UNIVERSITI TEKNOLOGI PETRONAS

EFFECT OF CAPILLARY PRESSURE ON ESTIMATION OF RELATIVE PERMEABILITY FROM CORE FLOODING TESTS

by

Abdulhadi Elsounousi Khalifa

Dissertation submitted in partial fulfilment of
the requirement for the
MSc. Petroleum Engineering

JULY 2012

Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh
Perak Darul Ridzuan

CERTIFICATE OF APPROVAL

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Approved by,

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Prof. Dr. Noaman El-Khatib

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

JULY 2012

CERTIFICATION OF ORIGINALITY

This is to certify that we are responsible for the work submitted in this project, that the original work is my own except as specified in the reference and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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ABDULHADI ELSOUNOUSI KHALIFA

ABSTRACT

The following investigation focuses on the impact of capillary pressure on estimation of two phases relative permeability curves. Accurate relative permeability is a crucial parameter for evaluating reservoir performance. The unsteady state core flooding tests, which is considered in this study, is mostly used to measure oil-water relative permeabilities.

The Johnson ,Bossler and Neumann (JBN) method is the conventional method for estimating relative permeabilities from field core. The limitations in the JBN method create an error in relative permeability curves and make it unrepresentative of a typical core flooding test results. There are always capillary pressure effects taking place during core flood tests. Ignoring of capillary pressure by JBN method will influence the calculation of relative permeability curves and final saturation levels.

One dimensional numerical model with uniform initial saturation has been implemented in this study using Eclipse 100 software to understand the relationship between relative permeability and capillary pressure. Pressure drop and recovery data obtained from 1-D numerical simulations are used to estimate the relative permeabilities by JBN method. Many scenarios have been studied by running the simulation at constant injection rate and varying the input capillary pressure.

The results obtained have shown the influence of capillary pressure on estimating relative permeability curves. It is shown that increase in capillary pressure increases the water relative permeability. Furthermore, the results demonstrate that the water flooding curves differ greatly in shape and position according to the corresponding values of capillary pressure.

Comparisons of relative permeability curves have shown that the capillary pressure dominates the displacement process. Capillary pressure gradient will increase the fractional flow of water and this increase in fractional flow of water results in lower frontal water saturation, higher frontal velocity and subsequently leading to a decrease in oil recovery.

ACKNOWLEDGEMENTS

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Table of Contents

LIST OF FIGURES

LIST OF TABLES

NOMENCLATURES

$\emptyset$	$\Rightarrow$	porosity
P_c	$\Rightarrow$	Capillary pressure
Pnw	$\Rightarrow$	Capillary pressure of non wetting phase
P_w	$\Rightarrow$	Capillary pressure of wetting phase
σ	$\Rightarrow$	Surface tension
r	$\Rightarrow$	Radius of the pore
Ɵ	$\Rightarrow$	Contact angle
V	$\Rightarrow$	Fluid velocity
K	$\Rightarrow$	Permeability
µ	$\Rightarrow$	Viscosity of the fluid
q	$\Rightarrow$	Flow rate through the porous medium
A	$\Rightarrow$	Cross-sectional area across which flow occurs
k_{eff}	$\Rightarrow$	Effective permeability
k_{abs}	$\Rightarrow$	Absolute permeability
k_{ro}	$\Rightarrow$	Oil relative permeability
k_o	$\Rightarrow$	Effective permeability of oil
k_{rw}	$\Rightarrow$	Water relative permeability
k_w	$\Rightarrow$	Effective permeability of water
k_{rg}	$\Rightarrow$	Gas relative permeability
k_g	$\Rightarrow$	Effective permeability of gas
Sw_i	$\Rightarrow$	Initial water saturation
S_{or}	$\Rightarrow$	Irreducible oil saturation
ΔP	$\Rightarrow$	Pressure drop
q_t	$\Rightarrow$	Total flow rate
fw	$\Rightarrow$	Fractional flow of water
$\overline{S_w}$	$\Rightarrow$	Average water saturation
µo	$\Rightarrow$	Viscosity of oil

μw	⇒	Viscosity of water
α	⇒	Reservoir dip angle
g	⇒	Gravitational constant
S_{wc}	⇒	Connate water saturation
S_w	⇒	Water saturation
S_{wf}	⇒	Water saturation at the Buckley-Leverett front
f	⇒	Fractional of displacing phase in flowing stream
fo	⇒	Fractional of displaced phase in flowing stream
W_i	⇒	Cumulative injection in pore volume
v	⇒	Average velocity
L	⇒	Length
I_r	⇒	Relative injectivity
V_o	⇒	Cumulative oil recovery
PV	⇒	Pore volume

CHAPTER 1

INTRODUCTION

1.1 BACKGROUND

Reservoir engineering studies generally require some indispensable parameters such as reservoir fluid flow and rock properties. Maximizing recovery and development strategy success depend on understanding the type of fluid and rock characteristics.

Relative permeability is a dominant factor controlling the movement of two immiscible fluid phases in porous media. Availability of accurate and representative relative permeability data is of significant concern to reservoir engineers as dearth of these data indicates poor forecasting of production, ultimate recovery and difficulties in reservoir management. The most important parameters required for reservoir engineering studies include the absolute permeability, capillary pressure and relative permeability to the fluids[1].

Relative permeability and capillary pressure of porous media are crucial properties for evaluating accurate reservoir performance. In reservoir simulation studies, relative permeability and capillary pressure data are required as input parameters for reservoir simulator to predict reservoir performance. Relative permeability data are incorporated in oil recovery forecasts and feasibility study of enhanced oil recovery methods[2].

Capillary pressure is the pressure difference existing across the curved interface of two immiscible fluids at equilibrium. Capillary pressure is used for determining the hydrocarbon distribution through the porous media. Surface forces of capillary pressure can either support or resist the displacement process in the pores of porous medium[3].

Capillary pressure = (pressure of the nonwetting phase)-(pressure of the wetting phase)

$P_c = P_{nw} - P_w$ ……………………………………………………………….Eq 1

Where

P_c Is capillary pressure (psi)

P_{nw} Pressure in nonwetting phase

P_w Pressure in wetting phase

Capillary pressure forces are important for determining the saturation distribution in the reservoir. Capillary pressure versus water saturation curve is shown in Figure 1.The relation between capillary pressure and pore size is shown in the following equation:

$P_c = \frac{2\sigma cos\theta}{r}$ ……………………………………………………………….Eq 2

Where

σ =surface tension, dynes/cm

r= radius of the pore, cm

ϴ= contact angle, degree

Pc=capillary pressure, dynes/cm^2

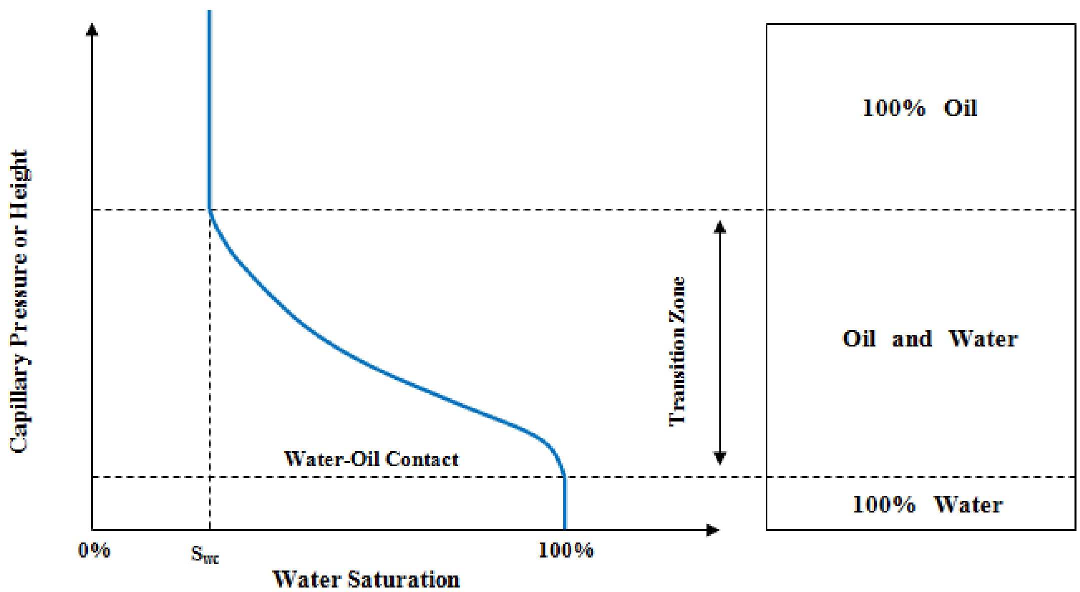

Figure 1: Capillary pressure versus water saturation [3].

Capillary pressure is used in [3]:

- Fluid saturation distribution.
- Reservoir fluid content.
- Connate water saturation.
- Input for reservoir simulation calculation.

The permeability is defined as the ability of the rock to transmit fluid through its interconnected pore. It is a vector quantity and determines the direction flow of fluid in the reservoir [3].

In 1856 Henry Darcy was the first engineer who illustrated mathematically the property of the rock. He developed the fluid flow equation for a linear horizontal system and it is given by Darcy equation [3]:

$$V = -\frac{k}{\mu}\frac{dP}{dL} \quad \text{Eq 3}$$

Where

V=fluid velocity, cm/sec

k= Permeability, Darcy's

μ= Viscosity of the fluid, cp

$\frac{dP}{dL}$ = Pressure drop per unit length, atm/cm

The apparent velocity in the previous equation can be determined by dividing flow rate by the area (q/A), so the equation3 can be written as [3]:

$$q = -\frac{kA}{\mu}\frac{dP}{dL} \quad \text{Eq 4}$$

Where

q= flow rate through the porous medium, cm^3/sec

A=cross-sectional area across which flow occurs, cm^2

The relative permeability is the ability of a porous medium to transmit fluid when more than one fluid is present in the reservoir and it is the ratio of effective permeability to the absolute permeability. Relative permeability can be represented by the following equation [3]:

$$k_r = \frac{k_{eff}}{k_{abs}} \qquad \text{Eq 5}$$

The relative permeability for oil, water and gas are shown in the equations below respectively [3]:

$$k_{ro} = \frac{k_o}{k} \qquad \text{Eq 6}$$

$$k_{rw} = \frac{k_w}{k} \qquad \text{Eq 7}$$

$$k_{rg} = \frac{k_g}{k} \qquad \text{Eq 8}$$

Where

k_{ro} = relative permeability to oil

k_{rg} = relative permeability to gas

k_{rw} = relative permeability to water

k = absolute permeability

k_o = effective permeability to oil for a given oil saturation

k_g = effective permeability to gas for a given gas saturation

k_w = effective permeability to water at some given water saturation

Core is usually used in the laboratory for measuring relative permeabilities of oil and water or gas. Typical curves for relative permeability versus water saturation are shown in Figure 2. The fluid saturations are assumed to be distributed uniformly with respect to thickness. Flow in reservoir where uniform saturation distribution exists over thickness of the sample can be described by either laboratory measurement or rock relative permeability relationship. Existences of capillary and gravity forces are very common over a range of core plug length. This results in a non-uniform water saturation distribution. Hence, rock relative permeability is not generally utilized in actual field displacement calculations [4].

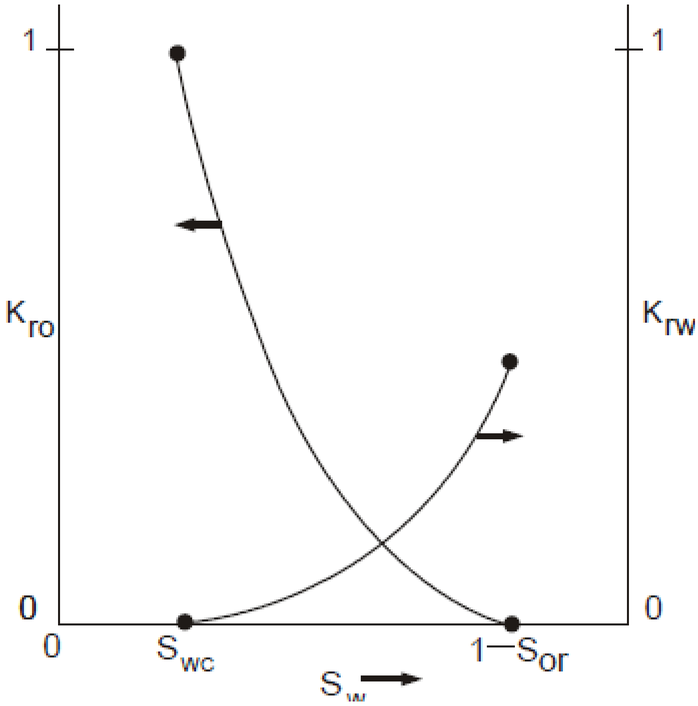

Figure 2: Relative permeability curves [4].

Drainage and imbibitions may be required in the estimation of relative permeability. Capillary pressure and relative permeability for drainage processes are shown in Figure 3. Reservoir rock was 100% saturated before oil accumulation. Oil accumulation results in the drainage process by which the saturation of the wetting phase (water) is reduced. The process of oil migration into the reservoir and displaces the water is called drainage [5].

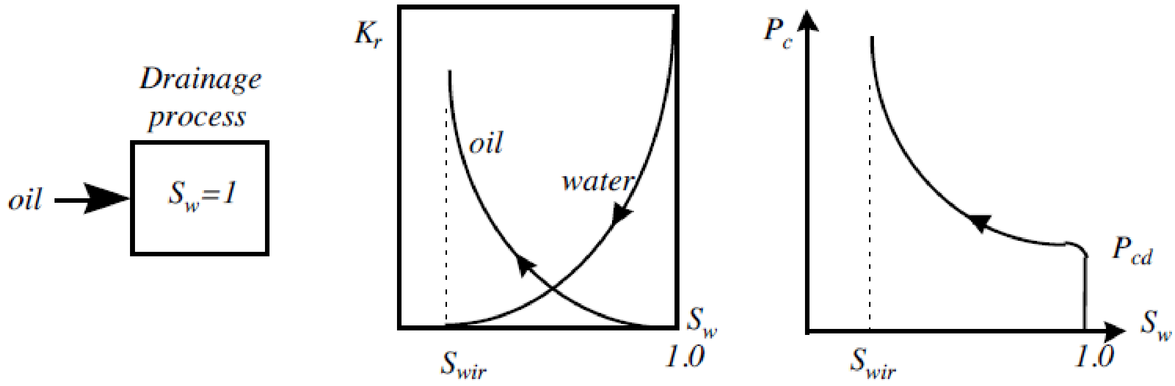

Figure 3: Drainage process[5]

On the other hand imbibition is the process when the oil is displaced by water. Figure 4 shows capillary pressure and relative permeability for imbibitions processes [5].

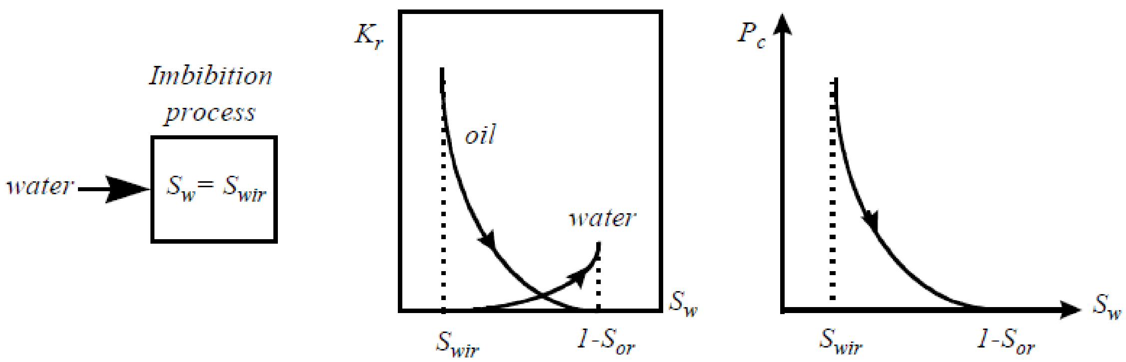

Figure 4: Imbibitions process [5]

Two common laboratory methods frequently used in measuring relative permeability are steady state displacement method where two immiscible fluids are injected simultaneously into the core and unsteady state displacement method in which one fluid displaces the other. The flow mechanism in the reservoir is believed to be like unsteady state method [5].

There are numerous methods of estimating relative permeability from unsteady state method but the Johnson, Bossler and Naumann (JBN) is the most commonly used. Individual phase relative permeability was calculated for first time by JBN method with some advantages over the Welge method [1].

1.2 PROBLEM STATEMENT

The relative permeability is a very important parameter to simulate the two phase fluid flow in porous media. The procedure for getting the relative permeability curve involves applying the mathematical model to analyze the data collected from core flooding tests. The three main forces that affect fluid flow in the porous media are viscous, gravity and capillary forces. Estimation of relative permeabilities by JBN method from unsteady state immiscible displacement ignores the effect of capillary pressure. The limitations in this method create error in relative permeability curve and make it unrepresentative of a typical core flooding test results. There are always capillary pressure end effects taking place during core flood tests at unsteady state condition. This ignoring of capillary force will influence the calculation of relative permeabilities and final saturation levels. This study is aimed to investigate the effect of capillary pressure on estimation of the relative permeability curve from core flooding tests by using core sample model and varying the input capillary pressure.

1.3 OBJECTIVES

The objectives of this study are:

a. To develop a core flood model for unsteady state core flood test to estimate relative permeability.

b. To investigate the problems associated with estimation of relative permeability by analyzing the core flooding “unsteady state” by using

JOHNSON, BOSSLER and NAUMANN method (JBN) which does not consider the capillary pressure. This limitation in analyzing the core flood data come up with the end capillary effect.

c. To demonstrate the important aspect of the error caused due to ignoring the capillary pressure and the effect of the injection rate on the feasibility of using the JBN to calculate the relative permeability curve.

1.4 SCOPE OF STUDY

This study addresses the determination of relative permeability from unsteady state core flooding tests. The project focuses on understanding the relationship between relative permeability and capillary pressure. The purpose is to check the accuracy of estimating relative permeability from JBN method by varying the input capillary pressure for core flood model in numerical simulation.

CHAPTER 2

THEORY AND LITERATURE REVIEW

This chapter gives an outline of relative permeability measurement and the effect of capillary pressure on it.

2.1 MEASURING RELATIVE PERMEABILITY

Accurate measurement of two or three phase relative permeability is vital to reservoir engineering application, especially in the reservoir simulation for forecasting production and ultimate recovery. The relative permeability is the ability of the porous medium to transmit fluid in porous media when more than one fluid is present [6].

Knowledge of relative permeabilities is required for simulation of multiphase flow in porous media. Relative permeability is usually obtained in the laboratory from core flooding tests. There are numerous methods for measuring relative permeability which can be categorized into two types: steady state and unsteady state core flooding tests [7].

2.1.1 Steady State Methods

The two immiscible phases are simultaneously injected into the core and the saturation and pressure drop across the core are measured as they are not changing with time. The core inlet and outlet are connected to pressure transducer. The oil and water are pumped into the core by metering pumps at steady flow rates. The pump rates are adjusted to control the individual flow rate of the liquids. The procedure for steady state tests is shown in Figure 5. End effects are prevented since the steady state test is an equilibrium flow test which make it preferable for some investigators [8][9].

The disadvantages of the steady state tests are [1]:

- Water saturation need to be determined correctly after each displacement level which is difficult and expensive in reservoir condition tests.
- It takes long time to reach the equilibrium at each saturation point; consequently estimation of relative permeability by this test will be at high cost.
- At high temperature and pressure conditions expensive experimental equipment is required.

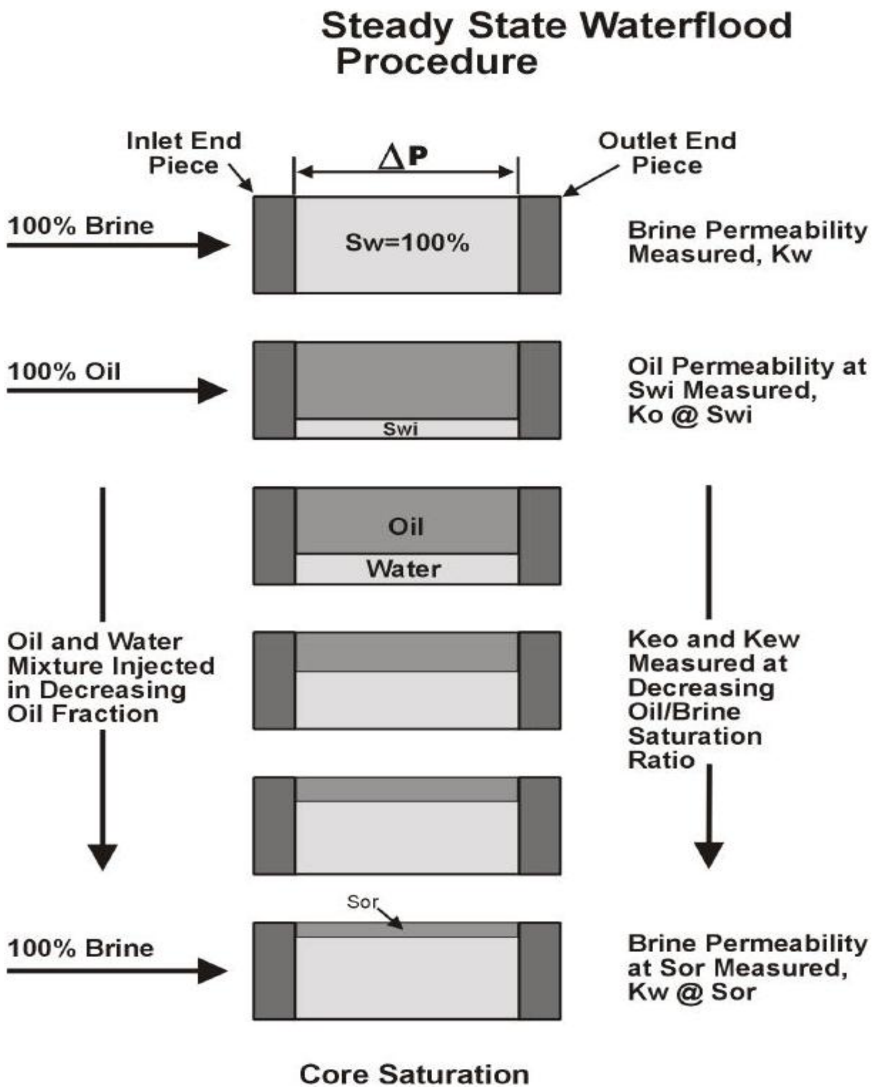

Figure 5: Steady state experiment procedure [9].

Leverett conducted relative permeability experiment on steady rate of oil and water in unconsolidated sand column. Relative permeability and water saturation were monitored when the steady condition had been reached. He applied the steady state method and concluded that at low flow rate, the pressure measurement will be affected by capillary discontinuities at the end of the core outlet. Also from his experiment result, he concluded that the oil-water relative permeability of an unconsolidated sand were extensively independent of the viscosity of the fluid but is related to its pore size distribution, displacement pressure, pressure gradient and water saturation [10].

2.1.2 Unsteady State Methods

One fluid is injected into the core to displace the other phase in the unsteady state core flood test. The core is saturated with 100% water then the oil is injected in the core sample to displace the water to irreducible level, until no water production is obtained (drainage).The amount of water production displaced by injecting oil is recorded and irreducible water saturation is calculated. Water at constant flow rate is injected into the core sample to displace the oil (imbibitions) [1][8].

The recovery and pressure drop across the core are measured during the displacement process. With the data collected from the test, relative permeabilities are calculated. The unsteady state core flooding test can be conducted quickly and the cost is low. It represented the mechanism which takes place in the reservoir and amount of fluid required is small. The unsteady state test procedure is shown in Figure 6.The disadvantage of unsteady state is that it facilitates instability and discontinuities of capillary force at the outlet of the core [1][8][9].

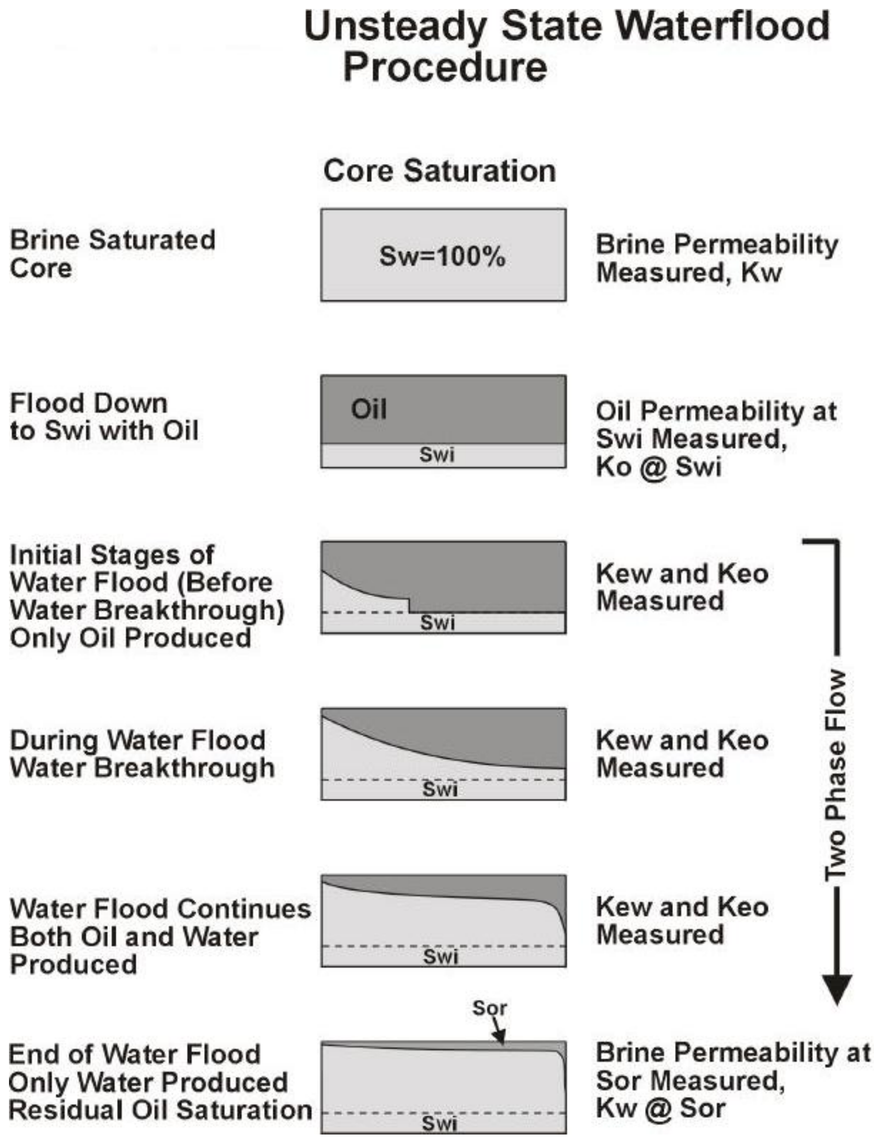

Figure 6: Unsteady state procedure [9].

2.2 FLOW OF IMMISCIBLE FLUID IN POROUS MEDIA

The capacity of a rock to conduct fluids is affected by the presence of immiscible fluids for example oil and water. The process of displacing one phase by another phase is an unsteady state displacement as the saturation of fluids changes with time and invariably changes the relative permeabilities and pressure or phase velocities.

Buckley-Leverett developed one of the methods which predict displacement performance and it is also called frontal advance method [11].

2.2.1 Buckley and Leverett Theory

In 1941 Leverett proposed the concept of boundary effect as a result of capillary forces and figured out that the discontinuity of capillary forces at the outlet of the core retains the wetting phase. This causes accumulation of saturation wetting phase at the outlet and decrease in the non-wetting phase permeability [12].

Leverett presented the approach of fractional flow which is important for water flood displacement process. He gave an expression for fractional flow of water as shown in the following equation [12][3]:

$$f_w = \frac{1+\frac{KK_{ro}}{q_t\mu_o}\left(\frac{\partial p_c}{\partial x} - g\Delta\rho\sin\alpha\right)}{1+\frac{K_{ro}\,\mu_w}{Kr_w\,\mu_o}} \qquad \text{Eq 9}$$

Where fw is the fractional flow of water, q_t is the total flow rate of oil and water, $\frac{\partial p_c}{\partial x}$ capillary pressure gradient, μo and μw viscosities of oil and water respectively, kr_o and kr_w are relative permeability of oil and water respectively ,Δρ is the difference in density between oil and water,α is the reservoir dip angle and g is the gravitational constant [12][3].

In the case of horizontal flow with capillary pressure is neglected the equation 9 becomes [4]:

$$f_w = \frac{1}{1+\frac{\mu_w}{\mu_o}\cdot\frac{k_{ro}}{k_{rw}}} \qquad \text{Eq 10}$$

From equation 10 fractional flow versus saturation curve can be generated from relative permeability data. The shape of fractional is illustrated in Figure 7.

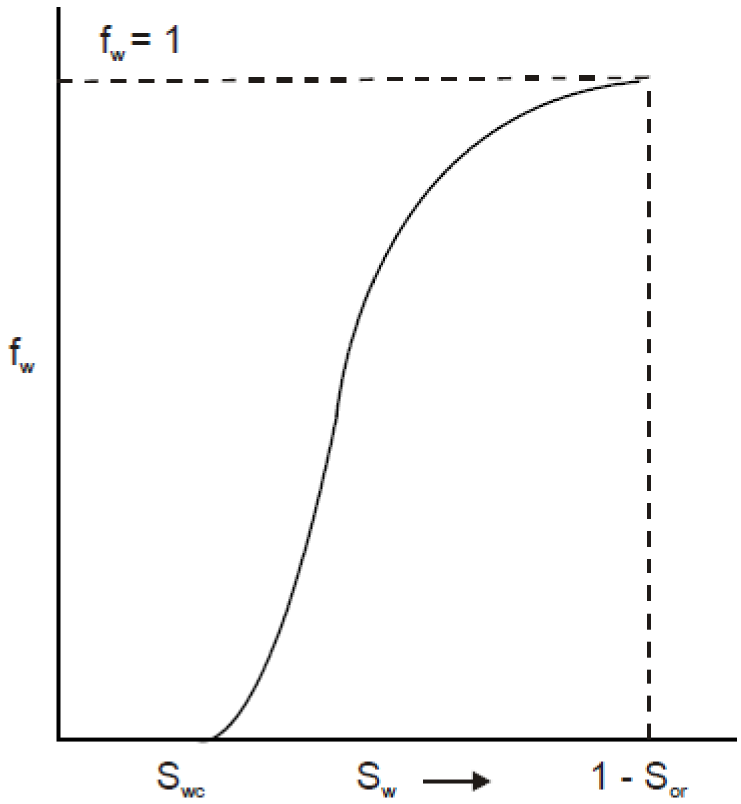

Figure 7: Fractional flow curve as a function of water saturation [4].

Buckley and Leverett in 1942 introduced the first theory for predicting linear displacement of one fluid by another fluid. They applied the law of mass balance to the flow of two fluids. Their theory was based on the linear and horizontal flow, both phases are incompressible and immiscible, and capillary pressure and gravity are negligible. The derivation of Buckley and Leverett equation gave a triple value of water saturation for invaded region by water flood at irreducible water saturation as shown in the Figure 8 [13].

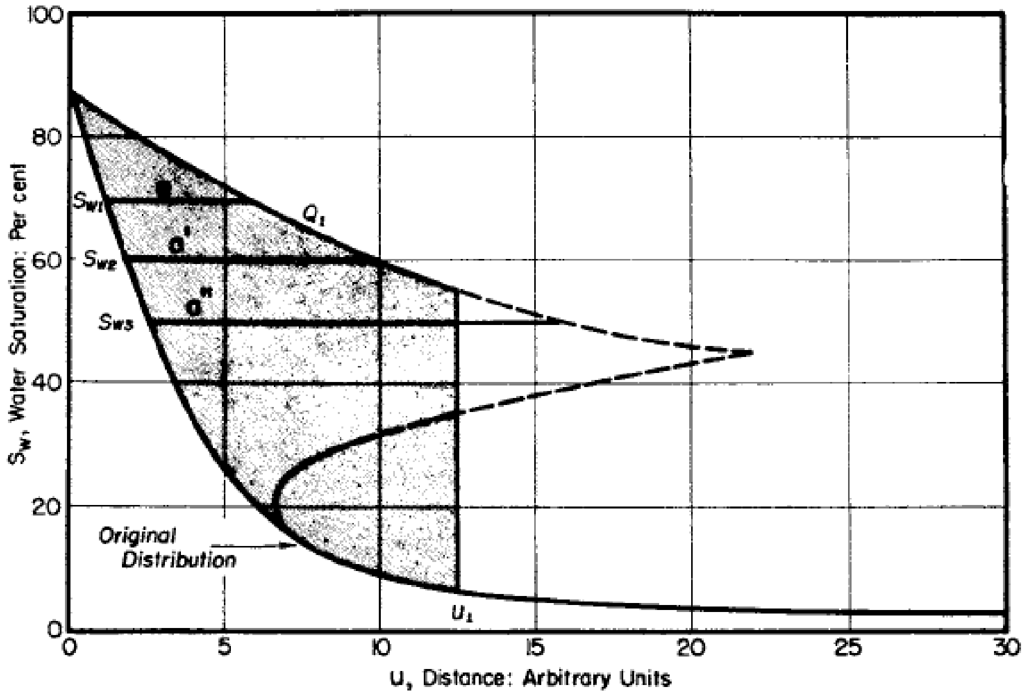

Figure 8: Water saturation versus distance [13].

Multiple water saturation profile as shown in Figure 9 is physically impossible. Buckley and Leverett theory assumes that water saturation is continuous however due to the discontinuity the approach of this theory will not be suitable to describe the saturation at the front itself [4].

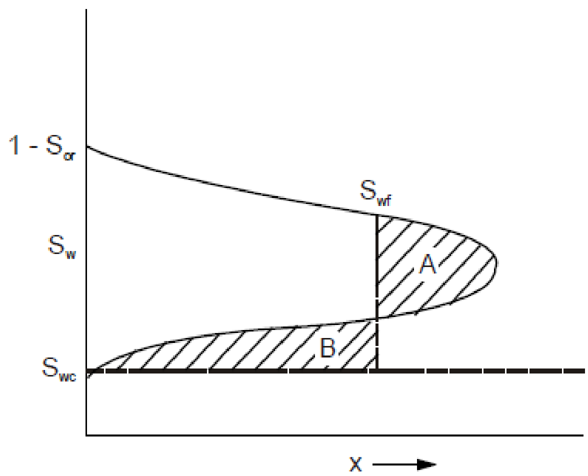

Figure 9: Water saturation distribution in the displacement path [4].

The presence of capillary forces is shown in the Figure 10 shows the relation between saturation and distance. The effect of capillary pressure gradient is given by this equation [4]:

$$\frac{\partial_{Pc}}{\partial_X} = \frac{d_{Pc}}{d_{Sw}} \frac{\partial_{Sw}}{\partial_x} \qquad \text{Eq 11}$$

$\frac{d_{Pc}}{d_{Sw}}$ is the slope of the capillary pressure curve as shown in the Figure 10(a) and is always has a negative value. $\frac{\partial_{Sw}}{\partial_X}$ is the slope of the water saturation in the direction of flow as shown in Figure 10(b) and it is also negative as seen from the graph. As a result of this $\frac{\partial_{Pc}}{\partial_X}$ is always positive and presence of capillary pressure gradient term have been observed to increase fractional flow of water. The water saturation distribution shown in Figure 10 (b) after injecting a given volume of water is considered typical for the displacement of oil by water. The diagram shows presence of a shock front. At the shock front, a discontinuity in the water saturation which increases sharply from S_{wc} to S_{wf}, known as the flood front saturation. At this point, both derivatives on the right hand side of equation (11) are maximised, as proven by inspection of Figure 10 (a) and (b). Therefore ∂Pc/∂x is also maximum. Beyond the flood front, saturation increase slowly from S_{wf} up to the maximum value (1 –S_{or}). Both $\frac{d_{Pc}}{d_{Sw}}$ and $\frac{\partial_{Sw}}{\partial_X}$ are considered small in this region. Therefore $\frac{\partial_{Pc}}{\partial_X}$ can be neglected in the equation [4].

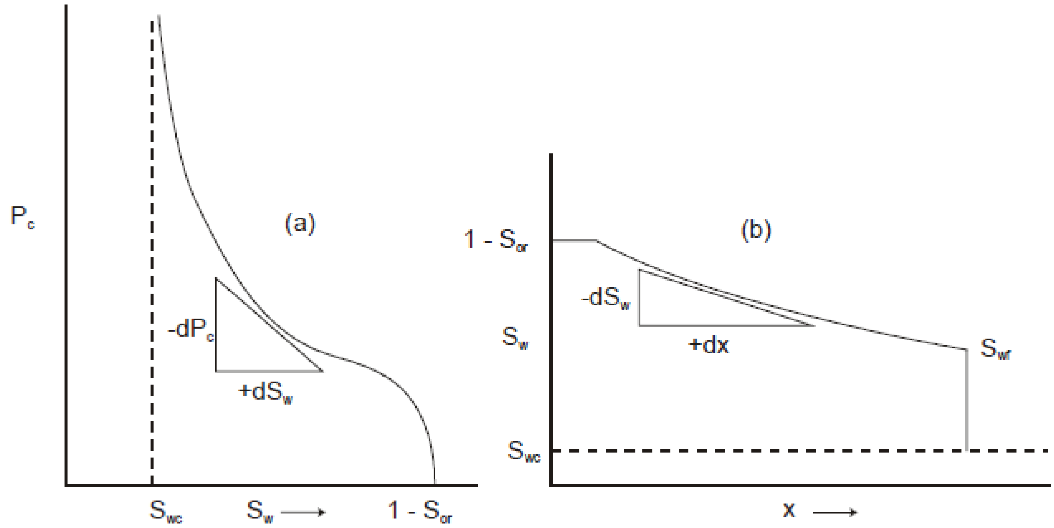

Figure 10 : (a) Capillary pressure versus saturation (b) Water saturation distribution as a function of distance [4].

Fayers and Sheldon in 1959 established that if the capillary pressure is included the triple saturation value does not exist. They also discovered that the gravity and capillary pressure affect the Buckley and Leverett shape at low flow rate only.[14]

2.2.2 Welge Displacement Approach

In 1952 Welge developed a simple approach of the Buckley and Leverett theory which includes the shock front effect for calculating oil recovery as a function of the cumulative water injected. He provided graphical method for calculating correct shock front saturation by drawing a tangent line from initial water saturation to the fractional flow curve as shown in the Figure 11 [15][16].

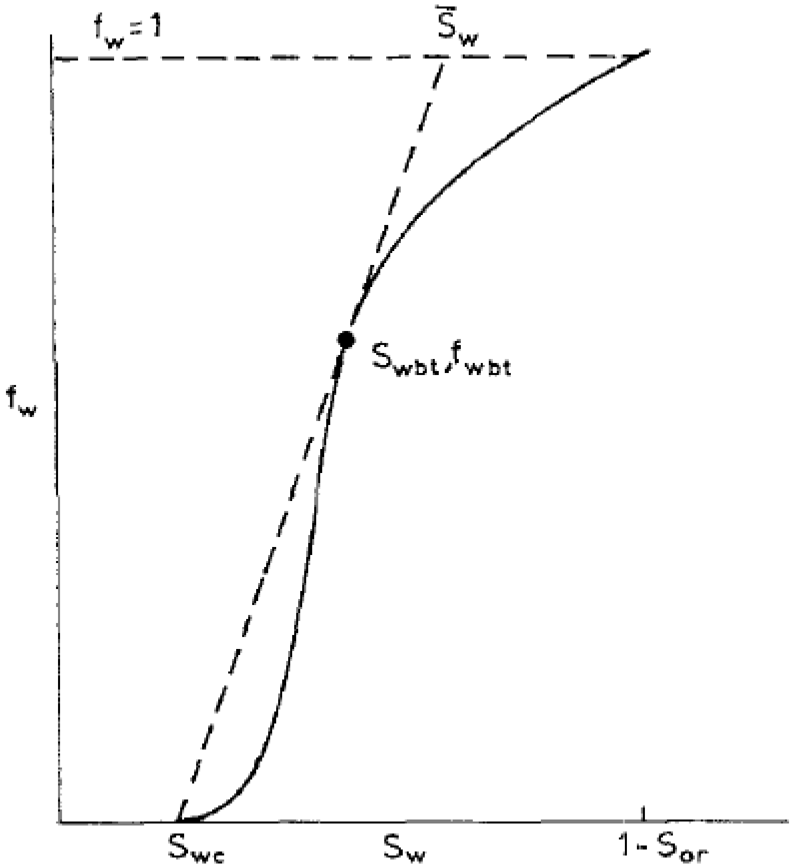

Figure 11: Welge graphical method [15].

The ratio of relative permeability was calculated by Welge method which was based on the Buckley and Leverett theory. He represented this theory by analyzing the production data from gas drive reservoir and showed that the method was suitable for waterflood. He pointed that the flow velocity should be high enough to give stabilized displacement and flow velocity is constant at all cross sections for immiscible incompressible fluids .[4][16]

2.3 THE JBN METHOD

There are many methods for estimating the relative permeability by using unsteady state core flooding experiments. The most commonly used method is the one proposed by JOHNSON, BOSSLER and NAUMANN called the JBN method in 1959 which is based on Welge work .The data required for calculating the relative permeabilities from core flooding experiments are the cumulative recovery of the displaced phase and the pressure drops across the core section. They pointed out that the result from their work is reliable and has agreement with direct measurement of steady state flow tests for measuring the relative permeabilities [17].

The JBN method is less time consuming compared to other reliable methods used to measure the relative permeability. From their results they confirmed that reliable relative permeability can be measured from data obtained from short core samples which is available for routine analysis [17].

2.3.1 JBN DERIVATION

The Buckley and Leverett theory (1941) was modified by Welge in 1952 to facilitate estimation of relative permeability in laboratory core flooding displacement tests. The work of Welge was extended by Johnson-Bossler-Naumann (JBN) 1958 for estimation of the relative permeability from unsteady state core flood test data which is consider in this study [17].

There are three important assumptions for JBN method [17]:

- Total flow velocity is the same throughout the cross section of linear porous body.
- Flow velocity is high enough to achieve Buckley and Leverett displacement.
- Capillary effect is negligible at high injection rates.

To overcome the capillary end effect the experiment should be done at high enough displacement rate. At higher rate the flow will be unstable and the concept of relative permeability will not hold. Cumulative recoveries of oil and water versus time are measured at the outlet face of the core during the JBN method to estimate the relative permeability curve. Some of the mathematical relations which have been developed by Welge are required for calculation of two phase relative permeability by JBN method as follow [17]:

$$W_i = \frac{1}{f'} = \frac{1}{df/dS} \quad \text{.........Eq 12}$$

$$\frac{f}{1-f} = \frac{f}{fo} = \frac{K_{rw}\mu_o}{K_{ro}\mu_w} \quad \text{.........Eq 13}$$

$$(f)_{o_2} = \frac{dS_{av}}{dW_i} \quad \text{.........Eq 14}$$

$$S_{av} = S_2 + W_i(f_o)_2 \quad \text{.........Eq 15}$$

$$f_o\, u = -\frac{kk_{ro}}{\mu_o}\frac{\partial p}{\partial x} \quad \text{.........Eq 16}$$

$$\Delta x = v\, \Delta t\, f' \quad \text{.........Eq 17}$$

The pressure drop across the core which has length L is shown as the integral

$$\Delta p = -\int_0^L \frac{\delta p}{\delta x} dx \quad \text{.........Eq 18}$$

Substituting $\frac{\partial p}{\partial x}$ from Eq16 will give,

$$\Delta p = \frac{u\mu_o}{k}\int_0^L \frac{f_o}{k_{ro}} dx \quad \text{.........Eq 18a}$$

By rearranging and substituting equations 17 and 18a, the following equation is obtained:

$$\int_0^{f'_2} \frac{f_o}{k_{ro}} df' = \frac{\Delta p k f'_2}{L u \mu_o} = f'_2 \frac{u_s/\Delta p_s}{u/\Delta p} = \frac{f'_2}{I_r} \text{......Eq18b}$$

Where I_r is the relative injectivity which is the ratio of the intake capacity at any given flood stage to the intake capacity of the system at the start of the flood. From measurements of flow rate and pressure drop in a water flood susceptibility test, relative injectivity function for a given type of reservoir rock can be determined [17].

Ordinary differentiation is used for equation 18b with respect to f'_2 since f' is the only independent variable [17],

$$\frac{d\left(\frac{f'_2}{I_r}\right)}{df'_2} = \frac{f_o}{k_{ro}} \text{......Eq 19}$$

When f'_2 is equal to the reciprocal of the cumulative volume injection, the equation 19 will be written as [17],

$$\frac{d\left(\frac{1}{W_i I_r}\right)}{d\left(\frac{1}{W_i}\right)} = \frac{f_o}{k_{ro}} \text{......Eq19a}$$

From the equation 19a individual relative permeability of oil can be calculated. The outlet face saturation S_2 is obtained by rearranging equation15 [17]:

$$S_2 = S_{av} - W_i(fo_2) \text{......Eq15a}$$

The relative permeability of the water at S_2 is calculated by solving equation13 [17]:

$$k_{rw} = \frac{(1-f_o)}{f_o} \frac{\mu_w}{\mu_o} k_{ro} \text{......Eq 20}$$

Jones and Roszelle in 1978 extended the JBN method for estimating relative permeabilities by presenting a graphical technique to perform the essential differentiation of the production data and the late time data analysis by their method. They figured out that the fractional flow of displacing phase concave downward when it is plotted against saturation. Jones and Roszell method could also be used for experiments conducted at constant pressure drop across the core, constant rate or changeable pressure drop and flow rate [18].

In 1984 Tao and Watson developed a Monte Carlo error analysis for JBN. The two sources of error in relative permeability are estimation error which related to the error included in the process of measured data to estimate relative permeability and modeling error which is attributed to the degree where the mathematical model fails to exhibit the physical experiment. They postulated that the use of various viscosity ratios did not affect very much the accuracy of relative permeability and the injection rate as well. The error will increase only when oil production or pressure drop are reduced. They also developed the algorithms for computer implementation for JBN method. They pointed out that the relative permeability can be estimated fairly accurately by using linear regression or optimal spline algorithm [19][20].

In 1986 Kerig and Watson included high flexible cubic splines for estimating relative permeability from unsteady state experiment. The error in estimating relative permeability was greatly reduced by using cubic splines and very accurate result can be obtained [21].

In 1988 Watson et al. introduced B-spline for use as functional representations of relative permeability curves. They indicated that serious error may be detected when relative permeability curves are performed with function having too few parameters. They used both hypothetical and real experiments data for core flood test and also pointed out that without acceptable number of parameters; large errors estimation can occur [22].

2.4 EFFECT OF CAPILLARY PRESSURE ON FLUID FLOW DURING CORE FLOODING TESTS

During core flooding test experiments in the laboratory the end effect of capillary pressure occurs due to the discontinuity of capillary pressure when the fluid leave the outlet of the core. This effect may lead to wrong interpretation of core flood tests data. During displacement process the water phase will accumulate at the outlet end of the core before the breakthrough. Sufficient water phase pressure can be achieved when water at the outlet section of the core continues to buildup [11].

To overcome the capillary pressure end effect, wetting phase (water) is injected at high flow rate using longer samples. On the contrary doing the core flooding tests using high water flow rate raises concern as to whether the displacement process test reflects what happens in the reservoir [23].

In 1956 Hadley and Handy investigated the end effect of capillary pressure in the steady state. They studied the effect of different variables as flow rate, viscosities and the outlet end saturation on the calculated relative permeabilities .They noticed the saturation gradients for steady state and dynamic displacement tests. They remarked that the pressure drop should be measured in both phases to get representative relative permeability. Also they observed that as the flow rate is increased the end effect of capillary pressure decreases [24].

In 1958 Kyte and Rapoport studied the linear water flood behavior and end effect of water wet porous media. Figure 12, shows the water wet core when the water first arrives at the outlet [25].

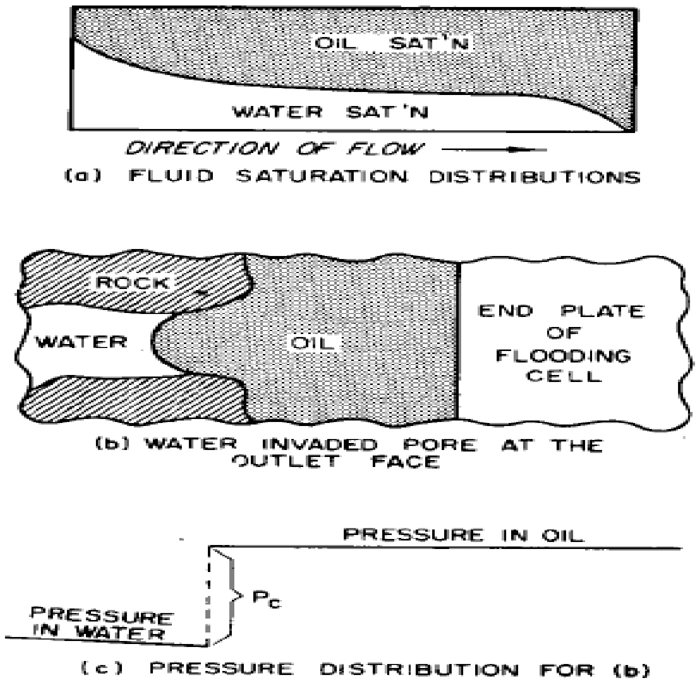

Figure 12: Water arrives at the outlet of the core [25].

They observed that for water to be produced the water phase pressure must rise above the pressure of the oil phase outside the core. Consequently, the water will accumulate at the outlet of the core and only oil will be produced from the core. Finally, the pressure in the water phase is increased due to increasing in water injection leading to water flow out of the core as shown in Figure 13 [25].

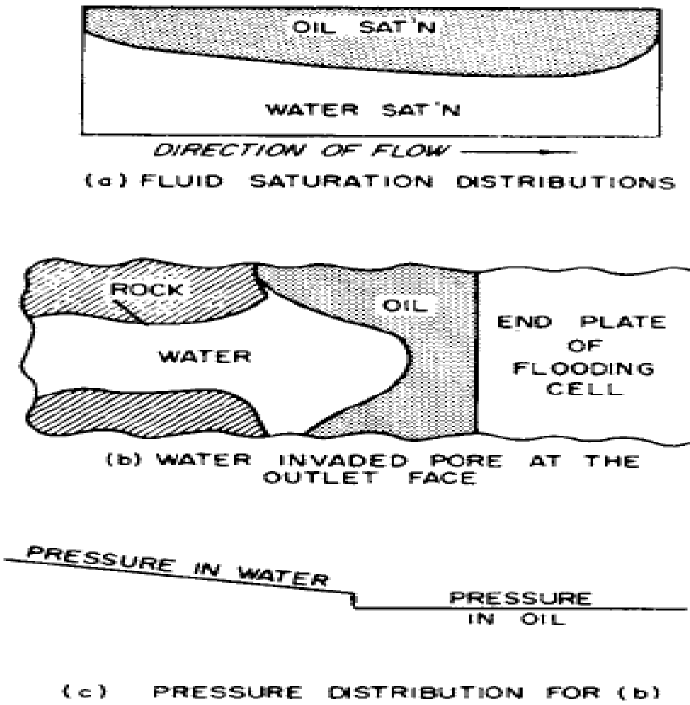

Figure 13: Water flow out of the core [25].

Water is held back by capillary pressure at the outlet and result in apparent increased breakthrough recovery .They reported that early breakthrough and instability may result from high pressure drops and high flow rate [25].

In 1973 Archer and Wong stated that the JBN method gives an error in heterogeneous cores due to ignoring capillary end effect. They indicated that the JBN method may have irregular shapes of relative permeability curves from such system. A computer model was proposed to history match the pressure drop and recovery for low displacement flow rate to get the relative permeability curves. They used one dimensional two phase mathematical model of the laboratory test conditions in their simulation .This model allowed them to make trial and error changes in the shapes of relative permeability curves until they get better match for laboratory production and pressure data [26].

In 1979 Sigmund and McCaffery extended the approach suggested by Archer and Wong. They performed a series of simulator calculations to investigate the effect of capillary pressure at the outlet of the core by using an automatic history matching technique. They pointed out that the recovery and pressure drop data obtained from unsteady state tests are significantly affected by capillary pressure in some cases. At drainage direction on low rate flow displacement, the calculation indicates serious influence of capillary pressure [27].

In 1981 Batycky et al. evaluated capillary pressure and wettability for unsteady state data by proposing method on low flow rate displacement as in situ reservoir condition. They modified Sigmund and McCaffery simulator to reflect displacement experiment perfectly. Capillary equilibrium was settled by stopping flow into the core for certain time, they got extra pressure drop influenced by the capillary end effect force .They pointed that further definition for understanding capillary pressure end effect by using the simulator for matching the pressure drop and recovery is needed. From their result, they observed that capillary end effect can be extended over large part of the core when the system has strong wetting characteristics. Also they mentioned that estimation of relative permeability from simulation when capillary end effect is eliminated can give large error [28].

In 1985 Odeh and Dotson proposed a method for correcting Jones and Roszelle technique by reducing the effect of flow rate and consequently reducing the errors caused by capillary end effects in water wet systems. From their results it was shown that at high oil saturation and high flow rate the relative permeability curves are not strong functions of rate or less independent of the flow rate. At low oil saturation the relative permeability curves are dependent on rate. Firstly, they calculated the relative permeability curves by Jones and Roszelle from the data obtained from the test and plotted $\frac{q_o}{k_{ro}}$ and $\frac{q_w}{k_{rw}}$ versus average water saturation $\overline{S_w}$ which is straight line at low water saturation for high flow rate, for low flow rate straight line may not exists. They assumed the capillary end effect will not affect the estimation of oil

relative permeability in this region. The straight line can be extended over the entire saturation range where relative permeability needed to be measured [29].
Corrected relative permeability values are given by the following equations [29]:

$$(k_{ro})_{cor} = k_{ro}\frac{\left(\frac{q_o}{k_{ro}}\right)_C}{\left(\frac{q_o}{k_{ro}}\right)_{SL}} \quad \text{Eq 21}$$

$$(k_{rw})_{cor} = k_{rw}\frac{\left(\frac{q_w}{k_{rw}}\right)_C}{\left(\frac{q_w}{k_{rw}}\right)_{SL}} \quad \text{Eq 22}$$

Where $\left(\frac{q_w}{k_{rw}}\right)_C$ & $\left(\frac{q_o}{k_{ro}}\right)_C$ are ratios of flow rate to the relative permeability of water and oil respectively which was calculated by Jones and Roszelle method, and $\left(\frac{q_o}{k_{ro}}\right)_{SL}$ & $\left(\frac{q_w}{k_{rw}}\right)_{SL}$ are the values read from the straight line, $(k_{ro})_{Cor}$&$(k_{rw})_{Cor}$ are the corrected relative permeability of oil and water respectively.

In 1987 Peters and Khataniar studied the effect of instability on estimation of relative permeability from displacement methods. They pointed out that the relative permeability estimated from the data collected from the displacement tests are significantly affected by unstable displacement. They calculated the relative permeability by Welge and Johnson method and pointed out that in the core flood displacement tests the oil relative permeability decreases and water relative permeability increases when the degree of instability increases. They advised that to obtain accurate and representative permeability the laboratory experiments should be conducted at the similar degree of instability in the reservoir [30].

Qadeer et al. in 1988 investigated the correction of oil/water relative permeability data for capillary effect in displacement experiment .They did the experiment under different flow rate for short and long cores .They estimated the oil relative permeability exponential functions by developing a computer model for displacement experiments. Their model was one dimensional two phase flow simulator with capillary effects and a simple Buckley Leverett non capillary flow simulator. The experiment data and the simulation model were used to investigate the effect of rate on the parameters of relative permeability. From their results they pointed out that the relative permeability parameters in drainage process have functional relationships with the rate. Also, they developed regression equations for changing saturation of non-wetting and wetting phase and find out that the end point for relative permeability and saturation exponent for drainage process of the non-wetting phase can be related to the dimensionless rate. They pointed out that with increase in the rate of displacement the saturation exponent of the wetting phase decreases [31].

In 1989 Civan and Donaldson studied relative permeability estimated from unsteady state displacement tests with capillary pressure included. They developed a semi-analytic method for calculating relative permeabilities which is not restricted to high flow rate due to incorporation of capillary pressure [32].

In 1992 Chardaire-Riviere et al. developed algorithm based on optimal control approach for automatically estimation of relative permeability and capillary pressure in incompressible two phase flow experiment [7].

The main enhancements achieved by this algorithm are [7]:

a) The experiment can be conducted at any flow rate; consequently reservoir flow condition can be used.
b) Estimation of relative permeability and capillary pressure from different core sample are possible.
c) Imbibitions or drainage displacement can be used for estimation of relative permeability with various boundary conditions.

In 1992 Savioli and Binder applied automatic history matching algorithm to evaluate the effect of capillary pressure on measuring relative permeability curves. The experimental and simulated data were tested by this algorithm. Inclusion of capillary pressure gave good adjustment between simulated and experimental data [33].

In 1994 K. Li,P. Shen and T. Oing calculated oil –water relative permeability by developing an analytical method that included capillary pressure. The core flooding tests can be achieved at typical reservoir flow rate by this analytical method [34].

Qadeer, Brigham and Castanier in 2002 studied the limitations of calculating relative permeability from unsteady state by JBN method .They used Bera sand stone core sample in their experiments which is known to be homogeneous and strongly water wet, also, they did simulation ,from their result they pointed out that JBN method gave large error at low water saturation .They used CT scanner to measure the saturation and recommended that to determine the range of the end effect of capillary pressure and the saturation gradients in the cores ,the control experiments should be conducted using in situ saturation measurement .They indicated that the end point saturation and relative permeability are function of rate. From their result relative permeability estimated by JBN method gave large error because of non-linear flow, capillary pressure end effect and the saturation gradient [35].

CHAPTER 3

METHODOLOGY

This chapter describes the method that will be followed in this study to achieve the objectives of this study that already stated.

The methodology of this study is described in flow Chart 1; the study starts with the introduction of the relative permeability and the methods of measuring the relative permeability from core flooding tests. A literature review of the estimation of relative permeability from core flooding tests and influence of capillary pressure on the accuracy of the estimated relative permeability is presented.

One dimensional numerical simulation model of imbibitions unsteady state test will be performed using input relative permeability and capillary pressure data. After running the simulation, the data will be collected to estimate the relative permeability by JBN method. The data required from the simulation model to calculate the relative permeability curves are cumulative recovery of oil, pressure drop across the core, and total water injected.

The following equations are used for the calculation:

$$\overline{S_w} = S_{wi} + V_o \qquad \text{Eq 23}$$

$$(f)_{o_2} = \frac{d\overline{S_w}}{dW_i} \qquad \text{Eq 24}$$

Water saturation at the outlet face of the core is calculated based on Welge method

$$S_{w2} = \overline{S_w} - f_{o2} W_i \text{ .... Eq 25}$$

Relative injectivity is calculated I_r from total flow rate and pressure drop to estimate individual relative permeability by:

$$I_r = \frac{\left(\frac{q}{\Delta P}\right)}{\left(\frac{q}{\Delta P}\right)i} \text{ .... Eq 26}$$

Where $\left(\frac{q}{\Delta_p}\right) i$ is at initial condition.

The oil relative permeability is given by:

$$k_{ro} = f_{o2} \frac{d\left(\frac{1}{W_i}\right)}{d\left(\frac{1}{W_i I_r}\right)} \text{ .... Eq 27}$$

The water relative permeability is calculated by:

$$k_{rw} = \frac{(1-f_{o2})}{f_{o2}} \frac{\mu_w}{\mu_o} k_{ro} \text{ .... Eq 28}$$

The water saturation during the simulation process will be observed to see the influence of capillary end effect on the breakthrough. The result from the simulation will be compared with input relative permeability data to check the error between the input relative permeability and the one that will be measured by the JBN method. Number of grid cells, injection flow rate and input capillary pressure will be varied until satisfactory results is obtained.

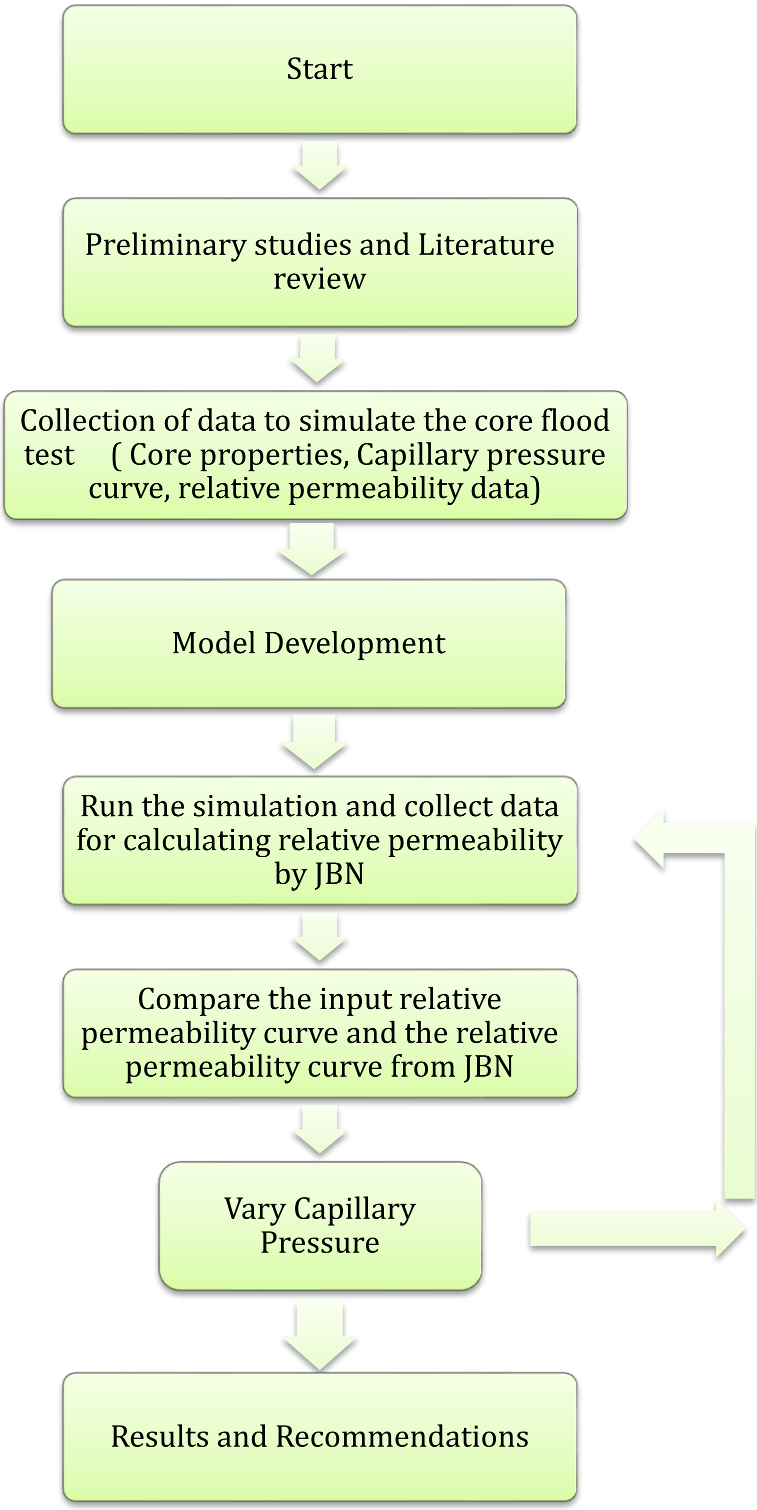

Chart 1: Project methodology

CHAPTER 4

NUMERICAL SIMULATION RESULTS AND DISCUSSION

4.1 ECLIPSE 100

Numerical simulation is performed in this study using a commercial black oil simulator "Schlumberger ECLIPSE 100".The recovery and pressure drop data from input relative permeability and capillary pressure were obtained by the Eclipse simulator. Four scenarios have been studied to investigate the effect of capillary pressure on estimation relative permeability curves. The calculation of relative permeability by JBN method and the simulation details are presented in this chapter.

4.2 SIMULATION OF CORE FLOODING TO DETERIMINE OIL-WATER RELATIVE PERMEABILITIES

Core flooding tests is used to evaluate and determine relative permeabilities which are required for simulation studies. Linear core was used to determine oil and water relative permeability with unsteady state method by reducing it to irreducible oil saturation.

Flow is uni-directional and the core is homogeneous and isotropic. Properties of the core are tabulated in the Table 1. The relative permeability data used in the model are shown in Figure 14 and the values are tabulated in Table 2.

Table 1: Core properties [11].

Parameter	Unit	Value
K	md	124
µo	cp	8
µw	cp	0.51
Q	cc/min	5
Injection pressure	atm	40
Sw_i	%	0.303
∅	%	0.28
L	cm	25
A	cm^2	25

Table 2: Oil/water relative permeability [11].

SW	Krw	Kro
0.303	0	0.722
0.342	0.022	0.485
0.381	0.036	0.325
0.426	0.057	0.193
0.463	0.079	0.128
0.492	0.104	0.088
0.522	0.132	0.056
0.556	0.167	0.035
0.586	0.209	0.021
0.621	0.262	0.012
0.653	0.314	0.0065
0.685	0.369	0.0035
0.707	0.409	0.0017
0.738	0.469	0.0017

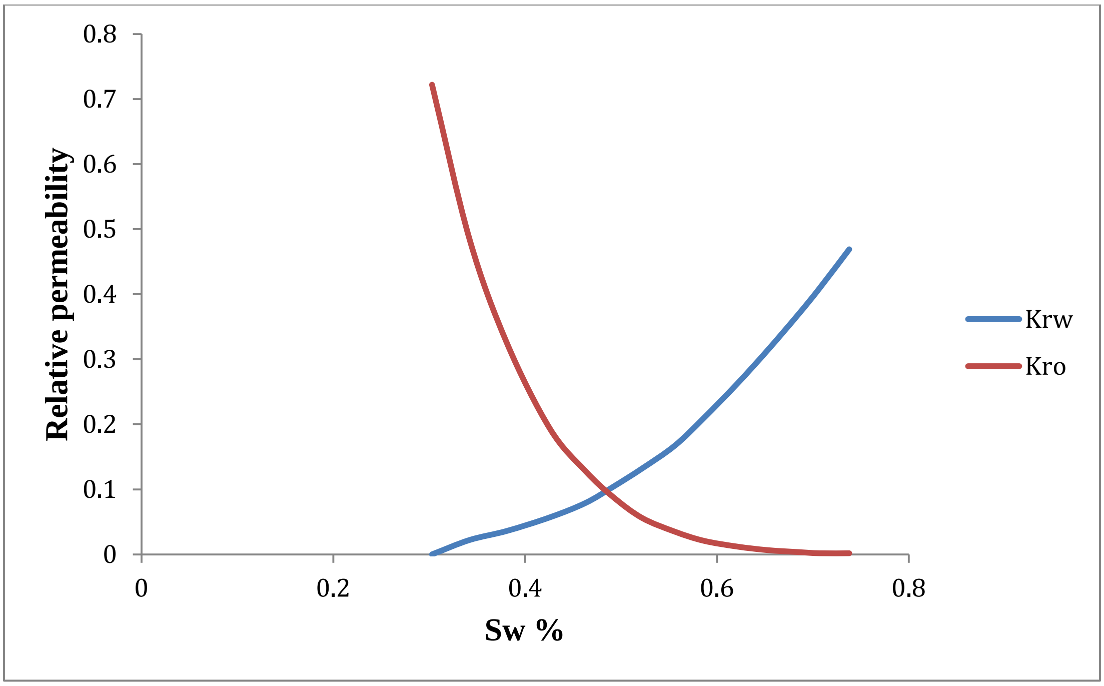

Figure 14: Relative permeability versus water saturation [11].

Capillary pressure for all the scenarios are illustrated in Figure 15 and values are tabulated in Table 3.

Table 3: Capillary pressures [11].

SW	PC1	PC2	PC3
0.303	2.274282	4.548563	1.137141
0.342	1.595325	3.190649	0.797662
0.381	1.326606	2.653211	0.663303
0.426	1.181933	2.363865	0.590966
0.463	1.082878	2.165755	0.541439
0.492	1.006928	2.013856	0.503464
0.522	0.944602	1.889203	0.472301
0.556	0.891019	1.782038	0.44551
0.586	0.843318	1.686635	0.421659
0.621	0.799638	1.599275	0.399819
0.653	0.758656	1.517312	0.379328
0.685	0.719339	1.438678	0.35967
0.707	0.680785	1.361569	0.340392
0.738	0.642096	1.284192	0.321048

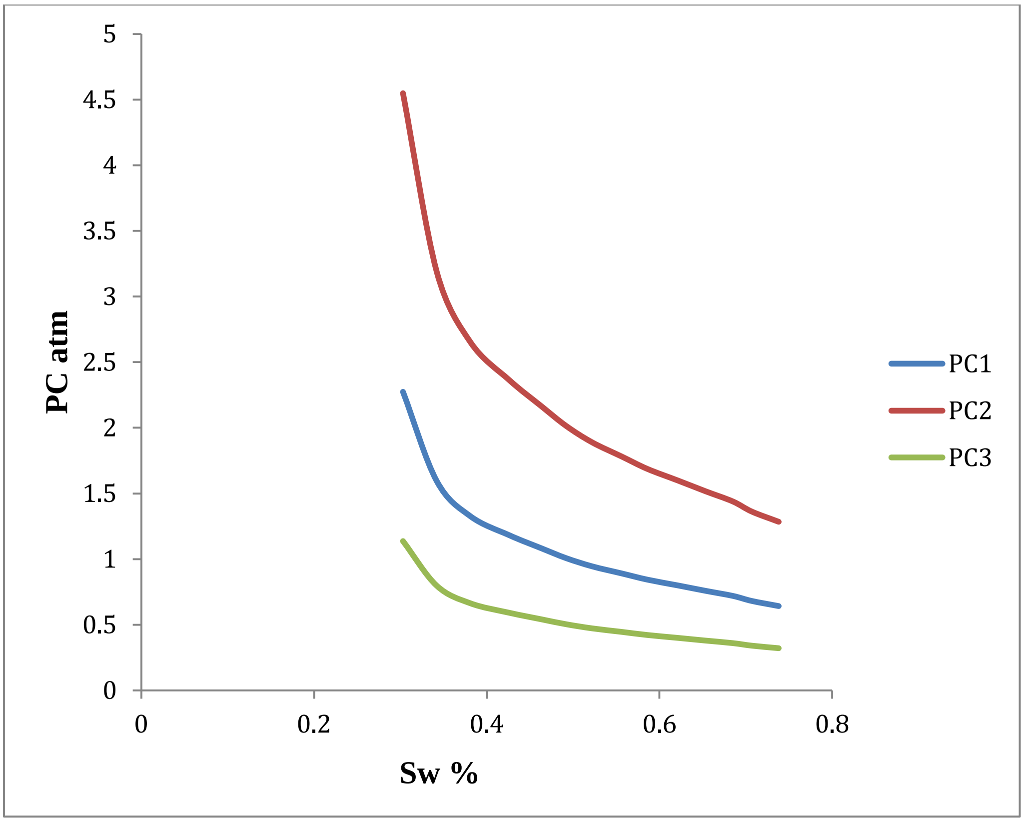

Figure 15: Capillary pressures versus saturation

The core sample modelled has 100 cells in X direction, 1 cell in Y direction and 1 cell in Z direction. One production well and one injection well will be integrated in the model. One dimensional Cartesian grid will be used in this model as shown in the Figure 16. The model has length of 25 cm and area of 25 cm^2.

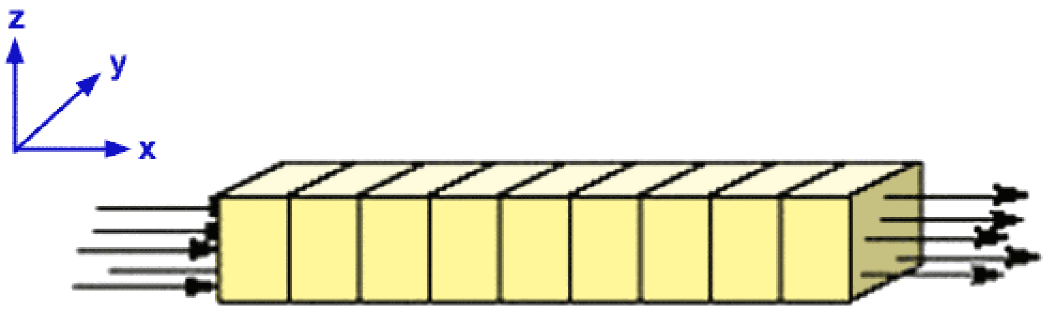

Figure 16: One dimensional cartesian grid

Recovery and pressure drop at given time are used to calculate the relative permeabilities by JBN method which gives the relative permeability curves as a function of saturation at the outlet face of the core sample after the beginning of the displacement. The relative permeability curves are generated by following steps:

- Collect the data from the simulator for constant water injection rate, and then injected water volumes and oil recovery are converted into the pore volume injected.
- Given the initial water saturation, average water saturation as a function of pore volume is calculated from equation 23.
- The fractional flow of oil is measured at the outlet of the core by plotting the average water saturation versus total water injected at each time step using equation 24 "i.e., the slope of the curve".
- Water saturation at the outlet face of the core at each time step is calculated based on Welge method using equation 25.
- Initial Pressure drop across the core is calculated using Darcy law by the following equation :

$$(\Delta P)i = \frac{q\mu_o L}{KA} \quad \ldots\ldots\ldots\ldots\ldots\ldots \text{Eq 29}$$

- Final pressure drop at each time steps is calculated from taking the difference of pressure at the injection well and production well.
- The reciprocal of the relative injectivity is calculated by the following equation :

$$\frac{1}{I_r} = \frac{\left(\frac{q}{\Delta P}\right)i}{\left(\frac{q}{\Delta P}\right)} \ldots\ldots\ldots\ldots\ldots\ldots \text{Eq 30}$$

Since the flow rate is constant during displacement, equation 30 becomes:

$$\frac{1}{I_r} = \frac{\Delta P}{(\Delta P)i} \ldots\ldots\ldots\ldots\ldots\ldots \text{Eq 31}$$

Substituting equation 29 in equation 31 gives:

$$\frac{1}{I_r} = \frac{K\Delta P}{\mu_o (L/A) q} \quad \text{Eq 32}$$

- From simulation results, slope of the $\frac{1}{W_i}$ as a function of $\frac{1}{W_i I_r}$ is calculated and individual relative permeability of oil is obtained using equation 27.
- Water relative permeability at each time steps is calculated using equation 28.

All simulation scenarios that are considered in this chapter were design to study the effect of capillary pressure on measuring relative permeability curves. Results have been obtained by simulation for estimation relative permeability curves by JBN method. Different results were acquired according to different capillary pressure.

4.2.1 Case 1

The first scenario is to measure relative permeabilities by JBN method based on the measurement of pressure drop across and the cumulative production of oil and water. For this case the capillary pressure used is PC1 is shown in Table 3.The data file for this case is shown in Appendix A.

The core model is flooded with water at constant flow rate of 0.0833cc/sec and variation of pressure drop during the displacement is measured. Since the rate is constant equation 32 becomes:

$$\frac{1}{I_r} = \frac{K\Delta P}{\mu_o (L/A) q} = 0.186\ \Delta P(\text{atm}) \quad \text{Eq 33}$$

Results from the JBN method are compared with values that used to generate the simulation recovery and pressure drop data. The graphs of total water injection per pore volume versus total oil recovery per pore volume and average saturation versus the total water injection are show in the Figure 17& Figure 18 respectively.

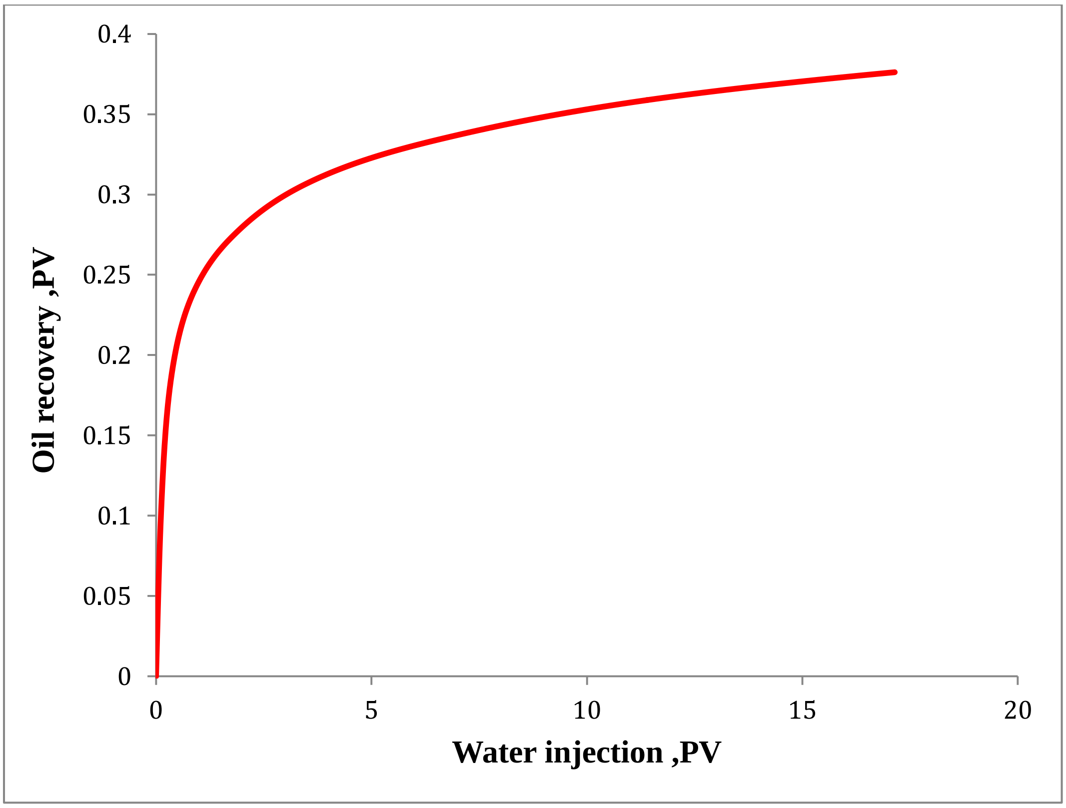

Figure 17: Water injected versus oil recovery

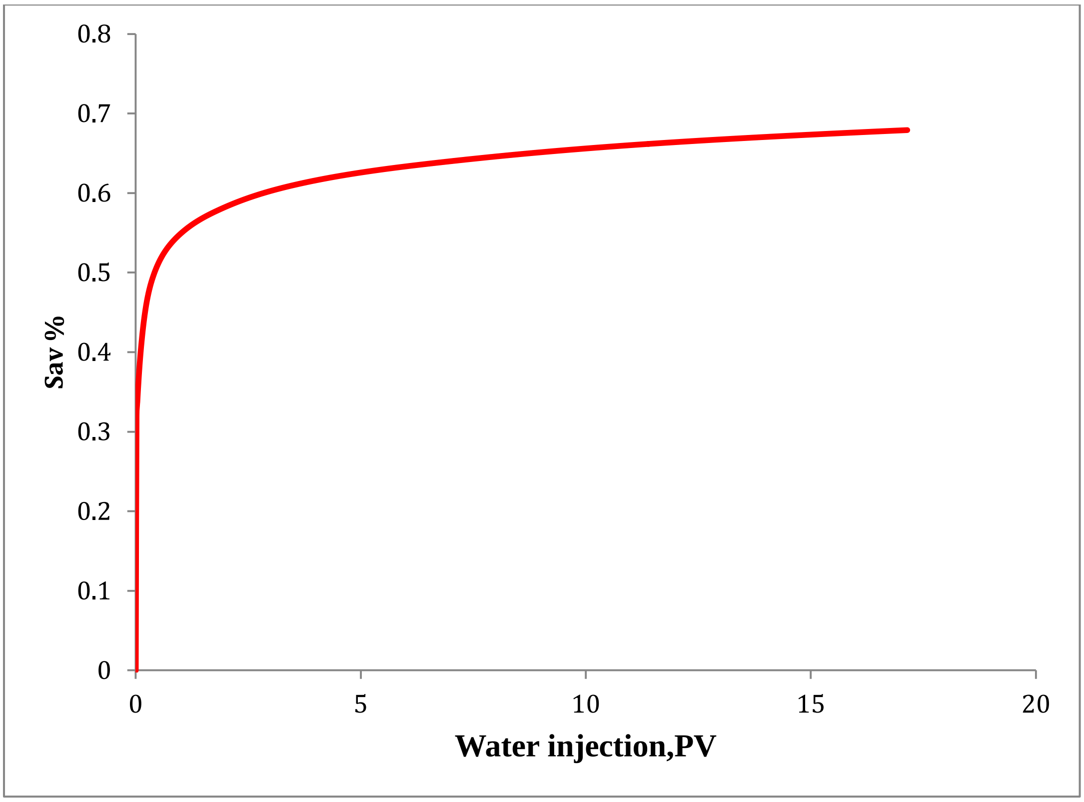

Figure 18: Average saturation versus total water injected

Initial water saturation is assumed to be immobile; hence oil will be produced at the same rate of water injected for an incompressible system. Water saturation gradient exist form inlet to the end of the system when the water breakthrough occurs.

Figure 17& Figure 18 shows that the slope of curve is equal 1 before breakthrough time, hence the fraction flow of oil is equal to the slope of curve at any given injection the oil fractional flow calculated. After breakthrough, water saturation continuously increases as water move through the core. From the graph, slope is decreasing after the breakthrough. This means that fractional flow of oil is decreasing and fractional flow of water is increasing as the water started producing from the outlet face of the core.

Pressure drop across the core during the displacement test is increasing from initial pressure drop until the point where the breakthrough happened and water started producing after that is decreasing as shown in Figure 19.

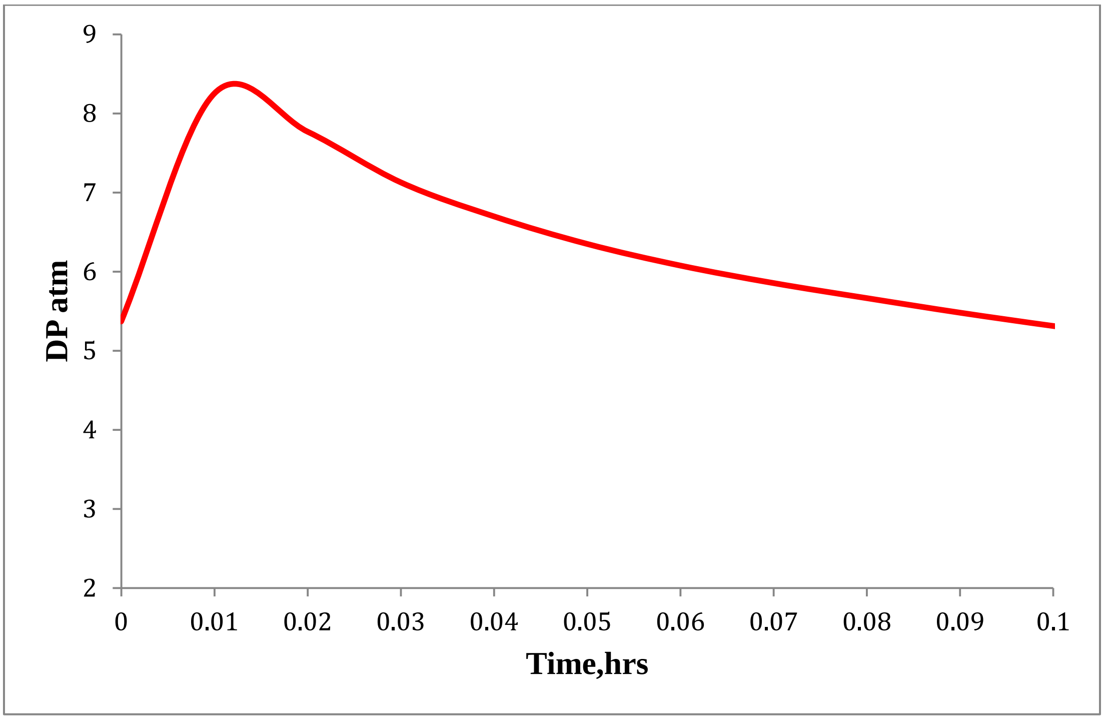

Figure 19: Pressure drop versus time

The error introduced by the assumption of JBN method is easy to evaluate as the simulation was run by known relative permeabilities. The input relative permeabilities and the calculated relative permeabilities from 5 cc/min imbibitions simulation are compared as shown in the Figure 20.

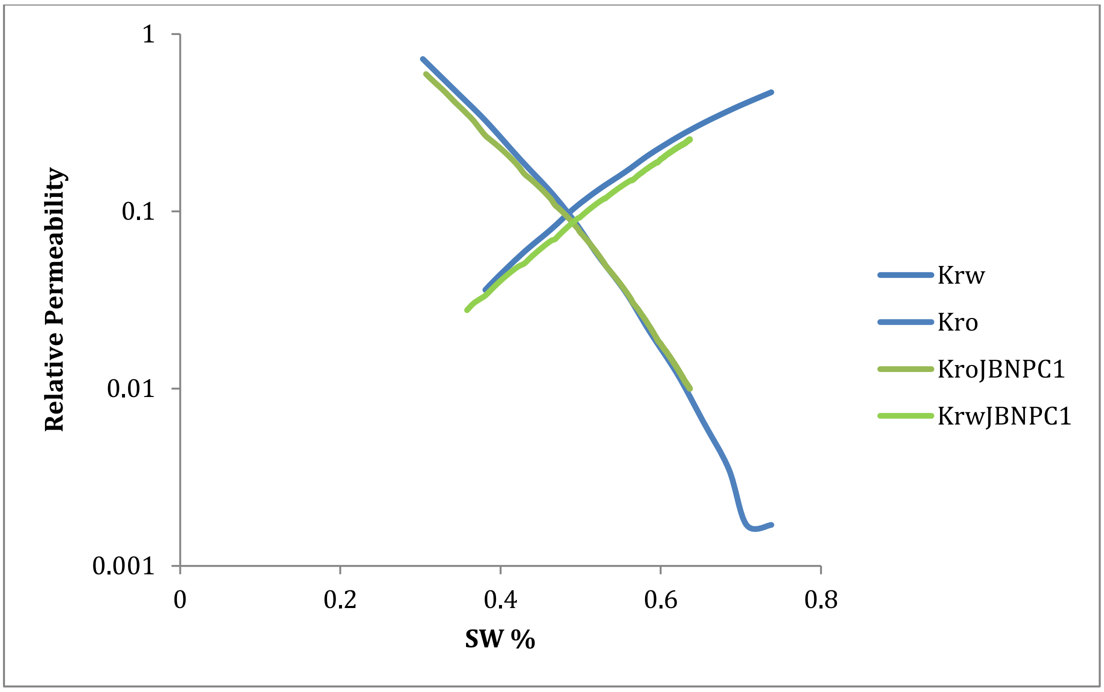

Figure 20: Relative permeability curves from JBN and input relative permeability curves

At the start of the displacement process water saturation is low, and because of this, there will be an error in the estimated relative permeability which is due to capillary pressure effect. The errors decrease when the water saturation increase and capillary pressure effect is reduced. The oil relative permeability calculated by JBN was small at the beginning of displacement compared with input data in the model.

The saturation at the outlet face of the core is unchanged during the displacement until water breakthrough. Also the water saturation at the outlet is always less than the average saturation. The saturation profile from the core model is shown for different time steps in Figure 21.

Water arrives at the outlet of the core and accumulates until water phase pressure exceeds the oil phase pressure. Finally accumulation of water at the end of the core leads to sufficient water phase pressure for flow. Increase in water saturation decreases the oil phase permeability. Error is created when accumulation of water at the outlet of core delays water breakthrough. This end effect results in large value of relative injectivity and give error for oil relative permeability. Due to end effect of capillary pressure, water saturation is changing in non-uniform manner and also effects the JBN assumption.

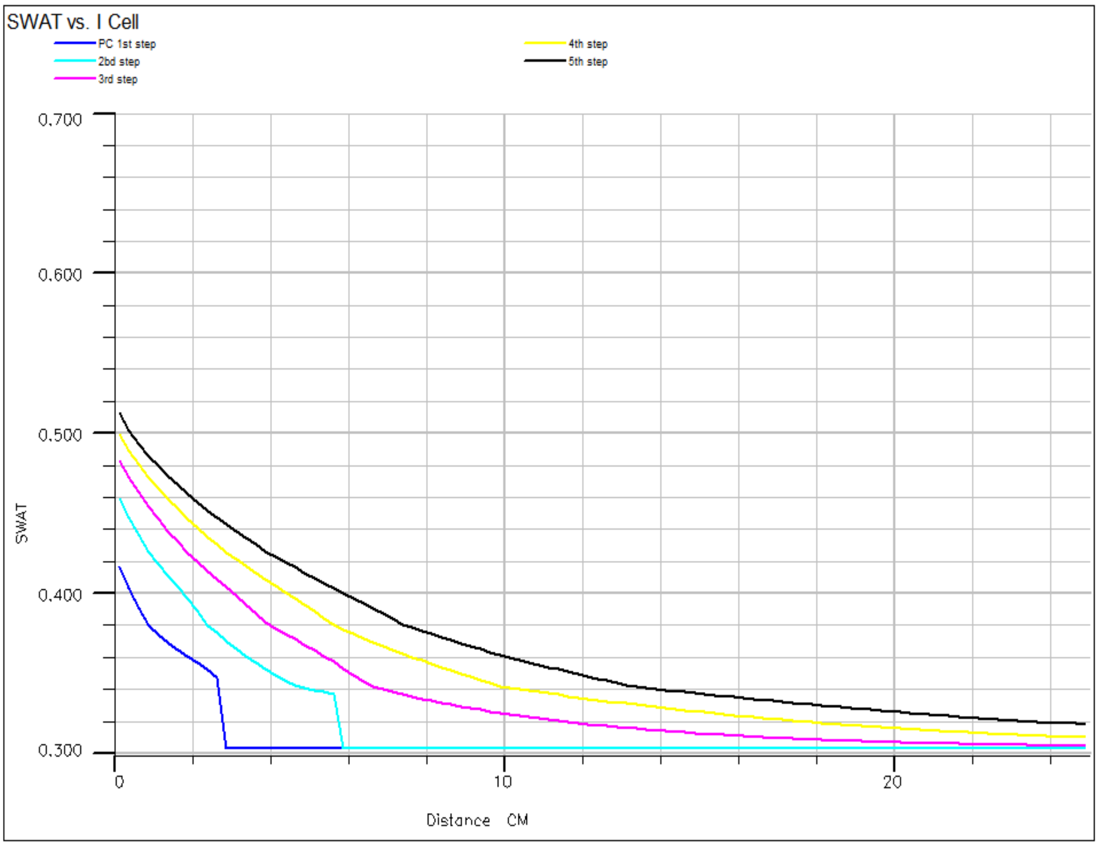

Figure 21: Water saturation versus distance

4.2.2 Case 2

JBN method requires the capillary pressure to be vanished or minimized. In this case the input capillary pressure for the simulation model is neglected (Pc=0). The cumulative water injection versus cumulative oil recovery is compared with the first cases as illustrated in Figure 22. The graph shows that oil recovery is enhanced as the capillary pressure is neglected.

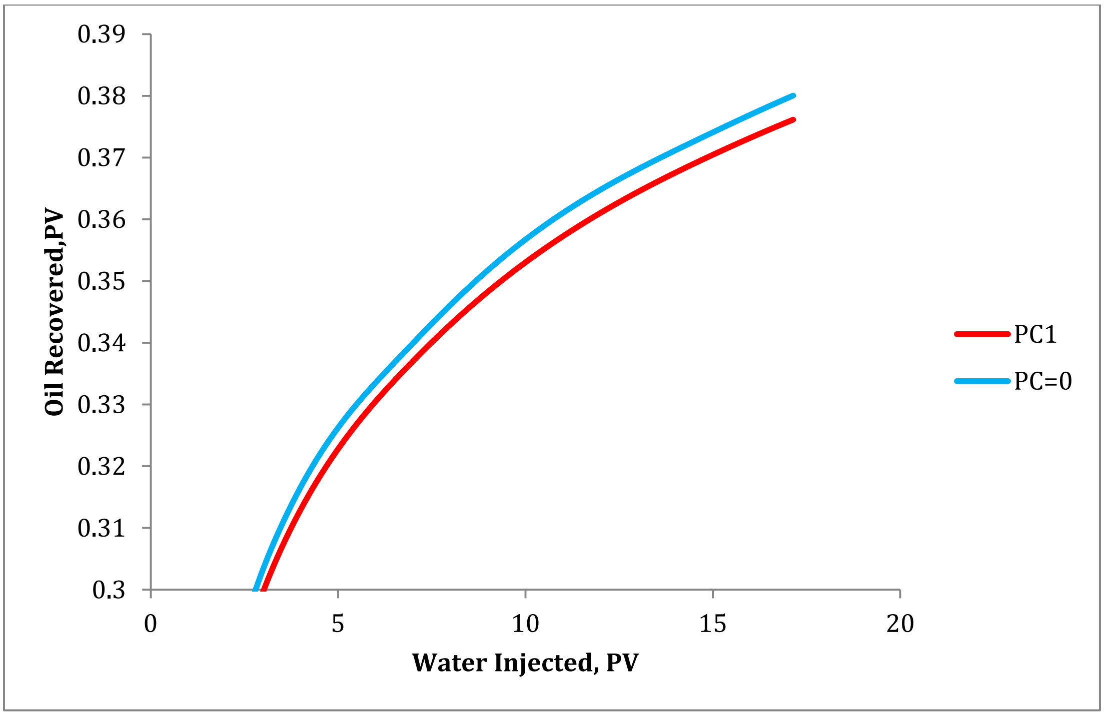

Figure 22: Water injection versus oil recovery

The average water saturation is compared with first case as illustrated in Figure 23. The slope of average water saturation versus cumulative water injected pore volume provides an estimate of oil fractional flow.

From the graph the slope is increasing when capillary pressure is neglected comparing to the first case and oil fractional flow is increasing. Ideally, oil fractional flow will decrease from one to zero monotonically.

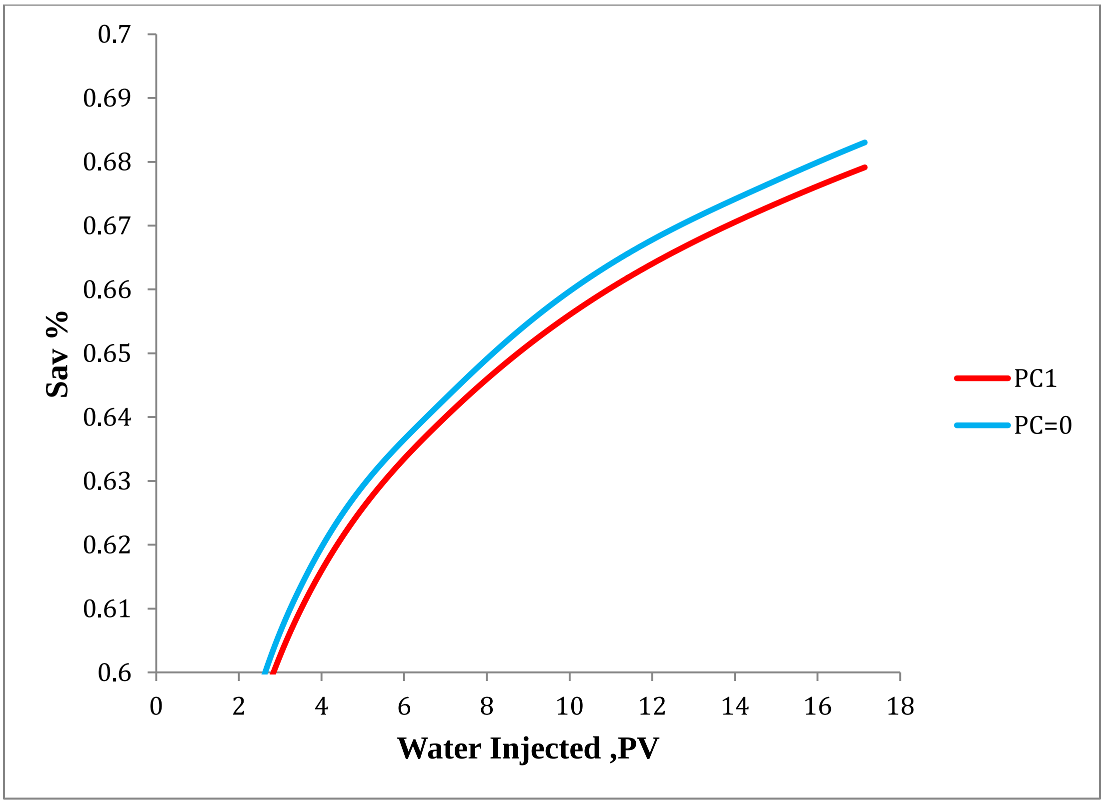

Figure 23: Water injection versus average saturation

Pressure drop across the core versus time for both cases are compared as illustrated in the Figure 24.The graph shows the pressure drop is greater when neglecting capillary pressure and the water breakthrough time is delayed.

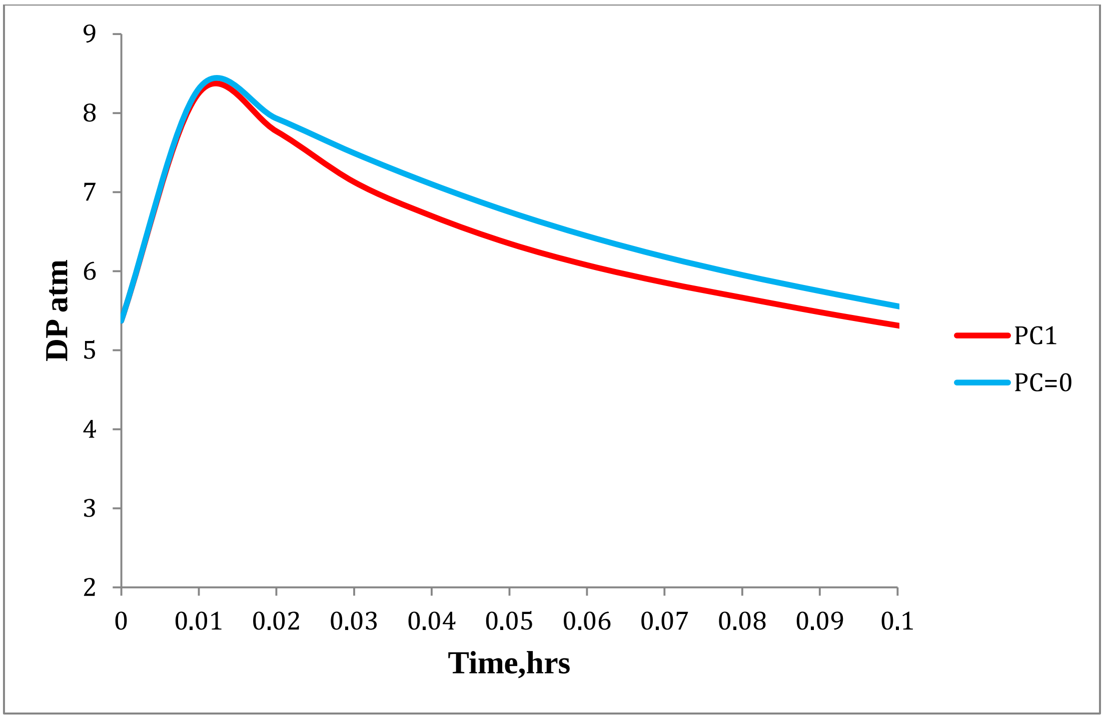

Figure 24: Pressure drop versus time

The input relative permeability curves are compared for both cases as shown in Figure 25.Water relative permeability is smaller when capillary pressure is neglected which leads to improve oil recovery.

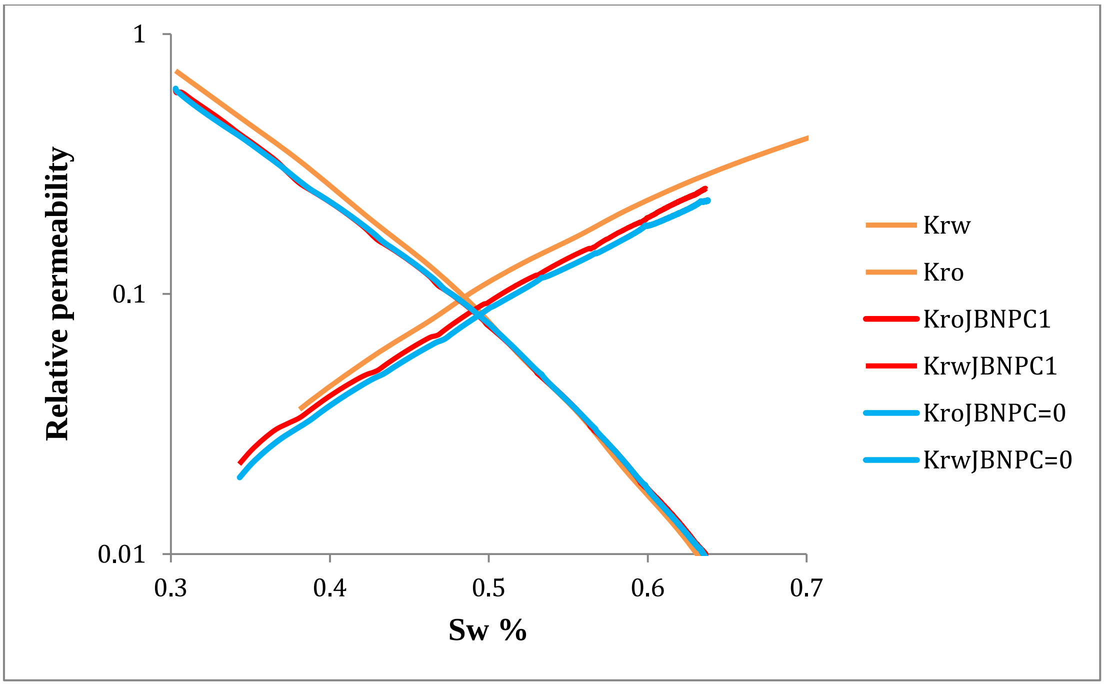

Figure 25: Relative permeability curves from JBN & input relative permeability curves for Case 2

Water saturation versus distance is compared for different time steps, the shock front happened early when neglecting capillary pressure and gave stable displacement and better recovery as shown in Figure 26.

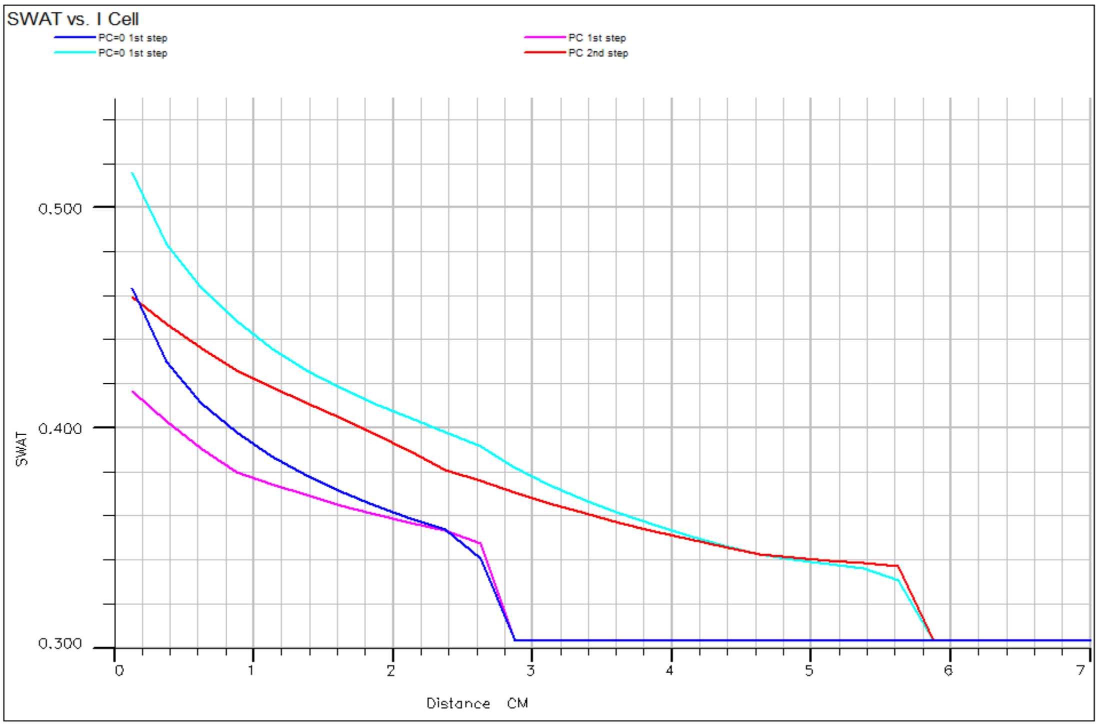

Figure 26: Water saturation versus distance

4.2.3 Case 3

The third scenario is when capillary pressure is twice of the first case (PC2) as shown in the Table 3. This is done to investigate the effect of increasing the capillary pressure on the data collected from the model. Higher capillary pressure gives higher water cut and decrease the fractional flow of oil. This phenomenon can be seen clearly as illustrated in Figure 27 for average water saturation versus cumulative water injection and from plotting cumulative oil recovery against the cumulative water injection as shown in Figure 28 comparing with the other scenarios.

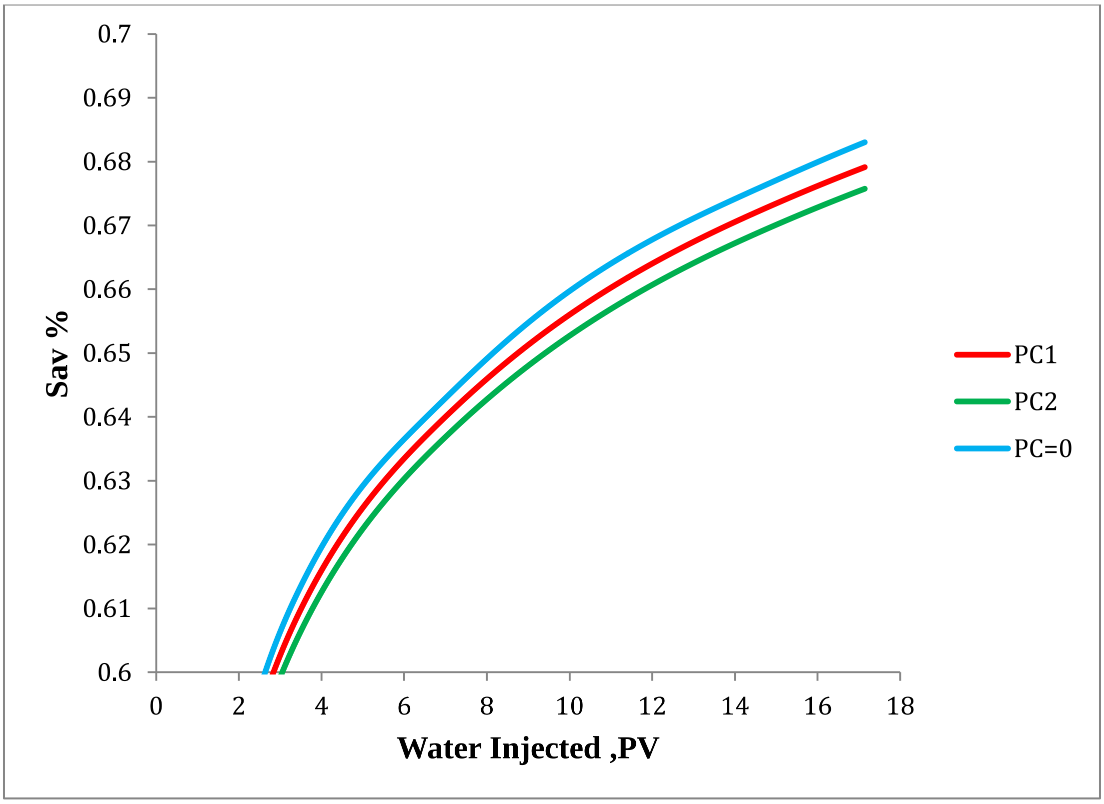

Figure 27: Water injection versus average saturation

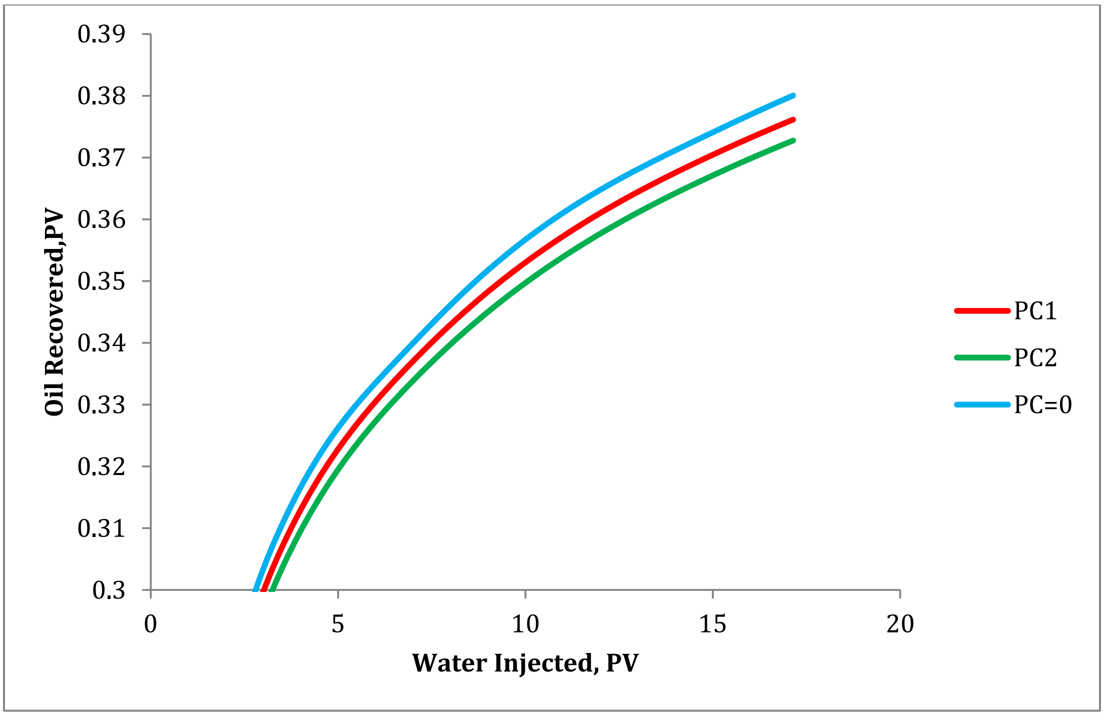

Figure 28: Water injection versus oil recovery

When water is injected to the core, capillary pressure acts on the water phase and hence, early breakthrough. However when capillary pressure is zero in the core flood simulator, a sharp decrease in water saturation occur and water will move in piston-like displacement and improve oil recovery. Pressure drop across the core for the three cases is illustrated in Figure 29.

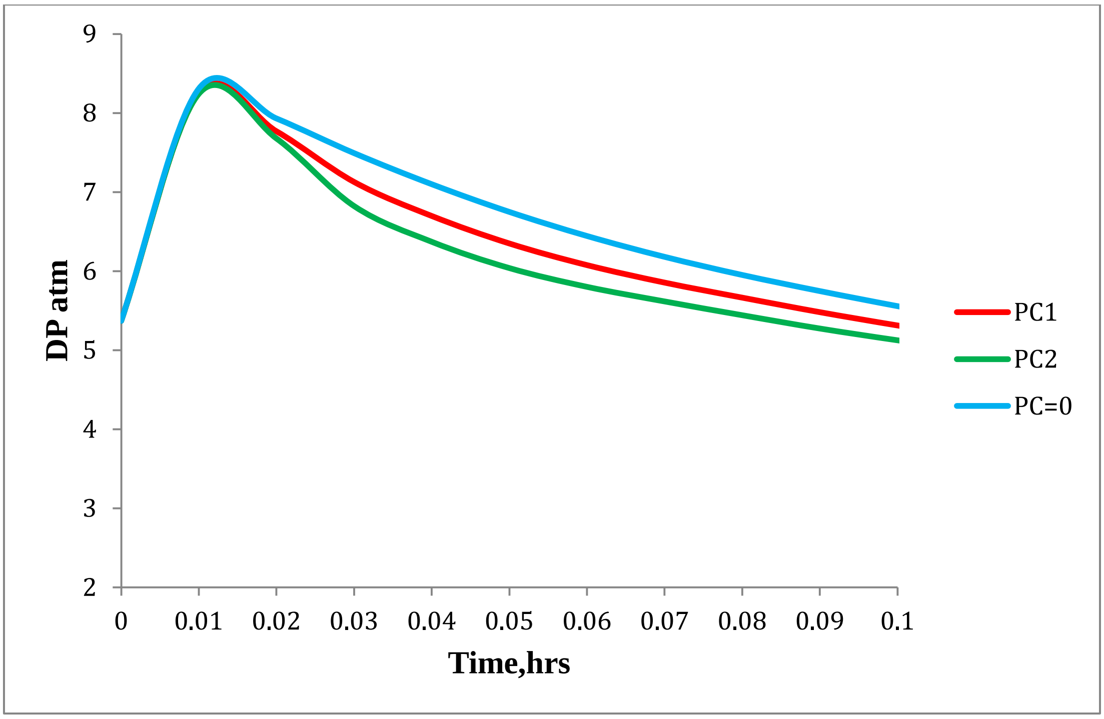

Figure 29: Pressure drop versus time

Relative permeability curves calculated by JBN method for the three scenarios compared with the input relative permeability curves are illustrated in Figure 30. Fractional flow of water is increased due to the presence of capillary pressure gradient as observed in equation (11). Water relative permeability increases with decrease in oil relative permeability. Water saturations profiles are illustrated Figure 31.

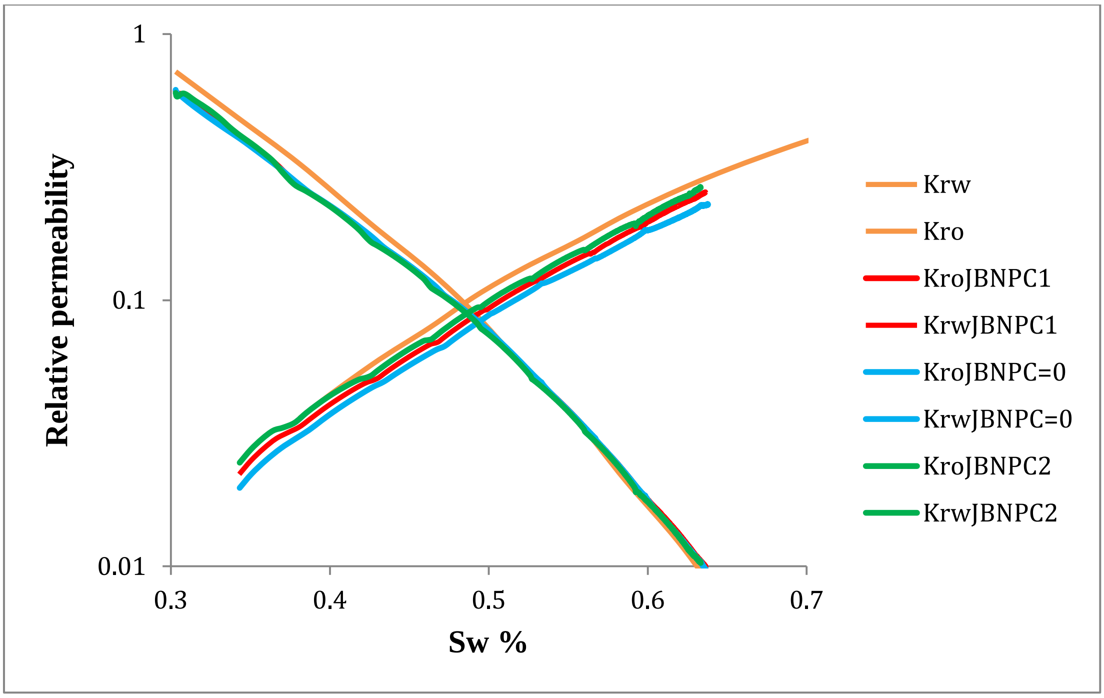

Figure 30: Relative permeabilities from JBN & input relative permeabilities for case3

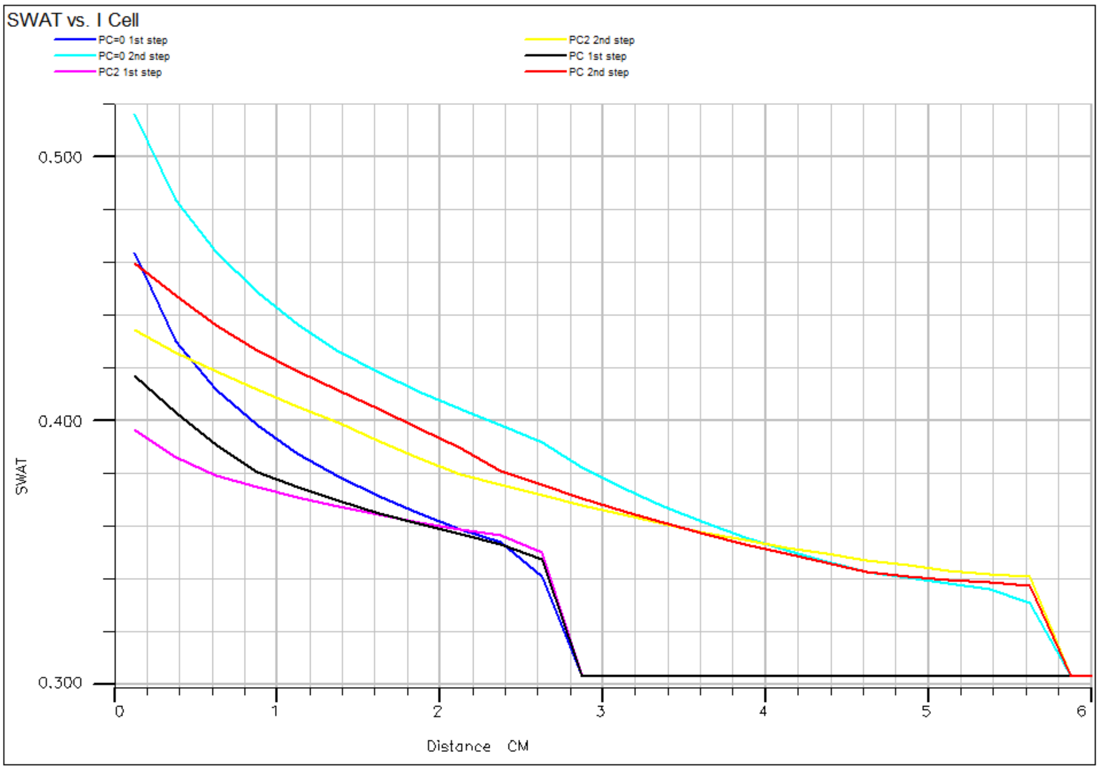

Figure 31: Water saturation versus distance

4.2.4 Case 4

Case 4 is when capillary pressure is half of the case PC3 as shown in the Table 3. It can be observed that water flooding curves differ greatly in shape and position according to the corresponding values of capillary pressure as illustrated in the Figure 32, Figure 33 and Figure 34.

All the flooding curves have the tendency to shift upward with the decreasing values of the capillary pressure and consequently increasing the slope and oil fractional flow increased. Result of this behavior in core flooding tests demonstrates qualitatively interchangeable capillary pressure on estimation relative permeability from core flooding tests.

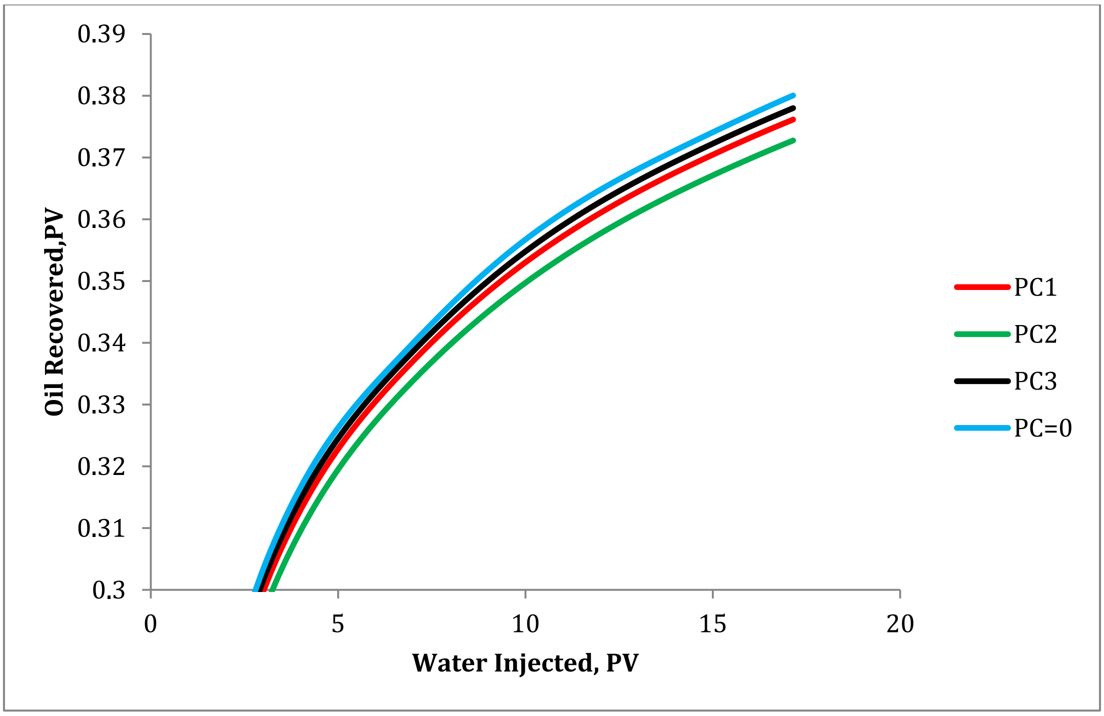

Figure 32: Water injection versus oil recovery

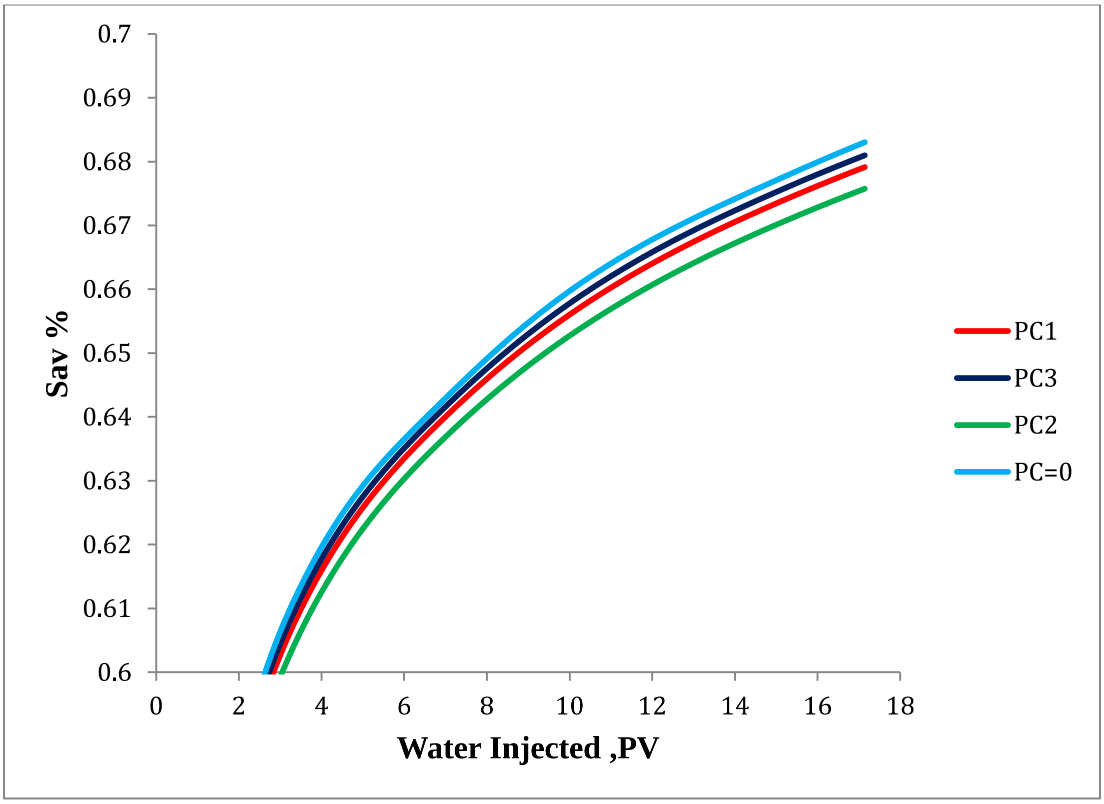

Figure 33: Water injected versus average saturation

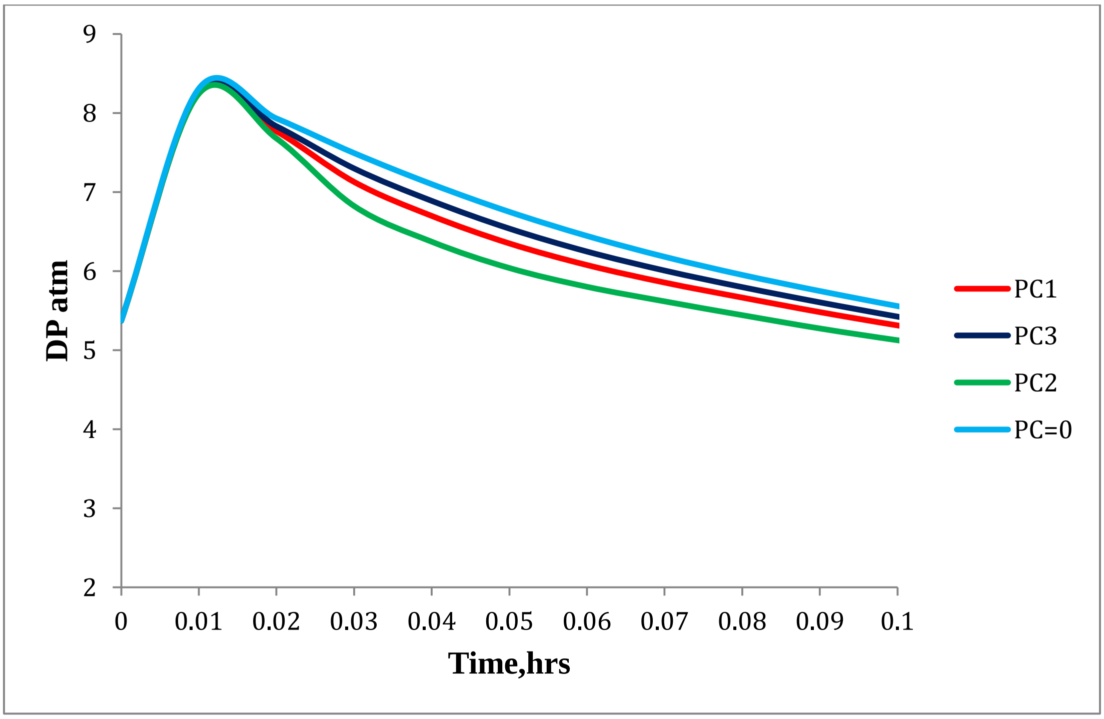

Figure 34: Pressure drop versus time

Relative permeability curves for all cases calculated by JBN method versus input relative permeability curves and water saturation profile are illustrated in

Figure 35 & Figure 36. The shape of relative permeability curves are influenced by capillary pressure, subsequently impacting the average saturation and oil recovery. A decrease in capillary pressure, results in a decrease in water relative permeability and a corresponding increase in oil relative permeability.

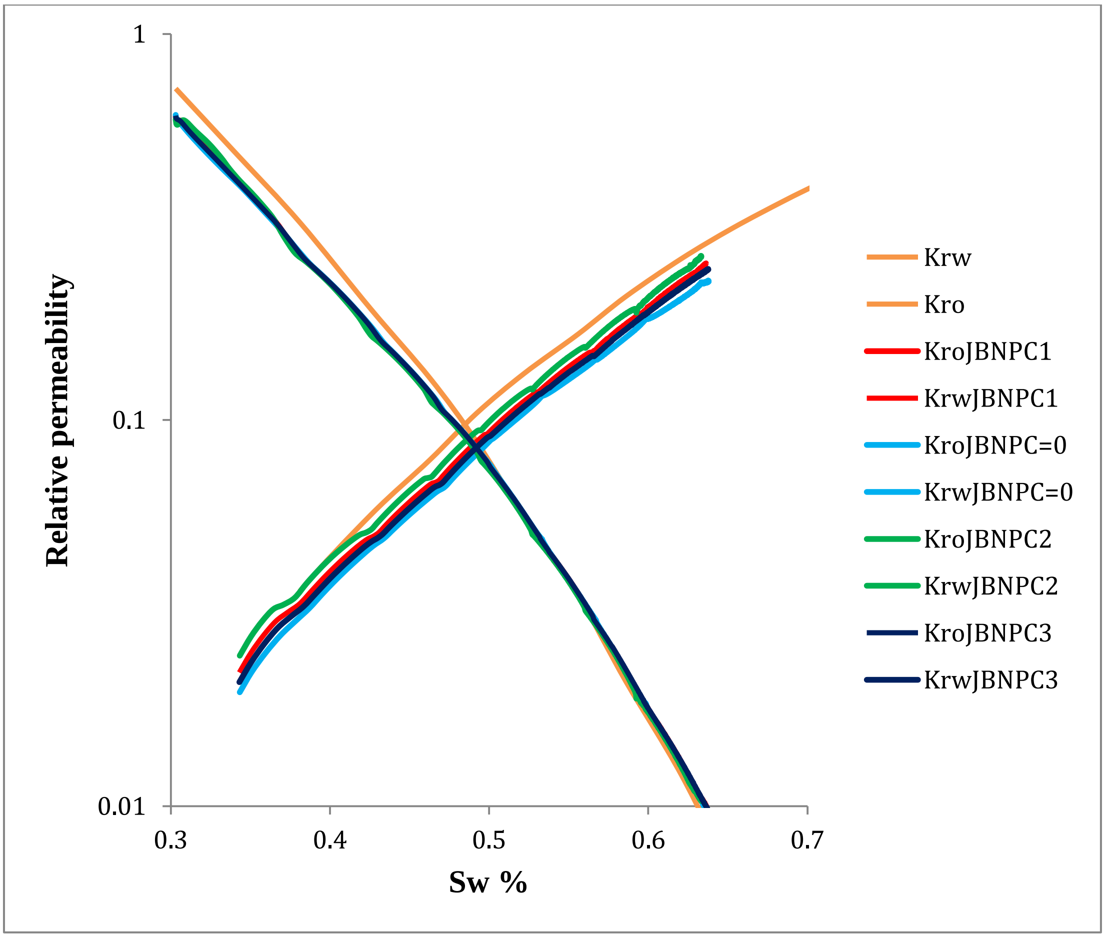

Figure 35: Relative permeabilities from JBN & input relative permeabilities for Case4

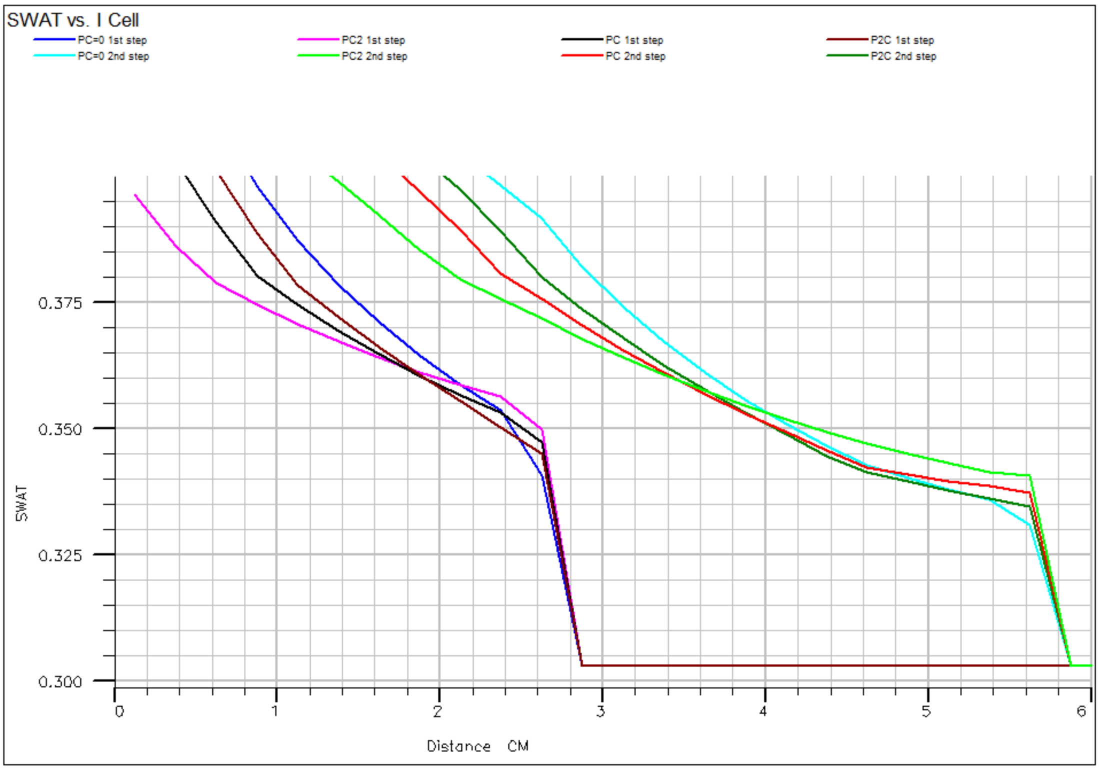

Figure 36: Water saturation versus distance

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

In this study, numerical simulation has been used to investigate the effect of capillary pressure on estimation relative permeability by a conventional method (JBN) from unsteady state displacement tests which are accepted to be the closest to the flow mechanism in the reservoirs. Influences of capillary pressure in computation of relative permeability and saturation on core flooding displacement tests have been addressed. The effect of capillary pressure on fluid flow in one dimensional cause errors in the analysis of displacement data by conventional methods for estimation of relative permeability curves.

All four study cases were investigated at various capillary pressures and their calculated relative permeability curves by JBN method were plotted along with the input relative permeability curves for comparison purposes.
Main conclusions based on the simulation results are:

1. Capillary pressure plays a dominate role in displacement processes and it is responsible for trapping a large portion of oil within the pore structure of the reservoir rocks.
2. Relative permeability calculated by JBN method is not accurate due to capillary pressure effect. Relative permeability of oil is decreases due to this effect.
3. Fractional oil flow is decreasing as capillary pressure increases and fractional flow of water increases. This increase in water fractional flow results in a lower frontal water saturation and a higher frontal velocity.

5.2 RECOMMENDATIONS

For future study, it is recommended to carry out core flooding experiment in the laboratory and calculate the relative permeability from the data collect in the lab. In the lab, distribution grooves at both ends of the core are used to distribute the fluid evenly over the core face. Also the saturation distribution as a function of time can be measured accurately by scanning the core during displacement process.

In order to reflect experimental cores used in lab, it is recommended to represent cores in simulation using radial grids. An evenly distributed groove for distribution of fluid should also be represented when carrying out simulation. This can be done by introducing a layer of high permeability grid blocks, with zero capillary pressure at the inlet and outlet of the core model. The simulator should be properly model at inlet and outlet end plugs with end effect and non-linear nature of the flow near the ends.

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APPENDICES

Appendix A

```
EFFECT OF CAPILLARY PRESSURE ON ESTIMATION
OF RELATIVE PERMEABILITY FROM CORE FLOODING TESTS
==========================================================
RUNSPEC



TITLE
 2-phase



--      Number of cells
--      NX      NY      NZ
--      --      --      --
DIMENS
       100      1       1   /

-- Phases

OIL

WATER

-- Units
LAB

-- Maximum well/connection/group values
--     #wells  #cons/w  #grps  #wells/grp
--     ------  -------  -----  ----------
```

```
WELLDIMS
          2       1       2        1  /




-- Unified output files
UNIFOUT



-- Simulation start date
START
    1 JAN 2013   /




==================================================================
====
GRID
DX
100*0.25 /
EQUALS
'DZ' 5 /
'DY' 5/

'PORO' 0.28  1 100 1 1 1 1 / MATRIX PROPERTIES
'TOPS' 0 /
'PERMX' 124 /
'PERMY' 124 /
'PERMZ' 124/
/



-- Output file with geometry and rock properties (.INIT)
INIT
```

```
==============================================================
PROPS


-- Surface densities
--          Oil      Wat
--          ---      ---
DENSITY
            0.76      1.09  /


-- PVT data for dead oil
--         P         Bo        Vis
--       ----       ----      -----
PVDO
       0.00000   1.00004      8
        100.     1.00002      8
       3600.00   1.00000      8 /




-- PVT data for water
--         P         Bw        Cw          Vis
--       ----       ----      -----       -----
PVTW
       100.0000   1.00000   0.00E-05    0.51000   0.00E-01 /




-- Rock compressibility
--         P          Cr
```

```
--      ----       -----
ROCK
        100.00     1.00E-06   /




-- Water and oil rel perms & capillary pressures
--         Sw       Krw      Kro      Pc
--       -----     -----     ---     ----
SWOF

-- table 1 for 124mD

0.303   0        0.722   2.274281
0.342   0.022   0.485   1.595325
0.381   0.036   0.325   1.326606
0.426   0.057   0.193   1.181932
0.463   0.079   0.128   1.082878
0.492   0.104   0.088   1.006928
0.522   0.132   0.056   0.944602
0.556   0.167   0.035   0.891019
0.586   0.209   0.021   0.843318
0.621   0.262   0.012   0.799637
0.653   0.314   0.0065 0.758656
0.685   0.369   0.0035 0.719339
0.707   0.409   0.0017 0.680784
0.738   0.469   0.00     0.642096

             /

=========================================================================
SOLUTION
```

```
BOX
1 100 1 1 1 1 /
PRESSURE
100*40 /
SWAT
100*0.303 /

--
=================================================================
====
SUMMARY

FOIP
-- Field average pressure
FPR

-- Bottomhole  pressure of all wells
WBHP
  /



-- Field Oil Production Rate
FOPR

-- Field Water Production Rate
FWPR

-- Field Oil Production Total
FOPT

-- Field Water Production Total
FWPT
```

-- Water cut in PROD
FWCT

--Field Water Injection Total
FWIT

--Field Oil Recovery Efficiency
FOE

FWIR

--Water saturation average value

-- CPU usage
TCPU

-- Create Excel readable Run Summary file (.RSM)
EXCEL

===
====
SCHEDULE

```
-- Output to Restart file for t>0 (.UNRST)
--    Restart file with basic output
--     every TSTEP
--    ------------
RPTRST
        'BASIC=2'   /


TUNING
1 1 /
/
/



-- Location of wellhead and pressure gauge
--     Well  Well   Location   BHP    Pref.
--     name  group   I    J   datum   phase
--    -----  ----    -    -   -----   -----
WELSPECS
      PROD    G1     100  1    2.5     OIL /

       INJ    G2     1    1   2.5     WAT /
  /

-- Completion interval
--     Well   Location  Interval  Status          Well
--     name    I    J    K1  K2   O or S           ID
--     ----    -    -    --  --   ------          ------
COMPDAT
       PROD    100    1     1   1   OPEN      2*   0.0625    /

        INJ    1    1    1   1   OPEN      2*    0.0625   /
```

```
 /


-- Production control
--  Well  Status  Control   Oil   Wat   Gas   Liq  Resv   BHP
--  name          mode     rate  rate  rate   rate  rate  limit
--  ----  ------  ------    ----  ----  ----   ----  ----  -----
WCONPROD
   PROD  OPEN    LRAT                3*    300      1*   10/
 /


-- Injection control
--  Well  Fluid  Status  Control   Surf   Resv   Voidage   BHP
--  NAME  TYPE           mode     rate   rate  frac flag  limit
--  ----  -----  ------  -------   ----   ----  ---- ----  -----
WCONINJ
   INJ   WATER  OPEN   RATE    300       3*       50 /
 /


-- Number and size (HR) of timesteps
TSTEP
1000*0.01/

END
```