



Oil Sands Reservoir Characterization: An Integrated Approach

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Summary

The objective of the process described in this paper is to integrate all available seismic and well data to produce a volume of deterministically estimated reservoir properties. This effectively upgrades the utility and value of seismic data enabling the final product to be used in exploration, development, engineering and strategic decision-making. The workflow is illustrated using an oil sands example in the Nexen/Opti Long Lake area where a 40 km² 3D seismic data set and over 100 wells were used to create a detailed volume of facies and fluids. The subsequent drilling results were compared with the predicted properties and showed very high average correlation of greater than 80%.

Introduction

The Athabasca oil sands contain more than a trillion barrels of oil within the Cretaceous McMurray Formation of northeastern Alberta. In most of the oil sands area, the McMurray Formation is generally considered to be a compound estuarine valley system characterized by multiple cuts and fills. 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. In the Long Lake area, for example, it is 60 to 100m thick, with net pays of greater than 40m. Stacked channel deposition exhibits a high degree of reservoir variability both vertically and laterally making lithology prediction challenging and reservoir management difficult.

Traditionally, at least 8 and often many more vertical wells per square mile are drilled and cored to obtain enough data to be confident in defining a SAGD¹ project area. Even then, significant variations occur between wells. 3D seismic data has been used successfully in the past mainly to define the base of the zone of interest (there is a strong reflector at the Cretaceous-Devonian boundary), and the gross thickness of the interval. Various attempts have been made to decipher the internal composition of the channeled interval with limited success. In this presentation, I describe the method, application and results of a technique of quantitatively extracting and classifying elastic rock properties from seismic data to provide more accurate estimates of reservoir properties between wells.

Method

As the conceptual flow-chart in Figure 1 shows, rock physics attributes are first determined from seismic data and 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 properties² such as shear rigidity (μ) and incompressibility (λ). 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 I incorporate an estimate of density obtained from seismic using a multi-attribute analysis approach³.

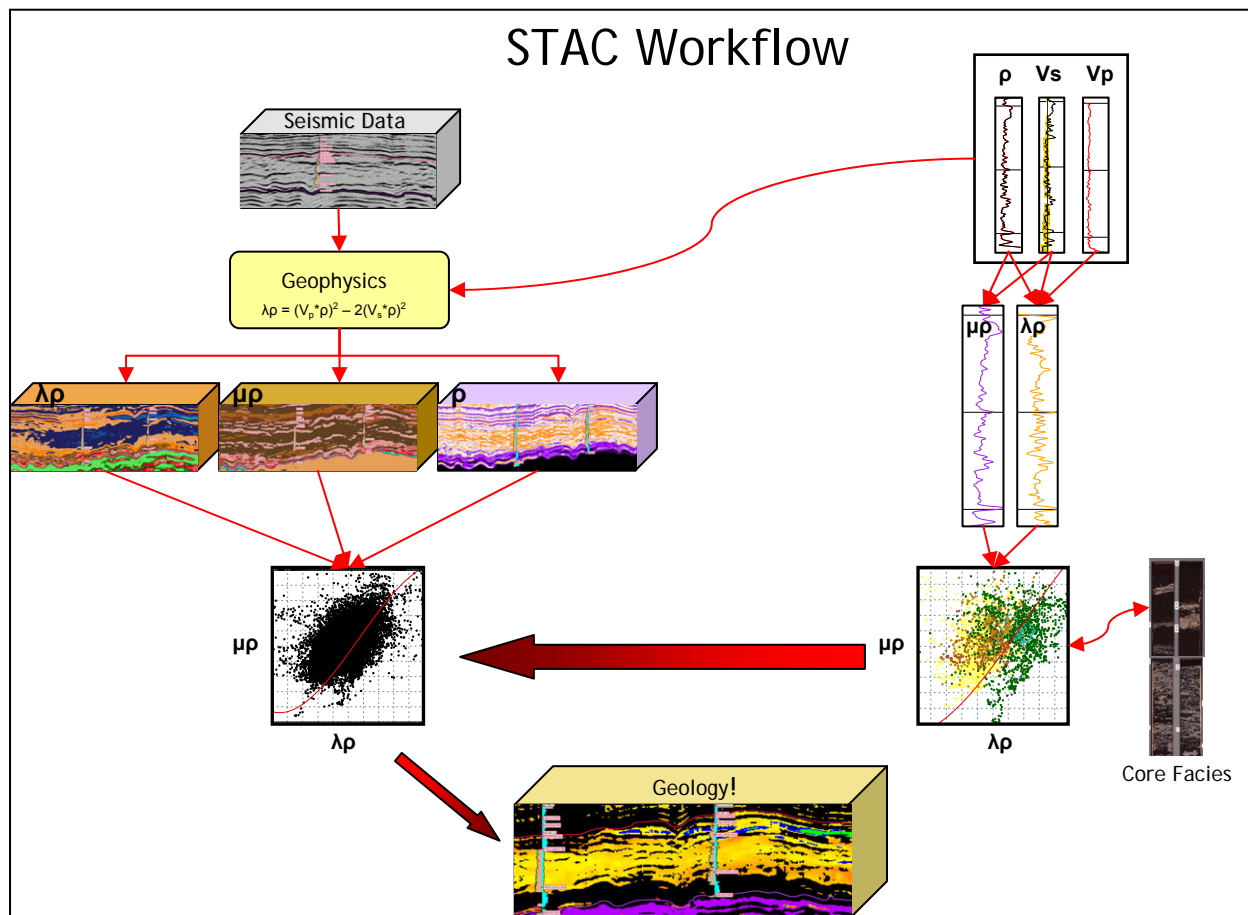


Figure 1: Conceptual flow-chart for the Oil Sands Imaging Seismic Transformation and Classification (STAC) process.

Wireline logs directly (or indirectly) measure P-wave velocity, S-wave velocity and density. Integrating this data with core and log analysis, the lambda and mu properties are calculated and assigned lithologies and fluid properties. Detailed quality assessment and cross-plot analysis is carried out to assign empirical limits and guidelines for lithology and fluid discrimination based on the measured rock physics properties (figure 2). The determined relationships are then used to calibrate and classify the seismically-derived properties. The result is a seismic volume transformed to a detailed lithological characterization of the reservoir within the zone of interest. Drilling results are shown to validate and quantify the success of the method (figure 3).

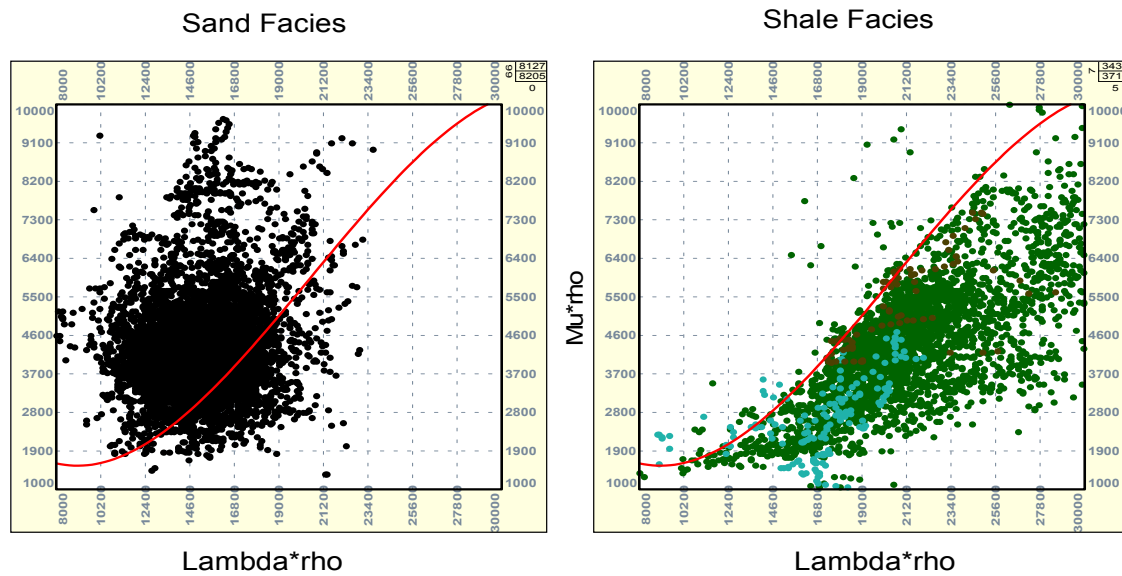


Figure 2: Cross plots of computed well logs from 85 wells with dipole sonic logs, separated by core facies. The curve shows the empirical limit of shale facies which when plotted on the sand facies plot shows the extent of facies overlap. The number of sand facies points that plot on the shale side of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

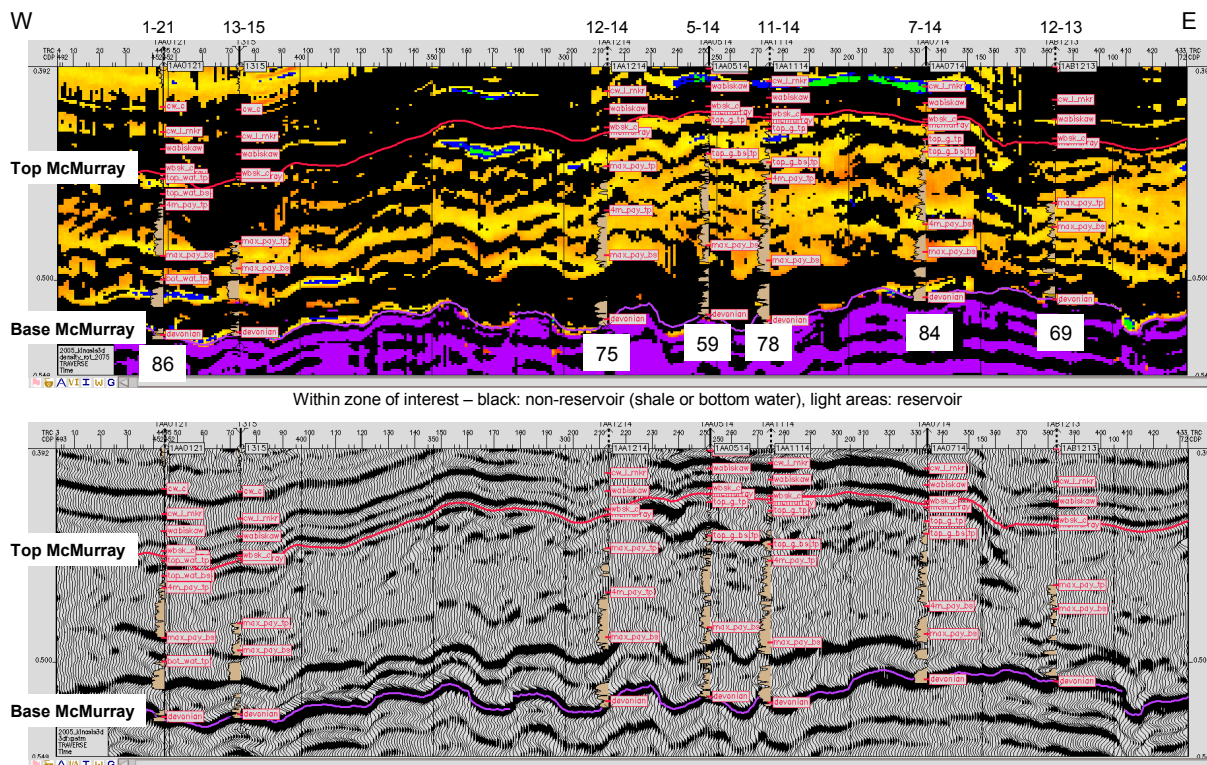


Figure 3: Comparison of conventional seismic profile (bottom) with derived facies profile (top). Black represents non-reservoir (shale or bottom water), yellow areas are bitumen reservoir. Gamma ray logs with 0 to 70 (at baseline) API range are displayed on the profiles. 13-15 was the only well on this 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 core within the zone of interest.

Applying this technique over a project area allows more confident mapping of the geological features and the reservoir quality and continuity within those features. A few of the potential benefits in the oil sands environment include fewer vertical wells required to define the resource area, more confidently placed horizontal wells for optimal production, and flow simulations based on deterministic facies models (figure 4).

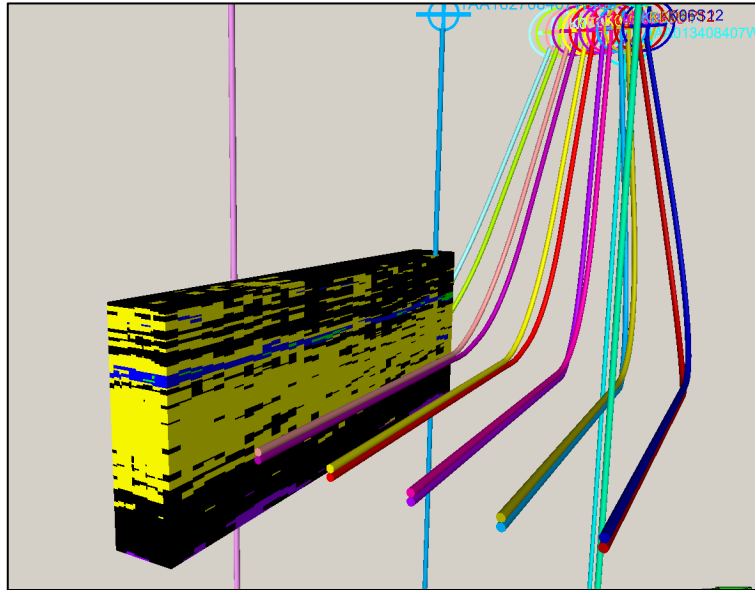


Figure 4: Portion of classified volume displayed in a geo-cellular grid over a single proposed horizontal well pair in a group of six from a surface pad location in Long Lake. With reservoir properties assigned to the facies classes, this is ready for simulation. Yellow represents bitumen reservoir, black is non-reservoir and blue is wet reservoir.

References

1. Steam Assisted Gravity Drainage – visit <http://www.nexeninc.com> to find more details on this process.
2. Goodway, W., Chen, T., and Downton, J., 1997, Improved AVO fluid detection and lithology discrimination using Lamé petrophysical parameters; “ $\Lambda \cdot \rho$ ”, “ $\mu \cdot \rho$ ” and “ λ/μ fluid stack”, from P and S inversions: 1997, 67th Annual International Meeting., SEG Expanded Abstracts, p183-186.
3. Dumitrescu, C., Weston Bellman, L., and Williams, A., 2005, Delineating Productive Reservoir in the Canadian Oil Sands using Neural Networks Approach, CSEG Technical Abstracts.