Capillary trapping of CO₂ in heterogeneous reservoirs during the injection period

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Abstract

Capillary trapping plays an important role in CO₂ storage. Two capillary trapping mechanisms have been extensively investigated, i.e., residual trapping or snap-off and capillary pinning. The latter mechanism works only in heterogeneous reservoirs. The majority of studies related to CO₂ trapping focus on the post-injection period, when the imbibition process dominates. The main reason for this is that snap-off trapping is absent in homogeneous reservoirs at the drainage stage, i.e., during the injection period. Here, we investigate capillary trapping in **heterogeneous** fluvial-type **reservoirs during injection period**. We show that snap-off trapping exists in heterogeneous reservoirs even during the injection period, when relative permeability characteristics are different for different facies. However, trapping by capillary pinning dominates during the injection period. The amount of snap-off and capillary pinned CO₂ critically depends on the contrast in rock properties, such as (1) intrinsic permeability, (2) irreducible water saturation, (3) maximum residual CO₂ saturation, and (4) capillary entry pressure barrier. The pinned amount is proportional to the fraction of the rocks with low capillary pressure. Pinning is larger in gravity-dominated flow than in viscous-dominated flow. The estimates show that the amount of snap-off and capillary pinned CO₂ can be up to 5% and 25%, respectively, from the total amount of injected CO₂, but, in most cases with realistic parameters, it is 2–3 times less than maximal amount estimated.

Introduction

The importance of capillary trapping for CO₂ storage processes has been broadly recognized (Krevor et al., 2015; Bachu, 2015). A sizable amount of injected CO₂ can be trapped before it reaches caprock. This assumption is based on results from reservoir modeling (Hovorka et al., 2004; Kumar et al., 2005; Bryant et al., 2006; Juanes et al., 2006; Ide et al., 2007; Flett et al., 2007; Han et al., 2010; Zhao et al., 2014; Gershenzon et al., 2014, 2015, 2016a and b) and laboratory experiments (Pentland et al., 2010, 2011; Iglaier et al., 2011a, b; Krevor et al., 2012; Sakaki et al., 2013; Trevisan et al., 2015). Two trapping mechanisms have been extensively investigated in recent years. In a

homogeneous reservoir, trapping occurs during post-injection phase via imbibition, i.e., when brine, the wetting fluid, replaces CO₂, non-wetting fluid. The CO₂ bubbles are trapped because of capillary forces (Hunt et al., 1988; Iglauer et al., 2011a). This mechanism, which includes snap-off, single-pore, and pore-doublet processes (Chatzis and Dullien, 1983; Valvatne and Blunt, 2004), works at the pore scale (Figure 1a). We will use the term “snap-off” to designate these mechanisms.

There is an additional capillary trapping mechanism in heterogeneous reservoirs, i.e., capillary pinning (Figures 1b and 1c). Capillary pinning occurs as a result of the difference in capillary pressure between coarse-grained (CG) and fine-grained (FG) rocks. Capillary pressure contrast between CG and FG rocks causes CO₂ pinning within CG rocks, when buoyant CO₂ rises through the lateral layers with different capillary pressure barriers (Bryant et al., 2006; Ide et al., 2007; Saadatpoor et al., 2009; Zhou et al., 2009; Frykman et al., 2013; Zhao et al., 2014; Gershenzon et al., 2014, 2015, 2016a and b). In contrast to snap-off, capillary pinning works in both the imbibition and drainage stages.

Figure 1

Previously we modeled trapping processes in fluvial type reservoirs (Gershenzon et al., 2014, 2015, 2016a and b). These reservoirs include small-scale (decimeter to meters) heterogeneities in petrophysical characteristics of depositional rocks (Lunt et al., 2004; Bridge, 2006; Lunt and Bridge, 2007). Gershenzon et al., (2014, 2015, 2016a and b) showed that the amount of trapping by capillary pinning at the post-injection stage is comparable with the amount trapped by snap-off, and it may even be dominant under some conditions, such as a strong contrast in capillary pressure between rock types. Gershenzon et al. (2016a) also showed that trapping by capillary pinning is different for two different conventional approaches to the capillary pressure characteristics, specifically Brooks-Corey (BC) (Brooks and Corey, 1964) and van Genuchten (vG) (van Genuchten, 1980). This difference is especially pronounced after a long time after CO₂ injection ceases. In the vG case, CO₂ trapped by capillary pinning escapes from the CG strata after a sufficiently long time. The main reason for this is that capillary pressure is equal to zero at water saturation equal to zero in the vG approach, in contrast to the BC approach where it has a positive value. So, when CO₂ saturation in the overlying FG strata decreases to zero the capillary barrier between CG and FG rocks becomes negligible and CO₂ may penetrate from the underlying CG strata to the overlying FG strata. To designate this difference, we introduced a new term for the capillary pinning in the vG case: capillary retardation (Gershenzon et al., 2016a).

The majority of studies related to CO₂ trapping focus on the post-injection period, when imbibition processes dominate. In many practical cases injection of CO₂ may continue for many years. Does capillary trapping exist during injection? To address this question, this article investigates capillary trapping in heterogeneous fluvial-type reservoirs during the injection period. We show that snap-off trapping also exists in

heterogeneous reservoirs, even during the injection period when relative permeability characteristics are different for different facies. While capillary pinning dominates during injection, snap-off trapping may also be substantial depending on petrophysical parameters. We systematically investigate this dependence.

Iglauer et al. (2011b) evaluated the capacity of capillary trapping in sandstones based on laboratory experiments. They found that the amount of capillary trapping could be up to 11%. Simulations and experiments show that this amount could be even larger, i.e., between 10% and 30% of the pore volume of the rock (Krevor et al., 2015). Note that these estimates only apply to the post-injection stage. The total amount of CO₂ trapped by snap-off can be routinely calculated by simulation software such as ECLIPSE, TOUGH2, and STOMP. However, an estimate of the amount of CO₂ trapped by capillary pinning is not as straightforward. Some analytical calculations have been implemented for reservoirs with specific simplified geometry of heterogeneity (Silin et al., 2009; Hesse and Woods, 2010). Here, we evaluate this amount for fluvial-type reservoirs. The quantitative relations between capillary pinning and parameters defining capillary pressure characteristics of reservoir rocks are also considered.

In the Methodology section, we describe the fluvial reservoirs used for simulations, the constitutive relationship characteristic curves, and the simulation setting. This is followed by a section on Results and Discussion and then a Conclusion.

Methodology

Some of the existing and potential CO₂ reservoirs have fluvial sedimentary architecture (Tye et al., 2003; Lu, 2011; Krevor et al., 2012; Freiburg et al., 2014). Three-dimensional quantified models have been created for typical fluvial reservoirs (Bridge, 2006; Lunt and Bridge, 2007; Guin et al., 2010; Ramanathan et al., 2010). Using the methodology described in Ramanathan et al. (2010), we generated several reservoir realizations that contain two textural facies, finer-grained (FG) cross-sets and coarser-grained (CG) cross-sets, in different proportions (Table 1, column 2). The permeability of each cell is assigned from the appropriate lithotype distribution (Ramanathan et al., 2010; Ritzi, 2013). Table 1 (third and fourth columns) includes values of the geometric average of permeability for CG and FG cells. Case 3 is considered the “base case” with permeability in the model reflecting actual permeability of the Lower Mt. Simon Sandstone zone into which CO₂ has been injected at the Illinois Basin–Decatur Project (Ritzi et al., 2016).

Table 1. Permeability, relative permeability, and capillary pressure parameters for CG and FG rocks for cases simulated. Here, we include only parameters for vG curves. Values for k are averaged for cells of that type. The actual permeability for each cell is

randomized with dispersion σ , where $\sigma/k \ll 1$, with exception for cases 0 and 16 where permeability is constant for each facies.

Case #	CG Cells (%)	k [mD] CG cells	k [mD] FG cells	S_{wi} CG cells	S_{wi} FG cells	S_t CG cells	S_t FG cells	P_g [bar] CG cells	P_g [bar] FG cells
0	0	11	11	0.35	0.35	0.3	0.3	0.0677	0.0677
1	24	11	11	0.25	0.35	0.35	0.3	0.03	0.0677
2	24	22	11	0.25	0.35	0.35	0.3	0.03	0.0677
3	24	112	11	0.25	0.35	0.35	0.3	0.03	0.0677
4	24	560	11	0.25	0.35	0.35	0.3	0.03	0.0677
5	24	560	55	0.25	0.35	0.35	0.3	0.03	0.0677
6	76	112	11	0.25	0.35	0.35	0.3	0.03	0.0677
7	24	112	11	0.125	0.175	0.35	0.3	0.03	0.0677
8	24	112	11	0.35	0.35	0.35	0.3	0.03	0.0677
9	24	112	11	0.25	0.35	0.17	0.15	0.03	0.0677
10	24	112	11	0.25	0.35	0.35	0.3	0.003	0.00677
11	24	112	11	0.25	0.35	0.35	0.3	0.3	0.677
12	16	112	11	0.25	0.35	0.35	0.3	0.03	0.0677
13	28	112	11	0.25	0.35	0.35	0.3	0.03	0.0677
14	24	112	11	0.35	0.35	0.3	0.3	0.0677	0.0677
15	24	112	11	0.25	0.35	0.35	0.3	0.	0.
16	24	112	112	0.25	0.35	0.35	0.3	0.	0.

The reservoir size is $200 \text{ m} \times 200 \text{ m} \times 5 \text{ m}$ (1 million cells of size $2 \text{ m} \times 2 \text{ m} \times 0.05 \text{ m}$). The CO_2 was injected at a rate of 0.5 kg/s (0.01136 kg-mol/s) for 50 days into the bottom of a vertical well placed in the middle of reservoir at a depth of 2360 m. For the limited number of simulations, injection rate was reduced to 0.167 kg/s (injection time 150 days) or increased to 1 kg/s (injection time 25 days). The pressure and temperature at the top of the reservoir are 230.8 bar and 53°C , respectively, such that the injected CO_2 was supercritical. The boundary conditions are that (1) there is no flow through the top and the bottom of the reservoir and (2) a Carter-Tracy aquifer (Carter and Tracy, 1960) is applied for all others reservoir boundaries.

We used the commercial reservoir simulator ECLIPSE-300 with the CO2STORE option. Three components were included in simulations: H_2O , CO_2 , and NaCl with initial total phase mole fractions of 0.9109, 0.0, and 0.0891, respectively. The water compressibility and viscosity are $4.35 \cdot 10^{-5} \text{ 1/bar}$ and 0.813 cP , respectively. Killough's hysteresis model for history-dependent capillary pressure and relative permeability functions was used (Killough, 1976). The diffusion flow in terms of liquid mole fraction is specified by the water-phase diffusion coefficients for each component. The values of all three coefficients are 10^{-4} . The gas-phase diffusion coefficients for both water and CO_2 are 10^{-3} .

Two different sets of capillary pressure and relative permeability curves were utilized for the CG and FG unit types. We use both the vG and BC approaches to describe capillary pressure P_c , and the vG approach to describe relative permeability curves for CO_2 (k_{r,CO_2}) and brine ($k_{r,w}$).

Capillary pressure for drainage is given by the following formula:

$$P_c = P_g [(S_w^*)^{-1/(1-1/n_g)} - 1]^{1/n_g}, \quad (1)$$

where $S_w^* = \frac{S - S_{wi}}{1 - S_{wi}}$; S is water saturation; S_{wi} is irreducible water saturation; n_g is a fitting parameter known as the pore-size distribution index for vG; and P_g is a capillary pressure scaling parameter, related to the average size of the pores. The value of P_g approximately corresponds to the position of the inflection point at the capillary curve. Formulae for the relative permeability for CO₂ for drainage and imbibition are

$$k_{r,CO_2} = (1 - S_w^*)^2 (1 - (S_w^*)^{1/m})^m, \quad (2)$$

where $m = 1 - 1/n_g$; and

$$k_{r,CO_2} = (1 - S_w^{**})^2 (1 - (S_w^{**})^{1/m})^m, \quad (3)$$

where $S_w^{**} = \frac{S - S_{wi}}{1 - S_t - S_{wi}}$ and S_t is the maximal residual CO₂ saturation. Relative permeability for water is given by

$$k_{r,w} = (S_w^*)^2 [1 - (1 - (S_w^*)^{1/m})^m]. \quad (4)$$

Here, we use the value $n_g = 2.68$ for all cases. Parameters S_{wi} , S_t , and P_g are different for different unit types and vary from case to case (Table 1).

We also use the BC capillary pressure curve:

$$P_c = P_e (S_w^*)^{-1/\lambda}, \quad (5)$$

where P_e is the minimum pressure required for the entry of CO₂ into the pore of the rock, and λ is a fitting parameter known as pore-size distribution index. The values of these parameters were chosen based on the vG parameters from base case 3 (Table 1) and calculated by the formulas proposed by Lenhard et al. (1989). Thus, we used the following values: $P_{e,CG} = 0.023$ bar; $P_{e,FG} = 0.052$ bar; and $\lambda = 1.12$.

Figures 2 and 3 show the capillary pressure and relative permeability curves calculated by formulae (2)–(5) for case 3.

Figure 2

Figure 3

Results and Discussion

There is no CO₂ trapping in a homogeneous reservoir during CO₂ injection with a constant (or monotonically increased) injection rate. Note that this is true if CO₂ relative permeability is monotonic function of CO₂ saturation starting from the point $k_{CO_2}(S_{CO_2} = 0) = 0$. Figure 4 depicts the total amount of CO₂ trapped by snap-off as a

function of time in homogeneous (case 0) and heterogeneous (cases 3, 15, and 16) reservoirs. As one can see, there is no snap-off trapping in a homogeneous reservoir during injection. In contrast, there is a visible amount of snap-off in the heterogeneous reservoirs during injection. After injection ceases (after 50 days), brine immediately begins replacing CO₂ (imbibition process) and the amount of snap-off trapping quickly increases in all four cases.

Trapping by capillary pinning is absent in the homogeneous reservoir (case 0) and in the heterogeneous reservoirs with negligible capillary pressure (cases 15 and 16). In these three cases, all CO₂, except for CO₂ trapped by snap-off and dissolution, slowly ascends (compare the plume shape after 50 and 250 days in Figure 5). However, in a heterogeneous reservoir, where different facies have different capillary pressure curves, the trapping by capillary pinning is considerable and practically unchanged after injection ceases (compare the plume shape in case 3 after 50 and 250 days in Figure 5). If capillary pressure is negligible (cases 15 and 16) or the same for both facies (case 14), capillary pinning is absent in both injection and post-injection stages (Figure 5). In the following subsections, we consider snap-off and capillary pinning trapping during the injection stage in detail.

Figure 4

Figure 5

Snap-off trapping

If relative permeability curves are the same for each facies, then there is no snap-off trapping during injection in heterogeneous reservoirs as in homogeneous reservoirs (see case 14 from Table 1). This is true even if intrinsic permeability is different for the different facies. However, if relative permeability curves are different, then there is snap-off trapping in a heterogeneous reservoir, even during injection (see cases 1–13 and 15). Although the difference in relative curves are necessary, the amount of trapped CO₂ critically depends on other parameters.

Trapping amount increases with an increase in intrinsic permeability and the permeability contrast between reservoir rocks (compare cases 1–5, Table 2; see also Figure 6). In examples considered the amount of snap-off ranges from 41.5 kg-mol (case 1) to 798.6 kg-mol (case 5). The percentage of CO₂ trapped in CG rocks reduces from 25.4% (case 1) to 9.3% (case 5; Table 2). Hereafter, all values of trapped CO₂ are considered to be at the end of the injection period. The snap-off amount decreases (1) with a decrease of irreducible water saturation (compare cases 3 and 7), (2) when relative permeability curves for FG and CG rocks approach each other (compare cases 3 and 8), (3) with a decrease of maximum residual CO₂ saturation, $S_{r,}$ (compare cases 3 and 9), and (4) with an increase of capillary-pressure barrier between two rock types (compare

cases 3 and 10). The snap-off trapping is maximal when the capillary pressure is negligible (see cases 15 and 16 in Table 2 and Figure 7).

Table 2. Total snap-off amount, the portion of snap-off in total injected CO₂, and the portion of snap-off in CG cells to total snap-off amount.

Case #	Snap-off [kg-mol]	Snap-off [%]	Snap-off in CG cells [%]
0	0	0	–
1	41.5	0.08	25.4
2	133.3	0.27	25.0
3	493.7	1.00	22.5
4	703.6	1.43	19.9
5	798.6	1.62	9.3
6	53.7	0.11	56.8
7	237.0	0.48	16.3
8	22.5	0.05	47.9
9	127.7	0.26	17.6
10	1090	2.21	18.9
11	30.0	0.06	6.8
12	136.1	0.27	22.2
13	612.5	1.24	29.7
14	0	0	–
15	2505	5.09	24.1
16	868.6	1.77	29.9

Figure 6

Figure 7

How does the ratio of CG to FG rocks affect snap-off trapping? If the ratio is less than 1 (the usual case), then an increase in the ratio increases the amount of snap-off. For realizations considered here, the snap-off amount ranges from 136.1 kg-mol for the ratio 16/84 to 612.5 kg-mol for the ratio 28/72 (see cases 12 and 13 in Table 2 and Figure 8). Respectively, the percentage of CO₂ trapped in CG rocks increases from 22.2% (case 12) to 29.7% (case 13). In some reservoirs, such as a portion of the Mt Simon reservoir, the percentage of CG rocks is larger than the percentage of FG rocks. In this case, the snap-off amount is much smaller than in cases with a reverse ratio (compare cases 3 and 6 at Figure 8).

Figure 8

Snap-off trapping occurs during the imbibition process when a wet liquid replaces a non-wet liquid/gas. In a homogeneous reservoir, brine may replace buoyant CO₂ only when injection ceases or the injection rate decreases. Thus, there is no snap-off trapping during injection. In a heterogeneous reservoir, there are some areas where local and temporary water replaces CO₂ even during the injection period. This effect occurs

because of the strong nonlinearity of the process and because different rocks have different constitutive relations.

For simplicity, let us consider case 16, where capillary pressure and homogeneous intrinsic permeability are negligible. In this case, the only difference between two rocks is the relative permeability (case 16, Table 1). Figure 9 shows CO₂ saturation as a function of time during the CO₂ injection period for a few cells. One can see that for all shown cells, except for the cell with coordinate (51, 37, 60), saturation increases at the beginning and then starts to decrease at time 20-30 days. Brine replaces CO₂ during the time that saturation decreases, and thus snap-off trapping occurs.

Figure 9

Snap-off trapping depends on the type of capillary pressure curve used. In the case of the BC curve, the amount of snap-off is larger by a factor of two than in the case of the vG curve (not shown). The CO₂ injection rate also influences snap-off trapping. The increase of injection rate from 0.167 kg/s to 1 kg/s decreases snap-off trapping by 32% in the BC case and increases trapping by 18% in the vG case.

Trapping by capillary pinning

Trapping by capillary pinning will occur whenever rock types have a difference in their constitutive relations, such as a difference in P_e (BC case), P_g (vG case), or S_{wi} . These differences are expected in natural rock, and thus we expect capillary pinning. (Cases 0, 14, 15, and 16 are artificial; they are homogeneous in their constitutive relations and thus do not exhibit capillary pinning.)

In a simplified model of sedimentary architecture, a reservoir can be presented as a succession of horizontal CG strata immersed in FG rocks at a typical distance of H (Figure 10). Buoyant CO₂ easily penetrates to CG strata from FG strata because there is no capillary entry pressure barrier. However, CO₂ cannot penetrate from FG to CG strata if the buoyant force is less than the capillary pressure barrier, i.e., if

$$\Delta\rho gh < P_{c,FG}(S_{CO_2,FG}) - P_{c,CG}(S_{CO_2,CG}), \quad (6)$$

where $\Delta\rho gh$ is the buoyant force upward per area, $\Delta\rho = \rho_w - \rho_{CO_2}$; ρ_w and ρ_{CO_2} are the density of brine and scCO₂, respectively; g is the gravitational constant; $P_{c,FG}(S_{CO_2,FG})$ is the capillary pressure of CO₂ at saturation $S_{CO_2,FG}$ in the overlying FG cell; and $P_{c,CG}(S_{CO_2,CG})$ is capillary pressure of CO₂ at saturation $S_{CO_2,CG}$ (see Figure 11 for schematic illustration). Thus, there is a threshold at the pairs of critical saturations at which, as defined by equation 6, the buoyant force equals $P_{c,FG} - P_{c,CG}$ (Figure 12).

Figure 10

Figure 11

Figure 12

To the extent that the CO₂ in the overlying FG stratum is not trapped and therefore mobile, saturations are dynamic. However, at any given time and state of capillary pressure the $S_{CO_2,CG}$ can never fall below the limit $S_{CO_2,CG}^{\min} = S_{CO_2,CG}^{Cr} - S_{CO_2,FG}^{Cr}$ as a function of $S_{CO_2,FG}^{Cr}$ in overlying strata. This relationship is plotted for case 3 in Figure 13 for different values of h and for $\Delta\rho = 300 \text{ kg/m}^3$. Two different sets of capillary curves based on the vG (formula (1)) and BC (formula (5)) approaches were used for the calculations. As one can see from the figure, the capillary trapping pattern is different between these two approaches. As shown, in the BC case pinning is *maximal* if $S_{CO_2,FG}^{Cr} = 0$ and *monotonically decreases* with an increase in $S_{CO_2,FG}^{Cr}$. In the vG case pinning is *zero* if $S_{CO_2,FG}^{Cr} = 0$ and *changes nonmonotonically* with an increase in $S_{CO_2,FG}^{Cr}$.

Figure 13

As expected, the trapping amount by capillary pinning depends on the capillary pressure scaling parameter P_g in the vG case and capillary entry pressure P_e in the BC case (Figure 14). This dependence is strongly nonlinear. Thus, the blue curve in Figures 14a and 14b can be considered as the saturation curve, i.e., further increases of P_g or P_e do not practically change the amount of capillary pinned CO₂. Also, the pinned amount strongly depends on the pore-size distribution index, which is n_g for vG and λ for BC (Figure 15). The values of λ were calculated based on n_g values using formulae from Lenhard et al. (1989). For rocks with a comparatively homogeneous pore-size distribution (red curves at Figure 15), the pinned amount is larger than in rocks with broadly dispersed pore sizes (green curves).

Figure 14

Figure 15

Saturation of pinned CO₂ in CG strata changes in time during injection and in post-injection, varying from zero to its maximal value (~ 0.3) in the vG case and from $(S_{CG,wi} - S_{FG,wi})$ to its maximal value (~ 0.4) in the BC case. During CO₂ injection, a new portion of gas may pass through a particular CG stratum and totally replace the existing gas; however, a certain amount of CO₂ is always trapped in such CG stratum. Only if there is no capillary pressure barrier between CG and FG rocks, and if the irreducible water saturation is the same for both rocks, is the value of $S_{CO_2,CG}^{trap}$ always zero.

To estimate the total amount of capillary pinned CO₂, let us first consider two edge limits, i.e., viscous-dominated flow and gravity-dominated flow. In the former case, which is applied to the area close to the injection well, the CO₂ saturation in both facies is close to the maximal CO₂ saturation, and thus the amount of trapping in CG cells is about $S_{CG,CO_2}^{trap} = S_{CG,wi} - S_{FG,wi}$. In the gravity-dominated flow case, which is applied to the margins of the plume area, the CO₂ saturation in FG strata (overlying CG strata) is about

zero in the BC case and close to saturation S_{FG,CO_2}^{max} in the vG case. Thus, the amount of trapping in CG cells is about $S_{CG,CO_2}^{trap,max}$ (Figure 16). In the cases considered here, this amount could be up to 0.5. Consequently, the total amount of capillary pinned CO_2 could be as large as $R \cdot S_{CG,CO_2}^{trap,max}$, where $R = V_{CG} / (V_{CG} + V_{FG})$ is the ratio of the volume of CG rocks to the total volume. If $R = 0.24$, as in the majority of cases considered here, the amount of capillary pinned CO_2 can be as large as 12% from the total amount of injected CO_2 . However, if R is about 0.5, the amount of capillary pinned CO_2 can be as large as 25%. Note that the procedure of estimating the amount of pinned CO_2 considered here is roughly valid only if $R \leq 0.5$. In cases where $R > 0.5$, CO_2 avoids entering FG rocks and the amount of capillary pinned CO_2 is negligible.

Figure 16

Conclusion

It is commonly assumed that a substantial amount (from 10% to 30%) of CO_2 injected into deep saline reservoirs is trapped in brine because a variety of capillary trapping mechanisms; consequently, the CO_2 does not reach the caprock (Krevor et al., 2015). This assessment is usually based on the estimate of residual trapping during the imbibition process when brine replaces CO_2 (Kumar et al., 2005; Juanes et al., 2006; Gammer et al., 2011; Szulczewski et al., 2012; Warwick et al., 2013). The latter happens during the post-injection period. However, storage of CO_2 at the industrial scale, such as disposal from fossil-fired power plants, would be continued for many (10–50) years. Thus, it is important to estimate the amount of capillary trapped CO_2 during the injection period.

Residual capillary trapping (snap-off) occurs only during imbibition. That is why there is no capillary trapping in homogeneous reservoirs during the injection period. There are two types of capillary trapping in heterogeneous reservoirs, specifically snap-off and capillary pinning. The first one works at the pore scale (Kumar et al., 2005; Juanes et al., 2006) and the second works at the scale of heterogeneity (Bryant et al., 2006; Ide et al., 2007; Saadatpoor et al., 2009; Zhou et al., 2009; Frykman et al., 2013; Zhao et al., 2014; Gershenzon et al., 2014, 2015, 2016a and b). In contrast to snap-off trapping, capillary pinning exists during both drainage and imbibition processes. Thus, it exists not only during the post-injection period but during the injection period as well. Interestingly, snap-off trapping also exists in heterogeneous reservoirs, even during the injection period, although its amount is less than during the post-injection period by an order of magnitude. The amount of snap-off increases with (1) an increase in contrast in intrinsic permeability, (2) an increase in contrast in irreducible water saturation, (3) an increase in contrast in maximal residual CO_2 saturation between CG and FG rocks, and

(4) a decrease in contrast in capillary pressure. In fluvial-type reservoirs, the amount of snap-off can be as large as 5% of the total amount of injected CO₂, but it is about 1%–2% when using realistic parameters, e.g., case 3. This amount also depends on the injection rate. An increase in the injection rate decreases snap-off trapping if the capillary pressure curve is described by the BC approach and increases trapping if the capillary pressure curve is described by the vG approach.

Trapping by capillary pinning dominates during the injection period and can be up to 25% but is about 10% when using the aforementioned realistic parameters. The amount of pinned CO₂ increases when the contrast between CG and FG rocks increases for one of the following: (1) irreducible water saturation, (2) capillary entry pressure (in the BC case) or capillary pressure scaling parameter (in the vG case), and (3) value of the pore-size distribution index. This pinned amount is proportional to the fraction of the rocks with low capillary pressure (CG rocks in the cases we present). Pinning is larger in gravity-dominated flow than in viscous-dominated flow. Rocks that have a capillary pressure curve more adequately described by the BC approach are able to trap more CO₂ than rocks that have a capillary pressure curve described by the vG approach.

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Figures

Figure 1. Schematic of snap-off trapping (a), capillary pinning (b), and capillary retardation (c).

Figure 2. Relative permeability of CO₂ in FG (blue and magenta) and CG (red and green) for drainage and imbibition as a function of brine saturation (cases 1–5).

Figure 3. Capillary pressure of CO₂ in FG (blue) and CG (red) for drainage as a function of brine saturation (cases 1–5). Solid curves are built using the vG approach (formula [1]) and dashed curved are built using the BC approach (formula [5])

Figure 4. Total amount of snap-off trapping as a function of time during CO₂ injection (50 days) and post-injection periods (cases 0, 3, 15, and 16)

Figure 5. Vertical cross section of reservoirs showing CO₂ saturation after 50 (injection period) and 250 days for cases 0, 3, and 14–16. Vertical exaggeration is 15×.

Figure 6. Total amount of snap-off trapping as a function of time during CO₂ injection period (cases 1–5).

Figure 7. Total amount of snap-off trapping as a function of time during CO₂ injection period (cases 3, 15, and 16).

Figure 8. Total amount of snap-off trapping as a function of time during CO₂ injection period (cases 3, 6, 12, and 13).

Figure 9. CO₂ saturation as a function of time during CO₂ injection period (cases 16, Table 1) for cells with the following x - y - z coordinates: (51, 37, 60; red line), (51, 37, 63; blue line), (51, 37, 65; green line), (51, 37, 67; teal line), and (51, 37, 70; purple line).

Figure 10. Simplified schematic representation of fluvial strata of CG rocks of height h with large permeability k_{CG} separated by strata of FG rocks of height H with small permeability k_{FG} .

Figure 11. The schematic figure of capillary pressure for CG (blue) and FG (red) rocks as a function of water saturation, illustrating formula (6).

Figure 12. Critical CO₂ saturation in CG strata $S_{CO_2,CG}^{Cr}$ as function of critical CO₂ saturation $S_{CO_2,FG}^{Cr}$ in overlying FG strata for vG (blue) and BC (red) calculated for the case 3 and $h=0.1$ m.

Figure 13. Maximal saturation of capillary trapped CO₂ in CG strata $S_{CO_2,CG}^{trap}$ as a function of CO₂ saturation of overlying FG strata $S_{CO_2,FG}$ for different CG strata widths h : (a) for van Genuchten and (b) for Brooks-Corey capillary pressure curves. $S_{CO_2,CG}^{trap} = S_{CO_2,CG} - S_{CO_2,FG}$, where $S_{CO_2,CG}$ is calculated from equation (5).

Figure 14. The same as in Figure 10 for different capillary pressure scaling parameter (a) and capillary entry pressure (b).

Figure 15. The same as in Figure 10 for different pore-size distribution index. The values of λ were calculated based on n_g values using formulae from Lenhard et al. (1989).

Figure 16. Vertical cross section of reservoirs showing CO₂ saturation after 50 (injection period) and 250 days for case 3 with vG and BC capillary pressure curves. Vertical exaggeration is 15 $\times$.