

Modeling caprock bending stresses and their potential for induced seismicity during CO₂ injection

David Dempsey, Sharad Kelkar, Rajesh Pawar, Elizabeth Keating, David Coblenz

Author's accepted manuscript (peer-reviewed, before publisher typesetting)

Published as: Dempsey, David, Kelkar, Sharad, Pawar, Rajesh, Keating, Elizabeth, Coblenz, David (2014). Modeling caprock bending stresses and their potential for induced seismicity during CO₂ injection. International Journal of Greenhouse Gas Control, 22, 223-236. <https://doi.org/10.1016/j.ijggc.2014.01.005>

Accepted manuscript. © 2014. This manuscript version is made available under the CC-BY-NC-ND 4.0 license <https://creativecommons.org/licenses/by-nc-nd/4.0/>. The version of record is available at <https://doi.org/10.1016/j.ijggc.2014.01.005>

Open copy, summary and machine-readable versions:
<https://ddempsey.github.io/papers/2014-dempsey-modeling-caprock-bending-stresses-their/>

Modeling caprock bending stresses and their potential for induced seismicity during CO₂ injection

David Dempsey^{1*}, Sharad Kelkar¹, Rajesh Pawar¹, Elizabeth Keating¹ and David Coblenz¹

¹Los Alamos National Laboratory, Los Alamos, NM

*corresponding author

d.dempsey@lanl.gov

Postal address:

Los Alamos National Laboratory

EES-16

Mailstop T003

Los Alamos

New Mexico, 87545

+1 505 664 0712 (phone)

+1 505 665 8737 (fax)

Abstract

Recent experiences with large-scale injection of fluids into geological formations within the Oil & Gas, Geothermal and Waste Disposal industries have demonstrated a risk of induced seismicity. In the case of geological sequestration of CO₂, reactivation of faults may result in leakage pathways for the buoyant plume and thus compromise the integrity of seal formations. In this study, we investigate the potential for an overpressured reservoir formation to cause deformation and mechanical failure in an overlying, low-permeability caprock, thereby compromising seal integrity. In particular, we show that uplift and associated extensional strain in the caprock lead to a reduction in the minimum horizontal principal stress that reinforces the ambient extensional tectonic stress. Changes in the Coulomb Failure Stress (ΔCFS) characterize the tendency for fault failure. We use normalized and ΔCFS -weighted frequency distributions as an integrated measure of the 3-D distribution of ΔCFS . These measures quantify the magnitude and nature of the risk of induced seismicity. Using the example of the Springerville-St Johns CO₂ reservoir as an analogue site, we explore the sensitivity of the induced seismic risk to caprock stiffness, reservoir overpressure and well configuration. Over a range of these parameters, we calculate the geomechanical response of a large reservoir over a ten-year period of injection. The magnitude of induced stresses within the caprock are approximately 1-2 MPa for typical overpressures of 5-10 MPa, even in regions where the low-permeability caprock prevents appreciable increases in pore pressure. These stresses would be sufficient to cause reactivation of an undetected, well-oriented, critically-stressed structure present above or near the injection location. Importantly, we show that this occurs outside a sphere of influence delineated by sub-surface pressure increase.

Keywords

CO₂ geologic storage; Springerville-St. Johns; geomechanical; induced seismicity; Coulomb Failure Stress

1 Introduction

Capture and Storage of carbon dioxide (CCS) produced by large ($> \text{Mt yr}^{-1}$) stationary emitters (e.g., coal and gas-fired power stations) is one proposed technology for mitigating rises in atmospheric greenhouse gases (IPCC, 2005). In order to be effective, it has been suggested that CO₂ storage sites should retain at least 99% of injected CO₂ for over 1000 years (Shaffer, 2010). However, to ensure long-term storage of CO₂ in the primary storage reservoir, it is necessary to ensure the fidelity of the low-permeability caprock that form the primary trap for buoyant CO₂.

One scenario for the creation of a leakage pathway through an otherwise low-permeability caprock is by reactivation of an existing fault. Conceptualized as a zero-cohesion, planar structure, subject to ambient rock stresses and in situ fluid pressure, fault triggering is approximately governed by the Mohr-Coulomb failure criterion (Sibson, 1985),

$$|\tau| = \mu(\sigma_n - p_f), \quad (1)$$

where τ and σ_n are the shear and normal stress resolved on the fault plane, μ is the coefficient of friction on the fault, and p_f is the pore fluid pressure. As CO₂ injection is concurrent with elevated

reservoir pressures, recent efforts in modeling caprock failure (e.g., Rutqvist and Tsang, 2002; Rutqvist et al., 2008; Rohmer and Seyed, 2010) have focused on upward migration of these overpressures as the trigger for mechanical failure, i.e., $p_f \rightarrow p_f + \Delta p_f$ in Equation (1). Such overpressures might be partially managed by use of brine production wells that reduce reservoir pressure through the extraction of formation brines (Buscheck et al., 2012; Elliot et al., 2013). However, these strategies are accompanied by additional costs of drilling and operating the extraction wells, in addition to treatment and disposal of the produced brine (\$0.40-\$2.30/ton CO₂; Sullivan et al., 2012).

Early work on the coupled flow and stress processes leading to mechanical failure in the caprock was undertaken by Rutqvist and Tsang (2002); who demonstrated surface uplift attributed to pressure-induced expansion of the aquifer and caprock, as well as CO₂ leakage through a pre-existing caprock fault whose permeability is a function of the stress dependent porosity. Rutqvist et al. (2008) followed up this work with an analysis of injection into multilayered systems under a variety of stress regimes that included consideration of both shear and tensile failure mechanisms. They concluded that CO₂-injection should be favored in compressional stress regimes where propagation of shallow dipping failure would be unlikely to breach upper layers. Rohmer and Seyed (2010), taking a similar approach, assess the geomechanical risks of 10 Mt yr⁻¹ of CO₂ injection into the Paris Basin, and conclude that the potential for induced failure is greatest near the injection site – where the highest overpressures occur. Vilarrasa et al. (2011) introduced a visco-plastic formulation to investigate mechanical failure of caprock overlying an injection well. In agreement with Rutqvist et al. (2008), they found that CO₂ injection in a compressional regime can avoid the propagation of plastic strain through the caprock. Furthermore, they note that pressurization of the reservoir causes overlying caprock to act as a bending plate, inducing horizontal extension in its upper parts. Gor et al. (2013) considered the effects of thermal stresses induced by injection of cold CO₂ on an overlying caprock. They showed that these stresses are sufficient to promote failure in a caprock pre-stressed by injection overpressures.

Another possibility is fault reactivation within the reservoir, which subsequently propagates into or through the caprock. Cappa and Rutqvist (2011) modeled the scenario of a propagating pressure front encountering lateral confinement by a caprock unit that is vertically offset by a normal fault. Fault activation, slip and stress drop were calculated according to a frictional-weakening model, with the severity of the fault rupture ultimately depending on the ratio of the minimum horizontal and vertical stress (σ_h/σ_v). The development of connections between the reservoir and caprock facilitate the propagation of the pressure front and suggest the possibility of cascading failure. For example, a sequence of earthquakes in northern Italy in 1997 was associated with the release and propagation of a naturally-occurring, deep, overpressured CO₂ source. Specifically, aftershock locations were found to be correlated strongly with the position of a high-pressure front that evolves according to a non-linear diffusion model, suggesting the CO₂ pulse was responsible for earthquake triggering (Miller et al., 2004). More generally, earthquake swarm behavior can be interpreted in the context of fluid migration and concurrent reactivation of a distribution of pre-existing fractures (Sibson, 1996).

Further insights have been provided by geomechanical modeling studies of the CO₂ injection operation at In Salah, Algeria. Injection of 0.5-1 Mt yr⁻¹ into a 20 m thick sandstone aquifer since 2004 has been accompanied by surface uplift of ~5 mm yr⁻¹ based on satellite measurements (interferometric

synthetic-aperture radar – InSAR). Coupled flow-stress modeling using the TOUGH2-FLAC3D code was able to reproduce uplift rates and lobe patterns; the analysis indicated deformation was due to poroelastic expansion of the overpressured reservoir and potentially part of the overlying formations (Rutqvist et al. (2010).

Several authors (Rohmer and Seyed, 2010; Cappa and Rutqvist, 2011) have noted that the likelihood of caprock failure is related to assumptions about the initial state of stress in the crust, specifically its proximity to ‘criticality’. A critically-stressed crust is one which contains an optimally-oriented fault that is close to failure, i.e., it requires only a small increase in shear stress to be reactivated. While ‘proximity to failure’ can be difficult to establish at a given location, compiled earthquake stress drop data (Kanamori and Anderson, 1975), observations of induced seismicity attributed to dam impoundment (Talwani and Acree, 1984) and injection of water into the subsurface (Hsieh and Bredehoeft, 1981; Horton, 2012; Zhang et al., 2013), and theoretical arguments regarding crustal permeability (Townend and Zoback, 2000) suggest that, in tectonically active regions, it is probably less than 5 MPa. This figure represents a reasonable upper bound for critically stressed crust; however, observations of reservoir and production induced seismicity suggest that in some locations induced stresses as low as 0.1-0.2 MPa may be sufficient to cause failure (Zoback and Hickman, 1982; Segall et al., 1994).

Concerns have recently been raised that CO₂ injection at a scale necessary to curb rises in atmospheric CO₂ will inevitably lead to reactivation of moderate-sized faults that compromise caprock integrity (Zoback and Gorelick, 2012). Furthermore, it is proposed that this induced seismicity will occur with sufficient frequency that the required sequestration targets will not be achieved. Many open questions remain, such as in which regions the critical-crust assumption is valid and the leakage implications of a through-going failure. It is clear that modeling of the orientation and magnitude of injection-related stresses and the associated permeability changes in the caprock, reservoir and basement formations is crucial to understanding and surmounting this particular challenge facing CCS.

In this paper, we use coupled flow and stress numerical modeling of CO₂ injection to investigate the potential for induced seismicity. This study is novel in two respects: (i) we focus on indirectly-induced caprock stresses that arise from expansion of the reservoir and associated doming and spreading in the overlying formations; and (ii) we calculate distributions of the change in Coulomb Failure Stress (Δ CFS) and related metrics that illustrate both the induced stress state and aggravating factors that promote fault failure. As a site analogue, we consider the Springerville-St Johns dome, a naturally-occurring, shallow CO₂ reservoir that straddles the Arizona-New Mexico border, and that is laterally confined by an offset normal fault (see Section 2). In Section 3, we detail the study methodology, including a description of the coupled thermo-hydro-mechanical code FEHM used to simulate CO₂ injection (3.1), an outline of the conceptual model for induced caprock stresses (3.2), and model setup (3.3). In Section 4, we describe the benchmark scenario of a single CO₂ injection well model (4.1), calculation of CFS distributions and curves (4.2), mesh and parameter sensitivity analysis (4.3-4.4), and, finally, scaled-up sequestration operations containing up to ten injection wells (4.5). The main findings and conclusions of this study are summarized in Section 5.

2 Analogue-site description

The Springerville-St Johns CO₂ reservoir is located on the southeastern margin of the Colorado Plateau, straddling the Arizona-New Mexico border, and spanning ~1800 km² (Rauzi, 1999). CO₂ bearing formations are found in Corduroy, Fort Apache, Big A Butte and Amos Wash members of the Supai Formation, with various anhydrite beds, clay and mudstones providing the impermeable gas seals (Rauzi, 1999). Stratigraphic units follow the NW-SE doubly-plunging anticline that defines the dome and provides structural trapping of in situ gas. These units are offset more than 100 m by the NW-SE trending Cedar Mesa and Coyote Wash normal faults that dip steeply to the SW. Offset of the Coyote Wash fault laterally confines much of the 830 Mt (Stevens et al., 2001) CO₂ reservoir within the upthrown block (Figure 1).

At 400 to 800 m depth, the CO₂-bearing layers of the Supai Formation are generally too shallow to serve as practical CO₂ storage repositories. While CO₂ could be injected into the formation as a liquid under the elevated injection pressures, over time, pressure dissipation could result in phase change and a reduction in storage efficiency. However, treating the Springerville CO₂ field as an analogue for CCS can nevertheless yield valuable insights into the geological and structural characteristics that facilitate and limit gas transport, as well as the consequences of long-term CO₂ leakage on the trapped reservoir and overlying groundwater aquifers. For instance, mapping of travertine deposits at the surface indicate that at many times in the past, CO₂ has leaked from the larger reservoir and migrated through the shallow groundwater to the surface. These deposits correlate with known structures that are inferred to provide leakage pathways to the surface (Gilfillan et al., 2011; Keating et al., 2012). Evidence of leakage is also found in the groundwater aquifers, which exhibit elevated concentrations of dissolved CO₂ (Moore et al., 2005). Pumping of groundwater wells in the region has resulted in drawdown of the shallow aquifer water table by up to 30 m (Keating et al., 2012). The specific pattern of drawdown indicates poor pressure communication across and enhanced communication along the strike of the Coyote Wash Fault; this is consistent with the classic conduit/aquitard view of fault architecture (Caine et al., 1996). Such architecture is indicative of either contemporary or an earlier period of episodic fault reactivation, sufficiently frequent to create an impermeable gouge while maintaining damage zone permeability, and at the same time accumulating the observed stratigraphic offset. The fault orientations are consistent with the inferred regional stress field, i.e., minimum horizontal stress oriented NE-SW (Aldrich and Laughlin, 1984). For the purposes of this analogue study then, we assume that, were they to exist, unidentified, critically-stressed structures would be similarly oriented to the Coyote Wash Fault.

3 Model methodology

Injection of CO₂ into a vertically-confined, laterally-open reservoir is modeled using the multi-fluid coupled thermo-hydro-mechanical (THM) code, Finite Element Heat and Mass transfer (FEHM; Zyvoloski, 2007). Our aim is to quantify the bending stresses that may be induced in the overlying caprock as a consequence of a pressurized reservoir. In these simulations, the geometry of the Springerville-St John's dome serves as a simplified schematic for the single-reservoir system; in practice, several CO₂ bearing units have been identified in the Supai formation at Springerville (Rauzi, 1999). A suite of models are constructed that explore the size and sensitivity of induced caprock stresses over a

range of mesh resolutions, material properties and injection configurations, e.g., pumping pressure, well pattern.

3.1 Simulator description

FEHM is a single code integrating heat, mass and reactive transport solutions using finite volume methods with a mechanical solution done on finite elements. The code handles multi-phase mixtures of water, air and CO₂, deploying complex relative permeability relationships, efficient analytical methods for calculation of thermodynamic functions and dynamic permeability models as functions of pressure and stress.

The degree of coupling between the stress and flow solutions is user-specified; volumetric thermal expansion and Biot pressure-coupling are supported within a linear-elastic framework, i.e.,

$$\sigma_{ij} = \lambda \epsilon_{kk} + 2\mu \epsilon_{ij} + (\beta \Delta p + \alpha \Delta T) \delta_{ij}, \quad (2)$$

where σ_{ij} and ϵ_{ij} are the stress and strain tensors, λ and μ are Lamé's parameters, p and T are pressure and temperature, and β and α are Biot's coefficient and the coefficient of thermal expansion; respectively, the pressure and temperature coupling terms. In this study, only pressure-coupling effects are considered, by setting $\beta = 1$.

In geomechanical analyses, the stress tensor is commonly reduced to a diagonal form, with the principal components denoted σ_1 , σ_2 and σ_3 in order of decreasing magnitude. In the Earth's crust, it is generally assumed that one of these stresses represents the overburden, i.e., is vertically oriented, while the other two are horizontal. For the extensional tectonic setting considered in this study, σ_1 is vertical and σ_3 is oriented parallel to the direction of horizontal extension. In a critically stressed crust, it is assumed that the magnitude of σ_3 is near to the frictional limit imposed by the strength of the rock (Jaeger et al., 2007)

$$\sigma_3 - p_f = (\sigma_1 - p_f) / \left((\mu^2 + 1)^{\frac{1}{2}} + \mu \right)^2, \quad (3)$$

where μ is the coefficient of friction for the rock and p_f the pore pressure. Taking a lower limit of $\mu = 0.6$ (Byerlee, 1978) then, the effective principal stresses are approximately in the ratio $\sigma'_3 \approx \sigma'_1/3$, where $\sigma'_i = \sigma_i - p_f$ defines the effective stress. If the fluid pressure can be assumed hydrostatic, and the ratio of fluid to rock density is approximately 0.4, then the total principal stresses are approximately in the ratio $\sigma_3 \approx 0.6\sigma_1$.

3.2 Conceptual model

The scenario considered here is that pressurization of a vertically confined aquifer leads to an expansion that is accommodated in the overlying caprock through doming and spreading (Figure 2A). This deformation manifests at the surface as uplift and is analogous (but in an opposite sense) to the subsidence associated with reservoir depletion. The horizontal component of this deformation is produced by a reduction of the existing horizontal effective stress, which is compressive. For the caprock thickness and permeability considered here, pressure changes are small; it is changes in total stress that

are responsible for the deformation. As the deformation is approximately radially symmetric and because we are considering an extensional tectonic regime, some component of injection-induced extensional strain must be aligned with strain caused by tectonic extension. Furthermore, if the stress reduction is sufficiently large, the possibility exists for reactivation of an existing, well-oriented fault.

The possibility of mechanical failure caused by elastic flexure of a seal formation was considered by Hangx et al. (2010) for both reservoir injection and depletion scenarios. Using analytical solutions formulated in terms of caprock geometry, vertical deflection and elastic properties, they calculate vertical and horizontal stress changes at the caprock/reservoir interface and conclude the likelihood of shear failure in intact anhydrite induced by CO₂ injection is low for an extensional stress state in which $\sigma_3 = \frac{2}{3}\sigma_1$. In contrast, this modeling study considers the potential reactivation of low-cohesion or cohesionless faults that are critically stressed (within 5 MPa).

Vilarrasa et al. (2011, 2013) developed visco-plastic numerical models to investigate mechanical deformation of a caprock overlying a pressurized reservoir. They noted an induced bending of the caprock, resulting in compression along the underside and extension at the surface. If the ambient stress state is extensional, then the induced horizontal stress reinforces the tectonic load; as a result, plastic deformation is more widespread throughout the caprock.

Failure can also occur within the reservoir itself, in which case it may be pressure driven (Cappa and Rutqvist, 2011), or on basement faults that are hydrologically connected to the reservoir (Zhang et al., 2013). Fault failure within the reservoir is further complicated by a Biot stress effect, which provides a stabilizing compression that offsets the reduction in effective stress due to fluid pressure in the fault. These scenarios, however, are outside the defined scope of this paper and will be addressed in future efforts.

3.3 Model construction

3.3.1 Mesh

The CO₂ reservoir at Springerville serves as the analogue storage formation in these simulations. Thus, the computational domain must cover an area sufficient to represent large-scale deployment of injection wells into the dome. We use an orthogonal, Cartesian mesh, rotated 43° counterclockwise from north to align with the approximate strike of the Coyote Wash Fault; this structure serves as one of the lateral boundaries of the model. As hydrological communication between the fault blocks is expected to be low, this boundary is closed to fluid flow and injection strategies are restricted to the upthrown block. The model domain extends 27 km eastward from the fault and is 65 km long from SE to NW.

In map view, the model mesh is increasingly refined in the vicinity of the dome with reduced resolution near the boundaries. The single exception is the SW boundary, corresponding to the Coyote Wash Fault ($x = 23.5$ km), near which high resolution is preserved. Vertically, nodes are distributed according to a stacked mesh, where each layer within and 100 m above and below the reservoir follow the stratigraphic contour of the base of the Ft. Apache unit (see Rauzi, 1999; Figure 2(c)). The contoured

surface in Figure 2 (c) corresponds to the top of the reservoir unit in Figure 2 (b). As nodal layers are topographically flat at both the top and bottom surface of the model, the magnitude of the stratigraphic offset applied to non-reservoir layers is gradually reduced with proximity to the boundaries.

Four meshes are used in these simulations; they differ only in horizontal nodal spacing in the high resolution center section of Figure 2 (c). The four grids comprise ~48 000, ~72 000, ~126 000 and ~290 000 nodes, corresponding to nodal spacings of 1000, 750, 500 m and 250 m, respectively. The 500-m resolution mesh is used for the majority of simulations in this study, while the remaining meshes are used to explore model sensitivity.

3.3.2 Material properties

Three main hydrological units are defined – reservoir, caprock and basement – with a fourth representing the near-fault region. The reservoir layer is assigned a permeability of 10^{-14} m² (10 mD); in comparison, the caprock (10^{-19} m²) and basement (10^{-18} m²) are much less permeable. These values are consistent with core-plug measurements at Springerville (Rauzi, 1999) and similar modeling studies (Rutqvist et al., 2010). While modeling more permeable confining units would certainly be worthwhile, the intent here is to investigate the induced stresses in the caprock in the absence of a significant pressure perturbation migrated from the reservoir.

For the benchmark simulation, the caprock and basement are considered more rigid and assigned a Young's Modulus of 20 GPa, in comparison to the 5 GPa in the reservoir, consistent with values used by (Rutqvist et al., 2010). The effect of rigidity in the confining units is discussed in Section 4.4. Other material parameters are documented in Table 1.

Five different well configurations were tested, comprising one, three, five, seven and ten injection sites; these are shown in Figure 2(c). Each subsequent well pattern is constructed by adding new wells to the previous, e.g., the seven-spot pattern contains the same wells as the five-spot plus two extras. All wells are assumed to be vertical and inject at a single node, i.e., the open-well section is less than the 20-m vertical node spacing. Injection occurs against a fixed overpressure of between 1 and 15 MPa (Table 1) for a period of ten years.

The mobility of injected CO₂ in a mixed CO₂-water system is controlled by the prescribed relative permeability relationship. In these simulations, we use exponential functions to obtain best-fit curves through compiled experimental data (Bachu and Bennion, 2008; Perrin and Benson, 2010; Krevor et al., 2012; Berg et al., 2013). In contrast, others have used non-linear Corey (Rutqvist and Tsang, 2002) or Van Genuchten functions (Pruess and Garcia, 2002; Keating et al., 2012). Figure 2 (d) shows the particular set of exponential curves used in this analysis, superimposed upon the compiled experimental data. We use an irreducible water saturation of 0.2 and a maximum CO₂ relative permeability 80% that of water. Capillary pressure is zero; pressure diffusion into the caprock is controlled by the permeability of this unit.

3.3.3 Boundary and initial conditions

Before simulating injection, pressures, temperatures and stresses must first be initialized. As we are considering a relatively shallow reservoir, corresponding to depths of 500-600 m, a uniform temperature of 20°C is assigned throughout the model with no heat flow through all boundaries. In practice, some of the higher modeled overpressures (Table 1) would be expected to exceed σ_3 at these shallow depths, resulting in tensile failure; this does not occur in the linear elastic models presented here.

A gentle hydraulic gradient, flowing from SE to NW, exists at Springerville. In the model, this is represented by setting pressure heads at the $y=0$ and $y=65$ km lateral boundaries for a 300 m drop across the domain ($\sim .005$ m/m). Zero mass flux is enforced at all other boundaries and pressures within the model are allowed to equilibrate. For the injection simulations, pressures at all boundaries permit inflow or outflow to maintain initial pressure. The boundary at $y = 0$ is the one exception; this corresponds to the Coyote Wash Fault and, due to its role as a cross-fault hydrological barrier, zero mass flux is enforced at this boundary.

The initial model stress state is largely arbitrary as we only consider elastic deformation and are primarily concerned with stress changes. However, for the purposes of calculating Coulomb Failure Stresses (Section 4.2), an extensional stress state is defined, i.e., vertical maximum principal stress and the minimum principal stress aligned along the x-axis (perpendicular to the Coyote Wash Fault). This is consistent with the expected stress state at Springerville (Aldrich and Laughlin, 1984) as evidenced by more than 100 m of accumulated normal offset on the Coyote Wash Fault. A constant stress boundary condition can be applied at the top surface to approximate the overburden; however, as we are using a linear elastic model, for simplicity this can be set to zero. Roller boundary conditions are assigned at the base of the model, $y = 0$ and at $x = 23.5$ km.

3.4 Analysis of induced seismic risk

The principal aim of this study is to evaluate the potential for induced seismicity in a caprock formation overlying an overpressured reservoir. To this end, it is useful to define a metric for the proximity of a fault, either hypothetical or identified, to frictional failure, i.e., an earthquake. Furthermore, such a metric can then be used as a tool to identify whether a given perturbation, e.g., injection into a reservoir, promotes or inhibits failure on that fault.

In this work, we propose a new metric for quantifying the potential for fault failure in these scenarios: the change in the Coulomb Failure Stress (ΔCFS). This quantity is constructed from the Mohr-Coulomb failure criterion for a given fault orientation,

$$CFS = |\tau| - \mu(\sigma_n - p_f) - C, \quad (4)$$

where τ and σ_n are the shear and normal stress on the fault, and μ and C are the coefficient of friction and cohesion. This quantity is mostly negative and approaches zero as the fault becomes critically stressed, dropping back again due to the drop in stress that accompanies an earthquake. Changes in the CFS have been used with some success to correlate aftershock locations with regions of co-seismic stress transfer (Reasenber and Simpson, 1992). This metric is similar to the strength-to-stress margin

employed by Rutqvist (2012) for defining the risk of induced seismicity around a horizontal injection well at In Salah, Algeria.

The CFS depends on fault orientation; thus, to avoid calculating CFS for a range of orientations, it is pragmatic to select either the optimal plane for reactivation in the prevailing tectonic regime, or the orientation of an identified structure. In the case of Springerville, we have chosen a NW-striking fault that dips at 60° and parallels the Cedar Mesa and Coyote Wash Faults. This is consistent with the extensional tectonic setting with minimum principal stress oriented NE-SW, and a rock internal friction of 0.6 (Byerlee, 1978). Other approaches have been proposed that consider a range of fracture orientations and derive a single measure of slip-probability (Lee et al., 2013). Steeper dip angles may be more appropriate for the structures at Springerville; however, the results presented here are not sensitive to steeper dips.

As principal stress magnitudes at Springerville have not been measured, even an approximate calculation of the absolute value of CFS is largely arbitrary. Nevertheless, insight is gained from relative changes in CFS as these indicate whether a particular operation tends to promote or inhibit fault reactivation. Therefore, ΔCFS is the primary metric for evaluating induced seismic threats in this paper,

$$\Delta CFS = \Delta|\tau| - \mu(\Delta\sigma_n - \Delta p_f). \quad (5)$$

This quantifies the amount by which a fault has approached or retreated from failure; one can see from (5) that if $\Delta\sigma_n = \Delta p_f = 0$, then ΔCFS is just the induced shear stress on the fault. For a given simulation, $\Delta CFS(x)$ is a scalar field in 3-dimensional space. For comparison between multiple simulations, we use two reduced representations of $\Delta CFS(x)$ – a weighted-frequency distribution and a mean value.

A $\Delta CFS(x)$ distribution is reduced to a normalized frequency distribution by binning the nodal values and scaling the area under the histogram to be 1 (Figure 3A). The position of the peak and the length of the right tail provide some information on the volume and magnitude of $\Delta CFS(x)$. However, the frequency distribution is generally dominated by a peak near $\Delta CFS = 0$, corresponding to the bulk of the model domain for which stress changes are very small. Therefore, the normalized frequency distribution is further modified, by multiplying by the corresponding ΔCFS bin value, to yield the ΔCFS -weighted frequency distribution (Figure 3B). In this form, the complete stress perturbation is concisely summarized and can be compared to other perturbations. The ΔCFS -weighted frequency distribution has the following properties:

- (i) The area under the curve is equivalent to the mean value of $\Delta CFS(x)$; we define this to be the integrated tendency toward fault-failure (ITF), i.e.,

$$ITF = \frac{1}{V} \int_V \Delta CFS(x) dx. \quad (6)$$

This is a single measure of the induced-seismic risk associated with that particular loading. ITF has units of stress.

- (ii) For constant ITF, if the distribution is right-skewed, then the major proportion of the induced seismic risk is from small increases in ΔCFS distributed over a large volume. If the

- distribution is left-skewed, then the major seismic risk is due to large increases in ΔCFS in localized regions (Figure 3C).
- (iii) Stretching of the distribution along the vertical axis indicates an increasing volume of influence of the ΔCFS perturbation (Figure 3D).

Both the normalized and ΔCFS -weighted frequency distributions can extend into the negative x-axis; this represents a reduction of the seismic risk. However, for the simulations presented here, ΔCFS is positive.

4 Results

4.1 Benchmark simulation

In order to provide a benchmark for subsequent simulations (see Table 2 for a complete list), we first model CO₂ injection into a single well in the north of the Springerville reservoir (black star in Figure 2 (c)). As we are primarily concerned with the interaction between reservoir overpressure and induced caprock stresses, control over reservoir pressures is desirable. Thus, the injection source term is prescribed in terms of a fixed inlet pressure, as opposed to a fixed or varying flow rate. For example, in the benchmark simulation, injection is achieved by pumping at 5 MPa higher than the in situ reservoir pressure; while the reservoir pressure is less than the wellbore, fluid will flow into the reservoir in proportion to the pressure difference. This applied overpressure thus represents the upper limit on pressures attainable within the reservoir. The one exception is a small region above the injector where the buoyancy force applied by the injected CO₂ leads to a small additional pressure increase, ~ 0.03 MPa.

Accurate modeling of the injected flow rate against a fixed pressure requires high resolution in the vicinity of the injection well. This is necessary to resolve the sharp pressure gradients that exist and govern flow in the near well-bore region. However, even the highest resolution mesh used in this study (horizontal nodal spacing of 250 m), will not sufficiently capture these pressure gradients; as a consequence, injected flow rate is over-estimated for a given injection pressure. Nevertheless, mesh resolution is sufficient to resolve the overpressured region, which occupies a much greater volume than that of the injected CO₂ (see Figure 4). Therefore, the model is suitable to achieve the main objective of this study – to simulate pressure perturbations in the reservoir and their consequences for induced stresses in the caprock.

Injection, shown in Figure 4(a), exhibits the usual behavior of a high initial rate and rapid decline as the near well-bore pressure equilibrates with the applied overpressure. Injection stabilizes at 0.2 Mt yr⁻¹ after two years. Surface uplift above the injection site depends on the CO₂ injection rate and pressure conditions within the reservoir; at the end of the ten-year simulation, maximum uplift above the injector is ~ 0.09 m.

Following ten years of CO₂ injection, a wide overpressured region is established within the reservoir unit (Figure 4D). Overpressures penetrate an appreciable distance into the basement, but a much shorter distance into the low-permeability caprock. These pressure changes have a direct effect on the rock

stress state though the Biot term in Equation (2); essentially, the rock matrix experiences an additional compressive stress as it is squeezed by the overpressured pore fluids. This stress increase is particularly evident within the reservoir (Figure 4E-F), where the pressure perturbation dominates.

In addition to the induced stresses directly linked (via the Biot term) to reservoir overpressure, there is second effect that can be indirectly attributed to the pressure rise (Figure 4). An area of horizontal extension is developed close to the surface where doming and spreading are identified (see Figure 2A and Figure 4B). Vilarrasa et al. (2013) link this horizontal extension with a decrease in hydraulic head – the so-called “Noordbergum effect”. Importantly, this stress change is a reduction in the magnitude of the compressive stress in the direction of the least principal stress, i.e., it has the same orientation and sense as the regional tectonic load. It is this tectonic forcing that was responsible for past activity on the Cedar Mesa and Coyote Wash Faults.

4.2 Coulomb Failure Stress

Figure 5 summarizes the distribution of $\Delta CFS(x)$ at the end of the ten-year injection period for the single-well CO₂ injection simulation. Increases of more than 0.5 MPa in much of the caprock above the injection point indicate that the operation would contribute to critical stressing of well-oriented faults outside the overpressured reservoir. Consistent with the findings of Vilarrasa et al. (2013), we note the largest propensity to failure at the top of the reservoir layer and with less substantial increases near the top of the caprock. Significant increases in CFS also occur in the basement – this may have implications for induced seismicity on crystalline basement faults, recently associated with waste-water disposal by deep injection (Zhang et al., 2013). Interestingly, ΔCFS is much lower in the reservoir, where Biot-compressive stresses partly counteract the pore pressure term in (5).

For this particular configuration of caprock stiffness, injection overpressure and injected volume, the maximum ΔCFS in the caprock is 1.2 MPa and occurs near the reservoir-caprock interface. Immediately above this point, there is a ~2 km-wide region of elevated (>0.5 MPa) ΔCFS that extends to the surface (Figure 5D). For intact caprock, these stresses are probably not large enough to exceed cohesion and cause damage. However, in the unfortunate scenario that an undiscovered, critically-stressed fault was located above or adjacent to the injection site, these induced stresses are significant.

Normalized and ΔCFS -weighted frequency distributions for this simulation are shown in Figure 5E-F; both are right-skewed. The ΔCFS -weighted distribution has been constructed for a conceivable range of normal fault dips (constant strike). The similarity of these curves indicates relative insensitivity to this parameter; in all subsequent calculations, a dip angle of 60° is assumed.

4.3 Mesh sensitivity

To assess the sensitivity of these results to the resolution of mesh used, the 10-year, 5-MPa CO₂ injection simulation was performed for two coarser meshes (horizontal refinement of 750 and 1000 m). A second set of simulations, injecting pure water in place of CO₂, was also performed; the reduced

number of degrees of freedom in a pure water simulation allows the use of a finer resolution mesh (250 m) and makes for a more robust sensitivity study.

Figure 6A shows ΔCFS -weighted frequency distributions for the three CO₂ injection simulations. With increasing resolution, the shape of the curve is largely preserved, albeit somewhat refined, with no significant shift in the position or height of the peak. The area under the curve, i.e., ITF, shows a modest positive relationship with resolution. The water injection simulations show a slightly stronger positive relationship with increased horizontal grid-spacing. Extrapolating these trends yields a zero-resolution ITF close to 0.17×10^{-3} MPa for both sets of simulations. Turning this argument around, subsequent use of the high resolution (500 m) mesh in all remaining simulations entails an approximate overestimation of ΔCFS magnitudes by 15-30%.

4.4 Evolution of ΔCFS and sensitivity analysis

Before injection into the reservoir, the distribution of ΔCFS is identically zero. Thus, as the injection operation proceeds, the ΔCFS -distribution must evolve toward that shown in Figure 5; it is this evolution that is tracked in Figure 6C-D. The main trend of the curves in Figure 6C is a rise in the peak value; this is an indication that the volume of the ΔCFS perturbation grows in concert with the pressure perturbation within the reservoir. Secondary growth in the right tail of the distribution indicates higher values of ΔCFS are being achieved at later time. The ITF exhibits a linear trend over the ten-year simulation, i.e., there is no indication that induced caprock stresses reach a steady-state.

Two parameters are expected to have a first-order effect on the magnitude and extent of induced caprock stresses: (i) the magnitude of the injection overpressure; and (ii) the resistance of the caprock to deformation, i.e., its Young's Modulus. The Biot parameter, taken as 1 in these simulations as in other studies (Rutqvist, 2012; Vilarrasa et al., 2013), directly modifies the coupling strength between injection overpressure and rock strength and is thus implicitly included in the first parameter. Figure 6E-H show the effect of these parameters on the shape of the ΔCFS -weighted frequency distribution, ITF, and the long-term surface uplift rate (see Figure 4A).

Defining the volume of caprock perturbed by pressure changes in the reservoir by some arbitrary threshold of ΔCFS , then increasing the pressure in the reservoir increases both the volume of this perturbed region and the magnitude of induced caprock stresses. For instance, increasing overpressure from 5 to 15 MPa increases the ITF by almost a factor of 10, while the maximum value of ΔCFS increases from 1.2 to 3.5 MPa, i.e., approximately 23-24% of the applied overpressure. Uplift above the injector increases in proportion to the applied pressure, from ~ 0.1 to almost 0.3 m.

For comparison, uplift rates have been measured using interferometric synthetic-aperture radar (InSAR) data from the In Salah CO₂ injection operation in Algeria (Vasco et al., 2008). There, uplift rates of 5 mm yr⁻¹ were observed for injection into a 1.9 km deep, 20 m thick sandstone unit (Ringrose et al., 2009) through three wells for a total rate of ~ 0.5 Mt yr⁻¹. Rutqvist et al. (2010) modeled geomechanical changes at the In Salah site applying similar stiffness moduli to those used here. The modeled uplift rate was sensitive to caprock permeability, as this controlled the vertical extent of the reservoir overpressure. The discrepancy between uplift in our model (10 mm) versus that observed at In Salah

(15-25 mm; Rutqvist et al., 2010) is attributed to the difference in reservoir overpressure, i.e., 5 MPa in our model c.f. 10 MPa at In Salah. It may also be due to an absence of site-specific features, e.g., a deep fracture-zone that might be responsible for double-lobe uplift at In-Salah (Rinaldi and Rutqvist, 2013). The relative differences in reservoir overpressure and uplift are consistent with the model sensitivity documented in Figure 6F. Response of ΔCFS to increasing caprock stiffness exhibits a non-intuitive, non-linearity at low stiffness. This is a consequence of two competing effects: (i) shear stresses that develop at the sub-horizontal reservoir-caprock interface as a result of caprock resistance against the laterally expanding reservoir – these shears stresses have a small magnitude when resolved on the plane of a steeply dipping normal fault; and (ii) the ΔCFS -perturbed region in the rest of the caprock expands as the stiffer rock is less able to accommodate spreading. The superposition of these two effects results in a brief decline, then increase in ITF with increasing caprock stiffness; while curious, no particular significance is attached to this result.

Of greater interest is the relative insensitivity of maximum ΔCFS to caprock stiffness, which ranges between 1.6 and 1.3 MPa over the range of Young's Moduli tested. Rather, increases in the ITF are attributed to a larger-volume ΔCFS perturbation. Unsurprisingly, surface uplift corresponds strongly with the softness of the caprock, exhibiting 0.18 m for the lowest simulated Young's Modulus of 5 GPa and approaching 0.05 m for the highest (100 GPa).

4.5 An expanded injection operation

So far we have considered only a single injection well to investigate cause-and-effect relationships between injection operation, material parameters and induced stresses. However, if CCS is to be undertaken at a commercial scale, then a given reservoir may need to accommodate multiple wells injecting several 10s of Mt yr⁻¹ (Keating et al., 2011), e.g., the Illinois Basin (Birkholzer and Zhou, 2009).

Here, we investigate caprock stresses induced by large-scale injection for three-, five-, seven- and ten-spot patterns. Each subsequent pattern is constructed through the incremental addition of wells to the previous, e.g., the five-spot pattern includes the same wells as the three-spot with two new locations (the blue stars in Figure 2C and Figure 7C). For all patterns, wells inject continuously at a sustained overpressure of 5 MPa for a period of ten years. Distributions of ΔCFS are summarized in Figure 7.

Comparing induced stresses for the one- and three-spot patterns, it is clear that the ΔCFS distribution for the three-spot is not merely a superposition of three one-spot ΔCFS distributions. While local ΔCFS maxima are associated with the well locations, the area between wells is characterized by a marked ΔCFS increase that is attributable to the interaction between wells. This non-linear 'linking' of ΔCFS patterns between wells results in increasingly larger ΔCFS magnitudes for each subsequent well pattern. Furthermore, in addition to increasing the area of induced stresses, the peaks of the ΔCFS -weighted frequency distributions are increasingly shifted toward the right (Figure 7F), indicating the greater contribution to the seismic risk is being derived from the high- ΔCFS regions between wells.

An important consequence arising from the compounding of the ΔCFS distribution between wells, is the observation that loading of geological structures deemed seismically hazardous cannot necessarily be avoided by injecting "around but not on" the structure. A more robust strategy would require both a

rigorous characterization of the volume contained within the point cloud of injection wells, as well as modeling of the extent of ΔCFS outside the point cloud in order to avoid loading previously-identified structures.

The importance of the interaction between multiple pressure sources and flow-redirecting structures was also highlighted by Morris et al. (2011). They demonstrated that a computational modeling approach could inform injection strategy design that avoids fault reactivation, providing site characterization has identified the relevant structures and ambient stresses. However, in the absence of these data, the approach outlined here can be used to delineate regions of induced seismic threat and provide a first-order quantification of that threat.

5 Discussion and concluding remarks

In recent years, several studies have investigated the potential for geomechanical failure caused by injection of CO₂ underground (Rutqvist and Tsang, 2002; Rutqvist et al., 2008; Rohmer and Seyed, 2002; Hangx et al., 2010; Vilarrasa et al., 2011; Rutqvist, 2012). There is widespread agreement that reactivation of existing faults by elevated pore pressures, and therefore management of the extent and size of reservoir overpressures, represents a major challenge for large-scale deployment of CCS technology (Zoback and Gorelick, 2012).

Here, we have demonstrated that indirect threats to caprock integrity may also be derived from reservoir overpressurisation and deformation. Uplift and flexure of the overlying formations can induce reductions in horizontal stress that compound those induced by tectonic extension. The magnitude of induced stresses – approximately 1-2 MPa corresponding to typical overpressures of 5-10 MPa – represent a significant perturbation if well-oriented, critically-stressed structures are present above or near the injection location. Furthermore, this stress perturbation is exacerbated at increasing overpressure and caprock stiffness, and where multiple injection wells are operating and interacting. Our recommendations are thus aligned with the litany of studies calling for both comprehensive site characterization and computational modeling prior to undertaking large-scale injection operations; knowledge of the location and stress state of nearby structures is crucial to assessing the risk of proposed CCS operations.

The magnitude of shear stresses induced in the overlying caprock depends both on the amount by which the reservoir is overpressured (Figure 6G) as well as the lateral extent of the overpressured volume (Figure 6E, Figure 7). Currently, pressure management strategies are designed to restrict formation pressures some safe margin below the minimum principal stress – the threshold at which hydraulic fracturing occurs. However, based on the findings of this study, we propose that pressure management strategies should also consider the potential areal extent of the overpressured region in prescribing maximum operating pressures. Site- and operation-specific numerical modeling would likely be required to support such decision-making. In addition to limits on pumping pressures, a degree of control of reservoir pressures may be provided by the deployment of brine production wells (Buscheck et al., 2012; Elliot et al., 2013). Such strategies can be designed for optimizing both local pressure relief and

improving CO₂ injectivity. The effect of such pressure management schemes in limiting the magnitude and scope of induced caprock stresses will be assessed in future studies.

Acknowledgements

This study was funded through the American Recovery & Reinvestment Act (ARRA). The work was performed as part of the National Risk Assessment Partnership (NRAP) project. NRAP is supported by US Department of Energy through its Cross-Cutting Research Effort and is managed by National Energy Technology Laboratory (NETL).

References

- Aldrich, M. J. Jr., Laughlin, A. W., 1984. A Model for the Tectonic Development of the Southeastern Colorado Plateau Boundary. *Journal of Geophysical Research* 89, 10,207-10,218.
- Bachu, S., Bennion, B., 2008. Effects of in-situ conditions on relative permeability characteristics of CO₂-brine systems. *Environmental Geology* 54, 1707-1722.
- Berg, S., Oedai, S., Ott, H., 2013. Displacement and mass transfer between saturated and unsaturated CO₂-brine systems in sandstone. *International Journal of Greenhouse Gas Control* 12, 478-492.
- Birkholzer, J. T., Zhou, Q., 2009. Basin-scale hydrogeologic impacts of CO₂ storage: Capacity and regulatory implications. *International Journal of Greenhouse Gas Control* 3, 745-756.
- Buscheck, T. A., Sun, Y., Chen, M., Hao, Y., Wolery, T. J., Bourcier, W. L., Court, B., Celia, M. A., Friedmann, S. J., Aines, R. D., 2012. Active CO₂ reservoir management for carbon storage: Analysis of operation strategies to relieve pressure buildup and improve injectivity. *International Journal of Greenhouse Gas Control* 6, 230-245.
- Byerlee, J. D., 1978. Friction of Rocks. *Pure and Applied Geophysics* 116, 393-402.
- Caine, J. S., Evans, J. P., Forster, C. B., 1996. Fault zone architecture and permeability structure. *Geology* 24, 1025-1028.
- Cappa, F., Rutqvist, J., 2011. Impact of CO₂ geological sequestration on the nucleation of earthquakes. *Geophysical Research Letters* 38, doi: 10.1029/2011GL048487.
- Deng, H., Stauffer, P. H., Dai, Z., Jiao, Z., Surdam, R. C., 2012. Simulation of industrial-scale CO₂ storage: Multi-scale heterogeneity and its impact on storage capacity, injectivity and leakage. *International Journal of Greenhouse Gas Control* 10, 397-418.
- Elliot, T. R., Buscheck, T. A., Celia, M., 2013. Active CO₂ reservoir management for sustainable geothermal energy extraction and reduced leakage. *Greenhouse Gas Science and Technology* 3, 50-65.

568 Gilfillan, S. M. V., Wilkinson, M., Haszeldine, R. S., Shipton, Z. K., Nelson, S. T., Poreda, R. J., 2011. He and
 569 Ne as tracers of natural CO₂ migration up a fault from a deep reservoir. *International Journal of*
 570 *Greenhouse Gas Control* 5, 1507-1516.

571 Gor, G. Yu., Elliot, T. R., Prevost, J. H., 2013. Effects of thermal stresses on caprock integrity during CO₂
 572 storage. *International Journal of Greenhouse Gas Control* 12, 300-309.

573 Hangx, S. J. T., Spiers C. J., Peach, C. J., 2010. Mechanical behavior of anhydrite caprock and implications
 574 for CO₂ sealing capacity. *Journal of Geophysical Research* 115, doi: 10.1029/2009JB006954.

575 Horton, S., 2012. Disposal of hydrofracking waste fluid by injection into subsurface aquifers triggers
 576 earthquake swarm in central Arkansas with potential for damaging earthquake. *Seismological*
 577 *Research Letters* 83, 250-260.

578 Hsieh, P. A., Bredehoeft, J. D., 1981. A reservoir analysis of the Denver earthquakes: A case of induced
 579 seismicity. *Journal of Geophysical Research* 86, 903-920.

580 IPCC (Intergovernmental Panel on Climate Change), 2005. IPCC Special Report on Carbon Dioxide
 581 Capture and Storage. Cambridge University Press, New York.

582 Kanamori, H., Anderson, D. L., 1975. Theoretical basis of some empirical relations in seismology. *Bulletin*
 583 *of the Seismological Society of America* 65, 1073-1095.

584 Keating, E. H., Newell, K. L., Viswanathan, H., Carey, J. W., Zyvoloski, G., Pawar, R., 2012. CO₂/brine
 585 Transport into Shallow Aquifers along Fault Zones. *Environmental Science & Technology* 45, 215-
 586 222.

587 Keating, G. N., Middleton, R. S., Stauffer, P. H., Viswanathan, H. S., Letellier, B. C., Pasqualini, D., Pawar,
 588 R. J., Wolfsberg, A. V., 2011. Mesoscale Carbon Sequestration Site Screening and CCS Infrastructure
 589 Analysis. *Environmental Science & Technology* 45, 215-222.

590 Krevor, S. C. M., Pini, R., Zuo, L., Benson, S. M., 2012. Relative permeability and trapping of CO₂ and
 591 water in sandstone rocks at reservoir conditions. *Water Resources Research* 48, doi:
 592 10.1029/2011WR010859.

593 Jaeger, J. C., Cook, N. G. W., Zimmerman, R. W., 2007. *Fundamentals of Rock Mechanics*. 4th ed.
 594 Blackwell Publishing Ltd, Oxford, UK.

595 Lee, J., Min, K.-B., Rutqvist, J., 2013. Probabilistic Analysis of Fracture Reactivation Associated with Deep
 596 Underground CO₂ Injection. *Rock Mechanics and Rock Engineering* 46, 801-820.

597 Miller, S. A., Collettini, C., Chiaraluce, L., Cocco, M., Barchi, M., Kaus, B. J. P., 2004. Aftershocks driven by
 598 a high-pressure CO₂ source at depth. *Letters to Nature* 427, 724-727.

599 Moore, J., Adams, M., Allis, R., Lutz, S., Rauzi, S., 2005. Mineralogical and geochemical consequences of
600 the long-term presence of CO₂ in natural reservoirs: An example from the Springerville-St. Johns
601 Field, Arizona, and New Mexico, U. S. A. *Chemical Geology* 217, 365-385.

602 Morris, J. P., Detwiler, R. L., Friedmann, S. J., Vorobiev, O. Y., Hao, Y., 2011. The large-scale
603 geomechanical and hydrogeological effects of multiple CO₂ injection sites on formation stability.
604 *International Journal of Greenhouse Gas Control* 5, 69-74.

605 Pasala, S. M., Forster, C. B., Deo, M., Evans, J. P., 2013. Simulation of the impact of faults on CO₂
606 injection into sandstone reservoirs. *Geofluids* 13, doi: 10.1111/gfl.12029.

607 Perrin, J.- C., Beson S., 2010. An Experimental Study on the Influence of Sub-Core Scale Heterogeneities
608 on CO₂ Distribution in Reservoir Rocks. *Transport in Porous Media* 82, 93-109.

609 Pruess, K., Garcia, J., 2002. Multiphase flow dynamics during CO₂ disposal into saline aquifers.
610 *Environmental Geology* 42, 282-295.

611 Rauzi, S. L., 1999. Carbon Dioxide in the St. Johns-Springerville Area, Apache County, Arizona. Open-file
612 report 99-2, Arizona Geological Survey.

613 Reasenber, P. A., Simpson, R. W., 1992. Response of Regional Seismicity to the Static Stress Change
614 Produced by the Loma Prieta Earthquake. *Science* 255, 1687-1690.

615 Rinaldi, A. P., Rutqvist, J., 2013. Modeling of deep fracture zone opening and transient ground surface
616 uplift at KB-502 CO₂ injection well, In Salah, Algeria. *International Journal of Greenhouse Gas*
617 *Control* 12, 155-167.

618 Ringrose, P., Atbi, M., Mason, D., Espinassous, M., Myhrer, O., Iding, M., Mathieson, A., Wright, I., 2009.
619 Plume development around well KB-502 at the In Salah CO₂ storage site. *First Break* 27, 85-89.

620 Rohmer, J., Seyedi, D. M., 2010. Coupled Large Scale Hydromechanical Modelling for Caprock Failure
621 Risk Assessment of CO₂ Storage in Deep Saline Aquifers. *Oil & Gas Science and Technology – Rev.*
622 *IFP* 3, 503-517.

623 Rutqvist, J., 2012. The Geomechanics of CO₂ Storage in Deep Sedimentary Formations. *Geotechnical and*
624 *Geological Engineering* 30, 525-551.

625 Rutqvist, J., Birkholzer, J. T., Tsang, C. F., 2008. Coupled reservoir-geomechanical analysis of the
626 potential for tensile and shear failure associated with CO₂ injection in multilayered reservoir-
627 caprock systems. *International Journal of Rock Mechanics & Mining Sciences* 45, 132-143.

628 Rutqvist, J., Tsang, C. F., 2002. A study of caprock hydromechanical changes associated with CO₂-
629 injection into a brine formation. *Environmental Geology* 42, 296-305.

630 Rutqvist, J., Vasco, D. W., Myer, L., 2010. Coupled reservoir-geomechanical analysis of CO₂ injection and
631 ground deformations at In Salah, Algeria. *International Journal of Greenhouse Gas Control* 4, 225-
632 230.

633 Segall, P., Grass, J.-R., Mossop, A., 1994. Poroelastic stressing and induced seismicity near the Lacq gas
634 field, southwestern France. *Journal of Geophysical Research* 99, 15,423-15,438.

635 Shaffer, G., 2010. Long-term effectiveness and consequences of carbon dioxide sequestration. *Nature*
636 *Geoscience Letters* 3, 464-467.

637 Sibson, R. H., 1985. A note on fault reactivation. *Journal of Structural Geology* 7, 751-754.

638 Sibson, R. H., 1996. Structural permeability of fluid-driven fault-fracture meshes. *Journal of Structural*
639 *Geology* 18, 1031-1042.

640 Stevens, S. H., Pearce, J. M., Rigg, A. A. J., 2001. Natural Analogues for Geologic Storage of CO₂: an
641 Integrated Global Research Program. *Proceedings of the First National Conference on Carbon*
642 *Sequestration*, Washington, D. C., pp. 14-17.

643 Sullivan, E. J., Chu, S., Stauffer, P. H., Pawar, R. J., 2012. A CO₂-PENS model of methods and costs for
644 treatment of water extracted during geologic carbon sequestration. *Desalination and Water*
645 *Treatment* 51, 1487-1493.

646 Talwani, P., Acree, S., 1984. Pore Pressure Diffusion and the Mechanism of Reservoir-Induced Seismicity.
647 *Pure and Applied Geophysics* 122, 947-965.

648 Townend, J., Zoback, M. D., 2000. How faulting keeps the crust strong. *Geology* 28, 399-402.

649 Vasco, D. W., Ferretti, A., Novali, F., 2008. Reservoir monitoring and characterization using satellite
650 geodetic data: Interferometric synthetic aperture radar observations from the Kereba field,
651 Algeria. *Geophysics* 73, 113-122.

652 Vilarrasa, V., Olivella, S., Carrera, J., 2011. Geomechanical stability of the caprock during CO₂
653 sequestration in deep saline aquifers. *Energy Procedia* 4, 5306-5313.

654 Vilarrasa, V., Silva, O., Carrera, J., Olivella, S., 2013. Liquid CO₂ injection for geological storage in deep
655 saline aquifers. *International Journal of Greenhouse Gas Control* 14, 84-96.

656 Zhang, Y., Person, M., Rupp, J., Ellet, K., Celia, M. A., Gable, C. W., Bowen, B., Evans, J., Bandilla, K.,
657 Mozley, P., Dewers, T., Elliot, T., 2013. Hydrogeologic Controls on Induced Seismicity in Crystalline
658 Basement Rocks Due to Fluid Injection into Basal Reservoirs. *Groundwater* 51, 525-538.

659 Zoback, M. D., Hickman, S., 1982. In Situ Study of the Physical Mechanisms Controlling Induced
660 Seismicity at Monticello Reservoir, South Carolina. *Journal of Geophysical Research* 87, 6959-6974.

661 Zoback, M. D., Gorelick, S. M., 2012. Earthquake triggering and large-scale geologic storage of carbon
662 dioxide. *Proceedings of the National Academy of Sciences* 109, 10,164-10,168.

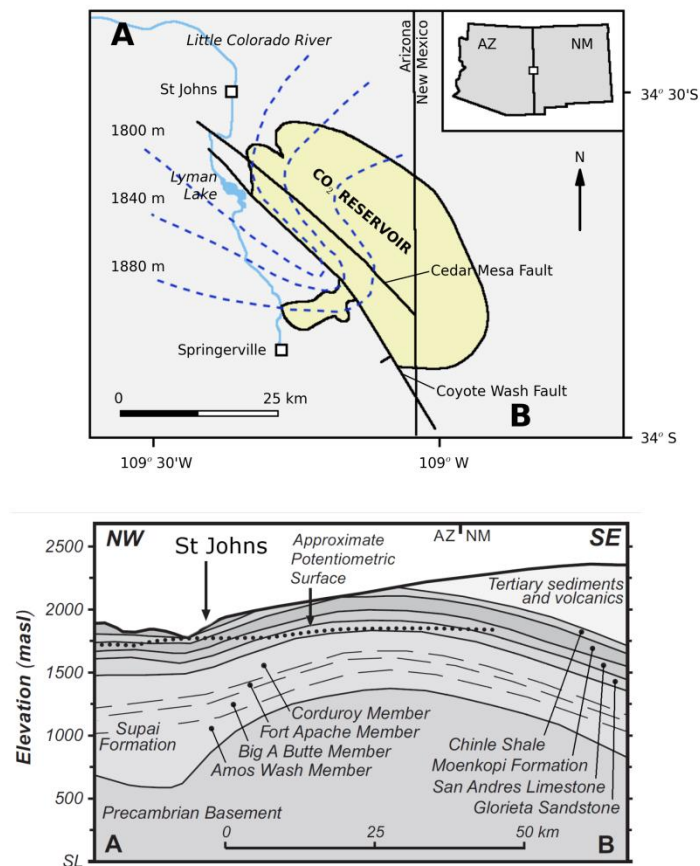
663 Zyvoloski, G. A., 2007. FEHM: A control volume finite element code for simulating subsurface multi-
664 phase multi-fluid heat and mass transfer. LA-UR-07-3359, Los Alamos National Laboratory, Los
665 Alamos, NM.

666

667

668

669 **Figures and figure captions**



670

671 **Figure 1: Map of the Springerville area (top), after Moore et al. (2005), showing relevant structures (Keating et al., 2012),**
 672 **inferred extent of the CO₂ reservoir (Rauzi, 1999), and water table contours showing pumping drawdown (Keating et al.,**
 673 **2012). A horizontal cross-section with important stratigraphic units is shown below (Rauzi, 1999; Moore et al., 2005).**

674

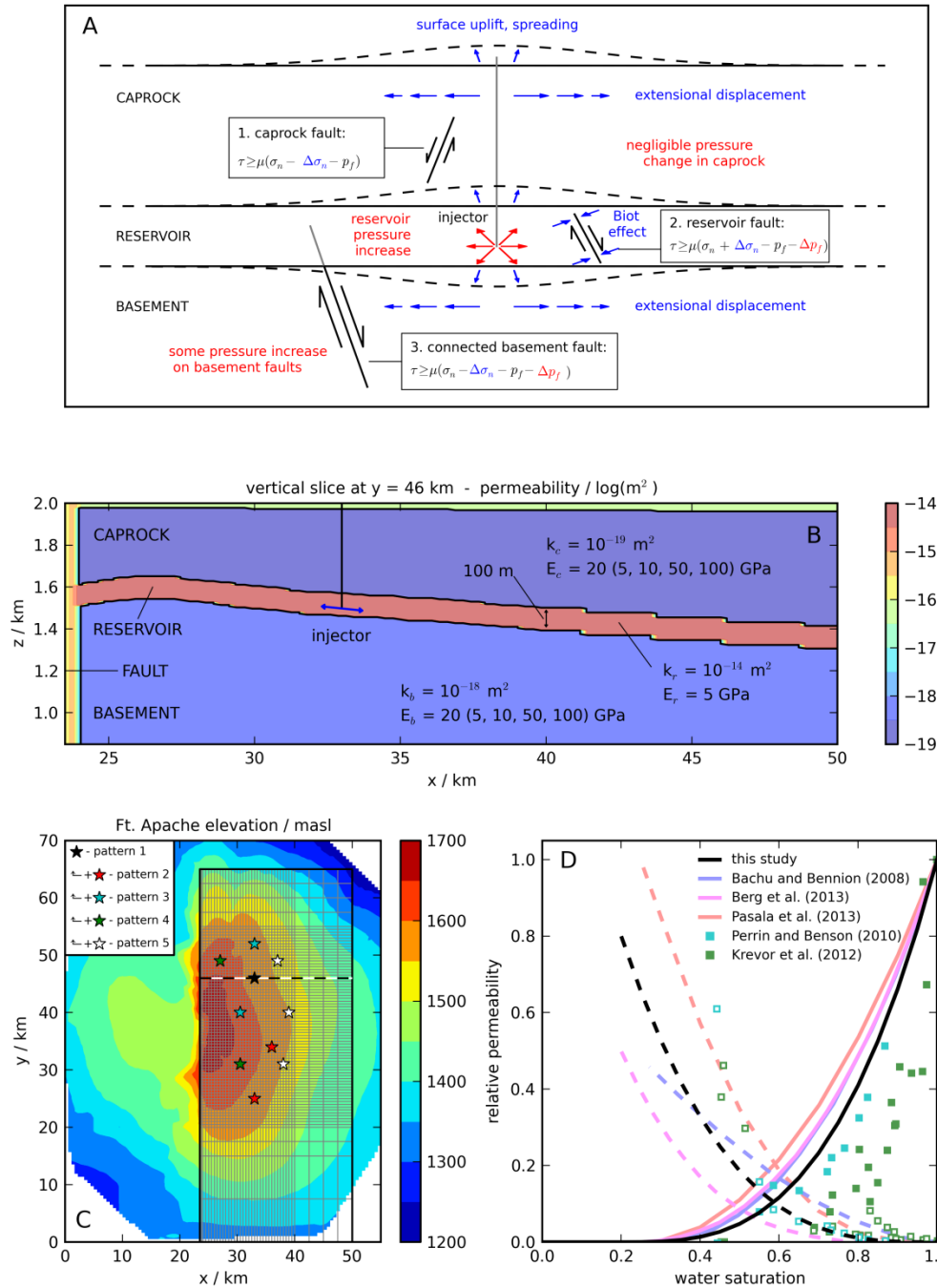


Figure 2: A. Conceptual model of injection into a confined reservoir leading to failure in (1) the caprock, (2) the reservoir, or (3) connected basement faults. Relevant failure criterion and contributing perturbation are shown for each (τ = shear stress, σ_n = normal stress, p_f = fluid pressure, μ = coefficient of friction). B. Vertical slice through the numerical model showing an idealized storage formation based on Springerville stratigraphy. Injection location and material properties are also shown. C. Map view of the medium resolution mesh superimposed upon stratigraphic contours corresponding to the base of the Fort Apache unit (Rauzi, 1999). The position of the vertical profile in B is marked by the black and white dashed line. The locations of injection wells used in the five well-patterns are shown; each subsequent well pattern is constructed by adding wells to the pattern before, e.g., pattern 3 adds the blue wells to the black and red wells it inherited from pattern 2. D. Relative permeability curves used for the CO₂ simulations, superimposed on experimental data (Bachu and Bennion, 2008; Perrin and Benson, 2010; Krevor et al., 2012; Berg et al., 2013) and other studies (Pasala et al., 2013).

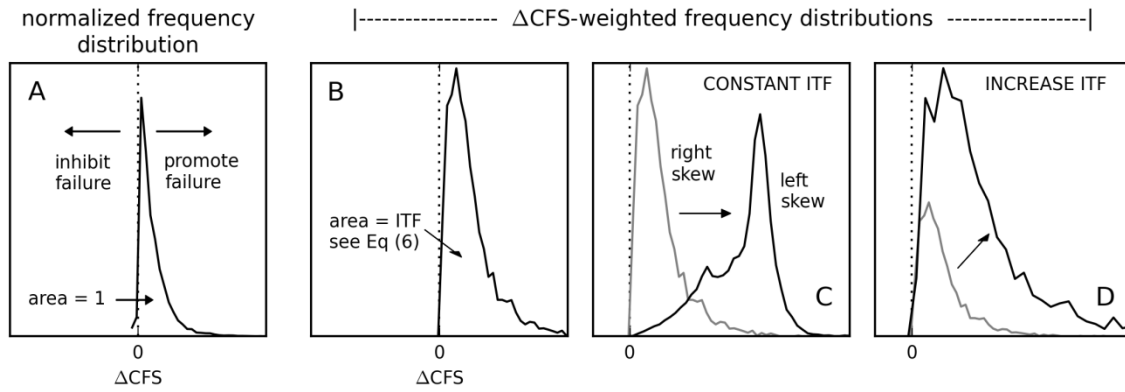
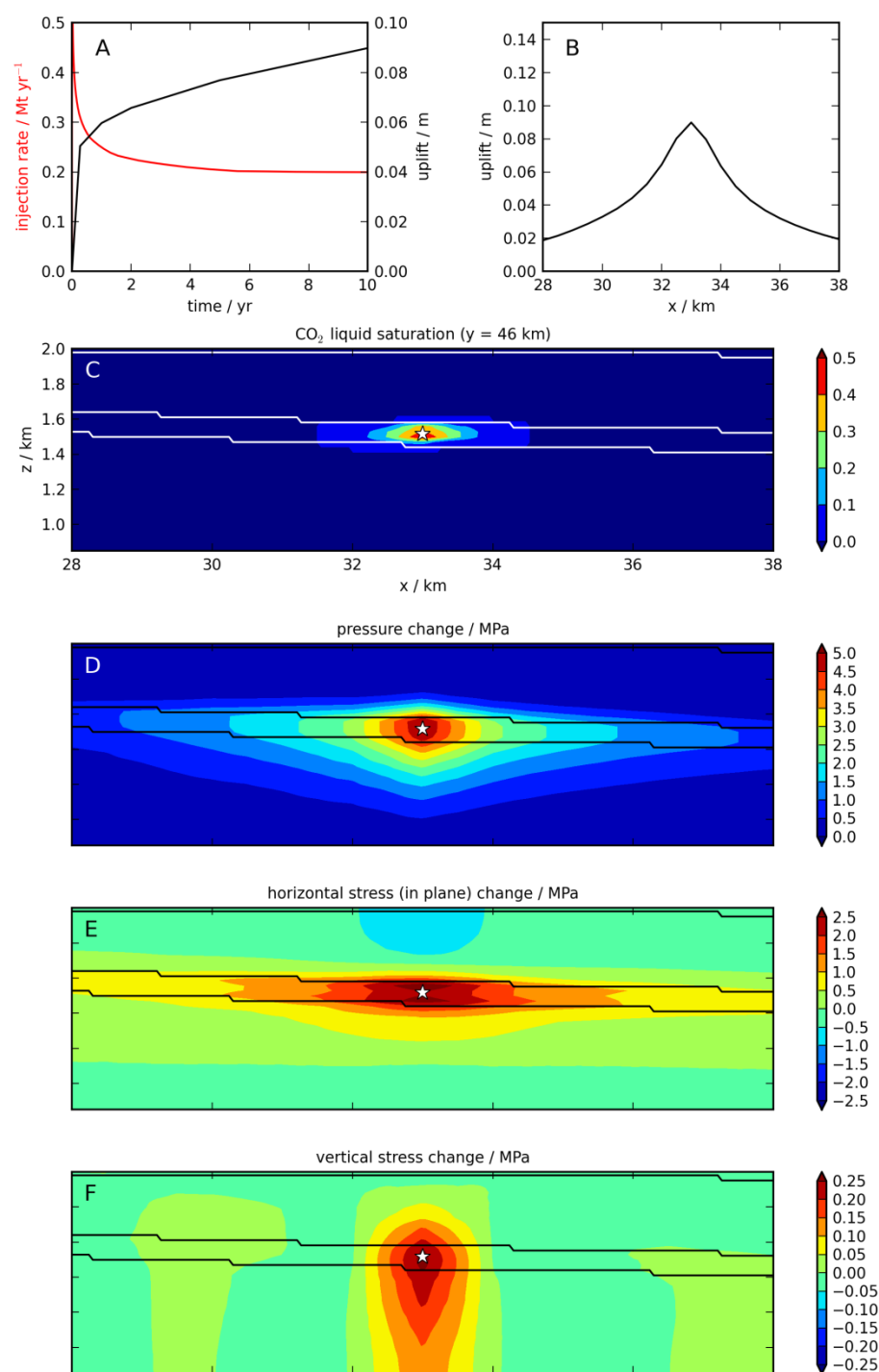


Figure 3: Example of normalized (A) and corresponding ΔCFS -weighted (B) frequency distributions for an arbitrary $\Delta CFS(x)$ distribution, as discussed in Section 3.4 – the area under these curves is 1 and the ITF, respectively. C. Example of transformation from right to left-skewed distributions for constant ITF distribution shown in B (grey profile). D. Vertical skewing results in increased ITF.



694

695 **Figure 4: Summary of benchmark CO₂ injection simulation. A. Injection rate (red) and surface uplift above injector (black)**
 696 **profiles with time. B. Surface uplift profile across the injection site at the top of the model at the end of the ten year**
 697 **simulation. C. Vertical slice plot of liquid CO₂ saturation at y = 46 km. Formation boundaries are shown by white lines and the**
 698 **injection location is indicated by a white star. Additionally, vertical slices of change in (D) pressure, (E) in-plane horizontal**
 699 **stress (σ_{xx}), and (F) vertical stress (σ_{zz}) are shown. Formation boundaries are indicated by black lines.**

700

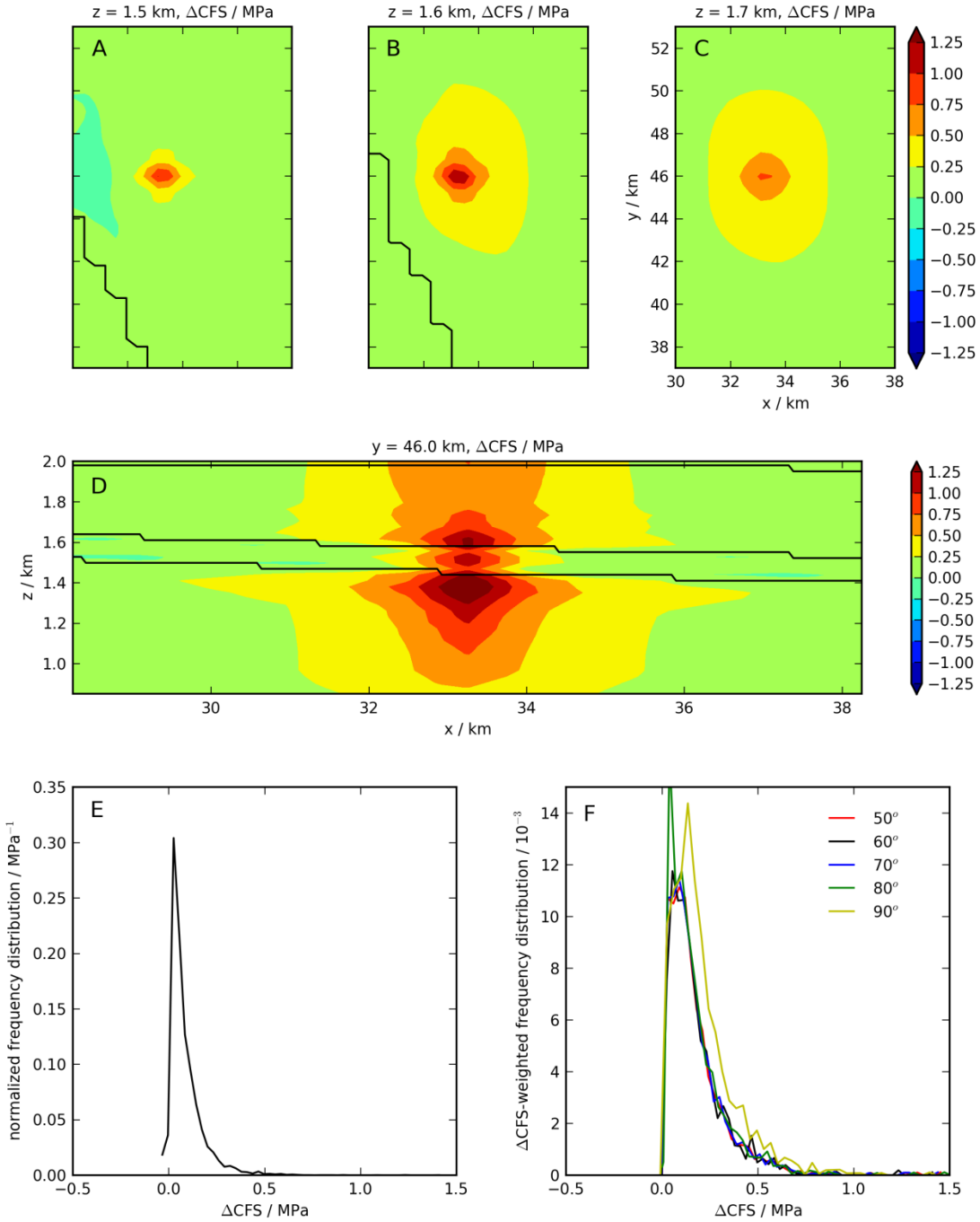


Figure 5: Contours of change in Coulomb Failure Stress (ΔCFS) for horizontal slices at three depths (A) 1.5 km, (B) 1.6 km, and (C) 1.7 km, and (D) vertical slice at $y = 46$ km. Contours of ΔCFS have been calculated for a fault striking parallel to the y -axis (i.e., aligned with structural grain of the region) and dipping at 60° . Black lines indicate unit boundaries. E. Normalized frequency distribution of ΔCFS values for all nodes in the caprock after ten years. F. The ΔCFS -weighted frequency distribution. Curves have been calculated for a range of possible fault dip angles.

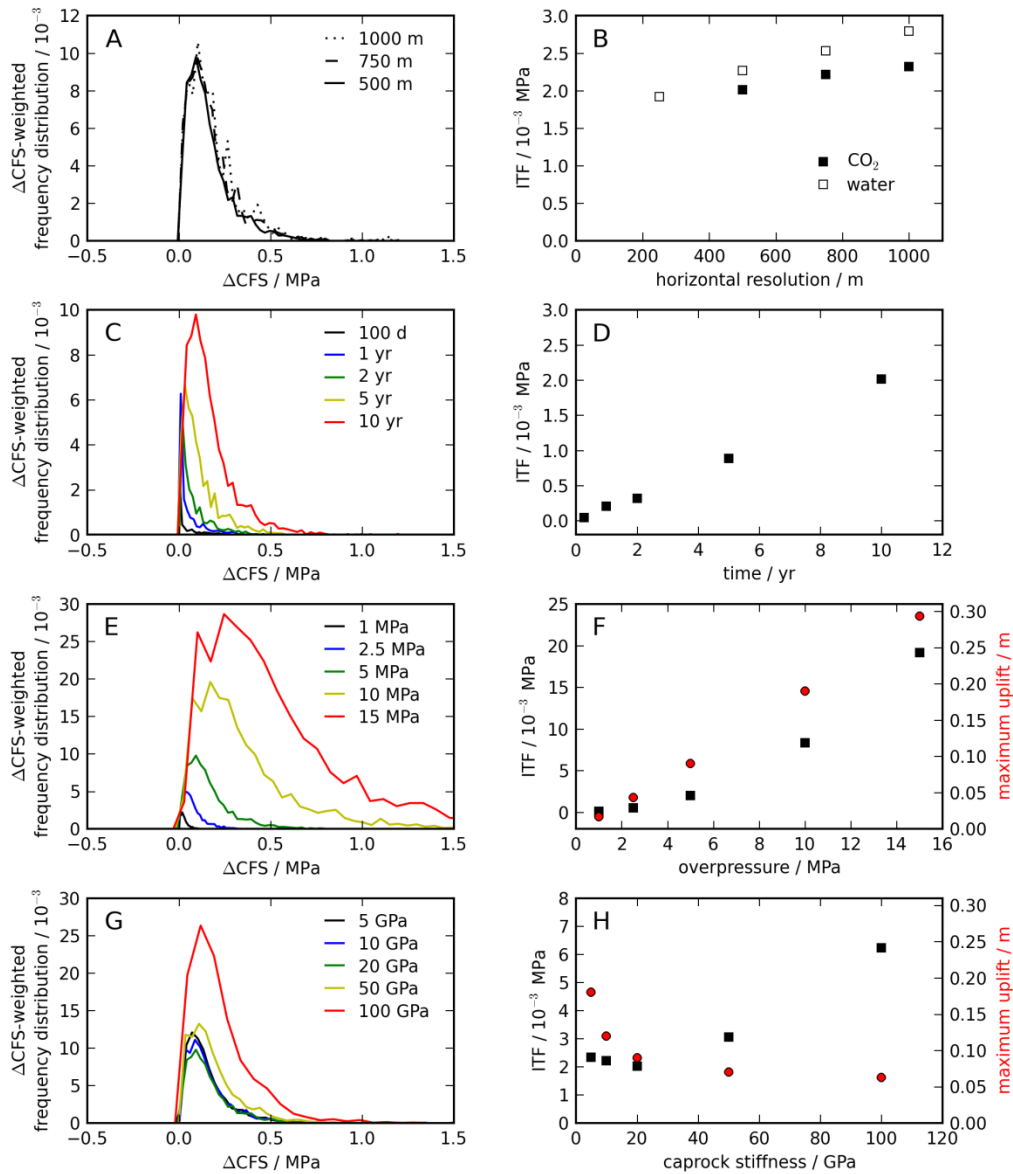


Figure 6: Sensitivity and parameter study of the single injection well simulation, comparing ΔCFS -weighted frequency distributions and ITF between simulations. A. ΔCFS -weighted frequency distributions for the low, medium and high resolution meshes under conditions of CO_2 injection. B. ITF for the three CO_2 injection simulations in A (solid squares) as well as all four mesh resolutions under conditions of pure water injection (open squares). Simulations detailed in the remaining figures were done on the high resolution (500-m) mesh using CO_2 as the injected fluid. C-D. Change in the ΔCFS -weighted frequency distribution and ITF with time. ΔCFS -weighted frequency distribution and ITF after ten years injection, and surface uplift above the injection point after ten years for (E-F) different injection overpressures and (G-H) different caprock stiffnesses.

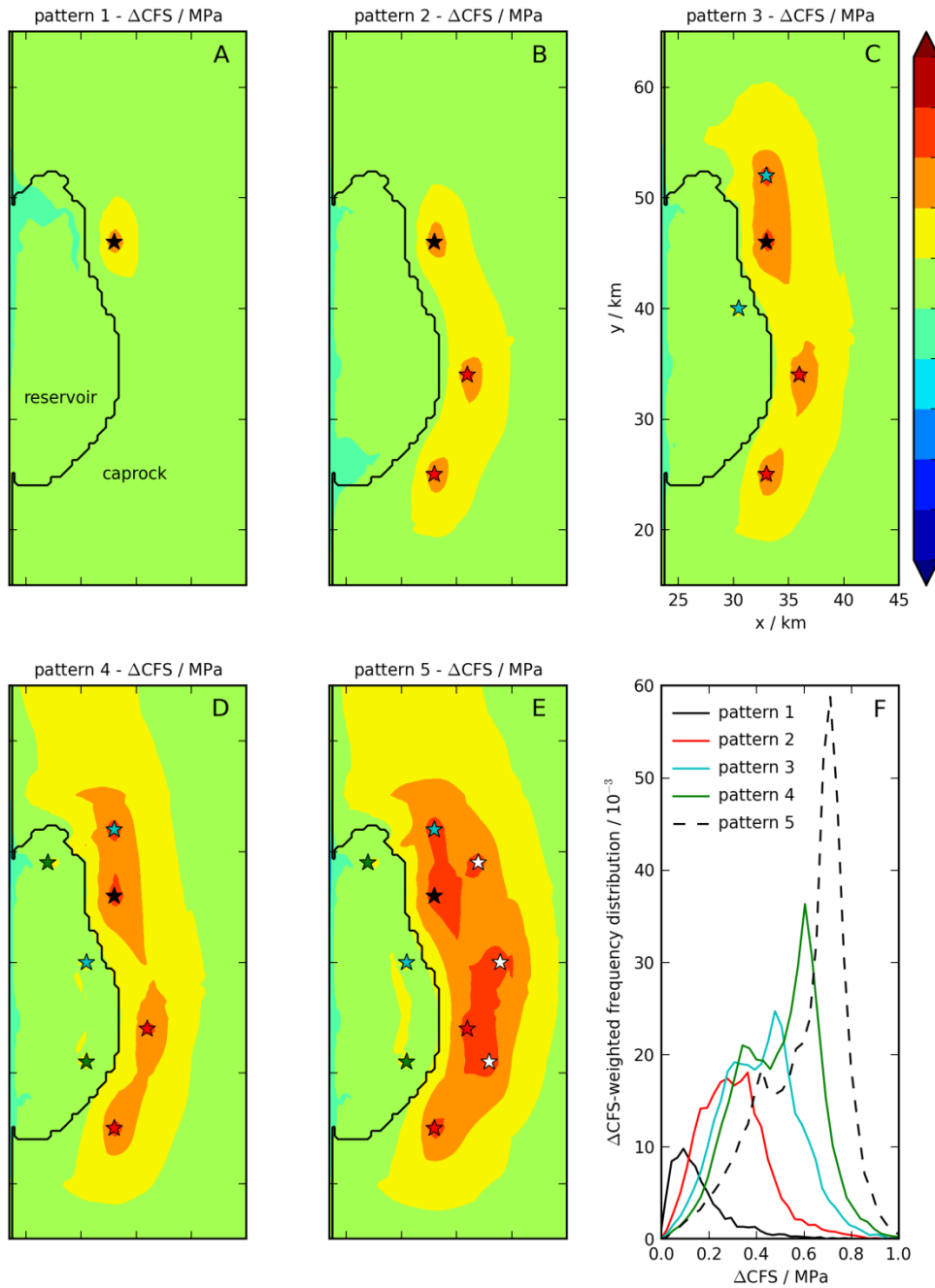


Figure 7: Summary of multiple injection well simulations. A-E. Contours of ΔCFS after ten years injection for a horizontal slice at $z = 1.6$ km. Well locations are shown for each pattern, after Figure 2(c). Reservoir and caprock units are indicated in A. F. ΔCFS -weighted frequency distribution after ten years injection for the five different well configurations.

Tables

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	30 m above base of reservoir.
Injection overpressure	5 (1, 2.5, 10, 15) MPa
<i>Material</i>	
Permeability	<i>Caprock</i> 10^{-19} m^2
	<i>Reservoir</i> 10^{-14} m^2
	<i>Basement</i> 10^{-18} m^2
Porosity	<i>Caprock</i> 0.01
	<i>Reservoir</i> 0.1
	<i>Basement</i> 0.01
Young's modulus	<i>Caprock</i> 20 (5, 10, 50, 100) GPa
	<i>Reservoir</i> 5 GPa
	<i>Basement</i> 20 (5, 10, 50, 100) GPa
Poisson's ratio	0.25
Biot coupling	1.0
<i>Relative permeability</i>	
Irreducible water saturation	0.2
Relative permeability exponents	3.1
Capillary pressure	0.
<i>Coulomb Failure Stress (CFS)</i>	
Friction coefficient	0.65
Failure plane strike	Parallel to y-axis and Springerville faults.
Failure plane dip	60° (50°, 70°, 80°, 90°)

728 **Table 2: Summary of models run. Well patterns are given in Figure 2C.**

Model	Mesh resolution	Injection fluid	Injection pressure (MPa)	Caprock/Basement Young's modulus (GPa)	Well pattern
1 (benchmark)	high	CO ₂	5	20	1
2	medium	CO ₂	5	20	1
3	low	CO ₂	5	20	1
4	highest	water	5	20	1
5	high	water	5	20	1
6	medium	water	5	20	1
7	low	water	5	20	1
8	high	CO ₂	1	20	1
9	high	CO ₂	2.5	20	1
10	high	CO ₂	10	20	1
11	high	CO ₂	15	20	1
12	high	CO ₂	5	5	1
13	high	CO ₂	5	10	1
14	high	CO ₂	5	50	1
15	high	CO ₂	5	100	1
16	high	CO ₂	5	20	2
17	high	CO ₂	5	20	3
18	high	CO ₂	5	20	4
19	high	CO ₂	5	20	5

729