. The change in Coulomb Failure Stress has been previously used to correlate aftershock locations with regions of co-seismic stress transfer (Reasenber and Simpson, 1992). This measure is similar to the strength-to-stress margin used by Rutqvist (2012) in a geomechanical modeling study of induced seismicity risk near a horizontal CO₂ injection well at In Salah, Algeria.

The advantage of using ΔCFS (relative) versus CFS (absolute) is that the Δ terms in Eq. (8) can be obtained through modeling; in contrast, absolute measures of σ_n , τ and p_f require site-specific measurements that can be more difficult and expensive to obtain. Nevertheless, calculation of the absolute CFS is valuable on a case-by-case basis as this is used to inform operating pressure limits within the reservoir so as to avoid fault failure. However, in the generic study presented here, a relative measure of CFS will suffice.

The Coulomb Failure Stress is sensitive to fault orientation. For example, in an extensional tectonic regime, a dipping fault that strikes in the direction of the intermediate principal stress, σ_2 , would have a higher CFS than a similar fault striking in the direction of σ_3 . Thus, some faults are more prone to failure than others and a conservative approach is to consider ΔCFS for the most critically stressed orientation. In this work, we consider induced stresses in the context of an extensional tectonic setting. Previous modeling studies have indicated that CO₂ injection in such regimes is more likely to lead to through-going mechanical failure of the caprock (Rutqvist et al., 2008; Vilarrasa et al., 2011).

Fig. 9A–E plots contours of ΔCFS at the conclusion of stage-1 and stage-3 for a critically oriented fault with regard to an extensional tectonic regime, i.e., dipping at 60°, striking parallel to σ_2 . With the exception of the region near the injection well – here, thermal stresses are high while passive injection maintains unchanged pressure – values for ΔCFS are negative, both within the reservoir and overlying caprock. ΔCFS continues to decrease with proximity to the production well and the source of the pressure drawdown.

Compiling a normalized frequency distribution of all ΔCFS changes in the model (Fig. 9F, essentially a histogram of all nodal values of ΔCFS divided by the number of nodes) we show that much of the reservoir and caprock is characterized by a 0.5 to 1 MPa decrease. This is on the order of stress drops typically recorded during earthquakes (Kanamori and Anderson, 1975). More importantly, it indicates that passive injection, rather than increasing the risks of induced seismicity, actually decreases the threat, providing a degree future protection for the sequestered CO₂.

Induced seismicity has previously been linked to pore pressure drawdown in oil production operations (Segall, 1989). Segall et al. (1994) describe an analytical model for induced stress changes due to drawdown of an idealized reservoir; they show that induced earthquakes associated with a 30 MPa pressure decline in the Lacq deep gas field, France, are associated with stress changes as small as 0.2 MPa. Given that the maximum pressure declines in our simulations are 10 MPa, it is reasonable that associated stress changes will be less than 0.2 MPa. For such small changes, we are justified in considering only the critically oriented failure surfaces in our analysis of ΔCFS .

The crust responds to pressure drawdown in the storage formation by subsiding. For the particular elastic properties, production pressure and injection depth considered in Fig. 9, up to 1 m of subsidence is recorded outside the ring of production wells, where the pressure drawdown is greatest. Even within the ring of injection wells, where pressures are partially recovered by CO₂ emplacement, more than 0.35 m of subsidence remains.

6. Conclusion

Injection of CO₂ into the subsurface raises the formation pressures, sometimes at great distance from the injection site (Birkholzer et al., 2009). Adverse effects associated with this overpressuring include brine migration and contamination of shallow aquifers and the generation of earthquakes. In response to these concerns, we have outlined a strategy for the emplacement of large volumes of CO₂ into subsurface storage formations with no increase – temporary or long-term – of in situ pressure. This strategy, called passive injection, extends the concepts of active CO₂ reservoir management in which brine production wells are used to limit injection-induced overpressure. In our strategy, brine production is the only driver of fluid flow in the system, drawing CO₂ out of injection wells at no overpressure. This is achieved by controlling the compression of CO₂ at the surface and leveraging converging pressure-depth profiles within the injection well and formation.

Numerical experiments were undertaken to demonstrate the feasibility of passive injection. We consider a multi-staged approach with advancing fronts of injection and production wells including recycling of production wells for injection. For a range of well-spacings, production pressures and aquifer conditions, we showed that CO₂ could be sequestered at rates of up to 6.4 Mt yr^{−1}; approximately 4 Mt yr^{−1}, when grid discretization effects are taken into account. In the long-term, concurrent brine production averages 1.7 tons for every ton of CO₂ sequestered.

One of the major challenges facing CCS is the high cost of implementation, including CO₂ capture at source, transport and sequestration. Passive CO₂ injection adds additional costs to the traditional sequestration operation by advocating voluminous production of deep brines. This brine would require either treatment or disposal, both of which would impose a financial penalty on the operation; estimates here range from \$2.50 to \$25.00 per ton of injected CO₂. Furthermore, the strategy calls for a configuration of advancing concentric rings of injection and production wells, with periodic drilling of new wells and construction of supporting infrastructure. Economies of scale, alternative revenue streams or further research and development is likely to be required if this scheme is to become economically viable. However, these costs must be balanced against the substantial advantages offered by this strategy: mitigation of the threat of induced seismicity and brine contamination of shallow aquifers.

An analysis of stress and pressure changes induced by passive injection confirms that: (i) reservoir pressure is everywhere less than or equal to its initial value, both during and after the injection; and (ii) the risk of induced seismicity, as parameterized by a change in the Coulomb Failure Stress, is decreased or unchanged. These results support our claim that passive injection neutralizes two of the substantial obstacles facing geologic CO₂ storage.

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