Hydrate predictions on the China-Russia eastern gas pipeline during the pipeline goes into production

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Abstract. The China-Russia eastern gas pipeline has the characteristics of large pipe diameter and high pressure. During the pipeline goes into production, the temperature along the pipeline was low, and the conditions of low temperature and high pressure brought the risk of hydrate formation. Based on the multiphase flow theory and the CSMHyK hydrate growth kinetic model, this paper studied the hydrate formation region, the amount of hydrate formed and the influence of hydrate formation on the temperature drop and pressure drop of the China-Russia eastern gas pipeline in the first winter the pipeline goes into production. The results show that in the first winter the pipeline goes into production when the water content is more than 150 mg/kg the hydrate formation risk exists in the pipeline. Hydrate accumulates mainly in the ascending part of the low-lying pipe section, and the greater the height difference of the pipe section, the more hydrate accumulation. In the stage of mass hydrate formation, the temperature in the pipeline will rise due to hydrate formation, but when hydrate growth reaches equilibrium, the temperature in the pipeline is mainly controlled by the external soil temperature. In addition, a large amount of hydrate accumulation will generate a throttling effect, which will lead to increased temperature drop and pressure drop of the pipeline. When the water content is 350 mg/kg, the maximum additional pressure drop generated by hydrate aggregation is 2.27MPa.

1. Introduction

The China-Russia eastern gas pipeline is China's first large-volume, long-distance, high-pressure gas transmission pipeline using an ultra-large diameter of 1422 mm [1-2]. In the first two years of pipeline put into operation, only the northern section of the pipeline (Heihe-Changling) was put into operation, and this section of the pipeline is in a cold area, with a minimum temperature of -40 °C in winter. At the initial stage of pipeline production, free water will inevitably exist [3-5], which will bring hydrate formation risk to pipeline operation. Figure 1 shows the schematic diagram of the route.

Scholars at home and abroad have carried out a lot of research on the formation and prevention of gas pipeline hydrates [6-9]. Most of them use the hydrate phase equilibrium theory to predict the formation area, study the deposition mechanism of hydrate particles in the pipeline, but no accurate prediction of the amount of hydrate formation and particle aggregation in the pipeline. In order to ensure the safe and efficient operation of the China-Russia eastern gas pipeline at the initial stage of production, based on the OLGA software and CSMHyK hydrate generation kinetic model, we studied...
the hydrate generation status of its northern pipeline, include hydrate generation risk area, hydrate generation quantity, the degree of hydrate accumulation and the effect of hydrate formation on temperature and pressure, so as to provide support for ensuring the stability of the initial production of the China-Russia eastern gas pipeline.

Figure 1. Schematic diagram of the route.

2. Basic data and calculation model

2.1. Basic data

Pipelines of the northern section of the China-Russia eastern gas pipeline include Heihe-Changling Main Line Pipeline and Changling-Changchun Branch Pipeline. Table 1 shows the pipeline parameters and Table 2 shows the gas composition of the China-Russia eastern gas pipeline.

Table 1. Pipeline parameters of the northern section of the China-Russia eastern gas pipeline.

| pipeline          | Length (km) | Design pressure (MPa) | Diameter (mm) | Inner wall roughness (μm) | Total heat transfer coefficient (W·m²·°C⁻¹) |
|-------------------|-------------|-----------------------|---------------|----------------------------|-------------------------------------------|
| Heihe-Changling   | 715         | 12                    | 1422          | 10                         | 1.093                                     |
| Changling-Changchun | 109       | 10                    | 1016          | 30                         | 1.344                                     |

Table 2. Composition of natural gas in the China-Russia eastern gas pipeline(Mole fraction).

| CH₄    | C₂H₆ | C₃H₈  | C₄H₁₀ | C₅H₁₂  | N₂     | CO₂   | He    | H₂    |
|--------|------|-------|-------|--------|--------|-------|-------|-------|
| 91.41% | 4.93%| 0.96% | 0.41% | 0.24%  | 1.63%  | 0.06% | 0.29% | 0.07% |

We simulated the hydrate formation along the northern section of the China-Russia eastern gas pipeline with the winter conditions of the first year. the flow rate is 1489×10⁴ m³/d, the starting pressure is 7.52 MPa, and the gas temperature at the starting point of the pipeline is 15.7 °C. Natural gas water dew point requirements at the China-Russia trade junction: in winter, it is not higher than -20 °C under the pressure of 4 MPa, according to the conversion method in GB/T 22634-2008, convert it The corresponding water content is 40 mg/kg.

Figure 2 shows the elevation changes along the pipeline, the sub-transport volume of each station, and the average ground temperature at the depth of the pipeline between the stations in winter(negative transmission volume means outward distribution, and positive transmission volume means positive gas storage to the pipeline).
2.2. Calculation model
In the case of hydrate formation, the flow in the natural gas pipeline belongs to gas-liquid-solid multiphase flow. Combining the simulation of physical property parameters of each node position in the pipeline transportation of natural gas, the OLGA software can calculate the process parameters under different flow conditions of the pipeline by setting the initial conditions, boundary conditions, and environmental conditions. On this basis, the hydrate growth kinetic model was used to calculate and analyze the hydrate formation rate, amount, and hydrate particle aggregation.

The Colorado School of Mines and the SPT Group of Norway jointly developed the CSMHyK model for the hydrate kinetics of natural gas in pipelines and applied it to the multi-phase flow simulation software OLGA. This model can well describe the generation status of natural gas hydrate in the pipeline, and predict the location of hydrate generation [10-13]. The kinetics model assumes that all the water is dispersed into the continuous oil phase as water droplets of fixed mean diameter. The surface area between water and hydrocarbon phases is calculated using the Hinze correlation [14]. Hydrate nucleation is assumed to occur immediately after a specified subcooling, and the hydrate growth is calculated using the following intrinsic kinetics equation of first order with an adjustable-rate constant:

$$- \frac{dm_{\text{gas}}}{dt} = uk_1 \exp \left( \frac{k_2}{T_{\text{sys}}} \right) A_s \left( \Delta T_{\text{sub}} \right)$$

Where $m_{\text{gas}}$ is the gas mass; $t$ is the hydrate growth time; $k_1$ and $k_2$ are the kinetic rate constants; $T_{\text{sys}}$ is the system temperature; $\Delta T_{\text{sub}}$ is the supercooling; $A_s$ is the surface area for hydrate growth.

In order to match flow loop data, a scaling factor $\nu=1/500$ was introduced, indicating the need to include mass and heat transfer resistances to the model.

On the basis of the flowloop investigations, Di Lorenzo et al [15] suggested that compared with the mass transfer limited model, the CSMHyK model was more suitable for gas-dominated systems with the presence of a free water phase. The model uses subcooling $\Delta T_{\text{sub}}$ as the driving force for hydrate growth, and the main feature of the northern section of the China-Russia eastern gas pipeline is the lower temperature along the line, so the model can well reflect the hydrate formation.

3. Numerical simulation
Calculate the hydrate generation curve based on the gas composition and import it into the OLGA software. Set the pipe diameter, pipeline roughness, flowrate, starting pressure, temperature, ground temperature, and heat transfer coefficient according to the winter operating conditions in the first year of production shown in section 2.1. The OLGA software uses its multiphase flow control equations and hydrates the kinetic model to simulate the hydrate formation based on these set parameters.
3.1. Hydrate formation risk area

The presence of free water is a necessary condition for the formation of hydrates. Although the water content of the requirements in the China-Russian gas custody transfer is not higher than 40 mg/kg, the water content in the pipeline at the initial stage of production is higher than this value. Therefore, it is inevitable that water is formed under high pressure and low temperature to form hydrate. For the China-Russia eastern gas pipeline, under the operating pressure and temperature conditions in the first year of winter, the converted saturated water content is 332 mg/kg. The water dew point changes corresponding to the water content. The results show that the temperature of the entire pipeline is lower than the hydrate formation temperature (Figure 3).

In this case, as long as there is free water in the pipeline, there is a risk of hydrate formation. As the water content in the pipeline increases, the water dew point rises. By comparing the water dew point curve along the pipeline with different water content, the temperature curve along the pipeline, and the hydrate generation temperature curve, the water separating area of the pipeline under different water content can be analyzed and obtained (Table 3). Under the water separating condition, the formation of hydrates along the pipeline under different water contents was simulated, and the simulation time was 60 days. Figure 4 shows the change of hydrate formation in the pipeline with time under different water contents and Figure 5 shows the distribution of hydrate volume fraction along the pipeline.

| water content/ (mg·kg⁻¹) | Water separating area                         |
|--------------------------|----------------------------------------------|
| 40                       | No water separating in the whole pipeline    |
| 100                      | No water separating in the whole pipeline    |
| 150                      | water separating after 73.5 km               |
| 250                      | water separating after 16.0 km               |
| 350                      | water separating in the whole pipeline       |
It can be seen from Figure 4 that with the increase of the simulation time, the initial hydrate formation amount increases rapidly, but after about 30 days, the hydrate formation amount growth slows down until it stops increasing. The reason is that the formation and accumulation of hydrates reduce the flow area of the pipeline, the gas flow rate increases, and the gas purge capacity is enhanced. After a period of time to reach equilibrium, so that the hydrate particles entrained by the gas no longer accumulate. The greater the water content, the greater the accumulation of hydrate in the pipeline when it finally reaches equilibrium.

It can be seen from Figure 5 that the hydrate generation area is mainly concentrated in the rising part of the low-lying pipe section, which is consistent with the hydrate blockage mechanism in the gas-dominated system pipeline summarized by Sloan et al [16]. And as can be seen from the figure, the greater the difference in pipeline height, the greater the amount of hydrate accumulation. The greater the water content, the more hydrate accumulation at the same position. The reason is that under the same working conditions, the greater the water content, the more water is precipitated, and the more water is accumulated in the low-lying pipelines, resulting in an increase in the amount of hydrate formation and accumulation.

3.2. Effect of hydrate formation on pipeline temperature and pressure

The temperature and pressure along the pipeline at different water contents under the winter conditions in the first year of China-Russia eastern gas pipeline commissioning were simulated. Figure 6 shows the temperature curve along the pipeline under different water contents and Figure 7 shows the pressure curve along the pipeline under different water contents.

Figure 6. Temperature curve along pipeline under different water content.
Figure 6 shows that in the rapid growth phase of hydrate, when the water content is greater than 150 mg/kg, the temperature in the pipeline changes significantly, and a sudden temperature increase occurs in many places. This is due to the large amount of hydrate formation that will release heat and cause the temperature in the pipeline to rise. After the hydrate growth reaches equilibrium, the temperature change trend of the entire pipeline under different water contents is basically the same. At this time, the hydrate formation is slow or stops growing, and the temperature along the pipeline is mainly controlled by the external ground temperature. Overall, the temperature along the line when hydrate is formed is lower than the operating condition when no hydrate is formed. This is due to the throttling of the pipeline due to a large amount of hydrate generation, resulting in a temperature drop.

Figure 7 shows that when the water content is greater than 150 mg/kg, pressure drops appear in many places in the pipeline. This is due to the throttling effect caused by the accumulation of hydrates, which causes the pressure drop to increase. With the increase of time, due to the accumulation of hydrates, the pressure drop caused by the throttling effect becomes larger and larger. As the water content increases, the total pressure drop of the pipeline also increases. At a water content of 350 mg/kg, the increased pressure drop due to hydrate formation reaches approximately 2.27 MPa.

4. Conclusions
(1) During the China-Russia eastern gas pipeline goes into production, free water will inevitably exist. Since the pipeline is in a cold area and the pipeline is under high operating pressure, there is a risk of hydrate formation at the China-Russia eastern gas pipeline.

(2) Under the winter conditions in the first year of production of the China-Russia eastern gas pipeline, when the water content is greater than 150 mg/kg, free water will start to precipitate in some sections along the pipeline. When the water content reaches 350 mg/kg, free water is separated throughout the pipeline and there is a risk of hydrate formation.

(3) Under the winter conditions in the first year of production of the China-Russia eastern gas pipeline, hydrates are mainly accumulated in the downstream of the low-lying pipe section, and the greater the height difference of the pipe section, the greater the hydrate accumulation.

(4) In the hydrate generation stage, the temperature in the pipeline rises due to the large amount of heat generated by the hydrate formation. When hydrate growth reaches equilibrium, the temperature in the pipeline is mainly controlled by the external ground temperature. Pipe sections with large amounts of hydrate accumulation will produce a throttling effect and lead to an increase in temperature and pressure drop of the pipeline. Under the winter conditions in the first year of the China-Russia eastern gas pipeline, the additional pressure drop due to hydrate formation at a water content of 350 mg/kg is approximately 2.27 MPa.

(5) It is recommended to prevent the formation of the hydrate by injecting inhibitors in the pipeline section with a large amount of hydrate accumulation and reducing the pigging cycle.
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