

Confronting the Carbonate Conundrum

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CMR (Combinable Magnetic Resonance), ELANPlus (Elemental Log Analysis), FMI (Fullbore Formation MicroImager), GeoFrame, MDT (Modular Formation Dynamics Tester), MRF (Magnetic Resonance Fluid), MRX (Magnetic Resonance eXpert), Platform Express, proVISION and Well-ID (Well-Informed Decisions) are marks of Schlumberger. Windows® is a registered trademark of Microsoft Corporation.

Heterogeneity of carbonate reservoirs at all scales makes it difficult for experts to build consensus in their descriptions of these reservoirs. Simplifying rock-classification schemes facilitates interpretations and offers a useful framework for reservoir-management decisions, but simplification is not enough. Greater understanding of carbonate rocks is developing from sustained advances in well logging technology, rigorous applications of petrophysical analysis, validation of petrophysical techniques using cores, and sophisticated probabilistic techniques.

Despite the hydrocarbon wealth they hold, carbonate rocks endure a bad reputation for having either complicated interrelationships, or no interrelationships at all, between porosity, permeability and other reservoir properties. Understanding the interrelationships that may exist is an important challenge in carbonate reservoir characterization. Historically, operating companies and service companies have attempted to create complete solutions for carbonate petrophysical analyses, only to have the reality of extreme heterogeneity of the pore systems nullify their efforts. Consequently, exploration and production companies have had to confront production challenges in carbonate reservoirs with less than ideal information.

In recent years, scientists and engineers have applied many techniques to try to understand carbonate reservoirs. The continued absence of a universal procedure to solve every problem is not for lack of effort. A major obstacle persists: a particular technique might not be suitable at all relevant scales of investigation; what works at one wellbore might be inadequate for others, or for the rest of a field. The heterogeneity of carbonate pore systems makes permeability prediction incredibly difficult. Nevertheless, the situation is far from hopeless.

In the years since *Oilfield Review* last examined carbonate reservoirs in detail, the goal of exploration and production (E&P) companies

has not changed: they want to find and produce hydrocarbons as safely and efficiently as possible.¹ At the wellbore scale, this entails formation evaluation and well-completion optimization. At the reservoir scale, rigorous reservoir characterization helps companies improve production and optimize the placement of new wells.² In carbonate rocks, these tasks are easier said than done.

In this article, we examine innovative approaches to challenges in carbonate reservoir characterization around the world. We introduce a cutting-edge nuclear magnetic resonance (NMR) sonde whose multiple depths of investigation improve characterization of fluid content. We also discuss how new data from carbonate reservoirs help scientists and engineers understand carbonate pore systems, and how this knowledge is guiding development of new NMR interpretation methods. First, however, we briefly review carbonate reservoir geology and early interpretation techniques.

Fewer Minerals, More Complications

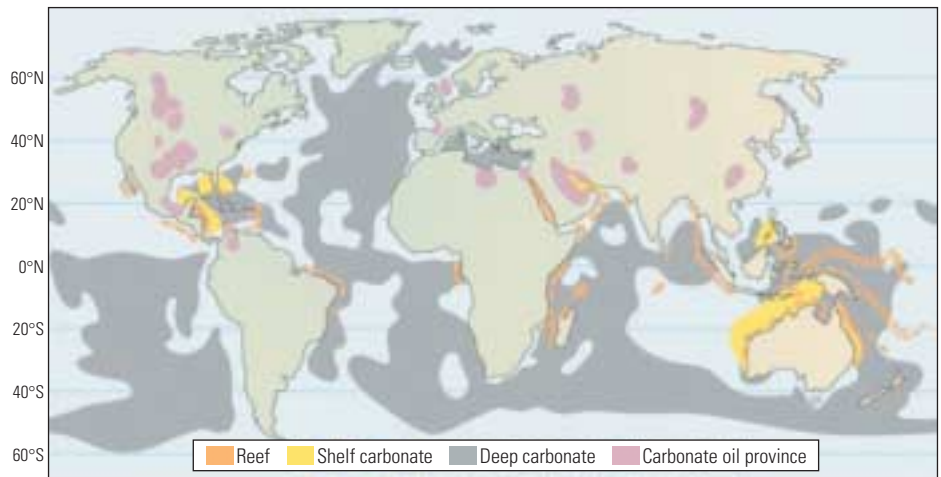
Carbonate reservoirs contain more than 60% of the world's remaining oil in place, but these hydrocarbons can be extremely difficult to produce ([next page, bottom](#)). Unlike siliciclastic reservoirs, which form through erosion and transportation of material from existing rocks, carbonate rock-forming materials develop mainly



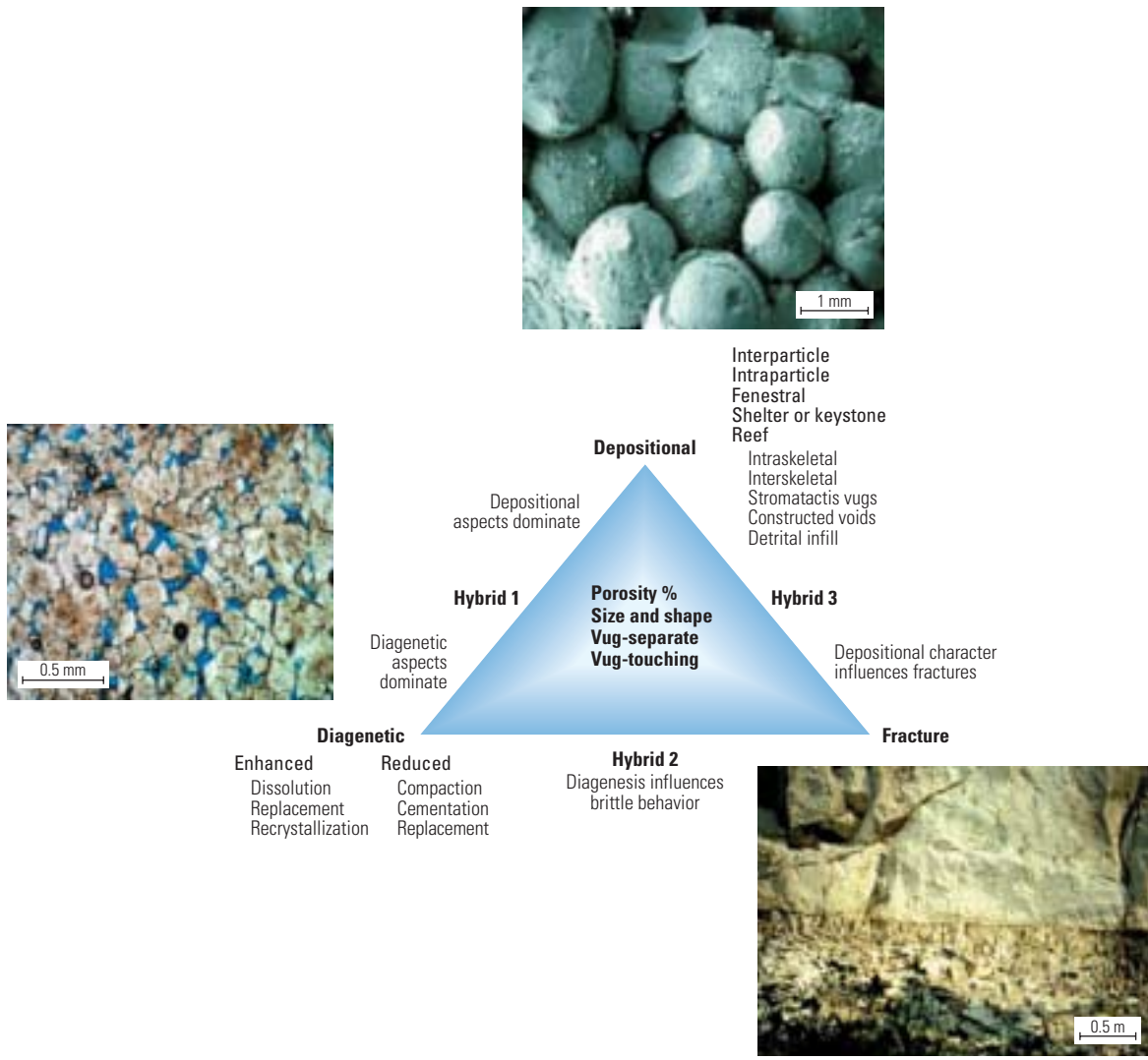
^ (Photographs courtesy of T.N. Diggs.)

through biological activity and, to a lesser degree, inorganic precipitation. The biological origins of many carbonate deposits restrict their occurrences to places with specific water temperatures and other life-sustaining conditions. In addition, carbonate-producing organisms evolve, adding complexity to carbonate studies.³

1. Akbar M, Vissapragada B, Alghamdi AH, Allen D, Herron M, Carnegie A, Dutta D, Olesen J-R, Chourasiya RD, Logan D, Stief D, Netherwood R, Russell SD and Saxena K: "A Snapshot of Carbonate Reservoir Evaluation," *Oilfield Review* 12, no. 4 (Winter 2000/2001): 20–41.
2. For more on advanced stimulation and logging-while-drilling (LWD) technologies in carbonate rocks: Al-Anzi E, Al-Mutawa M, Al-Habib N, Al-Mumen A, Nasr-El-Din H, Alvarado O, Brady M, Davies S, Fredd C, Fu D, Lungwitz B, Chang F, Huidobro E, Jemmali M, Samuel M and Sandhu D: "Positive Reactions in Carbonate Reservoir Stimulation," *Oilfield Review* 15, no. 4 (Winter 2003/2004): 28–45.
Alvarado RJ, Damgaard A, Hansen P, Raven M, Heidler R, Hoshun R, Kovats J, Morriss C, Rose D and Wendt W: "Nuclear Magnetic Resonance Logging While Drilling," *Oilfield Review* 15, no. 2 (Summer 2003): 40–51.
3. Kupecz JA, Gluyas J and Bloch S: "Reservoir Quality Prediction in Sandstones and Carbonates: An Overview," in Kupecz JA, Gluyas J and Bloch S (eds): *Reservoir Quality Prediction in Sandstones and Carbonates*. Tulsa: AAPG (1997): vii–xxiv.



^ Distribution of carbonate reservoirs. Carbonate rocks hold many barrels of oil and many years of reserves, with the bulk of reserves in the Middle East. Most spectacular are accumulations in Saudi Arabia, where production from carbonate reservoirs is expected to continue for many decades.



^ Carbonate porosity classification. A classification scheme developed by Ahr emphasizes the origins of porosity—deposition, diagenesis or fracturing—to distinguish carbonate rocks (*middle*). Depositional porosity represents space that remains between grains, such as the ooids in the scanning electron micrograph (*top*), skeletal fragments or other particles. Diagenetic porosity, filled with blue epoxy in a thin section of dolomitized limestone (*left*), can result from cementation, compaction, dissolution, recrystallization or replacement processes. Fracture porosity can occur at more than one scale, as is shown by at least two fracture sets in the outcrop photograph (*bottom right*). An infinite variety of hybrid pore types exists between the end members. (Photographs of ooids and fractures courtesy of Wayne Ahr; photograph of intercrystalline porosity courtesy of David C. Kopaska-Merkel.)

The mineralogy of carbonate rocks is relatively simple, with calcite [CaCO₃], dolomite [CaMg(CO₃)₂] and evaporite minerals such as anhydrite [CaSO₄] and gypsum [CaSO₄·2H₂O] predominant, and less clay than siliciclastic sedimentary rocks. Burial might preserve the calcium carbonate where it formed, or the material might be eroded or leached, transported as grains or in solution, and deposited elsewhere by moving water or reprecipitation. Physical, biological and chemical variations create heterogeneous rock textures and fabrics during and after deposition, often destroying any

comparatively simple relationships that might have existed between depositional attributes, porosity and permeability.

The susceptibility of carbonate minerals to chemical change once removed from, or even within, the environment of deposition means that diagenetic processes are more significant in carbonate rocks than in their siliciclastic counterparts.⁴ These processes affect carbonate rocks at scales from microns to kilometers, and commonly modify the sizes and shapes of pore spaces. Deformation, such as fracturing, can alter permeability and porosity. Dissolution

processes form caves, sinkholes and other features collectively known as karst, which also affect reservoir properties.

Realistic predictions and reservoir models depend on comprehending the processes that created or altered the carbonate formations, and on measuring rock properties at adequate resolutions.⁵ When developing models and making predictions, it is crucial to consider that pore-modifying geologic processes can occur repeatedly.⁶

Some carbonate-reservoir practitioners focus on a particular scale when considering carbonate reservoir properties. The smallest scale involves

the internal structure of the rock, including mineral grains, fossils and organic matter, and pore types and geometries.

An intermediate scale, which ranges from about one foot to hundreds of feet [1 to 100 m], offers insights into mineralogy, porosity, fluid saturation, permeability, reservoir continuity and diagenetic patterns. Geological features such as bedding, vugs, stylolites and fractures are readily observable at this scale.⁷

At the reservoir scale, experts focus on the overall geometry and boundaries of reservoir flow units, commonly using seismic data, log correlation and history-matching of production data. However, successful hydrocarbon-production strategies require understanding and integration of data; the subsequent interpretations and actions must be compatible at all scales.

Recent progress towards understanding carbonate reservoirs stems, in part, from simplifying carbonate rock characterization. Rather than attempting to subdivide carbonate rocks into an impractical number of categories, scientists and engineers are invoking more practical classification schemes that are leading to more reliable interpretations of pore systems, which are a critical step towards improving carbonate reservoir management. Classifications that emphasize flow behavior can lead to more straightforward decision making during production operations.

Various classification schemes have been applied to carbonate rocks.⁸ Perhaps the most widely known are those of Dunham and of Folk. The Dunham classification emphasizes depositional textures. The Folk system begins with grain types and their relative abundance, and then incorporates texture and grain size. Other geologists use classifications that focus on pore properties to evaluate reservoir quality.⁹ By carefully studying the carbonate rock components, textures and pores, geologists can determine the types and relative timing of depositional processes, diagenetic processes and natural fracturing ([previous page](#)).

Another conceptual framework involves petrophysical rock types, described by Archie in siliciclastic and carbonate rocks.¹⁰ Rocks of a common petrophysical type possess comparable attributes such as porosity, permeability, saturation or capillary-pressure properties. These similarities underpin expectations of similar reservoir performance. Lucia added descriptive pore-system attributes, which advanced the utility of petrophysical rock types for permeability prediction in carbonate reservoirs by linking describable, mappable

properties of carbonate rocks with geologic models to enhance quantitative analysis at a larger scale.¹¹

Understanding pore types or rock types provides an important foundation for studies of reservoir performance, but it is not enough, even in reservoirs that are not fractured. To predict reservoir behavior, scientists and engineers are turning to probabilistic techniques.¹² These techniques should help scientists and engineers quantify reserves remaining in a reservoir and select the technologies necessary to recover those reserves, but with a clear understanding of the uncertainty associated with each aspect of the work.

Novel Interpretation Techniques

Years ago, premature water breakthrough during waterflooding in carbonate reservoirs prompted Schlumberger scientists and engineers to initiate intensive studies of carbonate rocks. In contrast to empirical approaches taken previously, these studies led to a petrophysical interpretation methodology for carbonate rocks that integrated

log analysis with core studies.¹³ Researchers developed this approach to quantify macropores and to understand macropore connections and permeability.¹⁴

This type of analysis begins with borehole images, which help petrophysicists characterize and analyze porosity, including natural fractures and vug-filling material. Within the matrix, other measurements, such as those from nuclear magnetic resonance (NMR) logging tools, indicate characteristics of the carbonate pore volumes, which researchers enter into an algorithm to determine the relative amounts of intragranular, intergranular and vuggy porosity; integration with borehole images helps quantify the vug fraction.¹⁵ Finally, these data are used to build a geometric model from which it is possible to estimate fluid-transport properties, such as permeability.

This approach was validated using core and log data from the Middle East.¹⁶ However, scientists and engineers constantly pursue new approaches to better evaluate carbonate rocks (see “Reinventing Carbonate Petrophysics,” *page 1*).

4. Diagenesis involves the physical, chemical or biological alteration of sediments into sedimentary rock at relatively low temperatures and pressures, which can change the rock's original mineralogy and texture. Carbonate sediments often include substantial amounts of metastable minerals such as aragonite [CaCO₃], which is readily dissolved and replaced by calcite. After deposition, sediments are compacted as they are buried beneath successive layers of sediment and cemented by minerals that precipitate from solution. Grains of sediment, rock fragments and fossils can be replaced by other minerals during diagenesis. Porosity usually decreases during diagenesis, except in rare cases such as dissolution of minerals and certain types of dolomitization.
5. For a discussion about creating more effective carbonate reservoir models: Lucia J: “Linking Petrophysical and Geologic Information: A Task for Petrophysics,” *Dilfield Review* 12, no. 4 (Winter 2000/2001): i.
6. Ahr WM and Hammel BS: “Identification and Mapping of Flow Units in Carbonate Reservoirs: An Example from the Happy Spraberry (Permian) Field, Garza County, Texas, USA,” *Energy Exploration and Exploitation* 17 (1999): 311–334.
7. Stylolites are wave-like or tooth-like, serrated, interlocking surfaces most commonly seen in carbonate and quartz-rich rocks that contain concentrated insoluble residue such as clay minerals and iron oxides. Stylolites are thought to form by pressure solution, a dissolution process that reduces pore space under pressure during diagenesis.
8. For a detailed discussion of carbonate classification schemes: Scholle PA and Ulmer-Scholle DS: “Carbonate Classification: Rocks and Sediments,” in Scholle PA and Ulmer-Scholle DS: *A Color Guide to the Petrography of Carbonate Rocks: Grains, Textures, Porosity, Diagenesis*. The American Association of Petroleum Geologists Memoir 77. Tulsa: AAPG (2003): 283–302.
9. Ahr WM: “Carbonate Pore Properties as Indices of Reservoir Quality,” *AAPG Bulletin* 84, no. 13 (Supplement, 2000).
10. Archie GE: “Introduction to Petrophysics of Reservoir Rocks,” *AAPG Bulletin* 34, no. 5 (May 1950): 943–961.
11. Lucia FJ: “Rock-Fabric/Petrophysical Classification of Carbonate Pore Space for Reservoir Characterization,” *AAPG Bulletin* 79, no. 9 (September 1995): 1275–1300.
12. Feazel CT, Byrnes AP, Honefenger JW, Leibrecht RJ, Loucks RG, McCants S and Saller AH: “Carbonate Reservoir Characterization and Simulation: From Facies to Flow Units: Report from the March 2004 Hedberg Research Symposium,” *AAPG Bulletin* 88, no. 11 (November 2004): 1467–1470.
13. Ramakrishnan TS, Ramamoorthy R, Fordham E, Schwartz L, Herron M, Saito N and Rabaute A: “A Model-Based Interpretation Methodology for Evaluating Carbonate Reservoirs,” paper SPE 71704, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30–October 3, 2001.
14. Micropores, with pore-throat diameters less than 0.5 microns, usually contain mostly irreducible water and little hydrocarbon. Mesopores, with pore-throat diameters between 0.5 and 5 microns, may contain significant amounts of oil or gas in pores above the free-water level (FWL). Macropores, with throats measuring more than 5 microns in diameter, are responsible for prolific production rates in many carbonate reservoirs, but often provide pathways for early water breakthrough, leaving considerable gas and oil behind in mesopores above the FWL. For more on pore types: Akbar et al, reference 1. Others define microporosity as “pores whose dimensions are significantly smaller than those contributing to the rock's permeability.” For more information: Swanson BF: “Microporosity in Reservoir Rocks: Its Measurement and Influence on Electrical Resistivity,” *The Log Analyst* 26, no. 6 (November–December 1985): 42–52.
15. A vug is a cavity, void or large pore in a rock. Vugular porosity commonly occurs in rocks prone to dissolution, such as limestone, in which case it is classified as secondary porosity.
16. Ramakrishnan TS, Rabaute A, Fordham EJ, Ramamoorthy R, Herron M, Matteson A, Raghuraman B, Mahdi A, Akbar M and Kuchuk F: “A Petrophysical and Petrographic Study of Carbonate Cores from the Thamama Formation,” paper SPE 49502, presented at the 8th Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, November 11–14, 1998.

Evaluating Reservoir Properties

Geologists, petrophysicists and reservoir engineers might prefer different approaches for studying carbonate reservoirs, but in the end, oil and gas assets are usually managed by a team that includes people from these and other technical disciplines. All participants pursue a shared goal. To do this, the team must share an awareness of the problems at hand.

A common characteristic of carbonate reservoirs is loosely termed “heterogeneity,” and a common mistake is to try to approach it with techniques developed for noncarbonate rocks. Heterogeneity is not a problem in carbonate reservoirs if it is approached with the presumption that different types of heterogeneity exist at various scales of investigation or in different orientations. Heterogeneity may exist in the types of grains, textures and pores; in natural fracture distribution; and in diagenetic effects. Different types of heterogeneity may be superimposed on one another.

To better appreciate fundamental aspects of carbonate rocks, descriptions can be developed for a variety of purposes, just as various carbonate rock classification schemes have been developed. For example, one could use a framework of flow performance or a framework of pore types, but the description should fit the nature and scale of the problem. Building the appropriate foundation may be complicated by different types of heterogeneity or superimposed heterogeneities.

Regardless of the descriptive framework, effective reservoir management requires comprehensive knowledge of performance parameters of interest, such as permeability, saturation exponent and microscopic displacement efficiency, between distinct reservoir zones. Saudi Aramco is working to develop a more complete comprehension of the

microscopic displacement efficiency of the limestone pore systems of the Arab-D reservoir in the Ghawar field. The limestone pore systems are first being addressed by thorough analysis of 125 mercury-injection capillary pressure (MICP) samples from the carefully collected Hagerty-Cantrell dataset and by the acquisition of 500 more capillary pressure curves as part of the company’s Rosetta Stone project.¹⁷

Capillary-pressure curves are important for assessing fluid flow in reservoirs.¹⁸ The process of mercury injection into rock samples is analogous to the filling of the pore system by hydrocarbons—termed drainage because of the draining of the water-wetting phase—in the reservoir. In addition, MICP data help scientists and engineers estimate pore geometrical effects on reservoir performance.

The Thomeer method, pioneered at Shell in the 1960s, uses a laboratory measurement of the volume of liquid mercury injected into a rock sample as the pressure on the liquid mercury increases.¹⁹ The data typically are presented in plots of fractional bulk volume occupied by mercury versus pressure; the shape of the curve contains information about the pore-throat sizes and pore geometries, and the injection simulates the filling of the pore system with hydrocarbons. The experiment uses air as the wetting phase—analogue to water in the reservoir—and mercury as the nonwetting phase—analogue to hydrocarbon in the reservoir—so that pore geometrical information is captured without reservoir fluid wettability effects.

In the Thomeer method, a single pore system MICP curve can be described by one Thomeer hyperbola, which is characterized by only three parameters: the pore-system porosity, the size of the largest pore throat and a pore geometrical factor that reflects the pore throat-size

distribution. The capillary-pressure behavior of complex pore systems is matched by the superposition of multiple Thomeer hyperbolae. Specialized software performs interactive type-curve matching to MICP data and data derivative type-curve matching interactively in a manner similar to pressure transient analysis methods. This software allows large volumes of MICP data to be analyzed rapidly, helping scientists and engineers quickly capture information about pore geometries.²⁰ The Thomeer parameters represent a vastly compressed and petrophysically intuitive dataset for the reservoir pore geometries that can then be analyzed using statistical methods.

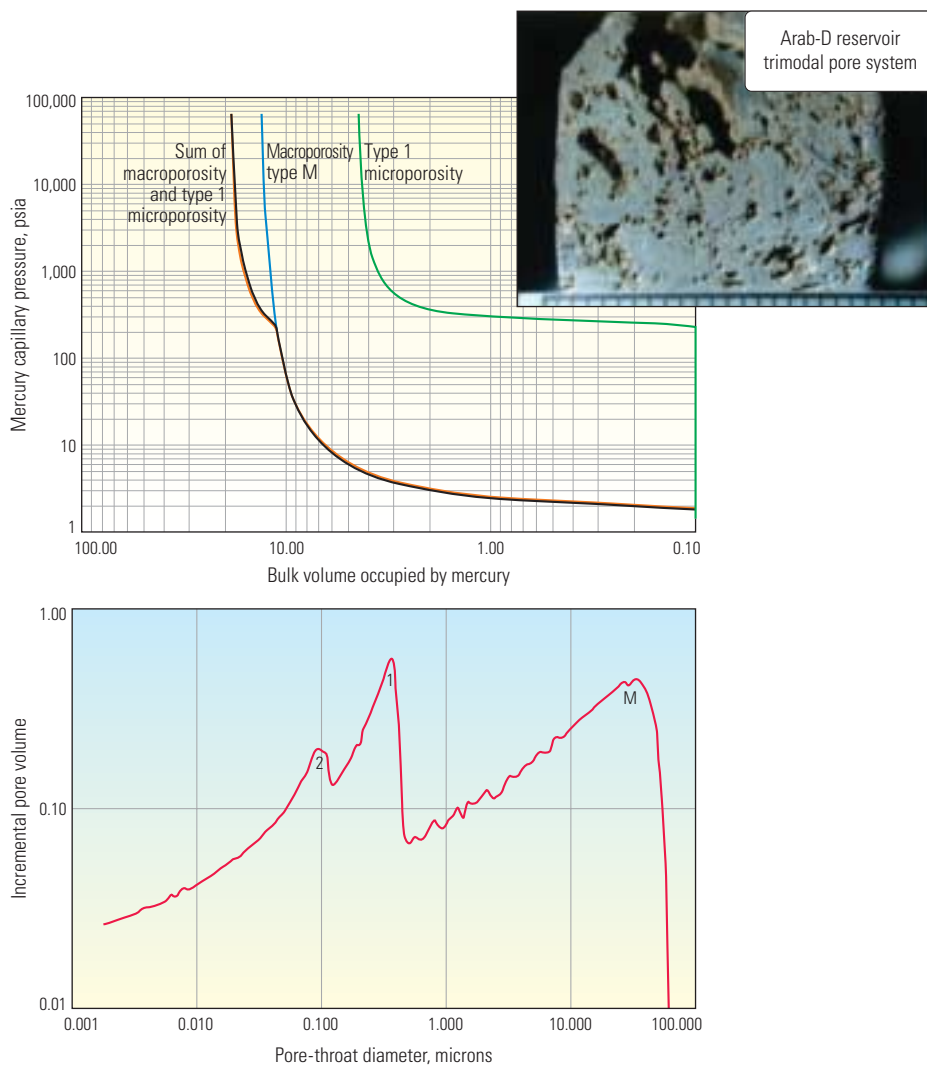
In the Arab-D limestones of Ghawar field, the Thomeer method is being used for saturation-height modeling, free-water level determination and evaluation of pore geometries, and is improving the permeability models. The Thomeer plots of cumulative volume occupied by mercury versus pore throat radius are used to describe the overall “plumbing” system of the reservoir (next page). Analysis of the first 125 samples has demonstrated that the many complex limestone pore systems are combinations of just three types or modes of simple Thomeer pore systems. The 500-sample Rosetta Stone study revealed a fourth mode of porosity. Thus, a reservoir that might previously have been described as “heterogeneous” is now known to be constructed from a just a few combinations of porosity subgroups—not a hopelessly complicated assemblage of differently performing reservoir rocks.²¹

Using pore-system models that incorporated porosity, permeability, capillary pressure and relative permeability for each rock type, Saudi Aramco is continuing to refine the comprehensive reservoir model. This approach to analysis and

17. Cantrell DM and Hagerty RM: “Reservoir Rock Classification, Arab-D reservoir, Ghawar Field, Saudi Arabia,” *GeoArabia* 8, no. 3 (2003): 435–462.
Clerke EA: “Beyond Porosity-Permeability Relationships—Determining Pore Network Parameters for the Ghawar Arab-D Using the Thomeer Method,” presented at the 6th Middle East Geoscience Conference and Exhibition, Manama, Bahrain, March 7–10, 2004.
18. For more on capillary pressure: Wardlaw NC and Taylor RP: “Mercury Capillary Pressure Curves and the Interpretation of Pore Structure and Capillary Behaviour in Reservoir Rocks,” *Bulletin of Canadian Petroleum Geology* 24, no. 2 (June 1976): 225–262.
19. Thomeer JHM: “Air Permeability as a Function of Three Pore-Network Parameters,” *Journal of Petroleum Technology* 35, no. 4 (April 1983): 809–814.
Thomeer JHM: “Introduction of a Pore Geometrical Factor Defined by the Capillary Pressure Curve,” *Petroleum Transactions of the AIME* (1959): 354–358.

20. Clerke EA and Martin PR: “Thomeer Swanson Excel Spreadsheet and FAQs and User Comments,” presented and distributed at the Carbonate Petrophysics Workshop of the SPWLA 45th Annual Logging Symposium, Noordwijk, The Netherlands, June 6–9, 2004.
21. Clerke has termed these Gaussian modes of pore-throat statistics from the Arab-D limestone porosity subgroups *parasitons*. It is anticipated that these parasitons also have pore body distribution mode equivalents, called *porobodons*, which will expedite analysis of the carbonate NMR signal. Analysis of logs acquired from an Arab-D well in Ghawar field revealed three such modes in the CMR Combinable Magnetic Resonance signal. The fourth mode is below the CMR time decay resolution.
22. For more on NMR techniques: Alvarado et al, reference 2. Allen D, Flaum C, Ramakrishnan TS, Bedford J, Castelijns K, Fairhurst D, Gubelin G, Heaton N, Minh CC, Norville MA, Seim MR, Pritchard T and Ramamoorthy R: “Trends in NMR Logging,” *Oilfield Review* 12, no. 3 (Autumn 2000): 2–19.

23. CPMG refers to the cycle of radio frequency pulses designed by Carr, Purcell, Meiboom and Gill to produce echoes and counteract dephasing caused by static magnetic field inhomogeneities.
24. The Timur-Coates method for calculating permeability is based on the ratio of free fluid to bound fluid from NMR measurements. As in many permeability computations, there is a term based on porosity and a term related to pore size, in this case the ratio of free fluid index (FFI) to bound fluid index (BFI). The SDR method, developed at Schlumberger-Doll Research, is based on the logarithmic mean T_2 from an NMR measurement, and the computation includes a term based on porosity and a term related to pore size, in this case the logarithmic mean T_2 .
25. For more information: Hassall JK, Ferraris P, Al-Raisi M, Hurley NF, Boyd A and Allen DF: “Comparison of Permeability Predictors from NMR, Formation Image and Other Logs in a Carbonate Reservoir,” paper SPE 88683, presented at the Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, October 10–13, 2004.



▲ Pore networks in the Ghawar field. Mercury-injection capillary-pressure data reveal a relatively simple system of three pore types in the Ghawar Arab-D reservoir (*bottom*), where this pore-throat view indicates a small amount of type 2 microporosity is visible. This apparently complex and heterogeneous pore system can be completely characterized by the superposition of only three Thomeer hyperbolae (*top*). The pore-network concept links geological interpretations with reservoir-engineering data to enhance reservoir models for decision making.

model building will help the multidisciplinary team perform even more powerful reservoir simulations and forecasts for the world's largest oil field.

Magnetic Resonance Technology for Fluid Characterization

NMR techniques are routinely used for carbonate formation evaluation. However, compared with sandstones, there are many challenges inherent in measuring carbonate porosity, deriving permeability and interpreting NMR data for pore-size distributions. Nevertheless, this is exactly the type of information formation-evaluation experts seek from NMR technology. Scientists and engineers continue to develop and optimize NMR applications, especially for

reservoir-fluid characterization. Recent advances include measurements of oil viscosity and saturations at multiple depths of investigation.²²

NMR measurements reveal pore and fluid properties in rock formations through a two-stage measurement. First, in the polarization stage, the hydrogen atoms are aligned like bar magnets along the direction of a static magnetic field, known as B_0 . This polarization takes a characteristic time known as T_1 that depends on the environment surrounding the hydrogen. In the second stage, known as acquisition, the hydrogen atoms are manipulated by short pulses of an oscillating magnetic field. The frequency of oscillation is chosen to match the Larmor resonance frequency, a quantity proportional to the applied magnetic field, B_0 . The pulses cause

the hydrogen atoms to rotate away from, and then precess about, the direction of B_0 . Properly timed pulses generate coherent responses, known as echoes, from the hydrogen atoms. Echoes induce voltage in an antenna placed in a plane perpendicular to the direction of B_0 . Many echoes can be generated after a single polarization stage, with successive echoes decreasing in magnitude by a process known as transverse relaxation.

In NMR logging, relaxation is caused by interactions of the hydrogen atoms with their surroundings, including bulk fluids and pore surfaces, and by diffusion in magnetic field gradients. The decay of the echo signal with time depends on the specific sequence of pulses. The most common is called the Carr-Purcell-Meiboom-Gill (CPMG) pulse sequence.²³ The total signal from this sequence and its decay is the sum of signals from different parts of the fluid sample, each decaying at a characteristic transverse relaxation time, T_2 . For the typical case of water-wet rocks, short T_2 values—fast signal-decay rates—arise from water in small pores or the presence of heavy hydrocarbons, while long T_2 values—slow signal-decay rates—arise from water in large pores or the presence of lighter hydrocarbons. The CPMG data can then be processed, or inverted, to quantify the T_2 times that contributed to the overall decay along with the amplitude, in porosity units, associated with each T_2 .

The T_2 distribution is the basic output of an NMR logging measurement, and is presented at each sample depth as amplitudes versus T_2 time, typically from 0.3 ms to 3 s. The T_2 decay can be further processed to quantify pore volumes associated within different ranges of T_2 . The volumes of interest typically are the bound fluid in small pores and free fluid that is readily producible from larger pores. A permeability estimate is made using a transform, such as the Timur-Coates or SDR permeability transforms.²⁴ New carbonate petrophysics software, discussed later in this article, implements a methodology based on a series of field studies. The software uses NMR measurements, FMI Fullbore Formation MicroImager data and a porosity interpretation to partition porosity into *micro*, *meso* and *macro* components.²⁵ The new application then uses that partition to reconstruct the permeability.

Knowing the volume of movable fluid and interpreting the permeability from a T_2 distribution is just the beginning. Schlumberger has continued developing NMR technology to shed light on which fluids are present in the

formation volume of investigation. The MRX Magnetic Resonance eXpert tool is the next-generation wireline-conveyed NMR logging tool (below).²⁶ Important features of the MRX tool include its gradient magnetic field and its multiple frequencies of operation.

A gradient tool has a static magnetic field that decreases uniformly away from the tool and into the formation. The resonance or Larmor condition will thus be met over a wide range of frequencies that correspond to measuring hydrogen at variable distances from the borehole. Changing the frequency of operation facilitates the acquisition of measurements at multiple depths of investigation (DOI). MRX programmability allows measurements to be taken at multiple DOI in a single pass. MRX data and answers from multiple DOI are processed and reported independently.

There are three antennae built into each MRX tool, two high-resolution antennae and one main antenna. The main antenna operates at multiple frequencies and is used primarily for fluid-characterization applications. For example, data from the most advanced mode of operation, called saturation profiling, can be used to indicate which fluids are present at both shallow and deep DOI used in the logging sequence. Because of the eccentric mode of operation and the antenna design, the DOI—ranging from 1.5 to 4 in. [3.8 to 10 cm]—are maintained across a wide range of hole sizes, mud types and temperatures. The contrast between deep and shallow DOI helps

analysts identify data-quality problems associated with rugose boreholes, mudcake and fluid invasion because the deepest DOI typically sense beyond drilling-induced formation damage (next page, top).

The MRX tool offers significant advantages for fluid characterization.²⁷ Of the three relaxation mechanisms—bulk relaxation, surface relaxation and diffusion in a gradient—the one most readily controlled by the pulse sequence is diffusion. By modifying a suite of standard CPMG sequences, the effects of diffusion can be

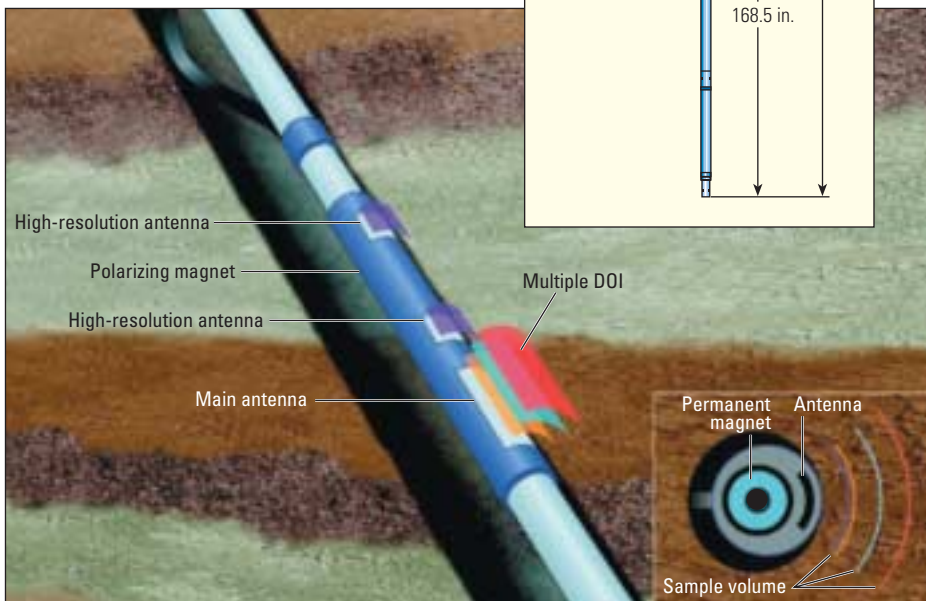
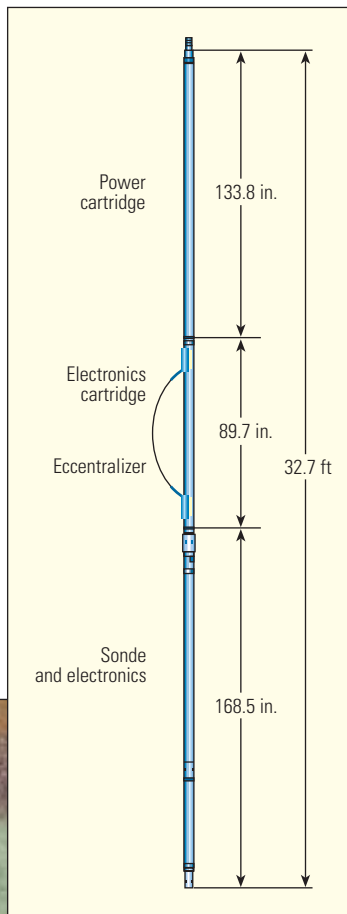
encoded successively into the data. Inversion and subsequent interpretation allow the effects of diffusion to be associated with different types of fluids, including gas, oil, water and oil-base mud filtrate.

The primary interpretation method is either a fluid-model inversion, known as the MRF Magnetic Resonance Fluid characterization method, or a model-independent inversion that generates a two-dimensional correlation between diffusion, D , and T_2 data, known as a D - T_2 map. Both methods, MRF inversion and interpretation of D - T_2 maps, apply the constituent viscosity model, which correlates oil diffusion with its T_2 .²⁸ The diffusion of gas and water is known, so a quantitative measurement of fluid volumes can be obtained. This information is useful in understanding carbonate formations, where multiple fluids, wettability, surface properties and vuggy pore systems present challenges to interpreting the traditional NMR T_2 distribution.

MRX technology is a complement to the existing pulsed NMR tool, the CMR Combinable Magnetic Resonance tool. The choice of which device to run depends on the formation-evaluation goals. If standard NMR answers at shallow DOI are sufficient, with the option of fluid characterization as a station log, then CMR technology might be appropriate. The CMR sonde is shorter and lighter, making for easier wellsite deployment. On the other hand, the MRX tool provides formation-evaluation answers that are unavailable from other tools. In Bahrain, for example, fluid characterization and multiple DOI analysis from the CMR and MRX tools proved instrumental in reevaluating bypassed pay.

Reevaluating Bypassed Pay in Bahrain

Bahrain Petroleum Company (BAPCO) recently reevaluated the upper Cretaceous Aruma zone in the Bahrain field (next page, bottom). Although the field was discovered in 1932 and now contains more than 400 producing wells, oil reserves behind casing in this dolomitic



▲ The MRX Magnetic Resonance eXpert device. The tool has a multifrequency main antenna designed for fluid characterization applications and two high-resolution antennae that provide rock-quality and producibility information.

26. For more on the MRX tool: DePavia L, Heaton N, Ayers D, Freedman R, Harris R, Jorion B, Kovats J, Luong B, Rajan N, Taherian R, Walter K, Willis D, Scheibal J and Garcia S: "A Next-Generation Wireline NMR Logging Tool," paper SPE 84482, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 5–8, 2003.

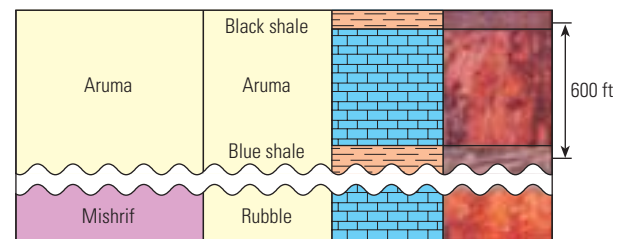
27. Freedman R and Heaton N: "Fluid Characterization Using Nuclear Magnetic Resonance Logging," *Petrophysics* 45, no. 3 (May–June 2004): 241–250.

28. Freedman R, Sezginer A, Flaum M, Matteson A, Lo S and Hirasaki GJ: "A New NMR Method of Fluid Characterization in Reservoir Rocks: Experimental Confirmation and Simulation Results," paper SPE 63214, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 1–4, 2000.

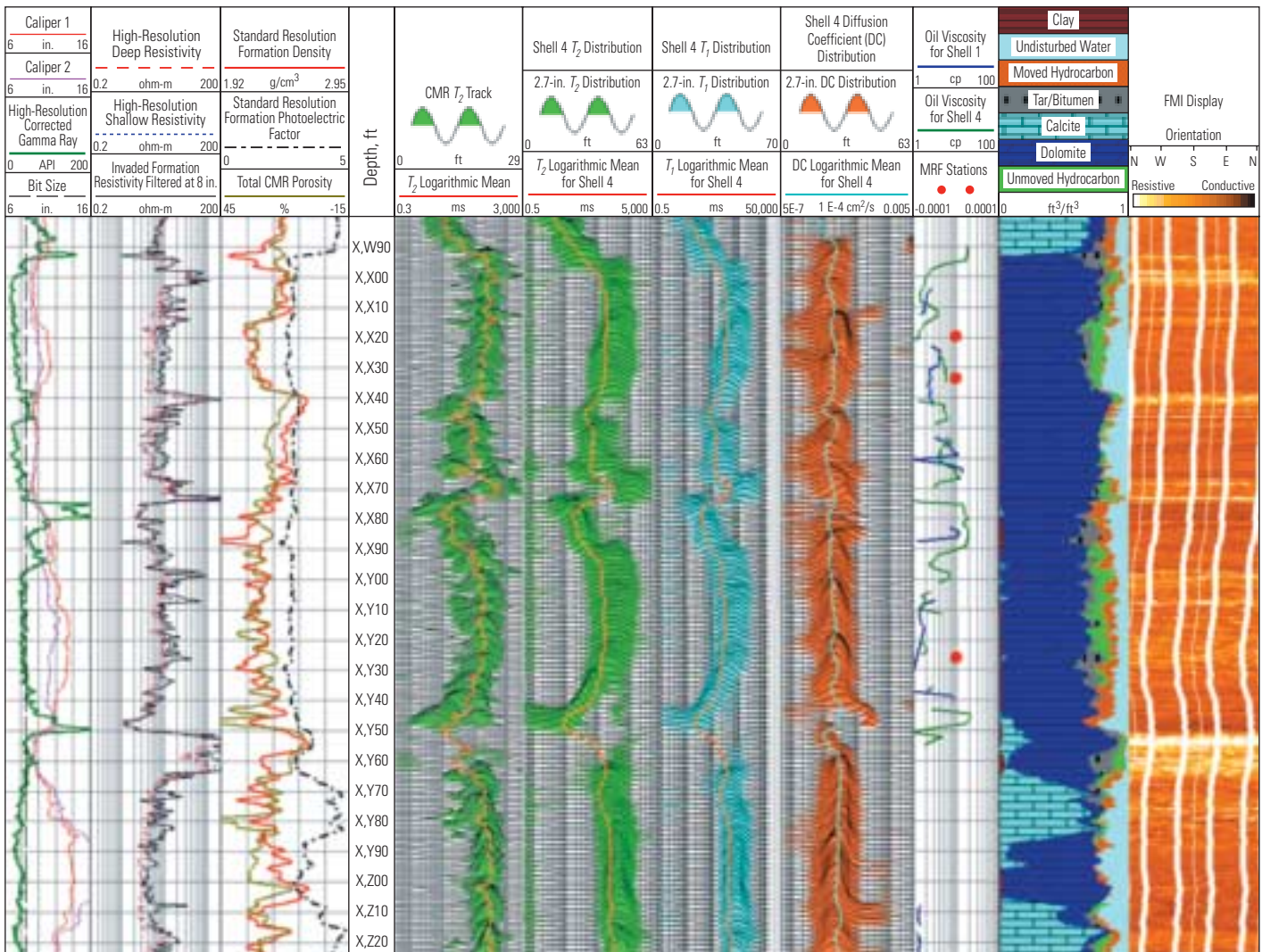
MRX Advantages in Carbonate Rocks	
Automatic tuning while logging	Continuous depth logs No sticking
High single-value gradients	Fluid characterization Well-defined DOI
Independent analysis at each DOI	Improved interpretation Unaffected by rugose boreholes and formation damage
Optimized acquisition	Precise answers in a wide range of environments
Long magnet	Robust T_1 and T_2 distributions in large pores and vugs
Programmability	Development of new modes



^ Advantages of the MRX tool in carbonate rocks.



^ Bahrain field location and stratigraphy. Discovered in 1932, Bahrain field is a faulted anticlinal structure (*left and top right*) from which more than 400 wells now produce. BAPCO studied the producibility of the upper Cretaceous Aruma zone (*bottom right*), long considered subeconomic, by acquiring fluid and rock data in the form of cores and logs.



^ Composite log from the Bahrain field. High-resolution log analysis was essential for proper interpretation of a complete log suite and core from Well B. Gamma ray, bit size and caliper data in Track 1 show the poor hole quality. CMR and MRX data appear in Tracks 4 through 8. Fluid-viscosity data in Track 8 include CMR station measurements and MRX profiles. A formation evaluation from ELANPlus Elemental Log Analysis software is presented in Track 9, and an FMI image in Track 10.

limestone were bypassed in favor of deeper low-viscosity oil.²⁹ The Aruma zone oil was widely believed to have a viscosity as high as 20,000 cp because earlier drilling often indicated the presence of tar in the Aruma zone, making it economically unattractive.

To fully assess the producibility of the Aruma zone, BAPCO initiated a detailed study in 2001 that focused on two wells in the north-central area of the field.³⁰ Working with Schlumberger, BAPCO acquired conventional core, a Platform Express integrated wireline logging tool suite and FMI and CMR logs in Well A to determine lithology, porosity, tar content and permeability, and to better predict flow from the Aruma reservoir. In Well B, drilled in 2003, BAPCO acquired the same data in addition to MRX data (above).

While logging Well B, the asset team found that samples of produced oil in the drilling mud had viscosities as low as 3 cp. Careful petrophysical analysis incorporated porosity, lithology and core data. Permeability predictions from the integrated dataset suggested that permeability improves with increasing dolomitization.³¹

All data—from drilling, logs and cores—were integrated using the Well-ID Well-Informed Decisions program, a Windows-based answer-product delivery system. The software allows users to integrate and view log, core and test data, photographs and interpretations on one screen, which facilitates knowledgeable decisions and input for reservoir simulations.

NMR data proved crucial to the petrophysical evaluation of the Aruma zone. In Well A, core photographs confirmed the accuracy of tar zone identification on the basis of the CMR log.

In Well B, the CMR and MRX tools were run together. In some sections, poor hole quality impaired log data quality except for the deep, 2.7-in. MRX shell, or volume, which was unaffected by borehole enlargement. The reservoir team was able to reliably evaluate porosity and tar volume by careful integration of the data.

The MRF technique was applied in Well B (next page). The MRF technique can be performed by station logging with the CMR tool; the MRX device can acquire fluid-characterization data versus depth in continuous logging mode. In this case, four stations were acquired with the CMR tool. The results of fluid characterization from both tools indicated that oil of a relatively low viscosity, less than 5 cp, existed in addition to tar, leading the team to conclude that the Aruma zone

contains economically producible saturations of movable oil.

On the basis of this revised assessment of the Aruma zone, BAPCO plans additional completions in this reservoir. The company will continue to integrate advanced logging and analytical approaches to efficiently increase production.

In addition to helping companies better evaluate bypassed reservoirs, NMR technology is playing an important role in evaluating the performance of individual reservoir zones. Identifying reservoir-significant units is an important part of understanding and predicting reservoir performance. This type of interpretation goes beyond standard petrophysical analysis by moving an interpretation from a single well into a larger context, such as a stratigraphic or sequence stratigraphic framework.³² From this interpretation, sedimentary packages can be properly grouped into reservoir flow units or compartments, and reservoir engineers can make informed reservoir-management decisions.

Identification of reservoir-significant units holds promise in oil-bearing carbonate rocks. Carefully mapped flow units are incorporated

into three-dimensional (3D) reservoir models. From these models, scientists and engineers can improve reservoir management. High-resolution sequence stratigraphic studies have been performed in carbonate oil reservoirs of the Middle East, where researchers are finding that the combination of image logs and NMR logs is a powerful tool for understanding reservoir behavior, addressing the general problem of distinguishing between porosity types in carbonate rocks.

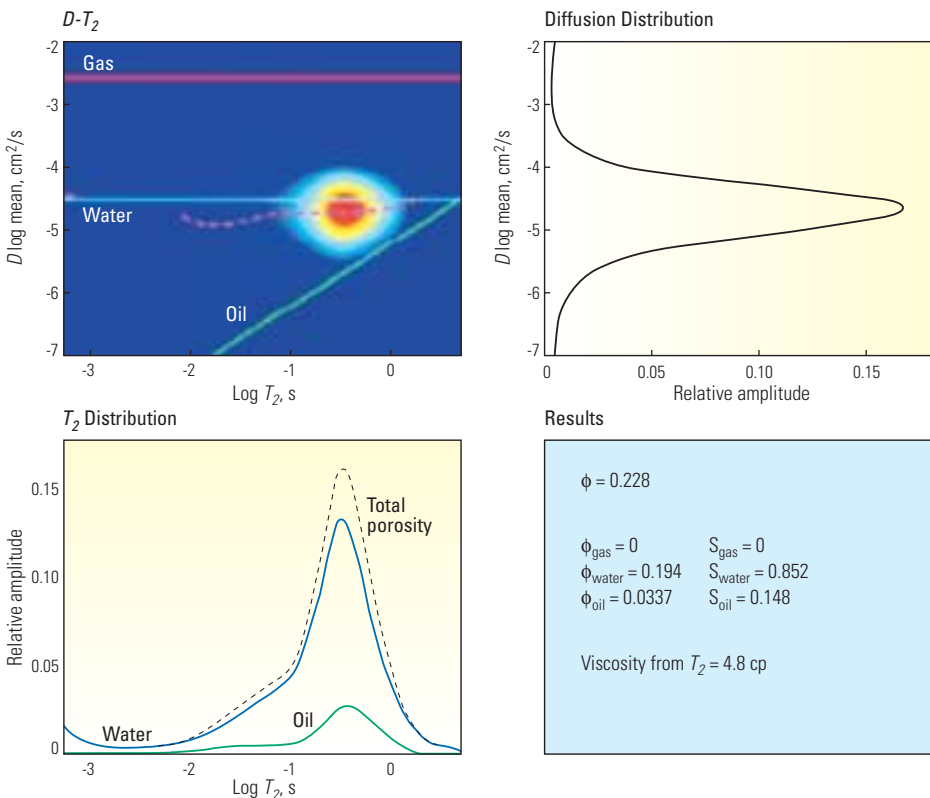
Understanding Flow in Carbonate Reservoirs

In the past, petrophysicists worked assiduously to estimate permeability in carbonate rocks, developing new techniques as new logging tools became available. Early NMR methods showed promise, but were less useful in zones of macroporosity. Sonic methods, such as Stoneley permeability, also proved useful for predicting trends.³³ Analysis of image logs provided a greater degree of vertical resolution and improved evaluations of fractures and secondary porosity. For some time, petrophysicists have recognized that certain combinations of tools and logs yielded better information about

carbonate rocks. For example, running borehole image logs after acquiring sidewall cores is a powerful way to relate core-derived data to log data in heterogeneous rocks. In some areas, however, experts find that permeability is difficult to predict reliably from logs, and that probe packer testing with devices such as the MDT Modular Formation Dynamics Tester device is the best method for estimating permeability.

Ongoing carbonate studies have led to the development of new carbonate petrophysics software. The porosity partitioning and permeability analysis application is a GeoFrame system software application that implements a new carbonate methodology based on a series of field studies done in the Middle East and elsewhere during the last few years. The porosity classification draws on Lucia's classification as well as other widely used classification schemes as a basis for carbonate rock typing.³⁴

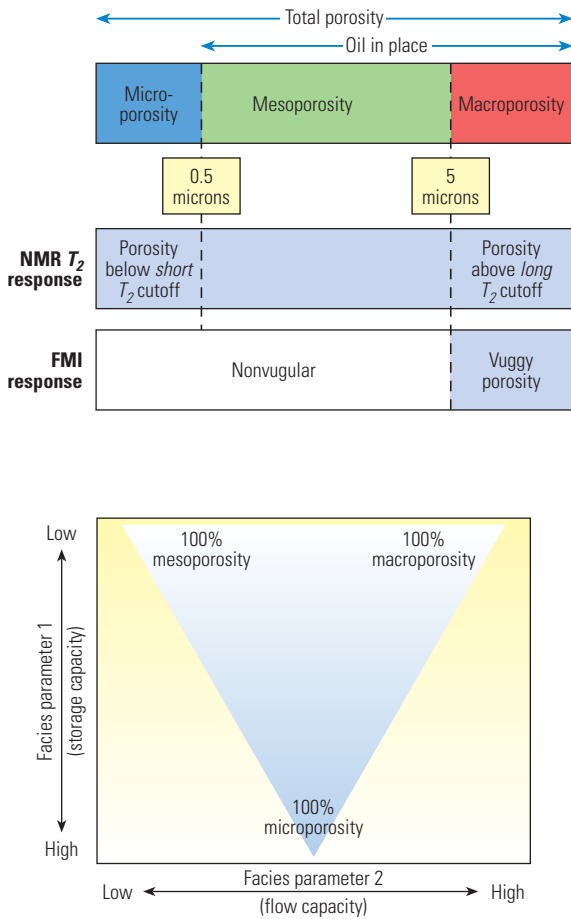
Following a thorough petrophysical analysis of lithology, porosity and fluid saturations, NMR measurements from the CMR tool, the MRX tool or the proVISION real-time reservoir steering service and FMI data, plus a porosity interpretation from ELANPlus Elemental Log Analysis software are introduced into the



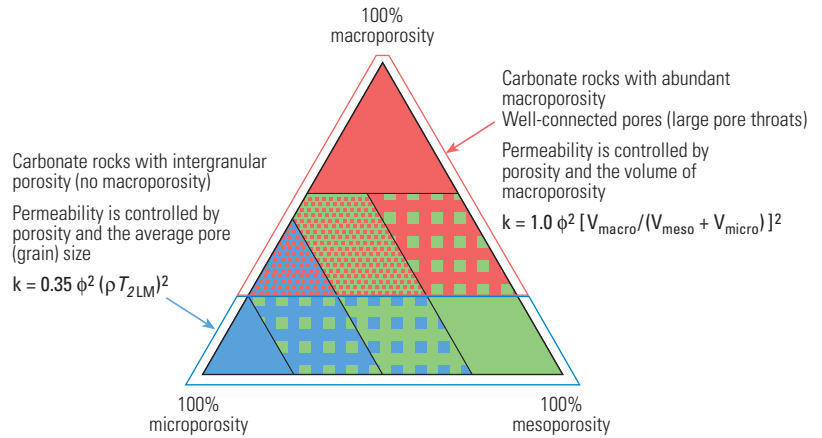
^ Fluid characterization in the Bahrain field. The colors on the map of diffusion (D) versus transverse relaxation time, T_2 (top left) indicate the amount of porosity associated with a given rate of diffusion, or diffusivity, and a given T_2 . This can be thought of as stretching out the T_2 distribution into a second dimension. This map of diffusion versus T_2 indicates low-viscosity oil. The bottom left and top right plots are projections of the map onto the T_2 and D axes. Interpretation results are shown at bottom right.

29. For more on the Bahrain field: Murty CRK and Al-Haddad A: "Integrated Development Approach for a Mature Oil Field," paper SPE 81438, presented at the 13th SPE Middle East Oil & Gas Show and Conference, Bahrain, June 9–12, 2003.
30. Zubari H, Murty CRK, Ramamoorthy R, Srivastava A and Stowe I: "Integrated Visualization and Manipulation of Well Data for Maximizing Data Value and Delivering Well-Informed Decisions for a Shallow Tar Formation," paper SPE 93468, presented at the 14th SPE Middle East Oil & Gas Show and Conference, Bahrain, March 12–15, 2005.
31. Dolomitization is a geochemical process in which dolomite replaces other minerals. The volume of dolomite is less than that of calcite, so in rare cases the replacement of calcite by dolomite in a rock can increase the pore space in the rock. More often, however, dissolution by fluids causes a reduction in porosity.
32. Sequence stratigraphy is a field of study in which basin-filling sedimentary deposits, called sequences, are interpreted in a framework of sedimentation, subsidence and eustasy, or sea-level variation, through time to correlate strata and predict the stratigraphy of relatively unknown areas.
33. Stoneley permeability refers to the ability of fluid to move through a rock, as measured by the reduction in amplitude or increase in slowness of the acoustic Stoneley wave generated in the borehole. The velocity and amplitude of the Stoneley wave are reduced by the presence of mobile fluids in the formation. Physically, the effect can be seen as a coupling of the Stoneley energy into a formation wave known as the slow wave. The amount of reduction is a complicated function of this mobility (or permeability divided by viscosity), the properties of the borehole fluid, the pore fluid and the mudcake, the elastic properties of the rock and the wave frequency.
34. Lucia, reference 11.

Marzouk I, Takezaki H and Suzuki M: "New Classification of Carbonate Rocks for Reservoir Characterization," paper SPE 49475, presented at the 8th Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, October 11–14, 1998.



Carbonate Pore System Classes and Permeability



▲ Porosity partitioning. Advanced software uses NMR T_2 measurements and FMI responses to distinguish micro-, meso- and macroporosity (*upper left*). From this, scientists and engineers can begin to assess crucial aspects of reservoir performance, including storage capacity and flow capacity (*lower left*). The pore-system classes shown above are used in standard interpretation displays.

porosity-partitioning package to divide the porosity into micro, meso and macro components (*above*).³⁵ The porosity-partitioning application then uses that result to reconstruct the permeability. The permeability is calculated according to specialized carbonate versions of the SDR or Timur-Coates equations depending on which pore-system classes have been identified. The final output can be tailored to assist decision making for testing, perforating or acid stimulation (*next page*).

This software, first used commercially in late December 2004 by Schlumberger consulting interpreters, has been rigorously tested on carbonate rocks. Petrophysicists from the Abu Dhabi Company for Onshore Oil Operations (ADCO), working with Schlumberger, acquired core measurements and used the software to complete development of the method.³⁶

Like other techniques to evaluate flow potential, porosity partitioning requires skilled interpretation and judicious application to obtain useful results. The model assumes that pore-body size is related to pore-throat size. Therefore, the software was not designed to

handle reservoirs dominated by separate vugs that do not communicate, by fractures that link pores or by large pores connected by small pore throats. However, the software excels in reservoirs that have macropores with intermediate pore connections. Calibration of results from the new application with measured permeabilities from cores or formation tests is essential to ensuring valid interpretations.

In the case of the Abu Dhabi analysis, the interpretation team initially selected a well with extensive data, including cores and a full suite of logs, in a giant field whose reservoir rocks previously had been carefully studied.³⁷ The team was particularly concerned about the wide range of permeability in the well—0.1 to 5,000 mD—and the need to understand the potential effects of high-permeability intervals on production in an active waterflood. Ultimately, the best estimate of permeability came from integrating NMR data with the image log.

Practitioners across the globe are actively pursuing various log-based techniques for porosity-partitioning and permeability quantification to improve completion and field-management strategies.³⁸ Properly adapting

these techniques for the specific nature of a field or region is a significant challenge. For example, successful secondary recovery requires that injected fluids sweep the reservoir efficiently rather than going into an isolated compartment or bypassing reserves along high-permeability zones. In these situations, determining how different carbonate rocks contribute to or impede flow is fundamentally important.

Different Technologies, Different Modalities, Different Insights

Carbonate experts are diligently developing ways to apply both old and new technology to better effect. For example, researchers at Schlumberger Cambridge Research are applying computerized tomography (CT) and immersive visualization techniques to examine the grains, cements and pore systems of rocks from thin-section to whole-core scales.³⁹ Displays at these different scales reveal details of mineralogy, grain types and shapes, pore structures and pore connections. The immersive environment facilitates interactive interpretation of CT data and integration of CT and other data.

