Ewa Knapik*, Damian Janiga*, Paweł Wojnarowski*, Jerzy Stopa*

THE ROLE OF CAPILLARY TRAPPING DURING GEOLOGIC CO$_2$ SEQUESTRATION**

1. INTRODUCTION

CO$_2$ injection to depleted deposits and aquifers is a common method of limiting CO$_2$ content in the atmosphere. Aside from a positive environmental impact, CCS is of great industrial significance when combined with enhanced oil recovery (EOR) methods. Generally speaking, there are four CO$_2$ fixing mechanisms in the porous medium: stratigraphic/structural trapping, dissolution trapping, residual (or capillary) trapping and mineral trapping [1]. Stratigraphic trapping occurs when free gas CO$_2$ migrates towards the top of the formation as a result of the buoyancy force and accumulates there in the form of the gas cap [2]. The cap rock of the structure plays a key role; to maintain storage integrity, injection pressure cannot exceed the fracture pressure. The storage capacity depends on available free pore space, thus it is beneficial to inject to the depleted deposits of hydrocarbons. Additionally, the depleted deposits are well-recognized in terms of petrophysical and geomechanical parameters, thanks to which it is easy to model CO$_2$ migration in the subsurface. CO$_2$ dissolution in the brine leads to the emergence of brine of high density, which sinks in the reservoir in the form of thick and thin fingers. This phenomenon is called dissolution trapping. The dissolution process occurs very slowly, Kampman et al. [3] estimates that the rate of CO$_2$ penetration into static brine is about 25 cm per year. A physical mechanism of the process is based on three phenomena: molecular diffusion of CO$_2$ into brine, dispersion during flow and convection of CO$_2$-saturated (heavier) brine in the formation. CO$_2$ solubility rises with increase of deposit pressure but drops with increase of temperature and brine salinity [4]. Carbonic acid formation results in dissolution of reservoir salts and precipitation of minerals, which leads to a permanent CO$_2$ fixing in the deposit, that is the so-called mineral trapping. Predicting the

* AGH University of Science and Technology, Faculty of Drilling, Oil and Gas, Krakow, Poland
** The research leading to these results has received funding from the Polish-Norwegian Research Programme operated by the National Centre for Research and Development under the Norwegian Financial Mechanism 2009–2014 in the frame of Project Contract No Pol-Nor/235294/99/2014
effective mineral trapping capacity of a reservoir is a complex problem due to the opposite CO\textsubscript{2} – cap rock interactions under geosequestration conditions. Mineral dissolution includes both direct dissolution of carbonates and hydrolysis of feldspars and phyllosilicates and increases permeability which also enhances the trapping process [5]. In contrast, precipitation of carbonate minerals may significantly reduce rock permeability by blockage of small pore throats. The kinetics of these phenomena varies over wide range, from a few weeks for gas adsorption onto the rock matrix to hundreds of years for minerals precipitation. Due to the complexity of the CO\textsubscript{2}-brine-porous medium interactions, it is difficult to identify the dominant mechanism and on this basis forecast for the security of the entire storage. In general, solubility and mineral trapping are considered as long-term processes that ensure the complete and permanent immobilization of CO\textsubscript{2} in the deposit.

Physical properties of the rock mass, in particular the size and distribution of pores and saturation with reservoir fluids play a vital role in the case of capillary trapping. From the point of view of the fluid mechanics, this phenomenon is highly interesting and in the last couple of years a set of studies have been conducted in order to explain it. The results of laboratory tests and a mathematical model for capillary trapping during CO\textsubscript{2} storage have been described below.

2. PORE SCALE PROCESSES UNDERLYING CAPILLARY TRAPPING

For geologic carbon sequestration, two different displacement regimes, namely drainage and imbibition, are observed [7–11]. Drainage refers to the decreasing saturation of a wetting phase. Imbibition occurs when the wetting-phase saturation increases. During the injection period CO\textsubscript{2} displaces the brine from the pore space in a drainage-like process. The only mechanism for drainage stage is a piston-type displacement. However, water is still present in small pores that have not been filled with CO\textsubscript{2} and in the corners of the pore space, with the non-wetting phase initially in the centre. After completion of the injection the gas is displaced by brine and forming a vertical path migrates towards the top of formation due to the buoyant force and the density difference — imbibition phase. System wettability determines fluid distribution on the pore scale [6–7]. Typically brine is a wetting phase for the rock matrix and during displacement gas bubbles (non-wetting phase) are trapped in small clusters of pores as an immobile phase (Fig. 1a). The increase of water pressure causes the water layers to expand and fill the narrower regions, called throats. CO\textsubscript{2} bubbles are pushed out of the narrower regions and trapped in larger pores, which is referred to as snap-off [8]. In the case of rocks which are water-wet (contact angle values measured through the aqueous phase vary from 0\textdegree{} to 90\textdegree{}), the potential flow occurs easier due to minor resistance, and snap-off effect is increased. According to the theory of percolation [8], the biggest pores are first to be filled with water, thus large pores and relatively smaller throats favor trapping. The snap-off mechanism may be reduced or eliminated entirely in intermediate-wet media.

For these two displacement regimes the hysteresis between the receding ($Q_r$, in drainage) and advancing contact angle ($Q_a$, in imbibition) occurs. The relative permeability and capillary pressures depend on the saturation path and the saturation history [9]. Oak’s studies [18] show that in the case of the water-wet porous medium for the wetting phase there is no relative permeability hysteresis or this effect is extremely low.
In turn, for the non-wetting phase, i.e. the CO₂ hysteresis effect is conspicuous. The trapped (residual) gas saturation applies to the CO₂ saturation value at the end of imbibition phase and determines the amount of permanently fixed CO₂. Trapped gas saturation, $S_{gt}$, can be calculated in accordance with the Land’s equation [9]:

$$ S_{gt} = \frac{S_{gt}}{1 + C \cdot S_{gi}} $$

(1)

where $S_{gi}$ is the initial gas saturation (actual at flow reversal). The Land trapping coefficient, $C$, is defined as:

$$ C = \frac{1}{S_{g, max}} - \frac{1}{S_{g, max}} $$

(2)

where $S_{g, max}$ is the highest gas saturation at the drainage stage possible to achieve, and $S_{g, max}$ is the maximum trapped saturation, associated with the bounding imbibition curve (see Fig. 1b). Basically, the higher the CO₂ saturation, the higher the residual saturation at the end of the drainage period after water flooding, the relationship between the initial and residual non-wetting saturations is known as the IR (for the initial-residual) curve. The Brooks–Corey model is often used to describe the relative permeability for a two-phase system [19]:

$$ k_{rw} = \left( S_w^* \right)^{\frac{2+3\lambda}{\lambda}} $$

(3)

$$ k_{rg} = \left( 1 - S_w^* \right)^2 \left( 1 - \left( S_w^* \right)^{\frac{2+3\lambda}{\lambda}} \right) $$

(4)
\[(S'_w) = \frac{S_w - S_{wir}}{1 - S_{wir}} \tag{5}\]

where: \(k_r w\) and \(k_r g\) are relative permeability for water and gas, respectively; \(S_w\) – current saturation with water, \(S_{wir}\) residual saturation with water, \(\lambda\) is the pore size distribution index.

Bennion and Bachu [20] indicated the relative permeability curves for different rock samples from the Wabamun and Zama areas, Alberta, Canada.

**Table 1**
The in-situ conditions and rock characteristics for relative permeability measurements [20]

<table>
<thead>
<tr>
<th>Rock sample</th>
<th>Lithology</th>
<th>Porosity [%]</th>
<th>(S_w) (trapped gas)</th>
<th>Corey-model parameter for brine</th>
<th>Corey-model parameter for CO(_2)</th>
<th>P [MPa]</th>
<th>T [°C]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Viking</td>
<td>sandstone</td>
<td>19.5</td>
<td>0.297</td>
<td>2.1</td>
<td>4.0</td>
<td>8.6</td>
<td>35</td>
</tr>
<tr>
<td>Calmar</td>
<td>shale</td>
<td>3.9</td>
<td>0.256</td>
<td>4.0</td>
<td>2.2</td>
<td>12.25</td>
<td>43</td>
</tr>
<tr>
<td>Nisku</td>
<td>carbonate</td>
<td>11.4</td>
<td>0.218</td>
<td>2.1</td>
<td>4.4</td>
<td>17.4</td>
<td>56</td>
</tr>
<tr>
<td>Muskeg</td>
<td>anhydrite</td>
<td>1.2</td>
<td>0.18</td>
<td>n/a</td>
<td>n/a</td>
<td>15</td>
<td>71</td>
</tr>
</tbody>
</table>

![Fig. 2. Relative permeability curves for CO\(_2\)/brine systems for in-situ conditions for the following core samples: a) Viking; b) Calmar; c) Nisku; d) Muskeg [20]](image-url)
High permeability assures easy CO$_2$ flow from the wells inside the formation (possible low bottom pressure) on the one hand, and facilitates displacement of CO$_2$ by water at the imbibition phase on the other. On the contrary, low vertical permeability hinders CO$_2$ escape towards the top of the structure as a result of the buoyancy force. The type of rock has a considerable influence on reservoir storage capacity. Due to their low porosity and extremely low permeability, anhydrites and shale have low critical CO$_2$ saturation at the drainage phase, but since water displacement is hindered, the final residual saturation remains at the level of 20%. It is thought that carbonates can be a promising storage area of CO$_2$ because it is possible to precipitate CO$_2$ in the form of minerals, but a system of double porosity (cracks and pores) can pose a hazard of uncontrolled leak.

Apart from the relative permeability hysteresis, one observes that the capillary pressure–saturation relationships also exhibit marked hysteresis effects. Yet, from the point of view of computer modeling of CO$_2$ migration in the reservoir, the capillary effects can be neglected because as a rule the characteristic capillary length is much smaller than the grid resolution [9].

The storage capacity of the porous medium resulting from the capillary trapping phenomenon, $C_{\text{trap}}$, depends on the residual CO$_2$ saturation and porosity, in accordance with the following equation:

$$C_{\text{trap}} = \varphi \cdot S_{gt}$$  \hspace{1cm} (6)

where:

- \(\varphi\) – porosity,
- \(S_{gt}\) – trapped CO$_2$ saturation.

Iglauer et al. [10] studies suggest that the maximum storage capacity is achieved when the deposit porosity equals 20–30%. The lower the porosity, the smaller the geometric space for fluids. High-porosity, unconsolidated media exhibit better connected pore spaces giving lower residual saturations. Pore-size distribution affects CO$_2$ relative permeability, microporosity enhances a more uniform displacement character.
3. INFLUENCE OF OPERATING PARAMETERS ON CAPILLARY TRAPPING EFFECTIVENESS

Numerous parameters determine migration and CO₂ retention in the reservoir, including capillary, viscous and gravitational forces. Dependencies between them are described by dimensionless numbers specified below [11]:

Capillary number, Ca, describes the relation of viscous to capillary forces:

\[
Ca = \frac{\mu_i \cdot v}{\sigma \cdot \cos \Theta}
\]  

(7)

where:

\( \mu \) – viscosity of the invading fluid,
\( v \) – superficial velocity of the invading fluid,
\( \sigma \) – interfacial tension between the two fluids,
\( \Theta \) – contact angle.

The viscosity ratio, \( M \), is used to compare the viscosities of the invading and displaced fluids, and defined as:

\[
M = \frac{\mu_i}{\mu_d}
\]  

(8)

where \( \mu_i \) and \( \mu_d \) are the viscosities of the invading and displaced fluids, respectively.

The effects of gravity on the system can be described by the Bond number (Bo), which is typically defined as [6]:

\[
Bo = \frac{\text{gravity forces}}{\text{capillary forces}} = \frac{\Delta \rho \cdot g \cdot d^2}{\sigma \cdot \cos \Theta}
\]  

(9)

where \( \Delta \rho \) is the density difference between the invading and displaced fluids, \( g \) is the gravitational constant, \( d \) is a representative length scale (the median bead or grain diameter).

The three distinct flow regimes could be identified: viscous fingering, capillary fingering, and stable displacement [19–21]. The residual non-wetting phase saturation depends on the capillary number during the imbibition stage. For very slow (quasi-static) displacements (that is low Ca values) capillary forces play a significant role in the system, they prevent the non-wetting phase from penetrating a porous medium. CO₂ can only enter a pore throat when the pressure in the non-wetting fluid exceeds the pressure in the wetting fluid by a value of capillary pressure. The displacement depends on the pore size distribution. The observed structures at the pore-network level consist of a rough and wide front which penetrate the largest pore throat accessible. Cense and Berg [15] indicated that a capillary dominated behaviour occurs at capillary numbers that are typically of the order of \( 10^{-6} \) to \( 10^{-4} \). At higher capillary numbers a viscous fingering regime is observed. A rapid breakthrough of the non-wetting fluid into the wetting fluid occurs and the front morphology is dictated by the viscosity ratio [11–14]. During imbibitions, brine is more viscous than the displaced CO₂ (\( M > 1 \)) and the stable displacement is observed. At drainage stage the invading fluid is less viscous (\( M < 1 \)) and the front is destabilized. Long and thin viscosity fingers are formed, which results in a higher residual saturation of CO₂.
For the 3D system the displacement front behavior may be deduced using the generalized Bond number ($Bo^* = Ca - Bo$) [16]. For values of $Bo^* > 0$ the displacement front due to gravity is observed to evolve from narrow branched fingers to a nearly flat geometry. At $Bo^*$ values in the range of $0 < Bo^* < -0.05$ capillary forces remain dominant and the front exhibits capillary fingering. For $Bo^*$ lower than $-0.08$ viscous forces grow and gravity is not sufficient to prevent the viscous fingering.

In accordance with the definition of $Ca$ and $Bo$ numbers, deposit fluid properties have a significant impact on residual CO$_2$ saturation. CO$_2$-brine interfacial tension (IFT) depends on aquifer pressure, temperature and water salinity due to CO$_2$ solubility effects. Bachu and Bennion [17] found that IFT decreases for relatively low pressures ($<10$ MPa) as pressure increases, and displays an asymptotic behavior towards a constant value for higher pressures. The studies [17] have showed that increasing IFT values increase residual CO$_2$ saturations in consolidated sandstone samples collected from a site in Alberta, Canada. As the difference in density between CO$_2$ and brine increases, the non-wetting fluid is more likely to be mobilized upward, which leads to decreasing residual CO$_2$ saturation. The impact of viscosity on fluid flow in the deposit is defined by mobility ratio.

4. RESERVOIR MODEL

The simulation of CO$_2$ injection were carried out using a realistic model of geologic formation. The simulation objective is to illustrate the long-term impact of capillary trapping on storage capability. The formation is initially filled only with brine (aquifer). The reservoir model contains eight layers. The first four are a sand layers, the next one is a shale and layers six to eight represent the second sand complex. Reservoir parameters is shown in Table 2. The reservoir model is shown in Figure 5. The modeled formation is a typical anticline which from the point of view of gas injection is undesirable because a gas cap may be easily formed. The model has five injection wells open to the reservoir. The injection wells are group rate controlled and operated with a constrain in the maximum bottom hole pressure of 200 bar. The relative permeabilities were taken for Viking reservoir after reference [20] as may be seen in Figure 2. The relative permeability hysteresis in Eclipse 300 was modeled by the
Killough method [22]. In this method, the gas relative permeability along a scanning curve is computed as [9]:

\[
k^i_{rg}(S_g) = k^i_{rg}(S^*_g) \frac{k^{d*}_{rg}(S_{gr}^*)}{k^{d*}_{rg}(S_{gr,max}^*)}
\]

(10)

\[
S^*_g = S_{gr,max}^* + \frac{(S_g - S_{gr}^*)(S_{gr,max}^* - S_{gr}^*)}{S_{gr}^* - S_{gr}^*}
\]

(11)

where \(k^d_{rg}\) and \(k^{i*}_{rg}\) represent the bounding drainage and imbibition curves, respectively.

Reservoir conditions ensure that the CO\(_2\) is present as a supercritical fluid. The CO\(_2\) injection is started at the bottom layer (6–8) using wells from I1 to I5. The injection period is 10 years. Well I3 is both an injection and observation well because of its location near to the top of the anticline structure (location of observation cell: 22, 21, 1 – 8). Two different scenarios were simulated: case 1 without relative permeability hysteresis and the second case within hysteresis. For each case the results of the fluid distribution are shown in Figure 6–8.

### Table 2

Reservoir parameters

<table>
<thead>
<tr>
<th>Model dimension (nx × ny × nz)</th>
<th>40 × 35 × 8</th>
<th>Cell</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average porosity</td>
<td>20 [%]</td>
<td></td>
</tr>
<tr>
<td>Average horizontal permeability</td>
<td>75 [mD]</td>
<td></td>
</tr>
<tr>
<td>Average thickness</td>
<td>144 [m]</td>
<td></td>
</tr>
<tr>
<td>Formation top</td>
<td>850 [m]</td>
<td></td>
</tr>
<tr>
<td>Reservoir pressure</td>
<td>110 [bar]</td>
<td></td>
</tr>
<tr>
<td>Reservoir temperature</td>
<td>322 [K]</td>
<td></td>
</tr>
</tbody>
</table>

Migration of CO\(_2\) to the top is relatively fast, after 20 years from the start of injection the saturation of CO\(_2\) in the upper layers is approx. 60%. In the first case, the gravity segregation of immiscible fluids leads to drastic changes in saturation of the lower layers, at the beginning of the injection the saturation of CO\(_2\) is at the level of 55% and after 83 years drops to less than 10%. Taking into account the hysteresis (case 2) the CO\(_2\) saturation distribution in layers is more uniform, the average saturation of the layer is approx. 30%. Capillary trapping thus leads to better use of storage space.

The capillary trapping process is sensitive to a set of various factors. Reservoir conditions, i.e. pressure and temperature, have a considerable impact on interfacial tension and the mobility ratio, and these in turn determines relative permeability, irreducible water and CO\(_2\) saturations.

The observation points were chosen along well I3. The observation grid blocks is shown in Figure 9. Figure 10 shows the dynamic movement of CO\(_2\) in the simulated region in terms of CO\(_2\) phase saturations.
Fig. 5. Reservoir model used to simulate CO₂ trapping

Fig. 6. CO₂ saturation distribution after 20 years from the beginning of injection for the reservoir vertical intersection. Results from case 1 (no hysteresis left). Results from case 2 (with hysteresis right)

Fig. 7. CO₂ saturation distribution after 30 years from the beginning of injection for the reservoir vertical intersection. Results from case 1 (no hysteresis left). Results from case 2 (with hysteresis right)
The saturation path for the top layer (observation point 1) is the same in both cases, after 20 years the saturation of CO$_2$ reaches the maximum value. In the scenario 1 the CO$_2$ saturation remains high, up to 50%, for the second and third layer and for layers below is low (approx. 10%). Within the hysteresis the saturation of CO$_2$ drops to 45% (layers 2–3) and for the other layers remains at the level of 30%. Simulations showed that the residual gas saturation is up to 30%. This result complies with previous works of Juanes et al. [9] and Bennion et al. [20]. The individual layers slightly differ in permeability, hence the time after which the layer saturation reaches a constant level varies, generally after 50 years no spontaneous movement of fluids is observed. Capillary trapping may be considered as dominant storage mechanism at early stage of geosequestration, dissolution and mineral trapping are considered as long-term processes.

Fig. 8. CO$_2$ saturation distribution after 83 years from the beginning of injection for the reservoir vertical intersection. Results from case 1 (no hysteresis left). Results from case 2 (with hysteresis right)

Fig. 9. Location of observation and injection points
5. CONCLUSIONS

Capillary trapping of the CO$_2$ determines the migration and distribution of CO$_2$ in aquifers. On small timescales (<100 years) the capillary trapping becomes a dominant storage mechanism. In the model without hysteresis any trapping of CO$_2$ occurs which is unfavorable for sequestration purposes. A higher amount of CO$_2$ reaches the top of the anticline as a mobile phase and is prone to leaks. Trapping of the CO$_2$ due to relative permeability hysteresis leads to the situation where a large fraction of the CO$_2$ is trapped and immobile and is more spread out throughout the aquifer. From Figure 10 it can be deduced that up to 60% (residual CO$_2$ saturation/ initial CO$_2$ saturation, in percent) of injected CO$_2$ is trapped by capillary trapping mechanism. The process can be effectively simulated using commercial software by implementation of a proper model for the relative permeability hysteresis.

REFERENCES


