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

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
11 May 2018 (11.05.2018)

WIPO | PCT

(10) International Publication Number
WO 2018/084871 A1

(51) International Patent Classification:
E21B 43/25 (2006.01) *E21B 43/17* (2006.01)
E21B 43/26 (2006.01)

(21) International Application Number:
PCT/US2016/060862

(22) International Filing Date:
07 November 2016 (07.11.2016)

(25) Filing Language: English

(26) Publication Language: English

(71) Applicant: **HALLIBURTON ENERGY SERVICES, INC.** [US/US]; 3000 N Sam Houston Pkwy E, Houston, Texas 77032-3219 (US).

(72) Inventors: **MADASU, Srinath**; 3000 N Sam Houston Pkwy E, Houston, Texas 77032-3219 (US). **INYANG, Ubong**; Halliburton Energy Services, Inc., 3000 N Sam Houston Pkwy E, Houston, Texas 77032-3219 (US). **KARALE, Chaitanya**; First Floor, Dhanalaxmi Bunglow, Galli No 3,bhag2,Sukhsagarnagar 2,Katraj, Pune 411046 (IN).

(74) Agent: **TURNEY, Corey S.** et al.; Turney L.L.P., PO Box 22188, Houston TX 77227-2188 (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, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD,

(54) Title: REAL-TIME MODEL FOR DIVERTER DROP DECISION USING DAS AND STEP DOWN ANALYSIS

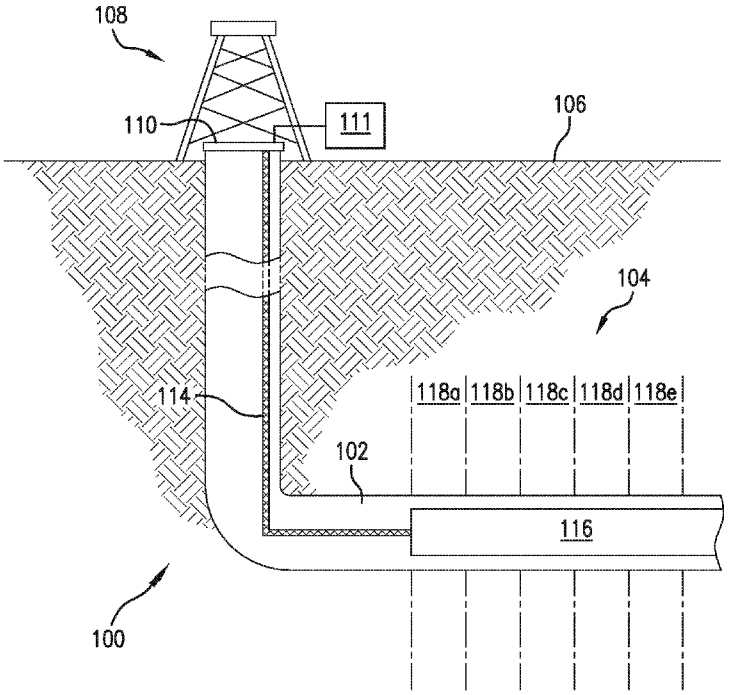


FIG. 1

(57) Abstract: A system includes at least one processor, and a memory coupled to the at least one processor having instructions stored therein. When executed by the at least one processor, the instructions cause the at least one processor to perform functions including functions to: apply a treatment at a first well in the subterranean formation, wherein the treatment is for stimulating production; perform a step down analysis of the first well at each of a plurality of stages of the first well; determine a downhole flow distribution at each of the plurality of stages; develop a model for correlating the downhole flow distribution and the step down analysis at each of the plurality of stages; use the developed model to estimate a downhole flow distribution at a stage of a second well; and determine whether to bypass a deployment of the diverter material at the stage of the second well based on the estimated downhole flow distribution.

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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, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, 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, KM, ML, MR, NE, SN, TD, TG).

Declarations under Rule 4.17:

— *as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))*

Published:

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

REAL-TIME MODEL FOR DIVERTER DROP DECISION USING DAS AND STEP DOWN ANALYSIS

BACKGROUND

In the oil and gas industry, a well that is not producing as expected may need stimulation to increase the production of subsurface hydrocarbon deposits, such as oil and natural gas. Hydraulic fracturing is a type of stimulation treatment that has long been used for well stimulation in unconventional reservoirs. A multistage stimulation treatment operation may involve drilling a horizontal wellbore and injecting treatment fluid into a surrounding formation in multiple stages via a series of perforations or formation entry points along a path of a wellbore through the formation. During each of the stimulation treatment, different types of fracturing fluids, proppant materials (e.g., sand), additives and/or other materials may be pumped into the formation via the entry points or perforations at high pressures to initiate and propagate fractures within the formation to a desired extent. With advancements in horizontal well drilling and multi-stage hydraulic fracturing of unconventional reservoirs, there is a greater need for ways to accurately monitor the downhole flow and distribution of injected fluids across different perforation clusters and efficiently deliver treatment fluid into the subsurface formation.

Diversion is a technique used in injection treatments to facilitate uniform distribution of treatment fluid over each stage of the treatment. Diversion may involve the delivery of diverter material into the wellbore to divert injected treatment fluids toward formation entry points along the wellbore path that are receiving inadequate treatment. Examples of such diverter material include, but are not limited to, viscous foams, particulates, gels, benzoic acid and other chemical diverters. Traditionally, operational decisions related to the use of diversion technology for a given treatment stage, including when and how much diverter is used, are made *a priori* according to a predefined treatment schedule. However, conventional diversion techniques based on such predefined treatment schedules fail to account for actual operating conditions that affect the downhole flow distribution of the treatment fluid over the course of the stimulation treatment.

BRIEF DESCRIPTION OF THE DRAWINGS

Accordingly, there are disclosed in the drawings and the following description a systems and related methods for deploying diverter material in a subterranean formation. In the drawings:

FIG. 1 is a diagram illustrating an example of a well system for performing a multistage stimulation treatment of a hydrocarbon reservoir formation;

FIG. 2 is a flowchart of an illustrative process for real-time monitoring and control of downhole fluid flow and distribution using diversion during stimulation treatments;

FIG. 3 illustrates an example of a flow distribution at one particular stage;

FIG. 4 shows a flowchart of an illustrative method for deploying diverter material in a subterranean formation; and

FIG. 5 is a block diagram of an exemplary computer system in which embodiments of the present disclosure may be implemented.

It should be understood, however, that the specific embodiments given in the drawings and detailed description do not limit the disclosure. On the contrary, they provide the foundation for one of ordinary skill to discern the alternative forms, equivalents, and modifications that are encompassed together with one or more of the given embodiments in the scope of the appended claims.

DETAILED DESCRIPTION

Disclosed herein are systems and related methods for controlling deployment of a diverter material. Particular embodiments relate to deploying diverter material in a subterranean formation during stimulation treatment. In at least some embodiments, a method includes applying a treatment at a first well in the subterranean formation, wherein the treatment is for stimulating production. The method further includes performing a step down analysis of the first well at each of a plurality of stages of the first well, and determining a downhole flow distribution at each of the plurality of stages. The method further includes developing a model for correlating the downhole flow distribution and the step down analysis at each of the plurality of stages, and using the developed model to estimate a downhole flow distribution at a stage of a second well. The method further includes determining whether to bypass a deployment of the diverter material at the stage of the second well based on the estimated downhole flow distribution.

A related system includes at least one processor, and a memory coupled to the at least one processor having instructions stored therein. When executed by the at least one processor, the instructions cause the at least one processor to perform functions including functions to: apply a treatment at a first well in the subterranean formation, wherein the treatment is for stimulating production; perform a step down analysis of the first well at each of a plurality of stages of the first well; determine a downhole flow distribution at each of the plurality of stages; develop a model for correlating the downhole flow distribution and the step down analysis at

each of the plurality of stages; use the developed model to estimate a downhole flow distribution at a stage of a second well; and determine whether to bypass a deployment of the diverter material at the stage of the second well based on the estimated downhole flow distribution.

FIG. 1 is a diagram illustrating an example of a well system 100 for performing a multistage stimulation treatment of a hydrocarbon reservoir formation. As shown in the example of FIG. 1, well system 100 includes a wellbore 102 in a subsurface formation 104 beneath a surface 106 of the wellsite. Wellbore 102 as shown in the example of FIG. 1 includes a horizontal wellbore. However, it should be appreciated that embodiments are not limited thereto and that well system 100 may include any combination of horizontal, vertical, slant, curved, and/or other wellbore orientations. The subsurface formation 104 may include a reservoir that contains hydrocarbon resources, such as oil, natural gas, and/or others. For example, the subsurface formation 104 may be a rock formation (e.g., shale, coal, sandstone, granite, and/or others) that includes hydrocarbon deposits, such as oil and natural gas. In some cases, the subsurface formation 104 may be a tight gas formation that includes low permeability rock (e.g., shale, coal, and/or others). The subsurface formation 104 may be composed of naturally fractured rock and/or natural rock formations that are not fractured to any significant degree.

Well system 100 also includes a fluid injection system 108 for injecting treatment fluid, e.g., hydraulic fracturing fluid, into the subsurface formation 104 over multiple sections 118a, 118b, 118c, 118d, and 118e (collectively referred to herein as "sections 118") of the wellbore 102, as will be described in further detail below. Each of the sections 118 may correspond to, for example, a different stage or interval of the multistage stimulation treatment. The boundaries of the respective sections 118 and corresponding treatment stages/intervals along the length of the wellbore 102 may be delineated by, for example, the locations of bridge plugs, packers and/or other types of equipment in the wellbore 102. Additionally or alternatively, the sections 118 and corresponding treatment stages may be delineated by particular features of the subsurface formation 104. Although five sections are shown in FIG. 1, it should be appreciated that any number of sections and/or treatment stages may be used as desired for a particular implementation. Furthermore, each of the sections 118 may have different widths or may be uniformly distributed along the wellbore 102.

As shown in FIG. 1, injection system 108 includes an injection control subsystem 111, a signaling subsystem 114 installed in the wellbore 102, and one or more injection tools 116 installed in the wellbore 102. The injection control subsystem 111 can communicate with the injection tools 116 from a surface 110 of the wellbore 102 via the signaling subsystem 114.

Although not shown in FIG. 1, injection system 108 may include additional and/or different features for implementing the flow distribution monitoring and diversion control techniques disclosed herein. For example, the injection system 108 may include any number of computing subsystems, communication subsystems, pumping subsystems, monitoring subsystems, and/or other features as desired for a particular implementation. In some implementations, the injection control subsystem 111 may be communicatively coupled to a remote computing system (not shown) for exchanging information via a network for purposes of monitoring and controlling wellsite operations, including operations related to the stimulation treatment. Such a network may be, for example and without limitation, a local area network, medium area network, and/or a wide area network, e.g., the Internet.

During each stage of the stimulation treatment, the injection system 108 may alter stresses and create a multitude of fractures in the subsurface formation 104 by injecting the treatment fluid into the surrounding subsurface formation 104 via a plurality of formation entry points along a portion of the wellbore 102 (e.g., along one or more of sections 118). The fluid may be injected through any combination of one or more valves of the injection tools 116. The injection tools 116 may include numerous components including, but not limited to, valves, sliding sleeves, actuators, ports, and/or other features that communicate treatment fluid from a working string disposed within the wellbore 102 into the subsurface formation 104 via the formation entry points. The formation entry points may include, for example, open-hole sections along an uncased portion of the wellbore path, a cluster of perforations along a cased portion of the wellbore path, ports of a sliding sleeve completion device along the wellbore path, slots of a perforated liner along the wellbore path, or any combination of the foregoing.

The injection tools 116 may also be used to perform diversion in order to adjust the downhole flow distribution of the treatment fluid across the plurality of formation entry points. Thus, the flow of fluid and delivery of diverter material into the subsurface formation 104 during the stimulation treatment may be controlled by the configuration of the injection tools 116. The diverter material injected into the subsurface formation 104 may be, for example, a degradable polymer. Examples of different degradable polymer materials that may be used include, but are not limited to, polysaccharides; lignosulfonates; chitins; chitosans; proteins; proteinous materials; fatty alcohols; fatty esters; fatty acid salts; aliphatic polyesters; poly(lactides); poly(glycolides); poly(ε-caprolactones); polyoxymethylene; polyurethanes; poly(hydroxybutyrates); poly(anhydrides); aliphatic polycarbonates; polyvinyl polymers; acrylic-based polymers; poly(amino acids); poly(aspartic acid); poly(alkylene oxides); poly(ethylene oxides); polyphosphazenes; poly(orthoesters); poly(hydroxy ester ethers); polyether esters; polyester amides; polyamides; polyhydroxyalkanoates;

polyethyleneterephthalates; polybutyleneterephthalates; polyethylenenaphthalenates, and copolymers, blends, derivatives, or combinations thereof. However, it should be appreciated that embodiments of the present disclosure are not intended to be limited thereto and that other types of diverter materials may also be used.

In one or more embodiments, the valves, ports, and/or other features of the injection tools 116 can be configured to control the location, rate, orientation, and/or other properties of fluid flow between the wellbore 102 and the subsurface formation 104. The injection tools 116 may include multiple tools coupled by sections of tubing, pipe, or another type of conduit. The injection tools 116 may be isolated in the wellbore 102 by packers or other devices installed in the wellbore 102.

In some implementations, the injection system 108 may be used to create or modify a complex fracture network in the subsurface formation 104 by injecting fluid into portions of the subsurface formation 104 where stress has been altered. For example, the complex fracture network may be created or modified after an initial injection treatment has altered stress by fracturing the subsurface formation 104 at multiple locations along the wellbore 102. After the initial injection treatment alters stresses in the subterranean formation, one or more valves of the injection tools 116 may be selectively opened or otherwise reconfigured to stimulate or re-stimulate specific areas of the subsurface formation 104 along one or more sections 118 of the wellbore 102, taking advantage of the altered stress state to create complex fracture networks. In some cases, the injection system 108 may inject fluid simultaneously for multiple intervals and sections 118 of wellbore 102.

The operation of the injection tools 116 may be controlled by the injection control subsystem 111. The injection control subsystem 111 may include, for example, data processing equipment, communication equipment, and/or other systems that control injection treatments applied to the subsurface formation 104 through the wellbore 102. In one or more embodiments, the injection control subsystem 111 may receive, generate, or modify a baseline treatment plan for implementing the various stages of the stimulation treatment along the path of the wellbore 102. The baseline treatment plan may specify initial parameters for the treatment fluid to be injected into the subsurface formation 104. The treatment plan may also specify a baseline pumping schedule for the treatment fluid injections and diverter deployments over each stage of the stimulation treatment.

In one or more embodiments, the injection control subsystem 111 initiates control signals to configure the injection tools 116 and/or other equipment (e.g., pump trucks, etc.) for operation based on the treatment plan. The signaling subsystem 114 as shown in FIG. 1 transmits the signals from the injection control subsystem 111 at the wellbore surface 110 to

one or more of the injection tools 116 disposed in the wellbore 102. For example, the signaling subsystem 114 may transmit hydraulic control signals, electrical control signals, and/or other types of control signals. The control signals may be reformatted, reconfigured, stored, converted, retransmitted, and/or otherwise modified as needed or desired en route between the injection control subsystem 111 (and/or another source) and the injection tools 116 (and/or another destination). The signals transmitted to the injection tools 116 may control the configuration and/or operation of the injection tools. Examples of different ways to control the operation of each of the injection tools 116 include, but are not limited to, opening, closing, restricting, dilating, repositioning, reorienting, and/or otherwise manipulating one or more valves of the tool to modify the manner in which treatment fluid, proppant, or diverter is communicated into the subsurface formation 104.

It should be appreciated that the combination of injection valves of the injection tools 116 may be configured or reconfigured at any given time during the stimulation treatment. It should also be appreciated that the injection valves may be used to inject any of various treatment fluids, proppants, and/or diverter materials into the subsurface formation 104. Examples of such proppants include, but are not limited to, sand, bauxite, ceramic materials, glass materials, polymer materials, polytetrafluoroethylene materials, nut shell pieces, cured resinous particulates comprising nut shell pieces, seed shell pieces, cured resinous particulates comprising seed shell pieces, fruit pit pieces, cured resinous particulates comprising fruit pit pieces, wood, composite particulates, lightweight particulates, microsphere plastic beads, ceramic microspheres, glass microspheres, manmade fibers, cement, fly ash, carbon black powder, and combinations thereof.

In some implementations, the signaling subsystem 114 transmits a control signal to multiple injection tools, and the control signal is formatted to change the state of only one or a subset of the multiple injection tools. For example, a shared electrical or hydraulic control line may transmit a control signal to multiple injection valves, and the control signal may be formatted to selectively change the state of only one (or a subset) of the injection valves. In some cases, the pressure, amplitude, frequency, duration, and/or other properties of the control signal determine which injection tool is modified by the control signal. In some cases, the pressure, amplitude, frequency, duration, and/or other properties of the control signal determine the state of the injection tool affected by the modification.

In one or more embodiments, the injection tools 116 may include one or more sensors for collecting data relating to downhole operating conditions and formation characteristics along the wellbore 102. Such sensors may serve as real-time data sources for various types of downhole measurements and diagnostic information pertaining to each stage of the stimulation

treatment. Examples of such sensors include, but are not limited to, micro-seismic sensors, tiltmeters, pressure sensors, and other types of downhole sensing equipment. The data collected downhole by such sensors may include, for example, real-time measurements and diagnostic data for monitoring the extent of fracture growth and complexity within the surrounding formation along the wellbore 102 during each stage of the stimulation treatment, e.g., corresponding to one or more sections 118.

In some implementations, the injection tools 116 may include fiber-optic sensors for collecting real-time measurements of acoustic intensity or thermal energy downhole during the stimulation treatment. For example, the fiber-optic sensors may be components of a distributed acoustic sensing (DAS), distributed strain sensing, and/or distributed temperature sensing (DTS) subsystems of the injection system 108. However, it should be appreciated that embodiments are not intended to be limited thereto and that the injection tools 116 may include any of various measurement and diagnostic tools. In some implementations, the injection tools 116 may be used to inject particle tracers, e.g., tracer slugs, into the wellbore 102 for monitoring the flow distribution based on the distribution of the injected particle tracers during the treatment. For example, such tracers may have a unique temperature profile that the DTS subsystem of the injection system 108 can be used to monitor over the course of a treatment stage.

In one or more embodiments, the signaling subsystem 114 may be used to transmit real-time measurements and diagnostic data collected downhole by one or more of the aforementioned data sources to the injection control subsystem 111 for processing at the wellbore surface 110. Thus, in the fiber-optics example above, the downhole data collected by the fiber-optic sensors may be transmitted to the injection control subsystem 111 via, for example, fiber-optic cables included within the signaling subsystem 114. The injection control subsystem 111 (or data processing components thereof) may use the downhole data that it receives via the signaling subsystem 114 to perform real-time fracture mapping and/or real-time fracturing pressure interpretation using any of various data analysis techniques for monitoring stress fields around hydraulic fractures.

The injection control subsystem 111 may use the real-time measurements and diagnostic data received from the data source(s) to monitor a downhole flow distribution of the treatment fluid injected into the plurality of formation entry points along the path of the wellbore 102 during each stage of the stimulation treatment. In one or more embodiments, such data may be used to derive qualitative and/or quantitative indicators of the downhole flow distribution for a given stage of the treatment.

One such indicator may be, for example, the amount of flow spread across the plurality of formation entry points into which the treatment fluid is injected. As used herein, the term "flow spread" refers to a measure of how far the downhole flow distribution deviates from an ideal distribution. An ideal flow distribution may be one in which there is uniform distribution or equal flow into most, if not all, of the formation entry points, depending upon local stress changes or other characteristics of the surrounding formation that may impact the flow distribution for a given treatment stage.

Another indicator of the downhole flow distribution may be the number of sufficiently stimulated formation entry points or perforation clusters resulting from the fluid injection along the wellbore 102. A formation entry point or perforation cluster may be deemed sufficiently stimulated if, for example, the volume of fluid and proppant that it has received up to a point in the treatment stage has met a threshold. The threshold may be based on, for example, predetermined design specifications of the particular treatment. While the threshold may be described herein as a single value, it should be appreciated that embodiments are not intended to be limited thereto and that the threshold may be a range of values, e.g., from a minimum threshold value to a maximum threshold value.

In one or more embodiments, the above-described indicators of downhole flow distribution may be derived by the injection control subsystem 111 by performing a qualitative and/or quantitative analysis of the real-time measurements and diagnostic data to determine the flow spread and stimulated cluster parameters. The type of analysis performed by the injection control subsystem 111 for determining the flow spread and number of sufficiently stimulated entry points or perforation clusters may be dependent upon the types of measurements and diagnostics (and data sources) that are available during the treatment stage.

For example, the injection control subsystem 111 may determine such parameters based on a qualitative analysis of real-time measurements of acoustic intensity or temporal heat collected by fiber-optic sensors disposed within the wellbore 102 as described above. Alternatively, the injection control subsystem 111 may perform a quantitative analysis using the data received from the fiber-optic sensors. The quantitative analysis may involve, for example, assigning flow percentages to each formation entry point or perforation cluster based on acoustic and/or thermal energy data accumulated for each entry point or cluster and then using the assigned flow percentages to calculate a corresponding coefficient representing the variation of the fluid volume distribution across the formation entry points.

In another example, the injection control subsystem 111 may determine the flow spread and/or number of sufficiently stimulated entry points by performing a quantitative analysis of real-time micro-seismic data collected by downhole micro-seismic sensors, e.g., as included

within the injection tools 116. The micro-seismic sensors may be, for example, geophones located in a nearby wellbore, which may be used to measure microseismic events within the surrounding subsurface formation 104 along the path of the wellbore 102. The quantitative analysis may be based on, for example, the location and intensity of micro-seismic activity. Such activity may include different micro-seismic events that may affect fracture growth within the subsurface formation 104. In one or more embodiments, the length and height of a fracture may be estimated based on upward and downward growth curves generated by the injection control subsystem 111 using the micro-seismic data from the micro-seismic sensors. Such growth curves may in turn be used to estimate a surface area of the fracture. The fracture's surface area may then be used to compute the volume distribution and flow spread.

In yet another example, the injection control subsystem 111 may use real-time pressure measurements obtained from downhole and surface pressure sensors to perform real-time pressure diagnostics and analysis. The results of the analysis may then be used to determine the downhole flow distribution indicators, i.e., the flow spread and number of sufficiently stimulated formation entry points, as described above. The injection control subsystem 111 in this example may perform an analysis of surface treating pressure as well as friction analysis and/or other pressure diagnostic techniques to obtain a quantitative measure of the flow spread and number of sufficiently simulated entry points.

In a further example, the injection control subsystem 111 may use real-time data from one or more tiltmeters to infer fracture geometry through fracture induced rock deformation during each stage of the stimulation treatment. The tiltmeters in this example may include surface tiltmeters, downhole tiltmeters, or a combination thereof. The measurements acquired by the tiltmeters may be used to perform a quantitative evaluation of the flow spread and sufficiently stimulated formation entry points during each stage of the stimulation treatment.

It should be noted that the various analysis techniques in the examples above are provided for illustrative purposes only and that embodiments of the present disclosure are not intended to be limited thereto. The disclosed embodiments may be applied to other types of wellsite data, data sources, and analysis or diagnostic techniques for determining the downhole flow distribution or indications thereof. It should also be noted that each of the above described analysis techniques may be used independently or combined with one or more other techniques. In some implementations, the analysis for determining the flow spread and number of sufficiently stimulated entry points may include applying real-time measurements obtained from one or more of the above-described sources to an auxiliary flow distribution model. For example, real-time measurements collected by the data source(s) during a current stage of the stimulation treatment may be applied to a geomechanics model of the subsurface formation

104 to simulate flow distribution along the wellbore 102. The results of the simulation may then be used to determine a quantitative measure of the flow spread and number of sufficiently stimulated formation entry points over a remaining portion of the current stage to be performed.

As will be described in further detail below, the injection control subsystem 111 may use analysis of a step down test and/or measurement data (e.g., data measured by sensors of injection system 108) to make real-time adjustments to the baseline treatment plan. For example, the analysis and/or the measurement data may be used to make real-time operational decisions on when and how to adjust the baseline treatment plan in order to optimize stimulation cluster efficiency and production cluster efficiency. Real-time adjustments to the baseline treatment schedule may be used to control diverter deployments over the course of a treatment stage. For example, the baseline treatment schedule may be adjusted in real-time such that a planned diverter deployment for a particular stage (e.g., an earlier-scheduled diverter deployment) is skipped or bypassed. Accordingly, the injection control subsystem 111 may initiate additional control signals to reconfigure the injection tools 116 based on the adjusted treatment plan.

In one or more embodiments, a downhole flow distribution (or a parameter related to the downhole flow distribution) may be used to determine whether or not a diverter deployment is performed. It is assumed for purposes of this example that the initial baseline treatment plan includes such a diversion phase. The determination of whether the diverter deployment is performed may be based on measure of uniformity with respect to flow distribution across perforations of a particular stage. If the flow distribution is sufficiently uniform, then the initial baseline treatment plan is modified such that diverter deployment is not performed at that stage. Otherwise, the initial baseline treatment plan is carried out such that the diverter deployment is performed between consecutive cycles.

In one or more embodiments, the determination of whether or not to deploy the diverter material may be made at some predefined point during the implementation of the stage along the wellbore 102. Examples of such a "determination point" include, but are not limited to, the end of the pad stage or the end of the first low concentration proppant ramp. The determination point may be selected prior to the beginning of the treatment stage.

FIG. 2 is a flowchart of an illustrative process 200 for real-time monitoring and control of downhole fluid flow and distribution using diversion during stimulation treatments. For discussion purposes, process 200 will be described using well system 100 of FIG. 1, as described above. However, process 200 is not intended to be limited thereto. The stimulation treatment in this example is assumed to be a multistage stimulation treatment, e.g., a multistage hydraulic fracturing treatment, in which each stage of the treatment is conducted along a

portion of a wellbore path (e.g., one or more sections 118 along the wellbore 102 of FIG. 1, as described above). As will be described in further detail below, process 200 may be used to monitor and control the downhole flow distribution using diversion in real-time during each stage of the stimulation treatment along a planned trajectory of horizontal wellbore (e.g., wellbore 102 of FIG. 1, as described above) within a subsurface formation. The subsurface formation may be, for example, tight sand, shale, or other type of rock formation with trapped deposits of unconventional hydrocarbon resources, e.g., oil and/or natural gas. The subsurface formation or portion thereof may be targeted as part of a treatment plan for stimulating the production of such resources from the rock formation. Accordingly, process 200 may be used to appropriately adjust the treatment plan in real-time so as to improve the downhole flow distribution of the injected treatment fluid over each stage of the stimulation treatment.

Process 200 begins with developing a model. According to at least some embodiments – once developed, the model is used for estimating a downhole flow distribution of injected treatment fluid. In more detail, the downhole flow distribution is estimated based on results obtained from a step down test. In at least some situations, the downhole flow distribution is estimated although other types of data are not available. For example, the downhole flow distribution is estimated although DAS data is not available. Such a situation may occur, for example, when fiber-optic sensors are not installed (or otherwise unavailable) at a particular location.

Before usage of the model is further described, development of the model will first be described in more detail with respect to various embodiments.

In at least some embodiments, one or more inputs are used in developing the model. With reference to block 202, such inputs may include information about the well (e.g., wellbore 102), information regarding flow rates (e.g., Q_{Tot}), bottom hole pressure (BHP) (as obtained, e.g., from one or more software tools used to calculate material and flow characteristics of oil field stimulation materials), number of steps, number of proppant cycles per stage, and the completion type. Using the flow rate and the BHP, the near wellbore pressure loss (NWBPL) is predicted.

With reference to blocks 204 and 206, the model is further based on a step down analysis at a particular stage (e.g., section 118a).

One technique for measuring in-situ stress involves pumping fluid into a reservoir, creating a fracture, and measuring the pressure at which the fracture closes. A step down test is an example of a well test that is used to measure the minimum principal stress. In naturally fractured or highly cleated formations, injection tests often result in the creation of multiple

fractures that follow tortuous paths. When these tortuous paths are created, the pressure drop in the near wellbore region can be very high. To determine the cause of near-wellbore pressure drop, a step down test is run.

A step down test is pumped just before the minifracture treatment. A step down test is pumped at fracturing rates with linear fluids, the friction pressures of which are well known. The pressure at the bottom of the hole during the injection is a function of the net pressure in the fracture and the near-wellbore pressure drop. To measure the near-wellbore pressure drop, the net pressure in the fracture needs to be relatively constant during the step-down portion of the test.

In at least one embodiment, the step down test is started by injecting into the well for 10 to 15 minutes. In most cases, the net pressure is relatively stable after approximately 10 to 15 minutes of injection. The injection rate is then "reduced in steps" to a rate of zero. For example, the injection rate at each step may be held constant for approximately 1 minute so that the stabilized injection pressure can be measured. The injection rate may be stepped from the maximum value to zero, in three to five steps, in less than 5 minutes. The objective of the step-down test is to measure the near-wellbore pressure drop as a function of injection rate. If the net pressure in the fracture is relatively stable, then the change in bottomhole injection pressure as the injection rate is reduced will be a function of the near-wellbore pressure drop.

Data of the step down test is analyzed to determine the cause of the near wellbore pressure drop. The analysis estimates the values of various parameters. These parameters include the tortuosity friction, and the perforation friction. The tortuosity friction and the perforation friction may be obtained using the NWBPL and the flow rate. The parameters may also include the near wellbore friction, and the number of perforations open. With reference to block 206, the perforation efficiency is estimated. For example, the perforation efficiency is obtained from the Perforation constant.

In one or more embodiments, the model is further developed based on real-time measurements. (As will described in more detail later, the model is further developed by correlating analysis results of the step down test with real-time measurements.) The real-time measurements may correspond to various locations (e.g., depths or formation entry points) in the particular stage (e.g., section 118a). The real-time measurements may be obtained from fiber-optic sensors disposed within the wellbore (e.g., wellbore 102). For example, the fiber-optic sensors may be coupled to at least one of a drill string, a coiled tubing string, tubing, a casing, a wireline, or a slickline disposed within the wellbore. Real-time measurements may also be obtained from other data sources at the wellsite. As described above, such other data sources may include, but are not limited to, micro-seismic sensors, pressure sensors, and

tiltmeters. Such data sources may be located downhole or at the surface of the wellsite.

In one or more embodiments, a parameter relating to the downhole flow distribution may be determined by applying the real-time measurements obtained from one or more of the aforementioned data sources to a geomechanics model of surrounding formations along the wellbore path. In some implementations, the downhole flow distribution may be determined by monitoring a distribution of particle tracers along the wellbore path, as described above.

In at least one embodiment, the parameter is a flow uniformity index (UI) that is based on a coefficient of variation c_v. The coefficient of variation c_v may be determined based on Equation (1) below:

$$c_v = \sigma/\mu \quad (1)$$

In Equation (1) above, σ denotes the standard deviation of the flow distribution in the particular stage (e.g., section 118a). μ denotes the mean of the flow distribution in the stage, which is equivalent to the flow into one formation entry point in the situation that all entry points in the stage are accepting equal flow distribution.

In at least one embodiment, the UI is determined using the coefficient of variation c_v of Equation (1), as expressed in Equation (2) below:

$$UI = 1 - \sigma/\mu \quad (2)$$

FIG. 3 illustrates an example of a flow distribution at one particular stage. Based on real-time measurements (e.g., DAS data), a flow distribution across three different positions (P1, P2, P3) is determined. The positions P1, P2, P3 correspond to different respective depths in the wellbore (e.g., Depth 1, Depth 2, Depth 3). With reference to table 300 of FIG. 3, there is a non-uniform distribution across the positions P1, P2, P3. Approximately 42% of the treatment fluid flows into the formation entry point at position P1. Similarly, approximately 32% of the treatment fluid flows into the formation entry point at position P2. Similarly, almost 26% of the treatment fluid flows into the formation entry point at position P3. Based on the illustrated flow distribution, a value of UI may be determined according to Equation (2).

So far, the development of the model with reference to one particular stage (e.g., section 118a) has been described. In addition, the model is developed further based on one or more additional stages (e.g., at least two additional stages, such as sections 118b and 118c). For example, the development processes described earlier with respect to the particular stage (e.g., section 118a) are repeated for each of the additional stages (e.g., sections 118b and/or 118c).

Similar to the particular stage -- at each of the additional stages, a step down analysis is performed to estimate various parameters. These parameters may include the perforation efficiency, the tortuosity friction, and the perforation friction. These parameters may also include the near wellbore friction, and the number of perforations open.

Also at each of the additional stages, the model is further developed based on real-time measurements. In at least one embodiment -- similar to the particular stage, a UI that is based on a coefficient of variation c_v is determined.

With reference back to FIG. 2 -- at block 208, the model is further developed by correlating analysis results of the step down test with real-time measurements. The correlation is performed across the multiple stages (e.g., sections 118a, 118b, 118c) on which the model is based.

According to at least one embodiment – for each of the multiple stages, the analysis results of the step down test (e.g., the perforation efficiency, the tortuosity friction and the perforation friction) are correlated with real-time measurements (e.g., as represented by the UI) based on Equation (3) below:

From DAS data; From Step down test; From Step down test

$$UI = a + b(Perf\ Efficiency) + c\frac{Tortuosity\ Friction}{Perforation\ Friction} \quad (3)$$

Fitting coefficients; Fitting coefficient

In Equation (3) above, a, b, and c denote respective fitting coefficients. A set of values of the fitting coefficients is chosen such that, across the multiple stages (e.g., sections 118a, 118b, 118c), a predicted value of the UI for a given stage is sufficiently close to a measured value of the UI for the given stage. For example, a value of the UI that is calculated based on Equation (3) for a given stage is sufficiently close to a value of the UI as determined based on real-time measurements for the given stage.

For example, the set of values of the fitting coefficients is chosen such that: (1) a predicted value of the UI for section 118a is sufficiently close to the measured value of the UI for section 118a; (2) a predicted value of the UI for section 118b is sufficiently close to the measured value of the UI for section 118b; and (3) a predicted value of the UI for section 118c is sufficiently close to the measured value of the UI for section 118c.

Accordingly, the developed model correlates the downhole flow distribution with results of a step down analysis.

With continued reference to block 208, the developed model is used to predict the downhole flow distribution (e.g., the UI) at one or more other stages. This may be especially useful if, for example, real-time measurements are not available at the other stage(s). This situation may occur, for example, when fiber-optic sensors for providing DAS data are not available at the other stage(s).

In one or more embodiments, the other stage(s) are stages of the same well (e.g., the same well that was analyzed in developing the model). For example, if the model was developed based on sections 118a, 118b and 118c of wellbore 102, then the model is used to predict the downhole flow distribution (e.g., the UI) at subsequent section 118d and/or subsequent section 118e.

Blocks 208 and 210 will be further described with reference to the embodiments described in the above paragraph. However, it is understood that such features are equally applicable to one or more other embodiments. In these other embodiment(s), the other stage(s) are stages of a different well. For example, this different well is a well that is in the vicinity of the well that was analyzed in developing the model. For example, a model that has been developed based on wellbore 102 is then used to predict the downhole flow distribution (e.g., the UI) at one or more stages of a different wellbore that is in the vicinity of the wellbore 102. This separate wellbore may be adjacent to the wellbore 102 and/or may be in a same pad as the wellbore 102. As another example, a model that has been developed based on wellbore 102 is then used to predict the downhole flow distribution (e.g., the UI) at one or more stages of a different wellbore that is in a similar type of geological region as the wellbore 102.

In one or more embodiments, the model used in sections 118a, 118b, 118c may be a machine learning model. In some implementations, the form of the model may be determined through any other techniques. Alternatively, the diagnostic data model may be a machine learning model generated from historical data acquired from a previously completed well in the hydrocarbon producing field.

In one or more embodiments, the functional form of the model can be edited, e.g., by adding or deleting specific parameters represented by the model, and/or calibrating one or more of parameter coefficients of the model, as described above.

With reference back to block 208, the developed model is used to predict the downhole flow distribution (e.g., the UI) at a certain stage (e.g., section 118d, 118e). As will be described in more detail with reference to block 210, the predicted value of the UI is used to decide (e.g., in real-time), whether to bypass (e.g., skip) a planned diverter deployment at the stage. The planned diverter deployment may be an earlier-scheduled diverter deployment that is part of the baseline treatment plan.

For example, a predicted UI value that is greater than a particular value is interpreted as indicating that the flow distribution has a suitable degree of uniformity and/or that a suitable number of clusters are open to accept the flow. In at least one embodiment, the particular value is related to a threshold value. The threshold value may be equal to a mean, or average, value. For example, the threshold value may be equal to the reciprocal of the number of clusters in a stage (1/(number of clusters)). According to at least one embodiment, in such a situation, the planned diverter deployment is bypassed. Because the deployment of the diverter is deemed not to be necessary, the diverter is not deployed at the stage.

As another example, a predicted UI value that is less than the particular value may be interpreted as indicating that the flow distribution has not attained a suitable degree of uniformity and/or that a suitable number of clusters have not opened to accept the flow. According to at least one embodiment, in such a situation, the planned diverter deployment is performed.

According to at least one embodiment, if the predicted UI value is less than the particular value (e.g., which is related to the threshold value), then either a continuous diverter deployment or a discrete diverter deployment may be performed, depending on the magnitude of the difference between the predicted UI value and the particular value. A continuous diverter deployment involves dropping a particular quantity (e.g., small quantity) of diverter material continuously in a treatment. In contrast, a discrete diverter deployment involves dropping (e.g., in bulk) a quantity of diverter material at a discrete time. Compared to a typical continuous diverter deployment, the quantity of diverter material that is dropped in a discrete diverter deployment is usually larger.

For example, if the predicted UI value is less than (1 – the threshold value), then a discrete diverter deployment is performed. As another example, if the predicted UI value is greater than (1 – the threshold value) and less than X * (1 – threshold value), then a continuous diverter deployment is performed. As another example, if the predicted UI value is greater than X * (1 – threshold value), then a diverter deployment is not performed. For example, neither a discrete diverter deployment nor a continuous diverter deployment is performed. Here, X may denote a number between 1.0 and 1.2.

FIG. 4 shows a flowchart of an illustrative method 400 for deploying diverter material in a subterranean formation. At block 402, a treatment is applied at a first well in the subterranean formation. The treatment is for stimulating production.

At block 404, a step down analysis of the first well is performed at each of a plurality of stages of the first well. At block 406, a downhole flow distribution of the applied treatment at each of the plurality of stages is determined. For example, the downhole flow distribution

at each of the plurality of stages is determined based on DAS data of the corresponding stage. As another example, the downhole flow distribution at each of the plurality of stages is based on at least one of geomechanics modeling data, DTS data, microseismic data, distributed strain sensing data, or tiltmeter data of the corresponding stage.

At block 408, a model is developed for correlating the downhole flow distribution and the step down analysis at each of the plurality of stages. For example, the model may be formulated using a formula such as Equation (3). As an example of the correlation, a uniformity measure of the downhole flow distribution (e.g., a UI) is correlated with the step down analysis.

At block 410, the developed model is used to estimate a downhole flow distribution at a stage of a second well. For example, the developed model is used to estimate a uniformity measure of the downhole flow distribution (e.g., a UI).

At block 412, a determination is made regarding whether to bypass a deployment of the diverter material at the stage of the second well based on the estimated downhole flow distribution. Determining whether to bypass the deployment of the diverter material at the stage of the second well may include determining to bypass the deployment if the uniformity measure is greater than a particular threshold value. The particular threshold value may be related to a mean value of the uniformity measure. Determining whether to bypass the deployment of the diverter material at the stage of the second well may include determining to bypass an earlier-planned deployment at the stage of the second well based on the estimated downhole flow distribution.

In at least one embodiment, the second well is in a vicinity of the first well (e.g., wellbore 102). For example, the second well may be in the same pad as the first well.

In at least one embodiment, the first well and the second well are the same well (e.g., wellbore 102). In this situation, the stage of the second well corresponds to an additional stage of the first well that is different from the plurality of stages (on which the development of the model is based).

FIG. 5 is a block diagram of an exemplary computer system 1000 in which embodiments of the present disclosure may be implemented. For example, the injection control subsystem 111 (or data processing components thereof) of FIG. 1 and the steps of processes 200 and 400 of FIGs. 2 and 4, respectively, as described above, may be implemented using system 1000. System 1000 can be a computer, phone, PDA, or any other type of electronic device. Such an electronic device includes various types of computer readable media and interfaces for various other types of computer readable media. As shown in FIG. 5, system 1000 includes a permanent storage device 1002, a system memory 1004, an output device

interface 1006, a system communications bus 1008, a read-only memory (ROM) 1010, processing unit(s) 1012, an input device interface 1014, and a network interface 1016.

Bus 1008 collectively represents all system, peripheral, and chipset buses that communicatively connect the numerous internal devices of system 1000. For instance, bus 1008 communicatively connects processing unit(s) 1012 with ROM 1010, system memory 1004, and permanent storage device 1002.

From these various memory units, processing unit(s) 1012 retrieves instructions to execute and data to process in order to execute the processes of the subject disclosure. The processing unit(s) can be a single processor or a multi-core processor in different implementations.

ROM 1010 stores static data and instructions that are needed by processing unit(s) 1012 and other modules of system 1000. Permanent storage device 1002, on the other hand, is a read-and-write memory device. This device is a non-volatile memory unit that stores instructions and data even when system 1000 is off. Some implementations of the subject disclosure use a mass-storage device (such as a magnetic or optical disk and its corresponding disk drive) as permanent storage device 1002.

Other implementations use a removable storage device (such as a floppy disk, flash drive, and its corresponding disk drive) as permanent storage device 1002. Like permanent storage device 1002, system memory 1004 is a read-and-write memory device. However, unlike storage device 1002, system memory 1004 is a volatile read-and-write memory, such a random access memory. System memory 1004 stores some of the instructions and data that the processor needs at runtime. In some implementations, the processes of the subject disclosure are stored in system memory 1004, permanent storage device 1002, and/or ROM 1010. For example, the various memory units include instructions for computer aided pipe string design based on existing string designs in accordance with some implementations. From these various memory units, processing unit(s) 1012 retrieves instructions to execute and data to process in order to execute the processes of some implementations.

Bus 1008 also connects to input and output device interfaces 1014 and 1006. Input device interface 1014 enables the user to communicate information and select commands to the system 1000. Input devices used with input device interface 1014 include, for example, alphanumeric, QWERTY, or T9 keyboards, microphones, and pointing devices (also called "cursor control devices"). Output device interfaces 1006 enables, for example, the display of images generated by the system 1000. Output devices used with output device interface 1006 include, for example, printers and display devices, such as cathode ray tubes (CRT) or liquid crystal displays (LCD). Some implementations include devices such as a touchscreen that

functions as both input and output devices. It should be appreciated that embodiments of the present disclosure may be implemented using a computer including any of various types of input and output devices for enabling interaction with a user. Such interaction may include feedback to or from the user in different forms of sensory feedback including, but not limited to, visual feedback, auditory feedback, or tactile feedback. Further, input from the user can be received in any form including, but not limited to, acoustic, speech, or tactile input. Additionally, interaction with the user may include transmitting and receiving different types of information, e.g., in the form of documents, to and from the user via the above-described interfaces.

Also, as shown in FIG. 5, bus 1008 also couples system 1000 to a public or private network (not shown) or combination of networks through a network interface 1016. Such a network may include, for example, a local area network ("LAN"), such as an Intranet, or a wide area network ("WAN"), such as the Internet. Any or all components of system 1000 can be used in conjunction with the subject disclosure.

These functions described above can be implemented in digital electronic circuitry, in computer software, firmware or hardware. The techniques can be implemented using one or more computer program products. Programmable processors and computers can be included in or packaged as mobile devices. The processes and logic flows can be performed by one or more programmable processors and by one or more programmable logic circuitry. General and special purpose computing devices and storage devices can be interconnected through communication networks.

Some implementations include electronic components, such as microprocessors, storage and memory that store computer program instructions in a machine-readable or computer-readable medium (alternatively referred to as computer-readable storage media, machine-readable media, or machine-readable storage media). Some examples of such computer-readable media include RAM, ROM, read-only compact discs (CD-ROM), recordable compact discs (CD-R), rewritable compact discs (CD-RW), read-only digital versatile discs (e.g., DVD-ROM, dual-layer DVD-ROM), a variety of recordable/rewritable DVDs (e.g., DVD-RAM, DVD-RW, DVD+RW, etc.), flash memory (e.g., SD cards, mini-SD cards, micro-SD cards, etc.), magnetic and/or solid state hard drives, read-only and recordable Blu-Ray® discs, ultra density optical discs, any other optical or magnetic media, and floppy disks. The computer-readable media can store a computer program that is executable by at least one processing unit and includes sets of instructions for performing various operations. Examples of computer programs or computer code include machine code, such as is produced

by a compiler, and files including higher-level code that are executed by a computer, an electronic component, or a microprocessor using an interpreter.

While the above discussion primarily refers to microprocessor or multi-core processors that execute software, some implementations are performed by one or more integrated circuits, such as application specific integrated circuits (ASICs) or field programmable gate arrays (FPGAs). In some implementations, such integrated circuits execute instructions that are stored on the circuit itself. Accordingly, the steps of processes 200 and 400 of FIGs. 2 and 4, respectively, as described above, may be implemented using system 1000 or any computer system having processing circuitry or a computer program product including instructions stored therein, which, when executed by at least one processor, causes the processor to perform functions relating to these methods.

As used in this specification and any claims of this application, the terms "computer", "server", "processor", and "memory" all refer to electronic or other technological devices. These terms exclude people or groups of people. As used herein, the terms "computer readable medium" and "computer readable media" refer generally to tangible, physical, and non-transitory electronic storage mediums that store information in a form that is readable by a computer.

Embodiments of the subject matter described in this specification can be implemented in a computing system that includes a back end component, e.g., as a data server, or that includes a middleware component, e.g., an application server, or that includes a front end component, e.g., a client computer having a graphical user interface or a Web browser through which a user can interact with an implementation of the subject matter described in this specification, or any combination of one or more such back end, middleware, or front end components. The components of the system can be interconnected by any form or medium of digital data communication, e.g., a communication network. Examples of communication networks include a local area network ("LAN") and a wide area network ("WAN"), an inter-network (e.g., the Internet), and peer-to-peer networks (e.g., ad hoc peer-to-peer networks).

The computing system can include clients and servers. A client and server are generally remote from each other and typically interact through a communication network. The relationship of client and server arises by virtue of computer programs running on the respective computers and having a client-server relationship to each other. In some embodiments, a server transmits data (e.g., a web page) to a client device (e.g., for purposes of displaying data to and receiving user input from a user interacting with the client device). Data generated at the client device (e.g., a result of the user interaction) can be received from the client device at the server.

It is understood that any specific order or hierarchy of steps in the processes disclosed is an illustration of exemplary approaches. Based upon design preferences, it is understood that the specific order or hierarchy of steps in the processes may be rearranged, or that all illustrated steps be performed. Some of the steps may be performed simultaneously. For example, in certain circumstances, multitasking and parallel processing may be advantageous. Moreover, the separation of various system components in the embodiments described above should not be understood as requiring such separation in all embodiments, and it should be understood that the described program components and systems can generally be integrated together in a single software product or packaged into multiple software products.

Furthermore, the exemplary methodologies described herein may be implemented by a system including processing circuitry or a computer program product including instructions which, when executed by at least one processor, causes the processor to perform any of the methodology described herein.

Embodiments disclosed herein include:

A: A system that includes at least one processor, and a memory coupled to the at least one processor having instructions stored therein. When executed by the at least one processor, the instructions cause the at least one processor to perform functions including functions to: apply a treatment at a first well in the subterranean formation, wherein the treatment is for stimulating production; perform a step down analysis of the first well at each of a plurality of stages of the first well; determine a downhole flow distribution at each of the plurality of stages; develop a model for correlating the downhole flow distribution and the step down analysis at each of the plurality of stages; use the developed model to estimate a downhole flow distribution at a stage of a second well; and determine whether to bypass a deployment of the diverter material at the stage of the second well based on the estimated downhole flow distribution.

B: A method for deploying diverter material in a subterranean formation during stimulation treatment. The method includes applying a treatment at a first well in the subterranean formation, wherein the treatment is for stimulating production. The method further includes performing a step down analysis of the first well at each of a plurality of stages of the first well, and determining a downhole flow distribution at each of the plurality of stages. The method further includes developing a model for correlating the downhole flow distribution and the step down analysis at each of the plurality of stages, and using the developed model to estimate a downhole flow distribution at a stage of a second well. The method further includes determining whether to bypass a deployment of the diverter material at the stage of the second well based on the estimated downhole flow distribution.

Each of the embodiments, A and B, may have one or more of the following additional elements in any combination. Element 1: wherein: the second well is in a vicinity of the first well; and the first well and the second well are in a same pad or a similar type of region. Element 2: wherein the instructions cause the at least one processor to determine the downhole flow distribution at each of the plurality of stages by determining the downhole flow distribution based on DAS data of the corresponding stage. Element 3: wherein DAS data for determining the downhole flow distribution is unavailable at the stage of the second well. Element 4: wherein the instructions cause the at least one processor to determine the downhole flow distribution at each of the plurality of stages by determining the downhole flow distribution based on at least one of geomechanics modeling data, DTS data, microseismic data, distributed strain sensing data, or tiltmeter data of the corresponding stage. Element 5: wherein the instructions cause the at least one processor to develop the model by correlating a uniformity measure of the downhole flow distribution and the step down analysis. Element 6: wherein the instructions cause the at least one processor to determine whether to bypass the deployment of the diverter material by determining to bypass the deployment if the uniformity measure is greater than a particular threshold value. Element 7: wherein the particular threshold value is equal to X times (1 minus a mean value of the uniformity measure), wherein X denotes a number greater than or equal to 1. Element 8: wherein the instructions cause the at least one processor to determine whether to bypass the deployment of the diverter material by, if X is greater than 1, determining to apply a continuous diverter deployment if the uniformity measure is less than the particular threshold value and greater than (1 minus the mean value of the uniformity measure), and determining to apply a discrete diverter deployment if the uniformity measure is less than (1 minus the mean value of the uniformity measure). Element 9: wherein the instructions cause the at least one processor to perform the functions in real-time.

Element 10: wherein: the second well is in a vicinity of the first well; and the first well and the second well are in a same pad or a similar type of region. Element 11: wherein determining the downhole flow distribution at each of the plurality of stages includes determining the downhole flow distribution based on DAS data of the corresponding stage. Element 12: wherein DAS data for determining the downhole flow distribution is unavailable at the stage of the second well. Element 13: wherein determining the downhole flow distribution at each of the plurality of stages includes determining the downhole flow distribution based on at least one of geomechanics modeling data, DTS data, microseismic data, distributed strain sensing data, or tiltmeter data of the corresponding stage. Element 14: wherein developing the model for correlating the downhole flow distribution and the step down

analysis at each of the plurality of stages includes correlating a uniformity measure of the downhole flow distribution and the step down analysis. Element 15: wherein determining whether to bypass the deployment of the diverter material at the stage of the second well includes determining to bypass the deployment if the uniformity measure is greater than a particular threshold value. Element 16: wherein the particular threshold value is equal to X times (1 minus a mean value of the uniformity measure), wherein X denotes a number greater than or equal to 1. Element 17: wherein, if X is greater than 1, determining whether to bypass the deployment of the diverter material at the stage of the second well further comprises: determining to apply a continuous diverter deployment if the uniformity measure is less than the particular threshold value and greater than (1 minus the mean value of the uniformity measure); and determining to apply a discrete diverter deployment if the uniformity measure is less than (1 minus the mean value of the uniformity measure). Element 18: wherein applying the treatment, performing the step down analysis, determining the downhole flow distribution, developing the model, using the developed model, and determining whether to bypass the deployment of the diverter material are performed in real-time.

Numerous other variations and modifications will become apparent to those skilled in the art once the above disclosure is fully appreciated. For example, in some embodiments, the order of the processing operations described herein may vary and/or be performed in parallel. It is intended that the following claims be interpreted to embrace all such variations and modifications where applicable.

CLAIMS

WHAT IS CLAIMED IS:

1. A method for deploying diverter material in a subterranean formation during stimulation treatment, comprising:

applying a treatment at a first well in the subterranean formation, wherein the treatment is for stimulating production;

performing a step down analysis of the first well at each of a plurality of stages of the first well;

determining a downhole flow distribution at each of the plurality of stages;

developing a model for correlating the downhole flow distribution and the step down analysis at each of the plurality of stages;

using the developed model to estimate a downhole flow distribution at a stage of a second well; and

determining whether to bypass a deployment of the diverter material at the stage of the second well based on the estimated downhole flow distribution.

2. The method of claim 1, wherein:

the second well is in a vicinity of the first well; and

the first well and the second well are in a same pad or a similar type of region.

3. The method of claim 1, wherein determining the downhole flow distribution at each of the plurality of stages comprises determining the downhole flow distribution based on distributed acoustic sensing (DAS) data of the corresponding stage.

4. The method of claim 3, wherein DAS data for determining the downhole flow distribution is unavailable at the stage of the second well.

5. The method of claim 1, wherein determining the downhole flow distribution at each of the plurality of stages comprises determining the downhole flow distribution based on at least one of geomechanics modeling data, distributed temperature sensing (DTS) data, microseismic data, distributed strain sensing data, or tiltmeter data of the corresponding stage.

6. The method of claim 1, wherein developing the model for correlating the downhole flow distribution and the step down analysis at each of the plurality of stages comprises correlating a uniformity measure of the downhole flow distribution and the step down analysis.

7. The method of claim 6, wherein determining whether to bypass the deployment of the diverter material at the stage of the second well comprises determining to bypass the deployment if the uniformity measure is greater than a particular threshold value.

8. The method of claim 7, wherein the particular threshold value is equal to X times (1 minus a mean value of the uniformity measure), wherein X denotes a number greater than or equal to 1.

9. The method of claim 8, wherein, if X is greater than 1, determining whether to bypass the deployment of the diverter material at the stage of the second well further comprises:

determining to apply a continuous diverter deployment if the uniformity measure is less than the particular threshold value and greater than (1 minus the mean value of the uniformity measure); and

determining to apply a discrete diverter deployment if the uniformity measure is less than (1 minus the mean value of the uniformity measure).

10. The method of claim 1, wherein applying the treatment, performing the step down analysis, determining the downhole flow distribution, developing the model, using the developed model, and determining whether to bypass the deployment of the diverter material are performed in real-time.

11. A system for deploying diverter material in a subterranean formation during stimulation treatment, comprising:

at least one processor; and

a memory coupled to the at least one processor having instructions stored therein, which when executed by the at least one processor, cause the at least one processor to perform functions including functions to:

apply a treatment at a first well in the subterranean formation, wherein the treatment is for stimulating production;

perform a step down analysis of the first well at each of a plurality of stages of the first well;

determine a downhole flow distribution at each of the plurality of stages;

develop a model for correlating the downhole flow distribution and the step down analysis at each of the plurality of stages;

use the developed model to estimate a downhole flow distribution at a stage of a second well; and

determine whether to bypass a deployment of the diverter material at the stage of the second well based on the estimated downhole flow distribution.

12. The system of claim 11, wherein:

the second well is in a vicinity of the first well; and

the first well and the second well are in a same pad or a similar type of region.

13. The system of claim 11, wherein the instructions cause the at least one processor to determine the downhole flow distribution at each of the plurality of stages by determining the downhole flow distribution based on distributed acoustic sensing (DAS) data of the corresponding stage.

14. The system of claim 13, wherein DAS data for determining the downhole flow distribution is unavailable at the stage of the second well.

15. The system of claim 11, wherein the instructions cause the at least one processor to determine the downhole flow distribution at each of the plurality of stages by determining the downhole flow distribution based on at least one of geomechanics modeling data, distributed temperature sensing (DTS) data, microseismic data, distributed strain sensing data, or tiltmeter data of the corresponding stage.

16. The system of claim 11, wherein the instructions cause the at least one processor to develop the model by correlating a uniformity measure of the downhole flow distribution and the step down analysis.

17. The system of claim 16, wherein the instructions cause the at least one processor to determine whether to bypass the deployment of the diverter material by determining to bypass the deployment if the uniformity measure is greater than a particular threshold value.

18. The system of claim 17, wherein the particular threshold value is equal to X times (1 minus a mean value of the uniformity measure), wherein X denotes a number greater than or equal to 1.

19. The system of claim 18, wherein the instructions cause the at least one processor to determine whether to bypass the deployment of the diverter material by, if X is greater than 1, determining to apply a continuous diverter deployment if the uniformity measure is less than the particular threshold value and greater than (1 minus the mean value of the uniformity measure), and determining to apply a discrete diverter deployment if the uniformity measure is less than (1 minus the mean value of the uniformity measure).

20. The system of claim 11, wherein the instructions cause the at least one processor to perform the functions in real-time.

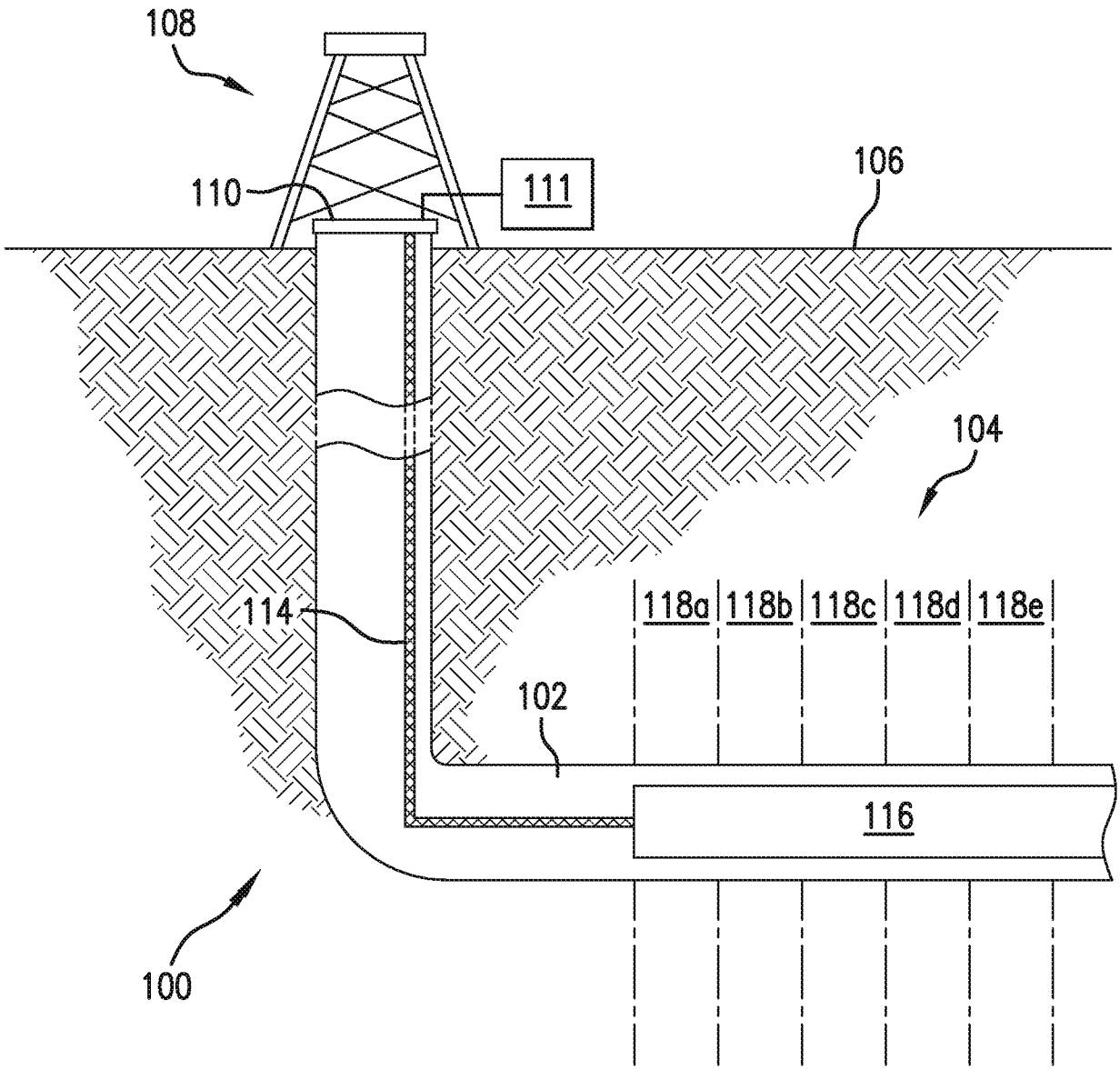


FIG. 1

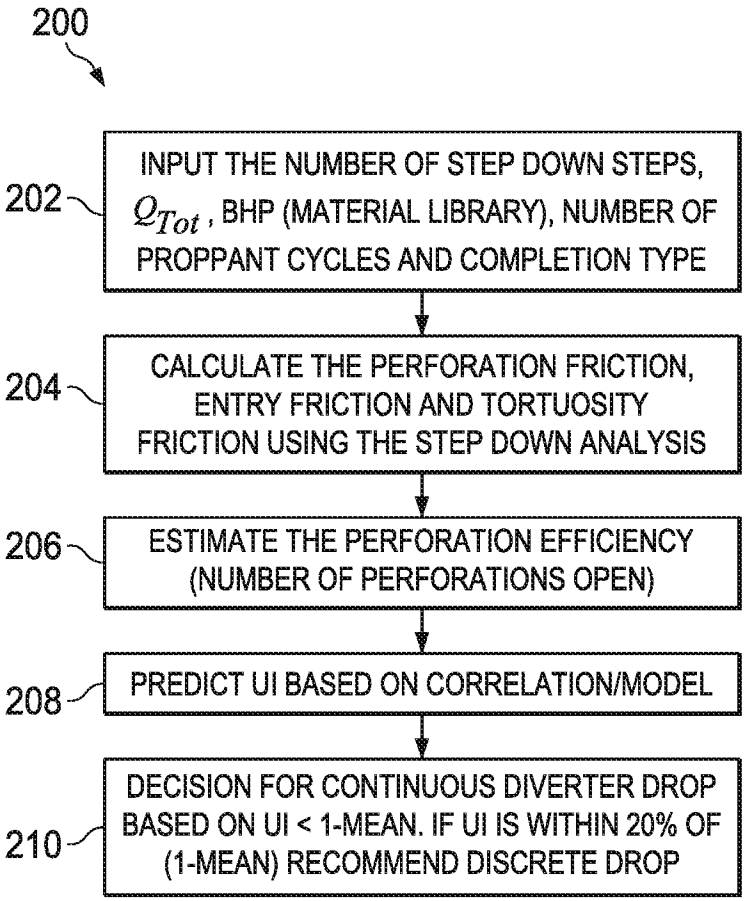

200
202
INPUT THE NUMBER OF STEP DOWN STEPS, Q_{Tot}, BHP (MATERIAL LIBRARY), NUMBER OF PROPPANT CYCLES AND COMPLETION TYPE
204
CALCULATE THE PERFORATION FRICTION, ENTRY FRICTION AND TORTUOSITY FRICTION USING THE STEP DOWN ANALYSIS
206
ESTIMATE THE PERFORATION EFFICIENCY (NUMBER OF PERFORATIONS OPEN)
208
PREDICT UI BASED ON CORRELATION/MODEL
210
DECISION FOR CONTINUOUS DIVERTER DROP BASED ON UI < 1-MEAN. IF UI IS WITHIN 20% OF (1-MEAN) RECOMMEND DISCRETE DROP

FIG. 2

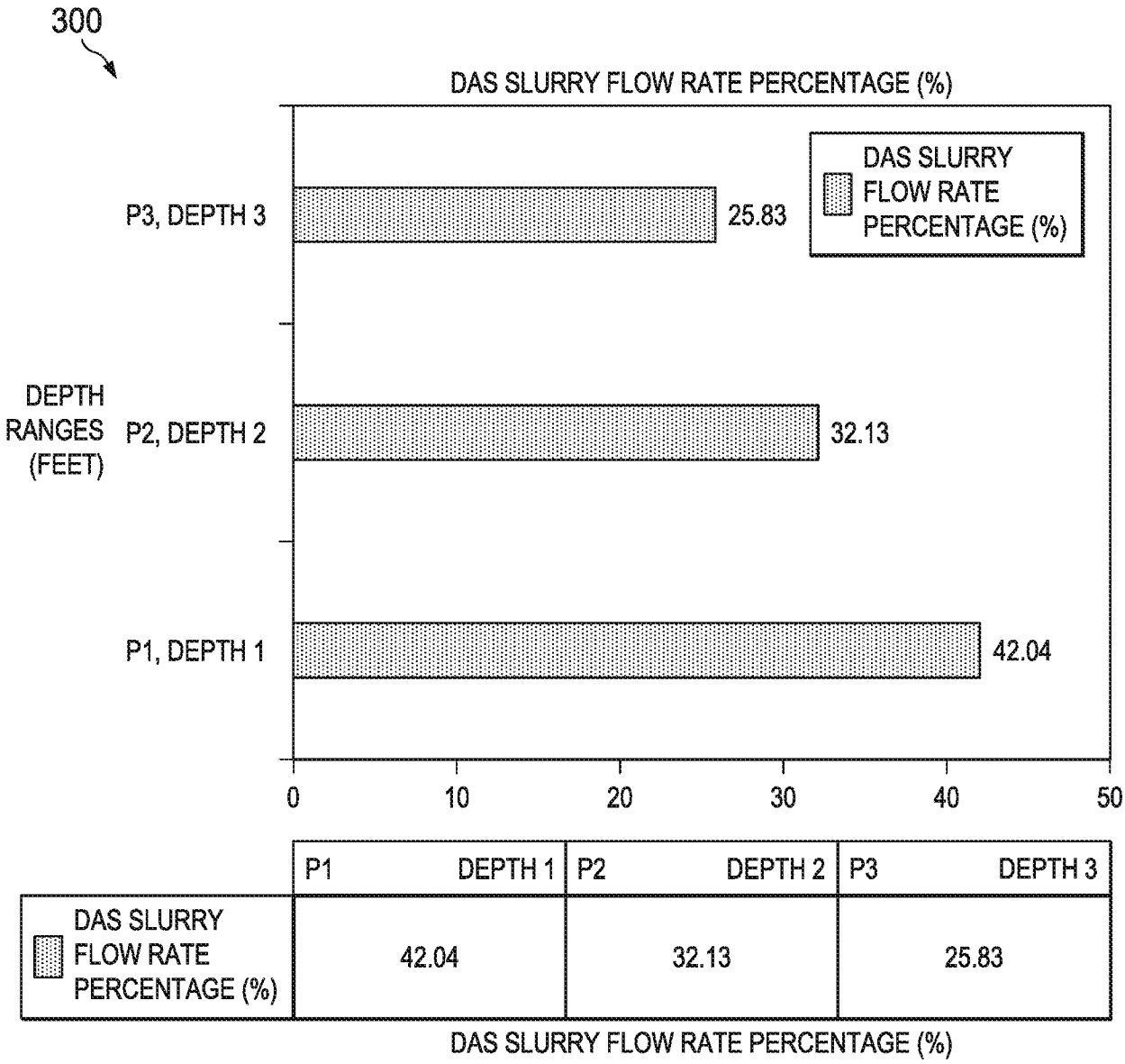

300
DAS SLURRY FLOW RATE PERCENTAGE (%)
DAS SLURRY FLOW RATE PERCENTAGE (%)
P3, DEPTH 3
25.83
DEPTH RANGES (FEET)
P2, DEPTH 2
32.13
P1, DEPTH 1
42.04
0
10
20
30
40
50
P1 DEPTH 1
P2 DEPTH 2
P3 DEPTH 3
DAS SLURRY FLOW RATE PERCENTAGE (%)
42.04
32.13
25.83
DAS SLURRY FLOW RATE PERCENTAGE (%)

FIG. 3

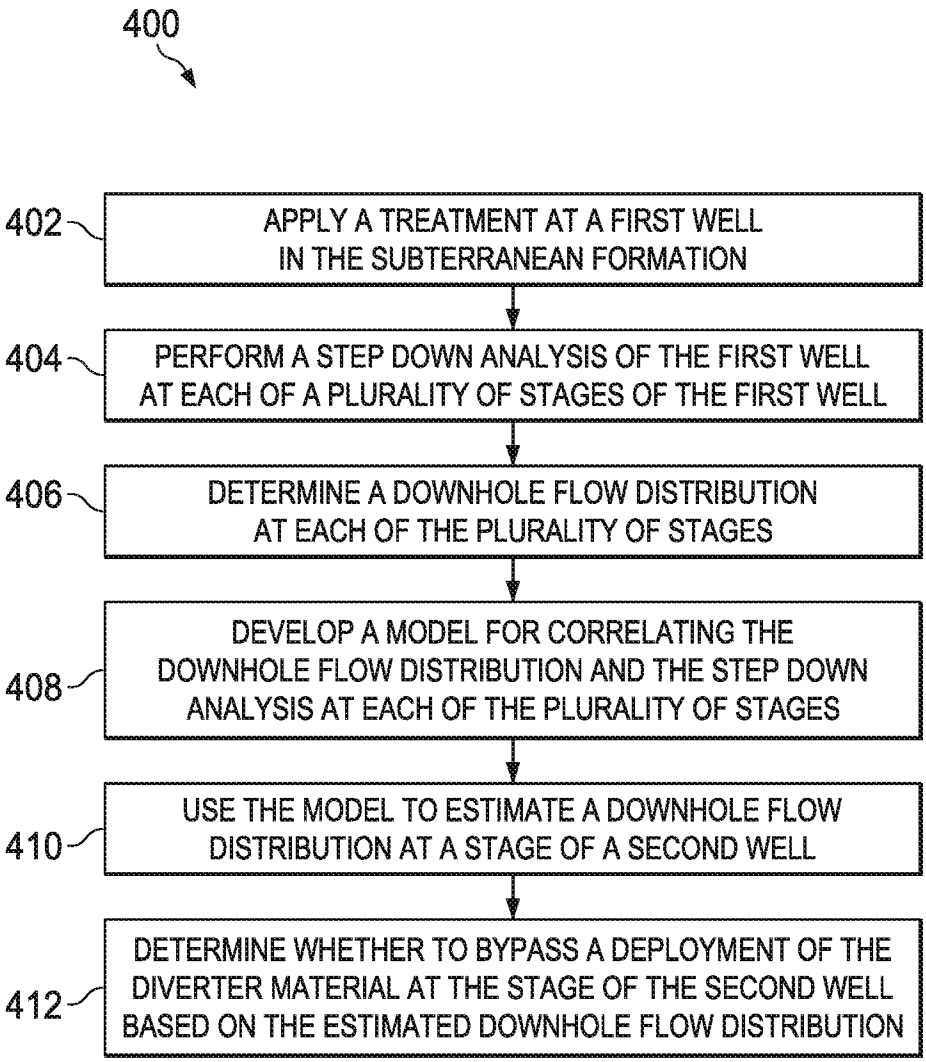

400
402
APPLY A TREATMENT AT A FIRST WELL IN THE SUBTERRANEAN FORMATION
404
PERFORM A STEP DOWN ANALYSIS OF THE FIRST WELL AT EACH OF A PLURALITY OF STAGES OF THE FIRST WELL
406
DETERMINE A DOWNHOLE FLOW DISTRIBUTION AT EACH OF THE PLURALITY OF STAGES
408
DEVELOP A MODEL FOR CORRELATING THE DOWNHOLE FLOW DISTRIBUTION AND THE STEP DOWN ANALYSIS AT EACH OF THE PLURALITY OF STAGES
410
USE THE MODEL TO ESTIMATE A DOWNHOLE FLOW DISTRIBUTION AT A STAGE OF A SECOND WELL
412
DETERMINE WHETHER TO BYPASS A DEPLOYMENT OF THE DIVERTER MATERIAL AT THE STAGE OF THE SECOND WELL BASED ON THE ESTIMATED DOWNHOLE FLOW DISTRIBUTION

FIG. 4

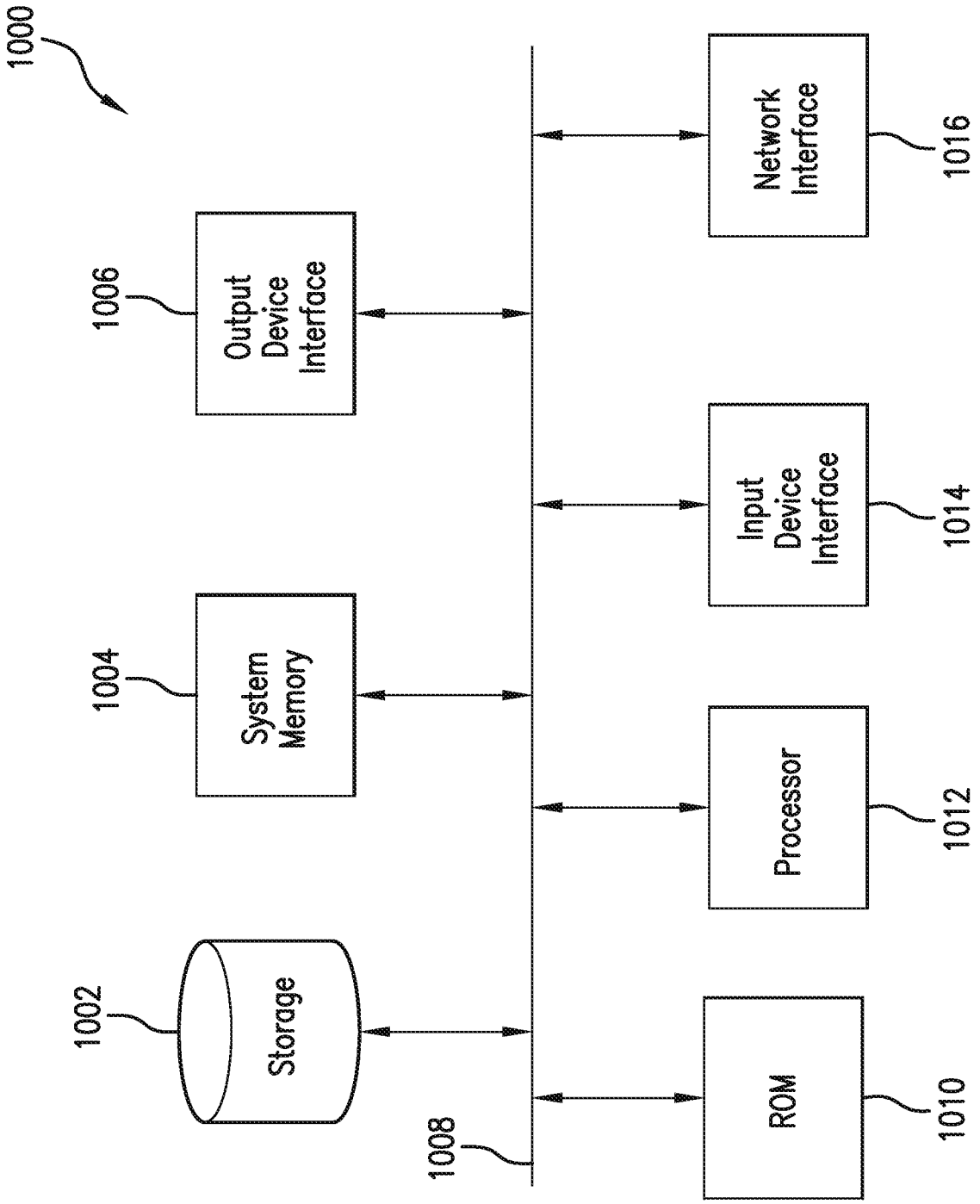

1000
Network Interface
1016
1006
Output Device Interface
Input Device Interface
1014
1004
System Memory
Processor
1012
1002
Storage
ROM
1010
1008

FIG. 10

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2016/060862

A. CLASSIFICATION OF SUBJECT MATTER

E21B 43/25(2006.01)i, E21B 43/26(2006.01)i, E21B 43/17(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)
E21B 43/25; E21B 49/00; E21B 47/06; E21B 43/267; G01F 1/66; E21B 43/17

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: diverter, stimulation, treatment, uniformity, flow, distribution, model, second, correlate

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2015-0075778 A1 (HALLIBURTON ENERGY SERVICES, INC.) 19 March 2015 See paragraphs [0032]-[0056], [0096]; and figures 1A-1B, 2.	1-5,10-15,20
A		6-9,16-19
Y	US 2015-0075292 A1 (LEE, ERIK N.) 19 March 2015 See paragraph [0013]; and figure 1.	1-5,10-15,20
A	US 6367548 B1 (PURVIS et al.) 09 April 2002 See column 11, line 17 - column 12, line 52; and figure 3.	1-20
A	US 2008-0149329 A1 (COOPER et al.) 26 June 2008 See paragraphs [0034]-[0048]; and figures 1-2.	1-20
A	WO 2014-105451 A2 (SCHLUMBERGER CANADA LIMITED et al.) 03 July 2014 See paragraphs [0020]-[0079], [00120]; and figures 1-4, 11.	1-20

☐ 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
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"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
28 July 2017 (28.07.2017)	**28 July 2017 (28.07.2017)**

Name and mailing address of the ISA/KR
International Application Division
Korean Intellectual Property Office
189 Cheongsa-ro, Seo-gu, Daejeon, 35208, Republic of Korea
Facsimile No. +82-42-481-8578

Authorized officer
LEE, Se Gyoung
Telephone No. +82-42-481-8740

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2016/060862

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		NO 20150756 A	10/06/2015
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