Grand Rapids Oil Sands 3D Seismic – Incorporating and Comparing Multiple Data Types for Reservoir Characterization

Laurie M. Weston Bellman*
Oil Sands Imaging Inc., Calgary, Alberta
laurie@oilsandsimaging.com
and
Marissa Whittaker
Oil Sands Imaging Inc., Calgary, Alberta
and
Marnie E. Connelly
Laricina Energy Ltd., Calgary, Alberta

Summary
Several advanced seismic methods were employed, incorporated and compared in this project with the objective of creating a detailed representation of reservoir lithology and fluids as accurately as possible. The respective results were assessed by the ultimate measure: the match with existing wells and the prediction of drilling outcomes.

Interpolated seismic data, densely-acquired seismic data, converted-wave (PS) seismic data, multi-component vertical-seismic-profile (VSP) data and dipole sonic logs were all integrated into comprehensive geological characterizations predicting bitumen-filled reservoir, water-filled reservoir and multiple facies types. Preliminary results have shown the VSP to be essential in calibrating PS and conventional P-wave (PP) data for pre-stack quantitative processes, the interpolated data to be adequate for predicting lithology but lacking in the subtle detail required for accurate prediction of fluids, and the PS data to be enigmatic.

Introduction
The Albian (late lower Cretaceous) age Grand Rapids Formation is younger, generally shallower and thinner than the more extensive McMurray Formation in the oil sands area of Northern Alberta, Canada. Nevertheless, its clean shoreface sands are more homogeneous laterally and vertically with fewer impairments to vertical permeability than the McMurray estuarine deposits and are therefore very attractive to producers who are planning and executing thermal operations. Laricina Energy is one of those producers and holds 63 sections (163 km²) in the play fairway with an estimated 2.5 billion barrels in place in the upper Grand Rapids.

The Grand Rapids zone is broadly divided into lower, middle and upper reservoir units capped by the Joli Fou shales. The bitumen resource is contained in the 15 to 30m-thick uppermost sand unit at approximately 205m depth as shown in figure 1. An irregular bitumen/water contact defines a basal water zone in the upper sand that can vary from 0 to 8m thick. An upper transition zone may also be present with the remaining bitumen pay ranging from 8 to 24 meters.
The objective of the integrated quantitative seismic investigation was to accurately image the gross reservoir zone and identify the various components affecting horizontal well planning, production predictions (simulations), and resource estimation to optimize ultimate recovery. These components include the depth and overall thickness of the reservoir, the thickness and extent of the upper transition zone and the basal water, the extent and presence of any shale zones, and the extent and presence of high density lenses or ‘hard streaks’ that may impact fluid flow.

To address these challenging objectives, multi-component 3D seismic was acquired in the Germain area in 2010. The acquisition included a densely-sampled zone (DZ) within a more sparsely-sampled overall program. The sparsely sampled data was interpolated in processing for a direct comparison of interpolated seismic data with acquired seismic data within the DZ. Converted-wave (PS) data was acquired and processed although not interpolated and a multi-component walk-away VSP was acquired at a well within the DZ. Finally, dipole sonic logs were available for many of the wells tying the seismic data.

This presentation will show how the different data types contributed to the geological predictions and compare the relative merit of the various seismic methods. Comparisons will also be shown between predictions of undrilled wells and actual results.

Method

The map in figure 2 shows the geometry of the 3D seismic acquisition highlighting the DZ and the well locations. The higher density acquisition was decimated to the equivalent geometry of the rest of the survey and then the entire volume was interpolated using a 5D algorithm. Both were processed appropriately for pre-stack seismic operations. The multi-component walk-away VSP was acquired at the 100/16-33 location and used to determine the phase of the P-wave seismic and the phase and PP-PS time registration of the PS data. All data types at the 100/16-33 location are shown in figure 3.

Figure 1: Grand Rapids type log 1AA/06-03-085-22W4/00

Figure 2: Germain 2010 3D seismic and well base map showing the densely acquired zone outline and the location of the VSP.
The geological characterization was accomplished using the general workflow in figure 4 illustrating two main analysis components: well log analysis and seismic attribute analysis which are combined to create a volume of predicted geology at seismic scale. Where possible, the parameters in this process were held constant between data volumes to ensure the most direct comparisons.

**Examples and Results**

Although the comparison between the interpolated and the densely-acquired seismic data in conventional view (figure 5) displays slight differences that may appear insignificant, the geological significance of these differences is not fully apparent until the final classification step in the STAC workflow. For example, the sensitivity of the fluid classification to subtle seismic differences is apparent in the cross-plots shown in figure 6. Figure 6 on the left shows log data points coloured by log-derived water saturation with a reasonable cutoff between wet and bitumen reservoir represented by the gray line. Analysis of the equivalent seismic attributes (figure 6 right) shows a different data distribution using the interpolated data than the densely acquired data. The data from the DZ shows a tighter, more definitive representation of the reservoir points into two separate clusters. Adjusting the fluid cutoff based on the DZ seismic clustering resulted in a

Figure 3: From left: densely-acquired PS seismic, near offset PS VSP, 100/16-33 density log, near offset PP VSP, interpolated PP seismic and densely-acquired PP seismic.

Figure 4: Seismic Transformation and Classification (STAC™) workflow.

Figure 5: Conventional seismic view of the same inline for the interpolated volume on the left and the densely acquired volume on the right. A density log is displayed at the well.
better match between the wells on the 3D and the fluid classification in not only the DZ (figure 7), but also
the entire interpolated volume. After depth conversion, predictions made for two new wells on the 3D
survey were within 1-2m of actual values for the top and base of the reservoir and the thickness of the basal
water (see table). Prediction of upper transition zone was less accurate, however it is more of a gradual
saturation change over several meters and was also less critical for engineering decisions. The combined
thickness of the upper transition zone with the bitumen thickness is fairly accurately predicted. Additional
wells are planned for this area and have also been predicted in detail based on the results of this study.

Figure 6: Left: well-log-derived lambda*rho vs mu*rho cross-plot with points coloured by water saturation; right:
seismic-derived lambda*rho vs mu*rho with colour signifying cluster density for the densely-acquired data (top) and the
interpolated data (bottom). The gray line on all plots is the cutoff between water and bitumen based on log data. The red
line is the adjusted cutoff based on densely-acquired seismic clustering and the oval encloses the reservoir points.

Figure 7: Final facies and fluids volumes: Left – densely-acquired volume with log-derived fluid classification and right
– densely-acquired volume with fluid cutoff adjusted for seismic clustering. Density log at the well displayed in black;
water saturation log in blue.
Table showing predicted vs actual drilled for two wells.

Conclusions

The integration of several data types in this project highlighted the sensitivity of attribute analysis and classification to subtle seismic variations. The VSP calibration of the PP and PS data provided a confident starting point for the detailed analysis and minimized the uncertainty related to phase and time shifts between the volumes. The comparison between interpolated sparse acquisition geometry and more detailed data acquisition showed that while interpolated data is adequate for lithological classifications in this area, more detailed acquisition is useful and preferred when accurate fluid prediction is necessary. Confirmation of these methods and conclusions has been provided by comparisons with existing well control and new drilling. The clearly identified sand base and bitumen/water contact will greatly assist in the efficient exploitation of the reservoir.

Analysis of the PS data continues and will be elaborated on in the convention presentation.

Acknowledgements

The authors would like to thank Laricina Energy Ltd. for permission to publish this work.

References


EUB Report ST96-38, Crude Bitumen Reserves Atlas, May 1996


