Storage 1- Site Selection, Capacity and Injectivity for CO₂ Storage

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Geological Storage of Carbon Dioxide

Lots of uncertainty!
Reducing Uncertainty for Site Selection: Critical Steps

- Country/Region Screening
- Basin Assessment
- Site Characterisation
- Site Deployment
Site Deployment

- Full project economics work
- Risk assessment / management
- Monitoring and verification
- Community acceptance
- Regulatory regime in place
- Closure & liability issues resolved

“Bankable” Project
Country/State/Region Screening

- Coarsest scale of assessment with the least site specific detail; “Reconnaissance”
- Identify sedimentary basins & screen and rank relatively quickly as to overall suitability for CO₂ storage before specific sites are identified and selected for further work.
- Determine size and thickness of the basin: quick clue to total pore volume
- Rule out areas beyond technical capability for drilling (e.g., deep water offshore) or politically or environmentally unviable areas (parks, refuges, urban areas, military zones, etc.) or areas of crystalline rocks; or depth where permeability is no longer sufficient to allow viable injection
- Identify oil, gas or other resources.

After Bachu & Shaw, 2005; CSLF, 2005
Basin Assessment

- Based on geological, geographical and industrial characteristics
- Assessment criteria: tectonic setting, basin size and depth, intensity of faulting, hydrodynamic and geothermal regimes, existing resources and industry maturity.

- Can be used in a semi quantitative manner to rank basins within a particular state or region.
  - Identify reservoir and seal pairs.
  - Establish depths for CO$_2$ to be supercritical
  - Identify potential migration pathways

- Identify potential sites

After Bachu & Shaw, 2005; CSLF, 2005
Site Characterisation

• Is the most time-consuming and costly part of the CO$_2$ storage site selection process!

• Typically involves greater detail than basin assessment; includes evaluation (or re-evaluation) of regional/structural geology, generation of new and/or updating of existing stratigraphic and seismic interpretations, static and dynamic models (flow simulation), geomechanics, and ultimately injection.

• Data sources include 2D and 3D seismic surveys, well logs, core data, drill cuttings, biostratigraphy, analogs, field production and fluid data.

• Screen & rank potential sites using, site specific geological criteria for
  - Injectivity
  - Capacity
  - Containment

After Bachu & Shaw, 2005; CSLF, 2005
Criteria for Site Characterisation:

- Injectivity  (can we put the CO$_2$ into the rock?)
- Containment  (can we keep the CO$_2$ in the rock?)
- Capacity  (what volume of CO$_2$ can the rock hold?)
Storage Capacity Estimation

Techno-Economic Resource-Reserve Pyramid for CO$_2$ Storage Capacity

- Total Pore Volume
- Prospective Capacity
- Contingent Capacity
- Operational Capacity

CO$_2$CRC, 2008
Modified from Bachu et al., CSLF, 2005
Total Pore Volume

Total physical limit of what the storage system can accommodate. This volume is accessible to store 

CO$_2$ in the pore space or dissolved in formation fluids or adsorbed at 100% onto total coal volume. This represents the maximum upper limit to a capacity estimate. However, this is an unrealistic number as there will always be physical, technical, regulatory and economic limitations.

Prospective Capacity

Subset of Total Pore Volume and obtained by applying technical (geological & engineering) limits. This estimate usually changes with acquisition of new data or knowledge.

Contingent Capacity

Subset of prospective capacity obtained by considering technical, legal and regulatory, infrastructure and general economic barriers. Value prone to changes as technology, policy, regulations and/or economics change. Corresponds to “Reserves” as used in energy and mining industries.

Operational Capacity

Subset of contingent capacity obtained by detailed matching of large, stationary sources with geological storage sites that are found to be adequate in terms of capacity and injectivity. Corresponds to “Proved, marketable reserves” used by mining industry.
Volumetric Equation for Capacity Calculation

\[ G_{\text{CO}_2} = A \ h_g \ \phi \ \rho \ E \]

- \( G_{\text{CO}_2} \) = Volumetric storage capacity
- \( A \) = Area (Basin, Region, Site) being assessed
- \( H_g \) = Gross thickness of target saline formation defined by \( A \)
- \( \phi \) = Avg. porosity over thickness \( h_g \) in area \( A \)
- \( \rho \) = Density of CO\(_2\) at Pressure & Temperature of target saline formation
- \( E \) = Storage “efficiency factor” (fraction of total pore volume filled by CO\(_2\))
Storage Capacity Estimation

Techno-Economic Resource-Reserve Pyramid for CO₂ Storage Capacity

Total Pore Volume

Prospective Capacity

Contingent Capacity

Operational Capacity

$1 - 4\%$

CO₂CRC, 2008
Modified from Bachu et al., 2005

(van der Meer and others)
Storage Capacity Estimation

Decreasing Storage Capacity;
Increasing Certainty;
Data / Effort /$$ Required
CO$_2$ storage effectiveness increases with depth
Geological Storage of CO$_2$

What do we need?

RESERVOIR ROCK – porous, e.g. sandstone

SEAL ROCK – non-porous, e.g. claystone

Claystone seal rock

Sandstone reservoir rock
Porosity is the storage space in the rock for fluids and is shown by the blue spaces in this photograph of a thin slice through a reservoir sandstone.

Permeability is a measure of the ability of the rock to allow fluid flow. Permeability is strongly affected by the geometry of the porosity – in particular the size of the spaces connecting the pores in the rock (red circles). Permeability is main control on injectivity.
PORES & PORE THROATS

Pore

Throat

Pore

Grain

Throat
Injection of CO$_2$ into reservoir

UPWARD MIGRATION OF CO$_2$ DRIVEN BY BUOYANCY
(DENSITY DIFFERENCE BETWEEN WATER AND CO$_2$) ($\Delta\rho$)

BUOYANCY PRESSURE IS OPPOSED BY CAPILLARY PRESSURE
(DISPLACEMENT PRESSURE OF PORE THROATS) (Pd)
1) Injected CO$_2$ enters reservoir pore system

2) In order to migrate CO$_2$ needs sufficient Pb to exceed Pd at each pore throat

3) A thin film of water remains around each grain: "Irreducible water saturation" Swirr

\[ Pb = \Delta \rho gh \]
CO$_2$ Storage Trapping Mechanisms

Structural / Stratigraphic Trapping (SST)

Most familiar; best understood; lowest risk

From IPCC SRCCS, 2005
Structural traps for CO$_2$ (Anticline)

Issues:

- Capacity (storage volume)
- Injectivity (rate, press, cost)
- Containment (caprocks, faults, wellbore)
Storage capacity issues: depleted reservoirs/structural traps
Storage capacity controlled by permeability (not just porosity)

Rock A: \( \phi = 28.4\% \)
\[ k = 1394 \text{ md} \]

Rock B: \( \phi = 28.4\% \)
\[ k = 0.22 \text{ md} \]
Irreducible water saturation: a critical control on storage capacity

Injection pressure

< frac pressure

Swirr = 7%

Swirr = 82%

Wetting phase (water) saturation

Rock A
θ = 28.4%
k = 1394 md

Rock B
θ = 28.4%
k = 0.22 md

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CO₂ Storage Trapping Mechanisms

- Structural, Stratigraphic & Hydrodynamic Trapping
- Residual CO₂ Trapping
- Solubility Trapping
- Mineral Trapping

Migration Associated Trapping (MAT)

- Least familiar
- Modeled, but poorly understood
- Highest uncertainty
- Focus of many storage demo projects

From IPCC SRCCS, 2005

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MAT: Storage in Deep Saline Formations
Migration Associated Trapping (MAT)

CO₂ Trapped in solution

CO₂ Trapped as a mineral

CO₂ Trapped in rock pores as Residual Saturation ($S_{gr_{CO₂}}$)

Residually trapped CO₂

Flow of CO₂

Rock grains

Water
CO₂ storage effectiveness increases with time

(Modelling the dissolution of injected CO₂)

- Homogeneous Reservoir
- Flat-lying Seal
- Cross-sectional view
CO₂ storage effectiveness increases with time

(Modelling the dissolution of injected CO₂)

From: J. Ennis-King
CO$_2$ storage effectiveness increases with time

(Modelling the dissolution of injected CO$_2$)

From: J. Ennis-King
Mineral trapping: also increases with time

CaCO$_3$ (Calcite) precipitation occurs at all scales at different rates
Migration Associated Trapping (MAT)

CO$_2$ Trapped in solution

CO$_2$ Trapped as a mineral

CO$_2$ Trapped in rock pores as Residual Saturation ($S_{gr,CO_2}$)
RESIDUAL CO$_2$ SATURATION BY PLUME MIGRATION

CO$_2$

Grain

Residual CO$_2$

“Snap-off”

H$_2$O
Injectivity

\[ I_{v/t} = A \times P_i \times k \]

- \( I_{v/t} \) = Injection rate
- \( A \) = Area (of wellbore in contact with formation)
- \( P_i \) = injection pressure (below frac)
- \( k \) = permeability

\( I_{v/t} \) is proportional to number of wells
Frac Pressure ($P_{frac}$)

![Graph showing the relationship between injection rate and pressure above initial pressure.](image)
Injectivity / Pressure Considerations:

• Injection of fluids (eg CO$_2$) causes reservoir pressure build up

• In depleted fields, pressure build-up may be neutral or beneficial

• In both depleted fields and saline aquifers, must maintain pressure below fracture pressure

• In low permeability reservoirs this may limit economic storage capacity due to decreased injection rate, requiring more wells

• Injection in saline formations may displace saline fluids & increase risk of possible mixing with freshwater system

• Drilling pressure relief (water production) wells possible solution
Depleted Field (pressure v. Time))

![Graph showing pressure vs. time for a depleted field with key events marked: initial pressure, fracture pressure, and water production with pressure relief.]

- Initial pressure
- Fracture pressure
- $P_{frac}$
- Water production (pressure relief)
- $P_{res}$
- $o/g$ production
- $CO_2$ injection
Saline Formation (pressure v. time)

Pressure vs. time graph showing:
- Initial $P_{res}$
- $P_{frac}$
- CO$_2$ injection
- Water production (pressure relief)

Legend:
- CO$_2$ injection
- Water production (pressure relief)