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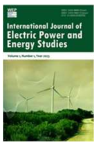

Research on Low Liquid Holdup Two Phase Flow in Horizontal Pipe

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ABSTRACT

Low liquid content gas-liquid two-phase flow is widely present in wet natural gas pipelines and is one of the typical phenomena of gas-liquid two-phase flow. Liquid hydrocarbons and free water are consistently produced during the natural gas extraction and transportation processes due to factors such as pressure differentials and temperature fluctuations, leading to a low liquid-holdup pipe flow. Previous research has shown that this reduced liquid retention significantly increases pressure loss compared to single-phase gas flow. Accurately predicting pressure drop is crucial for the selection of pipeline size, pipe material, and pressurization equipment. At the same time, the liquid holdup rate is also an important parameter that determines the frequency of natural gas pipeline cleaning and the design of downstream equipment. Therefore, this article mainly focuses on the characteristics of gas-liquid two-phase flow with low liquid content during wet natural gas transportation. This article studies the gas-liquid two-phase flow patterns and different gas-liquid interface models in the literature. This article mainly compares and analyzes three low liquid content gas-liquid two-phase flow models in the literature.

KEYWORDS

Gas-liquid Stratified Flow; Mechanistic Model; Liquid Holdup; Pressure Gradient.

1. INTRODUCTION

During natural gas extraction and transportation, liquid hydrocarbons and free water are continuously generated due to factors like pressure differences and temperature fluctuations, resulting in a pipe flow with low liquid holdup. Previous studies have demonstrated that this reduced liquid retention notably increases pressure loss compared to single-phase gas flow (Meng et al., 2001). Moreover, low liquid retention in pipelines can cause problems such as corrosion and ice blockages, affecting the safety and efficiency of pipeline operations (Birvalski et al., 2014; Zou et al., 2020; Sun et al., 2019). Hence, further research is essential to gain a comprehensive understanding of low liquid-holdup flow in pipes caused by various physical phenomena, which is a crucial aspect in the design and operation of natural gas pipelines.

Oliemans (1987) introduced an interfacial friction factor considering pipe sand roughness using the Flat model. The Apparent Rough Surface (ARS) model developed by Hamersma and Hart (1990) assumes that a portion of the pipe bottom is covered by a liquid film of constant average thickness when viewed from the cross-section of the pipe. However, the application of this model is limited because this phase interface shape can only be formed when the pipe diameter is sufficiently small and the gas velocity is sufficiently high. Subsequently, Grolman and Fortune (1997) experimentally found that the thickness of the liquid film does not maintain a homogeneous (flat) distribution in the circumferential direction, deviating from the assumptions of the ARS model, and the interface shape is usually concave. Then, the modified ARS model (MARS) was proposed without considering the influence of wave information on interfacial shear, which is the main factor increasing interfacial drag. Considering the distribution of gas velocity, Banafi and Talaie (2014) noted that the interface is mainly flat except for the creeping film near the pipe wall due to the transition from velocity head to static pressure head. In addition, they provided an empirical correlation of the interfacial friction factor considering the characteristics of liquid spatial distribution.

2. SEVERAL EXISTING MODELS

2.1. ARS Model

In 1989, Hamersma and Hart established a predictive model for isothermal, steady-state gas-liquid two-phase flow in horizontal pipes with a liquid holdup not exceeding 0.06. The flow patterns include stratified flow, wave stratified flow, and annular flow. In this flow, the liquid flowing along the pipe wall is considered as a local roughness of the pipe wall. Meanwhile, the gas-liquid interface shear stress generated by the gas phase above the liquid film can be equivalent to the gas wall shear stress generated by the gas phase on the rough pipe wall. Based on this assumption, they obtained a formula for predicting the two-phase pressure gradient at low liquid holdup. This model is based on horizontal pipelines and only considers accelerated pressure drop and frictional pressure drop, without considering pressure drop caused by gravity, to predict pressure drop gradients under low liquid holdup conditions in horizontal pipelines. Model usage conditions:

① Horizontal straight pipeline; ② Ultra low liquid holdup ($0 < \varepsilon < 0.06$);;

(1) Calculate the liquid holding capacity

$$\frac{\varepsilon}{1-\varepsilon}=\frac{u_l}{u_g}\left\{1+\left[10.4\,\mathrm{Re}_{sl}^{-0.363}\left(\frac{\rho_l}{\rho_g}\right)^{\frac{1}{2}}\right]\right\}$$

(2) Calculate the true gas velocity and liquid velocity

$$u_g=\frac{u_g}{1-\varepsilon}\qquad\qquad u_l=\frac{u_l}{\varepsilon}$$

(3) Calculate the corrected liquid phase Froude number and gas phase Reynolds number

$$Fr_l=\frac{u_l^2}{gD}\frac{\rho_l}{\Delta\rho}$$

Calculate wet wall fraction θ

$$\theta=\theta_0+0.26Fr^{0.58}$$

Among them:

$$\theta_0 = 0.52\varepsilon^{0.374}$$

(4) Calculate relative roughness

$$\frac{k}{D} = 2.3\left(\frac{\delta}{D}\right) \approx 2.3\left(\frac{\varepsilon}{4\theta}\right)$$

(5) Calculate the interfacial friction factor

$$f_i = \frac{0.0625}{\left[\log_{10}\left(\frac{15}{\mathrm{Re}_g} + \frac{k}{3.715D}\right)\right]^2}$$

(6) Calculate the friction factor of single-phase gas

$$f_g = \frac{0.07725}{\left[\log_{10}\left(\frac{\mathrm{Re}_g}{7}\right)\right]^2}$$

Note: The above formula is only valid within the following range.

$$2100 < \mathrm{Re}_g < 10^8$$

(7) Calculate the friction factor between two phases

$$f_{TP} = (1-\theta)f + \theta f_i$$

(8) Calculate two-phase pressure drop

$$\Delta P_{TP} = \left(\frac{1}{1-\varepsilon}\right)\left[4f_{TP}\left(\frac{L}{D}\right)\frac{1}{2}\rho_g u_g^2 - 4\theta f_i\left(\frac{L}{D}\right)\frac{1}{2}\rho_g\left(2u_g u_l - u_l^2\right)\right]$$

(9) The calculation of pressure drop in horizontal pipelines is as follows:

$$\Delta P_{TP} = 4f_{TP}\left(\frac{L}{D}\right)\frac{1}{2}\rho_g u_g^2$$

2.2. MARS Model

Grolman&Fortin (1997) found in their experiment that in the flow of gas-liquid two-phase pipelines, the liquid will climb along the inner wall of the pipeline to varying degrees, which has a significant impact on the circumference of the gas-liquid interface, the circumference of the gas phase wetting, the circumference of the liquid phase wetting, and the magnitude of the gas-liquid friction coefficient; And it is believed that in actual gas-liquid flow, the thickness of the liquid film will not be equal everywhere as assumed by Hart et al., but will show a downward trend. Therefore, they proposed the MARS model based on the ARS model.

$$f_g = \frac{0.07725}{\left[\log_{10}\left(\frac{Re_g}{7}\right)\right]^2} \qquad Re_g = \frac{\rho_g u_{sg} D}{\eta_g\left(1-\theta+s_i\right)}$$

$$f_{l,MARS} = \begin{cases} f_i 202\left(\frac{\eta_{water}}{\eta_l}\right)^{0.274} \theta_0 Re_{sl}^{-1} Re_g^{0.25} & Re_l < 2100 \\ f_i 108 Re_{sl}^{-0.726};\ Re_{sl} = \frac{\rho_l u_{sl} D}{\eta_l} & Re_l \geq 2100 \end{cases} \qquad Re_l = \frac{Re_{sl}}{\theta}$$

$$Fn = \frac{f_i}{\left(0.05+f_i\right)\left(1-\varepsilon_l\right)^{1.5}}\left(\frac{u_{sg}}{\sqrt{gD}}\right)\left(\frac{\sigma}{\eta_l\sqrt{gD}}\right)^{0.04}\left(\frac{\rho_l g D^2}{\sigma}\right)^{0.22}$$

$$\frac{k}{D} = 0.5145\varepsilon s_i^{-1.5}\left\{\tanh\left[0.05762\left(Fn-33.74\right)\right]+0.9450\right\}$$

$$f_i = \frac{0.0625}{\left\{\log_{10}\left(\frac{15}{Re_g}+\frac{k}{3.715D}\right)\right\}^2}$$

$$u_i = \begin{cases} 1.8\frac{u_{sl}}{\varepsilon}, & Re_l < 2100 \\ \frac{u_{sl}}{\varepsilon}, & Re_l \geq 2100 \end{cases}$$

$$\left(-\frac{\mathrm{d}p}{\mathrm{d}x}\right)_g = \frac{\tau_{wg} S_g + \tau_i S_i + A_g \rho_g g \sin\beta}{A_g}$$

$$\left(-\frac{\mathrm{d}p}{\mathrm{d}l}\right)_l = \frac{\tau_{wl} S_l - \tau_i S_i + A_l \rho_g g \sin\beta}{A_l}$$

Initi al estimation of liquid holding capacity ε:

$$\varepsilon \approx \frac{u_{sl}}{u_{sg}}\left\{1+\left(\frac{\rho_l}{\rho_g}108 Re_{sl}^{-0.726}\right)^{0.5}\right\}$$

2.3. Banafi Model

Banafi believes that the flat interface model only fits the actual situation when the gas-liquid phase is close to rest. As the gas-liquid flow velocity in the pipeline increases, the liquid phase film will climb up along the pipe wall, and the gas-liquid interface will have a downward trend. The main reason is that the liquid phase at the interface tends to move with the interface velocity. However, the liquid near the pipe wall has a velocity close to zero due to the absence of slip. Therefore, at the gas-liquid interface near the pipe wall, the velocity head of the liquid phase will be converted into a static pressure head, thus moving upwards.

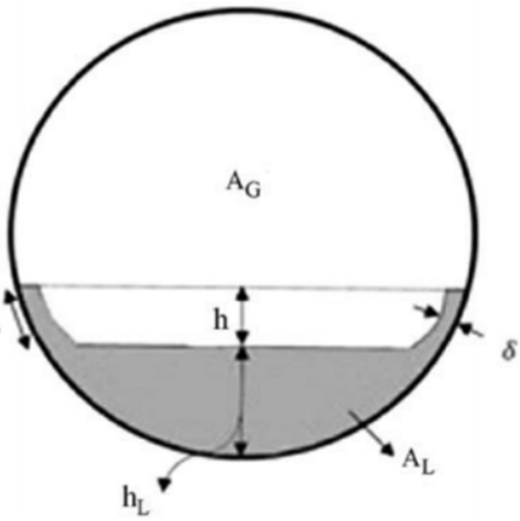

Fig.1 The gas–liquid pattern in the banafi model

The geometric relationships in the figure are:

$$A_l = 0.25d^2\left[\pi - \arccos\left(2\frac{h_l}{d}-1\right) + \left(2\frac{h_l}{d}-1\right)\sqrt{1-\left(2\frac{h_l}{d}-1\right)^2}\,\right] + 2l\delta$$

$$A_g = \frac{\pi d^2}{4} - \left\{0.25d^2\left[\pi - \arccos\left(2\frac{h_l}{d}-1\right) + \left(2\frac{h_l}{d}-1\right)\sqrt{1-\left(2\frac{h_l}{d}-1\right)^2}\,\right] + 2l\delta\right\}$$

$$S_l = d\left[\pi - \arccos\left(2\frac{h_l}{d}-1\right)\right] + 2l$$

$$S_g = \pi d - \left\{d\left[\pi - \arccos\left(2\frac{h_l}{d}-1\right)\right] + 2l\right\}$$

$$S_i = d\sqrt{1-\left(2\frac{h_l}{d}-1\right)^2} + 2l$$

3. RESULT ANALYSIS

This article uses data from Fan et al. to verify the effectiveness of the three models mentioned above. The predictive performance of the three models is shown in the following figure.

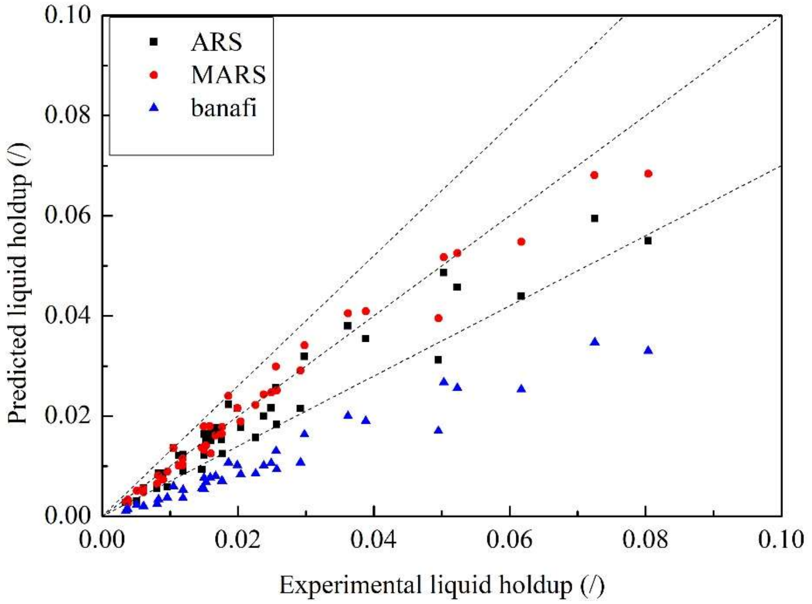

Fig.2 The comparison of the predicted liquid holdup of the three models

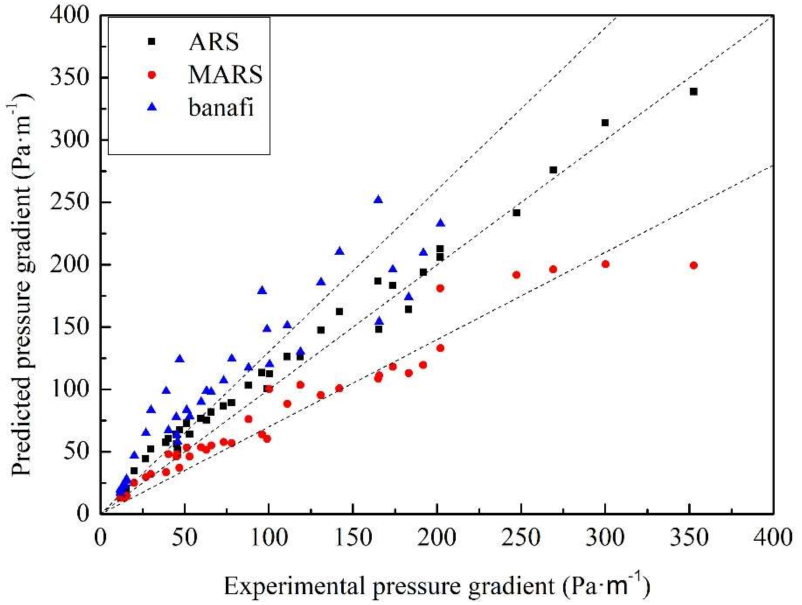

Fig.3 The comparison of the predicted pressure gradient of the three models

As shown in Fig. 2, the MARS model has the best performance in predicting liquid holdup, followed by the ARS model, and the worst is the banfi model. The holdup error of the ARS model is 17.59%, the holdup error of the MARS model is 10.96%, and the holdup error of the Banfi model is 56.87%.

As shown in Fig. 3, the MARS model has the best prediction of pressure drop effect, followed by the ARS model, and the worst banfi model. The pressure drop error of ARS model is 22.17%, MARS model is 18.78%, and Banfi model is 60.45%.

It is worth noting that the MARS model is prone to computational difficulties at low gas velocities, while the Banafi model is prone to computational difficulties at high gas velocities. Therefore, in some special cases, it is necessary to consider combining multiple models to adapt to complex situations

DECLARATION OF COMPETING INTEREST

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

DATA AVAILABILITY

Data will be made available on request.

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