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Pressure Analysis and Balanced Drilling in Yangyi Geothermal Field of Tibet by Coupling with Temperature

Xiuhua Zheng[1], Chenyang Duan[1], Hongyu Ye[2], Zhiqing Wang1

[1] China University of Geosciences (Beijing), No.29 Xueyuan Road, Haidian District, Beijing, China, 100083

*Corresponding E-mail: 3002140019@cugb.edu.cn

[2] Beijing Talent New Energy Technology Development Co., LTD, Houxiagongzhuang Industrial park, 280, Songzhuang Town, Tongzhou District, Beijing, 101100

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ABSTRACT

Balanced or managed pressure drilling is of great benefits for geothermal wells, not only preventing from lost circulation/blowout and fracturing rock by controlling formation pressure but also improving productivity by mitigating reservoir damage. Geothermal pressures in Tibet are somehow complicated that both high and low pressures may be encountered within shallow formations, which leaves narrow window for drilling fluids with appropriate densities and makes it more necessary to analyze the pressures of the geothermal field and to model the drilling fluid hydraulics under high temperature. Physical, rheological and thermal properties of drilling fluid vary with temperature of rock mass, which influence annulus pressure and pressure balance. This paper established mathematical models for coupling pressure-temperature and hydraulics-temperature under high temperature, which focused on wellbore temperature distribution and the variation of Equivalent Circulating Density (ECD). Formation pressures and ECDs with annulus friction loss pressure of the first medium-deep geothermal well ZK212 Yangyi Geothermal Field in Tibet were determined, with which the appropriate drilling fluid system was selected and monitored to avoid lost circulation/ blowout and fracturing formation.

1. INTRODUCTION

Geothermal energy is one of the renewable resources utilizing in the world, compared with the others, the cost of initial investment, which includes exploration, production and injection of geothermal wells, constitutes major component cost of geothermal projects. Loss circulation, stuck pipe and cementing is most common problems in geothermal drilling and completion(Carson,1981; Glowka, 1997). The wellbore pressure is usually expressed by equivalent specific weight. To maintain the pressure balance in the wellbore, the drilling fluid density should be in a safe density window, which should be equal with or slight larger than equivalent specific weight of formation pressure while lower than equivalent specific weight of fracture pressure. It will lead to wellbore diameter shrink and borehole collapse that the difference between maximum principal stress with minimum principal stress exceeds the shear strength of rock because of low drilling fluid density, while high drilling fluid density can provoke loss circulation as the axial stress surpasses the breaking strength of the rock. ECD is a crucial parameter for control the well bottom pressure, the temperature at the well-bottom may surpasses the temperature at surface more than 150℃, which affects the density and properties of drilling fluid, leads to the improper calculation of ECD and raises the risk of lost circulation/ blowout. It may generate the error if the constant drilling fluid density and rheology is used to calculate and control the pressure distribution. So, wellbore temperature, drilling fluid density and rheology should be involved when building the wellbore pressure distribution of high temperature geothermal wells.

Ansari (Ansari, et al, 1994) and Drift (Drift, et al, 1994) built the model to calculate deliverability curve, pressure gradient and flux rate by Geoflow. The discontinuous pressure gradient and deliverability curve obtained by Ansari Model, while suitable results for geothermal well can be achieved with Drift Flux Model (Peter, et al, 2010). Li (Li, et al, 2005) established the formation fracture pressure model with consideration of thermal stress subjected to heat transfer in the high temperature geothermal well. Zhong (Zhong, et al, 1998) discovered the formation pore pressure in the high pressure and high temperature wellbore was not equal with initial formation pressure, and varied with the time because of the temperature influence.

The density of drilling fluid change with the temperature and pressure, thus, in order to describe the wellbore pressure precisely, the properties under high temperature and high pressure should be studied. The research of drilling fluid properties is mainly focused on the oil well. Density model can be divided into two types, i.e., composite model and empirical model. As property per content in the drilling fluid performs different features with variety of temperature and pressure, composite model predicts the density model obtaining the rule per content in the drilling fluid under various temperature and pressure. McMordie (McMordie, et al, 1982) logged the density of water-based and oil-based drilling fluid under the conditions of 70-400℉and 0-14000psig. Hoberock (Hoberock, et al, 1982) provided the density prediction model of water-based and oil-based drilling fluid based on the mass balance. Empirical model determines the factor of the model through fitting the data acquired from several experiment. The key to succeed empirical model is to choose the expression of minimum error, as the diverse expressions would be derived with curve fitting. Babu (Babu, et al, 1993) determined the optimal density-pressure-temperature model used calculating the density of 12 mud samples by 3 models. Harris (Harris, et al, 2005) simulated the distribution of wellbore temperature and pressure by C-N difference scheme and established the density model of Bingham fluid based on the pressure and temperature functions. Wang(Wang, et al, 2000) built the calculus model of drilling fluid equivalent static density (ESD) in the high temperature and high pressure wells under conditions of formation temperature gradient, while water-based and oil-based drilling fluid were not distinguished. Composite model could acquire the accurate result, but is complex, for per content of the drilling fluid system need to be tested separately. Compared with composite model, empirical model is easy to utilize, while hardly getting a general expression, a certain drilling fluid system has a specific result.

The drilling fluid circulates during the drilling process; heat constantly transfers among the fluid in the tubing, tubing, annulus, casing and formation. Drilling fluid temperature at wellhead can't reflect the actual temperature in the wellbore, the drilling fluid density at wellhead isn't equal to the density in wellbore, the actual equivalent circulation density differs from the equivalent circulation density calculated by constant drilling fluid density. It is important for controlling the bottom hole pressure and fast drilling to describe the wellbore temperature distribution exactly. Ramey (Ramey, 1962) built the model of heat transfer in the wellbore and formation, while the model is suitable for the stable heat transfer and can't apply to transient heat exchange. Sagar (Sagar, et al, 1991) expanded Ramey Model into multiphase flow system which has weighed the kinetic energy variation and Joule-Thompson effect. Willhite (Willhite, et al, 1976) deduced the thermal resistance between wellbore and near wellbore formation in detail and gave out the expression of total heat transfer coefficient. Hasan and Kabir (Hasan and Kabir, 1994, 2010a) established one-dimension pseudo-steady state model and calculated the analytic solution and built two-phase flow model of geothermal well which considered heat loss caused by pressure drop and thermal resistance. Raymond (Raymond, et al, 1969) researched a numerical method to predict the wellbore temperature at stable state and quasi stability. Yang(Yang, et al, 2014) gave a mathematical model of wellbore temperature and formation temperature under lost circulation.

This paper modified the temperature of wellbore under circulation, deduced the density of drilling fluid change with the depth in the geothermal well (high temperature and low pressure), and modeled the ESD and ECD in the annulus.

2. THE TEMPERATURE AND PRESSURE MODEL IN THE WELLBORE AND SOLUTIONS

2.1 Temperature Model of Wellbore

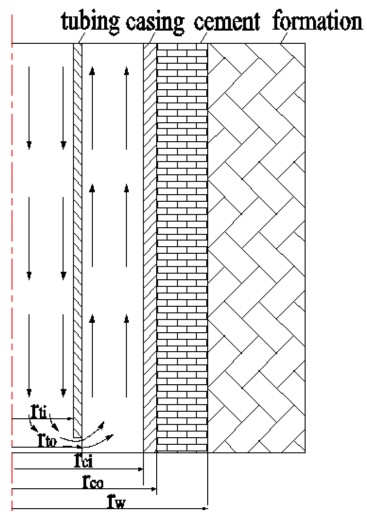

Figure 1: Circulation model parameter in the wellbore.

As shown in Fig.1, drilling fluid flows into tubing, then the drilling fluid flows into the annulus through the bit. During the circulation, temperature of drilling fluid in the tubing is lower than tubing temperature, the heat transfers from the tubing into the drilling fluid. The temperature of drilling fluid is below the casing/near wellbore formation temperature when the drilling fluid access the annulus, the drilling fluid acquires the heat from the formation and the temperature increases continuously. The temperature of drilling fluid and casing/formation will be equal at a certain depth in its travel up the annulus, the position which heat transfer will halt defines as isothermal depth. The drilling fluid temperature surpasses the casing/near wellbore formation temperature after the fluid passes through the isothermal depth, the heat from the drilling fluid transfer into the casing/formation. The heat transfer process occurs among the drilling fluid, tubing, casing and formation constantly in circulation. The stable temperature distribution will be established after a period of circulation time. The process is influenced by depth, drilling fluid density and rheological, flow rate, wellhead temperature, diameter and formation temperature gradient.

2.1.1 Assumed condition of model

To simplify the model, some assumed conditions of model should be given based on the characteristic of actual wellbore heat transfer, which are (1) the axial heat conduction can be neglected compared with axial heat convection, (2) there is no radial temperature gradient, (3) formation temperature gradient and circulation rate remain constant, (4) thermal properties of rock stay the same and don't change with the temperature and pressure, and (5)specific heat and heat conduction of rock perform isotropy.

2.1.2 Mathematical equations

The formation temperature is related to not only the well diameter, but also the drilling time. Heat loss will decrease with the time as the heat flow in annuli tends to stable. The heat transfer flux density between annulus and formation can be considered as invariant. The 3D heat transfer from wellbore to surroundings can be simplified to 2D due to the symmetry of wellbore and surroundings, and if it only considers a very short section, then it can be simplified to 1D diffusivity issue. The formation temperature surrounding the wellbore varies with radius and time can be calculated by the energy balance equation (Equation 1) (Hagoort, 2004).

$$\frac{\partial^2 T_f}{\partial r^2} + \frac{1}{r}\frac{\partial T_f}{\partial r} = \frac{\rho_f c_f}{k_f}\frac{\partial T_f}{\partial t} \tag{1}$$

Where T_f is the formation temperature near the wellbore,℃; ρ_f is rock density, kg/m^3; c_f is specific heat of rock, J/(kg·℃); k_f is thermal conductivity of rock, W/(m·K), r is the radius, m.

Transform the equation (1) into dimensionless form, dimensionless temperature T_D is obtained by the Kabir &Hasan Model(Kibir &Hasan, 1996) is,

$$T_D = \begin{cases} 1.1281\sqrt{t_D}(1-0.3\sqrt{t_D})(t_D \le 1.5) \\ (0.4063 + 0.5\ln t_D)(1+0.6t_D)(t_D > 1.5) \end{cases} \tag{2}$$

Where,

$$t_D = \frac{\alpha t}{r_w^2}$$

And,

$$\alpha = \frac{k_f}{\rho_f c_f}$$

Where, t_D is dimensionless time; α is coefficient of thermal diffusion, m^2/s; r_w is radius at the interface of wellbore and formation, m; t is time, s.

The annulus and tubing temperature differential model can be deduced according to the first law of thermodynamics and basic principle of heat transfer(Hasan & Kabir, 1994).

$$\begin{aligned} &\frac{dT_a}{dD} = \frac{1}{B}(T_a - T_p) - \frac{1}{A}(T_{\varepsilon i} - T_a) - T_{fa} \\ &\frac{dT_p}{dD} = \frac{1}{B}(T_a - T_p) + T_{fp} \\ &A = \frac{C_m Q\rho_m (k_f + r_w U_a T_D)}{2\pi r_w U_a k_f} \\ &B = \frac{C_m Q\rho_m}{2\pi r_{ti} U_p} \\ &U_a = \frac{1}{r_w\left[\frac{1}{r_{ci}h_a} + \frac{\ln(r_{ci}/r_{co})}{k_c} + \frac{\ln(r_{co}/r_w)}{k_{cm}}\right]} \\ &U_p = \frac{1}{r_{ti}\left[\frac{1}{r_{ti}h_{ti}} + \frac{\ln(r_{ti}/r_{to})}{k_t} + \frac{1}{r_{to}h_{to}}\right]} \end{aligned} \tag{3}$$

Where, T_a is drilling fluid temperature in annulus, ℃; T_{fa} is temperature generated by flow pressure drop in unit height of annulus, ℃; T_p is drilling fluid temperature in tubing, ℃; T_{fp} is temperature generated by flow pressure drop in unit height of tubing, ℃; D is the well depth, m ; k_f is formation heat conduction, W/(m·K); Q is drilling fluid flow rate, m^3/s; $T_{\varepsilon i}$ is initial formation temperature, ℃; U_a is total convection coefficient between annulus with formation, W/(m·K); C_m is specific heat of drilling fluid, W/(m·K); U_p is total convection coefficient between annulus with tubing, W/(m·K); ρ_m is drilling fluid density at the depth of L in the well, kg/m^3. r_{ci} is the inner radius of casing, m; r_{co} is the outer radius of casing, m; r_{ti} is the inner radius of tubing, m; r_{to} is the outer radius of tubing, m. k_t is thermal conductivity of tubing, W/(m·K); k_c is thermal conductivity of casing, W/(m·K); k_{cm} is thermal conductivity of cement, W/(m·K); h_a is convection heat transfer coefficient of annulus, W/(m^2·K); h_{ti} is convection heat transfer coefficient of inner tubing, W/(m·K); h_{to} is convection heat transfer coefficient of outer tubing, W/(m^2·K).

Ignoring the mechanical friction heat source of tubing and bit, T_{fp} and T_{fa} can be given by the following equations,

$$T_{fp} = \frac{1}{\rho_m C_m}\frac{dp_{fp}}{dD}$$
$$T_{fa} = \frac{1}{\rho_m C_m}\frac{dp_{fa}}{dD} \qquad (4)$$

Where p_{fp} is flow pressure drop of tubing, Pa; p_{fa} is flow pressure drop of tubing, Pa.

2.1.3 Initial and boundary conditions

Drilling fluid temperature of tubing and annulus at wellhead is known,

$$T_p(0,t) = T_{in}$$
$$T_a(0,t) = T_{out} \qquad (5)$$

Where, T_{in} is the inlet temperature of drilling fluid, ℃; T_{out} is the outlet temperature of drilling fluid, ℃.

Drilling fluid temperature of tubing and annulus at well bottom is equal,

$$T_a(Z,t) = T_p(Z,t) \qquad (6)$$

Where, Z is the depth of bottom hole, m.

Combine equations (3), (4), (5) and equation (6), the temperatures in the tubing and annulus can be calculated,

$$T_a = \beta_1 e^{\lambda_1 D} + \beta_2 e^{\lambda_2 D} + GD + T_{mf}$$
$$T_p = \beta_1(1 + B/A - B\lambda_1)e^{\lambda_1 D} + \beta_2(1 + B/A - B\lambda_2)e^{\lambda_2 D} + G(Z - B) + (1 + B/A)T_{mf} - BT_{fa} - B/AT_S \qquad (7)$$
$$T_{mf} = A(T_{fa} + T_{fp}) + T_s$$
$$\lambda_1 = \frac{1 + \sqrt{1 + 4A/B}}{2A}, \lambda_2 = \frac{1 - \sqrt{1 + 4A/B}}{2A}$$
$$T_{el} = T_S + \frac{GD}{100}$$

Where, β_1, β_2 are modeling coefficients; G is geothermal gradient, ℃/100m; T_s is surface temperature, ℃.

2.2 Pressure model in the wellbore

2.2.1 Pressure gradient of circulating drilling fluid in annulus

Pressure gradient of circulating drilling fluid in annulus is given as follows(Cinar, et al, 2006),

$$\frac{dp_c}{dL} = \frac{dp_s}{dL} + \frac{dp_f}{dL} + \frac{dp_a}{dL} \qquad (8)$$

Where, the three terms of the right equation are hydrostatic pressure gradient, frictional pressure drop gradient and acceleration press ure gradient, respectively, L is length, m. The acceleration pressure gradient is rather smaller compared with the other two pressure g radients when the circulation is stable, so the pressure gradient is neglected and equation (9) can be shortened as follows.

$$\frac{dp_c}{dL} = \frac{dp_s}{dL} + \frac{dp_f}{dL} \qquad (9)$$

2.2.2 Hydrostatic pressure gradient

$$\frac{dp_s}{dL} = \rho_m g \sin\theta \qquad (10)$$

Where ρ_m is drilling fluid density at depth D, kg/m^3, θ is well deflection, °.

Oil-based drilling fluid is generally considered that is not suitable for geothermal well because oil-based drilling fluid may pollute the reservoir and reduce the production of geothermal well. So, in this paper water-based drilling fluid is used. Empirical model is adopted in this study, variation law of drilling fluid density in high temperature(T) and high pressure(P) obeys power function(Wang, 2000).

$$\rho_m = \rho_{m0} \times e^{a(p-p_0)+b(T-T_0)+c(T-T_0)^2} \tag{11}$$

Where ρ_m is drilling fluid density under the condition of P and T, kg/m^3; ρ_{m0} is drilling fluid density measured at the surface, kg/m^3; p is experiment pressure, MPa; p_0 is the surface pressure, 0.1MPa; T is experiment temperature, ℃; T_0 is the temperature at surface, 15℃; a is pressure coefficient; b and c is temperature coefficient.

According to the experiment of water-based drilling fluid, the temperature coefficient a, b, c can be obtained by multivariate nonlinear regression.

$$a=3.0296\times10^{-6};\quad b=1.3547\times10^{-4};\quad c=-4.1444\times10^{-7} \tag{12}$$

2.2.3 Frictional pressure drop gradient

The frictional pressure drop gradient is shown as follows (Wang, 2011),

$$\frac{dp_f}{dL} = \frac{2f\rho_m\mu_w}{d_h} \tag{13}$$

$$N_{Re} = \frac{\rho\bar{v}d_h}{\mu_w} \tag{14}$$

$$\begin{cases} \dfrac{1}{\sqrt{f}} = -4lg\left(\dfrac{K}{307065\,D_h} - \dfrac{5.0452\,lg\,A}{Re}\right)(N_{Re} > 2300) \\ f = \dfrac{16}{N_{Re}}(N_{Re} < 2300) \end{cases} \tag{15}$$

$$A = \frac{(K/D_h)^{1.01098}}{2.8275} + \left(\frac{7.149}{N_{Re}}\right)^{0.8981} \tag{16}$$

$$d_h = d_2 - d_1 \tag{17}$$

Where, f is fanning friction factor; μ_w is viscosity of drilling fluid, mPa·s; d_h is equivalent diameter of annulus, m; K is velocity coefficient; d_1 is outer diameter of tubing, m; d_2 is inner diameter of casing, m; N_{Re} is Reynolds number of drilling fluid in annulus, when N_{Re}<2300, the fluid is in the laminar, when N_{Re}>2300, the fluid is in the turbulent.

So, the pressure gradient can be expressed as follow.

$$\begin{aligned} \frac{dp_c}{dL} &= \rho_m g \sin\theta + \frac{32\rho_m\mu_w}{d_h N_{Re}}(N_{Re} < 2300) \\ \frac{dp_c}{dL} &= \rho_m g \sin\theta + \frac{f\rho_m\mu_w}{4d_h\left[lg\left(\dfrac{K}{307065\,d_h} - \dfrac{5.0452\,lg\,A}{Re}\right)\right]^2}(N_{Re} > 2300) \end{aligned} \tag{18}$$

2.2.4 ESD and ECD

ESD(Equivalent Static Density) is used to express the pressure in the well for the convenience of control the drilling fluid system, so ESD can be represented as follow.

$$ESD = \frac{p_s - p_0}{gD} \tag{19}$$

Where P_0 is the surface pressure, MPa; p_s is the static pressure at the depth of D, MPa.

ECD(Equivalent Circulation Density) can be defined as the sum of ESD and the frictional pressure drop, the expression of the ESD are shown below.

$$ECD = ESD + \frac{p_f}{gD} \tag{20}$$

2.4 Iterative method to solve of pressure and temperature models

Divide well depth D into n-calculation pieces, so the iterative step length is *ΔD=D/n*. The temperature distribution of wellbore during the circulation should be calculated initially.

$$T_i = T(D_i)(i = 1,2,3,\cdots,n) \tag{21}$$

Suppose the temperature, pressure and density of drilling fluid are identical in each element of statics pressure, so the iteration equation of statics pressure is,

$$p_{i+1} = p_i + \Delta p_i = p_i + g\Delta D_i \rho_{mi}(i = 1,2,3,\cdots,n) \tag{22}$$

The boundary conditions are,

$$p_s(D = 0) = p_0, T(D = 0) = T_0 \tag{23}$$

So the static pressure in annulus is,

$$p_s - p_0 = g\sum_{i=1}^{n} \rho_{mi} \Delta D_i \tag{24}$$

And the calculation model of ESD is expressed as follows.

$$ESD = \frac{p_s - p_0}{gD} = \frac{1}{z}\sum_{i=1}^{n} \rho_{mi} \Delta D_i \tag{25}$$

3. SAMPLE AND ANALYSIS

According to the modeling method. the first production well ZK212, which has been drilled to exploit the deep reservoir in 2012 and 2013, is selected as the example. This well was drilled to 1508m deep without any kick or blowout, but certain fluid leak off or loss occurred that was affected by the circulating temperature,the input temperature of drilling fluid is 25℃.The thermodynamics properties of materials in the wellbore and formation are listed in Table 1 and the fresh water from the river was used as drilling fluids. According to the previous study(Zheng et al., 2014), the over height of ZK212 to the zero point was minus 11.87m, which means that the pore pressure was lower than the hydrostatic pressure.

Table 1: Thermodynamics properties of materials and formation.

Formations and materials	Density (kg/m^3)	Thermal conductivity (W/(m · K))	Thermal capacity (J/(kg · ℃))
sandstone	2231	1.869	711.76
basalt	1579	2.008	879.23
granite	2641	2.821	837.36
cement	2100	1.454	879.23
casing	7848	45.174	460.55

The ZK212 has a 245mm string to 600m. It is completed as an open hole from the 245mm casing shoe to the bottom. The pump capacity for drilling fluid is $1.6m^3$/min. The parameters of each section in the well are shown in Table 2.

Table 2: The inner and outer diameter of casing, tubing, cement.

	Inner diameter (mm)	Outer diameter(mm)
tubing	139	149

casing	245	311
cement	311	406

According to the temperature prediction progress based on the mathematical model and numerical solution, the wellbore temperature distribution in ZK212 can be calculated, according to the calculation, the fluid in the tubing and annulus is both turbulent flow.

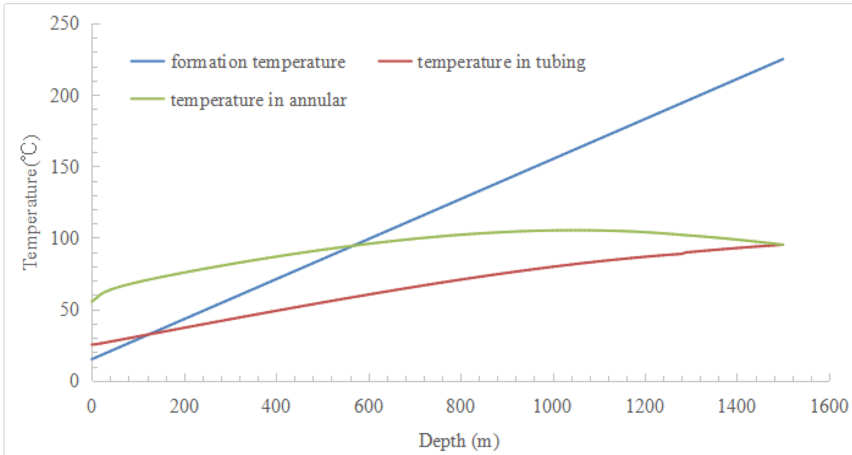

Figure 2: The temperature profile in tubing and annulus (circulation 10h).

As shown in Fig.2 the formation is heated from the surface to 600m, while is cooled from 600m to the bottom. The location of highest fluid temperature is not at the well bottom, while at a point above the well bottom in annulus, what makes it is that the high formation temperature influences when the fluid raises from the bottom.

According to the temperature of annulus and the density expression, the variation law of density, ESD, annulus pressure drop and ECD can be calculated by the model with the actual parameter. Variation curves of the drilling fluid density, pressure drop, bottom hole pressure with the well depth are calculated and compared with the regular method (the measured value of drilling fluid parameter at surface is considered as the parameter in the well), the change curve of ECD with the depth is obtained finally. The results are presented in Fig.3-Fig. 6.

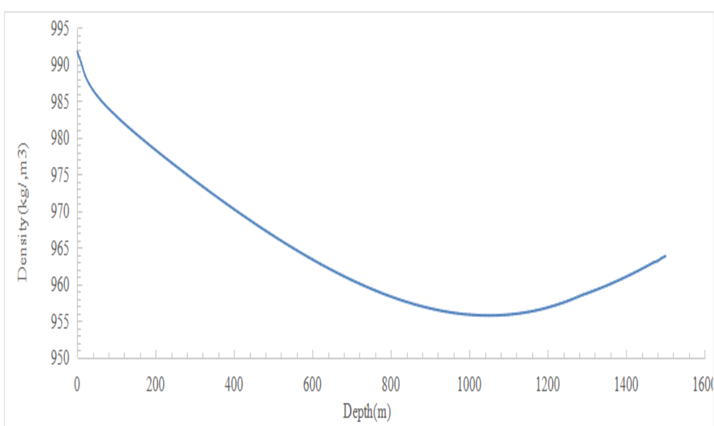

Figure 3: The density variation of drilling fluid with the depth.

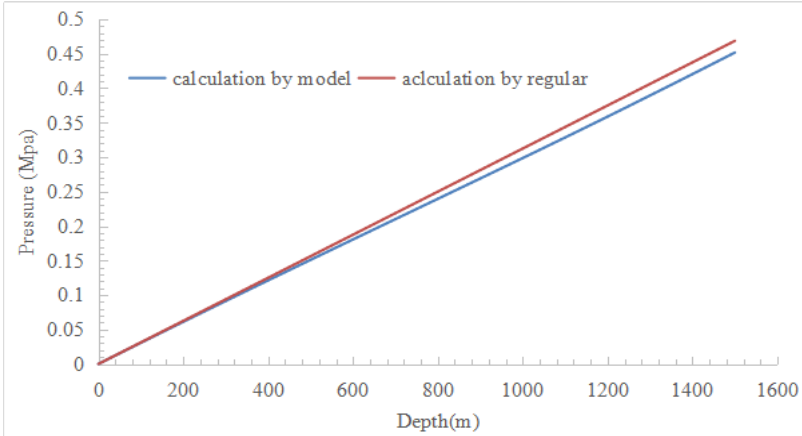

Figure 4: Comparison of pressure drop in annulus calculated by model and by regular method.

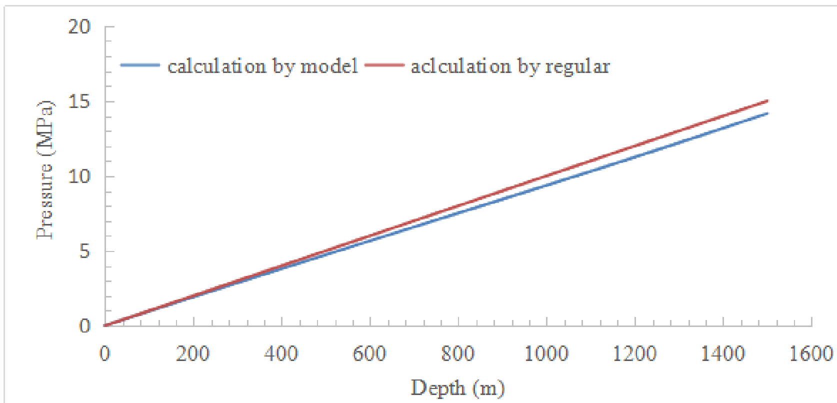

Figure 5: Comparison of bottom hole pressure in annulus calculated by model and by regular method.

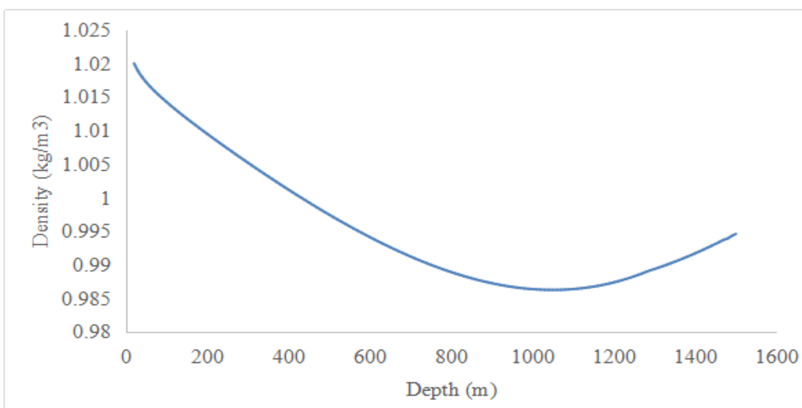

Figure 6: The result of ESD in annulus.

As illustrated in Fig.4 and Fig. 5, the results calculated by the model are different with the results calculated by the regular method, the difference of pressure drop in annulus at depth of 1050m is 0.016MPa, and the error is reached to 4.6%; the difference of bottom well pressure in annulus at depth of 1050m is 0.72MPa, and the error is reached to 6.7%. It is crucial for the geothermal well to predict the parameter of drilling fluid and wellbore temperature, which can make sure that predicting and controlling the ESD and ECD.

4. CONCLUSION

This study built the wellbore temperature model based on the model of Hasan. The highest drilling fluid temperature in ZK212 is not located at the bottom, while at the annulus above the bottom about 450m, so the characteristic at the highest temperature should be considered during the temperature test of drilling fluid.

The density prediction model was built by multivariate nonlinear regression method based on the drilling fluid density test under different temperature and pressure. The ESD, bottom hole pressure and ECD calculation model is established by iteration, compared with the regular method, the model is more precise. It provided the theoretical basis to control the bottom hole pressure, select the drilling fluid system and preventing the accidents.

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