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Full Length Article

Coupled fluid flow-geomechanics simulation in stress-sensitive coal and shale reservoirs: Impact of desorption-induced stresses, shear failure, and fines migration

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ABSTRACT

Long-term pore pressure depletion significantly alters reservoir stresses, which are known to have a substantial impact on permeability in fractured reservoirs. Increased effective stresses resulting from depletion often induce a decrease in permeability. The opposite has been observed in some reservoirs with an organic rock matrix that exhibits strong sorption-mechanical coupling. With depletion, adsorbed gas desorbs from micropores resulting in shrinkage of the rock matrix, relaxation of effective stresses, and opening of fractures. In addition, reservoir depletion results in an increased stress anisotropy, which may lead to potential reactivation of critically oriented natural fractures and shear failure. The objective of this study is to develop a reservoir simulator with a full poromechanical coupling accounting for sorption-induced change of stresses, shear failure, fines production, and their effect on permeability. This paper aims to estimate the influence of the various mechanical and transport parameters affecting reservoir permeability and to predict its evolution during reservoir depletion. We compare two natural gas reservoirs with strong (San Juan coal basin) and weak (Barnett shale formation) sorption-mechanical coupling. The results of the study highlight the interplay between mechanical moduli, swelling isotherm parameters, fracture compressibility, and rock strength in determining their impact on fracture permeability evolution during depletion. We show that simple stress-dependent permeability models cannot capture permeability evolution in the presence of shear failure and fines production. A modified permeability equation is introduced to describe fines migration and shear dilation. Numerical simulation confirmed that desorption-induced strains in shales may induce changes of horizontal stresses of several MPa. These changes of stress may have a minor effect on permeability but can significantly affect horizontal stress anisotropy and should be considered while planning refracturing.

1. Introduction

Natural gas consumption currently constitutes a fifth of the total energy sources [1]. About a half of non-associated gas accrues to unconventional gas reservoirs, mainly organic shales and coal seams [2]. Unconventional tight reservoirs have an extremely low matrix permeability, with natural fractures often acting as main fluid conduits. The openings of these fractures are dictated by lithology and in-situ stresses, which may alter during reservoir development [3–6]. The following competitive geomechanical processes are known to affect stresses during depletion in fractured reservoirs: pressure depletion, temperature changes, and chemically-induced strains, among others.

Decreases in pore pressure associated with reservoir depletion cause increases in effective stresses, which often leads to fracture closure and a decrease in permeability [4,7]. For example, linear isotropic poroelasticity predicts Biot effective vertical stress σ_v to change $\Delta\sigma_v = -b\Delta p$ and Biot effective horizontal stress σ_h to change $\Delta\sigma_h = -\frac{\nu}{1-\nu}b\Delta p$ with a change of pressure Δp (negative for depletion) in a horizontally extensive reservoir with constant total vertical stress, where b is the Biot coefficient and ν is the Poisson ratio [8]. If horizontal stresses differ, depletion would cause maximum horizontal effective stress σ_{Hmax} and minimum horizontal effective stress σ_{hmin} to change the same amount, assuming that the medium is homogeneous and isotropic. These equations are applicable for small strains. At large strains, shear failure may also limit stresses. Anisotropic changes of effective stresses induced by depletion have the potential to reactivate and create new fractures in shear, both within and outside the reservoir in some geologic

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environments [9]. At shear failure, stresses are no longer controlled by linear poroelasticity but by the frictional strength of the formation [4,10]. These changes have been measured in the field as changes of total stresses (total stress rather than effective stress is measured in the field) [7,11,12]. Variations in reservoir geometry, caprock stress arching and proximity to faults, among others, can modify changes of stresses in the reservoir and induce stress reorientation [13,14]. There have been a number of case studies in which both fluid withdrawal and fluid injection appear to have induced fault reactivation in oil and gas reservoirs [9,15–18]. In light of the fact that total vertical stress S_v is expected to remain essentially constant during depletion of laterally extensive reservoirs, reservoir depletion may change the faulting regime in the reservoir, especially if it was not originally homogeneous throughout the reservoir such as in anticlines with residual flexural stresses [4,11].

Changes in reservoir temperature due to the injection of fluids with temperature different from the reservoir temperature can induce thermal stresses. For example, the injection of hot water results in compressive stresses, which play a substantial role in geothermal applications [8]. During cold-water or cold-CO_2 injection, in contrast, the formation temperature around the wellbore decreases resulting in decreases in reservoir stresses (less compressive) and, as a consequence, a lower fracture gradient and reduced reservoir stresses [18–21]. The equations governing this process are dictated by the theory of thermoporoelasticity, but sometimes are simplified to thermoelasticity for the numerical estimations [4,22]. The thermomechanical effects of fluid injection depend on the difference between the temperatures of the injected and reservoir fluids, injection times, and thermal and mechanical properties of the geological formation such as thermal conductivity, volumetric heat capacity, thermal expansion coefficient, and Young's modulus [23–25].

Geomechanical alterations in oil and gas reservoirs during depletion may be also induced by changes in chemical potential of the reservoir fluid. For example, aqueous composition of the drilling mud or injected fluid different from that of the formation has been known to cause clay swelling that results in increased compressive stresses and a decrease in permeability [26]. Strain in a reservoir can be induced by mineral dissolution as well, which may take place during the acidization of calcite-rich rocks [27]. Another chemo-mechanical process that may affect the stresses in a reservoir is gas desorption. Gas desorption is of significant importance in coals because sorbed gas constitutes more than 50% of total gas in place and desorption induces a substantial amount of rock shrinkage and effective stress relaxation [28–30]. Sorbed gas in hydrocarbon-bearing shales constitutes 5–15% of the total gas in place. Sorption capacity is usually proportional to total organic carbon (TOC) in shales [31]. In contrast to pore pressure depletion, desorption and matrix shrinkage result in a drop in effective stresses and an increase in permeability [32–34]. Additionally, decrease of effective horizontal stress increases vertical to horizontal stress anisotropy and potentially causes shear failure [35–37]. Desorption-induced changes of stresses have been modeled previously using an analogy with thermoelasticity [38,39] and recently by using an extension of poromechanics to microporous media [40,41]. Sorption-mechanical couplings depend on sorptive properties of the rock matrix as well as mechanical properties. Fig. 1 summarizes typical values of Young's moduli and maximum sorption-induced strains measured for various coal and organic-rich shale rocks [38,39,41–45]. The figure indicates that the values of Young's moduli of shales are an order of magnitude higher than those of coals. At the same time, maximum sorption-induced swelling strains in coals exceed sorption-induced strains in shales by about an order of magnitude. Since

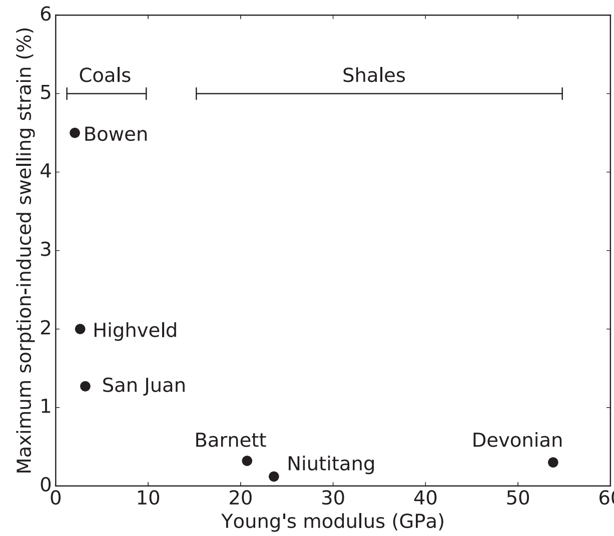

Fig. 1. Typical values of Young's moduli and maximum volumetric sorption-induced swelling strains in various organic shale and coal rocks.

sorption swelling stress is proportional to the product of the bulk modulus and sorption strain (shown in Section 2.1), a soft coal exhibiting large sorption strains and a stiff shale exhibiting small sorption strains may cause sorption stresses of similar magnitude. To the best of our knowledge, there are no studies of the impact of sorption stresses on fracture permeability of shales so far.

The objectives of this paper are to present a fully coupled reservoir model for unconventional natural gas engineering applications and to include the impact of sorption-induced stress changes and shear failure on long-term reservoir development via numerical simulation. We first introduce a model of a single phase gas flow coupled with linear elastic geomechanics accounting for sorption and then describe the numerical solution method. Second, we investigate production rates and permeability alterations due to changes in effective stresses induced by depletion by analyzing and comparing two field cases: San Juan Basin coal and Barnett shale gas reservoirs. Finally, we discuss the governing parameters of the permeability evolution due to geomechanical processes and highlight the limitations of a linear elastic formulation.

2. Model development

In this section we introduce the equations that describe single-phase ideal gas flow, coupled with linear elastic geomechanics in a sorptive medium. We first introduce a poromechanical model and then we derive the corresponding fluid flow equation. Last, we introduce a permeability model of an equivalent fractured medium accounting for fracture compressibility, shear dilation, and fine production (from shear failure) and clogging.

2.1. Poromechanical model with sorption stress

The equilibrium of stresses is dictated by Cauchy's equation:

$$\nabla \cdot \mathbf{S} = -\rho_b \vec{g}, \tag{1}$$

where $\mathbf{S}$ is the total stress tensor, ρ_b is the bulk mass density of the rock, and $\vec{g}$ is gravity acceleration. In porous media, effective stresses define the material deformation instead of the total stresses. The following relation between total and effective stresses is valid for isotropic rocks with the typical values of porosity:

$$\mathbf{S} = \boldsymbol{\sigma} + bp\mathbf{I}, \tag{2}$$