Flow Through Porous Media
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Lecture – 39
Immiscible Flow (Contd.)

I welcome you to this lecture module of Flow Through Porous Media where we are discussing Immiscible Fow.

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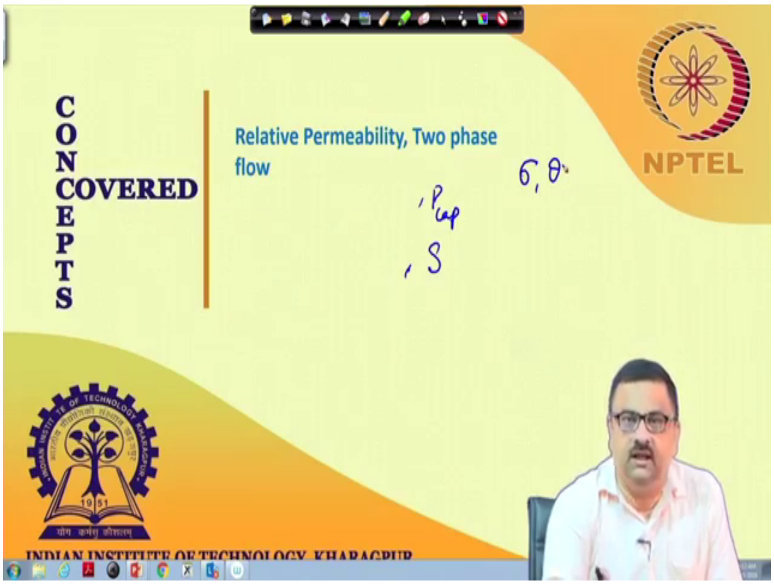

CONCEPTS COVERED

Relative Permeability, Two phase flow

σ, θ, P_{cap}, S

In particular we had talked about we are going to talk about in this lecture what is so, called relative permeability. What we have discussed so far is we have talked about capillary pressure, we have talked about saturation and we have talked about we have defined basically or how capillary pressure depends on the surface tension contact angle. So, these are the things that we have already studied and then we have some idea of how a multi phase flow can take place in the sense there could be a core annular flow, which we are referring it as funicular flow or a channel flow, where separate channels are dedicated to wetting phase and non - wetting phase respectively.

Now, we are going to define how what would be the pressure drop in this case, how do you calculate velocity as a function of pressure drop as we have done in case we have done for Darcy's law.

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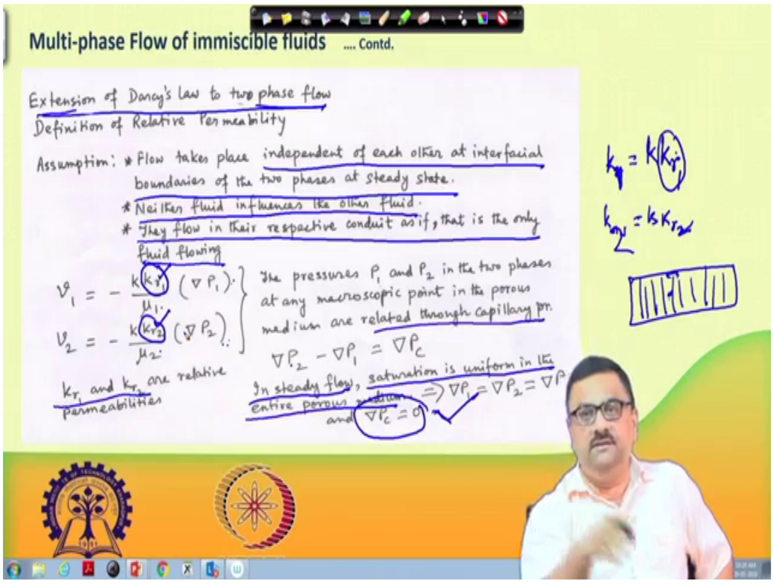

Multi-phase Flow of immiscible fluids …. Contd.

Extension of Darcy's law to two phase flow

Definition of Relative Permeability

Assumption:
- * Flow takes place independent of each other at interfacial boundaries of the two phases at steady state.
- * Neither fluid influences the other fluid.
- * They flow in their respective conduit as if, that is the only fluid flowing

$$v_1 = -\frac{k\,k_{r_1}}{\mu_1}(\nabla P_1)$$

$$v_2 = -\frac{k\,k_{r_2}}{\mu_2}(\nabla P_2)$$

The pressures P_1 and P_2 in the two phases at any macroscopic point in the porous medium are related through capillary pr.

$$\nabla P_2 - \nabla P_1 = \nabla P_c$$

k_{r_1} and k_{r_2} are relative permeabilities

In steady flow, saturation is uniform in the entire porous medium $\Rightarrow \nabla P_1 = \nabla P_2 = \nabla P$ and $\nabla P_c = 0$

$k_w = k\,k_{r_1}$

$k_{nw} = k\,k_{r_2}$

We see here that we are first of all we are trying to extend the Darcy's law to extend the Darcy's law to two phases flow. So, we are extending the Darcy's law to two phase flow. So, here in this regard we must define something called a relative permeability. What is relative permeability? You can see here very well that these are the superficial velocities as we had defined for Darcy's law. So, we are defined at that time minus k by mu grad of P; that means, minus k by mu del P del x, here I can see 2 changes one is instead of single permeability now there are two different pathways, two different way of moving.

So, that is why there is something a term which is their which is known as k r 1 which is relative permeability. So, basically k of wetting phase is basically the base permeability; that means, when you have only single phase single phase permeability generally the wetting phase permeability single wetting phase permeability multiplied by k of this is called relative permeability of phase 1 so, one has this k r 1. So, k r 1 is basically the dimensionless term which is the wetting phase permeability divided by the base permeability.

And similarly k for non- wetting phase you will have base k multiplied by so, this is k 1 and this is k 2 which is k r 1 and k r 2. So, this is basically this is called relative permeability, which is to be multiplied to the base permeability to get the actual permeability that is operational when one has a two phase flow. Here we can see the two viscosities at different mu 1 and mu 2 so, they are different. And we see for the grad of P

1 and grad of P 2 so, the pressure gradient they themselves may be different, we have already seen that when it comes to non - wetting phase one has to add the capillary pressure, because if the it has to enter into the pore water it gets a benefit, but here in when it comes to the other phase non- wetting phase one has to apply additional pressure for to penetrate into the pore.

So, the assumptions first of all let us look at what assumptions they have, flow takes place independent of each other at interfacial boundaries of the two phases at steady state. So, it is assumed that one phase does not affect the other phase, there is a pathway so, flow is taking place through that pathway. Only the total pathway is now segregated one path if this is; if this is the total pathway a part of the total pathway is used by the by wetting phase, another pathway is used by the non- wetting phase. So, that is why we have this term of k r 1 and k r 2 these are called relative permeability this k r 1 and this k r 2 these are referred as relative permeability.

Neither fluid influences the other fluid. So, these are completely as if they are parallel flow they have no nothing in that there is no coupling term that one layer is; one layer is applying some shear to the other those kind those are not accounted, they flow in their respective conduit as if that is the only fluid flowing. So, this is these are the major assumptions one makes and under such assumptions one can extend Darcy's law to two phase flow. So, now, here we have already talked about these relative permeability and k r 1 and k r 2 these are the relative permeabilitys.

So, now, the pressures P 1 and P 2 now we have assigned two different pressures for the two phases. So, these are the two pressure for the two phases at any macroscopic point; that means, this is the porous medium and I have broken it down into 100 or 1000 grids, at each grid I have now two pressures; one is P 1, another is P 2. So, now, these two phases at any macroscopic point in the porous medium are related through capillary pressure, this is basically see first of all this whole understanding is based on continuity right.

So, it is assumed that when we write this Darcy's law we have the differential volume that I pick up that differential volume is large enough to average out any sort of any fluctuations that can happen at the green level ok. So, we are conceptualizing this porous medium as a homogeneous medium only there are these this pressure velocity etcetera these are all continuous function in space and time and only we put some resistances at each grid. So, that is how we have conceptualize this porous medium. So, at every point now we are saying that every point the two phases they are at two different pressures in that conceptual understanding so, that is what is imposed.

And further it is said that the difference in two pressures is basically the capillary pressure. So, if that is, so if there if these two pressures are related through capillary pressure then when you take a grad of P. So, grad of P 2 minus grad of P 1 that also will be grad of P c; so, 2 is the oil and 1 is the water in this case. So, grad of P 2 minus grad of P 1 is grad of P c if you take the derivative with respect to x.

Now in steady flow we said, what was the definition of steady flow that the saturation remains constant in the entire pore body because the flow that is injected that is also at the same volumetric ratio of wetting and non - wetting phase. So, that at individual grids the saturation will not change. the two flows will happen they will follow their own path and the saturation at every grid will remain as it was at the beginning so, there that is that remains unchanged.

So, under such case one can see that the saturation is uniform in the entire porous medium. So, if saturation is uniform in the entire porous medium then grad of P c; grad of P c is del P c del x change in capillary pressure with respect to distance. So, capillary pressure because saturation remains constant so, capillary pressure remains constant so, this term is equal to 0 so, grad of P c is equal to 0. So, if grad of P c is equal to 0 then you can write del grad of P 1 is equal to grad of P 2 and then you can write a single pressure in this case. So, for steady flow; for steady flow you can work with single pressure and you can write P in minus P out by l as you have done for Darcy’s law, but if it is not a steady flow one should account for the capillary pressure.

So, this is how we have defined relative permeability, now how we obtain relative permeability that is a different thing, but now since we know these then now automatically all in our flow equations we can start using these; using these equations then it becomes much easier to handle.

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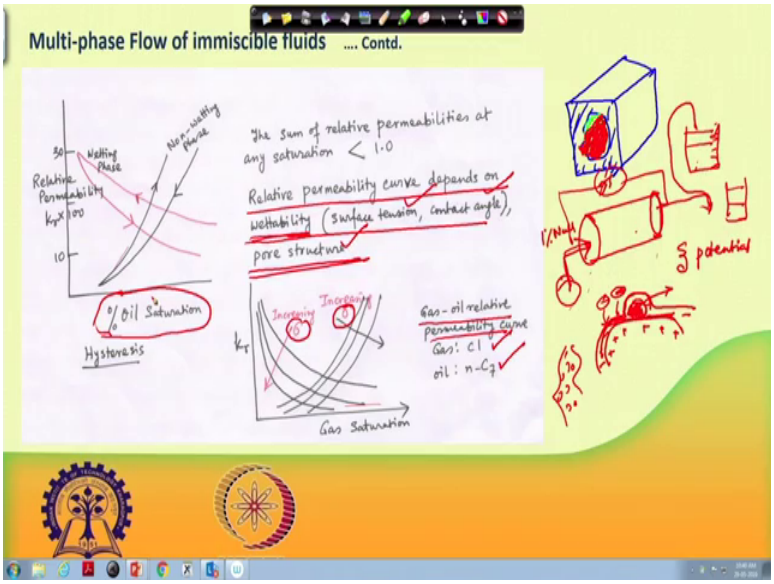

Multi-phase Flow of immiscible fluids .... Contd.

The sum of relative permeabilities at any saturation < 1.0

Relative permeability curve depends on wettability (surface tension, contact angle), pore structure

Gas - oil relative permeability curve

Gas: C1

oil : n-C_7

So, if we try to see how these relative permeability how they depend on saturation, one can expect that when relative when the saturation increases; that means, I have a pathway I have a pathway let us say this is the pathway and rest of it is all solid and this is the void volume and then we have a part which is wetting phase and a part which is non - wetting phase and they are flowing together.

So, now we are talking about relative permeability; that means, I impose a pressure gradient here and because of this pressure gradient there will be flow of either oil or flow of water. So, the I will say that as if these are parallel conduits they are not interfering with each other. So, now, we have to find out the relative permeability and moment we get then we can find out what is the superficial velocity as far as oil is concerned and what is the superficial velocity as far as water is concerned.

So, now, this relative permeability how we can find relative permeability? One thing you must appreciate is that the relative permeability is going to be a function of saturation, because you can see that when one saturation of one phase is increased let us say this is; this is; this is the red colored is let us say oil and you are increasing the oil saturation.

So, increasing oil saturation means that are we you are having a larger let us say I am taking this part also for oil flow, because I am injecting only oil, so gradually this part will also be taken by oil. So, naturally you have a larger pathway when you have when you are increasing the oil saturation, now you will have a larger pathway for flow of oil so; that means, automatically you have that the permeability the overall permeability of permeability to oil will increase.

Whereas, when you have a smaller pathway when the saturation is decreased you have a smaller cross section of the flow path would be occupied by oil, then automatically the permeability it will have it is effect on the permeability ok, because you are using a smaller part of the pathway so, naturally the permeability has to decrease.

So, now so, with increase in oil saturation you expect the relative permeability to permeability to oil will increase so, that is exactly what they have shown here. As the percentage oil saturation I mean you can expect the you can express this oil saturation as a percentage or you can express the oil saturation as a fraction. So, if you increase the oil saturation and track the relative permeability so, how would you first of all how would you do this, you can perform an experiment here. Perform an experiment in the sense you take a core you take a porous plug basically and then put it in a core holder or put it in a wrap or a wrap it somehow. So, that no flow can takes place through this side only flow enters through this and flow leaves from the other side.

So, now what you do is, you inject let us say first you completely saturate with water and then you inject oil moment you inject oil and run say inject several pore volumes of oil. So, first you saturate it generally the be a this course are saturated I mean if you pick up a reservoir plug for example, it is first you have to put a vacuum. So, that all the air that has already gone in I mean I am assuming that there is no fluid remaining inside, it is just a sample of reservoir core that is obtained and no fluid inside.

So, first one has to put it up apply vacuum. So, that all the air that is inside that will be drawn out and then introduce what do you call the brine which is 1 percent NaCl. Generally I mean I mentioned this before in earlier lecture once that if you inject water there is a tendency for this there is there are a lot of clay particles inside this porous medium.

So, when it comes to for example, sandstone if one picks up from a reservoir. So, there those clay particles they tend to swell, swell in the sense that there is something called, there are some see moment you introduce water, there are some charges they develop on the I mean when particularly when you introduce an electrolyte there are some charges develop on the pore surface.

So, generally this if you look at this porous medium these are let us say this is a sandstone grain and there are some small clay particles which is simply adhering simply attached to this; to this; to this grain and then moment that because of this presence of electrolyte there would be some charge very small charge it is not something that is I mean you see, but always whenever you have a surface and you have an electrolyte you bring them in contact you generally one generally develops a charge let us say this charge is positive.

And this charge will tend to attract the opposite charge from the other side and generally there is a formation of something called an electric double layer, electric double layer around; that means, since these are positive so, this would be attracting all the minus charges. So, very near the wall over a very small distance there would be all minus charges getting accumulated and generally how much a charge will accumulate on a surface is given by something called zeta potential for that particularly electrolyte and surface pair.

Now this because of this accumulation of charge now this is a clay particle so, here is a some accumulation of charge around the clay particle and there is some accumulation of charge around the grain. There would be some repulsion of these two charges two layers that are buildup of same charge and because of this repulsion one can see this clay is getting detached from the surface so, these clay can plug the pores.

So, generally it is preferred not to inject water directly instead to avoid such happening they inject brine which is I mean there is slight amount of salinity in reservoir water in information water so, trying to simulate that by putting 1 percent salt in water. So, this so, we started this was a core and one wanted to we wanted to first saturate this. So, apply vacuum and then inject 1 percent NaCl and one has to run it for quite some time for water to flow. So, that if there is any trapped air in this porous medium that has to be taken out and one can check whether there is any trapped air or not, by increasing the pressure checking of the pressure and then releasing it releasing the pressure suddenly if there is air trapped one can see there is a splash of fluid coming out because the compressed air will tend to come out.

So, one can find out whether there is any air inside or not so, this gets saturated by water. And then you one injects oil into the core it could be crude oil or it could be some simulated oil for example, one can take dodecane or some simulated oil phase so, that one can flow through this core. So, when this is done when the; when the; when the first it was flooded with water and then oil is introduced and if somebody keep track of the; somebody keeps track of the material balance; that means, how much of what was the original weight of the core, after doing this we injecting water and in entirely filling the pore space with water what is the weight?

So, what is the difference in weight? So, that difference in weight gives you gives me how much of water has or how much brine has gone into this pore space. So, that is the weight of that brine, if we divide it by density then that gives me the volume. So, that is the pore volume I can assume ok. So, now, they if given this being the pore volume, then now we start injecting oil let us say dodecane as simulating a crude oil.

So, and we have to inject it for quite some time I mean for maybe 10 pore volumes or 20 pore volumes of oil is injected through this and we add the outlet we have to keep track of it and it is very easy to keep track of whether you are getting water or oil you have to put it only in a measuring cylinder you have to collect it and in the measuring cylinder immediately you will find water will be settling in the bottom because there is a the density difference.

So, water would be settling in the bottom and oil will be on top. So, by making this on a measuring in a measuring cylinder one can find out how much of water is collected, how much oil is collected. So, one keeps track of this inventory I mean if you running 24 volumes these oil part will increase, but there would be some amount of oil initially coming out and then maybe some drop once in a while and then it stops.

So, if this is calculated how much of volume of water collected at the end of 24 volume of oil after displacing 24 volume of oil from this setup. So, that water is that volume of water has to be compared with the original volume of water that was in the system and this difference will tell me how much of water is still remaining inside this porous medium as trapped. So, that gives me these difference gives me the residual sorry the interstitial water saturation.

Similarly, now one can go back and start injecting oil so, then I start injecting water now and do the same thing, but this time water would be collected in the bottom and oil will be collected in the top. So, there has to be one has to be very careful that how much of oil it gets because oil will be on the top and the oil will tend to evaporate so, one has to make sure that it does not get evaporated. So, that so, you can find out how much oil is now coming out and from there one can get that at the other end point what is the residual saturation.

So, by doing this simple exercise one can get what is interstitial water saturation, what is the residual saturation of non - wetting phase so, these two are obtained. Once that is known then what you, but one can do is then they start putting in instead of water only or oil only we have done the two endpoints, then you start sending mixture 25 percent water, 75 percent oil ok.

So, this mixture what would be this mixture it would be again when you put them when two lines they are coming two lines and one line is water, another line is oil and they are mixing. So; obviously, one will get one as dispersed phase and one has continuous phase as I said there would be a continuous phase and inside there would be droplets. So, this is a typical mixture this is the way it looks like so, one will is say let us say I inject now 25 percent water and 75 percent oil through this. So, it will take some time for establishment of saturation. So, we will run it for quite some time and we will see that at the outlet also we are producing 25 percent water and 75 percent oil the same ratio that we are injecting. So, we can assume at that time we have reached a steady; we have reached a steady state.

So, at that steady state what is the permeability that we note, how do you find permeability? I know what is the oil flow rate I have, what is the water flow rate I have right, total flow rate it is 25 percent 75 percent and then we know the flow rate and I can measure the overall pressure drop; I can measure the overall pressure drop. So, from this pressure I know delta P, I know the velocity superficial velocity I know and at steady state that same delta P will apply for both phases. So, I know delta P, I know the viscosity of oil, I know the length of the core, I know the superficial velocity of oil. So, I can find out what is the relative permeability of using Darcy’s law. And similarly I can find out what is the relative permeability of I mean oil as well as relative permeability of water for this saturation then I change I mean after I got everything then I change the saturation.

Now, I start on the same quote now I start injecting 50 percent oil, 50 percent water and I run it for some time and we saw after some changes in the ratios you will find at the outlet we will again get 50 percent oil 50 percent water it is, now we consider this to be a steady situation. So, at steady state now again we find out what is the pressure drop and we know what are the superficial velocities for oil and water.

So, I can find out what is the relative permeability of oil and what is the relative permeability of water. So, using this, so running again now we can go for 60 percent 40 percent so by doing at various saturations, we can calculate what is the relative permeability of wetting phase, relative permeability or non-wetting phase, for a particular wetting phase non- wetting phase situation. So, now, if somebody plots relative permeability versus here we are writing oil saturation this is a standard curve generally the research as they have generated for oil water system.

So, you can see the we wetting phase saturation wetting phase saturation decreases with sorry wetting phase relative permeability decreases with oil saturation whereas, non-wetting phase permeability increases with non-wetting phase saturation. So, this is understood I mean we already mentioned that as more and more oil is occupying the pathway.

So, now, you have more part of the original cross section available for flow for the oil so, automatically oil permeability oil relative permeability will increase. So, this is the trend here and on top of that now we have this drainage and imbibition they are because we have already seen in case of capillary pressure that there is a hysteresis. So, the same problem also occurs here whether we go from whether we go follow the drainage curve or imbibition curve.

So, that is why we can see hysteresis there, but this is how; this is how the relative permeability is can be plotted. Now this relative permeability is the sum of relative permeabilities at any saturation is less than 1.0 sum of relative permeability is at any saturation; that means, k r wetting phase and k r non-wetting phase if we sum them up they have to be less than 1. Further this relative permeability curves depends on wettability; that means wettability in the sense surface tension contact angle and further the pore structure. And if one really looks at the relative permeability for example, relative permeability there was a plot of gas oil relative permeability car for gas is C 1; that means, methane and oil is n C 7 ok.

So, C 7 means and it is the alkane with 7 carbons so; that means it is heptane ok. So, n heptane and methane so, gas is the methane and oil is the n heptane. So, when they have drawn these relative permeability for oil gas system. So, this is the relative permeability versus gas saturation they have plotted and they have got at lines and what they did is now they change this sigma the surface tension interfacial tension. So, with increasing sigma they found this curve is getting shifted so; obviously, this relative permeability is a function of sigma and also the contact angle theta. So, there are theoretical work done how relative permeability can be expressed in terms of surface tension contact angle and pore structure.

So, theoretically how a relative permeability can be deduced we can get into this, but at this time I mean just make note that relative permeability is a function of saturation that is for sure because larger pathway would be followed when saturation is increased so, automatically relative permeability will increase and intuitively we can understand relative permeability will be a function of these parameters. So, if these parameters are changed automatically relative permeability will also change.

So, with this in mind I would because we are in porous medium this the standard literature mostly focuses on relative permeability there are some empirical information available how relative permeability changes with saturation and what people prefer to do is suppose they have for an unknown system.

So, they take a sample of porous medium and then directly run experiment as I pointed out just now and generate a relative permeability versus saturation curve, but there is good amount of work already done how on how relative permeability can be related to surface tension contact angle and pore structure from theoretical or first principle studies. But the general trend in with the practicing professional is a for an unknown system for an unknown fluid if we need to understand need to know relative permeability as a function of saturation generate these experiments are referred as core flooding experiment.

So, this core flooding lab would be their core planning experiment will be conducted to generate relative permeability versus saturation and then try to do some correlations. So, that is also another trend which is there. So, I am going to stop this module here I will discuss about this relative permeability again in the next lecture also, this is all I have for this module.

Thank you very much.