AN IMPROVED TECHNIQUE FOR DERIVING DRAINAGE CAPILLARY PRESSURE FROM NMR T_2 DISTRIBUTIONS

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ABSTRACT

Nuclear Magnetic Resonance (NMR) T_2 measurements can be used directly to estimate petrophysical properties of reservoir rocks such as porosity and irreducible water saturation. They are also sensitive to pore-size distribution enabling the estimation of permeability and potentially capillary pressure. Several methods have been proposed to derive synthetic drainage capillary pressure information directly from NMR data [1-5]. However empirical correction factors are usually introduced in the scaling factor to improve the capillary pressure prediction at low wetting phase saturation.

This paper presents an improved method to derive primary drainage capillary pressure from T_2 distributions of fully saturated rocks. The modification is based upon experimental observations that T_2 signal amplitude increases at shorter times when comparing data from partially saturated cores with that from fully saturated cores. This is usually assumed to be due to water (or wetting fluid) remaining in crevices in such partially saturated cores. Such water has a faster relaxation rate as it has a higher surface area to volume ratio. We propose the use of a simple model of triangular pores to estimate the irreducible water saturation and the T_2 distribution of the drained core. The drainage capillary pressure is then derived from an *effective* cumulative T_2 distribution, obtained by combining the measured T_2 distribution from the fully saturated core with the distribution calculated at drained conditions from the triangular capillary model.

The method has been applied successfully to a number of sandstone core samples with a wide range of permeabilities. The triangular pore model predicts reasonably well the connate water saturation at various capillary pressures. The NMR derived and primary drainage capillary pressure curves show a very good agreement. The improvement in prediction mainly takes place at high capillary pressures and is automatically calculated as a function of the T_2 distribution and the pressure applied.

INTRODUCTION

The determination of representative capillary pressure curves is of great importance for reservoir characterization and the evaluation of fluid distribution within the reservoir. The connate water saturation and its distribution are directly related to capillary pressure. There are various standard measurement techniques used to determine core plug capillary

pressure, such as mercury injection, porous plate and centrifuge, however mercury injection capillary pressure data is not always equivalent to the other two methods [6, 7].

Recently NMR interpretation has improved to the extent that NMR measurements may now be used to derive drainage capillary pressures directly from logs or cores (see for example Kleinberg [1]; Marschall *et al.* [2]; Lowden and Porter [3]; Altunbay *et al*. [4]; Volokitin *et al.* [5]). These methods are based on the fact that capillary pressure curves are a function of the underlying pore size distribution. As NMR T_2 distributions taken from water saturated porous media are sensitive to the pore size distribution it should be possible to convert the T_2 signal into a capillary pressure curve. For example, Volokitin *et al.* [5] suggested rescaling T_2^{-1} with a proportionality constant κ, to obtain capillary pressure. They compared Hg-air and NMR derived capillary pressure for 186 sandstone samples and showed a reasonably good agreement at intermediate and high water saturations. However, a systematic discrepancy was observed in most of the samples at higher capillary pressure, P_c, close to the irreducible water saturation, that was attributed to a variation of the ratio of pore body to pore neck size. They proposed using a variable, empirical, scaling factor which depends upon the pore size distribution to improve the prediction.

However all these methods predict too low water saturations at higher capillary pressures as they assume that drained pores do not contain any wetting fluid. In practice even large pores contain water trapped in crevices, pendular rings and thin films due to irregularities in the pore surface. This water drains slowly as pressure is increased [8], thus capillary equilibrium may not always be achieved. Recently, a pore a network model that includes remaining wetting fluid in the invaded pores, which is gradually displaced at higher capillary pressure was presented by Chang and Ioanidis [9]. Their simulation results indicate an increase in amplitude at shorter T_2 during desaturation, as observed experimentally. Borgia [10], Coates *et al*. [11], Chen *et al*. [12] and Marschall [13] have all developed models to predict the bulk volume irreducible (BVI) and irreducible water saturation, taking this trapped fluid into account. However, to our knowledge, this concept has not been incorporated directly into capillary pressure predictions.

The objective of this paper is to describe and validate a new method that improves capillary pressure estimation from T_2 measurements on fully saturated cores by including the effects of remaining water in the draining pores. The method is illustrated using NMR data from outcrop and reservoir sandstone samples, and the results are compared against experimental air-brine and Mercury injection capillary pressures. The estimated irreducible water saturation, at P_c= 100 psi, is compared with porous plate and centrifuge data.

THEORETICAL MODEL

It is widely accepted that during capillary drainage the smallest pores stay fully saturated and some wetting fluid remains even in the drained pores. This fluid in the partially drained pores alters the form of the drainage capillary pressure curve at low water saturations. The remaining water can be identified by an increase in the signal at small

values of T_2 when comparing the T_2 distribution of partially saturated cores with those obtained from fully saturated cores (Fig. 1). The increase in amplitude at short T_2's is not a measurement or inversion artifact as the water saturation calculated from these distributions agree well with the independently measured pore volume and saturation values, as it will be shown later. We shall use this change in signal to improve the estimation of drainage capillary pressure from T_2 distributions of fully saturated cores.

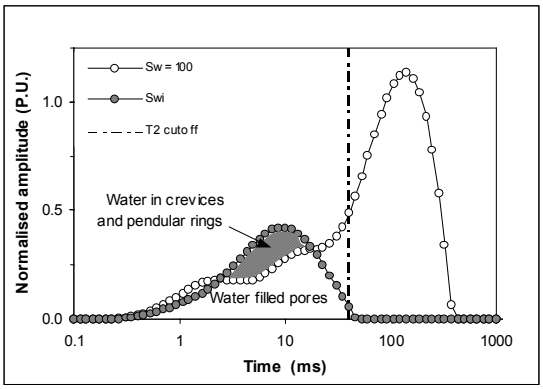

Figure 1. Comparison between fully saturated and air desaturated NMR T_2 distributions of a sandstone core. The smaller pores remain filled with water while some water remains in the larger, drained pores.

First we shall use a triangular capillary model to calculate the distribution of trapped water at any given capillary pressure, for any given pore size distribution. This can be used to estimate the trapped water saturation at a given capillary pressure. It can also be used to estimate the T_2 distribution that would be obtained from such a rock sample at irreducible water saturation. We shall then show how such a synthetic T_2 distribution can be used to 'correct' a real T_2 distribution from a fully saturated rock sample to produce more accurate drainage capillary curves.

Irreducible Water Saturation

One of the most common methods of determining irreducible water saturation using NMR is to obtain the T_2 distribution from fully saturated rock and then apply a T_2 cutoff to determine the volume of bound water. This assumes that only small pores (with shorter T_2's) contribute to the irreducible water saturation. In many cases, if the sample is a clastic, a value of 33ms can be used for this cutoff. However core calibration may be required for more accurate estimates, as the cutoff value can change with the facies present in the well.

Alternatively it is possible to use an empirical method, such as those proposed by Borgia [10] and Coates *et al*. [11] to estimate the irreducible water saturation. These models assume that the irreducible water is bound in the form of "films" that coat the surface of the larger pores as well as filling the smaller pores. A spectral weighting function, W, is determined which estimates the amount of water associated with each pore size and hence each T_2 relaxation rate.

The weighting functions for different pore geometries [11,12] are presented in Table 1. The use of these weights depends on the capillary pressure, the film thickness, h, and the surface relaxivity, ρ. The unknown parameters h/ρ should be estimated from desaturation

experiments in cores. It is worth noting that the spectral weight functions can be applied to any T_2 distribution. These functions are truncated to unity for fully saturated pores, e.g. small pore sizes below the threshold capillary pressure. Figure 2 shows an example of the spectral weight functions vs. relaxation time for the film models. It can be observed that the weight functions are dependent on h/ρ as well as the model used. By equating two permeability models, Coates *et al.* [11] derived an empirical weight function (Table 1), which is the basis for the spectral BVI method. They advocated that the values for m and b should be obtained by core calibration, however in most cases b could be fixed to one. By comparison with other models m must depend upon Pc and ρ.

In this paper a different pore geometry model is proposed, which is based upon triangular pores and is more appropriate to describe the water remaining in the crevices of the drained pores. For simplicity the pores used here are equilateral triangles (Fig. 3), however the same concept could be applied to other shapes with angular corners such as grain boundary pores [14].

Table 1. Spectral weight function for the film models and the empirical function of Coates.

Geometry	***W***
Cylindrical tube	$(h/\rho)/T_2\{2-(h/\rho)/T_2\}$
Spherical	$(h/\rho)/T_2^2\{3T_2-3h/\rho+(1/T_2)(h/\rho)^2\}$
Fracture (crack)	$(h/\rho)/T_2$
Coates Empirical	$1/(mT_2+b)$

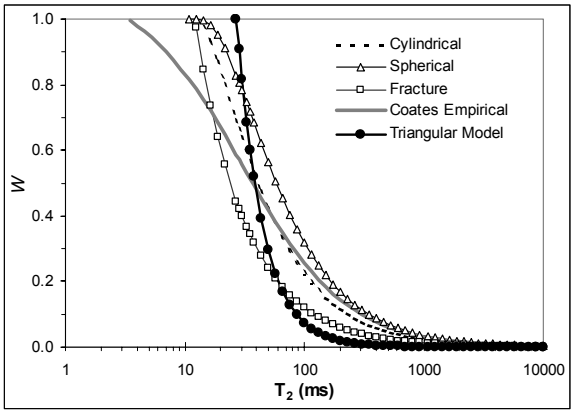

Figure 2. Comparison of the spectral weight functions. Parameters for the curves: film models h/ρ =12s; Coates m=0.03 and b=0.9; triangular model σ=72 mN/m, Pc =100 psi and ρ= 2.2 μm/s.

In the fast diffusion limit the relaxation rate is directly proportional to the surface to volume ratio of the pores [15]. Although, molecular diffusion may affect the NMR response, and pore coupling could induce a narrowing of the apparent pore size distribution [9], we need to assume that this effect is negligible in order to obtain the drainage capillary

pressure. Thus a fully water saturated triangular pore of side a (Fig.3 A) can be assume to have a relaxation rate $1/T_2$:

$$\frac{1}{T_2} = \rho \frac{12}{a\sqrt{3}} \tag{1}$$

When the threshold capillary pressure, P_{ct}, for a pore of size b is reached the non-wetting phase will fill the centre of the pore (Fig.3 B) with a radius R_t;

$$R_t = b / \sqrt{12}, \text{ or} \tag{2a}$$

$$R_t = (2\sigma \cos\theta / P_{ct}). \tag{2b}$$

Therefore, the relaxation rate at this condition becomes:

$$\frac{1}{T_2} = \rho \frac{18}{R_t\,(9 - \pi\sqrt{3})} \tag{3}$$

For higher capillary pressures or large pore sizes the wetting fluid will be pinned in the corners of the pores, with a radius of curvature R as shown in Figure 3C. For a zero contact angle it can be assumed that a circle of radius R is tangent to the sides of the triangle and the relaxation rate at this condition can also be calculated with Eq. 3 by replacing R_t by R. For a single pore size, the same concept and equations apply when the capillary pressure is increased. The water saturation, S_{wj}, for any drained pore of size d can be calculated as:

$$S_{wj} = \left(\frac{R}{d}\right)^2 \frac{(12\sqrt{3} - 4\pi)}{\sqrt{3}} \tag{4}$$

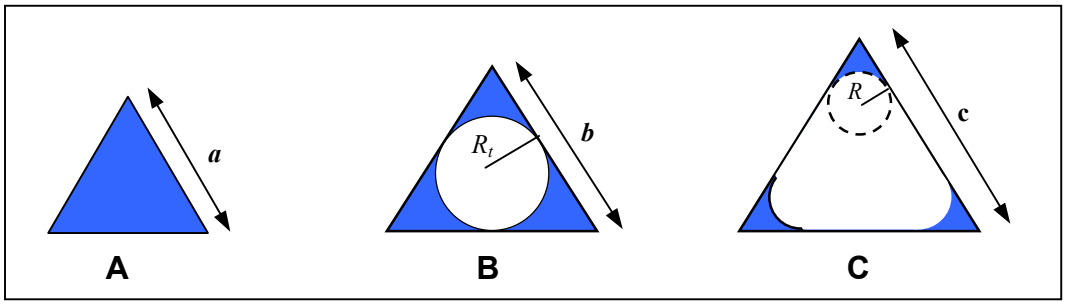

Figure 3. Schematic representation of the triangular pore model. **A**- fully saturated pore; **B**- pore at the threshold capillary pressure; **C**- pore at high capillary pressure.

The spectral weighting function for each pore, at a capillary pressure P_c, can be obtained by introducing the pore size from Eq. 1, and the radius of curvature from Eq. 2b into Eq. 4 to obtain:

$$W^j = \frac{\left(9 - \pi\sqrt{3}\right)\sigma^2}{9\rho^2 P_c^2 T_2^2} \tag{5}$$

This function has a quadratic dependence on the relaxation rate and explicitly accounts for the effects of interfacial tension, capillary pressure and surface relaxivity.

We assume that we can represent a porous medium by a bundle of triangular capillaries with a pore size distribution that is the same as that of the real porous medium. Thus the total water saturation at any capillary pressure can be obtained by adding up the water volume in each pore and dividing by the total volume of the pores. Thus, the irreducible water saturation, S_{wi}, can be calculated as:

$$S_{wi} = \sum_j W^j \phi_j \tag{6}$$

where ϕ_j is the effective porosity distribution.

Drainage Capillary Pressure from NMR

Our method for improving the estimation of drainage capillary pressure curves from T_2 measurements on fully saturated cores or rock is as follows.

1. The method proposed by Volokotin *et al.* [5] is used to obtain the full drainage capillary pressure curve as a function of water saturation. This involves first obtaining a cumulative T_2 distribution and plotting it on reciprocal T_2 scale. Then T_2^{-1} is rescaled with a proportional constant, κ; and finally the X and Y-axes of the plot are interchanged to give drainage capillary pressure as a function of saturation. The conversion comes down to find a suitable value for κ; which can be expressed as:

$$\kappa = P_c T_2 = \frac{\sigma \cos\theta \, R_p}{\rho \, r_n} \tag{7}$$

   where R_p and r_n are the pore body radius and pore neck, or throat, radius respectively.

2. The BVI is calculated using the triangular pore model, as described in the previous section. During this process the position of the interfaces (Fig.3) and the amount of water remaining in all the pores is obtained. These pores will have a relaxation time that is proportional to the surface to volume ratio (*S/V*) of the water remaining in them. A T_2 correction factor SV* is defined as the ratio of the *S/V* for the fully saturated pore divided by the *S/V* for the drained pore. Then T_2 for the drained pore is obtained by multiplying the T_2 of the fully saturated pore by the correction factor. Figure 4 shows the correction factor as a function of surface relaxivity and capillary pressure.

3. An estimated T_2 distribution for the drained sample is constructed with the corrected time and amplitude. The distributions obtained by this method compare quite well with the measured NMR of desaturated samples, an example is shown in Figure 5.

4. An effective cumulative T_2 distribution is then obtained from the distributions of the fully saturated sample and the calculated distribution at the drained condition.

5. Finally, the capillary pressure is calculated as proposed by Volokotin *et al.* using this *effective* cumulative T_2 distribution.

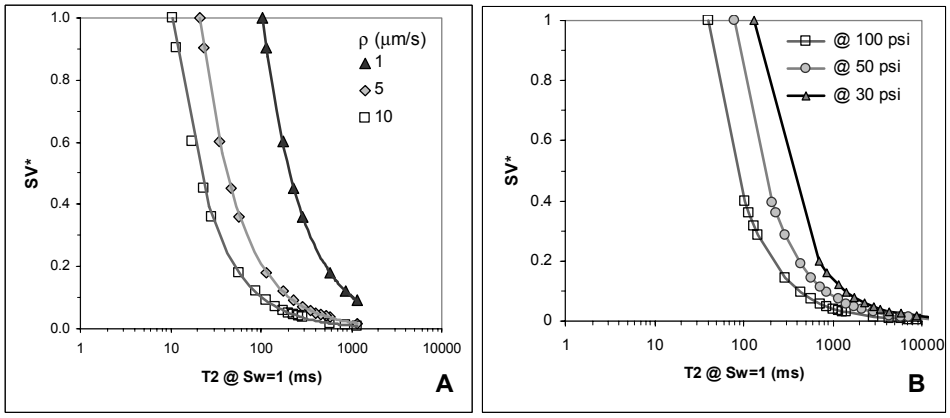

Figure 4. T_2 correction factor for different surface relaxivities and capillary pressures at: **A-** an air-brine capillary pressure of 100 psi; **B-** surface relaxivity of 1 μm/s.

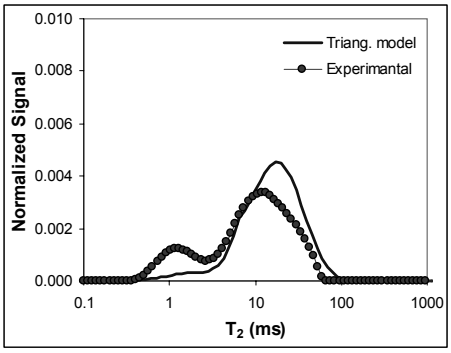

Figure 5. Comparison of experimental and synthetic NMR T_2 distributions for an air desaturated outcrop sample (Dod-4).

EXPERIMENTAL

A total of eleven samples were used to validate the new method. All the samples used and their petrophysical properties are given in Table 2.

Five outcrop and two reservoir core plug samples were tested in house. The samples tested were cleaned using Soxhlet extraction with methanol, and then dried in a vacuum oven and fully saturated with brine. Both the dry helium porosity, ϕ, and liquid permeability, k, of the samples were determined prior to the start of the experiments. The drainage capillary pressure was determined using a porous plate setup without confining stress and with a maximum applied pressure of 100 psi. NMR measurements were performed on fully brine saturated and drained plugs in a Resonance Instruments MARAN 2, 2 MHz spectrometer at 34 ^{o}C and ambient pressure. The CPMG sequence was used to generate the T_2 decay with an inter-echo time of 200μs, 8000 echoes and 100 scans. The inter-echo time was selected to minimise diffusion effects due to internal field gradients [16]. The relaxation time distribution was obtained with the DXP programme from Resonance Instruments.

Further data from four samples from the Applied Reservoir Technology Sandstone NMR Rock Catalogue [17] were also used to test the proposed method. The data from the

Sandstone NMR Rock Catalogue consist of NMR T_2 distributions for brine saturated samples with an inter-echo time of 350 μs; irreducible water saturation after drainage with air in a centrifuge (equivalent to a capillary pressure of 100 psi); and air-mercury capillary pressure for all the same samples

Table 2- Sample identification and petrophysical properties of the samples used. * Outcrop samples

Sample ID	Liquid Permeability (mD)	Porosity (%)	Irreducible water saturation @100 psi (% Pore Vol.)
Dod-4*	2220	22	7
Cla-4*	1019	16	7
Cros-4*	17	18	33
Sta-4*	38	17	20
Spri-4 *	7	18	35
PG-2	581	36	9
PG-4	299	38	12
ART- 06	1700	25	10
ART- 11	1000	15	--
ART- 13	67.2	21	--
ART- 18	0.22	16	87

RESULTS

Irreducible Water Saturation

In order to test the new weighting function, T_2 distributions from ten fully saturated core plugs were used to estimate the irreducible water saturation, S_{wi}. Then the values of surface relaxivity, ρ, for each plug were obtained from the optimum κ following Volokotin's method. Then the weighting function and water saturation was calculated (Eq. 5 and 6) for an air-brine P_c of 100 psi. Figure 6 shows the calculated S_{wi} vs. the conventionally measured core S_{wi} and the liquid permeability. The calculated water saturation values agree well with the experimental data. The discrepancy in S_{wi} observed for some samples is possibly due to trapped water at pore level resulting from low accessibility of some larger pores. It is worth noting that our model does not include interconnectivity effects.

The influence of surface relaxivity and capillary pressure on the value of bound water saturation was studied for some samples and is shown in Figure 7. The optimum ρ of the outcrop samples varied between 1.2 and 4.0 μm/s. However, if a single value of $\rho = 2.0$ μm/s were used for all the samples, the maximum error in the calculated saturation would be within 9 saturation units of the measured value. The capillary pressure, on the other hand, produces a larger influence in the amount of bound water. Nevertheless all the cores have almost reached irreducible water saturation at 100 psi.

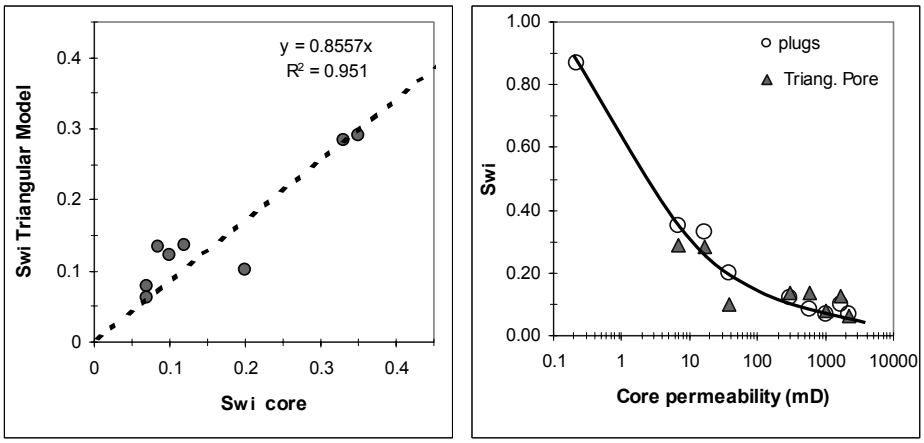

Figure 6. Calculated irreducible water saturation from the triangular pore model vs. the measured core plug saturation (at 100 psi) and liquid permeability.

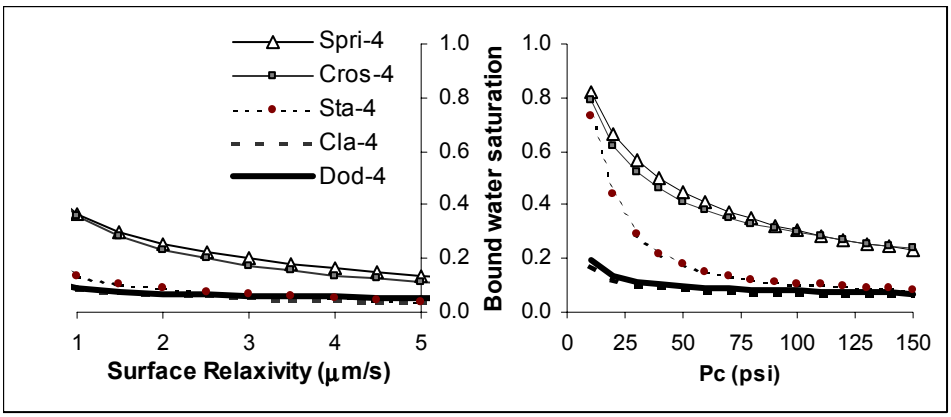

Figure 7. Effect of the surface relaxivity and capillary pressure on the calculated bound water saturation for the outcrop core plugs using the triangular pore model.

Drainage Capillary Pressure

For the purpose of demonstrating the methodology the optimum κ was obtained for each plug. A zero contact angle and a pore to throat ratio (R_p/r_n) of 2 were assumed. The results of using the Volokotin's method, with constant κ are presented in Figure 8. It can be seen that the capillary pressure obtained from NMR reproduces reasonably well the experimental data. However, as mentioned earlier there is a systematic saturation error at higher capillary pressures is observed when the remaining wetting phase in corners and crevices is ignored. The discrepancy between curves at high capillary pressures is proportional to the irreducible water saturation. Thus, the saturation error is a function of the permeability of the core, or in other words the mean pore size, as shown in Figure 6.

The improved method uses the effective cumulative distribution to calculate the *Pc* curve as described in a previous section and an example of this distribution is presented in Figure 9. The increase in signal due to the water remaining in the pores is obvious at short time. The calculated capillary pressure using the effective distribution is also plotted in Figure 8. As it can be observed there is a noticeable improvement of the prediction in all the cases.

The correction is negligible at higher saturation, however this correction is more pronounced as the saturation decreases. Additionally, it implicitly captures the pore size distribution from NMR and produces a larger correction for the less permeable cores.

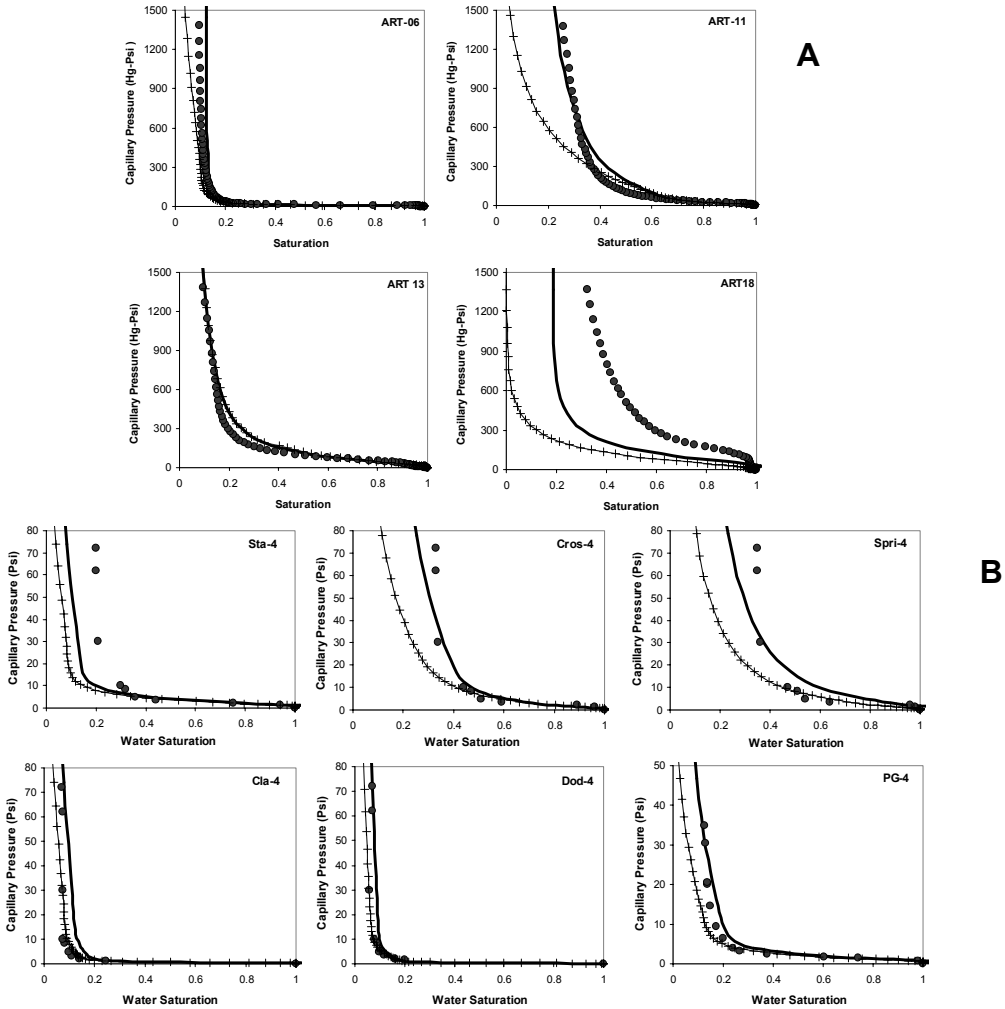

Figure 8. Experimental (circles) and NMR calculated capillary pressure curves. Comparison of Volokotin's method (crossed line) and improved method (continuous line). **A-** for mercury-air capillary pressure; **B-** for brine–air capillary pressure.

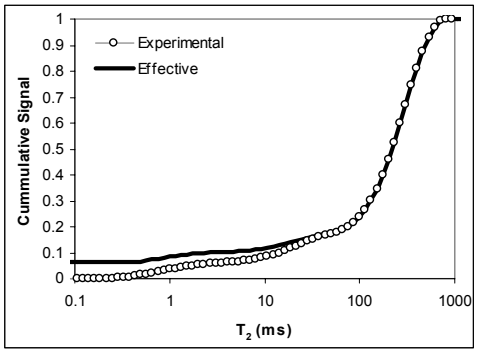

Figure 9. Experimental cumulative T_2 distribution for an outcrop sample (Dod-4) and the effective distribution used to calculate the improved capillary pressure.

The improved method for calculating drainage capillary curves from NMR provides an estimation based on physical principles without the need for variable scaling factors. Although a pore to throat aspect ratio of two may be acceptable for some sandstones, this value might not be applicable to other rocks such as carbonates. The method has the advantage that is based on fast and non-destructive measurements. However, to apply the method is necessary to know the surface relaxivity of the rock. This value can be obtained from calibration of a representative set of samples from the reservoir or if previous core data is not available a general sandstone scaling factor could be used (see Applied Reservoir Technology Sandstone NMR Rock Catalogue [17]). Volokotin [5] analysed the data form 19 fields and showed that a reasonably good prediction of capillary pressure curves could be obtained by using a general sandstone scaling factor, κ, of 3 psia (Hg).s.

CONCLUSIONS

In this paper, we provide a simple technique for improving the calculation of drainage capillary pressure from T_2 distributions taken from fully saturated sandstone core samples. The method is based on a simple, triangular, pore model that accounts for the wetting phase remaining in the crevices of the drained pores including their effect on saturation and relaxation rate. The fluid distribution of partially saturated cores during drainage can also be calculated from this model, thus providing a good estimate of the irreducible water saturation as a function of capillary pressure. Good agreement was obtained between experimental and calculated capillary pressure curves for different sandstone cores.

The proposed model improves the understanding of the relationship between NMR and capillary pressure enabling a better and faster prediction of drainage capillary pressure. The method could be applied to well log interpretation after the surface relaxivity is calibrated with representative core plugs. It may be possible to improve this calculation further by using more complex representations of the pore-space and network simulation.

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