GEOMECHANICAL ANALYSIS OF INITIAL STAGE OF GAS PRODUCTION FROM INTERBEDDED HYDRATE-BEARING SEDIMENT

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Abstract

Geomechanical stability of marine hydrate reservoirs during gas production by depressurization is the focus of this study. The reservoir considered here consists of thin hydrate rich sandy layers interbedded with mud layers. Because of the input parameter uncertainties involved, it is prudent from a geomechanical perspective to estimate the likely bounds of potential responses. A decoupled approach is presented herein for which the pressure and hydrate saturation in the sediments during gas production are obtained from multiphase flow computation, but could also be synthesized from various scenarios. This procedure is illustrated with sample problems.

Introduction

Geomechanical stability of marine sediments is one of the key design considerations in planning for offshore gas production from marine hydrate reservoirs. Assessing geomechanical stability requires computational modeling. Even with the recent advance in laboratory testing and constitutive modeling [1-4], computational modeling remains a challenging task due in part to the complexities of the modeling systems of coupled processes while accounting for uncertainties in the in-situ properties involved. Scenario studies provide a means of quantifying the possible outcomes resulting from variability in hydrological and mechanical properties of the sediments, as well as uncertainty about the in-situ conditions. This scenario study proposes an approach that utilizes spatial patterns of likely pressure and hydrate saturation changes to provide inputs for geomechanical analysis. During depressurization induced dissociation, there are two competing factors that determine the sediment stability: on the one hand, hydrate dissociation reduces sediment shear strength; on the other hand, the depressurization increases the confinement and thus raises shear strength. The in-situ shear stresses are low in flat marine sediments and the magnitude of the ground subsidence poses more of a problem than potential inelastic sediment yielding. Providing rational estimates of potential subsidence and other relevant sediment responses through scenario studies is the focus of this study. To illustrate the approach, two scenarios discussed in a companion paper on gas production [5] were analyzed. This study only considers gas production by depressurization method.

Modeling Overview

To carry out a full computationally intensive study, particularly one involving how various responses evolve over time, a closely coupled multiphase flow and geomechanical analysis would be used. For past studies of this type, we employed coupled TplusH [6] with FLAC3D in a staggered fashion [7, 8, 9]. In this scheme, TplusH updated fluid pressure, temperature and hydrate saturation changes at each time step for use by FLAC3D to perform a geomechanical analysis. In return, FLAC3D updated the porosity so TplusH could modify the permeability for the next time step. For scenario studies, in which the detailed changes with time are not the focus, a faster, less computationally demanding alternative approach would be desirable as an efficient means of exploring what is a fairly broad parameter space to find the combinations that are critical to the problem at hand and their potential impacts.

One such alternative proposed herein decouples the flow and geomechanical analyses. This is feasible only if the permeability reduction due to depressurization is properly accounted for in the standalone flow analysis. For gas production using depressurization, the sediment porosity changes during depressurization are caused mainly by the increase in the effective confining stresses. In the alternative decoupled approach presented here, geomechanical responses are obtained by using spatial distribution patterns of fluid pressure, hydrate saturation and temperature at a specific time as modeling inputs. By varying these patterns to represent different scenarios, a comprehensive picture of likely ranges of geomechanical responses can be constructed. In a direct geomechanical modeling approach, the porosity changes are obtained through non-linear stress analysis. For the decoupled approach, the standalone flow code introduces a pore compressibility parameter and uses it to find the porosity changes due to the fluid pressure changes. The pore compressibility parameter, α, gives porosity changes via $\phi = \phi_o e^{\alpha \Delta p}$, where ϕ_o and ϕ are, respectively, the porosities before and after the pressure change Δp. In this work, the multiphase flow induced by gas production through depressurization was analyzed by TplusH.

Cases Studied

To illustrate the proposed approach, we analyzed the geomechanical response of sediment at the site of a parametric gas production study which is described in detail in a companion paper [5]. Specifically, we studied two cases from that paper, denoted as Case 1A and Case 1B. These two cases differ only in the effective permeability of the hydrate rich sand layer within the reservoir: Case 1A used 0.1 mD, while Case 1B used 10 mD. This two-orders-of-magnitude difference resulted in very significant differences in the gas production rate. Of interests here are what the implications of such differences on geomechanical responses.

For this site, the sea floor is located 2,575 m below the sea surface. The sediment is divided into 5 units based on logging data. The hydrate reservoir is classified as UNIT 4 (Table 1) and lies from 272.8 to 296.9 m below the sea floor. It contains 18 thin hydrate rich sandy layers interbedded with hydrate-free muds. A sketch of UNIT 4 is depicted in Figure 1. The depressurization for gas production was introduced at a point on the left edge, corresponds to where the well is located, right below the top boundary of UNIT 4 via a fixed fluid pressure at 3 MPa, representing an 89.5% pressure reduction relative to the expected hydrostatic pressure of 28.55 MPa. The geological setting at the site confines the depressurized zone to lie within the reservoir. The flow domain of the axi-symmetric standalone flow studies extends vertically from the sea floor to 496.9 m below sea floor, and extends radially from 0 to 500 m. For the more demanding geomechanical study, a reduced model region was used that extended only to the depth of 300 m below the sea floor, and the radial extent was limited to 100 m from the wellbore.

TABLE 1 Geological units at the studied site

Major Model Unit	Sub-seafloor Depth (m)	Thickness (m)	Porosity
UNIT 1: uniform marine mud with no hydrate	0.0–151.0	151.0	0.67
UNIT 2: uniform marine mud with fracture filled gas hydrate	151.0–244.0	93.0	0.66
UNIT 3: uniform marine mud with no hydrate	244.0–272.8	28.8	0.71
UNIT 4: interbedded hydrate-bearing sand and hydrate-free mud	272.8–296.9	24.1	0.4
UNIT 5: uniform marine mud with no hydrate	Below 296.9		0.53

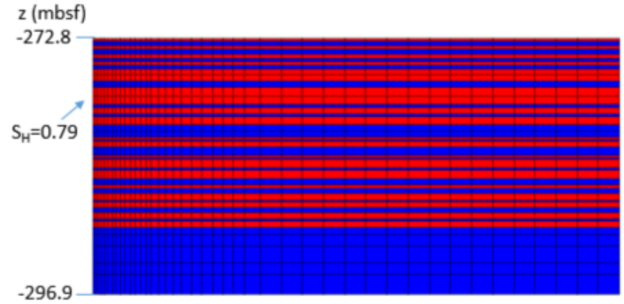


Figure 1 A sketch showing the interbedded thin hydrate rich layers (in red) in the hydrate reservior

In this study, the hydrate reservoir was modeled using a critical state subloading methane hydrate bearing soil model (MHBS) [3]. The model parameters were selected to fit the test data from Nankai Trough, they are

Critical state parameters	λ=0.16, κ=0.025, $\overline{p}_c$ =7 MPa ν_o=3.1 at $\overline{p}_0$ =98kPa M=1.2
Subloading parameter	u=4
Hydrate enhanced terms	a=22 MPa, b=1.5 c=0.2 MPa, d=1 km=0.95, m2=250 MPa

For a detailed explanation of the parameter definitions and model equations, please refer to [3]. The coefficient of at-rest earth pressure, *Ko*, for the site was fixed at 0.5. The bulk modulus, B, varied with depth and was dependent on the in-situ effective confining pressure. Using an average porosity of 0.675 for the overburden, i.e., UNITs 1 to 3, the specific volume, ν, would be 3.1. From the Cam-Clay model, the bulk modulus, *B*, can be found as $B = \nu \cdot \overline{p} / \kappa$. This resulted in an initial $B = 3.1 \cdot \overline{p} / \kappa$. The Poisson ratio used was 0.2, which resulted in a shear modulus, $G=0.75\ K$. According to Zhou et al. [10], the overburden at the Eastern Nankai Trough gas production test site has a smaller κ value that lies between 0.008 and 0.01. Using this lesser value for this study would increase both the bulk modulus and shear modulus by a factor of 2.5, but that did not meaningfully affect the resulting sea floor settlement of interest in this work as discussed below.

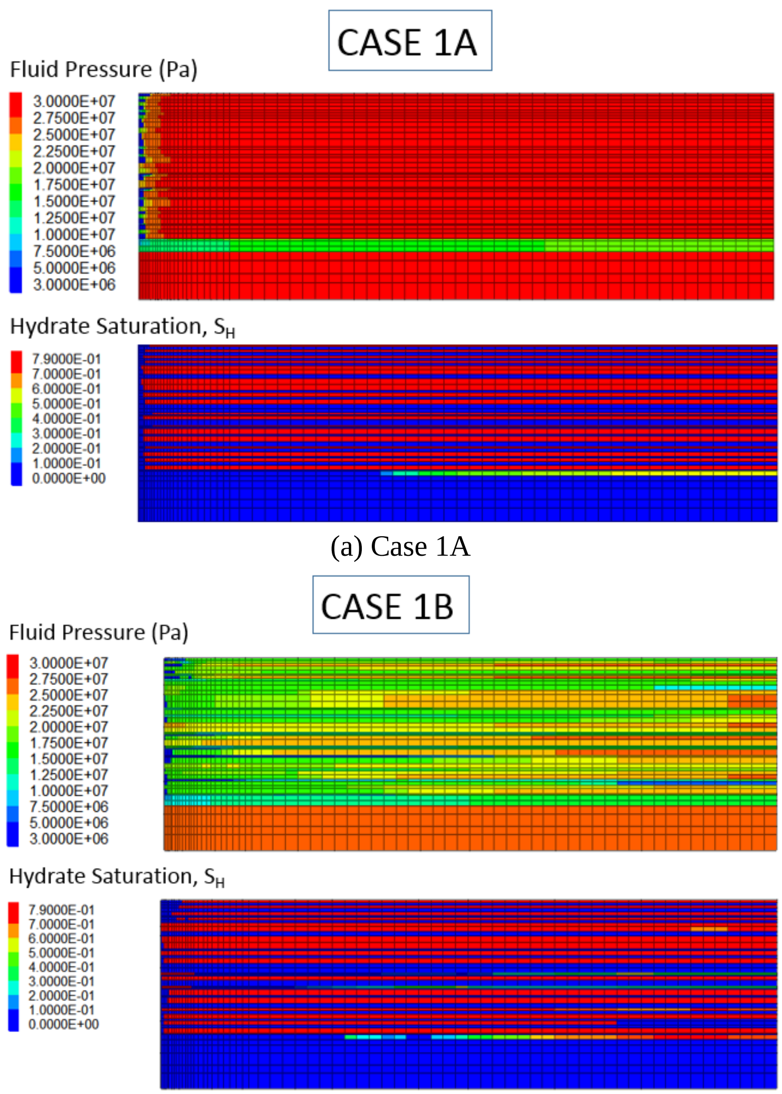
For this geomechanical study, the boundary at the bottom was fixed, and the two radial boundaries were constrained laterally but free to move vertically. Pressure at the top surface boundary was imposed by the 2,575 m of overlying sea water. The initial pore pressure within the sediment was obtained via hydrostatic consideration.

From the standalone flow study, spatial distributions of the fluid pressure and hydrate saturation within the Unit 4 hydrate reservoir after 90 days of depressurization for Cases 1A and 1B are summarized in Figure 2. Only results within 100 m in the lateral direction are shown. This study did not consider the effects of temperature changes on geomechanical responses as the temperature changes during the depressurization were small.

The hydrate rich thin sandy layers in the reservoir were 100 times more permeable for Case 1B than for Case 1A, which allowed the imposed pressure drop to be communicated more uniformly and further into the formation in Case 1B as shown in Figure 2. Using the pressure and hydrate saturation patterns from Figure 2, geomechanical analyses were carried out. The resulting settlements are summarized in Figure 3.

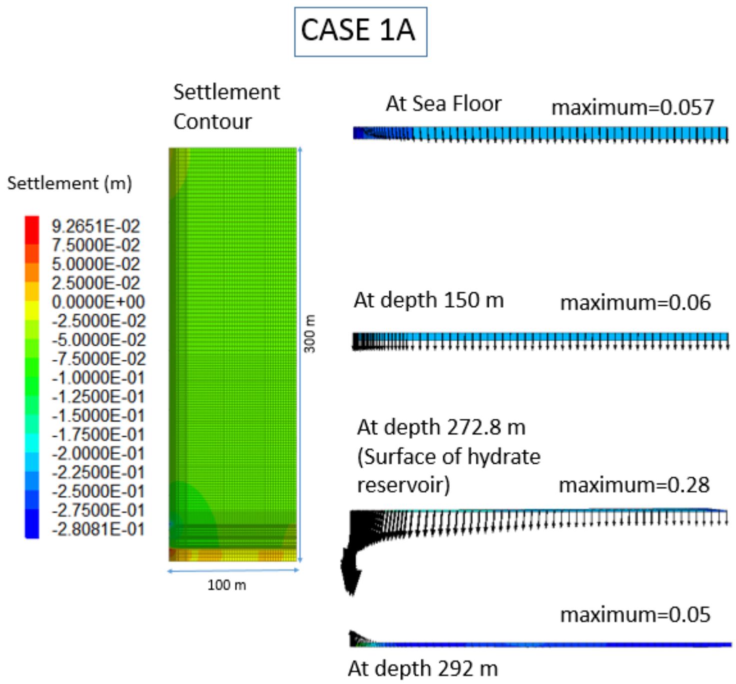
For the present case of a hydrate reservoir consists of thin hydrate rich sandy layers interbedded with mud layers, an issue arises because flow and geomechnical modeling have different meshing requirements. To capture the hydrate dissociation pattern, hence the gas production rate, the mesh used for flow modeling for UNIT 4 alone encompassed 241 layers using the same 0.1m thickness for each layer. The geomechanical modeling, on the other hand, uses a coarser mesh and only 44 layers were used to model UNIT 4 to reduce the computational time. The maximum depth-to-width aspect ratio of the geomechanical mesh used was 5 within 16 m radial distance from the wellbore, and 10 in the far field. Even though the geomechanical analysis uses a coarser mesh, the layer structures of UNIT 4 was preserved.

Figure 3 shows that sediments in both cases experienced the largest settlement at the top of the UNIT 4 reservoir, and underwent heave at its bottom. For Case 1A, this maximum settlement was 28 cm, and the maximum heave was 5 cm. The maximum sea floor settlement was 5.7 cm, and the maximum settlement at the depth of 150 m was 6 cm. This indicates that the sediment from sea floor down to 150 m depth experienced negligible stress changes. In other words, the overburden was simply too soft to take up any load. Relative to Case 1A, the more extensive pressure drop for Case 1B led to a larger maximum settlement at the top of the reservoir of 74 cm, while the maximum heave was also increased to 12 cm. The maximum sea floor settlement obtained was 30 cm, and at 150 m depth, the number again was only slightly different at 32 cm, further demonstrating the weakness of UNIT 1 observed in Case 1A. It is important to note that the large settlement is a result of a high permeability scenario after 90 days of production.

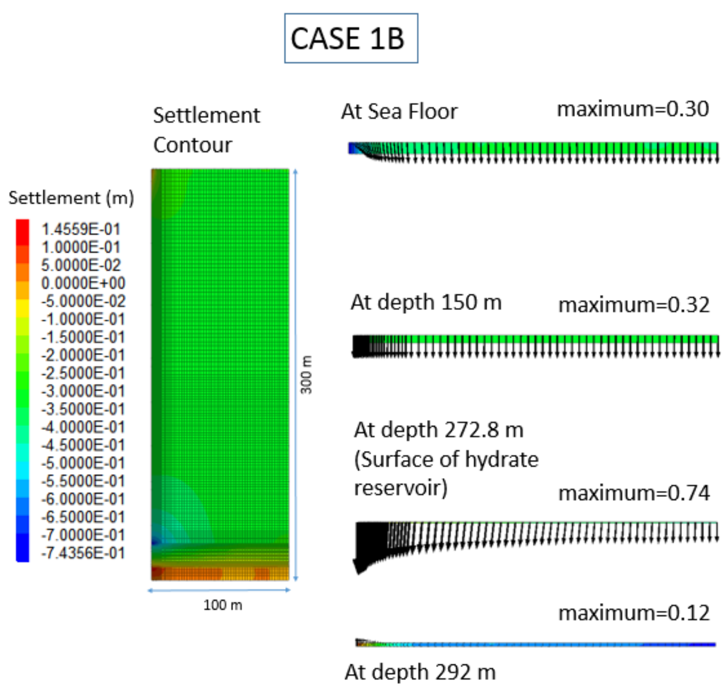


(b) Case 1B

Figure 2. The fluid pressure and hydrate distribution in UNIT 4 at 90 days after depressurization started (The region shown covers depth from -272 to -296 mbsf, and spans 100 m laterally.)



(a) Case 1A



(b) Case 1B

Figure 3. Computed settlements for both Cases 1A and 1B

A sensitivity analysis was carried out to quantify how settlement would be affected by a stiffer overburden. This was done by reducing κ from 0.025 to 0.01 [9], which increased both the bulk modulus and shear modulus of the overburden by 2.5 times. However, the resulting magnitudes of settlements and the settlement pattern remained about the same: the maximum settlements obtained were 31 cm at sea floor, 32 cm at 150 m depth, and 74 cm at the top of the reservoir.

Future scenario studies may be directed at boundary and driving force issues. This study set the bottom boundary at 300 m below the sea floor. How would a deeper domain affect the heave observed? The wellbore boundary was considered frictionless in the current study, but how would changing that boundary condition affect the settlement? Also, what would happen if the hydrate dissociation were more severe? These are just a few of the scenarios that would be worthwhile to investigate further.

Conclusions

This study used a computationally simplified approach to assess various scenarios in an effort to obtain in an efficient way an overall stability picture of ground response during gas hydrate production. The approach presented here used patterns of fluid pressure and hydrate saturation changes from a companion flow study as inputs for carrying out a decoupled geomechanical analysis. Such an analysis can be carried out to target specific issues such as the impact of boundary conditions or sediment stiffness variations. Though this study focused the discussion on settlement, the scenario study could also yield other important information for design such as lateral stresses exerted on the wellbore and shear stress levels within the sediments. This approach requires the standalone flow analysis to incorporate porosity change when fluid pressure changes, which can be accomplished through the adoption of calibrated pore compressibility parameters.

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