Evaluating low-resistivity pay requires interpreters to discard the notion that water saturations above 50% are not economic. Various tools and techniques have been developed to assess these frequently bypassed zones, but there are no shortcuts to arriving at the correct petrophysical answer.

When Conrad and Marcel Schlumberger invented the technique of well logging, low-resistivity pay was, practically speaking, a contradiction in terms. Their pioneering research hinged on the principle that gas- or oil-filled rocks have a higher resistivity than water-filled rocks. Through the years, however, low-resistivity pay has become recognized as a worldwide phenomenon, occurring in basins from the North Sea and Indonesia to West Africa and Alaska. With low oil prices driving the reexploration of mature fields, methods of interpreting low-resistivity pay have proliferated.

This article examines the causes of low-resistivity pay in sands, then explores the tools and techniques that have been developed to evaluate such zones. A case study shows how log/core integration helps pinpoint the causes of low-resistivity pay in the Gandhar field in India. Generally, deep-resistivity logs in low-resistivity pay read 0.5 to 5 ohm-m. “Low
contrast” is often used in conjunction with low resistivity, indicating a lack of resistivity contrast between sands and adjacent shales. Although not the focus of this article, low-contrast pay occurs mainly when formation waters are fresh or of low salinity. As a result, resistivity values are not necessarily low, but there is little resistivity contrast between oil and water zones.

Because of its inherent conductivity, clay, and hence shale, is the primary cause of low-resistivity pay (previous page). How clay contributes to low-resistivity readings depends on the type, volume and distribution of clay in the formation.

Clay minerals have a substantial negative surface charge that causes log resistivity values to plummet. This negative surface charge—the result of substitution in the clay lattice of atoms with lower positive valence—attracts cations such as Na⁺ and K⁺ when the clay is dry. When the clay is immersed in water, cations are released, increasing the water conductivity.

The cation exchange capacity, or CEC, expressed in units of milliequivalent per 100 grams of dry clay, measures the ability of a clay to release cations. Clays with a high CEC will have a greater impact on lowering resistivity than those with a low CEC. For example, montmorillonite, also known as smectite, has a CEC of 80 to 150 meq/100 g whereas the CEC of kaolinite is only 3 to 15 meq/100 g.

Clays are distributed in the formation three ways:
- laminar shales—shale layers between sand layers
- dispersed clays—clays throughout the sand, coating the sand grains or filling the pore space between sand grains
- structural clays—clay grains or nodules in the formation matrix.

Laminar shales form during deposition, interspersed in otherwise clean sands (left). In the Gulf Coast, USA, finely layered sandstone-shale intervals, or thin beds, make up 5Autumn 1995

In this article, AIT (Array Induction Imager Tool), ARC5 (Array Resistivity Compensated), CBT (Cement Bond Tool), CDR (Compensated Dual Resistivity tool), CMR (Combinable Magnetic Resonance tool), CNL (Compensated Neutron Log), DLL (Dual Laterolog Resistivity), ELAN (Elemental Log Analysis), EPT (Electromagnetic Propagation Tool), FMI (Fullbore Formation MicroImager), GeoFrame, GLT (Geochemical Logging Tool), Litho-Density, IPL (Integrated Porosity Lithology), MicroSFL, NGS (Natural Gamma Ray Spectrometry tool), Phasor, RAB (Resistivity-at-the-Bit tool), SFL (Spherically Focused Resistivity), SHARP (Synergetic High-Resolution Analysis and Reconstruction for Petrophysical Parameters) and TDT (Thermal Decay Time) are marks of Schlumberger. Sun is a mark of Sun Microsystems, Inc.

3. One milliequivalent equals 6 x 10²⁰ atoms.
Fragments—all fine grained—mimic the log signature of clays, featuring high gamma ray, low resistivity and little or no spontaneous potential (SP). Unlike thin beds, this type of low-resistivity pay can vary in thickness from millimeters to hundreds of meters. Finally, sands with more than 7% by volume of pyrite, which has a conductivity greater than or equal to that of formation water, also produce low-resistivity readings. This type of low-resistivity pay is considered rare.

The challenge for interpreting low-resistivity sands hinges on extracting the correct measurement of formation resistivity, estimating shaliness and then accurately deriving water saturation, typically obtained from some modification of Archie’s law. Improved vertical resolution of logging tools and data processing techniques are helping to tackle thin beds. Nuclear mag-

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Left: Induction Electrical Survey logs run in 1960 in a thinly bedded, gas-bearing section of the Vicksburg formation in south Texas, USA. Net pay is 7 ft. Right: Conventional triple combo—neutron, density and gamma ray tools—run in 1993 in a well offset 100 ft from the original 1960 well. Net pay is 14 ft.

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about half the low-resistivity zones. Many logging tools lack the vertical resolution to resolve resistivity values for individual thin beds of sand and shale. Instead, the tools give an average resistivity measurement over the bedded sequence, lower in some zones, higher in others.

Intervals with dispersed clays are formed during the deposition of individual clay particles or masses of clay. Dispersed clays can result from postdepositional processes, such as burrowing and diagenesis. The size difference between dispersed clay grains and framework grains allows the dispersed clay grains to line or fill the pore throats between framework grains. When clay coats the sand grains, the irreducible water saturation of the formation increases, dramatically lowering resistivity values. If such zones are completed, however, water-free hydrocarbons can be produced (see “Low-Resistivity Pay in the Gandhar Field,” page 8).

Structural clays occur when framework grains and fragments of shale or claystone, with a grain size equal to or larger than the framework grains, are deposited simultaneously. Alternatively, in the case of selective replacement, diagenesis can transform framework grains, like feldspar, into clay. Unlike dispersed clays, structural clays act as framework grains without altering reservoir properties. None of the pore space is occupied by clay.

Other causes of low-resistivity pay include small grain size and conductive minerals like pyrite. Small grain size can result in low resistivity values over an interval, despite uniform mineralogy and clay content. The increased surface area associated with finer grains holds more irreducible water, and, as with clay-coated grains, the increasing water saturation reduces resistivity readings. Intervals of igneous and metamorphic rock fragments—all fine grained—mimic the log signature of clays, featuring high gamma ray, low resistivity and little or no spontaneous potential (SP). Unlike thin beds, this type of low-resistivity pay can vary in thickness from millimeters to hundreds of meters.

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magnetic resonance (NMR) logging shows promise for assessing irreducible water saturation associated with clays and reduced grain size (see “Nuclear Magnetic Resonance Imaging—Technology for the 21st Century,” page 19). And because the most opportune time to measure resistivity occurs during drilling, when invasion effects are minimal, resistivity measurements at the drill bit also play an important role in diagnosing low-resistivity pay.

Thin Beds

One obvious method for resolving the resistivity of thin beds is to develop logging tools with higher vertical resolution, deeper depth of investigation, or both. Two logging devices that have proved especially helpful in evaluating thin beds are the AIT Array Induction Imager Tool and the FMI Fullbore Formation Microimager tool. The AIT tool uses eight induction-coil arrays operating at multiple frequencies to generate a family of five resistivity logs. The AIT logs have median vertical resolutions of 1 ft [0.3 m], 2 ft [0.6 m] and 4 ft [1.2 m]. The FMI tool images the borehole with an array of 192 button sensors mounted on four pads and four flaps. It has a vertical resolution of 0.2 in. [5 mm].

Successive improvements in resolving thin beds are strikingly visible in a series of logs made 33 years apart in adjacent wells in the south Texas Vicksburg formation (previous page and left). In 1960, induction and short normal logs indicated 7 ft of net gas pay and only two beds with resistivity greater than 2 ohm-m. In 1993, a new well was drilled within 100 ft [30 m] of the original well and logged with conventional wireline tools. The induction/SFL Spherically Focused Resistivity logs doubled the estimated pay to 14 ft [4.3 m], with seven beds above 2

(continued on page 11)

4. Thin beds have a thickness of 5 to 60 cm [2 in. to 2 ft] and laminae are less than 1-cm [0.4-in.] thick, commonly 0.05 to 1 mm [0.002 to 0.004 in.].


6. In 1942, Gus Archie proposed an empirical relationship linking a rock’s resistivity, \( R_t \), with its porosity, \( \phi \), and water saturation \( S_w \):

   \[
   R_t = \frac{R_w}{(\phi^{m} S_w^{n})}
   \]

   Other terms in the equation are the formation water resistivity \( R_w \) and the cementation and saturation exponents, \( m \) and \( n \). For further reading:


   For a discussion on the numerous versions of Archie’s law that have been developed to handle a variety of shaly sand environments: Worthington PF: “The Evolution of Shaly-Sand Concepts in Reservoir Evaluation,” The Log Analyst 26 (January-February 1985): 23-40.


The Gandhar field, on the western coast of India, is the largest on-land field in the country. Most hydrocarbon production comes from deltaic sands of the Hazad member, three of which contain low-resistivity pay.

One of these sands, called GS-11, has resistivity values of 2 to 6 ohm-m, but contains wells that produce clean oil on the order of 50 m³/d [315 B/D] (next page). A detailed study of GS-11, integrating core and log data, allowed interpreters to unravel the low-resistivity phenomenon and formulate a reliable mineralogical model and water saturation estimates.

Core Studies

Sixty core samples from three GS-11 wells provided thin sections for study of texture and mineralogy. Polished sections helped reveal the presence of metallic minerals. Scanning electron microscope (SEM) and X-ray diffraction (XRD) studies of cores identified clay minerals. In addition, laser and sieving methods were used to analyze grain size.

The core investigations showed several mechanisms contributing to high conductivity. Medium- to fine-grained sands ranged from gray to green-gray, with green indicating chloritic

**SEM photographs showing coated grains and clay matrix (left) and quartz overgrowth with chlorite coating on quartz grains (right).**
clays. Bioturbation created thin, fine clay laminations over clean sands. Quartz was the most prominent mineral, with minute opaque minerals—pyrite or magnetite—occurring in bioturbated sections. Pyrite, which increases the formation conductivity, was limited to the clayey part of the matrix and constituted less than 5% by volume.

Clay, primarily chlorite, coating the grain surfaces was indicated by SEM pictures and XRD studies (previous page, bottom). Smaller grains were coated more than larger grains. Laser analysis of samples shows the GS-11 sand to be in the silt range, with grain sizes averaging 22 to 32 microns.

Formation Evaluation
Logs were analyzed to identify clay types and heavy minerals. Thorium-potassium crossplots of the NGS Natural Gamma Ray Spectrometry logs identified predominant clays as chlorite in the sands and kaolinite/chlorite in the shales. The density-neutron crossplot showed a trend toward high density (low porosity) with little increase in the neutron. The particles associated with this behavior, which included fine-grained quartz and heavy minerals such as siderite, pyrite and ilmenite, were collectively called silt.

From core- and log-derived information, a mineralogical model of kaolinite, chlorite, quartz and silt was chosen for the GS-11 sands. Validation for the model came from geochemical analysis of 21 core samples from different wells. A few samples were analyzed to determine the weight percent of oxides, such as silicon dioxide [SiO₂], using X-ray fluorescence (XRF) and the results were interpolated between samples. The percentages were then converted into weight percent of elements using standard tables and processed.

Log response from Well Z shows an average resistivity reading of 3 to 4 ohm-m over the GS-11 sand, which produced clean oil during conventional testing.
with a mineralogical model to give weight percent of minerals. The model based on geochemical analysis was constrained to include only quartz, kaolinite, chlorite and ilmenite. This constraint allowed the weight percent of minerals to be converted to volume percent using the total porosity from log interpretation and the mineral densities.

Comparison of the log and XRF mineral analyses shows agreement between the total clay percentage and the relative volume of kaolinite and chlorite. The silt and ilmenite percentages do not agree, as might be expected since the silt was defined to include finer grained quartz.

Conclusions

The composite results from the extensive log-core analysis show agreement between core- and log-derived parameters. Water saturation values computed from the Waxman-Smits equation compare well with those derived from capillary pressure measurements. Because little water had been produced from existing GS-11 wells, the log-derived water saturation values were considered to represent irreducible water saturation values.

The core studies showed that the low-resistivity measurements in the GS-11 sand have two sources. First, individual sand grains are coated with clay. Second, the silt-sized formation grains lead to higher irreducible water saturations in the formation.

Later the same year, the second well was logged with a combination of AIT and IPL Integrated Porosity Lithology tools.10 The high resolution of the AIT tool—1 ft versus 2 ft for the induction—and the enhanced sensitivity of the IPL-derived neutron porosity increased net pay to 63 ft [19.2 m] and showed 13 beds with resistivity greater than 2 ohm-m.

Resistivity Measurements at the Bit
Improvements in measurements-while-drilling (MWD) technology have not only boosted the efficiency of directional drilling, but also enhanced thin-bed evaluation.11 Two tools, the RAB Resistivity-At-the-Bit tool and the ARC5 Array Resistivity Compensated tool—are especially useful in thin-bed environments by providing resistivity data before invasion has altered the formation.

The RAB tool provides five different resistivity readings plus gamma ray, shock and tool inclination measurements. Configured as a stabilizer or a slick collar, the RAB tool is run behind the bit in a rotary drilling assembly and above the motor in a steerable drilling assembly.

One resistivity measurement, called “bit resistivity,” uses the drill bit as part of the transmitting electrode. With the RAB tool attached to the bit, alternating current is circulated through the collar, bit and formation before returning to the drillpipe and drill collars above the transmitter. In the case of oil-base mud, which is an insulator, the current loop is complete only when the collars and stabilizers touch the borehole wall. The vertical resolution of the RAB bit resistivity is only 2 ft and it gives the earliest possible warning of changes in formation resistivity.

Four additional resistivity measurements, with 1-in. vertical resolution for thin-bed applications, are made with three button electrodes and a ring electrode. The shallow depths of investigation—3, 6 and 9 in. for

the buttons and 12 in. for the ring electrode — allow interpreters to characterize early-time invasion (left).

The recently-introduced ARC5 tool provides five phase and attenuation resistivity measurements, like the AIT tool, with a vertical resolution of 2 ft. With a 4 3/4-in. diameter, it is especially useful for formation evaluation in slim holes typical of deviated drilling (next page, top).

The measurements and spacings of the ARC5 and AIT tools are comparable, although not identical, making petrophysical evaluation with either tool in the same well or between wells seamless (below left). The multiple measurements of the ARC5 tool also allow interpreters to radially map out the invasion process. The additional phase and attenuation measurements provide a better characterization of electrical anisotropy than existing MWD tools.

Improving Thin-Bed Evaluation Through Data Processing

Despite the emphasis on developing high-resolution resistivity logging tools, many openhole tools still have a vertical resolution of 2 to 8 ft [0.6 to 2.4 m]. Several data processing techniques have been developed to enhance the vertical resolution of these traditional tools (next page, bottom). All methods use at least one high-resolution measurement to sharpen a low-resolution one and require a strong correlation between the two. An existing technique helpful in interpreting low-resistivity pay is Laminated Sand Analysis (LSA), a computer program for evaluating the shaliness, porosity and water saturation in beds as thin as 2 in. [4 cm].12

A newer approach for identifying and evaluating thin beds is the SHARP Synergistic High-Resolution Analysis and Reconstruction for Petrophysical Parameters software. SHARP processing improves the resolution of log inputs to the ELAN Elemental Log Analysis module, thereby improving saturation and reserve estimates. Currently, SHARP software exists as an interactive, stand-alone prototype application for Sun workstations but a second generation version will be incorporated into the GeoFrame reservoir characterization system by the end of 1995.

ARCS log run in wash down mode in front of thin gas stringers. Rough hole conditions precluded running wireline logs in the well except for a CBT Cement Bond Tool log and a TDT Thermal Decay Time log. The TDT log confirmed the presence of gas indicated by the ARCS log.

| Data Processing Methods for Enhancing Vertical Resolution |
|-----------------|-----------------|-----------------|-----------------|
| Technique       | Measurements    | Method                        | Improvement in Resolution |
| Enhanced Phasor Processing (1988) | Phasor Induction log | Medium-induction measurement used to enhance deep induction measurement | From 7 ft to about 3 ft [2 to 1 m] |
| Enhanced Resolution Processing (1986) | Litho-Density log | Near-detector measurement used to compensate for far detector measurement | From 18 in. to 4 in. [45 cm to 10 cm] |
|                  | CNL Compensated Neutron Log | Near-detector measurement used to compensate for far detector measurement | From 24 in. to 12 in. [61 cm to 30 cm] |
| Laminated Sand Analysis (1984) | Triple combo (gamma ray, neutron and density), EPT Electromagnetic Propagation Tool | Computes bound water saturation (shaliness) from EPT tool, used with dual-water model to redistribute the measured induction resistivity, yielding estimates of the resistivity of thin beds. Effective porosity, water saturation and permeability are computed. | Down to 2 in. [5 cm] |
SHARP analysis relies on high-resolution inputs, such as Formation MicroScanner, FMI or EPT Electromagnetic Propagation Tool logs to define a layered model of the formation (right). The program looks at the zero crossings on the second derivative of the high-resolution log, where the slope changes sign, to indicate bed boundaries. In the case of a Formation MicroScanner or FMI log, the SHARP program examines the second derivative of an average resistivity reading from all button sensors.

With bed boundaries established, SHARP analysis plots a histogram of the frequency of a particular resistivity value within the logged interval of interest. By studying how resistivity values cluster, an interpreter can group the values into different populations, or modes. SHARP analysis assumes that all resistivity data in a particular mode come from the same kind of formation, and further that the resistivity value in a particular mode is constant. In addition, SHARP evaluation assumes that petrophysical parameters such


as density, neutron porosity and sonic velocity are also constant in a given mode.

After establishing the number of beds and modes in the logged interval—the “square log”—the SHARP program calculates a set of mode values that minimizes the difference between the original and square logs. This model, a squared resistivity log of bed boundaries and mode values, is filtered with the response function of a logging tool to produce a synthetic, or so-called reconstructed, log (previous page, bottom). The model is refined by minimizing the difference between the measured log and the reconstructed log. At a workstation screen, the log interpreter can interactively adjust the boundaries and bed values of the modes to achieve a match.

When the synthetic and measured logs match, the model can be used as a high-resolution input into the ELAN interpretation. To sharpen the resolution of other logs, such as the gamma ray, the model of bed boundaries determined previously is utilized to reconstruct other squared, enhanced logs for high-resolution formation evaluation. A low-resistivity example from the Gulf of Mexico shows how SHARP analysis improved reserve estimates by 28%, even when applied to AIT measurements and a high-resolution triple combo of density, neutron and gamma ray logs (right and next page).

Rather than reconstruct logs using SHARP analysis, Raghu Ramamoorthy and Charles Flaum, of Schlumberger-Doll Research, Ridgefield, Connecticut, USA have developed a simpler technique to enhance producibility and hydrocarbon content estimates made with conventional petrophysical analyses in thin beds. Working with logs from the GLT Geochemical Logging Tool, they picked a high-resolution clay indicator, either the FMI or EPT log, and calibrated it to the clay volume derived from the GLT measurement. In addition to clay volume, the GLT tool combines nuclear spectrometry logging measurements to determine mineral concentrations and cation exchange capacity of the formation.

Comparison of original and SHARP-enhanced logs for a low-resistivity pay example from the Gulf of Mexico. The interval was logged with a high-resolution triple combo. The original 10-in. and 60-in. depth-of-investigation curves from the AIT log are shown with the enhanced AIT 60-in. log. Only the 60-in. curve was enhanced because the SHARP prototype software does not yet have the modeled tool response for other AIT measurements. An ELAN interpretation (next page) using the enhanced logs shows a 28% increase in estimated reserves.
respond to clays, the GLT-derived clay volume—a low-resolution measurement—is enhanced by looking at local variations of the high-resolution FMI measurement. The low-resolution GLT clay volume is adjusted by the difference between the FMI-derived clay volume and its value averaged over the resolution of the GLT tool, which is 2 ft:

\[ V_{\text{clay, high-res}} = V_{\text{clay, low-res}} \text{GLT} + \left[ V_{\text{clay, high-res FMI}} - \langle V_{\text{clay, high-res FMI}} \rangle \right]. \]

With well data, an empirical relationship is established between clay volume and porosity. This relationship is applied to the enhanced GLT clay volumes to derive high-resolution porosity values. Enhanced GLT clay volumes and porosity values are then processed with calibrated FMI resistivity values to boost the resolution of hydrocarbon saturation estimates.

Applying this technique to GLT and FMI logs from a well in Lake Maracaibo, Venezuela reveals overlooked reserves. The FMI image shows the highly laminated nature of the formation, with beds on the order of 1 ft. A comparison of standard-resolution and high-resolution ELAN interpretations shows that potential pay zones have been completely masked in the conventional processing (next page, top).

Using Electrical Anisotropy to Find Thin-Bed Pay

James Klein and Paul Martin of ARCO Exploration and Production Technology in Plano, Texas, and David Allen of Schlumberger Wireline & Testing in Sugar Land, Texas are modeling electrical anisotropy to detect low-resistivity, low-contrast pay such as thin beds. The researchers found that a water-wet formation with large variability in grain size is highly anisotropic in the oil leg and isotropic in the water leg. They attribute the resistivity anisotropy to grain-size variations, which affect irreducible water saturation, between the laminations.

They tested their theory by modeling the thin, interbedded sandstones, siltstones and mudstones of the Kuparuk River formation A-sands of Alaska’s North Slope, located 10 miles [16 km] west of Prudhoe Bay. The model, based on a Formation MicroScanner interpretation, contains layers of low-permeability mudstone and layers of permeable sandstone with variable clay content.

The simulated resistivity data are described as either perpendicular—measured with current flowing perpendicular to the bedding—or parallel—measured with current flowing parallel to the bedding.
Plotting perpendicular versus parallel resistivity for a given interval shows how hydrocarbon saturation influences electric anisotropy (below left). Simulated resistivity data in the oil column curve to the right, but simulated resistivity data in the water leg are nearly linear. The position of data along the oil column arc indicates the lithology of the formation.

Today, this technique works only with 2-MHz MWD tools such as the CDR Compensated Dual Resistivity tool. The CDR phase and attenuation measurements provide a unique response to anisotropy that allows the perpendicular and parallel resistivities to be determined. The technique requires that the logging tool be parallel to the beds so that differences in the phase and attenuation of resistivity measurements can be used to establish anisotropy. Although the technique cannot yet be applied at other angles, its originators believe some operators will value it enough to tailor the deviation of their wells so that logging tools can run parallel to beds of interest.

Nuclear Magnetic Resonance Logging

Although thin-bed evaluation is challenging, the tools and techniques described so far provide answers in most cases. More troublesome to interpreters than thin beds is another prominent cause of low-resistivity pay, reduced grain size, which contributes to high irreducible water saturations. The CMR Combinalbe Magnetic Resonance tool shows potential for measuring irreducible water saturation and pore size.

The CMR tool looks at the behavior of hydrogen nuclei—protons—in the presence of a static magnetic field and a pulsed radio

15. Anisotropy is the variation of a property with direction. In this case, it is variation of resistivity in the vertical (perpendicular) versus horizontal (parallel) planes.

For a review of electrical anisotropy:


frequency (RF) signal (right). A proton’s magnetic moment tends to align with the static field. Over time, the magnetic field gives rise to a net magnetization—more protons aligned in the direction of the applied field than in any other direction.

Applying an RF pulse of the right frequency, amplitude and duration can rotate the net magnetization 90° from the static field direction. When the RF pulse is removed, the protons precess in the static magnetic field, emitting a radio signal until they return to their original state. Because the signal strength increases with the number of mobile protons, which increases with fluid content, the signal strength is proportional to the fluid content of the rock. How quickly the signal decays—the relaxation time—gives information about pore sizes and, to some extent, the amount and type of oil.

A CMR log displays distributions of relaxation, or T2 times, which correspond to pore size distributions. The area under a spectrum of T2 times is called CMR porosity. Unlike previous NMR tools, the CMR tool is a pad-mounted device. Permanent magnets in the tool provide a static magnetic field focused into the formation. The CMR tool’s depth of investigation, about 1 in. (2.5 cm), avoids most effects from mudcake or rugosity. Its vertical resolution of 6 in. (15 cm) allows for comparison with high-resolution logs.

An example from the Delaware formation in West Texas shows how the NMR response allows log interpreters to measure residual oil saturation directly from the CMR log. NMR measurements on core samples from the Delaware formation show that the NMR response will decay within the first 200 milliseconds (msec) if the pores are filled with water. If the pores are filled with oil, however, the signal decays after about 400 msec.

The T2 distributions in track 4 have been divided into three parts. The area under the T2 curves to the left of the 33-msec cutoff is irreducible water saturation. From 33 msec to 210 msec, the area under the curve represents producible fluid. Above 210 msec, the area under the curve represents oil. In track 3, the mud log show curve was derived from the total gas measured on the mud log. It indicates that there is an oil-water contact halfway through the interval, at about X320 ft.

Early field test of the CMR tool in the Delaware formation, West Texas, USA. Based on NMR measurements of core samples from the Delaware formation, the T2 distributions in track 4 have been divided into three parts. The area under the T2 curve to the left of the first cutoff, shown as a blue line at 33 msec, represents irreducible water saturation. The area under the curve from 33 msec to 210 msec (red line) represents producible fluid. Above 210 msec, the area under the curve represents oil, presented as a CMR oil show in track 3. This measurement of oil actually refers to residual oil saturation since the CMR tool looks only at the flushed zone.

With the introduction of the CMR tool, log interpreters are gaining the upper hand in the struggle to assess low-resistivity pay. Although there are no easy answers when evaluating low-resistivity pay, the tools and interpretation techniques are in place to more efficiently find these frequently bypassed zones. —TAL