Reassessing the Geological Risks of Seal Failure for Saline Aquifers and EOR Projects

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Abstract

Concern about CO_2 leakage from geological storage sites has focused on the yield strength and efficacy of the seal rock itself (e.g., microseepage risks; overpressuring). In many geological targets, however, the seals are more than adequate for those tasks. In contrast, little effort has focused on the risk associated with small fault that offset the seal (fault seal risk) or porous and permeable strata that compromise the seal geometrically (thief zones). Based on data from hydrocarbon exploration efforts, these two geological effects commonly compromise seals in hydrocarbon plays, and may represent a much greater concern than the seal characteristics themselves.

Introduction

As geological carbon storage continues to gain prominence as a potential means to sequester CO_2 over long time scales, questions of permanence and viability have focused attention on potential leakage questions (e.g., Hawkins, 2002). Much of this attention concerns the viability of the geological seal rock itself, including questions of overpressure-induced failure (e.g., Odam et al., 2002; Bouchard and Delaytermoz, 2002) and chemical changes in the cap-rock through reactions with CO_2 rich fluids (e.g., Johnson et al., 2001). Although these are valid concerns, the experience of hydrocarbon exploration and production suggests that cap-rock or seal integrity is most commonly compromised through other mechanisms. These include faults that offset and fracture the seal and stratigraphic units that, either through primary geometry or fault juxtaposition, provide permeability fast-paths that are seal risks over time scales of 10 years or greater. Similarly, fault, fracture, and stratigraphic heterogeneities can also increase or decrease transmissivity and connectivity with a reservoir, affecting the short-term injection flow paths, reservoir pressure distribution, and chemical reactive transport. This paper aims to present an overview of industry and academic understanding of these risks, and to present ways for engineers and geoscientists to evaluate seal risks in potential CO_2 injection targets with accuracy and precision.

Like the hydrocarbon geologist, those who plan to store CO_2 in subsurface reservoirs must consider issues on both short (injection) and long (post-injection) time scales (Wehr et al., 2000). On short time scales, the key concerns are issues of connectivity and transmissibility, i.e., can CO_2 flow across a fault into the neighboring compartment. These issues can result in large pressure gradients within an injection reservoir that may change miscibility, injectivity, and in-situ stress. In contrast, long time scale issues such as post-injection leakage concerns are dominated by capillary forces within the sealing rocks. Here, pressure build-up can compromise the integrity of a sealing lithology, inducing either distributed micro-seepage or mechanical failure of the sealing rocks. Such circumstances could result in leakage that is difficult to monitor and mitigate. Perhaps of greater long term impact, poor seals would both limit the capacity and/or or permanence of storage sites and ultimately reduce the economic value of CO_2 stored.

Cap Rock Integrity

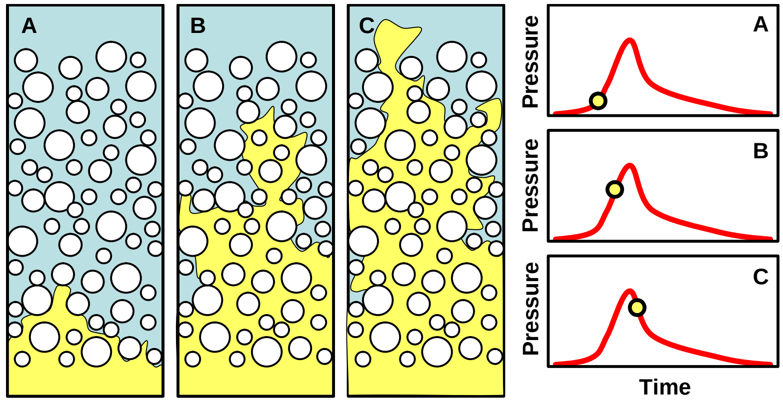

Figure 1. Cartoon of sealing sedimentary rock and penetration of a non-wetting fluid through time. As buoyant forces increase the pressure on the seal rock, the non-wetting phase can overcome surface tension forces and displace intergranular water. Distribution and depth of impregnation is a function of pore-throat diameter. If pressure is sufficiently high, fluids can migrate through the seal (seal leakage)

A geological seal is typically a rock of low permeability that serves as a physical barrier to fluid migration (e.g., Dahlberg, 1994; Downey, 1994). Fine-grained siliciclastic or calcareous stone (e.g., a clay-rich shale, micritic limestone) or an evaporate deposit (e.g., salt, anhydrite) are common seal rocks. The low-permeability character, typically in the range of micro-Darcy (µD) permeabilities or less, is the product of small grain size (µm) and smaller pore-throat diameters (nanometers). The tiny pore throats impede multi-phase fluid flow due to capillary forces (e.g., Berg, 1975; Dewhurst et al., 1999) trapping subjacent fluids at some finite upward (buoyant) pressure. The height of this buoyant fluid column can be calculated with this equation:

$$2\gamma(\cos\theta)/R = gH_f(\rho_w - \rho_f)$$

Where γ = interfacial tension, θ = wettability (interfaced angle), R = pore throat radius, g = gravitational acceleration, H_f = height of the fluid column beneath the seal, and ρ_w and ρ_f = water and fluid density respectively (Nakayama and Sato, 2002). In most cases of interest, the primary seal overlies the reservoir stratigraphically and inhibits the upward migration of low-density fluids (e.g., hydrocarbons, CO_2) and are called *cap rocks*. Faults may also form mechanical seals under special circumstances (see below).

Permeability is most often determined via tests of capillary entry pressure (Fig. 2a). In this test, a wet rock sample is injected with a non-wetting phase (e.g., air, mercury). The pressure difference is measured across the sample. The injected fluid displaces the pore fluid incrementally at higher and higher pressures until a pathway for cross-sample transport is established. At that rate, the pressure drops across the sample (Fig. 2b), defining the entry pressure, accompanied by

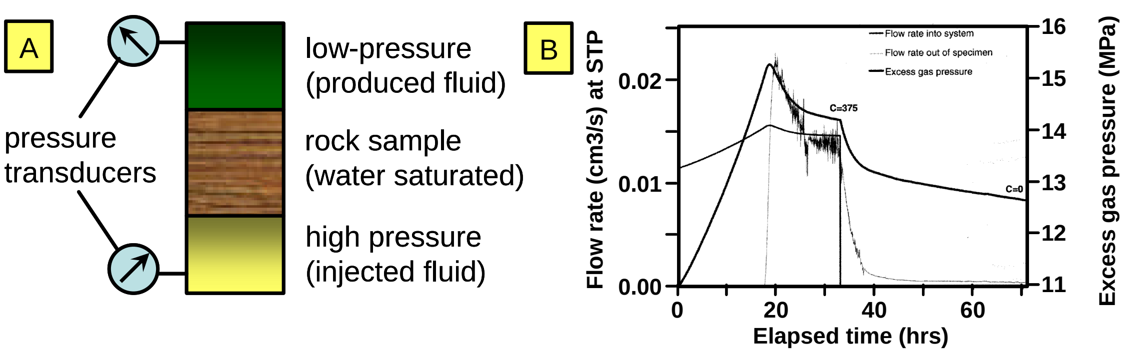

Figure 2. Capillary entry pressure (CEP) measurements. (A) Cartoon of test scheme: non-wetting fluid (gas, mercury) is injected into one side of sample, with pressure difference calculated across sample. (B) CEP data, showing pressure drop and flow through at ~18 hours. C = gas injection rate (µl/h). After Harrington and Horsemen, 1999

cross-sample fluid flow. In most seal rocks, the pore throats are extremely small (nanometer scale), and capillary forces become very large. As such, many samples experience a pressure drop when either fluid under pressure displaced in-situ fluid across the interval of interest (e.g., Dewhurst et al., 1999), or when the material yield strength is exceeded and fracture occurs (e.g., Harrington and Horseman, 1999).

Based on these cap-rock characteristics, it is possible to calculate the pressure that can be sustained under geological conditions (Berg, 1975; Watts, 1987). Where buoyant fluids are present beneath the seal, such estimates can be used to anticipate the maximum vertical column of fluids that can be trapped beneath a seal. This practice is routine in hydrocarbon exploration in order to constrain the likely hydrocarbon volume in place (e.g., Downey, 1984; Converse et al., 2000). If a good seal is present, then the hydrocarbon volume will be constrained by the geometry of the trap itself (Fig. 3, right). Spill points are defined by topographic lows below which fluids can escape the reservoir and provide a robust framework for determination of reservoir capacity and fluid migration pathways away from a reservoir target.

Fault Seal

Unfortunately for many explorationists, cap-rock characteristics often do not determine the height of hydrocarbon columns or maximum reservoir pressure. Rather, it is often faults, which commonly disrupt the seal rocks in ways that may compromised the seal and allow fluids to migrate out of a reservoir well below the structural spill point or the maximum allowable column (e.g., Gibson and Bentham, 2003; Fig. 3, left). *As a consequence, accurate fault mapping in the subsurface is the most important determinant of accurate seal characterization (Ingram and Urai, 1999; Wehr et al., 2000; Hesthammer and Fossen, 2000; Bretan et al., 2003).*

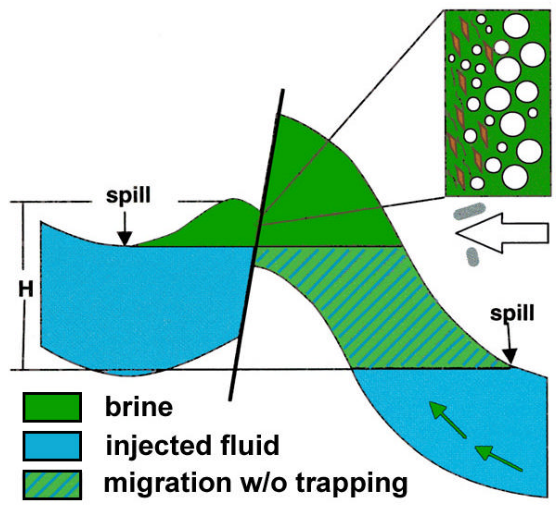

Figure 3. Schematic diagram of fault-seal effects and trapping mechanism. If the fault does not leak, then the right spill point determines trapped capacity and pressure. If the fault does leak, the left spill point determines capacity and pressure. After Wehr et al., 2000

The most common leakage scenario involves the juxtaposition of permeable units across the fault (e.g., Allan, 1989). In figure 4, one can see a schematic representation of beds that have been juxtaposed across a fault. Permeable and porous (reservoir) units are shown in yellow and blue to mark the up-thrown and down-thrown units respectively across the faults; impermeable units are gray. Where permeable beds are juxtaposed along a fault-plane section, they are shown in green. What is readily observed from this diagram is that permeable unit may be juxtaposed across this fault, allowing for cross-fault leakage of fluids. When the displacement along a fault changes along the fault (an extremely common occurrence), then there are often more points of cross-structural leakage and more units are affected (Fig. 4b.)

An assessment of fault leak potential using cross-fault juxtaposition (Allan diagrams) alone assumes that the fault itself is not a conduit for fluids, and that the fault itself has uniform transmissibility between juxtaposed beds (Allan, 1989). As such, only the permeability of juxtaposed units determines flow trajectory. The spatial distribution and thickness of permeable rocks, rather than the cap-rock characteristics, dominate the flow field and capacity. The primary

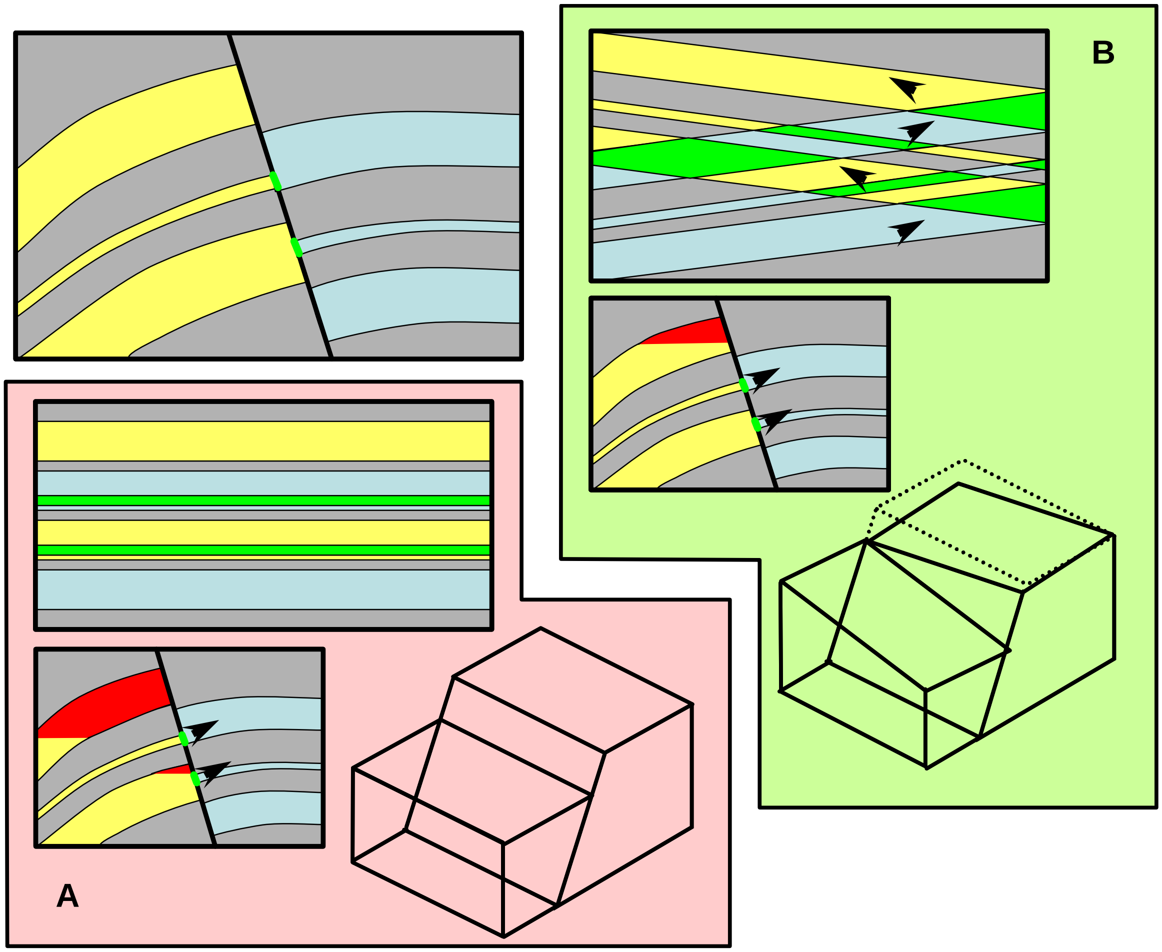

Figure 4: Two scenarios of juxtaposed strata along a fault. The scenarios use the same strata, but different throws along the fault length. Red shows the trapped volume of buoyant fluids. Note how the same strata along the same 2D cross-section can have very different fluid contacts and capacities. Other color explanation in text.

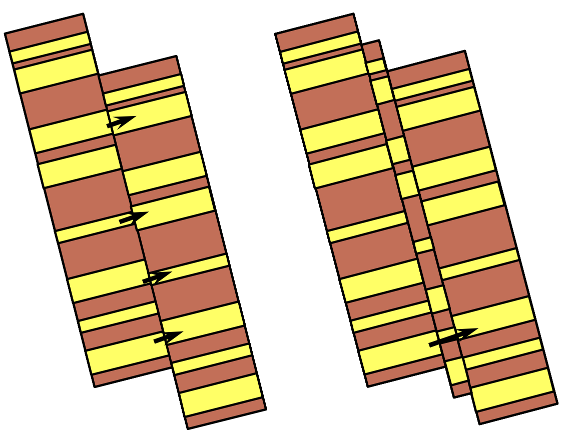

Figure 5: Two faulted blocks with identical strata and offset. The right block has a small faulted sliver between the block. Note the dramatically different leak points and closed reservoir volumes.

constraints for fault-seal conditions are geometric, so geometric accuracy is critical. As such, tremendous effort has gone into accurate subsurface fault mapping. The advent of 3D and 4D seismic mapping has greatly enhanced the ability to recognize the geometry and displacements of subsurface faults. Nonethless, many key aspects of the fault geometry are below the resolution of the seismic tool (Wehr et al., 2000), and often multiple data sets (core, well-log, and production data) are needed for accurate fault characterization. Factors such as small slivers or relay zones within the fault zone (Fig. 5) are particularly critical features to recognize.

In certain circumstances, a fault may

incorporate fine-grained material (e.g., muds and clays) into the faulted zone itself (Fig. 6). These argillaceous rock bodies are deformed during faulting and may lie between permeable units but with low permeability themselves (e.g., Childs et al., 2002). In effect, fine-grained rock may smear across permeable pathways and effectively block cross-fault flow.

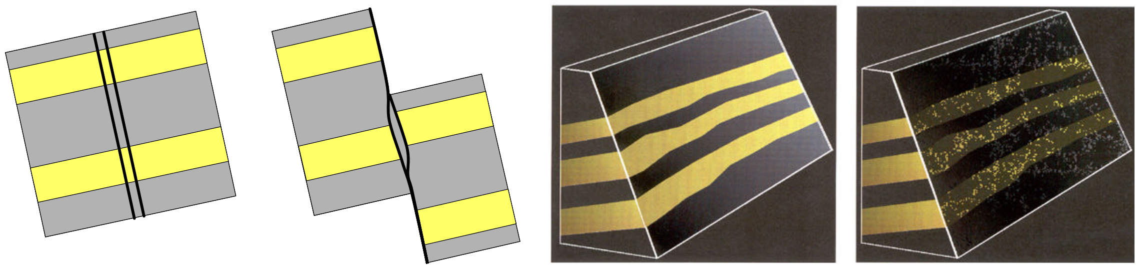

Figure 6: Faulted blocks with a clay smear that covers permeable zones. Left: schematic diagram showing pre- and post-faulting geometry of rock bodies. Right: incomplete coverage of a fault plane by clay smear. 90% of the fault surface is covered, with stochastic distribution producing multiple leak points: after Wehr et al., (2000)

In order for smear to close flow paths over long time scales, the distribution of smeared rock must be uniform along the fault's length. As such, this real and important phenomenon is extremely difficult to predict accurately (e.g., Foxford et al., 1998; Wehr et al., 2000). The most common approach involves the calculation of a shale-gouge ration (SGR), whose distribution changes as a function of fault displacement magnitude and lithologic characteristics of the bounding rocks (e.g., Yielding, 2002; Bretan et al. 2003 and references therein). The SGR can be calculated in one dimension for a given stratigraphic unit by the following equation:

$$\mathbf{SGR} = S\ (\mathbf{V_{sh}}\ D\mathbf{z})/\mathbf{t_f}$$

where V_{sh} is the percentage shale in a stratigraphic interval, Δz is the interval thickness, and t_f is the fault throw (displacement). These are then summed over each unit displaced along the fault relative to the unit of interest. There is abundant evidence from both subsurface and outcrop field studies that SGR calculations affect fluid flow on both short and long time scales, and that the calculations are both accurate and reasonably precise determinants of sealing potential.

Figure 7: Evidence of buoyant fluid migration along the Moab fault. Top: reduction (white) of previously oxidized (red) sandstones. Bottom: pipes coprising calcite cement with fluid inclusions showing CO2 and hydrocarbon exhalation. Photos from J. Holl, ExxonMobil

Faults as migration pathways

Using Allen diagrams and mapping cross-fault juxtaposition is the critical first step in assessing leak potential. However, the assumption that faults are not fluid conduits is often incorrect. Faults are commonly seen to serve as migration pathways that bring low-density fluids directly to the surface (e.g., Heggland, 2002).

There is overwhelming evidence of faults serving as conduits for buoyant fluid migration, including copper mineralization, fluid inclusions, migration-related mineralization and chimney structures (Fig. 7), and mud volcanism. Fluids can migrate along faults even through extremely impermeable rocks (e.g., Barton et al., 1995; Dholakia et al., 1998) provided that the fractures dilate during deformation. Faults are the sites of most natural springs, especially those that bring saline brines from depth. Of particular interest, many of the carbonated springs of the French carbogaseous province occur on faults within the natural CO_2 migration fairway.

In the case of most EOR provinces or potential projects, faults are unlikely to contribute significantly to the risk of leakage given that the target field held hydrocarbons for millions of years despite such leakage. This is not so, however, for saline aquifers, which do not hold hydrocarbons for many reasons, including leakage to the surface. Various faults around the world (e.g., Moab fault; Garden et al., 2001), leaked hydrocarbons both across the fault and along the fault as a conduit, and failed to trap buoyant fluids as a result.

Most saline aquifer targets have not been mapped carefully for potential leaking faults! As such, in is reasonable to suggest that before subsurface injection occurs in a significant volume within a saline aquifer target, detailed fault mapping be undertaken using whatever seismic and well data is available. This is a simple and cost-effective risk management strategy that will have an enormous impact on determining seal efficacy to a first order.

Stratigraphic seal issues

So far, the discussion has focused on fault-seal issues. However, permeable rocks connected to the reservoir directly may also compromise the ability of a reservoir to trap injected CO_2. Perhaps more importantly, permeable rock bodies may siphon injected fluids away from the main flow conduit, allowing fluids to leak away from the reservoir into unanticipated regions. Such rock bodies are often called *thief zones* because they steal the fluid of interest and take it from the reservoir.

One way to do this is through fault juxtaposition (see above). Even within thick stratigraphic seals, there are often thin sandy or silty beds with relatively high permeabilties and relatively low capillary entry pressures that could serve as a thieves. Even a solitary, thin sand body can compromise the seal if juxtaposed near the structural crest of a field (e.g., Wehr et al., 2000).

However, thief zones may occur within the reservoir without any faulting (Fig. 8). In the case of a structural closure, a thief zone may allow leakage well above a structurally defined spill point, reducing the

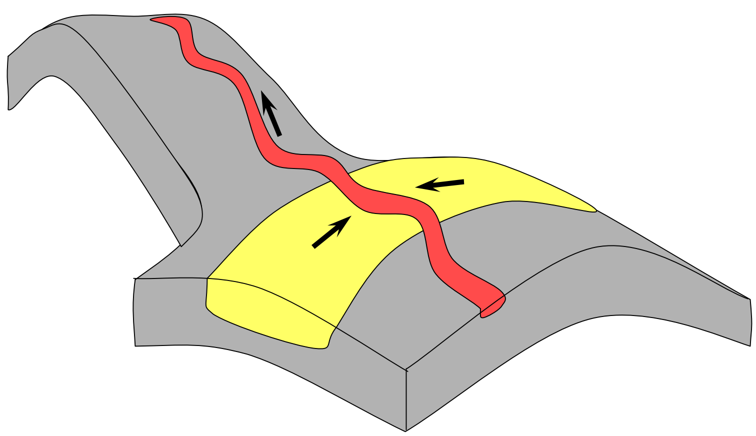

Figure 8: Cartoon of thief sand. The younger, smaller red channel cuts into the larger yellow channel, which is the primary target reservoir. CO2 migrates to the structural apex. In the absence of the red channel (the thief), the entire yellow sand body would charge with CO2. In the presence of the thief, most of all of the CO2 is diverted to a different high, which may or may not close.

reservoir capacity. In a common circumstance, a small channelized sand body (e.g., a small river deposit) can incise and physically remove the seal locally, allowing for fast-path leakage. Again, this risk may be of greatest concern for terms of saline aquifer injection schemes, where the reservoir may not be mapped in much detail. Even if a thief does not necessarily compromise the seal entirely, it may divert fluids away from the desired flow pathway, resulting in unanticipated fluid migration.

Over-pressured reservoirs

Under a variety of geological circumstances, geological reservoirs may become overpressured (e.g., Fertl et al., 1994; Converse et al., 2000). In this usage, overpressured means having a higher pore pressure (often significantly higher) than a hydrostatic pressure at the same depth. This can occur due to compaction disequilibrium, rapid sedimentary loading during rock deposition, or post-equilibration stress unloading. Overpressure can be either good or bad. It can be a significant drilling hazard producing loss of borehole containement and even borehole blow-out. It can also enhance production due to low cementation at depth and strong pressure drive. Either way, it is direct confirmation of exceptional seal capacity.

In the context of carbon storage, there are two points of relevance. First, under the right conditions, reservoirs can hold very high volumes and pressures of gas without leakage or seal rupture (Fertl et al., 1994). Unfortunately, that is not always so, and under the wrong circumstances overpressured reservoirs will induce seal failure and fluid transmission to the surface (e.g., Schowalter, 1979; Watts, 1987). Proper characterization of the fault configuration and the cap-rock mechanics can significantly reduce the risk of undesired leakage, and may be able to point to reservoirs where extra capacity might be achieve.

Discussion

There is both engineering and geological evidence that injection of CO_2 might, under the right circumstance, induce failure of a geological top-seal. However, the risk of leakage is ultimately much greater that CO_2-rich fluids could migrate upwards along permeable fast paths to the surface or near surface. The likeliest of these circumstances would be migration along a pre-existing fault. In addition, faults could juxtapose permeable beds without intervening gouge, which could significantly reduce the capacity of a target reservoir and/or provide unanticipated conduits for upward migration of CO_2. Finally, thief zones could divert injected CO_2 away from intended pathways towards other locations, including toward the surface. Many of these concerns are greatest for saline aquifers, which do not have an unambiguous geological history of fluid trapping.

In all circumstances, accurate subsurface mapping is the approach that will result in the most accurate risk characterization. This requires both detailed mapping and prediction of the stratigraphic and structural geometry and character before injection. Capillary entry pressure tests should be undertaken early on to evaluate the actual sealing capacity of the cap rock. After mapping, monitoring schemes should be planned with these potential risks in mind. For example, known faults might require a higher density of sensors and a broader range of approaches, while areas where the cap rock is not compromised by faulting or thief zones may require fewer sensors or approaches. Again, there is neither bad news nor good news here. Rather, the accurate geoscience assessment, once in place, can serve to provide the key information necessary for proper detailed planning and injection. It should be stated, however, than many detailed seal characterization tools may require significant production, core, and seismic data (e.g., Yielding, 2002; Childs et al., 2002) which may not be available until after years of injection.

Athough there is much direct geological and geophyscial evidence for migration of buoyant fluids, there is little information on the rate at which these flows occur. As such, CO_2

might flow to the surface given a particular scenario. While there have been many attempts to model these phenomena, there are few direct calibration points. In oil fields, where injection of water and CO_2 are common, it is often extremely difficult to determine whether faults seal, and may require years of production and pressure data matches with geochemical tracing. The problem is that much greater where flow to the surface may occur, and much work needs to be done to quantify the likely flow rates and volumes to arrive at a proper risk assessment.

Finally, one must recognized as well that leakage across faults and between reservoir bodies may not always be a bad thing. For example, CO_2 might be injected into a basal sandstone body within a structural closure and then flows upward in a “stair-step” fashion across an intervening fault. This would increase the time and surface area available for fluid-mineral interactions (e.g, potential precipitation of carbonate phases). Such considerations should be incorporated into future reactive transport models and future characterization of EOR-based reservoir targets. In addition, if faults allow leakage across their surface but do not serve as migration conduits (Allan’s modeling assumptions), then a given reservoir would have a reduced risk of anomalous pressure build up and would require fewer injection wells to bring large volumes into the subsurface.

Conclusions

1) Cap-rock integrity can be readily and accurately quantified through traditional techniques (e.g., capillary entry pressure tests).
2) Features that physically compromise cap-rock strata, i.e., faults and thieves, are first order risks and should be incorporated into any risk assessment or monitoring scheme.
3) Accurate subsurface mapping, followed by appropriate characterization (e.g., fault-seal analysis) can greatly reduce the risks and uncertainties associated with injection of large subsurface volumes of buoyant fluids like CO_2.

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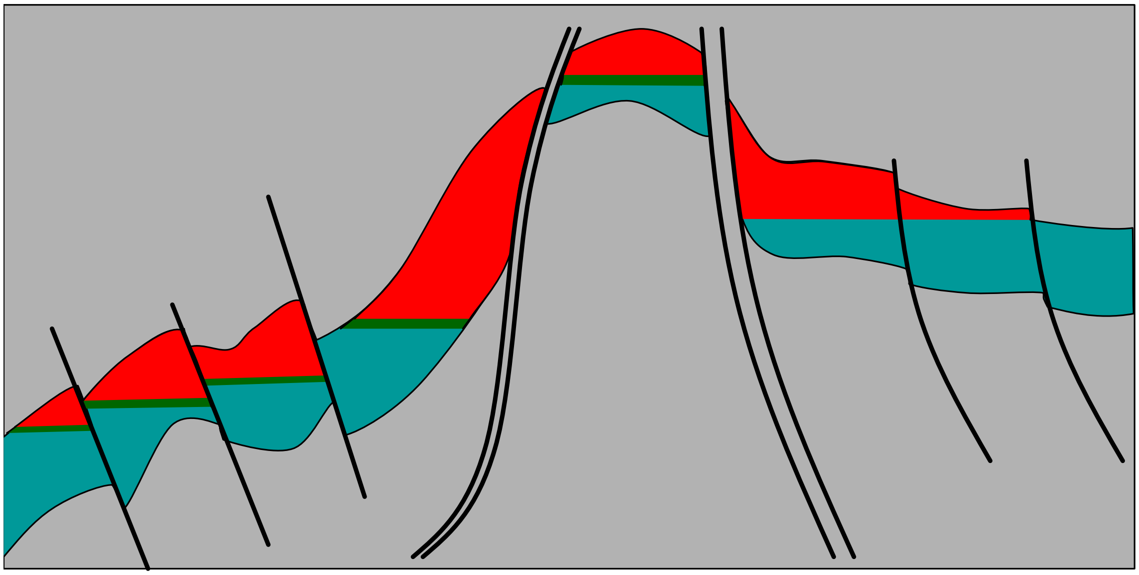

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