GEOSTATISTICAL MODELING OF A CARBONATE RESERVOIR: AN EXAMPLE FROM THE BRAZILIAN PRE-SALT

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Abstract

Reservoir geological modeling is one of the most important phases in reservoir studies, aiming to represent the geological characteristics of the reservoir. The objective of this work is to construct a geostatistical model of the Berbigão field. For the characterization and modeling of the reservoir, quality control of the interpretations was performed. Subsequently, the structural model was created, followed by the property model. Three facies were defined according to the porosity data. The porous facies is the most prevalent in the reservoir, constituting about 46% of the area. The second most common facies is the semi-porous facies, representing approximately 36% of the reservoir, and it is also present throughout the entire study area. The remaining composition of the reservoir consists of 18% closed facies. The results reflect the heterogeneity of the reservoir and may help in its management.

Introduction

Reservoir characterization is of paramount importance for the oil and gas industry as it helps minimize errors during the exploration phase. The geological reservoir model is one of the most crucial phases in reservoir studies, as it represents the geological characteristics of the reservoir (Cosentino, 2001).

Geostatistics emerges as an advanced tool for analyzing variables because it combines the available data's statistics with the theory of regionalized variables (Normando, 2022). Goovaerts (2000) mentions that geostatistics benefits from the spatial correlation between neighboring observations to predict attribute values at unsampled locations.

3D models bring significant benefits to the petroleum industry, as they result from the integration of data and knowledge aimed at reducing uncertainties before decision-making. Various types of data are employed in reservoir modeling, with seismic and well data being the most important (Caers, 2005).

The pre-salt section of the Berbigão field (Figure 1), located in the Santos Basin, was chosen for detailed study and reservoir modeling because significant amounts of oil are being retained in the pre-salt rocks (Neves, 2019). Since the beginning of production in the Berbigão field, the enhanced oil recovery (EOR) technique of water alternating gas (WAG) has been practiced. This technological solution is an optimal use of resources, as it simultaneously utilizes the high concentration of CO_2 naturally present in this field and the advantages of the WAG process to increase the recovery factor. For this, a thorough understanding of the geological and structural behavior of the studied reservoir is essential.

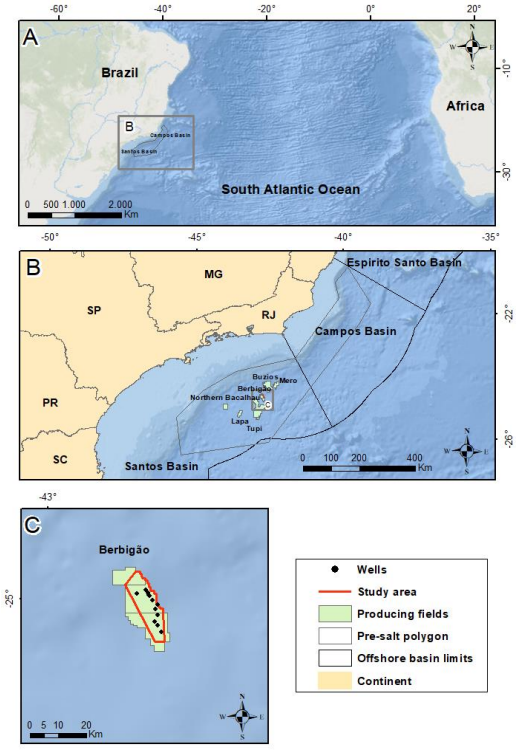

Figure 1 – Location of the study area: Berbigão Field, Deep waters of Santos Basin.

The objective of this work is to construct a three-dimensional geostatistical model of the Berbigão field, based on seismic and well data, and to understand the main facies, how they are distributed, and how they influence the production of the field.

Methodology

For the development of this work, public data provided by the National Agency of Petroleum, Natural Gas and Biofuels (ANP) were used. The data included seismic and well information (e.g., geophysical logging, facies, wellheaders, wellpaths, welltops) and petrography data. The Petrel® E&P Platform software, version 2021 by Schlumberger, was utilized for the integration and interpretation of the data.

To characterize and model the reservoir, the evaluation, organization, and quality control of the data and interpretations were conducted. Following this, the structural model was created, and subsequently, the property model was developed (Figure 2).

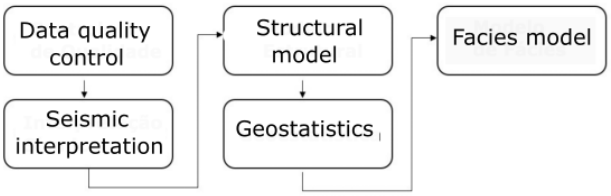

Figure 2 – General workflow used in the three-dimensional modeling.

Results

Four geological horizons, namely Barra Velha 100, 200, 300, and Itapema, were interpreted (Figure 3).

The Itapema Formation features a top characterized by a horizon with low continuity, compartmentalized by numerous faults (Figure 3). This horizon lies at a depth of approximately 6,400 meters in the northwest portion, but becomes shallower, around 6,300 meters, in the southeastern zone, precisely in an area of a structural high (Figure 4).

The horizon of the Barra Velha 300 Formation (BV 300) is at a depth of approximately 6,000 meters. It is a reflector with low continuity and medium to high amplitude (Figures 3 and 4).

The Barra Velha 200 (BV 200) is at a depth of approximately 5,800 meters. This horizon forms a mound in the northwest portion and a buildup in the southeastern sector of the field (Figure 3). The reflector has high amplitude and is influenced by faults.

The Barra Velha 100 (BV 100) represents the upper limit of the pre-salt and corresponds to the base of the salt. It exhibits good continuity, with the southeastern portion showing the presence of a buildup in an area of a structural high (Figure 3).

Figure 3 presents the interface between the oil and water phases. This interface is located at an approximate depth of 5,725 meters, situated within the geological context of the Barra Velha Formation.

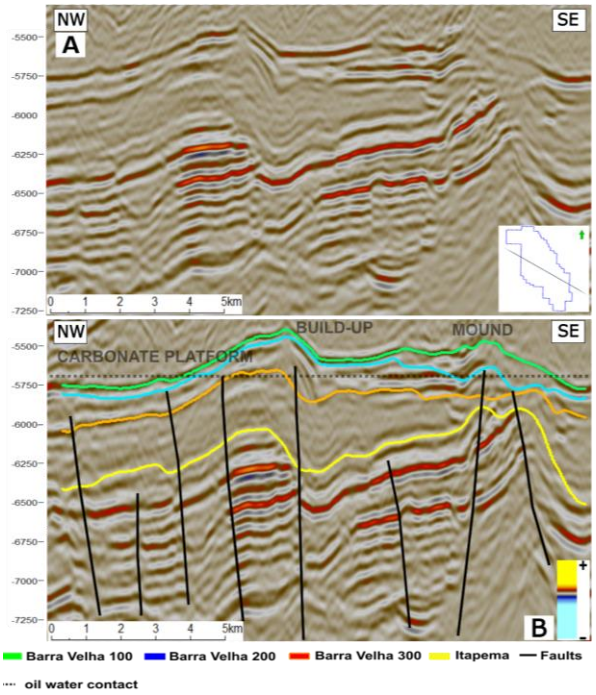

Figure 3 – Uninterpreted and interpreted seismic section, highlighting the surfaces of the Barra Velha Formation 100, 200, 300, and Itapema, faults, mound, carbonate platform, buildup, and the oil-water contact.

For the generation of the structural model, four surfaces were created according to the interpreted seismic horizons. The surface of the Itapema Formation is the deepest in the model, with a depth range between 5,800 and 6,500 meters (Figure 4d). The southern sector is deeper than the northern sector, and the structural highs in the northeastern region of the field are elongated and continuous.

The Barra Velha 200 and 300 surfaces are intermediate, with depths ranging from 5,250 to 6,000 meters (Figure 4b, c). Their deepest zones are also located in the southern sector of Berbigão.

The surface of Barra Velha 100 (BV 100) is the shallowest in the model (Figure 4a). The productive zones are found in the structural highs, reaching depths close to 5,000 meters. However, it is important to note that, in the southeastern zone of Berbigão, a deepening of the BV 100 surface is observed, reaching depths close to 5,900 meters.

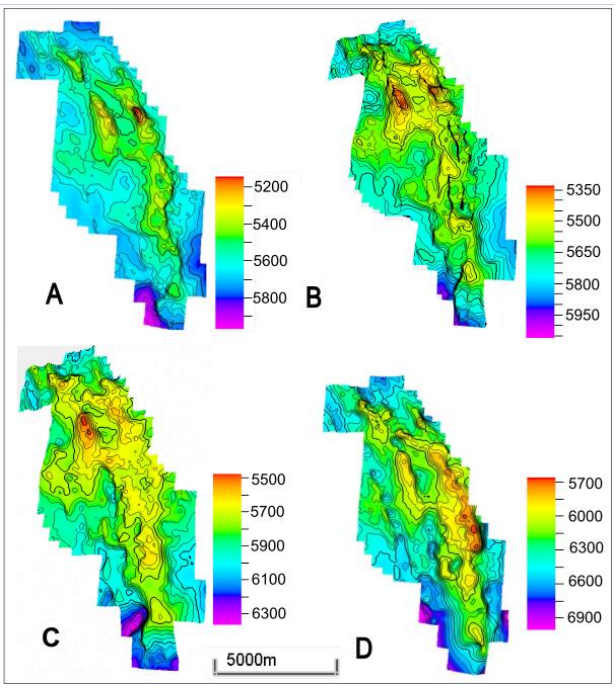

Figure 4 – Interpreted surfaces. The colors represent the depth variation. A) Barra Velha 100 surface; B) Barra Velha 200 surface; C) Barra Velha 300 surface; D) Itapema surface.

Three facies were classified according to porosity data: porous facies (ϕ>12%), medium porous facies (6<ϕ<12%), and closed facies (<6%).

According to the geostatistical analysis, the porous facies is the most prevalent in the studied reservoir, constituting about 46% of the field, making it the primary facies found (Figures 5 and 6). This facies is distributed throughout the area, with a higher occurrence near the base of the salt. The second most common facies is the medium porous facies, representing approximately 36% of the reservoir and also present throughout the entire study area.

The remaining composition of the reservoir consists of the closed facies with 18%. The closed facies is predominantly located in the southern part of the field.

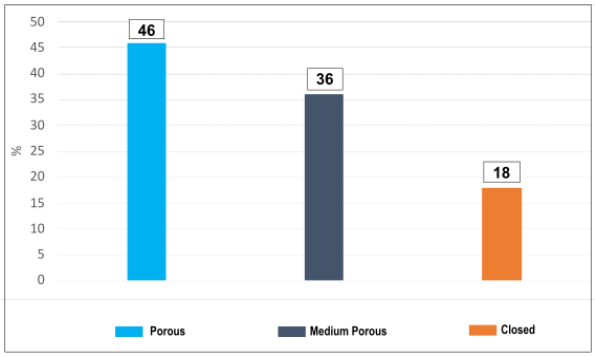

Figure 5 – Graph of facies distribution in percentage in the three-dimensional model.

In the model (Figure 6), it can be observed that the porous facies is distributed throughout the reservoir, including in the structural highs where the wells are located. The medium porous facies is more prevalent in the northern sector of the study area and on the carbonate platform, between the structural highs. The zones with closed facies are preferably located in the southern sector of the Berbigão field and mainly around the structural highs. On the opposite to the others structural highs, the high in the northwest presents the closed facies. Overall, the model is quite porous, demonstrating the significant importance of the Berbigão field.

By visualizing the model in layers (Figure 6), in the northeastern sector, the porous and medium porous facies are predominant. The most of the productive wells of the field were drilled in this area. Differently, a less porous region is observed in the northwest and south of the field.

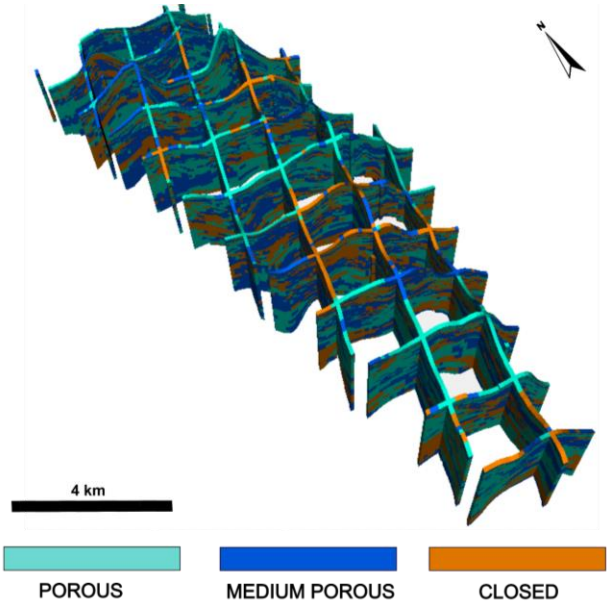

Figure 6 – Geostatistical model of the Berbigão field, Layer visualization.

Discussion and Conclusions

The facies model demonstrated that in the zone of the Aptian Sag section of the Pre-salt, there are more porous and medium porous facies. The Sag-type zone has a microbial origin with a predominance of microbial sediments and fine-grained carbonate muds in both the basal and upper portions of the Barra Velha Formation (Carminatti et al., 2008; Ferreira et al., 2021; Rebelo et al., 2022).

In the model, the predominant facies in the structural highs are the porous and closed facies (Figure 4). These results corroborate with the conceptual sedimentary model of Ferreira et al., (2021).

The south facies are primarily located in the southernmost sector of the field, where the depth is greater and there are less productive zones. The relevance in the

productive context lies in the fact that the zones corresponding to the closed facies appear to consist of rocks with lower porosity, corroborating observations by Maas et al. (2023) and Rebelo (2022).

The facies model reflects the heterogeneity of the reservoir, taking into account the tectono-structural context of the study area. Moreover, the results of the geostatistical simulations adequately reflected all the input data for the modeling, respecting the proportions of facies and the directions of variability. The results achieved will help in managing the reservoir and can be used as a basis for enhanced oil recovery (EOR) simulations using, for example, the WAG method.

Acknowledgment

To the Marine and Energy-applied Geology and Geophysics Laboratory (LGMA) for providing all the necessary conditions for the research. To ANP for providing the data. To CNPq (National Council for Scientific and Technological Development) for the financial support of the first author. To Schlumberger for the Petrel license.

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