Mapping Lithological Heterogeneity in Athabasca Oil Sand Reservoirs Using Surface Seismic Data: Case History

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Summary

A practical workflow is illustrated with the help of real examples for extracting lithology-sensitive rock physics parameters from surface seismic data. Improvement in terms of reliable 3-parameter AVO inversion is the key step in the workflow. A case history demonstrates that the method helps understand the lithological heterogeneity of Athabasca oil sand reservoirs.

Introduction

In the Athabasca oil sands, the distribution of bitumen in the formation varies due to the high degree of facies heterogeneity throughout the deposit. This lithological heterogeneity makes it difficult to interpret geology and estimat the bitumen distribution. In this article, we describe a two-step approach to understand the heterogeneity of Athabasca oil-sand reservoirs using surface seismic data. In the case study presented here, the derived results have been found to be encouraging as they calibrate well with the available log curves and a blind well test confirmed the accuracy of the calibration.

Method

Figure 1 shows our workflow for mapping reservoir heterogeneity in the study area. Due to the heterogeneity within the formation and weak correlation between seismic (P impedance or reflectivity) and lithology, "normal" attempts at geologic interpretation usually prove futile. We address this problem by using AVO attributes from surface data. Since the reservoir is shallow and seismic data usually have sufficiently high resolution in shallow zones, it was expected that reasonably convincing estimates of reservoir heterogeneity could be obtained. When more than a couple of seismic attributes are available, neural-network approaches could determine reservoir properties within the interval of interest. However, we emphasize that the approach in this work for estimating the lithology-sensitive density reflectivity attribute provides good quality control and validation with well ties.

It is generally perceived that density is difficult to solve from AVO inversion reliably. The lack of reliability originates from the large uncertainty in 3-parameters linear AVO inversion applied on data from the common surface seismic acquisition and necessitates the use of certain constraints for stabilizing the inversion. Furthermore, large incident angles are required for reliable results from three-term inversion. Here, we design the method to improve the AVO inversion by reducing the uncertainty in the inversion. Uncertainty is related to singularity of the inverse problem and the error in the data. Singularity of the inverse problem is determined by the geometry of the data. While using wide angle data can reduce the singularity, improvements on the uncertainty issue of the inversion can also be achieved by decreasing the error in the data by attenuation of the noise as well as increasing data-to-known ratio through redesign of the inversion. Also other practical techniques are used to improve the inversion for local geological setting in Athabasca oil sands, including (1) using a windowed approach instead of a sample-by-sample basis; (2) applying error-based weights in the frequency domain; (3) accounting for the strong reflection from the McMurray-Devonian interface; and (4) reducing the distortion due to NMO stretch and the related off set-dependent tuning. These improvements result in a more reliable inversion process and also relax the requirement for large angles in the inversion. In Figures 2 and 3, we demonstrate the use of the workflow and reliability of improved AVO 3-parameter inversion by a real data example. Good quality 2D line from Athabasca area is used in the analysis. Frequency high cut for signal is up to 130 Hz and the maximum angle for AVO inversion is chosen as 41 degrees. In Figure 2, correlations are made between synthetics of P reflectivity, S reflectivity, and density reflectivity calculated from P impedance, S impedance, density logs and corresponding reflectivities extracted from AVO inversion. Synthetic traces are generated using the same wavelet and depth-time curves. Correlation coefficients are reasonable good within the 300ms time window. A few arrows mark locations where the density varies opposite to P impedance. Large difference can be noticed on synthetics of P and density reflectivities at those locations. AVO inversion resolves these anomalies reliably. Figure 3 shows a set of attributes derived on key steps in the workflow. Reflectivity and relative impedance/density are 100% seismic data driven, while the impedance/density is partially dependent on models derived from well logs and interpretation.

Case history

We begin the rock physics analysis by crossplotting (Figure 4) different pairs of parameters for the McMurray Formation reservoir which is at a depth of about 100 m. Figure 4a shows a strong linear correlation between bulk density and gamma ray. If a linear relationship between gamma ray and shale volume (Vshale) is assumed, then Vshale can be estimated from density by using the relation Vshale = (density - 2.075)/0.165. Figure 4b reveals a weak correlation between gamma ray (shale volume) and Vp/Vs. Since P impedance can be accurately derived from seismic data, it is always desirable to look for any strong correlation between impedance and another rock parameter of interest. However, as seen in Figure 4c, P impedance is unable to indicate lithology variation, since in this case, shale and sandstone have similar P-wave impedance values as shown by the uncorrelated gamma ray and density scatter. A 2D seismic profile running through 11 wells in the study area was taken through an amplitude-preserved AVO processing flow. Data quality was reasonably good, and the usual noise problems in terms of ground roll and other wave modes were skillfully tackled using adaptive and iterative noise-attenuation schemes. The surface elevation variation along the profile is about 45 m, and this is of the same order as the reservoir depth variation of 55–90 m. This elevation variation was a significant factor regarding the amplitude recovery and the stability of the AVO inversion at the reservoir level. Care was exercised for amplitude recovery and superbinning was part of the data conditioning for AVO inversion. Figure 5 shows the results of different AVO attributes derived as per the workflow in Figure 1. The density reflectivity derived after AVO inversion is shown in Figure 5a. Relative density was derived from density reflectivity after simple trace integration without using density logs from wells, and this result (Figure 5b) indicates the richest sand areas (dark green) are in the middle of the McMurray Formation with a good seal cap in the upper McMurray around wells 5 and 6. These are verified by the overlain gamma-ray log curves. Next, the density logs from all the wells except wells 3 and 7 (not available at the time) were used to generate a density model. Model-based poststack inversion was performed on density reflectivity utilizing the density model to generate a density section (Figure 5c). This section has higher resolution than the relative density and better matches the log curves. The linear relationship indicated on the crossplot between density and gamma ray (Figure 4a) was used to transform the derived density section into a Vshale section (Figure 5d). Two recently drilled wells (3 and 7) were used in a blind test; well 3 is mainly shaley within the McMurray and the density inversion result verifies this. Well 7 has good sand in the middle McMurray, but a sandy cap in the upper McMurray. These results are clearly confirmed on the inverted density (Figure 5c) and the derived Vshale sections (Figure 5d). The same results are seen on the relative density sections. All four derived density estimate sections in Figure 5 yield encouraging confirmation with well logs and exhibit believable lateral variation in reservoir heterogeneity within the target zone.

Conclusions

A workflow using rock physics analysis and an improved three-term AVO inversion to map reservoir heterogeneity has been demonstrated on a case study from the Athabasca oil sands in Alberta. Rock physics analysis helps find a relationship between lithology and seismically-driven elastic attributes and pick out lithology-sensitive parameter(s). In the present study, density is closely correlated with lithology. The density reflectivity is reliably derived from 2D data in the area using the improved three-term AVO inversion. Other attributes derived from density reflectivity, confirmed with calibration to existing well-log data, have further provided convincing calibration to the two recently drilled wells. The discussed workflow has successfully demonstrated a methodology for mapping heterogeneity in oil-sand reservoirs. Considering the importance of the characterization of oil-sand reservoirs in Alberta, this methodology could have very promising applications.

References

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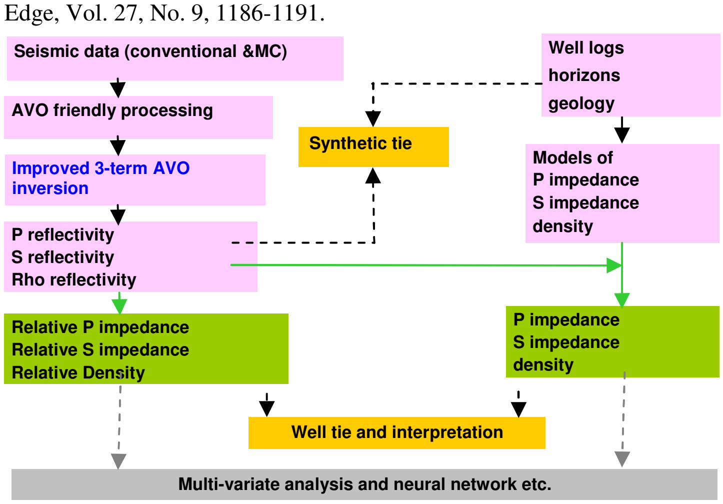

Figure 1. Workflow of deterministic interpretation of reservoir heterogeneity of oil sands using seismic data. This approach combines rock physics with a reliable inversion, and quality control including synthetic and well tie calibration with relative seismic attributes.

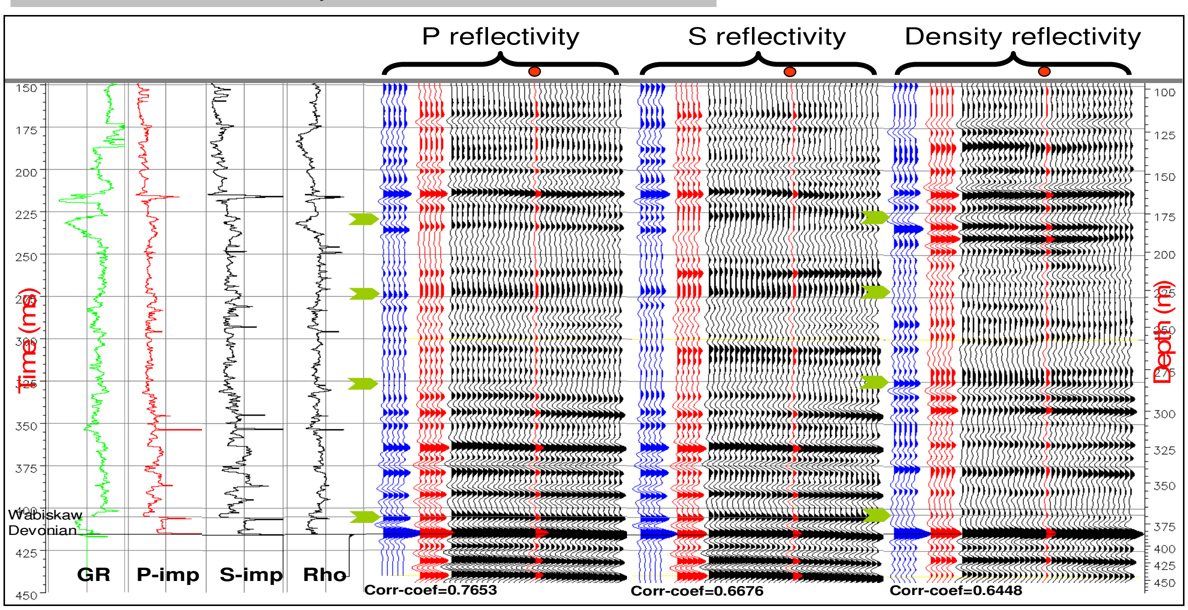

Figure 2. Correlation between synthetics from wells and reflectivities from inversion: Blue traces are synthetic reflectivities from P, S impedance and density well logs. Black traces are small portions of P and S reflectivities and density reflectivity sections from AVO inversion close to the well and well location is marked by the red traces in the middle of the sections. Reflectivity traces at well location are repeated a few times and drawn beside corresponding synthetic traces for comparison. Correlation coefficients within the time window shown for the three reflectivities are shown at the bottom of the correlations.

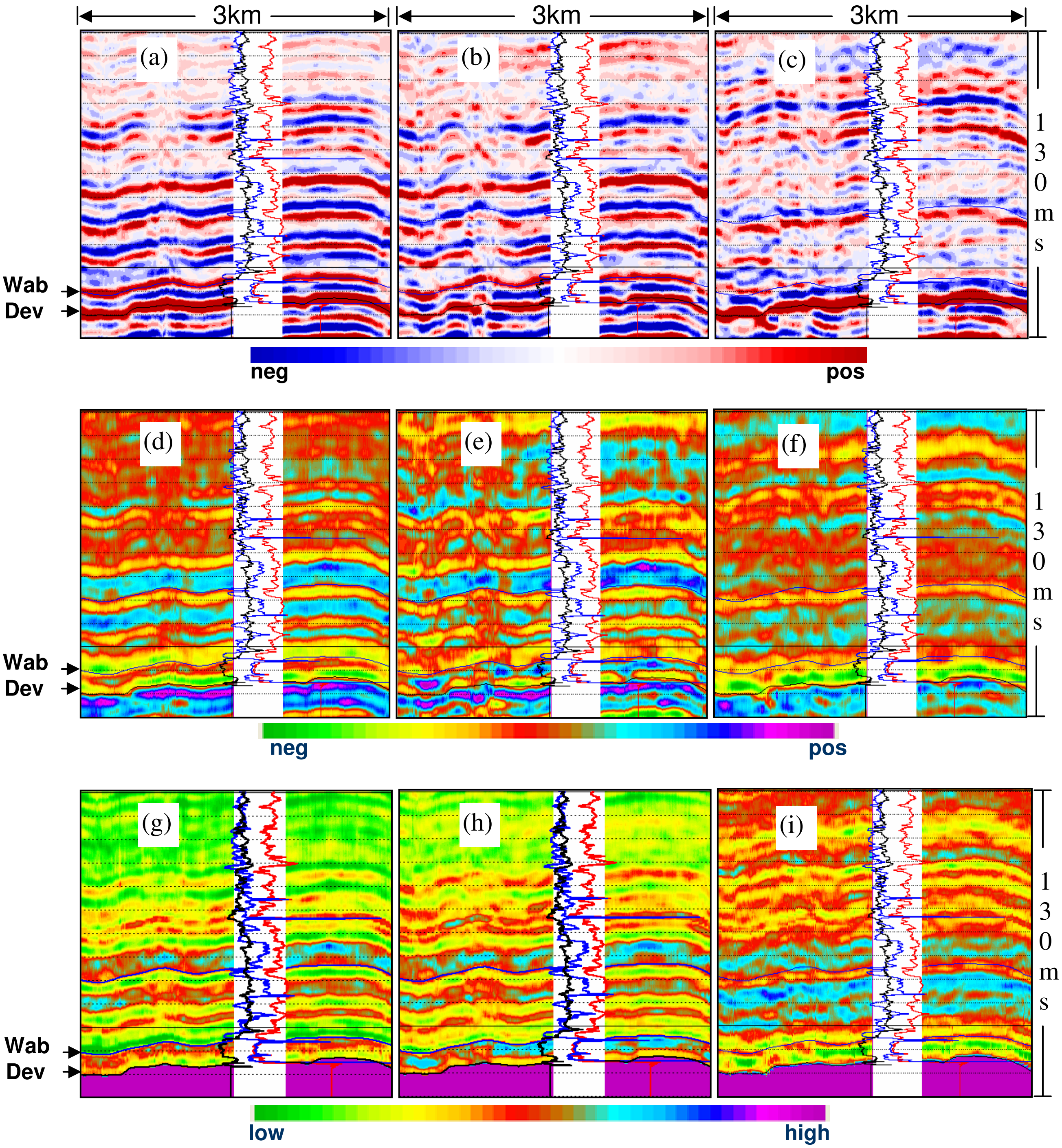

Figure 3. A set of attributes extracted from seismic data: (a) P reflectivity, (b) S reflectivity, (c) density reflectivity, (d) relative P impedance, (e) relative S impedance, (f) relative density, (g) P impedance, (h) S impedance, and (i) density. Log curves overlaid: black – gamma ray, red – density, and blue – P impedance. The time interval in 130 ms and sections are 3 kilometers long.

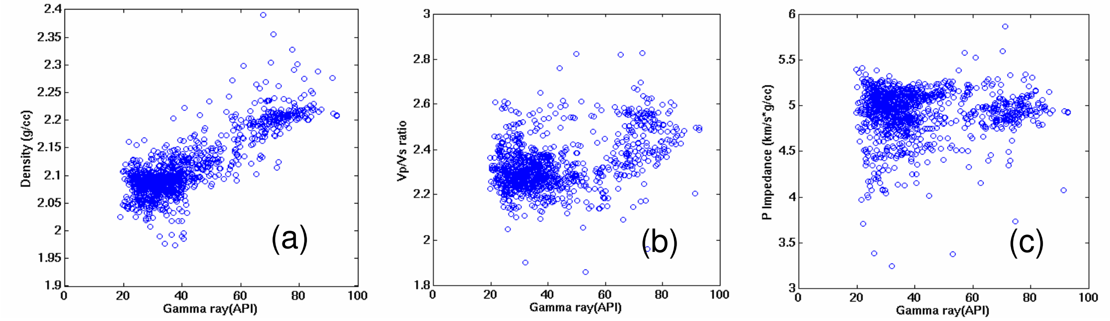

Figure 4: Crossplots of (a) density vs gamma-ray, (b) Vp/Vs ratio vs gamma ray, (c) P-impedance vs gamma ray.

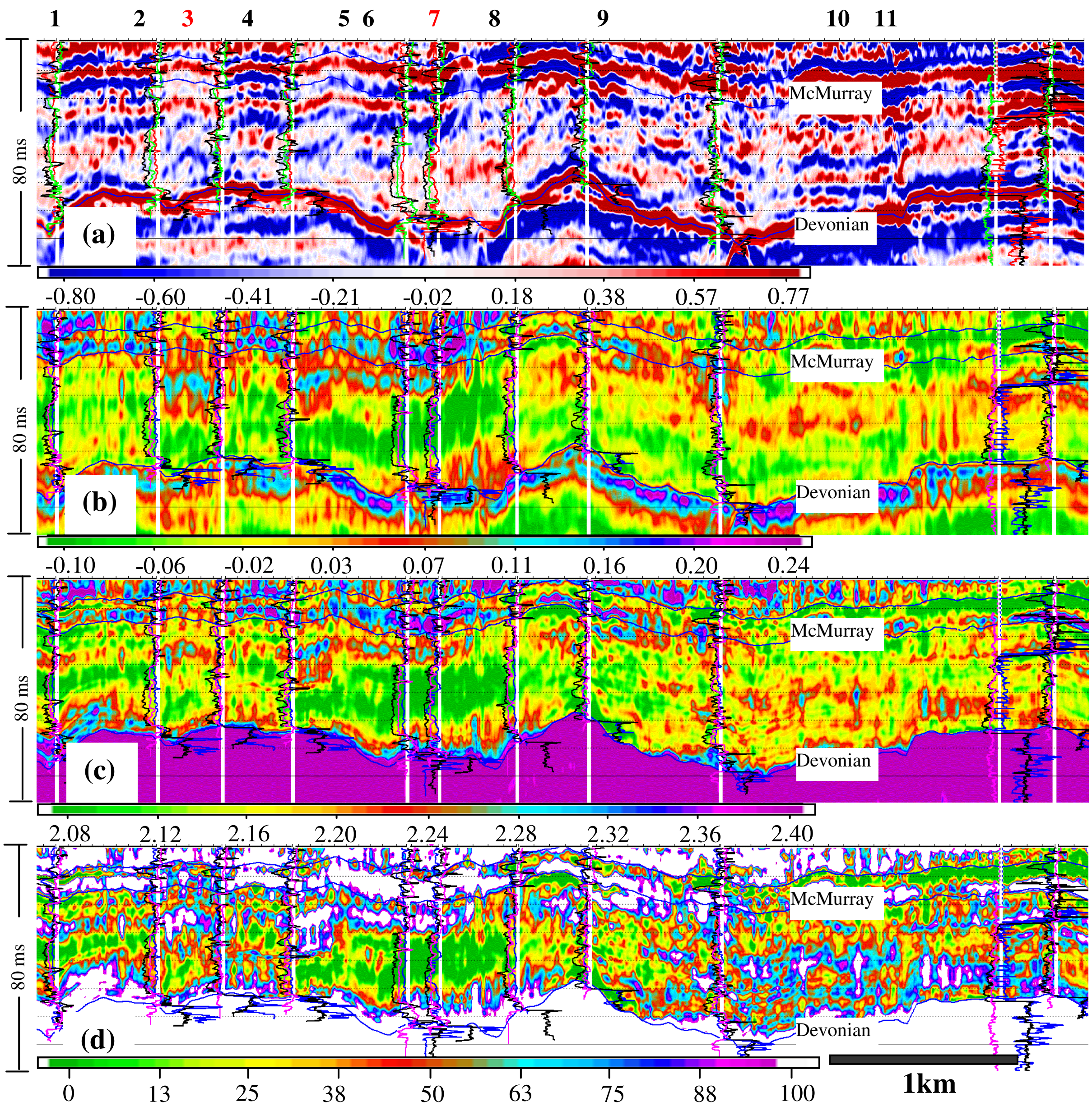

Figure 5: Top panel (a) is the density reflectivity; second panel (b) is the relative density – the trace-integration version of density reflectivity; third panel (c) is the density section from model based inversion; bottom panel (d) is V-shale transformed from density in the third panel.