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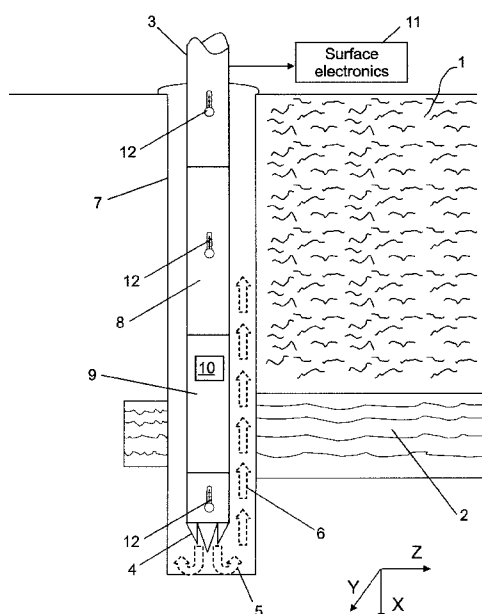
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- as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii))

[Continued on next page]

(54) Title: DISTRIBUTED MEASUREMENT OF MUD TEMPERATURE

FIG. 1



(57) Abstract: A method for estimating a temperature within sub-surface materials traversed by a wellbore includes: obtaining temperature data from a plurality of measurements of temperature taken within the wellbore; calculating an overall heat transfer coefficient from the measurement data; calculating a geothermal gradient from the overall heat transfer coefficient; and using the geothermal gradient to estimate the temperature within the sub-surface materials. A system and a computer program product are provided.



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DISTRIBUTED MEASUREMENT OF MUD TEMPERATURE

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BACKGROUND OF THE INVENTION**1. Field of the Invention**

5 [0001] The invention disclosed herein relates to exploration for oil and gas and, in particular, to evaluation of temperature profiles downhole.

2. Description of the Related Art

[0002] In the exploration for oil and gas, it is necessary to drill a borehole into the earth. While drilling of the borehole permits individuals and companies to evaluate
10 sub-surface materials and to extract desired hydrocarbons, many problems are encountered. Once such problem is that of elevated temperatures down hole.

[0003] Not only do elevated temperatures present a harsh environment to equipment downhole, but, the elevated temperatures may be indicative of properties of materials downhole.

15 [0004] Therefore, what are needed are methods and apparatus that provide for measurement of temperatures downhole. Preferably, the methods and apparatus provide information that is indicative of formation properties.

BRIEF SUMMARY OF THE INVENTION

[0005] An embodiment of the invention includes a method for estimating a
20 temperature within sub-surface materials traversed by a wellbore, the method including: obtaining temperature data from a plurality of measurements of temperature taken within the wellbore; calculating an overall heat transfer coefficient from the measurement data; calculating a geothermal gradient from the overall heat transfer coefficient; and using the geothermal gradient to estimate the temperature
25 within the sub-surface materials.

[0006] Another embodiment of the invention includes a system for determining a temperature of sub-surface materials, the system including: a plurality of temperature

sensors distributed along a drill string, the drill string providing for a wellbore that traverses the sub-surface materials; and a processor for receiving temperature data from the from the plurality of temperature sensors along at least a portion of the wellbore and for implementing machine executable instructions for calculating an
5 overall heat transfer coefficient from the measurement data; calculating a geothermal gradient from the overall heat transfer coefficient; and using the geothermal gradient to estimate the temperature within the sub-surface materials.

[0007] Yet another embodiment of the invention includes a computer program product stored on machine readable media and including machine executable
10 instructions for estimating a temperature in sub-surface materials, by implementing a method including: receiving temperature data from a plurality of measurements of temperature taken within a wellbore traversed by a logging instrument; calculating an overall heat transfer coefficient from the measurement data; calculating a geothermal gradient from the overall heat transfer coefficient; using the geothermal gradient to
15 estimate the temperature within the sub-surface materials; and outputting the estimate to a user.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] The subject matter which is regarded as the invention is particularly pointed out and distinctly claimed in the claims at the conclusion of the specification. The
20 foregoing and other features and advantages of the invention are apparent from the following detailed description taken in conjunction with the accompanying drawings in which:

- FIG. 1** depicts aspects of a drilling apparatus, and shows a flow of drilling fluid within a borehole;
- 25 **FIG. 2** is a flow chart providing an exemplary method for estimating temperatures related to a borehole;
- FIG. 3** depicts aspects of a temperature profile within a drillstring and a wellbore;
- FIG. 4** depicts relationships of temperature parameters as a function of depth;
30 and
- FIG. 5** depicts aspects of temperature averaging.

DETAILED DESCRIPTION OF THE INVENTION

[0009] Disclosed are techniques for estimating far-field temperature in a downhole environment. Measurement of pipe and bore fluid temperatures along a drill string can be used to infer the far-field formation temperature gradient, which is affected by the volume of contained water, and hence pore pressure. The temperature data may be used for cementing operations in estimation of the needed cement properties, monitoring of the setting of the cement, and for other aspects as deemed appropriate. Knowledge of the far-field temperature and temperature gradient is therefore important for pore pressure prediction, cementing operations, and correction of measurements made by wireline or measurement-while-drilling tools, among others. The term “far-field” as used herein relates to being away from the influence or effects of the borehole.

[0010] In general, the techniques take advantage of flow line measurement data, and assume conditions of steady state heat flow within the borehole. That is, it is considered that heat flow across the various thermal resistances within the borehole is relatively constant, and therefore independent of time. It is recognized that, in general, under normal operational wellsite conditions, that such assumptions are more reliable once the wellbore has been circulated continuously for at least one circulation. Before discussing the invention in detail, some context is provided.

[0011] Refer now to **FIG. 1** where aspects of a drill string are shown. In **FIG. 1**, an exemplary embodiment of an apparatus for performing logging while drilling is shown. In this example, a section of earth **1**, which includes at least one formation **2**, is penetrated by a drill string **3**. The drill string **3** drives a drill bit **4**. In this example, the drill bit **4** also provides a flow of a drilling fluid **5**, such as drilling mud. That is, the drilling fluid **5** may be pumped downhole through the drilling pipe **8**, and thus resulting in a flow of drilling fluid **6** that is provided upward within a borehole **7** (also referred to as a “wellbore”).

[0012] The drill string **3** may include a plurality of sections of the drill pipe **8**. The drill pipe **8** may include wired pipe providing users with a communications channel. Included within the drill string **3** may be at least one logging apparatus **9**. Exemplary logging apparatus include devices implementing resistivity, nuclear magnetic

resonance, acoustic, seismic and other such technologies. Generally, included with the logging apparatus 9 is a package of downhole electronics 10. The downhole electronics 10 generally provide for collection and/or communication of downhole data to a package of surface based electronics 11. Included in this drill string 3 is a plurality of temperature sensors 12. The drill string 3 may also be referred to as “drill stem,” and by other similar terms.

[0013] Collectively, the logging apparatus 9 and the associated electronics 10, 11 provide for such tasks as imaging of the at least one formation 2. In addition, the logging apparatus 9 and the associated electronics 10, 11 may provide for collection and/or communication of other information, such as temperature from each of the temperature sensors 12.

[0014] Generally, each of the temperature sensors 12 is disposed such that the respective temperature sensor 12 is operable for detection of local temperature, including a temperature of the drilling fluid 5. Each of the temperature sensors 12 provides a signal to at least one of the electronics units 10, 11. Generally, each temperature sensor 12 communicates an identity with the sensor output. Using identity and temperature, the electronics units 10, 11 are provided with adequate information for determining a temperature gradient within the borehole 7. In some embodiments, and as described herein, each of the electronics unit(s) 10, 11 may, alone or in combination, further estimate a far-field temperature (i.e., a temperature within some portion of the earth 1 and/or the formation 2).

[0015] In general, bore temperature and annulus temperature is measured at an outlet and an inlet (suction pit), and at several locations along the drillstring 3. These measurements, which may be made in real-time, are used by a temperature model to predict the far-field temperature. Since abnormal temperature gradients occur above and through intervals of abnormal pore-pressure, the predictions of far-field temperature may be used in real-time, such as while drilling. In some embodiments, modeling calls for use of other measurements, such as revolutions per minute (RPM), and formation properties (such as porosity). Accordingly, now consider certain input information useful for modeling far-field temperature.

[0016] Inputs useful for modeling far-field temperature include geometry of the borehole 7 (also referred to as a “wellbore”). The information may include, for example, presence, number, dimensions and/or quality of: casing strings, holes, cemented intervals and other such information. Mud composition may be used as an input and may consider, for example: particle properties, constituent identities and types, oil percentage, heat capacity, etc,... Also of interest is the temperature inside the drill string 3 and outside of the drill string 3.

[0017] Output of models used for estimating the far-field temperature include: a far-field formation temperature gradient; a drilled interval formation temperature gradient; a bottom hole circulating temperature; and a formation temperature.

[0018] In general, the teachings herein may be reduced to the form of an algorithm, and described in machine executable instructions stored on machine readable media (generally referred to herein as “software”).

[0019] As an example of a model of circulating mud temperatures, under steady-state linear heat transfer, the temperature of the mud in the drillstem (within the drill string 3) is given by Eq. (1) (see Holmes C.S. and Swift S.C, 1970, Calculation of Circulating Mud Temperatures,” JPT, June 1970, pp 670-674):

$$T_p = K_1 e^{(c_1 x)} + K_2 e^{(c_2 x)} + Gx + T_s - GA \quad (1)$$

and the temperature of the mud in the annulus (outside of the drill string 3 and in the borehole 7) is given by Eq. (2):

$$T_a = K_1 C_3 e^{(c_1 x)} + K_2 C_4 e^{(c_2 x)} + Gx + T_s \quad (2);$$

where:

T_p represents temperature in the drillstem at depth (x), in degrees Fahrenheit (°F);

T_a represents temperature in the annulus at depth (x), in degrees Fahrenheit (°F);

G represents the geothermal gradient, in degrees Fahrenheit per foot (°F/ft);

T_s represents surface temperature, in degrees Fahrenheit ($^{\circ}\text{F}$);

x represents a depth of interest, in feet (ft);

K_1, K_2 represent integration constants, as defined below; and

C_1 through C_4 are constants given by:

$$5 \quad C_1 = (B/2A)[1 + (1 + 4/B)^{1/2}] \quad (3.1)$$

$$C_2 = (B/2A)[1 - (1 + 4/B)^{1/2}] \quad (3.2)$$

$$C_3 = (1 + B/2)[1 + (1 + 4/B)^{1/2}] \quad (3.3)$$

$$C_4 = (1 + B/2)[1 - (1 + 4/B)^{1/2}] \quad (3.4)$$

$$A = m * C_p / (2\pi * r_{p0} * u_{p0}) \quad (4)$$

$$10 \quad B = r U_a / (r_{p0} * u_{p0}) \quad (5)$$

where

m represents mass flow rate, in lb/hr;

C_p represents mud heat capacity, in Btu (lb- $^{\circ}\text{F}$);

r_{p0} radius of drillpipe (outer diameter), in ft;

15 u_{p0} overall heat transfer coefficient across the drillpipe, in Btu/(ft² - $^{\circ}\text{F}$ - hr);

r represents hole radius, in ft; and,

U_a overall heat transfer coefficient across the wellbore face, in Btu/(ft² - $^{\circ}\text{F}$ - hr).

20 **[0020]** Various boundary conditions may be applied to the preceding series of equations to derive an analytic solution for the integration constants. As an example, given in the preceding reference, the following boundary conditions may be applied:

$$1. \quad \text{At depth } x = 0: T_p = T_{p_{in}} \quad (B1)$$

$$2. \quad \text{At depth } x = H: T_{HP} = T_{Ha} \quad (B2)$$

25 where

H represents total well depth (i.e., bit depth), in ft;

$T_{p_{in}}$ represents mud inlet temperature, in $^{\circ}\text{F}$;

T_{HP} represents drill stem temperature at depth H;

T_{Ha} represents annulus temperature at depth H.

Then,

$$K_1 = Tp_{in} - K_2 - T_s + GA \quad (6) \text{ and}$$

$$K_2 = \frac{GA - [Tp_{in} - T_s + GA]e^{(C_1^H)(1-C_3)}}{e^{(C_2^H)(1-C_4)} - e^{(C_1^H)(1-C_3)}} \quad (7).$$

[0021] Using the above boundary conditions, it is therefore possible to calculate the temperature at any depth downhole during circulation of the drilling fluid 5. However, this generally calls for pre-existing knowledge of the geothermal gradient in the formation (that is, inclusion of the term G into Eqs. (6) and (7) above). Since this information is not accessible, and the calculation of geothermal gradients is one of the objectives of the model, solving may apply another boundary condition, provided as Eq. (B3):

$$3. \text{ At depth } x = 0: Ta = Ta_{out} \quad (B3)$$

where

$$15 \quad Ta_{out} \text{ represents flowline temperature, in } ^\circ F.$$

This leads to:

$$Ta_{out} = K_1 C_3 + K_2 C_4 + T_s.$$

Using Eq. (6), this may be expressed as:

$$20 \quad Ta_{out} = (Tp_{in} - K_2 - T_s + GA)C_3 + K_2 C_4 + T_s.$$

Finally, using Eq. (7) and solving for G (geothermal gradient), provides Eq. (8):

$$G = \frac{y(Ta_{out} - Ta) + (Tp_{in} - T_s)[(1 - C_3)(C_4 - C_3)e^{(C_1^H)} - yC_3]}{A[(y - 1)C_3 + C_4 - (1 - C_3)(C_4 - C_3)e^{(C_1^H)}]}, \quad (8)$$

where

$$y = e^{(C_2^H)(1-C_4)} - e^{(C_1^H)(1-C_3)} \quad (9).$$

[0022] With knowledge of the geothermal gradient at depth $x = H$, the temperature of the formation **2** may be estimated using Eq. (10):

$$T_{\text{fmn}} = H * G + T_s \quad (10).$$

5 [0023] The preceding development is given by way of an example. If the temperature within the annulus or pipe is known by other along string measurements, then it is possible to solve this model, or one similar to it, and arrive at an estimate of the far-field geothermal gradient.

[0024] Having thus introduced certain models and relationships, it should be recognized that several constants are directly related to both geometry of the borehole
10 **7** and properties of the drilling fluid **5**. Derivation of these is provided further herein. However, it is useful to discuss a method and calculation of the output parameters.

[0025] Now with reference to **FIG. 2**, consider an exemplary method **20** for estimating formation temperature. In **FIG. 2**, the method **20** includes six stages (21-26). In a first stage 21, geometry of the borehole **7** is used (along with knowledge of
15 aspects of a composition of the drilling fluid **5**) to calculate heat transfer coefficients for each section of the borehole **7**. In a second stage 22, the heat transfer coefficients are averaged, using as a base the amount of time the fluid is in each section of the hole. In a third stage 23, the temperature inside the drill string **3** and the temperature outside of the drill string **3** is averaged. In a fourth stage 24, a geothermal gradient is
20 calculated at a total depth. This may be calculated, for example, by using Eqs. (3, 4, 5 and 8). In a fifth stage 25, the temperature of the formation is calculated at the total depth. This may be calculated, for example, by using Eq. (10). In a sixth stage 26, a bottom hole circulating temperature (BHCT) is calculated. This may be calculated, for example, by using Eqs. (6, 7 and either 1 or 2).

25 [0026] In some embodiments, instead of averaging, the heat transfer coefficients are “combined.” That is, for example, the heat transfer coefficients may be fit, such as by use of a linear fit, logarithmic fit, exponential fit, a fit to a power function, a weighted fit or some other type of relationship.

[0027] Consider now, the calculation of constants for use in the equations provided
30 herein. Mass flow rate (m) may be calculated as:

$$m = Q * \rho_m * 60 \text{ (expressed in lb/hr);}$$

where:

Q represents flowrate in gal/min; and,

ρ_m represents density of mud, in lb/gal.

- 5 Heat capacity of mud, (C_p), may be calculated using the weight by volume of the individual components in the mud. The heat capacities of the individual components may be given as:

water: C_{pw} is approximately 1 Btu/(lb-°F);

NaCl: $C_{pn} = 0.12569 + 0.0000245(T)$, where T is in °K;

- 10 Solids: $C_{ps} = 0.18 + 0.00006(T)$, where T is in °F; and

oil: $C_{po} = (0.388 + 0.00045(T))/S^{1/2}$, where T is in °F and S represents specific gravity.

With knowledge of the API gravity of the oil being used (where “API gravity” refers to a measure of how heavy or light a petroleum liquid is compared to water):

- 15 $S = (^\circ\text{API} + 131.5)/141.5$

The heat capacity of the mud can therefore be calculated from:

$$C_{pm} = \frac{(100 - x)C_{pw} + yC_{pn} + zC_{ps} + \ell C_{po}}{100}$$

where y , z and ℓ are the percentage concentrations of the relative components, and

$$x = y + z + \ell.$$

- 20 Rewriting these equations provides Eq. (11):

$$C_{pm} = 1 + \frac{y}{100}(C_{pn} - 1) + \frac{z}{100}(C_{ps} - 1) + \frac{\ell}{100}(C_{po} - 1) \quad (11)$$

Note that the effect of the temperature term in the empirical equations is minimal, and that, in general, the flowline temperature may be used.

- 25 [0028] Consider now heat transfer gradients (U_{p_o} and U_a). Under steady-state conditions, the rate of heat flow across wellbore (Q) is proportional to the temperature difference between the fluid and the formation, and the crosssectional area perpendicular to the direction of heat flow, as provided by Eq. (12):

$$Q = U_j A_j \Delta T_j \quad (12)$$

Note that in Eq. (12) and elsewhere herein as appropriate, the subscript (j) refers to a surface on which the calculation is based. For example, if as reference the outside surface area of the pipe is used, then:

$$Q = U_{p_o} * A_j * \Delta T_j \quad (12.1)$$

where

U_{p_o} represents overall heat transfer coefficient;

A_j represents $2\pi r_{p_o} * \Delta L$, or the surface area, outside wall drillstem; and

ΔT_j represents $(T_f - T_p)$ or the temperature of fluid at the formation and wellbore interface - temperature of fluid in the pipe.

The problem is the solution of two heat transfer coefficients:

U_{p_o} = heat transfer coefficient, drillstem to annulus; and

U_a = heat transfer coefficient, annulus to formation

To illustrate the general method of solution, an exemplary calculation for the heat transfer coefficient across the drillpipe is provided in detail.

[0029] Consider now a method for estimating the overall heat transfer coefficient across the drillpipe. First, note that the system can generally be split into three distinct thermal resistances: flowing fluid and inside pipe wall; pipe wall thickness; outside pipe wall and annulus. Based on the heat flow rate of Eq. (12), these resistances can be described by Eq. (13, 14 and 15):

1. Flowing fluid and inside pipe wall

$$Q_1 = 2\pi r_{pi} * h_f * (T_p - T_{pi}) * \Delta L \quad (13)$$

2. Across pipe wall

$$Q_2 = 2\pi r * K_{pipe} \frac{dT}{dr} * \Delta L \quad (14)$$

3. Outside pipe wall and flowing annular fluid

$$Q_3 = 2\pi r_{p_o} * h_f * (T_{p_o} - T_a) * \Delta L \quad (15)$$

where

r_{pi} represents radius, internal, drillpipe, ft

r_{p_o} represents radius, external, drillpipe, ft

h_j represents film coefficient, inside wall drillpipe, Btu/(hr-ft²-°F)

h_f represents film coefficient, outside wall drillpipe, Btu/(hr-ft²-°F)

T_p represents temperature of the fluid inside the pipe, °F

T_{p_i} represents temperature, inside pipe wall, °F

5 K_{pipe} represents thermal conductivity, drillpipe, Btu/(hr-ft-°F)

T_a represents annular fluid temperature, °F

T_{p_o} represents temperature outside pipe wall, °F

ΔL represents length of section of interest, ft

10 Reference may be had to **FIG. 3** for a graphic depiction of certain relationships between some of these parameters.

[0030] Equation (14) can be rearranged as follows:

$$Q_2 = 2\pi r * K_{pipe} \left(\frac{dT}{dr} \right) \Delta L$$

15 $\therefore \frac{dT}{dr} = \frac{Q_2}{2\pi * k_{pipe} * \Delta L} * \frac{1}{r}$

$$T = \frac{Q_2}{2\pi * k_{pipe} * \Delta L} \int \frac{1}{r} dr$$

and,

$$(T_{p_i} - T_{p_o}) = \frac{Q_2}{2\pi \Delta L * k_{pipe}} * \ln \frac{r_{p_o}}{r_{p_i}}$$

Rewriting the derivation provides Eq. (16):

20
$$Q_2 = \frac{2\pi * \Delta L * k_{pipe} (T_{p_i} - T_{p_o})}{\ln \left[\frac{r_{p_o}}{r_{p_i}} \right]} \quad (16)$$

Under steady-state conditions, the heat transfer rates (Q_1 , Q_2 , Q_3) are equal, and Equations (13), (14), and (15) can be combined to yield Eq. (17):

$$\begin{aligned}
(T_p - T_a) &= (T_p - T_{p_i}) + (T_{p_i} - T_{p_o}) + (T_{p_o} - T_a) \\
&= \frac{Q}{2\pi r_{p_i} * h_f * \Delta L} + \frac{Q * \ln(\frac{r_{p_o}}{r_{p_i}})}{2\pi \Delta L k_{pipe}} + \frac{Q}{2\pi r_{p_o} * h_f * \Delta L} \\
(T_p - T_a) &= \frac{Q}{2\pi \Delta L} \left[\frac{1}{r_{p_i} * h_f} + \frac{\ln(\frac{r_{p_o}}{r_{p_i}})}{k_{pipe}} + \frac{1}{r_{p_o} * h_f} \right] \quad (17)
\end{aligned}$$

5

[0031] Since the overall heat transfer rate across these elements is given by Eq. (12), such that Eq. (18) may be written:

$$Q = 2\pi r_{p_o} * \Delta L * U_{p_o} * (T_p - T_a) \quad (18)$$

then inserting Eq. (17) into Eq. (18) gives Eq. (19):

$$U_{p_o} = \left[\frac{r_{p_o}}{r_{p_i} * h_f} + \frac{r_{p_o} \ln(\frac{r_{p_o}}{r_{p_i}})}{k_{pipe}} + \frac{1}{h_f} \right]^{-1} \quad (19)$$

10

which provides the overall heat transfer coefficient, U_{p_o} , across the drillpipe, based on the outside surface of the drillpipe (r_{p_o}).

[0032] Now consider overall heat transfer coefficient across the wellbore face. Based on the method described previously, the heat transfer coefficient can be written for the general case as:

15

$$U_a = \left[\frac{1}{h_f''} + \frac{r_1 \ln(\frac{r_2}{r_1})}{K_1} + \frac{r_1 \ln(\frac{r_3}{r_2})}{K_3} + \dots + \frac{r_1 \ln(\frac{r_n}{r_{n-1}})}{K_n} \right]^{-1}$$

where h_f'' represents a film coefficient of the annulus wall. For an open borehole, let $r_2/r_1 = 10$, and:

$$U_a = \left[\frac{1}{h_f''} + \frac{r_n \ln(10)}{K_{fnn}} \right]^{-1}$$

20

where

r_1 represents the radius of the open borehole, ft (= rh);

r_2 represents radius to temperature point in formation (= 10 * rh); and

k_{fnn} represents thermal conductivity, formation, Btu/(hr-ft-°F) .

- 5 [0033] From the above, the overall heat transfer coefficients can be evaluated based on film coefficients and the thermal conductivities of the "solid" wellbore geometry elements. The thermal conductivities for various materials are listed below; a general method for evaluating film coefficients is given later herein.

- 10 [0034] Now with regard to calculation of thermal conductivities (K_i), the following may be applied:

$$K_{\text{pipe}} = 26, \text{ Btu}/(\text{hr} - \text{ft} - ^\circ\text{F});$$

$$K_{\text{cement}} = 0.6, \text{ Btu}/(\text{hr} - \text{ft} - ^\circ\text{F});$$

$$K_{\text{water}} = 0.346, \text{ Btu}/(\text{hr} - \text{ft} - ^\circ\text{F});$$

$$K_{\text{oil}} = \frac{0.0677}{S} [1 - 0.0003(t - 32)], \text{ Btu}/(\text{hr} - \text{ft} - ^\circ\text{F}); \text{ and}$$

$$15 \quad K_{\text{emulsions}} = K_c \frac{2K_c + K_d - 2\Phi d(K_c - K_d)}{2K_c + K_d + 2\Phi d(K_c - K_d)}.$$

where

K_c represents thermal conductivity, continuous phase;

K_d represents thermal conductivity, discontinuous phase;

20 Φd represents volume fraction of the discontinuous phase; and

$$K_{fnn} = K_{mtx} \left[\frac{\Phi^{2/3} (\nu - 1) + 1}{\Phi^{2/3} (\nu - 1) + \Phi(1 - \nu) + 1} \right].$$

where

Φ represents porosity, fractional;

K_{fnn} represents formation thermal conductivity, Btu/(hr-ft-°F);

25 K_{mtx} represents matrix thermal conductivity, Btu/(hr-ft-°F);

$\nu = K_{\text{pores}}/K_{\text{matrix}}$, and

$= K_{\text{water}}/K_{\text{matrix}}$;

$K_{\text{qtz}} = 1.06, \text{ Btu}/(\text{hr-ft-}^\circ\text{F}); \text{ and}$

$K_{\text{lime}} = 1.3, \text{ Btu}/(\text{hr-ft-}^\circ\text{F}).$

30

[0035] Now with regard to estimation of film coefficients, the following is provided. Various groups of dimensionless coefficients have been used in the literature and are generally of the following form:

$$N_{NU} = a N_{RE}^b N_{PR}^c$$

5 when

$$N_{NU} \text{ represents a Nusselt number} = \left(\frac{h \cdot D}{k} \right);$$

$$N_{RE} \text{ represents a Reynolds number} = \left(\frac{D \cdot \rho \cdot v}{\mu} \right); \text{ and}$$

$$N_{PR} \text{ represents a Prandtl number} = \left(\frac{C_{p_m} \cdot \mu}{k} \right)$$

and

- 10 h represents a film coefficient, Btu/(hr - °F - ft²);
 D represents flow diameter, ft;
 k represents fluid thermal conductivity Btu/(hr - °F - ft);
 μ represents density, lb/ft³;
 v represents fluid viscosity, lb/(ft - hr); and
 15 C_{p_m} represents mud specific heat, Btu/(lb - °F).

[0036] In general, the coefficients a , b , and c depend on the flow regime (laminar, transition, turbulent), defined as follows:

1. laminar, $N_{RE} < 2100$;
 20 2. transition, $2100 < N_{RE} < 10,000$; and
 3. turbulent, $10,000 < N_{RE}$.

[0037] In the cases of laminar and turbulent flow regimes, the coefficients are fairly well known. For laminar flow, ($N_{RE} < 2100$):

25
$$N_{NU} = 1.86 (N_{RE} \cdot N_{PR})^{0.33} \left(\frac{D}{L} \right)^{0.33}$$

where L = length of section, ft.

In the case of turbulent flow, ($10,000 < N_{RE}$)

$$N_{NU} = .023 N_{RE}^{0.8} N_{PR}^{0.33}$$

[0038] With known flow conditions and mud properties, the film coefficients for these flow regimes can be easily solved. However, for transition flow, the solution is slightly more complicated. That is for transition flow ($2100 < N_{RE} < 10,000$), a general form of the equation is given as:

$$5 \quad N_{NU} = a(N_{RE}^{2/3} - b)N_{PR}^{1/3} * c; \text{ where}$$

a , b , and c are coefficients

When $N_{RE} = 2100$ or $10,000$, the above equation should agree with the solutions for laminar and turbulent flow respectively.

- 10 [0039] A solution for the film coefficient in the transition flow regime may be further approximated by the following equation:

$$N_{NU} = .59 \left[1 - \frac{(N_{RE} - 2100)}{10,000} \right] (N_{RE}^{2/3} - 125) N_{PR}^{1/3} \left[\frac{N_{RE} - 2100}{7900} + \left(\frac{D}{L} \right)^{1/3} \right]$$

- [0040] Now consider an effect of pipe rotation on film coefficient. When pipe is
 15 being rotated in the wellbore, the fluid in direct contact with the pipe (outside drillstem wall) is probably in a slightly more turbulent flow regime than the rest of the annulus. Accordingly, an effect of such turbulence is to raise the film coefficient of the outer diameter of the drillpipe, as shown above in that an increase in turbulence implies an increase in the Reynolds number. From Eq. (19), this in turn causes an
 20 overall increase in the heat transfer coefficient across the drillpipe.

- [0041] Under such conditions it might be expected that the flowline temperature would increase at the wellsite as RPM decreases due to the more laminar flow regime at low (to zero) rotary speeds, thus resulting in "insulating" the annulus fluids from the cooler mud in the drillstem (i.e., lower film coefficients). In fact, this has been
 25 documented for various wellsites, where while circulating bottoms up, for example, at reduced rotary speeds, the flowline temperature often shows abnormal increases. In order to include this observation in the model, the following estimate of the Reynolds number for the outside wall of the drillpipe is made.

$$N_{RE} \text{ for flow} = \left(\frac{D * \rho * v}{\mu} \right);$$

$$N_{RE} \text{ for mixing} = \left(\frac{D^2 * Nr * \rho}{\mu} \right);$$

Adding these give

$$(N_{RE})_{Po} = \frac{\rho D}{\mu} [D * Nr + v]$$

5 where

$$Nr = \text{RPM} * 60$$

$(N_{RE})_{Po}$ represents the Reynolds number, outside wall, drillstring.

(if $Nr=0$ then $(N_{RE})_{Po} = N_{RE}$)

Accordingly, some embodiments further take into account at least one operational
 10 factor, such as an RPM of the drill string 3, length of interest, radius, flow rate, volume (such as of drilling mud within the drill string 3, or total volume within the wellbore) and others.

[0042] Further aspects are now provided. These further aspects include a technique
 15 for averaging of heat transfer coefficients; and averaging temperature inside and outside of the drillstring.

[0043] Consider the following with regard to averaging of heat transfer coefficients. A lagged mud packet will pass through several distinct wellbore geometry sections; each of these sections will have distinct overall heat transfer coefficients (Up_o and U_a)
 20 due to the physical elements (e.g., casing, open-hole, etc.) and different flow regimes.

[0044] Thus, the individual heat transfer coefficients may be averaged based on the time the mud packet is in each section. In order to estimate this, let Up_{oi} , U_{ai} be the i^{th} drillpipe and wellbore heat transfer coefficient. In this case:

$$\overline{Up_o} = \frac{\sum (\Delta t_i * Up_{oi})}{\sum \Delta t_i}; \text{ and}$$

$$25 \quad \overline{U_{ai}} = \frac{\sum \Delta t_i * U_{ai}}{\sum \Delta t_i}.$$

[0045] Where Δt_i is the time, in minutes, that the mud packet is in any distinct wellbore section having a constant Up_o or U_a . Δt_i can be calculated from:

$$\Delta t_i = \left[\frac{\pi}{4 * \bar{Q}} (d_h^2 - d_p^2) (0.004329) \right];$$

where d_h represents a hole diameter, (generally in inches); and d_p represents the drillstring outer diameter, (also generally in inches); and $\bar{Q}$ represents an average flow rate for the mud packet, gal/min. Accordingly, an average flow rate may be
 5 given by:

$$\bar{Q} = \frac{\sum_{r=1}^n (\Delta t_r * Q)}{\sum_{r=1}^n \Delta t_r};$$

where Q represents mud read flow rate, gpm and Δt_r represents mud sample interval, time (seconds or minutes).

[0046] Consider now techniques for averaging temperature inside and outside of the
 10 drillstem. Unlike other lagged quantities (e.g., Total Gas), the temperature of a mud packet is not isolated from the effects of the mud in the drillstem, or the effects of the wellbore wall as it is circulated to surface. The temperature out depends directly on the temperature of the mud being circulated down the drillstem (generally a heat sink) and the temperature of the wellbore face (at depth, a heat source; close to the surface,
 15 a heat sink). Therefore, calculation of both the temperature out and temperature in for a certain depth requires special handling.

[0047] Consider an example. In this example, let Δd be a depth increment. Consider that a user wishes to know the formation temperature at depth $D + \Delta d$. Formation temperature is represented as the average temperature over the interval Δd . This is
 20 reasonably accurate if Δd is small in relation to D . Refer to **FIG. 4**.

[0048] In **FIG. 4**, the model assumes a linear geothermal gradient and the mud packet must pass over a length of formation (wellbore wall) equal to $D + \Delta d$. Average mud temperature out for a depth increment Δd is simply the lagged mud temperature for the depth, or $D + \Delta d$.

$$[out]^{D+\Delta d} = \frac{\sum_{i=1}^n \Delta S_i * T_{out_i}}{\sum_{i=1}^n \Delta S_i} ;$$

where ΔS_i represents an averaging base. The averaging is triggered "on" when the return depth is D and triggered "off" when the return depth is $D + \Delta d$.

[0049] The average temperature in is, however, not so straightforward. As the mud packet is being circulated to the surface, it is influenced by the temperature in the drillstem, which is governed by the temperature in over the circulation period. At the start of the drilled interval, however, the drillstem contains mud which entered the pipe while the prior interval was being drilled. The "temperature in," which influences the temperature out, may therefore be represented as being the average of:

1. average mud temperature in for a volume equivalent to the volume of the drillstem at depth D ;
2. average mud temperature in during the drilled interval Δd ; and
3. average mud temperature in while the mud packet for depth $D + \Delta d$ is being circulated out.

[0050] Item 1 requires the prediction of the depth D for online averaging (unless raw data is stored in arrays). Its contribution to the overall average is however small, and it may be ignored. The average mud temperature in is therefore:

$$[\bar{T}_{in}]_D^{D+\Delta d} = \frac{\sum_{i=1}^n (\Delta S_i * T_{in_i})}{\sum_{i=1}^n \Delta S_i} ;$$

where ΔS_i represents an averaging base. The averaging is triggered "on" when the bit is at depth D and triggered "off" when the returns depth is $D + \Delta d$. This is shown diagrammatically in **FIG. 5**. However, it should be noted that there will be overlap in the average temperature in for sequential depth increments, and the monitor will contain N average temperature in values (being updated "simultaneously") for N mud packets in the wellbore annulus.

[0051] In summary, the foregoing equations represent, in detail, a straightforward method of calculating formation temperatures and both annular and drillstem circulating temperatures. Note that the method provided is illustrative. For example,

finite difference methods or finite element methods may be used. In general, the method provides results that are within a few degrees. Also, note that temperature measurements made at locations along the drill string 3 may be used to specify other boundary conditions and the model may be modified, or another model developed to include them.

[0052] The following interpretations and qualifications should be noted regarding the invention described herein. As used herein, the term “formations” may refer to the various features and materials that may be encountered in a subsurface environment. Accordingly, it should be considered that while the term “formation” generally refers to geologic formations of interest, that the term “formations,” as used herein, may, in some instances, include any geologic points or volumes of interest (such as a survey area). In general, the terms formation, formations, and other such terms are in reference to any volume of sub-surface materials that may be of interest.

[0053] One skilled in the art will recognize that aspects of the teachings herein may be performed in other ways. For example, it is not necessary to confine the teachings to those embodiments involving a drill string. That is, a logging instrument (such as a instrument deployed in wireline logging of a wellbore – or by a drill string) may make use of the technology provided herein.

[0054] As used herein, generation of data in “real time” is taken to mean generation of data at a rate that is useful or adequate for making decisions during or concurrent with processes such as production, experimentation, verification, and other types of surveys or uses as may be opted for by a user or operator. As a non-limiting example, real-time measurements and calculations may provide users with information necessary to make desired adjustments during the drilling process. In one embodiment, adjustments are enabled on a continuous basis (at the rate of drilling), while in another embodiment, adjustments may require periodic cessation of drilling for assessment of data. Such adjustments may also be useful in geosteering applications. Accordingly, it should be recognized that “real-time” is to be taken in context, and does not necessarily indicate the instantaneous determination of data, or make any other suggestions about the temporal frequency of data collection and determination.

[0055] In support of the teachings herein, various analysis components may be used, including digital and/or an analog systems. The system may have components such as a processor, storage media, memory, input, output, communications link (wired, wireless, pulsed mud, optical or other), user interfaces, software programs, signal
5 processors (digital or analog) and other such components (such as resistors, capacitors, inductors and others) to provide for operation and analyses of the apparatus and methods disclosed herein in any of several manners well-appreciated in the art. It is considered that these teachings may be, but need not be, implemented in conjunction with a set of computer executable instructions stored on a computer
10 readable medium, including memory (ROMs, RAMs), optical (CD-ROMs), or magnetic (disks, hard drives), or any other type that when executed causes a computer to implement the method of the present invention. These instructions may provide for equipment operation, control, data collection and analysis and other functions deemed relevant by a system designer, owner, user or other such personnel, in addition to the
15 functions described in this disclosure.

[0056] Although certain embodiments are described as being expressed in certain systems of measurement (generally, English), other systems of measurement may be used. For example, the Systems International (SI), the metric system and other systems of measurement may be employed. As appropriate, certain aspects of the
20 teachings herein may be rearranged such that at least some of the quantities are unitless.

[0057] Further, various other components may be included and called upon for providing for aspects of the teachings herein. For example, a sample line, sample storage, sample chamber, sample exhaust, pump, piston, power supply (e.g., at least
25 one of a generator, a remote supply and a battery), vacuum supply, pressure supply, refrigeration (i.e., cooling) unit or supply, heating component, motive force (such as a translational force, propulsional force or a rotational force), magnet, electromagnet, sensor, electrode, transmitter, receiver, transceiver, antenna, controller, optical unit, electrical unit or electromechanical unit may be included in support of the various
30 aspects discussed herein or in support of other functions beyond this disclosure.

[0058] One skilled in the art will recognize that the various components or technologies may provide certain necessary or beneficial functionality or features.

Accordingly, these functions and features as may be needed in support of the appended claims and variations thereof, are recognized as being inherently included as a part of the teachings herein and a part of the invention disclosed.

[0059] While the invention has been described with reference to exemplary
5 embodiments, it will be understood by those skilled in the art that various changes
may be made and equivalents may be substituted for elements thereof without
departing from the scope of the invention. In addition, many modifications will be
appreciated by those skilled in the art to adapt a particular instrument, situation or
material to the teachings of the invention without departing from the essential scope
10 thereof. Therefore, it is intended that the invention not be limited to the particular
embodiment disclosed as the best mode contemplated for carrying out this invention,
but that the invention will include all embodiments falling within the scope of the
appended claims.

CLAIMS

What is claimed is:

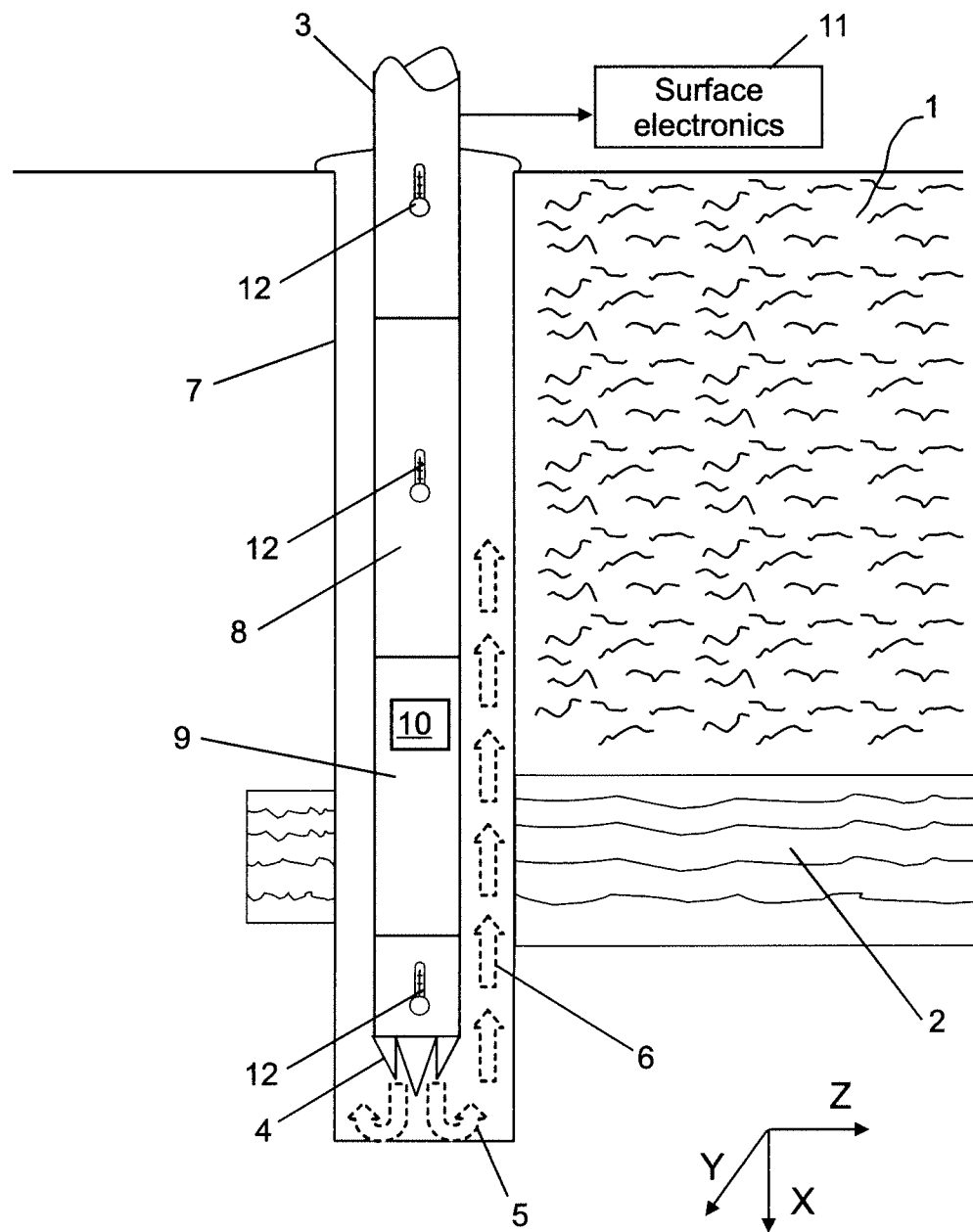
- 1 1. A method for estimating a temperature within sub-surface materials traversed
2 by a wellbore, the method comprising:
3 (a) obtaining temperature data from a plurality of measurements of
4 temperature taken within the wellbore;
5 (b) calculating an overall heat transfer coefficient from the measurement
6 data;
7 (c) calculating a geothermal gradient from the overall heat transfer
8 coefficient; and
9 (d) using the geothermal gradient to estimate the temperature within the
10 sub-surface materials.
- 1 2. The method as in claim 1, wherein each of the heat transfer coefficients relate
2 to a section of the wellbore.
- 1 3. The method as in claim 1, further comprising: combining a plurality of heat
2 transfer coefficients to provide the overall heat transfer coefficient.
- 1 4. The method as in claim 3, wherein combining comprises performing at least
2 one of: averaging, a linear fit, a logarithmic fit, an exponential fit, a fit to a
3 power function, a weighted fit and a least squares fit.
- 1 5. The method as in claim 1, wherein the temperature data comprises
2 measurements taken at a plurality of depths within the wellbore.
- 1 6. The method as in claim 1, the temperature data comprises temperature taken at
2 least one of internal to a drill string and external to a drill string.
- 1 7. The method as in claim 1, further comprising estimating the overall heat
2 transfer coefficient by estimating a thermal resistance for at least one of:
3 drilling fluid within a drill string; drilling fluid crossing a wall of a drill string;
4 and drilling fluid external to a drill string and within the wellbore.

- 1 8. The method as in claim 1, further comprising estimating at least one of: a
2 temperature at a total depth of the wellbore and a temperature within the
3 formation at a given radius from a center of the wellbore.
- 1 9. The method as in claim 1, further comprising accounting for at least one
2 operational factor in the calculating of a geothermal gradient.
- 1 10. A system for determining a temperature of sub-surface materials, the system
2 comprising:
3 (a) a plurality of temperature sensors distributed along a drill string, the
4 drill string providing for a wellbore that traverses the sub-surface
5 materials; and
6 (b) a processor for receiving temperature data from the from the plurality
7 of temperature sensors along at least a portion of the wellbore and for
8 implementing machine executable instructions for calculating an
9 overall heat transfer coefficient from the measurement data; calculating
10 a geothermal gradient from the overall heat transfer coefficient; and
11 using the geothermal gradient to estimate the temperature within the
12 sub-surface materials.
- 1 11. The system as in claim 10, wherein the processor is equipped to implement the
2 machine executable instructions in real time.
- 1 12. The system as in claim 10, further comprising an input for receiving at least
2 one parameter of operational data.
- 1 13. The system as in claim 12, wherein the processor further comprises
2 instructions for using the operational data to estimate the temperature within
3 the sub-surface materials.
- 1 14. The system as in claim 10, wherein the parameter of operational data
2 comprises at least one of radius, flow rate, revolutions per minute and volume.
- 1 15. The system as in claim 10, wherein the plurality of temperature sensors are
2 distributed at least one of internally and externally along the drill string.

- 1 16. A computer program product stored on machine readable media and
2 comprising machine executable instructions for estimating a temperature in
3 sub-surface materials, by implementing a method comprising:
- 4 (a) receiving temperature data from a plurality of measurements of
5 temperature taken within a wellbore traversed by a logging instrument;
 - 6 (b) calculating an overall heat transfer coefficient from the measurement
7 data;
 - 8 (c) calculating a geothermal gradient from the overall heat transfer
9 coefficient;
 - 10 (d) using the geothermal gradient to estimate the temperature within the
11 sub-surface materials; and
 - 12 (e) outputting the estimate to a user.
- 1 17. The computer program product as in claim 16, further comprising an input for
2 receiving a selected depth within the sub-surface materials.

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FIG. 1



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FIG. 2

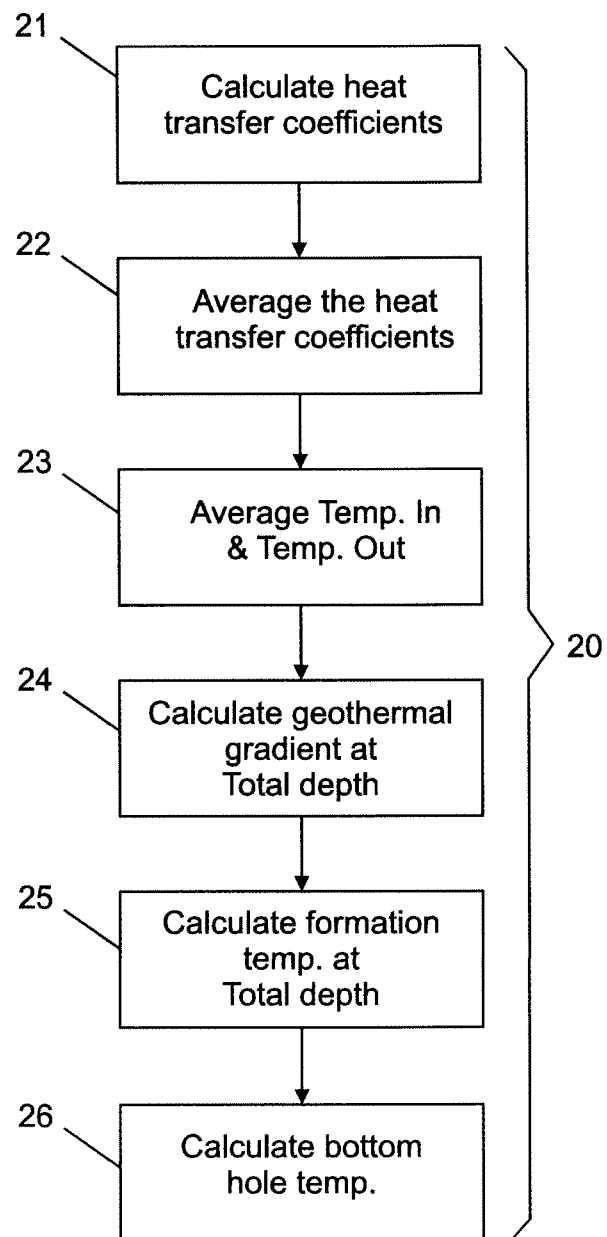
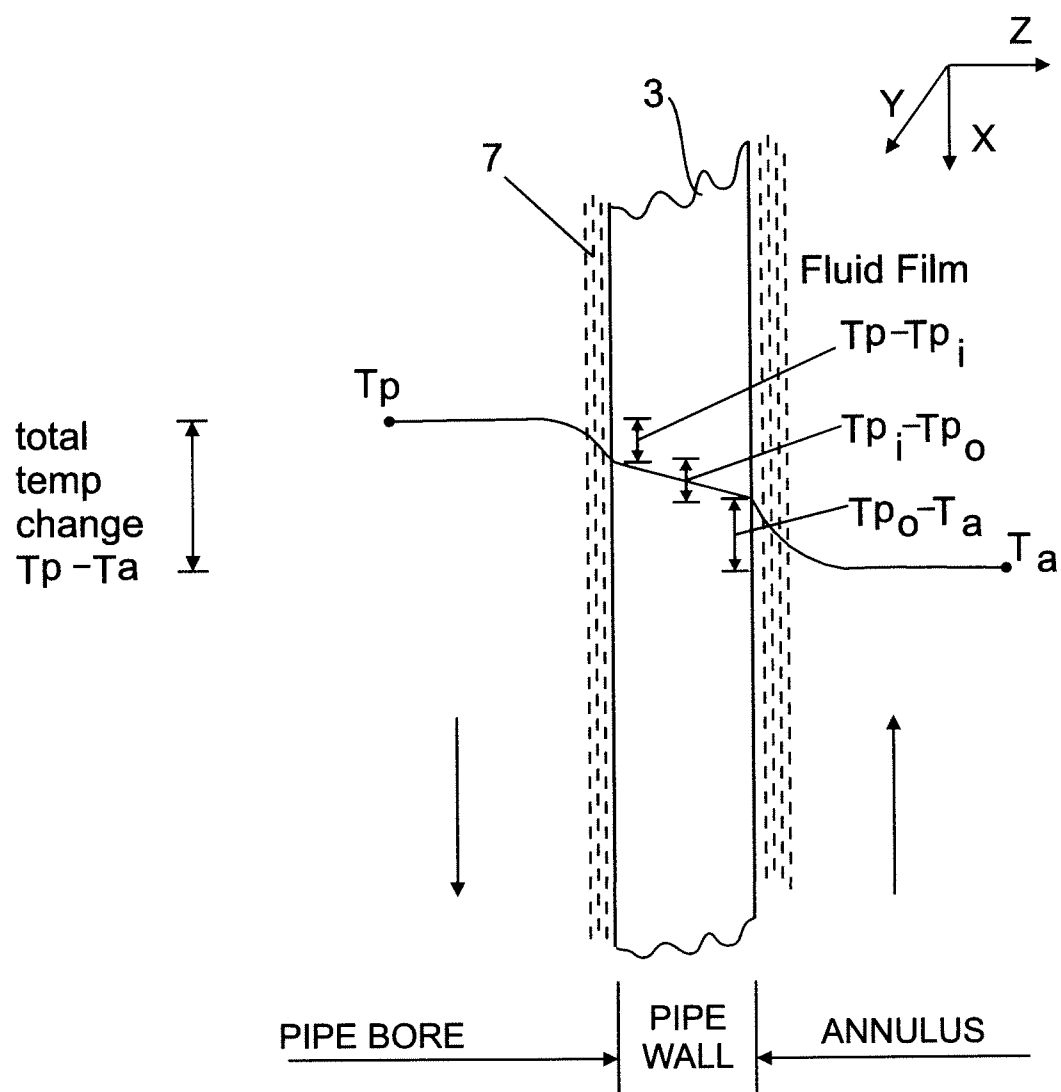
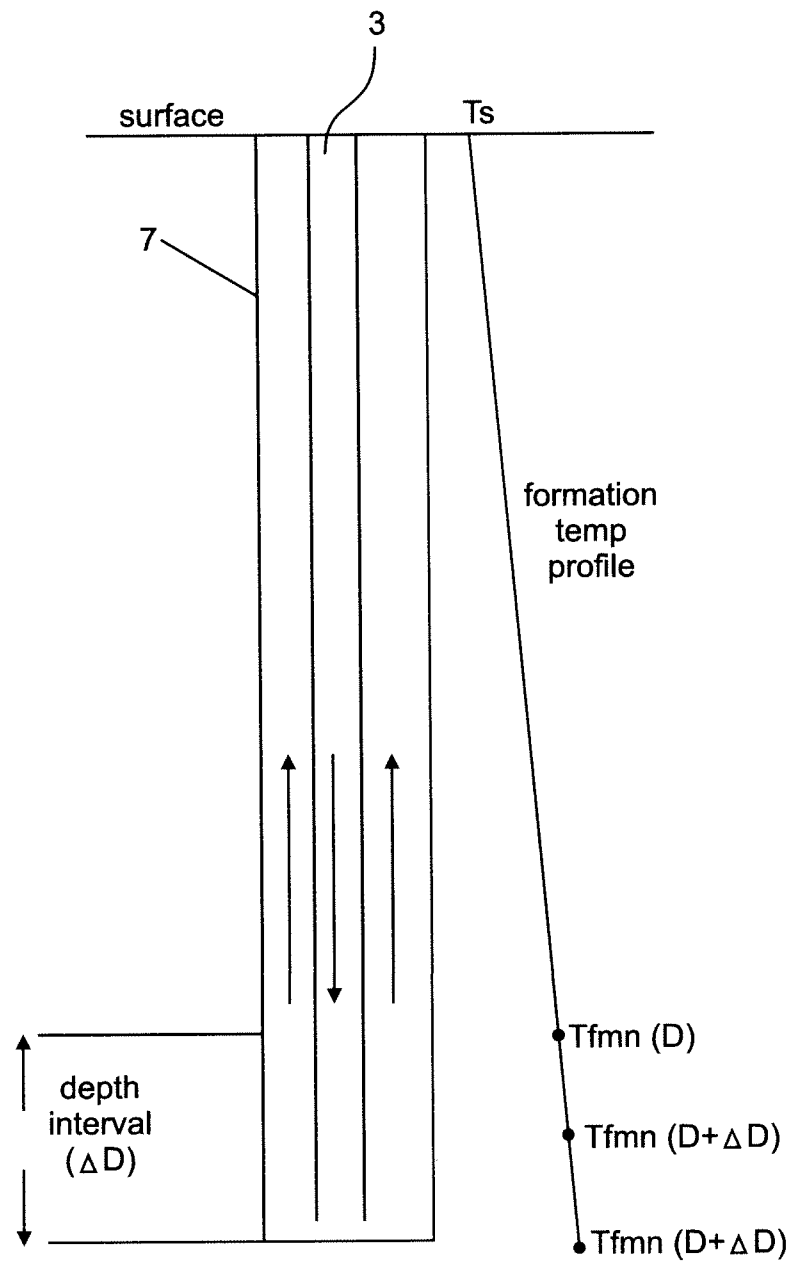


FIG. 3



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FIG. 4



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FIG. 5

