PETROPHYSICS, VOL. 45, NO. 3 (MAY-JUNE 2004); P. 241–250; 11 FIGURES

Fluid Characterization using Nuclear Magnetic Resonance Logging

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ABSTRACT

This paper presents a variety of field applications that illustrate recent advances in nuclear magnetic resonance (NMR) logging fluid characterization methods. The main concepts of NMR logging and the principles underlying NMR diffusion measurements, which form the basis for all standalone NMR fluid characterization methods, are briefly reviewed. Field examples of the MRF[2] Magnetic Resonance Fluid characterization method are presented to demonstrate the separation of oil and water signals, saturation measurements, and oil-viscosity determination. The MRF method is also applied in conjunction with new diffusion NMR techniques to infer wettability states in a suite of partially saturated core samples. The application of two-dimensional NMR maps of relaxation times and molecular-diffusion rates to identify fluids and determine their properties in complex multi-fluid environments, including oil-base mud (OBM) filtrate, light oil, and gas is illustrated with field examples from the deepwater Gulf of Mexico and the North Sea.

INTRODUCTION

The introduction of pulsed NMR logging tools in the early 1990s has provided the oil and gas industry with powerful new methods for evaluating petroleum reservoirs. The initial applications of pulsed NMR logging tools were aimed at providing important rock-quality properties such as (1) lithology-independent total porosity, (2) free- and bound-fluid porosity, and (3) permeability.

Akkurt et al. (1996) showed that NMR diffusion measurements could be used to quantify gas saturations in the near-wellbore region investigated by NMR logging tools. This paper stimulated much interest in NMR diffusion-based fluid-characterization methods and led to the publication of numerous papers on the subject. Many of the early methods relied on overly simplistic assumptions that limited their reliability and range of application. Those methods have since been replaced by more robust techniques (Slijkerman et al., 1999; Freedman et al., 2001) that incorporate realistic models for NMR responses of formation fluids.

Advanced NMR fluid characterization methods that provide fluid typing (oil, gas, and brine), flushed-zone saturations, and oil viscosities in addition to the rock quality answers mentioned above are presented in this paper. The application of NMR to infer the wettability state of oil reservoirs (Freedman et al., 2003) is also presented.

Brief description of NMR measurement principles

This section provides a brief discussion of the basic measurement used by NMR well-logging tools for the benefit of those readers who may not be familiar with NMR logging technology. Those who desire more details are referred to the extensive published literature on NMR well-logging tools and to textbooks on NMR well-logging methods and principles (e.g., Allen et al., 1997; Coates et al., 1999).

To observe an NMR signal, the first step is to magnetize the formation fluids by application of a static magnetic field. NMR logging tools are equipped with powerful permanent magnets that create magnetic fields in the rock for-

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mations surrounding the borehole. The hydrogen nuclei contained in the oil, gas, and brine filling the rock pore spaces behave like microscopic magnets. The magnetic moments of the hydrogen nuclei align along the direction of the applied magnetic field thus creating a net magnetization or polarization in the formation. The time required to align the hydrogen nuclei along the direction of the applied magnetic field, referred to as the longitudinal direction, is characterized by a *longitudinal relaxation time* denoted by T_1. In practice, a distribution of T_1s is required to describe the magnetization process. The distributions reflect the complex composition of crude oils and the distribution of pore sizes in sedimentary rocks. For bulk crude oils, the logarithmic mean of the T_1 distribution is inversely proportional to the viscosity and can vary from a few milliseconds or less for heavy oils to several seconds for low-viscosity oils. In reservoir rocks, T_1's of non-wetting phase fluids are equal to their bulk fluid values. For the wetting phase, T_1 of the fluid can be shortened by interactions of the fluid molecules with the pore surfaces. For water-saturated rocks, the surface interaction is usually dominant and provides a mechanism for estimating pore-size distributions from T_1 distributions (Allen et al., 1997).

The time that the hydrogen nuclei are exposed to the static magnetic field is referred to as the polarization time or wait time. Prior to the wait time, the hydrogen nuclei are randomly oriented and there is zero net magnetization in the formation. During the wait time, the nuclear magnetization grows exponentially towards its equilibrium value (M_o). The porosity and the types and volumes of fluids determine

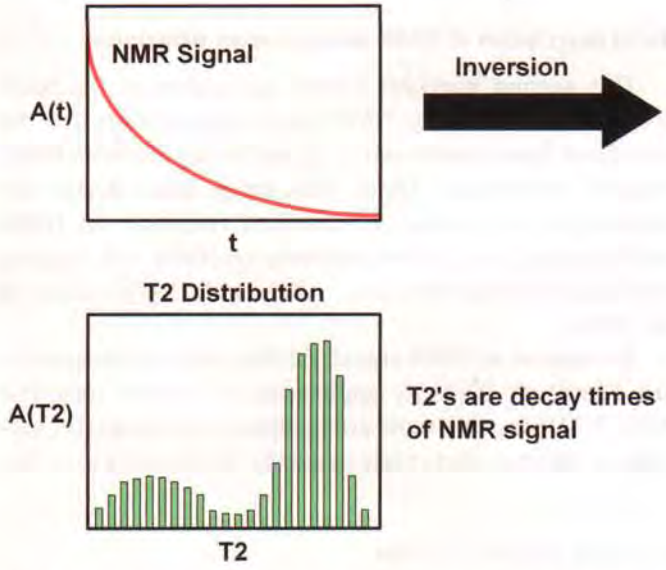

FIG. 1 Plot showing how a time-domain NMR signal is transformed into a T_2 distribution by inversion.

M_o. A wait time equal to three times the longest T_1 produces a magnetization equal to 95% of M_o. If too short a wait time is used, NMR total porosities will underestimate true formation porosities. Long wait times, and therefore, reduced logging speeds are required in formations containing low-viscosity oil or gas (i.e., fluids with long T_1's).

Following the polarization time, a train of radio-frequency (RF) pulses is applied. Between the RF pulses, the NMR signal is recorded using the same antenna used to transmit the pulses. The NMR signal observed between each pair of consecutive pulses is often called an *echo* because it builds up to a maximum at the midpoint between the pulses and then decays before the next pulse. In a typical NMR measurement several thousand echoes are acquired over a period of about a second. The echo amplitudes are proportional to the net magnetization in the transverse plane (transverse to the static magnetic field), which decays during the course of the measurement. It is the rate of decay of transverse magnetization that provides useful information concerning the fluids and their environment.

T_2 Distributions

The rate of decay of the NMR signal can be described by a distribution of decay times, T_2s, which are called *transverse relaxation times*. It is customary to fit the measured NMR signals to a sum of about 30 decaying single-exponential signals each with amplitude, $A(T_2)$, and associated decay time T_2. The fitting procedure is achieved by a mathematical technique known as inversion. The amplitudes $A(T_2)$ are outputs of the inversion procedure. A semilog plot of $A(T_2)$ versus T_2 is known as a T_2 distribution. Figure 1 illustrates how an exponentially decaying NMR signal is transformed into a T_2 distribution by the inversion process. T_2 distributions provide much useful information. The area under the T_2 distribution is proportional to the total porosity. In water-saturated rocks the T_2 distributions also can be qualitatively related to pore-size distributions (Coates et al., 1999). By defining appropriate T_2 cut-offs, the T_2 distribution can be partitioned into bound water and free water. Figure 2 shows a schematic of a typical T_2 distribution in a water-saturated rock. The T_2s can span several decades from less than one to several thousand milliseconds. The wide range of decay times in sedimentary rocks is caused by broad distributions of pore sizes.

For bulk crude oils, the T_2 distribution reflects the molecular composition of the oil. That is, each T_2 in the distribution is inversely proportional to a *microscopic constituent viscosity* of a particular constituent molecule (Freedman et al., 2001). The longer T_2s in a crude oil T_2 distribution correspond to signals from mobile molecules, whereas the short T_2s are associated with signals from larger molecules.

As discussed below, measured macroscopic oil viscosities can be computed from the logarithmic mean of crude oil T_2 distributions using empirically determined correlations. Figure 3 shows a schematic plot of a typical T_2 distribution for a bulk crude oil. Note that there is a single peak with a tail that extends toward short decay times. For intermediate- and high-viscosity crude oils the T_2 distributions of the bulk oils can span several decades in T_2 ranging from less than one to hundreds of milliseconds. The wide range of decay times is caused by the broad distribution of molecules with different sizes in the crude oil. Low viscosity oils with viscosities of a few centipoise or less have narrow distributions of decay times and do not exhibit the short relaxation time tail shown in Figure 3. In partially saturated rocks the brine and oil T_2 distributions typically overlap. This means that measured T_2 distributions cannot always be used to distinguish oil from brine signals. The same is also true for T_1 distributions. Fortunately, the molecular diffusion coefficients of oil and brine often differ significantly and this difference can be used to separate the NMR signals for the two fluids.

Differentiation of oil, gas, and brine using contrasts in molecular diffusion

Before concluding this introduction, it is instructive to discuss the attenuation of NMR signals caused by the molecular diffusion of oil, gas, and brine molecules. This effect is the physical mechanism that underlies all *standalone* NMR fluid-characterization methods. Molecular diffusion is the random thermal motion of molecules. The molecular diffusion constant of a molecule determines the mean square distance that the molecule will move per unit time. The diffusion of gas and water molecules can be described by a single molecular diffusion constant (Kleinberg and Vinegar, 1996). Crude oils, on the other hand, have distributions of molecular diffusion coefficients that reflect the diversity of molecular sizes. Small lightweight molecules like methane and ethane are relatively mobile in the gas phase and have molecular diffusion coefficients (D) that are typically about an order of magnitude greater than those of water molecules. In contrast, intermediate- to high-viscosity crude oils have molecular diffusion coefficients that are much smaller than those of water. Contrasts in the molecular diffusion coefficients of formation fluids are exploited by using specially designed NMR measurements that are sensitive to diffusion. The NMR data are then analyzed to provide oil, gas, and brine saturations.

Having discussed the differences in molecular diffusion constants of oil, gas, and brine molecules, we now look at how these differences affect the measured NMR signals. In fluid-filled rocks there are three independent and competing mechanisms that contribute to the total transverse relaxation (decay) times (T_2). These mechanisms are (1) bulk relaxation, (2) surface relaxation of the wetting-phase fluid, and (3) diffusion relaxation (i.e., attenuation) of the signal. The bulk and surface relaxation rates are independent of the spacing (TE) of the RF pulses. The diffusion attenuation rate, on the other hand, is proportional to the product $D \times TE^2$, where D is the molecular diffusion constant of the fluid molecule. The pulse spacing (i.e., echo spacing), TE, is an NMR tool acquisition parameter that can be changed for each measurement. By acquiring suites of measurements with different pulse spacings the signals from oil,

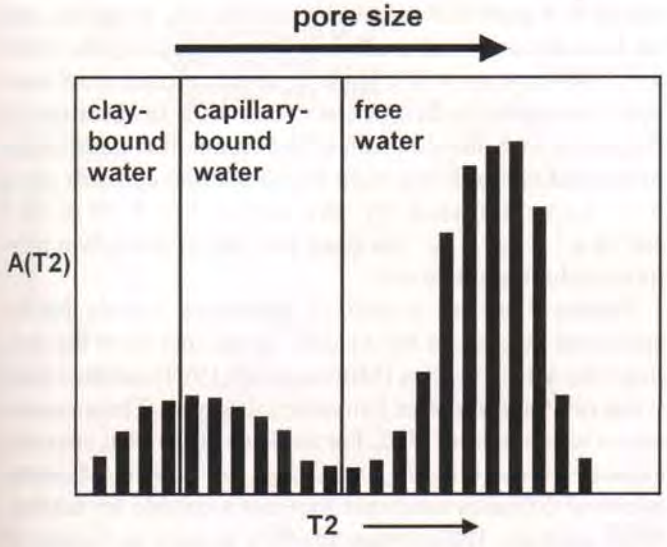

FIG. 2 Schematic plot of a typical T_2 distribution for a water-saturated rock. The distribution can be partitioned into free and bound water using empirically determined T_2 cutoffs.

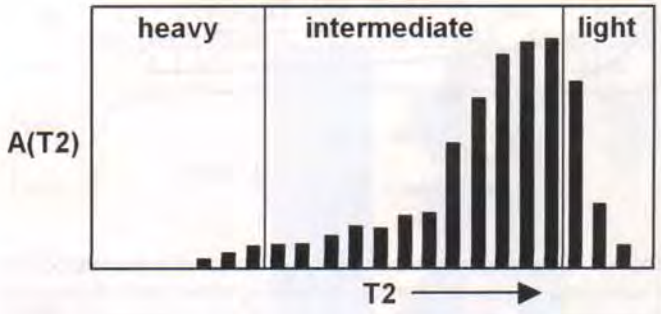

FIG. 3 A plot of a typical T_2 distribution of a bulk crude oil. The broad distribution of T_2 values reflects the broad distribution of molecular sizes. T_2 is approximately inversely proportional to molecular weight. Therefore, the distribution can qualitatively be partitioned into heavy, intermediate, and light components as shown.

gas, and brine in the formation are attenuated at different rates because of the differences in their molecular diffusion coefficients. This principle is illustrated schematically in Figure 4 where a suite of diffusion-encoded data consisting of three NMR measurements having different pulse spacings is shown for a rock saturated with an intermediate-viscosity oil and brine. For very short echo spacings there is negligible diffusion attenuation and signals from the brine and oil phases cannot be separated based on their decay rates. As the pulse spacing is increased the brine signal is attenuated much more strongly than the oil signal because the water diffusion coefficient is about 10 times greater than those of the oil. Multi-fluid relaxation models and associated inversion techniques for suites of diffusion-encoded data similar to those in Figure 4 have been developed for determining oil, gas, and brine saturations (Slijkerman et al., 1999; Freedman et al., 2001).

VISCOSITY AND SATURATION

This section first reviews the empirically derived equations that relate bulk crude oil T_2 and D distributions to viscosities. Laboratory data comparing NMR-derived viscosities with those measured by a laboratory viscometer are discussed.

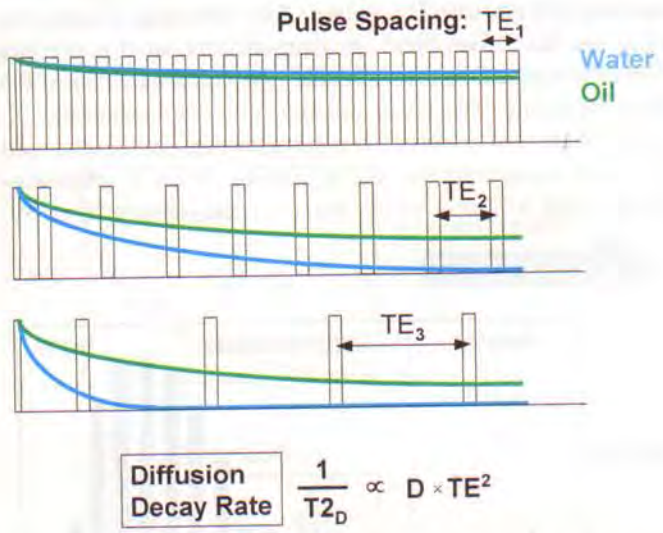

FIG. 4 Schematic plot of a suite of three diffusion-encoded measurements for a reservoir containing water and an intermediate-viscosity oil. The diffusion-induced decay or signal attenuation is proportional to the square of the pulse spacing (TE) multiplied by the diffusion constant (D) of the fluid molecule. As the pulse spacing is increased the water signal decays faster than the oil signal because the water diffusion coefficient is larger than that of the oil. This effect is the basis underlying all standalone NMR-based fluid characterization methods.

Two examples of field logs processed using the MRF method are presented. The first example shows a depth log acquired by the MRX* Magnetic Resonance eXpert tool (Heaton et al., 2002). The second field example shows brine and oil T_2 distributions, saturations, and oil viscosities from MRF analysis of station logs acquired at three depths in an oil well.

Viscosity from T_2 and D distributions

NMR viscosities are computed using empirically established equations that relate the logarithmic means of T_2 and D distributions of crude oils to their viscosities. The two empirical equations are

$$\eta_o = \frac{aT}{T_{2,LM} f(\mathrm{GOR})}, \tag{1}$$

and

$$\eta_o = \frac{bT}{D_{LM}}, \tag{2}$$

where η_o is the viscosity in cp and T is the sample temperature in Kelvin.

In equation (1), $T_{2,LM}$ is the logarithmic mean of the diffusion-free crude oil T_2 distribution in units of seconds, and f(GOR) is a dimensionless function of the gas/oil ratio (GOR). The function f(GOR) is discussed in detail by Freedman et al., 2001 and Lo et al., 2002. The constant (a) in equation (1) has been determined empirically. For a wide variety of crude oils the value $a = 0.004$ s × cp × K^{-1} is found to provide good agreement with measurements, as shown in Figure 5. It should be pointed out, however, that we have encountered crude oils for which using the value $a = 0.004$ s × cp × K^{-1} leads to underestimation of measured viscosities by as much as a factor of 2. In equation (2), D_{LM} is the logarithmic mean of the crude oil D distribution in units of cm^2/s. It has been found that the constant (b) is well approximated by the value $b = 5.05 \times 10^{-8}$ cm^2 × s^{-1} × cp × K^{-1} for dead and live hydrocarbon mixtures including crude oils.

Figure 5 shows a plot of measured versus NMR-estimated viscosities for 31 dead crude oils from the Belridge field in California (Morriss et al., 1994) and four dead crude oils from the Rice University database. The measurements were made at 27°C. For the Rice crude oils, viscosity estimates from both $T_{2,LM}$ and D_{LM} are shown. Measurements of diffusion constants were not available for the Belridge samples. The average absolute percent deviations of the NMR-estimated viscosities from the measured viscosities for these data are 11.9% and 26.8% as computed from D_{LM} and $T_{2,LM}$, respectively. Freedman et al. (2002) show

comparisons of NMR-estimated viscosities and measured viscosities for a live North Sea crude oil measured at three different GORs.

Fluid characterization example 1

The MRF logs in this example were acquired using the MRX tool. The data were acquired in an operator well in the East Mount Vernon field in Indiana that was drilled with a freshwater-based mud. Figure 6 shows the results of the MRF analysis for an oil-bearing interval of interest. Track 1 shows the gamma ray log. Track 2 contains the viscosity log and track 3 the flushed-zone oil and water saturations, both derived entirely from analysis of the MRX tool depth log. Note that NMR saturation analysis does not require knowledge of any input parameters such as Archie m and n exponents or accurate values of R_w and R_t. Track 4 shows the formation porosity partitioned into bound fluid (BFV), free fluid (FFV), and oil volumes. Also shown in Track 4 is the density log porosity (DPHI). Track 5 and 6 show diffusion-free T_2 distributions for brine and oil, respectively. The MRF logs clearly identify the oil zone in the interval from 2895 to 2908 ft. The average MRF-predicted water saturation (SXO) is 0.60 for this interval and the average viscosity is 15 cp, in excellent agreement with the value of 16.9 cp measured on a produced oil sample.

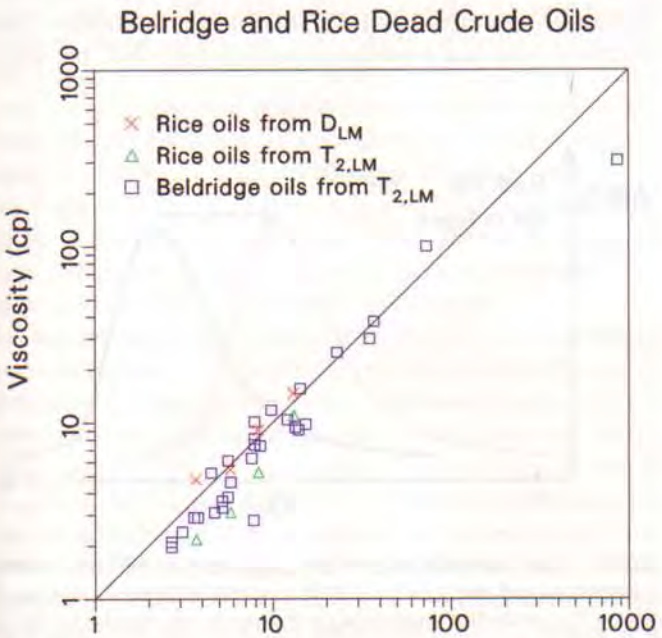

FIG. 5 Plot comparing NMR-estimated viscosities from equations (1) and (2) with viscosities measured with a viscometer for 35 dead crude oils.

Fluid characterization example 2

In this well, drilled in China, reservoir viscosities were known to vary widely, from roughly 10 to 1,000 cp. Conventional resistivity analysis was problematic because of uncertainties and variations in Archie parameters and deep invasion. Moreover, it was important to determine the oil viscosities for optimization of the well testing and completion program. The well was drilled with water-based mud.

The MRF data were acquired at three station depths using the CMR* Combinable Magnetic Resonance tool. The data suite acquired at each depth consisted of four diffusion-encoded measurements. For the intermediate- to high-viscosity oils found in this reservoir, the brine and oil T_2 distributions overlap. The overlap makes separation of the oil and brine signals difficult. Initially, several competing NMR fluid characterization methods were tried by operators in this field and gave poor results. The MRF analysis of the CMR tool data suites proved successful in separating the overlapping brine and oil signals as shown in Figure 7. The MRF analysis also provided flushed-zone water saturations and viscosities. Viscosities measured in the laboratory on produced oil samples, acquired by the MDT* Modular Dynamics Formation Tester, from two of the station depths are in excellent agreement with the predicted MRF viscosities as shown in Figure 7. Operators in this field are using MRF logs to select depths for MDT pressure measurements and fluid sampling as well as for a standalone fluid characterization method. The paper by Freedman et al. (2002) discusses this example in more detail and also examples from other wells.

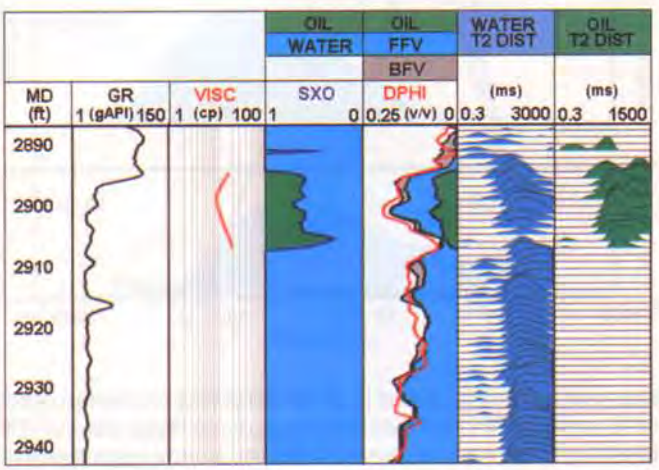

FIG. 6 MRF analysis of data acquired by the MRX tool. The analysis provides continuous measurements of fluid saturations and oil viscosities.

WETTABILITY

Wettability is the tendency of a fluid to spread on and preferentially adhere to or *wet* a solid surface in the presence of other immiscible fluids (Craig, 1971). Knowledge of reservoir wettability is critical to optimal reservoir production because it influences important reservoir properties including residual oil saturation, relative permeability, and capillary pressure. The most quantitative and widely used measure of wettability is the Amott wettability index (Amott, 1959), which is based on laboratory imbibition measurements. One of the problems with laboratory wettability measurements is that rock and fluid samples brought to the surface are not necessarily representative of those in the reservoir.

It has long been recognized that surface relaxation of the wetting-phase fluid provides a link between NMR measurements and wettability. Brown and Fatt (1956), in a pioneering paper, were among the first to explore this connection. A recent paper by Zhang et al. (2000) discusses wettability observation in sandstones using NMR measurements. This paper also provides a review of the important published NMR papers on wettability. The previous papers, including the work of Zhang et al. (2000), discuss methods that are limited to laboratory wettability determination.

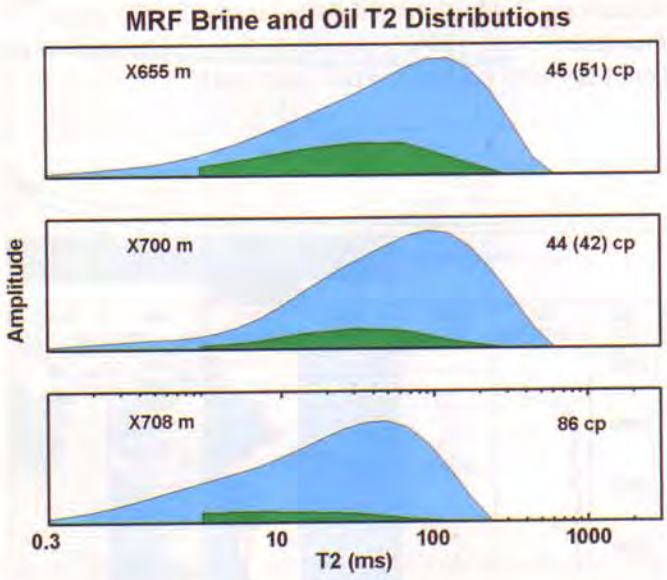

FIG. 7 Brine (blue) and oil (green) T_2 distributions computed by MRF analysis of CMR tool data acquired at three depths. The MRF analysis provides accurate results even though the brine and oil distributions completely overlap. Laboratory measurements of the viscosities of oil samples recovered by the MDT tool (shown in parenthesis) are in good agreement with NMR-estimated viscosities.

Basis for inferring wettability from NMR measurements

The basis for inferring wettability is the comparison of T_1 or T_2 distributions of a crude oil measured in a partially saturated rock with that of the bulk oil, on a produced oil sample. The partially saturated rock and the produced oil sample must be at the same conditions of temperature and pressure. If the oil measured in the rock has shorter relaxation times than the produced oil then this is unambiguous evidence of a surface relaxation effect in the rock. In this case the oil is in contact with the pore surfaces, which means that the rock is mixed wet (Salathiel, 1973). This principle is illustrated in Figure 8. As discussed below, if a shift in the oil distribution is not observed one cannot infer the wettability of the reservoir (Freedman et al., 2003).

Although the basis for inferring wettability from NMR relaxation-time measurements is simple, it is not a trivial matter to accurately compute the crude oil relaxation time distributions in a rock because of their overlap with the brine distributions. Freedman et al. (2003) have recently developed a new method for computing diffusion-free oil and brine T_2 distributions in partially saturated rocks. The new method combines the MRF with a new type of diffusion-edited NMR pulse sequence which encodes diffusion information by modifying the conventional pulse sequence (Hürlimann et al., 2002). The method can be practiced in situ by acquiring diffusion-edited pulse sequences with the MRX tool and using the MRF method to compute the brine and oil T_2 distributions in the rock. For comparison with the bulk oil T_2 distribution, a produced sample of the reservoir oil can be obtained using the MDT tester or another fluid sampling tool and brought to surface for NMR measure-

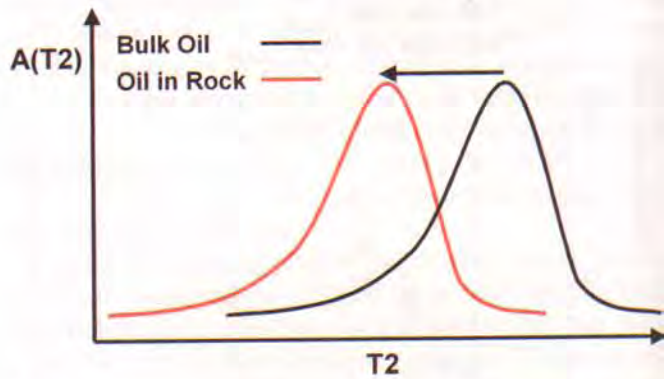

FIG. 8 This illustration shows the basis for the NMR method fo inferring mixed wettability. A shift towards shorter T_2 values o the oil T_2 distribution measured in the reservoir relative to the T distribution of a produced oil sample is an unambiguous indica tor of a mixed-wet reservoir. If there is no shift the NMR wettability indicator is ambiguous and the wettability state can not be inferred from NMR data.

ments at reservoir conditions. Because OBM filtrates can cause wettability alteration, the downhole NMR measurements should be performed in wells drilled with water-base muds.

INFERRING WETTABILITY: EXPERIMENTAL RESULTS

Freedman et al. (2003) performed experiments on a suite of four rocks, Bentheim and Berea sandstones and two dolomites from the Yates field in West Texas, to verify that wettability can be inferred from NMR measurements. The objective was to compare the crude oil T_2 distributions for the partially saturated rocks with the T_2 distribution of the bulk oil. Each rock was first measured fully brine saturated, then in a high oil-saturation state, and finally in a low oil-saturation state. A North Sea crude oil with a viscosity of about 10 cp at 27°C was used to saturate the rocks. MRF processing was used to compute separate brine and oil T_2 distributions. Imbibition experiments showed that the two dolomite rocks were mixed wet and the two sandstones were water wet. The paper by Freedman et al. (2003) provides the experimental details.

In mixed-wet rocks, the NMR surface relaxation of the oil is enhanced at low oil saturations because of the reduced thickness of the oil layer in contact with the pore walls. This effect enhances the surface relaxation rate by increasing the probability of surface interactions. Conversely, at high oil saturations the surface relaxation effect in mixed-wet rocks is reduced. The dependence of the surface relaxation rate on wetting phase saturation was clearly demonstrated in the experiments. Although the dolomite samples are mixed wet, the oil T_2 distributions measured in the four rocks in the high oil-saturation state did not show any significant shifts compared to the bulk oil distribution. Evidently, because of the high oil saturations (i.e., 72% and 74%), surface relaxation in the two mixed-wet dolomite samples is insignificant compared to bulk relaxation. However, for the dolomite samples measured in the low oil-saturation state (i.e., oil saturations of 27% and 31%), the oil T_2 distributions were shifted towards shorter T_2's relative to the bulk oil distribution. For the two water-wet sandstone samples, oil distributions measured in the sandstone rocks were not shifted relative to the bulk oil distribution. The results are shown in Figure 9; BEN3 and BER3 are the abbreviations used for the Bentheim and Berea sandstones, respectively, and Y1312 and Y1573 designate the Yates field dolomites. Note that the oil distribution measured in the Berea sandstone deviates from the bulk oil distribution for T_2 values less than about 20 ms as can be seen in Figure 9. This discrepancy highlights a practical limitation of diffusion measurements, which cannot accurately distinguish bound water with short relaxation times from viscous oil because of the lack of sensitivity to diffusion-induced decay for short T_2 values.

One can unambiguously conclude from the results shown in Figure 9 that samples Y1312 and Y1573 are mixed wet: the only mechanism that can cause the observed shifts is surface relaxation of the oil. Additional support for this conclusion is provided by the brine T_2 distributions computed by the MRF method. They show that the brine T_2 values in the oil-wet large pores are close to the T_2 of bulk water, indicating that the water is partially shielded from the pore surface (Freedman et al., 2003).

Before concluding the discussion of wettability, it is useful to summarize the experimental results. First, the NMR-based method infers the wettability state of the reservoir by comparing in-situ oil T_2 distributions with the T_2 distribution of a produced oil sample. A significant shift of the oil T_2 distribution measured in the rock towards shorter T_2 values relative to that of the produced oil T_2 distribution unambiguously implies mixed wettability. If the two distributions overlay one another then the wettability state of the reservoir cannot be inferred from NMR data.

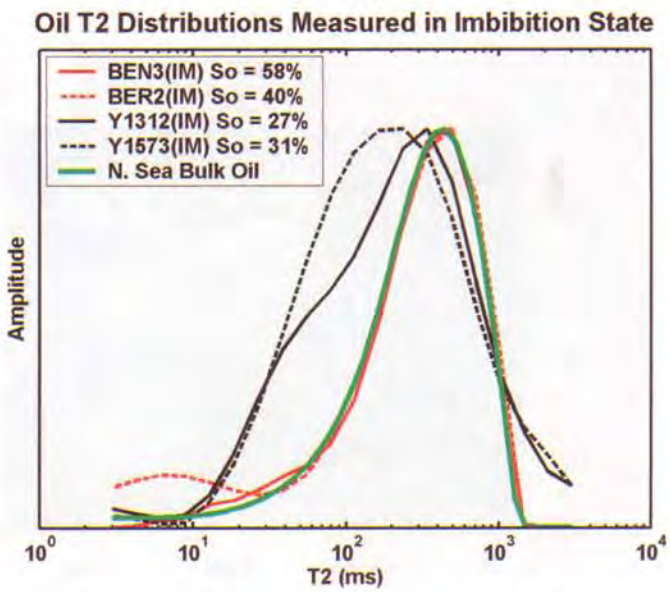

FIG. 9 Plot comparing the oil T_2 distributions computed by the MRF method with the T_2 distributions of the bulk oil. The distributions for the two Yates field dolomite samples are shifted relative to that of the bulk oil sample providing unambiguous evidence that these two samples are mixed wet. The oil distributions computed for the two sandstone samples overlay that of the bulk oil.

LIGHT HYDROCARBONS AND OBM

In the previous sections we demonstrated how the MRF method exploits differences in molecular diffusion rates to separate contributions to the NMR signal from different fluids in the formation. A principal component of the MRF method is the relationship between diffusion rates and bulk relaxation rates of crude oils. It is important to recognize that these relationships are based on empirical correlations and deviations from the correlations in equations (1) and (2) may be encountered as a result of the broad range of compositions of crude oils that can be found. Although compositional variations do place limits on the final quantitative accuracy of viscosity and saturation predictions, they do not usually result in major errors in interpretation.

More challenging situations can arise in wells drilled with OBM and when significant quantities of gas are present. Since the depth of investigation of the NMR measurement is typically just a few inches, we can expect the OBM filtrate as well as any residual native hydrocarbon and unmoved connate water to contribute to the NMR response. Because the filtrate is itself a hydrocarbon, it may mix with the native fluid, creating a new mixture for which the NMR response can be quite different from the responses of the separate fluids. Alternatively, the invasion process may occur without significant mixing so that the filtrate and native hydrocarbon would make separate identifiable contributions to the NMR measurements. When free gas or high-GOR oils are present, the situation is complicated further because the gas may also dissolve in the filtrate, thereby altering the filtrate NMR response. Unfortunately, it is not yet possible to predict with any certainty how these different fluids will interact as the filtrate invasion progresses.

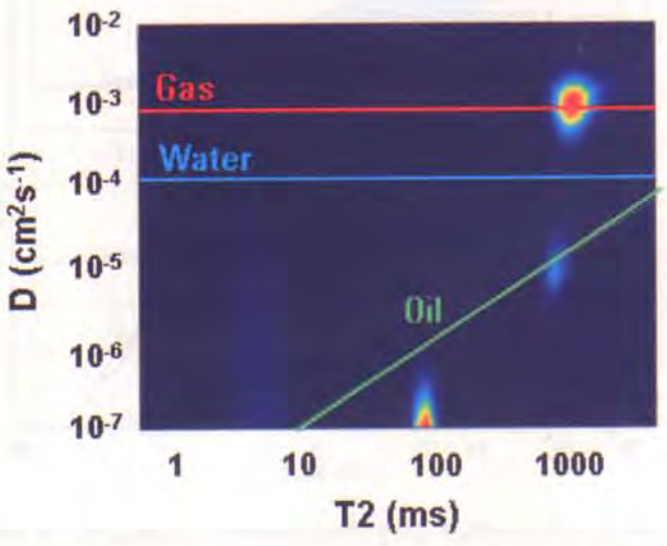

FIG. 10 D-T_2 map from a gas-bearing sand in a North Sea well drilled with OBM. The data were acquired as a station log using the CMR tool. The bright color peaks correspond to different fluids. The overlay lines represent the ideal responses of water, oil, and gas.

A new and powerful approach (Hürlimann et al., 2002) has been developed to address these complex multi-fluid environments. The new method consists of analyzing NMR data suites in terms of two-dimensional distributions of relaxation times and molecular diffusion rates. The mathematical inversion that produces the two-dimensional distribution is analogous to the standard T_2 inversion that produces a T_2 distribution from a single echo decay, as described in Figure 1. Instead of using one NMR measurement with pulse spacing, TE, the two-dimensional inversion simultaneously analyses multiple NMR measurements having different TE values. The two-dimensional distributions are typically displayed as color contour plots and are referred to as D-T_2 maps. To aid interpretation of the maps, overlays are usually included to indicate the ideal responses of water, oil, and gas.

Figure 10 shows a D-T_2 map for a gas-bearing sand in a North Sea well drilled with OBM. These data were acquired as a station log using the CMR tool. The gas signal is clearly seen in the top right corner on the red overlay gas line. Also apparent is a small peak that is directly below the gas peak but which falls on the green-overlay oil line. This peak corresponds to the OBM filtrate, which typically exhibits a T_2 of about 1 s. Interestingly, there is another peak close to the oil line with a T_2 of about 80 ms, which is consistent with residual oil of intermediate viscosity. The poorly resolved peak below 10 ms on the T_2 axis is bound water. The poor definition of the bound-water peak and its position well removed from the water cyan-overlay line demonstrate a limitation of the technique for fast-relaxing (short T_2) fluids. In general, for fluids with T_2 values less than about 20 ms, it is not possible to determine the corresponding diffusion rate and the inversion tends to apportion the signal over a broad area on the map, stretching out in the diffusion dimension. This is discussed in detail in the Appendix of the Freedman et al. 2003 paper.

The two D-T_2 maps shown in Figure 11 were obtained in a deepwater well drilled with OBM in the Gulf of Mexico. The left map was acquired in a water sand and shows a typical OBM filtrate response on the oil line with a T_2 of about 1.5 s. The faint peak with higher diffusion rate and shorter T_2 corresponds to water that was not flushed by the invading filtrate. The D-T_2 map on the right was obtained in an oil-bearing sand zone in the same well. Note that the strong filtrate peak does not fall on the oil line but has now shifted to a significantly higher diffusion rate and shorter T_2 relative to its position in the water sand. This shift is the result

of dissolved gas, which reduces the viscosity of the filtrate and causes an increase in its diffusion rate. The dissolved gas also reduces the T_2 of the filtrate. The same effect is known to occur in live oils with high GOR. The second peak that appears at the right edge (long T_2) of the map above the water diffusion line corresponds to the light hydrocarbon. Note that the OBM filtrate and native oil yield separate identifiable peaks, confirming in this case the fluids have not mixed. The long T_2 and high diffusion rate of the native oil peak indicate the oil is very light.

SUMMARY

This paper presented a variety of field examples that demonstrated recent advances in NMR fluid-characterization methods. Processed field logs showed the application of the MRF method to the prediction of oil and water saturations and oil viscosities. The definition of wettability in reservoir rocks and its connection to surface-induced decay of the NMR signal in fluid-filled rocks was discussed. Application of the MRF method to suites of diffusion-edited data acquired in the laboratory on partially saturated rocks was used to show how and under what conditions wettability can be inferred from NMR data. A model-independent NMR diffusion-based method for constructing two-dimensional maps of relaxation times and molecular diffusion rates to analyze fluids in complex environments, such as light oil or gas in wells drilled with OBM, was demonstrated using field data acquired in the deepwater Gulf of Mexico and the North Sea.

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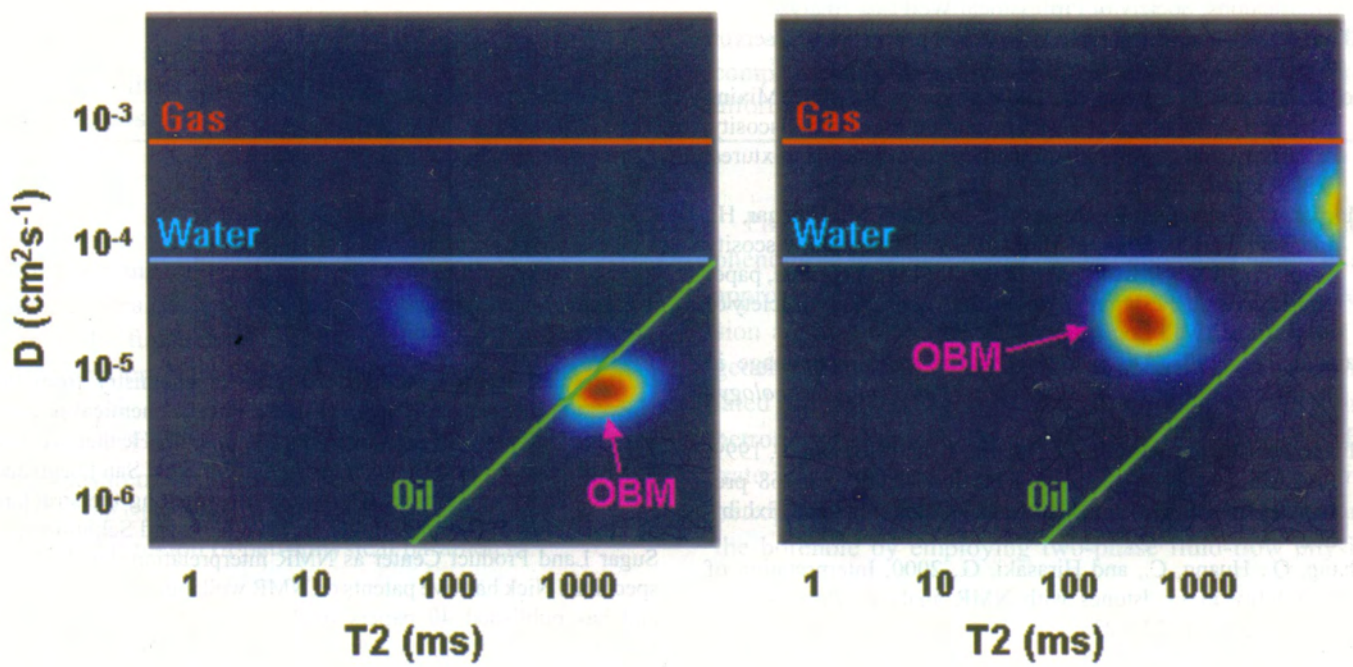

FIG. 11 *D*-T_2 maps from a water sand (left) and oil-bearing sand (right) in a Gulf of Mexico well drilled with OBM. Note that the peak corresponding to the OBM filtrate falls on the oil line in the water sand but moves to higher *D* and shorter T_2 in the oil-bearing sand because of the effects of dissolved gas.

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