Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 114 (2017) 3229 – 3236

Energy Procedia

13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland

Fault permeability and CO_2 storage

Andy Nicol[a,b,]*, Hannu Seebeck[a], Brad Field[a], David McNamara[a], Conrad Childs[c], James Craig[d], Alex Rolland[d]

[a]GNS Science, PO Box 30368, Lower Hutt 5010, New Zealand
[b]Department of Geological Sciences, University of Canterbury, Christchurch 8140, New Zealand
[c]Fault Analysis Group, School of Earth Sciences, UCD, Dublin 4, Ireland
[d]IEAGHG, Cheltenham GL52 7RZ, United Kingdom

Abstract

Faults comprise zones of crushed, sheared and fractured rock that have the potential to influence the migration of stored CO_2. Fault-zone permeabilities of 10^{-9} to 10^{-19} m^2 are controlled by many interdependent factors including; fault-zone architecture and rock types, mechanical strength and permeability of host rock, orientation and magnitude of *in situ* stresses, fracture aperture size and connectivity, fluid properties and burial history. Mitigating the risk of CO_2 migration via faults to the atmosphere or into economically valuable resources requires an understanding of the conditions under which they promote fluid flow from the reservoir. *In situ* flow data from natural seeps indicate that faults can promote the upward flow of CO_2, with flux rates being greatest where the highest densities of fractures occur. Flow simulation modelling suggests that low-permeability fault rock may compartmentalise reservoirs giving rise to increased pressures and promoting upward flow of CO_2. Migration rates along faults of up to 1000 m/yr are possible and could produce leakage rates of up to 15000 t/yr at natural seeps. These rates are likely to be site specific and positively related to reservoir pressures. Present understanding of fault hydraulic properties is generally not sufficiently complete to predict when and where faults will influence CO_2 migration. To improve understanding of fault hydraulic properties, studies of outcrop, analogue and numerical models are required. *In situ* flow measurements are critical for testing site-specific and generic fault fluid-flow models that are important in establishing guidelines for the inclusion of faults in risk assessment and determining what mitigation measures are most appropriate.

Peer-review under responsibility of the organizing committee of GHGT-13.

Keywords: fault permeability; fluid flow; CO_2 migration; *in situ* pressure; natural seeps; leakage rates.

* Corresponding author. Tel.:+64-3-364-2987; fax:+64-3-364-2769.
E-mail address: andy.nicol@canterbury.ac.nz

Peer-review under responsibility of the organizing committee of GHGT-13.
doi:10.1016/j.egypro.2017.03.1454

1. Introduction

Faults can displace CO_2 reservoirs and caprocks. In such cases they have the potential to modify the storage capacity, maximum injection rates and reservoir pressures, and seal integrity in CO_2 storage systems. They may form due to a range of processes and here we focus on faults that pre-date CO_2 injection which, in many cases, are of tectonic origin and form due to extension of the rock (i.e. normal faults). These faults can form barriers to across-fault flow and conduits to along-fault flow [e.g., 1-4]. Precisely how faults will impact on fluid flow is dependent on a number of factors, including permeabilities and relative permeabilities of fault rock and the rock formation hosting the fault (referred to here as host rock), the rheologies and burial depths of host rocks, the pressure and temperature conditions of the reservoir and fluids, the composition of the fluids and the fracture geometries (e.g. dimensions, interconnectedness and apertures) [e.g., 1-4]. The values of these parameters and the resulting fluid-flow rates may change between faults or parts of faults, and from one CO_2 storage site to another. The influence of these factors on permeability and fluid flow may also change through time at individual sites in response to changes in pressures, temperatures and injection rates. It is possible, for example, that increases in pore pressure or decrease in effective stresses arising from injection will increase fracture apertures, induce fault slip and/or generate new fractures, all of which could locally promote the flow of CO_2 and brine from the storage container [5-7]. CO_2 leakage along faults at natural seep sites also suggests that faults are potential migration pathways even in circumstances where CO_2 injection is not expected to significantly increase reservoir pressures.

Mitigating the risk of CO_2 migration via faults to the atmosphere or into economically valuable resources (e.g. water aquifers or hydrocarbon reservoirs), requires an understanding of the conditions under which they promote fluid flow from the reservoir. Knowledge gaps in our understanding of CO_2 migration along faults are widely accepted. The present paper uses the published literature to examine how fault permeability is modified by fault zone and host rock properties and *in situ* stresses of anthropogenic or geological origins. The primary goal of this paper is to use publically available information to examine when, where and how faults may negatively or positively impact the storage and migration of injected CO_2. In particular, we summarise key parameters that influence the hydraulic properties of fault zones and CO_2 flow data along faults at natural seeps, review practices for managing unwanted migration of fluids along faults, identify knowledge gaps in current understanding of fluid migration along faults and recommend the direction of future research and development to promote a better understanding of fault permeability.

2. Fault zone structure and permeability

It has long been known that faults can strongly influence the sub-surface movement of fluids (i.e. liquid and gas). Bulk fluid-flow rates through or along fault zones are important for many practical applications, including geothermal and hydrocarbon production and CO_2 storage. Whilst it is generally acknowledged that the structure of fault zones can be complex and spatially variable, a relatively simple fault damage zone model has been widely adopted (Fig. 1a). At outcrop scale the damage model is rarely correct in detail as fault zones form highly heterogeneous bodies. Fault surfaces are generally anastomosing, producing fault rock and fault zone thicknesses that range in excess of an order of magnitude over fault surfaces. Low permeability (clay-rich) fault rock retards cross-fault flow while, in many cases, jointing and small-scale faulting may locally elevate along-fault permeabilities (Fig. 1b). Therefore, faults may simultaneously impede cross-fault flow and enhance along-fault flow to form a dual conduit-barrier system. Understanding of the bulk flow properties of fault zones has been hindered by a general lack of *in situ* flow data which can be unambiguously related to the structure of fault zones and the lithologies of the surrounding rock-volume.

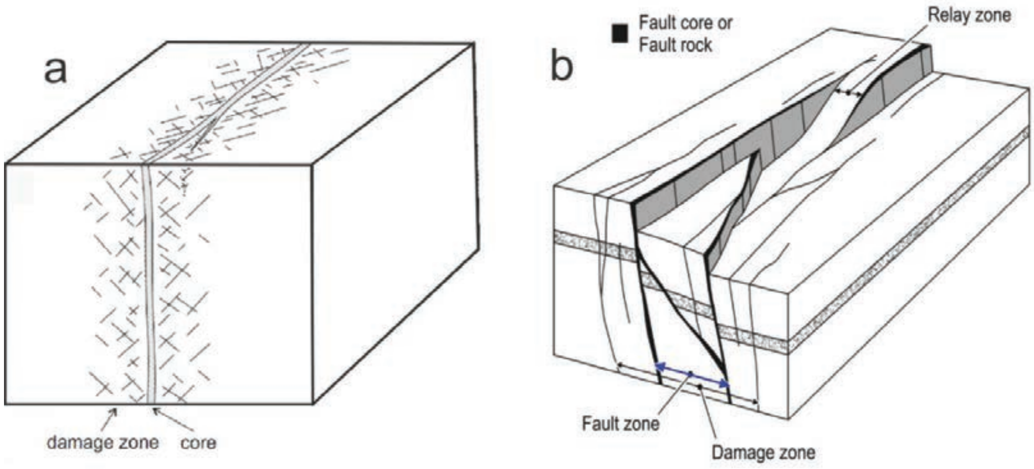

Fig. 1 Schematic diagrams illustrating fault zone models and terminology. (a) Fault damage zone – fault core model where a zone of fracturing encloses a clay-rich core comprising low permeability fault rock [8]. b) Fault zone model in which the thicknesses of clay-rich fault rock and fault zones dominated by small faults vary over the fault surface [9].

Fault-zone conductivity and transmissivity are controlled by many interdependent factors including among others; fault architecture and the types of fault rocks present at a given location, mechanical strength and permeability of the host lithology, fracture aperture size and connectivity, fluid composition, pressure and gradients, extent of pre-existing mineralisation and the orientation and magnitude of normal and shear stresses. Connectivity is critical for fluid flow in fractured media where networks of fractures above a critical density determine the flow properties of the system. For example, fault zones in a region may have the same general fault architecture, however only those having sufficiently connected high-permeability pathways will be hydraulically conductive. In such cases the hydraulic conductivity and permeability are positively related to fracture aperture. Fracture permeability generally decreases with depth (in the absence of mineralisation), however, once formed in stronger rocks fractures are rarely completely closed due to the misalignment of rough fracture surfaces. Open fractures are most likely to modify bulk conductivity in low permeability caprocks, where the bulk permeability of fractured rock can be more than three orders of magnitude higher than the intrinsic permeability of the host lithology. Transient high permeabilities may develop through episodic fluid flow within fault zones in response to high fluid pressures at depth (e.g., during earthquakes). High pore fluid pressures and/or preferential alignment within a regional stress field are not necessarily prerequisites for enhanced hydraulic conductivity within a fault zone. Pre-existing mineralisation of faults and fractures can have a greater control on bulk permeability than compressive stresses. Supercritical or water-saturated CO_2 may either increase or decrease permeabilities within fault and fracture networks through dissolution or precipitation reactions. Dissolution of pre-existing mineral precipitates, such as calcite for example, may result in the bulk permeability of a seal formation increasing, resulting in leakage.

3. Fault seal and geomechanical predictions

Fault seal analysis and geomechanical modelling are widely used to predict the potential hydraulic properties of fault zones [e.g., 10]. In the majority of fault seal studies fault rock is inferred to primarily form due to smear along the fault or mixing into the fault zone of clay-rich beds in the host rock (Fig. 2). Based on conceptual clay smear and mixing models a number of algorithms have been developed for estimating the flow properties of faults and their impact on lateral migration of fluids in reservoir rocks [10]. Shale Gouge Ratio (SGR) analysis is most widely adopted in the petroleum and CO_2 industries and in a number of cases has been positively correlated to oil/gas column heights; this correlation has been shown to vary with depth of burial. Fault seal analysis supports the widely held view that clay-rich fault rock can compartmentalise reservoirs on production timescales, while observations from the petroleum industry suggest that fault seal on geological timescales may be less common. Tests of the SGR-based predictions of column heights are relatively rare in the published literature and further research is required to reduce uncertainties and assess the predictive power of the methodology over a range of timescales.

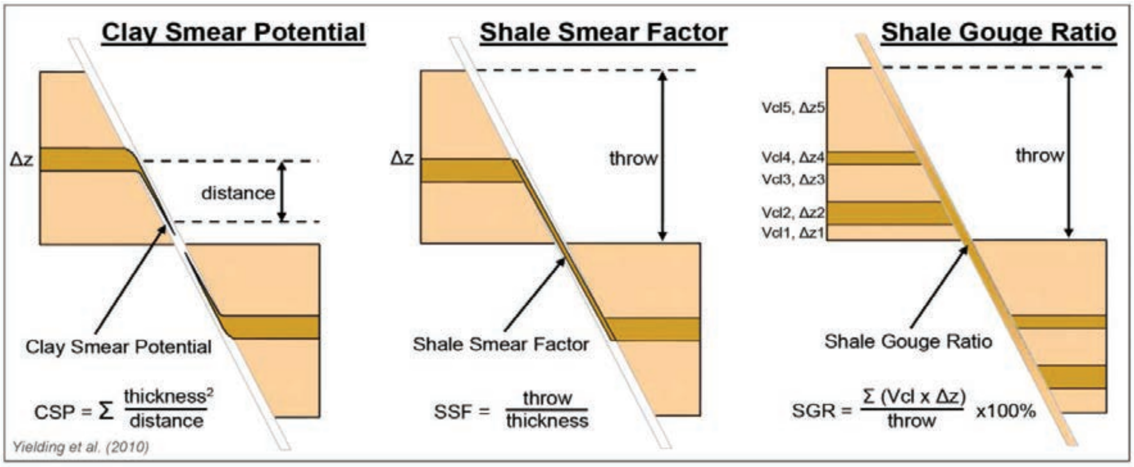

Fig. 2. Schematic diagram illustrating three of the main fault seal conceptual models and associated algorithms used to estimate the likelihood of low permeability clay within fault zones (from [10]).

Geomechanical modelling methods are applied to predict the probability that structural permeability can, or has, developed and whether it can be maintained within the contemporary stress field (for further details see [7]). Three main geomechanical modelling methods are in common use for predicting the locations of along-fault flow: i) slip tendency, ii) fracture stability and iii) dilation tendency. Each method uses estimates of the stress tensor, fault orientation and fault coefficient of friction to determine the faults, or parts of faults, closest to failure, and which are assumed to have the highest permeabilities. Numerous studies of borehole data support the use of the techniques for predicting which fractures will flow, however, few publications provide independent evidence in support of the predictions at reservoir or regional scales. In addition, a number of publications suggest that non-optimally oriented fracture/faults have unpredicted high permeabilities [e.g., 11]. Further research may therefore be required to understand better the conditions in which geomechanical predictions of fluid flow along faults are likely to be of value. Research that explicitly targets the mechanical response of caprocks to injection-induced pressure increases may also be beneficial to help guide CO_2 site selection and injection strategies.

4. CO_2 natural seeps and fault-related flow rates

Natural CO_2 seeps with fluxes at the ground surface interpreted to be facilitated by faults are widely documented in the literature [e.g., 12,13]. In the majority of the case studies examined in this paper CO_2 fluxes are associated with volcanic or geothermal activity and the role of faults is inferred based on spatial elongation of the CO_2 anomalies and their parallelism to mapped faults. Perhaps the most complete analyses of the spatial relations between faults and CO_2 flux rates have been conducted in the Paradox Basin, where fault mapping, measurements of surface flux and flow simulation modelling have been conducted [e.g., 14]. Collectively these data and analyses support a model in which faults can promote the upward flow of CO_2, with the flux rates being greatest where the highest densities of small-scale faults and fractures occur. Flow simulation modelling suggests that low-permeability fault rock may also compartmentalise reservoirs, giving rise to increased pressures and promoting upward flow of CO_2. A reservoir compartmentalisation and overpressure model may be supported by Crystal Geyser in the Paradox Basin, which formed along an uncased abandoned petroleum exploration well drilled in the immediate footwall of the Little Grand Wash Fault. Independent of where and how faults influence the upward flow of CO_2, the present case studies are likely to be biased towards examples where the flux rates are high and, at best, might provide an indication of the upper-bound of potential rates in natural systems but are considered unlikely to be representative of CO_2 storage sites. These high rates also indicate that self-sealing by mineral formation cannot necessarily be expected to occur in storage operations where CO_2-rich fluids migrate along faults [13], particularly on sub-geological timescales (for longer timescales, see discussion in [12]).

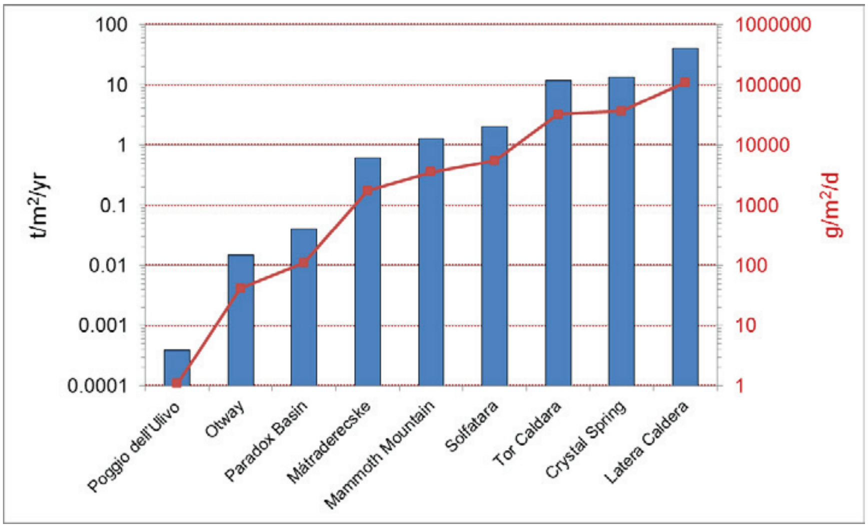

Fig. 3. Maximum rates of CO_2 emission from analogue studies. The rates plotted do not provide information on total volumes, or take into account temporal variations of rates, such as the spikes in rate that might occur during seismic pumping associated with proximal or distal earthquakes. For further details of the natural seeps presented see [15].

The rates of fluid flow along faults can vary spatially and temporally. Flow rates and fault permeabilities are controlled by a range of factors including, fault-zone architecture and orientations, pore pressures, pressure gradients and fluid supply rates. Reported fault zone permeabilities range from 10^{-9} to 10^{-19} m^2, with clay-rich fault rock typically having cross-fault permeabilities of 10^{-14} to 10^{-19} m^2 and along-fault values more often between 10^{-12} and 10^{-15} m^2. Maximum CO_2 flow rates for natural analogues of CO_2 seeps associated with faults are generally >0.1 $t/m^2/yr$ (Fig. 3). For these flow rates volumes of CO_2 leakage could reach 15000 t/yr, which is similar to the 25000 t/yr estimated for a submarine seep of <15 km^2 at Panarea, Greece [16]. These surface leakage rates and volumes are charged by sub-surface migration rates ranging between 100 and 1000 m/yr. Given the problems identifying and recording slow rates of migration (e.g. < 10m/yr) these values are likely to be a strongly biased sample of flow rates at natural seeps and provide little information on what is likely at CO_2 storage sites. The migration rates of CO_2 are likely to be site- and fault-specific and could vary by at least four orders of magnitude within a given fault system. A relatively small number of faults/fractures (e.g. <2%) can accommodate much of the recorded flow (e.g. 20–80%), with critically stressed faults and/or larger more connected faults potentially having the highest flow rates [e.g., 11].

5. Mitigating unwanted fluid flow along faults

Fluid extraction and injection industries, including petroleum, geothermal, waste water, CO_2 storage, can be affected by faults which locally promote and/or retard fluid flow. The experience of the petroleum and geothermal industries, in particular, has application at CO_2 storage sites for understanding and mitigating fluid-flow along faults. The techniques used to monitor, model and mitigate CO_2 flow are largely adapted or adopted from these industries. Techniques commonly used for mapping fluid migration include, 4D reflection seismic, gravity, microseismic monitoring, borehole image logs and core, and borehole geochemical sampling. While the geophysical techniques offer the best opportunity to determine the 3D location of injected fluid, they generally do not provide the resolution necessary to document the detailed spatial relationships between faults and flow. By contrast, well-based sampling techniques offer the opportunity to provide detailed information at points within a fault zone, but lack a 3D perspective on fluid flow and may miss or poorly sample the migrating fluids.

Fluid-flow simulation studies have been employed by many industries over the last 40 years (e.g., petroleum extraction, CO_2 storage, water extraction and radioactive waste management), as a tool for analysing reservoir performance during extraction/injection operations. These models can include faults and it is generally possible to vary fault geometries, thicknesses, and permeabilities. The models have reached a high level of sophistication and are validated in history-matching exercises. However, the outputs of the models are non-unique and uncertainty of the geologic input parameters (e.g., fault permeabilities) represents a universal weakness of the models. These issues are particularly severe for models constructed to predict reservoir performance before production wells are drilled. Given sufficient time and resources the rise in computer power and flexibility of fault modelling methods can help identify a range of possible faulting scenarios and migration outcomes.

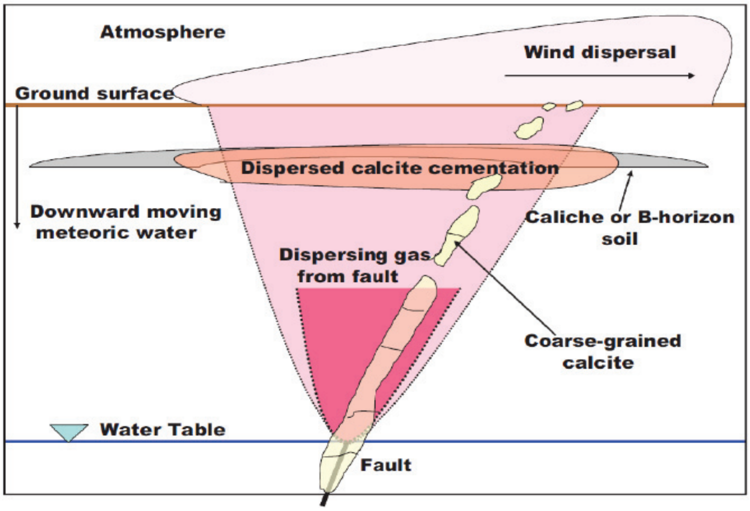

Fig. 4. Schematic of near-surface and surface expression of fault/fracture gas seepage from depth. The oxidation of carbon-containing gases frequently produces secondary calcite and other near-surface alteration. Gases may, or may not be transported into the atmosphere [17]. Note in some cases the fault may extend to the ground surface.

Potential corrective measures for undesirable CO_2 migration mainly stem from past efforts in the activities of oil and gas industry. Few measures have been outlined in the published literature to specifically combat along-fault flow, although techniques such as pressure relief, hydraulic barriers and chemical or biological sealants have received some attention as possible solutions. At the present time few of these proposed techniques have been trialed at CO_2 storage sites, and it is not known how effective they will be for remediating unwanted migration of CO_2 along faults (e.g., Fig. 4).

Leakage identification, intervention and remediation require a balance of engineering efficacy, geomechanical assessment and cost-benefit analysis [18]. Injection shutoff or passive remediation is the fastest, easiest, and likely the cheapest method to quickly reduce leakage from the storage reservoir. In some cases injection shutoff alone may not be sufficient to completely stop leakage. If passive remediation is not sufficient, hydraulic controls such as reservoir fluid production can be employed to further reduce reservoir pressures and increase effective stress on faults which, based on petroleum industry experience [19], can reduce leakage rates. Water injection may also be an effective remediation technique because it: (1) increases the pressure in the overlying aquifer relative to the base of the fault and can quickly stop leakage, (2) may push leaked CO_2 back down the fault, (3) could dissolve large quantities of CO_2 in the vicinity of the water injection and finally, (4) does not require injection directly into the fracture, which is likely to be required if a chemical or biological sealant is used. In some cases, water injection alone may be sufficient to stop current and future CO_2 leakage, especially when the leak is detected early, before a large amount of CO_2 has accumulated below and above the fault. Additional hydraulic controls, such as reservoir fluid production and water injection below the caprock to increase rates of dissolution, thus trapping CO_2 in the storage reservoir, can help [18].

6. Knowledge gaps and recommended future research

Present understanding of fault hydraulic properties is generally not sufficiently complete to predict when and where faults are likely to influence CO_2 migration, either positively or negatively. Knowledge and data gaps include limited understanding of heterogeneities in fault geometries and fault-zone permeabilities, the scaling of fault properties from outcrop to reservoir scales, and the spatial and temporal variations in stress conditions. These knowledge gaps have implications for whether flow simulation and geomechanical models contain sufficient information to adequately describe CO_2 migration in faulted reservoirs and caprocks. Independent reservoir pressure and flow data are essential for testing the predictions of the models and for increased understanding of the main processes that modify CO_2 flow across and along faults. The collection and analysis of fault-specific flow data at CO_2 storage sites may assist in developing CO_2 migration management plans for faulted reservoirs and caprocks.

Our recommendations for future research fall into three main categories; i) improved definition and quantification of fault hydraulic properties, ii) continued development and sensitivity testing of flow simulation models and geomechanical flow predictions, and iii) validation of models using empirical fluid flow data from fault zones. To improve understanding of the geometric and hydraulic properties of faults, studies of fault outcrop, analogue and numerical models are required. For example, Discrete Element Modelling of fault-zone development could be used to determine the conditions under which high and low permeability rock volumes form and have the potential to impact CO_2 migration. Of particular importance for CO_2 storage is faulting and its influence on caprock integrity. Future research should address the question "under what circumstances (e.g. fault properties, caprock rheology, reservoir pressures and ambient stress conditions), and how, are faults (and fractures) in caprocks likely to impact on the bulk permeability of these rocks?" at potential CO_2 storage sites. Fluid flow simulations and geomechanical modelling are important tools for examining the role of faults in CO_2 migration. Testing the predictions of numerical modelling results using *in situ* flow measurements is critical for the continued development of these techniques, while increases in computer power and sensitivity testing of the input parameters will be key aims of modellers.

Although it is widely accepted that faults represent a risk for undesirable migration of injected CO_2, there are few specific guidelines for how they should be treated in a risk assessment framework. These guidelines could address key questions including: i) under what circumstances (e.g. sizes of faults, rock types and reservoir stresses) should CO_2 contact with a fault be avoided? ii) What investigations are required to characterise the flow properties of faults? iii) Under what geological and stress conditions are faults likely to constitute a leakage risk? iv) What monitoring of faults are necessary/useful to record along-fault migration? v) What constitutes acceptable levels of migration from the geological container and how do we record these migration rates? vi) And what course of action should be taken if migration exceeds pre-defined limits?

Acknowledgements

This paper is based on report funded by IEAGHG. The authors wish to thank Mark Lawrence and Malcolm Arnot for their reviews of the paper. Rob Funnell and a number of anonymous reviewers provided constructive and helpful comments for the report [15] on which this paper is based.

References

[1] Caine JS, Evans JP, Forster CB. Fault zone architecture and permeability structure. Geology 1996: 24(11): 1025-1028.

[2] Cox SF. Deformational controls on the dynamics of fluid flow in mesothermal gold systems. In: McCaffrey K, Lonergan L, Wilkinson JJ, editors. Fractures, Fluid Flow and Mineralisation, Geological Society, London, Special Publications 1999:155: p.123-140.
[3] Faulkner DR, Jackson, CAL, Lunn RJ, Schlische RW, Shipton ZK, Wibberley CAJ, Withjack MO. A review of recent developments concerning the structure, mechanics and fluid flow properties of fault zones. Journal of Structural Geology 2010: 32(11): 1557-1575.
[4] Manzocchi T, Childs C, Walsh JJ. Faults and fault properties in hydrocarbon flow Models. Geofluids 2010: 10(1-2): 94-113.
[5] Rutqvist J. The Geomechanics of CO_2 Storage in Deep Sedimentary Formations, Geotechnical and Geological Engineering 2012: 30(3): 525-551.
[6] Rinaldi AP, Rutqvist J, Cappa F Geomechanical effects on CO_2 leakage through fault zones during large-scale underground injection. International Journal of Greenhouse Gas Control 2014: 20: 117-131.
[7] IEAGHG. Criteria of Fault Geomechanical Stability during a Pressure Build-up. Report 2015: 2015/04.
[8] Chester FM, Logan JM. Implications for Mechanical-Properties of Brittle Faults from Observations of the Punchbowl Fault Zone, California. Pure and Applied Geophysics 1986: 124(1-2): 79-106.
[9] Childs C, Manzocchi T, Walsh JJ, Bonson CG, Nicol A, Schopfer MPJ. A geometric model of fault zone and fault rock thickness variations. Journal of Structural Geology 2009: 31(2): 117-127.
[10] Yielding G, Bretan P, Freeman B. Fault seal calibration: a brief review In: Jolley, SJ, Fisher QJ, Ainsworth RB, Vrolijk PJ, Delisle S, editors. Reservoir Compartmentalization, Geological Society, London, Special Publications 2010: 347: p. 243-255.
[11] Seebeck H, Nicol A, Walsh JJ, Childs C, Beetham RD, Pettinga J. Fluid flow in fault zones from an active rift Journal of Structural Geology 2014: 62: 52-64.
[12] Frery E, Gratier JP, Ellouz-Zimmerman N, Loisele C, Braun J, Deschamps P, Blamart D, Hamelin B, Swennen R. Evolution of fault permeability during episodic fluid circulation: evidence for the effects of fluid-rock interactions from travertine studies (Utah-USA). Tectonophysics 2015: 651: 121–137.
[13] Heath JE, Lachmar TE, Evans JP, Kolesar PT, Williams AP. Hydrogeo-chemical characterization of leaking, carbon dioxide-charged fault zones in east-central Utah, with implications for geologic carbon storage. In: Mcpherson BJ, Sundquist ET, editors. Carbon Sequestration and Its Role in the Global Carbon Cycle 2009: p. 147–158, American Geophysical Union Washington, DC.
[14] Jung NH, Han WS, Watson ZT, Graham JP, Kim KY. Fault-controlled CO_2 leakage from natural reservoirs in the Colorado Plateau, East-Central Utah. Earth and Planetary Science Letters 2014: 403: 358-367.
[15] IEAGHG. Fault Permeability Study. IEAGHG report 2016.
[16] Italiano F, Favara R, Etiope G, Favali P. Submarine emissions of greenhouse gases from hydrothermal and sedimentary areas, paper presented at Water-rock Interaction 2001. Proceedings of the 10th international symposium, Swets and Zeitlinger, Lisse.
[17] Klusman RW. Comparison of surface and near-surface geochemical methods for detection of gas microseepage from carbon dioxide sequestration. International Journal of Greenhouse Gas Control 2011: 5(6): 1369-1392.
[18] Zahasky C, Benson SM. Evaluation of the effectiveness of injection termination and hydraulic controls for leakage containment, paper presented at 12th International Conference on Greenhouse Gas Control Technologies 2014, GHGT 2014, Elsevier Ltd.
[19] Quigley DC, Hornafius JS, Luyendyk BP, Francis RD, Clark J, Washburn L. Decrease in natural marine hydrocarbon seepage near Coal Oil Point, California, associated with offshore oil production. Geology 1999: 27(11): p. 1047-1050.