A Snapshot of Carbonate Reservoir Evaluation

Carbonate reservoir evaluation has been a high priority for researchers and oil and gas producers for decades, but the challenges presented by these highly heterogeneous rocks seem to be never-ending. From initial exploration through mature stages of production, geoscientists, petrophysicists and engineers work together to extract as much information as possible from their data to produce maximum reserves from the ground.

Mahmood Akbar
Badarinadh Vissapragada
Abu Dhabi, UAE

Ali H. Alghamdi
Saudi Aramco
Dhahran, Saudi Arabia

David Allen
Michael Herron
Ridgefield, Connecticut, USA

Andrew Carnegie
Dhruba Dutta
Jean-Rémy Olesen
Oil & Natural Gas Corporation-Schlumberger
Joint Research Center
New Delhi, India

R. D. Chourasiya
Oil & Natural Gas Corporation, Ltd.
Mumbai, India

Dale Logan
Dave Stief
Midland, Texas, USA

Richard Netherwood
Jakarta, Indonesia

S. Duffy Russell
Abu Dhabi Company for Onshore Oil Operations
Abu Dhabi, UAE

Kamlesh Saxena
Mumbai, India

Carbonate reservoirs present a picture of extremes. Reservoirs can be colossal though their pores can be microscopic (next page, top). Matrix permeability can be immeasurably low, while fluids flow like rivers through fractures. Evaluation techniques that succeed in sandstone reservoirs sometimes fail in carbonate reservoirs. These variations complicate both reservoir evaluation and hydrocarbon recovery. However, researchers are working to overcome these problems because of the economic significance of oil production from carbonate reservoirs, especially giant and supergiant fields in the Middle East.

The potential rewards are great: about 60% of the world’s oil reserves lie in carbonate reservoirs, with huge potential for additional gas reserves, particularly in the Middle East. In this article, we examine ways to evaluate carbonate reservoirs at the scale of cores and well logs with examples from both research and operations groups around the world (next page, bottom). Methods range from tried-and-true to experimental, and represent a subset of current initiatives rather than a comprehensive review. The results of borehole-scale evaluations play significant roles in larger scale field development, simulation and management efforts. We also discuss the impact of these results on ongoing research efforts.

Why the Fuss about Carbonate Rocks?
Carbonate sedimentary rocks differ from siliciclastic sedimentary rocks in several ways. Siliciclastic rocks form as sediments are transported, deposited and lithified, or compacted and cemented into solid rock. Most carbonate rocks develop from biogenic sediments formed by biological activity, such as reef building and accumulation of the remains of organisms on the seafloor. Other types form as water evaporates from shallow onshore basins or as precipitates from seawater. The fragments that make up most carbonate rocks typically have undergone much less transport than most siliciclastic sediments.

Carbonate heterogeneity. Photomicrograph pairs show three rock fabrics from the same reservoir. The images at the top are conventional plane-polarized light photomicrographs of thin sections. The cathodoluminescence photomicrographs (bottom) reveal different generations of carbonate minerals formed during diagenesis. Each rock fabric has a different response to nuclear magnetic resonance (NMR) because of the different relationships of the pores within and between grains. Differences in depositional facies and stratigraphic position produced three distinct diagenetic pathways. In the ooid grainstone (left), the cores of the ooids were dissolved early in the depositional history. Calcite cements filled both intergranular and intragranular porosity. The fabric-retentive, dolomitized ooid-peloidal grainstone (center) initially underwent minor diagenesis during which some skeletal grains were dissolved. Fine dolomite crystals then replaced the sediment and preserved the original fabric at an early stage. Later, dolomite cement filled some of the large moldic pores. Sucrosic dolostones (right) represent peloidal grainstone that was replaced by fine sucrosic dolomite crystals, destroying much of the original depositional texture.

Distribution of carbonate rocks. The black circles denote locations of examples described in this article.
clay minerals, fragments of preexisting rocks and remnants of plants or animals. Carbonate rocks consist of a more limited group of minerals—predominantly calcite and dolomite. Other minerals less commonly present in carbonate rocks are phosphate and glauconite; secondary minerals include anhydrite, chert, quartz, clay minerals, pyrite, ankerite and siderite.

These differences result in entirely different classification systems for clastic and carbonate rocks, with clastic rocks distinguished by grain composition and size, and carbonate rocks differentiated by such factors as depositional texture, grain or pore types, rock fabric or diagenesis (right). Differentiating present-day flow units from original depositional units is becoming more important than other aspects of classification because optimal well placement depends on understanding present-day flow units.

Once deposited, sediments undergo diagenesis, the postdepositional chemical and physical changes that transform the sediment into solid rock. Carbonate diagenesis can significantly modify pore space and permeability. Carbonate rocks are highly susceptible to dissolution; grains can be dissolved to form new pore space, and dissolution along fractures and bedding planes can produce large vugs and caves. Clastic diagenesis normally does not involve a change in mineralogy. Carbonate diagenesis, however, commonly involves replacing the original calcite and aragonite with the mineral dolomite, a process called dolomitization, which can improve the hydrocarbon-producing characteristics.

While both clastic and carbonate rocks are usually buried, compacted and cemented, carbonate sediments contain significant amounts of the metastable minerals aragonite and magnesium calcite; calcite itself is readily dissolved and reprecipitated by percolating pore fluids. Carbonate rocks are, therefore, more likely to undergo dissolution, mineralogical replacement and recrystallization. These effects vary according to temperature, pore-fluid chemistry and pressure. Carbonate diagenesis commonly begins with marine cementation and boring by organisms at the sediment-water interface prior to burial. It continues through shallow burial with cementation, dissolution and recrystallization, and then deeper burial where dissolution processes known as pressure solution may form such features as stylolites. When confronted with core samples or image logs from carbonate rocks, even casual observers notice the tremendous variety of pore types and sizes, and the irregular distribution of pores. Pores in clastic rocks are predominantly between the grains, or intergranular, and uniformly distributed throughout the rock matrix. Intergranular pores are also present in carbonate rocks. Intragranular porosity may be common within carbonate grains as a primary pore type, or may develop when grains, such as shell fragments, are partially dissolved. Moldic porosity preserves the shapes of dissolved shell fragments or other constituents. Carbonate rocks typically have a far wider range of grain shapes than most siliciclastic rocks. Clearly, several types of porosity may coexist in a carbonate reservoir, ranging from microscopic to cave-sized, which makes porosity and permeability estimation and calculation of reserves extremely difficult.

Another feature of carbonate rocks is their susceptibility to dissolution. At the surface, as water and carbon dioxide form carbonic acid, dissolution can lead to impressive karst topography, including sinkholes, caves and intricate drainage patterns like “disappearing” streams in active karst systems. Inactive karst systems, or

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2. Geologists have developed many different carbonate rock classification schemes. Some are general schemes; others are specific to a reservoir, basin or region. For more on carbonate rock classification:


3. Stylolites are interpenetrating, sutured surfaces that form during diagenesis.


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paleokarst, may form reservoirs dominated by angular rock fragments produced during cave collapse. For the oil industry, karst can be a mixed blessing—caves can result in catastrophic bit drops and fluid losses during drilling, but karst also can result in extremely high porosity and permeability.

Given the heterogeneity of carbonate rocks, it is not surprising that hydrocarbon production from these formations often is heavily influenced by the presence of faults and fractures, particularly in older Mesozoic and Paleozoic reservoirs. Experts caution that relationships between porosity and permeability in carbonate rocks cannot be determined without understanding the pore-size distribution (see editorial, “Linking Petrophysical and Geologic Information: A Task for Petrophysics”).6 Because carbonate reservoirs present enormous challenges, they have fueled substantial research efforts within Schlumberger and the petroleum industry for decades. These efforts take many different forms as experts struggle to solve difficult problems in carbonate reservoirs.

**Carbonate Evaluation in Indonesia**

Integrated carbonate evaluation is important in all stages of exploration and production. In 1997, an operator drilled a well in the Sibolga basin, offshore northwest Sumatra, to evaluate a carbonate buildup prospect identified in seismic data (above). A full petrophysical and stratigraphic analysis of well logs and seismic data was then undertaken to understand drilling results and reevaluate the prospectivity of this play.

Biostratigraphic analysis of well cuttings indicated the buildup formed in the Middle Miocene, around 13 million years ago, in a forearc setting similar to that of today, with consumption of Indian Plate oceanic crust beneath Sumatra along the Sunda trench. This was a period of global eustatic rise.7

The well was evaluated using openhole wireline logs—gamma ray, resistivity, density and neutron—and, because mud circulation problems during drilling prevented conventional coring, the FMI Fullbore Formation MicroImager tool also was run. Integration of wireline logs, especially the FMI image, with seismic data was key to determining depositional facies. Prior to formation of the carbonate buildup, massive shales were deposited in a low-energy offshore environment. Subsequent laminated shale and cross-bedded sandstone were deposited as water depths became shallower and depositional energy increased. The prograding reef-front succession was produced by smaller buildups that coalesced to form one large carbonate platform. Eventually, relative sea level rose rapidly and submerged the buildup (below).

The prospect was expected to contain biogenic gas. Further study of well logs and image logs, however, showed that reservoir-quality carbonate rocks formed almost continuously in the absence of internal sealing rocks. Top seals on the reservoir were deposited long after gas generation, so any biogenic gas that was generated was not trapped. As a consequence, the company decided against further appraisal and was able to redirect its resources. Nevertheless, this example underscores the usefulness of integrating all available data to develop reasonable 3D geological models of reservoirs as early as possible in the exploration process.

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![Seismic interpretation](image)

^ Seismic interpretation. This seismic line from the prospect was flattened on the M3 horizon, presumably a horizontal or nearly horizontal depositional surface. The prograding reef-front succession was produced by initial smaller sized buildups that coalesced to form one large carbonate platform. Eventually, relative sea level rose, submerging the buildup.
In contrast to the previous example from the exploration stage, the Permian Basin of West Texas, USA, is renowned for vast carbonate reservoirs, many of which are now undergoing secondary and tertiary recovery. New technology and methods greatly enhance production by offering interpreters a better understanding of how reservoir heterogeneity affects performance and which zones contribute to flow. Perhaps the most significant contributions come from nuclear magnetic resonance (NMR), borehole-image and production logs.

When using the CMR Combinable Magnetic Resonance tool in carbonate formations, engineers in West Texas adjust the acquisition parameters to compensate for longer polarization times relative to clastic formations. Typical CMR logging speeds in this region are 90 to 140 ft/hr (30 to 40 m/hr), as opposed to speeds of 300 ft/hr (100 m/hr) in clastic rocks. Increased cutoff values for $T_2$, more than three times the $T_2$ cutoffs used in sandstones, have been determined from laboratory measurements of cores and are applied to specific fields by local interpreters. These steps improve the measurement of porosity, permeability and fluid saturation in rocks whose pore sizes, shapes and pore-throat connections vary more widely than in most clastic rocks.

In addition to adjusting log-acquisition parameters, use of different logging suites allows more realistic interpretation of carbonate reservoirs. In West Texas dolomite formations, high gypsum content results in overestimation of porosity when using standard crossplotting techniques. Integrating results from CNL Compensated Neutron Log, Litho-Density and CMR logs provides better estimates of porosity and permeability. If core data are not available, which is the norm, combining these logs with the ECS Elemental Capture Spectroscopy sonde for geochemical logging also can help quantify mineralogy to obtain more accurate porosity. Adding a borehole image log, such as from the FMI tool, further improves understanding of pores, particularly vugs, which commonly are distributed irregularly in carbonate reservoirs (left).

Because of the maturity and marginal economics of some West Texas fields, operators must minimize data-acquisition costs. Since the...
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The cost of acquiring core may be higher than the cost of a wireline log, interpreters have calibrated cores and logs to make sure that interpretations are robust, building confidence in log interpretations when core data are unavailable. This is especially important when evaluating the permeability of water-flooded reservoirs. The ability to distinguish high-permeability zones allows operators to plug swept zones and improve flooding of unswept zones.

Customized solutions in West Texas include production logging below electrical submersible pumps. In one field, engineers from Schlumberger and an operating company were able to evaluate fluid entry in several wellbores by adapting the PS Platform tool for use below the pump. Custom-built G-plates were installed above and below the pump to guide the wireline and pump cables to avoid tangling around the tubing and employing a modified wellhead assembly.

As one producing well was logged with the PS Platform tool below the pump, it became apparent that oil entered from an interval above the reservoir section, and that the zone of interest was actually producing water. Evaluation with the FMI tool revealed that two thin, porous zones around 4660 ft contributed the oil flow (above). By using a bridge plug to shut off the water from the water-flooded reservoir section, the operator saved significant water recycling costs while increasing the oil production from the zone above. There were additional savings in offset wells because acid stimulations were no longer performed in water-prone zones. As a result of these types of experiences, operators are striving for earlier identification of high-permeability water conduits.

Carbonate Case Studies at Schlumberger-Doll Research

Researchers at Schlumberger-Doll Research (SDR), Ridgefield, Connecticut, USA, have followed many different paths, from complex theoretical methods to simpler approaches that emphasize well-by-well evaluation. The common goal, however, has been to develop interpretations that can be incorporated into field-scale solutions.

Any improvement in recovery from giant carbonate reservoirs has a tremendous impact on oil and gas supplies. Reservoir heterogeneity complicates everything from drilling to well completions, including petrophysical evaluation, so developing a reliable log-based interpretation methodology is essential for field development. Reservoir heterogeneity prohibits relating porosity and permeability directly, as might be done when analyzing relatively homogeneous reservoirs. Therefore, it is crucial to distinguish carbonate lithologies and rock fabrics to optimize...
production, whether one is deciding how to deal with a single well or preparing to simulate production from an entire field.

Work at SDR in the 1990s led to an integrated carbonate-evaluation methodology for the Thamama formation, a lower Cretaceous reservoir in the Middle East.11 This methodology was applied to studies of other carbonate reservoirs in the UAE and West Texas. Recognizing the wide variety of carbonate rocks worldwide, SDR researchers decided, in 1997, to embark on a series of additional studies. Several carbonate case studies have been, or are being, conducted jointly by SDR scientists and engineers with their counterparts from operating companies.

Investigations of two giant fields, the Bombay High field offshore India and a field in the Middle East, indicate that the variety of rock types and heterogeneity within a given carbonate reservoir lend themselves to customized, formation-specific evaluations, particularly in cases of extreme diagenetic alteration. Both studies, completed in 2000, draw on techniques that range from conventional petrophysical and petrographic analysis to the first application of a new laboratory NMR method, called decay due to diffusion in internal field (DDIF).

Bombay High study—The giant Bombay High field, offshore western India, covers about 1200 km² (463 sq miles) and has more than 800 development wells. Discovered in 1974 by Oil & Natural Gas Corporation, Ltd. (ONGC), the field was brought on production in 1976. The main pay is the Miocene L-III limestone, a reservoir with ten hydrocarbon-bearing layers separated by shale, clay-rich limestone and tight limestone. The layers are not continuous and have poor vertical communication. As of April 2000, the field produced 297 MMT (327 M tons) of crude oil and 110 BCM (3.9 TCF) of natural gas, and is now in the mature phase. A redevelopment program has been prepared to improve recovery. ONGC sought better understanding of reservoir petrophysics to control water breakthrough in heterogeneous, layered carbonate rocks that have undergone waterflooding since 1984.12 The primary reservoir generally is not fractured, so ONGC suspected that a few high-permeability zones were contributing to water breakthrough. The challenge, therefore, was to develop a consistent log-based method to identify these high-permeability zones. For the Bombay High study, 61 core plugs from the N5-9 well were evaluated along with the logs.

Middle East study—Scientists and engineers from a Middle East operating company and SDR evaluated the complexities of a giant gas field that produces from prolific carbonate rocks. Wireline logs and 80 core plugs from one well form the framework for an integrated interpretation. Researchers applied much of the same analytical methodology in both cases. At the outset, both operators believed that the volume of clay ($V_{clay}$) would prove to be the key problem that the studies should solve. Accurately quantifying the abundance of clay minerals is essential to accurate porosity and saturation calculations, which in turn affect reserve estimates.

Quantitative mineralogical and chemical analysis of core samples conducted at SDR enhanced petrophysical analysis of the reservoirs. Mineralogy was evaluated using a proprietary Fourier transform infrared (FT-IR) technique that
relates infrared absorbance spectra to 50 mineral standards from silicate, carbonate, clay and other mineral families. Chemical analysis included X-ray fluorescence, neutron activation and induction-coupled mass spectrometry. All of these results were integrated with log data. An important result of the core analysis was that gamma ray logs alone would have indicated an incorrect clay content in both reservoirs (previous page). Therefore, a method to accurately determine mineralogy without core analysis is critically important for future reservoir characterization.

The ECS logging tool allows accurate estimation of mineralogy, clay concentration and lithology, and also can be used to evaluate total and effective porosity and hydrocarbon type. The ECS tool uses a spectrometer to measure concentrations of certain elements—calcium, silicon, sulfur, iron, titanium, gadolinium, sodium and magnesium—that reflect the concentrations of specific minerals in the formation. The data can be analyzed to compute mineralogy in terms of sand, clay, evaporite and carbonate minerals by SpectroLith lithology processing. In both cases, the SpectroLith-processed ECS results give a more realistic picture of the mineralogy, as confirmed by mineralogical analysis of cores (above).


Another key goal of these integrated studies is to identify and understand the various pore types, including micropores, mesopores and macropores, and the effect of their distribution on production (above). Micropores, with pore-throat diameters less than 0.5 micron, usually contain mostly irreducible water and little hydrocarbon. Mesopores, with pore-throat diameters between 0.5 and 5 microns, contain significant amounts of oil or gas. 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. NMR logging has improved evaluation of porosity, pore-size distribution and bound fluids (next page).

NMR logging tools, such as the CMR device, use large magnets to strongly polarize hydrogen nuclei in water and hydrocarbons as they diffuse about the pore space in rocks. When the magnet is removed, the hydrogen nuclei relax. The relaxation time, $T_2$, depends on the pore-size distribution; larger pores typically have longer relaxation times. Tar and viscous oils relax more quickly than light oil or water. The variations in relaxation time produce a $T_2$ distribution from which fluid components and pore sizes are interpreted.

An important outgrowth of the studies was the ability to classify pores in the three size categories using NMR. This success resulted from the discovery that, in contrast with the earlier
carbonate rocks studied, T2 decay-time distributions are directly useful for interpretation because diffusive coupling is not a problem. Diffusive coupling results when spinning protons move between micro- and macropores during the measurement, blurring the T2 distribution.15 A new technique developed at SDR allows resolution of the three common pore sizes using spectra quantified in size rather than relaxation time. The new method, DDIF, delivers a quantitative pore-size distribution that is especially powerful in carbonate rocks.16 A laboratory measurement technique with its own associated processing, DDIF is separate and distinct from the conventional NMR T2 experiment. The new insight derived from DDIF studies is that the conventional T2 distributions resemble the DDIF distributions.


distributions. This confirms that there is no diffusive coupling, so \( T_2 \) distributions are valid for distinguishing pore sizes (above).

Scanning electron microscope (SEM) images helped explain the absence of diffusive coupling in both cases (above right). The two first samples are dolostones; the third is a sucrosic dolomite. The lower plots compare the mercury-injection distributions (blue) with the DDIF distributions (red). Mercury porosimetry uses mercury injection to determine the capillary pressures of the connected pore space. The plots obtained from these data are interpreted as the pore-throat sizes. On the other hand, DDIF measures the pore openings, including pore bodies and throats. Superimposing the two results reveals the connectivity of the pore network. For the sucrosic dolomite (right), the overlay reveals a network consisting of pore bodies with a diameter of 20 microns connected by throats of 1 to 2 microns. For the two grainstones, the pore-body size is larger and covers a broader range. They share a network of pore throats with a diameter of 2 microns; however, the second sample (middle) exhibits a bimodal system, with a very fine network of pore throats with 0.1 micron diameters.

In the Bombay High field, CMR data confirmed generally low permeability with numerous high-permeability streaks in leached, macroporous dolostones. The Timur-Coates permeability transform, which uses total porosity and the ratio of free-fluid volume to bound-fluid volume to compute permeability, was selected to determine permeability using CMR data because it correctly partitions the pore network found in these leached, macroporous limestones. Because high-permeability streaks are so important to production and because hydrocarbon signal masks macro pores on CMR logs, FMI data were incorporated into the log processing (next page).

The SDR equation, which relates permeability to the logarithmic mean of \( T_2 \) and total porosity, was used to determine permeability from CMR data for the Middle East well. In dolostones, more realistic permeability estimates were made using NMR \( T_2 \) values from the log and the core rather than using a porosity-permeability relationship alone. Permeability estimates in the limestones, which had more variable pore systems than the dolostones, also improved, but not as dramatically. The more accurate permeability calculations used a correction factor based on the temperature sensitivity of NMR \( T_2 \) values in each formation.

Three different NMR \( T_2 \) cutoff values were used in this well, allowing NMR logs to be used to determine micro-, meso- and macro porosity. The ratio of NMR \( T_2 \) values to pore-throat diameter determined by mercury injection (NMR \( T_2/throat \)) in 22 samples also showed three distinct NMR \( T_2/throat \) classes that correspond to fabric classes observed in thin-section analysis.

Improved prediction of permeability optimizes well placement and production, particularly for directional or extended-reach wells. The ability to distinguish pore types allows successful completion of producible hydrocarbon zones. The method also helps engineers anticipate which layers might be prone to early water breakthrough.

Integration of ECS and CMR logs with conventional log suites and core data resulted in the most rigorous interpretations of Middle Eastern and Bombay High carbonate fabrics and diagenetic histories to date. More importantly, the detailed joint studies provide an improved framework for ongoing interpretation problems in both regions. The study groups recommend that new wells be evaluated similarly to the wells in the joint studies. The optimal logging suite includes CMR and ECS logs in addition to routine resistivity, gamma ray, density and neutron logs.

Confidence in log-based interpretation will continue to grow as more wells in these fields and other fields that produce from similar formations are evaluated. Greater confidence in single-well interpretation is critical to ongoing reservoir characterization and simulation because it is not economically viable to acquire core samples from every well. Integrated core-log studies provide significant benchmarks for analysis of field wells lacking cores.

Both studies promoted close collaboration between research and operations personnel that strengthened working relationships, making future joint research more likely. The improved understanding of the reservoirs resulting from the research efforts can be applied to operations immediately. Based on research findings, tools developed for oil reservoirs can be tailored for use in evaluating gas-filled rock.

Some results of carbonate case studies at SDR can be carried over to clastic reservoir studies because there are analogies between carbonate rocks and certain clastic reservoirs. For example, ongoing work in sandstones confirms the presence of micropores associated with grain-coating clays and partially dissolved grains. Clearly, researchers and operations personnel may benefit from sharing nonconfidential results of their work.

Ongoing studies in the Middle Eastern reservoir include seismic imaging with the single-sensor Q system to better characterize the reservoir and optimize drilling targets.

Benefits of the Bombay High study include greater understanding of the L-III reservoir, particularly heterogeneity and its effects on fluid transport; development of a rigorous petrophysical approach; and evaluation of the applicability of the new methodology to older, less extensive data sets. ONGC has recognized the importance of ECS and CMR data for clay estimation. These results will be incorporated into future production strategies.

![Comparison of L-III log and core data for identification of high-permeability streaks. The lithology in the first track—clay, quartz, calcite and dolomite—is computed using ELAN analysis software with ECS data as the key input. The fluids are reported as oil that has not been moved by invasion (green), oil that was moved (orange), irreducible water contained in micropores (blue with black dots) and mobile water (white). NMR data help distinguish irreducible and mobile water. The second track is the porosity broken down into clay-bound water from ECS data, microporosity from CMR data and meso- and macropores from CMR and FMI logs. The third track contains the T2 distributions from the CMR log. The solid blue permeability curve in Track 4 is calculated from ELAN volumes. The light blue dots are permeability measured on core plugs. The black line is permeability measured with 1-cm sampling on the core slab face using a minipermeameter. The macroporosity computed from FMI data (shown in Track 6) is displayed in red in Track 5. Light blue dots indicate macroporosity determined by mercury injection in core samples. The black line represents vugular porosity measured on the face of the slabbed core.](image-url)
Integrated Carbonate Evaluation at the ONGC-Schlumberger Joint Research Center

Carbonate reservoirs in India present important interpretation challenges to scientists and engineers working at the Joint Research Center (JRC), a combined effort by the Oil and Natural Gas Corporation, Ltd., (ONGC) and Schlumberger. The JRC, located in New Delhi, was established in the 1980s to investigate formation evaluation, reservoir description, production, completion and reservoir-monitoring problems experienced by ONGC and to find solutions to those problems. Several noteworthy carbonate reservoirs are located offshore Mumbai, India, including the Neelam field, which JRC personnel have studied since its discovery and first production in 1990.

At the JRC, petrophysical, geophysical and geological evaluations of carbonate reservoirs provide the basis for an integrated reservoir solution. The ultimate goal is to maximize oil recovery and production efficiency by understanding and modeling the reservoir. This approach also minimizes the number of well interventions and the number and location of wells required so that all commercially viable oil pools are drained. By building a numerical simulation model of the field, geoscientists and engineers can extrapolate field behavior over time and evaluate “what if” scenarios, such as how a given workover program might affect overall field performance and production, or whether the failure to drill specific development wells might leave compartments of undrained hydrocarbon.

In the case of a mature field like Neelam, the first phase in building a simulation model is to calibrate it to reproduce the historical production behavior of the reservoir—history matching. Since this stage conditions the reservoir model to the dynamic data, such as well-production rates and changes in pressures and saturations, the history-matched model becomes a much more representative description of the reservoir than the input static model.

To correctly model flow behavior in carbonate reservoirs, it is essential to understand the permeability profile. Standard log data—density, neutron, sonic, gamma ray, SP and resistivity logs—evaluated by conventional methods all too often indicate a homogeneous reservoir. Porosity variations are not a reliable indicator of permeability variations because changes in carbonate texture affect permeability more than changes in porosity affect permeability. The time-honored method of using core data to derive a porosity-permeability relationship associated with a particular reservoir fails when reservoir-rock texture varies. Although the technique is fundamentally correct, it should be carried out separately for each carbonate depositional rock type or texture. In fact, previous studies of the Neelam field have shown that permeability increased as porosity decreased—a difficult conclusion for petrophysicists to reconcile with their interpretations.

Many carbonate reservoirs contain localized or extended layers of mud-supported rock, where permeability is appreciably reduced, but complete barriers to vertical fluid migration are rare. During the millions of years of reservoir evolution, fluids segregated, resulting in a water table at the bottom, a transition zone where both oil and water volumes are movable, and an oil zone at the top, where the water is entirely capillary-bound and only the oil is movable. Pressures also equalize in the reservoir over this period.

It is only by careful inspection of core data, or through innovative evaluation of NMR or borehole image logs, that the texture of the carbonate reservoir becomes apparent as distinct zones with varying degrees of carbonate-mud support and fluid-transport properties. Grainstone, often the least porous, generally yields the highest permeability among carbonate rock types. As mud content increases, resulting in packstone or wackestone, total porosity usually increases, but permeability is perhaps 10 to 100 times lower than in grainstone due to the increased importance of microporosity in associated muds.

These texture differences do not necessarily create true fluid-flow barriers over geologic time. However, when reservoir fluids are subjected to “instantaneous” withdrawal from the formation—for example production over perhaps 5 to 20 years as opposed to the millions of years it took the reservoir to form—the resulting pressure pulses create separate flow units within the reservoir separated by those zones of significant permeability reduction. This usually results in large pressure differences between flow units and complete breakdown of the smooth water-to-oil transition with decreasing depth. Fingers of edge water propagate laterally, at any depth, into the most permeable sections.

To complicate matters further, the permeability of a carbonate reservoir often is severely affected by tectonic and diagenetic phenomena. For example, extremely high-permeability layers, called “super-k” layers, commonly result from diagenetic alteration. Most of the available data for the Neelam reservoir imply that super-k layers are created by dissolution and leaching of the rock fabric by meteoric water during periods of low sea level, when the carbonate was exposed to water from the atmosphere and at the Earth’s surface.

Having an accurate permeability description significantly accelerates the history-matching process and greatly improves the reliability of predictions from the history-matched model.
Because history matching is a complex, multivariate process, it is sometimes possible to achieve what appears to be a satisfactory match of historic data with an inaccurate model of the reservoir permeability distribution. In this case, the model will deliver inaccurate predictions. Only by unraveling the general reservoir permeability distribution can a realistic and usable reservoir-simulation model be built.18

Geoscientists and engineers at the JRC decided to focus on mapping permeability using four complementary approaches. While each approach begins at a wellbore, the results from each well must be integrated into a three-dimensional model of the field to deliver maximum value to the operator. These approaches include the following:

- NMR analysis to evaluate rock texture and permeability profiles
- Cased-hole saturation logging to compare original fluid saturations with saturations after some period of production to develop a depletion profile
- Use of proportion curves and other geostatistical tools to highlight hidden correlations that can be confirmed in key wells by either of the two previous methods
- Geostatistical analysis of water breakthrough in historical well production data to evaluate high-permeability layers that conduct reservoir or injection water.

The geostatistical techniques are still in experimental stages.

Texture and permeability analysis with open-hole logs—During field development or infill drilling, operators have the opportunity to acquire new openhole data. In the past, carbonate geologists relied on image logs to reveal carbonate textures, from which they infer permeability. More sophisticated techniques now are being added to image-log analysis to assess permeability. Confirming findings shown previously in a laboratory setting and from computer modeling by Ramakrishnan and others, JRC geoscientists observed that the width of the borehole NMR T2 signal distribution is strongly correlated to carbonate lithology.19 Petrographic and core analyses corroborate JRC findings (previous page).20 This information can be used to calibrate the NMR permeability response to obtain an accurate, continuous permeability profile.

Previously, deriving permeability from NMR was challenging because of the variable and ill-defined T2 cutoff between capillary-bound and free fluids. The JRC-developed method first uses the Schlumberger-Doll Research permeability formulation, usually referred to as kSDR. This relationship, also used in the Middle East study described earlier, defines permeability as a function of porosity and the log-mean value of the NMR T2 distribution independent of a T2 cutoff. JRC scientists observed a well-defined dependence of the premultiplier in this relationship on rock texture, so they introduced a texture-related term into the kSDR relationship. They confirmed the accuracy of the method by comparing the trend of NMR-derived permeability with brine-corrected core permeability data. The agreement between the textural and permeability estimates from this technique and the results of an extensive core study is reasonable given the uncertainty in the permeability results caused by carbonate heterogeneity.

Meaningful reservoir production forecasts require an accurate knowledge of the respective volumes of free oil and free water, so JRC engineers obtained free water by inverting the Timur-Coates permeability relationship and equating it to the texture-related permeability measurement. This splits the total water—defined simply as effective porosity minus hydrocarbon volume—into free- and capillary-bound waters.

Saturation in carbonate reservoirs cannot be derived from a simple Archie relationship. It is common to encounter oolithic molds or solution vugs that affect the cementation factor m used in the Archie relationship.21 For years, carbonate enthusiasts have known that a “variable m” approach is required. The difficulty resides in properly partitioning the total porosity between primary, matrix and vuggy porosity.

A method first introduced by Brie and others in 1985 makes use of an acoustic-scattering model developed previously by Kuster and Toksöz to evaluate this partitioning.22 The technique uses a total porosity from density, neutron, or both logs, and compressional and shear velocities from sonic logs. An iteration technique adjusts the amount of vuggy porosity necessary to minimize the error between expected theoretical sonic compressional and shear transit times and measured values. Once partitioning of the porosity is evaluated, an equivalent approximation for electric properties provided by the Maxwell-Garnett model is used to assess the effect of conductive or isolated inclusions on the cementation factor.23 A variable m value is obtained to use in ELAN Elemental Log Analysis calculations to obtain a much more accurate volume of hydrocarbon. While other studies have used variable values for m, this is perhaps the first study in which the method has been validated against individual core measurements of m in the laboratory (above).

18. A full discussion of reservoir simulation is beyond the scope of this article, but will be covered in a future Oilfield Review article.
and also Extended abstract, presented at the AAPG International Conference and Exhibition, Bali, Indonesia, October 15-18, 2000.
21. Ooids are small, round grains of calcium carbonate layers around a sandy nucleus. Dolomite molds are the spherical holes that remain when ooids dissolve.
22. Brie A, Johnson DL and Nurmi RD: “Effects of Spherical Pores on Sonic and Resistivity Measurements,” Trans-
The petrophysical evaluation resulting from the combination of the improved capillary-bound, free-water and oil-volumes derivation has been compared with the results of an extensive MDT-derived pressure profile analysis and well-test data (above). Analysis of depletion profiles—In developed fields, operators commonly acquire new data through casing. In these cases, JRC members have taken advantage of the RSTPro answer-product line to improve remaining oil-saturation estimates from the RST Reservoir Saturation Tool device to a level of accuracy that allows direct comparison with original openhole saturation. This permits derivation of a depletion profile that clearly defines three kinds of reservoir zones: those with no apparent depletion, which are probably low-permeability, mud-supported rocks that separate flow units within the reservoir; partially depleted zones that consist of “normal” reservoir rock; and zones of extreme depletion, which may be super-k layers or zones containing massive solution channels.

A demonstration of these three zones comes from the Bassein reservoir in the Neelam field, where the zones were correlated over a distance exceeding 6 km [3.7 miles]. In every well studied, a combination of the RST depletion profile and a borehole temperature survey acquired during production highlights producing zones in perforated intervals and reveals a reservoir separated into three major flow units (next page, left). A large amount of oil is still present in the uppermost unit, but virtually no production occurs from this unit because pressure depletion here is more severe than in the lower units.

To improve cased-hole determination of remaining oil volume in carbonates using the RST tool, it is crucial to understand RST sensitivity to completion, especially cement, conditions. In siliciclastic rocks, cement thickness has a small effect on the length of the segments of the RST saturation-evaluation quadrilateral displayed in crossplots of carbon/oxygen ratios (C/O) from near and far detectors (NCOR versus FCOR). The quadrilateral and the crossplotted C/O ratios are used to determine fluid saturations (next page, right).

Borehole geometry, formation lithology, porosity and the carbon density of the hydrocarbon define the end points of the saturation-evaluation quadrilateral. The lower left corner, WW, is where both the borehole and the formation are water-bearing. Travelling clockwise, the WO point indicates water-bearing borehole and oil-bearing formation. At the upper right is the DD point, oil in both borehole and formation. Finally, the DO point represents oil in the borehole and water in the formation. The exact position of these four points is obtained in controlled laboratory conditions.

In carbonates, the entire evaluation quadrilateral is translated due the additional carbon and oxygen in the carbonate matrix. The amount of translation of the evaluation quadrilateral is related to the amount of carbonate rock surrounding the tool and also the distance between the tool and the carbonate material.

Intuitively, the effect will be greatest in a small borehole, with the tool and the rock matrix separated only by the casing. As hole size and cement thickness increase, the tool is less affected by the carbonate rock. At the limit, for a...
cement thickness larger than the radius of investigation of the tool, the carbonate rock has no effect on the measurement because the tool samples only the cement.

In the past, if an openhole caliper was available, it was incorporated in the RST data set to evaluate cement thickness from the difference between openhole radius and casing outer radius. Use of caliper data assumes that the borehole has not been enlarged from the time openhole logs were run to the time casing was cemented, that the casing was perfectly centered in the borehole and that the borehole was perfectly round rather than oval-shaped. The latter assumptions are highly unlikely, especially in deviated wells. With RSTPro technology, and the acquisition of an additional RST pass in sigma mode, it is possible to compute an optimized cement-sheath thickness that will result, after diffusion correction, in a minimal discrepancy between formation capture cross-section (sigma) measurements derived from the far and near detectors.

This cement thickness and the outer casing diameter can be used to generate an “RST caliper” for input to the RST oil-volume evaluation module. Previous RST logs of carbonate rocks offshore India exhibited remaining oil profiles that were difficult to justify. The new technique has produced credible logs since its introduction early in 2000. Changes in saturation profile of as much as 20 saturation units commonly occur between evaluations, with or without taking optimized cement thickness into account.

Depletion-profile analysis. In these four wells, a combination of the RST depletion profile and a borehole temperature derivative acquired during production shows the three major flow units in the reservoir. The base of Zone 1 is the original oil-water transition. Zone 2 includes the major producing horizons. Reserves remain in Zone 3, but reservoir simulation suggests that major pressure depletion has occurred.

Overlay of the RST saturation-evaluation quadrangle with near-detector C/O ratio (NCOR) to far-detector (FCOR) data from India. Color coding in the Z-axis represents shale volume (VILL); red is clean limestone, blue is 10 percent shale. The data were recorded in a 22-porosity unit limestone reservoir, in an 8.5-in. borehole with 7.0-in. casing. The borehole geometry, formation lithology and porosity, along with the carbon density of the hydrocarbon, fully define the end points of the characterization locus. The data points cluster along the WW-WO line, indicating a water-filled borehole. The formation oil saturation varies from 0 to 40%.

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26. More than 3000 combinations of hole sizes, lithologies, porosities, borehole and formation saturations have been measured. Interpolation between endpoints is obtained by nuclear modeling of the tool, formation and borehole conditions, with model endpoints calibrated with laboratory data.


Geostatistical analysis—Innovative use of statistical tools at the JRC extends NMR analysis and RST results from key wells to the entire field model, which previously comprised only conventional log data and downhole production data. These new techniques involve proportion curves and water-conduit tracking.

A vertical proportion curve plots a histogram at every stratigraphic level within the formation (right). In this example, logs of porosity categories are displayed with depths relative to the top of the reservoir—the conforming surface. The vertical sampling interval is 1 meter (3 feet) in these wells. The RST survey discussed earlier was run in a nearby well. The logs have been projected onto a north-south line shown on the map. The vertical proportion curve is generated by showing the relative percentages of the different porosity categories at every stratigraphic level. The curve becomes narrower with increasing depth because the wells have different depths of penetration. Nevertheless, it can be inferred that the formation probably consists of two relatively high-porosity zones separated by a low-porosity zone.

This example demonstrates that the proportion-curve technique uses grouped or categorical data rather than continuous data. Traditionally, vertical proportion curves have used depth-dependent lithofacies data to understand depositional cycles and to constrain geostatistical realizations. But, as shown at the JRC, these curves can have strong application in diagnosing reservoir flow behavior and relating this behavior to the reservoir characterization developed from openhole and cased-hole saturation logs.

To understand this technique more clearly, the example can be taken a step further by including a vertical proportion curve derived from production logs (right, lower right of figure). Productivity, or flow rate, is categorized as high, medium, low, or no flow. At the top of the reservoir, flow rates are high, which implies that a thin layer of high permeability exists at the top of the formation. Subsequent analysis showed that this is a super-k layer. Farther down, there are two other major zones of high flow rate mixed with lower flow rates. Those zones should have medium to high productivity. Nevertheless, it can be inferred that the formation probably consists of two relatively high-porosity zones separated by a low-porosity zone.

Comparison of the production log and porosity proportion curves shows that porosity alone is an incomplete descriptor of permeability in the region and, consequently, that better openhole permeability-based descriptors are needed—such as those derived from MDT or NMR data.

The proportion-curve technique has been applied elsewhere in the reservoir, and to other forms of dynamic and static data, to derive several useful results rapidly and efficiently. For example, it is possible to map throughout the field the lateral and vertical extent of high-permeability zones that have flowed water for an extended period by combining an openhole gamma ray with a cased-hole gamma ray run later in the life of a well into a proportion curve. Comparing openhole gamma ray logs to density-neutron curve separation enables detection of weathered zones where meteoric water has created super-k layers through diagenetic alteration.

Proportion curves allow quick, efficient analysis of vast amounts of data, an important consideration when interpreting and synthesizing data from an entire field, which may include openhole, cased-hole, and water-conduit tracking.


cased-hole and historical production data from several hundred wells. Proportion curves can be grouped to gain local insight about specific parts of a field. They also offer a high level of immunity to incorrect or low-quality data, since the “noise” created by such data sets tends to cancel itself, and since the amount of high-quality data far exceeds the amount of questionable data within the entire data set. A proprietary PC-based software package, refined at the JRC, performs interactive database management, computation, and 2D and 3D visualizations of these proportion curves. The package is compatible with the GeoFrame Application Builder program, which facilitates database access.

Water-conduit tracking method—Detection of high-permeability conduits, such as faults or super-k layers that conduct reservoir or injection water, can be improved by performing a network analysis of water breakthrough times on historical well-production data. A PC-based software package written at the JRC helps users detect the water path interactively. The water-breakthrough information comes from historical well-production data loaded into a production-management database. This tool allows quicker, more objective diagnosis of the progress and evolution of water breakthrough over an entire field than traditional manual analysis.26 This method, known as water-conduit tracking (WCT), makes assessing the validity of multiple scenarios more efficient than in the past.

By conducting the vital analyses of rock textures, permeability, depletion profiles and production data, and judiciously integrating all the results with other field data using geostatistical techniques, the JRC is creating models that result in more realistic reservoir simulations. These simulations provide more reliable guidance for development and production decisions than analyses performed in isolation.

Evaluating Carbonate Heterogeneity in Abu Dhabi
Local operations teams augment the contributions of formal research efforts to understand carbonate rocks. Scientists and engineers in Abu Dhabi, UAE, have developed new techniques to evaluate heterogeneous carbonate reservoirs by integrating geological, openhole and production-log data. Characterization of the small-scale heterogeneities within reservoir rocks has led to a classification of 17 reservoir rock types (RRT) in the Shuaiba formation. Reservoir rock types are based on lithofacies, wireline log data, core porosity and permeability, capillary pressure and pore-size distributions derived from mercury-injection analyses, and production data.29 RRTs can be used to better correlate zones within reservoirs in the absence of cores.

An oil field in Abu Dhabi has been producing from the Lower Cretaceous Shuaiba formation since 1962. Within the field, the Shuaiba formation varies from shallow-water shelf to deepwater slope sediments, with four distinct reservoir facies. RRTs range from nonproductive rocks to those with up to 30% porosity and 20-Darcy permeability (below). These significant heterogeneities must be considered when planning well trajectories, well completions and production strategies.

RRTs are defined on the basis of reservoir quality, distribution and productivity, but are products of their depositional environment and diagenetic history. RRTs observed in cores and logs from two wells in the field have been correlated.

Shuaiba heterogeneity. RRTs range from rudists—extinct mollusks similar to oysters—in lime mud (top left) to mixed rudists in a grainy matrix (top center) to diagenetically altered, debris-filled rudstone (top right). A pencil or fingertip in each photograph indicates the scale. RRTs from the northern part of the field comprise rudstone (bottom left photomicrograph) and fine-grained packstone or packstone (bottom right). The field of view of the photomicrographs is 4 mm by 6 mm.
Shuaiba RRTs and permeability indicator derived from core and log data. Photographs (far right) in this composite plot from a well in a field in Abu Dhabi show the heterogeneity of three of the distinct RRTs. Permeability characterized by analysis of Stratigraphic High-Resolution Dipmeter Tool (SHDT) data (Track 8) shows close agreement with log and core data.

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^ Shuaiba RRTs and permeability indicator derived from core and log data. Photographs (far right) in this composite plot from a well in a field in Abu Dhabi show the heterogeneity of three of the distinct RRTs. Permeability characterized by analysis of Stratigraphic High-Resolution Dipmeter Tool (SHDT) data (Track 8) shows close agreement with log and core data.
with logs in uncored wells; this correlation allows more accurate permeability estimation in those wells than with use of log data alone. The RRT study contributes significantly to the field development because the operator, Abu Dhabi Company for Onshore Oil Operations (ADCO), can use realistic permeability estimates and upgraded 3D geological models to optimize field drainage, thereby maintaining and prolonging production.

One innovative RRT characterization method relies on careful integration of conventional well logs, such as gamma ray, neutron and density, with high-resolution dipmeter and image logs. Heterogeneities in the form of conductivity variations are quantified using specialized software, including BorTex and RockCell applications, to identify RRTs and generate permeability indicators (previous page). In extremely heterogeneous carbonates, permeability derived using this methodology resolves heterogeneity better than 1-in. core plugs or minipermeameter data (above). The higher resolution and increased borehole coverage of imaging devices provide more accurate differentiation of RRTs than dipmeter logs alone and facilitate identification of flow paths between vugs and large pores. Because dipmeter and image logs are more widely available than core, RRT analysis is a powerful tool for evaluating wells that lack core samples.

Another successful technique to evaluate porosity in the Shuaiba formation uses borehole images to map primary and secondary porosity.

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1. Integrated permeability data. Core plugs from 246 one-foot intervals (left) and 586 minipermeameter measurements at 2- to 3-in. intervals (center) from a well in Abu Dhabi show significant scatter because of the extreme small-scale heterogeneity. On the other hand, the SHDT-derived permeability indicator (right) shows a clear trend that closely correlates with RRTs found in cores. Each color in the cored interval represents a distinct RRT of the Shuaiba formation.

30. A full discussion of BorTex and RockCell software is beyond the scope of this article. For more information: http://www.geoquest.com/pub/prod/index.html.
The wellbore azimuthal porosity spectrum reveals extreme porosity heterogeneity, which, in turn, is related to permeability (above). While RRT studies aid long-term reservoir characterization and simulation studies, the results also can impact field development in the short term. For example, recognition of different RRTs in a horizontal Shuaiba well allowed the operator to optimize production rates. A horizontal oil well drilled in 1997 initially produced 6000 BOPD [953 m³/d] water-free for four months, then abruptly lost pressure and was shut in. The operator needed to determine whether the decrease in reservoir pressure, migration of fines or water loading stopped oil flow. Interpretation of high-quality PL Flagship production logging data, coupled with RRT analysis that incorporated geological and openhole data, confirmed that the horizontal section penetrated two vastly different RRTs (next page, left).

Future Research Efforts
Clearly, significant work remains for those exploring and exploiting carbonate reservoirs. Although the complexity and heterogeneity of carbonate rocks present enormous interpretation and operational challenges, the examples presented in this article underscore the need for integration of all available data and prudent selection of evaluation tools.

Schlumberger is addressing carbonate issues more aggressively by establishing a Carbonate Research Center (CRC) at King Fahd University of Petroleum and Minerals (KFUPM) in Dhahran, Saudi Arabia (next page, right). The proximity of the center to the prolific carbonate reservoirs of the Middle East, key operators and select regional universities will facilitate intraregional collaboration. Innovative information-technology solutions for virtual teamwork will accelerate research progress and dissemination of successes worldwide (see “From Reservoir Specifics to Stimulation Solutions,” page 42).

Key areas of activity for the CRC include land seismic-data acquisition, NMR interpretation, water management and well stimulation in carbonate reservoirs. Research efforts will complement rather than duplicate work performed in other research facilities. For example, Middle East carbonate case studies will be performed in the CRC rather than SDR as appropriate. Because of the proximity to classic carbonate field locations,

an endeavor specific to the Dhahran facility will be field testing new tools and modification of existing tools to achieve the best possible results in carbonate rocks.

Much of the emphasis so far has been on oil reservoirs, but long-term strategic emphasis on gas production is pushing even the largest oil producers in the Middle East to pursue development of carbonate gas reservoirs. Deeper gas plays present significant interpretation, exploration and production challenges.

Although this article has focused on data at the scale of a wellbore, there are larger scales at which Schlumberger and operators are evaluating carbonate reservoirs. Interpretations from logs and cores are being incorporated in field-scale reservoir simulations. The simulations allow reservoir models to be extended into the fourth dimension, time, to better predict field response and optimize performance.

New seismic acquisition methods, such as the Q single-sensor technology that has been used for data acquisition in the Middle East, will address imaging challenges at an even larger scale. Preliminary results from these tests suggest that significant improvement in data quality will advance our understanding of carbonate reservoirs and, when properly integrated with other data, lead to greater success in carbonate exploration, development and production.

—GMG