Depth conversion and seismic inversion of the Scarborough gas field

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SUMMARY

The Scarborough gas resource is located in the Exmouth Plateau of the North Carnarvon Basin, Western Australia. The reservoir is a deep-water basin floor fan complex. The overburden has multiple layers of polygonal faults and shallow anomalies, which have caused distortions that have affected the depth conversion and inversion of the reservoir section from seismic.

This paper shows how the application of advanced seismic processing, innovative seismic to well matching techniques and subsequent seismic inversion have resulted in a significant improvement when compared with seismic reservoir characterisation results which were obtained in 2010.

The use of full waveform inversion (FWI) up to 30 Hz provided a better velocity model for seismic imaging and, in conjunction with well ties in depth and well constrained tomography were able to significantly reduce the depth errors with residuals below 1m while preserving the geologic information in the high frequency velocity model. Consideration of the bias versus variance trade-off with respect to seismic inversion led to changes in the inversion workflow that resulted in improved depth conformance and frequencies exceeding 100 Hz in the reservoir section.

This has led to a reduction in subsurface uncertainty of the geology of the gas resource. In addition to this, it was concluded that only inversion algorithms that contain an appropriate amount of complexity should be used and the number of input angle stacks to the inversion should be maximised where it is feasible to do so.

Key words: Depth Conversion, Inversion, Scarborough, Exmouth Plateau.

INTRODUCTION

The Scarborough gas resource was discovered in 1979 within a deep marine clastic reservoir. Several 2D and one 3D seismic surveys have been acquired over the discovery with the 3D survey being acquired in 2004 with a relatively short cable. The 3D seismic was reprocessed in 2018, with source and receiver deghosting and full waveform inversion applied up to 30 Hz, leading to better velocity model resulting in a remarkably flat gas water contact and high frequency content within the reservoir interval.

An iterative process of well to seismic tie in depth on the 3D seismic and inverted acoustic impedance data was used to generate the time depth errors at the well locations. These depth errors were used as inputs to well constrained tomography to adjust the 30 Hz FWI velocity model producing the final well calibrated velocity model.

To aid the depth conversion and the reservoir characterisation of the field, the seismic data were inverted using a deterministic algorithm and, due to the improved processing sequence, a significant uplift was achieved when compared with previous inversion results. However, to further improve the inversion results, we considered and tested an application of the bias versus variance trade-off. That is, the bias that is inherent in assumptions used in the available inversion procedures and the variance of the function that are used in the inversion. The goal is finding the sweet spot in the trade-off where the overall amount of error is minimised. While this is often considered in statistical learning, it is not in the field of quantitative geophysics. The result of considering this trade off in quantitative interpretation has led to a significant uplift in the inversion results with little extra cost.

To achieve this, the inherent bias associated with various inversion techniques were considered. In addition, changes in the variance of the forthcoming solution were reduced by conditioning the input seismic gathers.

ACQUISITION AND PROCESSING

The Scarborough 3D survey was acquired in 2004 with a 4 km cable. It was reprocessed in 2018 employing source and receiver dehosting and a hybrid 30 Hz FWI and tomographic velocity model. FWI of up to 40 Hz was tested over a portion of the survey however the improvement in the imaging was not large enough to justify its application over the whole survey. The result was a gas water contact that is significantly flatter than the legacy processing with a velocity model that clearly images the gas bearing reservoir with low velocity anomalies (Figure 1). Furthermore, shallow gas anomalies can be clearly identified in the velocity model (Dickinson, 2019). Despite the short cable length and irregular grid, the processing recovered frequencies exceeding 100 Hz within the reservoir section.

DEPTH CONVERSION

As well ties in time did not adequately resolve the residuals between the seismic and the wells, an iterative process of well ties in depth was employed. In this process, the wells were tied to the seismic in depth with the depth converted seismic using the velocity model, which was generated using the smoothed 30 Hz FWI model. The ties to the wells were achieved by adjusting
(stretching and squeezing) the seismic in depth at corresponding geophysical markers along the wellbore. This resulted in depth errors at the geophysical markers. Then, using these depth errors, a fast track velocity model was generated and the seismic and relative acoustic impedance data were then depth converted using this model. The depth synthetics and gamma ray logs were then compared with the depth converted seismic and acoustic impedance respectively to assess the quality of the velocity model. The velocity volume was also assessed to ensure that geologically plausible results ensued. For Scarborough, this process was repeated three times to optimise the mismatch of the synthetics with the seismic and acoustic impedance volumes.

Once acceptable depth errors were determined using this process, well constrained tomography was used to create the final velocity model. Well constrained tomography transforms depth errors into time errors. Then, the error in the velocity model is calculated by projecting the time errors along zero offset rays and minimising the vertical difference between the observed and modelled travel times. As only one ray path is considered, this approach is fast when compared with conventional tomography which optimises the travel paths along many ray paths (Mancini, 2013).

By using well constrained tomography, the original character of the 30 Hz model post depth conversion (Agarwal, Boorman and Mancini, 2013) was preserved while still matching the well depths to an accuracy of less than 1 m (Figure 2).

![Figure 2. Residual reduction in metres over several horizons before and after well constrained tomography.](image)

Overall, this is an advanced approach for time to depth conversions combining numerical optimisation and mathematical iterations to produce a velocity model which matches the geology of the basin as is shown in Figure 1.

### SEISMIC INVERSION

Deterministic seismic inversion is a form of statistical regression and therefore, it is important to consider the bias versus variance trade off in this context. To illustrate this, consider that the recorded seismic response of a formation is given by

\[ R_{\text{recorded}}(x, \epsilon) = R_{\text{earth}}(x) + \epsilon \]

where \( R_{\text{recorded}} \) is the recorded seismic, \( R_{\text{earth}} \) is a function that describes the true seismic response of the earth, and \( \epsilon \) is the recorded noise. When one approximates the true earth response, \( R_{\text{earth}} \) with an inversion approximation, \( R_{\text{inversion}} \), then one assumes that

\[ x = R_{\text{inversion}}(R_{\text{recorded}}) \]

leading to an expected error of

\[ E \left[ (R_{\text{recorded}} - R_{\text{inversion}}(x))^2 \right] = \text{Bias}^2 \text{Var} \left[ R_{\text{inversion}}(x) \right] + \text{Var} \left[ R_{\text{inversion}}(x) \right] \]

where the bias is the difference between the expected value of the assumed inversion model and the true earth operator, \( \text{Bias} \left[ R_{\text{inversion}}(x) \right] = E[R_{\text{inversion}}(x)] - R_{\text{earth}}(x) \)

(Friedman, Hastie and Tibshirani, 2001), and \( \text{Var} \) is the variance operator and is defined as \( \text{Var}[R_{\text{inversion}}(x)] = E[(R_{\text{inversion}}(x) - E[R_{\text{inversion}}(x)])^2] \)

(Kreyszig, 2007).

Clearly, a perfect inversion model will completely characterise the underlying physics thereby minimising the bias. However, the model complexity will be increased thereby increasing its variance. To characterise a model with high variance, the cardinality of data that are required must be increased however, this is often infeasible. Hence the trade-off between bias and variance (Figure 3).

![Figure 3. The data are a quadratic function with Gaussian noise. The fitted curves demonstrate the effect of bias and variance.](image)
1. The input data are biased by the assumption that the AVA response varies linearly with angle within the range of each partial angle stack;
2. All errors in the recorded data are propagated into the inversion products without attenuation; and
3. A least squares regressor is usually a better noise attenuator than gather stacking.

There is therefore a balance between the potential quality of an inversion result and the number of input angle stacks that can feasibly be prepared. In general, the maximum number of angle stacks should be used as input to an AVA inversion. This will reduce the bias caused by the linearity assumption made when generating angle stacks. It will also attenuate the noise included in the inversion result to a greater extent than stacking. Ironically, this means that a larger number of noisier inputs will yield a better result than a smaller number of less noisy inputs.

APPLICATION TO SCARBOROUGH

The Scarborough survey was inverted using the Aki and Richards approximation as acoustic impedance and Vp/Vs ratio data were required by the interpreter. As a three-term approximation was used as the inversion model that effectively characterises seismic reflections to wide angles of incidence, the bias in the model was acceptable. Initially the seismic data were inverted using three angle stacks as these were readily available. This resulted in a significant uplift in the Vp/Vs ratio data when compared with the inversion which was undertaken on the 2010 reprocessing of the data (Figure 4).

Given that the three term Aki and Richards (1980) approximation contains three independent terms, it is inappropriate to use three input seismic volumes into the inversion products is maximised as the problem is determined. Because of this, the gathers were split into six input angle stacks (5-11˚, 11-17˚, 17-23˚, 23-29˚, 29-35˚ and 35-41˚) thereby making the inverse problem overdetermined. This resulted in an inversion Vp/Vs ratio volume that is more resolved with enhanced depth conformance when compared with what could be created using three angle stacks as is shown in Figure 4.

Figure 5 shows the enhancements that were gained on the relative acoustic impedance result when compared with what could be achieved using the 2010 reprocessing of the data.

CONCLUSION

By utilising well constrained tomography in combination with high frequency FWI and considering the bias versus variance trade-off with respect to seismic inversion, excellent seismic inversion and depth conversion results were achieved over the Scarborough resource.

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Figure 1. (A) 2010 PreSDM reprocessing with a velocity model overlay. (B) 2018 30 Hz FWI reprocessing with velocity model overlay. (C) 2018 30 Hz FWI reprocessing with well constrained tomography depth conversion with corrected velocity overlay showing a flatter gas water contact.

Figure 4. Relative Vp/Vs ratio extracted over the 7 m thick upper fan horizon with the gas water contact shown by the black contour. (A) Results from 2010 reprocessing. (B) Results from three partial angle stacks from the 2018 reprocessing. (C) Results from six partial angle stacks from the 2018 reprocessing showing an improvement in depth conformance.

Figure 5. Upper: Relative acoustic impedance from the 2010 reprocessing. Lower: Relative acoustic impedance from the 2018 reprocessing.