Geophysical Research Abstracts
Vol. 21, EGU2019-6394, 2019
EGU General Assembly 2019

Comparison of different permeability models for production-induced reservoir compaction

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For oil and gas production optimization, it is generally required to estimate pressure and flow-rate (or production rate) conditions around producing boreholes. However, the whole series of looping process in the reservoir from fluid extraction, through changes in pore pressure and effective stress, to reservoir compaction and permeability evolution, and towards fluid extraction again makes the estimation of pressure and flow-rate condition difficult. Since pore pressure change associated with fluid extraction depends mainly on reservoir permeability, reliable assessment of permeability evolution is critical for production optimization. The goal of our study is to investigate the difference in pore pressure conditions estimated with different permeability evolution models and then validate them using field data. We use one-dimensional radial flow diffusion model around a producing well at the center of a cylindrical reservoir, from which fluid is extracted at a constant flow-rate. We assume three different permeability models normally imposed: (1) the most simplistic constant and invariable permeability, (2) reduced permeability under uncoupled stress-pore pressure condition, and (3) reduced permeability with stress-pore pressure condition coupled. We collect laboratory stress-dependent permeability data in different sandstones to integrate them into a generalized stress-permeability relationship used for models 2 and 3. We calculate pressure distribution and permeability conditions in the reservoir due to fluid extraction based on the three permeability models. All the three models yield pore pressure profiles in the form of pressure funnel with different amounts of drawdown. Model 1 assuming constant permeability obviously predicts the least amount of drawdown with pore pressure condition highest among the three models investigated. Model 2 estimates the largest amount of drawdown and lowest pore pressure condition. Model 3 shows slightly higher pore pressure condition than model 2 because stress-pore pressure coupling process reduces the effective stress increase due to pore pressure depletion. The results given by the 3 models are not so significant in high permeability reservoir (>1000mD). However, in relatively low permeability reservoir rocks (<100mD), the difference in pore pressure drawdown between model 1 and 2 can be as great as $\sim$25% after 100 days of production, while that between model 2 and 3 is $\sim$10%, which suggests the difference in the results given by the 3 models depends on reservoir initial permeability. In an attempt to validate the models, we compare the model results with actual production data (bottom-hole pressure and production rate versus time) obtained from tight sandstones with low permeability ($\sim$100mD). While model 1 and 2 respectively overestimates and underestimates the production rate, model 3 estimates the field data fairly well. Our result affirms that coupling process between stress and pore pressure occurs during production, and that it is important to incorporate the coupling process in the permeability modeling, especially for tight reservoir having low permeability.