Net Pay Cutoffs from Capillary Pressure*

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Abstract

Cutoffs are used to define "net pay" and "reservoir rock." Reservoir rock is sometimes referred to as "net sand." Reservoir rock, as used herein, is rock that is permeable enough to allow hydrocarbons to move to the well bore. It meets the permeability cutoff and/or the porosity cutoff, volume of shale cutoff, and other appropriate reservoir quality criteria.

Net pay is reservoir rock that meets the water-saturation cutoff. The water saturation cutoff is generally thought of as the highest Sw (or Swe in an effective porosity methodology) that will still produce hydrocarbons, the Sw where the oil- or gas-cut is roughly 1% or higher.

Hydrocarbons exist in most reservoirs in rocks that are not considered either net pay or reservoir rock. Using conventional petrophysical and reservoir engineering methods, these hydrocarbons will not be included in the computation of hydrocarbons-in-place. Therefore, by using cutoffs to compute net pay, a portion of the hydrocarbon-in-place is excluded from the reserves calculation. Great care must be used in selecting cutoffs so that the hydrocarbons excluded are truly not producible, using current and foreseeable technology.

Capillary pressure analysis, backed up with proper core measurements, can provide justification for cutoffs. This sort of analysis can also be used to help select the proper cutoffs. This presentation describes one method of building a capillary pressure model, how the parameters are selected, and how the model can be used to pick appropriate cutoffs in a heavy oil reservoir.

Net Pay Cutoffs from Capillary Pressure

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View Note for Slide 1

Cutoffs from a Capillary Pressure Model

- Justifying cutoffs is difficult in the absence of extensive test data
- Proper core measurements and a capillary pressure model can define reservoir rock and net pay
- Cutoffs are important because all hydrocarbons-in-place are not equal
- Provides a profile of the hydrocarbon/water transition zone for accurate reservoir simulation – Sw is not a constant or a simple function of porosity!

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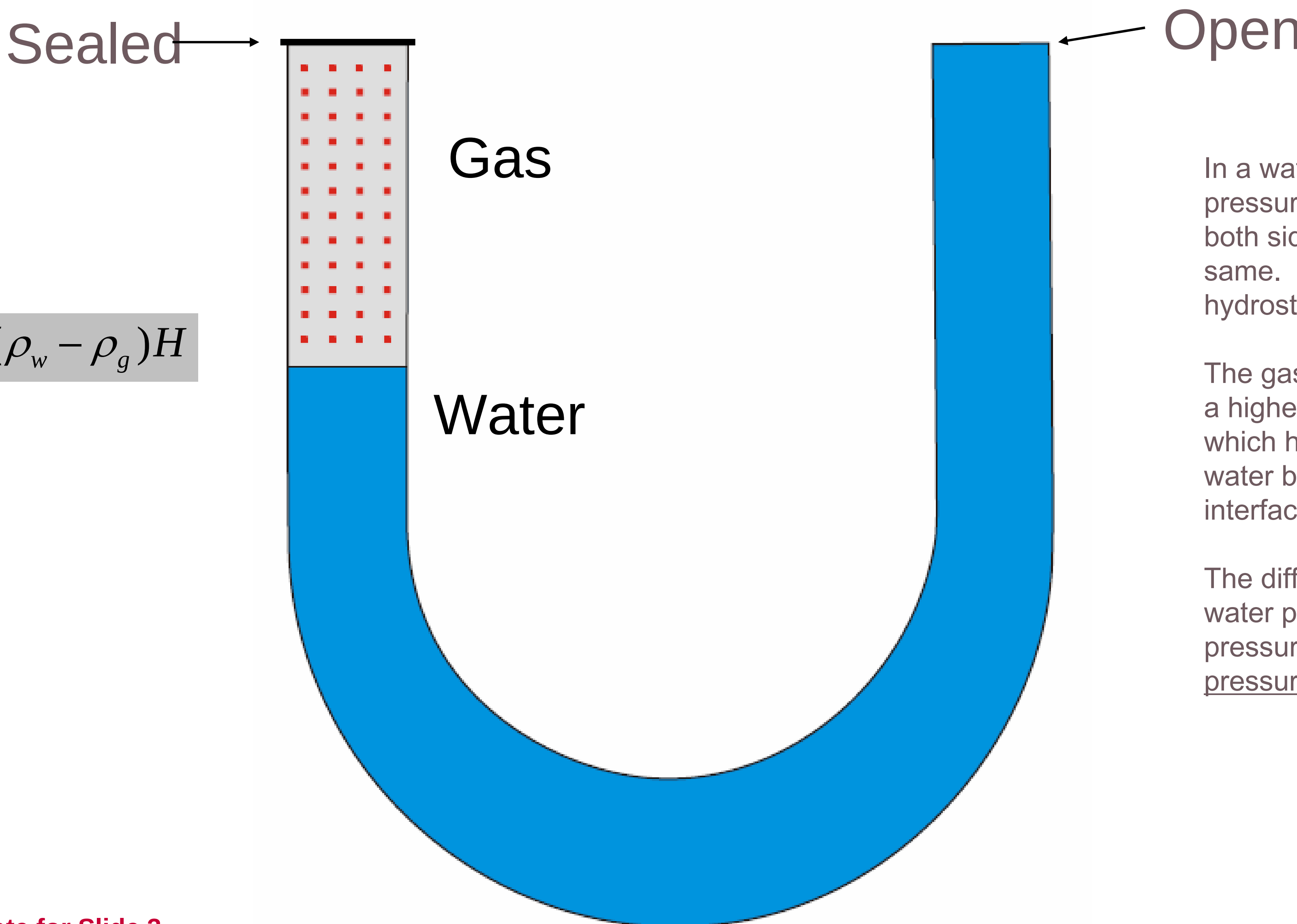
Origin of Capillary Pressure



$$Cp = (\rho_w - \rho_g)H$$

In a water-wet rock, the pressure in the water on both sides of the tube is the same. This is the hydrostatic pressure.

The gas in the left tube has a higher pressure which holds the heavier water below the gas/water interface.

The difference between the water pressure and the gas pressure is the capillary pressure.

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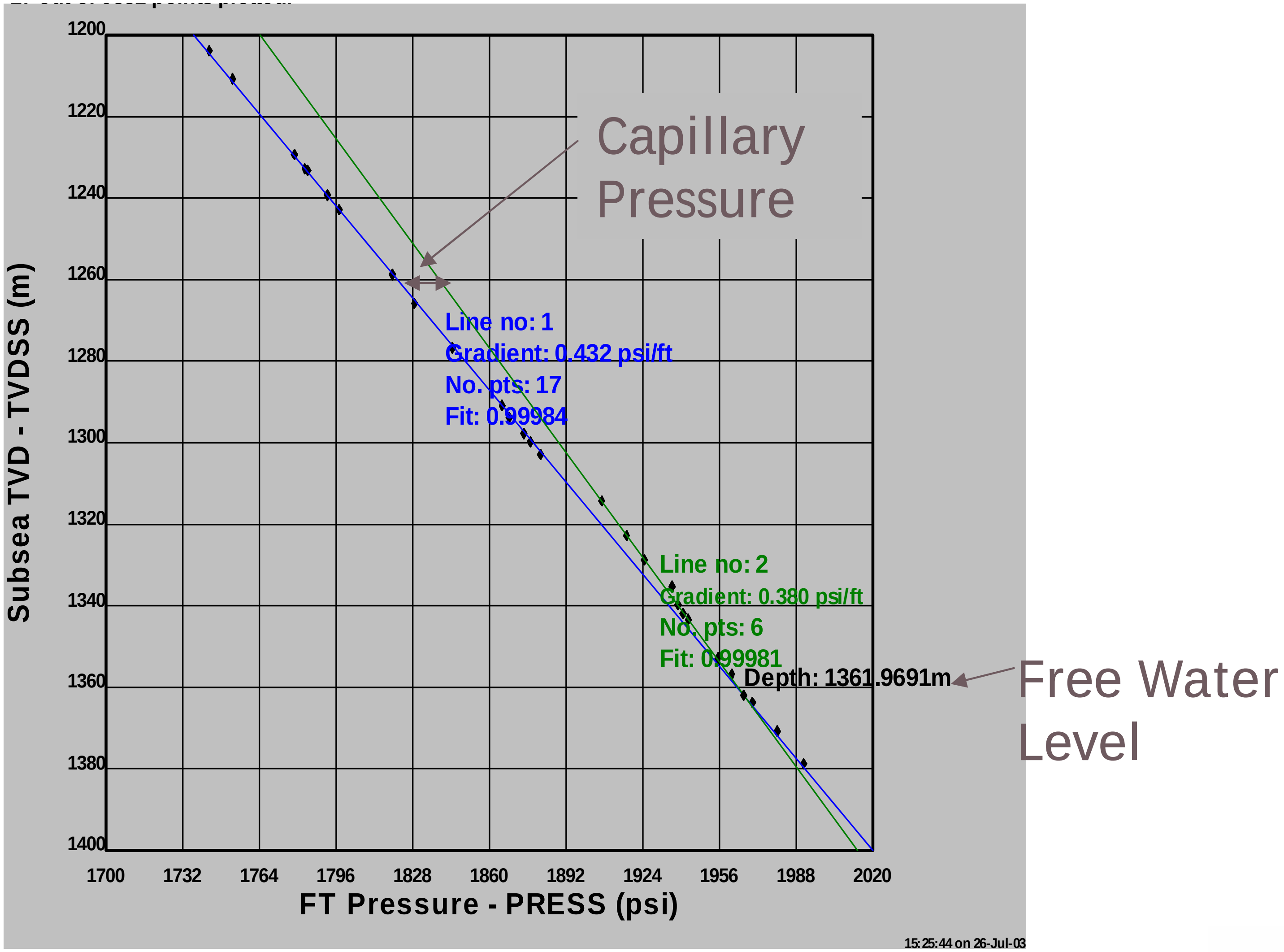
Capillary Pressure



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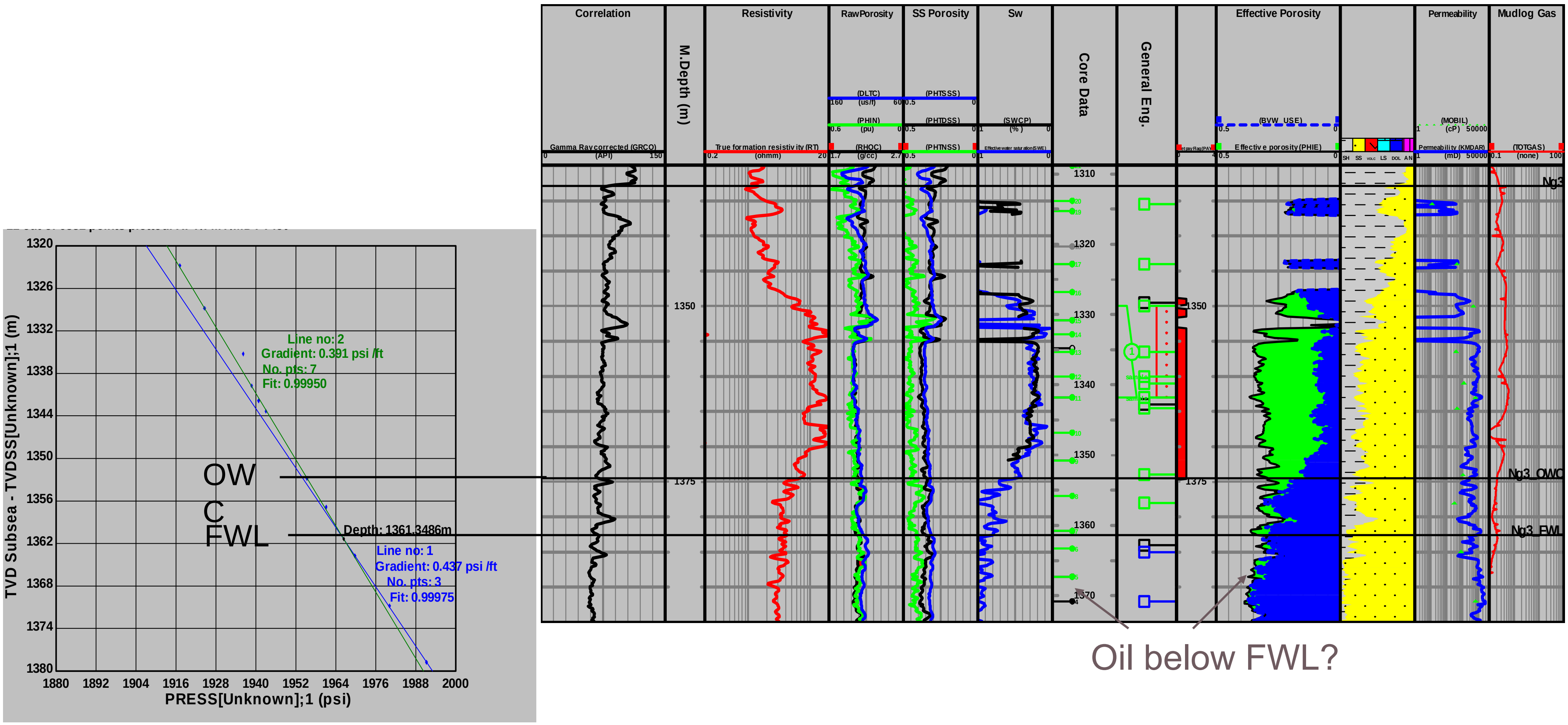
Neutral Wet Example



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Corey's Function

$$Swe^* = \left(\frac{P_b}{P_c}\right)^{\lambda}$$

Brooks and Corey, 1966 (eq. 24)

$$Sw = (1 - Sr)Swe^* + Sr$$

Substitute (J_{100}/J) for (P_b/P_c)

$$Sw = (1 - Sr)\left(\frac{J_{100}}{J}\right)^{\lambda} + Sr$$

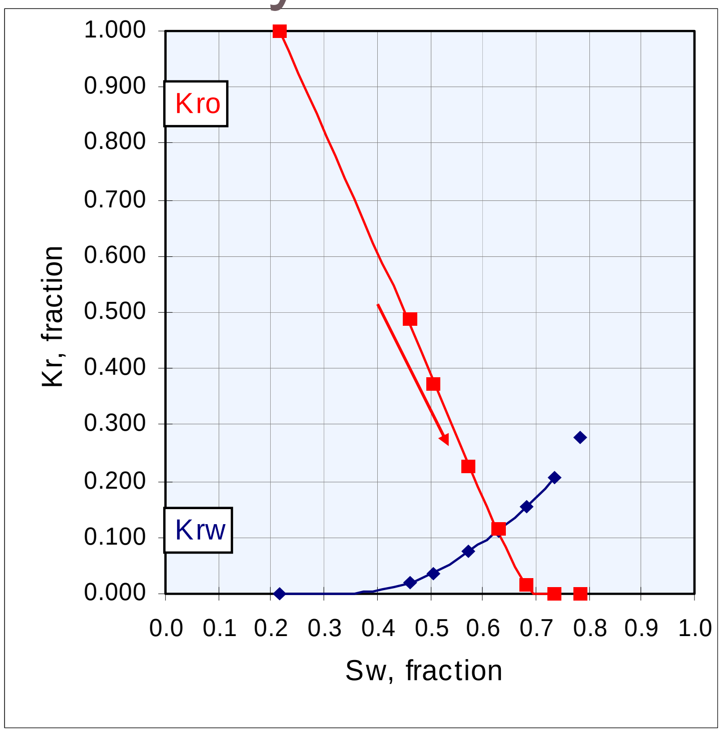
Derived from eq. 11, Amaefule, 1988

J_{100} is the J value for the bubbling pressure(Pb) or the Pc at the critical oil-phase Saturation

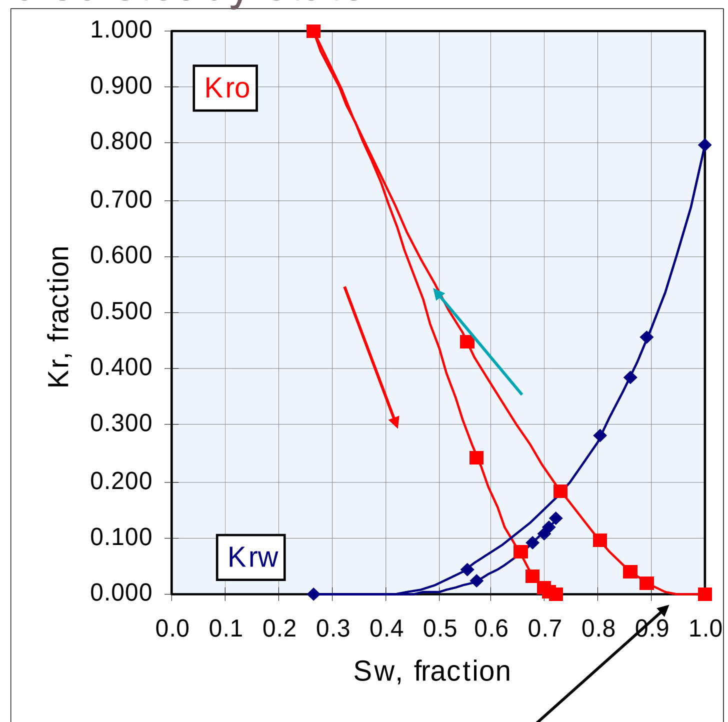
View Note for Slide 6

Critical Oil Phase Saturation

Steady State Rel K



Drainage, followed by Imbibition, also steady state



The Sw where Kro comes off zero in drainage mode is the critical oil saturation, the point at which the oil crosses the pore system (Pb).

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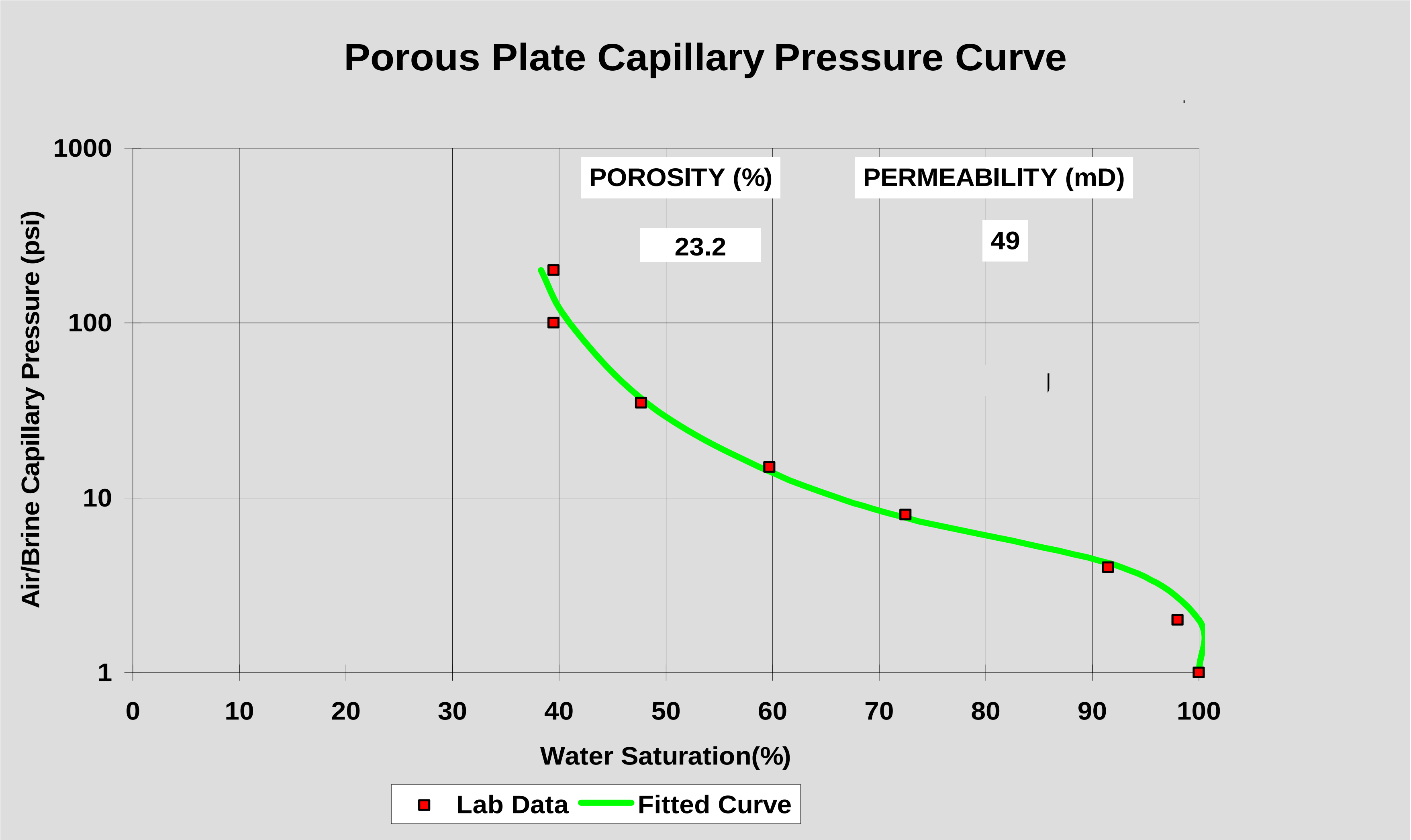
Capillary Pressure Model vs. Data



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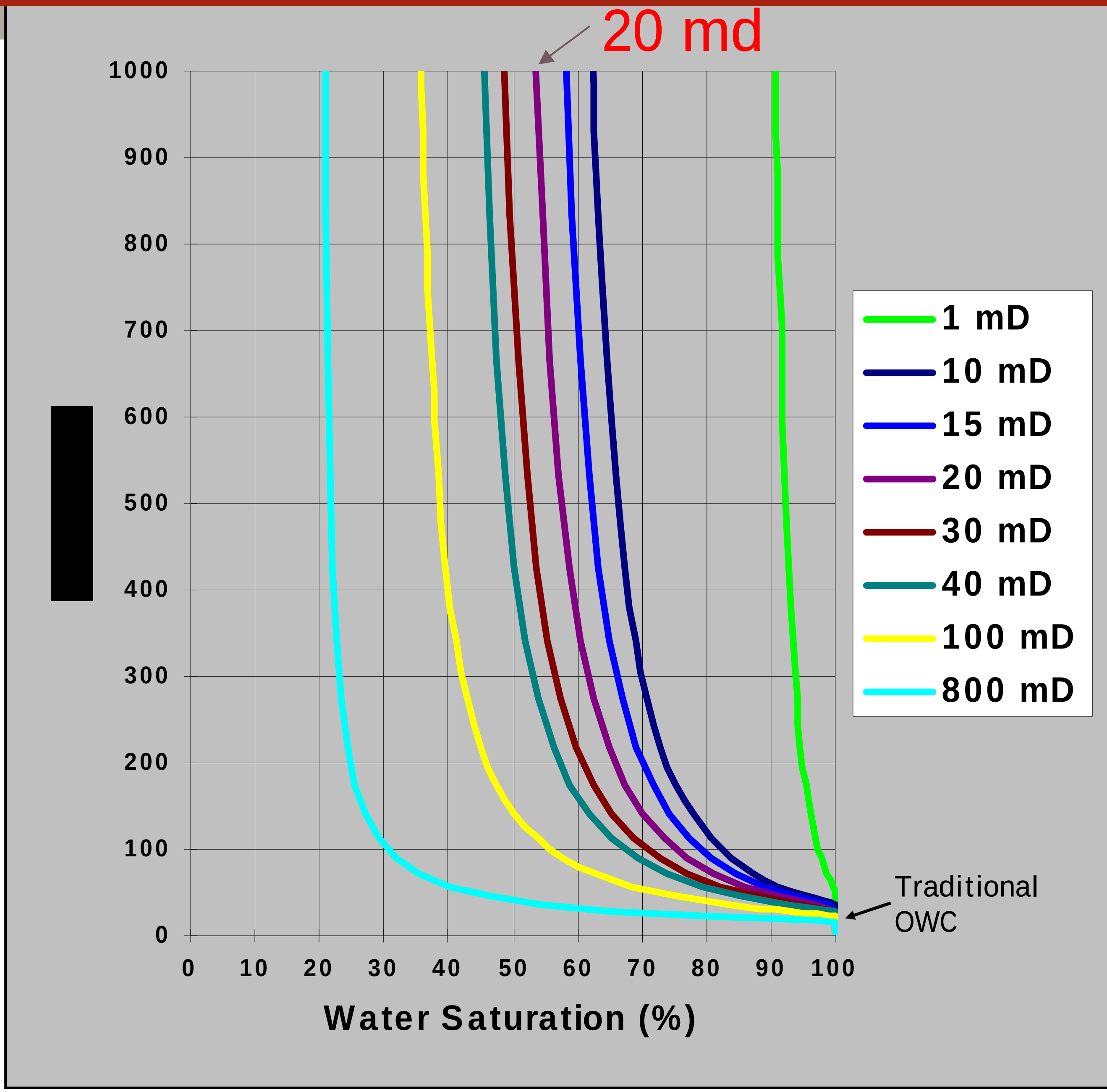
Sw versus Height, fine grained reservoir



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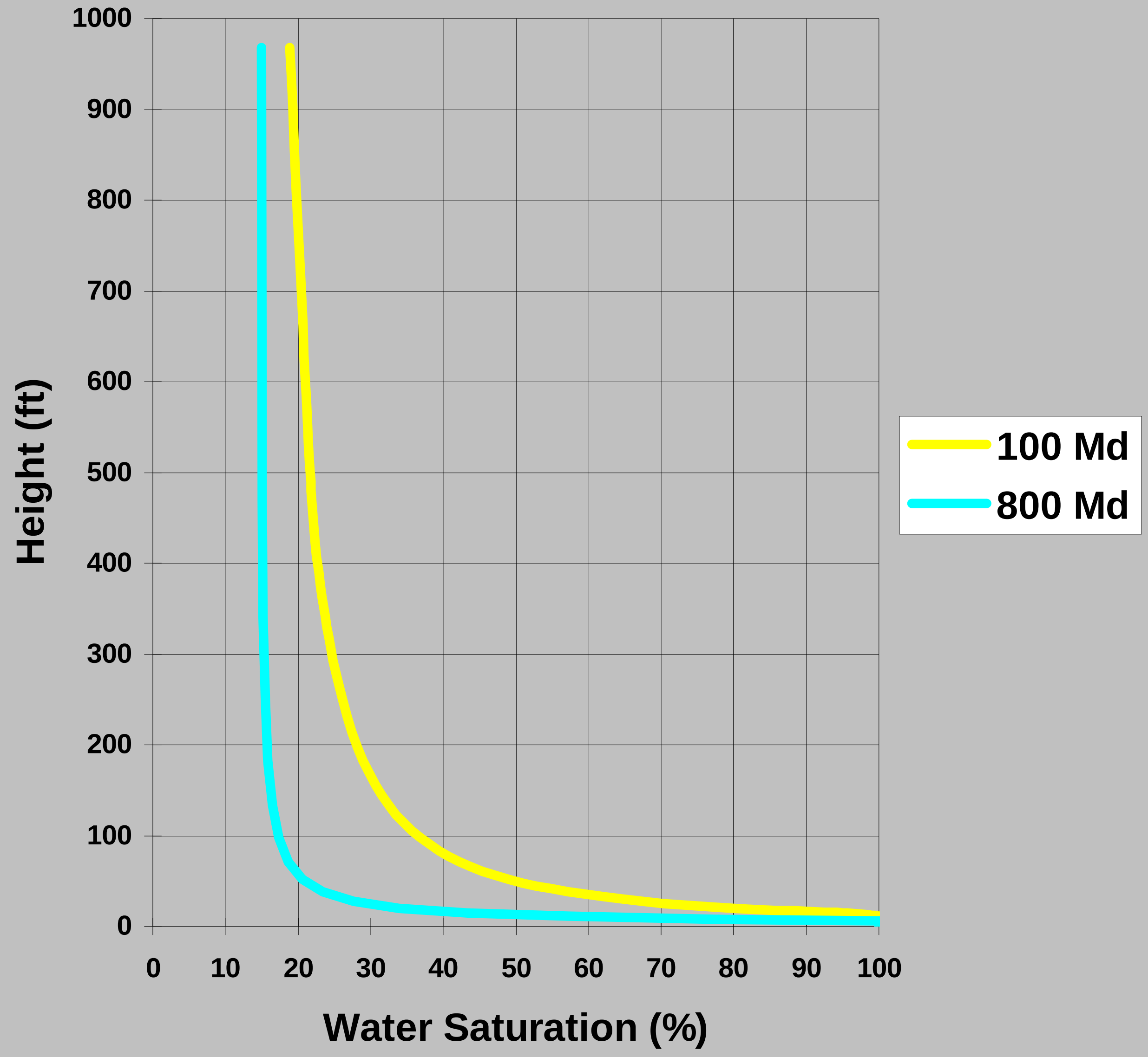
Sw versus Height, GOM reservoir



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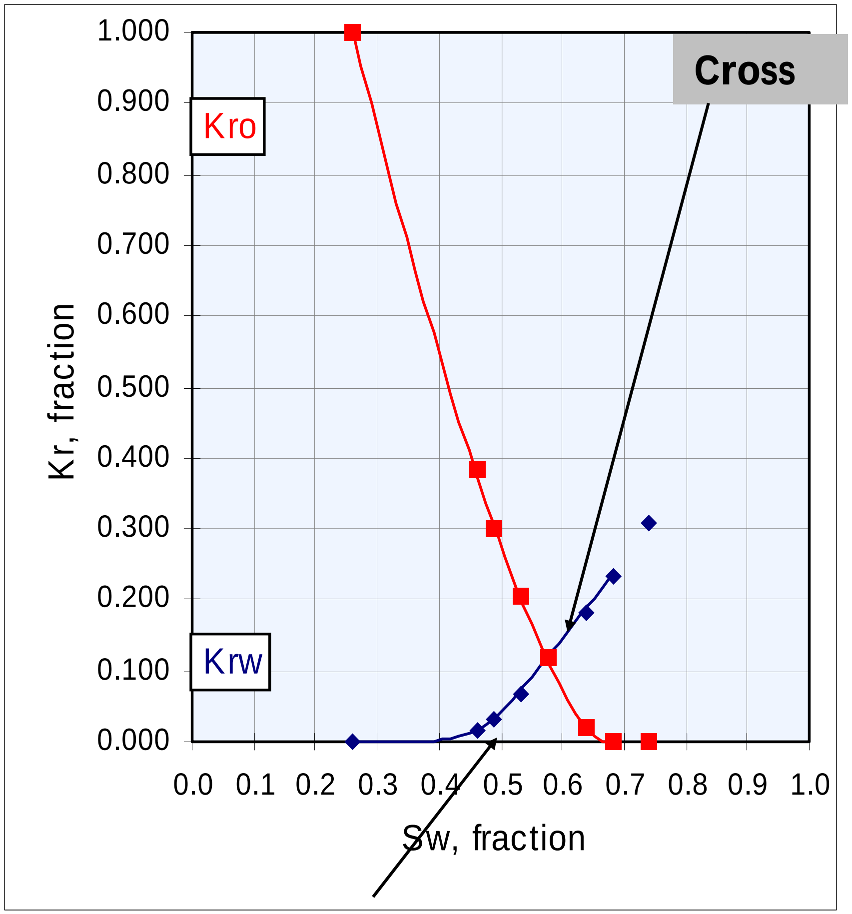
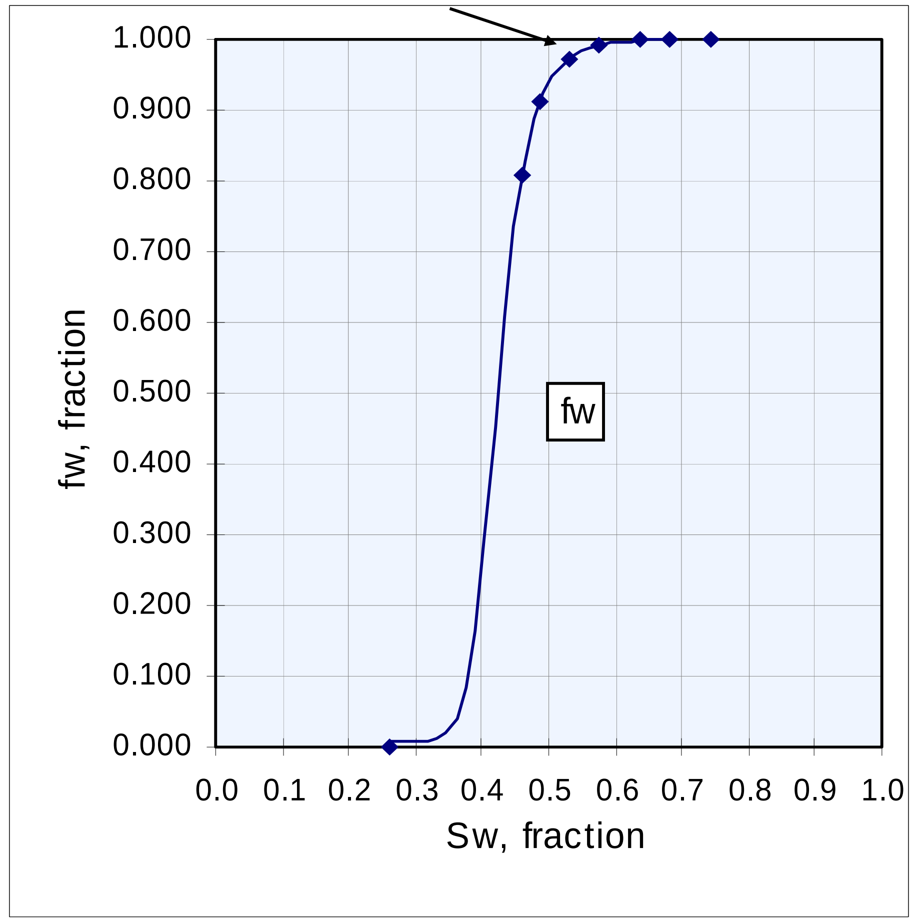
Sw Cutoff

99% water cut

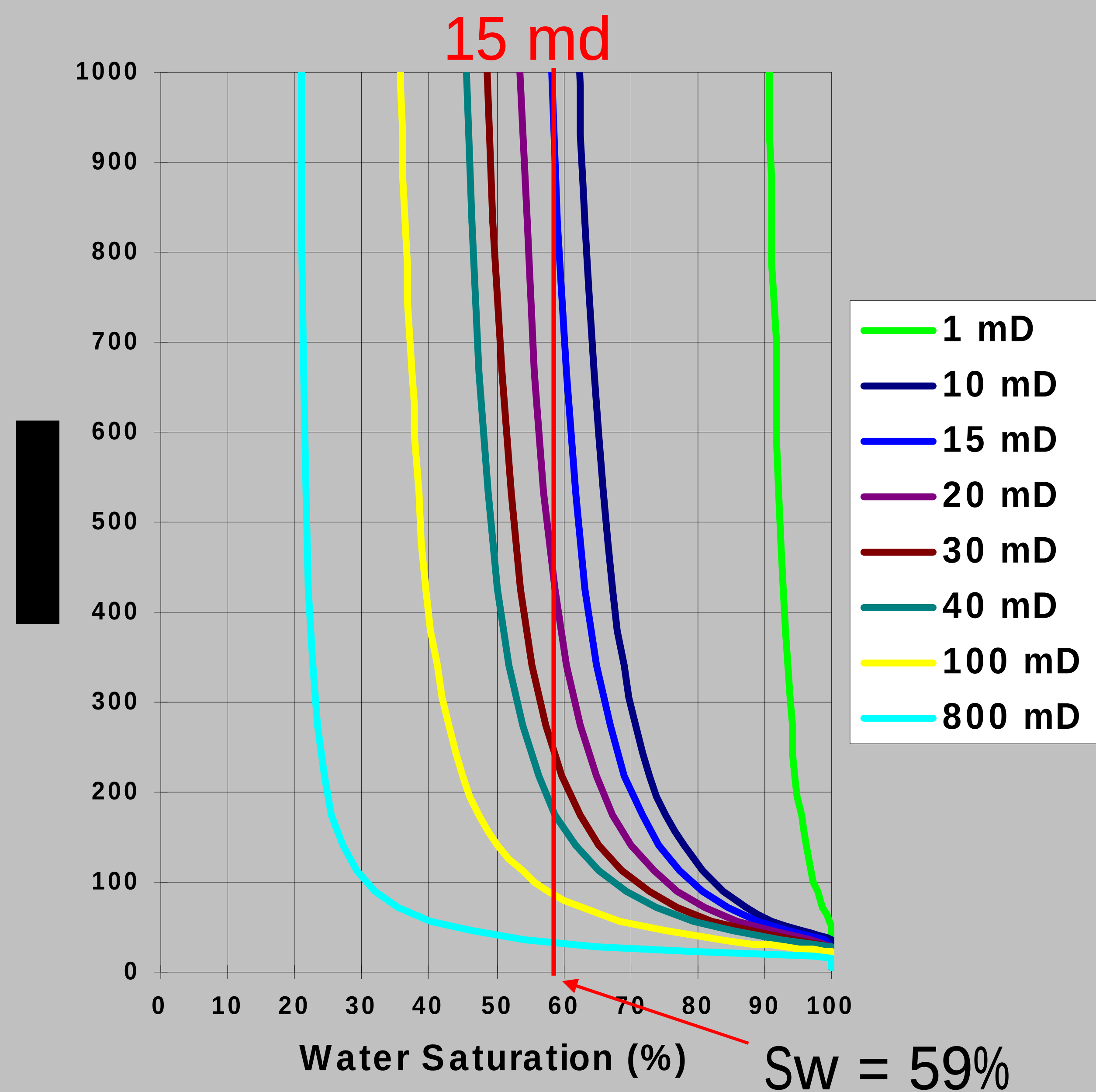




1st water cut

Sw cutoff = 59%

Sw cutoff to Perm cutoff



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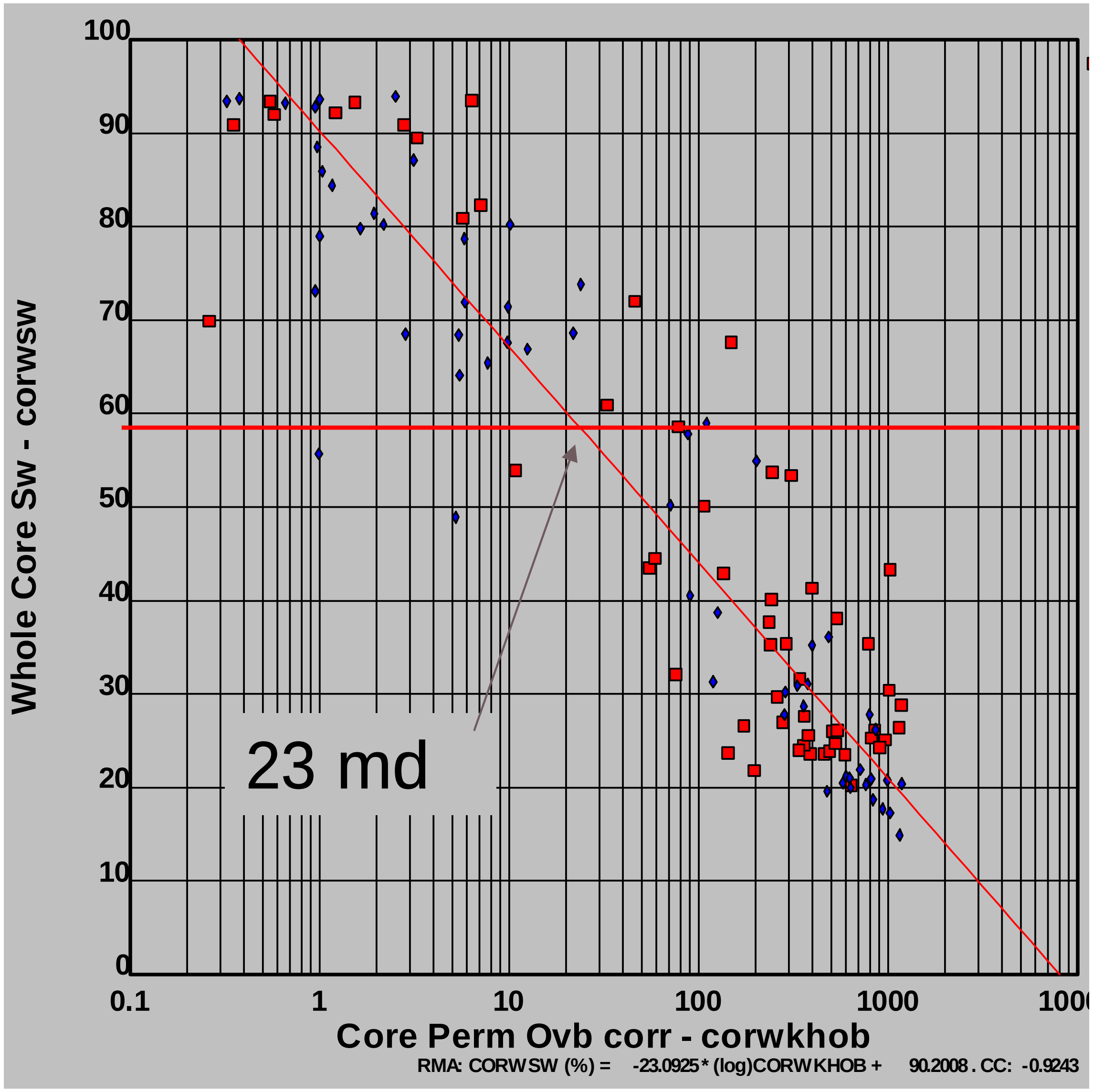
Core K vs. Core Sw



Settled on a perm cutoff of 20 md.

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Capillary Pressure Summary

A capillary pressure model rigorously describes the transition zone

The model provides a check on Sw

The model provides a clear backup for cutoffs

The model provides the best way to tie log and core data and the most comprehensive way to feed petrophysics to a reservoir simulator

Notes Accompanying Slides

Slide 1. Acknowledgments to Joe Hawkins and John Dacy.
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Slide 2. Many petrophysicists think of capillary-pressure models as a tool for finding the free-water level under a discovered hydrocarbon reservoir. Sometimes they can be used for this purpose, sometimes not. However, they are very useful for quantitatively determining and justifying net pay and reservoir rock cutoffs. Occasionally operators want to compute oil-in-place without cutoffs at all; this is a dangerous process. All oil-in-place, especially in heavy oil reservoirs, is not part of the current hydrocarbon column. It is residual oil from a previous accumulation or some other source and does not contribute to capillary pressure and cannot be produced. Reservoir simulation, in either a low-perm or heavy, viscous oil accumulation should not treat Sw as a constant or a simple function of porosity. The transition zone in these reservoirs contains a significant amount of hydrocarbons and should be explicitly modeled.
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Slide 3. Imagine the tube is the size shown and coated with Teflon, which is not wet by water or gas. The contact would be the same as the free-water level and the contact would be flat as shown. The capillary pressure in the gas would be the difference between the density of the gas and the water times the height above the contact. The Sw in the gas column would be zero. There is no transition zone. Capillary pressure implies capillaries and pore throats, but the basic definition (delta-density)xH does not require capillaries; keep this in mind during the presentation.
Secondly, imagine the tube was glass and the size shown. Glass is wet by water, but not gas. The water-gas interface would be curved upwards near the edges. Sw would be greater than zero, and the FWL would be near the contact only in the middle of the tube.
Finally, imagine the tube filled with sand and water. A portion of the water in the left side is displaced by gas, leaving a water film on the sand grains with the center of the pores filled with gas. The gas is continuous in the pore system. The pressure in the water film is the same as the pressure in the water in the right half of the U-tube at the same height. The pressure in the gas is higher in proportion to the difference between the density of the gas and the water. Because the gas is less dense, the pressure has to be higher in the gas in order for it to hold back the water. This difference in the gas pressure and the water pressure is called capillary pressure.
Capillary forces keep water up in the gas column, even though the pressure in the water is less than the gas pressure. Capillary forces affect Sw in this way, but do not affect capillary pressure per se.
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Slide 4. This is another way to look at the U tube in the previous slide. The water (hydrostatic) pressure line is well defined by the points on the blue line. The oil accumulation at the top of the lower sand forms an oil gradient that intersects the water line at the free-water level where the capillary pressure is zero. The difference in pressure between the two lines is the capillary pressure.
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Slide 5. This well has a heavy oil accumulation in a very permeable sand. The reservoir is neutral to oil-wet, according to restored-state whole-core measurements. The free-water level is clearly identified on the formation-test pressure plot shown on the left. The formation-test points are identified on the log plot as well. The PVT oil density matches the density computed from the formation-pressure gradient. The oil-water contact drawn on the log and on the pressure plot is at the point where the oil becomes mobile.
Oil can be clearly seen in the sidewall cores below the contact and below the free-water level. It is also computed from the resistivity logs using whole-core-derived parameters. This oil could be present because tectonic activity may have caused oil to leak from a previously present accumulation, or it could be oil that is migrating from active source rocks that are present down-dip from this well.
In light-oil or gas high-permeability reservoirs the choice of a contact is not very important. But in heavy-oil reservoirs it is important to choose an Sw cutoff that is low enough to exclude stray oil that is not part of the producible accumulation. This Sw should be between the point where water cut reaches 99% and Corey's Sw(critical). That is the point where Kro goes to zero.
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Slide 6. Swe* is a function of Sw and Sr. Sr is the total irreducible water, not just the irreducible water due to shale – usually called Swb in log analysis.
To build a proper Corey capillary pressure function one needs to determine J, J100, and Sr. To determine J one needs to know lambda, the contact angle, theta, and interfacial tension. J100 and lambda are the most important factors.
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Slide 7. In both plots are steady-state relative perm results.

The following is correspondence to presenter from John Dacy, with very slight editorial revision:
On the right the sample went through a stepwise Sw-decreasing (drainage) process starting at 100% Sw, at first flowing only water. Once the absolute kw was determined, both oil and water were flowed at a constant, high, water fraction; perhaps, for example, 95% water and 5% oil by volume. This fractional flow was held constant until pressure across the test sample equilibrated and X-Ray scans indicated a uniform Sw profile across the sample, indicating the steady-state condition had been achieved. At that point effective perm to both oil and water were computed and made relative to a selected basis (the ultimate ko at minimum water saturation in this case). Also at that point Sw was determined by XR scan. Decreasing fractional-flow-of-water steps followed, each reaching the steady-state

condition, yielding other points along the kro and krw drainage path. The last drainage fractional flow was 100% oil until SS conditions were reached. Here the test may be designed to further drain the sample, perhaps by centrifuge, to reach a representative minimum Sw that could not be achieved by oil flow (if that was done here—a procedure that is not unusual). This drainage test was immediately followed by a SS kwko imbibition test with gradually increasing water fractional flows until the last was 100% water flow at the trapped oil saturation (Sor).

On the left, the graph results represent a SS kwko imbibition, Sw-increasing, test identical to the 2nd half of the testing described for the graph on the right. However, the drainage process was performed external to the relative perm equipment and no drainage kwko data (except the end point, ko at Swi) were determined. External drainage methods to Swi vary generally from oil flow-down, to porous plate, to centrifuge.

To summarize, regarding some likely questions:

The SS method involves simultaneous flow of 2 phases (wetting and non wetting) except at end points when only 1 phase flows.

The SS method can be used for both drainage (Sw decreasing) and/or imbibition (Sw increasing).

During the SS imbibition test, water saturation gradually is increased to Sor, not to 100% Sw.

CRITICAL WATER SATURATION

This property has had a number of definitions in the industry and is often a point of confusion. The point labeled as Swcritical apparently is the point where, in drainage or HC accumulation mode, the non-wetting phase begins to flow. This point is generally known as the critical non-wetting phase saturation, Sgc or Soc. It represents a 1-Sw value, here of about 7%, and is described as that non-wetting phase saturation where that phase becomes continuous across the pore system and can flow.

To paraphrase the early definition of Critical Water Saturation by Arps (AAPG 1964), Sw crictical is that drainage water saturation below which there is no flow of water. However, where minimum Sw, or Swir, is less than Sw critical, there must be some water ‘flow’ or ‘perm to water’ below Sw critical as defined. Granberry and Keelan (GCAGS 1977) used a similar definition and adopted the abbreviation Sciw for the term. Their definition is as follows, “…a critical upper limit for formation water saturation, above which a significant percentage of water will be produced.” As with Arps, their Sciw examples fell in the ‘knee’ area of the drainage Pc curve.

There is another whole set of ‘critical’ saturation definitions that relate to curve-fit function limits. The function limit for drainage kro or krg is consistent with the Soc or Sgc as described above. However, there can be a function-limit definition of ‘critical water saturation’ (with respect to water) that describes it as the saturation below which there is no perm to water; i.e., the krw curve does not go beyond that saturation.

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Slide 8. The final test of the model is the fit between it and the actual core measurements. The plot shown is an excellent fit.

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Slide 9. This is a plot that we like to use to show the model to the reservoir teams. It shows clearly how the Sw changes with height and permeability. This reservoir is fine-grained and has a low lambda, which means it has an extremely variable permeability and pore-size distribution. As a result of the low lambda, the spread of the Sw at every height is large. Also note that the traditional OWC varies a lot in height due to permeability. This is a heavy-oil reservoir which contributes to the spread in Sw and the blurry traditional OWC.

Taking a point at 1000 feet above the FWL as the highest point possible in the reservoir, the perm cutoff appears to be between 20 and 10 md, if one assumes a Sw cutoff between about 53 and 60%.

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Slide 10. As contrast, a model of a typical GOM reservoir, with light oil and a high GOR. No reservoir rocks were measured with perms below 100 md; so we only show a 100-md line and an 800-md line. Comparing these lines with those in the previous slide (heavy oil and finer grained reservoir) we can see a dramatic shift to the left and a smaller transition zone. Also Pe is much lower and it is much better defined. No problems in the GOM!

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Slide 11. To determine the key Sw cutoff we use restored-state relative permeability whole-core measurements. The first water shows up at the critical Sw point; this is too conservative a point for the contact. Choosing a point near where the lines cross; where the water cut reaches 100% is usually best. This point moves as the relative viscosities of the hydrocarbons and water change. In this example we chose 59% total Sw.

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Slide 12. 59% total Sw crosses the 15-md line at 1000 feet above the FWL.

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Slide 13. Core-measured Sw and core-measured permeability have a strong relationship as one would expect. In this crossplot of cores from two wells, a cutoff of 23 md is indicated. The red symbols are from a water-based core and the blue are from an oil-based core. The oil-based core is less likely to be contaminated.

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References

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