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Fracture Quantification from Image Logs

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ABSTRACT
The potential contribution that natural fracture systems can make to reservoir flow rates and storage is largely determined by the collective geometric properties of the fractures. The basic geometric properties of fracture systems include: fracture orientation, fracture length (or radius), fracture aperture and/or shear offset and fracture density. From these properties, fracture porosity, fracture connectivity and fracture permeability can, potentially, be calculated or modeled. The most important geometric factors for the determination of these reservoir properties are fracture density and aperture.

Image logs have become a very widely used media for assessing the fractures that exist within subsurface reservoirs. The image logs, derived from either resistivity or acoustical logging tools, provide a pseudo- picture of the fractures, bedding fabrics, etc. that exist in the rocks bounding the wellbore. Fractures are detectable on image logs via a contrast in resistivity or acoustic reflectivity with the country rock. Although the orientation of the fractures can be directly measured from the image logs, the other geometric properties of the fracture systems must be derived indirectly. The challenge is to implement procedures for these indirect measurements that are reliable and accurate.

The wellbore generally intersects fractures at an oblique angle. As a result, the fracture spacing (and, thus, density) is not simply the distance between fracture intersections along the wellbore. Commonly, the “true fracture spacing” is calculated from the intersection distance using a simple trigonometric function (know as the Terzaghi correction, or some variant). We find, however, that this approach falters because of three issues: (1) the image log is sampling a cylindrical volume of rock rather than line, (2) most natural fractures do not cut entirely across the wellbore and (3) fractures that cross only a minor portion of the wellbore and/or intersect the wellbore at very low angles are difficult to detect on the image logs.

We have developed an alternative density correction procedure that is based on stochastic models of various fracture populations intersected by the wellbore and that considers only those fractures that intersect at least 50% of the wellbore. The resultant densities, combined with the orientation characteristics, can be used to anticipate how well interconnected the fracture network is. Fracture densities, combined with fracture aperture characteristics may be used to calculate fracture porosity and to anticipate fracture permeability.

The width and the intensity of a fracture trace on a resistivity image log (its pseudo-aperture) is a function of the fracture's physical aperture, the resistivity of the mud filtrate, the invaded zone formation resistivity and the amount of standoff between the image pad and the borehole wall. Back-calculating the physical aperture from the image log characteristics is theoretically possible, though it clearly requires specification of many parameters, several of which are difficult to obtain. Some of the common pitfalls with algorithms for the determination of the physical fracture aperture include: a false assumption that the measured fractures are perfectly linear, a miscalculation of fracture aperture for large events because the conductivity gather window is statically chosen, the miscalculation of aperture due to an intersection of the fracture with conductive beds and an error in the specified formation and mud resistivities.

Despite these pitfalls, image-log aperture determinations may be very useful in a qualitative sense. Many people in the industry have seen positive correlation between calculated fracture aperture and fluid flow rates. However, while computed apertures can be a reasonable tool to compare fracture sizes within a specific zone in a well, they may not be reliable when comparing between wells or between formations. Further, calculation of fracture porosity and permeability requires an accurate quantification of the fracture apertures, and this can only be assured where all of the affecting factors are very well constrained.