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Caprock Integrity and Induced Seismicity from Laboratory and Numerical Experiments

Victor Vilarrasa[a,b,*], Roman Y. Makhnenko[c]

[a]*Institute of Environmental Assessment and Water Research, Spanish National Research Council (IDAEA-CSIC), Barcelona, Spain*
[b]*Associated Unit: Hydrogeology Group (UPC-CSIC), Barcelona, Spain*
[c]*Department of Civil & Environmental Engineering, University of Illinois at Urbana-Champaign, USA*

Abstract

CO_2 leakage is a major concern for geologic carbon storage. To assess the caprock sealing capacity and the strength of faults, we test in the laboratory the rock types involved in CO_2 storage at representative in-situ conditions. We use the measured parameters as input data to a numerical model that simulates CO_2 injection in a deep saline aquifer bounded by a low-permeable fault. We find that the caprock sealing capacity is maintained and that, even if a fault undergoes a series of microseismic events or aseismic slip, leakage is unlikely to occur through ductile clay-rich faults.

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Keywords: CO_2 storage; reservoir behavior; geomechanics; breakthrough pressure; relative permeability; fault reactivation; CO_2 leakage

1. Introduction

The success of geo-energy applications requires a good understanding of the coupled thermo-hydro-mechanical-chemical processes that occur in the subsurface as a result of fluid injection. To advance in this understanding, it is crucial for predictive numerical models to use realistic rock properties obtained from laboratory experiments.

* Corresponding author. Tel.: +34 93 400 61 00
E-mail address: victor.vilarrasa@idaea.csic.es

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However, given the difficulties to reproduce in the laboratory the pressure and temperature conditions representative of geo-energy applications, i.e., between several hundreds of meters to a few kilometers deep, data availability is scarce. Thus, a large number of numerical studies had to assume approximate values of rock properties to identify the relevant processes related to geo-energies, e.g. [1-3]. Nevertheless, generic studies are useful to improve process understanding.

Despite the limitations for high pressure and temperature testing, recent developments have allowed to test rock samples at representative in-situ conditions, e.g. [4,5]. On the one hand, sedimentary rock, such as sandstone and limestone, is of interest for fluid injection related to CO_2 storage and wastewater disposal because of its relatively high permeability, which hinders excessive overpressure [6]. On the other hand, crystalline rock is important for enhanced geothermal systems [7] and to understand seismicity induced by fluid injection in overlying sedimentary rock [8].

The use of rock properties from actual laboratory measurements is of interest to model the behavior of the subsurface at a specific site. In particular, accurate measurements of rock properties are required to design field experiments, decide the location of monitoring wells, and define the maximum sustainable injection pressure in pilot, demonstration, and industrial scale projects. These laboratory measurements should be accompanied by field characterization to account for scale effects on rock properties.

In this study, we measure properties of both sedimentary and crystalline rock and use these measured properties to assess caprock and fault stability associated with CO_2 injection. We measure two-phase flow and geomechanical properties of (*i*) Berea sandstone, which is a high-permeable sedimentary rock representative of storage formations, (*ii*) intact and remolded Opalinus clay, which are representative of caprock and faulted material, respectively, and (*iii*) hydro-mechanical properties of Charcoal granite, which is a representative of the crystalline basement. We model a geological setting including a stratified sedimentary basin with alternating low- and high-permeable layers and the crystalline basement at the bottom. The model includes a normal fault with a non-negligible offset. The fault is composed of a low-permeable fault core and a damaged zone on each side of the core. We analyze how the overpressure induced by CO_2 injection affects both caprock and fault stability.

2. Experimental methods

2.1. Material

We consider Berea sandstone, Opalinus clay (shale), and Charcoal granite to be the representatives of reservoir, caprock, and basement, respectively, and we measure their properties in the lab. Berea sandstone is a quartz-rich (>90%) sedimentary rock with porosity of 0.23, permeability $k \sim 10^{-14}$ m^2, and slight degree of elastic anisotropy (5-7%). Opalinus clay, a Jurassic shale from Switzerland, is taken as a ductile clay-rich (>55% of clay minerals) and low-permeable ($k \sim 10^{-21}$ m^2) cap and base rock representative. Its porosity is 0.12 and its elastic anisotropy is about 20-30%. Additionally, its permeability along and perpendicular to the bedding planes differ by a factor of 3. The crystalline basement is assumed to be formed by Charcoal granite ($k \sim 10^{-20}$ m^2), with 0.015 porosity that consists mainly of open cracks, which also determine a high level of elastic anisotropy (up to 100%) [9]. To represent the fault core, we test reconstituted to less than 0.5 mm grains Opalinus clay powder that is subsequently saturated with brine and consolidated at mean stresses above 20 MPa (referred here as “remolded shale”), which is isotropic in terms of elastic properties and permeability. At simulated reservoir conditions, porosity of fault core is 0.15 and permeability is $k \sim 10^{-20}$ m^2. Mercury intrusion porosimetry tests are performed on non-damaged rock samples with characteristic size of 8mm and show that the dominant pore throat diameter for the reservoir rock is about 30 micron, while those for shale (0.015 micron), remolded shale (0.015 micron), and granite (0.009 micron) are three orders of magnitude smaller, which lead to low-permeability and strong capillary effects in these formations (Figure 1). Pore size distribution and knowledge of contact angles and interfacial tensions can also provide an evaluation of pore entry pressures for CO_2 for low-permeable formations.