Fuel 176 (2016) 222–236

Contents lists available at ScienceDirect

Fuel

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

Effect of fines migration on oil–water relative permeability during two-phase flow in porous media

Abbas Zeinijahromi [a,*], Rouhi Farajzadeh [b,c], J. (Hans) Bruining [c], Pavel Bedrikovetsky [a]

[a] Australian School of Petroleum, The University of Adelaide, Adelaide, SA 5005, Australia
[b] Shell Global Solutions International, Kessler Park 1, 2288 GS Rijswijk, The Netherlands
[c] Department of Geoscience & Engineering, Delft University of Technology, Stevinweg 1, 2628 CN Delft/2600 GA Delft, The Netherlands

HIGHLIGHTS

- Lower damage by salinity reduction at the presence of remaining oil was observed.
- Rel Perm were determined by modified JBN method for core flood with fines migration.
- Water Rel Perm curve showed decline at high saturations due to fines migration.

ARTICLE INFO

Article history:
Received 22 July 2015
Received in revised form 18 February 2016
Accepted 21 February 2016
Available online 11 March 2016

Keywords:
Low salinity water
Fines migration
Induced formation damage
Relative permeability
Water flood

ABSTRACT

One of the main physical characteristics defining oil recovery during water injection is the phase relative permeability. Salinity of the formation water can significantly differ from the injected water and consequently affect the relative permeabilities.

In the current work, we investigate the effect of fines migration on water and oil relative permeability. First, flow tests with piece-wise constant decreasing water salinity without oil are performed in order to identify the movable fine particles. Then the oil is displaced by the formation water from the sister-cores for a recovery assessment excluding the ion exchange processes. After re-saturation, oil is displaced by water with alternate salinity. The conditions of large-scale approximation, where the capillary pressure and dispersion effects are negligible, have been achieved in the tests. This allows the derivation of the modified Welge–JBN method to determine relative permeability from the performed tests. The obtained relative permeability curves for water exhibits an abnormal decline at high saturations, which is attributed to fines mobilization and straining yielding the water permeability decline.

1. Introduction

The shape and values of the relative-permeability function have a major impact on the results of the simulation of water-injection projects. Representative formulae for phase relative permeabilities are therefore among the important parameters in reservoir simulators. Different shapes of the relative-permeability curves have been reported for water-wet, oil-wet, and mixed-wet rocks [1–4].

Significant effects of water composition and fines migration on water and oil relative permeability during waterflooding have been widely reported in the literature [5–9]. Numerous physical mechanisms occur simultaneously during displacement of oil by water with a composition that differs from that of the formation water. Those mechanisms include change of electrostatic forces and contact angle with consequent wettability alteration, fines migration, multi-component ion exchange, rock-surface alteration, and saponification [10–13]. Usually, the reduction in residual-oil saturation and the water relative permeability in presence of the residual oil is observed with the reduction in the salinity or pH increase of the injected water.

Based on the results of the laboratory waterfloods with various water compositions, several authors use the salinity-dependent Corey-form of the relative permeability with monotonic curves for each phase [14–18]. However, Hussain et al. [19] observed a non-monotonic (pseudo) relative permeability for water at low salinities.

Permeability decline due to fines migration has been widely reported in the literature [20–22]. Fine particles, attached to the pore walls or grain surfaces are mobilized by viscous forces, exerting on the particles by the flowing fluids. Fig. 1 schematically shows the forces acting on a "fine" particle residing in a pore.

* Corresponding author. Tel.: +61 8 8313 8014; fax: +61 8 8313 4345.
E-mail address: abbas.zeinijahromi@adelaide.edu.au (A. Zeinijahromi).

http://dx.doi.org/10.1016/j.fuel.2016.02.066
0016-2361/

Nomenclature

Latin letters

A	area, L^2, m^2
A_w	water exposed area, L^2, m^2
A_o	oil exposed area, L^2, m^2
f	fractional flow of water
k	absolute permeability, L^2, mD
k_o	initial absolute permeability, L^2, mD
k_{ro}	oil relative permeability
k_{rw}	water relative permeability
L	reservoir/core length, L, m
p	pressure, $ML^{-1}T^{-2}$, Pa
q	volumetric flow rate, L^3T^{-1}, m^3/s
S	water saturation
S_o	oil saturation
t	time, T, s
U	overall flow velocity, LT^{-1}, m/s
x	linear co-ordinate, L, m

Greek letters

γ	brine ionic strength, $molL^{-3}$, mol/l
γ^J	ionic strength of the injected brine, $molL^{-3}$, mol/l
γ^I	ionic strength of the formation brine, $molL^{-3}$, mol/l
γ_{cr}	reservoir initial brine ionic strength, $molL^{-3}$, mol/l
ϕ	porosity
μ_w	water dynamic viscosity, $ML^{-1}T^{-1}$, cp
β	formation damage coefficient
σ	volumetric concentration of particles
σ_a	volumetric concentration of attached particles
σ_{ao}	initial volumetric concentration of attached particles
σ_{cr}	maximum volumetric concentration of captured particles
σ_t	volumetric concentration of strained particles
λ	total mobility

Abbreviations

FW	fresh water
HS	high salinity water (3 wt% NaCl)
PVI	pore volume injected

The drag, F_D, and lifting forces, F_l, detach the particle from the rock surface, and the electrostatic, F_e, and the gravitational forces, F_g, hold the particle attached to the surface. The mechanical equilibrium of the particle on the rock surface is determined by the torque balance [23,24]. The particles are detached if the detaching torque exceeds the attaching torque; otherwise, the fines remain attached. The equilibrium condition results in the maximum retention concentration of the fine particles

$$\sigma_{cr} = \sigma_{cr}(\gamma, \mathrm{pH}, T, U) \tag{1}$$

where γ is the brine ionic strength, T is the temperature, and U is the superficial flow velocity. Eq. (1) is a mathematical description of the particle detachment – the excess of the attached concentration over the current value of σ_{cr} is detached, mobilized, and eventually migrated.

The explicit formulae of maximum retention function (Eq. (1)) can be derived for a multi-layer deposit of mono-sized fines in a circular capillary [25], for multi-layers of mono-sized particles in a bundle of parallel capillaries with a size distribution [26] and for mono-layer of size-distributed fines [27].

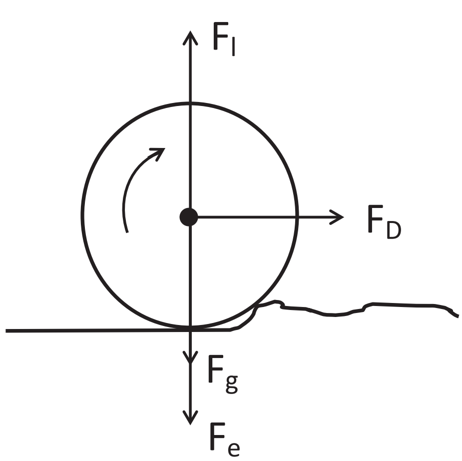

Fig. 1. Forces acting between fine particles and pore wall.

The detached particles migrate and plug the narrow pore throats, leading to permeability decline. It is assumed that only the particles that are attached by the electrostatic forces can be detached, i.e. the straining is irreversible. The term "retained" refers to the attached particles.

The detailed investigation of the permeability damage by fines migration in the presence of the residual oil has been performed by Sarkar and Sharma [28] and Sharma and Filoco [7]. Injection of the fines-mobilizing brine into the "dry" core may reduce the absolute permeability by a factor of 200–1000, while the presence of residual oil reduces the permeability-reduction factor down to 40–100. The smaller permeability reduction in presence of oil is attributed to the smaller surface accessible to water. The explanation agrees well with the concept of phase distribution in the pore space with a mixed wettability [29,30]. From the above follows that oil saturation is another variable in the expression for the maximum retention function (Eq. (1), Fig. 2). Therefore, Zeinijahromi et al. [26] assumed a saturation-dependence of the maximum retention function during two-phase displacement reflecting the water-accessible rock-surface increase due to rise in saturation. Yuan and Shapiro [31] argue that the maximum-retention function depends on saturation because the water velocity is saturation-dependent.

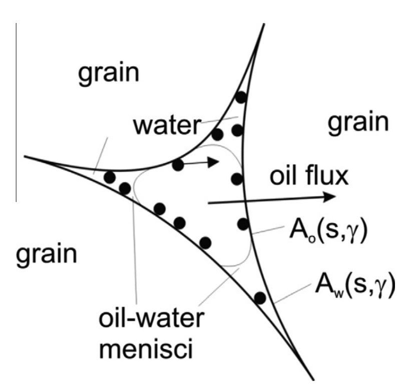

Fig. 2. Oil- and water-exposed surface areas during water-flood; here A_w and A_o are the fractions of the rock surface exposed to water and to oil, respectively.