# Calibration of FIS Factor 1 Response to Map API Gravity "Sweet Spots" in Unconventional Resource Assessments

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Abstract

Fluid Inclusion Stratigraphy (FIS) has been used for decades to successfully evaluate critical aspects of petroleum systems such as reservoir content, phase state, seal effectiveness, and migration pathways. This presentation extends those fundamental concepts to the unconventional realm and demonstrates the manner in which the calibrated FIS response is capable of directly measuring the API gravity as part of "sweet spot" assessment (e.g., prior to leasing). This is a distinct advantage over optical-based methods that fail to account for the gas phase contribution (e.g., gas-oil ratio) to the reservoir content, and is particularly advantageous when the hydrocarbon inclusions are hosted in a carbonate lithology. The advantages are demonstrated by the fact that the relative proportion of dissolved gas in the oil phase can account for up to 20°API gravity variation in the produced hydrocarbon resource, that fluid inclusions are difficult to image in carbonate lithologies (i.e., matrix and cements) due to the frequent small size and problematic optical properties, and that the fluorescence response of hydrocarbon is biased to the liquid phase since the fluorescence originates from the distribution of aromatic hydrocarbon components (i.e., benzene and higher aromatics). The Factor 1 response variable is the output from HCA and PCA statistical processing of the raw FIS signal (i.e., 1–180 amu) that provides a continuum between dry gas (i.e., <−2), wet gas/condensate (i.e., −2 to +1), and oil (i.e., >+1). For each of these intervals, the gas content is reflected in a continuous scale that is subsequently calibrated with known reservoir contents that allow the gas-oil ratio and API gravity to be determined. While the generic calibration is robust, additional precision is provided with the flexibility to include local calibrations. This method is superior to the optical-based fluorescence determination (i.e., including fluorescence spectroscopy) since a larger sampling of the resource is analyzed, the subjective color determinations are avoided, costs are lower, turn-around time is faster, and the output includes the gas phase dissolved in the liquid fraction. Best practice protocol includes analysis of a vertical profile through the target resource, and integrating the output with other parameters in the unconventional resource evaluation toolkit (e.g., basin modeling, rock mechanics, and mineralogy). The method is demonstrated to be particularly useful in complex reservoir facies, including complications introduced by fault offsets, to provide input for determining optimal lateral placement and length.

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