Petroleum Reservoir Engineering

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Lecture 8: Reservoir Rock Properties

Hello everyone and I welcome you again to the class of Petroleum Reservoir engineering. In this lecture, we are going to continue our discussion of reservoir rock and fluid properties. Earlier we had discussed the fluid properties like the properties of the gas, oil and water. If you see in the symmetric diagram here, the oil, gas and water are stored underneath the surface in the reservoir rock. This reservoir rock could be a variety of type, we discussed in the petroleum geology. Mostly it is carbonate and sandstone reservoir, where the hydrocarbon fluids are stored. That is, we call the sedimentary rock, where the possibility of getting the hydrocarbon reserves are high.

These petroleum fluids are in the contact with the reservoir rock. So it is very important to understand the properties of the reservoir rock that is actually holding the reservoir fluid in the reservoir rock as well as it is allowing the fluid to flow from one place to other place. So the properties like porosity, permeability, saturation would be discussed in this lecture of week 3, lecture number L1. So let us continue that discussion about the reservoir rock properties.

So what is the reservoir rock? From the society of petroleum engineering, the definition of reservoir rock is a rock that is porous in the nature, that is having the permeability to let the fluid flow and hold sufficient hydrocarbon reserves that can be produced in a commercial flow manner out of this reservoir to the surface and those can be utilized. Most prominent feature of these reservoir rocks are porosity, permeability and the fluid saturation. Actually, if reservoir rock is there, but it is not having any porosity or very limited porosity let us say less than 5% porosity, the amount of the hydrocarbon reserves going to be stored if they are there is very less. And this reservoir rock which is holding a small amount of the hydrocarbon fluid may not be viable to explore and produce to the surface in the economical manner. Similar property for the permeability, if reservoir rock is having very low permeability, let us say less than 1 millitarsi, then the fluid is not able to migrate from one place to other place within the reservoir rock and good amount of the flow rate cannot be achieved.

And again, this is also not a good commercial viable well or reservoir domain which is going to produce the significant amount of hydrocarbon fluid. Fluid saturation is how the fluids or hydrocarbon fluid are distributed within the reservoir rock. We will discuss all these properties one by one. Properties are investigated by performing the core analysis. So as this reservoir rock is underneath the surface, the measurement cannot be done in situ means going there and measuring it.

For that purpose, the rock is taken out to the surface, core plug samples are taken from that rock and those core samples are subjected for the laboratory analysis to measure several properties. Those are essential to characterize the reservoir rock in terms of their hydrocarbon production capacity. Study of rock properties and rock interaction are done by the group of the scientists we call the petrophysicist. Physical properties of petroleum reservoir rock can be estimated theoretically with the help of some fundamental theory and the developed correlation or it can be subjected to the laboratory where the real time data can be obtained for a particular sample that is subjected for the particular analysis. In this picture, I am showing you here, there is a several rock samples.

Those are in the box kind of the things. We can assume this is the reservoir. Within this reservoir, if we say they are placed randomly. It is similar kind of the structure in the reservoir rock where the small grains or particle size in different geometry and shape are distributed randomly. Within this sample of the fine particles, you will see there are certain reason where the connection is there.

Fluid can travel from one place to other place like this. But there are certain voids, those are isolated, those are not having any connection, fluid cannot enter to those. So many void spaces are interconnected while some are completely isolated within the reservoir and that makes the reservoir heterogeneous in nature in terms of both porosity, permeability and some other properties like the saturation or distribution of the hydrocarbon fluid. So the rock property determination of the rock properties is essential because these properties help us to quantify the hydrocarbon fluid those are present there and their distribution how much oil, gas and water are distributed within the reservoir rock. When these rock properties are combined with fluid properties, we can get a better control on the flow profile of different fluid, oil, gas and water from the reservoir to the surface.

So the core sample as I mentioned are taken out from the reservoir rock. This big chunk of the piece is again plugged to get the specific diameter or size of the core sample. Basically these cores are of 1 inches or 1.5 inches or depending on the analysis or the instrument available could be of different size. The length varies 6 inches to 12 inches even sometimes the 4 inches cores plug are also collected from the reservoir rock.

The core plug preparation needs to be done before the core are subjected for the core analysis like these need to be cut from the large rock cleaned in Soxhlet apparatus or ultrasonic cleaning can be performed to take out whatever the fluid that is present. So making this core as clean as possible this is having only the rock all the hydrocarbon fluid or the water can be taken out with the help of soxhlet apparatus or ultrasonic cleaning. And then further to remove the solvent that is used in the soxhlet apparatus or in ultrasonic the sample needs to be dried in the oven and after doing that the core sample is ready to subject for different core analysis. The core analysis can be performed in two categories first one is routine core analysis called the RC analysis. Basically the measurement of porosity permeability and saturation are done under this category.

So this is a routine job to measure the porosity and permeability and saturation when the core sample is taken out from the reservoir rock and sent to the laboratory. Some special test also need to be performed on these rock plugs depending on the need these special core analysis measurement include the relative permeability test, wettability measurement, core flooding experiment and some other. So the course analysis of this kind of the sample which is some 1 inch in the diameter and around 4 to 6 inch in the length is subjected routinely for porosity permeability and the saturation and the special test capillary pressure could also be included in it relative permeability wettability measure and the surface interfacial tension measurement of the fluid are also part of the analysis. So the properties of the rock those are measured in the laboratory depend on the types of the rock and the other properties like porosity, permeability, capillary pressure, water saturation and the distribution of the pores they are interrelated one parameter affect the others. So for example water saturation, capillary pressure they all depends on the pore distribution within the rock.

So porosity and permeability they are also interrelated in terms of how much porous the region is and how much permeable the region is. I mentioned if there is no porosity there is no permeability. So in continue to measurement the properties let us understand the reservoir dimension first. So the physical characteristic of reservoir are greatly affected by the depth at which they occur. So the reservoir as I mentioned earlier are underneath the surface they spread it from several thousand feet depth and the reservoir could be in the shallow depth or could be in a very deep reservoir.

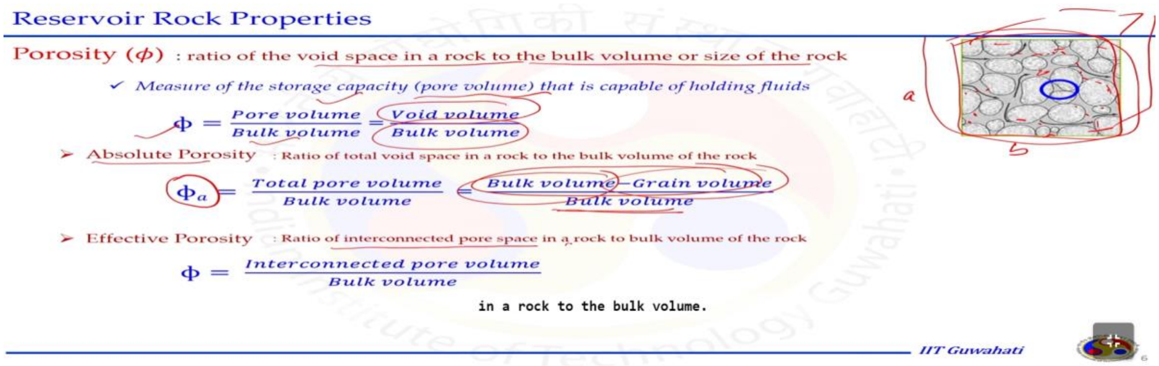
From the common understanding if we are going to deeper side the properties like the porosity and permeability reduces and actually the deeper we are going the chances of getting the gas reservoir is more. So let us restrict our discussion to the dimension of the reservoir that is in terms of area and thickness. So this is kind of the Q-wide assume Q-wide the actual geometry is very heterogeneous in nature where the structure of the rocks like the cap rock, source rock and the reservoir rock are arranged beautifully and within this reservoir rock the fluid like the gas, oil and water are stored because of the gravity differences they achieve the equilibrium and the position of gas, oil and water are stored in this. This is just not a pool kind of the structure where the fluids are stored there are several small pores also there where the fluids are stored in the microscopic dimension. So the overall recovery of such kind of the reservoir is divided into two parts macroscopic and the microscopic we will discuss that in later stage.

Here we want to see the thickness that is also we call the page on thickness and the area that is very important because when the drilling operation decided to drill at a particular location it is the foremost important to estimate what is the reservoir capacity how much oil and gas this reservoir is having and at what rate we can produce those to the surface that depends on the area and the thickness. So the total area of reservoir and its thickness are of considerable importance in determining if a reservoir that is going to be drilled with several wells is having commercial potential or not the greater the area and the thickness so the volume of the reservoir that is holding the hydrocarbon fluid if it is more the chances of getting the more oil and gas. However there are reservoir those are not in large size but they are producing the considerable amount of oil and gas that depends on how they are connected with the other sources and how the continuously the oil and gas is coming to that production zone and from where it is going to produce to the surface. But overall the area and thickness are two important parameter to define the size of the reservoir rock fluid those can be produced. Now the distribution is like this several sections are there the properties are distributed within the reservoir as I mentioned it is very heterogeneous in nature in almost every aspects so the averaging reservoir property data are considered whenever we are doing the mathematical calculation.

So for example when we are seeing what is the porosity of this reservoir it is not a single value because the porosity will vary from location to location several samples are collected and analyzed and the average value of the porosity is used in the calculation. So the porosity, permeability, compressibility factor, capillary pressure, wettability and relative permeability are some of the important parameter those actually characterize the reservoir in terms of its holding capacity for the hydrocarbon fluid and how much hydrocarbon fluid can be produced from this particular reservoir. So let us discuss one by one all these properties in little bit more detail for example we can start with the porosity. The porosity is the ratio of wide space in rock to the work volume or size of the rock. So in the previous diagram if we see this is looking like a cube wide we can take the dimension in all three direction and can calculate the volume.

For example, ABC the volume is length multiplied by the width and multiplied by the height. But this is the bulk volume of the rock or the reservoir domain. This entire volume is not available to occupy the hydrocarbon fluid. The volume that is in the form of void in the reservoir rock that is actually is responsible to hold some volume of the hydrocarbon fluid. So the void space in the rock divided by the bulk volume or the total dimension of the reservoir rock is the porosity.

Measure of the storage capacity this pore volume that is capable of holding the fluid. So if there is no pore volume in the reservoir rock it is not having any space to hold the reservoir fluid. Hence this reservoir is not having significant amount of the hydrocarbon fluid. Mathematically sense the phi that denotes the porosity is defined as the pore volume divided by bulk volume. Pore volume is the void volume divided by the bulk volume.



We can see in this picture the volume of the studio picture for example we can have A, B the bulk volume is A cross B and the other dimension cross C. But the void volume that is the volume here other than these grains that is actually the void volume. So the void volume is the volume that is having some empty space within the reservoir rock. The porosity that is the ratio of void space in the rock to the bulk volume can be classified into two parts. Absolute porosity and the effective porosity.

So what is absolute porosity? Absolute porosity is total pore volume of the reservoir domain that is under the consideration divided by the bulk volume of the same reservoir rock. In other terms the absolute permeability can be defined as bulk volume minus grain volume. So this is the total volume for example within the other dimension and the grains volume is calculated. The grain volume can be subtracted from the bulk volume and whatever remaining is the total pore volume divided by the bulk volume of the reservoir rock we call the absolute porosity and denoted by phi A. While on the other side effective porosity that is the ratio of interconnected pore space in a rock to the bulk volume.

So there are pore volume or pore space within the reservoir rock but those pore space are not connected. They cannot be accessed. They are having some isolated formation where no fluid can reach. They just having void is within it but nothing can reach to that fluid because those are isolated pores and the effective porosity does not count them.

Effective porosity only counts the interconnected pore volume where the fluid can reach, where the flow can happen even it is very less flow but they are connected.

For example, here you can say the pores here and the pores here they are connected by this arrow. We can say the fluid can travel from A point to B point through this part. So the interconnected pore volume divided by bulk volume is actually phi and that is actually the value that is used in almost all engineering calculation. So it is not the absolute porosity that is used it is the effective porosity that is used for the engineering calculation in the petroleum reservoir engineering because that is actually account for the recoverable hydrocarbon fluid. It does not mean the isolated pore are not having hydrocarbon fluid.

They might be having some hydrocarbon fluid but they are not connected to the reservoir domain they become isolated and they will remain isolated. That is why they are not counted in terms of the production profile or estimating the oil and gas in place calculation. It is the effective porosity that is calculated. In terms of the equivalency effective porosity will always lesser than or equal to total porosity. Total porosity means absolute porosity.

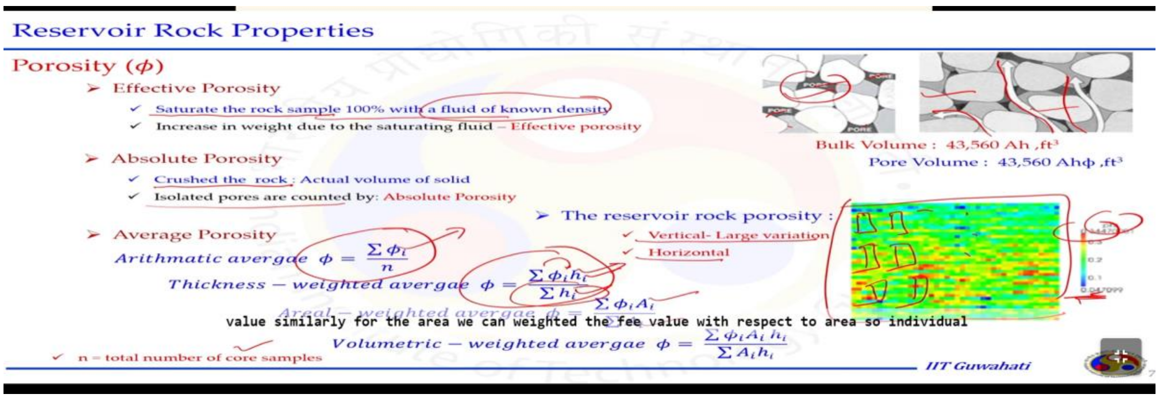
If we nicely place them in a systematically this more different size of the grains and arrange them nicely we can calculate the porosity possibility within the reservoir domain. But as reservoir domain is very heterogeneous the value of porosity varies from 10 to 30 percent or even sometimes lesser than 10 like 5 percent something sometimes greater than 30 around 40 percent. Depending on how this irregular shape grain particles are arranged underneath the surface overburden pressure is there, reservoir fluid pressure is there and in that domain the porosity could vary even within a small section. So the porosity can be defined further into three category primary porosity that is actual porosity in the deposition when the deposition happened. Secondary or the induced porosity when certain disturbance happen into the deposition by natural process or by some other mean the porosity changes because of the migration or some other physical processes that is happening in the reservoir domain or by the fracture.

So sometimes the fractures are created naturally or by the manmade process the porosity can vary but in general what we use the effective porosity taking out the core sample measuring in the laboratory and perform the experiment on a large number of the sample taking out the average to calculate the effective porosity. So the effective porosity let us elaborate more on these two properties effective porosity and absolute porosity. Effective porosity is calculated when the rock sample is saturated with a single fluid 100% one type of the fluid is there it is 100% saturated with a fluid of non-density.

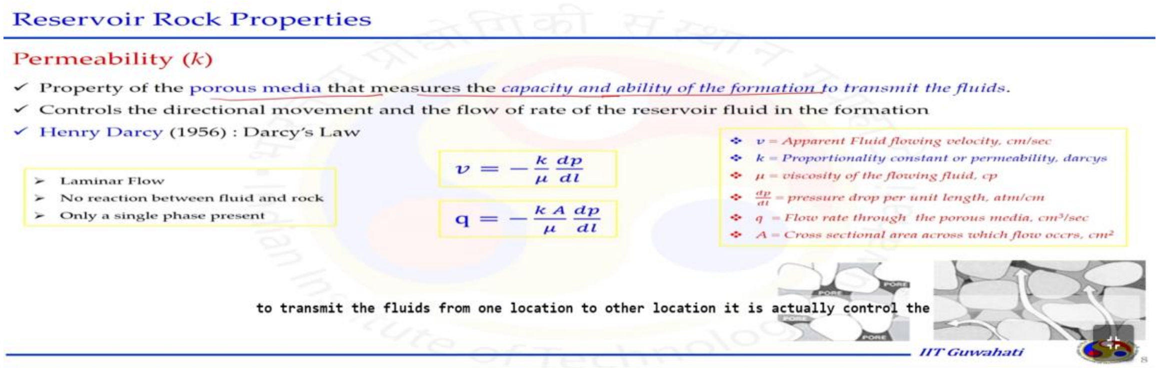
Increase in weight due to saturating fluid is actually the effective porosity. What does it mean if you see here these two picture are showing one is showing the pore volume that is here some pores are connected some are not connected and the other picture is showing how these pores can be accessed by passing the fluid.

So for example the core sample is taken the fluid of non-density is passed through it because of passing the fluid at a particular pressure into the porous region the fluid will occupy those small pores those are present in this rock sample and after understanding the 100% saturation is happen the core will be taken out and measure the weight. The increase in the weight is actually because of the fluid of non-density that is entered in those small pores those were connected and the weight can be converted to the volume by knowing the density and once we know that volume that is actually the pore volume divided by the dimension of that core that is the work volume we can calculate the effective porosity. To calculate the absolute porosity means the total porosity that is present that is connected or not connected we can crush the sample or we can destroy the region that is making some of the pores isolated in the domain and when we are breaking those the connection or reaching to those isolated region we are kind of letting every pore volume to be measured when we are passing the fluid of non-density. So, all the pores are accessible and this can be done when we can crush the sample make it powder so the small size of the grains those are put in the powder form now the fluid that is going to meet these pores is having the access to almost all the pores those were previously not connected are also excess this time. In that case the porosity of the crushed rock is called the absolute porosity and isolated pores are also counted in the absolute porosity calculations absolute porosity that is why is always greater than or equal to effective porosity.

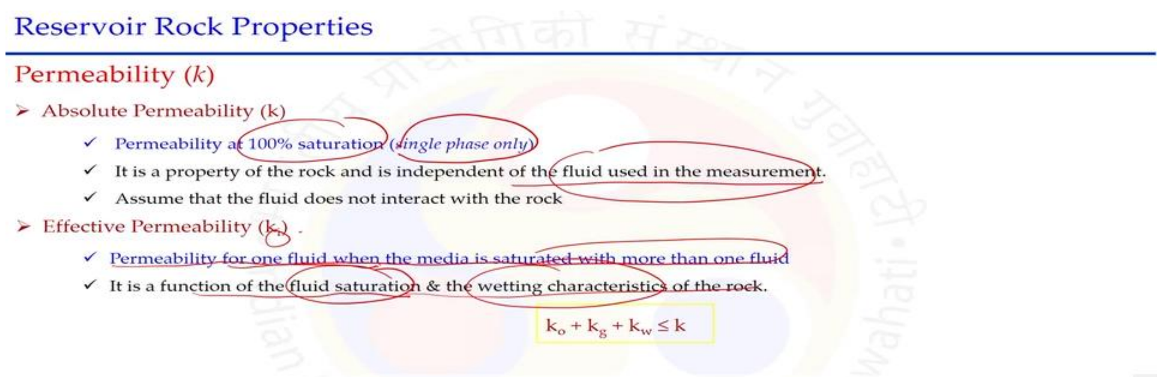
The porosity values varies as I mentioned even like in one feet or even within six inch course you can see some section is having high porosity some is having the lower porosity value so the distribution could be there from 5% to 40% the variation could be there in terms of the porosity that is accessible within the reservoir domain for that purpose we can see this picture is showing the variation in the value of the fee from 5% to 35% in terms of color coding. So the different colors are having the different value of the porosity and that says the variation is there large variation in the vertical direction and relatively in the horizontal direction the variation is not that much but the variation is there so for that purpose the samples from a different sections are taken multiple sections are used to take the core plug and then each core plug is subjected for the porosity measurement and that porosity measurement we do the effective porosity that I said the effective porosity that is the pores those are connected can be accessed by the fluid and that is actually the value is required in all the calculation related to reservoir engineering. So to take the average of the porosity we can take the arithmetic average take the sample n number of the samples are taken and those n number of the samples are having different fee value we can take out the arithmetic average of it to have the more or better accuracy as the value may vary with respect to the size of the sample every time it is not possible you are taking the same size of the sample in terms of the area or in terms of the height so for example the sample of different heights or thickness are taken out from the reservoir domain then the thickness weighted average value of the porosity can be calculated using this formula where the fee multiplied by hi of individual core samples divided by the summation of all the height so this is the weighing factor hi in thickness weighted average value similarly for the area we can weighted the fee value with respect



to area so individual porosity is multiplied by individual area and summation of all of that divided by the summation of the area and now similar can be done in terms of the volume so both area and height they are varying for all the core samples and in that case we can use area multiplied by height means the volume of that core sample for all the core samples and the volumetric weighted average value of fee can be calculated so the variation in the porosity can be taken out as the average value for multiple samples this is the value of fee that is actually holding the fluid so the bulk volume for example is area into height for the entire reason this is the numerical value coming because of the balance of the unit because area is measured in acre but when we are measuring the volume into feet cube some numerical value will come so we can ignore it this is just area into height is the bulk volume but the pore volume that is available to hold the fluid is ah multiplied by the porosity of that reason to calculate the pore volume similar to porosity permeability is also very important feature of the reservoir rock actually permeability is the property of the reservoir rock that is actually determine how much fluid migration can happen from one place to other place this is the property of the porous

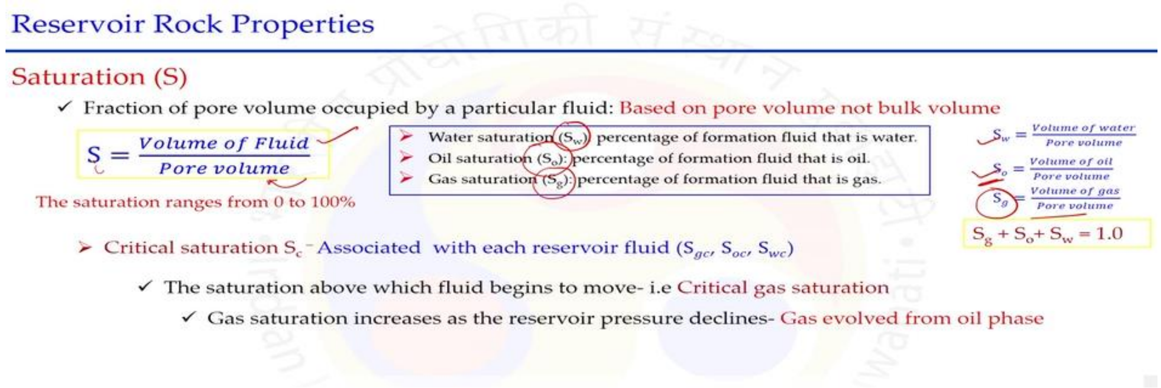


media that measure the capacity and ability of the formation to transmit the fluids from one location to other location it is actually control the directional movement and the flow of rate of reservoir fluid in the formation in which direction we are having the more permeability the fluid will move in that direction where the permeability is very less in a reason the fluid will not be moving in that direction or very low flow rate will be achieved in that direction the value of the permeability is calculated using the Darcy law Darcy law we discussed in detail previously under certain assumptions the Darcy law was established the Darcy law says the value of the flow rate or the velocity here Q is equal to area into velocity so we can convert the velocity into flow rate or flow rate into velocity that is value is proportional to pressure gradient across two points and inversely proportional to the viscosity of the fluid that is passing through that porous region and the proportionality constant K is actually the property of the rock we called it permeability that is measuring how easy the fluid can pass through that porous media so the notations are similar V is for the apparent fluid flowing velocity measure in centimeter per second the value of this proportionality constant or permeability is actually Darcy in the honor of Henry Darcy the permeability unit is given as Darcy when the unit value of all these like the viscosity pressure gradient area are put up in this expression to find out the value of K that comes out in a very small number hence the Darcy is converted into another form that is called Millie Darcy so one Darcy is equal to 1000 Millie Darcy that is the value of the permeability or the proportionality constant in Henry Darcy if we are following the Henry Darcy principle the assumptions are there that says only single fluid is passing through the porous media in that case the value of the permeability calculated is the absolute permeability and the absolute permeability is measured by the Darcy law when multi phase is present there are other form of the relative permeability and others we will discuss later on so measuring the fluid so the value of the permeability is measured by passing a fluid of non viscosity through a core plug of major dimension this dimension already known so we know the length we can measure the pressure across that length we know the viscosity of the fluid we can perform certain number of the experiment and the proportionality constant can be calculated when we are passing a single phase fluid we can calculate the value of K similar to porosity permeability is also classified into two parts initially absolute permeability and the effective permeability so what is absolute permeability the value of the permeability when there is only single phase is present at 100% saturation it is a property of the rock that is independent of the fluid using the measurement assume that the fluid does not interact with the rock is one of the assumption when we calculate the absolute permeability value by performing the experiment using the Darcy law effective permeability denoted by KI permeability for one fluid when the media is saturated with more than one fluid so the absolute permeability is the permeability of the media when only single phase is present while the effective permeability when more than one phase is present so we are calculating the permeability of one phase while the other phases are also present in the porous media it is a function of the fluid saturation and the wetting characteristic of the rock so the two terms are appearing fluid saturation and the wetting characteristics we will discuss what does it mean how much fluids of one phase is present and how much fluid of other phases are present in the reservoir the fluids share the void volume how much saturation of oil is there gas and the water

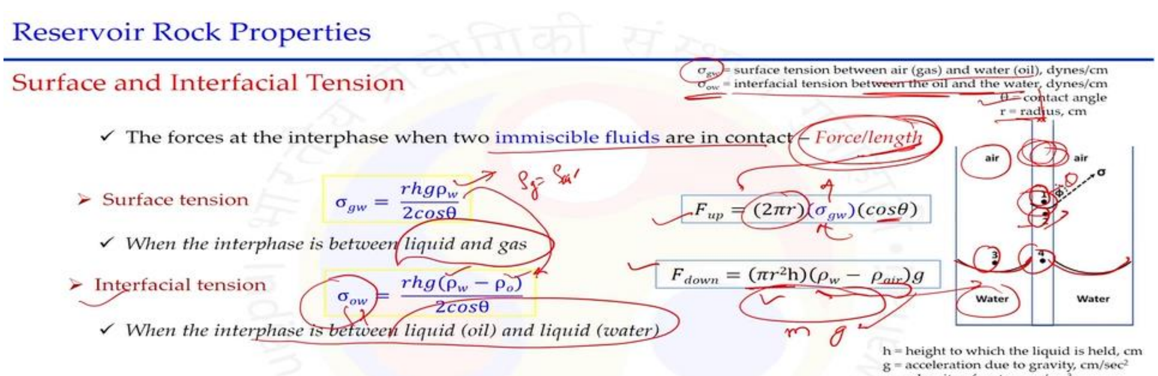


that affect the value of the effective permeability and how these properties or how these fluids are having the affinity to the rock they are stored in also affect the calculation of the effective permeability so the effective permeability is denoted by KI initially we will understood the permeability is absolute permeability and the effective permeability the effective permeability is denoted by KI so this could be KO for the oil KG for the gas KW for the water and the summation of all the phases those are present in the reservoir if we calculate the effective permeability for each phase sum all of them that will always lesser than or equal to absolute permeability that is K because that is the permeability when the single phase is present when multi phase is present even the summation of all of them could be equal to K or will always be lesser than equal to K another important features of the permeability is relative permeability actually this is the permeability that is used in the calculation when more than one phase is present in the system so this is the ratio of effective permeability to absolute permeability so this is effective permeability this is absolute permeability the ratio of these two is the relative permeability in mathematical sense this is KI divided by K and relative permeability is denoted by KRI I is the phase individual relative permeability of different phases like

KRW that is the relative permeability for water similarly for the oil and the gas that will vary in the range of 0 to 1 because the effective permeability divided by the absolute permeability could have the maximum value 1 or could have the lowest value 0 so the relative value will be between 0 to 1 the permeability depends on the pore geometry how the pore geometry is present in the reservoir domain what are the characteristic of the rock fluid interaction in terms of the wettability the fluid distribution within the porous medium and the saturation history of the reservoir rock with respect to different fluid those are present in the reservoir domain the variation in the permeability also there similar to the porosity for example here it is showing the variation in the value from a very small value like 10 to the power minus 16 to 10 to the power minus 13 in some very consolidated reservoir but the color coding is showing the variation is there and that variation again can be calculated by using different weighing factor sample are taken either the height and the area or some other parameter can be used to calculate the permeability of the reservoir domain while taking the different samples similar to the porosity value so different sample or different dimensions are taken permeability is measured and then calculated third properties in the routine core analysis is the saturation that is the fraction of pore volume occupied by a particular fluid that is based on the pore volume not the bulk volume so within the bulk volume the pore volume is there that is responsible to hold the reservoir fluid reservoir fluid is oil gas and water within that pore volume there are certain parties covered by the oil certain part by the gas and certain parties by the water so the volume of a particular fluid within that reservoir domain or porous domain divided by the pore volume is the saturation of that fluid within that pore volume so the saturation ranges from 0 to 100 percent means that fluid is not present at all in that pore volume or the entire pore volume is occupied by that particular fluid is only so the value could be vary from 0 to 100 percent if it is water saturation we use sw if it is oil saturation we use so the notation similarly the i can come here and for the gas it is sg so the sw so sg are the portion of the pore volume those are occupied by the water oil and gas respectively in mathematical form we can say sw that is the volume of water divided by the pore volume volume of the oil divided by the pore volume is so saturation of the oil and the volume of gas divided by the pore volume is sg that is the saturation of the gas the summation of all these should be equal to 1 because the total pore volume either occupied by the oil gas and water the relative distribution could vary but the summation should be equal to 1 some more terms are there like the



critical saturation associate with each reservoir fluid so the critical saturation is for gas critical saturation for oil critical saturation for the water for example when we are talking about the critical gas saturation the saturation above which fluid begins to move so the fluid is there in within the reservoir domain under certain forces in a small pore region the fluid is there but it is not moving and when the fluid is not moving means it is at or below the critical saturation the fluid will move only when the value of the saturation is above this critical saturation for example the critical gas saturation it increases as the reservoir pressure declines why it happens because when the reservoir pressure is declining the gas evolved out from the oil and the amount of the gas increases means its saturation is increasing it is occupying more volume and it is crossing the critical gas saturation barrier and it is flowing some more terms will be there residual oil saturation to water denoted by o r w irreducible water saturation means the value of the water saturation that will remain in the reservoir does not matter whatever the conditions are there certain part of the reservoir will always be filled by the water and this happens because of the porous nature or very very small pores are there capillary forces attract certain part of the fluids to remain in the reservoir that depends on the wetting characteristic of the fluid so the water that is considered as a wetting phase while is considered as a non wetting phase in that case the small percent of the water will always remain in the reservoir and that remains and that happens with the oil also there so when the oil is below critical saturation condition the oil will not be flowing doesn't matter how much porous and permeable the path is we will discuss that in more detail. Conic water saturation another condition within the reservoir that is because of the capillary forces the water remains within the reservoir domain it is important in poor space of capillary size when the small small poor reason we are talking about the conic water saturation is already so well water saturation becomes important the term residual saturation is usually associated with the non wetting phase when it is being displaced by wetting phase so wetting phase is displacing the non wetting phase the residual saturation terms is often used to characterize the phenomena when it comes to the average value of the saturation similar to the porosity and permeability it can also be weighted with respect to the porosity of that reason height of that core sample that is used for the characterization and s xi this is the i is the number of sample s is the saturation and x is that phase so when we are talking the s g this will become s gi i means number of sample not the phase and similar this is the weighing factor here the entire numerator has to be divided by summation of that factors in the denominator so hydrocarbon saturation can be measured by the direct method or from the core analysis by extracting the hydrocarbon fluid from the rock whatever the amount of the hydrocarbon fluid we are getting that is the actually saturation of that core sample another is the indirect methods this is acquired data to calculate the saturation based on some other physical properties what those other physical properties could be porosity resistivity saturation relationship this is given by arches long time back and this relationship between the capillary pressure and hydrocarbon saturation can be established that can also give us how much saturation is there if we are having the capillary pressure data so what is this capillary pressure is a natural phenomena that governed by the pore throat size and the wettability between oil to the rock surface and the surface tension between the immiscible fluid so this is in the capillary region or small pore region the pressure is there because of the discontinuity in the pressure of two phases and that is actually characterized by the wettability surface tension and other part so what is wettability is a fluid to solid attraction forces we will discuss later on similarly what is surface tension it is a fluid to fluid attraction so when we are talking about fluid to fluid attraction it is the surface tension when it is fluid to solid we call it wettability and these properties affect the capillary pressure within the reservoir domain in small pores so what is this wettability in more detail it is measure of the ability of a fluid to coat the rock surface so it is actually the interaction between the solid and the fluid how much affinity the rock is having to the fluid is measured by the wettability this affinity is let the fluid to either remains as a sphere or miss as a bubble on the surface not having affinity at all to the rock surface or it may spread over the surface between these two extreme range the wettability of different fluid with respect to different rock or the surface is defined so the wettability of reservoir rock to the fluid that is actually determined the distribution of the fluid in the porous media the wetting phase tends to occupy the smaller pores and the non-wetting phase occupies often open channels within the reservoir domain so the measurement of the wettability is done with the help of a property called the contact angle so the wettability characteristic of liquid for the solid is determined by the contact angle the liquid is making with respect to the surface so for example this is the surface it could be a glass surface it could be a glass surface it could be a rock surface or any surface different types of the fluid will be having the different affinity to the surface so for example here mercury when a drop of the mercury is placed here it will be in the form of the spare it is not spreading at all on the surface when it is oil the have my spare kind of this texture will be there it is having certain affinity but not as close as the water so when the water drop is placed on the rock surface the water just try to spread on the surface so the water is having almost completely wettability for the rock surface mercury is having almost no wettability to the surface oil remains somewhere in between so based on the contact value the complete wettability is the wettability when the theta is 0 the angle that's shown here theta that is 0 it means the wettability or the fluid rock interaction is completely wettable when the value is 180 then it is completely non wetting phase kind of the mercury here it is showing even this is also not having 180 degree angle when it is completely 180 degree angle the face is having complete non wetting behavior with respect to rock sample in more terms practical application of this contact angle when the system is having the theta that is lesser than 90 degree the rock is called the water wet it is having the affinity for the water and it is actually wetted by the water when the theta is greater than 90 degree it is oil wet and when the theta is around 90 it is a mixed bed plus minus 20 degree variation depending on the properties of the rock and the fluid in the contact the value may vary from 70 to 110 degree Celsius in that range the properties of rock fluid interaction that is wettability is measured and that is characterized as a system of mixed bed quality surface tension and interfacial tension the forces at the interface when two immiscible fluid are in contact so in the reservoir oil gas and water are there the oil and water they are two completely immiscible fluid water and air actually they are also completely two immiscible fluid so when the fluid are in contact at the interface there is a force that we call the surface tension or interfacial tension that is characterized what those two fluids are so for example surface tension when the interface is between liquid and gas we call the force that is measured as force per unit length at the surface is surface tension when the fluid are oil and water two immiscible fluid those are we can consider as oil and water the interface is form the properties of that interface force, force for length is called the interfacial tension.

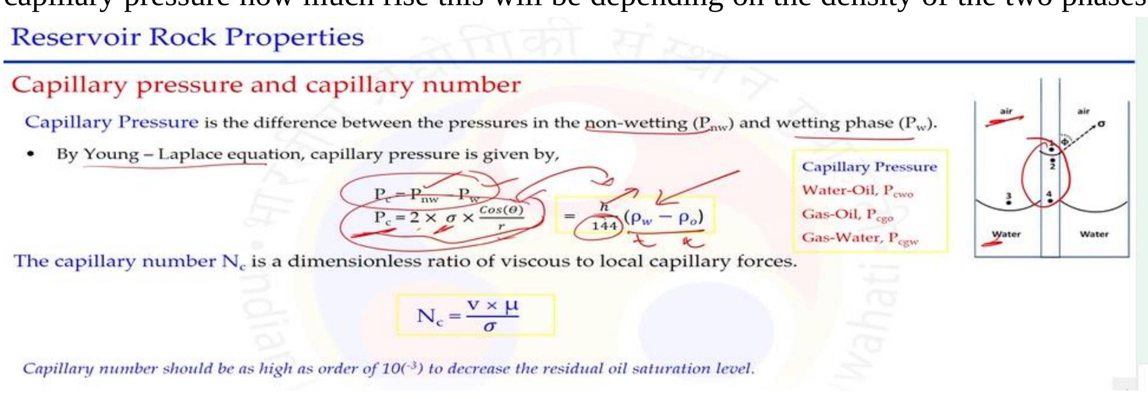


We can see in this picture so for example the small diameter capillary is placed in a large tub of the water and the upper side we are having here here we are having the water what happens at the interface a curvature nature is generated that depends on the wettability characteristic of the fluid with respect to the container we are having or the tube we are having here and if we find out 4.1234 they are having different pressure they are having different forces but the overall observation says the fluid in the water container is at a lower level while the fluid in the capillary has been risen to certain height and this happens because of the capillary forces that is capillary pressure that is applicable here and in that case the upward motion of the fluid happens this interfacial tension between the two phases come into picture and this is the theta the angle so this should be theta this is the length of that interface so this is the force for keeping the fluid upward direction gravity will pull it down so this is volume this is total density difference this will make the mass m and then we are having the j so this is the gravity forces that is pulling that fluid down and the balance of these two forces will determine how much rise the fluid can have the small capillary system so if we do the surface tension balance in this system where we can define sigma gw is the surface tension between air and water sigma ow is the interfacial tension between the oil and water theta is the contact angle and r is the radius of this tube that small diameter capillary tube that is placed we can get the condition of the surface tension when these two forces are in balance and when we do the balance we are going to get this expression in this expression it is assumed the density of the gas or the air that is very less compared to density of the water and the simple expression appears like this after doing the force balance similar expression can be get for the interfacial tension when the oil and water are the phases that is making the interface and in that case the density of the water and density of oil both are considered so if we compare this the same expression only the density term is different and in that case the value of the interfacial tension can be calculated the value of surface tension for air and water system is around 72 dyne per centimeter while for the water and oil system it varies from 20 to 30 dyne per centimeter depending on the composition of the crude oil or the quality of the crude oil.

So, the fluid in sedimentary rock are constantly subjected to different forces like cohesive surface tension addition forces and interfacial tension and capillary pressure are present in the porous media but all these forces study is subjected for the class of fluid mechanics where the more discussion is done or different types of the forces those are acting within the system for our understanding surface tension and interfacial tensions are good enough and we can relate those with respect to the fluid properties like the density and the size of the capillary or the small pores where these fluid are placed in. So, the capillary pressure in the reservoir rock domain the reservoir rock domain that is composed of varying size of the grains, pores and capillaries capillary means the small small throats are there where the fluid are restored is characterized by the capillary pressure. So, the capillary could be of different size for example here is shown in case of the water and oil the rise in the capillary depending on the diameter or the size of this capillary. So, if the capillaries of a small size the rise will be more and as the capillary is increasing the rise will be less means the force balance would be like this where the small capillary size will be having the more rise of the water in the capillary. As the size of the pores and channels decrease the surface tension of the fluid in rock increases and that is why it happens.

So, when there are several fluid in the rock each fluid is having a different surface tension and adhesion that cause a pressure variation between these fluids and the pressure that appearing because of this variation at the interface between the wetting phase and non-wetting phase is called the capillary pressure and is often sufficient to prevent the flow of one fluid in the presence of another. So, when the two fluids are present in the capillary none of them are flowing or at least one fluid is not letting the other fluid to flow because of the capillary pressure that is existing in that small capillary region. Large pore throat diameter for example here generally yield a lower capillary pressure because of the decrease in the amount of the surface tension. So, we can see here if the size is less the surface tension will be more the rise will be more and that happen in the small pore throat diameter reverse happens in the large pore throat diameter where the yield of capillary pressure is lower. So, the small pore diameter are having the higher yield of the capillary pressure because of greater amount of the surface tension.

So, the surface tension, better ability characteristic all those affect the capillary pressure. In mathematical sense we can see we are having the two phase non-wetting phase and the wetting phase the capillary pressure by the Young Laplace equation is the difference in the pressure at the interface between the non-wetting phase and the wetting phase. By equalizing the pressure value we can come out to an expression where the capillary can be shown as 2 sigma, sigma is the interface tension or the surface tension depending on the types of the fluid cos theta and r, r is the size of that pore or the capillary. If we accelerate this in terms of the density of the water and the density of the oil this is the numerical factor that is happening by the unit balance we can get the height rise in the capillary because of the density difference and the capillary pressure. So, due to the capillary pressure how much rise this will be depending on the density of the two phases.



Here it is shown for the air and water while the expression is written for water and oil. So, the density difference is more the capillary pressure will be more. Scapulary number is another important feature that says the dimensionlessly we can classify the properties of the reservoir domain in terms of nc that is the dimensionless number actually that is the ratio of viscous to local capillary forces. So, if we put the expression for the capillary forces and the viscous forces we get the capillary number in the form of V mu by sigma, sigma is the interfacial tension, mu is the viscosity, V is the velocity of the displacing fluid. To displace or recover more oil or the oil that will remain in the saturation condition or the irreducible saturation of the oil in the reservoir is inversely proportional to capillary number.

So, if we want more oil is flowing towards the production well and the more amount is getting produced and less amount is remaining in the reservoir the capillary number should be high it should be as high as 10 to the power minus 3 or more order to let the less amount of the residual oil remain in the reservoir. So, the graph is showing here the normalized residual saturation will move towards 0 when the capillary number is increasing. The capillary pressure between different phases is important. So, if the phases are different for example the water oil this is classified as PCWO when this is gas oil it is PCGO and when it is water gas it is PCGW. So, the nomenclature will depend on the two systems that is under the consideration one of them is the wetting phase another is the non-wetting phase.

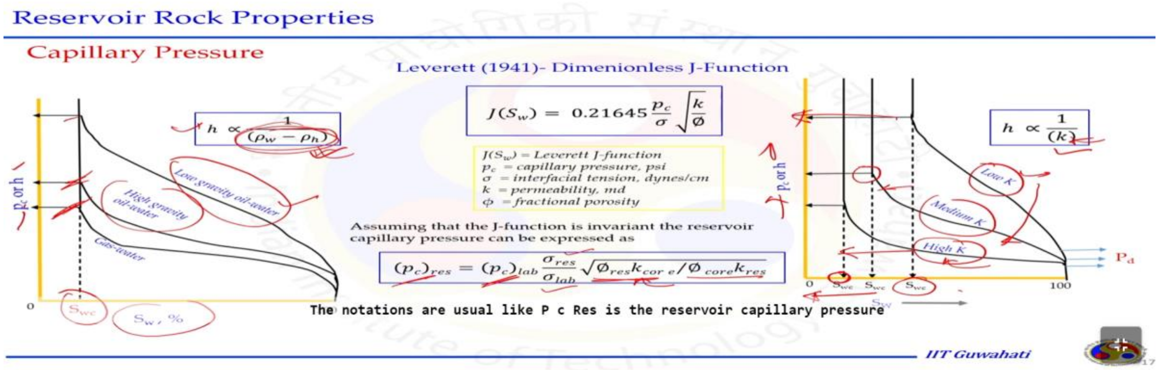
So, Lavergier function is given that actually relates several properties of the reservoir domain to relate the capillary number with the other properties of the reservoir domain like the porosity, phi, permeability k, interfacial tension sigma Lavergier function was given in 1941 to relate the several properties of the reservoir domain. Another features of the capillary pressure is the capillary hysteresis this is the process of saturating and desaturating a core with the non-wetting phase. So, this is the expression of the capillary pressure. So, when we are seeing the capillary pressure with respect to the water saturation this is the connate water saturation beyond that there is let the capillary pressure as high as but the water saturation cannot be reduced because this amount of the water will remain in the reservoir. So, the two process could happens the drainage process the process of generating the capillary pressure curve this called the capillary pressure curve by displacing the wetting phase means water with the non-wetting phase means the oil.

So, when the water is displaced by the oil and that is actually happened in the initial assumption what is the understanding of the reservoir when the oil is migrating from some other sources to what the reservoir rock. Reservoir rock was initially having the water that is actually displaced by the oil and that is process called the draining process. And another process that happens is the imbibition process this is the reverse of the drainage process where the displacing the non-wetting phase oil with the wetting phase that is water. So, the imbibition process happens when the water saturation is increasing and the drainage process happen when the water saturation is decreasing and the curve that is appearing here is called the capillary pressure curve and that can be obtained for different oil and water system. So, for example in the drainage system 100 percent saturation of the core done with the water and the oil is used to displace that water while in the other case in imbibition process oil and residual water because some amount of the residual water will always be there and that is displaced by the water.

So, the oil and residual water is displaced by the water we call the imbibition process. In case of the drainage process you will see there is certain value r, pd that is the pressure called the displacement pressure pd it is a finite capillary pressure at 100 percent water saturation. So, when we are having the 100 percent water saturation there is significant amount of the capillary pressure is required before it is allowed to displace that water with the oil. So, the drainage process will occur when some pd displacement pressure is there in the system that is the value of capillary pressure p c that should be equal to the value of pd then only the drainage process will start and this imbibition and drainage process can be utilized to understand how the wetting phase and non-wetting phase are able to displace each other. So, in summary like drainage this is the oil migration to displace water in the reservoir while in imbibition oil is being pushed out by water.

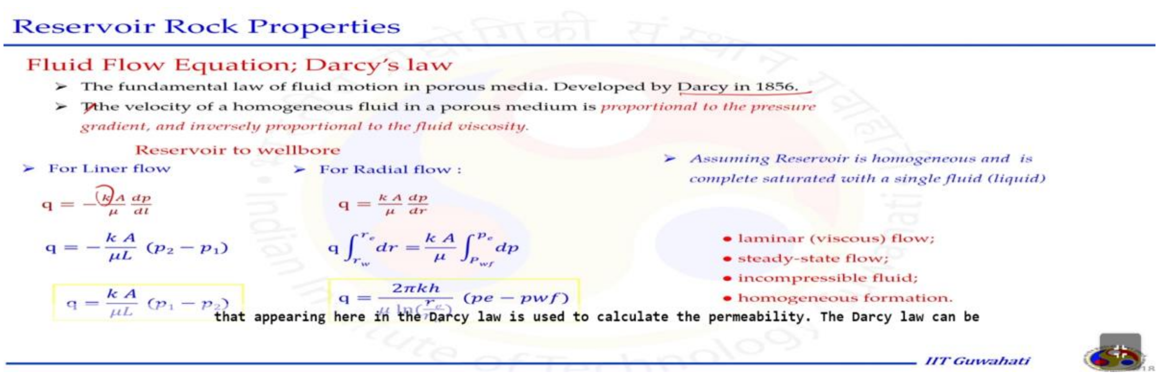
So, the water drive mechanism or the water flooding are the cases when the oil is pushed by injecting the water into the system. With respect to density of the fluid and the permeability of the formation the value of capillary pressure and the height may vary. So, the first graph is showing the with respect to water saturation the p c and height they will be different for different grade of the system. So, for example the water and the p h is the hydrocarbon fluid so it could be the oil or could be gas when the density of difference of these two wetting and non-wetting phases are plotted for the capillary pressure and the height they are inversely proportional. So, the low gravity oil water will be having the high capillary pressure and the high gravity oil water will be having somewhere here and the gas water will be having the value around it.

So, the before they are reaching to the saturation pressure the values will vary on the p c scale or on the h scale similar for the case of different permeability if you are having the low permeability reason your conate water saturation will achieve fast when you are having the medium you can produce little bit more water and when the high permeability is there you can produce more water while the connate water saturation will be on the lower side. So, the value of this water remain in the reservoir will be lower when the permeability is increasing with respect to permeability the value of capillary pressure and the height you can see the low permeability reason we having high value of the p c or the height of the rise in the column will be more compared to high permeability reason. So, this is the way the permeability and the density difference can be related to capillary pressure and the height. Similar expression Laplace function I discussed is relating these properties. Another expression is given to calculate the reservoir capillary pressure when the laboratory measurement are done on the sample.

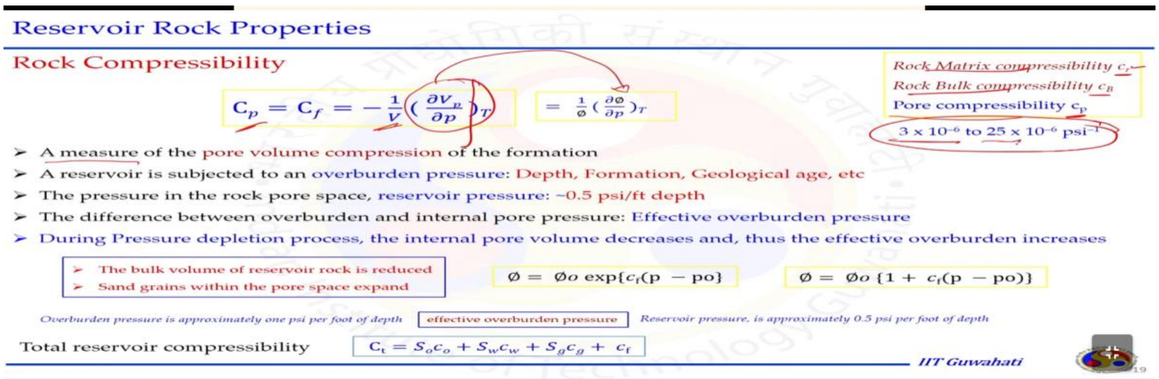


So, the interfacial tension at the reservoir condition to the laboratory conditions permeability and porosity at the reservoir and the laboratory conditions are utilized to calculate the value of capillary pressure at the reservoir condition. The notations are usual like P c Res is the reservoir capillary pressure sigma Rec is the reservoir surface or interfacial tension. So, Res is denoting for the reservoir condition while the core is denoting either the lab conditions or the core that is taken to the lab condition. So, the fluid flow happens in the reservoir because of Darcy law. So, the fundamental law of fluid motion in the porous media that is described by the Darcy law developed by Darcy in 1856.

The velocity of a homogeneous fluid in a porous media is proportional to the pressure gradient and inversely proportional to the fluid viscosity. We discussed this in the lecture 1.



We discussed when we are talking about the permeability calculation because the coefficient that appearing here in the Darcy law is used to calculate the permeability. The Darcy law can be applied for the linear flow system and for the radial flow system. The final expression in both the cases will be different but the fundamentals applications are same when we are applying the Darcy law for the porous medium either it is the axial system or radial system or very irregular system.



Certain conditions are required to apply the Darcy law if the violation is happening correction factor needs to be implemented. So, we discussed several properties of the rock fluid interaction. Another important property that remains is rock compressibility. Similar to natural gas and the oil the definition of the rock compressibility is change in the pore volume of the rock with respect to pressure at constant temperature divided by the original volume that is called the compressibility. It can be expressed in terms of the porosity also phi and this is a measure of the pore volume compression of the formation.

So, when the pressure is changing the compressibility of the rock will determine how much change in the volume is happening within the rock pore volume or rock matrix, rock bulk volume and the rock compressibility. So, the nomenclature could be different when it is CR when it is CB for the bulk it is CP when it is the compressibility of the pore volume. The value of compressibility varies in this range 3 into 10 to the power minus 6 to 25 into 10 to the power minus 6 PSI inverse. So, the rock compressibility is a measure of the pore volume compression of the formation. A reservoir is subjected to overburden pressure because of the depth formation in geological age it is having the overburden pressure.

It is considered as reservoir pressure changes as 0.5 PSI when we go some 1 feet depth. The difference between the overburden pressure and the internal pore pressure is actually the effective overburden pressure. So, the effective overburden pressure is overburden and the reservoir pressure is internal pore volume pressure that is actually the pressure within the reservoir domain. During the pressure depletion process the internal pore volume decreases as the production is happening thus the effective overburden increases and because of that the bulk volume of the reservoir rock is reduced and the grain within the pore start to expand within the system. Mathematically we can transfer this equation in the form of porosity by integrating this equation we will get porosity is equal to φ_0 exponential CF p minus p_0.

So, φ_0 is the value of porosity at p_0. Doing the Taylor series expansion up to the first term we can get the expression for porosity in this form where CF is defining the rock compressibility. So, the porosity is related to rock compressibility and the pressure difference at which the rock is subjected with respect to base pressure p_0. So, the total rock compressibility or the total reservoir compressibility can be calculated as CT that is the compressibility of the oil multiplied by the saturation of the oil similar for this water phase similar for the gas phase and the rock compressibility is added. So, the total compressibility of the formation is oil, gas, water and rock. Since summary of today's lecture we discuss several properties of the rock and rock interaction with the fluid that is actually kind of a petrophysicist job they provide that data.

These properties can be calculated by the theoretical commonunderstanding and the laboratory measurement log data collected from the different characterization of the rock performing the laboratory analysis developing the correlation and some other ISO porosity contour maps can be utilized to calculate the properties. In summary porosity is the void in the rock that hold the hydrocarbon fluid permeability is the ability of the rock that allow the movement of the fluid, fluid saturation the part of the volume that is occupied by a particular fluid capillary characteristic actually that is characterized the preference of a fluid to flow within the pore region compressibility is the change in bulk or the pore volume of the system in case of the rock it is a rock compressibility net pay thickness that is the amount of the height of the reservoir domain that is responsible or contributing for the fluid belt recovery fluid rock interaction that is characterized by the batability and the heterogeneity of the reservoir means the variation in the reservoir properties happen. So, the average value can be taken out to calculate the reservoir properties there are several means of calculating the reservoir average properties to account for the reservoir heterogeneity. So, in the next lecture we are going to continue our discussion about the reservoir rock properties in terms of the analytical tool those are used to measure the properties of the reservoir rock. Briefly we will discuss about the routine core analysis techniques and the special core analysis technique and then followed by the discussion on the permeability specifically on the relative permeability and more than one phase is present how relative permeability affect the production profile we will discuss in the next class. Thank you very much for watching the video. Thank you. Thank you.