

DETERMINATION OF OIL SATURATION FROM DIFFUSION NMR LOGS

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Abstract

Diffusion NMR on fluids contained in porous rock can be interpreted quantitatively in terms of oil saturation. This is a new application, which has proven to be very useful to supplement conventional saturation evaluations. This new method utilises the differences in molecular self diffusion between oil and water. The application requires at least two T2 decay measurements taken with different interecho spacings in a gradient magnetic field. The method has been applied successfully to the data recorded in wells that contain heavy oil. The NMR-derived saturations are in good agreement with core and log data, and have the advantage that core calibration is not required for each field; in this case available core data verified the method.

A sensitivity analysis showed that saturations can be derived with an uncertainty of some 5 to 7 percent pore volume, provided that the oil and water diffusion coefficients differ by at least a factor of five. The uncertainty in saturation is mainly due to the noise level of the data, and may thus be further reduced by improvements in hardware.

The NMR measured saturation is at a very shallow depth (typically 10 cm from the borehole) and is only representative of the virgin saturation if no, or only very shallow, invasion has taken place, or if the interval is at "residual" oil saturation, e.g. after water flood.

Interpretation of the 'standard' T2 data for distinguishing between bound water and movable fluid (water and/or oil) failed in the presented cases because of the short relaxation time of the viscous oil. Numerical simulation has shown that under most conditions encountered in sandstones the Free Fluid Index concept remains valid for oils with T2 greater than 50 ms, which corresponds to in-situ viscosities less than 20 cP.

Introduction

The MRIL-B was run by Petroleum Development Oman in four sandstone wells in 1993 to test its claimed ability to predict formation permeability and productivity. These applications were reported in the open literature [Miller et al, 1990, Coates et al, 1991],

and are based on the tool's ability to differentiate between bound water and movable fluid (water and/or oil). Although it was realised that this technique would break down for very viscous oil, the MRIL was run to investigate in the field what information could be obtained from NMR logs in heavy oil clastic reservoirs. Indeed, already during the field trial it became evident that the "traditional" interpretation of the MRIL is not valid for the oil-bearing intervals in the logged wells and that PDO's main objectives of permeability / productivity assessment could not be met in the hydrocarbon bearing intervals. However, the so-called diffusion (T2D) measurements, taken in these wells, turned out to be of specific value here, as it was recognised that the diffusive properties of water and viscous oil are very different and can be used to differentiate the two fluids. We developed a dedicated processing scheme to calculate the oil saturation from these data.

NMR response in water bearing rock

Fluids contained in porous media undergo an accelerated relaxation due to interaction with the pore surface [e.g. Kenyon 1992]. Provided that the diffusion is fast enough, the total effect is that the fluid in a pore relaxes as a single exponential decay $\exp(-t/T_2)$, with:

$$1/T_2 = 1/T_{2,bulk} + \rho S/V \quad (1)$$

with T_2 observed relaxation time
 $T_{2,bulk}$ relaxation time of bulk fluid
 ρ surface relaxivity
 S/V surface-to-volume ratio of the pore

Extensive laboratory studies have verified that this equation is indeed valid. For most sandstones, S/V turns out to be a reasonable measure of the effective diameter of the pore. Consequently, the NMR decay rate reflects the poresize. Several studies [Howard et al, 1990, Kenyon 1992, Kleinberg et al, 1993] indicate that ρ is of the order of $0.1 \mu\text{m/ms}$ and is fairly uniform (within a factor of 3) for most sandstones. Porous rock usually exhibits a large variation of poresizes. The observed NMR decay may be described as a multi-exponential of the form:

$$M(t) = \sum A_i \exp(-t/T_{2,i}) \quad (2)$$

with $M(t)$ echo amplitude at time t
 A_i the pore volume fraction associated
 with the i^{th} component
 $T_{2,i}$ the i^{th} relaxation time .

The range of $T_{2,i}$ values is restricted by the shortest time that can be measured (3 to 5 ms for the MRIL-B) and the value of bulk water (≈ 3 s). The number of relaxation times that can meaningfully be extracted from the data, depends on the poresize distribution and the noise level.

The total signal, given by $M(0) = \sum A_i$ (i.e. the amplitude at the onset of the decay), gives the total porosity. The part of the water in porous rock that is unable to flow is called the irreducible water $V_{w,irr}$, or bound volume index, BVI. Part of it is bound to clay, part is capillary bound. The remainder of the fluid (oil and possibly some water) is movable. In waterwet rock it may be assumed that these movable fluids are contained in the larger pores only. So, by ignoring the NMR signal from the smaller pores, the movable fluid (V_{mov} , or free fluid index, FFI) is determined.

FFI can be computed in two ways. One way is to integrate the T2 spectrum from about 30 ms to infinity. The other method calculates FFI by fitting a single exponential to the T2 data in the range $t > 20$ ms. The optimum values of these cut-offs were found from calibration against centrifuge data, and seem to be applicable for most sandstones [e.g. Straley et al., 1994].

When does the FFI concept fail

As discussed, the Free Fluid Index concept in water-saturated rock relies on the ability to distinguish between bound water and mobile water using a T2 cut-off of about 30 ms. Replacing mobile water by oil will not affect FFI, provided that the oil has a T2 value greater than 30 ms. An exact value for the minimum T2 cannot be given, as it depends on a large number of other factors, such as the oil saturation, the composition of the oil, the T2 distribution of the water in the rock. We carried out a series of numerical simulations and found that under most conditions encountered in sandstones, the FFI concept remains valid for oils with T2 greater than 50 ms, which corresponds to in-situ viscosities less than 20 cP.

NMR and molecular diffusion

The description of the NMR decay, given above, is valid provided all hydrogen nuclear spins precess at a

constant frequency during the experiment. This is not the case if the magnetic field is inhomogeneous, as with the MRIL. During the pulse echo experiment, some spins diffuse to places where the magnetic field is slightly different. As a consequence, they will have a different precessing frequency, and thus will not return to zero phase at time τ after each π pulse. The net effect over the entire sample is an additional attenuation factor of the echo amplitude, so that the decay curve for fluid in a single pore system is given by [e.g. Fukushima 1981]:

$$M(t) = M_0 \exp[-t/T_2 - t \gamma^2 D G^2 \tau^2 / 3] \quad (3)$$

where

- M_0 = signal amplitude at $t = 0$
- T_2 = transverse relaxation time,
- γ = nuclear gyromagnetic ratio
- D = molecular self diffusion coefficient of the molecule containing the nucleus
- G = gradient of the magnetic field
- τ = time between π pulse and echo.

In principle, the effect of diffusion can be made negligibly small by minimising τ . The MRIL-B has a large, fixed gradient of about 0.25 T/m (25 G/cm). Hence, measuring $M(t)$ for at least two values of τ permits evaluation of T_2 and D .

The dependence of the decay rate on τ is significant only for values of D greater than 1 (10^{-9} m²/s), which is about one third of the value for water at room temperature. The value of D is related to temperature and viscosity. Combining available experimental data on water and crude oils [Morriss et al, 1994], the following empirical relationship is obtained:

$$D \approx 2.5 T / 300 \eta \quad (4)$$

where T is temperature (in K), η is viscosity (in cP) and D is in (10^{-9} m²/s). The temperature dependence of D for water is shown in Fig. 1 [Pruppacher 1971].

The diffusion effect will be significant for water and light oils. Medium-light to heavy oils, on the other hand, have diffusion coefficients (much) smaller than that of water, allowing for the distinction between water and oil to be made through the diffusion effect on the observed decay curve, as illustrated in Fig. 2. This concept forms the basis for the saturation interpretation of the NMR logs given in this paper.

Combining eqs. (2) and (3) gives an expression for wetting fluid in a rock. However, molecular diffusion

is less efficient for a fluid contained in small volumes because the molecules cannot move over unlimited distance. The effect of restricted diffusion can be taken into account, but, as will be discussed later, turns out to be not significant in this context.

Relaxation decay of oils

As indicated, the intrinsic (bulk-) relaxation time of hydrogen spins in a fluid is related to the molecular motion, and thus to the temperature and the viscosity of the fluid. A comprehensive data set [Straley et al, 1994] of a large range of oil samples may be adequately described by:

$$T_2 = 4 T / \eta \tag{5}$$

with T_2 in ms, T in K and η in cP. Most crudes, and in particular heavy crudes, are mixtures of a large range of components. As a consequence, these oils do not exhibit a single-exponential relaxation decay, but rather a decay that is to be described by a spectrum of exponentials. An easier, be it approximate, way to this into account is a 'stretched exponential', which gives a fairly good fit of the experimental data while introducing only one additional parameter per liquid phase [Kenyon et al, 1986]], namely:

$$M(t) = M_0 \exp[-(t/T_{2\alpha,o})^\alpha] \tag{6}$$

where $T_{2\alpha,o}$ is the stretched relaxation time of the oil, and α is the stretch factor.

If the experiment is done in the presence of a gradient G in the external field, the observed decay is, in analogy with eq.(3), given by:

$$M(t) = M_0 \exp[-(t/T_{2\alpha,o})^\alpha] \times \exp[-t \gamma^2 D_o G^2 \tau^2 / 3] \tag{7}$$

where D_o is the diffusion coefficient of the oil.

Contrary to what happens to water, the relaxation time of oil does not change when the oil is contained in a waterwet rock. This is because the oil has no interaction with the rock surface, and consequently, does not get an extra relaxation mechanism. Theoretically, the oil-water interface may act as such, but the effect, if any, will be negligible. Consequently, the relaxation time of oil in a waterwet rock is the same as that of bulk oil.

The above is only valid for a waterwet rock. For a truly oilwet rock, oil and water change roles, and the water phase will show its bulk relaxation time, while the oil relaxation times show a distribution reflecting

the pore size distribution. The magnitude of this depends on the values of $T_{2,oil}$ and ρ_{oil} , which may be different for each type of oil.

Fluid saturation from diffusion processing

In essence, the method relies on varying the additional attenuation of the echoes due to self-diffusion of the fluid in between subsequent echoes by varying the interecho spacing. Since this is more effective for water than for the viscous crude, the observed effect is a direct measure of the amount of water. The same principle underlies the Shifted Spectrum Method [Akkurt et al, 1995] for gas detection from NMR logs.

Oil and water are immiscible fluids; hence, the observed decay is given by the superposition of the two individual components. The processing consists of determining the volume fractions of oil and of water at each depth increment, allowing for the special character of the noise and for a possible offset:

$$M(t,\tau) = M_{water}(t,\tau) + M_{oil}(t,\tau) + Noise(t,\tau) + DC \tag{8}$$

so that

$$Porosity = M_{water}(0,0) + M_{oil}(0,0)$$

$$S_w = M_{water}(0,0) / Porosity$$

The $M(t,\tau)$ are the echo trains measured for at least two τ values and over a time interval of at least $T_{2\alpha,o}$ in order to fully capture the oil spectrum.

Example: Well A, South Oman

The MRIL-B logs recorded in Well A were taken in a sandstone formation covering the oil leg and (part of) the water leg. A short core was cut in the oil zone. Both T2 (2 ms) and T2D (4&6 ms) logs were taken. All logs had sufficiently long wait times to ensure full polarisation of all fluid components.

The well was drilled with an 8.5" bit and was circulated to water base mud with $R_m = 0.89$ ohmm at BHT of 54C prior to running the logs.

Figure 8 shows a standard suite of logs in Well A. At the time when the MRIL was logged, uncertainties existed about the water saturation in this part of the reservoir. Conventional interpretation of the open hole logs indicate a clean sand of high porosity, however, with a water saturation well in excess of 0.6. Nevertheless, dry oil at a rate of 15 m³/day is produced from the 400 m horizontal sidetrack, which

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found better reservoir distributed over the penetrated length.

The standard interpretation of the T2 pass of the MRIL yields the NMR porosity, MPHI, and the volume of bound water, BVI. These results are also shown in Fig. 8. The first, but erroneous, impression would be that they confirm the pessimistic estimation of a low oil saturation. While below the OWC (around X70 m) a low BVI is measured (i.e. good reservoir potential), BVI increases dramatically in the oil zone. The BVI is about 0.6 MPHI, which would mean that the water saturation cannot be less than 0.6. This is in line with the conventional interpretation.

A number of points, however, remained unexplained. Why does this effect coincides with the fluid type, and what mechanism is responsible for binding such huge amounts of water, while not giving any noticeable effect on other lithology logs. Furthermore, no differences were seen in cuttings and sidewall samples from either side of the OWC by inspection under an optical microscope. Finally, while MPHI agrees with the density porosity in the water leg, a small, but consistent discrepancy is seen in the oil leg.

Solid evidence that the NMR interpretation suggested by Fig. 8 was wrong, was found from the NMR response of the crude oil, measured in the laboratory, which showed that the oil relaxation time is very short. As a result, the oil signal is interpreted as bound water, rather than free fluid as is usually the case. This implies that the concept of Free Fluid Index does not work with this kind of crude oil. The suggested agreement between NMR and other logs is thus misleading and purely coincidental.

Crude oil relaxation curve

The transverse relaxation of a sample of Well A crude was measured at 30°C and at the reservoir temperature of 55°C. The T2 spectra are shown in Fig. 3. The temperature effect is pronounced, since the viscosity of the oil changes drastically over this temperature range. It was found that the decay curve can be described excellently by a stretched exponential. At 55°C, the best fit parameters over the range up to 120 ms are $T_{2\alpha,o} = 8.0$ ms and $\alpha = 0.65$.

The T2 spectrum of the oil sample, both at 30°C and at 55°C shows a single distribution, with a considerable width of about a factor of 10 at half-height (corresponding with the low value for α). The width of the spectrum is due to the oil being a

mixture of oil components. For comparison, the T2 spectrum of a water sample, measured under the same conditions, gives a sharp peak.

In the case of Well A and other reservoirs with similar heavy oils, the oil has a T2 values in the order of 10 ms at reservoir conditions. Clearly this is much too small to be interpreted as 'free fluid', and the standard FFI concept is not applicable.

Parameter selection for diffusion processing

The diffusion processing was done on the combination of data with interecho times of 2, 4 and 6 ms. In principle, any set of only two different interecho times would be sufficient, but the best results were obtained by using all available data.

The number of exponentials for the water phase was chosen as $n = 5$, and the oil was described by a stretched exponential. The unknowns to be solved are the non-negative fluid volumes, i.e. five water volumes V_{w1} to V_{w5} and the oil volume, V_{oil} . A non-linear fitting routine without regularisation was used. The diffusion data were acquired in separate passes. The depth match between the two passes was verified by overlaying computed MPHI (using routine T2 processing) of the 2, 4 and 6 ms data individually.

The following parameter values were used:

$T_{2,1}$	3	ms	shortest water T2
$T_{2,2}$	9.5	ms	second water T2
$T_{2,3}$	30	ms	third water T2
$T_{2,4}$	95	ms	fourth water T2
$T_{2,5}$	300	ms	longest water T2
D_w	4.8	$10^{-9}m^2/s$	diffusion coefficient of water
$T_{2,\alpha}$	8.0	ms	stretched T2 of oil
α	0.65		stretch exponent of oil
D_o	0.03	$10^{-9}m^2/s$	diffusion coefficient of oil
G	25	G/cm	magnetic field gradient
Noise	2.5	pu	noise level
DC	0.4	pu	dc offset

The selection of the water T_2 values follows naturally from the available data. Extending the range to below 3 ms is not meaningful at a smallest echo spacing of 2 ms and a signal-to-noise ratio of 10. The longest component, 300 ms, is much longer than the total time interval of the measurement of 100 ms; hence, the split between the fourth and fifth amplitude may not be realistic; their sum, however, is probably more correct. Using more than two exponentials per decade did not make any difference in the calculated porosity and saturation.

The value for D_w was found by the requirement of an average zero oil saturation below the OWC; the value found appears to be in perfect agreement with the literature value, see Fig. 1. The value for D_o was estimated from $T_{2,\alpha}$ through eqs. (4) and (5); as long as its value is much less than that of D_w , its precise value is not important. The values for the stretched exponent of the oil were experimentally determined, as discussed above.

The average noise level of individual echoes amounts to 2.5 pu. This value was based on inspection of the late echoes, and on the mean square error of the fits. To reduce the noise, the data from 15 increments (i.e. over 0.75 m) were stacked. This does not seriously decrease the vertical resolution since the MRIL-B already measures over 1 m.

Comparison with other log and core data

The results of the diffusion processing comprise of five water volume fractions and the oil volume fraction. The results are shown in Fig. 9. In the water leg (X70 - X100 m) most of the fluid is found in V_{w3} and V_{w4} (i.e. T2 = 30 and 95 ms). Very little fluid is found in V_{w5} , i.e. the largest pore size. A small fraction is found in the smallest pores, V_{w1} , while V_{w2} is almost zero. Above the OWC at X70 m, the computed fluid distribution has changed. While V_{w5} and V_{w1} remain unchanged, oil has almost fully replaced the free water in V_{w4} and V_{w3} . Interestingly enough, V_{w2} has increased; this is interpreted to be due to the water layer surrounding the oil in the pores. The effective surface-to-volume ratio of such a water layer is much larger than when the same pore were fully water filled. Consequently, according to eq. (1), the remaining water in the pore will have a shorter relaxation time.

Examples of the observed T2 and T2D decays, stacked over 15 depth increments, at three different depths (water leg, transition zone and oil leg) are shown in Figs. 4-6. The fitted curves are also shown.

The volume fractions V_i can be rearranged into porosity (sum of all fluid fractions) and water saturation (total water volume / porosity), see eq. (8). The results are shown in Fig. 8, and compared with other log and core data.

Porosity

The NMR porosity is compared with the density porosity in Fig. 8, track 6. To eliminate apparent differences due to the larger vertical aperture of the MRIL compared to that of the density log, the

resolution of the density porosity was adapted by filtering it with the MRIL response function (i.e. the result of 1 m aperture and stacking over 0.75 m).

Below the OWC (at around X70 m), and in the top part of the oil leg the agreement between diffusion-NMR and density porosity is perfect. This is in contrast with the standard MPHI (from T2 only) which reads lower in the oil leg as shown in track 3. The reason for this is that part of the oil signal decays too fast to be seen by the tool in T2 mode. In our diffusion processing, however, the known shape of the oil's T2 spectrum is implicitly used, so that the not detected part of the signal is automatically compensated for. The good agreement now found for porosity forms an additional justification of the model used.

The very good match of the NMR porosity is further confirmed by core data, as shown in Fig. 7 in detail. Obviously, the tight streaks show up sharper in the core data as they are represented by just a single plug data point.

Only in the interval just above the OWC, X60-X70 m, the NMR porosity is too low. Since this discrepancy is consistently observed, even if part of the data is not used (see below), it is not likely to be an artefact caused by noise. However, we have not been able to find an unambiguous explanation. It is speculated that the discrepancy is related to an underestimation of the oil saturation in the same interval. If this is the case, although it is not clear why, the automatic porosity correction would indeed be too low.

Saturation

The NMR water saturation is shown in Fig. 8 in track 7. It averages to unity below the OWC; negative values are balanced by small positive values. The unity average has no value in itself because the diffusion constant for water, D_w , was chosen to achieve this. However, the D_w value found, agrees perfectly with the literature value. Furthermore, the water saturation is consistently flat. The scatter is not greater than that from the conventional logs.

Above the OWC the NMR-computed water saturation gradually decreases to around $S_w = 0.4$ near the top at X20 m.

An independent estimate of the oil saturation is given by Dean/Stark extraction of the core, taken in the interval X22-X41 m, shown in Fig. 7.

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Finally, a core analysis study at our laboratory indicated that the grains contain a smectite coating. We examined the electrical behaviour of the rock and found a very peculiar behaviour. In particular, I-Sw measurements at reservoir temperature indicated an exceptionally low saturation exponent of $n=1.0$ (i.e. clay effects are implicitly accounted for; clay corrected $n^*=1.56$). Using $n=1.0$ results in the log derived saturation profile SW1, given in Fig. 8. This saturation profile coincides with the NMR derived saturation over most of the interval, which results in a significant decrease in calculated water saturation, bringing it in line with other evidence such as core saturation data.

Error sources and sensitivity analysis

The results of the computation of water saturation are sensitive to errors (uncertainties) in the input, i.e. in the raw data, in the interpretation model, and in the parameters.

The uncertainty in the raw data includes noise, which has been studied in detail and is understood. It may also include systematic errors, for example due to imperfect pulses and other hardware shortcomings. Such errors are unknown, and it can only be inferred from (growing) experience that they are small.

The model may be wrong. The model has been derived on the basis of the current understanding of the NMR response in a water-wet porous medium in a magnetic gradient field. One assumption is that the rock is water-wet: if this is not true, the model may not hold. However, even if the rock were completely oil-wet, that would not change the diffusive properties of the fluids.

Another potential source of error is the occurrence of internal gradients. At low fields, internal gradients are usually small so that the resultant gradient is dominated by the external one, as is evidenced by finding the correct D_w value in the water leg.

Uncertainties in the parameters were estimated from the experimental data (for example, the noise is estimated from a series of late-echoes, and the uncertainty in this estimate follows from the variation in the estimates). Because of the complicated nature of the model and because of mutual dependency between some parameters, a straightforward error analysis cannot be done. Instead, the sensitivity of the results was evaluated by varying the input parameters one by one to the estimated maximum and minimum values. It was found that imposing an average water saturation of unity below the OWC, implies that most

of the (systematic) errors in the parameters automatically cancel out to a large degree. Obviously, this only holds if the rock properties remain more or less constant across the OWC. Of interest is the low sensitivity to errors in D_o ; from eq. (3) it can be appreciated that the observed oil response is the same for any D_o value less than, say, $0.3 (10^{-9} \text{m}^2/\text{s})$, which is clearly true in the present case.

The most important source of remaining uncertainty is probably the noise level. The total uncertainty in S_w of about 5-7 % is largely due to that in the noise. It is expected that future NMR tools will be able to significantly reduce the noise level.

Processing with only two TE values

As mentioned, data at three different TEs were available and used, but in principle, only two TEs would suffice for diffusion processing. In order to see whether this would be possible, the processing of the Well A data was repeated three times, with each time leaving out one of the TEs. That is, in stead of using the full (2,4,6) combination, we used (2,4), (2,6) and (4,6). The overall agreement for Porosity and S_w remains good, although the noise increases, in particular for the (4,6) combination. This is not surprising, as the number of echoes in the (4,6) set is only 36 compared to 86 in the full set.

Restricted diffusion

As mentioned earlier, molecular diffusion is less efficient if the fluid is contained in small volumes because the molecules cannot move over unlimited distance. The value of the restricted D can be estimated as it depends on τ and on the size and shape of the pores which may be characterised by its surface-to-volume ratio S/V [Hürliemann *et al.*, 1994], or its relaxation time, T_2 , using eq. (1).

The diffusion processing of the log data was done accounting for restricted diffusion. To check on the sensitivity, the processing was also done without this correction. The results appear to be virtually the same. The low sensitivity is due to the fact that the effect of restriction is greatest in the smallest pores. However, fluids in such pores have short T2 due to surface relaxation and are thus hardly influence by diffusion effects. Furthermore, only a small portion of water was found at the shortest T2 value of 3ms anyway.

In the evaluation without accounting for diffusion being restricted, a slightly lower D_w ($4.4 \cdot 10^{-9} \text{m}^2/\text{s}$) is found. Although this is still within the uncertainty

range, the value found when restricted diffusion is used (i.e. $4.8 \cdot 10^{-9}$ m/s² as plotted in Fig. 1) appears to be in better agreement with literature values.

Acknowledgement

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About the Author

Wim Looyestijn received his PhD from the University of Leiden on a subject in solid state physics using NMR techniques. He joined Shell Research in 1979 and has since worked on a variety of petrophysical subjects.

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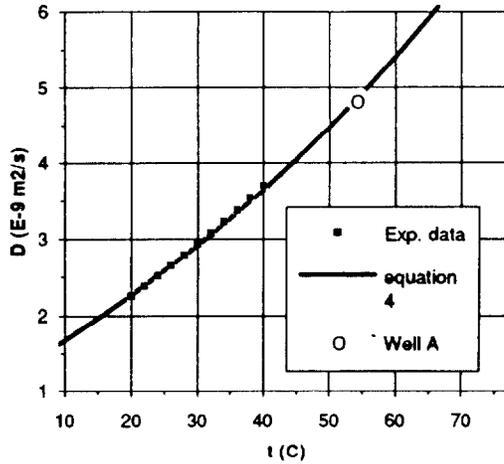


Figure 1. Self diffusion coefficient of bulk water

The experimental data are from [Pruppacher 1971]. The solid curve is the Einstein relationship $D \propto \eta / T$, fitted at 25°C. The D value for water found in the waterleg in Well A is in good agreement.

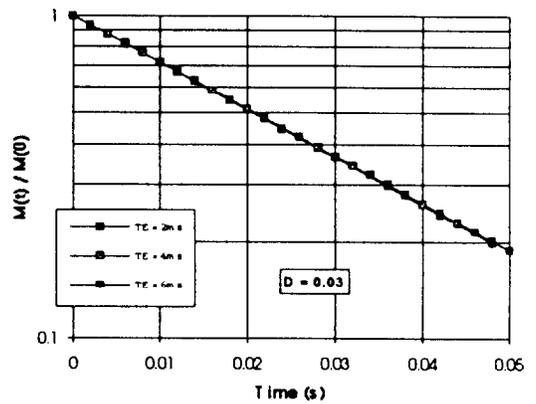
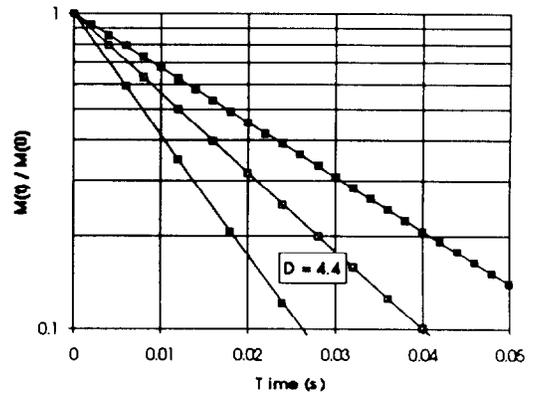


Figure 2. T2 decay of bulk fluid in a gradient magnetic field of 1 MHz

The decay follows a straight line on a logarithmic scale, but its slope also depends on the interecho spacing if the diffusion coefficient is sufficiently large ($D=4.4$ and $0.03 \cdot 10^{-9} \text{m}^2/\text{s}$, respectively). The gradient is 0.024 T/m , as with the MRIL-B.

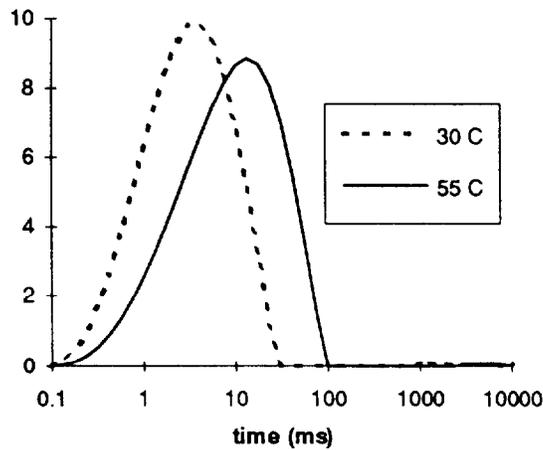


Figure 3. T2 spectrum of well-A crude

The spectrum shifts towards longer T2 values with increasing temperature. The uni-modal T2 spectrum is equivalent to a stretched exponential; the value of the stretch exponent is a measure of its width.

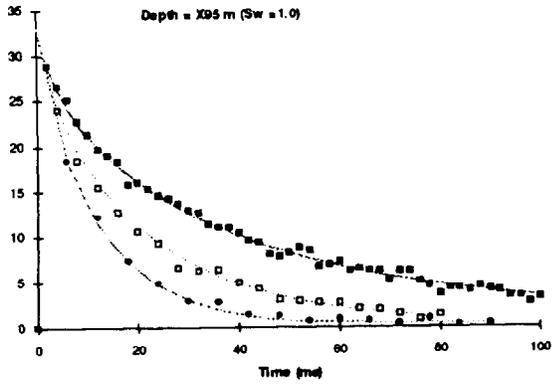


Figure 4. Well A: Echo data and fitted curves.

The data has been averaged over 2.5 m. This example is in the water leg: the separation between the curves is large.

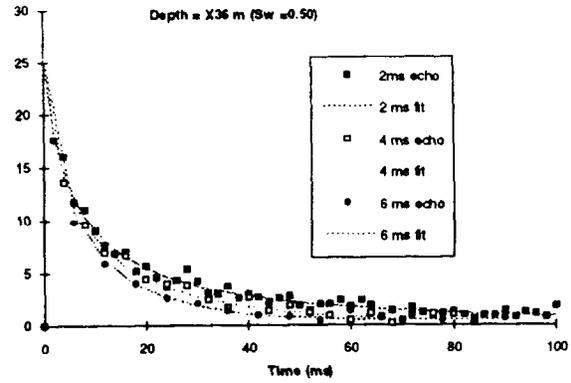


Figure 6. Well A: Echo data and fitted curves.

Same as previous plot. This example is in the oil leg: the separation between the curves is small.

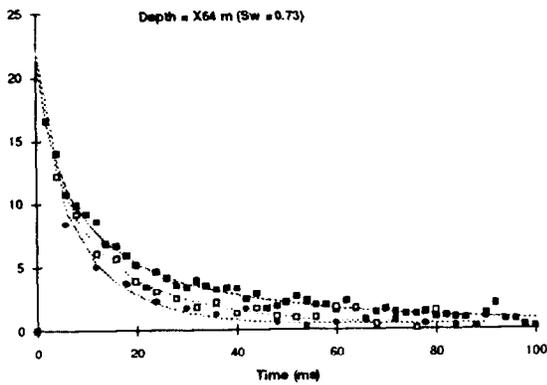


Figure 5. Well A: Echo data and fitted curves.

Same as previous plot. This example is from the transition zone: the separation between the curves is modest.

NMRPOR		NMRSW	
40	0	1.25	0
PORDEN		SW1	
4	0	1.25	0
PORCORE		SQCORE	
40	0	-25	PERC PV 100

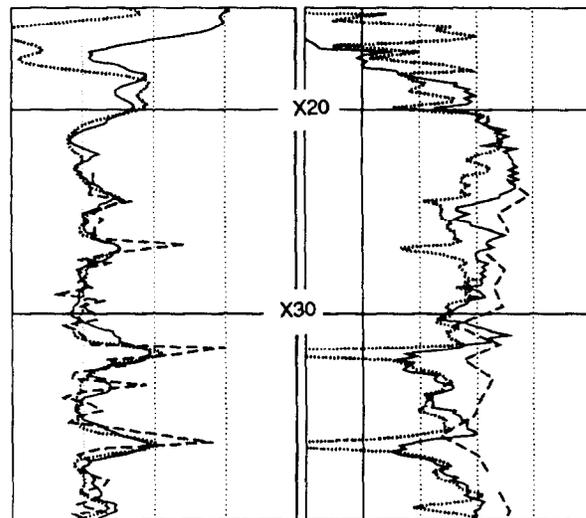


Figure 7. Well A: Comparison with core data.

Cored interval from Figure 8, showing verification against core porosity and saturation.

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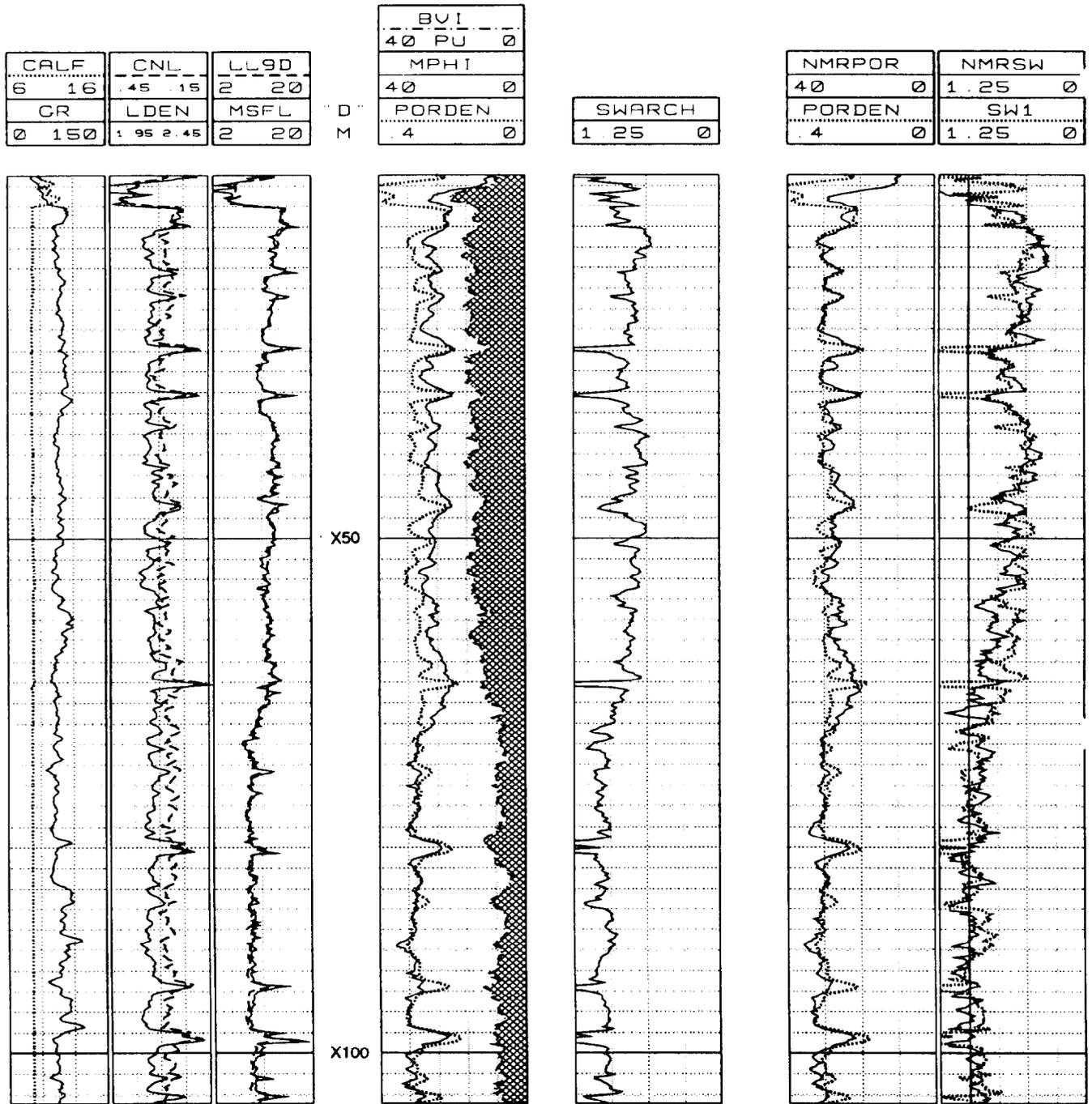
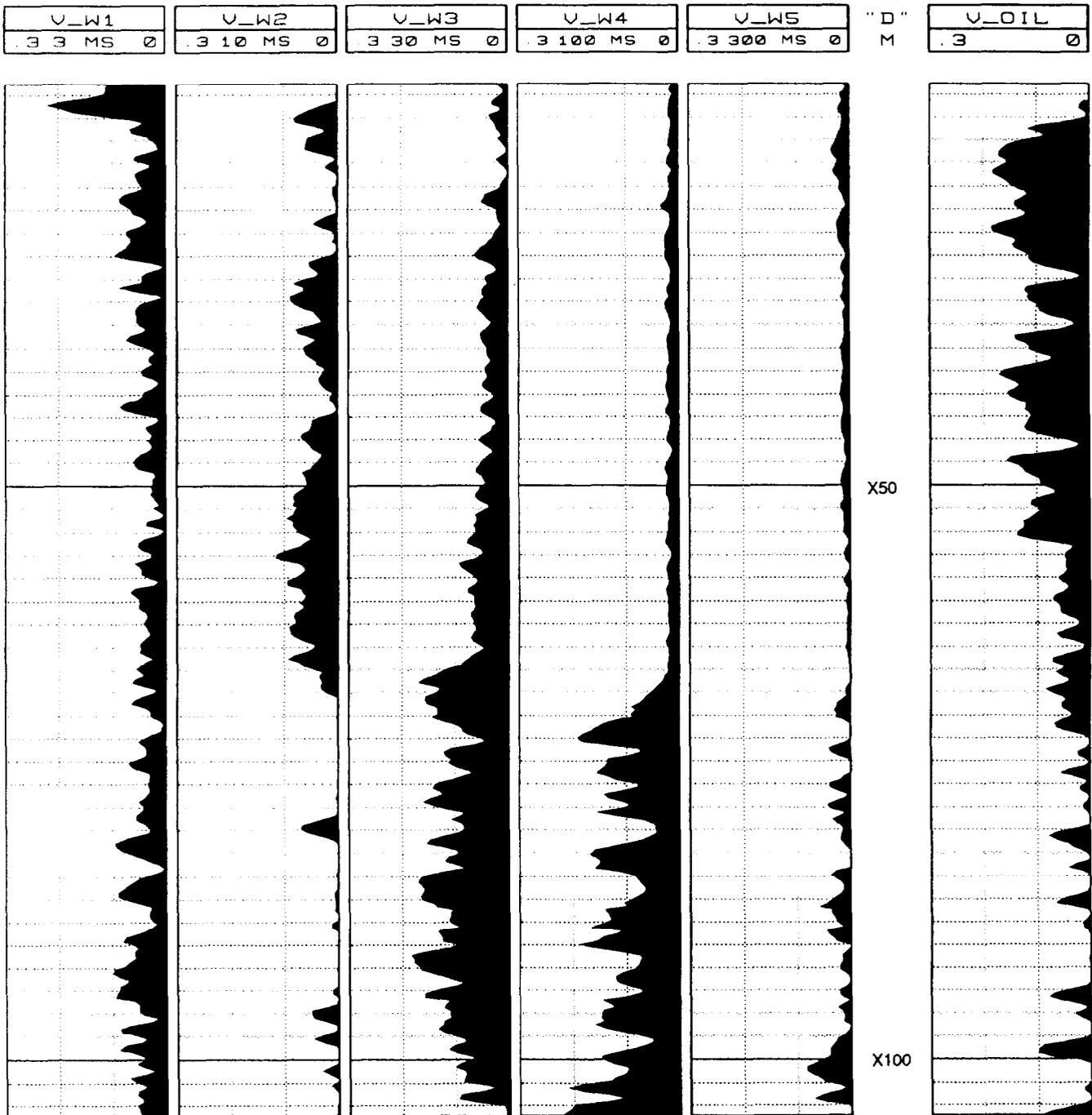


Figure 8. Well A: An evaluation problem solved by diffusion NMR.

The first impression of water saturation (SWARCH) from conventional logs in the oil leg is pessimistic, but seems to be supported by a drastic change in rock quality according to the NMR log. However, since the heavy oil has a NMR signature similar to bound water, rather than to movable water, the FFI concept is not valid here. The diffusion NMR porosity (NMRPOR) is in good agreement with density porosity and core data. The NMR saturation (NMRSW) compares well with core data and is in good agreement with log derived saturation (SW1, using $n=1.0$) which is based on extensive core analysis.



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Figure 9. Well A: Water distribution and oil saturation from diffusion NMR.

Diffusion processing reveals an oil saturation gradually increasing to some 60% at the top of the interval, at the expense of free water (V_W3 and V_W4) that is seen below the OWC. The increase in the T2=10 ms range (V_W2) is at result of water in edges of pores that behave like small pores if the remainder is occupied by oil.