Storage options 1. Geological storage
CO₂ capture and storage system

Diagram showing CO₂ capture and storage system with sections for Fuels, Processes, and Storage options.
Learning objectives

1. What can we do with captured CO2?
2. Can CO2 be stored underground?
3. What geological formations are suitable?
4. What are the issues associated to geological storage?
The carbon cycle

CO₂ loss to air through calcium carbonate deposition

CO₂ loss from air through transformation of silicates into carbonates

CO₂ uptake by rock weathering

Calcium ion (Ca²⁺) and bicarbonate (HCO₃⁻) transport by rivers

Calcium carbonate and organic matter deposition

Subduction

Metamorphism

Volcanism

Mantle

Sea level

A Carbonate rock weathering
CO₂ + H₂O + CaCO₃ → Ca²⁺ + 2HCO₃⁻

B Silicate rock weathering
2CO₂ + H₂O + CaSiO₃ → Ca²⁺ + 2HCO₃⁻ + SiO₂

C Carbonate formation in oceans
2HCO₃⁻ + Ca²⁺ → CaCO₃ + CO₂ + H₂O

D Silicate weathering plus carbonate formation
(reactions B + C)
CO₂ + CaSiO₃ → CaCO₃ + SiO₂

E Metamorphic/magmatic breakdown of carbonate
CaCO₃ + SiO₂ → CaSiO₃ + CO₂
Carbon inventory

CO₂ capture and storage
Geological storage

Geological Storage Options for CO₂
1. Depleted oil and gas reservoirs
2. Use of CO₂ in enhanced oil recovery
3. Deep unused saline water-saturated reservoir rocks
4. Deep unmineable coal seams
5. Use of CO₂ in enhanced coal bed methane recovery
6. Other suggested options (basalts, oil shales, cavities)
Trapping mechanisms for geological storage

Simulated CO₂ saturation

Seismic images
CO$_2$ density vs. depth relationship

Assuming a geothermal gradient of 25°C/km from 15°C at the surface, and hydrostatic pressure.
Commercial CCS projects

**Sleipner** (Statoil - 1996)

**Snøhvit** (Statoil - 2008)

**In-Salah** (BP, Statoil, Sonatrach - 2004)

**Weyburn** (Encana - 2000)

Images Courtesy of BP, Statoil, and PTRC
Commercial storage of CO$_2$
## Current locations of geological storage

<table>
<thead>
<tr>
<th>Project name</th>
<th>Country</th>
<th>Injection start</th>
<th>Daily injection (tCO₂/day)</th>
<th>Total planned storage (tCO₂)</th>
<th>Reservoir type</th>
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<tr>
<td>Weyburn</td>
<td>Canada</td>
<td>2000</td>
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<td>20,000,000</td>
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<td>Netherlands</td>
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<td>Frio</td>
<td>United States</td>
<td>2004</td>
<td>177</td>
<td>1,600</td>
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### List of current and planned projects of geological storage

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<th>Lead organization</th>
<th>Injection start date</th>
<th>Approximate average daily injection rate</th>
<th>Total storage</th>
<th>Storage type</th>
<th>Geological storage formation</th>
<th>Act of formation</th>
<th>Lithology</th>
<th>Monitoring</th>
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<td>Norway</td>
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<td>Statoil, IFA</td>
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<td>3000 t day⁻¹</td>
<td>20 Mt planned</td>
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<td>Utsira Formation</td>
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<td>Sandstone</td>
<td>Claystone, sandstone and water monitoring</td>
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<td>Japan</td>
<td>Demo</td>
<td>Japanese Ministry of Economy, Trade and Industry</td>
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<td>20 t planned</td>
<td>CO₂, ECBM</td>
<td>Yukut Formation (Yukut Coal Seam)</td>
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<td>Sonatrach, BR, Tunisia</td>
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<td>Sandstone               Planned comprehensive</td>
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<td>USA</td>
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<td>Heavy oil          Comprehensive</td>
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<td>Netherlands</td>
<td>Demo</td>
<td>Nexis de France</td>
<td>2004</td>
<td>100-1100 t day⁻¹ (2006–)</td>
<td>Approx 25 kt</td>
<td>ECGR</td>
<td>Rotliegensed Formation</td>
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<td>Ferm Lég Valley</td>
<td>Canada</td>
<td>Pilot</td>
<td>Alberta Research Council</td>
<td>1998</td>
<td>50 t day⁻¹</td>
<td>200 t</td>
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<td>Carbonstone</td>
<td>Cons</td>
<td>P. T. flow</td>
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<td>Perespol</td>
<td>Poland</td>
<td>Pilot</td>
<td>ENCO-NTG (Netherlands)</td>
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<td>1 t day⁻¹</td>
<td>10 t</td>
<td>CO₂, EOR</td>
<td>Sediment Basin</td>
<td>Carboniferous</td>
<td>Cons</td>
<td>P. T. flow</td>
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<tr>
<td>Qinshui</td>
<td>China</td>
<td>Pilot</td>
<td>Alberta Research Council</td>
<td>2003</td>
<td>30 t day⁻¹</td>
<td>1 t</td>
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<td>Qinshui Formation</td>
<td>Carboniferous</td>
<td>Permian</td>
<td>Cons</td>
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<td>Salt Creek</td>
<td>USA</td>
<td>Commercial</td>
<td>Anadarko</td>
<td>2004</td>
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<td>27 Mt</td>
<td>CO₂, EOR</td>
<td>Frontier</td>
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<td>Sandstone</td>
<td>Under development</td>
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### Planned Projects (2006 onwards)

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<tr>
<th>Project</th>
<th>Country</th>
<th>Scale of Project</th>
<th>Lead organization</th>
<th>Injection start date</th>
<th>Approximate daily injection rate</th>
<th>Total storage</th>
<th>Storage type</th>
<th>Geological storage formation</th>
<th>Act of formation</th>
<th>Lithology</th>
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<td>Statoil</td>
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<td>Coppen</td>
<td>Australia</td>
<td>Planned Commercial</td>
<td>Chevron</td>
<td>Planned 2009</td>
<td>Approx. 10,000 t day⁻¹</td>
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<td>Dupuy Formation</td>
<td>Lower Jurassic</td>
<td>Massive sandstone with saline</td>
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<tr>
<td>Nekia</td>
<td>Germany</td>
<td>Demo</td>
<td>OFZ Berchtesgaden</td>
<td>2005</td>
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<td>60 kt</td>
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<td>Stain Formation</td>
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<td>Oney</td>
<td>Australia</td>
<td>Demo</td>
<td>CO2CRC</td>
<td>Planned late 2005</td>
<td>160 t day⁻¹ for 2 years</td>
<td>0.1 Mt</td>
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<td>Ustick Formation</td>
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<td>Teapot Dome</td>
<td>USA</td>
<td>Proposed Demo</td>
<td>Rr607C</td>
<td>Proposed 2006</td>
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<td>10 kt</td>
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<td>Tindaro and Red Lake Fm</td>
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<td>Sandstone</td>
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<td>Canada</td>
<td>Pilot</td>
<td>Syncrude</td>
<td>2009</td>
<td>20 t day⁻¹</td>
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<td>Penn West</td>
<td>2009</td>
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<td>50 t</td>
<td>CO₂, EOR</td>
<td>Canadian Fm</td>
<td>Carbone</td>
<td>Sandstone</td>
<td>Comprehensive</td>
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</table>

**CO2 capture and storage – Storage options 1. 07.04.08**  
Marco Mazzotti  
12
Planned and current locations of geological storage
BP: Peterhead (Scotland), EOR + H$_2$
Geographical relationship between sources and storage opportunities

Global distribution of large stationary sources of CO$_2$ (Based on a compilation of publicly available information on global emission sources, IEA GHG 2002)
Geographical relationship between sources and storage opportunities

Prospective areas in sedimentary basins where suitable saline formations, oil or gas fields, or coal beds may be found. Locations for storage in coal beds are only partly included. Prospectivity is a qualitative assessment of the likelihood that a suitable storage location is present in a given area based on the available information. This figure should be taken as a guide only, because it is based on partial data, the quality of which may vary from region to region, and which may change over time and with new information (Courtesy of Geoscience Australia).
Natural accumulations of CO$_2$

Figure 5.11  Examples of natural accumulations of CO$_2$ around the world. Regions containing many occurrences are enclosed by a dashed line. Natural accumulations can be useful as analogues for certain aspects of storage and for assessing the environmental impacts of leakage. Data quality is variable and the apparent absence of accumulations in South America, southern Africa and central and northern Asia is probably more a reflection of lack of data than a lack of CO$_2$ accumulations.
Natural gas storage sites

[Map showing natural gas storage sites in Europe and Central Asia and the USA]
Acid gas injection sites in Canada
Trapping mechanisms for geological storage

- Structural & stratigraphic trapping
- Residual CO₂ trapping
- Solubility trapping
- Mineral trapping

Time since injection stops (years)

% Trapping contribution

Increasing Storage Security
Aquifers: Sleipner project (Norway)

Box 5.1. The Sleipner Project, North Sea.

The Sleipner Project, operated by Statoil in the North Sea about 250 km off the coast of Norway, is the first commercial-scale project dedicated to geological CO₂ storage in a saline formation. The CO₂ (about 9%) from Sleipner West Gas Field is separated, then injected into a large, deep, saline formation 800 m below the seabed of the North Sea. The Saline Aquifer CO₂ Storage (SACS) project was established to monitor and research the storage of CO₂. From 1995, the IEA GHG R&D Program has worked with Statoil to arrange the monitoring and research activities. Approximately 1 MtCO₂ is removed from the produced natural gas and injected underground annually in the field. The CO₂ injection operation started in October 1996, and by early 2005, more than 7 Mt CO₂ had been injected at a rate of approximately 2,700 tonnes per day. Over the lifetime of the project, a total of 20 MtCO₂ is expected to be stored. A simplified diagram of the Sleipner scheme is given in Figure 5.4.

The saline formation into which the CO₂ is injected is a brine-saturated unconsolidated sandstone about 800 to 1,000 m below the sea floor. The formation also contains secondary thin shale layers, which influence the internal movement of injected CO₂. The saline formation has a very large storage capacity, on the order of 1 to 10 GtCO₂. The top of the formation is fairly flat on a regional
Aquifers: Sleipner project (Norway) ...

scale, although it contains numerous small, low-amplitude closures. The overlying primary seal is an extensive, thick, shale layer.

This project is being carried out in three phases. Phase-0 involved baseline data gathering and evaluation, which was completed in November 1998. Phase-1 involved establishment of project status after three years of CO₂ injection. There are five main project areas regarding description of reservoir geology, reservoir simulation, geochemistry, assessment of need and cost for monitoring wells, and geophysical modelling. Phase-2, involving data interpretation and model verification, began in April 2000.

The fate and transport of the CO₂ plume in the storage formation has been monitored successfully by seismic time-lapse surveys (Figure 5.16). The surveys also show that the caprock is an effective seal that prevents CO₂ migration out of the storage formation. Today, the footprint of the plume at Sleipner extends over an area of approximately 5 km². Reservoir studies and simulations covering hundreds to thousands of years have shown that CO₂ will eventually dissolve in the pore water, which will become heavier and sink, thus minimizing the potential for long-term leakage (Lindeberg and Bergmo, 2003).
Aquifers: Sleipner project (Norway)
Sleipner Project
**Carbon dioxide capture process**

The first stage in the Sleipner CO2 capture process entails the mixing of an amine-water solution with the natural gas in two parallel columns (absorber A and B), both of which are kept at high pressure (100 bara) and moderate temperature (60-70°C). The amine—an organic compound derived from ammonia—selectively absorbs the CO2 by weak chemical bonding and separates out at the bottom of the columns. Thereafter it is transferred via a turbine to a 15 bara flash drum in which the co-absorbed hydrocarbons are removed. The amine is subsequently heated and depressurized to 1.2 bara in a second flash drum where the CO2 is boiled off. By now the gas is almost (95%) pure CO2.

As the lean liquid amine still contains residual CO2, some 10 per cent is subject to thermal regeneration where the CO2 is stripped off by steam in a desorber column operating at 120°C. The remaining, even leaner amine is then mixed with the regenerated amine and pumped back to the absorbers for a new separation cycle.

The carbon dioxide content in the natural gas can now be kept below 2.5 per cent by increasing the amine circulation rate and total heat input.
Sleipner project: capture

Natural gas with ~8% CO$_2$

Natural gas with 2.5% CO$_2$ to customer

Absorber A

Absorber B

Natural gas

Rich amine

Lean amine

CO$_2$

Turbine

1$^{st}$ flash drum

2$^{nd}$ flash drum

Hydrocarbon recycling

Heater

10% thermal regeneration

95% CO$_2$ for injection

CO$_2$ injection into the Utsira aquifer
Sleipner project: 3D picture

Natural gas with ~8% CO₂

CO₂ separation from gas

~ 2500 m

CO₂ injection into the Utsira aquifer; brine saturated unconsolidated sandstone

~ 3000 m

~ 1000 m
Sleipner project: monitoring
Sleipner project: monitoring
### Sleipner project: costs

<table>
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<tr>
<th>Project</th>
<th>Sleipner</th>
<th>Snøhvit</th>
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<tbody>
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<td>Norway</td>
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<tr>
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<td>References</td>
<td>Torp and Brown, 2005</td>
<td>Kaarstad, 2002</td>
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* No further breakdown figures are available. Subset of a larger system of capital and operating costs for several processes, mostly natural gas and condensate processing.
Aquifers: In Salah project (Algeria)

Box 5.2. The In Salah, Algeria, CO₂ Storage Project.

The In Salah Gas Project, a joint venture among Sonatrach, BP, and Statoil located in the central Saharan region of Algeria, is the world’s first large-scale CO₂ storage project in a gas reservoir (Riddiford et al., 2003). The Krechba Field at In Salah produces natural gas containing up to 10% CO₂ from several geological reservoirs and delivers it to markets in Europe, after processing and stripping the CO₂ to meet commercial specifications. The project involves re-injecting the CO₂ into a sandstone reservoir at a depth of 1,800 m and storing up to 1.2 MtCO₂ per year. Carbon dioxide injection started in April 2004, and over the life of the project, it is estimated that 17 MtCO₂ will be geologically stored. The project consists of 4 production and 3 injection wells (Figure 5.5). Long reach (up to 1.5 km) horizontal wells are used to inject CO₂ into the 5 md permeability reservoir.

The Krechba Field is a relatively simple anticline. Carbon dioxide injection takes place down-dip from the gas/water contact in the gas-bearing reservoir. The injected CO₂ is expected to eventually migrate into the area of the current gas field after depletion of the gas zone. The field has been mapped using 3D seismic and well data from the field. Deep faults have been mapped, but at shallower levels, the structure is unfaulited. The storage target in the reservoir interval therefore carries minimal structural uncertainty or risk. The top seal is a thick succession of mudstones up to 950 m thick.

IPCC-SRCCS 2005
In-Salah (BP, Statoil, Sonatrach-Algeria)
Aquifers: Snøhvit project (Statoil, Norway)

- Sandstone aquifer, offshore
- Depth: 2500 m
- 0.75 Mt CO₂ per year; Start in 2007 and last for 20 + years
- CO₂ source is removal from natural gas before cooling to LNG; limit 50 ppmvol.
Aquifers: Snøhvit project (Statoil, Norway)
Aquifers: Snøhvit project (Statoil, Norway)

Tubåen Formation storing CO2 under the Snøhvit Field
Enhanced Oil (Gas) Recovery

- 30 MtCO$_2$/y injected mainly in Texas
- CO$_2$ from natural wells
- CO$_2$ produced with oil, separated, reinjected

Figure 5.15 Injection of CO$_2$ for enhanced oil recovery (EOR) with some storage of retained CO$_2$ (after IEA Greenhouse Gas R&D Programme). The CO$_2$ that is produced with the oil is separated and reinjected back into the formation. Recycling of produced CO$_2$ decreases the amount of CO$_2$ that must be purchased and avoids emissions to the atmosphere.
EOR: Weyburn project (Canada)

Box 5.3. The Weyburn CO₂-EOR Project.

The Weyburn CO₂-enhanced oil recovery (CO₂-EOR) project is located in the Williston Basin, a geological structure extending from south central Canada into the north central United States. The project aims to permanently store almost all of the injected CO₂ by eliminating the CO₂ that would normally be released during the end of the field life.

The source of the CO₂ for the Weyburn CO₂-EOR Project is the Dakota Gasification Company facility, located approximately 325 km south of Weyburn in Beulah, North Dakota, U.S.A. At the plant, coal is gasified to make synthetic gas (methane), with a relatively pure stream of CO₂ as a by-product. This CO₂ stream is dehydrated, compressed, and piped to Weyburn in southeastern Saskatchewan, Canada, for use in the field. The Weyburn CO₂-EOR Project is designed to take CO₂ from the pipeline for a period of approximately 15 years, with delivered volumes dropping from 5,000 tonnes per day to about 3,000 tonnes per day over the life of the project.

The Weyburn field covers an area of 180 km², with original oil in place on the order of 222 million m³ (1,396 million barrels). Over the life of the CO₂-EOR project (20-25 years), it is expected that some 20 MtCO₂ will be stored in the field, using current economics and oil recovery technology. The oil field layout and operation is relatively conventional for oil field operations. The field has been designed with a combination of vertical and horizontal wells to optimize the sweep efficiency of the CO₂. In all cases, production and injection strings are used within the wells to protect the integrity of the casing of the well.
EOR: Weyburn project (Canada)

reservoir is an anhydrite zone. At the northern limit of the reservoir, the carbonate thins against a regional unconformity. The basal seal is also anhydrite, but is less consistent across the area of the reservoir. A thick, flat-lying shale above the unconformity forms a good regional barrier to leakage from the reservoir. In addition, several high-permeability formations containing saline groundwater would form good conduits for lateral migration of any CO₂ that might reach these zones, with rapid dissolution of the CO₂ in the formation fluids.

Since CO₂ injection began in late 2000, the performance of the EOR project has been largely as predicted. Currently, some 1,600 m³ (10,063 barrels) per day of incremental oil is being produced from the field. All produced CO₂ is captured and recompressed for reinjection into the production zone. At the moment, some 1,000 tonnes per day of CO₂ is reinjected; this will increase as the project matures. Monitoring is extensive, with high-resolution seismic surveys and surface monitoring to determine any potential leakage. Surface monitoring includes sampling and analysis of potable groundwater, as well as soil gas sampling and analysis (Moberg et al., 2003). To date, there has been no indication of CO₂ leakage to the surface and near-surface environment (White, 2005; Strutt et al., 2003).

IPCC-SRCCS 2005
EOR: Weyburn project (Canada)

- 325 km Pipeline
  - North Dakota Gasification Plant, USA
  - Completed - September 2000
  - 5,000 t/d of CO₂
  - 40% of total capacity
  - Gas Composition
    - 97% CO₂
    - 1% H₂S

Weyburn CO₂ Injection Project
- Oilfield operated by PanCanadian since 1954
- Conventional and water flood enhanced recovery
- Estimated recovery of oil reserves - 35%
- CO₂ injection commenced in September 2000
- Estimated to recover additional 10-15% of OIP
- Extend field life by 25 years
EOR: Weyburn project (Canada)

- 325 km Pipeline
- North Dakota Gasification Plant, USA
- Completed - September 2000
- 5,000 t/d of CO₂
Weyburn project

System Model of Weyburn CO₂ Project
Weyburn project
EOR: Weyburn project (Canada)
Weyburn project: monitoring

Figure 5.24 The produced water chemistry before CO₂ injection and the produced water chemistry after 12 months and 31 months of injection at Weyburn has been contoured from fluid samples taken at various production wells. The black dots show the location of the sample wells: (a) δ¹³C₅C₂₃ in the produced water, showing the effect of supercritical CO₂ dissolution and mineral reaction. (b) Calcium concentrations in the produced water, showing the result of mineral dissolution (after Perkins et al., 2005).
Enhanced Coalbed Methane Recovery (ECBM)

- CO₂ (about twice more adsorbable) displaces CH₄ from coal
- Advantages:
  - increased CH₄ recovery
  - storage of carbon dioxide

- Needs:
  - Capacity of the coal seam adsorption measurements
  - Coal bed dynamics swelling and permeability measurements
  - Geology site characterization
Enhanced Coalbed Methane Recovery (ECBM)

Primary Recovery: - sucking water out to release hydrostatic pressure

→ Drawbacks:
- CH₄ normal recovery from 20 to 60%
- large quantities of water to be disposed of

ECBM: - gas injection (CO₂, N₂ or mixtures)
- increased methane recovery

Source: Simulation results by Chaback et al. CH₄ removed from the coal by displacement chromatography as the CO₂ is transported through the coal bed.
Coal structure

**Microporosity** → controls adsorption (95% of surface)

**Macroporosity** → controls coal permeability (5% of surface)

*Butt fractures:* associated with diffusion of gas from matrix to face cleats, less continuous

*Face fractures:* control the flow of gas to the well bore, more continuous

→ sorption and diffusion in the matrix

→ Darcy-flow in the cleats
Coal structure

→ structure change during adsorption/desorption of gases
→ CO₂ and CH₄ dissolve in coal:
  - swelling during adsorption
  - shrinkage during desorption

These volumetric changes affect:
  - porosity
  - permeability to gases
  - mechanical properties

Source:
George & Barakat (2001)
Desorption experiments
CO$_2$-ECBM field tests

- Allison Unit, San Juan Basin, USA
  - World’s first experimental CO$_2$-ECBM recovery pilot
- Alberta sequestration project, Canada
  - Pilot site in the Fenn Big Valley
- RECOPOL project, Poland
  - First European field demonstration of CO$_2$ storage in coal seams
- South Qinshui Basin, Shanxi Province, China
  - Canadian Consortium and China United Coalbed Methane Corporation
ECBM: San Juan Basin project (USA)

The Allison Unit CO₂-ECBM Recovery Pilot Project, located in the northern New Mexico portion of the San Juan Basin, U.S.A., is owned and operated by Burlington Resources. Production from the Allison field began in July 1989, and CO₂ injection operations for ECBM recovery commenced in April 1995. Carbon dioxide injection was suspended in August 2001 to evaluate the results of the pilot. Since this pilot was undertaken purely for the purposes of ECBM production, no CO₂ monitoring program was implemented.

The CO₂ was sourced from the McElmo Dome in Colorado and delivered to the site through a (then) Shell (now Kinder-Morgan) CO₂ pipeline. The Allison Unit has a CBM resource of 242 million m³ per km². A total of 6.4 Bcf of natural CO₂ was injected into the reservoir over six years, of which 1.6 Bcf is forecast to be ultimately produced back, resulting in a net storage volume of 277,000 tonnes of CO₂. The pilot consists of 16 methane production wells, 4 CO₂ injection wells, and one pressure observation well. The injection operations were undertaken at constant surface injection pressures on the order of 10.4 MPa.

The wells were completed in the Fruitland coal, which is capped by shale. The reservoir has a thickness of 13 m, is located at a depth of 950 m, and had an original reservoir pressure of 11.5 MPa. In a study conducted under the Coal-Seq Project performed for the U.S. Department of Energy (www.coal-seq.com), a detailed reservoir characterization and modeling of the pilot was developed using the COMET2 reservoir simulator, and future field performance was forecast under various operating conditions.
Based on the study, there is evidence of significant coal-permeability reduction with CO₂ injection. This permeability reduction resulted in a two-fold reduction in injectivity. This effect compromised incremental methane recovery and project economics. Finding ways to overcome and/or prevent this effect is therefore an important topic for future research. The injection of CO₂ at the Allison Unit has resulted in an increase in methane recovery from an estimated 77% of original gas in place to 95% of the original gas in place within the project area. The recovery of methane was in a proportion of approximately one volume of methane for every three volumes of CO₂ injected (Reeves et al., 2004).

An economic analysis of the pilot indicated a net present value of negative U.S. $627,000, assuming a discount rate of 12% and an initial capital expenditure of $2.6 million, but not including the beneficial impact of any tax credits for production from nonconventional reservoirs. This was based on a gas price of $2.20 per MMbtu (at the time) and a CO₂ price of $0.30 per Mcf ($5.19 per tonne). The results of the financial analysis will change, based on the cost of oil and gas (the analysis indicated that the pilot would have yielded a positive net present value of $2.6 million at today’s gas prices), and the cost of CO₂. It was also estimated that if injectivity had been improved by a factor of four (but still using $2.20/MMbtu), the net present value would have increased to $3.6 million. Increased injectivity and today’s gas prices combined would have yielded a net present value for the pilot of $15 million, or a profit of $34 per tonne of CO₂ retained in the reservoir (Reeves et al., 2003).
San Juan Basin project

- Allison Unit, operated by Burlington Resources, CO2 injection
- Tiffany Unit, operated by BP America, N2 injection

CBM resource field: 242 m$^3$ per km$^2$
- 277,000 t CO$_2$ sequestrated in six years
- 16 CH$_4$ production wells, 4 CO$_2$ injection wells

http://www.netl.doe.gov/
San Juan Basin project

CO$_2$ injection well at the Allison Unit, New Mexico, injection started in 1995
San Juan Basin project: exp. data vs. prediction

CBM production: 1989-1995
CO₂ injection: 1995-2001

Produced gas composition of two producing wells

Shi and Durucan (2005)
RECOPOL Project (EU FP6)
ECBM targets: thin multiple coal seams of Carboniferous age
• MS -1,4: production wells
  x : injection well
RECOPOLE Project (EU FP6)
Storage potential

- **Geological storage**: likely at least about 2,000 GtCO₂ in geological formations
  "Likely" is a probability between 66 and 90%.

- **Ocean storage**: on the order of thousands of GtCO₂, depending on environmental constraints

- **Mineral carbonation**: can currently not be determined

<table>
<thead>
<tr>
<th>Reservoir type</th>
<th>Lower estimate of storage capacity (GtCO₂)</th>
<th>Upper estimate of storage capacity (GtCO₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas fields</td>
<td>675ᵃ</td>
<td>900ᵃ</td>
</tr>
<tr>
<td>Unminable coal seams (ECBM)</td>
<td>3-15</td>
<td>200</td>
</tr>
<tr>
<td>Deep saline formations</td>
<td>1000</td>
<td>Uncertain, but possibly 10⁴</td>
</tr>
</tbody>
</table>
Life cycle of a CO₂ storage project

<table>
<thead>
<tr>
<th>KEY QUESTION</th>
<th>NEED</th>
<th>ACTIVITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Is there a CCS opportunity?</td>
<td>Stationary sources of CO₂</td>
<td>• Determine magnitude of present and future emissions</td>
</tr>
<tr>
<td>Is storage capacity likely</td>
<td>Regional storage opportunities</td>
<td>• Screen and select potential sites</td>
</tr>
<tr>
<td>to be adequate?</td>
<td>Site specific characterisation and</td>
<td>• Characterise geology</td>
</tr>
<tr>
<td></td>
<td>assessment</td>
<td>• Develop monitoring plan</td>
</tr>
<tr>
<td>Is site suitable?</td>
<td></td>
<td>• Develop risk mitigation strategy</td>
</tr>
<tr>
<td>Is proposal viable?</td>
<td>Develop proposal for injection and storage of CO₂</td>
<td>• Develop well remediation program</td>
</tr>
<tr>
<td>Does proposal meet needs of</td>
<td>Submit application for licence to inject and store CO₂</td>
<td>• Perform economic analysis</td>
</tr>
<tr>
<td>regulator?</td>
<td>inject and store CO₂</td>
<td>• Engage stakeholders</td>
</tr>
<tr>
<td>Does program meet regulatory</td>
<td>Inject and monitor CO₂</td>
<td>• Dialogue with licencing authority</td>
</tr>
<tr>
<td>conditions and community</td>
<td></td>
<td>• Baseline monitoring</td>
</tr>
<tr>
<td>expectations?</td>
<td>Conclude injection commence post</td>
<td>• Monitor mass distribution of CO₂</td>
</tr>
<tr>
<td>Storage capacity reached. Can</td>
<td>injection/post closure period</td>
<td>• Monitor for potential migration of CO₂ outside containment area</td>
</tr>
<tr>
<td>injection be concluded and</td>
<td></td>
<td>• Carry out simulations history matching</td>
</tr>
<tr>
<td>closure commenced?</td>
<td></td>
<td>• Update mitigation plan etc</td>
</tr>
<tr>
<td>Is the regulator willing to accept</td>
<td>Site Closure</td>
<td>• Engage stakeholders</td>
</tr>
<tr>
<td>closure of site?</td>
<td></td>
<td>• Confirm site behavior matches conditions of licence</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Seal wells</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Site remediation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Periodic monitoring by state regulators</td>
</tr>
</tbody>
</table>
Geological data for a CO₂ storage project

- Seismic profiles across the area of interest, preferably three-dimensional or closely spaced two-dimensional surveys;
- Structure contour maps of reservoirs, seals and aquifers;
- Detailed maps of the structural boundaries of the trap where the CO₂ will accumulate, especially highlighting potential spill points;
- Maps of the predicted pathway along which the CO₂ will migrate from the point of injection;
- Documentation and maps of faults and fault;
- Facies maps showing any lateral facies changes in the reservoirs or seals;
- Core and drill cuttings samples from the reservoir and seal intervals;
- Well logs, preferably a consistent suite, including geological, geophysical and engineering logs;
- Fluid analyses and tests from downhole sampling and production testing;
- Oil and gas production data (if a hydrocarbon field);
- Pressure transient tests for measuring reservoir and seal permeability;
- Petrophysical measurements, including porosity, permeability, mineralogy (petrography), seal capacity, pressure, temperature, salinity and laboratory rock strength testing;
- Pressure, temperature, water salinity;
- In situ stress analysis to determine potential for fault reactivation and fault slip tendency and thus identify the maximum sustainable pore fluid pressure during injection in regard to the reservoir, seal and faults;
- Hydrodynamic analysis to identify the magnitude and direction of water flow, hydraulic interconnectivity of formations and pressure decrease associated with hydrocarbon production;
- Seismological data, geomorphological data and tectonic investigations to indicate neotectonic activity.
Figure 5.22 Comparison of the magnitude of CO₂ injection activities illustrating that the storage operations from a typical 500-MW coal plant will be the same order of magnitude as existing CO₂ injection operations (after Heinrich et al., 2003).
Monitoring technologies

- Time lapse seismic
- Remote sensing
  - Techniques for measuring ground heave
  - Remote surface gas analysis
- Geochemical monitoring
  - Subsurface geochemistry
  - Surface and near surface geochemistry
- Non-seismic geophysical techniques
  - Electromagnetic surveys
  - Gravity techniques
- Vegetational surveys (hyperspectral imagery etc)
## Monitoring technologies

<table>
<thead>
<tr>
<th>Measurement technique</th>
<th>Measurement parameters</th>
<th>Example applications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Introduced and natural tracers</td>
<td>Travel time</td>
<td>Tracing movement of CO₂ in the storage formation</td>
</tr>
<tr>
<td></td>
<td>Partitioning of CO₂ into brine or oil</td>
<td>Quantifying solubility trapping</td>
</tr>
<tr>
<td></td>
<td>Identification sources of CO₂</td>
<td>Tracing leakage</td>
</tr>
<tr>
<td>Water composition</td>
<td>CO₃⁻, HCO₃⁻, CO₂⁻</td>
<td>Quantifying solubility and mineral trapping</td>
</tr>
<tr>
<td></td>
<td>Major ions</td>
<td>Quantifying CO₂-water-rock interactions</td>
</tr>
<tr>
<td></td>
<td>Trace elements</td>
<td>Detecting leakage into shallow groundwater aquifers</td>
</tr>
<tr>
<td></td>
<td>Salinity</td>
<td></td>
</tr>
<tr>
<td>Subsurface pressure</td>
<td>Formation pressure</td>
<td>Control of formation pressure below fracture gradient</td>
</tr>
<tr>
<td></td>
<td>Annulus pressure</td>
<td>Wellbore and injection tubing condition</td>
</tr>
<tr>
<td></td>
<td>Groundwater aquifer pressure</td>
<td>Leakage out of the storage formation</td>
</tr>
<tr>
<td>Well logs</td>
<td>Brine salinity</td>
<td>Tracking CO₂ movement in and above storage formation</td>
</tr>
<tr>
<td></td>
<td>Sonic velocity</td>
<td>Tracking migration of brine into shallow aquifers</td>
</tr>
<tr>
<td></td>
<td>CO₂ saturation</td>
<td>Calibrating seismic velocities for 3D seismic surveys</td>
</tr>
<tr>
<td>Time-lapse 3D seismic imaging</td>
<td>P and S wave velocity</td>
<td>Tracking CO₂ movement in and above storage formation</td>
</tr>
<tr>
<td></td>
<td>Reflection horizons</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Seismic amplitude attenuation</td>
<td></td>
</tr>
<tr>
<td>Vertical seismic profiling and</td>
<td>P and S wave velocity</td>
<td>Detecting detailed distribution of CO₂ in the storage formation</td>
</tr>
<tr>
<td>crosswell seismic imaging</td>
<td>Reflection horizons</td>
<td>Detection leakage through faults and fractures</td>
</tr>
<tr>
<td></td>
<td>Seismic amplitude attenuation</td>
<td></td>
</tr>
<tr>
<td>Passive seismic monitoring</td>
<td>Location, magnitude and source characteristics</td>
<td>Development of microfractures in formation or caprock</td>
</tr>
<tr>
<td></td>
<td>of seismic events</td>
<td>CO₂ migration pathways</td>
</tr>
</tbody>
</table>
Table 5.4 Summary of direct and indirect techniques that can be used to monitor CO₂ storage projects.

<table>
<thead>
<tr>
<th>Monitoring techniques</th>
<th>Monitoring/Analysis</th>
<th>Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>Passive seismic monitoring</td>
<td>Location, magnitude and source characteristics of seismic events</td>
<td>Development of microfractures in formation or caprock CO₂ migration pathways</td>
</tr>
<tr>
<td>Electrical and electromagnetic techniques</td>
<td>Formation conductivity</td>
<td>Tracking movement of CO₂ in and above the storage formation</td>
</tr>
<tr>
<td>Time-lapse gravity measurements</td>
<td>Density changes caused by fluid displacement</td>
<td>Detecting migration of brine into shallow aquifers</td>
</tr>
<tr>
<td>Land surface deformation</td>
<td>Tilt</td>
<td>Detect geomechanical effects on storage formation and caprock</td>
</tr>
<tr>
<td></td>
<td>Vertical and horizontal displacement using interferometry and GPS</td>
<td>Locate CO₂ migration pathways</td>
</tr>
<tr>
<td>Visible and infrared imaging from satellite</td>
<td>Hyperspectral imaging of land surface</td>
<td>Detect vegetative stress</td>
</tr>
<tr>
<td>or planes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ land surface flux monitoring using flux</td>
<td>CO₂ fluxes between the land surface and atmosphere</td>
<td>Detect, locate and quantify CO₂ releases</td>
</tr>
<tr>
<td>chambers or eddy covariance</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Soil gas sampling</td>
<td>Soil gas composition</td>
<td>Detect elevated levels of CO₂</td>
</tr>
<tr>
<td></td>
<td>Isotopic analysis of CO₂</td>
<td>Identify source of elevated soil gas CO₂</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Evaluate ecosystem impacts</td>
</tr>
</tbody>
</table>
## CO₂ retention and release rates

<table>
<thead>
<tr>
<th>Kind of evidence</th>
<th>Average annual fraction released</th>
<th>Representative references</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ in natural formations</td>
<td>The lifetime of CO₂ in natural formations (&gt;10 million yr in some cases) suggests an average release fraction &lt;10⁻⁷ yr⁻¹ for CO₂ trapped in sedimentary basins. In highly fractured volcanic systems, rate of release can be many orders of magnitude faster.</td>
<td>Stevens et al., 2001a; Baines and Worden, 2001</td>
</tr>
<tr>
<td>Oil and gas</td>
<td>The presence of buoyant fluids trapped for geological timescales demonstrates the widespread presence of geological systems (seals and caprock) that are capable of confining gasses with release rates &lt;10⁻⁷ yr⁻¹.</td>
<td>Bradshaw et al., 2005</td>
</tr>
<tr>
<td>Natural gas storage</td>
<td>The cumulative experience of natural gas storage systems exceeds 10,000 facility-years and demonstrates that operational engineered storage systems can contain methane with release rates of 10⁻⁴ to 10⁻⁶ yr⁻¹.</td>
<td>Lippmann and Benson, 2003; Perry, 2005</td>
</tr>
<tr>
<td>Enhanced oil recovery (EOR)</td>
<td>More than 100 MtCO₂ has been injected for EOR. Data from the few sites where surface fluxes have been measured suggest that fractional release rates are near zero.</td>
<td>Moritis, 2002; Klusman, 2003</td>
</tr>
<tr>
<td>Models of flow through the undisturbed subsurface</td>
<td>Numerical models show that release of CO₂ by subsurface flow through undisturbed geological media (excluding wells) may be near zero at appropriately selected storage sites and is very likely &lt;10⁻⁴ in the few studies that attempted probabilistic estimates.</td>
<td>Walton et al., 2005; Zhou et al., 2005; Lindeberg and Bergmo, 2003; Cawley et al., 2005</td>
</tr>
<tr>
<td>Models of flow through wells</td>
<td>Evidence from a small number of risk assessment studies suggests that average release of CO₂ can be 10⁻⁵ to 10⁻⁷ yr⁻¹ even in existing oil fields with many abandoned wells, such as Weyburn. Simulations with idealized systems with ‘open’ wells show that release rates can exceed 10⁻², though in practice such wells would presumably be closed as soon as CO₂ was detected.</td>
<td>Walton et al., 2005; Zhou et al., 2005; Nordbotten et al., 2005b</td>
</tr>
<tr>
<td>Current CO₂ storage projects</td>
<td>Data from current CO₂ storage projects demonstrate that monitoring techniques are able to detect movement of CO₂ in the storage reservoirs. Although no release to the surface has been detected, little can be concluded given the short history and few sites.</td>
<td>Wilson and Monea, 2005; Arts et al., 2005; Chadwick, et al., 2005</td>
</tr>
</tbody>
</table>
Health, safety, environment risks

- In general: lack of real data, so comparison with current operations
- CO₂ pipelines: similar to or lower than those posed by hydrocarbon pipelines
- Geological storage:
  - appropriate site selection, a monitoring program to detect problems, a regulatory system, remediation methods to stop or control CO₂ releases if they arise:
  - comparable to risks of current activities (natural gas storage, EOR, disposal of acid gas)
Abandoned wells

(a) Cased abandoned well

(b) Uncased abandoned well
Design of a well
Potential leakage from geological reservoirs and remediation

**Potential Escape Mechanisms**

A. CO₂ gas pressure exceeds capillary pressure & passes through siltstone
B. Free CO₂ leaks from A into upper aquifer up fault
C. CO₂ escapes through 'gap' in cap rock into higher aquifer
D. Injected CO₂ migrates up dip, increases reservoir pressure & permeability of fault
E. CO₂ escapes via poorly plugged old abandoned well
F. Natural flow dissolves CO₂ at CO₂ / water interface & transports it out of closure
G. Dissolved CO₂ escapes to atmosphere or ocean

**Remedial Measures**

A. Extract & purify groundwater
B. Extract & purify groundwater
C. Remove CO₂ & reinject elsewhere
D. Lower injection rates or pressures
E. Re-plug well with cement
F. Intercept & reinject CO₂
G. Intercept & reinject CO₂
Will leakage compromise CCS as a climate change mitigation option?

- Fraction retained in appropriately selected and managed geological reservoirs is
  - very likely to exceed 99% over 100 years, and
  - is likely to exceed 99% over 1,000 years.

  "Likely" is a probability between 66 and 90%, "very likely" of 90 to 99%

- Release of CO₂ from ocean storage would be gradual over hundreds of years

- Sufficient?
## CCS component costs

<table>
<thead>
<tr>
<th>CCS component</th>
<th>Cost range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capture from a power plant</td>
<td>15 - 75 US$/tCO₂ net captured</td>
</tr>
<tr>
<td>Capture from gas processing or ammonia production</td>
<td>5 - 55 US$/tCO₂ net captured</td>
</tr>
<tr>
<td>Capture from other industrial sources</td>
<td>25 - 115 US$/tCO₂ net captured</td>
</tr>
<tr>
<td>Transportation</td>
<td>1 - 8 US$/tCO₂ transported per 250km</td>
</tr>
<tr>
<td>Geological storage</td>
<td>0.5 - 8 US$/tCO₂ injected</td>
</tr>
<tr>
<td>Ocean storage</td>
<td>5 - 30 US$/tCO₂ injected</td>
</tr>
<tr>
<td>Mineral carbonation</td>
<td>50 - 100 US$/tCO₂ net mineralized</td>
</tr>
</tbody>
</table>
Maturity of CCS technology

- **Research phase**
  - Mineral carbonation
  - Ocean storage

- **Demonstration phase**
  - Oxyfuel combustion
  - Enhanced Coal Bed Methane

- **Economically feasible under specific conditions**
  - Post-combustion
  - Pre-combustion
  - Industrial separation
  - Transport
  - Industrial utilization
  - Enhanced Oil Recovery
  - Gas and oil fields
  - Saline formations

- **Mature market**