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Determination of Relative Permeability from Well Production Data with Consideration of Formation Heterogeneity and Fluid viscosity by Mean of Reservoir Simulator

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Abstract

Accurate estimation of relative permeability is essential for reliable reservoir history matching and decision-making, and effective reservoir management. This information is also critical for the design, implementation, and monitoring of enhanced oil recovery processes.

This study presents an effective method for acquiring the relative permeability data directly from the well production data in oil reservoirs where water acts as the fluid phase displacing oil. The methodology presented in this study provides convenient interpretation formulae which are applicable to unsteady-state, two-phase, immiscible, and incompressible fluids. The total mobility and the mobility ratio of the immiscible fluids are related to the characteristic parameters of the displacement process and the cumulative injected fluid pore volume following [1] et al. These parameters are then incorporated into a general correlation function which allows for analytically estimation of the relative permeability functions. The present approach produces unique estimation of the relative permeability functions and is more practical than the previous approaches which rely on computationally complicated history matching procedures, often suffer from the non uniqueness issue of the obtained relative permeability data.

This study demonstrated that the fluid viscosity have significant effects on determined relative permeability curves using Toth et. [1]. Method for radial flow The Toth *et al.* method works satisfactorily even for heterogeneous reservoirs. The effect of heterogeneities on the relative permeability curves is negligible using Toth method. However, the effect becomes significant when there are channels.

Introduction

Relative permeability is a critical parameter for evaluation of reservoir performances. Also, relative permeability is a direct measure of the ability of the porous medium to conduct one fluid when two or more fluids are present. All of these require accurate and representative estimates of the relative permeability functions; therefore, there are many methods to determine relative permeabilities. One of these methods is called [1]. (2005, 2006) method the Toth et al. is depending upon production data to estimate relative permeability.

The objectives of this approach are study the effect of fulid viscosity and formation heterogeneity on the relative permeability curves using Toth method. [1] is evaluated using the simulated well production data generated by means of a commercial reservoir simulator EclipseTM. EclipseTM software developed by Schlumberger is a reservoir simulator well-known by the oil and gas industry by over the last 25 years, and it is considered to be the leading finite difference based reservoir simulator. EclipseTM is a three phase and three dimensional simulators. It can be used to simulate 1, 2 or 3 phase systems to predict and manage fluid flow more efficiently. The reservoir simulator has been found to be the most practical, less expensive, faster, more accurate and adequate when compared with other methods.

The simulation software is used to generate simulated production data with consideration of formation heterogeneity that substitutes for actual field data. The reason for this is that the actual data is unsuitable for testing of the method because of noise in the data. However, once the method has been tested and verified by using simulated production data, this method should be available for testing with real production data. For this purpose, we assume that the simulation software represents the real reservoir closely, even though there may be some inaccuracies in the software. The other main reason for using simulation software is because most of the previous methods available for determining of relative permeability curves relied upon the other methods to check and compare their results. Consequently, we cannot be sure about their accuracy. In addition, there is no real field data available for relative permeability to compare with. Therefore, the simulation software (Eclipse^{TM}) used for evaluating Toth method especially it is unique method for radial flow.

Reservoir Simulator Approach

The Toth et al. [2005, 2006] method considered a disk shape porous sample where the displacing fluid (water) is injected from a small hole in the center of the core to displace the displaced fluid (oil) from the surrounding area. Toth et al. assumed one-dimensional radial, isothermal and unsteady-state flow of two immiscible and incompressible fluids in homogeneous and isotropic porous media with uniform thickness. Its porosity is Ø and permeability is k. The thickness of the rock sample is h; the radius of the axial well is r_w, and the external radius is r_e. The rock sample is saturated with a fluid. Then, this fluid is displaced by another fluid. The volumetric rate of the injected fluid is q_i. The effect of the capillary force is neglected (P_c=0) during the displacement processes. The pressure at the inlet face is P_e; the pressure inside the well (fluid outlet face) is P_w. Thus, the pressure difference between the outer and inner faces of the disk is $\Delta P = P_e - P_w$. Also, this method assumes that all reservoir parameters will remain constant during the displacement. In addition, The Toth *et al.* method is applied at and after the breakthrough time.

The radial flow system was simulated using the Eclipse^{TM} software with a real reservoir size. The Production well is in the center and the injection wells in the surrounding areas as shown in figure (1).

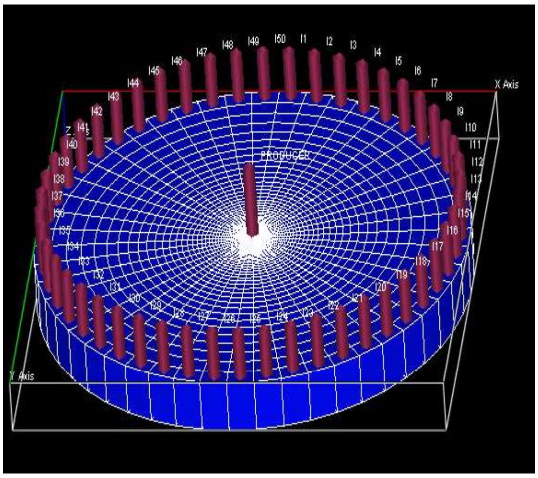

Fig. (1), three dimensional shapes by Eclipse

Injection wells were used instead of aquifer because it is easy to control the injection wells by constant rate or constant pressure.

In a radial flow system, there are three main parameters that need to be specified; (1) re is the block's outer radius which will divide into several grid blocks in the simulation software, (2) ϴ is the segment angle of the grid block in radians, (3) the number of layers (we assumed there is one layer in all our examples for simplicity). Therefore, a simple case was started and then developed the idea.

Toth et al. method can be applied only for unsteady state condition. The determination of relative permeability under an unsteady state condition can be applied faster than the steady state condition, but mathematically the application is more complex. In addition, flow conditions in steady-state methods experiments do not describe reservoir flow mechanisms that include displacement of one fluid by another. Therefore, unsteady-state methods have been used more considerably (Mehdi, 1988).

The system under unsteady-state can be operated by keeping the ∆P constant and letting the flow rate change or keeping the injection rate constant and letting the pressure vary. We used the first option ∆P constant for achieving more accuracy with the used the software. Water was used as a injection fluid to displace oil from one production well in the center.

The following approach is used for evaluating the Toth et al. (2006) method. The data are generated by using the reservoir simulation software in the following manner: (1) Assume the relative permeability curves as input data, (2) Simulate the flow in the radial system by using EclipseTM to generate the production data as a result, (3) Recalculate the relative permeability curves by using Toth et al. (2006) method using production data obtained from the software, and (4) Compare the calculated relative permeability values with the assumed values to check the accuracy.

Effective of the Viscosity on Toth *et al.* Method

The purpose for studying the viscosity effect is to determine the applicability of the Toth *et al.* method to gas/oil or water/gas systems because the viscosity ratio is very high when there is gas in the fluid system. The viscosity ratio should have a significant effect on determining the relative permeability curves. However, many literatures (JBN method 1959 and this was confirmed by T.M Tao (1984)) claim insignificant viscosity ration effect on relative permeability.

To study this issue, one example with different viscosity ratio as shown in table (1). After that we applied the Toth *et al.* method to recalculate relative permeability curves

Table (1).Viscosity ratio

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Parameter	Example 3	Example 2	Example 1
r_e, m	75	75	75
h , m	14.76	14.76	14.76
V_p ,m^3	71103	71103	71103
$Ø$	0.26	0.26	0.26
k , m^2	9.86 e -14	9.86 e -14	9.86 e -14
ΔP, kpa	7500	7500	7500
B_o	1.23	1.23	1.23
B_w	1	1	1
μ_o , pa.s	0.004	0.002	0.001
μ_w/μ_o	8	4	2
S_{wi}	0.3	0.3	0.3

According to Marle (Marle 1981) relative permeability is a function of the density and viscosity ratios. Thus, the relative permeability curves must change when the viscosity ratio changes. In fact, Welge (Amyx et al. 1960 and Marle 1981) demonstrated strong dependency of relative permeability on the viscosity ratio as shown figure (2).

Similar result is observed with the Toth et al. method because their graphs change with the change of the viscosity ratio as shown in figures (3, 4).

The main reason for changing Wedge's and Toth's graph with the viscosity ratio is because the unfavorable mobility ratio (M). If M ≤ 1 oil is capable of traveling with a velocity equal to or greater than the water and if M > 1 the water is capable of traveling faster than the oil and as the water pushes the oil through the reservoir, the latter will be by passed (Dake, 1978). Qin *et al.* (Qin et al. 2009) shown that the water cut increases when the oil become viscous as shown in figure (5). Therefore, Qin *et al.* tried to control the water cut by decreasing the mobility ratio to achieve effective displacement.

From the previous examples can be concluded that the Toth *et al*. method is very accurate for the viscosity ratio, even if the value of the viscosity ratio is not significantly high. However, there is a significant difference between the Toth *et al.* method and other methods saying that there is no significant effect (JBN method 1959, Richardson, 1957) for the viscosity ratio on relative permeability curves. Also, we can notice that varying slopes in the displacement equation for Toth disappear when the viscosity ratio is close to one as shown in figure(3). However, there is more than one slope when the viscosity ratio is greater or less than one.

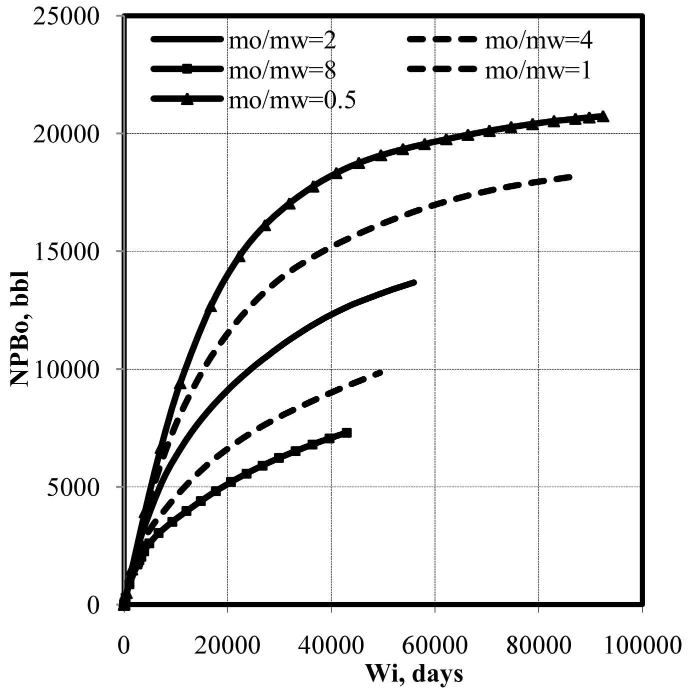

Fig. (2) Welge's plot for different viscosity ratio (Eclipse result data)

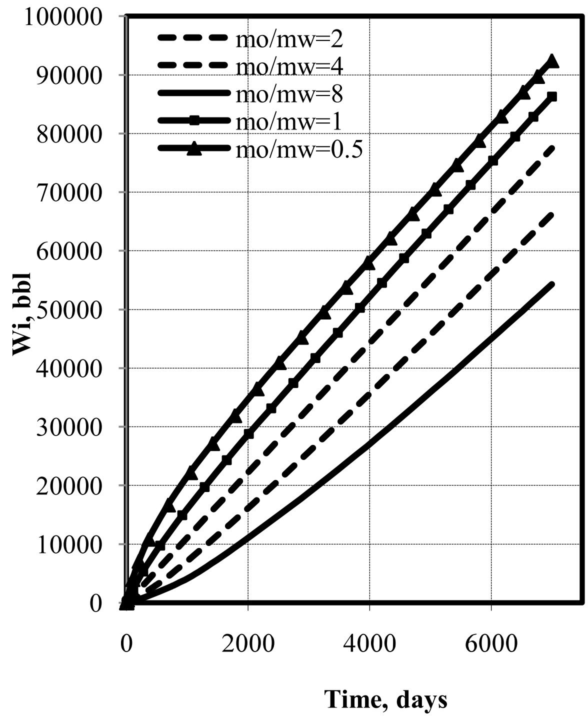

Fig. (4) Cumulative produced water volume (Toth et al.) for different examples with different viscosity ratios

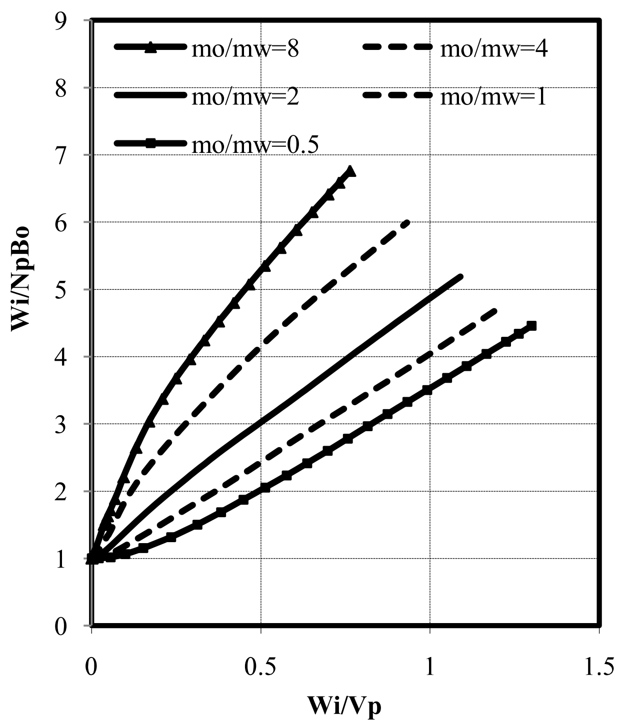

Fig. (3) Displacement equationToth et al. for different viscosity ratios

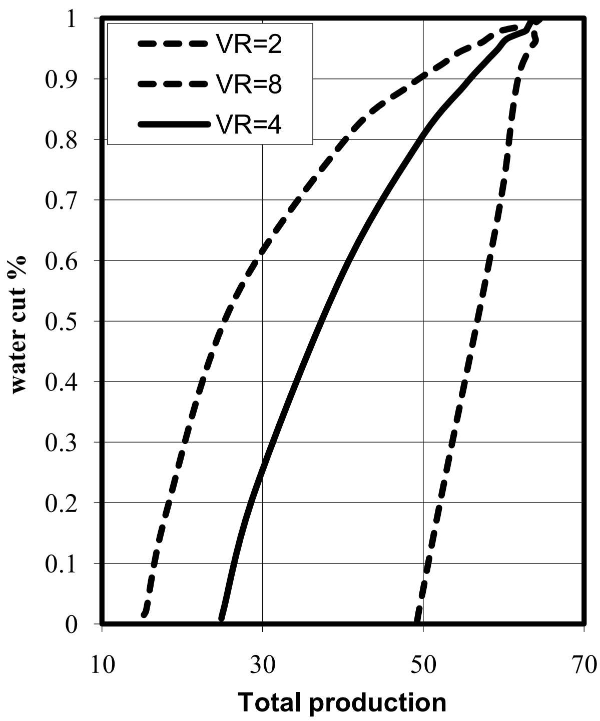

Fig. (5) Total production vs. water cut from Eclipse result data for different viscosity ratios

Effects of Heterogeneity on Relative Permeability Curves

Most reservoirs involve varying degrees of heterogeneity. However, all the methods for estimating relative permeability assumed homogenous reservoirs. There are many studies about the heterogeneity effect but the most important study is by Huppler in (John D. Huppler, 1970). He used a numerical technique to investigate the effects of heterogeneity on core samples and found that the heterogeneities have an insignificant effect on the relative permeability curves and as the heterogeneities become channel their influence on relative permeability curves becomes pronounced. Also, the Huppler study was for linear displacement. Therefore, this study were interested in investigating the heterogeneity effect using the Toth et al. radial method including channels by using a reservoir simulator with real reservoir size. This study used the Toth *et al.* (Toth 2006) method because it is a unique direct method for radial flow. The same previous example was used to study the heterogeneity. Concurrently, different random values for the permeabilities were generated. This study started with mean permeability equal to 100 md and standard deviation equal to 30 as shown in figure (6). Then, another example was lested with the mean permeability equal to 500 md and standard deviation equal to 100. The formation permeability assumed has a normal distribution. Also, there is a short or a long channel in the reservoir was assumed as shown in figures (7, 8).

After the production data was generated from the software, the relative permeability curves were determined including the heterogeneity effect with or without channels as shown in figures.(9,10). Also, that the heterogeneity reduced the relative permeability curves can be seen because the permeabilities distributed randomly, which indicates non-uniform displacement. In addition, there are increases in the relative permeabilities when there is a channel with the heterogeneity because channel means high permeability and an increase the production data. At the same time, there is an effect on the relative permeability curves by the dimension and permeability of the channel as shown in figure (10). From this figure can be seen that the dimension and permeability of the channel are directly proportional to the relative permeability curves.

From this study can be observed that the heterogeneities have an insignificant effect on the relative permeability curves. However, the effect becomes significant when there are channels.

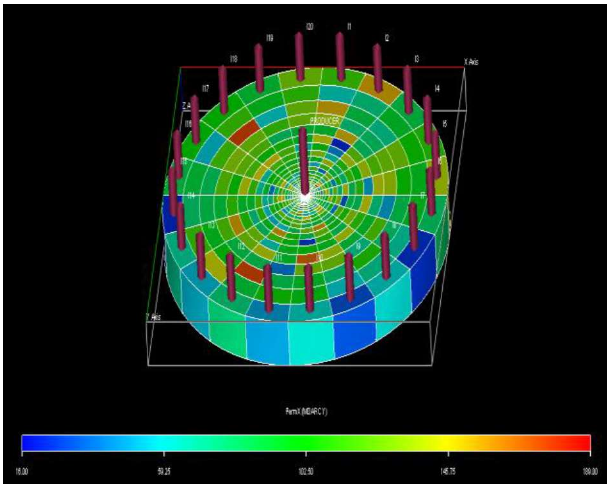

Fig. (6) The distribution for the permeability by Eclipse (Mean=100 md, S.D=30 md)

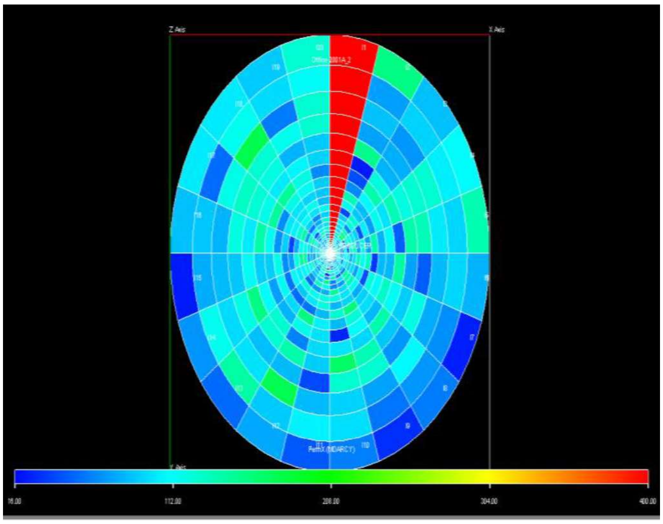

Fig. (7), 2 D. distribution for the permeability by Eclipse
(Mean=100 md, S.D=30 md) with short channel

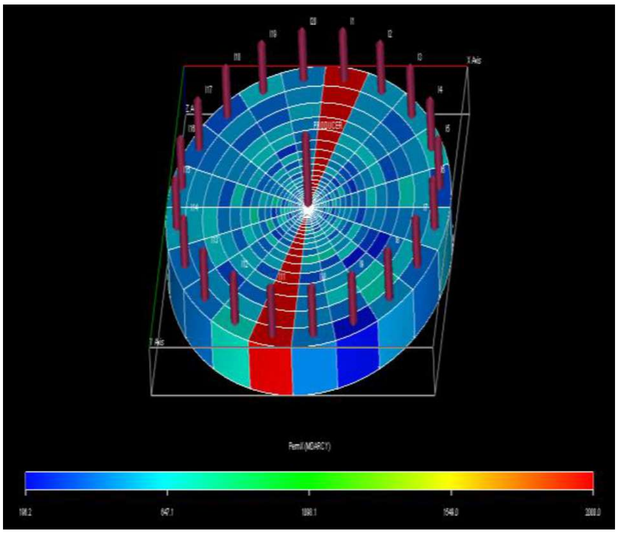

Fig. (8) The distribution for the permeability by Eclipse
(Mean=500 md, S.D=100 md) with long channel

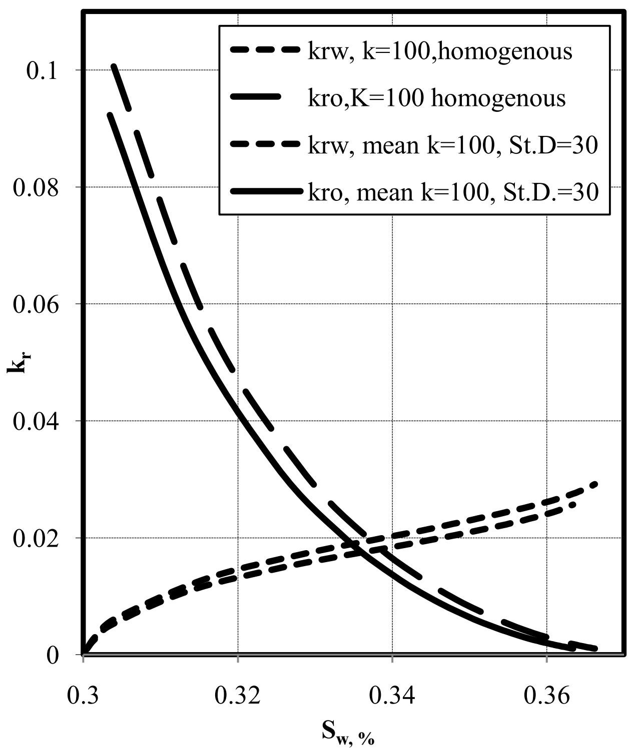

Fig. (9), Relative permeability curves for homogenous (k=100 md) and heterogeneous (mean=100,S.D.=30)

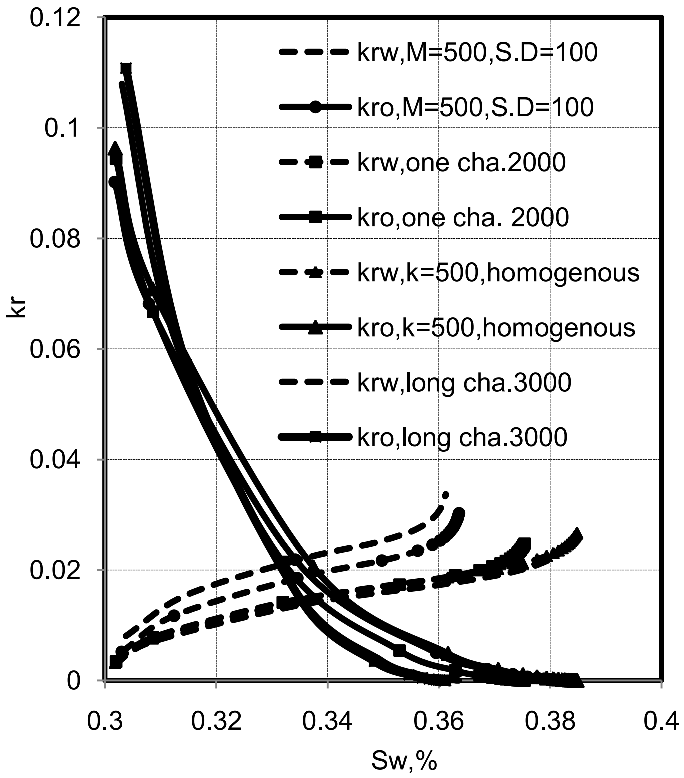

Fig. (10), Relative permeability curves for homogenous (k=500 md), heterogeneous (mean=500, S.D.=100) and heterogeneous with short and long channel (k=2000 md and 3000 md)

Conclusions

The following conclusions are made based on the studies carried out in this work:

1. The Toth et al. method gives accurate results when the fluid viscosity varies.
2. Toth et al. method works satisfactorily even for heterogeneous reservoirs.
3. The heterogeneities have an insignificant effect on the relative permeability curves using Toth method. However, the effect becomes significant when there are channels

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Appendix A:

Brief and important formulations that we use for applying Toth et al. method, these formulations were introduced from Toth et al. (2005, 2006, and 2007).

a) To determine cumulative oil and water productions and cumulative volume of water influx respectively

$$N_p = \int_o^t q_o dt \quad \text{------} A.1$$

$$W_p = \int_o^t q_w dt \quad \text{------} A.2$$

$$W_i = \int_o^t q_{wi} dt \quad \text{------} A.3$$

The total production is equal to the water influx, thus:

$$q_{wi} = q_o + q_w \quad \text{------} A.4$$

b) To determine the first two constants by use the theoretical displacement equation:

$$\frac{W_i}{N_p} = a + b\frac{W_i}{V_p} \quad \text{------} A.5$$

That will be a straight line with slope b >1 and intercept a <1, where the constant a is the oil fraction at the breakthrough time. Thus, the pore volume for redial system can be estimated by:

$$V_p = \pi(r_e^2 - r_w^2)h\varphi h \quad \text{------} A.6$$

c) To determine the water and oil fraction at the wellbore by:

$$f_w = \frac{q_w}{q_w + q_o} = 1 - \frac{a}{\left[a + b\frac{W_i}{V_p}\right]^2} \text{, and , } f_o = 1 - f_w \quad \text{--------------------A.7}$$

d) In the cases that the reservoir produces under constant pressure, the total mobility can be determined by:

$$Y(S_w) = \frac{k_{rw}}{\mu_w} + \frac{k_{ro}}{\mu_o} = \frac{a_1 b_1^2 t^{(b_1-1)}}{4\pi hk\Delta p(b_1-1)} \quad \text{------------------------------- A.8}$$

Where a_1 and b_1 are some empirical constant that can be determined from empirical power-low function as:

$$W_i = a_1 t^{b_1} \quad \text{--A.9}$$

Note: The value of b_1 must be greater than on (b_1>1).

e) In the case of the reservoir producing under a constant rate. The total mobility can be determined by new expression instead of Eq.(A.8):

$$Y(S_w) = -\frac{q_{wi}}{4\pi hka_2 b_2 t^{b_2}}$$

Where a_2 and b_2 are some empirical constants that can be determined from empirical power low function as:

$$\Delta p = p_e - p_w = a_2 t^{b_2}$$

Note: The value of b_2 must be negative ($b_2 < 0$).

f) To determine the relative permeability ratio by:

$$\frac{k_{rw}}{k_{ro}} = \frac{f_w \mu_w}{(1-f_w)\mu_o} \quad \text{---------------------------------------A.10}$$ g)

To determine individual relative permeability by:

$$k_{rw} = f_w \mu_w Y(S_w) \text{ -- A.11}$$

h)

$$k_{ro} = (1 - f_w) \mu_o Y(S_w) \text{ ------------------------------------- A.12}$$

To determine water saturation by:

$$S_w = S_{wi} + b\left[\frac{\frac{W_i}{V_p}}{a + b\frac{W_i}{V_p}}\right]^2 \text{ ------------------------------------- A.13}$$