CHAPTER 2
THEORETICAL BACKGROUND AND LITERATURE REVIEW

2-1 Theoretical Background:

Flow in hydrocarbon reservoir are not generally one-phase flows. Yet reservoir do exist, with oil (above the bubble point) or with gas – dry or wet- without an active aquifer. Other situations are marked by a simultaneous flow of two or even three phases, gas ,oil, and water, at least in some zones of the reservoir.

Multiphase flow can be thus be seen to represent a fairly widespread occurrence. The laws governing these flows are not always satisfactory. Particularly for three movable phases. However, the laws governing two-phases flows are fairly well represented on the "microscopic" scale is impossible, because the geometric description of the porous medium is too complex. This means that the laws of two-phase flow are based on experimental consideration of a porous block .

This is described in this chapter, following a definition of the concept of the relative permeability which is essential for the analysis of these flows.

2-1-1 Relative Permeability Concepts:

Routine permeability measurements are made with a single fluid filling the pore space. This is seldom the case in the reservoir situation except in water zones. Generally, two and sometimes three phases are present, i.e. oil, water, and occasionally gas as well. Here one would expect the permeability to either fluid to be lower than that for the single fluid since it occupies only part of the pore space and may also be affected by interaction with other phases. The concept used to address this situation is called relative permeability.(Paul Glover,2011)

$$Kro = \frac{Ko}{K}$$ ....(2-1)

$$krg = \frac{Kg}{K}$$ ....(2-2)

$$krw = \frac{Kw}{K}$$ ....(2-3)

Where:

k_{ro} = relative permeability to oil

k_{rg} = relative permeability to gas

k_{rw} = relative permeability to water

k = absolute permeability

k_o = effective permeability to oil for a given oil saturation

k_g = effective permeability to gas for a given gas saturation

k_w = effective permeability to water at some given water saturation

It should be pointed out that when three phases are present the sum of the relative permeabilities ($k_{ro} + k_{rg} + k_{rw}$) is both variable and always less than or equal to unity. An appreciation of this observation and of its physical causes is a prerequisite to a more detailed discussion of toward three-phase relative permeability relationships. It has become a common practice to refer to the relative permeability curve for the nonwetting phase as k_{nw} and the relative permeability for the wetting phase as k_w.

When a wetting and a nonwetting phase flow together in a reservoir rock, each phase follows separate and distinct paths. The distribution of the two phases according to their wetting characteristics results in characteristic wetting and nonwetting phase relative permeabilities. Since the wetting phase occupies the smaller pore openings at small saturations, and these pore openings do not contribute materially to flow, it follows that the presence of small wetting phase saturation will affect the nonwetting phase permeability only to a limited extent. Since the nonwetting phase occupies the central or larger pore openings which contribute materially to fluid flow through the reservoir, however, small nonwetting phase saturation will drastically reduce the wetting phase permeability.

Figure (2.1) presents a typical set of relative permeability curves for a water-oil system with the water being considered the wetting phase.
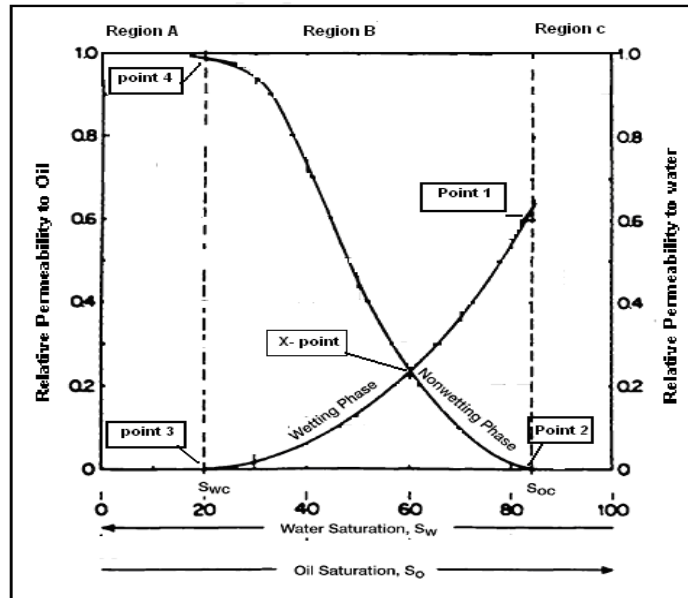
Fig (2-1): Typical Two-Phase Flow Behavior (Tareq Ahmad, 2005)

Point 1

Point 1 on the wetting phase relative permeability shows that a low saturation of the nonwetting phase will drastically reduce the relative permeability of the wetting phase because the nonwetting phase occupies the larger pore spaces.

Point 2

on the nonwetting phase relative permeability curve shows the nonwetting phase begins to flow at the relatively low saturation of the nonwetting phase. The saturation of the oil at this point is called critical oil saturation S_{oc}.

Point 3

on the wetting phase relative permeability curve shows the wetting phase will cease to flow at a relatively large saturation. This is because the wetting phase preferentially occupies the smaller pore spaces, where capillary forces are the greatest. The saturation of the water at this point is referred to as the irreducible water saturation S_{wir} or connate water saturation S_{wi} both terms are used interchangeably.

Point 4

on the nonwetting phase relative permeability curve shows that, at the lower saturations of the wetting phase, changes in the wetting phase saturation have only a small effect on the magnitude of the nonwetting phase relative permeability curve.

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The reason for the phenomenon at Point 4 is that at the low saturations the wetting phase fluid occupies the small pore spaces which do not contribute materially to flow, and therefore changing the saturation in these small pore spaces has a relatively small effect on the flow of the nonwetting phase.

This process could have been visualized in reverse just as well. It should be noted that this example portrays oil as nonwetting and water as wetting. The curve shapes shown are typical for wetting and nonwetting phases and may be mentally reversed to visualize the behavior of an oil-wet system. Note also that the total permeability to both phases, $k_{rw} + k_{ro}$, is less than 1, in regions B and C.

The above discussion may be also applied to gas-oil relative permeability data, as can be seen for a typical set of data in Figure (2.2). Note that this might be termed gas-liquid relative permeability since it is plotted versus the liquid saturation.
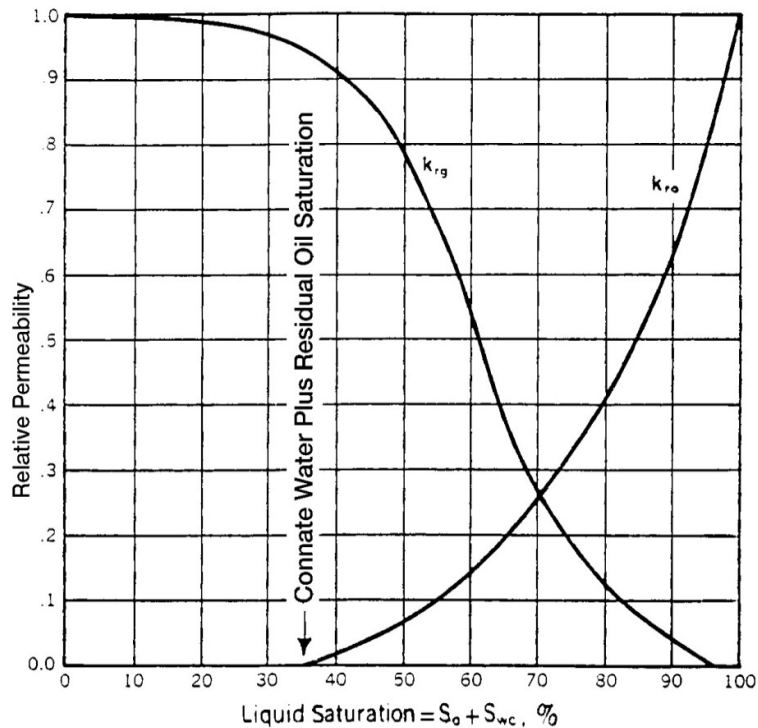

Fig (2-2): Typical of Gas-Oil Relative Permeability Data in the Presence of Connate Water (Tareq Ahmad, 2005)

2-1-2 Capillary Pressure

The capillary forces in a petroleum reservoir are the result of the combined effect of the surface and interfacial tensions of the rock and fluids, the pore size and Geometry ,and the wetting characteristics of the system. Any curved surface between

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two immiscible fluids has the tendency to contract into the smallest possible area per unit volume. This is true whether the fluids are oil and water, water and gas (even air), or oil and gas. When two immiscible fluids are in contact, a discontinuity in pressure exists between the two fluids, which depend upon the curvature of the interface separating the fluids. We call this pressure difference the capillary pressure and it is referred to by P_c.

Denoting the pressure in the wetting fluid by Pw and that in the nonwetting fluid by Pnw, the capillary pressure can be expressed as:

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

Pc= Pnw- Pw...(2-4)

The value of capillary pressure is dependent on the saturation of each phase, on which phase is the continuous phase, and on the shape and size of the pores and pore throats.

Displacement pressure (PD): is the threshold or entry capillary pressure needed for the non-wetting phase to displace the wetting phase from the largest pores.

Drainage: is a process in which the wetting phase saturation decreases and the non-wetting phase saturation increases.

Imbibition: is process in which the wetting phase saturation increases and the non-wetting phase saturation decreases.

The Free water level (FWL): in a reservoir is the level at which the oil-water capillary pressure vanishes. It is the oil water interface that would exist at equilibrium in an observation borehole, free of capillary effects, if it were to be drilled in the porous medium and filled with oil and water.

The Oil-water contact (OWC): is the level at which the hydrocarbon saturation starts to increase from some minimum saturation. In a water-wet rock, that minimum saturation is essentially zero.

The residual oil saturation (Sor): is the oil saturation level above which the oil starts to be moveable.

The connate or irreducible water saturation (Swc): is the water saturation level below which the water becomes immovable.

Supercharging: is a phenomenon that leads to measurement of a formation pressure that is higher than actual, leading to scattered pressure profiles or to altered

gradients. The degree of supercharging is generally inversely related to permeability (H. Elshahawi, 1999)

That is, the pressure excess in the nonwetting fluid is the capillary pressure, and this quantity is a function of saturation. This is the defining equation for capillary pressure in a porous medium.

There are three types of capillary pressure:

- Water-oil capillary pressure (denoted as Pcwo)
- Gas-oil capillary pressure (denoted as Pcgo)
- Gas-water capillary pressure (denoted as Pcgw)

Pcwo = Po - Pw...(2-5)

Pcgo = Pg - Po...(2-6)

Pcgw = Pg - Pw..(2-7)

where Pg , Po , and Pw represent the pressure of gas, oil, and water, respectively.

If all the three phases are continuous, then:

Pcgw = Pcgo + Pcwo..(2.8)
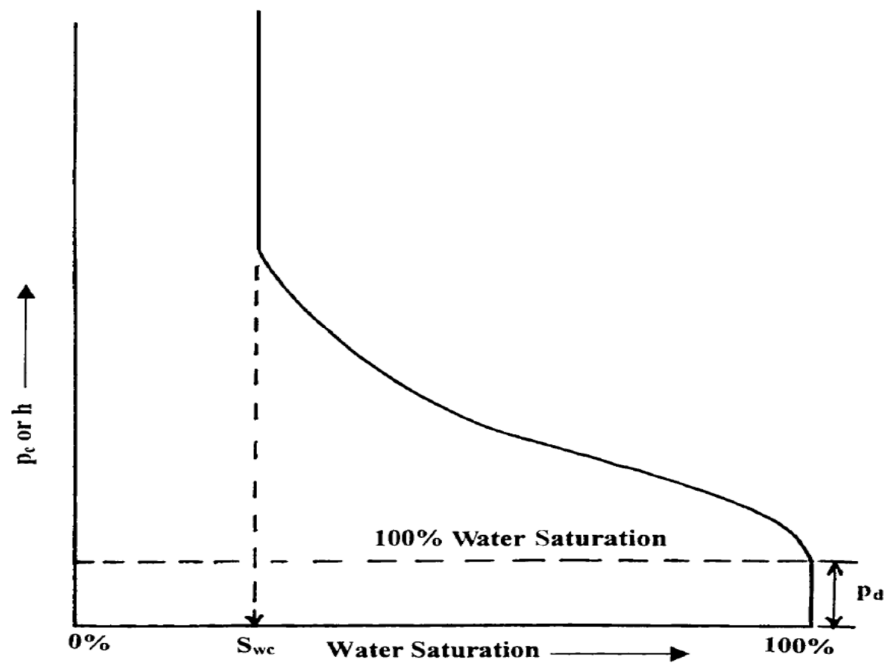

Fig (2-3): Capillary Pressure Curve (Tareq Ahmad, 2005)

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2.2 Literature Review:

2-2-1 Factors of Affecting The Relative Permeability Measurements :

The relative permeability is influenced by many factors which can be summarized as follows :
 • Rock Structure

 • Fluid Properties

 • Wettability

 • Saturation History

The relative permeability function were assumed as a quantity which describes the fluid transport properties of a particular rock-fluid pair system. In any individual rock sample where the flowing fluids are well defined i.e. oil and water, it can't concerned with rock structure as a variable, nor with the effects of changing fluid properties, e.g. viscosity ratio or interfacial tension. It's assuming for the sake of simplicity that these are fixed quantities for any system of interest. The wettability controls the mechanism of displacement (drainage or imbibition) is also fixed by using a controlled system with strong uniform surface wettability. Saturation history or the sequence of fluids flowing through the porous media is controlled by experiment. It is important to appreciate at the outset that the direction of saturation change also influences relative permeability and that the process is not simply reversible.

Although the concept of relative permeability is supposedly independent of experimental parameters, laboratory data has previously suggested a dependence on factors such as flow rate, core length, etc. Factors which affect the measurement and behavior of fluid flow in porous materials have been studied by other investigators.

2-2-1-1 The Effect Of Wettability On Two-Phase Relative Permeabilities

In 1974   McCaffery .F.G & Bennion D.W determined between wettability and the two-phase relative permeability saturation properties of three consolidation intergranular cores. Wettability was defined by the contact angel (θ), measured external to the porous medium, and by the ability of a fluid to spontaneously imbibe into the porous system. Close control over the wettability was achieved in these tests by using synthetic cores and various pure fluids which displayed essentially uniform wetting behavior with the solid. The formation media, which were of widely differing

porosity and permeability, provided systems of fixed pore geometry which were ideal for systematic studies of the wettability variable. Certain comparisons with published work suggested that the cores were representative models of naturally occurring intergranular porous media. Results determined during the study suggested that wettability effects may predominate over influences from the detailed pore structure.

Relative permeability test results indicated that the most efficient immiscible displacement was obtained with fluids capable of spontaneously imbibing into the porous media. Relative permeability saturation relations were media. Relative permeability saturation relations were virtually independent of (θ) for displacements with imbibing fluids. As (θ) was increased through values for which imbibition did not occur, a consistent shift in the relative permeability properties of both phases was found when the media contained an initial irreducible saturation of the displacing phase. For drainages or forced displacements from a core initially saturated with one fluid, relative permeability curves were little affected when the system contact angel through the displacing phase was varied over the range of 180 to 90 degrees. The sensitivity of the relative permeability relations to contact-angel changes was strongly influenced by the saturation history of a core.

The result of this study of wettability effects in intergranular porous media with uniform wettability were reached as Relative permeability test results indicated that most efficient recovery would be achieved with fluids capable of spontaneously imbibing into the porous medium. With an irreducible saturation of the displacing fluid initially present in a core, no measurable difference in relative permeability-saturation properties was found for systems with contact angles of 20, 42 and 49 degrees through the displacing phase. As the contact angle was increased to higher values, beginning with 73 degrees, a consistent shift of the relative permeability-saturation relations of both phases occurred. For drainage or forced displacements from a core originally saturated with one fluid, systems having contact angles through the displacing phase in the range of 180 to 90 degrees exhibited virtually the same relative permeability behavior. Wettability was found to exert a similar influence on immiscible displacement in porous media of widely different porosity and permeability. Results determined during this study suggest that wettability effects may predominate over influences from the detailed pore structure. The contact angle range of fluids capable of imbibing was affected by the initial saturation condition of the core. When imbibitions occurred, terminal saturations were usually reached that were

similar to that obtained in a displacement test when the displacing fluid was injected into the porous medium under an applied pressure. Wettability affects the position of relative permeabilities, as shown in Fig. (2-4).
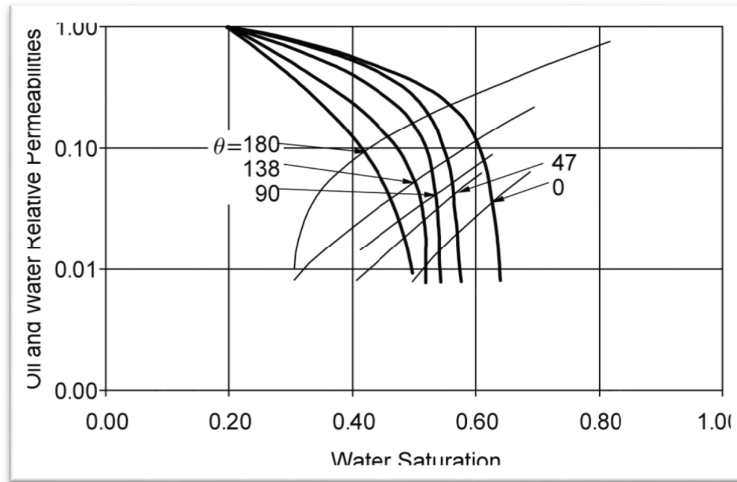

Fig (2-4): Oil/water relative permeabilities for Torpedo sandstone with varying wettability (McCaffery .F.G & Bennion D.W , 1974)

2-2-1-2 The Effect of Temperature and Interfacial Tension on Relative Permeabilities

In 1984 Torabzadeh .S.J.and Handy L.L. had relative permeability data for high low-tension systems were obtained experimentally at temperatures ranging from 22℃ to 175 ℃. No other data have been reported for high temperatures and low interfacial tensions. Results for high-tension systems at elevated temperatures and for low-tension systems at room temperature are compared with other published data. The results of this study can be used to predict the performance and efficiency of enhanced oil recovery methods in which chemicals are considered for use with hot water floods or as steam flood additives. They are of particular interest with respect to particular interest with respect to steam floods in viscous oil reservoirs.

Equipment was designed and constructed to measure water-oil relative permeabilities at elevated temperatures and pressures. It can be used for both steady-state and unsteady state dynamic displacement measurements. The apparatus permits very accurate measurement of fluid saturations volumetrically by monitoring the oil content of the total system using high pressure, high temperature water-oil separator. Experiments were conducted on sandstone cores using n-dodecane and 1% NaCl brine. Aqueous low-concentration surfactant solutions were used to change interfacial

tension levels. For the experiments reported here, the fluid pressure was kept constant at 300 psig and pressure was kept constant at 300 psig and the overburden pressure at 650 psig.

The experimental results indicate that relative permeability curves are affected by temperature, especially at low IFT'S. For the high-tension system, relative permeability to oil increased and relative permeability to water decreased at a given permeability to water decreased at a given saturation while residual oil saturation decreased and irreducible water saturation increased with increasing temperature. Water/oil relative permeability ratio decreased with temperature at a given water saturation. These results suggest an increase in the preferential water wettability of sandstone with temperature.

Temperature effects were found to be more pronounced for low-tension than high-tension systems. Residual oil saturation decreased significantly at higher temperatures, but only a small change in irreducible water saturation was observes. In any given temperature, irreducible water saturation for the low-tension system was lower than that observed for the high-tension system. Relative permeability to oil and water both increased with increasing temperature up to 100 °C for the low-tension system. At higher temperatures, a decrease in relative permeability to water was observed, probably due to wettability alteration.

The steady-state technique showed a hysteresis effect in relative permeability curves which tended to diminish at high temperatures and low IFVS as shown in Fig. (2-5) and a hysteresis effect in relative permeability curves which tended to diminish at high temperatures and high IFVS as shown in Fig. (2-6) . Rate effect was not significant for the rates used in this study. The change in wettability of the rock and reduction of IFT with increasing temperature were important factors affecting the observed relative permeability curves.
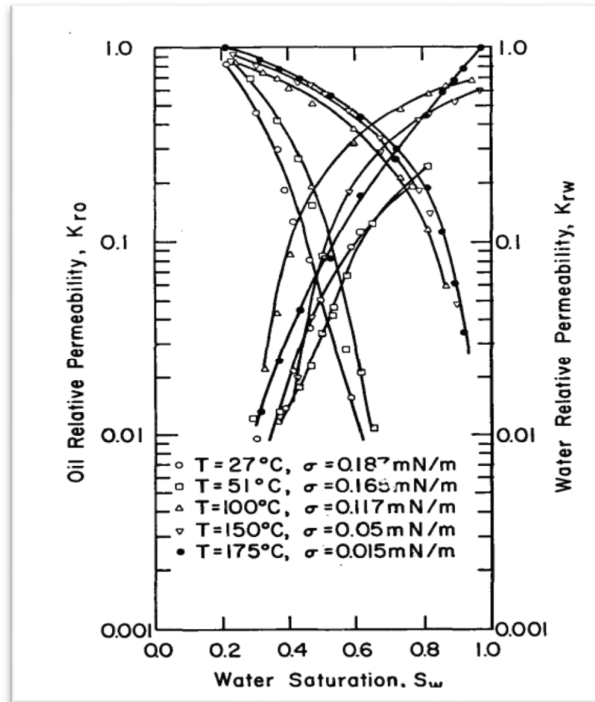
Fig (2-5):Steady-state imbibition water/oil relative permeability curves at elevated temperatures (low tension) (Torabzadeh .S.J.and Handy L.L.,1984).

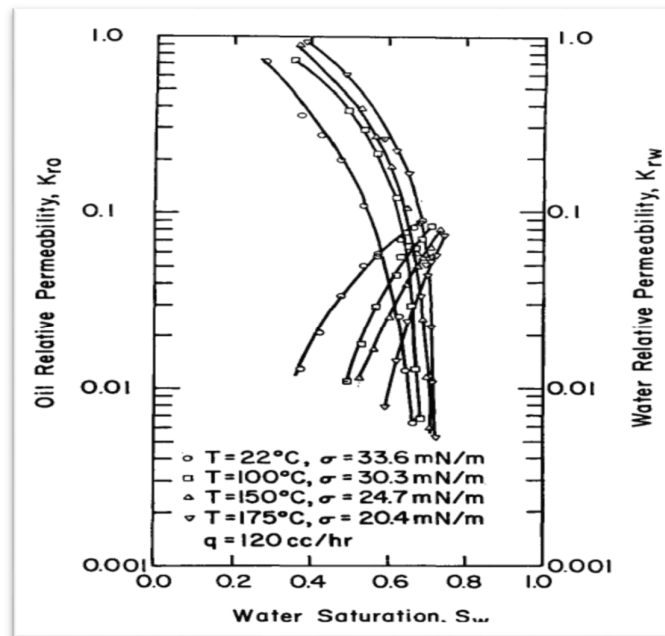Fig (2-6): S-Steady-state imbibition water/oil relative permeability curves at elevated temperatures (high tension) (Torabzadeh .S.J.and Handy L.L.,1984).

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2-2-1-3 The Effect of Fluid-Flow Rate and Viscosity on Laboratory Determinations of Oil-Water Relative Permeabilities

In1958 Sandber, C. R., Gournay, L. S. and Sippel , R.F were studied The effect of fluid-flow rate and fluid viscosity on oil-water relative permeability determinations by using the "dynamic flow technique." In this work relative permeability curves were obtained for homogeneous small core samples from several sandstone outcrop formations. Radio-tracers were used for the determination of fluid saturation and for the detection of saturation gradients. Cobalt-60 in the form of cobalt us chloride was used as a water-phase tracer in some of the experiments. Iodine-131 in the form of iodobenzene and Mercury-203 in the form of mercury were used as oil-phase tracers in other experiments. Flow rates for each phase were varied within a range of 2.5 to 140.6 ml/hr. Oil-phase viscosities under flowing conditions were varied from 0.398 to 1.683 cp.

The relative permeabilities obtained were found to be solely a function of saturation and independent of flow, provided there was no saturation gradient induced in the core sample by "boundary effect." Even though equilibrium with flowing that conditions was obtained at the lower flow rates, where a saturation gradient exists, this equilibrium is of a "contingent"-type rather than the "steady-state" equilibrium implicit in the relative permeability concept. The only effect of increasing the oil or non-wetting phase viscosity was to decrease the flow rate required for the elimination of the boundary effect.

Fairly good agreement between experimentally determined and calculated values of the boundary effect was obtained when the non-wetting oil phase was the only flowing phase.

2-2-1-4 Effect of Viscosity on Relative Permeability:

Downie, J. and Crane, F.E (1961) were discussed that the oil relative permeability should increase as the viscosity ratio increases. Odeh presents data corroborating this deduction. It also follows that the oil relative permeability should decrease as the viscosity ratio of oil to water decreases. However, our results show that a high relative permeability, when once attained by using viscous oil, may be maintained when that oil is replaced by an oil of much lower viscosity.

2-2-1-5 Effect of Capillary Number and Its Constituents on Two-Phase Relative Permeability Curves

In 1985 Fulcher, R.A. was discussed the effect of capillary number, a dimensionless group describing the ratio of viscous to capillary forces, on two-phase (oil-water) relative permeability curves. Specifically, a series of steady-state relative permeability measurements were carried out to determine whether the capillary number causes changes in the two-phase permeabilities or whether one of its constituents, such as flow velocity, fluid viscosity, or interfacial tension (IFT), is the controlling variable.

The nonwetting-phase (oil) relative permeability showed little correlation with the capillary number. As IFT decreased below 5.50 dyne/cm [5.50 N/m], the oil permeability increased dramatically. Conversely, as the water viscosity increased, the oil demonstrated less ability to flow. For the wetting-phase (water) relative permeability, the opposite capillary number effect was shown. For both the tension decrease and the viscosity increase (i.e., a capillary number increase) the water permeability increased. However, the water increase was not as great as the increase in the oil curves with an IFT decrease. No velocity effects were noted within the range studied.

Other properties relating to relative permeabilities were also investigated. Both the residual oil saturation (ROS) and the imbibition-drainage hysteresis were found to decrease with an increase in the capillary number. The irreducible water saturation was a function of IFT tension only.

A relative permeability model was developed from the experimental data, based on fluid saturations, IFT, fluid viscosities, and the residual saturations, by using regression analysis. Both phases were modeled for both the imbibition and the drainage processes. These models demonstrated similar or better fits with experimental data of other water- and oil-wet systems, when compared with existing relative permeability models. The applicability of these regression models was tested with the aid of a two-phase reservoir simulator.

This literature survey is divided into two sections:1) relative permeability ,2) capillary pressure. Are ference list at the end of this survey provides relevent papers for thses topics:

2-2-2 Relative permeability:

Relative permeability is the basis for multiphase flow through porous media .The literature search concentrated on: 1) the mechanistic theory of fluid movement from pore to pore, 2) the derivation of flow equation and boundary conditions, 3) the experimental procedure from measuring relative permeability from both the core flood and the centrifuge.

The concept of relative permeability and its effect on the movement of gas, oil and water through porous medium was first described by Buckley and Leverett (1942). They discussed the dynamics of oil displacement by either gas or water ,and proposed the (at the time)new concept that water was better displacement fluid than gas because of more favorable mobility ratios and less significant relative permeability reductions. Although they ignored capillary pressure effects in their calculations, they noted its importance in determining water\oil contact at equilibrium and analyzing gravity drainage rates. The paper ended by recommending moderate production strategies in areas of potential coning so that relative permeability reduction from water influx would be minimized.

The Bukley –Leverett method was modified by Welge in 1952 when he derived an analytical method for computing average saturation. Darcy's Law was used for both wetting and non-wetting phases, and then combined with a material balance equation that resulted in equations describing saturation in the core .With this method, the movement of the saturation front in a linear core could be tracked, and the average saturation behind the front could be calculated.

Corey (1954) presented a method for calculating oil relative permeabilties from measured gas permeabilities. The Kozeny – Carmen equation and the properties of the capillary pressure distribution function were used to relate pore volume and tortuosity to capillary pressure. He compared measured data versus calculated data from 40 samples and found a good correlation with about two- thirds of the experiments. Experimental error was noted in cores with considerable amounts of dolomite or in cores with pronounced stratification. He proposed a relationship between capillary pressure and saturation:

$$\frac{1}{P_c} = C \; \frac{(So-Sor)}{(1-Sor)} \; \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots(2\text{-}9)$$

where:

  Pc= capillary pressure

  So= oil saturation

  Sor= residual oil saturation

  C=constant

   He also proposed important expressions for gas \ oil and oil\water relative permeabilities:

$$Kro = [\frac{(So-Sor)}{(1-Sor)}]^4 \quad ....(2-10)$$

$$krg = [1 - \frac{(So-Sor)}{(Sg-Sor)}]^2 [1 - [\frac{So-Sor}{1-Sor}]^2] \quad ....(2-11)$$

Where:

  k_{ro}= oil relative permeability

  k_{rg}= gas relative permeability

  S_g= gas saturation

   A paper that described factors which affected laboratory measurement of relative permeability was prepared by Osaba and Richardson (1951). Results of laboratory measurement of relative permeability on small sample were presented using five different methods: Penn State, single core dynamic, gas drive, saturation liquid, and Hassler techniques. The influence of factors such as a boundary effects, hysteresis, and injection rate were discussed.

   He most significant boundary effect influencing core flooding was the capillary pressure effect at the outlet face of the core. This resulted in a higher water saturation at the outlet face. To minimize this boundary effect error, high rates of flow recommended. To remove hysteresis effects, core flooding in only one direction was recommended .The results indicated that all five methods yielded essentially the same relative permeabilitis to gas. For oil\water relative permeabilities, the Hassler Brunner method gave consistently lower residual oil saturation than other methods.

   The classic paper on determination of relative permeability from experimental coreflood data was prepared by Johnson,Bossler, and Naumann (JBN) in 1958. It used the theory initially proposed by Buckley and Levereet (later modified by Welge) to calculate individual relative permeabilities. JBN theory made three important assumptions: 1) the flow velocity was the same at all cores sections of the linear porous body, 2) flow velocity was high enough to achieve Buckley - Levereet

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displacement, 3) capillary effects were negligible at high injection rates. To verify theoretical proposal, JBN relative permeability curves from small core plugs were compared with steady state relative permeability curve from whole cores. It was concluded that the JBN method was faster, required smaller core samples, and reproduced steady state core flooding effectively.

Jones and Roszelle (1978) developed a graphical technique for determining relative permeability from unsteady state displacement experiments. A plot of average water saturation versus the reciprocal of pore volume injected was made. With this plot, the fractional flow of oil was equal to the inverse slope of the tangent line at any given saturation. Fractional flow was then converted to relative permeability using an effective viscosity plot. The Jones and Roszelle technique was used in this research to derive coreflood relative permeability curves.

Bentsen (1976) investigated scaling requirements during measurement of relative permeabilities and proposed several simplifying assumptions for determining boundary conditions and mobility ratios. He began by deriving the basic flow equations and converting them into dimensionless variables .He the proposed that the dimensionless function for K_{rw}, K_{rnw} , and capillary pressure were directly related to Sw, provided that transition zone between the displacing and displaced phase was sufficiently small. This allowed him normalize the relative permeability curves to Sw end points 0.0 and 1.0. He also proposed a method for estimating the mobility ratio by using the average water saturation behind the displacement front.

An important method for measuring oil relative permeability using centrifugal gas/oil displacement data from small cores was developed by Hagoort (1980). He derived the basic flow equations for a linear coreflood, then non-dimensionalized these equations to allow for curve fitting of experimental data. He concluded that relative permeability to oil is a critical factor in the gravity drainage process. A graphical technique for deriving the wetting phase coefficients for the Corey equation was presented. This methodology was used to determine the wetting phase relative permeability curves from experimental centrifuge data. Hagoort's assumptions included insignificant capillary pressure effects and large differences in mobilities between the witting and non-wetting phases.

O'Meara and Crump (1985) built a centrifuge simulation model that calculated relative permeability simultaneously with capillary pressure. The model was one-dimensional and contained terms for variable centrifuge acceleration and non-wetting

mobility. Darcy's Law with a term for centrifuge force was combined with material balance equations for the wetting and non-wetting phases. Capillary pressure and the total wetting and non-wetting superficial velocity were defined and included in the flow equation. The solution to these equations was carried out using a forward finite difference scheme. Boundary conditions assumed a vanishing Capillary pressure at the outlet face, and zero velocity of the wetting phase at the inlet face .Saturation endpoint data was used only to estimate the capillary pressure and as a starting point for the history match. Corey's equations and the capillary pressure term were parameterized. History matching consisted of using a least squares technique to find the parameters which minimized the deference between simulated data and measured production data. The major advantage of this method was that the near-equilibrium S_w vs. P_c data and the transient cumulative recovery data were both used the flow equations. This was a significant improvement over previous methods which only final cumulative recovery as a match point. This research uses O'Meara and Crump methodology to drive flow equations for the centrifuge model.

Firoozabadi and aziz (1986) used an IMPES reservoir simulator to model centrifuge laboratory tests. Their model followed the methodology of Hagoort, but included terms for capillary pressure and mobility ratio. Corey's equations were broken into two functional groups (wetting and non-wetting) and three parameters (two exponents the coefficient of the normalized saturation function for the non-wetting phase). A nonlinear, least square approach was used to match production history, the equations used were:

$$k_{rw} = (S_w^*)^{n_1} \quad\text{..(2-12)}$$
$$k_{rn} = k_{rnwc}(1 - S_w^*)^{n_1} \quad\text{...(2-13)}$$
$$S_w^* = \frac{Sw - Swc}{1 - Swc} \quad\text{..(2-14)}$$

. where :

n_1, n_2, krnwc= variable coefficients to be optimized

k_{rw}= wetting phase relative permeability

k_{rn}= nonwetting phase relative permeability

Munkvold, F.R., Torsaeter,O.in 1990 they measured relative permeability using the unsteady state and the centrifuge methods. The drainage of oil with gas was performed on water-wet cores containing irreducible water. An automated measurement system has been developed for the centrifuge experiments. The

automated system is of vital importance for the measurement of rapid fluid production, and exhibits excellent performance in data collection compared to manual reading. The oil relative permeability curves calculated from the two methods are comparable only if flow potential is kept equal in the two flow processes during the experiments. An automated centrifuge has been developed and used for the measurements of capillary pressure and relative permeability data. The oil relative permeabilities are measured in single speed tests in the centrifuge. The method is fast and easy to carry out, and supports good data at high gas saturations. Unlike unsteady state displacement, the centrifuge method is stable with respect to viscous fingering. The centrifuge measurements indicate that the oil relative permeability is rate dependent near residual oil saturation.

2-2-3 Capillary Pressure:

Capillary preussre was chosen as the initial subject for the literature survey because it provided a ditailed microscopic and mechanistic perspective on fluid flow through porous media .Aclassic paper by Leverett in 1940 is the basis for most modern theory on capillary pressure . The most significant idea proposed was the concept of a characteristic distribution of interfasial two fluid curvatures with water saturation .thesee general occurences of water in a porous solid were discussed :1) a saturation region ,2) a pendular region , and 3) a funicular existence of an outlet face capillary pressure boundary effect was noted , and it's significant effect on small scale flow experiments was emphasized.

Amore detailed paper on the mechanism of fluid flow through porous spaces was prepared by Mohanty in 1987 . This paper reported on the physics of pore level events when waterr displaced oil in an initially oil filed porous rock . these displacments were controlled by pressure distribution , capillary pressure , local pore geometry, pore topology , and PVT properties . A simple rock model , represented by a square network of pores ,analyzed the physics of oil advancement and disconnection at the pore level . The capillary –controlled oil displacment processes of chick –off ,jump ,and oil formation were discribed. The results gave insight into residual oil saturation and it's dependence on pore geometry and capillary number . As capillary number increased, the residual oil saturation decreased and oil tendend to be smaller .As pore size distribution became wider, the decrease of residual oil saturation with capillary number became smoother .

The standard experimental technique for determination of capillarry pressure from a centrifuge was developed by Hassler and Brunner in 1944. Their initial discussion focused on discribing two older methods determininig capillary pressure (capillary diaphragm and gravity drainage)and discussing their shortcomings (too slow and inaccurate at high displacement pressures). The centrifuge apparatus and laboratory procedure were described in detail. The 100% saturation core was centrifuged at increasing rates and the average saturation was measuered at each rate with a stroboscopic device. It was shown that accelerations and saturation values could be converted into a capillary pressure versus saturation plot . Finally capillary pressure curve compared favorably for all three techniques . Strength (speed , simplicity)and weaknesses (no hystresis data,experimental inccuracy) were noted .

Slobod and chambers (1951) compared the centrifuge with other method for determining capillary pressure .The primary advantage of the centrifuge were: 1)rapid establishment of equilibrium, 2) better precission and reproducible results, 3)availability of a high pressure difference between phases ,4) simple operational procedure;and 5) ability to complete experiment in one day or less.

Huffman (1963) proposed a variatiom of the Hassler-Brunner method that was faster and provided an analytic method for conversation of centrifuge data into capillary pressure data.The technique differed from the Hessler –Brunner method in that the centrifuge was slowly accelerated from zero to the maximum speed rether than being held at constant ,progrssively higher speed .Both techniques were described in detail, and capillary pressure results from the same piece of core compared favorably.Shorter experimental time was important advantage of the Hoffman technique over the Hassler-Burnner method.

However ,the Hoffman technique was not widelly used because of experimental error in the dynamic measurement of the recovery data, but may have new applications with introduction of more accurate centrifuges.

More recent articles on capillary pressuer investigated the intrrelationship between capillary force ,viscous forces ,and saturations. New mathmatical methods quntified these variables into functional groups with parameter that could be optimized for history matching .

The latest improvement in the measurement of capillary pressure is the result of a new, more accurate centrifuge designed especially for displacement tests. Firoozabadi, et al (1986) prepared a paper on the measurement and the simulation of capillary

pressure using this centrifuge. The unique feature of this centrifuge was that the rock sample was always in contact with the wetting phase at the outlet face. The improved accuracy in the measurement of expelled fluids gave higher quality experimental data, and the outlet face saturation condition made the centrifuge boundary condition more accurate. Their paper discussed the mechanism of gravity drainage and noted that its two primary components were relative permeability and capillary pressure. Basic equation used for driving capillary pressure was presented.

In this research the relative permeability is influenced by many factors and the results showed the different flow led to different curve and it depends to the end effect and permeability .