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CO_2-Brine Relative Permeability using a Multi-rate Unsteady State Method

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Abstract

Understanding CO_2/brine relative permeability is crucial for modeling fluid flow in CO_2 storage projects, which directly impacts the assessment of storage capacity, maximum injection rates, plume migration, and area of review (AoR). The U.S. Environmental Protection Agency (EPA) guidelines include the acquisition of this data for Class VI well permitting, to ensure safe and effective CO_2 sequestration. This paper describes a multi-rate unsteady-state method that aims to optimize the analysis time using an efficient, fit-for-purpose methodology. We discuss the methodology, compare it to the steady-state method, and provide an example dataset to validate its effectiveness.

Introduction

Two-phase relative permeability (Krel) is the permeability of rock to one fluid in the presence of another immiscible fluid, relative to an established, constant reference permeability, usually selected to be absolute permeability. Relative permeability varies as a function of fluid saturation. Relative permeability strongly affects CO_2 injectivity, plume migration, and area-of-review (AoR) for the injection site. Lab measurement of Krel is included in the EPA guidance for Class VI well site characterization and AoR estimation (EPA, 2013). These tests should be conducted at reservoir temperature and pressure using supercritical CO_2 ($scCO_2$). In addition, EPA recommends “data be obtained from analysis of samples collected from as many cores, boreholes, or wells as practical and available to provide an understanding of spatial variability in permeability.”

Theory and/or Methods

There are two common laboratory methods for determining full-curve relative permeability of both fluid phases, steady-state (SS) and unsteady-state (USS) (McPhee, et al, 2015, Muller, N., 2011). For $scCO_2$-brine systems, primary drainage is initiated from 100% carbonated brine saturation and imbibition should begin from irreducible brine saturation (S_{wir}). The steady-state method is where two immiscible fluids (e.g. humidified supercritical CO_2 and carbonated brine) are co-injected at several, pre-determined fractional flow rates. Each fractional rate continues until stable saturation and differential pressure values are achieved. Permeability to each fluid is computed from the flow rates and viscosities of the fluids, and the total pressure drop across the sample. The second method is unsteady-state, where supercritical CO_2 is injected to displace the carbonated brine whilst monitoring differential pressure and the production volumes of both fluids. Injection continues until $scCO_2$ fractional production flow reaches at least 99.9%, whereupon relative permeability (drainage path) is computed from the individual outflow fluid rates and the differential pressure after breakthrough. To avoid phase transfer between fluids we use a pre-equilibration process in both steady- and unsteady-state methods.

The method used in this project is a multi-rate unsteady state procedure where additional brine displacement is achieved by increasing, or "bumping", the $scCO_2$ injection rate multiple times. In addition, we use purpose-built reservoir simulation software designed for laboratory core flow experiments. This simulation process allows for correction of capillary end effects that can adversely impact the relative permeability computation for both steady- and unsteady-state methods. It also provides relative permeability curves across the full saturation range, thus comparable to the steady state data.

Results

The test shown here was performed on a clean sand sample of 22% porosity and 124 millidarcy permeability. These characteristics are consistent with many of the planned and active CCUS projects today. The brine displacement and differential pressure data for three different $scCO_2$ injection rates is shown in Figure 1.

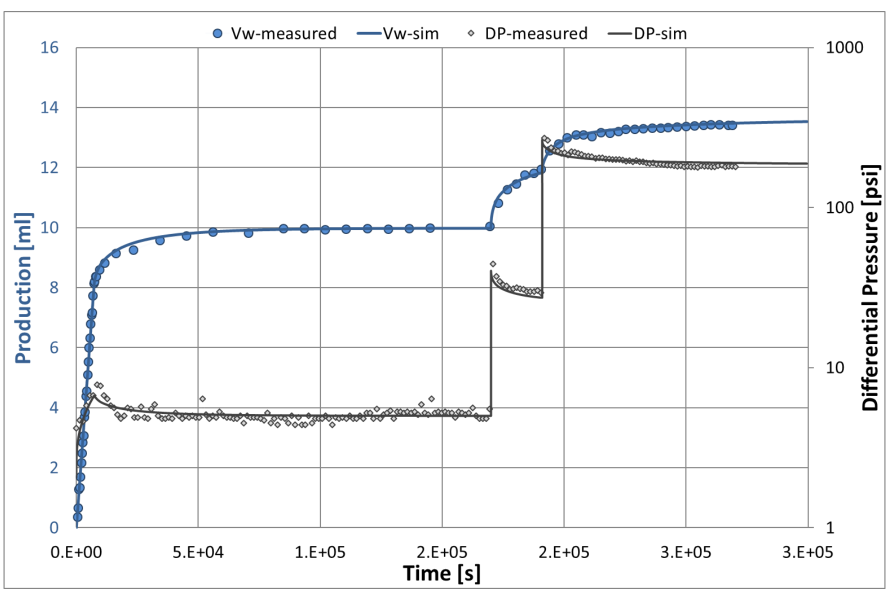

Figure 1. Circular dots show the cumulative brine displacement and diamond shapes show the differential pressure vs time.

Flow rate, pressure and volumes are just part of the data obtained. We also need brine/CO_2 capillary pressure. We can get this by converting air/Hg capillary pressure (P_{cap}) to brine/CO_2 P_{cap} at test conditions using the Young-LaPlace equation. Inputs are surface tension and contact angle between brine and scCO_2 at test conditions. The scCO_2/brine interfacial tension is measured at in-situ pressure and temperature.

The next step in the process is modelling to remove the capillary end effects. A common reservoir engineering tool is numerical simulation for understanding plume migration or how oil/gas reservoirs will produce over time. We use a similar process for the core plug sample under test, but with a much simpler and faster modeling process. The finite-element numerical code uses from 30 to 200 grid blocks, with refinement of the model towards the ends of the sample. The inputs are sample dimensions and properties, fluid properties (densities and viscosities), capillary pressure, surface tension, and contact angle at test conditions. This method provides a fine-scale description of capillary end effects and precludes the need for complex and costly in-situ saturation monitoring (ISSM) for saturation profiles of the core (Reed and Cense, 2019).

Discussion

The final computed relative permeability curves from this rapid relative permeability method are shown in Figure 2. Original SS and USS data points are both incorrect due to capillary end effects. The core flood simulator corrects data for both methods. The corrected USS curves closely follow the trend and shape of pre-breakthrough SS data. While not shown here, this method can be used for both drainage and imbibition path relative permeability which is recommended for estimation of AoR in CO_2 storage projects.

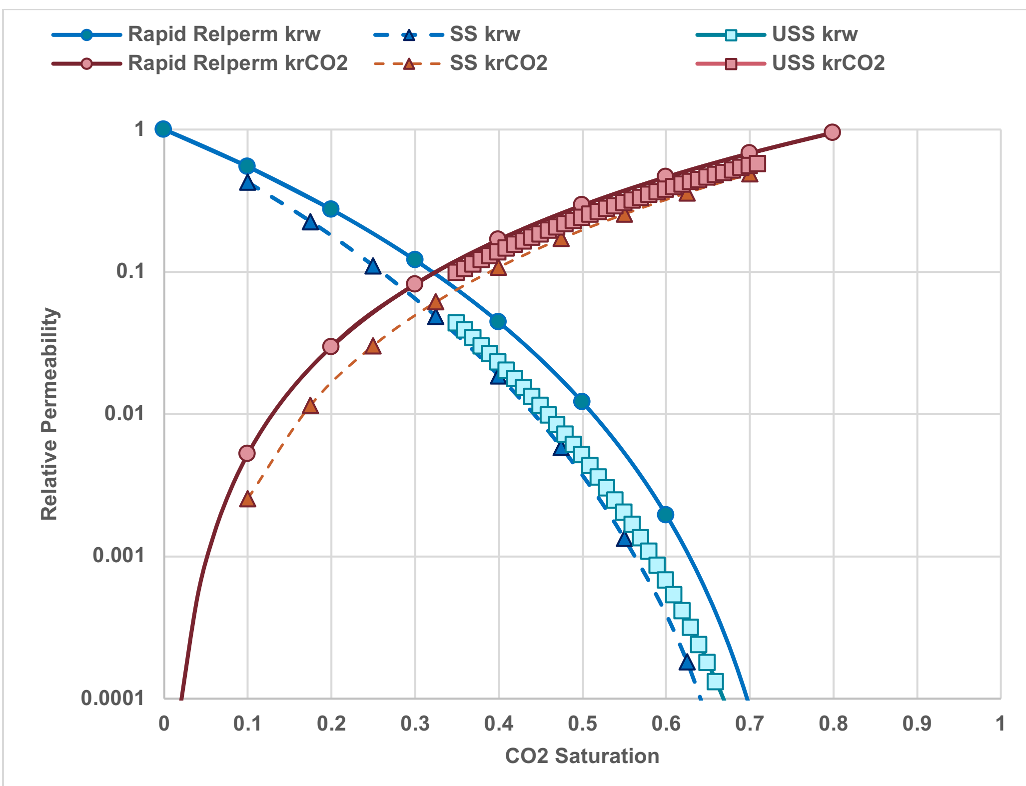

Figure 2: Final result is reservoir-condition relative perm curves that cover a wide range of expected fluid saturations. Diamonds are uncorrected steady state data and squares are uncorrected unsteady state data. Circles are capillary-pressure corrected USS relative perm. The simulation provides relative perm that is most representative of the true reservoir conditions.

Observations and Conclusions

This multi-rate unsteady-state relative permeability method, combined with appropriate simulator-corrected end effects, provides a rapid and reliable method for CCUS applications. Some advantages of the method include:

- Similar displacement process (Buckley-Leverett) as the actual reservoir
- Similar injection rates as in the actual reservoir can be used
- Faster testing (less expensive and/or more samples)
- Shorter samples (easier to obtain from whole core)
- No X-ray based saturation scans needed
- Reduced potential for clay and fines migration issues due to lower flow rates and throughput compared to SS

Some disadvantages are;

- Capillary boundary effects must be corrected using simulation (though this is also the case for SS testing)
- Only post-breakthrough data are used for direct analytical relative permeability calculations.

However, injection of lower viscosity, non-wetting phase supercritical CO_2 yields an early breakthrough and larger saturation range than in most brine/hydrocarbon cases. In addition, the multiple rates (bump-floods) increase the saturation range measured.

References

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