Treatment Order is the Cheapest and Easiest Change to Make Better Wells

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Scope

Multi-stage, multi-well completions cause pore-pressures to increase around each stage treated, compound from earlier offset treatment stages, then dissipate as the injected fluid leaks off into the rock formation. Rock stresses change in a dynamic fashion from virgin reservoir stress to an altered stress influencing subsequently treated treatments in terms of fracture half-length and height. Stress shadows are time-dependent and dissipate over time and return to the virgin stress state. Operators can take advantage of stress changes and contain fractures close to the stages by building stress wedges around subsequently treated stages. After stress dissipates fluid propagates into previously opened fractures leading to poor fracture containment.

Method

Microseismicity detected during hydraulic stimulation of multiple wells in the Denver-Julesburg basin were analyzed to establish a correlation among stage lag (time between current stage treatment and neighboring stage) and event-population centroid with respect to each stage treated. The correlation is used to constrain stage lag time for local stress shadows to dissipate allowing fluid to propagate toward previously treated stages along newly created fractured network. Results were compared to injected well-specific tracer chemicals during production over a 25-day period.
Microseismic focal mechanisms were analyzed to invert for the dynamically changing stress state due to treatment order. Stress changes were analyzed to understand their impacts on fracture characteristics.

Results

Results shows that in the Niobrara Formation SH_{max}=N125°E and stress anisotropy, ϕ=0.91 in the virgin stress state. Increased stresses from previous treatments remain elevated for ~12 days confining fluid distribution to near the well on ensuing stages. Production of well-specific tracer corroborates the hypothesis that local stress-shadows dissipate after ~12 days. Over 90% of tracer recovered for wells with stage lag times <12 days were produced on the same well that the tracer was injected. After ~12 days, stress dissipates and on average <60% of tracer is recovered by the same well that the tracer was injected.

Application

Stress changes are time-dependent and dissipate over time. After stress dissipates fluid propagates into previously opened fractures leading to poor fracture containment. Treatment of neighboring wells with stage lag time < time for stress dissipation time can result in better containment of injected fluids around treatment stages.