

# Practical Approach to Derive Wettability Index by NMR in Core Analysis Experiments

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## ABSTRACT

Wettability is a crucial factor for the dynamic properties of oil reservoirs. Early recognition of the wettability condition of a recovery may have a significant impact on the development options and of the expected recovery factor. NMR relaxation times of pore fluids are dependent on the wetting through surface relaxation, and are thus known to contain this valuable information.

This paper describes an easy-to-implement and reliable procedure to calculate a quantitative wettability index from standard NMR measurements, such as can be made in conjunction with SCAL experiments. The interpretation is fully auditable, and therefore suitable to be part of a standard protocol.

## WETTABILITY TYPES

If the rock is neither fully water-wet nor oil-wet, many types of wettability have been defined (Anderson, 1986). Most models assume the wetting of a certain pore to deviate from water-wet only if it has seen oil. Other than this, there is no direct correlation between saturation and wetting. However, certain minerals and solid hydrocarbon (bitumen, kerogen) always tend to be oil-wet.

In a water-wet rock, the oil has no contact with the surface, and thus does not experience additional surface relaxation, i.e., it relaxes at its bulk relaxation time. If, however, the rock is not completely water-wet, also the oil will undergo surface relaxation. This feature has been recognized by many authors (e.g., Brown and Fatt, 1956; Howard, 1998; Fleury and Deflandre, 2003). The strength of this effect depends on the fraction of the surface that is wet by oil. This feature has been used (Looyestijn and Hofman, 2006) to define a quantitative wettability index, *NWI*, as:

$$NWI = \frac{\text{Surface wetted by water} - \text{Surface wetted by oil}}{\text{Total Surface}} \quad (1)$$

To conform to existing indices (Amott, 1959; Donaldson et al., 1969), *NWI* scales from +1 for fully water-wet, through 0 for neutral, to -1 for fully oil-wet. The *NWI* NMR index will be consistent numerically with other indices at the endpoints. At intermediate values, it is not expected that all of these indices are consistent because the details

of the spatial variation are neglected. Yet each index has its own mechanism for sampling the internal spatial surface variations to arrive at an overall wettability assessment (e.g., Dixit et al., 1998). Hence, the NMR index, *NWI*, is not necessarily quantitatively equal to either the traditional Amott/Harvey or USBM indices. A single index is not a complete and sufficient characterization of the internal pore surfaces; nevertheless, the NMR index is a stable, reproducible, accessible and important first assessment of the pore-surface states and of the dynamic behavior of fluids in the rock.

The NMR method, described here, has the advantage that it is relatively inexpensive and fast, and can be done in conjunction with other SCAL experiments as it is noninvasive. It can even be done during a prolonged series of experiment, e.g., to monitor possible changes in wettability (Looyestijn et al., 2017). The interpretation is straightforward and does not involve human judgement, and is thus fully auditable.

## RELAXATION TIME DISTRIBUTION IN POROUS MEDIA

This paper is written for the transverse relaxation time,  $T_2$ , of the hydrogen nuclear spin, since that is the routine laboratory measurement. However, the same formulas hold for the longitudinal relaxation,  $T_1$ .

A simple bulk fluid, such as water, exhibits a single exponential decay  $\exp(-t/T_2)$ ; when the fluid is contained in a pore, the pore surface provides an additional relaxation mechanism. In a homogeneous magnetic field, as used in

standard NMR core analysis, the observed relaxation time becomes:

$$\frac{1}{T_2} = \frac{1}{T_{2,bulk,w}} + \rho_w \frac{A}{V}, \quad (2)$$

where  $T_2$  is the observed relaxation time,  $T_{2,bulk,w}$  is the relaxation time of bulk water,  $\rho_w$  is surface relaxivity,  $A$  is surface area of the pore, and  $V$  is volume of the pore.

The  $V/A$  ratio can be viewed as a measure of the pore size. Because normally  $T_{2,bulk,w}$  is large,  $T_2$  is directly proportional to the pore size. This feature is the main reason for the popularity of NMR as a petrophysical measurement.

Porous rocks usually exhibit a large variation of pore sizes. Consequently, the NMR response of completely water-filled rock will be the summed responses from all individual pores, and the decay may be written as a multiexponential of the form:

$$M(t) = \phi \sum_{i=1}^n M_i e^{-t/T_{2,i}}, \quad (3)$$

where  $M(t)$  is echo amplitude at time  $t$ ,  $M_i$  is the pore volume fraction associated with the  $i^{\text{th}}$  component, with  $\sum M_i = \phi$ ,  $\phi$  is the total porosity, and  $T_{2,i}$  is the  $i^{\text{th}}$  relaxation time.

The set of  $M_i$  values is usually referred to as the  $T_2$  distribution or  $T_2$  spectrum, and is commonly obtained by a stabilized inversion of the observed decay  $M(t)$ , with  $T_{2,i}$  evenly spaced on a logarithmic scale.

## PORES WITH WETTING AND NONWETTING FLUIDS

The above description can now be modified for the situation of two fluids. First consider a rock with a unimodal pore system containing water and oil. For the relaxation of these fluids one can write:

$$\frac{1}{T_{2,w}} = \frac{1}{T_{2,bulk,w}} + \rho_w \frac{(1-f)A}{VS_w}, \quad (4)$$

$$\frac{1}{T_{2,o}} = \frac{1}{T_{2,bulk,o}} + \rho_o \frac{fA}{V(1-S_w)}, \quad (5)$$

where the suffixes  $w$  and  $o$  refer to water and oil, respectively, and  $f$  denoting the fraction of oil-wet pore surface. Consequently,  $(1-f)A$  and  $fA$  are the surface areas wetted by water and by oil, respectively.  $S_w$  is the water saturation in the pore in question. Notice that in the water-wet case,  $f=0$ , the water relaxation is not the same as it would be in the  $S_w = 1$  case, because the water volume is smaller due to the

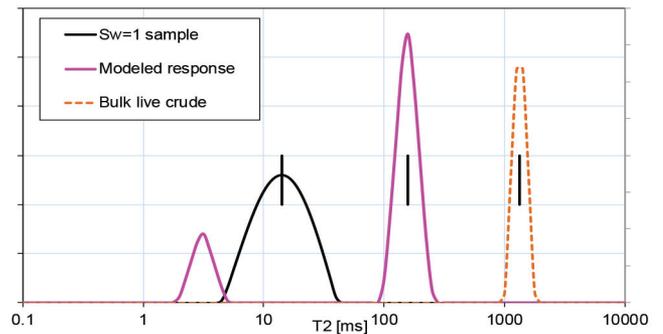
presence of oil. This causes an amplitude increase at lower  $T_2$  with increasing desaturation; this phenomenon is commonly observed. With increasing oil-wetness,  $f > 0$ , the opposite effect occurs and the water relaxation time increases.

The description is extended to a distribution of pore sizes in the same manner as is done in Eq. 3 above. Predicting the observed NMR response thus becomes a complicated matter. One needs to know the saturation in each pore size, as well as the oil-wet fraction of its surface, and then to compute the resulting  $T_2$  distribution of the water fraction, and that of the oil fraction. Standard  $T_2$  acquisitions cannot distinguish water from oil, and thus measure the sum of the water and (often overlapping) oil responses. A further complication is that crude oils are composed of a wide range of components, and consequently, show a wide distribution in bulk  $T_2$  values. The complete physical characterization of the NMR tool response has been covered in an earlier publication (Looyestijn and Hofman, 2006).

## SIMPLIFIED APPROACH FOR WETTABILITY INTERPRETATION

The full physical model is cumbersome and difficult to implement as a standard petroleum industry workflow. Routine laboratory analyses require a standard interpretation that can be audited and does not require human judgement. It appears that an approximate and easy-to-implement approach exists that fulfills this requirement for most water-wet to moderately oil-wet cases.

First consider the simplest case where the rock has a unimodal pore size, combined with a mineral oil, such as decane. All components are now represented by single peaks in the  $T_2$  distribution. For fully water-wet, the oil peak would be at its bulk value, but with increasing oil-wetting, it moves to shorter  $T_2$ . Figures 1 and 2 show two simulated responses for  $S_w = 0.15$ , with  $NWI = 0.5$  and  $NWI = 0.0$ , respectively. Notice that the remaining water (the small peak at short  $T_2$ ) not only has a reduced amplitude, but is also shifted to shorter  $T_2$  by a factor  $1/S_w$ , as given by Eq. 4.



**Fig. 1**—Simulated response for chalk/decane;  $S_w = 0.15$ ,  $NWI = 0.5$ . Bulk water is near the same  $T_2$  as decane. The small peak at short  $T_2$  is water at  $S_w = 0.15$ .

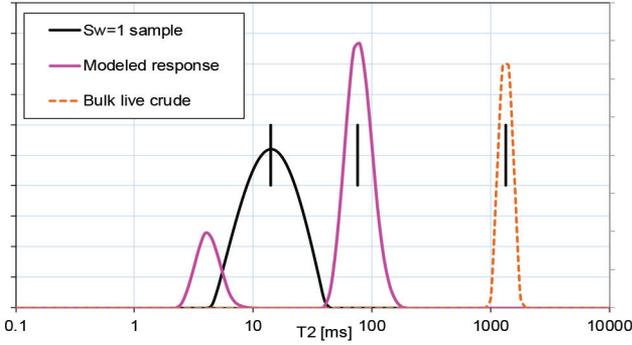


Fig. 2—Simulated response for chalk/decane;  $S_w = 0.15$ ,  $NWI = 0.0$ .

The wettability index can now be found by evaluating the shift of the oil peak. Combining Eqs. 2 and 5 yields an expression for  $f$ :

$$f = \frac{S_o}{\alpha} \left[ \frac{\left( \frac{1}{T_{2,o}} - \frac{1}{T_{2,bulk,o}} \right)}{\left( \frac{1}{T_2} - \frac{1}{T_{2,bulk,w}} \right)} \right], \quad (6)$$

where  $\alpha = \rho_o/\rho_w$  is the ratio of the surface relaxivity to oil and that to water. Notice that no explicit value is required for the surface relaxivity, nor of  $A/V$ .

According to Eq. 1, the NMR wettability index,  $NWI$ , is defined as:

$$NWI = 1 - 2f. \quad (7)$$

To evaluate Eq. 6, four  $T_2$  values are required from four separate experiments. These are (1) the mean value of the oil peak ( $T_{2,o}$ ) from the NMR response of the partially saturated sample, (2) that of the bulk oil ( $T_{2,bulk,o}$ ), (3) the  $T_2$  of the sample at  $S_w = 1$  ( $T_2$ ), and (4) that of the bulk water ( $T_{2,bulk,w}$ ). The oil saturation,  $S_o$ , is usually known, but can be computed from the integrated magnitude of the oil peak.

The value of  $\alpha$  may be found from Eq. 6 when the sample is completely filled with oil; in that case,  $f = 1$  and  $S_o = 1$ , and  $\alpha$  is the only unknown parameter. An example is shown in Fig. 3; when the sample is fully saturated with decane, the response has the same shape as with water, and the shift in  $T_2$  is due to the ratio of the surface relativities. By definition, this ratio is  $\alpha = \rho_o/\rho_w$ .

With actual crude oil, the response gets more complicated. To do this experiment properly, the sample needs to be completely dry; particularly for minerals that tend to be more water-wet, this is difficult to achieve. As a result, the  $f = 1$  condition may not be reached, and too low

values for  $\alpha$  may be found. As a rule,  $\alpha = 0.3$  may be adopted as the default.

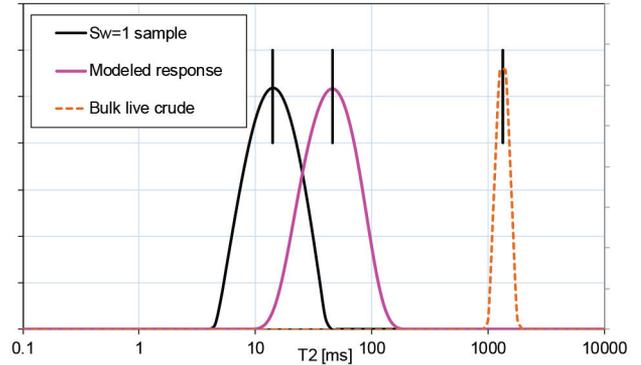


Fig. 3—Simulated response for  $S_w = 0$ ,  $S_o = 1$ .

### EXTENSION TO WIDE $T_2$ DISTRIBUTIONS

When dealing with real reservoir rocks and real reservoir crudes, which are multicomponent mixtures of hydrocarbons, the resulting NMR response often shows overlapping contributions from water and oil. Standard NMR acquisitions cannot discriminate between water and oil, and only the total response is obtained. Initially, attempts were made to approximate the response by its logarithmic mean,  $\log(T_{2m}) = S_w \cdot \log(T_{2,w}) + S_o \cdot \log(T_{2,o})$ . However, this failed because of the complicated behavior of the water response as function of  $S_w$  and  $f$ .

However, a much simpler solution proved to work very well. Instead of looking at the logarithmic mean of the  $T_2$  distributions, the  $T_2$  of the highest peak appears to be representative of the wetting effects. Most rock samples, in particular those that are used for SCAL experiments, have an asymmetric shape, with a dominant pore size, usually at the longer  $T_2$  range. Similarly, crude oils have a similar shape. The resulting  $T_2$  distribution, at any saturation and wettability, also shows a dominant peak. The  $T_2$  values of these peaks, of the rock at  $S_w = 1$ , of the crude, and of the rock at experimental condition, can easily be determined. As will be demonstrated below, when inserted in Eq. 7 a good approximation of the wettability index is obtained.

### VERIFICATION

The method was first verified by running a large number of simulations. The full model (Looyestijn and Hofman, 2006) was used to generate the NMR response on a series of actual rocks as a function of saturation and wettability. The rocks were chalk (Fig. 1), limestone (Fig. 4) and sandstone

samples (Fig. 5). The  $T_2$  distribution of the water-filled chalk pores are a narrow unimodal distribution. Limestone samples often show a narrow distribution, but to make the exercise more challenging, a sample was included with a broader pore distribution. Also, the sandstone samples include nontrivial cases with significant portions of smaller pores.

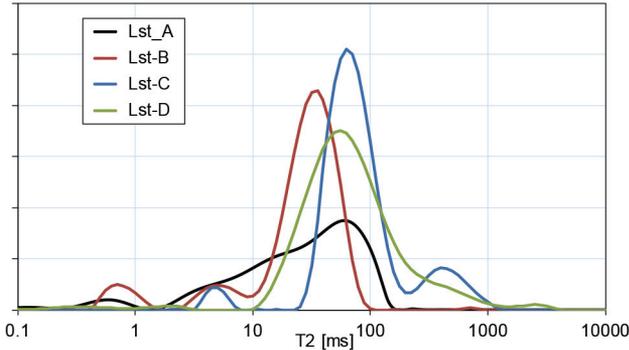


Fig. 4—Four limestone samples at  $S_w = 1$ .

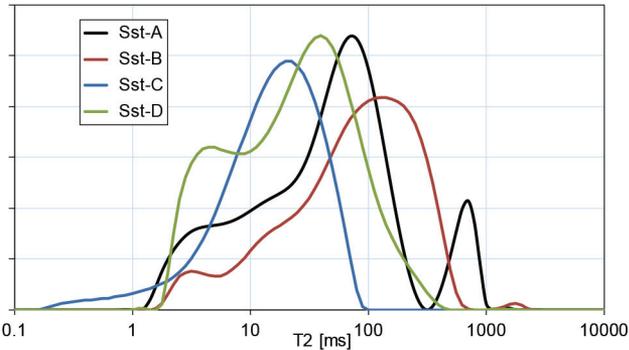


Fig. 5—Four sandstone samples at  $S_w = 1$ .

The oils comprised mineral oils, such as decane and isopar, and actual dead crudes. Some examples are shown in Fig. 6. The decane response is very sharp (for the display plotted at a reduced amplitude). The two crude oils show a more or less triangular shape which is typical for dead crudes. The viscosity of Crude A is roughly 13 times greater than the viscosity of Crude B.

A few examples of the simulated response are shown in Figs. 7 to 9. The location of the peaks is indicated by the vertical lines. The peak location is defined by the highest value; for asymmetrical peaks it is thus not centralized. Finding the peak value can easily be automated. At high  $S_w$ , the water peak may be the larger one, and care must be taken to select the oil peak; this is the only human judgement required for the interpretation.

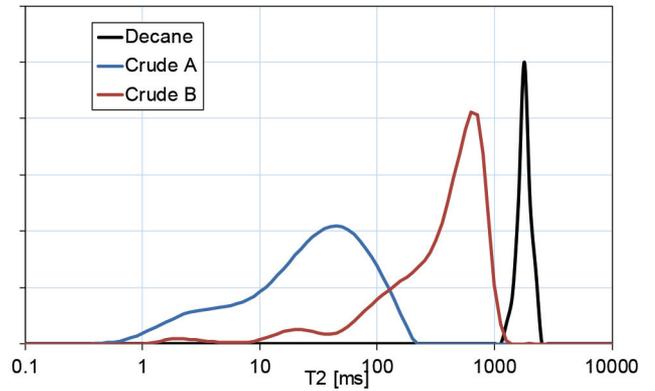


Fig. 6—Decane and two dead crudes.

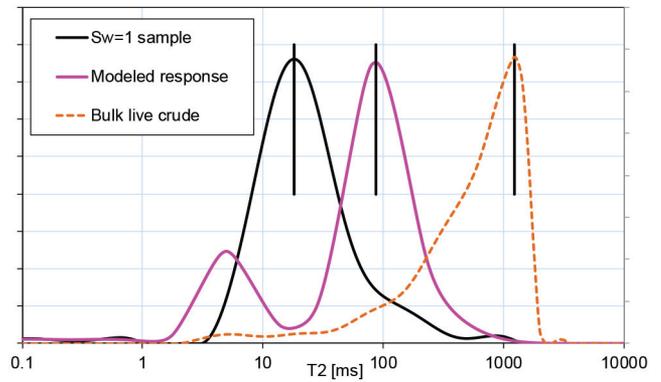


Fig. 7—Simulated response for Lst-D and crude at  $S_w = 0.2$  and  $NWI = -0.1$ ; computed from peaks  $NWI = -0.1$ .

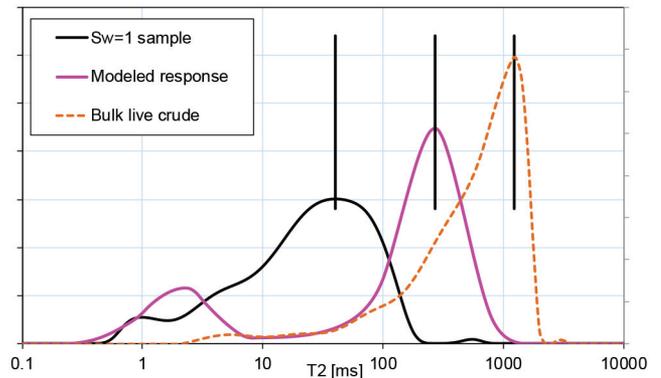


Fig. 8—Simulated response for Sst-B and crude at  $S_w = 0.2$  and  $NWI = 0.4$ ; computed from peaks  $NWI = 0.4$ .

Notice the change in the water response at short  $T_2$ ; this is the same effect as discussed before. As long as the water and oil responses do not strongly overlap, the peak  $NWI$  agrees fairly well with the value imposed in the forward model.

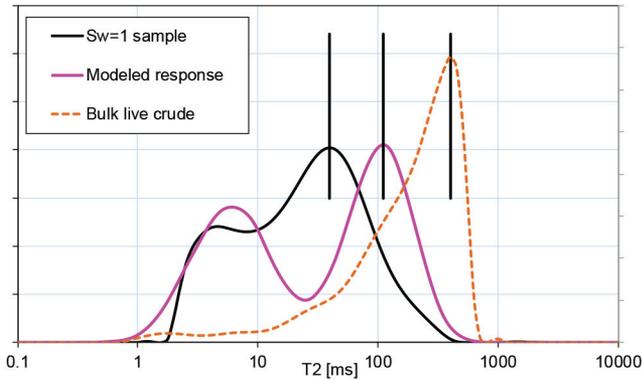


Fig. 9—Simulated response for Sst-D and crude at  $S_w = 0.4$  and  $NWI = 0.2$ ; computed from peaks  $NWI = -0.05$ .

The example in Fig. 9 poses an extreme case: high  $S_w$  and more viscous crude. The overall wettability (0.2) is not evenly distributed over the sample: the large portion of small pores is water-filled, and therefore water-wet. The larger pores are thus more oil-wet than the overall index suggests. The peak  $NWI$  may be more representative.

The result of all simulations is displayed in Figs. 10 to 12 for the three rock types. It can be observed that the approximate peak method agrees almost perfectly for the simple case of chalk with decane. Also, for the more complicated cases, the peak model corresponds fairly well with the actual  $NWI$  used in the full model for positive  $NWI$ ; at more negative  $NWI$  (i.e., more oil-wet), however, the peak method tends to overestimate the oil-wetness. Nevertheless, it still gives a reasonable indication, and the differences are not larger than between various other wettability indices.

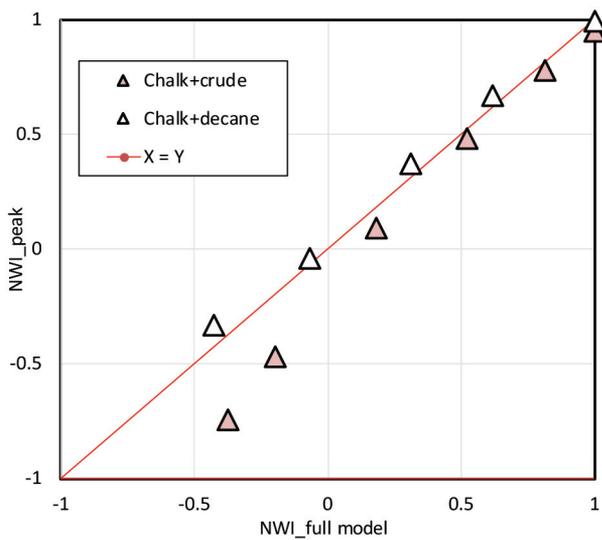


Fig. 10—Verification on simulated response for chalk.

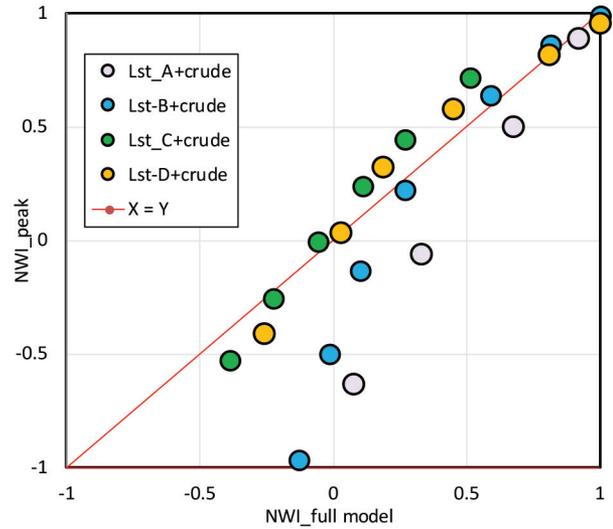


Fig. 11—Verification on simulated response for limestone.

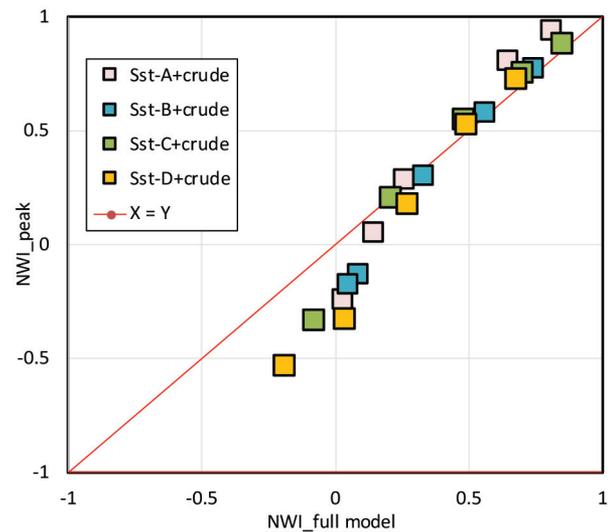


Fig. 12—Verification on simulated response for sandstone.

It is worth reminding that the NMR index requires only a single, standard  $T_2$  measurement. If made at subsequent times, e.g., to monitor any changes in wettability over time, such changes will be reflected in the computed  $NWI$ , whether this is obtained from the full model or from the peak model.

Finally, the peak method was verified against the full model for a series of actual experiments. Here, the full model was used to obtain the  $NWI$  value by careful modeling the response until full agreement was reached between the simulated and the actual response (Looyestijn and Hofman, 2006). As can be seen in Fig. 13, the peak method yields approximately the same  $NWI$  values, even for the few more oil-wet samples. The previous paper includes the verification of  $NWI$  against USBM for some of these samples.

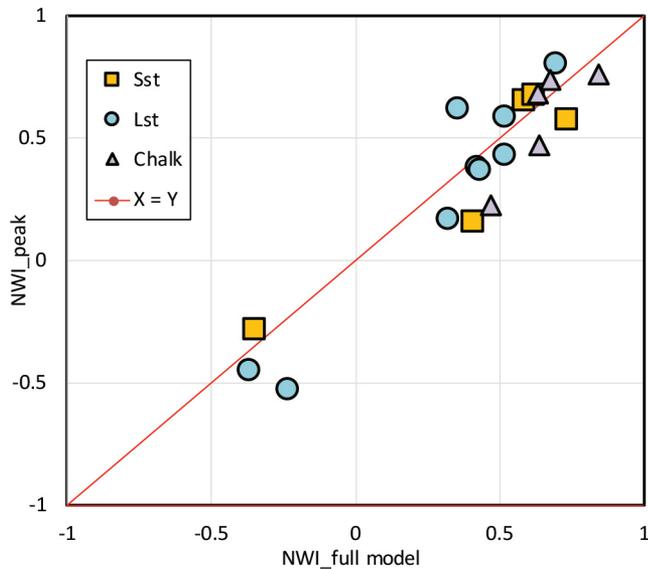


Fig. 13—Verification on actual experiments.

### SENSITIVITY AND LIMITATIONS

Because of the large variability in  $T_2$  distributions of real reservoir rocks and crudes, it is not possible to give precise rules for when the peak method is reliable or not. A few general observations can be given. It will be obvious that the best results are obtained when the peaks are far apart, i.e., rocks with small pores, and low-viscosity oil. Oil-wetness is often suspected in cases of more viscous crudes; since the surface relaxivity is additional in  $1/T_2$ , the wettability effect is too small to be observed in practice for such oils because their  $T_2$  is already small. Obviously, when the peaks are very close, no interpretation is possible, even not by the full model. Furthermore, the simulations show that the differences between the peak model and the full model increase with wider distributions, but never result in a completely false answer. The limitations and sensitivities that were discussed for the full model apply equally to the peak method.

### APPLICATION TO NMR LOGS

The method may be adopted to evaluate wettability from NMR logs. The additional complications with respect to core measurements are discussed in a previous publication (Looyestijn, 2008). The largest complication is that the  $T_2$  distribution of the rock at  $S_w = 1$  is not known. Experience has shown that this may often be approximated by the method described in Volokitin et al. (2001) that provides an attempt to correct the log for (remaining) hydrocarbon effects.

### EXPERIMENTAL PROTOCOL

For experiments on fresh or restored-state core samples the recommended procedure is:

- Measure  $T_2$  distribution of the cleaned, water-saturated sample.
- Measure  $T_2$  distribution of the bulk brine.
- Prepare the sample for the desired experimental condition. Measure its  $T_2$  distribution.
- Measure  $T_2$  distribution of the oil. In case the sample was aged, take an oil sample from the aging jar as this is the nearest to the oil in the sample. If the crude oil has been replaced by mineral oil, the latter is then the bulk oil.

For experiments on preserved core:

- Slowly flood the sample with crude to remove gas that was liberated during core tripping. Collect a few milliliters of the final effluent for the bulk oil  $T_2$  measurement.
- At the end of the experimental program, clean the sample and saturate with brine.
- Measure  $T_2$  distribution of sample and fluids.

Make sure that all NMR measurements are done at the same temperature because the bulk relaxation of oil is inversely proportional to its viscosity.

Obtain the  $T_2$  value at the peak of each  $T_2$  distribution, and enter the four required values in Eq. 6 with  $\alpha = 0.3$ . Compute  $NWI$  using Eq. 7.

Note that the usual requirement of a low noise level (e.g.,  $S/N > 200$ ) is necessary to avoid errors in the very short  $T_2$  range, as it is covered by only a few echoes. The peaks occur in the mid- to long- $T_2$  range. Here, many echoes measure the decay, and the  $S/N$  requirement may be relaxed, reducing measurement time. More efficiency can be obtained by using a larger interecho time as this allows a much wider window to sample the echoes, and thus more signal.

### CONCLUSIONS

- A reliable rock wettability index can be derived from NMR experiments using a peak-analysis approach.
- A recommended procedure for core experiments on restored or preserved state is given.
- The interpretation method is simple to implement and fully auditable, and thus acceptable as a standard protocol.
- The required NMR measurement is a standard  $T_2$  measurement available from most laboratories; this

is a relatively inexpensive measurement and can be made at any desired point during SCAL experiments to obtain the momentarily wettability state.

- Interpretation of wettability from NMR is restricted to cases where the bulk oil has a longer relaxation time than the water-saturated rock.
- The obtained wettability index is reliable in the range of water-wet to intermediate wet rocks. It deviates numerically from interpretation by full modeling in the more oil-wet range.
- Application of this method to NMR logs is, in principle, possible.

### NOMENCLATURE

$A$	=	surface area of the pore
$NWI$	=	NMR Wettability Index, scale $[-1,+1]$
$f$	=	surface fraction wetted by oil
$S_w$	=	water saturation
$T_2$	=	observed relaxation time
$T_{2,bulk,w}$	=	relaxation time of bulk water
$T_{2,o}$	=	relaxation time of oil in sample
$T_{2,w}$	=	relaxation time of water in sample
$V$	=	volume of the pore
$\alpha$	=	ratio $\rho_o/\rho_w$
$\rho_o$	=	surface relaxivity of oil
$\rho_w$	=	surface relaxivity of water

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### ABOUT THE AUTHOR



**Wim Looyestijn** is currently a consultant on NMR interpretation. Before this he worked as a principal research petrophysicist at Shell International E&P in Rijswijk, The Netherlands. He joined Shell in 1979 to work in petrophysical research on a variety of subjects ranging from core analysis to interpretation of well-logging tools, with a strong focus on NMR log interpretation. He is a Technical Editor for SPE and SPWLA. He holds MSc and PhD degrees in physics from Leiden University, The Netherlands.