Effect of Heavy Oil Reservoir Rock Texture on the Vp/Vs Ratios Derived from Logs

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Summary

Well logs are considered by geophysicists as “hard data” for seismic reservoir characterization. In the last few years, lots of wells have been drilled for heavy oil delineation in different fields. Also, many core samples were measured in the laboratory and a wide scattering of velocity within heavy oil sand was observed (Han et al., 2007).

Some of the factors controlling the velocities in heavy oil sands are: rock texture, pore fluid properties and the interaction between pore fluids and the rock frame at different temperatures. All of these have been investigated by laboratory measurements. In this paper we analyze and investigate the effect of rock texture on Vp/Vs ratio from well logs in two different heavy oil reservoirs located in the Athabasca basin in northern Alberta, Canada.

Introduction

The heavy oils are biodegraded and found in a shallow, low pressure (<10 MPa) and temperature environment (< 1000m depth). The shallow depth limits pressure, GOR values and their variation. Therefore, the pressure and GOR effect on heavy oil properties are limited. The classification of heavy oil in Table 1 is as a function of viscosity and API Gravity.

Table 1. Classification of Heavy oil

Oil type	Viscosity [cP]	API Gravity
Conventional crude oil	< 10,000	>20
Heavy oil	>10,000	10-20
Ultra heavy oil or bitumen	~ 1,000,000	<10
Heavy oil in reservoir #1	~ 1,000,000	9
Heavy oil in reservoir #2	~ 2,000,000	6 - 7

For this study we used two heavy oil reservoirs located in the Athabasca basin, which is the most extensive of the three main deposits (Peace River, Athabasca and Cold Lake) of northern Alberta, Canada (Figure 1a). The first reservoir is situated 40 km south-east of the City of Fort McMurray and the second reservoir is located 20 km north-west of the same city. Less than 20% of the Athabasca Oil Sands deposit can be recovered using conventional surface mining techniques. Additional exploitation requires expensive production techniques, typically by steam injection that requires detailed subsurface mapping to maximize steam penetration into the reservoir sand.

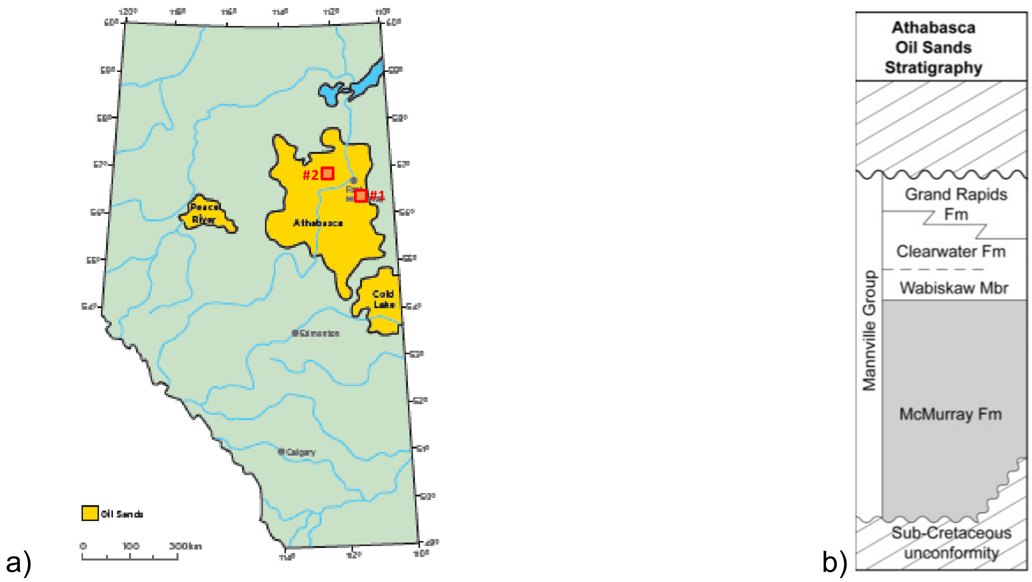

Figure 1 a) Location of the three major oil sands deposits in Alberta (Peace River, Athabasca and Cold Lake), and b) Stratigraphy of the Athabasca Oil Sands deposit (modified from Hubbard et al., 1999)

In the Athabasca Oil sands region, the Lower Cretaceous Mannville group is comprised of the McMurray, Clearwater and Grand Rapids Formations (Figure 1b). The McMurray Formation hosts the widespread bitumen saturated unconsolidated sands.

The first reservoir (#1) is situated in the main fairway paleovalley of the Athabasca basin. The McMurray Formation is comprised of three or more episodes of incision, valley creation, and subsequent infill with fluvio-estuarine sediments. Fluvio-estuarine deposits are, by their nature, heterogeneous (Leckie and Fustic, 2009). Reservoir deposits are primarily associated with point bars and sandstone-filled channels. In the second reservoir (#2), the bitumen pool consists of two to three superimposed wave-dominated shoreface sands. The Middle and Upper McMurray bitumen sands are accumulated as wave-dominated tidal shelf sands at the mouth of a smaller north-trending paleovalley that formed an embayment on the Devonian paleosurface west of the main fairway. The lower member of the McMurray Formation is characterized as a coarse-grained or fluvial unit.

Data available for the project

A database consisting of about 96 wells was available for this study (53 wells on the first reservoir and 43 wells on the second reservoir). All the wells have wireline logs such as gamma ray (GR), caliper, resistivity, sonic and shear sonic. A typical set of logs for each reservoir is presented in Figure 2. We used the wireline logs to interpret the lower, middle and upper members of the McMurray Formation. For the first reservoir the McMurray is fluvio-estuarine. For the second reservoir the Lower McMurray is fluvio-estuarine and is mainly non-reservoir but the Upper and Mid McMurray are shallow marine channel sands (low GR) and represent the upper and lower bitumen reservoir (characterized by resistivities of 60 – 300 ohmm).

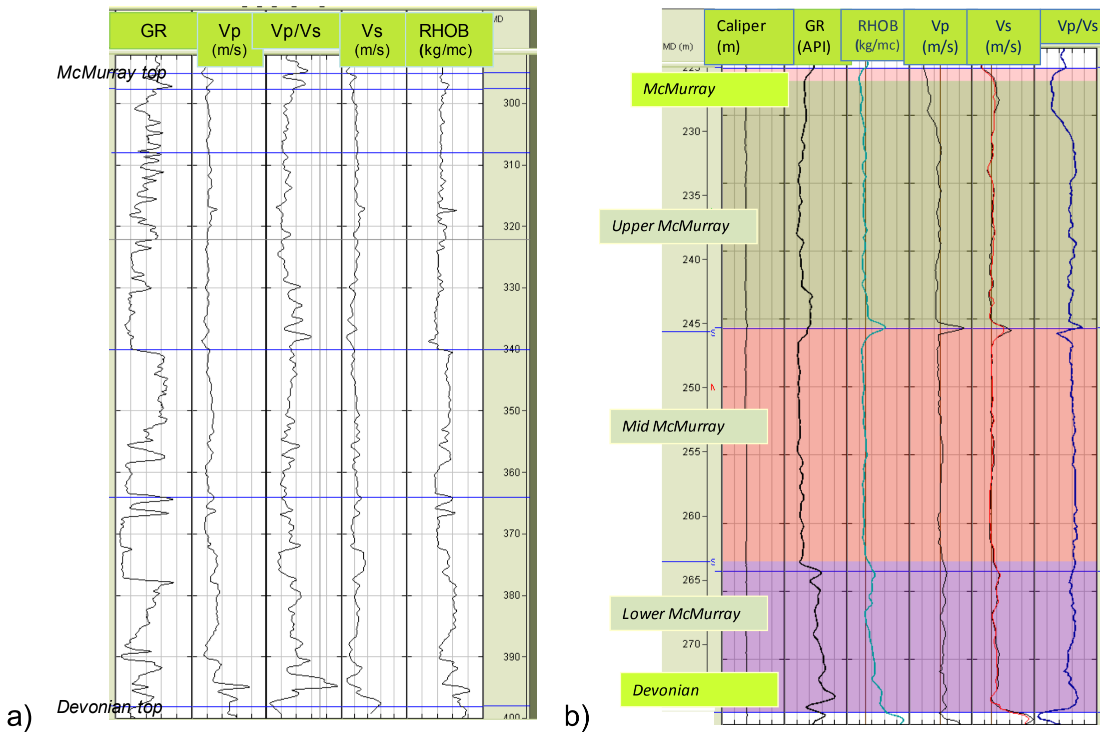

Figure 2 Display of wireline logs used to delineate stratigraphic tops; a) wireline logs for well A on reservoir #1; b) wireline logs for well B on reservoir #2.

There is a wide scattering of velocity in heavy oil sand samples from different fields and the main factor controlling velocities are: rock texture, pore fluid properties and interaction between pore fluids and rock frame at different temperatures (Han et al., 2007). Understanding the contribution of each of these factors is key to modeling heavy oil sand velocity.

Effect of rock texture on Vp/Vs ratio

From laboratory measurements incorporating the observation on rock texture, the effect of sand texture on velocity can be summarized: 1. Velocities as a function of differential pressure are high in sands with large grain size as (Figure 3a). Large grain sands also show high Vp/Vs ratio. 2. Good sorting (often associated with fine grain size and high porosity) show low P-wave velocities and low Vp/Vs ratios (Figure 3b) (Han et al., 2007).

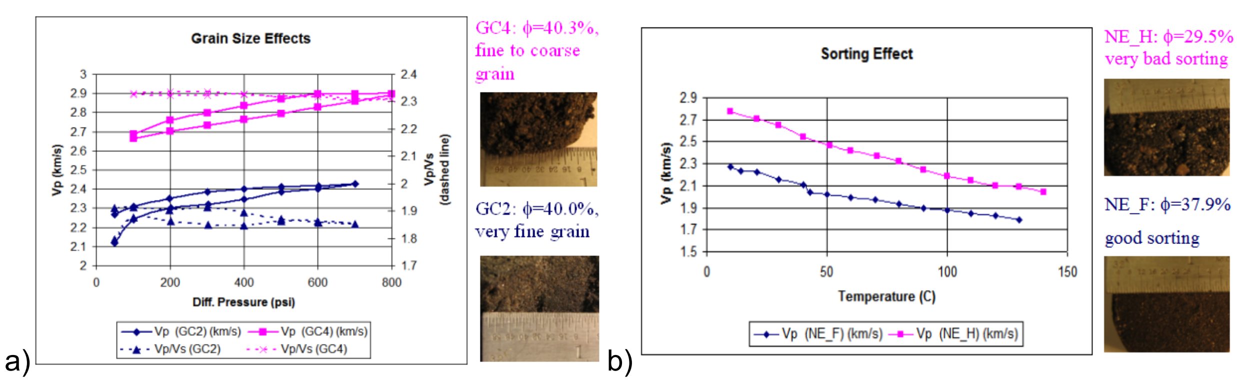

Figure 3 a) Grain size effect on velocity and Vp/Vs ratio for heavy oil sand samples; b) Grain sorting effect on velocity for heavy oil sand samples (Han et al., 2007)

The two reservoirs in our study are approximately at the same pressure (the second reservoir is at slightly lower pressure). In figure 4 we present a summary of Vp/Vs distribution within bitumen sands of the two reservoirs. The Vp/Vs ratio logs were calculated from wireline Vp and Vs logs at each well. Based on the statistics associated with the distributions of Vp/Vs ratio we conclude: (1) for the first reservoir the mean Vp/Vs has a wider range of variation (2.4 – 2.7) than for the second reservoir (2.16 – 2.3), and (2) the average value (for 90%) of the Vp/Vs for the first reservoir (2.8) is higher than the average value (for 90%) for the second reservoir (2.3). The wide range of the mean values for the Vp/Vs ratio indicate the poor sorting of the sand in the first reservoir. The lower average values (90%) of the Vp/Vs ratio in the second reservoir can be attributed to the finer grains in the second reservoir of mainly marine sands.

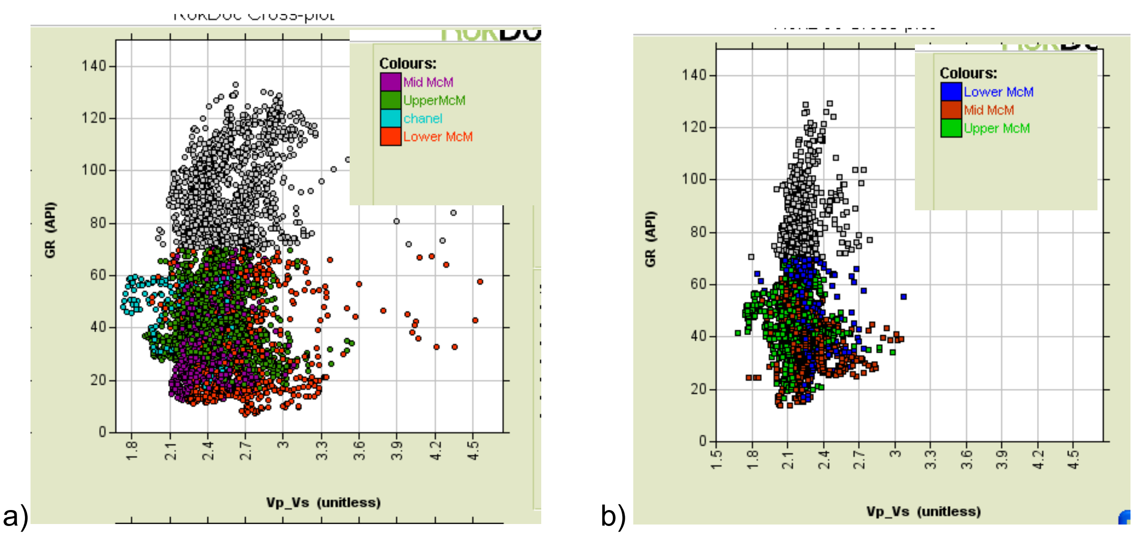

Figure 4 Vp/Vs ratio variation within McMurray bitumen sands, based on well logs; a) data from reservoir #1, and b) data from reservoir #2.

Conclusions

We investigated the effect of rock texture on Vp/Vs ratio from well logs in two different heavy oil reservoirs situated in the Athabasca basin, northern Alberta, Canada. Our conclusions are consistent with the conclusions from laboratory measurement: (1) large grain size sands increase the Vp/Vs ratio for heavy oil sand, and (2) good sorted sands have low Vp/Vs ratio.

As future work we would like to investigate the effect of temperature on all these factors.

Acknowledgements

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