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Numerical Investigations on the Sensitivity of Relative Permeability and Viscosity Ratio During Hot Water Flooding Under Non-Isothermal Conditions

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Abstract

Relative permeability and viscosity ratio is a matter of high concern when discussion of fluid flow inside the reservoir is stated. Several investigations have been done on relative permeability of the oil and water phase using experimental methods based on injection temperatures. In this study, authors have attempted to understand the injection temperature impacts on the relative permeability of oil and water and oil-water viscosity ratio using numerical models at transient temperature condition. Sensitivity analysis has been executed to check the influence of residual oil saturation on the relative permeability. An improved numerical model was developed in COMSOL Multiphysics by fully coupling energy conservation and multiphase flow under the rheological and thermal properties evolution in porous media. The relative permeability of oil and water phase has been observed changing significantly with the change in residual oil saturation. The cross over point of relative permeability curve has been found to shift towards strong water wet direction with the decrease in residual oil saturation. The oil and water relative permeability have been found insensitive to the change in injection temperature at field scale study. Oil-water viscosity ratio has been observed decreasing with the rise in temperature, which indicates oil viscosity decreases more significantly in comparison to water viscosity with the increase in reservoir temperature.

Keywords: *Numerical modelling; Relative permeability; Viscosity ratio; Transient temperature; Residual oil saturation.*

1. Introduction

The production of light crude oil has reached to its maximum nowadays and is becoming slow which has withdrawn the attention of the petroleum industry towards heavy crude oil and bitumen to meet the demand of the energy supply [1]. The crude oil which is comprised of high viscosity and low API gravity is termed as heavy in nature. The high viscosity makes the fluid almost immobile in the reservoir. The main aspects of extracting heavy oil from the reservoir depends on the feasibility of viscosity reduction and increment in relative permeability of the crude oil by economic and environment friendly.

The drop in heavy oil viscosity benefits the petroleum industry economically [2]. The viscosity reduction of heavy oil can be performed by various means. The application of chemical and surfactants are one of the most important means of reducing the viscosity of heavy crude oil but the cost of chemical and surfactants are generally high. The viscosity reduction of heavy oil can be attained by dilution [3]. It can also be achieved by the emulsification of oil in water [4]. Thermal methods to reduce the viscosity of oil are economical and environment friendly in comparison of chemical treatment.

The viscosity ratio plays a vital role in changing residual oil saturation as well as irreducible water saturation [5]. The viscosity ratio seems as a factor that effects the relative permeability of the oil-water system [6]. The higher reduction in viscosity ratio indicates the oil viscosity is decreasing rapidly in comparison to the water viscosity. The high viscosity reduction of oil can significantly contribute to the displacement process by improving the mobility ratio during hot water flooding [7].

Relative permeability is a critical factor that describes the multiphase flow in porous media at various water saturation [8]. Numerical modelling and simulation task to predict and forecast the performances of the reservoir cannot be performed without the consideration of relative permeability at the in-situ reservoir situation. A number of factors are considered to affect the flow performance of in-situ reservoir fluid [9]. The temperature impact studies on the relative permeability curve have gotten high attention during the last decades. The change in relative permeability of oil and water phase owing to temperature and its crossover saturation shift causes wettability change have been studied by using experimental methods [10]. The reservoir rock's wettability shifts to water wet with the increase in the saturation of water. Schembre *et al.* observed the diatomite reservoir core shifted toward increased water-wettability with increasing temperature [11]. The endpoint relative permeability of oil was observed to be decreased with a rise in temperature and water's relative permeability at endpoint was observed to remain unaffected. Iyi *et al.* observed temperature has no noticeable sensitivity over relative permeability for the temperature range 20°C to 90°C [12]. He suggested more research required to be performed at higher temperature to understand the relative permeability dependence over the temperature. Masoomi and Torabi found a reduction in residual oil saturation and an increment in irreducible water saturation with the increase in temperature from 20 to 80°C [13].

Thermal methods are broadly classified as hot water flooding, steam flooding, and in-situ combustion. Many researchers have worked in the area of thermal enhanced oil recovery around the globe [13-15]. Hot water flooding is the process in which high temperature fluid injected into the reservoir. The recovery mechanism consists of decreasing the viscosity of heavy oil by heating the reservoir to improve the liquidity, improving the mobility ratio, improving the relative permeability and decreasing the residual oil saturation during hot water flooding [15]. Hot water flooding is done to get better displacement efficiency and the recovery factor, and can be taken into consideration as an alternative technique in medium depth reservoirs.

Numerous studies have been performed using experimental methods to determine the relative permeability, viscosity ratio and wettability alteration using thermal methods. Very few earlier investigations were observed to estimate the relative permeability, viscosity ratio, and wettability under the transient temperature condition using numerical approach at field scale. To take the account of transient temperature, the oil-water relative permeability and viscosity ratio are investigated under non isothermal conditions in the present study.

2. Conceptual model

The reservoir is initially considered three dimensional as represented in Figure 1 (a). However, solving mathematical and numerical models of multi-directional fluid flow becomes highly complex [16]. Hence the reservoir is converted to two dimensions by slicing the reservoir along the XY plane, and is represented in Figure 1 (b). The variation of rock properties such as porosity, saturation and permeability are assumed constant in XY plane of the reservoir. The computational reservoir domain having oil and water phase is created to carry out hot water flooding to get the relative permeability, and viscosity ratio. The pressure and temperature of the reservoir is considered 20 MPa and 50°C initially. To understand the impedance of temperature, and residual oil saturation over the relative permeability, the two-dimensional reservoir has been taken, which is represented in Figure 1 (c) with desired boundary conditions. The viscosity ratio is also evaluated at varying injection temperature condition. The fluid flow has been considered happen in transverse and longitudinal direction.

The list of the physical processes occurring and the conceptual model diagram has been represented in Figure 1.

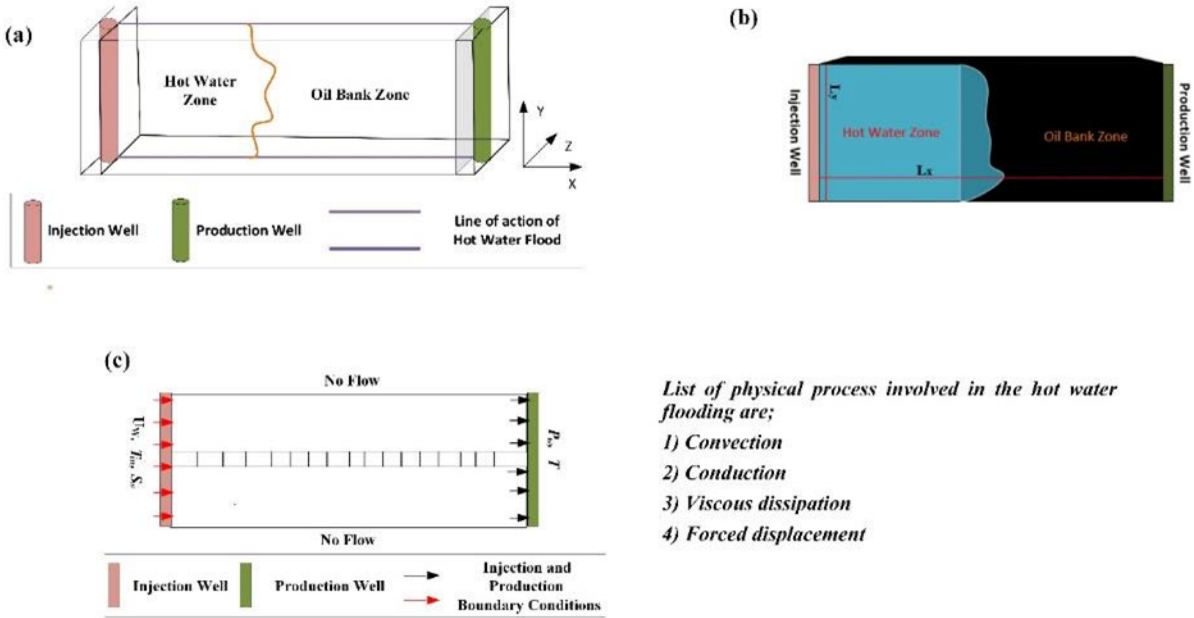

Fig. 1. Conceptual model representing the hot water flooding with physical process and boundary condition involved.

3. Mathematical model

3.1. Assumptions

Porous domain is considered water wet and to be in local thermal equilibrium (LTE). No heat and fluid flow are considered at the top and bottom boundaries. The oil and water viscosities are assumed to be changing with linearly to the temperature. Outflow is considered at the production well. Capillary and gravity influences are included. Fluid is assumed to be immiscible and incompressible.

3.2. Governing equations

The present model consists of conservation of energy, mass (water and oil), and momentum equations. The equation for the energy balance, mass and momentum transport has been described and are given in Equations 1, 7, 8, 9, and 10 [17].

The energy conservation in porous media at local thermal equilibrium is presented in Equation 1.

$$\left(\rho C_p\right)_{eef'}\frac{\partial T}{\partial t}+(\rho C_p)\mathrm{u}.\nabla T+\nabla q = Q_t \tag{1}$$

where 'u' fluid convection velocity, 'T' transient temperature 'Q_t' is heat source or sink (W/m^3).

The heat conduction is considered from the Fourier's law which is represented in Equation 2.

$$q=-k_{eef'}\nabla T \tag{2}$$

The effective heat capacity '$\left(\rho C_p\right)_{eef'}$', and the effective permeability '$k_{eef'}$' which are represented in Equations 3 and 5 respectively.

$$(\rho C_P)_{eef'}=\theta_c\rho_r C_{P,P}+(1-\theta_c)\rho C_P \tag{3}$$

$$\rho C_P=\rho_o C_o S_o+\rho_w C_w S_w;\quad \text{and} \tag{4}$$

$$k_{eef'}=\theta_c k_{tm}+(1-\theta_c)k_f \tag{5}$$

$$k_f=k_o S_o+k_{tw} S_w \tag{6}$$

Where '$C_{P,P}$' the rock's heat capacity, 'ρ_o' oil density, 'ρ_w' water density, 'C_o' oil's heat capacity, 'C_w' water's heat capacity, 'S_o'saturation of oil phase, 'S_w' saturation of water phase, 'θ_c' rock's volume fraction, 'k_{tm}' rock's thermal conductivity, 'k_{tw}' water's thermal conductivity, 'k_o' oil's thermal conductivity.

The flow inside the reservoir is considered to low velocity flow. The mass and momentum conservation equations for oil and water phases are written below in Equations 7, 8, 9, and 10.

$$\frac{\partial}{\partial t}(\phi\rho_o S_o) + \nabla.(\rho_o u_o) = Q_o \quad (7)$$
$$\frac{\partial}{\partial t}(\phi\rho_w S_w) + \nabla.(\rho_w u_w) = Q_w \quad (8)$$
$$u_o = -\frac{K_{ro}\ \ k\ (\nabla P_o - \rho_o g)}{\mu_{o\prime}} \quad (9)$$
$$u_w = -\frac{K_{rw}\ \ k\ (\nabla P_w - \rho_w g)}{\mu_{w\prime}} \quad (10)$$
$$S_w + S_o = 1 \quad (11)$$
$$Pc(S_w) = P_o - P_w \quad (12)$$

Where 'ϕ' porosity, 'u_o' oil's Darcy velocity , 'u_w' water's Darcy velocity, 'κ' the reservoir permeability (m^2), 'g' acceleration due to gravity, and 'μ_o' and 'μ_w', oil and water phase dynamic viscosity, 'P_o' and 'P_w' oil phase pressure and water phase pressure, 'K_{ro}' and 'K_{rw}' oil phase relative permeability and water phase relative permeability, 'Q_o' and 'Q_w' mass flux rate of oil and water. The phase pressures are related to the capillary pressure ($Pc(S_w)$) using Equation 12.

Relative permeability and influence of capillary are considered using the Brooks and Corey model which are presented in Equations 15, 16 and 17 [18].

$$S_o{}' = \frac{(S_o - S_{ro})}{(1 - S_{ro} - S_{rw})} \quad (13)$$
$$S_w{}' = \frac{(S_w - S_{rw})}{(1 - S_{ro} - S_{rw})} \quad (14)$$
$$Pc(S_w) = P_{ec}(S_w{}')^{\frac{-1}{\varepsilon}} \quad (15)$$
$$K_{rw} = (S_w{}')^{(3+\frac{2}{\varepsilon})} \quad (16)$$
$$K_{ro} = S_o'^2(1 - (1 - S'_o)^{(1+\frac{2}{\varepsilon})} \quad (17)$$

Where 'S_o'' normalised oil saturation, 'S_w'' normalised water saturation, 'S_{ro}' residual saturation of oil, 'S_{rw}' irreducible saturation of water, 'P_{ec}' entry pressure (capillary), and 'ε' pore distribution index.

3.3. Coupled relation to capture transient behaviour

The fully coupled heat transfer and multiphase flow modeling consists of a variation of reservoir rock and fluid properties with spatial and temporal distribution. The thermal conductivity of reservoir rock and the water thermal conductivity is considered depending on temperature represented in Equations 18, and 19 [19]. The viscosity of water and oil is presented in Table 2 [20]. It is assumed to be varied as linear interpolation with the temperature.

$$K_{tm} = 2.6 - 0.0025(T - 293.15) \quad (18)$$
$$K_{tw} = -0.869 + 0.009T - (1.58 \times 10^{-5})T^2 + (7.98 \times 10^{-9})T^3 \quad (19)$$

Table 2. Temperature dependent oil and water viscosity.

Temperature (K)	μw (Pa.s)	μo (Pa.s)
294.261	8 × 10-4	0.03090
310.928	6.2 × 10-4	0.01995
322.039	5 × 10-4	0.01412
338.706	3.8 × 10-4	0.00977
355.372	3.2 × 10-4	0.00759
366.483	2.8 × 10-4	0.00631
394.261	2.1 × 10-4	0.00354

4. Numerical model

4.1. Description of computational domain and parameters

The porous media evaluated has been assumed to have properties similar to the homogeneous media. The porous media used in this study is two-dimensional with two vertical wells spaced 100 m apart, and the thickness of the pay zone is considered 30 m. The fluid and rock properties which are used have been taken from the various literature are shown in Table 2 [12,21-26].

Porosity is incorporated into the porous media with an average value 0.30. The average permeability is considered 1.38×10^{-14} m^2 in the horizontal and vertical direction. The thickness of the pay zone is assumed saturated with 85 percent with oil and 15 percent with initial water saturation at the initial condition.

In the present study, the two-dimensional view of the reservoir has been considered to carry out the numerical simulation which is represented in Figure 1 (c). It is considered the flow in the porous domain is normal to the well. Initially, the injection temperature of the fluid is varied to understand and analyse the relative permeability with the change in the temperature of injected fluid. Later on, residual oil saturation of the oil is varied at a fix injection temperature, and velocity to understand and analyse the impact of residual oil saturation on the relative permeability of oil and water phase. The investigation was extended to analyze the impact of injection temperature on the viscosity ratio of oil to water.

The relative permeability has been evaluated using cut line. The reservoir temperature and viscosity ratio has been evaluated based on the surface average value. The Parallel Direct Solver is used to solve nonlinear system of equation. The implicit backward differentiation formula is used for temporal step discretization. Simulation has been performed to analyse the relative permeability using the COMSOL Multiphysics. The simulation has been performed for 500 days.

Table 1. Formation matrix and reservoir fluids properties.

Physical parameters	Value	Reference
Porosity	0.30	
Oil's saturation	0.85	
Density of water (kg/m^3)	1000	
Density of oil (kg/m^3)	965	[21]
Density of rock (kg/m^3)	1750	
Thermal conductivity of crude (W/mK)	0.14	
Rock's heat capacity (J/KgK)	860	
Water's heat capacity (J/KgK)	4200	
Formation permeability (m^2)	1.3817×10^{-14}	[12]
Reservoir pressure at initial condition (Pa)	20×10^6	[22]
Production well Pressure (Pa)	10×10^6	
Capillary entry Pressure (Pa)	10×10^3	[23]
Pore distribution index	2	[24]
Oil's heat capacity (J/KgK)	2.7855631×10^3	[25]
Injection Temperature (°C)	100, 110, 120	
Residual oil saturation	0.15, 0.10, 0.05	Present study
Velocity at inlet (m/s)	2×10^{-7}	
Initial Temperature (°C)	50	[26]

4.2. Initial and boundary conditions

The porous media has been assumed to have 85%, 20 MPa and 323.15 K oil saturation, pressure and temperature at initial conditions respectively. The initial conditions have been presented in Equations 20, 21 and 22.

$T\ (x, y, 0) = \text{Initial Temperature}$ (20)

$S_o\ (x, y, 0) = \text{Initial oil saturation}$ (21)

$P\ (x, y, 0) = \text{Initial Pressure}$ (22)

The boundary conditions which have been chosen to compute the problem are Dirichlet and Neumann types. The boundary conditions have been represented in Figure 1 (c) and have been presented in Equations 23 to 27.

$T\ (x=0, y, t) = \text{Injection Temperature}$ (23)

T (x=L, y, t) = Initial temperature (24)
U_w (x=0, y, t) = Inlet velocity (25)
S_w (x=0, y, t) = 1 - S_{ro} (26)
P (x=L, y, t) = Production Pressure (27)

4.3. Execution of COMSOL multiphysics

COMSOL Multiphysics is used in the present study to understand the change in relative permeability and viscosity ratio with respect to the injection temperature. It has been applied in the porous media applications in academia, R&D organisation and industries [19, 22, 27-30]. The commercial simulator COMSOL Multiphysics uses finite element method approach. The computational domain is discretized into quadrilateral grid. The extremely fine mesh has been adopted for running simulations. Dynamic local variables cell has been used to incorporate explicit rock and fluid properties variation. The representation of the workflow of the numerical model in COMSOL Multiphysics has been presented in Figure 2.

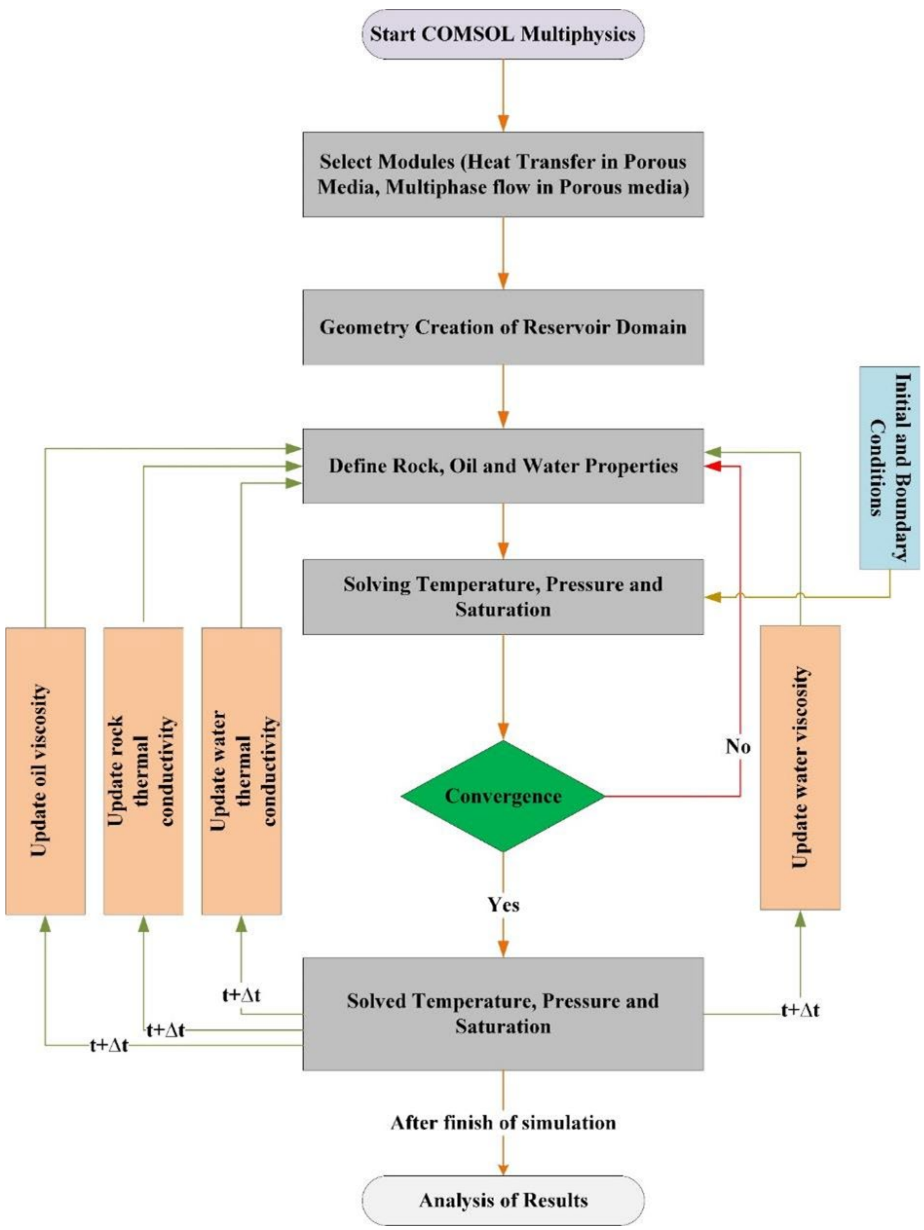

Fig. 2. The flow diagram illustrating the workflow of numerical simulation in COMSOL multiphysics.

5. Results and discussion

Numerical approach has been used to understand the transient temperature consequences on the oil-water relative permeability curves under different injection temperature and residual oil saturation. Viscosity ratio (oil-water) has also been investigated under the influence of injection temperature. The reservoir pressure and temperature have been considered in such a way that the injection hot water maintained its liquid nature in the reservoir condition. The reservoir initial pressure has been taken into consideration to designing the hot water injection.

5.1. Verification of the model

The present model is verified using the existing analytical model of Buckley and Leverett [31]. The physical operating parameter has been assigned for the verification similarly in analytical and present numerical model. The porous domain is considered saturated with the oil phase initially. The present numerical model has been found in close agreement with the analytical solution of the Buckley and Leverett. The profile of the present model has been found almost similar to existing analytical solution, and has been represented in Figure 3. The model is extended to the reservoir possessing 85 % of oil initially to analyze the oil-water relative permeability and viscosity ratio after gaining the confidence.

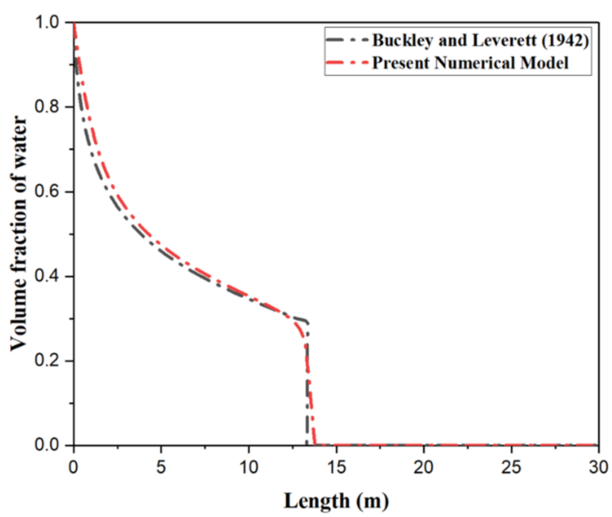

Fig. 3. Verification of the present numerical model.

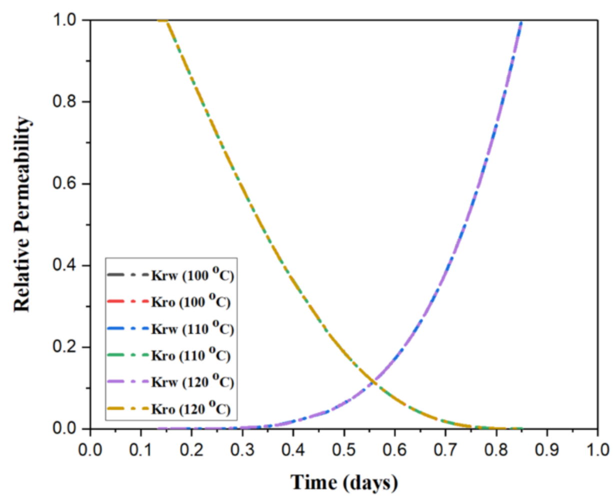

Fig. 4. The figure illustrating the relative permeability change of oil and water phase with temperature.

5.2. Impact of the injection temperature

The relative permeability under varying condition of injection temperature has been plotted against the volume fraction of water in Figure 4. The relative permeability has been measured under injection temperature of 100°C, 110°C and 120°C using numerical approach under transient temperature condition. Under different injection temperature conditions, the relative permeability plot proclaims that the change in relative permeability of oil phase and water phase is insignificant with the rise in temperature up to 120°C from 100°C. Iyi *et al.* also observed oil phase and water phase relative permeability is insensitive up to 90°C [12].

The temperature rise may cause a decrease in interfacial tension. The lower the interfacial tension means lower the surface energy needed to detach the fluid in contact with the rock surface. The lower surface energy required means the surface tension between the rock and oil has got weaken which may cause to increase flowability. On the other hand, the rise in temperature also reduces the viscosity of oil. The flowability of oil through the pores depends on the differential pressure between the inlet and outlet of the pores. As the oil viscosity decreases with the rise in temperature, means the less energy is required to make the oil flow through the porous media. Hence, injection temperature may improve the flowability by reducing interfacial tension and viscosity of oil rather than improving the relative permeability in the present study.

5.3. Impact of residual oil saturation

The relative permeability of oil and water phase under varying condition of residual oil saturation has been plotted against the volume fraction of water in Figure 5. The relative permeability has been measured under three different residual oil saturation 0.05, 0.10 and 0.15 at constant injection temperatures of 120° C simultaneously. The relative permeability has been observed changing significantly with a change in residual oil saturation. The oil relative permeability has been observed to increase with the decrease in residual oil saturation. The order of oil and water relative permeability is observed as 0.05 > 0.10 > 0.15. The higher residual oil saturation has been observed to show weak water wet behaviour in comparison with the lower residual oil saturation. The cross over point has been observed shifting towards the strong water wet direction with a decrease in residual oil saturation.

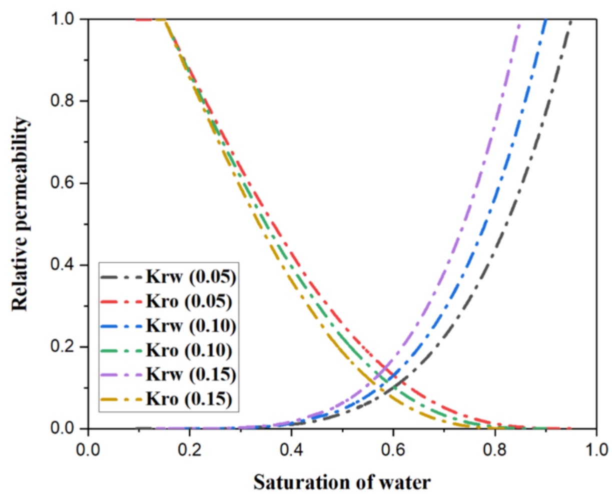

Fig. 5. The figure illustrating the sensitivity of residual oil saturation on relative permeability change.

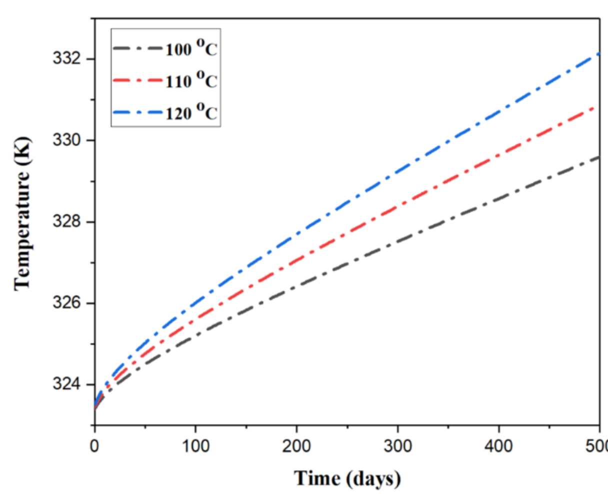

Fig. 6. The figure illustrating the temperature rise of the reservoir with time.

5.4. Impact of injection temperature on average reservoir temperature and oil-water viscosity ratio

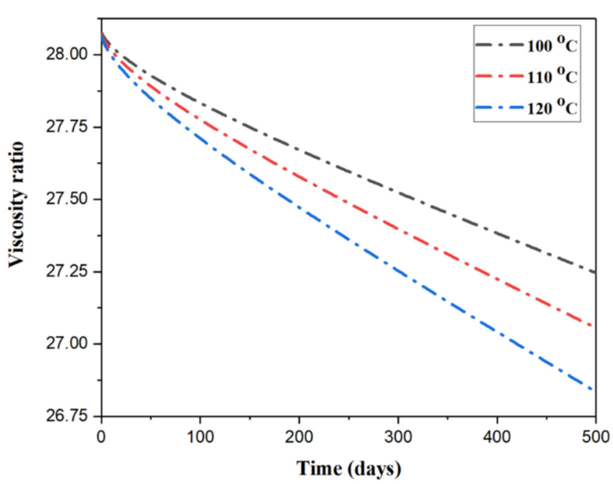

Fig. 7. The figure illustrating the oil-water viscosity ratio change with time.

The reservoir temperature rise has been plotted against the time in Figure 6. The reservoir's temperature has been found to increase with the time passage. The highest rise in reservoir temperature has been observed at 120°C. The relative increase of average temperature at 120°C, 110°C and 100°C has been observed 4.42 %, 3.63 % and 2.95 % from the initial reservoir condition. The rise in temperature reduces the oil and water phase viscosities.

The oil-water viscosity ratio has been plotted against the time in Figure 7. The viscosity ratio of the oil and water phase has been observed to decrease with time. The highest value of viscosity ratio reduction can be observed at 120°C. The order of viscosity ratio reduction is observed as 120°C > 110°C > 100°C. The high magnitude of viscosity reduction can improve the oil displacement. The decrease in the viscosity ratio indicates that the viscosity of oil has reduction more significantly than the viscosity of water with temperature rise. The oil viscosity falls more rapidly than water with the rise in the temperature of the reservoir. The oil displacement can be improved by increasing the injection temperature, and hence production can be enhanced by increasing the temperature.

6. Conclusions

A numerical investigation has been performed to evaluate the relative permeability curve behaviour based on various injection and reservoir parameters using COMSOL Multiphysics by fully coupling energy transport and multiphase flow. The impact of injection temperature and residual oil saturation on relative permeability and viscosity ratio have been evaluated at field scale simulation.

The relative permeability has been observed to have no discernible sensitivity to injection temperature in the temperature range 100°C - 120°C. The relative permeability has been observed to change with the change in residual oil saturation. The increase in residual oil saturation has decreased the relative permeability of the oil phase. The shift in cross over point has been observed with the decreasing residual oil saturation towards strongly water wet direction.

The viscosity ratio has been observed to decrease with the rise in reservoir temperature. The viscosity of oil has been observed to decrease significantly, which indicates the oil flowability can be enhanced with time by increasing the injection temperature.

The present study is limited to fluid flow model with injection temperature up to 120°C. It has been recommended to check the wettability and cross over point shifting of relative permeability curve at higher temperature with or without consideration of geomechanics.

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Credit authorship contribution statement

Md Irshad Ansari: Conceptualization, Methodology, Execution, Validation, Investigation, Writing original draft. Suresh Kumar Govindarajan: Supervision, Resources, Writing review & editing, Analysis.

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