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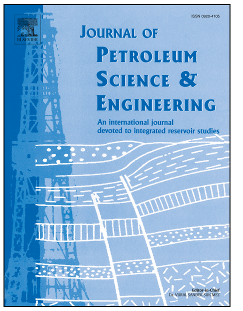

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Pore Network Modeling of the Non-Darcy Flows in Shale and Tight Formations

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Abstract

Pore network modeling is a powerful tool to simulate multiphase flow in porous media. Quasi-static model is used in this work and the drainage displacement process is simulated. In shale and tight formations, there are proposed non-Darcy flow mechanisms: gas non-Darcy flow and liquid low velocity non-Darcy flow. The gas flow in shale and tight formations is generally classified in slip flow and transitional flow regimes according to the Knudsen number values. The BK model (Beskok and Karniadakis 1999) is used for gas non-Darcy flow in this study and the liquid low velocity non-Darcy flow is mainly based on our previous work (Wang and Sheng 2017a; b). Both effects are incorporated into our pore network model separately. For gas-water flow, gas is the non-wetting phase with gas non-Darcy flow and water is the wetting phase with Darcy flow. For oil-water flow, the low velocity non-Darcy flow is considered for both water and oil phases. Then our model is applied in 3 cases. Case 1 is the Berea sandstone (Valvatne 2004), which is the benchmark for conventional pore network modeling. In this case, no non-Darcy flows is considered in our pore network model and it is totally Darcy flow. The absolute permeability and relative permeability are both matched with the experimental data. Case 2 is the Bossier tight gas sandstone (Rushing et al. 2003). Gas apparent permeability vs. pressure was measured at different water saturations in their experiments. In this way, the gas non-Darcy flow in two-phase conditions are verified. Case 3 is the Barnett shale (Moghaddam and Jamiolahmady 2016), which is our major focus. The two types of non-Darcy flows are studied and further discussed in this case. Specifically, the effect of gas non-Darcy flow enhances the gas permeability 2.66 times of the Darcy permeability when pressure is 10 MPa, while the effect of liquid low velocity non-Darcy flow decreases the liquid permeability to 40% of the Darcy permeability when pressure