The Influence of Wettability on Relative Permeability and Oil Recovery Scheme

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Abstract
The world's energy demands are met by crude oil, improving oil recovery is recognized as the major target and challenge at the different stages of an oil field development. After conventional primary and secondary production techniques have been employed, huge amount of crude oil is left underground. This point out the need to study and implement new and innovative methods to recover the remaining oil and in turn requires an in-depth study of reservoir characteristics such as properties of the crude oil, brine, the mineralogy of the rock surface and their effects on the interactions that take place between crude oil, brine and the rock surface. In this study, wettability was considered in order to understand these interactions. An analytical model was proposed to account for the influence of wettability on oil recovery and relative permeability. Results were represented graphically at different contact angle which represented the reservoir wettability. Water-wet conditions gave highest oil recovery and relative permeability to oil.

Keywords: *Wettability, Relative permeability, Oil recovery, and Contact angle*

1. Introduction

The world's energy demands are met by crude oil, improving oil recovery is recognized as the major target and challenge at the different stages of an oil field development. The U.S Department of Energy estimates that nearly 377 Billion barrels of discovered oil are left behind after conventional primary and secondary production techniques have been employed (USDOE).These huge amounts of oil left are deemed "unrecoverable" by present technologies. This point out the need to study and implement new and innovative methods to recover the remaining oil and in turn requires an in-depth study of reservoir characteristics such as properties of the crude oil, brine, the mineralogy of the rock surface and their effects on the interactions that take place between crude oil, brine and the rock surface. EOR is the alternative for revitalizing mature reservoirs. The target oil for EOR operations is the residual oil left behind after primary and secondary production modes. EOR is defined as the recovery of additional oil from the reservoir by using sophisticated techniques that alter the original properties of the oil (SLB glossary). Oil production from a reservoir can be classified into primary, secondary and tertiary recovery modes.

Primary recovery constitutes oil produced by inherent natural mechanisms present in the reservoir. Natural oil recovery mechanisms include solution gas, water influx and gas cap or gravity drainage (Muskat, 1949). Secondary recovery refers to techniques such as water injection and gas cap injection. The main purpose of this type of recovery is reservoir pressure maintenance and to displace hydrocarbons towards the wellbore. Tertiary recovery techniques on the other hand refer to any production technique applied after secondary recovery processes. These include chemical flooding, miscible processes, thermal processes and microbial recovery process. Enhanced oil recovery processes provide supplementary mechanism to depleting natural mechanism of the reservoir such as pressure maintenance, oil mobility control and wettability alteration.

In order to study and understand these interactions, the parameter that has been considered for this present study is wettability. Water and oil (or gas) in reservoirs coexist in an immiscible state (i.e., the water phase does not mix miscibly with the hydrocarbon phase). There is a natural and strong interfacial tension between the two fluids that keeps them separate, regardless of how small the individual droplets may be. In all reservoirs, connate water is immiscible with the oil or gas, but chemicals can be injected into the reservoir to reduce interfacial tension and make the water phase miscible with the oil. There are advantages in doing this, and it is a form of enhanced oil recovery. The oil and gas phases in reservoirs also generally behave immiscibly. On all interfaces between solids and fluids and between immiscible fluids, there is a surface free energy resulting from natural electrical forces. The forces cause molecules of the same substance to attract one another through cohesion, and molecules of unlike substances to attract one another through adhesion. Interfacial tension results from these molecular forces causing the surface of a liquid to form the smallest possible area and act like a membrane in tension.

Wettability can be defined as the ability of a fluid phase to preferentially wet a solid surface in the presence of a second immiscible phase. In the reservoir context, it refers to the state of the rock and fluid system; i.e., whether the reservoir is water or oil wet. Three possible states of wettability in oil reservoirs exist as shown in Figure 1.0. The arrows represent the tangent to the angle between the water droplet and the rock surface. The water droplet is surrounded by the oil phase.

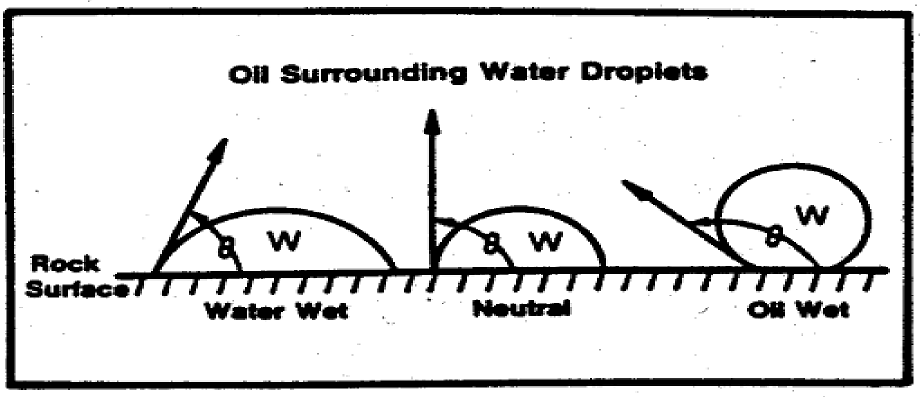

Figure 1.0: Three possible states of wettability in oil reservoirs.

Other lesser known types of wettability are neutral or intermediate wettability, fractional wettability, and mixed wettability.
Wettability is affected by various factors such as aging time between the fluids and the rock surface, surface heterogeneity, roughness and mineralogy of the rock surfaces and also on the composition of the brines and crude oils. The wetting nature of a particular fluid on the rock surface in preference to the other is measured in terms of contact angle. Contact angle is the

angle between a tangent drawn on the drop's surface at the resting or contact point and a tangent to the supporting surface. Surface and capillary forces account for most of the oil being left behind in the reservoirs after secondary production. Capillary forces are generally quantified by the capillary number, N_c, which is the ratio of viscous to capillary forces and is given by

$$N_c = \frac{v\mu}{\sigma cos\theta} \quad (1.1)$$

Where v is the velocity, μ is the viscosity, σ is the interfacial tension and θ is the contact angle.

The greater the capillary number, the lower the residual oil saturation and hence greater the recoveries. All the recovery of residual oil is thus linked to capillary number, which in turn depends on viscosity of the fluid, interfacial tension between the fluids, and the contact angle. So far, in the development of Enhanced Oil Recovery (EOR) processes, our attention has been to reduce the oil-water interfacial tension to a minimum so that capillary number would increase thereby yielding higher oil recovery. Neglecting contact angle, by assuming it to be zero, has been an erroneous assumption made in the past. As can be noticed from Equation 1.1, we can increase the capillary number to infinity without even altering the interfacial tension term just by increasing the contact angle to 90^o ($Cos\theta=0$ when $\theta=90^o$). A contact angle of 90^o means the system is intermediate-wet.

Oil recovery in reservoirs is greatly affected by fluid-fluid and fluid-rock interactions. These interactions control rock wettability, capillary pressure and relative permeabilities. Wettability is a significant issue in multiphase flow problems ranging from oil migration from source rocks to enhanced oil recovery processes (Buckley *et al.,* 1997). It has been generally observed in the past that relative permeability to the oil is higher in water-wet rocks. However, the ultimate oil recovery is higher in mixed-wet rocks. This lower residual oil saturation has been attributed to the presence of thin wetting films of oil on the surfaces of the rock grains (Anderson, W. G., 1985; Salathiel R. A., 1973) that allows the oil to drain over a long period of time. The ultimate oil recovery at the end of a waterflood has been shown to either increase or decrease with increasing oil-wetness (Marrow, N. R., 1990). The importance of wettability in determining oil recovery and relative permeability curves is well established in (Anderson, W.G., 1985).

Permeability is the ability of the porous media to transmit fluids. Effective permeability is the permeability of a given phase when more than one phase is present and the ratio of the effective permeability for a particular fluid to a reference or base permeability of the rock is known as relative permeability. The relative permeability to oil, K_{ro}, is defined as

$$K_{ro} = \frac{K_{eo}}{k} = \frac{effective\ oil\ permeability}{base\ permeability} \quad (1.2)$$

Similarly we can define:

$$K_{rw} = \frac{K_{ew}}{k} = \frac{effective\ water\ permeability}{base\ permeability} \quad (1.3)$$

$$K_{rg} = \frac{K_{eg}}{k} = \frac{effective\ gas\ permeability}{base\ permeability} \quad (1.4)$$

According to conventional wisdom, oil wet rocks exhibit higher values of relative permeability to water, and water wet rocks exhibit higher oil relative permeability. This is because the non-wetting phase tends to occupy larger pores, so that at the same water saturation relative permeability to water is larger when it is the non-wetting phase.
The recovery of oil from petroleum reservoirs is affected by several factors and wettability is

one of such factors. The reservoir rock wettability affects primary and secondary recovery and it is a vital factor to consider during EOR method selection as most of the processes depend on altering wettability to produce more volume of oil from the reservoir. Till date, a direct relationship between relative permeability, oil recovery and wettability has not been clearly presented which drives the purpose for this research

This research aims at developing an analytical model for petroleum engineering to show how reservoir wettability influences relative permeability and oil recovery, therefore aiding to suggest the best wettability values and to what extent wettability can be altered to get and optimum recovery from the reservoir.

2. Mathematical Formulation

In an attempt to understand the influence of wettability on relative permeability and oil recovered from a reservoir, the following will be considered;

a. Conservation of mass equation using; a water flood process
b. The fractional flow equation
c. Darcy flow equation
d. Corey's permeability correlation

The model uses a combination of the fractional flow equation and the Darcy flow equation to develop a relationship between the fractional flow of water injected and wettability. It assumes the pressure in the Darcy equation to be a function of the capillary force of migration as water displaces oil in the reservoir. When this occurs, it implies that pressure is equal to the capillary pressure. Oil recovery factor can then be calculated as the ratio of the volume of oil initially or originally in the reservoir to the volume of oil displaced by the fractional flow of water.

The relationship between relative permeability is also established by combining the Corey's correlation for unconsolidated well sorted grains and the Amott index by assuming a piston like displacement process with zero residual oil saturation.

The development of the fractional flow equation is attributed to Leverett (1941). The fractional flow equation is given as;

$$q_t = q_o + q_w \tag{2.1}$$

$$f_o = \frac{q_o}{q_t} = \frac{q_o}{q_o + q_w} \tag{2.2}$$

$$f_w = \frac{q_w}{q_t} = \frac{q_w}{q_o + q_w} \tag{2.3}$$

$$f_t = f_o + f_w = 1 \tag{2.4}$$

$$q_w = f_w . q_t \tag{2.5}$$

$$q_o = f_o . q_t \tag{2.6}$$

Solving for f_o in equation 2.4 and substituting result in equation 2.6, we have;

$$q_o = (1 - f_w). q_t \tag{2.7}$$

Volume of oil can therefore be calculated as

$$\text{Volume of oil, } N = \frac{q_{o\,.t}}{B_o} \tag{2.8}$$

For incompressible flow, equation 2.8 becomes

$$N = q_{o\,.t} \tag{2.9}$$

3.2.2 Corey's Permeability Correlation

Corey (1954) proposed that the water-oil relative permeability can be represented as follows:

$$k_{ro} = \left\{\frac{1 - S_w}{1 - S_{wc}}\right\}^4 \tag{2.10}$$

$k_{rw} = \left\{\frac{S_w - S_{wc}}{1 - S_{wc}}\right\}^4$ (2.11)

It should be pointed out that the above Corey's equations apply only to well-sorted homogeneous rocks.

For a displacement process where water displaces oil, the mass balance equation around a control volume of length Δx with well sorted grains (i.e. θ = constant) for a period of time Δt can be obtained as follows;

The 1-D mass balance equation may be written as;

$(q_w \rho_w)_x \Delta t = (q_o \rho_o)_x \Delta t$ (2.12)

If the fluid is incompressible and time is kept constant, equation 2.12 becomes

$q_w = q_o$ (2.13)

From Darcy equation,

$q_o = -\frac{k k_{ro} A}{\mu_o}\left\{\frac{\delta P_o}{\delta x} + \rho_o g \sin\alpha\right\}$ (2.14a)

$q_w = -\frac{k k_{rw} A}{\mu_w}\left\{\frac{\delta P_w}{\delta x} + \rho_w g \sin\alpha\right\}$ (2.14b)

Replacing the water pressure with, $P_w = P_o - P_{cow}$, so that

$q_w = -\frac{k k_{rw} A}{\mu_w}\left\{\frac{\delta P_o - P_{cow}}{\delta x} + \rho_w g \sin\alpha\right\}$ (2.15)

Subtracting equation 2.14a from 2.15

$-\frac{1}{kA}\left\{q_w \frac{\mu_w}{k_{rw}} - q_o \frac{\mu_o}{k_{ro}}\right\} = -\frac{\delta P_{cow}}{\delta x} + \rho g \sin\alpha$ (2.16)

Substituting for equation 2.1 and 2.3, and solving for the fraction of water flowing, we obtain:

$f_w = \frac{1 + \frac{k k_{ro} A}{q_t \mu_o}\left\{\frac{\delta P_{cow}}{\delta x} + \Delta\rho g \sin\alpha\right\}}{1 + \frac{k_{ro}}{\mu_w}\frac{\mu_o}{k_{rw}}}$ (2.17)

For a case of horizontal flow and when$P_{cow} = P_c$, equation 2.17 becomes

$f_w = \frac{1 + \frac{k k_{ro} A}{q_t \mu_o}\left\{\frac{\delta}{\delta x}\left(\frac{2\sigma\cos\theta}{r}\right)\right\}}{1 + \frac{k_{ro}}{\mu_w}\frac{\mu_o}{k_{rw}}}$ (2.18)

Recovery factor $R.F = \frac{N_i}{N_n}$ (2.19)

Where;

f_w = fractional flow of water
f_o = fractional flow of oil
q_w *and* q_0 = Flow rate of water and oil respectively
μ_w *and* μ_o = Viscosity of water and oil respectively
σ = Interfacial tension between oil and water
r = Capillary radius
A = area of the reservoir
N_n = Total volume of oil (see equation 2.9)
$N_i = \frac{q_t(1 - f_{wi})t}{B_o}$ at contact angle θ_i in bbl

In 1954, Corey suggested a correlation to measure relative permeability for well sorted rock grains can be measured from the effective saturation S_i^*. From his correlation,

$k_{ro} = \{S_o^*\}^4$ (2.21)

$k_{rw} = \{S_w^*\}^4$ (2.22)

Where;

$$S_w^{\ *} = \frac{S_w - S_{wc}}{1 - S_{wc}} \qquad (2.23)$$

$S_o^{\ *}$ = effective saturation of oil
$S_w^{\ *}$= the effective saturation of water
S_w= final water saturation
S_{wc}= initial water saturation
The Amott index for water can be written as

$$I_w = \frac{S_w - S_{wc}}{1 - S_{or} - S_{wc}} \qquad (2.24)$$

For a piston like displacement with zero residual oil saturation, equation 2.24 will be reduced to

$$I_w = \frac{S_w - S_{wc}}{1 - S_{wc}} = S_w^{\ *} \qquad (2.25)$$

Therefore equation 3.22 becomes

$$k_{rw} = I_w^{\ 4} \qquad (2.26)$$

Where I_w is the Amott index for water which ranges from 0 to 1 for strongly to weakly water wet reservoirs.

Equation 2.18 and 2.26 would be used in this study to show the influence of wettability on oil recovery and relative permeability respectively.
The mathematical equation developed in this study incorporates the following assumptions;

1. Incompressible fluid, therefore density remains constant
2. Flow is laminar
3. No interactions between reservoir fluids
4. Angle of inclination is negligible
5. Displacement is piston like, therefore no residual oil saturation
6. Fluid flow is single phase
7. The fractional flow of water is a function of saturation and capillary force of migration
8. Reservoir is homogenous, isotropic and reservoir rock grains are smooth and well sorted.

3. Results and Discussion

This section validates the model proposed and presents results

$$f_w = \frac{1 + \frac{k k_{ro} A}{q_t \mu_o}\left\{\frac{\delta}{\delta x}\left(\frac{2\sigma \cos\theta}{r}\right)\right\}}{1 + \frac{k_{ro}\ \mu_o}{\mu_w\, k_{rw}}} \qquad (3.1)$$

We have,

$$f_w = \frac{1 + \frac{k k_{ro} A}{q_t \mu_o}\left\{\frac{2\sigma}{\delta x r} \cos\theta\right\}}{1 + \frac{k_{ro}\ \mu_o}{\mu_w\, k_{rw}}} \qquad (3.2)$$

$$f_w = \frac{1 + b\cos\theta}{1 + \frac{k_{ro}\ \mu_o}{\mu_w\, k_{rw}}} \qquad (3.3)$$

Where b is a dimensionless constant
For very large reservoirs <<<A, b = 1.
Therefore, equation 3.3 becomes

$$f_w = \frac{1 + \cos\theta}{1 + \frac{k_{ro}\ \mu_o}{\mu_w\, k_{rw}}} \qquad (3.4)$$

Field Data
Field name: ABC

Parameters	Value and unit
Initial Pressure, p_i	2000psi
Viscosity of water, μ_m	1cp
Relative permeability of oil, k_{r0}	0.6
Porosity, Ø	25%
Production rate, q_w	200bbl/day
Viscosity of oil, μ_0	2cp
Relative permeability of water, k_{rw}	0.25
Compressibility factor, c	$5x10^{-5}psi^{-1}$

From previous assumptions, (equation 2.2) $q_w = q_o => f_o = f_w$

Finding fractional flow values for water-wet to oil-wet reservoirs $(\theta = 0^o \rightarrow 180^o)$
The fractional flow for this reservoir was calculated using equation 2.2 and tabulated in table 4.1 as seen in the appendix A.

Recovery factor $R.F = \frac{N_i}{N_n}$ (3.5)

But $N_i = qtf_{wi}$ and $N_n = qt$

Therefore $R.F = \frac{N_i}{N_n} = f_{wi}$ (3.6)

The recovery factor values at different contact angles are shown in table 3.2 in Appendix A.

The equation to be used to show the influence of wettability on relative permeability is given below.

$k_{rw} = {I_w}^4$ (3.7)

Where I_w ranges from 0 to 1 for weakly to strongly water wet rocks which can be likened to contact angles of $(\boldsymbol{\theta} = 0^o \rightarrow 90^o)$.

Therefore,

$k_{rw} = {I_w}^4 = (cos\boldsymbol{\theta})^{\mathbf{4}}$ (3.8)

The relative permeability to water values at different Amott index and contact angles are shown in table 3.2 in Appendix A.

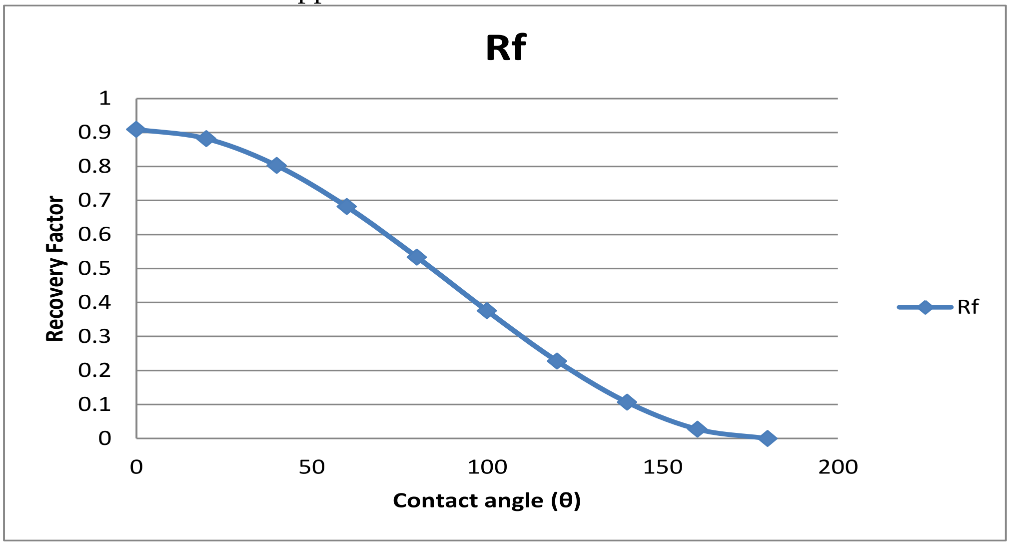

Figure 3.1: Plot showing the influence of wettability on oil recovery

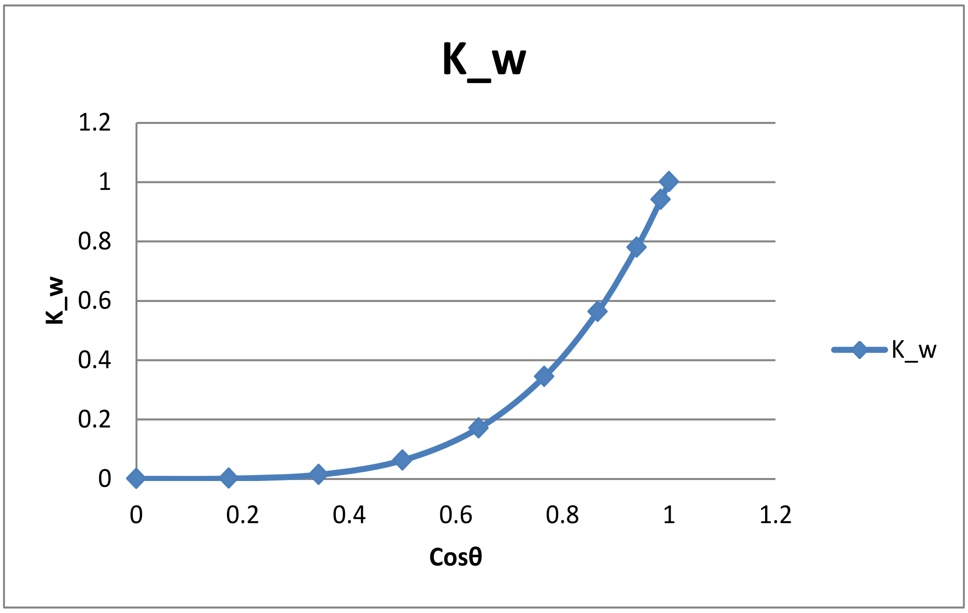

Figure 3.2: Plot of relative permeability versus $cos\theta$

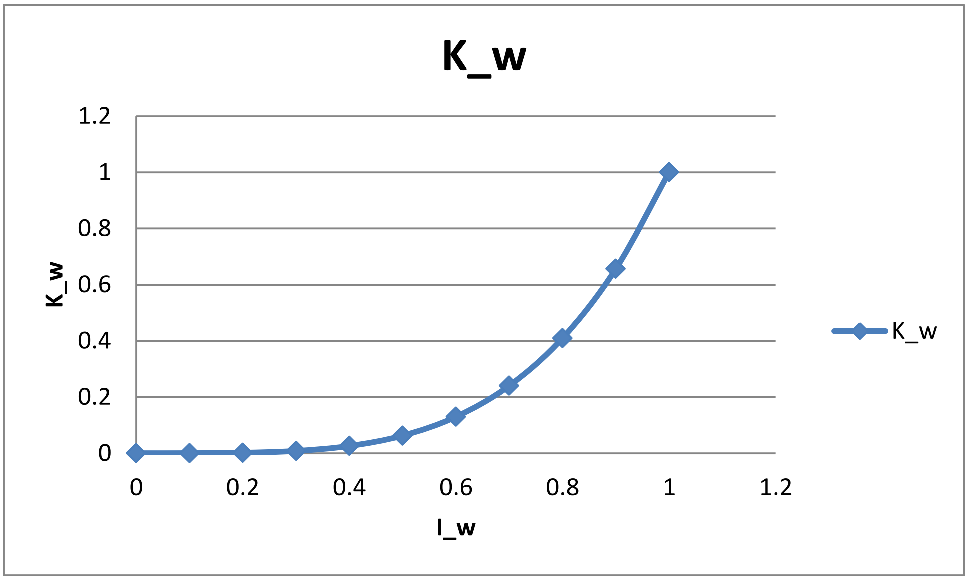

Figure 3.3: Plot of relative permeability $k_w$versus Amott index I_w

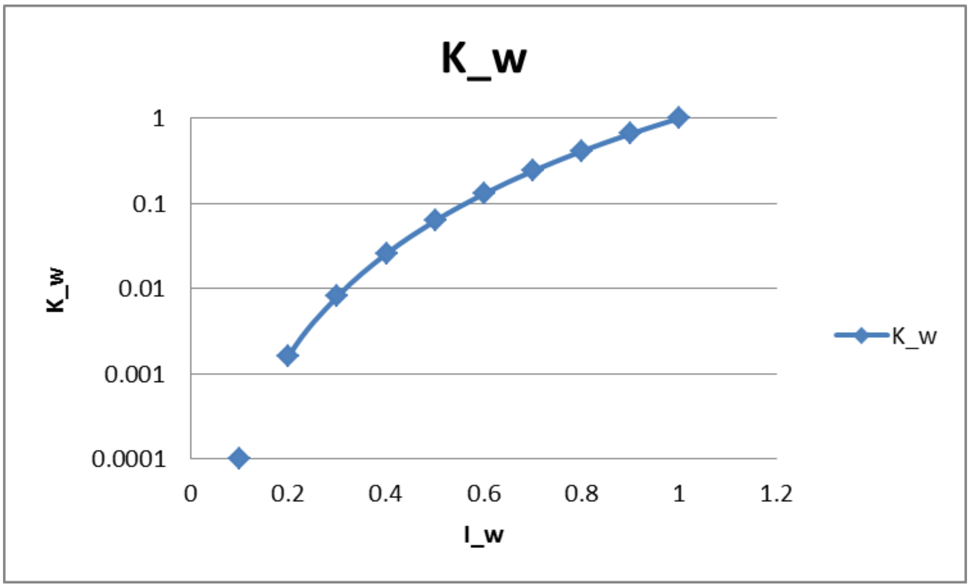

Figure 3.4: Semi-log plot of relative permeability $k_w$versus Amott index I_w

From the results and plots of oil recovery factor and relative permeability against wettability values, it was shown that oil recovery reduces as reservoir wettability changes from water-wet to oil-wet (at contact angles from $0^0 to\ 180^0$) this is because if the reservoir is water-wet, it will imbibe the water injected which will force out the oil in the pore spaces of the reservoir. As reservoir becomes oil-wet, the oil strongly adheres to the reservoir rock therefore less oil will be produced as shown in Fig. 3.1.

Figures 3.2, 3.3 and 3.4 show the relationship between wettability and relative permeability. Relative permeability of water increased as wettability of reservoir changes from strongly water-wet to weak water-wet. This is because if the rock is strongly water-wet, the water molecules are more attracted to the reservoir rock and do not move freely relative to the other fluids present in the reservoir. Invariably, as wettability changes from oil-wet to water-wet, relative permeability to oil increases.

4. Conclusion

The model and the analytical methods developed in this work have shown the influence of wettability on oil recovery and relative permeability. It has been shown that as wettability changes from oil wet to water wet, oil recovery and relative permeability to oil increases because the wetting phase adheres to the reservoir rock while, the none wetting phase moves freely. This in turn implies that wettability is an important reservoir rock and fluid property and must be considered before embarking on an EOR or water flood project.

5. References

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APPENDIX A

Table 4.1: Recovery values at each contact angle values

K_ro	K_rw	µ_w	µ_o	q_w	θ	cosθ	f_w	θ	Rf
0.6	0.25	1	2	200	0	1	0.909091	0	0.909091
0.6	0.25	1	2	200	20	0.939693	0.881678	20	0.881678
0.6	0.25	1	2	200	40	0.766044	0.802747	40	0.802747
0.6	0.25	1	2	200	60	0.5	0.681818	60	0.681818
0.6	0.25	1	2	200	80	0.173648	0.533476	80	0.533476
0.6	0.25	1	2	200	100	-0.17365	0.375614	100	0.375614
0.6	0.25	1	2	200	120	-0.5	0.227273	120	0.227273
0.6	0.25	1	2	200	140	-0.76604	0.106343	140	0.106343
0.6	0.25	1	2	200	160	-0.93969	0.027412	160	0.027412
0.6	0.25	1	2	200	180	-1	0	180	0

Table 4.2: Relative permeability to water at different Amott index and each contact angle values

I_w	K_w	θ	cosθ	K_w
0	0	0	1	1
0.1	0.0001	10	0.984808	0.940602
0.2	0.0016	20	0.939693	0.779728
0.3	0.0081	30	0.866025	0.5625
0.4	0.0256	40	0.766044	0.344363
0.5	0.0625	50	0.642788	0.170714
0.6	0.1296	60	0.5	0.0625
0.7	0.2401	70	0.34202	0.013684
0.8	0.4096	80	0.173648	0.000909
0.9	0.6561	90	6.13E-17	1.41E-65
1	1			