

Some simple methods for refining permeability estimates from NMR logs and generating capillary pressure curves¹

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Introduction

Empirical studies of capillary pressure data by Leverett (1941), Purcell (1949), Thomeer (1960), Swanson (1981), and others, show permeability in sandstones, and indeed many carbonates, can be predicted from the shape of the capillary pressure curve, which is used to define the threshold pore size:

$$k(mD) = a \cdot (\text{threshold pore size})^b = a \left(\frac{\text{Non-wetting phase saturation (\% bulk volume)}}{\text{Capillary Pressure (psi)}} \right)^b \dots \text{eq.1}$$

The standard permeability equations for NMR are fundamentally the same as the permeability equation obtained from capillary pressure experiments. The combined terms in the NMR equations (mean T2 and porosity in the SDR equation, or free-fluid/bound-fluid ratio and porosity in the Coates equation), provide an alternate measure of threshold pore size.

The Pc and NMR permeability equations incorporate the entire pore size distribution, so the resultant permeability relates to the average permeability for the sample. It follows therefore, that where permeability is accurately predicted from NMR logs, the pore system must be homogeneous over the volume range sampled by the log and the permeability measurement to which it is compared. It also follows that if NMR logs can be used to predict permeability, then they can also be used to generate capillary pressure curves.

Therefore, two main questions arise when analysing NMR logs:

- 1) how do we adjust the terms of the permeability equations to obtain accurate estimates of permeability?
- 2) how do we relate T2 relaxation to capillary pressure in the presence of a single fluid phase (e.g. water), and more than one fluid phase (e.g. oil and water)?

This article provides some practical methods for solving these problems.

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Optimising the standard NMR permeability equations

All terms in the SDR and Coates NMR permeability equations are adjustable, so there is a lot of flexibility when optimising the equations. The simplest approach is to combine all the available core data for the well, or entire field if possible, and build a statistical model.

Optimisation of NMR permeability can be achieved using a basic spreadsheet and following some simple steps:

- 1) Construct the data-base. This should include as a minimum; log depth, GR, NMR bound fluid, porosity (either from NMR logs or another log), core permeability, core porosity, and core Swirr and/or Dean & Stark Sw. Any information that helps define bed boundaries and potential flow units is also useful (e.g. log facies, borehole image logs, and geological core descriptions). Other permeability data, e.g. MDT mobility measurements and pressure tests, are useful for identifying flow units, and can be used to guide stacking of the raw echo trains.
- 2) Compute permeability using the standard SDR and Coates equations:
 - $kmD=4[T2lm (ms)^2 \cdot (PHIT(\%)/100)^4]$
 - $kmD=(FFI/BVI)^2 \cdot (PHIT(\%)/10)^4$
- 3) Plot predicted permeability versus core permeability as depth plots and cross-plots
- 4) Determine bound fluid for the best reservoir, either by selecting a fixed BVI value, or by computing bound fluid using a weighted moving average (e.g. BVI corresponding with the 25th percentile for a moving 3' window). In thin-bedded reservoirs, we sometimes need to weight log-derived bound fluid towards the better reservoir rocks because core plug sites are often biased towards these.
- 5) For selected depth intervals, adjust the exponents, the numerator applied to porosity, and the bound fluid estimator to achieve;
 - i) best visual match between core and log permeability by depth, with emphasis on picking up small scale features
 - ii) best cross-correlation between core and log permeability
 - iii) improvement on permeability predicted directly from porosity
- 6) Compare results against geological core descriptions, log facies (including borehole image logs), and well test data

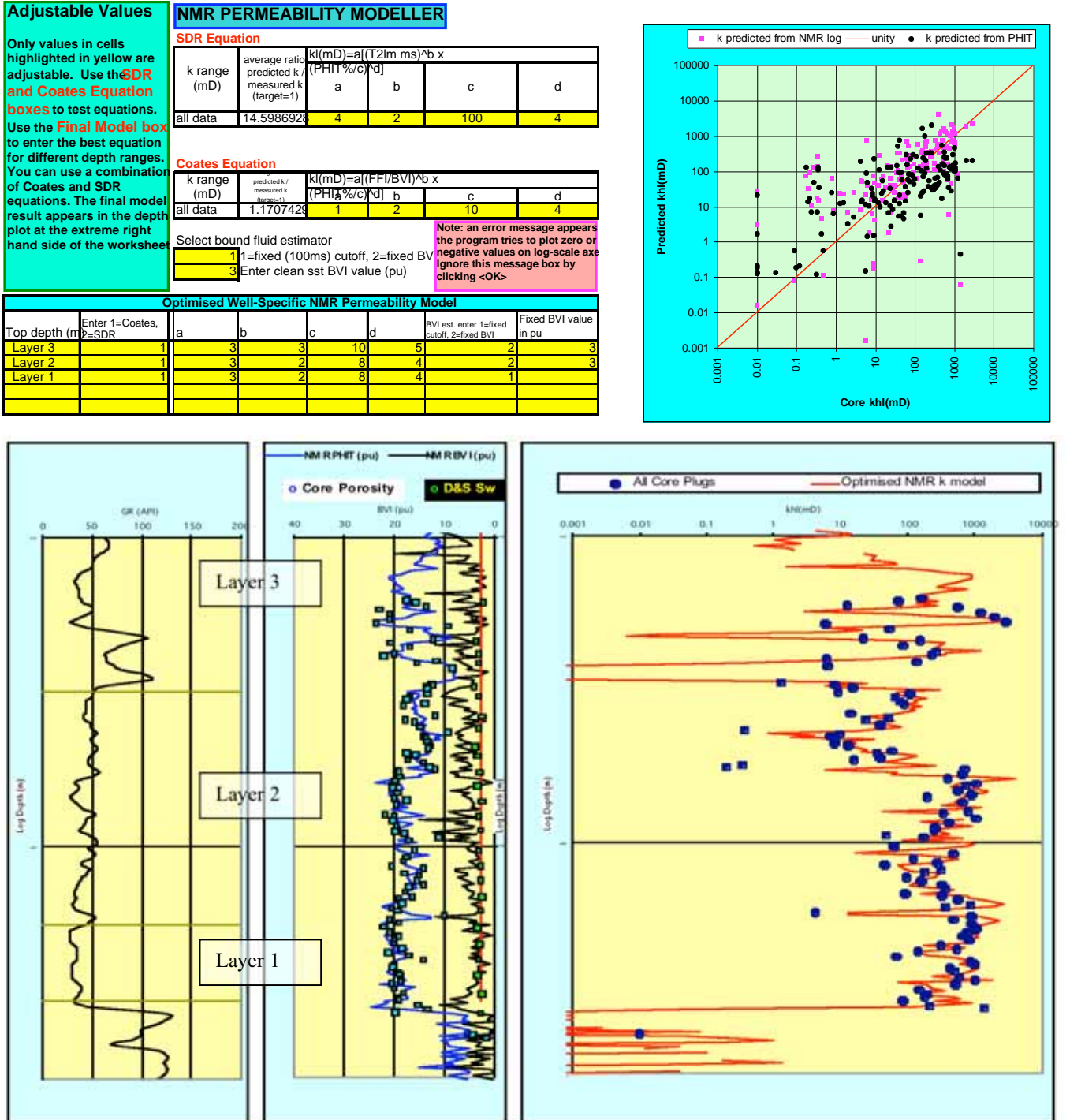
When adjusting the NMR permeability equations it is important to be aware that changes in the value of the exponents will impact on the required level of accuracy associated with the terms to which they are applied (i.e. T2lm, BVI and porosity).

An example of an NMR log with optimised permeability is shown in Figure 1. The reservoir section contains a fining-up sequence comprising a basal sandstone, grading into inter-laminated sandstones and siltstones, overlain by inter-bedded sands and shales. Over most of the section, log-derived BVI is significantly higher than the Dean & Stark Sw values obtained from core. This is because the log averages sandstones and siltstones together, whereas the plugs target the sandstones. In the basal sands (Layer 1), log BVI and core Sw coincide because this unit is relatively homogeneous. In layers 2 and 3, the permeability equations include a fixed BVI value of 3 pu to weight BVI towards the better sands. The fixed value is the average BVI value for the core plugs, but it could also be estimated from the log using a weighted average.

The form of the NMR permeability equations for layers 1 and 2 are similar to the standard Coates equation. The standard equation is derived from empirical studies of clean sands, so the pore system in these two layers is typical of 'clean' sand. The fact that the same equation can be used in the thick basal sand and in the thinner overlying sands suggests these sands have the same origin. In layer 3, the exponents differ from the standard values. This means the pore system in this upper layer differs from the pore system in the underlying layers, perhaps reflecting a change in source area. Where optimised NMR permeability equations differ significantly from the standard equations, then NMR, MICP and petrographic analyses

should be conducted on core samples to establish depositional and diagenetic controls on pore geometry.

Figure 1. Screen capture from an Excel spreadsheet showing how permeability from an NMR log is optimised using core data



Obtaining capillary pressure curves from T2 distributions

Single fluid phase

In a rock where the saturating phase is the same as the wetting phase, T2 relaxation will relate directly to pore size. Providing T2 relaxation takes place within the fast-diffusion limit, and the surface relaxivity (ρ_2) is known, T2 can be converted to pore size and capillary pressure very simply using the following procedure²:

- 1) Convert T2 to pore size using data obtained from core analysis (e.g. laboratory NMR vs MICP), or published scaling factors if core is not available (ref. Kleinberg, 1996, and The NMR Sandstone and Carbonate Rock Catalogues) (Figure 2):

$$\text{Pore diameter (microns)} = \rho_2 (\mu\text{m} / \text{ms}) \times T_2 (\text{ms}) \dots \text{eq.2}$$

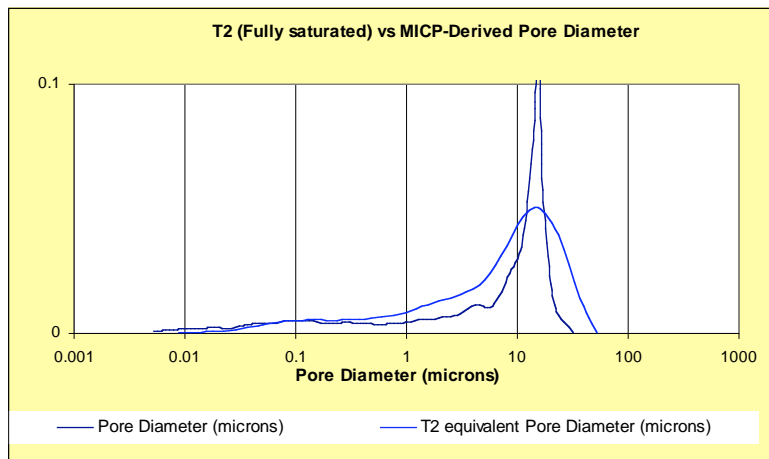


Figure 2. T2 distribution for a brine-saturated core plug converted to pore size using a scaling factor ($\sim \rho_2$) obtained from MICP analysis conducted on an end-trim from the same plug.

- 2) Convert the pore size to a cumulative plot by summing NMR porosity ($\phi_{\text{Effective}}$) such that ϕ at max diameter=0, and ϕ at min diameter= $\phi_{\text{Effective}}$. If small pores (short T2's) can be shown to relate to clay-bound water these should be removed before summing the porosity, otherwise clay-bound water will be treated as capillary bound water in the conversion to P_c .
- 3) Convert pore size to capillary pressure (Figure 3):

$$P_c(\text{psi}) = \frac{-4.T.\cos \theta.c}{\text{pore diameter } (\mu\text{m})} \dots \text{eq.3}$$

where, T = interfacial tension (dynes / cm)

θ_i = advancing contact angle (degrees)

c = conversion constant (0.145)

Capillary pressure can be computed for dual combinations of gas/air/water/oil/mercury using appropriate interfacial tension and contact angle constants.

² for a more detailed evaluation of the technique refer to Marschall *et al.*, 1995

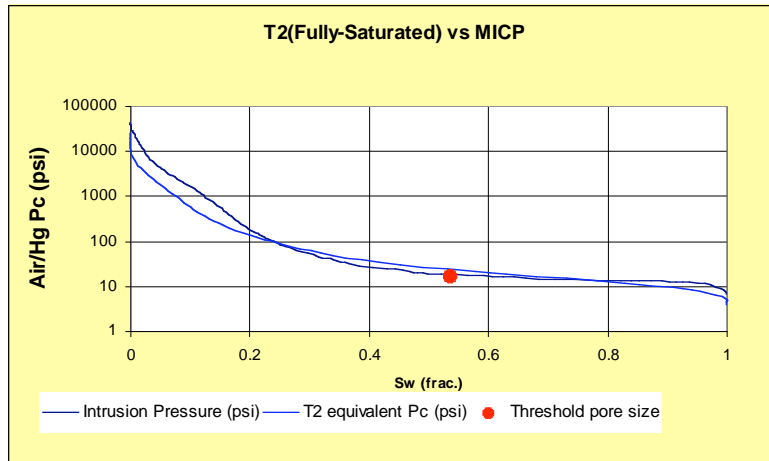


Figure 3. A T2-derived air/mercury capillary pressure curve obtained for a brine-saturated core plug. The predicted Pc curve is plotted against MICP data for the same sample. The red circle shows the threshold pore size controlling flow.

The number of pressure steps in the T2-derived Pc curve depends on the number of points, or bins, used in the inversion of the time-domain data (echo train), which is limited by the signal:noise level. Core NMR experiments typically achieve S:N levels > 100:1, which allows 50 – 100 points to be used in the inversion. Log NMR experiments typically achieve S:N levels <10:1, which allows between 10-30 points to be used in the inversion. Stacking the log data will increase S:N, and hence the number of points used in the inversion, but this will also reduce vertical resolution.

Multiple fluid phases

In wells drilled with oil-based mud (OBM), or where there is a native oil remaining in the flushed zone, the T2 distribution will contain a combination of pore size and bulk fluid information. In water-wet rocks, the lower mode at short T2's normally represents bound water (unless gas or heavy oil is present), and the mode at long T2's normally represents oil from OBM filtrate, formation oil, or a combination of these. The lower mode contains pore size information because water is in contact with the pore walls. The upper mode contains bulk fluid information because the oil is not in contact with the pore walls. Under these conditions, only the early part of the T2 distribution relates to pore size, and hence Pc. Generating the complete Pc curve (i.e. Sw=0-1) requires extrapolation of the T2 distribution out to long T2's.

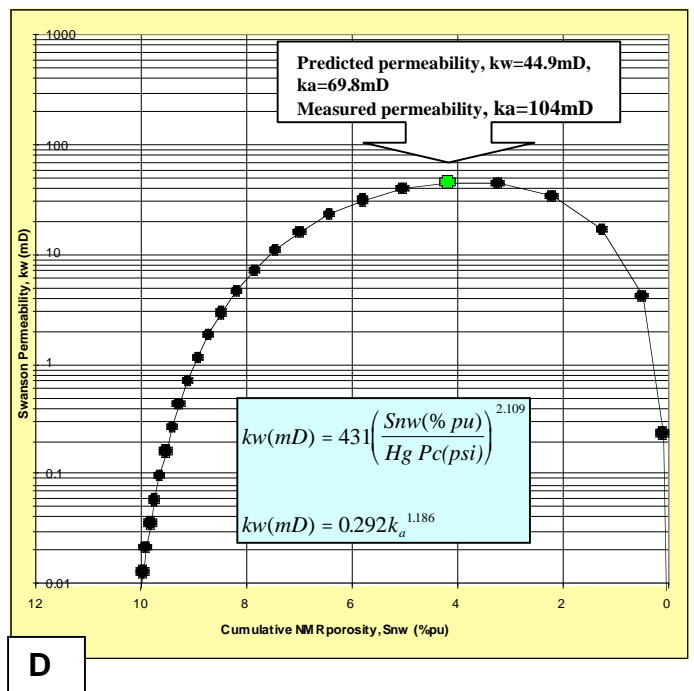
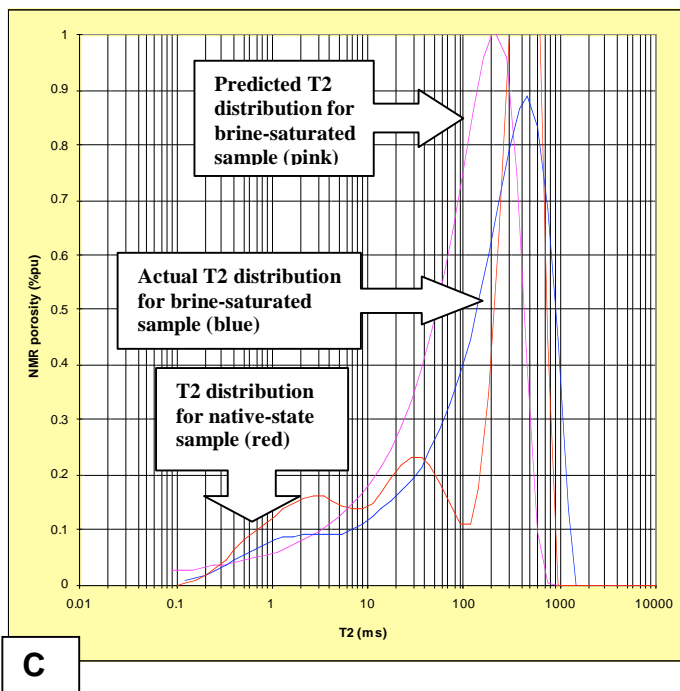
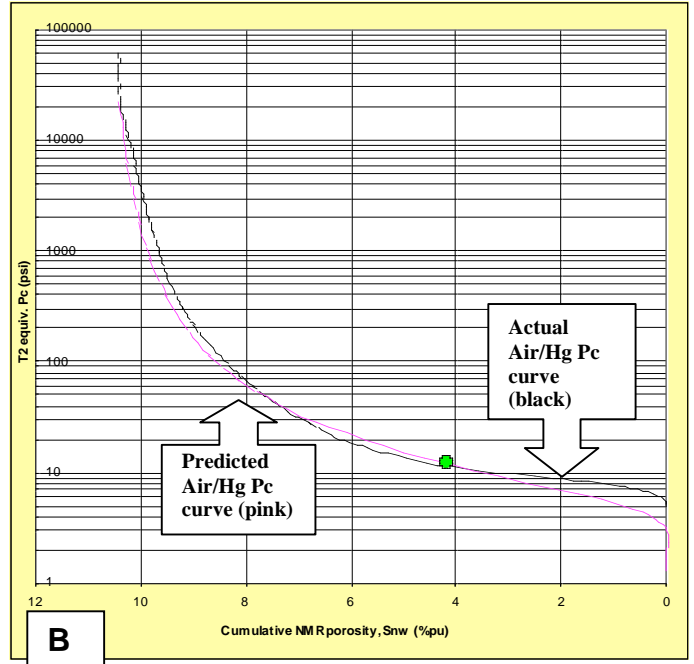
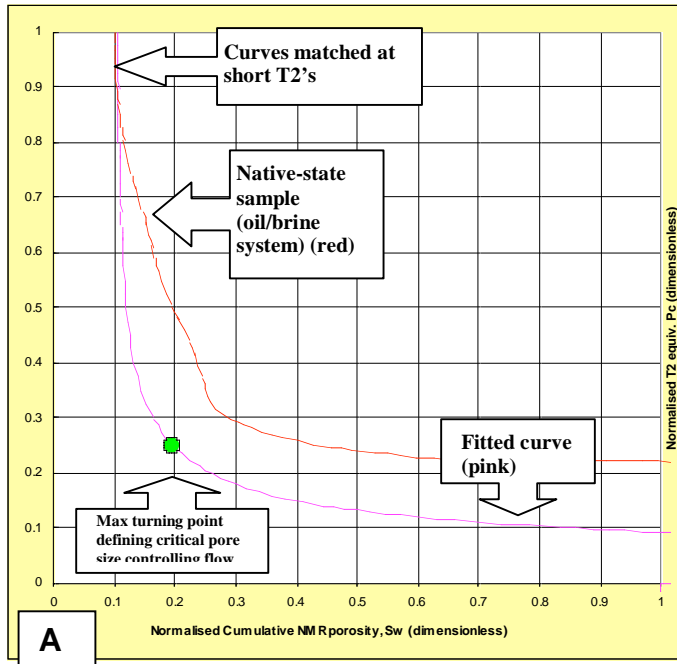
At the 1999 SPWLA conference, Volikitin *et al.* presented a method for completing the T2 distribution in rocks with partial water saturation. Their method uses a predicted mean T2 value obtained from an empirical relationship between geometric mean T2 and Swirr (data source: NMR Sandstone Rock catalogue, 1997). A moveable water spectrum is then added to the T2 distribution such that the sum of amplitudes equals porosity, and the resultant mean T2 value matches the predicted mean T2 value.

We have developed our own method for completing the T2 distribution which predicts the T2 values at long times by fitting a hyperbola through the early times. This approach is based on the work of Thomeer (1960) and Swanson (1981), which showed the maximum turning point on a hyperbola fitted through an air/mercury capillary pressure curve (log Pc vs log Sw expressed as % bulk volume) could be used to predict permeability.

Our method involves converting T2 and cumulative NMR porosity to log scales and then normalising the values so they both sum to 1, with 1/T2 on the Y axis ($\propto Pc$) and NMR porosity on the X axis ($\propto Sw$) (Figure 4a). The data are normalised so they are in a form suitable for fitting a rectangular hyperbola, such that the limbs of the curve are parallel to the axes. A curve is then fitted through the data ensuring the best match occurs at short T2's. The shape of the curve is adjusted by changing the point where the asymptotes to the curve intercept the X and Y axes, and by adjusting the exponent, a, for values of Y ranging from 0 to 1:

$$X = X \text{ axis intercept } (\xrightarrow{0-1}) + \left[\frac{\left(\frac{X \text{ axis intercept}^a \cdot (1 - X \text{ axis intercept})^a}{Y \text{ axis intercept } (\xrightarrow{0-1})^a} \right)}{Y^a} \right] \dots \text{eq.4}$$

Figure 4. Illustration of the method used to generate a capillary pressure curve from NMR data when part of the signal is dominated by a bulk fluid response. Panel A shows an hyperbolic curve fitted through the short T2's. Panel B shows the complete Pc curve obtained from the equation for the fitted curve. Panel C shows the original T2 distribution for the native-state sample and the predicted T2 distribution for sample saturated with brine. Panel D shows the estimated permeability for the sample using Swanson's equation for clean sandstones.



The values of X and Y for the predicted curve are converted to conventional units, Sw (%pu), and Pc (psi), to generate the complete Pc curve (figure 4b). The Pc values can be converted to T2 values using equations 2 and 3. The resultant T2 distribution shows us what the NMR log might look like if the formation in the sensitive region was occupied by a single fluid phase (e.g. brine) (figure 4c).

A drawback of our curve fitting method compared to the method of Volikitin *et al.* is that it does not take into account fluid lining the walls of large pores. Pore-lining fluid increases amplitude (porosity) at short T2's, and in order to generate the Pc curve, this additional porosity should be redistributed to long T2's (=large pores). If pore-lining fluid is expected, a simple approach for dealing with this is to shift the fitted curve just below the actual curve. This will have the effect of re-distributing the pore lining fluid to longer T2's because sum of porosity is always maintained at the same value.

NMR permeability from T2-derived Pc curves

We can also compute the permeability of the sample from the maximum turning point, or threshold pore size, obtained from the hyperbola fitted through the T2 distribution (Figure 4d). This approach, which was first presented by Marschall *et al.* (1995), uses a series of generalised empirical relationships between brine permeability and threshold pore size originally developed by Swanson (1981). If MICP data are available from the field, these can be used to develop field-specific equations. For the example shown in figure 3, the computed permeability, kw, based on the maximum turning point in the T2-derived Pc curve is 44.9mD. Using a statistical relationship between kw and ka for sandstones, this liquid permeability is equivalent to an air permeability of 69.8mD.

A quick way to test validity of the predicted Pc curve in the log is to locate an interval with a simple pore system (e.g. a clean sandstone) and compare predicted permeability against core permeability. If the Pc model is correct, and the pore system in the rock is homogeneous at the scale of the core and log measurement, predicted permeability should match core permeability.

It is possible to generate average Pc curves by stacking the log data, either in the T2 domain or time domain, and then applying the curve fitting routine to the averaged T2 distribution. A major advantage of this is that the stacked data will have a higher signal-to-noise ratio (S:N), and therefore greater accuracy in amplitude (porosity) at short T2's. Permeability can be calculated for the averaged log data using the turning point method, thereby providing a quick way to up-scale permeability.

Key to terms and mnemonics used in the text

BVI=Bound fluid volume, or volume of pore space occupied by immobile fluid (usually water), including capillary-bound and clay-bound water (CBW)

FFI=Free fluid volume, or volume of pore space occupied by moveable fluid

GR=Gamma Ray

MDT™=Modular Formation Dynamics Tester

MICP=Mercury Injection Capillary Pressure

NMR=Nuclear Magnetic Resonance

OBM=Oil-based mud

Pc=Capillary pressure

PHIT=total porosity, where PHIT=BVI+FFI

Rho2=constant of surface relaxivity for T2 (normally quoted in $\mu\text{m}/\text{ms}$)

SDR=Schlumberger Doll Research

S:N=signal-to-noise ratio; a measure of data quality associated with the echo train

SPWLA=Society of Professional Well Log Analysts

Sw=Water saturation (fractional or pu)

Swirr=Irreducible water saturation

T2=Transverse relaxation time (ms) (as opposed to T1, or longitudinal relaxation time)

T2lm=Log mean T2 (ms)

$\phi_{\text{Effective}}$ =Effective porosity; PHIT-CB

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