Predicting oil sands viscosity from well logs, NMR logs, and calculated seismic properties
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Summary

Viscosity is the key parameter controlling heavy oil and oil sands production. While viscosity can be measured in the lab from well samples, it would be very useful to have a method to reliably estimate oil sands viscosity from well logs.

Donor Company has provided viscosity measurements from a major oil sands project, with multiple measurements per well.

**Goal of this study:** Develop a viscosity prediction model using standard well logs, and seismic properties calculated from logs nearby well with a standard suite of logs.

**Project Data**

Data from 40 wells with viscosity measurements at 3 depth samples per well were used. Viscosity values ranged from 10,000 cP to 540,000 cP, with a mean of 121,000 cP.

![Map of the base reservoir viscosity measurements. All of the data points (wells) are shown in black. Note significant lateral variations.](image)

Multi-Attribute Analysis

Suppose we are trying to predict viscosity using density (D), gamma ray (G), and resistivity (R), as shown in Figure 4. We can write the equation for linear prediction as:

\[ V(x) = w_0 + w_1 D(x) + w_2 G(x) + w_3 R(x) \]  

where the \( w \) terms are the regression coefficients. This can be written in matrix form where each row represents a single depth sample:

\[
\begin{bmatrix}
V_1 \\
V_2 \\
\vdots \\
V_n \\
\end{bmatrix} = \begin{bmatrix}
1 & D_1 & G_1 & R_1 \\
1 & D_2 & G_2 & R_2 \\
\vdots & \vdots & \vdots & \vdots \\
1 & D_n & G_n & R_n \\
\end{bmatrix} \begin{bmatrix} w_0 \\
w_1 \\
w_2 \\
w_3 \\
\end{bmatrix}
\]

(2)

Or more compactly as:

\[ V = AW \]  

(3)

The regression coefficients can be solved for using least-squares:

\[ W = (A^T A)^{-1} A^T V \]  

(4)

![The basic multi-attribute regression problem showing the target log and in this example, the 3 attributes to be used to predict the target.](image)

![Illustration of how data can be “over-trained.”](image)

![Prediction error plot as a function of number of attributes. All well error is black and validation error is red.](image)

Conclusions

- Standard logs (+ NMR) successfully predicted viscosity with an average error of 70,000 cP (0.70 of 1 standard dev.), and detected variations between control points.
- Calculated seismic properties (from logs) predicted viscosity with an average error of 94,000 cP (0.94 of 1 standard dev.), but detected less variations.
- Including depth improves the prediction in most cases, but will always overestimate viscosity if the base reservoir has a low viscosity (shown on the right side of Figure 12).

![Top viscosity predictors from well logs and NMR logs:](image)

![Top predictors from calculated seismic properties:](image)

![Viscosity prediction results for an example well. The gold zones are the bitumen intervals. The new model (from logs) predicts two viscosity gradients from 440m to 460m, while matching the true values.](image)

![Viscosity prediction results for an example well. Both predictions (from logs and seismic properties) show a smooth trend of decreasing viscosity to the top of the reservoir.](image)

![Example well. Variations predicted above and below the viscosity measurements. Slow shear sonic from 330m to 350m causes problems with the predictions (from logs – left track).](image)

![Example well. Two viscosity gradients are modeled throughout the bitumen. Gas cap is influencing prediction at the top.](image)

![Influence of depth (height above base bitumen) as a viscosity predictor for three example wells (see depth correlation in Figure 3).](image)

![The new prediction model trains over a 3-meter interval centered around the true sample depths (left track in red). The old model used an interpolated target viscosity log (black), which has greater uncertainty. The dark gray area is the separation between the NMR Total Porosity and Density Porosity logs, which occurs because NMR cannot detect bitumen.](image)