Reducing Greenhouse Gas Emissions: The Role of Geologic Storage of CO₂

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Human and Natural Drivers of Climate Change

$\text{CO}_2$, $\text{CH}_4$ and $\text{N}_2\text{O}$ Concentrations
- far exceed pre-industrial values
- increased markedly since 1750 due to human activities

Relatively little variation before the industrial era
Predicted Global Average Temperature

Source: IPCC, 2007
The oceans have taken up ~400 Gt of fossil fuel CO$_2$. Global surface oceans now remove 20-25 Mt CO$_2$/day.

Decline in pH (0.1 since industrial revolution) affects bicarbonate, carbonate ion concentrations, rates of fixation of CaCO$_3$ by assorted critters in the trophic chain, potential for feedbacks with temperature change.

Source: Oceanography Vol.17, No.3, Sept. 2004
The Need for Technology

Concentrations of CO$_2$ will rise above current values (380 ppm), even under the most optimistic scenarios.

Stabilization will require that emissions peak and then decline. Peak timing depends on the stabilized concentration.

Improvements in efficiency, introduction of renewables, nuclear power, ... all help.

New technology will be needed for the really deep reductions.

Source: IPCC 2007
So what do we do about this?

- Look for energy efficiency at every turn – there is plenty of room for efficiency improvement with technologies we have today, especially in the US.
- But growth in demand, particularly in the developing world will require that new technologies be brought online if greenhouse gas emissions are to be reduced at the same time.
- Engage in a vigorous research effort to lay foundations for future energy technologies.
- Use a portfolio approach: guessing now the shape of the energy mix and markets 30-50 years in the future is doomed to failure.
Exergy Flow of Planet Earth (TW)

Current Global Exergy Usage Rate ~ 15 TW (0.5 ZJ per year)

(1 ZJ = 10^{21} J) ~86000/15 = ~5700

Exergy Flow of Planet Earth (TW):
Fossil Hydrocarbon Resource


(1 ZJ = 10^{21} J)
Gasification Options

Issues: Cost, operating reliability, overall efficiency if CO₂ recovered

Time scale: in use now, but not at large scale
Relative Carbon Emissions of Alternative Hydrocarbon Fuels

- Production of alternative liquid fuels from coal, tar sands, or oil shales increases GHG emissions significantly.
- Volumes of CO$_2$ storage required to mitigate the upstream emissions will be very large if coal, tar sands and heavy oils are used to offset a significant fraction of conventional hydrocarbon use.

Source: Farrell & Brandt, Env. Res. Let. 1, 2006
Geologic Storage of CO₂?

- Can we capture the CO₂? Efficiently? Cost?
- Do we have enough variety of geologic settings for storage?
- Is there sufficient volume available in the subsurface to store enough CO₂ to have an impact?
- Do we know enough about the physical mechanisms that will trap the CO₂ in the subsurface to design safe storage projects that won’t leak?
- Do we have enough experience with actual operations to undertake storage at scale?
There are multiple routes for capturing CO₂ (but it’s expensive!)

- Gas separation processes are available for commercial scale
- CO₂ is routinely separated from natural gas (amines, physical solvents)
- Early storage field tests have used CO₂ that must be separated anyway (Sleipner, In Salah, Weyburn)

Source: IPCC Special Report Carbon Capture & Storage, 2006
Efficiency and Cost

- Typical efficiencies for the solvent/amine separations are low: about 15% of the energy expended is required by the thermodynamics – the rest is lost to entropy creation and heat transfer losses.

- Est. costs (2002 $ per tonne CO$_2$ avoided), efficiency (LHV)
  - New natural gas combined cycle: $37-74$ 47-50%
  - New pulverized coal: $29-51$ 30-35%
  - New IGCC $13-37$ 31-40%
  - New H$_2$ $2-56$ 52-68%

- Cost of CO$_2$ capture is the largest component in cost of storage. A breakthrough in separations technology would make a big difference.

Source: IPCC Special Report on CCS, 2005
What Types of Rock Formations are Suitable for Geological Storage?

Rocks in deep sedimentary basins with barriers to vertical flow are suitable for CO$_2$ storage.

Specific formation types
- Oil reservoirs
- Gas reservoirs
- Saline aquifers
- Deep, unminable coal beds

What about CO$_2$ storage in basalt?
This is an unproven technology that is the subject of ongoing research.

Source: S.M. Benson, GCEP
Location of Storage Sites

North America: Oil and Gas Fields


CO₂ Storage Capacity (Billion Metric Tons)

- Big Sky: 0.8
- MGSC: 0.4
- MRCSP: 2.5
- PCOR: 19.6
- SECARB: 32.4
- SOUTHWEST: 21.4
- WESTCARB: 5.3
- TOTAL: 82.4

Source: S.M. Benson, GCEP
**Location of Storage Sites in North America: Saline Aquifers**

*Carbon Sequestration ATLAS of the United States and Canada*

*First North American Carbon Sequestration Atlas, 2006*

**CO₂ Storage Capacity (Billion Metric Tons)**

- Big Sky: 271, 1,085
- MGSC: 29, 115
- MRCSP: 47, 189
- PCOR: 97, 97
- SECARB: 360, 1,440
- SOUTHWEST: 18, 64
- WESTCARB: 97, 288

**Total:** 919, 3,378

*Source: S.M. Benson, GCEP*
Location of Storage Sites in North America: Coal


CO₂ Storage Capacity
(Billion Metric Tons CO₂)

<table>
<thead>
<tr>
<th>Site</th>
<th>CO₂ Storage Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Big Sky</td>
<td>NA</td>
</tr>
<tr>
<td>MGSC</td>
<td>2.3 3.3</td>
</tr>
<tr>
<td>MRCSP</td>
<td>0.7 1.0</td>
</tr>
<tr>
<td>PCOR</td>
<td>8.0 8.0</td>
</tr>
<tr>
<td>SECARB</td>
<td>57 82</td>
</tr>
<tr>
<td>SOUTHWEST</td>
<td>0.9 2.3</td>
</tr>
<tr>
<td>WESTCARB</td>
<td>87 87</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>156 183</strong></td>
</tr>
</tbody>
</table>

Source: S.M. Benson, GCEP
World Regional CO₂ Storage Opportunities

Emission regions (300 km buffer)

Prospective basins
Non-Prospective provinces

Source: John Bradshaw, Geoscience Australia
Physical Mechanisms of Storage

- How far does injected CO$_2$ propagate (where will we need to monitor)?
- How long does it take to immobilize the CO$_2$ by some mechanism?
- What is the ultimate fate of the CO$_2$?
- What fraction of the CO$_2$ has the potential to escape (as a function of time)?
- Can we design injection processes that reduce the potential for leakage?

The state of knowledge differs for the three main types of potential storage sites. Considerable simulation capability exists (but questions of large scale and long term mechanisms remain).
Regional and reservoir scale characterization will be needed

Site Selection and Characterization:

- Are the seals continuous over the storage reservoir?
- What is the 3-D geometry of faults and fractures?
- Are faults seals or fluid conduits?
- How much overpressure can the seals sustain?
- What is the injectivity of the storage formation?
- What is the storage capacity?

Source: S. M. Benson
Why CO$_2$ for EOR?

- If pressure is high enough, oil is displaced very efficiently due to chromatographic separations that occur during flow of two phases with different compositions.
- The displacement is efficient if the composition path approaches the critical locus.
Heterogeneity and gravity strongly influence well-to-well flow of injected gas.

Extremes of permeability dominate the flow.

Low viscosity CO\(_2\) will find the easy flow paths between wells.

Breakthrough of injected CO\(_2\) limits sweep efficiency and recovery.

Opportunity to optimize for storage and recovery.
The deep formations containing salt water and oil are separated from shallow aquifers by multiple, thick, low permeability formations.

Even if the oil were not present at Weyburn, it would be a good place to store CO\textsubscript{2}. But the oil indicates that there is a trap with a good seal. Storage in oil and gas settings relies on the existence of a seal in the long term.
CO$_2$ injection in gas reservoirs

- CO$_2$ could be used for pressure maintenance or condensate vaporization in gas reservoirs. First test underway in the Netherlands.
- At a given temperature and pressure, CO$_2$ is always more dense than CH$_4$. Injection low in the reservoir would limit vertical mixing.
- CO$_2$ is slightly more viscous than CH$_4$.
- CO$_2$ is an effective injection fluid for condensate vaporization.
- Issues include breakthrough of injected CO$_2$ in production wells (well-to-well flow still dominates, diffusional mixing).
- Driving force for upward migration remains indefinitely.
Density of CO₂ and CH₄

Methane could be removed from a gas field, oxidized, and reinjected. Pressure would decline because CO₂ is less dense than CH₄.
Schematic of CO$_2$ in an aquifer

(a) Stagnant pool of CO$_2$

(b) Gravity current
Mechanisms: immobilize CO$_2$ by capillary trapping

- Pushing CO$_2$ with water, causes CO$_2$ bubbles to be isolated in the tiny pores in the rock.
- These trapped bubbles are very difficult to move.
- Can we make use of trapping to design injection schemes that trap the CO$_2$ effectively?

Trapped bubbles (after removal of the rock)  
(Image: N. R. Morrow)

Capillary trapping can immobilize CO$_2$ relatively quickly. If the CO$_2$ is trapped, it can’t leak during the time required for it to dissolve. Once dissolved, it does not move upward in the rocks.
Permeability distributions for simulations

Homogeneous

Short Correlation Length

Longer Correlation Length

Shale between Layers

$\log_e K$
Gravity-Dominated Displacements

\[ N_{gv} = 55, \; P_c = 0 \]

- **a) Homogeneous**
  - End Injection
  - After Gravity Relaxation
  - Trapped \( \text{CO}_2 \)

- **b) Short Correlation Length**

- **c) Long Correlation Length**

- **d) Layered Aquifer**
  - (i)
  - (ii)
  - (iii)

Strong gravity forces move less dense \( \text{CO}_2 \) to the top of the aquifer. Capillary trapping occurs at the base of the gravity tongue as brine invades behind gas during gravity relaxation after injection ceases.
Water injection to trap CO$_2$

Injecting water after the CO$_2$ can trap part of it relatively quickly.
Small Amounts of Dip Enhance Trapping

Rel Perm Hysteresis, No $P_c$, $N_{gv} = 55.6$, Homogeneous

Tilting the reservoir enhances trapping efficiency (amount and rate)
Increasing brine salinity reduces CO$_2$ solubility in aqueous phase.

Source: G. A. Pope, UT Austin
Mechanisms: dissolution of $\text{CO}_2$ in brine

- Diffusion of $\text{CO}_2$ into brine creates more dense brine at the upper interface.
- That configuration is unstable, and gravity-driven fingers develop (but the fingers move slowly).
- More capillary snap-off as $\text{CO}_2$ dissolves.

The combination of capillary trapping and dissolution immobilizes much of the injected $\text{CO}_2$, but not instantly.

Storage security increases with time.

Source: Riaz, Hesse, Tchelepi & Orr, J Fluid Mech 2006
Storage in Coal Beds

- Storage mechanism is adsorption of CO₂ on coal
- CO₂ adsorbs more strongly than does CH₄ or N₂
- Complex flow in fractured coals
- Adsorbed gas reduces permeability – managing permeability reduction will be essential
- Very limited field experience to date
Separation of $\text{CO}_2$ from $\text{N}_2$ with coal

Adsorption chromatography separates $\text{CO}_2$ from $\text{N}_2$ as it flows through the coal.
Coal permeability increases as CH\textsubscript{4} desorbs, declines as CO\textsubscript{2} adsorbs.
Experience: Oil and Gas Reservoirs

- Known geologic seal (otherwise the oil or gas would not be there).
- Data needed for flow prediction available from geology, producing history.
- 30+ years of experience with injection of CO$_2$ for enhanced oil recovery provides significant practical experience.

Image: DOE Basin Oriented Studies for EOR, Permian Basin, 2006
Experience: aquifer injection in the North Sea

- Sleipner West: 1 million tonnes/yr injection.
- CO$_2$ separated from produced gas.
- About 10 million tonnes injected so far.
- CO$_2$ has been retained well in the target formation.
San Juan Basin CO$_2$ Injection Test

One project has been performed in the US, others underway in Europe, Japan.

Figure 2: Location of the Allison Unit, San Juan Basin

Source: Reeves, US DOE DE-FC26-00NT40924, Feb 2003
Potential for leakage?

Potential leakage routes and remediation techniques for CO2 injected into saline formations

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

Careful site selection, good injection design, careful operation will be required.

Source: IPCC Special Report Carbon Capture & Storage, 2006
Well-bore integrity is the most important risk issue

Cements used to seal wells are subject to attack by low pH brine. Poorly plugged wells that have been abandoned could also provide leak pathways.

Source: J. Friedmann, LLNL  After Gasda et al., 2004
## Estimated Costs for Geologic Storage (2002 $/tonne)

<table>
<thead>
<tr>
<th></th>
<th>Australia</th>
<th>Europe</th>
<th>USA</th>
<th>Australia</th>
<th>$-20 – 150 (depends strongly on gas price)</th>
</tr>
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<tbody>
<tr>
<td><strong>Onshore saline aquifers</strong></td>
<td>$0.2 – 5.0</td>
<td>$1.9 – 6.2</td>
<td>$0.4 – 4.5</td>
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<tr>
<td><strong>Offshore saline aquifers</strong></td>
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<td>$4.7 – 12</td>
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<tr>
<td><strong>Depleted Oil Fields</strong></td>
<td>$0.5 – 4</td>
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<tr>
<td><strong>Depleted Gas Fields</strong></td>
<td>$0.5 – 12.2</td>
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<tr>
<td><strong>Enhanced Oil Recovery</strong></td>
<td>$-92 – 66.7</td>
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</tbody>
</table>

There is considerable uncertainty in the cost estimates – but storage at costs well below the cost of CO$_2$ separation appears possible at significant scale.

Source: IPCC Special Report on CCS, 2005
Reality check: the volumes are very large!

- At a CO$_2$ density of 500 kg/m$^3$ (1000 m depth at 50°C), injection of 1 billion tonnes/yr of CO$_2$ is equivalent to ~35 million barrels/day.

- At a CO$_2$ density of 700 kg/m$^3$, 1 Gt CO$_2$ is equivalent to ~25 million barrels/day.

- Worldwide emissions of CO$_2$, ~25 Gt/yr: ~625 – 825 million barrels/day!

- World oil production is currently ~85 million barrels/day.

- These volumes are large enough that it is clear that CO$_2$ storage in geologic formations will be but one of a variety of ways to reduce CO$_2$ emissions to the atmosphere.
Do we know enough to undertake large-scale geologic storage?

- Can we capture the CO₂? Yes, though cost is an issue.
- Do we have enough variety of potential geologic settings for storage? Yes, in the US, at least.
- Is there sufficient volume available in the subsurface to store enough CO₂ to have an impact? Yes.
- Do we know enough about the physical mechanisms that will trap the CO₂ in the subsurface to design safe storage projects that won’t leak? Yes for oil and gas, better quantification needed for aquifers, no for coal storage.
- Do we have enough experience with actual operations to undertake storage at scale? Yes for oil and gas, not yet but beginning for aquifers, no for coal beds.
Conclusions

- In this century, we humans need to demonstrate that we can learn to live on this planet in a way that protects its essential systems.
- Energy is one of the prime ways we interact with planetary systems.
- Building our capability to limit the impact, carbon and otherwise, is just the sort of challenge we should all tackle!
- This is just the sort of challenge students and faculty at Caltech should tackle, so let's get to work!