DETERMINATION OF ROCK QUALITY IN SANDSTONE CORE PLUG SAMPLES USING NMR

Pedro Romero[1], Gabriela Bruzual[2] , Ovidio Suárez[2]
[1] PDVSA-Intevep, [2]Central University of Venezuela

ABSTRACT

NMR T_2 distribution has been related to pore geometry. In this work we present a new approach for rock quality determination using NMR measurements on core plug samples. We measured the NMR response in the laboratory for 42 core plug samples from clastic reservoirs in Eastern Venezuela. The transversal relaxation time distribution (T_2) and the capillary pressure curves have been obtained for all samples at 100% water saturation of 17.000 ppm salinity and at a irreducible water saturation after their drainage in the porous plate apparatus. Petrophysical values such as NMR-porosity, free fluid index (FFI), bound fluid volume (BFV), $T_{2\ cut\text{-}off}$ and irreducible water saturation Swi from capillary pressure curves have also been determined. The NMR-permeability has been calculated applying the Timur-Coates equation, calibrated using the Klinkenberg permeability obtained from Helium injection. In addition, a standard petrofacies classification for the whole sample set was performed based on the main pore throat radius for 40% of mercury saturation also called r_{40}.

After analyzing the NMR results of samples of each petrofacies we found characteristic patterns in their T_2 distribution curves. A detailed study reveals that the new classification can be defined on the basis of the ratio of FFI over BFV, already explicit in the Timur-Coates permeability equation. Unlike the conventional method based on the determination of the main pore throat radius using Pittman equations, this novel approach does not require measurements of capillary pressure curves obtained from mercury injection nor the commonly tedious determination of the main pore throat radius dominating the fluid transport. The rock quality classification using NMR correlates very well with conventional rock quality definition.

INTRODUCTION

The rock quality definition provides a classification of rock quality based on the pore throat radius that dominates the fluid flow. For intergranular or intercrystalline porosity, the size of pore throat radius determines its class as megaporosity, macroporosity, mesoporosity, microporosity or nanoporosity. Especially for reservoir engineers and petrophysicists the distribution of porosity and permeability as a function of pore throat and pore size distributions are very important in the formation evaluation and definition of recovery strategies. Table 1 shows the porosity classes and the size of the pore throat dominating the fluid flow.

In this paper we present the rock quality classification using the Winland and Pittman approach [1] to evaluate 42 sandstone core plug samples from a well located in the El Furrial field, Naricual Superior-Medio Formation in Eastern Venezuela. Toward this purpose, the capillary pressure curves obtained from Mercury injection and Helium injection in a porous plate have been performed in order to obtain the pore throat radius that dominates the fluid flow using Pittman and Laplace equations. In addition to that, the NMR T_2 distribution have been measured for 100% water saturation and for irreducible water saturation conditions after their drainage at about 100 psi.

Table 1. Classification of rock types according to pore throat radius

Rock type classes	Range of pore throat size/microns
Mega	> 10
Macro	2-10
Meso	0.5-2
Micro	0.1-0.5
Nano	< 0.1

In order to establish the link between rock quality based on the pore throat radius and the NMR response, we obtained from the Permeability vs. Porosity cross-plot some clusters of data points corresponding to porosity classes in a similar way [2].

It is already known that relationships between lithology and NMR T_2 distributions are present [3,4] in terms of the shape (patterns) of the T_2 distribution curves that correspond to particular lithofacies for some reservoirs in Western and Southern Venezuela Basins. To build upon this upon this knowledge, the NMR T_2 distributions for the samples belonging to each rock quality class were analyzed. We have found that pore throat radius obtained from the Pittman equations are equivalent to the Timur-Coates equations, regarding the equivalence between the pore throat radius and the ratio Free Fluid Index over Bound Fluid Volume (FFI/BFV), obtained using suitable T_2 cut-offs.

METHODOLOGY AND RESULTS

The pore throat dominating the fluid flow has been determined using two methods: the apex-method and the best correlation between the pore throat radius obtained from the Laplace vs. Pittman equations. Figure 1 shows the characteristic capillary pressure curves measure from He-injection in the porous plate.

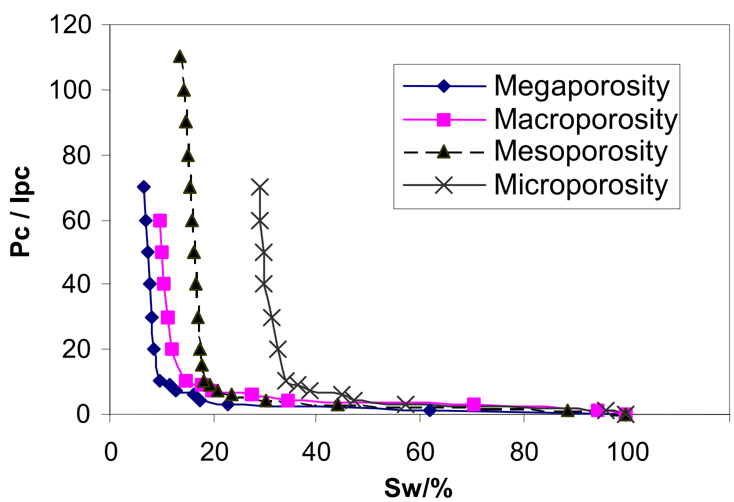

Figure 1. Capillary pressure curves for core plug samples of different rock types.

For the apex method, the values of Hg-Saturation over capillary pressure (SHg/Pc) versus Hg-Saturation (SHg) are plotted. The straight-line with the best approximation intersects the apex of the curves, and indicates that the crossing point with the x-axis is the Mercury saturation for the pore throat dominating the fluid flow. Figure 2 shows the results of this method, which yields SHg of 40%.

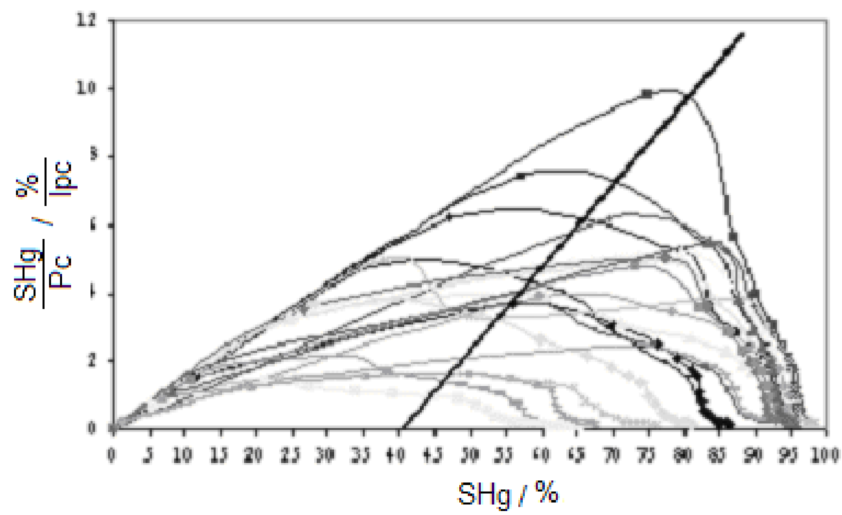

Figure 2. Apex method for determining pore throat radius.

Another method to obtain the main pore throat radius is the direct comparison between the pore throat radius for a given Hg saturation (i.e. 30%, 35% or 40%) obtained from the capillary pressure curve using the Laplace equation, and the radius obtained for the same saturation using Pittman´s equations. Results obtained for a selected sample group show that r_{40} satisfied the best fit correlation line with a coefficient of 73% (fig. 2). For r_{30} the coefficient was 61% and for r_{35} 69%. This means that for both methods r_{40} results are the best choice [5].

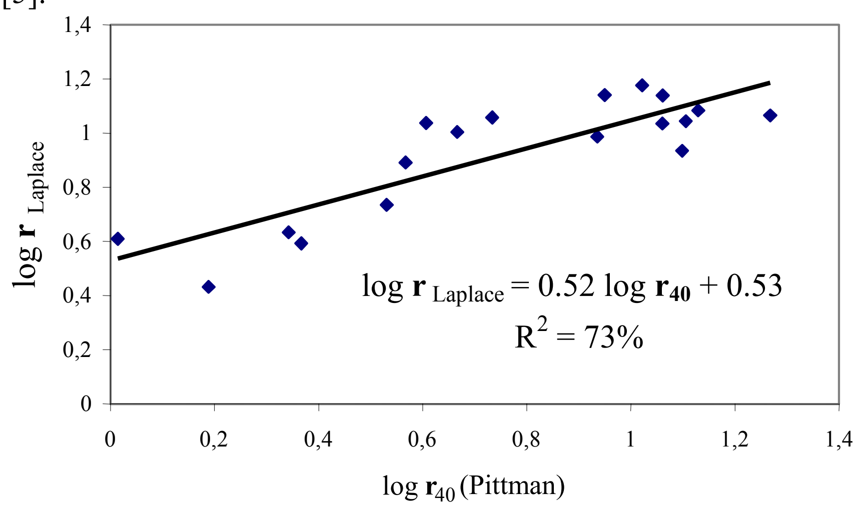

Figure 3. Comparison between pore throat radius obtained from Laplace and Pittman.

Determination of Rock Quality Using NMR

The parameters for the NMR permeability (K_{NMR}) following the Timur-Coates equation were determined based on the best correlation for the cross-plot of K_{NMR} vs. $K_{Klinkenberg}$ as shown in fig. 4. Equation 1 describes K in terms of other variables.

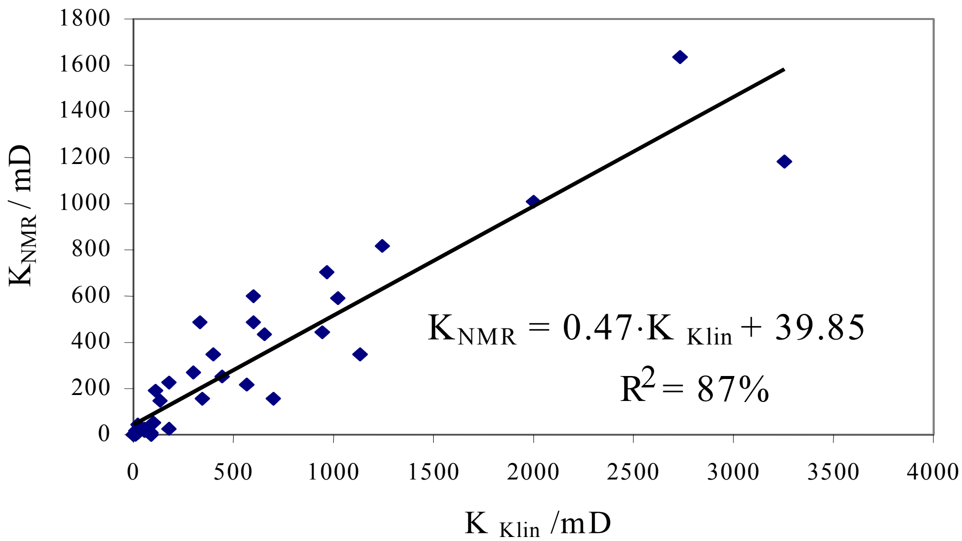

Figure 4. K_{NMR} vs. $K_{Klinkenberg}$.

$$K = 0.1 \cdot \phi^{3.05} \left(\frac{FFI}{BFV}\right)^{1.74} \tag{1}$$

The Pittman equation that better fits the characteristics of the formation studied is:

$$r_{40\,Pittman} = 0.360 + 0.528 \cdot \log K - 0.680 \cdot \log \phi \tag{2}$$

Using this equation and setting the radius of pore throat as a constant, several curves of permeability (K) as a function of the porosity (ϕ) can be plotted, defining the limits between the different rock types mentioned in table 1.

In order to find the correspondence between the Pittman and the Timur-Coates equations, it is necessary to solve both in terms of permeability as follows:

$$\log K = -0.682 + 1.288 \cdot \log \phi - 1.894 \cdot \log r_{40\,Pittman} \tag{3}$$

and

$$\log K = 0.1 + 3.05 \cdot \log \phi + 1.74 \log \frac{FFI}{BFV} \tag{4}$$

Comparing equations (3) and (4) follows that the logarithms of r_{40} and the ratio FFI/BFV are equivalent.

Following this hypothesis, the T_2 distributions of the core plug samples for 100% water saturation and for irreducible water saturation Swi have been analyzed in terms of the variables FFI and BFV. The results show that the samples corresponding to the different rock types also show a characteristic pattern in the shape of the T_2 distribution and that these rock types can also be characterized in terms of the FFI/BFV ratio. In Table 2, the corresponding values of each rock type in terms of pore throat radius, FFI/BFV ratio and T_2 cut-off are given. Figure 5 shows the permeability-porosity cross plot with the corresponding petrofacies delimitations and the typical T_2 distribution curves of each facies following Table 2. The results show a very good agreement between both approaches.

Table 2. Classification of porosity according to pore throat radius

Rock type classes	Range of pore throat size/microns	FFI/BFV	T2 cut-off/ms	Swi/%
Mega	> 10	>12	0.62	6.74
Macro	2-10	4-12	4.44	9.41
Meso	0.5-2	1.5-4	7.61	13-73
Micro	0.1-0.5	0.1-1.5	10.55	28.87
Nano	< 0.1	<0.1	---	----

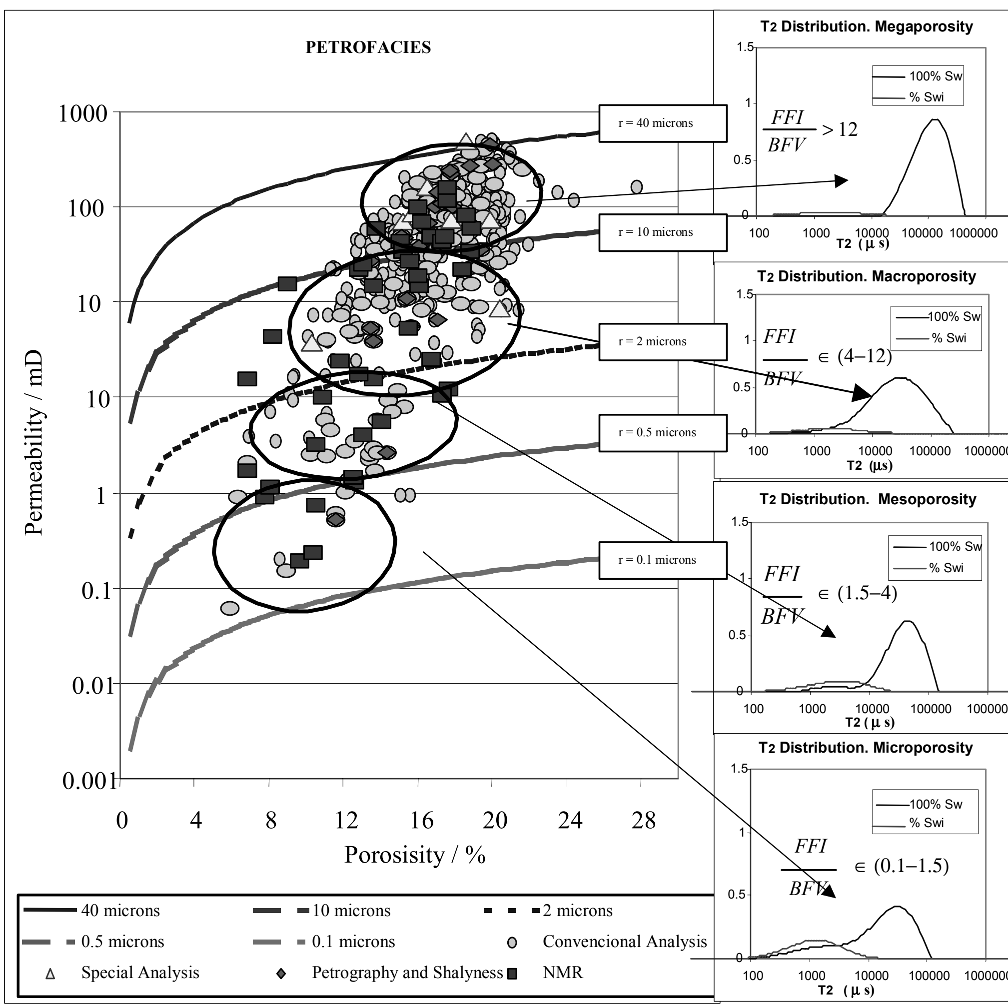

Figure 5. Permeability vs. Porosity cross-plot with NMR T2 distributions.

The advantage of a rock quality classification using NMR values lies in their direct determination, without going through the long way to find the pore throat radius dominating the fluid flow using the capillary pressure curves and the Laplace and Pittman equations. However, there is still a necessity of physical understanding of the correspondence between pore throat radius and the FFI/BFV ratio.

CONCLUSIONS

The low field NMR technique contributes in the classification of the rock quality. The correspondence between rock quality determination based on the definition of the pore throat radius dominating the fluid flow using Pittman equations and the FFI/BFV ratio has been shown. These results can contribute to an easy rock quality classification based on NMR T_2 distributions.

Further work has to be done in order to find the physical interpretations of the relationship between pore throat radius and the FFI/BFV ratio.

REFERENCES

[1] Pittman, E., "Relationship of porosity and permeability to various parameters derived from mercury injection-capillary pressure curves for sandstones", AAPG Bulletin, V.76, 1992, p. 191-198.

[2] Porras, J.C.; Barbato, R.; Salazar, D.: " Upscaling from core data to production: Closing the cycle. A Case Study in the Santa Barbara and Pirital Fields, Eastern Venezuela Basin". International Symposium of the SCA. Murrayfield, Edinburgh, 17-19 September U.K., 2001. Paper 02.

[3] Romero, P.; Golindano, Y.; Cedillo, I.; Azpiritxaga, I.; Perarnau, A.: "NMR as tool for reservoirs´ characterization and lithofacies recognition". AAPG, New Orleans, U.S.A., 17-19 April 2000.

[4] Romero, P.; Montoya, N.; "NMR and ultrasonic studies in core plug samples from carbonates and sandstones tight formations". International Symposium of the SCA. Murrayfield, Edinburgh, 17-19 September U.K., 2001. Paper 61.

[5] Bruzual, G.; " Aplicación de Resonancia Magnética Nuclear en la determinación de petrofacies en la formación Naricual Superior-Medio, campo El Furrial", Thesis, Central University of Venezuela, Petroleum Engineering Department, Caracas, Venezuela, September, 2001.