Design of Carbon Dioxide Storage in a North Sea Aquifer Using Streamline-Based Simulation

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Abstract

We propose a carbon storage strategy where CO$_2$ and brine are injected into an aquifer together followed by brine injection alone. This renders 80-95% of the CO$_2$ immobile in pore-scale (10s μm) droplets in the porous rock; over thousands to billions of years the CO$_2$ may dissolve or precipitate as carbonate, but it will not migrate upwards and so is effectively sequestered. The CO$_2$ is trapped during the decades-long lifetime of the injection phase, reducing the need for extensive monitoring for centuries. The method does not rely on impermeable cap rock to contain the CO$_2$; this is only a secondary containment for the small amount of remaining mobile gas. Furthermore, the favorable mobility ratio between injected and displaced fluids leads to a more uniform sweep of the aquifer leading to a higher storage efficiency than injecting CO$_2$ alone.

This design is demonstrated through the incorporation of a recent model of trapping and relative permeability hysteresis based on pore-scale modeling into a field-scale streamline-based simulator. One-dimensional results are verified through comparison with analytical solutions. Results are then shown for storage in a North Sea aquifer. We design injection to give optimal storage efficiency and to minimize the amount of water injected; for the case we study injecting CO$_2$ with a fractional flow between 85 and 100% followed by a short period of chase brine injection gives the best performance.

Introduction

Carbon Capture and Storage (CCS) – the collection of CO$_2$ from industrial sources and its injection underground – could potentially contribute significantly to the reduction of atmospheric emissions of greenhouse gases (IPCC, 2005). The North Sea, with mature hydrocarbon fields and saline aquifers offers an attractive storage location for CO$_2$ produced by the UK’s gas and coal-fired power plants. At present the principal barrier to its widespread implementation is cost, mainly associated with the collection of CO$_2$. The principal public and environmental concern is related to the long-term fate of the CO$_2$: can it be guaranteed that the CO$_2$ will remain underground for hundreds to thousands of years?

To date CO$_2$ storage has relied on an impermeable seal at the top of the formation to trap the CO$_2$ in both oilfields (Jessen et al., 2005), such as Weyburn (Malik and Islam, 2000), and aquifer injection, such as Sleipner (Korbøl and Kaddour, 1995). While this maybe a reliable storage mechanism in well-characterized sedimentary basins and in oil and gas fields where hydrocarbons have been trapped for geological time, it is problematic in general, where there it is possible that the top seal could leak, have gaps or be penetrated by wells through which the CO$_2$ could escape to the surface (Bruant et al., 2002).

Over time the injected CO$_2$ will dissolve into the formation brine, increasing its density; as a consequence this CO$_2$-laden water will sink slowly and will not reach the surface. However, the timescale for this process with natural aquifer flows is thousands of years (Ennis-King and Paterson, 2005; Hesse et al., 2006). The CO$_2$ can also react with the rock and precipitate forming solid carbonate. Again this is a slow process taking thousands to billions of years depending on the reactivity of the rock (Xu et al., 2003).

The most rapid method to immobilize the CO$_2$ is by capillary trapping. Recent simulation studies have highlighted the importance of this mechanism to CO$_2$ storage and have suggested that through a combination of aquifer flow, chase brine injection and buoyancy-driven upwards migration, much or all of the CO$_2$ could be trapped before it reaches the top seal (Ennis-King and Paterson, 2002; Kumar et al., 2005; Obi and Blunt, 2006; Juanes et al., 2006). While this is appealing, relying on just buoyancy-driven flow assumes that there is more-or-less uniform upwards movement with significant trapping as water re-invades the pore space.

There is one well-established method by which a non-wetting phase is rendered immobile in a short (years to decades) timescale: waterflooding. Abandoned oil and gas fields often contain hydrocarbon once well-connected in the pore space, but which is now almost entirely at residual saturation.

While the concept of trapping and residual saturation is familiar in the oil industry, there is remarkably little data on the amount of non-wetting phase trapping, particularly in...
systems that are not strongly water-wet, when three phases are present, or when the initial saturation of the non-wetting phase is low (Jerauld, 1997). All three of these situations are likely to pertain in CO₂ storage in aquifers and oilfields. To date the most sophisticated numerical assessments of CO₂ storage have used the Land (1968) trapping model with a Killough (1976) model for the resultant hysteretic relative permeabilities. This model is only applicable for strongly water-wet systems while recent experimental evidence suggests that CO₂/brine systems are weakly water-wet to intermediate-wet (Chiquet et al., 2007).

We suggest the use of waterflooding to render the CO₂ immobile during the injection phase of storage: we design a process such that 90% or more of the injected CO₂ is trapped. Hence we can guarantee that on abandonment the vast majority of the CO₂ will remain underground for geological time; any mobile CO₂ may indeed be contained by a top seal, but this is a secondary, not a primary, containment mechanism.

We propose injecting CO₂ and brine together to improve the storage efficiency of the injection process. Simulation studies imply that only around 2% of the pore space will contain CO₂ if it is injected alone (Obi and Blunt, 2006); injecting CO₂ and water reduces the mobility contrast between the injected and displaced phases leading to a more uniform sweep of the reservoir (Lake, 1989). This is followed by chase brine injection that rapidly traps the injected CO₂.

We design an injection strategy that maximizes the storage efficiency in aquifers and minimizes the total amount of brine injected. We study different possible injection processes using streamline-based simulation that accurately captures the effects of reservoir heterogeneity (Batycky et al., 1997). We incorporate a recently-proposed model for trapping and relative permeability hysteresis (Spiteri et al., 2005) that is anchored on pore-scale modeling and experimental data (Oak, 1990; Valvatne and Blunt, 2004) and which is applicable to weakly water-wet media.

Streamline-based simulator for CO₂ storage and the trapping model
The simulator we use is based on the model of Batycky et al. (1997) modified to include dispersion and dissolution of CO₂ in water by Obi and Blunt (2006). For this work we have extended the formulation to allow the block-by-block assignment of relative permeability and trapped saturation based on the model of Spiteri et al. (2005).

Relative permeability and trapping model. In each grid block of the simulator we record the maximum CO₂ saturation that has been reached, $S_{g}^{\text{max}}$. We then compute the amount of gas that could be trapped during a waterflooding cycle:

$$S_{\text{tr}} = \alpha S_{g}^{\text{max}} - \beta (S_{g}^{\text{max}})^2$$  \hspace{1cm} (1)

Then, for any intermediate value of the gas saturation between $S_{g}^{\text{max}}$ and $S_{\text{tr}}$, the trapped gas (CO₂) saturation, we find the following (untrapped) saturation:

$$S_{g} = \frac{1}{2\beta} \left[ \alpha - 1 + \sqrt{(\alpha - 1)^2 + 4\beta(S_{g} - S_{\text{tr}})(S_{g} - S_{g}^{\text{max}})} \right]$$  \hspace{1cm} (2)

Then using a Carlson (1981) model, we assume that we can compute the relative permeability for gas during water (brine) injection from the primary drainage relative permeability as a function of the flowing saturation (see also Blunt (2000)):

$$k_{D}^{\text{injection}} (S_{g}) = k_{D}^{\text{primary drainage}} (S_{g})$$  \hspace{1cm} (3)

$\alpha$, $\beta$ and $\gamma$ are empirical fitting parameters chosen to match the results of pore-scale simulation for waterflooding at different contact angles (Valvatne and Blunt, 2004). The pore-scale simulation results themselves match experimental data for water-wet systems (Oak, 1990). We do not consider hysteresis in the aequous phase relative permeability.

During streamline-based simulation, grid-block properties are mapped along streamlines. Along each streamline we solve the governing transport equations on a one-dimensional (1D) grid. For each cell face in the 1D streamline grid, we record which grid block in the underlying 3D model that it resides in. Then to compute the flux across this face, we use the relative permeabilities with the appropriate grid-block value of $S_{g}^{\text{max}}$.

Contact angles for CO₂ flooding. Recent experimental work has demonstrated that CO₂/brine systems are not necessarily strongly water-wet: the dissolution of CO₂ into the brine decreases the pH and affects the interfacial charge balance resulting, in some cases, in weakly water-wet conditions (Chiquet et al., 2007). So far measurements have only been made for drainage; in waterflooding the contact angles will be higher (representing even less water-wet conditions) because of surface roughness. We assume an average contact angle of 65° – this is consistent with the available experimental evidence, as well as the effective contact angles necessary to match oil/water experiments in sandstones (Valvatne and Blunt, 2004). Then, from the correlations provided in Spiteri et al. (2005) we take $\alpha$=1, $\beta$=0.5 and $\gamma$=0 in the trapping and relative permeability model, Eqs. (1)-(3); this rather simple combination of parameters is a co-incidence. We use a primary drainage relative permeability for Berea sandstone derived from pore-scale modeling that matches Oak’s (1990) experimental measurements. Compared to the traditional Land model, Eq. (1) predicts larger trapped saturations for intermediate values of $S_{g}^{\text{max}}$.

One-dimensional results and analytical solutions
To understand the behavior of our proposed injection scheme, we first present a series of fine-grid 1D simulation results. The parameters used are shown in Table 1: we allow CO₂ to dissolve in brine, but do not allow water to enter the CO₂ (gas) phase. We ignore dispersion and reaction. We assume incompressible flow.

We consider injection of CO₂ and brine simultaneously followed by the injection of brine only. Fig. 1 shows the mobility ratio between the injected CO₂ plus brine and the formation brine as a function of the injected fraction of CO₂. We assume that the injected brine is saturated with CO₂; while this affects the density of the aqueous phase, we assume that it does not affect the viscosity. The arrows indicate reservoir-condition CO₂-phase injected volumetric fractional flows, $f_{g}$.
of 0.85 and 0.5. Injecting CO₂ alone, i.e. \( f_{gi} = 1 \), results in a mobility ratio of more than 8 leading to channeling and fingering in a 3D displacement and a low sweep efficiency. If \( f_{gi} \) is approximately 0.85 or lower, the displacement is stable; this will result in a better sweep efficiency and more efficient storage of CO₂.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
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<tbody>
<tr>
<td>CO₂ viscosity</td>
<td>( 6 \times 10^{-7} , \text{Pa.s} )</td>
</tr>
<tr>
<td>Brine viscosity</td>
<td>( 5 \times 10^{-7} , \text{Pa.s} )</td>
</tr>
<tr>
<td>Temperature</td>
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<td>Reference pressure</td>
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<tr>
<td>Porosity</td>
<td>0.15</td>
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</table>

### 1D simulation parameters
- Darcy velocity: 1/15 m/day
- Chase brine injection rate: 1.065×10⁶ kg/day
- CO₂ injection rate: 1.500 m³/day
- CO₂ density: 710 kg.m⁻³
- Brine density: 1050 kg.m⁻³
- Brine density saturated with CO₂: 1061 kg.m⁻³

### 3D simulation parameters
- Darcy velocity: 1/15 m/day
- Chase brine injection rate: 1.065×10⁶ kg/day
- CO₂ injection rate: 1.500 m³/day
- CO₂ density: 710 kg.m⁻³
- Brine density: 1050 kg.m⁻³
- Brine density saturated with CO₂: 1061 kg.m⁻³

Table 1. Parameters used in the simulations. The values for CO₂ and brine properties are from Spycher et al. (2003) and Obi and Blunt (2006).

Chase brine injection will follow the waterflood curves and CO₂ will be trapped. Note that the fractional flow falls sharply, indicating that the gas is rapidly trapped.

The imbibition fractional flow curves do not exhibit a characteristic ‘S’ shape because of the relationship between the saturation and the flowing saturation in the trapping model. Fig. 2 shows that the imbibition fractional flow curves are concave everywhere that the gas phase is flowing. The shape of these curves means that chase brine injection will result in a shock from the maximum CO₂ saturation attained to its trapped value: the steep slope indicates that this shock will move very quickly.

Fig. 1. The ratio of the mobility of injected brine and CO₂ to the formation brine as a function of the injected reservoir-condition CO₂ volumetric fractional flow, \( f_{gi} \). For high \( f_{gi} \) the injected mixture is much more mobile than the brine, because of the low viscosity of CO₂ in its own phase. This indicates an unstable displacement which will have a poor sweep efficiency in three dimensions. The mobility ratio is less than one for \( f_{gi} < 0.85 \); this represents a stable displacement which will have reduced channeling and fingering and more efficient storage of CO₂. The indicated fractional flows correspond to the cases studied in one dimension.

Fig. 2 shows the drainage and waterflood CO₂-phase fractional flows, \( f_g \). The initial injection of CO₂ and brine will follow the drainage curve and in 1D the solution will be a Buckley-Leverett solution (Lake, 1989): a shock followed by a rarefaction for high values of the injected fractional flow.
There is a leading Buckley-Leverett shock front; however, the chase water front is moving more than 10 times faster. The analytical solution predicts that in only 89 days it will catch up with the CO$_2$ front and all the gas will be trapped. Near the injection well the gas saturation is zero since the chase brine dissolves the trapped CO$_2$. However, this dissolution front moves with velocity less than $1/100^\text{th}$ the speed of the injected brine, since the solubility of CO$_2$ in brine in these solutions is relatively low. The agreement between analytical and the numerical results is very good, validating the numerical solver.

Fig. 4 shows solutions for $f_{gi}=0.85$. Here the leading front is a shock followed by a rarefaction. As before, we have 1,000 days of brine and CO$_2$ injection followed by 50 days of chase brine. Again, the CO$_2$ is rapidly trapped. The agreement between numerical and analytical solutions is excellent.

It is clear from this 1D analysis that chase brine injection could be an effective and rapid method to trap CO$_2$; the chase brine front traps all the CO$_2$ and moves much more rapidly than the injection front. Using Land and Killough models for trapping and relative permeability hysteresis would lead to slightly less trapping and a slower chase brine front: the model we use is consistent with available experimental data, but further work is required to establish exactly what relative permeabilities are appropriate. The dissolution of CO$_2$ near the injection well has the added advantage of ensuring that the CO$_2$ will not escape back up the well when it is abandoned. However, in 3D, considering the effects of heterogeneity and buoyancy, the aqueous and CO$_2$ phases may not travel in the same direction and so the process may be less efficient.

Three-dimensional results

We performed a series of fine-grid 3D simulations of CO$_2$ storage and trapping. We used the SPE10 reservoir model (Christie and Blunt, 2001) to represent a heterogeneous sandstone North Sea aquifer. The model has 1.2 million grid blocks. Fig. 5 shows the permeability field and well placement. CO$_2$ and brine is injected into one corner of the field, while brine is produced from the other corner. The reservoir volume of brine produced is equal to the reservoir volume of fluids injected. The simulations stop before CO$_2$ breakthrough.

In all the simulations we inject the same amount of CO$_2$ (7.8 Mt = 7.8x10$^9$ kg) over 20 years. We define the trapping efficiency as the fraction of the injected mass of CO$_2$ that is either trapped or dissolved. We vary the injected fractional flow and then inject chase brine until the trapping efficiency is at least 95%. We assess the efficiency of the process in two ways. First, we measure the storage efficiency. This is

![Fig. 3. The one-dimensional saturation profile where brine and CO$_2$ injection with a fractional flow of 0.5 for 1,000 days is followed by 50 days of brine injection alone: the injection well is at a distance 0. Near the injection well all the CO$_2$ has dissolved. Beyond this there is chase water front that is moving much faster than the leading CO$_2$. After 89 days the chase water will have trapped all the CO$_2$. Numerical and analytical solutions are shown and are in good agreement.](image1)

![Fig. 4. Profiles corresponding to Fig. 3, but with an injection fractional flow of 0.85. Here the leading CO$_2$ shock is followed by a rarefaction. Again, within a relatively short time all the CO$_2$ will be rendered immobile.](image2)

![Fig. 5. The permeability field and well placement for the three-dimensional simulations presented.](image3)
effectively the fraction of the reservoir pore volume filled with CO$_2$, although its precise definition can be confusing. We take a box in the reservoir that just contains all the injected CO$_2$ (in both its own phase and dissolved). We compute the mass of CO$_2$ in the box (this is simply the injected mass). We divide this with the mass of CO$_2$ that would be contained in the box if all the pore space were filled with CO$_2$ in its own phase. This gives us the storage efficiency (Obi and Blunt, 2006). The second measure is the amount of brine required to render a given fraction of the CO$_2$ immobile. The ideal injection scheme has a high storage efficiency and yet requires very little brine to trap the CO$_2$.

Fig. 6 shows the 3D saturation profile after 2 years of chase brine injection for $f_{gi}=0.85$. While the sweep efficiency is low and the injected gas clearly rises to the top of the formation and channels along high permeability streaks, the chase brine displacement does tend to follow the CO$_2$ and the vast majority of the CO$_2$ is rapidly trapped, leaving only a relatively small amount of mobile CO$_2$. 95% of the CO$_2$ will be trapped after approximately 1,500 days (4.1 years) of chase brine injection.

Fig. 7 shows the storage efficiency near the end of the simulation (when the trapping efficiency is 90%) and the ratio of the mass of brine to CO$_2$ injected as a function of $f_{gi}$. The storage efficiency is always low – this is due to the extensive channeling of the injected CO$_2$ in this highly heterogeneous aquifer. The storage efficiency is highest for $f_{gi}$ around 0.85. If just CO$_2$ is injected, then the maximum CO$_2$ saturation reached in regions of the field contacted by the gas is large and hence locally the trapped saturation is high. However, from Fig. 1, the mobility contrast is also high, resulting in a poor sweep efficiency. If, in contrast, $f_{gi}$ is low, then the sweep efficiency is higher, since the mobility contrast is less than one. However, locally the trapped saturation – see Fig. 2 – is lower. The optimal combination of sweep efficiency and local trapped saturation occurs near the largest fractional for which the injection is still stable – from Fig. 1 this is around $f_{gi}=0.85$.

The minimum total amount of brine needed to trap a given fraction of the CO$_2$ occurs for $f_{gi}=1$. Since the chase brine front moves so rapidly, most brine is injected with the CO$_2$; clearly this is minimized when $f_{gi}=1$ and no water at all is injected initially. Fig. 8 shows the storage efficiency and brine injected where just chase water is considered. The minimum volume of chase brine to trap most of the CO$_2$ occurs for $f_{gi}=0.85$.

These simulations indicate that a combination of brine and CO$_2$ injection can lead to a storage design where the vast majority of the CO$_2$ is trapped after a relatively short period of chase brine injection and with a storage efficiency that is higher than for CO$_2$ injection alone. The results indicate that the optimal combination of storage efficiency and cost (related to the amount of brine injected for a fixed amount of CO$_2$ stored) is found for an injected CO$_2$ fractional flow in the range 85 – 100%. A simple design criterion is to choose the injection fractional flow such that the displacement is just stable and then during chase water injection to inject approximately 25% of the mass of CO$_2$ stored. Our simulation studies, in a very heterogeneous system, indicate that this approach will enable at least 90% of the CO$_2$ to be trapped.
Discussion and Conclusions

We have proposed a design strategy for CO2 storage in aquifers. CO2 and formation brine are injected simultaneously followed by chase brine. The injection of CO2 and brine together mitigates the mobility contrast between injected and displaced fluids, leading to higher storage efficiencies than injecting CO2 alone. The chase brine renders the CO2 trapped and a relatively short period of injection is sufficient to trap the vast majority of the CO2; in the examples we studied the chase brine front moved around ten times faster than the injected CO2. Once trapped the CO2 may slowly dissolve or react, but cannot escape.

We demonstrated this design through a combination of 1D and 3D streamline-based simulations that incorporate a state-of-the-art trapping and relative permeability hysteresis correlation based on pore-scale modeling verified by experiment and assuming, based on recent measurements, that the CO2/brine system is not strongly water-wet. Further work is required to validate the trapping model used here and to extend the study to oilfields.

We suggest applying the largest injection fractional flow of CO2 such that the mobility contrast with the formation brine is favorable, followed by the injection of around 25% of the stored mass of CO2 as chase brine.

Nomenclature

\[ f = \text{fractional flow, dimensionless} \]
\[ k_r = \text{relative permeability, dimensionless} \]
\[ S = \text{saturation, dimensionless} \]
\[ S_{max} = \text{maximum saturation of invading fluid} \]
\[ \alpha, \beta, \gamma = \text{parameters in the trapping and relative permeability hysteresis model, Eqs. (1)-(3), dimensionless} \]

Subscripts

\[ f = \text{flowing} \]
\[ g = \text{gas (CO2)} \]
\[ i = \text{injection} \]
\[ t = \text{trapped} \]

Superscripts

\[ max = \text{maximum} \]

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References


