Computer Aided Coupled Smart Prediction Model of Cement Temperature During Pressure Cementing in Deep-Water

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Abstract. Managed Pressure Cementing (MPC) is a new technology, which can precisely control the annular fluid pressure profile. Accurate calculation of wellbore temperature and pressure is the key to MPC. This paper focus on coupled models of temperature and pressure for MPC in deep-water region. On basis of the fluid rheology model, a coupled model of temperature and pressure in wellbore is established considering the transient flow characteristics during cementing displacement stage. A series of numerical simulations are conducted. Simulation results show that neglecting the interactions between temperature and pressure can cause a big error. During the well cementing, higher temperature in the deep part of wellbore reduces the fluid viscosity, which leads to a smaller friction. On the contrary, larger friction is observed near seabed as a result of the low temperature in deep-water environment. The pressure in wellbore changes frequently due to the coexistence of multiple fluids in wellbore.

1. Introduction

Managed Pressure Cementing technology [1] takes advantage of accurate wellbore hydraulic parameter calculations and wellhead back pressure control equipment. Thus the wellbore pressure can be precisely controlled in real time so that it always remains within the safe operation window. However, the process of cementing is complicated, and there are many coupling effects between temperature and pressure, which bring complicated wellbore temperature and pressure change in the process of cementing, challenging the accurate calculation of cementing wellbore hydraulic parameters.

At present, the prediction method of cementing wellbore temperature field given by American Petroleum Institute (API) is widely used [2], but it is a semi empirical prediction method based on adjacent well data, which can not truly reflect the current wellbore temperature. Therefore, based on the heat transfer characteristics of cementing process, scholars have proposed various heat transfer models to predict the fluid temperature of cementing wellbore. From the establishment of one-dimensional steady-state heat transfer model to three-dimensional unsteady heat transfer model, it has experienced a process from simple to complex and from considering the influence of single factor to considering the influence of multiple factors. Tragesser and some scholars first used a simple model to calculate wellbore temperature in the actual cementing process; In terms of wellbore pressure field, Carter et al. first found that the pressure of cement slurry decreased during cement setting stage. Based on this phenomenon, many scholars [3,4] have carried out relevant theoretical research based on experiments, and put forward their own theoretical models of cementing pressure drop.
The current research has not fully considered the temporal and spatial variation of rheological properties during cementing. In view of this, the coupling calculation model of wellbore temperature and pressure field in the whole process of cementing is established by comprehensively considering the unsteady flow characteristics, the temperature and pressure rheology. Based on this model, a series of numerical simulations were carried out with a case well, revealing the evolution law of transient temperature and pressure of Managed Pressure Cementing.

2. Coupled model of temperature and pressure during well cementing

2.1. Pressure calculation model

According to the law of conservation of momentum, the resultant force on a particle is equal to the rate of momentum change. The momentum equation of fluid in cementing wellbore can be calculated by the following formula:

$$\sum F = \frac{\partial (A \rho v)}{\partial t} + \frac{\partial (A \rho v^2)}{\partial s}$$

In the formula, $t$ is the time, s; $A$ is the cross-sectional area, $m^2$; $V$ is the flow rate, $m/s$; $\rho$ is the fluid density, $kg/m^3$; $s$ is the distance to the well-bottom, m; $F$ is the external force on the unit, N.

In the cementing unit, the external forces on the fluid include gravity, friction and pressure. Therefore, the momentum equation in cementing wellbore can be calculated by the following formula:

$$\frac{\partial (A \rho v)}{\partial t} + \frac{\partial (A \rho v^2)}{\partial s} = \rho g \cos \alpha + \frac{\partial (Ap)}{\partial s} + \frac{\partial (AF_r)}{\partial s}$$

Where $g$ is the acceleration of gravity, $m/s^2$; $\alpha$ is the inclination angle, $^\circ$; $P$ is the pressure, Pa; $F_r$ is the frictional pressure drop, Pa.

In the above formula, the friction terms of pipe flow and annular flow can be calculated as follows [5]. The general calculation formula of circulating pressure loss in casing and annulus are as follows:

$$\frac{\partial (F_r)}{\partial s} = \frac{0.01582 f_r \rho v^2}{d_i} \left(\frac{928 \rho vd_i \mu_d}{d_i} \right)^{0.25}$$

$$\frac{\partial (F_r)}{\partial s} = \frac{0.01582 \rho v^2}{d_h - d_p} \left[\frac{757 \rho v(d_h - d_p)}{d_h} \right]^{0.25}$$

In the formula, $f_r$ is the friction coefficient, s; $d_i$ is the inner diameter of casing, m; $d_h$ is the outer diameter of the annulus, m; $d_p$ is the inner diameter of the annulus, m; $\mu_a$ is the apparent viscosity, $pa.s.$

2.2. Temperature calculation model

The heat transfer process in wellbore during cementing circulation mainly includes the heat exchange between annulus and fluid in casing, and the heat carried by fluid flow in casing. According to the principle of energy conservation, the differential form of the fluid heat conduction model in the casing is obtained as follows:

$$\frac{1}{v_e} \frac{\partial T_c}{\partial t} + \frac{\partial T_c}{\partial z} = \frac{2 \pi r_c U_c}{c_p \lambda_v} (T_a - T_c)$$
In the formula, \( T_c \) is the temperature in casing, °C; \( c_f \) is the specific heat capacity of fluid, \( \text{J/(kg·°C)} \); \( z \) is the distance to wellhead, m; \( v_c \) is the velocity of fluid in casing, m/s; \( r_{ci} \) is the inner diameter of casing, m; \( U_c \) is the total heat transfer coefficient, \( \text{w/(m}^2·\text{°C)} \); \( T_a \) is the temperature in annulus, °C.

The heat transfer process in wellbore during cementing circulation, the heat transfer of unit cell in annulus mainly includes heat exchange between annulus and fluid in casing, heat exchange between annulus and formation, and heat carried by fluid flow in annulus. According to the principle of conservation of energy, the differential form of heat conduction model in annulus can be obtained as:

\[
\frac{1}{v_a} \frac{\partial T_a}{\partial t} - \frac{\partial T_a}{\partial z} = \frac{2\pi r_w U_a (T_{c,0} - T_a)}{c_f w} - \frac{2\pi r_w U_c}{c_f w} (T_a - T_e) \tag{6}
\]

In the formula, \( v_a \) is the velocity of fluid in the annulus, m/s; \( r_w \) is the wellbore size, m; \( U_a \) is the total heat transfer coefficient from the wellbore annulus to the formation, \( \text{w/(m}^2·\text{°C)} \); \( T_{c,0} \) is the formation temperature at the wellbore, °C.

2.3. Rheology parameters of cementing fluids

1) Prediction model of drilling fluid rheology parameter

Zhao Shengying [6] and others measured the rheological parameters of different drilling fluid systems under different temperature and pressure conditions based on laboratory tests, and proposed a prediction model of drilling fluid rheological parameters:

\[
f(P, T) = f(P_0, T_0) \exp[A(T - T_0) + B(P - P_0) + C(T - T_0)(P - P_0) + D(T - T_0)^2]
\tag{7}
\]

In the formula, \( f(P, T) \) represents the apparent viscosity, plastic viscosity and dynamic shear force under the condition of temperature \( T \) and pressure \( P \); \( f(P_0, T_0) \) represents the apparent viscosity, plastic viscosity and dynamic shear force under the condition of temperature \( T_0 \) and pressure \( P_0 \); \( A, B, C \) and \( D \) are the constants related to the characteristics of drilling fluid.

2) Prediction model of cement slurry rheology parameter

Perrot et al. and Haiyong Cheng et al. [7,8] have given the calculation model of rheological parameters of cement slurry with time and temperature changes on the basis of laboratory experiments:

\[
\phi = \phi_0 + \alpha e^{\beta T} t
\tag{8}
\]

Where, \( \phi \) is the rheological parameters of water mud at different temperatures and times, including apparent viscosity, plastic viscosity and dynamic shear force, Pa; \( \phi_0 \) is the initial rheological parameter value at a certain temperature, Pa; \( \alpha \) and \( \beta \) are experimental constants, which can be obtained based on the experimental values of \( \phi \) at different temperatures by means of curve regression of \( \ln(\Delta \phi)/T \).

3. Transient temperature and pressure evolution of wellbore during well cementing

A series of numerical simulation calculations were carried out for a simulation well by using the new model established in this paper. The formation of the simulation well has a typical narrow safety density window, with pore pressure of 72.21 MPa, formation fracture pressure of 79.07 MPa and. The target well is a horizontal well, with a total depth of 5890 m, a total vertical depth of 4902 m. The diameter of casing is 339.7 mm. The wellbore hole diameter is 444.5 mm.

3.1. Transient pressure distribution in wellbore during MPC

The wellbore pressure presents obvious unsteady characteristics during the cementing circulation stage, as shown in Figure 1. The cementing circulation stage is divided into nine processes. Process 1 is the initial stage of the cementing circulation, during which the spacer fluid is injected at the discharge rate
of 33.3 L/s. In this stage, the wellbore is mostly low-density drilling fluid, and the back pressure of 2.26 MPa needs to be added at the wellhead. Process 2 injects the flushing fluid at the discharge rate of 13.3 L/s. In process 3, the leading and tail cement slurry were injected at the displacement of 16.6 L/s, and the wellhead back pressure was reduced due to the increase of displacement. In process 4, the spacer fluid and flushing fluid began to enter the annulus and replace the light drilling fluid in the annulus, but mainly operated in the horizontal section, so the wellhead back pressure decreased slightly. In process 5, the spacer fluid and flushing fluid began to enter the vertical section of the wellbore. When the light drilling fluid in the annulus was replaced, the wellhead back pressure decreased obviously at this stage. In process 6, the displacement fluid 1 was injected at a flow rate of 8.3 L/s, and the wellhead back pressure needed to be increased due to the decrease of the flow rate. In process 7, the displacement fluid 2 and displacement fluid 3 were injected at a flow rate of 33.3 L/s, and the wellhead back pressure needed to be reduced due to the increase of the flow rate. Meanwhile, the leading and tail cement slurry also began to enter the annulus, and the wellhead back pressure gradually decreased. In process 8, the bottom hole pressure continues to increase due to the continuous entry of the leading and tail cement slurry into the annulus, but in the middle, the bottom hole pressure decreases briefly due to the entry of low-density flushing fluid into the vertical section. In process 9, the displacement fluid is injected at the rate of 8.3 L/s, and the bottom hole pressure decreases until the end of the cementing circulation.

![Simulation results of wellbore pressure during Managed Pressure Cementing](image)

**Fig 1.** Simulation results of wellbore pressure during Managed Pressure Cementing

### 3.2. Transient temperature distribution in wellbore during MPC

As shown in Fig. 2, based on the model established in this paper, the transient temperature at different depths of wellbore annulus during the cementing circulation stage is simulated. The simulation results show that the wellbore temperature is obviously affected by the fluid flow process in the circulation stage. Under the influence of geothermal gradient, the annulus temperature increases with the depth. In addition, the fluid in the wellbore flows from the well bottom to the wellhead, and the higher temperature fluid in the deep part flows to the shallow part, resulting in the gradual increase of the annulus temperature with time. But for the bottom hole position, the temperature of the bottom hole gradually decreases with time because the lower temperature fluid in the casing flows into the annulus at the bottom hole.
3.3. Fluid rheology in circulation stage of MPC

In order to reveal the influence of wellbore temperature and pressure environment on the rheological properties of cementing fluid, we simulated the distribution of rheological parameters in wellbore with and without temperature effect respectively. As shown in Figure 3, regardless of the influence of temperature and pressure, the rheological parameters of fluids in the wellbore are constant. Considering the temperature effect, it is found that the dynamic shear force and plastic viscosity of wellbore fluid decrease with the increase of well depth due to the higher wellbore temperature at the bottom hole. The comparison results show that the rheological properties of each fluid in cementing cycle stage are obviously affected by temperature, and the influence of temperature on accurate prediction of wellbore pressure can not be ignored.

Fig 2. Simulation results of wellbore temperature during cementing circulation

Fig 3. Simulation results of rheology parameters in wellbore during cementing circulation stage

4. Conclusions

(1) The cementing circulation stage involves a variety of fluids. The rheology, density and displacement of different fluids are different, which leads to the interference of many factors. The bottom hole pressure
presents obvious unsteady characteristics in the cementing circulation process, which puts forward higher requirements for wellbore pressure control.

(2) The influence of temperature on the rheological properties of each fluid in cementing cycle stage is obvious, and the rheological properties of different fluids are obviously different. The influence of temperature on rheology can not be ignored.

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