The 2012 World Congress on
Advances in Civil, Environmental, and Materials Research (ACEM' 12)
Seoul, Korea, August 26-30, 2012

Investigation of Capillarity in Gas Hydrate Deposits with Coupled flow and Geomechanics

*Jihoon Kim[1)] and George J. Moridis[2)]

[1), 2)] *Earth Sciences Division, Lawrence Berkeley National Laboratory, Berkeley, USA*
[1)] JihoonKim@lbl.gov

ABSTRACT

We perform numerical tests when a warm pipe is located through low permeable hydrate sediments that exhibit high capillarity. For highly compressible reservoirs, gas pressure around the pipe increases due to hydrate dissociation. In addition, capillary pressure also increases as gas saturation increases, although the decrease of solid phase saturation may lower the capillary pressure curve. As a result, aqueous pressure decreases because of high capillary pressure, and counterflow between gaseous and aqueous phases can occur. We also show changes in flow variables even for the undrained condition, because dilation of the area around the pipe results in deformation over the domain immediately (i.e., poromechanical effect), even though the changes are slight.

Introduction

Gas hydrate reservoirs are currently one of the clean future energy resources. Gas hydrates, which mainly consist of methane, are solid crystalline compounds in which gas molecules are trapped within the lattice of ice crystals. From their thermodynamic characteristics, they are typically found in the oceanic sediments or permafrost regions. Since hydrates are a solid phase, the stress distribution may be changed significantly, when they are dissociated. From the experimental tests, geomechanical properties highly depend on the hydrate saturation. In turn, changes in geomechanics, such as stress and strain fields, affect fluid and heat flow, changing porosity and permeability. Thus, geomechanics and flow are closely interrelated each other, and rigorous modeling in coupled flow and geomechanics is required.

Recently, Kim et al. (2012a) proposed the two-way coupling method for pore volume in flow and strain in geomechanics. The coupling method can account for geomechanical effects in porosity as well as permeability rigorously. Then, Kim et al. (2012b) showed that this method is readily applicable to the field scale hydrate reservoirs. Most of numerical tests have been discussed except the effects of capillary pressure.

Thus, in this study, we analyze responses of flow and gemechanics in gas hydrate deposits when strong capillarity exists, employing tight coupling between flow and geomechanics. For coupled flow and geomechanics, we use the constitutive equations proposed by Coussy (2004), where the equivalent pore pressure concept is used. According to Kim et al. (2011b), the

[1)] Geological Research Scientist
[2)] Geological Staff Scientist

equivalent pore pressure yields mathematical wellposedness and numerical stability for strong capillarity while the average pore pressure does not guarantee mathematical wellposedness, which may cause large numerical errors or numerical instability. The van Genuchten model is used for capillary pressure between aqueous and gaseous phases. We also account for the change in the capillary pressure curve from hydrate formation or dissociation, using the Leverett model. For relative permeability, the modified Stone model is used. In numerical simulation, we adopt the fixed stress sequential scheme for coupled flow and geomechanics, which can yield numerical stability and accuracy, used for the coupling of ROCMECH (geomechanics simulator) to TOUGH+Hydrate (flow simulator).

Mathematical modeling

The coupling between flow and geomechanics is formulated based on the extended Biot theory (Coussy, 2004), as follows.

$$\delta\boldsymbol{\sigma} = \overbrace{\mathbf{C}_e \delta\boldsymbol{\varepsilon}_e}^{\delta\boldsymbol{\sigma}'} - \overbrace{b_J \delta p_J}^{b\delta p_E}\mathbf{1} - 3\alpha_T K_{dr}\delta T\mathbf{1}, \tag{1}$$

$$\delta\zeta_J = b_J \delta\varepsilon_v + N_{JK}\delta p_K - 3\alpha_{m,J}\delta T\,, \tag{2}$$

$$\delta\overline{S} = \overline{s}_J \delta m_J + 3\alpha_T K_{dr}\delta\varepsilon_v - 3\alpha_{m,J}\delta p_J + \frac{C_d}{T}\delta T\,, \tag{3}$$

where $\boldsymbol{\sigma}$, $\boldsymbol{\varepsilon}_e$, p_J, S_J, T, ε_v, $\overline{S}$, $\overline{s}_J$, and α_T are total stress, elastic strain, pressure and saturation of fluid phase *J*, temperature, volumetric strain, total entropy and specific entropy of fluid phase *J*, and thermal dilation coefficient, respectively. The double indices indicate summation. The subscript *e* indicates elasticity. $\boldsymbol{\sigma}'$, K_{dr}, $\mathbf{C}_e$ are the effective stress tensor, drained bulk modulus, and drained isothermal elasticity tensor, respectively. **1** is the second order identity tensor. $\delta\zeta_J = \delta m_J / \rho_J$, where m_J and ρ_J is fluid mass and density, respectively. $b_J = bS_J$, where *b* is Biot's coefficient. $\mathbf{N}(=\{N_{JK}\})=\mathbf{M}^{-1}$, where **M** is the Biot modulus matrix. Readers can refer to Kim et al. (2012a) for more details.

Note that we use the equivalent pore pressure concept, $\delta p_E = S_J \delta p_J$, (Coussy 2004) when defining the effective stress. The equivalent pore pressure can yield mathematical wellposedness, while the average pore pressure, $\delta p_{ave} = S_J \delta p_J + p_J \delta S_J$, which is widely used in reservoir simulation, may cause large numerical errors or instability for strong capillarity (Kim et al. , 2011b).

For the modeling of the capillarity, we use the van Genuchten model for capillary pressure between aqueous and gaseous phases, and the Leverett model for the change in the capillary pressure curve due to hydrate formation or dissociation, as follows.

$$P_c = P_{en}\left(S_A^{-1/\lambda} - 1\right)^{1-\lambda},\ S_{A,e} = \frac{S_A - S_{A,r}}{S_{A,\max} - S_{A,r}},\ P_{c,s} = P_c / \sqrt{\xi_n}\ , \tag{4}$$

where P_c, P_{en}, $P_{c,s}$, S_r, λ, ξ_n are capillary pressure and capillary modulus, modified capillary pressure scaled by hydrate saturation, residual saturation of fluid phase J, the exponent for the capillary curve, and the permeability modification coefficient, respectively. The subscripts A, G, H, I indicate aqueous, gas, hydrate, ice phases, respectively.

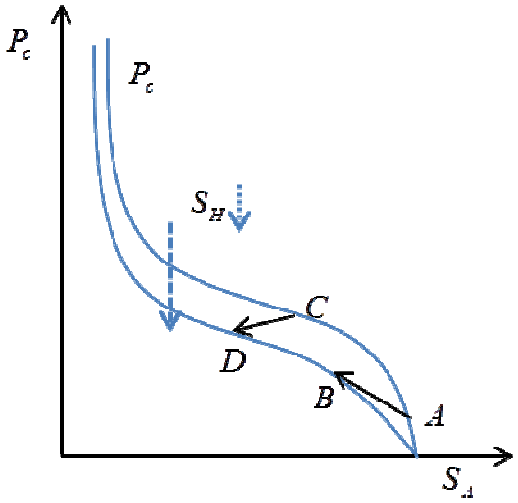

Fig. 1. Capillary pressure change during hydrate dissociation. As gas saturation increases, capillary pressure may increase (A to B) or decrease (C to D).

Hydrate dissociation increases gas saturation, increasing the capillary pressure (A to B in Fig. 1). But, at the same time, the dissociation can increase the pore sizes, decreasing the capillary pressure (C to D in Fig. 1). Then, the resulting capillary pressure is determined from both effects.

We use the porosity dependent permeability for the intrinsic or effective permeability and the modified Stone model for relative permeability, respectively, as follows.

$$\mathbf{k} = \mathbf{k}_0 \exp\left[\gamma_1\left(\frac{\Phi}{\Phi_0} - 1\right)\right]\left(\frac{\Phi_a - \Phi_0}{\Phi_0 - \Phi_c}\right)^{\gamma_2},\ k_{rJ} = \max\left\{0, \min\left\{\left(\frac{S_J - S_{J,r}}{1.0 - S_{A,r}}\right)^{n_p}, 1\right\}\right\}, \tag{5}$$

where $\mathbf{k}$, $\mathbf{k}_0$, Φ, Φ_0, Φ_c, k_{rJ}, γ_1, γ_2, n_p are current and initial intrinsic permeabilities, (Lagrange's) porosity, initial porosity, critical porosity, relative permeability, and the coefficients for the relative permeability curve, respectively. $\Phi_a = \Phi(S_A + S_G)$.

Numerical Simulation

We introduce a 2D reservoir with the plane strain geomechanics, placing a horizontal well located in the center of the left side, as shown in Fig. 2. The 2D plane strain geomechanics is

reduced from the 3D problem with long horizontal production wells. For flow simulation, we use TOUGH+Hydrate (Moridis et al., 2008). For geomechanics, we have recently developed a geomechanics simulator, called ROCMECH.

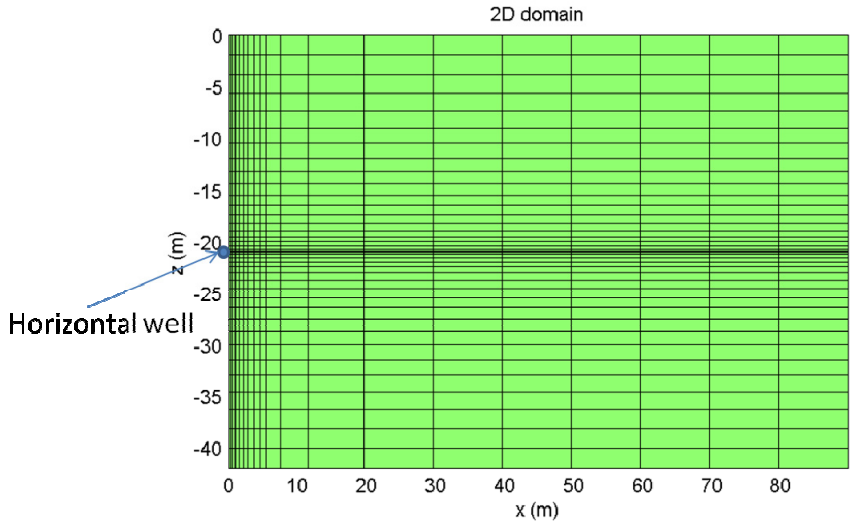

Fig. 2. 2D problem with the plane strain geomechanics and a horizontal well.

We set the reference depth of the top to be zero (i.e., z=0m), which is not the same as the real depth. For space discretization, the domain is divided into 20*39 gridblocks in (x, z), where the horizontal and vertical gridblock sizes are non-uniform, as shown in Fig. 2. We employ the finite volume method for flow, while the finite element method is used for geomechanics. In time discretization, we use the backward Euler method. Then, we use the fixed-stress sequential method (Kim et al, 2011a). The mixed space discretization with the sequential method is practical in using existing reservoir and geomechanics simulators, and more numerically stable.

For flow, we have no flow at the boundaries. The initial gas and aqueous saturations are 0.001, 0.5, respectively. The initial temperature is 12.5°C. Under the three phase (gas, aqueous, hydrate) system, the initial hydrate saturation and pressure are determined from thermodynamic equilibrium. The coefficients for capillarity are P_{en}=2MPa and $\lambda = 0.8$, which yield strong capillarity, compared with the initial pressure, 9.5036MPa. For permeability, we use $\gamma_1 = 0.0$, $\gamma_2 = 3.0$, $S_{J,r} = 0.0$. n_p's for aqueous and gas phases are 4.0 and 0.0. The intrinsic permeability and initial porosity are 0.03mD and 0.3. The medium heat capacity, wet and dry thermal conductivities are 1000Jkg^{-1}/ °C, 3.1W/m/ °C, 0.5 W/m/ °C, respectively. We have $b = 1.0$ and $\alpha_T = 4.0 \times 10^{-5}\ {}^0C^{-1}$. There is no fluid production. However, we place the horizontal well at z=-20.95m, which generates constant heat injection at the rate of 10W. We neglect gravity in this study.

For geomechanics, we have no horizontal displacement at both sides, and no displacement at the bottom, the overburden at the top, 9.7MPa. Drained bulk and shear moduli at zero solid saturation (i.e., $S_s (= S_H + S_I) = 0.0$) for the hydrate sediment are 61.67MPa and 92.5MPa,

respectively, and those at S_s=1.0 are 616.67MPa 925MPa. The vertical initial principal total stress at the top is -9.7MPa, and the bulk density is 2200kg/m^3, and we simply assume the total initial horizontal and vertical stresses to be the same. We have three monitoring points at P1(x=0.05m, z=-20.95m), P2 (x=0.45m, z=20.95m), and P3(x=1.25m, z=-20.95m).

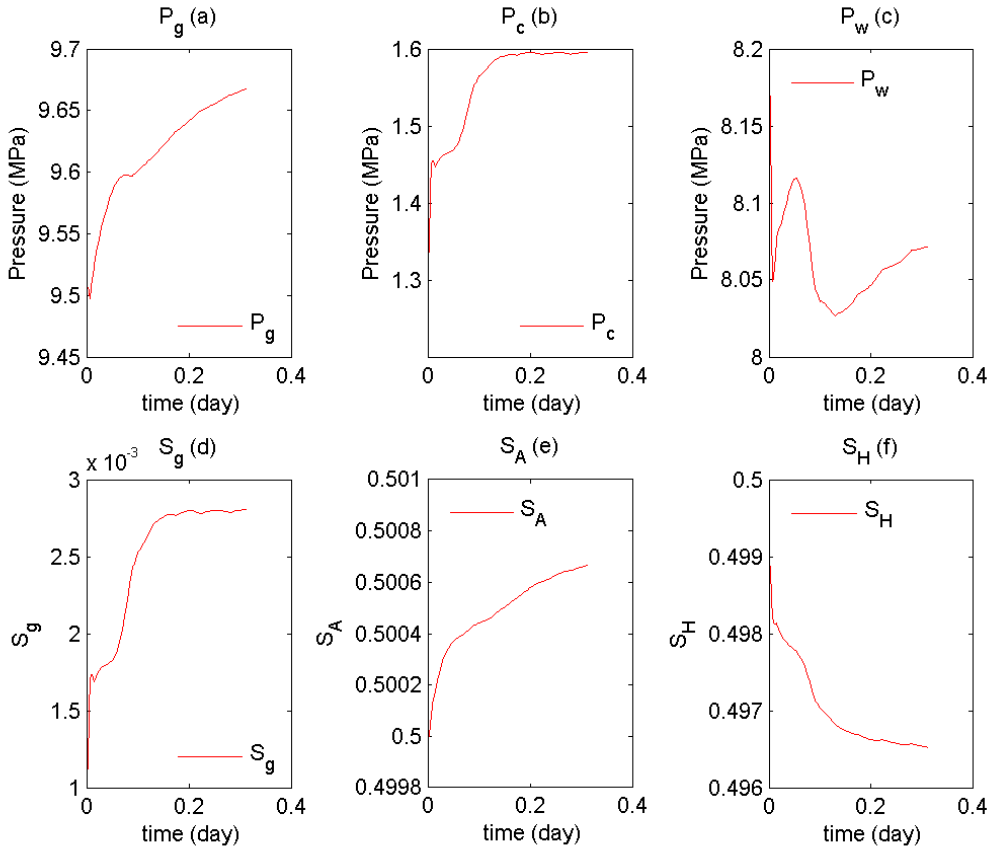

Fig 3. Evolution of pressure and saturation at P1. The aqueous pressure decreases 0.1~0.15 days, because the capillary pressure increases significantly even though gas pressure increases.

At P1, gas pressure increases as hydrates are dissociated because of heat injection from the horizontal well, shown in Fig 3. There is no change in ice saturation. The hydration dissociation decreases the solid phase saturation, which causes large pore sizes and might result in the decrease of capillary pressure. However, at the same time, the increase of gas saturation supports the capillary pressure, and, accounting for both effects, the capillary pressure finally increases. As a result, the aqueous pressure decreases between around 0.1 and 0.15 days. After the time, the aqueous phase increases due to influx from P2 and no change in the capillary pressure.

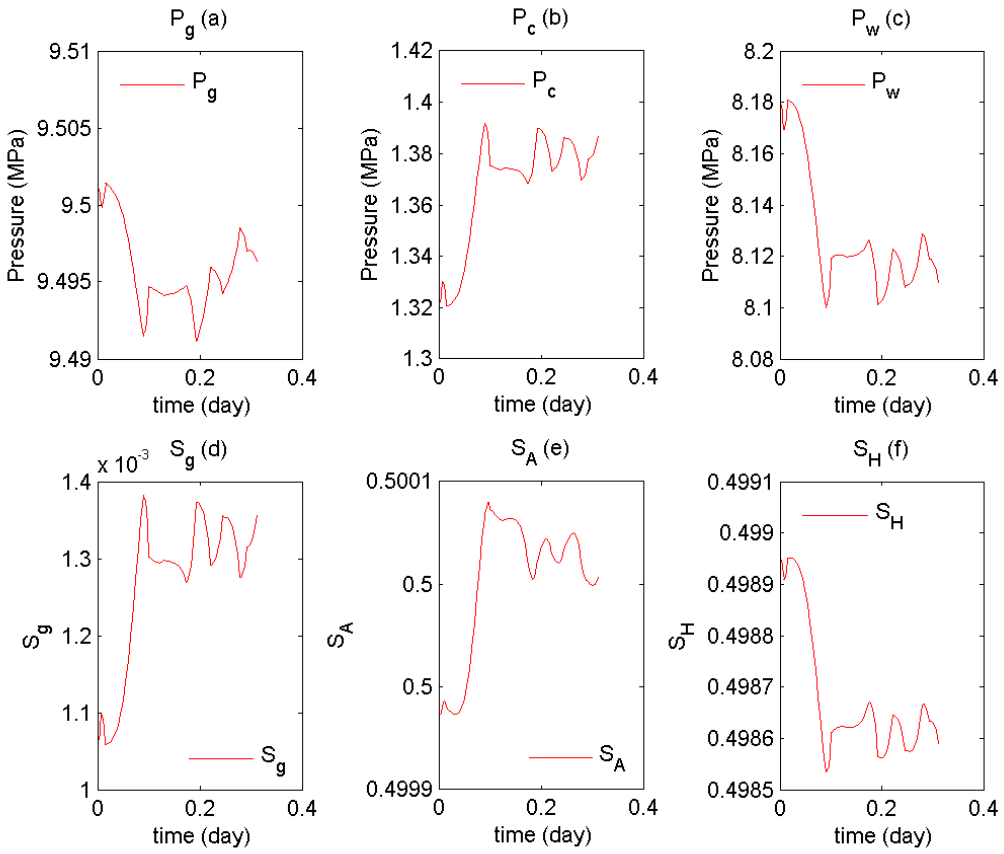

Fig 4. Evolution of pressure and saturation at P2. The gas pressure drops instantaneously due to the undrained condition and dilation at P2, as a result of poromechanical effects.

At P2, at early time, the gas pressure drops instantaneously due to the undrained condition and dilation at P2. The depressurization of gas at P2 induces the hydrate dissociation, releasing gas. This system response can only be captured by two-way coupling between flow and geomechanics, not one-way coupling nor flow-only simulation. After then, the gas pressure increases due to pressure diffusion from P1. The capillary pressure increases, lowering the aqueous pressure. But the decrease of the aqueous pressure at P2 is not greater than that at P1. Then, while gas flows from P1 to P2, liquid water flows from P2 and P1. Oscillations of the numerical results seem to be due to formation and dissociation of secondary hydrates during simulation.

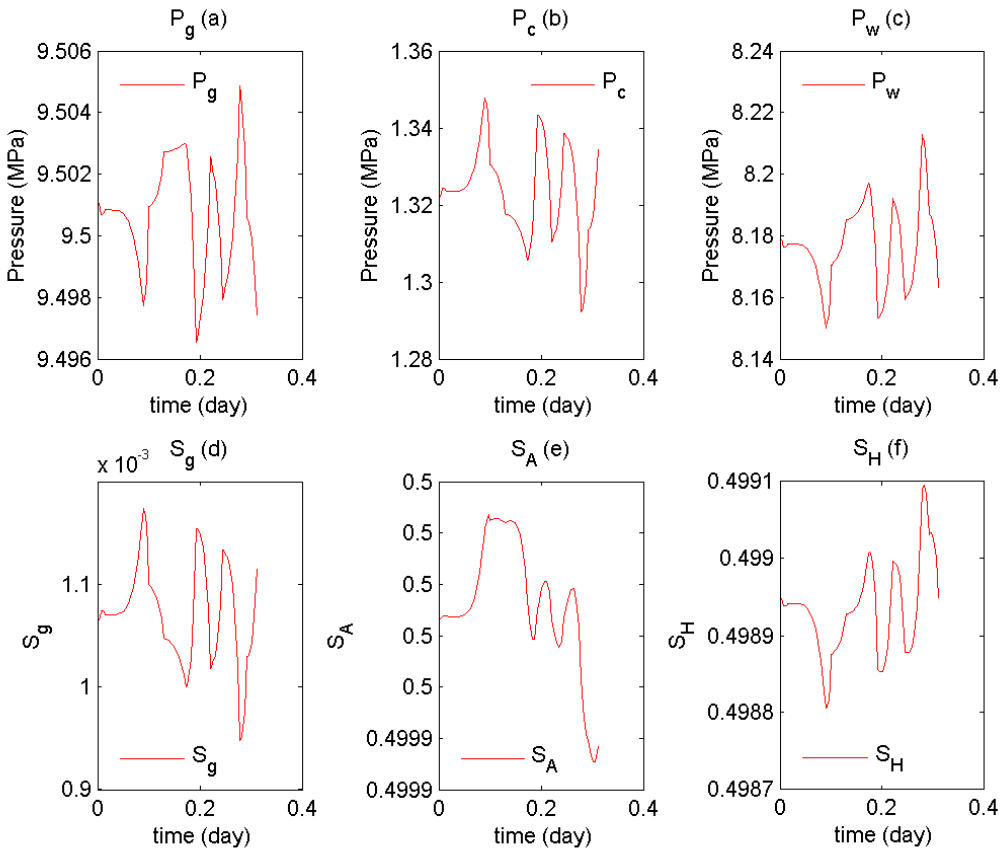

Fig 5. Evolution of pressure and saturation at P3.

At P3, the physical behavior results from the undrained condition in coupled flow and geomechanics, as explained as the early time behavior at P2. We also observe oscillations of the results, as seen at P2. The aqueous pressure decreases and increases repeatedly during simulation, but the pressure is still higher than those at P1 and P2. As a result, the counter-flow for gas and liquid water occurs between P1 and P3.

Conclusions

We developed a tightly coupled in-house coupled flow and geomechanics simulator, employing the equivalent pore pressure, performed numerical simulation in a gas hydrate sediment with strong capillarity. From the simulation, we found that strong capillary may cause counter-flow in gas and liquid water when heat generation occurs from the horizontal well. We also identified the early time behavior from coupled flow and geomechanics, which cannot properly be captured by flow-only or one-way coupled simulation.

REFERENCES

Coussy O. (2004), "Poromechanics", John Wiley and Sons: Chichester, England

Moridis, G.J., Kowalsky, M., Pruess, K. (2008). TOUGHþHYDRATE v1.0 User's Manual: A Code for the Simulation of System Behavior in Hydrate-Bearing Geologic

Media. Report LBNL-00149E, Lawrence Berkeley National Laboratory, Berkeley, California.
Kim J, Moridis GJ, Yang D, Rutqvist J. (2012a), “Numerical studies on two-way coupled fluid flow and geomechanics in hydrate deposits”, *Soc. Pet. Eng. J.,* **17**(2): 485–501. doi:10.2118/141304-PA
Kim J, Moridis GJ, Rutqvist J. (2012b), “Coupled flow and geomechanical analysis for gas production in the Prudhoe Bay Unit L-106 well Unit C gas hydrate deposit in Alaska”, *J. Pet. Sci. Eng.,* In press, http://dx.doi.org/10.1016/j.petrol.2012.04.012
Kim, J., Tchelepi, H.A., and Juanes, R. (2011a). Stability and convergence of sequential methods for coupled flow and geomechanics: Fixed-stress and fixed-strain splits. Comput. Meth. Appl. Mech. Eng. 200 (13–16): 1591–1606. http://dx.doi.org/10.1016/j.cma.2010.12.022
Kim, J., Tchelepi, H.A., Juanes, R. (2011b). Rigorous Coupling of Geomechanics and Multiphase Flow with Strong Capillarity. Paper SPE 141268 presented at the SPE Reservoir Simulation Symposium, The Woodlands, Texas, USA, 21–23 February. http://dx.doi.org/10.2118/ 141268-MS, minor revision in *Soc. Pet. Eng. J.*