Challenges of Discrete Fracture Network Integration into a Model of a Natural Fracture Play: Case Study of the Cane Creek Shale

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Abstract

The Cane Creek shale, a lower Pennsylvanian unit of the Paradox Formation in Utah's northern Paradox Basin, is an emerging oil and gas play. The most successful production has been from horizontal wells in the Big Flat field in the central basin. The DOE-funded project, "Improving Production in the Emerging Paradox Oil Play” (DE-FE0031775), aimed to enhance production from the Cane Creek through detailed characterization and modeling. The Cane Creek shale is a heterolithic unit with cycles of anhydrite, anhydritic-dolomitic mudstone, silty dolomite, very fine-grained sandstone to siltstone, and organic-rich calcareous mudstone. It is capped and underlain by thick halite beds, providing a regional seal and causing reservoir overpressure. Source rock analysis indicates the unit is within the oil window with up to 13% TOC, but it has low permeabilities (0.009-0.2 mD) and variable porosities (6-17%). Natural fractures are thus crucial for production. To characterize the northern Cane Creek and boost production, a 3D geocellular model was built from geological interpretations of formation surfaces, fault networks, and seismic attributes derived from 3D seismic data. A dual porosity and dual permeability numerical simulation model of the 16-2 well was developed to assess production potential from natural and induced fractures, with history matching based on the first year of production data. Several challenges arose in developing this numerical model due to the unique nature of the Cane Creek shale. Faulting and folding from salt tectonics in the lower Paradox Formation made creating a sealed fault model difficult, particularly the low-angle and listric faults that are orthogonal to each other. These caused severe warping of the numerical grid due to the rollover and overtopping sections of the formation. Extensive use of trends during the gridding process was required to avoid severe warping. Developing the Discrete Fracture Network (DFN) presented additional challenges. The resolution of the 3D seismic was lower than the natural fracture network, making imaging the fractures impossible. Seismic attributes were extracted and used to create stochastic realizations of potential DFNs. History matching revealed that the standard Petrel workflow for creating DFNs overestimated the fracture network by roughly 100 times. Additionally, details of the fractures, such as length, width, height, dip, and azimuth, could not be estimated solely from seismic attributes, leading to simplifying assumptions about their shape and orientation. The history-matched results indicated that hydraulic fractures intersecting a sparse DFN near the well's heel were responsible for nearly all gas production.