Permeability is a measure of the ability of a porous media to transmit fluids. It is a critical property in defining the flow capacity of a rock sample. The unit of measurement is the darcy, named after the French scientist who discovered the phenomenon. This chapter will begin with the factors which affect permeability and then lead to the experimental law defining permeability for porous media. The last three sections of this chapter investigate the relationship between porosity and permeability, the distribution of these rock properties and finally lab methods of measuring permeability.

3.2 Factors affecting permeability

Numerous factors affect the magnitude and/or direction of permeability.

1. Textural properties
    a. Pore size/ grain size
    b. Grain size distribution
    c. Shape of grains
    d. Packing of grains
2. Gas slippage
3. Amount, distribution, and type of clays
4. Type and amount of secondary porosity
5. Overburden pressure
6. Reactive fluids
7. High velocity flow effects

Let us begin by investigating the role of textural properties on the permeability. Experimental evidence has shown that $k \propto cd^2$, where *c* is a characteristic of the rock properties and *d* is the grain diameter. The dimensions of permeability are L^2, which is directly related to the cross-sectional area of the pore throats. Therefore as grain size increases, so will the pore throat size and a subsequent increase in permeability occurs. In Figure 3.1, an artificial mixing of sands illustrates the significant effect of grain size on permeability. As can be seen, an approximate 25:1 increase in permeability occurs from coarse to very fine grains.

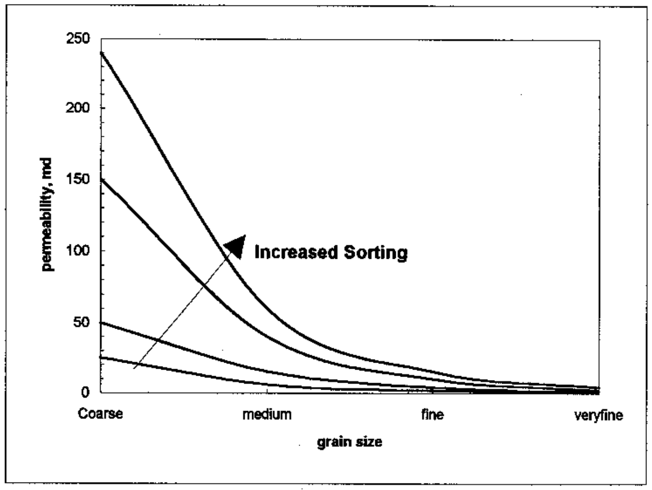

Figure 3.1 Effect of grain size and sorting on permeability

Also shown in Figure 3.1 is the effect of sorting on the permeability. It is not as dramatic as grain size, however, the illustration does show an increase in sorting (better or well sorted) will improve the permeability. This is why in gravel pack operations the selection of the gravel is important, both from a size and sorting viewpoint.

The effect of shape and packing on permeability can be seen in Figure 3.2.

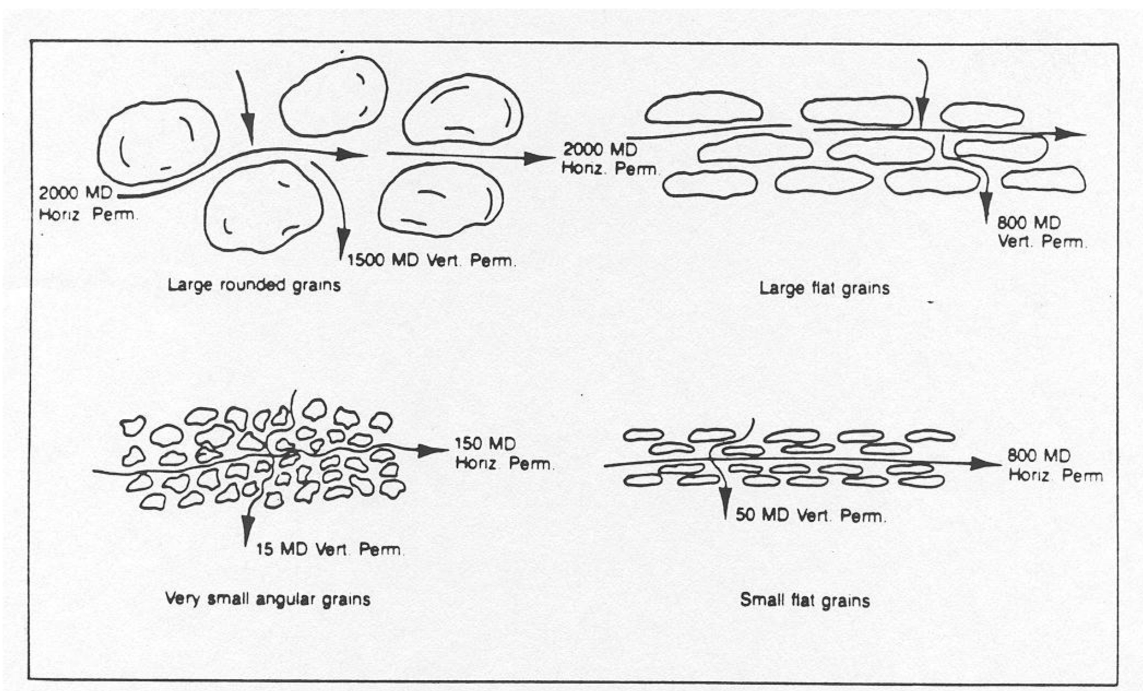

Figure 3.2 Textural parameters and permeability [Link, 1982]

Notice in these examples, the more angular the grains or the flatter the grain shape, a more pronounced anisotropy develops.

3.2.1 Klinkenberg's Effect, Gas Slippage

The true absolute permeability of porous rock is an intrinsic property of the rock, reflecting its internal structure. The permeability of a rock is a constant value, unchanged by different types of fluids that have different viscosities or other physical properties. This rule is followed by all liquids at laminar flow rates that are nonreactive with the rock. However, when gases are used as the flowing fluid at low pressures, calculated permeability may be greater than true permeability of the rock.

In liquid laminar flow, the layer of molecules adjacent to and contacting the solid walls of the pores, or tubes, is stationary. The velocity profile of the liquid is maximum at the center of the passageway and zero at the walls. However, when using gas in the same flow system, the gas velocity profile is not zero at the walls, but has a finite velocity in the direction of flow.

Gas molecules are in constant motion, colliding with one another after traveling an average distance equal to the "mean free path." At lower pressures, the mean free path is greater, and the distance between molecular collisions is increased. Internal resistance to flow is provided by gas molecular collisions with the walls. At any location on a wall, there will be some periods when no gas molecule is in contact with the wall, yet the congregation of gas molecules is continuing its movement through the pore due to molecular diffusion (slip) and not pressure differential.

During these periods of no wall contact, flow is being achieved without the normally expected friction loss at the wall. The result is that the gas molecules get through the porous medium more easily than expected (i.e., the calculated permeability of the rock or capillary tube would be artificially high). As might be expected, gas flow at higher pressures reduces the mean free path between molecular collisions, and the calculated permeability more closely approximates the true absolute permeability of the rock.

Klinkenberg (1941) conducted experiments on this phenomenon and conclude that (1) gas permeability is a function of the gas composition, (2) gas permeability is a function of mean pressure, and (3) the equivalent liquid permeability is independent of the above two factors. He presented a useful relationship,

$$k_g = k_L\left(1+\frac{b}{p}\right) \qquad (3.1)$$

where:

k_g = apparent permeability calculated from gas flow tests;

k_L = true absolute permeability of the rock;

p = mean flowing pressure of the gas in the flow system, measured in atmospheres;

b = Klinkenberg's factor, a constant for a particular gas in a particular porous medium.

Notice the term (1 + b/P) is always greater than or equal to 1.0, therefore the apparent permeability to gas is always greater than or equal to the true absolute permeability of the rock. This is shown in Figure 3.3, where k_L is the minimum value extrapolated to the y-axis.

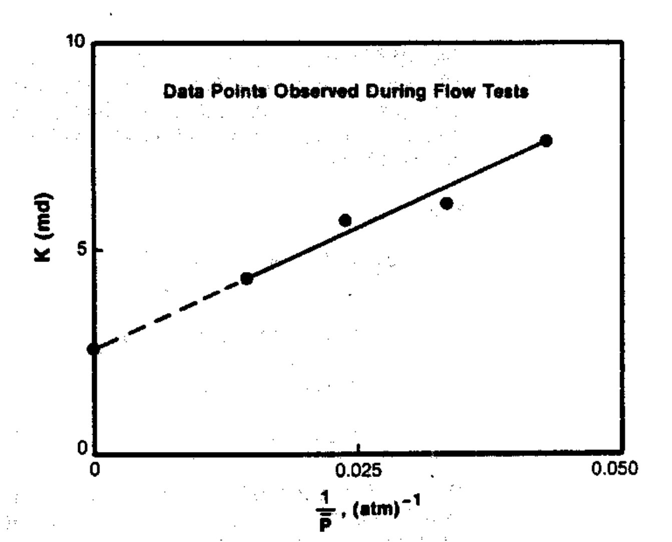

Figure 3.3 Permeability of a core sample to air at various pressures

Also note, that as pressure is increased, the term in the parentheses approaches 1.0, and the apparent gas permeability approaches the true absolute value. In practice when laboratory tests use gas as the flowing fluid, the following steps are performed:

1) A gas flow rate is established, and permeability is calculated from observed flow parameters;

2) Another flow test is conducted at a different rate (different P), and permeability is recalculated;
3) Calculated permeabilities are plotted versus the reciprocal of P (pressure is always measured in terms of atmospheric pressure in units of atmospheres) and extrapolate to p→∞, i.e., y-intercept, which gives the equivalent liquid permeability.

The klinkenberg correction to reduce gas permeability varies with the magnitude of the absolute permeability. Actually, the constant *b* declines with increasing absolute permeability. Several correlations have been developed, the most recent by Jones (1972) are,

$$\begin{aligned} b\{psi\} &= 6.9 k_L^{-0.36}\{md\} \\ b\{kPa\} &= k_L^{-0.36}\{md\} \end{aligned} \tag{3.2}$$

Also the Klinkenberg effect declines with increasing pressure. At most reservoir values of permeability and pressure, the Klinkenberg effect is insignificant. However, in tight gas reservoirs with low pressure, the effect may be noticeable. The following example illustrates the effect.

Example 3.1

A gas flow experiment is conducted at two mean pressures:

Case 1 uses P = 150 psia = 10 atm; Case 2 uses P = 30 psia = 2 atm.

The rock used in the experiment has a true absolute permeability of 1.0 md, and the gas viscosity, although truly not the same at both pressures, can be taken as constant at 0.01 cp. For a rock of 1.0 md permeability, literature correlations estimate Klinkenberg's b-factor to be approximately 1.0.

Solution

Therefore, for Case 1, the apparent gas permeability is calculated to be

$$k_g = 1\left(1 + \frac{1}{10}\right) = 1.1 md$$

The difference is 10%, and this would be a 10% error from the true absolute value if the gas flow test had been conducted to compute permeability without making any corrections.

For Case 2,

$$k_g = 1\left(1+\frac{1}{2}\right) = 1.5\text{md}$$

This difference of 50% would lead to a significant error in calculated permeability if Klinkenberg's effect were neglected.

The Klinkenberg effect is also dependent on gas composition as shown in Figure 3.4.

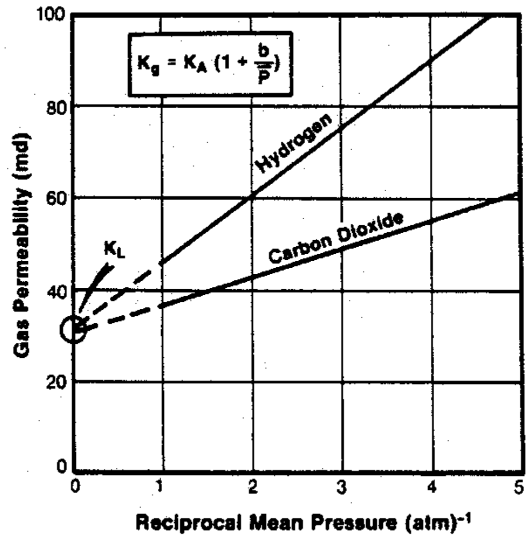

Figure 3.4 Effect of gas composition on air permeability

The different molecular sizes of the gases result in different slopes (various air permeability vs. pressure). Fortunately, the equivalent liquid permeability is unchanged.

A last parameter which affects slip is the magnitude of the confining pressure. Figures 3.5 and 3.6 illustrate this effect for the same core sample. The top diagram shows an increase in confining pressure will decrease the air permeability. The bottom diagram shows the decrease in k_L with an increase in confining pressure. This example confirms the need to perform core tests at confining pressures to represent the insitu stress state of the rock.

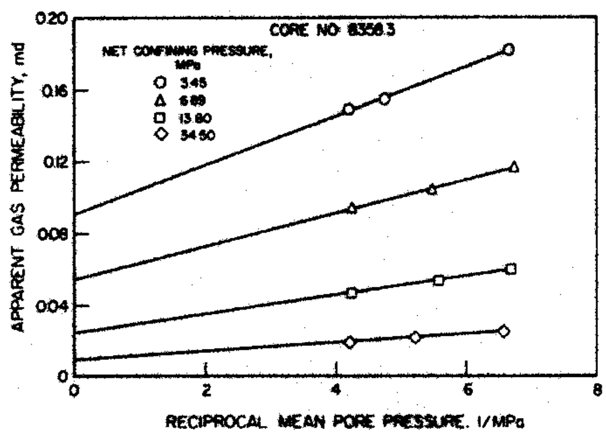

Figure 3.5 Effect of confining pressure on gas slip [Katz & Lee, 1990]

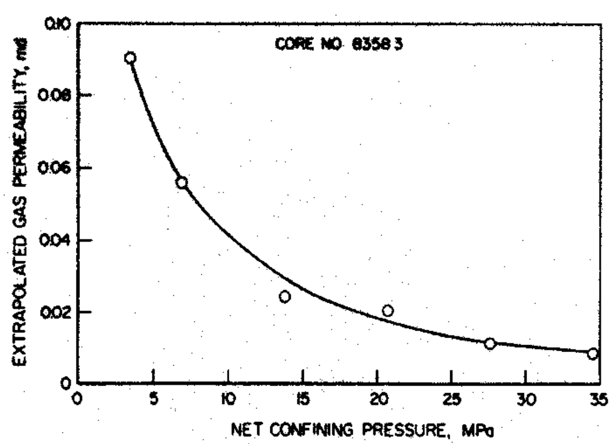

Figure 3.6 Effect of confining pressure on extrapolated gas permeability [Katz & Lee, 1990}

3.2.2 Effect of overburden pressure

We have already discussed the effect of overburden pressure on porosity in Sec. 2.4 and its effect on slip in Sec. 3.2.1. With increasing confining pressure the absolute permeability of the rock will also decrease. This is in response to the reduction in the pore throats; subsequently reducing the ability of the porous media to transmit fluids. The strength or competency of the rock therefore plays a role in the magnitude of the permeability reduction. Figure 3.7 illustrates the permeability reduction for well-cemented, friable, and unconsolidated rocks.

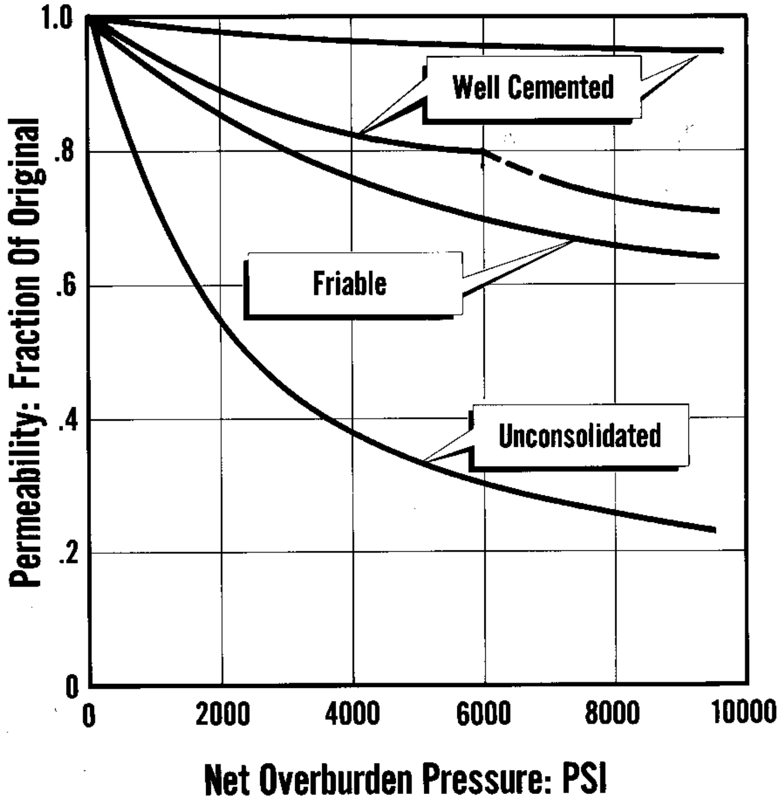

Figure 3.7 Permeability reduction with overburden pressure [CoreLab, 1983]

As shown on the figure, well consolidated rock has a high modulus of rigidity and does not reduce in volume significantly under confining pressures. The change in slope for the second sample could be due to crushing of the sand grains or fracture closure point. Permeability measurements are normally made on samples of this type with only an adequate confining pressure to prevent bypass of the flowing fluid around the sample. Unconsolidated or poorly consolidated rock undergoes much greater reduction of permeability under confining pressure. Reductions as great as a factor of four are observed in Figure 3.6.

In general, for a given rock type, well cemented or unconsolidated, a greater percentage of reduction in permeability will be effected in lower pemeability rock than in higher permeability rock. Figure 3.8 shows severe permeability reduction for the low permeability rock, while for samples with k > 10 md, the effect is minimal.

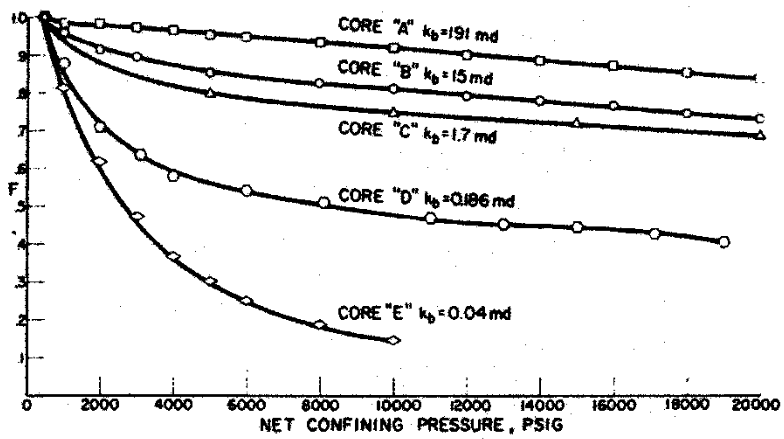

Figure 3.8 Impact of confining stress on samples with varying permeability [Katz&Lee, 1990]

3.2.3 Reactive Fluids

Many porous reservoir rocks contain clay material that swell on contact with fresh water. Naturally occurring saline connate waters do not cause such swelling, but drilling operations or laboratory procedures may introduce fresh water into the rock matrix. If water-sensitive clays are present, the resulting swelling can reduce the rock's permeability by several orders of magnitude.

This phenomenon in itself does not invalidate Darcy's Law, it simply makes the correct determination of permeability more difficult in laboratory flow tests that rely on Darcy's Law to calculate permeability.

The factors important in clay-water reaction include the following:

a. type of clay
b. amount of clay
c. distribution of clay
d. water composition
e. order in which fluids contact the rock
f. presence of residual hydrocarbons
g. water pH

Figure 3.9 shows that an increase in clay content will decrease the permeability. Also, the fresher the water, the more clay swelling, and therefore a greater reduction in permeability occurs in the sample.

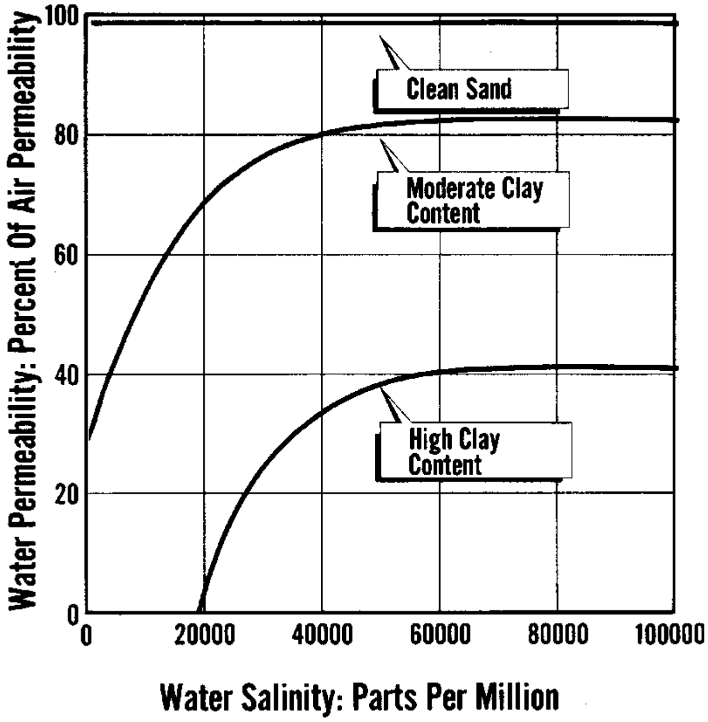

Figure 3.9 Variation in water permeability with salinity and clay content [CoreLab,1983]

The choice of drilling fluids and the use of air drilling or cable tool completions are influenced by the need to keep foreign waters away from some reservoir rocks. However, it may be ascertained that the chemistry of a given reservoir system permits contact with aqueous solutions without reduction of the permeability. Formation clays may be stabilized with hydroxy-aluminum solutions.

Recent literature has proved that particle movement is a prime mechanism for permeability reduction. The aqueous phase apparently makes clay particles mobile, and when they flow, they bridge at small cross sections causing flow stoppage; by reversing flow, permeability can be renewed temporarily. In Figure 3.10 particle movement is suspected after the flow direction is reversed due to the permeability reduction over time as particles move and plug pore spaces.

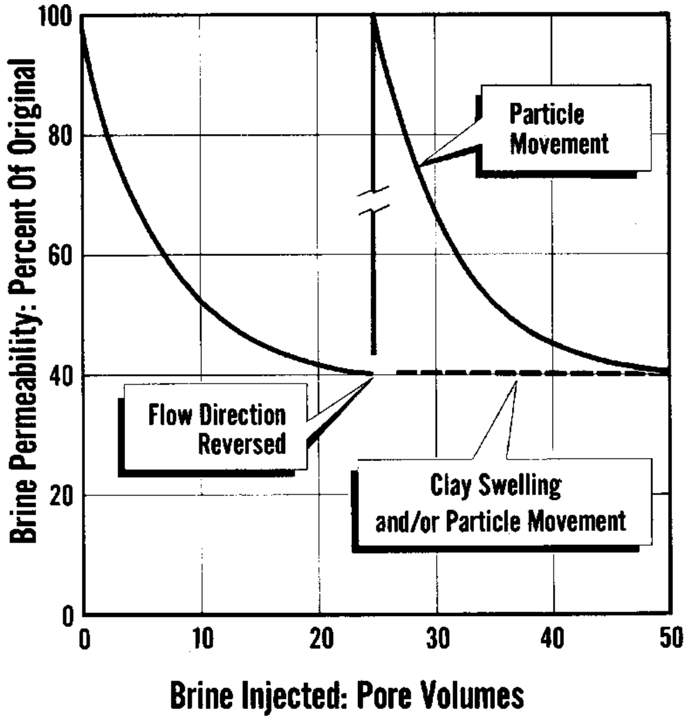

Figure 3.10 Permeability reduction due to clay swelling and/or particle movement [CoreLab,1983]