EXTRACTING PORE THROAT SIZE AND RELATIVE PERMEABILITY FROM MRI BASED CAPILLARY PRESSURE CURVES

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ABSTRACT

Capillary pressure (Pc) curves acquired using the Magnetic Resonance Imaging (MRI) technique, call GIT-CAP, have 70-100 data points. This extra data, when compared with traditional porous plate or centrifuge techniques, allows for the interpretation of more information from the Pc curve. In particular, the pore throat size and relative permeability can be extracted.

The pore throat size can be extracted from the capillary pressure curve by computing the change in saturation at each pressure and converting the pressure into a radius (similar to the mercury intrusion method). This information is valuable on its own but it can also be correlated with the T_2 NMR pore size distribution to extract more information, such as the NMR relaxivity parameter. The relaxivity parameter is required to convert the T_2 distribution into a quantitative pore size distribution. The T_2 NMR pore size distribution can easily be measured as part of the same test protocol that measures the MRI-based Pc.

The relative permeability of the rock can be modeled from the capillary pressure data using a Burdine model (or similar). The advantage of the MRI-based capillary pressure measurement is that with the additional measured data points, a Pc model (like Brooks-Corey) does not need to be applied to use the relative permeability model.

This work describes the techniques used in the acquisition and analysis of the data and a series of results on a variety of rocks from sandstones to carbonates.

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. Pore size and pore throat size are often related. NMR is a common way of determining the pore size distribution in a rock. Capillary pressure curves acquired using an MRI-based technique called GIT-CAP can be used to determine pore throat size distributions. Typical methods of acquiring capillary pressure, such as centrifuge and porous plate, do not have the resolution required [2].

Permeability is a measure of a porous media's ability to transmit fluid. Absolute permeability is a measurement of the permeability when only a single fluid is present. Effective permeability is the permeability of one fluid with a second fluid present. Relative permeability is the ratio of effective to absolute permeability.

The permeability of the first fluid is generally inhibited as the saturation of the second fluid increases. Typically, relative permeability is represented as a function of water saturation (water being the second fluid). Permeability and relative permeability can be computed or modeled from capillary pressure curves.

THEORY

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 rock is spun in the centrifuge until equilibrium is established. A one-dimensional saturation profile is then measured using MRI. Typically, two centrifuge equilibrium steps are sufficient to provide complete coverage on the capillary pressure curve. Figure 1 shows the relevant centrifuge distances, denoted as r_2, r_1 and r, as the distances from the rotational axis to the inlet face, the outlet face, and any point along the core length, respectively. The capillary pressure, Pc, can be calculated at any position, r, along the rock using the Hassler-Brunner equation, where ω is the rotational speed, and Δρ is the density difference:

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

A typical saturation profile as measured by MRI is overlaid on the rock in Figure 1. To produce the capillary pressure curve the pressure from equation (1) is plotted against the MRI measured saturation.

The pore throat distribution can be plotted by converting the capillary pressure, Pc, 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 Wasburn equation [5] where σ is the interfacial tension and θ is the contact angle.

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

This pore throat distribution can then be compared to the T_2 pore size distribution to derive the NMR relaxivity parameter, ρ. The T_2 NMR relaxation parameter is related to the surface, S, to volume, V, Ratio by the following equation:

$$\frac{1}{T_2} = \frac{1}{T_{2-Bulk}} + \rho\frac{S}{V} + (\gamma G T_E)^2\frac{D_O}{12} \tag{3}$$

The first (bulk T_2) and third (diffusion) terms in this equation are usually small and thus can be ignored leading to a direct relationship between T_2 and the pore size given as the ratio of the surface to volume ratio. Assuming a cylindrical geometry for the pores the equation reduces to a direct relationship with the pore radius, r.

$$\frac{1}{T_2} = \rho\frac{2}{r} \tag{4}$$

Once the relaxivity parameter is known the pore size distribution can be used to create a capillary pressure curve using equation (2) and the related NMR saturation change at that radius.

Relative permeability can be calculated from capillary pressure using a number of existing techniques. The Burdine model is a good example of an accepted method but the same methodology applies to all models [6]. The Burdine model expands on the Purcell model to include a tortuosity factor as a function of the wetting phase saturation. The wetting K_{rw} and non-wetting, k_{rnw}, relative permeability are:

$$k_{rw} = (\lambda_{rw})^2 \frac{\int_{S=0}^{S=Sw} \frac{dS}{P_c^2}}{\int_{S=0}^{S=1} \frac{dS}{P_c^2}} \quad \text{where} \quad \lambda_{rw} = \frac{\tau_w(1.0)}{\tau_w(S_w)} = \frac{S_w - S_m}{1 - S_m} \tag{5}$$

$$k_{nrw} = (\lambda_{rnw})^2 \frac{\int_{S=Sw}^{S=1} \frac{dS}{P_c^2}}{\int_{S=0}^{S=1} \frac{dS}{P_c^2}} \quad \text{where} \quad \lambda_{rnw} = \frac{\tau_{nw}(1.0)}{\tau_{nw}(S_w)} = \frac{1 - S_w - S_e}{1 - S_m - S_e} \tag{6}$$

Where S_m is the minimum wetting phase saturation from the capillary pressure curve; $\tau(1.0)$ and τ (S_w) are the tortuosity of the wetting phase when the wetting phase saturation is 100% and S_w; S_e is the equilibrium saturation of the non-wetting phase.

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.

$$P_C = p_e \left(S_W^*\right)^{-\frac{1}{\lambda}} \quad \text{where} \quad S_w^* = \frac{S_w - S_{wr}}{1 - S_{wr}} \tag{7}$$

Where p_e and λ are fitted parameters, P_C and is the capillary pressure. The normalized wetting phase saturation, S_W^*, can be computed using the water saturation, S_w, and the residual water saturation, S_{wr}. Applying the Burdine model to directly to the Brooks-Corey capillary pressure model determined from the data yields the following for the wetting, k_{rw}, and non-wetting, k_{rnw}, phase relative permeability.

$$k_{rw} = \left(S_W^*\right)^{\frac{2+3\lambda}{\lambda}} \qquad k_{nrw} = (1 - S_W^*)^2 \left[1 - \left(S_W^*\right)^{\frac{2+\lambda}{\lambda}}\right] \tag{8}$$

RESULTS

For samples 1 through 5, the rocks were cleaned, dried and then saturated with brine. NMR measurements were then performed to acquire the fully saturated one dimensional porosity profile and the T_2 NMR pore size distribution. The rocks were then spun in a centrifuge until equilibrium was established (minimum of 48 hours). The NMR measurements were then repeated. The data was then analyzed, as described by the theory above, to produce a primary drainage capillary pressure curve, a pore throat distribution from the Pc curve, a primary drainage relative permeability curve from the Pc data, a quantified T_2 pore size distribution (extracting the relaxivity parameter), and a capillary pressure curve derived from the T_2 NMR data. In some instances, more than one centrifuge speed was used to increase the resolution on the resultant capillary pressure curve. The entire testing protocol was typically completed within 14 days. For sample 6, the rock was flow cleaned to attempt to maintain the reservoir wettability. The rock was then saturated with deuterium based brine, then kerosene was spun into the rock to produce a primary drainage capillary pressure curve. The rock was then prepared at irreducible water saturation and an imbibition capillary pressure cycle was done. This was followed by a secondary drainage. See Green et al (2008)[4] for exact protocol details.

Figure 2 shows two T_2 NMR measurements, one with the rock fully saturated and one with the rock at the connate water saturation, for sample 4. From these two measurements, the clay bound water, free fluid, and bound fluid can be determined. For this low permeability sample, the T_2 cut-off was found to be 13 msec.

Figure 3 shows oil/brine first drainage, imbibition, and secondary drainage capillary pressure curves acquired using the GIT-CAP technique for sample 6. This complete test required only four centrifuge equilibrium steps. There are in excess of 30 points on each of the curves, which allows us to further interpret the result. First, the imbibition relative permeability can be extracted using the imbibition capillary pressure curve and the theory above (shown in Figure 4). Note from the figure, that we use the actual data points and not the modeled results. The same theory holds for deriving both imbibition and drainage relative permeability using a capillary pressure curve of the same type. The second and potentially more interesting result is the ability to extract pore throat size from the Pc data. Figure 5 shows the pore throat size extracted from the GIT-CAP capillary pressure, a mercury injection pore throat and the pore size from the fully saturated T_2. Note that this pore throat size extraction cannot be done on a modeled Pc curve as we lose the true distribution. Shown on the same figure is the T_2 distribution shifted to align the distributions. The amount of shift determines the relaxivity parameter which, in this case, is 5.4 um/sec. The relaxivity parameters for all six samples are shown in the table 1. The final figure, Figure 6, shows the T_2 distribution turned back into a capillary pressure curve for sample 4.

DISCUSSION AND CONCLUSION

A wealth of information can be determined from a simple rapid protocol procedure. With as few as two centrifuge equilibrium steps and two NMR measurements at each step (plus fully saturated) we have a good understanding of the pore structure and the fluid flow behavior.

It should be noted that the pore throat size derived from the capillary pressure curves and the pore size from the T_2 NMR results are not the same. The pore throat size refers to the diameter of the throats between the pores where as pore size refers to the diameter of the pore itself. Although these two diameters are often related (i.e. smaller pores usually mean smaller throats) this does not have to be the case. There are differences between the T_2 pore size and the pore throat size from mercury injection, especially for lower permeability samples. Future work will include examining the pore geometry itself through the use of thin sections.

Much of this work has been done on rocks from tight gas reservoirs (including shales). For these reservoirs the T_2 cut off values are typically much lower than the standard 33msec used for sandstones. We have found a more typical cut off is 10-15 msec. This reduced cut-off can increase the free fluid by a factor of two or more.

One of the main issues with converting capillary pressure to relative permeability is the difficulty in selecting the irreducible water saturation to use in equation (7). Changes in this value can greatly affect the resultant relative permeability curve. The capillary pressure models seem to under predict this value. Another limitation is the use of a model to predict relative permeability from capillary pressure. Different rocks might benefit from a different model than the Burdine model shown. The main point was to show that with the additional data of the GIT-CAP acquired capillary pressure this conversion can be more reliable than when used with other capillary pressure determined curves. Many of the results were obtained from cleaned cores and at ambient conditions. The original wettability of the rocks was therefore destroyed. It is well known that wettability will greatly affect the capillary pressure and the relative permeability. Future work will include comparisons to actual measured relative permeability curves with restored state plugs.

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 distributions to be used to compute capillary pressure. One advantage of this procedure is that the NMR technique can measure much smaller pores than can be achieved in current high speed centrifuges. For example, 1000 psi on an air/brine capillary pressure curve would correspond to 0.14 um radius pore. In some examples, T_2 NMR measures more sizes below 0.001 um. This means that, for T_2 derived Pc we can have pressures in excess of 10,000 psi.

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Table 1 - Summary of Results

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

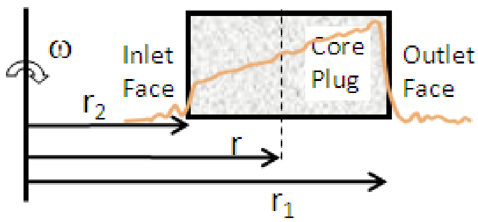

Figure 1 - Schematic of a rock core plug spinning in a centrifuge. Overlaid is the measured saturation profile using NMR.

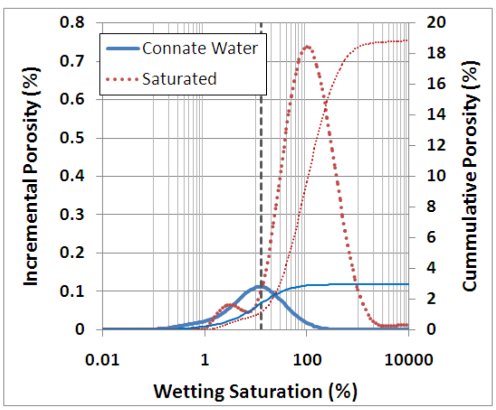

Figure 2 - T_2 cut off analysis of sample 4

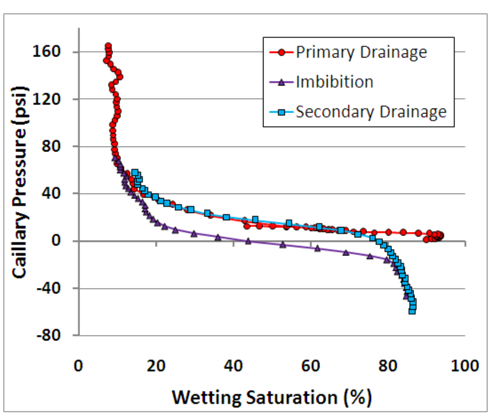

Figure 3 – Oil/Brine GIT-CAP acquired capillary pressure curves (primary drainage, imbibition, and secondary drainage) for sample 5.

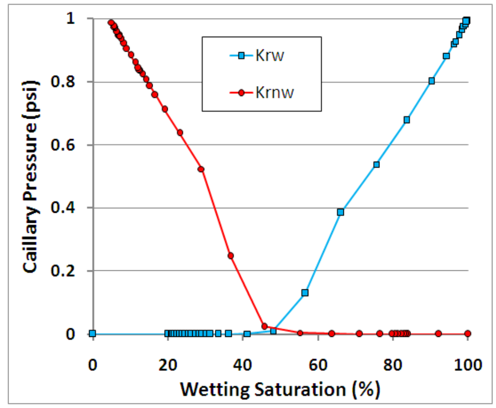

Figure 4 - Relative permeability from the imbibition GIT-CAP Pc of sample 6

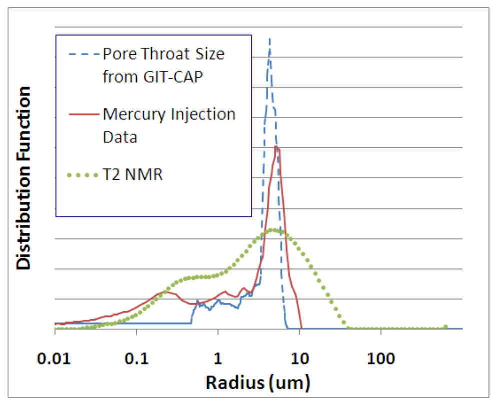

Figure 5 – Pore size (NMR) and pore throat size distributions from GIT-CAP Pc and mercury injection of sample 2

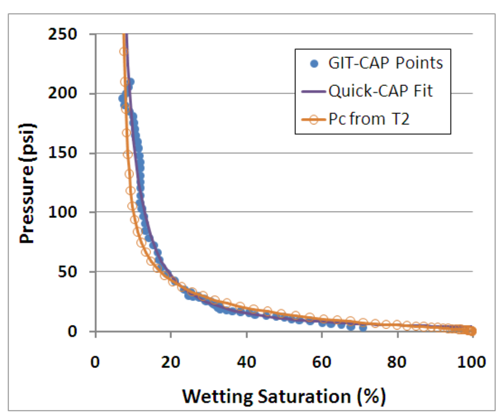

Figure 6 - Capillary pressure from T_2 of sample 4