The Sleipner CO$_2$ storage site: using a basin model to understand reservoir simulations of plume dynamics

Andrew J. Cavanagh*, R. Stuart Haszeldine$^2$ and Bamshad Nazarian$^3$ address the modelling challenge of simulating the layered CO$_2$ plume, and present their insights into plume dynamics from applying both basin modelling and reservoir simulation approaches to matching the observed distribution.

When simulating CO$_2$ storage, an accurate match to the observed CO$_2$ plume distribution is a prerequisite to establishing the dominant flow physics, and forecasting the storage site behaviour beyond the observed and expected injection period. The scale of industrial CO$_2$ storage pilots such as Sleipner, offshore Norway, is similar to that of small hydrocarbon fields, and lends itself to reservoir simulation. However, the reservoir conditions and dynamics are significantly different: oil and gas production are dominated by imbibition, which is suited to multi-phase Darcy flow simulation; whereas CO$_2$ storage represents the injection of a non-wetting fluid that displaces the in situ brine. The latter process is often termed ‘drainage’, and with respect to simulation, is more typical of regional basin modelling and percolating oil and gas migration. The challenge of modelling CO$_2$ storage is to accurately represent this drainage displacement at the reservoir scale on short decadal timescales. The advantage is the detailed observational dataset with which such models are constrained. Using a Darcy flow model, the first decade of reservoir simulations for Sleipner has been characterized by poor matches to the known plume distribution, and forecasted plume dynamics that persisted for decades-to-centuries beyond the injection period. To overcome this problem of poor simulated replication, and to test the veracity of long term plume dynamics, we applied a basin model to Sleipner, which simulated the gravity-dominated migration of a buoyant fluid using a capillary percolation method. The basin model achieved an accurate match to the observed CO$_2$ plume distribution. This suggests that simple Darcy-based reservoir simulation forecasts are misleading. The basin modelling insights allowed us to revisit the reservoir simulations, and, focusing on benchmark models of the uppermost layers, approximate the gravity-dominated regime of percolating flow. A pressure-compensated black oil reservoir simulation accurately matches the distribution and dynamics of the uppermost layers. The reservoir simulations also indicate that dissolution of CO$_2$ will contribute significantly to storage within decades. While both approaches have their limitations, a combination of basin modelling and reservoir simulation provide perspectives that illuminate the dominant flow physics processes within the storage site, implying that the plume is in a state of dynamic equilibrium and likely to stabilize within years of the injection ending. Two challenges remain for the benchmark reservoir simulations: (A) how to represent the trapping and breaching behaviour of thin shale barriers for percolating CO$_2$ within a storage formation; and (B) how to address pressure field artifacts in larger regional Darcy flow models of CO$_2$ storage.

A pioneering project

The Sleipner carbon capture and storage project has demonstrated the technical feasibility of storing CO$_2$ in geological formations since 1996. To date, over 15 Mt of CO$_2$ has been injected into the Utsira Formation, a sandstone aquifer, 1 km beneath the seabed of the Central North Sea. Sleipner also happens to be one of the most remarkable fluid flow experiments of our time. The storage site has been monitored with geophysical surveys approximately every two years, building up a detailed image of the CO$_2$ plume distribution and dynamics within the storage site. The plume is evidently layered and asymmetric, with the uppermost CO$_2$ layers closely conforming to the mapped topography of the caprock and underlying thick shale, in a similar manner to the flat oil-water contacts of many hydrocarbon fields (Figure 1); the deeper plume has a similar spatial distribution, forming a tight vertical stack of thin asymmetric CO$_2$ layers which are apparently trapping beneath mudstone barriers within the Utsira Formation (Cavanagh and Haszeldine, 2014). This paper addresses the modelling challenge of simulating the layered CO$_2$ plume, and the insights gained into plume dynamics from applying both basin modelling and reservoir simulation approaches to matching the observed distribution.

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The observed plume distribution

Early monitoring of the site showed that the plume had ascended more than 200 m vertically from the injection point (1012 mbsl) to the caprock from 1996 to 1999 (Arts et al., 2004). The plume had encountered and breached a series of thin shale barriers within the storage site, forming nine vertically stacked CO$_2$ layers, each approximately 10-20 m thick, and extending laterally for a few hundred meters (Figure 2). Each stacked layer has a pronounced north-south elongation, which is assumed to be the result of CO$_2$ ponding in subtle topographic traps immediately beneath the thin intraformational shale barriers that are observed in the Utsira Formation from adjacent well logs. Most of the barriers are too thin to be resolved seismically (Gregersen and Johannessen, 2001; Zweigel et al., 2004). However, the uppermost barrier is resolved as a 6 m thick shale, and the topographic trapping is locally mapped from the baseline 1994 seismic survey, along with the trap topography of the overlying caprock seal (Figure 1).

A paradigm shift from viscous to percolating flow models

The frequent seismic and gravimetric surveying of the plume make the Sleipner CO$_2$ plume an ideal candidate for numerical flow modelling studies. Early attempts with conventional Darcy flow simulators failed to match the observed distribution of CO$_2$ (Hellevang, 2006; Chadwick et al., 2006; Hermanrud et al., 2009). The flow physics assumed in such models requires viscous flow via a series of aligned holes in the shale barriers, and favors conceptual models with discrete vertical pathways such as chimneys, sand injectites, and subsurface faults. However, the estimated CO$_2$ density from gravi-
metric monitoring (Alnes et al., 2011) and lateral distribution of the layers (Bickle et al., 2007; Boait et al., 2012) are inherently at odds with the simulated pressure gradient required to match the vertical breakthrough rate via viscous flow along such pathways (Cavanagh and Haszeldine, 2014). The distribution of the CO$_2$ layers appears to be a gravity-controlled migration and trapping of buoyant fluid beneath the barriers under near-hydrostatic pressure conditions, thus conforming to the caprock and shale topography by back-filling small trap structures. This results in a near-flat fluid contact that is similar in fashion to regional hydrocarbon migration and percolating trap charge in petroleum systems (Cavanagh, 2013). Hydrocarbon migration is known to percolate into trap structures at pressures close to ambient hydrostatic conditions, and requires a paradigm shift in numerical simulation (Carruthers, 2003). The boundary condition for the cessation of viscous Darcy flow and onset of percolating capillary flow is defined by $Ca$, the capillary number. This is simply a dimensionless ratio of the viscous force to the interfacial tension that favours a cold plume interpretation, i.e. close to the ambient pressure and temperature conditions of the reservoir (Figure 3).

**Mass balance**

The percolation flow model not only provides a good spatial match, but also appears to suggest a reasonable mass balance for the plume: the simulated fluid distribution under ambient hydrostatic pressure and temperature conditions accounts for the entire injected mass of CO$_2$. However, confidence in the accuracy of the mass balance is undermined by uncertainty in three poorly constrained parameters: layer thickness, CO$_2$ density, and gas saturation (Cavanagh and Haszeldine, 2014). As Figure 3 demonstrates, for the top layer alone, reasonable variations in these three parameters result in widely varying estimates of mass. Microgravity surveying suggests an average plume density of 675±20 kg/m$^3$ (Alnes et al., 2011), which favours a cold plume interpretation.

<table>
<thead>
<tr>
<th>Plume layer</th>
<th>Units</th>
<th>L1</th>
<th>L2</th>
<th>L3</th>
<th>L4</th>
<th>L5</th>
<th>L6</th>
<th>L7</th>
<th>L8</th>
<th>L9</th>
<th>M/S</th>
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<tr>
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<td>905</td>
<td>890</td>
<td>875</td>
<td>860</td>
<td>845</td>
<td>825</td>
<td>795</td>
<td>–</td>
</tr>
<tr>
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<td>926</td>
<td>909</td>
<td>895</td>
<td>880</td>
<td>866</td>
<td>849</td>
<td>832</td>
<td>801</td>
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<tr>
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<td>12</td>
<td>9</td>
<td>9.5</td>
<td>13</td>
<td>10.5</td>
<td>10</td>
<td>14.5</td>
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<td>11</td>
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<tr>
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<td>9.20</td>
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<td>37.7</td>
<td>37.3</td>
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<td>35.9</td>
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<tr>
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<td>606</td>
<td>602</td>
<td>597</td>
<td>589</td>
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<td>571</td>
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<td>49</td>
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<td>56</td>
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<td>0.3</td>
<td>0.3</td>
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<td>0.2</td>
<td>0.1</td>
<td>0.1</td>
<td>0.2</td>
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<tr>
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<td>2.2</td>
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<td>2.7</td>
<td>1.9</td>
<td>2.3</td>
<td>2.4</td>
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<td>2.0</td>
<td>2.3</td>
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</table>

*Table 1* An estimated mass balance for Sleipner (5 Mt, 2002), calculated from the modelled CO$_2$ volume and density (based on ambient pressure and temperature at layer mean depth). Volume is critically sensitive to CO$_2$ layer thickness and gas density. This model assumes a mid-range temperature profile. Warmer models require slightly thicker CO$_2$ layers to account for a mass balance. Colder models require slightly thinner CO$_2$ layers. Threshold pressure, permeability, and fracture estimates are dependent on layer thickness and CO$_2$ density. Final column, M/S: mean (thickness, pressure, permeability, fracture width) or sum (mass balance).
However, CO$_2$ injection at Sleipner is not considered to be a likely cause of this fracturing, as the buoyant pressure at the top of each CO$_2$ layer is very much less than that required to initiate fractures. We suggest fracture re-activation.

It is proposed that the micro-fracturing occurred long before CO$_2$ injection commenced, as a result of pore pressure fluctuations associated with the rapid melting of thick ice sheets during multiple episodes of deglaciation in the region over the last million years (Cavanagh and Haszeldine, 2014). The overlying Nordland Group shales of the caprock may have also fractured during deglaciation. However, it is also noted that there is no evidence of CO$_2$ leaking, possibly as a result of a different caprock response for CO$_2$ retention relative to the thin shale barriers. It is inferred that fracture networks within the much thicker caprock are probably only proximal to the formation, and have a limited connectivity, preventing vertical migration through the overburden.

**Sleipner Benchmark**
The basin modelling approach provides a reasonable plume match, and raises a significant challenge to conventional reservoir simulations of CO$_2$ storage predicated on Darcy’s law, i.e. viscous flow under the influence of a pressure gradient in a continuum is a poor approximation of expected CO$_2$ spatial distributions in storage formations. The migration model also highlighted key uncertainties related to mass estimation for CO$_2$ storage sites in general. More significantly, the migration of buoyant fluids at near-hydrostatic conditions implies that

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**Figure 3** Mass balance uncertainty related to plume density and layer thickness assumptions for the uppermost layer: (a) plume density variations assuming linear geothermal gradients and the common range of uncertainty associated with the plume temperature profile, (b) uppermost layer thickness versus mass for the uppermost CO$_2$ layer, and related mass-balance estimates for the whole plume circa 2002 (equivalent to 5 Mt injected). The sensitivity of mass estimate for a single layer with respect to layer thickness is apparent (orange curves). A 10 m thick layer shows a mass variation of ±40% (80–200 kt), for a 35°C scenario, and a thickness uncertainty of ±4 m. As the trap fills, the volume and related mass increases rapidly. For gas layers with a fixed aerial footprint but uncertain thickness, it can be shown that the uncertainty in volume is equivalent to the error on thickness. Compounding this with density uncertainty, the solution space for a 5 Mt mass balance (gray trapezoid) varies from 50% (thin, warm layers) to 160% (thick, cool layers). Modified from Cavanagh and Haszeldine (2014).

**Figure 4** The Sleipner Benchmark, viewed from the southeast (3x6 km; 780–880 mbsl); Mesh count: 550,000 cells (50:50:0.5 meters). The reservoir-scale model is constructed from detailed topographic maps of the caprock and thick shale; the remaining surfaces are layer cake.
Reservoir simulation

Initial benchmark results (Singh et al., 2010; Nilsen et al., 2011) tested the efficacy of vertical equilibrium approaches commonly used in reservoir simulations of gas segregation, and indicated that the best match is derived from a black oil model (Figure 5), but only when adapted to approximate the near-equilibrium pressure conditions of gravity-segregated flow (Cavanagh, 2013). The principal adaptations are open boundary conditions on the lateral edges of the model, and a long compensation period for pressure dissipation from the model, as discussed below. The relative permeability for gas and water also applied a vertical equilibrium scheme to promote gravity segregation (Singh et al., 2010); however this had little effect without pressure dissipation (Cavanagh, 2013). The model outcomes are
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Figure 7 (a) a conceptual figure of Darcy-mediated viscous flow for the upper two layers; (b) the corresponding conceptual figure for capillary-mediated gravity-dominated flow; (c) the new Sleipner Benchmark in cross-section, with the Sand Wedge separated from the underlying Utsira Formation by a thick shale. A successful match for the observed distribution of CO$_2$ for layers 8 and 9 from 1999-2008 is the new challenge.

interesting from a flow-dynamics perspective: the gas-water contact is flat, representing a back-filling trap under hydrostatic conditions (Figure 5, right cross-section). The uncompensated model is cone-shaped (Figure 5, left cross-section).

The topographically-sensitive result is an expression of the near-equilibrium condition for a trapped buoyant fluid, and indicative of gravity-segregated flow. The black oil simulations are initially far from equilibrium, displaying a characteristic of CO$_2$ storage models: coning of the injected fluid away from the injection location (Singh et al., 2010; Cavanagh, 2013). This is a common feature of all Darcy flow simulations for CO$_2$ injection into saline formations, and speaks to the underlying dependence on permeability and viscosity-mediated flow in the presence of a non-hydrostatic pressure gradient (Cavanagh, 2013). However, as the pressure field decays, the redistribution results in an excellent match (Figure 5). Given the weak pressure field on dissipation, and the governing equation dependence on viscous flow, the simulated compensation is slow. For example, the Figure 5 simulation match for 2008 occurs approximately 100 years after injection began, and 90 years after injection ceased, circa 2098. This long compensation period allows the simulation to approach equilibrium.

The outcome is a significant improvement on the initial black oil simulation output and provides a methodology for calibrating the model to observations: the initial pressure field, i.e. the transient increase in pressure due to injection, needs to be compensated for by running the model forward until the overpressure has dissipated and the plume has reached near-stasis. For the benchmark simulation, a compensation period of several decades is necessary. This strongly favors a gravity-segregated/capillary-dominated interpretation of the plume behaviour at a relatively short distance from the injection location.

The simulation also suggests a significant local dissolution effect within decades (Figure 6). The black oil simulator handles CO$_2$ as ‘gas’ and the formation brine as ‘oil’, allowing for the miscibility of gas in oil in the reservoir simulation to act as a proxy for CO$_2$ dissolution (Duan and Sun, 2003; Hassanzadeh et al., 2008). The model dissolution is in agreement with analytical approximations (Alnes et al., 2011), and shows an interesting long-term stagnation and suppression of dissolution in the thin sand wedge beneath the caprock, as seen in cross-section (Figure 5).

Buoyant capillarity versus viscous flow
Both aspects (buoyant capillary flow and long-term dissolution) are further examined in the new benchmark, with the additional challenge of understanding CO$_2$ migration between layers (Figure 7). A range of scenarios are possible for flow communication across the thick shale barrier, which provides an exemplar for the thinner barriers that lie below. A sensitivity analysis of these scenarios for different methodologies (black oil and compositional reservoir simulation, invasion percolation basin modelling) is expected to provide insights into vertical flow across low permeability baffles and barriers within storage reservoirs in general. The new Sleipner Benchmark will also help to further develop ideas relating to the apparent need for pressure compensation in Darcy flow reservoir simulations. This has significant implications for all CO$_2$ storage models. Uncalibrated reservoir simulations are likely to (a) over-predict pressure increases within the storage site and beyond, i.e. forward models of regional pressure change; (b) poorly predict the plume spatial distribution; and (c) underestimate the rapid stabilisation of plume dynamics after injection. The first two consequences will be detectable in model deviation from observations based on monitoring data during the lifetime of a project. The latter consequence will be significant when anticipating long-term plume behaviour and the transfer of post-operational responsibility, especially where predicated on uncalibrated forward modelling of a storage site prior to injection.

Conclusion
Two very different flow modelling approaches have been applied to the Sleipner CO$_2$ storage site. The basin model
assumes 'drainage' migration of a buoyant non-wetting fluid under the influence of gravity, displacing the in situ brine into the surrounding porous media. The model implies that the injected CO$_2$ percolates vertically through the reservoir, and is trapped as layers beneath thin shale barriers which breach when the buoyancy pressure of the layer exceeds the capillary threshold pressure of the shale. This results in the vertical stack of thin CO$_2$ layers that characterize the Sleipner plume. Furthermore, the CO$_2$ is migrating through a hydrostatic environment and backfills beneath the shale barriers and overlying caprock under near-hydrostatic conditions. The basin model indicates that the barriers have a characteristic threshold pressure of around 50 kPa, equivalent to a permeability of 0.2 mD, suggesting hydraulic microfracturing prior to injection. We propose rapid ice sheet unloading as a causal mechanism.

These insights from a matched basin model of the Sleipner CO$_2$ plume led to the release of the Sleipner Benchmark model for detailed reservoir simulation. The aim of the benchmark model was to understand the plume distribution beneath the caprock, in order to accurately forecast the plume behaviour beyond the injection period. It was found that a black oil simulation, when adapted to compensate for a pressure artifact in the model associated with injection, accurately matched the evolution of the uppermost layer. The simulation results suggest a dynamic equilibrium for the current plume distribution.

In summary, Darcy flow simulations of CO$_2$ storage typically manifest roughly cone-shaped distributions, with curved fluid contacts, and a plume footprint that does not conform to the detailed topography of intra-formational barriers and caprock seal. Similar outcomes are often observed in simple bench-top laboratory experiments. These attributes attest to the underlying physics of two-phase viscous flow, primarily driven by the injection pressure at the well. We propose that the apparent flat gas-water contacts at Sleipner, and observed sensitivity to local trap topography, are more accurately described, to a first approximation, by a percolating flow model. However, when the decay of injection pressure is included, reservoir simulations provide a better match, suggesting that the plume distribution is dynamic, and close to equilibrium, i.e. subtly different from the static equilibrium outcome of a percolation model. Both the reservoir simulation and basin modelling results imply that the plume is likely to stabilize within years of the injection ending. An advantage of the adapted reservoir simulations is their ability to address CO$_2$ dissolution. The outcomes indicate that dissolution will make a significant contribution to storage within decades. A significant challenge remains for the benchmark reservoir simulations: how to represent the trapping and breaching behaviour of thin shale barriers and percolating CO$_2$ within a storage formation. The stratigraphic alternation of high and low permeability rocks is commonly found within storage formations; however, the baffled nature of stacked CO$_2$ layering is inherently challenging for reservoir simulations. The new Sleipner Benchmark will also allow modellers to address pressure distributions in larger-scale models, and further test the validity of anticipated subsurface pressure changes based on flow simulations.

In conclusion, the current benchmark reservoir simulation and basin modelling results clearly indicate that buoyant capillarity is the dominant process at Sleipner, as befits the non-wetting drainage physics of CO$_2$ migration. While Darcy’s law may characterize the very-near field of the injection well, the predominant flow physics of the storage formation appears to be best described by migration and invasion percolation. Similar behaviour can be expected in other large high permeability storage formations. A good approximation of this behaviour, in a black oil simulation, may be arrived at by allowing the model pressure to dissipate, and flow to approach its equilibrium position. However, the adaptation of this approach to vertically layered flow across a barrier like the thick shale is inherently challenging, and worthy of a new benchmark problem.

Furthermore, the models suggest that a combination of near-equilibrium conditions in the gravity-segregated layers at the present day, and the subsequent dissolution of these layers over the coming years and decades, significantly lowers the dynamic leakage risk associated with the Sleipner storage site. This is currently perceived to be extremely low, and is likely to further diminish in the immediate post-operational phase. The new Sleipner Benchmark is expected to further challenge our understanding of the detailed intra-formational plume dynamics and provide further insights into CO$_2$ storage.

**Acknowledgements**

The research benefited from discussions with Christopher Neufeld of the Permedia Research Group. We also acknowledge the contribution from our colleagues at the Statoil Research Centre and the University of Edinburgh, and thank Statoil ASA for permission to publish this material. Haszeldine is funded by SCCS, Scottish Funding Council, EPSRC and NERC. We are also grateful to the Norwegian Petroleum Directorate for their open-access data archives.

**References**


