

Article

Effect of Drilling Fluid Invasion on Natural Gas Hydrate Near-Well Reservoirs Drilling in a Horizontal Well

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Abstract: Horizontal wells can significantly improve the gas production and are expected to be an efficient exploitation method for the industrialization of natural gas hydrates (NGHs) in the future. However, the near-wellbore hydrate is highly prone to decomposition during the drilling process, owing to the disturbance aroused by the factors such as the drilling fluid temperature, pressure, and salinity. These issues can result in the engineering accidents such as bit sticking and wellbore instability, which are required for further investigations. This paper studies the characteristics of drilling fluid invasion into the marine NGH reservoir with varied drilling fluid parameters via numerical simulation. The effects of the drilling fluid parameters on the decomposition behavior of near-wellbore hydrates are presented. The simulating results show that the adjustments of drilling fluid density within the mud safety window have limited effects on the NGH decomposition, meanwhile the hydrates reservoir is most sensitive to the drilling fluid temperature variation. If the drilling fluid temperature grows considerably due to improper control, the range of the hydrates decomposition around the horizontal well tends to expand, which then aggravates wellbore instability. When the drilling fluid salinity varies in the range of 3.5–7.5%, the increase in the ion concentration speeds up the hydrate decomposition, which is adverse to maintaining wellbore stability.

Keywords: marine natural gas hydrate; horizontal well drilling; drilling fluid invasion; near-wellbore; drilling mud property; reservoir response



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1. Introduction

Natural gas hydrates (NGHs), the solid cage-like compounds formed by natural gas and water under low-temperature and high-pressure [1–3] conditions, are mainly found at the subsea formation of the continental shelf margin or in the permafrost of cold regions [4–7]. The total organic carbon of global gas hydrate (of which, more than 90% occur in the sea area [8]) is approximately double that of traditional fossil fuels [9,10], and gas hydrates are the crucial potential highly-efficient clean alternate for oil and gas [11–13]. In recent years, the development of natural gas hydrate has attracted global attention, yet the commercial exploitation of NGHs still has a long way to go [14–18].

The marine natural gas hydrate-bearing sediments (GHBS) is shallow buried, weakly cemented and poorly diagenetic [19–21], which is highly sensitive to the temperature and pressure, as well as external fluids. During the process of drilling, the invasion of drilling fluids will cause mass and heat transfer between fluids and NGHs in the reservoir.

Supposing that the drilling fluid properties were not well-regulated, it could easily trigger gas hydrate decomposition in the reservoir, which degrades the physical properties of the reservoir and could cause wellbore instabilities [22–25]. To investigate this type of issue, many scholars have established mathematical models to study the invasion of drilling fluid in hydrate formation. Ning [26] investigated and study the effects of drilling fluid properties (drilling fluid density, drilling temperature, and drilling mineralization) and sediment geophysical properties (inherent permeability, porosity, and initial hydrate saturation) in the invasion of drilling fluid into GHBS by TOUGH + HYDRATE numerical simulation software. Chen et al. [27] conducted experimental simulation of drilling fluid intrusion into hydrate sediments under different wellbore pressures. The results show that higher wellbore pressure can promote drilling fluid invasion, but its effect is limited by wellbore distance. Besides, Zheng [28], based on the Gulf of Mexico hydrate joint industrial project, simulated the process of drilling fluid intrusion into natural GHBS, and analyzed the impact of drilling fluid intrusion on physical properties by measuring temperature, pressure, and resistivity. Tian [29] indicates the invasion of drilling fluid changes the distribution pattern of hydrate in hydrate-bearing sediments and the mineralization of pore water, because of a significant increase in resistivity, difficulty in hydrate layer identification and even wrong results. Tu's [30] research shows that the invasion process of drilling fluid in hydrate bearing sediments is related to heat and mass transfer and hydrate phase transition in porous media, which affects the formation structure and permeability of hydrate, making the invasion of drilling fluid more difficult to predict. Afterwards, a two-dimensional cementing model was established by Zheng [31] in order reproduced the cement slurry invasion process with TOUGH + HYDRATE and analyzed the physical property response of hydrate reservoir in the cementing process according to the numerical simulation data. Among them, the viewpoint of “continuous stage simulation” is proposed and applied to solve the dynamic heat release problem of cement slurry for the first time. Meanwhile, the sensitivity analysis of drilling parameters has also been studied by scholars [32–34]. In 2020, China Geological Survey (CGS) explored horizontal well to extract NGH in deep-sea soft reservoir for the first time in the world, making a significant leap from “exploratory production” to “experimental production” [35]. The results showed that compared with the vertical well, the horizontal well significantly improved gas production and has great developmental potential and economic potential for improving the natural gas hydrate production capacity [36]. However, during the process of horizontal drilling, the wellbore instability becomes prominent due to the narrow mud weight window, the large contact area with borehole wall, long interaction time, and large volume of fluid invasion, which has seriously restrained the safety and efficiency of oceanic NGH drilling [37–42]. Therefore, it is crucial to figure out the distribution and evolution patterns of the pore pressure and NGH saturation of the reservoir around the wellbore with drilling fluids circulating in the wellbore to evaluate quantitatively the wellbore instability resulting from the drilling fluid invasion.

In this work, we investigate the effects of drilling fluid invasion on NGH reservoir characteristics. Based on the data of first production test at Shenhu area in the South China Sea, the drilling fluid invasion model of horizontal wells is constructed using the TOUGH + HYDRATE [43] simulator. The effects of the key parameters such as the drilling fluid temperature, density, and salinity on the hydrate decomposition behavior around wellbore are presented. This paper is aimed at providing targeted precaution and control measures for future field operations to avoid accidents like wellbore instability.

2. Modelling

2.1. Geological Background

In 2017 and 2020, two rounds of NGH production tests were conducted in the Shenhu area in the South China Sea. Field testing shows that the water depth is approximately 1266 m, and the NGH mainly occurs at 201–278 m below the seabed mudline with a total thickness of 77 m. The reservoir can be separated as three layers [35,44]: (1) the NGH-bearing layer, approximately 35 m thick (Hydrate saturation, about 30%); (2) the three-phase mixed layer, about 15 m thick; (3) the free gas layer, about 27 m thick. The hydrate is mainly the type of pore filling. In addition, the lithology of the NGH reservoir in Shenhu area is dominated by muddy fine siltstone.

2.2. Numerical Model

Referring to the design of second production test, the horizontal wellbore achieved by riserless drilling is placed in the middle of the NGH reservoir (as shown in Figure 1). Due to the symmetry of the model, only half of the reservoir is considered as the study area. A cuboid model with a length of 5.0 m, a height of 10 m, and a thickness of 0.1 m is built in TOUGH + HYDRATE (the horizontal wellbore can be extended). In the simulation, the wellbore diameter is 228.6 mm; the drill pipe diameter, 177.8 mm; the annulus gap, 25.4 mm; the temperature of drilling fluids, 15.2 °C; fluid density, 1070 kg/m³; fluid salinity, 3.5%. At present, it is a little difficult to exactly simulate the drilling fluid circulation in this model. Therefore, to simplify the simulation, we use the isotropic pressure as drilling pressure once the borehole is opened. In fact, due to the special character of the un-consolidated hydrate reservoir with narrow drilling fluid density window, the pump pressure should be controlled carefully. This illustrates that the high pump pressure is unlikely to be adopted. Besides, some borehole accidents may also stop drilling. Therefore, we approximately assume that the drilling fluid pressure is the sum of sea water and drilling fluid hydrostatic pressure in our simulation:

$$P_f = P_{atm} + g(\rho_{sw}h + \rho_f Z) \times 10^{-6} \quad (1)$$

where P_f is the wellbore fluid pressure in MPa; ρ_f is the density of drilling fluids in kg/m³; P_{atm} is the atmospheric pressure, 0.101325 MPa; h is the water depth in m; Z is the distance from the seabed to the subsea sediments of interest in m; g is the acceleration of gravity; ρ_{sw} is the average seawater density, which is the function of water depth, temperature, and salinity. The average seawater density is calculated as 1019 kg/m³ according to the existing fitting equation [45]. The drilling fluid elements inside the wellbore annulus are set to be the constant internal boundary, which means they have the fixed temperature and pressure. Moreover, the annular meshes are simplified as the “pseudo-porous medium” with the porosity of 1.0 mD, the permeability $k_x = k_y = k_z = 5.0 \times 10^{-9}$ m² and the pore pressure $P_c = 0$. The external boundary condition of the model is set as Dirichlet boundary that keeps the fixed pressure and temperature because it is very far from the wellbore. The simulation parameters in TOUGH + HYDRATE is shown in Table 1. Herein, the initial pore pressure should follow the hydrostatic pressure distribution, meanwhile the initial formation temperature is obtained upon seabed temperature and the geothermal gradient given in Table 1.

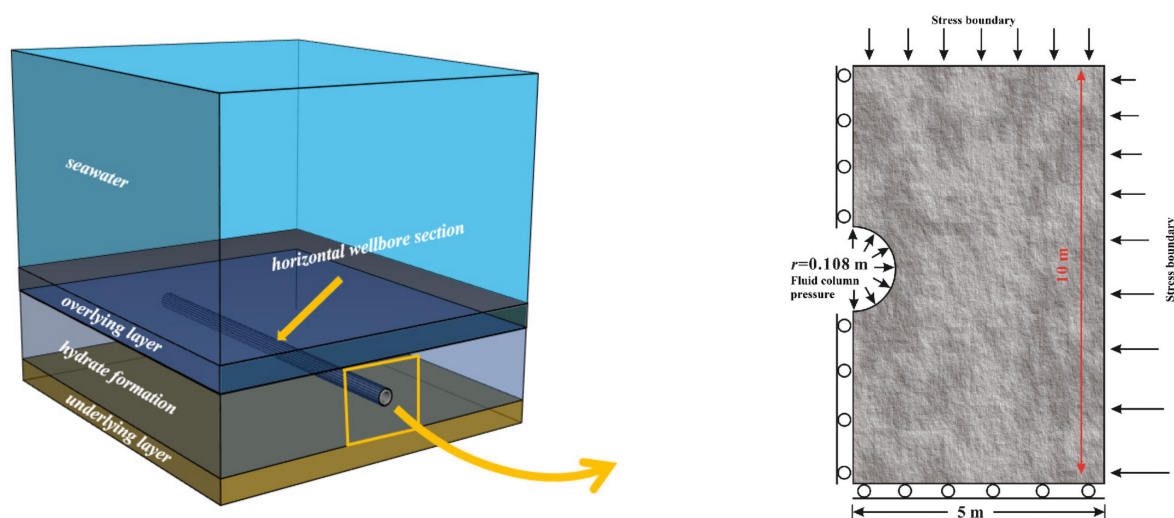


Figure 1. Diagram of the drilling fluid invasion and wellbore stability model during horizontal drilling.

Table 1. Main reservoir parameters and drilling fluid property parameters for simulation.

Parameters	Values	Parameters	Values
Absolute permeability of the hydrate reservoir	$k_H = 2.9 \times 10^{-15} \text{ m}^2$	Formation composite thermal conductivity model [46]	$\lambda_c = \lambda_{Hs} + (S_A^{1/2} + S_H^{1/2})(\lambda_s - \lambda_{Hs}) + \Phi S_I \lambda_I$
Wellbore annulus permeability	$k_W = 5.0 \times 10^{-9} \text{ m}^2$	Pore water pressure model [47]	$P_{cap} = -P_0[(S^*)^{-1/\lambda} - 1]^{1-\lambda}$, $S^* = (S_A - S_{irA})/(S_{mxA} - S_{irA})$
Hydrate reservoir porosity (Φ_H)	0.35	S_{mxA}	1
Compressibility (α)	$8.30 \times 10^{-8} \text{ Pa}^{-1}$	λ	0.25
Grain density (ρ_s)	2700 kg/m^3	P_0	10^6 Pa
Grain specific heat (C_s)	$1000 \text{ J} \cdot \text{kg}^{-1} \cdot ^\circ\text{C}^{-1}$	Relative permeability model [43]	$k_{rA} = [(S_A - S_{irA})/(1 - S_{irA})]^n$, $k_{rG} = [(S_G - S_{irG})/(1 - S_{irA})]^{nG}$
Thermal conductivity coefficient (wet)(λ_s)	$1.76 \text{ W} \cdot \text{m}^{-1} \cdot ^\circ\text{C}^{-1}$		
Thermal conductivity coefficient (dry)(λ_{Hs})	$0.30 \text{ W} \cdot \text{m}^{-1} \cdot ^\circ\text{C}^{-1}$	n	3.5
Geothermal gradient	$45.339 ^\circ\text{C/km}$	nG	2.5
Wellbore radius (r_w)	0.108 m	S_{irG}	0.03
Wellbore annulus porosity	1.0	S_{irA}	0.70
Specific heat of drilling mud	4000		

2.3. Meshing and Simulation Period

A total of 1040 elements have been meshed in the (x, y, z) coordinate system, with 20 inactive elements on the top, bottom, and external boundaries (Figure 2). During this riserless drilling, the temperature of drilling fluid and pressure are kept constant. With the increase of lateral length and gradual formation of mud-cake on borehole wall, the fluid invasion away from bit will gradually weaken. Therefore, 36 h is set as the simulation time to reflect the reservoir characteristics and the variation brought by drilling fluid invasion.

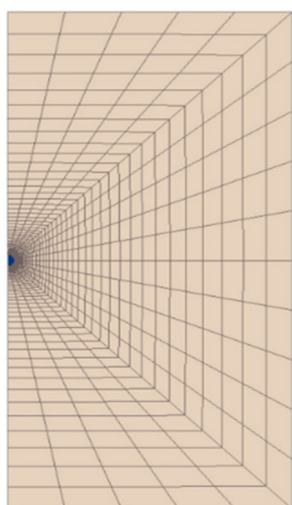


Figure 2. Schematic diagram of meshing.

3. Results and Analysis

The pore pressure distribution around horizontal wellbore during the drilling fluid invasion is illustrated in Figure 3. The distributions are a square far from the wellbore because the mesh node results are interpolated from the mesh center node information that provided by TOUGH + HYDRATE, noting that pore pressure can quickly respond if the pressure balance is broken after drilling. It shows that the overbalance of drilling favors fluid invasion into the reservoir due to the pressure difference, resulting in the increase of pore pressure. At the beginning of the drilling fluid invasion, the rapid pressure transfer leads to a rapid growth of pore pressure. However, during the sequent invading, the pressure variation slows down due to the pore pressure approaching equilibrium. Therefore, for the weakly/un-consolidated marine GHBS, the sudden drop of the effective stress at initial stage of drilling fluid invasion is highly likely to cause wellbore instability [48,49]. As shown in Figure 4, the drilling fluid invasion also results in the endothermic decomposition of hydrate. The decrease of NGH saturation around the wellbore will cause the decrease of reservoir mechanics, and meanwhile intensifies wellbore instability. In addition, the drilling fluid invasion and hydrate decomposition leads to the increase of reservoir water cut, which impairs the cohesion between the sediment particles and further reduces the reservoir mechanics, especially the shear strength [50,51]. In general, during the initial stage of drilling fluid invasion, the pore pressure of the near-wellbore reservoir rises significantly, while the heat transfer of drilling fluids delays. At later stages of invasion, the area of hydrate decomposition gradually expands with continuous invasion and heat transfer, resulting in the degraded mechanics of the reservoir that inevitably increases the risk of wellbore instability. The above finding can be confirmed by the evolution characteristics of the reservoir fluid salinity around the wellbore (as shown in Figure 5). When the drilling fluid with a salinity of 3.5% propagates into the reservoir, the salinity in the wellbore area ($r = 0.108$ m) remains unchanged. Nonetheless, due to water produced by hydrate decomposition (Hydrate has the characteristic of “expelling salt”, and thus the produced water has no salts), the fluid salinity of the reservoir reduces significantly within about 0.2 m from the borehole wall. As the depth increases, the reservoir fluid salinity gradually grows until reaching the initial salinity due to the gradual decline of the NGH decomposition. It should be noted that here the simulation calculates for only 36 h. If the simulation time is prolonged, the unstable area should further expand with the further invasion of drilling fluids.

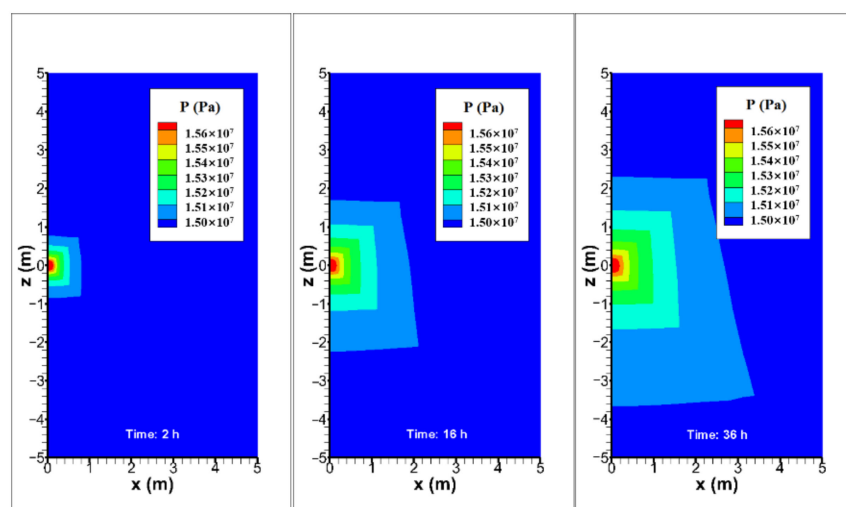


Figure 3. Pore pressure distribution evolution around the wellbore.

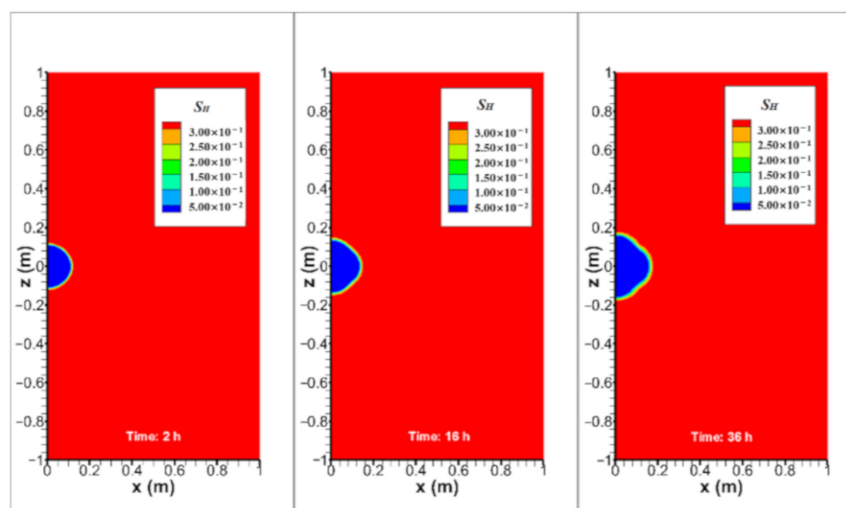


Figure 4. NGH saturation distribution evolution around the wellbore.

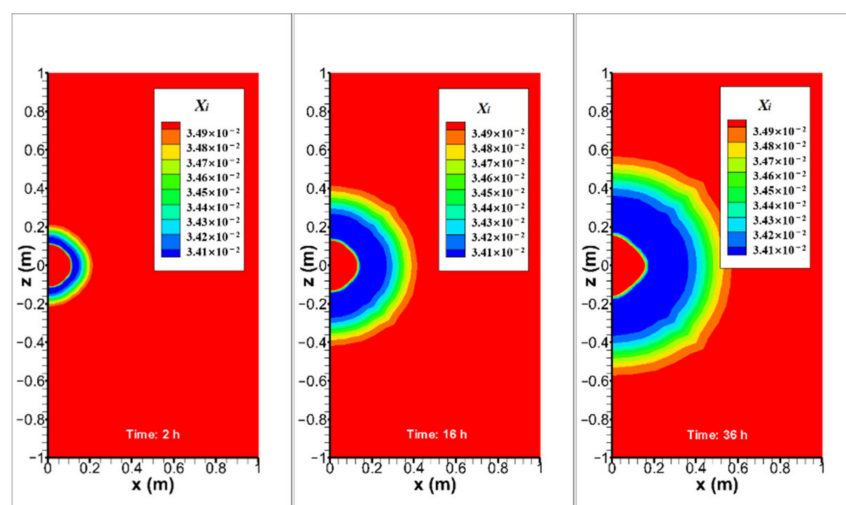


Figure 5. Cont.

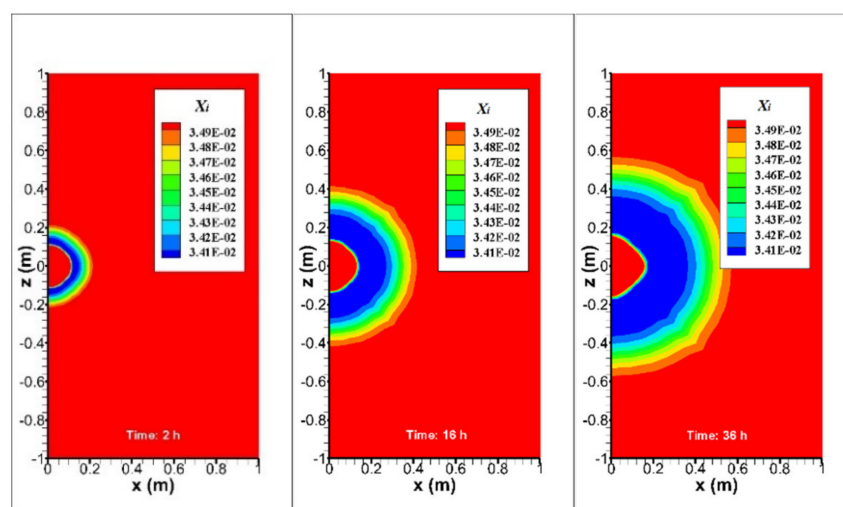


Figure 5. Salinity distribution evolution around the wellbore.

In conclusion, drilling fluids and the reservoir have prolonged interaction during horizontal drilling through the oceanic NGH reservoir. Thus, it is necessary to finely adjust and control the wellbore pressure by controlling the key parameters such as the drilling fluid density and pump rate. Moreover, the plugging performance and mud-cake properties shall be strengthened to fast form low-permeability rigid mud-cake on the borehole wall to minimize the effective stress drop and hydrate decomposition in near-wellbore zone caused by drilling fluid invasion. As a result, the wellbore stability can be effectively maintained to avoid accidents such as severe lost circulation, wellbore collapse and bit sticking.

4. Sensitivity Analysis

During the construction of horizontal wells, the variation of the drilling fluid properties will induce the temperature and pressure variations of the NGH reservoir, further resulting in the change of the NGH occurrence and ultimately wellbore instability [52–57]. Therefore, it is necessary to investigate the effects of the temperature, density, and salinity of drilling fluids on the invasion behavior. The same model is considered in this section. Based on the field survey performed in this area in 2007 and the latest publications, the following parameters are selected to perform the sensitivity analysis [35,44,58–60], as shown in Table 2. The other simulation parameters are the same.

Table 2. Varied parameters of drilling fluids for sensitivity analysis his is a table.

Drilling Fluid Parameters	Values		
Temperature (°C)	15.2	16.2	20.0
Density (kg/m ³)	1050	1070	1090
Salinity (%)	3.5	4.5	7.5

4.1. The Influence of Drilling Fluid Temperature

The variation of pore pressure distribution the near-wellbore zone with increasing temperatures of drilling fluid is shown in Figure 6. When the temperature of drilling fluids rises by only 1 °C, in the early stage of invasion, the variation of pore pressure is the same as that of 15.2 °C. Under both conditions the pore pressure around wellbore greatly grows due to external fluid invasion. In the later stage of invasion, the pore pressure evolution around the wellbore also presents no notable differences for the two temperature cases. The variation of the near-wellbore pore pressure slows down and gradually reaches equilibrium. With $r > 3.5$ m, the pore pressure of the reservoir presents no notable change. When the drilling fluid temperature is heated to 20 °C, at the early stage of invasion,

the hydrate decomposition in the near-wellbore reservoir considerably accelerates, and a certain volume of the produced gas accumulates at $r = 0.2$ m, which results in the pore pressure being significantly higher than that in other areas. At the later stage of invasion, due to the synergic effects of the sustained invasion of drilling fluids and heat transfer, the enriched area of produced gas has been gradually expanded and the pore pressure around the wellbore is significantly improved (radial depth of approximately 0.1–0.2 m). This leads to extreme proneness of the borehole wall and near-wellbore reservoir to failure.

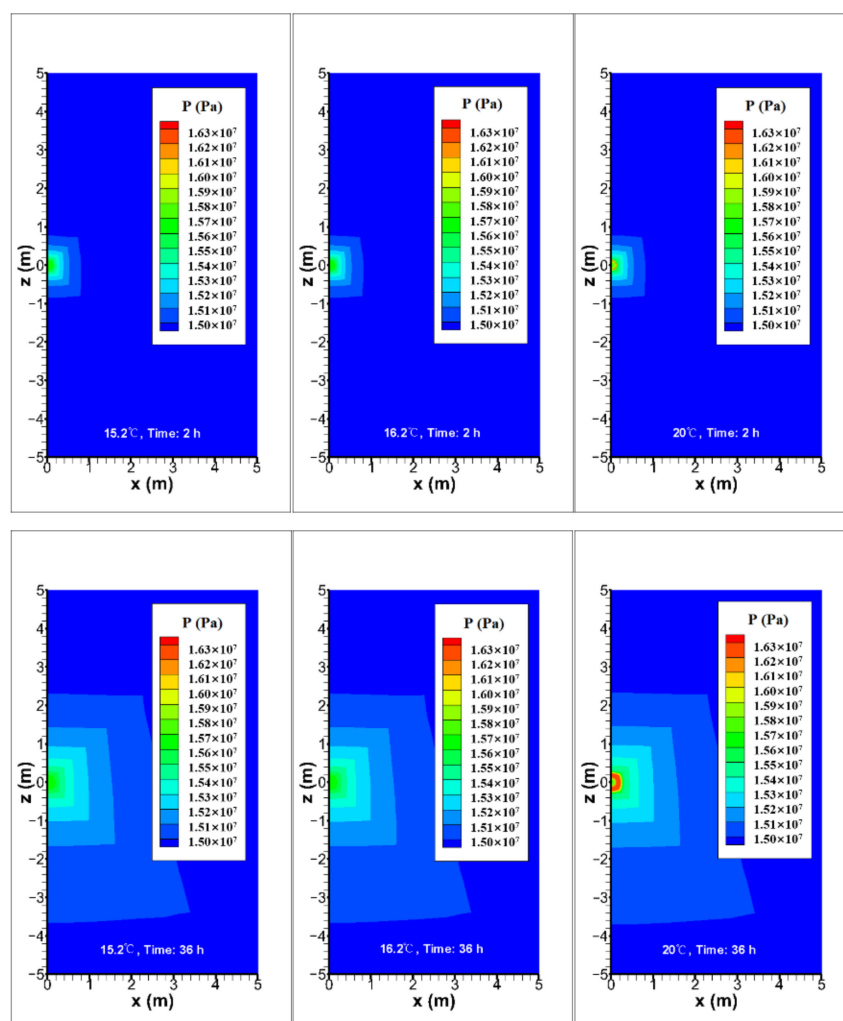


Figure 6. Pore pressure distribution evolution of the near-wellbore reservoir with different temperatures of drilling fluids.

The evolution of hydrate saturation distribution in the near-wellbore zone with rising temperatures of drilling fluid is shown in Figure 7. Apparently, in the initial stage of invasion, the drilling fluid slightly increasing temperature (1°C) brings in no major change in the NGH decomposition of the near-wellbore reservoir. However, when the wellbore temperature rises greatly (by 4.8°C), the hydrate decomposition rate is significantly improved. In the following stage of invasion, a minor increase of the drilling fluid temperature does not show notable impact on the saturation distribution, while the notable NGH decomposition is found in the area of $r = 0.18$ m. Besides, severe saturation reduction was found in the area of $r = 0.22$ m when the temperature of drilling fluid rising to 20°C . As a consequence, the wellbore instability is further aggravated.

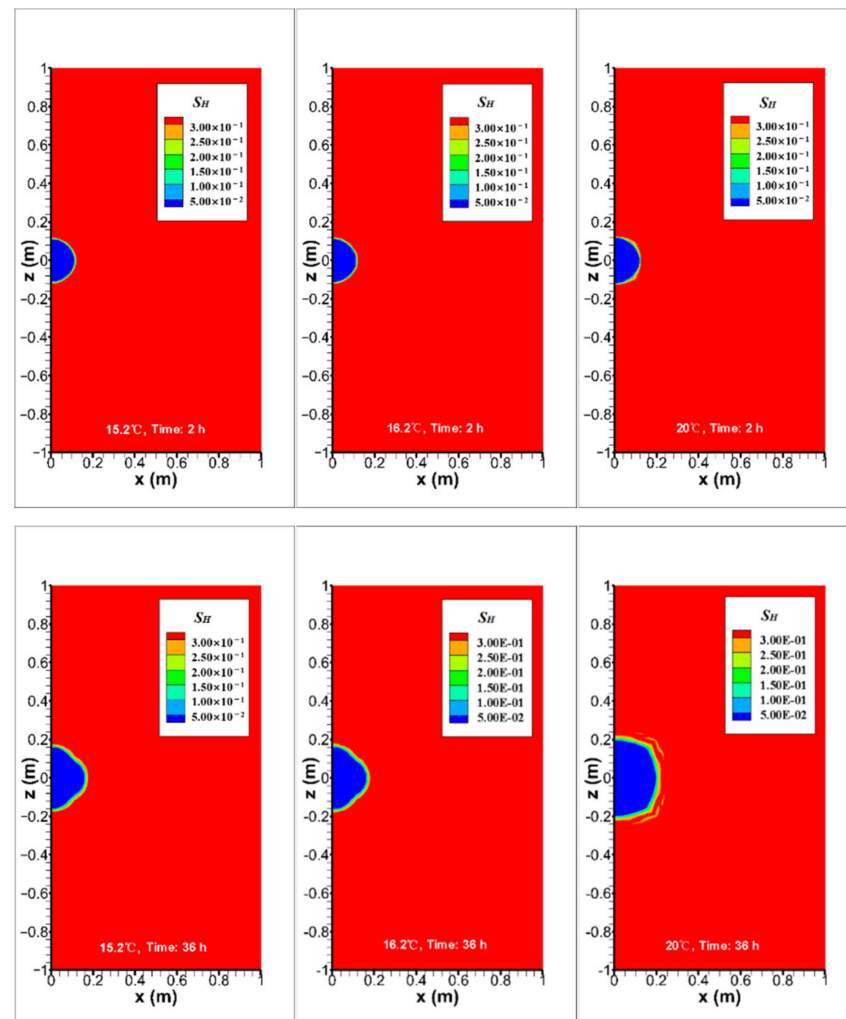


Figure 7. NGH saturation distribution evolution of the near-wellbore reservoir with different temperatures of drilling fluids.

4.2. The Influence of Drilling Fluid Density

The evolution of pore pressure distribution near-wellbore under the variable drilling fluid density is shown in Figure 8. In overbalance drilling, the decrease of fluid density can effectively reduce pressure transfer (a sharp drop of the pore pressure of the near-wellbore reservoir), limiting the invaded zone, and thus maintains the wellbore stability. On the contrary, if the fluid density increases, the pore pressure of near-wellbore zone tends to grow, and the effective stress will drop remarkably. By comparing the evolution of pore pressure under the varied drilling fluid density, it is shown that at the initial stage of low-density drilling fluid invasion, the pore pressure variation reaches a radial depth of about 0.6 m, while it reaches about 0.9 m in the case of invasion by high-density drilling fluid. The difference of the affected depth is about 0.3 m at the initial stage. At the following stage of invasion, the difference grows to 1.2 m.

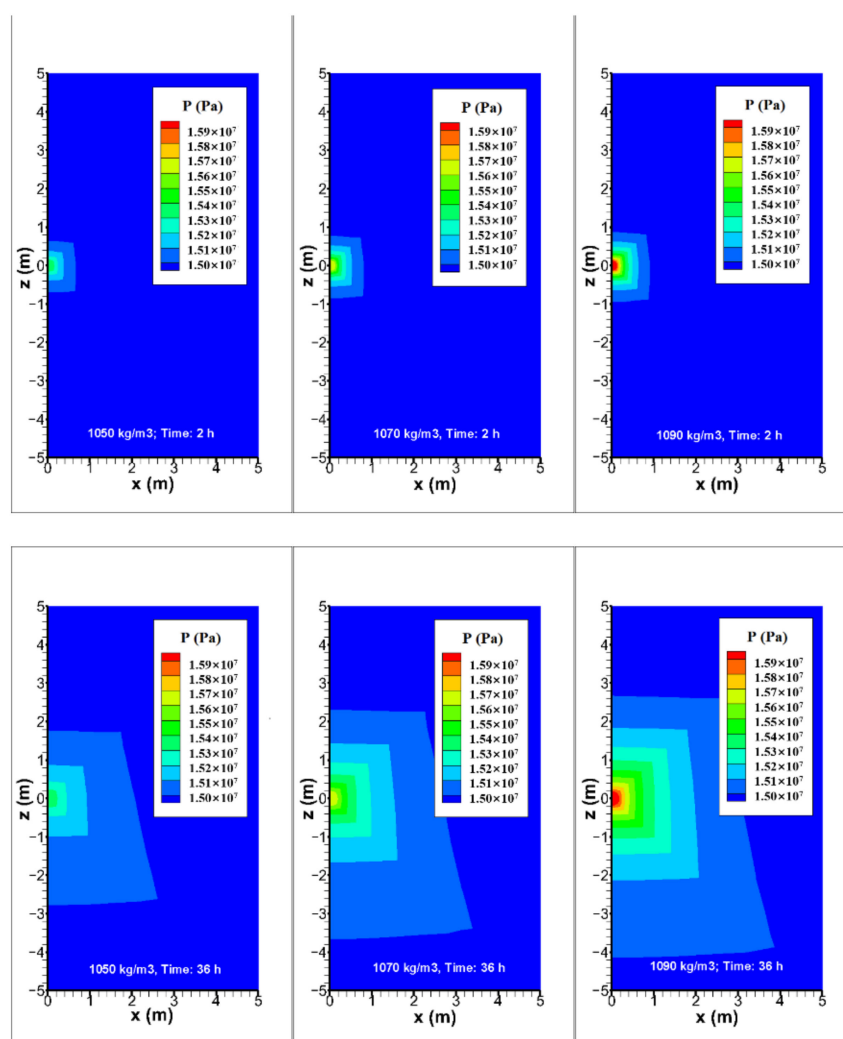


Figure 8. The pore pressure distribution evolution of the near-wellbore reservoir with the different drilling fluid densities.

The evolution of NGH saturation in near-wellbore zone with different drilling fluid densities is shown in Figure 9 (the predicted results do not reveal free gas, and the gas produced by NGH decomposition dissolves in the formation water). Although the variation of drilling fluid density has major impacts on the pore pressure of the near-wellbore zone, it has limited effects on the NGH saturation. At the initial stage of invasion, the radius of NGH decomposition induced by low-density drilling fluids is slightly smaller than that of high-density fluids. At the later stage of invasion, the radius of NGH decomposition have minor differences in regardless of drilling fluid density. Provided that the mud-cake doesn't form on the borehole wall, an insignificant decrease of the drilling fluid density is beneficial to alleviate the decline of effective stress, NGH decomposition, and contribute the wellbore stability [61,62]. On the contrary, a slight increase of the density may intensify the drilling fluid invasion while may also expand the radius of NGH decomposition, which is unfavorable for wellbore stability.

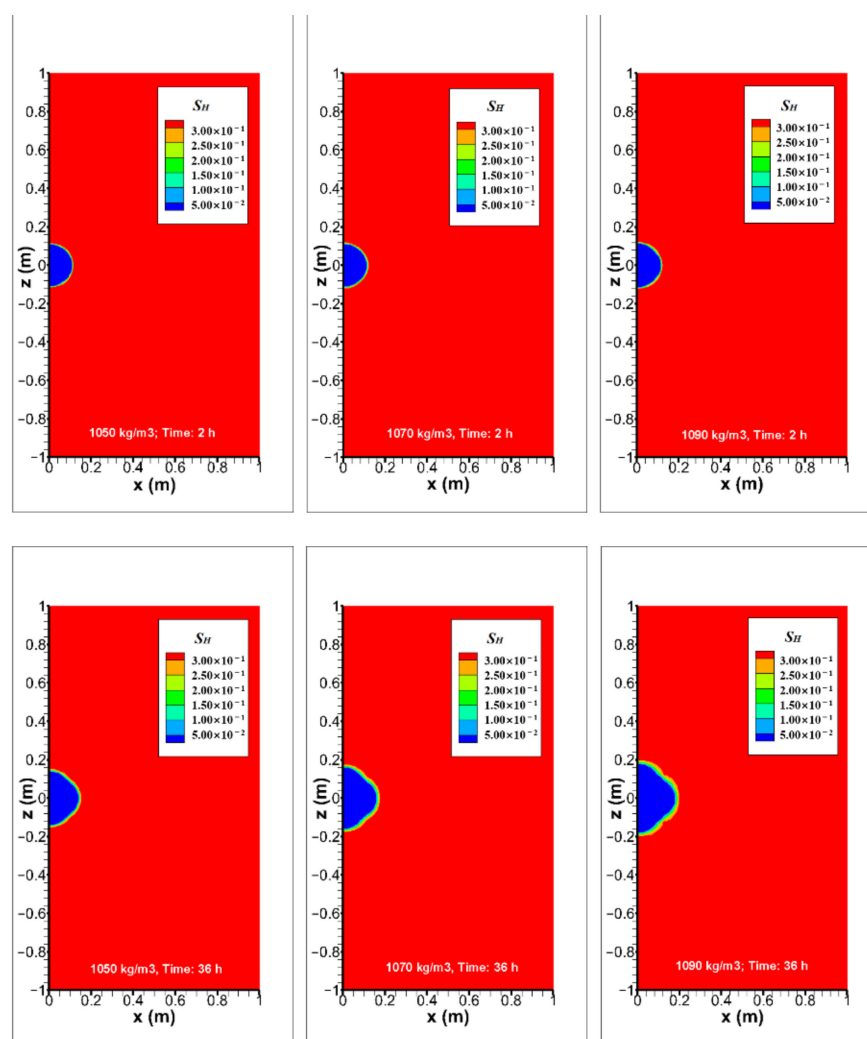


Figure 9. The NGH saturation distribution evolution of the near-wellbore reservoir with the different drilling fluid densities (without free gas).

4.3. The Influence of Drilling Fluid Salinity

The distributions of the pore pressure and NGH saturation with the gradually increasing drilling fluid salinity are illustrated in Figure 10. It is shown that a minor increase in the drilling fluid salinity has limited impacts on the NGH decomposition, while free gas is not found. Therefore, it also presents a limited influence on the distribution of pore pressure. However, the NGH decomposition around the wellbore greatly accelerates with further increase of salinity, which results in a significant increase of the local pore pressure and correspondingly a sharp decrease of the effective stress of near-wellbore reservoir. Moreover, with the significant rise of salinity, the scope of NGH decomposition expands due to drilling fluid invasion. Under such circumstances, the mechanics of the near-wellbore reservoir may deteriorate due to the intensified NGH decomposition. Furthermore, this deterioration propagates along the radial direction, impairing wellbore instability. Accordingly, the substantial increase of drilling fluid salinity is detrimental to the wellbore stability of horizontal wells in the oceanic NGH-bearing sediments.

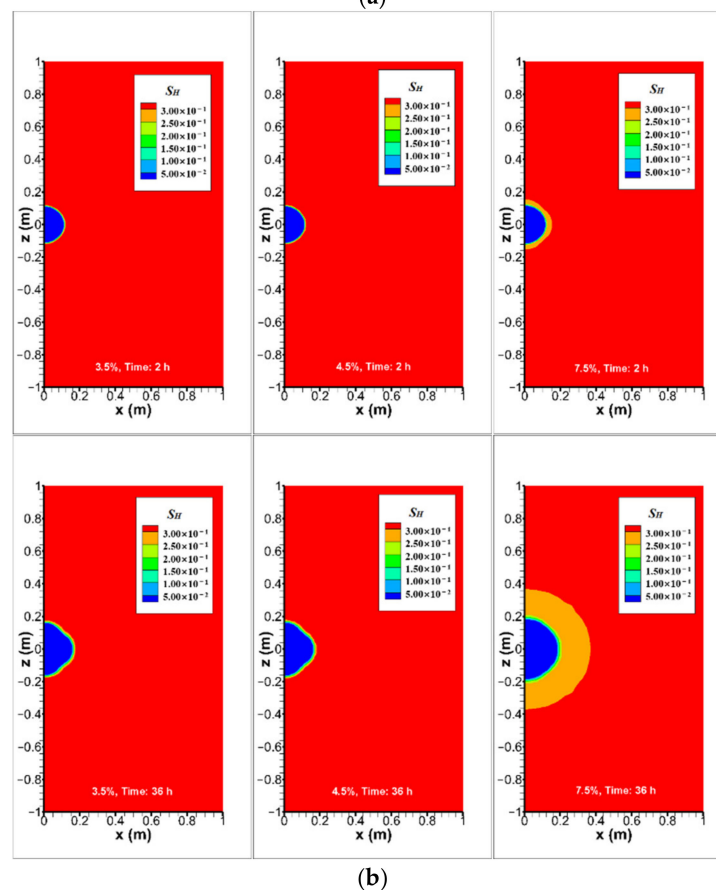
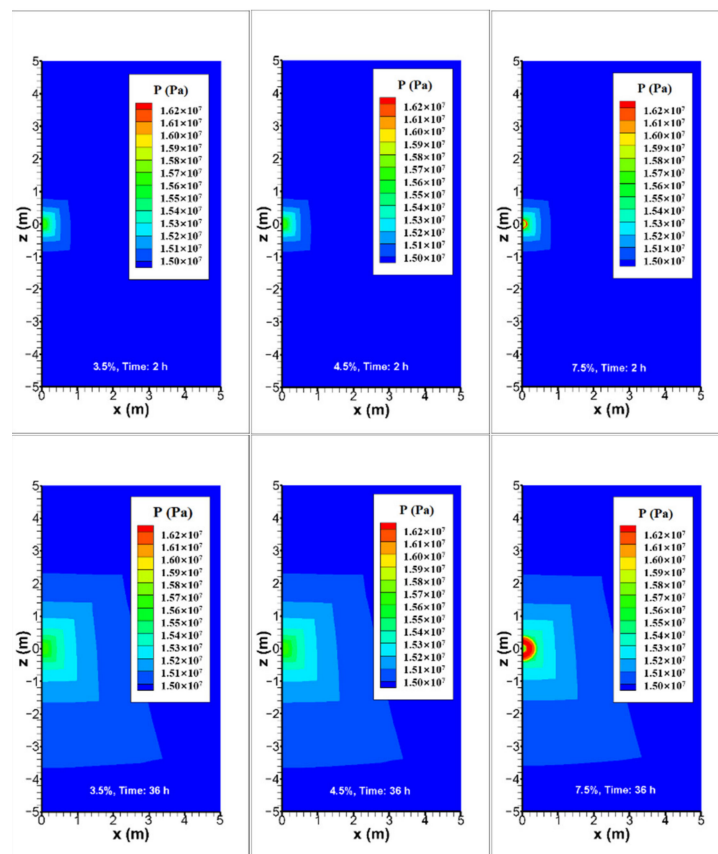


Figure 10. The Pore pressure and NGH saturation distribution evolution of the near-wellbore. (a). Pore pressure distribution around the wellbore; (b) NGH saturation distribution around the wellbore.

5. Conclusions

Based on the NGH formation data in the South China Sea, this paper investigates the invasion characteristics of drilling fluid under the drilling conditions of horizontal wells, revealing the response behavior of reservoirs under different temperatures, densities, and salinities. The main conclusions are presented as follows:

(1) The near-wellbore NGH is highly sensitive to the temperature variation of drilling fluids. If the drilling fluid temperature is too high, it is highly likely to trigger NGH decomposition which will aggravate the wellbore instability of the horizontal wells. A critical temperature exists for the influence of the drilling fluid temperature on the wellbore stability of horizontal wells. When the temperature is lower than this critical temperature, the wellbore instability can be controlled within a certain range. When the temperature is above the critical temperature, NGH decomposition is greatly accelerated, and the wellbore instability is aggravated. Therefore, the circulating temperature of drilling fluids shall be elaborately regulated.

(2) When the density of drilling fluids varies within a certain range, the volume of drilling fluids invaded into the reservoir also changes, due to the variation of the hydraulic pressure difference between the wellbore and reservoir. Moreover, the convection heat transfer around the wellbore is also affected. Given that wellbore instability results from NGH decomposition, a minor decrease of drilling fluid density contributes to the alleviation of the reduction of effective stress and NGH decomposition of the near-wellbore reservoir, which is beneficial to wellbore stability in overbalanced drilling. On the contrary, the increase of density will exacerbate the invasion of drilling fluid, expanding the hydrate decomposition range, which has a negative impact on the stability of the wellbore wall.

(3) The salinity variation of drilling fluids has a direct influence on the phase equilibrium of the NGH reservoir. When the salinity varies in the range of 3.5–7.5%, NGH decomposition accelerates with the rise of ion concentration, but it is not linear. Therefore, in the drilling process, under the premise that the secondary hydrate in the wellbore is inhibited, the salinity of drilling fluids shall be reduced to the minimum extent or low-permeability mud-cakes shall be formed as quickly as possible to avoid NGH decomposition. Hence, a massive invasion of drilling fluids and severe accidents such as wellbore collapse can be prevented.

Author Contributions: All authors contributed to publishing this paper. Q.W., R.W. and J.S. (Jinsheng Sun), conceived and designed the experiments. J.S. (Jiaxin Sun), R.W. and J.W. (Jianlong Wang), performed the experiments and wrote the paper. Q.W., J.Y. and C.L., prepared the experiments and analyzed the data. J.W. (Jintang Wang), Y.Q. and K.L., modified the content and format of the article. All authors have read and agreed to the published version of the manuscript.

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