International Journal of Heat and Mass Transfer 105 (2017) 535–548

Contents lists available at ScienceDirect

International Journal of Heat and Mass Transfer

journal homepage: www.elsevier.com/locate/ijhmt

# Effect of temperature on the oil–water relative permeability for sandstone reservoirs

Lie-hui Zhang, Jing Tong, Yu Xiong, Yu-long Zhao *

*The State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu, PR China*

A R T I C L E I N F O

*Article history:*
Received 23 June 2016
Received in revised form 6 October 2016
Accepted 8 October 2016
Available online 13 October 2016

*Keywords:*
High temperature
Sandstone reservoir
Relative permeability
Translate

A B S T R A C T

Temperature has a significant effect on oil–water relative permeability, which is very important in reservoir development. Considerable controversy persists regarding the effects of temperature and concerning how to obtain representative relative permeability curves. This work studies the effect of temperature on the oil–water relative permeability of tight sandstone and analyzes the influences of absolute permeability, clay mineral content, and pore throat structure on relative permeability curves at different temperatures. The results indicate that irreducible water saturation increases linearly with temperature increase, while residual oil saturation decreases nonlinearly with temperature increase. In addition, when temperature increases, both oil and water relative permeability increase under the same water saturation and the crossover saturation moves rightwards, which indicates that the system becomes more water-wet. Due to the significant effect of temperature on relative permeability, experimental results from lab tests cannot accurately reflect fluid flow characteristics under the reservoir condition. In order to overcome this problem, this paper proposes a novel method to translate lab results into reservoir values by combining the Johnson–Bossler–Naumann (JBN) technique and the empirical method. The comparison between the calculation and the lab results is consistent. The conclusions of the paper provide a valuable reference for laboratory tests under high temperature, and they can be used for preliminary evaluation purposes.



## 1. Introduction

As an indispensable part of reservoir numerical simulation, dynamic analysis, and field performance prediction, oil–water relative permeability curves can be used to describe the flow characteristics of the oil–water two-phase displacement system in porous media. Some basic methods to determine relative permeability have been applied successfully. These methods include field or laboratory measurement and theoretical modeling [21,41,51,57,9,7]. Among the most recent research work, the methods can be divided into analytical, laboratorial, empirical, and numerical methods [1,46]. Four major categories are used to test relative permeability in the lab: (a) the steady-state method, (b) the unsteady-state method, (c) the capillary manometric method, and (d) empirical models. In addition, many published papers have reported the effects of temperature on oil–water relative permeability with different test methods, and different results and conclusions have been drawn, as shown in Table 1.

Geffen et al. [19] started researching the influence of temperature on relative permeability in the 1950s. They first proposed that laboratory tests to represent real fluid flow in a reservoir must have a similar saturation history, as relative permeability is not a single-value function of saturation. Moreover, special care should be taken to disallow wettability change, at elevated temperatures, during relative permeability measurements.

The relationships between temperature and relative permeability can be divided into two major categories: independency and dependency. Based on the test data of Edmondson [16] and Shilolwd [45] conducted further study and drew an opposite conclusion, which was that relative permeability versus normalized saturation is independent of temperature. Later, similar trends were also observed that temperature has no effect on relative permeability [48,36,39,4]. Dynamic-displacement experiments were conducted by Kumar and Inouye [28]. They used light oil in a test at a temperature range of 20–150 °C. Their results showed that endpoint saturations are independent of temperature and are primarily a function of the viscosity ratio. These results are consistent with the viewpoint of Lefebvre du Prey [30], who believed that relative permeability was related to capillary to viscous forces. Nourmohammad et al. [38] emphasized that experimental

* Corresponding author.
*E-mail addresses:* 373104686@qq.com, swpuzhao@swpu.edu.cn (Y.-l. Zhao).

http://dx.doi.org/10.1016/j.ijheatmasstransfer.2016.10.029
0017-9310/

**Nomenclature**

| | | | |
|---|---|---|---|
| $K_{rw}(S_w)$ | water relative permeability, fraction | $I$ | value of relative injectivity, also known as flowing capacity ratio; as for displacement of constant speed mode, $I = \frac{\Delta P_o}{\Delta P_{(t)}}$ |
| $K_{ro}(S_w)$ | oil relative permeability, fraction | $Q_{(t)}$ | liquid production of outlet at time t, cm$^3$/s |
| $S_w$ | water saturation, fraction | $Q_{\infty(t)}$ | liquid production of outlet at the initial time, cm$^3$/s |
| $S_{wi}$ | irreducible water saturation, fraction | $\Delta P_{(t)}$ | displacement pressure difference at the initial time, MPa |
| $S_{or}$ | residual oil saturation, fraction | $\Delta P_o$ | displacement pressure difference at time $t$, MPa |
| $f_o(S_w)$ | oil ratio, fraction | $K^o_{rw}$ | water relative permeability at residual oil saturation, fraction |
| $V_{(t)}$ | cumulative fluid production, cm$^3$ | $K^o_{ro}$ | oil relative permeability at irreducible water saturation, fraction |
| $\overline{V_{(t)}}$ | dimensionless cumulative fluid production, percentage of pore volume | $S_{wD}$ | normalized water saturation, fraction |
| $V_p$ | pore volumes, cm$^3$ | | |
| $V_o$ | cumulative oil production, cm$^3$ | | |
| $\overline{V_{o(t)}}$ | dimensionless cumulative oil production, percentage of pore volume | | |

conditions should be considered accurately to find the true temperature effect on relative permeability, as the results of the measurements indicated no significant temperature effect on relative permeability curves and residual saturation for the system tested.

The dependency of relative permeability curves on temperature includes three categories: (a) change in the oil–water relative permeability ratio, (b) the contrary tendency of relative permeability value to water and oil, and (c) both the decrease and increase of the oil–water relative permeability value at elevated temperatures.

Davidson [15] conducted isothermal displacements by an unsteady state method and reported that the oil–water relative permeability ratio tended to be temperature dependent at a low and higher water saturation but independent of temperature at a middle water saturation, which was consistent with Edmondson [16] experimental result. Ehrlich [17] further stated that the oil–water relative permeability ratio increased in unconsolidated sand and decreased in consolidated sand. Utilizing both steady-state and unsteady-state technology, Kumar et al. [29] investigated the influence of elevating temperature, and the experimental results suggested that the relative permeability curves sensibly showed higher water wetness at higher temperatures. Sola et al. [43] and Wang et al. [52] reported a similar relative permeability trend for limestone using heavy oil at a temperature range of 37.8–93 °C and for sandstone using light oil at a temperature range of 40–100 °C, respectively. While opposite retrograde behavior was observed by Esfahania and Haghighi [18], their research results indicated that Iranian carbonate rocks became more oil-wet using light oil at room and reservoir temperatures. On the other hand, Karaei et al. [23] proposed that wettability was independent of temperature.

Some reports show that the value of oil relative permeability increases at higher temperatures while the value of water relative permeability decreases [47,50,5,59,61]. Unlike these studies, Maini and Batycky [33] proposed that the oil endpoint relative permeability decreased with an increase in temperature while the water endpoint relative permeability remained unchanged. Furthermore, although irreducible water saturation was found to increase gradually, residual oil saturation first decreased with an increase of temperature and then the trend reversed when the temperature increased to an optimum level [34].

Watson and Ertekin [54] studied the effect of temperature gradient on relative permeability and their experimental results indicated that both the oil and water relative permeability decreased at a high rate with an increasing temperature gradient. Sola et al. [43] also obtained similar trends and found that the relative permeability of oil and water, as functions of temperature, decreased with an increase in temperature.

As shown in the research overview in Table 1, most scholars observed a similar tendency that both oil and water relative permeability increased as the injection temperature increased [40,32,55,13,37,35,42,60,62,10,44,64,22]. They also reported an increase in irreducible water saturation and a decrease in residual oil saturation as the temperature of the system increased. This shift in saturation results in some changes in the value of relative permeability as well. Kamari et al. [24,25] further observed that irreducible water saturation and residual oil saturation had significant impact on the oil recovery and oil relative permeability. Li et al. [31] indicated that high temperature produced high ultimate oil recovery, and relative permeability curves had a tendency to move to the right with an increase of temperature.

Among recent research work, a novel observation was observed that relative permeability increases with temperature only under a certain range of temperatures. Then the trend reverses as the temperature rises further. Akhlaghinia et al. [2] used two core-flooding setups to measure heavy oil–water relative permeability at three different temperatures: 28 °C, 40 °C, and 52 °C. Analysis of the data showed that the oil relative permeability first increased from 28 °C to 40 °C and then it decreased when the temperature ranged from 40 °C to 52 °C. This means that the oil relative permeability shifts up until an optimum temperature somewhere between 40 and 52 °C is reached and then the trend reverses as the temperature increases further [2,3,49]. Compared to the studies of other researchers, the effect of temperature on water relative permeability is the same as the results observed by Bennion et al. [12] and Hamouda et al. [20].

On the basis of their literature review, analysis, and experiments, they stated that it was not possible to justify a unique trend of the relative permeability, even though the range of water saturation changes. Therefore, it seemed necessary to conduct our own core flooding experiments and investigate the dependency of relative permeability curves on temperature. Besides, experimental results at the lab state cannot reflect fluid flow characteristics under reservoir conditions, as the relative permeability is affected by temperature significantly. The objective of this paper was accomplished by performing core flooding experiments, investigating and analyzing the effects of temperature on sandstones cores with different permeability at different temperatures, and proposing a rapid and simple method to translate the lab results into reservoir values.