Understanding Fault and Fracture Networks to De-Risk Geological Leakage from Subsurface Storage Sites

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Summary

To verify successful long-term CO2 storage, it is critical to improve our understanding of leakage along natural faults and fractures within the primary caprock. In the proximity of a fault zone, interactions between multiple fracture sets can create complex networks which can play a fundamental role in fluid transport properties within the rock mass. Being able to fully characterise fault and fracture networks, in terms of fracture density, connectivity, aperture size and stress regime, can allow us to more accurately identify, analyse and model the bulk properties (e.g. transport, strength, anisotropy) and, therefore sealing behaviour, of faulted and fractured geological storage sites. Here, we present an integrated workflow which combines laboratory measurements of single fracture permeability with outcrop-scale analysis of fault and fracture networks occurring in reservoir/caprock sections. These data are then used to develop a hydromechanical model to upscale laboratory tests to network-scale and potentially to reservoir-scale, verified against in-situ fault permeability data, where available.

Introduction

Carbon capture and geological storage is a potential means of managing atmospheric carbon dioxide (CO_2) levels (Kampman et al., 2014). To verify successful long-term CO_2 storage, it is critical to improve our understanding of leakage along natural faults and fractures within the primary caprock. In the proximity of a fault zone, interactions between multiple fracture sets can create complex networks which can play a fundamental role in fluid transport properties within the rock mass. Being able to fully characterise fault and fracture networks, in terms of fracture density, connectivity, aperture size and stress regime, can allow us to more accurately identify, analyse and model the bulk properties (e.g. transport, strength, anisotropy) and, therefore sealing behaviour, of faulted and fractured geological storage sites. Here, we present an integrated workflow which combines laboratory measurements of single fracture permeability with outcrop-scale analysis of fault and fracture networks occurring in reservoir/caprock sections. These data are then used to develop a hydromechanical model to upscale laboratory tests to network-scale and potentially to reservoir-scale, verified against *in-situ* fault permeability data, where available.

Method and Theory

Geological storage of CO_2 requires impermeable – over human timescale – caprocks and effective trapping mechanisms to prevent leakage to the surface. The presence of fault and fracture networks, acting as conduits for fluid flow, can compromise the integrity of the caprock. To evaluate the risks related to possible CO_2 leakage, we need a detailed characterisation of fracture network permeability, representative of *in-situ* conditions. Laboratory experiments can recreate the stress conditions in the subsurface, yet these are limited to single fracture permeability. However, fractures rarely occur as single, isolated features, and more often they form highly complex networks. We can gather information on the properties associated with the fracture system as a whole analysing fracture and fault network on outcrops.

Laboratory data

We are using a custom-designed triaxial permeameter to run fracture permeability tests on samples with 1- and 1.5-inch diameter (Figure 1B) at pore pressures (P_p) up to 25 MPa, confining stresses (P_c) up to 35 MPa and temperatures (T) up to 70°C (Figure 1A). These P_p, P_c and T conditions are adequate to represent subsurface conditions down to 1500m, so representative for CO_2 storage reservoirs. We test the samples at different effective stress conditions with varying P_p and T, reflecting the different reservoir conditions over the course of a CO_2 storage project. The mass flow controller (MFC) has a range that allows measuring samples with steady-state nitrogen permeabilities between ~10^{-15} – 10^{-18} m^2. This is adequate for the samples we wish to test; the flow rate is then used to calculate the permeability of the sample (Figure 1C). The permeameter has been designed in a way that for samples with lower permeabilities, we can switch to an unsteady-state method. Unsteady-state experiments rely on a closed system where compartments of known volume are connected on either side of the sample. One of the volumes (upstream volume) will be filled with the permeating fluid and the pressure is recorded over time. Fluid will then flow from the upstream volume through the sample to the downstream volume until the pressure in both volumes has equilibrated. This typically takes hours to days, depending on permeability. The pressure difference between the two volumes throughout the experiment is then used to calculate the permeability of the sample.

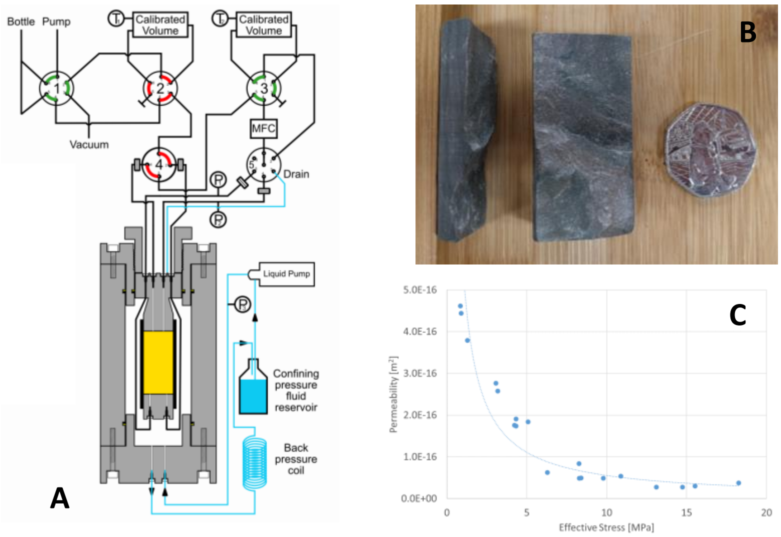

Figure 1 *A) Schematic flow diagram of permeameter used for determining fracture flow rates. B) Typical samples used, consisting of two half cylinders (fractures are either induced or natural). C) Permeability – Effective stress relationship showing exponential decrease in permeability with effective stress.*

Outcrop Analysis

The sealing potential of caprocks, in an otherwise impermeable mudrock, is fundamentally dependant on the connectivity, density, length and aperture of a fracture system. We focus our study on two-dimensional (2D) fault-related fracturing within reservoir/caprock seen within both compressional and extensional fault zones. 2D data of fault and fracture networks were acquired from the Mont Terri Rock Laboratory in Switzerland (compressional) and from the Longyearbyen CO_2 Lab in Svalbard, Arctic Norway (extensional). Data from the Mont Terri rock laboratory were collected from four gallery windows intersecting a major thrust fault, the “Main Fault”, with a thickness varying laterally between 0.9 and 3.0 metres (Jaeggi et al., 2017). Fault and fracture network data for an extensional setting were acquired using digital virtual outcrop models of outcropping reservoir and caprock units Konusdalen, Svalbard (Figure 2A-B). This area exposes reservoir/caprock sequences targeted during the pilot project of the Longyearbyen CO_2 Laboratory (Ogata et al., 2012, 2014; Mulrooney et al. 2019; Olaussen et al. 2019) cut by meso-scale faults. By digitising all the visible features over the images and then inputting them into the open-source toolbox FracPaQ (Healy et al., 2017), we obtain information about the fault and fracture networks (Figure 2C). In particular, we are interested in studying the variations in fracture size (i.e. length, height) and density (Figure 2D-E) distribution near and away from the fault zone(s), together with the connectivity of a fracture within the network (Figure 2F). These three parameters are then fundamental to understand if the network provides permeable pathways. They will also enable us to statistically reproduce and upscale a fracture network in a realistic way.

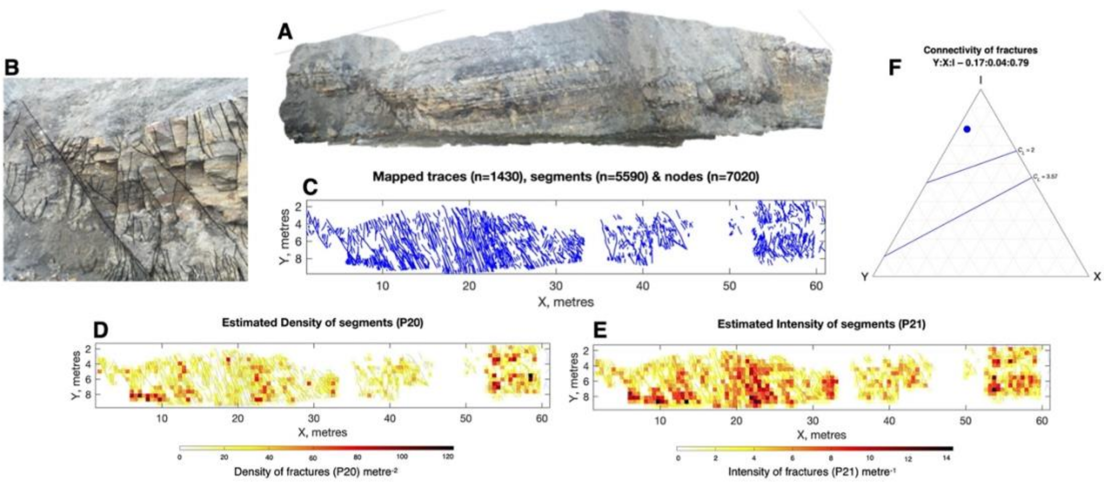

Figure 2 Overview of Konusdalen fault-related fracture network analysis. A) Orthorectified montage of the digital outcrop model. This model was processed from 75 images acquired using an iPhone (0.24 cm/pixels ground resolution, available at https://www.svalbox.no/portfolio/konusdalen-iphone/). B) Example of digitalisation of fracture network on a closer caption from the orthomosaic. C) Map of the fracture network. D-E) Density (fractures/m$_2$) and intensity (fractures length/m) maps. F) Connectivity plot illustrating the degree of connectivity within the fracture network and the types of topological fracture nodes: I, isolated nodes; Y, abutting nodes; X cross-cutting nodes.

The hydromechanical modelling

The hydromechanical procedure uses laboratory single-fracture stress/permeability relationships obtained through fracture core flood experiments and the real 2D field fracture networks (Figure 3B) as mapped from the two study sites to simulate the *in-situ* permeability of the fracture network. The numerical model uses the open-source PorePy (Figure 3C; Keilegavlen et al., 2017) for meshing the 2D fracture network. The meshes are then loaded and further processed using our implemented workflows in open-source SINTEF MRST (MATLAB Reservoir Simulation Toolbox; Lei, 2019). The workflow for upscaling the fracture network permeability is described in Figure 3A. The contact pressures at each node of the digitised fractures are computed using Finite-Element solver for a set of stress boundary conditions. We calculate a fracture network aperture field combining the contact pressure values with the laboratory stress/permeability data. The corresponding permeability field is obtained assuming a parallel plate law in the fractures. Finally, using single phase upscaling and Darcy's law, we determine the effective upscaled permeability for the fracture networks. Repeating the workflow for varying sets of stress boundary conditions provides a stress-sensitive fracture network permeability (Figure 3D) that can be used as a proxy for permeability at the reservoir scale.

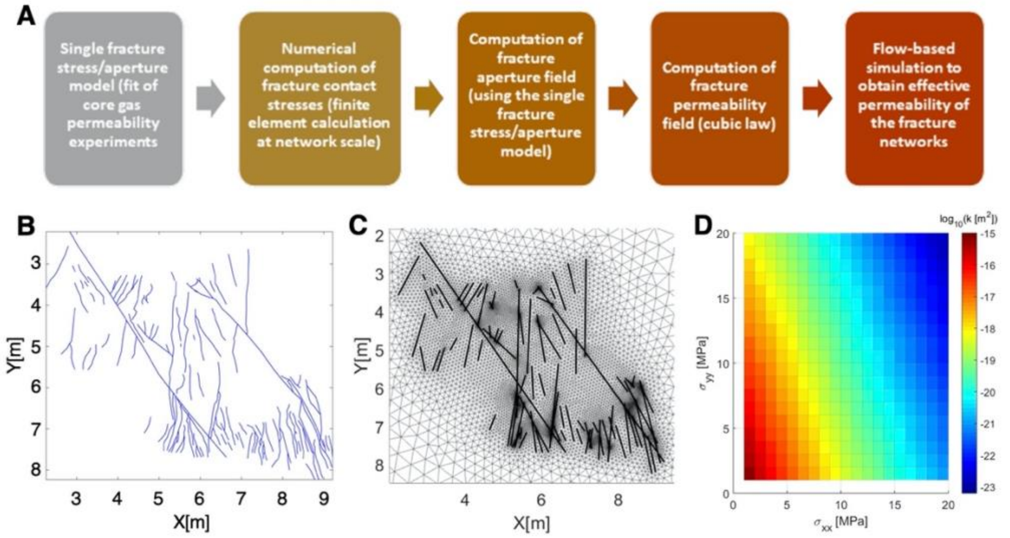

***Figure 3** A) Workflow used numerically compute the hydromechanical properties of the fault and fracture network. B) Portion (see Fig2B) of the digitised fracture network from Konusdalen. C) Computational mesh created from the digitised fracture network. D) Stress-permeability surface plot for fluid flow in the y-direction for a range of stress boundary conditions (1 MPa to 20 MPa).*

Conclusions

We present an integrated procedure for modelling effective permeability in real fracture networks associated with both compressional and extensional fault zones. Laboratory data on single fracture permeability are coupled to outcrop-derived fracture network and then used as input data in hydromechanical modelling. The combination of laboratory data on different samples and fault models allow flow simulations to quantify a range of fault effective permeability. Outputs of these models enable us to determine realistic stress-permeability relationships for different fault architectures, therefore allowing an assessment of fault and fracture fluid flow rates that can be expected in geological CO_2 storage or unconventional reservoirs.

Acknowledgements
The Svalbox.no geoscientific portal provided Konusdalen outcrop data. This project has been subsidised through the ERANET Cofund ACT (Project no. 271497), the European Commission, the Research Council of Norway, the Rijksdienst voor Ondernemend Nederland, the Bundesministerium für Wirtschaft and Energie, and the Department of Business, Energy & Industrial Strategy, UK. This work was also part of a project that has received funding by the European Union's Horizon 2020 research and innovation programme, under grant agreement number 764531.

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