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A numerical study of the effects of temperature and injection velocity on oil-water relative permeability for enhanced oil recovery

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A B S T R A C T

The paper quantitatively explore the influence of injection rate and temperature on oil-water relative permeability curves during hot water flooding operations in a porous medium flow. ANSYS-CFD was used to construct a numerical model of hot-water injection into an oil saturated sandstone core sample. The modelling technique is based on the Eulerian-Mixture model, using a 3D cylindrical core sample with known inherent permeability and porosity. Injection water at 20 °C was injected into a core sample that was kept at 63 °C and had 14-mD permeability and 26% porosity. For the investigation, three distinct injection rates of 2.9410–6 m/s, 4.41 $\times$ 10^{-6} m/s, and 5.88 $\times$ 10^{-6} m/s were utilised. Furthermore, same injection procedures were repeated under the same conditions, but the core temperature was changed to 90 °C, allowing us to quantify the influence of temperature on the relative permeability curves of oil-water immiscible flow.

The results of this study show that the relative permeability of oil is strongly influenced by flow, while the effect of the relative permeability of water is negligible. In addition, the flow rate influences the residual oil and water saturation, as well as the associated effective permeability. From 20 to 90 °C there is little sensitivity to relative permeability or temperature. This study does not provide proof that temperature effects do not exist with genuine reservoir fluids, rocks, and temperature ranges. However, this study has demonstrated the feasibility of utilising CFD approaches to estimate fluid relative permeability, as well as the combined influence of temperature change and flow rate on relative permeability, with the potential for considerable cost-time advantages.

1. Introduction

The simultaneous flow of two or more immiscible fluids occurs in a variety of natural and industrial processes, including petroleum recovery, CO_2 sequestration in deep saline aquifers, environmental investigations, and medication administration in biological tissues. Because two or more of water, oil, gas, and sand particles are commonly produced simultaneously in the petroleum sector, transfer of fluids within the reservoir or through the wellbore to surface facilities or to the refinery plant normally involves a multiphase flow scenario. A complete and accurate understanding of the fluid dynamics within the domain is critical for better decision making and eventual recovery when two or more immiscible fluids flow simultaneously within the reservoir or along the pipeline.

A petroleum reservoir is a complex assemblage of porous rock, water, and hydrocarbon fluids (oil and gas) that normally coexist underground at depths that make thorough measurement and characterisation difficult. Understanding reservoir mechanics and fluid dynamics for effective design schemes and hydrocarbon recovery is a critical task for petroleum and reservoir engineers. A thorough understanding of the hydrocarbon volume in place, as well as the flow conditions of the phases, is required for successful reservoir characterisation and management (water, oil, gas and sand). From well drilling, completions, and production to field abandonment, knowledge of reservoir mechanics and fluid dynamics supports strategic decision-making. Relative permeability, capillary pressure, and wettability are three multiphase flow parameters in porous media, with relative permeability being one of the most essential and critical phenomena of importance for understanding and characterising the hydrodynamics inside the flow domain [1]. This convoluted pore level displacement physics, as well as fluid-fluid and solid-fluid characteristics, are indicators of this complex multiphase flow behaviour in a porous

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Nomenclature

F	body force
K	permeability (m^2)
$keff$	effective conductivity (W/m-k)
M	mass (kg)
P	pressures (Pas)
Q	flow rate (m^3/s)
S	saturations
SE	volumetric heat sources
t	time (s)
T	temperature (K)
V	velocity (m/s)

Greek symbols

α	volume fraction (dimensionless)
$\sum$	summation
$\emptyset$	porosity (dimensionless)
μ	viscosity(kg/m-s)
p	density (Kg/m^3)

Subscript

o	oil
w	water
p,q,k	phase
r	relative
E	effective
dr	drift
$\dot{m}$	mass-average

media [2]. These qualities are measured either in the lab or in a predictable manner utilising empirical correlations or pore scale modelling.

It is difficult to measure porous media data that is reflective of a real-world environment. In the laboratory, however, accurate modelling of all fluid and rock parameters (temperature, pressure, geometry, and composition) is nearly impossible or prohibitively expensive. In order to make numerical predictions, reservoir characterisation entails mathematical modelling of the physical processes that occur between fluids and porous rock materials. The oil and gas sector has devoted a lot of study and money to the procedures mentioned above. [3–5]. The Computational Fluid Dynamics (CFD) method has been used to research and simulate multiphase flow and heat transfer problems in porous media under a variety of scenarios. ANSYS-Fluent software has been adopted to simulate both polymer and CO_2 flooding in a petroleum reservoir with consistent results generated which are within acceptable accuracy when compared to the experiment data [6–8].

2. Review of oil-water flow relative permeability in porous media

Laboratory approaches for measuring relative permeability are broadly classified as steady state, unsteady state (dynamic displacement), centrifuge, and gravity drainage [9,10]. Comparative examinations of these various approaches have occasionally revealed discrepancies in published results, and it has been argued that the main fundamentals of each method are valid under varied flow circumstances. In petroleum reservoirs, for example, a single method may not sufficiently reflect the varied flow regimes in the system, necessitating the employment of multiple approaches. The steady state experimental approach involves simultaneously pumping all fluid phases (water, oil, and gas) into a porous media at various fixed, measurable fractional fluxes. A drawback of this method is that it is difficult to achieve numerous steady states in materials with poor permeability, and there is a notable influence of capillary forces and capillary end effects detected [11]. Oak [12,13] offer extensive instructions for doing steady-state studies.

Due to the difficulties of steady-state experiments, notably the time factor, the unsteady state (also known as dynamic displacement) technique has been widely employed in the literature for relative permeability investigations. In this example, only one fluid is injected into the core sample, and data on the pressure decrease across the sample and phase recovery is collected. Despite its widespread use and applications, there are significant limitations that contribute to certain fundamental assumptions made in its implementation. The method is not appropriate for studies with low flow rates and a substantial influence of capillary pressure. High flow rates, on the other hand, may enhance the occurrence of viscous fingering, which refers to the creation of an uneven finger-like pattern at the interface of two fluids, such as oil and water [14]. According to Singh et al. [15], the unsteady-state approach is thus more suited for flow circumstances characterised by large front velocity displacements. Analytic, semi-analytic, and numerical/history-matching approaches are used to analyse relative permeability experimental data [16].

Arshad et al. [17] reported experimental research on the temperature impacts on oil-water relative permeability, with the findings suggesting that the relative permeability curves, as well as the endpoint saturations, are temperature independant. Miller and Ramey [18] made the same observation after doing dynamic-displacement laboratory tests on unconsolidated and consolidated porous medium using water and a refined white mineral oil to assess relative permeability to oil and water. The trials were carried out on 5.1 cm diameter and 52 cm long cores at temperatures ranging from ambient temperature to about 149 °C. The results presented demonstrate that the relative permeability curves largely do not vary with temperature fluctuation. They claimed that prior published results might have been influenced by variables such as viscosity instabilities, capillary end effects, or a potential difficulty in maintaining material balances.

To examine the link between relative permeability curves and temperature, Lie-hui et al. [19], performed a series of core flooding tests on five sandstone core samples with varying permeability values at various temperatures. Given that laboratory circumstances cannot completely replicate fluid flow behaviour in a reservoir, they suggested a method for translating laboratory results to reservoir size. The study discovered a substantial increase in the form of oil and water relative permeability curves as temperature increased for the various core samples and permeability ranges. With increasing temperature, residual oil saturation decreased nonlinearly, but irreducible water saturation rose linearly but decreased with decreasing permeability. Akhlaghinia et al. [20], utilised heavy oil, methane, and carbon dioxide to evaluate relative permeability in sandstone core samples, and the JBN method to compute two-phase relative permeability. To study the influence of temperature on the form of relative permeability curves, a series of tests were carried out at three distinct temperature values of 28, 40, and 52 °C for different fluid pairs. The oil relative permeability curve rose at a rate of approximately 70% with a temperature change from 28 to 40 °C and dropped at a rate of about 30% with a temperature change from 40 to 52 °C, according to the experimental data. The study concluded that at a particular temperature, the relative permeability trend reverses, indicating that the oil relative permeability varies up to an optimal temperature of about 40 to 52 °C, after which the trend reverses with further increase in temperature. Bennion et al. [21] demonstrated a relationship between temperature and oil-water relative permeability in unconsolidated bitumen producing strata in Canada. The study was a thorough examination of current field oil-water relative permeability data collected at temperatures ranging from 10 to 275 °C in order to show correlations for predicting oil-water relative permeability features and residual oil saturations (mainly for preliminary evaluation analysis). It was observed that when temperature rises, residual oil saturation falls in a non-linear fashion while water saturation rises. At temperatures less than 100 °C, the relative permeability to brine was shown to be sensitive.

Torabi and Ostap [22] conducted a series of unsteady state core flooding experiments to investigate the effect of various vital fluid flow parameters such as operating temperature, oil viscosity, injection rate, and pressure on oil-water relative permeability, and new correlations for computing oil-water relative permeability were proposed. According to the findings of this investigation, the relative permeability of water and oil increases considerably as temperature rises. A decrease in oil viscosity was shown to result in an increase in permeability to oil and water. Behnam et al. [23] conducted unsteady state core flood tests on core samples from carbonate reservoirs under reservoir pressure conditions and original fluid saturations at high temperatures ranging from 38 to 260 °C. The data from the tests were analysed using history matching and the JBN technique, with the findings indicating that the relative permeability of both fluids is a function of temperature. Possible wettability changes at increasing temperatures were proposed to have resulted in a shift in the oil relative permeability curve as temperature increased. This study contradicted earlier studies utilising sandstone core samples, which found that increasing temperature causes residual oil saturation to decrease while increasing irreducible water saturation. More recent studies on temperature dependant oil-water relative permeability were caried out by Esmaeili et al. [24,25] on water-bitumen system under temperature range of 70 to 220 °C and confining pressure of 1400 psi and reported that both oil and water relative permeability is temperature sensitive. The same authors [26] carried out similar sets of experiments under different operation conditions. Under temperature of between 23 and 210 °C with confining pressure of 800 psi for light oil of viscosity between 11.2 and 2281 cP, the study revealed that oil/water relative permeability is insensitive to temperature. The difference reported in both studies can be attributed to the complex rock-fluid system with features such as wettability and interfacial tension varying for the bitumen-rock system compared to the clean oil-rock system.

While ample research efforts have been put into studying temperature dependant relative permeability, there is lack of consensus on the effect as reported by Esmaeili et al. [27]. A key fact worth noting is that relative permeability is only sensitive to temperature fluctuation in specific temperature ranges. The pattern then reverses when the temperature increases more. While some investigators maintained that there are some modifications without recognising the optimal temperature, others claimed that there is no difference. The results of the experimental literature assessment and analysis do not clearly show a consistent trend between relative permeability and temperature. It is consequently important to examine the temperature dependence of relative permeability curves, although using numerical modelling using computational fluid dynamics software rather of practical experimentation.

Although theoretical or analytical methods for fluid mechanics and heat transfer have been established, multiphase flow modelling requires the solution of second-order partial differential equations, which are analytically intractable. This is due mostly to the intrinsic nonlinearity of the flow equations for multiphase porous-media flow issues [28–30]. The major reason for using a CFD experimental technique is that it is less time-consuming and expensive while providing capabilities that cannot be explored in a laboratory [31]. To help in the research of flow characteristics in porous medium, specialised software programmes, both commercial and open source, have been created in the field of CFD.

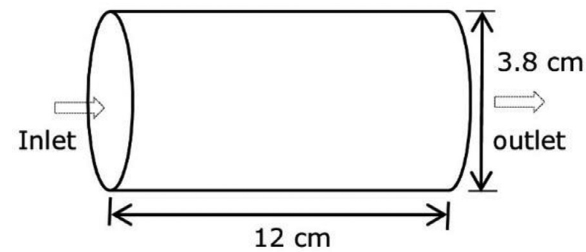

Fig. 1. Schematic of the flow domain.

Glatzel et al. [32] conducted comparative research on the applicability of four main commercial CFD software (Fluent, CFD-ACE, CFX, and Flow-3D) in flow simulations via micro channels and capillary structures and showed the usefulness of these software for various parameter investigations. Despite the fact that the usage of these CFD programmes has been established in these domains, the majority of the research have been focused on studying flow phenomena in micro-channels. Other research on macroscopic characteristics in porous media has been done [33–35].

The models essentially include the inclusion of the Darcy-Forcheimer equations as source terms in the momentum equations, which have been utilised to account for various system characteristics, including permeability and pressure drop in single-phase and multiphase flow regimes. Li et al. [33] demonstrated the capabilities of ANSYS® Fluent CFD software for modelling multiphase flows in porous media, with a particular emphasis on reservoir and well performance studies. To simulate reservoir and well conditions, oil-water flow was modelled in 1D, 2D, and 3D geometries. The numerical methodology used in this work is the Eulerian multiphase multi-fluid method in Fluent with a time-step and grid independant result, demonstrating the enormous potential of employing ANSYS-Fluent software for practical reservoir and well performance analysis.

To the best of our knowledge, no work in the open literature has used a CFD technique to evaluate relative permeability in a displacement flow scenario. Because multiphase flow in porous media is a complicated process, the complexity involved in include relative permeability and capillary pressure in the CFD solver might explain this result. Because relative permeability is a function of saturation, when the fluid saturation in the cells approaches irreducible values and relative permeability approaches zero, numerical instabilities in the CFD solver may occur if the relative permeability and capillary pressure are included in the solver [33].

In this work, a hot water injection procedure was performed in the Fluent CFD solver to model a thermal recovery process, and flow results from the solver were utilised to determine relative permeability by using multiphase equations derived from Darcy's equation. The scenario studied in this paper is a typical tertiary oil recovery operation in which hot water is pumped into the reservoir to lower the viscosity of the oil, therefore improving oil mobility and, ultimately, recovery. The final goal of this research is to investigate the influence of temperature and injection rate on relative permeability curves during hot water flooding operations. The examined simplified model includes a temperature-dependant two-phase (oil-water) flow through a porous medium associated with heat transfer.

3. Problem descriptions

ANSYS-Fluent was used to create a three-dimensional model of a cylindrical core sample with a diameter of 3.8 cm and a length of 12 cm. As indicated in Fig. 1, the model boundary condition comprises of the inlet face, outflow face, and wall body. Instead of specifying the shape and direction of each solid matrix within the porous body, the flow is described as a continuous process utilising average or "continuous" characteristics for the bulk system as a convention for a macroscopic description of fluid flow in the subsurface. The average flow rate for the total volume is calculated by plugging the bulk characteristics into the traditional Darcy's equation. The computational domain was built up to imitate the thermal recovery process with the injection of hot water from the inlet using specified operating settings to explore the influence of temperature and injection rate on relative permeability curves during water flooding. The processes were computationally simulated, and the relative permeability was calculated using multiphase equations derived from Darcy's equation. A mesh sensitivity analysis was performed, and all of the results presented in this paper used a structured mesh with an orthogonal quality of 1.

4. Numerical method

This section shows how to solve a problem involving the flow of two incompressible and immiscible fluids, oil and water, which are denoted by the letters *o* and *w*, respectively. The porous media is believed to be incompressible and homogeneous. The equations for Mass conservation equation (Eq. (1)) and generalised Darcy's law for multiphase flow (Eq. (2)) [36,31,37].

$$\begin{cases} \frac{\partial}{\partial t}(\emptyset\rho_w S_w) + \nabla(\rho_w v_w) = -Q_w \\ \frac{\partial y}{\partial x}(\emptyset\rho_o S_o) + \nabla(\rho_o v_o) = -Q_o \end{cases} \tag{1}$$

$$\begin{cases} v_w = -\frac{Kk_{rw}}{\mu_w}(\nabla P_w - \rho_w g) \\ v_o = -\frac{Kk_{ro}}{\mu_o}(\nabla P_o - \rho_o g) \end{cases} \tag{2}$$

Because both phases are incompressible, the fluid densities ρ_w and ρ_o are constant in the flow domain, and the petrophysical parameters of the media, such as porosity and permeability, are pressure independant. The following relationship must be met by the fluid saturations: $S_w + S_o = 1$ where $S_{wi} \le S_w \le 1 - S_{or}$ and $S_{or} \le S_o \le 1 - S_{wi}$. There will be no flow at water saturations below the irreducible water saturation (S_{wi}), and the oil phase will become immobile at oil saturations below the irreducible oil saturation (S_{or}). Under the premise that water is the wetting phase, the relationship for capillary pressure as a function of wetting phase saturation relates both fluid pressures; the correlation is stated as:

$$P_c(S_w) = P_o - P_w \tag{3}$$

The capillary pressure drops as the water saturation decreases. Eq. (4) below are obtained by combining Eqs. (1)–(3).

$$\begin{cases} \frac{\partial}{\partial t}(\emptyset S_w) + \nabla(-\frac{Kk_{rw}}{\mu_w}(\nabla P_o - \nabla P_c - \rho_w g)) = -Q_w \\ \frac{\partial}{\partial t}(\emptyset S_o) + \nabla(-\frac{Kk_{ro}}{\mu_o}(\nabla P_o - \rho_o g)) = -Q_o \end{cases} \tag{4}$$

4.1. Relative permeability

There is some blockage of flow on a given fluid phase by other fluid phases present in the system in multiphase flow in porous media where two or more fluids flow concurrently, and this is represented by a scalar called relative permeability. The ratio of the phase effective permeability (*Ke,q*) to the media's absolute permeability, *K*, is the relative permeability of a fluid phase *q*. The relative permeability *Kr* of the fluid phase *q* can be represented as:

$$K_{r,q} = K_{eq}/K \tag{5}$$

The relative permeability *Kr* is a dimensionless number with a value between 0 and 1, whereas the absolute permeability *K*, with a dimension in m^2, represents the ability of porous media to transport a single saturated fluid and is only dependant on the geometric properties of the pores. The permeability of the phase *q* in a multiphase system, or the ability of the media to transport the fluid phase *q* in the presence of other fluid phases is known as the effective permeability *Ke*, and it is influenced by the media's absolute permeability and phase saturation (volume fraction). Eqs. (2) and (5) clearly shows the relationship between the absolute permeability and the relative permeability in any porous media flow and were employed to evaluate the relative permeability in the two-phase porous media flows in this study.

Throughout the transient flow simulation, the sample average saturation for each fluid phase, as well as the pressure drop and flow rates were continuously monitored. The values of the input parameters at different flow times and water saturation were determined after a series of simulations for the different parameters of interest. We assumed a significant temperature dependence of the oil viscosity in our simulations in this study, and the power law model developed by Corey was used to predict the two-phase relative permeability. Eqs. (6) and (7) depicts the classical Corey model.

$$K_{rw} = K_{rw(Sorw)}(S)^{Nw} \tag{6}$$

$$K_{ro} = K_{ro(Swi)}(1 - S)^{No} \tag{7}$$

Where, K_{rw} and K_{ro} are the relative permeability to water and oil, respectively. $K_{rw}(S_{orw})$ and $K_{ro}(S_{wi})$ are the endpoint relative permeability to water at residual oil saturation(Sor) and oil at initial water saturation (S_{wi}), respectively. N_w and N_o are the Corey exponent to water and oil, respectively. The values 4 and 2 have been used for the water and oil exponent, respectively, as indicative of a water-wet porous media [22,38]. In addition, *S* in the Eqs. (6) and (7) is typically represented in normalised form as shown in Eq. (8).

$$S = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{orw}} \tag{8}$$

Where, S_w is water saturation, S_{wi} is initial water saturation and S_{orw} residual oil saturation. Following each set of simulations, both the water saturation and residual oil saturation were recorded in the volume fraction under the ANSYS-Fluent report section.

4.2. Mixture model

The primary idea of mixture theory is that the constituents that make up the mixtures are assumed to occupy the vacuum or pore spaces occupied by the fluid mixture, and each of them is treated as a continuum at each point within the medium filled with the mixture. The contributions of mass, momentum, and energy within the flow domain are considered relative to the effect of other elements, according to the conservation laws of mass, momentum, and energy. The mixture model is a condensed version of the multiphase model, which can simulate multiphase flow systems with various phases moving at different velocity yet assuming local equilibrium over short spatial length scales.

The continuity, momentum, and energy of the mixture are calculated, while the volume fraction of the secondary phase(s) is solved, as well as algebraic formulations for relative velocities in flows when the phases move at different velocities. The mixture model was chosen because it is less computationally costly than the full multiphase flow model in terms of solving the multiphase flow governing equations in less time. Its shortcoming is that it does not account for the pressure of individual phases; instead, it only accounts for the pressure of the mixture, making capillary pressure estimates impossible. CO_2 injection [7], Nano-fluid flooding [39], thermal recovery [40] and chemical flooding [41] are only a few of the multiphase flow challenges for which this model has been used. The Fluent model solves the following governing equations [37]:

Continuity equation for the fluid mixture

$$\frac{\partial}{\partial t}(\rho_m) + \nabla \cdot (\rho_m \vec{v}_m) = \dot{m} \tag{9}$$

Where $\vec{v}_m$ is the mass-averaged velocity expressed by $\vec{v}_m = \left(\sum_{k=1}^{n} \propto_k \rho_k \vec{v}_k\right)/\rho_m$ and ρ_m is the mixture density given as, $\rho_m = \sum_{k=1}^{n} \alpha_k \rho_k$, where $\propto_k$ is the volume fraction of the phase k and m is the mass sources.

Momentum equation for the mixture

$$\frac{\partial}{\partial t}(\rho_m \vec{v}_m) + \nabla \cdot (\rho_m \vec{v}_m \vec{v}_m) = -\Delta p + \Delta \cdot \left[\mu_m \left(\nabla \vec{v}_m + \Delta \vec{v}_m^T\right)\right] + \rho_m \vec{g} + \vec{F} + \Delta \cdot \left(\sum_{k=1}^{n} \alpha_k \rho_k \vec{v}_{dr,k} \vec{v}_{dr,k}\right) \tag{10}$$

Where n is the number of fluid phases, viscosity of the mixture represented as μ_m and body force $\vec{F}$. The drift velocity for the secondary phase in the mixture represented as $\vec{v}_{dr,k} = \vec{v}_k - \vec{v}_m$. The velocity of the secondary phase (p) relative to the primary phase (q) otherwise referred to as relative or slip velocity is given by $\vec{v}_{qp} = \vec{v}_p - \vec{v}_q$.

Energy equation for the mixture

$$\frac{\partial}{\partial t} \sum_{k=1}^{n} (\propto_k \rho_k E_k) + \nabla \cdot \sum_{k=1}^{n} (\alpha_k \vec{v}_k (\rho_k E_k + p)) = \nabla \cdot \left(k_{eff} \nabla \mathrm{T}\right) + S_E \tag{11}$$

Where k_{eff} represents the effective conductivity and S_E represents any other volumetric heat sources.

According to Mohammadmoradi et al. [42] accurate operation of the thermal increase oil recovery method requires knowledge of the heat transmission mechanism in a porous media. Effective heat helps to reduce fluid viscosity, which improves mobility and thus recovery. Effective thermal conductivity (ETC) and effective thermal diffusivity (ETD) are the two key core characteristics used to determine how effective thermal energy may be conveyed in a porous media. Furthermore, shape, porosity, and fluid saturation all have an impact on effective thermal conductivity [5]. The flow velocity is a crucial component in determining a non-isothermal condition in a system. In the case of the slow flow system discussed in this study, the distinct phases may interact and exchange energy locally to achieve a condition of local thermal equilibrium. A single energy equation is required in this situation to represent the temperature of all phases inside the domain at any given position. Coupling allows for a strong relationship between oil viscosity and temperature.

4.3. Operating conditions and assumptions

With initial water saturation *Sw* and initial oil saturation *So*, the displacement of oil with water in the consolidated cylindrical homogeneous porous core of porosity Ø. For the flow inside the porous media, incompressible laminar bi-phasic flow is examined. Between the fluids and the porous body, the local thermal equilibrium (LTE) assumption is considered valid. The following assumptions were considered when building the model:

- To displace the oil in the initially heated porous core, the porous core was injected with hot water at a steady rate and at a specified temperature at the intake face.
- It is assumed that the medium is isotropic, having the same flow in all three directions.

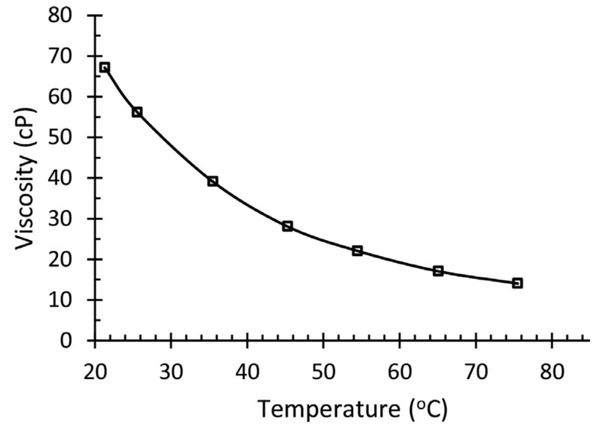

Fig. 2. Oil viscosity variation with temperature.

Table 1
Model parameters for Media properties.

Porous media property	Value	Porous media property	Value
Length (cm)	12.0	Initial Water Saturation (S_{wi}) (%)	20.0
Diameter (cm)	3.8	Pore volume (cc)	35.0
Porosity (%)	26.0	Thermal conductivity (W/m-k)	2.25
Permeability (mD)	14.0		

- The fluid viscosity can vary with temperature with the input done through the piecewise linear property input.
- With the same density, the fluids are incompressible, but at different pressures and temperatures.
- Petrophysical qualities of rocks, such as porosity and permeability, are thought to be constant and unaffected by pressure or temperature.

The effect of injection rate and injection fluid temperature on fluid relative permeability in a convectional core flooding system is explored in this paper. Three different velocities (2.94 × 10^{-6} m/s, 4.41× 10^{-6} m/s, and 5.88 × 10^{-6} m/s), as well as temperatures (20 and 70 °C) were simulated at the intake, with the core temperature set at 63 °C. The simulation input settings were chosen to be typical to core flooding laboratory experiment reported by Ahmadi et al. [43]. Prior to the start of the water injection, the model was set to a 20 percent water saturation. The water and oil phases have densities of 998.2 and 730 kg/m3, respectively. The water phase's viscosity is 0.001003 kg/m-s, while the oil phase's is temperature dependant (Fig. 2). The parameters of the fluid and porous media employed in this study are summarised in Table 1.

The physical characteristics of the system, as well as the operating conditions, has been designed in order to maintain the flow as a two-phase flow in a relatively low temperature petroleum reservoir. It is worth noting that because the ambient pressure condition was considered in the modelling, at temperatures above 100 °C, the liquid phase will change to vapour phase, giving rise to a three-phase flow, which is not the intention of this study. As a result, a low temperature was considered. Furthermore, we chose this range because it is representative of reservoir temperature in low-temperature petroleum reservoirs. Additionally, this is the temperature condition in the experimental benchmark study that was used as validation for this study. In particular, in the simulations, it was modelled as incompressible flow, with the density remaining constant in any fluid parcel. This is primarily due to the fact that no confining pressure was applied, resulting in an ambient pressure condition. Under these conditions, it is widely accepted that the liquid phase is nearly incomprehensible. Water, for example, is easily compressible in the vapour phase (steam), but the simulations did not reach the temperature of 100 °C required

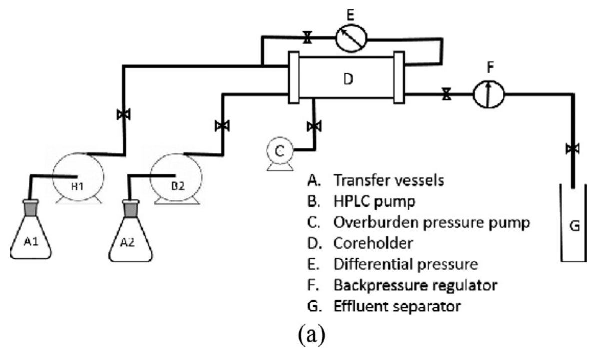

Fig. 3. Experimental set-up used for numerical results validation. Ahmadi et al. [43].

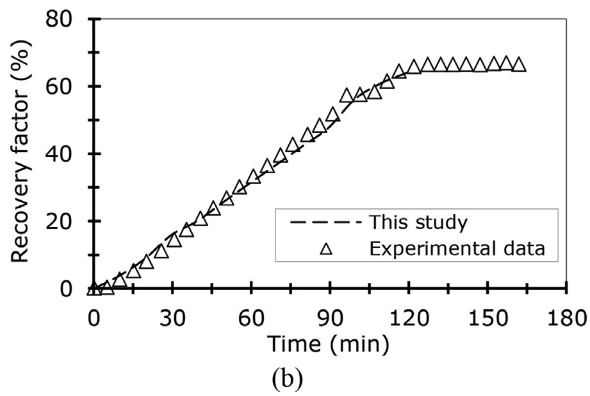

Fig. 4. Experimental and numerical simulation recovery factor plot.

for this to happen. We mentioned earlier that liquids are generally incompressible, but they are compressible if the pressure is high enough.

The concept of hysteresis has been neglected in this study, as the simulation is entirely an imbibition scenario. Typically, in a reservoir, relative permeability hysteresis is evident whenever a media with strong wettability preference experiences a change in saturation from a drainage to an imbibition process. However, in this study, there is no history of moving from drainage to imbibition in the workflow. In addition, as reported by Mobeen and Mehran [44] in a scenario where the reservoir is depleted by a reduction in the oil saturation and a corresponding increase of the wetting phase saturation (water), the imbibition relative permeability curves must be applied.

5. Results and discussion

This section examines the numerical results of temperature and injection rate effects on relative permeability. The oil-water saturation profiles at various flow periods and at varied sample lengths of 0.2 increments starting from the intake are given in Section 5.1, along with validation of the numerical methods against recovery factor data adapted from a core flood experiment [43]. In Section 5.2, the effects of temperature and injection velocity on the oil-water relative permeability are discussed.

5.1. Validation of the numerical method and oil-water saturation profiles

Fig. 3 shows a simplified schematic of the experimental set-up modified from Ahmadi et al. [43]. In Fig. 4, the recovery factor results from the current investigation were plotted against the core flooding experimental data at various time intervals. The numerical values used in the validation analysis are identical to the experimental conditions without calibration of the physical or numerical modelling parameters, except for the fluid viscosity dependence on temperature, which was incorporated as an interpreted User-Define-Function in ANSYS-Fluent, with injection temperature of 20 °C and inlet velocity of 2.94×10^{-6} m/s. With a smaller than ± 2.5 percent error margin, the results show a positive comparability between numerical and experimental data.

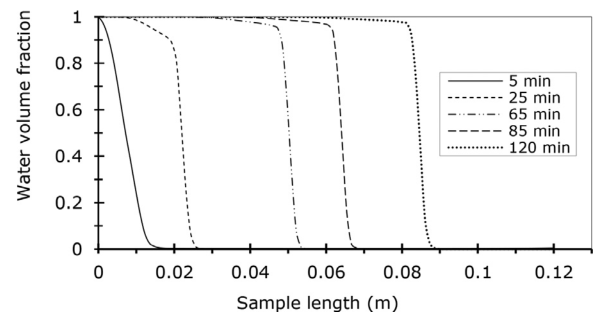

Fig. 5. Water saturation along the length of the sample with time.

In Fig. 4, the recovery factor calculated from the simulation is compared to results from a core flooding experiment published in the literature. The injection temperature and flow rates are modified based on the simulation and experiment results and the data is used to compute relative permeability curves to explore the sensitivity of relativity permeability to temperature and injection flow rate. Fig. 5 shows the water saturation (volume fraction) along the length of the core sample at various time intervals. With an inlet velocity of 2.94×10^{-6} m/s, the oil and water volume fractions are zero and one at the commencement of the injection. In Section 4.3, the fluid and porous media properties, as well as the initial flow conditions, are described.

The frontal advance profile volume-fraction curves often follow the linear Corey model, which has a zero residual saturation and a phase relative permeability of unity. It can be seen that when the injected water's saturation time increases from 5 to 85 min, it permeates a considerably larger section of the porous core at a faster rate. This could be owing to the relative permeability of the two fluids when they interact with one other, as predicted by the model's assumptions. In the core domain where displacement has occurred, the results also revealed an absolute oil saturation value of zero and a water saturation value of one. This is not the case in actual displacement processes, where some slippage will occur as irreducible saturation at the solid surface.

5.2. Temperature and injection velocity impact on oil-water multiphase the relative permeability

Fig. 6 compares the relative permeability of oil-water (two phases) at two distinct temperatures of 293 and 363 K. Three different injection rates were employed for each of the temperatures, and the results for relative permeability are shown in Fig. 6 (a-c). It can be seen that the trend of the curves does not alter significantly as the temperature rises. As a result, the relative permeability curves are insensitive to temperatures between 293 and 363 K. This could be due to the relative permeability of the oil shifting until an ideal temperature is achieved somewhere between 313 and 323 K, after which the trend reverses as the temperature rises further. This optimal temperature is known as the "viscous limit." In their experimental study to examine the effect of temperature on three-phase relative permeability isoperms in heavy oil systems, Akhlaghinia et al. [20] acknowledgd this behaviour.

Fig. 6d shows the influence of injection velocity on the oil-water relative permeability. The sensitivity of the phase relative

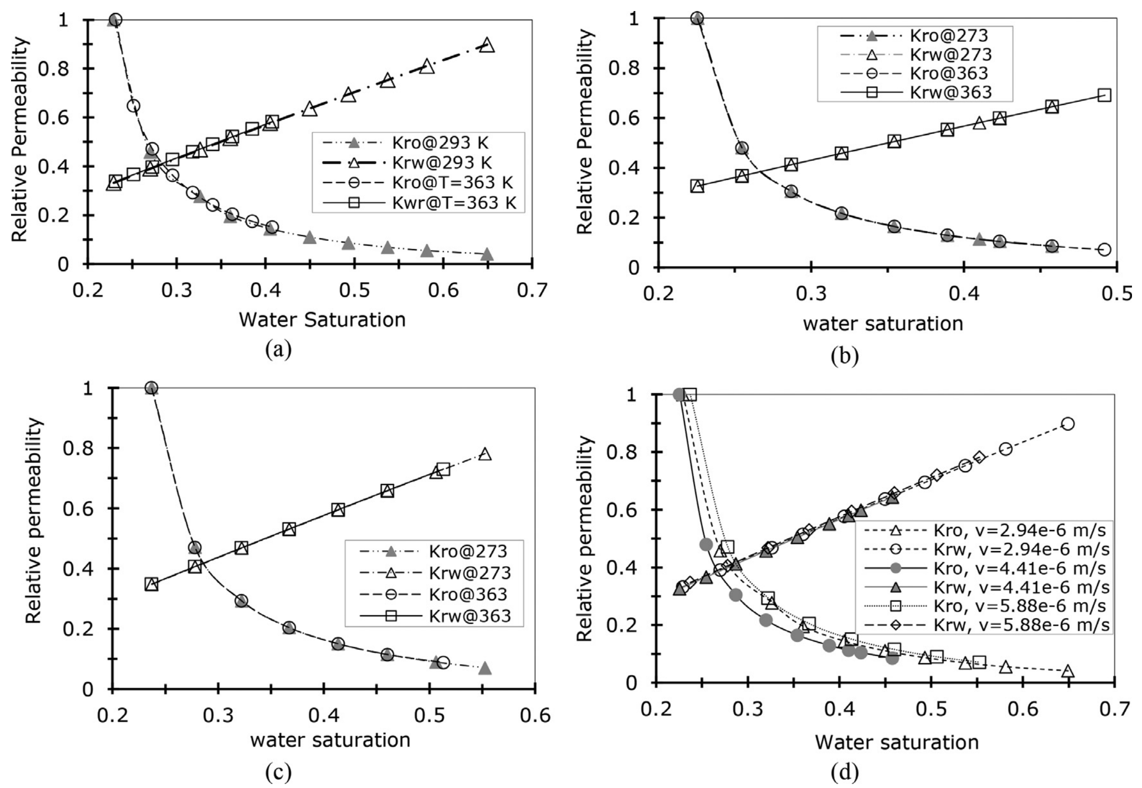

Fig. 6. (a–c): Comparison between results of relative permeability at different temperature. (d) Comparison of relative permeability for different injection velocities.

permeability to injection velocities was investigated using three distinct injection velocities of 2.94 × 10^{-6} m/s, 4.41 × 10^{-6} m/s, and 5.88 × 10^{-6} m/s. The water relative permeability curves indicate no significant change with changes in the injection flow rate for the three distinct flow rates evaluated, however the oil relative permeability curves show some sensitivity with changes in the injection flow rate. This is similar to the findings of Sandberg and Gournay [45] that attributed this occurrence to the tendency for the oil phase to flow in slugs. The highest flow rate caused a shift in relative permeability to the right, while the lowest is linked to the flow rate's median value. The relationship between relative permeability and flow rate is clearly visible in these results. Because relative permeability curves reflect a liquid's ability to flow in the presence of another fluid, higher oil relative permeability is necessary to improve oil phase displacement by water. Higher flow rates are also desirable for viscous oils in order to improve their relative permeability in relation to the water phase, according to the findings. Furthermore, flow rate has an impact on residual saturation levels, as an increase in injection flow rate resulted in a decrease in residual oil saturation but an increase in irreducible water saturation.

6. Conclusion

The goal of this research is to establish a complete numerical approach for modelling oil-water flow and heat transfer in porous media with water injection operations. In the simulation, a modified variation of the Eulerian mixture model was used, while the porous media were modelled using a physical velocity formulation. A viscous loss term based on Darcy's law without an inertial loss term was used to describe the resistance sink, which is the source term in the momentum equation. The approach used simulated oil displacement by water at high temperatures, simulating the conditions of a core flood experiment in the lab. The results were remarkably similar to the experimental data. The following conclusions can be drawn based on the results and analysis presented.

(i) The macroscopic properties of a porous media, such as relative permeability, can be estimated using a Computational Fluid Dynamics technique.
(ii) Permeability (relative) Oil flow curves are impacted by flow rate, whereas water relative permeability has little or no effect.
(iii) The injection flow rate has a major effect on the residual saturations of oil and water, as well as their effective permeability.
(iv) For temperature ranges of 20 to 90 °C, relative permeability has no discernible sensitivity. However, more research at higher temperatures is needed to determine how temperature affects relative permeability.

Declaration of Competing Interest

The authors declare that they have no conflict of interest.

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