REVISITING NMR CORE-LOG CALIBRATION

Wim Looyestijn, Xiangmin Zhang, Albert Hebing

PanTerra Geoconsultants B.V., The Netherlands

This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Vienna, Austria, 27 August – 1 September 2017

ABSTRACT

Historically, NMR (nuclear magnetic resonance) measurements are used to partition the water-filled pore space into bound water and free fluid. In practice, however, this is a gross oversimplification of reality. The T2-cutoff that is used in this process is calibrated by comparing fully saturated and desaturated plug samples. Since the desaturation is done at one particular capillary pressure, the result is strictly speaking valid for that pressure only, i.e. at just one height in the reservoir. Repeating the calibration at various desaturation pressures is impractical.

We show, with practical examples, how this fundamental shortcoming can be overcome. First, we compare NMR data with MICP capcurves, and show that conversion of NMR data into capcurves for a given lithological unit can reliably done with one set of fixed parameters. Second, we show that having one calibration point, the NMR response at any other desaturation pressure can be simulated faithfully. This enables the construction of a height-dependent T2-cutoff, yielding the correct connate water saturation at any desired height.

The benefit of this approach is that NMR logs can be interpreted independent of other logs, and thus provide verification of the, often complicated, resistivity interpretation. The concepts of the methods are not new, but consistent and practical workflows are still lacking. We demonstrate our workflow/methods for a sandstone reservoir, and validate the result against standard log analysis data.

INTRODUCTION

Traditionally, the T2-distribution, measured by NMR on a water-saturated sample, is divided into two parts: the (total) bound water, TBW, and the free fluid index, FFI. The split is made at a certain T2 value, called the TBW cutoff, or FFI cutoff, or T2-cutoff. In connection with NMR logs, we prefer the name TBW cutoff, because TBW can be computed in most cases, whereas FFI might be affected by the presence of hydrocarbons and/or acquisition parameter settings.

The concept of TBW/FFI is a simplification because what is “bound” water depends on the capillary pressure, i.e. on the height above FWL. The optimal procedure is to calibrate the cutoff against saturations obtained at a representative pressure in the reservoir. In reality, this is not always feasible, but errors may occur if this is not realised. Repeating the calibration at various desaturation pressures is possible, but impractical and is rarely done. Fortunately, two corrective approaches are available: (i) convert the NMR response to a (pseudo) cap curve, and (ii) adjust the T2-distribution to the required saturation (pressure) by modeling. These are described further below. We demonstrate the methodology using data from a recent study on a sandstone reservoir; the method is applicable to any data set.

Bound water T2-cutoff and permeability

The standard method of finding the TBW cut-off on individual samples is by finding the T2 value where the cumulative Sw=1 distribution matches the water volume of the desaturated sample. This method is graphically shown in Figure 1.The green arrow indicates where the desaturated water volume intersects the cumulative Sw=1 distribution. For the present study we found little variation in cutoff, so it is allowed to take the average value. This happened to be 32 ms, which is the same value as the global default for sandstone. Other sandstones may have a somewhat higher or lower cutoff. Carbonates typically have a much higher cutoff, but the concept often fails [Looyestijn and Steiner, 2012].

Since the desaturation on the present samples was done at 500 psi (air/brine, by centrifuge), this cutoff is valid far away from the FWL.

Permeability is usually predicted by either of two empirical formulas [Dunn et al, 2002], each having a porosity factor and a pore size factor, either the ratio FFI/TBW or the T_{2mean}.

$$K_{Coates} = A\,(POR/10)^{B}\,(FFI/TBW)^{C} \quad \text{Equation 1}$$

$$K_{SDR} \quad = a\,(POR/100)^{b}\,T_{2mean}^{c} \quad \text{Equation 2}$$

with POR in % and T_{2mean} in ms, and K in mD. The three parameters in each formula may be optimized using core NMR and permeability data. Care should be taken that the same TBW cutoff is used for the core and the NMR log.

Both permeability predictions work equally well; however, the presence of hydrocarbons will affect T_{2mean}, and thus the predicted permeability. In contrast, TBW is not affected (unless in heavier oil), and will give a more robust permeability in hydrocarbon intervals. These complications can be addressed by calibration at (simulated) in-situ conditions [Looyestijn and Steiner, 2012]. Gas will reduce FFI (and T_{2mean}), but not TBW; the equations need to be used with a gas-corrected (cross-plot) porosity, PORX, and FFI computed as PORX-TWB.

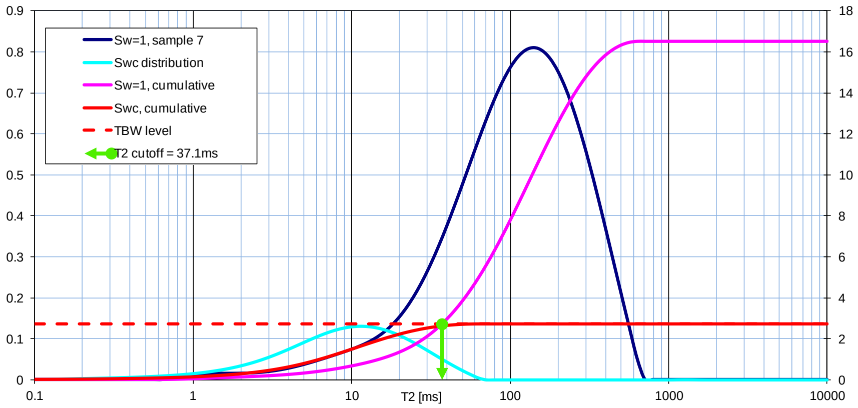


Figure 1 Derivation of TBW cutoff for sample 7

Conversion of NMR to capcurve

The approach taken in the previous section basically interrogates the T2-distribution at one particular desaturation pressure. This can be generalized. The NMR to capcurve conversion assumes a relationship between pore body size (NMR: T2 ~ R) and pore throat size (Pc ~ 1/r). Lumping all parameters together in a single parameter, κ, the relationship becomes [Looyestijn et al, 1999]:

$$P_{c,i} = \kappa / T_{2,i} \quad \text{or} \quad \kappa = P_c(S_w)\ T_2(S_w) \qquad \text{Equation 3}$$

The value for κ varies somewhat for different sandstones; the common range is 2 to 8 psi.s for Hg-air capcurve pressure. In the simplest form, κ is a constant, i.e. κ has the same value for all S_w. This implies a constant ratio between pore body size, R, and pore throat size, r, for all pore sizes. In most rocks, however, it has been found that κ starts off at a constant value, but increases towards the smaller pores, i.e. the shorter T2 and higher Pc. One such relationship is described in [Looyestijn et al, 1999], but many other functional relationships may be proposed.

We illustrate the concept using the form that is implemented in the software of Interactive Petrophysics (IP):

$$P_{c,i} = \frac{10^A}{T_{2,i}^B} \qquad \text{Equation 4}$$

For B=1 this defaults to a constant ratio, i.e. Pc and T2 are strictly inversely proportional as given by eq.3 with κ as a constant.

The result for two arbitrary individual samples from a recent study is shown in Figure 2 and 3. It can be seen that the NMR distribution (top left) is smoother than the MICP poresize distribution (bottom left); however this difference is not apparent in the capcurves (bottom right). The κ curve in the second figure (top right) is obtained by reading off the NMR and the MICP data as a function of Sw. It shows that the value of κ varies with T2, and that a simple formula cannot precisely describe κ over the entire range of T2. However, κ is reasonably flat over the range between roughly 3 and 300 ms, corresponding to approximately 500 to 2 m above the FWL. This is typically found in most rocks.

There are several reasons why the conversion is not perfect. The overlay of the MICP and pseudo NMR-capcurve (bottom left), shows that the NMR curve is smoother than the MICP curve. This is partly the reason of the observed Sw-dependence of κ. Furthermore, NMR does not really measure pore size, but rather the volume/surface ratio, and MICP does not measure pore throat size distribution, but rather that of the volumes accessible through throats. Finally, MICP is usually not done on the same sample as NMR, but on a trim end. The rock in this example is fairly clean, and clay effects do not play a significant role. In general, however, appropriate corrections to the MICP data need to be considered.

Although not fully correct over the entire range, the NMR-cap curve (bottom right) will give a good value for Sw over most of the reservoir, but may be off in the lower part of the transition zone; in particular, it may fail to predict the correct entry pressure.

Individual samples will have different A and B values. If the variations are small, the average values may be used, or, better, all samples should be matched with a single set of A and B. If the variations are large, the sample set needs to be broken up in two or more groups.

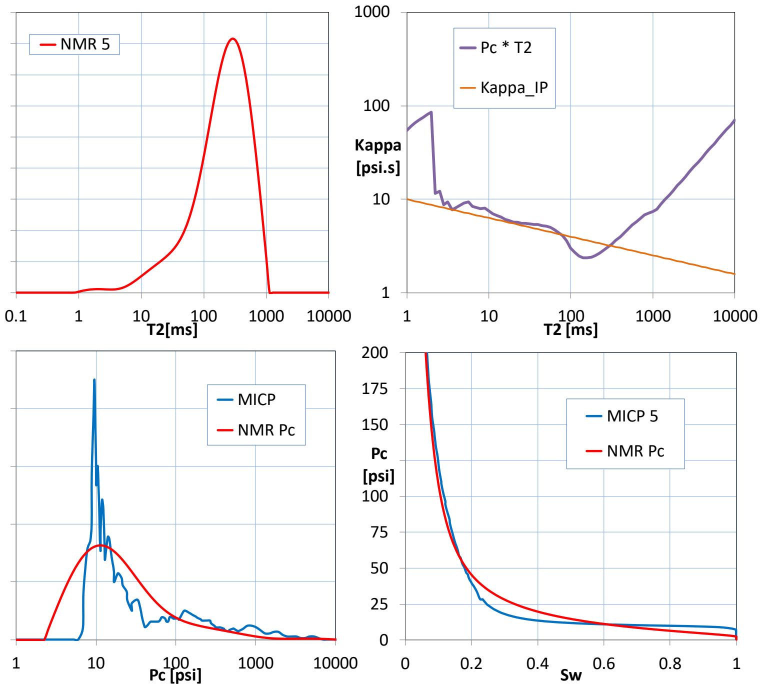


Figure 2 NMR - Pc calibration for sample 5. Pressure is for Hg-air systems.

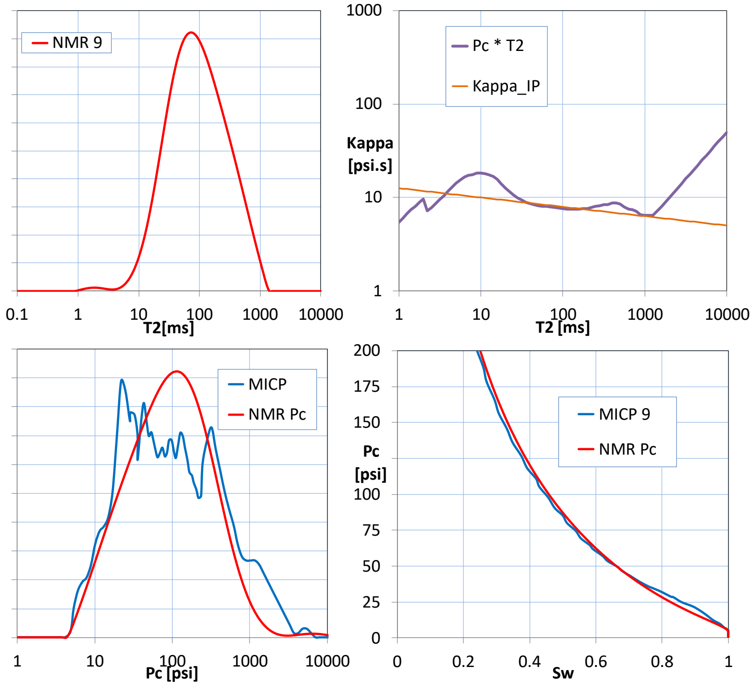


Figure 3 NMR - Pc calibration for sample 9. Pressure is for Hg-air systems.

Modeling NMR response at any desaturation

The desaturation process is modeled [Looyestijn and Hofman, 2005] by a gradual decrease of the signal amplitude as a function of T2, i.e. starting from the largest T2 (largest pores). The mechanism is shown below.

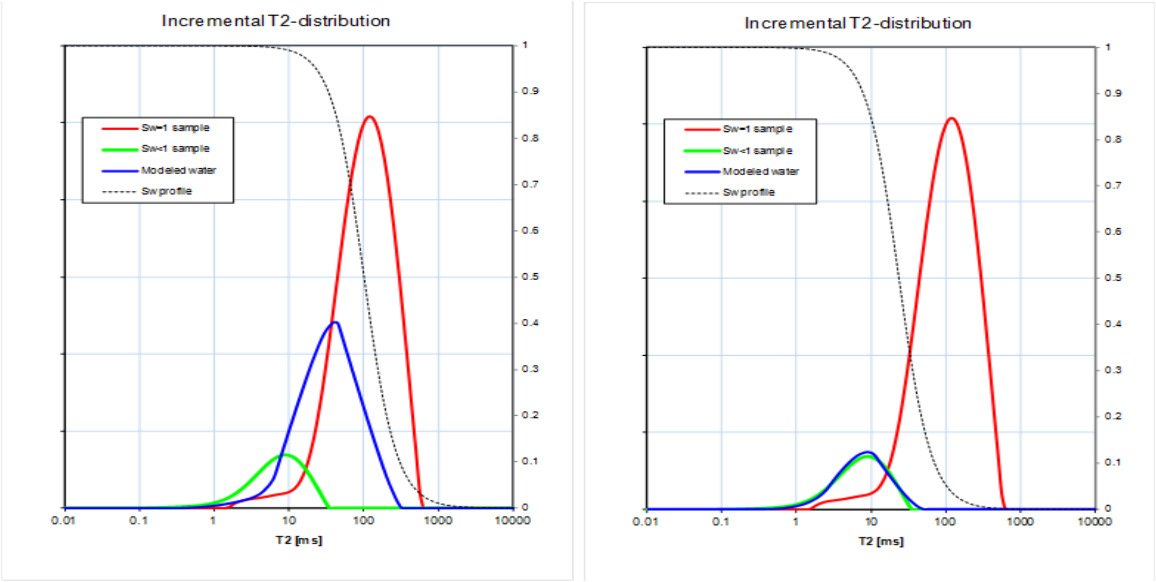
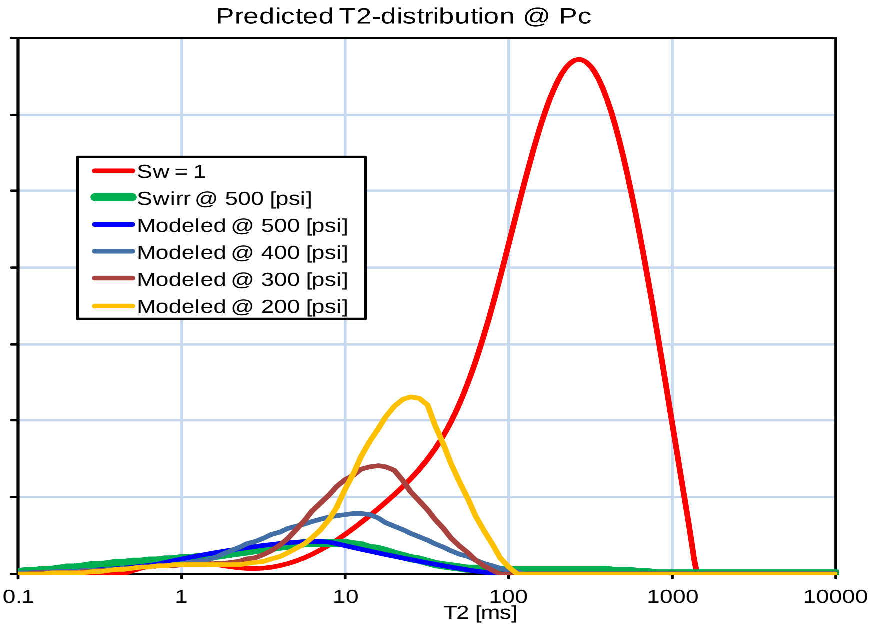


Figure 4 Desaturation modeling: (left) at intermediate saturation, and (right) matching actual experiment

The desaturation profile (black dotted line) gives the water fraction as a function of T2, and thus of pore size. The model accounts for the fact that a certain fraction of pores is only partly desaturated. The residual water is still wetting the pore surface, but the volume has reduced. This results not only in a reduced amplitude, but also in a shorter T2. Consequently, while the long T2 components disappear with increasing desaturation, there is a small increase at short T2. This is observed in all samples in this study.

The desaturation profile is then moved over the T2 axis until the experimental saturation is reached; the observation that the actual T2 position of the distribution agrees with the observed one validates the correctness of the modeling.



Sample: 2 Porosity: 15.2 %

	Pc [psi]	T2,mid [ms]	TBW [% BV]	Swi [% PV]	T2cutoff [ms]
Experimental	500	25	1.1	7.5	24.6
Modeled	400	32	1.9	12.6	42.4
	300	43	2.5	16.7	57.3
	200	68	3.6	24.2	85.0

Figure 5 Predicted T2-distribution at experimental conditions and other [Hg-air] pressures for sample 2

Because this experimental measurement is fully predicted by the model, other experimental conditions may now be modeled with confidence. Here, the T2-distribution is predicted for three lower pressures. The corresponding position of the desaturation profile was computed by shifting its mid-point, $T_{2,mid}$, using the relationship between Pc and T2 as defined by eq. 2; this yields (or, when using eq. 1, the same with B=1):

$$\tilde{T}_{2,mid} = T_{2,mid}\left({}^{P_c}/_{\tilde{P}_c}\right)^{1/B}$$ Equation 3

The corresponding T2-cutoffs are computed in the traditional manner, i.e. by finding the T2 value for which the cumulative T2-distribution (Sw=1) equals the desaturated water volume.

An arbitrary example is shown in Figure 5. The modeling perfectly predicts the response of the desaturated sample. Notice that there is a reasonable agreement between the mid-point of the desaturation profile, $T_{2,mid}$, and the T2-cutoff. This is usually found in all rock types. The relationship between Pc and T2-cutoff can now be used to calculate bound water (TBW) as a function of height above FWL. In fact, this is not really different from using the NMR-cap curve that was discussed in the previous section.

Hydrocarbon correction of NMR log data

Rigorous correction of the NMR log for hydrocarbon effects is not possible, because the part of that contains hydrocarbons could have had almost any shape. However, a reasonably good approximation is possible [Looyestijn et al. 1999]. The underlying principle is that the unknown FFI part must be such that the Coates and SDR permeabilities are equal.

An example is shown in Figure 6. Here the NMR response is simulated for a gas interval and subsequent invasion of OBM filtrate. The NMR porosity is too low because the remaining gas has a low hydrogen index. The simulated response (pink curve) clearly differs from the response that would be obtained if the interval were water bearing because the filtrate has a longer relaxation time than the water that it replaces. The reconstructed distribution (dotted curve) is not perfect, but much closer.

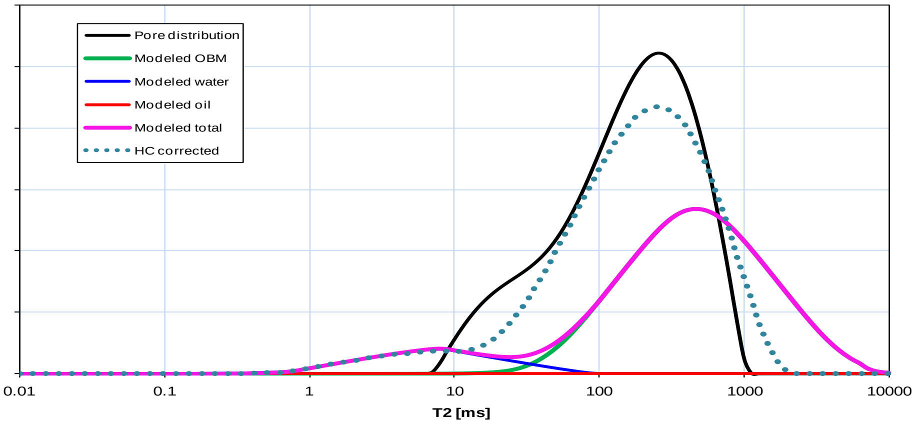


Figure 6 Simulated NMR response in a gas zone with OBM filtrate invasion and reconstructed Sw=1 response

Laboratory versus reservoir conditions

There are several effects that may cause the NMR log to differ from core measurements [for example, Looyestijn and Steiner, 2012]. The most important one is the presence of hydrocarbons, as mentioned in the previous section. Other effects are related to wettability, but that does not impact on the capcurve conversion. Similarly, temperature effects on surface relaxivity are small, if any.

Interpretation of NMR log

The result of the core calibration was applied to the NMR log, taken in the same well, using the approach implemented in Interactive Petrophysics (IP). The well was drilled with oil-base mud in a gas-bearing sandstone. Track-3 shows the NMR log with the default CBW cutoff at 3 ms, and the TBW cutoff at 33 ms. Track-4 shows the hydrocarbon-corrected T2-distribution.

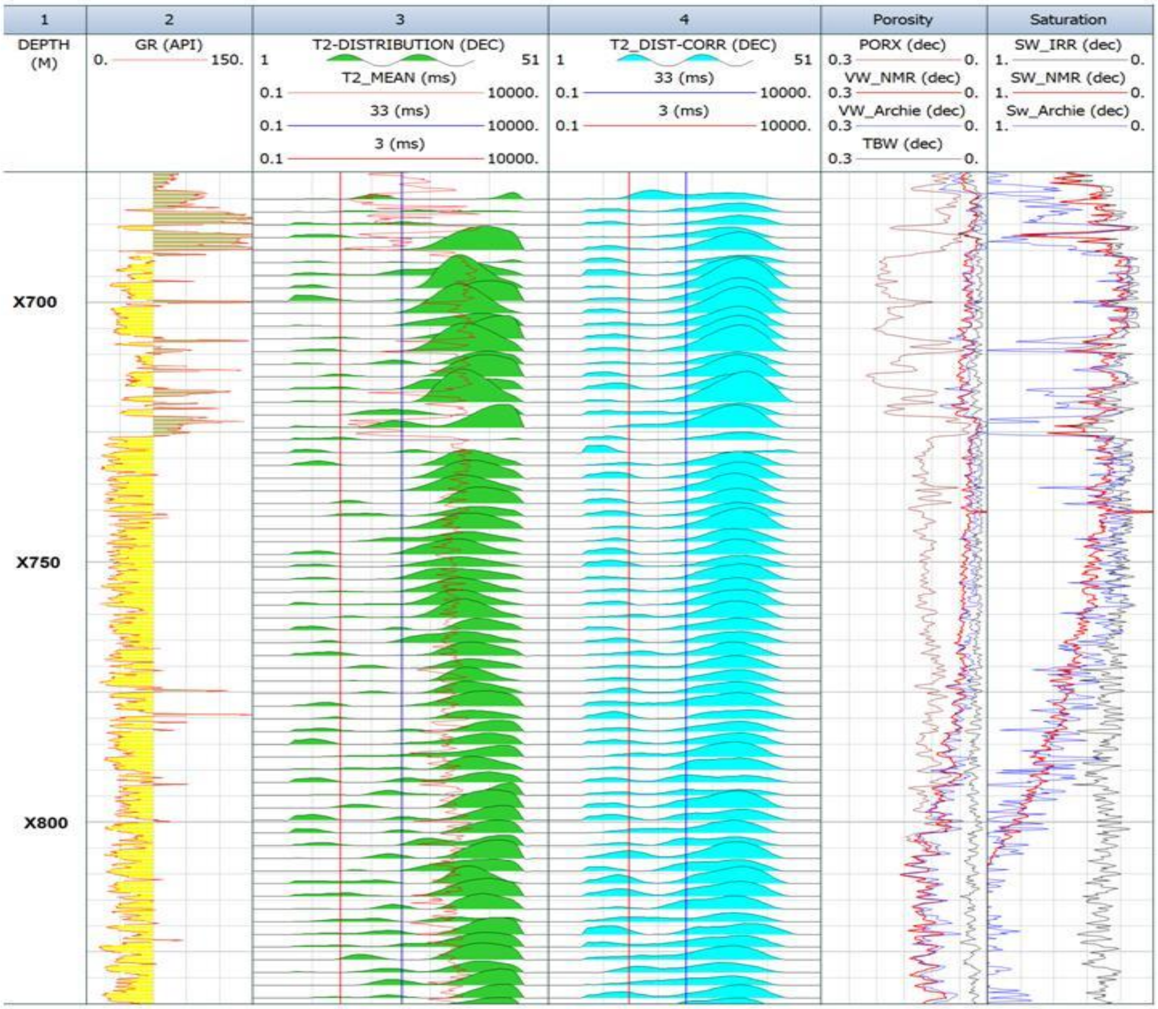


Figure 7 Interpretation of NMR log.

The value of TBW, computed with this cutoff, is shown in track-5, where it is compared against the water volume, Vw_Archie, computed by the Archie method using a combination of density, neutron and resistivity logs. PORX is the gas-corrected density-neutron cross-plot porosity. Track-6 shows the corresponding water saturations, and indicates a gas-water contact at x805 m. SW_IRR (=TBW/PORX) does not follow the transition zone and remains more or less constant. The saturation profile for the NMR capcurve, SW_NMR, correctly describes the transition zone, assuming the FWL at x810 m. Note that the scatter is much less than in Sw_Archie; this is because the latter is obtained by combining logs that probe different rock volumes, whereas SW_NMR is measured by a single log.

CONCLUSION

We demonstrated that the desaturated NMR response on core samples can faithfully be reproduced by modeling. As a consequence, this allows the prediction of the NMR interpretation parameters, such as T2-cutoff for bound water, at any other desaturation pressure, i.e. at any desired height above the FWL.

As a further step, the NMR log was converted into a cap curve log, using a conversion calibrated against MICP on the available core plugs.

Application of the NMR-cap curve shows a matching saturation profile with the resistivity derived saturation, with an indication of the FWL. Since these two interpretations are completely independent, they form a strong validation of the saturation levels.

The NMR-derived saturation profile shows less scatter than the traditional profile, because the latter combines a number of logs with very different measurement volumes.

ACKNOWLEDGEMENTS

We gratefully acknowledge the support of our customer to the publication of this work.

REFERENCES

1. Looyestijn, W.J, Volokitin, Y., Slijkerman, W.F.J., and Hofman, J., 1999, *A Practical Approach to Obtain Primary Drainage Capillary Pressure Curves from NMR Core and Log Data*, SCA9924; also published in Petrophysics (2001), volume 42, 4.3.
2. Looyestijn, W.J. and Hofman, J.P., 2005, *Wettability Index Determination by Nuclear Magnetic Resonance,* SPE 93624, presented at the MEOS, Bahrain, March 2005. Published in SPEREE April 2006, pp 146 – 153.
3. Looyestijn W.J. and Steiner S., 2012, *New approach to interpretation of NMR logs in chalks*, SPWLA 53rd Annual Symposium, Cartagena, Colombia, paper HH, published in Petrophysics, April 2013.
4. Interactive Petrophysics, 2013, *User Manual*. Synergy Software Ltd.
5. Dunn, K-J., Bergman, D.J. and Latorraca, G.A., 2002, *Nuclear Magnetic Resonance, Petrophysical and Logging Applications,* Pergamon, ISBN 0-08-043880-6.