Submission code: 0DVQ8WR7GX

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Can Seismic Data Suggest Fluid Relative Density?

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Abstract

The relationship between seismic data and subsurface fluid properties has gained increasing relevance in hydrocarbon exploration. Fluid relative density—whether oil, gas, or water—affects acoustic behavior due to impedance contrasts (Santos et al., 2025). Advanced seismic imaging and physical modeling contribute to more accurate subsurface fluid flow predictions (Sylta, 2010). This integrative framework enhances understanding of fluid behavior in geological formations and expands the role of seismic data.

This work explores how seismic interpretation integrated with structural restoration and migration modeling can indirectly suggest fluid density variations. Building on Øyvind Sylta's studies (Sylta et al., 2000; Sylta, 2003), we examine how structural geometry and flow patterns influence fluid migration and accumulation. A case study from the Búzios Field (Santos Basin) illustrates the effectiveness of the workflow in identifying migration pathways and fluid accumulation zones.

Although seismic data do not directly measure density, their integration with geohistorical modeling and probabilistic simulations enables new approaches to reservoir characterization (Sylta et al., 2018; Santos et al., 2019). We advocate for interdisciplinary collaboration to refine these methods, fostering innovation in seismic interpretation and reservoir analysis across diverse geological contexts.

Introduction

Understanding fluid behavior through seismic data remains a key challenge in geophysics, leading to the question: Can seismic data suggest fluid relative density? Øyvind Sylta's pioneering studies demonstrated that combining structural restoration with migration modeling reveals fluid pathways and accumulation zones driven by buoyancy (Sylta, 1991; Sylta et al., 2000; Sylta, 2003).

Building on this, our study integrates seismic imaging, structural modeling, and physical simulation to indirectly infer fluid density contrasts in reservoirs and migration routes. Although seismic data do not directly measure fluid properties, high-resolution interpretation—when coupled with basin and migration models—can reveal signatures related to density contrasts through flow behavior and trapping configurations (Santos et al., 2019; Santos et al., 2025). Recent work in the Búzios Field shows that pristine amplitudes from full PSDM or PSTM volumes may indicate migration routes and hydrocarbon retention zones, even in the absence of well data. Sylta's studies further emphasize that small-scale topographic variations, revealed by structural restoration, influence preferred migration paths due to fluid buoyancy. While parameters such as capillary pressure and permeability play a role, buoyancy remains the dominant migration force.

We argue that geometric seismic patterns—when interpreted via robust geohistorical and physical models—can offer indirect insights into fluid density. This approach depends on seismic data quality, structural interpretation, and a strong understanding of secondary migration processes.

Method and/or Theory

This study applies a methodology inspired by Sylta's integration of structural restoration, geohistorical modeling, and secondary migration simulation, supported by seismic interpretation around four workflow stages: (1) 3D Structural Restoration and Calibration with Seismic Data: The workflow begins with a 3D structural restoration of reservoirs and seals geometries to identify metric-scale topographic variations that influence fluid migration routes (Sylta, 1991; Sylta, 2003) - These reconstructions are calibrated using pre-stack migrated seismic data, establishing a detailed and robust geometric framework for further analysis (Santos et al., 2019). (2) Secondary Migration Simulation via Ray-Tracing: Ray-tracing algorithms are applied to simulate secondary fluid migration pathways. Buoyancy, governed primarily by fluid density contrasts, serves as the main driving force (Sylta et al., 2000). Additionally, permeability and capillary pressure effects are incorporated to model migration barriers and conduits within the system, providing a realistic representation of fluid flow (Sylta, 2003; Sylta, 2010). (3) Integration of Seismic Data for Structural and Fluid Analysis: Integrate seismic data to define geometry and to analyze fluid migration and accumulation patterns, inferring relative fluid density via acoustic impedance contrasts. Small-scale structural features, resolvable by seismic data, are evaluated for their influence on preferential flow (Sylta et al., 2018). Seismic volumes contribute not only structural context but also acoustic impedance contrasts, which serve as indirect indicators of fluid density and compressibility (Santos et al., 2025). These proxies enable qualitative and semi-quantitative interpretations, even without direct measurements. (4) To address uncertainties, the methodology integrates well logs, pressure tests, and petrophysical data with probabilistic and stochastic simulations (Sylta et al., 2018). This iterative approach allows to quantify and manage uncertainties and iteratively refine the model refinement as new data become available.

This study proposes a qualitative workflow to infer relative fluid density using seismic impedance data, structured as follows:

1. Identify Accumulation Zones: Locate areas of fluid accumulation and migration pathways in impedance volumes, focusing on geometries indicative of gravitational or lateral migration (Santos et al., 2025; Sylta et al., 2018).
2. Assess Flow Directions: Analyze structural control and vertical/lateral connectivity between layers to define preferential flow (Sylta, 2003; 2010).
3. Compare Recurrent Features: Examine recurring geometries (e.g., stacked lenses) for consistent fluid behavior (Sylta, 2010).
4. Interpret Accumulation Patterns: Correlate observed accumulations with expected fluid buoyancy behavior (water, oil, gas), considering pressure and saturation variations (Sylta et al., 2018).

This workflow is suitable for comparative studies in synthetic models or data-rich fields.

Results

The application of the methodology to the Búzios Field (Quintes and Santos, 2023; Santos et al., 2025) is shown in Figure 1, where a pseudo-elastic impedance volume reveals interpreted migration pathways and accumulation zones. The inline section and azimuthal dip depth slice suggest directional migration: warm tones indicate lower-density fluids; cool tones, water or seals.

The geometries align with Sylta's models (2000; 2003), where meter-scale topographic variations guide buoyancy-driven flow. Dip orientations and impedance groupings suggest anisotropies linked to fluid density and permeability. Observed plunging features and lateral alignments reflect migration shaped by structural and capillary controls. While qualitative, these results show that seismic impedance — being sensitive to elastic and saturation changes —, can suggest fluid type when integrated with structural and migration models (Santos et al., 2019; Sylta et al., 2018). These findings encourage the development of seismic templates and modeling strategies to improve fluid prediction and reduce exploration risks.

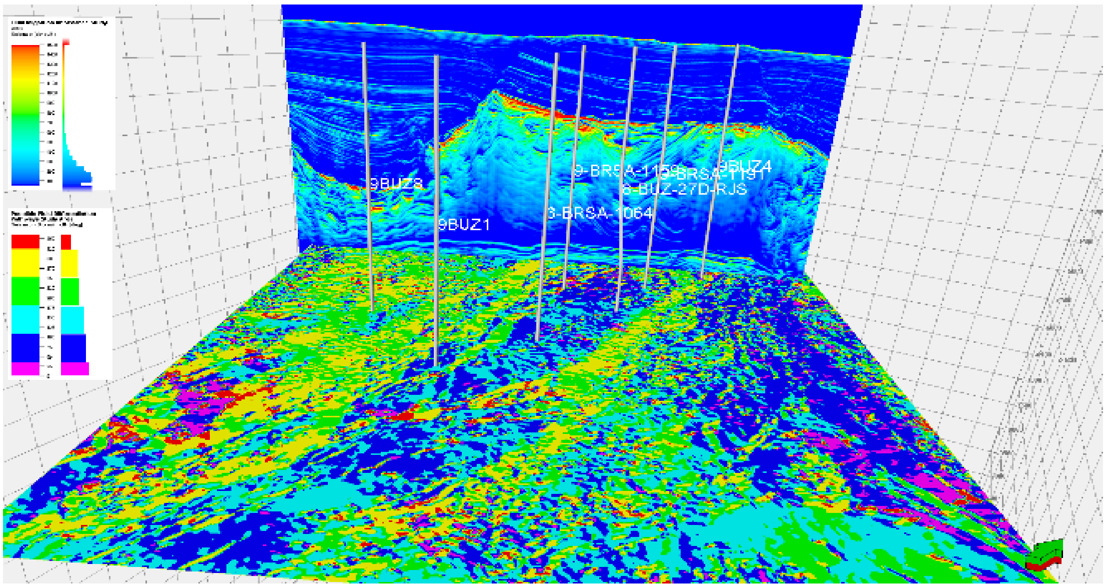

Figure 1: The back image illustrates a vertical In line of a pseudo-elastic seismic impedance volume, laterally composed with a depth slice of its derived azimuthal dipping in Búzios Field (EV=2x).

Conclusions

This study highlights the potential of integrating seismic imaging, structural modeling and physical simulation to improve indirect fluid density estimation in reservoirs and migration routes, providing new interpretive tools that can reduce exploration risks. We were able to examine how structural geometry and flow patterns influence fluid migration and accumulation. A case study from the Búzios illustrated the effectiveness of the workflow in identifying migration pathways and fluid accumulation zones.

The integration of seismic data with advanced structural modeling techniques, such as those developed by Øyvind Sylta pioneering studies, significantly enhances our understanding of fluid dynamics. The results suggest that seismic features interpreted as migration pathways and accumulation zones may, under certain conditions, contain indirect information about fluid relative density, particularly when analyzed within a robust structural and geohistorical framework (Sylta, 2003; Santos et al., 2025). This qualitative approach extends traditional seismic interpretation by linking geometric attributes to the physical-dynamic behavior of the reservoir system. Sylta demonstrated that structural geometry—obtained through restoration and basin modeling—is fundamental for comprehending the patterns of migration and accumulation of hydrocarbons (Sylta, 2000; Sylta, 2003; Sylta, 2010), with the density difference between fluids serving as the primary driving force behind these processes (Sylta et al., 2000).

We acknowledge the limitations imposed by seismic resolution, lithological ambiguity, and the subjectivity involved in the qualitative interpretation of patterns. In these cases, the inference of relative density should be treated as indicative and always contextualized with complementary geological and petrophysical data (Sylta et al., 2018; Santos et al., 2019). Rather than being limitations, these aspects represent opportunities for refinement, highlighting the value of interdisciplinary collaboration to refine these methods, fostering innovation in seismic interpretation and reservoir analysis across diverse geological contexts.

Future Work

Future research should focus on developing seismic indicators with greater sensitivity to fluid density and advancing multidisciplinary workflows to improve fluid characterization in exploration contexts. We believe this direction deserves further exploration with greater rigor and validation, especially through advances in machine-assisted interpretation and flow modeling integrated with seismic data. Thus, seismic data may indicate not only fluid location but also its nature. A natural progression is the application of quantitative seismic inversion methods to extract physical fluid properties with greater precision, complementing the qualitative workflow presented here. Furthermore, similar methodologies have proven valuable in CO_2 geological storage, where understanding fluid migration and density contrasts is essential to assess containment integrity and leakage risks (Sylta et al., 2000). Integrating seismic data with structural and migration models may support environmental monitoring and carbon capture and storage (CCS) initiatives, broadening their application beyond traditional hydrocarbon exploration.

Acknowledgments

This scientific publication was developed with the support of software and seismic data provided by SLB, which has been operating in Brazil since 1949. SLB is a global technology company committed to advancing technological innovations for industrial decarbonization. The donation of these resources aimed to promote scientific production in support of sustainability. We also wish to express our gratitude to Federal Fluminense University for facilitating these studies and to the Brazilian National Agency of Petroleum (ANP) for offering data from Brazilian basins.

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