INTRODUCTION

Narrow pressure margins are a significant factor during deepwater drilling. It is directly related to safety and efficiency, and also to the success of drilling operations. In order to conduct safe drilling for a narrow pressure window in deepwater, research institutions and scholars studied several dual-gradient drilling technologies, such as dual-gradient drilling with light medium (gas, hollow sphere), submarine pump lifting drilling, mud cap control drilling, and deepwater multi-gradient drilling, while developing corresponding core technologies, matching equipment, and drilling theories.

Abstract

In deepwater drilling, accurate prediction of wellbore gas-liquid two-phase flow behavior is significant for gas kick detection and well-control treatment. In this study, a new transient gas-liquid two-phase flow model was developed to simulate the wellbore gas-liquid two-phase flow during gas kick in deepwater dual-gradient drilling based on downhole separation. This model accounts for the impact of a sudden change in density on gas-liquid flow behavior. The transient model was solved using the finite-difference method. The accuracy and stability of the model were verified using data measured from a full-scale experimental well. Using this model, the differences in the apparent liquid velocity and the flow rate at the annular outlet during gas kick were compared between deepwater dual-gradient drilling and conventional single-gradient drilling. Additionally, the influences of numerous factors on variations in flow rate at the annular outlet were also studied. A new method of early gas kick detection was proposed for deepwater dual-gradient drilling based on downhole separation.

KEYWORDS

deepwater dual-gradient drilling, gas kick detection, gas-liquid two-phase flow, sudden density change, variations in flow rate
different injection volume fractions of hollow spheres, which proves the effectiveness of the separator and the feasibility of achieving double pressure gradients in wellbore. In addition, deepwater dual-gradient drilling technology based on downhole separation can be considered as a managed pressure drilling technology, and the wellbore pressure profile can be controlled by wellhead backpressure and separator.

In deepwater drilling, accurate prediction of wellbore gas-liquid two-phase flow behavior is significant for gas kick detection and well-control treatment. Depending on the relationship between flow state and time, the multiphase flow model can be divided into the steady multiphase flow and transient multiphase flow types. However, the steady-state flow model is limited owing to its inability to describe the dynamic flow process of fluids in wellbores. The transient multiphase flow model can be applied to the entire process of oil and gas drilling and production. For conventional drilling, Rommetveit et al. and Xu et al. developed gas-liquid two-phase flow models, which were established for water-based mud. For deepwater drilling, Sun et al. and Yu et al. developed gas-liquid two-phase flow models for oil-based mud and synthetic-based mud, respectively. For underbalanced drilling, Lage et al. and Song et al. developed a gas-liquid two-phase flow model and proposed the idea of combining the first-order Lax-Friedrichs scheme and the second-order MacCormack scheme to solve the model. Then, Fjelde et al. established a new transient model of multiphase flow in wellbores and proposed the idea of using MUSCL (Monotonic Upwind Scheme for Conservation Laws) scheme to modify the classical first-order upwind scheme, which can better describe the pressure fluctuation law when connecting single wellbores. For managed pressure drilling, Bacon et al. developed a gas-liquid two-phase flow model suitable for the well-control process. Several other oil-gas two-phase flow models were also developed to simulate wellbore pressure fluctuation and gas-liquid flow behavior in the process of oil-gas production. Later, based on the existing theoretical model, more advanced transient gas-liquid two-phase flow models were developed that included the impacts of gas compressibility, gas solubility in mud, and wellbore heat transfer, in order to accurately simulate gas-liquid two-phase flow in wellbores.

A majority of the existing gas-liquid two-phase flow models have been established for single-gradient drilling, which cannot be applied to dual-gradient drilling formed by the coexistence of dual density liquid phases in the wellbore. A sudden change of liquid density at the separator position was observed for the dual-gradient drilling after gas kick was compared. Additionally, the influences of well depth, gas rate, separator position, density difference between light and heavy drilling fluid, circulation displacement, and wellhead backpressure on variation in flow rate at annular outlet were also studied. Thus, a new method of early gas kick detection was proposed for deepwater dual-gradient drilling based on downhole separation.

2 PHYSICAL MODEL

The schematic diagram of wellbore gas-liquid two-phase flow for dual-gradient drilling based on downhole separation is shown in Figure 1. The dual-gradient drilling is formed by installing a separator in the drill pipe. During circulation, the mixed drilling fluid is made up of a certain proportion of hollow spheres and pure drilling fluid uniformly mixed on the ground and then injected into the drill pipe through a pump. Then, some hollow spheres are separated and entered into the annulus when the mixed drilling fluid flows through the separator. Therefore, taking the separator position as the boundary, the content of hollow spheres in the annulus above the transient gas-liquid two-phase flow model by considering the impact of sudden change of drilling fluid density on gas migration. The transient model was validated using measured data from a full-scale experimental well. Using this model, the difference of apparent liquid velocity and flow rate at annular outlet between deepwater dual-gradient drilling and conventional single-gradient drilling after gas kick was compared. Additionally, the influences of well depth, gas rate, separator position, density difference between light and heavy drilling fluid, circulation displacement, and wellhead backpressure on variation in flow rate at annular outlet were also studied. Thus, a new method of early gas kick detection was proposed for deepwater dual-gradient drilling based on downhole separation.

FIGURE 1 Schematic of wellbore gas-liquid two-phase flow for dual-gradient drilling
separator position is high, and the content of hollow spheres in annulus below the separator position is low. Because the density of a hollow sphere is lower than that of pure drilling fluid, there is light drilling fluid in annulus above the separator position and heavy drilling fluid in annulus below the separator position. During gas kick, gas inevitably undergoes a sudden change of fluid density in the process of gas migration from the bottom-hole to wellhead, which has a significant impact on gas migration. Therefore, the influence of sudden change of fluid density on gas migration should be considered while establishing the gas-liquid two-phase flow model for this drilling method.

It should be noted that for this deepwater dual-gradient drilling technology based on downhole separation, flowmeter is installed at the wellhead, which ensures that during drilling and circulation process, the annular outlet flow rate can be measured accurately as managed pressure drilling technology, rather than roughly estimated by observing the mud tank level.

3 | MODEL DEVELOPMENT

3.1 | Assumptions

In order to establish a gas-liquid two-phase flow model for deepwater dual-gradient drilling and accurately describe the variation of wellbore fluid flow parameters after gas kick, the following assumptions were made:

1. The effect of cuttings on gas-liquid two-phase flow in wellbore was negligible.
2. The hollow spheres were uniformly mixed in pure drilling fluid to form homogeneous mixed liquid.
3. There were sudden changes of fluid density at the separator position.
4. In the case of pure natural gas kick, the dissolution of gas in water-based mud is not considered.

3.2 | Gas-liquid two-phase flow model

The gas-liquid two-phase flow model is composed of a mass conservation equation and a momentum conservation equation, which are usually expressed in a differential form.

3.2.1 | Mass conservation equation

1. Mass conservation equation of gas phase

\[
\frac{\partial}{\partial z} (\rho_g \alpha_g v_g A) + \frac{\partial}{\partial t} (\rho_g \alpha_g A) = q_g
\]  

2. Mass conservation equation of liquid phase

\[
\frac{\partial}{\partial z} (\rho_l \alpha_l v_l A) + \frac{\partial}{\partial t} (\rho_l \alpha_l A) = 0,
\]  

where \( t \) is the time (s); \( z \) is the axial displacement (m); \( A \) is the annular channel area (m²); \( \rho_g \) is the density of the gas phase (kg/m³); \( \rho_l \) is the density of the liquid phase (kg/m³); \( \alpha_l \) is the volume fraction of the liquid phase; \( \alpha_g \) is the volume fraction of the gas phase; \( \alpha_l \) is the actual velocity of the gas phase (m/s); \( \alpha_l \) is the actual velocity of the liquid phase (m/s); and \( q_g \) is the gas rate per unit thickness (kg/(s·m)).

3.2.2 | Momentum conservation equation

Equation (3) is the gas-liquid two-phase momentum conservation equation.

\[
\frac{\partial}{\partial z} (\rho_g \alpha_g v_g^2 A + \rho_l \alpha_l v_l^2 A) + \frac{\partial}{\partial t} (\rho_g \alpha_g v_g A + \rho_l \alpha_l A) + (\rho_g \alpha_g + \rho_l \alpha_l) g \sin \theta A + \frac{\partial}{\partial z} (pA) + A \frac{\partial p_f}{\partial z} = 0
\]

where \( p \) is the pressure (Pa); \( g \) is the gravitational acceleration (9.81 m/s²); \( \theta \) is the angle between the wellbore direction and horizontal direction (°); and \( p_f \) is the friction pressure drop (Pa).

3.3 | Auxiliary equation

3.3.1 | Drift flow model

In this study, the drift flow model was used to describe gas-liquid two-phase flow as this model more accurately follows the actual flow law and has lower calculation error.\(^2\)\(^8\) According to Caetano,\(^2\)\(^9\) Hasan and Kabir,\(^3\)\(^0\) and Lage,\(^3\)\(^1\) two-phase flow patterns are divided into five categories: bubbly flow, dispersed bubbly flow, slug flow, agitated flow, and annular flow. The flow pattern discrimination method and the parameter calculation method under different flow pattern conditions are detailed in a previous study.\(^3\)\(^2\)

3.3.2 | Friction pressure drop model

The calculation model of friction pressure drop is detailed in Equation (4).

\[
\frac{\partial p_f}{\partial z} = \frac{2f_l \rho_m v_m^2}{(D_i - D_p)}
\]

In the Formula (4), \( \rho_m = \rho_l \alpha_l + \rho_g \alpha_g \), \( v_m = v_{sd} + v_{sg} = v_l \alpha_l + v_g \alpha_g \).
Here, $\rho_m$ is the density of the gas-liquid two-phase mixture (kg/m$^3$); $u_m$ is the velocity of the gas-liquid two-phase mixture (m/s); $\nu_{sg}$ and $\nu_{sl}$ are the apparent velocities of the gas and liquid phases (m/s), respectively; $D_1$ is the outer diameter of the annulus (m); and $D_p$ is the inner diameter of the annulus (m).

### 3.3.3 Fluid density distribution in annulus

Different from conventional single-gradient drilling, two kinds of density fluids exist simultaneously in annulus for deepwater dual-gradient drilling, and the distribution of fluid density is closely related to the position of separator. The density distribution formula is as follows:

$$\rho_i = \begin{cases} \rho_1, & h \leq H - D_{bs} \\ \rho_2, & h > H - D_{bs} \end{cases}$$  \hspace{1cm} (5)

where, $\rho_1$ is the density of the light drilling fluid (kg/m$^3$); $\rho_2$ is the density of the heavy drilling fluid (kg/m$^3$); $H$ is the total well depth (m); $h$ is the depth of the calculated point in the wellbore (m); and $D_{bs}$ is the distance between the separator and the bit (m).

It can be seen from Equation (5) that after gas kick, the gas migrates first from formation to wellbore in heavy drill-fluid. During the process of gas migration from bottom to wellhead, the annulus fluid density changes abruptly when the gas front reaches the separator, and then the gas front enters the light drilling fluid and migrates to the wellhead. The sudden change of annular fluid density at the separator position has a significant effect on gas migration, which is significantly different from that in conventional single-gradient drilling.

### 3.4 Model solution

#### 3.4.1 Initial and boundary conditions

1. Initial conditions

At the initial time of gas kick, there is only gas at the bottom hole in annulus. Combining with the steady flow model of drilling fluid, the pressure at each point in annulus at “0” time, the volume fraction and velocity of drilling fluid and gas can be determined.

$$p(z,0) = p(z)$$  \hspace{1cm} (6)

$$a_s(H,0) = \frac{\nu_{sg}(H,0)}{c_{0p} + \nu_{gr}}, \quad a_g(0: H - 1, 0) = 0$$  \hspace{1cm} (7)

$$a_s(z,0) = 1 - a_g(z,0)$$  \hspace{1cm} (8)

$$\nu_g(H,0) = \frac{\nu_{sg}(H,0)}{a_s(H,0)}, \quad \nu_g(0: H - 1, 0) = 0$$  \hspace{1cm} (9)

$$\nu_l(z,0) = \frac{\nu_{gr}(z,0)}{a_s(z,0)}$$  \hspace{1cm} (10)

where, $c_0$ is the dimensionless gas distribution coefficient and $\nu_{gr}$ is the gas slip velocity (m/s).

2. Boundary conditions

During the drilling process, the wellhead backpressure remained unchanged as the wellbore pressure boundary condition.

$$p(0,t) = p_{hp}$$  \hspace{1cm} (11)

### 3.4.2 Finite-difference equations

The first-order upwind difference scheme was used to discretize the space derivative term in the control equation, and the four-point central difference scheme was used to discretize the time derivative term. Based on this principle, the wellbore pressure model in gas-liquid two-phase flow was discretized and the corresponding finite-difference scheme was provided. Here, $i$ and $n$ represent the axial and time nodes, respectively.

1. Mass conservation equation of gas phase

$$\begin{align*}
\rho_g(a_g)_i^n & = x(\rho_g a_g)_{i-1}^{n-1} - x(\rho_g a_g)_{i}^{n-1} \\
& = \frac{\Delta z}{2\Delta t} \left[ x(\rho_g a_g)_{i-1}^{n} + (\rho_g a_g)_{i}^{n-1} - x(\rho_g a_g)_{i}^{n} - (\rho_g a_g)_{i}^{n-1} \right] \quad (12)
\end{align*}$$

2. Mass conservation equation of liquid phase

$$\begin{align*}
(\rho_l a_l)_i^n & = x(\rho_l a_l)_{i-1}^{n-1} - x(\rho_l a_l)_{i}^{n-1} \\
& = \frac{\Delta z}{2\Delta t} \left[ x(\rho_l a_l)_{i-1}^{n} + (\rho_l a_l)_{i}^{n-1} - x(\rho_l a_l)_{i}^{n} - (\rho_l a_l)_{i}^{n-1} \right] \quad (13)
\end{align*}$$

3. Gas-liquid two-phase momentum conservation equation

$$\begin{align*}
\rho_i^n - x p^n_{i-1} & = \frac{\Delta z}{2 \Delta t} \left[ x V_1^{n-1} + V_1^n - x V_1^n - V_1^{n-1} \right] + x V_2^n - V_2^n \\
& - \frac{g \Delta z}{2} \left[ x V_3^{n-1} + V_3^n - \frac{\Delta z}{2} \left( \frac{\partial p}{\partial z} \right)_{i-1}^{n} + \left( \frac{\partial p}{\partial z} \right)_{i}^{n} \right] \quad (14)
\end{align*}$$
where \( x = \frac{A_i}{A} \), \( V_1 = \rho_g \alpha_g v_g + \rho_l \alpha_l v_l \), \( V_2 = \rho_g \alpha_g v_g^2 + \rho_l \alpha_l v_l^2 \), and \( V_3 = \rho_g \alpha_g + \rho_l \alpha_l \).

### 3.4.3 Solution procedure

The solution procedure is shown in Figure 2.

### 4 MODEL VALIDATION

The two-phase flow model was validated by measured data from a full-scale experimental well at Louisiana University. The basic parameters of the experimental well are shown in Table 1.

Pressure sensors were installed at 1186 m and 1768 m in the annulus to measure the pressure value in real time. In the experiment, the gas-injection pipeline was connected to the bottom of the well, and the pressures at 1768 m and 1186 m were found to be 17.61 MPa and 11.81 MPa, respectively.

Figures 3 and 4 show the pressure curves calculated by the model vs time at 1768 m and 1186 m, respectively. The process of gas migration from bottom-hole to wellhead was simulated. First, the transient process takes place before the gas front reaches the wellhead, followed by the quasi-steady state. From Figures 3 and 4, it can be seen that in the quasi-steady-state stage, the pressure at 1768 m tends to 17.56 MPa, and the pressure at 1186 m tends to 11.87 MPa, which is very close to the experimental data. Therefore, the stability and accuracy of the model have been proved.

### 5 CASE STUDY

#### 5.1 Comparison of simulation results between deepwater dual-gradient drilling and conventional single-gradient drilling under gas kick condition

The numerical simulations for gas kick under two drilling methods were compared, and the influence of abrupt changes in the drilling fluid density on the apparent liquid velocity and flow rate at the annular outlet was analyzed.

| TABLE 1 Basic parameters of the experimental well |
|--------------------------------------------------|
| Vertical well depth/(m)                        | 1793 |
| Inner diameter of casing/(m)                  | 0.2184 |
| Outer diameter of drill pipe/(m)              | 0.0889 |
| Inner diameter of drill pipe/(m)              | 0.0656 |
| Density of drilling fluid/(kg/m³)             | 1120 |
| Dynamic shear force of drilling fluid/(Pa)    | 1.91 |
| Plastic viscosity of drilling fluid/(mPa s)   | 6 |
| Displacement/(L/s)                            | 12.6 |
| Injection gas rate/(m³/s)                     | 0.44 |

**FIGURE 2** Schematic of solution procedure

**FIGURE 3** Variation of pressure with time at 1768 m
The basic parameters of the simulated well are shown in Table 2.

Figure 5 shows the variation in apparent liquid velocity at the annular outlet with the position of the gas front after gas kick, in the two drilling methods. It can be seen that for conventional single-gradient drilling, the apparent liquid velocity at the annular outlet shows a “sudden increase–slow increase” rule after gas kick. In the early stage of gas kick, a large amount of formation gas suddenly poured into the wellbore, which pushed the drilling fluid in the annulus upward, resulting in a sudden increase in the apparent liquid velocity at the annular outlet. Generally, the sudden increase was small. As the gas moved upward, the distance between the gas front and the wellhead decreased, and the gas expanded gradually. Therefore, the apparent liquid velocity at annular outlet continued to increase slowly. In contrast, for deepwater dual-gradient drilling, the apparent liquid velocity at the annular outlet showed a “sudden increase–slow increase–sudden increase–slow increase” rule. The major difference from conventional single-gradient drilling was that when the gas front reached 3500 m (separator position), the apparent liquid velocity at the annular outlet suddenly doubled. When the gas front reached 3500 m, the presence of the separator resulted in a reduction in the liquid density. When the gas entered the low-density liquid, the bubble-slipping velocity in the bubble flow increased. In addition, the low-pressure environment helped the gas to expand during upward flow. Thus, when the gas front flows through the separator position, the sudden drop in liquid density further accelerates the development of gas expansion and gas kick, which in turn increases the apparent liquid velocity at the annular outlet. In short, the phenomenon of a sudden change in the apparent velocity of the liquid phase at the annular outlet is not observed in conventional single-gradient drilling.

Figure 6 shows the variation in annular outlet flow rate with gas front position after gas kick in the two drilling modes. It can be seen that for conventional single-gradient drilling, the variation rate of annular outlet flow rate showed a “sudden increase - slow increase” rule after gas kick. Combining with the black line in Figure 5, at the beginning of gas kick, the apparent velocity of liquid phase at the annular outlet increased suddenly, resulting in the sudden increase of flow rate at the annular outlet and the sudden increase in variation of flow rate. With the upward movement of gas, the apparent velocity of liquid phase at outlet increased slowly, and the variation rate of the annular outlet flow rate also increased slowly. In contrast, for deepwater dual-gradient drilling, the variation rate of annular outlet flow rate showed a “sudden increase - slow increase - sudden increase - slow increase” rule. The main difference between the two drilling methods was that when the gas front

![Figure 4](image1.png) **FIGURE 4** Variation of pressure with time at 1186 m

![Figure 5](image2.png) **FIGURE 5** The relationship between apparent liquid velocity at annular outlet and gas front position under the two drilling methods

**TABLE 2** Basic parameters of the simulated well

| Parameter                     | Value   |
|-------------------------------|---------|
| Well depth (m)                | 4000    |
| Water depth (m)               | 1500    |
| Casing shoe depth (m)         | 3000    |
| Inner diameter of riser (m)   | 0.4826  |
| Inner diameter of casing (m)  | 0.2445  |
| Diameter of bit (m)           | 0.2159  |
| Outer diameter of drill pipe (m) | 0.1270 |
| Inner diameter of drill pipe (m) | 0.1016 |
| Distance between separator and bit (m) | 500 |
| Density of light drilling fluid (kg/m³) | 900 |
| Density of heavy drilling fluid (kg/m³) | 1100 |
| Viscosity of light drilling fluid (mPa s) | 4 |
| Viscosity of heavy drilling fluid (mPa s) | 6 |
| Displacement (L/s)            | 20      |
| Gas rate (m³/s)               | 0.4     |
| Wellhead backpressure (MPa)   | 0.5     |

Note: The density of drilling fluid was 1100 kg/m³, and the viscosity of the drilling fluid was 6 mPa s for conventional single-gradient drilling under gas kick condition.
reached 3500 m (separator position) in the deepwater dual-gradient drilling, the variation in annular outlet flow rate doubled. This could be because when the gas front reached 3500 m, the apparent liquid velocity at the annular outlet increased sharply, resulting in a sudden increase in variation of the flow rate.

In summary, there were clear differences in apparent liquid velocity and annular outlet flow rate between the two drilling methods after gas kick. When the gas front reached the separator position, there was a sudden increase. However, the specific sudden increase depended on well depth, gas rate, separator separation, density difference of light/heavy drilling fluid, displacement, and wellhead backpressure.

5.2 Influences of different factors on annular outlet flow rate during gas kick

In deepwater dual-gradient drilling, the flow rate at the outlet, which is an important index for gas kick detection, can be measured in real time using a flowmeter. This is very important in order to accurately assess the variation law of the annular outlet flow rate during gas kick. Hence, a simulation was conducted to describe the variation law of the annular outlet flow rate, considering changes in different factors (well depth, gas rate, separator position, density difference between light and heavy drilling fluid, circulation displacement, and wellhead backpressure).

5.2.1 The influence of different well depths on annular outlet flow rate

Figure 7 shows the variation in the annular outlet flow rate with the gas front position after gas kick, under different well depths. When the well depths were 3200 m, 3600 m, and 4000 m, because the distance between separator and drill bit is always 500 m, the corresponding separator positions under the three well depths were 2700 m, 3100 m, and 3500 m, respectively. It can be seen that with the increase in well depth, the gas migration distance in the wellbore increased, that is, the gas breakthrough time at the wellhead increased.

From Figure 7, it can also be seen that the variation in annular outlet flow rate increased sharply when the gas front reached the separator position in the three well depths. Moreover, because of the same gas rate level, the annular flow rate varied similarly for the three different well depths and the variation rate increased sharply to 30.1%, 29.1%, and 28.4%, respectively. In addition, the time required for the gas front to reach the separator position was 7.8 minutes, 6.5 minutes, and 6.6 minutes, respectively, and the time required for the gas front to reach the bottom of riser is 25 minutes, 29 minutes, and 34 minutes, respectively.

5.2.2 The influence of different gas rates on annular outlet flow rate

Figure 8 shows the variation rate in the annular outlet flow rate with the gas front position after gas kick, under different gas rates. It can be seen that when the gas rate was 0.05 m³/s, 0.2 m³/s, and 0.4 m³/s, the variation in the annular outlet flow rate increased sharply when the gas front reached 3500 m (separator position).

Moreover, with the increase of gas rate, the variation range of flow rate also increased. This is because the higher the gas rate is, the greater is the amount of gas entering into the wellbore, and the gas pushes the drilling fluid upward. This leads to a higher annular outlet flow rate. Specifically, under the three different gas rates, the variation in flow rate increased sharply to 23.0%, 25.3%, and 28.4%, respectively. In addition, the time required for the gas front to reach the separator position was

![FIGURE 6](Image)

![FIGURE 7](Image)
6.9 minutes, 6.8 minutes, and 6.6 minutes, respectively, and the time required for the gas front to reach the bottom of the riser was 36 minutes, 35 minutes, and 34 minutes, respectively.

5.2.3 | The influence of different distance between separator and bit on annular outlet flow rate

Figure 9 shows the variation in the annular outlet flow rate with the gas front position after gas kick, under different separator positions. When the distances between the separator and bit were 500 m, 1000 m, and 1500 m, respectively, the corresponding separator depths were 3500 m, 3000 m, and 2500 m, respectively. It can be seen that the variation in the annular outlet flow rate increased rapidly when the gas front reached 3500 m, 3000 m, and 2500 m, and the variation rate increased rapidly to 28.4%, 29.6%, and 30.4%, respectively, for the three separator positions.

From Figure 9, it can also be seen that the shorter the distance between the separator and bit, the earlier the sudden increase in variation in the annular outlet flow rate occurred. This is because the smaller is the distance between the separator and the bit, the earlier the gas front reaches the separator position after the gas kick occurs. Hence, the sudden increase in the variation rate occurred earlier. Specifically, the times required for the gas front to reach the separator position were 6.6 minutes, 13.1 minutes, and 21.8 minutes, respectively. The times required for the gas front to reach the bottom of riser were 34 minutes, 35 minutes, and 34 minutes, respectively.

5.2.4 | The influence of different density difference between light and heavy drilling fluid on annular outlet flow rate

Figure 10 shows the variation in annular outlet flow rate with gas front position after gas kick under different density differences between light and heavy drilling fluid. When the density difference of drilling fluid was 100 kg/m³, 200 kg/m³, and 300 kg/m³, the density of light drilling fluid in the upper part of the separator was 1000 kg/m³, 900 kg/m³, and 800 kg/m³, respectively. It can be seen that under the three density differences between light and heavy drilling fluid, the variation in annular outlet flow rate increased rapidly when the gas front reached 3500 m (separator position).

From Figure 10, it can also be seen that with the increase of the density difference, the variation range also increased significantly. This is because the lower the density of the light drilling fluid above the separator, the greater was the bubble slip velocity in the bubble flow. Thus, there was a second sudden increase of the apparent velocity at annular outlet (as shown in Figure 5), leading to a larger variation in annular outlet flow rate.
rate. Specifically, the variation rate under the three density differences increased rapidly to 15.8%, 28.4%, and 44.1%, respectively. In addition, the time required for the gas front to reach the separator position was 6.6 minutes, 6.6 minutes, and 6.5 minutes, respectively, under the three density differences, and the time required for the gas front to reach the bottom of the riser was 36 minutes, 34 minutes, and 31 minutes, respectively.

5.2.5 | The influence of different displacement on annular outlet flow rate

Figure 11 shows the variation in annular outlet flow rate with the gas front position after gas kick under different displacement. It can be seen that under the three displacement values, the variation in annular outlet flow rate increased rapidly when the gas front reached 3500 m (separator position). In addition, the variation range decreased with the increase in displacement. This is because for the same gas rate, the larger the displacement, the larger the base number of flow rate, and lesser the influence of gas kick on wellbore fluid flow. Hence, the variation in annular outlet flow rate was lower. Specifically, under the three displacement values, the variation increased sharply to 28.4%, 26.1%, and 25.0%, respectively.

From Figure 11, it can also be seen that the larger was the displacement, the earlier the sudden increase in variation rate occurred. This is because the larger was the displacement, the faster was the migration velocity of the gas after the gas kick, and the earlier the gas front reached the separator position. Therefore, the sudden increase in variation occurred earlier. Specifically, under the three displacement values, the times required for the gas front to reach the separator position were 6.6 minutes, 4.7 minutes, and 3.7 minutes, respectively. The times required for the gas front to reach the bottom of the riser were 34 minutes, 25 minutes, and 19 minutes, respectively.

5.2.6 | The influence of different wellhead back pressure on annular outlet flow rate

Figure 12 shows the variation rate of annular outlet flow rate with gas front position after gas kick under different wellhead backpressure. It can be seen that under the three different backpressure, the variation rate of annular outlet flow rate increases sharply when the gas front reaches 3500 m (separator position). In addition, the influence of wellhead backpressure on variation rate is not significant and the variation rate under the three different backpressure is 28.4% after sudden increase. Moreover, under the three different wellhead backpressure, the time required for the gas front to reach the separator position was 6.6 minutes, and the time required for the gas front to reach the bottom of the riser is 34 minutes.

To summarize, when the gas front reached the separator position, the variation in annular outlet flow rate changed, corresponding to different parameter ranges, which indicates that the annular outlet flow rate can be monitored accurately. In addition, the sudden increase of annular outlet flow rate occurred earlier than the appearance of gas at the bottom of the riser.

5.3 | New method of early gas kick detection for deepwater dual-gradient drilling

From the results presented in section 5.2, the fluctuation range of variation in annular outlet flow rate under different factors can be obtained. The specific results are shown in Table 3. The “sudden increase” mentioned in this section refers to the sudden increase when the gas front reached the separator position, as shown in Figure 6.

It can be seen from Table 3 that the deeper the well depth, the smaller the gas rate, the smaller the distance between separator and bit, the smaller the density difference between...
light and heavy drilling fluid, and the larger the displacement. Combined, these lead to the decrease in variation of annular outlet flow rate after the sudden increase. In addition, wellhead backpressure is an inert factor for variation in annular outlet flow rate.

In order to determine whether variation in annular outlet flow rate still doubles when the gas front reaches the separator position in the case of small-scale gas kick, the combination of parameters that minimize the variation rate after sudden increase in different parameter ranges was used as a simulation condition. The specific simulation conditions used are as follows: well depth was 4000 m, gas rate was 0.05 m³/s, distance between separator and bit was 500 m, density difference between light and heavy drilling fluid was 100 kg/m³, displacement was 40 l/s, and wellhead backpressure was 0.1 MPa. The simulation results are shown in Figure 13.

It can be seen from Figure 13 that the variation in annular outlet flow rate increased abruptly when the gas front reached the separator position, and the minimum variation rate after the sudden increase reached 10.3%. In addition, under the simulated conditions, the sudden increase in variation occurred at 3.8 minutes and the gas appeared at the bottom of the riser at 21.4 minutes, which indicates that this detection method can detect gas kick earlier as compared with other methods.

In summary, based on the analysis of numerical simulations, a new method of early gas kick detection is proposed for deepwater dual-gradient drilling based on downhole separation. The method is as follows: gas kick can be determined when the second sudden increase occurs on the variation curve of annular outlet flow rate. For deepwater dual-gradient drilling, compared with the existing detection methods that monitor gas fraction at the bottom of riser, gas kick can be determined as long as the gas front moves to the separator position. The new method can detect gas kick when the gas front reaches the separator position. This method reduces the time needed to identify gas kick, which is conducive to taking timely control measures for avoiding further development of gas kick and ensuring the safety of deepwater drilling.

However, the proposed method of gas kick detection has a limitation. When the separator is above the mud line, the timeliness of this method is relatively poor as compared with the method of monitoring gas fraction at the bottom of riser.

6 | CONCLUSIONS

In this study, a new gas-liquid two-phase flow model considering sudden density change was developed. The main conclusions are presented below:

1. Compared with conventional single-gradient drilling, there was a second sudden increase on curves of apparent liquid velocity and variation in annular outlet flow rate for deepwater dual-gradient drilling based on downhole separation.
2. When the gas front reached the separator position, the variation in annular outlet flow rate changed across different parameter ranges, which indicates that the annular outlet flow rate can be monitored accurately.
3. The deeper the well depth, the smaller the gas rate, the smaller the distance between separator and bit, the smaller

| Factor                              | Range of factor | Variation rate of annular outlet flow after sudden increase |
|-------------------------------------|----------------|----------------------------------------------------------|
| Well depth/(m)                      | 3200-4000      | 30.1%-28.4%                                              |
| Gas rate/(m³/s)                     | 0.05-0.4       | 22.9%-28.4%                                              |
| Distance between separator and bit/(m) | 500-1500        | 28.4%-30.4%                                              |
| Density difference between light and heavy drilling fluid/(kg/m³) | 100-300           | 15.8%-44.1%                                              |
| Displacement/(L/s)                  | 20-40          | 28.4%-25.0%                                              |
| Wellhead backpressure/(MPa)         | 0.1-2          | 28.4%                                                     |

**TABLE 3** Fluctuation range of variation in annular outlet flow after sudden increase under different factors

**FIGURE 13** The relationship between minimum variation in annular outlet flow and gas front position
the density difference between light and heavy drilling fluid, and the larger the displacement. Combined, these factors lead to the decrease in variation of annular outlet flow rate.

4. Gas kick can be determined when the second sudden increase occurs on the variation curve of annular outlet flow rate. Using this new method of early gas kick detection, the time needed to identify gas kick can be reduced.

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