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On the Importance of Using Stochastic Seismic Inversion in Reservoir Modelling: An Application on a Tight Oil Reservoir

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SUMMARY

At appraisal stage of a reservoir characterization, a key step is the inference of its static properties, such as porosity. In this study, we present a new nested workflow that optimally integrates 3D acoustic impedance and geophysical log data for the estimation of the spatial distribution of reservoir porosity, which is applied to a tight sandstone oil reservoir located in Quebec, Canada. First, the non-linear and multi-modal statistical petrophysical relationship between acoustic impedance and reservoir porosity is established using collocated geophysical log data. Second, a conventional least-squares post-stack inversion of the impedance is computed on the seismic grid. The fit between well log data and numerically computed traces was found to be inaccurate. This leads to the third step, involving a post-stack stochastic impedance inversion using the same seismic traces to improve well and trace fit, but also to estimate the uncertainty on the inverted impedances. Finally, a Bayesian simulation algorithm adapted to the estimation of a multi-modal porosity distribution is used to simulate realizations of porosity over the entire seismic grid. Results show that the over-smoothing effect of least-squares inversion has a major impact on resource evaluation, especially by not reproducing the high-valued tail of the porosity distribution. The adapted Bayesian algorithm combined with stochastic impedance inversion thus allows a better reproduction the porosity distribution and improves estimation of the geophysical and geological uncertainty.

On the importance of using stochastic seismic inversion in reservoir modeling

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In this study, we demonstrate the importance of using stochastic impedance inversion for modeling the porosity field of a tight oil reservoir. The reservoir under study is an on-shore conventional oil play located in the province of Quebec, Canada. The reservoir shows strong spatial variability of the porosity. Two intervals show the presence of a high concentration of parallel, sub-vertical open fractures, which seem to be fed by matrix porosity. The cap rock is a non-fractured shale. Two faults limit the formation in the North and in the South, where the York River unit shows at the surface.

A 3D seismic survey was acquired in 2008 covering the entire potential reservoir area. The seismic cube sampling is 2 ms and its dominant frequency is estimated at 35 to 40 Hz at the reservoir depth. The seismic wavelength is between 125 m and 150 m, corresponding to a vertical resolution of 31.25 m to 37.5 m. The spacing of the modelling grid is the same as the seismic grid, 50 m laterally and 2 ms vertically. Two wells cross the entire reservoir approximately in the middle of the seismic cube. Acoustic impedance (AI) and effective porosity logs are acquired at a vertical resolution between 10 cm and 15 cm. The logs are then converted in TWT and upscaled at the grid resolution of 2 ms. There is a clear inverse, non-linear and heteroscedastic relation between AI and porosity. In addition, the geological log analysis showed that there are three different porosity families within the reservoir. Each of this family is well differentiated with the other in terms of AI and porosity.

A kernel density estimator was computed using a non-parametric mixture of three Gaussians, each representing the probability of occurrence of each family. The identification of family 3 is of prime importance in this project, because family 3 corresponds to the family having the highest porosity and the highest potential for oil exploitation.

First, the porosity field was simulated using sequential Bayesian algorithm constrained by the deterministic AI cube and porosity logs. This algorithm allows computing multi-modal porosity distribution. However, the distribution of the simulated porosity shows that the realizations reproduce the mean of the well logs, but fail at reproducing the two highest porosity families (Figure 1).

Second, the 3D stochastically inverted AI cubes together with the porosity logs are employed to compute multiple equiprobable 3D porosity scenarios using the same Bayesian simulation algorithm. Each realization represents a stochastic compromise between the stochastic AI cube and the measured porosity at wells. All the models reproduce well the different porosity families as measured and interpreted at the wells while accurately image the geology. Specifically, it reproduces the two high porosity families that were not found using the deterministic impedance cube. Figure 1 synthesizes the different results. The two right-hand subplots show the target histogram (red curves) and one simulated porosity field using deterministic (upper right) and stochastic AI cubes (lower right). It is obvious that the stochastic inversion permits to recover the upper-tail of the distribution, which consists on the most productive zones in such reservoir.

In conclusion, we clearly demonstrate that using stochastic AI inversion in a 3D porosity modelling is crucial to recover the lowest and highest values. In terms of reservoir engineering, those values and their connectivity are the most important parameters to model for an accurate forecast of the possible oil recovery.

Figure 1. Upper left: distribution of the deterministic AI. Lower left: distribution of the stochastic AI. Upper right: distribution of the simulated porosity using deterministic AI. Lower right: distribution of the porosity using the stochastic AI. The red curves represent the marginal distribution of the porosity modelled using a mixture of three Gaussians.