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[Continued on next page]

(54) Title: APPLICATION OF DEPTH DERIVATIVE OF DISTRIBUTED TEMPERATURE SURVEY (DTS) TO IDENTIFY FLUID LEVEL AS A TOOL OF DOWN HOLE PRESSURE CONTROL

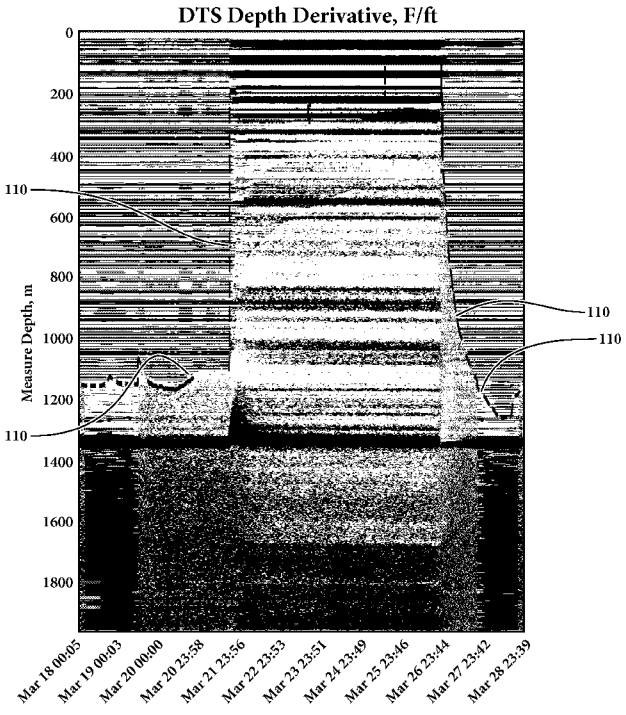

FIG 5

(57) Abstract: A method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control comprises providing a fiber optic based distributed temperature sensing measurement system through a production region; gathering the temperatures through the production region as a function of the depth in the subsurface well and as a function of the elapsed time; calculating from the gathered data the depth derivative of the temperature changes as a function of depth in the subsurface well and of the elapsed time; and displaying the depth derivative data for analysis of the fluid levels to identify fluid levels.

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Application of Depth Derivative of Distributed Temperature Survey (DTS) to Identify Fluid Level as a Tool of Down Hole Pressure Control

Background

This disclosure relates generally to temperature sensing, and more particularly, to the use of new methodologies for interpreting distributed temperature sensing information.

Fiber optic Distributed Temperature Sensing (DTS) systems were developed in the 1980s to replace thermocouple and thermistor based temperature measurement systems. DTS technology is often based on Optical Time-Domain Reflectometry (OTDR) and utilizes techniques originally derived from telecommunications cable testing. Today DTS provides a cost-effective way of obtaining hundreds, or even thousands, of highly accurate, high-resolution temperature measurements, DTS systems today find widespread acceptance in industries such as oil and gas, electrical power, and process control.

DTS technology has been applied in numerous applications in oil and gas exploration, for example hydraulic fracturing, production, and cementing among others. The collected data demonstrates the temperature profiles as a function of depth and of time during a downhole sequence. The quality of the data is critical for interpreting various fluid movements.

The underlying principle involved in DTS-based measurements is the detection of spontaneous Raman back-scattering. A DTS system launches a primary laser pulse that gives rise to two back-scattered spectral components. A Stokes component that has a lower frequency and higher

wavelength content than the launched laser pulse, and an anti-Stokes component that has a higher frequency and lower wavelength than the launched laser pulse. The anti-Stokes signal is usually an order of magnitude weaker than the Stokes signal (at room temperature) and it is temperature sensitive, whereas the Stokes signal is almost entirely temperature independent. Thus, the ratio of these two signals can be used to determine the temperature of the optical fiber at a particular point. The time of flight between the launch of the primary laser pulse and the detection of the back-scattered signal may be used to calculate the spatial location of the scattering event within the fiber.

Artificial lift refers to the use of artificial means to increase the flow of liquids, such as crude oil or water, from a production well. Generally this is achieved by the use of a mechanical device inside the well (known as pump or velocity string) or by decreasing the weight of the hydrostatic column by injecting gas into the liquid some distance down the well. Artificial lift is needed in wells when there is insufficient pressure in the reservoir to lift the produced fluids to the surface, but often used in naturally flowing wells (which do not technically need it) to increase the flow rate above what would flow naturally. The produced fluid can be oil, water or a mix of oil and water, typically mixed with some amount of gas.

Electric Submersible Pumps (ESP) is one of the important devices for artificial lift production. ESP consists of a downhole pump (a series of centrifugal pumps), an electrical motor which transforms the electrical power into kinetic energy to turn the pump, a separator or protector to prevent produced fluids from entering the electrical motor, and an electric power cable that connects the motor to the surface control panel. ESP is a very versatile artificial lift method and can be found in operating environments all over the world. They can handle a very wide range of flow rates (from 200 to 90,000 barrels (14,000 m^3) per day) and lift requirements (from virtually zero to 10,000 ft. (3,000 m) of lift).

Operators of ESP systems have to monitor the casing fluid level carefully to balance between production and protection. Large production rate requires a large pressure drop from the reservoir to the bottom hole of the well, which lowers the fluid level in the casing. However, the fluid level has to be kept above the ESP to a certain level so that the pump is not starved of the fluid it needs for cooling. If the fluid level is too low, an under-load condition will shut down the pump, potentially leaving the well production-less for hours, while the well fluid level increases as fluids flow from the reservoir into the well and refill the well bore to a safe level above the ESP.

Besides ESP protection, fluid level, playing a role of pressure indicator, can be used for monitoring down hole pressure change to control the production rate. Production optimization attempts to minimize water production rate while maximizing oil and gas rate. Due to different capillary pressure between oil and water and surface tension between formation rock and different fluids like water and oil, flow rate of oil, water and gas is different at different depth of the well under different draw down pressures. By monitoring the down hole pressure, an optimization can be reached to find the highest OWR (oil water ratio). Fluid level detection and monitoring is critical and often done using down hole gauge(s), but other means of fluid level monitoring are desirable especially when calibration or replacement is required of the down-hole pressure gauge.

When DTS fiber is installed along the production well, DTS data is plotted in time-depth scale to monitor the temperature along the wellbore. Besides the production intervals, DTS data can also be used in many other functions. One of them is fluid level detection. However, conventional DTS plots are not able to give a clear profile of the fluid level in time scale. Air and foam above the fluid level causes a much more unstable temperature comparing with the one below the fluid level. Variation of the temperature

above the fluid level is however too small to be observed from the DTS plot itself due to its large temperature range as 70F to 200F.

There is a need then for better analysis tools to detect fluid level changes.

Brief Description of the Drawings

Figure 1 illustrates an example of conventional DTS data displayed in the depth and time scale.

Figure 2 illustrates the same DTS data displayed as the DTS derivative data in the depth and time scale.

Figure 3 is the same DTS data shown as a trace in the depth scale only.

Figure 4 illustrates the readings from the bottom hole pressure gauge.

Figure 5 illustrates the depth derivative of the DTS data consistent with the bottom hole pressure gauge readings of figure 4 and further illustrates the algorithm results for mathematically calculating a fluid level profile as a function of time, plotted as a dashed line on the derivative map.

Figure 6 illustrates the data matrices representing the DTS data for representing the depth derivative display.

Figure 7 illustrates a workflow for generating the data analysis for the identification.

Detailed Description

In the following detailed description, reference is made to accompanying drawings that illustrate embodiments of the present disclosure. These embodiments are described in sufficient detail to enable a person of ordinary skill in the art to practice the disclosure without undue experimentation. It should be understood, however, that the embodiments and examples described herein are given by way of illustration only, and not by way of limitation. Various substitutions, modifications, additions, and rearrangements may be made without departing from the spirit of the present disclosure. Therefore, the description that follows is not to be taken in a limited sense, and the scope of the present disclosure will be defined only by the final claims.

The earlier discussion described the need for better analysis tools for operators to detect fluid level changes in production wells.

In this disclosure we describe depth derivative as a better analysis tool that can do the job excellently. Depth derivative of DTS data is derived by to subtracting temperatures at a depth from the temperatures at a next deeper depth. The difference is then divided by the distance between two depths. Depth derivative of DTS plots the temperature change in depth scale of all the time. It captures the small changes despite the absolute value of the temperature.

Depth derivative of the DTS can range from -0.3 to +0.3 degrees F/foot. It is able to capture the fluctuation regardless of the absolute temperature. In a derivative map, a clear fluid level boundary can be observed along the time axis. A variance algorithm is used in this disclosure later to identify this boundary mathematically so that the result can be obtained in real

time as an important tool to monitor the fluid level. It has been proved to be highly consistent with bottom hole pressure gauge readings. Once DTS fiber is installed, it can work as a tool to monitor the fluid level and down hole pressure.

Referring first to Figure 2, depth derivative of DTS data is displayed for a production and shut-in process that has experienced a shut-in **120** and a restart **130**. On earlier times before shut-in and later time after restart periods the depth derivative data clearly shows the fluid levels **110**. This is easily seen in this black and white rendering and can be seen in a full color rendering in which a red color can indicate a temperature increase along the depth and a blue color represents a decrease.

In use this data will normally be displayed in full color to show temperature changes. Color presentations cannot be used in patent applications so this data is being shown in a black/white scale that still shows the significant improvement in information available using derivative data to show the various boundaries during the production processes.

In the more conventional DTS plot (Figure 1) the fluid level is more difficult to asses because the color scales are normally set to simultaneously cover both cool area above the ESP and warm areas at the production intervals. The result is that much less information of use to an operator is available from this conventional display. A third alternative of a DTS trace plot in depth scale (Figure 3) is able to roughly show a boundary by identifying the fluctuation on the trace. It however highly depends on the trace picked and involves human error.

This example clearly shows the power of a new tool in interpreting fluid levels during production.

A further example using this same data (Figures 4 and 5) compares the readings from the bottom hole pressure gauge and the DTS depth derivative. A variance algorithm described in a later section is applied to the derivative data and calculated as a fluid level profile along time, plotted as dash line on the derivative map. The variance threshold used in the algorithm is 0.001 in this example. A value 0.002±0.0015 can be a universal reference to differentiate noise variance of the temperature derivative above and below the fluid level. The results are highly consistent and more information is available in the derivative plot.

This method can be described as using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control including at least: providing a fiber optic based distributed temperature sensing measurement system through a production region; gathering the temperatures through the production region as a function of the depth in the subsurface well and as a function of the elapsed time; calculating from the gathered data the depth derivative of the temperature changes as a function of depth in the subsurface well and of the elapsed time; displaying the depth derivative data for analysis of the fluid levels by operators.

The fiber optic sensing cable may also have other fibers the may be used for other sensing systems like for example Distributed Acoustic Sensing (DAS) systems. Acoustic energy will travel at different velocities in liquids and air, and can be a complementary system to enable automation of a fluid level monitoring system. Acoustic energy will also attenuate differently in liquids and air, so changes in acoustic velocities and/or amplitude changes in various frequency bands may be used for fluid level detection. DAS data can then be used in conjunction with the depth derivative data to better identify and validate the analysis of fluid levels.

Furthermore the depth derivative data can be presented in a number of ways. In one embodiment the actual numerical values of the depth derivative data are recorded and printed or displayed. In another embodiment the depth derivative data can be displayed in colors as a function of depth and time on a display monitor. In another embodiment the depth derivative data can be displayed in gray scale as a function of depth and time on a display monitor.

Generation of Derivative DTS Data

The disclosure herein anticipates any mathematically correct manner of generating the derivative data. The example embodiment for calculating the depth derivative is explained as follows.

Derivative data from DTS data can be generated by feeding the numerical data of temperature as a function of depth and time into a matrix and then computationally moving through all of the matrix data points to calculate derivative values for each matrix element. This can be done as either depth derivatives or as time derivatives. These derivative values can then be presented as a matrix of numbers, or, more usefully can be presented as color images in which the various colors represent different values of the derivatives. As discussed earlier, they are presented herein as gray scale images which show important features that are not evident in the presentation of the conventional DTS data alone.

Depth derivative of DTS:

In this example the computation language MatLab is used to compute regular DTS data into depth derivative of DTS. And the result can then be plotted by MatLab in depth- time scale.

For DTS measurement, Temperature is function of depth and time:

$$T=T(\text{depth}, \text{time}) \quad (1)$$

Data is loaded into Matab and stored as a DTS temperature matrix. See the first matrix in Figure 6.

The depth derivative of DTS, also called the DTS depth gradient, is then computed as:

$$\mathbf{T^{\wedge}\prime}(\mathbf{d},\mathbf{t})=(\mathbf{T}(\mathbf{d}+\Delta\mathbf{d},\mathbf{t})-\mathbf{T}(\mathbf{d}+\Delta\mathbf{d},\mathbf{t}))/(2*\Delta\mathbf{d}) \quad (2)$$

The depth derivative at any depth and time step is calculated by subtracting the temperature at its previous depth from the one at its next depth and the result is divided by the distance between these two depths. This results in a depth derivative of the DTS temperature matrix, shown as the second matrix in Figure 6, wherein each point is a derivative data point to be displayed.

Both the DTS temperature matrix and DTS derivative matrix can be plotted as a depth-time 2D color map by MatLab function pcolor(d,t,T) or pcolor(d,t,T'). Input parameters **d** and **t** are depth and time vectors. Input **T** is a 2D matrix with number of rows as **d** and number of columns as **t**.

The method can be described alternately with the process **100** as in Figure 7. In the first step **110** a DTS system is used to collect the distributed temperature data into a DTS matrix with dimensions of [m x n], where m is the number of samples taken in the depth scale and n is the number of samples taken in time scale. In the step **120** for each column of the DTS matrix, the derivative of temperature corresponding to depth is calculated. The result of this derivative is stored in a new matrix with dimension [m-2 x n]. The first and last row of the DTS matrix cannot be applied with the depth derivative. The developing depth derivative matrix is shown in

Figure 6. In the step **130** any viewing software such as MetLab can be used to plot the derivative matrix with depth as the horizontal axis and depth as the vertical axis. If color display is operable the color can be coded as a value of temperature derivative. The user can then adjust (step **140**) the color scheme of the derivative plot until a boundary across all of the time scale is clearly shown as in Figure 1. The observed boundary then can indicate the fluid level in the annulus between the tubing and the casing as a function to time. Above this boundary, horizontal stripes of negative and positive value (red-blue color stripes in the color version) lay alternately. Below this boundary, either positive or negative value dominates. Finally, as indicated in step **150**, if pressure data is available, it can be plotted in the same time scale as the derivative image and it is found that the boundary observed in the derivative plot fluctuates in a very similar profile as the pressure plot does. This can be a substitute if pressure data is not available.

By default, MatLab uses a Blue-Red color scheme represent the value of the temperature or value of the derivative. In the DTS plot if shown in color, shown in Figure 1 blue represents a low temperature while red represents a high temperature. Again, as explained before, because color cannot be used in patent applications these are presented as gray scale images which still show the new possibilities of data presentation possible by the use of displayed color data.

In DTS the depth derivative (DTS depth gradient), blue represents a temperature decrease along the depth. Red represents a temperature increase along the depth. Large value in red zone indicates a large temperature increase per unit length. Large negative value in blue zone indicates a large temperature drop per unit length. Again because color cannot be used in patent applications these are presented as gray scale images which still show the new possibilities of data presentation possible by the use of displayed color data.

The resulting depth derivative temperature data as a function of depth and time can be presented in a number of ways. In one example the actual numerical values can be stored for later retrieval and then either displayed on a monitor or printed for study. In another example the resulting depth derivative of temperature can be displayed as different colors on a color display for better understanding and interpretation. In yet another example that same data can be displayed in black and white as shown in Figure 1.

This methodology offers a more accurate monitoring tool than conventional distributed temperature sensing in the monitoring and analysis of fluid monitoring in subsurface wells.

Fluid level identification in the DTS derivative plot:

In this example the computation language MatLab is used to apply the following algorithm to each DTS traces to find the boundary between high noise signal (above fluid level) and low noise signal (under fluid level). By connecting all results from each DTS traces, a boundary profile in time scale can be found in real time and exploited as pressure indicator. The dashed line in Figure 5 represents the results of this automatic calculation. The data of Figure 5 is the same as in Figure 2 but with the algorithm applied to clearly indicate the boundaries. The algorithm reduces the need for expert visual interpretation of the results as it is done automatically.

At each time step, temperature derivative is only a function of depth. A variance can be computed as a function of depth by defining the window in 20 to 30 depths of the data that centered at the calculated depth:

$$T'_i = T'(d_i)$$

$$d_i = d_1, d_3, d_4, d_5, \ldots$$

$$M_i = \frac{T'_{i-10} + T'_{i-9} + T'_{i-8} + \cdots + T'_{i+8} + T'_{i+9} + T'_{i+10}}{21}$$

$$var_i = \frac{\sqrt{(T'_i - Mi)^2}}{M_i}$$

At each time step t_j, a derivative variance as function of depths is computed, a threshold of the variance can be found by trial and error process that its corresponding depth is such a boundary where all variance of the derivative above is larger than the threshold and variance of the derivative below is smaller than the threshold. The same threshold variance can be applied to all derivative traces corresponding to each time step and a depth function with time can be created. This is the fluid level depth function corresponding to time.

$$FL(t_j) = d_i \Big|_{var(d_i) = var_{threshold}}$$

The fluid level function with time is created by calibrating with visualization result on depth derivative map to decide a proper threshold variance. The threshold is adjusted until the calculated fluid level as function of time matches with the boundary visualized on a derivative map. The process is only required to be conducted once and the threshold variance can be applied to all later time steps in real time.

Although certain embodiments and their advantages have been described herein in detail, it should be understood that various changes, substitutions and alterations could be made without departing from the coverage as

defined by the appended claims. Moreover, the potential applications of the disclosed techniques is not intended to be limited to the particular embodiments of the processes, machines, manufactures, means, methods and steps described herein. As a person of ordinary skill in the art will readily appreciate from this disclosure, other processes, machines, manufactures, means, methods, or steps, presently existing or later to be developed that perform substantially the same function or achieve substantially the same result as the corresponding embodiments described herein may be utilized. Accordingly, the appended claims are intended to include within their scope such processes, machines, manufactures, means, methods or steps.

Claims

1. A method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control comprising:
    a. providing a fiber optic based distributed temperature sensing measurement system through a production region;
    b. gathering the temperatures through the production region as a function of the depth in the subsurface well and as a function of the elapsed time;
    c. calculating from the gathered data the depth derivative of the temperature changes as a function of depth in the subsurface well and of the elapsed time;
    d. displaying the depth derivative data for analysis of the fluid levels to identify fluid levels.

2. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 1 wherein the numerical values of the depth derivative data are recorded and printed or displayed.

3. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 1 wherein the depth derivative data is displayed in colors as a function of depth and time on a display monitor.

4. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of

downhole pressure control of claim 1 wherein the depth derivative data is displayed in black/white as a function of depth and time on a display monitor.

5. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 1 wherein the depth derivative data is displayed in grey scale as a function of depth and time on a display monitor.

6. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 1 further comprising:
    a. providing a fiber optic based distributed acoustic sensing measurement system through the production region;
    b. gathering the acoustic measurements from the distributed acoustic sensing system as a function of the depth in the subsurface well and as a function of the elapsed time;
    c. displaying the acoustic data for analysis of fluid levels;
    d. using the distributed acoustic data in conjunction with the depth derivative data to further define and validate fluid levels as a tool of downhole pressure control.

7. A method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control comprising:
    a. providing a fiber optic based distributed temperature sensing measurement system through a production region;
    b. gathering the temperatures through the production region as a function of the depth in the subsurface well and as a function of the elapsed time;

c. assembling the data into a DTS matrix of [m x n] wherein m is the number of sample collected in the depth scale and n is the number of samples collected in the time scale;
d. for each column of the DTS matrix calculating a derivative of the temperature as a function of depth and storing it in a new matrix with dimensions [m-2 x n];
e. displaying the derivative matrix with one axis as time and another axis as depth and color coding the value of the temperature derivative; and
f. adjusting the color scheme until a boundary is found through the production time period, indicating the fluid level in the annulus between the tubing and casing as function of time.

8. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 7 wherein the depth derivative data is displayed in colors as a function of depth and time on a display monitor.

9. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 7 wherein the calculated display of the derivative matrix is displayed in gray scale.

10. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 7 wherein the calculated display of the derivative matrix is displayed in black and white.

11. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 7 wherein the calculated

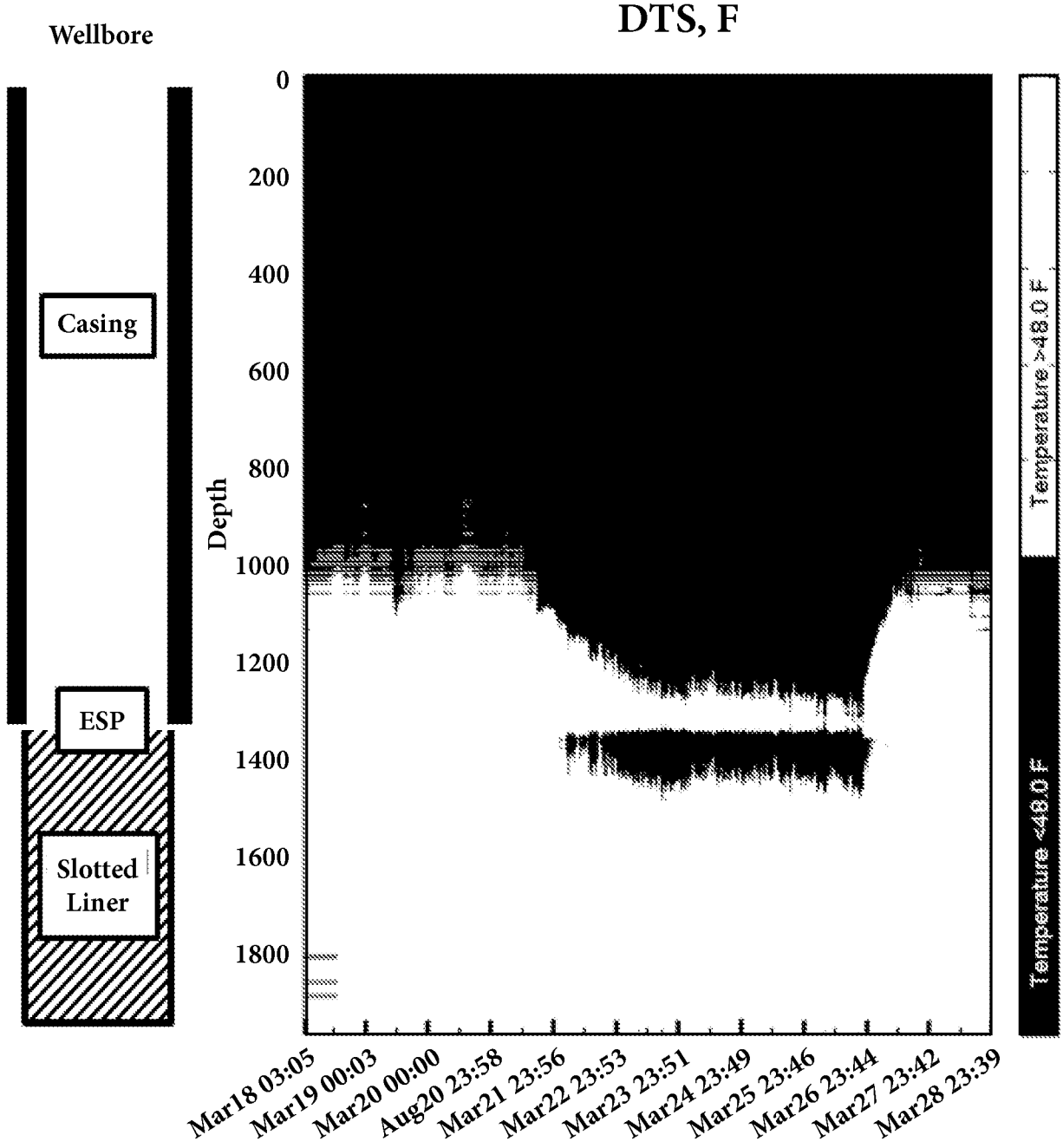
numerical values of the derivative matrix are recorded and printed or displayed.

12. A method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control comprising:
    a. providing a fiber optic based distributed temperature sensing measurement system through a production region;
    b. gathering the temperatures through the production region as a function of the depth in the subsurface well and as a function of the elapsed time;
    c. calculating from the gathered data the depth derivative of the temperature changes as a function of depth in the subsurface well and of the elapsed time;
    d. displaying the depth derivative data for analysis of the fluid levels; and
    e. mathematically calculating a variance of the derivative DTS data to find a boundary between high and low noise signals, and thereby generate a boundary fluid level profile in time that can be displayed and used to monitor downhole pressure.

13. The method for using the depth derivative of distributed temperature sensing data to identify fluid levels as a tool of downhole pressure control of claim 7 further comprising :
    a. providing a fiber optic based distributed acoustic sensing measurement system through the production region;
    b. gathering the acoustic measurements from the distributed acoustic sensing system as a function of the depth in the subsurface well and as a function of the elapsed time;
    c. displaying the acoustic data for analysis of fluid levels as a tool of downhole pressure control; and

d. using the distributed acoustic data in conjunction with the depth derivative data to further identify and validate fluid levels as a tool of downhole pressure control.

5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Casing
ESP
Slotted Liner
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Mar23 23:51
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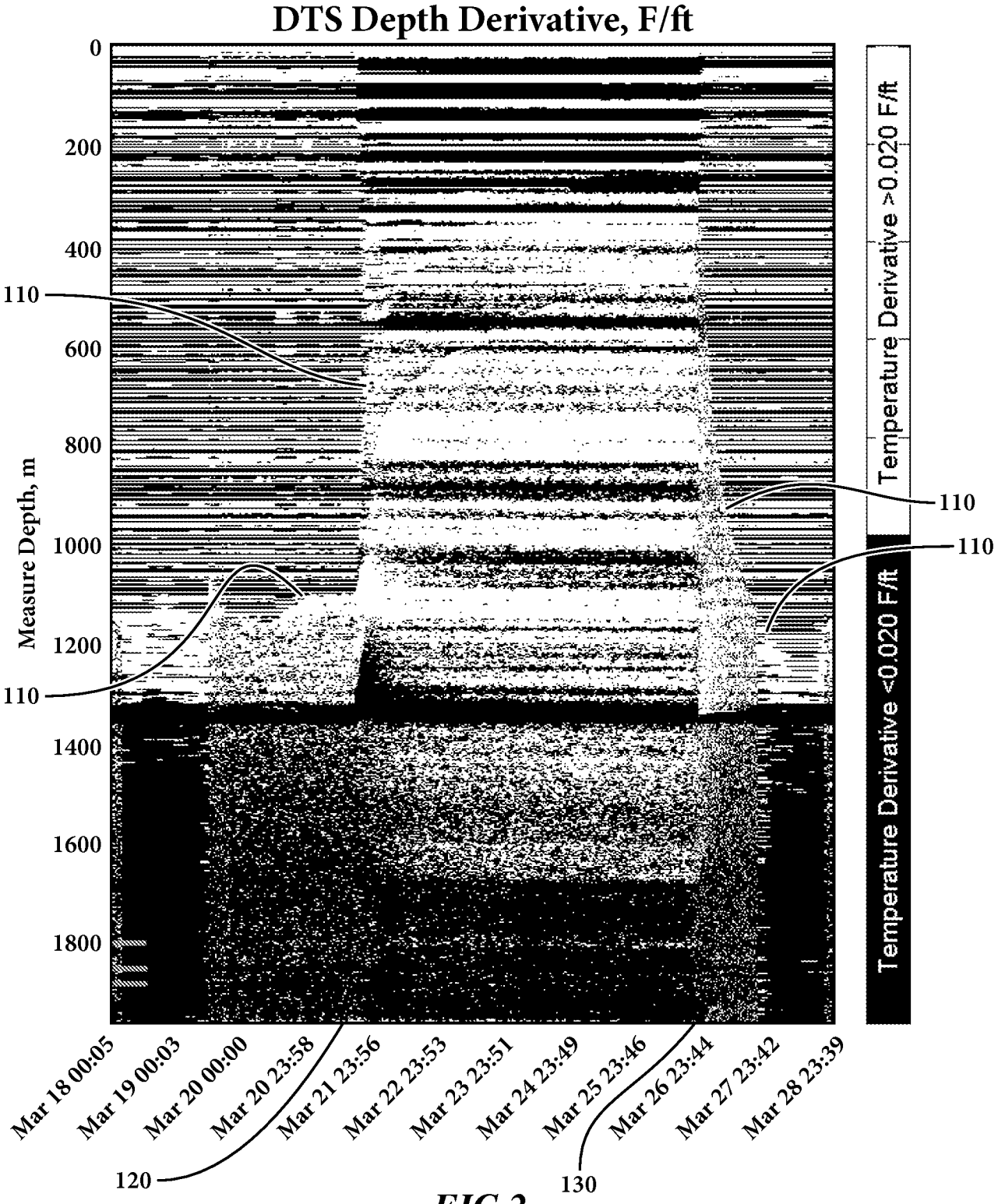
Temperature <48.0 F

FIG 1


DTS Depth Derivative, F/ft
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400
600
800
1000
1200
1400
1600
1800
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Mar 20 00:00
Mar 20 23:58
Mar 21 23:56
Mar 22 23:53
Mar 23 23:51
Mar 24 23:49
Mar 25 23:46
Mar 26 23:44
Mar 27 23:42
Mar 28 23:39
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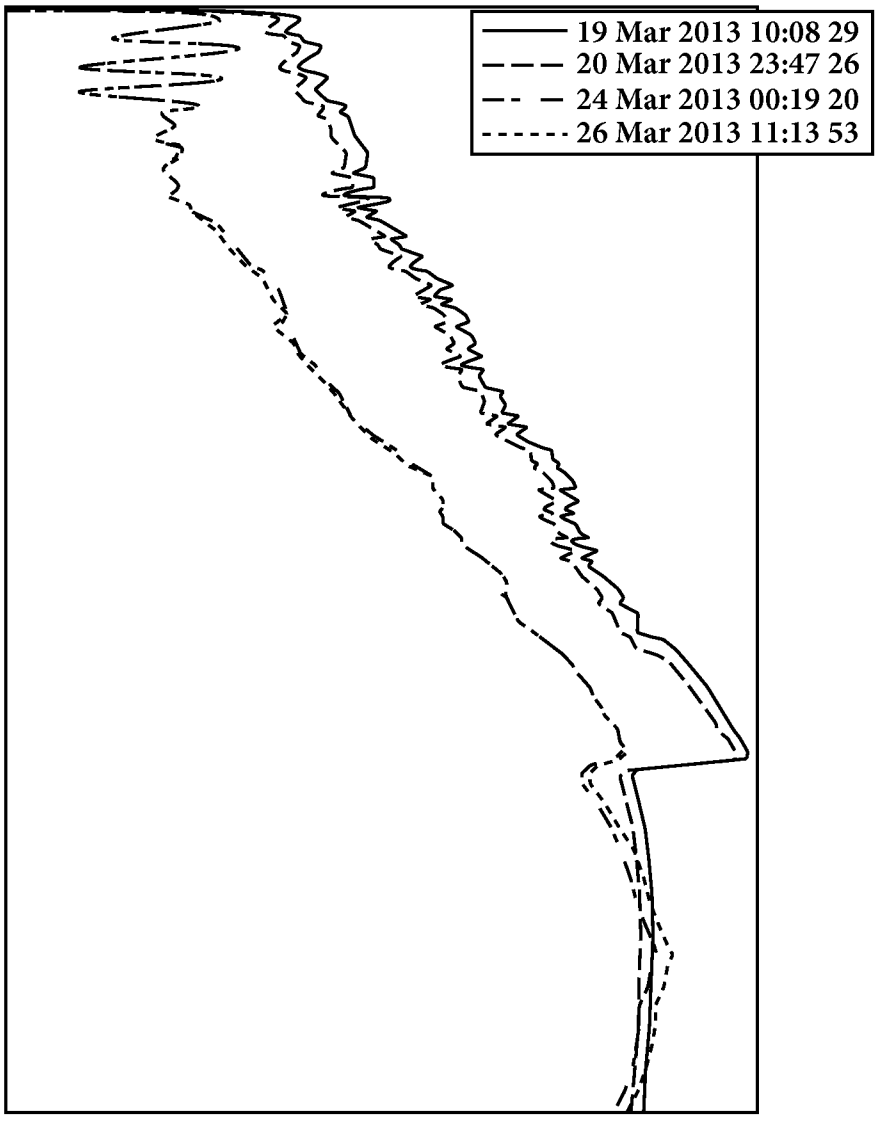
110
110
110
120
130

FIG 2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24 Mar 2013 00:19 20
26 Mar 2013 11:13 53

FIG 3

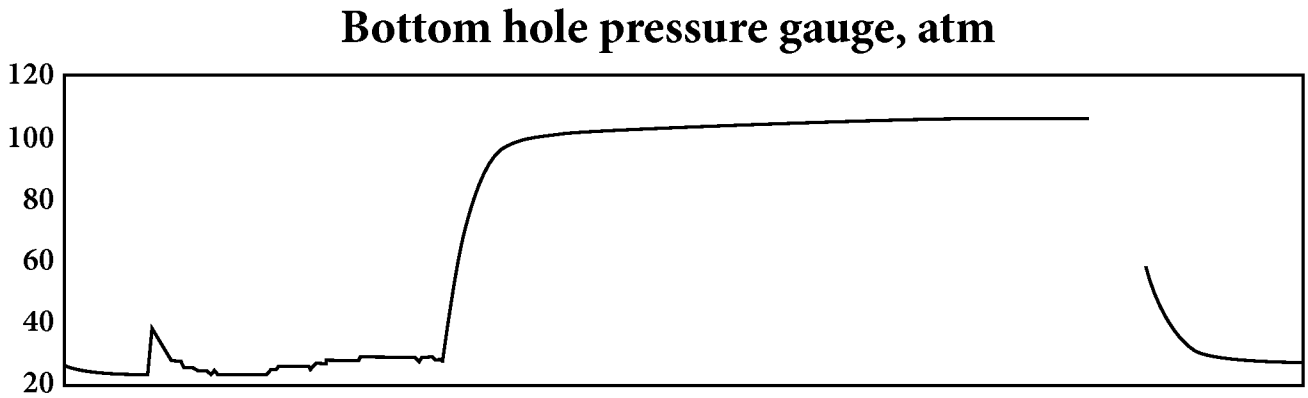


FIG 4

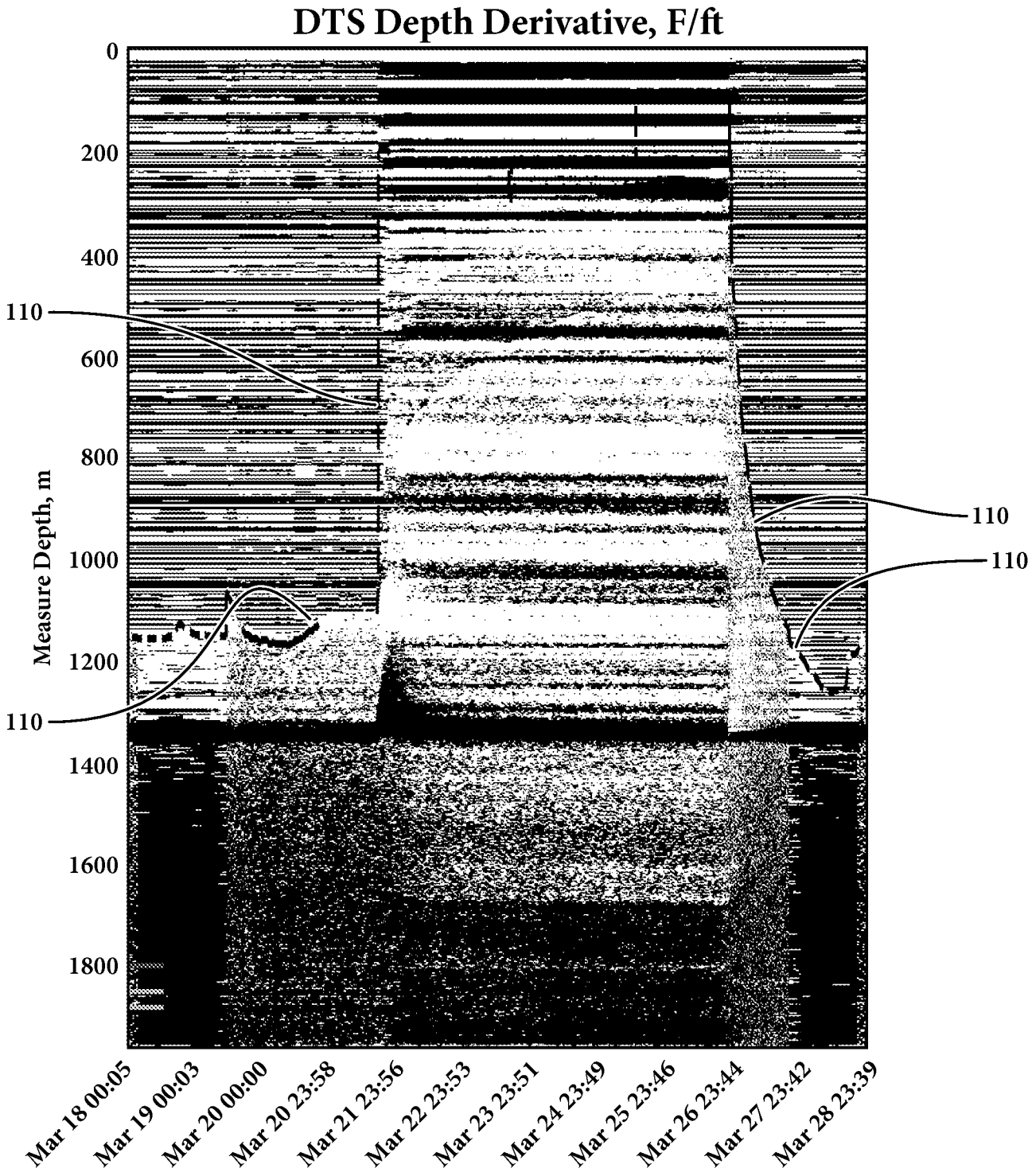
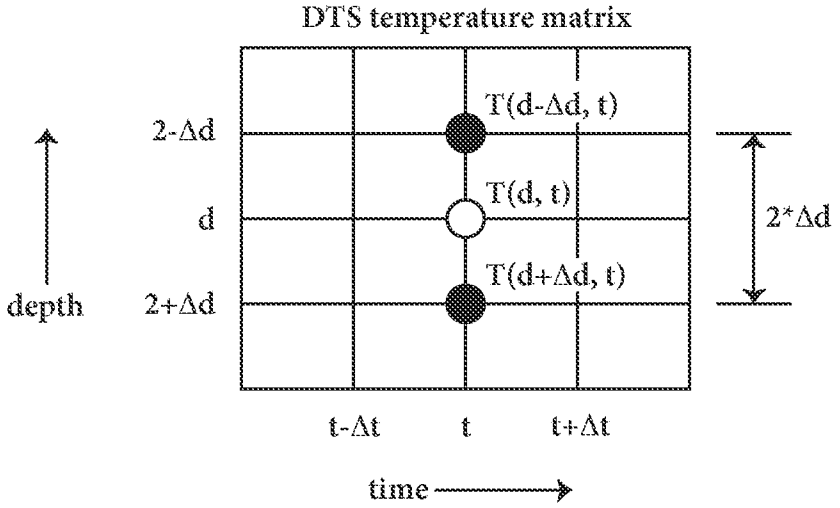

DTS Depth Derivative, F/ft
Measure Depth, m
0
200
400
600
800
1000
1200
1400
1600
1800
110
110
110
110
Mar 18 00:05
Mar 19 00:03
Mar 20 00:00
Mar 20 23:58
Mar 21 23:56
Mar 22 23:53
Mar 23 23:51
Mar 24 23:49
Mar 25 23:46
Mar 26 23:44
Mar 27 23:42
Mar 28 23:39

FIG 5


DTS temperature matrix
T(d-Δd, t)
T(d, t)
T(d+Δd, t)
2-Δd
d
2+Δd
depth
2*Δd
t-Δt
t
t+Δt
time

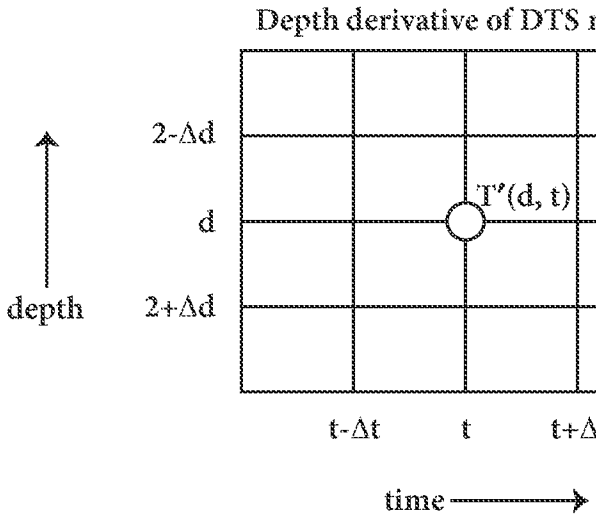
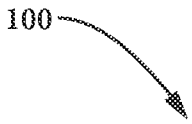

Depth derivative of DTS matrix
T'(d, t)
2-Δd
d
2+Δd
depth
t-Δt
t
t+Δt
time

FIG 6



Collect DTS temperature data in matrix with dimension of [mxn].

m -number of samples in depth scale-

n - number of samples in time scale 110

For each column of the DTS matrix , apply derivative of temperature corresponding to depth.

Result of derivative is restored in a new matrix with dimension of [m-2 x n]. The first and last row of the DTS matrix can not be applied with depth derivative. 120

Plot new derivative matrix in MatLab or other viewing software with horizontal axis as time, vertical axis as depth and color coded as value of temperature derivative. 130

Adjust color scheme of the derivative plot between [-a ,a] until a boundary is found through whole production period above lateral. Above this boundary, horizontal stripes of negative and positive value (red-blue color stripe in color version) lay alternately. Below this boundary, either positive or negative value dominates. The observed boundary indicates fluid level in annulus between tubing and casing as function of time. 140

If pressure (either treating or downhole) data is available, it can be plotted in the same time scale as the derivative image. One can find that the boundary observed from derivative fluctuates in a very similar profile as pressure plot does. It can be a substitute if pressure data is not available. 150

FIG 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2015/035871

A. CLASSIFICATION OF SUBJECT MATTER

E21B 47/06(2006.01)i, E21B 47/07(2012.01)i, E21B 47/047(2012.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 47/06; E21B 47/00; G01F 1/688; G01V 8/10; G06F 17/21; E21B 47/09; E21B 47/07; E21B 47/047

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords: distributed temperature sensing, distributed acoustic sensing, depth, time, derivative, flow, function, color, fiber optic, matrix, axis and distinct

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2015-0120194 A1 (CHEN, JEFF) 30 April 2015 See paragraphs [0019]-[0036] and figures 1, 3, 7.	1-5
Y		6
A		7-13
Y	US 2014-0075297 A1 (SRISTY TECHNOLOGIES LLC.) 13 March 2014 See paragraphs [0019]-[0020], [0035] and figure 2.	6
A	US 2008-0120036 A1 (KIMMINAU et al.) 22 May 2008 See paragraphs [0035]-[0083] and figures 1-17.	1-13
A	US 2014-0291499 A1 (MATHIEU et al.) 02 October 2014 See paragraphs [0030]-[0064] and figures 1-15.	1-13
A	US 2015-0114631 A1 (CHEN et al.) 30 April 2015 See paragraphs [0023]-[0055] and figures 1-12C.	1-13

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
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"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents,such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
26 February 2016 (26.02.2016)	**29 February 2016 (29.02.2016)**

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.
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