Quantitative hydrate deposition prediction method and application in deep-water or permafrost gas pipelines

Yu Jing 1,*, Hui Cheng 2, Lubing Zhuo 1, Wenchao Sun 1, Liu li 1, Chang long 1, Zhiyuan Wang 3

1 CNPC Engineering Technology R&D Company Limited, Beijing, China
2 China University of Petroleum (Beijing), Beijing, China
3 China University of Petroleum (East China), Qingdao, China

*Corresponding author e-mail: yujingdr@cnpc.com.cn

Abstract. Hydrate formation in pipelines seriously affects the efficiency of energy transmission. Adopting the production process of gas pipelines in deep-water or permafrost regions as the engineering application background, hydrate formation and deposition characteristics at different locations in gas pipelines are analyzed to realize the quantitative prediction of high-risk areas and degree of hydrate plugging in pipelines. A typical deep-water gas pipeline in the South China Sea is selected as an example. The calculation results show that the long-distance pipeline exhibits an obvious hydrate blockage risk area, which occurs 700-3200 m away from the pipeline inlet. The high-risk area of hydrate plugging in the system moves upstream of the pipeline with decreasing ambient temperature. The risk of hydrate blockage increases with decreasing pipeline inner diameter. The established quantitative prediction method for hydrate deposition in deep-water or permafrost gas pipelines accurately locates high-risk areas of hydrate plugging, which could effectively guide hydrate prevention and notably reduce the cost of hydrate control in deep-water or permafrost gas pipelines.

1. Introduction

Long-distance pipelines are one of the main ways to transport oil and gas resources in deep-water or permafrost regions. However, the harsh low-temperature environment results in severe challenges in the exploitation and export of hydrocarbon energy in deep-water or alpine permafrost regions [1-3]. Once hydrate blockage accidents occur during the development of hydrocarbon energy, they seriously affect the efficiency and safety of energy transmission and even cause very high economic losses [4-8]. Previous studies on hydrate formation/deposition mechanisms in gas phase-dominated systems have mostly focused on systems with a small amount of free liquid phase. Dissolved water conditions under gas-phase dominance are not considered in current studies, which are the main working conditions in deep-water or permafrost gas pipelines[9-13]. Rao et al. [14, 15] and Nicholas et al. [16] proposed a hydrate deposition model for a dissolved water system based on the wax deposition theory. The average error between their model calculation results and experimental data was 67.98% without considering system pressure drop calculation results affected by hydrate particles.

In this study, based on the analysis of hydrate blockage under different working conditions, a method was established to predict hydrate deposition in deep-water or permafrost gas pipelines. The research
results in this article provide references for hydrate prevention, early blockage monitoring and plugging removal operations in field operations.

2. Quantitative prediction method of hydrate deposition plugging

This paper proposes a method to determine hydrate blockage risk areas and deposition rate in deep-water or permafrost gas pipelines. The proposed method can be applied to predict the location and degree of hydrate flow obstacles in pipelines. The results of this study provide a reference for on-site hydrate prevention and control measures.

2.1. Dynamic calculation of temperature and pressure distribution in pipeline

There exists a dynamic coupling relationship between the heat release of hydrate formation and the thermal insulation effect of the hydrate layer in deep-water or permafrost gas pipelines [17, 18]. Moreover, the velocity and pressure drop in the system constantly change with hydrate deposition [18, 19]. Based on the interaction between the heat transfer process in the system and hydrate deposition behavior, a fluid temperature gradient equation is proposed to determine the temperature distribution in a pipeline [20].

\[
\frac{dT_g}{ds} = -\frac{q}{w_m C_p} - \frac{1}{C_p} \left( -g \sin \theta + U_g \frac{dU_g}{ds} \right)
\]  

(1)

where \( w_m \) is mass flow rate of fluid kg/s, \( C_p \) is specific heat capacity of fluid, J/(kg·K), \( T_g \) is system temperature, K, \( s \) is the distance from the pipe inlet, m, \( \mu_j \) is Joule-Thomson coefficient, K/Mpa, \( p \) is system pressure, Pa, \( U_g \) is fluid velocity, m/s, \( g \) is gravitational acceleration, m/s², \( q \) is heat transfer rate, W/m.

According to the influence of the hydrate layer, flow area and wall roughness on the pressure distribution, a calculation method of the hydrate deposition plugging in the system is proposed [20].

\[
\frac{\partial}{\partial t} (ApU_g^2) + \frac{\partial}{\partial s} (ApU_g^2) + \frac{dp}{ds} + 32f_f \frac{w_m^2}{\rho \pi^2 D_i} = 0
\]  

(2)

where \( A \) is effective cross-sectional area of the pipeline, m², \( \rho \) is density of the fluid in the system, kg/m³, \( D_i \) is pipe inner diameter, m, \( f_f \) is Fanning friction coefficient, which can be calculated by using the explicit Colebrook white correlation [12].

2.2. Quantitative prediction of hydrate blockage in pipelines

In the production process of deep-water or permafrost gas pipelines, the saturated water content of fluid varies with the system temperature and pressure. When supersaturated steam in the main flow region diffuses to the cold wall with a relatively low temperature, liquid water condenses on the wall [15, 21]. Liquid water condenses into droplets on the surface of insoluble particles in the gas core region [22-24]. Therefore, in the dissolved water system dominated by the gas phase, free water mainly originates from two sources, namely, the liquid film near the cold wall and the small droplets in the gas phase.

Natural gas molecules continuously diffuse to the surface of droplets in the gas core region through diffusion and grow into hydrate particles when the system temperature and pressure meet the hydrate formation conditions [25, 26-28]. Moreover, natural gas molecules continuously diffuse to the surface of the condensate film on the cold wall and combine with water to form a hydrate layer [27].

According to the amount of condensate, the hydrate formation rate per control unit (ds) is calculated [29].

\[
\frac{dm_f}{dt} = \alpha \frac{\pi r_f^2 \Delta W_T ds}{ds / U_g}
\]  

(3)

where \( dm_f \) is overall hydrate formation in control volume in unit time, kg, \( \Delta W_T \) is difference between control volume inlet and outlet saturated water contents, kg/m³, \( \alpha \) is ratio of hydrate relative molecular mass versus molar mass of water molecule in hydrate molecule.
(1) Hydrate deposition in liquid film

Previous micromechanical experiments have demonstrated that the hydrate layer formed on the pipe wall tends to be directly deposited when the pipe wall is wetted by free water [14, 30]. Therefore, it is considered that the hydrate deposition rate in the condensate film on the pipe wall equals its formation rate [15].

$$\frac{dm_{hl}}{dt} = \alpha \cdot 2\pi r_h \Delta W_f ds$$  \hfill (4)

where $dm_{hl}$ is mass of the formed hydrate from liquid film in a control volume, kg, $h_m$ is mass transfer coefficient, m/s, $\Delta W_f$ is difference between control volume inlet and outlet saturated water contents, kg/m$^3$.

(2) Hydrate deposition in droplets

The heterogeneous nucleation process on the surface of small insoluble particles is greatly affected by the diameter and surface properties of the particles, which are difficult to obtain. Therefore, it is assumed that liquid water condenses and precipitates on the particle surface when the system temperature and pressure distributions reach the conditions of liquid-phase condensation [27, 28]. The formation rate of hydrate particles per control unit is calculated with Eq. 5 [29].

$$\frac{dm_{lp}}{dt} = \frac{dm_{fl}}{dt} - \frac{dm_{ld}}{dt}$$  \hfill (5)

where $dm_{lp}$ is hydrate particle formation in control volume gas core, kg.

Under the influence of various factors, such as high-speed flow, turbulence disturbance and gravity deposition, hydrate particles exhibit a partial velocity to the wall and are finally deposited on the wall. Because the wall is always wetted by a liquid film, it is considered that the deposited hydrate particles are attached to the pipe wall [29]. Therefore, the deposition rate of hydrate particles per control unit can be modified, as expressed in Eq. 6 [29].

$$\frac{dm_{gd}}{dt} = \frac{dm_{lp}}{dt} - \frac{dm_{ld}^{r}}{dt}$$  \hfill (6)

where $dm_{gd}$ is hydrate particle deposition in control volume gas core, kg, $V_d$ is radial velocity of hydrate particles in pipelines [30], m/s

In summary, the total hydrate deposition rate in deep-water or permafrost gas pipelines is Eq. 7.

$$R_t = \frac{dm_{ld}}{dt} + \frac{dm_{pl}}{dt}$$  \hfill (7)

where $R_t$ is overall deposition rate of hydrate, kg/s.

In conclusion, Eq. 10 can be employed to determine the total deposition rate of hydrate in deep-water or permafrost gas pipelines [29].

2.3. Hydrate layer growth

The growth process of the hydrate layer is influenced by hydrate deposition in the condensate film and dispersed droplets. Considering the influence of the hydrate layer porosity, it is assumed that the deposited hydrate layer per control unit grows uniformly. Collapse and exfoliation after hydrate deposition are neglected. The initial conditions are $t=0$ and $r=e=r$. The effective pipe diameter can be expressed with Eq. 8 as hydrate deposition continues [29].

$$R_d = \frac{d}{dt} \left[ \pi \left( r_d^2 - r_{d,i}^2 \right) (1 - K_d) \rho_h ds \right]$$  \hfill (8)

where $K_d$ is porosity of hydrate layer, $\rho_h$ is density of gas hydrate, kg/m$^3$.

The thickness of hydrate deposited at different time can be calculated with Eq.9 [29].
\[ \delta_j = r_w - r_{ej} \]  

where \( \delta \) is thickness of hydrate layer, m.

The experimental parameters of Rao et al. [31] are substituted into the model, and the calculated results are in good agreement with the experimental data, while the average relative error is 7.17%.

3. Method application and discussion

3.1. Basic parameters of the case

The proposed quantitative prediction method of hydrate deposition is applied to the gas pipeline of the X-2 well in the South China Sea to analyze the formation mechanism and evolution law of hydrate flow barriers in a deep-water or permafrost gas pipeline. The total length of the pipeline is 7.6 km. The fluid in the example is natural gas with methane content of 91.67%. Please refer to Table 1 for the other basic parameters.

| Parameter                      | Unit    | Value | Parameter                      | Unit    | Value   |
|--------------------------------|---------|-------|--------------------------------|---------|---------|
| Water depth                    | m       | 1500  | Thermal conductivity of steel  | W·m⁻¹·K⁻¹ | 43.2    |
| Gas production rate            | \( \times 10^4 \) (Nm⁻³·a⁻¹) | 120   | Relative density of natural gas | /       | 0.629   |
| Inlet temperature              | °C      | 29.5  | Thermal conductivity of seawater | W·m⁻¹·K⁻¹ | 1.73    |
| Inlet pressure                 | MPa     | 7.5   | Specific heat capacity of seawater | J·kg⁻¹·K⁻¹ | 3890   |
| Sea surface temperature        | °C      | 23    | Roughness of pipe wall         | mm      | 0.046   |
| Nominal diameter of the pipeline | mm      | 558.8 | Types of hydrate               | /       | II      |
| Wall thickness                 | mm      | 25.4  | Density of hydrate             | kg·m⁻³  | 900     |

3.2. Prediction of the hydrate formation area in pipelines

The components of the produced fluid in the pipeline are substituted into the calculation model to determine the hydrate-phase equilibrium conditions (Fig. 1, solid blue line). The calculation results combined with the hydrate thermodynamic phase equilibrium curve determine the hydrate formation region in the system.

In Fig. 1, the shaded area indicates the hydrate formation area, which is observed in the gas pipeline at a distance of 150 m from the inlet. Large areas occur in gas pipelines in deep-water or alpine permafrost zones that satisfy the conditions of hydrate formation. If only the traditional method of the excessive injection of an inhibitor to prevent hydrate formation is adopted, the operation cost and difficulty greatly increase. Therefore, it is necessary to further analyze the hydrate deposition and plugging behaviors in the hydrate formation area.

3.3. Quantitative prediction of hydrate blockage in pipelines

In this paper, deep-water gas well X-2 in the South China Sea is adopted as an example to analyze the distribution characteristics of the hydrate deposition thickness along the pipeline. Fig. 2 shows that the
inner diameter of the pipeline changes with hydrate deposition, and hydrates are notably unevenly
distributed along the pipeline. The simulation results indicate that there are obvious hydrate-blocking
high-risk areas in the system with increasing production time. The high-risk area of hydrate blockage
under the considered case conditions occurs 700-3200 m away from the pipeline inlet.

3.4. Influence of different production conditions on the hydrate deposition rate

3.4.1. Influence of the flow rate on hydrate blockage. The effect of different flow rates on hydrate
deposition in the pipeline is shown in Fig. 3. The hydrate deposition rate at different positions in the
pipeline increases with increasing fluid flow in the system. With increasing fluid flow in the system,
more water vapor is transported into the deep-water gas pipeline system, and the free water-cooling
condensation rate increases. In addition, the high-risk area of hydrate blockage in the pipeline moves
downstream of the pipeline with increasing fluid flow in the system. With increasing fluid flow in the
system, the fluid velocity in the pipe increases, the heat transfer between the system fluid and low-
temperature seawater outside the pipe becomes insufficient, the temperature drop rate decreases, and the
hydrate generation area moves downstream of the pipeline.

3.4.2. Influence of the ambient temperature on hydrate blockage. Previous studies have pointed out that
the seawater temperature in regard to pipes below 1500 m decreases with increasing water depth [29].
As shown in Fig. 4, the hydrate deposition rate in the gas pipeline at different ambient temperatures is
analyzed as a function of the water depth.
The hydrate blockage high-risk area in the deep-water gas pipeline gradually moves upstream of the pipeline with increasing water depth. The seawater temperature outside the pipeline obviously decreases with increasing water depth, which leads to an increase in the temperature difference between the high-temperature fluid inside the pipeline and the low-temperature seawater environment [29]. As a result, heat exchange intensifies, resulting in an increase in the temperature drop in the fluid in the system, which in turn causes the hydrate formation area to move upstream of the pipeline.

3.4.3. Influence of the pipeline size on hydrate blockage. As shown in Fig. 5, based on simulation of hydrate deposition on the inner wall of gas transmission pipeline systems of different sizes, it is observed that the thickness growth rate of hydrate deposition on the pipe wall accelerates with decreasing inner diameter of the pipeline. For the same production, the smaller the inner diameter of the gas pipeline is, the smaller the total hydrate amount to establish the same thickness of the deposited hydrate layer. Therefore, the smaller the inner diameter of the deep-water gas pipeline, the higher the growth rate of the deposited hydrate layer on the pipe wall and the risk of hydrate blockage are.

4. Conclusion
Based on the production process in deep-water or permafrost gas pipelines, this paper analyzes the formation, migration and deposition mechanisms of hydrates in deep-water or permafrost gas pipelines. A quantitative prediction method for the risk area and degree of hydrate plugging is also proposed. Application of this method in the field of hydrate control is also analyzed.

(1) A quantitative prediction method for hydrate blockage in gas transmission pipelines in deep-water or permafrost regions is proposed, which can be employed to analyze hydrate formation and deposition characteristics at different locations in the deep-water or permafrost gas transmission pipeline.

(2) The quantitative prediction method for hydrate plugging is verified via simulation of a 7.6-km long $120 \times 10^4$ (Nm$^3$ a$^{-1}$) deep-water gas well pipeline in the South China Sea. The calculation results indicate that the hydrate formation area occurs 150-7600 m from the pipeline inlet, the hydrate blockage
high-risk area extends from 700-3200 m, and the maximum thickness of hydrate deposit is 1270 m from the pipeline inlet.

(3) Based on the analysis of the influence of different production conditions on hydrate deposition in deep-water or permafrost gas pipelines, it is observed that the time required to form a hydrate blockage at a relatively high production rate is reduced. The hydrate blockage area moves upstream of the pipeline with decreasing ambient temperature. The smaller the inner diameter of the gas pipeline is, the higher the growth rate of the deposited hydrate layer on the pipe wall.

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