Case Study: Seismic Reservoir Characterization of a Deep Water Prospect Offshore Newfoundland

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Summary

Recently a deepwater exploration well was drilled offshore Eastern Canada that did not yield an economical discovery, although from a technical perspective, it can be considered as an exploration success. This paper describes the geophysical approaches used to locate the reservoir sands and demonstrates how log calibrated seismic inversions made the identification of hydrocarbons possible.

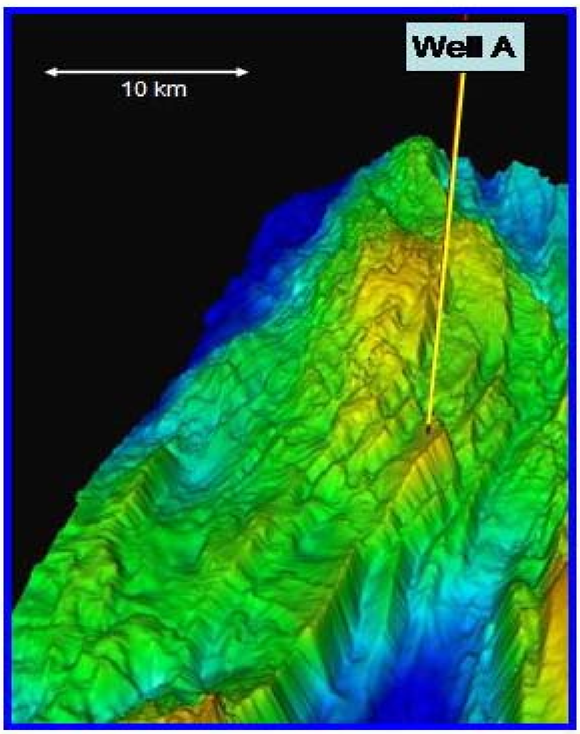

Figure 1: Location of Well

Geologic Framework

The study area is located offshore Newfoundland where the target sands are in the lower Cretaceous and upper Jurassic age strata. Extensional tectonics creates numerous rotated fault blocks. One of these is the target for well A (Fig. 1), which is located in deep water.

Seismic and Log Data Base

The study area is covered with a large 3D seismic survey. The survey was processed through pre-stack time migration outputting 25 offsets that were summed into three partial offset range stacks for use in the ensuing neural network and AVO/LMR analysis. Overall the data quality is good. Well B, which is within the 3D seismic survey, served as calibration for the seismic attribute analysis before well A was drilled. However, well A did not encounter hydrocarbons and in this case an oil hydrocarbon response was modeled using a Biot-Gassmann fluid replacement approach.

A full set of logs was acquired at the new well location A, which also included a shear sonic and a zero-offset VSP. Using the new data for calibration, Rp and Rs reflectivities were extracted from the 3D and inverted to P- and S-wave impedances in order to create LMR attributes.

Pre-Drill Seismic Analysis

3D migrated stack traces along with the three offset stack traces from the equivalent bins were extracted in the neighborhood of the existing well B. These traces were correlated with the time-converted Vshale and Gamma-Ray log of well B. By comparing several trace attributes and time windows it was found that average frequency and energy yielded the best correlation for predicting Vshale and Gamma logs from seismic. A neural network was trained to predict sand using these frequency and energy attributes extracted from the full and partial offset range stacks. Since real blind validation tests were impossible, log samples from well B were split into training and validation samples. Even though this was not a true independent validation it allowed for testing the neural network's performance. Figure 2 illustrates the predicted and measured Gamma-Ray log at well B. As can be seen a high correlation and confidence was established for sand prediction. The optimized neural network was eventually applied to the full 3D data set and Vshale was predicted at the proposed well location A. Figure 3 shows the prediction at the new well location in comparison with the actual post-drill measured Gamma-Ray. An impressive prediction and correlation was established at the correct zones where high quality sands were encountered.

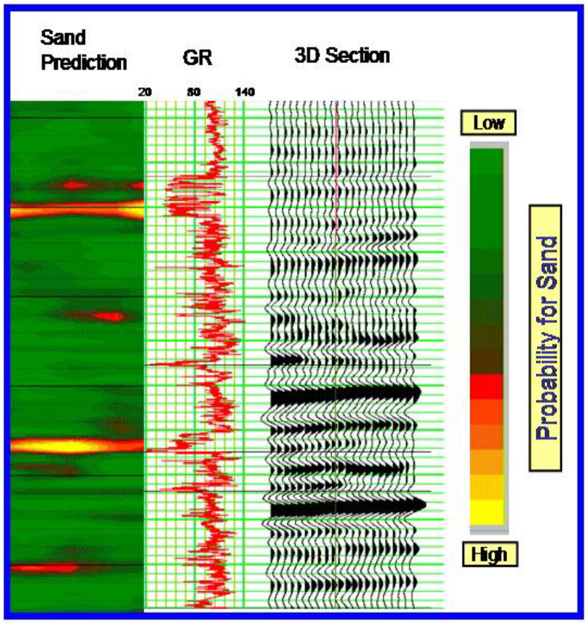

Figure 2: Sand Prediction Well B

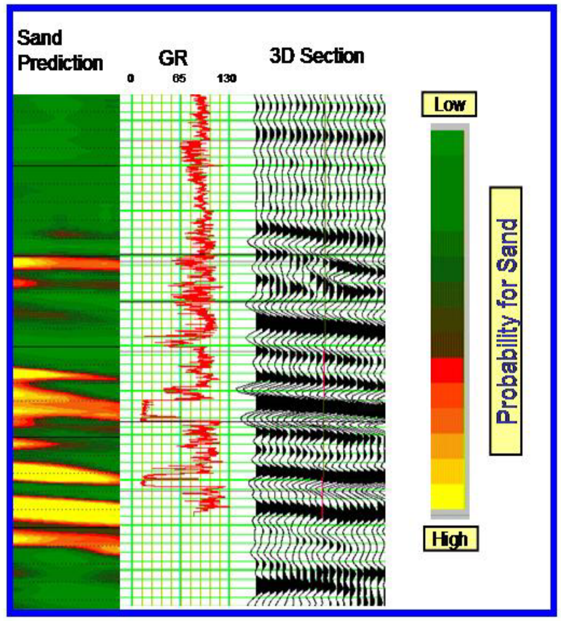

Figure 3: Sand Prediction Well A

Post-Drill Seismic Analysis

Following the successful pre-drill Neural Network analysis for sand presence, the post-drill log data from well A was used for a detailed AVO/LMR study in order to try and predict hydrocarbons. Figure 4 shows a LMR crossplot with the log data mapped as a function of porosity. The location and direction of the outlying points in the upper

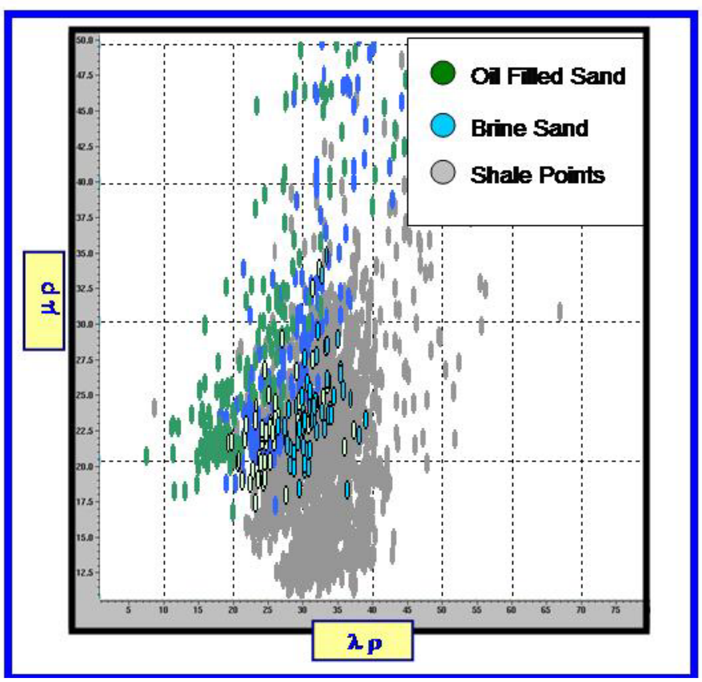

Figure 5: $\lambda\rho - \mu\rho$ Crossplot with Fluid

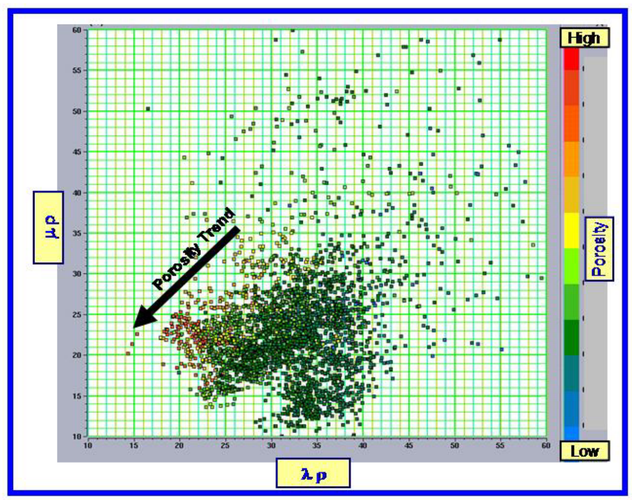

Figure 4: $\lambda\rho - \mu\rho$ Crossplot

left edge of the background cloud show an increasing porosity (hot colors) towards the origin and follow the established trends (Goodway 2001, Dewar J. and J. Downton 2002). Applying Biot-Gassmann fluid replacement of brine sand with oil filled sand was modeled in the LMR domain (Fig. 5). The expected horizontal $\lambda\rho$ shift (blue to green points) shows that LMR analysis has the capability to separate the oil from brine response and also shows the degree of discrimination. Using the velocity and density profile from well A the reflectivities Rp and Rs were extracted. LMR cubes were computed from impedance inversion of the Rp and Rs volumes. Applying the LMR results from the log based fluid substitution as templates to guide the 3D seismic cross-plot polygons, generated a map able anomaly with a down-dip limit that conforms closely with structural contour lines and closure (Fig. 6). Figure 7 shows a seismic section view across the main fault of the targeted fault block and explains why the particular fault block, on which the well was located, was not filled to spill. As shown by the red circle there is the possibility of a thief zone intersecting the anomaly at the limiting contour line. These observations confirmed that the mapped anomaly from LMR attributes is most likely linked to fluid fill.

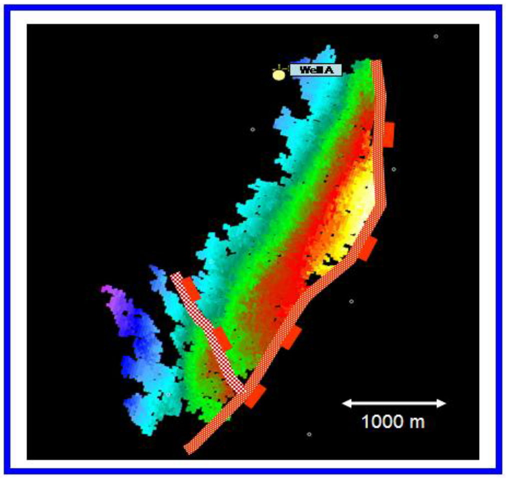

Figure 6: Structural Map with LMR Anomaly

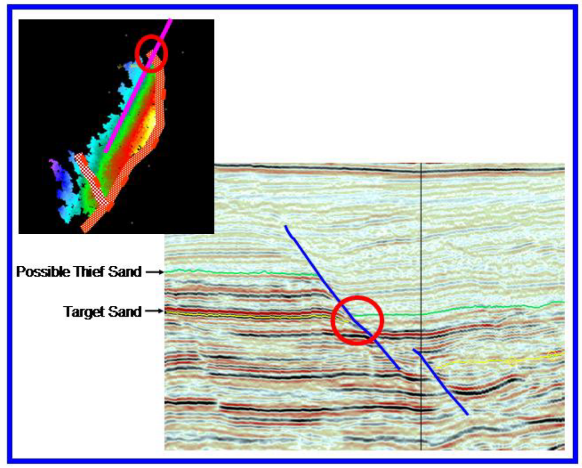

Figure 7: Seismic Section with possible Thief Zone

Conclusions

The discussed NN and LMR reservoir characterization techniques illustrate powerful tools to map sand bodies and possibly hydrocarbon potential within the 3D survey area. After calibration of the seismic inversions to the logs from a new well, this method was expanded to map the fluids in the reservoir. Based on these characterization methods new prospects have been identified.

References

Dewar, J. and Downton, J. Getting Unlost and Staying Found – A Practical Framework for Interpreting Elastic Parameters. In *Expanded Abstract CSEG Annual Conference,* (Calgary, Canada, 2002).

Goodway, W. "AVO and Lame Constants for Rock Parameterization and Fluid Detection". *Recorder,* 26, 2001, pp.39-60.