Lecture 1

Introduction

Reservoir engineering covers a broad range of subjects including the occurrence of fluids in a gas or oil-bearing reservoir, movement of those or injected fluids, and evaluation of the factors governing the recovery of oil or gas. The objectives of a reservoir engineer are to maximize producing rates and to ultimately recover oil and gas from reservoirs in the most economical manner possible.

A reservoir is defined as accumulation of oil and/or gas in a porous and permeable rock – almost invariably of sedimentary origin.

Fundamentals of rock properties

Knowledge of the physical properties of the rocks and the existing interaction between the hydrocarbon system and the formation is essential in understanding and evaluating the performance of the reservoir.

Rock properties are determined by performing laboratory analyses on cores from the reservoir to be evaluated. The cores are removed from the reservoir environment, with subsequent changes in the core bulk volume, pore volume, reservoir fluid saturations, and sometimes, formation wettability. The effect of these changes on rock properties may range from negligible to substantial, depending on characteristics of the formation and property of interest, and should be evaluated in the testing program.

There are basically two main categories of core analysis tests that are performed on core samples regarding physical properties of reservoir rocks. These are:

1- Routine core analysis tests:

- Porosity
- Permeability
- Saturation

2- Special tests:

- Overburden pressure
- Capillary pressure
- Relative permeability
- Wettability
- Surface and interfacial tension

The above rock property data are essential for reservoir engineering calculations as they directly affect both, the quantity and the distribution of hydrocarbons and, when combined with fluid properties, control the flow of the existing phases (i.e., gas, oil, and water) within the reservoir.

Porosity

The porosity of a rock is a measure of the storage capacity (pore volume) that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically by the following generalized relationship:

$$\text{Porosity} = \frac{\text{Pore volume}}{\text{bulk volume}}$$

$$\phi = \frac{V_p}{V_b}$$

$$\phi = \frac{V_b - V_g}{V_b}$$

Where ϕ : porosity

V_p : pore volume

V_b : bulk (total) volume

V_g : grain volume

The porosity can be expressed either as a fraction or as a percentage. The porosity of the commercial reservoirs may range from about 5% to about 30% of bulk volume.

The sedimentary rock consists of grains and pore spaces (void spaces). Some of the pore spaces are isolated from the other pore spaces by cementation, whereas in many states, the pore spaces are interconnected. This leads to two distinct types of porosity:

1- Absolute porosity

2- Effective porosity

Absolute porosity

The absolute porosity is defined as the ratio of the volume of all pore spaces in the rock to the total volume (bulk volume) of the rock. A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of pore interconnection. The absolute porosity is generally expressed mathematically by the following relationships:

$$\phi_a = \frac{\text{total pore volume}}{\text{bulk volume}}$$

or

$$\phi_a = \frac{\text{Bulk volume} - \text{grain volume}}{\text{bulk volume}}$$

Where ϕ_a : absolute porosity

Effective porosity

The effective porosity is defined as the ratio of the interconnected pore volume to the total or bulk volume of the rock:

$$\text{Effective porosity} = \frac{\text{interconnected pore volume}}{\text{bulk volume}}$$

The value of the effective porosity is used in all reservoir engineering calculations because it represents the interconnected pore space that contains the recoverable hydrocarbon fluids. One important application of the effective porosity is its use in determining the original hydrocarbon volume in place.

Effective porosity is affected by a number of lithological factors including the type and content of the clays present in the rock; the heterogeneity of grain size; the packing and cementation of the grains.

Porosity can be classified according to the mode of origin into two types:

1- Primary porosity

2- Secondary porosity

Primary porosity

The primary porosity is that developed during the deposition of the rocks. The intergranular porosity of sandstone rocks and the intercrystalline and oolitic porosity of some limestone rocks typify original porosity.

Secondary porosity

The secondary porosity is that developed after the deposition of the rocks by some geological processes. The secondary porosity is classified into three classes based on the mechanisms of formation:

1- Solution porosity: This porosity formed by the solution of the more soluble portions of the rock.

2- Fractures and joints porosity: This type is common in many sedimentary rocks, and it is created by structural failure of the reservoir rocks under tension caused by tectonic activities such as folding and faulting.

3- Dolomitization porosity: This type of porosity is formed when limestone (CaCo3) is transformed into dolomite CaMg(Co3)2 according to the following chemical reaction:

$$\underset{\text{Limeston}}{2CaCo3 + Mg^{2+}} \longrightarrow \underset{\text{Dolomite}}{CaMg(Co3)2 + Ca^{2+}}$$

The volume of dolomite is less than that of calcite, so the replacement of calcite by dolomite in a rock increases the pore space in the rock by 13% and forms an important reservoir rock.

2- Permeability:

The permeability is a property of the porous medium that measures the capacity and ability of the formation to transmit fluids. The rock permeability is a very important rock property because it controls the directional movement and the flow rate of the reservoir fluids in the formation. The permeability depends on how well the pore spaces within the rock are interconnected (Fig.1).

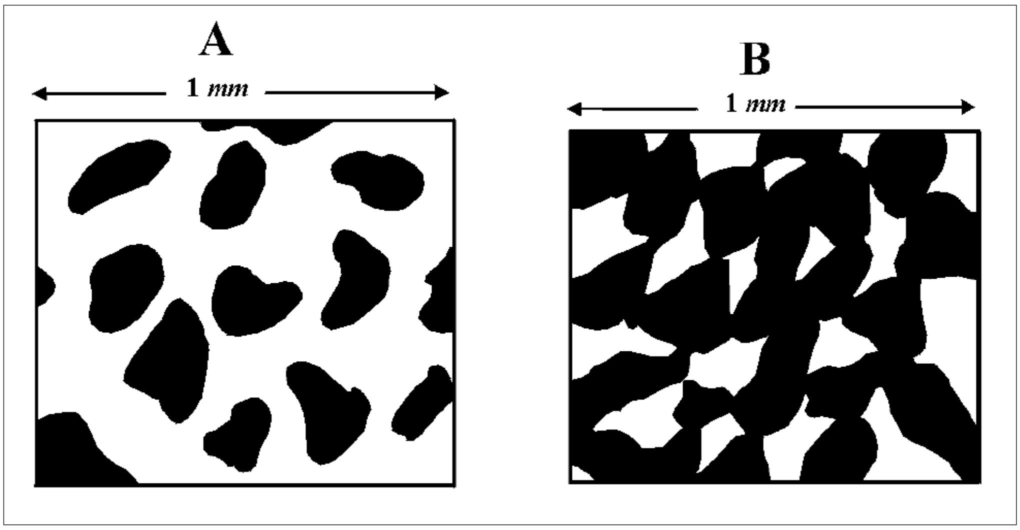

Figure 1: (A) Interconnected pore spaces (good permeability), (B) Isolated pore spaces (poor permeability).

The fundamental law of fluid motion in porous media is Darcy’s law. If a horizontal linear flow of an incompressible fluid is established through a core sample of length (L) and a cross-section of area (A), (Figure 2), then the governing fluid flow equation is defined as:

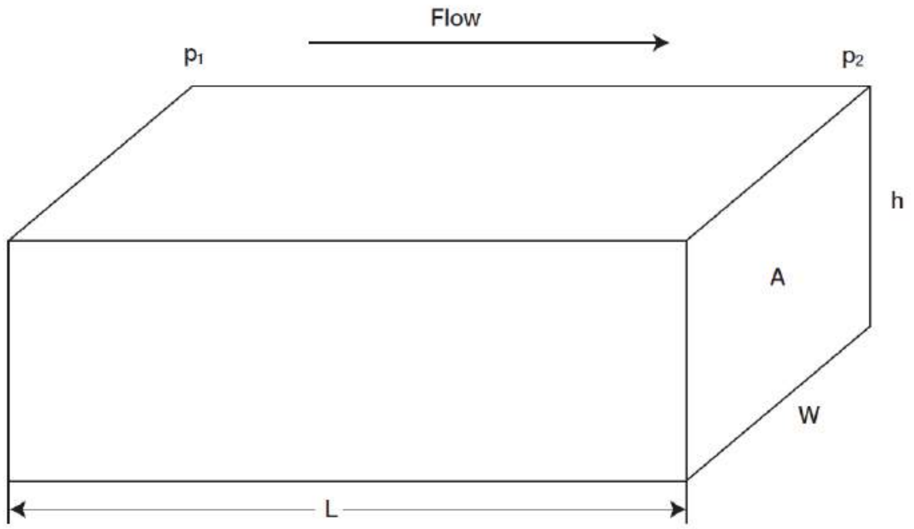

Figure 2: Linear flow model.

$$\nu = -\frac{k}{\mu}\frac{dp}{dL}$$

where ν = apparent fluid flowing velocity, cm/sec
k = proportionality constant, or permeability, Darcy's
μ = viscosity of the flowing fluid, cp
dp/dL = pressure drop per unit length, atm/cm

The velocity, v, in the above equation is not the actual velocity of the flowing fluid but is the apparent velocity determined by dividing the flow rate by the cross-sectional area which fluid is flowing. Substituting the relationship, q/A, in place v will result:

$$q = -\frac{kA}{\mu}\frac{dp}{dL}$$

where q = flow rate through the porous medium, cm^3/sec
A = cross-sectional area across which flow occurs, cm^2

With a flow rate of one cubic centimetre per second across a cross-sectional area of one square centimetre with a fluid of one centipoises viscosity and a pressure gradient at one atmosphere per centimetre of length, it is obvious that k is unity. The unit of the permeability is the Darcy (D), although the permeability of many reservoirs measured in millidarcy (md):

1 Darcy = 1000 md

The permeability can be classified into absolute and effective. If the permeability is measured at 100% saturation of a single fluid, such as oil, gas or water is called the absolute permeability. When two or more fluids are present, the permeability is called effective permeability.

3- Saturation:

Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). This property is expressed mathematically by the following relationship:

$$\text{Fluid saturation} = \frac{\text{Total volume of the fluid}}{\text{Pore volume}}$$

The pore spaces of a petroleum reservoir are never filled completely with hydrocarbons; water is always present in the liquid state, and the hydrocarbons can exist in one or more states (gas or oil). Applying the above mathematical concept of saturation to each reservoir fluid gives:

$$S_o = \frac{\text{volume of oil}}{\text{pore volume}}$$

$$S_g = \frac{\text{volume of gas}}{\text{pore volume}}$$

$$S_w = \frac{\text{volume of water}}{\text{pore volume}}$$

Where S_o: oil saturation

S_g: gas saturation

S_w: water saturation

Thus, all saturation values are based on pore volume and not on the gross reservoir volume. The saturation of each individual phase ranges between zero to 100%. By definition, the sum of the saturation is 100%, therefore:

$S_g + S_o + S_w = 1.0$

The saturation of a fluid in a reservoir seldom remains constant. Water can enter the reservoir either naturally from an adjacent aquifer, or artificially by water injection. Oil saturation decreases with oil production and the replacement of oil by another fluid such as water. Gas saturation could increase with gas injection into the reservoir or as gas evolves naturally from the oil when the pressure drops.

The fluids in most reservoirs are reached a state of equilibrium and, therefore, will have become separated according to their density, i.e., oil overlain by gas and underlain by water. In addition to the bottom water, there will be connate water distributed throughout the oil and gas zones. Connate water saturation (S_{wc}) is important because it reduces the amount of space available between oil and gas.

Critical oil saturation, S_{oc}:

For the oil phase to flow, the saturation of the oil must exceed a certain value, which is termed critical oil saturation. At this particular saturation, the oil remains in the pores and will not flow.

Residual oil saturation, S_{or}:

During the displacing process of the crude oil from the porous media by water or gas injection, there will be some remaining oil left that is characterised by a saturation value that is larger than the critical oil saturation. This saturation value is called the residual oil saturation (S_{or}).

Moveable oil saturation, S_{om}:

Moveable oil saturation is defined as the fraction of pore volume occupied by moveable oil as expressed by the following equation:

$S_{om} = 1 - S_{wc} - S_{oc}$

Where S_{wc}: connate water saturation

S_{oc}: critical oil saturation

Critical gas saturation, S_{gc}:

Critical gas saturation is defined as the maximum gas saturation at which the gas phase remains immobile. Above the critical gas saturation value, the gas begins to move.

Critical water saturation, S_{wc}:

Critical water saturation is defined as the maximum water saturation at which the water phase will remain immobile.

Average saturation:

The average porosity of each reservoir fluid is calculated from the following equations:

$$S_o = \frac{\sum_{i=1}^{n} \phi_i\ h_i\ S_{oi}}{\sum_{i=1}^{n} \phi_i\ h_i}$$

$$S_w = \frac{\sum_{i=1}^{n} \phi_i\ h_i\ S_{wi}}{\sum_{i=1}^{n} \phi_i\ h_i}$$

$$S_g = \frac{\sum_{i=1}^{n} \phi_i\ h_i\ S_{gi}}{\sum_{i=1}^{n} \phi_i\ h_i}$$

Where the subscript (i) refers to any individual measurement and h_i represents the depth interval to which ϕ_i, S_{oi}, S_{gi}, and S_{wi} apply.

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Lecture 2

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Wettability:

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. Figure 1 illustrates the concept of wettability. Small drops of three liquids (mercury, oil, and water) are placed on a clean glass plate. The three droplets are then observed from one side as illustrated in Figure 1. It is noted that the mercury retains a spherical shape, the oil droplet develops an approximately hemispherical shape, but the water tends to spread over the glass surface.

The tendency of a liquid to spread over the surface of a solid is an indication of the wetting characteristics of the liquid for the solid. This spreading tendency can be expressed more conveniently by measuring the angle of contact at the liquid-solid surface. This angle, which is always measured through the liquid to the solid, is called the contact angle θ.

The contact angle θ has achieved significance as a measure of wettability. As shown in Figure 1, as the contact angle decreases, the wetting characteristics of the liquid increase. Complete wettability would be evidenced by a zero contact angle, and complete nonwetting would be evidenced by a contact angle of 180^o. For intermediate wettability, contact angles of 60^o to 90^o.

The wettability of reservoir rocks to the fluids is important in that the distribution of the fluids in the porous media is a function of wettability. Because of the attractive forces, the wetting phase tends to occupy the smaller pores of the rock and the nonwetting phase occupies the more open channels.

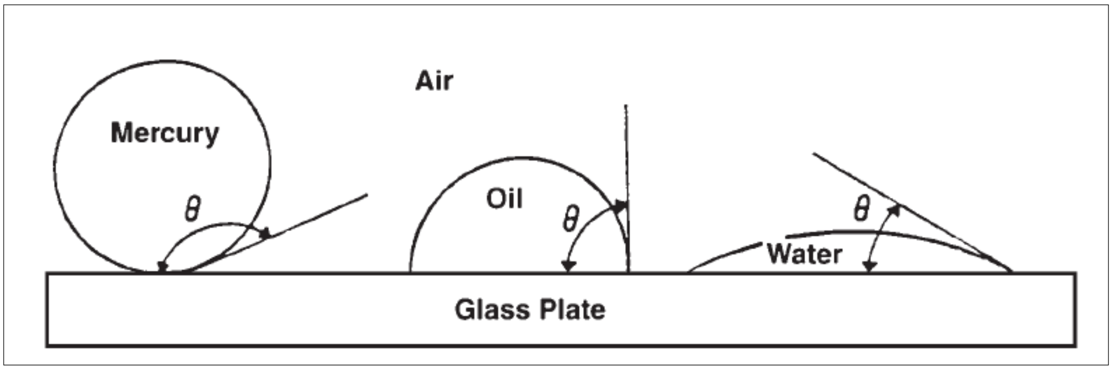

Figure 1: Illustration of wettability.

Surface and interfacial tension:

In dealing with multiphase systems, it is necessary to consider the effect of the forces at the interface when two immiscible fluids are in contact. When these two fluids are liquid and gas, the term ***surface tension*** is used to describe the forces acting on the interface. When the interface is between two liquids, the acting forces are called ***interfacial tension.***

Consider the two immiscible fluids, air (or gas) and water (or oil), as shown schematically in Figure 1. A liquid molecule, which is remote from the interface, is surrounded by other liquid molecules, thus having a resulting net attractive force on the molecule of zero. A molecule at the interface, however, has a force acting on it from the air (gas) molecules lying immediately above the interface and from liquid molecules lying below the interface.

Resulting forces are unbalanced and give rise to surface tension. The unbalanced attraction force between the molecules creates a membrane like surface with a measureable tension, i.e., surface tension. As a matter of fact, if carefully placed, a needle will float on the surface of the liquid, supported by the thin membrane even though it is considerably more dense than the liquid.

The surface or interfacial tension has the units of force per unit of length, e.g., dynes/cm, and is usually denoted by the symbol σ.

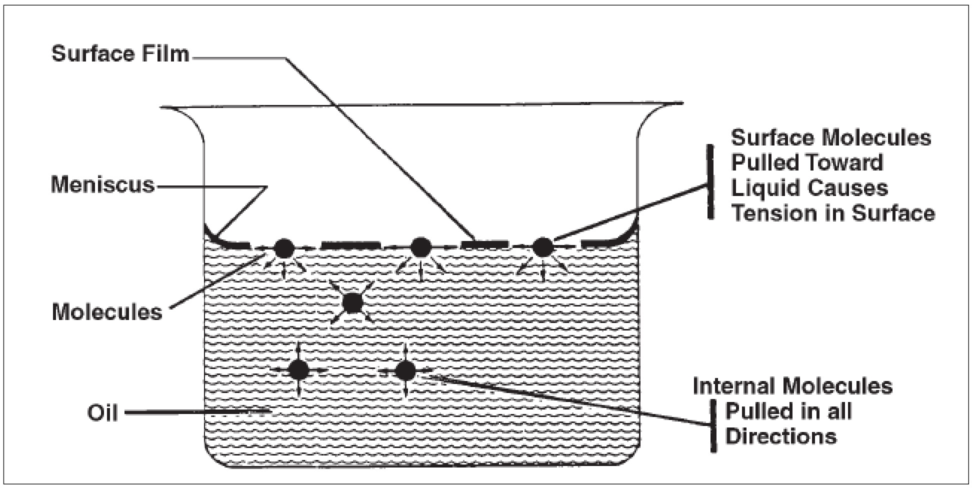

Figure 1: Illustration of surface tension.

If a glass capillary tube is placed in a large open vessel containing water, the combination of surface tension and wettability of tube to water will cause water to rise in the tube above the water level in the container outside the tube as shown in Figure 2.

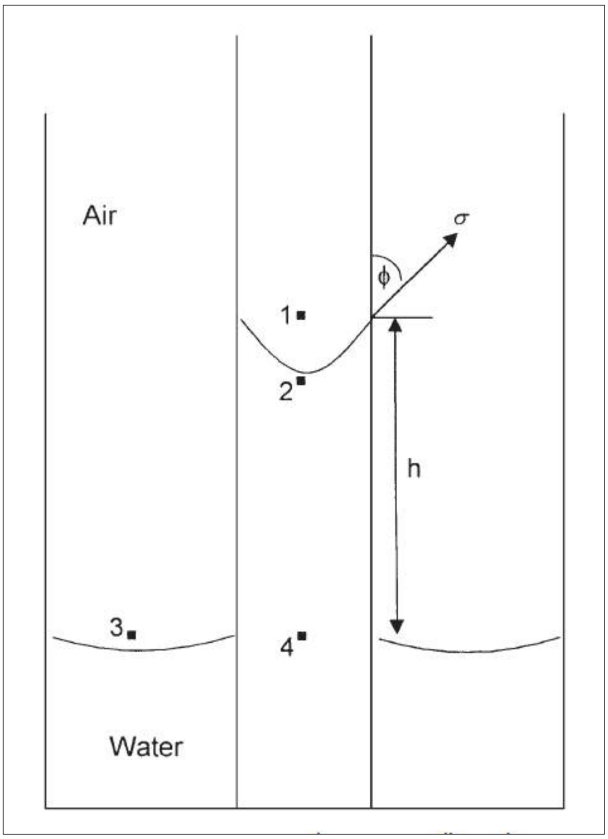

Figure 2: Pressure relations in capillary tubes.

The water will rise in the tube until the total force acting to pull the liquid upward is balanced by the weight of the column of liquid being supported in the tube. Assuming the radius of the capillary tube is r, the total upward force F_{up}, which holds the liquid up, is equal to the force per unit length of the surface times the total length of the surface, or:

$$F_{up} = (2\pi r)\,(\sigma_{gw})\,(\cos\theta) \qquad \text{--------------------- (1)}$$

where σ_{gw} = surface tension between air (gas) and water (oil), dynes/cm
θ = contact angle
r = radius, cm

The upward force is counteracted by the weight of the water, which is equivalent to downward force of mass times acceleration, or:

$$F_{down} = \pi r^2 h (\rho_w - \rho_{air}) g$$ --------------------- (2)

where h = height to which the liquid is held, cm
g = acceleration due to gravity, cm/sec^2
ρ_w = density of water, gm/cm^3
ρ_{air} = density of gas, gm/cm^3

Because the density of air is negligible in comparison with the density of water, the equation 2 is reduced to:

$$F_{down} = \pi r^2 \rho_w g$$ --------------------- (3)

Equating equation 1 with 3 and solving for the surface tension gives:

$$\sigma_{gw} = \frac{r h \rho_w g}{2 \cos \theta}$$ --------------------- (4)

In the case of two liquids (water and oil). Because the density of oil is not negligible, equation 4 becomes:

$$\sigma_{ow} = \frac{r h g (\rho_w - \rho_o)}{2 \cos \theta}$$ --------------------- (5)

where ρ_o = density of oil, gm/cm^3
σ_{ow} = interfacial tension between the oil and the water, dynes/cm

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 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.

The displacement of one fluid by another in the pores of a porous medium is either aided or opposed by the surface forces of capillary pressure. As a consequence, in order to maintain a porous medium partially saturated with nonwetting fluid and while the medium is also exposed to wetting fluid, it is necessary to maintain the pressure of the nonwetting fluid at a value greater than that in the wetting fluid.

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

Capillary pressure = (pressure of the nonwettong phase) – (pressure of the wetting phase)

$P_c = P_{nw} - P_w$ ------------------------ (6)

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 P_{cwo})
- Gas-oil capillary pressure (denoted as P_{cgw})
- Gas-water capillary pressure (denoted as P_{cgw})

Applying the mathematical definition of the capillary pressure as expressed by equation 6, the three types of the capillary pressure can be written as:

$P_{cwo} = P_o - P_w$

$P_{cgo} = P_g - P_o$

$P_{cgw} = P_g - P_w$

Where P_g, P_o, and P_w represent the pressure of gas, oil, and water, respectively.

If all the three phases are continuous, then:

$P_{cgw} = P_{cgo} + P_{cwo}$

In the case of gas-water system, the equation for computing the capillary pressure is:

$P_c = gh\,(\rho_w - \rho_g) = gh\Delta\rho$ ---------------------- (7)

Where $\Delta\rho$ is the density difference between the wetting and nonwetting phase. The density of gas is negligible in comparison with the water density.

The capillary pressure equation can be expressed in terms of the surface and interfacial tension by combining equations 6 and 7 with equations 4 and 5 to give:

- **Gas-liquid system**

$$P_c = \frac{2\,\sigma_{gw}\,(\cos\theta)}{r}$$

and

$$h = \frac{2\,\sigma_{gw}\,(\cos\theta)}{r\,g\,(\rho_w - \rho_{gas})}$$

where ρ_w = water density, gm/cm^3
σ_{gw} = gas-water surface tension, dynes/cm
r = capillary radius, cm
θ = contact angle
h = capillary rise, cm
g = acceleration due to gravity, cm/sec^2
p_c = capillary pressure, dynes/cm^2

- **Oil-water system**

$$p_c = \frac{2\,\sigma_{ow}\,(\cos\theta)}{r}$$

and

$$h = \frac{2\,\sigma_{wo}\,(\cos\theta)}{r\,g\,(\rho_w - \rho_o)}$$

where σ_{wo} is the water-oil interfacial tension.