Natural Fractures
A Significant Variable In Completion Design

As the industry begins to see signs of increased activity in the lower-48, the discussion of how to model and design for natural fractures becomes a key component to fracture design and ultimate success. In the March 2017 issue of JPT, technology editor Chris Carpenter discusses using seismic data to construct a discrete fracture network (DFN) model. In that study, the authors use an established workflow to extract seismic-scale fracture networks, allowing them to feed the model and develop a better calibration during simulation.

The interest in DFN makes a lot of sense, considering the continued movement and growth into fracturing tight rock and shales. It’s no secret this technology is so pervasive that even mature plays are receiving renewed attention. In its most basic sense, hydraulic fracturing in low permeability formations is all about surface area. The more surface area the fracture can create in the pay, the better the chances of a successful well. For low- and ultralow-permeability zones such as shale formations and tight rock, fracturing engineers typically want to design long, narrow fractures to allow hydrocarbons a greater opportunity to flow into the wellbore.

Several variables must be taken into account during this process for it to achieve the most effective design. Chief among them is the natural fracture network. According to remarks from Michael B. Smith of NSI Technologies during a Society of Petroleum Engineers training session, natural fracture networks are common and can dramatically affect the operation’s net treating pressures.

For example, while looking at pressure versus time as illustrated in the Nolte-Smith plot, while pumping a fracture treatment, an engineer encounters a pressure increase as the fracture length continues to grow. This can indicate the treatment pressure is approaching a level that ultimately could result in a screen-out. However, when looking again at pressure versus time, a flattening net pressure while pumping at a consistent rate can point to excessive leak-off into the natural fracture network, demonstrating that the operation has reached critical pressure.

Obviously, each of these situations can dramatically impact the fracture treatment’s ultimate success. Typically, operators address each situation with technology designed specifically to propagate the fracture treatment. For formations with permeability in the nanodarcies, a slickwater treatment may help optimize fracture length. For formations in the microdarcies, an operator may choose to pump 100 mesh propellant into the natural fractures, plugging them to once again grow the fracture to the desired length. Each of these techniques can improve the well and have been used for years. However, neither necessarily takes advantage of the natural fracture network. Microseismic technology is one of many tools being used to help identify natural fractures and discern how they affect hydraulic fracture treatments.

In an SPE paper titled, Fracture Network Connectivity? A Key to Hydraulic Fracturing Effectiveness and Microseismic Generation, (ICHF-2013-053) authors F. Zhang, N. Nagel, B. Lee, and M. Sanchez-Nagel assert that the effect of fracture network connectivity on the overall performance of a fracture treatment directly corresponds to the leak-off ratio. Using a discrete elemental numerical model, the group reviewed multiple cases and noted that where the discrete fracture network was sparse, a flat microseismic distribution zone was observed. In the cases where the discrete fracture network was dense, a complex microseismic map was observed, indicating a significant relationship between the fracture treatment and the natural fracture network.

In another SPE paper, Controlled Hydraulic Fracturing of Naturally Fractured Shales–A Case Study in the Marcellus Shale Examining how to Identify and Exploit Natural Fractures, (SPE 164524) Jordan Ceizkba and Iraj Salehji look at ways to optimize the interaction between hydraulic fracturing and the natural fracture network. Additionally, the team looks at methods for real-time fracture optimization that are based on identifying natural fractures by analyzing fracturing parameters along the wellbore. The authors conclude that, although the Marcellus’ permeability is low, there are concentrations, or “swarms,” of natural fractures that enhance gas storage and potentially natural gas flow.

These are only a couple examples of the work and time going into identifying and optimizing the natural fracture network in relationship to hydraulic fracturing operations. If successful, ultimate returns from fracture stimulated wells can improve greatly. Overall, like most things in the oil and gas industry, true optimization for an operator likely will rest within a combination of foundational principles of fracturing, enhancements in technology and economics. Whether natural fractures are a blessing or a curse depends on understanding the relationship between one’s fracture design and the natural fractures it certainly will encounter.

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