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Wellbore and Formation Temperatures During Drilling, Cementing of Casing and Shut-in

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ABSTRACT

The knowledge of downhole and surrounding the wellbore formations temperature is an essential factor during drilling operations, shut p-in and cementing of casing periods. The downhole temperatures while drilling affects the viscosity of the drilling mud and, subsequently, the frictional pressure losses; the performance of drilling bits in hot wells; the density of drilling fluids a.o. In deep and hot wells, the densities of water/oil muds and brines can be significantly different from those measured at surface conditions. For this reason determining the density of drilling mud under downhole conditions is needed for calculating the actual hydrostatic pressure in a well. It is very important to estimate the effect of pressure and temperature on the density of the formation fluid. This will permit a more accurate prediction of differential pressure at the bottom-hole and will help to reduce the fluid losses resulting from miscalculated pressure differentials. In areas with high geothermal gradients, the thermal expansion of drilling muds can lead to unintentional underbalance, and a kick may occur. The effect of the borehole temperature recovery process (disturbed by drilling operations) affects the technology of the casing cementing operations. The design of cement slurries becomes more critical when a casing liner is used because the performance requirements should be simultaneously satisfied at the top and at the bottom of the liner. For these reasons it is logical to assume that the bottomhole shut-in temperature should be considered as parameter in the cement slurry design. Assessment of the temperature development during hydration is necessary to determine how fast the cement will reach an acceptable compressive strength before the casing can be released. Temperature surveys following the cementing operation are used for locating the top of the cement column behind casing. Field experience shows that in some cases the temperature anomalies caused by the heat of cement hydration can be very substantial. Thus, it is very important to predict the temperature increase during the cement setting. This will enable to determine the optimal time lapse between cementing and temperature survey. During the shut-in period in the wellbore are conducted transient downhole and bottomhole temperature surveys and geophysical logging. In interpretation of geophysical data is used the temperature dependence of mechanical and electrical properties of formations. In the paper we present methods of determination of the drilling mud circulation temperatures, borehole temperatures during cementing of casing and temperature in surrounding wellbore formations during drilling and shut-in periods. We also present several techniques of calculation of the static formation temperatures.

1 DRILLING PERIOD

The wellbore temperature during drilling is a complex function of wellbore geometry, wellbore depth, penetration rate, flow rate, duration of the shut-in intervals, pump and rotary inputs, fluid and formation properties (Eppelbaum et al., 2014).

Two approaches are used in the studies of heat interactions of the circulating fluid with formation. In the first case heat interactions of circulating fluid and formation are treated under the condition of constant-bore face temperature or heat flux (e.g. Edwardson et al., 1962; Ramey, 1962; Lachenbruch and Brewer, 1959; Shen and Beck, 1986; Kutasov, 1999). In the second approach the thermal interaction of the circulating fluid with formation is approximated by the Newton relationship on the bore-face (Raymond, 1969; Holmes and Swift, 1970; Keller et al., 1973; Sump and Williams, 1973; Wooley, 1980; Thompson and Burgess, 1985; Hasan and Kabir, 1994; Fomin et al., 2003; Espinosa-Paredes et al., 2009, a.o.). However, the discontinuity of the mud circulation process during drilling poses a serious problem in using the Newton relationship for determining the heat flow from the mud in the drill pipe to the wall of the drill pipe as well as the heat flow through the formation-annulus interface (q_f). According to the Newton relationship

$$q_f = \alpha_{fa}(T_m - T_{fa}), \tag{1}$$

where α_{fa} is the film heat transfer coefficient from mud in the annulus to the formation, T_m is the average mud temperature (in annulus section), and T_{fa} is the temperature at the formation-annulus interface.

For a developed turbulent flow the Dittus-Boelter formula is usually used to estimate the value of the film heat transfer coefficient and for applications in which the temperature influence on fluid properties is significant, Sieder-Tate correlation is recommended (Bejan, 1993). On theoretical grounds the Newton equation is applicable only to steady-state conditions. This means that in our case both temperatures (T_{fa}, T_m) cannot be time dependent functions. In practice, however, the Newton relationship is successfully used in many areas when the temperature of the fluids and the temperatures at the fluid-solid wall interfaces are slowly changing with time. Therefore, it is necessary to find out under which conditions Eq. (1) can be used to predict the wellbore temperatures during drilling.

Some results of field investigations in the USA and Russia have shown that using conventional values of the film heat transfer coefficients in predicting wellbore temperatures during drilling are very questionable (Deykin et al., 1973; Sump and Williams, 1973). Predictions using Raymond's (1969) method for 7 wells, for example, differed from the measured values by 12 percent on the average (Figure 1) and in one case missed the measured temperature by 65°F (36°C) (Sump and Williams, 1973).

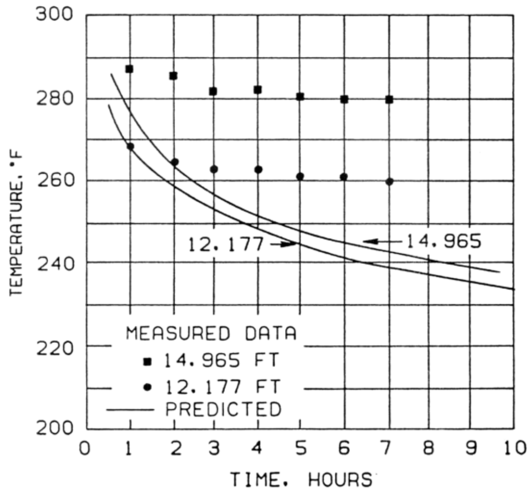

Figure 1: Comparison of measured and predicted mud temperatures from Well 1 (Sump and Williams, 1973)

As correctly mentioned by Fomin et al. (2003) the first approach can be used in the case of highly intensive heat transfer between the circulating fluid and surrounding rocks, which takes place for fully developed turbulent flow in the well. However, in all our studies we used the term effective temperature (at a given depth) of the drilling fluid (Kutasov, 1999; Kutasov and Eppelbaum, 2005). This unknown parameter is introduced only to evaluate the amount of heat obtained (or lost) during the entire drilling period. In their classical work Lachenbruch and Brewer (1959) have shown that the wellbore shut-in temperature mainly depends on the amount of thermal energy transferred to (or from) formations during drilling.

2 Radial Temperature Distribution

The results of field and analytical investigations have shown that in many cases the temperature of the circulating fluid (mud) at a given depth $T_m(z)$ can be assumed constant during drilling or production (Lachenbruch and Brewer, 1959; Ramey, 1962; Edwardson et al., 1962; Jaeger, 1961; Kutasov et al., 1966; Raymond, 1969). However for super deep wells (5000-7000 m) the temperature of the circulating fluid is a function of the vertical depth (z) and time (t).Thus the estimation of heat losses from the wellbore is an important factor which shows to what degree the drilling process disturbs the temperature field of formations surrounding the wellbore. It is known that, if the temperature distribution $T(r, z, t)$ or the heat flow rate $q(r = r_w, z, t)$ (r_w is the well radius) are known for a case of a well with a constant bore-face temperature, then the functions $T(r, z ,t)$ and $q(r = r_w, z, t)$ for a case of time dependent bore-face temperature can be determined through the use of the Duhamel's integral.

To determine the temperature distribution $T(r, t)$ in formations near a wellbore with a constant bore-face temperature it is necessary to obtain a solution of the diffusivity equation for the following boundary and initial conditions:

$$\left\{ \begin{array}{ll} T(r,0) = T_f, & r_w \le r \le \infty, \quad t > 0, \\ T(r_w,t) = T_w, & T(\infty,t) = T_f. \end{array} \right\}.$$

It is well known that in this case the diffusivity equation has a solution in a complex integral form (Jaeger, 1956; Carslaw and Jaeger, 1959). Jaeger (1956) presented results of a numerical solution for the dimensionless temperature $T_D(r_D, t_D)$ with values of $r_D = r/r_w$ ranging from 1.1 to 100 and t_D (ratio of the thermal diffusivity and time product to the squared well radius) ranging from 0.001 to 1000. We have found that the exponential integral (a tabulated function) can be used to describe the temperature field of formations around a well with a constant bore-face temperature (Kutasov, 1999):

$$T_D(r_D,\, t_D) = \frac{T(r,t) - T_f}{T_w - T_f} = \frac{Ei\left(\frac{-r_D^2}{4t_D^*}\right)}{Ei\left(\frac{-1}{4t_D^*}\right)}, \tag{2}$$

$$r_D = \frac{r}{r_w}, \qquad t_D = \frac{at_c}{r_w^2}, \qquad t_D^* = Gt_D, \tag{3}$$

$$\left\{ \begin{array}{l} G = 1 + \dfrac{1}{1 + AF}, \quad t_D \le 10, \\ F = \left[\ln\left(1 + t_D\right)\right]^n, \quad n = \dfrac{2}{3}, \quad A = \dfrac{7}{8}, \\ G = \dfrac{\ln t_D - \exp\left(-0.236\sqrt{t_D}\right)}{\ln t_D}, \quad t_D > 10 \end{array} \right\}, \tag{4}$$

where α is the thermal diffusivity of formations, t_c the time of mud circulation at a given depth, r_w is well radius, T_w is the temperature of the drilling mud at a given depth, T_f is the static formation temperature. Earlier we introduced adjusted circulation time concept (Kutasov, 1987, 1989). It was shown that a well with a constant borehole wall temperature can be substituted by a cylindrical source with a constant heat flow rate. The correlation coefficient $G(t_D)$ varies in the narrow limits: $G(0)=2$ and $G(\infty)=1$.

2.1 Downhole circulating mud temperature

2.1.1 Analytical Methods and Computer Programs

A prediction of the downhole mud temperatures during well drilling and completion is needed for drilling fluids and cement slurry design, for drilling bit design and for evaluation of the thermal stresses in tubing and casings. One of best attempts at predicting the fluid temperature during mud circulation was made by (Raymond, 1969). For the first time a comprehensive technique to predict transient formations profiles and downhole fluid temperatures in a circulating fluid system was developed. The calculating procedure suggested by Raymond can be modified to account for the presence of the casing strings cemented at various depths. The main features of the drilling process were not considered in the Raymond's model: change of well's depth with time, the disturbance of the formation temperature field by previous circulation cycles, the discontinuity of the mud circulation while drilling, and the effect of the energy sources caused by drilling. However, the Raymond's model allows one to evaluate the effect of circulation time and depth on downhole temperatures, to estimate the effect of mud type weight on the difference between bottom-hole fluid and outlet temperatures. It is very important to note that this model enables also to determine the duration of the circulation period, after which the downhole temperatures calculated from the pseudo-state equations are practically identical with those computed from unsteady state equations.

It an actual drilling process many time dependent variables influence downhole temperatures. The composition of annular materials (steel, cement, fluids), the drilling history (vertical depth versus time), the duration of short shut-in periods, fluid flow history, radial and vertical heat conduction in formations, the change of geothermal gradient with depth, and other factors should be accounted for and their effects on the wellbore temperatures while drilling should be determined. It is clear that only transient computer models can be used to calculate temperatures in the wellbore and surrounding formations as functions of depth and time (Wooley, 1980; Mitchell, 1981; Wooley et al., 1984, a.o.). Usually the computer simulators are tested against analytical solutions and in some cases field tests data were used to verify the results of modeling.

We present an example of circulating temperatures predictions by the WELLTEMP computer code (Figure 2).

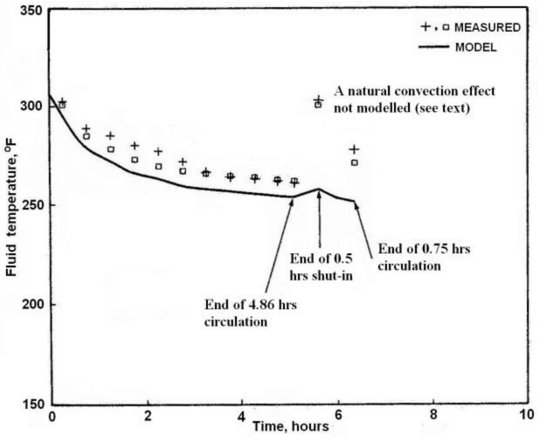

Figure 2: Circulating mud temperature at 16,079 ft, Mississippi well (Wooley et al., 1984)

As can be seen from Figure 2 computed circulating temperatures are in a good agreement with the field data. Here we should also take into account that due to incompleteness of the input data (fluid and formations properties, geothermal gradients) some assumptions have to be made before the simulation can be conducted.

2.2 Empirical formula, Kutasov-Targhi equation

2.2.1 Empirical formula

The temperature surveys in many deep wells have shown that both the outlet drilling fluid temperature and the bottom-hole temperature varies monotonically with the vertical depth. It was suggested (Kuliev et al., 1968) that the stabilized circulating fluid temperature in the annulus (T_m) at any point can be expressed as

$$T_m = A_0 + A_1 h + A_2 h, \quad h < H, \tag{5}$$

where the values A_0, A_1 and A_2 are constants for a given area, h is the current vertical depth and H is the total vertical depth of the well (the position of the bottom of the drill pipe at fluid circulation). The values of A_0, A_1 and A_2 are dependent on drilling technology (flow rate, well design, fluid properties, penetration rate, etc.), geothermal gradient and thermal properties of the formation. It is assumed that, for the given area, the above mentioned parameters vary within narrow limits. In order to obtain the values of A_0, A_1, and A_2 the records of the outlet fluid (mud) temperature (at h = 0) and results of downhole temperature surveys are needed. In Eq. (5) the value of T_m is the stabilized downhole circulating temperature. The time of the downhole temperature stabilization (t_s) can be estimated from the routinely recorded outlet mud temperature logs. Eq. (5) was verified (Kutasov et al., 1988) with more than 10 deep wells, including two offshore wells, and the results were satisfactory ones. Here we are presenting one example of applying Eq. (5) for prediction of downhole circulating temperatures. It will be shown that only a minimum of field data is needed to use this empirical method.

Mississippi well. The results of field temperature surveys and additional data (Table 1) were taken from the paper by Wooley et al. (1984).

Table 1: Measured (T_m*) and predicted (T_m) values of wellbore circulating temperature

h, m	H, m	T_m*, °C	T_m, °C	T_m* - T_m, °C
Mississippi well				
4900	4900	129.4	130.7	-1.3
6534	6534	162.8	163.4	-0.6
7214	7214	178.3	177.0	1.3
0	4900	50.0	48.1	1.9
0	6534	51.7	53.2	-1.5
0	7214	55.6	55.4	0.2

Three measurements of stabilized bottom-hole circulating temperatures and three values of stabilized outlet mud temperatures were run in a multiple regression analysis computer program and the coefficients of the empirical Eq. (5) were obtained

$$A_0 = 32.68^{o}\text{C}, \quad A_1 = 0.01685\ ^{o}\text{C/m}, \quad A_2 = 0.003148\ ^{o}\text{C/m}.$$

Thus, the equation for the downhole circulating temperature is

$$T_m = 32.68 + 0.01685h + 0.003148H.$$

In 1995 American Petroleum Institute (API), Sub-committee 10 (Well Cements) has developed new temperature correlations for estimating circulating temperatures for cementing (Covan and Sabins, 1995, Table 2). The surface formation temperature (T_0) for the current API test schedules is assumed to be 80 °F.

Table 2: The new API temperature correlations (Covan and Sabins, 1995)

Depth ft	Temperature gradient, °F/100 ft					
	0.9	1.1	1.3	1.5	1.7	1.9
8,000	118	129	140	151	162	173
10,000	132	147	161	175	189	204
12,000	148	165	183	201	219	236
14,000	164	185	207	228	250	271
16,000	182	207	233	258	284	309
18,000	201	231	261	291	321	350
20,000	222	256	291	326	360	395

It should be also mentioned that for high geothermal gradients and deep wells, the API circulating temperatures are estimated by extrapolation. Here one should note that the current API correlations which are used to determine the bottom-hole circulating temperature permit prediction in wells with geothermal gradients up to only 1.9°F/100 ft.

2.2.2 Kutasov-Targhi equation

We conducted an analysis of available field measurements of bottom-hole circulating temperatures (Kutasov and Targhi, 1987). It was found that the bottom-hole circulating temperature (T_{mb}) can be approximated with sufficient accuracy as a function of two independent variables: the geothermal gradient, Γ and the bottom-hole static (undisturbed) temperature T_{fb}:

$$T_{\text{bot}} = d_1 + d_2\Gamma + (d_3 - d_4\Gamma)T_{fb}. \tag{6}$$

For 79 field measurements (Kutasov and Targhi, 1987), a multiple regression analysis computer program was used to obtain the coefficients of formula:

$$d_1 = -50.64\ ^{o}\text{C}\ (-102.1^{o}\text{F}), \quad d_2 = 804.9\ \text{m}\ (3354\ \text{ft}),$$

$$d_3 = 1.342, \quad d_4 = 12.22\ \text{m}/^{o}\text{C}\ (22.28\ \text{ft}/^{o}\text{F}).$$

These coefficients are obtained for

$$74.4^{o}\text{C}\ (166\ ^{o}\text{F}) \le T_{fb} \le 212.2\ ^{o}\text{C}\ (414^{o}\text{F}),$$

$$1.51^{o}\text{C/100m}\ (0.83\ ^{o}\text{F/100ft}) \le \Gamma \le 4.45\ ^{o}\text{C/100m}\ (2.44\ ^{o}\text{F/100 ft}).$$

Therefore, Eq. (6) should be used with caution for extrapolated values of T_{fb} and Γ. The accuracy of the results (Eq. (6)) is 4.6°C, and was estimated from the sum of squared residuals. The Kutasov-Targhi equation is recommended by API for estimation of the bottomhole circulation mud temperature (API 13D Bulletin…, 2005).

3 CEMENTING OF CASING

3.1 Strength and Thickening Time of Cement

Temperature and pressure are two basic influences on the downhole performance of cement slurries. They affect how long the slurry will pump and how it develops the strength necessary to support the pipe. Temperature has the more pronounced influence. The downhole temperature controls the pace of chemical reactions during cement hydration resulting in cement setting and strength development. The shut-in temperature affects how long the slurry will pump and how well it develops the strength to support the pipe. As the formation temperature increases, the cement slurry hydrates and sets faster and develops strength more rapidly. Cement slurries must be designed with sufficient pumping time to provide safe placement in the well. At the same time the cement slurry cannot be overly retarded as this will prevent the development of satisfactory compressive strength. The thickening time of cement is the time that the slurry remains pumpable under set conditions. While retarders can extend thickening times, the thickening time for a given concentration of retarder is still very sensitive to changes in temperature. Slurries designed for erroneously high circulating temperatures can have unacceptably long setting times at lower temperatures. A compressive strength of 500 psi (in 24 hours) is usually considered acceptable for casing support (Romero and Loizzo, 2000). From Figure 3 follows that a temperature difference of only 6 ^{o}F (3.3^{o}C) significantly affects the compressive strength development of the cement. To reduce the wait on cement we recommend increasing the outlet mud temperature. Earlier we suggested this technique to reduce wait on cement at surface casing for wells in permafrost regions (Kutasov, 1999). This may reduce the cost associated with cementing of the conductor and surface casing.

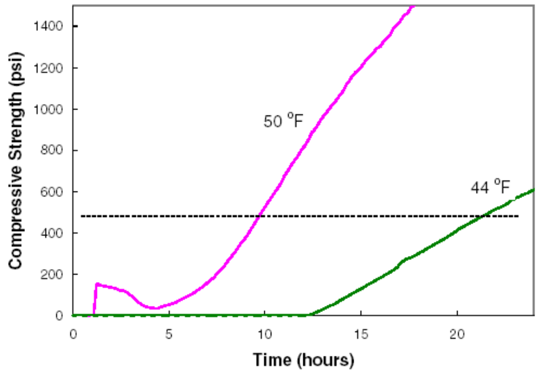

Figure 3: Compressive strength development for a deep-water system at two temperatures (Romero and Loizzo, 2000)

As we mentioned earlier American Petroleum Institute (API), Sub-committee 10 (Well Cements) has developed new temperature correlations for estimating circulating temperatures for cementing (Covan and Sabins, 1995; Table 2). To use the current API bottom-hole temperature circulation (BHCT) correlations (schedules) for designing the thickening time of cement slurries (for a given depth) the knowledge of the averaged static temperature gradient is required. The surface formation temperature (SFT) for the current API test schedules is assumed to be 80 ^{o}F. The value of SFT (the undisturbed formation temperature at the depth of approximately of 50 ft, where the temperature is practically constant) of about 80^{o}F is typical only for wells in Southern U.S. and some other regions. For this reason the API test schedules cannot be used for determination values of BHCT for cementing in wells drilled in deep waters, in areas remote from the tropics, or in Arctic regions. For example, the equivalent parameter of SFT for offshore wells is the temperature of sea bottom sediments (mud line) that is close to 40 ^{o}F. In Arctic areas the value of SFT is well below the freezing point of water. Many drilling operators came to a conclusion that computer temperature simulation models (instead of the API schedules) should be used to estimate the cementing temperatures (Honore et al., 1993; Guillot et al., 1993; Calvert and Griffin, 1998). In this section we present a novel concept - the Equivalent “API Wellbore Method” (Kutasov, 2002) and we will show that the current API bottom-hole temperature circulation (BHCT) correlations can be used for any deep well and for any values of surface formation temperature. We will call this technique as the “API-EW Method”. An empirical formula and results of computer simulations will be utilized to verify applicability of the suggested technique.

As was mentioned above, for on land wells the value of T_0 is the temperature of formations at the depth of about 50 ft.

$$T_{fb} = T_o + \Gamma(H - 50).$$

In practice, for deep wells is usually assumed that

$$T_{fb} = T_o + \Gamma H. \tag{7}$$

For offshore wells the value T_0 is the temperature of bottom sea sediments. It can be assumed that $T_o \approx 40$ ^{o}F and if the thickness of the water layer is H_w, then

$$T_{fb} = T_o + \Gamma(H - H_w). \tag{8}$$

Firstly, we have to note that the API bottom-hole circulation temperature correlations are based on field measurements in many deep wells. To process field data the staff of the API Sub-Committee 10 has used two variables – the averaged static temperature gradient and the vertical depth. The problem is in assuming a constant value of the surface formation temperature. Indeed, to use the API schedules the drilling engineer has to estimate the static temperature gradient from the following formula

$$\Gamma = \frac{T_{fb} - 80}{H}. \tag{9}$$

The Reader can see the difference between relationships 7 and 8 and the last formula. It is logical to assume that for wells with T_0 = 80 °F a good agreement between measured and estimated from API correlations values of BHCT should be expected. Therefore we suggest to "transform" a real wellbore to an "Equivalent API Wellbore". As an example let us consider a well with following parameters: H = 20,000 ft, Γ = 0.020 °F /ft and T_0 = 60 °F. Then the depth of the 80 °F isotherm is: (80-60)/0.020 = 1,000 (ft). Thus the vertical depth of the "Equivalent API Wellbore" is H^* = 20,000-1,000 = 19,000 (ft). Similarly, for a well with T_0 = 100°F, H^* = 20,000 + 1,000 = 21,000 (ft).

Below we present simple equations for estimation of the equivalent vertical depth (H^*). For on land well,

$$T_{fb} = T_0 + \Gamma H = 80 + \Gamma H^*. \tag{10}$$

$$H^* = H + \frac{T_0 - 80}{\Gamma}. \tag{11}$$

For an offshore well,

$$H^* = (H - H_w) + \frac{T_0 - 80}{\Gamma}, \tag{12}$$

where T_0 is the temperature of bottom sediments (mud line) and Γ is the average temperature gradient in the $H - H_w$ section of the wellbore.

$$\Gamma = \frac{T_{fb} - T_0}{H - H_w}. \tag{13}$$

Examples

Below we present three examples of determination bottom-hole circulating temperatures (BHCT) by the API-EW Method.

The parameters for three wells (cases) were taken from Goodman et al. (1988). The results of calculations and computer simulations are presented in Table 3. One can observe that the suggested API-EW Method predicts the bottom-hole circulating temperatures with a satisfactory accuracy. The average deviation from computer stimulation results (for three cases) is 11°F.

Table 3: Results of simulations and calculations of bottom-hole circulating temperature

Parameters	Well 2	Well 6	Well 8
TVD, ft	15,000	15,000	11,000
Water Depth, ft	0	1,000	1,000
Equivalent TVD, ft	15,000	12,000	8,000
Surface Temp., °F	80	80	80
Seabed Temp., °F	-	50	50
Static Gradient, °F/ft	0.015	0.015	0.015
BHST, °F	305	260	200
BHCT: API-EW, °F	244	201	140
BHCT: Stimulator, °F	248	189	157
BHCT: KT-Formula, °F	255	210	150

3.2 The optimal time lapse to conduct a temperature log

When cement is mixed with water, an exothermic reaction occurs and a significant amount of heat is produced. This amount of heat depends mainly on the fineness and chemical composition of the cement, additives, and ambient temperature. Assessment of the temperature development during hydration is necessary to determine how fast the cement will reach an acceptable compressive strength before the casing can be released (Romero and Loizzo, 2000). Therefore, for deep wells heat generation during cement hydration has to be taken into account at cement slurry design. The experimental data show that the maximum value of heat generation occurs during the first 5 to 24 hours (Halliburton, 1979). During this period the maximum temperature increase (ΔT_{max}) can be observed in the annulus. In order to evaluate the temperature increase during cement hydration it is necessary to approximate the heat production versus time curve by some analytical function $q = f(t)$. Temperature surveys following the cementing operation are used for locating the top of the cement column behind casing. Thus, it is very important to predict the temperature increase during the cement setting. This will enable to determine the optimal time lapse between cementing and temperature survey.

It was found that a quadratic equation (Eq. (14)) can be used for a short interval of time to approximate the rate of heat generation (q) per unit of length as a function of time (Kutasov, 1999).

$$\left\{ q_D = a_0 + a_1 t + a_2 t^2, \quad q_D = \frac{q^*}{q_r}, \quad t = t^* - t_0, \quad \frac{dq_D}{dt} = 0, \quad a_1 + 2a_2 t_{xc} = 0, \quad t_{xc} = -\frac{a_1}{2a_2} \right\}, \tag{14}$$

where a_0, a_1, and a_2 are coefficients, t^* is the time since cement slurry placement, t_0 is cement retardation time, $t = t^* - t_0$, time since onset of cement hydration, A_0 is the reference rate of heat generation per unit of length, q_D is the dimensionless rate of heat production q^* is the rate of heat production per unit of mass, q is the rate of heat production per unit length, q_r is the reference rate of heat generation per unit of mass, t_{xc} is the calculated time when $q = q_{mc}$ (calculated maximum value of heat production rate per unit length). In our recent paper (Kutasov and Eppelbaum, 2013) we demonstrated how field and laboratory data can be utilized to estimate the temperature increase during cement hydration. Below we will discuss two methods of processing of field and laboratory data.

(a) The values of heat production rate versus time during cement hydration are available. In this case a quadratic regression program can be used to obtain coefficients in Eq. (14). After this, by the use of Eq. (15) and Eq. (18) we can calculate temperature increase during cement hydration:

$$q = A_0 q_D, \qquad A_0 = \pi\left(r_w^2 - r_c^2\right)\rho_c q_r, \tag{15}$$

$$a_1^* t_x + a_2^* t_x^2 = q_{mD} \qquad \frac{dq_D}{dt} = a_1^* + 2a_2^* t_x = 0, \tag{16}$$

$$a_1^* = \frac{2q_{mD}}{t_x}, \qquad a_2^* = -\frac{q_{mD}}{t_x^2}, \qquad q_{mD} = \frac{q_m}{q_r}, \tag{17}$$

where A_0 is the reference rate of heat generation per unit of length, a_1^* and a_2^* are coefficients, r_w is the well radius, r_c is the outside radius of casing, ρ_c is the density of cement, t_x is the observed time when $q = q_m$, and q_m is the observed maximum value of heat production rate per unit length.

Earlier we developed a semi-analytical formula which allows one to estimate the temperature increase versus setting time (Kutasov, 2007). Eq. (18) describes the transient temperature at the cylinder's wall (T_v), while at the surface of the cylinder the radial heat flow rate (into formations) is a quadratic function of time.

$$\Delta T = T_v(t) - T_i = \frac{A_0}{2\pi\lambda} W(t), \tag{18}$$

where T_v is the temperature of wellbore's wall, T_i is the static temperature of formations, λ is the thermal conductivity of formation. The function $W(t)$ is rather too cumbersome and is presented in our publications (Kutasov, 2007, Kutasov and Eppelbaum, 2013; Eppelbaum et al., 2014). In this case by the use of Eq. (15) and Eq. (18) we can calculate temperature increase during cement hydration.

(b) Let us assume that from laboratory cement of hydration tests or field tests we are able only to determine the peak of the heat production rate – time curve (Figure 4). For some small time interval we can assume that a parabola equation approximates the $q_D = q_D(t)$ curve. Then from Eqs. (16) and (17) we can estimate the coefficients, a^*_1, and a^*_2. Finally, from Eq. (18) (at $t = t_x$, $a_0 = 0$, $a_1 = a_1^*$, and $a_2 = a_2^*$) we can determine the temperature increases when heat production rate reaches its maximum value.

Field case. Well #4 (Venezuela) is a vertical wellbore. The total depth was 12,900 ft the bottomhole static temperature at 12,600 ft was 244°F. The casing size of this well is $5^{1/2}$ in, and the hole size was 8 1/2-in. the 14.0 ppg composite blend cement slurry was used. We assumed that the surrounding formation is oil-bearing sandstone with thermal conductivity – 1.46 kcal/(m·hr ·°C) and thermal diffusivity -0.0041m^2/hr.

At our calculations we will use the heat evolution curve at 150°F and it will be referred as Ve150 (Figure 4). In this well to guaranty pumpability of the cement slurry some chemicals-retarders were used. To conduct calculations after Eq. (18) it is necessary to approximate the sections of the $q^* = q(t)$ curve by a quadratic equation. For this reason a table of q^* versus t is needed. However, only a plot of $q^* = q(t)$ was available (Figure 4). We selected value of q_r =1 *BTU*/(lbm·hr) = 553.1 cal/(hr·kg) In this case the values of heat flow rates per unit of mass will be *numerically equal* to its dimensionless values. To digitize plot and obtain the numerical values of q_D and time the *Grapher* software was used.

The values of heat production rate versus time during for a short interval of cement hydration are available.

Step 1. The parameter t_0= 7.7 hours was estimated from a linear regression program for small values of q_D ($q_D(t = t_0) = 0$, Figure 4).

Step 2. A quadratic regression program was used to process data and the coefficients in Eq. (14) were determined: $a_0 = -1.6355,\ a_1 = 5.8675 hr^{-1},\ a_2 = -0.7014 hr^{-2},\ 3.4 \le t \le 6.4 hrs,\ R = 2.5\%,$ where R is the relative accuracy (in %) of approximation q_D by a quadratic equation. The following parameter is also calculated t_{xc}= 4.18 hr.

Step 3. Calculation of A_0:

$$A_0 = 3.1416\,\frac{8.5^2 - 5.5^2}{4}\,0.0254^2 \cdot 1680 \cdot 0.5531 = 19.78\left(\frac{\text{Kcal}}{\text{m}\cdot\text{hr}}\right).$$

Step 4. From Eq. (18) at t_{xc} = 4.18 hr (calculated time when $q = q_{mc}$) we estimate the temperature increase ΔT_{mc} = 17.3 °C (31.1 °F).

Step 5. From the Figure 5 we estimate the maximum temperature increase during cement hydration at t = 5.6 hr, and ΔT_{max} = 19.5 °C (35.0 °F).

It is interesting to note that the maximum values of the temperature increase and the dimensionless heat flow rate do not coincide in time (Figure 5).

b. Let us assume that from laboratory cement of hydration tests or field tests we are able only to determine the peak of the heat production rate and the corresponding time (Figure 4). Input data are: t_x =3.79 hrs and q_{Dm} =10.53.

Step1. From Eqs. (16) and (17) we estimate the coefficients $a_1^* = 5.5533\ hr^{-1}$, $a_2^* = -0.7322\ hr^{-2}$.

Step 2. From Eq. (18) at t = 3.79 hrs and a_0 = 0, a_1 = a_1^*, a_2 = a_2^* we determine the temperature increase ΔT_m = 18.0 °C (32.4 °F).

Thus, the optimal time interval to conduct a temperature survey is $11.5(3.8+7.7) \geq t^* \leq 13.3(5.6+7.7)$ hours since cement placement.

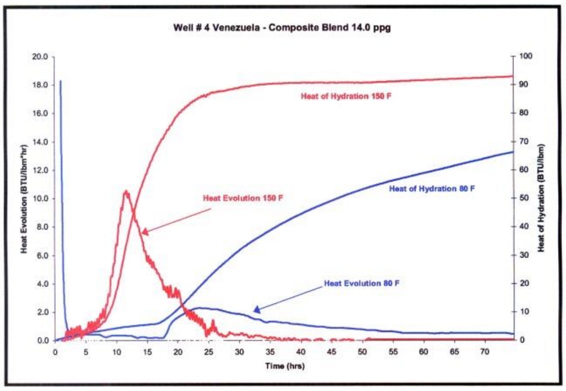

Figure 4: Heat of hydration and heat of evolution per unit of mass as a function of time, Well #4, Venezuela (after Dillenbeck et al. (2002))

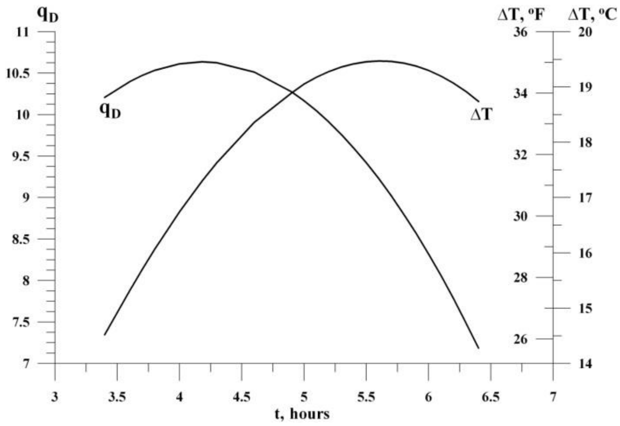

Figure 5: Behavior of functions q_D and ΔT

4 SHUT-IN PERIOD

During the shut-in period in the wellbore are conducted transient downhole and bottomhole temperature surveys and geophysical logging. In interpretation of the geophysical data is used the temperature dependence of mechanical and electrical properties of formations. In this Section presented methods of determination of the temperatures in surrounding wellbore formations during the shut-in period. We also present several techniques of calculation of the static formation temperatures. In their classical work Lachenbruch and Brewer (1959) investigated the effect of variation with time of the heat source strength on the shut-in temperatures. From the drilling data the authors concluded that the effective temperature on the walls of the borehole at a given depth could be considered constant during drilling

4.1 Temperature distribution in formations

Knowledge of the temperature distribution around the wellbore as a function of the circulation time, shut-in time, and the radial distance is needed to estimate the electrical resistance of the formation water. This will permit to improve the quantitative interpretation of electric logs. The temperature distribution around a shut-in well is an important factor affecting thickening time of cement, rheological properties, compressive strength development, and set time. For the fluid circulating period an approximate analytical solution was obtained (Eq. (3)), which describes with high accuracy the temperature field of formations around a well with a constant bore-face temperature. Using the principle of superposition for the shut-in period we present an approximate analytical solution which describes the temperature distribution in formation surrounding the wellbore during the shut-in period

$$T_{sD} = \frac{T_s(r,t_s) - T_f}{T_w - T_f} = \frac{Ei\left(-\frac{r_D^2}{4(t_D^* + t_{sD})}\right) - Ei\left(-\frac{r_D^2}{4t_{sD}}\right)}{Ei\left(-\frac{r_D^2}{4t_D^*}\right)}, \qquad (19)$$

$$t_D = \frac{at}{r_w^2}, \quad t_D = \frac{at_s}{r_w^2}, \quad r_D = \frac{r}{r_w}, \quad t_D^* = Gt_D,$$

where t_D* is the adjusted dimensionless drilling mud circulation time and G is a function of t_D (Eq. 4).

4.2 The Basic Formula

To determine the temperature in a well (r = 0) after the circulation of fluid has ceased, we used the solution of the diffusivity equation that describes cooling along the axis of a cylindrical body with a known initial temperature distribution ($T_D^{'}$), placed in an infinite medium of constant temperature (Carslaw and Jaeger, 1959; p. 260).

$$T_{sD} = \frac{1}{2at_s}\int_o^\infty \exp\left(-\frac{\tau^2}{4at_s}\right) T_D^{'}(\tau, t_D)\tau\, d\tau, \quad T_{sD} = \frac{T_s(0,t_s) - T_f}{T_m - T_f}, \qquad (20)$$

$$T_D^{'}(\tau,t_D) = T_D(\tau,t_D), \; r \ge r_w \qquad \tau = r_D, \quad t = t_c,$$
$$T_D^{'}(\tau,t_D) = 1, \quad r < r_w.$$

where τ is the variable of integration. From Eq. (20), we obtained the following expression for T_{sD} (Kutasov, 1999):

$$\left\{T_{sD} = 1 - \frac{Ei\left[-\beta\left(1 + t_D^*/t_{sD}\right)\right]}{Ei\,(-\beta)}, \quad t_{sD} = \frac{at_s}{r_w^2}\, T_D^{'}(\tau,t_D) = T_D(\tau,t_D),\; r \ge r_w, \quad \tau = r_D, \quad t = t_c,\; \beta = \frac{1}{4t_D^*}, \quad t_D^* = Gt_D\right\}. \qquad (21)$$

At derivation of Eq. (21) it is assumed that the thermal diffusivity is the same both within the well and in the surrounding formations. The good agreement between Jaeger's (1956) numerical solution and the calculated values of T_{sD} shows that Eq. (21) can be used for temperature predictions during the shut-ion period (Kutasov, 1999).

4.3 "Two Temperature Logs" Method

The mathematical model of the "Two temperature logs" ("Two thermograms") method is based on the assumption that in deep wells the effective temperature of drilling mud (T_w) at a given depth can assumed to be constant during the drilling process. As was shown before (Kutasov, 1999), for moderate and large values of the dimensionless circulation time (t_D > 5) the temperature distribution function T_{cD} (r_D, t_D) in the vicinity of the well can be described by a simple Eq. (22).

$$\left(T_D(r_D,t_D)\right) = 1 - \frac{\ln r_D}{\ln R_{in}}, \quad 1 \le r_D \le R_{in}, \qquad R_{in} = 1 + Do\sqrt{t_D}\,. \qquad (22)$$

Thus the dimensionless temperature in the wellbore and in formation at the end of mud circulation (at a given depth) can be expressed as:

$$\left\{ T_{cD}(r_D,t_D) = \begin{array}{ll} 1 & 0 \le r_D \le 1 \\ 1 - \frac{\ln r_D}{\ln R_D} & 1 \le r_D \le R_{in} \\ 0 & r_D > R_{in} \end{array} \right\}, \quad T_{cD} = \frac{T(r_D,t_D) - T_f}{T_w - T_f}\,. \qquad (23)$$

To determine the temperature in the well (r = 0) after the circulation of fluid ceased, we used the radial temperature profile (Eq. (22)) and performed integration of the integral (Eq. (20)). We obtained the following expression for T_{sD}

$$\left\{T_{sD} = \frac{T(0,t_s) - T_f}{T_w - T_f} = 1 - \frac{Ei(-pR_{in}^2) - Ei(-p)}{2\ln R_{in}}, \quad t_D > 5, \quad p = \frac{1}{4nt_D}, \quad n = \frac{t_s}{t_c}\right\}. \qquad (24)$$

It was assumed that for deep wells the radius of thermal influence (R_{in}) is much larger than the well radius, and, therefore, the difference in thermal properties of drilling muds and formations can be neglected. In the analytical derivation of Eq. (24) two main simplifications of the drilling process were made: it was assumed that drilling is a continuous process and the effective mud temperature (at a given depth) is constant. For this reason field data were used to verify Eq. (24). Long term temperature observations in deep wells of Russia, Belarus, and Canada were used for this purpose (Djamalova, 1969; Bogomolov et al., 1972; Kritikos and Kutasov, 1988). The shut-in times for these wells covered a wide range (12 hours to 10 years) and the drilling time varied from 3 to 20 months. The observations showed that Eq. (24) gives a sufficiently accurate description of the process by which temperature equilibrium comes about in the borehole.

If two measured shut-in temperatures (T_{s1},T_{s2}) are available for the given depth with $t_2 = t_{s1}$ and $t_s = t_{s2}$ we obtain:

$$T_f = T_{s2} - \gamma(T_{s1} - T_{s2}), \quad (25)$$

where

$$\left\{ \gamma = \frac{Ei(-D/n_2) + \ln n_2 - D_1}{Ei(-D/n_2) - Ei(-D/n_1) + \ln \frac{n_2}{n_1}}, \quad n_1 = \frac{t_{s1}}{t_c}, \quad n_2 = \frac{t_{s2}}{t_c}, \quad D = 1.1925, \quad D_1 = 0.7532 \right\}. \quad (26)$$

The derivation of last equation can be found in Kutasov (1999).

Figure 6 presents the results of calculations of values T_f for the well 1225 (Kola Peninsula, Russia). Measured temperatures observed at t_{s1} = 4.5 days and t_{s2} = 20 days were used (a total of seven temperature logs were made with $0.5 \le t_s \le 63$ days). The total drilling time of this well was 94 days.

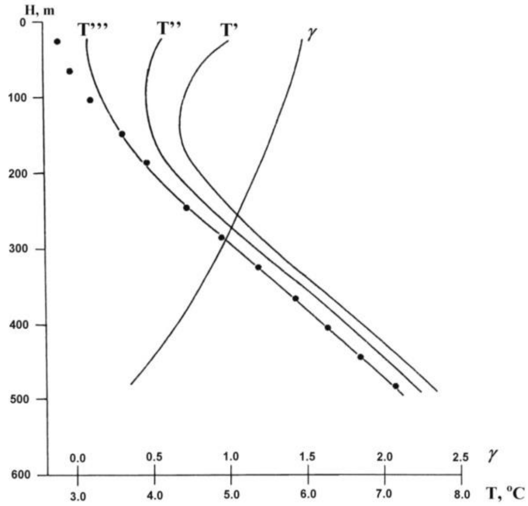

Figure 6: Rate of the temperature recovery in the well 1225. Thermograms *T''*, *T'''* and *T'* were observed at t_s = 0.5, 4.5, and 63 days correspondingly. Points designate the calculated values of T_f, and γ is the correlation coefficient (Kutasov, 1999)

The field data and the calculated T_f values show that, for a depth range 200-500 m, a shut-in time of two months is adequate if the accuracy in the determination of T_f is 0.03°C

4.4 Generalized Horner method (GHM)

Field investigations have shown that the bottom-hole circulating (without penetration) fluid temperature after some stabilization time can be considered constant (Figure 7).

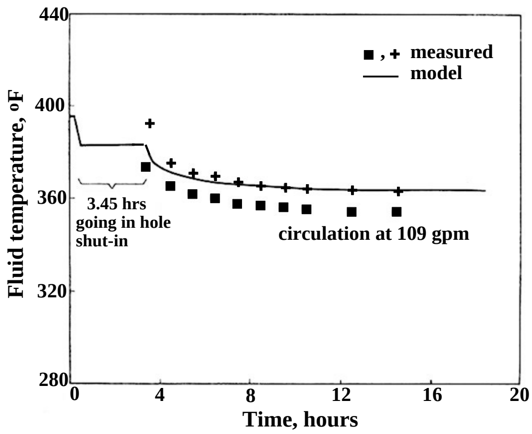

Figure 7: Circulating mud temperature at 23,669 ft (7214 m) – Mississippi well (Wooley et al., 1984). Courtesy of Society of Petroleum Engineers

In was shown that by using the adjusted circulation time concept (Kutasov 1987, 1989) a well with a constant borehole wall temperature can be substituted by a cylindrical source with a constant heat flow rate. Let us assume that at a given depth the fluid circulation started at the moment of time t = 0 and stopped at $t = t_c$. The corresponding values of the flow rates are

$$q(t = 0) = \infty, \qquad q(t = t_c) = q.$$

Using the adjusted circulation time concept and the principle of superposition for a well as a cylindrical source with a constant heat flow rate $q = q(t_c)$ which operates during the time $t = G \cdot t_c$ and shut-in thereafter, we obtained a working formula for field data processing (Kutasov and Eppelbaum, 2005):

$$T(r_w, t_s) = T_i + m \ln X; \quad m = \frac{q}{2\pi\lambda}, \tag{27}$$

$$X = \frac{1 + \left(c - \frac{1}{a + \sqrt{Gt_{cD} + t_{sD}}}\right)\sqrt{Gt_{cD} + t_{sD}}}{1 + \left(c - \frac{1}{a + \sqrt{t_{sD}}}\right)\sqrt{t_{sD}}}, \tag{28}$$

$$a = 2.7010505; \quad c = 1.4986055.$$

As can be seen from Eq. (27) the field data processing (semilog linear log) is similar of that of the Horner method. For this reason we have given the name "*Generalized Horner Method*" (*GHM*) to this procedure for determining the static temperature of formations (some authors, for instance, Wong-Loya et al. (2012) called this methodology as *KEM* – Kutasov-Eppelbaum Method). To calculate the ratio X the thermal diffusivity of formations (a) should be determined with a reasonable accuracy. An example showing the effect of variation of this parameter on the accuracy of determining undisturbed formation temperature was presented in the paper (Kutasov and Eppelbaum, 2005). It is easy to see that for large values of t_{cD} ($G \to 1$) and t_{sD} we obtain the well-known Horner equation).

$$T_s(r_w, t_s) = T_i + M \ln\left(\frac{t_s + t_c}{t_s}\right), \qquad M = \frac{m}{2} = \frac{q}{4\pi\lambda}. \tag{29}$$

Field examples and a synthetic example were used to verify Eq. (27) (Kutasov and Eppelbaum, 2005).

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