A WORKFLOW TO ESTIMATE RESERVOIR PROPERTIES OF UNCONVENTIONAL GAS SHALES: A CASE STUDY OF THE HAYNESVILLE SHALE

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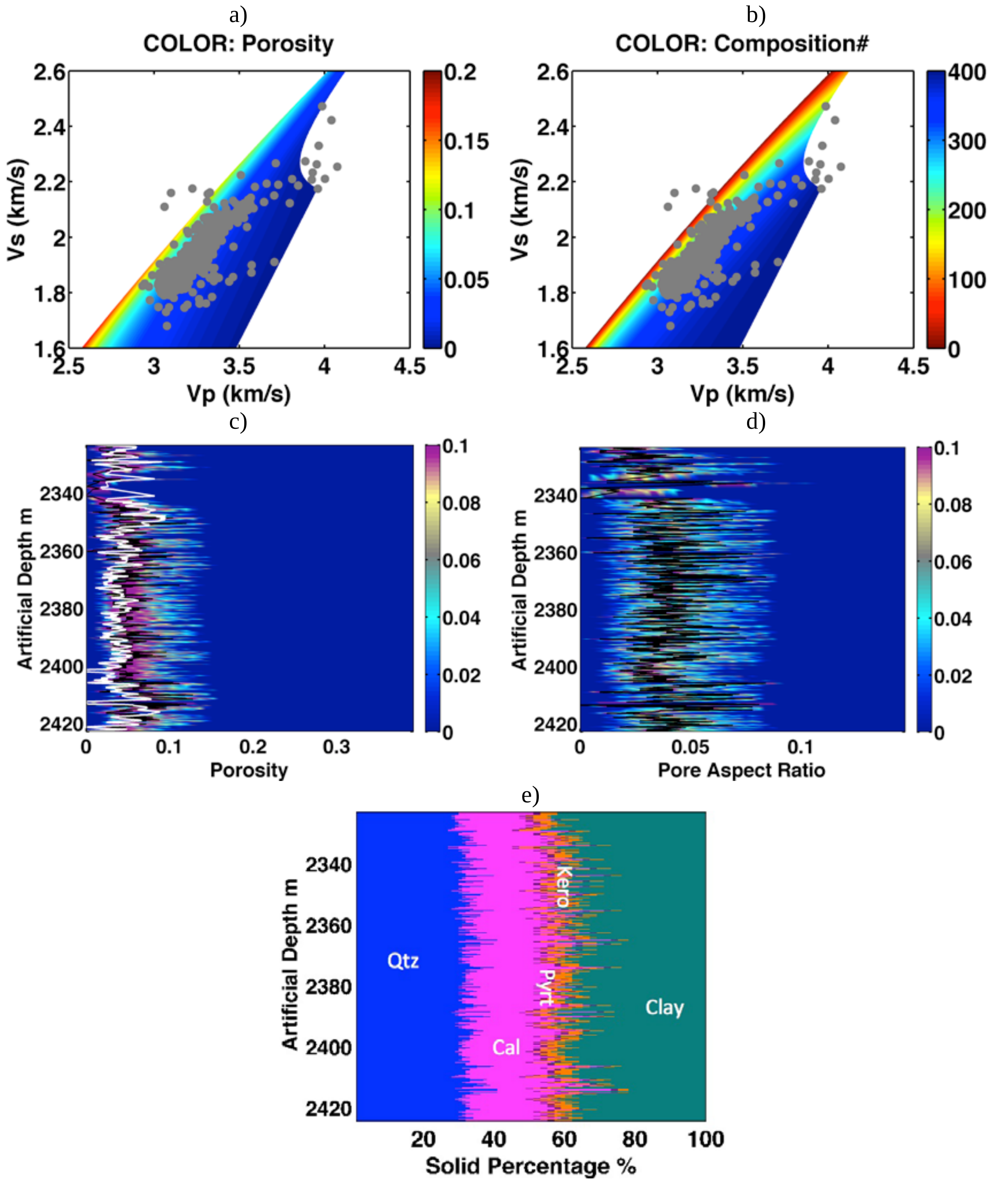
ABSTRACT

Reservoir properties, such as porosity, composition, and pore shape of gas shales are important for both exploration and production purposes of these complex reservoir rocks. This work presents a workflow to invert these properties from well log sonic data for unconventional gas shales, using the Haynesville Shale as a case study. Two rock physics models, an isotropic and an anisotropic one, were combined with a grid search method. The isotropic model initiates the numerical simulation by including grains and pores of different shapes and sizes; the anisotropic model then treats the shale as a vertical transversely isotropic medium by introducing aligned fractures. After the relationships between the reservoir properties and elastic properties (P- and S- wave velocities) were built through the rock physics models, a grid search method was used to estimate the reservoir properties and the associated uncertainties. In the grid searching, P- and S-wave velocities from the rock physics models were compared with the measured log data. The modeled seismic velocities that satisfied specific acceptance criteria provided the estimated reservoir properties. The workflow was applied to the Haynesville Shale and provided joint distributions of porosity, composition and pore aspect ratio at the well location. The porosity and composition estimations matched the observations from log and core data within a few percent. Aspect ratio estimation matched those observed in microscale images. When we apply this workflow to the seismic scale where there are continuous seismic velocities inverted from 3D seismic data, we will be able to obtain spatial distributions of these reservoir properties and, therefore, provide optimal locations for exploration and production wells.



Crossplot of Vs Versus Vp colored by porosity a) and composition b), where composition consists of quartz, calcite, pyrite, kerogen and clay. Gray dots are well log data, and the background color shows the rock physics modeling results. Almost all the data points are covered by the modeling results, and the modeling results follow the data trend very well, indicating that the model is constrained by both Vp and Vs simultaneously. Estimation of porosity c) and pore aspect ratio d) are shown, with the background color representing probability, and the black curve representing the estimation with the highest probability. For porosity estimation, the white curve shows the density porosity from log data. The estimated porosity matches with density porosity very well. Estimated percentages of quartz, calcite, pyrite, kerogen and clay e) is plotted along the artificial depth.