Predicting Flow Behavior for Geologic Storage of CO$_2$

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Key Questions for Flow Prediction

• 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 fraction of the CO$_2$ has the potential to escape (as a function of time)?
• What modeling approaches are appropriate?

Models used should be based on an understanding of the relevant physics – the length and time scales of the flow and storage processes.
Multiple Time Scales for Various Storage Settings

- Convection – the injection period (or the time for flow between wells if there are production wells).
- Gravity relaxation – redistribution of fluids in reservoir after injection ceases.
- Capillary trapping of CO$_2$ by imbibition of brine.
- Dissolution in water or oil (aided by unstable convection?).
- Adsorption of CO$_2$ on solid coal surfaces.
- Chemical reactions of dissolved CO$_2$ with minerals present.

**Key task:** Make quantitatively reasonable estimates of all these time scales for realistic storage settings.
The Injection Period

- Heterogeneity and gravity strongly influence the flow path.
- Extremes of permeability determine the flow paths.
- Low viscosity CO$_2$ will find the easy flow paths between wells. CO$_2$ is an order of magnitude less viscous than brine or oil. It is slightly more viscous than natural gas.
Flow Prediction for the Injection Period

- If permeability variation and gravity dominate flow behavior, sufficient resolution to define probable flow paths will be required.
- If composition variations strongly affect flow behavior (they do in oil and gas settings, but they are less important in aquifers), then a sufficient number of components is also required.
- Conventional finite-difference representations are often too slow to allow high resolution (spatial or compositional) for field-scale simulations.
- Streamline methods offer a way to improve speed and therefore, resolution.
• CO₂ storage processes are inherently compositional (components move between phases).
• Conventional finite-difference compositional simulation methods are slow and badly affected by numerical dispersion.
• Use streamlines to capture effects of heterogeneity – high resolution is required to represent effects of high and low perm flow paths.
• Propagate 1D solution along streamlines to account for component transfers between phases (can use analytical solutions or numerical solutions here).
• Update streamlines occasionally to account for changing mobilities.

Streamlines are the method of choice for compositional processes during the injection period. They are fast and accurate. They are not appropriate for periods long after injection ceases.
Example: CO$_2$ Storage in a Gas Reservoir containing Condensate

Numerical dispersion prevents finite-difference methods from resolving the condensate bank, except at very high grid resolution, even in 1D.

13 component fluid description (35% H$_2$S), pure CO$_2$ injection

Heterogeneous permeability field, $30 \times 90 \times 5 = 13,500$ grid blocks
CSLS approach is 1600 times faster than FD (and the speedup scales as the number of grid blocks squared).

For large-scale compositional simulations sensitive to numerical dispersion, CSLS is the only feasible approach.
• Grid resolution: 180 x 180 x 16 = 518,400 grid blocks
• Compare simulations of a fully implicit “black oil” simulator (FIM) with compositional streamline calculations (CSLS).
Calculated Flow Behavior with FIM and CSLS

- FIM (232 min)
- CSLS (21 min)

Top
Middle
Bottom

CLSL an order of magnitude faster than FIM.
What Happens after Injection Ceases?

- The streamline approach offers an efficient way to predict flow behavior during the convection-dominated injection period.
- Streamlines are probably not the right approach for subsequent periods, when gravity relaxation, capillary trapping, dissolution, and reaction operate.
- Consider next the time scales for gravity relaxation, capillary trapping, and dissolution.
Capillary Trapping of a Nonwetting Phase

- Capillary trapping has been well studied, because it creates residual oil to waterflooding.
- When the saturation of the nonwetting phase declines (as will happen due to dissolution of CO$_2$ and gravity relaxation), bubbles of CO$_2$ will snap off and trap.

Capillary pressure differences (due to curved interfaces in pores with high aspect ratio) create unstable interface configurations. A neck of wetting phase snaps off bubbles. After snap-off, bubbles are immobile.
In water-wet systems, significant fractions of the CO$_2$ will trap as a residual phase when gas saturations start to decline. The trapped gas saturation depends on $S_{g,max}$.

What happens after injection ceases: effect of capillary trapping of residual CO₂

For this example, significant capillary trapping happens during the gravity relaxation period, and it happens on ~ the injection time scale.
Dissolution of CO$_2$ in Brine

- Diffusion of 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).

Conventional reservoir simulations do not resolve these fingers well enough to give accurate estimates of transport rates.

Source: A. Riaz, M. Hesse, H. Tchelepi, Stanford University, 2005
Time Scales for Dissolution

- Linear stability theory and high-order numerical simulation show three time scales:
  - Onset of fingering is diffusion-controlled ($t_{on}$)
  - Convection significantly increases dissolution rate after onset
  - When fingers reach the bottom of the aquifer, the rate slows ($t_{slow}$)
  - The time to saturate ($t_{sat}$) all the brine is much longer.

- Dissolution rate depends on Rayleigh number, $Ra = k\Delta \rho g H/\mu D$. For a 200 m thick aquifer:
  - 3400 md, $Ra \sim 59000$, $t_{on} = 0.08$ yr, $t_{slow} = 100$ yr, $t_{sat} = 1500$ yr
  - 100 md, $Ra \sim 2000$, $t_{on} = 200$ yr, $t_{slow} = 1000$ yr, $t_{sat} = 15000$ yr

Unstable convection matters only in high perm aquifers. Dissolution reduces saturation of the CO$_2$ phase. Capillary snap-off will immobilize CO$_2$ as dissolution proceeds.
Adsorption/Desorption/Transport in Fractured Coal

adsorption on internal coal surfaces  diffusion through the matrix and micropores  bulk flow in the fracture network

In many coal beds, CH$_4$ is adsorbed on coal surfaces. When CO$_2$ is injected, it replaces the CH$_4$, which can then be recovered.

Key issues for modeling: time scale for adsorption equilibrium, changes in permeability as CO$_2$, CH$_4$ adsorb and desorb.
Equilibrium Adsorption in Coal Beds

If fractures are closely spaced, the equilibrium assumption is reasonable. Analytical solutions for 1D flow are then possible, as are streamline computations.
Conclusions

• Streamline methods offer speed and accuracy for the injection period – for high resolution compositional simulation (oil and gas) they are the only feasible choice.

• Other methods, tuned to physically-determined spatial and time scales, are needed for subsequent periods.

• Gravity relaxation in aquifers will cause capillary trapping, which occurs more rapidly than dissolution.

• Unstable convection, once underway, is always faster than diffusion for dissolving CO₂ in brine – it causes additional capillary trapping.

• High permeability is better than low, for injection rate, and for dissolution.

• Coal beds offer plenty of remaining challenges for modeling that honors the most important physical mechanisms.
Please see the following posters for the full story (and the assumptions and caveats) behind these statements:

- **Effect of Natural Convection on the Dissolution Trapping of CO\textsubscript{2} in Saline Aquifers** (Marc Hesse, Amir Riaz, Hamdi Tchelepi).
- **Three-dimensional Streamline Simulation of CO\textsubscript{2} Injection in Aquifers** (Kristian Jessen)
- **Analytical Modeling of CO\textsubscript{2} Storage and Enhanced Coal Bed Methane Recovery** (Carolyn Seto and Kristian Jessen)
- **Displacement Efficiency of Brine by CO\textsubscript{2}** (Taku Ide and Kristian Jessen)
- **Movement of the CO\textsubscript{2} Plume in Aquifers without Structural Closure** (Marc Hesse)