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Distinguishing Fluid Properties and Producibility from NMR Logs

W.J. Looyestijn
Shell International Exploration and Production, Technology Applications and Research, Rijswijk, The Netherlands

Abstract

Crucial issues in formation evaluation are the determination of porosity, permeability, hydrocarbon volumes and net-to-gross ratio. NMR logging provides measurements that are directly related to these parameters. This paper discusses some recent advances in the determination of both rock and fluid properties from NMR logging.

The generally applied interpretation method of NMR data is to split the signal into a fast relaxing part and a slow relaxing part. The first is interpreted as bound water, and the later as free fluid, i.e. mobile water and/or hydrocarbons. The split between these two parts is made by applying a cut-off in T2, typically at 33 ms in sandstone. While this has proven to be very powerful, there are many shortcomings with this simple approach.

Bound water is not an absolute quantity, but related to capillary pressure. Methods exist to convert NMR relaxation time distributions directly to capillary pressure curves. The main advantage would be that capillary pressure data can be acquired continuously and with sampling equal to that of the wireline logs. Unfortunately, the presence of hydrocarbons strongly dictates the shape of the T2 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 any NMR log acquisition and does not require special or complicated pulse sequences.

In some instances, the NMR response of fluids contained in pores possesses a sufficiently large contrast in T2 to allow them to be separated from each other. A more differentiating parameter, though, is the molecular diffusion. Provided that NMR data has been acquired with suitably chosen acquisition parameters (i.e. wait times and/or interecho times) a separation of water, oil and gas NMR responses can be made. From these separate NMR responses the hydrocarbon volumes, porosity and permeability estimates are subsequently calculated. Key in these applications is the ability to include all acquired NMR log data into the processing towards the desired end result. Simultaneous inversion using a rigorous forward model of such data showed unambiguous identification of fluid types and volumes where other methods failed.

Introduction

Nuclear Magnetic Resonance (NMR) has found many applications to the Oil and Gas industry (e.g. Kenyon 1997, Kleinberg *et al*. 1996). A NMR instrument (logging tool or laboratory unit) 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

contributions originating from hydrogen spins experiencing different local surroundings, which are responsible for the relaxation of the nuclear magnetisation.

For a hydrogen nucleus in a water molecule in pore i in a water-wet rock, the relaxation time, T_{2i} is given by:

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

The proportionality constant $\boldsymbol{r}$, 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, $T_2 \sim V/S \sim R_{pore}$, i.e. T_2 is proportional to the size of a pore. The magnitude of signal decaying with each T_2 directly gives the pore volume corresponding to a certain R_{pore}. The whole set of amplitudes obtained from the decay inversion procedure is thus proportional to the poresize distribution of a rock.

For a hydrogen nucleus 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). This will be treated later in this paper.

The generally applied interpretation method of NMR data is to split the signal into a fast relaxing part and a slow relaxing part. The first is interpreted as bound water (BVI), and the later as free fluid (FFI), i.e. mobile water and/or hydrocarbons. The split between these two parts is made by applying a cut-off in T2, typically at 33 ms in sandstone.

While this has proven to be very powerful, there are many shortcomings with this simple approach. The most important one is that bound water is not an absolute quantity, but related to capillary pressure. Applying a single cutoff is equivalent to chosing a single pressure. Hence, the logical improvement would be to convert NMR relaxation time distributions directly to capillary pressure curves. The main advantage would be that capillary pressure data can be acquired continuously and with sampling equal to that of the wireline logs.

Capillary curves from NMR on rocks at $S_w=1$
A drainage capillary pressure curve describes injection of a non-wetting fluid into a porous medium (rock). 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, and is expressed as

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

Thus, simplified, a drainage capillary pressure curve represents a cumulative poreneck distribution plotted on a reciprocal $1/r_{neck} \sim P_c$ scale.

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 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.

Mathematically, the conversion comes down to finding a suitable value for the proportionality constant $Kappa = P_c/T_2^{-1}$. At first glance, the most natural way to define the optimum scaling would seem 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). However, the optimum scale should depend on the application of the result. Often,

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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 prediction of saturations by the "NMR capillary pressure curves". Therefore, 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 curve (Volokitin *et al.* 1999). These differences are averaged with a uniform sampling in P_c and only across the capillary pressure range that is of relevance in the field, for example 0-500 psi Hg, as illustrated in Figure 2.

It is important to notice that, as a rule, poresize and poreneck distributions are shown on *logarithmic* scales, whereas capillary pressure curves are related to depth which, of course, should always be considered on a *linear* scale. Thus, minimising the error in saturation prediction should be done with linear sampling in P_c. Seemingly large differences in distributions at the high T_2 end are much less pronounced when comparing saturations from capillary pressure curves.

Another point worth mentioning is that we suggest to determine a single value of *Kappa* on the whole set of relevant core samples, rather than taking the average of individual *Kappa* values for individual samples. The reasoning behind it is that we want to *predict* capillary pressure curves for samples (core or downhole) from their T_2 data. Obviously, 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 approach.

Saturation prediction from NMR capillary pressure curves

A comparison of "NMR Capcurves" with real Hg-Air curves for a set of 9 samples is shown in Figure 3. The average error in saturation for this set is 8.5 saturation units. Note that the character of Hg-Air capillary pressure curves is very well reproduced. Similar results are obtained for other datasets.

The S_w error described above should be considered as a value of scatter at every log depth rather than a systematic deviation. By virtue of the minimisation, the latter is essentially zero provided a representative core dataset is chosen to calibrate the conversion factor.

Prediction of Entry Pressure from NMR capillary pressure curves

Another important capillary pressure curve parameter is the entry pressure (further denoted as $P_{c,entry}$). The entry pressure shows when the non-wetting phase begins to enter the porespace. The $P_{c,entry}$ is of course related to the largest present poreneck size. In principle, $P_{c,entry}$ is the P_c value at which the wetting phase saturation is $S_{wet}=100\%$. In practice, we found it more convenient to use P_c at $S_{wet}=85\%$ (Volokitin *et al.* 1999). Although such a procedure does introduce a small error, it makes it less sensitive to errors in closure correction and to the difference in smoothness in NMR spectra and in differential Hg injection spectra. In figure 4 the correlation between NMR and Hg/Air $P_{c,entry}$ is shown for a large data set. We found that $P_{c,entry}$ can be predicted from NMR T_2 distributions within a factor of 1.8.

Capillary Curves from NMR on Rocks at partial Water Saturation

A serious complication arises, if non-wetting hydrocarbons are present. NMR signal coming from such hydrocarbons has a relaxation time that does not depend on poresize but only on its viscosity (Kleinberg *et al.* 1996). Straightforward application of a T_2-P_c conversion to oil-water distributions can lead to erroneous results. Fortunately, we found an elegant method to correct the data with sufficient accuracy (Volokitin *et al.* 1999). In principle, this correction

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relies on the fact that hydrocarbons enter the larger pores only. Hence, it is the long-T2 part of the distribution that has to be corrected. We found that this can be done by using a general FFI shape function. Its amplitude is determined by the porosity, and its mean T2 value by the BVI/FFI ratio. Note that BVI is still correct (unless the oil is heavy), and porosity is known.

To test this method, we looked how well capillary pressure can be reconstructed from NMR distributions obtained after drainage (with air) in a centrifuge. This comparison is shown in Figure 5. As can be seen the overall agreement is quite reasonable, especially in reproducing the contrast in poresize distributions.

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 the capillary pressure curve reconstruction, but removes a potentially large systematic error.

The above technique has also been implemented as an application to NMR log data, allowing a pseudo capillary pressure curve to be constructed at every measured depth in the wellbore (Volokitin *et al*. 1999).

Multi Acquisition NMR inversion (MacNMR)

In the preceding section we described a method to correct for the presence of hydrocarbons, i.e. treating its effect as an unwanted nuisance. However, the hydrocarbon signal bears information about the composition of the oil or gas (e.g. Kleinberg *et al*. 1996), and can thus be valuable.

In some instances, the NMR response of fluids contained in pores possesses a sufficiently large contrast in T2 to allow them to be separated from each other. A more differentiating parameter, though, is the molecular diffusion (Appel *et al*. 2000). Provided that NMR data has been acquired with suitably chosen acquisition parameters (i.e. wait times and/or interecho times) a separation of water, oil and gas NMR responses can be made. From these separate NMR responses the hydrocarbon volumes, porosity and permeability estimates are subsequently calculated. Key in these applications is the ability to include all acquired NMR log data into the processing towards the desired end result. Simultaneous inversion using a rigorous forward model of such data showed unambiguous identification of fluid types and volumes where other methods failed (Slijkerman *et al*. 2000).

In multi-acquisition NMR there are two parameters that can be varied: wait time and interecho time. Depending on wait time and interecho time a certain echo decay vector is measured. The wait time determines the polarisation of the fluid and the interecho time determines the diffusion decay.

Polarization of a fluid in a pore is dependent on its T_1 and the applied wait time T_w according to:

$$P_f = 1 - e^{-\frac{T_w}{T_{1f}}}$$

In case the fluid is non-wetting T_{1f} is equal to its bulk T_1. In case the fluid is wetting the T_1 is a distribution, which can be estimated from the T_2 distribution.

In a gradient field an additional decay arises due to molecular diffusion within the sensed volume. For a fixed gradient this additional decay is described by the following expression:

$$d_f(t) = e^{-\frac{D_f \gamma^2 G^2 T_e^2 t}{12}}$$

in which D_f is the diffusion constant of the fluid, γ the gyromagnetic ratio of hydrogen, G the prevailing magnetic field gradient and T_e the interecho time. If the field gradient is not single valued (as with the CMR), an integration over its distribution is required.

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With the forward model available to describe the measured decay vectors the inversion process is nothing more than finding the A_{fi} (T_2-spectra for fluids present) that best-fit the measured echo decay vectors.

A few features make this processing method very attractive:

- It is not just dual wait time or dual interecho time but both techniques at the same time.
- Provided acquisitions are chosen suitably, fluid properties can be extracted from the log data, providing valuable information on the formation fluids (i.e. T_1 and/or D may correlate with gas-oil ratio or condensate-gas ratio).
- The MRIL Total Porosity mode of logging generates a separate echo decay vector of 10 echoes with an interecho time of 0.6 ms. The CMR Enhanced Precision Mode generates a similar short echo decay vector (30 to 100 echoes). Both these acquisitions are measured with high S/N and will better resolve the fast T_2 components. MacNMR includes such high S/N decay vector in its simultaneous inversion just like another acquisition.

Example

The example is from a sandstone reservoir containing a light oil. Neutron and density are affected by wash outs. Based on the viscosity (0.34 cP) and known pressure (88 bar) and temperature (107 °C), the T_1 of the oil is estimated to be 4.5 s and the diffusion constant is estimated to be $4.9 \cdot 10^{-9}$ m^2/s. The well was drilled with a water-based mud. The well was logged with a 4.5 inch MRIL-C tool (holesize 6 inch) with the objective to determine (among other things) the type and volumes of the fluids in the flushed zone.

A number of acquisitions were gathered in different passes. The following passes were used in data analysis:

- A dual wait time pass at an interecho time of 0.9 ms with 1 and 8 s wait times (210 echoes).
- A dual interecho time pass at 1.2 and 2.4 ms interecho times and 10 s wait time.
- A pass with a bound fluid acquisition at an interecho time of 1.2 ms and 0.8 s wait time and a Total Porosity acquisition (10 echoes at 0.6 ms interecho time with a 0.02 s wait time).

Figure 7 shows the MacNMR analysis of this dataset together with the conventional logs. The figure clearly shows the washouts in the shale sections. On the NMR log these sections are recognized from the too high porosity (340 to 360 ft). The fluid volumes resulting from the MacNMR analysis are plotted in track 7. The track shows the oil to be present in the sand from 300 to 340 ft and also in the thinner sands deeper down. The water based mud filtrate is visible as free water. (Note that the NMR tools read in the invaded zone and hence the derived volumes are valid for the flushed zone). In the analysis we have included the Total Porosity acquisition leading to a well-resolved T_2 spectrum at low T_2 and hence a reliable CBW measurement.

As part of the data analysis it was attempted to extract fluid properties. For the set of wait times available it can be shown that there is not a large sensitivity to T_1 of the oil. With the availability of the set of interecho times there is sensitivity to the diffusion constant of the oil. Optimisation for oil diffusion coefficient leads to a value of $7 \cdot 10^{-9}$ m^2/s which is slightly larger than expected from viscosity correlations. This appears to be a common observation and is caused by a non-zero GOR of the formation oil.

More examples have been published elsewhere (Epping *et al.* 1999, and Savignol *et al.* 1999).

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Conclusions

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 can be used to screen core samples e.g. prior to elaborate flooding tests.

- A method is proposed to compensate the destructive effect of the presence of hydrocarbons on the measured T2 distribution.

- The MacNMR methodology described provides inversion of multiple acquisitions by forward modelling. It allows simultaneous use of all data, both with varying wait time and varying interecho time.

- MacNMR is a powerful tool for differentiating water from hydrocarbon, thus providing a water saturation in the flushed zone, and allowing an accurate porosity evaluation in cases of low hydrogen index, such as gas. Another application is the in-situ determination of the NMR parameters (T_1 and D), in order to differentiate gas from oil, or to estimate crude properties.

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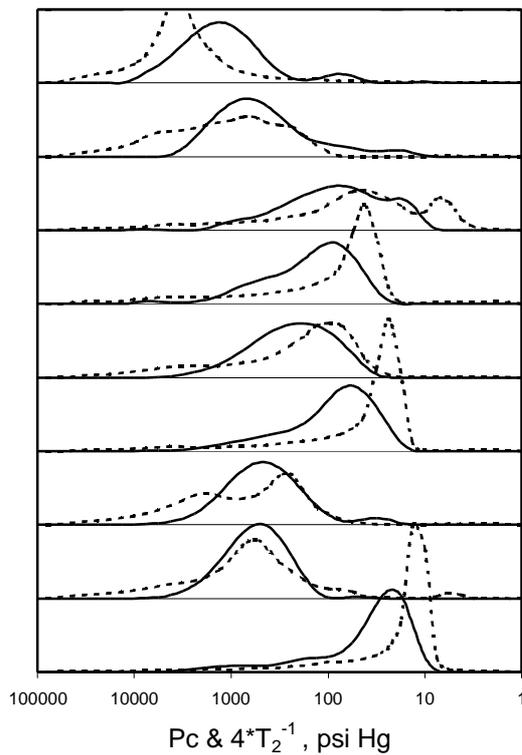15-16 May 2001, NTNU, Trondheim, Norway
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Figure 1 Comparison of NMR T2 distributions (solid line) and differential Hg injection (dashed line) for a set of 9 sandstone samples.
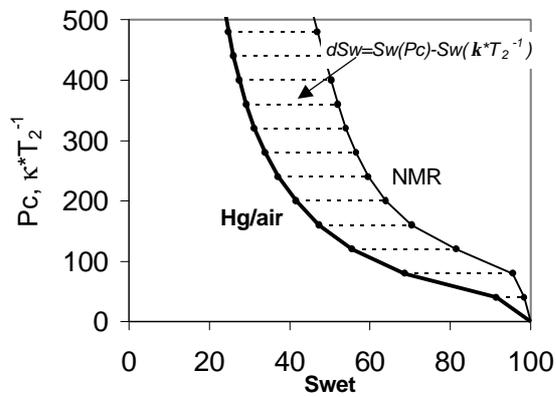

Figure 2 Preferred optimum scale *Kappa* is the one giving the smallest saturation error when predicting saturations from NMR capcurve.
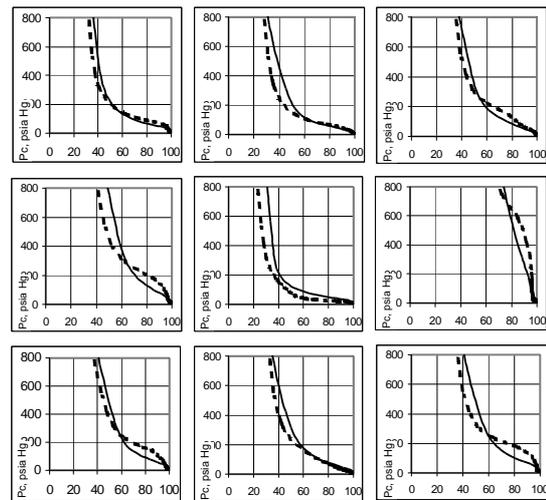

Figure 3 Hg-Air capillary curves (black dash) compared with NMR derived (S_w=1) capillary curves (thin solid) for an entry of the database. One $P_c/T2^{-1}$ scale was used for all samples. For this core data set porosity variation was 3-23 p.u., permeability 0.03-2550 mD.
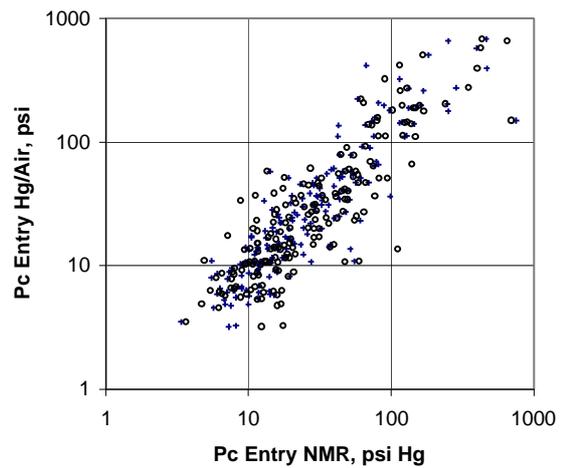

Figure 4 Crossplots of values of $P_{c,entry}$ as found from Hg/Air capillary curves vs those calculated from NMR T2 distributions.

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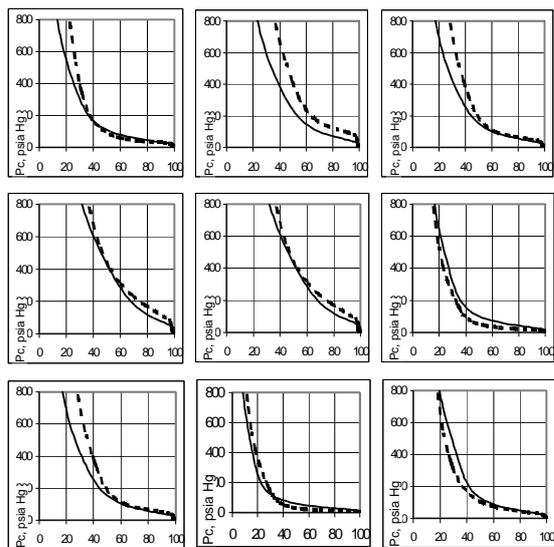www.ipt.ntnu.no/nordic

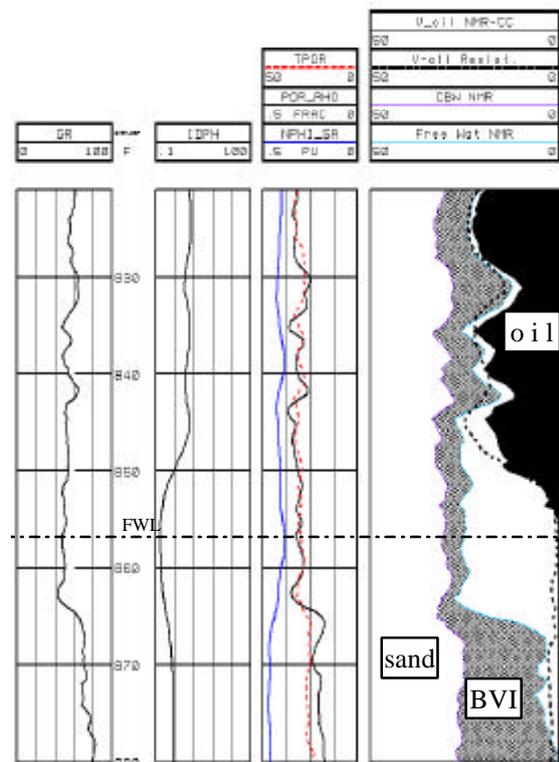Figure 5. CapCurves from NMR spectra on desaturated samples (thin) and Hg CapCurves (thick dash).

Figure 6. Application of a capcurve-derived saturation from NMR (shading) in excellent agreement with R_t-derived saturation (dashed line)

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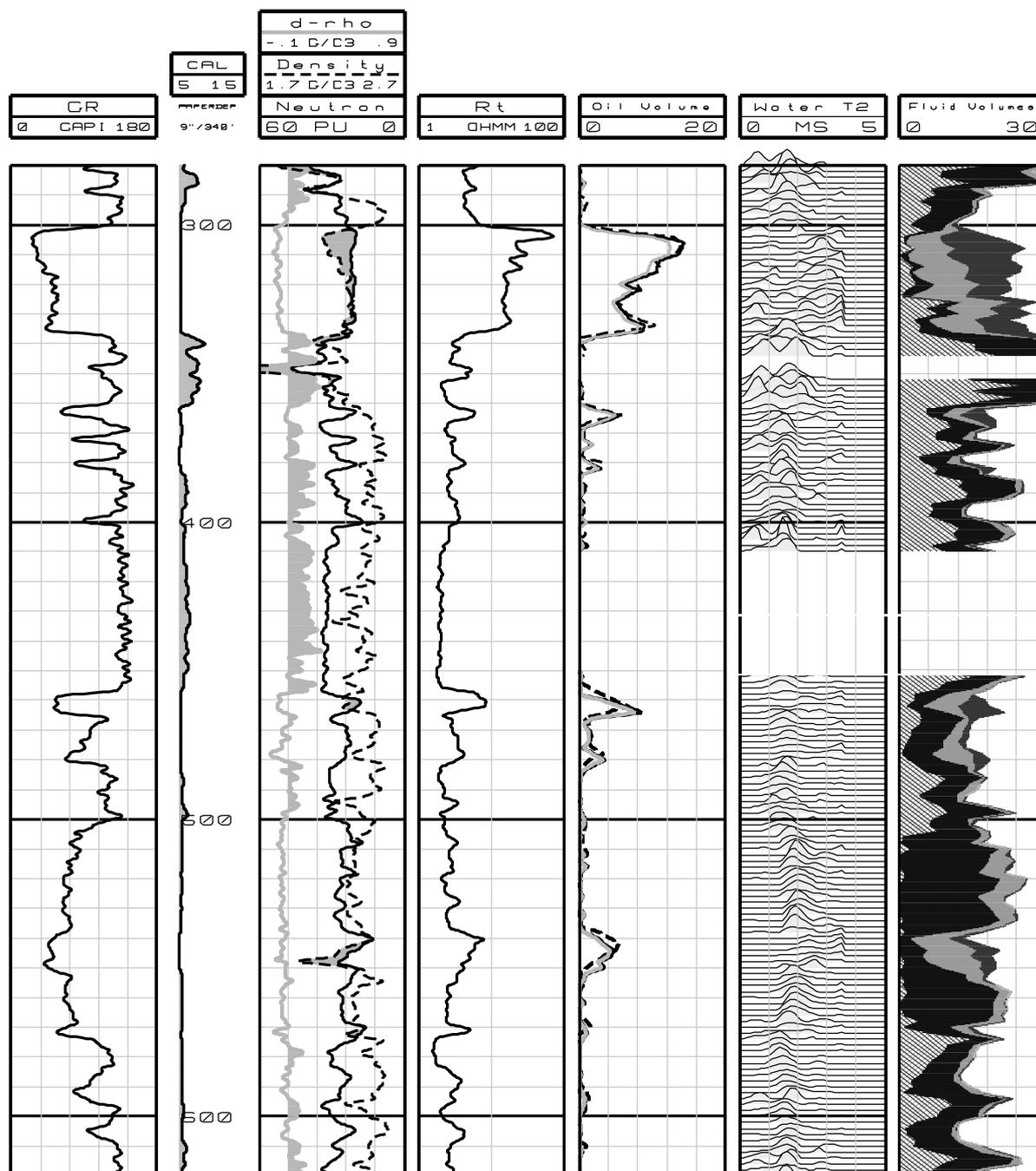www.ipt.ntnu.no/nordic

Figure 7. Example MacNMR evaluation. Track 5 shows the oil volume (i.e. not oil saturation) as found from MacNMR. In solid gray when using the estimated fluid properties. In solid black when using the best-fit fluid properties and the dashed line when using only the dual wait time data. Track 7 shows the fluid volumes in gray coding: Hatched is CBW, Black in BVI, light gray is free water and dark gray is oil.

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