

Comparing AVO inversion techniques for gas saturation mapping

Introduction

Distinguishing commercial from residual gas accumulations is a well-known challenge when relying primarily on 3D seismic and limited well data. This difficulty stems from the fact that introducing small quantities of gas into water-saturated rock causes a severe drop in seismic velocity. Standard seismic amplitude analysis and/or rock physics analysis is impacted by this non-linear velocity response resulting in ambiguity between commercial and residual gas saturations. In contrast, the changes in bulk density are linear with changes in gas saturation. It is therefore suggested that a more reliable gas saturation estimation could be computed with a reliable density inversion.

The key to a reliable density inversion using AVO methods is contained in the ultra-far angle ($>45^\circ$) data. However, these data tend to exhibit lower signal-to-noise ratios and are often contaminated with other wave-phenomena that are not accounted for in conventional AVO algorithms. Two such phenomena include VTI anisotropy and non-primary energy. The presence of VTI anisotropy in overlying shales and non-primary energy, such as multiple and mode conversion, can both introduce changes in the AVO response that will affect the curvature term that is critical for a successful AVO-based density inversion. Other auxiliary data, such as fluid ordering, thickness statistics and geologic information provide constraints to reduce solution space in a probabilistic inversion that by design handles elastic property ambiguity. In this study, we present how careful data preconditioning and the use of different AVO inversion algorithms can help to better capture the changes in gas saturation observed in the study area.

Methods and Theory

In this study, we will be making use of various AVO inversion techniques to investigate the challenge of gas saturation estimation. Two key aspects that we will investigate include density inversion and auxiliary statistical or geologic data, each of which can help separate residual and commercial gas. For density inversion, we must consider the shortcomings of standard inversion techniques in characterizing density. In particular, we will focus on extending traditional Aki-Richards three term reflectivity equations to Ruger's VTI approximation. The importance of VTI effects for density estimation lie in the crosstalk at far angles between VTI epsilon and density. In a standard Aki-Richards approximation, the subsurface is assumed to be isotropic. As such, any anisotropic contributions to reflectivity will propagate through inversion as an error to the gradient and curvature terms. As shown in Goodway et al. (2025), by using Ruger's VTI approximation as the reflectivity equation, we can account for these effects and potentially improve the inversion. Equation 1 show Ruger's VTI approximation. Note in the Ruger approximation, we see contributions of VTI delta and epsilon that are multiplied by $\sin^2 \theta$ and $\sin^2 \theta \tan^2 \theta$ angle, respectively. This highlights the impact the contrasts in VTI delta will contribute most strongly to errors in V_p/V_s , whereas VTI epsilon contributes more at far angle terms and will thus impact the density.

$$2Rp(\theta) = \left(\frac{1}{\cos^2 \theta} - 8 \left(\frac{V_s}{V_p} \right)^2 \sin^2 \theta \right) \frac{\Delta A I}{A I} + 4 \left(\frac{V_s}{V_p} \right)^2 \sin^2 \theta \frac{\Delta V_p / V_s}{V_p / V_s} + \left(\tan^2 \theta + 4 \left(\frac{V_s}{V_p} \right)^2 \sin^2 \theta \right) \frac{\Delta \rho}{\rho} + \sin^2 \theta \Delta \delta + \sin^2 \theta \tan^2 \theta \Delta \epsilon \quad (1)$$

Next, we will consider the inclusion of auxiliary data, in the form of statistics computed from well logs and geologic ordering rules, in a probabilistic inversion framework to help constrain the inversion to only geologically reasonable results. Direct probabilistic inversion (DPI) (Hansen and Jakobsen, 2018) addresses the shortcomings of deterministic inversion workflows for facies/lithology classification when resolving thin beds and elastically overlapping facies. The classic deterministic inversion workflow is a two-step process. First a deterministic AVO inversion solves for elastic properties, then

a single point classification is applied to these elastic properties. Due to the non-uniqueness of the inversion problem (a thin gas sand can look like a thicker wet sand) the AVO inversion problem is solved through regularization resulting in a smooth solution which continuously moves through elastic properties in a way that yields facies relationships that do not necessarily make physical sense (e.g. water bearing sand above hydrocarbon sand) or transitioning from one facies to another that does not conform to known geologic knowledge.

In the Bayesian approach of DPI, the non-uniqueness is handled by solving for probabilities directly from seismic data. All spatial information and uncertainty in the facies, elastic and seismic domains are propagated into the posterior solution. In the facies domain we can invoke hard constraints on the solution space by specifying disallowed transitions such as zero probability of transitioning from an older rock to a younger rock. With this framework we can also incorporate softer information such as facies thickness distributions or transition statistics invoking a particular geologic context such as fining upwards etc. In the elastic domain, each facies' elastic property statistics are calculated. In the seismic domain a seismic noise model is applied to constrain the inversion further.

Results

The first step to confirming the presence of VTI anisotropy is to compute forward modelled seismic with and without a VTI forward model and compare to the input seismic. Better correlations between synthetic and input seismic confirms the applicability of VTI in the forward model. Figure 1 shows a comparison between well ties across three angle-stacks for one well in the survey area. As epsilon and delta logs were not available for this study, a simple approximation was made using the shale curve. We observe a clear increase in correlation from 0.47 to 0.68 in the 40-45 degree angle-stack and an increase from 0.54 to 0.64 in the 25-30 degree angle-stack.

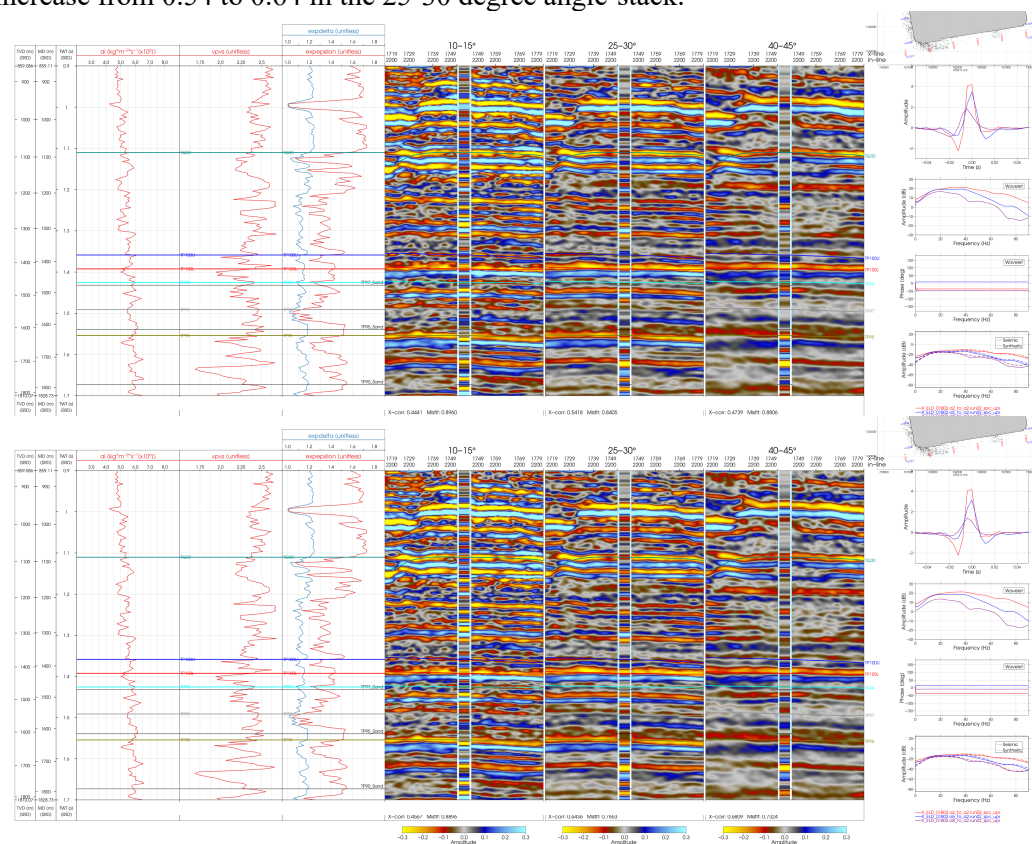


Figure 1 Comparison of well ties using isotropic Aki-Richards approximation (top) to Ruger's VTI approximation (bottom).

Following the success of this result, we perform a deterministic VTI inversion to invert for AI, Vp/Vs and density. The workflow for the deterministic inversion includes seismic pre-conditioning, wavelet estimation, low-frequency model building and rock physics modelling. For this study, seismic pre-conditioning was key to improving inversion quality as the input data contained dramatic amplitude and frequency variability in space and noticeable misalignment in of seismic data both azimuthally and in angle. The seismic pre-conditioning sequence included frequency-based amplitude compensation, computed via comparison to a reference FWI image full-stack, AVO compensation and azimuthal alignment. The low-frequency model was computed using a single-well, extracting sand and shale trends, in conjunction with FWI velocities that provide a high resolution, data-driven input to account for both depth trends and regional geology. Rock physics modelling was computed to establish a relationship between elastic and rock properties such that we are able to perform a second inversion step to invert for porosity, volume of clay and water saturation from input elastic inversion results. The rock physics model used in this study takes the form of a modified Berryman equation. The equation for this study is shown in Equation 2.

$$\frac{1}{M + M_0} = \sum_i \frac{(1 - \varphi)V_i}{M_i + M_0} + \frac{\varphi}{M_{fluid} + M_0} \quad (2)$$

The results of the 3D rock physics inversion at a key well are shown in Figure 2. Notice the match between observed (in red) and measured (in blue) of the gas saturation response in the lower gas saturated sands. We also observe that in several key sands, we can accurately compute gas saturations, but we also observe distinct crosstalk between porosity and gas saturation (see ~1.8s). This crosstalk demonstrates the even where elastic inversion results, including density, are accurate there is still ambiguity in the interpretation of these results into rock properties.

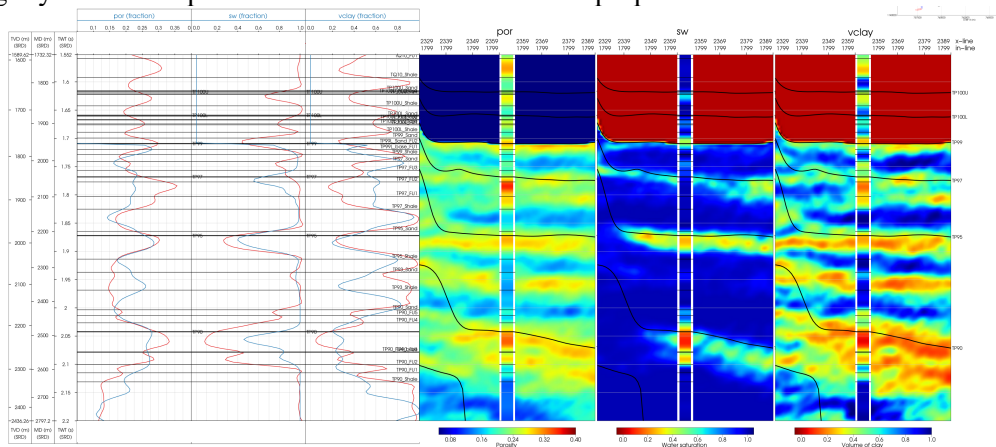


Figure 2 Rock physics inversion results (blue) compared to observed logs (red) for porosity, water saturation and volume of clay.

The DPI workflow begins with the creation of a statistical prior model that consists of two components, a statistical geologic framework and statistical rock physics models. We must first identify all facies present in our target intervals. Facies in this case refer to both lithology and stratigraphic unit. For this study, five primary lithofacies were provided including proximal shelf, intermediate shelf, outer shelf, shelf and slope. The outer shelf, shelf and slope are non-target clay-rich facies. All other lithofacies are further sub-divided into brine, commercial gas and residual gas for a total of 9 lithofacies. Facies were then sub-divided by target into 8 zones. The result is a total of 72 facies.

Once these facies are defined, we begin computing statistics to form the probabilistic geologic prior model. These statistics include hard constraints, such as invoking stratigraphic and fluid ordering, as well as soft constraints, such as facies thicknesses, and probability of transitioning from one lithology

to another. A statistical rock physics model is computed by calculating means, standard deviations, and correlations between elastic properties for each facies. From this framework, a likelihood is computed at each sample in our inversion window by densely sampling from the geologic framework to generate geologically plausible realizations. The probabilistic elastic properties of those realizations are computed using the statistical rock physics model and finally the resulting probabilistic synthetic seismic data using Ruger's VTI AVO approximation. In Figure 3, we show the results of DPI at the same well as that shown in Figure 2. Here, we observe a clear differentiation between commercial gas (in red colours) to partial saturations (in green and yellow) and brine saturations (in blue). Clay facies are in gray. There remain some observable false negatives (brine instead of gas) in some of the thinner sands, but false positives are limited and accurate thicknesses are much more clearly defined.

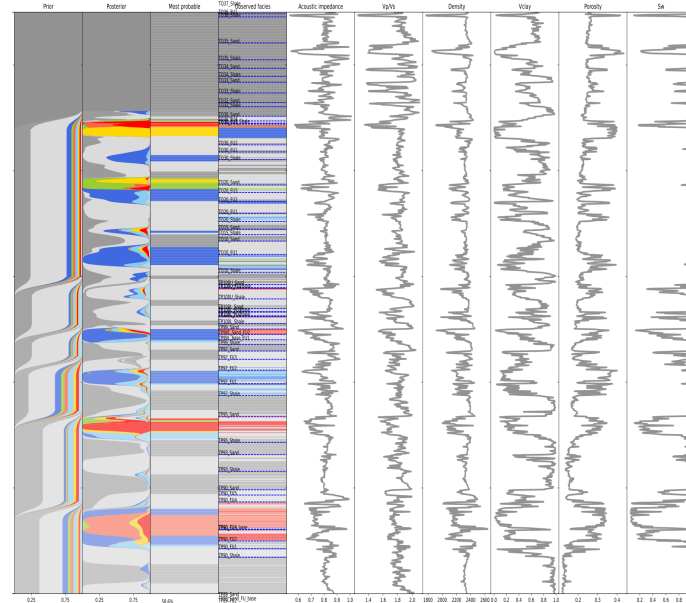


Figure 3 DPI results at the same well as Figure 2. Far left is 3D prior field, followed by posterior (DPI output), most likely facies and observed facies. Logs are right hand side are observed well log data.

Conclusions

In this study, anisotropic VTI AVO inversion techniques are applied to an offshore dataset to investigate methods of differentiating between partial and residual gas saturation. The addition of VTI to the AVO forward models improves the inversion for density, a potentially key parameter in gas saturation calculations as saturation is linear in density. Deterministic rock physics inversion showed good correlations to observed well log data, but highlighted the issue of cross-talk in the rock physics domain between porous, partially gas saturated sands and less porous, fully gas saturated sands. A direct probabilistic inversion algorithm was tested as a means to provide additional constraints to the inversion framework thereby helping to mitigate rock physics crosstalk and elastic property ambiguity. Results showed promise in reducing false positives of commercial gas saturations.

References

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