Seismic petrophysics workflow in data-poor environment: a case study for Petrel field (offshore Australia)

Introduction

Rock physics modelling (RPM) is often applied to forward model seismic rock properties (P-, S-wave velocity, and density) from observed reservoir properties. However, it is equally useful to apply RPM in a reverse sense when elastic properties are available and petrophysical properties are desired for formation evaluation and reservoir model building. Therefore, theoretically substantiated RPM, when accurately calibrated using core and log data, may guide reservoir quality evaluation by filling gaps in the intervals of poor or missing data.

We have designed a custom-built workflow that allows accurate restoration of both formation evaluation and seismic rock property logs and successfully implemented it in the Petrel gas field, offshore Australia, which suffers from poor quality input log data. The resulting shale and sandstone RPMs combined with core measurements were used to help validate reservoir quality in five of the seven exploration and appraisal wells drilled in the Petrel field to date.

Geology and formation evaluation

The Petrel gas field is located in the Bonaparte Basin, North-West offshore Australia. The good quality reservoir interval is interpreted to be attributed to deposition of tidal sand bar of the Cape Hay Formation. Special core analysis carried out on 73 samples complements regular core analysis performed on 418 samples. Petrographic analysis, including SEM images, and reservoir quality measurements (helium porosity and air permeability) on cores extracted from some wells in the field show significant level of chemical diagenesis manifesting as pressure solution and quartz cementation (3-25% of the rock) and resulting in extensive, often sutured grain contacts and porosity reduction in reservoir sandstones. The residual primary porosity ranges from 5-25% and typically displays chlorite clay coating, which may be one of the porosity preservation mechanisms (Saigal et al., 2016).

Necessity of core data usage in this study is dictated by the poor quality of the wireline logs in all study wells. Quality of the relatively shallow reading logs, such as density (RHOB), neutron (NPHI) and shallow resistivity (SRES), was dramatically affected by extensive borehole breakouts (Figure 1). The logs with greater depth of investigation, such as gamma ray (GR), deep resistivity (DRES), and compressional sonic velocity (Vp) were assumed to be of fair quality, i.e., negligibly affected by the washouts. Available shear velocity (Vs) logs often exhibited inconsistency with compressional sonic (old wells with a monopole shear travel time acquisition without processing). Therefore, all the Vs logs had to be either extensively edited or entirely reconstructed from the other available data.

Methodology

The first iteration of the deterministic petrophysical analysis of the Cape Hay sand-shale formation takes advantage of the core data in combination with the wireline logs of better quality in the following sequence:

1. available XRD data were used to calibrate the volume of clay $V_{cl}$ on the solid rock basis in all wells using normalised GR log; the XRD data clearly indicate that the shallow marine sands in the reservoir sections are relatively clean sandstones and coarse grain siltstones (from thin bed sections) with $V_{cl} = 1-12\%$, i.e., arenites in terms of their seismic petrophysics classification (Vernik, 2016); final $V_{cl}$ log shows good agreement with core XRD-based total clay volume determination (Figure 1);

2. the volume of shale, $V_{sh}$, was calculated from $V_{cl}$ by distinguishing the relatively homogeneous shale intervals with $V_{sh} = 1$ ($V_{cl} > 35\%$), arenite-quality sandstones with $V_{sh} = 0$ ($V_{cl} < 10\%$), and then linearly interpolating between these $V_{cl}$ thresholds for heterolithic (thin bed) intervals, where $0 < V_{sh} < 1$ (Figure 1);

3. the first version of the total porosity log (PHIT, den, core) was compiled from the core porosity log and augmented by the PHIT log calculated from the mud filtrate invasion-corrected density log in intervals of reasonable log quality (Figure 1).
Second iteration of petrophysical evaluation was carried out to fill extensive gaps in the log data and it was predominantly guided by the rock physics models. In this effort, the RPM templates, calibrated in sandstone and shale end member lithologies (wherever resolved by logs), were applied followed by the appropriate mixing models (arithmetic/harmonic) with Vsh as the lithology discriminator and the weighting factor in heterolithic intervals. PHIT logs in shales (Vsh=1) were predicted from P-wave velocity and clay content using the calibrated heuristic RPM designed for inorganic shale (Vernik, 2016). Prediction of the missing porosity in the Cape Hay sandstones was done by calibrating the Vernik-Kachanov (VK) RPM (Vernik and Kachanov, 2010; Vernik, 2016) in Vp-PHIT domain using core porosity. This sandstone diagenesis model was preferred over other popular alternatives (e.g., “patchy cement” model of Avseth et al., 2016), as it accounts for the entire porosity (and, hence cementation) range, realistic pore geometries, and microcrack densities as well as mineralogy. The log and core porosity-based calibration of these RPMs is shown in Figures 2a and 2b. Importantly, the sandstone RPM calibration resulted in (1) pore geometry constraints consistent with SEM images, and (2) the crack density values greater than the default values.
Finally, a continuous porosity (PHIT final) was obtained over the entire Cape Hay Formation by (1) weighting between the shale porosity and the sandstone porosity logs using Vsh as the weighting factor, and then (2) merging the result with the reliable porosity derived during the first petrophysical iteration (Figure 1 and Figure 3a).

Results and Discussion

The cross plots of RHOB vs. Vp and Vs vs. Vp shown in Figure 3b and 3c incorporate our final set of key petrophysical and seismic rock properties logs for all study wells. Density and shear modelling process is also shown in one of the study wells in Figure 1. However, the ultimate validation of the workflow for the missing/unreliable log restoration and, notably, the rock physics based forward modelling of the seismic rock properties logs can only be achieved by a quantitative comparison of the AVO synthetic based on the RHOB, Vp, and Vs logs and seismic gather collocated at each well.

Figure 3 Log restoration results: (a) Vp-PHIT plot coloured by vcl; (b) Vp-RHOB plot coloured by vcl where in situ RHOB is computed from the total porosity logs in each well; underlying grey data points – raw data; (c) Vp-Vs plot coloured by vcl where the final in situ Vs is spliced from the good quality measured log fragments and the RPM-based Vs. Model line colours are the same as in Figure 2.

Figure 4 One of the five wells showing the final set of seismic rock properties logs, the initial and final AVO synthetics.

Indeed, Figure 4 illustrates improvement in AVO match between the synthetic model and the seismic gathers when the final set of seismic rock properties was used. This improvement is exemplified by the
comparison of the AVO curves generated in example well at the base of the porous reservoir sandstone interval using raw and conditioned/restored logs sets and the collocated seismic gather.

The workflow validation presented in Figure 4 corroborates the rock physics models of end member siliciclastic rocks, such as sands and shales, presented in Vernik’s (2016) book. It is important to emphasize that the Vernik-Kachanov sandstone RPM is based on the robust Mori-Tanaka effective field theory (Benveniste, 1987) and its applicability range is much greater than that in other rock physics alternatives (e.g., the frequently used Constant Cement model of Avseth et al., 2016), which are limited to lower levels of cementation. We also note that those alternatives often rely on some heuristic concepts and ignore pore geometry and crack density parameters. In all fairness, the shale RPM described in Vernik (2016) and applied in our workflow is also quite heuristic; however, its bedding-normal velocity predictions were recently independently verified by the Maxwell scheme-based inorganic shale model presented by Sevostianov and Vernik (2020).

Conclusions

We demonstrated that reliable seismic rock properties logs, such as density, P- and S-wave velocities, may be restored in wells with exceptionally poor data quality, especially when core data is available and used in conjunction with fundamental rock physics modelling approach. Calibrated rock physics models of end member siliciclastic rocks, such as sands and shales, are the key building blocks of the workflow. The models used are either based on strong theoretical foundation (the sandstone RPM) or are in reasonable agreement with Maxwell’s scheme-based shale models for bedding-normal velocity. Both RPMs show impressive accuracy over the entire porosity range.

The results of this petrophysical and rock physics study are now being used as the basis for joint impedance and facies inversion from a newly acquired broadband 3D seismic survey in an attempt to more accurately delineate the extent of the reservoir sands within the Petrel gas field. The methods described in this paper could be further applied to other siliciclastic reservoirs which have undergone similar depositional and diagenetic environments worldwide.

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References


