Factors Governing Accumulation of Oil and Gas in Stratigraphic Traps

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ABSTRACT

This thesis is a study of those characteristics of sedimentary rocks, that determine their capability to function as cap rocks for petroleum accumulations.

The function of the cap rock is to prevent the oil from upward migration. The active upward forces on the oil (or gas) are due to the buoyancy of the oil (or gas) on water. The forces opposing upward migration of the oil are due to the capillary retention of the water in the cap rock. For any oil trap it is necessary that the capillary forces in the cap rock are larger than the buoyancy of the accumulating oil on the subsurface waters.

For a given combination of oil or gas and subsurface water, the magnitude of the capillary retention forces on the water in the cap rock is given by the displacement pressure of that rock.

An outline is given of the theories, relating the displacement pressure to the basic characteristics of the rock, such as permeability, porosity, interstitial surface area and the Kozeny constant.

The displacement pressure for a given rock is directly proportional to the interfacial tension between the water and the non-wetting phase. The buoyancy of the oil or gas on the water depends upon the density difference between the non-wetting phase and the water. The variations of densities and interfacial tensions with temperature and pressure are discussed and graphical relations are given between these quantities and the depth of the accumulation in question.

Displacement pressures for various types of sandstones were determined from experimental studies of the capillary pressure versus saturation relationships. From the experimentally determined displacement pressures, permeabilities and porosities, the interstitial surface area and the Kozeny constants for the various rocks were computed.

It was found that the interstitial surface areas could be correlated with the electrochemical formation coefficients of the sediments in question, which were measured in the course of another research project by this author. This correlation indicates the possibility of a subsurface method for the determination of displacement pressures, using the S. P. curves of electrologs.

Different types of stratigraphic traps are described and the relative positions of the cap rocks are considered for the various cases.

A schematic example is given of the location of a "permeability pinch-out" type of stratigraphic trap by computation of the displacement pressures from electrologs of drill holes in the vicinity.

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INTRODUCTION

The purpose of this thesis is to investigate some of the inherent characteristics of sediments which enable them to become caprocks, for trapped accumulations of oil and gas.

We assume that in the geologic history of most commercial-size oil pools the source rock, carrier bed, reservoir rock and trap relationship exists. However, regardless of whether the oil migrated as such or whether organic fluids accumulated in the trap and the final stages of conversion to oil, occurred in the same places where the oil now is found, the requirements for the caprock to initially block the passage of oil or to keep the oil in place after it was formed, will be essentially the same.

In structural oil traps the relations between reservoir rocks and caprock are often relatively simple. Where structural closure exists, mostly a large thickness of beds has been involved in the formation of the structure. In the vertical succession of beds, sooner or later a bed with the necessary properties to act as caprock, will be present. This is especially true for the anticlinal or dome shaped structures with quaquaversal dips. For fault traps, the problem of finding suitable caprocks on all sides of the structure already is far more complicated, unless the fault gauge zones are "tight" enough to retain the oil. Our analysis may then be applied to the fault zone to find whether or not this is the case.

The most interesting application of analysis of sediments on their suitability to serve as caprocks, is to the case of stratigraphic traps. The types of stratigraphic traps (see later) vary from truncated strata and depositional pinch-outs, where trapping of oil depends upon the properties of the overlying or adjoining rocks, to the permeability

pinch-out type where the oil is retained by changes in the reservoir rock itself.

In classifying rocks as to their ability to serve as caprocks, it is obvious that layers with absolutely no permeability will always serve effectively to retain oil.

By and large the greatest number of caprocks, however, is of a different type. These rocks will be permeable to water, although their specific permeability may be low. In addition, they will be preferentially water wetted and because of their capillary retention of water, they will resist displacement of water by a non-wetting phase. Thus when 100% water wetted they will block the passage of oil, until the pressure of the oil overcomes the capillary forces retaining the water. Practically all sediments, even unconsolidated sandstones, have such a "threshold pressure," or "displacement pressure." In most cases, however, this pressure is very low and is soon offset by the buoyancy of the oil. Only rocks with a high enough displacement pressure to withstand the buoyancy caused by columns of tenths or hundreds of feet of oil will be effective as caprocks for commercial accumulations of oil or gas.

In this thesis an outline is given of the theory of capillary behavior of porous solids, relating the displacement pressures to some of the basic characteristics of the porous rocks, and experimental attempts are made to correlate some of these properties in order to enable us to determine the displacement pressure by sub-surface geological methods.

PART I

Migration and accumulation of oil in general

In this work we will accept the general idea of a source rock carrier bed - trap relationship in the history of the formation of the larger part of the commercial oil pools.

The most likely source beds are dark shales or marls and in some cases, bituminous limestones. This has been demonstrated both on grounds of their organic content and their frequent relationships to commercial oil accumulations. It is recognized, however, that not <u>all</u> dark shales or marls are actual source beds (1).

From the shales the oil is driven into the more permeable carrier beds by compaction. Beckstrom and van Tuyl (2) demonstrated conclusively that compaction is a completely effective means of removing oil from shales. Actual migration of oil from shales into sandstones was shown experimentally by E. T. Thomas (3), who also brought out the following important conclusions: (a) Oil moves more readily into water wetted, than into dry sand; (b) Oil moves fastest in the direction of greatest pressure decline (this is, in most cases, upward). The mechanism of the migration of the oil from the source beds into the more permeable sands is based on the differential compaction. While sandstones will decrease only 2% in volume, due to a burial to a depth of 4000 feet, a clay will lose close to 45% of its original volume for the same depth of burial. A detailed description of shale compaction with depth of burial was given by Athy (4). The squeezing out of oil by compaction pre-assumes that the oil is formed as such before too great a depth of burial is reached and the larger part of compaction has taken place.

An alternative hypotheses was formulated by Fash (5), namely, that the formation of oil is not completed and only a preliminary product, neokerogen, has been formed by the time squeezing by compaction has stopped. This neokerogen reaches the porous media in a decomposed, partly gaseous stage and disperses in all directions, "travelling as films on the surfaces of the sedimentary particles and along crystal surfaces inside the particles and accumulate in traps, where they are subjected to the catalytic effect of the surfaces of the sediments, with which they are in contact." In the trap the main transformation to petroleum occurs.

It is not clear what factors govern the accumulation of the decomposition products in traps, in other words, what kind of traps would be required to halt the migration of the films, on the surfaces and through the crystal-lattices of the sedimentary particles.

We will therefore only work with the assumption that oil as such, or a very similar product, reaches the porous media mainly in the liquid state, after being squeezed out of the shales by compaction.

The reasons for assuming the oil to be mainly in the liquid state were summarized by Russell (6) who compared rock pressures and temperatures at depth with the vapour pressures of the various hydrocarbon compounds usually present in oil. Russell showed that for the oil fractions to occur as vapours in appreciable quantities they must be above their critical temperatures, and even then a large portion would remain dissolved in the liquid, heavier fractions.

There is, however, no important qualitative difference between the migration and accumulation of oil, and that of gas.

The migration of oil to its final place of accumulation has been the subject of many papers and discussions and also of considerable

experimentation, of which some of the most important ones will be referred to later.

The most widely accepted idea of oil migration is the hydraulic theory as described most thoroughly by J. L. Rich (7,8).

This theory postulates moving underground water as the primary cause of the migration of oil and gas. The migration may take place either directly in the porcus reservoir rock to the place where the oil is trapped, or through so-called carrier beds, which are very permeable horizons between the source and the place where the oil is found (9).

The hydraulic theory, although closely fitting the field evidence in many cases, is liable to convey a physical misconception, namely, that the moving water is carrying the oil or forcing it ahead of it. A more correct picture is that the oil and gas, as well as the water, are all moving under the same pressure gradient. This pressure gradient may be due to differences in hydrostatic head of the underground water or to lateral differences in compaction or any other cause. Once a pressure gradient is established, all fluids will move at velocities corresponding to the relative permeabilities, to the different fluids, which again depend on their partial saturations.

The relationships of relative permeabilities to saturation for liquid-gas mixtures were established by Wyckoff and Botset (10), and for oil-water mixtures by Leverett (11) for the case of unconsolidated sands. Leverett and Lewis (12) worked out the relations for gas-oil-water mixtures also for unconsolidated sands, while Botset (13) found that for gas-liquid mixtures the flow through consolidated sand gave very nearly the same characteristics.

Fig. 1 gives the saturation - relative permeability relationship



for an oil-water mixture in unconsolidated sands as taken from Leverett's paper (14).

In the above cited papers it was shown that for small saturations of a particular component of the mixture its relative permeability goes to zero, or in other words, the component will no longer move. The saturation at which for practical purposes this zero relative permeability is reached depends upon the pressure gradient and the characteristics of the sand. For larger saturations the relative permeabilities increase, and, of course, they equal the specific permeability at 100% saturation for any particular component.

With these characteristics in mind we can explain many features of the migration of mixtures of cil, water and/or gas as observed in the field or in the laboratory. We must remember, however, that the above relationships are only valid for steady flow of homogenous mixtures and cannot serve to evaluate the phenomena that occur when a water saturated medium is invaded by one of the mixtures in question.

Through a carrier bed with constant permeability the flow will continue unobstructedly as long as the pressure gradient continues to exist. If, however, the permeable bed pinches out either by truncation, successive overlapping or by a change in facies, we must consider a different medium being invaded by a fluid mixture. The question arises here, whether all components of the mixture are capable of penetrating the new medium or whether one or more of the components will be "screened out" at the boundary. For a continuous facies change we actually have to consider an infinite succession of such boundaries. If screening out occurs, the oil and/or gas will accumulate at the boundary and we have a so-called stratigraphic trap.

Before analyzing the factors involved in the screening out of oil and the formation of a stratigraphic trap, we want to consider one question regarding the migration of the fluid mixtures through the carrier beds, which has caused some confusion in the past.

As shown in fig. 1 the relative permeability to oil becomes zero when the oil saturation becomes smaller than approximately 20% in unconsolidated sands, while in consolidated sandstones this value will generally be even higher. However, in many beds that are considered to be carrier beds between the source rocks and the place of accumulation of oil we do not find any trace, of the migrating oil, left. By what mechanism was this oil removed?

In this case the diagrams of the articles cited before are of little or no help, as the oil is removed by very minute quantities, at a rate too low to be measured by the apparatus employed for the construction of the relative permeability graphs. Where oil is flushed completely from a carrier bed it is almost certain that free gas was present with the moving water for a considerable period of time. The oil will collect at the interface between the gas and the water and move as a thin film coating the gas bubbles. There is no steady flow of oil, the minute oil particles moving corresponding to a fraction of the total amount of gas bubbles that migrates per unit time. This process may go on till the last oil is removed. The gas may be removed by solution after it stops being supplied from a source.

This influence of gas on removal of oil restants was already accurately described by Dodd (15) in 1922, who termed the secondary migration of trapped oil under the influence of gas, "rejuvenated migration." He also states that by this rejuvenated migration, in the

course of time most, if not all, of the oil would be removed. This is the only case in which the term "carrying" of the oil by another fluid can be properly applied. As long as there is enough oil present to form continuous flow in a fine network of channels, it will move under any pressure gradient at a rate corresponding to its relative permeability. After being transported through the carrier bed, accumulation of the oil may be affected by screening out, where the flow of water continues, or where the waterflow is slowed down or stopped, oil may accumulate in the higher part of the structure under the effect of gravity. In both cases the characteristics of the overlying rock must be such that oil is prevented from migration into them, under the existing pressure differentials.

PART II

Theoretical considerations on the migration of oil into a porous medium, completely saturated with water

The problem of infiltration of a water saturated porous medium by an oil-water mixture is rather complicated. Basically, however, the mechanism is much the same as that in the case of pure oil infiltrating a medium one hundred per cent saturated with water, as the flow of the water does not change the phase relations and merely defines part of the pressure gradient. We will, therefore, concentrate upon the invasion of a 100% water saturated porous medium by a non-wetting fluid, assuming that the porous solid is preferentially water wetted.

Water in a saturated porous medium exhibits a capillary pressure. The magnitude of this pressure is equal to the pressure at the base of a column of water, of a height equal to the height to which the water would rise in the capillary interstices against the force of gravity above an adjacent free water level. Or, in other words, in the equilibrium position the gravitational pressure of the water column just balances the capillary pressure under which the water-air interface tends to advance. To penetrate a water saturated porous medium, one has to overcome this same capillary pressure. One has to drive back the water against its tendency to advance in the capillary interstices. The minimum pressure that is necessary to cause a continuous penetration into the water saturated porous medium, is called the displacement pressure.

As capillary pressure is caused by interfacial tension, displacement pressure must always be defined for a given combination of fluids. In our case displacement pressure will always be used to indicate

the pressure of displacement of water, by oil, unless otherwise indicated.

In order to relate the displacement pressures to other characteristics of a sand, we will have to analyze more fully the capillary behavior of porous media. The first thorough analysis of capillary behavior in porous media was made by M. C. Leverett (16). At several points in the following discussion we will use some of Leverett's derivations and conclusions.

We will first discuss the over-simplified case, where the porous medium is represented by a bundle of straight cylindrical capillary tubes.

This assumption gives a rather close approximation for an extremely well-sorted sand consisting of well-rounded grains. Such a sand would have a distribution of pores of equal size which latteral dimensions might be represented by an equivalent circular section.

This representation was used by Bartell and Osterhof (17), who used measurements of displacement pressures for the computation of interfacial contact angles and adsorption tensions. The material used by them consisted of finely ground pure silica, smaller than 350 mesh, and compacted into a porous membrane. As displacement pressure, they measured the minimum pressure necessary to prevent water from advancing in the capillary pores of the membrane, the pores of the membrane being filled with air. This arrangement measures a displacement pressure corresponding to an "advancing contact angle," which means that the pressure is measured which just prevents the liquid, which wets the solid material preferentially, from advancing. (The contact angle is defined as the angle made between the interface of the wetting and the non-wetting fluid, and the solid walls.) As was pointed out by the same authors later (18), there is a distinct difference between advancing and receding contact angle in many

cases. The receding contact angle is established when the porous medium is first saturated with the liquid that wets it preferentially and then pressure is applied to displace this liquid from the interstices against its capillary tendency, to retain its advanced position in the interstices. The receding contact angle method of determining displacement pressures was used later by Bartell and Whitney (19) for determination of adhesion tensions and seemed to give more consistent results. As will be shown later, there is a definite relationship between the interfacial contact angle and the displacement pressure. The distinction between receding and advancing contact angles makes, therefore, that the displacement pressure is not uniquely defined. In the case of infiltration of a watersand by oil, however, we always deal with a receding contact angle, and unless otherwise defined, our displacement pressures will always refer to receding contact angles.

To facilitate better understanding of the factors involved in capillary phenomena, we want to summarize, at this point, some of the basic relationships.

All capillary phenomena are directly related to surface and adhesion tensions, and the tendency always prevails to reach a condition of minimum free surface energy.

One of the most important theorems on capillary behavior is the following: The excess of pressure on one side of a film of constant interfacial tension, over that on the other side, is equal to $S(1/R_1 \pm 1/R_2)$ where S is the interfacial tension and R_1 , R_2 are the principal radii of curvature of the film at the point in question (20). The positive or negative sign allotted to the curvatures depends upon whether the center of curvature lies on one side of the film or on the

other, and is mostly established by convention.

This theorem relates the pressure across an interface to the interfacial tension and the curvature of the interface. In the case of two fluids within a porous medium, the pressure across the interface is termed the "capillary pressure." When the capillary pressure is zero, the curvature is zero and the interface is a plane. Such interface is often referred to as a "free liquid surface."

One of the best known capillary phenomena is the capillary rise of liquids, in circular tubes of small diameters, above a free liquid surface. The magnitude of this capillary rise can be related to the interfacial tension for the combination of fluids under consideration, the radius of the capillary tube and the interfacial contact angle, made with the walls of the tube (21).

The derivation of the relationship is based on the following considerations: The interfacial tension exists throughout the interface with an equal magnitude and tends to keep the interface as small as possible at a given set of conditions. To maintain this tension at the contact line of the walls with the interface, the walls must exert a force per unit length, on the interface which equals the interfacial tension. (Compare, for instance, a rope under tension fastened to a wall. The wall exerts the same force on the rope as the tension within the rope.) For a circular tube of radius r the total force exerted by the walls on the liquid at the interface is 2 Π r s, and the total vertical force on the liquid column 2 Π r s cos Θ if Θ is the interfacial contact angle.

This force must equal the force exerted by gravity on the liquid column above the free liquid surface.

Equating the two forces leads directly to the expression:

$$S = \frac{r H d g}{2 \cos \theta}$$

where r is the tube radius, d the density difference between the two fluids, Θ the interfacial contact angle with the solid material of the walls of the tube, and H is the height above the free liquid surface, when the fluid within the tube is in capillary equilibrium. (H refers to the lowest point of the interface.) H d represents here the pressure differential across the interface (in g/cm^2) and is therefore identical with the capillary pressure. Corresponding to this capillary pressure, the interface has a fixed curvature, in the above equilibrium position.

We are now able to analyze more clearly the relation between the displacement pressure and the capillary pressure. Assume again a porous block completely saturated with water. At its boundary the curvature of the liquid surface is zero and the capillary pressure is zero. We now mount this block so that a pressure differential can be applied across it, lengthwise, for instance by applying a pressure via a fluid (air or oil) above it, while keeping the pressure below it constant. As we increase the pressure above the block, the pressure across the fluid interface at the upper boundary increases and correspondingly the curvature of the interface increases. In this way we can increase the exterior pressure differential and thereby the capillary pressure across the interface and the interface curvature, until the force exerted by the exterior pressure equals the force due to the interfacial tension. Any increase of pressure above this point will cause the fluid to flow. This critical capillary pressure is the displacement pressure corresponding to the receding interfacial contact angle. The curvature that is reached at this point is the minimum interfacial curvature with which the two fluids can be contained

together within this particular porous medium.

If we can compare the porous medium to a bunch of vertical capillary tubes, we see that the critical capillary pressure, or the displacement pressure, is equal to the gravitational pressure differential in the equilibrium position of capillary rise in a tube.

Bartell and Osterhof, using this analogy, used the formula

derived for the capillary tubes, in the case of the porous membrane, substituting the displacement pressure π for the gravitational pressure H dg thus having:

$$S = \frac{r \cdot \pi}{2 \cos \theta}$$

From this formula, r (the equivalent radius of the pores) can be calculated if θ is known, or vice versa.

We see that according to the above derivation 77 is inversely proportional to r and that for a porous medium, strictly speaking, we can only sharply define the displacement pressures if all pores have the same equivalent radius. For a normal sandstone or other porous sediment, we have a wide range of pore sizes and irregularly shaped pores. Fortunately not all large pores are mutually inter-connected, and neither are the small ones. Therefore, for a reasonably homogenous sandstone penetration in a given direction will have to make use at least of part of the smaller pores. The displacement pressure is the pressure at which continuous flow will take place through the specimen, using the easiest continuous path in a given direction. This makes that even for very badly sorted sandstones the displacement pressures are still defined within a fairly narrow range of values.

As pointed out by Leverett (16), the comparison of an average

sandstone with a bundle of straight capillary tubes is over-simplified and leads, in most cases, to erroneous results. In the case of sandstones we certainly cannot speak any longer about any one equivalent radius of the pores, and even assuming a fixed distribution of equivalent radii does not give the complete picture, as it does not take into account the irregular shapes and inter-connections of the pores. Leverett therefore suggests to abandon the representation by parallel straight capillary tubes completely, and focused attention instead on the relationships between capillary pressure, interfacial curvature and the relative saturation of the different fluid components. The treatment of these relationships by Leverett is of great importance in the theoretical evaluation of the displacement pressure, in terms of the basic characteristics of the rocks in question. We will summarize in short, therefore, the results of Leverett's work.

Part of the derivations are made for a vertical column of porous solid, preferentially wetted by one fluid (forming zero contact angle with the solid) and partly saturated with a second fluid of smaller density. The fluids may be taken as respectively, water and oil.

Use is made again of the relationship between capillary pressure and interfacial curvature:

$$P_{c} = S(\frac{1}{R_{1}} + 1/R_{2})$$

An additional formula is derived for the vertical distribution of capillary pressure, in the following manner:

Consider a large porcus mass, preferentially wetted by water in which two fluids such as oil and water are distributed in the manner required for capillary equilibrium. Suppose a small volume of water Δ V

is transferred from the level h, to the level $h \bullet dh$. Since equilibrium exists, the change in free energy due to the infinitesimal displacement of V will be zero (dF = 0). dF, however, consists of two parts, which therefore must be equal and of opposite sign:

a) The change in free energy of \triangle V by the rise in the gravitational field:

$$\frac{\partial F}{\partial h} = \varsigma_w.g.\Delta V \qquad (g = acceleration of gravity)$$

b) The change of free energy of ΔV passing from a level h where the pressure of the water is P_W to a level (h + dh) where the water pressure is $(P_W + dP_W)$: $\frac{\partial F}{\partial P_W} = \Delta V$ We have therefore:

$$dF = \left(\frac{\partial F}{\partial h}\right) dh + \left(\frac{\partial F}{\partial P_W}\right) dP_W = \mathcal{G}_W g \Delta V dh + \Delta V dP_W = 0$$

or $-dP_W = \mathcal{G}_W g dh$ (1)

A similar derivation may be made for the oil, which gives:

 $-dP_{0} = g_{o}gdh \qquad \dots \qquad (2)$

The capillary pressure P_c across the water-oil interface is by definition $P_c = P_0 - P_w$, whence differentiating:

$$dP_{c} = dP_{o} - dP_{w} \qquad \dots \qquad (3)$$

Combination of expressions (1), (2) and (3) gives:

 $dP_{\mathbf{c}} = (\Delta^{c} \varsigma_{wo}) g dh$ (4)

where $\Delta \varphi_{wo}$ is the density difference between water and oil.

As shown before, there is a definite minimum value for the capillary pressure across the interface between the two fluids within the porous medium, equal to the displacement pressure. For all larger values of P_c we find the relation between P_c and h by integrating equation (4),

so that we obtain:

$$P_{c} = (\Delta S_{wo})gh = S(\underline{1} + \underline{1}) \dots (5) \text{ for } P_{c} \text{ where}$$

is the displacement pressure for water by oil for the particular porous medium under consideration.

It should be emphasized that equation (5) was derived without any assumptions regarding the fluids or the porous medium, except that they are isothermal and in capillary equilibrium. A corollary of equation (5) is that <u>all interfaces in any particular two-fluid system have the</u> <u>same curvature and capillary pressure at the same horizontal level</u>, if they are in capillary equilibrium.

Assuming a hypothetical level of zero curvature and zero capillary pressure, which would coincide with a free liquid surface outside the porous medium, the zone of 100% water saturation will for a given porous medium, always extend to the same elevation above the hypothetical zero level. At the top of this zone of 100% water saturation the capillary pressure will be equal to the displacement pressure, for that particular two-fluid system.

After establishing the relationship between capillary pressure (or curvature) and height, it remains to find the relation between curvature and saturation in order to find the vertical distribution of the fluids in the sand column.

Although we are, in our case, not interested in any static fluid distribution, the relationship between curvature and saturation in terms of normal characteristics of the sand in question, will fix automatically the relation between the displacement pressure (which is just one point on the curvature-saturation graph) and these sand characteristics. The curvature of the oil-water interface is apart from its thermodynamic relation to capillary pressure and height, a geometric quantity determined by the dimensions of the interstices in which it exists, the contact angle of the interface with the solid and the proportions of the fluid phases present.

Work by W. O. Smith (22) and others has shown that the curvature saturation function is not single valued over its entire range. There is a considerable hysteresis loop in the function. The reasons for this behavior are derivable from the geometry of the system as discussed in detail by Smith. <u>There also are good indications that the two branches</u> of the hysteresis loop correspond respectively to the establishment of a receding or an advancing contact angle.

Leverett determined the saturation - curvature relationship experimentally for clean, unconsolidated sands. He used both imbibition and drainage to obtain the saturation gradients. Corresponding to imbibition (advancing contact angle) one branch of the curves was obtained, while drainage (receding contact angle) gave the other branch of the hysteresis loop. The receding contact angle curve gives higher values of capillary pressure for a given saturation than the advancing contact angle curve.

The most important result of Leverett's work, as far as our problem is concerned, is that regardless of the degree of sorting or the character of the sands, the same curves were obtained for the curvature saturation relationship, when plotted in the dimensionless form

 $\frac{A \, \varrho \, g \, h}{S} \, \left(\frac{K}{\varphi} \right)^{\frac{1}{2}} \text{ against } S_{W} \text{ or } \frac{P_{C}}{S} \, \left(\frac{K}{\varphi} \right)^{\frac{1}{2}} \text{ against } S_{W} \text{ (both are exactly equivalent according to equation (5)). Here K is the permeability$

and φ is the fractional porosity. K must be expressed in c.g.s. units, consistent with the other variables of the group.

Fig. 2 gives the relationship as determined by Leverett (23) for clean, unconsolidated sands. With clean sands are meant sands void of clayey and amorphous materials.

The replacement pressure is the largest capillary pressure found for 100% water saturation and is determined from the largest value of

 $\frac{P_c}{S} = \left(\frac{K}{\varphi}\right)^{\prime/2}$ for 100% water saturation on the receding contact angle

(drainage) curve. This maximum value is the same for all clean sands and has a value of .3 in fig. 2. To find the displacement pressure for any clean, unconsolidated sand, we may use, therefore, the following procedure: Determine the porosity and permeability (one c.g.s. unit of permeability = 1.014 x 10^8 darcies); find the interfacial tension for the oil-brine combination in question (approximately 35 dynes/cm) and apply the formula:

$$\pi \pm 0.3 \,\mathrm{S} \,(\mathrm{K}/\varphi)^{-1/2}$$
 (6)

If clayey or hydratable material is present, the water is held by other than capillary forces only. The tendency seems to be, a decrease of the constant in formula (6), for increases in content of hydratable material. The decrease of the constant does not mean, however, that π decreases with increasing amount of clayey material, as the latter decreases the permeability very strongly, while practically not changing the porosity.

The capillary behavior in porous media has been elaborated upon in a recent paper by Rose and Bruce (24) who extended the principles outlined earlier, to consolidated porous rocks and derived several new relationships between the fundamental characteristics of those rocks and

their capillary properties.

The following paragraph gives an outline of their analysis, which they start with Leverett's equation for the capillary retention relation:

$$j(S_w) = \frac{P_c}{S} \left(\frac{K}{\varphi}\right)^{\frac{1}{2}} \cdots (7)$$
 where $j(S_w)$ is a dimensionless

function of the wetting phase saturation.

It can be shown from the Poisewille and Darcy equations for permeability that the term (K/φ) 1/2 is equal to the average pore radius of the porous medium under consideration. Hence Leverett's equation conforms with the basic expression for capillary rise in circular tubes, in that it combines the same variables in a simple relationship.

Starting with the equation $P_c = d g h = 28$ for capillary rise in spherical tubes, Carman (25) showed that to evaluate capillary rise in more complex systems, such as random-packed non-spherical sand grains, we can replace the radius r, by twice the hydraulic radius. The latter is defined as the ratio of porosity, φ , to the surface area of the grains ,A, in units of bulk volume. This leads to the relation:

$$\frac{P_c}{S} = \frac{dgh}{S} \frac{A}{\varphi} \dots (8)$$

The connection between equations (7) and (8) becomes evident by considering the Kozeny equation (26, 27) which expresses the specific surface area in terms of permeability and porosity.

Rose and Bruce rearranged this equation as follows:

$$A = \varphi \left\{ \frac{\varphi}{K} \right\}^{1/2} (1/k)^{1/2} \dots (9)$$

where k is the so-called "rock textural constant". Equation (9) is the

expression for streamline motion through granular beds.

Combining (9) and (8) we have:

$$\frac{\overline{P_c}}{S} = \left(\frac{K}{\varphi}\right)^{1/2} \left(\frac{1}{k}\right)^{1/2} \text{ or } \frac{\overline{P_c}}{S} \left(\frac{K}{\varphi}\right)^{1/2} = (1/k)^{1/2} \dots (10a)$$

Remembering that (8) is the expression for capillary rise and that for circular tubes h is measured to the lowest point of the meniscus, above the free liquid surface, while $\overline{P_c}$ is the pressure differential across the interface (or meniscus) we see, that $\overline{P_c}$ is the capillary pressure, corresponding to the highest point of 100% water saturation, as in the case of the circular tube. In other words, $\overline{P_c}$ in equation (10a) equals the displacement pressure π .

Rewriting (10a) gives us:

$$\frac{\pi}{s} (K/\varphi)^{1/2} = (1/k)^{1/2} \dots (10b)$$

where the displacement pressure $\pi = \lim_{S_{c} \to C} P_{c}$.

Equation (10b) shows that for consolidated systems the constant of equation (6) which was found to be approximately equal to 0.3 for unconsolidated clean sand, equals the square root of the reciprocal Kozeny constant.

That is $\lim_{S_{W} \to 1} j(S_{W}) = (1/k) 1/2$

The Kczeny constant is related to the specific surface area by equation (9), which gives:

$$k = \frac{\varphi^3}{K A^2} \quad \text{or with} \quad A^1 = A/\varphi$$

$$k = \frac{\varphi}{K (A^1)^2} \quad \dots \quad (11) \quad \text{where } A^1 \text{ is the inter-}$$

stitial surface area in cm² per cm³ pore volume.

Equation (8) applied to porous media gives the direct relation between the displacement pressure and the specific surface area per bulk-volume.

$$\frac{\pi}{s} = \mathbb{A}/\varphi = \mathbb{A}^{1} \quad \dots \quad (12)$$

Equation (10b) showed the relationship between the displacement pressure and Kozeny's constant.

For clean unconsolidated sands the value of k is about 5.5 .

Rose and Bruce showed that k depends very strongly on the fine fraction (\approx clay content) of the sands.

They found for a clay percentage of 5.9 a value of k = 31.2 and for a clay percentage of 8.5 and 11.6 respectively, k = 155.0 and k = 400.0.

This indicates that the Kozeny constant k can be used as a measure of the extent to which the sediment behaves as an argillaceous rock.

This suggests that k may be related to the factors determining the magnitude of the electrochemical potentials which are established when solutions of different salinities are brought into contact with each other within the interstices of the sediments.

These potentials are also dependent on the relative position of the sediment in the sandstone shale series. The factor that identifies this position is the electrochemical "formation coefficient." This factor is at a minimum for clean sands and at a maximum for purely argillaceous shales.

A description of the characteristics of the above mentioned electrochemical potentials and the precise definition of the formation coefficient are given in another thesis by this author (28). The purpose of the experimental part of this thesis will be to determine whether any of the constants related to the displacement pressure, can be correlated with the electrochemical formation coefficients.

Such correlation, if established, will furnish a means of determining the displacement pressure by subsurface geological methods.

Before describing the experimental procedure and results, two other factors governing the accumulation and final distribution of oil and gas, in reservoir, have to be analyzed.

These factors are the interfacial tension, S, and the density difference between the wetting phase and the non-wetting phase, 4 q .

The displacement pressure for any given rock and an water-oil combination, is directly proportional to the interfacial tension, S, while $\Delta \gamma$ is the factor governing the buoyancy of the oil, which forms the counterpart of the capillary forces.

Both factors enter, as well, in the trapping of the oil and gas, under a caprock as in the final distribution of the wetting and non-wetting phases, in the porous reservoir rock.

If the force of buoyancy caused by the density difference between the brine and the oil is larger than the displacement pressure of the caprock, the trap will leak, permitting oil to infiltrate the caprock. During this infiltration buoyancy must remain larger than the displacement pressure, until a minimum oil saturation in the caprock is reached, at which the relative permeability of the rock to oil is larger than zero. Until this point is reached no continuous flow of oil can occur. Once the minimum saturation is established, however, the oil will flow under any pressure gradient and it will migrate out of the trap.

It is of primary importance, therefore, to know the magnitude of oil and gas densities and of the interfacial tensions, under reservoir conditions.

A discussion of the variations of these quantities with temperature and pressures, which will enable us to estimate their magnitude at depth, is given in Part III of this thesis.

PART III

Densities of oil and gas.

Oil-water and oil-gas interfacial tensions.

The variations with temperature and pressure of density difference and interfacial tension between oil or gas and oil field brines, will be analyzed in the following paragraphs. They will be presented in terms of variations with depth, assuming a constant temperature gradient with depth and an average rock pressure.

The analysis will be carried out in the following order:

- 1. Density variations of natural gases with depth.
- 2. Surface tension of oil field brines against natural gas and its variation with depth.
- Density of crude oils and its variation with reservoir temperatures and pressures.
- 4. Oil-water interfacial tension.

1. Density variations of natural gases with depth.

To facilitate analysis of the variation of densities and interfacial tensions with depth, we will assume an average temperature gradient of 1° F per 60 feet of depth and an increase in rock pressure of 4 p.s.i. per 10 feet.

If reservoir pressures and temperatures deviate considerably from the conditions resulting from the above assumptions, the relations derived later have to be used step by step.

Fig. 3 shows the variation of temperatures and pressures with depth, corresponding to the above assumptions.

To find the variation of gas density with depth we cannot simply apply the gas law of Boyle, which holds true only for ideal gases.



Deviations from Boyle's law are taken into account by applying an experimentally determined correction factor to the value of the volume, V, found for a given quantity of gas at elevated temperature and pressure.

The density then is inversely proportional to the corrected volume.

The correction factors as mentioned above were given by Sage and Lacey (28) for pressures up to 3000 psi and temperatures ranging from 70° F to 220° F.

These data were extended by Standing and Katz (29) to pressures up to 10,000 psi and temperatures up to 300° F. The latter authors furthermore found that many types of gases give smooth relationships between their pseudo-critical conditions and their gravity (compared to air). All gases whose pseudo-critical temperatures and pressures fit a certain set of gravity curves, have the same density for a given temperature, pressure and gas gravity, independent of their composition. This simplification makes it possible to construct charts giving gas density as a function of temperature, pressure and gas gravity. (Gas gravity = specific gravity of gas / specific gravity of air.)

Such charts were made up by Standing and Katz for hydrocarbon gases containing more than 83% of combined methane, heptanes and heavier fractions. This includes most of the natural gases.

From these charts fig. 4 has been prepared giving gas density $(in g/cm^3)$ as a function of depth, for gas gravities ranging from .6 to 1.0.

For gases containing more than 3% nitrogen and larger fractions of ethane, propane and butanes, the densities deviate from the relation presented in fig. 4 and have to be calculated with the use of the extended



Fig. 4

26A

compressibility correction factor chart given by Standing and Katz.

For our purposes, however, fig. 4 gives a good representation of the magnitude of density variation with depth for most saturated natural gases.

2. <u>Surface tension of oil field brines against natural gas and its</u> variation with depth.

The behavior of the surface tension of water against natural gas at elevated temperatures and pressures was investigated by Hocott (30).

Fig. 5 gives the results of these investigations for a gas consisting mostly of methane, with some ethane and propane, as given by Hocott. The curve for 225° F is extrapolated.

From the relations presented in figs. 3 and 5, curve (a) of fig. 6 has been prepared giving the water-gas interfacial (surface) tension as a function of depth.

For studies of the equilibrium distribution of gas and water in a gas reservoir-sand the ratio $\frac{\Delta \Im}{S}$ is one of the most important factors.

in this case is the density difference between the brine ($\varsigma \approx 1.1 \text{ g/cm}^3$) and the natural gas. For a gas of 0.8 gravity $\Delta \varsigma$ has been calculated from fig. 4 and $\Delta \varsigma$ is given in fig. 6, curve (b). To make the latter relation applicable in reservoir computations we have to assume that the interfacial tension between water and a relatively dry gas does not differ greatly from that between water and a "wet" gas.




27B

3. <u>Density of crude oils and its variation with reservoir temperatures</u> and pressures.

The variation of the density of crude oils with temperature and pressure is very much complicated by the solution of gas in the oil. Especially the lighter hydrocarbon gases, such as methane and ethane, cause large changes in oil density, when they are dissolved in the oil in sufficient quantities.

Therefore the density of a given crude oil can only be computed if the methane and ethane content at the depth in question is known. The computation may be carried out following a method outlined by Standing and Katz (31). This method consists of first determining a hypothetical surface density, which would represent the gravity of the oil under surface conditions, if all of the methane and ethane dissolved at depth would remain in solution. This hypothetical density is then corrected for the effects of temperature and pressure. The corrected value equals the actual density at the depth under consideration.

The difficulty in obtaining a generalized relation between oil densities and reservoir temperatures and pressures, is caused by the fact that the crude oil at depth is not generally saturated with the lighter hydrocarbon gases (methane and ethane).

If complete saturation did exist, the amounts of methane and ethane in solution, at various temperatures and pressures, could be calculated from the experimental data assembled by Sage, Lacey and co-workers (32, 33, 34). These data include experimental determinations of the amounts of methane and ethane dissolved in various oils at reservoir temperatures and bubble-point pressures. With the aid of these values, the oil densities could be easily computed following the

method of Standing and Katz, for the case of complete saturation.

As the actual saturation varies from case to case, no general rule can be laid down for the variation of crude oil density with depth. In specific cases, however, the densities may be computed following the above principles.

Fig. 7 shows two examples of such computations. Curve (a) represents a crude of 25.7° A.P.I. gravity which does not contain methane nor ethane. Curve (b) shows the density variation for a crude oil containing 5% methane and 15% ethane at a depth larger than 7000 feet and being saturated with methane closer to the surface.

4. <u>Oil-water interfacial tension</u>.

The data on oil-water interfacial tensions are extremely scarce. Livingston (32) found the following generalities for the interfacial tension between reservoir brines and "dead-oil": At 70° F oils with viscosity higher than 7 centipoises gave an average of 21.3 dynes/cm interfacial tension. Oils with a viscosity smaller than 4 centipoises gave an average of 19 dynes/cm. This indicates that changes with the character of the crude oil are not too important. In general higher viscosity crudes have higher interfacial tensions.

For the variation of interfacial tension with temperature, Livingston gives an average decrease of 0.15 dynes/cm per ^o F increase in temperature.

The average value for all crudes tested at 70° F was found by him as 20.4 dynes/cm.

However, under reservoir conditions, the pressures are generally above the saturation pressures for the prevailing temperatures



29A

and the oil is saturated with natural gas, so that conclusions reached for dead oil do not apply.

Hocott (30) found that variations in pressures above and below the saturation pressure, at a given temperature, have relatively little influence on the interfacial tension. Hocott's measurements were made for oils in equilibrium saturation with natural gas, at various pressures, for a given reservoir temperature. Unfortunately no measurements were made for one given oil at various temperatures.

The curves obtained by Hocott are represented in fig. 8. On these curves we have indicated points corresponding to the temperature for which the curves were plotted and the pressure that would prevail at a depth at which such temperature would occur according to the depth - temperature pressure relationship of fig. 3. The points are indicated by small triangles.

The gravity of the crudes used for the experiments from which curves I, II and III of fig. 8 were obtained was respectively 33.5, 36.9 and 41.3° A.P.I.

This means they are essentially all high gravity oils, and neglecting differences in the interfacial tensions due to the variations in the character of these oils will cause relatively small errors. The position of the three triangular points shown in fig. 8 gives us therefore the approximate trend of the relationship between pressure, depth or corresponding temperature and the interfacial tensions for crude oils completely or nearly saturated with natural gas at elevated temperatures. In fig. 8 this trend has been indicated by a straight line through the three points.

We note from fig. 8 that at low pressures, the variations in pressure or in the amounts of gas dissolved have a much greater influence



on the interfacial tension. For pressures below 1200 p.s.i. (or at depths below 3000 feet) the interfacial tension decreases rapidly for decreasing amounts of gas dissolved. It is known that in the same range of pressures the surface tension of crude oils decreases with increasing amounts of gas dissolved. These two trends are in agreement with Antonow's rule which states that for mutually saturated solutions the interfacial tension approximately equals the difference between the two surface tensions. It was shown, however, by Livingston (35) that for crude oil water systems Antonow's rule cannot be applied to compute the oil-water interfacial tensions.

The decrease in interfacial tension with decreasing amounts of gas dissolved in the range of low pressures will explain in part the differences in absolute values of the interfacial tensions as found by Livingston and by Hocott. At atmospheric pressure and 130° F Hocott finds for a 41.3° A.P.I. gravity oil, an interfacial tension of 31 dynes/cm. For the same temperature Livingston finds values of the interfacial tension of the order of 12 dynes/cm.

As Hocott's experiments seem to represent more closely reservoir conditions we will use the trend established by his data to represent roughly the variation of interfacial tension at depth. For the range of lower pressures we have to take into account the decrease of the interfacial tension due to the decrease in amounts of gas dissolved. The overall variation of interfacial tension with depth following the above relations is represented schematically in fig. 9.

From figs. 6 and 9 we note that at large depths (10,000 feet) the interfacial tension water-cil and the interfacial tension water-natural gas, approach each other very closely.



31A

PART IV

Experimental procedure

The purpose of the experimental part of this thesis, is to measure displacement pressures of porous rocks and compare them with data compiled from research on self-potentials of similar rocks.

To measure the displacement pressures, a cylindrical core of approximately 2.8" diameter and 2" height is mounted in the bottom part of the cylinder of a baroid wall building tester. The core is then flushed with CO_2 gas to remove the air from the interstices. Thereupon water is forced through. All trapped CO_2 gas will dissolve in the water. This flushing is continued until the electrical resistivity of the core (measured with a four electrode system) does no longer change. A second check is made by comparison of the resistivity of the influent and effluent water. When the latter are equal, no more CO_2 is going into solution, which means that no more CO_2 is present in the core.

After the core is thus 100% saturated with water, the permeability to water is measured and also the porosity (as the weight difference between the wet and the dry core, divided by the bulk volume).

Oil (30° A.P.I. gravity) is then poured in the upper part of the cylinder to a height of approximately $1/2^n$ and pressure is applied, using a nitrogen bottle with regulating values.

It was initially attempted to measure the displacement pressure directly as the minimum pressure at which water would be effluent from the core. It was found, however, that this point is difficult to determine, as oil will enter some large pores first and displace some water before complete infiltration takes place.

To avoid this difficulty the apparatus was adjusted to measure the capillary pressure - saturation relationship for each core. The displacement pressure is then defined as $\pi = \lim_{s \to \infty} P_{c}$.

The baroid wall building tester was adapted for capillary measurements in the following manner: (See fig. 10)

The holder (H) shown in fig. 10a was replaced by a holder (H¹) which is shown schematically in fig. 10b.

In addition an insert (I) was machined to fit with a sliding fit inside H^1 , resting with its flange on the inside shoulders of H^1 and just clearing the bottom of H^1 to allow fluid passage.

In the insert I a high grade circular porous disc is fitted, which has a controlled pore size of approximately 1 micron. The disc is secured in place by castolite casting resin and a circular groove is cut in the resin, to hold an "0"-seal gasket, which fits against the lower rim of the baroid cylinder. The castolite is a thermo-setting resin, which is cured for approximately 35 minutes at 170° F. It makes a very tight bond with the porous material, but a rather poor one with the brass of the insert. The "0"-seal gasket, however, prevents any leakage between the resin and the brass, and the only passage for effluent fluids is through the porous disc. The bottom of the insert is perforated by symmetrically placed small holes (1/16"). Water passing through these holes collects in the small clearing between H¹ and the bottom of I and drains off through the little tube inserted in the center of H¹.

The porcus plate (Coors #740 porcelain) when water wetted has a displacement pressure of more than 40 psi. Thus by increasing the gas pressure on the oil we may increase the confining pressure on the oil



BAROID WALL BUILDING TESTER WITH SAMPLE MOUNTED IN CYLINDER

to 40 psi. The water, on the other hand, can freely move through the permeable porcelain. In this way we can establish any differential pressure between the oil and water up to 40 psi, the water remaining at atmospheric pressure. The pressure differential across the oil-water interface is in effect the capillary pressure. To any pressure thus established corresponds a fixed water-saturation, which is measured by subtracting the amount of effluent water from the amount originally present, or by weighing.

To insure operation of this mechanism we must establish a continuous water path between the core and the porcelain. Forcing the core directly onto the porcelain might result in breakage of the latter. Therefore a thin layer of powdered Coors porcelain was spread between the core and the porcelain. A small amount of cold water putty was mixed in with the porcelain powder, to provide a better bond with the sandstone and the porcelain powder, to provide a better bond with the the water was maintained, preventing formation of an oil sheet between the core and the porcelain, while the compressibility of the intermediate layer protected the porcelain from physical damage.

The samples used, were outcrop samples of the following formations: Pico sandstone (Lower Pliocene, Southern California) Modello shaley sandstone (Upper Miocene, Southern California) Saugus, landlaid sandstone (Pleistocene, Southern California) Berea "clean" sandstone* (Lower Mississippian, Ohio) Mezozoic dense sandstone (Jurassic ?, Redlands, California)

*Obtained by courtesy of the production department of the Union Oil Company, Whittier, California.

Of the first four groups, sieve analysis were made using divisions between 16 and 250 mess/inch. In addition, thinsections were prepared of these samples and analyzed by the point counter method described by Chayes (36).

The interfacial tension between the oil and water used in the experiments was determined by measurements of the displacement pressure of a fritted glass disc. The measurements were made by connecting the glass tube of a fritted glass gas-disperser, via a pressure regulating valve to a nitrogen bottle. Before pressure was applied the disperser was immersed in water, which would imbibe the disc and partly fill the tube of the disperser. Then pressure was applied and gradually increased in very small steps of the order of 0.05 p.s.i. The pressure was measured by a 0 - 15 p.s.i. gage. The minimum pressure at which gas would escape through the disc was registered as the displacement pressure for nitrogen gas, which for all practical purposes is equivalent to the displacement pressure for air, π_{a-w} . After this measurement was made the disc was imbibed fully with water again, and oil was injected into the partly water filled tube of the disperser below the water-air interface. The oil would collect at the surface of the water and form a clean oil-water interface, free of gas bubbles. The procedure was then repeated using the nitrogen pressure to force the oil against the water-saturated fritted glass disc and the displacement pressure for oil, π ow, was measured.

As the displacement pressures for porous membranes are directly proportional to the interfacial tension (see page 14) and the interfacial tension air-water is a known quantity (namely 72 dynes/cm) we can easily compute the oil-water interfacial tension. For the 30° A.P.I. gravity oil the following results were obtained: $\pi_{a=W} = 3.86$ psi $\pi_{0=W} = 1.2$ psi. This gives for the interfacial tension: $S = \frac{1.2}{3.86} \times 72 = 22.4$ dynes/cm.

PART V

Description of samples and experimental results

A. Berea sandstone

Sample description:

Average porosity: 27.1%

Average permeability to water: 25. m. darcies

Sieve analysis:

		Mess/inch	mm (opening)	% by weight
Larger	than:	16	•991	1.13
88	17		.420	.635
88	Ħ	80	.177	65.9
84	11	120	.125	19.85
12	17	170	.088	6.87
11	n	210	•070	4.22
Ħ	1	250	.061	.662
Smalle	than:	250	.061	.855

Point counter thinsection analysis:

Classification	20	of total volume
Quartz		62.7
Porespace		28.1
Calcite		7.0
fines (clay)		1.5
Mica (white)		0.5
Feldspar		0.2
	Total	100.0

The porespace as determined with the point counter method is 28.1% of the total volume, as compared to 27.1% found as average porosity from determinations by imbibition with water. The difference in this case is probably due to the closed, noneffective pore space, which appears in the thinsections as open space, but does not effect the imbibition by water.

The capillary pressure versus water saturation relations are given for two samples in fig. 11.

We see that 77 : $\lim_{S_w \to 1} P_c$: 0.6 psi

The irreducible or bound water saturation is approximately 0.18 .

B. Pico sandstone (from outcrop near Sunland, California)

Sample description:

Average porosity: 37.6%

Average permeability to water: 354 m. darcies

Sieve analysis:

-		Mess/inch	mm (opening)	% by weight
Larger	than:	16	.991	9.31
n	11		.420	37.54
Ħ	ŧł	80	.177	26.3
Ħ	n	120	.125	7.91
Ħ	Ħ	170	.088	7.06
11	88	210	.070	9.0
Ħ	17	250	.061	1.725
Smaller	r than	: 250	.061	1.485



Point counter thinsection analysis:

Classification	% of total volume
Quartz	43.6
Porespace	38.6
Limonite	6.75
Feldspar	5.46
Mica	2.58
Accessories	1.01

The capillary pressure versus water saturation relations are shown for two samples of the Pico sandstone, in fig. 12 and fig. 13.

We find for the displacement pressure the values of = 0.5 and = 0.4, respectively, and for the bound water content 0.27 and 0.26 expressed, as a fraction of the total porespace.

It must be pointed out that of necessity, the sieve and thinsection analyses are not made from the same specimen, for which the capillary relations are established. For this case, however, the displacement pressure for nitrogen gas was measured directly on the specimen of which the thinsection was made. We obtained a value air = 1.25 psi. This gives for the displacement pressure for oil, approximately 30 x 1.25 = 0.49 psi, which checks well 78 with the above results.

C. Saugus sandstone

Sample description:

Average porosity: 11.7%

Average permeability to water: 2.48 m. darcies



38A



38B

			Mess/inch	mm (opening)	% by weight
. 1	Larger	thans	16	.991	20.1
	17	Ħ	*	.420	35.0
	11	17	80	.177	28.1
	Ħ	, tł	115	.131	6.8
	¥	11	170	•088	3.4
	10	11	210	•070	3.2
	Ħ	99	250	.061	0.7
1	Smaller	r than:	: 250	.061	2.7
Point	counte	er this	nsection anal	ysis:	
C	lassifi	lcation	1	%	of total volume
1	Quartz				34.2
1	Porespa	ace			25.*
(Calcite	9			19.8
÷	Fines				9.6
1	Feldspa	r	*		6.9
1	Mica				3.6

Sieve analysis:

Accessories

The capillary characteristics are given in fig. 14. We find $\pi = \lim_{S_w \to 1} P_c = 3.8 \text{ psi}$ The bound water content is approximately 60.2%.

Total

0.9

100.0

*This value is not at all representative as because of the poor cementation of the sandstone, the thinsection was badly torn.



D. Modello shaley sandstone

Sample description:

Porosity: 15.04%

Permeability to water: 1.47 m. darcies

Sieve analysis:

		Mess/inch	mm (opening)	% by weight
Larger t	than:	16	•991	1,12
N .	转		.420	12.3
Ħ	88	80	.177	41.7
Ħ	11	115	.131	19.33
11	n	170	•088	7.39
11	99	210	.070	7.06
17	Ħ	250	.061	7.94
Smaller	than:	250	.061	4.16

Point counter than section analysis:

Classification	volume %
Quartz	47.
Porespace	15.3
Feldspar	6.64
Mica (primary and secondary)	11.16
Fines	16.7
Accessories (including calcite)	3.3
Total	100.0

The capillary pressure versus water saturation relationship is given in fig. 15.

 $\Pi = \lim_{S_w \to 1} P_c = 2.2 \text{ psi}$ and the bound water content, $C_w = .675$.



E. Finally fig. 16, curve (a), gives the same relations for a dense Mesozoic (Jurassic?) sandstone. We find 77 = 5.4 p.s.i. and Cw = .45.

Fig. 16, curve (b), shows the capillary pressure - saturation graph for a Modello sandstone. Here we have

T = 1.25 p.s.i. and Cw = 0.48 .

The Kozeny constants for these various rocks can be calculated from equation (10b) using the measured values of the displacement pressure π , the permeability K, and the fractional porosity φ .

From equation (12), the interstitial surface areas A^{*} per unit of porespace and A, per unit of bulk volume are calculated, using the measured values of 7 and \mathscr{V} . In both equations (10b) and (12) the value of S = 22.4 dynes/cm as was determined in part IV (page 35) is substituted.

The masured and computed quantities are listed in Table A. Also given are the electrochemical formation coefficients for the various sandstones which were measured in the course of another research project by this author (28).

We notice from the data given in Table A, that a fairly good correlation exists between the interstitial surface area per unit of bulk volume and the electrochemical formation coefficient. Fig. 17 represents this correlation graphically.

The scattering in the points as shown in fig. 17 is probably partly due to experimental inaccuracies, and partly caused by the fact that the samples on which the capillary measurements were made are not exactly identical to the ones for which the electrochemical potentials were measured.

The large differences in character, composition, age and origin of the samples used, gives good assurance that the graph of fig. 17 represents a universal relationship for sediments of the shale sandstone series.



41A



Sample 77 No. p.s.i. dy Berea ss 0-7 0.6 Pico ss P-4a 0.45 Pico ss	77 nes/cm ² 41,400 31,000	frac- tional porosity _254	K milli- darcvs 25	K c.g.s. units 2.462 x 10 ⁻¹⁰	$\frac{\pi}{S} \left(\frac{K}{\varphi}\right)^{\frac{1}{2}}$ c.g.s. units	<u>k</u>	A! cm ²	A cm ²	C formation coefficien
Berea ss 0-7 0.6 Pico ss P-4a 0.45 Pico ss	<u>41,400</u> 31,000	.254	25	2.462 x 10 ⁻¹⁰	05777				
Pico ss P-4a 0.45 Pico ss	31,000				.0211	300	1850	470	0.142
Pico ss		•333	318	3.14 x 10 ⁻⁹	.1339	55.9	1380	460	0,181
P-4b 0.45	31,000	.284	390	3.85 x 10 ⁻⁹	,1608	38.6	1380	393	0.126
Saugus ss <u>S-3h 3.80 2</u>	62,400	0.106	2.62	2.59 x 10-11	.1828	50	11700	1241	0.64
Modello shaley ss <u>M-4 2.2 1</u>	52,000	0.150	1.47	1.45 x 10-11	.0668	224	6790	1020	0.55
Mesozoic dense ss X-1 5.4 3	72.000	0.058	0.015	1.48 x 10-13	.0265	1420	16600	964	0.177
Modello ss M-9 1.25	86,200	0.202	35	3.46 x 10 ⁻¹⁰	.1590	39.6	3840	777	0.410

S = 22.4 dynes/cm

The large calcite content of the Saugus sandstone (see thinsection analysis) may well indicate that the relation also holds true for calcarecus sediments.

Rose and Bruce (24) have shown that a rough correlation exists between the bound water content C_W and the interstitial surface area per unit pore volume.

Table B gives the values for C_{w} , C and A¹ for the sandstones that were investigated.

A second se			TABLE B			
Sample	No.	<u>C</u> w	<u>_C</u>	A ¹ (cm ² per cm ³ pore volume)		
Berea ss	0-7	0.18	0.142	1850		
Pico ss	P-4 a	0.27	0.181	1380		
Pico ss	P-4b	0.255	0.126	1380		
Saugus ss	S-3h	0.63	0.64	11700		
Modello shaley ss	M-4	0.675	0.55	6790		
Mesozoic ss	X-1	0.45	0.477	16600		
Modello ss	M+9	0.48	0.41	3840		

We see that for these samples the correlation between $C_{\rm W}$ and $A^{\rm l}$ is not very good.

There seems to be some correlation between C_W and C. It appears however, that the character of the rock minerals other than their surface area per unit volume seems to have a larger effect on C_W than on C. In general the presence of argillaceous materials will increase C_W more, percentagewise, than they increase the interstitial surface area.

From the values of k, and C listed in Table A it is apparent that no direct correlation exists between the Kozeny constant and the electrochemical formation coefficient. This means that probably the correlation found by Rose and Bruce, between the amount of elay in a

sandstone and the Kozeny constants applies only to sandstones which differ in clay content but do not vary to any important extent in other characteristics such as the overall composition of the non-argillaceous parts, the sorting and the cementation. This explanation is supported by the data for the Pico and Modello sandstones. Table A shows that within each group k is larger for the sample with the higher formation coefficient. However, comparison between the groups indicates that no general correlation exists.

Table C shows a listing of the amount of fines as determined from sieve analysis and the Kozeny constants of various samples. The fines being taken as the material < 250 mesh.

TABLE C

Sample	No.	fines (weight %)	k
Berea ss	0-7	1.63	300
Pico ss	P-4b	2.59	38.6
Saugus ss	S-3h	2.69	30
Modello shalev ss	M-4	5.1	224

We see that for these widely varying specimen no correlation is obtained between the amount of fines and the Kozeny constant. It is realized, however, that the weight percentage of fines depends very strongly on the maximum size taken as the limit of the fine fraction. For instance taking 200 mesh as the upper limit would result in very different percentages.

For this reason it seems that the information obtained by sieve analysis is not of great value in determining the characteristics of sediments with respect to the behaviour of fluids contained in their interstices.

Part VI

Applications of subsurface determinations of

displacement pressures

As pointed out in the introduction to this thesis, the most interesting application of displacement pressure determinations are as an aid in the location of stratigraphic traps.

The stratigraphic traps may be divided into four groups:

a) Depositional pinch-outs, caused by gradual thinning up-dip of all members of the formation.

b) Truncated pinch-outs, where the beds of a formation are truncated by an overlying series of sediments.

- c) Overlap pinch-outs, occurring on regional unconformities or at the base of marine overlap of a basement complex.
- d) Permeability pinch-outs, caused by a latteral change in facies of a rock unit.

Fig. 18 gives an illustration of the mode of occurrence of these various traps.

In all cases the traps are caused by "impermeable" rocks overlying or bordering the porous reservoir rocks. In cases a, b, c, there is mostly a sharp contact between the two units. In the case of the permeability pinch-out the facies change is gradual.

Whether or not the trap has the required properties to hold a commercial accumulation of oil or gas depends upon the geometric



Fig 18

dimensions of the traps and the displacement pressure of the capping formation.

In the course of geological and geophysical exploration for oil reservoirs, unconformities and overlaps of the types a, b and c can be found by existing methods of exploration. The permeability pinch outs cannot be detected so easily.

However, to determine whether or not the capping formation has the right properties we have to use information from outcrops or drill holes. If the caprock outcrops we can determine its properties directly. If no outcrops are present or the rocks change laterally in facies we have to rely upon drill hole information and make extrapolations or interpolations from the data assembled from the existing holes.

As electrologs are run in practically all exploratory holes, they are the natural tool to be used for the required determinations. The computation of the displacement pressures from the electrochemical formation coefficients which in turn are determined from the self potential curves of electrologs introduces a rapid means of obtaining the necessary information.

To illustrate the proposed usage of this method more specifically, an example is given in fig. 19 of the location of a permeability pinch-out trap. Wells 1 and 2 show a watersand at the depth of the formation in which we are interested. The electrochemical formation coefficient is larger in case 2 than in case one, showing lateral variation of the sand. Well three shows a tight shaley sand with a high formation coefficient. Interpolation between wells 2 and 3 enables us to determine at which point the displacement pressure of the formation becomes large encugh to screen out a commercial quantity of oil.



LOCATING OF A PERMEABILITY PINCH-OUT TRAP

Fig 19

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At this point it remains to consider the quantitative relationship between displacement pressures and the size of accumulations of oil or gas that can be obtained.

If we have an oil density of 0.80 g/cm^3 and a brine density of 1.1 g/cm³, the density difference between the water and the oil,

 $g_{WO} = 0.3 \text{ g/cm}^3$. Therefore the total upward force acting on 1 cm³ of oil will be 0.3g. This force is counteracted by the capillary forces in the caprock.

A displacement pressure of 1 p.s.i. is the equivalent of 70.31 g/cm². This means that a displacement pressure of 1 p.s.i. is sufficient to prevent upwards migration of a column of $\frac{70.31}{0.3} = 234$ cm = $\frac{7.68}{0.3}$ feet of cil.

In general $H = \underbrace{2.3 \pi}_{9 \text{ wo}}$ (13) where H is the height of accumulated oil in feet and π is the displacement pressure of the caprock in p.s.i. and g_{wo} is given in g/cm³.

The same relation holds for accumulations of gas, with g_{wg} , the density difference between the water and the gas substituted for

8 WO.

To determine S_{WO} the approximate surface gravity and content of light hydrocarbons of the oil must be estimated from data of producing fields in the region in question. If no such data are available, average values have to be assumed. The estimate of the subsurface density of the oil is then made using fig. 7 and/or the procedure outlined by Standing and Katz (31).

If the electrochemical formation coefficient is found from electrologs, we obtain the interstitial surface area per unit bulk volume, A, from fig. 17. The displacement pressure, π , is then found

from the formula

$$\frac{\pi}{s} = \frac{A}{\varphi}$$

where \mathscr{P} is the fractional porosity, which also may be found from electrologs (37).

The interfacial tension, S, is estimated from the relations shown in figures 5 and 9, for the depth to the horizon in question.

The possible cil or gas accumulation is determined using equation (13). Whether or not the possible accumulation is commercial depends amongst other factors, on the size of the trap and the porosity and connate water content of the reservoir rock, that is the total amount of cil that can be expected after the height of the accumulation has been determined.

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