Reducing exploration risk through probabilistic characterisation of a basin-floor fan, offshore WA

By
Sagar Ronghe & **Anne Locke,** DownUnder GeoSolutions

INTRODUCTION

The Beg-1 exploration well was drilled in 2007 to intersect a class IV seismic AVA anomaly, prognosed to be a gas-filled sand in the Carnarvon Basin (Block WA-476-P), offshore Western Australia. The well encountered 125 m of brine-filled net sand reservoirs with 10-12% average porosity (Figure 1). The intersected sands come from two lobes of the Late Jurassic Batavus basin-floor fan. A higher porosity (up to 25%) layer of brine sand was responsible for the class IV seismic anomaly.

Characterising reservoir distributions and properties from seismic and wireline data is complicated in this area by the presence of two kinds of sandstones intersected in regional wells. The sands occur in multiple stacked lobes of the Batavus fan. One of these is the high porosity brine sand known to create a significant seismic AVA response. Assessing prospectivity of exploration targets requires mapping the discrete distributions of each sand type, determining their thicknesses and reservoir properties, establishing fluid content and quantifying prediction uncertainties.

In this paper we show how a depth-dependent statistical rock physics model along with constrained absolute simultaneous inversion of seismic angle stacks were used to derive probabilistic estimates of lithology, fluid and porosity distributions for the two reservoir sands. Particular attention was given to the low frequency model building component of the inversion workflow to optimally capture the distributions and thicknesses of the anomalous high porosity sands through a first-pass relative inversion. This study has derived reservoir property volumes that can be used in prospect appraisals and risk assessment. The workflow is robust and has universal applicability (Lamont, et al., 2008; Thompson et al., 2011).

STATISTICAL ROCK PHYSICS

Wells are often preferentially located and few in number. Formation lithologies may be sampled over narrow depth ranges. Variations in formation properties outside the logged intervals are unknown. Statistical rock physics aims to overcome these limitations by deriving the population behaviour of key lithology and fluid combinations as a function of end-member rock types, fluid content, reservoir quality and depth. Logs from Beg-1 and four regional wells were subjected to comprehensive petrophysical evaluation followed by statistical rock physics analysis and modelling.

Statistical rock physics analysis involved picking end-member lithology types

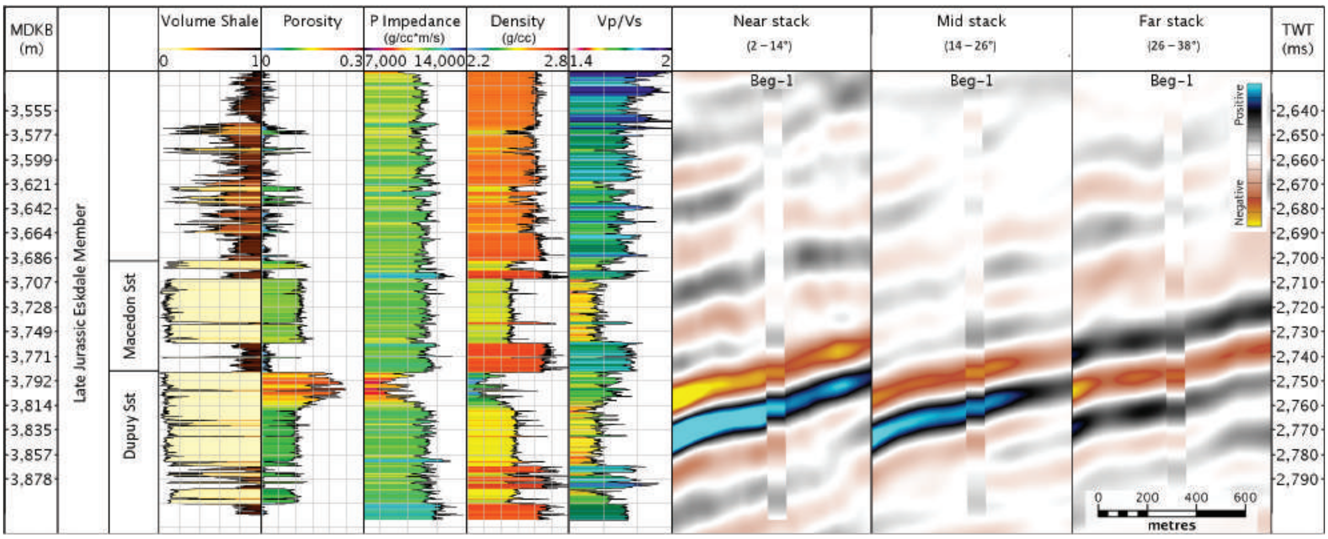

Figure 1: *Beg-1 well logs and intersection with seismic angle stacks. The seismic panels are overlain with corresponding synthetic seismograms. The top of the high porosity sand layer corresponds to a strong class IV seismic AVA event (negative amplitudes at near angles that reduce at far angles).*

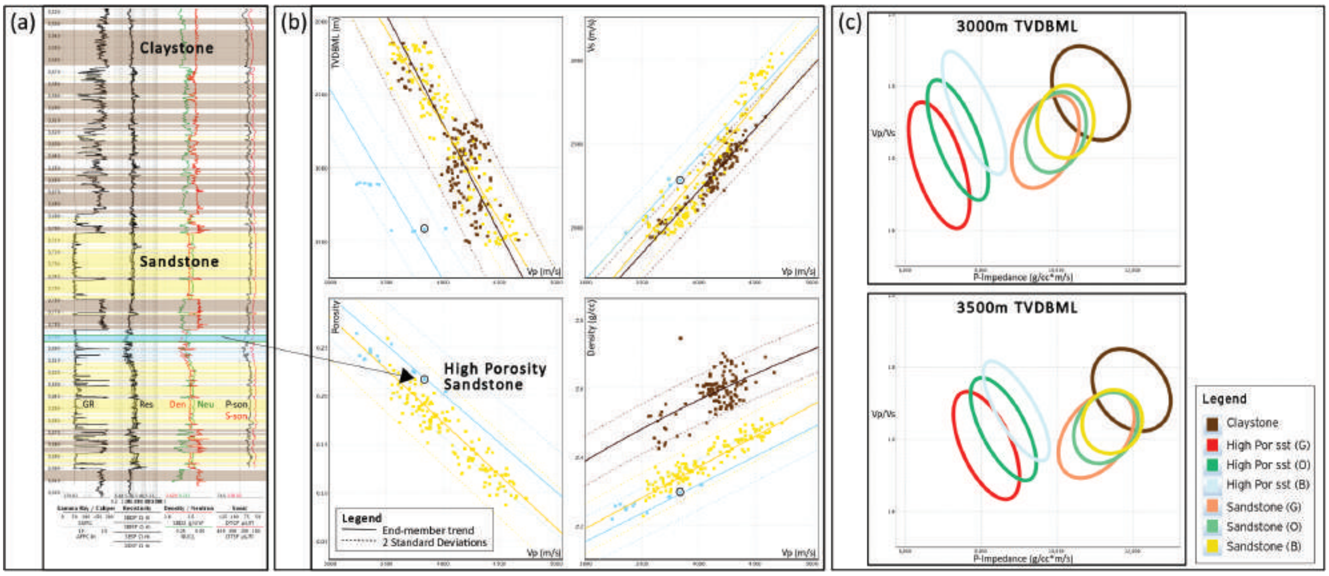

Figure 2: *Statistical rock physics analysis and modelling. **(a)** Intervals picked on Beg-1 logs. **(b)** End-member picks and end-member trends. **(c)** Depth-dependent probability density functions (PDFs) from stochastic forward modelling of the end-member trends and their associated standard deviations.*

and establishing end-member trends. End-members are the cleanest logged examples of any lithology defined using distinct elastic properties. End-member intervals (picks) were selected on logs (Figure 2a) and their elastic properties were upscaled to form single values. End-members relevant to this study comprised two reservoirs – high porosity sandstone and sandstone; and one non-reservoir – claystone. Picks for the reservoir end-members were Gassmann corrected to brine properties. The data points were cross-plotted: Vp vs depth below mudline (TVDBML), Vp vs shear wave velocity (Vs) and Vp vs density. End-member trends w ere established from the cross-plots for the reservoir and non-reservoir lithologies (Figure 2b).

Statistical rock physics modelling sampled the rock property distributions defined by end-member trends and associated standard deviations to derive large numbers of data points representative of the possible range of formation properties (the population behaviour) for each lithology and fluid mixture at any depth. Prior to sampling, reservoir and non-reservoir trends were proportionally mixed to represent formation characteristics consistent with petrophysical evaluations; and fluid mixture properties were obtained for these lithologies using Gassmann fluid substitution. The stochastically sampled data were cross-plotted for P-impedance vs Vp/Vs and were characterised using Probability density functions (PDFs) for each lithology and fluid mixture at depth increments (Figure 2c). The results were used to assess whether lithologies and fluids could be discriminated at any depth based on their elastic properties. At the depth of intersection of the reservoirs in Beg-1 (approx. 3,500 m TVDBML), the two types of sandstones are well discriminated from each other and from the claystone. Fluid discrimination is difficult for the sandstone lithology due to overlapping properties.

CONSTRAINED ABSOLUTE SIMULTANEOUS INVERSION

A proprietary constrained simultaneous inversion algorithm was used to transform three seismic angle stacks (2 to 38° at 12° increments) into elastic property volumes (P-impedance and Vp/Vs). An important component of the absolute inversion workflow is building the background low frequency elastic property models that supplement the results and account for information (in this case < 8 Hz) that is missing from the seismic. The presence of high porosity sandstone made this workflow particularly challenging. The thickness and elastic properties of the high porosity sand exerted a significant low frequency influence. The background models therefore needed to incorporate the 3D distribution of the sand in each of the multiple lobes of the basin-floor fan, along with their depth-dependent elastic properties. This was achieved through a two stage workflow.

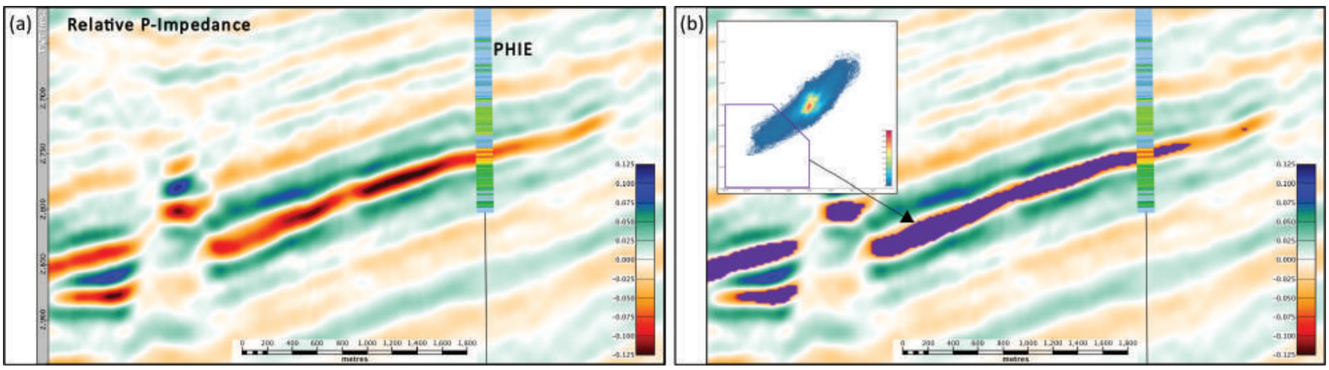

Figure 3: ***a)*** *Relative near stack impedance section overlain by the Beg-1 effective porosity (PHIE) log. The high porosity sandstone has a strong negative relative impedance response.* ***(b)*** *Relative near stack impedance section with the body-captured high porosity sand highlighted in purple. Inset shows a cross-plot of relative near vs relative far stack impedance volumes coloured by the density of data points. The polygon captures the high porosity sand layer depicted on the section.*

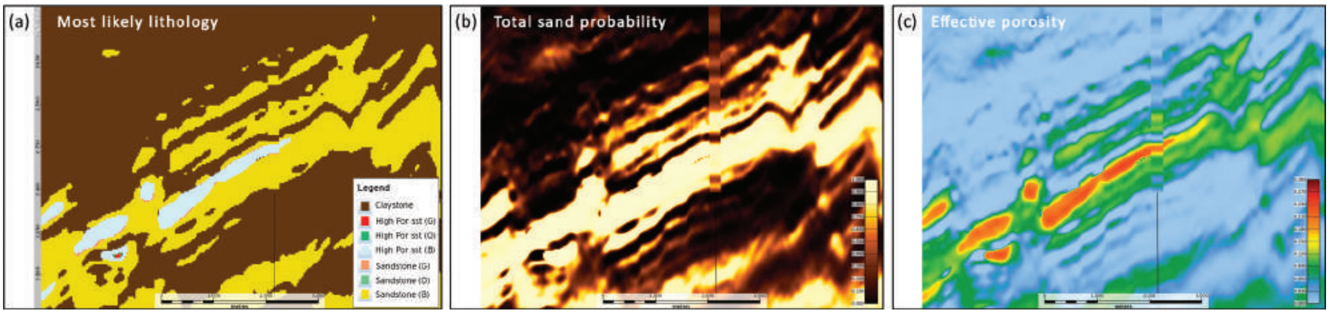

Figure 4: *Reservoir characterization from absolute inversion results.* ***(a)*** *Most likely lithology (MLL). The section is overlain by the upscaled (high-cut 60 Hz) MLL log calculated from the wireline elastic logs.* ***(b)*** *Total probability of sand overlain by the upscaled Vshale log.* ***(c)*** *Effective porosity section overlain by the upscaled PHIE log.*

In the first stage a relative simultaneous inversion was run and the high porosity sand body-captured based on relative near vs relative far elastic impedance volumes (Figure 3). The high porosity sand bodies were filled with elastic properties from the corresponding rock physics end-member trends. In the second stage, the high porosity samples were removed from the wireline logs, and background models were built using a polynomial relationship between the edited logs, end-member trend mixtures and seismic velocities. The models were updated to include the 3D morphology and elastic properties of the captured high porosity sand bodies. Absolute simultaneous inversion used the low frequency component of these updated background models.

PROBABILISTIC RESERVOIR CHARACTERISATION

Lithology and fluid probabilities (Figure 4) were derived by comparing absolute P-impedance and Vp/Vs volume samples against the depth dependent PDFs from statistical rock physics analysis. A Bayesian classification system was used to derive individual probability volumes for all lithology and fluid types. A most likely lithology or fluid type was also calculated at each sample in the volume. Rock physics trends were used to derive relationships, per reservoir end-member type, between porosity and P-impedance. Porosities were then calculated using absolute P-impedance from inversion weighted by the estimated probability of each reservoir lithology at each sample. This ensured that porosity calculations took into consideration the uncertainties associated with lithology estimation. Also, estimated values represent porosities of lithology mixtures in the formation rather than just their end-member types.

Lithology distributions (Figure 5) were converted to net pore thickness (NPT) maps by depth integration of the porosity trace for each reservoir type. Net pore volumes (NPV) were also computed. It is worth mentioning that tests of more conventional – but non-optimal – low frequency model building strategies (such as extrapolation of in-situ log measurements) resulted in NPV differences of up to 25% for the high porosity sandstone.

CONCLUSIONS

A complex basin-floor fan comprising multiple lobes containing two types of sand with different elastic properties has been successfully characterised for reservoir properties using a combination of depth-dependent statistical rock physics analysis and constrained absolute simultaneous inversion of seismic angle stacks. The workflow incorporated a novel approach to low frequency model building. The results can be used to de-risk prospects, especially for the high porosity sand lithology which is known to create a significant AVA response, even when brine saturated. A difference of up to 25% in NPV compared with more traditional low frequency model building strategies highlights the importance of the workflow used in this study.

ACKNOWLEDGEMENTS

We would like to thank DownUnder GeoSolutions and Murphy Australia Oil Corporation for their support and permission to present this study.

REFERENCES

LAMONT, M.G., THOMPSON, T.A., AND BEVILAQUA, C. [2008] Drilling success as a result of probabilistic lithology and fluid prediction: a case study in the Carnarvon Basin, W.A. APPEA Journal, 48(1).

THOMPSON, T., LAMONT, M., BEVILACQUA, C., AND HENDRICK, N. [2011] Fit for Purpose Seismic Reservoir. ◗

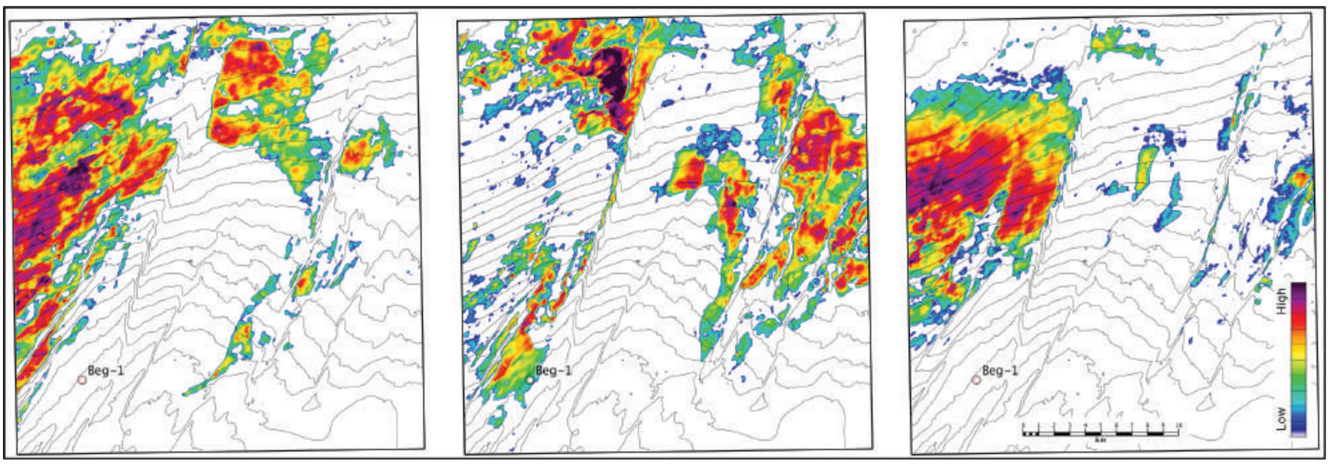

Figure 5: *Sample counts of the high porosity sandstone from three lobes of the Batavus fan. The Beg-1 well intersects the high porosity sandstone at the level of the Dupuy sand (middle panel).*