Geophysical well logs analyses for mineralogy and pore-typing determinations of Barra Velha Formation carbonates, Santos Basin

Marta Jácomo, Gelvam A. Hartmann, Emilson P. Leite
Institute of Geosciences, University of Campinas (IG/UNICAMP)

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Abstract

The pre-salt lacustrine reservoirs from Barra Velha Formation (BVF), Santos Basin, were deposited during the sag phase of opening South Atlantic Ocean. Small variations in climate or tectonic can induce large variations in the lake level and chemical composition of waters, resulting in heterogeneous deposition composed by carbonate particles with a wide range of sizes and shapes mixed to form heterogeneous depositional textures. Understand and predict their mineralogical and petrophysical heterogeneity is not a simple task. Several works describe the genesis and tectonic of pre-salt carbonates, however, few ones show and interpret petrophysical and log wells. Here, we use the public geophysical well logs dataset to estimate the lithology and pore types from four wells – 3-BRSA-883 (3-RJS-680), 3-BRSA-496 (3-RJS-646), 9-BRSA-716 (9-RJS-660) and 9-BRSA-908D (9-RJS-686D) – located in south-southeast of Tupi Oilfield, throughout the BVF. Results indicate that the BVF is formed by calcitic and dolomitic matrix, where the firsts 10-20 m are characterized by dolomitization of rudstones and grainstones in well 3-BRSA-496, while in well 9-BRSA-716 it occurs in laminites and stromatolites. Regarding the petrophysical results, the vuggy porosity was characterized using T1LM X T2LM, which T2LM around 300 ms. This kind of porosity was observed in all four studied wells. The interpreted data contributes to a better understanding the variability of matrix and porosity through geophysical results. Hence, this model can help us to predict the mineralogy to other close wells and provide important parameters to the reservoir.

Introduction

The Santos Basin is located on southern of Brazil and comprises the States of Rio de Janeiro, São Paulo and Paraná. It is the most extensive Brazilian offshore sedimentary basin, occupying an area of more than 350.000 Km². Its 20 producing fields are responsible for 66% of the national oil production and 67.3% for natural gas production where the most of which comes from sub-salt reservoirs (ANP, 2021).

Since the discovery of oil accumulations in pre-salt Barra Velha Formation (BFV), several works have been published to understand their genesis, mineralogy and petrophysics (Terra e t al., 2010; Herlinger et al., 2017; Wright and Barnett, 2020; Gomes et al., 2020; Lima and DeRos, 2019). However, these reservoirs are heterogeneous, forming a complex relationship between the mineralogy and pore properties (Rocha et al., 2019) and require diverse tools to characterize them. Among them, geophysical well logs have a good cost-benefit and can provide important geological information without sampling. The objective of this work is to predict the mineralogy of carbonate matrix and pore-typing of four wells using geophysical curves and characterize the variability in a faster and cheaper way.

Data and Methods

The studied data come from the well logs dataset of four wells of the Tupi Oilfield, Santos Basin. Datasets were provided by Agência Nacional de Petróleo, Gás Natural e Biocombustíveis (ANP). The wells 3-BRSA-883, 3-BRSA-496, 9-BRSA-716 and 9-BRSA-908D (Figure 1) were selected since they present the most complete available petrophysical and mineralogical datasets for BVF.

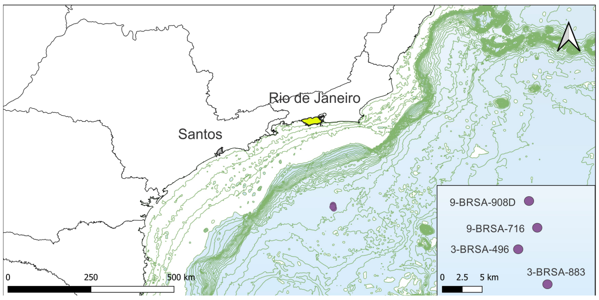

Figure 1: Map showing the four selected wells in Santos Basin.

The datasets include wireline curves, which present best depth control, Caliper (CALI), Gamma-Ray (GR), shallow (ResShal), medium (ResMed) and deep (ResDeep) resistivities, compressional (DTc) and shear slowness (DTs), bulk density (RHOB), photoelectric factor (PEF), neutron (NPHI), NMR T2 log mean (T2LM), NMR T2 distribution (T2_DIST), NMR free fluid (NMRff), NMR effective porosity (NMReff) and NMR total porosity (NMRtt). The NMR T2 distributions curves provided by ANP were reprocessed using NMR module of Techlog Software (Schlumberger) due to check the values of T2 cut off (T2CF). The results suggest that T2CF values of 100 ms for all studied wells.

In this work, we follow the petrophysical workflow from Ramamoorthy et al. (2010) (Figure 2). The calculus of some calculated properties of reservoir and their intepretation (e.g. fluid saturations, formation tests, cementation and saturation coefficients of Archie´s analyses) are not described in this work. However, they were important parameters to characterize the reservoir and to create the mineral model. The petrophysical analysis for these wells indicates that whole BVF is saturated by oil.

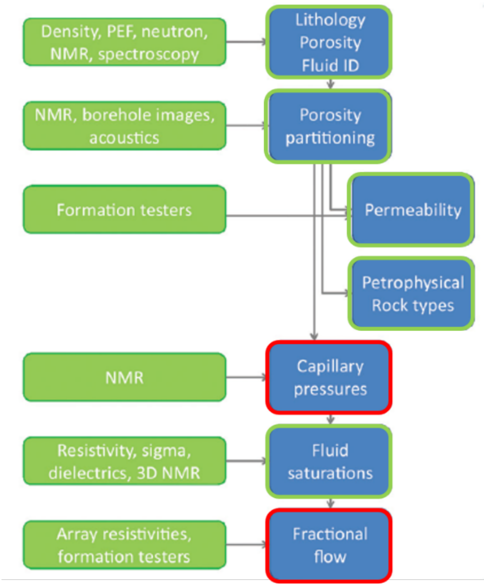

Figure 2: Petrophysical workflow. Boxes in green outline refer to used properties and the boxes in red outline refer to the not used ones (adapted from Ramamoorthy et al., 2010).

For mineralogical determinations, the Quanti Elan module from Techlog Software (Schlumberger) was used. The geological dataset was provided by descriptions of thin sections and drill cuttings of ANP final reports. The mineralogical zones were firstly determined based on X-Ray Diffraction (XRD) measurements. Mineral contents and elemental capture spectroscopy (ECS) were provided by ANP for well 9-BRSA-716, which contain the most complete geological information. Then, these zones were used to compare the mineral model obtained through the QuantElan module to estimate the mineralogy to the other studied wells.

Geological Setting

The pre-salt sequence from Santos Basin is related to the breakup of Western Gondwana and opening of the South Atlantic Ocean during the Late Hauterivian-Early Barremian (Moreira, 2007; Moulin et al., 2010; Chaboureau et al., 2013; Farias et al., 2019). The sin-rift lacustrine carbonate deposits are formed by shales and siltstones from Piçarras Formation, while intercalations of coquines and shales rich in organic matter are from Itapema Formation. The post-rift BVF is formed by continental to shallow marine carbonates deposited during the Eoaptian to Neoaptian (Moreira et al., 2007). The Eoaptian sequence is characterized by microbial limestones (Dias, 2005; Moreira et al., 2007, Terra et al., 2010), which nowadays are interpreted as been abiotic (Wright and Barnett, 2015; Herlinger et al., 2017; Lima and De Ros, 2019), stromatolites and laminites in proximal environment, while shales occur in distal environment. The Neoaptian is characterized by deposition of conglomerates and sandstones in proximal areas while stromatolytic limestones and microbial laminites locally dolomitized occur in distal ones (Moreira et al., 2007). Generally, the mineralogy is highly heterogeneous comprising in situ or reworked grains of calcite, dolomite, Mg-silicate-clays (stevensite and talc). The dissolution of these minerals, mainly Mg-silicate clay, is the most significant process of porosity generation (Wright and Barnett, 2020).

Results and Discussion

Mineralogy

The 9-BRSA-716 is the well with the most geological data, including a good XRD and ECS sampling for entire well. Therefore, we use the correlation between these variables to create mineralogical zones as shown the last track of Figure 3. Firstly, we correlated calcite and dolomite from XRD data (light and dark blue points, respectively, in last track) with carbonate from ECS (blue curve or WCAR in last track), besides the quartz contents from both XDR and ECS (orange points and yellow curve or WQFM, respectively). Both datasets present a good correlation for the entire well since we observe that almost of points coincides with ECS curves. The zones were defined based on proportions of each other: dolomite XRD (dark blue), calcite XRD (light blue), quartz XRD (light yellow) and vshale for all the well 9-BRSA-716 (Figure 3). We observe that BVF is composed exclusively by dolomite and calcite zones. Then, I could use this zonation to compare with to the mineralogical models of other studied wells.

The mineralogical model using the Quanti Elan module is showed on Figure 4. Modelling was done using the geophysical curves for the entire BVF well log. However, for wells 3-BRSA-496 and 9-BRSA-908D, the modelling was done for each interval of BVF: micro and macroporous intervals separately. It occurred because the microporous interval – evidenced by short T2 times in T2 distributions in last track, besides high NMRtt (brown curve) and low NMRff (light blue) in last but one track, respectively – present different reservoir properties (e.g. increase of DT and NPHI) than macroporous interval – evidenced by longest T2 times in T2 distributions in last track, besides high NMRff (light blue) in last but one track (Figure 4). We observed that doing this analysis by interval, some heterogeneity in mineral modelling appeared, which is mainly related with the dolomitization and silicification process. The output variables are calcite, dolomite, quartz and Vshale. Tests with chlorite, barite, illite, smectite and kaolinite also been done but the results are not good when we check with geological descriptions. The proportions of these amounts allow us to define four zones based on mineral modelling: calcite (light blue), dolomite and calcite (medium blue), dolomite (dark blue) and calcite+dolomite+quartz (yellow) in Figure 4.

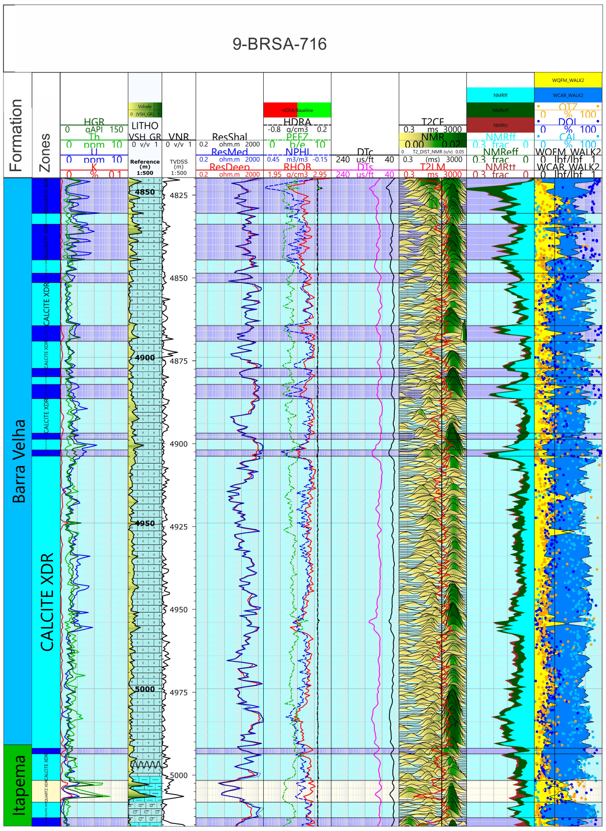

Figure 3: The mineralogical zones (second track) for the well 9-BRSA-716 was created using the relationship between XRD (points dark blue, light blue and orange), which are related to dolomite, calcite and quartz, respectively) and ECS data (blue and yellow curves which are related to carbonate and quartz, respectively) in last track. Light blue zone is formed mainly by calcite matrix, while dark blue is formed by dolomite matrix in Barra Velha Formation.

We observe that matrix of reservoir intervals is predominantly calcitic for entire well, mainly in wells 3-BRSA-883 and 3-BRSA-496. In uppermost 10 to 20m of BVF, the GR curves present a zig zag shape, which are correlate with an increase and decrease of uranium (U) and thorium (Th), while potassium (K) is very low for all the wells (Figure 4). This interval coincides with the so-called “Lula fingers”, which occurs at uppermost 15 m of the Upper BVF and is characterized by microbial textures and increasing of mudstone for diverse lack Mg clays facies (Gomes et al., 2020). The intense dolomitization of well 9-BRSA-716 (dolomite > calcite in XRD estimations or dolomite >50%) allows us to classify this zone as dolomite zone (dark blue), while this one was classified as calcite + dolomite (medium blue) since dolomite amounts are between 30 and 38%) in the other wells. According to core descriptions and XRD data, the dolomite + calcite zone (mineralogical model) of the Lula fingers in well 3-BRSA-496 is composed by dolomitized grainstone and rudstones (dolomite >20%). The intervals in which calcite matrix is predominant are correlated with crenulated porous laminite. The descriptions of well 9-BRSA-716 cores indicate intercalations of laminate, stromatolites and grainstones for ¨Lula fingers¨, which dolomitization is correlated with good properties of reservoir (high values of NMRff in last but one track in Figure 4) probably due to important dissolution. It seems that wells 9-BRSA-716 and 9-BRSA-908D, this dolomitization follows and increase of U contents and quartz.

According to the core and drill cuttings descriptions, the BVF is formed by limestones, laminites, stromatolites, spherulites. The mineralogical model presented a very good correlation with geological data. For example, according the uppermost 9 m (from 4891m to 4900m TVDSS) cored samples descriptions of well 3-BRSA-496 (pink square in Figure 4), the calcite is related with crenulated laminated samples while the dolomitization occurs in grainstone and rudstone. Here, the dolomitization clogs the pore.

The macroporous interval bellow “Lula fingers” and bellow microporous interval in well 3-BRSA-496 are characterized mainly by calcitic matrix for all wells, with dolomite amounts generally around 18% in 3-BRSA-883 and 3-BRSA-496 and around 21% in 9-BRSA-716 and 9-BRSA-908D in calcite XRD zones. Three or four intervals of dolomitization – >25% in 3-BRSA-883 and 3-BRSA-496 and 40% in 9-BRSA-716 since it is a more dolomitized well – are evidenced for all wells with exception of well 9-BRSA-908 D (1D,2D,3D and 4D in Figure 4). According the public ANP geological descriptions, these intervals are composed mainly by dolomitized in situ or reworked stromatolites and spherulites, associated with some silicification or silexite levels.

The estimative of quartz in macroporous interval suggests that silicification is a common process, mainly in 3-BRSA-883, 9-BRSA-716 and 9-BRSA-908D wells. According the generated mineralogical model, the quartz amounts are around 12%, 24% and 17%, respectively, while in well 3-BRSA-496 they vary from 0% to 9%. In modelling, the peaks are composed by samples with more than 25%, 35 and 40% for 3-BRSA-883, 9-BRSA-716 and 9-BRSA-908D, respectively (S in Figure 4). These high levels of quartz occur mainly in reworked or in situ spherulites and stromatolites, generally associated with some dolomitization and more close porosity (e.g. the green area of NMReff in last but one track is more evidenced). Besides that, presence of silexite, silica filling the fractures also are described in ANP reports. In well 9-BRSA-716, the zone calcite + dolomite+ quartz (yellow zone in Figure 4) is the unique interval which these three elements occur with similar amounts and geologically it coincides with presence of important amounts of talc-stevensite, silexite and dolomite).

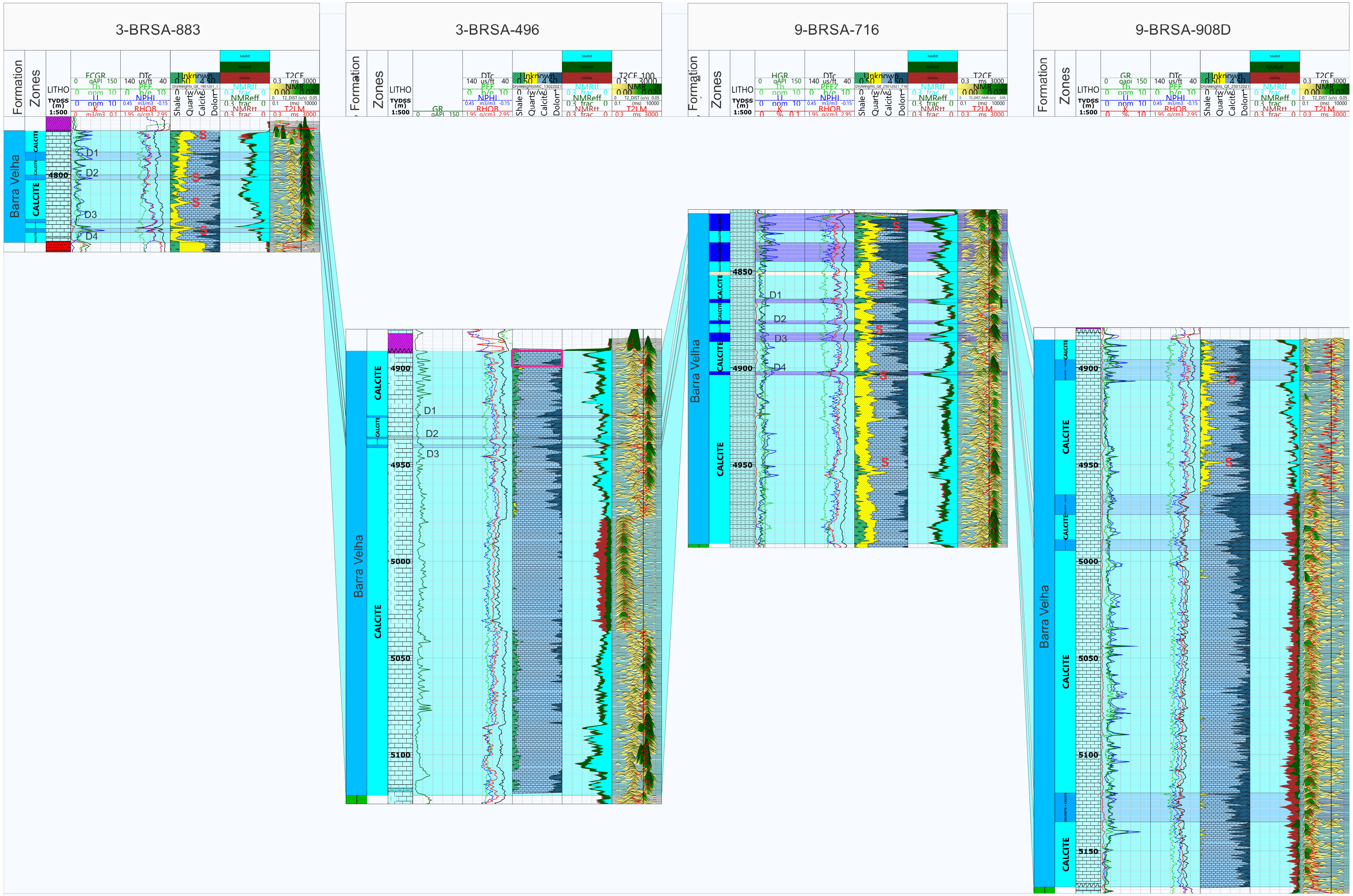

Figure 4: Mineralogical model for wells A, B, C and D (left to right). The mineralogical zones were determined through relationship between XRD and spectra data (last track); they show that light blue zone is formed by mainly calcite matrix, while dark blue is formed by dolomite matrix.

According to the drill cuttings descriptions, the microporous interval of well 9-BRSA-908D is due to the presence of talc stevensite. Although the dolomitization occurs in the entire interval, here it seems overestimated. When we increase the bulk density of calcite from 2.71 to 2.73 or 2.75, is that, changing a pure calcite to heterogeneous calcite, the estimative of dolomite decrease, improving the estimative to more real conditions. There is no report for talc-stevensite presence in the microporous interval for the well 3-BRSA-883. However, the low GR, increase of NPHI and DT data suggest the presence of stevensitic claystone, beside the low quartz content. The matrix is calcitic for both wells as shown in the mineralogical model and the highest PEF values, when compared with other intervals. According to Lima and De Ros (2019), fine-grained deposits of stevensite and other Mg silicates occur throughout the sag succession, which can be replaced by finer-crystalline dolomite, magnesite and microcrystalline quartz.

Type of pores

We use the T1LM X T2LM crossplots for qualitatively estimate the vuggy porosity. This relationship is very common in laboratory measurements; however generally they are correlated for each sample and each measurement of relaxation time (Rios et al., 2010; Souza, 2012). Here, we adapted it using T1LM and T2LM data, even knowing about their limitations – not only about differences between lab and well log conditions, different types of fluids into pore space or NMR tools, but also about the limitations of working with log mean (e.g it is a mean, that is not a real measured as occur in laboratory measurements which T1 is directly correlated with T2 for each relaxation time; when the number of micropores in the sample increase, the T2LM can be subestimated) . In ideal conditions (homogeneous matrix and one type of fluid saturated rock), T1 is equal to T2. Then, we observe that samples have T1LM higher than T2LM for almost all samples (Figure 5).
T2LM values result from the horizontal trend with relaxation times around 300-350 ms for BVF intervals. from the wells, indicating the presence of vuggy porosity. It is worth mentioning that this classification is based only in petrophysical characterization, that is, the vuggy porosity is defined when the pore is large enough for the NMR tool to identify only the bulk relaxation or when the pore size is not a limiting factor for relaxation. The classification of pore size is complex and there is not a consensus in the literature. The maximum size-limit for micropores vary from less than 1 µm (according to the classification of Pittman, 1971) to 62.5 µm diameter for carbonate rocks (according to Choquette and Pray, 1970). These values seem inadequate since, petrographically, visible pores are less than 62.5 µm. According Cantrell (1999), macropores are larger than 10 µm and for Marzouk et al. (1995) and Ramamoorthy et al (2010) macropores are larger than 5 µm, which seems better since this is limit for visualization through microscopy. Ramamoorthy et al (2010) define that pores larger than 50-100 µm have the same T2 as occur mainly in BVF samples.

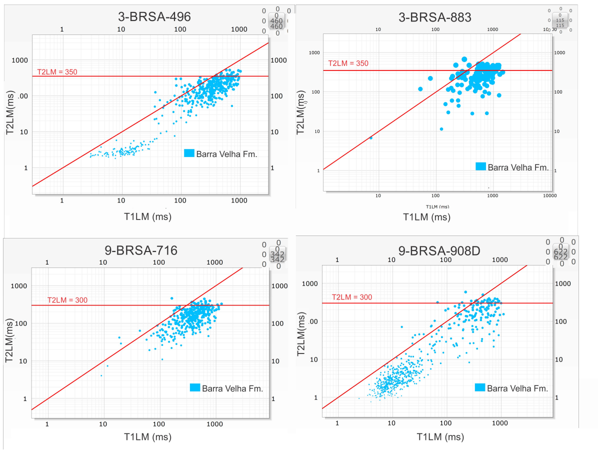

Figure 5: T1LM X T2LM crossplots show a horizontal trend between T2LM = 300 and 350 ms, indicating the predominance of bulk relaxation or vuggy porosity.

Conclusions

The public ANP geophysical datasets allow us to define a calcite and a dolomite matrix for carbonates of BVF for the four wells from Tupi Oilfield. The well 9-BRSA-716 presented a more intense dolomitization than the other wells in the uppermost 10-20 m of BVF. Silicification is common into the entire wells, however, is more intense when it is associated with some dolomitization. Probably, there is an increase of dolomitization from wells of south to north, although more mineralogical dataset is necessary to better understand it. The geophysical logs allow defining a mineralogical model, which presented a good correlation with XRD data, core and drilling cuttings descriptions. Petrophysical results indicated that the vuggy porosity is characterized by T2LM around 330 ms and dominates all studied wells. Based on one characterized well (9-BRSA-716), it was possible to caracterized the mineralogy of 3 other wells (3-BRSA-883, 3-BRSA-496 and 9-BRSA-908D). This result can be also very useful for reservoir upscaling and predictions of mineralogy of other wells.

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