Unlocking the properties of a presalt carbonate reservoir offshore Brazil with facies-constrained geostatistical inversion

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Abstract

A continuing concern regarding presalt carbonate reservoirs offshore Brazil is how to derive accurate quantitative estimates of reservoir properties. It is challenging to understand the link between the facies model and the variation in elastic properties, recover a reliable model of elastic properties from seismic, estimate porosities and permeabilities to use in reservoir simulations, and ultimately close the loop in integrated geology and engineering workflows. This case study describes our use of geostatistical inversion as a tool to unlock reservoir properties. We show how the integration of diverse information from various sources and at different scales is used to produce a meaningful range of probabilistic realizations of this Brazilian deepwater presalt reservoir. We do this while respecting the reservoir properties observed at the locations of drilled wells. We also present a workflow for an optimized implementation of the inversion results at the modeling stage, resulting in fast and geologically consistent history matching in an extremely challenging reservoir management environment. In this way, we achieve accurate history-matched cases on a field level and on a well-by-well basis while remaining within the uncertainty limits. Therefore, we produce geologically plausible and reliable scenarios.

Introduction

The geologic complexity of the prolific Brazilian presalt carbonate reservoirs challenges industry asset teams and academic researchers to find the best way to characterize them. Facies characterization is a significant issue that causes concern when attempting to best represent reservoir behavior. For the characterization described in this case study, it was paramount to include modeling that coupled elastic properties and facies (Wang et al., 2016).

The offshore oil field that we studied is in the Santos Basin, more than 300 km off the coast of Rio de Janeiro in water depths exceeding 2000 m. Discovered in the late 2000s, it is estimated to have more than 3.5 billion stock tank barrels of oil initially in place. This type of field in this oil province is characterized by challenging reservoir management issues. These oil fields normally implement water and gas injection to improve production efficiency while maintaining pressure. Coupled with the significant geologic complexity of its facies variation and distribution and its pattern of petrophysical properties (reservoir heterogeneities), it is particularly difficult to obtain reliable and predictive models of reservoir behavior.

An initial feasibility study highlighted the need to conduct an advanced seismic reservoir characterization project using state-of-the-art geostatistical inversion technology that is capable of integrating a priori knowledge and multiscale data (Haas and Dubrule, 1994). Our main motivation is the ability to fully integrate the results of geostatistical inversion into the reservoir simulation to obtain a reliable history match. Such an approach makes it possible to reduce uncertainty while overcoming the geologic bias that is mostly defined in scenario building. This will aid in making better-informed decisions about further development and production in the field while taking uncertainty into account (Caumon et al., 2004; Caers, 2005).

We showcase a set of evidence-based results that provide insight into reservoir behavior for presalt carbonates. For this, we ran the characterization using available information (a priori geologic knowledge and a database that includes prestack seismic data and 20 wells with a suite of wireline log data available for the area). With careful handling of the available data, it was possible to establish a reliable basis for quantitative estimates of the facies and elastic properties. The key to the success of this study was the interplay between static and dynamic modeling (an interdisciplinary integration of geology and engineering expertise and data).

Geologic setting

This project investigates an Early Cretaceous microbial reservoir deposited in a deep perennial alkaline lake that fills the space left by an antecedent rifting stage. The conceptual model for the reservoir fabric (Figure 1) consists of a system of gulfs and capes along the east-west coast of the lake, with microbial carbonate buildups located on the capes elongating in the north-south direction. The bench interior facies (or terrace) may consist of facies with low energy that have developed intercalated sets of irregular and discontinuous reworked thin fragments of intraclastic grainstone buildups. This indicates the possible presence of evaporite relics, nodules, or sparse thin spherulites. The bench margin facies (or crest) of higher energy consist of truncated tops of major domes that are interpreted as buildups of grainstones that may have developed thick sets of shrubs with large vugs, breccia, and oncolites in between. The downdip slope facies with slump and ripple features and calcarenites are interpreted to consist of moderate-energy sets of spherulites. The last facies set from profundal or distal parts is interpreted to consist of low-energy laminated sets of varves, with some occurrences of phosphatic fragments entrenched within the deeper lake and muddy argillaceous carbonates.

It is interpreted that the main bioconstructions developed in the shallower-water areas along the edges of pre-existing north-south rift fault blocks. These faults are thought to have reactivated

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later during the geologic record. The best reservoir facies are found in the bench margin paleoenvironment and are associated with the development of shrubs that were heavily affected by porosity-enhancing diagenetic processes. They transition laterally into slopes formed by reworked sediments and some in-situ deposition controlled by the slope of the paleorelief. Finally, they shift laterally into deep lake facies (profundal) consisting of shalier microporous carbonate sediments that are assumed to be nonreservoir.

Diagenesis has played a significant role in the current petrophysical characteristics of the reservoir. The interpretation concludes that this diagenesis occurred very early (right after carbonate formation). This means that its processes were directly affected by the original reservoir fabric. This may be why the legacy approach of neglecting sedimentary facies modeling in the geologic models has not proven effective. The modeling is key to characterizing the geographic distribution of diagenetic effects and present-day petrophysical properties.

The main conclusion from the geologic study is that present-day properties are essentially defined by diagenesis that was largely constrained by the original reservoir facies (syndepositional, very early diagenesis). In turn, the facies were controlled by paleobathymetry defined by the historic structural footprint. This conceptual chain of processes set the framework for developing all of the necessary reservoir characterization work. It helped integrate seismic structural interpretation and seismic amplitude analysis with sedimentological and diagenetic interpretation.

Data set

Prestack depth migration seismic gathers cover an area of approximately 525 km^2 in Santos Basin and include five partial angle stacks: near (11°), mid (17°), mid far (24°), far (30°), and ultra far (36°). The seismic inline and crossline bin spacing is 12.5 × 12.5 m. The wireline log suite available for 20 wells includes gamma ray, compressional and shear sonic, density, neutron porosity, deep and shallow resistivity, computed total and effective porosity, water saturation, volume of clay, P-impedance, S-impedance, and V_P/V_S ratio. Additionally, there are nine wells with limited log data. The good-quality seismic data are essential to perform the reservoir characterization study and to ensure good-quality geostatistical inversion.

Feasibility study

The best way to start any reservoir characterization study is with a feasibility study (Teixeira et al., 2017). The feasibility study performed for this field aimed to address the following questions. Which elastic properties can help distinguish between rock types with different reservoir quality? Are the available seismic data able to supply knowledge of these elastic properties?

The work started with a simplified facies definition based on a free fluid porosity cutoff for reservoir/nonreservoir discrimination using the 20 available wells. As seen in Figure 2, V_P/V_S ratio distinguishes between different facies, with higher values in argillaceous carbonates (considered nonreservoir). When complementary studies were performed, the facies definition was changed to one based on depositional systems: bench interior (terrace), bench margin (crest), and slope and profundal (distal). Profundal facies are considered nonreservoir and characterized by high V_P/V_S ratio values. The other three facies, considered as potential reservoir, cannot be distinguished based on V_P/V_S ratio and largely overlap in P-impedance values, although a tendency can be observed with lower impedance values associated with crest facies.

The crossplot in Figure 3 highlights that good correlation exists between impedance and effective porosity values in all three reservoir facies. This correlation is exploited to cosimulate effective porosity from impedance values. Because no correlation exists for profundal facies, separating them from the other facies is required before performing the calculation of the effective porosity.

To address the second question, we ran inversion tests focused on recovering the V_P/V_S ratio values. We also performed preconditioning of the seismic gathers to improve the signal-to-noise ratio while preserving the amplitude, with the aim of achieving a better match of the inverted V_P/V_S ratio with log values in the reservoir interval. Optimizing the range of angle stacks and increasing the number of angle stacks from four to five helped improve the elastic inversion quality. However, despite improved inversion results, recovering reliable V_P/V_S ratio values from seismic remains challenging. Figure 4 shows an elastic inversion test from a representative well, through a comparison of the acoustic impedance and V_P/V_S ratio well logs with the inverted values, before and after angle stack optimization.

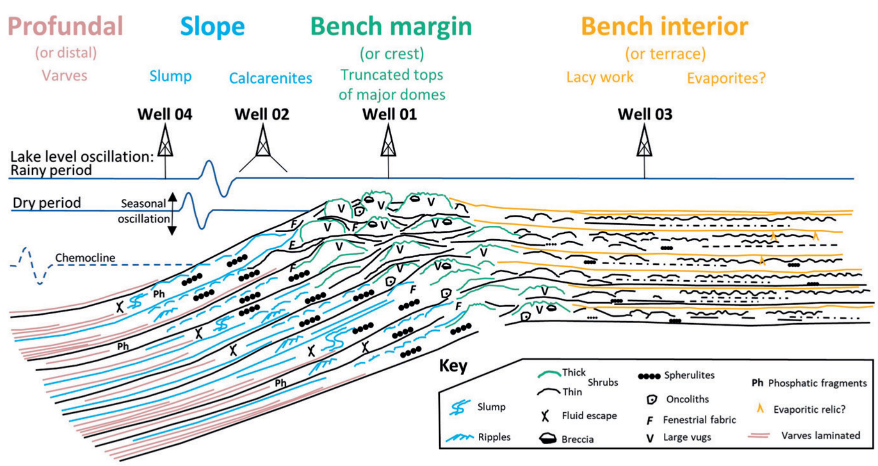

Figure 1. Conceptual geologic cross section displaying the four main paleoenvironments: bench interior (terrace), bench margin (crest), slope, and profundal (distal). This image also illustrates base lake level oscillation during rainy and dry cycle periods related to the cyclic exposition of the environments, along with main features and elements for each.

Methodology

Based on the sampling methods of Markov chain Monte Carlo (MCMC) and Bayesian inference to simultaneously combine the prior probabilities of multiscale data, we produced 3D models of elastic properties and lithofacies (Figure 5) (Wang et al., 2016; Pendrel and Schouten, 2020). The different data sources to be incorporated are represented by prior probability

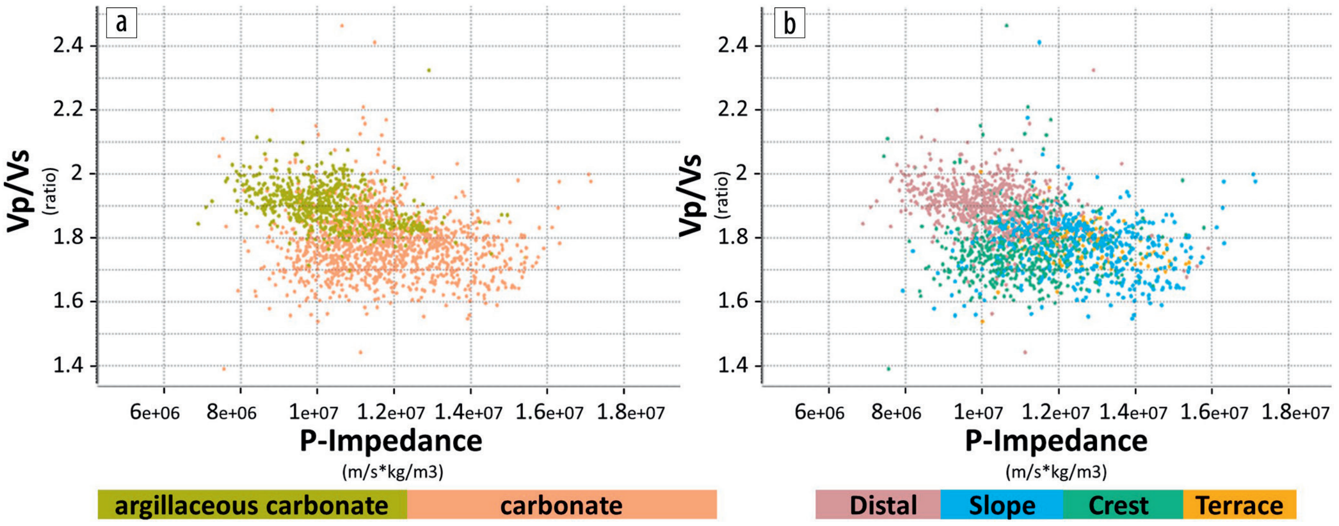

Figure 2. Facies analysis in the elastic domain showing crossplots of the P-impedance versus V_P/V_S ratio values from well logs, color coded by (a) facies types based on the free fluid porosity values and (b) sedimentary environment facies for the various stratigraphic units analyzed in this case study.

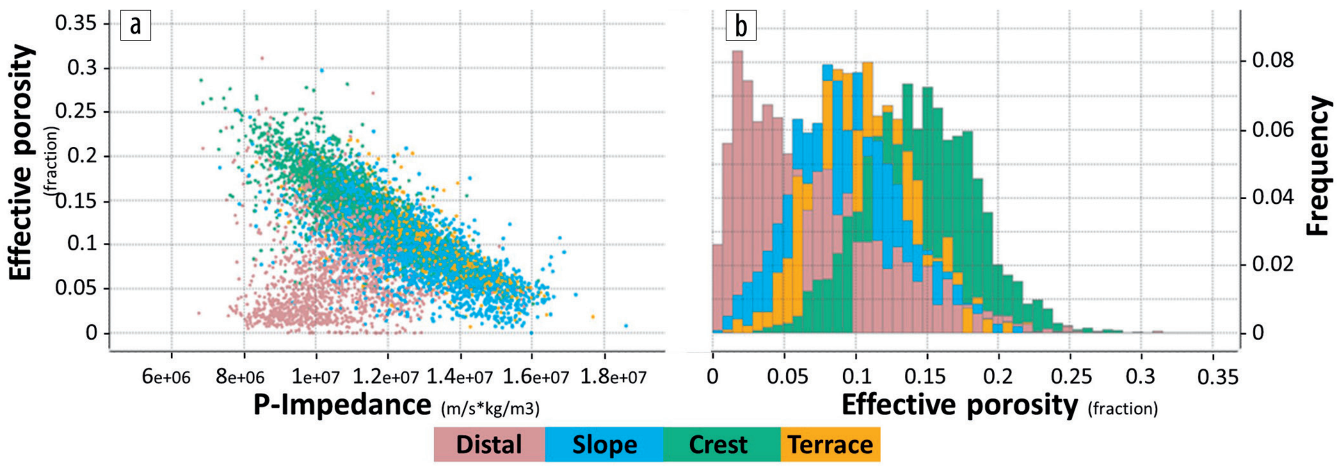

Figure 3. P-impedance versus effective porosity crossplot and effective porosity histogram from well logs, color coded by sedimentary environment facies for the various stratigraphic units analyzed in this case study. It is possible to see the trend for reservoir-prone facies in contrast with the profundal (distal) facies with lower porosities.

density functions (PDFs) and merged afterward using Bayesian inference to obtain the posterior (or output) PDFs (Cherrett et al., 2007). MCMC is then used to resample the posterior PDFs and produce probabilistic versions of the reservoir. The main inputs for the prior PDFs include the elastic property PDFs, seismic angle stacks with a defined signal-to-noise ratio (i.e., confidence), and corresponding representative wavelets, which are key to obtaining good-quality inversion results. Vertical and lateral trends for reservoir facies, in the form of map trends or variograms, may also be included. Vertical and lateral variograms for the elastic properties should be defined. We defined the vertical variogram models based on the well logs, and we defined the lateral variograms based on the deterministic inversion result. We fine-tuned both vertical and lateral variograms during inversion tests. In this case, we used the facies maps combined with the vertical and lateral variograms in a prior PDF per facies per layer to produce a complex posteriori PDF. The ability to incorporate various multiscale data with geostatistical inversion is key for the Brazilian presalt reservoirs. This is mainly due to the highly challenging depositional systems with heterogeneous facies distributions and complex petrophysical behavior. This geostatistical inversion approach helps better constrain the spatial behavior of the reservoir properties (Moyen and Doyen, 2009).

The MCMC and Bayesian inference-based models should be detailed enough to support a highly reliable interpretation and a statistically consistent reservoir characterization that honors in a robust manner all of the input data (Escobar et al., 2006). Models for elastic properties (e.g., P-impedance, density, and V_P/V_S ratio) undergo a detailed parameter optimization and are inverted in a stratigraphic grid, along with a jointly inverted facies model (Wang et al., 2016). The inversion task is parameterized and optimized in a two-step fashion, starting with an unconstrained case (no direct well input) to provide a less-biased result. Then, constrained inversion with well data directly included is used to fine-tune the parameters, which are already close to their optimum values after the first step (Tehrani et al., 2016).

Following the inversion, we perform quantitative interpretation by analyzing the statistical distributions of the inverted

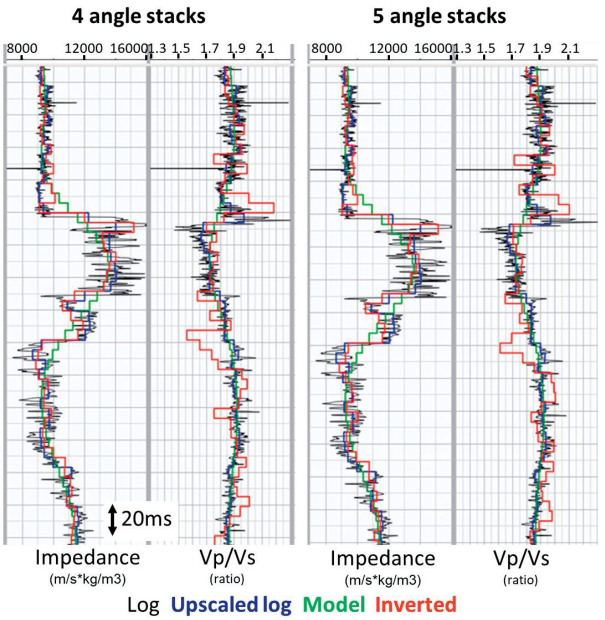

Figure 4. Elastic inversion test before and after angle stack optimization at one of the well locations that is representative of the whole study. It can be seen that the inverted impedance honors the well logs. It also shows how challenging it is to recover the V_P/V_S ratio for some parts.

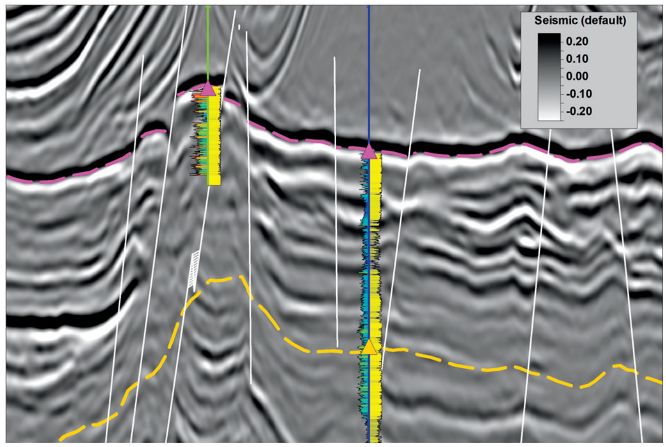

Figure 6. Seismic section prestack depth migration reflectivity volume with well tops (triangles) showing top and base of the interval of interest, and horizons corresponding to the top and base of the reservoir interval. Effective porosity and gamma-ray logs are shown to the left and right of the well trajectories, respectively. The well logs are shown for both wells in their original sampling rate (scale) to enable comparison between higher gamma-ray and porosity contrasts that are comparable with the main reflection contrasts in the seismic section.

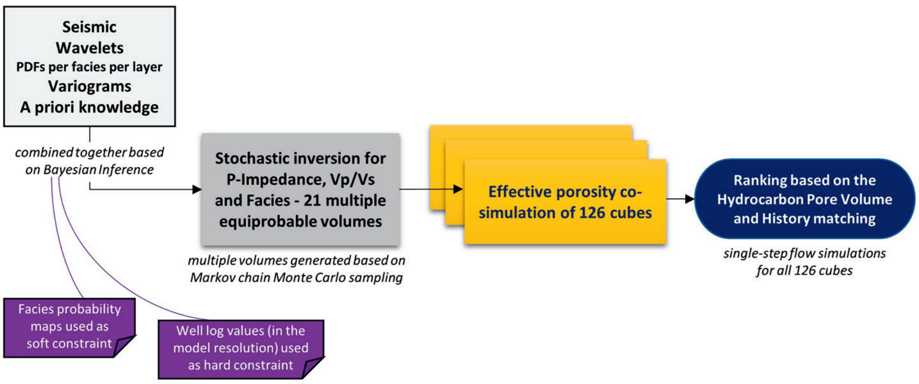

Figure 5. Simplified workflow that shows the main blocks of interaction and steps that enabled the closed-loop reservoir characterization and full static and dynamic integration in the streamlined production history matching. The image is based on proprietary expertise and interpretation from different works (Tehrani et al., 2016; Wang et al., 2016; Pendrel and Schouten, 2020).

properties that match between the original well logs and the inversion results at the well locations. Seismic residuals provide interpreters with a good quality-check index. Depending on the purposes and specific objectives of each project, time-sensitive approaches and quality controls may be followed to optimize time management.

This method is particularly useful for capturing the geologic heterogeneities at a fine-scale resolution for the type of projects where seismic-driven methods do not provide sufficiently reliable results (Kneller et al., 2019). An integrated approach makes it possible to combine the use of additional information with the seismic data. Ultimately, interpreters will be better equipped for improved decision making, which has a direct and positive impact on the characterization of the reservoir under investigation.

Generation and use of geologic trends

According to the conceptual geologic model, we can summarize and simplify the idea behind reservoir genesis and underlying processes by assuming that lake paleobathymetry or paleorelief is the key control on both deposition (carbonate buildup, reworking, and deposition) and early diagenetic processes. This suggests that paleobathymetric maps can be a tool for understanding 2D reservoir facies distribution and properties.

As seen in Figure 6, horizon interpretation was available for the top and base of the reservoir. Also, some internal reflectors were interpreted, and this helped split the package into several stratigraphic units. To gain an approximate idea of reservoir layer unit thicknesses, we used an approach linked to bathymetry that involves flattening the top of any given layer and mapping its base to yield an approximate qualitative map of the lake's bathymetry at the time of deposition. By sequentially discounting gross thickness maps from seismic interpretation tied to wells, we can produce such bathymetry measurements for all stratigraphic units.

In Figure 7, we can see one such map that gives a flavor of the location and extension of the different depth regimes that can be tied to the different facies sets. The overlaid facies proportions from wells for the same stratigraphic unit support these observations. Qualitative structural analysis based on the bathymetry maps and the conceptual sedimentary model represents similar concepts and shapes, confirming one another.

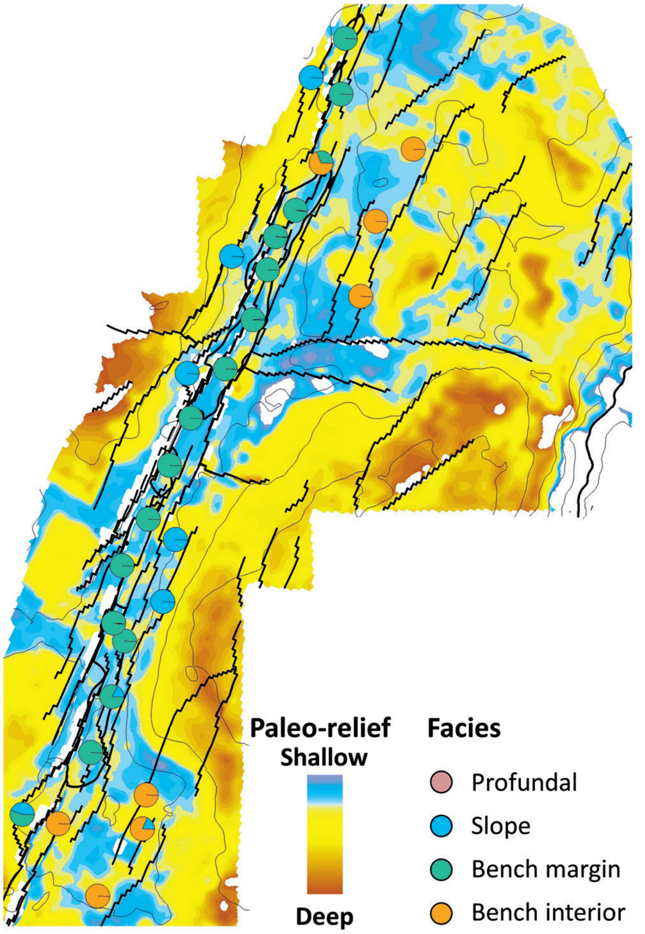

Figure 7. Paleorelief map overlaid with facies proportions at well locations for one of the stratigraphic units. Light blue represents slope facies. Green represents bench margin or crest facies. Orange represents bench interior or terrace facies. The facies proportions circular plots from wells are referred to the stratigraphic unit depicted so a comparison can be made between well and seismic scale in terms of paleolevel of the environment.

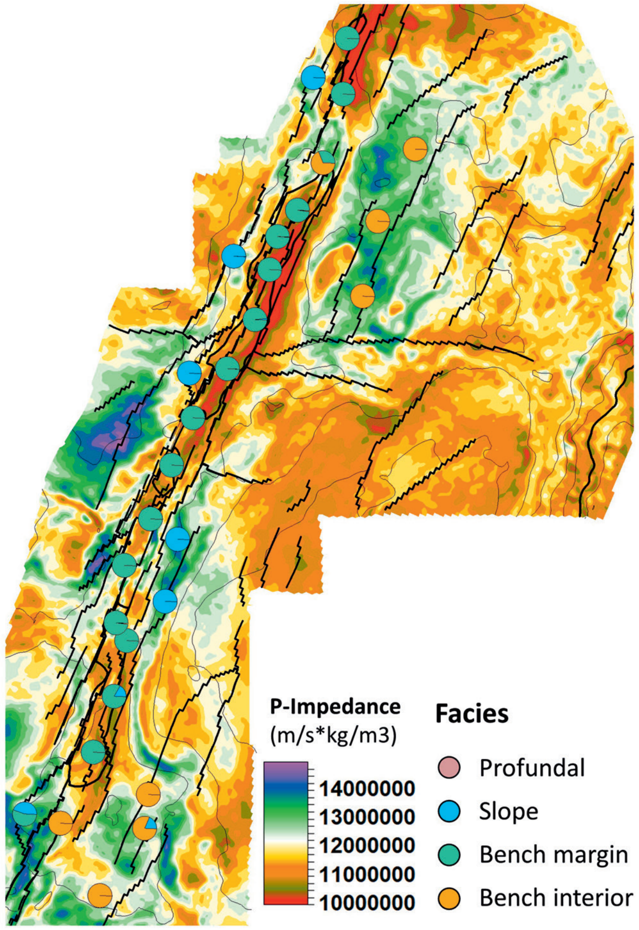

Figure 8. Average P-impedance map from deterministic inversion overlaid with facies proportions at well locations for one of the stratigraphic units. Light blue represents slope facies. Green represents bench margin or crest facies. Orange represents bench interior or terrace facies. The facies proportions circular plots from wells are referred to the stratigraphic unit depicted so a comparison can be made between well and seismic scale in terms of mean P-impedance response.

Looking at the P-impedance map for the same layer (see Figure 8) from the initial deterministic inversion, we can detect similar trends to the ones shown in the paleobathymetry displays but with some distinct details and caveats. The V_P/V_S ratio values obtained from the deterministic elastic inversion did not demonstrate the required quality and were dismissed from most of the analysis. However, the P-impedance volume demonstrated a good match with well logs and was used to predict the effective porosity for all three reservoir facies.

By comparing these P-impedance maps and the paleorelief result, we can draw some conclusions:

1) Paleorelief can be used as a substitute for V_P/V_S ratio and guide the

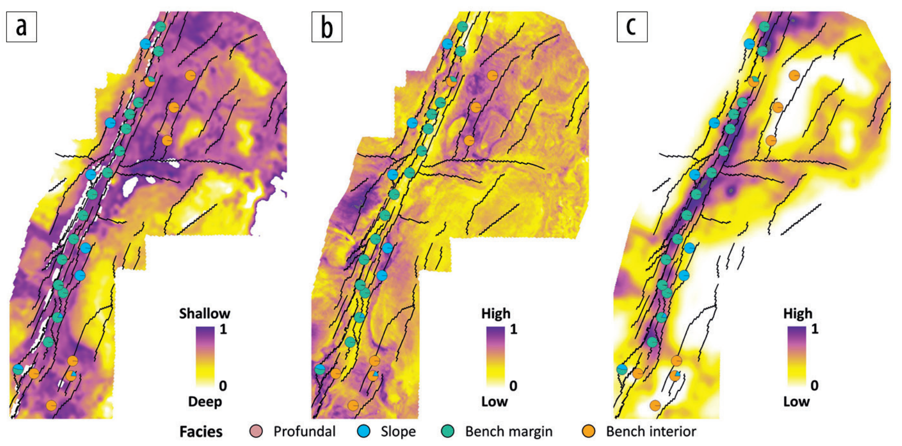

Figure 9. Normalized maps depicting the (a) paleorelief, (b) P-impedance, and (c) bench margin probability. They are overlaid with facies proportions at well locations for one of the stratigraphic units. Light blue represents slope facies. Green represents bench margin or crest facies. Orange represents bench interior or terrace facies. A good match is observed between the predicted bench margin probability and the occurrence of the facies at the different well locations, shown by the facies proportions circular plots.

mapping of the profundal facies. Figure 9a illustrates how the three reservoir facies coincide with high paleorelief values (purple). Lower values (yellow) are interpreted as nonreservoir profundal facies. This distinction is not possible based on P-impedance, as shown in Figure 9b, with similarly low values observed in the central part of the structure (where wells have reached the best-quality reservoir) and in the profundal facies.

2) P-impedance can help distinguish terrace facies from bench interior and slope facies. Figure 9b illustrates how high values coincide with the location of wells with predominantly terrace facies. This distinction is not possible based on the paleorelief map, as indicated in the previous point.

These observations were key to defining a robust workflow that combines complementary structural and amplitude information (both coming from seismic data) to estimate facies and properties distribution.

Based on the normalized impedance and normalized paleorelief maps, it is possible to generate facies probability maps (Figure 9c) that capture lateral variations representative of the conceptual geologic model. The result was fine-tuned by smoothing out minor noisy features. These maps were input into the geostatistical inversion workflow as a constraint.

Integration and ranking of inversion results in 3D modeling

The main priority once seismic inversion has been performed is to utilize the elastic properties volumes (i.e., P-impedance) in the reservoir modeling workflow. The idea is to unlock all of the potential from the seismic data in an unbiased way.

A total of 21 different inversion realizations were created, all equally compliant with well and seismic data. From each realization, six effective porosity cosimulated volumes were obtained for the reservoir facies. This set of realizations is assumed to be representative of the uncertainty associated with the reservoir properties. In Figure 10, even the mean P-impedance volume from the 21 realizations shows a significant uplift over the deterministic result. Grid-based stochastic inversion also helps integrate the results directly at modeling scale.

For this project, the final workflow used seismic inversion in two ways. In the first way, a 3D profundal facies probability volume was incorporated into the facies modeling as a 3D trend and is the result of the 21 joint facies estimations during inversion. In the second way, cosimulated porosity cubes were included as a secondary property for collocated cokriging of the porosity logs in 3D.

The vast number of realizations and porosity cosimulations (126 cubes) (see Figure 11 for an example) were ranked by seismic hydrocarbon pore volume (HCPV). However, because the range of HCPV is small, the ranking is not very meaningful. This can be related to the prior constraints being set strong. Once seismic inversion is constrained to wells and the location of the oil-water contact is set, the overall HCPV range becomes even smaller with a more constrained distribution.

Therefore, an alternative approach was investigated. In the static model, permeability was conditioned to porosity by facies because variations between cosimulated porosity realizations are impactful in terms of connectivity and history-matching

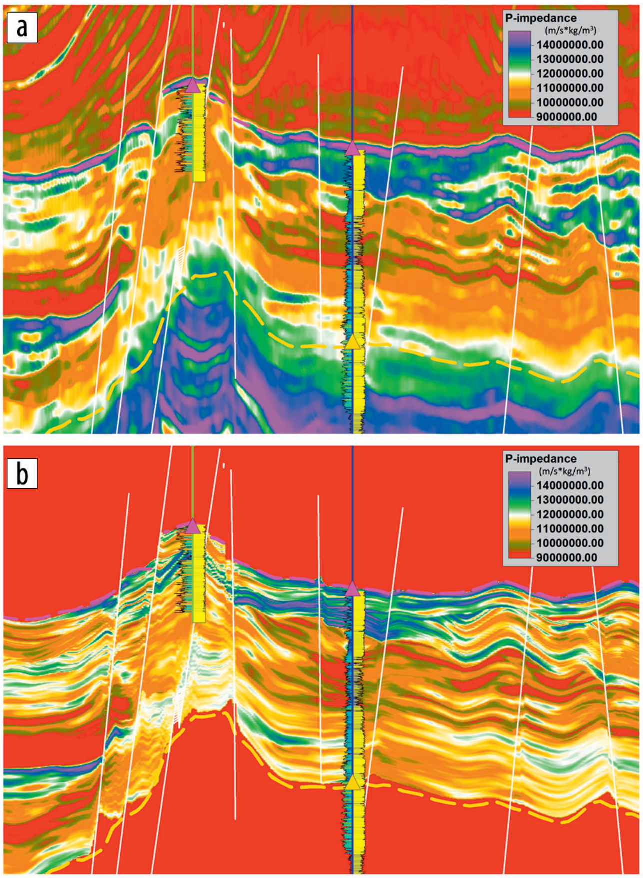

Figure 10. Comparison between (a) deterministic P-impedance result and (b) mean P-impedance from 21 realizations of the stochastic inversion. It is possible to see improvement in the resolution from the deterministic to the stochastic result. Also, the well logs (effective porosity and gamma ray at original sampling scale) enable the understanding and visual assessment of their variation in comparison with the main seismic-scale impedance contrasts.

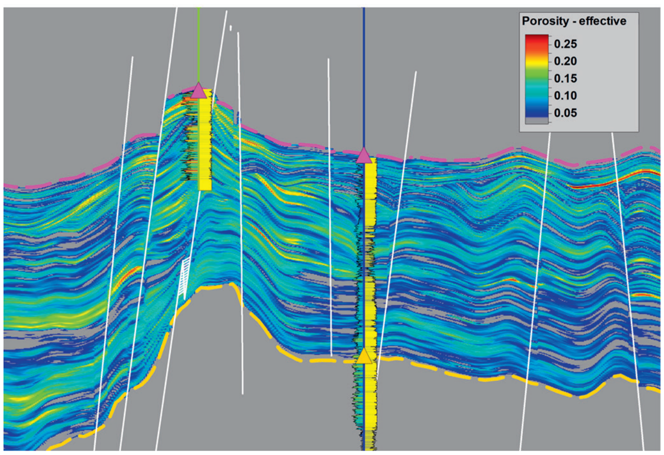

Figure 11. This section shows the most likely realization of effective porosity using HCPV ranking, which represents the input to the streamlined history matching. As in previous figures, the well logs (both effective porosity and gamma ray at original sampling scale) enable the understanding and visual assessment of their variation in comparison with the main seismic-scale effective porosity contrasts.

results. In order to rank the porosity results, single-step flow simulations for all 126 cubes were performed under a fixed reservoir modeling schema. In this way, the cosimulated porosity realizations can be ranked according to connectivity metrics rather than volume. The connectivity metrics used in this study are "breakthrough time" and "cumulative injected fluid production." These metrics can be used to understand the connectivity between the injectors and producers in the static model. It can be considered as a static step in assisted history matching.

By including all of the subsurface uncertainty in a single workflow and utilizing the inversion results as explained, the process of matching historical data was expedited. In fact, in the past, these types of reservoirs have proven to be extremely difficult to history match, and this proposed inversion and modeling workflow was key to improving the result substantially. Figure 12 illustrates one such realization where we can see a good match of oil and gas production at field level that also matches fluids and pressure at well scale. This kind of realization, considering that it involved minor (if any) manual modifications, underlines the efficacy of the workflow and gives confidence in the predictive capacity of the model for production forecasting.

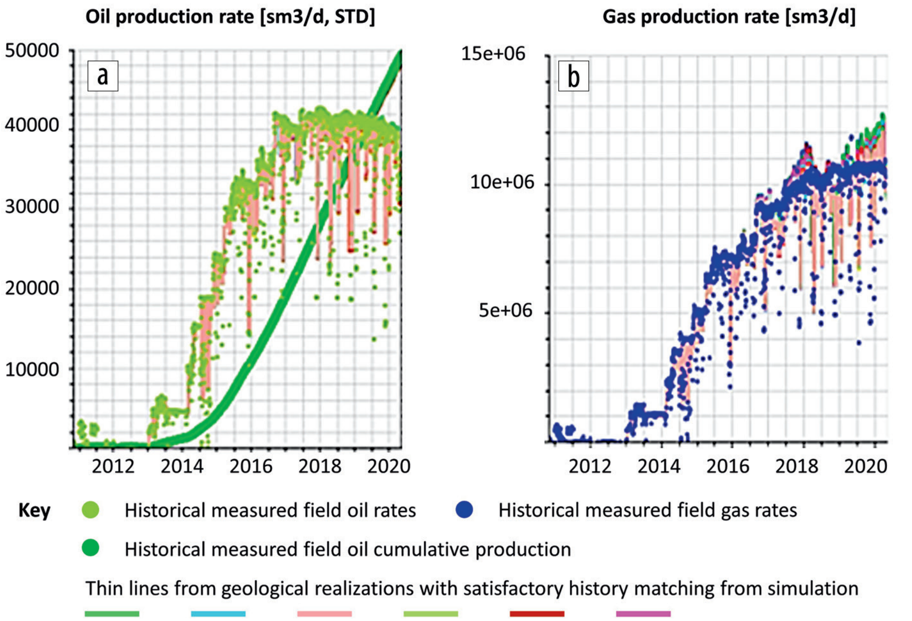

Figure 12. These two plots show the assisted history matching of oil and gas production. Both (a) oil and (b) gas production show the relationship between the history data and the geologic realizations, along with how this may be key to further improving the dynamic characterization of reservoirs.

Conclusions

A good understanding of sedimentological and diagenetic models is key to designing an interpretation and reservoir characterization workflow that is better suited for complex carbonate fields such as the ones found offshore Brazil. In addition, qualitative analysis based on bathymetry maps proved to be a powerful tool to help extrapolate a 1D conceptual well-based geologic model to the entire area of study in terms of facies distribution.

Feasibility analysis prior to seismic inversion and the integration of background geologic knowledge can improve inversion results used in reservoir modeling. In this case, deterministic inversion and paleorelief maps were used as constraints. As a result, geostatistical inversion made it possible to extract detailed information from the seismic data for reservoir characterization purposes. The results provide valuable insight into reservoir properties and their associated uncertainty.

Volumetric property ranking of geostatistical inversion results struggled to be informative in this mature field, despite ample well control and a good understanding of the petrophysical model. Instead, ranking according to flow connectivity metrics based on reservoir simulation was more valuable and positively impacted the turnaround time to achieve a successful production history matching. In this way, a fully integrated approach to geologic and seismic characterization translated into an effective and meaningful reservoir modeling workflow. The workflow helped rapidly produce a geologically sound history-matched reservoir model that heightened confidence in forecast estimations. TLE

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Data and materials availability

Data associated with this research are confidential and cannot be released.

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