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MODELING OF RESERVOIR PROPERTIES USING SEISMIC ATTRIBUTES AND EVALUATION OF WELL LOGS: A CASE STUDY IN BAUNA AND PIRACABA OIL FIELDS, SANTOS BASIN, BRAZIL

Wagner Moreira Lupinacci*, Ana Schanzembach and Antonio Fernando Menezes Freire

ABSTRACT. The Santos Basin, located in the southeastern Brazilian margin, presents a high diversification of reservoirs in both pre- and post-salt, with many fields still under study and which present great production potential. The Oligocene reservoirs of the Bauna and Piracaba offshore oil fields, the target of this study, are formed by turbidite sandstones. We propose an approach using the integration of seismic attributes and evaluation of well logs for building a 3D model of reservoir properties. From the analysis of seismic attributes, we built a geobody containing the turbidite bodies. Then, the porosity and saturation calculated from well logs were extrapolated, thus generating a static model with these petrophysical properties. The results showed two unconnected turbidite lobes, thus creating two independent productive zones, which have excellent porous properties and considerable oil volume in place.

Keywords: reservoir properties; Piracaba-Bauna turbidite complex; geobody models.

RESUMO. A Bacia de Santos, localizada na margem sudeste brasileira, apresenta grande diversificação de reservatórios tanto no pré-sal quanto no pós-sal, com muitos campos ainda em estudo e que apresentam grande potencial produtivo. Os reservatórios oligocênicos dos campos de Bauna e Piracaba, alvo deste estudo, são formados por arenitos turbidíticos. Propomos uma abordagem utilizando a integração de atributos sísmicos e avaliação de perfis de poços para a construção de um modelo 3D de propriedades de reservatórios. A partir da análise dos atributos sísmicos, construímos um *geobody* contendo os corpos turbidíticos. Em seguida, extrapolamos a porosidade e saturação calculadas a partir dos perfis dos poços, gerando um modelo estático com essas propriedades petrofísicas. Os resultados mostraram dois lóbulos turbidíticos desconectados, criando assim duas zonas produtivas independentes, que apresentam excelentes propriedades porosas e considerável volume de óleo no local.

Palavras-chave: propriedades de reservatório; complexo turbidítico Piracaba-Bauna; modelos *geobody*.

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INTRODUCTION

The construction of static reservoir models consists in the three-dimensional determination of petrophysical properties. This information provides the evaluation, monitoring and design strategies for a field development plan. The use of 3D seismic data for reservoir mapping is essential, but its application can be limited when we evaluate turbidite reservoirs and the complex distribution of sandstone bodies, due to data resolution. When evaluating seismic data, it is necessary to keep in mind the limitations of data resolution (Kallweit & Wood, 1982), which make it a challenge to identify and characterize turbidite geometries, leading to errors in the definition and estimation of the oil reserves in a field.

From the integration of seismic, well logs and rock data, a better reservoir characterization is possible. Well logs provide 1D information with a higher resolution than seismic data and upscaling the well to seismic is one of the major challenges in oil industry. For this, it is necessary to combine the knowledge of geoscientists and engineers to build models where all the information and data available about a reservoir can be incorporated. These integrated models are important for the performance of an oil field throughout its life cycle.

Turbidite reservoir analyzes, using seismic attributes, and the evaluation of well logs lead to new approaches in the development of an area. In this sense, Mayall et al. (2006) used the RMS amplitude to predict facies in reservoirs of turbidite channels and associate facies with reservoir properties such as net-to-gross. Berton & Vesely (2016) used seismic stratigraphic analysis with seismic attributes to characterize an Eocene progradational shelf margin in the northern Santos Basin. Zhao et al. (2016) promoted an approach using attributes for the automatic classification of seismic facies, based on machine learning algorithms. With this, the authors were able to identify turbidite geometries like channels and channel complexes, and recognize the importance of a right choice of attributes within of a workflow.

Each attribute usually has more than one application and, when combined, it can lead to new information and conclusions. The use of seismic attributes to understand the depositional system and build a geobody of reservoir was studied in Othman et al. (2017) and Huang (2018), and demonstrates an important strategy for the development of a petroleum field. Huang (2018) correlated seismic attributes with well data to characterize the Lower Congo Basin turbidite system and predict reservoir facies and their properties. Othman et al. (2017) carried out a study based on the analysis of seismic attributes and well logs for extraction of reservoir properties within the geobody composed of turbidities slope channels in offshore west Nile Delta, Egypt.

The main objective is to propose an approach to more accurately identify the limits of the reservoirs and their spatial distribution, through the use of seismic attribute and the creation of a geobody to understand how the sandstone bodies are distributed in the Bauna and Piracaba Fields, Santos Basin. Then, the geobody is filled with the porosity and saturation properties from the results of the well evaluation to build a more robust static model.

Study Area

The Santos Basin has a long history of discoveries of oil and gas fields, with several very promising regions that have been poorly studied. The Bauna and Piracaba Oil Fields were discovered in 2008 through wells 1-BRSA-607-SPS (well A) and 1-BRSA-658-SPS (well B), respectively. These oil fields are located in block BM-S-40 in the southern part of Santos Basin, approximately 210 km from the south coast of the state of São Paulo, in water depths between 225 and 295 meters (Fig. 1). The reservoirs correspond to the Oligocene turbiditic sandstones of the Marambaia Formation, related to a complex system of submarine fans, which occur at depths between 2000m and 2200m. The reservoirs have excellent permo-porous characteristics. AGR's updated independent assessment of the remaining reserves for the Bauna and Piracaba field is estimated for the period from January 1st, 2020 through to an economic cut-off year of 2031.

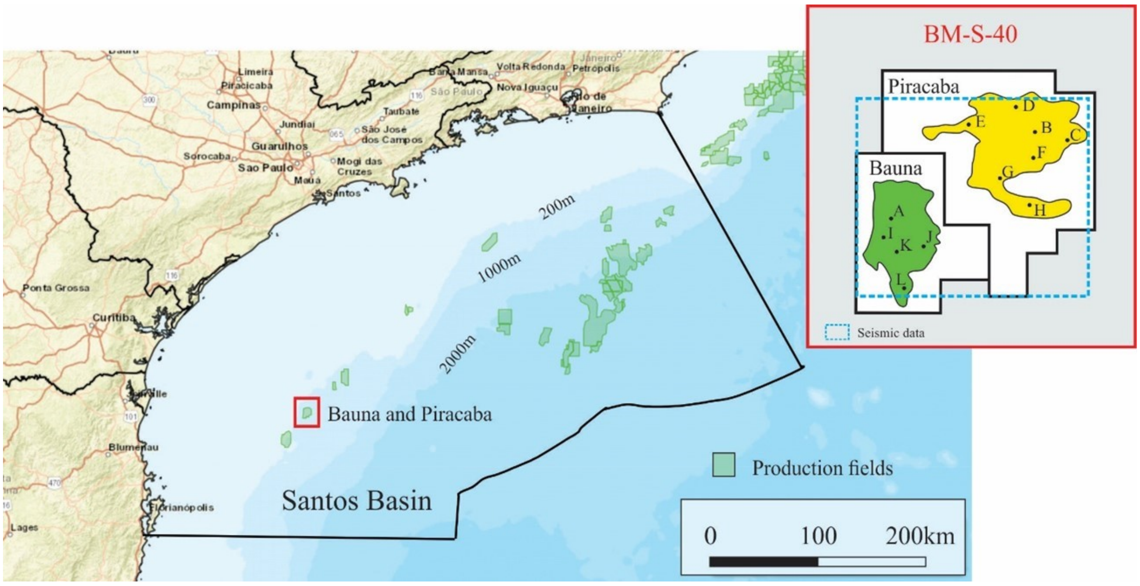

Figure 1 - Location map of the Bauna and Piracaba Fields (BM-S-40), Santos Basin. The blue dashed line outlines the used 3D seismic survey. Wells are represented by letters and points in BM-S-40.

The Marambaia Formation is characterized by the interlayer of pelitic sediments with tens of meters of sandstone bodies. The whitish-gray sandstones showing good to moderate selection occur in turbidite channels and lobes (Pereira & Feijó, 1994; Moreira et al., 2007).

The production and drainage system of the oil fields occurs through a system that connects six producing wells, three water injector wells and one gas injector well to a leased floating production, storage and offloading facility (FPSO), named Cidade de Itajaí. Most of the natural gas produced is reinjected into the reservoir as a secondary recovery method and it is consumed in the gas lift of the producing wells. Bauna and Piracaba Oil Fields have a long production history which began in 2011 and have continued to perform well with 129.9MMbbl up to 30 June 2020 (OE Offshore Engineer, 2020).

With the change of concession in 2019, block BM-S-40, previously handled by Petrobras, is now operated by Karoon. This study sought to arrive at a more accurate assessment of the Oligocene turbidite reservoirs of the Bauna and Piracaba Fields. These reservoirs are secondary exploratory targets in the Santos Basin, since the currently major targets are in the pre-salt, leading to a greater scarcity of information from Oligocene reservoirs in this basin.

MATERIALS AND METHODS

To perform this study, we used a seismic volume and data from ten wells. The seismic data used is a 3D post-stacked time migration (PSTM) that covers an area of 100 km². This data belongs to the program R0268_BM-S-40 and is aimed at the development of the Bauna and Piracaba Oil Fields (Fig. 1). We propose a workflow for the identification and characterization of petrophysical properties of sandstone bodies after the integration of well data and seismic attributes. Figure 2 shows the workflow used in this work, and for a better organization, it is divided in well log evaluation, seismic interpretation, and construction and filling of the geobody.

Well log evaluation

The evaluation of well logs aimed to define reservoir zones and estimate reservoir properties: clay content, total and effective porosities and saturation. For this, the following well logs were used: gamma rays (GR), caliper (CAL), neutron porosity (NPHI), density (RHOB), sonic (DT), deep resistivity (RES), acoustic impedance (IP), and photoelectric (PE).

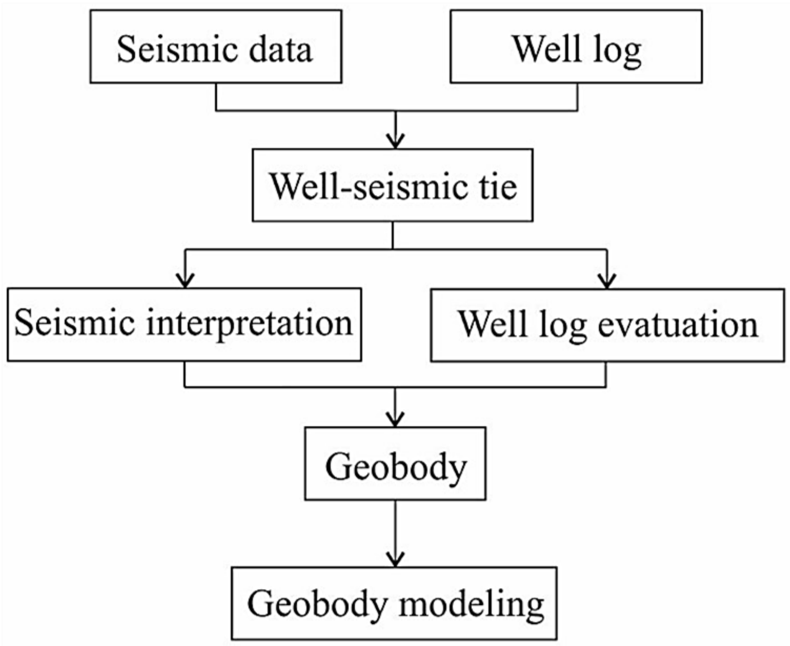

Figure 2 - Proposed workflow for the individualization and modeling of porosity and oil saturation of the geobody formed by the sandstone reservoirs.

Well log evaluation

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After the loading and quality control of the well logs, we performed a zonation separating the sandstone intervals from the shales, using GR, RHOB, and NPHI logs, separating the zones following the characteristics presented in Table 1. As an example, the zonation carried out in well 1 is shown in Figure 3.

Then, we calculated the temperature curve for each well. The temperature curves were calculated by measuring the temperature at two depths and were extrapolated to the entire well. When only one temperature measurement was available, this value was used in conjunction with the geothermal gradient. The geothermal gradient obtained for the study area was 24°C/km.

The next step was the calculation of the clay volume. Dewan (1983) points out that the presence of clay can be very harmful to the production of a reservoir. A relatively low amount of clay can clog pores and considerably reduce the values of effective porosity and permeability. In addition, by affecting the connection between the pores of the rock, clays may prevent fluid flow in reservoir. We used the gamma ray log (GR) to estimate the clay volume. This log measures the natural radioactivity of rocks, which comes from three radioactive elements: potassium, uranium and thorium. The characteristic of the GR log is associated with the clay volume, as clays have the facility to retain radioactive minerals in their structure (Ellis & Singer, 2007), generating a reading of the log proportional to the amount of clay.

To obtain the clay volume, we used the gamma ray index (IGR):

$$\mathrm{IGR} = \frac{\mathrm{GR_{log}} - \mathrm{GR_{min}}}{\mathrm{GR_{max}} - \mathrm{GR_{min}}}, \tag{1}$$

Table 1 - Patterns observed in well logs for zonation.

Lithology	Gamma Ray	Density and Neutron	Photoelectric	Sonic	Acoustic Impedance
Sandstone	Low	Crossover: decrease in density and neutron values	Relatively Low	Relatively High	Relatively Low
Shale	High	Increase in density and neutron values	Relatively High	Relatively Low	Relatively High

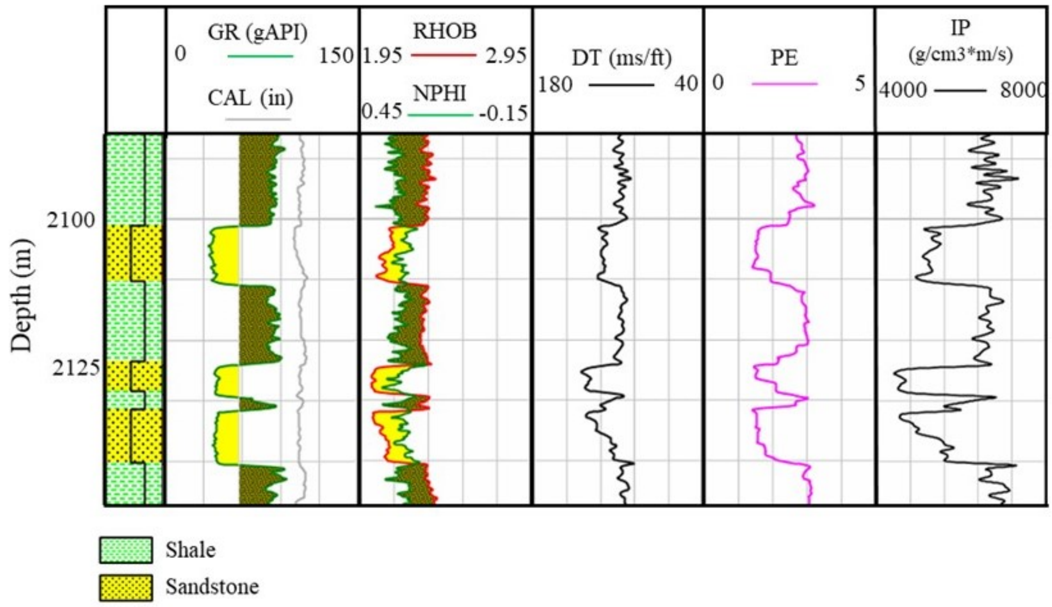

Figure 3 - Well log patterns for identifying sandstone and shale lithologies.

where $\mathrm{GR_{log}}$ is the value measured by the GR log at the depth of investigation, $\mathrm{GR_{min}}$ and $\mathrm{GR_{max}}$ are the averages of the minimum and maximum values measured in a clean zone (without the presence of clay) and in a shale zone, respectively. With the IGR, empirical models can be used to calculate the clay volume (Vclay). With the IGR, empirical models can be used to calculate the clay volume (Vclay). The most used empirical models are: Linear, Larionov for recent and older rocks, Clavier and Stieber (Schön, 2011). For this study, we used the Larionov's model for Paleogene and Neogene rocks:

$$\mathrm{Vclay} = 0{,}083\left(2^{3{,}7*\mathrm{IGR}} - 1\right). \qquad (2)$$

This equation was used to estimate the lowest clay values in the interval of interest in the Oligocene reservoirs.

After obtaining the clay volume in wells, we calculated porosity and saturation. For the estimation of porosity, we used a method that combines the neutron and density logs, and the clay volume to obtain the total and effective porosities, for more details see Dewan (1983).

We used Archie's equation to calculate water saturation (Ellis & Singer, 2007):

$$\mathrm{S_w} = \sqrt[n]{\frac{\mathrm{a}}{\emptyset^{\mathrm{m}}}\frac{\mathrm{R_w}}{\mathrm{R_t}}}, \qquad (3)$$

where $\mathrm{R_t}$ is the resistivity of the uninvaded formation, $\mathrm{R_w}$ is water resistivity, $\emptyset$ is the porosity, m is the cementation exponent, n is the saturation exponent and a is the tortuosity parameter. The following values were used for the parameters: $\mathrm{m} = \mathrm{n} = 2$ and $\mathrm{a} = 1$. To obtain the value of $\mathrm{R_w}$, we verified a zone 100% saturated with water and used the following formula:

$$\mathrm{R_w} = \mathrm{R_t} \times \emptyset^2. \tag{4}$$

It is worth mentioning that we chose Archie's equation because the sandstones have low values of clay volume, with up to 15%.

From the evaluation of the well logs, we obtain a better understanding of the reservoirs. With the porosity and saturation logs, we performed the extrapolation in the geobody formed by the sandstone bodies, which will be detailed later.

Seismic Interpretation

Seismic interpretation integrated with evaluation of well logs was the basis for the characterization of the reservoirs. The first step in the seismic interpretation was the well-seismic tie. With the help of additional data, which accompanied the well data (composite log and exploration reports), we delimited the reservoirs in the study area. We observed that the sandstones have a lower acoustic impedance than the shales (as shown in Fig. 3). Because of this, the top of the sandstone is characterized by the trough, while the base as a peak (SEG standard).

In seismic interpretation, we evaluated the maximum time limits of all reservoirs in the area and created three surfaces; one limiting the top and the other the base that encompassed the reservoirs of the Marambaia Fm., and an intermediate surface. Even though the targets are turbidite reservoirs of Oligocene age, we also analyzed the behavior of the lower layers and their interference in the above deposits, as the region is affected by halokinesis that impacts the configuration of the reservoirs. The seismic interpretation provided structural information on the area to understand the spatial position of the reservoirs and how they are related.

Seismic Attributes

We selected the seismic attributes that highlighted the following criteria: structural and fault visibility or the turbidite lobes. Given these criteria, we chose the root-mean-square (RMS) amplitude and pseudo-relief attribute (also known as TecVA) attributes for this study.

The RMS amplitude ($\mathrm{X_{RMS}}$) attribute is the square root of the average of the squared trace within the analysis window specified of the seismic trace (X):

$$\mathrm{X_{RMS}} = \sqrt{\frac{1}{\mathrm{N}}\sum_{\mathrm{n}=1}^{\mathrm{N}} \mathrm{X_n^2}}, \tag{5}$$

where N is is the sample number of the window. RMS amplitude is usually appropriate for intervals that encompass both peaks and troughs (Barnes, 2016). Attributes related to the energetic content of the seismic trace are usually used to distinguish different types of lithologies. In the study, high RMS amplitude values were related to high porosity sandstones, which are the high-quality hydrocarbon reservoirs in the Bauna and Piracaba Fields.

The TecVA attribute was developed by Bulhões & Amorim (2005) and is an attribute with the potential to show small variations in amplitude that in lateral correlation trace by trace reveal geometric features such as faults and channels. This attribute is calculated in two steps:

1. Calculate the RMS amplitude (Eq. 5), obtaining an estimate of the trace envelope.
2. Apply an inverse Hilbert transform (-90º phase rotation) of in the RMS amplitude:

$$\mathrm{X_{RMS_{-90^\circ}}} = H^{-1}\{\mathrm{X_{RMS}}\}, \tag{6}$$

The RMS and TecVA traces of a seismic trace are shown in Figure 4, where trace highlights high amplitude contrasts, while TecVA is related to layer properties.

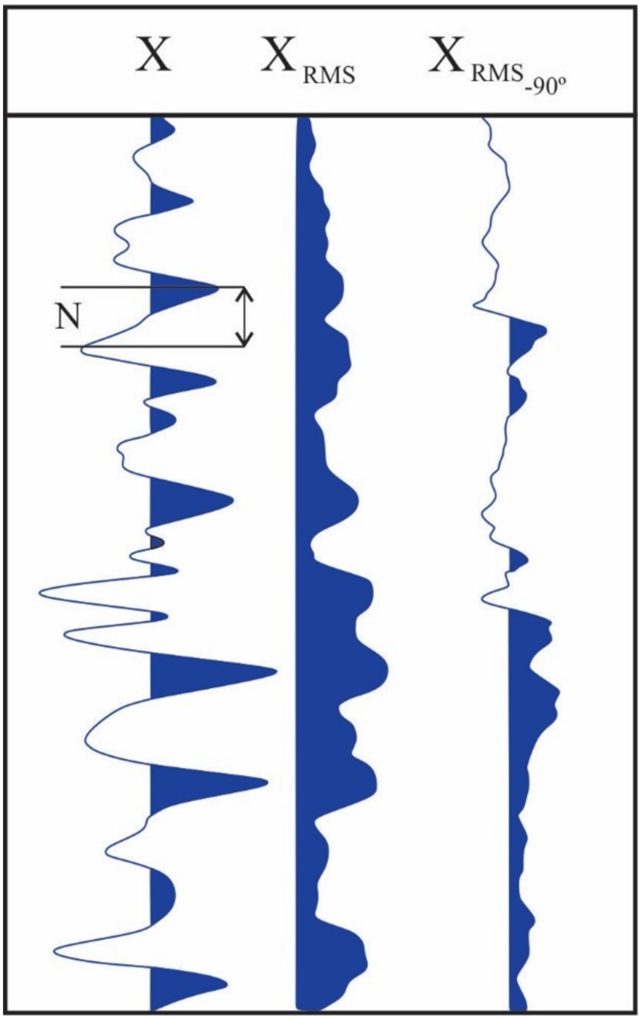

Figure 4 - Step for calculating the TecVA attribute. From left to right: seismic trace ($\mathbf{X}$), RMS trace ($\mathbf{X_{RMS}}$) and TecVA ($\mathbf{X_{RMS_{-90°}}}$) (After Bulhões & Amorim, 2005).

The TecVA attribute assisted in the mapping of faults and in the identification of the limits and compartmentalization of the two fields. The RMS attribute, on the other hand, was fundamental in the delineation of the turbidite lobes in the reservoir interval, used for the construction of the geobody.

Construction of the reservoir model and filling of the geobody with reservoir properties

The first step to build the geobody was to understand the turbidite system and the type of reservoir in the area. The reservoirs are clean sandstones with good porosity composed of channels and lobes. Then, we selected a seismic attribute to highlight the characteristics of the turbidite lobes and the generation of the geobody followed the steps: identification, isolation and extraction.

The attribute RMS was the attribute that most highlighted the complexes of channels and lobes in the study area. This attribute was calculated from the PSTM seismic volume using equation 5 between the interval from 1700 to 2200ms with a window of 25ms. The RMS amplitude values obtained range from -9.687 to 9.687. Then, manipulating the opacity of this attribute, it was possible to filter and highlight the range of values related to the turbidite sandstones and select the seeds for their detection. Seed is a tool that works through rendering, where some points are chosen (seeds) and automatically similar values are detected in the interval of interest, thus forming the geobody. For this, we performed some tests, always having the RMS attribute on the map as a quality control, for the final construction of the geobody.

For the geobody modeling, we created trend maps to assess how the effective porosity and oil saturation properties behave within the seismic volume. Trend map is a geostatistical resource that helps to predict the behavior of two-dimensional distribution (x and y axes) of a property. Each well provides information on the property in a single value of x and y, but it is necessary to understand how the property is distributed in other areas where there are no wells. For this study, the arithmetic mean was used to build the trend maps. The next step was to define the interpolation method to be used and how many wells could contribute to fill the geobody. We use the simple kriging method. It assumes that local averages are relatively constant and of a value similar to the population average, which is used to estimate local values together with neighboring points (Azevedo & Soares, 2017).

RESULTS AND DISCUSSION

The interpretation of the well logs involved a joint analysis of the original and estimated curves and the descriptions of sidewall samples. This analysis helped in the definition of the reservoir zones and in the oil/water contact identification. To exemplify the evaluation of logs in the 10 wells used, the zones and curves estimated from one representative well are presented in Figure 5.

The evaluation of the well logs was initiated at the discovery well (well A), presenting the results that helped as a guide in the evaluation of the other wells. In well A, we identified three sandstone zones, all surrounded by shale layers and with their well-defined limits, as can be seen in Figure 5. The sandstone zones were named as 1, 2 and 3 and have thicknesses of 12.1m, 5.2m and 9.8m, respectively. These zones present values of low and similar clay volumes, with an average of 1.77% obtained from Larionov's method (Eq. 2). From the identification of the oil/water contact in some wells, we calculated the resistivity of the formation water (Eq. 4) obtaining 0.018 ohms in average value. With the water resistivity value and the temperature and clay volume curves, we used the neutron-density method combined with the Archie equation (Eq. 3) to estimate effective porosity and water saturation. The average values, considering the three sandstone zones, of water saturation and effective porosity are 22% and 33%, respectively. In this well, the results show that the reservoirs are thin, clean (low clay volume), with high porosity, and good oil saturation.

In the wells, we identify from one to three sandstone intervals, ranging in thickness from 2 to 45m. Comparing the two oil fields, Bauna Field presents intervals with an average thickness of 25m divided into two zones, while Piracaba Field has reservoirs with an average thickness of 14m and generally in a single interval. Evaluating the reservoir properties, the Bauna Field has an average clay volume of 8.68%, an average effective porosity of 29% and an average oil saturation of 54%. The Piracaba Field has an average clay volume of 7.72%, an average effective porosity of 30% and an average oil saturation of 47%. We identified the oil-water contact depth in some wells. In the Bauna Field, it is at 2135m and in the Piracaba Field at 2050m. Our results reveal sandstone reservoirs with low clay volume, high effective porosity and high oil saturation.

The TecVa attribute was used to assist in the faults identification and mapping. The faults have NE-SW direction and a large normal fault that partitions the Oligocene age reservoirs (Fig. 6c) in the Piracaba Field. The RMS attribute gives a better visualization and identification of turbidite lobes and channels. Figure 6a shows a time-slice (2052ms) of the RMS attribute with identified lobes and channels. We observe (Fig. 6) the feeder channel and lobe in the Piracaba Field (north) while only the central and distal parts of the turbidite lobe appear in the Bauna Field (south). Due to the limits of our seismic dataset, it is not possible to conclude whether the two lobes are fed by the same channel. In Figure 6b, blue colors show the detectable regions from the renderization of the chosen seeds, where we can see an excellent fit with the lobes shown in the image on the left (yellow). Figure 6c shows the final model of the geobody in plain view with the location of the wells and a quote time-slice 2186 ms of the TecVA attribute.

The 3D geobody models with the properties of effective porosity and oil saturation are shown in Figure 7. It can be noted that these properties are distributed consistently throughout the turbidite lobes. It is also observed that in the northernmost turbidite system, the highest values of effective porosity are in the median part of the lobe. This is

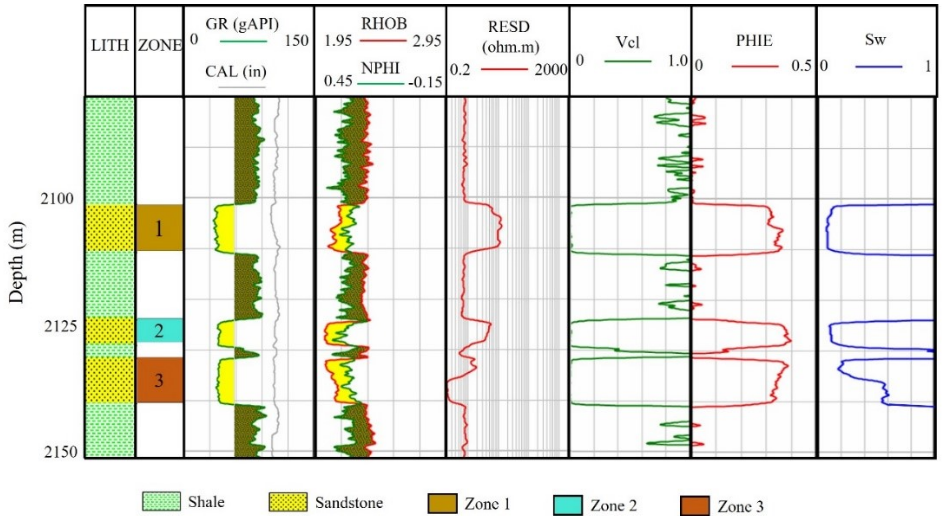

Figure 5 - Analysis of well A. Tracks: 1) Lithology (LITH); 2) Zones; 3) Gamma ray (GR) and caliper (CAL); 4) Density (RHOB) and neutron (NPHI); 5) Deep resistivity (RESD); 6) Clay volume (Vcl); 7) Effective porosity (PHIE); 8) Water saturation (Sw).

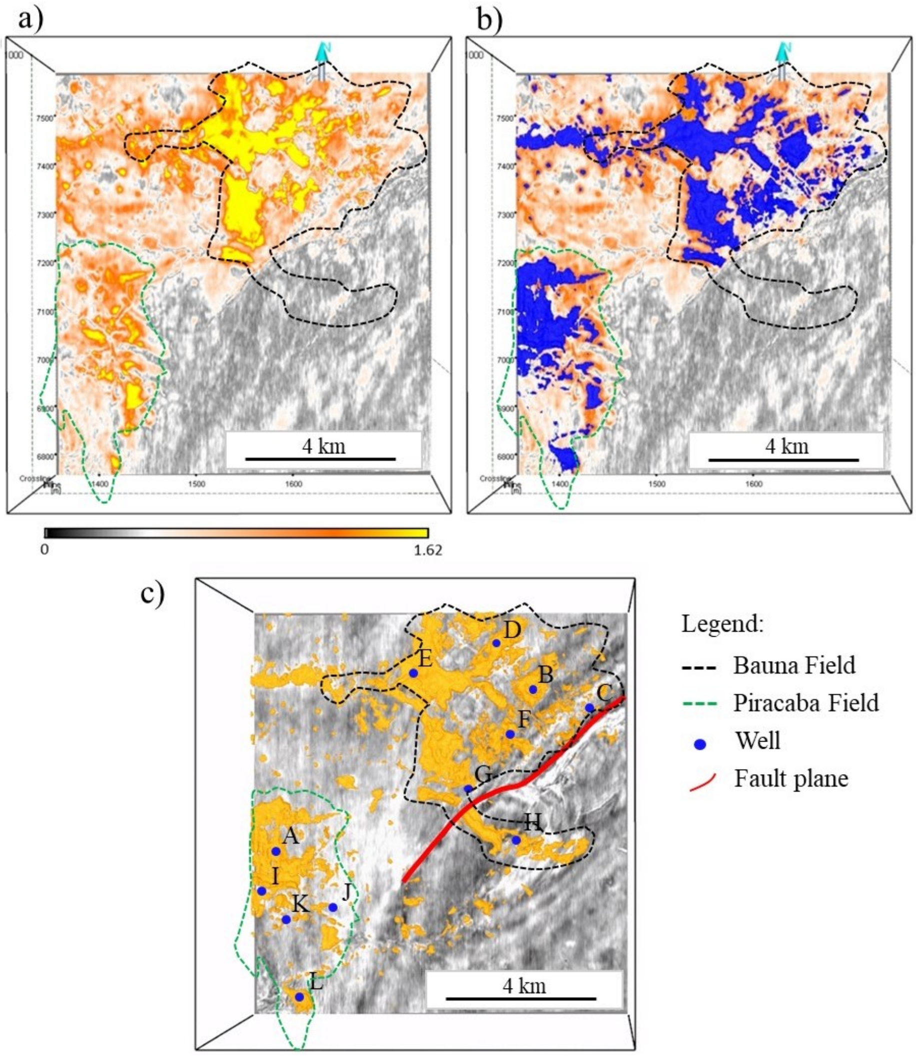

Figure 6 - (a) RMS attribute and (b) the shape of the detected geobody (blue; right) in the time-slice at 2052ms. (c) Geobody seen in plain view with the TecVa attribute in 2186ms.

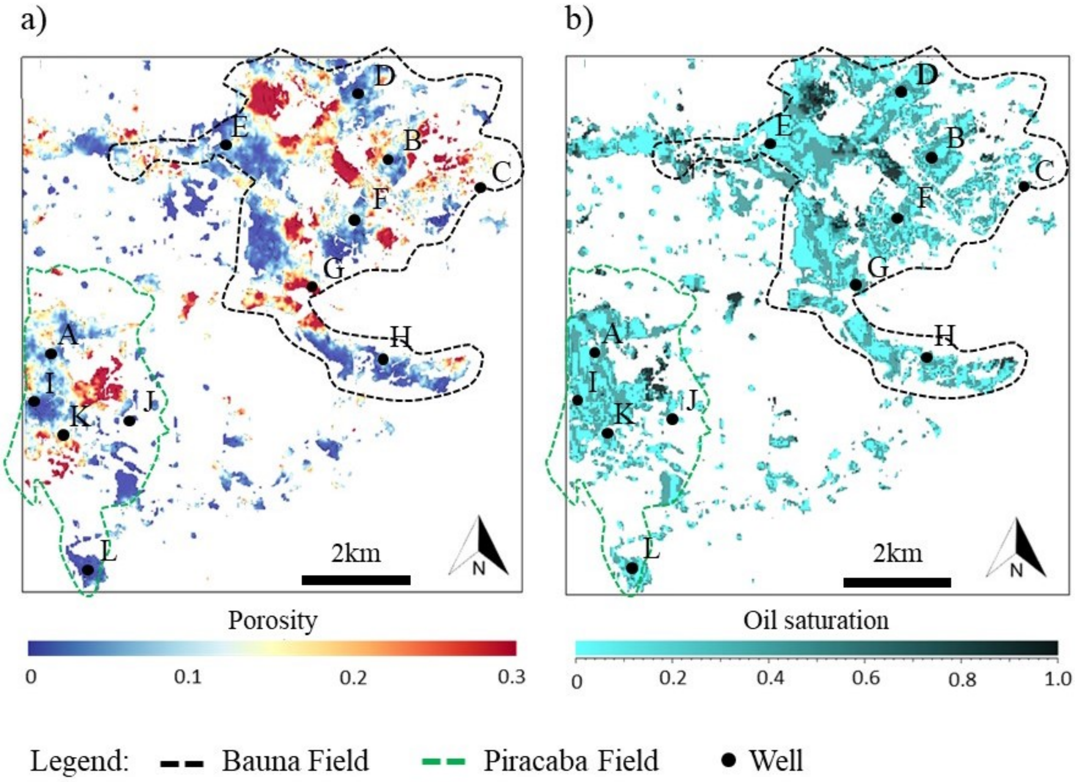

Figure 7 - 3D geobody models: (a) Effective porosity and (b) Oil saturation.

expected as in a turbidite system this portion of the turbidite deposit has a higher thickness and cleaner sandstones. In the most distal part, the lobes have lower thickness and a higher presence of mudstones, due to the energy loss of the system (Tinterri et al., 2020).

The analysis of the logs and the geobody provides the understanding that the reservoirs were located at different depths and that they were formed by two main turbidite lobe-channel systems. In Piracaba Field the turbidite system seems to have a W-E trend, while in Bauna Field the lobe-channel complex trend is not clear because the lack of our seismic coverage is cut over it (Fig. 8). However, in both turbidite systems, it is possible to infer a second channel complex arriving from the west, but the respective lobe is not observed in the seismic data, suggesting they are at deeper water depth.

In the Bauna Field, it is worth noting that wells I (currently the largest producer in both fields) and K are productors, and wells A, J and L are injectors. In the Piracaba Field, wells D, F, G and H are responsible for production and have the well C as an injector. Wells B and E are abandoned wells. The sandstone reservoir in well H is deeper than in other wells, with a major normal fault of NE-SW direction that separates it (Fig. 6c), demonstrating that there is no connectivity with the other wells of the Piracaba Field.

CONCLUSIONS

We verified that the reservoirs are constituted of two distinct lobe-channel turbidite complexes. One is on the northern portion and represents the Piracaba Field, and the second, to the south, represents the Bauna Field. They seem to have a W-E depositional trend, based on the shape and distribution of the lobes and channels. The construction of the geobody was a powerful tool for the identification of the turbidite geometry. The seismic attribute that best managed the

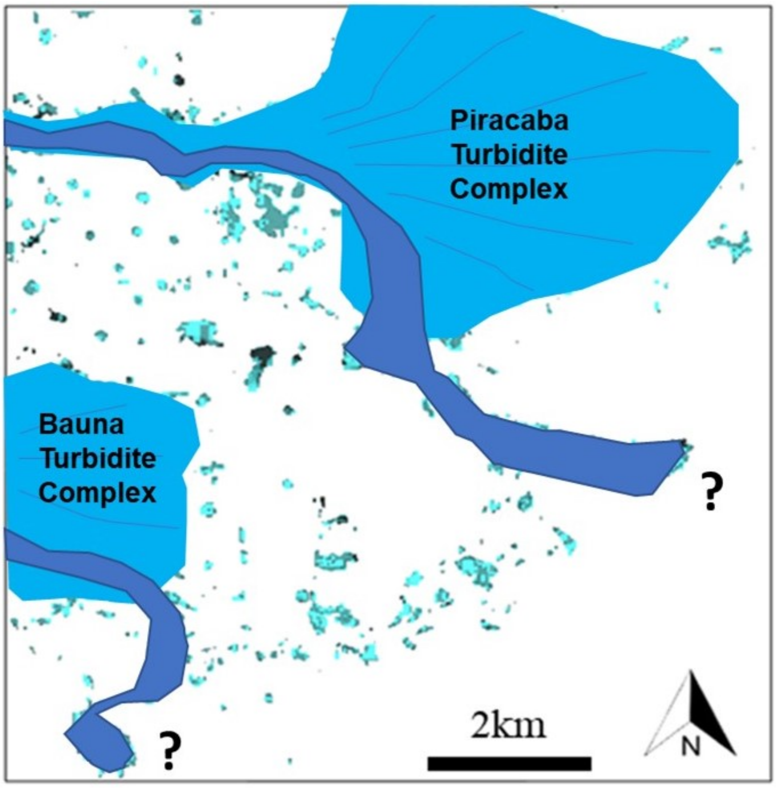

Figure 8 - Lobe-channel geometry for the Piracaba-Bauna turbidite complex. Note the lobe-channel geometry suggesting a depositional trend W-E for the Piracaba Complex. Depositional trend for Bauna turbidite system is not clear because of seismic data limits. Newer channels are developing and may indicate the existence of potential lobes to SE

identification of these geometry systems was the RMS attribute. From the evaluation of the well logs, we conclude that the sandstone reservoirs have a low clay volume, high effective porosity, and high oil saturation. This demonstrates a high production potential of these reservoirs, although they are not very thick. The workflow for filling the geobody with the properties of porosity and oil saturation proved to be efficient. The workflow will serve to identify sedimentary structures (e.g., delta lobes). The creation of the static model and understanding of the distribution of these properties are extremely important in the decision making for the exploration and production of these fields.

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