GEOPHYSICAL RESEARCH LETTERS, VOL. 38, L06401, doi:10.1029/2011GL046683, 2011

Measurements of the capillary trapping of super-critical carbon dioxide in Berea sandstone

Christopher H. Pentland,[1] Rehab El-Maghraby,[1] Stefan Iglauer,[1] and Martin J. Blunt[1]

Received 5 January 2011; revised 1 February 2011; accepted 3 February 2011; published 17 March 2011.

[1] We measure primary drainage capillary pressure and the relationship between initial and residual non-wetting phase saturation for a supercritical carbon dioxide (CO_2)-brine system in Berea sandstone. We use the semi-permeable disk (porous-plate) coreflood method. Brine and CO_2 were equilibrated prior to injection to ensure immiscible displacement. A maximum CO_2 saturation of 85% was measured for an applied capillary pressure of 296 kPa. After injection of brine the CO_2 saturation dropped to 35%; this is less than the maximum trapped saturation of 48% measured in an equivalent *n*-decane (oil)-brine experiment. The dimensionless capillary pressure is the same to within experimental error for supercritical CO_2-brine, *n*-decane-brine and a mercury-air system. CO_2 is the non-wetting phase and significant quantities can be trapped by capillary forces. We discuss the implications for CO_2 storage. **Citation:** Pentland, C. H., R. El-Maghraby, S. Iglauer, and M. J. Blunt (2011), Measurements of the capillary trapping of super-critical carbon dioxide in Berea sandstone, *Geophys. Res. Lett.*, *38*, L06401, doi:10.1029/2011GL046683.

1. Introduction

[2] Saline aquifers have been identified as suitable storage locations for anthropogenic CO_2 emissions collected from fossil-fuel burning power stations and other industrial sites, because of their large capacities and wide geographical spread [*Lackner*, 2003]. Storage would likely occur at depths greater than 800 m where the formation temperature and pressure render the CO_2 in a dense supercritical phase. The CO_2 is trapped by dissolution, mineralisation, structural and stratigraphic confinement, and capillary trapping. Capillary trapping is a rapid and effective mechanism to ensure safe storage. It occurs when brine displaces and traps the CO_2 as discontinuous droplets at the trailing edge of a rising CO_2 plume, or when engineered through brine injection [*Ide et al.*, 2007; *Juanes et al.*, 2006; *Kumar et al.*, 2005; *Qi et al.*, 2009; *Saadatpoor et al.*, 2009]. Where the resident formation brine has become saturated with CO_2 – and the CO_2 is saturated with water – there will be a region within the aquifer where immiscible displacement occurs. Simulation and analytical studies imply that this region covers the majority of the plume [*Hesse et al.*, 2008; *Qi et al.*, 2009].

[3] There are two key properties that influence the subsurface behaviour of CO_2: the primary drainage capillary pressure; and hysteresis in the CO_2 saturation – specifically, the amount of CO_2 that is trapped as a function of initial CO_2 saturation – the trapping curve. The primary drainage capillary pressure determines the threshold pressure to enter the rock that controls the ability of low permeability layers to stop the upwards migration of CO_2. The trapping curve will determine how much CO_2 can be rendered immobile by capillary forces which in turn controls how far the CO_2 migrates and the effectiveness of brine injection as a design for safe storage [*Qi et al.*, 2009].

[4] If supercritical CO_2 were the non-wetting phase in the presence of aquifer brines, then there would be significant trapping of CO_2, allowing safe storage [*Hesse et al.*, 2008; *Qi et al.*, 2009]. In contrast, if the CO_2 were wetting or neutrally-wet, there would be little capillary trapping within the aquifer, making safe CO_2 storage problematic. For instance, *Spiteri et al.* [2008] showed using pore-scale modelling that the residual saturation can be almost 0.5 in Berea sandstone when the trapped phase is non-wetting, but that this saturation drops rapidly to 0.25 when the contact angle becomes greater than 90° and falls further if the residual phase is wetting (contact angles much larger than 90°). Capillary pressure and the trapping curve have been measured before on oil-water systems with applications to hydrocarbon recovery, where the oil is the non-wetting phase (see *Pentland et al.* [2010] for a review of the literature). However, only isolated measurements of trapped CO_2 saturation have been reported [*Plug and Bruining*, 2007; *Perrin and Benson*, 2010; *Bennion and Bachu*, 2008; *Okabe et al.*, 2010; *Shi et al.*, 2010; *Suekane et al.*, 2008, 2009]. The CO_2 trapping curve has not been measured and there has been no comparison with equivalent strongly non-wetting systems.

[5] The receding contact angle (CO_2 displacing brine) affects the primary drainage capillary pressure and caprock invasion, while the advancing angle (brine displacing CO_2) governs capillary trapping. A recent review of the literature [*Naylor et al.*, 2010] concluded that for primary drainage, super-critical CO_2 remains the non-wetting phase with contact angles up to 49°. For brine displacing CO_2, however, there is disagreement over the typical wettability. *Plug and Bruining* [2007] measured the drainage and imbibition capillary pressures for super-critical CO_2 and suggested that during water displacement, CO_2 could become the wetting phase. *Dickson et al.* [2006] and *Yang et al.* [2008] found values of the advancing contact angle close to 90° on limestone and chemically treated glass surfaces, again implying neutral wettability with little trapping. However, several other authors [*Chiquet et al.*, 2007; *Espinoza and Santamarina*, 2010; *Tonnet et al.*, 2010; *Shah et al.*, 2008] found lower contact angles on quartz, mica and caprock surfaces: although the contact angle is a function of temperature and pressure, at super-critical conditions CO_2 remained

---

[1] Department of Earth Science and Engineering, Imperial College London, London, UK.

0094-8276/11/2011GL046683

Table 1. Estimated Phase Properties at 343 K and 9 MPa (Unless Stated) From the Literature

	CO_2	Brine (CO_2 Saturated)	*n*-Decane
Density, ρ (kg m^{-3})	208^a	1025^b	700^c
Viscosity, μ (Pa s)	$2.1 \times 10^{-5\ d}$	$5.1 \times 10^{-4\ e}$	$5.5 \times 10^{-4\ f}$

[a] *Span and Wagner* [1996].

[b] *Bando et al.* [2003] assuming an unsaturated brine density of 1020 kg m^{-3} [*Mao and Duan*, 2008].

[c] *Banipal et al.* [1991] and *Lee and Ellington* [1965].

[d] *Fenghour et al.* [1998].

[e] *Bando et al.* [2003]; 3.0wt.% NaCl aqueous solution at 10.0 MPa, 333 K.

[f] *Lee and Ellington* [1965]; 9.48 MPa, 344K.

the non-wetting phase. We address this ambiguity by measuring directly the physical quantities of interest: namely the amount of capillary trapping for the full range of initial saturation – the trapping curve – and the primary drainage capillary pressure on a Berea sandstone core, representative of aquifer rocks. We use the semi-permeable disk (porous plate) technique to control the initial saturation and a stirred reactor to ensure equilibrium between the CO_2 and brine prior to injection. Our results suggest that CO_2 is the non-wetting phase and that significant trapping is possible.

2. Experiments

[6] The experiments were performed on two consolidated Berea sandstone samples. One sample was used for CO_2-brine experiments and the other for oil-brine experiments. Measured properties were the same for both samples (porosity = 0.22; brine permeability = 4.6 × 10^{-13} m^2; diameter = 0.0385 m; length = 0.0753 m). A modified semi-permeable disk (porous plate) method [*Hassler and Brunner*, 1945; *McCullough et al.*, 1944] was used to vary the capillary pressure and hence saturation within the sample. A hydrophilic semi-permeable disk (aluminium silicate, Weatherford Laboratories, Stavanger, Norway) was placed at one end of the rock sample. The non-wetting phase was injected into the opposite face of the rock sample and its production was prevented by the high capillary entry pressure of the disk on the outlet face. The resident brine could pass freely through the disk. In this manner the brine pressure was held almost constant throughout the system while the non-wetting phase pressure was increased. The difference between the phase pressures was equal to the capillary pressure at hydrodynamic equilibrium.

2.1. Experimental Conditions

[7] Experiments were performed at conditions representative of storage formations – 343 K (70°C) and 9 MPa pore pressure. The wetting phase was aqueous 5wt.%-sodium chloride, 1wt.%-potassium chloride synthetic brine which was saturated with CO_2 in the CO_2-brine experiments using a stirred reactor. In the oil-brine experiments the non-wetting phase was *n*-decane. The phase properties at these conditions are estimated from the literature and shown in Table 1.

2.2. Experimental Equipment

[8] The rock sample and semi-permeable disk were housed within a pressure cell. A radial confining pressure (2.76 MPa above pore pressure) was applied. The semi-permeable disk was modified by drilling a hole in the centre, through which a tube could pass. This tube was used during waterflooding to avoid large pressure drops across the disk. The tube was connected to a valve which was closed during primary drainage to prevent non-wetting phase production. A fluoroelastomer o-ring provided a seal between tube and disk to prevent bypassing of the non-wetting phase. All flowlines and most valves were C276 alloy metal to mitigate the risk of corrosion. Experimental pressure and displacement rates were controlled by high precision syringe pumps (Teledyne ISCO 500D & 1000D, Lincoln, NE, USA). One pump was used to pressurise the non-wetting phase to experimental conditions for injection into the sample. An identical pump received the effluent from the sample during each flooding sequence. In the CO_2-brine experiments the phases were equilibrated prior to use inside a stirred reactor (1200mL C276 autoclave with gas entrainment stirrer – Parr Instruments Co., IL, USA).

2.3. Experimental Procedure

[9] The CO_2-brine experimental procedure is given below; it provides one unique data point comprising initial saturation, corresponding drainage capillary pressure and residual saturation after waterflooding. After depressurisation of the pore space to measure the residual CO_2 saturation steps 2–5 were repeated to vary the initial saturation, each time producing an additional data point.:

[10] Phases equilibrated in the stirred reactor at experimental conditions.

[11] Rock sample and semi-permeable disk saturated with brine.

[12] CO_2 injected into rock sample at a predetermined capillary pressure P_c (primary drainage) to initial saturation S_i.

[13] Rock sample waterflooded to residual saturation S_r.

[14] S_r measured by an isothermal depressurisation of the pore space.

[15] The phases were initially equilibrated by agitation in the stirred reactor. Equilibrium was reached when no more CO_2 entered the rector from an attached pump held at constant pressure. The solubility of CO_2 in brine was measured to be a mole fraction of 0.0136 ± 0.0020 for the experimental conditions investigated. This is in the range of solubilities measured on similar systems [*Koschel et al.*, 2006]. The sample was saturated by introducing un-equilibrated brine into the pore space under vacuum. Once the pore space was pressurised injection was switched to equilibrated brine and five pore volumes were pumped though the sample. During immiscible CO_2 injection, hydrodynamic equilibrium corresponded to a uniform pressure distribution along the sample length in each of the phases. The difference in the equilibrium pressure of the two phases corresponded to P_c. At equilibrium the phase saturations were assumed to be uniform along the length of the sample. No additional CO_2 entered the sample and no brine was produced. P_c was accurately controlled by the inlet and outlet syringe pumps. The difference in pump pressures was varied up to 296 kPa at equilibrium. This is equivalent to a CO_2 column height of 37 m in a formation at our experimental conditions. This P_c was sufficient to de-saturate the sample to irreducible brine saturation. The duration of primary drainage was inversely related to the applied P_c. The longest drainage time was 166 hours and the shortest was 14 hours. The sample was flooded to residual CO_2 saturation by immiscibly displacing

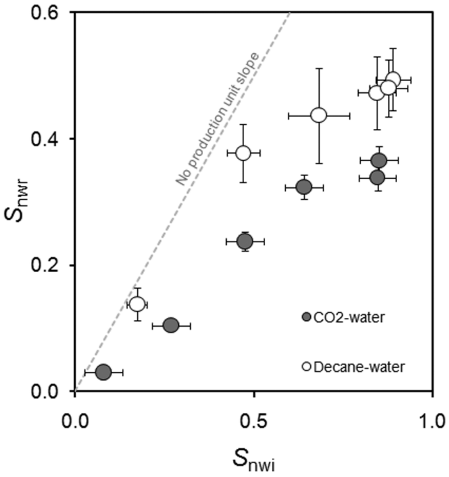

Figure 1. Saturation hysteresis data – the trapping curve – measured on Berea sandstone.

and trapping CO_2 with equilibrated brine. Five pore volumes were injected at a capillary number of 4.1×10^{-7}; the maximum capillary number during drainage was in the range $0.5–3 \times 10^{-10}$. It was not possible to measure imbibition capillary pressures with our apparatus. The initial CO_2 saturation was determined from a volume balance measurement. The volume of brine produced during primary drainage was considered equal to the volume of CO_2 injected. Knowing the dead volume and pore volume S_i was calculated. S_r was measured by isothermal depressurisation of the CO_2 within the sample pore space immediately after waterflooding [*Suekane et al.*, 2008]. The same procedure was followed in the oil-brine experiments except S_i and S_r were determined by mass and volume balance measurements and phase pre-equilibration was unnecessary – further details are given elsewhere [*Pentland et al.*, 2010].

3. Results

[16] The capillary trapping curve – S_r as a function of S_i – is shown in Figure 1. A small but distinct difference exists between the magnitude of S_r in the CO_2-brine and oil-brine systems – especially at high S_i.

[17] Figure 2 shows the dimensionless primary drainage capillary pressure – expressed as the Leverett-J Function $J[S_w]$ [*Leverett*, 1941] – for each corresponding S_i in Figure 1. $J(S_w)$ is defined as [*Rose and Bruce*, 1949]:

$$J(S_W) = \frac{P_c}{\sigma \cos\theta}\left(\frac{K}{\phi}\right)^{1/2} \quad (1)$$

where K and ϕ are the sample permeability and porosity respectively, σ the interfacial tension and θ the contact angle between the phases and the solid rock surface. Also shown in Figure 2 are mercury injection capillary pressure (MICP) measurements (Autopore IV 9520; Weatherford Laboratories, Stavanger, Norway) performed on the same Berea rock type at a commercial core laboratory. The interfacial tensions for the CO_2-brine, oil-brine and mercury-air systems are assumed to be 36.0 [*Chalbaud et al.*, 2009; *Chiquet et al.*, 2007], 48.3 [*Zeppieri et al.*, 2001] and 485 mN m^{-1} respectively. The contact angle during primary drainage is assumed to be 130° for mercury-air and 0° for CO_2-brine and oil-brine. There is good agreement between the mercury-air, oil-brine and CO_2-brine datasets with the exception of the absence of an irreducible saturation in the MICP results. This is expected as the irreducible saturation is clay bound in the presence of brine [*Omoregle*, 1988]. The error bars on Figures 1 and 2 represent the standard deviation of the measured values; the greatest errors (as a proportion of the absolute value) were associated with the differential pressure at low capillary pressure. Each data point represents one complete experiment: primary drainage and brine flooding. We checked the reproducibility of the results by repeating several experiments with similar initial CO_2 or oil saturations; the results were similar to within the estimated measurement error.

4. Discussion and Conclusions

[18] Significant quantities of CO_2 (up to 35% of the pore space) are trapped in Berea sandstone by capillary forces after the re-injection of brine. This is achieved by applying a realistic P_c during primary drainage equivalent to a CO_2 column height of 37 m. When compared with oil-brine data there is a decrease in the quantity of capillary trapping. It is proposed that this is due to an increase in the effective imbibition (advancing) contact angle in the CO_2-brine system, consistent with measurements of contact angle on quartz surfaces (Berea sandstone is principally composed of quartz) at conditions similar to ours by *Chiquet et al.* [2007] and *Espinoza and Santamarina* [2010]. However, the system remains water-wet with a large degree of trapping possible. If the rock were neutrally or CO_2-wet,

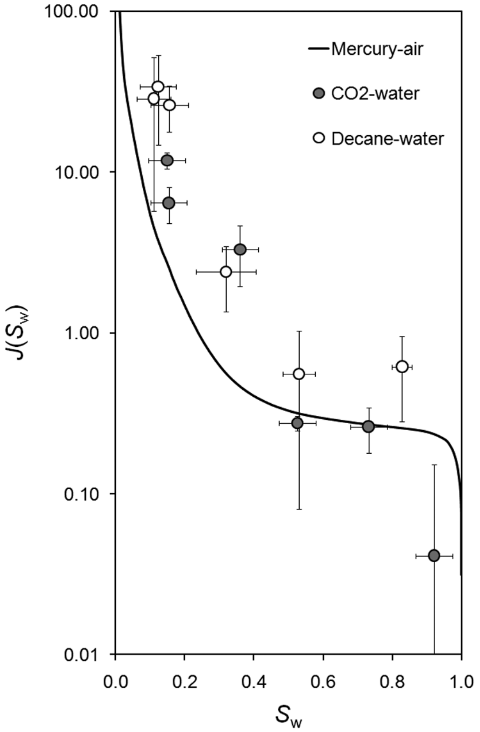

Figure 2. Primary drainage capillary pressure versus saturation data measured on Berea sandstone. The three sets of data (CO_2-brine; oil-brine; mercury-air) have been normalised using the Leverett-J Function (equation (1)).

lower residual saturations would have been expected, as CO_2 would no longer become stranded in the larger pore spaces [*Spiteri et al.*, 2008].

[19] The dimensionless capillary pressure (the Leverett J function) is the same, to within experimental error, for oil-brine and CO_2-brine systems assuming, in both cases, that the contact angle during primary drainage is zero, except at the lowest capillary pressures. The discrepancy at low pressures (corresponding to low non-wetting phase saturations) could be caused by dynamic effects, pressure fluctuations or subtle differences in wettability. The assumption of low contact angles during primary drainage is in agreement with other studies, as reviewed by *Naylor et al.* [2010]. Future work will focus on investigating a wider range of pressure and temperature conditions and different rock samples and relating these to independent measurements of wettability and contact angle.

[20] **Acknowledgments.** We would like to thank Shell under the Grand Challenge on Clean Fossil Fuels for funding this work.

[21] The Editor thanks one anonymous reviewer.

References

Bando, S., F. Takemura, M. Nishio, E. Hihara, and M. Akai (2003), Solubility of CO_2 in aqueous solutions of NaCl at (30 to 60) °C and (10 to 20) MPa, *J. Chem. Eng. Data*, *48*(3), 576–579, doi:10.1021/je0255832.

Banipal, T., S. Garg, and J. Ahluwalia (1991), Heat capacities and densities of liquid -octane, -nonane, -decane, and -hexadecane at temperatures from 318.15 K to 373.15 K and at pressures up to 10 MPa, *J. Chem. Thermodyn.*, *23*(10), 923–931, doi:10.1016/S0021-9614(05)80173-9.

Bennion, D. B., and S. Bachu (2008), Drainage and imbibition relative permeability relationships for supercritical CO_2/brine and H_2S/brine systems in intergranular sandstone, carbonate, shale, and anhydrite rocks, *SPE Reservoir Eval. Eng.*, *11*(3), 487–496, doi:10.2118/99326-PA.

Chalbaud, C., M. Robin, J. Lombard, F. Martin, P. Egermann, and H. Bertin (2009), Interfacial tension measurements and wettability evaluation for geological CO_2 storage, *Adv. Water Resour.*, *32*(1), 98–109, doi:10.1016/j.advwatres.2008.10.012.

Chiquet, P., D. Broseta, and S. Thibeau (2007), Wettability alteration of caprock minerals by carbon dioxide, *Geofluids*, *7*(2), 112–122, doi:10.1111/j.1468-8123.2007.00168.x.

Dickson, J. L., G. Gupta, T. S. Horozov, B. P. Binks, and K. P. Johnston (2006), Wetting phenomena at the CO_2/water/glass interface, *Langmuir*, *22*(5), 2161–2170, doi:10.1021/la0527238.

Espinoza, D. N., and J. C. Santamarina (2010), Water-CO_2-mineral systems: Interfacial tension, contact angle, and diffusion—Implications to CO_2 geological storage, *Water Resour. Res.*, *46*, W07537, doi:10.1029/2009WR008634.

Fenghour, A., W. A. Wakeham, and V. Vesovic (1998), The viscosity of carbon dioxide, *J. Phys. Chem. Ref. Data*, *27*(1), 31, doi:10.1063/1.556013.

Hassler, G. L., and E. Brunner (1945), Measurement of capillary pressures in small core samples, *Pet. Trans. AIME*, *160*, 114–123.

Hesse, M. A., F. M. Orr, and H. A. Tchelepi (2008), Gravity currents with residual trapping, *J. Fluid Mech.*, *611*, 35–60, doi:10.1017/S002211200800219X.

Ide, S. T., K. Jessen, and F. M. Orr Jr. (2007), Storage of CO_2 in saline aquifers: Effects of gravity, viscous, and capillary forces on amount and timing of trapping, *Int. J. Greenh. Gas Control*, *1*(4), 481–491, doi:10.1016/S1750-5836(07)00091-6.

Juanes, R., E. J. Spiteri, F. M. Orr Jr., and M. J. Blunt (2006), Impact of relative permeability hysteresis on geological CO_2 storage, *Water Resour. Res.*, *42*, W12418, doi:10.1029/2005WR004806.

Koschel, D., J. Coxam, L. Rodier, and V. Majer (2006), Enthalpy and solubility data of CO_2 in water and NaCl(aq) at conditions of interest for geological sequestration, *Fluid Phase Equilib.*, *247*(1–2), 107–120, doi:10.1016/j.fluid.2006.06.006.

Kumar, A., M. Noh, R. Ozah, G. Pope, S. Bryant, K. Sepehrnoori, and L. Lake (2005), Reservoir simulation of CO_2 storage in deep saline aquifers, *SPE J.*, *10*(3), doi:10.2118/89343-PA.

Lackner, K. S. (2003), Climate change: A guide to CO_2 sequestration, *Science*, *300*(5626), 1677–1678, doi:10.1126/science.1079033.

Lee, A. L., and R. T. Ellington (1965), Viscosity of n-decane in the liquid phase, *J. Chem. Eng. Data*, *10*(4), 346–348, doi:10.1021/je60027a013.

Leverett, M. C. (1941), Capillary behavior in porous solids, *Pet. Trans. AIME*, *142*, 152–169.

Mao, S., and Z. Duan (2008), The *P,V,T,x* properties of binary aqueous chloride solutions up to $T = 573$ K and 100 MPa, *J. Chem. Thermodyn.*, *40*(7), 1046–1063, doi:10.1016/j.jct.2008.03.005.

McCullough, J. J., F. W. Albaugh, and P. H. Jones (1944), Determination of the interstitial-water content of oil and gas sand by laboratory tests of core samples, in *Drilling and Production Practice*, pp. 180–188, Am. Pet. Inst., New York.

Naylor, M., M. Wilkinson, and R. Haszeldine (2010), Calculation of CO_2 column heights in depleted gas fields from known pre-production gas column heights, *Mar. Pet. Geol.*, doi:10.1016/j.marpetgeo.2010.10.005, in press.

Okabe, H., Y. Tsuchiya, C. H. Pentland, S. Iglauer, and M. J. Blunt (2010), Residual CO_2 saturation distributions in rock samples measured by X-ray CT, in *Proceedings of the 3rd International Workshop on X-Ray CT for Geomaterials*, pp. 381–389, New Orleans, La.

Omoregle, Z. (1988), Factors affecting the equivalency of different capillary pressure measurement techniques, *SPE Form. Eval.*, *3*, 146–155, doi:10.2118/15384-PA.

Pentland, C. H., Y. Tanino, S. Iglauer, and M. J. Blunt (2010), Capillary trapping in water-wet sandstones: Coreflooding experiments and pore-network modeling, paper presented at SPE Annual Technical Conference and Exhibition, Florence, Italy, 20–22 Sept.

Perrin, J., and S. Benson (2010), An experimental study on the influence of sub-core scale heterogeneities on CO_2 distribution in reservoir rocks, *Transp. Porous Media*, *82*(1), 93–109, doi:10.1007/s11242-009-9426-x.

Plug, W., and J. Bruining (2007), Capillary pressure for the sand–CO_2–water system under various pressure conditions. Application to CO_2 sequestration, *Adv. Water Resour.*, *30*(11), 2339–2353, doi:10.1016/j.advwatres.2007.05.010.

Qi, R., T. C. LaForce, and M. J. Blunt (2009), Design of carbon dioxide storage in aquifers, *Int. J. Greenh. Gas Control*, *3*(2), 195–205, doi:10.1016/j.ijggc.2008.08.004.

Rose, W., and W. Bruce (1949), Evaluation of capillary character in petroleum reservoir rock, *Trans. AIME*, *186*, 127–142.

Saadatpoor, E., S. L. Bryant, and K. Sepehrnoori (2009), Effect of capillary heterogeneity on buoyant plumes: A new local trapping mechanism, *Energy Procedia*, *1*(1), 3299–3306, doi:10.1016/j.egypro.2009.02.116.

Shah, V., D. Broseta, and G. Mouronval (2008), Capillary alteration of caprocks by acid gases, paper 113353 presented at SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Okla.

Shi, J., Z. Xue, and S. Durucan (2010), Supercritical CO_2 core flooding and imbibition in Tako sandstone—Influence of sub-core scale heterogeneity, *Int. J. Greenh. Gas Control*, doi:10.1016/j.ijggc.2010.07.003, in press.

Span, R., and W. Wagner (1996), A new equation of state for carbon dioxide covering the fluid region from the triple-point temperature to 1100 K at pressures up to 800 MPa, *J. Phys. Chem. Ref. Data*, *25*(6), 1509–1596, doi:10.1063/1.555991.

Spiteri, E., R. Juanes, M. J. Blunt, and F. Orr (2008), A new model of trapping and relative permeability hysteresis for all wettability characteristics, *SPE J.*, *13*(3), 277–288, doi:10.2118/96448-PA.

Suekane, T., T. Nobuso, S. Hirai, and M. Kiyota (2008), Geological storage of carbon dioxide by residual gas and solubility trapping, *Int. J. Greenh. Gas Control*, *2*(1), 58–64, doi:10.1016/S1750-5836(07)00096-5.

Suekane, T., N. H. Thanh, T. Matsumoto, M. Matsuda, M. Kiyota, and A. Ousaka (2009), Direct measurement of trapped gas bubbles by capillarity on the pore scale, *Energy Procedia*, *1*(1), 3189–3196, doi:10.1016/j.egypro.2009.02.102.

Tonnet, N., D. Broseta, and G. Mouronval (2010), Evaluation of the petrophysical properties of a carbonate-rich caprock for CO_2 geological storage purposes, paper 131525 presented at SPE EUROPEC/EAGE Annual Conference and Exhibition, Barcelona, Spain, 14–17 June.

Yang, D., Y. Gu, and P. Tontiwachwuthikul (2008), Wettability determination of the reservoir brine−reservoir rock system with dissolution of CO_2 at high pressures and elevated temperatures, *Energy Fuels*, *22*(1), 504–509, doi:10.1021/ef700383x.

Zeppieri, S., J. Rodríguez, and A. L. López de Ramos (2001), Interfacial tension of alkane + water systems, *J. Chem. Eng. Data*, *46*(5), 1086–1088, doi:10.1021/je000245r.

M. J. Blunt, R. El-Maghraby, S. Iglauer, and C. H. Pentland, Department of Earth Science and Engineering, Imperial College London, Prince Consort Road, London SW7 2BP, UK. (c.pentland07@imperial.ac.uk)