A PRACTICAL APPROACH TO OBTAIN 1st DRAINAGE CAPILLARY PRESSURE CURVES FROM NMR CORE AND LOG DATA

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ABSTRACT

The purpose of the current study was to find a way of constructing 1st drainage capillary pressure curves from NMR T_2 distributions with an accuracy which can satisfy most of practical applications. The application that initiated the study was to predict initial virgin reservoir saturations from NMR log data. However, an equally important application proved to be a fast, cheap and non-destructive estimation of capillary pressure curves on core samples.

Proposed method of relating NMR distributions to 1st drainage capillary pressure curves can be seen as a development that enables better and faster integration of core capillary pressure data and log interpretation. Namely, once a calibration of T_2-P_c conversion against a few core samples has been established, the capillary pressure information can easily be obtained continuously across the whole reservoir section logged with NMR tool. Advantage compared to other methods comes from the fact that NMR T_2 distribution is much more directly related to the porestructure and, thus to capillary pressure information

A serious shortcoming of all conversion methods proposed so far is that they could be applied to NMR measurements on fully water-bearing rock only. The presence of hydrocarbons strongly dictates the shape of the T_2 distributions and thus invalidates the predicted capillary pressure curve. In this paper we present an approach which can greatly alleviate this problem. The presented technique can be applied to NMR T_2 distributions obtained on sandstone rocs at any water saturation.

INTRODUCTION

Distribution of the pore necks is an important characteristics of a reservoir rock because it determines the magnitude of capillary pressures in a rock and thus (among other things) the saturation-height profile. Formation evaluation methods requires measurements of both a pore-neck distribution (capillary pressure curves) and a pore-size distribution (NMR, image analysis) of a rock. Of those, at present only NMR measurement can be performed in a borehole by a wireline logging tool. The rest have to be conducted in laboratory on core samples, and have either a limited range, or are destructive. Developing a reliable method to convert NMR T_2 distributions to 1st drainage capillary pressure curves lifts these limitations, and provides a continuous reading of capillary pressure curves with depth.

In this study we have been considering only 1st drainage capillary pressure curves. Hence, to facilitate the readability of this communication we will be further referring to 1st drainage capillary pressure curves simply as "capillary pressure curves".

In the first part of the paper we describe how capillary pressure curves are constructed and present the appropriate definition of the *optimal* conversion constant between NMR relaxation time T_2 and capillary pressure P_c. Then practical ways to determine this constant for a particular core dataset are discussed. To quantify uncertainties introduced by using the so-obtained NMR capillary pressure curves we assessed the accuracy of saturation prediction with core calibration of the data. Also "default sandstone" parameters were determined which should be applied to log data if no core information is available. Also, attention is given to prediction of the Entry Pressure, another important capillary pressure curve parameter.

Further, we present a way to reconstruct NMR T_2 distributions at Sw=1 from the measurements on partially saturated rocks. This step enables one to reliably construct capillary pressure curves from NMR data even if the latter are measured when hydrocarbons are present in the porespace. The proposed technique is based on reconstruction of the spectra at Sw=1 from spectra of bound water and model spectra of moveable water. The position of the moveable water peak is determined from a correlation between geometrical mean T_2 of spectra at Sw=1 and irreducible water saturation. The full capillary pressure curves can then be calculated from the reconstructed spectra. This reconstruction is a key element in implementation of the capillary pressure calculations to log data.

EXPERIMENTAL

Most of the study was performed on the data from "The NMR sandstone catalogue" compiled in 1996 by Applied Reservoir Technology Ltd., UK, as a result of a JIP (joint industry project). This core database comprises data from 19 contributing oil companies each submitting 20 samples from one sandstone oil or gas field. This resulted in a database of 380 core plugs.

In this study we have used NMR measurements obtained on 100% brine-saturated samples and on the same samples after drainage with air in a centrifuge. The NMR measurements with interecho time of 0.35 ms were used. For capillary pressure curves only data on Hg-Air injection were available, so in this work only this type of capillary pressure curves will be discussed. Hg-Air injection measurements were performed only on 10 samples from each field, thus for this study a set of 186 samples (with both NMR and Hg-Air) was available. For this work all T_2 distributions were obtained by processing the original NMR decay curves with Shell decay inversion software. The results of this study have been collaborated by verification against a large in-house dataset that has been acquired over the past years.

The core samples for NMR experiments have been cleaned using the soxhlet extraction with toluene and methanol and afterwards dried at 80°C. Further, they were saturated with 50,000 ppm $CaCl_2$ brine. Desaturation of samples in the centrifuge was performed at 5.5 bar capillary pressure.

A comprehensive treatment of Nuclear Magnetic Resonance (NMR) and its applications to Oil and Gas industry can be found in refs. (Kenyon, 1997, Kleinberg et al., 1996). Here only a brief summary of relevant facts is given. An NMR logging tool (or laboratory instrument) measures the strength and the decay with time of the signal induced by magnetisation of hydrogen nuclear spins. The strength of the signal is proportional to the amount of hydrogen atoms in the fluid (water or hydrocarbon) in the measurement volume and thus to the porosity of a rock. The decay of magnetisation represents a sum of exponentially decaying contribution which come from hydrogen spins experiencing different local surroundings.

For a hydrogen in a water molecule in a water-wet rock, the relaxation time, T_{2i} is proportional to the Volume-to Surface ratio of the water phase in a pore.

$$T_{2i}^{-1} = r \frac{S_i}{V_i} + T_{2,bulk}^{-1}$$

The proportionality constant r, between T_2^{-1} and Surface-to-Volume ratio of the pore, S/V is called the surface relaxivity. The bulk relaxation rate, $T_{2,bulk}^{-1}$ is normally negligibly small. Hence, for a fully water-filled pore, T_2 is proportional to the size of a pore $T_2 \sim R_{pore}$. The magnitude of signal decaying with a certain T_2 directly gives the pore volume corresponding to this R_{pore}. The whole set of amplitudes obtained after the decay inversion procedure is proportional to the poresize distribution of a rock.

For a hydrogen forming part of a hydrocarbon molecule the relaxation time depends only on intrinsic fluid properties and does not depend on pore size (see e.g. Kleinberg et al., 1996).

Drainage capillary pressure curve describes injection of a non-wetting fluid into a porous medium (rock). More precisely, every point of such a curve shows what percentage of the porespace is occupied by a non-wetting fluid if a certain overpressure is applied to this fluid. The pressure, at which a fluid enters a pore, is determined by the surface tension of the fluid interface and the radius of a neck of a pore.

$$P_c = \frac{2s \cos q}{r_{neck}}$$, s is surface tension, q - contact angle between the fluid interface and pore wall

Fluid entering through a pore neck would immediately fill most of the volume of a pore. Thus, simplified, a drainage capillary pressure curve represents a cumulative poreneck distribution plotted on a reciprocal $1/r_{neck} \sim P_c$ scale. It is worthwhile to note that the meaning of a distribution is here the same as when discussing a NMR measurement: namely, a distribution element represents pore *volume* corresponding to a particular poreneck size.

Both NMR T_2 and capillary pressure measurements represent the distributions of pore volumes which correspond to a certain poresize ($\sim T_2$) or a certain poreneck size ($\sim 1/P_c$). The method of converting NMR T_2 distributions to capillary pressure curves requires the existence of a relationship between the radii of pore-bodies and pore-necks. For sandstones, and perhaps also for some types of carbonates, the existence of this relationship can be expected because the radius of the grains determines both the size of a pore and

the size of a pore opening (pore neck). Hence, if R_{pore} is proportional to r_{neck} then the two measurements reflect *the same* distribution. The similarity between the two distributions is illustrated in Figure 1 where the data on 9 samples from the same oilfield are shown.

CAPILLARY CURVES FROM NMR ON ROCKS AT SW=1

In order to arrive at a capillary pressure curve starting from an NMR T2 distributions, the following steps should be made. First, one should obtain a cumulative T_2 distribution (sum the amplitudes); plot it on reciprocal T_2^{-1} scale; then rescale T_2^{-1} with some proportionality constant $Kappa = P_c/T_2^{-1}$; and finally, interchange the X and Yaxes of the plot. Clearly, the choice of *Kappa* is the most crucial element in the conversion. At first glance, the most natural to define the optimum scaling is to find the best match between the differential Hg injection and NMR T_2 distributions like the ones shown in Figure 1 (Marschall et al., 1995, Lowden et al., 1998). Mathematically it is done by finding the maximum of the correlation coefficient of the two spectra (as described in e.g. Marschall et al., 1995).

Finding the optimum scale clearly depends on the application of the result. Often, capillary pressure curves are used to provide the value of saturation, corresponding to a certain capillary pressure. Thus, we would argue that the correct way of determining the optimum scale is to search for the best reproduction of saturations by the "NMR capillary pressure curves". As a measure of the fit quality for a given value of *Kappa*, we introduce the average saturation error between the constructed NMR capillary pressure curve and the corresponding Hg/air one. This average saturation error is the root mean square (RMS) average of saturation differences: *Sw(Pc)-Sw(Kappa·T$_2^{-1}$)*. These differences are averaged across a certain capillary pressure range with the uniform sampling with *Pc*. In the studies presented here we used 0-500 psi Hg as a representative range of *Pc*'s. This procedure of calculating the average saturation error is graphically depicted in Figure 2. The value of *Kappa* where so obtained saturation error is at minimum defines the optimum scale for a sample.

An important notice is that, as a rule, poresize and poreneck distributions are plotted, sampled and compared on a logarithmic scale, whereas capillary pressure curves are related to depth which is of course always considered on a linear scale. Thus, minimising the error in saturation prediction (points equally spaced in Pc) can lead to a different optimum scaling constant than when searching for maximum correlation (logarithmic sampling) due to decreased weight of the contribution coming from large pores. Also one can conclude that seemingly large differences in spectra at the high T_2 end would be much less pronounced when comparing saturations from capillary pressure curves. This is due to the fact that this mismatch would often manifest itself in the region of *Pc*'s around 1 psi.

Another point worth mentioning is that we suggest to search for optimal reconstruction of capillary curves for the whole set of core plugs from a reservoir rather than determining individual $Kappa= P_c/T_2^{-1}$ scaling constants for every sample. This means optimising the sum of average saturation errors of all core plugs that belong to the same set. Reasoning behind it is to *predict* capillary pressure curves for samples (core or downhole) from their T_2 spectra. Within one reservoir unit a formation can consist of different geological facies each described by a different capillary pressure curve. The main contrast between saturation-height functions in different facies is likely to originate from a contrast in poresize distributions and will thus be correctly reproduced by NMR spectra converted with the same $Kappa=P_c/T_2^{-1}$. In some cases the scaling constant can also vary with formation type, for example in clastics/carbonate sequences because of strong variations in surface relaxivity. Then, determination of separate conversion factors per zonation unit would certainly be the right choice.

Saturation prediction from NMR capillary pressure curves

In order to quantify uncertainties in saturation determination from NMR capillary pressure curves and to find optimum conversion constants for core datasets of the ART catalogue we performed the following study. For every database entry, i.e. a set of 10 core plugs with NMR and Hg-Air data, an average saturation error was calculated. Averaging was done over a range of capillary pressures as described above and over all samples in the set. These saturation errors were calculated as a function of *Kappa* for a range of *Kappa* values. The results of this study are shown in Figure 3.

In Figure 3, for every set of 10 plugs the average saturation error is shown as a function of $\kappa = P_c/T_2^{-1}$ with a thin dash curve. The minima of the error curves indicate the optimum $\kappa = P_c/T_2^{-1}$ scales that should be used to reconstruct capillary pressure curves from NMR data for these formations.

A thicker curve represents a database average of all samples. As can be seen, a clear minimum of the thicker curve (whole set of 186 core samples) can be found. This defines the optimum scale for the database as a whole. This scaling (*Kappa*= 3 psia·s) should be used for constructing of NMR capcurves if no core information is available. The minima of individual entry errors lay lower than that of the average curve, thus better saturation prediction can be achieved by applying a local scaling constant.

The results show that for the P_c range of 0-500 psi Hg, an average error in prediction of the saturation-height profiles without any core calibration with the "world" scale (*Kappa*= 3 psi·s) is around 12 saturation units. If core data are available, then saturation error reduces to 9 sat.units i.e. the average of the minimum errors of different entries.

Comparison of "NMR Capcurves" with the real Hg-Air ones for 9 samples (an entry of the ART catalogue) is shown in Figure 4. The average error in saturation for this set is 8.5 sat. units. From this figure one can conclude that the suggested NMR - CapCurve conversion really works, especially the character of Hg-Air capillary pressure curves is very well reproduced. Similar results are obtained for other datasets.

The Sw error described above should be considered as a value of scatter at every log depth and not as an error of resulting sums and averages. In order to make the latter as low as possible one should always choose a representative core dataset for performing NMR and capillary pressure measurements and calibration of conversion factor.

Improvement of T2-Pc conversion using variable scaling

One way to improve the conversion of NMR T_2 distributions to the capillary pressure curves is to introduce a variable P_c/T_2^{-1} scaling. Namely, one can use a scaling that increases with increasing *Pc*. The main effect would be to make NMR capillary curves "go steeper" at high *Pc*, thus showing *irreducible* water saturation behaviour seen in real capillary pressure curves. The effect of using variable scale is especially pronounced in cases where NMR T_2 distributions are represented by one relatively narrow peak, as for example is the case in chalk formations. The reason why the P_c/T_2^{-1} is different for large and small pores stems most probably from the fact that the *effective* poresize/poreneck ratio is dependent on the size of the pore, e.g. related to a larger effect of clay minerals in the smaller pores.

An example of variable scaling is shown in Figure 5. The formula for the curve in Figure 5 is:

$$Kappa\ (Pc) = Kappa\ \cdot (1 + \frac{4}{(\frac{200}{Pc} + 1)^{10}})$$

A comparison between capillary pressure curves obtained with fixed and variable scales is shown in Figure 6 and Figure 7. As mentioned above, the improvement in saturation prediction takes place at high capillary pressure values and is quite pronounced. To summarise, the introduction of the variable scale allows to improve the agreement at irreducible saturation region whilst not jeopardising the fit in the "transition zone" at low *Pc*'s.

Prediction of Entry Pressure from NMR capillary pressure curves

So far the focus of this study was on predicting the wetting phase saturations from the capillary pressure curves obtained from NMR spectra. Another important capillary pressure curve parameter is the entry pressure (further denoted as PcEntry). The entry pressure shows at which overpressure the non-wetting phase begins to enter rock porespace. Knowledge of the entry pressure is of interest for example in such problems as predicting the sealing rock strength or looking at the difference between the Free Water Level and Hydrocarbon-Water Contact.

As poreneck distribution is related to poresize distribution, it is clear that the possibility exists to predict PcEntry from the NMR T_2 distribution. The PcEntry is of course related to the largest present poreneck size. We have performed a study to quantify uncertainty of such a prediction.

In our study we used the following method to determine PcEntry of a capillry pressure curve (both Hg/Air and NMR). In principle, PcEntry is the value of *Pc* at which the wetting phase saturation is Swet=100%. In practice, we found it more convenient to use *Pc* at Swet=85%. This method is illustrated in Figure 8. Although such a procedure does introduce an error, it has also important advantages. We used

Hg/Air capillary curves after applying closure correction. However, some artefacts still could be seen, and the procedure above allows to largely suppress them. More important, it allows compensating for the difference in smoothness in NMR spectra and in differential Hg injection spectra. Also, as shown below, such method is precise enough for comparing PcEntry from NMR and Hg/Air.

In Figure 9 the correlation between NMR and Hg/Air PcEntry is shown with circles. The values of PcEntry from NMR were obtained from T_2 distributions that were converted using the variable P_c/T_2^{-1} scaling as shown in Figure 5. For each set of samples (entry of the catalogue) we used the value of *Kappa* which gives the best prediction of saturation as discussed in previous sections (minima of the dashed curves in Figure 3). With the crosses in Figure 9 we show the "as good as it gets" correlation, where values of *Kappa* were chosen specially such as to minimise the difference between values of PcEntry from Hg/Air and NMR capillary pressure curves.

From the analysis of the crossplots shown in Figure 9, we calculated that PcEntry can be predicted from NMR T_2 distributions within a factor of 1.85 if one uses the same values of Kappa that give the best saturation prediction. The best accuracy which one can achieve in principle is a factor of 1.7.

Capillary Curves from NMR on Rocks at partial Water Saturation.

The subject of the previous section was the reconstruction of capillary pressure curves from NMR T_2 distributions obtained on samples at 100% water saturation. This method relies on the fact that both capillary pressure curve and NMR T_2 distribution reflect the pore geometry. However, if non-wetting hydrocarbons are present in the pores then this assumption is no longer true. NMR signal coming from hydrocarbons has a relaxation time, which does not depend on poresize (Kleinberg et al. 1996). Simple application of a T_2-Pc conversion to oil-water distributions can lead to erroneous results.

Clearly, correcting oil-water spectra is necessary if one would like to use data from NMR logs in oil or gas fields for reconstructing CapCurves in the whole capillary pressure range.

One can start with a notice that for a water-wet rock NMR T_2 distributions at short T_2 (i.e. high Pc) values remain determined by water signal and still reflect poresize *volume* distribution of the smaller pores. This principle is widely used in NMR log interpretation to predict the bound water volumes. Porosity of the rock is also usually known, either from measurement on the same core or log data (NMR or "conventional"). Thus also *saturations* up to at least Swirr can be correctly calculated using the conversion procedure discussed in the previous section. The only exception is with reservoirs containing heavy oil if the oil spectrum extends to very short T_2 values.

As one can rely on the T_2 distribution at low T_2's, only the (missing) spectrum of the moved water need to be estimated to obtain an estimate of a distribution at 100% water saturation. From studying the entire database, we found that a suitable approximation of the moveable water spectrum can be made by a broad peak centered around some T_2 value, T_{2ffi}. The area under this peak is known because the total sum of amplitudes equals (1-Swirr).

However, prediction of T_{2ffi} remains a real challenge. To do this we used an empirical correlation between S_{wirr} and $<T_2>$, the geometrical mean T_2 of NMR spectra at Sw=1. This correlation is shown in Figure 10. The value of Swi is found by applying a 25 ms T_2 cutoff to NMR distributions obtained at Sw=1. It appears that better results are obtained if the value (1-Swi)/Swi is taken instead of Swi.

We expected the existence of this correlation between $<T_2>$ and Swi from the fact that the two permeability estimators from NMR:

$$k = A \cdot f^4 \langle T_2 \rangle^2$$

$$k = B \cdot f^4 \left(\frac{1 - Swi}{Swi} \right)^2$$

work almost equally well in water-filled rock. The reason *why* it exists lies apparently in the self-similarity of the sandstone rock at different lengthscales, which also enables the existence of a R_{pore}/r_{neck} proportionality. Thus this correlation should be valid for the same types of rock where the conversion of NMR to capillary pressure curves holds as well and vice versa.

Based on this correlation, one can undertake the following steps to obtain "the best guess" T_2 distribution at Sw=1. These steps are also illustrated in Figure 11 on an example of a T2 distribution, measured on partially water saturated sample.

1. From NMR T_2 distribution at any water saturation and a porosity measurement determine the value of Swi.
2. Obtain a spectrum of bound water by applying a T_2 cutoff or a weight function (see e.g. Chen et al., 1997). Add a moveable water spectrum centered at some T_{2FFI} such that the sum of amplitudes equals porosity.
3. From Swi and the correlation shown in Figure 10 determine "ideal $<T_2>$" of T_2 distribution at Sw=1. Adjust T_{2FFI} position of the "free fluid peak" such that the geometrical mean T_2 of the overall spectrum equals "the best guess" $<T_2>$.

To test this method, we have looked how good the NMR T_2 spectra at Sw=1 can be reconstructed from the distributions after drainage (with air) in a centrifuge. This comparison is shown in Figure 12. As can be seen the overall agreement is quite reasonable, especially in reproducing the contrast in poresize distributions. The differences between "the best guess" spectra and really measured ones at long T_2 ends have less influence on capillary pressure curves, as these T_2 values correspond to low values of *Pc*.

After the spectra at 100% water saturation have been "obtained" one can use the T_2-Pc conversion discussed in a previous section to obtain capillary pressure curves. To illustrate the results, the NMR capillary pressure curves from "the best guess" spectra for an entry of the database are shown in Figure 13.

To optimise NMR-to CapCurve conversion and to quantify uncertainties, the same average errors as in 100% water case were estimated (Figure 2 and Figure 3). It appears that starting from the T_2 distributions after drainage the average Sw error (0-500 psia Hg) is 10.5 (8.5) saturation units with (without) core calibration.

It can be thus concluded, that applying such a hydrocarbon correction and using only bound water part of T_2 spectra does not introduce extra errors into Capillary Curve reconstruction.

Conclusions

1. Capillary pressure curves can be reliably obtained from NMR T2 distributions using a single scaling factor. Since NMR measurements are fast, cheap and non-destructive, this offers an attractive alternative to conventional capillary pressure measurements, or to screen samples e.g. prior to elaborate flooding tests.
2. A universal scaling factor *Kappa*=Pc·T_2 = 3 psi Hg·sec seems to work well for all sandstones, which makes the technique very valuable in exploration wells, reducing the need to take cores.
3. A more accurate prediction can be obtained through local calibration, possibly allowing the scaling factor to vary with poresize.
4. A method is proposed to compensate the destructive effect of the presence of hydrocarbons on the measured T2 distribution.

NOMENCLATURE

Sw - Water saturation
Swet - Wetting Phase saturation
T_2 - NMR transverse relaxation time
Pc - Capillary pressure
Swir - 1st drainage capillary curve irreducible water saturation
PcEntry - 1st drainage capillary curve entry pressure
BVI - Bulk Volume Irreducible
FFI - Free Fluid Index
$<T_2>$ - Geometrical mean T_2 of the NMR T_2 distribution
Kappa, κ - Scaling factor between Pc and $1/T_2$
ρ - NMR surface relaxivity
σ - Interfacial Tension

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Chen, S., Arro, R., Minetto, C., Georgi, D., Liu, C., 1998, "Methods for computing Swi and BVI from NMR logs", Transactions of 39th SPWLA annual symposium, Keystone, CO, May 26-29, paper HH.

FIGURES
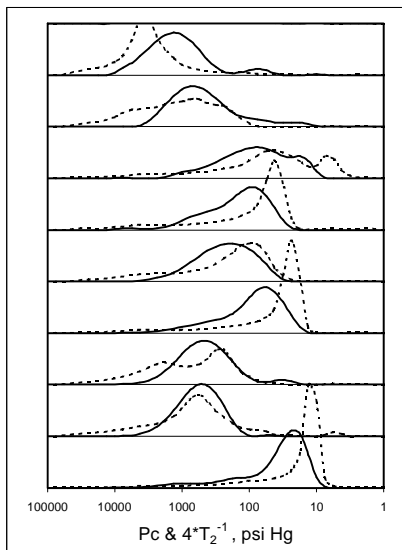
Figure 1 Comparison of NMR T2 distributions (solid line) and differential Hg injection (dashed line) for the set of 9 samples from
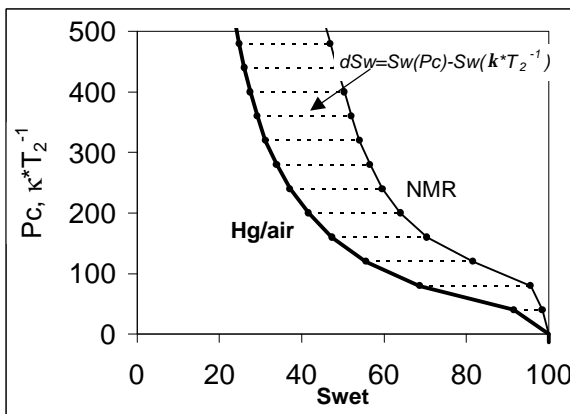
Figure 2 Preferred optimum scale *Kappa* is the one giving the smallest saturation error when predicting saturations from NMR capcurve.
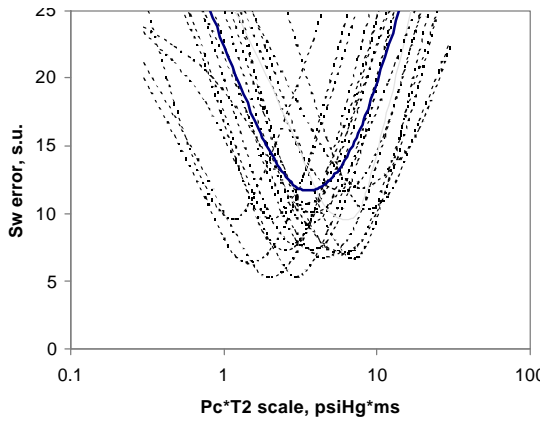
Figure 3 Average saturation error between NMR-derived and Hg-Air capillary pressure curves on 0-500 psi Hg capillary pressure range (approx. 0-120 m haFWL) as a function of *Kappa*$=Pc/T_2^{-1}$**. Thin dotted lines represent average errors from different sandstone reservoirs, the thick solid line is the average of all 186 core samples.**
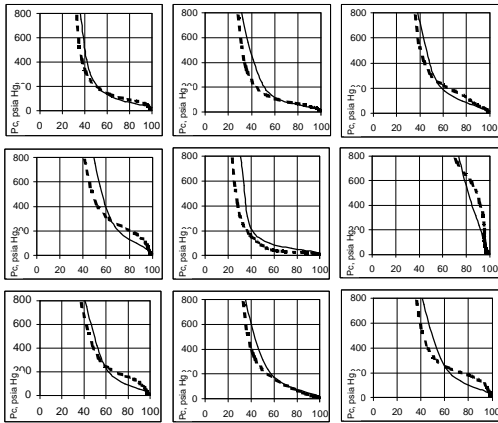

Figure 4 Hg-Air capillary curves (black dash) compared with NMR derived (Sw=1) capillary curves (thin solid) for an entry of the database. One Pc/ T_2^{-1} scale was used for all sampls. Average Sw error (9 samples, 0-500 psi Hg) is 8.5 sat. units. For this core dataset porosity variation was 3-23 p.u., permeability - 0.03-2550 mD.
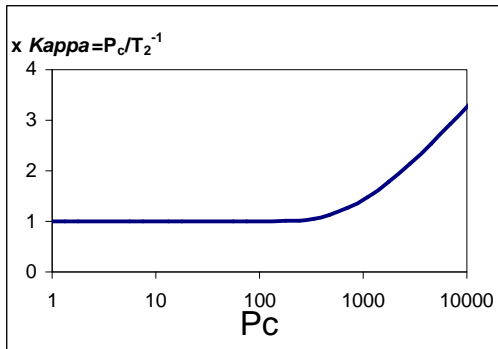
Figure 5 Typical variable scale used for converting NMR T2 distributions to capillary pressure curves.
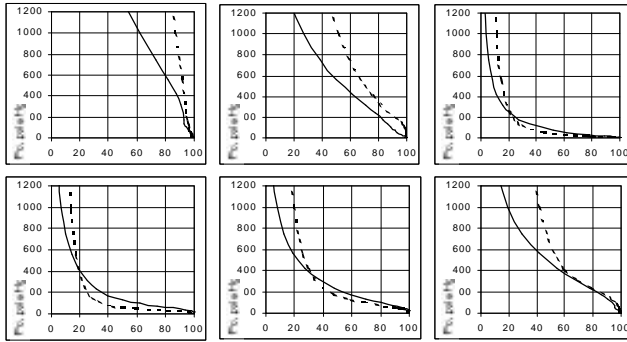
Figure 6 NMR capillary curves (solid line) obtained from T_2 distributions with a fixed $Kappa=P_c/T_2^{-1}$. At high Pc's, the values of Sw are underestimated compared to real Hg/Air curves (dashed lines)
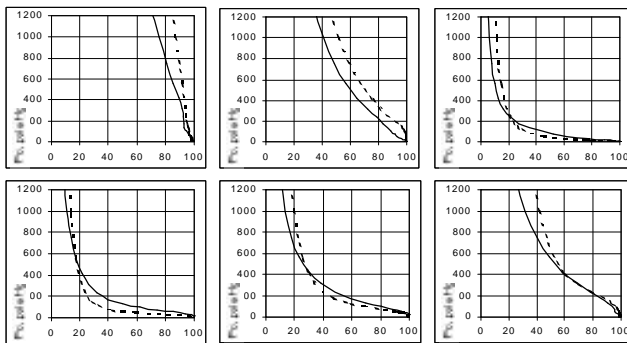
Figure 7 NMR capillary curves (solid line) obtained from T_2 distributions with a variable scaling. At high Pc's the agreement with real Hg/Air curves (dashed lines) is much better than in Figure 6.
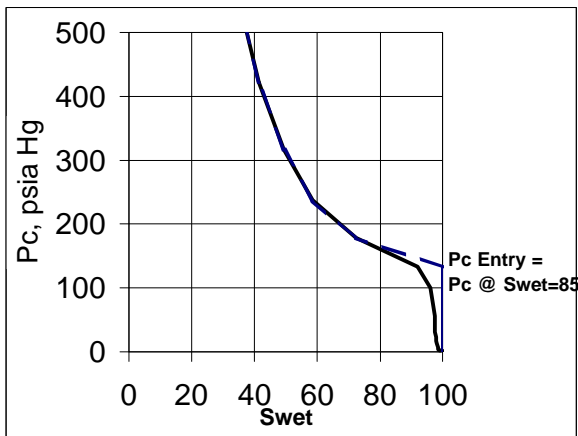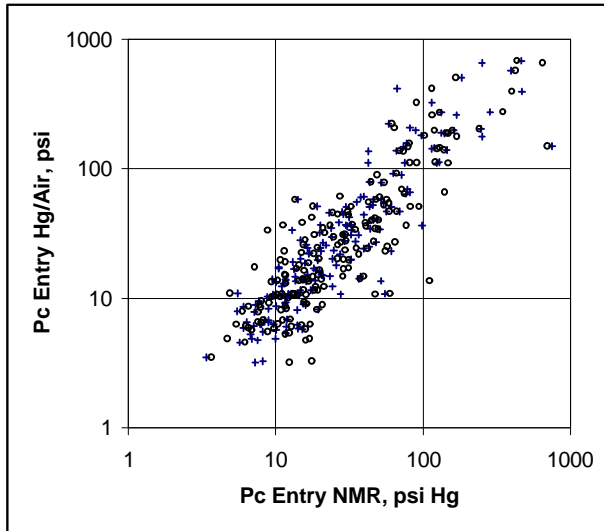

Figure 8 Entry pressure was determined as the value of P_c where Swet=85%.

Figure 9 Crossplots of values of PcEntry as found from Hg/Air capillry curves vs the ones calculated from NMR T2 distributions. Different symbols denote different calibration of Kappa=P_c/T_2^{-1}.
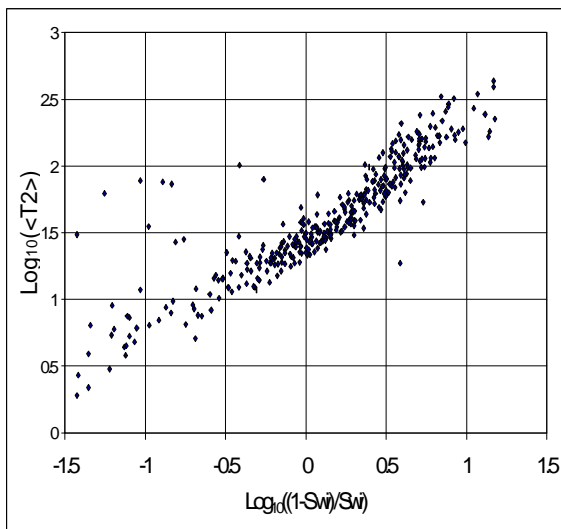

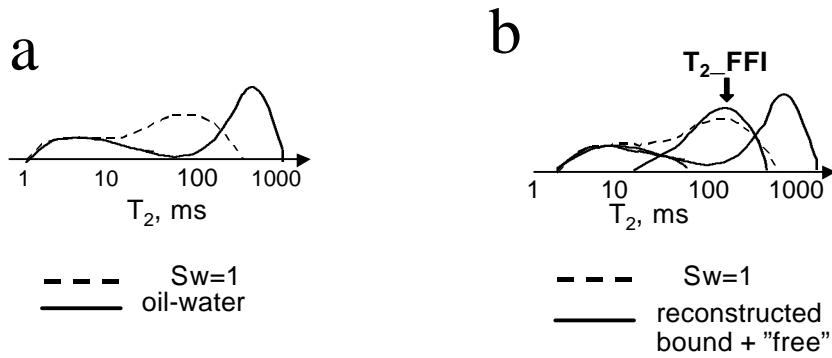**Figure 10 Database correlation between <T2> of NMR spectra at Sw=1 and Swi calculated from NMR spectra at Sw=1 with 25 ms T_2 cutoff.**

Figure 11 In figure a) a T2 distribution at Sw=1 is compared to T2 distribution of oil-water signal from the same sample. In figure b) the hydrocarbon correction procedure is illustrated, namely the distribution at Sw=1 is reconstructed from bound water signal and a model "free" water distributions. The position of the "free water signal", T2_ffi is tuned to get the "ideal" mean T2 of resulting distribution which is obtained from the correlation shown in Figure 10.
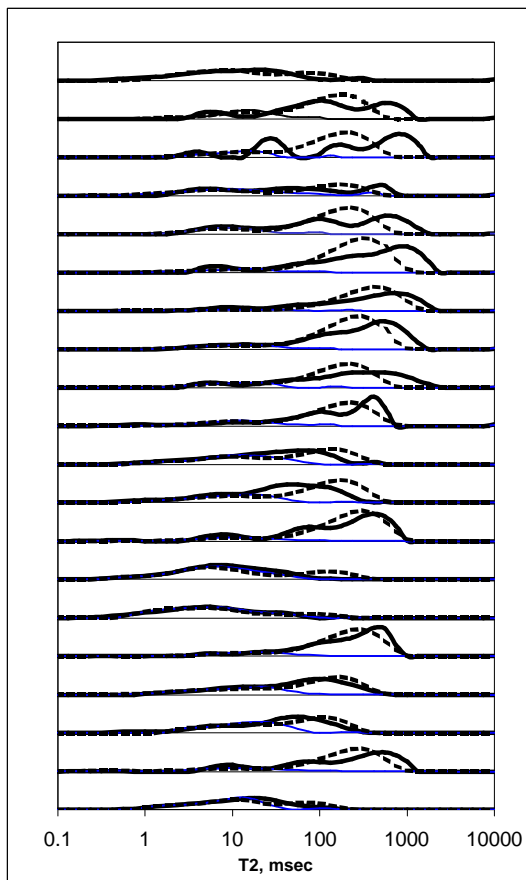

Figure 12 Reconstructed 100% water spectra (thick dashed) from bound water spectra (thin) compared to real 100% Sw spectra (thick solid).
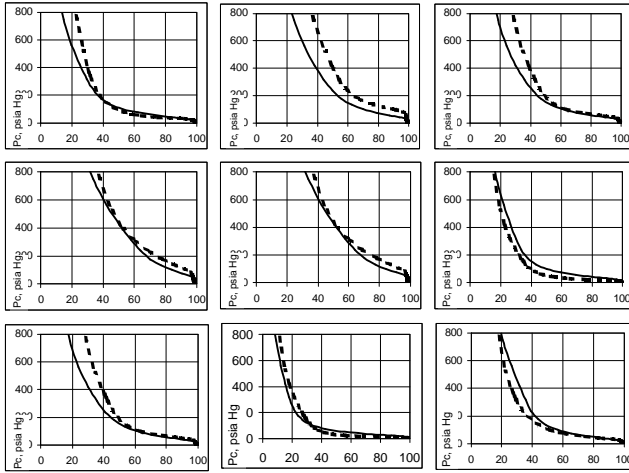
Figure 13 CapCurves from "the best guess" spectra (thin) and Hg CapCurves (thick dash) for an entry of the database.