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- (71) Applicant (for US only): **SCHLUMBERGER TECHNOLOGY CORPORATION** [US/US]; 300 Schlumberger Drive, Sugar Land, Texas 77478 (US).
- (71) Applicant (for CA only): **SCHLUMBERGER CANADA LIMITED** [CA/CA]; 125 – 9 Avenue SE, Calgary, Alberta T2G 0P6 (CA).
- (71) Applicant (for FR only): **SERVICES PETROLIERS SCHLUMBERGER** [FR/FR]; 42 rue Saint Dominique, 75007 Paris (FR).
- (71) Applicant (for all designated States except CA, FR, US): **SCHLUMBERGER TECHNOLOGY B.V.** [NL/NL]; Parkstraat 83, 2514 JG The Hague (NL).
- (72) Inventors: **LIU, Yongzan**; 1 Hampshire Street, Cambridge, Massachusetts 02139-1578 (US). **LIANG, Lin**; One Hampshire Street, Cambridge, Massachusetts 02139 (US). **ZER-OUG, Smaine**; One Hampshire Street, Cambridge, Massachusetts 02139 (US).
- (74) Agent: **BROWN, Ashley E.** et al.; Schlumberger, 10001 Richmond Avenue, Room 4720, Houston, Texas 77042 (US).
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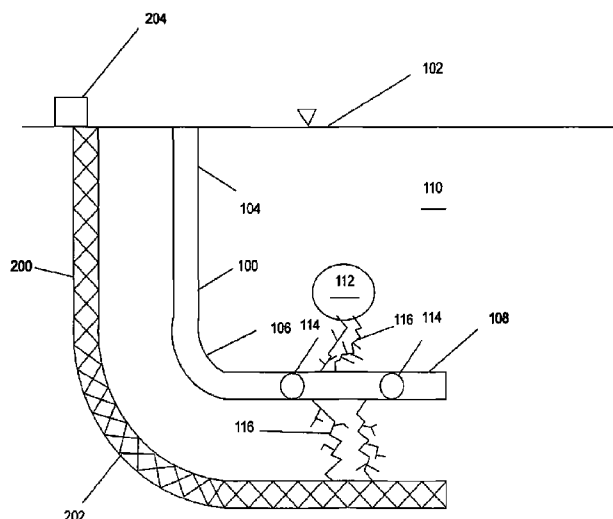


FIG. 1

(57) Abstract: Embodiments presented provide for evaluating fracture characterization resulting from hydraulic fracturing. In embodiments, fiber-optic elements are placed in a wellbore and subjected to forces from a hydraulic fracture operation occurring within a geological stratum. Readings from the fiber-optic elements are taken and evaluated to form a fracture characterization of the geological stratum.



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A STOCHASTIC INVERSION METHOD FOR EQUIVALENT HYDRAULIC FRACTURE CHARACTERIZATION USING DISTRIBUTED FIBER-OPTIC STRAIN MEASUREMENTS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims priority to U.S. Provisional Patent Application No. 63/484371, filed on February 10, 2023, which is incorporated by reference herein.

FIELD OF THE DISCLOSURE

[0002] Aspects of the disclosure relate to characterization of hydraulic fractures in wellbores. More specifically, aspects of the disclosure relate to a stochastic inversion approach for equivalent hydraulic fracture characterization using distributed fiber-optic strain measurements.

BACKGROUND

[0003] Research and development efforts have been expended on different sensing systems used primarily in oil and gas development. One particular technology that has received attention is that of interpreting low-frequency distributed acoustic sensing strain data. The evaluation of this low-frequency data is generally handled at a quantitative level. Conventional technologies perform the evaluation based on a well known least-square inversion. These technologies have been further expanded to the identification of defects or cracks in stratum. In these more expanded technologies, multiple fractures may be evaluated. To verify the accuracy of data, field surveys have been conducted.

[0004] One common theme in conventional evaluation techniques; however, is that a constant fracture height is assumed by researchers. Fracture height is not a constant value and an accurate estimation of fracture height without referring to other data is generally inaccurate. While errors from such assumptions can be accepted by some engineers in some circumstances, the errors in analysis grow too large when the assumed height is twice as great as the actual height. The overall error becomes very

pronounced when the discrepancy between the assumed value and true value is enlarged.

[0005] In conventional algorithms, the whole fracture needs to be discretized into many elements and the focus is the fracture width of the element at the fracture-hit location. At this location the distributed strain measurements impose the strongest constraint on the fracture geometry. In conventional analysis techniques, after obtaining the fracture width, the fracture height is estimated by matching the strain data under different heights with additional assumptions. This approach is computationally expensive, which hinders wide scale adoption. Although this essentially two-step inversion algorithm approach has shown some success, there is a need to provide an alternative method for fracture characterization that is not computationally expensive. There is a further need that this alternative method is more accurate than the conventional analysis.

[0006] There is a need to provide an apparatus and methods that are computationally more simple than conventional apparatus and methods.

[0007] There is a further need to provide apparatus and methods that do not have the drawbacks discussed above, wherein inaccurate estimates are required by/from engineers.

[0008] There is a still further need to reduce economic costs associated with operations and apparatus described above with conventional tools, wherein analysis techniques can be performed without specialized equipment by field personnel.

SUMMARY

[0009] So that the manner in which the above recited features of the present disclosure can be understood in detail, a more particular description of the disclosure, briefly summarized below, may be had by reference to embodiments, some of which are illustrated in the drawings. It is to be noted that the drawings illustrate only typical embodiments of this disclosure and are; therefore, not to be considered limiting of its scope, for the disclosure may admit to other equally effective embodiments without specific recitation. Accordingly, the following summary provides just a few aspects of the description and should not be used to limit the described embodiments to a single concept.

[0010] In one example embodiment, a method is disclosed. The method may comprise fracturing a geological stratum in a first well. The method may further comprise obtaining data at a second well through a fiber-optic system. The method may further comprise converting the obtained data at the second well to a strain rate. The method may further comprise integrating the strain rate to obtain measured distributed strain data. The method may further comprise creating a model and calculating simulated strain data. The method may further comprise, as step F, comparing the measured distributed strain data and the simulated strain data. The method may further comprise when the comparing of the measured distributed strain data and the simulated strain data achieves an acceptance level, making the model a recorded finalized model as step G and proceeding to step J. The method may further comprise optimizing the model and running the model to calculate new simulated strain data at step H when the comparing of the measured distributed strain data and the simulated strain data does not achieve the acceptance level. The method may further comprise performing steps F through I, until the finalized

model is recorded. The method may further comprise displaying the recorded finalized model at step J.

[0011] In another example embodiment, a method may be performed. The method may comprise at step A, hydraulically fracturing a geological stratum in a first well. The method may further comprise, at step B, obtaining acoustic data at a second well through a fiber-optic system placed within the second well, the acoustic data generated by propagating fractures in the geological stratum. The method may further comprise, at step C, converting the acoustic data to a set of strain rate data points. The method may further comprise, at step D, integrating the set of strain rate data points to obtain a set of measured distributed strain data points. The method may further comprise, at step E, creating a forward model and calculating simulated fracture induced distributed strain data. The method may further comprise, at step F, comparing the simulated fracture induced distributed strain data to the set of measured distributed strain data points. The method may further comprise, when the comparing of the simulated fracture induced distributed strain data to the set of measured distributed strain data points reaches an acceptance level, at step F, defining the model as a recorded finalized model at step G and proceed to step J. The method may further comprise, at step H, optimizing the model and calculating new simulated fracture induced distributed strain data when the comparing of the simulated fracture induced distributed strain data to the set of measured distributed strain data points does not achieve the acceptance level and thereafter returning to step F. The method may further comprise, at step I, performing steps F through I, until the model is recorded as the finalized model at step G and displaying the recorded finalized model at step J.

BRIEF DESCRIPTION OF THE DRAWINGS

[0012] So that the manner in which the above recited features of the present disclosure can be understood in detail, a more particular description of the disclosure, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the drawings. It is to be noted; however, that the appended drawings illustrate only typical embodiments of this disclosure and are; therefore, not be considered limiting of its scope, for the disclosure may admit to other equally effective embodiments.

[0013] FIG. 1 is a schematic of a system that uses an inversion algorithm for quantitative hydraulic fracture characterization.

[0014] FIG. 2 is a graph of low-frequency distributed acoustic sensing measurements during a single-fracture propagation process.

[0015] FIG. 3 is a graph of distributed fiber-optic strain data measured by distributed acoustic sensing.

[0016] FIG. 4 is a graph of distributed strain data excluding the extensional data around the fracture-hit location.

[0017] FIG. 5 is a graph of model parameters of 1000 chains, including (a) fracture height, (b) fracture width and (c) pairwise correlation between height and width.

[0018] FIG. 6 is a graph of evolution of fracture width and fracture height as a function of treatment time.

[0019] FIG. 7 is a method flow chart of a stochastic inversion approach for equivalent hydraulic fracture characterization using distributed fiber-optic strain measurements.

[0020] To facilitate understanding, identical reference numerals have been used, where possible, to designate identical elements that are common to the figures (“FIGS”). It is contemplated that elements disclosed in one embodiment may be beneficially utilized on other embodiments without specific recitation.

DETAILED DESCRIPTION

[0021] In the following, reference is made to embodiments of the disclosure. It should be understood; however, that the disclosure is not limited to specific described embodiments. Instead, any combination of the following features and elements, whether related to different embodiments or not, is contemplated to implement and practice the disclosure. Furthermore, although embodiments of the disclosure may achieve advantages over other possible solutions and/or over the prior art, whether or not a particular advantage is achieved by a given embodiment is not limiting of the disclosure. Thus, the following aspects, features, embodiments and advantages are merely illustrative and are not considered elements or limitations of the claims except where explicitly recited in a claim. Likewise, reference to “the disclosure” shall not be construed as a generalization of inventive subject matter disclosed herein and should not be considered to be an element or limitation of the claims except where explicitly recited in a claim.

[0022] Although the terms first, second, third, etc., may be used herein to describe various elements, components, regions, layers and/or sections, these elements, components, regions, layers and/or sections should not be limited by these terms. These

terms may be only used to distinguish one element, components, region, layer or section from another region, layer or section. Terms such as “first”, “second” and other numerical terms, when used herein, do not imply a sequence or order unless clearly indicated by the context. Thus, a first element, component, region, layer or section discussed herein could be termed a second element, component, region, layer or section without departing from the teachings of the example embodiments.

[0023] When an element or layer is referred to as being “on,” “engaged to,” “connected to,” or “coupled to” another element or layer, it may be directly on, engaged, connected, coupled to the other element or layer, or interleaving elements or layers may be present. In contrast, when an element is referred to as being “directly on,” “directly engaged to,” “directly connected to,” or “directly coupled to” another element or layer, there may be no interleaving elements or layers present. Other words used to describe the relationship between elements should be interpreted in a like fashion. As used herein, the term “and/or” includes any and all combinations of one or more of the associated listed terms.

[0024] Some embodiments will now be described with reference to the figures. Like elements in the various figures will be referenced with like numbers for consistency. In the following description, numerous details are set forth to provide an understanding of various embodiments and/or features. It will be understood; however, by those skilled in the art, that some embodiments may be practiced without many of these details, and that numerous variations or modifications from the described embodiments are possible. As used herein, the terms “above” and “below”, “up” and “down”, “upper” and “lower”, “upwardly” and “downwardly”, and other like terms indicating relative positions above or below a given point are used in this description to more clearly describe certain embodiments.

[0025] Embodiments of the disclosure provide for a simultaneous inversion of fracture width and height with uncertainty quantification. Applications of this simultaneous inversion of fracture width and height simplifies calculations. Confidence in calculations using the distributed fiber-optic strain data interpretation for analysis of hydraulic fractures is increased compared to conventional technologies.

[0026] In embodiments, an inversion algorithm for quantitative hydraulic fracture characterization is provided. This characterization uses distributed fiber-optic strain measurements that occur during multi-stage hydraulic fracturing. The hydraulic fracturing may take place, for example, in a horizontal wellbore.

[0027] In embodiments, accurate characterization of fractures created by hydraulic fracturing operations are achieved by the methods described. Embodiments provide for use of a distributed fiber-optic sensing system. In embodiments, this distributed fiber-optic sensing system is placed inside an observation wellbore. The distributed fiber-optic sensing system is used to measure fracture-induced rock deformation. In embodiments, Rayleigh frequency shift-based distributed strain sensing may be used to determine fracture-induced rock deformation. In some embodiments, distributed acoustic sensing may be used to determine fracture-induced rock deformation.

[0028] Referring to FIG. 1, a schematic of a system that uses an inversion algorithm for quantitative hydraulic fracture characterization is illustrated. A first wellbore **100** is provided that extends from surface level **102**. The wellbore **100** may have a first vertical portion **104**, a radius **106** and a horizontal portion **108**. The wellbore **100** may be configured to pass through geological stratum **110**. Different layers of stratum **110** are

possible. These layers may include sand, silt, clay and rock. Interspersed within the stratum **110**, hydrocarbons **112** may have collected. As the hydrocarbons **112** may be trapped within the stratum **110**, it may be desired to free the hydrocarbons **112** to allow them to flow to the first wellbore **100**. Once the hydrocarbons **112** collect within the wellbore **100**, they may be removed. In one embodiment, the hydrocarbons **112** may be pumped from the first wellbore **100**. The flow of hydrocarbons **112** may occur through a difference of pressure between the relatively higher-pressure stratum **110** and the relatively lower pressure first wellbore **100**. Thus, the hydrocarbons **112** flow to the first wellbore **100**.

[0029] Further referring to FIG. 1, a second wellbore **200** is located in the vicinity of the first wellbore **100**. Within the second wellbore **200** a distributed fiber-optic network **202** is positioned. Signals may pass through the fiber-optic network **202** such that the signals may be sent and received by operators. An up-hole control system **204** may send and receive the signals through the fiber-optic network **202**.

[0030] It may be desired to allow the hydrocarbons **112** to travel through the stratum **110**. To achieve this task, operators may use a hydraulic fracturing device **114** in the horizontal portion **108** of the first wellbore **100**. The hydraulic fracturing device **114** may be activated, thereby creating fractures **116** within the stratum **110**. These cracks **116** allow the hydrocarbons **112** to flow to the first wellbore **100**. The stress created in the stratum **110** may cause rock deformation thereby causing changes in the second wellbore **200**.

[0031] The fiber-optic network **200** experiences a dynamic strain change induced by the propagating cracks **116**. In general, the characteristic signatures of distributed fiber-

optic strain rate measurements may be recorded. The data may be presented on waterfall plots, which can be summarized in several ways. First, a heart-shaped extension zone is present as the fracture tip approaches the second wellbore **200**. After the fracture **116** hits the second wellbore **200**, the fiber section around the fracture-hit location keeps its extension while the sections on both sides of the fracture are compressed, corresponding to a stress-shadow behavior. After pumping stops with the hydraulic fracturing device **114**, fractures **116** will start to decrease and close due to fluid leak-off and pressure drop. The pressure drop causes a decrease in rock deformation. This leads to a decrease in the fracture-induced strain magnitude, indicated by a polarity flip in the strain rate signals. In this example embodiment, an extended fiber section around the fracture **116** shows a compressing trend while the compressed sections on the sides of the fracture **116** generate an extending pattern. Such detailed in-situ measurements can contain critical information regarding hydraulic fracture geometry.

[0032] In one example embodiment, a stochastic inversion algorithm is used to interpret the distributed fiber-optic strain measurements in terms of equivalent hydraulic fracture geometry characterization with uncertainty quantification. In one example embodiment, a Markov-chain Monte Carlo (MCMC) based inversion algorithm is used to simultaneously quantify both the width and height of an equivalent fracture in the vicinity of the second wellbore **200**. As described above, hydraulic fracturing procedures may be optimized based upon the results obtained.

[0033] As will be understood, an overall well configuration may be obtained from the original drilling report. Thus, the configurations of both the first wellbore **100** and second wellbore **200** are known. Based on the location of the hydraulic fracture **116** or treatment location, it is generally known approximately where in the second wellbore **200** the

strongest signals will be located. In the data obtained and presented with FIG. 2, the measured depth of the event window ranges from 4000 meters to 5400 meters. According to data from FIG. 2, the fracture hit location is about 4750 meters. As presented in the lower portion of FIG. 2, a graph of bottomhole pressure vs. monitoring time is provided. During early parts of the data, pressure maximizes at around 8:23 then decreases until reaching a semi-stable level until 10:04. FIG. 2 also graphs slurry rates on the right axis over monitoring time. In this separate plot, a high value is reached around 8:24 followed with two dips at 9:04 and 9:38.

[0034] Referring to FIG. 3, distributed strain data is presented. This distributed fiber-optic strain data is measured by distributed acoustic sensing. If extensional data is removed from the distributed strain data near the fracture-hit location, then only compressional data in the stress shadow region for inversion remains in FIG. 3.

[0035] The MCMC-based stochastic inversion algorithm involves calculating the sum-of-squares (SOS) error between the modeled data and the measured data. As such, a forward model is developed that calculates simulated values. These simulated values are compared with measured data. In this specific problem, the measured data, denoted as d , is the distributed fiber-optic strain data. The forward model, denoted as f , is developed based on a 3D Displacement Discontinuity Method (DDM). In a Cartesian coordinate system for a rectangular fracture element with length $2L$, width w and centered at $x_f=(x_f, y_f, z_f)$, the fracture-induced directional strain along the wellbore, ϵ_i , at a sensing point I , whose coordinate is $x_s=(x_s, y_s, z_s)$, can be expressed as:

$$\epsilon_i = f(L, H, w, x_f, x_s). \quad \text{Equation 1}$$

The sum-of-squares error function can be written as:

$$\epsilon = \sum_{i=1}^N |\epsilon_i - d_i|^2 \quad \text{Equation 2}$$

where N is the number of total sensing points along the fiber.

[0036] In one embodiment of the disclosure, an efficient adaptive MCMC method may be used. Such a method may be a Delayed Rejection Adaptive Metropolis (DRAM) algorithm to perform optimization. The parameters of interest are fracture width (w) and fracture height (2H). The algorithm requires a pre-defined equivalent fracture half-length (L), initial guess (w_0 , H_0) and associated search range as well as the simulation number (number of chains). The results contain all the models at each step, which can be visualized to analyze the convergence properties. For example, FIG. 5, shows the chains of an MCMC simulation with 1000 runs. We observe that the model parameters stabilize after about 100 iterations. It is therefore reasonable to calculate the statistics of the model parameters using the remaining 900 runs. FIG. 6, shows changes of fracture width and height as a function of monitoring time after fracture hit.

[0037] Referring to FIG. 7, a method for stochastic inversion method for equivalent hydraulic fracture characterization using distributed fiber-optic strain measurements is presented. The method **700** may entail, at **702**, fracturing a geological stratum in a first well. The method may further entail, at **704**, obtaining data at a second well. The obtaining of the data may be through a fiber-optic system. As discussed above, the data may be, for example, a strain on the fiber-optic system developed by cracks or fractures from a hydraulic fracturing operation in the first well in one non-limiting embodiment. These values may be obtained at various points within the second well or may be pre-

identified as areas closest in geometry to the first well where crack initiation occurred. The method may further entail, at **706**, converting the obtained data at the second well to a strain rate. The method may further entail, at **708**, integrating the strain rate to obtain measured distributed strain data. The method may further entail, at **710**, creating a model to calculate simulated strain data. As explained, the model may be a computer based model that uses various numerical operations. The model may be placed on a server, a computer or other computing arrangement. The model may be stored in a non-volatile medium. Output of the model may be through a computer monitor, printing or saving to a non-volatile memory. The method may further entail, at **712**, comparing the measured distributed strain data and the simulated strain data. The comparing may be through an MCMC-based stochastic inversion algorithm which may involve calculating sum-of-squares (SOS) error between the modeled data and measured data. Other inversion techniques may be used. In embodiments, equation 1 may be used. The method may further entail, at **712**, when the comparing of the measured distributed strain data and the simulated strain data achieves an acceptance level, making the model a recorded finalized model at **714** followed by of displaying the finalized model **722**. As will be understood, the acceptance level may be any criterion set by researchers upon which acceptance of the model is achieved. Such acceptances can be, but not limited to, differences in values between simulated and calculated strains. Acceptance criteria may be based on graphical models, plots, superposition of plots and/or numerical algorithms. The method may further entail, proceeding to **716**, optimizing the model and running the model to calculate new simulated strain data when the comparing of the measured distributed strain data and the simulated strain data does not achieve the acceptance level at **712**. The model may then return to **712** for an additional comparison and further evaluation. Iterative runs of the method may be performed. During the comparisons, the aforementioned inversion methods may be performed.

[0038] Example embodiments will next be disclosed. The example embodiments should not be considered limiting. In one example embodiment, a method is disclosed. The method may comprise fracturing a geological stratum in a first well. The method may further comprise obtaining data at a second well through a fiber-optic system. The method may further comprise converting the obtained data at the second well to a strain rate. The method may further comprise integrating the strain rate to obtain measured distributed strain data. The method may further comprise creating a model and calculate simulated strain data. The method may further comprise, as step F, comparing the measured distributed strain data and the simulated strain data. The method may further comprise when the comparing of the measured distributed strain data and the simulated strain data achieves an acceptance level, making the model a recorded finalized model as step G and proceeding to step J. The method may further comprise optimizing the model and running the model to calculate new simulated strain data at step H when the comparing of the measured distributed strain data and the simulated strain data does not achieve the acceptance level. The method may further comprise performing steps F through I, until the finalized model is recorded. The method may further comprise displaying the recorded finalized model at step J.

[0039] In another example embodiment, the method may be performed wherein the comparing the measured distributed strain data and the simulated strain data is through a Markov-chain Monte Carlo based stochastic inversion algorithm.

[0040] In another example embodiment, the method may be performed wherein the Markov-chain Monte Carlo-based stochastic inversion algorithm includes sum-of-squares calculations.

[0041] In another example embodiment, the method may be performed wherein the fiber-optic system is equipped with distributed acoustic sensing.

[0042] In another example embodiment, the method may be performed wherein the fiber-optic system is equipped with a Rayleigh frequency shift-based distributed strain sensing arrangement.

[0043] In another example embodiment, the method may be performed, wherein the model is based upon a 3D Displacement Discontinuity Method.

[0044] In another example embodiment, the method may be performed wherein the model is a forward model.

[0045] In another example embodiment, the method may be performed wherein the data is acoustic data.

[0046] In another example embodiment, a method may be performed. The method may comprise at step A, hydraulically fracturing a geological stratum in a first well. The method may further comprise, at step B, obtaining acoustic data at a second well through a fiber-optic system placed within the second well, the acoustic data generated by propagating fractures in the geological stratum. The method may further comprise, at step C, converting the acoustic data to a set of strain rate data points. The method may further comprise, at step D, integrating the set of strain rate data points to obtain a set of measured distributed strain data points. The method may further comprise, at step E, creating a forward model and calculating simulated fracture induced distributed strain data. The method may further comprise, at step F, comparing the simulated fracture induced distributed strain data to the set of measured distributed strain data points.

The method may further comprise, when the comparing of the simulated fracture induced distributed strain data to the set of measured distributed strain data points reaches an acceptance level, at step F, defining the model as a recorded finalized model at step G and proceed to step J. The method may further comprise, at step H, optimizing the model and calculating new simulated fracture induced distributed strain data when the comparing of the simulated fracture induced distributed strain data to the set of measured distributed strain data points does not achieve the acceptance level and thereafter returning to step F. The method may further comprise, at step I, performing steps F through I, until the model is recorded as the finalized model at step G and displaying the recorded finalized model at step J.

[0047] In another example embodiment, wherein the comparing is through a Markov-chain Monte Carlo based stochastic inversion algorithm.

[0048] In another example embodiment, wherein the Markov-chain Monte Carlo-based stochastic inversion algorithm includes sum-of-squares calculations.

[0049] In another example embodiment, wherein the Markov-chain Monte Carlo-based stochastic inversion algorithm is a Delayed Adaptive Metropolis algorithm.

[0050] In another example embodiment, wherein the fiber-optic system is equipped with distributed acoustic sensing arrangements.

[0051] In another example embodiment, wherein the fiber-optic system is equipped with a Rayleigh frequency shift-based distributed strain sensing arrangement.

[0052] In another example embodiment, wherein the fiber-optic system is equipped with a Rayleigh frequency shift-based distributed strain sensing arrangement.

[0053] In another example embodiment, wherein the model is based upon a 3D Displacement Discontinuity Method.

[0054] The foregoing description of the embodiments has been provided for purposes of illustration and description. It is not intended to be exhaustive or to limit the disclosure. Individual elements or features of a particular embodiment are generally not limited to that particular embodiment, but, where applicable, are interchangeable and can be used in a selected embodiment, even if not specifically shown or described. The same may be varied in many ways. Such variations are not to be regarded as a departure from the disclosure, and all such modifications are intended to be included within the scope of the disclosure.

[0055] While embodiments have been described herein, those skilled in the art, having benefit of this disclosure, will appreciate that other embodiments are envisioned that do not depart from the inventive scope. Accordingly, the scope of the present claims or any subsequent claims shall not be unduly limited by the description of the embodiments described herein.

CLAIMS

What is claimed is:

1. A method, comprising:

- A) fracturing a geological stratum in a first well;
- B) obtaining data at a second well through a fiber-optic system;
- C) converting the obtained data at the second well to a strain rate;
- D) integrating the strain rate to obtain measured distributed strain data;
- E) creating a model and calculate simulated strain data;
- F) comparing the measured distributed strain data and the simulated strain data;
- G) when the comparing of the measured distributed strain data and the simulated strain data achieves an acceptance level, making the model a recorded finalized model and proceeding to step J;
- H) optimizing the model and running the model to calculate new simulated strain data when the comparing of the measured distributed strain data and the simulated strain data does not achieve the acceptance level;
- I) performing steps F through I, until the finalized model is recorded; and
- J) displaying the recorded finalized model.

2. The method according to claim 1, wherein the comparing the measured distributed strain data and the simulated strain data is through a Markov-chain Monte Carlo based stochastic inversion algorithm.
3. The method according to claim 2, wherein the Markov-chain Monte Carlo-based stochastic inversion algorithm includes sum-of-squares calculations.
4. The method according to claim 2, wherein the Markov-chain Monte Carlo-based stochastic inversion algorithm uses a Delayed Adaptive Metropolis algorithm.
5. The method according to claim 1, wherein the fiber-optic system is equipped with distributed acoustic sensing.
6. The method according to claim 1, wherein the fiber-optic system is equipped with a Rayleigh frequency shift-based distributed strain sensing arrangement.
7. The method according to claim 1, wherein the model is based upon a 3D Displacement Discontinuity Method.
8. The method according to claim 1, wherein the model is a forward model.
9. The method according to claim 1, wherein the data is acoustic data.
10. A method for performing a hydraulic fracture characterization, comprising:
 - A) hydraulically fracturing a geological stratum in a first well;
 - B) obtaining acoustic data at a second well through a fiber-optic system placed within the second well, the acoustic data generated by propagating fractures in the geological stratum;

- C) converting the acoustic data to a set of strain rate data points;
- D) integrating the strain rate data points to obtain a set of measured distributed strain data points;
- E) creating a forward model and calculating simulated fracture induced distributed strain data;
- F) comparing the simulated fracture induced distributed strain data to the set of measured distributed strain data points;
- G) when the comparing of the simulated fracture induced distributed strain data to the set of measured distributed strain data points reaches an acceptance level, defining the model as a recorded finalized model and proceeding to step J;
- H) optimizing the model and calculating new simulated fracture induced distributed strain data when the comparing of the simulated fracture induced distributed strain data to the set of measured distributed strain data points does not achieve the acceptance level;
- I) performing steps F through I, until the model is recorded as the finalized model; and
- J) displaying the recorded finalized model.

11. The method according to claim 10, wherein the comparing is through a Markov-chain Monte Carlo based stochastic inversion algorithm.

12. The method according to claim 11, wherein the Markov-chain Monte Carlo-based stochastic inversion algorithm includes sum-of-squares calculations.

13. The method according to claim 12, wherein the Markov-chain Monte Carlo-based stochastic inversion algorithm is a Delayed Adaptive Metropolis algorithm.
14. The method according to claim 10, wherein the fiber-optic system is equipped with distributed acoustic sensing arrangements.
15. The method according to claim 10, wherein the fiber-optic system is equipped with a Rayleigh frequency shift-based distributed strain sensing arrangement.
16. The method according to claim 10, wherein the model is based upon a 3D Displacement Discontinuity Method.

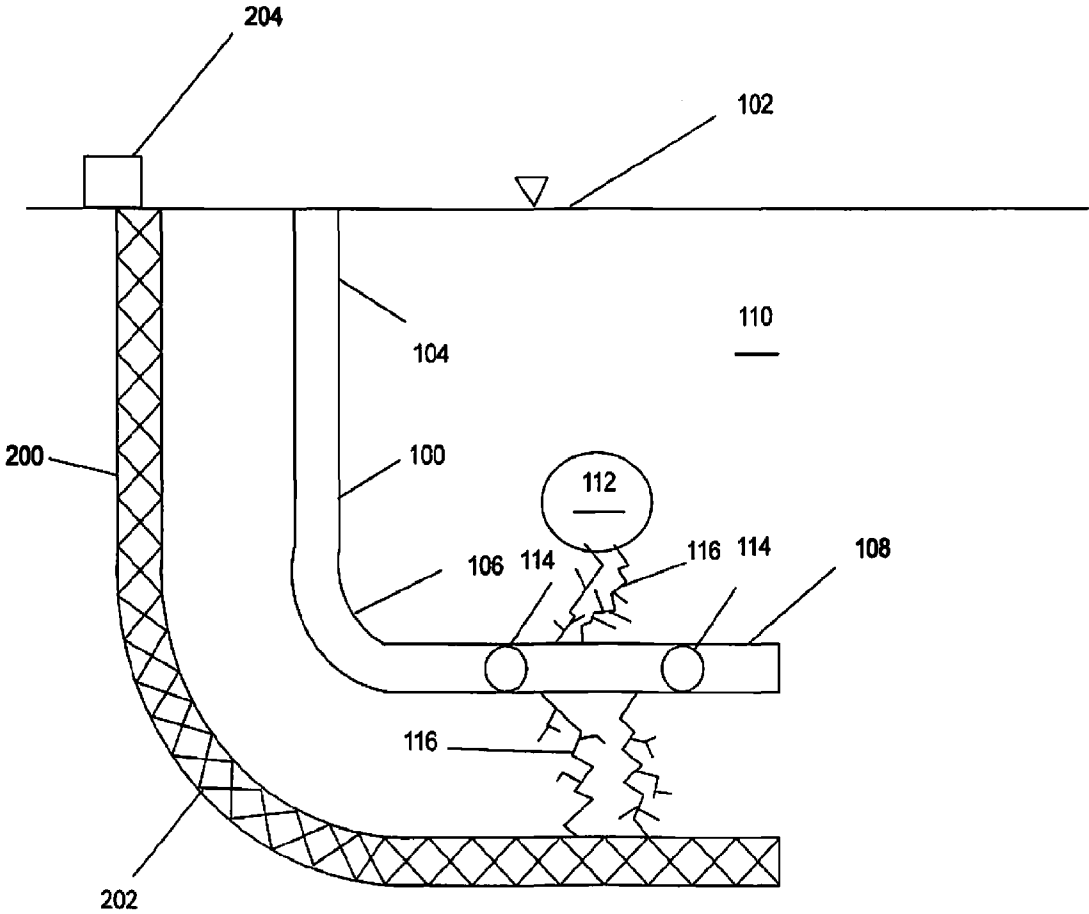


FIG. 1

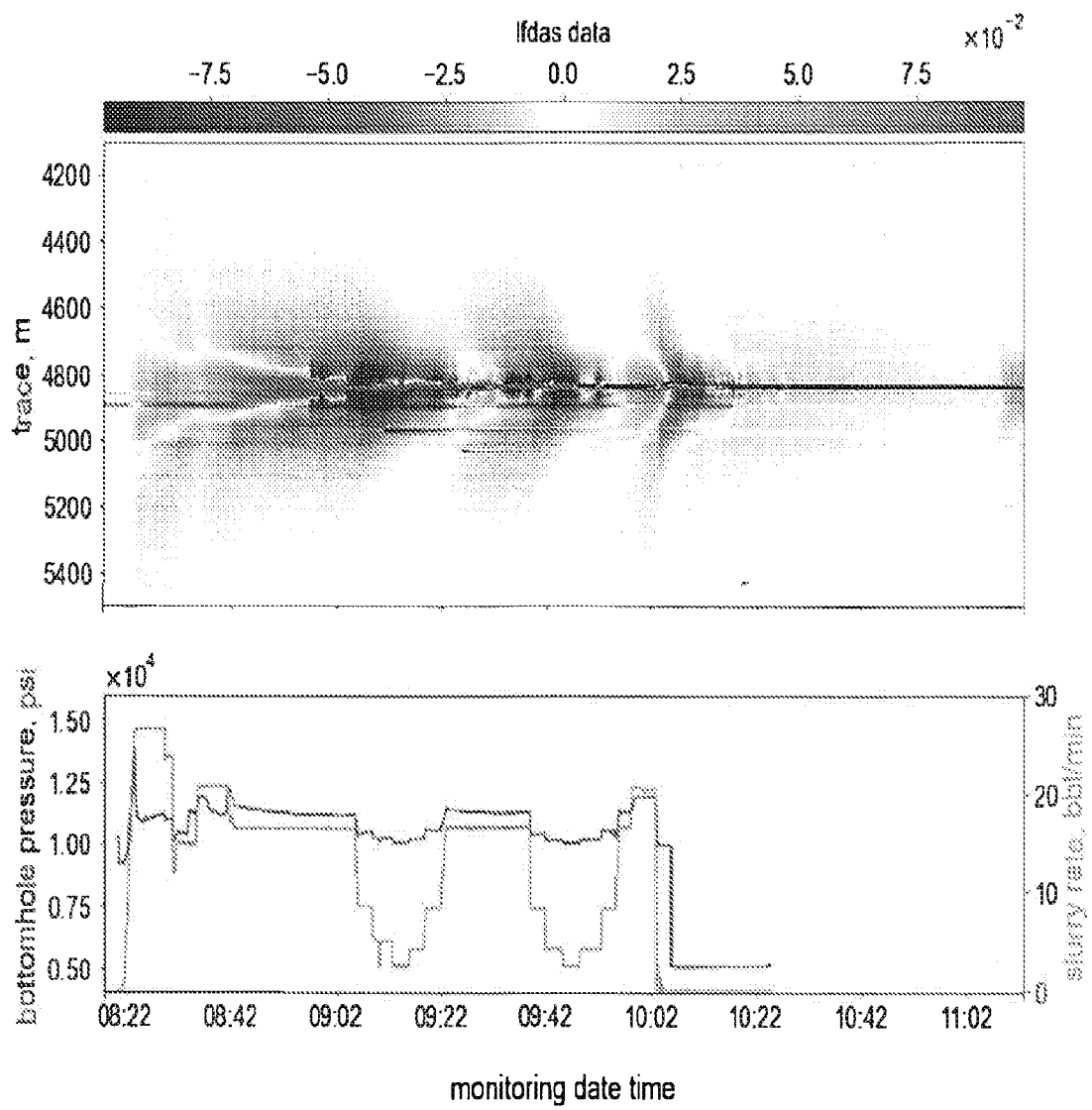


FIG. 2

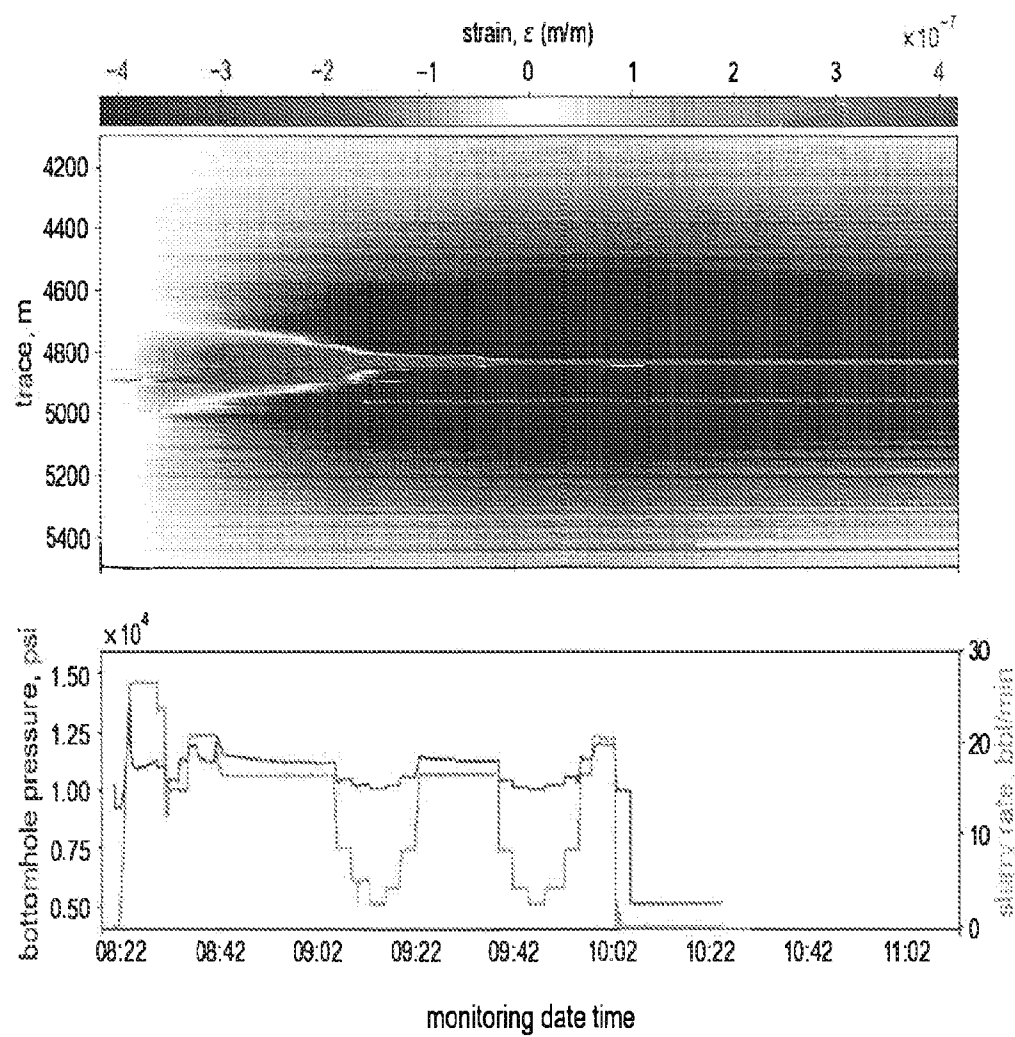


FIG. 3

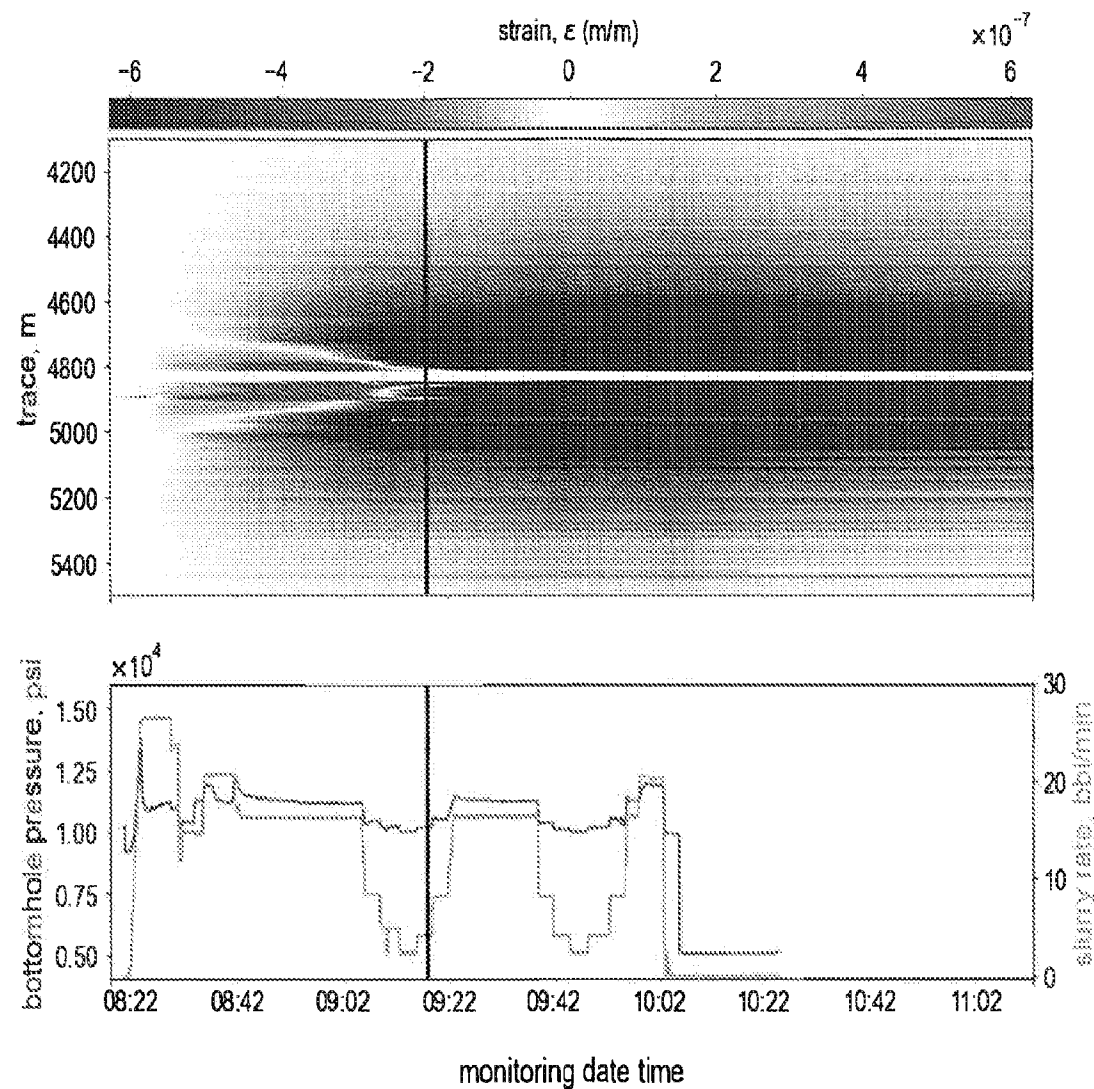


FIG. 4

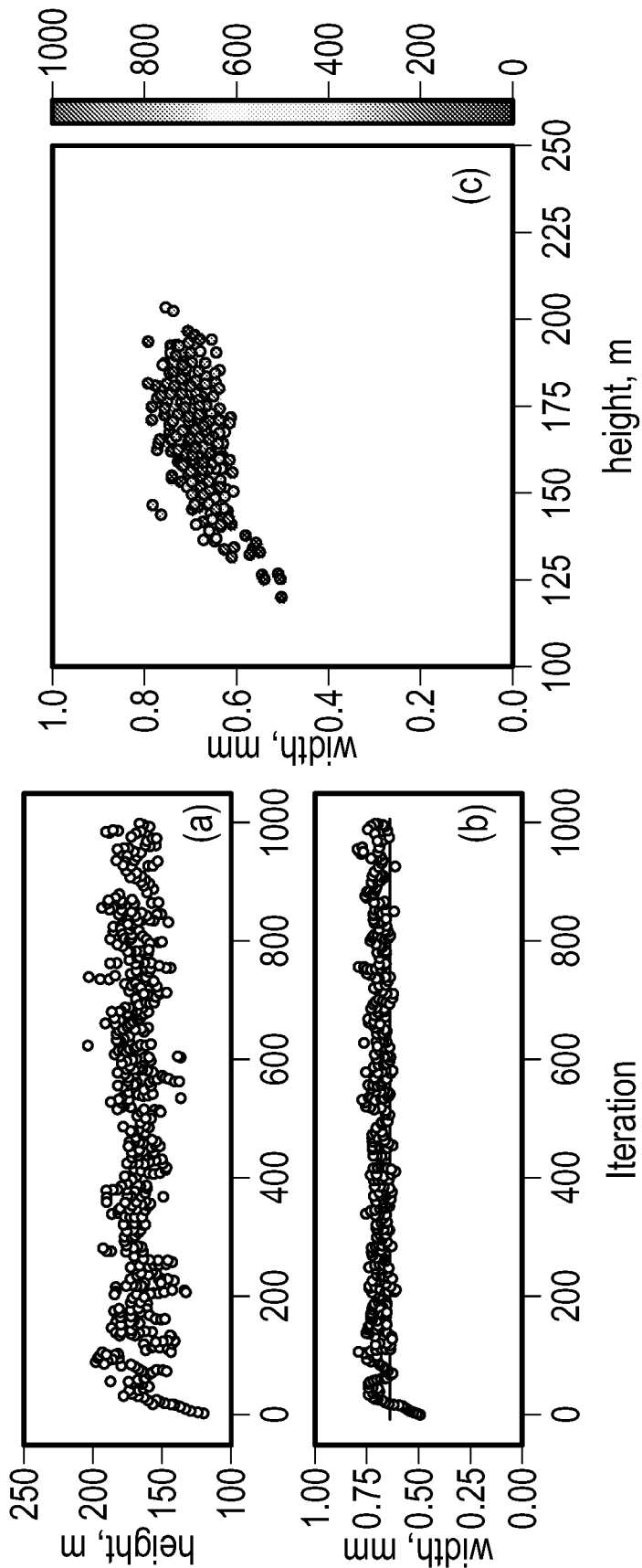


FIG. 5

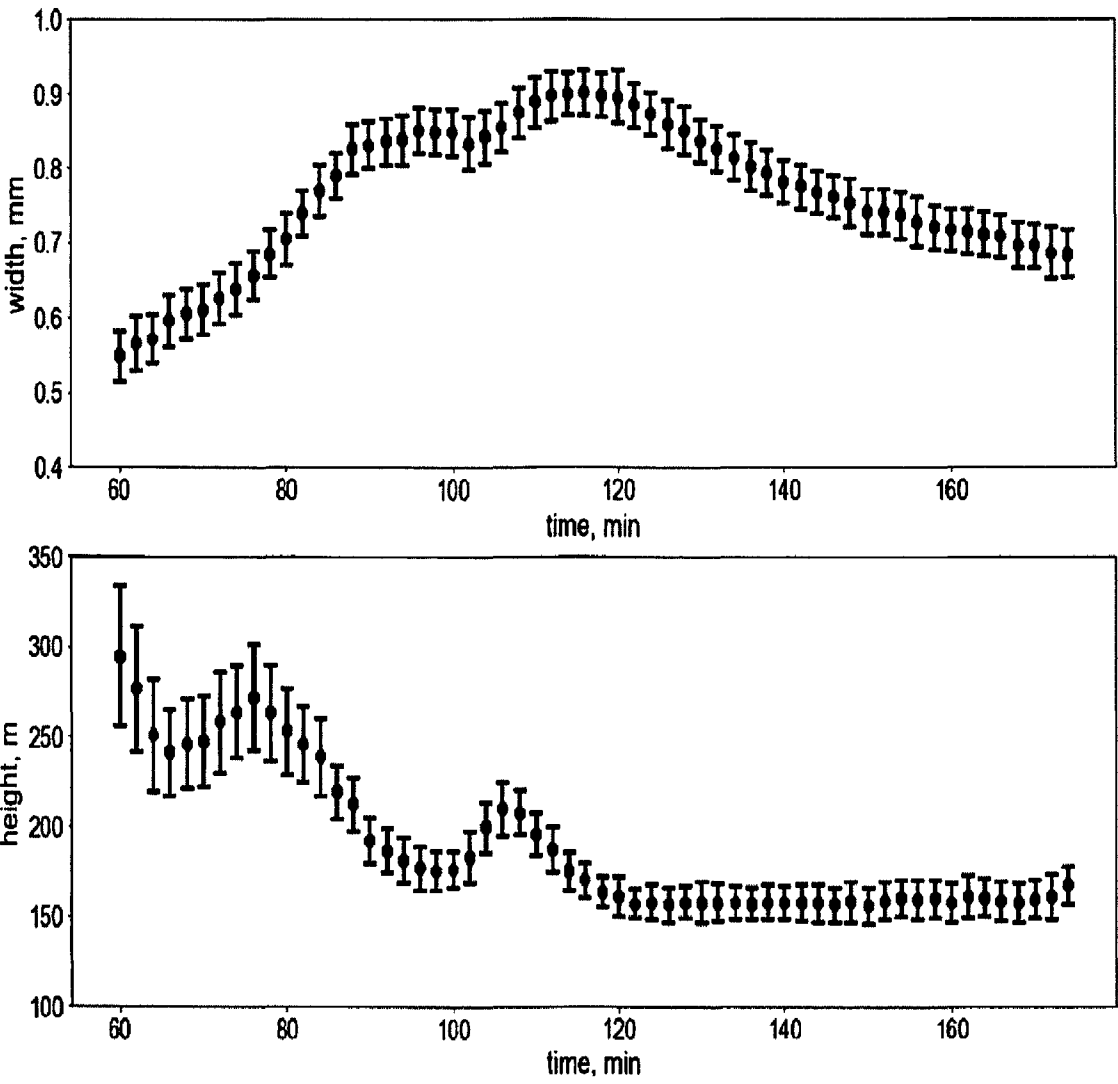


FIG. 6

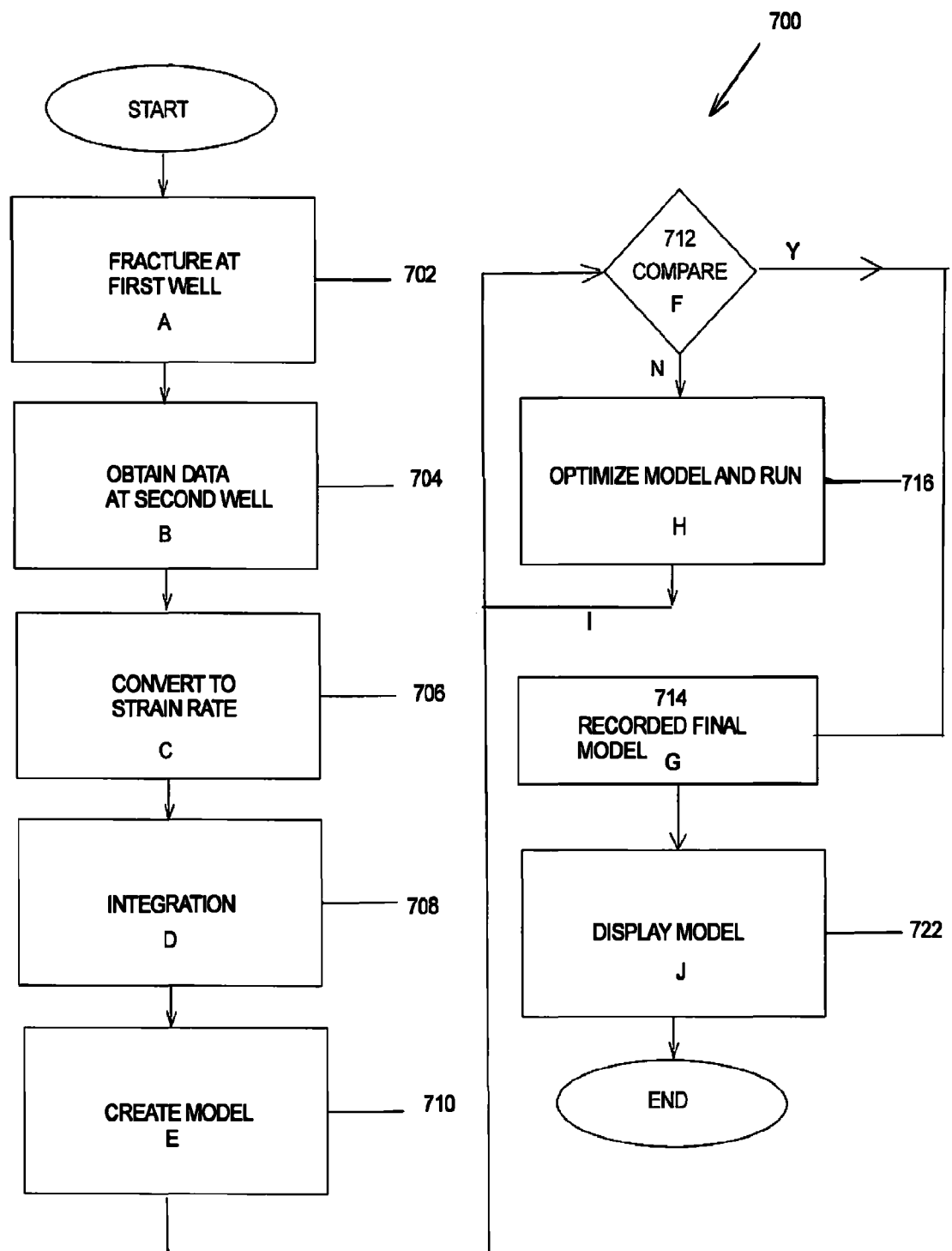


FIG. 7

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US2024/014985

A. CLASSIFICATION OF SUBJECT MATTER G01V 1/40(2006.01)i; E21B 43/267(2006.01)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) G01V 1/40(2006.01); E21B 21/08(2006.01); E21B 43/16(2006.01); E21B 44/00(2006.01); E21B 47/00(2006.01); E21B 49/00(2006.01); G01F 1/66(2006.01) 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: fracture, model, strain, fiber, and inversion		
C. DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	LIU, YONGZAN et al. Hydraulic-Fracture-Width Inversion Using Low-Frequency Distributed-Acoustic-Sensing Strain Data-Part I: Algorithm and Sensitivity Analysis, SPE journal, February 2021, pages 359-371. pages 359-369 and figures 1-16	1-16
Y	ZHANG, ZHISHUAI et al. Modeling of fiber-optic strain responses to hydraulic fracturing, GEOPHYSICS, 22 October 2020 (online publication date), Vol. 85, No. 6, pages A45-A50. pages A45-A47 and figures 1-3	1-16
Y	US 2021-0238972 A1 (CONOCOPHILLIPS COMPANY) 05 August 2021 (2021-08-05) paragraphs [0002], [0107]-[0119], [0126]-[0130] and figures 1-2	4,13
A	CN 112576245 A (CHINA UNIVERSITY OF PETROLEUM (EAST CHINA)) 30 March 2021 (2021-03-30) paragraphs [0087]-[0170] and figures 1-6	1-16
☒ 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 “D” document cited by the applicant in the international application “E” earlier application or patent but published on or after the international filing date “L” document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified) “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 30 May 2024		Date of mailing of the international search report 31 May 2024
Name and mailing address of the ISA/KR Korean Intellectual Property Office 189 Cheongsa-ro, Seo-gu, Daejeon 35208, Republic of Korea Facsimile No. +82-42-481-8578		Authorized officer PARK, Tae Wook Telephone No. +82-42-481-3405

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US2024/014985

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 2019-0145239 A1 (SCHLUMBERGER TECHNOLOGY CORPORATION) 16 May 2019 (2019-05-16) paragraphs [0027]-[0241] and figures 1-17	1-16

INTERNATIONAL SEARCH REPORT
Information on patent family members

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				CA	3097930	A1	07 November 2019
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				WO	2019-099693	A1	23 May 2019