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Research on evaluation method of wellbore hydrate blocking degree during deepwater gas well testing

Wenyuan Liu[a,b,d], Jinqiu Hu[a,b,d,*], Xiangfang Li[c,d], Fengrui Sun[c,d], Zheng Sun[c,d], Yunjian Zhou[b,d]

[a] College of Mechanical and Transportation Engineering, China University of Petroleum - Beijing, 102249, Beijing, PR China
[b] State Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum, 102249, Beijing, PR China
[c] College of Petroleum Engineering, China University of Petroleum - Beijing, 102249, Beijing, PR China
[d] China University of Petroleum,Beijing, 102249, Beijing, PR China

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ABSTRACT

Although considerable advances have been achieved in recent years, there is still a long way to go for hydrate prediction and prevention during deepwater gas well testing. Well hydrate blockage is a time-dependent continuous process, and evaluation of wellbore blockage is critical for hydrates prevention and control. In this work, the authors presented a novel wellbore blocking degree evaluation model for deepwater gas-well testing. Firstly, a new evaluation model consisting of mass, momentum and energy balance equations considering hydrates formation was proposed. Secondly, considering hydrate phase equilibrium, the finite difference method and iterative technique were used to obtain the model results. Finally, the model was applied to the deepwater gas wells in the South Sea of China for verification and was subjected to sensitivity analysis. The predicted results were in good agreement with field test results. According to the sensitivity analysis, gas output, methanol concentrations, water production rate have different degrees of influence on hydrate blocking. The length of the hydrate stability region (HSR), the position of largest plugging point, and the distribution of wellbore inner diameter are the key to hydrate prevention and control. Meantime, combining the model evaluation results, optimizing the testing process can achieve the purpose of preventing-controlling gas hydrates economically and effectively.

1. Introduction

At present, the hydrate generation and pipeline blockage during deepwater gas wells testing are major problems affecting safety testing (Arrieta et al., 2011; Reyna and Stewart, 2001). During the flow testing, the fluid temperature and pressure will change significantly, often causing complex gas-liquid-solid three phase flow in the pipeline with hydrates formation (Sloan, 2007; Zhao et al., 2016). The large amount of hydrate will block the flow channel directly, and the actual test results will not be obtained. Even, the ultra-high pressure will cause the pipe string rupture, resulting in test failure (Chaudhari, 2016; Trummer et al., 2013). Researchers have done a lot of work to prevent hydrate accidents. In terms of on-site construction, persons have changed the two-open and two-off test process to one-open and one-off test process for reducing the hydrate production by open-close wells. Persons switched the ground shut-well to the underground shut-well mode, which cuts off the gas and water supply in the wellbore and reduces the hydrate blockage risk at the shut-well stage. In addition, the hydrate inhibitors injection is still the main measure for controlling hydrates, and it often requires a lot of inhibitor injection during testing process (Fu et al., 2002; Xin et al., 2015).

Now, researchers have done a lot of basic research on hydrates formation, and they all agree that the hydrates formation is a crystallization process in which the medium changes from fluid to solid. Hydrate formation is mainly divided into two processes: nucleation and growth. Early in 1980s, Vysniauskas and Bishnoi (1985) had already begun experiments on methane and ethane hydrate formation in semi-batch stirred reactors and established semi-empirical formula. Later, Englezos et al. (1987) improved the V−B experimental apparatus, remeasured the kinetic data of methane and ethane hydrates, and established a representative hydrate growth intrinsic kinetics model based on crystallography and gas-liquid interface mass transfer theory. Subsequently, Yapa et al. (2001) simulated the hydrate growth of methane bubbles in deepwater during the ascent process based on Englezos's model (1987). Then, Al-Otaibi et al. (2010) took experimentally measured hydrate particle size data into the Englezos's model (1987),

* Corresponding author. College of Mechanical and Transportation Engineering, China University of Petroleum - Beijing, 102249, Beijing, PR China.
E-mail addresses: hjqcup@qq.com, CUPB_SSE666@163.com (J. Hu).

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removed three differential equations for calculating the particle size distribution, and improved the accuracy of the methane and ethane's intrinsic rate constants. For Englezos's model (1987), the hydrate growth rate is not limited by the transfer rate of gas molecules in liquid phase. Skovborg and Rasmussen (1994) assumed that there are no secondary nucleation and differences in hydrate particles size in system and proposed a mass transfer-based hydrate growth kinetic model. Zerpa (2013) verified that the S-R model (1994) fits well with the experiment when simulating gas-water pipelines, and added the model to multiphase flow simulation software OLGA. He also pointed out that the key to using this model is to determine the gas concentration in liquid phase, mass transfer coefficient and gas-liquid interface area. Different from the intrinsic kinetic model, based on the classical nucleation theory and crystal growth principle, Kashchiev and Firoozabadi (2003) established expressions of nucleation rate and crystal growth rate for single-component gas hydrates, and he linked the rate of natural gas consumption to hydrate formation and growth. Later, based on K—F expressions (2003), Sarshar et al. (2010) established a mathematical model to calculate the growth rate of multi-component gas hydrates in pipelines, and experiments have shown that the average error for hydrate prediction is less than 10%. In addition, Meindinyo et al. (2015), Mochizuki and Mori (2006), Freer et al. (2001) studied the exothermic and heat transfer characteristics for hydrate formation, and established a hydrate growth kinetics model based on heat transfer. The above researchers have made significant contributions to the study of hydrate formation models.

There are also many studies on hydrates formation and blocking in pipelines. Based on Sloan et al. (2010)'s research, according to the different flowing media composition, gas-liquid-solid multiphase flow systems with hydrate formation are generally divided into oil-dominated system, water-dominated system, and gas-dominated system. Initial hydrate formation-deposition research focused on oil-based flow systems, Aman et al. (2011), Anklam et al. (2008), Mcculfor et al. (2011), Camargo and Palermo (2002), Colombel et al. (2009) had explained the hydrates formation and hydrate particles accumulation mechanism in oil-based pipeline. For water-dominated flow systems, Joshi et al. (2013) had performed high-pressure loop experiments, and obtained the hydrate formation, flow, and plugging regulations under methane-water pipeline flow system. Then, based on Joshi et al.'s experiment (2013), Zerpa (2013), Sakurai et al. (2014), Balakin et al. (2010) studied the hydrates formation and deposition regulations under different gas-water flow conditions. For the gas-dominated flow system, Rao et al. (2013) studied the deposition process of the saturated water-containing methane system, and pointed out that the research on hydrates distribution in pipe wall and fluid is very important for calculating the frictional pressure drop in the multiphase flow system. Afterwards, Jassim et al. (2010) established a model describing the law of hydrate particle deposition. Sonne and Pedersen (2009) simulated a condensate-gas transportation system with a water content of 40% and believed that the feasibility of gas hydrate transmission depends on the hydrates amount, liquid holdup and liquid phase shear rate. Di Lorenzo et al. (2014a, 2014b) used a circulation line to study a gas-liquid annular flow system with a 6% water content and found that an increase in hydrates volume fraction will increase the pipe pressure drop significantly, and hydrate-particles deposition also have a significant influence on pipeline pressure drop. Then, they performed a hydrate formation experiment in a horizontal gas-dominant flowloop again, and obtained the pressure drop and hydrate formation characteristics. Based on Di Lorenzo experiment (2014a, 2014b), Zhiyuan Wang et al. (2017) established a hydrate generation model under horizontal annular flow, emphasizing that both the liquid film and the entrained droplets in the gas phase play an important role in the hydrates formation. The above research makes people further understand the hydrate growth and deposition rule in pipelines.

For the hydrate research during deepwater gas well testing, on the one hand, it is necessary to study the hydrates formation conditions. On the other hand, we must combine the deepwater test conditions to obtain the pipeline plugging characteristics. Wang et al. (2008, 2009) first studied wellbore hydrate formation region in deepwater drilling and Wang et al. (2014) also predicted the hydrate formation zone during deepwater gas well testing, and analyzed gas output, gas components, geothermal gradient, water depth, inhibitors content, and throttle's effects on hydrate formation region. Then Wang et al. (2018) analyzed the hydrate flow assurance in the wellbore, but the research under different test conditions is still insufficient. However, the influence of hydrate formation-deposition on gas wells test safety is still not enough at present.

In summary, most of the current hydrate prevent and control measure for gas wells testing is to avoid the hydrates formation in the pipeline completely, which will greatly increase the complexity of the construction process and the inhibitors usage. However, pipeline hydrate blockage is a time-dependent process and it is not reasonable to determine the flow risk only according to whether hydrate is generated. So, it is necessary to quantify the pipeline blockage degree during deepwater gas well testing and propose specific hydrate control measures.

2. Wellbore blockage assessment model

During deep-water gas well testing, the hydrate formation within column is a continuous process of hydrate formation-growth-sedimentation-blockage. Hydrates continuously generated and thickened on the inner wall of column during testing, as shown in Fig. 1. Therefore, to evaluate the wellbore blockage during testing, in addition to considering the hydrate formation condition, the hydrate thickening process on the pipe wall must also be taken into consideration.

2.1. General assumptions

Combined the heat transfer theories in different well depth section and the hydrate formation-deposition characteristics in wellbore, some basic assumptions are made as follows:

(1) The gas flow in the wellbore is a one-dimensional steady flow.
(2) In the wellbore, the heat transfer direction is radial and heat transfer in the vertical direction is ignored.
(3) For a small time segment, the heat loss rate from fluid to outside wall of the wellbore is assumed to be steady state. The heat transfer

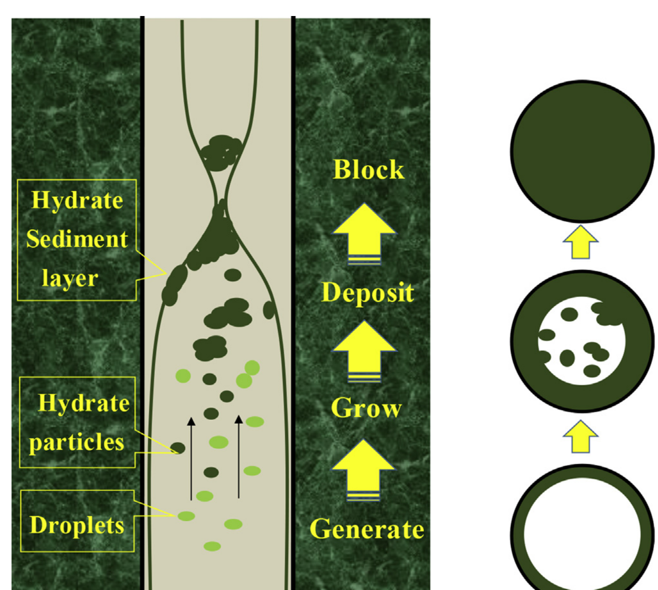

Fig. 1. Hydrate generate -growth-deposition-blockage diagram.