Using Surface Geochemistry to Map Enhanced Reservoir Characteristics and Maximize Production

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Abstract

While seismic imaging provides critical and useful stratigraphic and structural information, it does not address other critical issues such as reservoir characteristics, or hydrocarbon potential. Ultrasensitive hydrocarbon mapping can be used to evaluate and map hydrocarbon richness, pressure, porosity and net pay thickness across a field. Ultrasensitive surface hydrocarbon mapping technologies are unique among surface geochemical technologies in that they use passive monitoring to capture and concentrate microseepage hydrocarbons at parts per billion (ppb) levels which is 1,000 time more sensitive than traditional methods. In microseepage hydrocarbon compounds pervade the overlying seal and migrate vertically through the stratigraphic sequence to the surface. It is important to note that the three primary factors that drive microseepage are reservoir pressure, porosity, and net pay thickness. The greater the combination of pressure, porosity, and net pay thickness, the stronger the hydrocarbon expression at the surface. Consequently, these hydrocarbon measurements are directly related to reservoir characterizes. The first case study takes place in the Jonah Field in the western United States. The field entails a 400 meter thick tight sandstone gas play at a depth of ~3000 meters. Twelve wells, both normal-pressured and over-pressured, were sampled at the surface survey with 15 samples around each well. The resulting hydrocarbon probability values were then plotted verses Original Gas in Place times Reservoir Pressure. The results showed a direct correlation between the geochemical probability factors and the original gas in place times pressure. The second case study took place in the Anadarko Basin in Oklahoma in the Red Forks channel sands. Seismic resolution is often insufficient to map narrow sinuous sand beds. Thus, maximizing

production can be difficult. The purpose of the survey was to map over pressured gas condensate from the Pennsylvanian Red Fork channel sands at a depth of ~14,000'. The data set encompassed nine surveys covering 120 mi^2 over a three year period. The AGI ultrasensitive hydrocarbon mapping data correctly predicted 27 of the 30 wells post-survey wells (90%). Additionally, the data showed a strong correlation (i.e. $r^2 = 0.87$) between production, effective reservoir porosity (ϕ), net pay thickness (h), and the surface geochemical expression. In conclusion, ultrasensitive hydrocarbon surface mapping is driven by reservoir pressure, porosity, and net pay thickness. Empirical data shows that ultrasensitive probability factors can be directly related to production and good reservoir characteristics. This data, when combined with quality seismic imaging, can provide dramatic insight into optimizing field production and reducing development costs.

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