Fuel 237 (2019) 91–116

Contents lists available at ScienceDirect

Fuel

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

Review article

Review of the effect of temperature on oil-water relative permeability in porous rocks of oil reservoirs

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ARTICLE INFO

Keywords:
Heavy oil
Thermal recovery
Relative permeability
Effect of temperature
Porous media

ABSTRACT

Thermal methods of heavy oil recovery involve multiphase flow at high temperatures. Numerical simulation studies of such processes require accounting for changes in the multi-phase flow behavior of the rock-fluid system with increasing temperature. Although the effect of temperature on two-phase relative permeability has been studied for more than five decades, it remains an unresolved issue. Experimental results that frequently contradict each other are still being reported and the issue remains a matter of debate. The purpose of this review is to critically examine the reported results and explore the possible reasons for contradictory results. We have examined the reported results of more frequently cited papers from past five decades and attempted to rationalize the disagreements in findings.

There appear to be three main reasons for the lack of consensus in experimentally observed results. The measurements of relative permeability at high temperature are complex and the reported results often include experimental artifacts. Secondly, meaningful relative permeability measurements require that capillary forces control the fluid distribution within the pore space, but this condition is difficult to ensure in viscous oil systems. The third reason is that the impact of temperature is not same in all rock-fluid systems, it depends on how the wettability, interfacial tension and the pore geometry changes with temperature.

It becomes apparent that it is not advisable to generalize the effect of temperature on relative permeability from previous studies without having a good understanding of how the underlying parameters that can influence the relative permeability are changing with temperature. The relative permeability of a specific petroleum reservoir may (or may not) vary with temperature.

1. Introduction

Thermal recovery of heavy oil and bitumen involves two-phase and three-phase flow of oil, water and gas at high temperatures in oil bearing porous formations. Modeling of such processes requires accounting for changes in the multiphase flow properties of reservoir rocks resulting from the increase in temperature. Heating the rock from original reservoir temperature to the high temperatures, which can exceed 300 °C in steam injection and much higher in in-situ combustion processes [1], brings about changes in rock-fluid properties that can have a large impact on the flow behavior. The viscosity of heavy oil decreases by several orders of magnitude [2–7] and this by itself can significantly change the flow characteristics [8–11]. Furthermore, such large increase in temperature can also change other rock-fluid properties, including wettability [4,12–20], interfacial tension [7,14,16,21–25] and pore geometry.

Multiphase flow in porous media is complicated due to contributions of many factors, such as, complex pore geometry, the rock wettability, properties of different phases, capillary pressure, pore and throat size distributions and compressibility of the porous medium. The commonly used mathematical description of multiphase flow in porous media is based on the extension of the Darcy's equation to multiphase flow [26] by introducing the concept of effective permeability for each phase that varies with saturations of different phases. Under two-phase flow conditions, the effective permeability for each fluid phase becomes a function of its own saturation [27–29]. This dependence of effective permeability on saturation is usually described by defining a relative permeability, which represents the ratio of the effective permeability to a base permeability, which is often the absolute permeability of the medium [28–30]. The advantage of using relative permeability to describe the variation with saturation is that it separates the changes in absolute permeability from the effects of fluid saturation. It allows one to account for the effect of permeability heterogeneity in the reservoir by assuming that the same relative permeability curve applies at different values of the absolute permeability. In most reservoir engineering flow studies, the relative permeability is one of the most

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https://doi.org/10.1016/j.fuel.2018.09.100
Received 22 June 2018; Received in revised form 14 September 2018; Accepted 22 September 2018

Nomenclature

C^*	wettability number
g	gravitational acceleration
k_w	absolute permeability to water
k_{wor}	water relative permeability endpoint
k_{ei}	effective permeability to ith phase
k_{oir}	oil relative permeability endpoint
L	core length
N_c	capillary number
no	oil exponent
S_{or}	residual oil saturation
S_{wi}	irreducible water saturation
T	temperature
D	core diameter
k_{ro}	relative permeability to oil
k_{ri}	relative permeability to ith phase
k_{rw}	relative permeability to water
k_{abs}	absolute permeability
k_{ro}^0	oil relative permeability endpoint
k_{rw}^0	water relative permeability endpoint
M	mobility ratio
nw	Water exponent
S_w	water saturation
S_e	normalized water saturation
S_i	ith phase saturation
V	fluid velocity

Greek symbols

μ_w	water viscosity
v^*	constant superficial velocity
v_c	characteristic velocity
ρ_w	water density
θ	contact angle
μ	displacing fluid viscosity
μ_o	oil viscosity
v	fluid velocity
ρ_o	oil density
σ	interfacial tension

Abbreviation

CA	cross section area
ID	inner diameter
N/A	information not available
ROS	residual oil saturation
SS; USS	steady state; unsteady state
CSS	cyclic steam stimulation
IFT	interfacial tension
PV	pore volume
SAGD	steam assisted gravity drainage

crucial parameters [31].

The knowledge of two-phase water/oil relative permeability is needed to predict the production rate, breakthrough time and the ultimate oil recovery in processes involving displacement of oil by water [32,33]. The relative permeability also affects the pressure response and velocity profile of fluids flowing through the porous rock in such displacements. The relative permeability varies from one oil reservoir to another and it may even be different for two core plugs with the same geometry, geology, lithology, composition, and physical properties (porosity and permeability) but with different pore size distributions [29,34]. In the same rock, the relative permeability can change with the type of fluids saturating the pores [29,32]. Accordingly, there is always some uncertainty when a given set of relative permeability data, which was measured using the best available technique on a core sample from a specific reservoir using native fluids, is used for analysis of other similar reservoirs [29,30]. Actually, uncertainty remains, to some extent, even in the analysis of the reservoir from which the core sample was obtained, due to the possibility of changes in the behavior in different parts of the formation.

Numerous studies have been reported in the petroleum literature on relative permeability properties of different types of porous media and on the effects of rock-fluid characteristics that affect the flow behavior [29,35,36]. The effect of temperature on relative permeability curves has received significant attention since 1950's [6]. There are published reports that contradict each other on the temperature impact on two-phase relative permeability for various systems [2–4,6,7,12,25]. In addition, numerous studies have attempted over the years to present the effect of temperature on relative permeability by proposing some useful relative permeability models even for a particular system [5,25,37–42]. The objective of this study is to critically review such published articles [2–4,6–8,12,13,15–17,19,21,24,25,38,40–53] on the effect of temperature on two-phase relative permeability and distill useful information and insights into the changes in behavior that occur as a function of the temperature. This involves careful examination of the effect of temperature on characteristics of relative permeability curves for different porous media types and various fluid types in a wide range of temperature and pressure. This extensive survey endeavors to clarify how the contribution of various variables including wettability alteration, viscosity ratio, capillary end effect, saturation history, data interpretation method, type of oil and porous medium, and the employed experimental procedure, as well as human errors and experimental artifacts could have led to contradictory findings. In this review, the most cited publications since 1956 are examined and the effect of temperature on different attributes of the relative permeability curves are extracted and analyzed.

2. Relative permeability concept

When two immiscible fluids flow simultaneously through a reservoir rock, the conductivity of the rock to each fluid depends not only on the permeability of the rock but also on the relative amount of each fluid present in the pore space. In other words, the effective permeability to each fluid depends on the absolute permeability of the rock and the fraction of the pore space occupied by that fluid, which is called the fluid saturation. The relative permeability is defined as the effective permeability divided by a base permeability, which is often the absolute permeability of the medium, as shown in Eq. (1) below.

$$k_{ri}(S_i) = k_{ei}(S_i)/k_{abs} \quad (1)$$

where k_{ri} is the relative permeability to fluid *i*, when its saturation is S_i, $k_{ei}(S_i)$ is the effective permeability to fluid *i* at the same saturation, k_{abs} is the absolute permeability and *i* denotes either oil or water. Very often, under two-phase flow conditions in oil reservoirs, the relative permeability to each fluid is a function only of the saturation of that fluid and it is independent of other flow parameters. The rationale for treating the relative permeability to be a determinable function of saturation is based on the concept that the two immiscible fluids flow largely in parallel but separate pore networks and that the fluid distribution within the pores is controlled primarily by capillary forces [27,29]. It is generally true that the capillary forces acting on the fluids under typical reservoir flow conditions are several orders of magnitude larger than viscous and inertial forces [54,55]. Therefore, the distribution of the two immiscible fluids is often controlled by the capillary forces [54,55]. This dominance of surface forces favors the fluid