



Assessing the Uncertainty of Relative Permeability by Inverse Modelling

Introduction

Assessing feasibility and optimizing the process of storing carbon dioxide in underground geological simulations is typically performed by reservoir simulation. Geological and other uncertainties are probed by scenario modelling in which field-scale flow simulations are performed using the extended 2-phase Darcy formulation which requires besides porosity and permeability also relative permeability and capillary pressure-saturation functions as input. The situation is depicted in Figure 1.

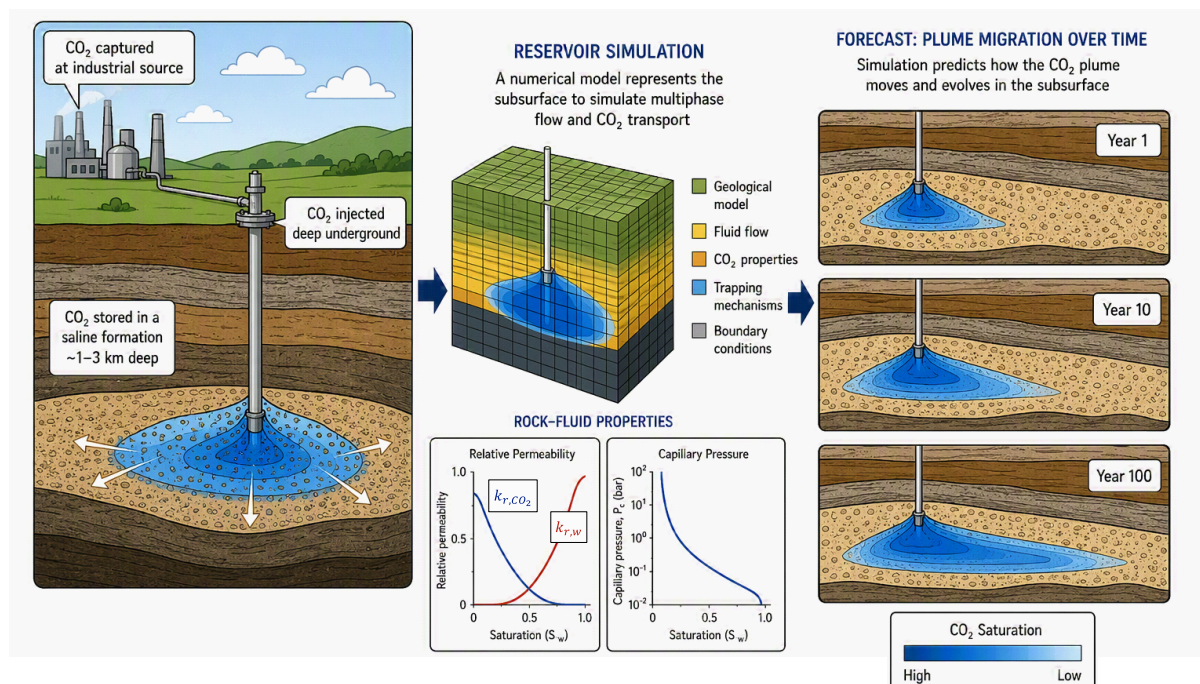


Figure 1 Illustration of the injection of CO₂ into a deep saline aquifer. For design and optimization, reservoir simulations are used for which – besides porosity and permeability – also relative permeability and capillary pressure saturation functions are required as input.

Field-scale model predictions have, besides the geological heterogeneity, porosity and permeability also commonly a very high sensitivity to relative permeability-saturation functions which requires emphasizes the relevance of consistency when determining relative permeability from laboratory core flooding experiments in special core analysis (SCAL).

Besides the industry-standard steady-state and unsteady-state methods there are numerous methods and even more interpretation protocols used in the literature to determine relative permeability (Berg et al. 2021a & 2021b, Berg et al. 2024). However, most of these workflows lack a coherent validation and quantification of the associated uncertainties on relative permeability and capillary pressure. What is commonly overlooked is the treatment of typical laboratory artefacts such as capillary end-effects and the extent to which the resulting relative permeability is constrained by the experimental data. This leads to a large variation of relative permeability even within the same rock for presumably similar conditions (Moussawi et al. 2026). This is illustrated in Fig. 2 where CO₂-brine and related model fluids relative permeability in Berea sandstone is taken from various studies published in the literature and plotted in the same figure. A large spread is observed which is only partially explainable by difference between the fluid properties and wetting conditions. This leaves the experimental protocols and interpretation methodologies as main source of uncertainty (Parente et al. 2026).

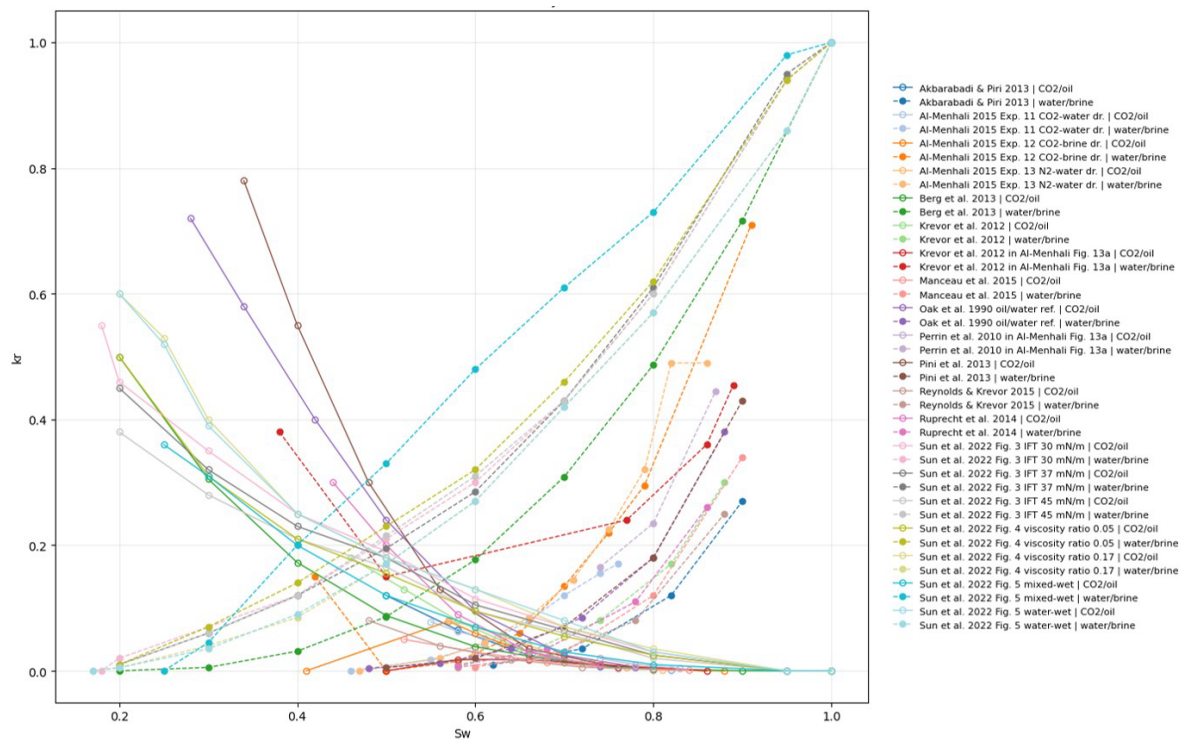


Figure 2 Relative permeability $k_r(S_w)$ for CO_2 -brine and related model fluids for Berea sandstone taken from the literature. There is a large variation which is only partially explainable by differences in fluid properties and wetting conditions which leaves the differences in experimental protocols and interpretation methodologies as the main source of uncertainty.

Method and/or Theory

The determination of relative permeability is based on the industry-standard protocols of steady-state and unsteady-state experiments with a particular focus on unsteady-state experiments which may have advantages in terms of instrumental complexity. For the interpretation methodology inverse modelling / Bayesian inversion is used which is a strategy that delivers consistency for the resulting relative permeability, treatment of common laboratory artefacts, and provides an assessment of the resulting uncertainties. Inverse modelling protocols for relative permeability can be realized by coupling a 2-phase 1D flow simulator with an optimization method to perform a least squares minimization or maximization of the likelihood. Here Core2Relperm,

<https://github.com/sede-open/Core2Relperm/>

a self-contained Python package made publicly available on Github is used in which a native Python implementation of a 2-phase 1D flow simulator with capillary is coupled with a gradient based optimization using the `lmfit` toolbox and a Markov-chain Monte Carlo (MCMC) scheme using `emcee`. The workflow is illustrated in Fig. 3. The code can be used as inversion method to determine relative permeability and capillary pressure from standard core flooding experiments including the uncertainty ranges. It can also be used to design experimental methodologies and assess optimum conditions and types and quality of data required to achieve a desired uncertainty range.

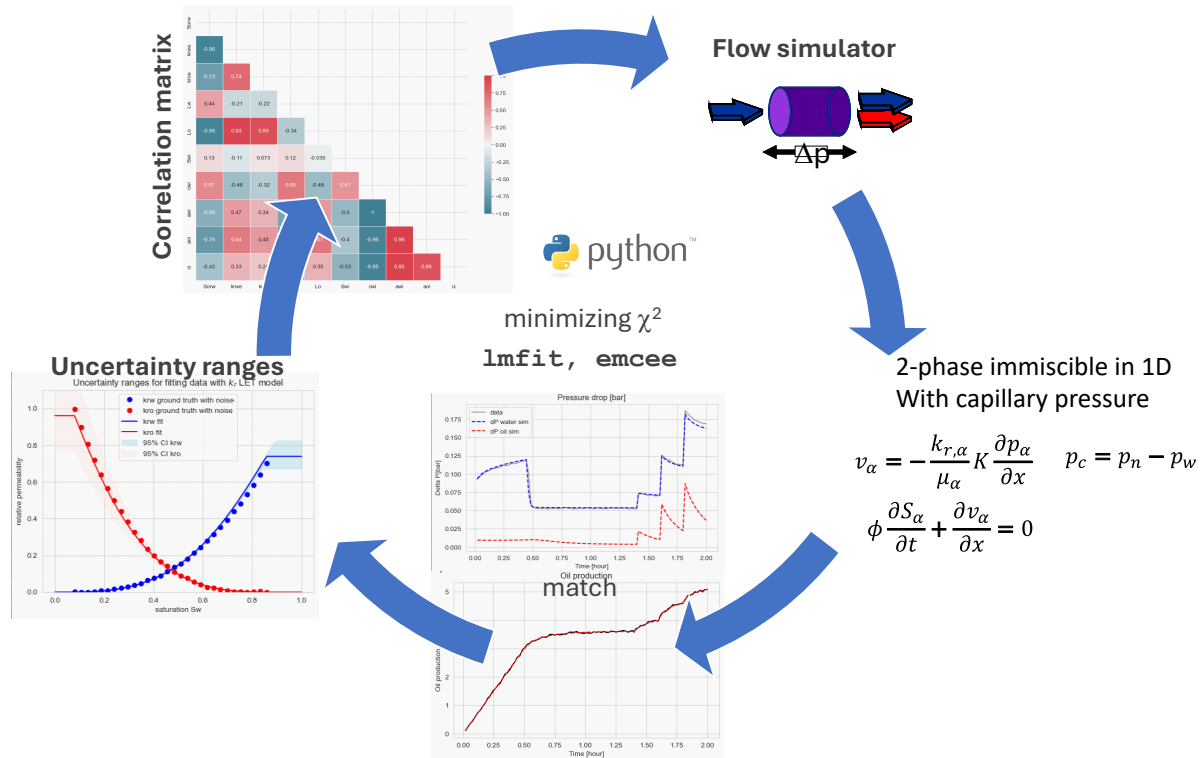


Figure 3 Inverse modelling workflow using a Python-based flow simulator and the `lmfit` toolbox for performing a Levenberg-Marquardt fit to match the numerical solution with the experimentally measured core flooding data (production curve, pressure drop, saturation profiles). The flow simulator solves numerically the 2-phase Darcy equations and conservation of mass in 1D. The match with the experimental data then provides the relative permeability $k_r(S_w)$ and capillary pressure $p_c(S_w)$. Uncertainties in individual fit parameters (e.g. Corey parameters), cross correlation between parameters and overall uncertainty envelope on relative permeability is obtained from the covariance matrix in the Levenberg-Marquardt fit, or from a more extensive Markov chain Monte Carlo (MCMC) Bayesian inversion using the `emcee` package.

Conclusions

We find in practically all cases with experimental data that have been considered a signature of non-uniqueness (Berg et al. 2021a), which can be suppressed by involving more and different types of data, e.g. saturation profiles but not fully eliminated. By matching the flow model directly to the data provides significantly smaller uncertainty ranges than first performing a manual match and then fitting the resulting tabulated relative permeability with an analytical function. Due to the phenomenological history of the 2-phase Darcy approach, it is furthermore not clear which parameterization for relative permeability should be used. By comparing Corey with LET parameterizations we obtain better consistency with the data using the LET function (Berg et al. 2021b). Determining relative permeability and capillary pressure from one single unsteady-state core flooding experiment is possible only under the most favorable conditions (Berg et al. 2024). Core2Relperm can be used to assess and optimize experimental and interpretation protocols to minimize non-uniqueness and uncertainties.

Acknowledgements

Elenora Parente, Vishal R. Ahuja, Shashank Tiwari, Stefania Moioli and Daan de Kort are gratefully acknowledged for helpful discussions, contributions to the Core2Relperm code development, and applying it to test cases. The SCAL & Imaging team at Shell Global Solutions International B.V. and the Shell SCAL network is gratefully acknowledged for developing the underlying concepts of determining relative permeability from core flooding experiments by inverse modelling.



References

- Berg, S., Unsal, E. and Dijk, H. [2021a] Non-Uniqueness and Uncertainty Quantification of Relative Permeability Measurements by Inverse Modelling. *Computers and Geotechnics*, 132, 103964.
- Berg, S., Unsal, E. and Dijk, H. [2021b] Sensitivity and uncertainty analysis for parameterization of multi phase flow models. *Transport in Porous Media*, 140(1), 27-57.
- Berg, S., Dijk, H., Unsal, E., Hofmann, R., Zhao, B. and Ahuja, V. [2024] Simultaneous Determination of Relative Permeability and Capillary Pressure from an Unsteady-State Core Flooding Experiment. *Computers and Geotechnics*, 168, 106091.
- Moussawi, R., Ghorayeb, K. and Yehya, A. [2026] Relative permeability uncertainty and its impact on CO₂ plume predictability and trapping in saline aquifers. *GeoEnergy Science and Engineering*, 266, 214653.
- Parente, E., Gao, Y., de Borst, K., Ahuja, V.R., Tiwari, S., Moioli, S.S., Unsal, E. and Berg, S. [2026] Using Hybrid Pore Scale Imaging/Modelling and Minkowski Functionals to Assess the Similarity of Imbibition Relative Permeability of Hydrogen, Methane and Nitrogen. *International Journal of Hydrogen Energy*, 229, 154730.