Transient flow in wellbores and phase transition of CO$_2$ during formation supercritical CO$_2$ invasion

Liangbin Dou$^{1,2,3}$ | Ming Zhang$^{1,3}$ | Gang Bi$^{1,3}$ | Tiantai Li$^{1,3}$

$^1$School of Petroleum Engineering, Xi’an Shiyou University, Xi’an, China
$^2$State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum, Beijing, China
$^3$Engineering Research Center of Development and Management for Low to Extra-Low Permeability Oil & Gas Reservoirs in West China, Ministry of Education, Shaanxi, China

Correspondence
Liangbin Dou, School of Petroleum Engineering, Xi’an Shiyou University, Xi’an, China.
Email: 77129dou@163.com

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Abstract
CO$_2$ reservoirs and high CO$_2$ content gas reservoirs in marine sediments generally have complex pressure system, which usually encounters supercritical CO$_2$(SC-CO$_2$) invasion into the wellbore during drilling process. The wellbore transient flow and phase transition along the wellbore during the drilling process has not been thoroughly investigated, because the CO$_2$ physical properties and the reservoirs petrophysical properties could affect the transient flow of mixed fluid and phase transition of CO$_2$ along the well. A numerical model is presented in this research to analyze the transient flow in wellbores and to predict phase transition of CO$_2$ during formation SC-CO$_2$ invasion in the drilling process. The main considerations were the following: multiphase transient flow in wellbores was coupled with the non-Darcy flow through the formation; wellbore temperature, pressure and the mixture of drilling fluid and SC-CO$_2$ were calculated in the method of coupling; the invaded SC-CO$_2$ could affect the mixed fluid physical properties in the annulus; the change of physical properties of CO$_2$ (e.g., solubility, phase transition) was considered and integrated. The research results indicate that as the mixture of drilling fluid and SC-CO$_2$ flows from the bottom to the surface, the invaded CO$_2$ is difficult to be detected at the early invasion stage because of high CO$_2$ density and solubility; the CO$_2$ would change from supercritical to gas phase and the dissolved quantity and density of CO$_2$ rapidly decrease near the wellhead, and further cause well-control issues. Furthermore, the bottom-hole pressure (BHP) would decrease and could not provide sufficient balance to the formation pressure, which could significantly increase the risk of well blowout. Sensitivity analysis was utilized to evaluate the effects of the choke pressure, drilling fluid pumping rate, initial pressure difference, reservoir permeability, and drilled reservoir thickness on the BHP and the depth of phase transition of CO$_2$.

KEYWORDS
bottom-hole pressure, heat transfer, phase transition of CO$_2$, supercritical CO$_2$, wellbore transient flow
1 | INTRODUCTION

Natural gas reserves with higher CO₂ concentration than 10% has more than 18.23 × 10¹² m³ gas in place around the world. A total of 33 CO₂ reservoirs and high CO₂ content gas reservoirs were discovered in east China and offshore shelf basins, and the source of CO₂ is classified into three types as crust origin, crust-mantle origin and volcano-mantle origin (Table 1).1,2 In most of these basins, such as Songliao Basin, Bohai Bay Basin, Subei Basin, Sanshui Basin, East China Sea Basin, Qiongdongnan Basin, Pearl River Mouth Basin and Yinggehai Basin, the maximum concentrations of CO₂ are greater than 90%. The maximum concentration of CO₂ from the produced fluids of Shatouwei gas field and Zhaizhuangzi gas field reaches 99.55% and 98.61%, respectively. Also, CO₂ was frequently injected for purposes of enhanced oil recovery, which increased the concentration of CO₂ in formations.3

CO₂ reservoirs and high CO₂ content gas reservoirs in marine sediments generally have complex pressure system with narrow drilling fluid density window. In this way, overflows are readily to happen. Formation temperature and pressure is generally much higher than CO₂ critical point (31.1°C, 7.38 MPa), hence CO₂ is generally in a supercritical state in the formation. The density of SC-CO₂ is close to liquid while the viscosity is close to gas. The diffusion coefficient of SC-CO₂ fluid is large while the surface tension of SC-CO₂ is close to zero. Owing to the high solubility and possible phase transition of CO₂ (CO₂ transforms from supercritical state to gas state caused by the drop of wellbore temperature and pressure), a complex multiphase flow caused by the supercritical CO₂ (SC-CO₂) invasion in the wellbore may induce severe well blowout during drilling, oil testing and production processes. For example, a vast scale of pure CO₂ gas gushed out of the wellbore in Sanshui gas field and Huangqiao gas field in China. Similar incidences of CO₂ gas well blowout also occurred in New Mexico, Colorado and Wyoming of America.4

Although high CO₂ content gas influx has resulted in serious drilling and completion accident, there were few researches on CO₂ and/or high CO₂ content gas in the past. Before this research, there is a lack of information about well control safety during formation high CO₂ content fluid invasion. Only Yuan,5 Shi et al.,5 Sun et al.6 and Dou et al.7-8 have done some work on annular flow during formation sour gas invasion. However, some common problems appeared in these researches. For example, gas was assumed to constantly influx to a wellbore, which was not coupled with the processes of the multiphase flow in wellbore and seepage flow in the formation. This does not confirm with the actual situation. Also, quantitative calculation lacked adequate accuracy. Furthermore, the wellbore heat transfer, solubility and possible phase transition of CO₂ in wellbore were neglected, the effect of drilling operating parameters on annular pressure and CO₂ phase transition were not taken into consideration. Hence, the challenges were not fully solved.

In this paper, a numerical model coupling the flow-temperature distribution in wellbores with the non-Darcy seepage through formation media was formulated to study the transient multiple-phase flow during SC-CO₂ invasion. In this model, invaded CO₂ fluid properties, such as density, viscosity and solubility, were determined as functions of temperature and pressure in the wellbore. The characteristics of gas-liquid two-phase transient flow and phase transition of CO₂ in the annulus were investigated. The mechanisms for well blowout triggered by solubility variation and phase transition of CO₂ were studied through the complex calculation of relevant samples in the research, which was of great importance in discovering the kick and for measuring the annular transient flow and phase transition during SC-CO₂ invasion. This modeling of formation SC-CO₂ invasion facilitates the improvement of well control design and operational safety guidance during the exploration of CO₂ reservoirs and high CO₂ content gas reservoirs.

2 | MATHEMATICAL MODELS OF WELLBORE TRANSIENT FLOW DURING SC-CO₂ INVASION

2.1 | Transient flow physics model and basic hypothesis

Based on the laws of mass, momentum and energy conservation, Figure 1 demonstrates a physical model formulated to describe multi-phase transient flow and heat transfer. In this diagram, the annulus flow direction is assigned as Z where dZ is taken as an infinitesimal section. An intrusive source Qi is assumed at the bottom of the wellbore.

Taking into account of the wellbore multiphase transient flow and heat transfer during SC-CO₂ invasion, the following assumptions are made to deduce the mathematical model:

1. The heat transfer state remains steady in the wellbore, but unsteady in the formation. The heat conduction in the wellbore and its surrounding formation occurs only in the radial direction.
2. 1D flow is assumed along the well trajectory.
3. The internal energy changes caused by CO₂ phase transition will not be taken into account.
4. Gas and liquid phases have identical pressures and temperatures.
5. The impact of cuttings on the flow patterns of two-phase flow is not considered, and the heat generated from drill string rotating is ignored.
6. The formation of methane or carbon dioxide hydrate is not supposed to occur in the wellbore transient flow process.
| Genesis of CO₂ | Basin             | Gas reservoirs | Typical well | Layer | Natural gas composition (%) | Carbon isotope (PDB, ‰) | R/R₀ | CO₂ | CH₄ |
|----------------|-------------------|----------------|--------------|-------|-----------------------------|------------------------|------|------|------|
| Volcano-mantle origin | Songliao Basin | Wanjinta | Wan5 | K₁q₃ | CO₂ 93.43  N₂ 2.67  CH₄ 3.74  C₂⁺ 3.34 | R/R₀ 3.34 | CO₂ −4.95 | CH₄ −38.66 |
|                 |                   | Qian | Qs10 | K₁q₄ | N₂ 80.73  CH₄ 16.16  CO₂ 0.99  C₂⁺ 0.20 | R/R₀ 3.16 | CO₂ −3.73 | CH₄ −43.97 |
|                 |                   | Gudian | Gu9 | K₁q₄ | CH₄ 97.05  N₂ 2.65  CO₂ 0.20 | R/R₀ 3.22 | CO₂ −8.44 | CH₄ −43.97 |
| Bohai Bay Basin | Zhaizhuangzi | Guang151 | E₅₁ |  | CO₂ 72.50  CH₄ 0.33  N₂ 23.52  C₂⁺ 3.51 | R/R₀ 2.76 | CO₂ −4.57 | CH₄ −51.67 |
|                 | Pingfangwang | Bīn₄-6-6 | E₄₄ |  | CO₂ 79.17  N₂ 0.38  CH₄ 17.13  C₂⁺ 3.19 | R/R₀ 2.58 | CO₂ −4.50 | CH₄ −51.80 |
|                 | Ping12-61 | Bīn₄-6-6 | E₄₄ |  | CO₂ 79.17  N₂ 0.38  CH₄ 17.13  C₂⁺ 3.19 | R/R₀ 2.58 | CO₂ −4.50 | CH₄ −51.80 |
|                 |                 | Pingnán | Bīngu14 | O₂ 96.99  N₂ 0.46  CH₄ 1.16  C₂⁺ 1.39 | R/R₀ 2.00 | CO₂ −4.76 | CH₄ −47.50 |
|                 | Huagou | Hua7 | E₅₃ |  | CO₂ 93.78  CH₄ 1.60  N₂ 3.89  C₂⁺ 0.73 | R/R₀ 3.18 | CO₂ −3.41 | CH₄ −54.39 |
|                 | Yang25 | Yang25 | E₄₄ |  | CO₂ 96.50  CH₄ 3.06  N₂ 0.44 | R/R₀ 2.94 | CO₂ −4.38 | CH₄ −42.51 |
| Subei Basin | Huangqiao | Sū174 | P₁q₄ |  | CO₂ 95.10  CH₄ 0.85  N₂ 0.05 | R/R₀ 3.96 | CO₂ −2.65 | CH₄ −29.61 |
|                 | Dingzhuangduo | Sūdōng203 | E₂d |  | CO₂ 92.06  CH₄ 5.09  N₂ 2.05  C₂⁺ 0.11 | R/R₀ 2.74 | CO₂ −3.82 | CH₄ −46.60 |
|                 | Gaoyou | Jī | E₁₄ |  | CO₂ 92.32  CH₄ 5.31  N₂ 0.81  C₂⁺ 0.18 | R/R₀ 4.58 | CO₂ −4.10 | CH₄ −46.60 |
| Sanshui Basin | Baoyue | Nān7 | E₁₁+b |  | CO₂ 83.99  CH₄ 1.79  N₂ 12.29  C₂⁺ 1.93 | R/R₀ 3.80 | CO₂ −4.51 | CH₄ −34.12 |
|                 | Shatouwei | Sūshīn9 | E₁₁+b|  | CO₂ 99.55  CH₄ 0.26  N₂ 0.19  C₂⁺ 0.13 | R/R₀ 4.29 | CO₂ −5.03 | CH₄ −46.30 |
| East China Sea Basin | Shimentan | Shimentan1 | E₁lf |  | CO₂ 95.63  CH₄ 0.67  N₂ 1.62  C₂⁺ 0.85 | R/R₀ 4.58 | CO₂ −4.36 | CH₄ −42.07 |
|                 | Wenzhou13-1 | WZ₁₃-1-1 | E₁lf |  | CO₂ 98.59  CH₄ 1.19  N₂ 0.22  C₂⁺ 8.80 | R/R₀ 8.80 | CO₂ −4.20 | CH₄ −46.60 |
|                 | Lishui36-1 | LS₃₆-1-1 | E₁₁₈rf |  | CO₂ 34.15  CH₄ 55.45  N₂ 6.85  C₂⁺ 1.54 | R/R₀ 4.25 | CO₂ −7.50 | CH₄ −38.80 |
| Qiongdongna Basin | BD19-2 | BD19-2-2 | E₁₁₈ |  | CO₂ 87.92  CH₄ 1.50  N₂ 9.84  C₂⁺ 0.74 | R/R₀ 4.25 | CO₂ −7.50 | CH₄ −38.80 |
|                 | BD15-3 | BD15-3-1 | E₁₁₈ |  | CO₂ 97.64  CH₄ 0.48  N₂ 1.80  C₂⁺ 1.84 | R/R₀ 4.58 | CO₂ −4.36 | CH₄ −42.07 |
| Pearl River Mouth Basin | Wenchang15-1 | WC₁₅-1-1 | N₁₁₁ |  | CO₂ 76.98  CH₄ 4.81  N₂ 12.46  C₂⁺ 5.76 | R/R₀ 4.11 | CO₂ −4.09 | CH₄ −40.00 |
|                 | Wenchang14-1 | WC₁₄-3-1 | E₂zh |  | CO₂ 38.87  CH₄ 1.31  N₂ 43.62  C₂⁺ 16.20 | R/R₀ 3.06 | CO₂ −4.53 | CH₄ −41.88 |
|                 | Huizhou18-1 | HZ₁₈-1-1 | E₁₁₁ |  | CO₂ 93.56  CH₄ 5.26  N₂ 0.61  C₂⁺ 0.16 | R/R₀ 3.60 | CO₂ −3.60 | CH₄ −43.19 |
|                 | Panzong28-2 | PY₂₈-2-1 | E₂zh |  | CO₂ 82.70  CH₄ 9.02  N₂ 5.68  C₂⁺ 0.90 | R/R₀ 3.92 | CO₂ −3.92 | CH₄ −41.35 |
| Crust origin | Yinggehai Basin | DFI1-1/2 | N₃₁ |  | CO₂ 64.70  CH₄ 5.82  N₂ 27.97  C₂⁺ 1.52 | R/R₀ 1.25 | CO₂ 0.07 | CH₄ −3.80 | CH₄ −31.90 |
|                 | DFI1-1Z | DFI1-1/2 | N₃₁ |  | CO₂ 49.52  CH₄ 5.24  N₂ 43.11  C₂⁺ 2.13 | R/R₀ 0.03 | CO₂ −0.65 | CH₄ −30.08 |
|                 | DF29-1/1 | DF29-1/1 | N₃₁ |  | CO₂ 88.91  CH₄ 5.45  N₂ 5.26  C₂⁺ 0.38 | R/R₀ 0.14 | CO₂ −2.00 | CH₄ −32.10 |
|                 | LD15-1 | LD15-1-1 | N₃₁ |  | CO₂ 93.40  CH₄ 0.8  N₂ 5.30  C₂⁺ 0.50  | R/R₀ 0.26 | CO₂ −4.15 | CH₄ −34.54 |
|                 | LD21-1 | LD21-1-1 | N₃₁ |  | CO₂ 83.97  CH₄ 6.63  N₂ 8.71  C₂⁺ 0.68  | R/R₀ 0.31 | CO₂ −4.18 | CH₄ −36.08 |
| Crust-mantle origin | Yinggehai Basin | LD8-1 | LD8-1-1 | N₃₁ | CO₂ 71.20  CH₄ 4.21  N₂ 22.73  C₂⁺ 2.02 | R/R₀ 1.56 | CO₂ −3.65 | CH₄ −31.32 |
2.2 Transient flow mathematical model development

The whole process in the wellbore during SC-CO₂ invasion is divided into three parts: (a) SC-CO₂ influxes into the bottom hole; (b) The invaded CO₂ fluid arises along the drilling fluid; (c) Single phase of drilling fluid flows in the uppermost part of the wellbore. The three parts altogether must comply with the physical conservation law. Compared to part (a), part (b) lacks an invasion item and part (c) describes a single-phase flow which is relatively simple, so no further details will be provided.

2.2.1 Mass conservations

When SC-CO₂ fluid flows into a bottom hole, the multiphase fluids consist of free gas, dissolved gas and the drilling fluid, with the mass conservation equations given by Equations 1-3. CO₂ dissolves in drilling fluid resulting in dissolved gas. Drilling fluid is mixed with the dissolved gas into a liquid phase. So the velocity of dissolved gas equals to the velocity of drilling fluid.

\[
\frac{\partial (AE_g \rho_g)}{\partial t} + \frac{\partial}{\partial z} (AE_g \rho_g v_g E_g) = q_i - q_s
\]

\[
\frac{\partial (AE_s \rho_s)}{\partial t} + \frac{\partial}{\partial z} (AE_s \rho_s v_s E_s) = q_s
\]

\[
\frac{\partial (AE_d \rho_d)}{\partial t} + \frac{\partial}{\partial z} (AE_d \rho_d v_d E_d) = 0
\]

\[
E_g + E_s + E_d = 1
\]

where, \( A \) is wellbore annulus cross-sectional area, \( m^2 \); \( E \) is fluid volume fraction, dimensionless; \( \rho \) is fluid density, kg/\( m^3 \); \( t \) is time; \( s \) is well-trajectory spatial variable; \( m \); \( v \) is superficial velocity of mixture, m/s; \( q_i \) is invaded gas flow rate per micro unit length, kg/(m s); \( q_s \) is dissolved quantity of invaded gas per micro unit length, kg/(m s). Subscripts, \( g \) is free gas, \( s \) is dissolved gas; \( d \) is drilling fluid.

2.2.2 Momentum conservation equations

In our model, momentum equations are derived for the liquid phase in which dissolved gas and drilling fluid are mixed together.

\[
\begin{align*}
\frac{\partial}{\partial t} (AE_g \rho_g v_g E_g) + \frac{\partial}{\partial z} (AE_g \rho_g v_g^2 E_g) + Ag \cos \theta (E_g \rho_g) + \frac{d(Ap)}{dz} + A \frac{dv}{dz} |_{fr} = 0 \\
\frac{\partial}{\partial t} (AE_s \rho_s v_s) + \frac{\partial}{\partial z} (AE_s \rho_s v_s^2) + \frac{d(Ap)}{dz} + A \frac{dv}{dz} |_{fr} = 0
\end{align*}
\]

where, \( g \) is gravity acceleration, 9.81 m/s²; \( \theta \) is deviation (°). Subscripts, \( fr \) is friction pressure.

Except for the partial differential term of time variables, the annular multiphase flow pressure drop includes hydrostatic pressure gradient, friction pressure gradient and acceleration pressure gradient. Perez model⁹ for gas-liquid two phase flow pressure drop gradient calculation is adopted in the paper.

2.2.3 Energy conservation equations

As shown in Figure 1, the upward direction is designated as positive. In the micro unit \( dZ \), the heat of annulus fluid comes from two parts; one is heat entered from the lower annular \( Q(Z+dZ) \) and the other is the heat transmit from the formation to the micro unit of annular fluid \( Q_A \). For the process of SC-CO₂ flowing to bottom hole, the additional heat source is the formation SC-CO₂ fluid brought \( Q_i \) relative to the wellbore fluids flowing. The heat loss of micro unit includes two aspects; one is heat outflow from the upside of annular \( Q(Z) \) and the other one is the heat transmit from annular to drill pipe \( Q_{AD} \). According to the energy conservation, the following expressions are derived.

Heat transfer of the annular two-phase flow can be written as

\[
Q(Z+dZ) - Q(Z) = Q_{AD} - Q_F
\]

Heat transfer of the two-phase flow in the bottom hole with SC-CO₂ influx is expressed as

\[
Q(Z+dZ) - Q(Z) = Q_{AD} + Q_i - Q_F
\]
where, \( h \) is specific enthalpy, kJ/kg.

Heat transfer of the two-phase flow in the bottom hole with SC-CO\(_2\) influx is

\[
\frac{d}{dz} \left[ Apv \left( h + \frac{v^2}{2} - g dz \cos \theta \right) \right] = Q_{AD} - Q_F
\]

(9)

where, \( Q_{AD} \) is the rate of heat transfer in the drill pipe, W.

2.2.4 Two-phase flow heat transfer coefficient

A variety of empirical models of two-phase flow heat transfer coefficient have been developed for different flow patterns. Adequate accuracy has been demonstrated in some of them cited in the literature review. In the Chemical Engineering Department at the Oklahoma State University, some models were proposed to investigate different flow states. For example, the Aggour\(^{11}\) model was built for studying bubble flow; the Knott et al\(^{12}\) model was established to investigate dispersed bubble; the Rezkallah\(^{13}\) model was used for slug and churn flow; the Ravipudi\(^{14}\) model was proposed for annular flow in vertical pipes. The two-phase flow mainly exists as turbulent flow, so only turbulent flow models are shown in the paper.

Aggour model:

\[
\frac{h_{tp}}{h_l} = (1 - \alpha)^{-0.83}
\]

(12)

where, \( h_{tp} \) is convective heat transfer coefficient of two-phase, W/(m\(^2\)K); \( h_l \) is convective heat transfer coefficient of liquid, W/(m\(^2\)K); \( \alpha \) is void fraction, dimensionless.

\[
Nu_l = 0.0155(Re_d)^{0.83}(Pr_t)^{0.5}\left( \frac{\mu_b}{\mu_w} \right)^{0.33}
\]

(13)

where, \( Nu_l \) is Nusselt number of liquid, dimensionless; \( Re_d \) is superficial Reynolds number of liquid, dimensionless; \( Pr_t \) is Prandtl number of liquid, dimensionless; \( \mu_b \) is dynamic viscosity of gas, kg/(m s); \( \mu_w \) is dynamic viscosity of liquid, kg/(m s).

Knott et al. model:

\[
\frac{h_{tp}}{h_l} = (1 + \frac{v_{sg}}{v_{sl}})^{1/3}
\]

(14)

where, \( v_{sg} \) is superficial velocity of gas, m/s; \( v_{sl} \) is superficial velocity of liquid, m/s.

\[
Nu_l = 0.027(Re_d)^{0.83}(Pr_t)^{0.33}\left( \frac{\mu_b}{\mu_w} \right)^{0.14}
\]

(15)

Rezkallah model:

\[
\frac{h_{tp}}{h_l} = (1 - \alpha)^{-0.9}
\]

(16)

\[
Nu_l = 0.027(Re_d)^{0.83}(Pr_t)^{0.33}\left( \frac{\mu_b}{\mu_w} \right)^{0.14}
\]

(17)

Ravipudi model:

\[
Nu_l = 0.56\left( \frac{v_{sg}}{v_{sl}} \right)^{0.3}\left( \frac{\mu_b}{\mu_w} \right)^{0.2}(Re_d)^{0.6}(Pr_t)^{1/3}\left( \frac{\mu_b}{\mu_w} \right)^{0.14}
\]

(18)

where, \( Nu_l \) is Nusselt number of two-phase, dimensionless; \( \mu_b \) is dynamic viscosity of gas, kg/(m s); \( \mu_l \) is dynamic viscosity of liquid, kg/(m s).

2.3 Auxiliary equation

2.3.1 Equation of state for CO\(_2\)

For pure CO\(_2\) or almost pure CO\(_2\) (ie CO\(_2\) takes over 90% of the total volume), Span and Wagner\(^{15}\) developed an equation of state for CO\(_2\), SW-EOS, using the basic form of the dimensionless Helmholtz energy. SW-EOS can be divided into an ideal part (\( \Phi^o \)) and a residual part (\( \Phi^r \)) and is written as

\[
\Phi(\delta, \tau) = \Phi^o(\delta, \tau) + \Phi^r(\delta, \tau)
\]

(19)

where, \( \Phi(\delta, \tau) \) is the Helmholtz energy with reduced density and inverse reduced temperature (\( \delta = \rho/\rho_c \) and \( \tau = T_c/T \)), dimensionless; \( \rho \) is fluid density, kg/m\(^3\); \( T_c \) is temperature, K; \( \rho_c \) is critical density of CO\(_2\), kg/m\(^3\); \( T_c \) is critical temperature of CO\(_2\), K.

\[
\Phi^o(\delta, \tau) = \ln \delta + a_1^o + a_2^o \tau + a_3^o \ln \tau + \sum_{i=4}^{8} a_i^o \ln \left( 1 - \exp \left( -\tau \delta^{\alpha_i} \right) \right)
\]

(20)

\[
\Phi^r = \sum_{i=1}^{7} \sum_{j=1}^{n_{ij}} \left[ a_{ij} \delta^{\theta_{ij} \tau} e^{\theta_{ij} \delta - \theta_{ij} \tau} \right] + \sum_{i=1}^{42} n_i A_i^b \delta^{c_i \delta - c_i \tau} + B_i \left( \delta - \tau \right)^{d_i}
\]

(21)

where, \( a_i^o, a_{ij}, a_{ij}^o, \theta_{ij}, n_i, t_i, d_i, \beta_i, \gamma_i, C_i, D_i, A_i, B_i \) are non-analytic coefficients, dimensionless.

This equation was adopted to calculate density (compressibility factor), isobaric specific heat and specific enthalpy,
which are extremely important parameters in fluid flow and heat transfer calculation. The estimated uncertainty in density ranges from 0.03% to 0.05%, as reported by the authors. CO₂ density could be determined by solving Equation 4 numerically.

\[
n = \frac{\rho(\delta, \tau)}{(RTZ)} = \frac{\rho(\delta, \tau)}{(RT(1 + \delta \Phi_r^o))}
\]  

(22)

where, \( p \) is pressure, MPa; \( R \) is universal gas constant, 8.314 J/(mol K); \( \Phi_r^o \) is derivatives of the reduced Helmholtz energy, dimensionless.

Equation 23 provides an analytical solution of the isobaric specific heat of CO₂.

\[
C_p(\delta, \tau) = R \left[ -\tau^2(\Phi_p^0 + \Phi_r^0) + \frac{(1 + \delta \Phi_r^o - \delta \tau \Phi_r^o \Phi_r^o)^2}{1 + 2\delta \Phi_r^o + \delta^2 \Phi_r^o} \right] \]  

(23)

where, \( C_p \) is isobaric specific heat, J/(kg K); \( \Phi_p^o, \Phi_r^o, \Phi_r^o, \Phi_{r\tau}^o, \Phi_{oo}^o, \Phi_{r\tau}^o \) are derivatives of the reduced Helmholtz energy, dimensionless.

CO₂ enthalpy could be determined by solving Equation 24.

\[
h(\delta, \tau) = RT[1 + \tau(\Phi_r^0 + \Phi_r^0) + \delta \Phi_r^o] \]  

(24)

where, \( h \) is specific enthalpy, kJ/kg; \( \Phi_r^0, \Phi_r^0, \Phi_r^0 \) are derivatives of the reduced Helmholtz energy, dimensionless.

2.3.2 | Viscosity and thermal conductivity of CO₂

The models from Fenghour et al.\(^\text{16}\) and Vesovic et al.\(^\text{17}\) were adopted to calculate viscosity and thermal conductivity of CO₂, respectively. The uncertainties associated with the proposed representation vary from ±0.3% for the viscosity of the dilute gas near room temperature to ±5.0% at the highest pressures.

The viscosity and thermal conductivity can be expressed in a same formula.

\[
X(\rho, T) = X^0(T) + \Delta X(\rho, T) + \Delta_x X(\rho, T)
\]  

(25)

It is decomposed into three separate contributions, where \( X^0(T) \) is the value in the zero-density limit, \( \Delta X(\rho, T) \) is an excess viscosity which represents the increased value at elevated density over at the same temperature, and the \( \Delta_x X(\rho, T) \) dilute gas value a critical enhancement accounting for the increase in the immediate vicinity of the critical point.

So we can obtain the viscosity expression as:

\[
\eta(\rho, T) = \eta_0(T) + \Delta \eta(\rho, T) + \Delta_\eta(\rho, T)
\]  

(26)

Similarly, the thermal conductivity can be expressed as:

\[
\lambda(\rho, T) = \lambda^0(T) + \Delta \lambda(\rho) + \Delta_x \lambda(\rho, T)
\]  

(27)

2.3.3 | Solubility of CO₂

To study the solubility of CO₂, a thermodynamic model\(^\text{18}\) was established to apply in both pure water and aqueous NaCl solutions, where temperature ranged from 273 to 533 K, pressure from 0 to 2000 bar. Predictions from this model show a small uncertainty compared to experimental data and the uncertainty is 7% in CO₂ solubility. Equation 10 provides an analytical solution of the solubility of CO₂.

\[
\text{Par}(T, P)_{\text{CO}_2} = C_1 + C_2 T + C_3 / T + C_4 T^2 + C_5 / (630 - T) + C_6 P + C_7 P \ln T + C_8 P / T + C_9 P / (630 - T)
\]  

(28)

\[
+C_{10} P^2 / (630 - T)^2 + C_{11} T \ln P
\]

where, \( c_1-c_{11} \) are non-analytic coefficients, dimensionless; \( T \) is absolute temperature, K; \( P \) is total pressure, bar.

In order to compare the dissolution difference between CO₂ and CH₄ which is the main component of conventional natural gas, another thermodynamic model\(^\text{19}\) to calculate methane solubility in H₂O–CH₄ and H₂O–CH₄–NaCl systems under the temperature ranging from 273 to 523 K (possibly up to 573 K), the pressure ranging from 1 to 2000 bar and the NaCl solubility from 0 to 6 mol/kg. Results from this model were accurate enough when compared to experimental data.

Equation 11 provides an analytical solution of the solubility of CH₄.

\[
\text{Par}(T, P)_{\text{CH}_4} = C_{11} + C_{12} T + C_{13} / T + C_{14} T^2 + C_{15} / T^2 + C_{16} P + C_{17} P T + C_{18} P / T + C_{19} P / T^2 + C_{20} P^2 / T
\]  

(29)

where, \( c_{11-c_{20}} \) are non-analytic coefficients, dimensionless; \( T \) is absolute temperature, K; \( P \) is total pressure, bar.

2.3.4 | Gas reservoir seepage-flow model

A semianalytical model\(^\text{20}\) to examine the transient pressure behavior of vertical wells with non-Darcy flow in sour gas reservoirs is applied, which accounts for the different values of inertial factor in the completion and in the gas reservoir.

2.3.5 | Drift-flux model

There is a slip velocity between liquid and gas due to the gravitational effects, which is an important factor in the analysis of multiphase flow and cannot be neglected for a realistic simulation.

The drift-flux equation for gas is given by

\[
v_{\text{tg}} = c_o (E_s v_s + E_d v_d + E_g v_g) + v_{\text{gr}}
\]  

(30)

where, \( v_{\text{tg}} \) is the flow velocity of the gas phase, m/s; \( c_0 \) is the profile parameter (or distribution coefficient), which describes the effect of the velocity and concentration profiles dimensionless; \( v_{\text{gr}} \) is slippage velocity of gas, describing the buoyancy effect, m/s.

\( c_0 \) and \( v_{\text{gr}} \) are determined according to the flow pattern.\(^\text{9}\)
3 | MODEL SOLUTION

To resolve these equations, proper initial and boundary conditions are defined as the following.

3.1 | Initial conditions

The fluid flow in the annulus transforms from a single phase flow of drilling fluid to a gas-liquid two-phase flow because of SC-CO2 invasion. Simultaneously, the flow in annulus transforms from a steady flow to a transient flow. Therefore, the initial condition for the temperature field when SC-CO2 invasion starts equals to the temperature field at the steady-flow state of drilling fluid. The initial condition of the temperature field for transient flow is obtained by

\[ T(z,0) = T_{st}(z) \]  

(31)

where, \( T_{st} \) is temperature of drilling fluid steady flow, K.

At the beginning of the gas invasion, the initial condition of the pressure field for transient flow is given by the pressure field for steady state single phase flow of the drilling fluid.

\[ p(z,0) = p_\text{st}(z) \]  

(32)

where, \( p_\text{st} \) is pressure of drilling fluid steady flow, MPa.

And the initial conditions of gas and liquid velocities in the wellbore when gas invasion starts are listed as follows.

\[ v_g(z,0) = 0 \]  

(33)

\[ v_l(z,0) = 0 \]  

(34)

\[ v_d(z,0) = 0.001Q_d/A \]  

(35)

where, \( Q_d \) is injection rate of drilling fluid, L/s.

At the first moments of gas invasion, the initial volume fraction of different components in the annulus are as follows:

\[ E_d(z,0) = 1 \]  

(36)

\[ E_g(z,0) = E_l(z,0) = 0 \]  

(37)

3.2 | Boundary conditions

The temperature of the drilling fluid injected at the entrance of the drilling pipe and the choke pressure at the exit of annulus need to be specified as the boundary conditions of the flow and heat transfer model in the wellbore.

\[ T(0,t) = T_{inj} \]  

(38)

where, \( T_{inj} \) is injection temperature of drilling fluid, K.

\[ p(0,t) = p_\text{c} \]  

(39)

where, \( p_\text{c} \) is choke pressure, MPa.

3.3 | Solution method

The physical parameters of CO2 fluid, such as viscosity, density, and solubility, have a major influence over wellbore temperature and pressure and vice versa. Simultaneously, the temperature and the pressure of the wellbore will influence one another. In order to improve the accuracy of the calculation, the wellbore temperature, pressure and physical parameters of CO2 fluid were calculated in the method of coupling.

The governing Equations (1) to (11) form a system of nonlinear equations. Therefore a finite difference method is used to solve the governing equations. According to the concrete finite difference equations, the difference scheme has second order accuracy which could satisfy the simulation demand. The following steps are the procedures to simulate the dynamic process of gas invasion between node \( i \) and node \( i+1 \) from time \( n \) to time \( n+1 \). The flow parameters in the wellbores at time \( n \) have been known.

1. Estimate the bottom-hole pressure (BHP) \( p_0^n \) at time \( n+1 \) and get the sour gas invasion rate \( q_i \) according to the gas reservoir seepage-flow model.

2. Assume the pressure at node \( i+1 \) and time \( n+1 \) as \( p_i^{n+1}(0) \), and calculate the temperature \( T_i^{n+1}(0) \) by solving the energy conservation equations and the flow parameters like density and viscosity of each component by solving the state equation.

3. Assume the gas volume fraction at node \( i+1 \) and time \( n+1 \) as \( \alpha_i^{n+1}(0) \) and calculate the velocity of fluid, dissolved gas and free gas by solving solubility equation and mass conservation equation.

4. Recalculate the new gas volume fraction \( \alpha_i^{n+1} \) by solving physical equations. If \( |\alpha_i^{n+1} - \alpha_i^{n+1}(0)| < \epsilon \) then go to the next step, otherwise return to step (3).

5. Calculate the new pressure \( p_i^{n+1} \) by solving the momentum conservation equation with the obtained parameters. If \( |p_i^{n+1} - p_i^{n+1}(0)| < \epsilon \) and \( |T_i^{n+1} - T_i^{n+1}(0)| < \epsilon \), it indicates that the prediction of \( p_i^{n+1} \) and \( T_i^{n+1} \) is accurate enough, and the calculation results at node \( i+1 \) could be used as the known parameters in calculation at node \( i+2 \). Otherwise return to step (2) until the requirement of accuracy is achieved.

6. Keep calculating until the node goes up to the wellhead, and the choke pressure \( p_\text{c} \) at the exit of annulus and the temperature of the drilling fluid injected \( T_{inj} \) at the entrance of the drilling pipe are got. If \( |p_\text{c} - p_i^*| < \epsilon \) and \( |T_{inj} - T_i^*| < \epsilon \),

\[ T_i^* \text{ is the new temperature of the drilling fluid, K.} \]
it indicates that the prediction of $p_c^*$ and $T_{\text{inj}}^*$ is accurate enough to begin the calculation of the next time step. Otherwise return to step (1).

4 | CALCULATIONS AND RESULTS

The comprehensive model was evaluated and analyzed by using data of Well LD15-1-1 in Yinggehai Basin, China. Table 2 shows the input parameters for the cases that we used in this section. In fact, SC-CO$_2$ invasion during drilling process is of frequent occurrence in CO$_2$ reservoirs and/or high CO$_2$ content gas reservoirs in east China and offshore shelf basins. Conventional natural gas whose main component is methane(CH$_4$) invasion was used as a contrast to SC-CO$_2$ invasion.

4.1 | Annular temperature and pressure

Figure 2 compares the temperature profiles generated from formation SC-CO$_2$ and CH$_4$ invasion at the time when the invaded gas flows into the wellhead. The maximum temperature position is higher than that at the bottom of well. The mixed fluid temperature is usually lower than the formation temperature, but is greater near the wellhead. The SC-CO$_2$ invasion and CH$_4$ invasion generated similar temperature profiles. This is due to a minor heat transfer resulted from minor differences in heat exchange time and coefficient for different gas invasion. The annular temperature for SC-CO$_2$ invasion is slightly lower than the temperature for CH$_4$ invasion near the wellhead, and the reason for this result is that the annular fluid velocity for CH$_4$ invasion is relatively higher, which resulted in less heat exchange time.

Figure 3 shows that the annular pressure profiles generated from formation SC-CO$_2$ invasion and CH$_4$ invasion at the time when the invaded gas flows into the wellhead. As a contrast, the annular pressure profile given during no gas invasion is presented in Figure 3. The results show that the annular pressure during formation SC-CO$_2$ invasion is greater than that during CH$_4$ invasion. Since the two-phase flow pressure gradient is proportional to the density of invaded gas and the density and solubility of invaded CO$_2$ is significantly greater, the pressure gradient becomes higher with SC-CO$_2$ invasion. Besides, the pressure gradient is negatively proportional to the free gas flow rate, which is reduced by the higher CO$_2$ solubility and results in a higher pressure gradient.

Specifically, CO$_2$ transition from supercritical to gas state near the wellhead during its rising in the annulus is caused by the drop in pressure and temperature. The density of CO$_2$ slowly decreases in the rising process before the phase transition happens until a sharp decline when the annular pressure reaches the critical point, shown in Figure 5 below. The annular flow above phase transition point is a two-phase flow and below the phase transition point it is a single-phase flow. Meanwhile, the pressure gradient of the two-phase flow is lower than that of the single-phase flow. After the occurrence of CO$_2$ phase transition, the annular pressure also drops drastically as shown in Figure 3. As the depth of phase transition (DPT) of CO$_2$ is close to the wellhead, the operation response time is so short that severe consequences may occur such as blowout, as shown in Figure 13 below.

Figure 4 illustrates the annular pressure profiles given for formation SC-CO$_2$ and CH$_4$ invasion when the mixed fluid top reaches the middle wellbore depth. For any given depth below the middle wellbore depth, the annular pressure for SC-CO$_2$ invasion is greater, similar to the case in Figure 3. For any depth above the middle wellbore depth, annular pressures remain the same as there is only the drilling fluid single-phase flow. Figure 4 also show that the annulus pressure for SC-CO$_2$ invasion is almost equal to the annulus pressure during no gas invasion. From SC-CO$_2$ invasion initial moment to the moment of the mixed fluid top of SC-CO$_2$ and drilling fluid reaching middle wellbore depth, the density of invaded CO$_2$ in the wellbore is high caused by high pressure, which in turn results in no obvious pressure reduction. Besides, the invaded rate is small and increases extremely slowly caused by the small and almost constant initial pressure difference between formation pore pressure and BHP. In addition, the invaded CO$_2$ completely dissolves in drilling fluid which also leads to the no significant pressure change. And Figure 4 also implies that CO$_2$ invasion is not easy to be detected at the early stage.

4.2 | Properties of invaded gas in the annulus

Figure 5 demonstrates how the curves of invaded gas (fluid) density vary for formation SC-CO$_2$ and CH$_4$ invasion at the time when the invaded gas flows into the wellhead. The density of CO$_2$ is significantly larger than that of CH$_4$ (conventional natural gas) before phase transition of CO$_2$. This implies a high risk of well control owing to a small pressure drop with relatively large density of CO$_2$. As the pressure and temperature decrease to the critical point, the phase transition of CO$_2$ occurs, and the density sharply drops and the volume dramatically increases. This indicates that the pressure in the wellbore also drop drastically, as shown in Figure 3. When the density of drilling fluid is constant, the slip velocity of gaseous CO$_2$ increases caused by the decrease of CO$_2$ density after the phase transition, the increased gas velocity will reduce the well control operation response time. The decrease of annular pressure after the phase transition results in the gaseous CO$_2$ transforming from dissolved state to free gas, which in turn further leads to pressure reduction.
### TABLE 2  Basic parameters of Well LD15-1-1

| Input parameters | Value | Input parameters | Value |
|------------------|-------|------------------|-------|
| Seawater depth   | 87 m  | Formation heat capacity | 837 J/(kg K) |
| Well depth       | 4500 m| Formation density | 2.63 g/cm³ |
| Surface temperature | 30°C | Outer diameter of riser | 533.4 mm |
| Choke pressure   | 1 MPa | Inner diameter of riser | 501.65 mm |
| PDC bit size     | 212.73 mm | Riser thermal conductivity | 0.07 W/(m °C) |
| Inner diameter of drill pipe | 121.36 mm | Riser heat capacity | 1300 J/(kg °C) |
| Outer diameter of drill pipe | 139.7 mm | Cement stone thermal conductivity | 0.7 W/(m °C) |
| Drill collars length | 140 m | Cement stone heat capacity | 2000 J/(kg °C) |
| Inner diameter of drill collar | 76 mm | Cement stone density | 3.14 g/cm³ |
| Outer diameter of drill collar | 165.1 mm | Steel thermal conductivity | 43.75 W/(m °C) |
| Drilling fluid density | 1.9 g/cm³ | Steel heat capacity | 400 J/(kg °C) |
| Drilling viscosity | 0.051 Pa s | Steel density | 7.8 g/cm³ |
| Drilling fluid heat capacity | 2000 J/(kg °C) | Seawater thermal conductivity | 0.58 W/(m °C) |
| Drilling fluid conductivity | 1.45 W/(m °C) | Roughness of drill pipe and casing wall | 0.045 mm |
| Drilling fluid pumping rate | 25 L/s | Roughness of borehole wall | 2.5 mm |
| Injection temperature | 40°C | Circulation time | 30 min |
| Gas reservoirs permeability | 15 mD | Drainage radius of gas reservoir | 300 m |
| Geothermal gradient | 0.041 °C/m | Drilled gas reservoir thickness | 5 m |
| Formation thermal conductivity | 2.25 W/(m °C) | Skin factor | 1.5 |
| Initial pressure difference | 2 MPa | |

**FIGURE 2**  Comparison of annular temperature of SC-CO₂ invasion with CH₄ invasion at the time when the invaded gas flows into the wellhead

**FIGURE 3**  Comparison of annular pressure of SC-CO₂ invasion with CH₄ invasion at the time when the invaded gas flows into the wellhead
Figures 6 and 7 show the profiles of free gas (or liquid) quantity and dissolved quantity of invaded gas (or fluid) when the invaded SC-\(\text{CO}_2\) and \(\text{CH}_4\) flow to the wellhead. In Figure 6, the non-zero intervals of free \(\text{CO}_2\) quantity are located in near the wellhead and at the well bottom. For the small interval near the wellhead, this occurs owing to the small solubility caused by the low annulus pressure. For the situation at the well bottom, there is a large rate of invasion indicating that the mass flow rate of invaded \(\text{CO}_2\) is greater than the solubility. The large middle interval with zero mass flow rate exists showing that the mass flow rate of \(\text{CO}_2\) is less than or equals to the solubility. Figure 6 also demonstrates that the free \(\text{CH}_4\) gas quantity is large. This is because the solubility (dissolved quantity) of \(\text{CH}_4\) is extremely small and significantly less than the solubility of \(\text{CO}_2\) as shown in Figure 7.

Note that dissolved quantity of invaded gas \(V_{\text{dis}}\) is calculated by the following formula.

\[
V_{\text{dis}} = 10^{-6}S_{\text{CO}_2}Q_d \rho_d M
\]  

(40)

where, \(V_{\text{dis}}\) is dissolved quantity of invaded gas, kg/s; \(S_{\text{CO}_2}\) is solubility of \(\text{CO}_2\) in NaCl solution, mol/kg; \(M\) is molecular weight of \(\text{CO}_2\), 44 g/mol.

And free gas quantity (kg/s) is equal to invaded gas quantity (kg/s) minus dissolved quantity of invaded gas (kg/s).

Figure 7 shows that the dissolved quantity of invaded \(\text{CO}_2\) fluid is greater than \(\text{CH}_4\) in drilling fluid, which results in difficulty detecting SC-\(\text{CO}_2\) influx at the early stage of invasion. Figure 7 manifests that the dissolved quantity of \(\text{CO}_2\) fluid rapidly decreases when approaching the wellhead, in which a portion of dissolved \(\text{CO}_2\) transforms to free gas resulting in a rapid decrease in annular pressure.

Figures 8 and 9 show the profiles of annular void fraction of free gas when it reaches the wellhead and the middle wellbore depth, respectively. Below the wellbore depth where the phase transition starts to occur, the annular void fraction of \(\text{CO}_2\) is equal to zero as \(\text{CO}_2\) exists as supercritical state rather than gas state. Above this depth, \(\text{CO}_2\) transforms from supercritical state to gas state, but the void fraction of free \(\text{CO}_2\) gas is small because of the large dissolved quantity of \(\text{CO}_2\) shown in Figure 7. From Figures 8 and 9, the annular void fraction of free \(\text{CH}_4\) gas is remarkably greater than that of free \(\text{CO}_2\) gas. In Figure 8, the void fraction of free \(\text{CH}_4\) gas remains larger near the wellhead than that in the middle interval because of a lower pressure causes the rapid expansion of gas. Also in the bottom part, it is larger than that in the middle interval owing to a high invasion mass rate. In Figure 9, the void fraction of free \(\text{CO}_2\) gas is equal to zero, which illustrates that invaded \(\text{CO}_2\) is completely dissolved in the drilling fluid and no free gas.

Figure 10 shows that annular pressure changes with increasing gas column from the wellbore bottom. Generally, the BHP declines with rising gas height from the bottom-hole.
For SC-CO₂ invasion, the BHP declines slowly when the invaded gas goes through the wellbore until it reaches the wellhead, where it decreases sharply caused by the phase transition as shown in Figure 5. This readily results in the accident of blowout.

4.3 Bottom-hole pressure and kick time

Figure 11 shows that BHPs changes with kick time. Generally, BHPs declines with increasing kick time. The decline amplitude of BHP for CH₄ (conventional natural gas) invasion is significantly greater when compared with SC-CO₂ invasion. And there is a significant drop in BHP for CH₄ invasion at the initial moment which implies that the CH₄ invasion can be detected at the early stage. For SC-CO₂ invasion, the BHP declines slowly as kick time increases at the initial time, but the BHP decreases sharply in a very short time caused by the phase transition near the wellhead. This readily results in the accident of blowout.

Figure 12 demonstrates the kick time in response to varying concentration of CO₂ in the invaded gas. The kick time is the time that it takes for the invaded gas to flow from the bottom-hole to the wellhead within the annulus. As the CO₂ concentration increases, kick time decreases but the invaded gas has higher concealment. The kick time for CH₄ invasion is much less than that for SC-CO₂ invasion, and the possible mechanism contributing to the reduction of kick time for CH₄ invasion are the higher mixed fluid velocity caused by higher invaded gas quantity from Figure 6 and higher slippage velocity of gas caused by the lower density of CH₄ for CH₄ invasion.

4.4 Sensitivity analysis

For well control, it was desirable to investigate major factors affecting the annular pressure, especially the BHP and the DPT of CO₂ during formation SC-CO₂ invasion and to further optimize the well-control design. The BHPs and DPTs were dependent on the choke pressure, drilling fluid pumping rate, initial pressure difference between formation pore pressure and BHP, reservoir permeability, and drilled reservoir thickness. All these factors were investigated with the proposed numerical model by use of the same data presented in Table 2, with one parameter varied at a time. Sensitivity analysis was performed to identify the key factors that affect the BHP and the DPT. The analysis would provide the guidelines for the design and operation of the CO₂ reservoirs and high CO₂ content gas reservoirs drilling.

As seen from Figure 3, the temperature of the mixed fluids of CO₂ and drilling fluid is always higher than 49°C in the annulus (greater than critical temperature of CO₂), so the phase transition of CO₂ from supercritical state to gas state near wellhead occurs owing to the decrease of annular pressure. Consequently, the DPT is governed by the annular pressure.

**FIGURE 6** Comparison of annular free gas quantity for SC-CO₂ invasion with CH₄ invasion at the time when the invaded gas flows into the wellhead

**FIGURE 7** Comparison of annular dissolved quantity of invaded gas for SC-CO₂ invasion with CH₄ invasion at the time when the invaded gas flows into the wellhead
4.4.1 Effect of choke pressure on the BHP and the DPT

Figure 13 illustrates the BHP and the DPT calculated by the numerical model with the choke pressure varied from 0.1 to 4 MPa when the initial pressure difference remains constant. Figure 13 indicates that the BHP increases as the choke pressure increases, and the degree of increment of BHP is significantly greater than that of the choke pressure. The DPT decreases with the increasing choke pressure. The BHP and the DPT show an opposite trend, which is because the expansion of CO₂ volume decreases and the annular pressure gradient increases with the increasing choke pressure, and which will result in the increase of BHP and the decrease of DPT.
4.4.2 | Effect of drilling fluid pumping rate on the BHP and the DPT

Figure 14 demonstrates the BHP and the DPT calculated by the numerical model with the drilling fluid pumping rate varied from 20 to 35 L/s when the initial pressure difference remains constant. It indicated that the fast pumping of drilling fluid could increase the BHP, and the DPT was slightly reduced because higher pumping rate contributes to the increase of the mixed fluid density.

4.4.3 | Effect of initial pressure difference on the BHP and the DPT

Figure 15 presents the effect of initial pressure difference between formation pore pressure and BHP. The initial pressure difference was varied from 1 to 5 MPa. As the initial pressure difference increased, the BHP first declines, then attains a minimum, and thereafter increases. Figure 15 also shows an initial increase of the DPT with an increase of initial pressure difference, after which the DPT decreases again with the increase in initial pressure difference. The main reason is that annular pressure gradient first decreases sharply with the increase of initial pressure difference. But as the SC-CO$_2$ invasion rate continues to increase, the annular friction pressure climbs, especially near the wellhead, the two-phase flow rate is very high because of the drastic expansion of CO$_2$ volume and this will lead to the significant increase of two-phase flow friction pressure.

4.4.4 | Effect of reservoir permeability and drilled reservoir thickness on the BHP and the DPT

Figure 16 illustrates that the BHP would first decrease, and then increase as the reservoir permeability increases from 5 to 25 mD. The DPT would first increase, and then decrease with increase in reservoir permeability. The BHP and the DPT show an opposite trend. As seen from Figure 17, the effect of drilled reservoir thickness over the range 0-9 m on the BHP and the DPT is nearly same as the effect of reservoir permeability. As compared to reservoir permeability, the effect of drilled reservoir thickness was more pronounced. A possible mechanism contributing to the change of the BHP and the DPT is the increase of SC-CO$_2$ invasion rate as reservoir permeability and(or) drilled reservoir thickness increase. Higher SC-CO$_2$ invasion rate could first
reduce the annulus pressure of the mixed fluids, thereafter elevate the annulus pressure caused by the increase of annular friction pressure.

5 | CONCLUSIONS

A numerical model is presented in this research to analyze the transient flow in wellbores and to predict the phase transition of CO₂ during formation SC-CO₂ invasion in the drilling process. In this model, the multiphase transient flow in the wellbore was coupled with non-Darcy seepage through formation media, and the fluid properties were treated as functions of the temperature and pressure in the wellbore. Thermodynamic models for the solubility of CO₂ in pure water and in aqueous NaCl solution were considered, which significantly affected on the transient multi-phase flow of mixed fluid. With proposed numerical method and field data, the characteristics of gas-liquid two-phase transient flow and phase transition of CO₂ were further investigated. Sensitivity analysis was conducted to evaluate the effects of the choke pressure, drilling fluid pumping rate, initial pressure difference, reservoir permeability, and drilled reservoir thickness on the BHP and the DPT of CO₂. The following conclusions were drawn.

1. The annular pressure during formation SC-CO₂ invasion is higher than that during CH₄ invasion, and the annular pressure during SC-CO₂ invasion is slightly higher than that during CH₄ invasion.
2. As the mixture of drilling fluid and SC-CO₂ flows from the bottom to the surface, the invaded CO₂ is difficult to be detected at the early stage of invasion because of high CO₂ density and solubility.
3. CO₂ transforms from supercritical to gas state near the wellhead during its rising process in the annulus. The density of CO₂ slowly decreases in the rising process before the phase transition. However, the density decreases sharply as the annular pressure reaches the critical point, which will probably cause associated well-control issues.
4. The invaded SC-CO₂ is dissolved remarkably more than CH₄, but the free CO₂ flow rate is less than that of CH₄. CO₂ completely dissolves in drilling fluid in most part of the wellbore except places near the wellhead and at the bottom-hole. The dissolved quantity of CO₂ rapidly decreases near the wellhead, where a portion of dissolved CO₂ transforms to free gas resulting in a rapid decrease of the annular pressure.
5. For SC-CO₂ invasion, the BHP declines slowly as kick time increases at the initial time, but the BHP decreases sharply in a very short time caused by the phase transition near the wellhead. SC-CO₂ invasion hardly be detected and has higher concealment at the early stage. The kick time from the bottom-hole to the wellhead of CH₄ invasion is much less than that of SC-CO₂ invasion.
6. Choke pressure could greatly affect the DPT. The BHP increases as the choke pressure increases, and the degree of increment of BHP is significantly greater than that of the choke pressure. So it is a practical and effective method to control wellbore annular pressure by adjusting the choke pressure.
7. The fast pumping of drilling fluid could increase the BHP and slightly reduce the DPT.
8. As the initial pressure difference increased, the BHP first declines, then attains a minimum, and thereafter increases.
9. The effect of drilled reservoir thickness and reservoir permeability on the BHP and the DPT is nearly same as the effect of the initial pressure difference. The effect of drilled reservoir thickness was more pronounced in contrast to reservoir permeability.
10. The BHP and the DPT affected by all these factors on show an opposite trend.

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ORCID

Liangbin Dou http://orcid.org/0000-0002-8293-1794
Gang Bi http://orcid.org/0000-0001-8119-2902

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