Unconventional Approach for an Unconventional Reservoir: Example of Hydraulic Fracturing Treatments in Adjacent Horizontal Wells in a Faulted Reservoir

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Technology- and economics-driven shale oil and gas production is gaining momentum throughout many basins worldwide with US land and Canadian operators developing local knowledge at a fast pace. Large-scale faulting and fracturing partly control stress distribution hence stimulation-derived hydraulically-induced fracture systems. We present the results of a workflow associated to an ongoing multi-stage, multi-lateral stimulation project in the Fort Worth Basin. We highlight how integration of data gathered at various scales from different investigation methods both in the geosciences and engineering domains may improve our understanding of the reservoir when hydraulically stimulated. Well locations and trajectories were determined in and around large-scale faults using 3D surface seismic. As a result, three horizontal wells were drilled in the Lower Barnett Shale section, 150 m apart with the center well landed about 25 m shallower than the outside laterals. Surface seismic indicates that the surface locations are on top of a major fault complex with the lateral sections drilling away from the major fault system and through a smaller fault. An extensive modeling of the borehole-based microseismic monitoring options led to an optimum configuration. All three wells were completed using a perf-and-plug approach. Real-time microseismic monitoring allowed to avoid the faulted zone and to modify as needed the perforation and stimulation plans.

Completion led to an initial gas production of over 3 MMCF/day each. Early decline rates confirm successful completion in avoiding the faulted areas. A geomechanical model was subsequently developed to help characterize hydraulically-induced fracture development in this naturally fractured formation. The model consists in two perpendicular sets of vertical planar fractures with mechanic interaction among them and between injected fluid and fracture faces fully accounted for. This model applied to several stages indicates average spacing of fractures parallel to the minimum horizontal stress smaller than those parallel to the maximum horizontal stress direction while fracture spacing decreases. Minimum confining stress increases as treatment progresses heel-ward, probably due to increasing fracture interaction. Proppant placement modeling indicates that only the near-wellbore region is properly propped, likely due to quick proppant settling in low-viscosity slickwater fluid.