geoconvention
Calgary • Canada • May 13-17 2019

A Machine Learning Approach for Viscoelastic Fluid Substitution in Oil Sands

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Summary

I present an online web application for viscoelastic fluid substitution using well data. The application utilizes machine learning algorithms to estimate required but not provided inputs like elastic properties of the shale and the dry rock, as well as shear wave velocity log. Saturation may change from in-situ state to a second state based on the provided pressure and temperature log curves for the second state.

Theory

The process of fluid substitution within the reservoir pore space is quite complex and dynamic. Apart from the important role of pressure differential, the process generally depends on the properties of individual fluid components, pore space of the rock, and physio-chemical interactions between them. It is important how the selected recovery method modifies these parameters. Moreover, fluid substitution is not necessarily limited to the changes in saturation state and from a geophysical standpoint, it can be generalized to the change in effective fluid properties. This can happen due to changes in pressure (P), temperature (T) or frequency with or without numerical changes in the saturation.

Viscoelastic properties of bitumen are mainly a function of temperature, its API gravity, and the frequency of the wave (Javanbakhti, 2018). As a result, oil sands are inherently viscoelastic and P- and S-wave velocities (V_P and V_S) of these deposits are strongly dependent on reservoir temperature. Using artificial intelligence, Javanbakhti et al. (2019) introduced an empirical relationship to estimate the shear rigidity of oil sands at different reservoir conditions using commonly available petrophysical quantities. Proper estimation of the shear modulus can enhance quantitative seismic monitoring of the reservoir using either PP or PS seismic surveys.

For any given point inside a reservoir under Steam Assisted Gravity Drainage (SAGD) recovery method, the state of saturation, pressure and temperature can be estimated through fluid flow simulation.

In real world, however, reservoirs are not homogeneous and their lithology (clay content), porosity, permeability, etc., varies spatially. Complex geology and changes in reservoir litho-facies along with practical limitations in implementation of the recovery process (e.g. SAGD) impose a great challenge on estimation of the saturation distribution inside the reservoir.

I developed a machine learning approach to perform fluid substitution on well data for the given T and P data. The algorithm is able to automatically estimate shear wave velocity (if not provided), elastic properties of the dry rock and shale, probable state of saturation, and finally outputs the resulted V_P, V_S and density curves. Readers can refer to the cited web page for further information and to perform the analysis.

Results, Observations, Conclusions

Figure 1 shows the in-situ and the estimated post-steam curves from a sample well where the temperature changes from 6.5 °C to 240 °C constant along the depth column. Second state saturation (i.e. post steam) is not constant. However, the mean values of residual oil, residual water, and gas-phase saturations are about 12%, 23% and 65%, respectively. Resulted moduli and wave velocities at sonic frequencies are shown in tracks 5 to 8. Application of Javanbakhti's model (2019) shows a significant decrease in the velocities compared to Ciz and Shapiro (2007) model.

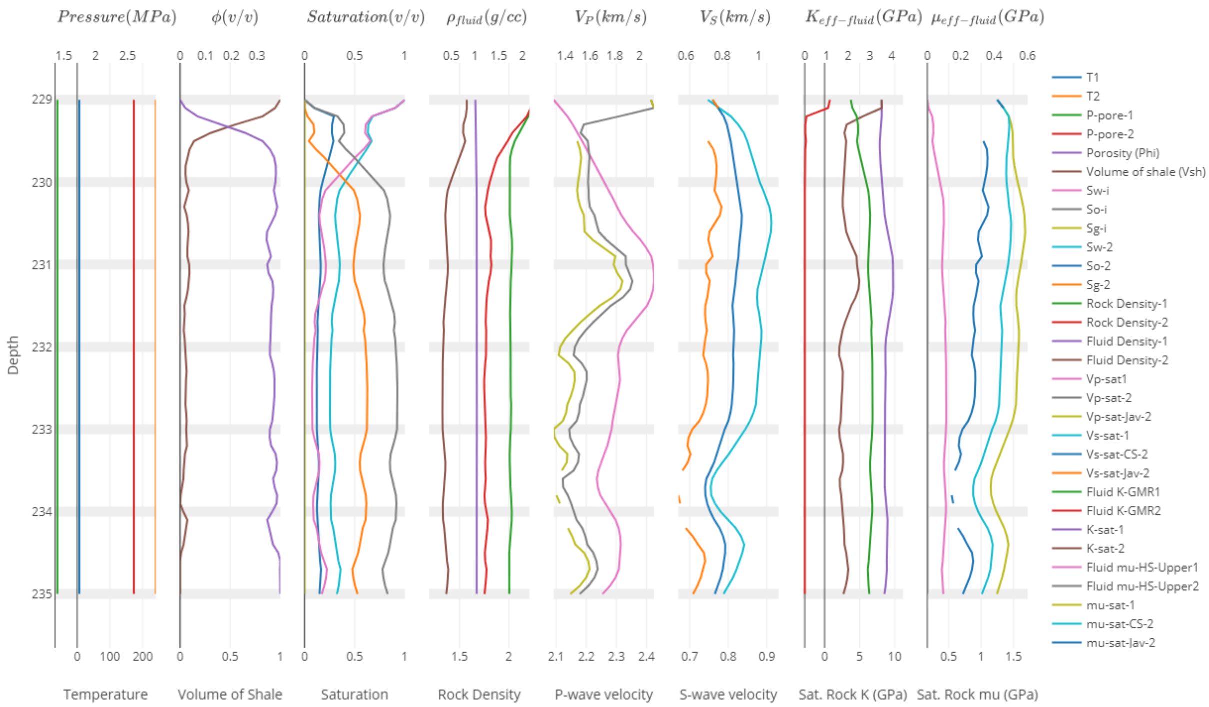

Figure 1 Application of the viscoelastic fluid replacement model on a sample well log. The entire column is assumed to be occupied by the steam chamber (T = 240 °C, pore pressure = 2.6 MPa). Indices 1 and 2 correspond to first (in-situ) and second (post-steam) states. So, Sw, Sg are oil, water and gas-phase saturations, respectively. K and mu are the bulk and shear modulus. HS, CS, Jav correspond to Hashin-Shtrikman, Ciz and Shapiro, and Javanbakhti models, respectively.

References

Ciz, R., and S. A. Shapiro, 2007, Generalization of Gassmann equations for porous media saturated with a solid material: Geophysics, 72, no. 6, SM293–SM300

Javanbakhti A., Lines L. R., Gray D., 2019, "Empirical Modeling of The Saturated Shear Modulus in Oil Sands", in press, GEOPHYSICS. https://doi.org/10.1190/geo2018-0309.1

Javanbakhti A., 2018, "Empirical Modeling of the Saturated Shear Modulus in Heavy Oil Saturated Rocks", PhD thesis, University of Calgary

Web application can be accessed via: http://sagdseis-env-1.6msy2fmxap.us-east-2.elasticbeanstalk.com