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Poro-viscoelastic modeling of production from shale gas reservoir: An adaptive dual permeability model

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ABSTRACT

In most simulations of gas production from shale reservoirs, only the elastic deformation of reservoir rock and fractures is modeled. However, many experimental studies and field investigations indicate shale experiences viscoelastic deformation. In this work, a numerical model is constructed by implementing a poro-viscoelastic model into a dual permeability model (DPM) by using finite element method (FEM), to investigate the coupled time-dependent viscoelastic deformation of shale, and fracture permeability evolution in response to compressible flow of gas and gas desorption. The viscoelastic effect is considered through both deviatoric and mean effective stresses to allow for the effect of shear strain localization. The geomechanical model is first verified against available analytical and numerical solutions. Then, the model is applied to a few synthetic production cases to investigate the geomechanical evolution of a fractured reservoir. Comparing the case of poroelasticity and poro-viscoelasticity shows that the pore pressure differences throughout the domain are small, however, the stress evolution is quite divergent, with higher fracture closure in the poro-viscoelastic case. Comparison of the cumulative gas productions for poroelastic and poro-viscoelastic cases shows that cumulative gas production predicted by the poro-viscoelastic case is always lower than that of the poroelastic one. The difference between the two cases increases for long production times, as the viscous deformation (creep) of the reservoir rock closes the fracture. Results of the numerical simulations suggest that viscous deformation-enhanced closure of natural fractures that feed the main propped fractures can have a critical role in production decline.

1. Introduction

The coupling between matrix/fracture deformation and fluid flow in fractured reservoirs such as shale gas are important for predicting fracture permeability change and reservoir production behavior (Huang and Ghassemi, 2015; Tao et al., 2011). Most reservoir simulators for shale gas, either disregard reservoir deformation or consider only the elastic deformation of reservoir rock and fractures (Yu and Sepehrnoori, 2014).

The geomechanical deformations of shale reservoirs usually demonstrate time-dependent behavior and follow viscoelastic, even viscoplastic constitutive behavior from extensive experimental tests. Olsson (1980) demonstrated that the stress-strain relationship of the oil shale from Anvil Points, Colorado exhibited a linear viscoelastic behavior which was supported from relaxation tests. And he suggested that the confining pressure and temperature could profoundly influence the viscoelastic behavior of the shale samples, especially with the elevated temperature. Blanton and Teufel (1983) considered the viscoelastic deformation of transversely isotropic Devonian shale to determine in-situ stress and corrected the temperature effect in his model. Warpinski (1989) incorporated both the elastic and viscoelastic deformation to estimate the stress state and history over geological timeframe. He pointed out that the viscoelastic behavior and material variation of shale could change the stress state significantly and should be detailed investigated. Huang et al. (1987) investigated the correlation between the water content and creep rate of shale formations from DaQing oil field. In both their tests and numerical models, the stress condition and water content were considered to characterize the viscoelastic properties of the shale specimens and temperature influence was neglected for relative low formation temperature. Zhou et al. (1992) and Remvik (1995) showed that the viscoelastic properties and strength of shales could be significantly altered in their experiments when subjected to water based drilling muds. The shale-fluid interaction induced creep effect and clay swelling may introduce wellbore stability issue with time, depending on the rock composition and loading condition. Sone and Zoback (2011, 2014)

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carried out some creep tests to examine the time-dependent mechanical properties of some gas shale samples. Also, Li and Ghassemi (2012) conducted the multi-stage triaxial creep tests to quantify the viscoelastic properties of the Barnett, Haynesville, and Marcellus Shale and explored the role of temperature on creep. The power law viscoelastic model was used in both sets of creep tests. These results showed that the creep behavior of the samples can be described by a linear viscoelastic constitutive law. As time elapses, higher degrees of viscoelastic deformation can be manifestly identified in gas shale reservoirs, which are enriched in clay and water content and subjected to higher reservoir temperature and differential stress. Following the experimental findings, Furthermore, the time dependent viscoelastic response of the gas shale reservoir upon depletion could enhance the proppant embedment and conductivity loss of hydraulic fractures over production timeframe (Sone and Zoback, 2011; Li and Ghassemi, 2012; Huang and Ghassemi, 2013; Ghassemi and Suarez-Rivera, 2012). Failure to account for this viscoelastic deformation of gas shale reservoirs may result in significant errors when predicting reservoir properties, mechanical response (Almasoodi et al., 2014; Khosravi and Ghassemi, 2017) and hence production performance (Huang and Ghassemi, 2013), especially for clay-rich formations.

The viscoelastic theory is widely developed in the literature and the temperature and water content influence are extensively investigated and corroborated in many tests; however, the coupled effects of pore pressure diffusion and viscoelastic deformation have not received much attention, especially during the production period. Biot (1956) initially proposed a poro-viscoelasticity theory to investigate the linear viscoelasticity and anisotropy of porous medium. The linearized formulation of Biot's poro-viscoelasticity theory was established based on a thermodynamic approach, in which a generalized free energy as well as dissipation function was used to define the thermodynamic system. A linear operator (containing both elastic and viscous terms) between stress, strain, fluid content and pressure was given and applied to solve the field equations. Abousleiman et al. (1993) introduced a micromechanical method to interpret Biot's poro-viscoelasticity theory. In their micromechanical approach, the generalized Kelvin's model (three parameters) was utilized to compute the bulk modulus of rock matrix (K) and solid constituent (K_s) in Laplace domain. Then, an analytical solution for wellbore problem was derived to investigate the coupled process between fluid flow and rock viscoelastic deformation. Bloch et al. (1999) applied the poro-viscoelasticity theory to interpret anelastic strain recovery test by using modified Kelvin's model (three parameters). Simakin and Ghassemi (2005) developed another poro-viscoelastic model by taking the relaxation in both deviatoric stress and the symmetric effective stress into consideration. In that work, a Maxwell linear viscoelastic model was employed to describe the mechanical nature of reservoir rock, and shear viscosity was assumed to be proportional to the second invariant of the strain rate for viscous rheology in a damage model. Based on these assumptions, a numerical model was constructed to study the shear strain localization and fluid flow in rock. All these constitutive models can be utilized to simulate the coupling process between fluid flow and creep deformation of matrix rocks and to prove that the coupling process can notably impact the reservoir compaction and hence the fluid flow. However, they are not directly applicable for simulating the gas production from shale reservoirs, as the gas desorption mechanism and fracture network deformation are not considered.

Gas shale is characterized in both tiny pore size (nanometer-scale) and high organic content. Gas in shale can be stored not only within small pores and natural fractures as free gas, but also adsorbed onto the pore surface or confined onto the matrix grains as solution gas. Therefore, gas shale commonly presents higher gas adsorption potential, when compared to the conventional reservoirs. Based on field and experimental data, adsorption gas can contribute to a considerable portion (50% or more) of gas-in-place (Lane et al., 1990; Montgomery et al., 2005) and actual production (Huang and Ghassemi, 2015; Yu and Sepehrnoori, 2014; Cipolla et al., 2010; Wang, 2017) from shale gas reservoirs. As suggested by experiment results, the adsorption of natural gas, mostly CH4, onto the internal surface of gas shale, usually demonstrates Langmuir-type isotherms (Montgomery et al., 2005; Li and Elsworth, 2015; Vermylen, 2011). Typically, the adsorptive behavior of the Barnett Shale fits Langmuir-type mono-layer adsorption isotherm (Montgomery et al., 2005; Vermylen, 2011) and can constitute up to 15% of the final gas production (Cipolla et al., 2010). Nevertheless, the adsorptive capacity of gas shales could vary remarkably (Yu and Sepehrnoori, 2014), which is dominated by organic content, pore size, reservoir temperature and stress condition (Leahy-Dios et al., 2011). Desorption is an important mechanism for gas production for shale reservoirs and can impact the mechanical reservoir response (Huang and Ghassemi, 2015; Yu and Sepehrnoori, 2014). The gas desorption could alter the stress condition in the near well and far field region, which could influence the reservoir compaction behavior by changing the porosity and permeability throughout the reservoir (Huang and Ghassemi, 2011). Furthermore, this stress change induced by gas desorption could also affect the fracture mechanical closure and conductivity reduction (Cipolla et al., 2010; Wang, 2017), which is sensitive to the stress condition acting on the fracture surface. The associated reservoir compaction and fracture deformation could in turn impact the pore pressure condition as well as the gas desorption process. Therefore, the gas desorption could introduce additional coupling effect between fluid flow and rock deformation (Huang and Ghassemi, 2015). By taking these effects into consideration, the contribution of gas desorption can be highly dictated and manipulated by the stimulation strategy (Cipolla et al., 2010; Wang, 2017). Neglecting desorption process of adsorbed gas may eventually lead to vital errors in simulating reservoir performance and assessing final production, especially for stimulated wells in gas shale. The coupling effect between desorption gas and reservoir mechanical deformation is heavily investigated in the literature, however, most of the studies focus only on the elastic behavior of the formations and the time-dependent viscoelastic effect is excluded.

As demonstrated by microseismic events, shale gas reservoirs usually presented irregular and complex fracture network upon hydraulic fracturing (Cipolla et al., 2010; Maxwell et al., 2002; Weng et al., 2011). The presence of pre-existing natural fractures and/or mega faults could dominate and complex and hydraulic fracture growth. Based on experimental results (Bahorich et al., 2012; Gale et al., 2007), this complexity is evidently attributed to the natural fracture reactivation (opening, dilation or the combination of the two) (Tao et al., 2011) and the interaction with propagating hydraulic fractures. Multiple interaction scenarios could take place along a fracture propagation path (Weng et al., 2011; Huang et al., 2015; Zhou et al., 2016), which is governed by intersection angle, in-situ stress anisotropy, natural fracture filling material, fracture size and fluid property (Huang et al., 2016). Thus, the fracure network with complex geometry should be included in the reservoir simulator to assess the production efficiency for shale gasreservoirs (Huang and Ghassemi, 2015; Tao et al., 2011). Post stimulation, the created fracture network tends to close gradually due to fluid depletion and proppant embedment. Obviously, the reservoir mechanical compaction could greatly impact the fracture network closure behavior during production (Huang and Ghassemi, 2015; Tao et al., 2011; Yu and Sepehrnoori, 2014; Cipolla et al., 2010; Wang, 2017). Due to the characterization of natural fractures, as orientation, density and proppant coverage, the reactivated natural fractures could experience different mechanical deformation and non-uniform closure (Huang and Ghassemi, 2015; Cipolla et al., 2010). Thus, chocking points or early closure of certain fractures could be observed and cause the early decline of production. As mentioned, both the creep deformation and gas desorption could complicate the local stress condition acting on the fracture surface and hence alter the fracture network closure behavior. In such a way, the viscoelastic deformation combined with gas desorption could influence the gas extraction from complex fracture network, which are commonly observed in the shale gas reservoirs.

Thus, a thorough understanding of multi-physics (elasticity,