Anisotropy Key For Baxter Shale Wells

By Scott Goodwin, Shannon Higgins, Tom Bratton, Adam Donald, George Tracy and Felicia Yuen

DENVER—If one takes a cube of rock and measures several physical parameters across the three opposing sides, why does he get different results? The answer is anisotropy. Engineers and geoscientists have witnessed this phenomenon for decades, but since it was impossible to actually make those measurements in a given well bore, they had to make relatively basic assumptions and hope for the best.

When performing hydraulic fracture stimulation, the formation breaks down at its point of least resistance. Stress anisotropy determines this point. Therefore, formation anisotropy has become a prominent factor in completion design, and the ability to measure stress anisotropy could be an invaluable tool in the hands of a fracture design engineer.

New technology to measure anisotropic data has proven effective in the Baxter Shale in the Vermillion Basin, a sub-basin of the prolific Green River Basin. It has been explored and produced since the 1930s, starting with the shallow Wasatch and Fort Union formations. Exploration progressively moved deeper over the years, until the 1980s when drillers began setting their sights on the deep Nugget formation. In the Rock Springs uplift portion of the basin, Nugget explorers found they had to drill through the overlying Baxter Shale. The Baxter was classified as a drilling challenge. It was gas-bearing and overpressured, but it was thought too tight to produce in economic quantities.

The 2003 U.S. Geological Survey National Oil and Gas Assessment recognized the Baxter and its cohorts, the Hilliard and Mancos shales, as having one of the highest resource potentials in the nation, largely because of its gas content and the fact that it had relatively few producing wells. Approximately 2,000 feet thick and overpressured, the Baxter has a total organic content between 1 and 3 percent with very low porosity and permeability. Even very sophisticated logs run through the Baxter show little character, and operators have been challenged when it comes to picking locations for perforations and subsequent fracture treatments.

**Point Of Least Resistance**

Hydraulic fracturing science has evolved dramatically, significantly improving stimulation effectiveness and connectivity between the formation and the well bore. Advances in rock mechanics allow engineers to better model and predict how rocks will fracture, and together with diagnostic tools, allow frac designs to be optimized to achieve more consistent results.

Regional tectonic stress patterns create maximum and minimum horizontal stresses, and hydraulic fractures tend to occur along a plane parallel with the maximum horizontal stress field. Three factors establish this field: pore pressure, overburden and elastic moduli (Poisson’s Ratio and

**FIGURE 1**

*Anisotropic (Purple) and Isotropic (Black) Horizontal Stresses*
Young’s Modulus). Since there was no way to easily measure anisotropy, Poisson’s Ratio and Young’s Modulus have been assumed to be isotropic. Even with this simplification, the ability to determine the minimum horizontal stress made a major improvement in the efficacy of hydraulic fracturing.

The development of dipole shear sonic technology has greatly improved stress analysis in the region surrounding the bore hole. However, there has been no precise way to determine the point of least resistance that marked the most likely site of fracture initiation in complex lithologies. Usually, multistage fractures have more than one possible point where the rock may break down. Operators try to isolate these points using perforating techniques or open-hole packers, but if isotropic techniques are used to analyze the stress fields, the results can be suboptimal.

A new measurement has been introduced that, for the first time, enables anisotropic elastic moduli to be determined with wireline logs. The new measurement, called Sonic Scanner™, is part of an acoustic scanning platform that measures axially, azimuthally and radially from both monopole and crossed-dipole transducers over a wide frequency range and overcomes the acoustic measurement barriers that constrained previous technology. Dynamic measurements of Young’s Modulus in both horizontal and vertical directions are possible. Along with the dynamic Poisson’s Ratio, this allows full analysis of both vertical and horizontal rock properties. The anisotropic moduli measurements can be further refined with specific core data to help constrain and validate the measurements.

In the Baxter Shale, these data have revealed that the dynamic Young’s Modulus measured in the horizontal direction was almost double that of the same measurement in the vertical direction. Additionally, the Poisson’s Ratio measured in the vertical direction was significantly different than the measurement in the horizontal direction. This information allowed for a quantification of transverse isotropy with a vertical axis of symmetry. With these new measurements, a better stress model can be developed for more accurate estimates of the point of least resistance that controls hydraulic fracture stimulations.

**Isotropic Versus Anisotropic**

A comparison of isotropic and anisotropic stress profiles tells the story. In one Baxter fracture stage, five perforation clusters were planned (orange bars in left-hand track of Figure 1). Isotropic horizontal stress varied from 9,600 to 9,900 psi from top to bottom, with a fairly uniform gradient. Under these conditions, one would expect fractures to propagate more or less uniformly across the stage.

The zone actually was fractured using the isotropic data. However, when anisotropic horizontal stress data were introduced, the stress profile changed. Anisotropic horizontal stress (purple) is higher and shows more character than isotropic horizontal stress (black). The top zone still calculated out at 9,600 psi, but the bottom was 10,600 psi. Under these conditions, the expectation is for most of the frac to propagate in the upper...
two zones. A production log was used to help validate this analysis. As shown, a full 68 percent of the production from the entire well is from the top two zones, with little production from the three zones at the bottom of the stage. This strongly indicates that the majority of the fracture treatment propagated in the zones that the anisotropic model would predict.

The engineers decided to change the design after the fact to see, theoretically, how the design could have been improved had the anisotropic stress data been used. Two redesign options were proposed (Figure 2). The first option was to perforate only the top two zones, assuming that the bottom zone lacked the needed reservoir quality to warrant a treatment. The second option was to divide the treatment into two stages using zonal isolation media to ensure fracture propagation from the lower-zone perforations.

A second, deeper zone was analyzed. It also showed a uniform isotropic stress gradient from 10,000 to 10,350 psi across six perforation clusters. But when anisotropic stress was introduced, a much different picture emerged (Figure 3). The deeper zone exhibits erratic anisotropic stress gradient, and the results clearly indicated that the zone at about 11,150 feet should be the best zone (it is weaker and would be expected to take the bulk of the treatment).

Indeed, the subsequent production logs confirmed that the third set of perforations from the top was contributing most of the production from this particular treatment stage. A possible redesign was suggested, again with two options: Increase the number of perforations in the 11,110-foot zone to force treatment into that zone, or break the zone into two stages to be treated separately.

**FIGURE 4**

Offset Well Comparison

![Offset Well Comparison](image)

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Optimizing Treatment Design

The importance of factoring in anisotropic measurements to completion design cannot be overstated. Engineers have known this for some time, but lacked the technology to make the in situ measurements that would enable such analyses. By taking stress anisotropy into account, fracture treatment design can be optimized, saving money while boosting production.

A detailed analysis of two offset wells tells the tale (Figure 4). On the left is a log from a well that was completed without using anisotropic stress analysis in the treatment design (isotropic stress analysis only). Base gamma ray is in the left track, the post-frac radioactive tracer log is in the right-hand track, and the perforations are shown by the red bars in the middle track.

A total of 96 perforation clusters were shot. Of these, 29 were completely untreated, likely because the fracture fluid followed the path of least resistance. These untreated zones are designated with ellipses in Figure 4, and represent only 70 percent treatment efficiency. Compare this with the log on the right from an offset well that was completed after applying the anisotropic stress model and the completion strategies discussed earlier. The operator selected 15 frac points and achieved treatment in 14 of them, or 94 percent efficiency.

Since the same amount of rock was treated in both wells, the two wells have a remarkably similar production profile. However, because of the aggressive improvement in the efficiency of the completion, the total cost of the well on the right was reduced by hundreds of thousands of dollars. This one step significantly improved the economics of the entire area.