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Site Selection and Storage Capacity for Geosequestration of Carbon Dioxide

John Kaldi[1] and Stefan Bachu[2]
[1]Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), University of Adelaide, Adelaide, South Australia, 5005
[2]Alberta Research Council, 250 Karl Clark Road NW, Edmonton, AB, T6N 1E4, Canada

Introduction

Carbon dioxide (CO_2) capture and geological storage (CCS) has been identified as a critical technology for reducing greenhouse gas emissions from major stationary sources such as coal-fired power stations, gas processing plants and large industrial facilities. Any CO_2 storage site must demonstrate that it satisfies three fundamental requirements: 1) capacity to store the intended volume of CO_2 over the lifetime of the operation, 2) injectivity, to accept/take CO_2 at the rate that it is supplied from the emitter(s), and 3) containment, to ensure that CO_2 will not migrate and/or leak out of the storage unit. In addition, sites must meet a series of legal and regulatory, economic and financial, and societal requirements. Site screening and selection criteria could be classified as: 1) eliminatory criteria: criteria which cause sites to be eliminated from further consideration; and 2) selection criteria: criteria by which sites that passed the eliminatory screening are selected on the basis of having most favourable characteristics. Sites may still be rejected if too many unfavourable conditions exist. The eliminatory criteria fall into two categories: a) critical – these criteria have to be met without exception; and b) essential – these criteria should also be met, but some exceptions may occur/be granted, depending on circumstances. Optimally, sites should be: legally available and accessible (i.e., located outside protected or reserved areas, and have right of access), available time-wise (e.g., producing hydrocarbon reservoirs may not be available), and must not adversely affect, directly or indirectly, other resources, including groundwater. In addition the storage site should not be located in over-pressured strata and/or in an area of high seismicity; should posses a demonstrable containment mechanism to prevent the upward migration of CO_2; and it should posses monitoring potential. Favourable or desirable criteria for site selection are: sufficient capacity and injectivity, adequate depth, sufficient thickness, low temperature, favourable hydrodynamic regime, low number of penetrating wells, and the presence of secondary containment and attenuation potential in case of CO_2 leakage. In addition, a storage site should have favourable economics for transportation and delivery at the site (e.g., distance, terrain, right of access, transportation corridors, infrastructure) and for storage (e.g., site facilities, compression, operational monitoring), and should be located, as much as possible, away from high-density population areas. Oil reservoirs suitable for CO_2 miscible flooding must meet a set of specific additional criteria.

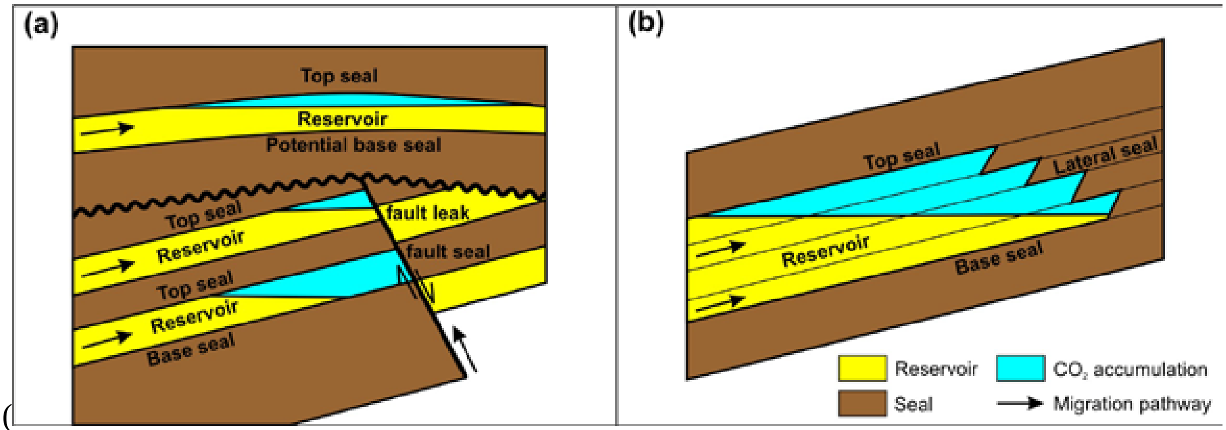
Storage capacity is one of the important criteria for site selection because it affects the economics and feasibility of the CCS operation. A major challenge is that current methodologies for storage capacity estimates are variable and some are inaccurate, and, crucially, there is little in the way of real data on which to base analogues. Thus, a key gap in the selection of storage sites in is the accurate estimation of the storage capacity at any potential site (Bachu et al. 2007). It is very important to assess the “static” storage capacity according to accepted methodology and guidelines and based on ultimately-available pore volume (through displacement of native fluids, compression of the rock matrix and contained fluids, and CO_2 dissolution during the injection period). It is equally important to estimate the “dynamic” storage capacity, i.e., the storage capacity that can be achieved during the active lifetime of the project by injecting CO_2 at rates and pressures that meet safety and regulatory requirements. This refers to maintaining maximum bottom hole injection pressure (BHIP) at injection wells, and/or aquifer or reservoir pressure below one of, or some combination of, the following:

1. Initial reservoir pressure (in the case of storage in hydrocarbon reservoirs),
2. The threshold pressure estimated to cause rock fracturing in the storage unit or the caprock (established by regulation),
3. The threshold pressure estimated to cause opening, and/or reactivation of pre-existing fractures and/or faults in the storage unit,
4. The threshold pressure estimated to cause opening, and/or reactivation of pre-existing fractures and/or faults in the caprock,
5. The displacement pressure at which the injected CO_2 intrudes into the caprock, (related to capillary pressure, wettability and interfacial tension of the site-specific CO_2/brine system).

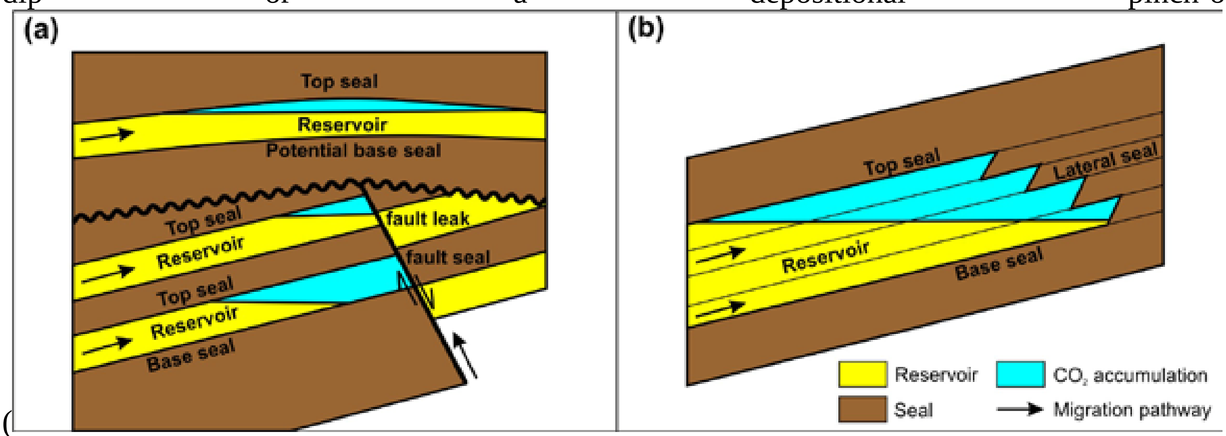
The dynamic storage capacity is likely to be significantly less than the static storage capacity, and along with injectivity can be better evaluated through numerical modelling. Storage of CO_2 during the active-injection phase of a CCS operation is achieved mainly through stratigraphic or structural trapping of mobile free-phase CO_2, and through residual-gas trapping of immobile free-phase CO_2, and estimating the capacity for storage through these two mechanisms will be discussed here.

Trapping of Free-Phase CO_2

Structural/stratigraphic trapping relates to the free-phase (immiscible) mobile CO_2 that is not dissolved in formation water and that forms a continuous phase in the porous medium. When supercritical CO_2 rises upwards by buoyancy it can be physically trapped in a structural or stratigraphic trap (as a result of the CO_2 being the non-wetting phase) in exactly the same manner as a hydrocarbon accumulation. The nature of the physical trap depends on the geometric arrangement of the reservoir and seal units. Common structural traps include anticlinal folds or tilted fault blocks



(Figure 1a), and typical stratigraphic traps include those created by a lateral change in facies up-dip or a depositional pinch-out



(Figure 1b). As with hydrocarbon accumulations, there are numerous variations of structural and stratigraphic traps, plus combinations of both structural and stratigraphic elements, that can provide physical traps for geological storage of CO_2. In a dipping formation with no defined structural closure, any small bumps in the seal geometry will behave like small anticlinal structural traps and free-phase CO_2 will fill these to the spill point (due to buoyancy) before migration continues (Ennis-King & Paterson, 2001).

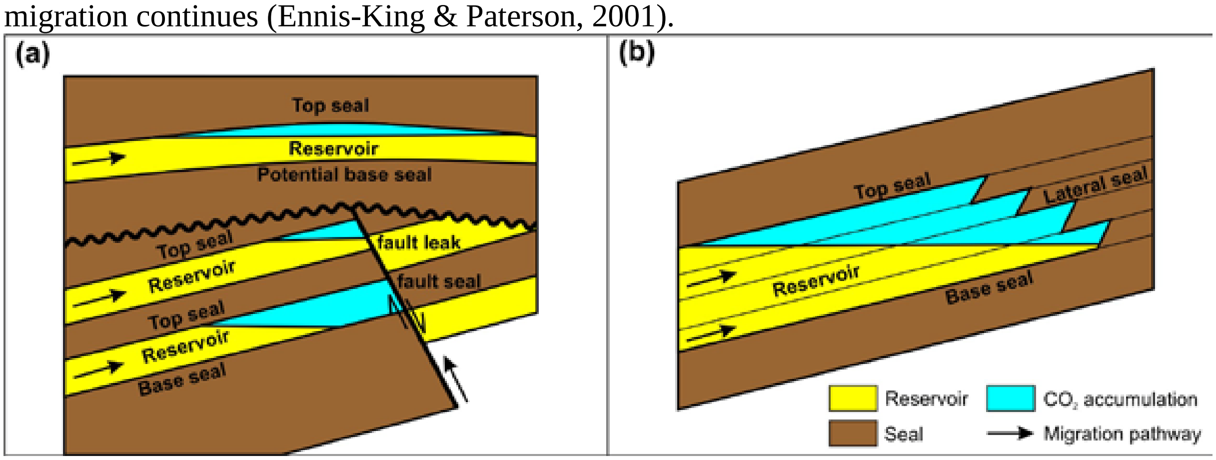


Figure 1: Examples of (a) structural and (b) stratigraphic physical traps for CO_2 (modified from Biddle & Wielchowsky, 1994)

Residual-gas trapping occurs when free-phase CO_2 becomes trapped by capillary forces in the pore space as a residual immobile phase forming a discontinuous phase (Figure) (Ennis-King & Paterson, 2001; Flett et al., 2005). At the tail of the migrating CO_2 plume, imbibition processes are dominant as the formation water (wetting-phase) imbibes behind the migrating CO_2 (non-wetting phase). When the concentration of the CO_2 falls below a certain level it becomes trapped by capillary pressure forces and ceases to flow. Therefore, a trail of residual, immobile CO_2 is left behind the plume as it migrates upward (Juanes et al., 2006). Residual CO_2 saturation values vary between 10–35 % based on relative permeability measurements for CO_2/brine systems performed for rocks from the Alberta basin (Bennion and Bachu, 2008). Over time, the residually trapped CO_2 dissolves into the formation water (Ennis-King & Paterson, 2002; Flett et al., 2005).

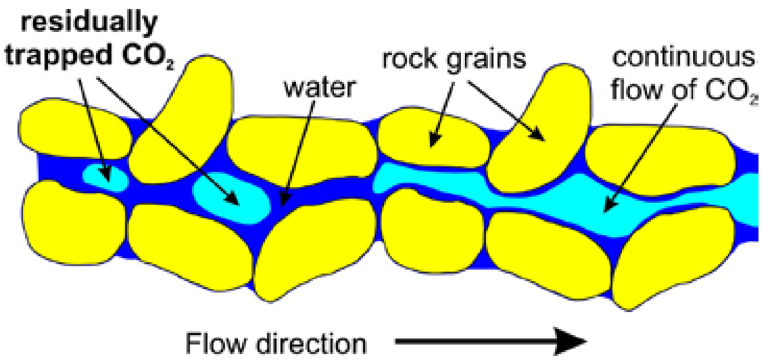


Figure 2: Residual trapping of CO_2.

Storage Capacity

Storage capacity is considered a resource, and as in petroleum accumulations and mineral deposits, categorised based on levels of certainty of resource availability. A distinction is made between theoretical pore volume (an estimate of the amount of pore space that can be used to store CO_2 in subsurface geologic formations) and storage capacity (the pore volume constrained by economic or engineering feasibility limitations). Four categories are proposed (CO2CRC, 2008): *total pore volume* (TPV) refers to the entire volume of pore space which is estimated to exist in sedimentary basins, or in potential storage sites. TPV is subdivided into discovered and undiscovered pore volume. *Prospective storage capacity* is the estimate of the total undiscovered pore volume in a basin or site which at present is non-commercial, but which might become commercial at some future time. *Contingent storage capacity* is the total discovered pore volume which will be commercial in the future when technical, economic and regulatory conditions are in place. *Operational storage capacity* is discovered pore volume that is considered commercially viable i.e. CO_2 could be stored under existing technical, economic and regulatory conditions. Operational storage capacity, which is further classified as *proved* (1P), *proved plus probable* (2P) and *proved plus probable plus possible* (3P) categories following standard petroleum industry nomenclature (SPE, 2007).

DOE (2006) and Bachu et al. (2007) provide a volumetric equation for the calculation of CO_2 storage capacity in geological formations (Equation 1 and

Table 1) based on the concept that CO_2 occupies the pore space (or parts of it) within a permeable rock:

$$G_{CO2} = A \; h_g \; \phi_{tot} \; \rho \; E \qquad (1)$$

Table 1: Volumetric equation parameters for capacity calculation in saline formations.

Parameter	Description
G_{CO2}	Mass estimate of saline-formation CO_2 storage capacity
A	Geographical area that defines the basin or region being assessed for CO_2 storage-capacity calculation
h_g	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A
ϕ_{tot}	Average total porosity of entire saline formation over thickness h_g
ρ	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over the depth range associated with h_g
E	CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled, or contacted, by CO_2

Whereas many of the parameters listed above can be estimated using fairly routine resource industry assessment methodologies, the storage efficiency factor (E) is more difficult to ascertain. "E", analogous to the Recovery Factor (RF) in petroleum resource assessment, adjusts total gross thickness to net gross thickness, total area to net area and total porosity to effective (interconnected) porosity actually containing CO_2, and also takes into account the efficiency of the CO_2 sweep, i.e., the interplay between buoyancy, viscous and capillary forces. Without "E", equation 1 presents the Total Pore Volume or maximum upper limit to capacity. Inclusion of "E" provides a means of estimating storage volume for a basin or region with the level of knowledge (uncertainty) in specific parameters determining the type of CO_2 storage capacity estimated.

CO_2 storage capacity estimations in depleted (or near depleted) oil and gas fields are generally more straight forward than estimates for coal seams or saline formations because there is typically a greater amount of data associated with oil and gas fields and hence they are better characterised. Also, unlike coal seams and saline formations, oil and gas fields are considered as a single discrete system. This means that estimates of CO_2 storage volume in oil and gas fields can either be based on the effective pore space volume, the calculated original oil and gas in place and estimated recovery factor, or from the volume of oil and gas produced from the field. In general, storage in depleted oil and gas fields is based initially on two primary assumptions: (1) the volume previously occupied by the produced hydrocarbons will become available for CO_2 storage (minus an amount deemed to be filled with residual hydrocarbons); and (2) the existing caprock seal will also contain the CO_2 provided the pressure does not increase above the original reservoir pressure prior to production.

The viability of storage capacity estimates in commercial projects relies on the proper evaluation of the efficiency factor based on laboratory measurements of residual trapping and on numerical simulations for various depositional environments and in-situ conditions. This will require integrated laboratory, pilot, and field/demonstration testing if industry and/or the financial sector are to confidently base commercial (bankable) CO_2 storage projects on calculated storage capacities.

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