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Development of Source Rock Kinetic Models for Fluid Property Prediction in Unconventional Shale Plays: A Case Study from the Permian and Neuquen Basins

Lucia Rodriquez[1] and Changrui Gong[1]

[1]Apache Corporation

ABSTRACT

Hydrocarbon fluid properties are essential factors in the well performance of unconventional shale plays, together with the effective permeability and a favorable pore pressure regime. Fluid properties depend on the source rock type and maturity level; higher gas-oil-ratio, lower density, and lower viscosity fluids will provide the best production rate and ultimate recovery in liquid-rich shale plays (Wan *et al*., 2013).

Basin and petroleum system modeling can be used to predict in-situ hydrocarbon fluid properties when coupled with description of source rock characters and its generation kinetics. In this study, data from Vaca Muerta and Woodford shales are used to propose and test a series of kinetic models. Different datasets include lab-derived kinetics data on selected source rock samples, large set of regular RockEval data on shales, and field production data. A comparison of these custom kinetic models against default models for different organofacies source rocks is shown and a discussion of the importance of the different model input parameters is presented.

The resulting kinetic models are coupled with a regional basin and petroleum system model to predict in-situ fluid properties, such as gas-oil-ratio, API gravity, and viscosity. The expulsion model used in these calculations considers inorganic porosity and saturation, organic porosity, and initial oil sorption capacity. An important aspect of these predictions involves a good characterization of source rock facies and its lateral variations as the source rock properties (HI, TOC) also impact kerogen conversion and, in the end, fluid properties.

Instantaneous generation and expulsion over a narrow thermal stress range are thought to be more representative of the in-situ fluids in shale plays than cumulative products from expulsion and migration (Cander, 2012). A comparison of the instantaneous generation results against data from produced fluids is shown, and differences in results are discussed taking into account multiple factors such as capillarity, multi-phase flow dynamics, and in-situ versus migrated fluids.