A high-fidelity discrete fracture model of fracture-matrix flow in fractured shale or low-permeability reservoirs

Yue Hao, Andrew F. B. Tompson, Pengcheng Fu, Randolph R. Settgast, Joseph P. Morris and Frederick J. Ryerson
Lawrence Livermore National Laboratory, Livermore, CA 94551

Key words: multiphase flow, discrete fracture model, fracture-matrix interactions, fractured reservoirs

Multiphase flow and transport phenomena in fractured rocks occur in a variety of subsurface applications. One important example of multiphase flow between fractures and matrix rocks is related to hydrocarbon production from hydraulically fractured shale or low permeability reservoirs. The combination of horizontal drilling and hydraulic fracturing – aka “fracking” – has enabled the creation of extensive fracture networks in low permeability shale gas/oil reservoirs as a means to increase overall formation permeability, leading to significantly enhanced hydrocarbon production. Nevertheless, once created, these new “unconventional” wells experience much faster production declines than conventional hydrocarbon production wells. Maintaining sustainable and economically viable shale gas/oil production has required additional wells and re-fracturing with associated environmental impacts and costs.

While various processes (e.g. proppant compaction and embedment and swelling of clays) may contribute to decreasing productivity, multiphase flow behaviors of hydrocarbon and injection fluids at the interface between the low permeability host rock and the stimulated fractures play an important role in controlling both hydrocarbon production and fracturing fluid recovery rates. Therefore, accurate modeling of such multiphase flow and transfer processes is critical for understanding fundamental physical mechanisms driving hydrocarbon fluid flow and unconventional hydrocarbon production, and may provide the key to sustainable productivity.

Towards this effort we develop a high-fidelity discrete fracture model (DFM) in GEOS, which is a LLNL-developed, massively parallel and multi-physics computational code, to simulate multiphase flow and transfer in hydraulically fractured rocks. The DFM model can explicitly account for both individual fractures and their surrounding rocks, thus providing a more precise representation of multiphase flow behaviors at the fracture-matrix interface. In this study we adopt a cell-centered multipoint flux approximation (MPFA) finite volume method to discretize complex fracture networks and heterogeneous geologic formations with anisotropic permeability. Fractures are represented by lower-dimensional mesh.

The developed DFM model is applied for simulating multiphase (water, oil, and gas) flow and transport in fractured shale or low-permeability rocks at different spatial scales. Specifically, we perform a high-resolution simulation of oil displacement through water flooding into a meter-scale fractured rock block (Figure 1). The discrete fracture network is generated statistically. To best represent fine-scale rock and fracture heterogeneities and in particular examine how they affect multiphase flow behaviors we use a numerical grid size of 3.75x3.75x3.75 mm³ in the simulation, which results in a total number of about 21 million grid blocks including 2 million fracture elements. Numerical results show significantly different flow behaviors in fractures and their surrounding rock matrix. While slowly migrating into tight rock matrix, water quickly flows inside highly permeable fractures, leading to a fast breakthrough in the formation (Figure 1). It is found that multiphase flow processes in fractured, low-permeability rocks are strongly influenced by both viscous and capillary-driven fluid movements across the fracture-matrix interface.
The DFM model developed in this study can not only help accurately describe effects of fracture-matrix interactions on multiphase flow processes in low-permeability formations, but also provide a useful interface to couple with the hydro-fracture model for accurate prediction and assessment of hydrocarbon production and hydraulic fracturing performance. We further extend the meter-scale DFM model to directly simulate multiphase flow and hydrocarbon production in a hydraulically fractured shale reservoir (Figure 2). The stimulated discrete fracture networks used in the simulation are calculated by the hydro-fracture model (also implemented in GEOS). Model results suggest that fracture-matrix interactions play a key role in redistributing pumping and residual fluids within tight rock formations during hydraulic fracturing and hydrocarbon production operations. Use of the DFM model also allows us to analyze some key parameters and processes (e.g. fracture and matrix permeability, stress-permeability relationship, capillary pressure and natural fracture heterogeneity) that might contribute to unconventional hydrocarbon production and fracturing fluid recovery.

This work was performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under Contract DE-AC52-07NA27344.