Evaluation of fine-grains in pre-salt reservoirs

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Abstract

Pre-salt carbonates of the Santos Basin represent many challenges in the characterization of their reservoirs. This paper proposes the reservoir characterization of the Barra Velha and Itapema Formations based on the analysis of geophysical well logs, highlighting the influence of fine-grains presence. In the analyzed well, the results show that the Itapema and Barra Velha Formations are the exploratory targets in the Buzios Field. The Itapema Fm is less influenced by the occurrence of fine-grains, and presents better permo-porous characteristics than in the Barra Velha Fm. The presence of fine-grains causes a great negative impact on the Barra Velha Fm reservoir, affecting substantially the response of the well logs and compromising the reservoir quality. Due to this behavior, we propose the Barra Velha Fm sag phase division into Lower Sag and Upper Sag. This division is grounded at the end of fine-grain deposition. In its turn, the intra-Alagoas unconformity which separates the Upper Rift phase from the Sag phase, in the well logs, was correlated with the beginning of fine-grains deposition.

Introduction

Carbonate reservoirs present great heterogeneity in their properties due to the complex combination of depositional and diagenetic processes (Dunham, 1962). These factors imply in challenges in reservoir characterization, production, and management.

In Brazil, carbonate reservoirs are responsible for more than 50% of the petroleum production in the pre-salt section, constituting the main exploratory target of the country. In this context, the Santos Basin plays a prominent role. Located in the southeast of the Brazilian continental margin, this basin is the main producer in the pre-salt section and it has the coquinas of the Itapema Formation and the microbialites of the Barra Velha Formation as reservoirs.

These rock facies variability exhibit complex depositional and textural characteristics. This variability results in extremely heterogeneous reservoir properties, varying both in vertical and horizontal directions (Mohriak et al., 2015).

Another factor that affects the reservoir characterization is the presence of fine-grains which obstruct the porous connections and prevent the fluids flow in the reservoirs, compromising the oil and gas production (Dewan, 1983; Pennington, 2000). Fine-grains that differ from conventional clays represents an additional challenge for the production optimization at Barra Velha Fm (Wright and Barnett, 2015; Muniz and Bosence, 2015; Ceraldi and Green, 2016; Wright and Tosca, 2016, Herlinger et al., 2017). Few studies evaluate how the presence of these fine-grains affects the geophysical well logs responses and negatively impact the production of the pre-salt reservoirs.

Thus, we propose a flow for the characterization of the pre-salt carbonate reservoirs from well logs in the Buzios field, with the following goals: 1) Characterize and compare the properties of the reservoirs in the Barra Velha and Itapema Formations; 2) Identify the presence of fine-grains and the impact that they have at the reservoirs, especially in the Barra Velha Formation; 3) Propose a division in the Barra Velha Fm based on the well logs evaluation.

Method

This section describes the procedures used for the evaluation of the Barra Velha and Itapema formations and to build the rock physics crossplots, in order to characterize and compare the reservoirs in these formations.

The well 3-BRSA-1064-RJS of the Buzios Field, Santos Basin, was used for these purposes. The choice of this well is justified by the peculiar characteristics presented by the well logs in the upper part of the Barra Velha Fm. Another reason for this choice was the large amount of available information about this well, which ensures more reliability to the analyses. The data used consist of well logs, core sample descriptions, well-testing reports, and laboratory petrophysics measurements.

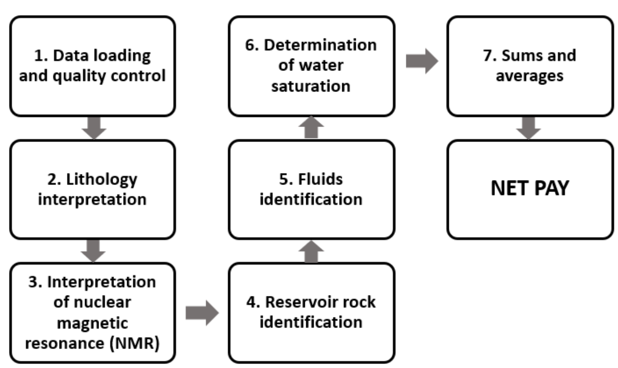

Figure 1: *Workflow used to evaluate the Itapema and Barra Velha formations in the well 3-BRSA-1064-RJS.*

The evaluation stage of the Itapema and Barra Velha Formations aims to obtain some reservoir properties like clay content, water saturation, and net pay. According to the workflow shown in Figure 1, this stage is divided into 8 steps which are described below.

1. Data loading and quality control

In order to load the curves and analyze the data quality, the following procedures were undertaken: verification of acquisition type (LWD or Wireline) and sampling rate; adjustments of depth and deviations; analysis of the caliper, bit size, and cable speed logs.

2. Lithology interpretation

This step comprises the core sample descriptions analysis. Also, it is concerned to the gamma-ray and photoelectric logs analysis. These parameters were analyzed to determine the types of lithologies in the formations. Based on this information and the responses of other well logs, the boundaries for the Itapema and Barra Velha Formations were defined as well as the boundaries for the shales of the Jiquia Stage.

3. Interpretation of nuclear magnetic resonance (NMR) logs

The NMR logs like T2 distribution, total and effective porosities, and free fluid were analyzed. A relevant parameter calculated was the clay volume estimation from NMR data. As proposed by Ehigie (2010), the clay volume ($\mathrm{V_{cl}}$) can be estimated using the clay-bound water (CBW) and the NMR total porosity ($\mathrm{PHIT_{NMR}}$):

$$\mathrm{V_{cl}} = \frac{\mathrm{CBW}}{\mathrm{PHIT_{NMR}}}. \tag{1}$$

The clay-bound water (CBW) can be rewritten as:

$$\mathrm{CBW} = \mathrm{PHIT_{NMR}} - \mathrm{PHIE_{NMR}}, \tag{2}$$

where $\mathrm{PHIE_{NMR}}$ is the NMR effective porosity. Thus, the equation (1) can be rewritten as:

$$\mathrm{V_{cl}} = \frac{\mathrm{PHIT_{NMR}} - \mathrm{PHIE_{NMR}}}{\mathrm{PHIT_{NMR}}}. \tag{3}$$

This equation was applied as one of the methods to estimate the clay volume.

It is worth mentioning that such equation underestimates the clay content values in shale zones, being necessary to use another approach in these regions. As the goal of this work is the carbonate reservoirs analysis, this other approach was not used. For more information see Eighie (2010).

4. Reservoir rock identification

The gamma-ray log was used to calculate the gamma-ray index (IGR), and then the IGR was applied in the classical empirical models of clay volume estimation ($\mathrm{V_{clay}}$). Considering the rock age, the Larionov equation (1969) for old rocks was chosen:

$$\mathrm{V_{clay}} = 0{,}33\left[2^{2{,}0\times\mathrm{IGR}} - 1\right]. \tag{4}$$

The analysis of the clay volume estimation logs, obtained from equations (3) and (4), together with the gamma-ray, neutron, density, and NMR logs allowed the identification of the reservoir zones.

5. Fluids identification

The well-testing information and the interpretation of the resistivity log were used to identify the fluid type present in the reservoirs. It allowed us to define the water-bearing and oil-bearing zones.

6. Water saturation determination

Archie's equation (1942) was applied in order to obtain the water saturation. It demands some parameters as water resistivity and the values of m (cementation exponent) and n (saturation exponent). The first one was calculated using the salinity and formation temperature data. The values of m and n were estimated using the Pickett-plot technique (1973).

7. Sums and averages

The main step of this stage was the determination of the cut-off values which are responsible for establishing the separation between the interest zones and the low productivity or unproductive zones. It was possible to obtain sums and averages of important reservoir parameters (porosity and hydrocarbons saturation) from these cut-off values.

8. Net pay

The net pay for the Itapema and Barra Velha Formations was determined based on the parameters obtained in the previous steps.

It was possible to segment the Barra Velha Fm in three zones from the properties observed in the formation evaluation stage. These zones were named as: Upper Rift, Lower Sag, and Upper Sag.

Then, the elastic parameters (compressional velocity, shear velocity, $\mathrm{V_P/V_S}$ ratio and acoustic impedance) were calculated using the density (RHOB), sonic transit time (DTCO) and shear transit time (DTSM) logs.

(I) Compressional velocity ($\mathrm{V_P}$)

Compressional velocity corresponds to the inverse of the sonic transit time, that is:

$$\mathrm{V_P} = 1/\mathrm{DTCO}. \tag{5}$$

(II) Shear velocity ($\mathrm{V_S}$)

Shear velocity is the inverse of the shear transit time, that is:

$$\mathrm{V_S} = 1/\mathrm{DTSM}. \tag{6}$$

It is necessary to observe the unit to calculate both velocities. In general, the transit time logs are in μs/ft. Therefore, it was necessary to convert the unit to obtain the velocities in m/s.

(III) $\mathrm{V_P/V_S}$ ratio

The $\mathrm{V_P/V_S}$ ratio, that is an important parameter for lithologies and fluids prediction, is obtained from the division of the velocities calculated in (I) and (II).

(IV) Acoustic impedance (IP):

The acoustic impedance is defined as the product of compressional velocity ($\mathrm{V_P}$) and density (RHOB):

$$\mathrm{IP} = \mathrm{RHOB} \times \mathrm{V_P}. \quad (7)$$

Comparison of elastic parameters between the zones of the Barra Velha Fm was performed by rock physics crossplots.

Results

The results of the formation evaluation in the well 3-BRSA-1064-RJS are presented in Figure 2.

The caliper (CAL) log shows good response over the interval and does not present important alterations. Only small borehole breakouts are observed, mainly in the Itapema Fm. The NMR effective porosity (PHIE) and matrix density (RHOMAA) logs are well calibrated with the laboratory data. In a first visual analysis, it is highlighted the logs behavior in the upper part of the Barra Velha Fm, in the interval from 5473m to 5515m. This interval is shown later with a higher level of detail.

In general, the clay contents estimated by NMR ($\mathrm{V_{cl}}$) and GR ($\mathrm{V_{clay}}$) show very similar values, with $\mathrm{V_{cl}}$ always a little higher than $\mathrm{V_{clay}}$. However, at two intervals such behavior is not observed. The first one is at the top of Barra Velha Fm, between 5473m and 5515m, where the $\mathrm{V_{cl}}$ is much higher than the $\mathrm{V_{clay}}$. The second one occurs in the interval with the presence of the Jiquia Shale, where the $\mathrm{V_{cl}}$ values are underestimated. As described in the methodology, this behavior in the shale zone was already expected because another approach to the $\mathrm{V_{cl}}$ estimation should be used in these regions.

The Barra Velha Fm shows a very heterogeneous behavior and several segmentations. The upper part (interval from 5427m to 5473m) presents slightly higher values of GR, a gradual increase of resistivity, a smaller amount of free fluid, and a higher water saturation when compared to the lower part of the formation. Then, there is a non-reservoir behavior between 5473m and 5515m. Finally, from 5515m to 5684m, it is observed a region with higher values of free fluid and lower values of clay content and water saturation. This region represents the largest interval of net pay in this formation.

The Itapema Formation is more homogeneous in well logs responses and shows gamma-ray lower values, being a cleaner formation than the Barra Velha Fm. The Itapema Fm also presents a high amount of free fluids and low water saturation in its upper part, where is the hydrocarbon reservoir interval.

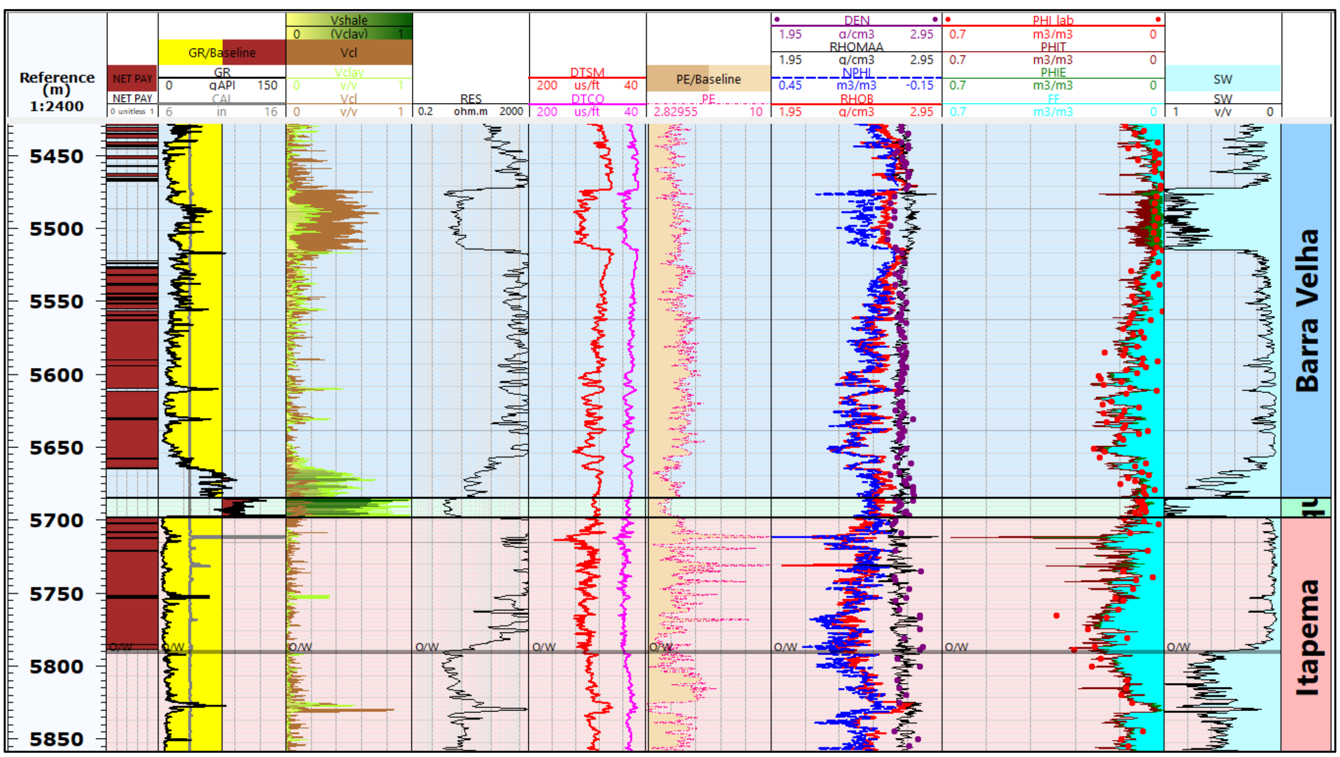

Figure 2: *3-BRSA-1064-RJS well logs. Tracks: 1) depth; 2) net pay; 3) gamma-ray (GR) and caliper (CAL); 4) clay content estimation from NMR (V_{cl}) and gamma-ray (V_{clay}) logs; 5) resistivity (RES); 6) sonic transit time (DTCO) and shear transit time (DTSM); 7) photoelectric factor (PEFZ); 8) density (RHOB), matrix density (RHOMAA), neutron (NPHI), and data point of density measured in the laboratory (DEN); 9) Porosity measured in laboratory (PHI_lab) and NMR logs: free fluid (FF), effective porosity (PHIE) and total porosity (PHIT); 10) water saturation (S_w). The zones delimited in blue represent the Barra Velha Fm, in green the shales of the Jiquia Stage, and in pink the Itapema Fm. The oil-water contact (O/W) is highlighted in the gray line.*

Table 1: *Comparison between the properties of the Barra Velha and Itapema Formations.*

PROPERTIES	BARRA VELHA Fm	ITAPEMA Fm
Thickness	257m	165m
Reservoir thickness:	151m	154m
PHIT:	9.0%	14.0%
PHIE:	8.0%	13.0%
Porosity_Lab.:	7.8%	12.7%
Permeability_Lab.:	0.55 mD	6.65mD
Vcl	5.0%	2.0%
Vclay	4.0%	1.3%
***Net pay*:**	**146m**	**89m**

Table 1 shows the averaged values of clay content, porosity and permeability of the formations, excluding Jiquia Stage shales. It is verified that despite presenting a lower thickness of net pay, the Itapema Fm presents better permo-porous features than the Barra Velha Fm. Thus, in addition to the Barra Velha Fm, the Itapema Fm also constitutes an important exploratory target in the analyzed well.

The Figure 3 highlights the behavior of the logs in the Barra Velha Fm in the interval between 5473m and 5515m. In this interval, it is noticed a slight increase in the gamma-ray response, that almost does not impact the clay content estimation from the GR log (V_{clay}). A high decrease in the resistivity values is also observed. The increase of the sonic transit time ($DTCO$) and shear transit time ($DTSM$) indicates that in this region occurs a significant decrease of the compressional and shear velocities. The photoelectric log remains unchanged, suggesting that there was no alteration of the matrix. It can be confirmed by the core sample descriptions that indicate the presence of spherulitic and stromatolitic microbialites. The neutron log increases while the density log decreases. The NMR logs are also very affected: the NMR total porosity presents values around 7-9%, the NMR effective porosity values are around 2-4% and the NMR free fluid has values close to zero.

These factors indicate that there are fine-grains compromising the porous space in this interval. The clay volume estimation from NMR (V_{cl}) was the one that best represents the presence of these fine-grains. In general, a decrease in the $DTCO$ and $DTSM$ logs is observed in cemented or dolomitized carbonates, which does not occur in this region. Therefore, this possibility has been discarded.

Discussions

Recent works about the pre-salt in the Santos, Campos and Kwanza basins highlight the strong presence and influence of magnesian clays (stevensite) in the Barra Velha Formation and in its analogous formations (Wright and Barnett, 2015; Muniz and Bosence, 2015; Ceraldi and Green, 2016; Wright and Tosca, 2016, Herlinger et al., 2017).

Wright and Barnett (2015), Wright and Tosca (2016) and Wright and Rodriguez (2018) present a model for the depositional setting of the Barra Velha Fm, which is an extensive, hyper-alkaline, shallow evaporitic lake. They use the stevensite presence in the formation as one of the key elements for depositional environment characterization.

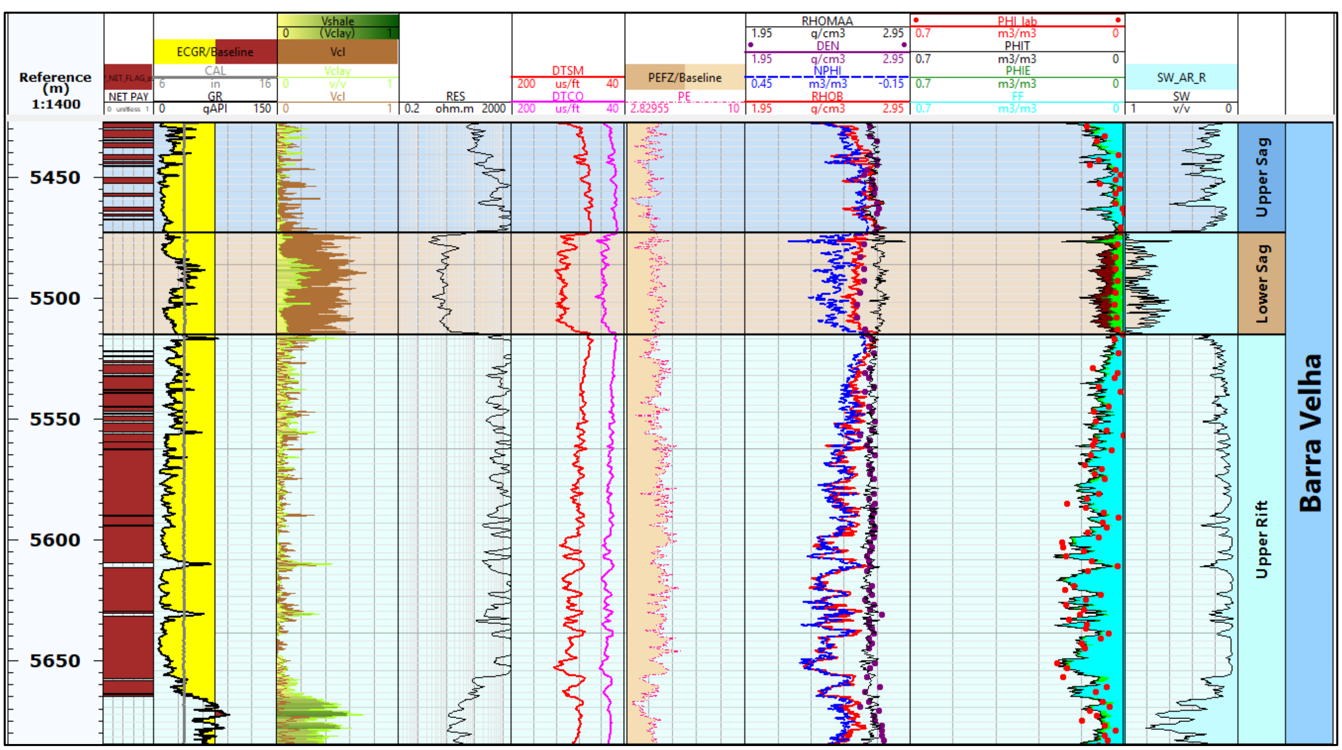

Figure 3: *Barra Velha Fm well logs. This formation is segmented in: Upper Rift, Lower Sag and Upper Sag.*

Muniz and Bosence (2015) show that the presence of stevensite is responsible for the slight increase in the gamma-ray values in the Macabu Fm - analogous to the Barra Velha Fm. Herlinger et al. (2017) state that in the sag phase, of the Campos Basin pre-salt, most of the deposits of magnesian clays were replaced by calcite spherulites, dolomite, and silica. However, they found the stevensite preserved in one of the analyzed wells. The authors add that microporosity is observed by NMR data in preserved stevensite deposits. This leads us to the hypothesis that in the well 3-BRSA-1064-RJS, analyzed in this work, the stevensite is preserved. Such assimilation occurs because of the high level of microporosity (low relaxation times of T2) present in the interval of 5473m to 5515m.

The presence of stevensite also affected others logs. Thus, it is observed a segmentation within the Barra Velha Fm, with the intercalation of a non-reservoir zone between two reservoirs regions. Wright and Barnett (2015) state that the intra-Alagoas unconformity separates the Barra Velha Fm between the rift phase microbialites (that are located between the pre-Alagoas and intra-Alagoas unconformities) and the sag phase microbialites (that are above the intra-Alagoas unconformity and extend until the base of salt). In addition, these works mention that the presence of stevensite is in the initial sag phase of the basins.

Thus, we propose the division of the sag phase into Lower Sag and Upper Sag based on the responses observed in the analyzed well logs. The limit between these phases is given by the end of the presence of fine-grains (stevensite). According to this and to the division proposed by Wright and Barnett (2015), we consider that the Barra Velha Fm can be segmented into three zones – Upper Rift, Lower Sag, and Upper Sag, showed in Figure 3.

We analyzed the crossplots shown in Figure 4 using this division into three zones and seeking a better understanding of the stevensite-bearing interval (Lower Sag) characteristics.

The region with the presence of fine-grains (Lower Sag) stands out from the others in both rock physics crossplots. In the first crossplot ($\mathrm{IP} \times \mathrm{PHIE}$), the zone with the fine-grains presents lower values of acoustic impedance and a smaller variation of the effective porosity values than observed in the other zones. In the second crossplot ($V_P/V_S \times \mathrm{IP}$), the zone with the fine-grains has a higher V_P/V_S ratio when compared to the other zones. Thus, the rock physics crossplots show a potential for the identification of fine-grains, in volume, from data resulting of elastic inversion. In addition, low IP values derived from acoustic inversion may lead to misinterpretations about high porosities in the Lower Sag region.

Conclusions

In the analyzed well, the Itapema Fm presents as a cleaner formation and with better reservoir properties than the Barra Velha Fm. Despite its smaller net pay thickness, the Itapema Fm also represents an important exploratory target in the study area. In the Barra Velha Fm the anomalous response of the well logs is due to the presence of stevensite, probably preserved in the interval. It causes a great negative impact on the Barra Velha Fm reservoir. The clay volume estimated from the NMR data proved to be more suitable for the identification of stevensite than the empirical model that uses the gamma-ray log. It was also possible to segment the Barra Velha Fm into three phases: Upper Rift, Lower Sag, and Upper Sag based on the behavior of well logs. In this formation, the reservoirs are in the Upper Sag and Upper Rift phases. The Upper Rift presents better permo-porous characteristics and greater thickness than the Upper Sag. The Lower Sag phase, characterized by the presence of stevensite, was considered as a non-reservoir zone. It is worth mentioning that the proposed division for the Barra Velha Fm correlates the location of intra-Alagoas unconformity with the beginning of fine-grains presence, that is, in the lower limit of the Lower Sag phase. Such location was corroborated by the seismic interpretation.

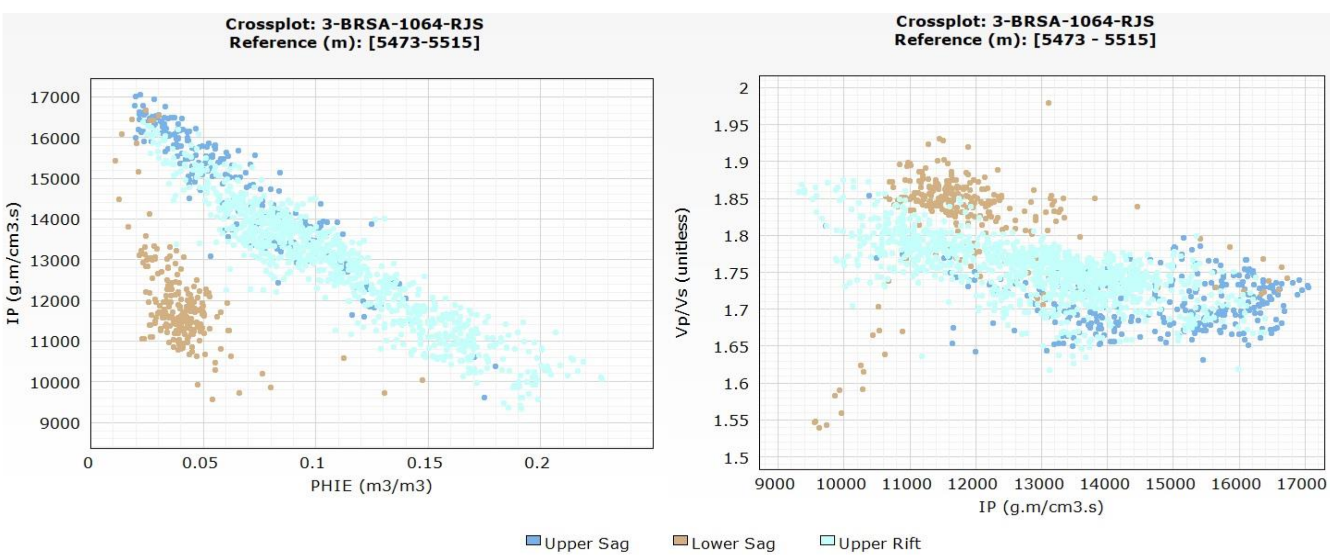

Figure 4: *Rock physics crossplots for the Barra Velha Formation.*

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