THE IMPACT OF RESERVOIR CONDITIONS ON MULTIPHASE FLOW IN THE CO_2-BRINE SYSTEM IN PERMEABLE SANDSTONE

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ABSTRACT
Capillary strength and multiphase flow are key parameter inputs for modeling CO_2 injection processes for enhanced oil recovery and CO_2 storage. Experimental observations of the multiphase flow properties in this system reported over the past 10 years have raised important questions about the impact of reservoir conditions on flow through effects on wettability, interfacial tension and fluid-fluid mass transfer. In this work we report the results of a three year investigation aimed at resolving many of these outstanding questions for flow in sandstone rocks. The capillary pressure, relative permeability and residual trapping characteristic curves have been characterized in Bentheimer and Berea sandstone rocks across a pressure range 5 – 20 MPa, temperatures 25 – 90 C and brine salinities 0-5M NaCl. In total over 30 reservoir condition core flood tests were performed evaluating these properties with techniques including the steady state relative permeability test, the semi-dynamic capillary pressure test and a novel test for the rapid construction of the residual trapping initial-residual (IR) curve. Test conditions were designed to isolate effects of interfacial tension, viscosity ratio, density ratio and salinity. The results of the tests show unequivocally that reservoir conditions have minimal impact on relative permeability and residual trapping, consistent with continuum scale multiphase flow theory for water wet systems. The invariance of the characteristic curves is observed across the range of conditions, including transitions of the CO_2 from a gas to a liquid to a supercritical fluid, and in comparison with N_2-brine systems. Variations in capillary pressure curves are generally well explained by corresponding changes in IFT although some further variation may reflect small changes in wetting properties that have been observed in sessile drop experiments. As with gas-brine systems, the low viscosity of CO_2 at certain conditions results in particular sensitivity to rock heterogeneity. We show that (1) heterogeneity is the likely source of much of the uncertainty around relative permeability observations for this system and (2) that appropriate scaling of the driving force for flow by a quantification of capillary heterogeneity allows for the selection of core flood parameters that eliminate this effect. Similarly this scaling can be used to approximate the effect of small scale heterogeneity on flow for real reservoir systems.

INTRODUCTION

Fluid flow during CO_2-injection processes, for enhanced oil recovery and CO_2 storage, is governed by the multiphase flow properties - capillary pressure, relative permeability, hysteresis and residual trapping. A sketch of fluid flow during buoyant CO_2 migration in a reservoir is shown in Figure 1. The leading edge and upper portions of a plume maintain high capillary pressures and CO_2 saturation is high in these regions – leading to high values of relative permeability. In the lower and distal sections of the plume a capillary fringe will appear as saturation tapers to the residual. The disconnection of CO_2 ganglia results in hysteresis in the multiphase flow functions.

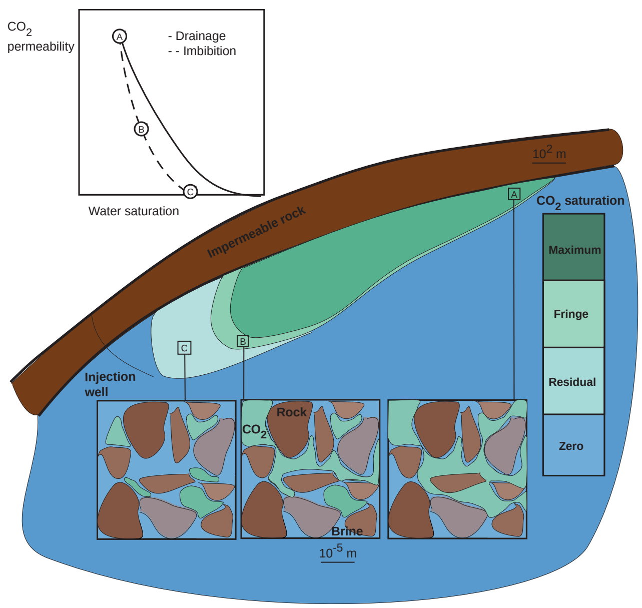

Figure 1. A sketch of key flow processes during CO_2 storage. During drainage, at the leading edge of the plume, CO_2 displaces resident brine to near the connate water saturation and relative permeability is high. Where the CO_2 plume is receding, brine imbibes and results in a disconnected fluid saturation. Ultimately, the saturation is lowered to residual immobile CO_2 which remains trapped. Figure from [25]

These relationships between the capillarity of a geologic system, and the saturation and permeability of the fluids have a direct bearing on the migration speed and reservoir sweep of a CO_2 plume (Figure 2, [1]), immobilisation through capillary trapping [2] and are used directly in assessments of the capacity of a storage site to contain CO_2 over geologic timescales [3].

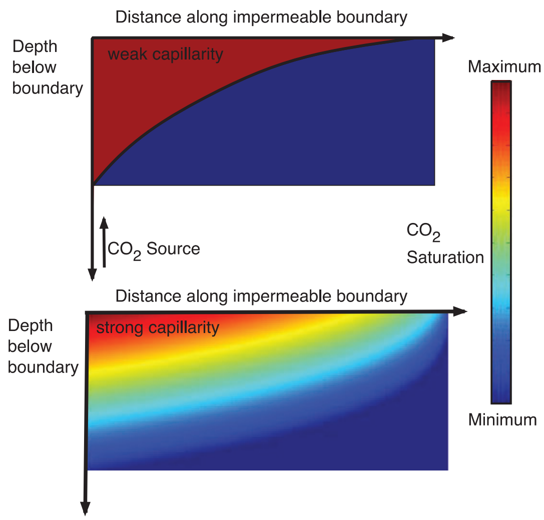

Figure 2. The impact of capillarity on multiphase flow – in systems with strong capillarity, i.e. strongly water wet systems, there is a larger plume sweep and lower forward propagation of CO_2 compared to systems with weaker capillarity, i.e. less strongly water wet systems. Figure adapted from [1].

Previous and ongoing experience with industrial scale carbon dioxide injection has come mostly from operations of enhanced oil recovery in the United States although there are pilot CO_2 storage projects around the world [4].

Despite the long history of the use of CO_2 for enhanced oil production there are longstanding uncertainties about the multiphase flow properties underlying descriptions and predictions of CO_2 migration and trapping in the subsurface. Major outstanding uncertainties include the impact of reservoir conditions of pressure, temperature and brine salinity on the wetting state and the relative permeability characteristic curve.

A large number of studies using sessile drop observations to characterise wetting have observed effects of pressure, temperature and brine salinity on wetting in this system with silicate and carbonate minerals, but the direction of the effects (increasing or decreasing wetting strength) and the magnitude have at times been contradictory [5-10]. A review of this issue has recently been published by [11].

Similarly, there are a large number of relative permeability curves reported in the literature (Figure 3, [12]). Based on these observations studies have variously described the CO_2-brine system as both less [13] and equivalently [14, 15] water wetting than hydrocarbon systems, to have relative permeabilities sensitive to variation in reservoir conditions [16], and for the system to have unusually low endpoint CO_2 relative permeabilities [17].

The work of [14] stands alone as a comprehensive evaluation of the sensitivity of the multiphase flow properties of the CO_2-brine system to reservoir conditions. In this approach, capillary pressure and relative permeability curves of rocks were characterised with mercury-air and nitrogen-water observations respectively. These properties were shown to lead to accurate modelled predictions of observations of unsteady state drainage, CO_2 displacing brine, at various temperatures and pressures. This lead to the conclusion that the CO_2-brine-rock system was water wet and the multiphase flow characteristics insensitive to reservoir conditions.

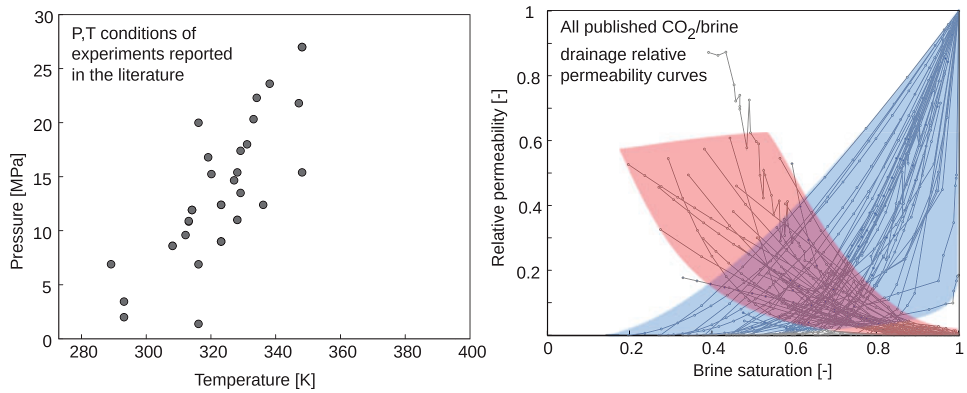

Figure 3. Compilation of drainage relative permeability curves published for CO_2-brine systems. From [12].

Characterisation of the capillary pressure characteristic curve can provide useful insight into the wetting state of a system and its impact on multiphase flow. Figure 4 shows sketches of capillary pressure primary drainage and secondary imbibition curves for water and mixed-wet CO_2-brine systems. In the mixed wet system during drainage there is a lower capillary entry pressure, a lower range of pressures required for full brine desaturation compared with the water wet system. During imbibition, there is more trapping in the water wet system and the residual is approached at capillary pressures close to zero. In the mixed-wet system, significant desaturation occurs at negative capillary pressures.

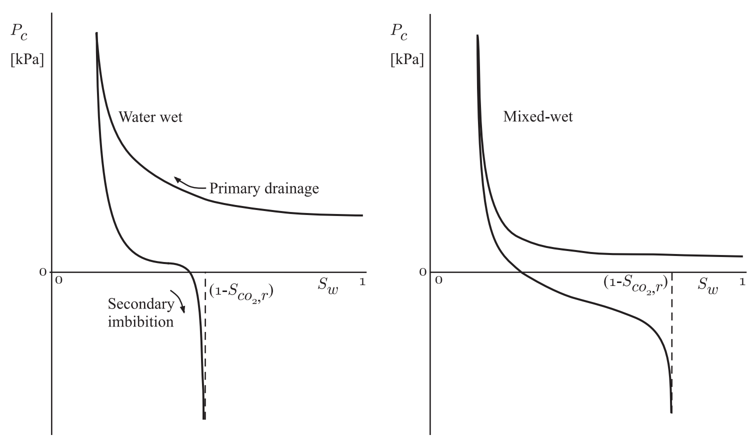

Figure 4. Primary drainage and secondary imbibition capillary pressure characteristic curves for water wet (left) and mixed-wet systems (right).

The residual trapping characteristic of a rock can thus be used partly as a diagnostic for the wetting state of the system. As described above, it is also a key reservoir characteristic, with primary controls on plume migration and storage capacity. The characteristic curve – described by the initial residual relationship shown in Figure 5 – is also often used to parameterise hysteresis models for capillary pressure and relative permeability, i.e. the Land model shown in Figure 5 [18].

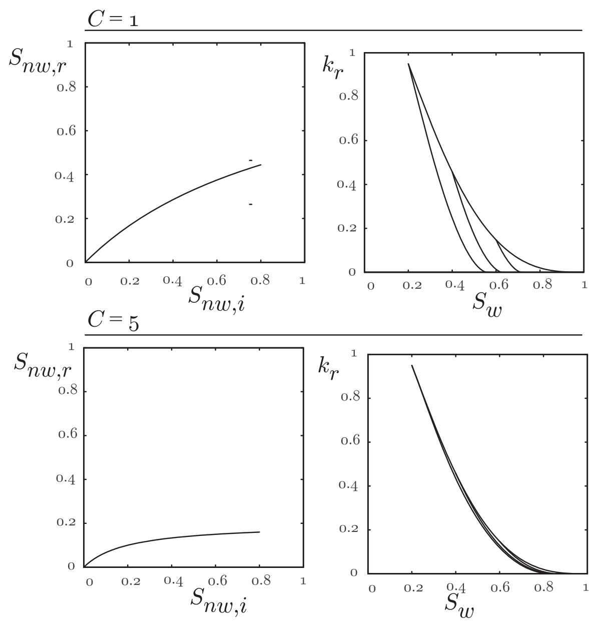

Figure 5. Initial-residual characteristic curves are shown on the left, constructed from the Land model with various values of the constant *C* [18]. On the right are the corresponding relative permeability curves with hysteresis tracking curves constructed with the Land model.

In this study we have sought to address outstanding questions around the response of multiphase flow properties in the CO_2-brine-sandstone rock system to reservoir conditions. We have evaluated the drainage capillary pressure, steady state relative permeability, and initial-residual curves characterising residual trapping at a range of reservoir conditions. These curves were compared with observations of the characteristic curves using the N_2-water system, known to be water-wet.

MATERIALS AND METHODS

A homogenous Berea sandstone rock core was used for the studies on capillary pressure and residual trapping. The homogeneity of the rock was most evident in the highly uniform saturation distribution of CO_2 and brine during multiphase flow displacement. The core was 3.8cm in diameter and 20cm in length and had a porosity and permeability of 0.19 and 210 mD respectively. The rock core was heated in an oven at 700°C to stabilise mobile clays. A Bentheimer sandstone sample was used for the observations of relative permeability. The rock core was 3.8 cm diameter, 23 cm in length and had a porosity and permeability of 0.22 and 1.8 D respectively.

The ranges of pressures, temperatures and brine salinities for all of the tests are summarised in Table 1.

Table 1. Conditions and rock samples used in the multiphase flow experiments.

Observation	**Pressures [MPa]**	**Temperature [°C]**	**Salinity [M NaCl]**	**Rock core**	**Technique**
Capillary pressure (drainage)	5-20	25, 50	0,1,3,5	Berea sandstone	Semi-dynamic Pc
Relative permeability (drainage)	10 – 21	30 - 90	0,1,3,5	Bentheimer sandstone	Steady state
Residual trapping	5- 20	25, 50	0,1,3,5	Berea sandstone	[19]

We used a variation of the semi-dynamic capillary pressure method [20-22] to measure the capillary pressure characteristic curves. A detailed description of the procedure is included in another paper in this symposium [23].

A steady state technique was used to characterise relative permeability. The saturation in the core sample was controlled by the ratio of injected phases, i.e. the fractional flow. In-situ saturation was measured along the entire sample with x-ray CT for each fractional flow once a constant pressure drop (i.e. steady state) was achieved. Evaluating the impact of reservoir conditions on multiphase flow in the CO_2-brine system is not a trivial task given that multiple fluid properties (density, viscosity) are changing over the same conditions of pressure, temperature and brine salinity**.** Experiments were designed to make observations of the relative permeability by varying interfacial tension while holding one or more of these parameters constant.

To construct the initial-residual capillary trapping characteristic curve, a core flood test was used to exploit the presence of capillary end effects to rapidly observe the relationship across a wide range of saturations at reservoir conditions [19]. In a given test, a range of initial CO_2 saturations along the length of the core were created by performing drainage at a flow rate that maximised the capillary end effect. Subsequently, imbibition was performed at a flow rate representative of reservoir conditions until the CO_2 saturation reduced to the residual. A range of residual saturations observed along the length of the core corresponded to the range in initial saturation existing prior to imbibition. As a result, a single core flood could be used to parameterise the initial-residual curve along a range of saturations.

RESULTS

One group of capillary pressure characteristic curves for tests evaluating the impact of pressure on capillarity are shown in Figure 6. In the right graph of the figure, the capillary pressures are scaled by the respective interfacial tensions for each condition. Variation in the capillary pressure characteristic curves are accounted for by the variation in interfacial tension for each condition suggesting that any variation in wettability is not making an impact on capillarity for this system. This was generally the case for all of the conditions tested, although there was some variation in the scaled curves. The consistency with the N_2-water system indicates that the CO_2-brine system is water wet during drainage. Further results are detailed in another paper in this symposium, [23].

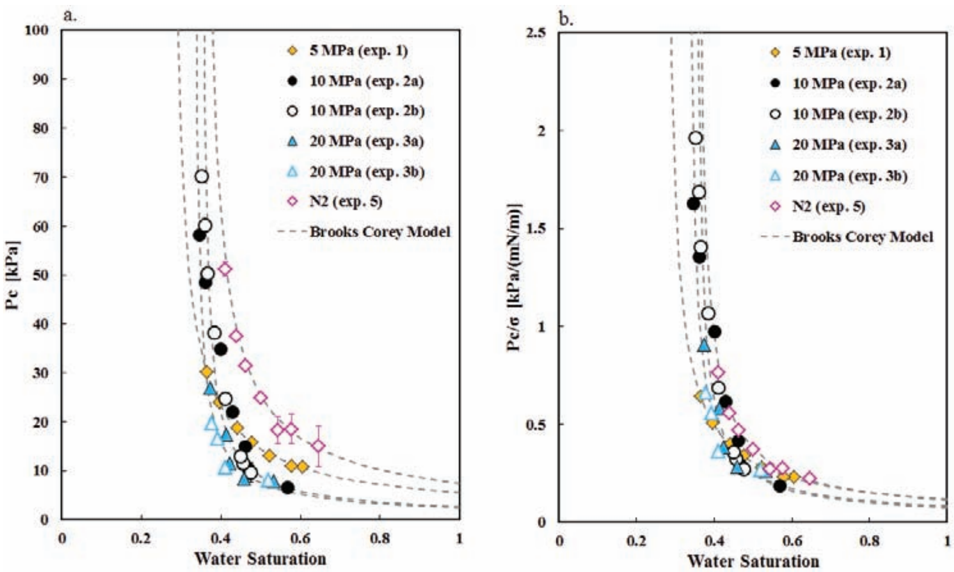

Figure 6. Capillary pressure characteristic curves evaluating the impact of pressure variation on capillarity in the system. Curves measured at pressures ranging from 5 MPa to 20 MPa are shown on the left and scaled by interfacial tension on the right. [23].

In the relative permeability tests the relative permeability of the rock core obtained when fluid saturations were unaffected by end effects, gravity segregation, and rock heterogeneity, was found to be invariant with reservoir conditions and equivalent to the N_2-water relative permeability. This will be referred to as the *intrinsic* relative permeability.

One group of results is shown in Figure 7. Two of the tests were performed with CO_2 and brine at reservoir conditions of pressure, temperature and brine salinity, while a third test was performed using a nitrogen-brine system at ambient conditions. The range of interfacial tension spanned from 37 mN m^{-1} to 62 mN m^{-1}. The results show little variation in the relative permeability between the tests.

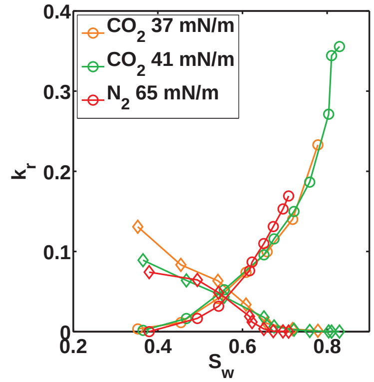

Figure 7. The intrinsic relative permeability of the rock core obtained from CO_2 and N_2 systems.

At conditions that resulted in CO_2 viscosities less than 30 μPa s, the fluid distributed heterogeneously throughout the core due to natural heterogeneity in the rock. Under these conditions, the derived relative permeability will be referred to as the *effective* relative permeability. We use this as the observational counterpart of a pseudo relative permeability. See [24] for a study in which pseudos have been applied to investigate core scale rock heterogeneity.

The effective relative permeability was observed to be sensitive to the test conditions, pressure, temperature, brine salinity and fluid flow rate. This is consistent with past observations and modelling of the impact of rock heterogeneity on observed flow properties [24]. Figure 8 shows one example of the intrinsic curve measured compared with an effective curve in which the interfacial tension was constant, but the viscosity of the CO_2 was less than 30 μPa s in the measurement affected by rock heterogeneity.

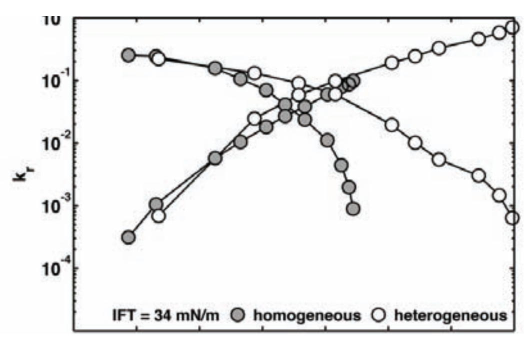

Figure 8. An intrinsic relative permeability curve (grey) and an effective relative permeability curve (white) measured at the same interfacial tension but distinct values of pressure and temperature. The difference in CO_2 viscosity led to homogenous and heterogeneous fluid distributions in the rock core.

The relative permeability core floods were all performed at a constant total flow rate of 20 ml min^{-1}, this being sufficient to minimise capillary end effects. Thus the total viscous pressure differential across the core, $\Delta\Phi = P_{\mathrm{inlet}} - P_{\mathrm{outlet}}$, varied primarily depending on the viscosity of CO_2 for a given test. When the viscous force was high enough to support the capillary pressure gradients prevalent at constant saturation (Figure 9), a homogenous saturation was obtained and the intrinsic relative permeability was achieved. When the viscous force was low compared with the capillary heterogeneity in the core, capillary driven flow redistributed fluid towards a system with constant *Pc*, but heterogeneous saturation distribution and an effective relative permeability was observed.

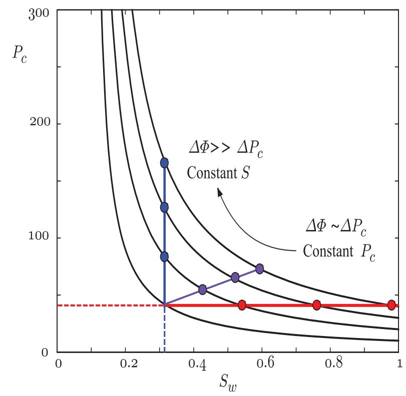

Figure 9. Conceptualising heterogeneity in the rock core with distinct capillary pressure characteristic curves. Low viscous force leads to a system of constant capillary pressure, but heterogeneous saturation distribution. A high viscous force leads to a system of homogenous saturation but capillary pressure gradients.

This study confirms the importance of evaluating the capillary heterogeneity in reservoir rock cores. We recommend in particular a characterisation of spatial heterogeneity in capillary pressure characteristic curves, e.g. [22]. A comparison of this with the estimated driving force for flow – e.g., pressure gradients, buoyancy - in a reservoir allows for one to design laboratory experiments either so that (1) an intrinsic relative permeability curve may be obtained or (2) effective flow functions representative of reservoir conditions can be observed. If capillary heterogeneity is significant, this provides quantitative guidance as to the conditions at which core tests should be operated to obtain representative effective relative permeabilities.

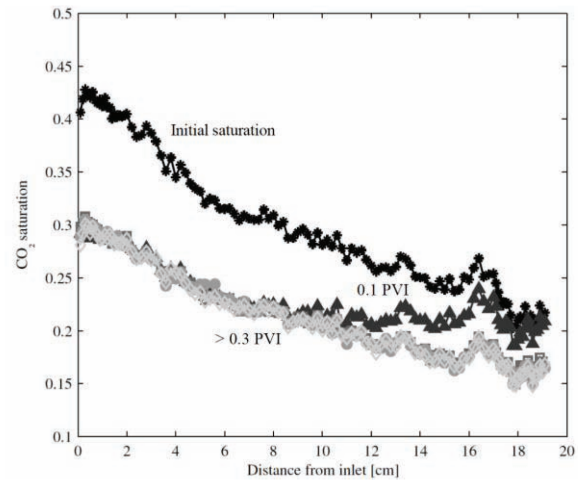

Figure 10. In-situ saturation profiles of CO_2 saturation after drainage (Initial saturation), after 0.1 pore volume of brine injection (PVI) and greater than 0.3 PVI showing the residually trapped saturation. From [19].

Observations of the saturation profile in a residual trapping experiment after drainage and during imbibition is shown in Figure 10. A compilation of the initial-residual data from all of the floods reported in [19] is shown in in Figure 11, along with the data obtained with an N_2-water system. There was little, if any, impact of reservoir conditions on the residual trapping characteristics of this system. The N_2-water curve was also indistinguishable from the CO_2-brine curves suggesting that this system was water wet during imbibition.

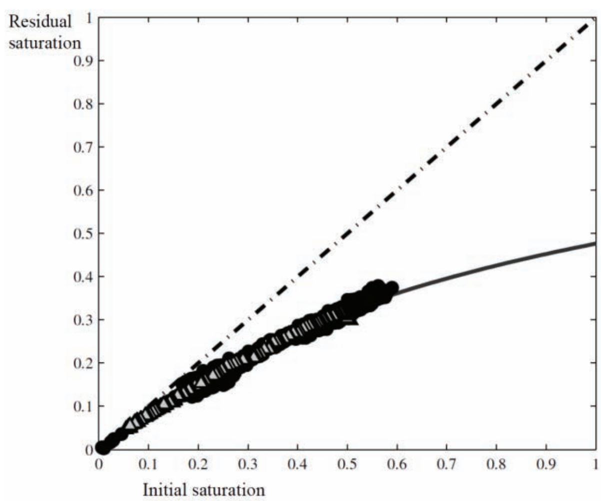

Figure 11. Initial-residual data from CO_2-brine core floods at all of the conditions are shown in black. Light colored symbols show trapping data obtained from a N_2-water system. From [19].

CONCLUSION

The body of observations demonstrate definitively that (1) the CO_2-brine system is water wet, and (2) the intrinsic multiphase flow properties of this system are invariant across the range of pressure, temperature and brine salinity in subsurface reservoirs worldwide. These two conclusions are consistent with the findings of [14] where a comprehensive evaluation of CO_2-brine multiphase flow was evaluated in carbonate rocks. It was also observed that (3) relative permeability in the CO_2-brine system may be sensitive to the presence of rock heterogeneity. In this case effective relative permeabilities should be obtained with appropriate scaling to reservoir conditions by comparing capillary heterogeneity to the viscous flow force representative of the reservoir system.

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