Reservoir property estimation in Carbonates

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Abstract

We present some key challenges in rock and fluid property prediction in carbonates. Most traditional rock physics models have been developed for siliciclastic rocks. Carbonates, which have a completely different mineralogy, pore structure and geometry, pose new challenges to us. We look into the applicability of traditional rock physics models on carbonate reservoirs. We analyze the effect of porosity, mineralogy, clay content, and fluids on the bulk and shear stiffness of carbonate rocks in a middle-eastern deep reservoir, composed predominantly of limestone with varying proportions of anhydrite, dolomite, and clay. We also analyze the effect of in-situ stresses on the elastic properties, with particular emphasis on pore-pressure. We demonstrate the ability to model the elastic properties (bulk and shear moduli) as functions of mineralogy, clay content, porosity, and pore-pressure. We use a stochastic rock physics framework to build a probabilistic forward model, based on and calibrated to well-log and drilling data. Using the joint probability distribution functions, we use a Bayesian inversion technique to estimate reservoir properties (porosity, clay content, and pore-pressure) from seismic inversion data (acoustic impedance, shear impedance, and density) along with the associated uncertainties.

It is well-known in the rock physics community that sonic and shear velocities of rocks are strongly dependent on lithology and porosity. Other factors affecting rock velocities are pore shapes (aspect ratio of pores), fluid type, and in-situ stresses (including pore-pressure). Most commonly used rock physics models, such as those derived from effective medium and granular medium theories, have been tested on siliciclastics. Also several widely-used empirical models, for example, the Marion model and the Critical porosity model have been developed using sand-shale mixtures. Due to the complex grain and pore structure of carbonate rocks, granular medium type of models that are based on contact theories may not be applicable to carbonate rocks. However, the upper and lower bounds on elastic properties (such as Voigt, Reuss, and Hashin-Shtrikman bounds,) do not depend upon the rock-type or the pore-shape, and therefore should be applicable to carbonate rocks.

We verify that Hashin-Shtrikman bounds can be used to constrain the elastic properties of carbonate rocks with varying amounts of clay content. We also propose a calibrated, semi-empirical rock model that uses a combination of the Hashin-Shtrikman bounds and the Critical porosity concept to predict elastic properties as a function of lithology (mineralogy and clay content) and porosity in the clay-rich carbonates that make up the reservoir of interest. Variation in fluid type and hydrocarbon saturation is not a major concern in this field, as particular lithology units appear to be associated with particular fluid-type and saturation (for example, the dolomites show spatial variation in porosity but are always hydrocarbon-saturated). Porosity, clay content, and pore-pressure are the main variables that we address in this reservoir.

We show an example of rock property estimation in a carbonate reservoir using statistical rock physics. We used rock physics theories and concepts developed in siliciclastic rocks, modified and calibrated them to the available data in a carbonate reservoir. Specifically, we found that the Hashin-Shtrikman upper bound modified with a Critical porosity constraint provides a good fit to the existing data in terms of predicting elastic properties (bulk and shear moduli) as functions of porosity and relative amounts of dolomite, calcite, and clay. We use this model in a Bayesian inversion framework to estimate 3D distributions of lithology and porosity from seismically derived Acoustic impedance and Poisson's ratio. As a next step, we use lithology-dependent porosity-effective stress transforms (calibrated to well data) to estimate 3D distributions of pore-pressure in the reservoir and overburden zones.