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FRONTAL INSTABILITIES WHEN WATERFLOODING AT UNFAVOURABLE VISCOSITY RATIOS

by

ROLF WIBORG ©

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled "FRONTAL INSTABILITIES WHEN WATERFLOODING AT UNFAVOURABLE VISCOSITY RATIOS", submitted by ROLF WIBORG, in partial fulfilment of the requirements for the degree of Master of Science in Petroleum Engineering.

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ABSTRACT

Displacement tests have been conducted on an unconsolidated Ottawa silica sand pack to study the effect of viscous fingering on the recovery of oil at water breakthrough.

Tests were performed with three oils using distilled water as the displacing fluid. The oil-water viscosity ratios were 15.5, 34.2 and 111.4 respectively. The recovery data were correlated using the dimensionless group I, which represents the ratio of viscous to capillary forces.

The results indicate that the value of I at which the effect of viscous fingers manifests itself as a reduction of the breakthrough recovery may be estimated from:

$$I = \frac{C^2 \; L \sqrt{K}}{3(\mu_o/\mu_w - 1)D^2}$$

if the constant, C, is taken as 30 for each system.

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1. INTRODUCTION

Waterflooding has by far been the most useful secondary recovery technique developed by the oil industry to increase the recoveries from depleting oil reservoirs around the world. Extensive research and past experience have provided methods to predict production performance within a reasonable confidence level. There is however, a constant need for improvements as the industry takes on marginal projects with a rapid increase in capital costs.

It is therefore important to study some of the uncertainties which still exist regarding the effect of certain variables. Rate is probably the most important of these, since it is fairly easy to control and has a huge impact on the economics of a project.

The interest in recovery of heavy high viscosity crudes is rapidly gaining momentum. The literature dealing with immiscible displacements at such unfavourable viscosity ratios contains obvious inconsistencies. An especially controversial subject has been the effect of viscous fingering on the displacement efficiency. Although it may not be a significant phenomenon in an actual reservoir, fingering must be taken into account when evaluating data from otherwise scaled laboratory models.

This study was conducted to obtain a better understanding of the viscous fingering phenomenon and its effect on the recovery of oil from an unconsolidated porous medium. Three different oils with a wide range in viscosity were employed; the rate of displacement was varied from 2.5 to 35.20 cc/hr and recoveries at break-through and subsequent production behavior were recorded and correlated using a classical scaling parameter.

2. LITERATURE REVIEW

2.1 Viscous Fingering

Fingering of the advancing water into the less mobile oil was early recognized as a problem in the oil industry. However, it was mainly attributed to gravity effects, permeability stratifications and other gross inhomogeneities.

Miller[1] reported in 1941: "Visual observations of the oil-filled test sand column during the water encroachment experiments indicate conclusively that different volumes of oil are recovered from different unit volumes of sand as a result of 'fingering' of the water and bypassing of oil". However, he made no special point of this in his discussion of the data.

Engelberts and Klinkenberg[2], in 1951, were probably the first to point out the important role the instability of the transition zone played when a fluid is displaced by one which has a lower viscosity. They called the phenomenon "viscous fingering". Their results showed a consistent decrease in breakthrough recoveries with increasing viscosity ratios. They also observed a decrease in the breakthrough recovery with increasing rates ($\mu_o/\mu_w = 24$) for both oil-wet and water-wet media.

Van Meurs and van der Poel[3] provided a simple mathematical description of a water drive involving viscous fingering. Their equations can be used to predict the production performance in a field with regularly spaced wells. The data required are; the viscosity ratio, the residual oil saturation and the minimum water saturation. A water-cut value must be selected to complete the evaluation of a specific project. They obtained satisfactory agreement with production data from an actual field. The theory is presented in detail in Chapter 3.

Chuoke et al.[4] presented a theoretical description of the instability of fluid displacements in porous media. They derived an equation representing the wavelength of maximum instability, or the most probable peak-to-peak distance, for a given system when fingering occurs. Assuming neutral wettability and horizontal displacement (i.e. gravity effects can be ignored) the equation becomes:

$$\lambda_m = C \sqrt{\frac{\gamma K}{V(\mu_o - \mu_w)}} \qquad (1)$$

where

λ_m = the most probable finger spacing (cm)

C = a dimensionless constant

γ = interfacial tension (dynes/cm)

K = absolute permeability (cm^2)

V = total flow rate per unit cross-sectional area or volumetric velocity (cm/sec)

μ_o = viscosity of oil (poise)

μ_w = viscosity of water (poise)

Instability will occur if the volumetric velocity exceeds a critical value for a specific rock-fluid system, provided the perturbation contains wavelengths greater than a critical wavelength, λ_c. The relationship between the two wavelengths is:

$$\lambda_c = \frac{\lambda_m}{\sqrt{3}} \tag{2}$$

where

λ_c = the critical wavelength or finger distance (cm).

An expression for λ_c as a fraction of the tube diameter is obtained by a combination of equations 1 and 2:

$$\frac{\lambda_c}{D} = C \sqrt{\frac{\gamma K}{3\ V\ (\mu_o - \mu_w) D^2}} \tag{3}$$

where

D = the diameter of the tube (cm).

From the above definition of λ_c, it follows that the oil water interface is stable for any rate if the critical finger distance exceeds the diameter of the tube. Equation 3 would have been a powerful tool if the constant C could be easily predicted. Chuoke et al. obtained a reasonable fit to their observed finger spacing if C in equation 1 was taken as 30. That was for a neutral wettability system containing no initial water. Although their experimental data were insufficient to calculate a value, they indicated that C was larger for water-wet media containing connate water. The value of C must be established experimentally for each system. Let us assume that viscous fingers will be formed as soon as λ_c becomes equal to D. If this shows up in the recovery data as a noticeable decrease, then this point can be used to determine the constant in equation 3 from:

$$C = \sqrt{\frac{3 V (\mu_o - \mu_w) D^2}{\gamma K}} \qquad (4)$$

Chuoke et al. stressed the fact that larger values of their constant lead to increased critical wavelengths. The lateral extent of a laboratory model or core sample may then easily be exceeded. They suggested that this might explain why viscous fingering effects may not reveal itself even though the system satisfies all other criteria for instability. Their visual observations showed that increased viscosity ratios and decreased interfacial tensions both favoured the formation of smaller and more numerous fingers.

The main limitation on the applicability of their theory is the assumption that the Muskat model of displacement, where oil and water flow in separate macroscopic regions, is valid for an actual reservoir containing an initial water saturation.

de Haan[5] provided experimental support for Chuoke et al.'s[4] theory. He was able to predict the rate at which fingers started to form using their equations. The recoveries at low rates were high, decreasing in an intermediate range and levelling out at high rates. He concluded that at low rates, water tended to fill up the whole cross-section, and an efficient frontal displacement resulted. In the intermediate range, fingers were formed, and as a result the recoveries dropped. At high rates, numerous fingers were observed, and the recovery became insensitive to further rate increases.

de Haan[5] explained that viscous fingering effects are unlikely to be pronounced in oil-wet systems due to the distribution of the fluids. The constrictions are filled with oil in an idealized oil-wet system, and the flood fronts in adjacent channels will therefore move quite independently. Fingers of macroscopic dimensions will only be formed when a more or less coherent oil-water interface exists, and this condition is clearly not met in an oil-wet system.

Scheidegger[6,7] dealt with the instability problem in two theoretical papers. According to his analyses fingering should be independent of the displacement velocity. He cited the work of Blackwell et al.[8] to support this controversial conclusion. These authors obtained breakthrough recoveries that were independent of rate with a mobility ratio of 93. An explanation of this surprising result might be the fact that the displacement rates used, 1.0 - 100 ft/day, placed all their results in the insensitive range described by de Haan[5].

Outmans[9] included some of the nonlinear terms previously neglected in the analyses of the instability equations. He showed that viscous fingering then could become independent of rate only if both gravity and interfacial tension effects were negligible.

Rachford[10] was the first to use the Buckley-Leverett flow model, in which oil and water flow simultaneously, in the analyses of the stability of the interface. He included the effects of connate water and the transition zone, both normally present when water-wet systems are flooded. The transition zone tended to insulate incipient fingers from the high-mobility water and thus reduced the fingering effect. This is not accounted for in the parallel plate theory.

Perkins and Johnston[11] confirmed Rachford's[10] findings experimentally. The fingering behaviour differed in the presence of connate water. Numerous small fingers developed near the entrance, but they soon broke up and formed a graded saturation zone. No sharp front could be followed. Perkins and Johnston suggested that the dampening of the fingers was caused by crossflow of the phases, transverse to the direction of the gross fluid movement. Their experiments supported this explanation, and they concluded that immiscible dispersion ought to be incorporated in the analyses of the stability to adequately describe the viscous fingering phenomenon in natural systems.

Hagoort[12] highlighted the effect that the choice of flow-model (i.e. Muskat or Buckley-Leverett) has on the stability criteria. He showed that the Buckley-Leverett approach, previously only attempted by Rachford[10], yields different criteria for the initiation of fingers than those derived from a Muskat-model. He found that the interface became unstable if the so-called shock mobility ratio was greater than 1, provided the wavelength of the instabilities was smaller than the canal width. The shock mobility ratio is defined as:

$$M_s = \frac{\text{the mobility of fluids behind the shock front}}{\text{the mobility of fluids ahead of the shock front}}$$

or

$$M_s = \frac{k_{ocw}\, k_{ro}\,(S_s)/\mu_o + k_{wor}\, k_{rw}\,(S_s)/\mu_w}{k_{ocw}/\mu_o}$$

where

k_{ocw} = permeability to oil at the connate water saturation

$k_{ro}(S_s)$ = normalized relative permeability to oil at the shock saturation

k_{wor} = permeability to water at the residual oil saturation

$k_{rw}(S_s)$ = normalized relative permeability to water at the shock saturation

The shock mobility ratio is considerably lower than the end-point mobility ratio which determines the stability of a Muskat-type displacement. The higher the mobility ratio, the faster instabilities arise. The Buckley-Leverett approach is generally believed to describe immiscible displacements in water-wet media better than the Muskat-model. The stability of these displacements is therefore probably better than earlier results based on the Muskat flow model indicated.

2.2 Scaling

Numerous papers on the scaling of waterflood models have been published since Leverett et al.[13] introduced the concept in 1942. In the present work no effort was made to scale any particular reservoir. The problem was therefore limited to the end-effects and the fingering phenomenon.

The dimensionless scaling group, I, defined as:

$$I = \frac{LV \mu_w}{\gamma \sqrt{K}}$$

where

L = length of the system (cm)

was used by Engelberts and Klinkenberg[2] to correlate horizontal displacement experiments. It is simply a measure of the ratio of the viscous to the capillary forces.

de Haan[5], using the data of Rapoport and Leas[14] and Kyte and Rapoport[15], concluded that the recovery became independent of I when I was larger than 0.1. Substitution of normal field-values indicated that I was always in this insensitive range.

The same scaling group has been used by Jones-Parra et al.[16], Collins[17], Scott[18] and Kloepfer[19] which facilitated the comparison of results.

Geertsma et al.[20] arrived at a more universal scaling number given by:

$$L_t = \frac{\gamma \cos\theta \sqrt{K\phi}}{LV \mu_w}$$

where

θ = wetting angle of fluid interface (dimensionless)

ϕ = porosity (dimensionless)

This is the reciprocal of I, except that the effects of porosity and contact angle are included. The problems involved in establishing the contact angle makes the application of this scaling group difficult.

End-effects, as described by Kyte and Rapoport[15], can obscure data obtained from unscaled laboratory models. Spontaneous localized imbibition or the inlet effect is minimized if rate and viscosity ratio are kept low. This effect could probably be eliminated if the inlet system was designed to assure uniform liquid contact at the sandface. The so-called outlet effect, caused by the discontinuity of the capillary pressure, becomes less severe when rates and viscosity ratios are increased. The relative importance of both effects decreases if longer systems are employed.

Chuoke et al.[4] indicated that scaling of viscous fingering should be straightforward in most cases. Problems would arise however, if the wavelength of maximum instability was of the same magnitude as the model width.

Outmans[9] indicated that it might prove impossible to accurately scale the fingering phenomenon, because to achieve similarity the small heterogeneities that initiate the fingers have to be scaled.

Rachford[10] concluded that no additional scaling requirements were necessary to deal with the instability problem. His model, based on the Buckley-Leverett displacement mechanism assuming a porous medium with a connate water saturation, should be more representative than the previous idealized parallel plate models.

Perkins and Johnston[11] showed that any experiment aimed at scaling immiscible fingering in a water-wet reservoir should be performed with an initial connate water saturation. However, no indication was given as to the need for matching the initial saturation of the prototype.

3. THEORY

van Meurs and van der Poel[3] presented a flow-model that accounted for viscous fingering in immiscible displacements. Their simplifying assumptions were based on pictures of scaled waterflood experiments in a transparent system. According to their observations the flow mechanism could be idealized in the following way.

1. The displacement process is of a one dimensional character in the region where both oil and water are present (i.e. movement is parallel to the direction of flow).
2. Oil flow outside the water fingers and water flow in the center of the fingers proceeds unhindered.
3. In the edge zone of the water fingers both water in protrusions and oil in enclosed pockets are completely prevented from moving in the direction of flow.
4. The fractions of both immobile oil and water in a cross section of the formation are independent of time and place.

They considered a unit cross section of the formation large enough to contain sufficient fingers to be representative of the total cross section, see Figure 1. This section was divided into three areas:

a) Area 1, the sum of all areas outside the water fingers where oil flows unhindered.

b) Area 2, the sum of the center areas of the water fingers where water flows unhindered.

c) Area 3, the sum of all areas containing edges and protrusions. In this area both the oil and the water are immobile.

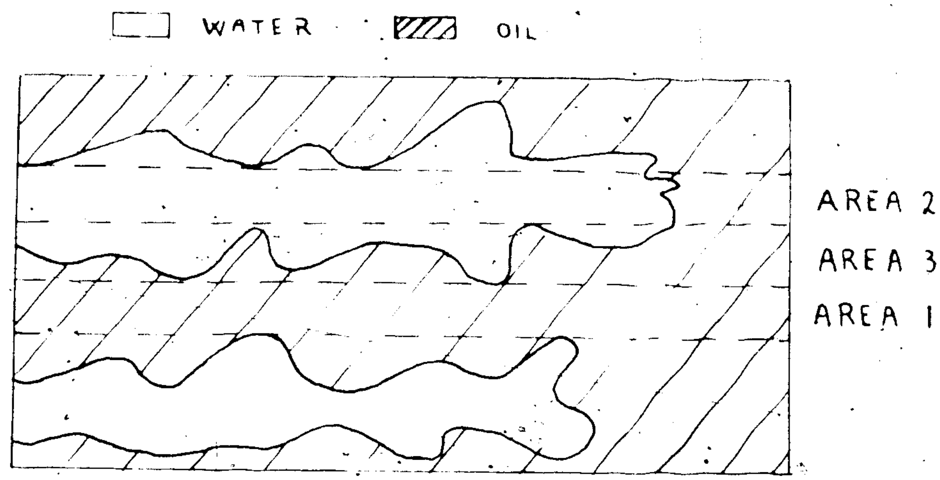


FIGURE 1: IDEALIZED PICTURE OF WATER FINGERS

The sizes of these areas can be characterized by means of oil and water saturations.

All immobile water of Area 3 expressed as a fraction will be denoted S_{wm}. This means that S_{wm} is the average immobile water saturation for the unit cross section we are looking at. In the same way S_{or} is defined by averaging the immobile oil saturation. If the average water and oil saturations of the unit cross section are denoted S_w and S_o respectively, then the areas can be written:

Area 1 = $S_o - S_{or}$

Area 2 = $S_w - S_{wm}$

or since

$$S_w + S_o = 1$$

$$\text{Area } 1 = 1 - S_{or} - S_w$$

If q_w is defined as the flow rate of water per unit cross sectional area (dimension, L t^{-1}), then the volumetric velocity of the water in Area 2 is defined by:

$$V_w = \frac{q_w}{S_w - S_{wm}} \tag{5}$$

The flow in this area was assumed unhindered and Darcy's Law for a single phase can be used:

$$V_w = -\frac{K}{\mu_w}\frac{\partial P_w}{\partial x} \tag{6}$$

where

P_w = pressure in the water phase

x = distance travelled in x - direction

The same analyses for the oil phase yields:

$$V_o = \frac{q_o}{1 - S_{or} - S_w} \tag{7}$$

and

$$V_o = -\frac{K}{\mu_o}\frac{\partial P_o}{\partial x} \quad (8)$$

where

P_o = pressure in the oil phase

Although the authors did not mention it specifically, it should be noted that the use of the absolute permeability in equations 1 and 2 is justified by the assumption of unhindered flow. The oil present in Area 2 and the water present in Area 1 do not affect the ability of the porous medium to conduct fluids. Hence, the medium behaves as if it was completely saturated with a single fluid. Since macroscopic parts of the oil-saturated formation are bypassed by the penetrating water fingers, it is understandable that the difference in pressure in the two phases, P_c, stays approximately constant as long as the finger edges are not interfering. This assumption was found to be true up to high water saturations. Consequently:

$$P_c = P_o - P_w = \text{constant}$$

and

$$\frac{\partial P_w}{\partial x} = \frac{\partial P_o}{\partial x} \quad (9)$$

from Equations 6, 8 and 9 it follows that:

$$V_w = MV_o \quad (10)$$

where

$$M = \frac{\mu_o}{\mu_w} \tag{11}$$

The total amount of fluid passing through the cross section is:

$$q = q_o + q_w \tag{12}$$

and will be a function of time only since the fluids are assumed incompressible.

An equation for the fractional flow of water is obtained by combining 5, 7, 10 and 12:

$$f_w = \frac{q_w}{q} = \frac{M\ (S_w - S_{wm})}{(M-1)\ (S_w - S_{wm}) + B} \tag{13}$$

where

$$B = 1 - S_{or} - S_{wm} \tag{14}$$

The equation of continuity for the water phase is:

$$\frac{\partial q_w}{\partial x} + \phi\ \frac{\partial S_w}{\partial t} = 0 \tag{15}$$

or

$$\frac{\partial f_w}{\partial X} + \frac{\partial S_w}{\partial W_i} = 0 \tag{16}$$

where

$W_i = \frac{\int q\ dt}{\phi L}$ = cumulative water injected as a fraction of the pore volume

L = Length of the formation

$X = \frac{x}{L}$ = the dimensionless distance along the flow direction taken from the point of injection.

f_w is a function of S_w only according to Equation 13. Equation 16 can therefore be written as:

$$\frac{df_w}{dS_w} \cdot \frac{\partial S_w}{\partial X} + \frac{\partial S_w}{\partial W_i} = 0 \qquad (17)$$

Differentiation of Equation 9 gives:

$$\frac{df_w}{dS_w} = \frac{MB}{[(M-1)(S_w - S_{wm}) + B]^2} \qquad (18)$$

The general solution of this differential equation is:

$$X = \omega(S_w) + \frac{df_w}{dS_w} W_i \qquad (19)$$

If the initial water front (at $t = 0$ or $W_i = 0$) is assumed to be undisturbed and perpendicular to the flow direction then:

$$\omega(S_w) = 0 \qquad (20)$$

Substitution of Equations 18 and 20 in Equation 19 yields:

$$X = \frac{MBW_i}{[(M-1)(S_w - S_{wm}) + B]^2} \qquad (21)$$

and we can solve for the water saturation distribution in the region where both oil and water flow:

$$S_w = S_{wm} - \frac{B}{M-1} + \frac{\sqrt{MB}}{M-1} \sqrt{\frac{W_i}{X}} \qquad (22)$$

Equation 21 and 22 will only be valid within a certain range of water saturation values. It should be clear from Figure 2 that S_w must be less than $1-S_{or}$.

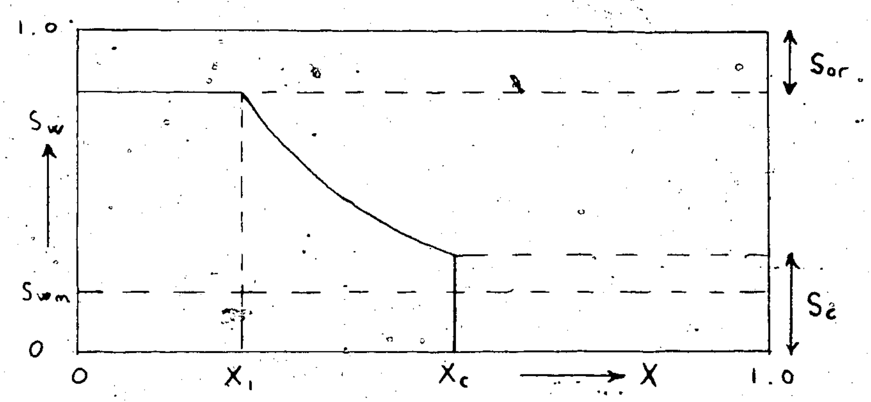


FIGURE 2: SCHEMATIC REPRESENTATION OF WATER SATURATION DISTRIBUTION BEFORE BREAKTHROUGH

The distance at which S_w reaches its maximum, $1-S_{or}$, can be found from equation 20:

$$X_1 = \frac{W_i}{MB} \tag{23}$$

The foregoing treatment depends on the assumption that no flow occurred perpendicular to the main direction of fluid movement. van Meurs and van der Poel observed that the fingers did not deviate too much from the X-direction. However, they also noted that especially at the top of the fingers there should have been components in directions perpendicular to the X-axis. This phenomenon was analysed in more detail in the following manner.

The formation of water protrusions at the finger tips requires a certain amount of water; however, once filled, these protrusions do not constitute a passageway for the water. This means that S_w must exceed S_{wm}, and the theoretical water saturation distribution should therefore be cut-off at a point, X_c, where the saturation is larger than S_{wm}, see Figure 2. This critical water saturation is denoted S_c. Obviously, the vertical cut-off as indicated in Figure 2 is an idealization. The real change is probably a gradual transition.

To determine this cut-off point the authors reasoned as follows.

The amount of water entering the unit cross section in one second at X_c, $(q_w)_{S_w=S_c}$, is used to fill the formation to the critical saturation. If the velocity at which S_c propagates is denoted V_c then:

$$(q_w)_{S_w=S_c} = \phi V_c S_c \tag{24}$$

The velocity at which the critical saturation moves is defined by:

$$V_c = \left(\frac{dx}{dt}\right)_{S_w=S_c} \tag{25}$$

or using the definitions of X and W_i:

$$V_c = \frac{q}{\phi}\left(\frac{dX}{dW_i}\right)_{S_w=S_c} \tag{26}$$

Equations 19 and 26 combined yield:

$$V_c = \frac{q}{\phi}\left(\frac{df_w}{dS_w}\right)_{S_w=S_c} \tag{27}$$

Substitution of Equation 27 in Equation 24 gives for the condition at the cut-off boundary:

$$\left(\frac{q_w}{q} = f_w = \frac{df_w}{dS_w} S_w\right)_{S_w=S_c} \tag{28}$$

Combination of Equations 13, 18 and 28 yields the water saturation at the cut-off point:

$$S_c = S_{wm} + \sqrt{\frac{BS_{wm}}{M - 1}} \tag{29}$$

An expression for X_c is obtained by combining Equations 21 and 29:

$$X_c = \frac{MBW_i}{[B + \sqrt{B(M-1)S_{wm}}]^2} \tag{30}$$

Breakthrough will occur when the critical saturation, S_c, arrives at the outflow end, $X_c = 1$. The total cumulative production at that moment, W_i, is equal to the breakthrough recovery, N_{pb}. Equation 30 solved for N_{pb} can be written:

$$N_{pb} = \frac{A^2}{MB} \tag{31}$$

where

$$A = B + \sqrt{B(M-1)S_{wm}} \qquad (32)$$

Equation 31 shows that when $M \rightarrow \infty$, $N_{pb} \rightarrow S_{wm}$, i.e. breakthrough occurs at the moment the minimum water saturation is established throughout the formation.

The cumulative oil recovery after breakthrough, N_p, is easily found by integrating the water saturation present in the formation, see Figure 3:

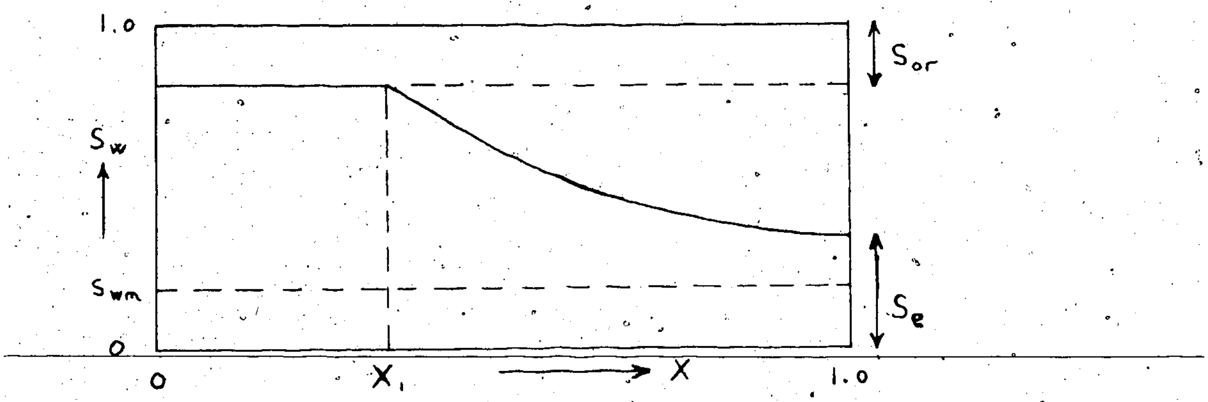


FIGURE 3: SCHEMATIC REPRESENTATION OF WATER SATURATION DISTRIBUTION AFTER BREAKTHROUGH

$$N_p = X_1 (1-S_{or}) + \int_{X_1}^{1.0} S_w dX \qquad (33)$$

by substitution of Equations 22 and 23 and integration Equation 33 becomes:

$$N_p = S_{wm} + \frac{1}{M-1} (2\sqrt{W_i MB} - W_i - B) \qquad (34)$$

Equation 34 is valid up to the moment that $X_1 = 1$ or according to Equation 23, for $W_i < MB$. The recovery is given by $N_p = 1 - S_{or}$ if $W_i \geq MB$.

The theory presented above was derived for a porous medium containing no connate water, and it involved numerous simplifying assumptions. However, in spite of these limitations, the theory could be used to predict the observed behaviour of the CWO oil. The calculations and the comparison can be found in Chapter 7.

4. EXPERIMENTAL EQUIPMENT

Viscosity correlations were obtained from the Research Council of Alberta for the refinery fractions, and the manufacturer provided this information for the Dow Corning fluid. The viscosities were checked with a Bendix Lab Viscometer. Satisfactory agreements were obtained.

Interfacial tensions were measured with a Du Nouy tensiometer (A. Krüss, Nr. 1385). The measured values were corrected using the data of Zuidema and Waters[21]. Several tests were performed on each system, and the reported interfacial tensions are arithmetic averages.

Imbibition tests were conducted with apparatuses similar to that described by Bobek et al.[22]. Small Lucite cylinders contained the unconsolidated sand.

The displacement equipment is shown schematically in Figure 4. Pictures of the experimental layout are presented in Figures 5 - 7. Water and oil in the bombs were displaced with mercury driven by one or two positive displacement Ruska pumps. An Hg - detector connected to a relay assured that the power supply was cut off if mercury reached the tip of an electrode installed in a vertical flow line just above the bombs. This design removed the danger of getting mercury into the

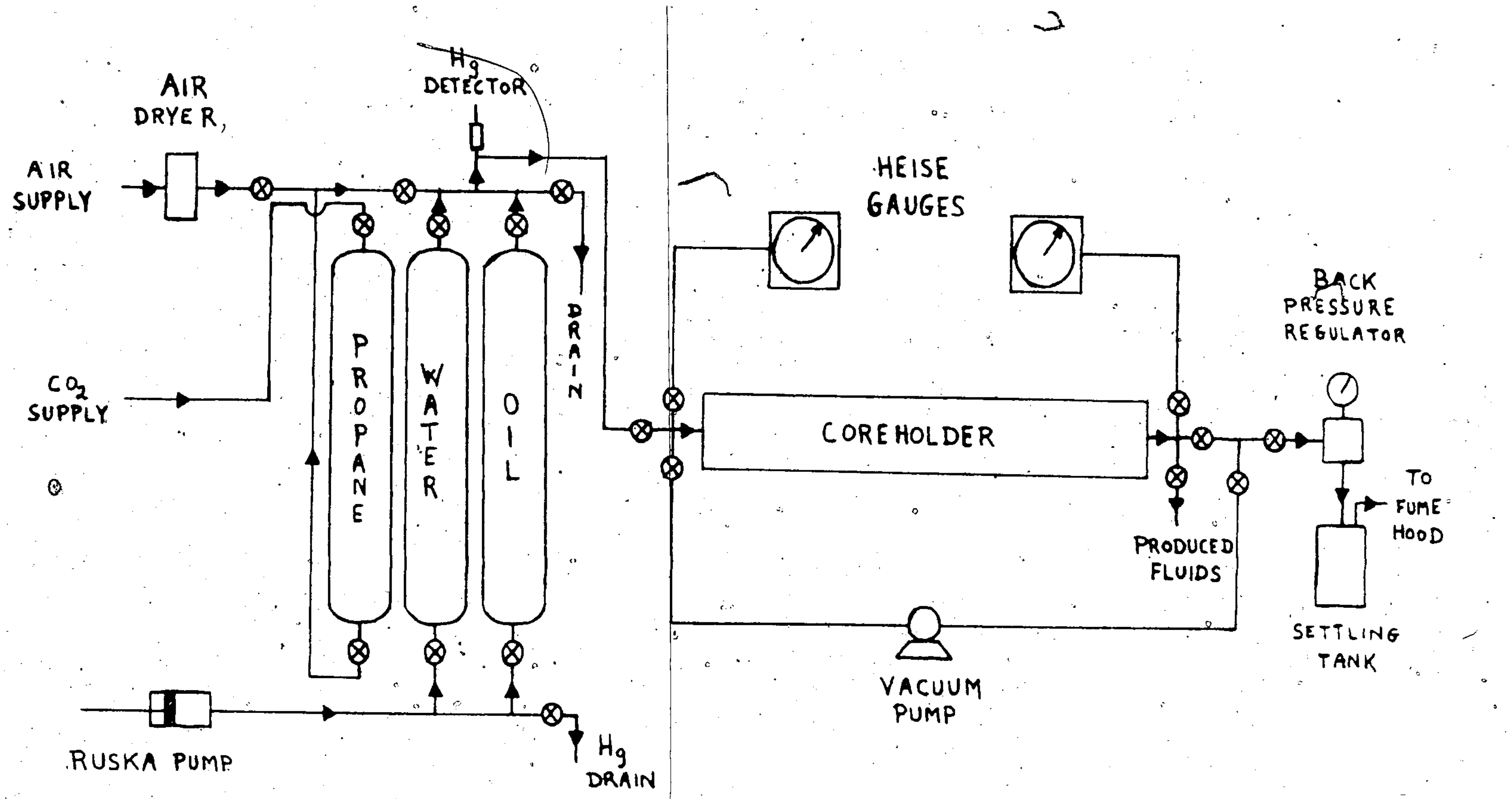


FIGURE 4 : SCHEMATIC FLOW DIAGRAM OF THE DISPLACEMENT EQUIPMENT

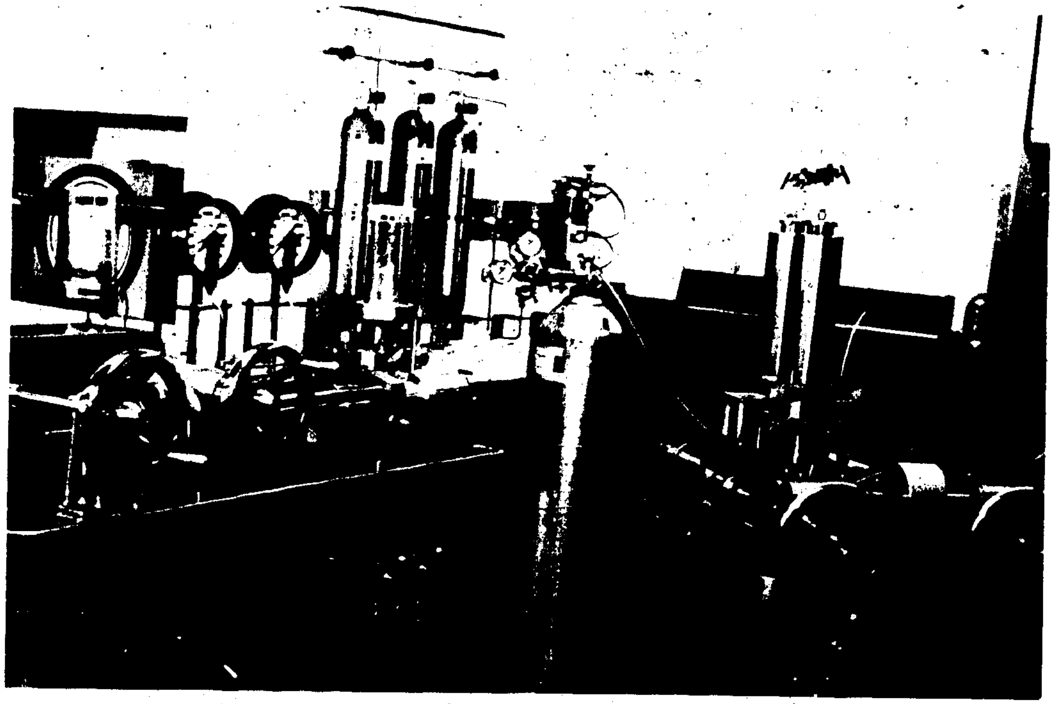


FIGURE 5: PUMPS AND INLET LAYOUT

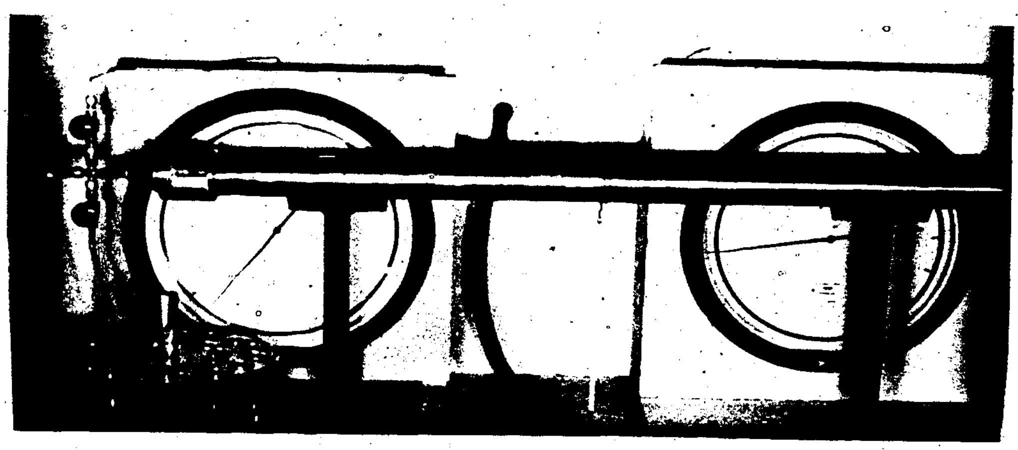


FIGURE 6: COREHOLDER, GAUGES AND OUTLET

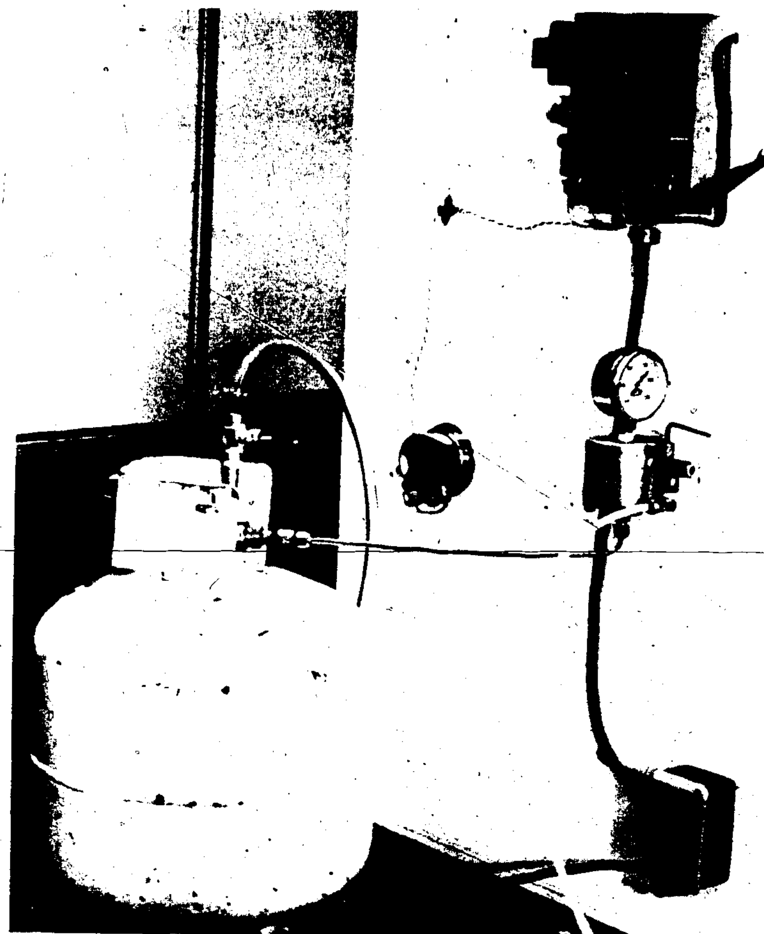


FIGURE 7: BACKPRESSURE REGULATOR
AND SETTLING TANK

sandpack.

Pressure drops were measured on Heise gauges (range 0-300 psig). The vacuum pump was a Duo-Seal, model 1405.

Two different coreholders were employed:

Run 1-46: Stainless steel tube, Length = 117.3 cm
ID = 5.08 cm, OD = 6.03 cm

Run 47-49: Lucite tube, Length = 134.8 cm
ID = 5.08 cm, OD = 6.35 cm

A new type of endpiece was designed for the stainless steel coreholder, see Figure 8. The Teflon packings are expanded when the conical metal rings are forced to move by tightening the nut. The design was tested to 2000 psig without leaks. The Lucite coreholder has been described in detail by Kloepfer[19].

~~Movement of the sand was prevented by a 200-mesh~~ stainless steel screen clamped down on top of the spreader plate, see Figure 8. The screen also kept the grooves in the plate free from sand so that the spreading ability was retained.

The propane was driven by carbon dioxide. A back pressure regulator (Grove) maintained the pressure necessary to keep propane liquefied. Separation of the two phases was done in an old propane tank, see Figure 7, and the gas led to a fume hood.

The fluid bombs were taken out of the holders and

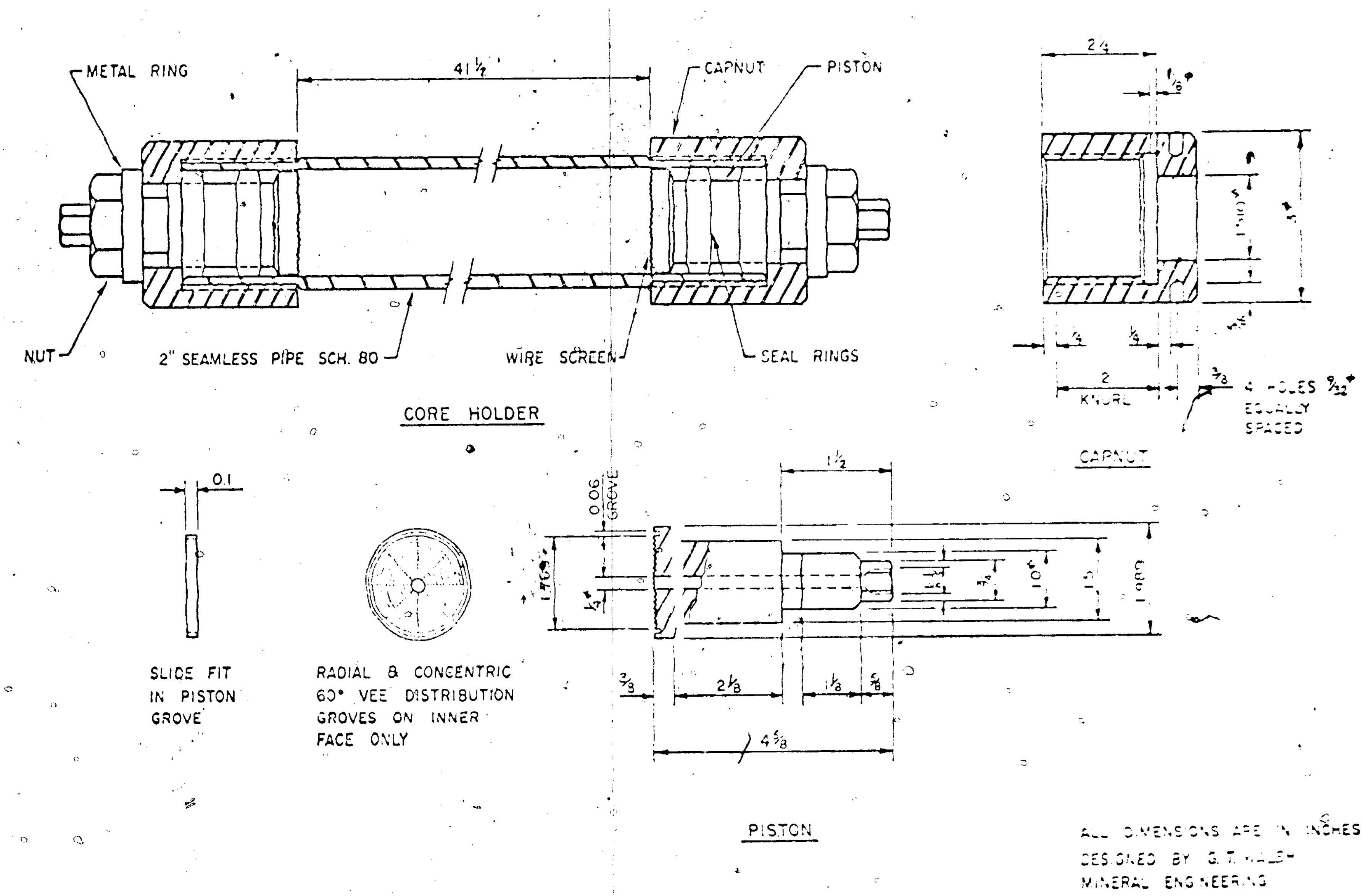


FIGURE 8: THE DESIGN OF THE STAINLESS STEEL COREHOLDER

filled externally. The 90° bend in the tube connections, see Figure 5, simplified this procedure.

5. EXPERIMENTAL MATERIALS

5.1 Fluids

Distilled water was the displacing fluid in all runs. It was dyed with potassium permanganate in the experiments with the Lucite coreholder.

Displacement tests were conducted with three different oils. Two refinery fractions, CWO and MCT 5, were obtained from Imperial Oil through the Energy Conservation Board's Laboratory. Private communication[23] indicated that the approximate compositions of these oils in volume % were:

	Aromatics	Naphthenes	Paraffins
CWO	25	70	5
MCT 5	15	75–80	10–15

The third oil was a Dow Corning 200 Fluid with a viscosity of 100 CS. This is a silicone oil with a density very close to that of water at room temperatures. The viscosity is a weak function of temperature compared with normal hydrocarbon fluids.

Viscosity, as a function of temperature for all four fluids, is given in Table 1. The values of the interfacial tension between water and each of the oils are also given.

TABLE 1

FLUID PROPERTIES

Temperature (°F)	Viscosity (cp)			
	Distilled Water	CWO	Dow Corning 200 Fluid (100 CS)	MCT 5
68	1.005	15.6	111.8	–
69	0.992	15.4	110.9	34.3
70	0.980	15.2	110.0	33.9
71	0.966	14.6	108.1	33.5
72	0.954	14.4	106.3	32.6
73	0.941	13.8	104.4	31.7
74	0.929	–	102.5	30.8

Oil Type	Interfacial Tension Between The Oil And Distilled Water At 74°F (dynes/cm)
CWO	21.7
Dow Corning	34.5
MCT 5	34.4

The fluids were separated and used again. This should assure that equilibrium was reached in case of a reaction between the two phases. Viscosities and interfacial tensions were measured on the recycled fluids, but the variations from the values obtained with fresh fluids were always less than the experimental errors involved.

5.2 Sand

The coreholders were packed with a clean dry Ottawa sand screened to contain grains between 80 and 120 U.S. mesh (Fisher Scientific S-151). The narrow range of particle size and the subrounded nature of the grains facilitated reproducibility of porosity and permeability. Uniform grain size also reduced the unavoidable inhomogeneities.

5.3 Cleaning Agents

Propane driven by carbon dioxide was used to clean the sand. It was preceeded by cyclohexane to clean up the silicone oil, since Dow Corning reported excellent solubility of the 100 CS oil in this hydrocarbon liquid.

6. EXPERIMENTAL PROCEDURES

6.1 Packing of Coreholders

The coreholders were packed with dry sand. Electrical hammers vibrated the tubes as they were slowly filled. A rubber hammer was used every 15-20 centimeters for additional power. The vibrators were then left on for 10-12 hours. A couple of blows with the hammer afterwards could produce a settling of several centimeters. The procedure was repeated until no further settling was observed.

The stainless steel coreholder was opened after run # 46. No settling or channeling of the sandpack could be detected when it was cleaned out.

6.2 Initial Conditions, Porosity and Absolute Permeability

The packed coreholder was mounted in the displacement apparatus. The Ruska pump was used to fill the inlet system with water up to the last valve before the sandface. All valves except those leading to the vacuum pump were closed, and this pump was left on for about 20 minutes. (Later experiments showed that the absolute pressure of the system was reduced to around 5-7 mm Hg). The valves leading to the vacuum pump were then closed, the pump shut off and the inlet valve opened. The Ruska pump was used to push water from the bomb into the pore space. The outlet valve was opened as soon as the pressure indicators on the pump started to climb. Water was injected until a stabilized flow pattern, input equal to output, was established. This usually required 2-3 pore volumes. The scale on the pump gave the volume injected. The amount of fluid ejected was measured, and the difference between the two was taken as the volume of the pores. The bulk volume was calculated and the porosity determined.

Pressure drops across the sandpack were measured at several stabilized rates, and the absolute permeability to water calculated from Darcy's Law. The reported values are the arithmetic average for each case.

6.3 Initial Water Saturation and the Effective Permeability to Oil

The core, 100% saturated with water, was then flooded with oil at a fairly low rate (used 100 cc/hr). After the injection of 1000 cc, the rate was increased to 1120 cc/hr. and kept constant until water ceased leaving the core. The pressure drop was recorded and used to calculate the effective permeability to oil at the initial water saturation, denoted K_{oi}. The initial water saturation was calculated from a volumetric balance.

The core was flooded with oil after each experiment to restore the initial conditions. Earlier work by

Maguss[24] and some preliminary runs showed that this had to be done exactly the same way each time for any given waterflood series to obtain reproducibility. Even then problems were encountered as is evident from Figure 9. These are further discussed in Chapter 8. The procedure used was the same as the one given above to arrive at the initial saturation. An additional 200-1200 cc of oil was usually required to reach the stage where almost no water was produced at 1120 cc/hr.

6.4 Waterflooding

Rates were selected utilizing the gear facilities on the Ruska pumps. Production was gathered in graduated cylinders and centrifuge tubes. Pressure drops across the coreholder and the produced volumes of oil and water were recorded at different intervals. The breakthrough of water was taken as the time the first drop of water was produced in the effluent for the runs on the steel coreholder. At high rates however, some water is produced along with the oil almost immediately. Breakthrough was then taken as the point where the water-oil ratio increased by a factor of approximately 10.

Runs were terminated when water-oil ratios greater than six were reached. Because of the excessive time involved, some of the slow experiments were only brought to the breakthrough point. The same was done with several tests performed to check the reproducibility of results. For each oil a residual oil saturation was obtained, and the effective permeability to water at that condition was calculated. This was the last test performed before the sand was cleaned in preparation for a new test series.

6.5 Cleaning Procedures

The sand was thoroughly cleaned before a change to a new oil took place. Liquid propane was driven through the pack by carbon dioxide. An appropriate back pressure assured that the propane did not vaporize.

Cyclohexane was employed to obtain proper cleaning after the runs with silicone oil.

The complete clean-up procedures were:

1. After CWO - runs: 3000 cc of propane at 150 psig
   3 x 3000 cc of propane at 400 psig
2. After Dow Corning 200 Fluid runs:
   3000 cc of cyclohexane
   3 x 3000 cc of propane at 400 psig

In both cases dried air was passed through the sand for three days before a new test was started.

The reproducibility of the initial conditions, see Table 2, is within experimental errors. This indicates that the cleaning procedures were sufficient.

6.6 Imbibition Tests

Imbibition tests were carried out with small Lucite coreholders. They were evacuated before saturation with the desired fluid. The saturated cores were placed in the imbibition cells, and the apparatuses filled with the imbibing liquid. The amount of liquid exchange after 72 hours was recorded. Tests were performed on the following systems:

	Core System	Imbibing Fluid
1.	Clean sand and water	CWO oil
2.	Clean sand and water	Dow Corning Fluid
3.	Clean sand and water	MCT 5
4.	Clean sand and CWO	Water
5.	Clean sand and Dow Corning Fluid	Water
6.	Clean sand and MCT 5	Water

7. RESULTS AND DISCUSSION

7.1 Sandpack Properties

The design of the stainless steel coreholder is such that the length of a sandpack has to be determined after packing as the total length of tube and endpieces less the fixed length of the endpieces.

Length and diameter for both coreholders are given in Table 2 together with the porosity and the permeability values determined initially and after each cleaning procedure.

Runs 1 - 46 were all performed on the same sandpack. The sand was thoroughly cleaned and dried before a change of the displaced fluid and a redetermination of the initial conditions took place. The variation in porosity values from these tests are within the errors involved in determining the volumes of injected and ejected water. The permeability variations are also within the experimental error.

The porosity and permeability value for the experiments with the Lucite coreholder, runs 47 - 49, differed from those obtained on the steel coreholder, even though the same type of sand was used in both cases. However, the sand used to fill the Lucite coreholder was from a different shipment than that used for the steel tube. A

TABLE 2

CORE PROPERTIES

Diameter = 2" = 5.08 cm

all runs:

The sand was Fisher Scientific S-151 80 - 120 mesh

run 1 - 46: Length = 107.38 cm (steel)

run 47 - 49: Length = 134.78 cm (Lucite)

Run #	ϕ Porosity (%)	K_a Absolute permeability to water (darcy)	Sand Status
1-20	37.2	16.9	new
21-29	37.1	16.7	cleaned
30-46	37.3	17.1	cleaned
47-49	40.0	13.8	new

possibility exists that the variation in sand parameters was caused by a distributional variation within the specified grain size range.

Another, and more likely cause of the higher porosity value was the settling problem encountered when the Lucite coreholder was packed. The tube was discoloured from previous experiments and had to be washed with various hydrocarbon solvents. The chemicals attacked the inner surface and made it rough, and it was evident that this created a settling problem. A looser pack would explain the higher value obtained for the porosity with this coreholder.

The chemicals also removed the hard glossy surface and made the tube vulnerable to further attack as manifested by small amounts of dissolved plastic in the effluent water. Plastic particles might have caused a blocking of some of the available flowpaths, and this could explain the lower value obtained for the absolute permeability.

The porosity and permeability values given in Table 2 are in the same range as those determined by Kloepfer[19], who performed tests with the same sand.

7.2 Displacement Tests

Pertinent data from the displacement tests are given in Table 3. Detailed results from each run are included in

TABLE 3

DISPLACEMENT TEST DATA

RUN #	OIL	S_{wi} (%)	K_{oi} (darcy)	Q (cc/hr)	V x 10^3 (cm/sec)	V (ft/day)	RECOVERY BREAKTHROUGH	(%I.O.I.P.) WOR=6	RECOVERY BREAKTHROUGH	(%P.V.) WOR=6	I x 10^3
1	CWO	10.7	11.0	20	0.27	0.78	<48.6	53.3	<43.3	47.6	33.4
2	$\mu_o/\mu_w = 15.5$	12.3	10.6	40	0.55	1.55	<45.1	52.3	<39.6	45.8	68.7
3		16.4	10.8	20	0.27	0.78	48.7	51.9	40.7	43.4	33.4
4		17.7	10.8	140	1.92	5.44	<47.0	54.6	<38.6	44.9	237.3
5		17.6	11.0	200	2.74	7.77	36.5	56.5	30.1	46.5	334.4
6		18.0	10.8	20	0.27	0.78	48.6	53.1	39.9	43.5	33.4
7		17.8	10.7	70	0.96	2.72	46.2	56.3	38.0	46.[illegible]	117.04
8		18.2	10.7	120	1.64	4.66	44.1	57.4	36.1	46.9	[illegible]
9		20.4	10.9	1120	15.35	43.51	45.7	58.2	36.3	46.3	1872.7
10		21.1	10.8	320	4.39	12.43	48.1	59.1	38.0	46.6	535.0
11		22.8	10.8	480	6.58	18.65	43.6	58.5	33.6	45.2	802.6
12		21.7	10.8	640	8.77	24.86	46.7	60.6	36.6	47.5	1070.1
13		23.3	10.8	960	13.16	37.30	48.9	58.9	37.5	45.2	1605.1
14		24.2	10.9	6.25	0.086	0.24	51.0	55.6	38.7	42.1	10.2
15		24.0	10.6	1720	23.57	66.82	46.7	-	35.5	-	2875.9
16		23.6	10.6	2320	31.80	90.13	45.9	60.1	35.0	45.9	3879.1
17		22.6	10.7	2.5	0.034	0.10	53.7	-	41.6	-	4.18
18		23.5	10.8	6.25	0.086	0.24	54.2	-	41.6	-	10.45
19		24.5	11.0	35	0.48	1.36	51.7	-	39.1	-	57.1
20		25.6	10.7	3520	48.24	136.75	46.7	60.7	34.9	45.4	5657.1

TABLE 3 (Continued)

DISPLACEM[illegible]T DATA

RUN #	OIL	S_{wi} (%)	K_{oi} (darcy)	Q (cc/hr)	V x 10^3 (cm/sec)	V (ft/day)	RECOVERY BREAKTHROUGH (%O.O.I.P.)	WOR=6 (%O.O.I.P.)	RECOVERY BREAKTHROUGH (%P.V.)	WOR=6 (%P.V.)	I x 10^3
21	DOW*	9.6	12.7	160	2.19	6.22	25.9	38.9	23.8	35.1	160.4
22	CORNING	10.0	12.8	80	1.10	3.11	25.0	38.2	22.6	34.4	81.2
23	μ_o/μ_w = 111.4	10.5	12.6	5	0.07	0.19	32.8	38.0	23.6	34.0	5.15
24		10.8	12.7	15	0.21	0.58	31.2	36.8	28.0	32.6	15.0
25		9.5	12.6	30	0.41	1.17	26.7	34.6	24.2	31.3	30.9
26		9.2	12.7	2.5	0.03	0.10	31.6	-	28.7	-	2.54
27		10.2	12.5	20	0.27	0.78	29.9	35.0	26.9	31.5	20.1
28		9.7	12.5	60	0.82	2.34	26.6	34.2	24.3	30.8	59.3
29		9.5	12.4	320	4.39	12.43	17.3	35.0	16.9	31.7	316.4
30	MCT 5	15.0	[illegible]	100	1.37	3.89	18.4	[illegible]	15.7	40.7	98.7
31	μ_o/μ_w = 34.2	18.7	11.3	200	2.74	7.77	17.3	46.0	14.1	37.4	198.7
32		20.0	11.5	20	0.27	0.78	21.0	-	[illegible]	-	19.94
33		21.1	11.4	10	0.14	0.39	26.8	-	21.2	-	10.21
34		22.5	12.2	5	0.07	0.19	33.3	-	25.8	-	5.13
35		23.0	12.1	400	5.48	15.54	24.3	51.0	16.7	39.3	329.0
36		23.6	12.0	200	2.74	7.77	27.0	-	21.8	-	198.7
37		23.4	11.8	100	1.37	3.88	25.6	58.0	19.6	44.5	100.6
38		27.7	12.2	800	10.96	31.08	37.7	-	27.3	-	794.8

TABLE 3 (Continued)

DISPLACEMENT TEST DATA

RUN #	OIL	S_{wi} (%)	K_{oi} (darcy)	Q (cc/hr)	$V \times 10^3$ (cm/sec)	V (ft/day)	RECOVERY BREAKTHROUGH	(%I.O.I.P.) WOR=6	RECOVERY BREAKTHROUGH	(%P.V.) WOR=6	$I \times 10^3$
39	MCT 5	28.1	11.5	200	2.74	7.77	29.8	-	21.4	-	197.4
40	μ_o/μ_w = 34.2	28.3	11.9	20	0.27	0.78	30.8	-	22.1	-	19.87
41		29.4	11.4	5	0.07	0.19	38.0	-	25.8	-	4.97
42		31.0	11.4	10	0.14	0.39	36.7	-	25.9	-	10.33
43		31.6	11.6	560	7.67	21.76	34.3	59.8	23.4	40.9	571.5
44		32.2	11.7	400	5.48	15.54	33.6	-	22.8	-	408.2
45		33.5	11.9	80	1.10	3.11	29.9	-	19.9	-	79.5
46		32.8	11.9	1120	15.35	43.51	37.8	-	25.5	-	1112.7
47	CWO	15.1	12.3	240	3.29	9.32	41		35.6	-	[illegible]
48	μ_o/μ_w = 15.5	16.4	11.1	6.25	0.086	0.24	39.7 (Corrected)		-	-	-
49		15.6	10.7	320	4.39	12.43	43.6 (Corrected)				

Appendix B. The calculated values of the dimensionless group I are also given in Table 3.

7.2.1 Initial Conditions

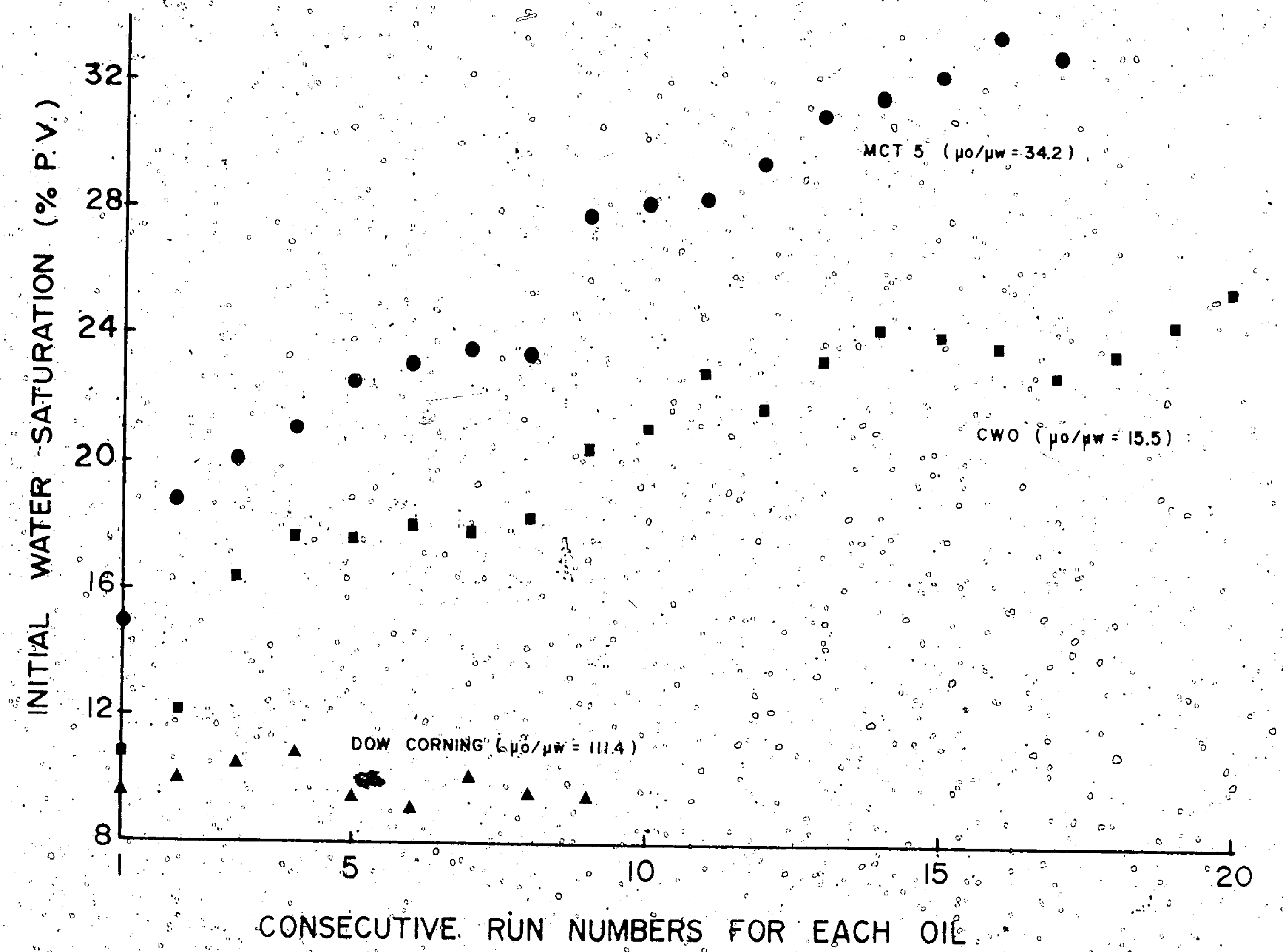
The initial water saturation varied between consecutive runs for the three oil types tested. The variations encountered are plotted as a function of consecutive run numbers for each oil in Figure 9.

The CWO and the MCT 5 oil can be seen to exhibit similar trends, probably a reflection of their similar chemical composition (see Chapter 5).

The initial water saturation was almost constant during the Dow Corning runs according to Figure 9. However, it must be mentioned that it was necessary to sequentially decrease both the amount of oil injected and the injection rate to prevent a decrease in the value of S_{wi}. The water repellency of the silicone oil was believed to be the cause of this phenomenon. The imbibition tests performed, see Appendix A, showed that sand saturated with Dow Corning fluid imbibed less water than the two other sand-oil systems. Water had difficulty in entering the sand once it had been contacted by the silicone oil.

The problems with the initial water saturation are further discussed in Chapter 8.

FIGURE 9: THE VARIATION OF THE INITIAL WATER SATURATION



Note that the effective permeability to oil at S_{wi} (K_{oi} in Table 3) stayed almost constant for each oil, even though the initial water saturation increased significantly during the CWO and the MCT 5 runs. This can be taken as support for the reasoning presented in Chapter 8 on the nature of the initial water saturation and its effect on the performance of the tests.

7.2.2 Oil Recovery at Breakthrough, The Effect of Emulsification and Viscous Fingering

Oil recovery as a function of cumulative amount of water injected at low, intermediate and high rates for each of the oils employed is presented in Figures 10 - 12. The breakthrough points are marked with arrows. The correction applied to the breakthrough point for the Dow Corning curve in Figure 12 is commented upon later.

The lines representing recovery before breakthrough have varying slopes in these Figures due to the differences in the initial water saturations.

The recovery at breakthrough decreased from the low rate to the intermediate rate for all three oils studied, and it was significantly higher for the oil with the lowest viscosity. The breakthrough recoveries for the MCT 5 and the Dow Corning are about the same for the tests shown.

FIGURE 10: RECOVERY HISTORIES AT A LOW RATE

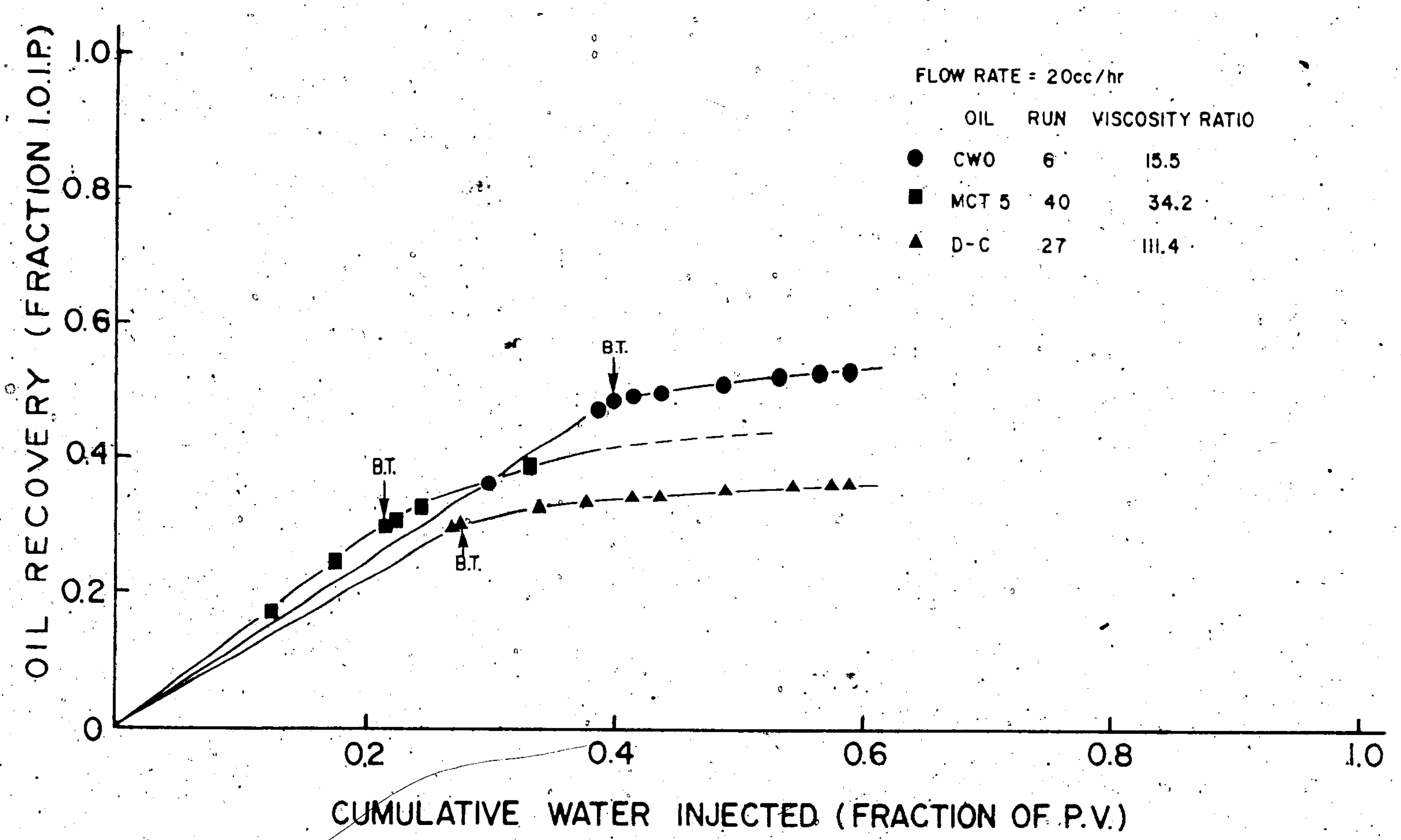


FIGURE 11: RECOVERY HISTORIES AT INTERMEDIATE RATES

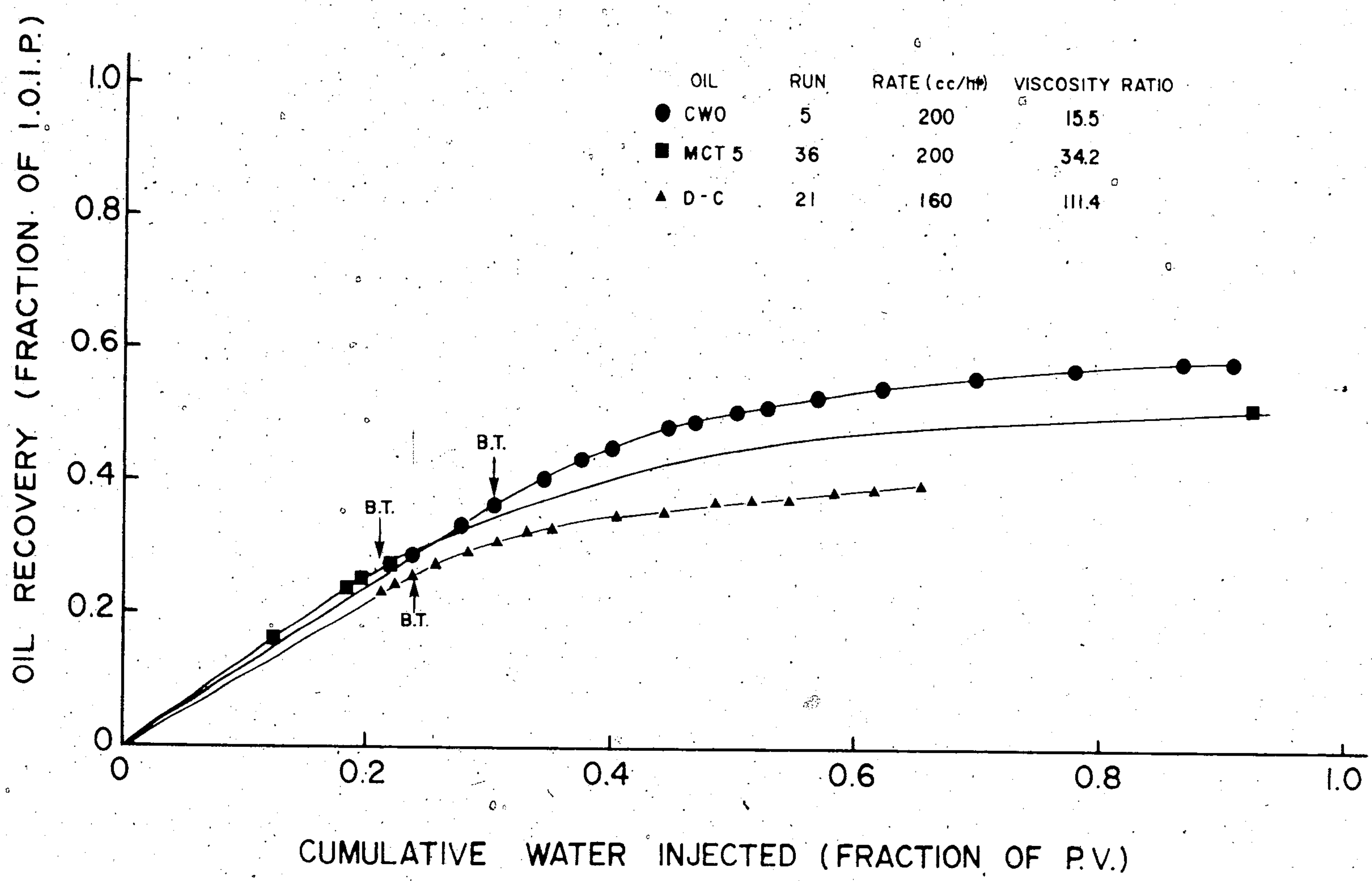
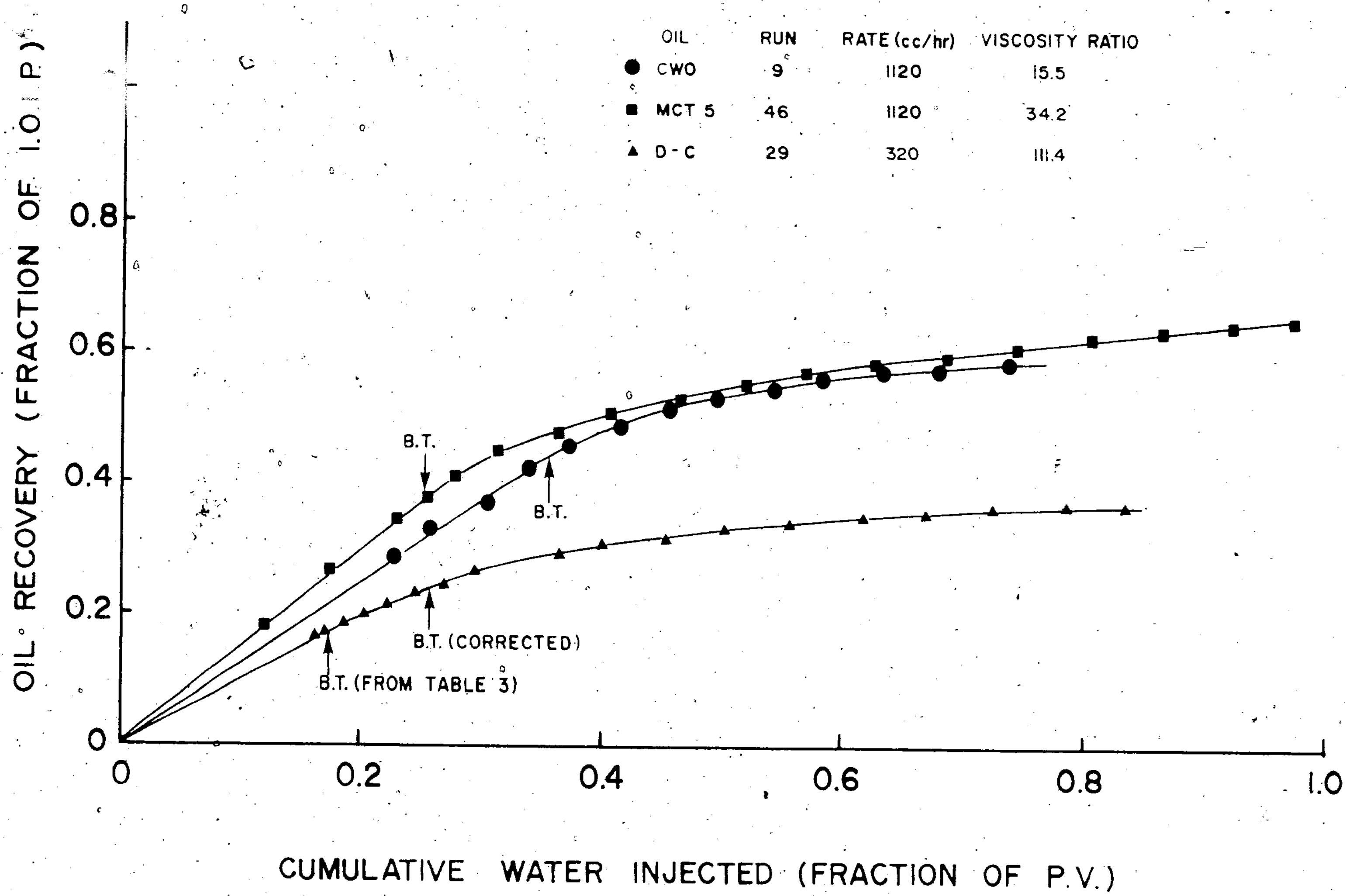


FIGURE 12 : RECOVERY HISTORIES AT HIGH RATES



The relative importance of the production after breakthrough increases with increasing rates and viscosity ratios according to the CWO and MCT 5 curves in Figure 10 and 11. The Dow Corning fluid shows the same variation with rate, but the effect of the higher viscosity ratio is not evident when compared with the two refinery oils.

Figure 12 shows a different relationship between the two refinery fractions. Recovery at breakthrough is still higher for the CWO oil, but more of the MCT 5 was recovered at any value of cumulative water injected. This improvement in the recovery of the MCT 5 oil was observed in all runs where the displacement rate was higher than 200 cc/hr (i.e. runs 35, 38, 43, 44 and 46). These runs correspond to values of the scaling group I larger than 0.2 in Figure 14. It is evident from the sudden increase in the breakthrough recovery value observed in Figure 14, that a change in the mechanisms controlling the displacement took place for a value of I between 0.2 and 0.4.

The change is believed to have been caused by the formation of water-in-oil emulsions in the pore structure. A single phase "slurry" was produced after breakthrough in all these experiments. The stability of the emulsions varied, and the time required for the separation of the two phases was anywhere from 10 minutes to 10 - 15 hours.

The increased breakthrough recoveries can be explained as an interaction between two factors which affect the recovery:

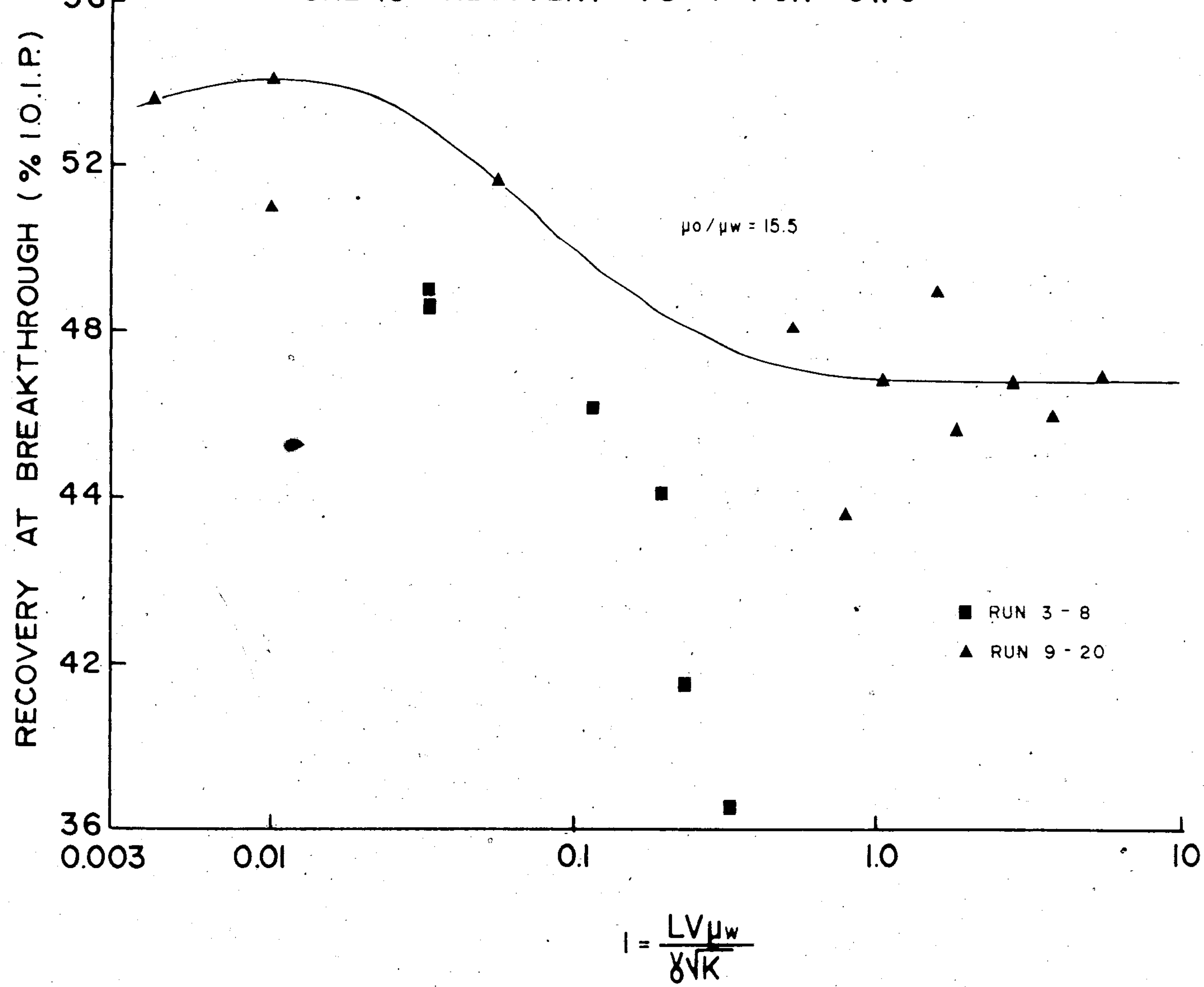
1. The viscosity ratio between the displacing front and the displaced oil decreases since the viscosity of an emulsion depends mainly on the viscosity of the external phase[25], i.e. the oil in this case.
2. The emulsification taking part at the displacing front leads to a partial blocking of paths with low resistance to flow, and this can be expected to improve the microscopic sweep efficiency.

The data shown in Figure 14 indicates that no further improvement of breakthrough recoveries could be obtained once an I value of 0.8 had been reached. The breakthrough recovery at this point, 37.7% of I.O.I.P., is seen to be approximately the same as that obtained with a very low rate.

Figures 13 to 15 show the recovery at breakthrough versus the log of the scaling factor I for the three oils employed.

The data from the CWO and the MCT 5 experiments have been split into two groups representing runs performed in the early stage, where the initial water saturation still changed rapidly between each experiment, and the

FIGURE 13: RECOVERY VS I FOR CWO



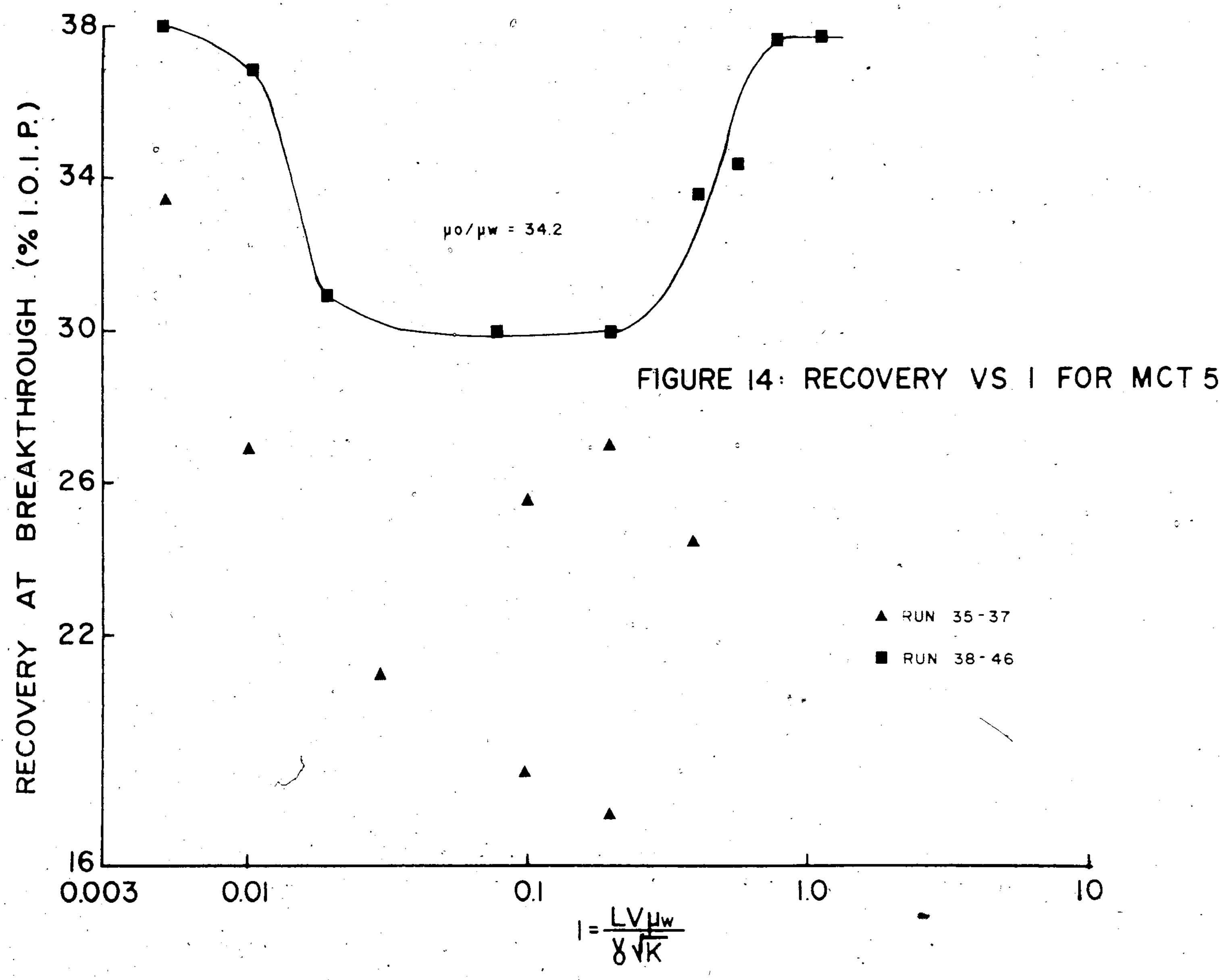
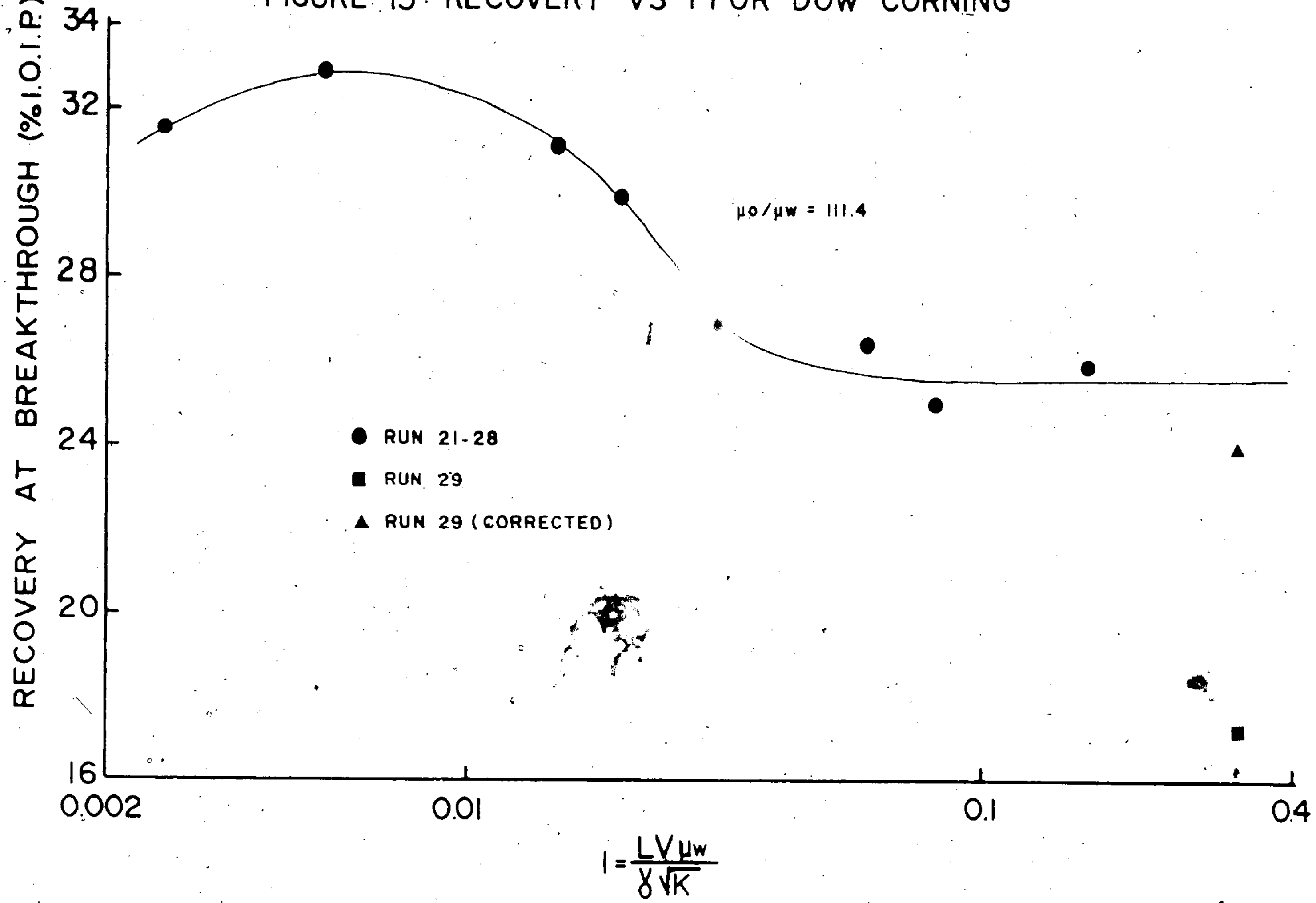


FIGURE 14: RECOVERY VS I FOR MCT 5

FIGURE 15: RECOVERY VS I FOR DOW CORNING



late runs performed with each oil, where the change in S_{wi} was less dramatic. The split can more or less be anticipated from Figure 9. In the case of the CWO oil the first 8 runs are seen to have an initial water saturation less than 18.5%, where as the last 12 runs have S_{wi} values between 20.4% and 25.6%. Only the latter points were considered when the curve in Figure 13 was drawn. The first 8 runs with the MCT 5 had S_{wi} values less than 24%, whereas S_{wi} varied between 27.7% and 33.5% for the last 9 runs which were utilized for the drawing of the curve in Figure 14.

The data obtained with the Dow Corning fluid, Figure 15, could be correlated without discarding runs. This could be expected in view of the almost constant value for S_{wi} during these experiments (see Figure 9). However, it was necessary to correct the breakthrough value obtained in run 29. Breakthrough determined as a 10 fold jump in WOR values gave an abnormally low value for this run. The reason for this was probably the previously mentioned problem of retaining the S_{wi} level. The water in the system became easier to move with every run, and this resulted in a premature breakthrough determination for run 29. The recovery history for this experiment was shown in Figure 12. The breakthrough value given in Table 3 is indicated together with a a corrected breakthrough value obtained by considering an extension of the straight line relationship up to this point. Both points are plotted in Figure 15.

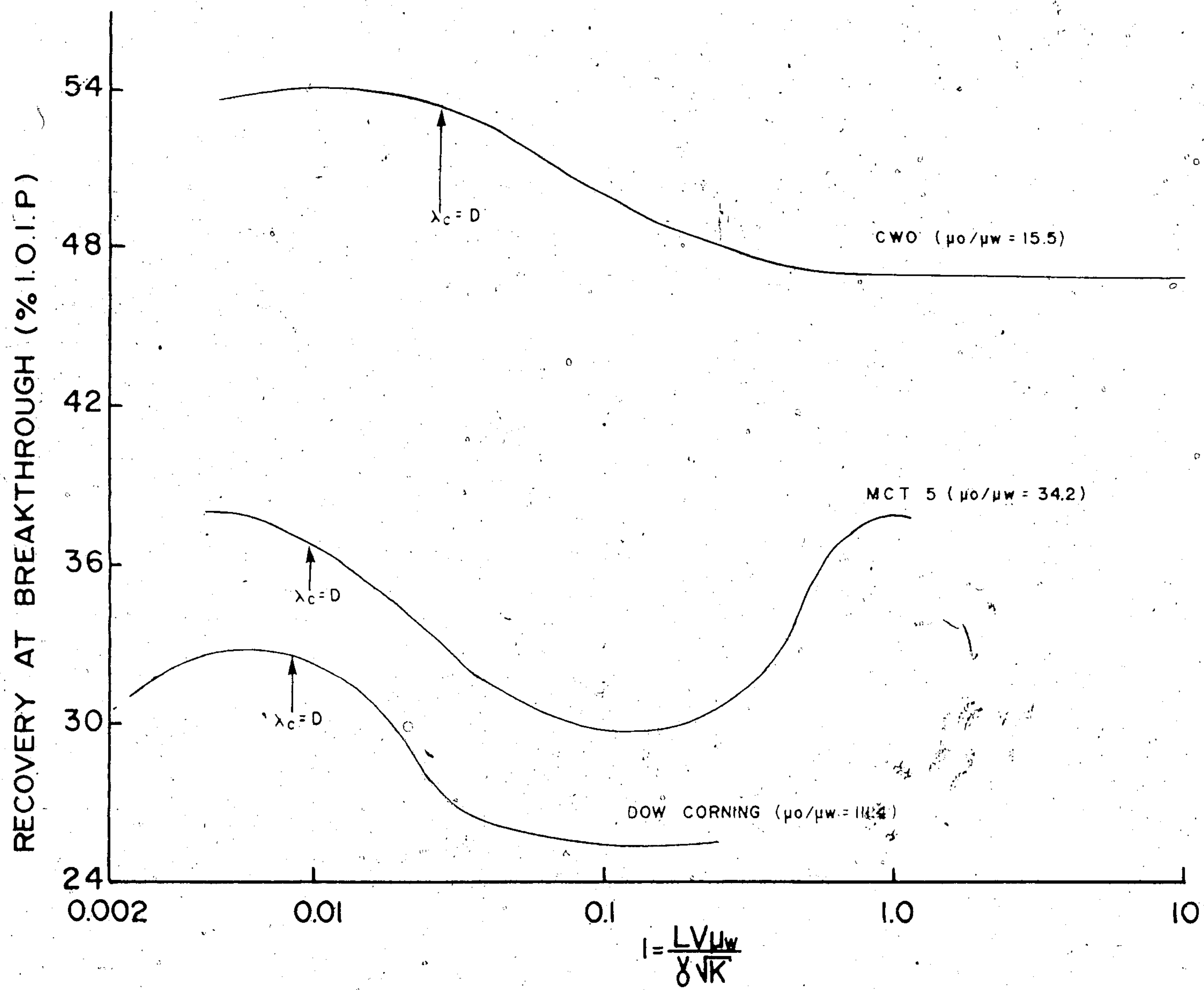
The curves from Figures 13 - 15 have been transferred to Figure 16 to facilitate comparisons. Figure 17 shows breakthrough data from the work of de Haan[5], Engelberts and Klinkenberg[2] and Collins[17] plotted versus the log of the same scaling number.

All the curves shown in Figures 16 and 17 exhibit the same features if the anomally of the MCT 5 curve, the emulsification effect at I values larger than 0.2, is ignored. Similar curves were also obtained by Jones-Parra et al.[16] and Newcombe et al.[26] for comparable systems.

Low values of the scaling group I yielded high breakthrough recoveries. This is explained by the instability theory as the region where the peak-to-peak distance is larger than or in the same order of magnitude as the tube diameter. The displacing front will therefore always move in a piston-like fashion and high breakthrough recoveries can be expected.

Breakthrough recovery decreased with increasing I values in an intermediate range. This is attributed to the formation of viscous fingers. Oil was bypassed and left as "islands" in the pore space behind the flood front.

FIGURE 16 RECOVERY VS I



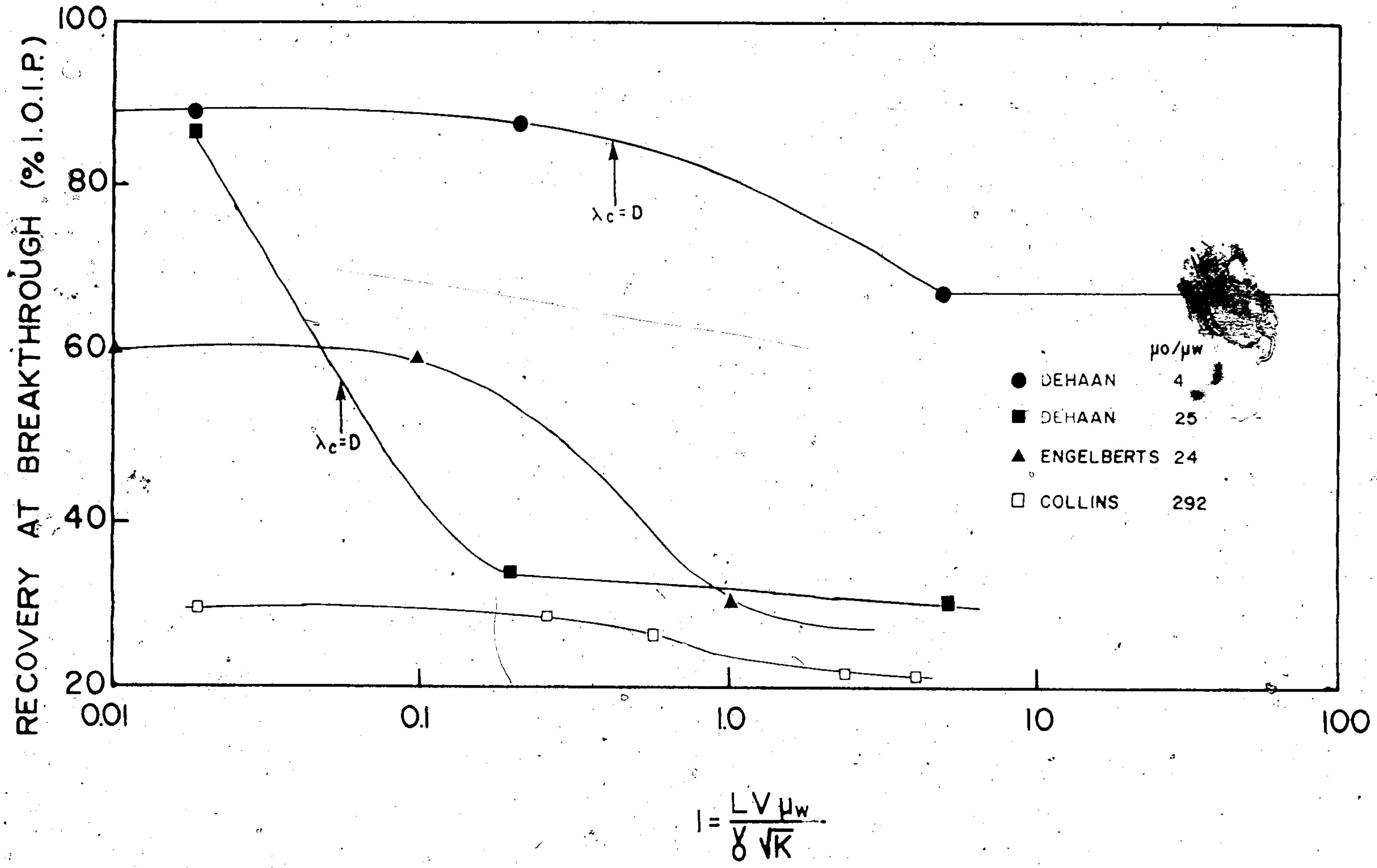


FIGURE 17: DATA FROM THE WORK OF DEHAAN, ENGELBERTS AND COLLINS

The breakthrough recovery stabilized for I values larger than a fixed number for each system. This means that the amount of oil bypassed by the front remained approximately constant as the fingers became more numerous and the distance between the peaks decreased.

Values for the constant C in Chuoke et al.'s[4] theory can be calculated for the systems shown in Figure 16. Recall Equation 4 (Chapter 2):

$$C = \sqrt{\frac{3V\ (\mu_o - \mu_w) D^2}{\gamma K}} \tag{4}$$

and the dimensionless group I determined by:

$$I = \frac{LV\mu_w}{\gamma \sqrt{K}}$$

a combination of these two equations yields:

$$C = \sqrt{\frac{3I\ (\mu_o/\mu_w - 1) D^2}{L\sqrt{K}}} \tag{35}$$

The value of I in Equation 35 must be taken at the point where the decrease in the recovery at breakthrough becomes evident. A point was assigned to each curve as indicated by the arrows in Figure 16. The C values calculated are given in Table 4, together with the value used by de Haan[5] to determine the points shown in Figure 17.

TABLE 4

SYSTEM	VISC. RATIO	C
CWO	15.5	27.7
MCT 5	34.2	24.3
Dow Corning	111.4	39.4
de Haan	4 & 25	30

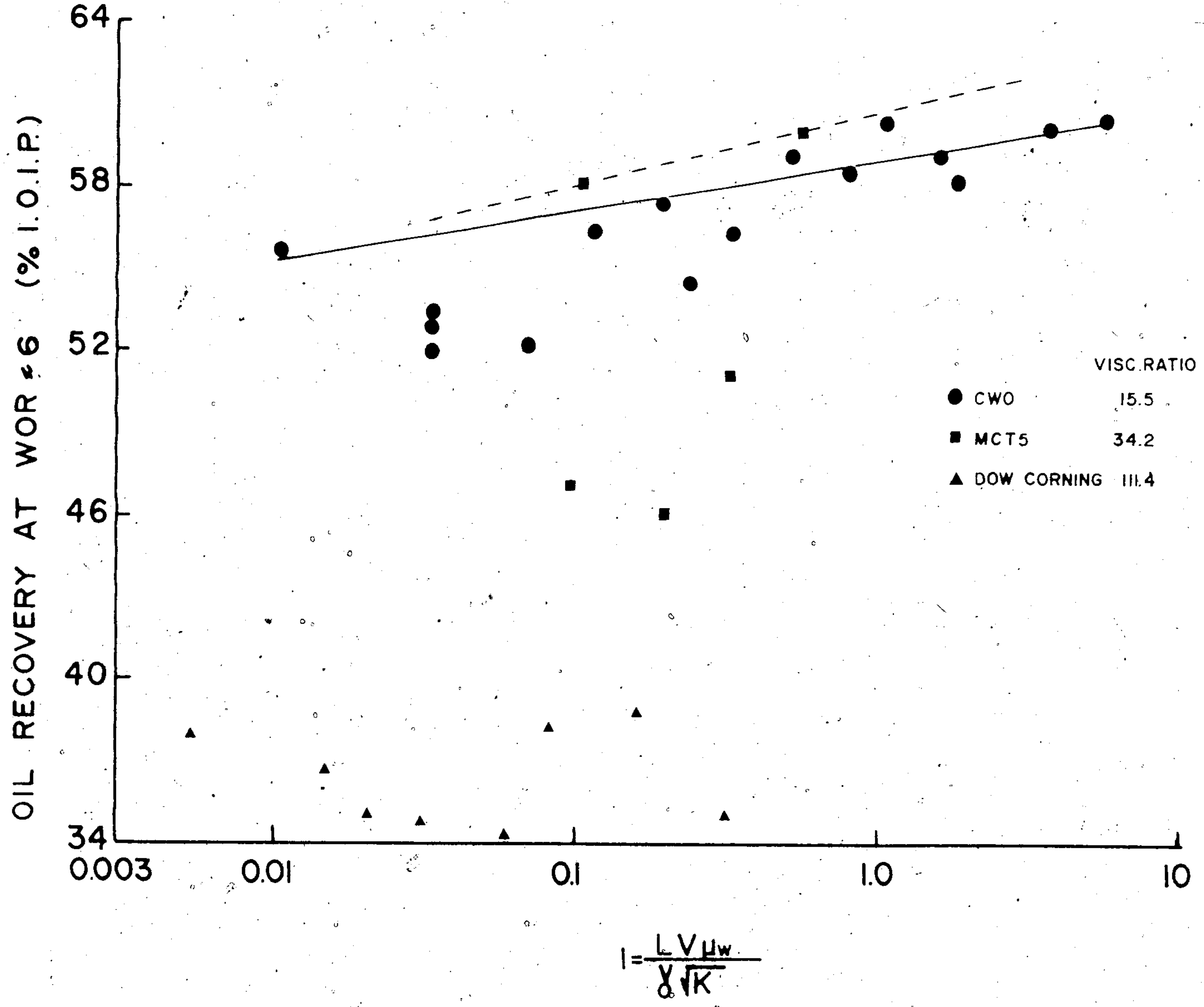
The values of C obtained for the three systems employed are seen to be very close to that used by de Haan[5] to determine the point where the formation of viscous fingers started to influence his breakthrough recovery data. He took the value from Chuoke et al.'s[4] original paper where they found that a C value of 30 gave the best fit between the theory and their visual observations. de Haan's paper and this study indicate that Equation 35 can be used to estimate the value of I at which the viscous fingering phenomenon becomes significant by assuming C = 30 for a wide range of viscosity ratios.

7.2.3 Recovery After Breakthrough

Figure 18 is a plot of the recovery obtained at a water-oil ratio of approximately six (6) versus the log of I.

The data are seen to be scattered. The lines for

FIGURE 18: RECOVERY AT WOR ≈ 6



the CWO and the MCT 5 oil were drawn by discarding the early runs as done before. Only two data points were then left for the MCT 5 case, so this line was dashed. The Dow Corning data points were not exhibiting any trend.

The recovery at WOR ≈ 6 is seen to increase with increasing values of I for the CWO experiments. The dashed MCT 5 line indicates the same, but suffers from the lack of further data points.

Figure 19 shows the recovery at a cumulative throughput of water of 0.5, 0.3 and 0.4 pore volumes for the CWO, the MCT 5 and the Dow Corning oil respectively plotted as a function of the log of the scaling number I.

It appears as if the recovery obtained at an equal amount of injected water stabilized for each oil some time after breakthrough.

7.2.4 Applying the Theory of van Meurs and van der Poel[3]

The following equations were derived in Chapter 3: Recovery at breakthrough was given by:

$$N_{pb} = \frac{A^2}{MB} \tag{31}$$

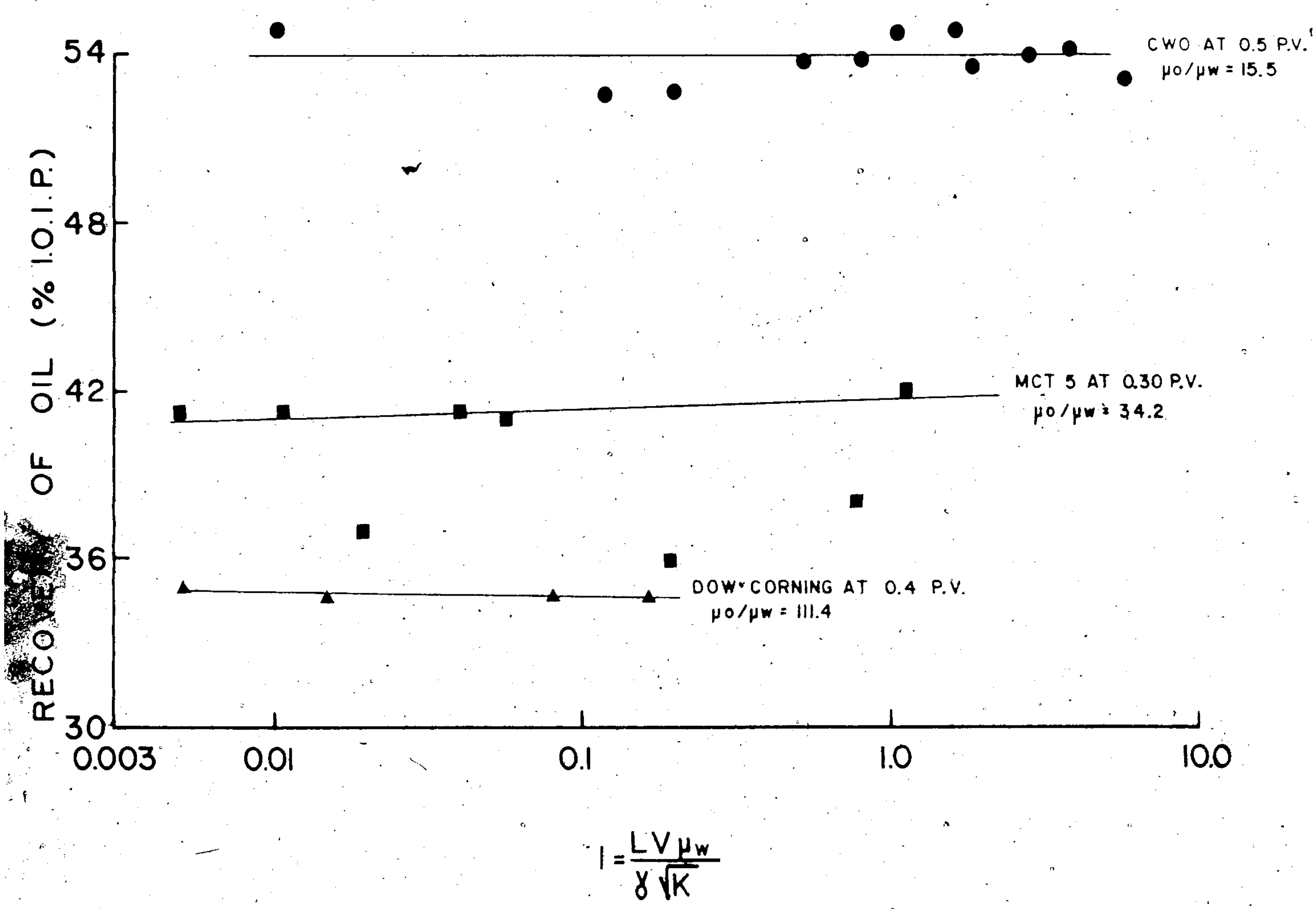
where

$$A = \sqrt{(M-1)BS_{wm}} + B$$

$$M = \mu_o/\mu_m$$

$$B = 1 - S_{or} - S_{wm}$$

FIGURE 19: RECOVERY AT A CONSTANT VOLUME OF INJECTED WATER FOR EACH OIL.



and the recovery after breakthrough was determined by:

$$N_p = S_{wm} + \frac{1}{M-1}(2\sqrt{W_i MB} - W_i - B) \qquad (34)$$

A value for S_{or} was obtained by injecting water at a high rate until practically no more oil was produced. This was done after the last run with each oil, and the values obtained can be found in Appendix A.

a) The CWO System.

From Appendix A: $S_{or} = 0.204$

Runs where viscous fingering occurred were selected, and the value of S_{wm} taken as the S_{wi} value in Table 3. The viscosity ratio, M, was taken as 15.5 for all runs. The calculation of the breakthrough recovery, N_{pb}, is performed in Table 5 and values obtained experimentally have been entered for comparison.

TABLE 5

CALCULATION OF RECOVERY AT BREAKTHROUGH FOR THE CWO OIL

Run	S_{wm}	B	A	N_{pb} (P.V.)	Exp. (P.V.)
10	0.211	0.585	1.923	0.408	0.380
11	0.228	0.568	1.938	0.427	0.336
12	0.217	0.579	1.929	0.415	0.366
13	0.233	0.563	1.942	0.432	0.375

The calculated values are seen to depend heavily on the values introduced for S_{wm}. van Meurs and van der Poel found that S_{wm} = 0.15 gave the best fit for the data available to them. That would yield N_{pb} = 0.335 for the CWO experiments if S_{or} is assumed to be the same as above. A value of S_{wm} between 0.15 and 0.211 leads to theoretical breakthroughs between 33.5% and 40.8% of the pore volume. This encompases all the breakthrough recoveries obtained in the viscous fingering region with this oil.

The theoretical recovery after breakthrough was calculated from Equation 34 for run 10, since this showed the best fit at the breakthrough point:

	Run 10 (320 cc/hr)		
W_i	0.451	0.648	0.874
Exp. N_p	0.403	0.458	0.482
Calc. N_p	0.426	0.468	0.505
ΔN_p	0.023	0.010	0.023

The theory predicts the observed behaviour surprisingly well considering the many assumptions involved in arriving at Equations 31 and 34.

However, the theory could not be used to predict the behaviour observed with the Dow Corning and the MCT 5 oil as is evident from the following.

b) The Dow Corning System

From Appendix A: $S_{or} = 0.47$

From Table 3: $S_{wm} \approx 0.10$

From Table 1: $M \approx 111.4$

this yields: $B = 0.43$

$A = 2.619$

and $N_{pb} = 0.143$ P.V.

The experimental values varied from 16.9 to 29.6% P.V. according to Table 3.

c) MCT 5 - System

From Appendix A: $S_{or} = 0.147$

From Table 3: $S_{wm} \simeq 0.28$

From Table 1: $M \simeq 34.2$

this yields: $B = 0.573$

$A = 2.915$

and $N_{pb} = 0.434$ P.V.

The breakthroughs obtained experimentally were between 14.1 and 25.9% P.V.

7.2.5 Results From the Transparent Lucite Core, Runs 47 - 49

The Lucite coreholder and the dyed injection water were employed to be able to visually observe the behaviour of the CWO system. Run 47 was performed with clear water to stabilize the fluid saturations.

a) Run 48, Rate = 6.25 cc/hr.

No fingering was observed at this rate. Some clear water was produced just ahead of the arrival of the dyed water at the outlet end. Approximately 10 cc of oil was produced between the arrival of the dyed water at the end of the sandpack and the first appearance of coloured water in the effluent.

This indicated that the error introduced by the outlet effect was around 1.3% of the pore volume for the determination of breakthrough with the CWO oil at low rates.

b) Run # 49, Rate = 320 cc/hr.

Numerous fingers were formed at the early stage of the flood. However, they broke up and formed a transition zone with a tongue along the bottom part of the tube. The behaviour was similar to that described by Perkins and Johnston[11].

Clear water was again produced, but this time over the whole period before breakthrough.

Only about 2-3 cc of additional oil was produced between the arrival of the dyed water at the outlet end and its appearance in the effluent. This indicated that the error introduced by the outlet effect was in the order of 0.4% P.V. for breakthrough determinations at this rate.

The dyed water was successfully washed out after the completion of run 48. Approximately 2 pore volumes of clear water was used before the sand was resaturated with oil in preparation for the next run.

7.2.6 Applying Buckley - Leverett Theory

The possibility of applying the Buckley-Leverett theory to obtain the recovery at breakthrough was suggested. The average mobility at this point can be obtained from:

$$\left(\frac{K}{\mu}\right)_m = \frac{L\,q}{A\Delta P_{B.T.}} \qquad (36)$$

where

$\left(\frac{K}{\mu}\right)_m$ = average mobility of the fluids at breakthrough

$\Delta P_{B.T.}$ = pressure drop across the core at breakthrough

It was also mentioned that Equation 36 could be used as a criterion to determine the recovery at breakthrough. Theoretically experiments are only comparable if $(K/\mu)_m$ is the same for each run. The calculations are performed below for runs 10 - 13:

Run	q (cc/hr)	$\Delta P_{B.T.}$ (psia)	$(K/\mu)_m$
10	320	5.0	1.39
11	480	8.6	1.21
12	640	11.4	1.21
13	960	13.8	1.51

Note that the following conversion is necessary to obtain consistent units above:

$$\left(\frac{K}{\mu}\right)_m = \frac{14.7 \times 107.38\, q}{60^2 \times 20.268\, \Delta P_{B.T.}} = 0.021642 \frac{q}{\Delta P_{B.T.}}$$

These results indicate that the scattering in the data presented might have been caused by the inability to obtain the same conditions for each run as evident from the random changes in the average mobilities calculated above.

8. ERROR SOURCES

8.1 Experimental Errors

The mercury in the pump cylinder was subjected to the static head of the mercury reservoir when filled and the static head of the fluid bomb after each injection cycle. The volume of injected fluid taken from the scale on the pump will therefore be in error due to the compressibility of the mercury. The error was found to be in the order of 1-4 cc for the porosity determinations, depending on the levels of mercury. This would show up as a maximum error in the porosity values obtained for runs 1 - 46 of approximately 0.2%.

The respective volumes of oil and water in the pores at any moment were thereafter calculated from volumetric balances. The total volume ejected was measured and taken as the true volume injected. The possibility of a cumulation in the error discussed above was thereby prevented.

Gravity segregation affected these tests since the oils had densities different from that of the water. The effect was reduced by rotating the coreholder 180° each time the injection fluid was changed. However, the core could not be rotated during an experiment. The tests performed on the transparent system indicated that gravity segregation might be an important factor even though it has been neglected in most of the work done on horizontal linear displacements.

The permeabilities calculated are subjected to errors involved in determining the pressure across the sandpack. The pressure drops during the determination of absolute permeabilities were in the range of 2 - 3 psia, and small errors in zero-setting or reading off the gauge could easily explain the variation from 16.7 to 17.1 darcys obtained in the tests on the steel coreholder (see Table 2, Chapter 7).

The determination of breakthrough for runs 1 - 46 was influenced by the outlet end effect. The magnitude of the error introduced was in the order of 0.4 - 1.3% P.V. according to the experiments with the transparent system.

8.2 The Nature of the Initial Water

Run 48 and 49, conducted with dyed injection water, showed that some of the initial water in the system was mobile. Water was always produced along with the oil at high rates (see the tables in Appendix B), but at low rates no water was produced until just before breakthrough. This difference in behaviour was probably caused by the capillary end effect, which prevented water from leaving the core until the exerted pressure gradient exceeded the capillary pressure.

The mobile nature of the connate water has been studied by several researchers[27,28,29]. It has been shown that connate water, in many cases, is banked up ahead of the displacing fluid, and it is this bank which actually displaces the oil[28,29].

Breakthrough determined as the point when water reaches the outlet end differs from the actual breakthrough of injected water when the initial water is banked up ahead of the front. It was impossible to estimate to what degree this affected the breakthrough recoveries obtained.

The recovery at breakthrough was seen to increase with increases in the initial water saturations during the preliminary runs with both the CWO and the MCT 5 oil when the curves in Figures 13 and 14 were established. Two explanations of this behaviour seems to be possible:

1. A contact period was necessary to bring out effects of the water-wet nature of the sand. It retained more and more water closely bounded to the grain surface as time passed, and less water was left to move and cause premature breakthroughs.
2. W/o emulsions were formed in the sandpack. The water globules in the oil phase would be difficult to move, and the increase in the initial water saturation will therefore not lead to a greater mobility of the initial water.

Emulsions could have been formed with the CWO oil in view of the similarity in composition between the two oils. However, these must have been unstable since no emulsification was evident in the effluent during runs 1 - 20.

An equilibrium stage would be expected if reactions between the sand grains and the fluids were important. It is evident from Figure 9 that the S_{wi} never reached an equilibrium level in the CWO and the MCT 5 runs. However, it had a tendency to stabilize for a few runs at various levels.

It might be that the variations observed could be explained by a combination of 1 and 2 mentioned above.

There is no doubt about the fact that the greatest uncertainties in the data obtained in this study were introduced by the variation of the initial water saturations between consecutive runs and the mobile nature of this water.

9. CONCLUSIONS

The following conclusions are made based upon the experimental data and the discussion presented:

1. The initial water in an artificial unconsolidated core is mobile. The determination of breakthrough as the moment water reaches the outlet end might therefore differ from the value obtained if the breakthrough of the injected water could be detected separately.
2. Formation of viscous fingers caused decreasing breakthrough recoveries. This took place for values of the scaling factor I between 0.005 and 0.02 with the three oils studied.
3. High breakthrough recoveries were obtained at low values of "I".
4. The breakthrough recovery stabilized at high values of the scaling factor. The stabilization took place for "I" values larger than 0.1 with the MCT 5 and the Dow Corning systems. "I" had to exceed 0.8 in the case of the CWO oil before breakthrough recoveries stabilized.
5. The value of the scaling group I at the point where viscous fingers will begin to form can be estimated for all three systems studied if a value of 30 is assigned to the constant C in

Chuoke et al.'s[4] theory. The same value was obtained by them in their experimental work, and de Haan[5] used it to successfully predict the onset of fingering in his experiments.

6. Breakthrough recoveries were drastically improved when a water-in-oil emulsion was formed.
7. The simplified theory of van Meurs and van der Poel[3] might deserve more attention. The problem seems to be the determination of reasonable values for S_{wm} and S_{or}.

10. RECOMMENDATIONS

The following modifications of the displacement apparatus might prove useful:

1. Design a high pressure swivel connection so that the coreholder can be rotated during a displacement experiment. A slow rotational movement would reduce the observed effect of gravity.
2. The outlet end of the stainless steel coreholder should be redesigned, if possible, so that breakthrough can be detected as the moment the injected fluid reaches the end of the sandpack.

The following suggestions are made for further experimental work in the same area:

3. Conduct an investigation of the nature of the initial water. The effect of the mobile character on the determination of breakthroughs should be studied, together with the effect of letting cores "age" before they are employed in a displacement experiment.
4. Consider the necessity and feasibility of dying either the injected water or the water used to establish the initial saturation.

- Tests should be performed with systems having viscosity ratios in the order of 500 and higher in view of the current interest in the recovery of extremely viscous crude oils.
- The diameter of the coreholder should be varied to study the effect of the canal width on the occurrence of viscous fingers.

NOMENCLATURE

A	=	$B + \sqrt{B\ (M-1)\ S_{wm}}$
B	=	$1 - S_{or} - S_{wm}$
C	=	dimensionless constant
D	=	diameter of tube
f_w	=	fractional flow of water
I	=	$\frac{LV\mu_w}{\gamma\sqrt{K}}$, dimensionless group
K	=	absolute permeability, cm^2
K_a	=	absolute permeability, darcy
K_{oi}	=	effective permeability to oil at S_{wi}
$K_{wS_{or}}$	=	effective permeability to water at S_{or}
k_{ocw}	=	permeability to oil at connate water saturation
k_{wor}	=	permeability to water at residual oil saturation
k_{ro} ($\bar{S}$	=	normalized relative permeability to oil at the shock saturation.
k_{rw} (S_s	=	normalized relative permeability to water at
L	=	length of tube
L_t	=	$\frac{\gamma \cos\theta \sqrt{K\phi}}{LV\ \mu_w}$
M	=	viscosity ratio

M_s = shock mobility ratio

N_p = cumulative oil production

N_{pb} = recovery at water breakthrough

P_c = capillary pressure difference

P_o = pressure in oil phase

P_w = pressure in water phase

q = water injection rate

q_o = amount of oil flowing through a unit cross section of the formation per unit time

q_w = amount of water flowing through a unit cross section of the formation per unit time

S_c = critical water saturation

S_o = oil saturation

S_{or} = immobile oil saturation

S_w = water saturation

S_{wi} = initial water saturation

S_{wm} = immobile water saturation

t = time

V = total flow rate per unit cross sectional area

V_c = speed of propagation of S_c

$$= \left(\frac{dX}{dt}\right)_{S_w = S_c}$$

V_o = darcy single-phase flow velocity for oil

V_w = darcy single-phase flow velocity for water

W_i = $\frac{\int q\, dt}{\phi L}$, cumulative production

x = distance in x-direction

X = $\frac{x}{L}$

X_1 = Coordinate where $S_w = 1 - S_{or}$

X_c = highest value of X where water occurs

γ = interfacial tension

η = kinematic viscosity

θ = wetting angle

λ_c = critical wavelength

λ_m = wavelength of maximum instability

μ_o = viscosity of oil

μ_w = viscosity of water

ϕ = porosity

ρ = density

ω = constant

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APPENDIX A

PROPERTIES OF FLUIDS AND SAND

PROPERTIES OF FLUIDS AND SAND

The Gasoline and Oil Laboratory, Research Council of [illegible] measured the following viscosities and densities for [illegible] the MCT 5 oils:

Viscosity In Centistokes

	CWO	MCT 5
at 70°F	17.69	39.53
at 100°F	9.47	19.04
at 130°F	5.93	10.74

Densities

	CWO	MCT 5
at 60°F	0.8618	0.8618
at 70°F	0.8581	0.8581
at 100°F	0.8474	0.8474
° API	32.7	32.7

The viscosity data was plotted on a standard viscosity-temperature chart (A.S.T.M. D 341-43) to obtain the kinematic viscosity, η, at room temperatures. The densities, ρ, were plotted vs temperature on normal graph paper, and the dynamic viscosity at each temperature calculated from:

$\mu = \eta \times \rho$

The values are entered in Table 1, Chapter 5.

Viscosities for the Dow Corning 200 Fluid were calculated from the specification charts provided by the manufacturer.

The viscosity of distilled water was obtained from Perry's "Handbook of Chemical Engineering".

The results of the imbibition tests after 72 hours were as follows:

	System	Imbibed Volume (cc)
1.	Sand & CWO imbibing water	0.3
2.	Sand & D-C imbibing water	0.1
3.	Sand & MCT 5 imbibing water	0.3
4.	Sand & water imbibing CWO	0.0
5.	Sand & water imbibing D-C	0.0
6.	Sand & water imbibing MCT 5	0.0

These results indicate that the three systems were water-wet. However, the sand saturated with Dow Corning 200 Fluid, imbibed only one-third of the water amount observed with the two refinery fractions. The water repellancy of the silicone oil prevented water from entering to the same degree.

The residual oil saturation, S_{or}, and the permeability to water at this point, $K_{wS_{or}}$, were determined after the completion of the last experiment with each oil. The following values were obtained:

	Oil-type	S_{or} (%)	$K_{wS_{or}}$ (darcy)
After run 20	CWQ	20.4	4.16
After run 29	Dow Corning	47.0	2.28
After run 46	MCT 5	14.7	3.61

APPENDIX B

DATA FROM THE DISPLACEMENT TESTS

TABLE B-1

DISPLACEMENT TEST DATA FROM RUN #1

T = 68 °F, P_{Bar} = 70.9 cm Hg, Q = 20 cc/hr, S_{wi} = 10.7%, K_{oi} = 11.0 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	10.20						
	10.50		10.0	1.4		1.2	
	11.45		28.0	3.9		3.4	
	12.45		49.0	6.8		6.0	
	13.45		69.0	9.5		8.5	
	14.45		89.0	12.3		11.0	
	15.45		109.0	15.0		13.4	
	16.45		129.0	17.8		15.9	
	19.45		189.0	26.1		23.3	
	20.45		209.0	28.8		25.7	
	22.45		249.0	34.3		30.7	
	23.45		269.0	37.1		33.1	
	03.30		352.0	48.6	28.0	46.3	0.34
	05.50		353.5	48.8	32.5	47.5	3.00
	06.05		355.5	49.0	36.5	48.3	2.00
	07.20		362.5	50.0	55.5	51.5	2.71
	09.10		369.5	51.0	84.5	55.9	4.14
	11.28		377.5	52.1	122.5	61.6	4.[illegible]5
	STOP FOR	1.5 HRS.	REINJECTING FROM 13.00				
	16.24		386.5	53.3	178.5	69.6	6.22
STOP	16.46		387.5	53.5	185.5	70.4	7.00

TABLE B- 2

DISPLACEMENT TEST DATA FROM RUN #2

T = 66 °F, P_{Bar} = 70.7 cm Hg, Q = 40 cc/hr, S_{wi} = 12.3%, K_{oi} = 10.6 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	0.03						
	0.15	1.2					
	7.50	0.8	321.5	45.1	6.5	40.4	1.02
	8.20	0.7	329.0	46.2	18.0	42.7	1.53
	8.50	0.6	337.0	47.3	31.0	45.3	1.63
	9.20	0.6	343.0	48.1	46.0	47.9	2.50
	9.50	0.6	348.0	48.8	61.0	50.4	3.00
	10.20	0.5	352.0	49.4	78.0	52.9	4.25
	10.50	0.45	357.0	50.1	94.0	55.5	3.20
	11.20	0.45	361.5	50.7	110.5	58.1	3.67
	11.50	0.45	365.0	51.2	127.5	60.6	4.86
	12.20	0.4	368.0	51.6	144.5	63.1	5.67
	STOP, RESTART 12.24						
	13.10	0.4	372.5	52.3	172.0	67.0	6.11
	13.40	0.4	375.0	52.6	190.0	69.6	7.20
	14.30	0.4	379.0	53.2	221.0	73.9	7.75
	15.05	0.4	381.5	53.5	245.0	77.1	9.60

TABLE B-3

DISPLACEMENT TEST DATA FROM RUN #3

T = 68 °F, P_{Bar} = 70.9 cm Hg, Q = 20 cc/hr, S_{wi} = 16.4 %, K_{oi} = [illegible] darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	17.37						
10/4	07.23		275.0	40.5		33.9	
	08.00		287.5	42.3		35.4	
	08.30		297.0	43.7		36.6	
	09.00		307.0	45.2		37.8	
	09.30		317.0	46.7		39.0	
	10.00		327.0	48.2		40.3	
	10.10		330.5	48.7	0.5	40.8	0.14
	10.30		333.0	49.0	4.0	41.5	1.40
	11.00		335.0	49.3	12.0	42.7	4.[illegible]
	11.30		337.0	49.6	20.0	44.3	4.[illegible]
	12.00		339.0	49.9	28.0	45.2	4.[illegible]
	13.00		343.0	50.5	44.0	47.7	4.[illegible]
	14.00		346.5	51.0	60.5	50.1	4.[illegible]
	15.00		349.5	51.5	77.5	52.6	5.[illegible]
	16.00		352.5	51.9	95.5	55.2	6.[illegible]

TABLE B-4

DISPLACEMENT TEST DATA FROM RUN # 4

T = 67 °F, P_{Bar} = 70.4 cm Hg, Q = 140 cc/hr, S_{wi} = 17.7%, K_{oi} = 10.8 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	10.55						
	11.29	4.0	63.0	9.4		7.8	—
	13.35	1.6	314.0	47.0	50.0	44.8	0.20
	13.47	1.5	324.0	48.5	66.5	48.1	1.65
	14.02	1.4	334.0	50.0	92.5	52.5	2.6
	14.20	1.4	344.0	51.5	126.5	57.9	3.4
	14.30	1.4	349.0	52.2	146.5	61.0	4.0
	14.50		355.0	53.1	180.5	65.9	5.67
	15.07	1.2	361.0	54.0	215.0	70.9	5.75
	15.20	1.2	365.0	54.6	243.0	74.9	7.00
	15.35	1.1	369.0	55.2	271.0	78.8	7.00
STOP	15.37		371.0	55.5	282.0	80.4	5.5

TABLE B-5

DISPLACEMENT TEST DATA FROM RUN # 5

T = 68 °F, P_{Bar} = 70.6 cm Hg, Q = 200 cc/hr, S_{wi} = 17.6 %, K_{oi} = 11.0 darcy

TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START 11.25						
11.35	7.8					
11.55	7.2					
12.15	6.2					
12.27	5.8	194.0	29.0		23.9	
12.35	3.5	224.5	33.6		27.6	
12.40	3.3	244.5	36.5	0.7	30.2	0.04
12.50	3.0	273.5	40.9	3.7	34.1	0.10
12.55	2.9	282.5	42.2	7.7	35.7	0.44
13.00	2.7	292.5	43.7	13.7	37.7	0.60
13.05	2.6	303.0	45.3	21.2	39.9	0.71
13.16	2.2	321.0	48.0	39.2	44.4	1.00
13.21	2.1	328.0	49.0	50.2	46.6	1.57
13.28	2.0	337.5	50.4	68.2	50.0	1.89
13.36	1.9	344.5	51.5	83.2	52.7	2.14
13.45	1.8	353.5	52.8	106.2	56.6	2.56
13.56	1.6	362.5	54.2	139.7	61.8	3.72
14.06	RESTART USING NEW CYLINDER ON PUMP					
14.15	1.5	368.5	55.1	164.7	65.7	4.17
14.25	1.5	373.5	55.8	190.7	69.5	5.20
14.35	1.4	378.0	56.5	219.7	73.6	6.44
14.45	1.4	382.0	57.1	248.7	77.7	7.25
14.55	1.3	385.5	57.6	277.7	81.7	8.29
15.07	1.2	389.0	58.1	312.7	86.4	10.00
15.15	1.2	391.5	58.5	338.7	89.9	10.4
STOP		392.0	58.6	345.7	90.8	14.0

TABLE B- 6

DISPLACEMENT TEST DATA FROM RUN # 6

$T = 68\ °F$, $P_{Bar} = 70.2$ cm Hg, $Q = 20$ cc/hr, $S_{wi} = 18.0\%$, $K_{oi} = 10.8$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	21.20						
16/4	09.25	0.5	242.0	36.3		29.8	
	13.00	0.4	314.0	47.1		38.7	
	13.30	0.4	324.0	48.6	0.1	39.9	0.01
	14.00	0.2	328.5	49.3	5.6	41.1	1.22
	14.30	0.2	331.0	49.7	13.6	42.4	3.20
	15.00	0.1	333.0	50.0	21.6	43.7	4.0
	16.00	0.1	337.0	50.6	40.1	46.4	4.5
	17.0	0.1	341.0	51.2	55.1	48.8	3.6
	17.35	0.1	343.0	51.5	64.6	50.2	4.8
	18.45	0.1	347.0	52.1	84.1	53.1	4.9
	20.06	0.1	351.0	52.7	107.1	56.4	5.8
	21.00	0.1	353.5	53.1	122.6	58.6	6.2
	STOP		353.5	53.1	124.6	58.9	

TABLE B-7

DISPLACEMENT TEST DATA FROM RUN # 7

T = 68 °F, P_{Bar} = 70.1 cm Hg, Q = 70 cc/hr, S_{wi} = 17.8%, K_{oi} = 10.7 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	10.48						
	14.27	1.1	248.0	37.2		30.5	
	14.45	1.0	275.0	41.2		33.9	
	14.59	1.0	291.0	43.6		35.8	
	15.17	1.0	308.5	46.2	2.5	38.3	0.14
	15.30	0.8	319.5	47.9	8.5	40.4	0.55
	15.50	0.6	331.5	49.7	19.5	43.2	0.92
	16.10	0.6	341.5	51.2	33.5	46.2	1.4
	16.40		351.5	52.7	58.5	50.5	2.5
	16.48		354.0	53.0	66.0	51.7	3.0
	17.36		364.0	54.5	112.0	58.6	4.6
	18.01		369.5	55.4	137.5	62.4	4.6
	18.40		375.5	56.3	176.5	68.0	6.5
	STOP		378.5	56.7	195.5	70.7	6.33

TABLE B-8

DISPLACEMENT TEST DATA FROM RUN #8

$T = 69\ °F$, $P_{Bar} = 69.7$ cm Hg, $Q = 120$ cc/hr, $S_{wi} = 18.2\%$, $K_{oi}' = 10.7$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	17.34						
	17.40	2.9					
	19.27		221.0	33.3		27.2	
	19.35		242.0	36.4		29.8	
	19.45		263.0	39.6		32.4	
	20.00		292.9	44.1	0.6	36.1	0.02
	20.09		305.4	46.0	4.1	38.1	0.28
	20.20		319.9	48.2	13.1	41.0	0.62
	20.35		334.9	50.4	29.1	44.8	1.07
	20.50		346.9	52.2	51.1	49.0	1.83
	21.05		354.9	53.4	73.6	52.8	2.81
	21.25	1.1	369.9	55.7	104.1	58.4	3.39
	21.45	1.0	371.9	56.0	138.1	62.8	4.25
	22.00	1.0	376.9	56.8	163.1	66.5	5.0
	22.15	1.0	380.9	57.4	188.1	70.1	6.25
	STOP		385.9	58.1	223.6	75.1	7.10

TABLE B-9

DISPLACEMENT TEST DATA FROM RUN # 9

T = 68 °F, P_{Bar} = 69.7 cm Hg, Q = 1120 cc/hr, S_{wi} = 20.4 %, K_{oi} = 10.9 darcy

	TIME (Hrs.)	PRESSURE DRCP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	13.36						
	13.40	30.0					
	13.45	26.8	183.0	28.3	2.0	22.8	0.01
	13.47	24.0	215.5	33.4	2.5	26.8	0.02
	13.49		244.0	37.8	3.0	30.4	0.02
	13.51		272.5	42.2	3.5	34.0	0.02
	13.53		295.0	45.7	7.0	37.2	0.16
	13.55	14.5	319.5	49.5	18.5	41.6	0.47
	13.56		334.5	51.8	36.5	45.7	1.20
	13.575		345.5	53.5	57.5	49.6	1.91
	13.59		354.5	54.9	85.5	54.2	3.11
	14.01		361.5	56.0	114.0	58.6	4.07
	14.03		368.0	57.0	145.0	63.2	4.77
	14.05		374.0	57.9	178.0	68.0	5.50
	14.07	9.5	380.0	58.8	218.0	73.6	6.67
STOP	14.095		382.0	59.1	232.0	75.6	7.0

TABLE B-10

DISPLACEMENT TEST DATA FROM RUN #10

T = 68 °F, P_{Bar} = 70.1 cm Hg, Q = 320 cc/hr, S_{wi} = 21.1%, K_{oi} = 10.8 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	12.48						
	13.18	6.6	166.0	25.9	3.0	20.8	0.02
	13.22		185.5	29.0	3.5	23.3	0.03
	13.28		217.8	34.0	4.2	27.3	0.02
	13.33		251.2	39.2	4.8	31.5	0.02
	13.38		282.2	44.1	6.8	35.6	0.06
	13.45	4.5	308.2	48.1	17.8	40.1	0.42
	13.52		327.2	51.1	38.8	45.1	1.11
	14.00	3.5	343.7	53.7	64.3	50.2	1.55
	14.07		355.7	55.5	91.3	55.0	2.25
	14.14		364.7	56.9	120.3	59.7	3.22
	14.22	2.8	371.7	58.0	154.8	64.8	4.93
	14.32	2.5	378.7	59.1	198.8	71.1	6.29
	14.47		383.7	59.9	235.8	76.3	7.40
	14.54		387.2	60.4	269.8	80.9	9.71
	STOP		391.7	61.1	317.8	87.4	10.67

TABLE B-11

DISPLACEMENT TEST DATA FROM RUN #11

$T = 68\ °F$, $P_{Bar} = 70.0$ cm Hg, $Q = 480$ cc/hr, $S_{wi} = 22.8\%$, $K_{oi} = 10.8$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	21.03						
	21.20	12.0	175.5	28.0	4.5	22.2	0.02
	21.29	10.0	200.5	32.0	5.1	25.9	0.02
	21.32	9.2	225.5	35.9	5.7	28.4	0.02
	21.35	8.6	259.2	41.3	7.0	32.8	0.04
	21.39		273.2	43.6	9.5	34.8	0.18
	21.415	7.4	304.2	48.5	26.0	40.7	0.53
	21.475	6.2	325.7	52.0	47.5	46.0	1.00
	21.525	5.6	342.7	54.7	76.0	51.6	1.68
	21.58	5.0	351.7	56.1	103.5	56.1	3.06
	22.03	4.8	359.7	57.4	141.5	61.7	4.75
	22.08	4.2	365.7	58.3	177.0	66.8	5.92
	22.14	4.0	371.7	59.3	217.0	72.5	6.67
	22.18	3.9	376.2	60.0	252.5	77.4	7.89
STOP	22.26	3.5	378.2	60.3	269.0	79.7	8.25

TABLE B-12

DISPLACEMENT TEST DATA FROM RUN #12

T = 68 °F, P°_{Bar} = 69.8 cm Hg, Q = 640 cc/hr, S_{wi} = 21.7%, K_{oi} = 10.8 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	11.36						
	11.41	17.0					
	11.50	15.5	141.5	22.3	1.5	17.6	0.01
	11.52	14.2	179.5	28.2	2.1	22.4	0.02
	11.56	12.8	221.0	34.8	2.7	27.5	0.01
	12.00	11.4	256.5	40.3	3.2	32.0	0.01
	12.03	10.0	274.6	43.2	4.9	34.4	0.09
	12.05	9.6	297.1	46.7	13.4	38.2	0.38
	12.08	8.6	326.9	51.4	27.4	43.6	0.47
	12.12	7.5	346.9	54.6	53.4	49.3	1.30
	12.16	6.6	358.9	56.5	81.4	54.2	2.33
	12.20	6.0	372.9	58.7	109.4	59.4	2.00
	12.24	5.8	379.4	59.7	143.9	64.4	5.31
	12.28	5.4	385.4	60.6	178.9	69.5	5.83
STOP	12.32	5.0	391.4	61.6	222.9	75.6	7.33

TABLE B- 13

DISPLACEMENT TEST DATA FROM RUN # 13

T = 68 °F, P_{Bar} = 69.4 cm Hg, Q = 960 cc/hr, S_{wi} = 23.3 %, K_{oi} = 10.8 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	21.00				0		
	21.06	26.0					
	21.10	22.2					
	21.15	18.4	196.0	31.5	5.0	24.3	0.03
	21.17	16.0	231.0	37.1	6.0	29.2	0.03
	21.18	15.4	247.5	39.7	6.3	31.3	0.02
	21.19	14.4	263.5	42.3	6.7	33.3	0.03
	21.20	13.8	278.5	44.7	7.9	35.3	0.08
	21.22	12.0	304.5	48.9	14.9	39.3	0.27
	21.24	10.8	322.0	51.7	30.4	43.4	0.89
	21.26	10.0	335.5	53.8	49.9	47.5	1.44
	21.28	9.4	345.5	55.4	74.9	51.3	2.50
	21.30	8.8	352.0	56.5	98.9	55.5	3.69
	21.32	8.5	358.0	57.4	125.9	59.6	4.50
	21.34	8.2	363.0	58.2	153.9	63.6	5.60
	STOP		367.0	58.9	177.9	67.1	6.00

TABLE B- 14

DISPLACEMENT TEST DATA FROM RUN #14

T = 70 °F, P_{Bar} = 69.2 cm Hg, Q = 6.25 cc/hr, S_{wi} = 24.2%, K_{oi} = 10.9 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	14.00						
25/4	7.40		261.0	42.4		32.1	
	9.48		274.5	44.6		33.8	
	12.15		291.5	47.4		35.9	
	14.15		304.5	49.5		37.5	
	15.48		313.7	51.0	0.3	38.7	0.03
	16.26		315.9	51.3	1.3	39.1	0.45
	17.00		316.4	51.4	3.3	39.4	4.0
	19.34		321.4	52.2	13.3	41.2	2.0
	21.32		324.4	52.7	24.3	42.9	3.67
26/4	00.30		328.9	53.5	37.3	45.1	2.89
	13.05		341.9	55.6	103.3	54.8	5.08
	STOP		342.9	55.7	112.8	56.1	9.5

TABLE B- 15

DISPLACEMENT TEST DATA FROM RUN # 15

T = 68 °F, P_{Bar} = 70.3 cm Hg, Q = 1720 cc/hr, S_{wi} = 24.0%, K_{oi} = 10.6 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	13.55						
	13.59	47.0					
	14.01		111.5	18.1	2.5	14.0	0.02
	14.02		141.5	22.9	3.2	17.8	0.02
	14.03		171.0	27.7	3.7	21.5	0.02
	14.0375		194.0	31.4	4.4	24.4	0.03
	14.0415		209.0	33.9	4.6	26.3	0.01
	14.045		224.0	36.3	4.8	28.2	0.01
	14.055		246.0	39.8	5.3	30.9	0.02
	14.06		261.0	42.3	5.6	32.8	0.02
	14.065		275.5	44.6	6.4	34.7	0.06
	14.07		288.2	46.7	8.7	36.6	0.13
	14.075		298.7	48.4	13.2	38.4	0.43
	14.09		319.7	51.8	37.2	43.9	1.14
	14.10		328.7	53.2	58.2	47.6	2.33
	14.105		332.2	53.8	69.2	49.4	3.14
	14.11		335.9	54.4	80.2	51.2	2.97
	14.115		338.9	54.9	91.2	53.0	3.67
	14.12		342.1	55.4	102.7	54.8	3.59
	14.125		345.1	55.9	119.2	57.2	5.50
	14.13		348.6	56.5	130.7	59.0	3.29
	STOP		355.6	57.6	163.7	63.9	4.71

TABLE B-16

DISPLACEMENT TEST DATA FROM RUN #16

T = 68 °F, P_{Bar} = 70.6 cm Hg, Q = 2320 cc/hr, S_{wi} = 23.6%, K_{oi} = 10.6 darcy

	TIME (Min.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
	3.0	62.0					
	7.0	37.0	226.0	36.4	4.0	28.3	0.02
	7.5		246.0	39.7	4.2	30.8	0.01
	8.0		267.0	43.0	4.4	33.4	0.01
	8.5		284.5	45.9	6.9	35.9	0.14
	9.0		299.5	48.3	12.9	38.5	0.4
	9.5		311.0	50.1	21.4	40.9	0.74
	10.5	24.0	326.5	52.6	46.4	45.9	1.61
	11.5		336.5	54.2	76.4	50.8	3.0
	12.5		345.5	55.7	107.9	55.8	3.5
	13.5		353.5	57.0	139.9	60.8	4.0
	14.5	20.0	360.5	58.1	172.9	65.7	4.71
	15.5		367.0	59.2	206.4	70.6	5.15
	16.5		373.0	60.1	240.4	75.5	5.67
	17.5		378.0	60.9	275.4	80.5	7.0
	18.5		383.0	61.7	310.4	85.4	7.0
STOP	19.5		387.0	62.4	346.4	90.3	9.0

TABLE B- 17

DISPLACEMENT TEST DATA FROM RUN #17

$T = 68\ °F$, $P_{Bar} = 70.7$ cm Hg, $Q = 2.5$ cc/hr, $S_{wi} = 22.6\%$, $K_{oi} = 10.7$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	12.53						
24/5	14.00		247.0	39.3		30.4	
25/5	10.05		296.0	47.1		36.4	
	13.40		306.0	48.7		37.7	
	18.32		321.0	51.1		39.5	
	22.30		330.0	52.5		40.6	
26/5	01.00		337.5	53.7	0.5	41.6	0.37
	10.00		344.0	54.8	16.5	44.4	2.46
STOP	12.10		347.00	55.2	25.5	45.9	3.00

TABLE B-18

DISPLACEMENT TEST DATA FROM RUN # 18

$T = 68\ ^{\circ}F$, $P_{Bar} = 70.3$ cm Hg, $Q = 6.25$ cc/hr, $S_{wi} = 23.5$ %, $K_{oi} = 10.8$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	13.10						
29/5	14.30						
	15.40						
	16.20						
	16.45		333.0	53.6		41.0	
STOP	17.45		337.0	54.2	0.6	41.6	0.15

TABLE B-19

DISPLACEMENT TEST DATA FROM RUN #19

T = 70 °F, P_{Bar} = 70.5 cm Hg, Q = 35 cc/hr, S_{wi} = 24.5%, K_{oi} = 11.0 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	11.20						
	18.30		250.0	40.8		30.8	
	18.50		261.5	42.6		32.2	
	19.25		282.0	46.0		34.7	
	19.50		297.5	48.5		36.6	
	20.17		313.0	51.0		38.5	
	20.25		317.0	51.7	0.2	39.1	0.05
	20.37		320.5	52.3	3.7	39.9	1.00
	STOP		362.0	59.0	145.7	62.5	3.42

TABLE B-20

DISPLACEMENT TEST DATA FROM RUN #20

T = 71 °F, P_{Bar} = 69.7 cm Hg, Q = 3520 cc/hr, S_{wi} = 25.3%, K_{oi} = 10.7 darcy

TIME (Min.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
2.0	88.0					
3.0	76.0					
4.0	64.0	170.7	28.1	4.3	21.5	0.03
4.5	58.5	202.7	33.4	5.0	25.6	0.02
5.0	51.1	232.1	38.2	5.6	29.3	0.02
5.5	45.0	262.1	43.2	7.3	33.2	0.06
6.0	40.5	283.6	46.7	16.8	37.0	0.44
6.5	37.2	298.4	49.2	33.0	40.8	1.09
7.0	35.0	309.4	51.0	53.0	44.6	1.82
7.5	33.5	318.6	52.5	74.8	48.4	2.37
8.0	32.2	325.1	53.6	97.8	52.1	3.54
8.5	31.0	332.3	54.8	121.6	55.9	3.31
9.0	30.0	338.4	55.8	145.6	59.6	3.93
9.5	29.0	344.4	56.8	169.6	63.3	4.0
10.0	28.2	349.9	57.7	194.6	67.0	4.55
10.5	27.6	354.9	58.5	219.6	70.7	5.0
11.0	27.0	359.6	59.3	245.1	74.5	5.43
11.5	26.2	364.1	60.0	270.6	78.2	5.67
12.0	25.6	368.4	60.7	298.1	82.1	6.40
12.5	25.0	372.4	61.4	324.1	85.8	6.50
13.0	24.7	375.7	61.9	349.8	89.3	7.79
13.5	24.1	379.2	62.5	377.8	93.2	8.0
14.0	23.7	382.2	63.0	404.8	96.9	9.0
14.5	23.2	385.2	63.5	433.8	100.8	9.67
15.0	22.8	388.2	64.0	460.8	104.5	9.0
STOP		394.2	65.0	519.8	112.5	9.83

TABLE B-21

DISPLACEMENT TEST DATA FROM RUN #21

T = 72 °F, P_{Bar} = 70.5 cm Hg, Q = 160 cc/hr, S_{wi} = 9.6 %, K_{oi} = 12.7 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	19.33						
	19.50	25.4					
	20.00	23.8					
	20.21	18.4					
	20.35	15.4					
	20.45	12.7	171.0	23.4	0.5	21.2	
	20.48	12.0	178.0	24.4	1.0	22.2	0.07
	20.52	11.0	189.0	25.9	3.0	23.8	0.18
	20.58	10.0	200.4	27.5	6.6	25.6	0.32
	21.06	8.9	215.0	29.5	12.8	28.2	0.42
	21.12	7.9	226.0	31.0	22.8	30.8	0.91
	21.19	7.2	234.0	32.1	32.8	33.0	1.25
	21.25	6.6	240.0	32.9	42.8	35.0	1.67
	21.42	5.7	253.0	34.7	73.3	40.4	2.35
	21.53	5.1	260.0	35.6	97.3	44.2	3.43
	22.07	4.8	267.0	36.6	123.3	48.3	3.71
	22.15	4.5	271.0	37.1	142.3	51.2	4.75
	22.25	4.3	276.0	37.8	166.3	54.7	4.80
	22.36	4.0	280.3	38.4	189.8	58.2	5.47
	22.44	3.9	283.7	38.9	212.4	61.4	6.65
	22.52	3.8	286.2	39.2	230.4	63.9	7.20
	STOP		287.2	39.3	238.9	65.1	8.50

TABLE B-22

DISPLACEMENT TEST DATA FROM RUN #22

T = 71 °F, P_{Bar} = 73.1 cm Hg, Q = 80 cc/hr, S_{wi} = 10.0 %, K_{oi} = 12.8 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	13.50						
	14.22	10.6					
	14.25	11.0					
	14.30	11.5					
	14.38	11.4					
	14.45	11.0					
	14.50	10.5					
	15.05	9.4					
	15.10	9.0					
	15.[illegible]	9.7					
	15.[illegible]	[illegible]					
	15.40	7.3					
	15.50	6.8					
	15.58	6.4					
	16.08	5.9	152.5	21.3		13.1	
	16.15	5.5	177.5	24.4	0.1	[illegible]	0.00[illegible]
	16.19	5.4	182.0	25.0	0.5	22.5	0.09
	16.30	4.7	197.0	27.1	2.5	24.7	0.13
	16.35	4.2	206.1	28.4	4.3	26.[illegible]	0.20
	18.00	2.0	252.1	34.7	70.[illegible]	29.[illegible]	1.43
	18.5[illegible]	1.9	264.1	35.[illegible]	120.[illegible]	47.[illegible]	4.17
	19.0[illegible]	1.7	268.1	36.9	141.3	50.7	5.25
	19.45	1.5	277.1	38.1	190.3	57.9	5.44
	21.05	1.3	289.6	39.8	230.8	70.6	7.24
	22.06	1.1	299.1	41.2	354.8	80.9	7.79
	STOP		300.5	41.3	366.3	82.5	8.21

TABLE B-23

DISPLACEMENT TEST DATA FROM RUN # 23

T = 70 °F, P_{Bar} = 69.4 cm Hg, Q = 5.0 cc/hr, S_{wi} = 10.5 %, K_{oi} = 12.6 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
Start	02.56						
24/6	02.40		237.0	32.8		29.4	
B.T.	03.10		237.5	32.8	2.0	29.6	4.0
	12.45		248.5	34.4	40.5	35.8	3.5
	15.00		251.5	34.8	52.5	37.6	4.0
			258.5	35.7	80.5	42.0	4.0
			271.0	37.5	144.0	51.4	5.08
25/6	15.40		273.4	37.8	157.5	53.3	5.63

TABLE B-24

DISPLACEMENT TEST DATA FROM RUN # 24

T ≐ 72 °F, P_{Bar} = 69.4 cm Hg, Q = 15.0 cc/hr, S_{wi} = 10.8 %, K_{oi} = 12.7 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	22.00						
27/6	13.00		221.5	30.7		27.4	
B.T.	13.24		225.2	31.2	1.1	28.0	0.30
	15.14		235.7	32.7	18.1	31.4	1.62
	16.30		241.2	33.5	33.6	34.0	2.82
	19.15		249.2	34.6	65.6	39.0	4.00
	21.05		254.7	35.3	89.6	42.6	4.36
28/6	01.45		265.2	36.8	149.6	51.3	5.71
	02.11		266.2	36.9	157.6	52.5	8.0

TABLE B- 25

DISPLACEMENT TEST DATA FROM RUN #25

T = 70 °F, P_{Bar} = 70.2 cm Hg, Q = 30 cc/hr, S_{wi} = 9.5 %, K_{oi} = 12.6 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	14.30						
	15.20	4.2					
	15.35	4.6					
	15.46	4.6					
	19.10	2.8	132.0	18.1		16.3	
	19.35	2.6					
	19.50	2.4					
	20.10	2.2	163.7	22.4		20.3	
	20.30	1.9					
	20.5[illegible]	1.8	185.2	25.3		22.9	
	[illegible]	1.6					
	[illegible]	1.5	195.3	26.7	0.05	24.2	0.005
	[illegible]	1.4					
	[illegible]	1.2	201.3	27.5	3.05	25.3	0.50
	[illegible]	1.0					
	[illegible]0	1.0	207.1	28.3	9.25	26.8	1.07
	[illegible].21	1.0	211.1	28.9	18.05	28.4	2.2
	22.45	0.9	214.6	29.3	25.05	29.7	2.0
	23.06	0.8	217.9	29.8	33.65	31.1	2.61
	23.28	0.8	219.7	30.0	41.95	32.4	4.61
30/6	00.50	0.7	229.7	31.4	73.45	37.5	3.15
	01.50	0.6	235.7	32.2	98.45	41.4	4.17
	03.04	0.6	242.6	33.2	129.45	46.1	4.49
	04.13	0.6	248.4	34.0	159.45	50.5	5.17
	05.18	0.6	252.9	34.6	186.95	54.4	6.11
STOP	05.36		254.8	34.8	198.75	56.1	6.21

TABLE B-26

DISPLACEMENT TEST DATA FROM RUN #26

$T = 71\ ^\circ F$, $P_{Bar} = 70.5$ cm Hg, $Q = 2.5$ cc/hr, $S_{wi} = 9.2\ \%$, $K_{oi} = 12.7$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	23.00						
4/7	16.00		231.5	31.6		28.7	
	20.00		234.0	31.9	4.0	29.2	1.6
5/7	02.10		239.0	32.6	16.0	31.6	3.2

TABLE B- 27

DISPLACEMENT TEST DATA FROM RUN # 27

T = 72 °F, P_{Bar} = 70.2 cm Hg, Q = 20 cc/hr, S_{wi} = 10.2 %, K_{oi} = 12.5 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	23.00						
6/7	09.20		217.3	29.9	0.2	26.9	
	09.54		219.9	30.3	1.8	27.4	0.62
	12.30		237.9	32.8	36.8	34.0	1.94
	13.55		243.7	33.6	60.8	37.7	4.14
	14.28		248.7	34.3	86.8	41.5	5.20
	16.10		251.2	34.6	100.8	43.6	5.60
	18.35		257.2	35.4	138.8	49.0	6.33
	20.40		261.2	36.0	178.8	54.5	10.00
	21.50		263.2	36.3	199.8	57.3	10.5
STOP	22.15		264.2	36.4	211.3	58.9	11.5

TABLE B- 28

DISPLACEMENT TEST DATA FROM RUN #28

T = 73 °F, P_{Bar} = 71.3 cm Hg, Q = 60 cc/hr, S_{wi} = 9.7 %, K_{oi} = 12.5 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	16.15						
	18.55	4.9	140.0	19.3	0.5	17.4	
	19.13	4.6	157.7	21.7	0.6	19.6	0.006
	19.19	4.5	163.7	22.5	0.9	20.4	0.050
	19.43	3.5	188.1	25.9	2.0	23.5	0.045
B.T.	19.48	3.2	193.1	26.6	3.5	24.3	0.30
	19.56	2.9	198.9	27.4	6.7	25.4	0.55
	20.10	2.7	203.9	28.1	14.7	27.1	1.60
	20.20	2.6	207.7	28.6	21.2	28.3	1.71
	20.36	2.4	212.7	29.3	31.2	30.2	2.00
	20.50	2.2	217.7	30.0	42.0	32.2	2.16
	21.07	2.1	221.7	30.5	54.0	34.1	3.00
	21.23	1.95	225.6	31.1	68.0	36.3	3.59
	21.43	1.8	229.9	31.7	84.0	38.9	3.72
	22.01	1.8	233.6	32.2	101.0	41.4	4.59
	22.35	1.6	238.4	32.8	127.0	45.2	5.42
	23.13	1.5	244.4	33.7	162.0	50.3	5.83
	23.40	1.5	248.6	34.2	186.8	53.9	5.90
STOP	23.45	1.5	250.1	34.5	194.8	55.1	5.33

TABLE B-29

DISPLACEMENT TEST DATA FROM RUN #29

T = 73 °F, P_{Bar} = 70.8 cm Hg, Q = 320 cc/hr, S_{wi} = 9.5 %, K_{oi} = 12.4 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	21.05						
	21.17	49.6					
	21.21	44.5					
	21.27	34.6					
	21.30	30.0					
	21.34	26.5	122.0	16.7	9.0	16.2	0.07
	21.355	25.8	126.5	17.3	10.1	16.9	0.24
	21.38	23.9	136.6	18.7	13.0	18.6	0.29
	21.40	22.2	146.6	20.0	17.0	20.3	0.40
	21.43	20.5	157.5	21.5	22.1	22.2	0.47
	21.47	18.5	172.0	23.5	28.6	24.3	0.45
	21.50	16.8	182.5	24.9	35.6	27.0	0.67
	21.54	15.0	193.5	26.4	45.6	29.6	0.91
	22.05	11.2	216.8	29.6	79.6	36.7	1.61
	22.10	10.0	223.8	30.6	99.6	40.0	2.86
	22.18	8.9	233.3	31.9	131.1	45.1	3.32
	22.26	8.0	241.3	33.0	163.1	50.1	4.00
	22.34	7.4	248.3	33.9	200.1	55.5	5.29
	22.45	6.8	256.3	35.0	243.1	61.8	5.38
	22.53	6.4	259.8	35.5	281.6	67.0	11.00
	23.02	6.0	264.0	36.1	323.1	72.7	9.88
	23.11	5.8	267.5	36.6	365.1	78.3	12.00
	23.20	5.5	270.5	37.0	406.1	83.7	13.67

TABLE B- 30

DISPLACEMENT TEST DATA FROM RUN #30

$T = 72.5°F$, $P_{Bar}' = 69.7$ cm Hg, $Q = 100$ cc/hr, $S_{wi} = 15.0\%$, $K_{oi} = 9.5$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	12.00						
	12.30	6.0					
	12.45	5.4					
	13.08	4.4					
	13.25	3.6	127.0	18.4	1.5	15.8	0.01
	13.35	3.3	137.8	20.0	4.5	17.6	0.28
	13.45	3.1	156.3	22.7	9.7	20.5	0.28
	14.05	2.8	182.1	26.4	20.7	25.0	0.43
	14.30	2.5	208.1	30.2	35.7	30.1	0.58
	14.45	2.1	225.1	32.7	50.7	34.0	0.88
	15.05	1.8	236.1	34.3	69.7	37.7	1.73
	15.25	1.7	247.1	35.9	90.7	41.7	1.91
	15.40	1.6	255.6	37.1	111.2	45.2	2.41
	16.00	1.5	264.6	38.4	136.2	49.4	2.78
	16.20	1.4	272.1	39.5	158.7	53.1	3.00
	16.30	1.3	276.6	40.1	174.7	55.7	3.56
	18.45	1.0	315.1	45.7	361.7	83.5	4.86
	21.00	0.9	341.1	49.5	558.5	111.0	7.57
STOP	21.18	0.8	345.6	50.1	595.5	116.1	8.22

TABLE B- 31

DISPLACEMENT TEST DATA FROM RUN #31

T = 72 °F, P_{Bar} = 69.4 cm Hg, Q = 200 cc/hr, S_{wi} = 18.7%, K_{oi} = 11.3 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	12.05						
	12.30	9.8					
	12.43	7.6	98.0	14.9		12.1	
	12.46	7.1	109.0	16.5		13.4	
B.T.	12.48	6.7	114.0	17.3	0.1	14.1	0.02
	12.52	6.2	119.0	18.1	3.9	15.2	0.76
	12.59	5.4	136.7	20.7	10.9	18.2	0.40
	13.05	5.0	149.5	22.7	17.1	20.5	0.48
	13.13	4.4	167.5	25.4	29.1	24.2	0.67
	13.24	3.5	187.3	28.4	47.1	28.9	0.91
	13.32	3.2	197.8	30.0	63.1	32.2	1.52
	13.42	2.9	208.3	31.6	87.1	36.4	2.29
	13.51	2.8	217.3	33.0	106.1	39.9	2.11
	14.00	2.7	225.8	34.3	130.1	43.9	2.82
	14.08	2.5	233.8	35.5	153.1	47.7	2.88
	14.18	2.3	241.8	36.7	178.1	51.8	3.13
	14.27	2.2	248.3	37.7	201.6	55.5	3.62
	14.37	2.2	254.1	38.6	226.6	59.3	4.31
	14.48	2.0	262.1	39.8	262.1	64.7	4.44
	14.59	1.9	268.8	40.8	294.1	69.4	4.78
	15.14	1.8	276.8	42.0	334.1	75.3	5.00
	15.25	1.7	282.8	42.9	367.1	80.2	5.50
	15.35	1.6	287.8	43.7	399.1	84.7	6.40
	15.58	1.5	299.8	45.5	466.1	94.5	5.58
	16.27	1.4	312.8	47.5	549.1	106.3	6.38
STOP	16.30		315.8	47.9	568.1	109.0	6.33

TABLE B- 32

DISPLACEMENT TEST DATA FROM RUN #32

T = 71.5°F, P_{Bar} = 69.8 cm Hg, Q = 20 cc/hr, S_{wi} = 20.0%, K_{oi} = 11.5 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	15.56						
	20.35		94.0	14.5		11.59	
	21.35		114.0	17.6		14.06	
	22.31		134.0	20.7		16.53	
B.T.	22.37		136.0	21.0	0.4	16.82	0.20
	23.12		143.0	22.1	3.4	18.06	0.43
19/7	14.40		248.0	38.3	209.6	56.44	1.96
	15.30		251.0	38.7	220.6	58.17	3.66
	19.40		262.5	40.5	279.6	66.86	5.22
STOP	20.10		266.6	41.1	304.6	70.45	6.10

TABLE B- 33

DISPLACEMENT TEST DATA FROM RUN # 33

T = 70 °F, P_{Bar} = 70.2 cm Hg, Q = 10 cc/hr, S_{wi0} = 21.1%, K_{oi} = 11.4 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	14.20						
21/7	03.43		134.0	21.0		16.5	
	05.50		156.0	24.4		19.2	
	07.25		171.5	26.8	one drop	21.2	
	10.10		182.5	28.5	15.0	24.4	1.36
	12.20		192.0	30.0	28.0	27.1	1.37
	SWITCH TO 240 cc/hr						
	12.35		203.5	31.8	61.[illegible]	32.6	2.87
	12.46		216.5	33.8	93.5	38.2	2.50
	12.58		229.0	35.8	126.5	43.8	2.64
	13.11		239.5	37.4	162.5	49.6	3.43
	13.20		249.0	38.9	198.0	55.1	3.74
	13.30		258.0	40.3	234.0	60.7	4.00
	13.42		266.0	41.6	270.0	66.1	4.50
	13.52		273.0	42.7	307.0	71.5	5.29
	14.04		279.5	43.7	344.5	77.0	5.77
STOP	14.06		283.2	44.3	364.5	79.9	5.41

TABLE B-34

DISPLACEMENT TEST DATA FROM RUN #34

T = 71 °F P_{Bar} = 70.4 cm Hg, Q = 5.0 cc/hr, S_{wi} = 22.5%, K_{oi} = 12.2 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	01.10						
	20.30		97.0	15.4		12.0	
23/7	06.10		144.0	22.9		17.8	
	09.20		161.0	25.6		19.9	
	16.35		200.0	31.8		24.7	
	18.40		209.0	33.3	traces	25.8	
STOP	00.19		219.5	34.9	18.0	27.1	1.71

TABLE B- 35

DISPLACEMENT TEST DATA FROM RUN #35

T = 73 °F, P_{Bar} = 70.1 cm Hg, Q = 400 cc/hr, S_{wi} = 23.0%, K_{oi} = 12.1 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	22.10						
	22.23	19.0					
	22.26	17.8	81.0	13.0	0.2	10.0	0.002
	22.29	16.4	100.0	16.0	0.3	12.4	0.005
	22.32	14.1	124.0	19.9	0.5	15.4	0.008
	22.36	11.8	151.5	24.3	1.0	18.8	0.018
	22.40	10.5	170.0	27.2	7.5	21.9	0.35
	22.46	8.4	195.8	31.4	21.5	26.8	0.54
	22.52	7.2	212.8	34.1	41.5	31.4	1.18
	22.57	6.2	227.8	36.5	66.5	36.3	1.67
	23.03	5.6	241.6	38.7	95.5	41.6	2.10
	23.10	5.0	254.6	40.8	127.5	47.1	2.46
	23.17	4.7	264.3	42.4	159.3	52.2	3.28
	23.24	4.4	274.3	44.0	195.3	57.9	3.60
	23.32	4.0	284.3	45.6	235.3	64.1	4.00
	23.40	3.8	293.6	47.0	275.5	70.2	4.32
	23.47	3.6	302.5	48.5	315.5	76.2	4.49
	23.54	3.5	309.5	49.6	355.5	82.0	5.71
	24.00	3.4	316.5	50.7	396.3	87.9	5.83
25/7	00.07	3.3	323.0	51.8	437.3	93.8	6.31
	STOP		325.0	52.1	449.3	95.5	6.00

TABLE B-36

DISPLACEMENT TEST DATA FROM RUN # 36

T = 72 °F, P_{Bar} = 70.4 cm Hg, Q = 200 cc/hr, S_{wi} = 23.6 %, K_{oi} = 12.0 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	15.21						
	15.58		98.8	15.9	1.2	12.3	0.01
	16.11		145.9	23.5	2.0	18.2	0.02
	16.14		155.5	25.1	2.5	19.4	0.05
	16.20		168.9	27.3	8.9	21.9	0.48
STOP			319.9	51.6	427.9	92.2	2.77

TABLE B- 37

DISPLACEMENT TEST DATA FROM RUN # 37

$T = 71$ °F, $P_{Bar} =$ cm Hg, $Q = 100$ cc/hr, $S_{wi} = 23.4$ %, $K_{oi} = 11.8$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	13.30						
	14.30	4.1	94.0	15.1	1.0	11.7	0.01
	15.00	3.0	141.3	22.7	1.9	17.7	0.02
	15.03	2.8	146.4	23.6	2.3	18.3	0.08
	15.15	2.6	158.9	25.6	8.3	20.6	0.48
	15.35	2.1	174.9	28.2	24.3	24.6	1.00
	20.20	0.9	351.4	56.6	334.3	84.6	1.76
	20.40	0.8	355.5	57.2	359.3	88.2	6.10
	21.00	0.8	360.8	58.1	388.0	92.4	5.42
STOP	21.10		363.3	58.5	404.5	94.7	6.60

TABLE B- 38

DISPLACEMENT TEST DATA FROM RUN # 38

T = 72 °F, P_{Bar} = 69.6 cm Hg, Q = 800 cc/hr, S_{wi} = 27.7%, K_{oi} = 12.2 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	21.55						
	22.07	34.0	101.0	17.2	0.7	12.5	0.01
	22.10	28.0	147.5	25.2	1.2	18.3	0.01
	22.13	21.8	189.2	32.3	1.4	23.5	0.005
	22.16	17.7	221.2	37.7	11.4	28.7	0.31
	22.19	14.8	241.7	41.2	30.9	33.6	0.95
	22.22	12.9	258.7	44.1	55.9	38.8	1.47
	22.25	11.5	266.7	45.5	87.4	43.7	3.94
	22.29	10.5	278.5	47.5	119.9	49.2	2.71
STOP	22.30		285.2	48.6	140.9	52.6	3.23

TABLE B- 39

DISPLACEMENT TEST DATA FROM RUN #39

T = 72.5°F, P_{Bar} = 70.1 cm Hg, Q = 200 cc/hr, S_{wi} = 28.1%, K_{oi} = 11.5 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	14.32						
	15.06	8.3	95.3	16.3	0.7	11.8	0.01
	15.18	6.6	136.7	23.4	1.2	17.0	0.01
B.T.	15.24	6.2	156.7	26.9	1.7	19.5	0.03
	15.31	5.5	173.7	29.8	4.3	22.0	0.15
	15.49	4.2	207.2	35.5	32.3	29.5	0.84
STOP	15.55		219.0	37.5	45.8	32.7	1.14

TABLE B- 40

DISPLACEMENT TEST DATA FROM RUN # 40

T = 72 °F, P_{Bar} = 70.5 cm Hg, Q = 20 cc/hr, S_{wi} = 28.3%, K_{oi} = 11.9 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	10.50						
	15.47		99.5	17.1		12.3	
	17.50		141.5	24.3		17.5	
	19.30		174.4	30.0	0.05	21.5	0.002
	19.45		178.8	30.8	0.65	22.1	0.14
	20.35		195.3	33.6	5.65	24.8	0.30
STOP	23.48		230.0	39.6	38.95	33.2	0.96

TABLE B-41

DISPLACEMENT TEST DATA FROM RUN #41

$T = 72\ °F$, $P_{Bar} = 70.7$ cm Hg, $Q = 5.0$ cc/hr, $S_{wi} = 29.4\%$, $K_{oi} = 11.4$ darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	13.20						
1/8	09.00		98.0	17.1		12.1	
	15.30		133.5	23.3		16.5	
	20.30		158.2	27.6		19.5	
	22.57		170.0	29.7		21.0	
2/8	06.40		211.0	36.9		26.0	
	08.00		217.5	38.0	0.1	26.8	0.02
	12.55		239.7	41.9	10.9	30.9	0.49
STOP	21.45		260.7	45.6	35.9	36.6	1.19

TABLE B-42

DISPLACEMENT TEST DATA FROM RUN #42

T = 69 °F, P_{Bar} = 70.6 cm Hg, Q = 10 cc/hr, S_{wi} = 31.0%, K_{oi} = 11.4 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	01.50						
	15.25		135.0	24.1		16.7	
	19.25		175.8	31.4		21.7	
	21.46		205.2	36.7		25.3	
	22.41		210.4	37.6	3.5	26.4	0.67
	STOP		232.9	41.6	23.0	31.6	0.87

TABLE B- 43

DISPLACEMENT TEST DATA FROM RUN # 43

T = 70 °F, P_{Bar} = 70.2cm Hg, Q = 560 cc/hr, S_{wi} = 31.6%, K_{oi} = 11.6 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	15.00						
	15.09	30.6	46.7	8.4	0.1	5.8	0.002
	15.14	26.8	97.5	17.6	0.8	12.1	0.014
	15.19	22.0	146.5	26.4	1.4	18.2	0.012
B.T.	15.24	17.0	190.0	34.3	2.0	23.7	0.014
	15.30	13.0	227.5	41.0	17.5	30.2	0.41
	15.35	10.8	262.5	47.3	41.0	37.4	0.67
	15.41	9.2	282.5	50.9	75.5	44.2	1.73
	15.46	8.2	295.5	53.3	109.5	50.0	2.62
	15.50	7.6	304.5	54.9	136.5	54.4	3.00
	15.535	7.3	312.2	56.3	161.5	58.4	3.25
	15.57	6.8	319.7	57.6	190.5	62.9	3.87
	16.01	6.6	326.7	58.9	223.5	67.9	4.71
	16.05	6.3	331.7	59.8	253.5	72.2	6.00
	16.09	6.0	336.7	60.7	285.0	76.7	6.30
STOP	16.09		338.7	61.1	299.0	78.7	7.00

TABLE B- 44

DISPLACEMENT TEST DATA FROM RUN # 44

T = 70 °F, P_{Bar} = 70.4 cm Hg, Q = 400 cc/hr, S_{wi} = 32.2%, K_{oi} = 11.7 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	22.50						
	23.00	21.4					
	23.10	18.8	96.9	17.6	0.05	12.0	
	23.16	16.2	137.9	25.1	0.15	17.0	0.002
	23.22	13.5	177.9	32.4	0.25	22.0	0.003
B.T.	23.23	13.0	184.9	33.6	0.30	22.8	0.008
	23.27	11.8	205.4	37.4	2.70	25.7	0.11
	23.31	10.0	227.4	41.4	11.70	29.5	0.41
	23.36	8.6	244.4	44.5	26.70	33.4	0.88
	23.40	7.8	261.4	47.6	42.7	37.5	0.94
	23.45	7.0	277.9	50.6	60.2	41.7	1.06
	STOP		290.9	52.9	89.2	46.9	2.23

TA[illegible]B-[illegible]

DISPLACEMENT TE[illegible] DATA FROM RUN #45

$T =$ 72 °F, P_{Bar} = 70.6 cm Hg, $Q =$ 80 cc/hr, S_{wi} = 33.5%, K_{oi} = 11.9 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	14.10						
	14.34	4.6					
	15.35	4.0	97.0	18.0		12.0	
	15.55	3.0	129.5	24.0		16.0	
B.T.	16.19	2.5	161.1	29.9		19.9	
	16.35	2.2	173.1	32.1	8.8	22.4	0.73
	16.50	1.6	186.1	34.5	18.8	25.3	0.77
	17.02	1.4	195.3	36.2	[illegible]5.4	27.2	0.72
	STOP		200.7	37.2	30.5	28.5	0.94

TABLE B-46

DISPLACEMENT TEST DATA FROM RUN #46

T = 72 °F, P_{Bar} = 71.[illegible] cm Hg, Q = 1130 cc/hr, S_{wi} = 32.8 %, K_{oi} = 11.9 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	13.59						
	14.05	50.0	99.0	18.2	0.1	12.2	0.001
	14.075	42.0	142.0	26.1	0.15	17.5	0.001
	14.10	33.5	186.3	34.2	0.35	23.0	0.005
B.T.	14.11	30.0	206.1	37.8	0.55	25.5	0.01
	14.12	27.0	223.1	40.9	2.75	27.9	0.13
	14.14	23.0	245.9	45.1	10.75	31.7	0.35
	14.155	20.0	260.9	47.9	35.75	36.6	1.00
	14.175	18.0	273.9	50.3	[illegible].75	40.8	1.62
	14.20	16.0	287.4	52.[illegible]	87.75	46.3	2.30
	14.22	14.8	299.9	55.0	120.25	51.[illegible]	2.6[illegible]
	14.25	13.9	308.9	56.7	15[illegible].25	57.0	3.67
	14.27	13.0	317.4	58.2	190.25	62.6	4.35
	14.30	12.2	325.4	59.7	232.25	68.3	5.25
	14.33	11.5	332.4	61.0	273.25	74.7	5.86
	14.36	11.0	339.4	62.3	316.25	80.9	6.14
	14.38	10.6	345.4	63.4	357.25	86.7	6.83
	14.41	10.2	350.4	64.3	396.25	92.1	7.80
	14.43	9.8	355.4	65.2	436.25	97.6	8.00
	14.46	9.6	360.4	66.1	478.25	103.4	8.40
	14.485	9.3	364.4	66.9	518.25	108.3	10.00
	14.51	9.0	368.4	67.6	557.25	114.2	9.75
	14.55	8.8	374.9	68.8	627.25	123.6	10.77
STOP/RESTART							11.25
	15.20	8.4	380.9	69.9	694.75	132.7	
	15.25	8.1	387.4	71.1	782.25	144.3	13.46
	15.30	7.8	393.9	72.3	873.25	156.3	14.00
	15.37	7.5	399.9	73.4	969.75	168.9	16.08
	15.42	7.2	403.9	74.1	1062.75	180.9	23.35
	15.48	7.0	407.9	74.8	1154.75	192.7	23.00
	16.10	6.4	423.9	77.8	1522.75	240.1	23.00
STOP	16.13	6.4	425.9	78.1	1597.75	249.6	37.50

TABLE B- 47

DISPLACEMENT TEST DATA FROM RUN #47

T = 68 °F, P_{Bar} = 69.6 cm Hg, Q = 240 cc/hr, S_{wi} = 15.1%, K_{oi} = 12.3 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	21.15						
	21.23	7.6					
	21.32	7.8					
	22.05	5.4					
	22.21	4.5	248.0	26.8		22.7	
	22.31	3.9	289.5	31.3		26.5	
	22.42	3.4	332.5	35.9		30.5	
	22.53	3.0	376.0	40.6		34.4	
B.T.	22.56	3.0	388.0	41.9	0.1	35.6	0.01
	23.06	2.8	407.0	43.9	16.1	38.8	0.84
	23.17	2.6	425.0	45.9	42.6	42.8	1.47
	23.24	2.6	434.0	46.8	60.6	45.3	2.00
	STOP		438.0	47.3	68.1	46.4	1.88

TABLE B-48

DISPLACEMENT TEST DATA FROM RUN #48

T = °F, P_{Bar} = cm Hg, Q = cc/hr, S_{wi} = %, K_{oi} = darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	16.43						
26/8	16.00		288.0	31.6		26.4	
	17.50		301.0	33.0		27.6	
	19.42		312.5	34.2		28.6	
	21.34		324.0	35.5		29.7	
27/8	02.00		351.7	38.5	2.2 (clear)	32.4	0.08
	03.47		357.7	39.2	8.2 (clear)	33.5	1.00
STOP	05.25		362.5	39.7	14.3 (dyed)	34.5	1.27
	RESTART AT 05.32 RATE = 400 cc/hr.						
	05.38		367.1	40.2	43.3	37.6	6.30
	05.44		369.6	40.5	78.3	41.0	14.00
	05.50		372.6	40.8	115.3	44.7	12.33
	STOP		373.6	40.9	126.3	45.8	11.00
	TURNED OVER AND STARTED AGAIN AT 400 cc/hr. (More reduction of inlet zone)						
	1		381.1	41.8	155.3	49.1	3.87
	2		388.1	42.5	190.3	53.0	5.00
	RESTART AT 1120 cc/hr						
	1		442.1	48.4	490.3	85.4	5.56

TABLE B-49

DISPLACEMENT TEST DATA FROM RUN #49

T = 70 °F, P_{Bar} = 69.8 cm Hg, Q = 320 cc/hr, S_{wi} = 15.6%, K_{oi} = 10.7 darcy

	TIME (Hrs.)	PRESSURE DROP (psi)	CUMULATIVE OIL PROD. (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PROD. (cc)	CUMULATIVE TOTAL PROD. (% P.V.)	WATER OIL RATIO
START	14.10						
	14.40	9.0					
	15.00	6.5					
	15.25	4.2	375.0	40.7	8.0 (clear)	35.1	0.02
	15.27	3.9	396.0	43.0	11.6 (clear)	37.3	0.17
B.T.	15.29	3.8	401.8	43.6	13.8 (dyed)	38.1	0.38
	15.35	3.5	420.3	45.6	26.8	41.0	0.70
	15.40	3.2	433.0	47.0	45.8	43.9	1.50
	15.46	3.1	444.0	48.2	67.8	46.9	2.00
	15.51	3.0	452.0	49.1	90.8	49.7	2.88
	15.57	2.9	460.0	49.9	114.8	52.7	3.00
	16.03	2.8	468.0	50.8	140.3	55.7	3.19
	STOP		471.5	51.2	153.3	57.2	3.71