Lawrence Berkeley National Laboratory

Recent Work

Title

Fully coupled two-phase flow and poromechanics modeling of coalbed methane recovery:
Impact of geomechanics on production rate

Permalink

<https://escholarship.org/uc/item/4qg689j1>

Authors

Ma, T
Rutqvist, J
Oldenburg, CM
et al.

Publication Date

2017

DOI

10.1016/j.jngse.2017.05.024

Peer reviewed

1**Fully Coupled Two-Phase Flow and Poromechanics Modeling of Coalbed Methane**
2**Recovery: Impact of Geomechanics on Production Rate**

3

4Tianran Ma ^{a,b,c}, Jonny Rutqvist ^c, Curtis M. Oldenburg ^c, Weiqun Liu ^{a,b}, Junguo Chen ^d,

5^a Key Laboratory of Coal-based CO₂ Capture and Geological Storage, China University of
6Mining and Technology, Xuzhou, Jiangsu, China

7^b State Key Laboratory for Geomechanics and Deep Underground Engineering, China
8University of Mining and Technology, Xuzhou, Jiangsu, China

9^c Lawrence Berkeley National Laboratory, Earth Sciences Division, Berkeley, CA, USA

10^d College of Mining and Safety Engineering, Shandong University of Science and
11Technology, Qingdao, Shandong, China

12

13

14

15 **Submitted manuscript accepted for publication in**
16 **Journal of Natural Gas Science and Engineering**

17 <https://doi.org/10.1016/j.jngse.2017.05.024>

18

19 Final Version Published as:

20 Ma T., Rutqvist J., Oldenburg C.M., Liu W. and Chen J., Fully coupled two-phase flow and
21 poromechanics modeling of coalbed methane recovery: Impact of geomechanics on
22 production rate. *Journal of Natural Gas Science and Engineering* 45, 474- 486 (2017).

23

24

25

26

27

28

29

30Abstract

31This study presents development and application of a fully coupled two-phase (methane and
32water) and poromechanics numerical model for the analysis of geomechanical impact on
33coalbed methane (CBM) production. The model considers changes in two-phase fluid flow
34properties, i.e., coal porosity, permeability, water retention, and relative permeability curves
35through changes in cleat fractures induced by effective stress variations and desorption-
36induced shrinkage. The coupled simulator is first verified for poromechanics coupling and
37simulation parameters of a CBM reservoir model are calibrated by history matching against
38one year of CBM production field data from Shanxi Province, China. Then, the verified
39simulator and calibrated CBM reservoir model are used for predicting the impact of
40geomechanics on production rate for twenty years of continuous CBM production. The
41simulation results show that desorption-induced shrinkage is the dominant process in
42increasing permeability in the near wellbore region. Away from the wellbore, desorption-
43induced shrinkage is weaker and permeability is reduced by pressure depletion and increased
44effective stress. A sensitivity analysis shows that for coal with a higher sorption strain, a
45larger initial Young's modulus and smaller Poisson's ratio promote the enhancement of
46permeability as well as the production rate. Moreover, the conceptual model of the cleat
47system, whether dominated by vertical cleats with permeability correlated to horizontal stress
48or with permeability correlated to mean stress can have a significant impact on the predicted
49production rate. Overall, the study clearly demonstrates and confirms the critical importance
50of considering geomechanics for an accurate prediction of CBM production.

51

52**Keywords: CBM Recovery; Two-Phase Flow; Poromechanics; Coupled Model**

53

54

55**Highlight:**

56

57(1) A fully coupled two-phase flow and poromechanics model for methane recovery

58(2) Simulation parameters are calibrated by history matching against field data

59(3) The geomechanics behaviors significantly affect the prediction of CBM production

601. Introduction

61 Coalbed methane (CBM), an unconventional gas resource, has caught considerable attention
62 and interest, particularly in China, India, and Australia, because of the decline of
63 conventional gas supplies and high demand of the global energy market (Moore, 2012;
64 Thararoop, 2010; White et al., 2005). CBM has a unique reservoir mechanism compared to
65 those of conventional gas and oil. Up to 98% of CBM within a reservoir is stored on the inner
66 surface of the coal grains, or skeleton, in a matrix system by adsorption. The remainder is free
67 gas that exists in the fractures of the cleat system. To extract CBM from the coal reservoir,
68 large amounts of water must be pumped out (McKee and Bumb, 1987) in order to decrease
69 the reservoir pressure down to the critical desorption pressure to release absorbed gas from
70 the matrix into the cleat system. The different sizes of fractures in the cleat system act as the
71 conduits for methane and water migration into the well. A typical CBM recovery with a
72 vertical well is illustrated in Fig. 1.

Fig. 1. Conceptual model of CBM and water production through a vertical well.

77 During the CBM production process, the variation in pore pressure causes a change in the
78 stress state, which induces deformation of the reservoir. The permeability of coal is sensitive
79 to stress changes and deformation (Clarkson et al., 2013; Wei and Zhang, 2013). As the pore
80 pressure declines during production, the effective stress increases to narrow or even close the
81 apertures of fractures in the cleat system and thus reduces coal permeability. Meanwhile, a
82 shrinkage phenomenon occurs when methane desorbs from the surface of the matrix system.
83 The shrinkage induced by gas desorption will enlarge the width of the cleat fractures, which
84 enhances coal permeability. These coupled hydraulic and geomechanical processes can
85 change permeability dramatically and will therefore have a significant impact on the
86 evolution of CBM methane production.

88 A number of permeability models have been proposed to consider both the effects of pore
89 pressure changes and shrinkage/swelling of the matrix system due to gas

90desorption/adsorption. Gray (1987) was the first to propose a permeability model, which
 91considers both the geomechanical deformation caused by pore pressure depletion and the
 92shrinkage caused by gas desorption. Seidle et al.'s (1992) derived an exponential relationship
 93between coal permeability and net confining stress. The well-known S&H model (Seidle and
 94Huitt, 1995) assumes that permeability changes are solely controlled by a Langmuir-type
 95swelling strain induced by gas desorption. Under uniaxial stress conditions, Palmer and
 96Mansoori (1998) proposed a theoretical formulation for porosity and permeability change as a
 97function of pore pressure. The P&M model was derived based on linear elasticity for porous
 98rock deformation and sorption-induced strain, analogous to thermal expansion/contraction in
 99a thermo-elasticity. Shi and Duncan (2004) developed a permeability model (S&D model),
 100which also considers sorption-induced strain and pressure depletion under uniaxial strain
 101conditions. The S&D model includes an exponential relationship between permeability and
 102stress, similar to that of Seidle et al.'s (1992), but with permeability related to horizontal
 103effective stress rather than mean effective stress. Cui and Bustin (2005) (C&B model) is
 104equivalent to the S&D model, but mostly applied for the case when absolute permeability of
 105the cleat system varies with the mean effective stress. Pan and Connell (2007) (P&C model)
 106derived a theoretical model that describes adsorption-induced swelling resulting from the
 107energy balance between the surface energy change from adsorption and the elastic energy
 108change from the change in the solid skeleton.

109

110 In recent years models have been developed considering additional aspects such as internal
 111swelling, multicomponent adsorption, anisotropy, stress-dependent compressibility. Among
 112those, Liu and Rutqvist (2009) considered the fracture–matrix interaction during coal-
 113deformation processes based on the concept of internal swelling stress, which results from the
 114partial separation of the matrix block by discontinuous fractures. Clarkson (Clarkson et al.,
 1152010) proposed coupling the P&M and P&C model to extend the P&M model and
 116incorporate multicomponent adsorption. Here, the P&M model refers to a more general
 117expression, in which the sorption-induced volumetric strain is converted from the linear strain
 118calculated in the P&C model. Moore (Moore et al., 2014) proposed an anisotropic
 119permeability model to match the apparent exponential-type increase in permeability in the
 120San Juan basin. The C&B and S&D models are both deduced with an assumption of a
 121constant pore compressibility or bulk modulus; thus, initial porosity does not appear in both.
 122Based on the C&B model, Ma et al. (2016) developed a new permeability model (M&R
 123model) considering the variations in pore compressibility during pressure drawdown.

124

125The recovery process of CBM is frequently simplified as a single phase gas flow process,
 126neglecting the water existing on different scales of pores or injected into the coal seams for
 127fracturing (Chen et al., 2013; Wang et al., 2012). Such simplification can have a strong
 128influence on the predicted evolution of the CBM flow rate and cumulative production
 129recovery. Saturation is one of most vital factors in determining the CBM production rate
 130(Roadifer et al., 2003), as it affects the mobility, not only through variation in intrinsic
 131permeability with swelling, but also through changes in the relative permeability. The impact

132 of swelling on mobility can be more significant in dry coal than coal saturated with water and
 133 gas (Moore, 2012). The free water that exists in the cleat system or the water that is injected
 134 during hydraulic fracturing affects the degree of saturation and capillary pressure that in turn
 135 affects the relative permeability of methane and water. The two well-known relatively
 136 permeability models of Brooks and Corey (1966) and Van Genuchten (1980), have been
 137 developed for unconsolidated and consolidated porous media, respectively. Laboratory
 138 experiments have been conducted to investigate the permeability of different coal with
 139 steady-state and unsteady-state methods (Durucan et al., 2013; Shen et al., 2011). In another
 140 approach, relative permeability has been determined by history matching with field
 141 production data (Zhou, 2012). Dynamic relative permeability models have also been
 142 proposed with consideration of the combined effects of stress changes and desorption-
 143 induced shrinkage of the matrix system (Xu et al., 2014). Chen et al. (2013) proposed a more
 144 direct relationship between effective mean stress changes and effective saturation, which was
 145 calibrated against experiments on different types of coal. In any case, the water retentions
 146 and relative permeability curves are a crucial multiphase flow property in predicting both the
 147 recovery rate of CBM and the amount of produced water (Clarkson et al., 2011).

148

149 In this paper, a mathematic model is developed to describe the coupled process of
 150 incorporating two-phase fluid flow and coal deformation caused by pore pressure and gas
 151 desorption during CBM production. The governing equations of the model are then
 152 implemented and solved in the multiphysics software COMSOL based on the finite element
 153 method. The performance and accuracy with respect to poromechanics are tested by a 1-D
 154 Terzaghi's consolidation problem. Then, a history matching of one year of CBM production
 155 data from the Shanxi Province, China, is performed to calibrate reservoir properties for the
 156 model. Finally, the same model is used in a sensitivity study to investigate the influences of
 157 geomechanics during 20 years of CBM and water production.

158

159 2. Theoretical Background

160 2.1. Fluid flow

161 The general mass balance equation for immiscible phases flow in a coal seam is given as

162

$$\frac{\partial m_{\alpha}}{\partial t} + \nabla \cdot (\rho_{\alpha} u_{\alpha}) = Q_{\alpha} \quad (1)$$

163

164 where Q_{α} is the flow sources or sinks ($\alpha = w \wedge g$ represent water and CBM,
 165 respectively).

166

167 The velocity u_{α} of fluid can be described by Darcy's law:

168

169

$$u_{\alpha} = \frac{-K k_{r\alpha}}{\mu_{\alpha}} \nabla p_{\alpha} \quad (2)$$

170

171where K and $k_{r\alpha}$ are the intrinsic and relative permeabilities, respectively. μ_{α} is the
172flow viscosity, and p_{α} is the pore pressure. m_{α} is the flow mass. The water mass is
173described as

174

$$m_w = S_w \rho_w \phi \quad (3)$$

175

176where S_w is the water saturation, ρ_w is the density of water and ϕ is the porosity of
177the cleat system.

178

179The model assumes that coal is a single porosity and permeability medium, which implies
180that the methane absorbed on the surface of the coal grain diffuses instantaneously into the
181cleat without a desorption time lag. Thus, the methane mass in the fractures of the cleat
182system consists of free and adsorbed phases. The total mass is expressed as (Thararoop, 2010;
183Webb, 2011)

184

$$m_g = S_g \rho_g \phi + (1 - \phi) \rho_{ga} \rho_c \frac{V_L p_g}{p_g + p_L} \quad (4)$$

185

186where ρ_c is the density of the coal seams and p_L and V_L are the Langmuir pressure
187and volume constant, respectively. To simplify the expression, this study assumes that
188 $(1 - \phi) \approx 1$. ρ_{ga} is the density of methane under standard conditions. This study also
189considers the compressibility of gas and water, which means that the density is not a constant
190that varies with pore pressure. The density is described by $\rho_{\alpha} = 1 / C_{\alpha} (d\rho_{\alpha} / dp_{\alpha})$, where

191 C_{α} is the fluid compressibility, which is obtained from the NIST (NIST, n.d.).

192

193Substituting Eqs. (3) and (4) into (1), the water flow equation can be rewritten as

194

$$\phi \rho_w S_w C_w \frac{\partial p_w}{\partial t} + \phi \rho_w \frac{S_w}{\partial t} + \rho_w S_w \frac{\partial \phi}{\partial t} + \nabla \cdot \left(-\rho_w \frac{K k_{rw}}{\mu_w} \nabla p_w \right) = Q_w \quad (5)$$

195

196The methane flow equation is expressed as

197

$$\rho_g S_g C_g \frac{\partial p_g}{\partial t} + \rho_{ga} \rho_c \frac{V_L p_L}{(p_g + p_L)^2} \frac{\partial p_g}{\partial t} + \phi \rho_g \frac{\partial S_g}{\partial t} + \rho_g S_g \frac{\partial \phi}{\partial t} + \nabla \cdot \left(-\rho_g \frac{K k_{rg}}{\mu_g} \right) \quad (6)$$

198

199 There are four variables (S_g , S_w , p_g and p_w) in the above equations. These
200 variables cannot be solved without supplementary equations for saturation and capillary
201 pressure.

202

$$S_w + S_g = 1 \quad (7)$$

203

$$p_c = p_g - p_w \quad (8)$$

204

205 where p_c is the capillary pressure, which is a function of saturation. The different
206 functional relationships between capillary pressure and saturation and the relative
207 permeability are adopted (Brooks and Corey, 1966; Leverett, 1941; Van Genuchten, 1980). In
208 this study, capillary pressure and relative permeability are governed by the following
209 functions (Pruess et al., 2012):

210

$$p_c = p_e (se)^{-1/\lambda} \quad (9)$$

211

$$k_{rg} = (1 - se)^2 (1 - se^2) \quad (10)$$

212

$$k_{rw} = \sqrt{se} \left\{ 1 - (1 - se^{1/m})^m \right\}^2 \quad (11)$$

213

214 where p_e is the entry pressure and λ is a coefficient related to the pore size distribution.

215 k_{rg} and k_{rw} are the relative permeabilities of gas and water, respectively. se is the
216 effective saturation, defined as

217

$$se = \frac{S_w - S_{wr}}{1 - S_{wr} - S_{gr}} \quad (12)$$

218

219 where S_{wr} and S_{gr} are the residual saturations of water and gas, respectively, which
220 change with the stress-induced porosity or permeability ratio (Chen et al., 2013):

221

$$S_{wr} = S_{wr0} \left(\frac{\phi}{\phi_0} \right)^{-n_{wr}} = S_{wr0} \left(\frac{\alpha}{\phi_0} + \frac{(\phi_0 - \alpha)}{\phi_0} \exp \left(\frac{-\nabla \sigma'}{K} \right) \right)^{-n_{wr}} \quad (13)$$

222

$$S_{gr} = S_{gr0} \left(\frac{\phi}{\phi_0} \right)^{-n_{gr}} \left(\frac{\rho_g}{\rho_{ga}} \right)^{-1} = S_{gr0} \left(\frac{\alpha}{\phi_0} + \frac{(\phi_0 - \alpha)}{\phi_0} \exp \left(\frac{-\nabla \sigma'}{K} \right) \right)^{-n_{gr}} \left(\frac{\rho_g}{\rho_{ga}} \right)^{-1} \quad (14)$$

223

224 where n_{wr} and n_{gr} are fitting parameters that are calculated by the experimental data.

225 S_{wr0} and S_{gr0} are the initial values of the residual saturation in the water and gas
226 phases, respectively. Hereto, the porosity, permeability, residual saturation, saturation and
227 capillary pressure are all functions of the mean stress.

228

229 The production mass of water and methane on the well boundary are expressed as (Chen et
230 al., 2013; Peaceman, 1978)

231

$$Q_w = \rho_w \frac{K k_{rw} (\bar{p}_w - p_{wb})}{\mu_w \left(\ln r_e - \ln r_w - \frac{3}{4} + S \right)} \quad (16)$$

232

$$Q_g = \rho_g \frac{K k_{rg} (\bar{p}_g - p_{wb})}{\mu_g \left(\ln r_e - \ln r_w - \frac{3}{4} + S \right)} \quad (17)$$

233

234 where p_{wb} is the bottom hole pressure (BHP), $\bar{p}_w$ and $\bar{p}_g$ are the average water and
235 gas pressure in the reservoir, respectively, r_e is the drainage radius, r_w is the wellbore
236 radius and S is the skin factor.

237

238 2.2. Stress-dependent porosity and permeability model

239 A new model of porosity/permeability was proposed in Ma et al. (2016) by considering the
240 gas desorption/adsorption:

241

$$\phi = \alpha + (\phi_0 - \alpha) \exp \left(\frac{-\Delta \sigma'}{K} \right) \quad (18)$$

242

$$\frac{k}{k_0} = \left(\frac{\phi}{\phi_0} \right)^3 = \left(\frac{\alpha}{\phi_0} + \frac{(\phi_0 - \alpha)}{\phi_0} \exp \left(\frac{-\Delta \sigma'}{K} \right) \right)^3 \quad (19)$$

243

244Biot's coefficient α is assumed to be 1. From Eq. (18), the partial derivative of ϕ with
 245respect to time is expressed as

246

$$\frac{\partial \phi}{\partial t} = \frac{-S}{K} \frac{\partial \sigma'}{\partial t} \quad (20)$$

247

248where $S = (\phi_0 - \alpha) \exp\left(\frac{-\Delta \sigma'}{K}\right)$.

249

250Substituting Eq. (20) into Eqs. (5) and (6), the model containing the governing equations for
 251describing the effects of capillary pressure and coal deformation on porosity and permeability
 252for water and gas flow in a coal seam is given as

253

$$\phi \rho_w S_w C_w \frac{\partial p_g}{\partial t} + (\phi \rho_w - \phi \rho_w S_w C_w d p_{c_{sw}}) \frac{\partial S_w}{\partial t} + \nabla \cdot \left(-\rho_w \frac{K k_{rw}}{\mu_w} (\nabla p_g - \nabla p_w) \right) = \rho_w S_w \frac{\partial \phi}{\partial t} \quad (21)$$

254

$$\left(\phi \rho_g S_g C_g + \rho_c \frac{V_L p_L}{(p_g + p_L)^2} \right) \frac{\partial p_g}{\partial t} - \phi \rho_g \frac{\partial S_w}{\partial t} + \nabla \cdot \left(-\rho_g \frac{K k_{rg}}{\mu_g} \nabla p_g \right) = \rho_g S_g \frac{\partial \phi}{\partial t} \quad (22)$$

255

256where $d p_{c_{sw}} = \frac{\partial p_c}{\partial s_e} \frac{\partial s_e}{\partial S_w} = p_e \left(\frac{-1}{\lambda} \right) (s_e)^{\frac{-1}{\lambda} - 1}$

257

2582.3. Geomechanical model for coal deformation

259Based on the constitutive relation of poro-elasticity and considering the methane-desorption-
 260induced volumetric strain, the governing equation for deforming coal seams is expressed as
 261follows (Rutqvist et al., 2001):

262

$$\sigma = \sigma' - \alpha I p = D : (\varepsilon - \varepsilon_s \delta) - \alpha I p \quad (23)$$

263

264where σ and σ' are the total and effective stress (with tensile stress being a positive
 265quantity), respectively, p is the pore pressure tensor, D is the tangential stiffness matrix

266and ε_s is the desorption-induced linear strain calculated by the Langmuir-type equation as

267

$$\varepsilon_s = \varepsilon_L \frac{p_g}{p_g + p_L} \quad (24)$$

268

269where ε_L and p_L represent the Langmuir linear strain and Langmuir pressure constant,
270respectively. p is the mean pore pressure, expressed as

271

$$p = S_w p_w + S_g p_g = S_w (p_g - p_c) + S_g p_g = p_g - S_w p_c \quad (25)$$

272

2732.4. Implementation of the numerical model

274Eqs. (21), (22) and (23) are the final coupled equations for fluid flow and coal seam
275deformation. The three equations are implemented and solved with the COMSOL
276multiphysics software. A pre-arranged COMSOL geomechanics module is selected to solve
277the geomechanical part with Eq. (23). Two immiscible phase flows are implemented with
278Eqs. (21) and (22) using the COMSOL General Form PDE interface. In COMSOL, the
279General Form PDE equation for the primary variable $\mathbf{u}$ has the following expression:

280

$$e_a \frac{\partial^2 \mathbf{u}}{\partial t^2} + d_a \frac{\partial \mathbf{u}}{\partial t} + \nabla \cdot \Gamma = f \quad (26)$$

281

282The two primary variables are

283

$$\mathbf{u} = \begin{pmatrix} p_g \\ S_w \end{pmatrix} \quad (27)$$

284

285In this study, pressure and saturation are chosen as the primary variables to achieve a
286relatively stable and robust convergence in COMSOL (Bjørnara and Aker, 2008). The PDE
287coefficients d_a , Γ and f are introduced as

288

$$d_a = \begin{bmatrix} \phi \rho_w S_w C_w & (\phi \rho_w - \phi \rho_w S_w C_w) dp_{c_{sw}} \\ \phi \rho_g S_g C_g + \rho_{ga} \rho_c \frac{V_L p_L}{(p_g + p_L)^2} & -\phi \rho_g \end{bmatrix} \quad (28)$$

289

$$\Gamma_w = \begin{bmatrix} -\rho_w \frac{K k_{rw}}{\mu_w} (pgx - dp_{c_{sw}} swx) \\ -\rho_w \frac{K k_{rw}}{\mu_w} (pgy - dp_{c_{sw}} swy) \end{bmatrix} \quad \Gamma_g = \begin{bmatrix} -\rho_g \frac{K k_{rg}}{\mu_g} pgx \\ -\rho_g \frac{K k_{rg}}{\mu_g} pgy \end{bmatrix} \quad (29)$$

290

$$f = \begin{bmatrix} \rho_w S_w \frac{S}{K} \frac{\partial \sigma'}{\partial t} \\ \rho_g S_g \frac{S}{K} \frac{\partial \sigma'}{\partial t} \end{bmatrix} \quad (30)$$

291

292 where p_g^x , p_g^y , s_w^x and s_w^y represent the partial derivative of gas pressure
 293 and water saturation in the x and y directions. The schematic of solving a coupled
 294 model of CO₂ flow and coal seam deformation in COMSOL Multiphysics is illustrated in Fig.
 295 2.

296

297

298 **Fig. 2.** Schematic of solving the coupled model of methane and water flow and coal
 299 deformation with COMSOL.

300

3013. Model verification and calibration

3023.1. Terzaghi's consolidation problem

303 The numerical solution and analytical solution of Terzaghi's consolidation problem were
 304 compared to verify the accuracy of our implementations and solution of the coupled
 305 equations in COMSOL Multiphysics. The analytical solution of the problem is presented by
 306 Verruijt (2013).

307

308 Fig. 3 describes the one-dimensional Terzaghi's consolidation problem. The sample is located
 309 at $z=0$, and its thickness is denoted by $2h=10$ m. The upper and lower are both fully
 310 drained, which ensures that the pore pressure remains zero along the two boundaries. A
 311 vertical load of $q=5 \text{ MPa}$ was applied at the top at $t=0$. Due to the sudden loading,
 312 the initial pore pressure is zero and instantaneously increases to the maximum. To solve
 313 Terzaghi's problem, a fine triangular element mesh is chosen to discretize the simulation
 314 region. The simulation parameters are listed in Table 1 (Yang et al., 2014).

315

Fig. 3. Description of Terzaghi's consolidation problem.

Table 1 Simulation parameters for Terzaghi's consolidation problem.

Parameter	Value	Unit
Shear modulus of the rock	3×10^{10}	Pa
Compression modulus of the rock	5×10^{10}	Pa
Permeability	1×10^{-12}	m^2
Porosity	0.25	-
Compressibility of the fluid	1×10^{10}	Pa^{-1}
Viscosity of the fluid	1×10^{-3}	Pa
		s

Fig. 4 presents the comparison between the analytical and numerical solutions when dimensionless time $t = 0.2, 0.3$ and 0.5 . The results indicate that the discrete points of pore pressure extracted from COMSOL and the analytical solutions correspond well.

327

328**Fig. 4.** Comparison of analytical and numerical results for the 1-D Terzaghi's consolidation
329problem.

330

3313.2. History matching of field methane production

332In this section, the relative permeability for the coupled simulation is calibrated by history
333matching of CBM production data from a vertical well in the south of Shanxi Province, China
334(Liu, 2013). Initially, approximately 320 m³ of pressurized water was injected into the coal
335seam for hydraulic fracturing to improve connectivity to the well and increase the
336permeability of the reservoir. Then, during subsequent production, reservoir pressure was
337reduced to the critical desorption pressure to release adsorbed methane from the coal matrix
338into the cleat system. Both the methane and water was produced through the vertical well.
339Field history data of methane and water production from October 4th, 2007 to September 3rd,
3402008, are used for model calibration in this study.

341

342Fig. 5 presents a schematic of the model geometry and boundary conditions for the
343simulation. The reservoir extends laterally 600 by 600 m and is 5 m thick with a well at
344the center. In the numerical simulation, a quarter of the reservoir and the vertical well is
345considered in a 2-D plain stress model. The initial pore pressure of the reservoir is
346approximately 4 MPa. The top of the coal seam is located at an average depth of 525.6 m and
347assumed to have a vertical boundary loading σ_v of -11.3 MPa corresponding to an
348overburden rock density of 2,300 kg/m³. An isotropic initial horizontal stress calculated as
349 $\sigma_h = \nu / (1 - \nu) \sigma_z = -6.08$ MPa, considering the condition of passive basin or zero lateral
350strain. Displacement constraints are assigned normal to the inner symmetric lateral
351boundaries, while constant stress are applied to the outer lateral boundaries. The parameters
352for history matching are summarized in Table 2.

353

354
 355 **Fig. 5.** Schematic of the geometric model for simulating the production of methane and
 356 water.
 357
 358

359
 360 **Fig. 6.** Comparison between the simulation results and field data.
 361
 362
 363
 364
 365

366 **Table 2** Simulation parameters for history matching.

Parameters	Value	Unit
Drainage area	600×600	m^2
Coal seam thickness	5	m
Depth of coal seam	525.6	m
Coal density	1650	kg/m^3
Poisson's ratio of coal	0.35	
Elastic modulus of coal	3	GPa
Cleat permeability	1.628×10^{-13}	m^2
Cleat porosity	0.0302	
Biot coefficient	1	
Langmuir pressure constant	2.7	MPa
Langmuir volumetric constant	0.045	
Langmuir strain constant	0.03	
Initial reservoir pressure	3.99	MPa
Initial water saturation	0.592	
Viscosity of water	10^{-3}	$Pa \cdot s$
Viscosity of gas	1.84×10^{-5}	$Pa \cdot s$
Initial water density	1000	kg/m^3
Initial methane density	0.684	kg/m^3
Compressibility of water	1.38×10^{-5}	Pa^{-1}
Compressibility of methane	3.84×10^{-10}	Pa^{-1}
Capillary pressure model:	Eq. (9)	
Entry capillary pressure P_e	0.1	MPa
Coefficient λ	2.0	
Relative permeability model:	Eqs. (10) and (11)	
Coefficient m	0.6	
Residual saturation model:	Eqs. (13) and (14)	
Initial residual water saturation S_{wr0}	0.2	
Fitting parameter n_{wr}	0.49	
Initial residual methane saturation S_{gr0}	0.0	

367

368The mass production rates of water and methane computed with Eqs. (16) and (17). are
369applied to the wellbore. Using the input data listed in Table 2, a good agreement is achieved
370between simulation results and field data (Fig. 6).

371

372

3734. Modeling of HM effects on longer term CBM production

374Having tested and calibrated the COMSOL CBM model, a sensitivity study is conducted to
375investigate coupled HM effects on longer-term CBM production. The same model grid is
376used as in the previous model calibration. The production is in this case modeled with a
377constant wellbore pressure at 0.1 MPa as this is numerically much more efficient for the

many simulations needed in the sensitivity study. All other parameters are those listed in Table 2. In the simulation, the BHP is linearly decreased down to 0.1 MPa in a short time and then kept constant for twenty years of production.

381

3824.1 Base-case production modeling

383

Fig. 7 displays the spatial distribution of the pore pressure p , water saturation S_w , mean effective stress change $\Delta\sigma$ and permeability ratio k/k_0 after twenty years (7200 days) of production. The pressure and saturation decrease considerably all the way to the outer boundary, though largest decrease occurs close to the wellbore. Consistently, the mean effective stress change and permeability ratio are also the highest near the wellbore. The pore pressure and water saturation are below their initial state before production, which is because the drainage has already reached the outer lateral boundaries.

391

392

Fig. 7. Spatial distributions of the pore pressure P , water saturation S_w , mean effective stress change $\Delta\sigma$ and permeability ratio k/k_0 after twenty years of production.

395

The methane and water daily production rates are shown in Fig. 8. The gas production increases and approaches the peak in a short time as a result of continuous dewatering. Fig. 9 shows the temporal evolution of the four key parameters at monitoring points P1 and P2. P1 is located at the wellbore, whereas P2 ($x = 150$ m, $y = 150$ m) is located $150\sqrt{2} \approx 212$ m diagonal distance away from the production well. The pore pressure drops almost instantaneously at P1 as a result of the pressure drawdown applied at the well. The water saturation also decreases dramatically in a relatively short time because the majority of the water is extracted early on as a result of high initial water saturation and water relative permeability. The high water production prompts methane to migrate and accumulate near the wellbore. An almost instantaneous increase in effective mean stress occurs at P1 along with the initial pressure drop. This is followed by a gradual decrease in mean effective stress at both P1 and P2, which is a result of shrinkage as methane is desorbed from the rock matrix.

409

Fig. 8. CBM and water production rate versus time.

410

411

412

At P1, an initial increase in permeability by a factor of 1.3 is the net effect of an increased effective stress and rapid desorption shrinkage. Thereafter, the permeability at P1 decreases gradually as the shrinkage effect weakens along with continuous increased effective stress. At P2, a decrease in the mean effective stress σ with the drawdown of pore pressure and desorption shrinkage causes a reduction in the permeability of the cleat system.

Fig. 9. Temporal evolution of the pore pressure p , water saturation S_w , mean effective stress σ and permeability ratio k/k_0 at monitoring points P1 and P2.

4.2. Production with different permeability models

The permeability model proposed in Ma et al., (2016), and the three other widely used models of P&M, S&D, and C&B are applied. The production profiles of CBM and water and the evolution of permeability are predicted, as shown in Fig. 10. The comparison indicates that the production of methane and water and the permeability ratio show similar variation. However, the permeability values obtained with the S&D model are significantly higher than those obtained with the other models. This phenomenon can be explained by the fact that under the S&D model, the dominant controlling effect of permeability variation during pressure depletion is the horizontal effective stress, whereas the other three models adopt the mean effective stress. The S&D model can reflect a greater increase in permeability as the pore pressure approaches a minimum (Thararoop, 2010). The results estimated from the C&B and P&M models and the model proposed in Ma et al. (2016) have subtle differences, which results from the different simplifications in each model. The C&B model assumes that the bulk modulus of the pores is constant, whereas the P&M model is deduced for low-porosity (less than 1%) coal seams.

440
441**Fig. 10. (a)** CBM and water production rate **(b)** permeability ratio versus time with different
442permeability models.

443

4444.3. Effect of shrinkage and coal deformation

445The effect of shrinkage and coal deformation are investigated with the results shown in Fig.
44611.. The model assuming a constant permeability and porosity produces a lower rate than the
447coupled model. The highest and lowest production rates are predicted within the models that
448do not consider the effect of pore pressure and shrinkage on permeability. As noted above,
449depressurization releases the methane absorbed on the skeleton of the matrix system, which
450induces shrinkage and thus widens the aperture of fracture in the cleat system. This gives rise
451to the enhancement of its corresponding permeability, as well as the water and methane rate
452of production, whereas the pore pressure has the reverse effects. Moreover, the model without
453pore pressure displays a stronger permeability variationthe model without shrinkage, which
454also indicates the dominance of shrinkage-induced strain.

455
456**Fig. 11. (a)** CBM and water production rate **(b)** permeability ratio versus time for four
457different cases

458

4594.3. Effect of sorption strain constants

460Fig. 12 presents the CBM and water production rates and the change in permeability with
461different Langmuir strain constants ϵ_L of 0.01, 0.03, 0.05. The production curves shown in

Fig. 12a follow similar trend. However, the production rate of methane is higher in the coal with a larger sorption strain, which is attributed to stronger shrinkage effects on the fracture apertures, thus resulting in a larger increase in permeability, as shown in Fig. 12b. The permeability increases to approximately 1.7 times the initial value in the case with a high ϵ_L . The decrease in ϵ_L will weaken the dominance of shrinkage, and as expected, the permeability has only a small and brief enhancement in that case.

Fig. 12. Impacts of different Langmuir strain constants $\epsilon_L = 0.01, 0.03, \text{ and } 0.05$ on (a) CBM and water production rate (b) permeability ratio.

4.4. Effect of Young's modulus and Poisson's ratio

The Young's modulus and Poisson's ratio ν are two of the most important parameters for coal deformation. The influences of E and ν are investigated in this section. The E and ν values for coal with low, medium and high deformability are listed in Table 3 (Balan and Gumrah, 2009).

Table 3 Different Young's moduli and Poisson's ratios.

Cases	E (GPa)	ν
Low	0.85	0.21
Medium	4.1	0.35
High	6.10	0.48

The methane and gas production rates for three different Young's moduli are compared in Fig. 13a. The results show that greater production is obtained for the coal seam with a higher Young's modulus. The increase in the modulus will reduce the compressibility of the cleat and suppress the influence of pore pressure on permeability. If the Young's modulus of the coal seam increases to infinity, the predicted production would be equivalent to the model without consideration of the deformation induced by the pore pressure in Fig. 11a.

Fig. 13. Impacts of Young's modulus on the (a) CBM and water production rate (b) permeability ratio.

Fig. 14a shows the influences of Poisson's ratio during production. The model predicts that the production rate is higher for a coal seam with a higher Poisson's ratio. Poisson's ratio affects both shrinkage and pressure-induced deformation; thus, the boundary conditions or even the initial value for simulation parameters would result in distinct conclusions for a different permeability model. Coal with a higher Poisson's ratio results in a higher production rate with the C&B and G&C models but lower values in the S&D and P&M models (Cui and Bustin, 2005; Gu and Chalaturnyk, 2005; Zulkarnain, 2005). Thus, our results show significant influence of Poisson's ratio, which somewhat contradicts finding by Balan and Gumrah (2009) who stated that Poisson's ratio does not affect CBM recovery.

Fig. 14. Impacts of Poisson's ratio on the (a) CBM and water production rate (b) permeability ratio.

5. Summary

This study presents development and application of a fully coupled two-phase (methane and water) and poromechanics numerical model for the analysis of geomechanical impact on coalbed methane (CBM) production. The model considers changes coal porosity, permeability, water retention, and relative permeability curves through changes in cleat

fractures induced by effective stress variations and desorption-induced shrinkage. The coupled simulator was first verified for poromechanics coupling and simulation parameters of a CBM reservoir model were calibrated by history matching against one year of CBM production field data from Shanxi Province, China. Then, the verified simulator and calibrated CBM reservoir model were used for predicting the impact of geomechanics on production rate for twenty years of continuous CBM production.

515

The simulation results show that the production reduces the pore pressure and water saturation, particularly near the wellbore. The depressurization increases the effective stress and thus decreases the intrinsic permeability away from the well. However, the permeability near the wellbore exhibits an increase early on because of a pronounced shrinkage-induced strain by gas desorption. Among different permeability models tested, the S&D predicts distinctly larger permeability values because of the assumption that the permeability is a function of the horizontal effective stress, rather than the mean effective stress.

523

Ignoring the influences of pore pressure or matrix shrinkage-induced strain may lead to over- or under-estimated prediction of CBM production rate. The sensitive results indicate that for coal with a high sorption strain, a larger initial Young's modulus and smaller Poisson's ratio promote the enhancement of permeability and hence results in a higher production rate. Overall, the simulation results show that geomechanical behavior has a significant impact, which is important to consider for more accurate prediction CBM production.

530

531 Acknowledgments

Tianran Ma would like to thank Tore Ingvald Bjornara and Dong Chen for their helpful discussions on the simulation. This study was supported by Special Subject Grant of National "973" Basic Research Program of China (No. 2015CB251602 and No.2009CB219605), National Natural Science Foundation of China (No. 41074040 and No. 50774083), Jiangsu Natural Science Foundation (No. BK20141125), Chinese Program for New Century Excellent Talents in University (No. NCET-07-0803) and Opening Fund (NO. 2016A01). The work was funded in part by the U.S. Department of Energy under contract no. DE-AC02-5905CH11231. Special thanks to the anonymous reviewers for their valuable comments.

540

541

542 References

- Balan, H.O., Gumrah, F., 2009. Assessment of shrinkage–swelling influences in coal seams using rank-dependent physical coal properties. *Int. J. Coal Geol.* 77, 203–213.
- Bjørnara, T.I., Aker, E., 2008. Comparing equations for two-phase fluid flow in porous media, in: *Proceedings of the Conference on COMSOL*, Hannover.
- Brooks, R.H., Corey, A.T., 1966. Properties of porous media affecting fluid flow. *J. Irrig. Drain Eng.* 92, 61–90.
- Chen, D., Pan, Z., Liu, J., Connell, L.D., 2013. An improved relative permeability model for coal reservoirs. *Int. J. Coal Geol.* 109–110, 45–57.

551 Clarkson, C.R., Pan, Z., Palmer, I.D., Harpalani, S., 2010. Predicting sorption-induced strain
552 and permeability increase with depletion for coalbed-methane reservoirs. SPE J. 15,
553 152–159.

554 Clarkson, C.R., Qanbari, F., 2015. Transient flow analysis and partial water relative
555 permeability curve derivation for low permeability undersaturated coalbed methane
556 wells. Int. J. Coal Geol. 152, 110–124.

557 Clarkson, C.R., Qanbari, F., Nobakht, M., Heffner, L., 2013. Incorporating geomechanical
558 and dynamic hydraulic-fracture-property changes into rate-transient analysis: example
559 from the haynesville shale. SPE Reserv. Eval. Eng. 16, 303–316.

560 Clarkson, C.R., Rahmanian, M., Kantzas, A., Morad, K., 2011. Relative permeability of CBM
561 reservoirs: controls on curve shape. Int. J. Coal Geol. 88, 204–217.

562 Cui, X., Bustin, R.M., 2005. Volumetric strain associated with methane desorption and its
563 impact on coalbed gas production from deep coal seams. AAPG Bull. 89, 1181–1202.

564 Durucan, S., Ahsan, M., Syed, A., Shi, J.-Q., Korre, A., 2013. Two phase relative
565 permeability of gas and water in coal for enhanced coalbed methane recovery and CO₂
566 storage. Energy Proced. 37, 6730–6737.

567 Liu, A.H., 2013. Dynamic change features of water chemistry during coal reservoir drainage
568 and physical simulation of cbm desorption at fixed pressures and flow in southern
569 qinshui basin. (Doctoral Dissertation), geological resources and geological engineering.
570 China University of Mining and Technology.

571 Gray, I., 1987. Reservoir engineering in coal seams. Part 1: the physical process of gas
572 storage and movement in coal seams. SPE Reserv. Eng. 2, 28–34.

573 Gu, F., Chalaturnyk, R.J., 2005. Sensitivity study of coalbed methane production with
574 reservoir and geomechanic coupling simulation. J. Can. Pet. Technol. 44.

575 Gu, F., Chalaturnyk, R.J., 2006. Numerical simulation of stress and strain due to gas
576 sorption/desorption and their effects on *in situ* permeability of coalbeds. J. Can. Pet.
577 Technol. 44.

578 Leverett, M.C., 1941. Capillary behavior in porous solids. Trans. AIME 142, 152–169.

579 Liu, H.-H., Rutqvist, J., 2009. A new coal-permeability model: internal swelling stress and
580 fracture–matrix interaction. Trans. Porous Media 82, 157–171.

581 Ma, T., Rutqvist, J., Weiqun, L., Zhu, L., Kunhwi, K., 2016. Modeling of CO₂ sequestration
582 in coal seams: role of CO₂-induced coal softening on injectivity, storage efficiency and
583 caprock deformation. Sumbit to greenhouse gases. Science and Technology.

584 McKee, C.R., Bumb, A.C., 1987. Flow-testing coalbed methane production wells in the
585 presence of water and gas. SPE Form. Eval. 2, 599–608.

586 Moore, R., Palmer, I., Higgs, N., 2014. Anisotropic model for permeability change in coalbed
587 methane wells, in: SPE Western North American and Rocky Mountain Joint Meeting,
588 Society of Petroleum Engineers, Denver, Colorado.

589 Moore, T.A., 2012. Coalbed methane: a review. Int. J. Coal Geol. 101, 36–81.

590 NIST, n.d. Thermophysical properties of fluid systems.

591 Palmer, I., 2009. Permeability changes in coal: analytical modeling. Int. J. Coal Geol. 77,
592 119–126.

593 Palmer, I., Mansoori, J., 1998. How permeability depends on stress and pore pressure in
594 coalbeds: a new model. *SPE Reserv. Eval. Eng.* 1, 539–544.

595 Pan, Z., Connell, L.D., 2007. A theoretical model for gas adsorption-induced coal swelling.
596 *Int. J. Coal Geol.* 69, 243–252.

597 Peaceman, D.W., 1978. Interpretation of well-block pressures in numerical reservoir
598 simulation (includes associated paper 6988). *Soc. Pet. Eng. J.* 18, 183–194.

599 Pruess, K., Oldenburg, C.M., Moridis, G.J., 2012. TOUGH2 User's Guide Version 2.
600 Lawrence Berkeley National Laboratory, Berkeley, CA.

601 Roadifer, R.D., Moore, T.R., Rateman, K.T., Farnan, R.A., Crabtree, B.J., 2003. Coalbed
602 methane parametric study: what's really important to production and when? in: *SPE*
603 *Annual Technical Conference and Exhibition*, Society of Petroleum Engineers, Denver,
604 CO.

605 Rutqvist, J., Børgesson, L., Chijimatsu, M., Kobayashi, A., Jing, L., Nguyen, T.S., Noorishad,
606 J., Tsang, C.F., 2001. Thermohydromechanics of partially saturated geological media:
607 governing equations and formulation of four finite element models. *Int. J. Rock Mech.*
608 *Mining Sci.* 38, 105–127.

609 Seidle, J.P., Jeanson, M.W., Erickson, D.J., 1992. Application of matchstick geometry to
610 stress dependent permeability in coals, in: *SPE Rocky Mountain Regional Meeting*,
611 Society of Petroleum Engineers, Casper, Wyoming.

612 Seidle, J.R., Huitt, L.G., 1995. Experimental measurement of coal matrix shrinkage due to
613 gas desorption and implications for cleat permeability increases, in: *International*
614 *Meeting on Petroleum Engineering*, Society of Petroleum Engineers, Beijing.

615 Shen, J., Qin, Y., Wang, G.X., Fu, X., Wei, C., Lei, B., 2011. Relative permeabilities of gas
616 and water for different rank coals. *Int. J. Coal Geol.* 86, 266–275.

617 Shi, J.Q., Durucan, S., 2004. Drawdown induced changes in permeability of coalbeds: a new
618 interpretation of the reservoir response to primary recovery. *Trans. Porous Media* 56, 1–
619 16.

620 Thararoop, P., 2010. Development of a Multi-mechanistic, Dual-porosity, Dual-permeability
621 Numerical Flow Model for Coalbed Methane Reservoirs accounting for Coal Shrinkage
622 and Swelling Effects (Doctoral Dissertation), Petroleum and Mineral Engineering. Penn
623 State University.

624 Van Genuchten, M.T., 1980. A closed-form equation for predicting the hydraulic conductivity
625 of unsaturated soils. *Soil Sci. Soc. Am. J.* 44, 892–898.

626 Verruijt, A., 2013. Theory and Problems of Poroelasticity. Delft University of Technology,
627 Delft.

628 Wang, J.G., Kabir, A., Liu, J., Chen, Z., 2012. Effects of non-Darcy flow on the performance
629 of coal seam gas wells. *Int. J. Coal Geol.* 93, 62–74.

630 Webb, S.W., 2011. EOS7C-ECBM Version 1.0: Additions for Enhanced Coal Bed Methane
631 Including the Dusty Gas Model. Canyon Ridge Consulting Report, Sandia Park, NM.

632 Wei, Z., Zhang, D., 2013. A fully coupled multiphase multicomponent flow and
633 geomechanics model for enhanced coalbed-methane recovery and CO₂ storage. *SPE J.*
634 18, 448–467.

635 White, C.M., Smith, D.H., Jones, K.L., Goodman, A.L., Jikich, S.A., LaCount, R.B., DuBose,
636 S.B., Ozdemir, E., Morsi, B.I., Schroeder, K.T., 2005. Sequestration of carbon dioxide in
637 coal with enhanced coalbed methane recovery: a review. *Energy Fuels* 19, 659–724.
638 Xu, H., Tang, D.Z., Tang, S.H., Zhao, J.L., Meng, Y.J., Tao, S., 2014. A dynamic prediction
639 model for gas–water effective permeability based on coalbed methane production data.
640 *Int. J. Coal Geol.* 121, 44–52.
641 Yang, D., Moridis, G.J., Blasingame, T.A., 2014. A fully coupled multiphase flow and
642 geomechanics solver for highly heterogeneous porous media. *J. Comput. Appl. Math.*
643 270, 417–432.
644 Zhou, F., 2012. History matching and production prediction of a horizontal coalbed methane
645 well. *J. Pet. Sci. Eng.* 96–97, 22–36.
646 Zulkarnain, I., 2005. Simulation Study of the Effect of Well Spacing, Effect of Permeability
647 Anisotropy, and Effect of Palmer and Mansoori Model on Coalbed Methane Production.
648 Master’s thesis, Texas A&M University.