

Quantitative producibility
and textural analysis for
carbonate reservoirs

Carbonate Advisor



More than 60% of the world's oil and 40% of the world's gas reserves are held in carbonates, but carbonate reservoirs pose significant challenges in finding and recovering these resources.

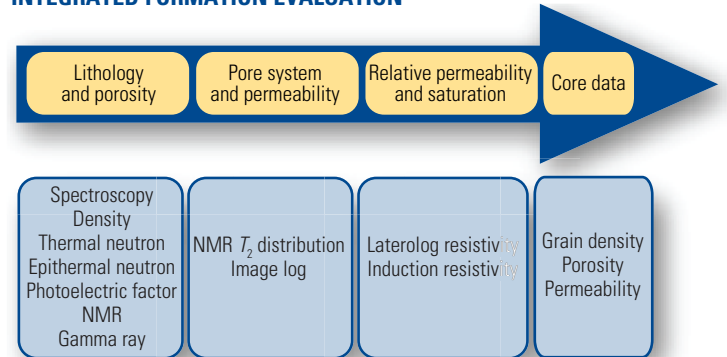
Unlike sandstones, with their well-characterized correlations of porosity, permeability, and other reservoir properties, the heterogeneous pore systems of carbonate rocks defy routine petrophysical analysis. Carbonates are deposited primarily through biological activity. The resulting rock composition of fossil fragments and other grains of widely varying morphology produces highly complex pore shapes and sizes. Carbonate mineral species are also comparatively unstable and are subjected to multiple stages of dissolution, precipitation, and recrystallization, adding further complexity to the porosity and permeability of the rocks. Any comparatively simple relationships that might have existed between depositional attributes, porosity, and permeability are obscured by these multiple physical, biological, and chemical influences, operating at different scales, during and continuing after deposition.

The principal challenge for the accurate evaluation of carbonate formations is accounting for reservoir heterogeneity on a multiplicity of scales—of the grains, the pores, and the textures. The solution is the integrated Schlumberger Carbonate Advisor* petrophysics and productivity analysis. This novel approach meets the carbonate challenge by integrating a comprehensive suite of petrophysical logging measurements for the quantitative determination of reservoir producibility in carbonate formations.

Until the advent of Schlumberger Carbonate Advisor analysis, there was no systematic analytical framework that could efficiently deliver a timely, comprehensive petrophysical evaluation of carbonate formations.



INTEGRATED FORMATION EVALUATION



Schlumberger Carbonate Advisor interpretation methodology integrates multiple inputs within sequential steps.

THE KEY TO CARBONATE ANALYSIS: PORE GEOMETRY

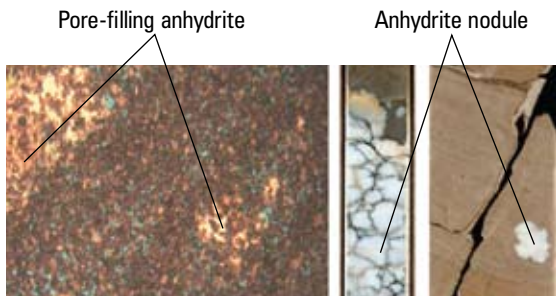
Over the past two decades, numerous experts have teased out relationships of rock texture to various individual petrophysical properties of carbonates. But until the advent of Schlumberger Carbonate Advisor analysis, there was no systematic analytical framework that could efficiently deliver a timely, comprehensive petrophysical evaluation of carbonate formations.

It is the pore geometry of carbonates that makes it possible to sequentially interrelate logging data to producibility. Schlumberger Carbonate Advisor evaluation centers on characterization and size partitioning of the pore geometry by using texture-sensitive borehole logs, such as nuclear magnetic resonance (NMR) and borehole imaging. The methodology leverages pore geometry analysis to confirm the identification of petrophysical rock types (mineralogy and pore system class), determine fluid saturations, and estimate permeabilities and relative permeabilities.

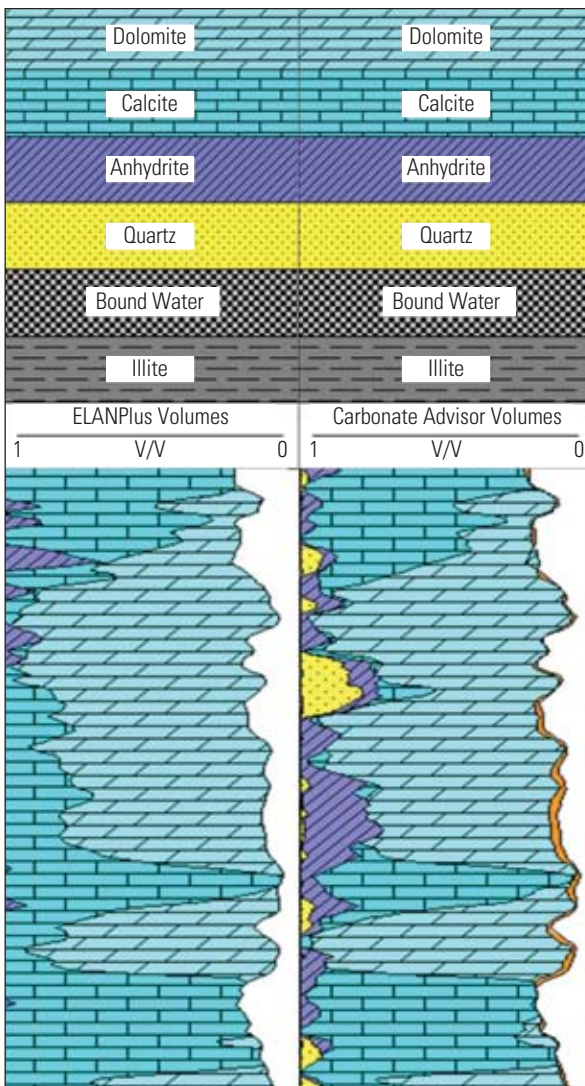
The Schlumberger Carbonate Advisor interpretation methodology consists of integrated sequential steps, each providing an answer that evaluates specific reservoir properties and feeds critical information to the subsequent steps while confirming the results of previous steps. The three steps of the integrated workflow are the determination of

- lithology and porosity
- pore type and permeability
- relative permeability and saturation.

At each step, customized log displays and crossplots facilitate quality control, parameter selection, and graphical zonation.



Whether anhydrite is present in carbonate rocks as pore-filling cement (thin-section view on the left) or as nodules (core scale on the right), it must be quantified to prevent biasing the petrophysical evaluation.



Schlumberger Carbonate Advisor lithology evaluation (right) of a carbonate formation correctly identified dispersed nodular anhydrite in comparison with the conventional ELANPlus* evaluation made with triple-combo logs. In addition to the same triple-combo logs, the Schlumberger Carbonate Advisor evaluation incorporates neutron spectroscopy measurements in a simultaneous lithology-porosity analysis. The identification of anhydrite improved the porosity estimates (shown in orange), which are up to 2 pu higher than the porosity derived from triple-combo logs alone.

LITHOLOGY AND POROSITY

Lithology and porosity are derived by combining measurements sensitive to the rock matrix properties, such as the photoelectric factor (PEF) and neutron capture spectroscopy, with those sensitive to both the rock matrix and contained fluids, such as density and neutron porosity, and measurements sensitive primarily to the fluids and pore space, such as NMR porosity and bound-fluid volume. The measurements are integrated in a simultaneous solution. The sensitivity of each measurement to individual components of the rock-fluid system is properly accounted for, optimizing the solution for the particular borehole and reservoir environment. For example, light hydrocarbons can bias the porosity estimate if the measurements used do not investigate the same volume of rock. Density, epithermal neutron porosity, and NMR measurements are sensitive to similar volumes and therefore can be used to determine hydrocarbon-corrected total porosity. Thermal neutron porosity, however, reads deeper into the formation and is more likely to be affected by the presence of light hydrocarbons, resulting in a lower porosity measurement if not recognized and corrected for.

Determining carbonate mineralogy is not necessarily straightforward. In some cases, calcite and dolomite, the primary carbonate minerals, can be readily distinguished with the PEF log from a density tool. However, if the PEF log is affected by the presence of barite in the drilling mud or if the formation contains anhydrite, then the mineralogy cannot be accurately determined with basic triple-combo logs.

Neutron capture spectroscopy measures elemental concentrations including magnesium and sulfur, which can be respectively used to further discriminate dolomite from calcite and accurately estimate anhydrite volume. Anhydrite quantification is important because anhydrite has a significantly higher density than other minerals commonly associated with carbonates.

Underestimating anhydrite content results in an underestimation of grain density, which in turn leads to an underestimation of total porosity.

In addition, anhydrite itself typically has low porosity.

If anhydrite is not identified and properly accounted for, the analysis of carbonate formations containing anhydrite nodules is biased toward poor quality, although the carbonate fraction of the rock may have good porosity and permeability. Thus, incorporating neutron capture spectroscopy in the Schlumberger Carbonate Advisor evaluation corrects for the subjectivity involved in determining mineralogy, substantially reducing uncertainty in comparison with total porosity results derived strictly from basic logs.



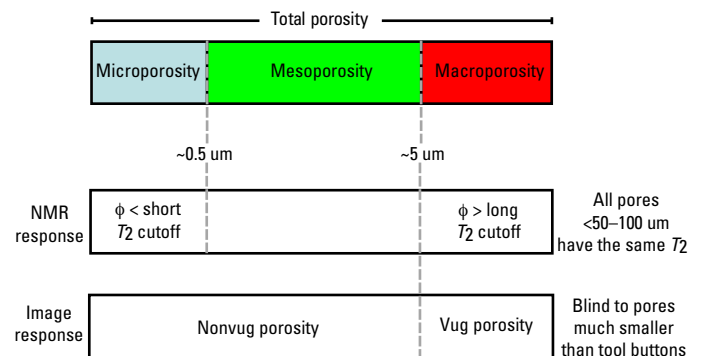
Rather than sparse data points obtained from laboratory core analysis delivered long after the well has been drilled, Schlumberger Carbonate Advisor service provides a continuous log detailing the quantitative producibility of the non-fractured carbonate reservoir.

PORE TYPE AND PERMEABILITY

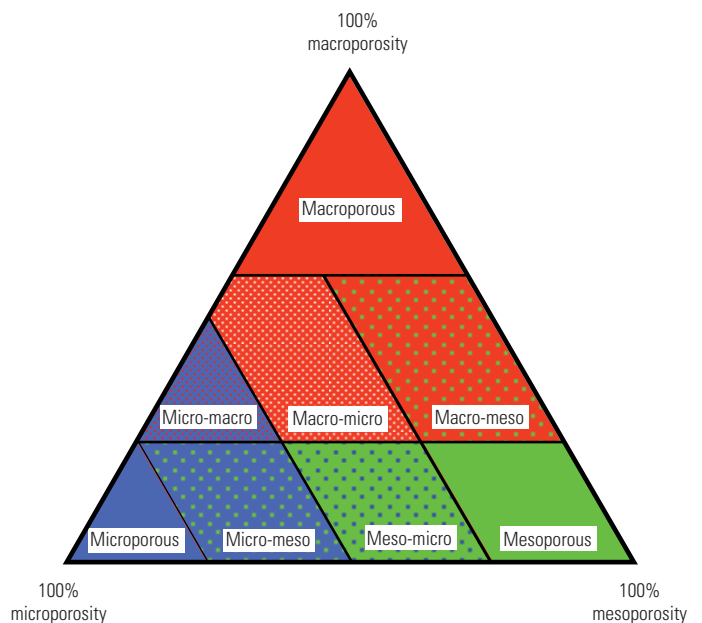
Knowledge of only the porosity and mineralogy is insufficient to determine carbonate reservoir quality and fluid-flow properties. This step of the Schlumberger Carbonate Advisor evaluation is where pore geometry comes into play. The pores are evaluated to partition the total porosity into different pore types based on pore-throat size. The partitioning is conducted with NMR transverse relaxation time (T_2) distributions augmented by borehole images.

As shown schematically, two cutoffs are applied to the pore body size distribution inherent in the NMR T_2 distribution. The short cutoff defines the microporosity fraction and the long cutoff defines the macroporosity fraction; the mesoporosity fraction falls between the cutoffs. The macroporosity component is also determined from borehole images by converting the resistivity image into a porosity image and extracting the fraction of large pores present. Porosity histograms are then created over short depth windows, and histograms with a bimodal character indicate the presence of large pores in the background porous matrix. The fraction of large-pore porosity computed from the image is compared with macroporosity from the NMR T_2 distribution and can be used to adjust for distortions introduced by oil saturation effects.

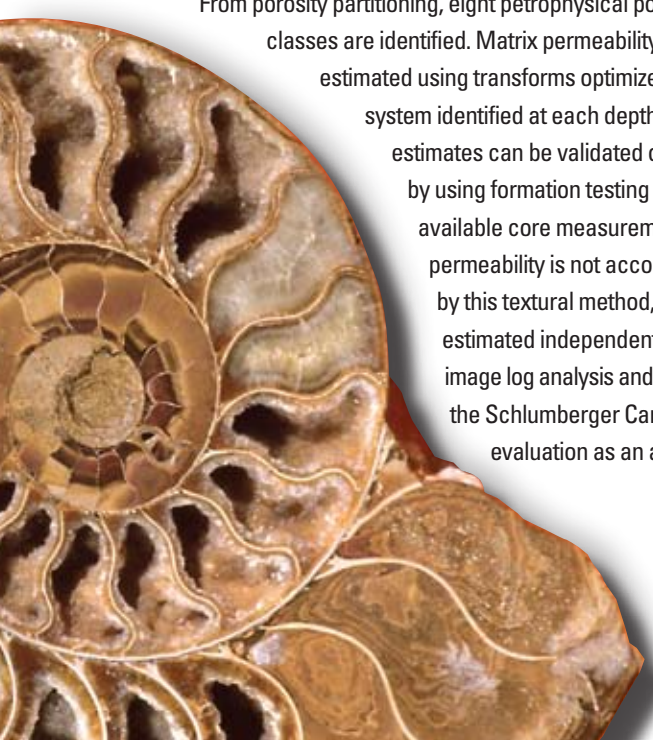
From porosity partitioning, eight petrophysical pore system classes are identified. Matrix permeability is also estimated using transforms optimized for the pore system identified at each depth. Permeability estimates can be validated or calibrated by using formation testing tool data or available core measurements. Fracture permeability is not accounted for by this textural method, but can be estimated independently from image log analysis and included in the Schlumberger Carbonate Advisor evaluation as an additional array.

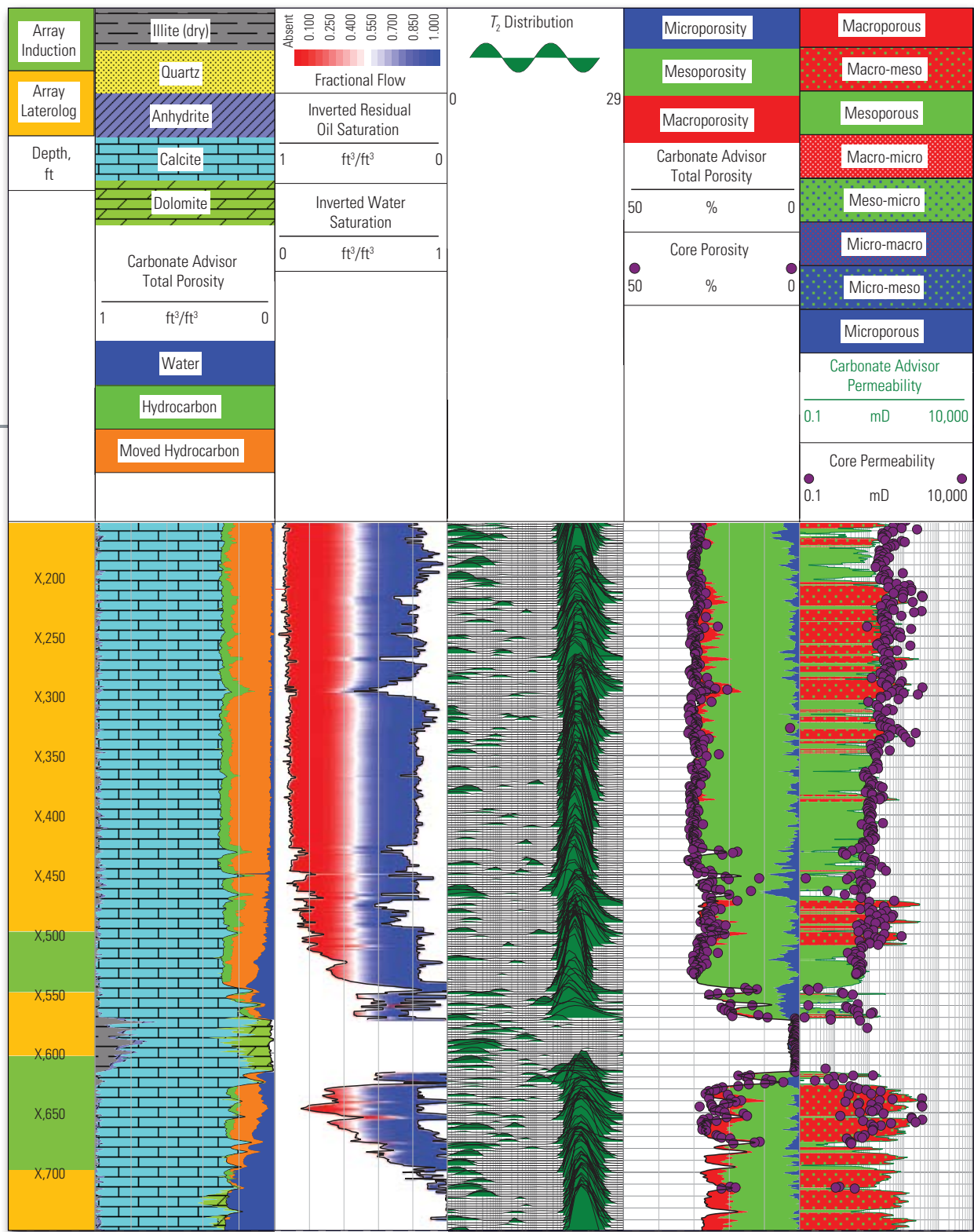


Carbonate porosity partitioning of NMR and image logs determines the proportions of different pore types within the total porosity.

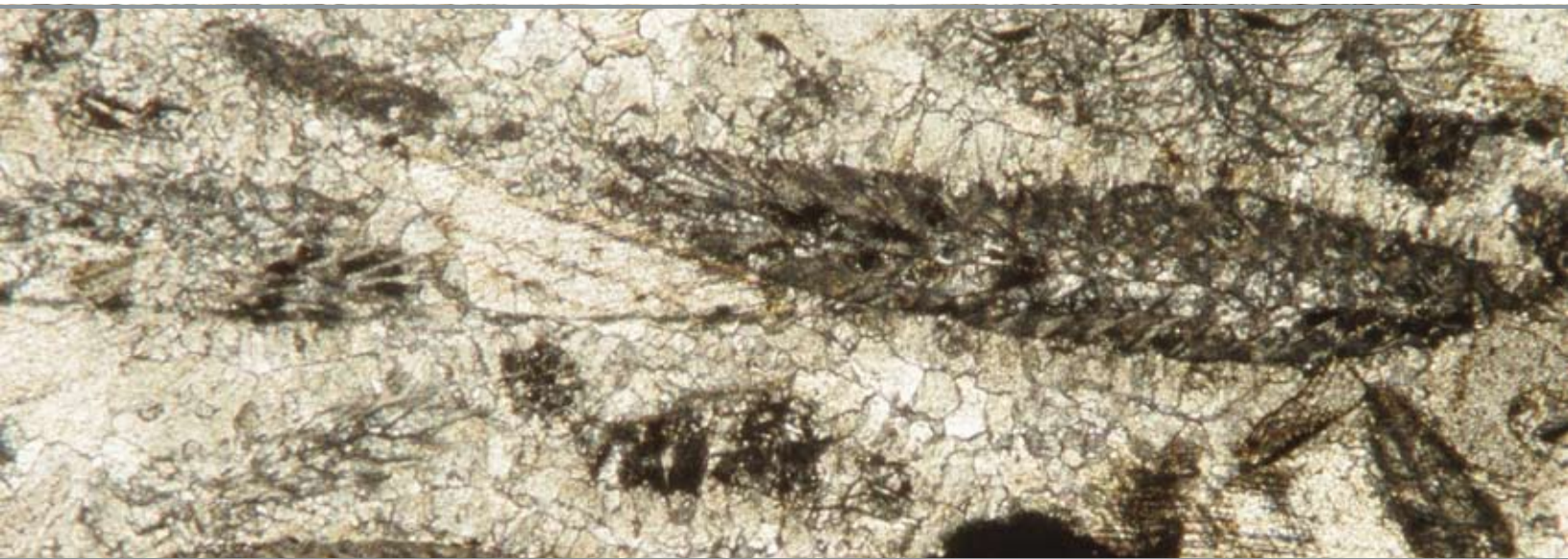


Porosity partitioning is used to identify eight pore system classes.





The composite log produced by Schlumberger Carbonate Advisor integrated evaluation of a Cretaceous Middle Eastern reservoir displays volumetric analysis and fractional flow logs in Tracks 1 and 2, respectively. Measured NMR T_2 distributions are in Track 3, and porosity and permeability from the Schlumberger Carbonate Advisor analysis are compared with core and minipermeameter data in Tracks 4 and 5. Despite the relatively simple lithology—predominantly calcite—Schlumberger Carbonate Advisor evaluation reveals that the pore geometry displays a remarkable degree of variability. Zones containing substantial amounts of macroporosity are interspersed with intervals dominated by mesoporosity and lesser amounts of microporosity. Both array induction and array laterolog tools were logged over the entire interval. A full analysis of relative permeability and saturation was performed with each log, and the results were merged according to the validity of the measurements in each interval. The final result is a single optimal evaluation of relative permeability and saturation.



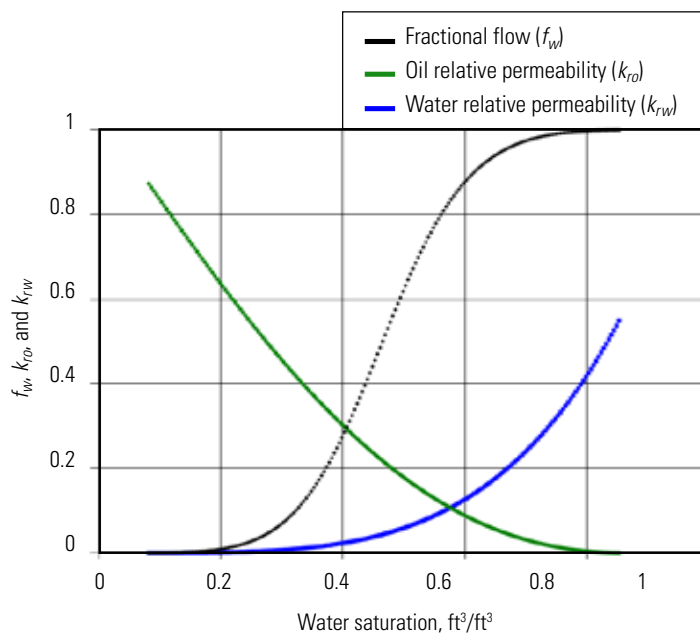
RELATIVE PERMEABILITY AND SATURATION

Simultaneous solution of saturation and relative permeability is performed using a powerful forward model that accounts for the radial variation of resistivity due to the fluid distribution caused by invasion of borehole fluid into the formation during drilling. The full model includes both the resistivity tool response and a model for the invasion process itself. Archie's equation is used to describe the local resistivity. A conventional zoned value can be used for the cementation exponent m , or alternatively a variable value of m can be computed with a self-consistent Bruggeman model, which incorporates macroporosity information from the preceding pore type and permeability stage of the Schlumberger Carbonate Advisor analysis.

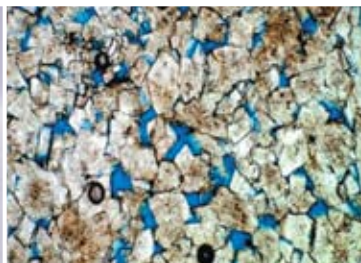
Both array induction and array laterolog measurements can be used for the analysis, which is valid in carbonate formations drilled with water-base mud (WBM). Invasion of the WBM filtrate is considered a two-phase flow event. With their multiple depths of investigation, the resistivity logs can accurately characterize the invasion front, which is inverted to determine imbibition relative-permeability curves. This method uses a realistic invasion model, not a simple assumption such as piston displacement or a ramp invasion profile. Both the saturation front and salinity front are simultaneously solved for—because the two do not necessarily coincide—to determine fractional flow, relative permeability versus saturation, and true formation resistivity.

CONTINUOUS UNDERSTANDING, WHEN YOU NEED IT

Rather than sparse data points obtained from laboratory core analysis delivered long after the well has been drilled, the continuous log provided by Schlumberger Carbonate Advisor service details the quantitative producibility of the nonfractured carbonate reservoir. The evaluation is available within hours of acquiring the log data, providing critical information for the timely optimization of completion strategies or to guide further operations while tools are still in the well or available at the wellsite.



Fractional flow curves and average relative permeability generated for intervals of the Schlumberger Carbonate Advisor evaluation on the opposite page include this set for the interval from X,270 to X,300 ft.



PORE GEOMETRIES

Micropores, with pore-throat diameters less than 0.5 μm , usually contain mostly irreducible water and little hydrocarbon. Mesopores, with pore-throat diameters between 0.5 and 5 μm , may contain significant amounts of oil or gas in pores above the free-water level (FWL). Macropores, with throats measuring more than 5 μm 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 the mesopores above the FWL.

Vugs are cavities, voids, or large pores in rocks. Vugular porosity is common in rocks prone to dissolution, such as carbonates.

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