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Evaluating the Impact of Processing Variants on 4D Seismic Inversion and Interpretation: Case study in the Brazilian Pre-salt

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Abstract Summary

Time-lapse seismic plays a vital role in reservoir surveillance, as it detects temporal variations associated with dynamic reservoir changes. However, interpreting such data is challenging in the complex carbonate reservoirs of the Brazilian pre-salt, where 4D signals are small and comparable to the 4D noise present in the data. This study evaluates how alternative seismic processing techniques, deployed to try to address the data quality issues, influence the results of 4D seismic inversion and therefore the interpretation of the main 4D signals. We applied the same inversion methodology to a 4D dataset processed using two distinct workflows. By comparing the two inversions and the independent interpretation of 4D signals, we assess the uncertainty implicit in conclusions drawn about reservoir dynamics. The processing workflows studied here differ mostly in the imaging algorithm. More radical differences, involving earlier steps in the workflow, may generate additional uncertainties, as would the type of 4D inversion methodology used.

Introduction

Time-lapse (4D) seismic is a key tool for reservoir monitoring, however, the interpretation of 4D seismic signals remains a challenge, particularly in carbonate reservoirs such as those in the Brazilian pre-salt, where impedance variations often approach the detection limits of seismic data (Cruz et al., 2021). Seismic inversion plays a crucial role in addressing these challenges by transforming amplitude data into impedance models that correlate more directly with rock properties rather than reflection interfaces (Maleki et al., 2017). This method enhances vertical resolution and interpretability, improving reservoir characterization even in challenging datasets.

However, key uncertainties remain. Given the sensitivity of inversion results to seismic data quality, can variations in seismic processing workflows significantly impact the reliability of 4D signal interpretation? In a context where 4D signal magnitudes are near the detection threshold, does optimizing seismic processing techniques become essential to ensure robust and accurate interpretations? Furthermore, are 3D inversion algorithms—using independent inversion rounds for baseline and monitor surveys—capable of delivering consistent and reliable 4D results in such scenarios? To address these important questions, this study evaluates how different seismic processing workflows, particularly in the imaging stage, influence 4D seismic inversion outcomes and, consequently, the interpretation of dynamic reservoir changes. The analysis is conducted in the Tupi pilot field, Santos Basin, Brazil, using highly repeatable OBN (Ocean Bottom Node) seismic data acquired in 2015 (baseline) and 2017 (Monitor-1). Identical inversions methods were applied to two versions of the seismic dataset (Workflow 1 and Workflow 2), processed using distinct approaches.

Study area

The Tupi field is located in the highly productive Santos Basin, in the Brazilian eastern margin. The main reservoir interval in Tupi comprises the Aptian lacustrine deposits from the Barra Velha Formation. This Formation is composed primarily of carbonate rocks characterized by spherulites and shrub-like calcite grains intricately interbedded with mud-graded laminated carbonates and magnesian clay minerals (Gomes et al., 2020). The Barra Velha Formation consists of three distinct production intervals, from top to base: BVE100, BVE200, and BVE300. BVE100 and BVE300 typically exhibit macroporosity and reservoir properties, while BVE200 is predominantly microporous and non-reservoir. Since production is largely concentrated in the upper meters of the formation, this study focuses on the upper BVE100 interval, where most of the production activity and 4D signals are detected.

Method

The seismic data employed in this study consists of one pair of 3D volumes acquired in 2015 (Baseline - Bs) and 2017 (Monitor-1 – M1) using Ocean Bottom Nodes (OBN), featuring a shot point carpet of 345 km2 and node area covering 111 km² within the Tupi Field. Two 4D seismic processing workflows were applied to the (Bs, M1) pair, which differ essentially only in the imaging algorithm: Workflow 1 (W1) used RTM, while Workflow 2 (W2) used Kirchhoff migration. As Kirchhoff migration typically preserves a broader frequency bandwidth, especially in the higher frequency range, it is often associated with better vertical resolution—a characteristic that can be particularly relevant in reservoir-scale seismic interpretation. In addition to seismic data, this study also incorporates information from 18 wells located within the OBN node area.

We employed the constrained sparse-spike inversion (CSSI) (Geosoftware, 2022), which is a deterministic method based on a trace-based algorithm. We applied this inversion, independently, to the Bs and M1 datasets, and computed 4D impedance changes by direct subtraction of the inverted acoustic impedances. The 3D inversions comprise four key steps: (1) Well-seismic tie, (2) wavelet estimation, (3) low-frequency modelling and (4) inversion parametrization. The inversion procedures were essentially identical for W1 and W2. This type of 4D inversion is quick and simple, although it may be overly sensitive to 4D noise and processing uncertainties.

Results

Quality control steps, including NRMS (normalized root mean square) analysis, were performed prior to inversion. Both workflows showed most values within the 0–2% range, indicating good repeatability. A noise analysis revealed similar statistical distributions between datasets, although with notable differences in spatial distribution. With these initial evaluations confirming the datasets quality, the inversion process was conducted. A comparison of the inversion residuals was performed to evaluate the fit between the seismic data and the inversion outputs, revealing significant differences in their statistical and spatial distribution. The mean residual at the top of BVE100 in the W1 seismic map is nearly six times larger than that of W2. Indicating that W1 had a weaker fit to the real data in comparison to W2.

The inversion results reveal some differences between the delta impedance maps generated from the W1 and W2 processing variants (Figure 1). To improve the maps legibility the well names were replaced by acronyms representing the well type: P for producers, IW for water injectors, WAG for water-alternating-gas injectors and IG for gas disposal wells. The acronym W was employed for wells that had no production/injection activity and the acronym PI was used for the pioneer well. While both workflows capture key production-related anomalies, the spatial distribution and intensity of the signals differ (Figure 1A and B). Most of the 4D anomalies are stronger and better defined on the W2 map, particularly around key injection wells, where the main anomalies were outlined using the acronym H to denote hardening signals and S for softening signals: WAG1 (anomaly H1), WAG2 (anomaly S1), IW1 and IW2 (anomaly H2). The most significant differences between the maps occurs around the producer wells P3 and P5 (anomaly H3), as well as around the water injector IW5 (anomaly H6).

All interpreted 4D signals were cross-checked with well history data to validate their consistency and to assess which of the tested workflows provided a more accurate response based on production information. While the examples below illustrate specific cases, this validation procedure was systematically applied to all identified anomalies. For instance, well history data indicates that well WAG1 injected water between the baseline and Monitor 1 acquisitions (Figure 2A), resulting in the anomaly referred to as H1. Production data confirm that well P2 experienced a water breakthrough during this same period (Figure 2B). Consequently, the H1 anomaly appears more clearly towards well P2 in the W2 seismic data than in W1, suggesting that W2 more accurately captures the associated fluid movement.

Another case involves wells IW1 and IW2, which also injected water between the baseline and Monitor 1 (Figure 2A), giving rise to the H2 anomaly. Production data shows that well P4 registered a water breakthrough during this interval, whereas well P6 experienced breakthrough shortly after the M1 acquisition (Figure 2B). In the W2 seismic volume, the H2 anomaly appears elongated toward well P6. In contrast, the W1 data shows the anomaly extending in a direction opposite to well P6. This is considered unlikely, as the pressure gradient generated by a producing well would generally draw injected water toward it. Therefore, the anomaly observed in the W2 data aligns better with the expected fluid dynamics.

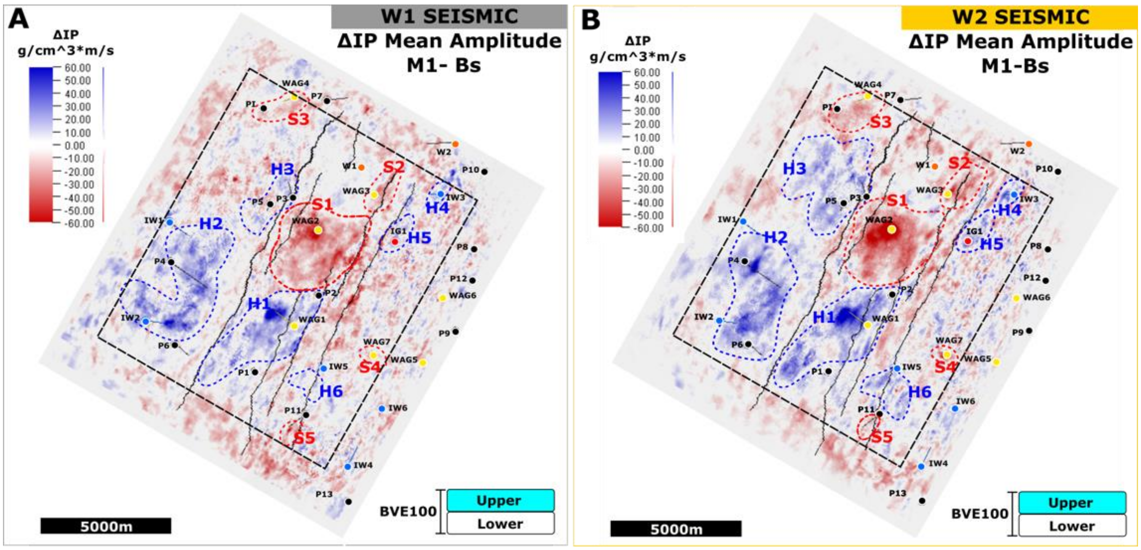

Figure 1: (A) Impedance difference maps of the Upper BVE100 interval. (A) Map derived from the W1 processing workflow (RTM). (B) Map derived from the W2 processing workflow (Kirchhoff). Main 4D anomaly areas (e.g., H1, S1, H2) have many similarities but also important differences between W1 and W2. The latter shows stronger and better defined 4D anomalies.

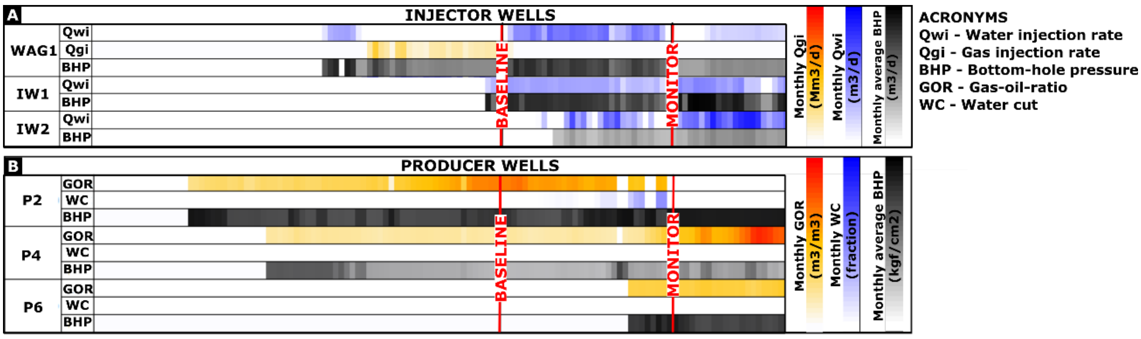

Figure 2: Well history charts for wells used as example. (A) Well history data for injector wells. (B) Well history data for producer wells.

Analysis of anomaly overlaps in the W1 and W2 maps provide further insights into signal consistency and confidence levels. Regions where anomalies were present in both maps and were aligned with well history data were classified as “consistent and reliable” signals. Conversely, regions where signals appeared in only one of the maps, but remained spatially related to high-confidence anomalies, were classified as areas of potential 4D signal extension. These regions require further validation through additional data sources such as facies information, structural elements, or chemical tracer data.

Finally, regions where 4D signals do not correlate with well history data were classified as high-uncertainty areas. Regions surrounding wells P3 and P5 exhibit consistent signals across both maps, yet their lack of correlation with production history suggests potential issues with seismic inversion artifacts. Uncertain signals also occur around the wells IW5 (present only in W2 map) and around P11(present in both maps). These signals are in a thin reservoir area and may reflect processing limitations.

Conclusions

Simple 4D seismic inversions performed on the W1 and W2 datasets generated ΔIP maps with localized anomalies showing that this approach may be an option for the challenging pre-salt area. The inversion residuals and delta impedance noise are lower in the W2 dataset, suggesting that Kirchhoff imaging may be preferred for 4D seismic inversion, resulting in better delineation of 4D signals due to the increased seismic resolution in W2. This improved performance is consistent with the broader frequency content typically associated with Kirchhoff migration, which can enhance seismic resolution and thereby improve the delineation of 4D signals

The comparison between the anomalies and historical well data revealed that several regions displayed more coherent and reliable signals in the map derived from the W2 seismic dataset, providing a closer match to the expected fluid flow behavior. This highlights the enhanced interpretability and consistency of the W2-derived results in key reservoir areas.

By overlapping the 4D signals obtained from the W1 and W2 maps and validating them against well history data, we identified areas of high and low uncertainty in the 4D interpretation. These findings can provide valuable insights during the data assimilation stage and serve as a guide for constructing more reliable fluid flow simulation models.

Acknowledgments

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