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(54) **METHOD OF HYDRAULIC FRACTURE IDENTIFICATION USING TEMPERATURE**

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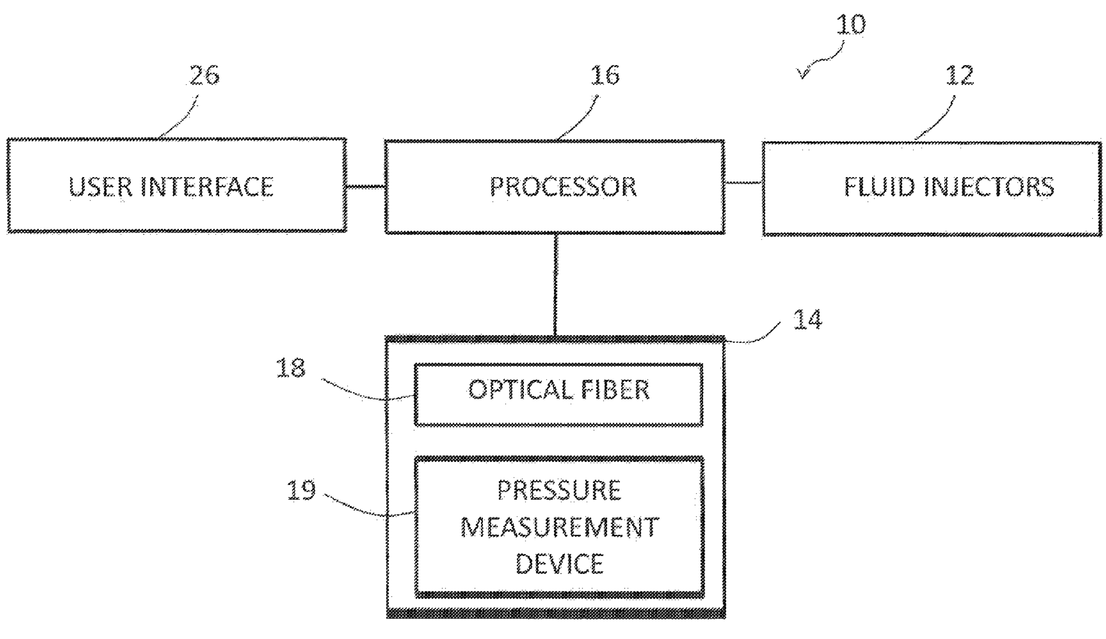
(57) **ABSTRACT**

A method for identifying fractures in a formation.



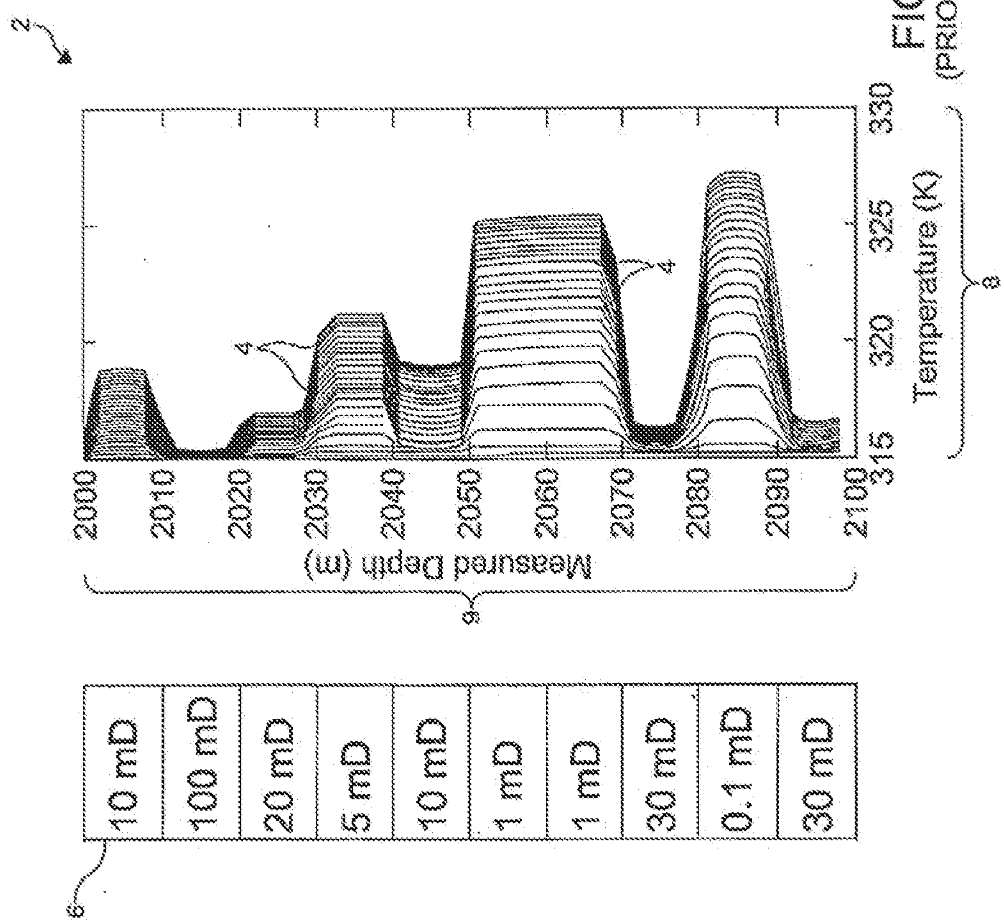


FIG. 1
(PRIOR ART)

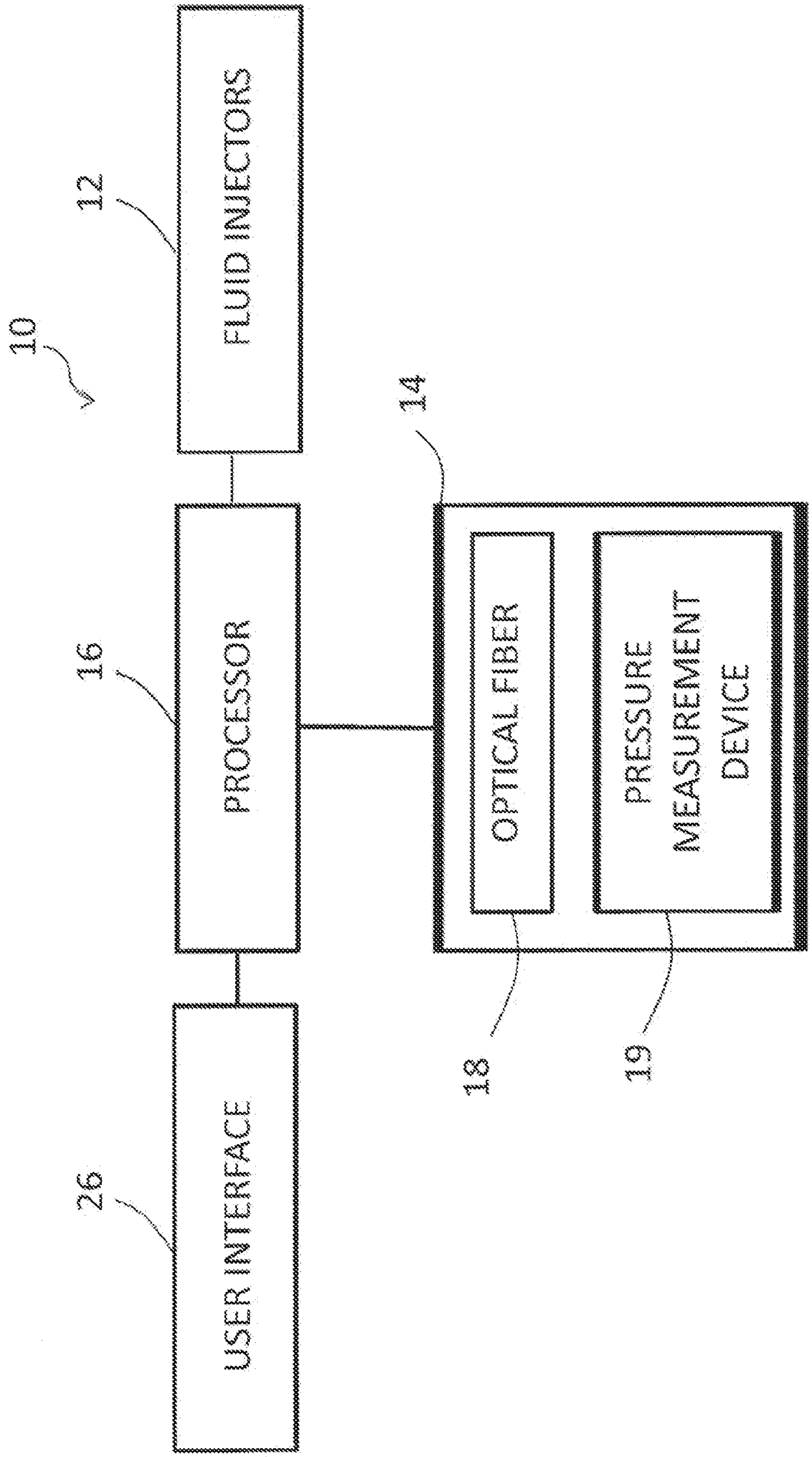

10
12
FLUID INJECTORS
16
PROCESSOR
14
OPTICAL FIBER
PRESSURE MEASUREMENT DEVICE
18
19
26
USER INTERFACE

FIG. 2

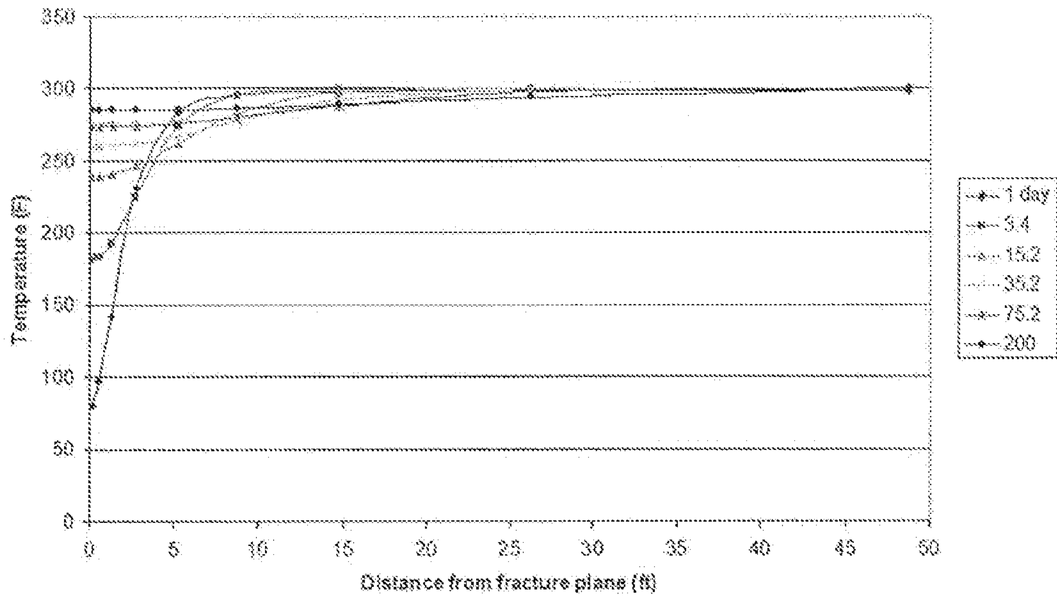

350
300
250
200
150
100
50
0
Temperature (F)
0
5
10
15
20
25
30
35
40
45
50
Distance from fracture plane (ft)
1 day
5.4
15.2
35.2
75.2
200

FIG. 3

METHOD OF HYDRAULIC FRACTURE IDENTIFICATION USING TEMPERATURE

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a non-provisional application which claims benefit under 35 USC §119(e) to U.S. Provisional Application Ser. No. 61/829,374 filed 31 May, 2013, entitled "METHOD OF HYDRAULIC FRACTURE IDENTIFICATION USING TEMPERATURE," which is incorporated herein in its entirety.

FIELD OF THE INVENTION

[0002] This invention relates to a method for identifying the presence of fracture in a wellbore during and after treatment.

BACKGROUND OF THE INVENTION

[0003] Hydraulic fracturing, matrix acidizing, and other types of stimulation treatments are routinely conducted in oil and gas wells to enhance hydrocarbon production. The wells being stimulated often include a large section of perforated casing or an open borehole having significant variation in rock petrophysical and mechanical properties. As a result, a treatment fluid pumped into the well may not flow to all desired hydrocarbon bearing layers that need stimulation. To achieve effective stimulation, the treatments often involve the use of diverting agents in the treating fluid, such as chemical or particulate material, to help reduce the flow into the more permeable layers that no longer need stimulation and increase the flow into the lower permeability layers.

[0004] However, during a stimulation treatment, the flow distribution in a well can change quickly due to either stimulation of the formation layers to increase their flow capacity or temporary reduction in flow capacity as a result of diverting agents. To determine the effectiveness of stimulation or diversion in the well, an instantaneous measurement that gives a "snap shot" of the flow distribution in a well is desired. Unfortunately, there are few such techniques available.

[0005] One technique for substantially instantaneous measurement is fiber optic Distributed Temperature Sensing (DTS) technology. DTS typical includes an optical fiber disposed in the wellbore (e.g. via a permanent fiber optic line cemented in the casing, a fiber optic line deployed using a coiled tubing, or a slickline unit). The optical fiber measures a temperature distribution along a length thereof based on an optical time-domain (e.g. optical time-domain reflectometry (OTDR), which is used extensively in the telecommunication industry).

[0006] One advantage of DTS technology is the ability to acquire in a short time interval the temperature distribution along the well without having to move the sensor as in traditional well logging which can be time consuming. DTS technology effectively provides a "snap shot" of the temperature profile in the well. DTS technology has been utilized to measure temperature changes in a wellbore after a stimulation injection, from which a flow distribution of an injected fluid can be qualitatively estimated. The inference of flow distribution is typically based on magnitude of temperature "warm-back" during a shut-in period after injecting a fluid into the wellbore and surrounding portions of the formation. The injected fluid is typically colder than the formation temperature and a formation layer that receives a greater fluid flow rate during the injection has a longer "warm back" time compared to a layer or zone of the formation that receives relatively less flow of the fluid.

[0007] As a non-limiting example, FIG. **1** illustrates a graphical plot **2** of a plurality of simulated temperature profiles **4** of a laminated formation **6** during a six hour time period of "warm back", according to the prior art. As shown, the X-axis **8** of the graphical plot **2** represents temperature in Kelvin (K) and the Y-axis **9** of the graphical plot **2** represents a depth in meters (m) measured from a pre-determined surface level. As shown, a permeability of each layer of the laminated formation **6** is estimated in units of millidarcies (mD). The layers of the formation **6** having a relatively high permeability receive more fluid during injection and a time period for "warm back" is relatively long (i.e. after a given time period, a change in temperature is less than a change in temperature of the layers having a lower permeability). The layers of the formation **6** having a relatively low permeability receive less fluid during injection and a time period for "warm back" is relatively short (i.e. after a given time period, a change in temperature is greater than a change in temperature of the layers having a higher permeability).

[0008] By obtaining and analyzing multiple DTS temperature traces during the shut-in period, the injection rate distribution among different formation layers can be determined. However, current DTS interpretation techniques and methods are based on visualization of the temperature change in the DTS data log, and is qualitative in nature, at best. The current interpretation methods are further complicated in applications where a reactive fluid, such as acid, is pumped into the wellbore, wherein the reactive fluid reacts with the formation rock and can affect a temperature of the formation, leading to erroneous interpretation. In order to achieve effective stimulation, more accurate DTS interpretation methods are needed to help engineers determine the flow distribution in the well and make adjustments in the treatment accordingly.

SUMMARY OF THE INVENTION

[0009] In an embodiment, a method for identifying fractures in a formation having a wellbore includes: (a) positioning a sensor within the wellbore, wherein the sensor generates a feedback signal representing at least one of a temperature and pressure measured by the sensor; (b) injecting a fluid into the wellbore and into at least a portion of the formation adjacent the sensor; (c) waiting a predetermined period of time; (d) generating a standstill simulated model representing at least one simulated temperature characteristic and at least one pressure characteristic of the formation during and after fluid injection; (e) shutting-in the wellbore for a pre-determined shut-in period; (f) generating a shut-in simulated model representing at least one simulated temperature characteristic and at least one pressure characteristic of the formation during the shut-in period; (g) generating a data model representing the standstill simulated model and the shut-in simulated model, wherein the data model is derived from the feedback signal; and (h) observing the data model for presence of fractures within the wellbore, wherein fractures are present when the temperature characteristics are lower than the temperature characteristics of other sections of the wellbore.

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] The invention, together with further advantages thereof, may best be understood by reference to the following description taken in conjunction with the accompanying drawings in which:

[0011] FIG. **1** is a graphical plot of a plurality of simulated temperature profiles during a six house period of warm back, according to the prior art.

[0012] FIG. **2** is a schematic diagram of an embodiment of the present invention.

[0013] FIG. **3** is a graphical plot showing an embodiment of a temperature profile for a wellbore in accordance with the present invention.

DETAILED DESCRIPTION OF THE INVENTION

[0014] Reference will now be made in detail to embodiments of the present invention, one or more examples of which are illustrated in the accompanying drawings. Each example is provided by way of explanation of the invention, not as a limitation of the invention. It will be apparent to those skilled in the art that various modifications and variations can be made in the present invention without departing from the scope or spirit of the invention. For instance, features illustrated or described as part of one embodiment can be used in another embodiment to yield a still further embodiment. Thus, it is intended that the present invention cover such modifications and variations that come within the scope of the appended claims and their equivalents.

[0015] Referring now to FIG. **2**, there is shown an embodiment of a wellbore treatment system according to the invention, indicated generally at **10**. As shown, the system **10** includes a fluid injector(s) **12**, a sensor **14**, and a processor **16**. It is understood that the system **10** may include additional components.

[0016] The sensor **14** is typically of Distributed Temperature Sensing (DTS) technology including an optical fiber **18** disposed in the wellbore (e.g. via a permanent fiber optic line cemented in the casing, a fiber optic line deployed using a coiled tubing, or a slickline unit). The optical fiber **18** measures the temperature distribution along a length thereof based on optical time-domain (e.g. optical time-domain reflectometry). In certain embodiments, the sensor **14** includes a pressure measurement device **19** for measuring a pressure distribution in the wellbore and surrounding formation. In certain embodiments, the sensor **14** is similar to the DTS technology disclosed in U.S. Pat. No. 7,055,604 B2, hereby incorporated herein by reference in its entirety.

[0017] The processor **16** is in data communication with the sensor **14** to receive data signals (e.g. a feedback signal) therefrom and analyze the signals based upon a pre-determined algorithm, mathematical process, or equation, for example. As shown in FIG. **2**, the processor **16** analyzes and evaluates a received data based upon an instruction set **20**. The instruction set **20**, which may be embodied within any computer readable medium, includes processor executable instructions for configuring the processor **16** to perform a variety of tasks and calculations. As a non-limiting example, the instruction set **20** may include a comprehensive suite of equations governing a physical phenomenon of fluid flow in the formation, a fluid flow in the wellbore, a fluid/formation (e.g. rock) interaction in the case of a reactive stimulation fluid, a fluid flow in a fracture and its deformation in the case of hydraulic fracturing, and a heat transfer in the wellbore and in the formation. As a further non-limiting example, the instruction set **20** includes a comprehensive numerical model for carbonate acidizing such as described in Society of Petroleum Engineers (SPE) Paper 107854, titled "An Experimentally Validated Wormhole Model for Self-Diverting and Conventional Acids in Carbonate Rocks Under Radial Flow Conditions," and authored by P. Tardy, B. Lecerf and Y. Christanti, hereby incorporated herein by reference in its entirety. It is understood that any equations can be used to model a fluid flow and a heat transfer in the wellbore and adjacent formation, as appreciated by one skilled in the art of wellbore treatment. It is further understood that the processor **16** may execute a variety of functions such as controlling various settings of the sensor **14** and the fluid injector **12**, for example.

[0018] A temperature of the injected fluid is typically lower than a temperature of each of the layers of the formation. Throughout the injection period, the colder fluid removes thermal energy from the wellbore and surrounding areas of the formation. Typically, the higher the inflow rate into the formation, the greater the injected fluid volume (i.e. its penetration depth into the formation), and the greater the cooled region. In the case of hydraulic fracturing, the injected fluid enters the created hydraulic fracture and cools the region adjacent to the fracture surface. When pumping stops, the heat conduction from the reservoir gradually warms the fluid in the wellbore. Where a portion of the formation does not receive inflow during injection will warm back faster due to a smaller cooled region, while the formation that received greater inflow warms back more slowly.

[0019] After injection of fluid into the well, wait a predetermined period of time before shitting in the well. While waiting, any number of operations may be performed except injecting fluid that is comparable to the total heat transfer of hydraulic fracturing into the well. Some operations, for example, include to plug or ball-seat drill outs, clean-outs, produced, cased hole logging runs, etc.

[0020] FIG. **3** illustrates a graphical plot **48** of the temperature profiles normal to fracture at various time periods. The region near the well warms up quickly just after the injection period ends, but the temperature at the well is still about 15° F. less than the initial reservoir temperature.

[0021] In closing, it should be noted that the discussion of any reference is not an admission that it is prior art to the present invention, especially any reference that may have a publication date after the priority date of this application. At the same time, each and every claim below is hereby incorporated into this detailed description or specification as a additional embodiments of the present invention.

[0022] Although the systems and processes described herein have been described in detail, it should be understood that various changes, substitutions, and alterations can be made without departing from the spirit and scope of the invention as defined by the following claims. Those skilled in the art may be able to study the preferred embodiments and identify other ways to practice the invention that are not exactly as described herein. It is the intent of the inventors that variations and equivalents of the invention are within the scope of the claims while the description, abstract and drawings are not to be used to limit the scope of the invention. The invention is specifically intended to be as broad as the claims below and their equivalents.

1. A method for identifying fractures in a formation having a wellbore comprising:

a. positioning a sensor within the wellbore, wherein the sensor generates a feedback signal representing at least one of a temperature and pressure measured by the sensor;

b. injecting a fluid into the wellbore and into at least a portion of the formation adjacent the sensor;

c. waiting a predetermined period of time;

d. generating a standstill simulated model representing at least one simulated temperature characteristic and at least one pressure characteristic of the formation during and after fluid injection;

e. shutting-in the wellbore for a pre-determined shut-in period;

f. generating a shut-in simulated model representing at least one simulated temperature characteristic and at least one pressure characteristic of the formation during the shut-in period;

g. generating a data model representing the standstill simulated model and the shut-in simulated model, wherein the data model is derived from the feedback signal; and

h. observing the data model for presence of fractures within the wellbore, wherein fractures are present when the temperature characteristics are lower than the temperature characteristics of other sections of the wellbore.

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