


Hidden Potential: The Impact of Seismic Tuning on Gas Volumes Estimation: Case Study of a Tertiary Reservoir, Onshore Niger Delta

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Abstract

Seismic amplitude anomalies are widely used as direct hydrocarbon indicators (DHIs) to infer fluid contacts where well control is sparse, yet seismic tuning can bias amplitude-derived fluid contacts and volumetric estimates towards conservatism. We analyze the M1000 gas reservoir in the Bonn-Ario field (onshore Niger Delta) to quantify how tuning-driven effects produce an apparent seismic gas-water contact (GWC) that underestimates the true gas column. Using forward modelling, amplitude variation with angle (AVA) analysis and wedge models, we show that amplitude “shut-off” on the seismic corresponds to a tuning roll-off rather than the physical termination of reservoir gas; tuning effects produced a seismic-derived GWC that would reduce gas initially in-place (GIIP) by ~15% relative to a well log-constrained contact. Wedge modelling indicated that amplitude dimming becomes dominant below ~35 ft of gas column for the local wavelet and velocity. The seismic response effectively fails to detect a gas column thinner than ~35 ft. Analogous examples from the Niger Delta and other basins confirm that this mechanism is widespread. We demonstrate practical mitigation: routine forward-modelling, AVA calibration and wedge modelling to identify tuned intervals and avoid systematic under-booking of volumes. The study highlights that amplitude maps should be treated as $\lambda/4$ -contour (resolution) indicators, rather than fluid contact proxies, unless verified by wedge modelling, AVA analysis and well calibration. Emerging technologies such as broadband seismic acquisition, machine learning and multi-attribute analysis provide additional toolbox for mitigating tuning-related pay and volumetric mis-estimations.

Keywords

Bonn-Ario, Tuning, Frequency, Seismic, Wedge Modelling, Forward Modelling

1. Introduction

Accurate volumetric estimation is fundamental to exploration, appraisal, and development planning. Seismic amplitude anomalies are among the most persuasive indicators of hydrocarbons, often used to infer fluid contacts and guide drilling. In practice, geoscientists, in the absence of data on fluid contacts, may interpret and delineate amplitude terminations to identify gas-water or oil-water contacts for probable (2P) reserves volume estimates in a reservoir, in line with the Society of Petroleum Engineers (SPE) Petroleum Resources Management System (PRMS) guidelines [1]. Yet seismic is band-limited, and vertical resolution constraints mean that thin layers may not be accurately imaged. When pay thickness is below the tuning threshold, amplitudes no longer scale linearly with thickness. This produces premature amplitude shut-offs that can be misinterpreted as fluid contacts, with direct implications for in-place volumes. The issue is not simply academic. In regions where national reserves underpin government budgets and investment strategies, underestimating gas volumes can lead to conservative planning, reduced investor confidence, and missed development opportunities. For operators, misinterpreting amplitude behavior risk under-booking 2P reserves under the SPE PRMS guidelines [1], directly impacting business decisions.

Tuning-derived pay thickness misrepresentations are likely to be encountered more in gas reservoirs, where even low gas saturations can disproportionately reduce the impedance, producing very high seismic amplitude anomalies. Our case study, the M1000 reservoir in the Bonn-Ario field is a brownfield gas reservoir in a Tertiary clastic sequence, with a gross stratigraphic thickness of ~260 ft. The reservoir properties are excellent, typical of channel and shoreface deposits of estuarine origin, with an average porosity of 28% and multi-darcy permeabilities. The field is an elongated East-West trending faulted roll-over anticline (**Figure 1(A)**). The M1000 reservoir lies at ~1.5 - 1.7 seconds two-way travel time (TWT) (5540 - 6000 ft subsea depth (SS TVD)). The reservoir is penetrated by 26 wells, mostly at the crest (center) and the western edge of the reservoir, clearly defining the Gas-Water Contact at 5811 ft subsea (SS) TVD (**Figure 1(B)**). The maximum gas column height (crest to GWC height) in the reservoir is ~320 ft.

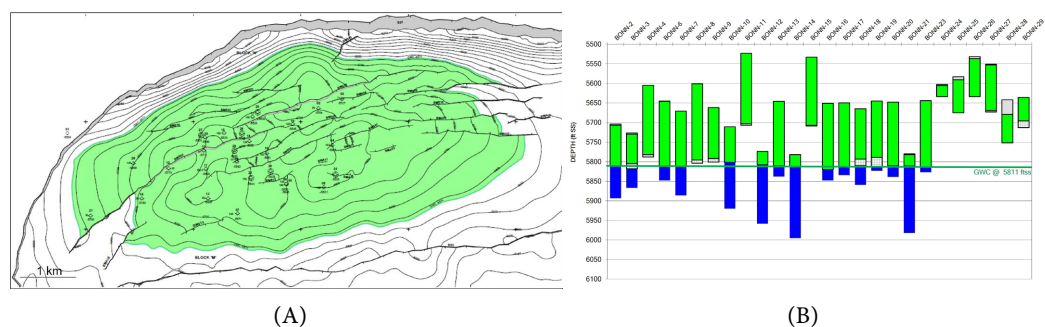


Figure 1. Top structure map and fluid fill for Bonn-Ario field M1000 reservoir (A) Bonn-Ario M1000 reservoir top (Depth) map (contour Interval = 50 ft). The field is a large East-West trending roll-over anticline. (B) Fluid Distribution Plot for the M1000 reservoir. The total gas column height is ~320 ft (98 m). There are 26 existing well penetrations in the reservoir.

The field is covered by conventional broadband 3D seismic data, acquired in 1994 and reprocessed into Pre-Stack Depth Migration (PSDM) seismic volume in 2014. Spectral analysis showed that the PSDM seismic data has a bandwidth of ~ 75 Hz with a dominant frequency at the interval of interest of ~ 45 Hz (**Figure 2(A)** and **Figure 2(B)**).

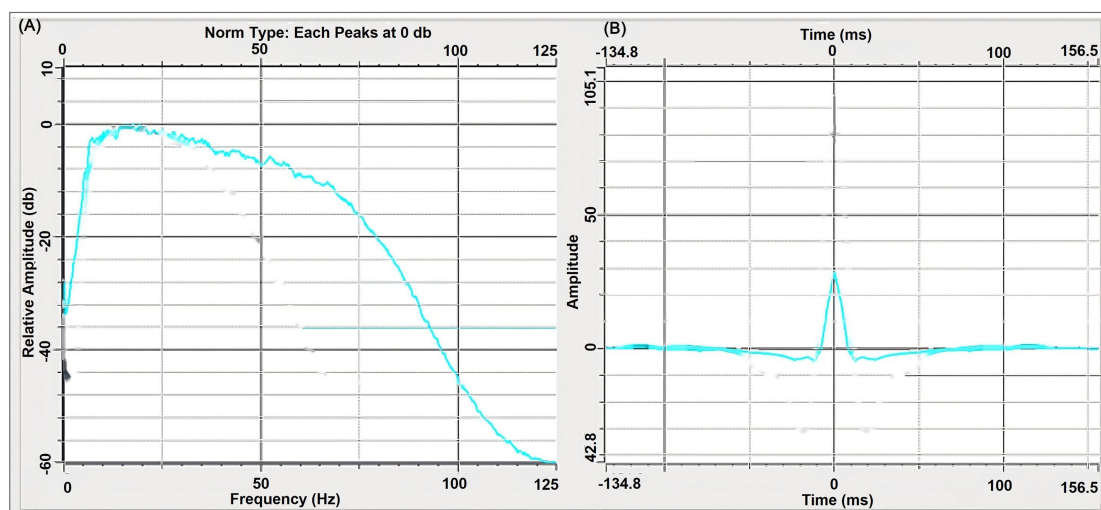


Figure 2. Seismic volume frequency spectrum and wavelet. (A) Frequency Spectrum of the Bonn-Ario field Pre-Stack Depth Migration (PSDM) 3D seismic volume. The bandwidth is $\sim 7 - 75$ Hz, with a dominant frequency of ~ 45 Hz at the M1000 reservoir level (~ 1.6 seconds). (B) Extracted Seismic wavelet at the M1000 reservoir level.

A Well-to-Seismic tie (**Figure 3**) performed on well Bonn-Ario-03 (BONN-3) confirmed the reservoir top to coincide with a strong, soft (blue seismic loop) impedance kick consistent with gas-filled sands encased in shales. The reservoir level is easily identifiable on the seismic volume by a seismic amplitude anomaly—a classical bright spot at ~ 1550 ms. A clear flat spot DHI hints at the GWC (**Figure 4**).

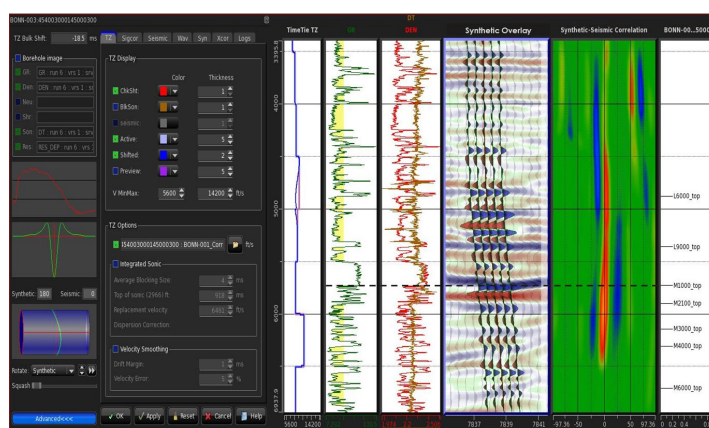


Figure 3. Well-to-Seismic tie for well Bonn-Ario-03. Good match of the synthetic seismogram and the seismic data along the well path confirms the reservoir top is a soft impedance kick (blue loop). Note that the synthetic wavelet has been phase-rotated 180 degrees (left-most panel) to match the seismic data (Reverse Polarity). A bulk shift of -18.5 ms was applied to the synthetic seismogram to achieve a good match with the seismic data.

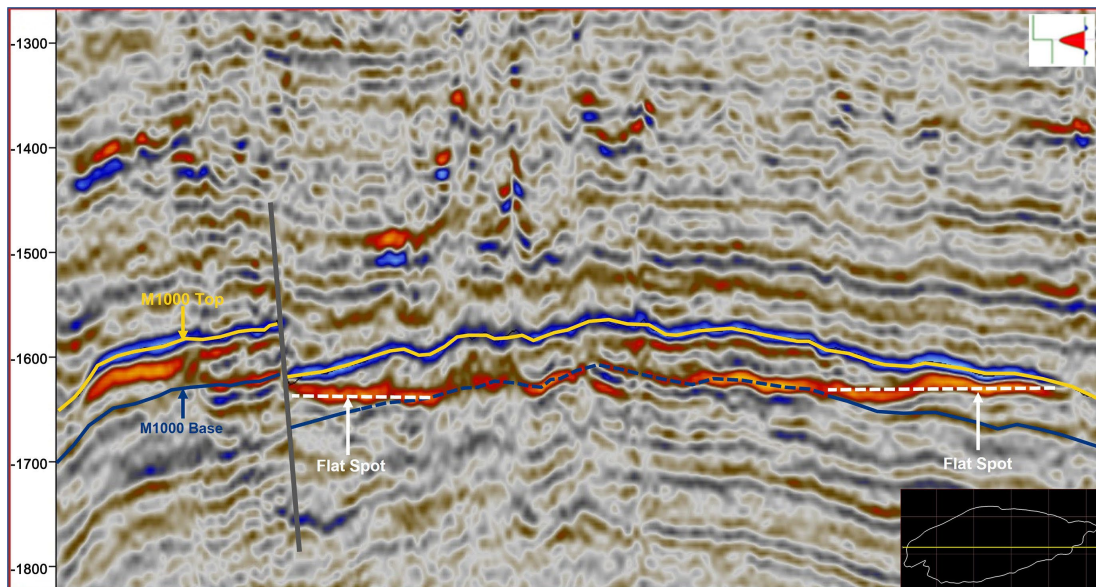


Figure 4. East-West seismic section across the Bonn Ario M1000 reservoir. Note the strong seismic reflection of the reservoir top and the prominent flat spot (GWC reflection) which gives confidence to hydrocarbon presence in the reservoir. The seismic data is zero phase, reverse polarity.

Seismic amplitude extractions on the reservoir top showed structure conformable bright amplitude signature (**Figure 5(A)**). A North-South seismic section shows the intersection of the flat spot with the top reservoir bright reflection (**Figure 5(B)**). The areal extent of the bright amplitude was mapped, defining the boundary of the gas accumulation. However, a couple of wells outside the originally mapped DHI amplitude outline encountered gas pay. In other words, the bright spot (amplitude) map suggested the gas reservoir ended at a certain boundary, but wells beyond that boundary still encountered > 20 ft of gas pay. This indicated that the seismic amplitude had “shut off” not because the gas physically ended, but because the gas layer became too thin or the contrast too subtle for the seismic vintage to detect.

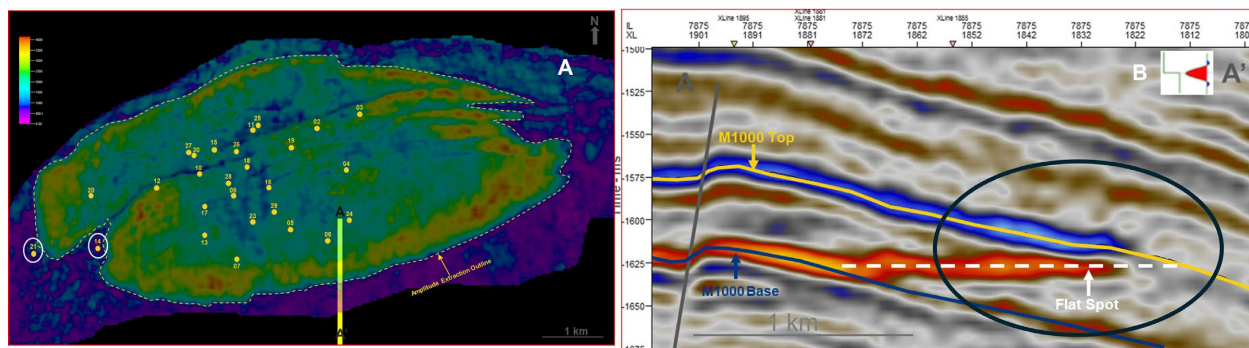


Figure 5. M1000 reservoir seismic amplitude expression. (A) Seismic amplitude extraction of the M1000 reservoir top. The amplitude expression is conformable to the reservoir structure, hinting at a hydrocarbon origin to its expression. Two wells - Bonn-Ario-14 (Bonn-14) and Bonn-Ario-21 (Bonn-21) (white circles to the West) outside of the amplitude expression encountered 29 ft and 21 ft of gas pay, respectively. (B) North - South seismic section across the M1000 reservoir zooming into the top reservoir amplitude expression and flat spot.

This study investigates the origin of this discrepancy between the seismic amplitude map and well data, articulates its implication for reservoir volumetric estimations in reservoirs where no fluid contacts have been logged (drilled) by the wells and the fluid contacts defined by seismic amplitude mapping. The implications for reservoir in-place volume estimations are examined in line with the SPE PRMS.

1.1. Theoretical Background

The foundations for wavelet analysis highlight how frequency and phase control seismic response [2]. When thin-bed effect was first articulated [3], it showed that beds thinner than one-quarter of the dominant wavelength (λ) produce composite reflections. The wedge model became the standard framework for analyzing tuning effects. This was further formalized by examining various resolution criteria [4], concluding that the ultimate limit of resolution is governed by the bandwidth and dominant frequency of the seismic wavelet. In essence, higher frequency (broader bandwidth) yields finer resolution in direct proportion.

Subsequent research has focused on improving resolution. Spectral decomposition was introduced [5]. The applications of spectral attributes were expanded to stratigraphic interpretations [6]. AVA and inversion frameworks sought to extract fluid and lithology information [7]-[9], though these remain subject to tuning limits. More recent work emphasizes bandwidth expansion via broadband seismic, Q-compensation, and Full Waveform Inversion (FWI) to sharpen imaging. Still, tuning remains a persistent source of volumetric uncertainty.

Seismic Tuning, Thickness Resolution and Wedge Models

When a bed's thickness is less than approximately $\lambda/8$ (one-eighth of the dominant wavelength), the separate reflections from the top and bottom cannot be distinguished [3]. They form a single composite reflection whose amplitude is roughly proportional to the bed's thickness. The bed is effectively "tuned" – below this limit, thinner beds yield progressively weaker composite amplitudes, approaching zero amplitude as thickness tends toward zero. At exactly zero thickness, the reflections from the interface would perfectly overlap in opposite polarity and cancel out. For a zero-phase wavelet that in the ideal case of equal but opposite reflection coefficients, the maximum amplitude occurs when bed thickness is $\lambda/4$ (quarter wavelength). $\lambda/4$ is therefore often referred to as the tuning thickness, corresponding to the peak constructive interference of a thin bed's reflections. Beyond $\lambda/4$, further increases in thickness cause the top and bottom reflections to separate in time such that their interference diminishes.

Quantitatively, the relationship between amplitude and thickness for a thin-bed reflection is often visualized by a wedge model and tuning curve. **Figure 6** shows a tuning curve derived from the wedge model (**Figure 6(A)**) (for a simplified case of a gas sand layer encased in shales) [10]. **Figure 6(B)** shows the synthetic seismic section when the wedge is illuminated by a zero-phase Ormsby wavelet. The thickness estimates and amplitude tuning curves measured from the seismic response are

shown as **Figure 6(C)** and **Figure 6(D)**, respectively. Labels are added to these curves to indicate the thickness of the wedge in units of the dominant wavelength (λ).

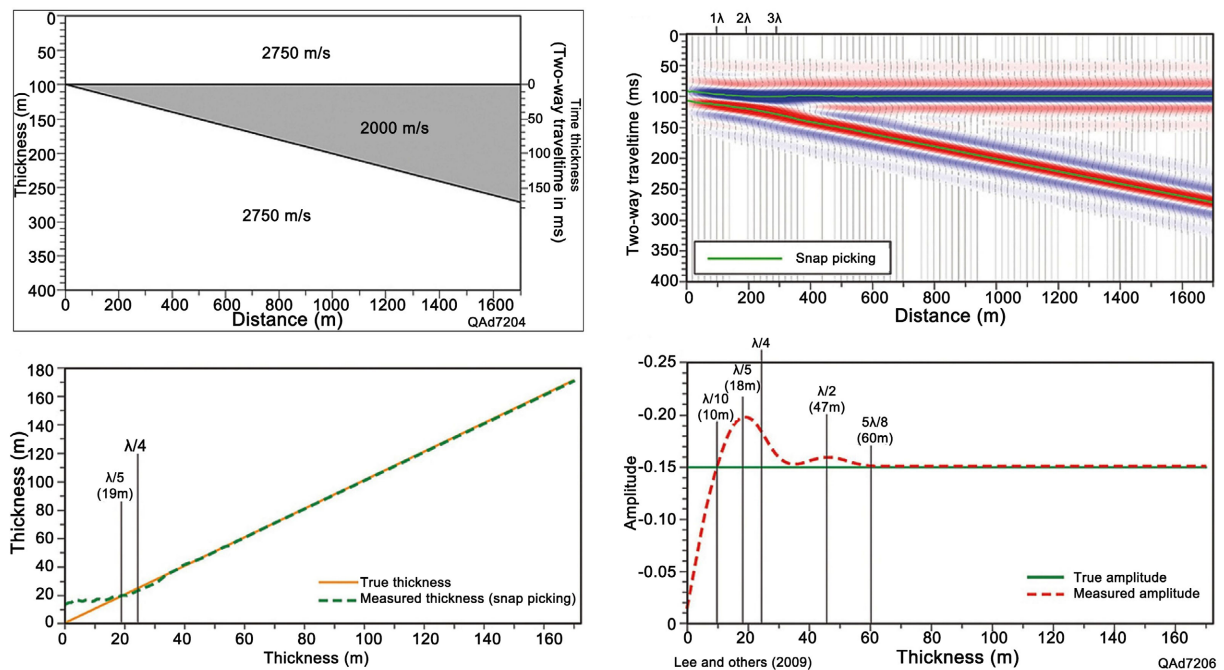


Figure 6. Model tuning effect for a low-impedance wedge that mimics a gas-sand layer embedded in shale [10]. (A) Acoustic model of a low impedance wedge (mimicking a gas sand encased in shales). (B) Synthetic seismic section when the wedge model is illuminated with the zero-phase Ormsby wavelet. Green horizons are the top and base of the wedge picked by snapping to the central trough and central peak, respectively. The lateral dimension of the wedge in units of the dominant wavelength (λ) of the Ormsby wavelet is marked along the top of the section. (C) The thickness estimate measured from the seismic response compared to the true thickness. (D) The seismic amplitudes (Tuning curve for bed thickness) measured from the seismic response.

The vertical axis (**Figure 6(D)**) is the peak amplitude of the composite reflection (normalized to the amplitude of a single interface reflection), and the horizontal axis is the wedge thickness expressed in meters. At zero thickness, the amplitude is zero (since the top and base reflections cancel exactly). As thickness increases, amplitude rises almost linearly at first - in this “thin” regime ($< \sim \lambda/10$), amplitude is roughly proportional to thickness. The onset of tuning can be marked around $\lambda/5$, beyond which the simple linear relationship breaks down as interference becomes significant. The curve reaches a maximum at the tuning thickness ($\lambda/5$ or 18 m in this case), where amplitude is at its peak constructive interference. Notably, this maximum amplitude is higher than the amplitude would be for a very thick bed with the same reflectivity - a thin bed at tuning can produce a “super-bright” reflection. For instance, a bed at tuning thickness can have considerably more reflective power than the isolated reflectors would suggest, purely due to wavelet interference. Beyond this point, as thickness grows further, the two reflections start to separate, and the composite amplitude begins to drop. By $\sim \lambda/2$ thickness, the amplitude often falls below the tuning peak. In the example curve,

after $\lambda/4$ the amplitude declines and eventually flattens out to the level of a single-interface response (100% of true reflectivity) once the top and base are fully resolved (no interference). This means a thick bed ($\gg \lambda/4$) will show the “correct” amplitude for the top reflection (assuming standard processing and no attenuation), but a thinner bed ($< \lambda/4$) will either exaggerate or mute that amplitude. Specifically, in the zone just below $\lambda/4$, amplitude is boosted (tuning boost), whereas much thinner beds ($\lambda/4$) see amplitude diminished (tuning roll-off).

These theoretical insights have direct implications for interpreting seismic DHIs. A “bright spot” on seismic could mean a thick gas sand with strong reflectivity, but it could equally be a thinner sand tuned to $\lambda/4$ that produces an anomalously high amplitude. Conversely, the absence or dimming of an amplitude could mean there is simply no pay, *but it might also mean the pay is present but below tuning thickness or tuned out by destructive interference*. Cases have been documented where thin-bed tuning led to underestimation of net pay when using seismic amplitude alone [10] [11]. As shown in **Figure 6**, a wedge model mimicking gas sand found *that beds thinner than $\sim \lambda/4$ yielded measured thicknesses and amplitudes that deviated substantially from true values, introducing amplitude responses at “tuned” thicknesses that could mislead interpreters*.

1.2. Geological Setting

Bonn-Ario field is in the Coastal Swamp depo belt of the Niger Delta basin, 40 km South-East of Port Harcourt. The study interval is part of the Agbada formation, a paralic sequence of sands and shales up to 4 Km thick in the central parts of the basin.

The Tertiary Niger Delta lies in the Gulf of Guinea, equatorial West Africa, between latitudes $3^\circ - 6^\circ \text{N}$ and longitudes $5^\circ - 8^\circ \text{E}$ (**Figure 7**) [12]. It occupies the site of a triple-junction created by South Atlantic opening during the Late Jurassic breakup of Africa and South America [13] [14]. Deltaic progradation began in the Early Tertiary (Eocene) and built one of the world’s largest regressive deltas, covering roughly $300,000 \text{ km}^2$ [15], containing an estimated $500,000 \text{ km}^3$ of sediment [16] and reaching sediment thicknesses in excess of 10 km at the basin depocenter [17].

Stratigraphically the delta is divided into three lithostratigraphic units that record an overall progradational stratigraphic succession: the marine (pro-delta) Akata Shale Formation, the paralic (delta-front) Agbada Formation, and the continental (delta-plain) Benin Formation (**Figure 8(A)**). The Akata Formation is the basal Tertiary unit and consists predominantly of marine shales that act as the Niger Delta’s principal source rock; thickness estimates for this unit reach up to about 7 km [18]. Above it, the Agbada Formation comprises alternating sand and shale sequences and represents the “true” deltaic portion of the basin; the proportion of shale decreases progressively toward the upper part of the Agbada Formation. The Benin Formation, the youngest unit, is characterized by continental sands and gravels with only minor coastal-plain shale interbeds and attains thicknesses of up to ~ 2 km in the central delta [14].

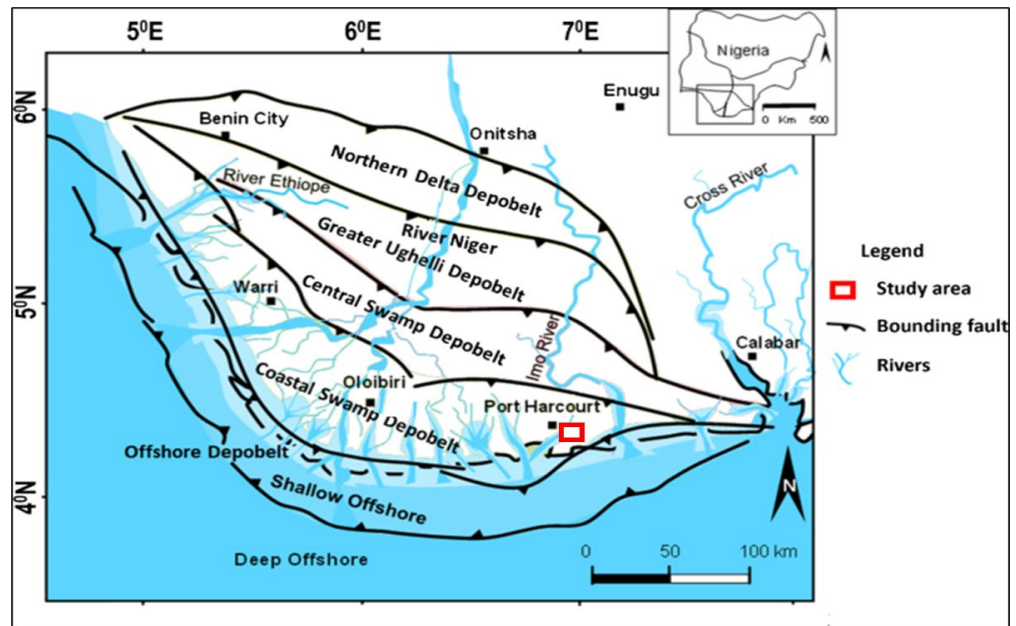


Figure 7. Location of the study area (Bonna-Ario field) in the Niger Delta [19].

Structurally the basin is commonly described as a linked extension-contraction system: extensional regimes dominate on the onshore delta top while contractional features are more apparent toward the deep-water toe of thrust. The Niger Delta evolved as a prograding extensional complex riding above a ductile, over-pressured substrate - the marine Akata shales. Characteristic structural elements include roll-over anticlines (often with collapsed crests), back-to-back structures, and growth (syn-sedimentary) faults (Figure 8(B)). Many of these faults cut through parts of the Agbada Formation, the largest of which commonly sole out onto detachment planes near the top of the Akata Formation.

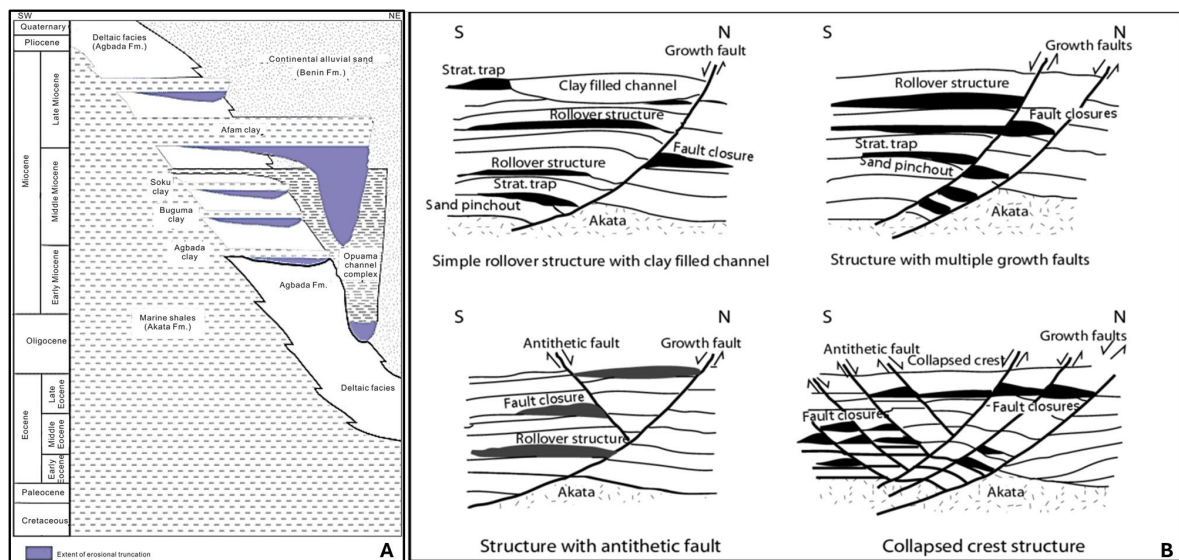


Figure 8. Stratigraphy and Structural Styles in the Niger Delta. (A) Stratigraphic Section across the Niger Delta Basin [18]-[20]. (B) Schematic diagram of Niger Delta structural styles and associated trap styles [18]-[21].

2. Case Study Materials and Methods

Seismic amplitude maps indicated a bright anomaly terminating at a depth that could be interpreted as the seismic amplitude-derived GWC. However, two wells drilled outside of this amplitude shut off, ~5 - 10 m deeper than the amplitude shut-off, encountered more than 20 ft of gas pay. No structural or stratigraphic barriers explain the discrepancy. The most parsimonious interpretation is that amplitude shut off is caused by tuning effects rather than fluid termination.

The M1000 reservoir has a fairly consistent thickness, with an average thickness of ~260 ft (~80 m) (Figure 9(A)). Beds thinner than ($\lambda/4$) see amplitudes diminished (tuning roll-off) [10]. The seismic interval velocity at the M1000 reservoir level, derived from the checkshot in 4 wells (Figure 9(B)) is ~9200 ft/s. With a dominant seismic frequency of ~45 Hz at the M1000 reservoir interval, the ($\lambda/4$) is ~51 ft. The reservoir thickness is evidently much greater than the theoretical tuning thickness. What then is the origin of the tuning-imposed amplitude shut-off in the M1000 reservoir?

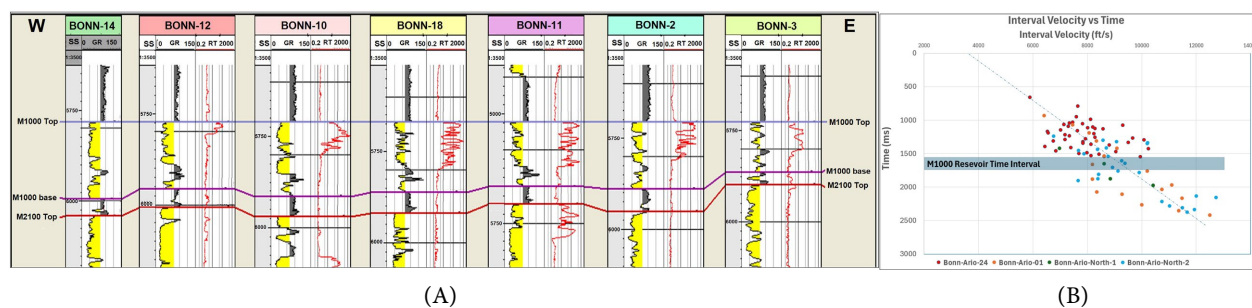


Figure 9. M1000 reservoir stratigraphic correlation and velocity profile. (A) Bonn-Ario M1000 reservoir correlation across wells Bonn-Ario-14, -12, -10, -18, -11, -02 and -03) (yellow and black color filled log - gamma Ray; Red color trace log - resistivity). (B) Bonn-Ario field interval velocity graph derived from wells Bonn-Ario-01, Bonn-Ario-24, Bonn-Ario-North-1 and Bonn-Ario-North-2 Time-Depth pairs.

Forward Modeling and Wedge Analysis

The Wedge model (section 1.1), describes the seismic response due to thickness variations in an acoustic layer sandwiched between two interfaces. In the M1000 reservoir case, the acoustic layer is the gas-filled M1000 reservoir sand. The upper and lower acoustic interfaces are the shale-gas sand interface and the Gas-Water Contact (GWC), respectively. The wedge in this case is the thinning portion of the gas pay between the reservoir top and the flat GWC.

Synthetic seismogram (Figure 3) generated using BONN-03 well logs and the extracted wavelet from the reservoir interval confirmed the top reservoir reflection is a soft kick, consistent with gas sands encased in shales. A forward model (Gassmann Fluid Substitution) was carried out to assess the effect of reservoir fluid fill on seismic amplitude, separate from thickness effects, by substituting the in-situ M1000 reservoir case (gas-filled case) with brine (Figure 10).

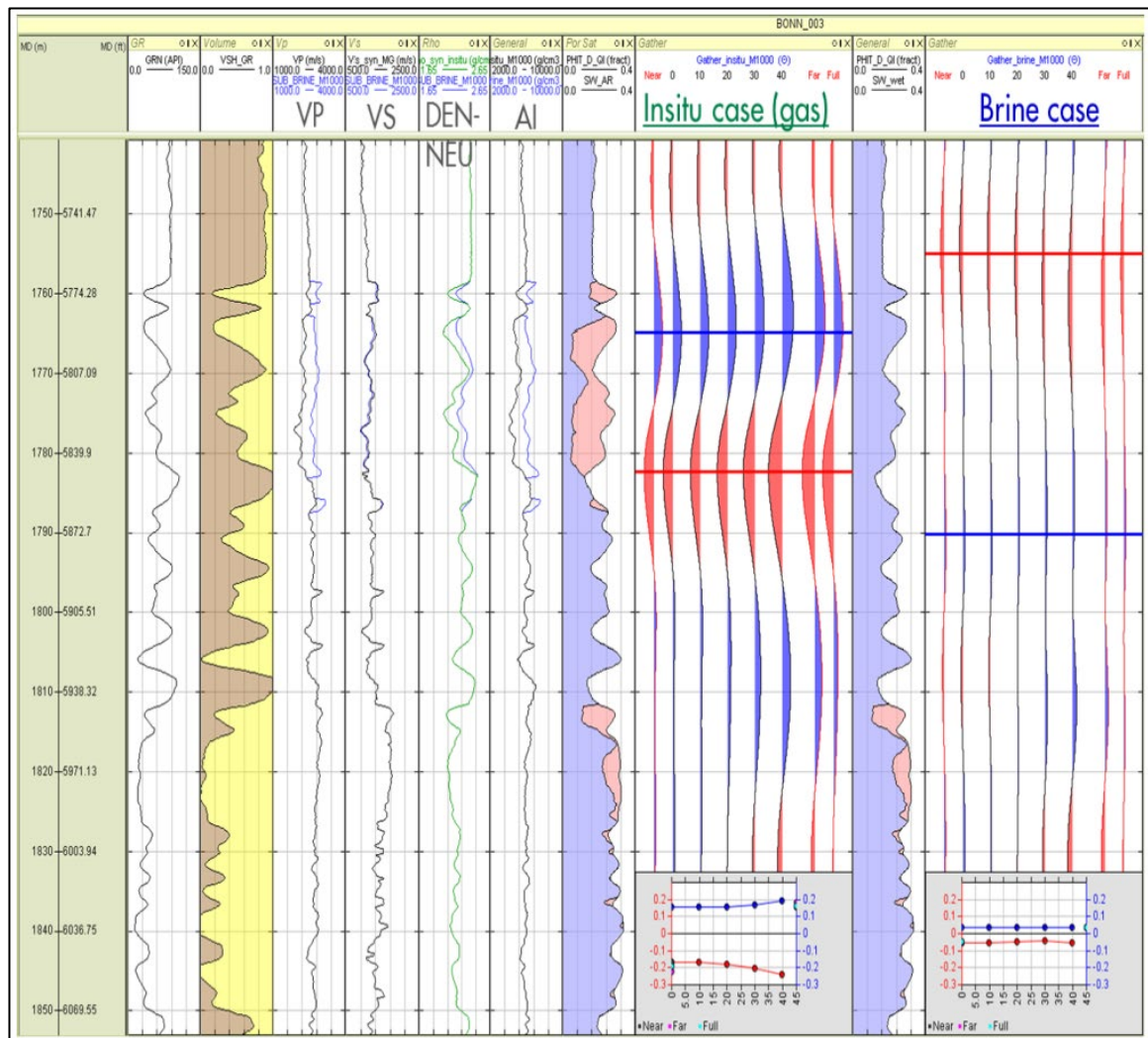


Figure 10. Gassmann Fluid substitution (forward model) for M1000 reservoir in Bonn-Ario-03 well. Soft sands getting softer with offset for the in-situ case, brine sands transparent to weakly hard. The blue curves on the compressional velocity (VP), shear velocity (VS), density/neutron (DEN/NEU) and acoustic impedance (AI) tracks are the brine-substituted values.

The critical part of the evaluation was the use of wedge models to quantify how tuning affected seismic amplitude in the M1000 reservoir. The wedge model was constructed in a manner similar to the synthetic wedge model described in section 1.1 but using the Bonn-Ario field-specific wavelet and rock properties. The wedge model, varying in thickness from 0 - 85 ft showed that amplitudes declined rapidly from a gas pay thickness of 85 ft. At 35 ft, amplitudes were significantly reduced, consistent with the observed seismic amplitude shut off (**Figure 11**). This confirms that the apparent GWC derived from seismic amplitude is an artifact of seismic resolution. The key insights from the forward and wedge modelling can be summarized as follows.

- At M1000 reservoir level, seismic amplitudes are strongly correlated to gas presence.

- M1000 “Gas” amplitudes are “soft” whereas the “Brine” amplitudes are “weakly soft to transparent”.
- The seismic amplitude responses are affected by gas column and thickness. Below a gas pay thickness of ~35 ft, the “brine” amplitudes dominate. Above that, “gas” amplitudes are seen to dominate. In other words, at gas pay thickness < 35 ft, tuning derived amplitude dimming (tuning roll-off) prevents the seismic data from “seeing” any gas in the reservoir.

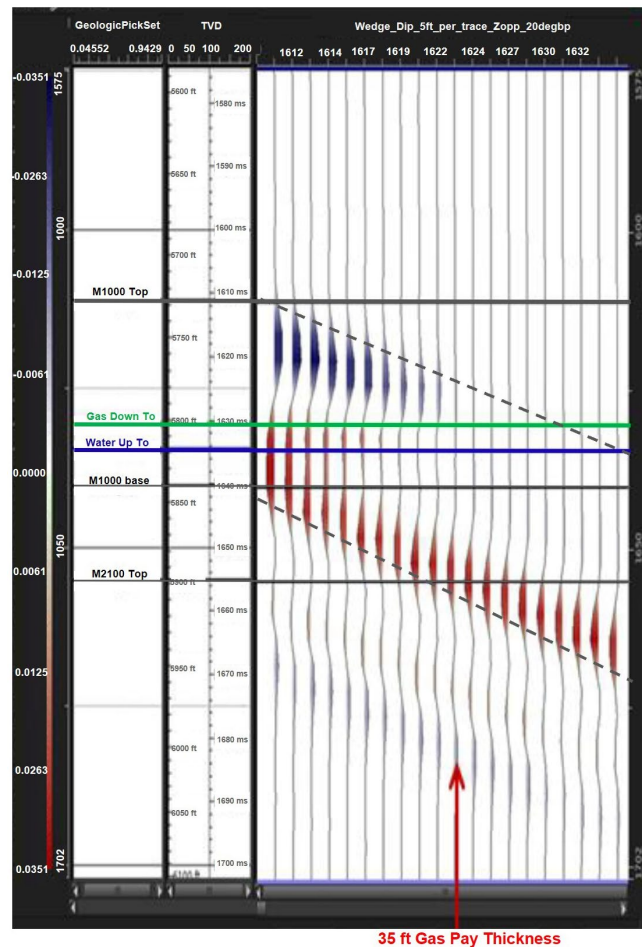


Figure 11. Wedge model for the Bonn-Ario M1000 reservoir. Each successive seismic trace (left to right) represents a 5 ft decrease in gas pay thickness (from 85 ft). The M1000 reservoir top and base are in dashed black lines. Note the diminishing amplitude response until the top reflectivity shuts off at interval thickness of 35 ft.

3. Results and Discussion

Amplitude extractions are used for fluid contact delineations when changes in pore fluid are likely to produce reliable, measurable changes in seismic amplitudes and when those signals can be calibrated against well data. The changes are expressed as strong impedance contrast with the surrounding rocks and visible amplitude anomalies on the seismic data (bright/dim spots). In reservoirs with limited down-dip well control where the fluid contacts (Gas-Water Contact, Oil-Wa-

ter Contact or Gas-Oil Contact) have not been penetrated, geoscientists commonly turn to seismic amplitude extractions.

Our case study, the Bonna-Ario M1000 reservoir, has demonstrated that using seismic amplitude shut-off as a proxy for the GWC would lead to an underestimation of the gas column height by ~35 ft and invariably lead to an underestimation of the GIIP. In this case, GIIP estimates using the GWC “seen” by the wells was 1.89 trillion cubic feet (TCF), and seismic amplitude-derived GWC was 1.60 TCF (Figure 12). In other words, seismic-only volumes underestimated the GIIP by ~15%. This magnitude of error could materially affect reserves booking, project sanctioning, and investment decisions. For reservoirs globally, tuning can evidently bias volumetric assessments toward conservatism in well data-sparse reservoirs where no fluid contacts have been logged by the wells.

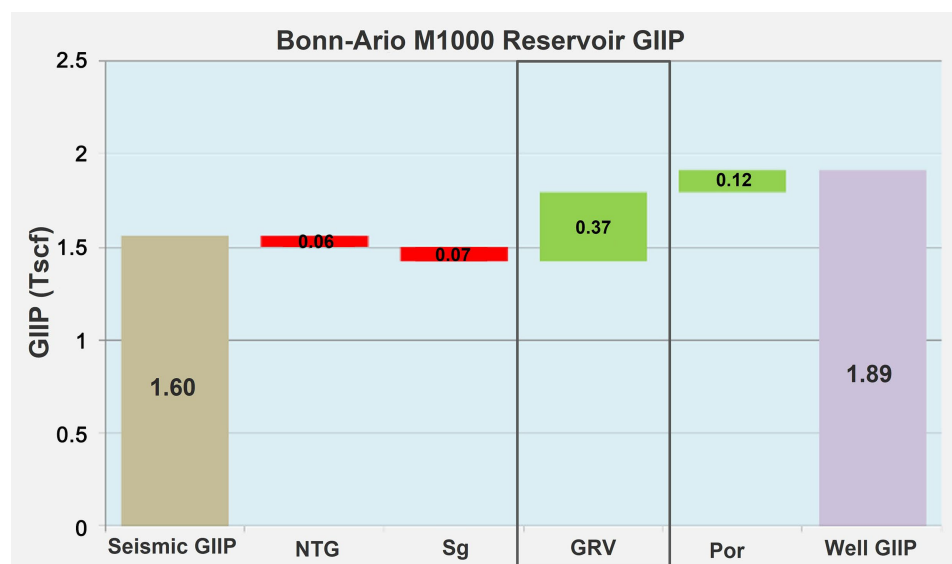


Figure 12. Washline plot of the impact of seismic amplitudes derived contacts on the GIIP. Shallower seismic GWC due to tuning-induced amplitude dimming underestimated the GRV by 0.37 Tscf! This underestimate of the GRV is only driven by the shallower seismic GWC; there is no change in reservoir structure.

In the SPE PRMS [1] oil and gas resources estimation rules, seismic indicators fall under reliable technology - a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation - that may be used to extend hydrocarbon presence below the lowest known hydrocarbon in reservoirs where no hydrocarbon (fluid) contacts have been drilled by the wells for Probable (2P) Volumes estimation [22]. This study has, however, shown that seismic amplitude extractions alone will not be sufficient to accurately define fluid contacts. *Equating seismic amplitude cutoffs with fluid contacts in sub-tuning areas of reservoirs introduces systematic pay thickness and volumetric underestimation risks. Rather, amplitude extractions should be treated as the $\lambda/4$ resolution limit of the seismic*

data. For more accurate estimation of the in-place volumes in such reservoirs, this resolution limit must be determined through wedge modelling and AVA analysis, and factored into the seismic amplitude-derived fluid contact estimate.

The broadband PSDM seismic volume covering the Bonn-Ario field has been shown to have a bandwidth of ~75 Hz typical of conventional seismic acquisitions. This pales in comparison to modern broadband seismic data with useable frequencies up to 100 Hz, with extensions above 150 Hz for high resolution applications [23] [24]. Advances in broadband seismic acquisition and processing will mitigate, but not eliminate tuning-induced pay and volume mis-estimations. Seismic amplitude extractions paired with AVA analysis and wedge modelling have been demonstrated to provide a reliable, cheap, quick and consistent estimation of the pay thickness and fluid contacts.

Industry Analogues

The challenges and solutions illustrated by the case study above are by no means unique to the Bonn-Ario field.

In the Niger Delta basin, gas pay underestimation due to tuning-induced amplitude dimming (tuning roll-off) have been observed in reservoirs analogous to our case study. In Epudeno field (110 Km Southwest of Port Harcourt), seismic amplitudes underestimated the gas pay by ~30 ft (~9 m) in the E7000 reservoir (~80 ft (24 m) stratigraphic thickness), where a well outside the amplitude expression encountered ~26 ft (~8 m) of gas pay. Here, Gassmann fluid substitution, AVA analysis and wedge modelling demonstrated that the seismic amplitudes did not capture gas pay thickness less than 30 ft due to tuning between the reservoir top and the Gas-Water Contact (**Figure 13**).

Elsewhere, very little literature exists describing the underestimation of pay and in-place volumes due to seismic tuning in reservoirs with stratigraphic thickness greater than the tuning thickness. In such reservoirs, tuning of course, is the result of the destructive interference of the reflections from the reservoir top and the fluid contact as the dipping reservoir top approaches the fluid contact, creating a tapering wedge towards the edges of the reservoir. Analogous studies in different settings focus on seismic response in sub-tuning, stratigraphically thin reservoirs and pay zones, often with emphasis on the overestimation of reservoir and pay thickness, and petrophysical properties, or false positive anomalies where tuning-induced bright amplitudes fooled interpreters into assuming a large, non-existent gas accumulation. A couple are highlighted below.

- A 2015 study of a seismic volume from F3 in the North Sea noted that many strong amplitudes were tuned responses of thin gas layers and associated flat spots (gas-water contacts) [25]. Through wedge modeling and AVA analysis, they showed that the tuning of a flat spot with an overlying bright spot can create amplitude peaks and nulls not directly correlated to pay thickness. They demonstrated two possible effects of a flat spot's tuning. 1) If the flat spot aligns constructively with the top reservoir reflection, it boosts amplitude (a bright

spot stronger than expected), and 2) *if misaligned, it can cause dimming or even a polarity reversal*. This means a mapped bright spot might be partially due to tuning rather than simply a thick gas column. *Conversely, sometimes a dimming of amplitudes may just be a tuning artifact and not necessarily because the accumulation “terminates”*.

- A 2005 study describes a situation in the Gulf of Mexico where low-saturation gas in a thin sand can produce a bright amplitude but not enough hydrocarbon to be commercial [9]. The amplitude is high because the small gas saturation still lowers impedance a lot, but the reservoir may be thin or laterally limited, so volume is low. Tuning had made the gas response look more laterally extensive on the stack than it was, leading to overestimation of volumes.

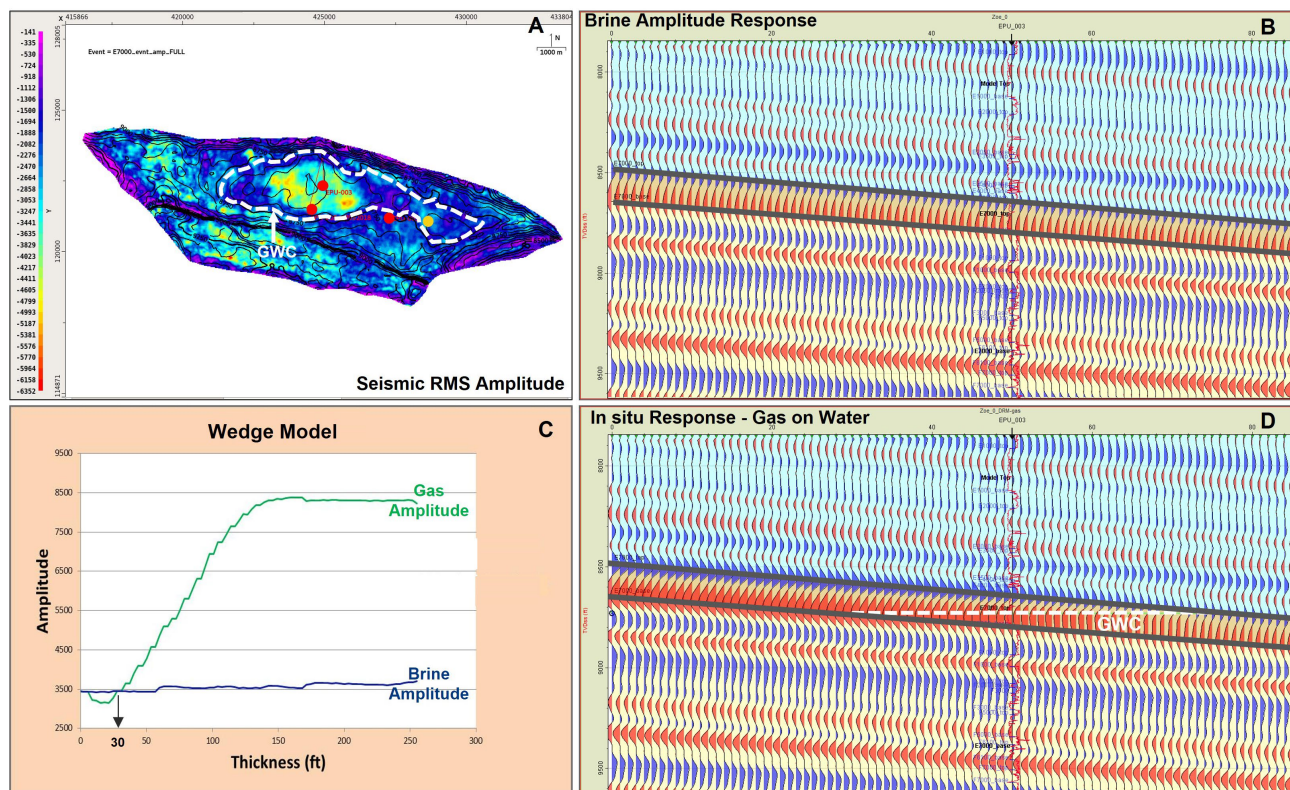


Figure 13. Analogue Epudeno E7000 reservoir forward model and wedge analysis (A) Seismic amplitude extraction of Epudeno E7000 reservoir draped on the top structure map. The amplitude expression is conformable to the structure. The GWC logged by the wells penetrating the structure is shown in white dashed line. The seismic amplitude expression shuts off before the logged GWC. One well (yellow dot) outside of the amplitude expression encountered 26 ft (~ 8 m) of gas pay. (B) Forward Modelling (fluid substitution) showing the modelled brine amplitude response for Epudeno E7000 reservoir (Top and base of the reservoir in black lines). (C) In-situ seismic response for Epudeno E7000 reservoir (Top and base of the reservoir in black lines). Notice the wedge is between the reservoir top and the flat GWC (dashed white line). (D) Wedge model amplitude response (tuning curve) for Epudeno E7000 reservoir. Brine amplitudes dominate at pay gas pay thickness less than 30 ft (~ 9 m).

These analogues drive home a consistent point: whenever a reservoir pay thickness is near or below the seismic resolution limit, extra diligence is required in interpretation and volume estimation. Whether it is shallow marine shoreface sands in the Niger Delta Onshore, a shallow gas pocket in the North Sea or a deep-

water turbidite in the Gulf of Mexico, the interplay of seismic wavelet, pay thickness and layer geometry can fool a naive amplitude-based approach. Fortunately, the industry has developed a toolkit to mitigate this - from reprocessing for bandwidth extension leading to an improvement in seismic resolution, to seismic inversion, AVA analysis, wedge modelling and advanced interpretation attributes.

4. Conclusion

This study demonstrates how tuning thickness controls seismic amplitudes and can lead to the underestimation of GIIP when amplitude shut offs are misinterpreted as fluid contacts. For the Bonn-Ario M1000 reservoir, wells outside the seismic amplitude outline encountered > 20 ft gas pay. Forward modeling and wedge analysis confirm that the observed seismic amplitude Shut off before the logged GWC is resolution-driven, and for the M1000 reservoir, could potentially lead to a 35 ft underestimation of gas pay thickness and a ~15% underestimation of in-place volumes if the seismic amplitude derived GWC is used for volumetric estimations. This finding is of particular importance to reservoirs with no logged fluid contacts, where the estimated fluid contacts are seismic amplitude-derived even if the reservoir stratigraphic thickness may be above the tuning thickness. Analogues from the Niger Delta and multiple basins confirm the global relevance of this issue. Adoption of integrated workflows and advanced seismic processing can mitigate the risk, ensuring more accurate reserves booking and investment decisions. The following recommendations can be drawn from the M1000 reservoir case.

1) *Calibrate seismic to wells and don't ignore discrepancies.* If wells find hydrocarbon outside the seismic anomaly, do not dismiss it as an outlier - it likely means the seismic picture is incomplete. Investigate the cause (tuning, noise, processing issues) and update the interpretation. An interpreter should actively seek to reconcile well and seismic data to avoid tuning pitfalls.

2) *Tuning will mask or distort hydrocarbon volume.* In our case study, seismic amplitude anomalies only registered on seismic where it thickened towards 35+ ft; thinner gas pay beyond the "bright" area was essentially invisible on the data. This resulted in a significant underestimation of gas initially in place by the seismically derived fluid contact estimates. Always consider that amplitude anomalies may not delineate true reservoir boundaries - *they often delineate the $\lambda/4$ thickness contour. Seismic amplitude shut offs do not necessarily delineate the down-dip limit of hydrocarbon accumulations.*

3) *Use AVA analysis, wedge models and synthetics as routine tools.* Building a quick wedge model for your reservoir, using expected wavelet and rock properties, is extremely useful. It will tell you what the tuning curve looks like and at what thickness you can trust amplitudes. This can guide whether an amplitude map needs scaling. In the case study, the wedge model predicted a 35 ft tuning thickness, which aligned with observations on seismic data. We recommend doing this modeling prior to finalizing volumetrics in reservoirs where the fluid contacts are

determined from seismic amplitudes.

Conflicts of Interest

The author declares no conflicts of interest regarding the publication of this paper.

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