Influence of small scale heterogeneity on CO₂ trapping processes in deep saline aquifers

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Abstract

The physical mechanism of CO₂ trapping in porous media by capillary trapping (pore scale) incorporates a number of related processes, i.e. residual trapping, trapping due to hysteresis of the relative permeability, and trapping due to hysteresis of the capillary pressure. Additionally CO₂ may be trapped in heterogeneous media due to difference in capillary pressure entry points for different materials (facies scale). The amount of CO₂ trapped by these processes depends upon a complex system of non-linear and hysteretic relationships including how relative permeability and capillary pressure vary with brine and CO₂ saturation, and upon the spatial variation in these relationships as caused by geologic heterogeneity.

Geological heterogeneities affect the dynamics of CO₂ plumes in subsurface environments. Recent studies have led to new conceptual and quantitative models for sedimentary architecture in fluvial deposits over a range of scales that are relevant to the performance of some deep saline reservoirs. We investigated how the dynamics of a CO₂ plume, during and after injection, is influenced by the hierarchical and multi-scale stratigraphic architecture in such reservoirs. The results strongly suggest that representing small scales features (decimeter to meter), including their organization within a hierarchy of larger-scale features, is critical to understanding trapping processes.

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1. Introduction

The idea of sequestering CO₂ in the Earth’s crust has been discussed and evaluated for more than two decades [1-3]. The most likely sites for sequestration are deep saline aquifers and depleted hydrocarbon reservoirs [4-8]. Sites must be evaluated for reservoir capacity and the risk of CO₂ leakage, which requires detailed modelling of CO₂ movement. Such modelling must account for coupled processes occurring over a wide range of scales. For example Middleton et al. [9] defined and described processes relevant at these scales: sub-pore (Å -10 nm), pore (10 nm - 10 cm), CO₂ reservoir (10 cm – 100 m), site (100 m – 10 km, the deep groundwater system), and region (10 km – 1 Mm, the sedimentary basin). At any site dependent on structural (or hydrodynamic) trapping, caprock may be compromised by improperly abandoned wells, stratigraphic discontinuities, or faults. Therefore, other trapping mechanisms must be considered, including dissolution, mineralization, and capillary trapping. We focus on capillary trapping processes that operate over a range of scales of heterogeneity intermediate between the pore scale [10] and the site scale [11], scales that have not yet received full consideration in the literature.

Typically, CO₂ is injected in a supercritical state with liquid-like properties. After injection the CO₂ plume migrates towards the top of the reservoir, driven by buoyancy forces. CO₂ becomes virtually immobile due either to capillary trapping in reservoir rock pores (time scale: 10 to 100 years), dissolution of CO₂ into brine (100 to 1000 years), or mineral trapping through reaction with rock minerals (thousands to millions of years) [12-14]. We modeled both capillary trapping and dissolution processes, but our main interest is in capillary trapping, especially the effects of reservoir heterogeneity.

The physical mechanism of CO₂ trapping in porous media by capillary trapping incorporates three related processes: (1) residual trapping, (2) trapping due to hysteresis of the relative permeability, and (3) trapping due to hysteresis of the capillary pressure [15-17]. The basics of these processes are as follows. After injection into deep saline reservoirs, the low viscosity CO₂ tends to migrate to the top of the reservoir due to a density difference between the CO₂ and the brine. During the injection period CO₂ displaces brine in a drainage process. After the injection is finished, the buoyant CO₂ migrates upward and water displaces CO₂ at the plume “tail” in an imbibition-like process. The latter causes the CO₂ stream to divide into immobile blobs and ganglia [18]. A larger scale trapping process occurs when CO₂ is trapped in heterogeneous media due to difference in capillary pressure entry points for different materials [19-21]. The amount of CO₂ trapped by these four processes is a complicated nonlinear function of the spatial distribution of permeability, permeability anisotropy, capillary pressure, relative permeability of brine and CO₂, permeability hysteresis, and residual gas saturation.

Geological heterogeneities affect the dynamics of CO₂ plumes in subsurface environments. Their role in capillary trapping and dissolution of CO₂ has been investigated extensively [22-28]. Usually the effects of heterogeneity are considered within two-dimensional geostatistical models using various correlation lengths. While such an approach is capable of capturing qualitatively some typical features of the process, full understanding requires modeling three-dimensional flow within reservoirs with realistic representations of sedimentary architecture and the associated relative permeability and capillary pressure distributions, across a range of scales.

Recent studies have led to new conceptual and quantitative models for sedimentary architecture in fluvial deposits over a range of scales that are relevant to fluid flow in some petroleum and deep saline reservoirs [29-31]. From these studies emerged a generalized, three-dimensional, quantitative model for the multi-scale and hierarchical stratal architecture found in fluvial deposits. Importantly, the lengths of stratal units at all hierarchical levels scale together with the width of the formative channels (Bridge [32]), making it possible to adapt the general model to specific deposits. The software package (GEOSIM) uses a geometric-based approach to create three-dimensional geocellular models representing this multiscale and hierarchical fluvial architecture [33-35].

Here we focus on fluvial deposits dominated by sandy gravel (see Fig. 1 in [36]). Lunt et al. [29] studied the gravelly channel belt of the Sagavanirktok River Alaska, an analog for a number of important reservoirs composed of fluvial deposits [11, 37]. At the smallest scale are sets of cross-strata (decimeters thick and meters long), which occur within unit bar deposits (tens of decimeters thick and tens of meters long). Unit bars and cross-bar channel fills occur within compound bar deposits (meters thick and hundreds of meters long). Compound bar deposits and the channel fills that bound them occur within channel belts (tens of meters thick and kilometers long). Importantly, open-framework gravel (OFG) cross strata are known to create preferential flow pathways that confound attempts at gas injection. The OFG are found to make up 25 to 30 percent of the volume of a deposit.
Guin et al. [34] used the GEOSIM code to create a hierarchical geocellular model that honored proportions and length statistics of units at all scales as quantified by Lunt et al. [29]. The geocellular model was interrogated and the connectivity of preferential flow paths of OFG were quantified. The high-permeability OFG cells percolate (i.e., connect across domain boundaries in spanning clusters) at all levels and thus form preferential flow pathways, as observed in nature [29, 37, 38]. The number, size, and orientation of percolating clusters change across the different hierarchical levels (scales) of the stratal architecture. OFG cross strata form many paths that vertically span single unit bar deposits. Connections across unit bar boundaries enhance lateral branching and the many smaller vertical clusters within unit bars connect into a smaller number of larger spanning clusters at the scale of multiple unit bars. At the scale of a whole compound bar deposit, these clusters are typically connected as one or two large, percolating clusters.

This geocellular model has been used for numerical investigation of three-dimensional displacement of oil during waterflooding [39]. Here we use a part of the model in a numerical investigation of how the dynamics of a CO₂ plume, during and after injection, are influenced by the hierarchical and multi-scale stratal architecture in such reservoirs. We used the commercial reservoir simulator ECLIPSE-300 [40]. Importantly, we define different relative permeability and capillary pressure relationships, with hysteresis, for each type of cross strata.

The complexity of the heterogeneity and highly non-linear nature of the problem make it challenging to achieve numerically convergent solutions. Consequently, the simulations presented here are limited to an examination of CO₂ within a relatively small reservoir compartment of 100 m x 100 m x 5 m illustrated in [36]. Our longer-term goal is to run larger simulations that include more of the geocellular model (e.g. [33], Fig. 10), and thus include some of the larger-scale sedimentary architecture not yet represented here. However, the preliminary work presented here shows the fundamental importance of properly representing the within-reservoir heterogeneity, and therefore justifies this line of research.

2. Methodology

We generated a realization of the channel-belt architecture including two materials, i.e. sand (76%) and OFG (24%) with geometric mean permeability 58 mD and 3823 mD, respectively. We simulated injection of CO₂ in a reservoir with size 100 m x 100 m x 5 m (250 thousand cells of size 2 m x 2 m x 0.05 m). This represents the heterogeneity created by an assemblage of unit bars within a compound bar. This simulation includes a cluster of OFG cells which tortuously spans the domain boundaries in all directions and contains 55% of all OFG cells. CO₂ was injected at a rate of 3.6 (standard) m³/day during 10 days into the bottom of a vertical well at a depth 2360 m. In one case the well was placed to penetrate a spanning OFG cluster and in another case placed so it does not. The boundary of the CO₂ reservoir was not permeable. For comparison we also simulated injection into two homogeneous reservoirs: (1) homogeneous, isotropic, and with permeability equal to the geometric mean of the heterogeneous reservoir; and (2) homogeneous but anisotropic with permeability five times smaller in the z direction than in horizontal directions.

When simulating CO₂ injection in a reservoir with realistic heterogeneity, the choices for relative permeability and capillary pressure tables are very important. The tables define the relations between water relative permeability, CO₂ relative permeability, and CO₂ capillary pressure as a function of water saturation. Two different sets of tables were utilized for the sand and OFG unit types. Thus, the total number of property tables was 12 including six for drainage and six for imbibition (see Fig. 1 and [36] for more details).
3. Results

Fig. 2 shows vertical cross sections with CO₂ saturation for the heterogeneous and homogeneous anisotropic reservoirs after 10 days (panels on the left) and after 1010 days (panels on the right). After injection CO₂ propagates in the horizontal and vertical directions. The force of buoyancy moves the CO₂ plume up.

The ratio of the viscous to gravity forces defines the geometry of the plume in the homogeneous case. In the homogeneous anisotropic reservoir the CO₂ plume reaches the top of the reservoir in 10 days and then the top of the plume slowly spreads laterally. Essentially the same behaviour is exhibited by a plume in the homogeneous isotropic reservoir (not shown), but in the latter the plume reaches the top of the reservoir 5 times faster (in 2.5 days). The shape of the plume, the rate of capillary trapping of CO₂, and the CO₂ solution in brine are similar in these two cases.

Fig. 2. Vertical cross section of heterogeneous (top panels) and homogeneous anisotropic (bottom panels) reservoirs showing CO₂ saturation after 10 days (left panels) and after 1010 days (right panels) from the beginning of CO₂ injection.
In contrast, in the heterogeneous case the plume is two times wider and never reaches the top of the reservoir (see Fig. 2, top panels). This is caused by the difference in capillary entry pressure between sand and OFG and the presence of multiple boundaries between sand and OFG. After injection a buoyancy force moves the CO₂ plume up. In the heterogeneous case it is more complicated. CO₂ propagates faster in OFG clusters since permeability of OFG material is much higher than in sand. However, in clusters that do not span the domain, CO₂ cannot escape from the cluster and remains trapped unless the buoyancy force is large enough to overcome the capillary entry pressure of sand. In spanning clusters, CO₂ propagates mainly in the horizontal direction since OFG clusters extend further in this direction. CO₂ can exit from a spanning OFG cluster through its upper boundary if buoyancy force is large enough. It will propagate upward through sand to the next OFG cluster, into which it will be pushed by both buoyancy force and capillary pressure. This process continues up to the point when buoyancy force becomes comparable with capillary pressure and the plume becomes immobile or trapped, or the plume reaches the top of the reservoir.

Due to the process described above the contact area between brine and the CO₂ plume is larger than in the homogeneous case. As a result the dissolution rate is larger in the heterogeneous case. The “regular” capillary trapping rate is also largely affected. Overall the results indicate that the presence of small and large OFG clusters essentially controls behavior of CO₂ plumes on reservoir scale.

Importantly, in the heterogeneous case considered here the plume never reaches the caprock. Total amount of inserted CO₂ is effectively trapped. The trapping is mostly in sand (in blobs and ganglia) and by the secondary sealing effect in OFG material (on the boundary between sand and OFG).

Injected CO₂ can be apparently divided into four parts, i.e. 1) mobile gas, 2) immobile gas trapped in the form of blobs and ganglia by hysteresis, 3) gas trapped at the boundary between sand and OFG due to different entry point pressures, and 4) dissolved gas. Note that gas trapped at the boundary between sand and OFG could be mobilized by increased gas injection, pushing it through the boundary.

Fig. 3 depicts the total amount of the mobile, capillary trapped and solute CO₂ in sand and OFG. While OFG material comprises only 24% of the reservoir, most of the mobile CO₂ is in OFG cells (Fig. 3a). The amount of capillary trapped CO₂ in OFG is about twice that in sand (Fig. 3b). The amount of solute CO₂ is two to three times larger in sand than in OFG (Fig. 3c).

To further illustrate the roles of 1) capillary pressure, 2) hysteresis of relative permeability of water and CO₂ and 3) heterogeneity of permeability on plume geometry and dynamics as well as on CO₂ trapping and dissolution we compare the results of the five cases described in Table 1. The results from each case are given in Fig. 4. Case 1 includes heterogeneity and all 12 property tables; it is the standard for comparison. This figure shows that plume geometry is very different from case to case. The plume quickly reaches the top of the reservoir for the homogeneous reservoir (case 2), in heterogeneous reservoir with capillary pressure “off” (case 5) and if capillary pressure is “on” but the properties tables are the same for both materials (case 3). In contrast, the spreading of the plume in the vertical direction is much slower in cases 1 and 4. The results illustrate that the most important factor affecting capillary trapping is the different entry point pressures for the different geologic unit types (the so called secondary seal effect).

<table>
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<tr>
<th>Case #</th>
<th>Permeability</th>
<th>Capillary pressure</th>
<th>Hysteresis</th>
<th>Relative permeability</th>
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<td>on</td>
<td>Different for sand and OFG</td>
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</tr>
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<tr>
<td>3</td>
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<td>on</td>
<td>on</td>
<td>The same for all cells</td>
<td>6</td>
</tr>
<tr>
<td>4</td>
<td>Heterogeneous</td>
<td>on</td>
<td>off</td>
<td>Different for sand and OFG</td>
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<tr>
<td>5</td>
<td>Heterogeneous</td>
<td>off</td>
<td>on</td>
<td>Different for sand and OFG</td>
<td>6</td>
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</table>
4. Conclusions

Several features distinguish our approach from others:
1. The modelled heterogeneity structure and scales, hence permeability map, realistically reflects the typical fluvial type reservoirs; permeability ranges by 4 orders of magnitude.
2. The size of reservoir heterogeneities ranges from a few cm to dozens of meters.
3. The reservoir contains two different materials -- sand and open framework gravel -- with different properties, requiring that two sets of property tables be used for simulation.
4. Capillary pressure and hysteresis effects are utilized in the simulation. Overall, 12 properties tables were used including relative permeability and capillary pressure curves for drainage and imbibition for both brine and CO₂.

Fig. 3. Total amount of the mobile (a), capillary trapped (b), and solute CO₂ (c) in sand and OFG as function of time.

Fig. 4. Vertical cross section of reservoirs showing CO₂ saturation after 170 days from the beginning of CO₂ injection for the five cases described in the Table 1. For each, the injection well is located in the lower-left corner.
The results demonstrate that small and medium scale inclusions of high-permeability cross strata fundamentally control trapping processes and hence the shape and dynamics of the CO₂ plume. This occurs because the capillary entry pressures of the two materials are different. In a highly heterogeneous reservoir this trapping mechanism may considerably surpass all other capillary trapping mechanisms. Indeed, in the example considered here (Fig. 2) the total amount of injected CO₂ is trapped and never reaches the top of the reservoir. The results strongly suggest that representing these small-scale features, and representing how they are organized within a hierarchy of larger-scale features, is critical to understanding trapping processes. It is also obvious that ignoring both the small-scale heterogeneity and the secondary-seal effect in simulations of CO₂ sequestration may produce misleading results.

A number of studies have considered CO₂ sequestration in fluvial reservoirs but have not represented sedimentary architecture at the scale of our study (e.g. [11, 41]). The results of our study indicate that the amount of trapping of CO₂ and the geometry of the CO₂ plume may be very different from the results of their current simulations if sedimentary architecture is represented at smaller scales.

The total amount of trapped (immobile) gas and its spatial distribution are different in heterogeneous and homogeneous cases with similar averaged characteristics. It is interesting that the mobile part of the gas is placed mostly inside of high-permeability material, i.e. OFG. The ratio between amounts of gas in OFG to sand is about 8, although reservoir contains only 24% of OFG material. At the same time the amount of capillary trapped immobile gas is larger in sand.

Plume dynamics and the amount of trapped CO₂ depend on the structure and content of the OFG cross strata, and how these are organized within larger units. The large OFG clusters and especially spanning clusters are responsible for the horizontal extent of CO₂ plume, which may be three times larger than in the case of a homogeneous reservoir. The size and shape of clusters are important with respect to the amount of gas trapped.

The simulations presented here were performed using a relatively small piece of the geologic model and with injection of small amount of CO₂. We expect that simulations representing larger scales of the stratal architecture will be important to further understanding trapping in the reservoir. It is also important to study how the amount, rate, and schedule of CO₂ injection affect

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References


