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METHODOLOGY FOR THE PERMEABILITY PREDICTION USING SPATIAL ENCODING OF THE MAGNETIC FIELD IN NUCLEAR MAGNETIC RESONANCE (NMR)

José Carlos Xavier da Silva[1,2]*, Giovanni Chaves Stael[2,3], Silvia Lorena Bejarano Bermudez[2],

Luis Jacobo Aguilera Aguilera [2,5] and Rodrigo Bagueira de Vasconcellos Azeredo [4]

ABSTRACT. We present a new formulation to determine permeability in reservoir core rocks based on the spatial encoding of the magnetic field used in the NMR technique. The variations of the magnetic field generate multiples T_2 spectra in one sample, creating a representative data of porosity distribution. In this study, each T_2 spectrum was called "magnetic cut" and the quantity depends on the length of the samples. The novel methodology was built on the assumption that the permeability in the axial direction is a linear combination of two magnetic cuts, which correspond to the maximum and minimum area, calculated from the integration of the porosity distribution in function of the transverse relaxation time. Four groups of wells were analyzed. Three were carbonates from India and Tunisia and one was sandstone from Brazil. The model was adapted to each type of formation and a specific generatrix equation was obtained for each one. The K_{ON} permeability method demonstrated a good correlation to the data obtained by routine-gas analysis. In addition, the K_{ON} model showed a good accuracy even when compared with classic permeability models like Timur-Coates K_{TC} and Schlumberger-Doll Research K_{SDR}. This model could improve the determination of permeability parameters for different lithologies.

Keywords: porosity, permeability model, transverse relaxation time, magnetic cut, spatial encoding.

RESUMO. Apresentamos uma nova formulação para determinar a permeabilidade em rochas de núcleos de reservatórios com base na codificação espacial do campo magnético utilizado na técnica de RMN. As variações do campo magnético geram múltiplos espectros T_2 numa amostra, obtendo dados representativos da distribuição da porosidade. Neste estudo, cada espectro T_2 foi chamado "corte magnético" e a quantidade depende do comprimento das amostras. Esta metodologia foi construída partindo do pressuposto de que a permeabilidade no sentido axial é uma combinação linear de dois cortes magnéticos que correspondem à área máxima e mínima, calculados a partir da integração da distribuição da porosidade em função do tempo de relaxamento transversal. Foram analisados quatro grupos de poços dos quais três eram carbonatos da Índia e da Tunísia e um era de arenito do Brasil. O modelo foi adaptado a cada tipo de formação e foi obtida uma equação geratriz específica para cada um deles. O método de permeabilidade K_{ON} demonstrou uma boa correlação com os dados obtidos pela análise de rotina. Além disso, o modelo K_{ON} mostrou uma boa precisão, mesmo quando comparado com modelos clássicos de permeabilidade, como Timur-Coates K_{TC} e Schlumberger-Doll Research K_{SDR}. Este modelo poderia melhorar a determinação dos parâmetros de permeabilidade para diferentes litologias.

Palavras-chave: porosidade, modelo de permeabilidade, tempo de relaxação transversal, corte magnético, codificação espacial.

Corresponding author: José Carlos Xavier da Silva

[1]Universidade do Estado do Rio de Janeiro - UERJ, Institute of Physics, Department of Quantum Electronics. R. São Francisco Xavier, 524, Bloco B, Maracanã, 20550-900 RJ, Brazil – E-mail: jcxsfis@yahoo.com.br

2Observatório Nacional - ON, Department of Geophysics, R. Gal. José Cristino, 77, 20921-400 RJ, Brazil – E-mails: stael@on.br, silviabermudez@on.br, luisjacobo@on.br

[3]Universidade Federal Fluminense - UFF, Institute of Geosciences, Av Gal. Milton Tavares de Souza, s/n, 24210-346 Niterói, RJ, Brazil

[4]Universidade Federal Fluminense - UFF, Institute of Chemistry, Outeiro de São João Batista, s/n, 24020-141 Niterói, RJ, Brazil – E-mail: rodrigo.bagueira@gmail.com

[5]Université de Caen Normandie - UNICAEN, École Nationale Supérieure des Ingénieurs de Caen - ENSICAEN, Centre National de la Recherche Scientifique - CNRS, Laboratoire Catalyse & Spectrochimie - LCS, 14000 Caen, France

INTRODUCTION

Studies on the characteristics of the rocks that form hydrocarbons reservoirs, water or even both are highly significant to make well drilling economically viable (Monicard, 1980). Following the decision to start drilling, a good-knowledge of the formation petrophysical properties, such as porosity and permeability, are essential (Minh et al., 2012). Porosity indicates the amount of pore spaces, and permeability represents the capacity of the rocks to transmit fluids. Determinations of the two above-mentioned petrophysical parameters have an undeniable role in the evaluation of reservoir and consequently development and production planning of the oil field (Aghda et al., 2018). NMR technology, in laboratory scale and well logging, has had many applications in the oil industry from 1990 onwards, particularly for determining important parameters of rock and fluid such as porosity, fluid type, pore size distribution, permeability, bulk volume movable (BVM) and bulk volume irreducible (BVI) (Timur, 1968; Coates et al., 1991; Coates et al., 1999; Kenyon et al., 1988, Dunn et al., 1999; Behroozmand et al., 2015; Rios, 2015). This technology is able to measure porosity directly from NMR data of reservoir rocks, but to estimate permeability it is necessary to use a mathematical model. Therefore, a few models have been presented to estimate permeability (Coates et al., 1999). Two typical models using NMR T_2 data to estimate permeability in reservoir rocks are Timur-Coates (TC) model (Coates et al., 1999) and SDR permeability model (Kenyon et al., 1988).

Timur-Coates Model stands out among the most typical models of permeability (Eq. 1) (Coates et al., 1991; Coates et al., 1999; Rios, 2011; Schuab et al., 2015).

$$K_{TC} = a\left(\frac{FFI}{BVI}\right)^{b}\phi^{c}, \quad (1)$$

where FFI is the Free Fluid Index, BVI is the Bound Volume Irreducible, ϕ is the porosity and a, b and c are coefficients to be determined depending on the lithology of the rocks. Classical SDR and Generalized SDR (Kenyon et al., 1988; Arns et al., 2008; Oxford Instruments, 2009; Rios, 2011) are represented by Equations 2a and 2b.

$$K_{SDRclas} = a\phi^{4}{T_{2LM}}^{2}, \quad (2a)$$

$$K_{SDRgen.} = a\phi^{b}{T_{2LM}}^{c}, \quad (2b)$$

where T_{2LM} is the logarithmic mean value of the T_2 relaxation time distribution, the parameters *a*, *b* and *c* are coefficients to be determined depending on the lithology of the rocks, and ϕ is the total porosity (%). These equations are frequently used to estimate the specific permeability in oil reservoir wells in different formations (Allen et al., 2000; Freedman, 2006; Souza et al., 2013). There are some models using longitudinal relaxation time T_1 (Sen et al., 1990; Elgagah et al., 1998); however, transverse relaxation time T_2 requires less operation time and the porosity response is reliable (Hürlimann et al., 1994; Sun et al., 2004; Schoenfelder et al., 2008; Souza et al., 2013).

In this paper, we proposed a novel permeability model (K_{ON}) using spatial coding varying the NMR magnetic field. Multiple T_2 spectra, individually called "magnetic cut", were collected for each sample generating an image that represents the distribution of the internal porosity in the sample length (Petrov et al., 2011). After that, a Multiple Linear Regression was made for correlating it with permo-porous properties. Samples of different formations and lithologies, including sandstones and carbonates, from oil wells located in India and Tunisia and from a drill well in Brazil were analyzed.

MATERIALS AND METHODS

It was studied four core rock groups of well samples collected from four different locations and formations; three of them are carbonates from India and Tunisia, and one is sandstones from Brazil. The groups were named India, Tunisia, Tunisia T and Rio Bonito (Table 1). The methods used in this paper to evaluate the properties of porosity and permeability were realized in the laboratory. The samples of reservoir rocks were analyzed by NMR, and their porosity and permeability by Nitrogen (N_2). Before routine and NMR analyses, the samples were prepared and subsequently cleaned in the Soxhlet apparatus using toluene and methanol. After that, the grain density, porosity and permeability were measured using the Corelab Autopore 500 and Autoperm 300 equipments, using 500 psi as the standard confining pressure. These analyses were carried out at the Petrophysical Laboratory of the National Observatory (LabPetrON).

Table 1 - Information about type, location and number of samples.

Type	Formations	Number of samples
Carbonate	India	5
	Tunisia	7
	Tunisia T	9
Sandstones	Rio Bonito	10

The Rio Bonito formation was generated by a succession of cyclic sediments of sandstones, siltstones and shales, in addition to large deposits of coal found in the state of Santa Catarina, Brazil. The porosity is basically secondary, with predominance of intergranular moldic porosity, in addition to intragranular and fractures, the latter being filled with clay minerals. The carbonate samples named India, Tunisia and Tunisia T are samples of oil wells which belong to these respective countries but cannot be identified.

The cores were saturated with brine. Afterwards, NMR analyses were made using a Maran Ultra 300 NMR spectrometer by Oxford Instruments, operating a permanent 460 Gauss magnet equivalent to a resonance frequency of 2MHz for the ^1H, with a coupled pulsed-gradient amplifier. Spatially resolved data were obtained as a function of transverse relaxation time T_2 and porosity (ϕ), where multiples T_2 spectra for each sample were collected and called "magnetic cut". The number of magnetic cuts depends on the length of the samples. The transverse time decay provides information about distribution of pore sizes and T_2 vs ϕ integral can bring information about porosity. This value was called area A.

We selected two specific magnetic cuts, the magnetic cut with a maximum area (A_{max}) and the magnetic cut with a minimum area (A_{min}) for each sample. As permeability is determined by the amount of fluid flowing through the rock, in the longitudinal direction, and tortuosity is a linear function of the path traveled by the fluid through the porous system (Amyx et al., 1960; Roque & Valério, 2012), a linear combination with A_{max} and A_{min} in each formation was developed to calculate permeability, which from now on will be called K_{ON}, as shown in Equation 3.

$$K_{ON} = aA_{min} + bA_{max} + c, \qquad (3)$$

where A_{min} and A_{max} are the minimum and maximum areas integrated into space (ϕ x T_2), respectively $[T^1]$, and the constants a, b ($[L^2T^{-1}]$) and c ($[L^2]$) are dependent on the lithology. This methodology is based on our innovate idea that the permeability in one direction could depend on the maximum and minimum porosities values inside the core, simulating a reservoir and a controller flow, respectively.

RESULTS AND DISCUSSION

As we mentioned, we applied successive variations to the NMR magnetic field to obtain different magnetic cuts along the samples. Figure 1 shows the different magnetic cuts for one representative sample of each formation that was studied. The x-axis represents the relaxation time distribution T_2, the y-axis the porosity (p.u.), and the z-axis the length of the sample. Samples from India (I-03) and Tunisia T (T-02), Figures 1a and 1d respectively, have almost a uniform T_2 distribution behavior in all magnetic cuts, which indicates a homogeneous distribution of pore dimensions. Tunisia (BG-1A) and Rio Bonito (AH1) samples (Figs. 1b and 1c respectively) have a heterogeneous pore distribution that corresponds to different pore sizes. These two samples have bigger pore sizes than the previous ones, besides being more remarkable for BG-1A.

Determined areas in space (ϕ x T_2)

Calculating the areas under the curve of all distributions of T_2 throughout the sample is the basis of this new permeability formulation (K_{ON}). For each sample, it is only considered the maximum (A_{max}) and minimum (A_{min}) areas. The areas can only be compared if they belong to the same formation, and using the same experimental parameters for all samples. In Figure 2 it is possible to see a representation of the A_{min} and A_{max} values of the four samples from the regions studied.

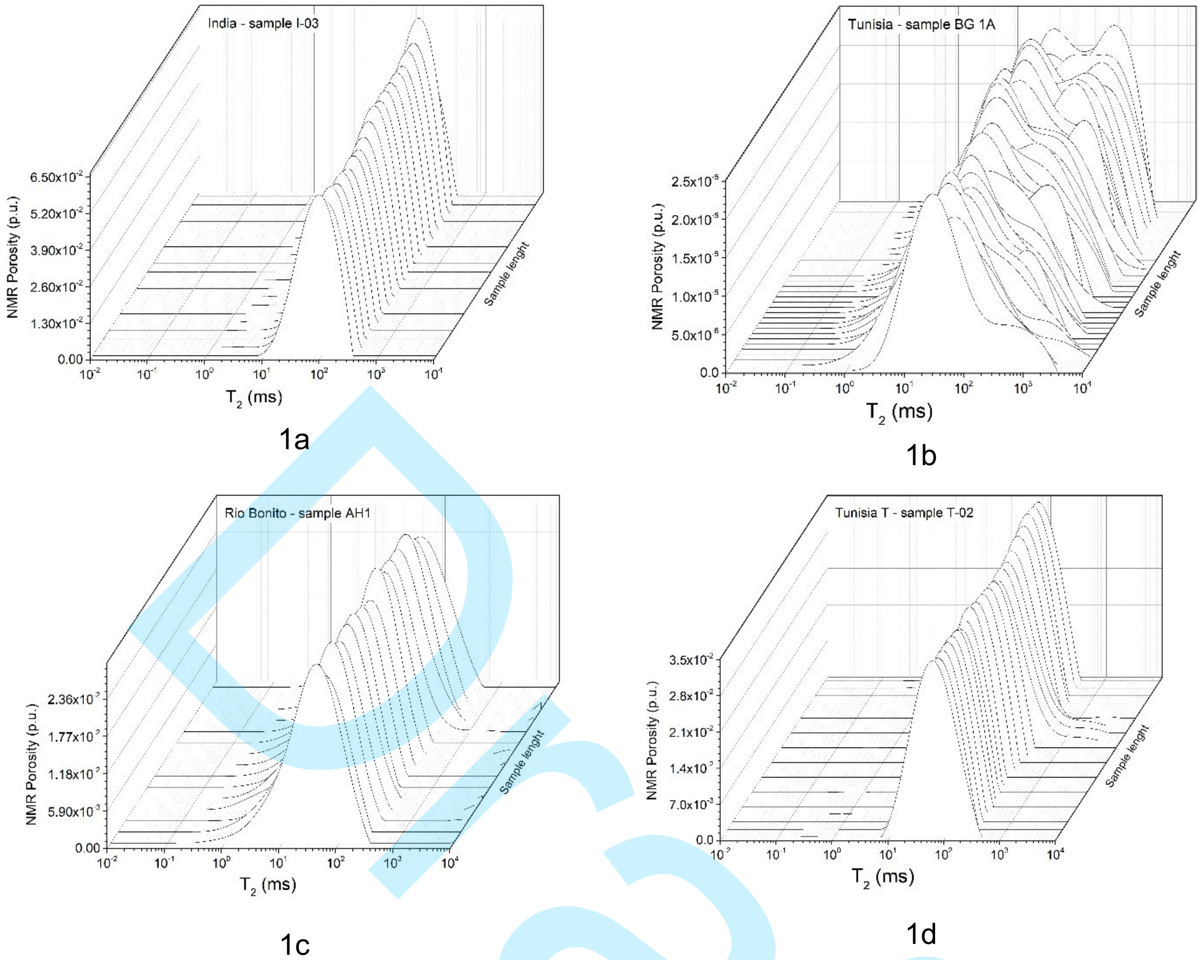

Figure 1 - Representation of magnetic cuts to four representative samples: a) Indian Formation, sample I-03; b) Tunisia Formation, sample BG-1A; c) Rio Bonito Formation, sample AH1; c) Tunisia T Formation, sample T-02.

Generatrix equation (MLR)

In order to calculate the coefficients *a*, *b* and *c* for each sample (see Eq. 3), a Multiple Linear Regression (MLR) was made. MLR explains the relationship between a continuous dependent variable and two or more independent variables. In this case, the dependent variable is the value of the gas permeability measured by a routine petrophysical analysis, and the independent variables are A_{min} and A_{max}. The determined values of R^2 were 0.989, 0.959, 0.935 and 0.927 for India, Tunisia, Rio Bonito, and Tunisia T, respectively.

The generatrix equations established for each formation after the MLR analysis are shown in Equations 4, 5, 6 and 7.

- *Samples from India*

$$K_{ON} = -6.019 + 1.942A_{min} - 0.509A_{max}, \quad (4)$$

- *Samples from Tunisia*

$$K_{ON} = -0.28 + 137.04A_{min} - 0.27A_{max}, \quad (5)$$

- *Samples from Rio Bonito*

$$K_{ON} = -0.286 - 0.281A_{min} + 0.292A_{max}, \quad (6)$$

- *Samples from Tunisia T*

$$K_{ON} = -2.304 - 0.388A_{min} + 0.467A_{max}, \quad (7)$$

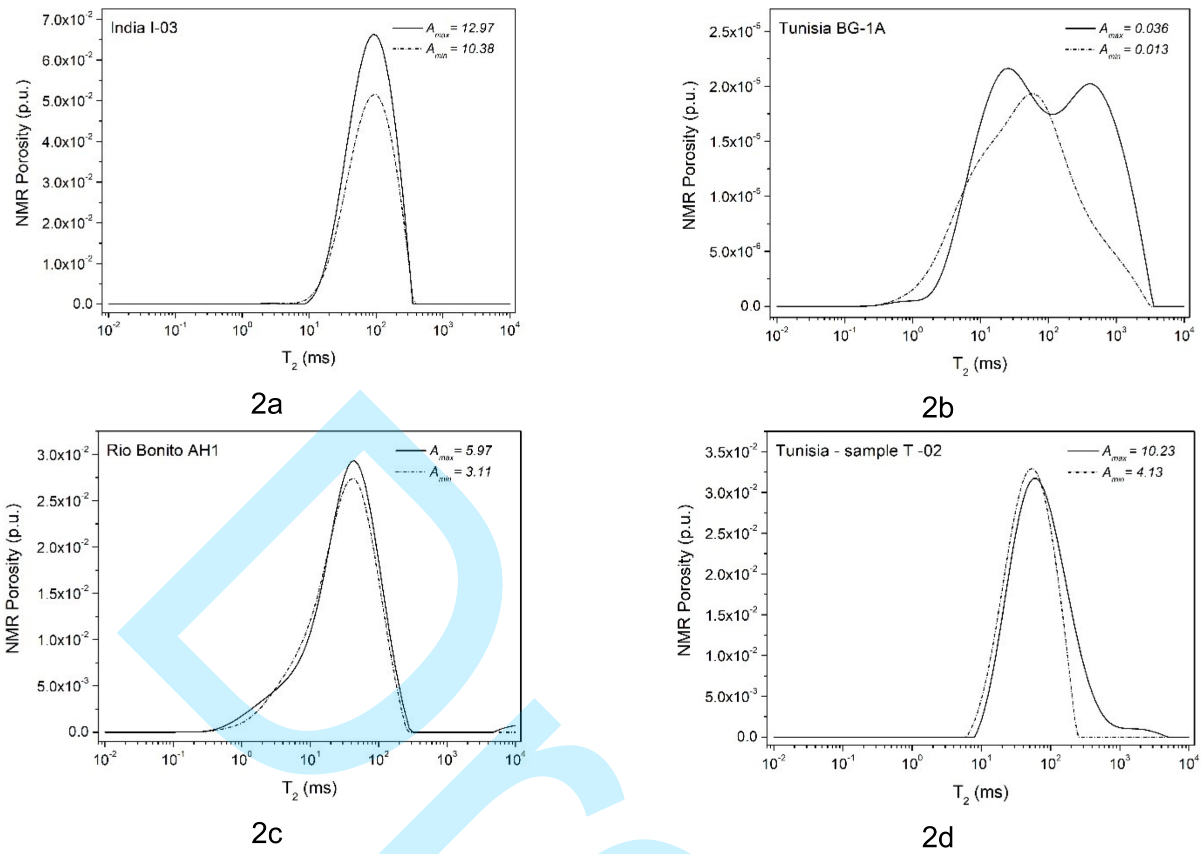

Figure 2 - Representation of the Amin and Amax values of the four representative samples of the study formations. a) Indian Formation, sample I-03; b) Tunisia Formation, sample BG-1A; c) Rio Bonito Formation, sample AH1; c) Tunisia T Formation, sample T-02.

Comparison between the calculated values for the K_{ON} model and the experimental results, K_{gas}, measured in the laboratory

A simple linear regression was made to all groups of samples in order to compare the results between the K_{ON} permeability model and K_{gas} permeability laboratory values (Fig. 3). This graphic proves that there is a good relationship between the gas permeability values, measurements made in the laboratory, and the values of the permeability model implemented in this work.

The values of the determination coefficients (R^2) and slope (α) are presented in Table 2. It is important to note that the values of R^2 are very close to one, however, this does not guarantee a good accuracy of the model itself. It was necessary to consider the slope (α) to complement this information which is an important factor to analyze. If it is also very close to unity, this can indicate a better estimate of the values obtained, as it can be observed in Table 2.

Determination of percentage deviation between calculated permeability values (K_{ON}) and laboratory measurements (K_{gas})

Figure 4 shows the comparison of the permeability data obtained by routine laboratory experiments and the permeability values estimated by the K_{ON} model for each formation. The samples from India (Fig. 4a) showed an error of approximately ± 5%, the Tunisia samples (Fig. 4b) showed a high error variation of approximately ± 35%. The Rio Bonito samples (Fig. 4c) indicated an error variation near ±10 % and the Tunisia T samples (Fig. 4d) exhibited some error values greater than ±35%. Figure 4 shows the adjustment of the values of the models as a function of K_{gas}. The samples from India and Rio Bonito show the best permeability adjustment values with errors less than 10% and 20%, respectively, in relation to those from Tunisia and Tunisia T, and corroborated with the values of R^2 in Table 2. From the examples observed in Figure 1, it is possible to state that there is not a direct)

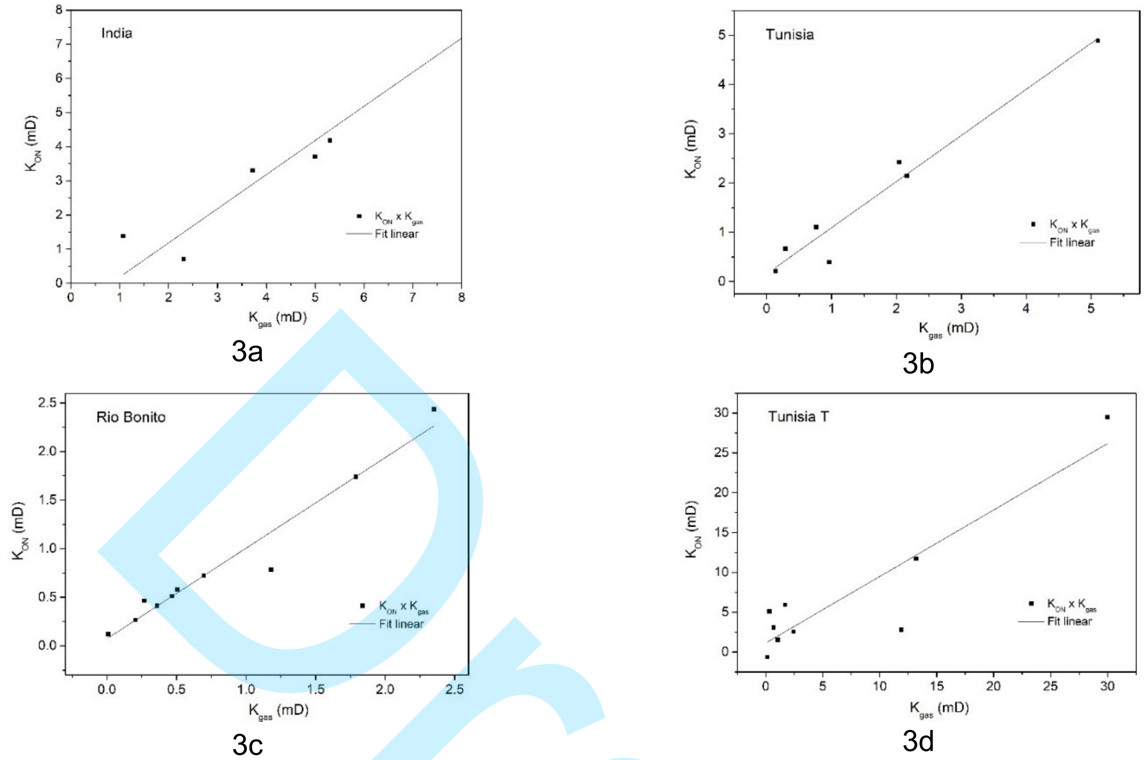

Figure 3 - Comparison between the K_{ON} permeability values and K_{gas} permeability laboratory results to all groups of samples.

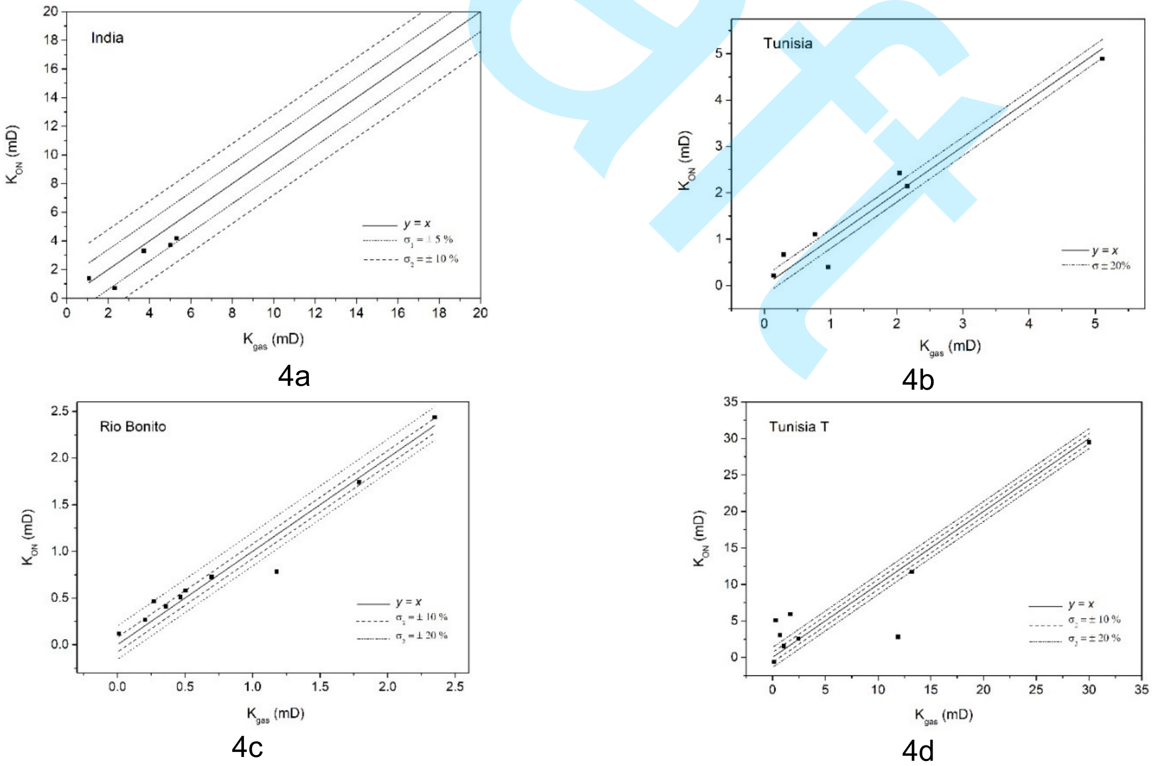

Figure 4 - Error limits between the K_{ON} and K_{gas} values for all formations.

correspondence between the accuracy of the permeability values and the texture, which is an arrangement characteristic of each rock or formation.

Table 2 - Parameters of the linear regressions for the formations.

Type	Formations	Determination coefficients (R^2)	Slope (α)
Carbonate	India	0.999	0.999
	Tunisia	0.949	0.936
	Tunisia T	0.866	0.881
Sandstone	Rio Bonito	0.951	0.932

Data effectiveness from the K_{ON}, Timur-Coates K_{TC}, and Schlumberger-Doll Research K_{SDR} models

In order to measure the accuracy of the K_{ON} model, the traditional Timur-Coates K_{TC} and Schlumberger-Doll Research K_{SDR} models were applied to the samples and then compared with the values obtained by the K_{ON} model. Some data used in these models, such as free fluid volumes, fluid irreducible ratio, porosity, and Logarithm Mean Transverse Relaxation time (T_{2LM}), of the studied samples are presented in Equations 1, 2a and 2b, respectively. Table 3 shows R^2 and the slope of the fit line, for the respective formations and models. In general, it was noticed that the K_{ON} model presents the best fit in determining permeability, when R^2 and α are compared. Evaluating the samples from India formation, we observed that the K_{ON} and K_{SDR} Classic models present good permeability estimation, with very close R^2 values. However, the angular coefficient of linear adjustment of the permeability, based on the spatial encoding, is closer to the laboratory measures for this set of samples. For the carbonate and sandstone samples from the Tunisia, Tunisia T and Rio Bonito formations, the K_{ON} model showed R^2 coefficients and slopes higher than the values generated by traditional models, thus showing greater precision in the inferred permeability values when compared with experimental data.

Due to the non-viability to access the T_2 spectra of the Tunisia samples, it was not possible to obtain the Free Fluid Index (FFI) and the Irreducible Limit Volume (BVI) measurements to calculate the permeability using the Timur-Coates model. In general, the K_{ON} model presented relevant results, close to one, in determining the permeability for the varied set of samples studied.

Table 3 - Comparison indicators among the permeability models for all investigated formations.

Type	Formation	Permeability Model	Determination coefficient (R^2)	Slope (α)
Carbonate	India	Generalized SDR	0.672	0.058
		Classic SDR	0.995	0.564
		Timur-Coates	0.128	0.028
		ON	0.999	0.999
	Tunisia	Generalized SDR	0.620	0.562
		Classic SDR	0.350	0.487
		ON	0.949	0.936
	Tunisia T	Generalized SDR	0.783	0.720
		Classic SDR	0.825	0.635
		Timur-Coates	0.376	0.528
		ON	0.866	0.881
Sandstone	Rio Bonito	Generalized SDR	0.470	0.221
		Classic SDR	0.280	0.519
		Timur-Coates	0.001	0.141
		ON	0.951	0.931

Determination of the permeability using linear adjustment equations between K_{ON} and K_{gas}

A good permeability model should be able to predict the permeability of the entire formation, even when a few numbers of samples from a specific formation are used. Using the linear Equations 8 and 9, that we obtained from the comparison of the permeabilities calculated by the K_{ON} model, with the laboratory measurements K_{gas}, we estimate the permeabilities of samples from Rio Bonito and Tunisia that were not measured by NMR, as they do not have magnetic cuts data but only the K_{gas} measurements. Tables 4 and 5 show the calculated permeability (K_{cal}) for Rio Bonito and Tunisia, respectively.

$$K_{cal\ Rio\ Bonito} = K_{ON} = 0.881K_{gas} + 0.386, \quad (8)$$

$$K_{cal\ Tunisia} = K_{ON} = 0.936K_{gas} + 0.192, \quad (9)$$

Table 4 shows that calculated values for permeability (K_{cal}) are very close to the K_{gas} experimental measurements. The most significant deviations were found in samples IV1, IV2 and IH1, which have gas permeability data very close to zero.

Table 4 - Comparison between calculated permeability (K_{cal}) values and gas measurements of Rio Bonito samples.

Sample	K_{gas} (mD)	K_{cal} (mD)
AV1	1.18	1.17
AH1	0.51	0.54
AH2	0.91	0.92
BV1	2.35	2.26
BV2	1.13	1.13
CV1	0.20	0.26
CH1	0.27	0.32
DH1	0.47	0.51
DH2	0.55	0.59
DH3	2.53	2.43
EH1	0.36	0.41
EH2	0.32	0.37
EH3	0.38	0.43
FV1	0.70	0.72
FH1	2.85	2.73
GV1	0.21	0.27
GH1	0.40	0.45
HV1	1.79	1.74
HV2	0.67	0.70
HH1	10.70	10.04
IV1	0.00	0.07
IV2	0.00	0.07
IH1	0.00	0.07
JV1	0.10	0.16
JH1	0.55	0.59

Table 5 shows the same analysis for Tunisia samples. It was noticed that the samples with high permeability present a better correlation between the K_{ON} model and the experimental data, while the samples with low permeability have a greater deviation.

Table 5 - Comparison between calculated permeability values and gas permeability measurements of the others Tunisia samples.

Sample	K_{gas} (mD)	K_{cal} (mD)
1B	0.04	0.19
2B	0.05	0.20
3B	2.50	2.50
5B	2.41	2.41
6B	8.43	8.05
7B	3.85	3.76
9B	0.82	0.92
10B	0.16	0.31
12B	0.03	0.19

CONCLUSIONS

We developed a new formulation for predicting permeability of real reservoir samples using spatial encoding of the magnetic field of the Nuclear Magnetic Resonance technique and correlating the permo-porous properties using MLR. The K_{ON} model showed a good accuracy, even when compared with classic permeability models like Timur-Coates K_{TC} and Schlumberger-Doll Research K_{SDR}. The determination coefficient R^2 and the slope of the adjustment line were analyzed, and the results show that both are very close to unity for the four groups of samples. Based on this information, it is possible to accurately determine the permeability values from the proposed model for different sandstone and carbonate lithologies.

The coefficients in the generatrix equations for minimum areas had a more significant influence on the determination of permeability as it is responsible for controlling the fluid flow inside the rock. The equations of linear adjustments allowed us to estimate values of permeability of other samples of the same formation that were not analyzed by NMR.

Finally, this proposal is a good alternative, since, besides showing precise values for the permeability estimation, it provides another method for performing permeability measurements using spatial encoding of the magnetic field in the Nuclear Magnetic Resonance technique. It was also observed that the K_{ON} model responded better in low permeability sandstone samples than in carbonate samples.

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