Injection Testing
Opens Window To What Occurs Down Hole

One complicating factor in hydraulic fracturing is that we can’t see exactly what is going on with the reservoir. While this may be the case in the literal sense, I would assert that we actually can see what is happening down hole during hydraulic fracturing, and that the technology has been developing since the 1970s.

Experts agree that the best measurement of the reservoir by far is through injection testing. In their book, Hydraulic Fracturing, published earlier this year, Michael B. Smith and Carl Montgomery discuss how fracture pressure analysis based on wellbore pressure and flow rate can help create a picture of what is going on down hole.

From almost the start of hydraulic fracturing nearly 70 years ago, folks have recognized the value of fracture pressure data, specifically measured bottom-hole pressure and closure pressure. The thinking at the time was that if one could understand these two variables, he would be able to determine the type of fracture he was creating, or ultimately, the type of fracture he would like to create.

Smith and Montgomery discuss how pioneers of fracturing began to model the relationship of pressure and fracture width. Then in 1978, Amoco Production Company set forth a coordinated effort to collect field data to better understand the fracturing process.

Amoco’s work was the first of its kind, and as the process unfolded, two key Society of Petroleum Engineers papers were published. In 1979, Ken Nolte published a paper discussing the pressure decline after a hydraulic fracture treatment. Then in 1981, Nolte and Mike Smith published a paper that first interpreted the impact of pressure on the fracture. These papers combined set the stage for modern fracture pressure analysis.

Nolte and Smith presented a way to identify “critical pressure” as a means to avoid potential screen-outs or undesired height growth. A log-log plot illustrating the relationship of fracture pressure versus treating time can be used to identify the specific characteristics of the fracture. Dubbed the Nolte-Smith plot, this process has been used extensively across the industry to analyze and optimize fracture treatment designs.

Smith even calls matrix and determining the existence of natural fracture permeability, possibly the most critical information needed for unconventional frac design. This controls desirable fracture spacing, fluid selection (since a clean slickwater fluid is best for any natural fractures), and ultimately, completion success. For low-permeability reservoirs, this information can be gleaned only from a properly designed and analyzed (small volume) injection test.

The data used in this process are obtained best by conducting an injection test of the well prior to a fracture treatment. There have been multiple injection tests developed and each test has multiple names. This matter sometimes is complicated by individual companies that have similar tests and use their specific company-developed brand names for each test.

That said, some of the more common tests are the step-rate test, where fluid is injected into the formation at various rates to help identify the closure pressure of the fracture as well as the fracture extension pressure.

The diagnostic fracture injection test, which typically is used in low-permeability environments, involves injecting a small amount of clean fluid into the reservoir and watching the pressure decline over time, giving the operator an idea of fracture closure pressure, pressure dependent leak-off, and height recession and reservoir parameters.

Finally the “mini frac”–sometimes called “data frac”–which typically is used in high-permeability environments, uses a more viscous fluid such as a cross-link gel in order to determine the leak-off coefficient as well as closure pressure.

One of the main issues some operators face in regard to injection testing is the cost, and these tests definitely do add cost to each well. However, experts agree that, especially onshore, an injection test does not need to be conducted on every well, but rather on a few in the region in which one is working. The analysis from just a few wells can help optimize your completions for the best chance of success.

At the end of the day, these tests help engineers and operators paint a picture of what is occurring down hole. This is critical in terms of the investment operators make on each well they complete. It is not uncommon for a company to conduct pressure analyses using these data to get a clear picture of the reservoir they are working with, and to pull out of a play and maybe even a region all together.

Sometimes saving money is making money. At the same time, using pressure data analysis can help to optimize the completion effectiveness and make a good well a great well. Whatever name one wants to attach to the process, the value of injection testing for the independent operator should not be underestimated.

“Pressure data analysis can help optimize completion effectiveness and make a good well a great well.”

Jeremy Visconi is the director of technology transfer for the University of Kansas Tertiary Oil Recovery Program and the PTTC Midcontinent Region office. He has more than a decade of experience in developing and organizing technical conferences and special events.