In Search of Hidden Gas: Simultaneous Inversion for Acoustic Impedance and Elastic Properties, SW Tapti, Offshore Western India

Michelle Parks*[1], Gautam Kumar[2], Shivatosh Deb[2] and Stuart Burley[2&3];

[1]BG Group, UK; [2]BG E&P India, Mumbai;
[3]Basin Dynamics Research Group, University of Keele, Staffordshire UK.

Summary

Seismic modelling and simultaneous inversion of angle-limited stacks for AI, Poissons' ratio (PR) and Lambda-Rho (LR) aid in better understanding of side-lobe interference between stacked channel sands, low acoustic impedance shales, and gas charge in a complex Tertiary sand-shale reservoir section from offshore western India. Volume blending, opacity stacking and geobody detection techniques were used to map individual sand bodies and reveal the geometry of channel sands and tidal bars. High resolution mapping of sand bodies has enabled optimal placement of subsequent appraisal well locations in targeting high quality reservoir sandstones.

Introduction

The South West Tapti prospects are located in the Gulf of Cambay, approximately 160 km NNW of Mumbai (Fig. 1), and are part of the Tapti Block Joint Venture (JV) Concession (ONGC, RIL and BG).

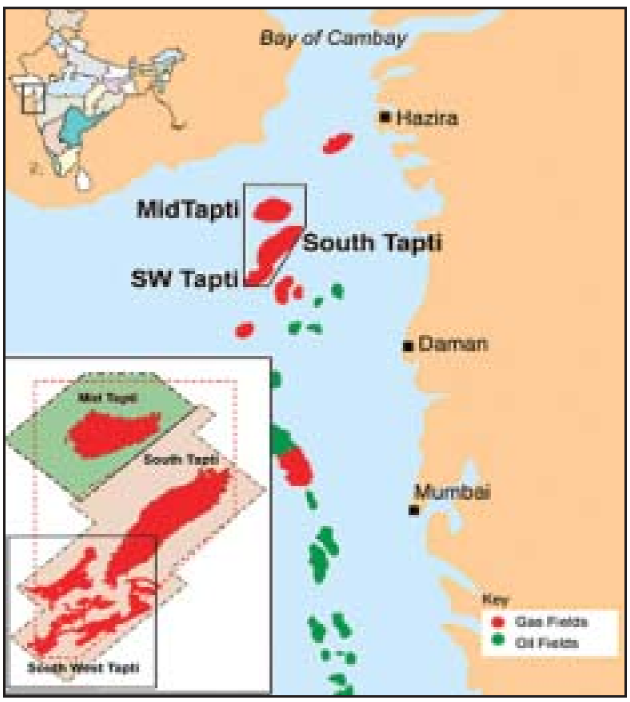

Fig. 1: Location of the South West Tapti Prospects offshore western India, showing the extent of the seismic survey.

The 2004 reprocessed seismic survey includes both South and South West Tapti and extends across an area of approximately 996 km^2. The South West Tapti prospects are a stacked series of combined stratigraphic-fault seal traps, developed on the highly faulted, plunging nose of the South Tapti Field. Unlike the South Tapti Field - a four way structural closure - the South West Tapti prospects rely on gas charge in 'ribbon'-type distributary channel sands, enclosed in estuarine muds and associated tidal sand bars, and sealed by either sand-on-shale juxtaposition across NW-SE oriented faults or shale smear across sand-on-sand juxtaposition.

Amplitude bodies mapped from the 2004 reprocessed seismic indicated that almost 1 Tcf of gas could be trapped in these reservoirs. Confidence in these prospects was high because of the presence of gas in sands of the same age and depositional system in the immediately adjacent South Tapti Field (Deb et al. 1997), which exhibits identical amplitude anomalies. The first exploration well drilled by the JV (SWT-1), was spudded in April 2005 in order to appraise three such mapped stacked negative amplitude bodies. However, to the astonishment of all parties concerned, the first bright negative amplitude was argillaceous sand while the second and third anomalies corresponded to high porosity but water-wet channel sands.

Prior to the drilling of SWT-1, amplitude anomalies mapped on the full stack volume had been successfully used with confidence for targeting development wells in the South Tapti Field. However, the absence of gas-charged sands in the exploration well, despite the clear presence of mappable amplitude anomalies in South West Tapti, forced a re-evaluation of the seismic understanding of the Tapti Block reservoirs. Rock physics studies of the reservoir section indicated that a combination of acoustic and elastic attributes could be used as a lithology discriminator and to some extent were indicative of hydrocarbons. Accordingly, a simultaneous inversion was undertaken on the South West Tapti angle-limited stacks for AI, Poissons' ratio (PR) and Lambda-Rho (LR) to attempt to differentiate lithology, particularly clean porous channel sands from background shale and argillaceous tidal bars, and also to investigate the possibility of discriminating between water-wet and gas-charged sands. The occurrence of a range of reservoirs from clean, high porosity channel sands with multiple fluid contacts through to argillaceous tidal bar sands makes this data set ideal for investigating the seismic response to porosity and fluid content. We outline here the methods used in a simultaneous inversion and interpret some of the results in light of the known geology of the South West Tapti prospects.

Methods

A comprehensive rock physics analysis of the SW Tapti data set was carried out to determine the optimal attributes for differentiating lithology and fluids. A Gassmann fluid substitution was undertaken to predict the 80% gas-saturated case for Vp, Vs and density for all sands encountered in SWT-1, followed by computing acoustic and elastic logs for both the water and gas-charged scenarios. For QC purposes the same attributes were computed for an additional six wells in the South and South West Tapti seismic volume. Where shear data was not recorded, the Modified Gassmann equation was used to generate Vs logs. The results were cross-plotted to determine which attributes gave maximum separation of gas sands compared to water-wet sands and shales (Fig. 2).

The results of the rock physics studies clearly indicated that AI could not solely be used as a hydrocarbon discriminator due to an overlap in AI values between sands and shales. However, a combination of AI, PR and LR may be used qualitatively in determining lithology and potentially the presence of hydrocarbons, because of the partial spatial separation of the elastic properties.

Seismic modelling was carried out utilising the sonic and density logs from the study wells, to determine the relative effect of porosity and saturation on seismic amplitudes. A series of 2D synthetic models were created by varying the porosity and water saturation of a

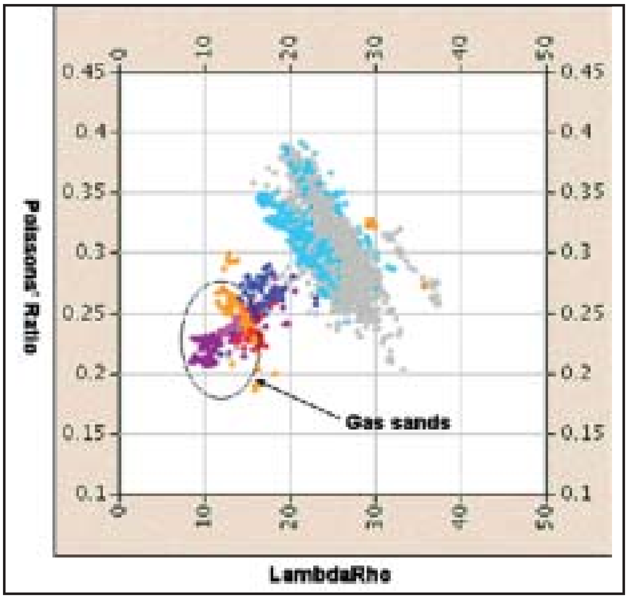

Fig. 2: Cross plot of Poissons' ratio (PR) and LambdaRho (LR) showing separation between shales (grey), water sands (blues) and gas-charged sands (yellow to red) for the study wells.

representative sand in SWT-1. The results of this modelling demonstrate that variation in sand porosity exerts a much larger effect on seismic amplitude response than fluid content. There is an initial increase in amplitude with increasing saturation after the introduction of 5% gas - however, beyond this saturation level the gradient of the amplitude response is almost constant. The varying porosity model displays a much steeper gradient, with the largest change in amplitude between 15-20% (Fig. 3).

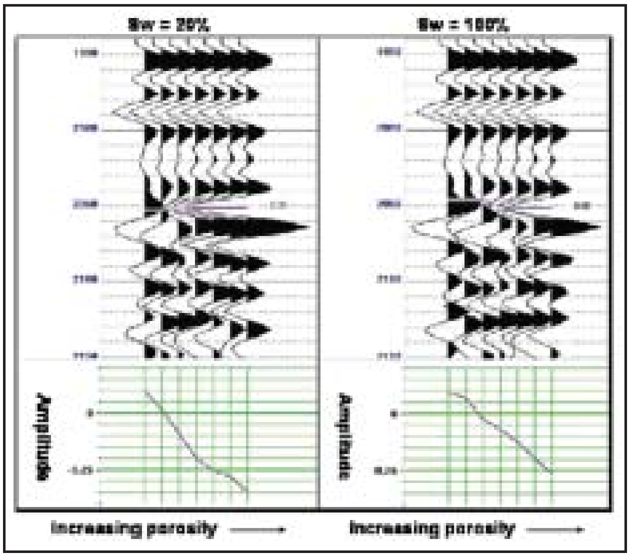

Fig. 3: Synthetic seismograms for varying porosity model at 20% and 100% Sw, showing an increase in amplitude from left to right corresponding to an increase in porosity.

Increasing porosity

Knowing that any amplitude response due to the presence of gas may be masked by the porosity effect, we endeavoured to solve the problem of distinguishing argillaceous sands from porous sands. Thus simultaneous inversion for P-impedance (Zp), S-impedance (Zs) and Vp/Vs was carried out using a modification of Aki-Richards' equation, as per Fatti et al. 1994.

The input data to the inversion were the partial angle stacks, the background models for Zp, Zs and density and wavelets extracted from the partial stacks. The low frequency models were generated by interpolating representative logs between seven wells from the South Tapti Field and South West Tapti prospect area, using a inverse-distance squared algorithm, constrained by the horizons. Wavelets extracted from the near and mid stacks were used to account for changes in phase and frequency between the volumes. A summary of the simultaneous inversion workflow is displayed in Figure 4.

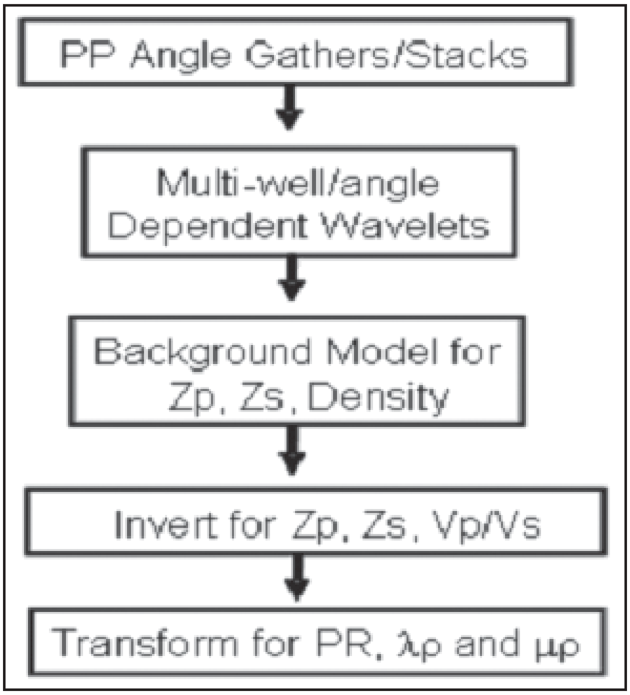

Fig. 4: Summary workflow for the simultaneous inversion.

QC of the inversion volumes at well locations confirms that low AI and LR values correspond exactly to clean, high porosity distributary channel sands. Additionally, low AI argillaceous tidal sands intersected in the study well can be distinguished from porous sands using the LR volume (Fig. 5).

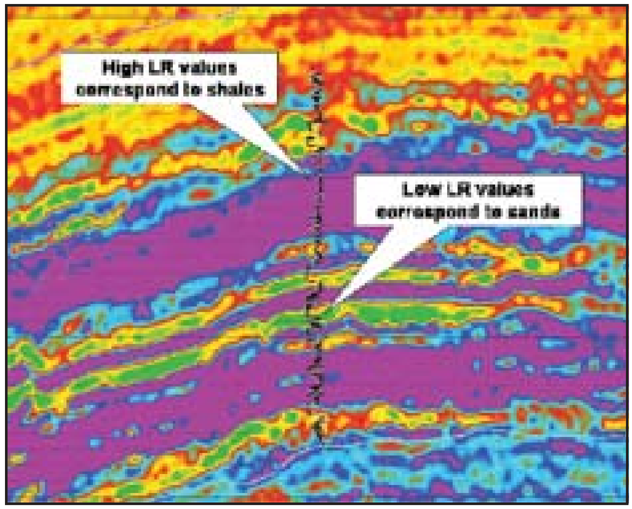

Fig. 5: Section through the LR volume at the SWT-1 well location showing the coincidence of low LR values with clean, high porosity channel sandstones and high LR values corresponding to argillaceous sands and shales.

The generated (Zp), (Zs) and VpVs volumes were then combined to produce LR, MR and Poissons' ratio seismic cubes. 3D visualisation software was used to blend AI-LR and LR-PR volumes. The volumes were then flattened on key horizons and opacity stacking was used to accentuate the various low AI, LR and PR bodies. Panning through the stacked horizon slices in 3D revealed a sequence of stacked sand bodies with various geometries, that were interpreted to represent distinct depositional systems (Figures 6 to 8).

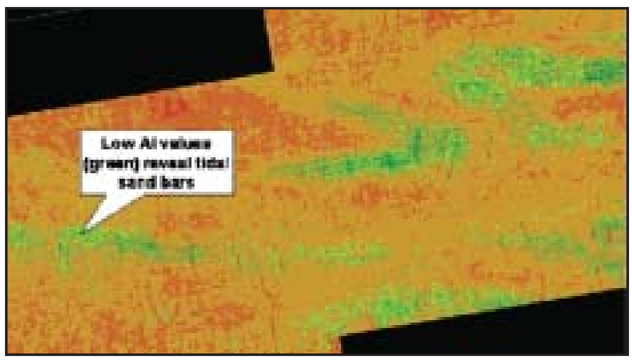

Fig. 6 : Horizon slice through AI volume reveals geometry of low AI (green) tidal sand bodies in a background of estuarine mud (orange)' in the upper reservoir unit.

The stacked horizon slices reveal in detail the depositional evolution of an Oligocene coastal plain, which has been progressively inundated by a lower Miocene transgression. This reconstruction is consistent with well data. Argillaceous tidal bars can be distinguished from background estuarine mud and highly porous channel sands.

Additionally, hydrocarbon-bearing sands should

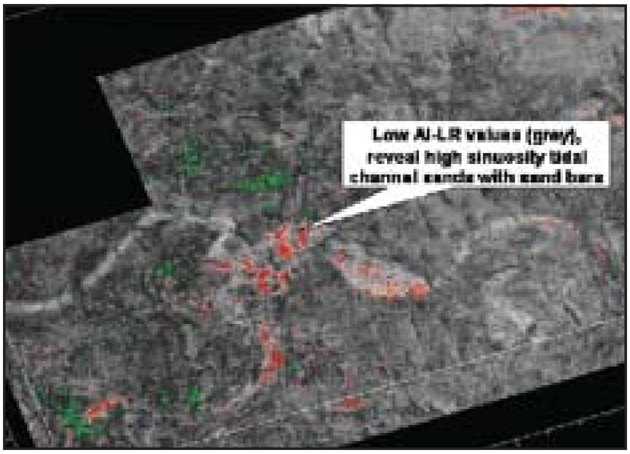

Fig.7: Horizon slice through AI-LR blended volume, reveals highly sinuous low AI-LR distributary channel, meandering across a coastal plain of estuarine mud.

correspond to low AI, LR and PR values, however, high porosity, low gas-saturated sands appear to produce a similar seismic response. Simultaneous inversion has provided high resolution discrimination of porous sand bodies, but has not enabled the distinction of high saturation gas-charged sands from low gas saturation water wet sands. Residual gas saturations thus remain the main risk in the South West Tapti prospects.

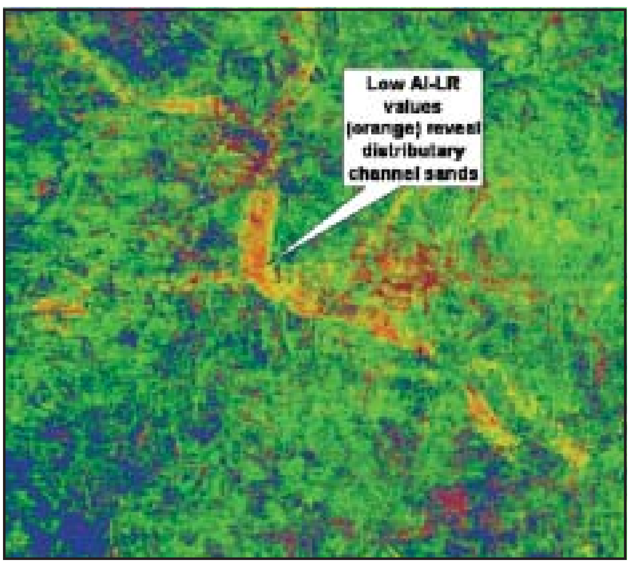

Fig.8 : Horizon slice through AI-LR blended volume reveals geometry of low AI-LR (orange) distributary channel sands meandering across a coastal plain of estuarine mud in the lower reservoir unit. Dark blue areas represent thickest area of mud development.

Conclusions

Simultaneous inversion of angle-limited stacks for AI, PR and LR demonstrates that low AI shaly sands can be distinguished from porous sands, using the derived LR volume in a complex Tertiary sand-shale reservoir section. This has enabled mapping of the main reservoir sand bodies such that appraisal well trajectories can be optimally placed.

Unfortunately, while seismic attributes effectively predict the presence of good quality sands, they are not able to distinguish low from high gas saturations. Thus leakage across faults leaving behind low gas saturations, is therefore the main risk for further appraisal wells.

Acknowledgment

The authors thank BG India and BG Advance for their assistance in conducting this project. The Tapti Concession JV Partners Reliance (RIL) and ONGC are especially thanked for their technical support through the project and for permitting submission and publication of this paper to the 2005 SPG Conference.

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