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An Improved Model for Predicting Fluid Temperature in Deep Wells

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Abstract: The objective of this study was to develop an improved method to predict fluid temperature profiles in high-temperature wells for designing production string in deep-water development. The method was developed on the basis of heat transfer involves heat convection and conduction inside the production string and in the annular space. The governing equations were solved using the method of characteristics, resulting in two simple closed-form equations. The method was coded in a spreadsheet for easy applications. Data from three wells were employed to check the accuracy of the new method. Comparisons of results from Hasan's method, Gilbertson et al.'s method, and the new method with temperature data measured in two gas-lift wells show that the new method best predicts well temperatures in trend. A comparison of results given by Mao's method and the new method with temperatures observed in a deep-water gas well testing indicates that the new method better predicts well temperatures with errors less than 4%. This work provides petroleum engineers a simple and accurate method for predicting temperature profiles in oil and gas production operations, especially deep-water operations. It eliminates the need for sophisticated analytical and numerical models in fluid temperature analysis.

Keywords: Fluid Temperature, Deep Wells, Gas-Lift Wells, Heat Transfer

1. Introduction

Prediction of fluid temperature profile is vitally important for designing test string in deep-water gas wells. A literature survey shows that several researchers have proposed their theoretical models for fluid temperature profiles in oil wells. Ramey (1962) presented a theoretical model to estimate fluid temperature as a function of well depth and production time. An approximate analytical solution to the transient heat-conduction problem involved in movement of hot fluids through a wellbore was derived. This model was modified by later researchers.

Sagar extended Ramey's model to multiphase flow in wellbore by considering kinetic energy and Joule-Thompson expansion effect [1], [2]. A simplified model suitable for hand calculations was proposed on the basis of the general model in which the Joule-Thomson and kinetic-energy terms were replaced with correlations. In addition, his contribution was to introduce the Coulter-Bardon equation into gas lift wells. Alves developed a general model for predicting flowing temperature in deviated wellbores and pipelines [3]. Also, approximate methods for determining two-phase heat capacity and Joule-Thomson coefficient were proposed.

Hasan presented an approach to estimate wellbore fluid temperature during steady-state two phase flow. It allows for wellbore heat transfer by conduction, convection, and radiation [4]. King showed an analytical solution for transient temperature field around a cased and cemented wellbore [5]. Guo developed a simple model for predicting heat loss and temperature profiles in insulated pipelines [6]. Spindler derived analytical models for wellbore-temperature distribution [7].

Some investigations were performed on heat losses in steam injection in the wellbore. Investigators include Satter, Huygen, Back, Durrant, and Pacheco [8] ~ [12]. Chiu and Thakur presented heat losses in directional wells considering the change of injection conditions [13].

The initial investigation of gas temperature at injection depth of gas-lift wells was presented by Kirkpatrick [14]. His simple model presented a flowing temperature gradient to calculate gas temperature at depth of injection valves. Winkler presented algorithm for more accurately predicting nitrogen-charged gas-lift valve operation at different temperatures [15]. Lagerlef claimed gas-lift-valve test rack opening design methodology for extreme kickoff temperature conditions [16]. Hasan developed a mechanistic model for the flowing temperature of annular and tubing in gas lift wells based on energy balance equation [17]. The author assumes steady state flow and steady heat transfer between tubing and casing. However, kinetic and potential energy terms are neglected in the energy balance equation. Hernandez performed downhole temperature survey analysis for wells on intermittent gas lift [18]. Yu modeled the prediction of wellbore temperature profiles during heavy oil production assisted with light oil lift [19]. Several researchers, including Gilbertson et al, have designed thermally actuated safety valves for gas lift wells [20]. Gilbertson modeled steady-state temperature profile in gas lift wells and verified with experimental data. However, Joule-Thompson effect was not considered when calculating the mixed temperature in tubing. So the accurate prediction of temperature profiles became the limits for their design. Han presented iteration algorithms for multi-interface heat transfer in pipe flow based on mass- and momentum conservation [21].

Wooley computed downhole temperatures in circulation, injection, and production wells with a numerical model [22]. Other numerical models include those developed by Leutwyler, Tragesser, and Nelson [23] ~ [25]. Although these numerical models have removed several unrealistic assumptions made for deriving those analytical models, their applications have not been popular due to their very limited access by most engineers.

In summary, a number of thermal models, both analytical and numerical, have been developed for predicting fluid temperature profiles in oil wells. These models cover natural flow, gas-lift, and thermal-recovery oil wells. Among these models, Hasan's mechanistic model has gained most applications in gas lift wells and Gilbertson et al's model has been widely accepted for naturally flowing oil wells [17] [20]. These two models are compared with a new model developed for deep-water gas wells and field data in this work.

2. New Analytical Model

A new analytical solution was derived in this study for predicting temperature profiles inside work string (test string, tubing, or drill string) and in the annulus, assuming upward flow in the string and down-ward flow in the annulus. Resultant equations in the new model are summarized in this section. Derivation of the model is available upon request. The derivation of the mathematical models was based on the following assumptions:

(1) The thermal conductivity of casing is infinite.
(2) The geothermal gradient is not affected by the fluids in the wellbore.
(3) Heat capacity of fluid is constant.
(4) Friction-induced heat is negligible.

The fluid temperature profiles inside the string T_t and in the annulus T_a are expressed as:

$$T_t = \frac{C_1}{q^2} e^{r_1 L} + \frac{C_2}{q^2} e^{r_2 L} + EL + D \tag{1}$$

$$T_a = -\frac{1}{f}\left(\frac{r_1}{q^2} C_1 e^{r_1 L} + \frac{r_2}{q^2} C_2 e^{r_2 L} + E\right) - \frac{h}{f}\left(\frac{C_1}{q^2} e^{r_1 L} + \frac{C_2}{q^2} e^{r_2 L} + EL + D\right) \tag{2}$$

where

$$C_1 = \frac{R(A-J)-SG}{FR-KG} \tag{3}$$

$$C_2 = \frac{K(A-J)-SF}{GK-FR} \tag{4}$$

$$r_1 = \frac{-p+\sqrt{p^2-4q}}{2} \tag{5}$$

$$r_2 = \frac{-p-\sqrt{p^2-4q}}{2} \tag{6}$$

$$a = \gamma - \beta \tag{7}$$

$$a' = -\frac{\pi \rho_t d_t^{\,2}}{4\dot{m}_t} \tag{8}$$

$$b = \frac{2\pi D_t K_t}{C_t \dot{m}_t \left(D_t - d_t\right)} \tag{9}$$

$$c = \beta G \tag{10}$$

$$d = \beta T_{go} \tag{11}$$

$$D = \frac{dfq - Q}{q^2} \tag{12}$$

$$E = \frac{cf}{q} \tag{13}$$

$$F = -\frac{r_1 + h}{fq^2} \tag{14}$$

$$f = b \tag{15}$$

$$G = -\frac{r_2 + h}{fq^2} \tag{16}$$

$$h = -b \tag{17}$$

$$I = -\frac{Eh}{f} \quad (18)$$

$$J = -\frac{E + hD}{f} \quad (19)$$

$$K = \left(\theta F - \frac{1}{q^2}\right)e^{r_1 L_{max}} \quad (20)$$

$$m = -\gamma \quad (21)$$

$$N = (ah - mf)M + (a + h)cf \quad (22)$$

$$p = a + h \quad (23)$$

$$q = ah - mf \quad (24)$$

$$R = \left(\theta G - \frac{1}{q^2}\right)e^{r_2 L_{max}} \quad (25)$$

$$S = EL + D - \theta IL - \theta J - \sigma \quad (26)$$

$$\alpha = \frac{\pi\rho_a\left(d_c^{\,2} - D_t^{\,2}\right)}{4\dot{m}_a} \quad (27)$$

$$\beta = -\frac{2\pi D_c K_c}{C_a \dot{m}_a (D_w - D_c)} \quad (28)$$

$$\gamma = \frac{2\pi D_t K_t}{C_a \dot{m}_a (D_t - d_t)} \quad (29)$$

$$\theta = \frac{0.84 \cdot C_a \cdot \dot{m}_a}{C_o \cdot \dot{m}_o + C_a \cdot \dot{m}_a} \quad (30)$$

$$\sigma = \frac{C_o \cdot \dot{m}_o \cdot T_{oil} \text{-} 43.7 C_a \cdot \dot{m}_a}{C_o \cdot \dot{m}_o + C_a \cdot \dot{m}_a} \quad (31)$$

where

A_a = Cross section area of the annulus, m^2.
A_t = Cross section area of string, m^2.
C_a = Heat capacity of fluid in annulus, J/kg- C.
C_o = Heat capacity of fluid from formation, J/kg- C.
C_t = Heat capacity of fluid in string, J/kg-C.
D_c = Outer diameter of cement sheath, m.
d_t = Inner diameter of string, m.
D_t = Outer diameter of string, m.
D_w = D_c, wellbore diameter of cased hole, m.
K_c = Thermal conductivity of cement, W/m- C.
K_t = Thermal conductivity of string, W/m- C.
L_{max} = Total depth, m
$\dot{m}_a$ = Mass flow rate of fluid in annulus, kg/s.
$\dot{m}_t$ = Mass flow rate of fluid in string, kg/s.
Q_a = Flow rate in annulus, m^3/s.
$T_{a,0}$ = Temperature in annulus at surface L, C.
$T_{a,L}$ = Temperature in annulus in point L, C.
T_{oil} = Temperature of formation fluid, C.
$T_{t,L}$ = Temperature in string at point L, C.
ρ_a = Density of fluid in annulus, kg/m^3.
ρ_t = Density of fluid in string, kg/m^3.

3. Model Comparison

The new analytical model was compared with Hasan's model, Gilbertson et al.'s model, and data measured in the actual wells reported by these authors [17], [20]. Figure 1 presents a comparison of results given by Hasan's model and the new model using the basic well data presented by Hasan's paper [17].

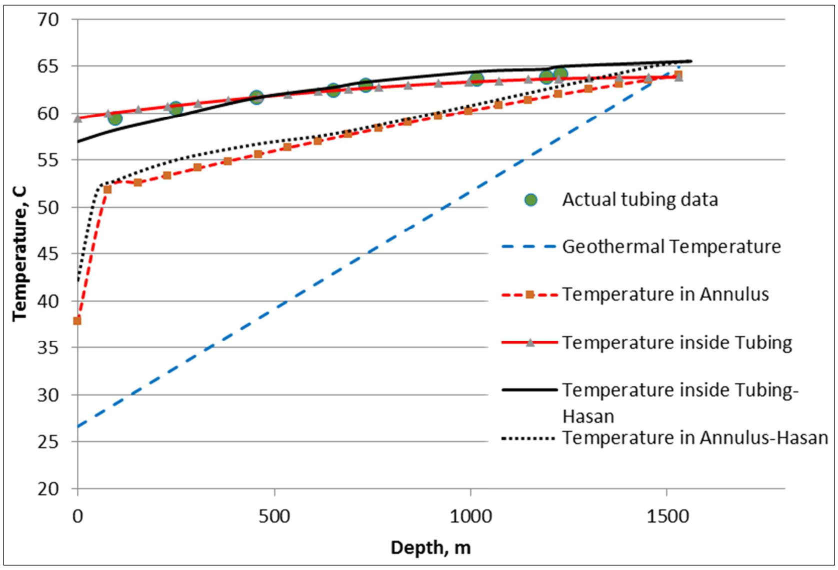

Figure 1. *Comparison between the new model and Hasan's model.*

Figure 1 indicates that, in general, there is a good agreement between the temperature profiles in annulus and tubing from Hasan's model and the new model. The calculated temperatures of fluid in tubing from these two models are both close to the actual data. The temperature of fluid inside the tubing given by the new model is slightly higher at shallow depth and lower at deep depth than that by Hasan's model. Temperature profile given by the new model is more accurate than that by Hasan's model. The new model that considers Joule-Thomson cooling rigorously gives temperatures in tubing and in annulus that are lower than the geothermal temperature at the bottom. However these three temperatures are identical according to Hasan's model. This is because in Hasan's model, the Joule-Thomson effect is accounted by using the theoretical approach developed by Alves et al. where the mass fraction of annular fluid is neglected [3]. In addition, the kinetic and potential energy terms are neglected in the energy balance equation in Hasan's model.

Figure 2 illustrates a comparison of results given by Gilbertson et al's model and the new model using the basic well data provided by Gilbertson et al's paper [20]. It shows that Gilbertson et al's (2013) model underestimates tubing temperature at shallow depth and significantly over-estimates tubing temperature at deep depth. This is due to the fact that Gilbertson's model does not consider Joule-Thomson cooling effect. In addition, Gilbertson's model does not have the capability of calculating the annular temperature, which limits its applications. In contrast, the new model over-estimates tubing temperature at shallow depth and underestimates tubing temperature at deep depth. This is consistent with the result shown in Figure 1. The reason is due to the fact that the new model considers sonic flow of fluid when it enters the string through a restriction (gas lift valve in this case), which "generates" the upper bound of Joule-Thomson cooling.

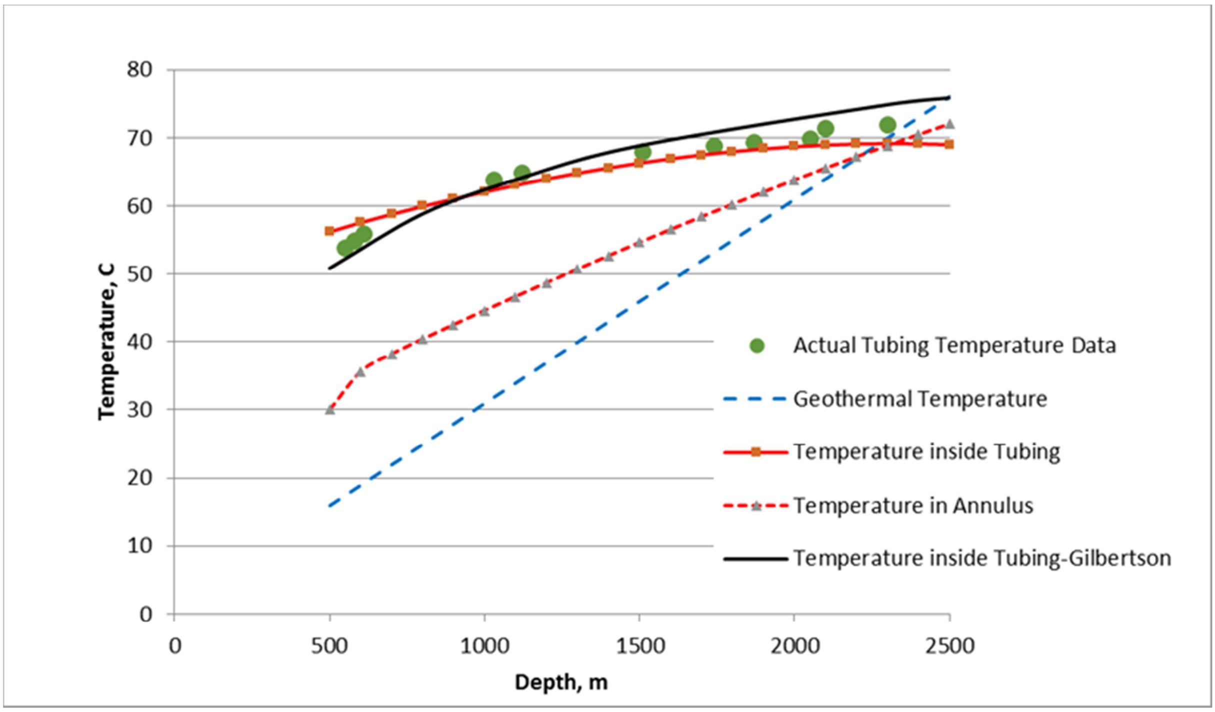

Figure 2. *Comparison between the new model and Gilbertson's model.*

4. Model Application

The new analytical model was derived for general applications including

- oil and gas production through tubing (annular flow is set zero in the model),
- oil production through gas lift,
- water and gas injection (pipe size and in-pipe flow are set zero in the model), and
- well drilling and work over with reverse circulation.

It was first used for designing test string in a deep-water gas well where the annular fluid is the stationary drilling fluid both in the wellbore and drilling riser sections. The well was drilled in South China Sea. The basic well parameter values of this deep water well are presented in Table 1. Estimated material properties are given in Table 2.

Table 1. *Basic parameters of the deep-water well in South China Sea.*

Well depth	3,200 m
Water depth	1,380 m
Outer diameter of testing pipe	0.1143 m
Inner diameter of testing pipe	0.095 m
Outer diameter of casing	0.2445 m
Inner diameter of casing	0.2168 m
Outer diameter of cement	0.3111 m
Inner diameter of cement	0.2445 m
Outer diameter of drilling riser	0.5334 m
Inner diameter of drilling riser	0.0489 m
Geothermal gradient	0.057 C/m
Surface sea water temperature	20 C

Table 2. *Estimated material properties for the deep-water well in South China Sea.*

Material	Density (kg/m^3)	Specific heat (J/kg-K)	Thermal conductivity (J/(m-K)
Gas	6.5	2,227	0.03
Sea water	1,025	4,180	0.57
Drilling fluid	1,200	1,600	1.75
Steel	7,850	400	43.7
Cement	2,700	600	1.75
Rock	2,640	837	2.25

Figure 3 presents the temperature profiles from bottom hole to the mudline calculated by the new model. As expected, the temperature of gas inside the test string increases with gas production rate. Based on the temperature at the mudline, the temperature profiles of the gas inside the drilling riser were calculated with the classical heat transfer model presented by Guo et al. [6]. The predicted temperatures of gas at surface are summarized in Table 3. Also included in the table are the temperatures measured in the field test and calculated by Mao's model [26]. It is seen that the new model gives error less than 4%. Although Mao's model gives error of less than 6%, it is argued that the gas density of 650 kg/m^3 employed in Mao's model is too high.

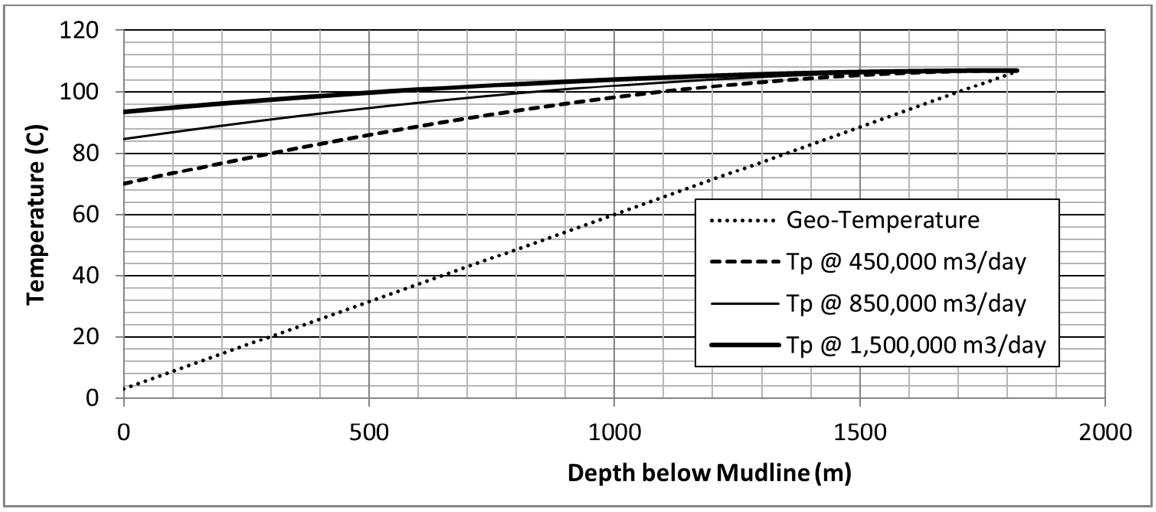

Figure 3. *Temperature Profiles Calculated by the New Model.*

Table 3. *Comparison of Model-Calculated and Observed Surface Temperatures for the deep-water well in South China Sea.*

Gas Production Rate (m^3/day)	Temperature at Surface (C) Field Test	Mao's (2016) Model	Error (%)	New Model	Error (%)
450,000	55	57.9	5.27	56.4	2.55
850,000	62.5	65.8	5.28	64.6	3.36
1,500,000	70.5	73.3	3.97	73.1	3.69

5. Conclusions

A new closed-form analytical model was developed in this study for predicting fluid temperature profiles in deep-water wells. The following conclusions are drawn:

(1) Comparisons of results from Hasan's (1996) model, Gilbertson et al.'s (2013) model, and the new model with temperature data measured in two gas-lift wells show that the new model best predicts well temperatures in trend.

(2) A comparison of results given by Mao's (2016) model and the new model with temperatures observed in a deep-water gas well testing indicates that the new model better predicts well temperatures with errors less than 4%.

(3) The new model was derived for general applications including oil and gas production through tubing, oil production through gas lift, water and gas injection, and well drilling and work over with reverse circulation. Accuracy of the model in these applications needs further investigations.

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