Factors Affecting Permeability Measurement

Gas Slippage.

_Klinkenberg has reported variations in measured permeability when

comparing data, which were collected using non-reactive liquids versus gases. These variations were associated with a laboratory effect called gas slippage, which can be described as the ability of a gas molecule to more easily retain forward velocity along a solid interface compared to a liquid molecule.

Liquid velocities normally approach zero at the solid wall. However, gas molecules have a nonzero wall velocity. This may result in two different measurements of rock permeability depending on the fluid used in the experiment. Since permeability is a rock property, it should be independent of the fluid injected into the system. .Therefore, data obtained through gas injection should be corrected

Klinkenberg showed that measured permeability values are higher at low mean (average) pressures, since gas molecules do not adhere to the pore walls as liquid molecules do and hence the slippage of gases along the pore walls occurs. This so-called slippage effect decreases with increasing pressure, as gas begins to act like a liquid once the flowing pressure increases.

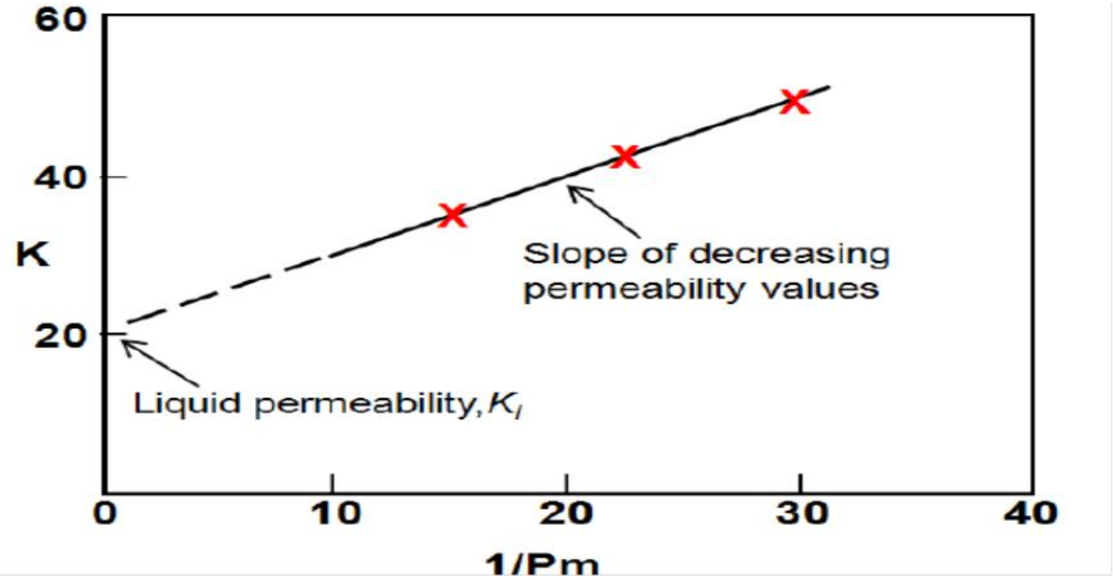
Experimental data show that a plot of reciprocal of mean flowing pressure with respect to permeability yields a straight line. The straight line can be extrapolated to infinite mean pressure and the permeability value at the extrapolated point is referred as the equivalent liquid permeability.

The mathematical expression of this phenomenon is called the Klinkenberg:equation and can be written as where Kl is the equivalent liquid permeability, Kg is gas permeability, Pm is the mean flowing gas pressure and b is Klinkenberg constant which is dependent on the type of the gas and rock.

$$K_l = \frac{K_g}{\left(1+\frac{b}{P_m}\right)}$$

Note that the correction factor, on a percentage basis, is greater for low permeability and low pressure conditions. It becomes smaller as the permeability value and the pressure increase. It is usually negligible at reservoir conditions due to large fluid pressure.

An illustration of the Klinkenberg permeability correction. Note that the crosses are the measured permeability values at different pressures. The straight line is extrapolated to infinite mean pressure (reciprocal converges to zero) and the permeability value is recorded as the equivalent liquid permeability.



Confining Pressure

Ideally, permeability measurements should be conducted by applying a net overburden pressure in order to simulate the reservoir conditions. It has been found that overburden pressure reduces the measured permeability values. The impact is observed more on unconsolidated rocks and on samples containing fractures and microcracks. In order to better understand and account for its impact, a series of confining stress measurements should be performed on selected samples.

Inertial Effects

If the gas flow rate through the core is significantly high, inertial effects may become important and should be accounted for. They usually generate additional pressure drop and may result in underestimation of permeability if not properly accounted for. Although it is often evident in laboratory studies, turbulence effects are in general only applicable in the near wellbore region of high-rate gas or light-oil reservoirs. High-production gas wells have demonstrated the need for extended core analysis that provides a non-Darcy flow coefficient.

Reactive Liquids

Although water is considered to be a non-reactive fluid, its interaction with clay minerals may make it behave like reactive in terms of its impact on permeability determination. Fresh water may cause significant clay swelling. Therefore, extra care should be taken while choosing the proper core plugging, cleaning and drying techniques.

For example:

if the rock contains significant amount of clay minerals, fresh water should be avoided while drilling a plug from the core, instead brine with an appropriate salinity level and ion-balance should be used

Permeability reduction may also be encountered due to particle movement which is a function of flow velocity and fluid density. Critical velocity can be used to determine the maximum displacement rate for experimental studies in order to avoid the initiation of the movement of fine particles.

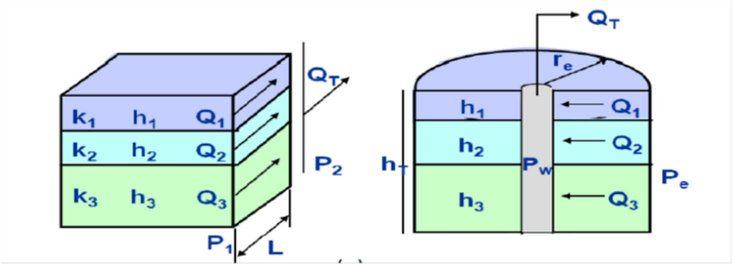
Average Permeability of a Combination of Layers

Horizontal Flow (parallel to the layering)

If the flow occurs in the horizontal direction, then the effective permeability for flow is the weighted arithmetic mean of the individual permeabilities, weighted by the thickness of each individual layer.

$$k_{eff} = \sum_{j=1}^{n} k_j h_j \Big/ \sum_{j=1}^{n} h_j$$

where keff is the effective permeability, kj is the permeability for each individual layer, n is the number of layers and hj is the thickness of each layer.

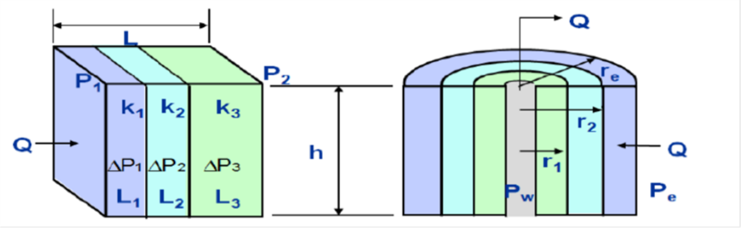


Vertical Flow (perpendicular to the layering)

- If the flow occurs in the vertical direction
- then the effective permeability is the weighted harmonic mean of the individual permeabilities.

$$k_{eff} = L \Big/ \sum_{j=1}^{n} L_j / k_j$$

where L is the total length of the each individual layer Lj. the effective permeability for flow parallel to layering is controlled by the most permeable layer, whereas for flow perpendicular to layering, it is controlled by the least permeable layer.

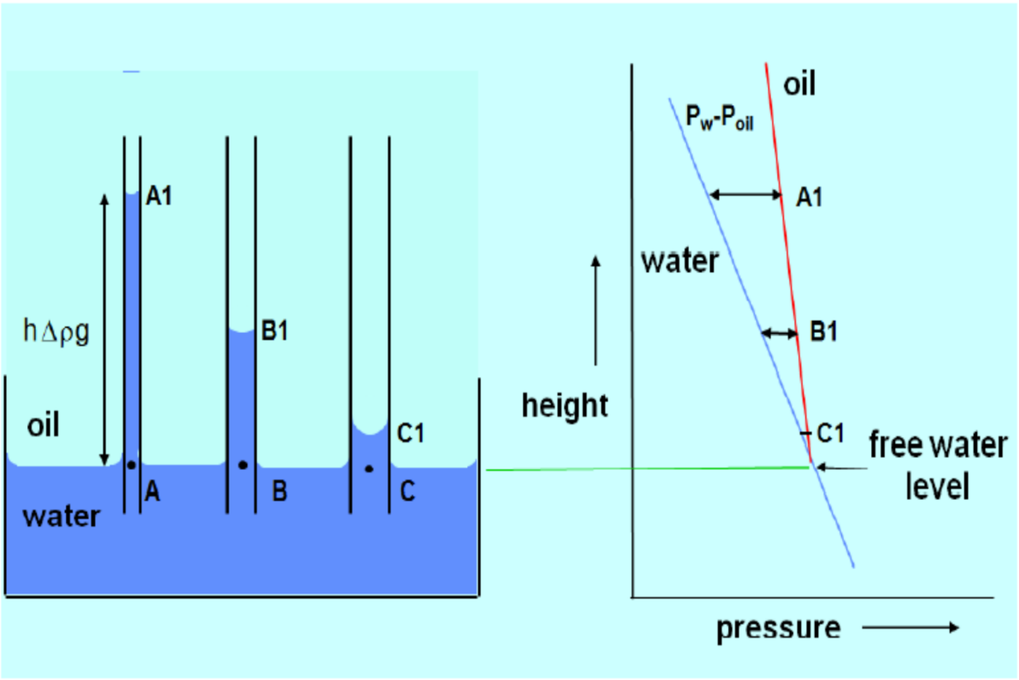


Capillary Rise:

If we consider a case where a clean and water-wet capillary tube with a circular cross-section and a small diameter is placed in a large open vessel containing oil and water, the water level would rise in the capillary tube above the height of the water level in the large vessel. This rise in the height is due to the capillary forces. The water level would rise in the tube until the hydrostatic equilibrium is reached (see the Figure). The capillary force acting to pull the water upward is balanced by the force due to weight of the water column in the tube. By equating the two quantities, we reach the below mentioned relationship:

$$(\rho_w - \rho_o)gh = \frac{2\sigma cos\theta}{r}$$

As can be seen from the Equation and the Figure, the equilibrium height of the water column, h, is a function of the radius of the capillary tube and the wettability. If the wetting characteristics of the medium remain unaltered and the radius of the capillary tube decreases, the column height increases proportionally with the decrease in radius. If the radius of the capillary tube is kept constant and the wetting characteristic of the solid changes, the height of the water column increases or decreases depending on the direction of the change in wettability. For example, if the system had initially been less water-wet (contact angle increases) the column height would have been shorter as the capillary forces would have become weaker.



An illustration of hydrostatic equilibrium in capillary tubes.

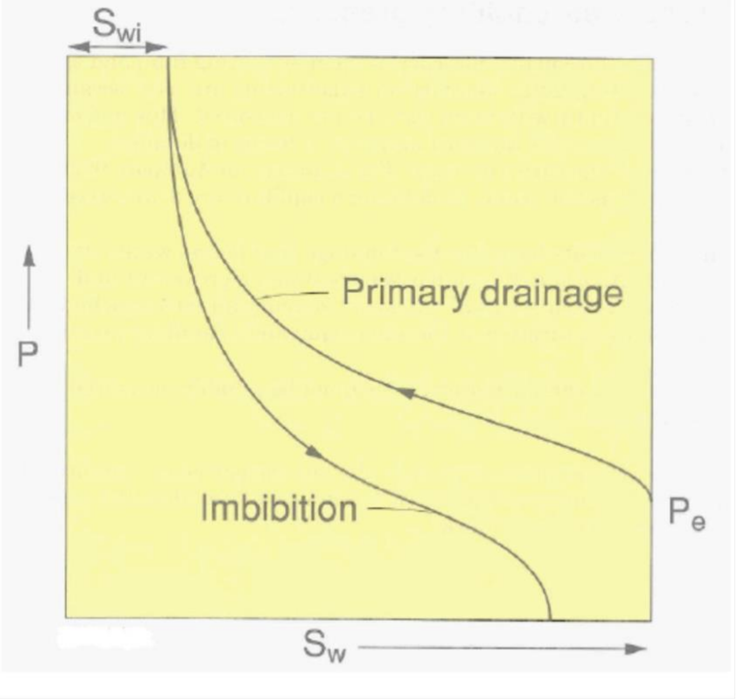
Characteristics of Capillary Pressure Curve:

As discussed above, the capillary pressure curve depends not only on the fluid saturation but also on the saturation history of the system. The Figure shows a typical capillary pressure curve for an oil-brine system for drainage and imbibition cycles. It is worthwhile to mention that although in theory, the non-wetting phase displacing the wetting phase is called drainage, and the wetting phase displacing the non-wetting phase is called the imbibition process, the industry convention is to use the drainage term for oil-displacing-water, and the imbibition term for water-displacing oil,

irrespective of the system's wettability. A minimum threshold pressure must be exceeded in order to initiate the invasion of the oil phase, which is called entry capillary pressure for primary drainage . As the pressure increases further, water saturation decreases and reaches the irreducible water saturation (or connate water saturation, Swc). This point reflects the

fluid distribution typically found at the time of reservoir discovery. Therefore, it is also called the initial water saturation, Swi. Once water is injected into the system after the primary oil drainage, it usually follows a different path which is called the imbibition capillary pressure curve. This difference between drainage and imbibition capillary pressure curves is called the hysteresis effect and it has a significant impact for reservoir engineering applications.

The primary drainage process represents hydrocarbon accumulation and fluid distribution at initial reservoir conditions, whereas imbibition represents the displacement performance upon water injection into the reservoir. Therefore, it is crucial to utilize the proper capillary pressure curve for a specific reservoir application.



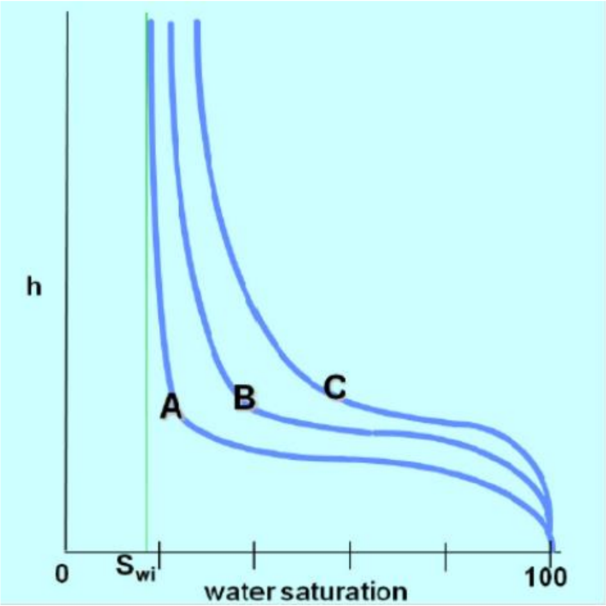
A typical capillary pressure curve for primary drainage and imbibition cycle

The shape of the capillary pressure curves depends on the pore size distribution hence relates to permeability of the reservoir rock. This also determines the height of the transition zone above the free water level (FWL). Low permeability rocks have high capillary pressures and generally long transition zones whereas high permeability rocks have low capillary pressures and short transition zones. The figure illustrates the impact of absolute permeability on capillary pressure

Curves.

An illustration of the impact of permeability of a rock on the capillary pressure curve

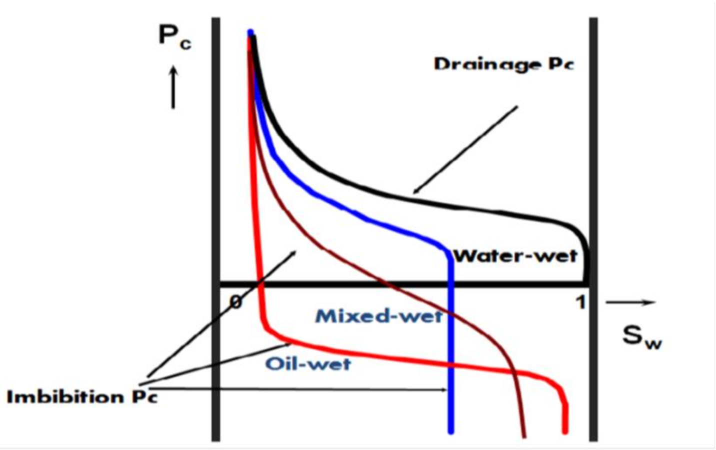
A, B and C represent the capillary pressure curves of 3 different core samples, C being the least permeable and A being the most permeable



It is worthwhile to mention that most carbonate reservoirs in the world (a significant proportion is located in Middle East) show mixed-wet to oil-wet behaviour. In these reservoirs, a rather significant hysteresis effect can be observed between the .primary drainage and imbibition capillary pressure curves (see the Figure)

Not only their wettability characteristics but also the low matrix permeabilities associated with them makes the transition zone modelling quite

challenging but important in these reservoirs. Masalmeh and co-workers conducted an extensive study on improved characterization of transition zone in carbonate reservoirs. They showed that a carefully conducted petrophysical and SCAL data analysis is crucial in order to successfully build a static and dynamic reservoir model, which can then be used to accurately predict the original oil in place as well as to make proper reservoir performance predictions.



An illustration of the capillary pressure hysteresis with varying degree of wettabilities. Note that once the system becomes oil-wet, there is almost no spontaneous imbibition.

Laboratory Measurements of Capillary Pressure:

The capillary pressure curve is the most common special core analysis measurement performed on core plugs. There are three widely used measurement techniques; these are the mercury injection, the

.centrifuge, and the porous plate methods

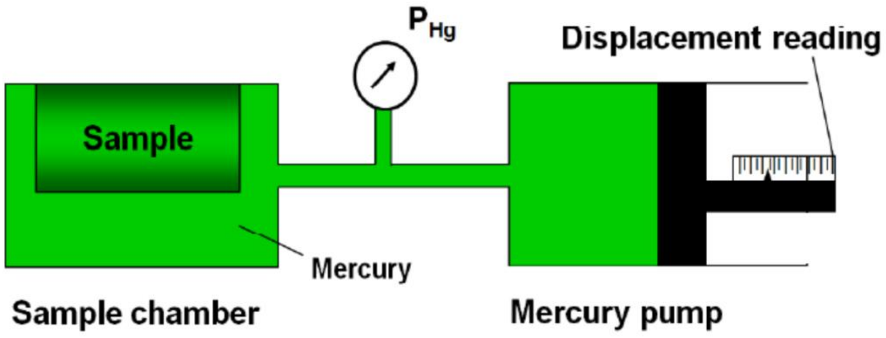
Mercury Injection Measurement.

Centrifuge Technique.

Porous Plate Method.

Mercury Injection Measurement

In the mercury injection technique , mercury is the non-wetting fluid and air is the wetting phase. The core is initially cleaned and dried. Then the mercury is injected into the clean, dry core sample by increasing the injection pressure where the volume of mercury entering into the sample is measured at each pressure step. Mercury injection is a frequently used capillary pressure measurement technique as it is relatively cheap, fast and requires relatively straightforward data interpretation. The measured data, however, need to be converted to in situ reservoir conditions by taking into account the differences in interfacial tension and contact angle between the rock/fluid systems used in the laboratory and that found in reservoir .The main disadvantage of mercury injection measurement is it is only applicable for the drainage cycle and one of the other techniques should be employed for obtaining the capillary pressure curve which is representative to the imbibition cycle. A mercury injection experiment should be conducted as the last measurement since this technique is destructive and samples cannot be used for further measurements. Figure shows a schematic of the mercury injection apparatus.



A schematic of the mercury injection apparatus.

Centrifuge Technique

Another capillary pressure measurement technique is the multi-speed centrifuge method. Brine (or oil) saturated samples are placed in a centrifuge and are spun at a series of increasing constant speeds. The rotation speed is converted into a force unit, which determines the capillary pressure.

It is a relatively fast (compared to the porous plate measurement) and non-destructive technique. A complete set of capillary pressure data points can be obtained in a few days for relatively high permeability samples and longer time is .

The main drawback of this technique is the design of the experiment and interpretation of the data are not straightforward and numerical simulation of centrifuge experiments is generally required to derive capillary pressure data. Figure 1 shows the centrifuge process. For drainage

experiments, brine saturated cores are used whereas for imbibition, oil saturated (saturated with oil and connate water) cores are utilized (see Figure 2).

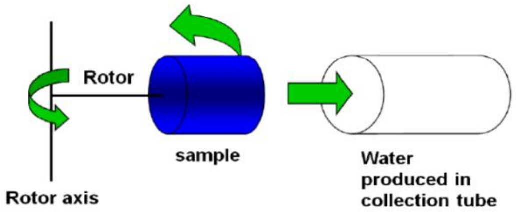


Figure 1. An illustration of capillary pressure measurement using the centrifuge method.

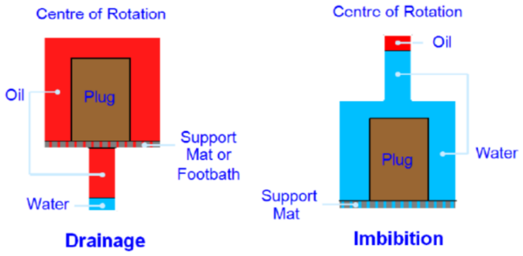


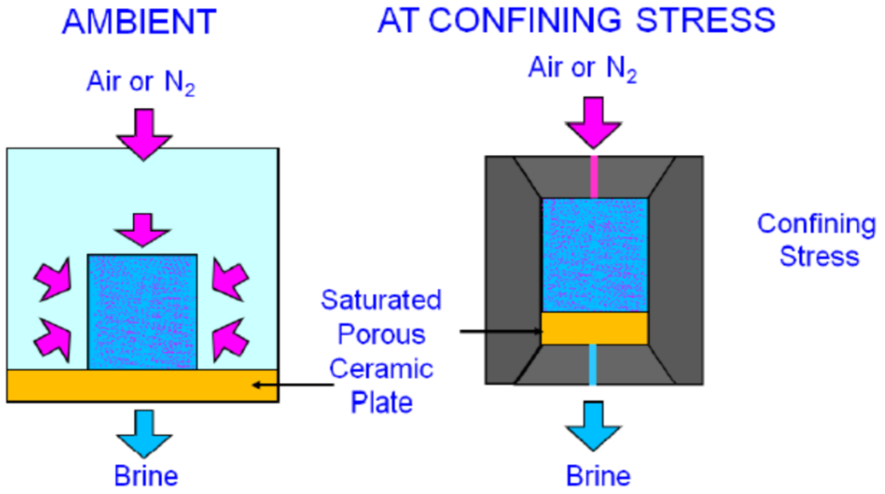
Figure 2. Core is saturated with brine for drainage, and with oil for imbibition experiments (Courtesy of Core Laboratories).

Porous Plate Method

The porous plate method is another widely used capillary pressure measurement technique, which can also be employed for resistivity index measurements. It is applicable for both drainage (oil-displacing-water) and imbibition (water-displacing-.oil) capillary pressure measurements.

For the drainage capillary pressure measurement, a clean sample is initially saturated with the wetting fluid (brine or oil). The sample is then placed in a semi-permeable membrane, which is only permeable to the wetting phase. The gas (air or nitrogen) pressure is then increased in order for the gas to invade the core by expelling the wetting fluid through the porous plate. Once the equilibrium reaches (when no more wetting fluid production is observed), the change in the saturation is determined volumetrically. The process is repeated for the next pressure step until sufficient data points are collected. The main drawback of this technique is being slow since reaching pressure equilibrium at each saturation point takes significant amount of time, which renders the technique impractical for certain field applications especially for tight and heterogeneous carbonates.

The advantage of the porous plate measurement is that it can be conducted both at ambient conditions and at the representative reservoir conditions of confining stress and temperature and using reservoir fluids.



A schematic of capillary pressure measurement using the porous plate method. Note that the experiments can be conducted at either ambient conditions or at conditions where a confining stress is applied (Courtesy of Core Laboratories).