



# Extracting Pore Throat Size and Relative Permeability from MRI-based Capillary Pressure Curves

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## 1. Introduction

- The pore throat size and its distribution is important in many fluid transport processes in porous media (like reservoir rock)[1]. The pore throat size affects the fluid saturation distribution, porosity, permeability and, to some extent, wettability.
- Capillary pressure curves acquired using an MRI-based technique called GIT-CAP can be used to determine pore throat size distributions by calculating the saturation change at each pressure and converting the pressure into a pore throat size.
- Relative permeability is the ratio of the permeability of one fluid with a second fluid present compared to having no second fluid present.
- Relative permeability can be modeled from capillary pressure curves.

## 5.1 Relative Permeability from Pc

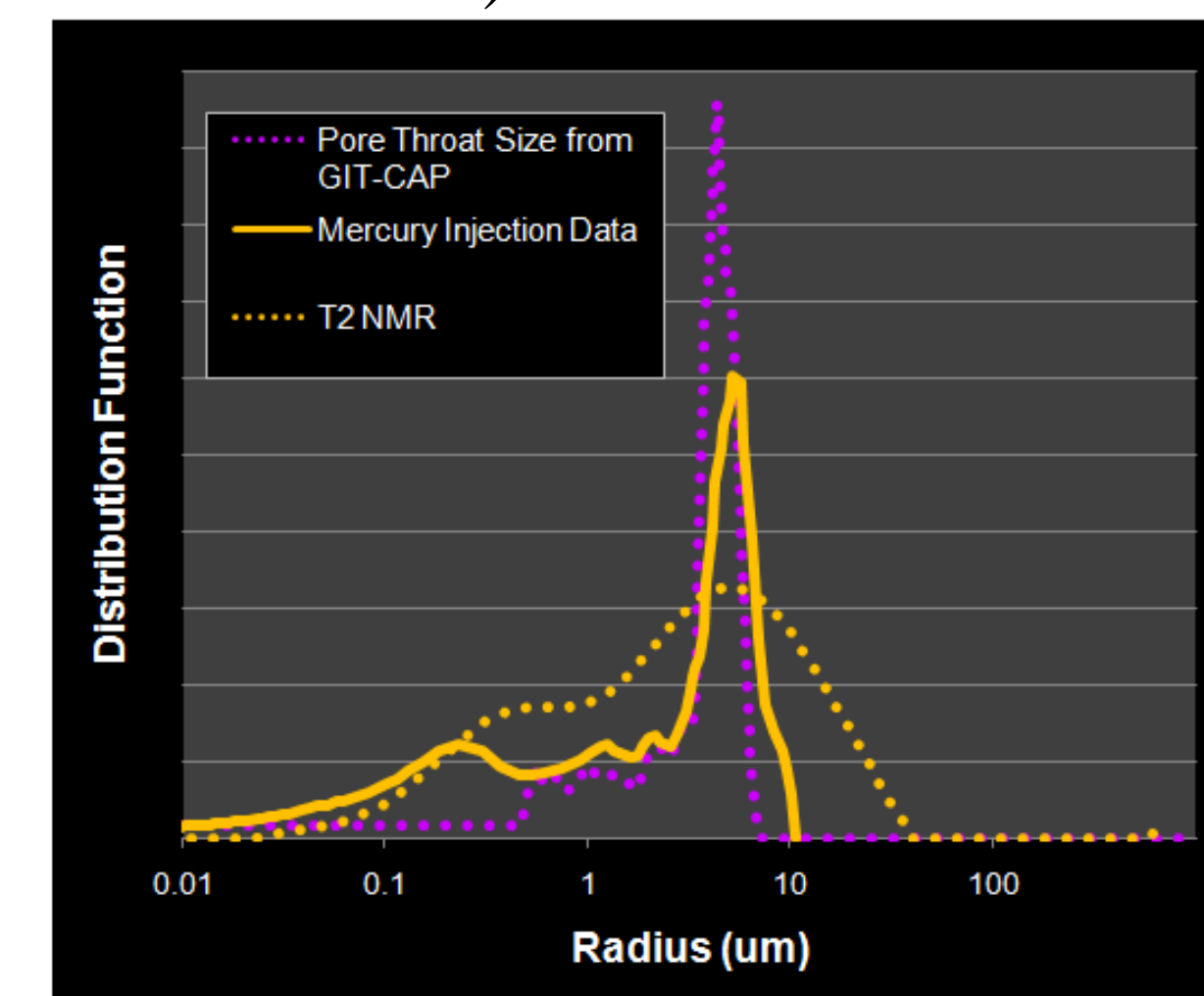
- Relative permeability can be calculated from capillary pressure using a number of existing techniques including the Burdine model [6].
- The wetting  $K_{TW}$  and non-wetting,  $k_{rnw}$ , relative permeability are:

$$k_{rw} = (\lambda_{rw})^2 \frac{\int_{S=0}^{S=S_w} \frac{dS}{P_c^2}}{\int_{S=0}^{S=1} \frac{dS}{P_c^2}} \quad \lambda_{rw} = \frac{\tau_w(1.0)}{\tau_w(S_w)} = \frac{S_w - S_m}{1 - S_m}$$

$$k_{rnw} = (\lambda_{rnw})^2 \frac{\int_{S=S_w}^{S=1} \frac{dS}{P_c^2}}{\int_{S=0}^{S=1} \frac{dS}{P_c^2}} \quad \lambda_{rnw} = \frac{\tau_{nw}(1.0)}{\tau_{nw}(S_w)} = \frac{1 - S_w - S_e}{1 - S_m - S_e}$$

## 8. Pore Size/Throat Comparisons

- The graph below shows an overlay of the pore size distribution from the  $T_2$  NMR data; mercury injection pore throat size; and the pore throat size derived from the MRI-based Pc.
- The  $T_2$  NMR data was scaled using a relaxivity value of 6.24  $\mu\text{m/s}$  (additional results are shown in the table in Section 11).



1 1/2" Sandstone plug  
Porosity = 22.5%  
Permeability = 158mD

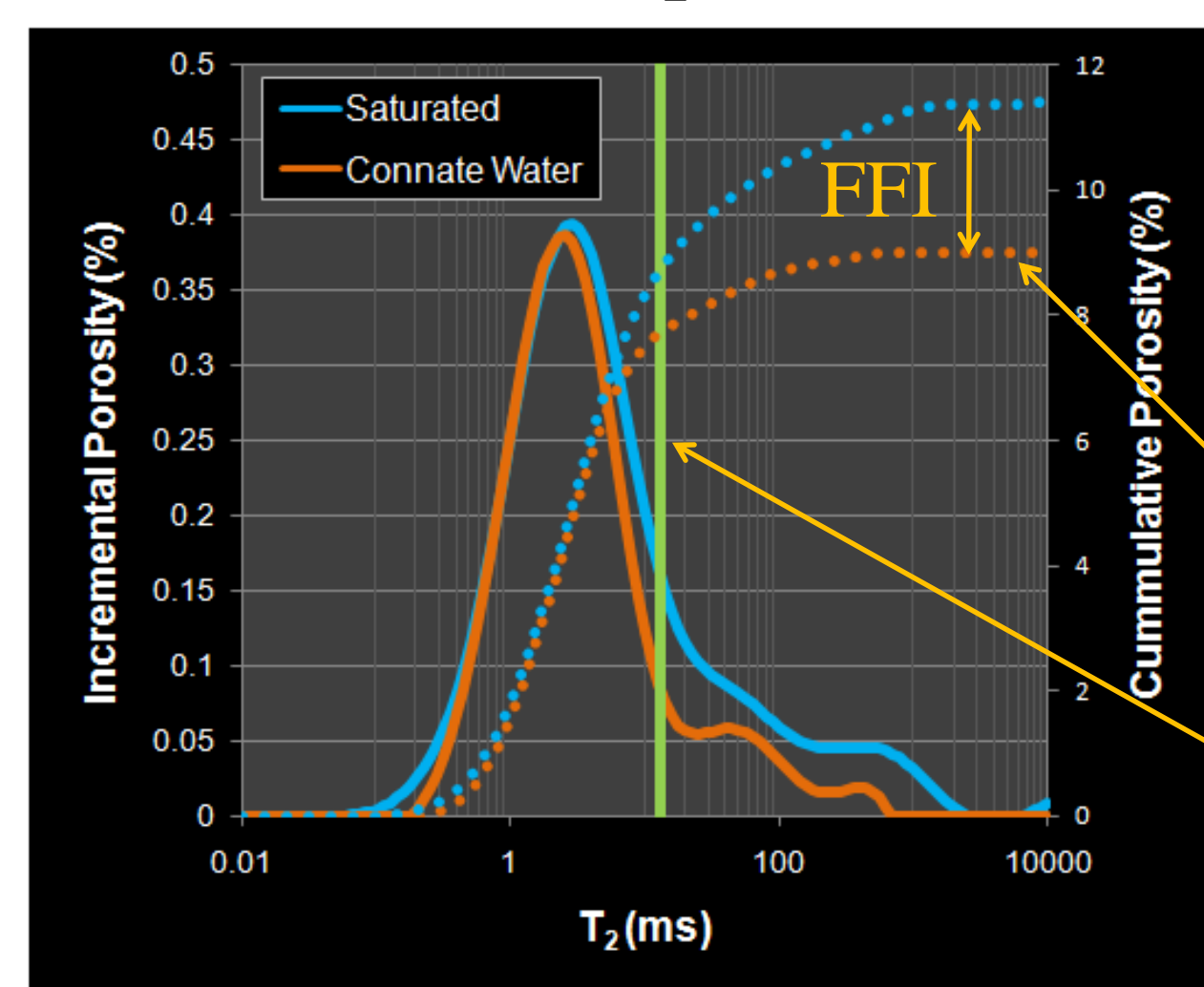
NOTE: Pore size is related to pore throat size but they are not equal.

## 2. $T_2$ NMR Pore Size Distribution

- The  $T_2$  NMR relaxation parameter is related to the surface, S, to volume, V, Ratio by the following equation:

$$\frac{1}{T_2} = \frac{1}{T_{2-Bulk}} + \rho \frac{S}{V} + \left( \frac{GT_E}{12} \right) \frac{D_0}{12}$$

- Laboratory measurements of  $T_2$  with the rock fully saturated and again at the connate saturation can be used to compute the FFI, BVI, CBW, and  $T_2$  cut-off.



Sandstone  
Porosity = 11.4%  
Perm. = 0.22mD

BVI

$T_2$  Cut-off  
(13ms)

## 5.2 Relative Permeability from Pc

- The capillary pressure data can be modeled and the conversion to relative permeability can be applied directly using the modeled constants.
- Below is a Brooks-Corey capillary pressure model equation.

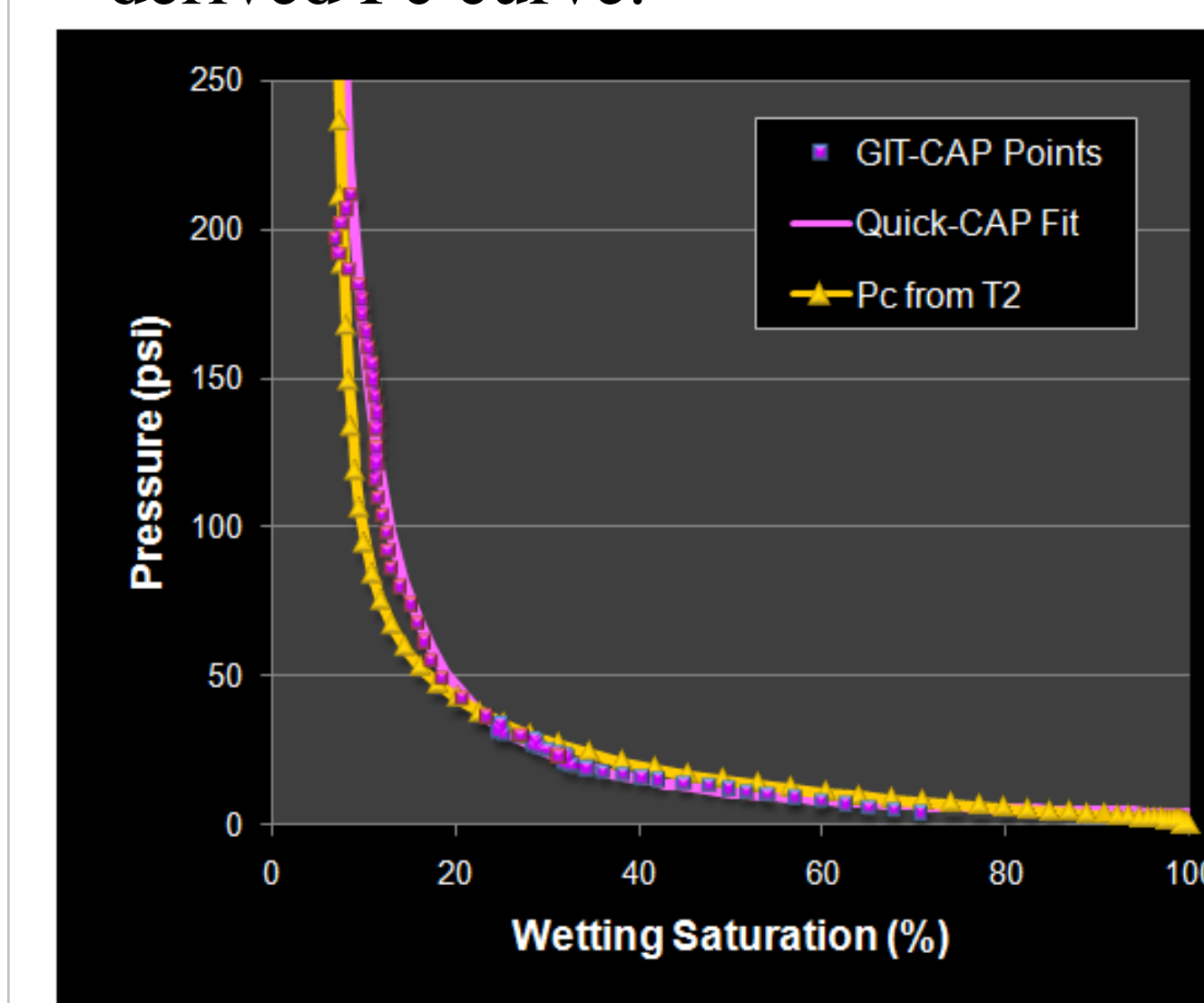
$$P_c = p_e \left( S_w^* \right)^{\frac{1}{\lambda}} \quad \text{where} \quad S_w^* = \frac{S_w - S_{wr}}{1 - S_{wr}}$$

- Applying the Purcell model directly to the Brooks-Corey Pc model yields:

$$k_{rw} = \left( S_w^* \right)^{\frac{2+3\lambda}{\lambda}} \quad k_{rnw} = (1 - S_w^*)^2 \left[ 1 - \left( S_w^* \right)^{\frac{2+\lambda}{\lambda}} \right]$$

## 9. Capillary Pressure Comparisons

- Once the relaxivity value is known, the  $T_2$  NMR pore size distribution can be used to model a Pc curve (similar to mercury injection).
- Below is a comparison of the MRI-based Pc measurement; a Brooks-Corey fit of the MRI-based data; and the  $T_2$  NMR derived Pc curve.

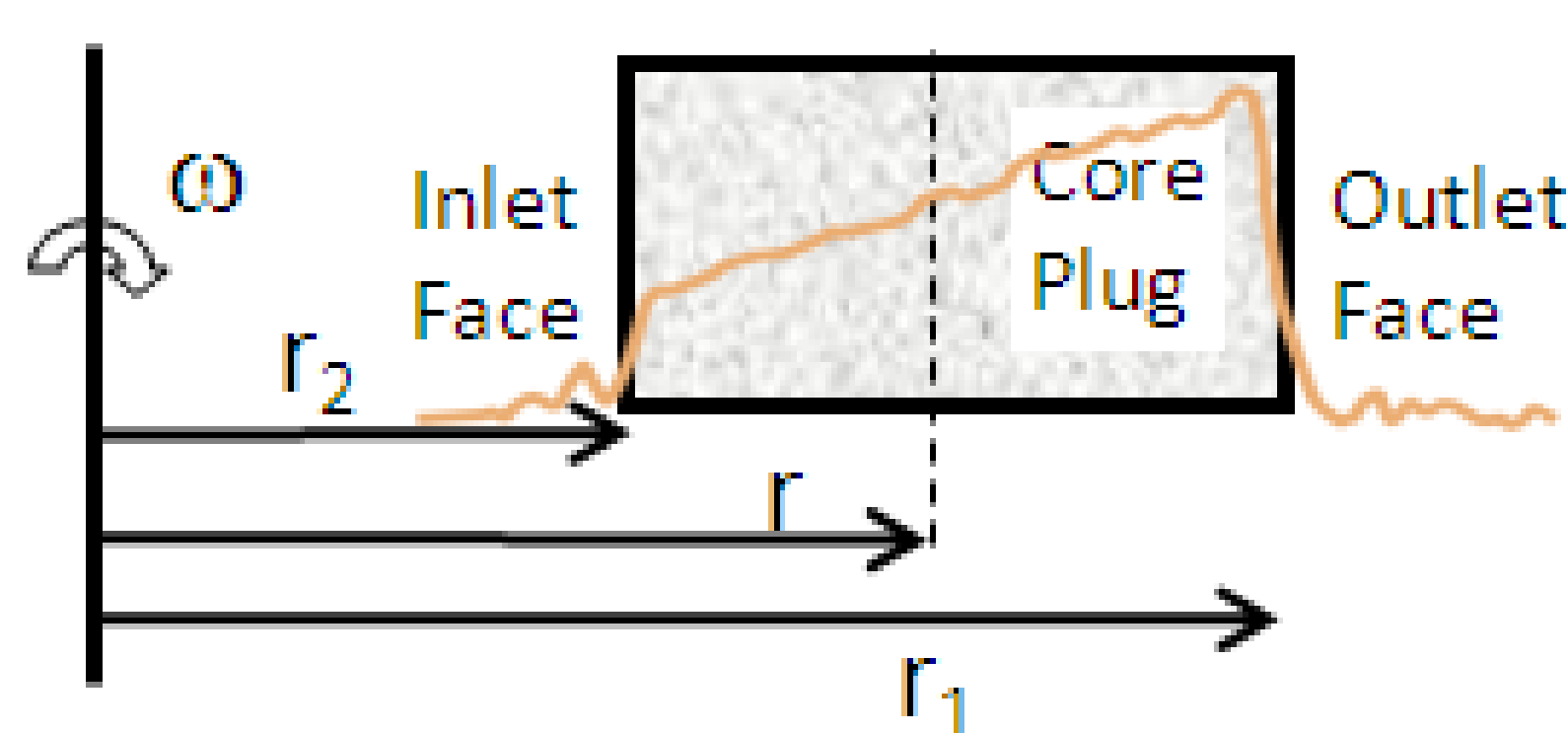


1 1/2" Carbonate plug  
Porosity = 18.9%



## 3. MRI-based Capillary Pressure Curves (GIT-CAP)

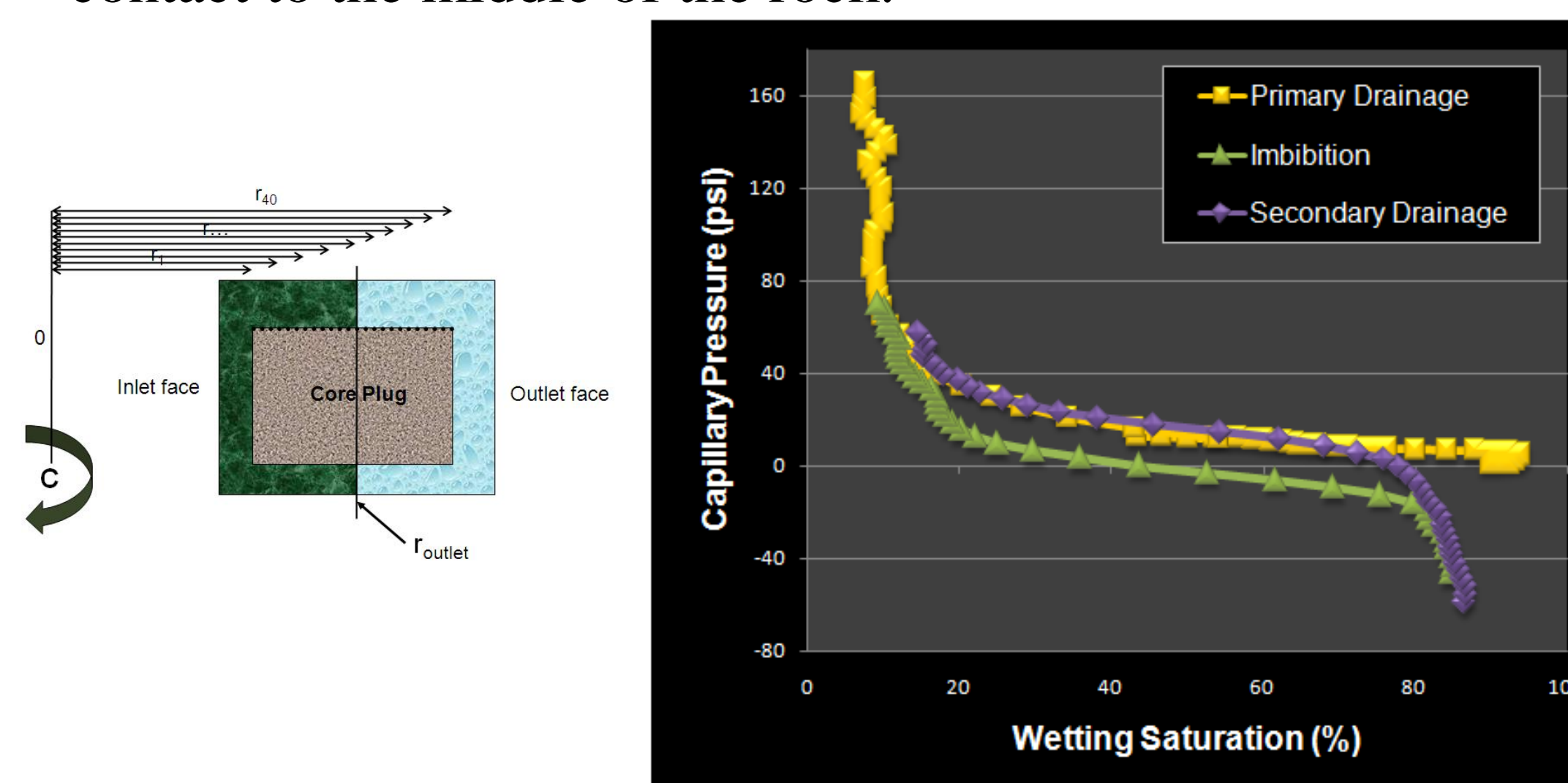
- MRI-based capillary pressure measurements are acquired by using a centrifuge to create a distribution of pressures and saturations inside the rock and then using MRI to determine the saturation profile [3, 4].
- The capillary pressure,  $P_c$ , can be calculated at any position,  $r$ , along the rock using the Hassler-Brunner equation:



$$P_c(r) = \frac{1}{2} \Delta \rho \omega^2 (r_1^2 - r^2)$$

## 6. Imbibition and Drainage Pc

- Oil/Brine imbibition and drainage (1<sup>st</sup> and 2<sup>nd</sup>) can be acquired using the MRI-based technique [4].
- A unique quality of MRI-based Pc is that both positive and negative pressures can be measured by moving the oil/brine contact to the middle of the rock.



Graphed results show kerosene/brine capillary pressure on 1-1/2" diameter chalk sample, porosity 36.5%

## 11. Conclusions

- The pore throat size acquired from GIT-CAP is non-destructive and uses reservoir fluids so there is no impact on the clays, pore matrix or wettability.
- Determination of the NMR relaxivity value allows for the  $T_2$  pore size distribution to be quantified and capillary pressure can be modeled.
- Relative permeability can be modeled directly from the Pc data or from the model applied to the Pc data.
- Standard  $T_2$  cut-off values are not valid in tight rocks.

Table of rock results

Sample	Permeability	Porosity	Lithology	Relaxivity
1	29.3 mD	23.9 %	Sandstone	8.71 $\mu\text{m/s}$
2	158 mD	25.5 %	Sandstone	6.24 $\mu\text{m/s}$
3	1.36 mD	17.4 %	Sandstone	9.21 $\mu\text{m/s}$
4	Unknown	18.9 %	Carbonate	5.47 $\mu\text{m/s}$
5	0.002 mD	7.25 %	Sandstone	2.66 $\mu\text{m/s}$
6	Unknown	36.5 %	Carbonate (chalk)	1.65 $\mu\text{m/s}$

## 4. Pore Throat from Pc

- The pore throat distribution can be plotted by converting the capillary pressure,  $P_c$ , into radius,  $r$ , using the Washburn equation, and plotting that against the incremental change in water saturation at that pressure.
- The capillary pressure can be related to radius by the Washburn equation [5]

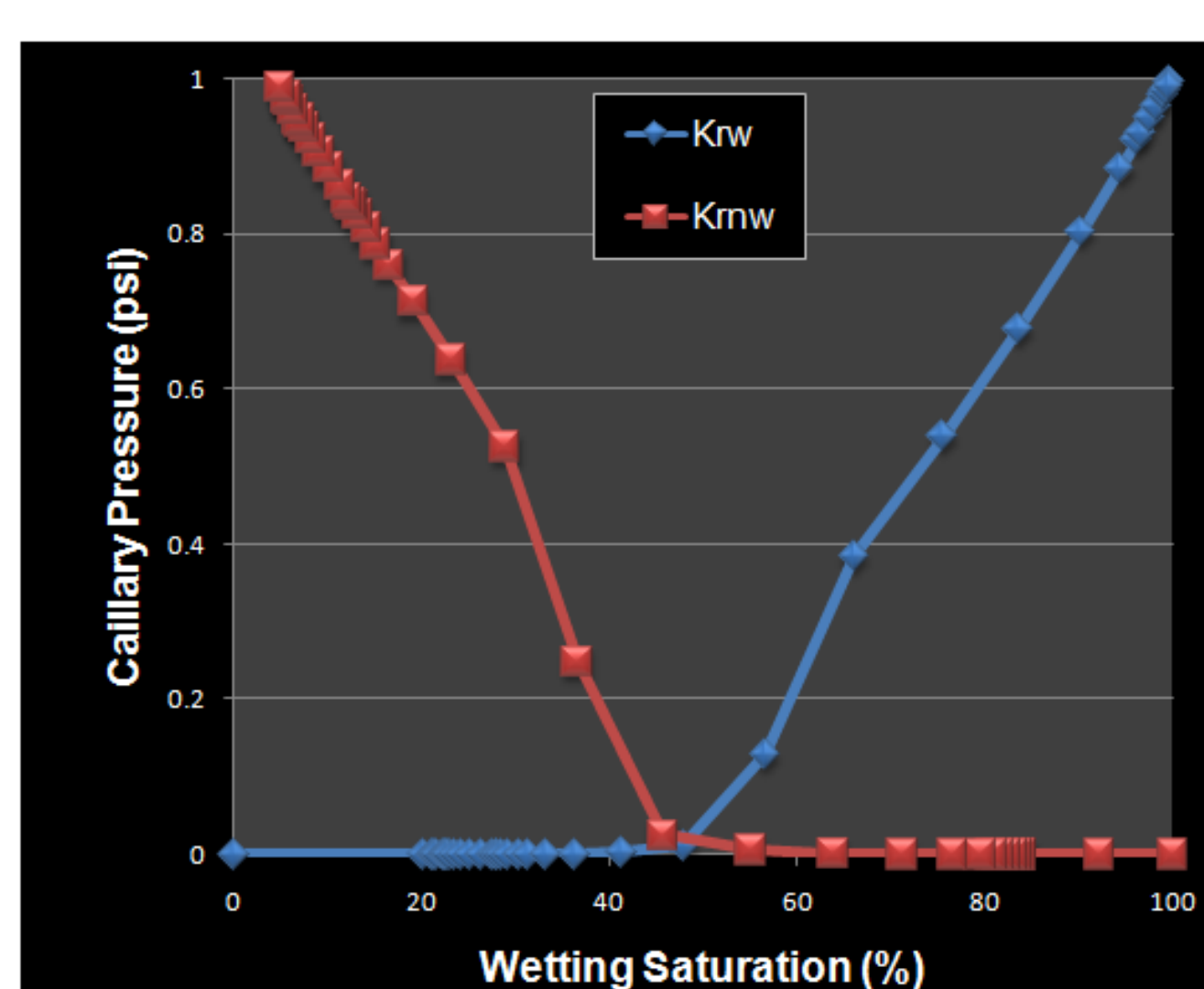
$$r = \frac{2\sigma \cos(\theta)}{P_c}$$

- This pore throat distribution can then be compared to the  $T_2$  pore size distribution to derive the NMR relaxivity parameter,  $\rho$ .
- Assuming a cylindrical geometry, ignoring the bulk and diffusion terms in the  $T_2$  equation, the relationship reduces to:

$$\frac{1}{T_2} = \rho \frac{2}{r}$$

## 7. Results (Relative Permeability from Pc)

- The relative permeability model can be directly applied to the Pc data.
- The difficulty lies in selecting the correct irreducible or residual saturation value,  $S_{wr}$ .



Relative permeability from the oil/brine imbibition Pc data shown in Section 6. Chalk sample porosity of 36.5%



## 12. References

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- US patent 7,352,179, "Methods and apparatus for measuring capillary pressure in a sample"
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