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Review

Modeling of complex hydraulic fractures in naturally fractured formation

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ABSTRACT

This paper presents a general overview of hydraulic fracturing models developed and applied to simulation of complex fractures in naturally fractured shale reservoirs. It discusses the technical challenges involved in modeling complex hydraulic fracture networks, the interaction between a hydraulic fracture and a natural fracture, and various models and modeling approaches developed to simulate hydraulic fracture–natural fracture interaction, as well as the induced large scale complex fractures during fracturing treatments.

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Introduction

It has long been observed in mine-back experiments and core-through of fractured formations (Warpinski and Teufel, 1987; Jeffrey et al., 1994, 2009; Warpinski et al., 1993) that hydraulic fracture interaction with natural fractures can result in branching and offset at the natural fractures and consequently lead to complex fractures. Fig. 1 shows an example of complex parallel fractures and offsets created as a hydraulic fracture propagates through natural fractures and zone boundaries, observed by Warpinski and Teufel (1987) in a mine-back experiment.

However, it was not always clear if these complexities are only small-scale features relative to an otherwise planar fracture at large scale and whether they also occur in formations at greater depth. Limited direct observations available at depth by coring through the hydraulically fractured interval at the GRI/DOE-sponsored Multiwell Experiment Site (Warpinski et al., 1993) also revealed multiple closely spaced hydraulically induced fractures, filled with the residue of the fracturing fluid. In spite of the general awareness of potential complexity in the hydraulically induced fractures, based on the observations like these, over the years hydraulic fracturing treatment design continued to be simulated based on the models that assume a planar fracture. Some of the models introduced correction factors to account for increased resistance to fracture propagation (apparent fracture toughness), to fluid flow in the fracture (wall roughness effect), or the effect of multiple parallel fractures that increases apparent fracture stiffness and reduces width. These factors tend to be used as pressure-matching parameters and have limited predictive capability.

In the last decade, following the success of horizontal drilling and multistage fracturing in the Barnett shale, exploration and drilling activities in shale gas and shale oil reservoirs have skyrocketed in the US and abroad. Economic production from these reservoirs depends greatly on the effectiveness of hydraulic fracturing stimulation treatment. Microseismic measurements and other evidence suggest that creation of complex fracture networks during fracturing treatments may be a common occurrence in many unconventional reservoirs (Maxwell et al., 2002; Fisher et al., 2002; Warpinski et al., 2005). The created complexity is strongly influenced by the pre-existing natural fractures and in-situ stresses in the formation. However, due to the lack of industry's modeling capability in simulating complex fractures and lack of proper characterization of key reservoir properties, drilling, completion, and stimulation designs for the unconventional reservoirs relied heavily on imprecise estimates of the stimulated reservoir volume (SRV) from microseismic observations and through a highly inefficient trial-and-error approach. Not being able to accurately simulate complex fractures generated during the fracture treatment presented a major limitation that promoted a cookie-cutter completion and fracture design approach rather than one that is based on engineering approach to optimize the fracture parameters and production according to formation properties. Fracture simulation can provide information such as induced overall fracture length and height, propped versus unpropped fracture surface areas, proppant distribution and its conductivity, etc., all of which influence the short- and long-term production from the unconventional reservoir, and cannot be obtained from microseismic measurement alone (Cipolla et al., 2011b).

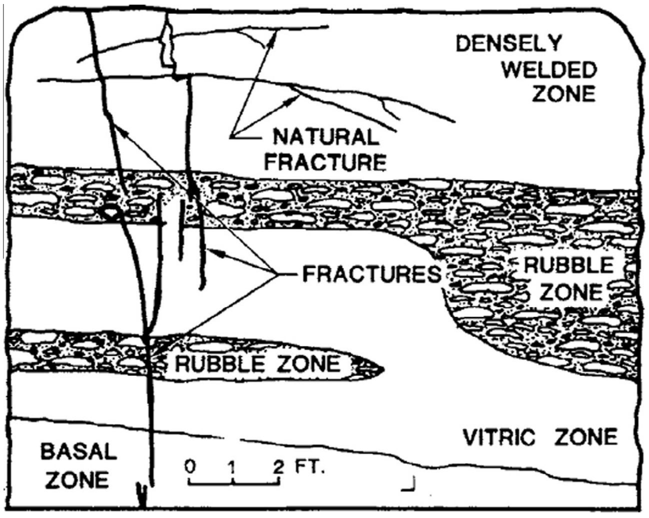

Fig. 1. Complex fractures observed in mine-back experiments, by Warpinski and Teufel (1987).

However, modeling the process of hydraulic fracture network creation and interaction between hydraulically induced fractures and natural fractures presents many technical challenges. Significant progress has been made in recent years in the development of complex fracture models to address the needs for more suitable design tools for the unconventional reservoirs than the conventional planar fracture models. However, some aspects of this complex fracturing process are still not fully understood in terms of their impact or importance to the overall fracture geometry creation, or the complexity of simulating them is still beyond the current modeling capabilities or requires computation power or time that is not practical for engineering use. Therefore, these models will continue to evolve in the coming years.

One of the difficulties in fracturing design is the lack of clear understanding of the nature of fracture complexity created during fracture treatment. Microseismic monitoring does not provide sufficient resolution to delineate the exact hydraulic fracture planes. Microseismic events are mostly attributed to shear failures along natural fractures or faults surrounding a hydraulic fracture (Rutledge et al., 2004; Williams-Stroud et al., 2012). The events cloud forms a "halo" surrounding the hydraulic fracture. In conventional sandstone formations, the observed events cloud has a relatively narrow width, whereas in unconventional reservoirs, a much wider events cloud is often observed (Fisher et al., 2002). A wide microseismic cloud may possibly be explained by either deep fluid penetration into natural fractures in the shale while the induced hydraulic fracture remains planar or simple (Savitski et al., 2013), or by the creation of complex hydraulic (tensile) fracture network. Although deep fluid penetration into a highly permeable and initially well-connected natural fractures network is certainly possible (Zhang et al., 2013), many unconventional plays have very low effective permeability, and observation of cores shows that most natural fractures in these shales are mineralized (Gale et al., 2007; Gale and Holder, 2008; Han, 2011; Williams-Stroud et al., 2012). Therefore, in very low permeability shale, fluid penetration in the natural fractures network is limited. Fluid penetration into natural fractures can also occur due to dilation of natural fractures as a result of shear, but this typically occurs under the condition of large stress anisotropy and for natural fractures oriented 30 to 60° from the principal stress directions (Murphy and Fehler, 1986). For many shale reservoirs where the tectonic environment is relaxed and the difference between the horizontal stresses is low, a wide microseismic cloud is a strong indication that complex, tensile open hydraulic fracture networks are created, although the hydraulic fractures may follow the paths of the natural fractures. A field case in the Barnett shale presented by Fisher et al. (2002), in which fracturing fluid unexpectedly connected to and brought down the production of several adjacent wells not