Integrated 3D Reservoir Characterization for Oil Sands Evaluation, Development and Monitoring*

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Abstract

The Athabasca oil sands contain more than a trillion barrels of oil within the Cretaceous McMurray Formation of northeastern Alberta. The McMurray Formation is generally considered to be a compound estuarine valley system characterized by multiple stacked channel sequences. It is bounded below by Devonian rocks at the pre-Cretaceous unconformity and above by the widespread transgressive marine shales and sands of the Wabiscaw Formation. Post oil migration, the reservoir has been subjected to structural changes caused by salt dissolution and tectonics. At the same time due to its shallow burial, fresh water infiltration has caused severe biodegradation of the oil creating the complex mixture of bitumen, gas and water present today.

So far, the preferred method of in-situ bitumen production is the Steam-Assisted-Gravity-Drainage (SAGD) process. Multiple horizontal well pairs are drilled to inject steam into the reservoir and pump out the heated, liquified oil. The objective of every oil sands operator is to minimize the steam-injected to oil-recovered ratio by maximizing the efficiency of the SAGD process. Reservoir heterogeneity has been found to have the single most significant negative effect on the efficiency of steam chamber development and overall bitumen recovery, directly impacting steam/oil ratios. Detailed knowledge of the reservoir can therefore allow for better prediction and management of the inherent complexity of the McMurray Formation. An accurate baseline reservoir characterization is also essential for subsequent time-lapse seismic analysis and comparison for production monitoring.

The process described in this presentation integrates all available data to produce a detailed volume of deterministically derived reservoir, non-reservoir and fluid properties. The workflow is illustrated using 3D seismic and well data from the Nexen/Opti Long Lake SAGD Phase 2 area near the city of Fort McMurray, Alberta. The subsequent drilling results were compared with the predicted properties and showed that most wells matched the prediction with greater than 75% accuracy.

Method

As the conceptual flow-chart in Figure 1 shows, rock physics attributes are first determined from seismic data, then classified in terms of facies and fluids using the wireline log and core data from wells. The seismic process involves the use of AVO (amplitude vs offset) analysis to separate the compressional (P-wave) and shear (S-wave) components of the seismic data. The resulting components are then used to calculate physical rock properties such as shear rigidity (mu) and incompressibility (lambda) (Goodway et al., 1997). It is common knowledge among oil sands geoscientists that the density log through the McMurray Formation shows a strong correlation to the gamma ray log and is therefore a good lithology indicator. In this process, an estimate of density is obtained from seismic using a multi-attribute analysis approach (Russell et al., 1997).

Wireline logs directly (or indirectly) measure P-wave velocity, S-wave velocity and density. From these measured logs, the rock physics attributes lambda (incompressibility) and mu (shear rigidity) can be calculated. Cross-plot analysis of these and various other attributes leads to empirical limits and guidelines for lithology and fluid discrimination based on core facies. Figure 2 shows cross-plots of lambda*density vs mu*density. The 'pure' sand and shale facies are shown separately on these plots in order to determine empirical limits based on facies. The relationships between attributes and facies determined from the cross-plots are then used to calibrate and classify the equivalent properties derived from seismic data. The result is a seismic volume transformed to a detailed lithological and fluid characterization within the zone of interest. The drilling results compared with the predictions were very positive with over 75% of the total number of meters drilled by 90 wells correctly predicted. A few of these 'blind test' well results are shown in Figure 3.

The facies and fluids products described in this presentation have been created prior to steam injection. These can be used as an accurate baseline reservoir characterization for comparison with post-production time-lapse seismic analysis at regular intervals. At initial reservoir temperatures and pressures, bitumen behaves as a solid and unlike conventional fluids and will support a shear wave. When it is heated through steam injection, it becomes fluid and no longer supports shear waves (Han et al., 2008; Kato et al., 2008). Therefore, the bulk shear rigidity of the bitumen reservoir post-steaming is considerably altered compared to the baseline. Similarly, when steam replaces the bitumen, it causes a significant change in the P-wave velocity relative to the baseline. Figure 4 shows the acoustic parameter cross-plot for a well with both bitumen and wet reservoir intervals. Modelling the changes in bitumen reservoir due to temperature and the replacement of the bitumen with steam show significant changes to the acoustic parameters and consequently to the seismic response post-steam-injection.

Conclusion

This technique has obvious advantages in an oil sands development project area allowing more confident identification of the geological features and associated reservoir quality and continuity. Potential benefits include fewer vertical wells required to define the resource area, more effectively placed horizontal wells for optimal production and improved steam/oil ratios, and flow simulations based on deterministic facies models. Figure 5 shows an example of a geo-cellular grid containing a small portion of the Long Lake Phase 2 facies and fluids volume over a single pair of a proposed 6-well-pair pad. With a reservoir parameter distribution assigned to the facies, this sub-volume is ready for simulation. After production has commenced, monitoring of steam injection and heated bitumen can be assessed by repeating the reservoir characterization process with time-lapse seismic data.

Acknowledgements

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References

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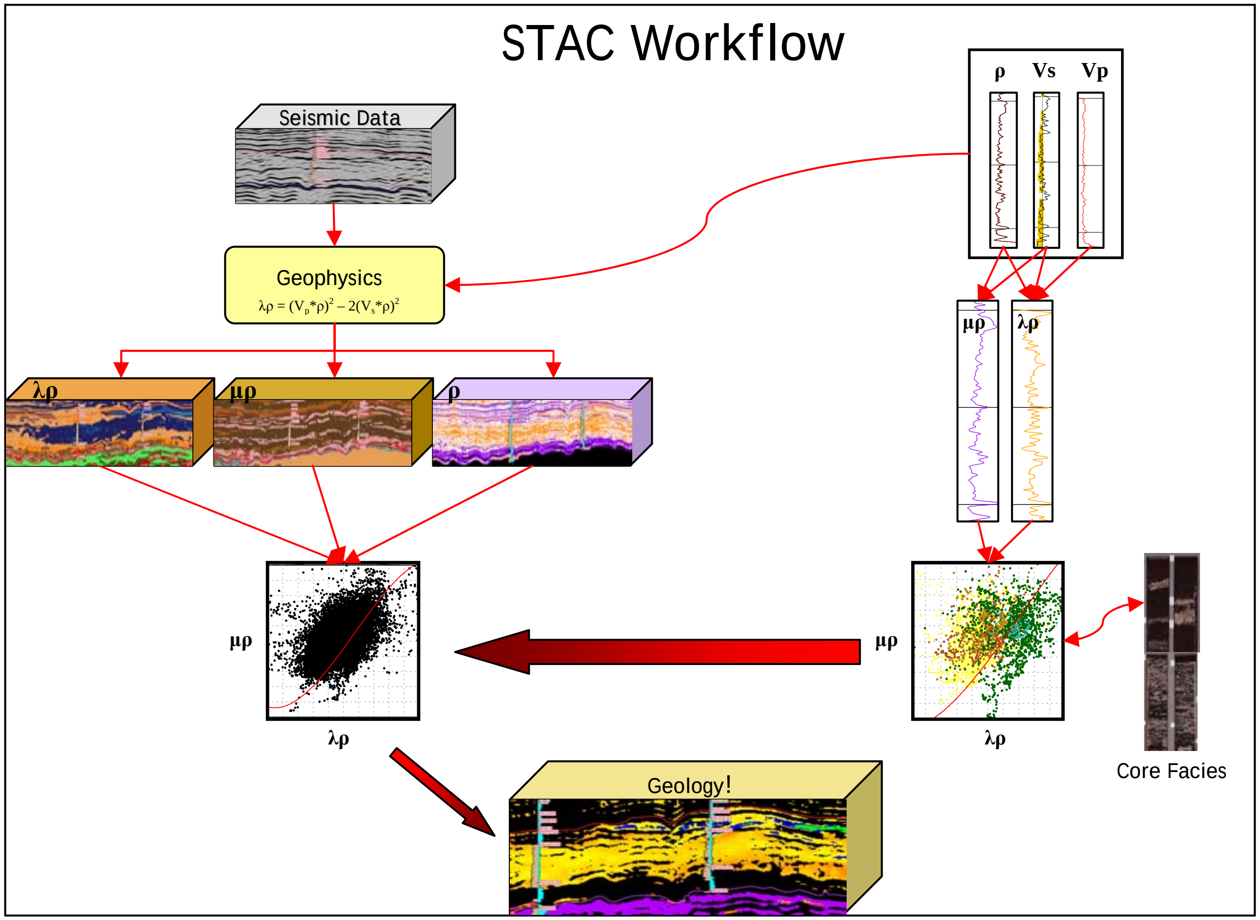

Figure 1: Conceptual flow-chart for the Seismic Transformation and Classification (STAC) process.

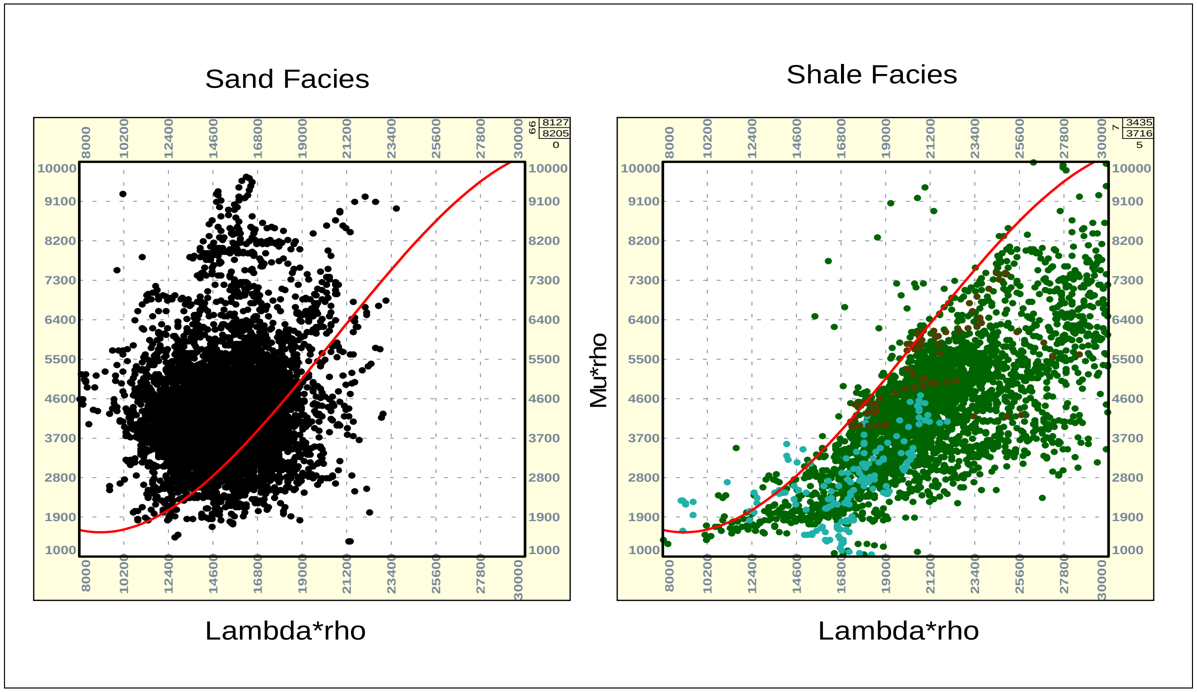

Figure 2: Cross plots of computed well logs from 85 wells with dipole sonic logs, separated by core facies. The curve shows the empirical limit of shale facies which when plotted on the sand facies plot shows the extent of facies overlap. The number of sand facies points that plot on the shale side of the line is less than 20% of the total.

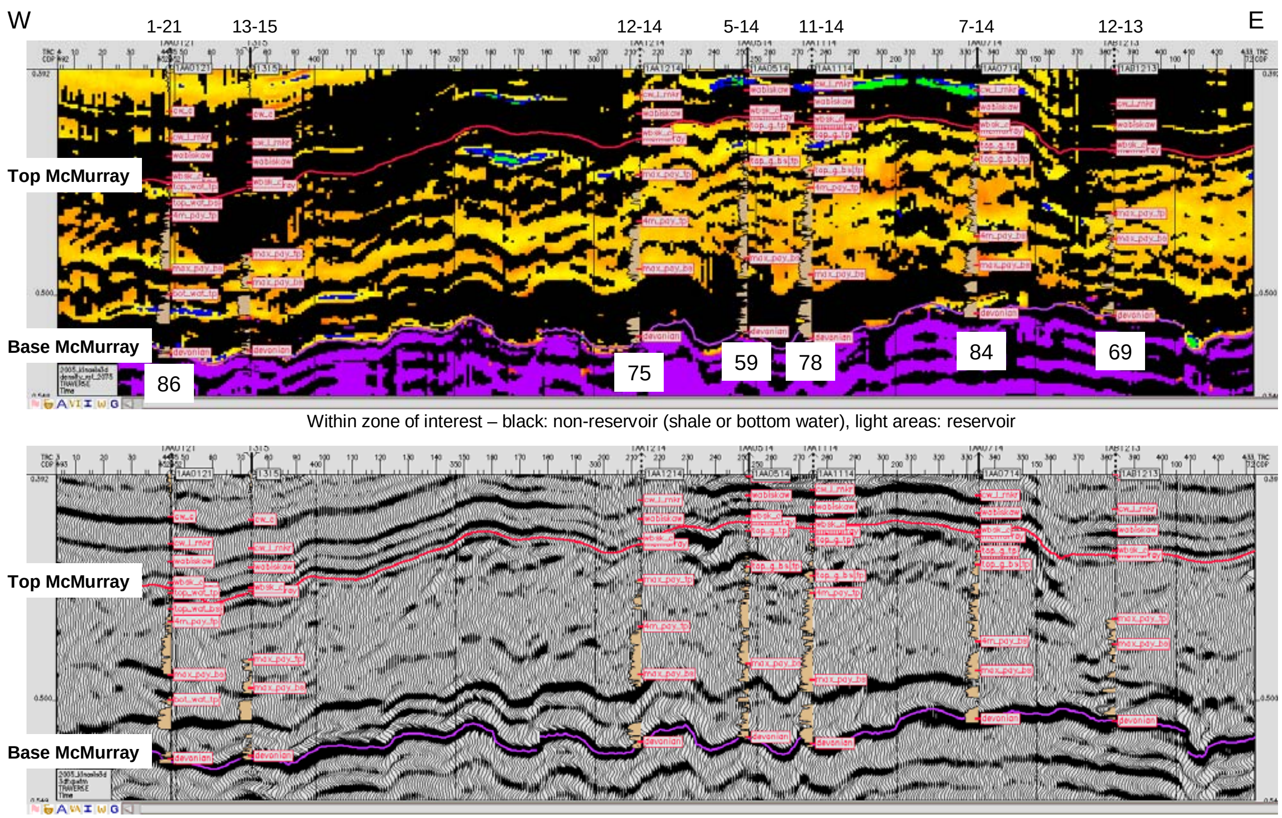

Figure 3: Comparison of conventional seismic profile (bottom) with derived facies profile (top). Black represents non-reservoir (shale or bottom water), yellow is bitumen reservoir, blue is wet reservoir and green is gas reservoir. Gamma ray logs with 0 to 70 (at baseline) api range are displayed on the profiles. 13-15 was the only well on this profile used in the derivation of facies shown above, the rest were drilled after the facies volume was completed. The numbers shown below the well bores are the percentage match on a meter-by-meter basis of the predicted facies from seismic with the actual facies from logs within the zone of interest.

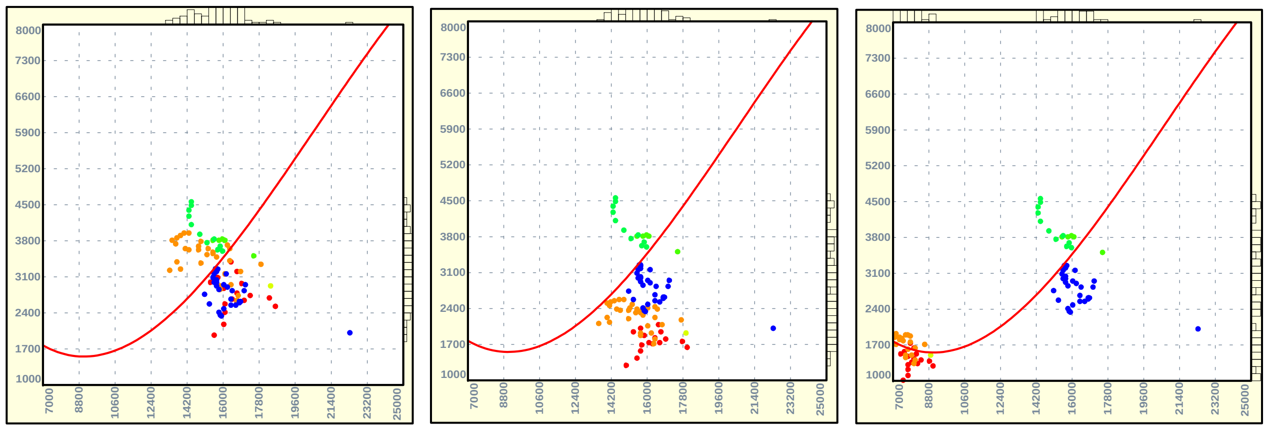

Figure 4: Lambda*rho (x-axis) vs Mu*rho (y-axis) crossplots for a well with both bitumen and wet reservoir intervals. The plot on the left is the unaltered data; blue points are wet reservoir, orange points are the bitumen reservoir. The center plot illustrates the effect of heating the bitumen – the bitumen reservoir points move to the same area of the plot as the wet reservoir as the bitumen becomes fluid. The plot on the right shows a significant change in acoustic properties when the bitumen is replaced by steam. The red line is the dividing line between reservoir and non-reservoir as shown in figure 2.

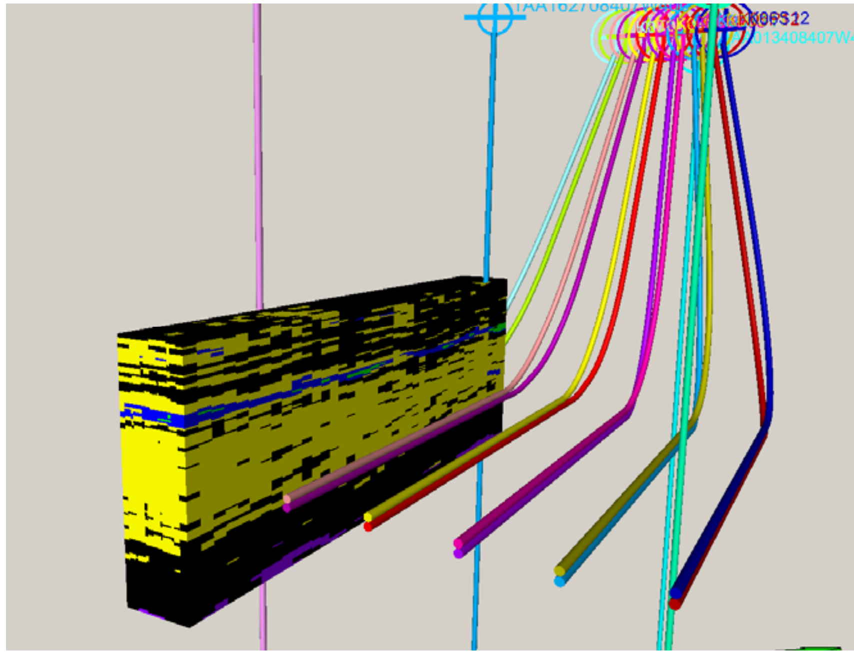

Figure 5: Facies and fluids sub-volume assigned to a geo-cellular grid over a single planned horizontal well pair.