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Passive Seismic Monitoring to Optimize Hydraulic Fracturing Treatments: Lessons Learned from our American Cousins

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SUMMARY

North American shale-gas recovery efforts are quite large, while the extent of such unconventional gas reserves in Europe is largely unknown. Some tests of gas shale formations have recently been carried out with good success in various basins (e.g., Germany s Lower Saxony, Vienna Basin, southern Sweden, etc.) The development of Europe s gas resources will take years and may benefit from lessons learned in North America. Firstly production from unconventional shale formations (e.g., Barnett, Fayetteville, Marcellus, Woodford, etc.) has been enabled by modern well log evaluation techniques and completion methods. These are particularly important since stress anisotropy strongly influences fracture system development. Secondly, it is critical to monitor the initiation and evolution of hydraulically-induced fracture systems. Currently almost all predictive models used by reservoir and production engineers to estimate recovery in stimulated wells are based on assumptions that naturally lead to oversimplified fracture geometry. Microseismic monitoring enables reservoir engineers and geoscientists to understand the development of hydraulically-induced fracture systems as well as naturally pre-existing fracture networks in four dimensions.

Introduction

Significant volumes of gas are currently being produced in the continental US from unconventional shale reservoirs (e.g., Barnett, Fayetteville, Whirlpool and Woodford Shales). These plays are partly technology driven and partly economics-driven. Hydraulic fracturing is used to stimulate these formations characterized by extremely low porosity and permeability. The degree to which a hydraulically-induced system develops laterally or vertically depends on numerous factors (e.g., treatment parameters, local geological and geomechanical environments, fluid leakoff, etc.) Monitoring the spatial and temporal development of the hydraulically induced fracture system and being able to alter its geometry are important aspects of today's requirements. Microseismic monitoring has been shown to be a viable real-time solution to assess and understand fracture propagation and geometry.

Method

The typical procedure for any given hydraulic fracture monitoring (HFM) project is to gather the well coordinate data and directional surveys to build the project recording geometry and decide of the optimal monitoring configuration based on parameters such as velocity structure, attenuation, cultural noise, well integrity, etc. Figure 1 shows three wellbore geometries for different HFM projects. Once the project geometry is determined, methods of recording and data streaming are needed to get the data into an efficient algorithm for microseismic event location. A pre-designed accurate velocity model for the site is needed for proper event location. Therefore, sonic logging data, preferably from the wells of interest, are necessary to build the velocity model needed to invert travel-times for hypocentral determination (Drew et al. 2004). As event locations are computed they are plotted by a 3D visualization software for assessment by the stimulation engineering team (Le Calvez et al. 2007).

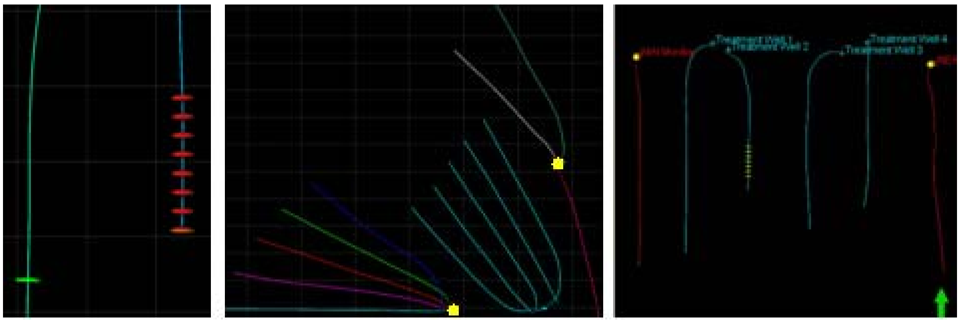

Figure 1 *Displays of geometries for sensor array deployment relative to the treatment well. Vertical treatment and monitoring wells in a shale-gas play (left), one vertical monitoring well (south pad) and one highly deviated monitoring well (northern pad) for a multi-well (5-well pad center) simulfrac in the Barnett Shale (center), and two vertical monitoring wells (yellow disks) with a horizontal monitoring well deployment (yellow disks) for a multi-well simulfrac in the Woodford Shale (right).*

Examples

In this first example, an approximately one-kilometer long lateral was drilled along the minimum stress direction and had one offset well from which the fracture treatment was monitored using microseismic mapping. A sonic scanner log was run in the cased horizontal wellbore to gain a better understanding of how mechanical properties change along a lateral, and to understand how these properties relate to microseismic activity. The toe section of the lateral, shown in blue on the log below (Figure 2 left) has the highest stress normal to the borehole and therefore likely has the highest degree of stress anisotropy. Predicted planar narrow hydraulic fracture network is confirmed by microseismic activity distribution in the first two stages (green and red respectively). Conversely, the heel section of the lateral, shown in red in the log has the lowest amount of stress in the maximum horizontal stress direction and hence the lowest anticipated stress anisotropy. In such a section the induced fracture system should be a relatively wide and complex network as illustrated by the microseismic activity of the third (yellow) and fourth (red) stages.

In this second example (Figure 2 middle), the operator drilled a horizontal well through a faulted section of the Fayetteville Shale example. The faults represented geohazards to fracturing potentially allowing (i) the stimulation of nonreservoir rock and (ii) communication with the underlying water-bearing Penters formation. Mapped activity indicated that the induced fracture from the first four stages developed downward. Based on these observations, the operator decreased the pumping rate in time to avoid fracturing into the water-bearing zone. Mapped events associated to the fifth and sixth stages indicated an upward development heelward indicating the activation fractured-zone dip; hence the subsequent stage was cancelled to prevent potential fluid loss into the fault system and overlapping stimulated volumes.
This third example (Figure 2, right) shows the results from a re-fracturing treatment of a cased and un-cemented horizontal well. The original hydraulic stimulation performed using five perforation clusters resulted in a dominant stimulation of the heel section of the lateral. During the re-fracturing treatment, performed four years later through a new set of perforation clusters, events from the first stage are predominantly located in the mid-lateral region. Subsequent diverting formulations resulted in a slight shift of the microseismic activity toward the heel without shutting down activity in the active zone (Potapenko et al. 2009).

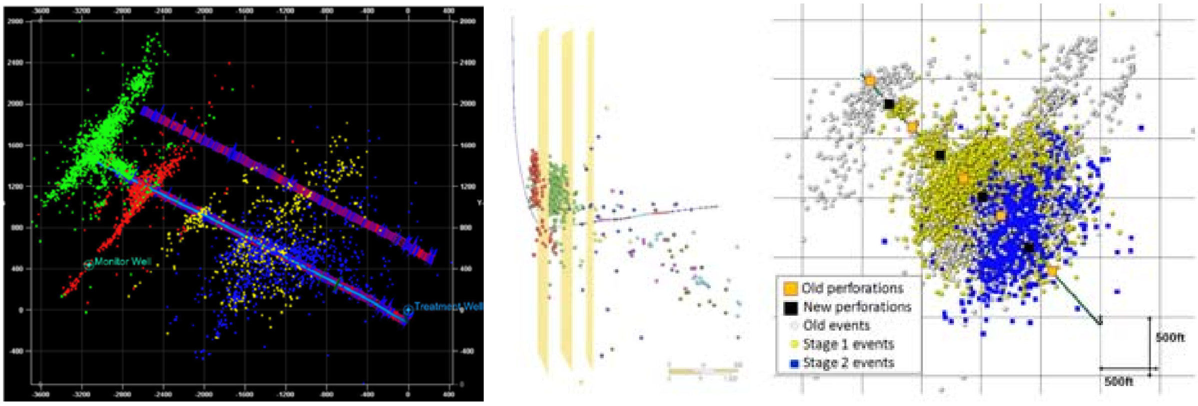

Figure 2 *Microseismicity distribution vs. stress along a lateral in the Barnett Shale formation (left), perspective view of microseismic hypocentral locations in a Fayetteville shale well (centre) and microseismic events for a re-fracturing treatment of an existing well in the Barnett Shale Fm.(right).*

Conclusions

Unconventional plays call for unconventional thinking. Many challenges have yet to be overcome in bringing the full potential of shale gas production to fruition. These examples illustrate how the application of innovative techniques and technologies is used to improve the completion process and well performance in various shale gas formations in the continental US. Knowledge and experience developed in these plays could benefit shale gas formation in other parts of the world.

References

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