

Advances in NMR Logging

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Introduction

This summary of the state of the art in nuclear-magnetic-resonance (NMR) well-logging technology is aimed at nonspecialists who would like to gain some knowledge of the formation-evaluation capabilities of NMR logging tools. The objective is to explain the basic measurement principles and interpretations needed to understand NMR formation-evaluation techniques and to discuss a few examples of these methods.

Introduction of pulsed-NMR logging tools in the 1990s provided the industry with unique, even revolutionary, new methods for analyzing reservoir fluids, rocks, and fluid/rock interactions. The introduction of this technology came at an opportune time. It coincided with rapidly declining production after the 1970s drilling boom and the need for new tools to evaluate the more complex reservoirs being explored and developed. Pulsed-NMR logging tools brought a wealth of new and unique formation-evaluation applications, and this technology has grown rapidly since its inception. Today, major service companies (e.g., Baker Hughes, Halliburton, and Schlumberger) offer NMR logging services.

Historical Perspective¹

The potential value of NMR logging was first recognized in the 1950s, leading to development of nuclear-magnetic-logging (NML) tools in the early 1960s. NML tools had many limitations and eventually were retired from service in the late 1980s. In spite of these limitations, laboratory research conducted to support NML logging anticipated many formation-evaluation applications in use today. These applications include estimation of permeability, pore-size distribution, free-fluid volume, oil viscosity, and wettability.

The modern phase of NMR logging can be traced to the initiation of an NMR borehole-logging research project at Los Alamos Natl. Laboratory in 1978. The goal of this project was, in part, to build and test a borehole NMR logging tool that would overcome the limitations of the NML tools. The Los Alamos experimental tool used strong permanent magnets and performed pulsed-NMR spin-echo

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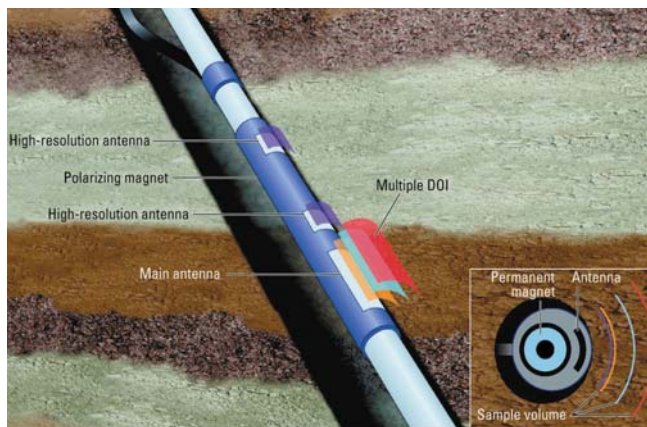


Fig. 1—The Schlumberger MRX Magnetic Resonance eXpert wireline tool has a multifrequency main antenna for fluid-characterization applications and two high-resolution antennas for providing rock-quality and producibility information (after Ahr et al.¹⁰).

measurements like those used in modern laboratory-NMR instruments. The value of these measurements is that they are extremely flexible and can be tailored to fit many different formation-evaluation applications.

The Los Alamos tool demonstrated feasibility but did not meet the requirements for a commercial tool because the signal-to-noise (S/N) ratio was too low and the magnet and radio-frequency (RF) coil design produced a large borehole signal. Soon after this demonstration of feasibility, Numar Corp., a company founded in 1983, and Schlumberger began independent research efforts to design NMR magnets and RF antennas that would be suitable for commercial NMR logging measurements.

These efforts came to fruition in the early 1990s when both companies began field tests of prototype wireline tools. These tools were vastly superior to the NML tools and quickly had an effect on formation evaluation. Since introduction of the first commercial tools, both companies have introduced advanced NMR wireline tools as well as logging-while-drilling (LWD) NMR tools. Numar was sold to Halliburton in 1997 and operates today as a wholly owned subsidiary. In 2001, Halliburton introduced an NMR fluid analyzer that is part of its wireline fluid-sampling tool. Halliburton and Schlumberger introduced LWD tools in 2000 and 2002, respectively. Baker Hughes introduced a wireline NMR tool in 2004 and an LWD NMR tool in 2005.

Modern NMR Logging

Pulsed-NMR Logging Tools. The sensor (i.e., magnet and antenna) is the heart of a pulsed-NMR logging tool. It has a significant effect

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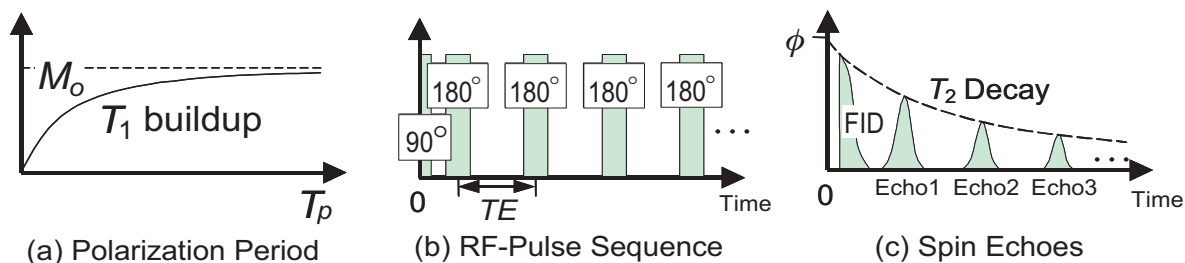


Fig. 2—The NMR-measurement process. The first step (a) is the polarization period during which the reservoir fluids are magnetized. The second step (b) is the application of RF pulses to the formation, which creates the spin-echo signals (c).

on important tool characteristics including S/N ratio, minimum echo spacing, depth of investigation (DOI), logging speed, and vertical resolution. Available tools all have somewhat different sensor designs. Further differences are electronics, firmware, pulse sequences, data processing, and interpretation algorithms. Detailed logging specifications for NMR tools can be found on service company websites.

Fig. 1 is a schematic of Schlumberger's NMR wireline logging tool. This tool has three antennas and a fully programmable pulse sequencer and can perform a large variety of different measurements.² Two 6-in. antennas are used for making high-resolution measurements of NMR-derived total, bound-fluid, and free-fluid porosities. The high-resolution antennas are also used to detect gas and light hydrocarbons and to provide estimates of permeability and pore-size distributions. The main antenna is 18 in. long. It provides a variety of NMR measurements made at multiple frequencies for different formation-evaluation applications. Each frequency corresponds to a different DOI in the range from 1.5 to 4 in., measured from the borehole wall. The formation-evaluation applications provided by the main antenna include all of those provided by the two high-resolution antennas, and it is used for radial profiling of fluid types, fluid volumes, and oil viscosities.

Some features are common to all commercial NMR tools. For instance, the tools all use powerful samarium cobalt permanent magnets that are relatively insensitive to changes in temperature. The magnets are used to polarize (i.e., magnetize) the hydrogen nuclei (protons) in hydrocarbon and water molecules. Another common feature is that they all perform pulsed-NMR measurements.

Measurement Principles. The NMR measurement comprises two steps. The first step is to create a net magnetization of the reservoir fluids.³ As the logging tool moves through the borehole, the magnetic-field vector, \mathbf{B}_0 , of the magnet polarizes the hydrogen nuclei in the reservoir fluids creating a net magnetization. The magnetization is along the direction of \mathbf{B}_0 , which is called the longitudinal direction. The magnitude of \mathbf{B}_0 typically is a few hundred gauss in the near-wellbore region (within a few inches of the borehole wall). The magnitude of \mathbf{B}_0 decreases with the radial distance from the magnet, which causes a magnetic-field gradient or distribution of gradients over the measurement volume. As discussed below, the magnetic-field gradient is used to identify and characterize the fluids in the reservoir.

Before exposure to \mathbf{B}_0 , the magnetic moments of the hydrogen nuclei are randomly oriented so that the fluids have zero net magnetization. During the polarization time, T_p , the magnetization grows exponentially toward its equilibrium value, M_0 . The time constant that characterizes the exponential buildup of the magneti-

zation is the longitudinal relaxation time, which is referred to as T_1 . The T_1 buildup of the magnetization during the polarization time is shown in **Fig. 2a**.

In reservoir rocks, a distribution of T_1 values is needed to describe the magnetization process. The T_1 distribution reflects the complex compositions of hydrocarbons and the distribution of pore sizes in sedimentary rocks. A polarization time equal to at least three times the longest T_1 is used to ensure that adequate magnetization is achieved. If a polarization time is too short, NMR-derived porosities underestimate true formation porosities.

Immediately following the polarization time, a train of RF pulses is applied to the formation. The first RF pulse is called a 90° pulse because it rotates the magnetization vector, which initially is parallel to \mathbf{B}_0 , into the transverse plane perpendicular to \mathbf{B}_0 . Once the magnetization is in the transverse plane, it rotates around \mathbf{B}_0 , producing a time-varying signal in the same antenna used to create the pulses. An NMR free-induction-decay (FID) signal first occurs immediately after the 90° pulse but decays too fast to be detected. The 90° pulse is followed by a series of evenly spaced 180° pulses that are used to refocus the magnetic moments of the hydrogen nuclei to form coherent spin-echo signals. The spin echoes are recorded between each pair of 180° pulses. The RF pulses and spin-echo signals are shown schematically in Figs. 2b and 2c, respectively. The signals are called echoes because they reach maximum amplitude at the midpoint between each pair of 180° pulses and then decay rapidly to zero before the following pulse, which refocuses the magnetic moments to produce the next echo.

The RF pulses and associated spin echoes in Figs. 2b and 2c are known as the Carr-Purcell-Meiboom-Gill (CPMG) sequence. It is the most widely used NMR logging sequence. The envelope of the spin-echo signal decays exponentially with a characteristic time constant, T_2 , known as the transverse or spin-spin relaxation (i.e., decay) time. The amplitude of the spin-echo decay curve extrapolated back to zero time (immediately following the 90° pulse) is equal to the NMR-derived total porosity, assuming that the hydrogen index of the fluid is equal to 1.

An important specification for an NMR logging tool is its minimum echo spacing. The minimum echo spacing plays an important role, together with the S/N ratio, in determining the T_2 sensitivity limit—the shortest T_2 value that can be measured by the tool. Short minimum echo spacing is essential for accurate and repeatable measurements of NMR total porosity in formations containing clay-bound and small-pore waters (i.e., for measuring T_2 values shorter than approximately 3 milliseconds).⁴ Minimum echo spacings for available tools range from about 0.2 to 1.2 milliseconds.

The number of echoes and the echo spacing, TE , in a CPMG sequence are programmable acquisition parameters. Both are select-

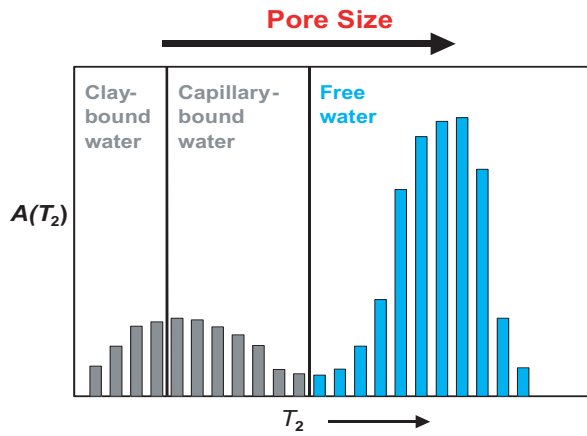


Fig. 3—Partitioning of the T_2 distribution of a typical water-saturated sandstone into bound (irreducible) and free water by use of empirically determined cutoffs.

ed on the basis of logging objectives and expected formation and fluid properties. In a typical NMR measurement, thousands of echoes are acquired over a period of approximately 1 second. The number of echoes depends on the expected formation T_2 relaxation times. In formations with long T_2 relaxation times (e.g., formations with light oils or rocks with large pores and/or vugs), more echoes are needed to measure the long T_2 values accurately in the T_2 distribution. In practice, the diffusion of molecules in the tool's magnetic-field gradient causes an additional T_2 diffusion-decay mechanism that places an upper limit on the longest T_2 that can be measured. Longitudinal relaxation times, T_1 , are not affected by diffusion.

Importance of Prejob Planning. An important part of running a successful NMR logging job is prejob planning. Prejob planning involves close communication between the service company and the client. The service companies have developed job-planning software that is tool specific and can be used to select optimal NMR acquisition modes, measurement parameters, and logging speeds on the basis of the client's objectives. The logging speed of wireline NMR logging tools depends on the logging modes that are being run, which depend on the logging objectives. One of the most important factors determining logging speed is how much polarization time is needed, which depends on T_1 . Formations that contain gas or low-viscosity oils with T_1 values of several seconds need long polarization times, which results in slower logging speeds (i.e., typically speeds in the range from 250 to 900 ft/hr). In many formations (e.g., shaly sands having oils with viscosities greater than 10 cp) logging speeds of 1,800 ft/hr or faster are possible.

The S/N ratio of an NMR measurement determines the repeatability of the measurement. As noted above, the S/N ratio of an NMR-logging-tool measurement depends on the sensor design (i.e., on the magnitude of B_0 , magnitude of the RF magnetic field, and the volume of the formation measured by the tool). Special pulse sequences are used to enhance the accuracy and repeatability of NMR measurements.^{5,6} These sequences can improve measurement S/N ratios by a factor of approximately two compared with a standard CPMG sequence.⁶ Highly conductive drilling fluids, low-porosity formations, and high temperatures can reduce the S/N ratio significantly. Service companies can provide information about the effects of conductive boreholes on measurements made by specific tools. NMR logging measurements are averaged to enhance the S/N ratio and improve the repeatability of the results.

A good practice is to perform enough averaging to achieve a precision of at least ± 1.0 porosity unit on NMR total porosities. Depending on the drilling-fluid and formation conductivities and tool specifications, averaging three to nine depth levels usually is required. The number of levels averaged, the antenna length, and the sampling interval determine the vertical resolution of the measurement. As part of prejob planning, service companies can provide the vertical resolution of the tool for different logging modes and environments.

NMR-Log Interpretation

T_2 Distributions. T_2 distributions provide much useful information about reservoir-rock and -fluid properties and constitute the basic outputs displayed on an NMR log. Most other NMR-log outputs can be computed from these distributions. T_2 distributions computed from NMR echo data are used to compute NMR total, bound-fluid, and free-fluid porosities, and also are used for permeability and reservoir-quality estimation. T_2 distributions are computed by fitting spin-echo signals to a sum of approximately 30 single-exponential functions, 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 outputs of the inversion are the amplitudes, $A(T_2)$, in porosity units corresponding to each T_2 value. A semilog graph of $A(T_2)$ vs. T_2 is known as a T_2 distribution. The area under the T_2 distribution equals NMR total porosity. **Fig. 3** shows a T_2 distribution for a typical water-saturated shaly sandstone.

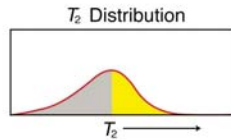
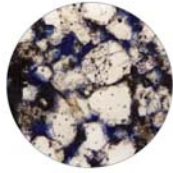
In water-saturated rocks, T_2 distributions are qualitatively related to pore-size distributions. The T_2 values typically span several decades from less than 1 millisecond to several seconds. The wide range of T_2 values observed in sedimentary rocks is caused by the broad distributions of pore sizes. As a first-order approximation, each T_2 in the T_2 distribution is proportional to a pore-size diameter. Thus, the short T_2 values in a T_2 distribution are associated with signals from water in small pores, whereas the longer T_2 values correspond to signals from water in larger pores. T_2 distributions are used to predict total porosity, bound-fluid porosity, free-fluid porosity, permeability, and pore-size distribution. **Fig. 4** shows scanning-electron-microscope (SEM) images of two sandstones that have nearly identical porosities but measured brine permeabilities that differ by a factor of approximately 37. The T_2 distributions clearly reveal the sandstone of better quality. The lower-permeability sandstone has shorter T_2 values and more pore-filling clay as indicated by higher bound-water volume (e.g., the gray shaded part) than the more permeable rock.⁷

Comparisons frequently are made between the pore-size information contained in T_2 distributions and mercury-injection capillary pressure curves. It is important to note that capillary pressure curves provide information on pore-throat sizes, whereas T_2 distributions are related to pore-body sizes. T_2 distributions have been found to provide information that complements capillary pressure curves in many sandstones that have pore-body and pore-throat sizes that are well correlated.

Lithology-Independent NMR Total Porosity. One of the most significant recent advances in formation evaluation is lithology-independent NMR total porosity. The measurement of lithology-independent total porosity is unique to NMR tools because porosities derived from density, neutron, and sonic measurements depend on knowing rock-matrix properties. In heterogeneous formations having mixed or unknown lithology, the use of NMR logs for accurate porosity prediction is highly recommended. **Fig. 5** shows the advan-

T₂ Distributions Predict Reservoir Quality

Porosity = 20%
Permeability = 7.5 md



Porosity = 19.5%
Permeability = 279 md

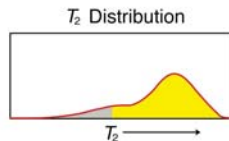
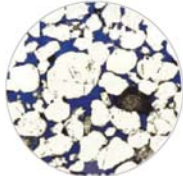


Fig. 4—SEM images for two sandstones that have nearly identical porosities but very different permeabilities. The lower permeability sandstone has more pore-filling clays and smaller pores than the higher permeability sandstone. The differences in the rocks are revealed by the T₂ distributions—the lower permeability rock has shorter T₂ values and more bound water (i.e., the gray part of the distribution).

tage of lithology-independent NMR porosity in mixed-lithology carbonates. Track 1 contains logs of rock mineralogy and fluid volumes. The upper portion of the interval is mostly dolomite with traces of clay and quartz. The lower part of the interval is predominantly limestone with varying amounts of dolomite. Track 2 contains two density-log porosity curves—computed either by assuming 100% limestone or 100% dolomite. The NMR total porosity also is shown in Track 2. Note that the density-log porosities computed assuming a dolomite matrix agree with NMR total porosities in the upper dolomite section but read incorrectly in the lower section that contains limestone mixed with dolomite. Similarly, the density-log porosities computed assuming limestone read incorrectly in the upper section and approach the NMR porosities only at the very bottom of the section. The NMR-log porosities are insensitive to the lithology changes and read correctly over the entire interval.

NMR total porosity equals actual formation porosity in most hydrocarbon-bearing and wet rocks, including shales. However, exceptions can occur in heavy-oil reservoirs with oil viscosities on the order of 10,000 cp or greater. Such oils can have T₂ distributions with significant amplitudes below the T₂ sensitivity limits of NMR tools. NMR-derived porosities in these heavy-oil reservoirs underestimate true formation porosities. The deficit of NMR-derived porosities compared with density-log porosities can be used to infer the presence of heavy oil and, with some assumptions, to place bounds on the oil viscosity and oil saturation.

Estimating Bound and Free Water. T₂ distributions in water-saturated rocks can be partitioned into bound (i.e., irreducible) and free water by use of empirically determined T₂ cutoffs. The partitioning of the T₂ distribution divides the total porosity into bound- and free-water-filled porosities. The bound water for shaly sandstones consists of clay- and capillary-bound water as shown in Fig. 3. For sandstones, a default value of 33 milliseconds is commonly used for the T₂ cutoff that separates the bound water from the free water. This works well in many cases; however, the default value is not applica-

Lithology-Independent NMR Total Porosity

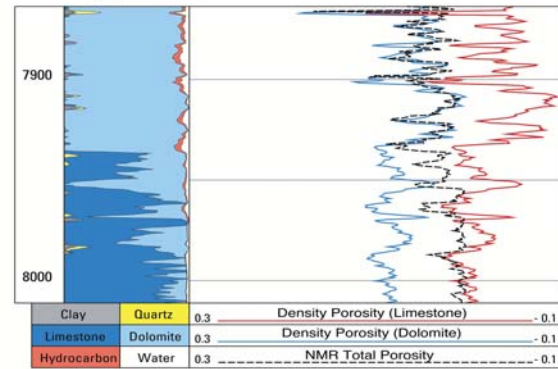


Fig. 5—Porosity logs in mixed-lithology carbonates show the advantage of NMR lithology-independent total porosity. NMR total porosity is not sensitive to lithology and reads correctly over the entire interval. The density tool reads correctly only in intervals in which the assumed matrix density (lithology) used to compute the density-log porosity matches the actual matrix density of the formation.

ble to all sandstones. Laboratory NMR measurements made on water-saturated core samples, before and after centrifuging, often are used to obtain more-accurate T₂ cutoffs for a specific rock formation. In water-saturated carbonates, T₂ cutoffs are significantly greater (e.g., hundreds of milliseconds) than the cutoffs for sandstones.

The computation of bound and free water from T₂ distributions in carbonates is more complex than in sandstones because in many carbonates, there are signals with long T₂ decay times that come from bound water in isolated vugs. Another complication is that different pore-size systems (e.g., dual-porosity pore systems with micro- and macroporosities) often are found in carbonates. Molecules can diffuse from the micropore system to the macropore system during the NMR measurement time, obscuring the true pore-size distribution.⁸

The partitioning of T₂ distributions into bound water and free water discussed above for water-saturated rocks assumes that short T₂ relaxation times are associated with clay-bound, capillary-bound, and small-pore waters. This assumption is not valid in hydrocarbon-bearing rocks, which contain, for example, viscous but movable oil with T₂ values less than the cutoff.⁹ Obviously, this movable oil would be incorrectly tagged as bound water if one applied a cutoff to the total or composite T₂ distribution. One approach for solving this problem is to separate the two T₂ distributions by use of diffusion-based fluid-characterization methods.^{3,9}

Estimating NMR-Derived Permeability in Sandstones. Two empirical permeability equations are used widely in the industry—the Schlumberger-Doll Research (SDR) equation and the Timur-Coates equation. The NMR permeability equations provide estimates of brine permeabilities in water-saturated sandstones. A good correlation between pore-body and -throat sizes exists for many sandstones, which is the underlying basis for NMR-derived permeability. Both permeability estimators contain model parameters (e.g., exponents and proportionality constants). The default parameter values used by service companies usually provide NMR permeability logs that are qualitatively accurate (i.e., they can be used to predict that one zone is more permeable than another zone). Although this information is valuable, the estimated permeabilities can deviate significantly from those of the formation. To estimate quantitatively accurate log permeabilities for a specific type of rock, it is rec-

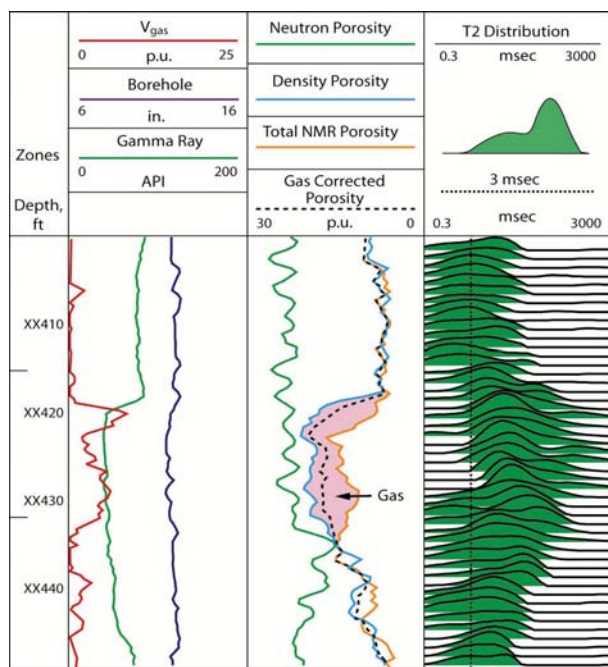


Fig. 6—A log showing the DMR method in a shaly gas-bearing sandstone. The density- and magnetic-resonance-porosity logs exhibit a crossover effect in the gas-bearing sandstone. Thermal neutron absorbers in the shaly sandstone cause the neutron porosities to read too high and suppress the neutron/density crossover. The gas volume (V_{gas}) in Track 1 and gas-corrected porosity in Track 2 are computed by use of the DMR equations.¹¹

ommended that measurements on core samples be analyzed to determine optimal permeability-equation parameters. Estimates of SDR and Timur-Coates permeability both are affected by hydrocarbons, and more research is needed to develop equations to predict relative permeabilities to hydrocarbons and water.

The SDR and Timur-Coates permeability equations are based on assumptions that are not valid for carbonates because pore-body sizes measured by NMR and pore-throat sizes are not well correlated in carbonates. Carbonates also can have NMR signals from fluids in isolated vugs, which contribute to NMR porosity but not to permeability. Permeability estimation in carbonates is one of the most active and challenging areas of NMR-logging research.¹⁰

Methods for Evaluating Hydrocarbon-Bearing Reservoirs
Density/Magnetic-Resonance (DMR) Method for Gas-Bearing Reservoirs. The DMR method combines density- and NMR-log porosities to predict gas-corrected formation total porosities and flushed-zone water saturations.¹¹ The DMR method exploits the fact that density-log porosities read too high and NMR total porosities read too low in gas-bearing reservoirs. Density porosities read too high because of the reduced density of gas. NMR total porosities read too low because of the reduced hydrogen index of gas (i.e., density of protons of a fluid relative to water). This effect causes density- and NMR-porosity logs to exhibit a crossover effect in gas zones similar to that exhibited on neutron/density logs.

The DMR method is superior to the traditional thermal neutron/density method for detecting and evaluating gas zones. The thermal neutron gas response in shaly sands can be suppressed by the presence of thermal neutron absorbers, which cause neutron porosities to read too high. As a result, neutron/density logs can miss gas-bearing zones in shaly sands. NMR total porosities are not affect-

ed by shale or rock mineralogy, and, therefore, the DMR method is a more reliable gas indicator.

Fig. 6 shows an example of the DMR method. The logged interval consists of a shale overlying a shaly gas-bearing sandstone. Note that the neutron/density crossover effect in the gas sand is suppressed. The NMR-tool response in the gas zone is not affected by shale and exhibits an NMR-/density-log crossover effect. The volume of gas shown in Track 1 and the gas-corrected total porosity shown in Track 2 were computed with the DMR gas equations.¹¹

The DMR method provides a simple and robust technique for evaluating gas-bearing reservoirs; however, other methods are needed to differentiate water from viscous oils. These methods are discussed in the next two sections.

Diffusion-Based NMR Fluid-Characterization Methods. Akkurt *et al.*¹² first recognized that diffusion in a magnetic-field gradient could be used as a mechanism for fluid characterization and proposed a standalone NMR diffusion-based method for differentiating gas from water. The early diffusion-based methods were limited in their range of applicability and were superceded by more-accurate and general model-based inversion methods.⁹ Today, diffusion-based methods provide a means for detecting and evaluating zones that are difficult or impossible to accurately interpret by use of conventional log-analysis methods. Applications include low-resistivity pay zones, which can be missed using conventional resistivity-tool interpretation; formations with low-salinity connate water or water with unknown or variable salinity; and formations with complex lithology for which Archie parameters are variable or unknown.

Modern fluid-characterization methods use data suites consisting of diffusion-encoded pulse sequences that are simultaneously inverted to provide continuous logs of fluid (water, oil, and gas) saturations and oil viscosities.³ These data suites are sensitive to both the diffusion coefficients, D , and the relaxation times of the fluids. Molecular diffusion is the random thermal motion of molecules in a fluid. Diffusion-encoded sequences are modifications of CPMG sequences in which one or two echoes have an increased spacing.¹³ Molecular diffusion in a magnetic-field gradient shortens the T_2 relaxation times, and this effect is amplified during the increased echo spacings of the diffusion-encoded sequences. By acquiring several diffusion-encoded measurements with different long echo spacings, it is possible to measure molecular-diffusion rates directly.

Multidimensional NMR Fluid Characterization. Recent advances in NMR data acquisition and processing use suites of diffusion-encoded data to compute 2D or 3D maps that can be used to visually identify fluids present in a reservoir on the basis of contrasts in either the relaxation time and/or diffusion-coefficient distributions of the fluids.^{13–15} The term multidimensional refers to the measurement and display of NMR-signal amplitudes as functions of two or three of the fluid parameters T_1 , T_2 , T_1/T_2 , and D .

Multidimensional maps have proved essential for accurate fluid analysis of reservoirs invaded with oil-based drilling-mud filtrate (OBMF). The multidimensional inversions used to construct maps do not rely on empirical models, which is an advantage when attempting to identify and characterize several miscible fluids. If OBMF is present in the formation, then it can contribute to the NMR signal, together with any residual native hydrocarbons and uninvaded connate water. The presence of OBMF complicates the interpretation of the NMR data. The severity of the interpretation problem posed by the invasion of OBMF depends on whether it mixes with the native hydrocarbons. The invasion dynamics and fluid properties that determine if mixing will occur are not well

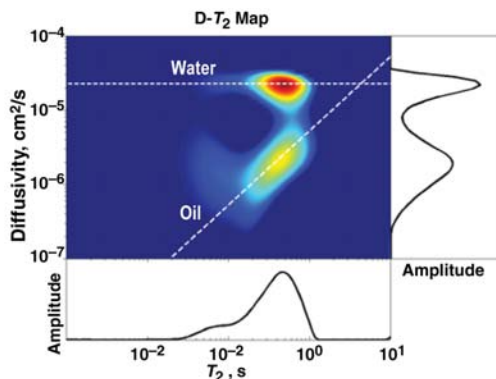


Fig. 7—The D - T_2 map from a clay-free Bentheim sandstone saturated with water and a dead (i.e., zero GOR) North Sea stock-tank oil. The water and oil signals are well separated because water molecules have a larger diffusivity coefficient than the bigger and less-mobile hydrocarbon molecules in the oil.

understood, but experience with the maps has shown that mixing does occur in some cases. If the OBMF and native hydrocarbons remain separate, and if they have significantly different relaxation-time or diffusion-coefficient distributions, then the maps can be used to identify the separate fluids and predict the saturation and viscosity of the native oil. If the OBMF and the native hydrocarbons mix, the fluids can lose their identities and coalesce into a single fluid with properties not representative of the native reservoir.

Fig. 7 shows a 2D map of signal amplitude vs. D and T_2 for a clay-free Bentheim sandstone core partially saturated with water and dead [i.e., zero gas/oil ratio (GOR)] North Sea stock-tank oil. The oil gravity was 33°API, and the oil saturation in the core was 57%. The NMR data were acquired with a laboratory NMR instrument. The colors of the map indicate the signal amplitude at each point in the D - T_2 plane. The dark blue background corresponds to zero signal amplitude. Maximum amplitude is red. The horizontal reference line indicates the diffusion coefficient of free water (i.e., for unrestricted diffusion). A strong water signal can be seen to lie on the free-water diffusion line. The oblique line is the so-called dead-oil line, on which signals from dead crude oils typically lie. For live oils, the oil signal is shifted away from the dead-oil line toward the northwest. The magnitude of the shift depends on the GOR. A strong signal from the dead North Sea oil can be seen to lie on the dead-oil line.

The two subplots below and to the right of the map are the projections of the map amplitudes onto the T_2 and D axes, respectively. These projections are composite T_2 and D distributions that represent all of the fluids in the rock (e.g., in this case, oil and water). Observe that the oil and water signals are not well separated by the T_2 distribution because the water and oil T_2 distributions overlap. The water and oil show separate peaks in the D distribution because the diffusion coefficient of the water is approximately 10 times larger than the diffusion coefficients of the North Sea oil. This is a good example of how contrasts in the diffusivities, D , of water and oil can be used for fluid identification, even when the relaxation times are similar or identical, which occurs frequently.

The next example is a field log from the paper by Freedman and Heaton.³ The two D - T_2 maps in **Fig. 8** were obtained in a deepwater well drilled with an OBM in the Gulf of Mexico. The left map was acquired in a water-saturated sandstone and shows a typical OBMF response on the oil line with a T_2 of approximately 1.5 seconds. The faint peak with higher diffusion rate and shorter T_2 cor-

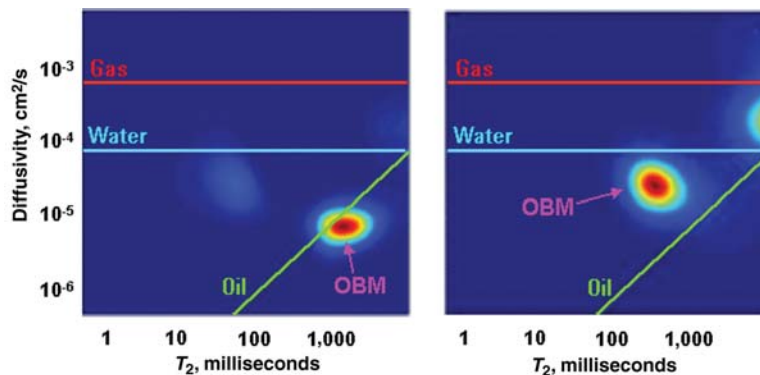


Fig. 8— D - T_2 maps from a water-saturated sandstone (left) and oil-bearing sandstone (right) in a deepwater Gulf of Mexico well drilled with OBM. Note that the peak corresponding to the OBM filtrate falls on the oil line in the water-saturated sandstone but moves to higher D and shorter T_2 in the oil-bearing sandstone because of the effects of dissolved gas (after Freedman and Heaton³).

responds to water that was not flushed by the invading filtrate. The D - T_2 map on the right was obtained in an oil-bearing sandstone in the same well. Note that the strong filtrate peak does not fall on the oil line but has shifted to a significantly higher diffusion rate and shorter T_2 relative to its position in the water-saturated sandstone. 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 GORs. 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 OBMF and native oil yield separate identifiable peaks, confirming, in this case, that the fluids have not mixed. The long T_2 and high diffusion rate of the native-oil peak indicate that the oil is very light.

When interpreting these maps, one must be aware of deviations from ideal-fluid responses. For example, in some rocks, the water signal is observed to lie significantly above the free-water diffusion line. This effect is caused by the presence of “internal gradients” that are induced by the magnetic field of the NMR magnet. Iron-rich chlorite clays or other magnetic minerals in the rock matrix cause the internal gradients. Internal gradients tend to be large in small pores and can perturb the magnetic-field gradient of the tool, which leads to uncertainties in measured diffusion coefficients. In some rocks, water signals lie significantly below the free-water diffusion line. This effect is caused by “restricted diffusion” of water molecules in small pores. This effect is common in carbonates and other rocks with microporosity and occurs when the distance that water molecules diffuse during the measurement time becomes comparable to the pore size. The effects of restricted diffusion can complicate interpretations because restricted water can be mistaken for oil.¹⁵ Other log data (e.g., from resistivity and fluid-sampling tools) often are used in conjunction with NMR data to develop an unambiguous interpretation.

For heavy oils, with small diffusion coefficients (e.g., $D \leq 0^{-7}$ cm²/s), it is not possible to measure the diffusion accurately with NMR logging tools. There is a lack of sufficient diffusion sensitivity for oils with T_2 values below approximately 20 milliseconds.

Ongoing Research and Possible Future Applications

Recent and ongoing research on methods for inferring rock wettability from NMR looks promising. It is hoped that this work will lead to useful downhole techniques for inferring wettability.^{16,17} Another promising research area is the use of NMR measurements

to estimate pressure/volume/temperature (PVT) properties of reservoir fluids. It is anticipated that this research will eventually lead to predictions of in-situ PVT properties of reservoir fluids including molecular composition of crude oils.¹⁸ This method would have a large effect on improving conventional formation-evaluation and well-completion results.

Also, promising research efforts are under way to exploit NMR diffusion measurements to better define rock/pore-space connectivity and structure.¹³ Such research can lead to a better understanding of producibility in complex reservoirs.

Looking further into the future, there is potential to use NMR methods to image fluids in reservoirs in the same way that magnetic-resonance imaging is used in medicine to image soft tissues. On the distant horizon are possible applications of NMR spectroscopy to well logging, such as in-situ measurements of the aliphatic/aromatic ratios in crude oils.

Conclusions

NMR logging was first introduced during the 1960s when NML tools were used to make crude free-precession measurements in the Earth's magnetic field. The NML tools were retired from service in the late 1980s. Modern pulsed-NMR tools were introduced in the early 1990s, and this technology has had a major effect on formation evaluation. A wide variety of wireline and LWD tools and services is available.

The proper use of NMR technology requires good communication between oil and service companies to ensure that logging objectives and data-quality expectations are met. The latter involves careful prejob planning that includes if necessary, plans to mitigate borehole environmental effects (e.g., high mud conductivities and high temperatures) on data quality.

There are unique and powerful standalone NMR formation-evaluation methods available for evaluating fluid types, saturations, and porosities in complex reservoirs. Additionally, NMR logs provide estimates of bound- and free-water volumes, oil viscosities, and formation permeabilities subject to the caveats discussed in this article. In complex reservoirs, NMR and other log data should be integrated with all other available reservoir information (e.g., especially data from fluid-sampling and pressure tools and core data) to provide the most accurate picture of the reservoir.

Nomenclature

$A(T_2)$ = Amplitude in a T_2 distribution corresponding to relaxation time T_2 , porosity units.

\mathbf{B}_0 = Magnetic field vector* in the formation produced by the logging tool as it moves through the borehole, gauss.

D = Molecular diffusion coefficient of a water, gas, or oil molecule, cm^2/s .

M_0 = Equilibrium value approached by the proton magnetization at infinite polarization time, gauss.

TE = Echo spacing (also equal to pulse spacing) in a CPMG spin-echo sequence, milliseconds.

T_1 = Longitudinal relaxation time used to characterize the build-up of the proton magnetization during the polarization time, seconds.

T_2 = Transverse relaxation time used to characterize the decay of the NMR spin-echo signal, seconds.

T_p = Polarization time during which the proton magnetization is allowed to build up prior to application of the 90° pulse, seconds.

ϕ = Porosity, fraction

* Boldface type is used to denote that the magnetic field is a vector.

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