AAPG International Conference
Barcelona, Spain
September 21-24, 2003

Dr. Paul B Basan[1], Dr. Benjamin D Lowden[2], Mr. Joachim Strobel[3] (1) Energy Scitech Ltd, Woking, Surrey, United Kingdom (2) Energy Scitech Ltd, Woking, Surrey, (3) RWE-DEA, Hamburg, Germany

Maximising the Value of NMR Core Data for Geologists and Petrophysicist

Introduction

Petroleum scientists have been using new vintage Nuclear Magnetic Resonance (NMR) technology for more than a decade. However, our experience shows that many interpreters fail to glean the wealth of information available from both NMR core and log data. Among the various reasons for the under utilisation of these data, the most significant is reliance on default processes or interpretations. The use of default applications comes under two categories, one for the core calibration process and the other for log interpretation. Although somewhat separate issues, the two default applications are interrelated. More important, relying on misleading core calibration only aggravates the problem of log interpretation.

Another contributing reason for under utilisation of NMR data is that the technology has not penetrated deeply into the geological disciplines. The application of NMR technology still largely resides with NMR specialist perhaps only peripherally interested in geology. Why sedimentologists and reservoir geologists have not embraced NMR technology is a mystery because facies (flow units) and pore geometry, which are easily retrievable from the data, are important aspects of reservoir characterisation.

This paper shows an example of how we used NMR data to calibrate a CMR log and define facies in a reservoir from the Nile Delta, Egypt. Our second paper shows how we used the data to improve permeability prediction and hydrocarbon detection.

NMR Core Analysis

Log calibration

Few use NMR core analysis strictly for obtaining a better understanding of the rock pore system. Con-sequently, the calibration of NMR logs still drives the desire for NMR core analysis. Early calibration concepts revolved around finding a default cutoff (the T2 cutoff) for separating bound fluid (BVI) from moveable fluid (BVM) (e.g. Howard and Kenyon, 1992; Howard et al. 1990; Kenyon, 1992; Straley, et al., 1991 among numerous others). These authors found that a cutoff value of 33 ms, on average, provided a useful default parameter for log interpretation (also see The NMR Sandstone Rock Catalogue).

Our experience shows that the 33 ms T2 cutoff (or one near 33 ms) does work well in clean, homoge-neous sandstone reservoirs. However, T2 cutoffs from NMR core analysis results frequently fail to validate that cutoff. In fact, much of the NMR core work we see produces cutoffs either significantly lower or higher than 33 ms. The inability to validate this important interpretation parameter is unproductive because it creates uncertainty and misunderstanding. In some cases, the log interpreter ignores the laboratory results and simply uses the default parameter, which introduces uncertainty. In other cases, the log interpreter attempts to force the laboratory parameter into the interpretation, which almost always is incorrect.

Copyright © 2003 by AAPG

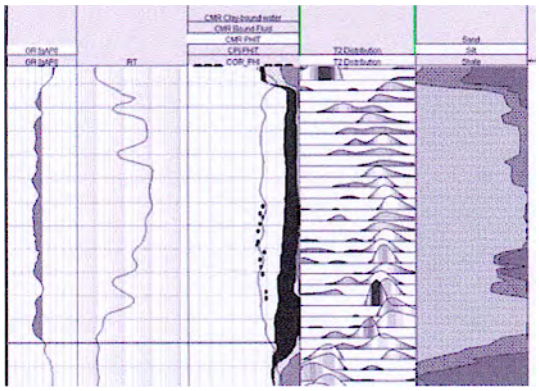

Figure 1. NMR log showing the characteristics of the channel sands

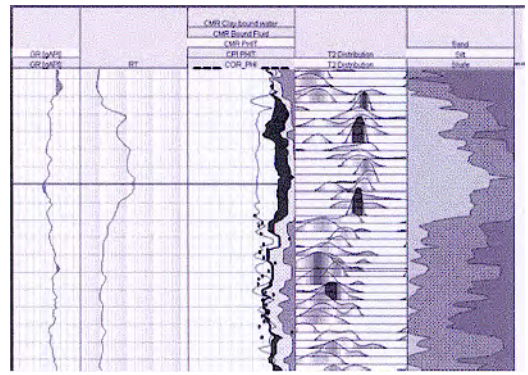

Figure 2. NMR log showing the characteristics of the overbank sands below a channel sand

An Example from the Nile Delta

The conventional reservoirs here are from a deepwater channel facies tract (Fig. 1). Thin-bedded sand-silt-shale sequences, appearing below channel sands create unconventional reservoir units (Fig. 2). Comparison of NMR and conventional core porosity illustrates the textural difference between the two reservoir sections (Fig. 3). The two porosity values are identical in clean channel sands, whilst NMR porosity is higher than core porosity in the shaly, overbank deposits. This relationship also illustrates the difference between a technique that measures gas volume and a technique that measures fluid volume. The conventional measurement will not account for pore space containing fluid, whereas the NMR measurement does (i.e. effective versus total porosity).

Table 1. Rock Properties

Sample No.	Coreϕ (p.u.)	Kcore (mD)	T_2 Cutoff (ms)	Swi (Frac. %)
Channel				
2	33.02	3200	184.21	0.105
5	35.39	3596	8.69	0.034
13	38.29	1797	1.33	0.073
19	28.82	3161	71.97	0.056
28	32.61	3420	44.58	0.034
Average	**33.63**	**3034.80**	**62.16**	**0.06**
Overbank				
32	37.18	566	2.12	0.216
36	33.78	92	2.68	0.829
38*	0.78	0.01		
44	30.63	11.7	3.39	0.559
46	32.09	3.0	1.68	0.765
48	42.34	590	2.68	0.170
51	36.36	214	2.68	0.396
52	31.77	14.2	2.68	0.649
56	31.89	21	3.39	0.481
59	33.31	72	3.39	0.380
Average	**31.01**	**158.39**	**2.74**	**0.49**

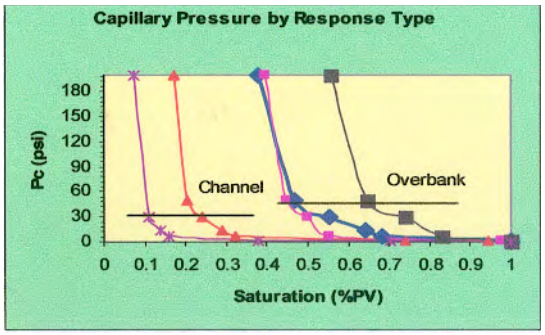

Figure 3. Comparison of porosity values showing that NMR porosity is higher in the shaly, overbank deposits

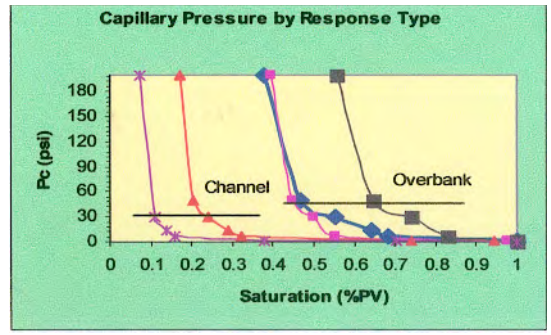

Figure 4. Capillary pressure curves showing the pressure selected for the calculation

T2 Cutoffs for the Different Reservoirs

NMR core experiments produced results that identify T2 cutoffs both greater and less than 33 ms (Table 1). Indeed, most of the values show cutoffs <10 ms. Interestingly, the channel samples come from a rather homogeneous deposit. Nevertheless, the cutoffs still range between 1.33 ms and 184 ms, at a capillary pressure of 200 psi. The overbank deposits have uniformly low T2 cutoffs averaging only 2.74 ms.

End-point capillary pressure measurements, which were made at 200 psi, showed that the critical parameter for calculating the T2 cutoff -Swi- did not represent reservoir conditions. This information pointed out that all the end-point measurements were unsuitable for log calibration. We identified the appropriate capillary pressure for the channel sand and the thin-bedded sands at 30 psi and 40 psi, respectively (Fig. 4).

Fortunately, the combination of capillary pressure and NMR data provide a way to compensate for the default laboratory measurements. The process requires finding the appropriate capillary pressure and back calculating the cutoff using the relationship between the NMR measurement and pore size (Eq. 1).

The surface:volume ratio is the pore size term, whereas ? is the scaling factor for relating time to pore size. We used a scaling factor of 0.05µm/ms (see the NMR Sandstone Rock Catalogue). This value is a robust first approximation *in lieu* of any other data. The next step is to calculate the pore-size diameter using the Washburn equation (Eq. 2). Using 30 psi and 40 psi as the capillary pressure in equation 2B gives a pore size of 1.39 µm for the channel sands, and 1.04 µm for the overbank deposits. The pore size information used in equation 1C gives T2-cutoff values of 27.84 ms and 20.88 ms, respectively.

Incorrect analysis of BVI (~Swi) of course affects estimates of hydrocarbon saturation, as well as the ratio for

Equation 1. NMR and Pore size

$$(A)\ \frac{1}{T_2} = \rho * \frac{S}{V}$$

$$(B)\ \rho = \frac{\frac{S}{V}}{T_2} = \frac{Diameter}{T_2}$$

$$(C)\ T_2 = \frac{Diameter}{\rho}$$

Where :

ρ = *Surface relaxivity (0.05 µm / ms)*

$\frac{S}{V}$ = *Surface : Volume ratio*

Equation 2. Washburn Equation

$$(A)\ Pore-throat\ Diameter = \frac{4\sigma(Cos\theta)\bullet C}{Pc(psi)}$$

$$(B)\ Pore-throat\ Diameter = \frac{41.76}{Pc}$$

Where :

σ = *Interfacial tension (72 dynes / cm)*

$Cos\theta$ = *Contact angle (0°)*

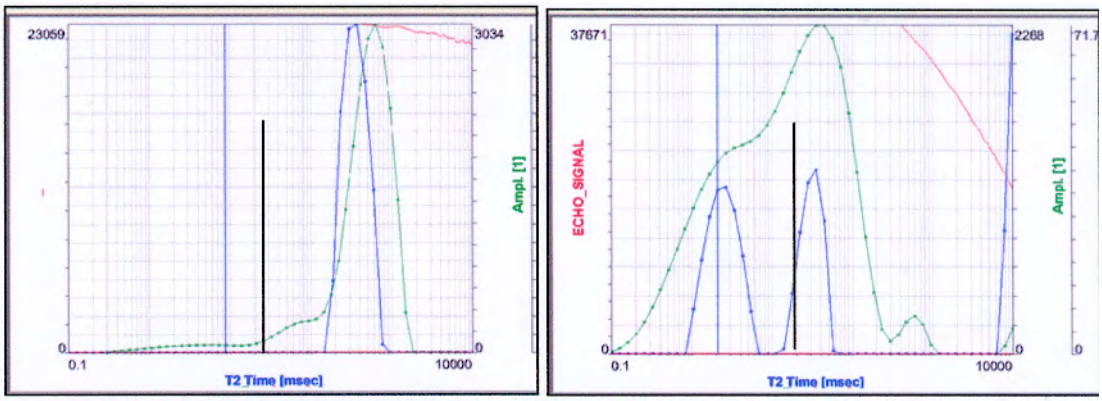

Figure 5. Comparison of lab and log distributions. Channel distribution left, overbank distri-bution right. The blue vertical line shows the lab cutoff of 8.69 ms; the black vertical line shows the recalculated cutoffs

estimating permeability (Lowden, 2003; Lowden, et al., 2003). Consequently, validating the cutoff values becomes an important issue. We accomplished validation by comparing the log T2 distributions with the core distributions (Fig. 5). Once validated, the interpretation proceeds to the next stages, as discussed in Lowden (2003) and Lowden, et al. (2003).

Facies and 'Rock Types'

Facies and rock types are geological entities usually associated with depositional, mineralogical, or diagenetic attributes. Identifying facies or rock types provide a framework for mapping their distribu-tion, which in turn helps to define the geometry of reservoir and non-reservoir bodies. This framework is fundamental for creating a static model for predicting reservoir behaviour. However, facies and rock types are inherently observational entities, and therefore contain no direct indication of their influence on reservoir behaviour (i.e. facies and rock types are not measurements of rock properties). True reser-voir characterisation requires combining observations with measurements in some way. In our experi-ence, and given the alternatives, combining NMR data with observation offers a robust way.

Both NMR core and log measurements provide two fundamental parameters- relaxation time and amplitude- required for 'rock typing.' Consequently, the NMR Response Typing techniques illustrated here works equally well with log data. In fact, we use log NMR Response Typing where no core is available for calibration.

We term the process of identifying NMR data having similar responses as *NMR Response Typing* to distinguish it from the process of identifying rock types. NMR Response Types possess a measurement that relates to reservoir behaviour, thereby further differentiating this process from traditional facies or rock-type identification. Of course, linking pore structure to the traditional facies or rock-types adds the rock-property dimension.

Example of NMR Response Typing from a Nile Delta Formation

Figure 6 shows cumulative T2 distributions, as opposed to the normal distributions. Cumulative T2 dis-tributions mimic capillary pressure curves, albeit with scales reversed. Small pores equivalent to high capillary pressures appear to the left, whilst large pores appear to the right. The cumulative curves reveal that the conventional and unconventional reservoirs contain rock types having different pore structures. The positively skewed (concave) distributions define the channel sands (Fig. 6). Although we consolidated all the channel samples into a single NMR Response Type, one sample stands out from the group. We could argue, therefore, the channel sands are not completely homogeneous.

The unconventional reservoir is composed of alternating sand-silt-clay lamina. These lithologies form a continuum of

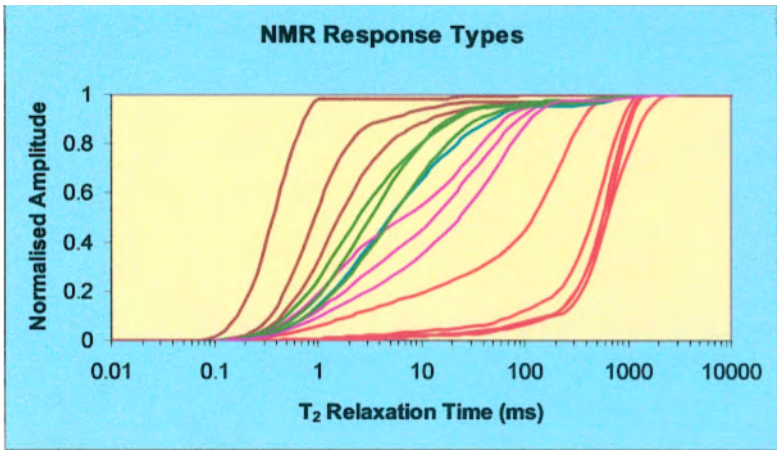

Figure 6. Red distributions are negative skewed (concave) showing a predominance of large pores. The magenta distributions are rectangular (linear), typical of a system having an equal distribution of small and large pores. Green and brown distributions are positively skewed (convex), illustrating samples having an increasing abundance of small pores

pore structures controlled by the abundance and distribution of small pores. Assuming that the thin-bedded sands have the same source as the channel sands, we could argue that the pore geometries found in both reservoirs are a continuum. Depositional energy, grain size, diagenesis, and clay content (etc.) account for the differences. Here is an excellent example of where petrographic information coupled with NMR data can optimise reservoir characterisation.

Summary

A great deal of information resides within NMR data to assist reservoir scientists. The application of NMR core data for calibration requires consideration all experimental parameters, especially capillary pressure. Default, end-point laboratory saturations frequently are not appropriate for calculating the T2 cutoff. Although more expensive, obtaining a capillary pressure curve for each rock type provides a method validating the cutoff for log calibration. Comparing the core and log distributions also is a good way to validate the cutoff value.

The relationship between pore size and NMR responses links these data to a method for characterising the internal structure of rock types. The process called NMR Response Typing works equally well with core and log data, and adds a dimension to reservoir characterisation unavailable from other techniques.

REFERENCES CITED

Howard, J.J., W. E Kenyon, and C. Straley, 1990, Proton-magnetic-resonance and pore-size variations in reservoir sandstones: Paper 20600, SPE Ann. Tech. Conf. and Exhib., p. 733-742.

Howard, J. J. W. E. and Kenyon, 1992, Determination of pore size distribution in sedimentary rocks by proton Nuclear Magnetic Resonance: Mar. and Petrol. Geol., v. 9, no. 2, p. 139-145.

Kenyon, W. E., 1992, Nuclear Magnetic Resonance as a petrophysical measurement: Nuclear Geo-phy., v. 6, no. 2, p. 153-171.

Lowden. B. D, 2003, A new method for separating lithologies and estimating thickness-weighted per-meability using NMR logs. 45th Ann. Logging Symp. Trans: Soc. Prof. Log Analysts, 2003.

Lowden, B. D., P. B. Basan, J. Strobel, 2003 (abs), Maximising NMR log interpretation in thinly bed-ded reservoirs: An example from offshore Egypt: AAPG Ann. Conv., Barcelona, Spain.

The NMR Sandstone Rock Catalogue, 1995: Produced by Applied Reservoir Technology, Long Mel-ford, UK.

Straley, C., C. E. Morriss, W. E. Kenyon, and J. J. Howard, 1991, NMR in partially saturated rocks: Laboratory insights on free fluid index and comparison with borehole logs: Paper CC, 32nd Ann. Logging Symp. Trans: Soc. Prof. Log Analysts, 25 p.