PROCEEDINGS, 44th Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 11-13, 2019
SGP-TR-214

The Impact of Pore-Scale Flow Regimes on Two-Phase Relative Permeabilities in Geothermal Reservoirs

Davide Picchi and Ilenia Battiato

Department of Energy Resources Engineering, Stanford University, Stanford CA

dpicchi@stanford.edu, ibattiato@stanford.edu

Keywords: relative permeability, viscosity ratio, pore-scale flow regime, water, steam,

ABSTRACT

Two-phase flow conditions are frequently encountered in geothermal reservoirs due to gradients in pressure and temperature. Although Darcy's law is routinely used in the multiphase flow scenario, the role of pore-scale flow regimes is usually neglected in the estimation of the relative permeabilities, frequently computed using empirical models like the Corey and the Brooks-Corey correlations. In this work, we extend the generalized model for relative permeabilities developed in Picchi and Battiato (2019) to scenarios typical of geothermal reservoirs. We aim at understanding and quantifying the impact that the topology of the flowing phases may have on relative permeability estimates and derive scaling laws for relative permeabilities when the viscosity ratio is very small (i.e., the non-wetting phase is much less viscous compared to the wetting one) as typical in water-steam systems. Finally, we provide preliminary validation of the model with data available in the literature.

1. INTRODUCTION

A geothermal reservoir is a large-scale convective system where hot water migrates through permeable rocks from a deep and high-temperature zone to a cooler region near the earth surface. The natural recirculation of water is fed by buoyancy effects that are generated by gradients in temperature and pressure. In this context, water may experience a phase-change yielding to two-phase flow conditions (water and steam), see Grant and Brixely (2011). For example, boiling can occur when the colder and heavier water is heated up in proximity of a magma intrusion. Alternatively, steam can form near production wells as a result of flashing due to the local drop in pressure when hot fluid is extracted from the reservoir. Being able to model the onset of multiphase flow conditions across scales represents a critical challenge to develop reliable forecasting tools.

Due to their limited computational burden, upscaled models are routinely used to describe flow at the continuum scale. Among them, the most common is Darcy's law, which has been extended to the multiphase flow scenario either empirically, Bear (1972) or following rigorous upscaling methods, see Auriault (1987), Whitaker (1986), Hassanizadeh and Gray (1980), Hornung (1997), Lasseux et al. (2008), Daly and Roose (2015), just to mention a few. In such models, pore-scale physics is taken into account through relative permeabilities, usually computed from empirical models like the Corey (1954), Brooks and Corey (1964), and Chierici (1984) correlations. In the context of geothermal reservoirs, experiments collected on natural cores samples, see Arihara (1974), Council and Ramey (1980), Verma (1986), Sanchez and Schechter (1990), Closmann and Vinegar (1993), Piquemal (1994), Ambusso et al. (1996), Satik (1998), Tovar (1997), Mahiya (1999), O'Connor (2001), Gudjonsdottir et al. (2015a), have not led to an identification of a universal set of relative permeability curves, generally applicable to water-steam systems. In fact, these systems are quite sensitive to thermal variations (e.g., the saturation is a function of the steam fraction), which render the control of experimental conditions more challenging compared to immiscible systems where the input flow rates are unequivocally determined.

Another aspect which needs to be accounted for in the determination of the relative permeability is the distribution of the flowing phases at the pore-scale. Experiments and simulations performed on immiscible phases, see Blunt et al. (2013), Armstrong et al. (2012,2016) Reynolds et al. (2017), Gao et al. (2017), Garing et al. (2017), have shown show that the non-wetting phase can become disconnected and flow in the form of individual ganglia or even remain immobilized (trapped) in the porous matrix. Specifically, four possible pore-scale flow regimes have been identified by Avraam and Payatakes (1995): large-ganglion dynamics, small-ganglion dynamics, drop-traffic flow, and connected-pathway flow. While in large and small ganglion dynamics the non-wetting phase is disconnected and flows intermittently, in the connected pathway regime, both phases flow through separate and uninterrupted pathways. The fact that such topological features of the flowing phases are not taken into account has been accepted as one of the main deficiencies of macroscale models. An example is the hysteric behavior of relative permeability curves, which has been associated with the transition from one regime to another, see Datta et al. (2014); Rucker et al. (2015) and Schluter et al. (2016), along with the coexistence of different flow regimes within the pore domain, see Avraam and Payatakes (1995), Armstrong et al. (2016), Gao et al. (2017).

In order to overcome these difficulties, several approaches have been developed to incorporate the evolution of the phase topology into macroscopic equations, e.g., Hassanizadeh and Gray (1990), Niessner and Hassanizadeh (2008), Miller and Gray (2005), Gray et al. (2015), McClure et al. (2016), Schluter et al. (2016), or more practical and ad hoc formulations of the relative permeabilities have been proposed, e.g., Dehghanpour et al. (2011), Clavier et al. (2017), Pasquier et al. (2017). However, to the best of our knowledge, a general formulation that accounts for pore-scale flow regimes in the context of geothermal reservoirs needs still to be proposed. Just recently, Picchi and Battiato (2018) have developed a new homogenization framework that allows one to derive upscaled equations that are regimespecific: the main idea is to reduce the complexity of the problem by proposing an analogy between flow regimes in real porous media and in a capillary tube. By use of one-dimensional closures, Ullmann and Brauner (2004) and Picchi et al. (2018), the effective parameters of the macroscopic equations are determined by postulating the pore-scale flow regimes and, in the Darcy's limit, expressions of the relative permeability have been obtained analytically. This approach has been extended in Picchi and Battiato (2019) to realistic porous media by proposing a formulation of the relative permeabilities that depends on the mobile saturation, the viscosity ratio, and the capillary number and inherently accounts for the coexistence of flow regimes. Although such model has been validated with published data covering a wide range of systems, e.g., from brine-CO_2 to oil-water systems, the question of whether it can be applicable to geothermal flows remains still open.

In this paper, we test the model proposed by Picchi and Battiato (2019) to conditions typical of water-steam systems. We identify the scaling of relative permeabilities in terms of the viscosity ratio which, for geothermal systems, varies with temperature and pressure. We also provide a preliminary validation against water-steam data available in the literature. Our goal is to provide new insights in the modeling of relative permeability in the context of geothermal reservoirs. Furthermore, exploring the possible ramifications in the determination of heat and mass fluxes, see Bodvarsson et al. (1980) and O'Sullivan (1981), is subject of current investigations. Finally, this analysis can potentially help in the interpretation of field data, e.g., Reyes (2004), Gudjonsdottir et al. (2015b).

2. THE RELATIVE PERMEABILITY MODEL BASED ON PORE-SCALE FLOW REGIMES

In this Section, we first report the upscaled equations and the regime-dependent formulation of the relative permeability proposed in Picchi and Battiato (2018, 2019) and, then, discuss their applicability to geothermal systems. The model, applied to geothermal systems, is based on the following main assumptions

- water is in a biphasic state, i.e. water/steam systems;
- at a fixed saturation for a prescribed boiling temperature and pressure, water and steam are modelled as two immiscible phases;
- water is the wetting phase, and steam is the non-wetting phase;
- at the pore-scale, the flow is in the laminar regime and gravitational effects are negligible;
- both phases are subjected to the same driving force.

In the Darcy's limit (the conditions for which this simplification holds are discussed in detail in Picchi and Battiato (2018)), the macroscale equations that describe the flow of two immiscible fluids in a porous medium are

$$\langle u_{\mathrm{w}} \rangle = -\frac{k_{\mathrm{w}}}{32} \nabla p_{\mathrm{w}} \,, \tag{1a}$$

$$\langle u_{\mathrm{s}} \rangle = -\frac{k_{\mathrm{s}}}{32M} \nabla p_{\mathrm{s}} \,, \tag{1b}$$

where, $\langle u_{\mathrm{w}} \rangle$, $\langle u_{\mathrm{s}} \rangle, p_{\mathrm{w}}$, and p_{s} are the average dimensionless velocities and the macroscopic pressures of water and steam, respectively; the viscosity ratio is defined as

$$\mathrm{M} = \frac{\mu_{\mathrm{s}}}{\mu_{\mathrm{w}}} \,, \tag{2}$$

with μ_{w} and μ_{s} being the dynamic viscosity of saturated water and steam, respectively. The relative permeabilities, k_w and k_s, are the terms that effectively depend on the spatial distribution of the flowing phases at the pore-scale as outlined in Picchi and Battiato (2019). Specifically, an analogy with flow regimes in the capillary tube setting is proposed for capturing the transition from the capillary limit, where the flow is dominated by the *quasi-static* connected pathway flow (i.e., phases flows through separated and interrupted pathways), and the viscous limit, where viscous forces stabilize topological features by increasing the phases connectivity (i.e., coalescence phenomena lead to the formation of very long ganglia.), see Fig. 1. We define the relative permeabilities normalized with the endpoint relative permeabilities, β_w and β_s,

$$k_w^* = \frac{k_w}{\beta_w} \text{ and } k_s^* = \frac{k_s}{\beta_s} \,. \tag{3}$$

Then, the permeability-saturation relationships have the following form

$$k_{\mathrm{w}}^* = S_*^2 \,, \tag{4a}$$

$$k_{\mathrm{s}}^* = (1 - S_*)^2 \left(1 + \frac{2S_*}{1-S_*} M\alpha\right) , \tag{4b}$$

where S_* is the mobile fluid saturation,

$$S_* = \frac{S_w - S_{ir}}{1 - S_{or} - S_{ir}} \,, \tag{5}$$

with S_{ir} and S_{or} the irreducible saturation of the wetting phase and the residual saturation of the non-wetting phase, respectively. Eq. (4) accounts for the pore-scale flow regimes through the flow-regime parameter α, which controls the transition from the capillary (when $\alpha = 0$) to the viscous (when $\alpha = 1$) limits at the Darcy scale, $0 \leq \alpha \leq 1$. The only three fitting parameters of the model are $(\beta_w, \beta_s, \alpha)$:

the analysis of experimental data in Picchi and Battiato (2019) suggests that α depends linearly with the logarithm of the capillary number, i.e., that a universal relation between the flow-regime parameter and Ca may exist. Furthermore, three scaling classes have been identified:

- *Class I*: if $M \ll 1$, or $\mu_s \ll \mu_w$, i.e. the non-wetting phase is much less viscous than the wetting phase, the effect of the flow-regime parameter is negligible, and both the relative permeabilities scale with the square of the mobile saturation

  $$k_w^* = S_*^2 \quad \text{and} \quad k_s^* = (1 - S_*)^2 \tag{6}$$

- *Class II*: if $O(M) = 1$ and the flow is in the capillary regime, both the relative permeabilities scales as the square of the mobile saturation;

- *Class II*: if $O(M) = 1$ at intermediate and high capillary number the effect of pore-scale flow regimes cannot be neglected.

In the following, we will validate the aforementioned model against experimental relative permeabilities measurements of water-steam systems in the geothermal context.

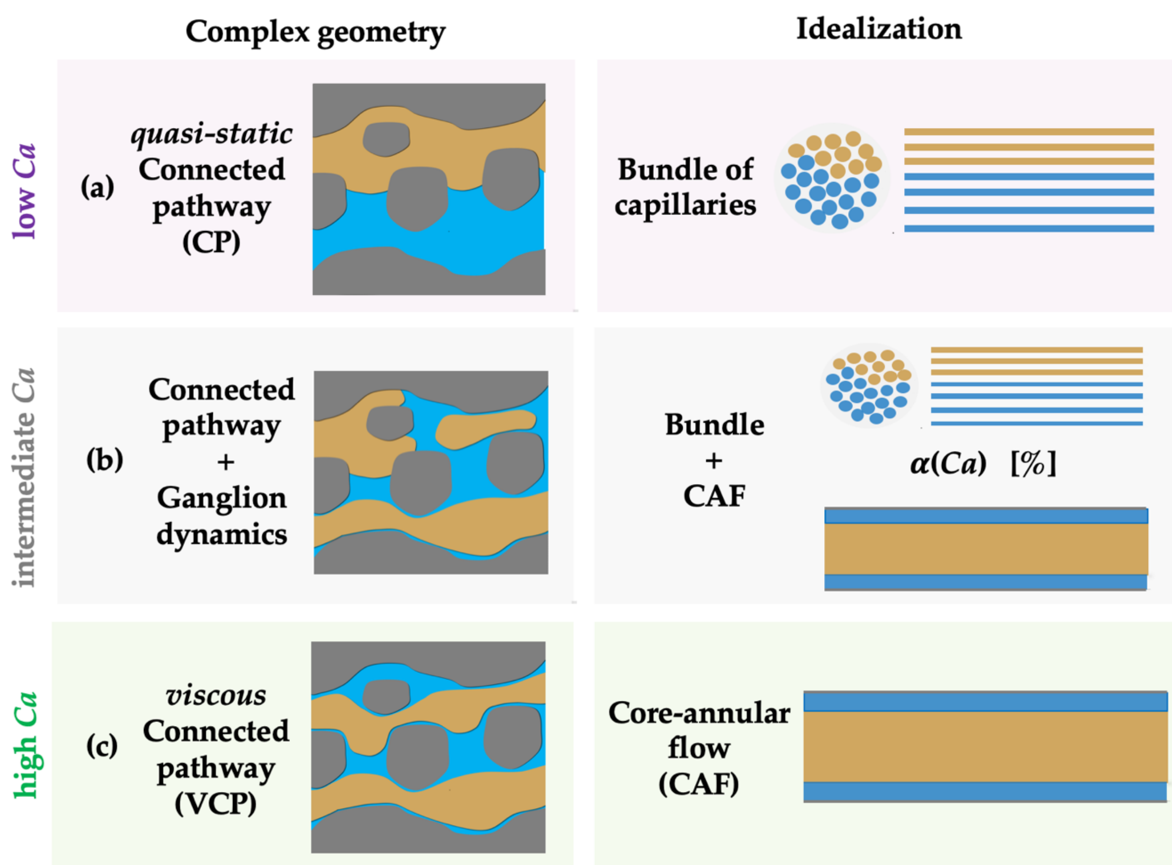

Figure 1: Sketch of flow regimes in a realistic geometry and their idealization in the framework of the capillary tube analogy. Water (wetting-phase in dark blue) and steam (the non-wetting phase in orange). Figure from Picchi and Battiato (2019).

3. RESULTS AND DISCUSSION

In this Section, we show a preliminary validation of the model presented in Section 2 with water-steam relative permeabilities data taken from the literature. We have analyzed experiments performed in a porous matrix, namely in real rock samples, following the procedure outlined below:

- we identify whether the experimental data set belongs to *Class I, ClassII*, or *Class III* depending on the viscosity ratio;
- we identify whether the experiments exhibit residual and irreducible saturations, S_{ir} and S_{or};
- we rescale the saturation of the wetting phase in terms of mobile saturation;
- we determine the fitting parameters of the model, β_w, β_s, α.

The datasets that we used in the validation are listed in Table. 1. We also list the working temperature, the estimated viscosity and density ratios, the model parameters, and the coefficient of determination computed for all the parameters.

3.1 Remarks on two-phase flow systems in geothermal reservoirs

Before proceeding with the validation of the model with experimental data, we briefly discuss which of the scaling described above is applicable to geothermal systems. Specifically, we restrict our analysis on biphasic states at constant boiling temperature and a pressure within the triple point (0.01°C, 611.2 Pa) and the critical point (374°C, 22.06 MPa), see Fig. 2(a). At a fixed saturation, we idealize water and steam as two immiscible phases and we define the viscosity ratio (Eq. 2) as the ratio between the dynamic viscosity of saturated water and steam, respectively. Similarly, we can also define the density ratio between saturated steam and water $R = \rho_s/\rho_w$.

In Figs. 2(c,d) we show a plot of the viscosity ratio and the density ratio as a function of the boiling temperature and the pressure: we can see that, for a wide range of conditions, $O(M) < O(0.01)$ and $R \ll 1$ and, just in proximity of the critical point, M and R becomes of order one. This trend confirms that sufficiently far from the critical point a steam-water system behaves effectively like a gas-liquid system where the non-wetting phase is much lighter and less viscous compared to the wetting phase. Therefore, in the framework of geothermal reservoirs, most of the systems belong to *Class I* and we expect that the relative permeabilities, once normalized, scale as the square of the mobile saturation and do not depend on the capillary number. In fact, since $M \ll 1$, the effect of pore-scale flow regimes on Eq. (4b) is negligible. Water-steam systems shift to *Class III* only in the proximity of the critical point.

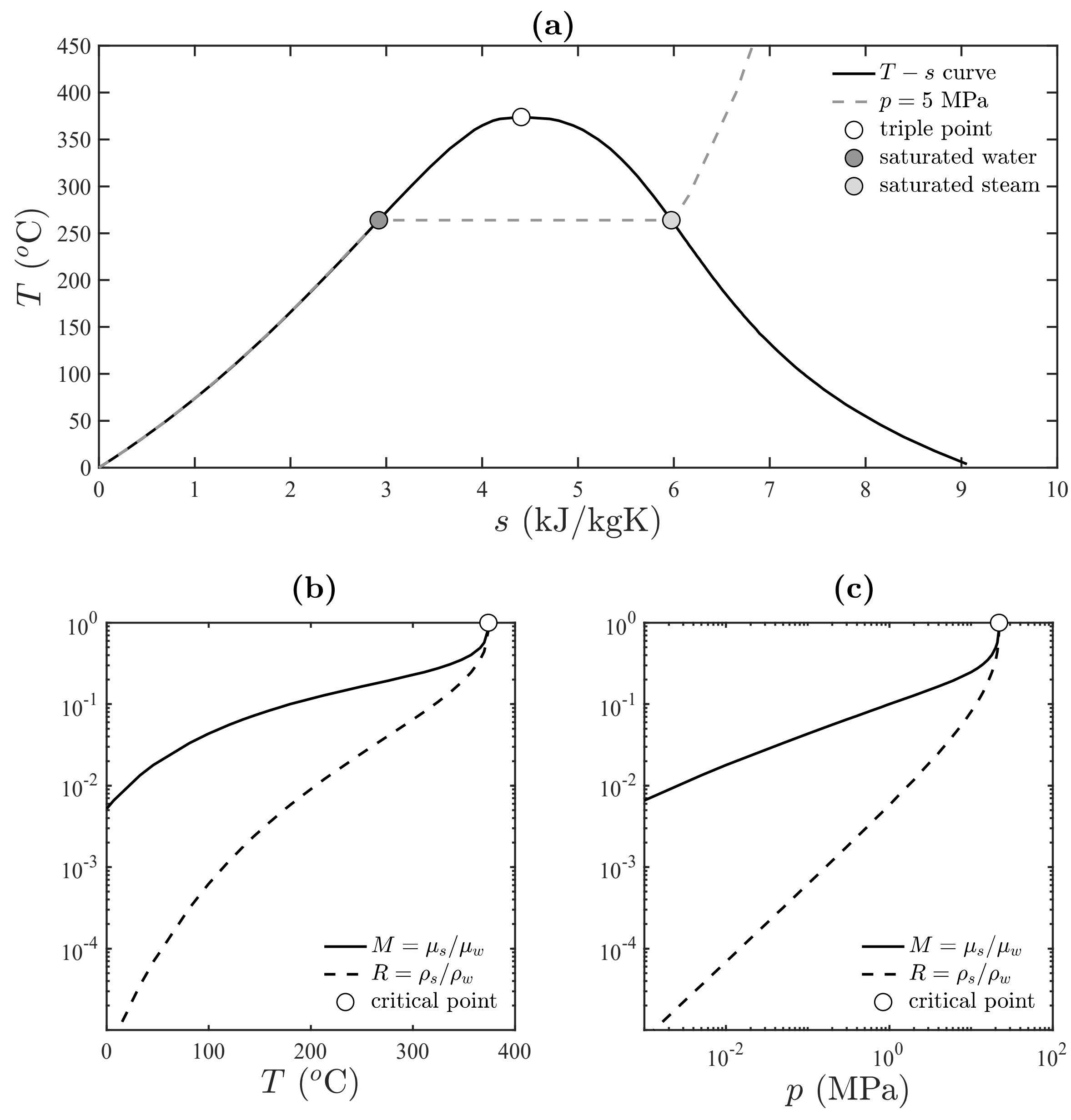

Figure 2: (a) T-s diagram of water; (b) viscosity ratio and density ratio between saturated water and steam as a function of the boiling temperature. (c) viscosity ratio and density ratio between saturated water and steam as a function of the pressure.

Table 1: Parameters of Eq. (4) and classification of the experimental data used in the validation of the model. The coefficient of determination R^2 for the fitting parameters β_w and β_s.

	T [°C]	M	R	S_{ir}	$1-S_{or}$	β_w	β_s	$R^2_{\beta_w}$	$R^2_{\beta_w}$
Piquemal (1994)	180	0.010	0.006	0.22	1	0.55	0.76	0.95	0.98
	150	0.008	0.003	0.22	1	0.68	0.76	0.96	0.97
Mahiya (1999)	100÷130	0.006	0.001	0.27	0.87	0.51	1.0	0.88	0.91
	100÷130	0.006	0.001	0.27	0.87	0.28	1.1	0.97	0.81

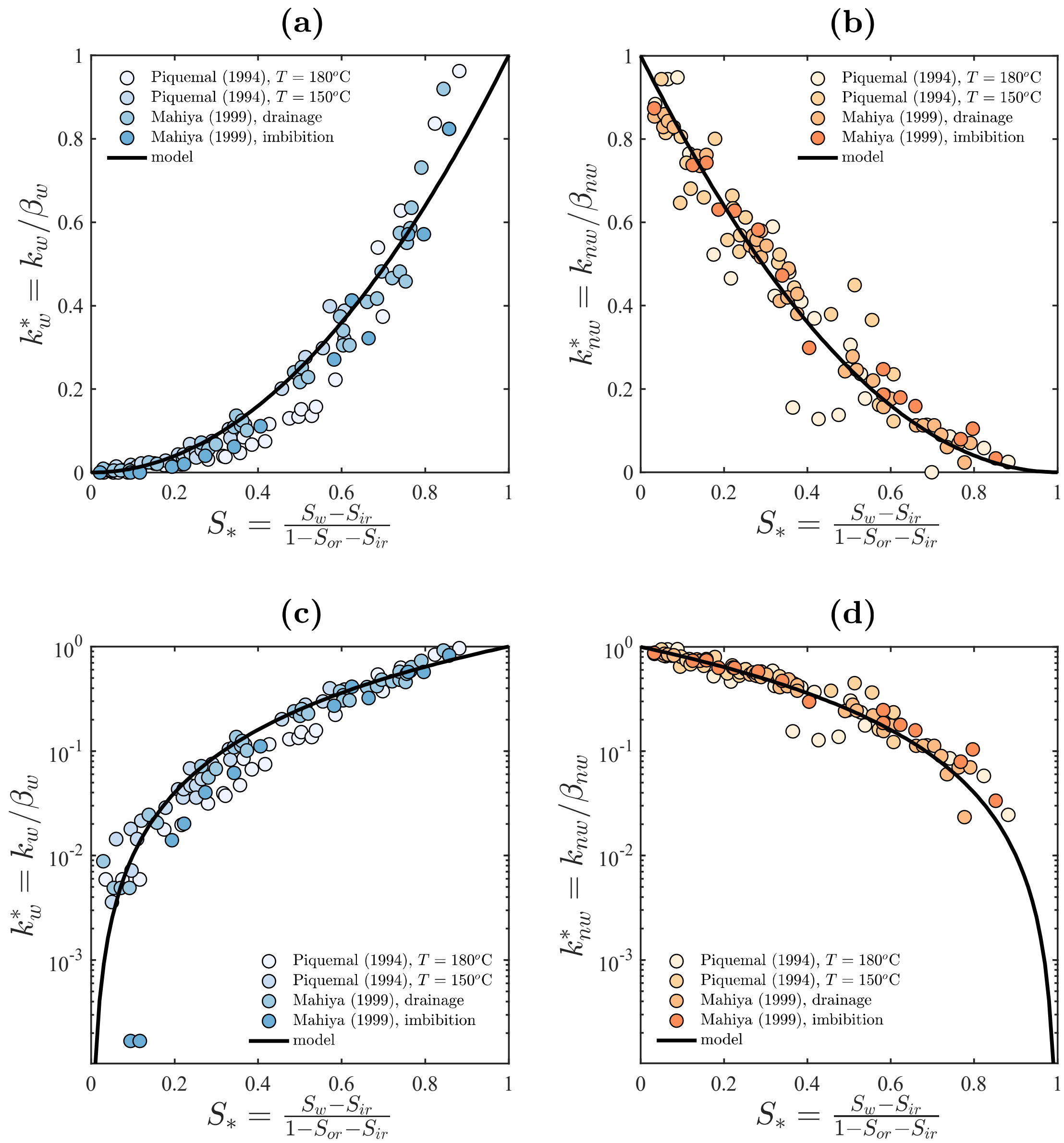

Figure 3: Comparison between the predicted scaling of the normalized relative permeability as a function of the mobile saturation with experimental data of core-samples taken from the literature. (a) and (b) plot the relative permeability of the wetting and non-wetting phase in linear coordinate system, while (c) and (d) is in logarithmic coordinate system.

3.2 Validation with experimental data

Here, we compare the predictions of Eq. (4) with the relative permeability data collected by Piquemal (1994) and Mahiya (1999). In both cases, the experiments are performed at a prescribed temperature so that water is in a biphasic state and the saturation of steam and water can be defined as the ratio of the volume of the pore space occupied by one phase with respect to the whole pore space, i.e.,

$$\mathrm{S_w} = \frac{V_w}{V_w+V_s} \text{ and } \mathrm{S_w} + S_s = 1, \quad (7)$$

where V_w and V_s are the volumes occupied by water and steam, respectively. We also want to emphasize that, since the saturation is a function of the local steam fraction, we can interpret the variations in the water saturation as variations in the steam fraction in the core sample. Following our classification, both the experimental datasets belong to *Class I* (i.e., the working temperature is lower compared to the critical point and, therefore, $M \ll 1$), see in Table.1.

In Fig. 3, we can see that the data collapse around the model predictions for the whole range of saturations both in linear and logarithmic scales suggesting that Eq. (6) captures the trend displayed by the data at different temperatures. Importantly, once the relative permeabilities have been normalized, they scale as the square of the mobile saturation. Note that in the proposed model, differently from the Brooks-Corey (1964) correlation, the exponents are not fitting parameters and just the endpoint relative permeabilities have been fitted to the data (see the procedure in Section 3.1). The endpoint relative permeabilities and the coefficients of determination are listed in Table 1.

From this preliminary validation, we can conclude that steam-water relative permeabilities follow the same scaling of *Class I*, i.e. the saturation-square trend which is typical of immiscible systems where the non-wetting phase is much less viscous compared to the wetting phase (see Picchi an Battiato (2019) where an extensive validation is proposed). This behavior is confirmed by the analysis of the additional experiments that Piquemal (1994) performed in the same core using air and water as test fluids: although, the endpoint relative permeabilities may vary a little, the rescaled data follow the same scaling. As a consequence, the analysis of the experimental data supports the hypothesis that, at a first approximation, water-steam systems can be treated as two immiscible phases with a very low viscosity ratio.

4.CONCLUSIONS

In this work, we have validated, in the context of geothermal engineering applications, the relative permeability model that accounts for pore-scale flow regimes proposed by Picchi and Battiato (2019). Our analysis leads to the following main conclusions:

- when water flows in a biphasic state inside a porous medium, the flow can be idealized as a multiphase flow of two immiscible fluids where a viscosity and density ratio can be defined. The viscosity and density ratio are of order one just in proximity of the critical point. Otherwise, the non-wetting steam is much less viscous, and much lighter, compared to liquid water. Both the relative permeabilities of steam and water, once normalized, scale with the square of the mobile saturation, as predicted for systems of *Class I* by the Picchi and Battiato (2019) model.
- The steam-water relative permeabilities measured in cores samples at a temperature in the range 100-180°C follow the saturation-square trend.
- The relative permeability scaling of water-steam system is the same as that of immiscible two-phase flows where the non-wetting phase is much less viscous than the wetting phase, e.g. air-water, nitrogen-water, and CO_2-brine. This supports the hypothesis that at a fixed saturation, in first approximation, water and steam can be treated as two immiscible phases and can be modeled as a multiphase system with a very low viscosity ratio.

Current active research is focused on furthering the validation with other steam-water data available in the literature and on the possible ramifications for interpretation of thermal measurements and field data.

REFERENCES

Ambusso, W., Satik, C., Horne, R. N.: Determination of Relative Permeability for Steam-Water Flow in Porous Media, *Society of Petroleum Engineers*, (1996), 36682.

Arihara, N.: A Study of Non-Isothermal Single and Two-Phase Flow Through Consolidated Sandstones, PhD dissertation, Stanford University, Stanford, California (1976).

Armstrong, R. T., M. L. Porter, and D. Wildenschild: Linking pore-scale interfacial curvature to column-scale capillary pressure, Advances in Water Resources, **46**, (2012), 55-62.

Armstrong, R. T., J. E. McClure, M. A. Berrill, M. Rücker, S. Schlüter, and S. Berg: Beyond darcy's law: The role of phase topology and ganglion dynamics for two-fluid flow, *Phys. Rev. E*, ***94***, (2016), 043113.

Auriault, J.-L.: Nonsaturated deformable porous media: Quasistatics, *Transport in Porous Media*, ***2***, (1987), 45–64.

Avraam, D. G., and A. C. Payatakes: Flow regimes and relative permeabilities during steady-state two-phase flow in porous media, *Journal of Fluid Mechanics*, ***293***, (1995), 207–236.

Bear, J.: *Dynamics of Fluids in Porous Media*, Dover Civil and Mechanical Engineering Series, Dover, (1972).

Blunt, M. J., B. Bijeljic, H. dong, O. Gharbi, S. Iglauer, P. Mostaghimi, A. Paluszny, and C. Pentland: Pore-scale imaging and modelling, *Adv. Water Resour*., **51**, (2013), 197-216.

Bodvarsson, G.S., O'Sullivan, M.J., and Tsang, C.F.: The Sensitivity of Geothermal Reservoir Behavior to Relative Permeability Parameters, Proceedings, 6th Workshop on Geothermal Reservoir Engineering, Stanford, CA, Dec. 16-18, 1980.

Brooks, R., and A. Corey: Hydraulic properties of porous media, *Hydrology Papers*, 3, (1964), 1–29.

Chierici, G. L.: Novel relations for drainage and imbibition relative permeabilities, *Society of Petroleum Engineers Journal*, **24**(03), (1984), 275–276.

Clavier, R., N. Chikhi, F. Fichot, and M. Quintard: Modeling of inertial multi-phase flows through high permeability porous media: Friction closure laws, *International Journal of Multiphase Flow*, **91**, (2017), 243-261.

Clossman, P.J., and Vinegar, J.J.: A technique for measuring steam and water relative permeabilities at residual oil in natural cores: CT scan saturations, *The Journal of Canadian Petroleum Technology*, **32**, (1993), 55-60.

Corey, A.: The interrelation between gas and oil relative permeabilities, *Producers Monthly*, **19**, (1954), 38–41.

Council, J.R., and Ramey, H.J., Jr.: Drainage Relative Permeabilities Obtained from Steam-Water Boiling Flow and External Gas Drive Experiments, GRC Trans. 3 (1979), pp 141-143.

Daly, K. R., and T. Roose: Homogenization of two fluid flow in porous media, *Proceedings of the Royal Society of London A: Mathematical, Physical and Engineering Sciences*, **471**, (2015), 2176.

Datta, S. S., J.-B. Dupin, and D. A. Weitz: Fluid breakup during simultaneous two-phase flow through a three-dimensional porous medium, *Physics of Fluids*, ***26***, (2014), 062004.

Dehghanpour, H., B. Aminzadeh, M. Mirzaei, and D. A. DiCarlo: Flow coupling during three-phase gravity drainage, *Phys. Rev. E*, **83**, (2011), 065302.

Grant, M., Bixley, P.: Geothermal Reservoir Engineering, second ed. Academic Press, 2011.

Gao, Y., Q. Lin, B. Bijeljic, and M. J. Blunt: X-ray microtomography of intermittency in multiphase flow at steady state using a differential imaging method, *Water Resources Research*, ***53***, (2017), 10,274–10,292.

Garing, C., J. A. de Chalendar, M. Voltolini, J. B. Ajo-Franklin, S. M. Benson: Pore-scale capillary pressure analysis using multi-scale x-ray micromotography, *Advances in Water Resources*, **104**, (2017), 223-241.

Gray, W. G., A. L. Dye, J. E. McClure, L. J. Pyrak-Nolte, and C. T. Miller: On the dynamics and kinematics of two-fluid-phase flow in porous media, *Water Resources Research*, ***51***, (2015),5365–5381.

Gudjonsdottir M., Palsson, H., Eliasson, J., Saevarsdottir G.: Calculation of relative permeabilities of water and steam from laboratory measurements, *Geothermics*, **53**, (2015a), 396-405.

Gudjonsdottir M., Palsson, H., Eliasson, J., Saevarsdottir G.: Calculation of relative permeabilities from field data and comparison to laboratory measurements, *Geothermics*, **54**, (2015b), 1-9.

Hassanizadeh, M., and W. G. Gray: General conservation equations for multi-phase systems: 3. constitutive theory for porous media flow, *Advances in Water Resources*, ***3***, (1980), 25 – 40.

Hassanizadeh, S., and W. G. Gray: Mechanics and thermodynamics of multiphase flow in porous media including interphase boundaries, *Advances in Water Resources*, ***13***, (1990), 169 – 186.

Hornung, U.: *Homogenization and Porous Media*, Springer-Verlag New York, Inc., New York, NY, USA, (1997).

Lasseux, D., A. Ahmadi, and A. A. A. Arani: Two-phase inertial flow in homogeneous porous media: A theoretical derivation of a macroscopic model, *Transport in Porous Media*, ***75***, (2008), 371–400.

Mahiya, G.F.: Experimental Measurement of Steam-Water Relative Permeability, MS report, Stanford University, Stanford, CA (1999).

McClure, J. E., M. A. Berrill, W. G. Gray, and C. T. Miller: Influence of phase connectivity on the relationship among capillary pressure, fluid saturation, and inter- facial area in two-fluid-phase porous medium systems, *Phys. Rev. E*, ***94***, (2016), 033102.

Miller, C. T., and W. G. Gray: Thermodynamically constrained averaging theory approach for modeling flow and transport phenomena in porous medium systems: 2. foundation, *Advances in Water Resources*, ***28***, (2005), 181 – 202.

O'Connor, P.: Constant-pressure measurement of steam–water relative permeability. MS report, Stanford University, Stanford, CA (2001).

O'Sullivan, M. J.: A similarity method for geothermal well test analysis, *Water Resour. Res*., 17(2), (1981), 390-398.

Niessner, J., and S. M. Hassanizadeh (2008), A model for two-phase flow in porous media including fluid-fluid interfacial area, *Water Resources Research*, ***44***, (2009), w08439.

Pasquier, S., M. Quintard, and Y. Davit: Modeling two-phase flow of immiscible fluids in porous media: Buckley-leverett theory with explicit coupling terms, *Phys. Rev. Fluids*, **2**, (2017), 104.

Picchi, D., Ullmann, A., and Brauner, N.: Modelling of core-annular and plug flows of Newtonian/non-Newtonian shear-thinning fluids in pipes and capillary tubes, *International Journal Multiphase Flow*,**103**, (2018) *43-60.*

Picchi, D., Battiato, I.: The impact of pore-scale flow regimes on Upscaling of immiscible two-phase flow in porous media, *Water Resources Research, **54**, (2018), 6683-6707.*

Picchi, D., Battiato, I.: Prediction of relative permeabilities from pore-scale flow regimes, *Water Resources Research, under revision, (2019).*

Piquemal, J.: Saturated Steam Relative Permeabilities of Unconsolidated Porous Media, *Transport in Porous Media,* **17,** (1994), 105-120.

Reyes, J., Chen, C.Y., Li, K., Horne, R.: Calculation of steam and water relative permeabilities using field production data, with laboratory verification. *GRC Trans*. **28**, (2004), 609–615.

Reynolds, C. A., H. Menke, M. Andrew, M. J. Blunt, and S. Krevor: Dynamic fluid connectivity during steady-state multiphase flow in a sandstone, *Proceedings of the National Academy of Sciences*, ***114***, (2017), 8187–8192.

Rucker, M., S. Berg, R. T. Armstrong, A. Georgiadis, H. Ott, A. Schwing, R. Neiteler, N. Brussee, A. Makurat, L. Leu, M. Wolf, F. Khan, F. Enzmann, and M. Kersten: From connected pathway flow to ganglion dynamics, *Geophysical Research Letters*, ***42***, (2015), 3888–3894.

Sanchez, J.M., and Schechter, R.S.: Comparison of Two- Phase Flow of Steam/Water through an Unconsolidated Permeable Medium, *SPE Reservoir Engineering*, Aug. (1990), 293-300.

Satik, C.: A Measurement of Steam-Water Relative Permeability, Proceedings, 23rd Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA (1998).

Schluter, S., S. Berg, M. Rucker, R. T. Armstrong, H.-J. Vogel, R. Hilfer, and D. Wildenschild: Pore-scale displacement mechanisms as a source of hysteresis for two-phase flow in porous media, *Water Resources Research*, 52(3), 2016, 2194–2205.

Tovar, R.A.: Measurement of Relative Permeability for Steam-Water Flow in Porous Media, MS report, Stanford University, Stanford, CA (1997).

Ullmann, A., Brauner N.: Closure relations for the shear stresses in two-fluid models for core-annular flow, *Multiphase Science and Technology*, **16**(4), (2004), 355–387.

Verma, A., and Pruess, K.: Enhancement of Steam Phase Relative Permeability Due to Phase Transformation Effects in Porous Media, *Proceedings,* 11th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA (1986).

Whitaker, S.: Flow in porous media ii: The governing equations for immiscible, two- phase flow, *Transport in Porous Media*, **1**, (1986), 105-125.