Petrophysical studies in Albian carbonate reservoir of Campos Basin using multivariate statistical analysis

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Abstract

Well logging is an operation that records the physical characteristics of the geological formations and the fluids present in the same mechanical conditions of the well, through appropriate sensors, whose response is transmitted to the surface. The information gained through this operation is of great importance in the petrophysical characterization of petroleum reservoirs, both siliciclastic and carbonate. Through this process it is possible to derive properties inherent to the reservoirs, such as porosity, permeability, and fluid saturation. This study proposes to reinforce the importance of the measurement and interpretation of logs in the exploration of a reservoir. The objective here is to study Albian carbonate reservoirs in the Campos Basin through the interpretation of logs (gamma ray, resistivity, sonic, density and neutron porosity) and laboratory petrophysical data for the identification of electrofacies, which allowed the geological characterization when comparing with the lithofacies. In increase, the use of multivariate statistics in a joint interpretation of several wells, this allowed to identify petrophysical parameters such as porosity and permeability, as well as the saturation of water along the zones of interest.

Introduction

This work was performed in a carbonate reservoir of Campos Basin, which is located along the continental shelf of Southeast Brazil. These rocks were deposited in an extensive carbonate platform environment, with more than 1500 km of extension along the Campos and Santos Basins (Figure 1). The sedimentary evolution of this platform was conditioned by pre-Albian section structures (Sao Tome Low, internal and external highs, NW and NE lines). The evaporites movement was influenced by the sediment load, substrate slope and reactivation of faults (direction NW/SE), controlling the geometry and distribution of facies. These reservoirs are represented by isolated structures, which correspond to shallow platform carbonate deposits that were formed during a transgressive Lower/Middle Albian regime. They correspond to carbonate sediments deposited in the marine environment with high to moderate energy, represented by hairy packstones to oolitic grainstones (Torrez, 2012).

This reservoir has three zones being called, from the youngest to the oldest, as packstone, grainstone and cemented grainstone. The grainstone is considered the reservoir in this oilfield because has the higher values of porosity and permeability (Bruhn et al., 2003).

Rock porosity is obtained by direct, as laboratory experiments on core samples, or indirect measurements, as well logs. Determining porosity through logs is not easy and immediate task, because, usually, a single log is unable to provide a reliable estimate, because they are dependent on various interaction forms between lithology, fluid type, porous geometry and physical properties (Abreu, 2015). Therefore, it is common to use more than one log, for the purpose to reach a better estimation of porosity. In the case of permeability, this parameter is often assessed in the laboratory from reservoir core samples or evaluated from well test data, which are normally only available from a few wells in an oilfield. But, almost all wells are logged and to derive permeability from logs many approaches exist (Tavares, 2015).

Method

To obtain the petrophysical parameters, the interpretative software used was Interactive Petrophysics (IP) by Senergy (2015) and the statistical analyzes were performed as the Minitab software (Minitab, 2015). Initially, the porosity was calculated from the density log, as well as from the sonic and neutron logs (Ijasan et al., 2013). On the other hand, permeability was estimated from the approaches of Timur, Morris Biggs Oil and Schlumberger Chart K3 (Ahmed, 2010). In the calculation of water saturation, the Archie equation was used, because there is a little clay in the carbonate reservoirs (Crain, 2015). As for multivariate statistics, the methods used in the study were the cofenic correlation coefficient and the discriminant analysis (Hardle & Simar, 2007).

Results

Figure 2 shows the logs of wells A3 and A10 (curves in tracks 2, 3 4 e 5), porosity and permeability laboratory data plotted together with their estimates (black dots and curves in tracks 6 and 7) and water saturation estimated by Archie Equation (track 8). The correlation between both wells is also shown, delimiting the zones of interest of each well. As presented in this figure, the porosity and permeability estimates are not acceptable, therefore, we need better estimates of these two parameters, as we are trying in this work.

For well A3, with the use of Euclidean distances in the nearest neighbor method for the porosity, it was possible to start the formation of groups. The smallest distance between the two distinct variables is 0.99, that is, this will be the first group to be formed. It is between the variables 2 and 4 forming in this way the Group I, which will be assembled in the dendogram in 0.99. The second smallest distance is 4.38, which is between variables 1 and 3 forming thus the Group II. The next distance is 5, which is between Groups I and II, which form the Group III (Figure 3).

With the matrix of the Euclidean distances with the method of the most distant neighbor for the porosity, it is possible to start the formation of the groups, and the smallest distance between the two distinct variables is 0.99, that is, this will be the first group to be formed. It is between variables 2 and 4 forming thus the Group I, which will be assembled in the dendogram at height 0.99. The second smallest distance is 4.38, which is between variables 1 and 3 forming therefore the Group II. The next distance is 5.27, which is between Groups I and II, which form the Group III. Therefore, we have the dendogram of the porosities for the largest Euclidean distance (Figure 4).

The degree of deformation caused by the construction of the dendogram was evaluated by means of the "cofenetic correlation coefficient", which serves to measure the degree of fit between the dissimilarity matrix (F-matrix) and the matrix resulting from the simplification provided by the grouping method (Cofenetic C). The fenetic matrix is composed of the Euclidean distances, while the cofenetic matrix is composed of the smallest distances found in the nearest and near-neighbor methods. The co-behavioral correlation coefficient is the Pearson coefficient R. These coefficients obtained by the methods of the nearest and furthest neighbor were 0.96 and 0.97, respectively. The methods showed a very close correlation coefficient, so that either method can be applied in the multivariate analysis of porosity for wells A3 and A10.

For the permeability, the Fenon Line, or cut line, marks the distance where the largest jump occurs in the graphs of Figure 5. We chose to draw this line between heights 0.1 and 3755.93, which represents the largest jump in Euclidean distances between the variables. In accord to the separation made by the Fenon Line, 3 distinct groups are formed. The permeabilities obtained by the Timur (TI) and Schlumberger Chart K3 (SCH) methods resemble and have a jump of only 0.1 between them, forming Group I. While the permeability obtained by the Morris Biggs Oil (MBO) method with a distance Euclidian of 3755.93 for Group I represents a very large leap, thus this variable does not resemble Group I variables. On the other hand, the permeability obtained in the laboratory (Lab) does not resemble any of the other variables. Therefore, the permeability obtained by the IP functions in this study did not fit. For this reason, a permeability curve was generated from a multilinear regression between the permeability obtained in the laboratory and the gamma ray, sonic, shallow resistivity and density logs. The regression was performed with these logs, since they were the best fit, having a coefficient of determination of R^2 = 0.63 (track 7 of Figure 6).

$$PermAjust = 12.43836 - 24.58322RHOC + 2.232.23864(\mathrm{RXO}) + 1.30435(\mathrm{DLT}) - 5.30228(\mathrm{GRCO}), \quad (1)$$

em que:

RHOC = density log;
RXO = resistivity log;
DLT = sonic log;
GRCO = gamma ray log.

The final responses of the parameters studied in this work for both wells are summarized in the Table 1.

Conclusions

In the analysis of the data, around the depth of A750 m it was found that there is a radioactive rock with high porosity, a rock capable of storing oil. This rock, in accord to the interpretations, it was identified as a porous wackestone. In the deepest part, with low values of radioactivity, porosity and transit time, and high density values, indicate a compacted but clay-free rock, such a rock was recognized as a cemented grainstone. This formation is situated in the water zone of the reservoir and because it is a carbonate, it is likely that the water in contact with this has caused a dissolution and thus reducing its characteristics of a good rock reservoir. Between these two zones, the grainstone is located, which is considered the reservoir in this oilfield because has the higher values of porosity and permeability. The porosity determined in the laboratory correlates well with the porosities obtained from the logs and had a greater similarity with the neutron porosity in accord to the dendograms presented. The methods for estimating the permeability did not establish a good fit to the permeability measured in the laboratory, then it was necessary to do a multilinear regression using some logs. The estimation resulted close to the permeability obtained in the laboratory, presented, in this way, a more coherent result than those previously calculated. The water saturation analysis showed that the zone of interest of well A3 would be contained in the transition zone of the reservoir. The water saturation of the A10 well was very close to that of the entire extent of the zone of interest of well A3. Finally, based on the results obtained in this work, we think that the application of the electrofacies method in another well that has a lithology analysis done by geologists. We also recommend using more advanced logs such as image and NMR logs to promote a better understanding of the relationship between porosity, permeability, pore size distribution and sedimentary facies.

Acknowledgments

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Table 1. Final results of petrophysical parameters.

Well and depth (m)	Porosity (%)				Permeability (mD)		Water Saturation (%)
	Laboratory	Sonic	Neutron	Density	Laboratory	Fit	Archie
A3 (A780 to A865)	18.63	16.98	22.61	17.84	132.40	27.92	49.25
A10 (A745 to A864)	22.32	17.60	20.49	17.11	659.39	166.37	35.85

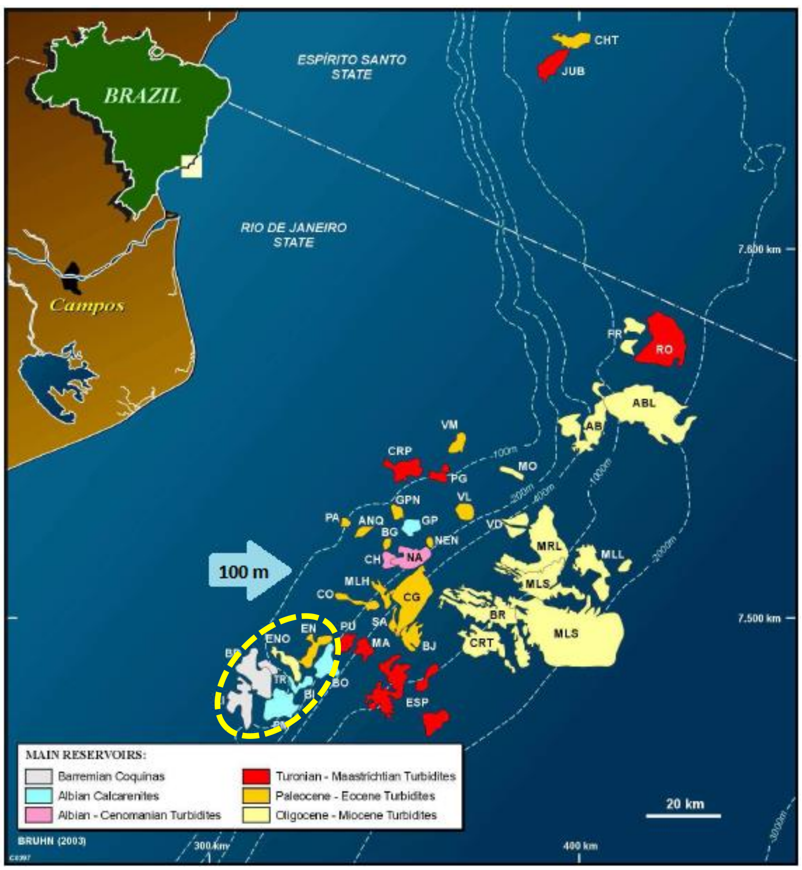

Figure 1. Location of the Campos Basin with Albian carbonate oilfields inside the ellipse (Guardado et al., 1990).

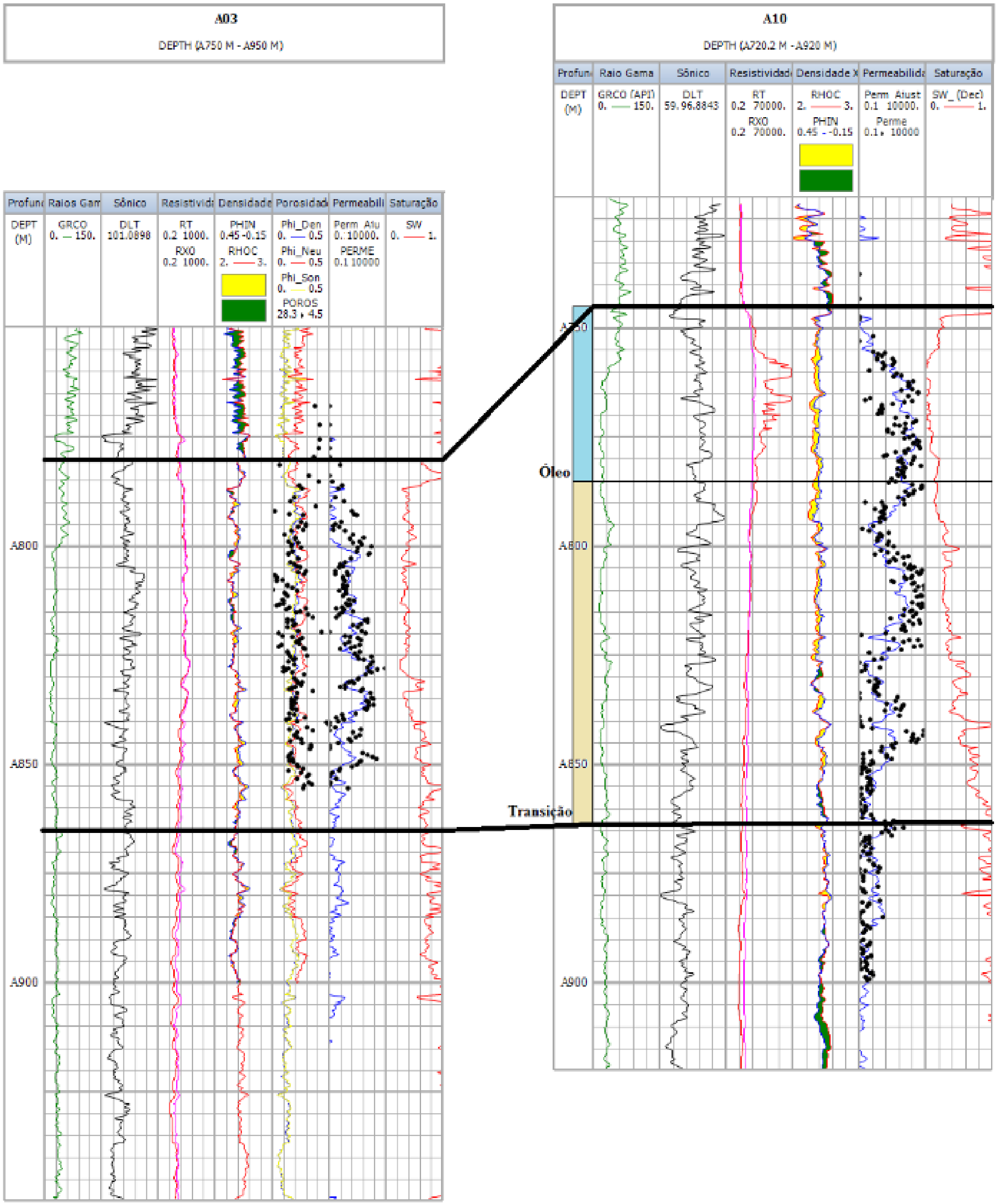

Figure 2. Data from well logs of wells A3 and A10 (curves), porosity and permeability laboratory data (black dots) plotted together with their estimates and correlation delimiting the zones of interest of each well.

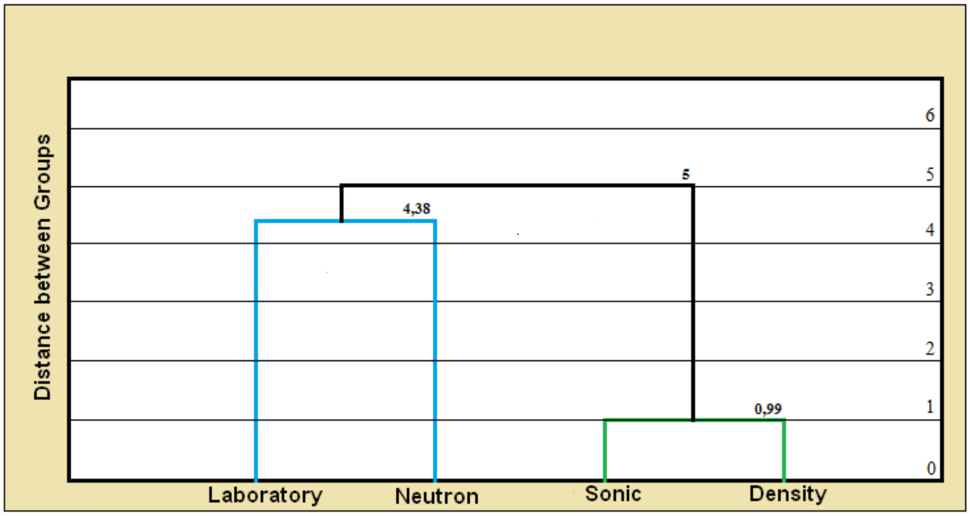

Figure 3. Dendogram of the porosities of the nearest neighbor method.

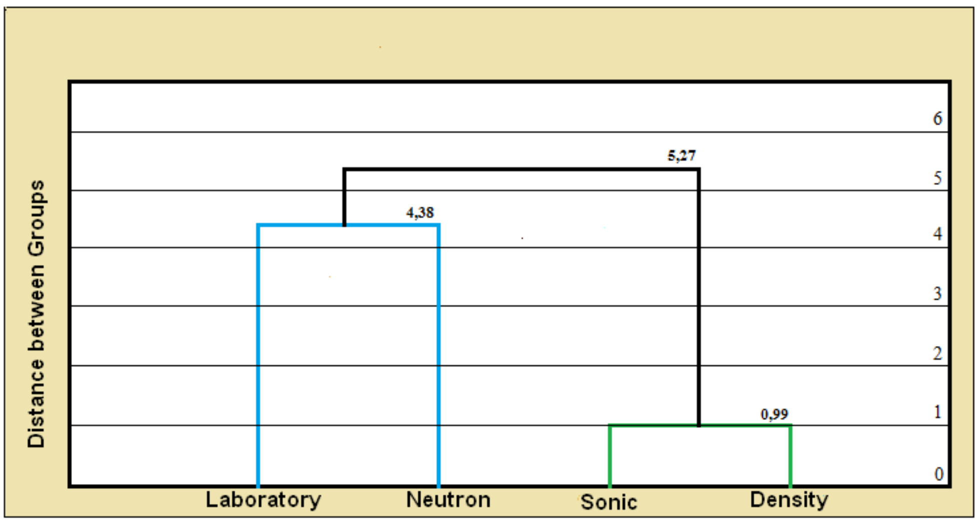

Figure 4. Dendogram of the porosity of the most distant neighbor method.

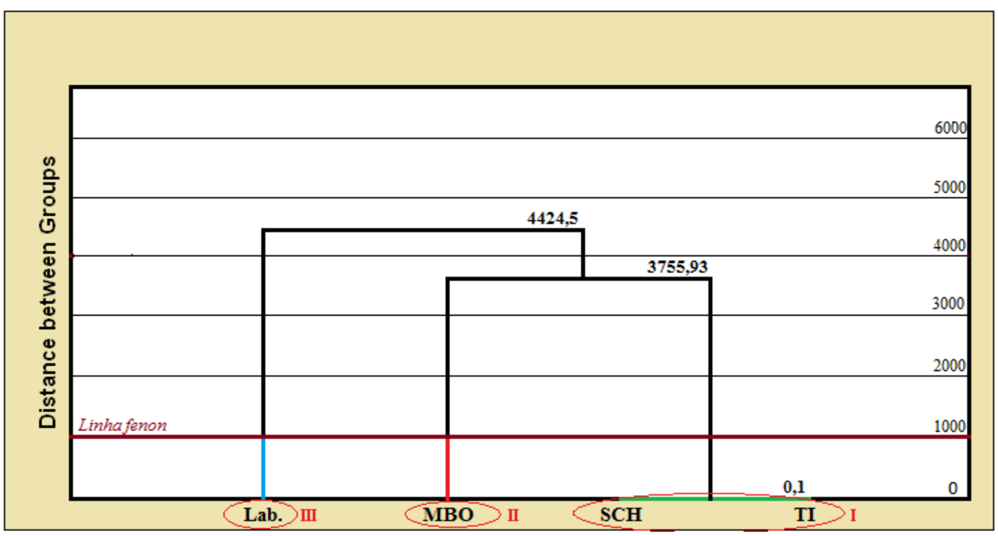

Figure 5. Dendogram of the nearest neighbor method permeabilities.

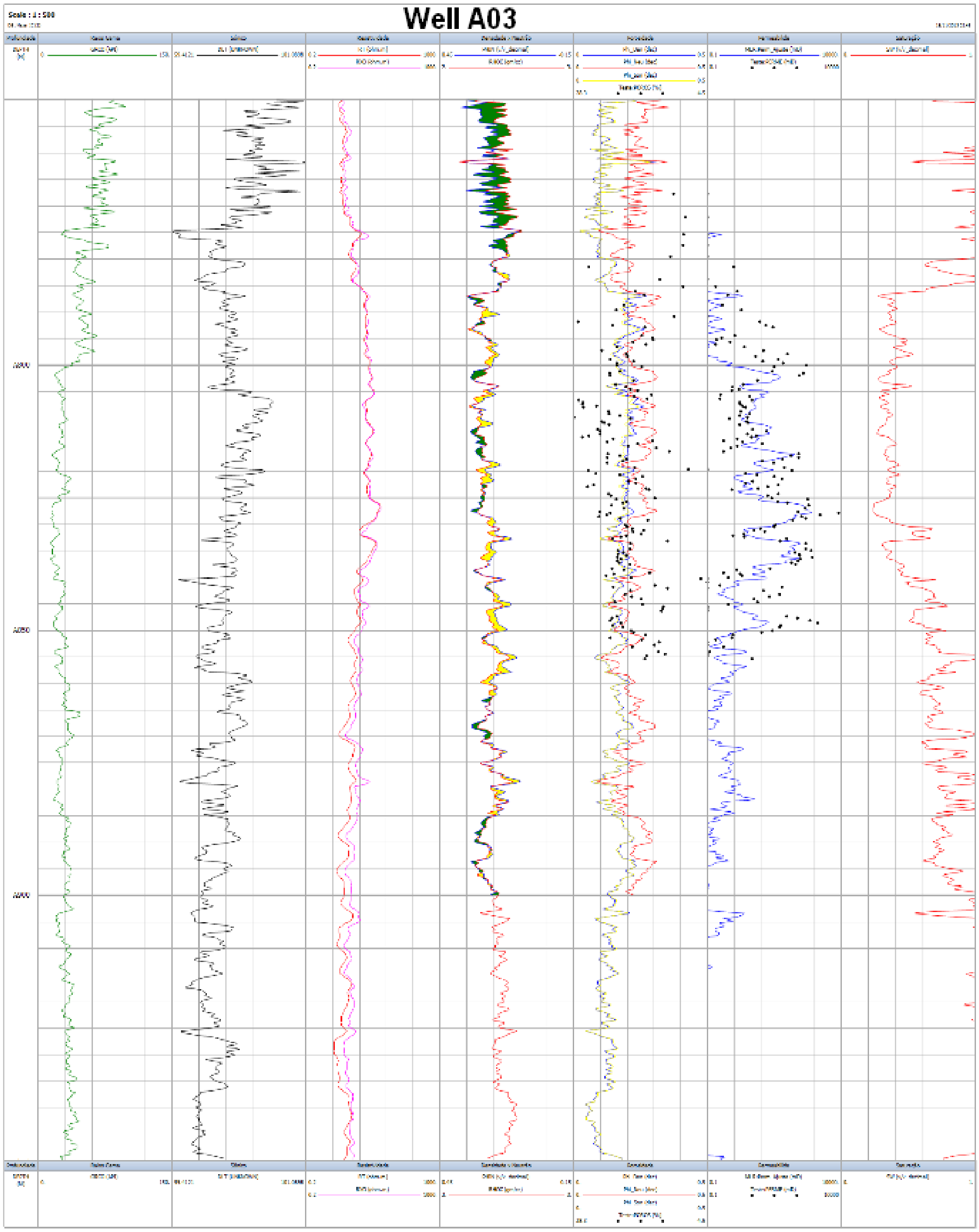

Figure 6. Final interpretation of the basic logs in obtaining the parameters of porosity (track 6), permeability (derived by multilinear regression in track 7) and water saturation (track 8) of well A3.