Capillary limited flow behavior of CO$_2$ in target reservoirs in the UK

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Abstract

The flow of supercritical CO$_2$ and brine in the subsurface is predicted to be strongly dependent on both the fluid properties and the heterogeneity of the pore space. However, there are few laboratory studies that characterise the interaction between fluid properties and heterogeneity in real reservoir rocks. We explore the sensitivity of CO$_2$ flow paths and relative permeability to pore space capillary heterogeneity in target CO$_2$ storage reservoirs in the UK and Australia. Samples from potential North Sea and East Irish Sea reservoirs and a current CO$_2$ storage site in Australia are compared. The rock samples are all of high permeability (>500 mD) and porosity (>12%), and are clean and homogeneous sandstones. Relative permeability is found to be highly sensitive to minor heterogeneities in pore structure at reservoir conditions that give rise to a low CO$_2$ viscosity and in particular when the flow is capillary limited, as will be the case for most of the reservoir. We use a simple capillary number in guiding the measurement of relative permeability and residual trapping under viscous and capillary limited conditions. Observations suggest that to fully characterise the behaviour in a reservoir a range of relative permeability curves must be measured which can be applied as the flow of CO$_2$ slows with distance from the near wellbore and flow behaviour changes from viscous-dominated to capillary-dominated. Experiments are performed at 8-20 MPa, 40-90°C and brine molalities of 0 – 5 mol/kg NaCl. Saturation is measured in situ, using a medical x-ray CT scanner, which allows the fluid arrangement to be observed at a resolution of 0.25x0.25x1 mm.

Keywords: Relative permeability; Residual trapping, CO$_2$ storage in the United Kingdom.

1. Introduction

Relative permeability curves are a fundamental input to reservoir models, which allow predictions to be made about the flow behaviour of CO$_2$ and the storage capacity of a particular reservoir. There have been many suggestions of potential storage sites around the UK but there is only one CO$_2$-brine relative permeability curve available in the literature. Smith et al. (2012) [1] provide an example of a relative permeability measurement used for modelling CO$_2$ storage capacity of a hypothetical site in the Southern North Sea for the 2008 CASSEM (CO$_2$ Aquifer Storage Site Evaluation and Monitoring) project to assess the CCS in the UK. The measurement was made on a sample of Sherwood Sandstone from the Cleethorpes-1 well but no detail as to the specific experimental procedure employed in making the measurement or the sample characteristics or fluid properties are provided. Due to the lack of relevant relative permeability data, most modelling studies make use of CO$_2$-brine relative permeability curves measured on arbitrary rock samples [2]. However, a recent parameter sensitivity study finds the major controlling parameter on CO$_2$ injectivity is the endpoint $k_{r CO2}$ [3] which highlights that accurate, site specific core- flood measurements are a basic requirement necessary to have confidence in the plume migration and storage estimates provided by reservoir modelling.

The objective of this study is to measure drainage and imbibition relative permeability for target or actual CO$_2$ storage sites in the UK and globally. We use the steady state methodology at two flow rates for each sample – in the viscous and capillary limits, respectively [4] - in order to fully characterise the CO$_2$-brine flow behaviour from near wellbore to far field.
2. Experimental conditions and procedures

Three samples are selected from reservoir formations for potential CO$_2$ storage sites around the UK and one sample from a current pilot CO$_2$ storage site, the CO2CRC Otway Project, in Australia (Figure 1 and Table 1).

![Map showing major onshore and offshore regional saline sandstone aquifers in the UK and the Otway Sedimentary Basin](image1)

Figure 1: Major onshore and offshore regional saline sandstone aquifers in the UK [5] including the Bunter Sandstone, Leman Sandstone & Sherwood Sandstone Group, Captain Sandstone, Ormskirk Sandstone [6] and Utsira Sandstone [7]. The Otway Sedimentary Basin, target of Australia’s Otway CO$_2$ pilot site, is also shown. Locations of core samples are shown by black dots and are listed in Table 1.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Storage Location</th>
<th>Well Location</th>
<th>Well</th>
<th>Source</th>
<th>Sample depth [m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bunter</td>
<td>Southern North Sea</td>
<td>onshore geothermal borehole</td>
<td>Cleethorpes-1</td>
<td>BGS</td>
<td>1312.7-1316.1</td>
</tr>
<tr>
<td>Ormskirk</td>
<td>East Irish Sea</td>
<td>depleted gas field</td>
<td>Block 110/2a</td>
<td>Centrica</td>
<td>1247.9-1248.1</td>
</tr>
<tr>
<td>Captain</td>
<td>North Sea</td>
<td>onshore hydrocarbon borehole</td>
<td>14/29a-3</td>
<td>BGS</td>
<td>2997.6-3005.1</td>
</tr>
<tr>
<td>Paaratte</td>
<td>Otway Project, Australia</td>
<td>onshore CO$_2$ storage site</td>
<td>CRC-2</td>
<td>CSIRO</td>
<td>1498.5-1498.8</td>
</tr>
</tbody>
</table>

![Porosity and capillary pressure characteristic curves](image2)

Figure 2 shows the porosity measured along the lengths of the core and the capillary pressure characteristic curves as measured by mercury porosimetry.

![Graphs showing porosity and capillary pressure](image3)

Figure 2. Porosity (left) and capillary pressure characteristic curves (right) of the samples used in this study.
Table 2: Rock sample characteristics

<table>
<thead>
<tr>
<th>Exp</th>
<th>Rock</th>
<th>K_{abs}</th>
<th>L</th>
<th>P_{entry}</th>
<th>Pore throat diameter</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>[D]</td>
<td>[m]</td>
<td>[Pa]</td>
<td>[m]</td>
</tr>
<tr>
<td>19-24, 37-8</td>
<td>Bunter</td>
<td>0.260</td>
<td>0.012</td>
<td>2.201</td>
<td>1</td>
</tr>
<tr>
<td>25-28, 39-40</td>
<td>Ormskirk</td>
<td>0.271</td>
<td>0.014</td>
<td>12.143</td>
<td>0.3787</td>
</tr>
<tr>
<td>29-32, 41</td>
<td>Captain</td>
<td>0.267</td>
<td>0.007</td>
<td>1.145</td>
<td>0.098</td>
</tr>
<tr>
<td>33-36, 42-43</td>
<td>Paaratte</td>
<td>0.280</td>
<td>0.003</td>
<td>2.328</td>
<td>0.575</td>
</tr>
</tbody>
</table>

Drainage and imbibition relative permeability curves between CO₂ and brine were measured under capillary and viscous limited conditions and residual trapping experiments were per-formed to characterise the flow and trapping behaviour for four reservoir sandstones, using the methods described in [4].

Pressure, temperature and salinity conditions were chosen so as to be representative of likely injection sites in each formation, either by using site specific conditions or regional averages for the formation (Table 2). Pressure and temperature for the Bunter core were taken from the Hewett field and a regional average salinity for Bunter Formation reservoir brines in the Southern North Sea was used [8]; the conditions of the South and North Morecambe fields were used for the Ormskirk core [9]; pressure and temperature for the Goldeneye field and regional Captain Sandstone brine salinities were used for the Captain core [10]; and conditions for the Paaratte core were taken from the Otway storage site [11].

Two sets of drainage and imbibition relative permeability core-floods were performed on each core; one at high flow rate, viscous limited conditions and the other at low flow rate, capillary limited conditions. The particular flow rates selected depended on the heterogeneity in the rock core and the absolute permeability. As all the cores had relatively little observable heterogeneity in porosity and high absolute permeability (> 1 D), a flow rate of 20 ml min⁻¹ was used for all the viscous limited experiments. However, in practice, there will still be some control on the fluid distributions exerted by regions of high capillarity. The capillary limited experiments were performed at flow rates of 0.2 - 4 ml min⁻¹.

Table 2: Experimental conditions and fluid parameters for CO₂-brine core-floods.

<table>
<thead>
<tr>
<th>Experiment</th>
<th>Rock</th>
<th>T [°C]</th>
<th>P [MPa]</th>
<th>S [mol kg⁻¹]</th>
<th>IFT [mN m⁻¹]</th>
<th>e_{nw} [Pa s]</th>
<th>d_w [Pa s]</th>
<th>c_{nw} [kg/m⁴]</th>
<th>e_w [kg/m⁴]</th>
</tr>
</thead>
<tbody>
<tr>
<td>19-24, 37-8</td>
<td>Bunter</td>
<td>53</td>
<td>13.1</td>
<td>1.0</td>
<td>34.7</td>
<td>45.9</td>
<td>581.6</td>
<td>604.4</td>
<td>1021.9</td>
</tr>
<tr>
<td>25-28, 39-40</td>
<td>Ormskirk</td>
<td>33</td>
<td>12.7</td>
<td>4.3</td>
<td>38.7</td>
<td>70.4</td>
<td>1198.0</td>
<td>797.6</td>
<td>1118.7</td>
</tr>
<tr>
<td>29-32, 41</td>
<td>Captain</td>
<td>80</td>
<td>18</td>
<td>1.0</td>
<td>32.9</td>
<td>41.1</td>
<td>403.8</td>
<td>540.1</td>
<td>1003.4</td>
</tr>
<tr>
<td>33-36, 42-43</td>
<td>Paaratte</td>
<td>63</td>
<td>12.5</td>
<td>0.1</td>
<td>34.2</td>
<td>32.4</td>
<td>454.4</td>
<td>437.7</td>
<td>989.4</td>
</tr>
</tbody>
</table>

a NaCl brine, b [9, 203], c [6], d [2], e [7].

3. Results and discussion

Two sets of viscous limited drainage and imbibition relative permeability curves and one capillary limited set are shown for the Bunter sandstone sample in Figure 3. Saturation maps at the low and high flow rates are provided in Figure 4. The k_{e,CO₂} and k_{r,CO₂} at a given saturation are higher when measured under viscous limited conditions (Experiments 19 and 21) rather than capillary limited conditions (Experiment 23). This is opposite to what has been observed previously in a Bentheimer sandstone [4] with layering parallel to the flow axis, where the relative permeability was higher under capillary limited conditions. It is likely that in this case that the oblique angle of the layering in the core relative to flow causes this result.

Under high flow rates, the viscous pressure drop exerted on the core is greater, and thus more of the pore space can be accessed. However, the orientation of heterogeneity with respect to the fluid flow direction is also important. In the experiments with the Bentheimer core, the layering was parallel to the flow direction. CO₂ only swept through one half of the core under low flow rate, capillary limited conditions, bypassing half of the core, and therefore resulting in a higher relative permeability. However, in the Bunter core, the layering is oblique to the flow direction, creating a barrier to the flow of CO₂, which is overcome under high flow rate, viscous limited conditions.

The capillary limited drainage curves (Experiment 23) are characteristic of a water wet system, i.e., a rapid decrease in k_{r,CO₂} and corresponding increase in k_{e,CO₂} with decreasing S_w and the cross point of the curves (k_{e,CO₂} = k_{r,CO₂}) occurs at S_w 0.6 (Figure 5.5). The endpoint k_{e,CO₂} is extremely low (10⁻¹⁰) meaning the CO₂ mobility will be very low even at high CO₂ saturations and only low CO₂ injectivity will be achievable. The capillary limited imbibition behaviour
(Experiment 24) is unusual. The $k_{rCO_2}$ is lower for imbibition than for drainage, which is expected as water re-invades the pore space. This causes snap-off in narrow pore throats, leading CO$_2$ to become isolated and immobilised in parts of the pore space. However, the $k_{rw}$ is significantly higher for imbibition than for drainage. If the wetting behaviour stays constant and is strongly water-wetting, there should be negligible hysteresis in $k_{rw}$ between drainage and imbibition. This suggests that there may have been a change in the wetting character of the rock due to the interaction with supercritical CO$_2$. Another possibility for the unusual imbibition behaviour is mineral dissolution affecting the pore space morphology. However, there is no significant change in absolute permeability over the course of performing Experiments 19-24 suggesting this is not the case.

Figure 3: Relative permeability curves for Bunter Sandstone, Experiments 19-24. Initial-residual curve for Bunter Sandstone, Experiments 37-38. White or grey symbols - drainage, black symbols - imbibition, circles - capillary limited, squares & triangles - viscous limited.

Figure 4: Saturation and porosity maps for Bunter Sandstone, Experiments 21-24

The viscous limited drainage curves (Experiments 19 and 21) also indicate a water-wet system. However, the endpoint $k_{rCO_2}$ ($10^{-1}$) is reached early, with little increase in $k_{rCO_2}$ between $S_w = 0.4$ and the irreducible water saturation, $S_{w;irr} = 0.25$. The $k_{rw}$ decreases exponentially with decreasing $S_w$ and the cross point is shifted to lower water saturations ($S_w = 0.5$) compared with the capillary dominated core-floods. There is small shift in the viscous limited drainage $k_{rCO_2}$ curves between Experiments 19 and 21 which is within the error in the saturation measurement. Again, the viscous limited imbibition behaviour (Experiments 20 and 22) is unusual, but it is the behaviour of the $k_{rCO_2}$ curves that are unusual. The $k_{rw}$ behaviour shows a lack of hysteresis typical for strongly water-wet media, with similar relative permeability to brine measured under drainage and imbibition conditions. However, the $k_{rCO_2}$ is slightly higher for imbibition than for drainage, meaning that the CO$_2$ mobility is similar or greater after imbibition. This suggests there
has been little loss in CO₂ connectivity during imbibition.

The saturation maps (Figure 4) show the distribution of CO₂ under capillary limited conditions is strongly controlled by the capillary heterogeneity (approximated by the CT-measured porosity) of the core, with high CO₂ saturations in the thin, high porosity layers, where the strength of cross flow between the layers is strongest. This saturation profile is maintained after imbibition, with the highest residual CO₂ saturation in the thin, high porosity parts of the core. Under viscous limited conditions there is only a minor impact on the CO₂ distribution during drainage and no impact during imbibition, with an even distribution of CO₂ in all parts of the core.

Residual trapping experiments (Experiments 37–38) indicate a range of residually trapped CO₂ saturations from S_{CO₂} = 0.3 – 0.6 for initial CO₂ saturations of S_{CO₂} > 0.8. The trapping is best characterised by a Land coefficient of C = 1.6, which suggests the Bunter Sandstone has favourable trapping characteristics, although less CO₂ can be trapped compared with measurements made on other high permeability sandstones with a similar heterogeneity, such as Berea sandstone.

4. Conclusion

1. There is a high degree of variability in the measured relative permeability and residual trapping characteristics amongst seemingly homogeneous and high permeability sandstones due to the strong dependence of CO₂ flow on the capillary heterogeneity of the pore space. This suggests that even for simple heterogeneous sandstones, the scale at which relative permeability can be measured in the laboratory is smaller than the REV of the heterogeneity. Thus we suggest that core- floods in heterogeneous sandstones can be used to provide a measure of capillary pressure heterogeneity which is then used as an input to core-scale simulations, rather than directly measuring the continuum property on a single core.

2. Heterogeneous cores can be characterised using core- flood experiments if the REV which captures the heterogeneity is smaller than the volume of the core. Then relative permeability can be characterised sufficiently for reservoir modelling by measuring relative permeability under viscous and capillary limited conditions.

3. Low measured endpoint relative permeability to CO₂ is due in part to the limitation of core-scale experiments but also due to the low viscosity of CO₂ and the low pressure drive achievable. This suggests that in the reservoir the injectivity of CO₂ under real reservoir conditions will also be low and saturations close to the irreducible water saturation will not be reached. Consequently, low relative permeability and a very strong dependence on capillary heterogeneity will control the migration of CO₂ throughout the life of a storage project.

4. Classic hysteresis behaviour in the relative permeability to CO₂ is observed in core- floods performed under capillary dominated conditions, where the imbibition relative permeability drops significantly with increasing water saturation. However, a lack of hysteresis in relative permeability to CO₂ in strongly water-wet sandstones in core-floods performed under viscous dominated conditions indicates there is a change in the pore-scale arrangement of CO₂.

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References


