Solutions to Problems Faced in Well Log Analysis in Carbonate Reservoir Systems Due To Multiple Porosities and Lithologies*

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Abstract

Carbonate rocks are the most abundant non-terrigenous sedimentary rocks and are composed primarily of carbonate minerals. Most carbonate rocks form from calcareous deposits that accumulate in marine environments ranging from tidal flats to reefs to deep ocean basins. Distinctive and unique aspects of carbonate rocks are their predominantly intrabasinal origin, their primary dependence on organic activities for their constituents and their susceptibility to modification by post-depositional mechanisms. In conventional analysis of Wireline logs of carbonates, the results are commonly not reliable. There are primarily two reasons. Firstly, the rocks are composed of two intermingled carbonate litholigies, namely dolomite and calcite. Secondly, porosity distributions commonly encompass a wide range of values. In recent developments, such problems were encountered in the Campos Basin, offshore Brazil. Intensive drilling and seismic, gravity, and magnetic data have contributed to the recognition of four tectono-stratigraphic units related to the rifting and break-up of Pangaea. Its most important Sag/Macabu Formation has been characterized as microbial and stromatolitic limestones, locally dolomitized and often silicified. Log correlation is very challenging in the Macabu Formation due to large scale heterogeneities and variable porosity characteristics within the Sag section, which is divided into three different porosity units: Upper, Middle, and Lower Sag. The pay interval to date has been limited to the Upper Sag in the Campos Basin wells. However, the Lower Sag is productive and has significant reservoir potential. Here, companies are using a combination of various technologies and methods for proper interpretation and understanding of logging data. The present paper reviews the various challenges of log analysis in carbonate reservoirs and also proposes solutions such as comparison of Density and Neutron logs as its combination provides a robust method of differentiating dolomite from limestone. For porosity related issues, integrating log analysis with core studies provides a handy solution as it quantifies macropores and understands connections and permeability. NMR measurements reveal pore

and fluid properties in rock formations through a two-stage measurement. Various approaches have been suggested for this ranging from empirical methods to theoretical methods.

Introduction

Formation evaluation is a very crucial phase in the E&P process. It plays an essential role when it comes to differentiating various formations that are encountered during the well drilling operations. Characterizing the formation helps us to determine the lithologies, petrophysical parameters, and other characteristics. Such analysis helps us in locating the source rocks, reservoir rocks, trapping mechanisms, and other structural features. Such key factors are necessary in developing a well and taking it into the next phase of commercial profit.

Logging techniques provide a rather effective method of recognizing such features and evaluating their potential. When it comes to logging of formations likes shales, sandstones, and other stratigraphic and structural features it is a relatively simpler technique as compared to those of carbonate rocks. Carbonate reservoirs hold nearly 60% of the world's oil reserves. Hence it becomes much more essential to analyze them in greater detail. But using basic logging suites it becomes difficult or sometimes impossible to evaluate them. Also with carbonates, due to extensive heterogeneities, determining optimal locations from petrophysical analysis often becomes little more than a statistical exercise. But with upcoming techniques and integrating two or more methods, operators are now able to effectively overcome the challenges that carbonates pose and utilize these reservoirs and maximize their potential.

Carbonates and Their Complexities

Carbonate rocks are a class of sedimentary rocks composed primarily of carbonate minerals. They are called carbonate rocks because they contain large amounts of carbonate (CO_3). Carbonate rocks are the most abundant non-terrigenous sedimentary rock. Most carbonate rocks form from calcareous deposits that accumulate in marine environments ranging from tidal flats to reefs to deep ocean basins. The deposits are derived from calcareous algae or the skeletal remains of marine organisms that range from foraminifera to molluscs.

The problem with carbonates is not that they have been studies less, in fact a lot of efforts have been made to classify carbonate systems, see Figure 1. But these efforts have not been sufficient in completely understanding specific reservoir rock properties in a given well or field.

Difficulties begin with quantifying in situ mineral, fluid, and textural properties using conventional logging techniques. Because of the vast heterogeneities, evaluation process relies heavily on core analysis for evaluating the reservoir.

Carbonate sediments are particularly sensitive to environmental changes. Carbonate sedimentation is rapid but easily inhibited. Temperature variations influence biogenic activity and affect sediment production; thus most carbonate production is strongly depth dependent. When conditions are favorable for carbonate sedimentation, organic productivity is high; when unfavorable, organic productivity ceases. Carbonates form in special environments, and, in contrast with sandstones, are biochemical in nature. Environments range from near-shore lagoons, platform organic build-ups, and shelf margin shoals to slope and basinal settings. Carbonates typically are found in warm, shallow, clear marine water in low latitudes.

Carbonates are essentially autochthonous, as they form very close to the final depositional sites. Texture is more dependent on the nature of the skeletal grains than on external influences. Intrabasinal factors control facies development. In contrast, sandstone and shale were formed of sedimentary particles derived from sources outside the depositional basin. Reefs, bioherms, and biostromes are examples of in-place local deposition where organisms have built wave-resistant structures above the level of adjacent time-equivalent sediments. Many reefal deposits are commonly composed of fragmented, locally-transported skeletal debris and a minor volume of in situ framework organisms. Biofacies and lithofacies often correlate, or in other words, organisms produce typical lithofacies. Substrates control inhabiting organisms. Basin configuration and water energy are the dominant controls on carbonate deposition. Organic productivity varies with depth and light (photic zone); upwellings and water agitation influence organic productivity.

The depositional system of a carbonate reservoir plays a vital role in estimation of its properties. They usually consist of skeletal remains of organisms that settled where they lived, which is primarily in warm and shallow marine environments. These structures usually require additional internal connectivity to be productive as the usually lack the intergranular permeability of clastics. Once settled these fragments undergo lithification, during which they often undergo chemical and biological diagenesis, which produces metastable compounds that are susceptible to change.

The most abundant carbonate form, calcite is chemically unstable and is hence susceptible to change by transformation into other minerals like Siderite, Dolomite, etc. Carbonates are particularly sensitive to post-depositional diagenesis, including dissolution, cementation, recrystallization, dolomitization, and replacement by other minerals. Abundant unstable aragonite (in bioclasts and cements) converts to more stable low-magnesium (or high-magnesium) calcite. Calcite can be readily dolomitized, sometimes increasing porosity. Complete leaching of grains by meteoric pore fluids can lead to textural inversion which may enhance reservoir quality through dissolution or occlude reservoir quality through cementation. Burial compaction fracturing and stylolithification are common diagenetic effects in carbonates, creating high-permeability zones and permeability barriers or baffles, respectively.

Determining the correct lithology - be it dolomite, limestone, or a combination of minerals – is an important step in carbonate reservoir evaluation as lithology determines the matrix density or grain density which is then used for computing porosity.

Porosities in Carbonates

Pore types in carbonate rocks can generally be classified on the basis of the timing of porosity evolution into: (1) **primary pores** (or depositional porosity), which are pores inherent in newly-deposited sediments and the particles that comprise them. Such pore types include inter-particle pores in, for example, carbonate sands (but also in muddy carbonates), intra-particle pores (within particles such as foraminifera or gastropod shells), fenestral pores (formed by gas bubbles and sediment shrinkage in tidal-flat carbonates), and shelter and growth-framework pores (common in-reef build-ups); and (2) **secondary pores**, which are those that form as a result of later, generally post-depositional dissolution. Such pore types include all of those mentioned above, but only when it can be demonstrated that primary pores which subsequently were occluded by cement later had all or some of that cement dissolved (resulting in the generation of exhumed pores see Figure 2), as well as vugs (large pores that transect rock fabric, that is, dissolution was not fabric-selective) and dissolution-enlarged fractures. Most of these primary and secondary pore types can readily be identified in cores, and with the possible exception of shelter and growth-framework pores, also in well cuttings samples.

Inter particle porosity - Porosity between particles. It is seldom preserved because of porosity loss by cementation. **Intra particle porosity** - Porosity within the particles of grains. **Fenestral porosity** - Lense shaped or globular sparry carbonate cement formed chiefly by the decay of sediment covered algal mats, shrinkage during drying, and accumulation of pockets of gas or water. **Shelter porosity** - It is a type of primary interparticle porosity created by the shattering effect of relatively large sedimentary particles which prevent in filling of pore space beneath them by finer clastic particle. **Growth framework porosity** - Primary porosity created by the in place growth of a carbonate rock framework. **Intra crystal porosity** - Porosity within the individual crystals. **Moldic Porosity** - A pore formed by selective removal by solution from an original shell, oolite, etc. Unlike other lithologies, the original primary porosity in carbonates may be totally destroyed during diagenesis and significant new secondary porosity may be created. The types of porosities encountered are quite varied (see Figure 1). Inter-particle, intra-particle, growth-framework, shelter and fenestral porosities are depositional porosities. Porosity formed during diagenesis may bemoldic, channel, inter-crystalline, fracture, or vuggy porosity.

Photoelectric Effect (PEF) Measurement

PEF or Photoelectric Factor is a standard output of most density logs. It is related to the average atomic number of the formation. It is based on the following Power law:

$PEF = K \text{ X } Z_{3.6}$

- **Problem 1:** It loses accuracy due to its dependence on the power-law moreover especially in carbonate as small quantities of heavy elements or variation in the atomic numbers can alter the value drastically.

- **Problem 2:** There is also a porosity dependence and a smaller fluid-type dependence and although they can be accounted for, they do complicate matters.
- **Problem 3:** The physics of the measurement means that it is inherently imprecise; For example, a reading of 4.5 does not necessarily imply a mixture of 25% dolomite and 25% calcite.

Poor precision results from the fact that the measurement uses only a small fraction of the total number of gamma rays that are exploited in the measurement of density. Thus PEF can sufficiently distinguish limestone from dolomite even though it is not related linearly to the quantity of dolomite in the formation.

The Archie Equation Problem

Gus Archie introduced his equation in 1942 which laid the foundation of modern log interpretation. His relationship linked water resistivity to fluid saturation. The three variables a, m, and n are empirically fit based on reservoir characteristics. In absence of specific data they are usually assumed to be 1, 2 and 2 respectively. The assumptions regarding connectivity of the pores, wettability of rock, and morphology of pore space are best suited to siliclastic rocks. Although most methods utilize some form of Archie's equation it is generally recognized that there are problems with the approach when used on carbonates. Moreover, the complex nature of carbonates makes determination of these variables a daunting task. Other issues include matrix complexity, pore shape, pore size heterogeneity, variability in formation water salinity, and uncertainty in true formation resistivity measurement

Solutions

Since carbonates encompass a huge range of heterogeneities, the exact solution to their problems is quite field specific. Still, the following methods are commonly used in the industry.

Comparison of Density and Neutron Logs

The density–neutron combination of logs provides information that is more robust in distinguishing limestone from dolomite. In many parts of the world, density and neutron scales are chosen so that the two curves are overlain in water-bearing limestone; in dolomite they have a positive “shale-like” separation i.e., the neutron curve records the greater amounts of “porosity”. To use this method and achieve best results, the neutron log should be recorded using the assumption of a limestone matrix. Basically, this means that the algorithm that converts raw counts to neutron porosity is designed so that neutron porosity is equal to total porosity in limestone that is totally water-saturated. The original prints should be checked to confirm that the log was recorded using the parameter of the limestone. Even if the scales and the matrix are set up to show the overlain density and neutron curves in limestone that is water bearing only, the amount of separation between the two curves for dolomite is quite varied. The variation depends not only on tool type, porosity, and fluid type, but also impurities in the matrix, temperature, and pressure.

Classification of Porosity Systems

Classification systems have been developed by experts to classify the pore geometry by partitioning the total porosity measurement into three systems based on size: **Micro [less than 0.5 microns], Meso [0.5 – 5 microns], and Macro [larger than 5 microns]** as shown in Figure 2. From these classifications, reservoir quality and fluid flow properties are inferred.

Another partitioning method uses relative pore geometry and classifies it into eight rock classes, see Figure 3. The resulting ternary diagram was first developed through systematic analysis of texture-sensitive borehole logs, which included NMR data, Borehole Images, full waveform acoustic logs, and dielectric data.

Other Methods

Other log-based methods of distinguishing limestone from dolomite are described best as empirical methods that are field specific or applicable, at most, in a limited range of settings. Among the logs that have been shown to respond reliably to dolomite are gamma-ray, resistivity, and sonic logs and particularly, the combinations of these curves. In reality, these logs probably respond to some secondary feature of dolomites, such as pore systems different from those of associated limestones, or an anomalous concentration of uranium. Geochemical tools can be used in which neutron-activation is used to identify the combination of various elements in a formation. Hence, if a formation is known to be carbonate but has only half of the amount of calcium, will most probably be dolomite. Recent modifications have suggest a technology to measure the exact amount of magnesium in a given carbonate formation; but such tools are expensive and slow to run.

Integrating Log Analysis with Core Studies

Researchers developed this approach to quantify macropores and to understand macropore connections and permeability. 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 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. 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 by Schlumberger using core and log data from the Middle East.

Magnetic Resonance Technology

NMR measurements reveal pore and fluid properties in rock formations through a two-stage measurement. First, in the polarization stage, the hydrocarbons are aligned like bar magnets along the direction of a static magnetic field, known as B0. This polarization takes a characteristic time known as T1 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, B0. These pulses cause the hydrogen atoms to rotate away from, and then precess about, the direction of B0. Properly timed pulses generate coherent responses known as echoes, from the hydrogen atoms, which in turn induce voltage in an antenna placed in a plane perpendicular to the direction of B0. The decay of echo signal with time depends on specific sequences of pulses. The most common is called the Carr-Purcell-Meiboom-Gill (CPMG) pulse sequence. The total signal from this signal and its decay is the sum of signals from different parts of the fluid sample, each decaying at a characteristic transverse relaxation time, T2. For the typical case of water-wet rocks, short T2 values – fast signal-decay rates arise from water in small pores or the presence of heavy hydrocarbons, while the long T2 values - show 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 T2 times that contributed to the overall decay along with the amplitude, in porosity units, associated with each T2. Although time-consuming, core analysis can reliably identify and quantify pore geometry. But the standard resistivity and porosity measurement is not sufficient to determine such porosities. NMR log data however is able to demarcate such changes see Figure 4.

Spectral Gamma Ray Logging

In pure carbonates, thorium will usually be absent because the common thorium ions are insoluble, and potassium will also be negligible. So we can say that, if the formation has very low Th and K abundances, the rock may be a pure carbonate. The rock, however, may contain uranium. Uranium usually indicates material of an organic origin as organisms are extremely good at concentrating and storing uranium. Uranium ions are either soluble or insoluble depending upon their oxidation state. Highly oxidized uranium ions, from oxidizing environments (such as deserts) are insoluble. Thus a carbonate, which also has low U abundance, comes from an oxidizing (maybe desert) environment. Conversely, non-oxidized uranium ions from sub-surface depositional environments are more soluble, and hence can be present in carbonates.

It should be noted that oxidizing environments are not conducive to the conservation of organic material, while reducing environments not only favor the conservation of organic material, they aid the conversion of the organic material to hydrocarbons. The source organic material for hydrocarbons in carbonate rocks is often algal mats that are incorporated in the deposited rocks in a sub-sea (reducing) environment and contain a significant amount of uranium.

In clay-bearing carbonate rocks high total gamma readings are not related only to the clay fraction, but are also due to the presence of uranium-radium series isotopes of organic origin. High total gamma ray readings are therefore not a reliable indicator of the shaliness of a carbonate. However, if the spectral gamma ray log indicates the presence of K and Th together with the U, it may be said that the K and Th contributions are associated with the clay content of the shaly carbonate, while the U is associated with some organic source which was deposited in a reducing environment that favors the conservation of organic material. Similarly, high K and Th values together with low U indicates a shaly carbonate, deposited in an oxidizing environment which is not a favorable environment for the conservation of organic material.

Note that K and Th must be present together for a clay to be indicated. The presence of K and no Th (with or without U) is usually an indicator of the remains of algal mats in the carbonate, or of glauconite. Thus, when calculating the shaliness of a carbonate, it is better to use the CGR as in the case of sandstones. The actual values of K and Th in the shaly carbonate will depend upon the type of clay present. Note that isolated intervals of any combination of high U, K, and Th in carbonate rocks may correspond to stylolites, which tend to concentrate uranium, organic matter, and clay minerals. Table 1 shows the main interpretations of the spectral gamma ray data for carbonate rocks.

For Saturation Parameters

Various approaches have been suggested for this ranging from empirical methods to theoretical methods. Wafta and Nurmi (1987) produced a chart from which the “m” value could be estimated, given total porosity and the amount of fracture or vuggy porosity. Herrick and Kennedy (1995) used a more rigorous approach to produce theoretical relationships between “m” and the proportion of porosity composed of vugs. To use any of these methods effectively, the nature of the pore system must be characterized well – in particular, the proportion of total porosity attributable to vugs must be accurately known. Lucia (1981) and Ehrlich et al. (1991) advocated the use of thin sections to estimate saturation parameters.

Conclusion

Carbonate rocks are one of the most common reservoir rocks found in the world with a majority of the giant oil field in carbonate reservoirs. In comparison to well-log analysis of clastic reservoirs, carbonate-rock reservoirs are burdened with a greater probability of gross errors. This inconvenient fact is a result of the possibility of two lithologies and numerous types of porosities. Errors in lithologies i.e. dolomite or calcite are one of the originating factors for errors in porosity calculations. Imprecise judgment on either account leads to gross misinterpretation of logging data. Errors also occur on account of saturation parameters. Solutions to each of the above cannot be completely definitive although some promising efforts have been made by the researchers of the industry. Like the varying porosities and lithologies of the carbonate rocks even these methods need to be adjusted and chosen wisely. Using the techniques discussed above and by effectively utilizing the data in hand like seismic we should better interpret the carbonate reservoir and utilize it effectively to make the drilling of wells a technical process rather than a statistical effort. Finally, care is necessary for interpretation of such logs to recognize the minute anomalies. Hence such measures or proposed solutions are not only feasible but rather necessary in petroliferous basins with huge carbonate reservoirs.

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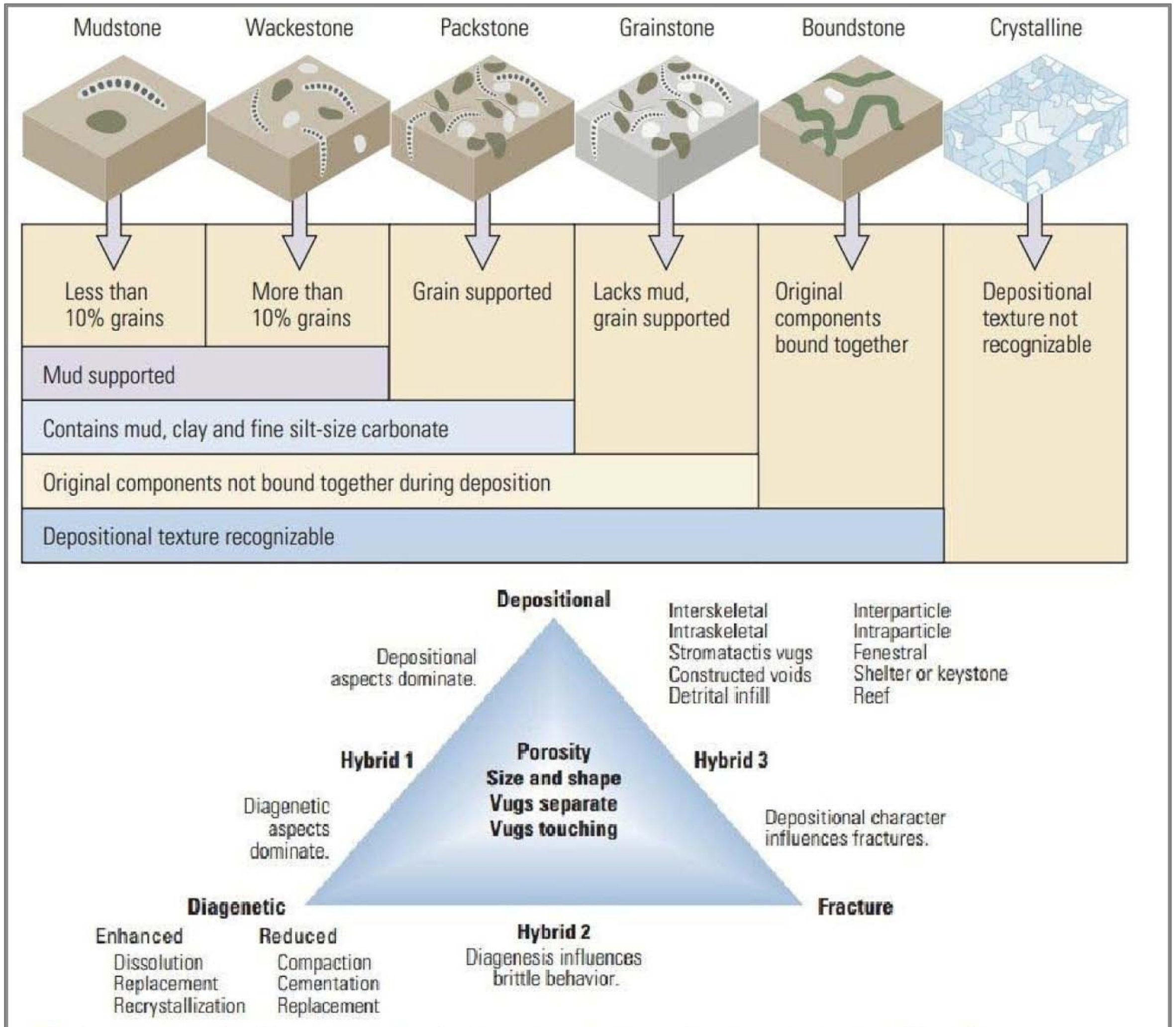
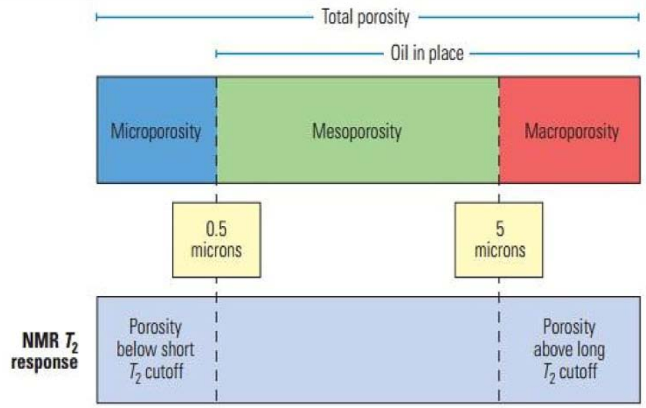


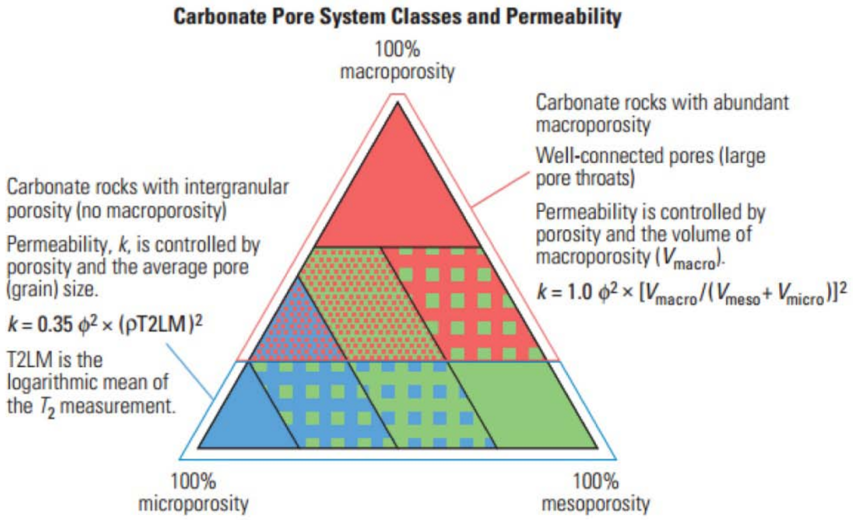
^ Carbonate classification systems. The Dunham classification system (*top*), devised in 1964, is based on rock texture and grain size. (Adapted from Akbar et al, 2000/2001, reference 1.) The Ahr classification system (*bottom*), published in 2005, maps pore geometry and attempts to relate stratigraphy to field-level permeability predictions. (Adapted from Ahr et al, reference 1.) Although these parameters are important for characterizing carbonate rock properties, neither classification system adequately describes key reservoir storage capacity or flow characteristics.

Figure 1. Carbonate Classification Systems



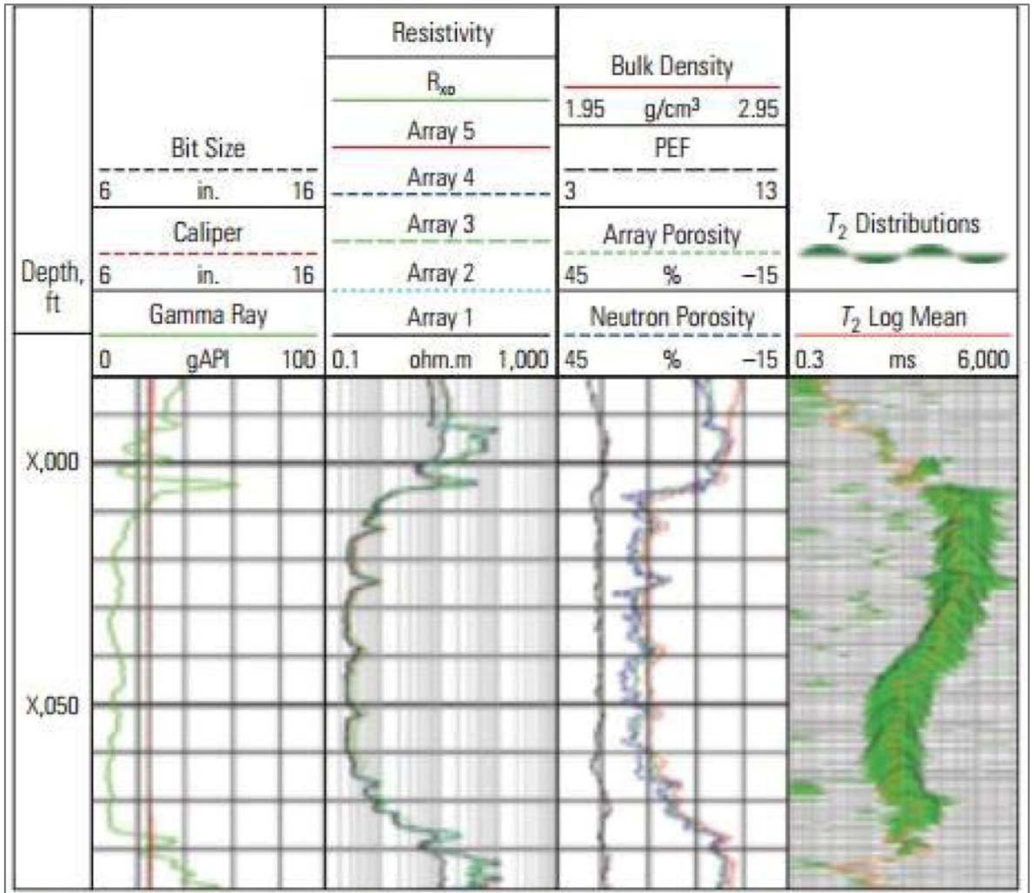
^ NMR porosity partitioning. When NMR logging tools were introduced to the oil industry, the T_2 distributions were scaled as pore sizes. For a number of reasons, this practice was abandoned. However, the concept works fairly well for carbonates. Pore sizes are determined according to a range of T_2 distributions, and then the porosity is partitioned into macro-, meso- and microporosity based on these measurements. The longest T_2 distributions correspond to macroporosity, large pores and vugs. The shortest T_2 distributions respond to microporosity. Oil migrating into water-filled rock displaces water in macro- and mesopores first. Micropores generally remain water filled.

Figure 2. Porosity Classification Systems



^ A ternary diagram based on pore size. Carbonate pore geometry and size are inputs to this ternary diagram, which indicates reservoir quality. On the lower left side of the triangle, permeability is a function of grain size. For the upper section, permeability is controlled by the volume of macropores. On the lower right, the permeability is a function of both grain and pore size.

Figure 3. Carbonate Pore System Classes and Permeability



^ Pore size and geometry. Measurements from NMR logging tools are more sensitive to pore size and geometry than are resistivity and other porosity measurements. The gamma ray log (Track 1), resistivity logs (Track 2) and porosity measurements (Track 3) are consistent throughout the interval shown. The NMR data (Track 4) indicate a large increase in pore size above X,040 ft that is not seen in the other measurements. (Adapted from Ramamoorthy et al, reference 5.)

Figure 4. NMR Log Results Compared to Standard Logging Suites

K	**Th**	**U**	**Explanation**
Low	Low	Low	Pure carbonate, no organic matter or Oxidizing environment.
Low	Low	High	Pure carbonate, organic matter, reducing environment.
Low	High	Low	Not a carbonate, or shaly carbonate with rarer low K high Th clay minerals, no organic matter or oxidizing environment.
Low	High	High	Not a carbonate or shaly carbonate with rarer low K high Th clay minerals, organic matter, reducing environment.
High	Low	Low	Glauconite carbonate, no organic matter or oxidizing environment. Also consider K-bearing evaporites.
High	Low	High	Algal carbonate, or glauconite present, organic matter, reducing environment.
High	High	Low	Shaly carbonate, no organic matter or oxidizing environment.
High	High	High	Shaly carbonate, organic matter, reducing environment.

Table 1. Interpretation of K, Th, and U Concentrations from the Spectral Gamma Ray Data for Carbonate Rocks