

# SCA2003-45: EVALUATION OF EFFECT OF CAPILLARY FORCES ON MEASUREMENTS IN LINEAR WATERFLOODS BY SIMULATION

Murali, R., Institute of Reservoir Studies, ONGCL, Ahmedabad, India

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## ABSTRACT

This paper attempts to evaluate the effects of capillary number, viscosity-ratio, wettability and heterogeneity on the measured relative permeability, by assuming a set of relative permeability curves for a 1D black-oil simulation model simulating unsteady-state experiments. The relative permeability in each case, calculated by Jones and Roszelles (JR) method are compared with the input relative permeabilities. The trends of measured relative permeabilities, water relative permeability end-point and breakthrough recoveries for different wettability, capillary numbers, viscosity ratios and heterogeneity were obtained and studied.

## INTRODUCTION

Relative permeability measurements in corefloods are prone to some errors due to varied interaction of different forces responsible for flow, namely, Viscous, Capillary and Gravity Forces. While gravity forces almost play no role at the core-scale (mesoscopic scale in centimeters), capillary forces are active at the core scale, which have to be evaluated and quantified while interpreting the measurements done in laboratories. The Jones-Roszelles method [1] for calculating relative permeability from unsteady state experiments are based on the following assumptions, which are often violated :

- ◆ The capillary forces are negligible
- ◆ The core is homogeneous

The sensitivity of these assumptions on the relative permeability measurements were studied by simulating experiments.

## LITERATURE SURVEY

While there were several works indicating increase in oil recoveries with increasing rates of water injection, there were still others who reported low recoveries with increase in injection rates. Rapoport, L.A. and Leas, W.J.[2] presented a dimensionless form equation for linear waterflooding process using dimensionless variables defined as

$$X = \frac{x}{L} \quad \text{and} \quad T = \frac{t \cdot q_{winj}}{L \cdot A} \quad (1)$$

$$\frac{\partial S_w}{\partial T} + \frac{\partial f_w}{\partial S_w} \cdot \frac{\partial S_w}{\partial X} - \frac{k}{(VR)} \cdot \frac{1}{LVm_w} \cdot \frac{\partial}{\partial X} \left[ k_{ro} \cdot f_w \cdot \frac{dP_c}{dS_w} \cdot \frac{\partial S_w}{\partial X} \right] = 0 \quad (2)$$

The second term in equation (2) being the viscous term, the third term is the capillary term, The third term may become more prominent, in case if the coefficient of the derivative in the terms becomes large enough. For a medium and a pair of fluids (say oil and water), permeability and mobility ratio are fixed. Thus the factor  $N_c (=L\mu_w q_{winj}/A)$  controls the influence of the capillary term in the solution of the linear waterflood. They also presented a generalised form of scaling coefficient as

$$\text{Generalised Scaling Coefficient} = \frac{Lm_w q_{winj}}{As \cdot \cos q} \quad (3)$$

It was found that the  $(L\mu_w q_{winj})/A$  can be used as a scaling factor and all floods performed at a scaling coefficient higher than a critical value would yield identical recovery curves. In field conditions, L is very large and thus the second term in equation (2) could be safely neglected. But they are active in playing a role in laboratory scale waterfloods. Thus the capillary forces should be either bypassed while doing the experiments or taken care off, before applying the laboratory measured relative permeabilities to field scale simulations.

Sigmund, F.R.[3] observed that the recovery curves were responding to change in capillary number, the ratio of viscous to capillary forces,  $R_D^*$  given by

$$R_D^* = \frac{Lm_w q_{winj}}{Ak \left( \frac{s}{\sqrt{k/f}} \right)} \quad \dots(4)$$

The recovery curves of imbibition experiments were not sensitive to  $R_D^*$  greater than 1, and those of drainage were not sensitive to  $R_D^*$  greater than 10. However, another way of expressing the ratio of viscous to capillary forces using the Leverett's expression for capillary pressures

$$\frac{dP_c}{dS_w} \propto \sqrt{\frac{k}{f}} \quad (5)$$

which will give Capillary number Ca, to be redefined as

$$Ca = \frac{L \cdot q_{winj} \cdot m_w}{s \cdot \cos q \cdot \sqrt{kf}} \quad (6)$$

The “scaling coefficient” suggested by Rapoport and Leas [2], is being used to scale core-scale flow to signify the effect of capillary forces. Though this is being used widely, it suffers from the disadvantages such as

- ◆ having units
- ◆ not reflecting the comparison of capillary forces with respect to other forces, which will actually determine the extent of perturbation of capillary forces on the flow model.

Batycky. J.P. et al. [4], have presented a discussion on capillary number and arrived at an expression that removes the disadvantage suffered by the one defined by Rapoport and Leas. He defined a dimensionless capillary number,  $Ca$  as

$$Ca = \frac{L \cdot q_{winj} \cdot m_w}{S \cdot \cos \theta \cdot \sqrt{k f}} \quad (7)$$

## SCALING COEFFICIENT

The Rapoport and Leas [2] Scaling Coefficient,  $N_c = L m_w \frac{q_{winj}}{A}$  as a parameter to design flooding experiments is commonly used in the industry. The experiments are done at rates confirming the condition

$$L m_w \frac{q_{winj}}{A} \geq 1 - 5 \quad (8)$$

This condition might imply very high flooding rates, often higher than the reservoir rates by an order or two, thus are non-representative of the reservoir conditions. Sometimes these high rates are not achievable in laboratory. At higher velocities, the fines in the core may also travel, severely disturbing the experiments. The study of capillary forces could be a guideline to make meaningful interpretation to laboratory measured quantities and design laboratory experiments to obtain the desired parameters.

## METHODOLOGY

### Simulation Model

A homogeneous core of dimensions 7.45 cm x 3.45 cm x 3.45 cm was simulated using 102 X 1 X 1 black-oil model in ECLIPSE [8,9] simulator. Typical values of  $k_{abs}$ ,  $\phi$ ,  $S_{wi}$ ,  $S_{or}$ ,  $J(S_w)$  were taken to be the parameters of the core (Table 1). The mid-100 block represent the core under study. Since we were going to study the effect of capillary forces on relative permeabilities, the relative permeability were taken to be a function of normalised water saturation  $S_w^*$ , as given below

$$k_{ro} = (1 - S_w^*)^3 \quad (9)$$

$$k_{rw} = k_{rw}^{end} (S_w^*)^3 \quad (10)$$

The 1<sup>st</sup> and 102<sup>nd</sup> blocks had been assigned (Figure 1) a thickness of one-tenth of the numerical blocks representing the core, porosity of 1.0, permeability of  $10^4$  times that of the core, straight line relative permeabilities and zero capillary pressures. These endblocks were meant to minimise the

capillary end-effects as suggested by Maas. J. and Schulte. A.M. [7]. The recovery and pressure drop across the core are observed to be insensitive to the number of endblocks. The water and oil properties are given in Table 2. The salient simulation parameters are given in Table 3.

## **SIMULATION RUNS**

The sensitivity of following parameters were studied

Flooding Rate : The flooding or injection rates were changed in such a way that the scaling coefficient  $N_c$  is chosen to be 0.1, 0.2, 0.5, 1, 2, 5 and 10. The scaling coefficients of  $N_c$  of 0.1, 0.2, 0.5, 1, 2, 5 and 10 corresponding to dimensionless capillary number (Ca) of 0.00045, 0.00091, 0.00227, 0.004, 0.009, 0.022 and 0.045 respectively.

Viscosity Ratio : The viscosity of oil is changed in such a way that the viscosity ratio ( $\mu_o/\mu_w$ ) were chosen to be 0.5, 1.23 and 5.

Wettability : The  $J(S_w)$  function considered for water-wet and mixed-wet cores are given in Table 4.

Heterogeneity : Apart from homogeneous cores, simulations were done on heterogeneous cores having a log normal permeability distribution characterized by Dykstra-Parson coefficient ( $V_{DP}$ ). Simulations were carried out for  $V_{DP}$  values of 0.1, 0.5 and 0.8. (Figure 13)

## **INTERPRETATION OF SIMULATION RUNS**

The simulator output file .RSM [5,6] was used as input for calculating relative permeability data by Jones and Roszelle's method for further comparison with the input relative permeabilities.

## **OBSERVATIONS**

### **Homogenous Water Wet Cases**

Figures 2 and 3 shows that the measured  $k_o$  and  $k_w$  are higher for higher flow rates (higher capillary scaling coefficient) as observed by Heaveside J. and Black C.J.J.[9]. Further the behaviour of calculated  $k_w$  against the assumed  $k_w$  (the input) at different rates for water wet cores and mixed wet cores are similar to those observed by Odeh A.S. and Dotson B.J. [8] (fig. 2 and 3)

The calculated  $k_o$  are found to be underestimated severely at low saturations. Figure 2 shows that the higher viscosity ratios and higher scaling coefficient (high flow rates) give a better estimate of  $k_{ro}$ , at intermediate and higher water saturations. The  $k_{rw}$  calculated are overestimated at low saturations (fig. 3). It is observed that the higher scaling coefficient and higher viscosity ratios leads to best possible estimates of  $k_{rw}$ . Thus these observations on calculated  $k_{ro}$  and  $k_{rw}$  shows that their best estimates, which are obtained only at higher saturation ranges, are possible at higher viscosity ratios and higher flooding rates. (Figures 4 and 5) At lower flooding rates the estimate of  $k_{rw}$  is close to that of the true  $k_{rw}$  at lower saturations. But at higher saturations, the calculated relative permeabilities to water are very much underestimated. With higher viscosity ratios the calculated  $k_{rw}$  are more close to true  $k_{rw}$  than those measured with low viscosity ratios. Further, the range of saturation (at higher side) at which the calculated  $k_{rw}$  is close to the true  $k_{rw}$ , is large for high viscosity ratios (figure 5)

It is observed that the lower viscosity ratios lead to higher recoveries at breakthrough implying a more piston-like displacement. The observation that the breakthrough recovery remains practically constant at higher scaling coefficient is not a sufficient condition to obtain the correct relative permeabilities throughout the whole saturation range (figure 6).

### **Homogeneous Mixed Wet Cases**

The behaviour of measured  $k_{rw}$  against the assumed  $k_{rw}$  at different rates for water wet cores and mixed wet cores are similar to those observed by Heaveside J. and Black C.J.J. [9] (figures 7 and 8). The  $k_{ro}$  is underestimated at lower saturations and overestimated at higher saturations. The  $k_{rw}$  is overestimated at higher saturations and underestimated at lower saturations. However, the measured relative permeabilities at higher velocities are the closest but still not close enough to the true (input) relative permeabilities for the whole range of saturations.

The measured  $k_{ro}$  tends to approach the true  $k_{ro}$  at higher flooding rate and higher viscosity ratios. Even at higher flooding rates the errors are larger at lower saturations, in spite of higher viscosity ratios. But at higher water saturations, the measured  $k_{ro}$  are very close to true  $k_{ro}$  (figure 7). The measured  $k_{rw}$  are higher than the true  $k_{rw}$  at lower saturations. The higher the viscosity ratios, more close are the measured  $k_{rw}$  to the true  $k_{rw}$  at lower saturations. But the low rate  $k_{rw}$  are closer to true  $k_{rw}$  at lower water saturations (figure 8). Though highly underestimated, the measured  $k_{ro}$  are close to the true  $k_{ro}$  for higher viscosity ratios. The measured  $k_{rw}$  are severely underestimated at low flooding rates (figure 9 and 10). However, the endpoint  $k_{rw}$  depends on the flooding rates rather than the viscosity ratio (figure 11)

The breakthrough recovery behaviour with the scaling coefficient at different viscosity ratios are shown in figure 12. It is observed that the lower viscosity ratios leads to higher recoveries at breakthrough implying a more piston-like displacement. However, the observation that the breakthrough recovery remains practically constant at higher scaling coefficient is not a sufficient condition to obtain the correct relative permeabilities through out the whole saturation range.

The simulation runs were done for high flooding rates with capillary pressures as zero, hence the calculated relative permeabilities were close to those of input curves. The base case is shown in figure 2 and 3.

### **Heterogeneous Water Wet Case**

As a common feature the measured relative permeabilities are different from the true relative permeabilities by two or three orders. At high saturations the measured relative permeabilities are closer to the true relative permeabilities (figure 14 and 15). However, they are close to true relative permeabilities only at high flooding rates (high capillary number).

The measured oil relative permeabilities,  $k_{ro}$  for all cases of heterogeneity are close to the true oil relative permeabilities when the viscosity ratio were chosen to be high (figure 16). The measured

water relative permeabilities are closest to true water relative permeabilities when the viscosity ratios were chosen to be low (figure 17). This is evident that the end point  $k_{rw}$  approaches the true  $k_{rw}^*=0.46$ , at high capillary number (lower rates) for lower viscosity ratio cases, than the higher viscosity ratio cases (figure 16). For a given flooding rate, the measured endpoint  $k_{rw}$ , breakthrough recovery and total oil recovery for  $V_{DP}=0.1$  and  $0.5$  are close to each other (figure 18). However in case of  $V_{DP}=0.8$ , endpoint  $k_{rw}$ , breakthrough recovery and total oil recovery are highly reduced. Thus the deviation in measured parameters caused by heterogeneities ranging from small to medium ( $V_{DP}=0.5$ ) are less and are of similar order. However, the deviations in measured parameters are large in high  $V_{DP}$  cases. The deviations or errors do not increase linearly as expected. The errors are smaller at low  $V_{DP}$  and larger at high  $V_{DP}$ .

Interestingly, the breakthrough recoveries show very slight increase, with increase in heterogeneities (at lower  $V_{DP}$ ), at all viscosity ratios. At very low rates the breakthrough recoveries are higher for the lower heterogeneity factor  $V_{DP}$ . At higher flooding rates, the breakthrough recovery is higher for a core with higher heterogeneity factor  $V_{DP}$ . However, for samples with large heterogeneity factors the breakthrough recoveries are very low. For a given heterogeneous core sample, the breakthrough oil recovery and the total oil recovery decreases for increase in flooding rates (increase in Ca) and then increases for further increase in flooding rates (further increase in Ca) (figure 18). For a given viscosity ratio and flooding rate, the total oil recovery, taken at 10 pore volume of injection, decreases with increase in heterogeneity factor. However, the reduction in recoveries due to increase in flooding rate are observed to be more in case of high viscosity ratio and in cores with larger heterogeneities.

The oil used as displaced fluid should be moderately viscous in case of heterogeneous samples. In case of higher viscosity, we measure erroneous  $k_{rw}$  (figure 19) but the measured  $k_{ro}$  is very close to true  $k_{ro}$ . Thus the choice of the viscosity of oil is not straight forward.

### **Heterogeneous Mixed Wet Cases**

The measured  $k_{ro}$  are close to the true  $k_{ro}$  at higher flooding rates and higher viscosity ratios (figure 20). However, the shape of measured  $k_{rw}$  curve are totally different from that of true  $k_{rw}$ . The measured  $k_{rw}$  shows largest deviation from the true  $k_{rw}$  (figure 21), for moderately heterogeneous cores, say  $V_{DP} = 0.5$ . But for cores with lower and higher variation of permeability,  $V_{DP} = 0.1$  or  $0.8$ , the measured  $k_{rw}$  are nearer to the true  $k_{rw}$ .

The measured endpoint  $k_{rw}$  shows least deviation for lower viscosity ratios. At lower viscosity ratios the measured  $k_{rw}$  are highly erroneous for a large range of water saturations. At higher viscosity ratios the measured  $k_{rw}$  are close to the true for a large range of saturation. The error in the endpoint  $k_{rw}$  for the best design (in terms of flooding rate and viscosity ratio) is larger in comparison to that of the waterwet core, even at highest flooding rates (figure 22). For a given capillary number, increase in heterogeneity decreases the measured  $k_{rw}$ . But at higher ranges of heterogeneity factors the increase in heterogeneity increases the measured  $k_{rw}$ . The errors on measured relative permeabilities increases as the heterogeneity increases. But for higher heterogeneity factor the errors reduces (figure 22).

For a given capillary number or flow rate the breakthrough recoveries increase for increase in heterogeneity variation in permeability of the core. But on further increase in heterogeneity, the breakthrough recoveries decrease for large heterogeneity factors (figure 23). It is worth noting that the core heterogeneity will promote instability (hence segregated flow) in the physical USS experiment often leading to severe interpretation difficulties. Thus 1D numerical simulation will not be able to capture this properly.

## CONCLUSIONS

The following conclusions were drawn in light of the results obtained :

- ✓ The best estimates of  $k_o$ , in general, are obtained when the displacements are done at high capillary number and high viscosity ratio. It is widely observed that the errors are large at lower saturations. The range of saturations (at high saturations) for which the best estimates are obtained, increases with viscosity ratio.
- ✓ The best estimates of  $k_w$ , in case of homogeneous cores are obtained when the displacements are done at high capillary number and high viscosity ratio, while those for heterogeneous cores are obtained at high capillary numbers and low viscosity ratio.
- ✓ The measured endpoint  $k_w$  is equal to the true endpoint  $k_w$  in case of homogeneous waterwet cores
- ✓ The shape of the  $k_w$  curves obtained from experiments conducted at low capillary number, in homogeneous waterwet cores and heterogeneous (water-wet and mixed-wet) cores, are severely perturbed, because the measured endpoint  $k_w$  are lower than the true end-point  $k_w$ .
- ✓ The errors in measured quantities, in case of heterogeneous water wet cores, do not differ much at lower range of permeability variations, say for  $0.1 < V_{DP} < 0.5$ . But the errors are large in case of high permeability variations, say for  $V_{DP} \sim 0.8$ .
- ✓ The errors in measured quantities, in case of heterogeneous mixed wet cores, are less for cores with very high and very low permeability variations ( $V_{DP} \sim 0.1$  and  $0.8$ ), in comparison to those with intermediate values of  $V_{DP}$  ( $\sim 0.5$ ).
- ✓ The Unsteady-state technique is very prone to experimental and interpretation errors

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## NOMENCLATURE

### English Symbols

A	Area of Cross Section, perpendicular to flow
a,b	Parameters in the expression for Relative Permeability
Ca	Dimensionless Capillary Number defined in eq.(7)
f	Fractional Flow

H	Height of the System
J	Levertt J-function Value
k	Permeability
L	Length of the linear system
$N_c$	Capillary Scaling Coefficient by Rapaport and Leas
P	Pressure
q	Rate
S	Saturation
T	Dimensionless Time
t	Time
V	Velocity of flow
VR	Viscosity Ratio
$V_{DP}$	Dykstra-Parsons Coefficient
X	Dimensionless Distance
x	Distance from the Injection end

### Greek Symbols

$\phi$	Porosity
$\Phi$	Potential
$\lambda$	Mobility
$\lambda^*_{Di}$	Relative Mobility of phase I
$\mu$	Viscosity
$\theta?$	Contact Angle
$\rho$	Density
$\sigma?$	Interfacial Tension

### Subscripts

end	endpoint
inj	Injection
nw	Non-wetting phase
o	Oil
or	Residual Oil
r	Relative
w	Water or Wetting phase

### Superscripts

true	True Quantity
*	Normalised Value of Saturation



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**Table 1 Rock Properties of the Simulated Linear Waterflood Model**

Length of the core	cm	7.45
Width	cm	3.3588
Height	cm	3.3588
Equivalent Diameter	cm	3.79
Porosity	fraction	0.176
Absolute Permeability	md	415
Initial Water Saturation	fraction of PV	0.271
Residual Oil Saturation	fraction of PV	0.202

**Table 2 Fluid Properties**

		Water	Oil
Density	g/cc	1.000	0.831
Viscosity	cP	1.102	0.551 (VR=0.5)
			1.355 (VR=1.23)
			5.51 (VR=5.0)
Formation Volume Factor	v/v	1.000	1.000
Solution Gas-Oil Ratio	v/v	0.000	0.000
Interfacial Tension between Water and Oil	mN/m	50.000	

**Table 4 Leverett J-Function for Water Wet and Mixed Wet Cores**

Normalised Water Saturation $S_w$	$J(S_w)$ Water Wet Cores	$J(S_w)$ Mixed Wet Cores
0	1	6.365
0.1	0.738	1.871
0.2	0.544	0.921
0.3	0.406	0.437
0.4	0.312	0.089
0.5	0.25	-0.141
0.6	0.208	-0.315
0.7	0.174	-0.489
0.8	0.136	-0.868
0.9	0.082	-1.978
1	0	-6.316

**Table 3 Simulation Parameters**

Solution Method	IMPES
Maximum length of Initial Time Step (hr)	1.00E-04
Maximum length of Next Time Step (hr)	0.05
Minimum length of all Time step (hr)	0.05
Minimum choppable Time step (hr)	0.15
Maximum Pressure Change in a time step (atm)	0.1
Maximum Saturation Change in a time step (fr)	0.01

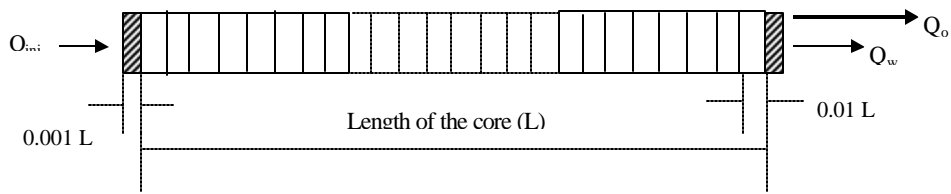


Figure 1 Simulation Model of the Core

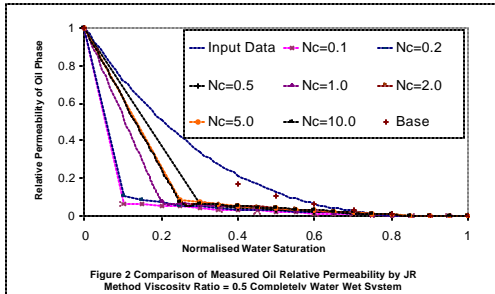


Figure 2 Comparison of Measured Oil Relative Permeability by JR Method Viscosity Ratio = 0.5 Completely Water Wet System

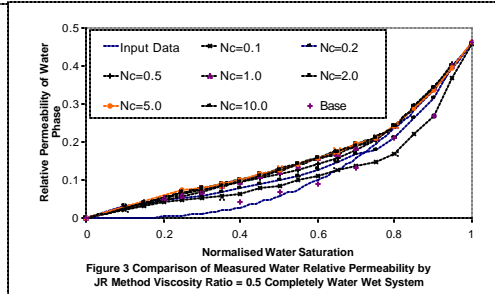


Figure 3 Comparison of Measured Water Relative Permeability by JR Method Viscosity Ratio = 0.5 Completely Water Wet System

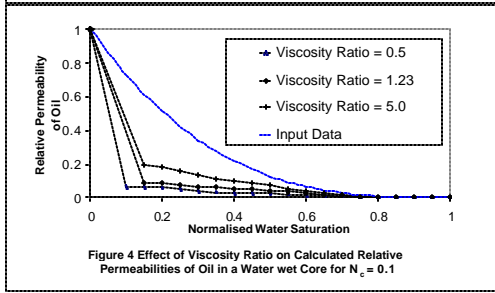


Figure 4 Effect of Viscosity Ratio on Calculated Relative Permeabilities of Oil in a Water wet Core for  $N_c = 0.1$

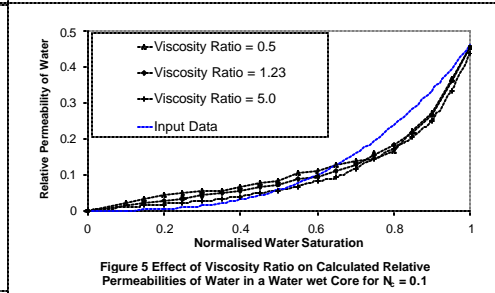


Figure 5 Effect of Viscosity Ratio on Calculated Relative Permeabilities of Water in a Water wet Core for  $N_c = 0.1$

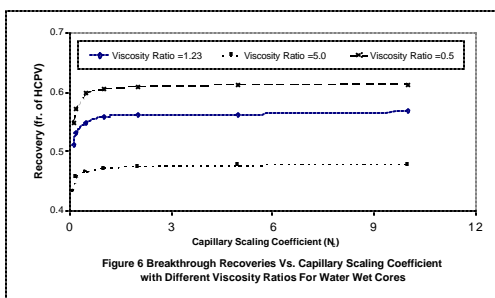


Figure 6 Breakthrough Recoveries Vs. Capillary Scaling Coefficient with Different Viscosity Ratios for Water Wet Cores

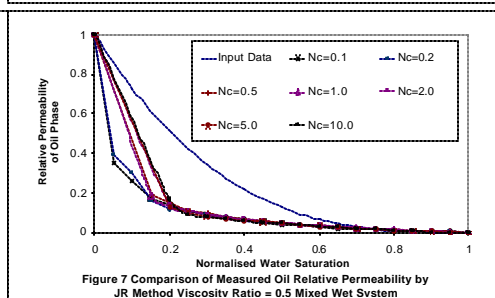


Figure 7 Comparison of Measured Oil Relative Permeability by JR Method Viscosity Ratio = 0.5 Mixed Wet System

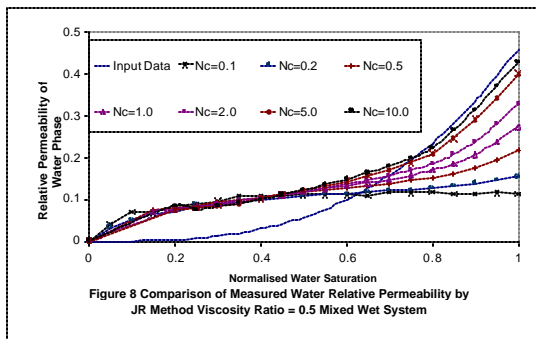


Figure 8 Comparison of Measured Water Relative Permeability by JR Method Viscosity Ratio = 0.5 Mixed Wet System

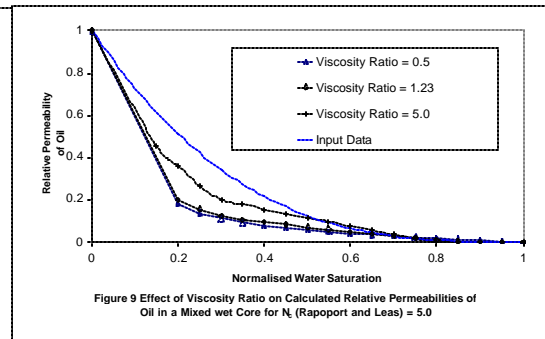


Figure 9 Effect of Viscosity Ratio on Calculated Relative Permeabilities of Oil in a Mixed wet Core for  $N_c$  (Rapoport and Leas) = 5.0

