Innovation, Sciences et Développement économique Canada
Office de la Propriété Intellectuelle du Canada

Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 2822033 C 2019/02/26

(11)(21) 2 822 033

(12) **BREVET CANADIEN**
CANADIAN PATENT

(13) **C**

(86) Date de dépôt PCT/PCT Filing Date: 2011/12/09
(87) Date publication PCT/PCT Publication Date: 2012/06/28
(45) Date de délivrance/Issue Date: 2019/02/26
(85) Entrée phase nationale/National Entry: 2013/06/17
(86) N° demande PCT/PCT Application No.: US 2011/064105
(87) N° publication PCT/PCT Publication No.: 2012/087604
(30) Priorité/Priority: 2010/12/21 (US61/425,603)

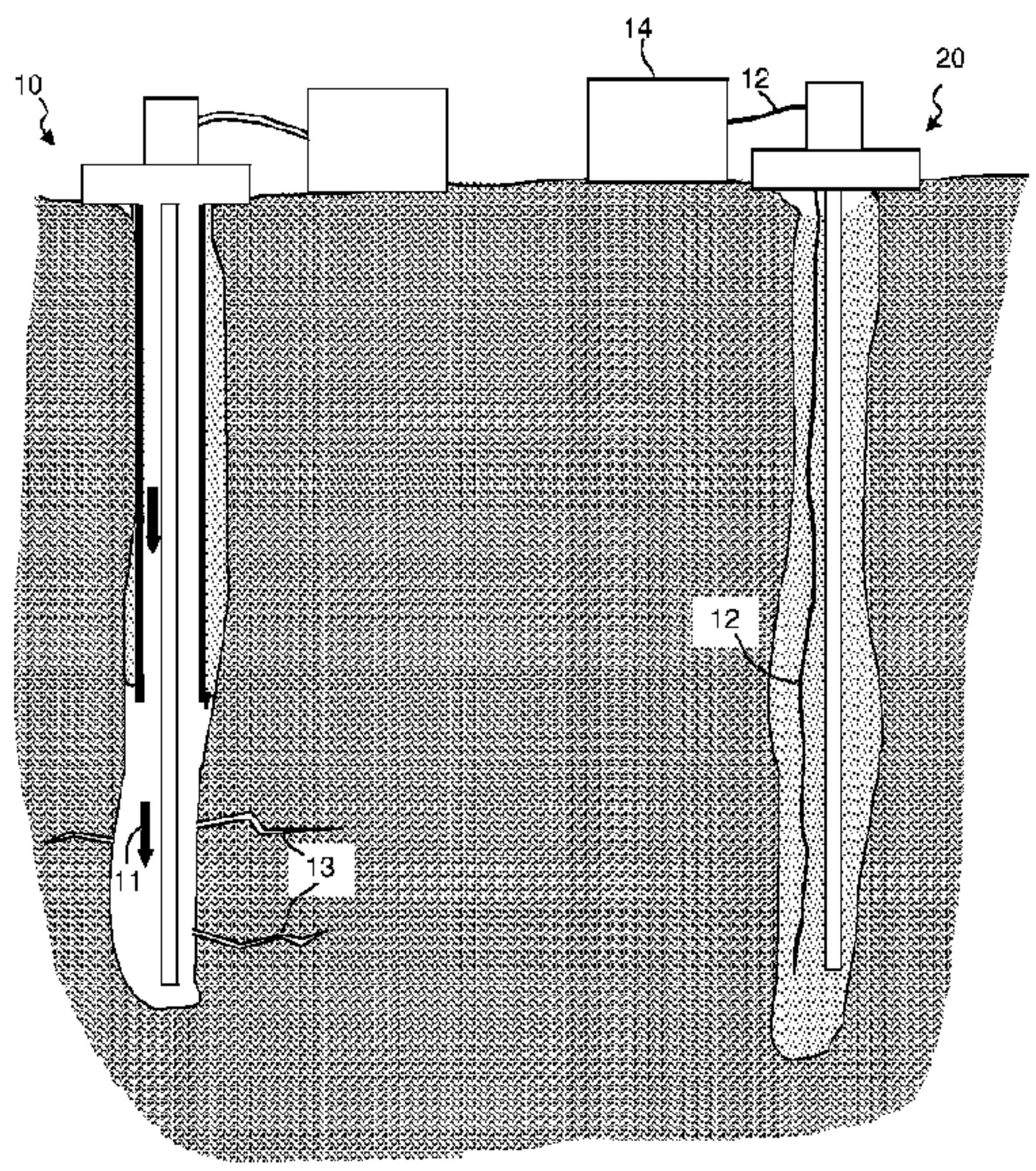
(51) Cl.Int./Int.Cl. *G01V 8/16* (2006.01), *E21B 47/00* (2012.01), *G01B 11/16* (2006.01)

(72) Inventeurs/Inventors:
MINCHAU, MICHAEL CHARLES, CA;
WEBSTER, PAUL SIMON, CA;
WILLS, PETER BERKELEY, US;
WINSOR, JONATHAN DION, CA

(73) Propriétaire/Owner:
SHELL INTERNATIONALE RESEARCH MAATSCHAPPIJ B.V., NL

(74) Agent: SMART & BIGGAR

(54) Titre : SYSTEME ET PROCEDE POUR CONTROLER UNE CONTRAINTE ET UNE PRESSION
(54) Title: SYSTEM AND METHOD FOR MONITORING STRAIN & PRESSURE



(57) Abrégé/Abstract:
A method for monitoring a well treatment, comprising the steps of installing at least one distributed acoustic strain sensor in at least one monitoring well, said monitoring well being a known distance from the treatment well, initiating a well treatment on the first well, monitoring the formation surrounding the monitoring well using the distributed acoustic strain sensor, and using the distributed acoustic strain sensor, detecting a change in strain at a first location in the monitoring well, using the change in strain to make determinations about the well treatment. The sensor may comprise a fiber optic cable. The change in strain may be used as an indicator that the effect of the well treatment has extended beyond a predetermined preferred treatment zone, the treatment may be a fracture treatment, and the well treatment may be controlled or ceased based on the determinations made in step e).

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) **World Intellectual Property Organization**
International Bureau

(43) **International Publication Date**
28 June 2012 (28.06.2012)

WIPO | PCT

(10) **International Publication Number**
WO 2012/087604 A3

(51) **International Patent Classification**:
G01V 8/16 (2006.01) ***G01B 11/16*** (2006.01)
E21B 47/00 (2006.01)

(21) **International Application Number**:
PCT/US2011/064105

(22) **International Filing Date**:
9 December 2011 (09.12.2011)

(25) **Filing Language**: English

(26) **Publication Language**: English

(30) **Priority Data**:
61/425,603 21 December 2010 (21.12.2010) US

(71) **Applicant** *(for SM only)*: **SHELL OIL COMPANY** [US/US]; One Shell Plaza, P.O. Box 2463, Houston, Texas 77252-2463 (US).

(71) **Applicant** *(for all designated States except US)*: **SHELL INTERNATIONALE RESEARCH MAATSCHAPPIJ B.V.** [NL/NL]; Carel van Bylandtlaan 30, NL-2596 The Hague (NL).

(72) **Inventor; and**

(75) **Inventor/Applicant** *(for US only)*: **MINCHAU, Michael Charles** [CA/CA]; 6219 Silver Springs Hill, N.W., Calgary, Alberta (CA).

(74) **Agent**: **WATKINS, Marcella D.**; Shell Oil Company, One Shell Plaza, P.O. Box 2463, Houston, Texas 77252-2463 (US).

(81) **Designated States** *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) **Designated States** *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE,

[Continued on next page]

(54) **Title**: SYSTEM AND METHOD FOR MONIITORING STRAIN & PRESSURE

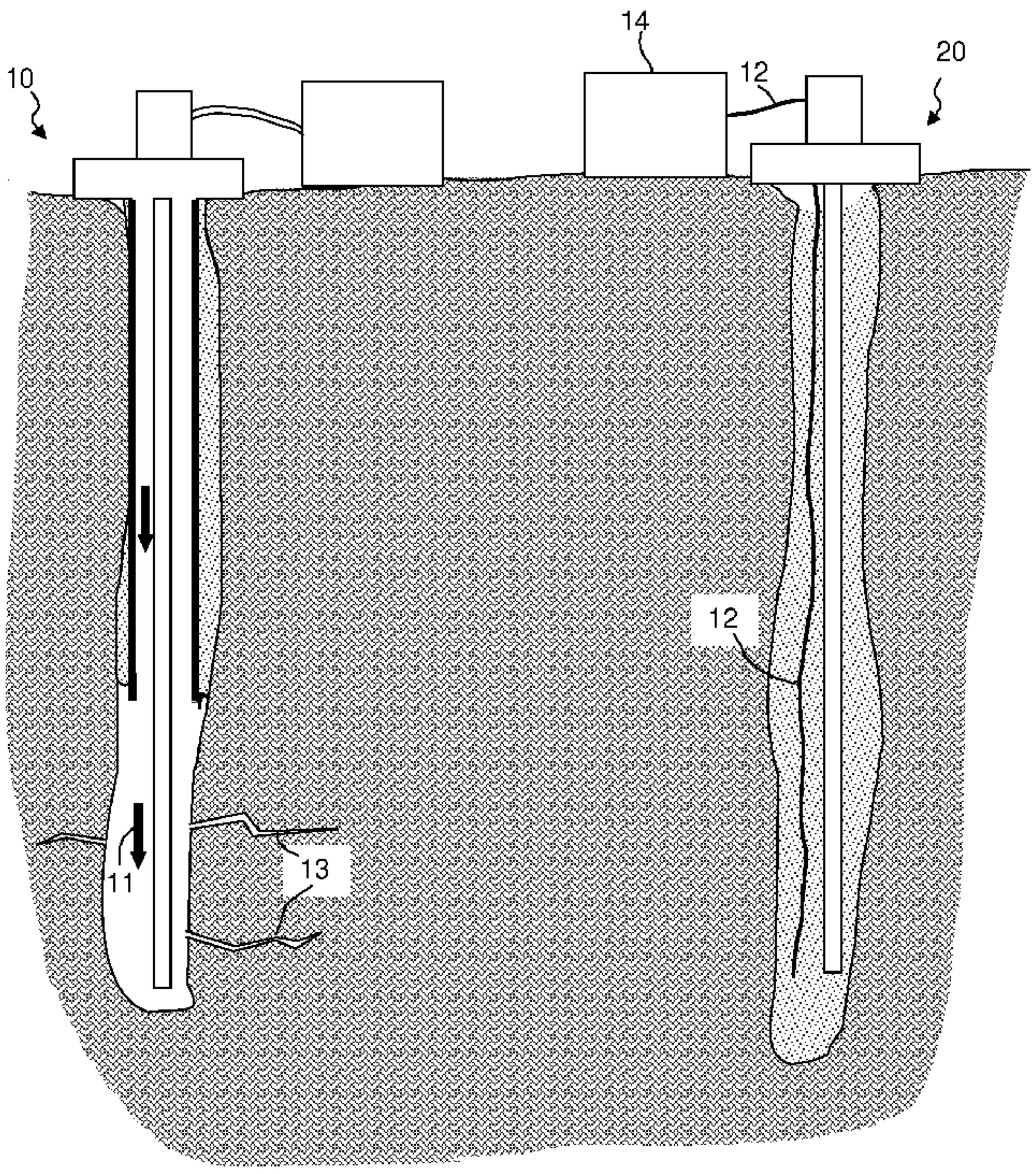


Fig. 1

(57) **Abstract**: A method for monitoring a well treatment, comprising the steps of installing at least one distributed acoustic strain sensor in at least one monitoring well, said monitoring well being a known distance from the treatment well, initiating a well treatment on the first well, monitoring the formation surrounding the monitoring well using the distributed acoustic strain sensor, and using the distributed acoustic strain sensor, detecting a change in strain at a first location in the monitoring well, using the change in strain to make determinations about the well treatment. The sensor may comprise a fiber optic cable. The change in strain may be used as an indicator that the effect of the well treatment has extended beyond a predetermined preferred treatment zone, the treatment may be a fracture treatment, and the well treatment may be controlled or ceased based on the determinations made in step e).

WO 2012/087604 A3

WO 2012/087604 A3

DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))*

(88) Date of publication of the international search report:
26 October 2012

SYSTEM AND METHOD FOR MONITORING STRAIN & PRESSURE

RELATED APPLICATIONS

The present case claims priority to U.S. provisional application Serial No. 61/425,603, filed on 21 December 2010.

TECHNICAL FIELD OF THE INVENTION

[0001] The present disclosure relates generally to a system and a method for measuring strain and/or pressure in an underground formation.

BACKGROUND OF THE INVENTION

[0002] In oilfield operations there is a often need to measure changes in formation strain or pressure that occur as a result of well interventions such as hydraulic fracturing and fluid injection. These operations generally create high pressures in the formation, often leading to breakdown (fracturing) of the rock matrix, and will strain the formation in a volume surrounding the intervention. Measurement of this formation strain can be diagnostic of the effectiveness of the intervention and can lead to modification of the intervention parameters that can give significant economic benefit if the measurement technique is inexpensive enough. Changes in strain can occur over time scales ranging from fractions of a second to years and can occur at locations that are far away from the well where the intervention takes place ("treatment well"), often affecting rock volumes intersected by neighboring wells. Similarly, detection of abnormal pressure may indicate fluid paths or potential breakdown or formation/concrete.

[0003] Various methods for applying transducers and/or sensors to a cylindrical structure such as casing and using the sensors or transducers to monitor deformation of the structure as the structure is subjected to various forces are known. For example, U.S. Patent No. 7,245,791 discloses that temperature variations may impart additional strain to an optical fiber and to a supporting structure, such as a well tubular and/or casing, about which the optical fiber is wrapped, and that these temperature variations affect the index of refraction in the optical fiber, so that temperature variations may be considered independently for calibrating the strain measurements.

[0004] Notwithstanding the foregoing, there is currently no *in-situ* method for measuring, in a volume around the treatment well and at an acceptable cost and accuracy, formation strain during well interventions. Surface and vertical seismic profile (VSP) measurements can be used, but these are not accurate and require calibration, as they yield formation velocity as the raw measurement, which in turn needs to be converted into strain. In principle, formation strainmeters could be deployed in a permanent installation outside of casing but this can be prohibitively expensive, especially if multiple wells and depth stations are targeted. Furthermore, it is sometimes desirable to detect formation strain and/or pressure in a treatment well, which is difficult if not impossible using traditional pressure or strain gauges.

SUMMARY OF THE INVENTION

[0005] The present disclosure provides a system and an *in-situ* permanent method for measuring formation strain in a volume around the treatment well and at an acceptable cost and accuracy.

[0006] In preferred embodiments, the invention includes installation of DAS fibers in both a treatment well and in neighboring wells. Laser light enters the fiber above the wellhead and a backscattered signal is measured by optical components at the surface. Known optical time-domain reflectometry (OTDR) methods and preferably used to infer formation strain based on the backscattered signal from a segment of the fiber adjacent to the formation. All depths can be interrogated in the time scale of fractions of a millisecond, providing a virtually instantaneous strain measurement at all depths of interest. Strain/pressure assessments can be performed on many wells at once, providing a sampling of the volume strain or pressure over potentially a large area. The measurements can be used to diagnose and correct a geomechanical model or can be used to directly intervene in the treatment with or without integration with other measurements.

[0007] In some embodiments, the invention includes a method for detecting the effect of a well treatment such as a fracturing treatment or fluid injection performed in a first well, comprising the steps of: a) installing at least one distributed acoustic strain sensor in at least one monitoring well that is located a known distance from the first well, b) initiating a well treatment on the first well, c) monitoring the formation surrounding the monitoring well using the distributed acoustic strain sensor, d) using the distributed acoustic strain sensor, detecting a change in strain at a first location in the monitoring well, and e) using the change in strain or pressure detected in step d) to make determinations about the well treatment in step b). The invention can also be used to determine the lateral, horizontal or vertical (formation) extent of the fracture network or induced hydraulic fracture.

[0008] The distributed acoustic strain sensors may be installed in one or more monitoring wells, with each monitoring well between 50 m and 5000 m from the first or treatment well. Each distributed acoustic sensor preferably comprises a fiber optic cable and associated laser interrogator unit for sending and receiving optical signals through the fiber.

[0009] The change in strain detected in step d) can be used as an indication that the effect of the well treatment has extended to or beyond the limit of a predetermined preferred treatment zone and the well treatment may be controlled or ceased based on the determinations made in step e). The present method can also be used to determine information about the formation between the first well and the monitoring well.

[0010] Other embodiments of the invention relate to time-lapse measurement of either proximal and/or distal strain or pressure, in a formation before, during, and after production operations. According to the invention, strain measurements can be measured over long periods of time—seconds /minutes/days/weeks/months/years—giving them greater scope than normal seismic data.

[0011] As used herein, "well treatment" refers to any fluid injection or removal process that may be carried out on a well, including fraccing, solvent injection, production, and the like.

[0011a] According to one aspect of the present invention, there is provided a method for detecting the effect of a well treatment performed in a first well, comprising the steps of: a) installing at least one distributed acoustic strain sensor in at least one monitoring well, said monitoring well being a known distance from the first well; b) initiating a well treatment on the first well; c) monitoring a formation surrounding the monitoring well using the distributed acoustic strain sensor; d) using the distributed acoustic strain sensor, detecting a change in strain or pressure at a first location in the monitoring well; and e) using the change in strain detected in step d) to make determinations about the well treatment in step b).

[0011b] According to another aspect of the present invention, there is provided a method of performing a well treatment in a first well, comprising the steps of: a) providing at least one monitoring well comprising at least one distributed acoustic strain sensor installed in said monitoring well, said monitoring well being a known distance from the first well; b) initiating the well treatment on the first well; c) monitoring a formation surrounding the monitoring well using the distributed acoustic strain sensor; d) using the distributed acoustic strain sensor, detecting a change in strain or pressure at a first location in the monitoring well; and e) using the change in strain detected in step d) to make determinations about the well treatment in step b).

BRIEF DESCRIPTION OF THE DRAWINGS

[0012] For a more complete understanding of the preferred embodiments, reference is made to the accompanying drawing, which is a schematic illustration of a system in accordance with a first embodiment of the invention.

DETAILED DESCRIPTION OF ILLUSTRATIVE EMBODIMENTS

[0013] The present disclosure relates generally to a system and a method for monitoring strain or pressure in one or more monitoring wells and using the collected information to control processes in a treatment well or to understand the effectiveness of those treatments.

[0014] In one embodiment, distributed acoustic sensors comprising fiber optic cables such as are known in the art are deployed in one or more monitoring wells that are located at a distance from the treatment well. The distance between the treatment well and any given monitoring well may be in the range of from 50m to 5000m. If more than one monitoring well is used, the wells can be arranged on opposite sides of or evenly spaced about the treatment well, or the monitoring wells can be located in locations determined by the geology and/or topography surrounding the well. If more than one monitoring well is used, it is possible to collect more data about the subsurface and therefore to provide more useful information.

[0015] By way of example only, referring initially to Figure 1, a treatment well 10 and a monitoring well 20 are preferably located according to a predetermined plan. In some embodiments, the treatment well will be one in which a fraccing or other injection operation will be performed.

[0016] Treatment well 10 may contain one or more tubulars and may be cased, as shown. In some cases, the well treatment will comprise pumping fluid into the well at sufficiently high pressure to fracture the adjacent formation, as illustrated by arrows 11, resulting in fractures 13.

[0017] One or more fiber optic cables 12 designed to collect distributed strain measurements are deployed in monitoring well(s) 20 and coupled to the formation by any suitable means. In the embodiment shown, monitoring well 20 has been cemented with a fiber optic sensor embedded in the cement. It will be understood that the optic fiber can also be clamped or bonded to a downhole tubular, or acoustically coupled by any other means. One or more light boxes 14 containing laser light sources and signal-receiving means are optically coupled to the fiber at the surface. The cable may be double-ended, i.e. may be folded back in the middle so that both ends of the cable are at the source, or it may be single-ended, with one end at the source and the other end at a point that is remote from the source. The length of the cable can range from a few meters to several kilometers, or even hundreds of kilometers. In either case, measurements can be based solely on backscattered light, if there is a light-receiving means only at the source end of the cable, or a light receiving means can be provided at the second end of the cable, so that the intensity of light at the second end of the fiber optic cable can also be measured.

[0018] In some embodiments, the light source may be a long coherence length phase-stable laser and is used to transmit direct sequence spread spectrum encoded light down the fiber. Localized strain or other disruptions cause small changes to the fiber, which in turn produce changes in the backscattered light signal. The returning light signal thus contains both information about strain changes and location information indicating where along the fiber they occurred. In some embodiments, the location along the fiber can be determined using spread spectrum encoding, which uniquely encodes the time of flight along the length of the fiber.

[0019] When it is desired to make measurements, the light source transmits at least one light pulse into the end of the fiber optic cable and a backscattered signal is received at the signal-receiving means. Known optical time-domain reflectometry (OTDR) methods are preferably used to infer formation strain based on the backscattered signal from one or more segments of the fiber adjacent to the formation of interest.

[0020] Using the present invention, formation strain or pressure can be measured in the monitoring well(s) or treatment well(s) over the duration of the treatment process and, if desired, for a period of time thereafter, providing information about changes in the formation strain or pressure over time. Of particular interest are strain measurements indicating that the effect of the injection in the treatment well has extended to or beyond the limit of a predetermined preferred treatment zone. Thus, for example, strain in the formation resulting from the injection of fluid is preferably detected by fiber optic cable 12 for at least the duration of the injection. In addition, acoustic events attributable strain-induced fractures may also be detectable by fiber optic cable 12.

[0021] Similarly, measurements in a pressurize zone can be used to sense movement of a pressure front. Pressure in the formation will cause a dilation in the matrix, i.e. an isotropic strain in all directions. A fiber oriented in any direction will pick this up as long as is passes through a region of changing pressure – the "pressure front."

[0022] All depths can be interrogated in the time scale of fractions of a millisecond, providing a virtually instantaneous strain measurement at all depths of interest. Strain and pressure assessments can be performed on many wells at once, providing a sampling of the volume strain over potentially a large area. The measurements can be used to diagnose and correct a geomechanical model or can be used to directly intervene in the treatment with or without integration with other measurements. Thus, the present invention allows control of pressures to reduce out-of-zone effects and also allows better understanding of production given the measured connectivity.

[0023] In addition to the foregoing, it has been observed that strain anomalies typically travel from the treatment well to neighboring wells and that, shortly after the strain anomaly reaches a neighboring well, it travels up and down that wellbore, creating pressure connectivity over a significant vertical column (as measured using pressure gauges in the field data). This is undesirable for optimal production of the zones. The present invention makes it possible to monitor the treatment using DAS signals in the monitoring wells and to stop pumping when initial inter-well connectivity is established.

[0024] The present methods have no inherent lower limit to the frequency of investigation and are therefore limited only by the stability of the hardware over long time scales. There are various methods of backscatter measurement, including the use of Rayleigh and Brillouin backscattering, and one method may be preferred over others for this implementation of the present invention, especially at low frequency.

[0025] The particular embodiments disclosed above are illustrative only, as the present claimed subject matter may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered or modified and all such variations are considered within the scope and spirit of the present claimed subject matter. By way of example only, one of skill in the art will recognize that the number and location of the monitoring well(s) with respect to the first well, the number and configuration of cables and sensors, the sampling rate and frequencies of light used, and the nature of the cable, coupling devices, light sources, light signals, and photodetectors can all be modified within the scope of the invention. By way of further example, embodiments have been described in which a fiber is placed in one or more wells that are spaced apart from the treatment well. It will be understood that fibers could also be placed in the treatment well itself. Moreover, it will be appreciated that such a development effort might be complex and time-consuming, but would nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of the present disclosure.

[0026] The subject matter of the present disclosure is described with specificity. However, the description itself is not intended to limit the scope of the claimed subject matter. The claimed subject matter, thus, might also be embodied in other ways to include different steps or combinations of steps similar to the ones described herein, in conjunction with other present or future technologies. Moreover, although the term "step" may be used herein to connote different methods employed, the term should not be interpreted as implying any particular order among or between various steps herein disclosed except when the order of individual steps is explicitly described.

[0027] For illustrative purposes only, two examples of implementation of the inventive concepts are set forth below.

Example 1: Hydraulic Fracturing

[0028] According to a first exemplary embodiment, distributed OTDR sensing can be used to detect hydraulic fracturing according to the following workflow:

- deploy one or more DAS fibers in one or more wells in the vicinity of an intended hydraulic fracturing operation;
- prior to hydraulic fracturing in the area, record noise levels along the fiber as a control measurement;
- upon initiation of pumping of fracture fluids, for any or all fracture stages and fluid types, including mini-frac (or test frac), record the strain field as measured by the DAS system, for all locations in the well where the formation can be affected by the fracture operation;
- simulate the strain field as a function of time and space using a geomechanical simulation;
- from the results of the simulation, make a prediction of the axial strain measurements at the places where the DAS fibers have made the measurements;
- compare the predictions and measurements and adjust the geomechanical model parameters to minimize the difference;
- use the new geomechanical model to make further predictions that can be compared with DAS (or other) measurements;
- use the new geomechanical model to optimize perforation locations and pumping schedule (and any other relevant parameters) such that the predictions of the updated model, with the new perforation locations and pumping schedule, predict optimal production over the life of the field; and
- keep the geomechanical model evergreen by including data from either infill hydraulic fracturing, recompletion fractures, long-term depletion or other changes in formation strain due to production operations.

[0029] The foregoing workflow can be generalized beyond hydraulic fracture detection to include any earth motion that can be measured with DAS, including but not limited to pressure or radial strain.

Example 2: Depletion

[0030] According to a second exemplary embodiment, the inventive methods are used to measure time-dependent strain in a depleting field. More specifically, the inventive methods provide a way to measure moderate resolution differential depletion in a reservoir. The cost and availability of fiber optic sensors, allows construction of an areal picture of depletion induced strain.

[0031] Thus, according to this embodiment, distributed OTDR sensing can be used to detect and monitor field depletion according to the following workflow:

- deploy one or more DAS fibers in one or more wells in the vicinity of an intended hydraulic fracturing operation;
- prior to field startup, record noise levels along the fibers as a control measurement;
- upon initiation of field depletion, the strain field as measured by the DAS system, for all instrumented wells;
- simulate the strain field as a function of time and space using a geomechanical simulation;
- from the results of the simulation, make a prediction of the axial strain measurements at the places where the DAS fibers have made the measurements;
- compare the predictions and measurements and adjust the geomechanical model parameters to
minimize the difference therebetween;
- make changes in the model as required to match the data highlight differences in subsidence/depletion for different parts of a formation, leading to localized interventions;
- alternatively, depleted/depleting areas may be obvious even without the benefit of a geomechanical model as areas with greater or lesser strain changes;
- if the fiber is also configured to measure formation pressure, a measure of rock compressibility might be possible from strain and pressure.

[0032] While the invention has the particular advantaged described above, it can be used advantageously to detect inter-well effects caused by other sources and can be used to determine information about properties of the formation between wells. Accordingly, the protection sought herein is as set forth in the claims below.

CLAIMS:

1. A method for detecting the effect of a well treatment performed in a first well, comprising the steps of:

a) installing at least one distributed acoustic strain sensor in at least one monitoring well, said monitoring well being a known distance from the first well;

b) initiating a well treatment on the first well;

c) monitoring a formation surrounding the monitoring well using the distributed acoustic strain sensor;

d) using the distributed acoustic strain sensor, detecting a change in strain or pressure at a first location in the monitoring well; and

e) using the change in strain detected in step d) to make determinations about the well treatment in step b).

2. The method according to claim 1 wherein distributed acoustic strain sensors are installed in at least two monitoring wells.

3. The method according to claim 1 wherein each monitoring well is between 50 m and 5000 m from the first well.

4. The method according to claim 1 wherein the distributed acoustic sensor comprises a fiber optic cable.

5. The method according to claim 1 wherein the change in strain detected in step d) indicates that the effect of the well treatment has extended to or beyond the limit of a predetermined preferred treatment zone.

6. The method according to claim 1 wherein the well treatment is a fracture treatment.

7. The method according to claim 1 further including the step of controlling the well treatment of step b), based on the determinations made in step e).

8. The method according to claim 1, further including the step of ceasing the well treatment of step b), based on the determinations made in step e).

9. The method according to claim 1 further including the step of detecting, at one or more locations that are vertically spaced from the first locations, further changes in strain that are related to the change in strain detected in step d).

10. The method according to claim 1 further including the step of using the change in strain detected in step d) to determine information about the formation between the first well and the monitoring well.

11. A method of performing a well treatment in a first well, comprising the steps of:

a) providing at least one monitoring well comprising at least one distributed acoustic strain sensor installed in said monitoring well, said monitoring well being a known distance from the first well;

b) initiating the well treatment on the first well;

c) monitoring a formation surrounding the monitoring well using the distributed acoustic strain sensor;

d) using the distributed acoustic strain sensor, detecting a change in strain or pressure at a first location in the monitoring well; and

e) using the change in strain detected in step d) to make determinations about the well treatment in step b).

12. The method according to claim 11 wherein distributed acoustic strain sensors are installed in at least two monitoring wells.

13. The method according to claim 11 wherein each monitoring well is between 50 m and 5000 m from the first well.

14. The method according to claim 11 wherein the distributed acoustic sensor comprises a fiber optic cable.

15. The method according to claim 11 wherein the change in strain detected in step d) indicates that the effect of the well treatment has extended to or beyond the limit of a predetermined preferred treatment zone.

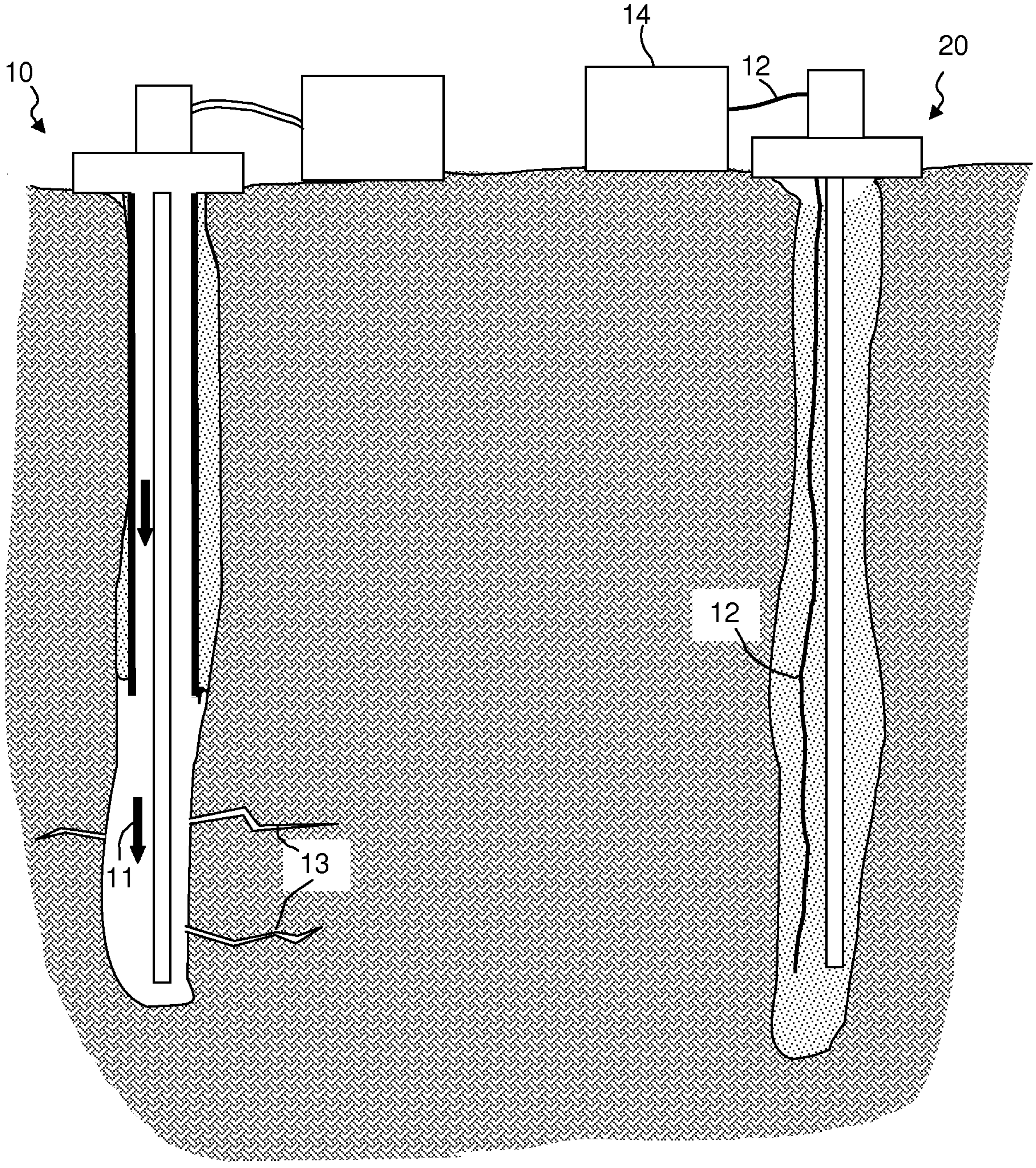
16. The method according to claim 11 wherein the well treatment is a fracture treatment.

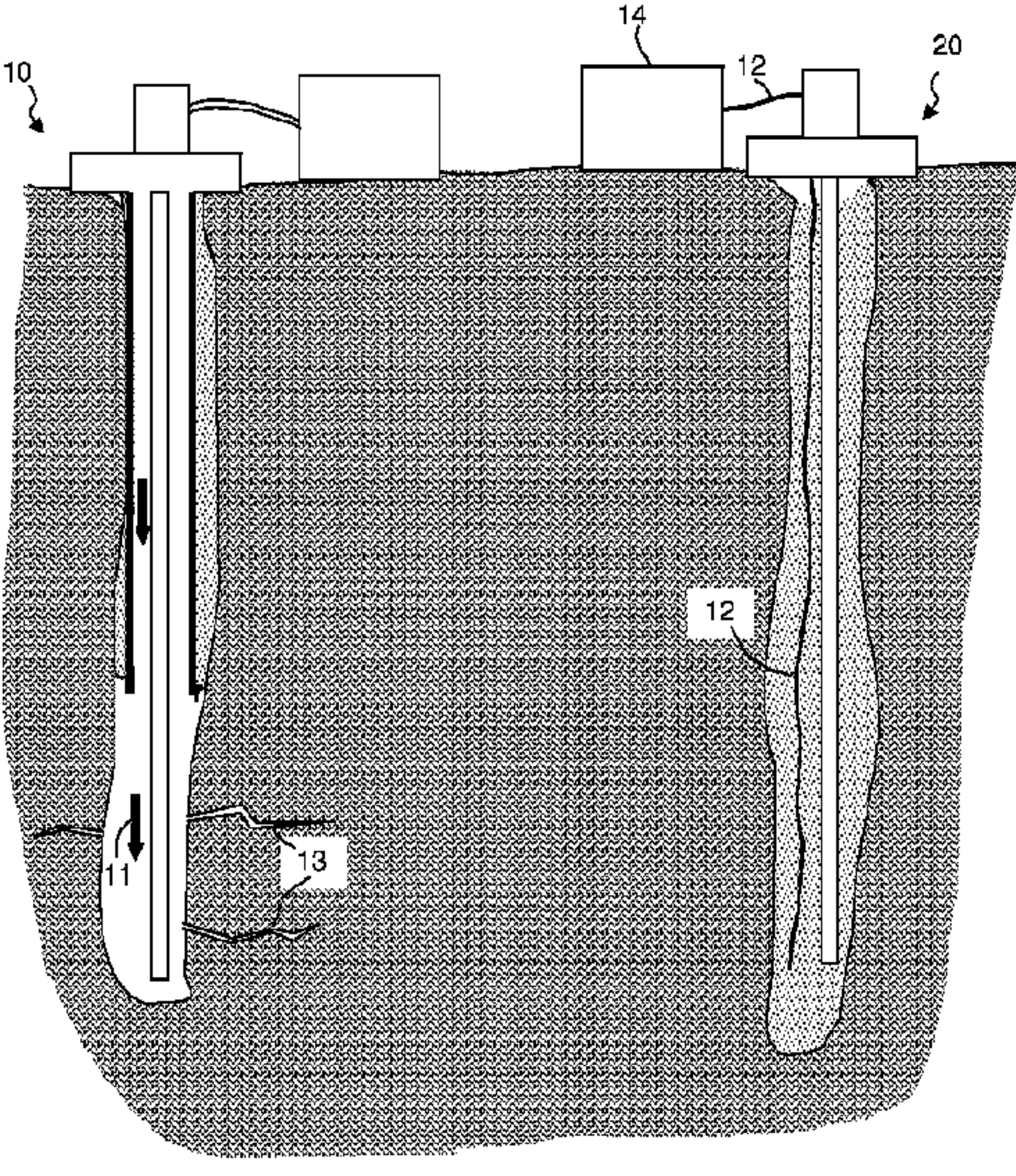
17. The method according to claim 11 further including the step of controlling the well treatment based on the determinations made in step e).

18. The method according to claim 11, further including the step of ceasing the well treatment based on the determinations made in step e).

19. The method according to claim 11 further including the step of detecting, at one or more locations that are vertically spaced from the first locations, further changes in strain that are related to the change in strain detected in step d).

20. The method according to claim 11 further including the step of using the change in strain detected in step d) to determine information about the formation between the first well and the monitoring well.


10
14
12
20
12
11
13



14
12
20
10
12
13
11