Chapter 6: Single Phase Permeability

6.1 Introduction and Definition

Permeability is a property of a porous medium that characterises the ease which fluids flow though it in response to an applied fluid pressure gradient.

The primary objective for permeability measurements applied to the hydrocarbon industry is that they should be *fit for purpose*. In this case the purpose is to provide data that can be used in accurate and effective reservoir modelling. If the reservoir model is to be used to help the understanding of a dry gas reservoir at ambient conditions, then horizontal air permeability measurements at ambient conditions will be fine. However, the reservoirs that are of interest are rarely so simple, and it should be our aim to build multi-phase models capable of modelling oil reservoirs at *in situ* conditions. Fluid permeabilities measured at or corrected to relevant reservoir conditions using relevant fluids are essential inputs if such models are to be representative of the reservoir. The fluid saturation and number of mobile fluids have a great effect on permeability, reducing it below that for a dry rock containing a single fluid. This section will deal with single phase fluid permeabilities. In particular the gas and Klinkenberg permeability measurements that are made as part of RCAL, and the single phase liquid permeabilities that are part of the more complex relative permeability SCAL tests, but which are sometimes carried out on their own as part of RCAL.

6.1.1 Basic Definitions

Feynmann once said that, for a scientific measurement to be successful, the scientist or engineer must know exactly what he or she is measuring. This comment has many implications for the scientist. For the reservoir engineer/petrophysicist it requires that the meaning of permeability is understood. So back to basics; permeability characterises the ease with which fluids flows through a medium in response to a fluid pressure gradient. However, permeability is not measured directly, but calculated from other physical measurements with various theoretical and empirical relationships. The dependence on these relationships has the implication that the resulting permeabilities are dependent on various assumptions and boundary conditions. The relationship used in the hydrocarbon industry is the empirically derived Darcy's Law in 1856, derived using the apparatus shown in Figure 6.1.

$$q = K\,A\,\frac{\Delta h}{L} = K\,A\,\frac{(P_{in} - P_{out})}{L} \tag{6.1}$$

where: q = water flow rate

A = cross-sectional area of sand pack

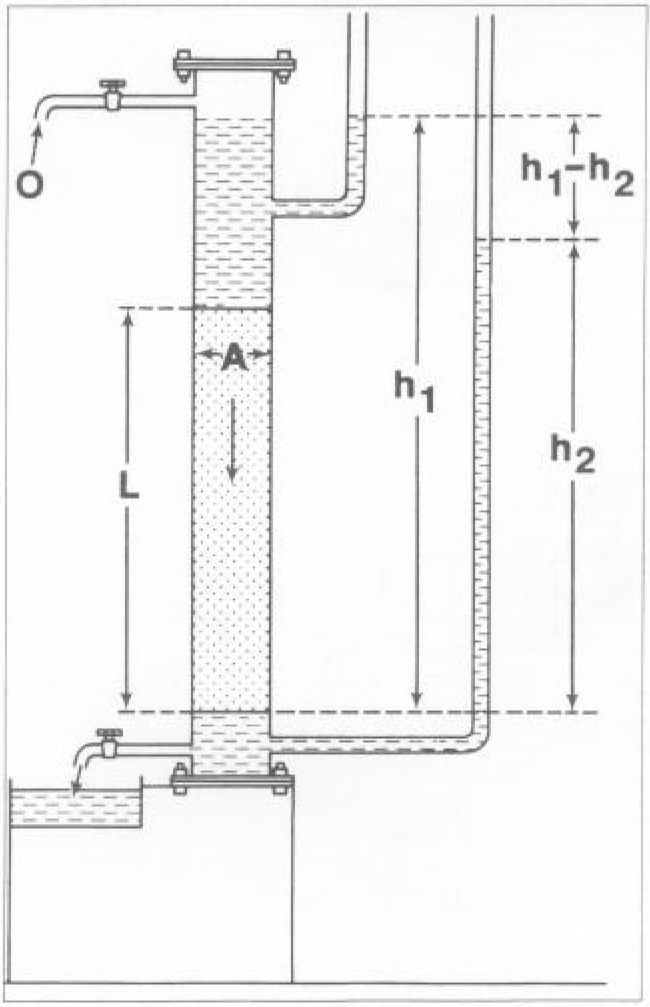
L = length of sand pack

Δh = difference between the water heights in the manometers in Figure 6.1 (h_1-h_2)

K = A constant of proportionality characteristic of the sand pack (permeability)

P_{in}-P_{out} = fluid pressure gradient.

Figure 6.1 Modified Schematic Diagram of Darcy's Apparatus (after Hubbert, 1953)



The units of permeability used in the oil industry are the 'darcy', D, and the 'millidarcy', mD. It is worth noting that the S.I. unit of permeability is in per metres squared (m^{-2}), and shows that there is an implicit spatial scaling of permeability in the measurement itself. This fact is often overlooked when we use core measurements made at core plug scale (core volume approximately 40 cm^3), and then happily (and naively) compare it directly with logging measurements, whose scale volume (volume of sensitivity) is 15000 cm^3, and model reservoir wide processes, whose scale volume may be approximately 10^{15} cm^3! A permeability of 1 D allows the flow of 1 cm^3 per second of water with 1 centipoise, cP, viscosity, through a cross-sectional area of 1 cm^2, when a pressure gradient of 1 atmosphere pressure per centimetre is applied. (1 D ~ 10^{-12} m^{-2}.)

It should be understood that Darcy's law, Eq. (6.1), was derived for unconsolidated sand packs, assumes unreactive aqueous fluids with constant properties, and requires correction for the different viscosity of different fluids, and correction for gas slippage (Klinkenberg effect) and inertial effects (Forchheimer effect) if used with gaseous fluids. In practice it is applied to all rocks even though it is not clear that this is a valid extrapolation. One should, therefore, always question the accuracy of a core permeability measurement. The law, Eq. (6.1), has been extended for practical use in the following ways:

- Inclusion of a fluid dynamic viscosity so that unreactive fluids other than brines can be used.
- Rewriting the Δh term in terms of absolute pressures.
- Writing the flow rate, q, as volume flow per time (q=V/t).
- Inclusion of a constant to take account of the units commonly used in measurement.

Thus the working equation for measuring single phase liquid permeabilities in the hydrocarbon industry is:

$$K(mD) = 1000\ m\ \frac{L}{A}\ \frac{V}{t}\ \frac{1}{\left(P_1 - P_2\right)} \qquad (6.2)$$

If gas is used we must take account of the compressibility of the gas giving the working equation for measuring single phase gas permeability in hydrocarbon industry RCAL:

$$K(mD) = 2000\ m\ \frac{L}{A}\ \frac{V}{t}\ \frac{P_{atm}}{\left(P_1^2 - P_2^2\right)} \qquad (6.3)$$

where:

K	=	permeability, (millidarcies, mD)
m	=	viscosity, (centipoise, cP)
L	=	plug length (cm)
A	=	plug cross section (cm^2)
V	=	volume of fluid passed in t seconds (cm^3)
t	=	time (seconds)
q	=	Flow rate, q=V/t, $cm^3 s^{-1}$
P_1	=	inlet pressure (atmospheres absolute)
P_2	=	outlet pressure (atmospheres absolute)
P_{atm}	=	atmospheric pressure (atmospheres absolute)

Gas permeability measurements are the most common RCAL permeability measurements. These measurements suffer from two problems that are not encountered with liquid permeabilities. These are the Klinkenberg and Forchheimer effects.

6.1.2 The Klinkenberg Effect

Darcy's modified law for gases Eq. (6.3) is not applicable at low gas pressures (gas densities). This is because, at such low pressures, the mean free path of the gas molecules become larger than the pore dimensions. When this happens, the gas cannot be considered to be a continuous medium and fluid mechanics cannot be used reliably. In practice the effect causes measured permeabilities to be overestimated at low pressures (Figure 6.2a). In the low density (gas pressure) limit the permeability is expressed as:

$$K_{app} = K_L \left(1 + \frac{a}{P}\right) \qquad (6.4)$$

Here the apparent or measured permeability K_{app} is dependent on the so-called Klinkenberg permeability K_L, the gas pressure P and a constant known as the slip factor, α. The standard solution to the problem involves the following steps:

- Repeating the measurement of gas permeability, K_{app}, at four or five different gas inlet pressures, P_1 and gas outlet pressures, P_2.
- Calculating the mean gas pressure in the core for each determination; $P_{mean} = (P_1 + P_2)/2$.
- Plotting K_{app} against $1/P_m$.

Figure 6.2a Gas Permeabilities as a Function of Fluid Pressure Difference

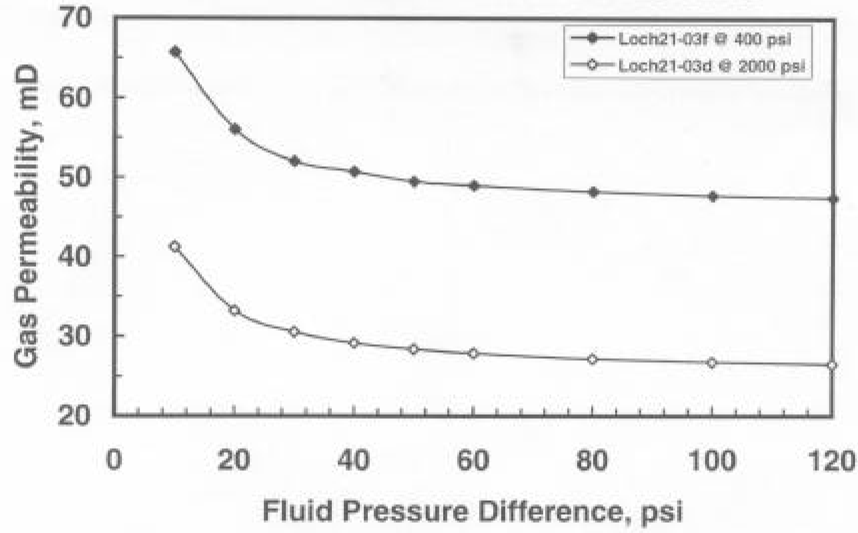
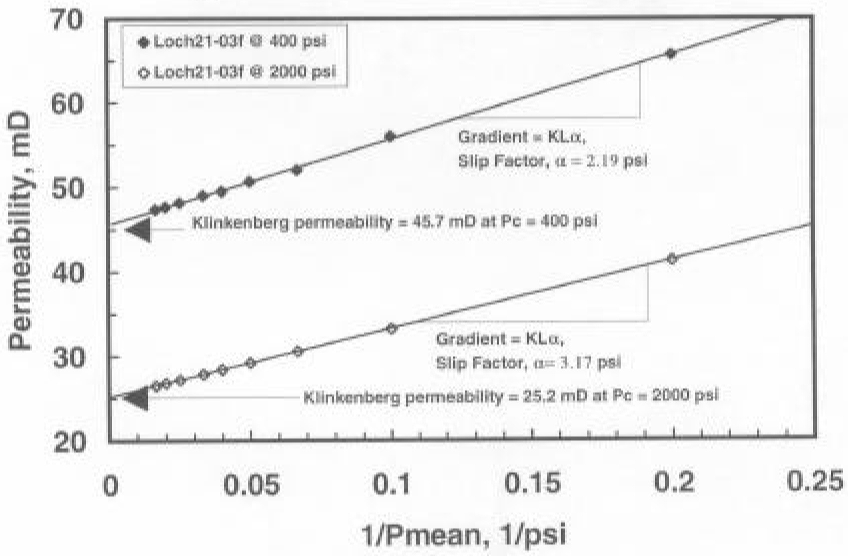


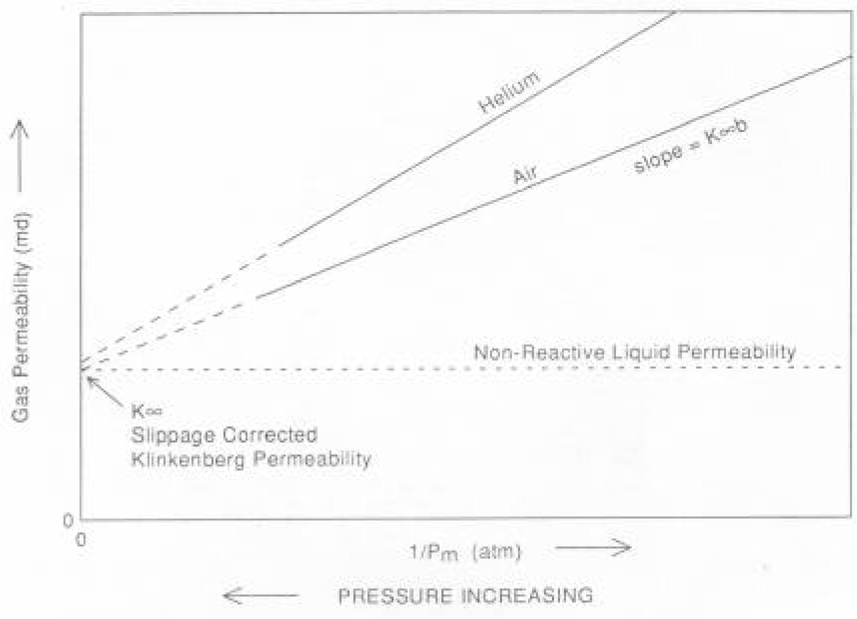
Figure 6.2b The Klinkenberg Plot



The resulting plot is a straight line with a positive gradient (Figure 6.2b). The intersection of the curve with the x-axis at $1/P_m = 0$ gives K_L . The Klinkenberg permeability is independent of gas pressure, and is effectively the permeability of the gas as $P \rightarrow \infty$, i.e. the permeability for a near perfect liquid (an infinitely compressed near perfect gas). The values of apparent permeability depend on the type of gas used even though their different viscosities are taken into account in the calculation of apparent permeability. However, the Klinkenberg permeability is independent on the type of gas used as all gases have the same properties in the $P \rightarrow \infty$ limit (Figure 6.2c). This makes the Klinkenberg permeability very useful, for it can be compared for different samples that had their gas permeabilities measured with different gases at different gas pressures. The Klinkenberg permeability should be approximately the same as the permeability of the rock when 100% saturated with a single phase reservoir liquid such as water or oil. The gradient of the Klinkenberg plot gives the slip factor, which can be used to characterise the rock microstructure.

The Klinkenberg correction should be applied to all core analysis measurements without fail.

Figure 6.2c Klinkenberg Permeability for Different Gases



Note that the use of different gases results in different values of apparent gas permeability for any given gas pressure in the core. However the Klinkenberg plots show that the curves converge to the same Klinkenberg permeability. The Klinkenberg permeability is that for a perfect liquid, which is independent of the gas used.

6.1.3 The Forchheimer Effect

At high gas flow rates (high differential pressures P_1-P_2), the gas accelerates through pore throats and decelerates in pore bodies sufficiently for the gas inertia to cause turbulence. Darcy's law is an approximation of Navier-Stokes law, both of which require flow to be laminar. Thus when the flow rate is fast enough for the flow to be turbulent, neither work. In practice such high flow rates are avoided in all core analysis measurements. If they are encountered they show up as underestimates in gas permeability measurements that are recognised as an increase in the gradient of the K versus $1/P_m$ curve at low values of $1/P_m$.

6.1.4 Averaging Permeabilities

It has been shown that the most probable permeability behaviour of a heterogeneous porous medium made up of n randomly distributed regions of differing uniform permeabilities, K_1 to K_n, is described by the *geometric* mean of the individual permeabilities, which corresponds to the mode of a log-normal distribution:

$$K_g = \sqrt[n]{K_1 \cdot K_2 \cdot K_3 \cdots K_n} \qquad (6.5)$$

The analysis is extremely complex. However, it is possible to analyse two simple systems of different permeabilities that occur within core analysis and reservoir systems. These are (i) flow through linear beds in series, and (ii) flow through linear beds in parallel.

Linear Beds in Series. The system is shown in Figure 6.3a. The beds have a cross-sectional area A that is constant. Each bed has a thickness, T_i , and a uniform permeability K_i. The pressures at the contact between each of the beds, P_i. can be analysed thus:

$$(P_1 - P_4) = (P_1 - P_2) + (P_2 - P_3) + (P_3 - P_4) \qquad (6.6)$$

Now using Eq. (6.1) with Δh replaced by the pressure difference, and noting that the thickness of the total unit T is equal to the sum of the individual beds T_1 etc., we get:

$$\frac{q\ T}{\overline{K}\ A} = \frac{q\ T_1}{K_1\ A} + \frac{q\ T_2}{K_2\ A} + \frac{q\ T_3}{K_3\ A} \qquad (6.7)$$

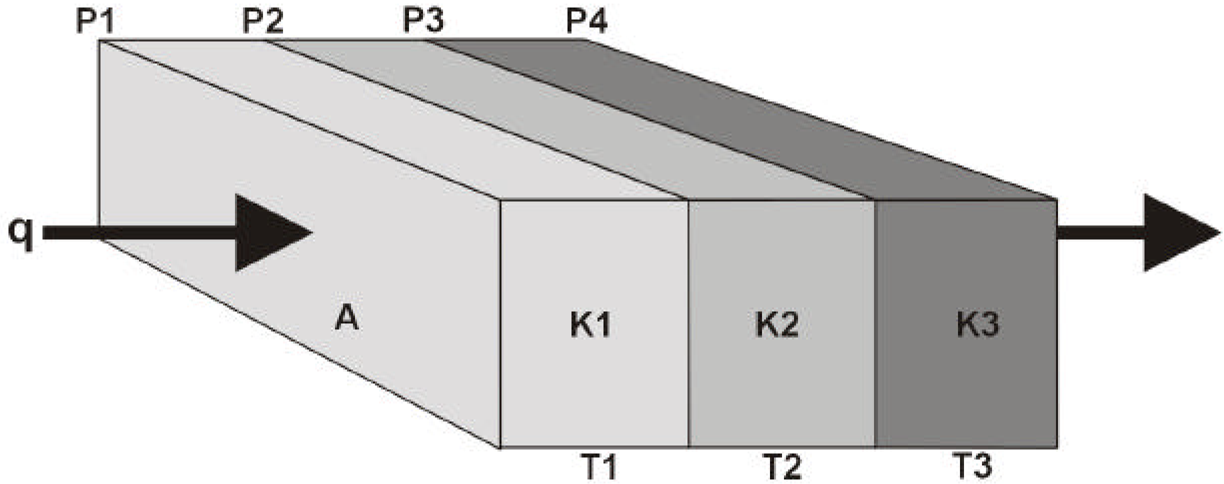
Rearranging we find that the mean permeability is the harmonic average of the individual permeabilities:

$$\overline{K}_h = \frac{T}{\sum_{i=1}^{n}\{T_i / K_i\}} \qquad (6.8)$$

For example analysing Figure 6.3b, where three layers of equal thickness T=1 m have permeabilities 1000 mD, 200 mD, and 1 mD, we get the mean permeability equals 2.98 mD!

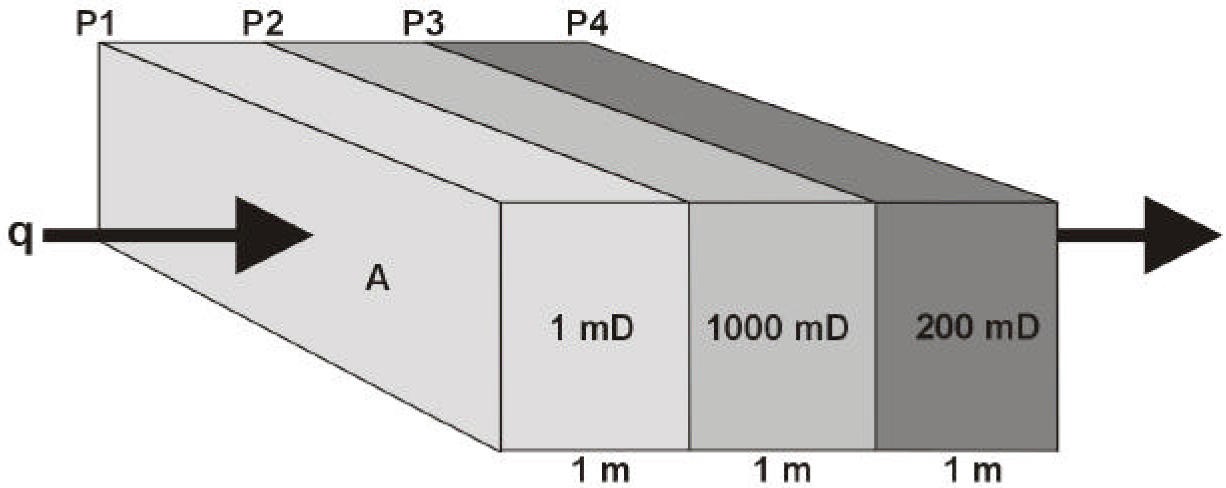
Figure 6.3a and 6.3b
Averaging Permeabilities

(a)



Linear Beds in Series (General Case)

(b)

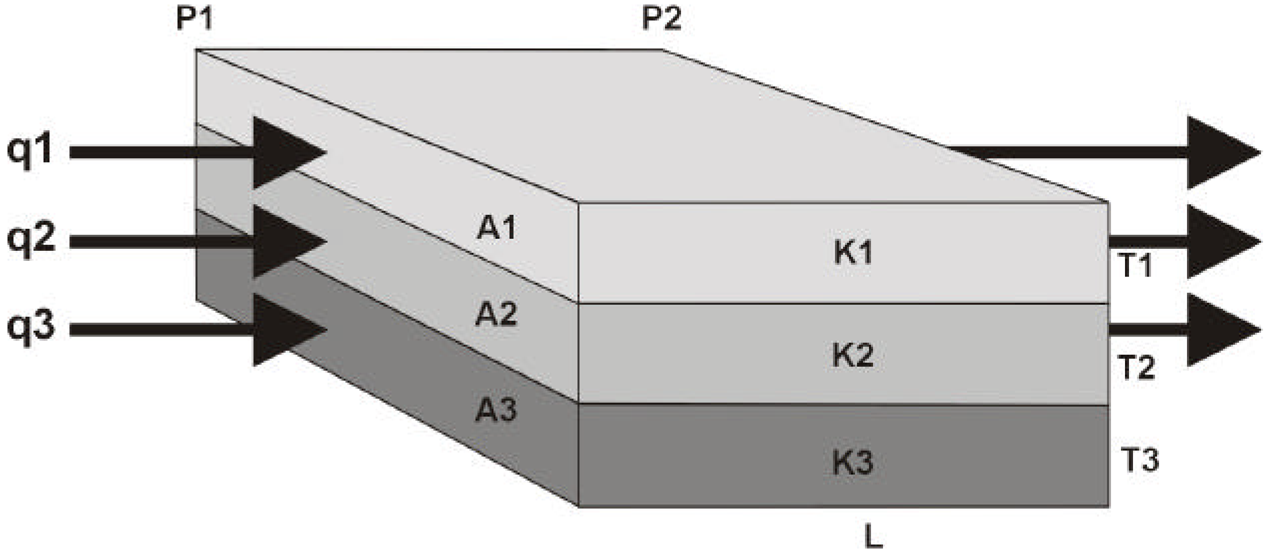


Linear Beds in Series (Example)

Mean Permeability = 2.98 mD

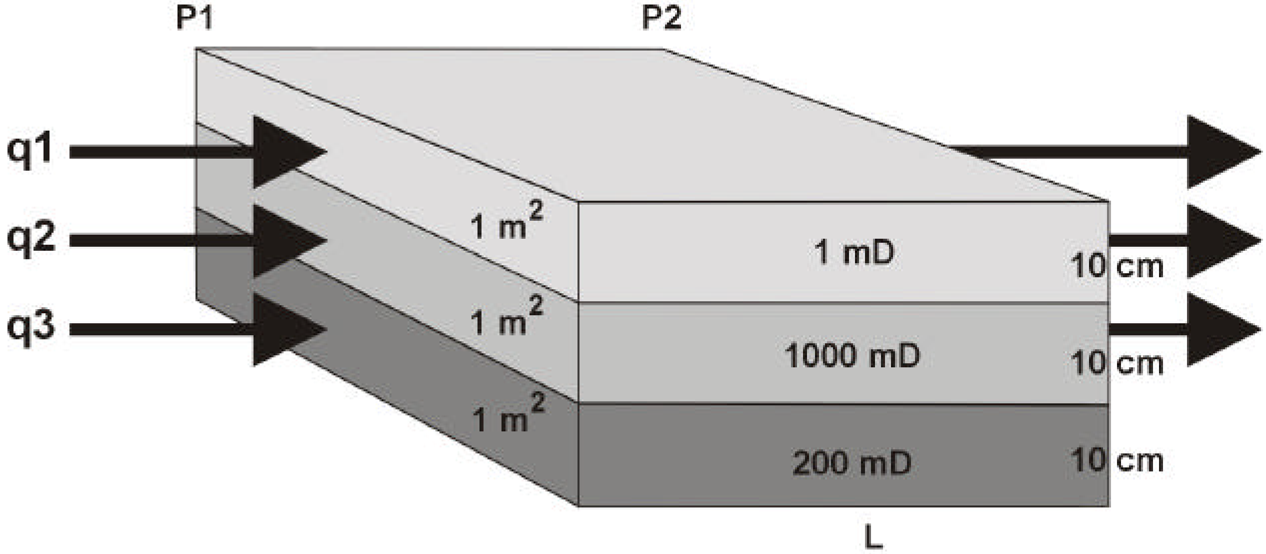
Figure 6.3c and 6.3d
Averaging Permeabilities

(c)



Linear Beds in Parallel (General Case)

(d)



Linear Beds in Parallel (Example)
Mean Permeability = 400 mD

Clearly the permeability is controlled by the smallest permeability because all the fluids that pass easily through the higher permeability layers are held up by the low permeability layer.

Linear Beds in Parallel. The system is shown in Figure 6.3c. The beds have a thickness T that is constant. Each bed has a cross-sectional area to flow, A_i , and a uniform permeability, K_i. The pressures at the inlet P_1 and outlet P_2 of the complete unit will be the same for all layers, but each layer will transport a different fraction q_i of the total flow rate q_t thus:

$$q_t = q_1 + q_2 + q_3 \tag{6.9}$$

Now using Eq. (6.1), with Δh replaced by the pressure difference and noting that the total area $A = A_1+A_2+A_3$, we get:

$$\frac{\overline{K}\,A\left(P_{in}-P_{out}\right)}{T} = \frac{K_1\,A_1\left(P_{in}-P_{out}\right)}{T} + \frac{K_2\,A_2\left(P_{in}-P_{out}\right)}{T} + \frac{K_3\,A_3\left(P_{in}-P_{out}\right)}{T} \tag{6.10}$$

Rearranging we find that the mean permeability is the arithmetic average of the individual permeabilities:

$$\overline{K}_a = \frac{\sum_{i=1}^{n} K_i\,A_i}{A} \tag{6.11}$$

For example, analysing Figure 6.3d, where three layers of equal area $A = 1\ m^2$ have permeabilities 1000 mD, 200 mD, and 1 mD, we get the mean permeability equals 400 mD! The mean permeability falls much more into the mid range because the fluids partition for flow into each of the layers depending on its permeability. In this case, the layer with the highest permeability conducts 83.3% of the flow.

For comparison, the geometric mean of equal volumes of 1000 mD, 200 mD, and 1 mD is 10.6 mD, which falls between the two extreme cases analysed above, and represents random arrangement of equal volumes of material with these three permeabilities.

6.1.5 Notes on RCAL Permeabilities

Gas permeabilities corrected for the Klinkenberg effect are commonly used, however this measurement provides the *most optimistic* values of permeability mainly due to the measurement being done for; (i) single phase gas fluids that are not representative of the true reservoir fluids, (ii) low overburden pressures and temperatures that are not representative of the *in situ* reservoir conditions, and (iii) cleaned dry rocks. Other measurement methods account for these problems, but are more expensive, and often we are asked to use Klinkenberg permeabilities where better measurements are unavailable. It is therefore important for us to understand the factors affecting the determination of permeability measurements, such that the quality and relevance to the problem of any permeability dataset can be assessed.

The factors affecting core permeability measurements fall into three broad categories; (i) planning errors, (ii) sample errors, (iii) measurement errors, and (iv) analysis errors. *Planning errors* are the fault of the person who commissions the permeability study. It is very tempting to order a standard routine core analysis study. However, resources and time can be saved by the commissioning manager thinking carefully about the purpose that the data is required for. Klinkenberg permeabilities should not be used to estimate the efficiency of a waterflood, yet some companies do so by correcting them to effective relative permeabilities using rules of thumb that do not take account of the fluids and reservoir wettability adequately. *Sample errors* are associated with; (i) sampling frequency, location, orientation, type and size; all of which affect how representative the 40 cm^3 sample is of the properties of the 10^{15} cm^3 sized reservoir, (ii) the type of drilling fluids, and (iii) the state of preservation and the process of cleaning and drying, which can affect permeability greatly in shaly sandstones. *Measurement problems* are related to the accurate measurement of pressure and flow, and are dependent both on the initial experimental rig design as well as the permeameter operator. Finally, *Analysis problems* involve the relevant use of the derived data and close the circle to the planning stage. The indiscriminate lumping together of permeability data from different measurement techniques, bad poroperm cross-plot analysis, and inefficient core-log correlation of poroperm data, all contribute to inaccurate analysis, and almost always are the result of either ignorance of the meaning and limitations of permeability data, or an effort to ‘make do’ with irrelevant data resulting from poor permeability study planning.

6.2 Controls on Permeability

6.2.1 Porosity

There have been several attempts to derive a general relationship between porosity and permeability. In many ways, however, all attempts are bound to fail at a fundamental level since porosity is a scalar measurement and permeability is a vector measurement. Clearly though it is reasonable to assume that permeability should increase with porosity in unfractured reservoirs without significant diagenetic. One of the most well known models linking porosity and permeability is known as the Kozeny-Carman model that considers the porous media to be made up of bundles of capillary tubes. The basic equation is:

$$K_{KC} = \frac{c\, d^2\, f^3}{(1-f)^2} \qquad (6.12)$$

where:

K_{KC}	=	Kozeny-Carman predicted permeability, mD
c	=	A constant
d	=	Median grain size diameter, microns
f	=	Effective porosity

Despite the obvious invalid capillary tube assumptions, this model remains one of the best predictors of permeability, and is often used in the hydrocarbon industry.

Another commonly used empirical model is that of Berg:

$$K_B = d^2 \, f^{5.1} \tag{6.13}$$

where K_B is the predicted permeability. Although this empirical model has been concocted from a range of rocks and it is clear that the equation may not work on samples from other locations.

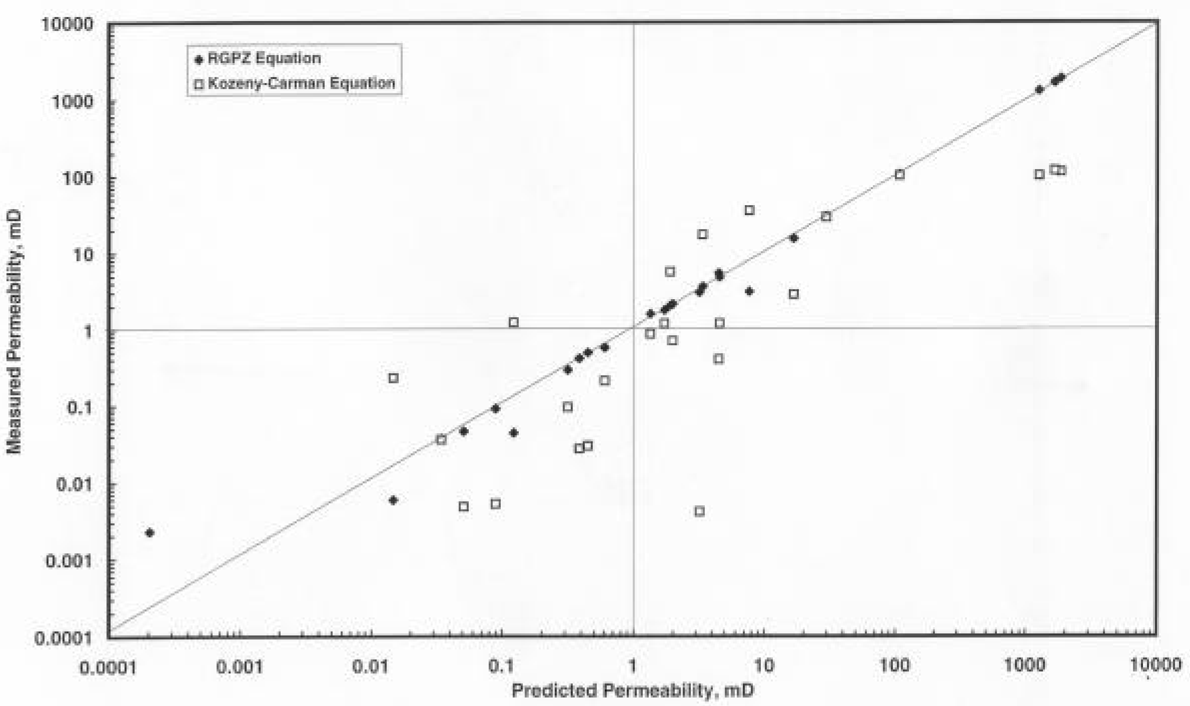
Recently, a new model has been proposed by Revil, Glover, Pezard and Zamora (RGPZ). This is a non-empirical model that is derived from the fundamental understanding of the electro-kinetic properties of rocks, and hold the potential for improved permeability prediction for rocks of different porosities, grain sizes, and pore tortuosities. It is expressed as:

$$K_{RGPZ} = \frac{d^2 \, f^{3m}}{4 \, a \, m^2} \tag{6.14}$$

where:

K_{RGPZ}	=	RGPZ predicted permeability, D
m	=	The cementation exponent
d	=	Median grain size diameter, microns
a	=	Grain packing index
f	=	Effective porosity

Figure 6.4 Permeability Prediction using the Kozeny-Carman equation, and the RGPZ equation



Note that all of these models use a grain size diameter to scale the predicted permeability to the size of rock microstructure, and to ensure that the models are dimensionally correct. Figure 6.4 compares the three models described above for a range of clean sandstone, shaly sandstone, and carbonate samples. Lines are placed at 1 mD in Figure 6.4; rocks with permeabilities less than this value are considered to be non-reservoir rock (i.e. unproducible economically).

6.2.2 Bedding

Permeability is a vector property, and as such, is greatly affected by directional heterogeneity within core samples. The commonest cause of such heterogeneities is bedding. It is a general rule that the vertical permeability within a reservoir (i.e. that perpendicular to the bedding) is lower than that in the bedding plane (horizontal permeability). In fact the vertical permeability is often about a third of that in the horizontal direction. It should also be noted that some of the difference between the vertical and horizontal permeabilities results from differences in the way the local stress fields in the vertical and horizontal directions compact pores and close microcracks.

6.2.3 Pore Geometry

Permeability is highly dependent on the tortuosity of the pore fluid flow paths. Tortuosity can be affected by many rock characteristics, including:

- Grain size and its distribution
- Grain shape
- Sorting
- Grain orientation
- Packing arrangement
- Degree and type of cementation
- Amount, orientation and connectivity of micro-fractures
- Clay content
- Bedding
- Diagenesis

The detailed relationships are known only qualitatively, and the relative importance of each vary from rock type to rock type. For example, the permeability of carbonates is primarily controlled by; (i) dissolution porosity, (ii) dolomitization, and (iii) fractures.

6.2.4 The Stress Conditions

Permeability is very sensitive to stresses that compact the rock. This compaction can occur in any direction not just vertically. However, vertical compaction is usually the most important. Indeed the local stress state may be such that dilatancy occurs (formation of fractures) increasing the permeability of the rock. In all cases it is poorly consolidated rocks that are affected to the greatest extent. Figure 6.5a and b show the effect of increasing the hydrostatic confining pressure on the permeability of a rock. Figure 6.5c compares the effect of overburden stress on permeability compared to the effect upon porosity. It can be seen that overburden stress affects permeability much more than porosity. This is because permeability is very sensitive to the tortuosity of fluid flow paths through the rock, and such changes are associated with very small changes to the rock porosity Overburden stress compacts the rock pressing the grains together. The size of the pores reduces little, but the pore throats that control the passage of gas between the pores undergo much greater closure, effecting the permeability to a greater extent.

Figure 6.5a Effect of Overburden Pressure on Permeability

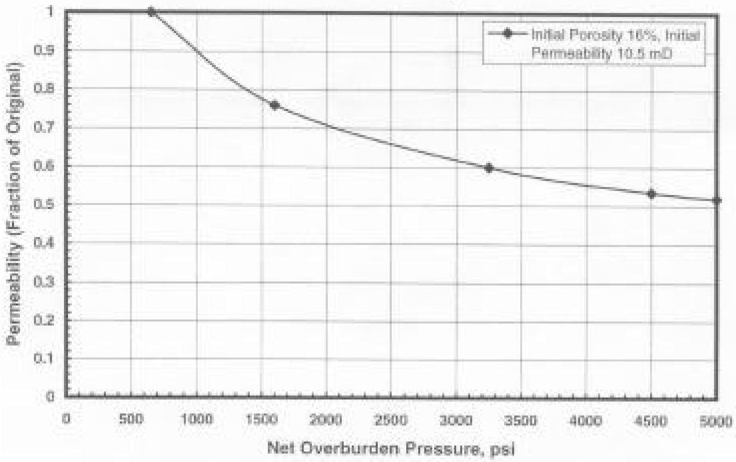
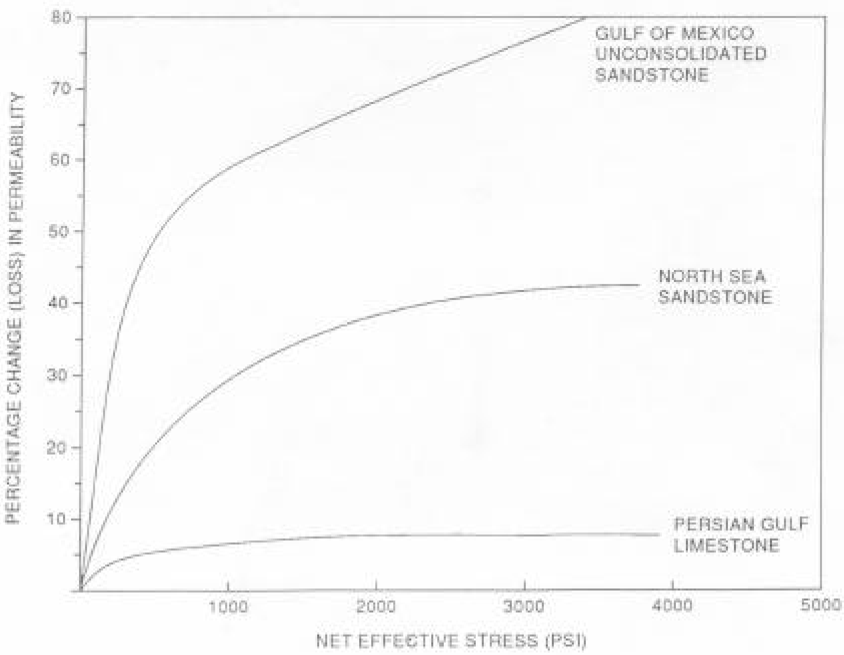
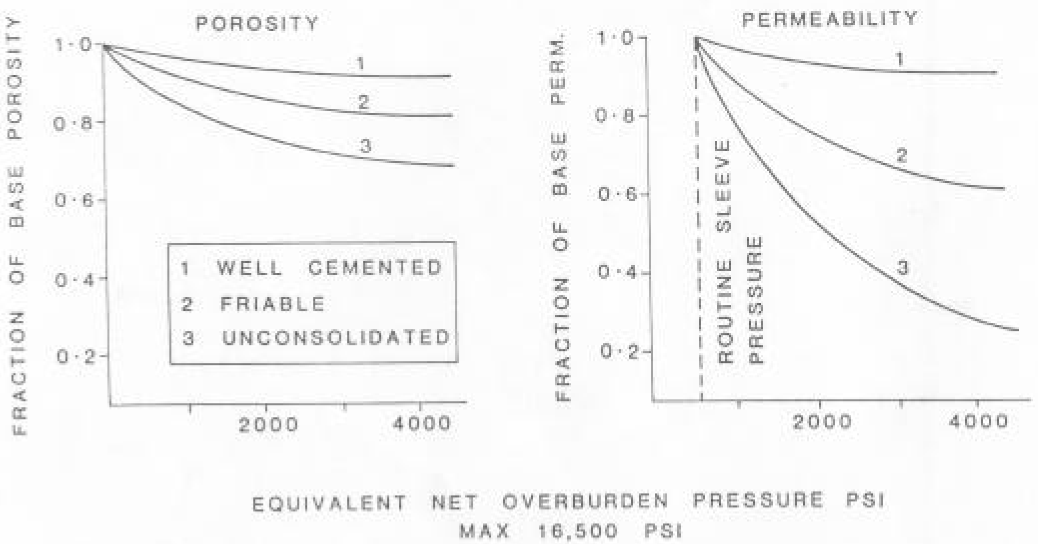


Figure 6.5b Change in Permeability due to Overburden Pressure for Three Different Rock Types



The large decreases observed indicate that it is very important to apply corrections to permeabilities measured at low confining pressures before they are considered to be representative of the reservoir, or measure the permeability at reservoir stress conditions in the first place (SCAL). It should also be noted that fracturing (both macroscopic and micro-fractures), that increases the permeability of the rock samples when measured in the laboratory, can be caused by drilling and concomitant upon the sudden reduction in stress experienced by the rock upon extraction of the core from the well. These fractures can be closed again by measuring the rock at reservoir conditions, but it is very difficult to know how to correct low pressure Klinkenberg permeability determinations for such fracturing.

Figure 6.5c Comparison of the Effect of Overburden Pressure on Porosity and Permeability



Note the much larger effect on permeability than on porosity due to the extreme sensitivity of permeability on the tortuosity of the pore structure.

6.3 Laboratory Determinations

6.3.1 Steady State Gas Permeability Determinations

Routine permeability measurements are made by confining plugs in Hassler core holders, Figure 6.6, applying nitrogen pressure to one end and measuring flow rate and pressure differential. Figure 6.7 shows a steady state gas permeability rig that is equipped to measure a large range of permeabilities (i.e. gas flow rates). Standard hydrocarbon industry rigs look similar, but have fewer options for measuring upstream pressure and flow rate.

Figure 6.6 Hassler Coreholder for Gas Permeability Determinations

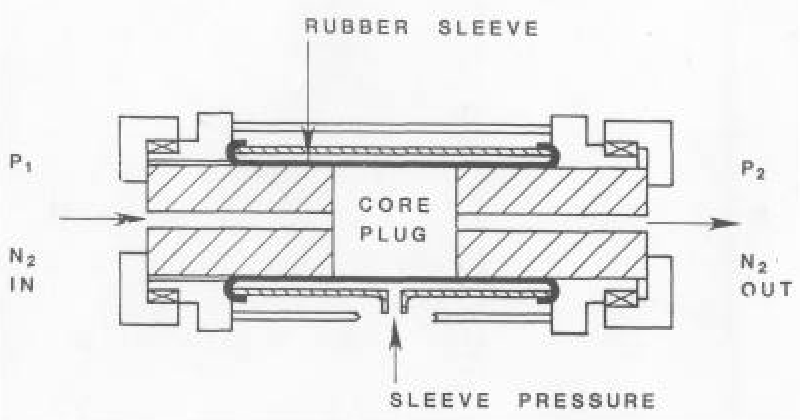
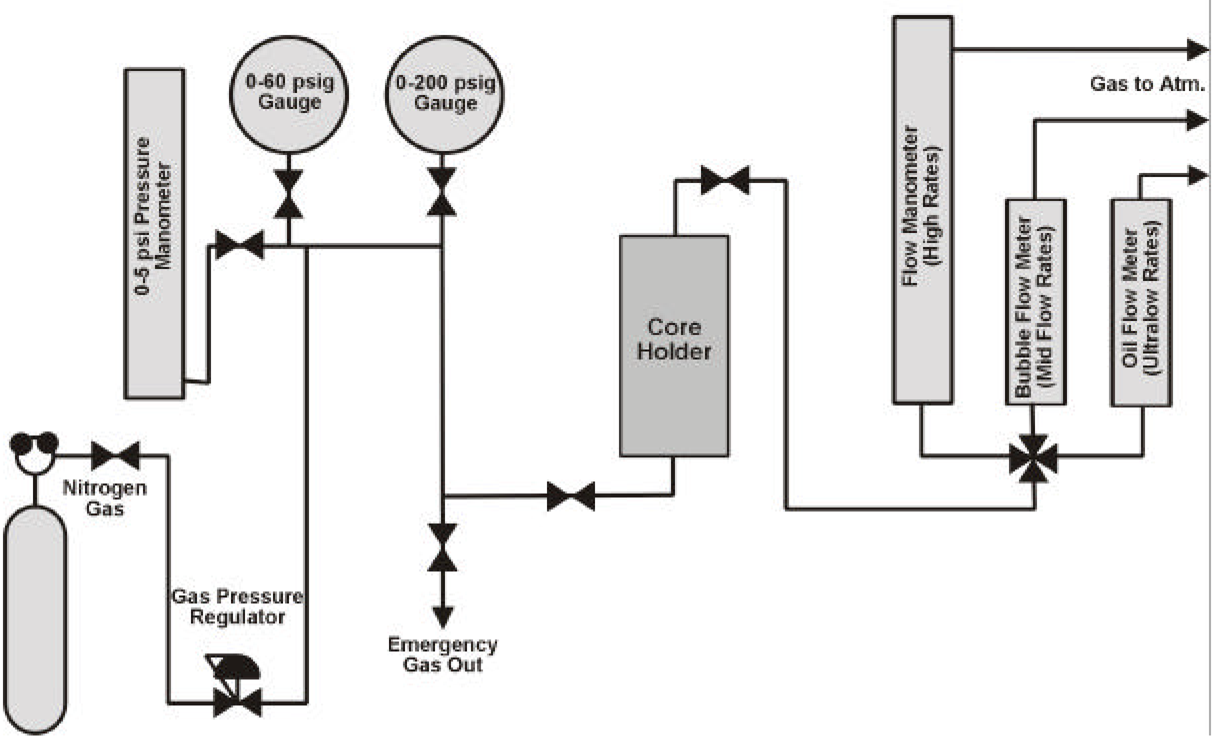


Figure 6.7 Steady State Gas Permeability Rig



For plugs having moderate permeabilities, 5-500 mD, repeat determinations at given confining, inlet and outlet pressures should fall within a few percent. Normally four or five consecutive measurements are made at various mean pressures (P_m) to enable a Klinkenberg plot (Figure 6.2b) of permeability vs. $1/P_m$ to be made. Extrapolation to infinite mean pressure gives the equivalent liquid permeability, K_L. Permeabilities above about 500 mD become less precise as the measured pressure differential falls leading to higher experimental errors. High permeabilities also imply large pores, large grains and rough surface texture.

Very rough surfaces may need wrapping in soft PTFE tape or repair with epoxy to ensure proper sealing by the Hassler sleeve. The sleeve pressure used will depend upon plug surface texture and the hardness of the rubber sleeve. Low permeabilities (less than 5 mD) do not normally present any problems; but for normal reservoir applications, a cut off value of 0.01 mD is applied. Values below this are simply reported as less than 0.01 mD, and are not interesting as a reservoir. In practice rocks with permeabilities less than 1 mD are considered to be non-reservoir rock (i.e. unproducible economically). If cap rocks are being investigated, the actual permeability values will be reported, whatever their permeability. Caution is needed in the handling of friable, poorly cemented samples. Gradual compaction can occur even with sleeve pressures as low as 400 psi. Consequently long equilibration times may be necessary for this type of sample. The first indication of this type of behaviour occurs when carrying out the normal repeat timings of gas flow, when steadily decreasing flow rates are observed.

6.3.2 Unsteady State Gas Permeability Determinations

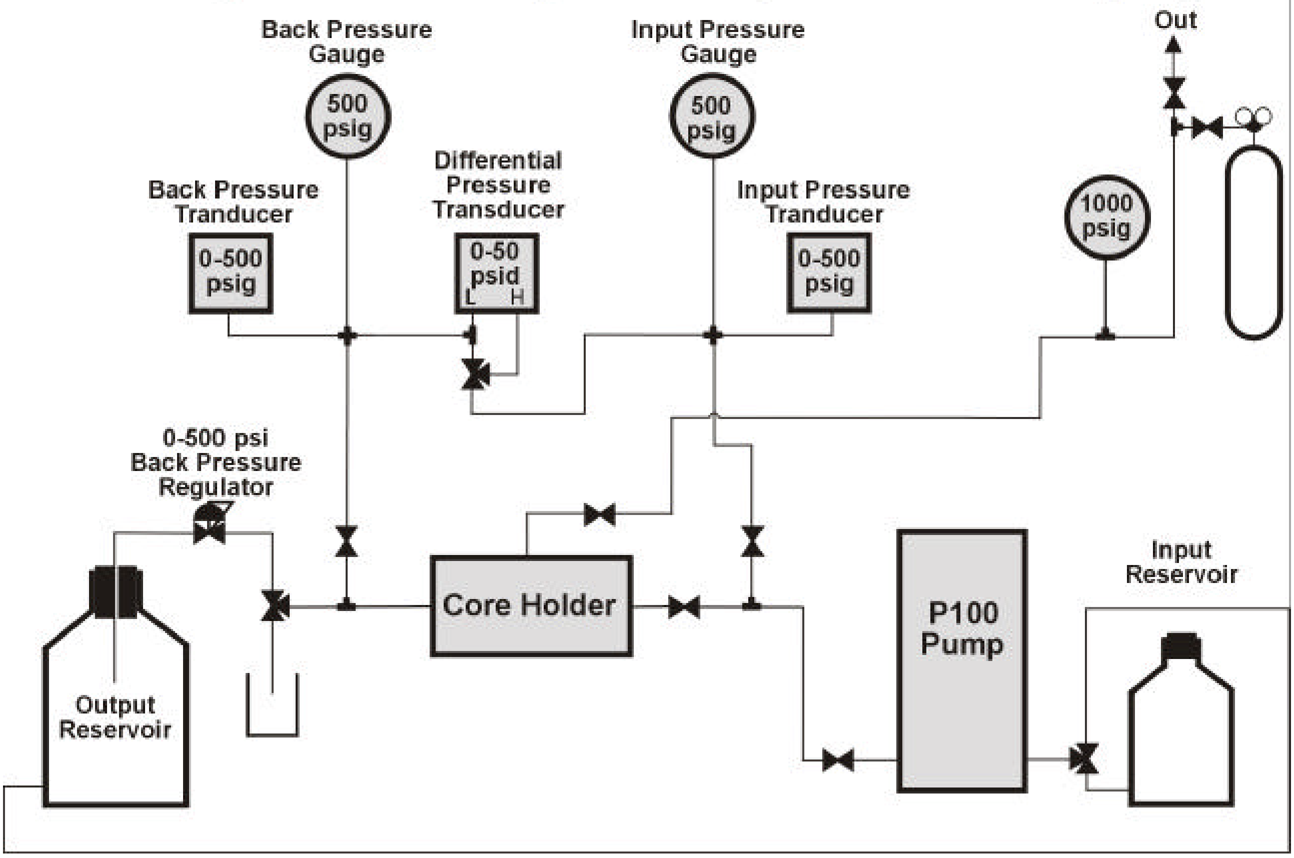
This is not as standard as the steady state method. It applied a volume of gas at a high initial pressure to one end of the sample and then measures the decay of the pressure as the gas leaks away through the core. One advantage of this method is that it can be used to determine the permeability of very low permeability rocks. It has therefore been used to measure the permeability of cap rocks. It must be said, however, that leakage through cap rocks is now recognised to depend primarily on fractures through the cap rock rather than the permeability of the bulk rock itself, and so these measurements are being done less and less.

6.3.3 Steady State Liquid Permeability Determinations

Permeabilities to oil and water at 100% saturation of each fluid, or of oil in the presence of S_{wi} can also be easily carried out. The saturated samples are placed in a core holder. The required fluid is flowed through the sample, while measuring the steady state volume flow and pressure differential (see Figure 6.8 for a schematic diagram of a typical permeameter set-up). All fluids used should be degassed prior to use. The permeability is calculated from Eq. (6.2). There is no need to institute a Klinkenberg correction, but the data is carefully examined to ensure that the flow is laminar by carrying the test out at various flow rates and checking whether they all give approximately the same permeability. Those high flow rates that are suspected to contain turbulent (Forchheimer) effects are discarded.

The values of permeability K_w at S_w=1 or K_o at S_o=1 should be approximately the same as the Klinkenberg permeability, K_L. K_o at S_w=S_{wi} and S_o=1-S_w will be less that that at S_o=1.

Figure 6.8 Steady State Liquid Permeability Rig



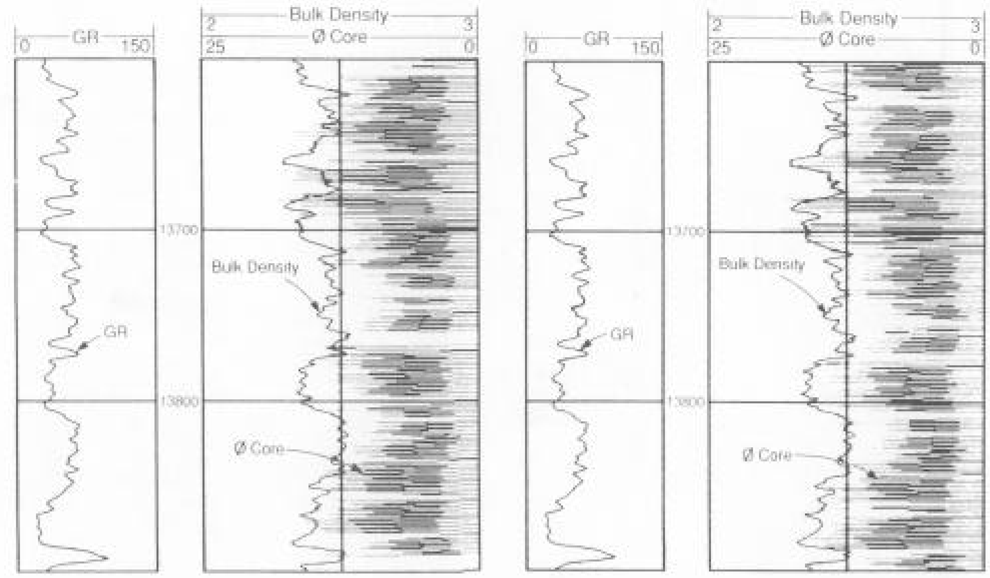
6.4 Data Handling

The correlation of core and logging data enable reservoirs to be assessed for production potential. The full description of this process is outwith the scope of this course. However, we will briefly examine some of the issues related to the correlation of core measurements with logs, and the use of permeability measurements in poroperm cross-plots.

6.4.1 Core-Log Comparison

The comparison of porosity and permeability data from core measurements and log methods is important to ensure that there is good agreement between them, allowing the measurements to be used in reservoir modelling with confidence. The process should compare the log and core data on the same log-type display (Figure 6.9). It is usually clear whether one of the curves needs to be depth shifted relative to the other. If a shift is necessary it is usually implemented for the core data, as uncertainties in core depth occur when there is not 100% core recovery form the hole. Corrections of 10 to 20 m are not uncommon. When comparing the depth corrected core and log data it is usually clear whether there is a good match between the two. The degree of match is an average determination made by eye as the two measurements will rarely be in very close agreement. This is because the measurements are made by widely varying techniques, with varying scales of measurement. For example, a standard core plug will have a volume of investigation of about 40 cm^3, compared to approximately 15000 cm^3 for a wireline tool. Additionally, the various methods measure different properties. For example core porosities are usually measurements of effective porosities (with non-connected porosity and clay bound water excluded, and usually avoiding fractures), whereas log derived porosities are generally measurements of total porosity. This results in the log porosities being generally a little higher than the log-derived porosities.

Figure 6.9 Core and Log Porosity Correlation



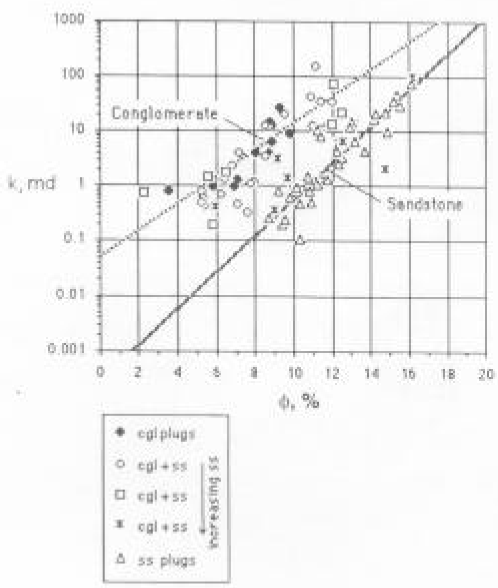
Unmatched core and log data **Matched core and log data**

6.4.2 Poroperm Cross-plots

Permeability is of incredible interest to the hydrocarbon industry as it describes how profitable fluids can be extracted from reservoirs. Clearly, any way of predicting permeability is of great interest too. One of the fundamental processes that is applied to permeability data is to plot it on a log-lin permeability-porosity diagram (Figure 6.10). Often there is a relationship within a given rock unit, and differences between rock units can be useful in the analysis of the reservoir. The main aims are:

Figure 6.10 A Typical Poroperm Crossplot

Klinkenberg permeability run at reservoir overburden pressure is plotted against helium porosity at overburden pressure.



- **To estimate permeability where only porosity data is available** (e.g. In Figure 6.10, a conglomerate with a porosity of 13.3% has a permeability of 100 mD).
- **To establish a porosity cut-off below which the reservoir is unproductive** (e.g. the data in Figure 6.10 has porosity cut-offs of 5.3% in the conglomerate and 10.7% in the sandstone, corresponding to a permeability of 1 mD..

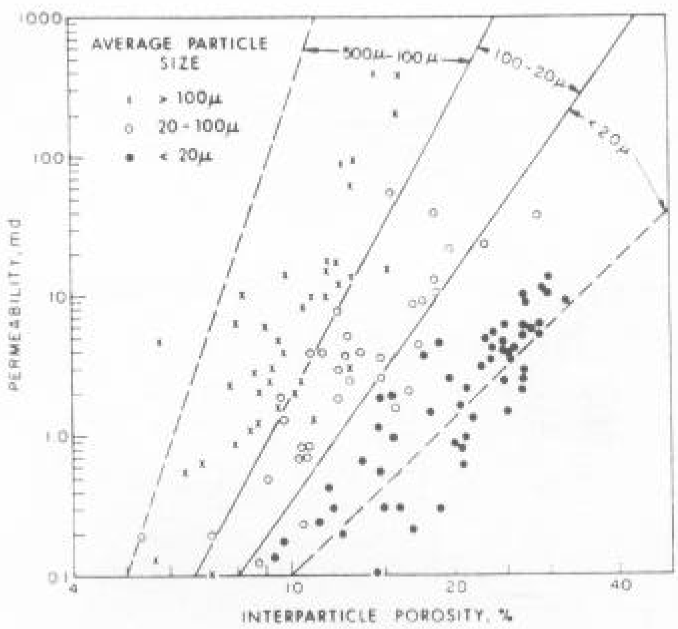
This method is very powerful if used in an homogeneous formation, but can produce remarkably erroneous results if carried out badly. There are a few points to bear in mind when using cross-plots:

- Some positive correlation between porosity and permeability exists for non-fractured, non-vuggy rocks with the same degree of diagenesis (Figure 6.11).
- The estimation method is based on a mathematical correlation that only takes account of porosity and permeability.
- No other factors are taken account of (e.g. diagenesis, fractures, vugs).
- The log permeability scale can generate large permeability errors.
- The cross-plot should be done for each individual rock unit if the relationship is to be valid. Doing a cross-plot for the whole reservoir is a waste of time. Individual cross-plots for each mineralogy/lithology and/or based upon grain and pore size information from mercury porosimetry. Individual permeability zones can also be delineated by plotting the distribution of permeabilities on a lin-log plot. This results in a log-normal distribution for well controlled permeability data (see section 6.1.4). If the distribution is unimodal (Figure 6.12a) then a cross-plot for all the data will be valid. If the distribution is multi-modal (Figure 6.12b) then a cross-plot must be done for the data belonging to each of the

unimodal populations making up the multi-modal dataset (3 in the case of Figure 6.12b). There are statistical tests that can distinguish which population a sample belongs to, e.g. the Kolmogorov-Smirnoff test.

- Some rocks do not produce a clear relationship (e.g. commonly carbonates).
- There is *no physical basis* for this type of plot. In fact reference to Eqs. (6.12) to (6.13) indicates that a log-log plot would be more appropriate, and Eq. (6.14) indicates that a lin-lin plot of permeability against f^{3m}/m^2 would provide the best results.

Figure 6.11 Poroperm Crossplot for Different Grain Sizes in Non-fractured Non-vuggy rock



There are two other important points to bear in mind. First, for the cross-plot to be the most valid, it should be done with permeabilities and porosities that are representative of the reservoir. This means that the permeabilities should be Klinkenberg corrected, and both permeabilities and porosities should be corrected to reservoir stress conditions. Any derived permeabilities are then the permeabilities for complete saturation of the rock with the test fluid, and will need to be reduced to relative permeabilities if required. If drill stem test permeabilities are used, then these will have been made in the presence of multi-phase fluids, and it is important to know more about the fractions of each fluid present and the wettability of the rock before valid deductions can be made. The second point is that the porosities from core measurements are effective porosities, whereas those from log measurements are commonly total porosities. If data from both sets are to be used, then they must be reconciled before use. Figure 6.13 shows the typical ranges of poroperm relationships for various lithologies and rock microstructure.

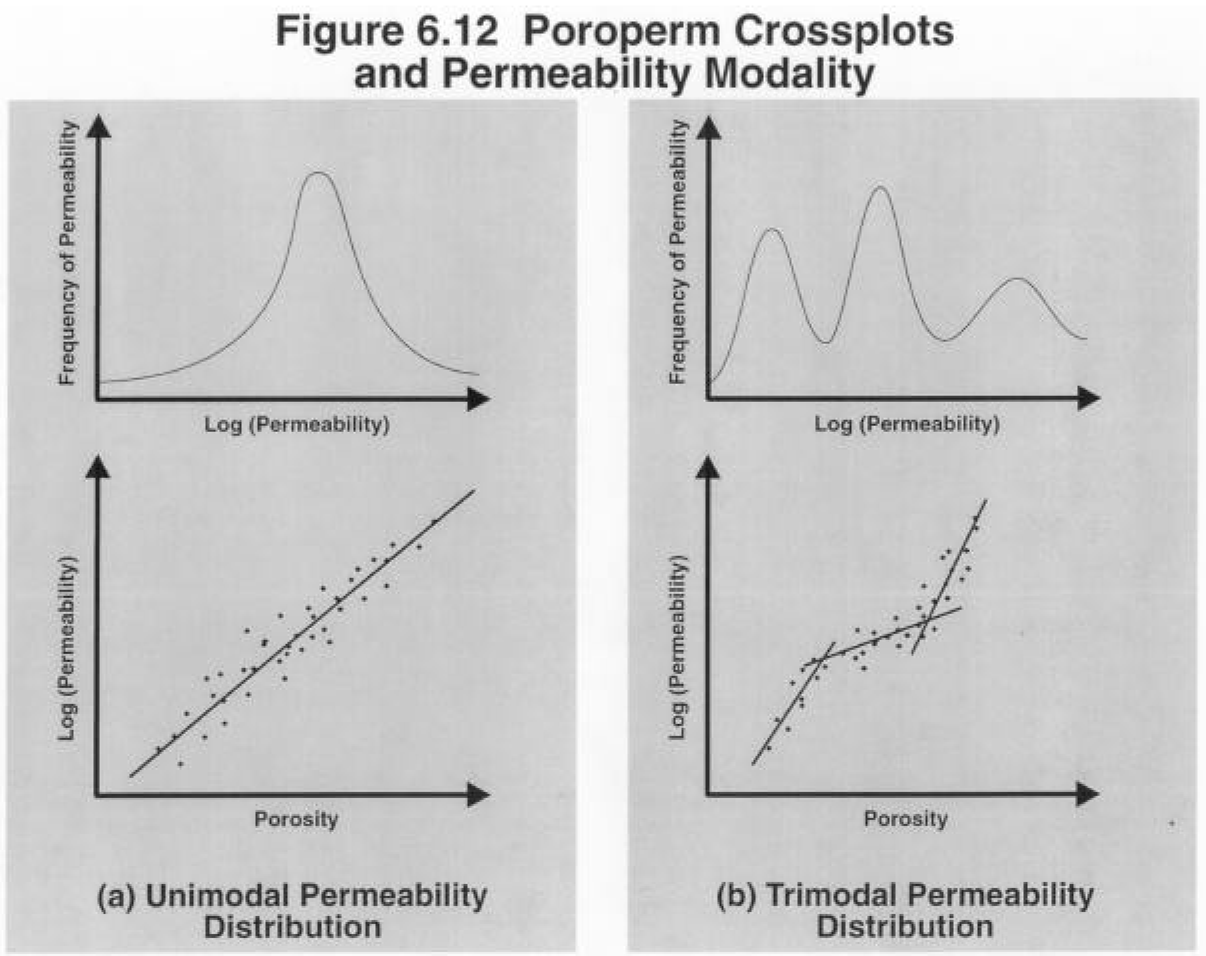


Figure 6.13 Poroperm Crossplots for Common Lithologies and Rock Structures