Petroleum Reservoir Engineering

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Lecture 9: Relative Permeability

Hello everyone and welcome again to the class of petroleum reservoir engineering. In the last lecture, we had discussed about various properties of the rock means petroleum reservoir rock where the petroleum fluid along with the waters are stored. The arrangement of the reservoir rock is such like there is some bulk domain where the fluid are stored and there is a porous domain where small pores are also there where these fluids are stored in the reservoir rock. So we discuss about the properties of the reservoir rock that is holding this fluid for example porosity that is the void volume within the reservoir where the hydrocarbon fluids are stored. We discussed permeability that is how easy the fluid can travel within this porous media, fluid saturation the part of the void or the porous region that is occupied by each phase capillary pressure that is holding the fluid in those small size of the pores within the reservoir. Compressibility nature of the rock so under high pressure the rock is compressible when the pressure is released the compressibility of the rock also changes and how it changes with respect to pressure was discussed.

Net peak thickness that is the layer of the hydrocarbon petroleum reservoir rock that is actually contributing towards the production and then fluid rock interaction that is the characteristic of the rock that is offering a special affinity to a special type of the fluid within the reservoir domain. So the rock may be oil wet means it is having the affinity for oil more than the water and gas or it may be the water wet where the rock is holding the water on the surface compared to oil and gas. The wettability or in other terms contact angle is one of the way of measuring the affinity of the rock towards a particular phase. Reservoir heterogeneity is one of the important things that should be considered when we are measuring the properties related to reservoir rock.

Heterogeneity exists in the reservoir in fact in a small section even within a small section there could be heterogeneity in terms of porosity, permeability, rock formation itself, saturation and other things. So special care should be taken care when we are measuring the properties for the reservoir rock and accounting the heterogeneity by using certain mathematical way of averaging out the property. For example the porosity can be average out for multiple samples with respect to the thickness or the area or the volume considered as a weighing factor to calculate the average value of the porosity. In today's lecture that is week 3 lecture number 2 we are going to continue our discussion with one specific property of the reservoir rock that is permeability. Actually permeability is very important phenomena or very important features of the reservoir rock as discussed in last class also if the reservoir rock is not having permeability means even the fluid are there in the porous region but that porous region is not connected through connecting pores or it is not having any permeability path for this fluid to flow from one place to the other place it is not going to be a good commercial reservoir well in terms of the hydrocarbon fluid production.

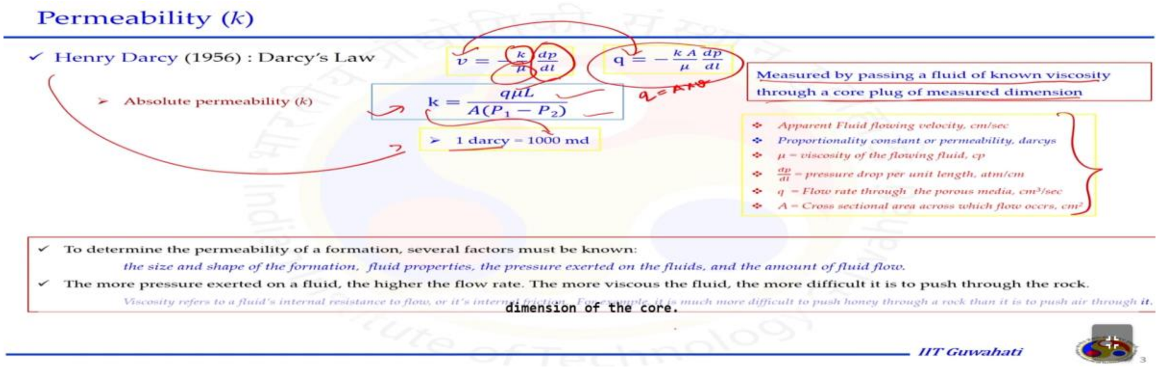
So for example if the value of the K is too low the reservoir is considered very poor reservoir if the value of permeability K is high, high means more than 500 milli Darcy the reservoir is considered very fair to go for the commercial production. In general it is believed if reservoir is having the permeability less than 50 milli Darcy it is not going to produce at a commercial rate and that is one of the parameter this permeability that is classified the conventional and unconventional reservoir. In unconventional reservoir the permeability is very, very low like for the tight gas reservoir the permeability is 0.01 milli Darcy and so. So the permeability becomes very important property of the reservoir rock that is we are going to discuss in little bit more detail and after that we will discuss some of the core analysis that should be performed in the laboratory to find out some of the important features of the reservoir rock.

Broadly we classified them in the routine analysis and the spatial analysis that also we discuss towards the end of this lecture. So permeability as we discussed in last class also it is estimated using the Darcy law. Darcy law is a flow equation that is applicable for the flow of any fluid in the porous media. So the measurement of the permeability is done using this Darcy law the coefficient that is appearing in this equation k that is actually the permeability. The Darcy law can be expressed in terms of velocity of the fluid that is passing through a section of the core in the laboratory where the pressure difference is there across this core and that pressure drop is with respect to the length of the core is denoted by dP by dl and it depends on the viscosity of the fluid that is flowing through this core sample.

This can be represented in terms of the volumetric flow rate also. So we are having this relationship Q is equal to area into velocity. So the velocity can be transferred in the form of Q and the equation can be arranged like this. So the volumetric flow rate across the length of the core which is having the pressure drop dlP cross sectional area A and the fluid that is flowing having viscosity mu if those are represented in this unit we are going to get the permeability arrangement of this equation. We can get the arrangement of this equation to calculate the permeability k.

So these parameters should be known we can get the value of permeability. So this is measured by passing a fluid of non-viscosity means viscosity is non mu through a core plug of measured dimension means we know the cross sectional area we know the length. This equation that is shown here is for the case where the linear flow is happening the cross sectional area is A length is L and the expression will appear like this. If the radial flow is happening from all the direction fluid is coming towards the production zone the equation will differ little bit more means in terms of the radius of the reservoir rock. The expression will appear almost similar but the expression will be having the log form of the radius that we discussed already in the Darcy law or we will continue the discussion when we will be setting up the equation for radial diffusivity.

This expression gives us the value of permeability that we call the absolute permeability because the single phase is used to measure the permeability or the single phase is used for this Darcy law to flow that fluid through the core which is 100 percent saturated with that single phase fluid. The numerical value that comes out with this expression is very low or fractional value. So the value is often represented in form of the milli Darcy. So 1 Darcy that is the unit of the permeability is equal to 1000 milli Darcy. Darcy unit is given in the honor of this Henry Darcy to represent the value of the permeability.



Permeability (k)

- ✓ Henry Darcy (1956) : Darcy's Law
  - ➢ Absolute permeability (k)

$$v = -\frac{k}{\mu}\frac{dp}{dl}$$

$$q = -\frac{k\,A}{\mu}\frac{dp}{dl}$$

q = A×v

$$k = \frac{q\mu L}{A(P_1 - P_2)}$$

➢ 1 darcy = 1000 md

Measured by passing a fluid of known viscosity through a core plug of measured dimension

- ❖ Apparent Fluid flowing velocity, cm/sec
- ❖ Proportionality constant or permeability, darcys
- ❖ μ = viscosity of the flowing fluid, cp
- ❖ $\frac{dp}{dl}$ = pressure drop per unit length, atm/cm
- ❖ q = Flow rate through the porous media, cm^3/sec
- ❖ A = Cross sectional area across which flow occrs, cm^2

- ✓ To determine the permeability of a formation, several factors must be known:
  the size and shape of the formation, fluid properties, the pressure exerted on the fluids, and the amount of fluid flow.
- ✓ The more pressure exerted on a fluid, the higher the flow rate. The more viscous the fluid, the more difficult it is to push through the rock.
  Viscosity refers to a fluid's internal resistance to flow, or it's internal friction. For example, it is much more difficult to push honey through a rock than it is to push air through it.

dimension of the core.

So the unit Darcy for the permeability in the honor of Henry Darcy. To determine the value of the permeability certain features of the rock and the fluid should be known. For example the size and shape of the formation in the laboratory when we are doing it the dimension of the core. Fluid properties like the viscosity, the pressure that is applied across the core sample and the amount of the fluid flow that the Q value here that is appearing here also in the expression of K. We know that thing more pressure is required to flow at a higher rate.

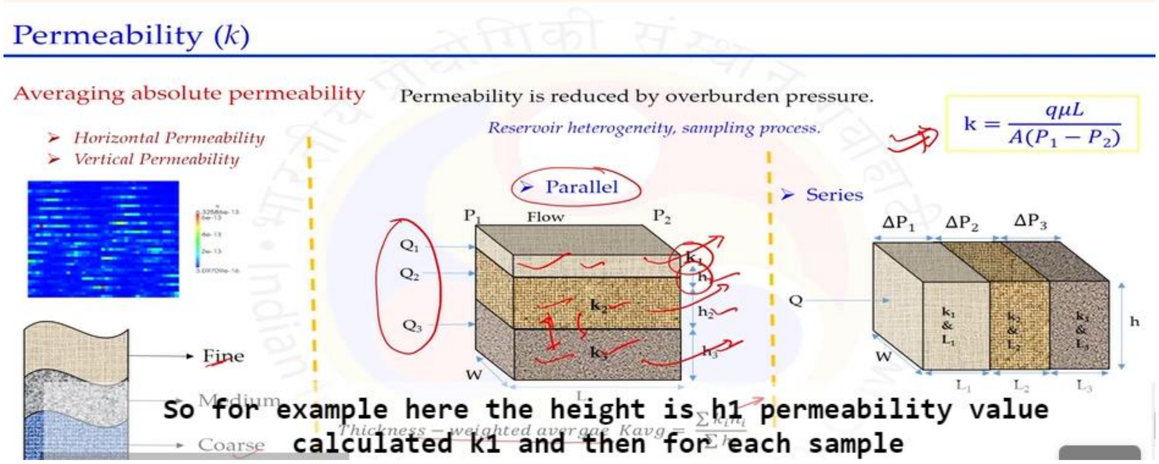
So if the more pressure is applied across the core the flow rate will be higher and if the fluid is more viscous for example honey it is very difficult to push that fluid through the rock and in that case more pressure will be required. So the viscosity of the fluid that is actually represent the fluids internal resistance to flow is important. For example it is much more difficult to push honey through a rock than it is to push the air through the same rock. So to calculate the average value of the permeability as mentioned the variation could be in both horizontal and vertical direction. The diagram showing here is the variation in color coding like happening in all horizontal and vertical direction.

So the permeability should also be average out. The permeability is reduced by the overburden pressure so at what depth the sample is taken that should also be considered when we are calculating the permeability. Reservoir heterogeneity means the variation in the samples or the sampling process should also be carefully chosen because the core plug that is taken out from the reservoir rock collected from underneath the surface the sampling itself may disturb the rock and the permeability calculation may be wrong. Sometimes we may choose very appropriate rock that looks like more porous and the calculation of the average value of the permeability may be not accurate. Hence the sampling procedure should also be done very carefully.

You are taking the representative sample from different section of the core and applying the Darcy law across all those core samples to take out the or to estimate the average value of the permeability. So the sample that are taken out could be of different shape, could be of different texture in appearance. For example the sample those are taken out from a single section that section itself could have the distribution of the porosity like it is core sample, it is medium or it is very fine, very fine particles are there and calculating the value of the permeability for all these three samples from the same section will be difficult or will be different. So if we are taking the single sample the permeability in the lower section will be different than the middle section and then the top section. Hence the sampling of the samples should be done very appropriately at least in one section is representing a little bit homogeneity in the terms of appearance and in terms of the values of the rock properties those are estimated for example the porosity.

So for that purpose the sample could be arranged in the parallel manner or could be in series manner. The arrangement means when we are taking out the rock how we are taking the samples if we are taking the samples in this way the vertical layer one by one then we should arrange them also in the parallel manner to calculate the permeability in the laboratory. It means like each sample should be subjected for the permeability measurement using the Darcy law and then the concept of parallel flow should be applied to calculate the average value. What is the meaning of the parallel sampling? It means like the sample of height h1 that is the top one is subjected for a flow rate q1 and the permeability k1 is estimated. Now the samples 2 that is also having the same dimension as the sample 1 and similar sample 3 is also having the same dimension.

So dimensions are same only thing is their length is same width is same only the height is changing. So the h1 is changing in this case permeability k1, k2, k3 for individual sample can be calculated with the help of this Darcy law. And when it comes to average out these properties for the parallel section we know the total flow rate is going to be the summation of q1, q2, q3 if they are placed one by one on one above the other and there is no cross flow. So we are assuming this thing there is no cross flow is happening each sample is individual and the flow rate is q1, q2, q3 are flown and the permeability k1, k2, k3 respectively are measured. In that case the average value can be calculated by weighing each value of the k with respect to the height of that section.


Permeability (k)

Averaging absolute permeability

- Horizontal Permeability
- Vertical Permeability

Permeability is reduced by overburden pressure.

Reservoir heterogeneity, sampling process.

$$k = \frac{q\mu L}{A(P_1 - P_2)}$$

- Parallel
- Series

Thickness – weighted avergae $Kavg = \frac{\sum k_i h_i}{\sum h_i}$

So for example here the height is h1 permeability value calculated k1 and then for each sample

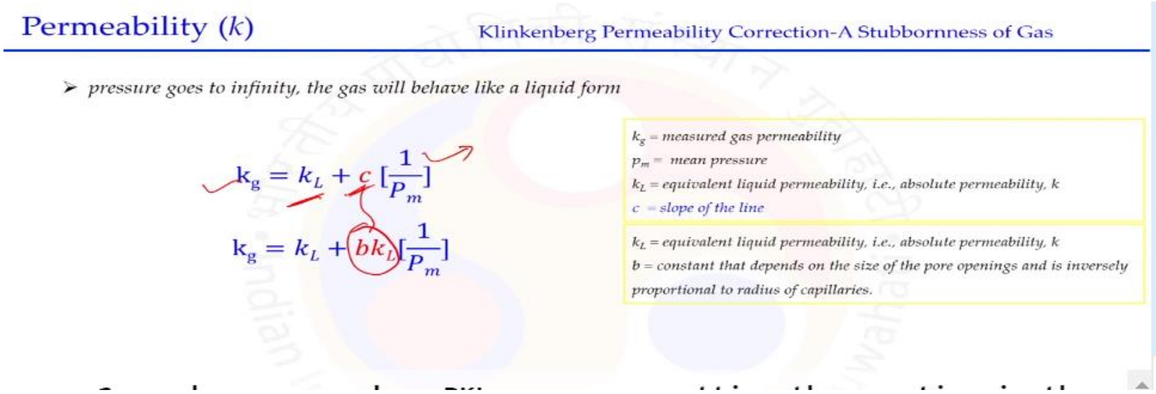
So for example here the height is h1 permeability value calculated k1 and then for each sample like 1, 2 and 3 all these parameter can be placed here ki, hi multiplication of both the parameters and then summation of that divided by the total height the summation of all the height we will get the average value that is weighted with respect to thickness. Similar thing can be done when the other dimension are also varying for example the width is varying for all these three samples. In that case the weighing factors should be calculated area and that area is width multiplied by the height. So both height and width those are varying can be calculated in terms of area and this part could be used in calculating the average value of the permeability with respect to weighing the parameter calculate the average value of the permeability using area as a weighing factor. When it comes to the series arrangement of the samples so for example the samples are taken like one from here another from here third one is from here so the arrangement is like this.

In this case all three samples are individually subjected for the permeability measurement we can get the permeability of these three samples those are having the permeability k1, k2, k3 these three samples are having different length l1, l2, l3 other dimensions are same like the width and height and we are flowing q same flow rate from each sample and because of the length the pressure drop in each sample would be different. And in that case the measured value of the permeability for this kind of the arrangement can be used to calculate the average value of the permeability by the principle of harmonic average. So if we do total pressure drop is equal to delta p1 plus delta p2 plus delta p3 when we arrange that equation we will be getting the expression of average value of the entire section with respect to length because length is varying here for each section along with the permeability of course varying and the arrangement will give us the average expression that is actually the harmonic average expression. Another way of could be calculate the value of the permeability for n number of the sample not necessary from where the samples are collected and calculate the permeability for all those samples take the geometric average that is multiply all those permeability calculated for n number of the samples and put them under the root n to calculate the geometric average. For example if we are having only the two samples the geometric average will be k1 k2 square root of k1 and k2 to calculate the average value similar for the n sample we can use this expression to calculate the average permeability.

So far we discuss about like permeability is a property of the rock irrespective of what fluid we are flowing through the samples should give us the expression of permeability using the Darcy law and that coefficient k appearing in the Darcy law is the permeability. But Klinken work 1941 itself he identified that things the measurement of the permeability using a single phase either liquid or gas actually is the intrinsic permeability. If gas is used instead of the liquid then the permeability is going to be higher compared to liquid it means the gas permeability will be higher compared to the liquid permeability depending on under what pressure or pressure range we are subjecting our core sample for permeability measurement. So the Klinken work effect is actually the permeability measurement depend on the flowing fluid if you are using the gas the value will be different if you are using the liquid the value will be different. Later value will be achieved in case of the air compared to the liquid this happens because the gas exhibit slippage effect it is compressible in the nature it is having the tendency to move fast it is having some finite velocity means higher flow rate.

So because of the slippage effect and higher flow rate the value will be calculated for the permeability will be actually more compared to the liquid. If we see in this diagram this line is showing for the gas permeability this is for the liquid and we see the value of the liquid permeability of the porous media with respect to the mean temperature that mean temperature Pm is equal to the average temperature P1 plus P2 divided by 2 with respect to this average pressure is almost constant. So the liquid permeability is constant that is not depending on the pressure while in case of the gas the value is higher when the pressure is lower the average pressure is lower. So the x axis that we see here is 1 by Pm means here is the low pressure here is the high pressure. So at lower pressure the gas will slippage out easily from the core section and the value of the permeability that is appearing will be more.

So two or three measurement can be done and the straight line can be fitted how the permeability of the rock sample is changing when the pressure is changing with respect to gas flow and when we extrapolate that thing means very high pressure 1 by Pm is low means very high pressure the value of the gas permeability will be equal to liquid permeability. It means when the pressure is very high P is tends to infinity the 1 by Pm will tends to 0 and both gas permeability and liquid permeability will be same. It means when pressure goes to infinity the gas behaves like the liquid and in that case we are having the same permeability then it becomes the property of the rock. So the care should be taken care when we are measuring the permeability using the gas we have to do the experiment at very high pressure to actually calculate the true value of the K at the low pressure the value of the K will be higher for the air flow or when the fluid is used here. What others observation from the Klinker effect it says the value of the K not only differ for the air and the liquid but it also differ for different gases.



Permeability (k)

Klinkenberg Permeability Correction-A Stubbornness of Gas

- pressure goes to infinity, the gas will behave like a liquid form

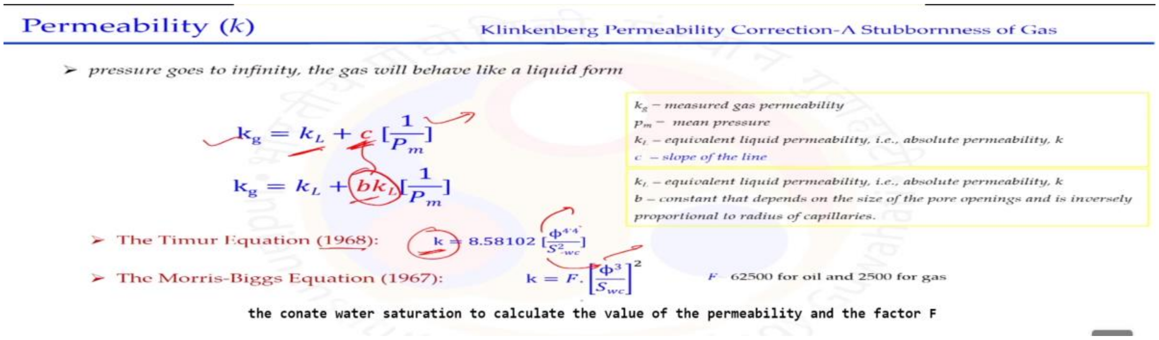
$$k_g = k_L + c\,[\frac{1}{P_m}]$$

$$k_g = k_L + bk_L[\frac{1}{P_m}]$$

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

k_L = equivalent liquid permeability, i.e., absolute permeability, k
b = constant that depends on the size of the pore openings and is inversely proportional to radius of capillaries.

So if you are having the different gases for example methane nitrogen CO_2 you are using different gases the value may be little bit different and the care should be taken care and the difference in the value happens because of the size of the gas molecules. Mathematically this equation can be represented in the linear form with respect to parameter involved so the gas permeability is equal to liquid permeability that is actually the intercept of the extrapolated equation this is our x axis parameter and the slope is C of this line that is appearing because of the effect of the gas molecules slippage effect. Now the equation can be converted in the form of the liquid permeability so this coefficient C can be expressed as BKL so we are getting the equation in the form of gas permeability and the liquid permeability with respect to pressure. So calculate the permeability or the effective permeability several equations are given in the literature with respect to the porosity and the conate water saturation that is SWC so the Timur equation developed in 1968 to relate these two parameter with the permeability and this expression can be used for that purpose. The Morris-Biggs equation was developed for similar concept like using the porosity and the conate water saturation to calculate the value of the permeability and the factor F here depends on what is the fluid used to calculate the value of the permeability.



Permeability (k) Klinkenberg Permeability Correction-A Stubbornness of Gas

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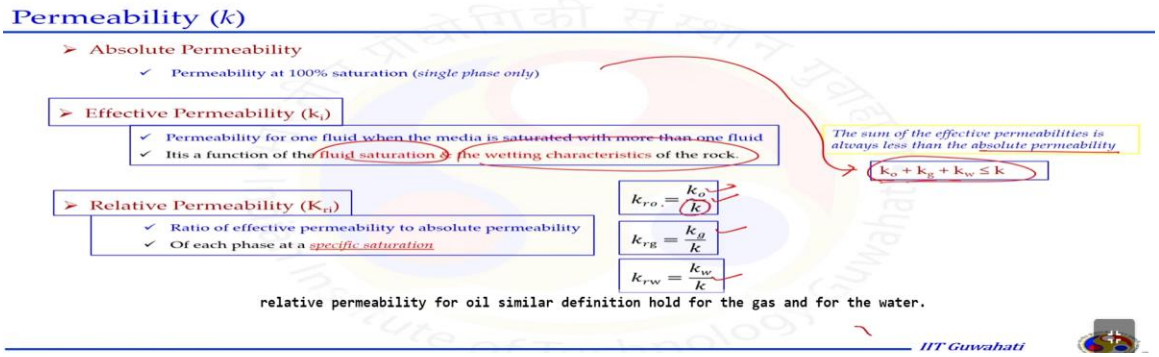
- The Timur Equation (1968): $k = 8.58102\left[\frac{\phi^{4.4}}{S^2_{wc}}\right]$
- The Morris-Biggs Equation (1967): $k = F.\left[\frac{\phi^3}{S_{wc}}\right]^2$ F 62500 for oil and 2500 for gas

the conate water saturation to calculate the value of the permeability and the factor F

So for the oil it is different factor and for the gas it is different factor if you put that value the value of the permeability for oil and gas can be calculated with the help of this equation. So here K is the absolute permeability, phi is the porosity and WC of S means SWC that is the conate water saturation so all these are the fractions so the value of the permeability will be in milli Darcy. So another important feature of this parameter B that is used to represent the slope C the parameter B actually this is the constant that depends on the size of the pore opening and is inversely proportional to the radius of the capillary so that factor should be calculated considering these two important features. In the further discussion of the permeability so we discuss about the absolute permeability that is the permeability if 100% single phase is present in the rock sample effective permeability when more than one phase is present then we are calculating the permeability of a particular phase in the domain it depends on the fluid saturation and the wetting characteristic of the rock means how much pore volume is occupied by that particular fluid whose effective permeability we are going to calculate and secondary what is the nature of the rock the affinity it offers to oil gas and water. The sum of the effective permeability is always less than the absolute permeability absolute is when single phase is present so if more than one phase is present the summation of all these three either can be equal to or lesser than the absolute permeability.



Permeability (k)

- Absolute Permeability
  - ✓ Permeability at 100% saturation (*single phase only*)
- Effective Permeability (k_i)
  - ✓ Permeability for one fluid when the media is saturated with more than one fluid
  - ✓ Itis a function of the fluid saturation & the wetting characteristics of the rock.
- Relative Permeability (K_{ri})
  - ✓ Ratio of effective permeability to absolute permeability
  - ✓ Of each phase at a *specific saturation*

The sum of the effective permeabilities is always less than the absolute permeability

$k_o + k_g + k_w \leq k$

$k_{ro} = \frac{k_o}{k}$

$k_{rg} = \frac{k_g}{k}$

$k_{rw} = \frac{k_w}{k}$

relative permeability for oil similar definition hold for the gas and for the water.

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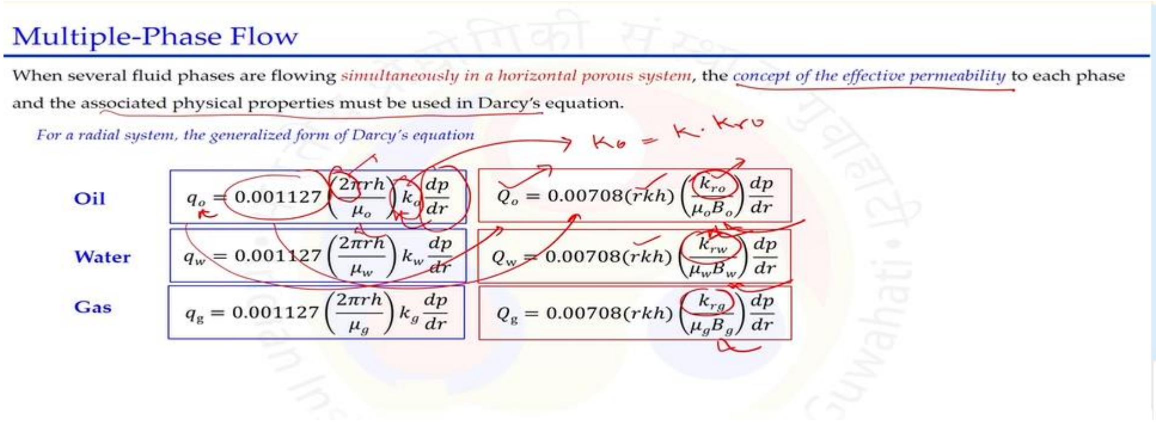
Another parameter is relative permeability defined to account this effective permeability and absolute permeability together so that is the ratio of effective permeability to absolute permeability it is also depends on specific saturation so we need to define at what saturation the relative permeability is calculated. So here is the definition of relative permeability for oil gas and water so the ratio of the two value effective permeability for the oil divided by the absolute permeability is the relative permeability for oil similar definition hold for the gas and for the water. In terms of the quantity manner the relative permeability value will also vary between 0 to 1 so either there is no permeability for a particular phase when more than one phase is present or it is 100 percent permeability the effective permeability that is here may range from 0 to k that is we define here 0 to k hence the relative permeability may have the value between 0 to 1 that is we defined here. Another feature the sum of relative permeability if we sum 1, 2, 3 or the number of phases present in the domain if we calculate their relative permeability and put up the summation sign for them we will see the value of the relative permeability for the individual phases depends. It is a variable depends on the saturation but it will always be less than or equal to unity so it cannot exceed the value more than unity when we sum up the relative permeability for each phase.



Multiple-Phase Flow

When several fluid phases are flowing *simultaneously in a horizontal porous system*, the *concept of the effective permeability* to each phase and the associated physical properties must be used in Darcy's equation.

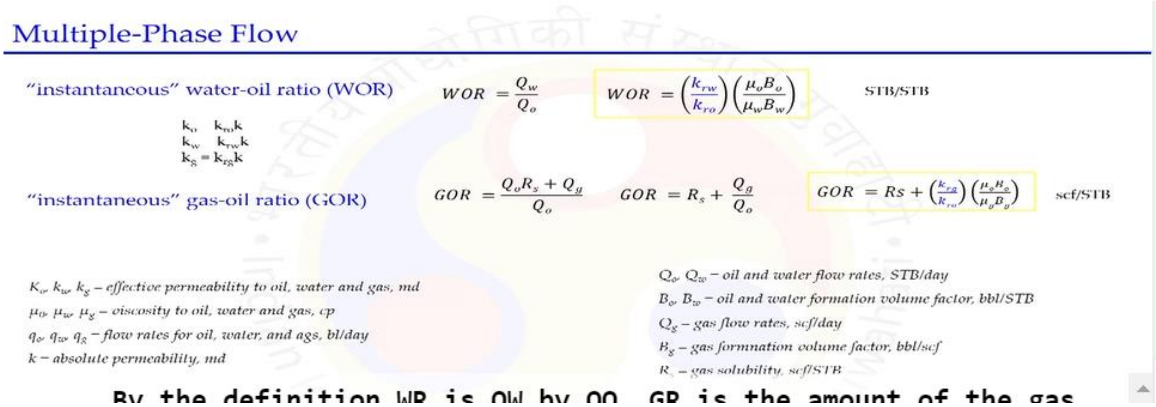
For a radial system, the generalized form of Darcy's equation

$K_o = K \cdot K_{ro}$

Oil	$q_o = 0.001127\left(\frac{2\pi rh}{\mu_o}\right)k_o\frac{dp}{dr}$	$Q_o = 0.00708(rkh)\left(\frac{k_{ro}}{\mu_o B_o}\right)\frac{dp}{dr}$
Water	$q_w = 0.001127\left(\frac{2\pi rh}{\mu_w}\right)k_w\frac{dp}{dr}$	$Q_w = 0.00708(rkh)\left(\frac{k_{rw}}{\mu_w B_w}\right)\frac{dp}{dr}$
Gas	$q_g = 0.001127\left(\frac{2\pi rh}{\mu_g}\right)k_g\frac{dp}{dr}$	$Q_g = 0.00708(rkh)\left(\frac{k_{rg}}{\mu_g B_g}\right)\frac{dp}{dr}$

When it comes to the multi phase flow we can see the multi phase flow system is a system when all the fluids are flowing together in the porous medium simultaneously, they are flowing and the concept of effective permeability to each phase and the associate physical properties must be used in the Darcy law. So for example the radial flow system the generalized Darcy law is like this here Q_o represent like the value is for oil phase and the expression using the Darcy law is for the oil phase where this is the pressure drop in the radial manner this is the area fluid properties and then this is K_o is the effective permeability of oil when only oil phase is present. But when we talk about the multi phase system we will see this value should be replaced with the relative permeability and we can do that using this relative permeability expression. Now the concern here is this parameter is change so this parameter is change because of this numerical value of 2 pi and another feature is change from between these two equations is small q_o and capital Q_o. This capital Q_o is actually the value measured at standard condition and the volume formation factor of oil is used to relate the reservoir condition to the standard conditions and in this manner we can replace this value of effective permeability by absolute permeability multiplied by the relative permeability.

So K is appearing here in all three phases oil, water and gas. So the expression is just differing we are placing the relative permeability of each phase here and the volume formation factor for each phase is included to relate the Q from reservoir condition to standard condition. The core idea here is when we are having the multi phase flow effective permeability should be scaled up to relative permeability to have the better expression for oil, gas and water phase flow within the porous media. So the notations are as usual we are having the effective permeability for each phase we are having the viscosity of the each phase flow rate of each phase at the some specified conditions may be the reservoir condition. K is the absolute permeability the unit is milli Darcy while the capital Q are the flow rate and the B is the volume formation factor.



Multiple-Phase Flow

"instantaneous" water-oil ratio (WOR) $WOR = \frac{Q_w}{Q_o}$ $\boxed{WOR = \left(\frac{k_{rw}}{k_{ro}}\right)\left(\frac{\mu_o B_o}{\mu_w B_w}\right)}$ STB/STB

$k_o \quad k_{ro}k$

$k_w \quad k_{rw}k$

$k_g = k_{rg}k$

"instantaneous" gas-oil ratio (GOR) $GOR = \frac{Q_o R_s + Q_g}{Q_o}$ $GOR = R_s + \frac{Q_g}{Q_o}$ $\boxed{GOR = Rs + \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{\mu_o B_o}{\mu_g B_g}\right)}$ scf/STB

K_o, k_w, k_g – effective permeability to oil, water and gas, md

μ_o, μ_w, μ_g – viscosity to oil, water and gas, cp

q_o, q_w, q_g – flow rates for oil, water, and ags, bl/day

k – absolute permeability, md

Q_o, Q_w – oil and water flow rates, STB/day

B_o, B_w – oil and water formation volume factor, bbl/STB

Q_g – gas flow rates, scf/day

B_g – gas formnation volume factor, bbl/scf

R_s – gas solubility, scf/STB

By the definition WR is QW by QO GR is the amount of the gas

So here we should also have QG and here is BG those are mentioned here actually. Knowing the Q value we can calculate instantaneous water oil ratio or instantaneous gas oil ratio. By the definition WR is QW by QO, GR is the amount of the gas that is produced divided by the amount of the oil that is produced all are at standard conditions means at the separator condition we are measuring. But now with the help of this relative permeability expression that is shown in the previous slide we can convert these expression from Q to some values those can be estimated. So for example we can use those expression to put up here and we will get the relative permeability ratio here the viscosity ratio of the fluids under the consideration like water oil and their volume formation factor.

Similar for the gas oil ratio the gas produces because some of the gas that was soluble in the oil that is evolved out at the standard conditions and then we are having the gas that is free gas produced total gas divided by the total amount of the oil that is got produced. So we are going to get this expression and converting that in the form of relative permeability we can use again the relative permeability concept to calculate the GOR by knowing the fluid properties of the considered fluid oil and gas and similarly the volume formation factor for oil and gas. So with the help of knowing the relative permeability we can calculate the instantaneous value of water oil ratio and gas oil ratio. Let us keep this discussion further in terms of the effective and relative permeability. So we already discussed in the last lecture about the drainage process and imbibition process.

So the drainage process happens when a core is saturated 100 percent with the water and we are displacing this water with oil. In this case the non-wetting phase is displacing the wetting phase. So the core is saturated with the water and it is having more affinity for the water it means it is water wet and the wetting phase will be water and the non-wetting phase will be oil. This process is called the drainage process. Reverse of this is called the imbibation process where the oil and some residual water is in the core sample and we are replacing this oil with the help of water.

In that case the wetting phase that is water because this rock is having the wetting characteristic for the water is displacing the non-wetting phase means the oil that is in the core sample or in the reservoir. So the oil is getting replaced by the water this process called the imbibation process. Where this happens initially, we assume like the reservoir rock before oil migrated to it was saturated with the water. So the oil migration happened from different places and the water is replaced by the oil. In case of the second imbibation process the oil is there and when we are injecting the water to displace this oil towards the production well the imbibation process are encountered in the reservoir domain.

Both the process can be carried out in the laboratory saturated with the oil saturated with the water and opposite phase can be used for displacing the fluid. When it comes to the effective permeability for the oil and water system so our water is the wetting phase while is the non-wetting phase. Rivers can also be happened the rock is having affinity to oil and it is the oil wet rock where the oil will become the wetting phase and water will become the non-wetting phase. For the example here we are considering water as the wetting phase and the oil is the non-wetting phase. So let us see how effective permeability with respect to the saturation of the water when two phases are present.

So only we are talking about the two phase oil and water in the system how the permeability varies with respect to the saturation. So on this side we are having the effective permeability of oil this side we are having the effective permeability of water. Ultimately both reach to the absolute value of the permeability K and the water is varying in terms of saturation from 0 to 1. So there is no water or 100 percent water is present. So we know when the two phases are there water and oil the summation of saturation will be equal to 1 for these two phases.

So when SW is 0 we are having only oil and the permeability calculated in that case is the absolute permeability with respect to oil of course on this scale KO will equal to K and when we are having on the other side SW is equal to 1 it means SO is equal to 0 and we are having only water and the permeability will be absolute permeability of the formation with respect to water and both the values will be same. But what happens when the saturation is changing? So the water saturation is changing the oil permeability is also changing. So there will be a situation when the oil is having no permeability although oil is there because this is the situation when some saturation of oil is there we called it the irreducible water saturation or the conic water saturation at which conditions some part of the oil is there because the summation of saturation should be equal to 1 but the oil permeability is not there. So oil is not able to flow. Similar thing happens with the water there is certain amount of the conic water saturation will be there if the water saturation is below that one the water will not be flowing.

When we move further, we see there are two conditions and here though says beyond these two conditions on the left side we are having the immobile water region where the water saturation is there means water is present in the formation but that is not flowing. On the other side when the small part of the oil remains in the reservoir while it is not having any permeability it is not having any flow and that is happened because of the capillary pressure those are existing in the porous region at the reservoir condition. So the conditions when SW is called to conic water saturation this is the situation the conic irreducible water saturation irreducible water saturation conic water saturation are interchangeable word we will discuss what the difference between these two in the next slide. At this condition the water is not flowing the value of the permeability is also 0. Of course when SW is called to 1 the rock is entirely filled with the water and the permeability value will be of the water will be equal to absolute permeability value.

So KW will equal to K value. Similar observation can be done with respect to the oil when SW is called to 0 means 100% saturated with the oil then the absolute value of the permeability will be equal to the effective value of the oil permeability. When the oil saturation decreases to SOR this is the situation SOR the residual saturation there will be no flow for the oil and the oil permeability will be 0. So that is the way the window that is allowing both oil and gas to flow is this together if either of them are moving to immobile water or immobile oil zone then the movement of those phases will not be there. Similar diagram can be transferred to the relative permeability concept. Here phenomena are same everything is same we are having the conic water, reducible water saturation only difference between these two is the value becomes 1 because at this condition the effective permeability and the absolute permeability both are same.

So the relative permeability value will be 1 and the scale of course change here. Here it was effective permeability here it is relative permeability for oil and relative permeability for water otherwise the movement of the fluid with respect to saturation is same in both effective permeability calculation and relative permeability diagram. As we already discussed the sum of the individual effective permeability will always be lesser than or equal to K. So at any point whenever we are calculating the permeability of water and permeability of the oil this is permeability of oil this is permeability of water the summation will be always lesser than or equal to absolute permeability. So let us discuss little bit more about this non wetting phase and wetting phase permeability.

So the wetting phase occupies the smaller pores at smaller saturation and do not contribute to flow at this condition. While the non wetting phase they occupy the central or the large pore opening in the reservoir domain and they actually contribute materially to flow through the reservoir. So in this case our wetting phase is water and non wetting phase is oil the reverse situation could also be there depending on the rock affinity. So what happens the same diagram that we had seen so here it is the oil here it is the water permeability diagram there should be some reason where the water is not able to flow it is reached to some a reducible water saturation or the conic water saturation. Similar situation will be here for the oil when it reached to certain saturation the flow is not happening that is the situation here and this is for the water.

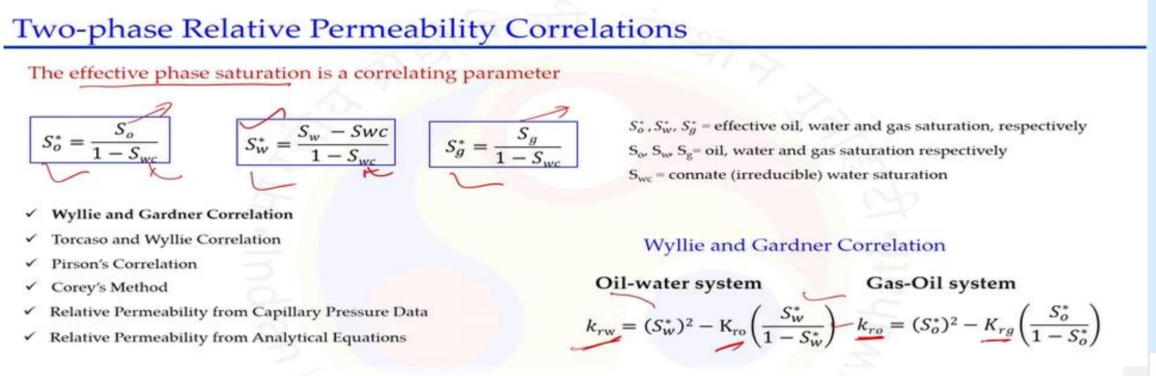
So this is conic water saturation this is critical water saturation at which the water will start moving from the formation if the saturation is below the critical saturation the water will not be flowing similar situation will be here for the oil when the oil saturation is below the critical saturation oil is having no permeability as the saturation of the oil increases the permeability will also increase. So in this direction we are increasing the saturation of the oil while in the other this direction we are increasing the saturation of the water on this diagram. So let us say this will be the reason A where only oil will be flowing this will be the reason B where only water. This will be the reason B where oil and water will be flowing and in the third where the only water will be flowing and that will be the situation when only the single phase is present. So the other two sections are immobile water and immobile oil phase only one of them will be flowing while in between oil and water both will be flowing together and the summation of the permeability for both the relative permeability for the oil and relative permeability of the water will be summation of individual relative permeability.

So certain observation can be made here so for example the water curve this is here a small saturation of oil that is in this region k r w drastically reduced so this is drastically changing and this happen because the oil phase occupies the larger pore volume, they are easy to flow they are actually contributing towards the production means total flow rate. Hence the water flow rate will drastically reduce the permeability will drastically reduce in that region. Second observation will cease to flow at relatively large saturation so if we see here the water flow will cease relatively the large saturation here compared to oil and the water will not be moving this happens because the water is the wetting phase and the capillary pressure is large in those small pores and they are not allowing water to flow until significant cornet water saturation is achieved. In oil curve side oil begin to flow at the relatively low saturation so compared to water water need this much saturation to flow while the oil is having little bit less value compared to the water when it begins to flow when the fluid begins to flow the saturation at this condition is called the critical saturation. Oil curve at low SW change in the SW have only small effect on k ro so the relative permeability does not change much at the relatively low water saturation conditions so the changes there in the water saturation while the permeability of the oil does not change much in that region.

The critical saturation and the noticeable saturation they are interchangeable word but their values differ depending on how we are calculating them. Similar to capillary pressure hysteresis we can have the imbibition and drainage process both to calculate the relative permeability of oil and water in two phase system and when we are having the imbibition process the diagram or the value will be little different compared to the drainage process and this will happen for both oil phase as well as a water phase the imbibition and drainage curve will start from a different point. So for example here the critical saturation for oil in drainage process will be lesser than compared to the imbibition process. So imbibition process means the value of the critical saturation or the saturation below which the flow will not happen will be more for the imbibition compared to the drainage process. While the critical value for the water remains same but you will see the irreducible value will be different in both the cases drainage and imbibition process.

So the difference comes the critical saturation is measured in the direction of increasing the saturation for a particular phase and the irreducible saturation is measured in the direction of reducing the saturation of that phase and the value calculated here for example is different for the critical water saturation and the irreducible water saturation and similarly the value is different for the conduit water saturation for the oil and for the irreducible water saturation. So depending on we are doing the drainage process or we are doing the imbibition process the value of irreducible water saturation or the conduit water saturation will be little bit different. The diagram can also be seen in this similar manner as we had seen previously where the immobile water will be there or immobile oil region will be there between these two region the flow is not happening and at this conditions the value of permeability will be called the permeability of oil means the relative permeability of oil at conate water saturation and here the relative permeability of the water at the conate oil saturation condition and they will become flat means beyond this point they are not the function of the saturation. So when it comes to calculate the relative permeability a laboratory experiment can be done and then laboratory experiment need to be done at different saturation because the relative permeability is a function of saturation. So large number of the experiment will be required and when the core is changing every time we have to do such kind of the experiment and then all of those data will be utilized to calculate the relative permeability.

Another way could be defining effective phase saturation as a correlating parameter for each phases oil water and gas in terms of the saturation of oil, conate water saturation and saturation of the gas using these three expression and these effective phase saturation can be used to calculate the value of the relative permeability when two phases are present. So the conate and reducible water saturation is the lowest water saturation found in C2 condition. So this conate water saturation or irreducible water saturation depending on imbibition in drainage process the value most of the time they are interchangeable but they are having little bit different value and this is the lowest water saturation that is found under in-situ condition. So with respect to that the effective phase saturation of oil water and gas can be calculated using this expression and then several correlations are given in the literature to calculate relative permeability of the phases those are present in two phase system using the effective phase saturation.



Two-phase Relative Permeability Correlations

The effective phase saturation is a correlating parameter

$$\boxed{S_o^* = \frac{S_o}{1 - S_{wc}}} \quad \boxed{S_w^* = \frac{S_w - Swc}{1 - S_{wc}}} \quad \boxed{S_g^* = \frac{S_g}{1 - S_{wc}}}$$

S_o^*, S_w^*, S_g^* = effective oil, water and gas saturation, respectively
S_o, S_w, S_g = oil, water and gas saturation respectively
S_{wc} = connate (irreducible) water saturation

- ✓ **Wyllie and Gardner Correlation**
- ✓ Torcaso and Wyllie Correlation
- ✓ Pirson's Correlation
- ✓ Corey's Method
- ✓ Relative Permeability from Capillary Pressure Data
- ✓ Relative Permeability from Analytical Equations

Wyllie and Gardner Correlation

Oil-water system

$$k_{rw} = (S_w^*)^2 - K_{ro}\left(\frac{S_w^*}{1 - S_w^*}\right)$$

Gas-Oil system

$$k_{ro} = (S_o^*)^2 - K_{rg}\left(\frac{S_o^*}{1 - S_o^*}\right)$$

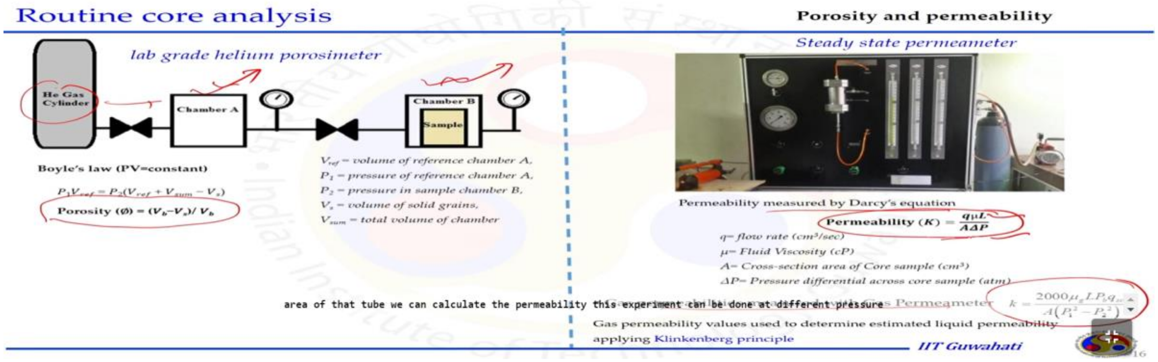
For example, Billy and Gordon correlation they gave the expression to calculate the because MMC can calculate the relative permeability of one phase when the other phase relative permeability is known using the expression of these effective phase saturation for water similar for gas-oil system the relative permeability of oil can be calculated if the relative permeability of gas is known so if one phase relative permeability is known the other phase relative permeability can be calculated using the effective saturation expression when it comes to the-,igg three the reservoir domain is occupying the three phases it becomes more difficult to calculate the value of relative permeability for each phase experimentally it is very difficult it involves rather complex technique to determine the fluid saturation distribution along the length of the core hence it is proposed to calculate relative permeability of the three The three phases system the pore available for the flow of oil and the pore available for the flow of gas and the remaining for the water needs to be classified and the system can be simplified with certain assumptions for example the relative permeability of the water is just a function of the water saturation relative permeability of the gas is just a function of the gas saturation and the relative permeability of oil is a function of both water and gas saturation.

It happens because it is believed or it is assumed the pore available within the reservoir domain are occupied by oil and gas in a systematic manner like the pore available for flow of oil are those that is in size are larger than pore passing only the water and the pores those are occupying the oil are smaller than those allowing the gas to pass through it. So the oil are in the poorest region of in the size lesser than gas more than water. So the pore available in the reservoir domain are occupied by oil and gas in water. So it is considered in three phase permeability calculation or relative permeability calculation the oil is occupying the pores those are larger than the pores occupied by the water and smaller than the pores occupied by the gas and further two phase system need to be designed to calculate the relative permeability of the phases like the oil water system and oil gas system using this two phase relative permeability calculation can be used to calculate the relative permeability of particular phase in three phase system. So this is the relative permeability of oil water system relative permeability of the oil gas system that is here in the oil gas system both are multiplied to calculate the value of relative permeability of the oil in three phase system more complex expression are there in the literature to calculate the three phase relative permeability using the and other reservoir properties.

So let us discuss little bit more about the core analysis that is the way of characterizing the rock sample. So the rock sample collected from the field is subjected for the core analysis that is divided into two parts routine core analysis porosity permeability and the saturation measurement and special test to measure the wettability of the rock it is oil weight or the water weight capillary pressure relative permeability calculation and the surface and interfacial tension. Later on the core flooding experiments needs to be performed to understand the nature of the core with respect to implementing secondary and tertiary recovery process. So we will discuss few of them in today's lecture how these core analysis are performed in the laboratory. So the core samples are collected from the field they are taken like plug form taken out from a big piece of the rock they are in the cylindrical form having fixed length and the fixed diameter these core plugs cut from the big size needs to be cleaned in the Soxhlet apparatus or in the ultrasonic bath further dried them to take out the solvent out of these samples and then these core samples become ready to be characterized in the lab.

So the routine analysis is the porosity measurement lab grade helium porosimeter is shown here this is a two chamber system where one chamber is the reference another is the sample holder where the sample is placed the dimension of chamber A and chamber B are same the volume occupied by the gas let us say helium gas is flown here in chamber A is just occupied within that tank while chamber B the volume is reduced because the sample is there if the sample is having no porosity means no permeability no porosity the completely like not allowing any gas to diffuse in then the volume of level for the gas to filled is chamber B volume minus the volume of the sample but if the sample is porous in the nature and then that volume will be utilized by the gas to fill in hence the volume will be depending on how much porous that material is using the voice law P1V1 is equal to P2V2 we can measure the pressure of this non volume chamber pressure at this volume that is need to be corrected with respect to the porosity we can calculate the value of the porosity of a sample that is placed in the chamber now we can flow the gas at different pressure does not matter because ultimately the pressure change with respect to the volume in both the chamber is utilized to calculate the value of porosity of the sample the steady state perimeter is shown here so both the setups are in

IIT Guwahati so the picture are taken from the IIT Guwahati lab where the permeability measured using the Darcy law we know the permeability is measured using the Darcy law that is this is the expression for that and the gas permeability measured with gas perimeter and this is the expression is used to calculate the permeability so the packing of the porous medium is created the pressure difference across that length L is calculated we know the viscosity of the flowing fluid we know the cross sectional area of that tube we can calculate the permeability this experiment



Routine core analysis

lab grade helium porosimeter

Boyle's law (PV=constant)

$P_1 V_{ref} = P_2(V_{ref} + V_{sum} - V_s)$

Porosity (Ø) = $(V_b - V_s) / V_b$

V_{ref} = volume of reference chamber A,
P_1 = pressure of reference chamber A,
P_2 = pressure in sample chamber B,
V_s = volume of solid grains,
V_{sum} = total volume of chamber

Porosity and permeability

Steady state permeameter

Permeability measured by Darcy's equation

Permeability (K) = $\frac{q\mu L}{A\Delta P}$

q= flow rate (cm³/sec)
μ= Fluid Viscosity (cP)
A= Cross-section area of Core sample (cm³)
ΔP= Pressure differential across core sample (atm)

Gas permeability measured with Gas Permeameter $k = \frac{2000\mu_g L P_b q}{A(P_1^2 - P_2^2)}$

Gas permeability values used to determine estimated liquid permeability applying Klinkenberg principle

`area of that tube we can calculate the permeability this experiment can be done at different pressure`

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16

can be done at different pressure to see the effect of the pressure because with respect to gas the permeability will be varying then the true value of the permeability and later on those different value of the gas permeability calculated at different pressure can be extrapolated to get the actual value or the liquid permeability of the formation so the gas permeability values used to determine or estimate liquid permeability applying the Klinken work principle the wettability determination of the rock sample estimated through the contact angle measurement as we already discussed the procedure is take the cylindrical core disc prepared from the rock you may take just a small chip of that cylindrical core disc cleaned it dry it and surface polished it and then saturated it with the brine or the crude oil with respect to which fluid we want to measure the contact angle the surface should be polished with it or saturated with it and then the contact angle can be measured in two ways first one is like the surface where we are putting a drop of the face whose affinity towards the rock is measured for example we are measuring for the brine the brine will be dropped if we are measuring for the crude oil the crude oil will be dropped after equilibrium is achieved the droplet image is captured and the contact angle is measured and this contact angle theta will tell us the nature of the rock for that particular type of the fluid that is used to measure the contact angle so we can do it for the brine we can do it for the crude oil we can do it for the water and this second picture is showing how the crude oil is spread not completely but the contact angle changes and in this case the rock is having the affinity for the oil and the rock that is taken out from this section of the big piece is actually the oil wet reservoir rock. Second method is the surface is placed on the top while the droplet is injected into the media from the bottom so this is kind of a closed chamber where the fluid is there saturated with the brine the entire section and then the drop of the liquid is injected that is going to adder on the surface and then the spread of that liquid droplet will determine by the contact angle measurement and we will be able to measure the contact angle and that contact angle will tell us the affinity of the rock to that fluid it is going to be oil wet or water wet or the mixed wet. So in this core disc is immersed in the water brine while droplet dispense from the underneath of the core and after equilibrium again the contact angle is measured as done in the first method. Under the special core analysis we are having this core flooding experiment this will be discussed in more in the water flooding and the enhanced oil recovery class but let us understand the basic of the core flooding setup. This core flooding is having this core holder section which can be maintained at a particular temperature and pressure using the syringe pump we can flow specific types of the fluid either it is gas, oil, brine or any chemical through this cores.

So we are having the core that is plugged from the field that core of a specific dimension is put in this core holder shield it nicely pressure gauge are there to measure the upstream and downstream pressure and the fluid with this help of syringe pump at a constant flow rate is passed through it. So first we pass the brine solution to saturated the core with the brine then the oil for the oil saturation and for the recovery purpose we inject the CO2 and the other gases. So the procedure is laid out here if we are using this core flood for the recovery purpose procedure could be little bit different. We are using to determine the rock permeability and estimate the oil recovery the fluid the procedure could be like this clean the core and placed in the core holder. So when we determine the rock permeability and estimate the oil recovery systematically procedure can be adopted for example the clean and dried core plug first need to be placed in the core holder.

The air is removed by pushing the CO2 so there should not be any air within the core we can flush out the core with the CO2 and then vacuum it. So even the CO2 is taken out and then it is saturated by supplying the brine this formation water Fw is formation water or the brine solution that is passed through it then saturated with the crude oil secondary water flooding is performed and then the tertiary injection depending on what is scheme of the tertiary injection is adopted it can be done and later stage how much oil still remain there or the crude remain there the extended water flooding is performed to recover that and later on the core sample is taken out from this core holder subjected to soxhlet extraction and again we can measure how much oil was still trapped in the core even after perform the secondary tertiary and extended water flooding. So the measured data what we can measured here we can measured conduit water saturation absolute permeability oil recovery and pressure drop pressure drop with the help of these two pressure gauge across this section now this pressure drop data knowing the fluid viscosity knowing the dimension of the core we can calculate the permeability also.

Some more characterization of the rocks need to be done in the laboratories some of the images I am showing here those facilities are available at IIT, Guwahati so for example these are the rock samples these rock samples can be utilized as it is if the process is able to handle the core plug otherwise they are crushed into powder form and subjected for different analysis. So for example FTIR that can be used for the solid and liquid sample it will give us the functionality of different compound present in the sample SEM that will give us the morphology of the samples this FE SEM EDS that will give us the elemental analysis of the element present in the rock sample XRD can also give us the crystallinity of the samples.

Porosimeter and gas perm they are the commercial equipment those can give us the porosity and permeability value for the samples and BET surface area can also be utilized to measure the pore size and the pore volume present in the sample. Similarly the BET surface area is done with the powder sample so we get total porosity using the BET. For the rock fluid interaction we can use the goniometer that is the instrument to measure the contact angle or in other terms the wettability of the rock for a particular fluid. Spin drop tensiometer this is utilized to calculate the interfacial tension of two phases heavy and light phases. Auto tensiometer to calculate the surface tension between the fluid of interest and the air and the rheometer to calculate the or estimate the value of the viscosity of the fluid in the consideration.

So for example we are using the Darcy law to calculate the permeability we need to know the viscosity of that fluid that can be measured with the help of rheometer. When we are trying to understand the wettability nature of the rock we can use this goniometer to calculate the contact angle and the IFT and surface tension they are also important as a part of the fluid rock interaction can be measured with the help of spin drop tensiometer and auto tensiometer. So with this I would like to end my today's lecture on properties of the rock. In the next lecture we are going to understand different types of the primary dry mechanism those are responsible for the primary production of the fluid to the surface from reservoir depth. This diagram is broadly classifying the type of the rock those need to be there like the source rock from where the petroleum fluid is produced.

There should be the reservoir rock that can hold these fluid and there should be a cap rock and the cap rock that is letting the fluid at the reservoir domain. The production well are drilled to reach that point and getting the production happen and this production happen because of the pressure energy that is the primary source of the energy. So there could be several mechanism responsible to maintain that pressure that could be a aqueous fire gas cap and the production wells are drilled to take this fluid to the surface. So in the next lecture we will discuss about the primary recovery drives those are responsible for the primary production of the fluid. So with this I would like to end today's lecture thank you very much for watching the video we will meet in the next lecture thank you.