

Enhanced Oil Recovery

The effect of wetting on the relative permeability behavior and oil recovery

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The effect of wetting on the relative permeability behavior and oil recovery

By

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In partial fulfillment of the requirements for the degree of

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Preface

This report was written for the course 'AESB3400–Bachelor Thesis', as a partial fulfillment of the requirements for the degree of Bachelor of Science in Applied Earth Sciences at the University of Technology in Delft.

The Bachelor thesis has been performed at the Faculty of Civil Engineering and Geosciences, TU, Delft, with Professor Hans Bruining. I would like to thank my supervisor, Professor Hans Bruining for his time and supervision of my Bachelor thesis.

*A. Toutouh
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Abstract

Oil is one of the major contributors to energy consumption. Oil reserves are expressed as the total amount of economically and technically producible oil. Total oil consumption is increasing (per capita it remains more or less the same) but it has no unambiguous influence on the remaining reserves due to new discoveries. However, increasingly sophisticated recovery methods are used to produce oil i.e. enhanced oil recovery methods. A recently proposed enhanced oil recovery method is by injection of low-salinity water in completely oil-wet reservoirs, which leads to more water-wet behavior and “consequently” to improved oil recovery.

This report will focus on the effect of wettability on the recovery efficiency. Based on the papers by Lomeland, Ebeltoft and Thomas we derive so-called LET relative permeability curves that only depend on irreducible water saturation. This is possible by using the irreducible water saturation dependence of the residual oil saturation, end point relative water permeability and the sketched behavior (Lomeland, Ebeltoft and Thomas) of the other six parameters. Admittedly this is a gross simplification, but it grasps the essence of the relative permeability behavior and makes it possible to study the recovery in terms of two parameters viz. the irreducible water saturation and viscosity ratio as opposed to eight relative permeability parameters and the viscosity ratio. High irreducible water saturation is both indicative of pore size heterogeneity and water-wet behavior. We use the theory of Buckley-Leverett to construct recovery curves for 1D and 2D displacement and various mobility ($M = \text{displacing fluid mobility} / \text{displaced fluid mobility}$) ratios. We solve the 1-D equations both analytically (using fractional flow theory) and numerically. For the numerical simulations in 1D and 2D we use COMSOL 5.2©. The simulations show that water-wet behavior is conducive to stable displacement, however, low recovery at breakthrough, whereas intermediate oil-wet behavior is more unstable but conducive to high ultimate recoveries. Completely oil-wet behavior leads to less stable displacement and low ultimate recoveries.

Nomenclature

In order of appearance

I	Ionic strength
c_i	Molar concentration of ion i
z_i	Charge number of ion i
σ_{ow}	Interfacial energy between the oil and water,
σ_{os}	Interfacial energy between the oil and solid,
σ_{ws}	Interfacial energy between the water and solid,
θ	Contact angle, the angle of the water/oil/solid contact line.
k	Permeability
k_{rw}	Relative permeability of aqueous phase
k_{ro}	Relative permeability of oil
$S (S_w)$	Saturation (water)
S_e	Effective saturation
S_r	Residual saturation
λ	Sorting factor
S_{iw}	Initial water saturation
S_{wir}	Irreducible water saturation
$S_{or} (S_{orw})$	Residual oil saturation
k_{rw}^0	Relative end point permeability for water
f_w	Fractional flow rate
S_{wc}	Connate water saturation
A	Cross section of sample
φ	Porosity
x	Displacement coordinate
t	Time
q_t	Total flow rate
q_o	Flow rate of oil
q_w	Flow rate of water
f_o	Fractional flow of oil
f_w	Fractional flow of water
M	Mobility ratio
Pe	Peclet number
N_{pd}	Pore volume production of oil
$N_{pd_{bt}}$	Pore volume production of oil at breakthrough
S_{wbt}	Water saturation at breakthrough
D	Diffusion coefficient
P_c	Capillary pressure
G	Gravity number

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1. Introduction

When a well is drilled the first recovery that occurs is due to natural mechanisms that drive the hydrocarbons to the surface. As time passes, the pressure inside the reservoir drops and the recovery decreases. When the natural mechanisms do not suffice secondary recovery methods are introduced. The reservoir pressure is then increased by the injection of water or the injection of different types of gases. In order to further increase oil recovery tertiary recovery methods are used. Tertiary methods or enhanced oil recovery methods can be divided in thermal methods, im(miscible) high pressure gas injection and chemical methods. Low-salinity water in order improve the relative permeability behavior can be considered as a chemical method. One can also use the injection of low-salinity water as a secondary recovery method. Injection of low-salinity water leads to more water-wet behavior and “consequently” to improved oil recovery.

1.1. Wettability

Wettability is a major factor controlling the location, flow, and distribution of the fluids in a reservoir (Anderson, W.G. (1987)). It has been shown in the literature (Morrow, N.R. and Buckley, J. (2011)) that for clayey formations, oil with polar components and an aqueous phase with divalent ions, a secondary waterflood with low-salinity water composition improves the oil recovery by some 5-20%. Following Hirasaki (1996), based on the DLVO (Derjaguin, Landau, Verwey and Overbeek) it is suggested that water films between the rock and the oleic phase are more stable at low-salinity than at high salinity. Hirasaki considers two surfaces, viz. the aqueous-rock interface and oleic-aqueous phase interface. Depending on the pH the surfaces are positively or negatively charged (Israelachvili (2011)). If they are both positively or both negatively charged the double layers (surface charge and surrounding ions) show a net repulsion. However, the ions in the solution cause the ionic strength ($I=1/2 \sum c_i z_i^2$) to be non-zero and this makes that the surface charges are partly shielded leading to a diminished repulsive force. There are also dipole-dipole (Van der Waals) interaction forces (Hirasaki, G.J. (1993)) which are usually attractive. Consequently at high ionic strength the attraction forces may dominate leading to a destruction of the water film between the two surfaces. It is implicitly assumed that water-wet behavior leads to more favorable relative permeability behavior, i.e. leads to improved recovery.

1.2. Permeabilities

There are a number of semi-empirical relations (Reservoir Engineering Handbook, Ahmed (2006)) that one can use when experimental data of relative permeabilities (Leverett (1939)) are lacking. We disregard the viscosity dependence of the relative permeabilities (Dullien (1982)); however, the lubrication effect at high oil viscosities can become significant (Honarpour (1986)). General observations are that in water-wet media, oil will occupy the larger pores and obstruct the flow of water in these pores, leading to low relative water-permeabilities (Craig (1993)). Low relative water permeability leads to a favorable mobility ratio and more stable displacement. In oil-wet media (Owens and Archer (1971)) oil will occupy the smaller pores and wet the pore walls of the larger pores, leading to a higher value of the relative water permeability (Honarpour (1986)). Initial or connate water saturations in water-wet media are usually high, i.e. 25-35%, whereas initial water saturations in oil-wet media are small 15-20%. Consequently residual oil saturations in water-wet media are usually high; whereas they are low in oil-wet reservoirs (see Fig. 1).

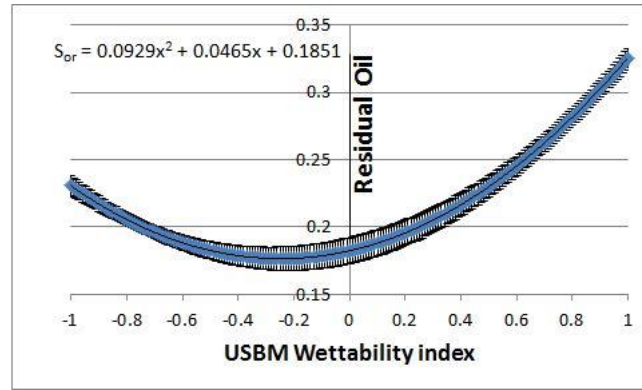


Figure 1.1: Residual Oil Saturation as a function of the USBM wetting index x (Ebeltoft et al. (2014)). The error bars are calculated using a Boots trap method for the data presented by Ebeltoft

1.3. Scope of Work

Based on the papers by Lomeland, Ebeltoft and Thomas we derive so-called LET relative permeability curves that only depend on the irreducible water saturation. In the literature there are no simple empirical relations for relative permeabilities as a function of the wettability (Brooks and Corey, Chierici). Lomeland et al. give relative permeability functions that incorporate the effect of wettability; however, it has eight undetermined parameters. These parameters describe the low saturation, the middle saturation and the large saturation range of both the relative oil permeability and the relative water permeability. Lomeland et al. do suggest, sketch wise, the behavior of these parameters as a function of wettability (Ebeltoft, E. and Lomeland, F. and Brautaset, A. and Haugen, Å. (2014)). They also refer to papers that describe the residual oil saturation and the end point permeabilities as a function of wettability.

We propose based on the sketches of Lomeland et al. to describe the relative permeabilities as a function of a single parameter, being the irreducible water saturation. For high irreducible water saturation the system behaves more water-wet. More water-wet behavior implies high residual oil saturations and low end-point permeabilities (Honarpour et al., (Anderson, W.G. [1987])).

We use those relative permeability equations and constructed a model with COMSOL 5.2©. This model uses the Buckley-Leverett theory. From the fractional flow functions we are able to obtain recovery plots for various irreducible water saturations and three mobility ratio's. The mobility ratio depends on both the relative permeability and viscosity of oil and water.

1.4. Thesis Organization

In section 1, we describe some aspects of wettability. In section 2 we describe how we obtain relative permeabilities and how we can formulate their dependence of the irreducible water saturation. In section 3, we use the relative permeability behavior to obtain recovery curves in 1-D, using the Buckley-Leverett theory, i.e. based on fractional flow functions. Section 4 shows the results, we show the recovery for various irreducible water saturations and different mobility ratio's. We end with some conclusions, which can be found in section 5.

2. Wettability

Wettability is the degree of wetting and tells us something about the interaction between immiscible fluids and solid phases. In reservoir rocks the immiscible fluid phases are oil, gas and water. The solid phase is determined by the rock mineral composition of the reservoir. The interaction between the fluids and the solid phases results from intermolecular interactions. The wettability is determined by the adhesive and cohesive forces between phases (Anderson W.G. (1987)). In this chapter we will further discuss some aspects of wettability. We will also discuss the way in which wettability affects our problem.

2.1. Reservoir Wettability

The degree of wetting can be measured by the contact angle θ as can be seen in figure 2.1. A small contact angle results in a small contact area for the non-wetting phase and a large contact angle results in a high contact area for the non-wetting phase.

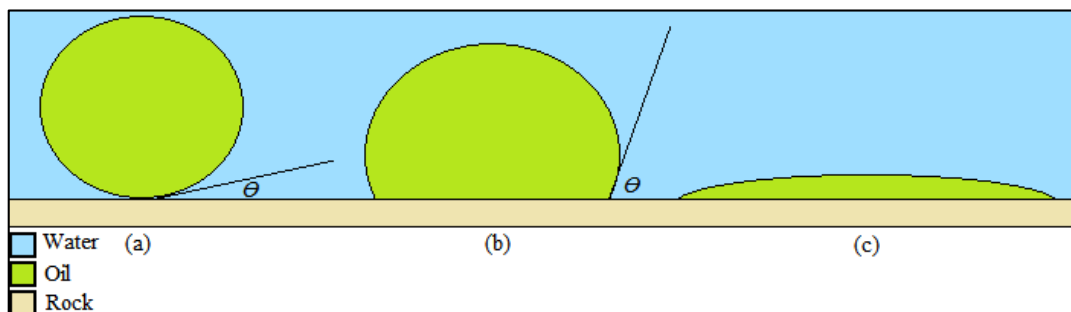


Figure 2.1: Spreading of an oil drop on a rock surface with different types of wettability (Anderson W.G. (1986))

Reservoir rocks have different types of chemical compositions. The chemical composition of the surface of these rocks and the chemical composition of the fluids inside the pores have an influence on the wetting behavior of this reservoir. Reservoirs can be oil, water or mixed wet. A strongly oil-wet reservoir means that the rock surfaces of the pores prefer contact with oil. When a wetting fluid (oil) enters this reservoir it will spread over the surface and in doing that it will displace the other fluid present (Abdallah, W et al. (2007)). This effect can be seen in figure (c) where the oil spreads on the surface, resulting in a large contact angle ($\sim 180^\circ$). When a non-wetting fluid (water) enters this reservoir, it will avoid contact with the rock surface and thereby lead to a small contact angle ($\sim 0^\circ$) as illustrated in figure 2.1 (a).

There are also systems that are neither strongly water-wet nor strongly oil-wet and are called the 'intermediate-' wet system. The contact angle in those kinds of reservoirs is determined by (Adamson, A.W. (1982)):

$$\cos(\theta) = \frac{\sigma_{os} - \sigma_{ws}}{\sigma_{ow}} \quad (2.1)$$

Where σ_{ow} = Interfacial energy between the oil and water,

σ_{os} = Interfacial energy between the oil and solid,

σ_{ws} = Interfacial energy between the water and solid,

and θ = Contact angle, the angle of the water/oil/solid contact line.

When $\sigma_{ws} < \sigma_{os}$ we can say that the system is water-wet, and when $\sigma_{ws} > \sigma_{os}$ we can say that the system is oil-wet. If $\frac{\sigma_{os}-\sigma_{ws}}{\sigma_{ow}} > 1$, which is equivalent to

$$\sigma_{os} > \sigma_{ow} + \sigma_{ws}, \quad (2.2)$$

a water film is formed between the oleic and solid phase. Such a system will behave water-wet. If surface active components are present the rock can become hydrophobic and $\sigma_{os} < \sigma_{ow} + \sigma_{ws}$. In such a case a water film is no longer stable and the system can become intermediate-wet or even oil-wet.

	Contact Angle (degrees)
Water-wet	0 to 75
Intermediate wet	75 to 105
Oil-wet	105 to 180

Table 2.1: Distribution of wettabilities based on contact angle (Treiber, L.E. et al. (1972))

It can also occur in the same porous medium that some pores are oil-wet and other pores are water-wet. In this case the saturation history is also an important factor when dealing with wettability (Anderson W.G. (1987)). Indeed, it happens often that not all pores are always filled with the same fluids. Pores that have been filled with oil can be oil-wet but those never filled with oil may be water-wet and the other way around. Reservoirs that do not have a uniform preference for a certain fluid are called mixed wet.

2.2. Wettability Changes

Numerous experiments are done and reports are written on the influence of wettability on the oil recovery (Moore, T.F. and Slobod, R.L. (1956), Owens, W.W. and Archer, D.L.J. (1971), Treiber, L.E, et al. (1972), Morrow N.R. and Lim H.T. and Ward J.S. (1986), Anderson W.G. (1987)), Morrow N.R, (1990), Jadhunandan, P. P., & Morrow, N. R. (1995), Morrow, N.R. and Buckley, J. [2011] etc.).

All these reports and experiments show the importance of knowledge about the wetting behavior of reservoir rocks. Numerous enhanced oil recovery methods depend on manipulating the wetting forces in order to reduce the amount of oil in contact with the pore surface. By doing this the wettability changes and more oil may be recovered. In this report the wettability is changed to behave more water-wet due to the injection of low-salinity water. This change in wettability will alter both the relative oil- and the relative water-permeability as explained in the introduction.

3. Relative Permeability

The permeability of a reservoir relates the pressure drop to a given fluid flow inside the reservoir. Higher permeabilities allow a lower pressure drop for the same flow rate. We consider an oil reservoir with two fluid phases, i.e. an oil phase and an aqueous phase. The oil phase may consist of a large number of hydrocarbons, whereas the aqueous phase may contain considerable amounts of dissolved salts. Each of the phases has a given viscosity, but for the fluid flow we need to consider the permeability reduction effects due to the presence of the other phase. The permeability reduction factor is called the relative permeability and is defined by

$$k_{r\alpha} = \frac{k_{\alpha}}{k} \quad (3.1)$$

3.1. Correlations

Usually it is assumed that the relative permeability is only a function of the water saturation. There are a variety of approximations to represent the relative permeability as function of the water saturation. The simplest representation of relative permeabilities is by the so-called power law with saturation exponent n , i.e. $k_{r\alpha} \sim S_{\alpha}^n$. A more realistic representation is given by the Corey expressions (Brooks, R.H. and Corey, A.T. (1964))

$$k_{rw} = S_e^{\frac{2+3\lambda}{\lambda}} \quad (3.2)$$

$$k_{ro} = (1 - S_e)^2 \left(1 - S_e^{\frac{2+\lambda}{\lambda}} \right), \quad (3.3)$$

where S_e is the dimensionless effective saturation

$$S_e = \frac{S - S_r}{1 - S_r}$$

S_r is the residual saturation. These equations use the sorting factor λ , where a small value of λ corresponds to a heterogeneous distribution of pore sizes and a large value of λ corresponds to a homogeneous distribution. Chierici (Chierici, G.L. (1984)) proposed exponential relative permeabilities as:

$$k_{rw}^* = \exp(-BR_w^{-M}) \quad (3.4)$$

$$k_{ro}^* = \exp(-BR_w^L) \quad , \quad (3.5)$$

Where A , B , L and M are > 0 and with

$$R_w = \frac{S_w - S_{iw}}{1 - S_{or} - S_w}$$

$$k_{rw}^* = \frac{k_{rw}}{k_{rw}(S_{or})}$$

$$k_{ro}^* = \frac{k_{ro}}{k_{ro}(S_{or})}$$

A recent development was introduced by Lomeland *et al.* (Ebeltoft, E. and Lomeland, F. and Brautaset, A. and Haugen, Å. (2014)), who matched centrifuge data to a seven parameter representation of water and oil relative permeabilities. His approximation is called the LET-type (Lomeland, Ebeltoft and Thomas) approximation and is the one used in this report. The approximation of Lomeland *et al.* has more parameters and thereby gives smoother relative permeability curves. The LET stands for the 3 parameters that are L , E and T . The LET parameters are obtained from special core analysis (SCAL) experiments. SCAL experiments are flow experiments done on core plugs taken from a petroleum reservoir in order to measure the relative permeability and the capillary pressure. The LET parameters dominate different parts of the relative permeability curves. The L parameter for example dominates the part with the low relative permeability (lower part) and the T parameter dominates the part with the high relative permeability of the relative permeability curve (upper part). The E parameter dominates the part in between the L and the T parameter. This is shown in figure 3.1.

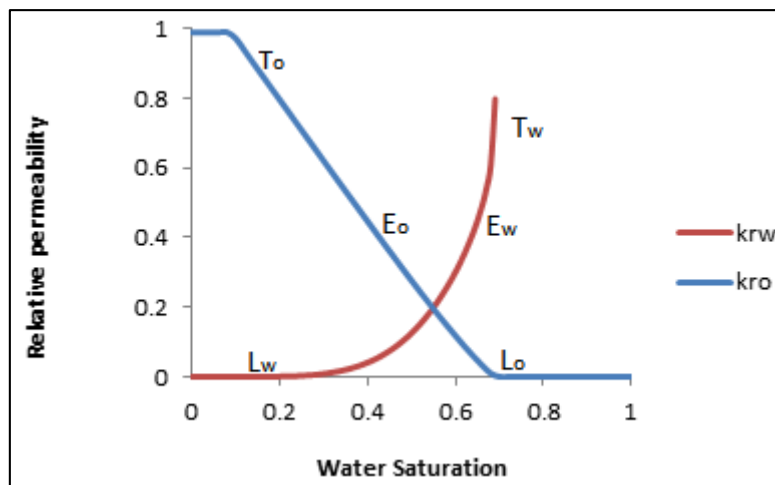


Figure 3.1: Dominating parts of the LET parameters. (Lomeland *et al.*)

From various SCAL experiments, trends were obtained for the different parameters as function of the irreducible water saturation (S_{wir}).

3.2. Determination of LET parameters

Lomeland *et al.* sketched the behavior of the LET parameters as a function of the irreducible water saturation. We used the WebPlotDigitizer 2.8 to obtain the LET parameters as function of the irreducible water saturation and subsequently used EUREQA® to obtain polynomial regression equations. The typical trend model for the six LET parameters (three for water and three for oil) is analyzed in order to obtain a function for the relative permeability which depends on the irreducible water saturation (S_{wir}). For each parameter we obtained the following function which can be used to find the L , E or T parameter for a given S_{wir} :

For oil:

$$\begin{aligned} L_o &= 1.2035x^2 - 1.8396x + 1.2895 \\ E_o &= -0.7465x^2 + 1.4229x + 0.9008 \\ T_o &= -1.3488x^2 + 2.07109x + 0.7428 \end{aligned}$$

For water:

$$L_w = 14.045x^4 - 34.681x^3 + 25.466x^2 - 2.3533x + 3.7625$$

$$E_w = 85.448x^6 - 282.96x^5 + 367.32x^4 - 237.66x^3 + 81.275x^2 - 14.92x + 3.121$$

$$T_w = -4.4018x^5 + 13.105x^4 - 14.901x^3 + 8.0546x^2 - 2.013x + 0.5821,$$

where for convenience of notation we use x to represent the irreducible water saturation.

The residual oil saturation (S_{orw}) is also a function of S_{wir} . A typical trend model for the residual oil saturation is obtained from earlier research by Lomeland *et al.* It can be seen in figure 3.2 that the S_{orw} increases with increasing S_{wir} until a certain maximum is reached after this S_{orw} decreases to zero.

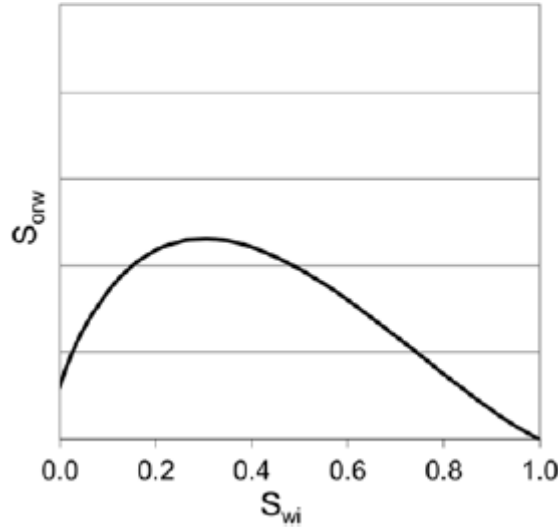


Figure 3.2: Typical trend model for the residual oil saturation versus irreducible water saturation (Lomeland *et al.*)

Analyzing with EUREQA this data gives us the following correlation between the S_{orw} and S_{wir} :

$$S_{orw} = 2.0698x^3 - 4.3857x^2 + 2.1741x + 0.1482$$

Lomeland *et al.* found a polynomial regression model for the relative end point permeability of water. The end point relative permeability also depends on S_{wir} . As can be observed in figure 3.3 an increased S_{wir} leads to low end point permeability. From this trend model they derived the following equation for the relative end point permeability (k_{rw}^0):

$$k_{rw}^0 = C_{wko} + \frac{(A_{wko} - C_{wko}) * (1 - S_{orw} - S_{wi})^{L_{wko}}}{(1 - S_{orw} - S_{wi})^{L_{wko}} + E_{wko} * S_{orw}^{T_{wko}}} \quad (3.6)$$

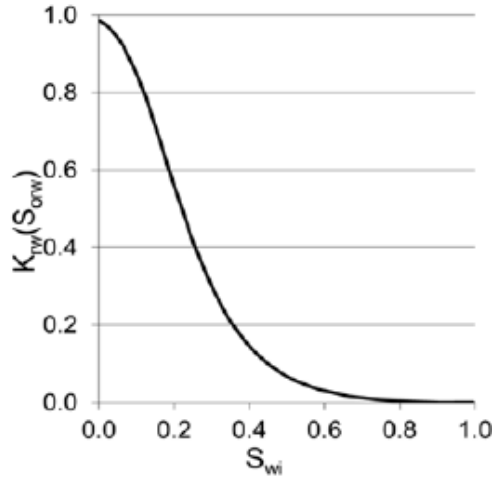


Figure 3.3: Typical trend model for end-point relative permeability to water as function of S_{wir} . (Lomeland et al.)

All this gives the following relations for the relative permeability for oil and water:

$$\text{Water:} \quad k_{rw} = k_{rw}^0 \frac{(S_w^*)^{L_w}}{(S_w^*)^{L_w} + E_w^*(1-S_w^*)^{T_w}} \quad (3.6)$$

$$\text{Oil:} \quad k_{ro} = k_{ro}^0 \frac{(1-S_w^*)^{L_o}}{(1-S_w^*)^{L_o} + E_o^*(S_w^*)^{T_o}} \quad , \quad (3.7)$$

$$\text{with} \quad S_w^* = \frac{S_w - S_{wir}}{1 - S_{orw} - S_{wir}} \quad (3.8)$$

Lomeland et al. (2012) implicitly assume that $k_{ro}^0 \approx 1$. Those formulas are used in order to obtain smooth relative permeability curves depending only on the irreducible water saturation.

Remark: A highly heterogeneous core, i.e. one for which λ is small, will be characterized by a capillary rise curve where the water saturation changes slowly from one at the water-oil contact point to somewhat lower values away from the oil-water contact point. Consequently water more or less evenly contacts the rock throughout the reservoir and consequently behaves more water wet over its entire height (Hirasaki, G.J. (1991)). When λ is large, the capillary rise curve is will be separated in a bottom domain where the water saturation is very high and a top domain where the water saturation is very low. Following Hirasaki it can be expected that the bottom part behaves more water-wet and the top part behaves more oil-wet. Of course this is a gross simplification, but can be used as a rationale, why we used the irreducible water saturation as a single parameter to represent both the heterogeneity and the wetting behavior.

3.3. Relative Permeability as Function of S_{wir}

Now that we have obtained the formulas for the relative permeabilities for oil and water we are able to see how they change with respect to the water saturation. Because we made the LET parameters and the end point permeabilities dependent on the irreducible water saturation (S_{wir}), and the relative permeabilities are a function of those parameters, S_{wir} will affect the relative permeability of water and oil. The relative permeability behavior is characteristic for wetting behavior. We distinguish two different wetting behaviors, viz. water-wet and oil-wet. Water displaces oil in

different ways for those two different wetting behaviors as can be seen in figure 3.4 (Raza et al. (1968)).

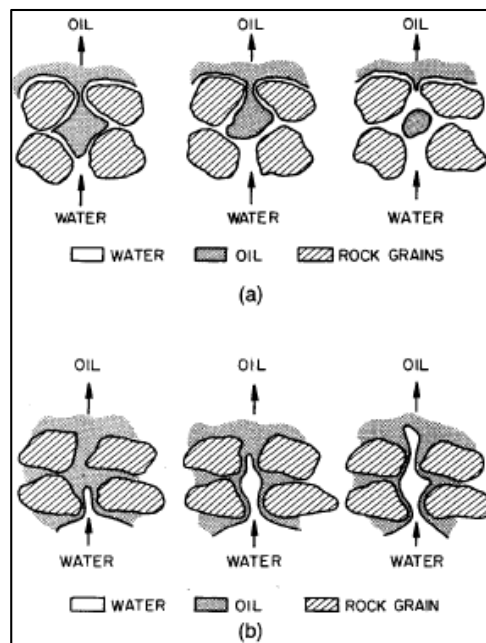


Figure 3.4: Water displacing oil from a pore during a waterflood: (a) strongly water-wet rock, (b) strongly oil-wet rock (Raza et al.(1968))

3.3.1. Water-wet

In figure 3.5 S_{wir} is set to be 0.1. Here we can observe that the cross-over point, i.e. where the water and oil relative permeability are equal, occurs at saturations larger than 0.5 meaning that this is an water-wet system (Ahmed, T. (2006)) . In this system the water will prefer occupying the small spaces causing the oil to occupy the large pores. For low water saturations, the relative permeability of water will be zero. Indeed, even if there will be connate water present, the low saturation will cause the relative water permeability to essentially be zero. When water flooding occurs the water saturation increases driving a flow of both the oil and the water. The relative water permeability increases as the water saturation increases. In water-wet media, water will first occupy more and more of the smaller pore spaces due to the wetting forces. After this, water will occupy the larger pores, leading to an increase of the water relative permeability. The oil relative permeability starts high at low water saturations and decreases as the water saturation increases. This happens because more and more oil filled pores will become cut off from the rest of the oil due to the increased presence of water. This oil is trapped and thus leads to a decrease in relative oil permeability. If the water saturation keeps increasing, oil will stop to flow and the relative oil permeability will become zero. This happens at the point where all the flow paths of oil are blocked by water. In figure 3.5, it can be seen that in water –wet media, the relative water permeability, in the presence of residual oil, at high water saturation is lower than the relative oil permeability at the connate water saturation. In other words, this difference is caused by the fact that oil is trapped in the larger pores. This oil is also called the residual oil saturation.

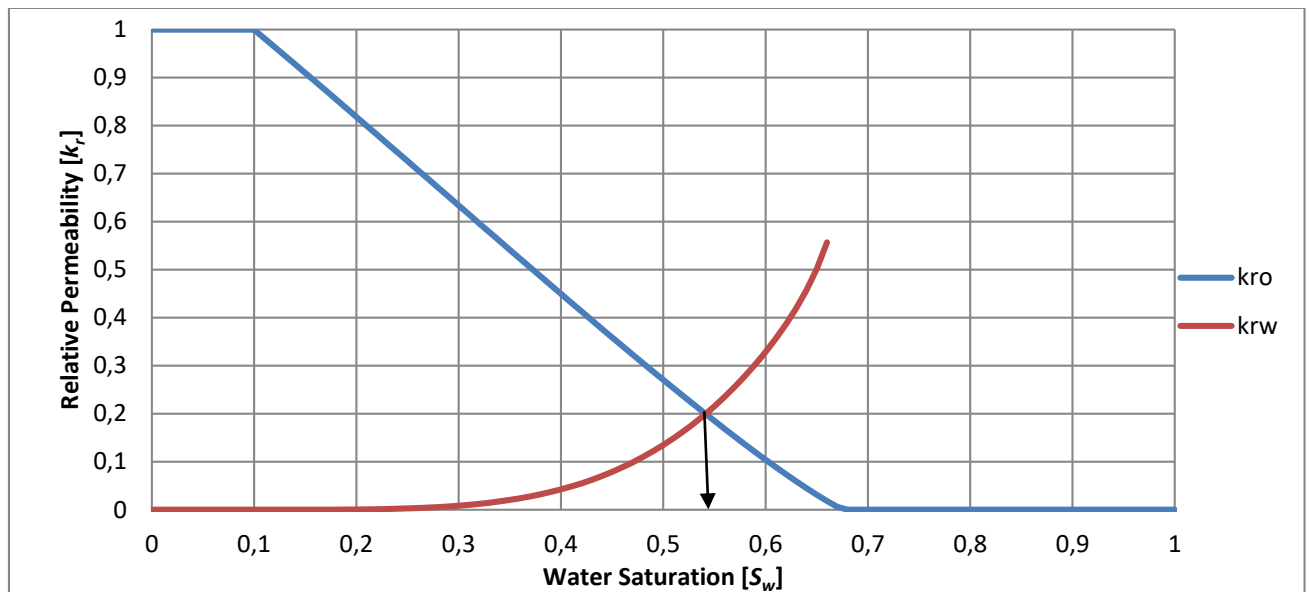


Figure 3.5: Oil (k_{ro})- and water (k_{rw})- relative permeability plotted against the water saturation for an irreducible water saturation of 0.1.

3.3.2. Oil-wet

In figure 3.6 S_{wir} is set to be 0.3. It can be seen that the saturation at which the relative oil permeability and the relative water permeability are equal (cross-over point) is less than 0.5. This tells us that this is an oil-wet system. When the water saturation in an oil-wet system is increased the water will occupy more of the large pores. The water will remain more in the center of those pores. So the pathways that have a high permeability will become more and more filled with water. This will cause a strong decline in the oil relative permeability and a strong increase in relative water permeability. This decline and increase will be more significant than in a water-wet system because in a water-wet system the small pores will first be water filled and in the oil-wet system the large pores will be water filled. In the oil-wet system oil will still have a path to flow due to the oil-wet surfaces. This leads to less oil trapped oil.

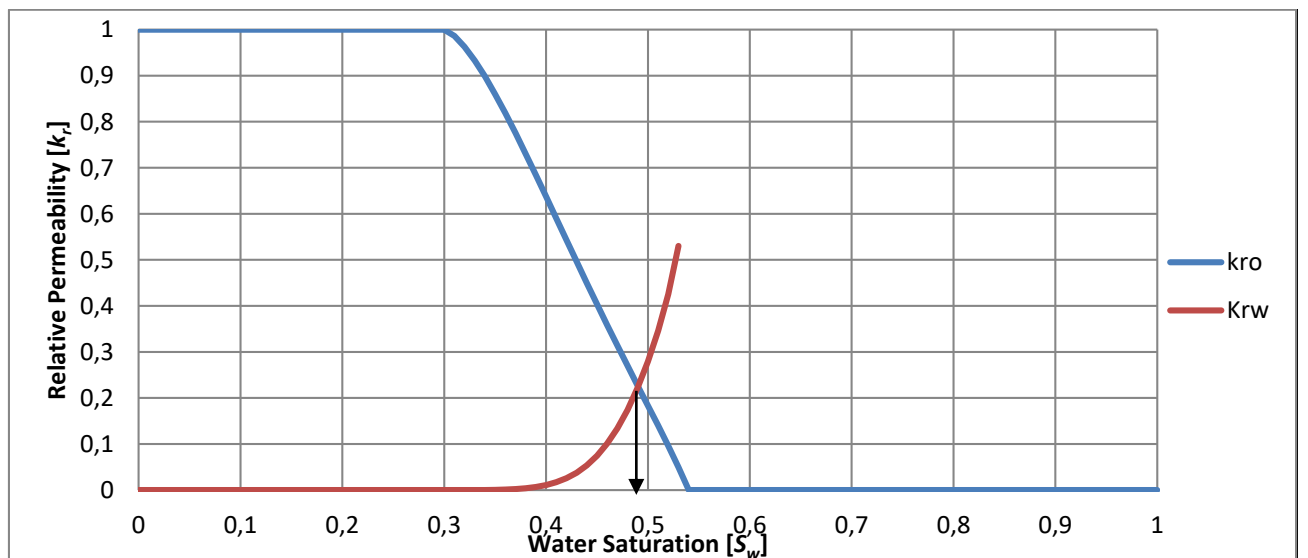


Figure 3.6: Oil (k_{ro})- and water (k_{rw})- relative permeability plotted against the water saturation for an irreducible water saturation of 0.3.

Tests that are done on cores that are oil-wet and water-wet, show that a higher oil recovery is achieved in water-wet cores (Jadhunandan & Morrow, 1995). Indeed, the residual oil in completely oil-wet cores is high, albeit lower than in completely water-wet cores. However, the end point permeabilities in water-wet, i.e. at high irreducible water saturation, cores are lower (as illustrated in figure 3.3) improving the mobility ratio (making it lower), which is conducive to more efficient oil recovery.

4. Model

In order to model this problem where water displaces oil, we used the Buckley-Leverett theory. The Buckley-Leverett equation is expressed as (Buckley, S.E. and Leverett, M.C. (1942))

$$-\frac{\partial f_w}{\partial S_w} \frac{\partial S_w}{\partial x} = \frac{A\phi}{q} \frac{\partial S_w}{\partial t} \quad , \quad (4.1)$$

where f_w = fractional flow rate
 S_w = water saturation
 A = cross section of sample
 ϕ = porosity
 x = position
 t = time

As we are dealing with incompressible fluids we can say that the total production rate equals the injection rate. This allows us to give an estimation of the fraction of water and oil in the produced fluids. In order use the Buckley-Leverett equation we assumed furthermore that the flow is linear and the gravity and pressure effects are negligible.

4.1. Fractional Flow Rate

For determining the fractional flow rate (f_w) we use the Darcy equations. We hypothesize flow through a small volume element with length dx and area A . The total flow rate can be expressed as

$$q_t = q_o + q_w \quad (4.2)$$

$$q_w = q_t f_w \quad (4.3)$$

$$q_o = q_t f_o = q_t (1 - f_w), \quad (4.4)$$

where q_t = total flow rate
 q_o, q_w = flow rate of oil and water respectively
 f_o, f_w = fractional flow to oil and water respectively

From Darcy's Law we get that

$$q_w = \frac{k_{rw} k A}{\mu_w} \frac{dp}{dx} \quad (4.5)$$

$$q_o = \frac{k_{ro} k A}{\mu_o} \frac{dp}{dx} \quad , \quad (4.6)$$

where k = permeability
 k_{rw}, k_{ro} = the water- and oil- relative permeability respectively
 μ_w, μ_o = viscosity of water and oil respectively
 p = pressure

This results in the following equation for the horizontal fractional flow with negligible capillary pressure

$$f_w = \frac{q_w}{q_o + q_w} \quad (4.7)$$

$$= \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w}}$$

This can be written as

$$f_w = \frac{1}{1 + \frac{k_{ro}}{k_{rw}} \frac{\mu_w}{\mu_o}} \quad (4.8)$$

This can also be written in terms of the Mobility ratio (M) as

$$f_w = \frac{1}{1 + \frac{1}{M(S_w)}} \quad , \quad (4.9)$$

with

$$M = \frac{k_{rw}}{k_{ro}} \frac{\mu_o}{\mu_w} \quad (4.10)$$

For the relative permeability of water and oil we used equations 3.6 and 3.7 that we derived in chapter 3.1 from the LET parameters. The relative permeabilities (k_{ro} and k_{rw}) are functions of the irreducible water saturation. For constant viscosity the fractional flow of water will be only dependent on the irreducible water saturation. A typical plot of the fractional flow of water against water saturation can be seen in figure 4.1.

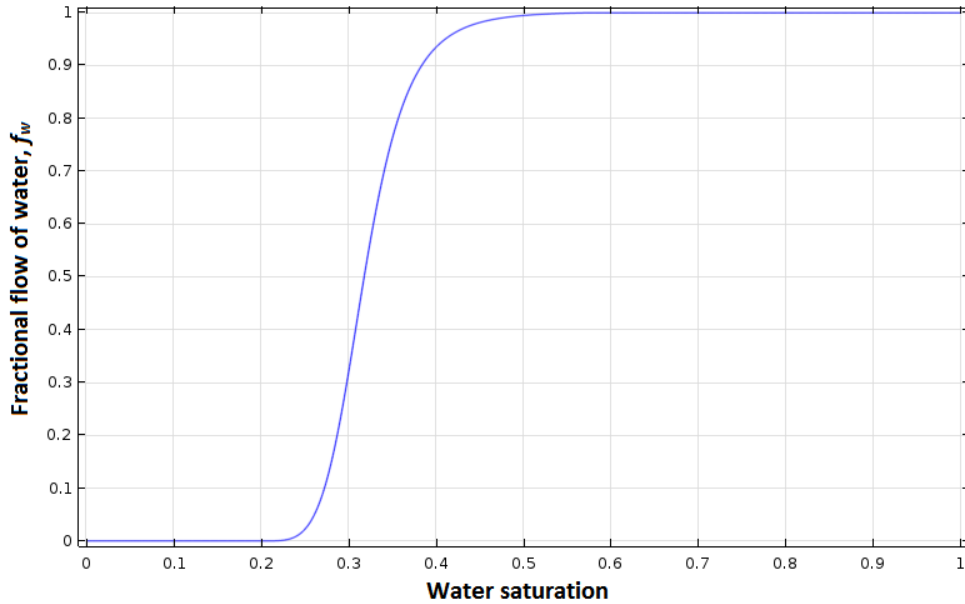


Figure 4.1: Fractional flow of water curve against water saturation.

4.2. Recovery

If we assume a grid where water is entering from the left side and leaving from the right side we can come up with the following equations describing the water flow rate that enters and leaves the grid.

$$\begin{aligned} \text{entering} &= q_t f_w \\ \text{leaving} &= q_t (f_w + \Delta f_w) \end{aligned} \quad (4.11)$$

As we are dealing with incompressible and immiscible fluids performing a mass balance gives the change in flow rate.

$$\begin{aligned} \text{change in flow rate} &= \text{entering} - \text{leaving} \\ &= -q_t \Delta f_w \end{aligned} \quad (4.12)$$

In this grid the oil is displaced by the water entering. The water accumulation in this grid can be expressed as

$$\frac{\Delta S_w A \phi \Delta x}{\Delta t} \quad (4.13)$$

The change in flow rate per unit of time and the accumulation of water per unit of time must be equal to each other giving

$$\frac{\Delta S_w A \phi \Delta x}{\Delta t} = -q_t \Delta f_w \quad (4.14)$$

$$\frac{\Delta S_w}{\Delta t} = -\frac{q_t \Delta f_w}{A \phi \Delta x} \quad (4.15)$$

Setting $\Delta t \rightarrow 0$ and $\Delta x \rightarrow 0$

$$\left(\frac{dS_w}{dt} \right)_x = -\frac{q_t}{A \phi} \left(\frac{df_w}{dx} \right)_t \quad (4.16)$$

We then multiply this equation by the quadratic Lagrange using COMSOL 5.2©.

$$\frac{x-x_1}{x_0-x_1} f(x_0) + \frac{x-x_0}{x_1-x_0} f(x_1) \quad (4.16b)$$

Further derivation using the method of Welge (Welge, H.J. (1952)) and implementing this all in COMSOL 5.2© resulted in recovery plots, which can be found in section 5.

4.3. Mobility ratio

As can be seen in equation 4.8, the fractional flow depends only on the relative permeabilities at constant viscosities. There are multiple types of oil, varying from light oil to tar(bitumen). These types of oil have different viscosities as can be observed in figure 4.2. In order to analyze the effect of more viscous oil on the fractional flow curve, different mobility ratios will be used. The mobility ratio will affect the fractional flow curve (as shown in figure 4.3) and thereby the recovery. The mobility ratio will be changed by increasing the viscosity ratio logarithmically ($\frac{\mu_o}{\mu_w} \approx 2, 20, 200$). We increase

the viscosity ratio by increasing the oil viscosity. We use three different oil viscosities resembling light oil, light viscous oil and viscous oil.

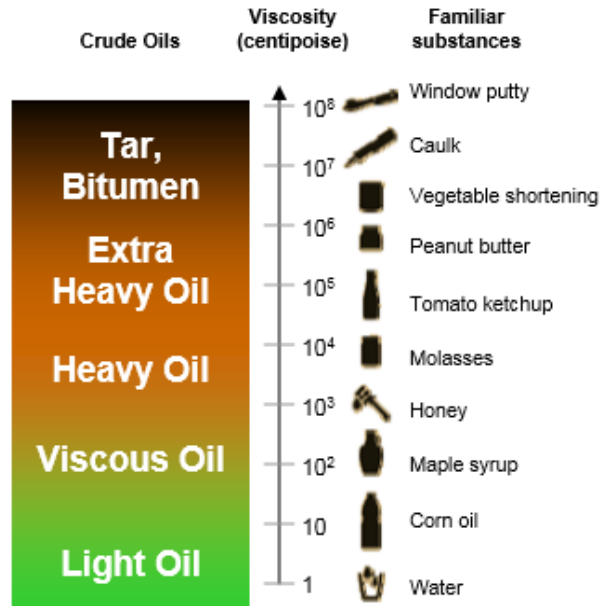


Figure 4.2: Different types of crude oils with their viscosity [cp] and familiar substances. (West, E. (2011))

4.4. Parameters

The parameters used for the COMSOL 5.2© simulations are tabulated in table 4.1. A COMSOL© report can be found in the Appendix.

Variable	Value	[Dimension]
φ	0.37	[-]
μ_w	0.00097	[Pa*s]
μ_o	0.00174; 0.0174; 0.174	[Pa*s]
σ_{ow}	0.03	[N/m]
k	$1.18e-12$	[m ²]
S_{co}	$S_{wir}+0.01$	[-]
S_{bound}	$1-S_{orw}$	[-]
S_{wir}	0.01; 0.1; 0.2; 0.3; 0.4; 0.5; 0.6; 0.7; 0.8	[-]
Pe	100	[-]
S_{init}	S_{wir}	[-]
k_{ro}^0	1	[-]

Table 4.1: Parameters used in the COMSOL© script.

5. Results and Discussion

In order to compare the different recoveries at different irreducible water saturations, we run multiple simulations. In each simulation another value has been taken for S_{wir} . As stated before, all the relative permeabilities and thereby the fractional flow curves (at constant viscosity) are dependent on this S_{wir} , where an increasing S_{wir} characterizes more water-wet behavior. In order to analyze the effect that wetting has on more heavy oils we also use different viscosity ratios. The results will be shown and discussed in this chapter.

5.1. Effect of Mobility Ratio on f_w

In figure 5.1 the fractional flow curve of three different viscosity ratios is given at an irreducible water saturation of 0.2. It can be seen that the S shape of the curve gets less visible at a decreasing viscosity ratio, leading to more favorable recovery.

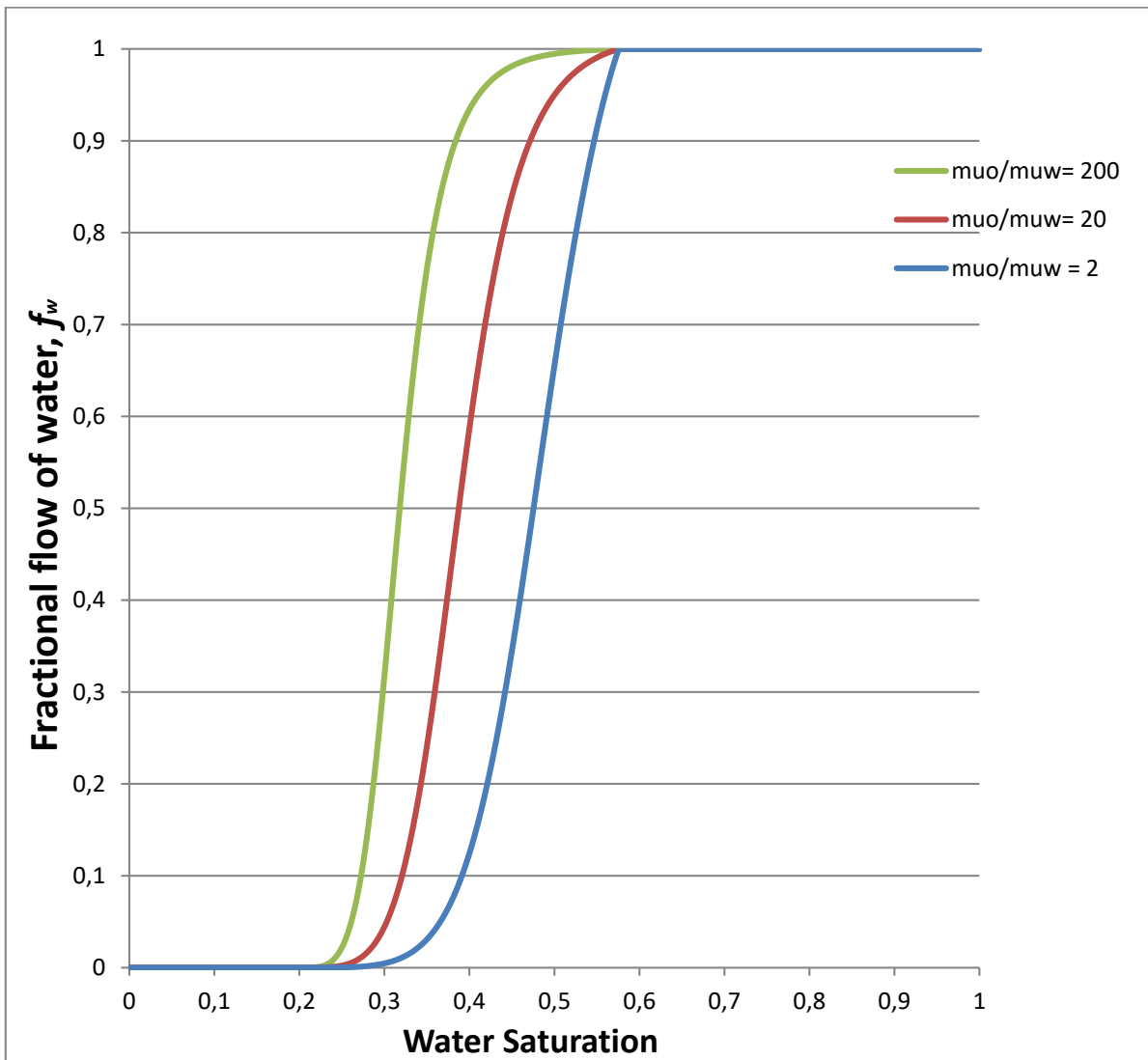


Figure 5.1: Fractional flow of water plotted against the water saturation for different viscosity ratios.

5.2. Recovery Against Pore Volume Injected

The recovery against pore volume injected are done for various viscosity ratio's. The viscosity ratio's used increase logarithmic and are almost equal to 2, 20 and 200.

5.2.1. Viscosity ratio $\left(\frac{\mu_o}{\mu_w}\right) \approx 2$

After running simulations for a range of S_{wir} values we obtained a recovery plot for each S_{wir} . Transferring this data to Excel and combining the plots of different S_{wir} gives us the recovery against the pore volume injected plot seen in figure 5.2. This plot clearly shows that higher S_{wir} i.e. more water-wet behavior, leads to earlier breakthrough at less injected pore volumes and less to no more oil recovery after breakthrough.

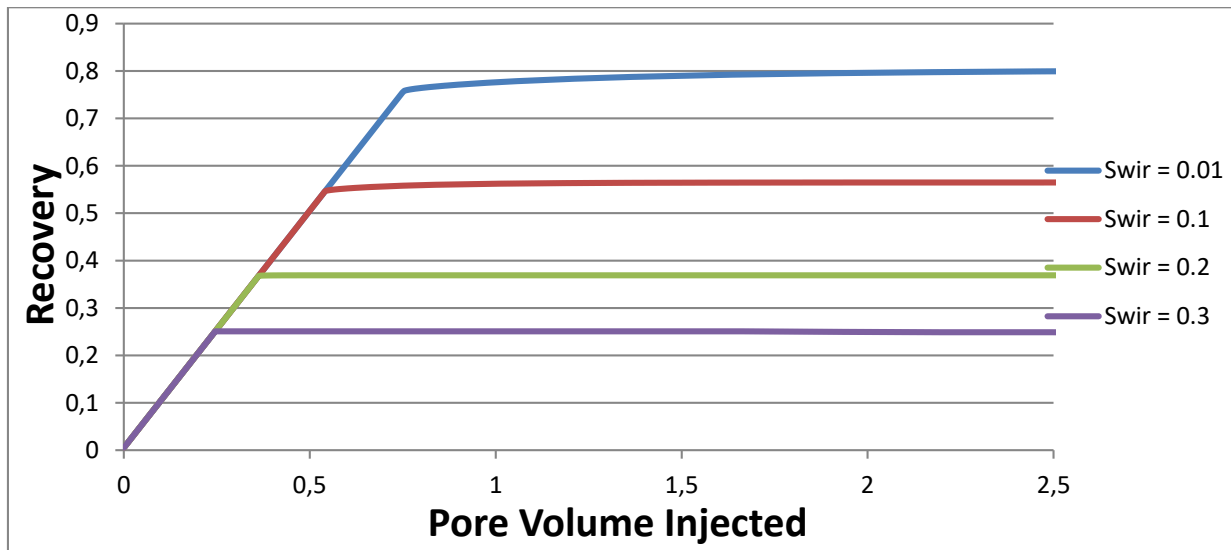


Figure 5.2: Recovery against pore volume injected with a viscosity ratio of $\left(\frac{\mu_o}{\mu_w}\right) \approx 2$

5.2.2. Viscosity ratio $\left(\frac{\mu_o}{\mu_w}\right) \approx 20$

In figure 5.3 we set the viscosity ratio ≈ 20 , resembling light viscous oil. The plot shows that the ultimate recovery of all the different irreducible water saturations is less than in figure 5.2, where we used a lower viscosity ratio. Furthermore at “clean” breakthrough i.e. breakthrough, at which no oil is recovered after, occurs at an irreducible water saturation of 0.4 in comparison to figure 5.2 at which this occurs at an irreducible water saturation of 0.2. As can be observed, also in figure 5.2 more water-wet behavior leads to a “cleaner = no mixed water-oil recovery” and earlier breakthrough.

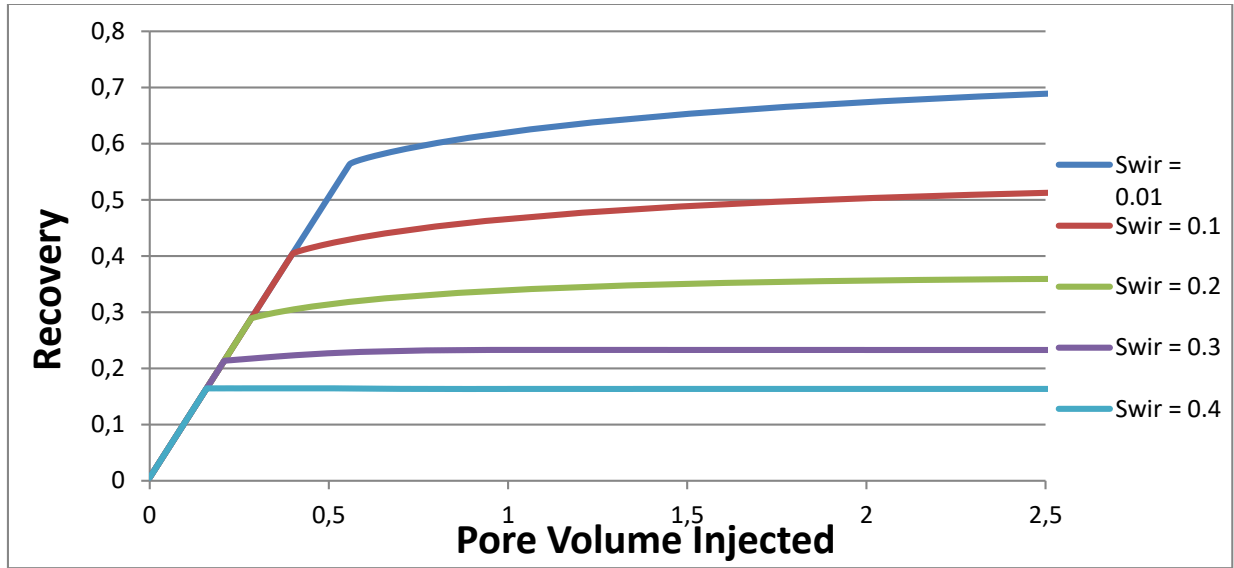


Figure 5.3: Recovery against pore volume injected with a viscosity ratio of $\left(\frac{\mu_o}{\mu_w}\right) \approx 20$

5.2.3. Viscosity ratio $\left(\frac{\mu_o}{\mu_w}\right) \approx 200$

In figure 5.4 the viscosity ratio is set to ≈ 200 , resembling viscous oil. The maximal recoveries are further decreased in comparison to lower viscosity ratios. Also after water breakthrough, water and oil is produced at more irreducible water saturation in comparison to figures 5.2 and 5.3. At an irreducible water saturation of 0.5 no oil after breakthrough is produced. It can be observed that the higher the viscosity ratio the more unfavorable this is for the oil recovery.

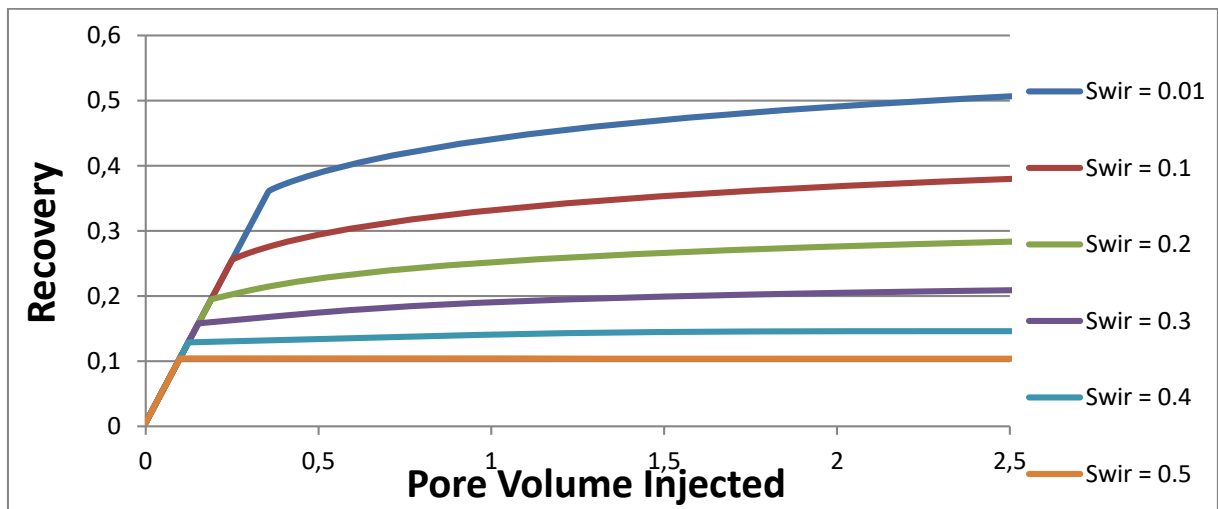


Figure 5.4: Recovery against pore volume injected with a viscosity ratio of $\left(\frac{\mu_o}{\mu_w}\right) \approx 200$

5.3. Recovery Dependence on S_{wir} per Pore Volume Injected

We also made plots which show the recovery dependence on S_{wir} per pore volume injected. This is also done for logarithmically increasing viscosity ratio's ($\frac{\mu_o}{\mu_w} \approx 2, 20, 200$), resembling light oil, light viscous oil and viscous oil.

5.3.1. Viscosity ratio $\left(\frac{\mu_o}{\mu_w}\right) \approx 2$

In figure 5.5 the recovery is plotted against the irreducible water saturation per pore volume injected for a viscosity ratio ≈ 2 . It can be observed that the data points for the different pore volumes injected and thereby the trend lines are really close to each other. This happens because this viscosity ratio causes early breakthrough, i.e. at low pore volume injected, resulting in no more oil recovery after breakthrough. In other words injecting more pore volumes does not result in more oil recovery.

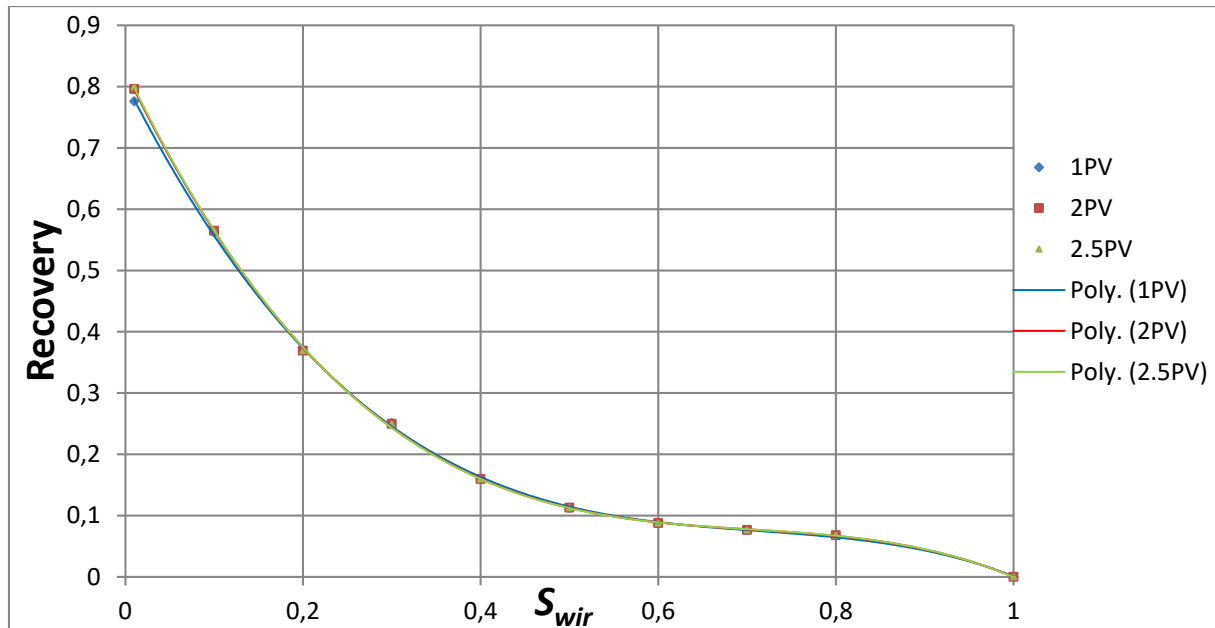


Figure 5.5: Recovery dependence on S_{wir} for different values of pore volume injected and a viscosity ratio of $\left(\frac{\mu_o}{\mu_w}\right) \approx 2$

5.3.2. Viscosity ratio $\left(\frac{\mu_o}{\mu_w}\right) \approx 20$

In figure 5.6 it can be observed that the recovery per pore volume injected differs at $S_{wir} < 0.3$. From figure 5.3 it can be seen that at a $S_{wir} > 0.3$ there is no oil recovery after breakthrough. This causes the trend lines of the pore volumes injected to coincide at $S_{wir} > 0.3$.

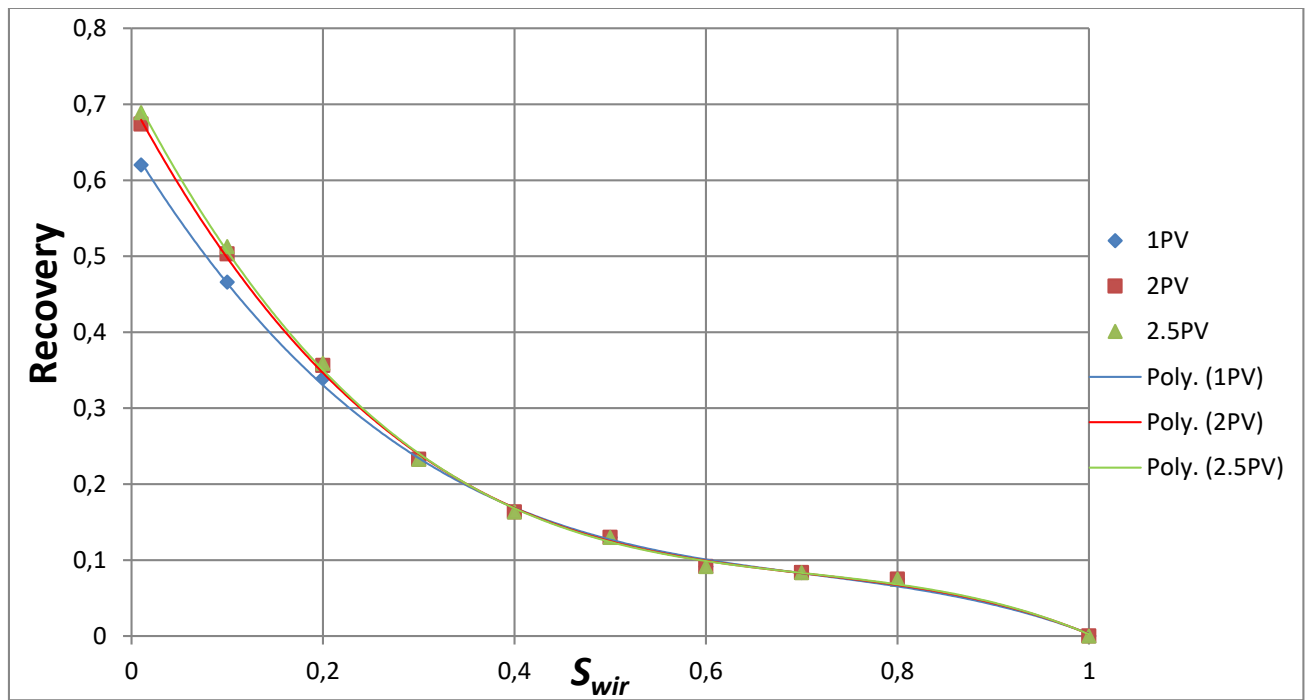


Figure 5.6: Recovery dependence on S_{wir} for different values of pore volume injected and a viscosity ratio of $\left(\frac{\mu_o}{\mu_w}\right) \approx 20$

5.3.3. Viscosity ratio $\left(\frac{\mu_o}{\mu_w}\right) \approx 200$

As can be observed in figures 5.5, 5.6 and 5.7, the higher the viscosity ratio the more difference between the pore volumes injected at low S_{wir} . At a viscosity ratio ≈ 200 the trend lines for the different pore volumes injected coincide at $S_{wir} > 0.5$. Also it can be seen that a higher viscosity leads to a lower overall recovery.

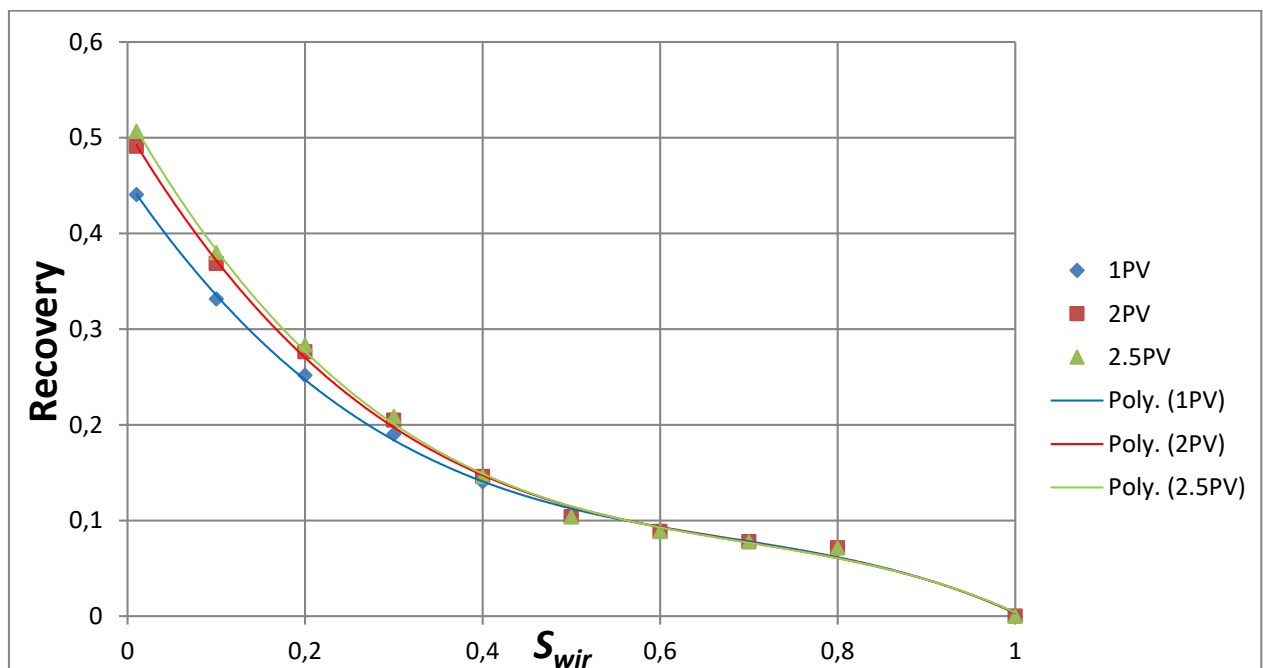


Figure 5.7: Recovery dependence on S_{wir} for different values of pore volume injected and a viscosity ratio of $\left(\frac{\mu_o}{\mu_w}\right) \approx 200$

5.4. Analytical expressions for the recovery

The theory for obtaining analytical expressions for the recovery curves have been developed and are shown in (Dake, L.P. (1978)), where the pore volume production of oil is

$$N_{pd} = (1 - f_w)W_{id} + S_{we} - S_{wc} \quad , \quad (5.1)$$

where S_{we} is the effective saturation $\frac{S_w - S_{wc}}{1 - S_{wc}}$. The pore volume production of water is given by

$$W_{id} = \frac{1}{\frac{df_w}{dS_w}} \quad (5.2)$$

In order to calculate N_{pd} we firstly draw the fractional flow curve (blue line in figure 5.8). After this we draw a straight line from $(S_w = S_{wc}, f_w = 0)$ tangent to the fractional flow curve. From the equation 5.3 and S_w at breakthrough we can calculate the pore volume production of oil at breakthrough.

$$N_{pd_{bt}} = \frac{1}{\left(\frac{df_w}{dS_w}\right)_{S_{w_{bt}}}} \quad (5.3)$$

After breakthrough N_{pd} is calculated by taking any $S_w > S_{w_{bt}}$ and draw a line tangent to that point on the fractional flow curve, as seen in figure 5.8 (green line). Using equations 5.2 and 5.1 we can calculate the pore volume production of oil after breakthrough.

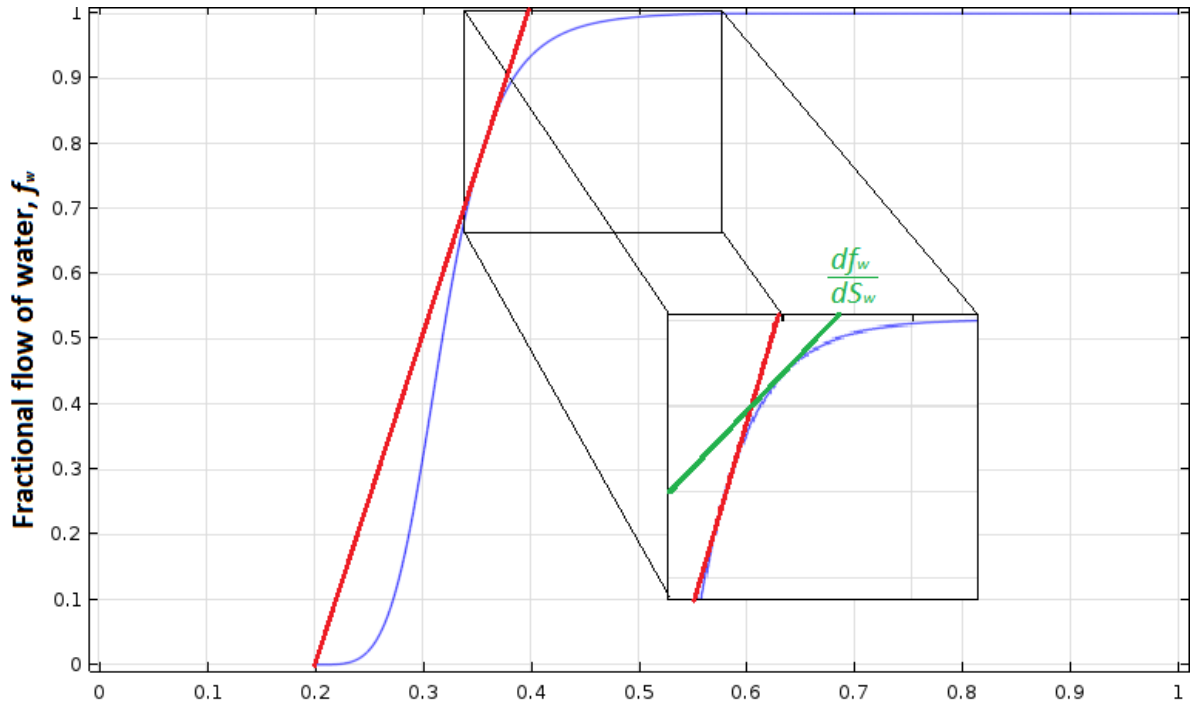


Figure 5.8: Application of the analytical technique using Welges approach. The red line gives the front saturation and the green line the oil saturation after breakthrough.

5.5. 2D Saturation Profiles

In order to gain more understanding of the saturation distribution in a field, we also simulated saturation profiles. The first simulation disregards gravity and capillary forces and gives an aerial view

of a field. The second simulation includes gravity and capillary forces and gives a cross sectional view of a reservoir.

5.5.1. Aerial View Disregarding Gravity and Capillary Forces

We show areal saturation profiles in 2-D. In the absence of gravity and capillary forces we obtain a simulation which illustrates the saturation profile at various time steps (figure 5.9). The progress starts at the injecting well in the lower left corner. In the upper right corner we have an oil producing well.

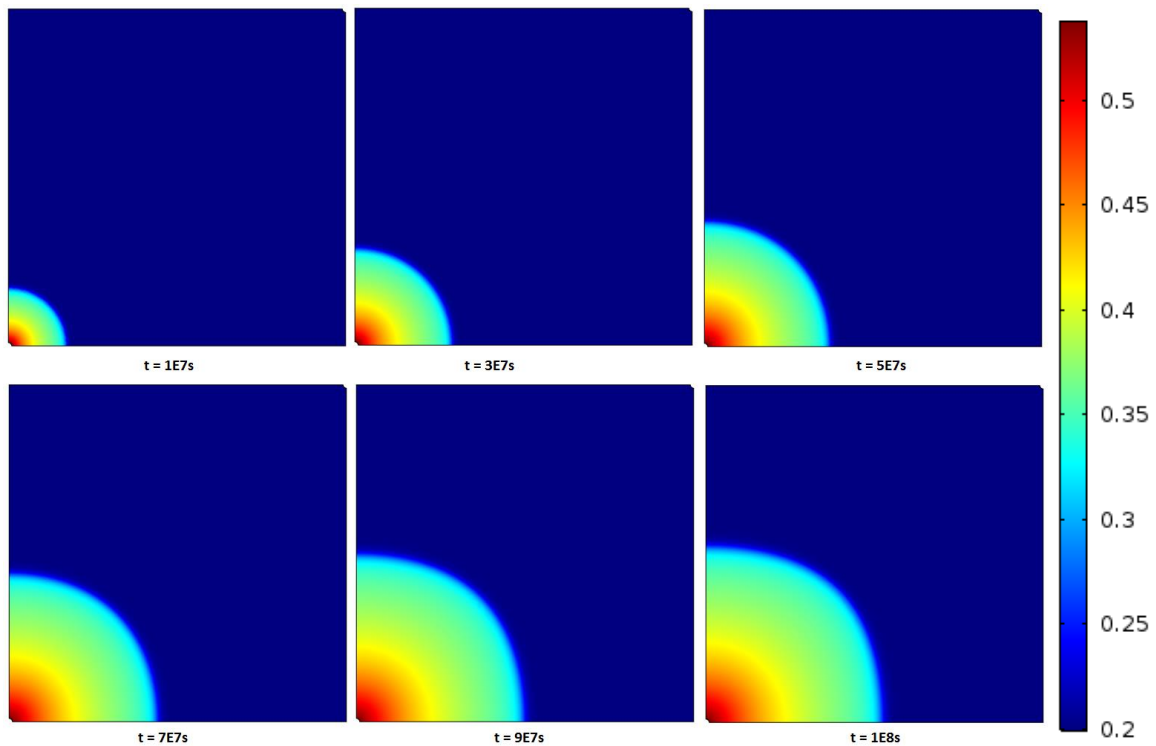


Figure 5.9: 2D aerial view of the saturation profile in a field at various time steps in seconds disregarding gravity and capillary forces, and a injecting well in the bottom left corner and a producing well in the top right corner using COMSOL 5.2©.

5.5.2. Cross Sectional View Including Gravity and Capillary Forces.

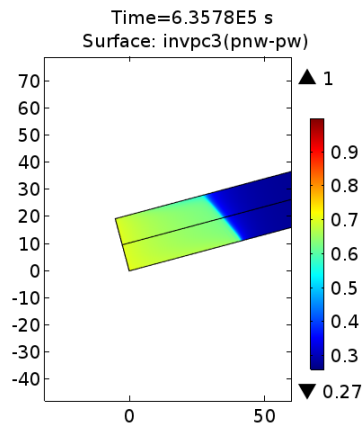


Figure 5.10: 2D simulation including capillary forces and gravity forces using COMSOL 5.2©. Injection occurs through the plane at the left. At the right plane we use zero capillary pressure. The upper and lower planes are no flow boundaries. We transform the equation $\phi \partial_t S_w + \text{div } u_w = \text{div } D \text{grad } P_c - \gamma P_c (50 P_{cb} - P_c) \text{grad } P_c / \text{sqrt}((\partial_x P_c)^2 + (\partial_y P_c)^2)$. The first term on the right stabilizes the profile in the flow direction and the second term avoids the formation of fingers. The height is 20m and the length is 60 m and the angle is 15° . $D=10^{-10}$ and $\gamma=-10^{-15}$. The global mobility ratio is $M=2.15$ and the Gravity number is $G=1.47632$. We need to choose the shock mobility ratio, which is close to 1.3 and the slope of the interface when predicted with the interface model would be $dy/dx = (M-1-G)/G$. However, no unambiguous match can be obtained. This needs further validation.

6. Conclusion

- Wettability has a significant effect on the recovery efficiency.
- Based on the papers by Lomeland, Ebeltoft and Thomas it was possible to derive the so-called LET relative permeability curves that only depend on the irreducible water saturation. Admittedly this is a gross simplification, but allows us to study wetting effects on the relative permeability behavior in terms of one parameter (irreducible water saturation) as opposed to eight.
- High irreducible water saturation is both indicative of pore size heterogeneity and water-wet behavior. We use the theory of Buckley-Leverett to construct recovery curves for 1D and 2D displacement and various mobility ($M = \text{displacing fluid mobility} / \text{displaced fluid mobility}$) ratios.
- At high mobility ratios the displacement efficiency, i.e. the recovery at breakthrough is less. However, a low end point permeability, which occurs for strong water-wet behavior leads to a lower mobility ratio and hence to more stable behavior.
- It is possible to solve the 1-D equations both analytically (using fractional flow theory) and numerically.
- For the numerical simulations in 1D and 2D we can use COMSOL 5.2©.
- The simulations show indeed, that water-wet behavior is conducive to stable displacement and high recovery at breakthrough, whereas intermediate-wet behavior is conducive to high ultimate recoveries.

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Image on the front page: <http://rhamnolipid.com/applications/>

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