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# Applications of a New-Generation NMR Wireline Logging Tool N.J. Heaton, SPE, R. Freedman, SPE, C. Karmonik, R. Taherian, K. Walter and L. DePavia, Schlumberger

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# Abstract

This paper discusses applications of a new-generation, nuclear magnetic resonance (NMR) wireline logging tool. The new design is a multi-frequency, eccentered, gradient-field NMR logging tool with multiple depths of investigation, which are maintained regardless of the hole size and are deeper than those of previous NMR logging tools. The new-generation tool features a high-resolution acquisition mode, making it possible to perform both fluid characterization and thin-bed analysis.

We present the results of MRF<sup>\*</sup> Magnetic Resonance Fluid characterization logging in a range of different environments. MRF acquisition modes comprise suites of spin-echo sequences having sensitivity to molecular diffusion. Simultaneous analysis of an entire suite of data provides depth logs of oil viscosity and fluid saturations measured in the nearwellbore region as well as total porosity,  $T_2$  distributions, and permeability estimates.

Several logs acquired in different formations are used to demonstrate the high-resolution capability of the new tool. Data acquired in a test well with known characteristics are used to validate the vertical resolution, precision, and accuracy of the measurements.

# Introduction

The strength of NMR well logging lies in its ability to provide information concerning a broad range of different formation properties. Applications for which NMR tools are commonly used include the following :

• porosity

- reservoir quality
- permeability
- thin-bed analysis
- hydrocarbon identification

The new tool brings the following new answers to the NMR arsenal :

- hydrocarbon *characterization* (oil viscosity)
- near-wellbore fluid saturation
- potential for wettability<sup>1</sup> and pore geometry<sup>2</sup> evaluation

This entire array of answers can be derived independently from NMR measurements and may be sufficient by itself to provide a detailed description of the formation close to the wellbore. In practice, the quantity and quality of NMR data acquired in a typical well-logging job is not always sufficient to provide all the answers listed. For example, reliable hydrocarbon characterization requires comprehensive suites of data with sufficient NMR contrast to distinguish between the various formation and drilling fluids, as well as a realistic physical model that adequately describes the observed NMR responses of these fluids. Additional information may also be required to correct for less-than-ideal conditions and to recalibrate standard transforms. Notably, the hydrogen index of the formation fluids must be known or estimated to accurately determine porosity. In a similar manner, empirical relationships between measured NMR parameters and permeability need to be established in different environments to account for the effects of variable mineralogy and porenetwork geometry.

Over the past decade, NMR well-logging technology has made remarkable progress in the realm of tool hardware and measurement techniques, as well as in interpretation methodology, stimulated by advances in the understanding of NMR responses of reservoir fluids. The first generation of pulsed NMR logging tools<sup>3-5</sup> were introduced in the early 1990s. These tools provided a measure of effective porosity

<sup>\*</sup> Mark of Schlumberger

and estimates of permeability based on interpretations of the  $T_2$  relaxation time distributions. Hardware and processing enhancements were later introduced,<sup>6</sup> providing an order of magnitude improvement in  $T_2$  sensitivity. Increased efforts were also made to integrate NMR data with conventional logs to derive information not provided by the individual measurements. For example, the DMR<sup>\*</sup> Density-Magnetic Resonance Interpretation Method<sup>7</sup> was developed to identify gas zones and provide accurate porosities and flushed-zone gas saturations.

The main drawbacks of the early pulsed NMR tools were their slow logging speeds, shallow depth of investigation, and limited signal-to-noise ratios (SNR). Economic constraints, imposed by the high cost of rig-time, inevitably limited the application of NMR logging tools to reduced intervals, selected on the basis of other logs. Furthermore, because of the limited SNR, data averaging is usually necessary to provide acceptable precision, degrading vertical resolution.

With the introduction of the latest generation of wireline NMR logging tools,<sup>8,9</sup> logging speed and precision issues were addressed by incorporating pre-polarization magnets and implementing more sophisticated acquisition sequences that provided substantial improvements in effective SNR. These advances were further enhanced by improvements in vertical resolution achieved using alternative data-processing methods.<sup>10,11</sup> Significant progress has also been made in the understanding of NMR responses of reservoir fluids which has stimulated the development of new acquisition strategies and methods of interpretation.

The MRF method<sup>12</sup> invokes a comprehensive and realistic relaxation model for reservoir fluids. Applying this model to appropriate suites of NMR data, MRF analysis provides flushed-zone fluid saturations and oil viscosities. Initial results obtained with station logs<sup>13</sup> have demonstrated the potential of the MRF technique.

Despite the rapid progress in NMR tool hardware and improvements in data quality made over the past decade, the development of alternative acquisition sequences and interpretation strategies has imposed new demands which may not be completely satisfied by current NMR logging tools. A new wireline NMR tool has been developed to address these demands while maintaining or enhancing data quality and operational efficiency. The main features of the new tool are summarized below :

- High degree of programmability allowing rapid introduction of new NMR acquisition sequences and answer products.
- MRF depth-log acquisition and real time processing capability.

- A range of depths of investigation, independent of hole size, permitting radial profiling of the near-wellbore region.
- Increased maximum depth of investigation to better probe native fluids and reduce sensitivity to hole rugosity.
- Enhanced vertical resolution capability.
- Prepolarizing magnet to enable fast logging even in long T<sub>1</sub> environments.

An experimental version of the new tool has been tested extensively. The objectives of the field tests were to evaluate the tool response in a variety of environments and assess the different applications of the tool. This paper presents some of the results of these tests, focusing on specific applications that demonstrate the overall capability of the new tool. A more detailed description of the tool and its specifications will be reported in a future publication.

# Acquisition Sequence Programmability

Currently, acquisition sequences used for NMR logging comprise single Carr-Purcell-Meiboom-Gill (CPMG) measurements or combinations of CPMG measurements with different polarization times, echo spacings, and number of echoes. In view of the immense variety of different pulse sequences that are employed in other areas of NMR technology, it is natural to consider alternative measurement sequences for well logging applications. One such technique that shows great potential for fluid typing and pore geometry determination is the Diffusion Editing (DE) sequence that was introduced recently.<sup>2</sup>

This sequence differs from the standard CPMG in that the time between successive refocusing pulses is not constant. In a typical DE measurement, the first two echo spacings are long and are followed by a train of closely spaced echoes. The measurement is represented schematically in **Fig. 1**. In most applications, several DE measurements are acquired in which the long echo spacing,  $t_{e,l}$ , is varied and the short echo spacing,  $t_{e,s}$ , is maintained constant. The main benefits of the new scheme, relative to the standard CPMG, are that it provides a much higher data density (improved SNR) and largely separates diffusion effects, that are active during the first two long echoes, from bulk or surface relaxation that dominate the subsequent short echo spacing train. The pulse-programmer of the new tool is sufficiently flexible to enable non-standard measurement schemes such as DE to be implemented quickly.

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<sup>\*</sup> Mark of Schlumberger



Fig. 1. Schematic representation of the DE sequence. The example shown includes three different long echo spacings,  $t_{e,l}$  (1) –  $t_{e,l}$ (3) and a constant short echo spacing,  $t_{e,s}$ .

Two sets of DE data acquired with the tool are presented in **Fig. 2**. In each case the polarization time was maintained fixed at 3 seconds, the short echo spacing was 0.6 ms, and the long echo spacing varied between 0.6 ms (standard CPMG) and 10 ms. The upper plot corresponds to a sample of doped water with a  $T_2$  of about 100 ms. The lower plot shows data acquired for a sample of crude oil. Observe that the water signal has virtually disappeared in the long  $t_{e,l}$  measurements whereas the oil signal remains clearly visible, indicating the much lower diffusivity of the hydrocarbon.



Fig. 2. DE data acquired with the new tool for samples of doped water and crude oil. The sequence included a CPMG measurement followed by five DE measurements with different  $t_{e,l}$  values, which are listed above the decay profiles.

The  $T_2$  distributions for the doped water and crude oil samples derived from the first (standard CPMG) and last ( $t_{e,l} =$ 10 ms) DE measurements are shown in **Fig 3**. All distributions were obtained using a standard  $T_2$  inversion scheme after discarding the first two echoes of the individual DE measurements. As indicated by the raw echo data, the water  $T_2$ distribution for the  $t_{e,l} = 10$  ms measurement is reduced to zero whereas the same measurement provides a reasonable estimate of the full oil  $T_2$  distribution. Note that the short  $T_2$ components for the oil are reduced in amplitude primarily because of the bulk relaxation, whereas the long  $T_2$ components are reduced largely as a result of diffusion that occurs during the first two echoes (echo spacing =  $t_{e,l}$ ).



Fig. 3.  $T_2$  distributions for doped water and crude oil samples computed from DE measurements with  $t_{e,l} = t_{e,s} = 0.6$  ms (standard CPMG) and  $t_{e,l} = 10$  ms.

It has become evident over recent years that significant improvements in precision and information content of NMR data can be achieved by using acquisition sequences other than standard single CPMG echo trains. With the introduction of the last generation of NMR logging tools it was recognized that greater precision and accuracy in porosity estimates could be obtained by appending multiple short-wait-time CPMG bursts to the standard, fully polarized long CPMG train.<sup>8,9</sup> The repeated short wait-time sequences are averaged together to yield a single short echo train with reduced noise. These averaged burst data are then submitted along with the long CPMG echo data to a simultaneous inversion that provides a unique  $T_2$  distribution and  $T_1/T_2$  ratio consistent with both the bursts and long CPMG. This Enhanced Precision Mode (EPM) strategy is extended on the new tool to allow multiple bursts with different wait times and numbers of echoes.

An example of the type of EPM sequences that have been used is given in **Table 1**. WT is the effective recovery time, TE, the echo spacing, NECHO the number of echoes in the measurement and REPT is the number of times the measurement is repeated.

Table 1 : Typical Parameters for Multiple Wait- Time Sequence for Porosity Measurement						
Measurement	WT(ms)	TE(ms)	NECHO	REPT		
а	8000	0.6	600	1		
b	8	0.6	8	32		
С	16	0.6	16	8		

Echo data, and corresponding fit profiles obtained with the new tool using this sequence are presented in **Fig. 4**. Note that decays (b) and (c) are the result of averaging repeated burst measurements.



Fig. 4. Upper panel shows echo data (blue trace) and postinversion fit profile (red trace) for an EPM acquisition. Parameters for measurements (a), (b) and (c) are given in Table 1. Lower panel shows the  $T_2$  distribution obtained from simultaneous inversion of all the echo data.

The data were recorded in a shale zone in one of the Schlumberger test wells and are the result of averaging 26 multiple wait-time acquisitions in a station log. Observe that the signal amplitude for the 8 ms wait-time measurement (b) is about 90% of that for the fully polarized measurement (a), emphasizing the effectiveness of the burst sequences in short  $T_1$  environments. Because of the large number of burst repetitions (32 for measurement (b)) and short wait time (8 ms), the effective SNR of the measurement is substantially improved at a relatively low cost in acquisition time.

The precision improvement provided by the EPM acquisition is demonstrated in **Fig. 5**, which compares the porosity and  $T_2$  distributions obtained for a series of independent measurements acquired at the same depth.

Results are shown for inversion of single CPMG data (left) and the EPM inversion. Note that the single CPMG analysis used the same long wait-time data included in the EPM measurement so that comparisons between the two inversions are strictly unbiased. Since all the measurements are made at the same depth, fluctuations in the computed quantities directly reflect repeatability. Evidently, the porosity and  $T_2$ distributions derived from the EPM data show much better consistency than do those from the single CPMG measurement. In addition to improved precision, the EPM inversion provides  $T_2$  distributions with greater detail. In particular, the small feature that appears just below 10 ms is repeatable and well-defined in the EPM distributions but appears only as a broadening of the main peak in the distributions from the single CPMG. The statistical variations of the porosity estimates for the two series of measurements are summarized in Table 2.

Table 2 : Comparison of single CPMG and EPM Sequences					
Measurement Avg. Porosity (v/v)		Std. Deviation (v/v)			
Single CPMG	0.281	0.017			
EPM	0.288	0.003			

Average noise per echo for these measurements was 0.02 v/v. We find that the EPM sequence provides a reduction in standard deviation for the porosity of a factor of almost 6 relative to the single CPMG. Note that this short  $T_2$  environment provides a particularly stringent test of porosity estimation. Precision of porosity estimates improves markedly in environments without significant short  $T_2$  components.



Fig. 5. Porosity (MRP) and  $T_2$  distributions derived by inversion of single CPMG data (blue) and EPM data (green) acquired at a constant depth.

#### Fluid Characterization

One of the principal applications of the new tool is fluid characterization, which is performed using the MRF technique. This method determines fluid properties by simultaneous inversion of a suite of NMR data comprising measurements with different acquisition parameters. The method is applicable to standard CPMG sequences, DE sequences, or combinations of the two. For each measurement in an MRF sequence, the echo amplitude at time *t* after the initial pulse can be expressed in terms of  $T_2$  distributions for oil,  $P_o(T_2)$ , and water,  $P_w(T_2)$ ,

$$M(t,t_{e,l}) \approx \int dT_2 \ P_w(T_2) \exp(-\frac{t}{T_2}) I(t,t_{e,l},D_w) f(W,\xi_w T_2)$$

$$+ \int dT_2 \ P_o(T_2) \exp(-\frac{t}{T_2}) I(t,t_{e,l},\lambda\lambda_2) f(W,\xi_0 T_2).$$
(1)

For CPMG measurements with echo spacing,  $t_e = t_{\text{Q}/p}$ , the diffusion kernel is

$$I(t, t_e, D) = exp\left(-\frac{\gamma^2 g^2 D t_e^2 t}{12}\right),....(2)$$

and for the third and subsequent echoes in DE measurements,

$$I(t, t_{e,l}, D) = \left[ a_d \exp(-\frac{\gamma^2 g^2 D t_{e,l}^3}{6}) + a_s \exp(-\frac{\gamma^2 g^2 D t_{e,l}^3}{3}) \right]_{(3)}$$
$$\times \exp(-\frac{\gamma^2 g^2 D t_{e,s}^2 t}{12}),$$

where  $\gamma = 2\pi 4258$  Hz/Gauss is the proton gyromagnetic ratio, g is the magnetic field gradient,  $t_{e,l}$  is the long echo spacing for the initial two echoes,  $t_{e,s}$  is the short echo spacing, and D is the molecular diffusion coefficient. The direct- and stimulated-echo coefficients,  $a_d$  and  $a_s$ , depend on the receiver bandwidth of the NMR instrument or logging tool. They can be determined by fitting the diffusion kernel in Eq. 3 to a suite of DE data acquired on a water sample. The diffusion kernel for the initial two echoes in DE measurements is given by Eq. 2 with  $t_e$  replaced by  $t_{e,l}$ . The polarization function  $f(W,T_l)$ corrects for insufficient recovery time. Wbetween measurements,

$$f(W, T_1) = 1 - \exp(-\frac{W}{T_1})$$
 .....(4)

and is the same for both CPMG and DE measurements. In the case of depth-logging, the polarization function should be modified to account for both re-polarization and prepolarization. To minimize the number of independent parameters it is usual to assume that the  $T_1/T_2$  ratios for water and oil,  $\xi_w$  and  $\xi_o$ , are independent of  $T_2$ . A similar relationship is adopted for the oil diffusion rates.

For many dead crude oils it has been established that a default value of  $\lambda \approx 1.25 \times 10^{-5} \text{ cm}^2/\text{s}^2$  is appropriate.<sup>12</sup> For live crude oils the ratio is modified by f(GOR), an empirically determined function of the solution gas/oil ratio (*GOR*) which is discussed in References 12 and 14. Equation 5 summarizes the principal result of the Constituent Viscosity Model (CVM). This relationship is fundamental in enabling the accurate determination of oil  $T_2$  distributions, fluid saturations and oil viscosity from a limited number of NMR measurements. The oil viscosity is given by

where  $T_{2LM}$  and  $D_{LM}$  are the logarithmic means of the oil  $T_2$  and D distributions, T is the sample temperature in K and a is an empirically determined constitutive constant for crude oils. Further details concerning the MRF method can be found in previous publications.<sup>12,13</sup>

#### Fluid Characterization Example 1

The MRF method was tested in an operator well in the East Mount Vernon Field, Indiana, drilled using a fresh waterbased mud. **Fig. 6** shows conventional depth logs over an interval containing the oil zone. The gamma-ray log is presented in track 1. Track 2 shows deep- and shallow-resistivity logs. Results of a standard Archie saturation analysis are shown in track 3 and porosity logs are compared in track 4. Note that the  $T_2$  distributions in track 5, recorded with the CMR\* Combinable Magnetic Resonance tool, show the presence of significant long  $T_2$  components for most of this interval but provide little indication of the transition from water to oil at ~ 2908 ft.

Table 3 : Fluid Characterization Depth Log						
Sequence used in Indiana Well						
Measurement	WT(ms)	TE(ms)	NECHO	REPT		
а	2500	0.6	500	1		
b	600	2.0	100	2		
С	150	3.0	75	2		
d	50	3.0	50	10		
е	150	6.0	50	2		
f	50	6.0	10	10		

The new tool was logged over the same interval using the fluid characterization acquisition sequence summarized in **Table 3**. In this example, the sequence comprised a series of 6 CPMG measurements.

<sup>&</sup>lt;sup>\*</sup> Mark of Schlumberger



Fig. 6. Conventional depth logs over the oil-bearing interval of the Indiana well. The saturation analysis in track 3 was derived using standard Archie analysis.

Results of the MRF analysis are presented in Fig. 7. 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 depth logs. Note that the NMR saturation analysis does not require any knowledge of Archie *m* and *n* exponents or resistivity information such as  $R_w$  and  $R_t$ . Track 4 shows the new tool porosity, divided into bound-fluid (BFV), free-water (FFV) and oil volumes. Separate diffusion-free water and oil  $T_2$  distributions are presented in Tracks 5 and 6. Note that the NMR logs clearly identify the oil zone from 2908 ft to 2895 ft, in excellent agreement with the conventional analysis. The MRF water saturation (SXO) is about 0.6 for this interval and the average viscosity is 15 cp.



Fig. 7. MRF depth logs over the oil-bearing interval of the Indiana well. Oil viscosity (track 2), water saturation (track 3) and fluid volumes (track 4) were derived from the separate diffusion-free water and oil  $T_2$  distributions (tracks 5 and 6) that were obtained by analysis of the multiple measurements.

After acquiring the fluid characterization depth log, the tool was positioned at approximately 2900 ft and a station log was acquired. The station sequence comprised nine DE measurements with  $t_{e,l}$  values ranging from 2 ms to 12 ms, followed by a standard CPMG measurement. The echo spacing for the CPMG and the short echo spacing,  $t_{e,s}$ , of the DE measurements were 0.6 ms. A wait time of 2.5 s was used for all the measurements. Raw echo data are presented in **Fig.** 8. Also shown in Fig. 8 are fit profiles derived from MRF analysis of the entire DE data set.



Fig. 8. DE data acquired at ~2900 ft in the Indiana well. The black lines are post-inversion fits obtained by simultaneous analysis of the entire data set.

The oil and water  $T_2$  distributions provided by the MRF analysis are shown in **Fig. 9**. Also shown is the oil  $T_2$  distribution obtained from a laboratory CPMG measurement at reservoir temperature (37 °C) of an oil sample produced from an adjacent well. Excellent agreement is obtained between the downhole MRF oil  $T_2$  distribution and that from the laboratory measurement.

Minor discrepancies between the MRF and laboratory results at short  $T_2$  occur because of the low diffusion contrast of NMR measurements for this region of the  $T_2$  distribution. Note that this is a limitation of NMR measurements in general. The DE sequence actually provides significantly enhanced oil/water contrast in the short  $T_2$  region of the distributions compared to standard CPMG sequences. A more detailed comparison of CPMG and DE sequence sensitivity is given in a separate paper.<sup>1</sup>

MRF analysis of the DE data gives a water saturation of 0.51 and oil viscosity of 8.5 cp. Applying the correlations outlined in Eq. 6 to the laboratory measurement of the produced oil sample we obtained a viscosity estimate of 11.8 cp. A conventional viscosity measurement on the same oil at reservoir temperature provided a value of 16.9 cp. The good agreement between the NMR-derived viscosity estimate and

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the conventional measurement is most encouraging. Note that the NMR depth logs indicated an average oil viscosity of  $\sim 15$  cp, also in very good agreement with the conventional measurement.



Fig. 9. Oil and water  $T_2$  distributions derived by MRF analysis of DE station log data acquired at 2900 ft in the Indiana well. The red profile was obtained from a laboratory measurement at reservoir temperature of an oil sample from an adjacent well.

#### **Fluid Characterization Example 2**

The next example was acquired in a well in West Texas. This well was drilled in a dolomite formation with a 130,000 ppm saline mud, providing a relatively difficult environment for NMR measurements. The NMR log was acquired using the acquisition sequence given in **Table 4**.

Table 4 : MRF Sequence used in West Texas Well					
Measurement	WT(ms)	TE(ms)	NECHO	REPT	
а	5000	0.6	1000	1	
b	8	0.6	8	32	
С	600	6.0	100	2	
d	600	4.0	150	2	
е	2000	2.0	300	2	

Fig. 10 shows the NMR and standard logs over a section containing hydrocarbon. Track 1 shows the gamma ray. Deep and shallow resistivity curves are plotted in track 2. Tracks 3 and 4 show the MRF viscosity and saturation estimates. Porosity, oil, and water volumes are shown in track 5. Also shown is the density porosity computed for a dolomite matrix. Water and oil  $T_2$  distributions are presented in tracks 6 and 7. The MRF analysis clearly indicates the presence of oil between 3130 and 3160 ft. MRF oil saturations are about 50% over the interval and viscosity is estimated to be approximately 4 cp. Although no independent viscosity data

are available, the NMR result is broadly consistent with the 38° API gravity oil produced in this field.



Fig. 10. MRF and standard logs acquired in the West Texas well. The MRF analysis indicates a flushed-zone water saturation, SXO, of about 50% and an oil viscosity of approximately 4 cp.

# **High-Resolution Measurements**

Unlike most other log measurements, the NMR measurement has a well-defined volume of investigation that is essentially independent of the logging environment. In principle, this feature renders NMR well-suited for high-resolution analysis provided that sufficient SNR can be achieved from a small measurement volume. In practice, CMR logs with vertical resolution of 12 in. can currently be acquired. Additional processing provides porosity and permeability estimates with an effective resolution of about 6 in.<sup>10,11</sup> One of the objectives of the new tool is to provide measurements with comparable or superior vertical resolution to those from current NMR tools.

The high-resolution capability of the tool has been tested in the Schlumberger test well in Houston. This well is constructed from a series of cut blocks of known porosity, lithology, and with well-defined thickness. Two identical passes were made at 650 ft/hr using an EPM acquisition sequence. The logs from these two passes are compared in Fig 11. Tracks 1 and 2 show the free-fluid volume and porosity logs respectively.  $T_2$  distributions for the two passes are compared in tracks 4 and 5. The lithology column is presented to the right of the logs. Repeatability of the porosity as well as the free-fluid volume is very good, particularly bearing in mind the exceptional vertical resolution of the measurements. The resolution is clearly demonstrated over the interval between ~28 ft and 31 ft, which contains three successive 1-ft thick beds with the porosity varying from 0 to 19 pu. The high-resolution logs clearly identify the three separate 1-ft thick blocks and correctly show the porosity variation of almost 20 p.u.



Fig. 11. High-resolution logs from two identical multiple wait-time sequences recorded in the Schlumberger test well. The test well lithology column is shown on the right.

High-resolution acquisition modes have also been tested in several client wells. Results from one of these field tests are shown in **Fig. 12**. This well in South Texas was drilled with fresh-water-based mud and penetrated a shaly sand formation. High-resolution logs were acquired with the new tool at 700 ft/hr using an EPM sequence. The CMR-Plus tool was also run in this well, providing a useful benchmark with which to compare the new high-resolution logs.



Fig. 12. Comparison of high-resolution logs from the new tool with CMR logs acquired in the South Texas well. High-resolution deep resistivity and shallow resistivity measurements are shown in track 2.

Track 1 shows the gamma ray on an expanded scale to emphasize variations. High-resolution, deep-resistivity, and shallow-resistivity measurements are shown in track 2. Track 3 compares the free-fluid volumes from the CMR-Plus and the new tool. Although the two free fluid curves show most of the same features, the log acquired on the new tool (MRFF) displays improved resolution in several sections of the log. In particular, differences can be seen over the laminated section between ~2120 ft and 2130 ft, and also in the interval below ~2150 ft. In both these intervals, sharp features observed in the MRFF log correspond with analogous features in the highresolution resistivity logs. The same features are also identified but are less-well-pronounced in the CMR-Plus free fluid log (CMFF). Porosity logs are compared in track 4. Tracks 5 and 6 show the  $T_2$  distributions from the new tool and the CMR-Plus respectively. Overlaying the  $T_2$ distributions are the corresponding logarithmic mean  $T_2$ curves (T2LM).

#### **Radial Profiling Capability**

Typically, the volume of investigation of NMR tools is located within a few inches of the borehole wall. The precise depth of investigation (DOI) of a particular measurement is determined by the measurement frequency and the radial variation of the magnetic field produced by the tool's permanent magnet. By acquiring measurements at different frequencies, it is possible to examine volumes over a range of DOIs. In many cases we do not expect significant variations in the properties of interest over this relatively short range. However, there are some situations where the drilling and invasion process can result in a marked heterogeneity within a few inches of the borehole. Perhaps the most obvious and common cause of such variations is hole rugosity. Invasion of fine solids from the drilling mud into the formation can also result in heterogeneity in the vicinity of the borehole and may be difficult to detect using standard measurements. As well as having a direct impact on production, this kind of drilling damage can seriously affect permeability estimation, potentially leading to poor future drilling or completion decisions. It is important to be able to identify the problem early to allow appropriate action to be taken.

The new tool has multiple-frequency acquisition capability that allows it to measure formation properties over a range of DOIs in a single pass. This feature is nicely demonstrated in a log acquired in one of the Schlumberger test wells in Houston. This 8-in. diameter well is drilled through a shaly sand formation and has plastic casing over several hundred feet. Fig. 13 shows the results of a radial profile acquisition from the test well. The sequence comprised EPM measurements at four different frequencies, corresponding to 4 DOIs between about 1 and 3 in., and was logged at 1000 ft/hr. Standard gamma ray and induction logs are shown in tracks 1 and 2. Porosities and free-fluid volumes at four different DOIs are shown in tracks 3 and 4. The corresponding  $T_2$ distributions are plotted in the remaining tracks, with DOI increasing from left to right. The variation in the  $T_2$ distributions is particularly marked in the lower section of the log, showing more long  $T_2$  amplitude at deeper DOI. This observation is shown quantitatively in track 3 which indicates higher free-fluid volume at deeper DOI. Conversely, shallow measurements indicate a greater proportion of high-porosity short  $T_2$  signal. These observed variations reflect the transition from mud solids and silt accumulated between the casing and formation, to the unperturbed formation at deeper DOI.



Fig. 13. Radial profile logs from a Schlumberger test well. Tracks 1 and 2 show gamma ray and induction logs. Porosity and freefluid volumes are presented in tracks 3 and 4.  $T_2$  distributions from 4 DOIs are shown on the right.

To date, the deepest DOI investigated by the new tool is 6 in. **Fig. 14** shows the  $T_2$  distributions and free-fluid volumes derived from two 6-in. DOI passes in a California well. Also shown are the CMR  $T_2$  distributions and free fluid volume recorded over the same interval. To facilitate visual



Fig. 14. Six-in. DOI free-fluid volume estimates (MRFF, track 1) and  $T_2$  distributions (tracks 2 and 3) acquired with the new tool in a California well. Also shown are the CMR free fluid volume (CMFF, track 1) and  $T_2$  distribution (track 4).

comparison, the CMR free-fluid curve is averaged to provide a similar vertical resolution to the logs from the new tool. The good overall agreement between the 1.1-in. DOI CMR and 6-in. DOI results from the new tool indicates that there is no significant formation damage in this case. The capability to acquire NMR logs at a DOI of 6 in. is very encouraging and promises to open new horizons for NMR logging.

#### Conclusions

A new wireline NMR logging tool has been developed to address a range of formation evaluation problems.

The new tool is fully programmable, enabling rapid implementation of new pulse sequences as they are developed. Programmability has been demonstrated with the acquisition of several different EPM logging sequences for porosity and  $T_2$  distribution measurement. Alternative non-CPMG sequences can also be implemented. One example of these new techniques, the DE sequence, has been demonstrated in laboratory measurements on fluid samples and implemented downhole. This type of sequence has exciting potential for fluid typing and pore geometry analysis.

MRF depth logs have been successfully acquired and analysed to provide continuous fluid saturation and oil viscosity logs. The MRF technique has been applied to DE data suites as well as suites of standard CPMG measurements.

High resolution logs acquired in a Schlumberger test well and in a client well have been evaluated. Analysis of the logs indicates good repeatability and good vertical resolution.

Multiple-frequency acquisition modes have been implemented on the new tool, allowing radial profiling of the near-wellbore formation. A measurement with 6-in. DOI has been demonstrated.

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#### Nomenclature

- $a = \text{constitutive constant defined in Eq. 6, s \cdot cp \cdot K^{-1}$
- $a_d$  = direct echo coefficient for DE measurement diffusion kernel in Eq. 3
- $a_s$  = stimulated echo coefficient for DE measurement diffusion kernel in Eq. 3
- D = molecular diffusion coefficient, cm<sup>2</sup>s<sup>-1</sup>
- $D_{LM}$  =logarithmic mean diffusion coefficient, cm<sup>2</sup>s<sup>-1</sup>
- $D_w$  = molecular diffusion coefficient of brine, cm<sup>2</sup>s<sup>-1</sup>

 $f(W,T_1)$  = polarization kernel in NMR response function

- f(GOR) = empirically derived function in Eq. 5
  - $g = magnetic field gradient, Gauss cm^{-1}$
  - $GOR = \text{gas/oil ratio in a live oil, } m^3/m^3$

 $I(t, t_{e,b}, D) =$  diffusion kernel in NMR response function

- $M(t, t_{e,l}) =$  signal amplitude in Eq. 1
- $P_w(T_2) = T_2$  distribution of water, p.u. s<sup>-1</sup>
- $P_o(T_2) = T_2$  distribution of oil, p.u. s<sup>-1</sup>

- t = time from the beginning of measurement, s
- $T_1$  = longitudinal relaxation time, s
- $T_2$  = transverse relaxation time, s
- $T_{2LM}$  = logarithmic mean transverse relaxation time, s
  - $t_{e,l}$  = long echo spacing in DE measurement, s
  - $t_{e,s}$  = short echo spacing in DE measurement, s
  - W = effective recovery time, s
  - $\gamma$  = proton gyromagnetic ratio, Gauss<sup>-1</sup>s<sup>-1</sup>
  - $\lambda = D / (f(GOR) T_2)$  ratio for oil, cm<sup>2</sup>s<sup>-2</sup>
  - $\xi_w = T_1 / T_2$  ratio for water-filled porosity
  - $\xi_o = T_1 / T_2$  ratio for oil

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