

SUCCESSFUL FLUID DISCRIMINATION IN TIGHT, OVERPRESSURED RESERVOIRS USING AVO INVERSION

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INTRODUCTION

In 1995, the Longtom-1/ST1 wildcat well – drilled in the northern part of the offshore Gippsland Basin (Figure 1) - encountered dry gas in tight, overpressured sandstones. The reservoir is situated in the Admiral Formation of the Emperor Subgroup. The Longtom-2/ST1 exploration well confirmed significant vertical and lateral extension of these prospective gas sands (see Figure 2) in 2004, and also provided very encouraging production test and core data. The recent Longtom-3 and -4 wells have demonstrated the viability of this new play by confirming significant lateral continuity of the thicker gas sands and demonstrating high gas flow rates. A multi-disciplinary and interactive approach, guided by seismic inversion techniques and real-time petrophysical data, resulted in the successful planning and execution of the Longtom-3 (for more information see Lanigan et al., 2007) and subsequently the Longtom-4 drilling and evaluation program.

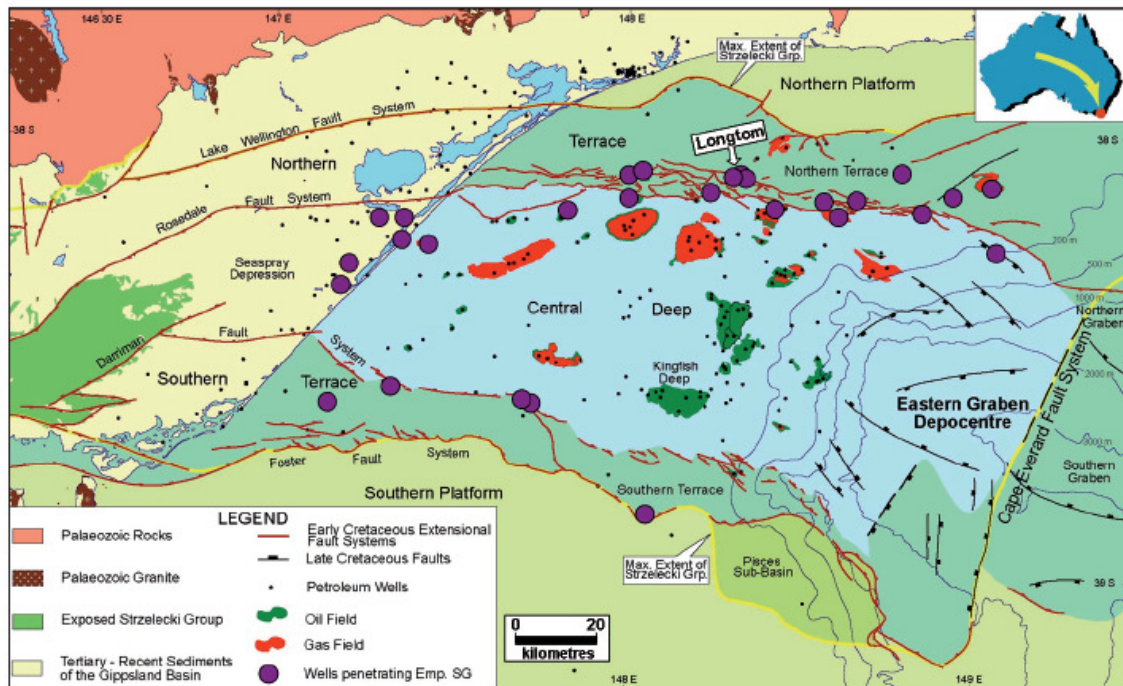


Figure 1: Gippsland Basin regional setting showing major tectonic elements and well locations where the Emperor Subgroup has been intersected (modified from Bernecker and Partridge, 2001).

The data from the first two Longtom wells indicated the potential for a sizable gas accumulation. However, structural mapping combined with the interpretation of the few pressure points and amplitude extractions from full stack seismic did not allow for a proper delineation of the size of the field. Before entering into an appraisal campaign, additional information was extracted from the seismic data through seismic inversion.

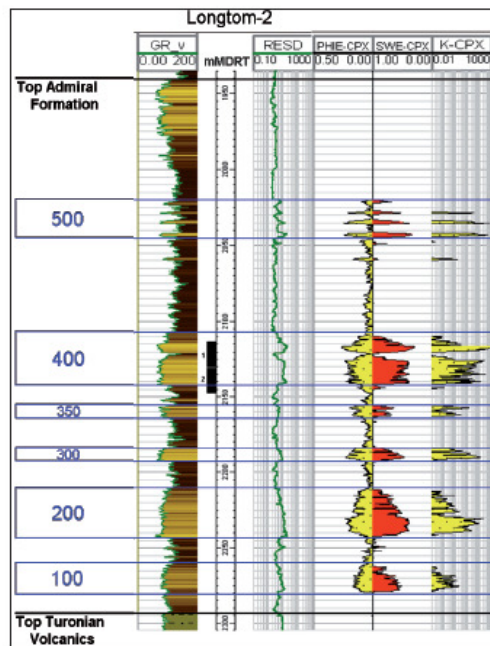


Figure 2: Admiral Formation gas reservoir nomenclature as used in Longtom-2. Note also the equivalent position of cores extrapolated from Longtom-2 ST1. (from Lanigan et al., 2007)

CORRELATION OF ELASTIC PROPERTIES AND PETROPHYSICAL PROPERTIES

Prior to the seismic inversion a petrophysical and rock physics study was carried out. The petrophysical study involved editing and conditioning of well log data to ensure consistency of the measured data between and within the wells. In addition, the petrophysical log analysis yielded volumes of fluids and minerals that are required inputs to the rock physics modelling.

The rock physics modelling provides a link between the petrophysical properties (water saturation, porosity, and clay content) and the elastic properties (v_p , v_s and density) of the rocks. Based on the method of Xu and White (1995), a single model was designed that is equally applicable to the reservoir and the encasing shales.

One way of analysing the effect of various petrophysical parameters on properties such as P-Impedance (P_{Imp}) and v_p/v_s is to use the rock physics model to compute those elastic properties as functions of the full range of petrophysical properties (Avseth et al., 2005). The result is a template made up of lines of constant properties such as porosity (PHIE) and water saturation (S_w) in any given parameter space, i.e. P_{Imp} vs v_p/v_s (see Figure 3).

The template illustrates that there is a pronounced fluid effect in the Admiral sands at Longtom. The ability to discriminate the gas from brine even at average reservoir porosities of less than 15% is somewhat surprising, since the HC effect is more pronounced at higher porosities. At relatively low porosities the gas and brine data points are usually not separated by much and often overlap. Therefore, a quantitative interpretation is generally not attempted at the porosity range encountered at Longtom.

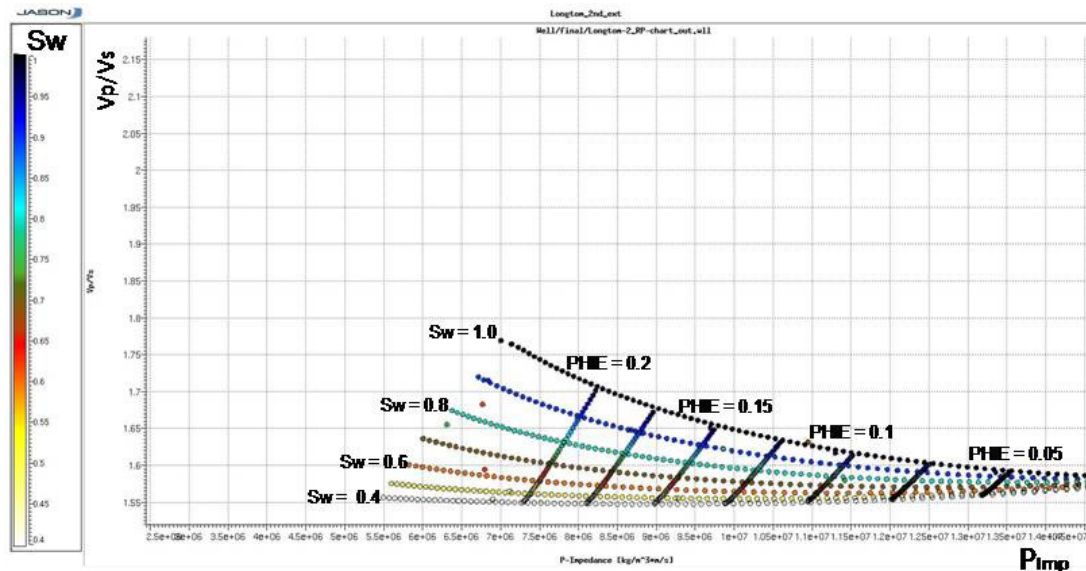


Figure 3: Rock physics modelling of the relevant range of S_w and $PHIE$. The sub-vertical lines represent contours of constant $PHIE$ whereas the hyperbolic lines mark lines of constant S_w . This cross plot represents sands with 5% V_{clay} only (after Avseth et al., 2005)

Plotting of the measured well log data (Figure 4) confirms that the gas sands and the brine sands are indeed well separated. The core in Longtom-2ST1 reveals that the 400 sands are unconsolidated despite their age and depth of burial. This may be the main reason why the fluid effect is so pronounced. In comparison, the separation of gas and brine sands is noticeably smaller for consolidated sands of the same porosity (Avseth et al., 2005).

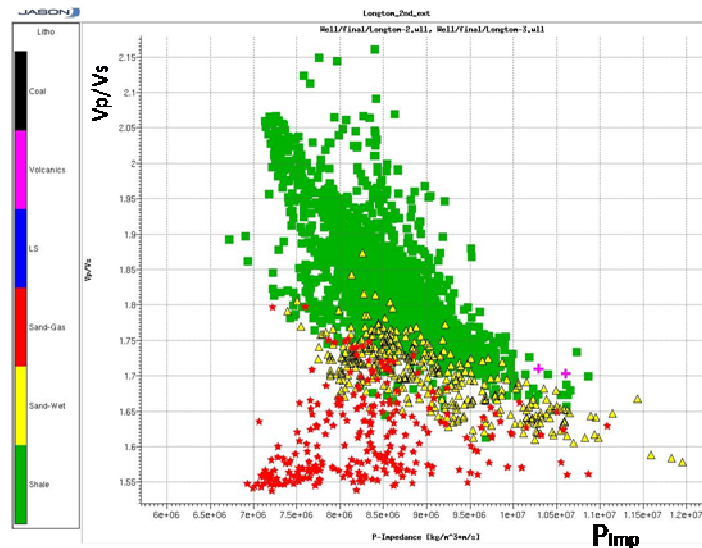


Figure 4: P_{Imp} vs v_p/v_s cross plot including well log data of the Admiral Formation from Longtom-1, Longtom-2 and Longtom-3P. The points are coloured by lithofacies.

Dvorkin and Walls (2000) have shown that in gas filled sands P_{Imp} and in particular v_p/v_s decrease with increasing overpressure which results in a greater separation from brine filled sands. This enhanced fluid discrimination is very similar to that of friable sands. The overpressure might in fact be to some extent related to the unconsolidated state of the gas sands (see discussion).

FLUID INDEX AND SEISMIC INVERSION

Definition of a fluid index

Figure 4 demonstrates how the cross-plot of P-Impedance versus v_p/v_s allows for the discrimination of gas sands from brine-filled sands as well as the discrimination between sands and shales. This plot and the rock physics model have shown that there is a significant overlap in P_{Imp} between gas sands, brine sands, and shales. v_p/v_s is a better discriminator. However, an optimal separation of the lithofacies can only be achieved by combining P_{Imp} and v_p/v_s .

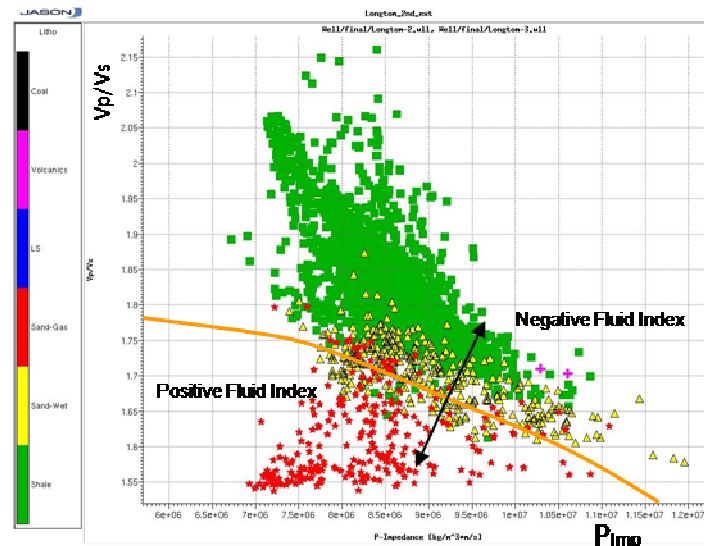


Figure 5: Definition of the fluid index. The orange line represents the fluid index zero-line.

In order to combine P_{Imp} and v_p/v_s and thus enable an enhanced discrimination of gas sands an attribute referred to as fluid index (FI) is calculated. FI is a generic term for an attribute that is likely to show a good correspondence with reservoir fluids. It is tied directly to the rock physics by defining a line that in the centre of the plot is sub-parallel to the $S_w=0.9$ contour line from the rock physics template of Figure 3. Each P_{Imp} , v_p/v_s data point is given an FI value directly proportional to its perpendicular distance from the line, negative above and positive below (see Figure 5).

We have seen that fluid discrimination is possible at log scale but what happens at seismic scale? One way of testing the averaging effect of seismic is to high-cut filter the logs to the upper seismic frequency limit. Figure 6 demonstrates that fluid discrimination is still possible at seismic frequencies.

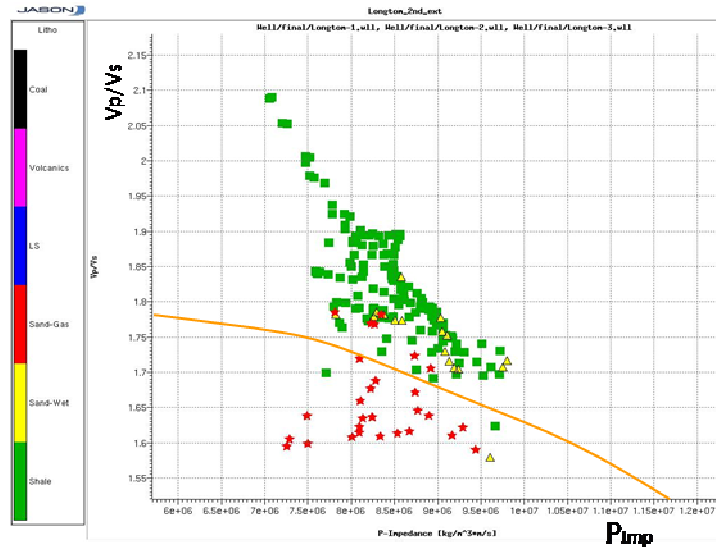


Figure 6: P_{imp} vs v_p/v_s cross plot including high-cut filtered well log data of the Admiral Formation from Longtom-1, Longtom-2 and Longtom-3P. The high-cut is set to 40 Hz. The points are coloured by lithofacies.

Moreover, Figure 6 reveals a slight shift to the right of the brine sand points which implies a decrease in porosity. This can be confirmed by a comparison between average porosities of brine and gas sands, which exhibits a marked difference of the order of 2%-4% (see Table 1). Since the seismic inversion result effectively averages properties due to the limited bandwidth of the input seismic, it is reasonable to look at the average porosities of each sand.

Sand	Average Porosity		Difference
	Gas	Water	
400	15.8	13.2	2.6
300	14.7	12.2	2.5
200	14.4	10.3	4.1
Average			3.1
100	13.3	n/a	n/a

Table 1: Differences in average porosities (PHIE with 8% net reservoir cut-off) between gas and brine sands in Longtom-1, Longtom-2 and Longtom-3P.

A successful seismic inversion depends on favourable rock physics and on seismic data quality and seismic resolution. The limits of the latter are tested by seismic forward modelling of thickness variations of the Longtom-2 reservoir sands. This modelling indicates that the seismic inversion should be capable of identifying moderate to good quality gas-bearing sands with a thickness of greater than 13 m, particularly where they are bounded above and below by shaley intervals as thick as at Longtom-2 (Figure 7). The impact of the seismic data quality is usually examined during the inversion process itself and will be briefly discussed below.

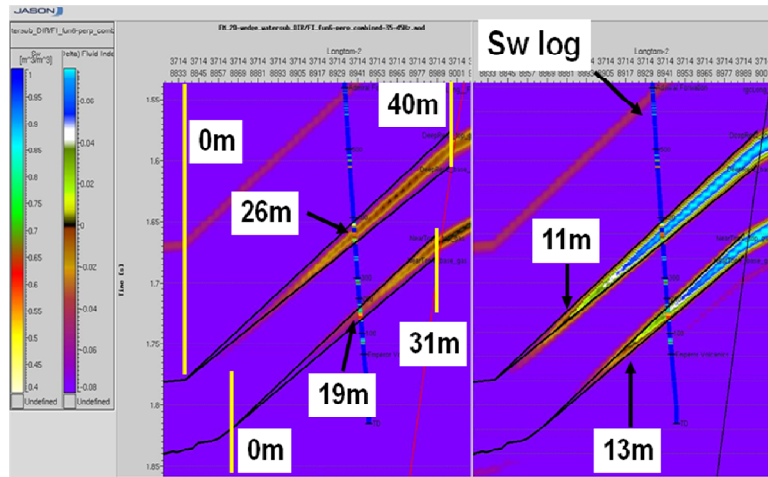


Figure 7: Seismic forward models of thickness variations of the 400 (upper) and 200 (lower) sands, respectively, from Longtom-2. The left panel shows the brine case and the right panel the gas case. The sections show the modelled FI response. The posted thicknesses on the left panel refer to the minimum, maximum and well thickness and the posted thicknesses on the right panel refer to minimum, resolvable. The inserted well log is Water Saturation.

Simultaneous AVA inversion

The technique for deriving FI from P_{Imp} and v_p/v_s was applied to an inversion of the Northern Fields 3D (NF-3D) seismic data using Fugro-Jason's Simultaneous AVO/AVA Constrained Sparse Spike Inversion processing, which inverts multiple offset/angle stacks (Pendrel and Dickson, 2003). Previous reprocessing of the NF-3D data had provided an improved seismic dataset with an extended angle range and this was used in the inversion processing, generating three angle stacks with ranges of 5–15° (near), 15–30° (mid) and 30–45° (far).

Figure 8 illustrates how well the technique works on seismic data that is rather limited in its quality and frequency range (dominant frequency of about 20 Hz and far stack limited to about 35 Hz). The positive FI values are represented by yellow to blue colours whereas the negative values are orange and purple. FI of zero is black. The drilling of Longtom-3H was guided by this depth converted FI section.

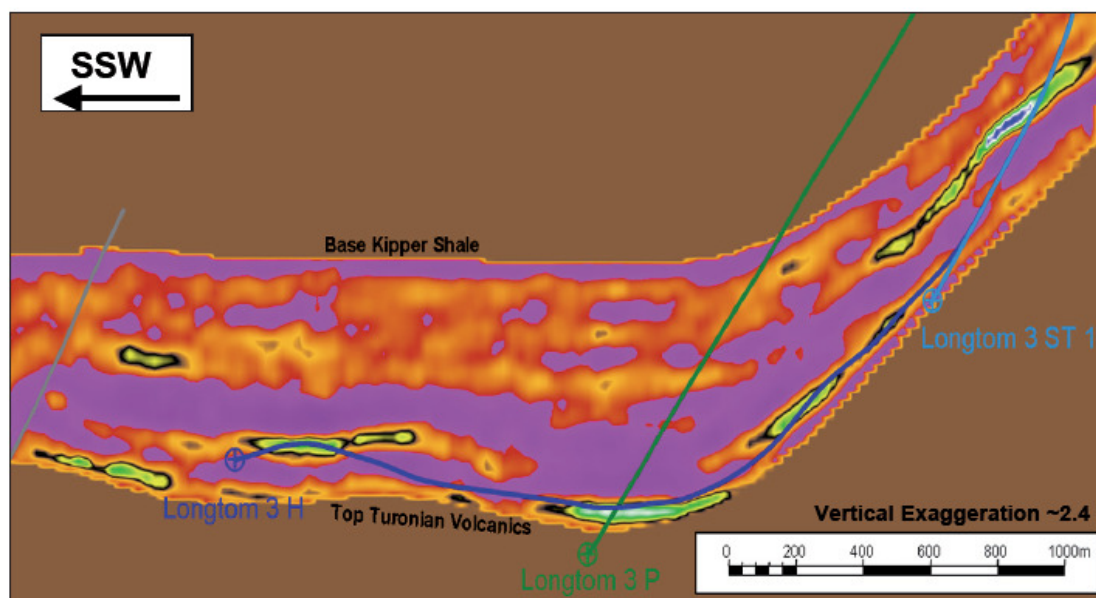


Figure 8: Fluid Index depth section along the Longtom-3H well trajectory showing anomalies ascribed to the presence of thick gas-filled sands.

DISCUSSION

One question that has arisen is: why are the gas sands unconsolidated? There are two processes that have been identified, which result in a soft elastic rock frame similar to that of friable sands. On the one hand, the difference in porosity between brine sands and gas sands suggests either delayed cementation or cement dissolution in the gas sands. Both processes can result in reduced pore stiffness. On the other hand, an increase in pore pressure also softens the elastic rock frame (Avseth et al., 2005). Hence, it appears likely that a combination of diagenetic processes and overpressuring has contributed to the observed friable state of the gas sands. There might be other reasons as well.

Generally, when modelling the elastic properties of sands with varying fluid fill to determine the feasibility of detecting the hydrocarbon effect, porosities within the same sand are kept constant. The presented example suggests that it might be beneficial to include differences in porosity for different fluid phases if there are indications for such a scenario. The porosity contrast results in an increased P_{Imp} contrast between gas and brine sands which potentially improves the fluid discrimination through seismic inversion.

A rock physics framework offers the opportunity to go beyond the mere exploitation of a fortuitous rock physics setting by enabling insight into the factors that drive the response. Such insight can lead to integrating other geologic aspects such as diagenesis, sand composition and texture. The wider integration of geophysical and geological properties holds the potential to advance the understanding of the field in general.

CONCLUSION

The presented example of the Longtom gas field demonstrates how quantitative seismic interpretation is possible in low porosity sands. The discrimination of gas from brine is largely driven by v_p/v_s , which requires AVO inversion. At Longtom, the imaging of gas sands by simultaneous inversion is potentially further enhanced by the difference in porosities between gas and brine sands.

Overpressure is a factor to be aware of because it potentially enhances fluid discrimination. At Longtom, it might be a key reason for the unconsolidated state of the sands, which causes the pronounced gas effect.

The simultaneous seismic inversion has been a key contributor to the successful appraisal of the Longtom gas field. It is hard to imagine how the two sinusoidal wells, Longtom-3 and -4, could have been drilled with such success without the simultaneous inversion and associated fluid index images.

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