Lecture Eight: Permeability Measurement

8.1. Absolute Permeability Correlations

1- Timur correlation

Timur (1968) proposed the following expression for estimating the permeability from connate-water saturation and porosity:

$$K(md) = \left(\frac{93 \times \emptyset^{2.2}}{S_{wc}}\right)^2 \qquad \text{....... (8-1)}$$

$$K(darcy) = 8.58102\left(\frac{\emptyset^{2.2}}{S_{wc}}\right)^2 \qquad \text{....... (8-2)}$$

2- Morris and Biggs correlation

While Morris and Biggs (1967) presented the following two expressions for estimating the permeability of oil and gas reservoirs:

For an oil reservoir:

$$K(darcy) = 62.5\left(\frac{\emptyset^{3}}{S_{wc}}\right)^2 \qquad \text{....... (8-3)}$$

For a gas reservoir:

$$K(darcy) = 2.5\left(\frac{\emptyset^{3}}{S_{wc}}\right)^2 \qquad \text{....... (8-4)}$$

where:

k = absolute permeability.

ϕ = porosity, fraction.

S_{wc} = connate water saturation, fraction.

Example 1

Estimate the absolute permeability of an oil zone with a connate-water saturation and average porosity of 25% and 19%, respectively.

Solution:

Applying the Timur equation:

$$K = 8.58102\left(\frac{0.19^{2.2}}{0.25}\right)^2 = 0.092\ Darcy$$

From the Morris and Biggs correlation:

$$K = 62.5\left(\frac{0.19^{3}}{0.25}\right)^2 = 0.047\ Darcy$$

8.2. Laboratory Measurement of Absolute Permeability

Laboratory measurement of absolute permeability usually involves the direct application of the Darcy equation, based on the measurement of individual variables such as flow rate, pressure drop, sample dimensions, and fluid properties. Most laboratory measurements are carried out on formation samples of well-defined geometry, such as cylindrical core plugs. These core plugs are generally 1 or 1.5 in. in diameter with lengths typically varying from 2 to 4 in.

Prior to using core plug samples for permeability measurements, the residual fluids or in situ formation fluids are removed so that the sample is 100% saturated by air. Considering the fact that Absolute permeability can only be measured by conducting a flow experiment in a porous media, gases or nonreactive liquids are commonly used as a fluid phase.

The most common liquids used for the measurement of absolute permeability are formation waters (sometimes called brine) or degassed crude oil. Formation water or crude oil used is generally from the same formation for which the absolute permeability measurement is desired. In some cases, synthetic oil is also used. Absolute permeability measurements of core plug samples are also carried out using gases instead of liquids. Dry gases such as nitrogen, helium, or air are commonly used as the fluid medium in permeability measurements. Choosing a gas is simply convenient and practical because a gas is clean, nonreactive, and does not alter the pore network; in other words, absolute permeability measurements are not influenced by any rock‐fluid interactions.

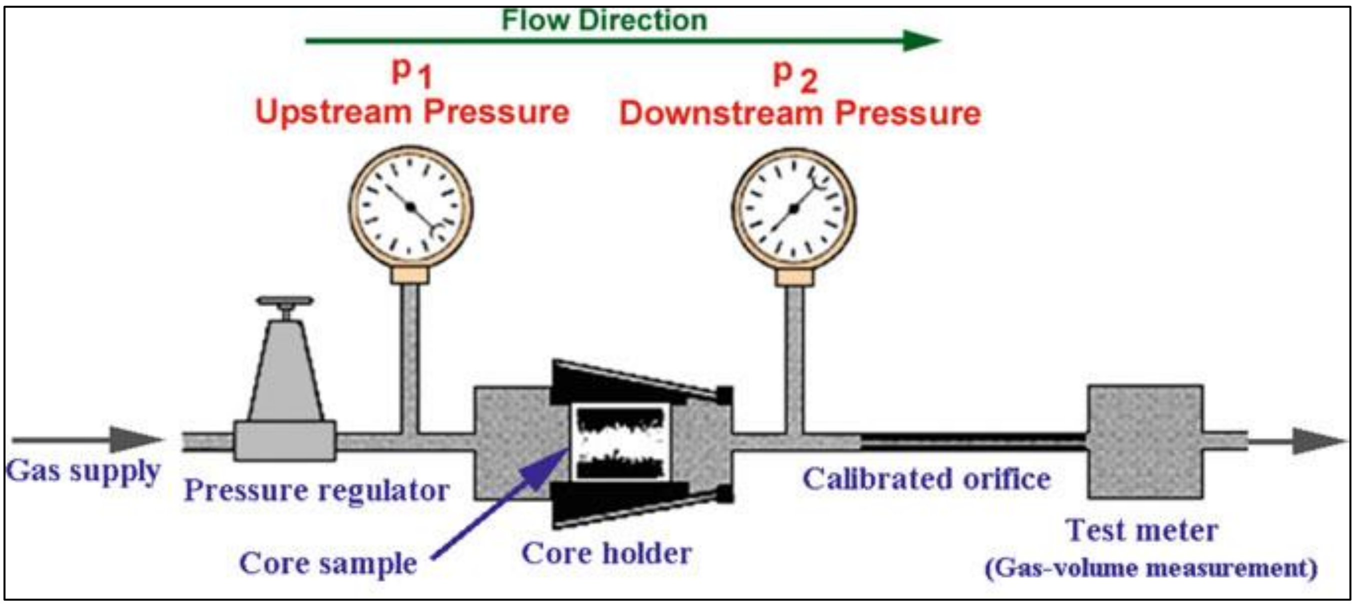

Fig. 8-1 Schematic diagram of a constant head permeameter

8.3. Gas Permeability and Klinkenberg Effect

Klinkenberg (1941) discovered that permeability measurements made with air as the flowing fluid showed different results from permeability measurements made with a liquid as the flowing fluid. The difference is considered to be caused by slippage effect. The permeability of a core sample measured by flowing air is always greater than the permeability obtained when a liquid is the flowing fluid. Klinkenberg postulated, on the basis of his laboratory experiments, that liquids had a zero velocity at the sand grain surface, while gases exhibited some finite velocity at the sand grain surface. In other words, the gases exhibited slippage at the sand grain surface. This slippage resulted in a higher flow rate for the gas at a given pressure differential.

This effect is related with the different physical actions of a liquid and a gas flowing in a porous network. At lower pressures, this effect is most noticeable while it gradually becomes less noticeable as pressure increases.

Darcy's equation assumes laminar flow, incompressible fluid and steady state flow. Gas flows with slippage (turbulence flow).

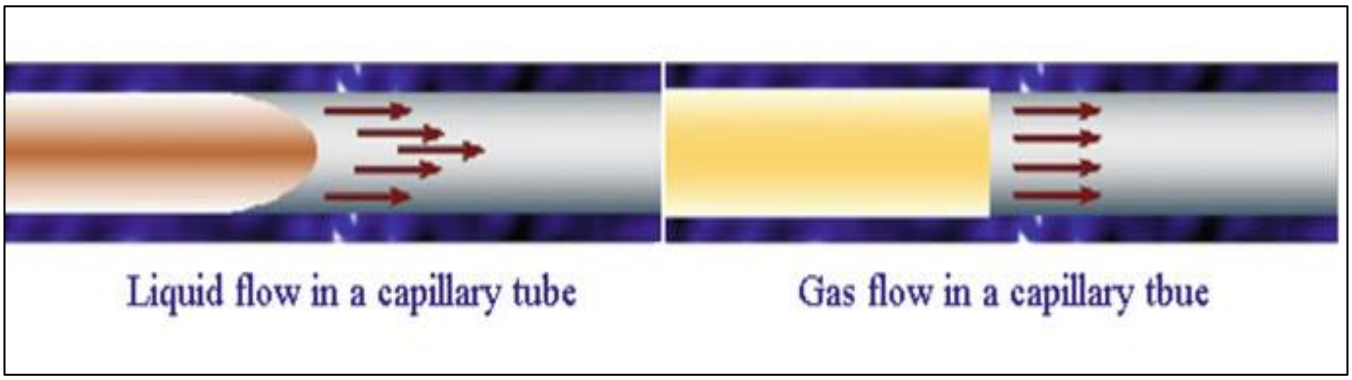

Fig. 8-2 Velocity profiles for a viscous fluid and a gas

Gas permeability is directly dependent on the size of gas molecules, the pore size of a rock, and the average pressure for measurement; thus magnitude of the Klinkenberg effect varies with the core permeability and the type of gas used in the experiment.

Permeability is a function of size of capillary opening, the slippage effect is more remarkable in small pore radius; thus Klinkenberg effect is greater for low permeability rocks.

The smaller the size of gas molecules, the lower the average pressure, and the larger the gas permeability; and the slippage effect is more remarkable.

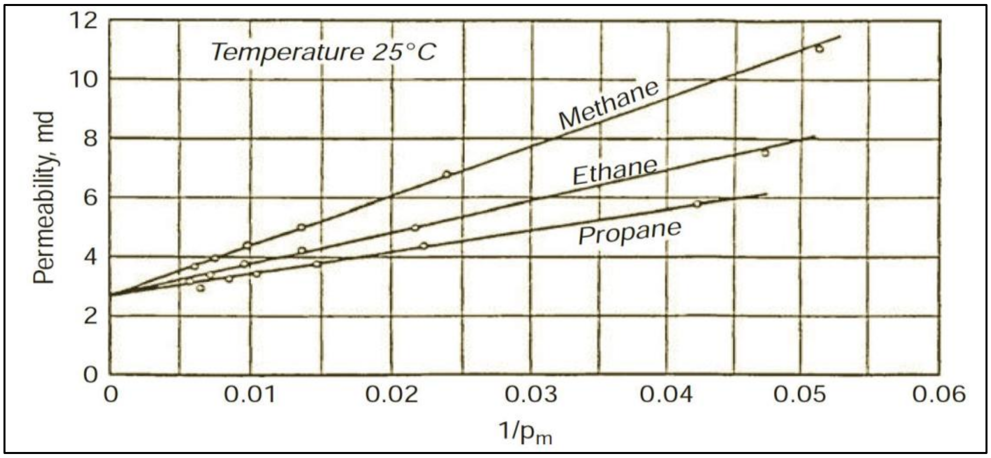

Fig. (8-3) Effect of gas pressure on measured permeability for various gases.

The effect of gas slippage can be eliminated by making measurements at several different mean pressures and extrapolating to high pressure (1/p => 0).

$$K_g = K_L + c\,\frac{1}{P_m} \qquad \text{……. (8-5)}$$

where
k_g= measured gas permeability.
p_m = mean pressure.
k_L = equivalent liquid permeability, i.e., absolute permeability, k.
c = slop of the line.

$$P_m = \frac{P_1+P_2}{2} \qquad \text{……. (8-6)}$$

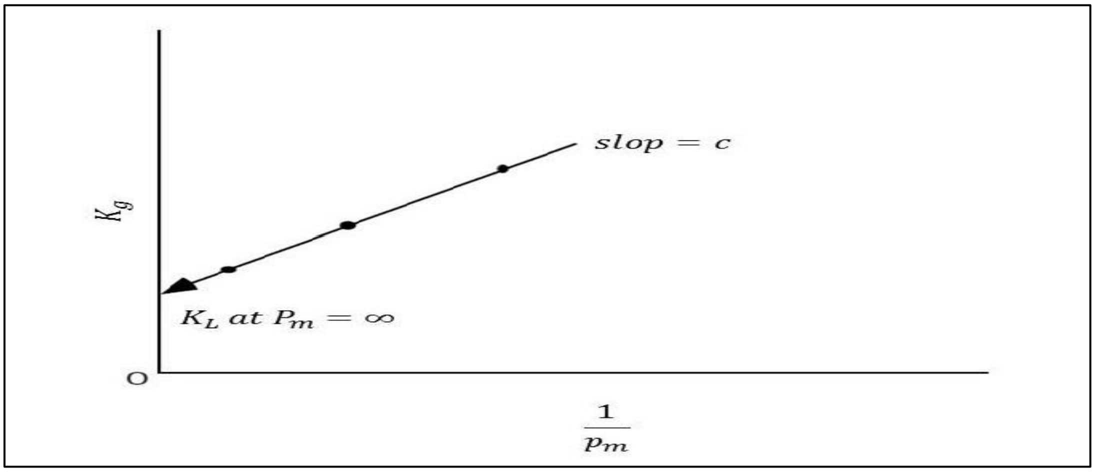

Fig. (8-4) Equivalent liquid permeability

Example 2

Calculate the equivalent liquid permeability for a core sample if the nitrogen gas was used in the permeameter from the following data.

Mean Pressure (atm)	Measured Permeability (md)
1.192	3.76
2.517	3.04
4.571	2.76
9.484	2.54

Solution:

Plot $k_{measured}$ vs. 1/pressure

Intercept is equivalent to liquid permeability

From graph:

$k_{liq} = 2.38$ md