Rock physics analysis of reservoir elastic properties often assumes homogeneity of the intra-reservoir shales, and simplifies the cap-rock shale variability. The main reason for simplifying shale variation is lack of data and suitable analogues; however, such simplification could lead to misinterpretation of seismic amplitudes, including missed opportunities in the exploration phase. Assuming favourable rock physics, seismic analysis in the exploration phase often links bright amplitude areas with high quality reservoir rock or increasing hydrocarbon saturation, while areas with weak amplitudes are considered as poor quality reservoir or water-bearing. Variations in amplitude could however also be caused by variations in the elastic properties of the overlying shale. For example, high hydrocarbon saturated reservoir sands might be overlaid by elastically softer cap-rock shale, resulting in weak seismic amplitudes. This paper describes a detailed shale-variability analysis for the Enfield oil field using rock physics models, and discusses the implications for seismic reservoir characterisation and inversion.

The Enfield appraisal wells are openly available for the rock physics analysis to understand lithology variation effect on the seismic amplitudes. The target reservoirs for this study are Upper Jurassic to Lower Cretaceous in age, and consist of good quality sands with intra-reservoir shales. Detailed reservoir descriptions and the details of field development have been widely published (Ali, et al, 2008; Davis, 2011; Hamp et al., 2008). An analysis of the field’s eastern-most block briefly mentioned the importance of overlying shale variability and the requirement for Vp/Vs ratio to track the fluid response in this area (Sliver block Figure 1). The block was initially thought to be water-bearing because of the weak amplitude contrasts, but was proved hydrocarbon bearing by the Well-4 drilling (Smith, et. Al., 2008). Five appraisal wells (including Well-4) and the Enfield seismic dataset acquired in 2004 are used in this analysis (Figure 1).
Figure 1. Enfield reservoir top amplitude map, Sliver block weak amplitude area is highlighted (left plot). SEG normal convention seismic full stack (right plot) shows the Top Reservoir as trough amplitude across five appraisal wells. Well-1, 3 and 4 are in the oil leg, Well-2 is in the water-leg, and Well-5 penetrates the gas–oil contact.

Rock Physics Analysis

Preparation for the rock physics analysis includes petrophysical review, Gassmann fluid substitution, well-to-seismic ties, and depth trend analysis. Part of the log review process uses Gardner (Mavko, 2009) trends and Castagna (Mavko, 2009) models to improve elastic log consistency for all wells. Gassmann fluid substitution provides logs with brine, oil and gas saturations in the sands of interest. Depth trend analysis indicates that the reservoir sand trends appear consistent, but highlights the spatial variation in the cap rock shales across the wells. The cap rock shale at Well-4 in the Sliver block is the softest among the five wells, while the Well-2 cap rock shale is the stiffest. The exact source of such shale variation is unknown; however one may speculate on variations in local clay diagenesis associated with variations in depth and the proximity to faults.

The sand trend appears consistent but an analysis of velocity-porosity variation indicates variation in the intra-reservoir shales. The transition of the clean sand to shaly-sand from the velocity-porosity analysis seems gradual for most of the wells, which is consistent with the reservoirs units being dominated by laminated sand-shale structures. All wells except Well-4 show a stiffening effect with gradual pore-filling clay (Figure 2, Model-3). Well-2 and Well-3 shaly-sand transition follows a v-shaped trend with increasing clay content, which is interpreted as dispersed clay materials in the sand pore space as described by Yin-Marion and Dvorkin-Guiterrez models (Avseth, 2005). The mixture of the dispersed and laminated structures in the intra reservoir shales is visible from all wells; some wells indicate one structure is more dominant than the other. Additional analysis of the intra reservoir shale variation using Thomas-Stieber model underlines the low and high porosity shale mixtures in laminar, dispersed and structural shapes (Mavko, 2009). The analysis shows a separate effect of the dispersed and laminar shales to the reservoir sand effective porosity. It also confirms the previously observed softening effect at Well-4 reservoir sand is related to the laminated structure, as the reservoir sand net-to-gross is reduced dominantly by the laminar clays.
The cementation and sorting interpretation is performed in the subsequent analyses. The rock texture interpretation uses velocity-porosity diagnostics, proposed by Dvorkin and Nur in 1996 (Avseth, 2005). The shale points (Vsh >0.5) are separated from the sands, and brine velocity is plotted against the total porosity to remove the fluid effects. Interpretation of the reservoir cement content and sorting trend uses Dvorkin’s Contact-cement and Avseth’s Constant-cement models (Avseth, 2005). The Contact-cement model describes the behaviour of the velocity with cement volume at high porosity, and is used to model the porosity reduction because of the increasing cementation. The Constant-cement model describes the velocity variation associated with sorting at specific cement volume, typically corresponding to near constant depth. The analysis suggests reservoir sand porosity is largely reduced by increasing clay content, but the velocity is relatively insensitive to this porosity variation. It also shows three possible porosity reduction mechanisms (Figure 2), as follows:

1. Porosity reduction by increasing cementation. This dramatically stiffens the rock (increases velocity). For example, a ten percent porosity reduction will increase Vp and Vs by 14%, and density by two percent.
2. Porosity reduction by stiffening clay. About twelve percent porosity decrease will increase Vp, Vs and Rho by two percent.
3. Porosity reduction by softening clay. Ten percent porosity decrease will reduce Vp and Vs by two percent while increase the density slightly by 1.5%.

The three porosity models show that in the sorting-dominated reservoir, porosity reduction could cause softening and stiffening effect depending on the clay distribution. The intra reservoir shale variation is equally important as the cap rock shale variation changes the seismic reflectivity. The Enfield data suggests the velocity variation with increasing clay distribution could be very small (2%) on the velocity change. AVO variation upon adding different clay distribution over the water-bearing sands is however measureable. For example, the water-bearing sand at Well-4 produces Class-II AVO, while the oil-bearing sand produces Class-III AVO. The increasing soft clay volume in the sand pore space will change
the AVO response into a weak Class-III, whereas adding the stiffening clays will change the AVO response into Class-IIp. This means the shalier water sand AVO response might overlap with some of the oil sands.

AVO analysis further shows larger velocity variation associated with fluids than with lithology variations. It also shows the porosity reduction by pore-filling clays in the oil-bearing reservoir could change the AVO intercept and gradient. The acoustic impedance contrast might be similarly weak for water-bearing Well-2 and oil-bearing Well-4 on the full stack seismic data but AVO variation should separate fluids and lithology changes. The combination of the rock physics models, e.g. porosity reduction models and the AVO modelling should improve the understanding of the fluid and lithology effects. For the comparable exploration cases as in the Enfield Sliver block to be successful, rock physics analysis should facilitate a wider range of the lithology substitution scenarios to capture the softer cap rock shale in the forward modelling and AVO analysis.

**Inversion Implications**

Variability within the reservoir because of the pore-filling clay is considerable but still smaller than changes related to the pore fluids. The porosity reduction because of pore-filling clays causes too small of a velocity variation. The AI contrasts between the water-bearing sand and the cap rock shale are small for most of the wells except for Well-2. As the shales become stiffer, it may be feasible to separate shales from the sands around Well-2 location in the down dip northeast block using the AI inversion. The clay distribution and cementation variation appear to change Vp/Vs ratio more than Vp. The conventional AI inversion of the full stack seismic consequently will not fully resolve the porosity variation but the gradient impedance inversion according to the AVO modelling could potentially be used to interpret the reservoir net-to-gross variation.

Conversely, increasing hydrocarbon saturation tends to decrease Vp, slightly increase Vs, slightly decrease density, and hence decrease AI, and Vp/Vs significantly. The overall hydrocarbon effect will soften the reservoir regardless of the porosity variations. The Vp/Vs or Poisson Ratio variations are large within Enfield. Well-4 and Well-5 water sands Vp/Vs is overlapped with the cap rock shales Vp/Vs, thus creating very weak AVO contrast. The increasing hydrocarbon saturation in both wells decreases both AI and Vp/Vs and separates the reservoir from the cap rock shale properties. This means the AVO inversion should be able to identify different pore fluid content in spite of weak acoustic impedance contrast at Well-4.

Well-1 and Well-3 water sand AI’s are well-separated from the cap rock shales, but the Vp/Vs properties are overlapped. Increasing oil saturation in both wells decreases AI and Vp/Vs away from the shale range producing strong AVO responses, especially at the larger offsets or angles. Well-2 water sand AI and Vp/Vs are well-separated from the stiff cap rock shales and increasing hydrocarbon saturation will create even stronger seismic amplitude contrast at any seismic offset or angle range. Combination of AI and Vp/Vs information at different angle stacks will track the fluid responses for all wells. Simultaneous inversion of the partial stacks is therefore needed to interpret pore fluids from seismic amplitudes (Figure 3).
Conclusions

Enfield shaly sand rock physics analysis shows the underlying effects of the cap rock shale and intra reservoir shale variations on the seismic reflectivity. The seismic amplitude changes because of the cap rock and intra reservoir shales can cause misinterpretation of seismic amplitudes and inversion results. The rock physics analysis shows the Sliver block case where the cap rock shale is softer and the pore-filling clay softens the reservoir sands. The acoustic impedance contrasts are similarly weak for the oil-bearing sands in the Sliver block and the water-bearing sands in the northeast block. Combination of the rock physics model and AVO analysis can be used to separate the oil-bearing from the water-bearing sands fairly accurately. The rock physics model in such cases should capture a wider range of forward modelling scenarios, including softer cap rock shales, variation in the intra reservoir shales, cementation model and porosity reduction models by different pore-filling clay type distributions. The porosity reduction process does not necessarily always increase the velocities.

Rock physics analysis suggests the reservoir is insensitive to porosity and accordingly the conventional full stack acoustic impedance inversion would provide little value in the porosity interpretation. AVO gradient and intercept inversion could provide more information in the net-to-gross estimation because the laminar and dispersed clays in the intra reservoir shale variations appear to change the AVO responses. Simultaneous inversion of partial stacks is needed to track the fluid response using AI and Vp/Vs because the pore fluid has a larger effect on both elastic properties.

The analysis of the reservoir shaly sand and cap rock heterogeneity should be empirical. Rock physics models can be used to inspect the shale variations in absence of core measurements. Well data should be carefully studied to understand the underlying lithology variations and the hydrocarbon saturation effects to avoid misinterpretation of the seismic amplitudes.

References


DAVIS, O., 2011 - Improved reservoir management using 4D seismic at Enfield oil development, Western Australia, presented at the EAGE/SPE Joint Workshop – Closing the Loop: Reservoir Simulation & Geophysical Measurements. Istanbul, Turkey, 4-6 April 2011.


SMITH, M., GERHARDT, A., Mee, B., RIDSDILL-SMITH, T., WULFF, A., and BOURDON, L., 2008 - The benefits of early 4D seismic monitoring to understand production related effects at Enfield, North West Shelf, Australia, 78th annual SEG meeting, expanded abstracts, 3159-3163. Las Vegas, USA.

THOMAS, G.P. and SMITH, M., 2010 - 4D Seismic Benefits to Development Drilling at Enfield - North-West Shelf – Australia, presented at 72nd EAGE Conference & Exhibition incorporating SPE EUROPEC. Barcelona, Spain, 14 - 17 June 2010.