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

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

(43) **International Publication Date**
04 July 2024 (04.07.2024)

WIPO | PCT

(10) **International Publication Number**
WO 2024/145159 A1

(51) **International Patent Classification:**
E21B 43/20 (2006.01) ***G05B 13/04*** (2006.01) ***C09K 8/58*** (2006.01)

(21) **International Application Number:** PCT/US2023/085386

(22) **International Filing Date:** 21 December 2023 (21.12.2023)

(25) **Filing Language:** English

(26) **Publication Language:** English

(30) **Priority Data:**
63/477,920 30 December 2022 (30.12.2022) US

(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)*: **GEOQUEST SYSTEMS B.V.** [NL/NL]; Parkstraat 83, 2514 JG The Hague (NL).

(72) **Inventors: SHARMA, Arvind**; 10001 Richmond Ave, Houston, Texas 77042-4205 (US). **SHARAN, Shashin**; 10001 Richmond Ave, Houston, Texas 77042-4205 (US). **WU, Jing**; 10001 Richmond Ave, Houston, Texas 77042-4205 (US).

(74) **Agent: PATEL, Julie D.** et al.; Schlumberger, 10001 Richmond Avenue, Room 4720, Houston, Texas 77042 (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, CV, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IQ, IR, IS, IT, JM, JO, JP, KE, KG,

(54) **Title:** MACHINE LEARNING ENABLED WATER FLOODING OPTIMIZATION

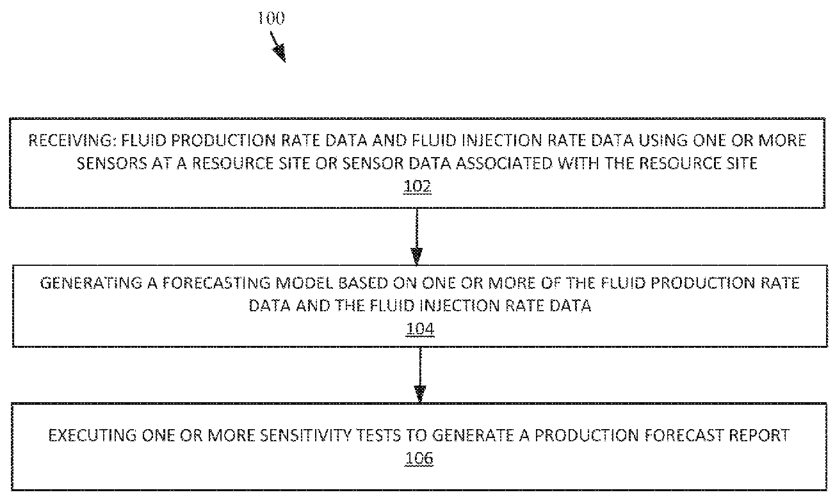

FIG. 1

(57) **Abstract:** The disclosed methods and systems are directed to water flooding optimizations at a resource site for increased production of hydrocarbons. According to some implementations, the methods include receiving at least one of: fluid production rate data and fluid injection rate data using one or more sensors at a resource site. The methods may also include generating a forecasting model based on one or more of the fluid production rate data and the fluid injection rate data. The disclosed methods further comprise executing, using the forecasting model, one or more sensitivity tests to generate a production forecast report.

WO 2024/145159 A1

[Continued on next page]

KH, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, MG, MK, MN, MU, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, WS, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, CV, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SC, 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, ME, 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).

Published:

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

MACHINE LEARNING ENABLED WATER FLOODING OPTIMIZATION

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims priority to U.S. Provisional Patent App. No. 63/477,920, filed on December 30, 2022, and titled "Machine Learning Enabled Water Flooding Optimization," which is incorporated herein by reference in its entirety for all purposes.

BACKGROUND

[0002] During hydrocarbon extraction operations, water or some other fluids may be injected or otherwise pumped into certain wells to facilitate hydrocarbon extraction. Identifying optimal fluid injection rates and or fluid extraction rates for specific wells comprised in a plurality of wells coupled to a reservoir can be problematic, especially due to subtle differences including fluid pressure differentials between the plurality of wells and the reservoir.

[0003] There is therefore a need for determining optimal fluid injection rates that facilitate maximum hydrocarbon extraction rates for specific wells coupled to a reservoir at a resource site.

SUMMARY

[0004] Disclosed are methods, systems, and computer programs for water flooding optimization at a resource site for increased production of hydrocarbons. According to an embodiment, a method for water flooding optimization at a resource site for increased production of hydrocarbons comprises: determining a geo-radius circumscribing one or more injectors and one or more producers at a resource site; and receiving: fluid production rate data obtained from one or more sensors disposed about the one or more producers at the resource site, and fluid injection rate data obtained from one or more sensors disposed about the one or more injectors at the resource site.

[0005] The method also includes correlating the fluid production rate data with the fluid injection rate data to determine correlated pairs of injectors and producers associated with the one or more injectors and the one or more producers, the correlated pairs of injectors and producers indicating a relationship between a first injector comprised in the one or more injectors and a first producer comprised in the one or more producers.

[0006] In addition, the method includes generating a forecasting model using the correlated pairs of injectors and producers, the forecasting model being parameterized using one or more of: a first variable indicating a first range of fluid production rate values, and a second variable indicating a second range of fluid injection rate values.

[0007] Furthermore, the method includes executing, based on the forecasting model, one or more sensitivity tests comprising at least one simulation based on the first variable or the second variable to generate a production forecast report for the first producer, wherein one or more injectors including the first injector are combined with one or more producers including the first producer to generate the forecasting model, such that at least a first range parameter associated with the forecasting model is parameterized by the first variable and a second range parameter associated with the forecasting model is parameterized by the second variable.

[0008] Following this, the method includes executing, using the computer processor, one or more of: initiating generation of a visualization indicating the production forecast report for viewing on a display device, or initiating transmission of a pump rate control signal to configure a pump mechanism disposed about the first producer or the first injector at the resource site.

[0009] In other embodiments, a system and a computer program can include or execute the method described above. These and other implementations may each optionally include one or more of the following features.

[0010] The geo-radius, according to some embodiments, defines a geometrical pattern bounding or selecting the one or more injectors or the one or more producers at the resource site while: the one or more injectors comprise at least one well into which fluid including water is pumped; and the one or more producers comprise at least one well from which fluid including hydrocarbons is extracted.

[0011] In exemplary implementations, the injection rate data includes data indicating a rate at which water is injected or pumped into one or more wells at the resource site.

[0012] Furthermore, the production rate data includes data indicating a rate at which fluid including hydrocarbons is extracted from one or more wells at the resource site.

[0013] In some instances, the sensitivity tests include a computational analysis that quantifies an impact of a plurality of injection rates based on the second variable relative to a plurality of production rates based on the first variable.

[0014] The production forecast report, according to one embodiment, includes data indicating an optimal injection rate for which maximum fluid is produced for one or more of: the first producer at the resource site; or the one or more producers bounded by the geo-radius.

[0015] In some embodiments, the forecasting model is further parameterized with time duration data for which production estimates are generated based on the forecasting model.

[0016] Moreover, one or more of the fluid production rate data or the fluid injection rate data is preprocessed to remove anomalous data values due to instrumentation errors, wherein the removed anomalous data values are substituted with interpolated values derived from the fluid production rate data or the fluid injection rate data.

[0017] In one embodiment, the visualization indicating the production forecast report includes a plurality of production forecast data for a plurality of wells bounded by the geo-radius.

[0018] In addition, the visualization aggregates production forecast data for a plurality of wells bounded by the geo-radius according to some embodiments.

BRIEF DESCRIPTION OF THE DRAWINGS

[0019] The disclosure is illustrated by way of example, and not by way of limitation in the figures of the accompanying drawings in which like reference numerals are used to refer to similar elements. It is emphasized that various features may not be drawn to scale and the dimensions of various features may be arbitrarily increased or reduced for clarity of discussion.

[0020] **FIG. 1** shows a high-level flowchart for water flooding optimization at a resource site for increased production of hydrocarbons, according to an embodiment.

[0021] **FIG. 2** shows a cross-sectional view of a resource site for which the process of **FIG. 1** may be executed, according to an embodiment.

[0022] **FIG. 3** shows a networked system illustrating a communicative coupling of devices or systems associated with the resource site of **FIG. 2**, according to an embodiment.

[0023] **FIGS. 4A, 4B-1** to **4B-6,** and **4C** provide exemplary visualizations associated with a production forecast report, according to an embodiment.

[0024] **FIG. 5** shows an exemplary workflow for water flooding optimization at a resource site for increased production of hydrocarbons, according to an embodiment.

DETAILED DESCRIPTION

[0025] Reference will now be made in detail to embodiments, examples of which are illustrated in the accompanying drawings and figures. In the following detailed description, numerous specific details are set forth in order to provide a thorough understanding of the disclosed solution. However, it will be apparent to one of ordinary skill in the art that this disclosure may be practiced without these specific details. In other instances, well-known methods, procedures, components, circuits, and networks have not been described in detail so as not to unnecessarily obscure aspects of the embodiments.

[0026] The disclosed systems and methods may be accomplished using interconnected devices and systems that obtain a plurality of data associated with various parameters of interest at a resource site. The workflows/flowcharts described in this disclosure, according to some embodiments, implicate a new processing approach (*e.g.*, hardware, special purpose processors, and specially programmed general-purpose processors) because such analyses are too complex and cannot be done by a person in the time available or at all. Thus, the described systems and methods are directed to tangible implementations or solutions to specific technological problems in exploring natural resources such as oil, gas, water well industries, and other mineral exploration operations. More specifically, the systems and methods presently disclosed may be applicable to exploring resources such as oil, natural gas, water, and Salar brines.

[0027] Attention is now directed to methods, techniques, infrastructure, and workflows for operations that may be carried out at a resource site. Some operations in the processing procedures, methods, techniques, and workflows disclosed herein may be combined while the order of some operations may be changed. Some embodiments include an iterative refinement of one or more data associated with the resource site via feedback loops executed by one or more computing device processors and/or through other control devices/mechanisms that make determinations regarding whether a given action, template, transformer model, or other resource data, etc., is sufficiently accurate.

Overview

[0028] The disclosed methods and systems are directed to water flooding operation optimizations at a resource site. According to one embodiment, a model (e.g., a time series forecasting model) built using machine learning operations is used to generate forecasts that recommend optimal water flood strategies that maximize oil production from one or more wells at a resource site. For example, the model may be used to maximize oil production at the resource site with minimum production costs (e.g., minimum water production and minimum water injection). In one embodiment, a signal processing engine (e.g., an optimizer engine) of a computing device is used to execute one or more processes, workflows, or operations associated with maximizing hydrocarbon production at a resource site. For example, the signal processing engine including the optimizer engine may analyze, using the model, the feasibility of achieving a target amount of production enhancement at a future time and provide a best or otherwise optimal water injection report for each injector as needed. Taking advantage of the high-performance of the model, the optimizer engine can be easily adopted to make fast and low-risk water flood management plans.

[0029] Moreover, the disclosed techniques, according to some embodiments, are based on a forecasting model that is used to forecast fluid (e.g., hydrocarbon) production rates as a function of water injection rates. In some cases, sensitivity tests are conducted using the forecasting model to learn the impact of water flooding on oil production from the perspective of production patterns for a given reservoir and/or from the perspective of a given well coupled to the reservoir. The disclosed technique allows various scenarios to be tested within a relatively short time (e.g., within seconds and/or minutes of executing one or more simulations). Furthermore, the disclosed techniques enable the use of the optimizer engine to find an optimal solution for water flood operations for a target increase of cumulative oil production within a predicted future duration (e.g., a future day, a future week, a future month, a future year, etc.). In addition, the disclosed techniques provide reports that control water flood operations at the resource site to maximize oil recovery from a reservoir at the resource site and enables configuration or update capabilities based on the most recent production data at the resource site to mitigate risk. In some embodiments, the term optimize/optimal and its variants (e.g., efficient, optimally, etc.) may simply indicate improving, rather than the ultimate form of 'perfection' or the like.

High-Level Flowchart

[0030] **FIG. 1** shows an example high-level flowchart 100 for water flooding optimization at a resource site for increased production of hydrocarbons.

[0031] At block 102, a signal processing engine receives: fluid production rate data and fluid injection rate data using, for example, one or more sensors at a resource site or sensor data associated with the resource site. The fluid production rate data, for example, includes data indicating a rate at which fluid including hydrocarbons is extracted from one or more wells at the resource site while the fluid injection rate data includes data indicating a rate at which water is injected or pumped into one or more wells at the resource site.

[0032] At block 104, the signal processing engine generates a forecasting model based on one or more of the fluid production rate data and the fluid injection rate data. In one embodiment, the forecasting model is configured to generate or otherwise provide forecasts that recommend optimal water flood strategies that maximize oil production from one or more wells at a resource site.

[0033] At block 106, the signal processing engine executes, based on the forecasting model, one or more sensitivity tests to generate a production forecast report. The production forecast report, according to one embodiment, includes a plurality of production forecast data for a plurality of wells bounded by a geo-radius circumscribing one or more injectors and one or more producers at a resource site. In particular, the production forecast report includes data indicating an optimal injection rate for which maximum fluid can be produced for one or more producers bounded by a geo-radius at the resource site. Thus, the production forecast report beneficially includes recommendation data indicating optimal water injection strategy at the resource site that maximize fluid (e.g., oil) production and minimize the cost of fluid (e.g., water) injection and other fluid (e.g., water) production at the resource site. These and other aspects are further discussed in conjunction with **FIG. 5** below.

Resource Site

[0034] **FIG. 2** shows a cross-sectional view of a resource site 200 for which the process of **FIG. 1** may be executed. While the illustrated resource site 200 represents a subterranean formation, the resource site, according to some embodiments, may be below water bodies such as oceans, seas, lakes, ponds, wetlands, rivers, etc.

[0035] According to one embodiment, various measurement tools capable of sensing one or more parameters such as seismic two-way travel time, density, resistivity, production rate, etc., of a subterranean formation and/or geological formations may be provided at the resource site. As an example, wireline tools may be used to obtain measurement information related to geological attributes (e.g., geological attributes of a wellbore and/or reservoir) including geophysical and/or geochemical information associated with the resource site 200. In some embodiments, various sensors may be located at various locations around the resource site 200 to monitor and collect data for executing the process of **FIG. 1**.

[0036] Part, or all, of the resource site 200 may be on land, on water, or below water. In addition, while a resource site 200 is depicted, the technology described herein may be used with any combination of one or more resource sites (e.g., multiple oil fields or multiple wellsites, etc.), one or more processing facilities, etc. As can be seen in **FIG. 2**, the resource site 200 may have data acquisition tools 202a, 202b, 202c, and 202d positioned at various locations within the resource site 200. The subterranean structure 204 may have a plurality of geological formations 206a-206d. As shown, this structure may have several formations or layers, including a shale layer 206a, a carbonate layer 206b, a shale layer 206c, and a sand layer 206d. A fault 207 may extend through the shale layer 206a and the carbonate layer 206b. The data acquisition tools, for example, may be adapted to take measurements and detect geophysical and/or geochemical characteristics of the various formations shown.

[0037] While a specific subterranean formation with specific geological structures is depicted, it is appreciated that the resource site 200 may contain a variety of geological structures and/or formations, sometimes having extreme complexity. In some locations of a given geological structure, for example below a water line relative to the given geological structure, fluid may occupy pore spaces of the formations. Each of the measurement devices (e.g., sensors) may be used to measure properties of the formations and/or other geological features. While each data acquisition tool is shown as being in specific locations in **FIG. 2**, it is appreciated that one or more types of measurement may be taken at one or more locations across one or more sources of the resource site 200 or other locations for comparison and/or analysis. The data collected from various sources at the resource site 200 may be processed and/or evaluated and/or used as training data, and or used to generate high resolution result sets for characterizing a resource at the resource site, and/or used for generating resource models, etc.

[0038] In one embodiment, the data collected by one or more sensors at the resource site may include data associated with the number of wells of a first reservoir or second reservoir at the resource site, data associated with the number of grid cells of the first or second reservoir, data associated with the average permeability of the first or second reservoir, data associated with the production duration history (e.g., number of years of production) of the first reservoir or second, etc. According to some embodiments, the number of wells of the first or second reservoir at the resource site may include one or more injectors (e.g., wells into which fluid including water is pumped) and/or one or more producers (e.g., wells from which fluid including hydrocarbons are extracted).

[0039] Data acquisition tool 202a is illustrated as a measurement truck, which may comprise devices or sensors that take measurements of the subsurface through sound vibrations such as, but not limited to, seismic measurements. Drilling tool 202b may include a downhole sensor adapted to perform logging while drilling (LWD) data collection. Wireline tool 202c may include a downhole sensor deployed in a wellbore or borehole. Production tool 202d may be deployed from a production unit or Christmas tree into a completed wellbore. Examples of parameters that may be measured include weight on bit, torque on bit, subterranean pressures (e.g., underground fluid pressure), temperatures, flow rates, compositions, rotary speed, particle count, voltages, currents, gamma ray data associated with the well at the resource site, resistivity data associated with the well at the resource site, density, or porosity data associated with the well at the resource site, water saturation data associated with the well at the resource site, hydrocarbon saturation associated with the well at the resource site and/or other parameters associated with operations at the resource site.

[0040] Sensors may be positioned about the resource site 200 to collect data relating to various oil field operations, such as sensors deployed by the data acquisition tools 202. The sensors may include any type of sensor such as a metrology sensor (*e.g.*, temperature, humidity), an automation enabling sensor, an operational sensor (*e.g.*, pressure sensor, H_2S sensor, thermometer, depth, tension), evaluation sensors, that can be used for acquiring data regarding the geological formation, wellbore information, formation fluid/gas information, wellbore fluid information, data associated with gas/oil/water comprised in the formation/wellbore fluid, etc.

For example, the sensors may include accelerometers, flow rate sensors, pressure transducers, electromagnetic sensors, acoustic sensors, temperature sensors, chemical agent detection sensors, nuclear sensor, and/or any additional suitable sensors. In one embodiment, the data captured by the one or sensors may be used to characterize, or otherwise generate one or more parameter values for a high resolution result set used to, for example, generate and/or configure a resource model and/or a transformer model and/or a forecasting model. In other embodiments, test data or synthetic data may also be used in developing and/or configuring the resource model and/or the transformer model and/or the forecasting model via one or more simulations and or testing operations.

[0041] Evaluation sensors may be featured in downhole tools such as tools 202b-202d and may include for instance electromagnetic, acoustic, nuclear, and optic sensors. Examples of tools including evaluation sensors that can be used in the framework of the current method include electromagnetic tools including imaging sensors such as FMI™ or QuantaGeo™ (mark of SLB, Houston, TX); induction sensors such as Rt Scanner™ (mark of SLB, Houston, TX), multifrequency dielectric dispersion sensor such as Dielectric Scanner™ (mark of SLB, Houston, TX); acoustic tools including sonic sensors, such as Sonic Scanner™ (mark of SLB, Houston, TX) or ultrasonic sensors, such as pulse-echo sensor as in UBI™ or PowerEcho™ (mark of SLB, Houston, TX) or flexural sensors PowerFlex™ (mark of SLB, Houston, TX); nuclear sensors such as Litho Scanner™ (mark of SLB, Houston, TX) or nuclear magnetic resonance sensors; fluid sampling tools including fluid analysis sensors such as InSitu Fluid Analyzer ™ (mark of SLB, Houston, TX); distributed sensors including fiber optic. Such evaluation sensors may be used in particular for evaluating the formation in which the well is formed (*i.e.*, determining petrophysical or geological properties of the formation), for verifying the integrity of the well (such as casing or cement properties) and/or analyzing the produced fluid (flow, type of fluid, etc.).

[0042] As shown, data acquisition tools 202a-202d may generate data plots or measurements 208a-208d, respectively. These data plots are depicted within the resource site 200 to demonstrate that data generated by some of the operations executed at the resource site 200.

[0043] Data plots 208a-208c are examples of static data plots that may be generated by data acquisition tools 202a-202c, respectively. However, it is herein contemplated that data plots 208a-208c may also be data plots that may be generated and updated in real time. These measurements may be analyzed to better define properties of the formation(s) and/or determine the accuracy of the measurements and/or check for and compensate for measurement errors. The plots of each of the respective measurements may be aligned and/or scaled for comparison and verification purposes. In some embodiments, base data associated with the plots may be incorporated into site planning, modeling a test at the resource site 200. The respective measurements that can be taken may be any of the above.

[0044] Other data may also be collected, such as historical data of the resource site 200 and/or sites similar to the resource site 200, user inputs, information (e.g., economic information) associated with the resource site 200 and/or sites similar to the resource site 200, and/or other measurement data and other parameters of interest. Similar measurements may also be used to measure changes in formation aspects over time.

[0045] Computer facilities such as those discussed in association with **FIG. 3** may be positioned at various locations about the resource site 200 (*e.g.*, a surface unit) and/or at remote locations. A surface unit (e.g., one or more terminals 320) may be used to communicate with the onsite tools and/or offsite operations, as well as with other surface or downhole sensors. The surface unit may be capable of sending commands to the oil field equipment/systems, and receiving data therefrom. The surface unit may also collect data generated during production operations and can produce output data, which may be stored or transmitted for further processing.

[0046] The data collected by sensors may be used alone or in combination with other data. The data may be collected in one or more databases and/or transmitted on or offsite. The data may be historical data, real time data, or combinations thereof. The real time data may be used in real time, or stored for later use. The data may also be combined with historical data or other inputs for further analysis or for modeling purposes to optimize production processes at the resource site 200. In one embodiment, the data is stored in separate databases, or combined into a single database.

High-Level Networked System

[0047] **FIG. 3** shows a high-level networked system 300 illustrating a communicative coupling of devices or systems associated with the resource site 200. The system shown in the figure may include a set of processors 302a, 302b, and 302c for executing one or more processes discussed herein. The set of processors 302 may be electrically coupled to one or more servers (e.g., computing systems) including memory 306a, 306b, and 306c that may store for example, program data, databases, and other forms of data. Each server of the one or more servers may also include one or more communication devices 308a, 308b, and 308c. The set of servers may provide a cloud-computing platform 310. In one embodiment, the set of servers includes different computing devices that are situated in different locations and may be scalable based on the needs and workflows associated with the resource site 200. The communication devices of each server may enable the servers to communicate with each other through a local or global network such as an Internet network. In some embodiments, the servers may be arranged as a town 312, which may provide a private or local cloud service for users. A town may be advantageous in remote locations with poor connectivity. Additionally, a town may be beneficial in scenarios with large networks where security may be of concern. A town in such large network embodiments can facilitate implementation of a private network within such large networks. The town may interface with other towns or a larger cloud network, which may also communicate over public communication links. Note that cloud-computing platform 310 may include a private network and/or portions of public networks. In some cases, a cloud-computing platform 310 may include remote storage and/or other application processing capabilities.

[0048] The system of **FIG. 3** may also include one or more user terminals 314a and 314b each including at least a processor to execute programs, a memory (e.g., 316a and 316b) for storing data, a communication device and one or more user interfaces and devices that enable the user to receive, view, and transmit information. In one embodiment, the user terminals 314a and 314b is a computing system having interfaces and devices including keyboards, touchscreens, display screens, speakers, microphones, a mouse, styluses, etc. The user terminals 314 may be communicatively coupled to the one or more servers of the cloud-computing platform 310. The user terminals 314 may be client terminals or expert terminals, enabling collaboration between clients and experts through the system of **FIG. 3**.

[0049] The system of **FIG. 3** may be associated with at least one or more resource sites 200 having, for example, a set of terminals 320, each including at least a processor, a memory, and a communication device for communicating with other devices communicatively coupled to the cloud-computing platform 310. The resource site 200 may also have one or more sensors (e.g., one or more sensors described in association with **FIG. 2**) or sensor interfaces 322a and 322b communicatively coupled to the set of terminals 320 and/or directly coupled to the cloud-computing platform 310. In some embodiments, data collected by the one or more sensors/sensor interfaces 322a and 322b may be processed to generate a one or more resource models (e.g., reservoir models) and/or one or more forecasting models and/or one or more resolved datasets used to generate the resource model and/or forecasting model which may be displayed on a user interface associated with the set of terminals 320, and/or displayed on user interfaces associated with the set of servers of the cloud computing platform 310, and/or displayed on user interfaces of the user terminals 314. Furthermore, various equipment/devices discussed in association with the resource site 200 may also be communicatively coupled to the set of terminals 320 and or communicatively coupled directly to the cloud-computing platform 310. The equipment and sensors may also include one or more communication device(s) that may communicate with the set of terminals 320 to receive orders/instructions locally and/or remotely from the resource site 200 and also send statuses/updates to other terminals such as the user terminals 314.

[0050] The system of **FIG. 3** may also include one or more client servers 324 including a processor, memory and communication device. For communication purposes, the client servers 324 may be communicatively coupled to the cloud-computing platform 310, and/or to the user terminals 314a and 314b, and/or to the set of terminals 320 at the resource site 200 and/or to sensors at the oil field, and/or to other equipment at the resource site 200.

[0051] A processor, as discussed with reference to the system of **FIG. 3**, may include a microprocessor, a graphical processing unit (GPU), a microcontroller, a processor module or subsystem, a programmable integrated circuit, a programmable gate array, or another control or computing device.

[0052] The memory/storage media discussed above in association with **FIG. 3** can be implemented as one or more computer-readable or machine-readable storage media that are non-transitory. In some embodiments, storage media may be distributed within and/or across multiple internal and/or external enclosures of a computing system and/or additional computing systems. Storage media may include one or more different forms of memory including semiconductor memory devices such as dynamic or static random access memories (DRAMs or SRAMs), erasable and programmable read-only memories (EPROMs), electrically erasable and programmable read-only memories (EEPROMs) and flash memories; magnetic disks such as fixed, floppy and removable disks; other magnetic media including tape; optical media such as compact disks (CDs) or digital video disks (DVDs), BluRays or any other type of optical media; or other types of storage devices. "Non-transitory" computer readable medium refers to the medium itself (i.e., tangible, not a signal) and not data storage persistency (*e.g.*, RAM vs. ROM).

[0053] Note that instructions can be provided on one computer-readable or machine-readable storage medium, or alternatively, can be provided on multiple computer-readable or machine-readable storage media distributed in a large system having possibly plural nodes and/or non-transitory storage means. Such computer-readable or machine-readable storage medium or media is (are) considered to be part of an article (or article of manufacture). The storage medium or media can be located either in a computer system running the machine-readable instructions, or located at a remote site from which machine-readable instructions can be downloaded over a network for execution.

[0054] It is appreciated that the described system of **FIG. 3** is an example that may have more or fewer components than shown, may combine additional components, and/or may have a different configuration or arrangement of the components. The various components shown may be implemented in hardware, software, or a combination of both, hardware and software, including one or more signal processing engines and/or application specific integrated circuits.

[0055] Further, the steps in the flowchart described below may be implemented by running one or more functional modules in an information processing apparatus such as general-purpose processors or application specific chips, such as ASICs, FPGAs, PLDs, GPUs or other appropriate devices associated with the system of **FIG. 3**. For example, the flowchart of **FIG. 1** as well as the flowchart below may be executed using a signal processing engine including an optimizer engine stored in memory 306a, 306b, or 306c such that the signal processing engine includes instructions that are executed by the one or more processors such as processors 302a, 302b, or 302c as the case may be. The various modules of **FIG. 3**, combinations of these modules, and/or their combination with general hardware are included within the scope of protection of the disclosure. While one or more computing processors (e.g., processors 302a, 302b, or 302c) may be described as executing steps associated with one or more of the flowcharts described in this disclosure, the one or more computing device processors may be associated with the cloud-based computing platform 310 and may be located at one location or distributed across multiple locations. In one embodiment, the one or more computing device processors may also be associated with other systems of **FIG. 3** other than the cloud-computing platform 310.

[0056] In some embodiments, a computing system is provided that includes at least one processor, at least one memory, and one or more programs stored in the at least one memory, such that the programs comprise instructions, which when executed by the at least one processor, are configured to perform any method disclosed herein.

[0057] In some embodiments, a computer readable storage medium is provided, which has stored therein one or more programs, the one or more programs including instructions, which when executed by a processor, cause the processor to perform any method disclosed herein. In some embodiments, a computing system is provided that includes at least one processor, at least one memory, and one or more programs stored in the at least one memory for performing any method disclosed herein. In some embodiments, an information processing apparatus for use in a computing system is provided for performing any method disclosed herein.

Embodiments

[0058] The present disclosure is directed to methods and systems that use a forecasting model to make sensitivity tests that generate operational recommendations data as well as equipment control signals at a resource site. The forecasting model used may comprise a vector auto regression construct that learns relationships between production rates (dependent variable(s)) and waterflood rates (independent variable(s)) for multivariate time series data captured from one or more wells in a pattern, or a group of wells that produce fluid including hydrocarbons associated with a reservoir at the resource site. To develop the forecasting model, operational data may be generated that comprises daily production rates data from all producers (e.g., locations associated with the resource site for producing hydrocarbons) and daily injection rates data from all injectors (e.g., locations associated with the resource site into which fluid (e.g., water) is injected) at the resource site.

[0059] According to one embodiment, workflows associated with the disclosed methods include a data wrangling operation by a signal processing engine that selects a group of wells (e.g., a group of wells within a pattern or well configuration) at the resource site. To define a valid pattern according to some embodiments, a distance threshold may be set or otherwise established and used to select injectors and/or producers within a defined radius distance (e.g., X meters in radius relative to a selected central locus at a resource site). The defined radius (e.g., also referred to as geo-radius elsewhere herein) may include a radius between 100 – 1000 meters or 1000 – 5000 meters relative to a selected central locus at the resource site.

[0060] Furthermore, a correlation-based filter of the optimizer engine may be used to select pairs of injection and production wells which are strongly correlated or related. The correlation-based filter, according to some implementations, ensures that only wells with strong correlation go into the forecasting model, resulting in a more stable and reliable performance. Additionally, the filtered data may be applied to the forecasting model. According to one embodiment, production rate data (e.g., daily production rate data) is correlated with injection rate data (e.g., daily injection rate data) to determine whether the production rate data is strongly correlated with the injection rate data. For example, strong correlation between production rate data and injection rate data may include determining that changes in the production rate data are strongly sensitive to changes in the injection rate data. In other embodiments, strong correlation between the production rate data and the injection rate data includes determining that the production rate data positively or negatively tracks the injection rate data. If correlation between the injection rate data and the production rate data is poor, then there will be little to no impact of the changes in the injection rate data on the production rate data.

[0061] The disclosed methods may also involve conducting sensitivity tests using the forecasting model. The sensitivity tests, according to one embodiment, analyzes and quantifies the impact of injection on production with different setups, configurations, or parameterizations of the forecasting model to provide reports that beneficially facilitate optimal water injections for maximum hydrocarbon productions at the resource site. With a validated forecasting model, the disclosed workflows may automatically change future injection rates (e.g., daily, weekly, or monthly injection rates) of injectors in percentages from a baseline value or in an absolute value so that the forecasting model may predict the daily, weekly, or monthly oil production rates for a given timeframe based on one or more tested injection rate(s). Comparing the forecasting between baseline and updated injection rates indicates the impact of water injection on future hydrocarbon production.

[0062] According to some embodiments, the sensitivity tests can be carried out with multiple scenarios to illustrate the behavior of the oil production from both pattern level and well level. For example, **FIG. 4A** shows a scenario where an injector's injection rate is altered from -20% to 20% within an interval or step size of 5%. In particular, this figure indicates that increasing injection rate leads to a decrease in oil production from pattern level. According to one embodiment, the pattern level indicates combined fluid production data for all the wells (e.g., producers) within a group of wells (e.g., a group of selected wells bounded by a geo-radius) at a resource site.

[0063] **FIGS. 4B-1** to **4B-6** shows production data plots for individual wells at the resource site with different responses from each producer relative to water injection. As shown in **FIGS. 4B-2** and **4B-3**, these plots show a positive impact of water injection into two wells while the remaining plots, **FIGS. 4B-1**, **4B-4** to **4B-6**, show a negative impact. For example, **FIGS. 4B-1** and **4B-4** show that for a first duration of time (e.g., from Date 1 to Date 2), the fluid (e.g., water) injection rate based on the above noted altered rates (e.g., from -20% to 20% within an interval or step size of 5%) leads to an increased production of hydrocarbon for one or more selected wells. Beyond the first duration, the hydrocarbon production rate reduces for the one or more selected wells. It is important to conduct well level analysis to ensure that the normal production flow is well maintained with changing of water flood. Meanwhile, understanding the pattern level response effectively indicates whether oil recovery can be enhanced with a changing water flood operation.

[0064] The optimizer engine, according to some embodiments, computes the best solution for water injection rate of each injector to achieve total oil production enhancement for a given period (e.g., next month, next week, next day) relative to a specific observation data (e.g., last observation date). The optimizer engine may iterate simulations or sensitivity tests over a plurality of injection setups or configurations and may generate forecasts in the form of reports, for example, that indicate the cumulative oil production for each injection setup. For each increase in the amount of fluid production, the optimizer engine searches for one or more situations that require minimum water injection and produces a minimum water production configuration for the forecasting model. In addition, changes in the water injection rates may be constrained by specific preset ranges such as between -20% to 20%. The one satisfying the constraints is output as the single solution. According to one embodiment, the optimizer engine provides changes in injection rate data within an operational constraint of -20% to +20% of the injection rate data to minimize the water production and water injection and thereby maximize fluid production rate data (e.g., maximize rate of production of hydrocarbons such as oil at the resource site).

[0065] Taking a well pattern as an example and assuming there are two injectors and seven producers, the optimizer engine may show an optimal water flood change required to achieve various percent increases of the total oil production for a future timeframe as shown in **FIG. 4C**. The optimal solution may indicate an injection rate with a minimum water injection leading to a minimum water production. This scenario may add constraints that calibrate the water injection within -20% - 20%. The optimizer engine may indicate that the maximum oil production rate can be increased by 2.3% for a future timeframe, which would facilitate production configurations (automatic calibration of pumps) for hydrocarbon production enhancements. Based on the choice of an achievable target, the optimizer engine may provide data on for updating water injection controls for each injector in the pattern.

Exemplary Flowchart

[0066] **FIG. 5** shows an exemplary detailed workflow 500 for water flooding optimization at a resource site. It is appreciated that a signal processing engine stored in a memory device may cause a computer processor to execute the various processing stages of the workflows discussed herein. For example, the disclosed techniques may be implemented as signal processing engine within a geological software tool such that the signal processing engine enables determining water flooding optimization at a resource site for increased production of hydrocarbons based on the processes outlined herein.

[0067] At block 502, the signal processing engine determines a geo-radius circumscribing one or more injectors and one or more producers at a resource site. The geo-radius, according to one embodiment, defines a geometrical pattern bounding or selecting one or more injectors or one or more producers at the resource site. Furthermore, the one or more injectors may comprise at least one well into which fluid including water is pumped while the one or more producers comprise at least one well from which fluid including hydrocarbons can be extracted.

[0068] At block 504, the signal processing engine receives: fluid production rate data obtained from one or more sensors disposed about, or associated with the one or more producers at the resource site or derived/obtained from sensor data associated with the resource site; and fluid injection rate data obtained from one or more sensors disposed about, or associated with the one or more injectors at the resource site or derived/obtained from sensor data associated with the resource site.

[0069] At block 506, the signal processing engine correlates the fluid production rate data with the fluid injection rate data to determine correlated pairs of injectors and producers associated with the one or more injectors and the one or more producers such that the correlated pairs of injectors and producers indicate a relationship between a first injector comprised in the one or more injectors and a first producer comprised in the one or more producers.

[0070] At block 508, the signal processing engine generates a forecasting model using the correlated pairs of injectors and producers, the forecasting model being parameterized using one or more of: a first variable indicating a first range of fluid production rate values, and a second variable indicating a second range of fluid injection rate values.

[0071] At block 510, the signal processing engine executes, based on the forecasting model, one or more sensitivity tests comprising at least one simulation based on the first variable or the second variable to generate a production forecast report for the first producer. According to one embodiment, one or more injectors including the first injector are combined with one or more producers including the first producer to generate the forecasting model, such that at least a first range parameter associated with the forecasting model is parameterized by the first variable and a second range parameter associated with the forecasting model is parameterized by the second variable.

[0072] At block 512, the signal processing engine executes one or more of: initiating generation of a visualization indicating the production forecast report for viewing on a display device, or initiating transmission of a pump rate control signal to configure a pump mechanism disposed about the first producer or the first injector at the resource site.

[0073] These and other implementations may each optionally include one or more of the following features. The injection rate data, according to one embodiment, includes data indicating a rate at which water is injected or pumped into one or more wells at the resource site.

[0074] Moreover, the production rate data includes data indicating a rate at which fluid including hydrocarbons is extracted from one or more wells at the resource site.

[0075] In addition, the sensitivity tests include a computational analysis that quantifies an impact of a plurality of injection rates based on the second variable relative to a plurality of production rates based on the first variable.

[0076] In some instances, the production forecast report includes data indicating an optimal injection rate for which maximum fluid is produced for the first producer. According to some embodiments, the production forecast report may indicate an optimal injection rate for which maximum fluid is produced for the one or more producers bounded by the geo-radius. Thus, the production forecast report beneficially includes recommendation data indicating optimal water injection strategy at the resource site that maximize fluid (e.g., oil) production and minimize the cost of fluid (e.g., water) injection and other fluid (e.g., water) production operations at the resource site.

[0077] For example, the optimizer engine or the signal processing engine may be used to maximize, based on the production forecast report, the cumulative hydrocarbon (e.g., oil) production for the whole pattern comprising multiple selected producing wells (e.g., producers bounded by the geo-radius) at the resource site.

[0078] In some cases, the signal processing engine recommends an optimal or an ideal (e.g., best) water injection rate(s) that leads to an increased hydrocarbon production for the selected producing wells. According to some embodiments, a plurality of injector-producer well pairs are selected from the one or more injectors and the one or more producers bounded by the geo-radius in response to executing the correlation operation discussed above. As part of selecting the plurality of injector-producer well pairs, the signal processing engine may execute a pattern analysis operation including distance thresholding operations and correlation thresholding operations using the injection rate data and the production rate data for the one or more injectors and the one or more producers bounded by the geo-radius. The geo-radius, according to one embodiment, comprises a distance parameter that extends from a central geolocation at the resource site to an edge of a geometrical pattern that is used to bound, select, or encompass one or more producers and/or one or more injectors at the resource site.

[0079] The forecasting model may be further parameterized with time duration data (e.g., daily time period, weekly time period, or monthly time period) for which production estimates are generated based on the forecasting model. In some instances, the time duration data includes time data associated with a future period for which the production forecast report is generated.

[0080] According to one embodiment, one or more of the fluid production rate data or the fluid injection rate data is preprocessed to remove anomalous data values due to instrumentation errors. The removed anomalous data values may be substituted with interpolated values derived from the fluid production rate data or the fluid injection rate data.

[0081] Moreover, the visualization indicating the production forecast report may include a plurality of production forecast data for a plurality of wells bounded by the geo-radius.

[0082] In some cases, the visualization aggregates production forecast data for a plurality of wells bounded by the geo-radius.

[0083] The disclosed technology beneficially provides an advisory tool or optimizer engine that enhances workflows related to waterflooding or water injection operations at a resource size. The advisory tool, according to some embodiments facilitates maximizing hydrocarbon production (e.g., oil production) with minimum amount of water at minimum fluid injection costs.

[0084] While any discussion of or citation to related art in this disclosure may or may not include some prior art references, this is neither a concession nor acquiescence to the position that any given reference is prior art or analogous prior art.

[0085] The foregoing description, for purpose of explanation, has been described with reference to specific embodiments. However, the illustrative discussions above are not intended to be exhaustive or to limit the disclosure to the precise forms disclosed. Many modifications and variations are possible in view of the above teachings. The embodiments were chosen and described in order to explain the principles of the disclosure and its practical applications, to thereby enable others skilled in the art to use the invention and various embodiments with various modifications as are suited to the particular use contemplated.

[0086] It will also be understood that, although the terms first, second, etc., may be used herein to describe various elements, these elements should not be limited by these terms. These terms are used to distinguish one element from another. For example, a first object or step could be termed a second object or step, and, similarly, a second object or step could be termed a first object or step, without departing from the scope of the disclosure. The first object or step, and the second object or step, are both objects or steps, respectively, but they are not to be considered the same object or step.

[0087] The terminology used in the description herein is for the purpose of describing particular embodiments and is not intended to be limiting. As used in the description of the disclosure and the appended claims, the singular forms "a," "an" and "the" are intended to include the plural forms as well, unless the context clearly indicates otherwise. It will also be understood that the term "and/or" as used herein refers to and encompasses any possible combination of one or more of the associated listed items. It will be further understood that the terms "includes," "including," "comprises" and/or "comprising," when used in this specification, specify the presence of stated features, integers, steps, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, steps, operations, elements, components, and/or groups thereof.

[0088] As used herein, the term "if" may be construed to mean "when" or "upon" or "in response to determining" or "in response to detecting," depending on the context.

[0089] Those with skill in the art will appreciate that while some terms in this disclosure may refer to absolutes, *e.g.*, *all* source receiver traces, *each* of a plurality of objects, etc., the methods and techniques disclosed herein may also be performed on fewer than all of a given thing, *e.g.*, performed on one or more components and/or performed on one or more source receiver traces. Accordingly, in instances in the disclosure where an absolute is used, the disclosure may also be interpreted to be referring to a subset.

CLAIMS

What is claimed is:

1. A method for water flooding optimization at a resource site for increased production of hydrocarbons, the method comprising:

determining a geo-radius circumscribing a first injector and a first producer at a resource site;

receiving fluid production rate data from the first producer and fluid injection rate data from the first injector;

correlating the fluid production rate data with the fluid injection rate data to determine a correlated pair of injectors and producers associated with the first injector and the second injector;

generating a forecasting model using the correlated pair of injectors and producers, the forecasting model being parameterized using one or more of:

a first variable indicating a first range of fluid production rate values, and

a second variable indicating a second range of fluid injection rate values;

executing, based on the forecasting model, one or more sensitivity tests comprising at least one simulation based on the first variable or the second variable to generate a production forecast report for the first producer; and

executing one or more of:

initiating generation of a visualization indicating the production forecast report for viewing on a display device, or

initiating transmission of a pump rate control signal to configure a pump mechanism disposed about the first producer or the first injector at the resource site.

2. The method of Claim 1, wherein:

the geo-radius defines a geometrical pattern bounding or selecting the first producer and the first injector at the resource site,

the first injector being comprised in one or more injectors including at least one well into which fluid including water is pumped, and

the first producer being comprised in one or more producers including at least one well from which fluid including hydrocarbons is extracted.

3. The method of Claim 1, wherein the injection rate data includes data indicating a rate at which water is injected or pumped into one or more wells at the resource site.

4. The method of Claim 1, wherein the production rate data includes data indicating a rate at which fluid including hydrocarbons is extracted from one or more wells at the resource site.

5. The method of Claim 1, wherein the sensitivity tests include a computational analysis that quantifies an impact of a plurality of injection rates based on the second variable relative to a plurality of production rates based on the first variable.

6. The method of Claim 1, wherein the production forecast report includes data indicating an optimal injection rate for which maximum fluid is produced for one or more of:

the first producer at the resource site, or

one or more producers bounded by the geo-radius.

7. The method of Claim 1, wherein the forecasting model is further parameterized with time duration data for which production estimates are generated based on the forecasting model.

8. The method of Claim 1, wherein one or more of the fluid production rate data or the fluid injection rate data is preprocessed to remove anomalous data values due to instrumentation errors, wherein the removed anomalous data values are substituted with interpolated values derived from the fluid production rate data or the fluid injection rate data.

9. The method of Claim 1, wherein the visualization indicating the production forecast report includes a plurality of production forecast data for a plurality of wells bounded by the geo-radius.

10. The method of Claim 1, wherein the visualization aggregates production forecast data for a plurality of wells bounded by the geo-radius.

11. A system for water flooding optimization at a resource site for increased production of hydrocarbons, the system comprising:

a computer processor, and

memory storing instructions that are executable by the computer processor to:

determine a geo-radius circumscribing a first injector and a first producer at a resource site;

receive fluid production rate data from the first producer and fluid injection rate data from the first injector;

correlate the fluid production rate data with the fluid injection rate data to determine a correlated pair of injectors and producers associated with the first injector and the first producer;

generate a forecasting model using the correlated pairs of injectors and producers, the forecasting model being parameterized using one or more of:

a first variable indicating a first range of fluid production rate values, and

a second variable indicating a second range of fluid injection rate values;

execute using the forecasting model, one or more sensitivity tests comprising at least one simulation based on the first variable or the second variable to generate a production forecast report for the first producer; and

execute one or more of:

initiating generation of a visualization indicating the production forecast report for viewing on a display device, or

initiating transmission of a pump rate control signal to configure a pump mechanism disposed about the first producer or the first injector at the resource site.

12. The system of Claim 11, wherein:

the geo-radius defines a geometrical pattern bounding or selecting the first producer and the first injector at the resource site,

the first injector being comprised in one or more injectors including at least one well into which fluid including water is pumped, and the first producer being comprised in one or more producers including at least one well from which fluid including hydrocarbons is extracted.

13. The system of Claim 11, wherein the injection rate data includes data indicating a rate at which water is injected or pumped into one or more wells at the resource site.

14. The system of Claim 11, wherein the production rate data includes data indicating a rate at which fluid including hydrocarbons is extracted from one or more wells at the resource site.

15. The system of Claim 11, wherein the sensitivity tests include a computational analysis that quantifies an impact of a plurality of injection rates based on the second variable relative to a plurality of production rates based on the first variable.

16. The system of Claim 11, wherein the production forecast report includes data indicating an optimal injection rate for which maximum fluid is produced for one or more of:

the first producer at the resource site, or

one or more producers bounded by the geo-radius.

17. The system of Claim 11, wherein he forecasting model is further parameterized with time duration data for which production estimates are generated based on the forecasting model.

18. The system of Claim 11, wherein one or more of the fluid production rate data or the fluid injection rate data is preprocessed to remove anomalous data values due to instrumentation errors, wherein the removed anomalous data values are substituted with interpolated values derived from the fluid production rate data or the fluid injection rate data.

19. The system of Claim 11, wherein the visualization indicating the production forecast report includes a plurality of production forecast data for a plurality of wells bounded by the geo-radius.

20. A method for water flooding optimization at a resource site for increased production of hydrocarbons, the method comprising:

determining a geo-radius circumscribing one or more injectors and one or more producers at a resource site;

receiving:

fluid production rate data obtained from one or more sensors disposed about the one or more producers at the resource site, and

fluid injection rate data obtained from one or more sensors disposed about the one or more injectors at the resource site;

correlating the fluid production rate data with the fluid injection rate data to determine correlated pairs of injectors and producers associated with the one or more injectors and the one or more producers, the correlated pairs of injectors and producers indicating a relationship between a first injector comprised in the one or more injectors and a first producer comprised in the one or more producers;

generating a forecasting model using the correlated pairs of injectors and producers, the forecasting model being parameterized using one or more of:

a first variable indicating a first range of fluid production rate values, and

a second variable indicating a second range of fluid injection rate values;

executing using the forecasting model, one or more sensitivity tests comprising at least one simulation based on the first variable or the second variable to generate a production forecast report for the first producer; and

executing one or more of:

initiating generation of a visualization indicating the production forecast report for viewing on a display device, or

initiating transmission of a pump rate control signal to configure a pump mechanism disposed about the first producer or the first injector at the resource site.

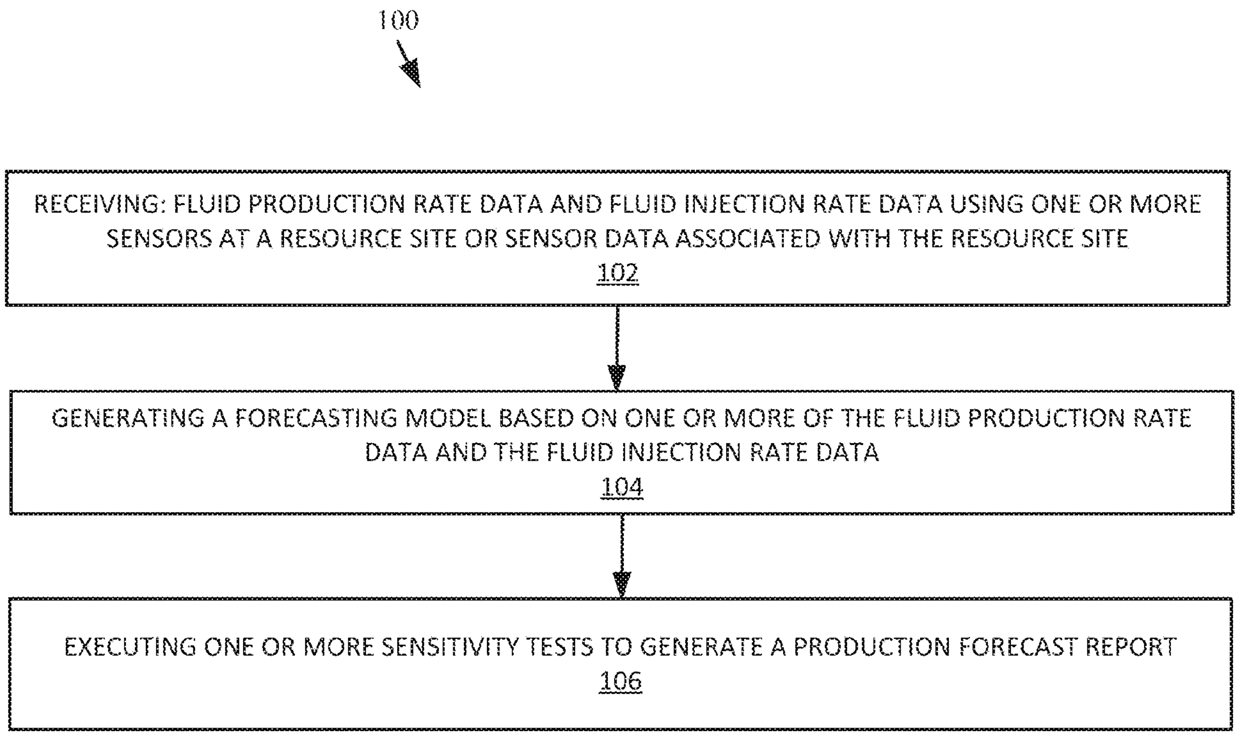
100
RECEIVING: FLUID PRODUCTION RATE DATA AND FLUID INJECTION RATE DATA USING ONE OR MORE SENSORS AT A RESOURCE SITE OR SENSOR DATA ASSOCIATED WITH THE RESOURCE SITE
102
GENERATING A FORECASTING MODEL BASED ON ONE OR MORE OF THE FLUID PRODUCTION RATE DATA AND THE FLUID INJECTION RATE DATA
104
EXECUTING ONE OR MORE SENSITIVITY TESTS TO GENERATE A PRODUCTION FORECAST REPORT
106

FIG. 1

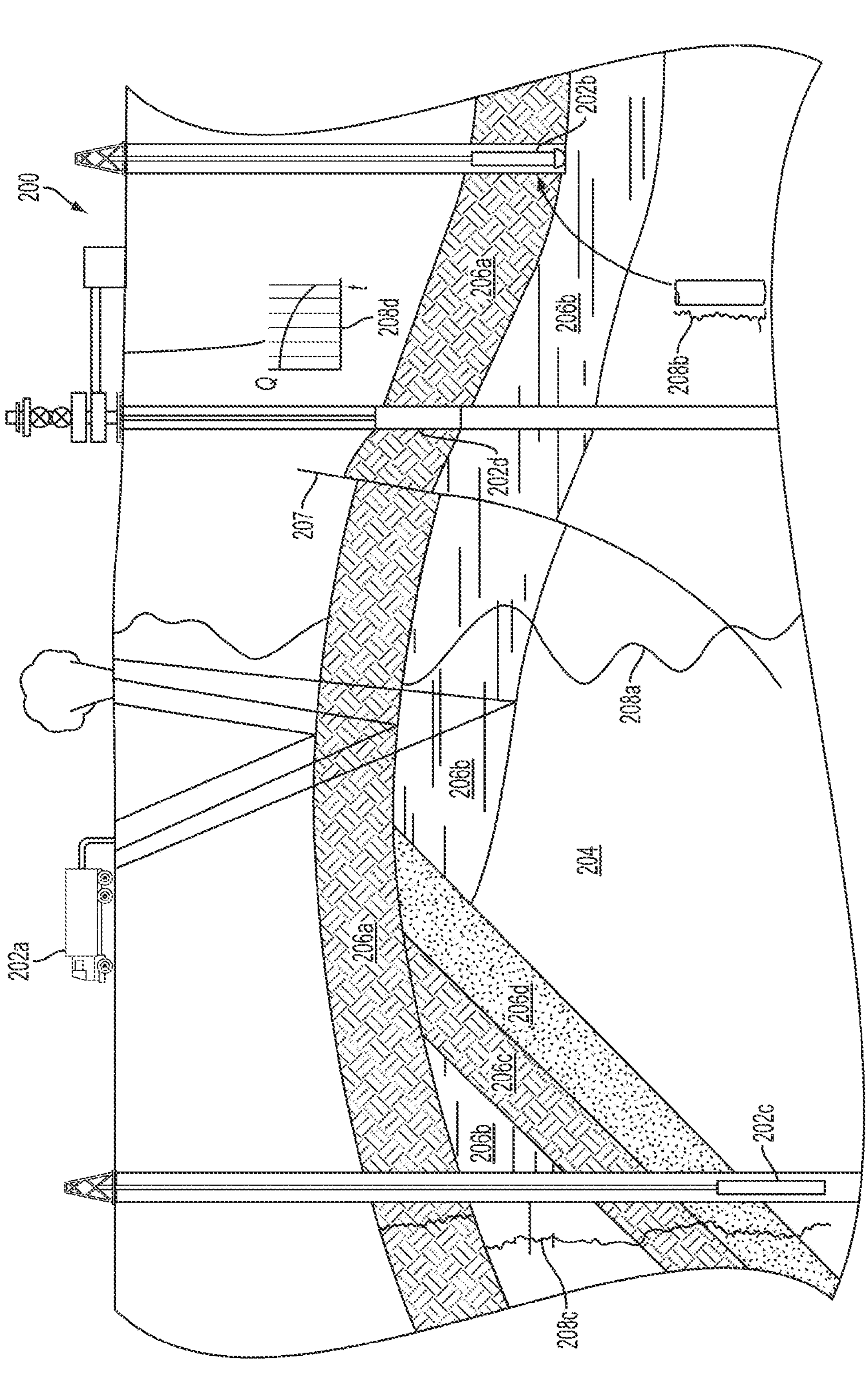
200
202a
202b
202c
202d
204
206a
206b
206c
206d
207
208a
208b
208c
208d
Q
t

FIG. 2

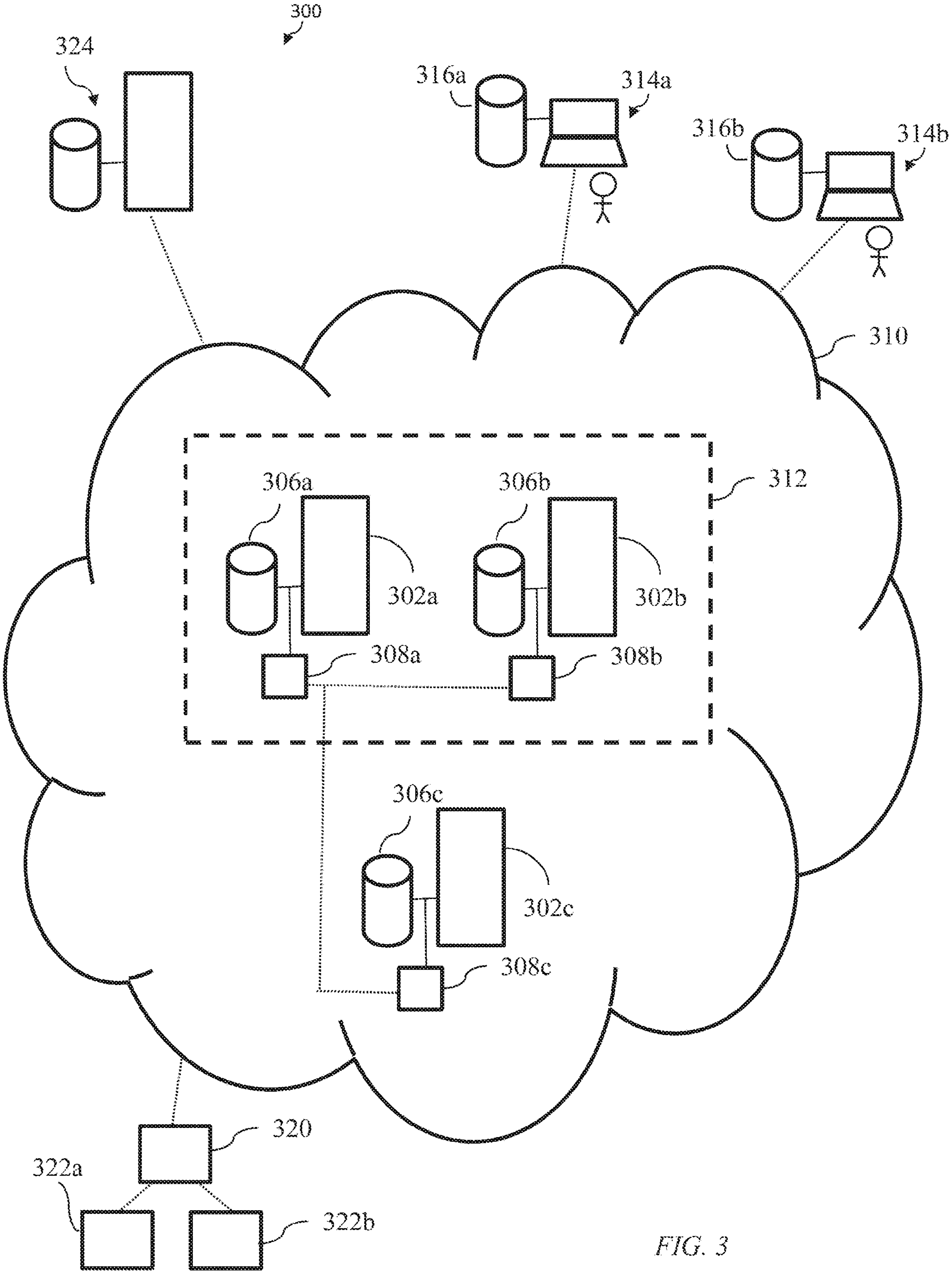
300
324
316a
314a
316b
314b
310
312
306a
306b
302a
302b
308a
308b
306c
302c
308c
320
322a
322b

FIG. 3

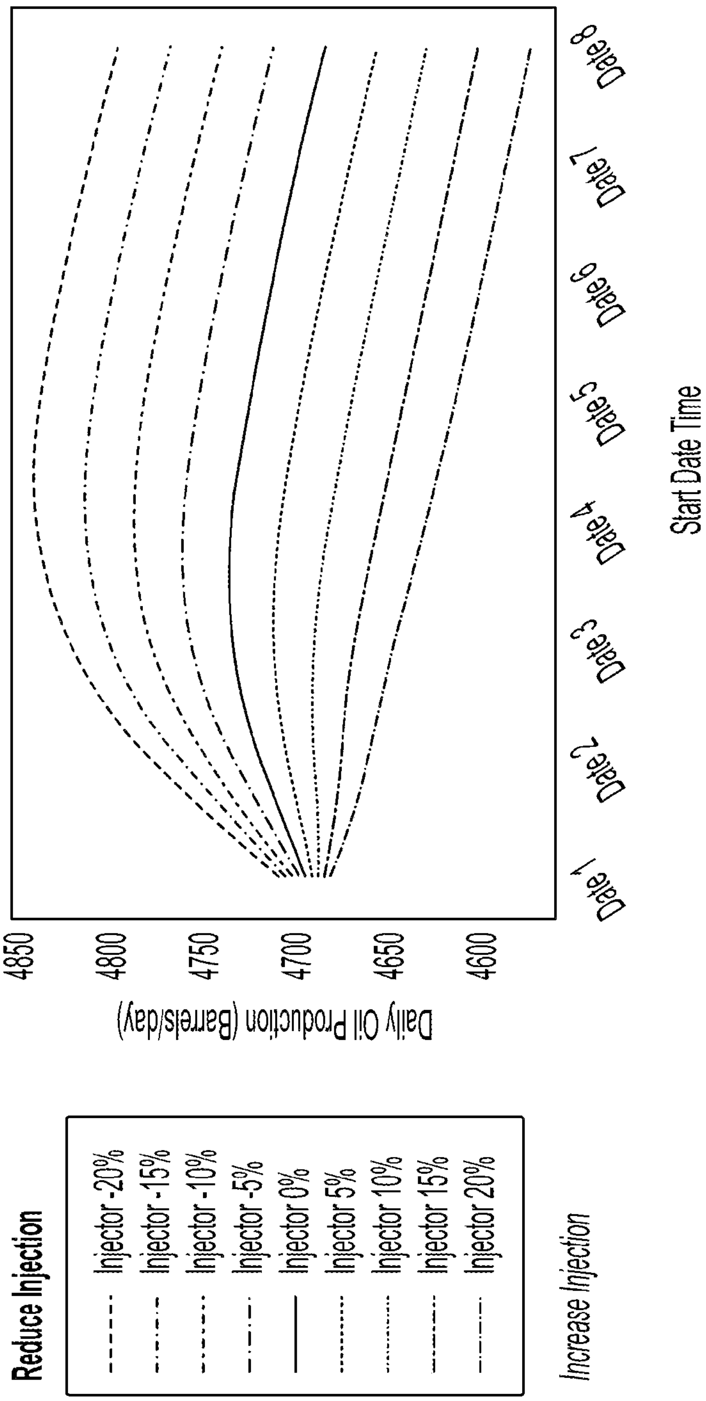
Daily Oil Production (Barrels/day)
4850
4800
4750
4700
4650
4600
Date1
Date2
Date3
Date4
Date5
Date6
Date7
Date8
Start Date Time
Reduce Injection
Injector -20%
Injector -15%
Injector -10%
Injector -5%
Injector 0%
Injector 5%
Injector 10%
Injector 15%
Injector 20%
Increase Injection

FIG. 4A

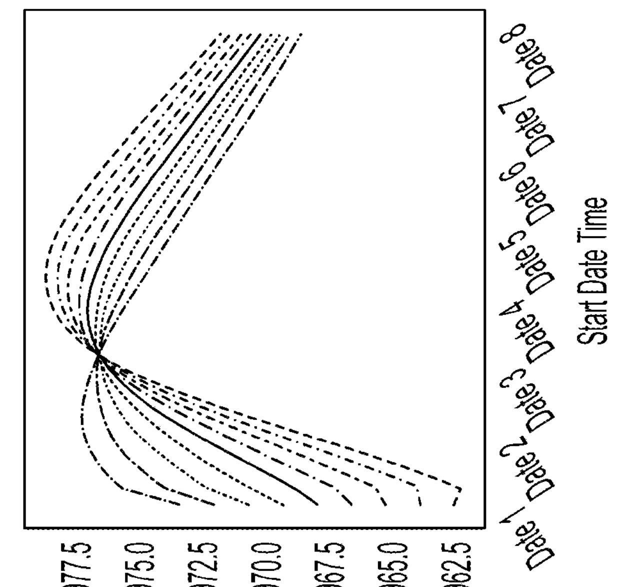

FIG. 4B-1

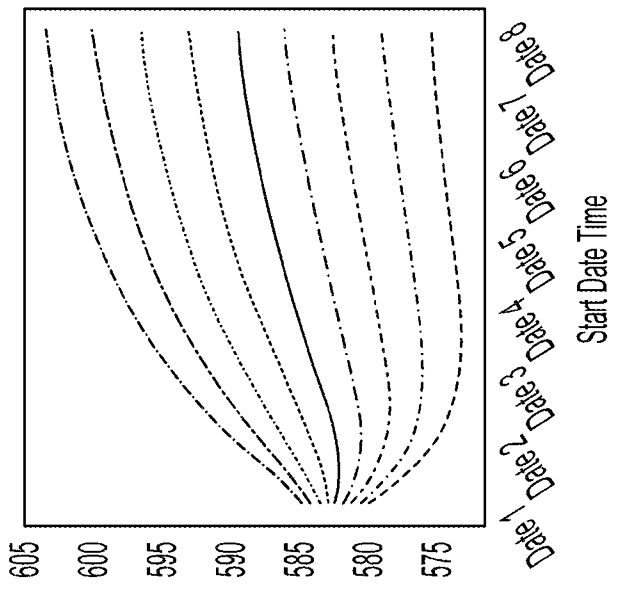

FIG. 4B-2

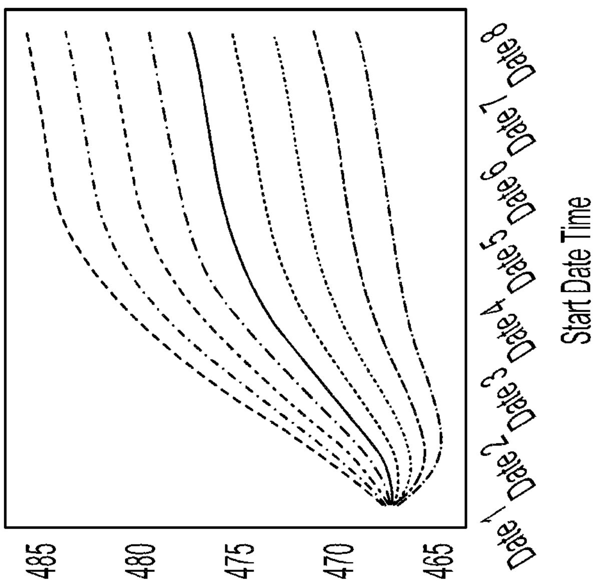

FIG. 4B-3

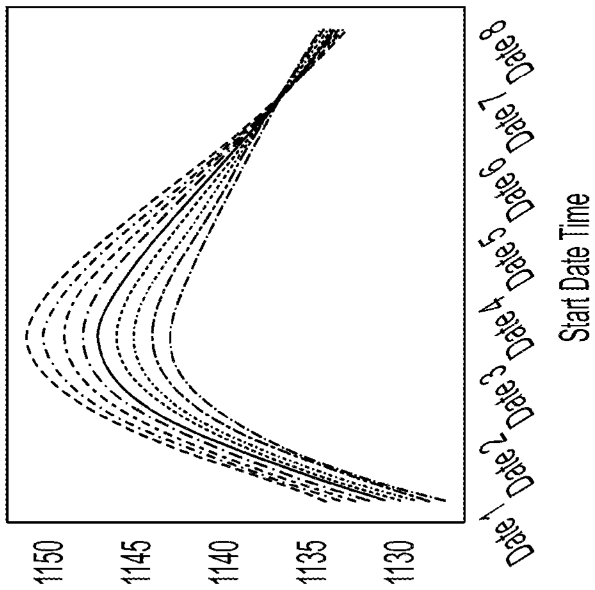

FIG. 4B-4

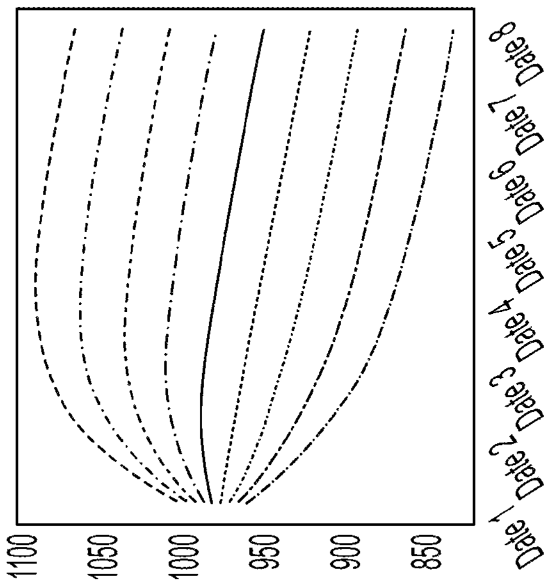

FIG. 4B-5

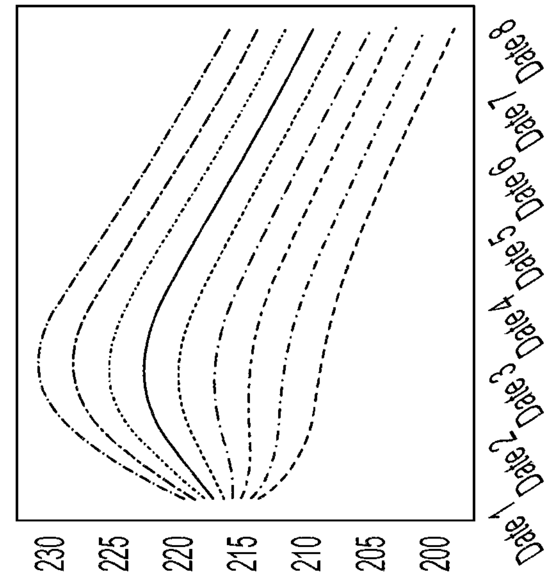

FIG. 4B-6

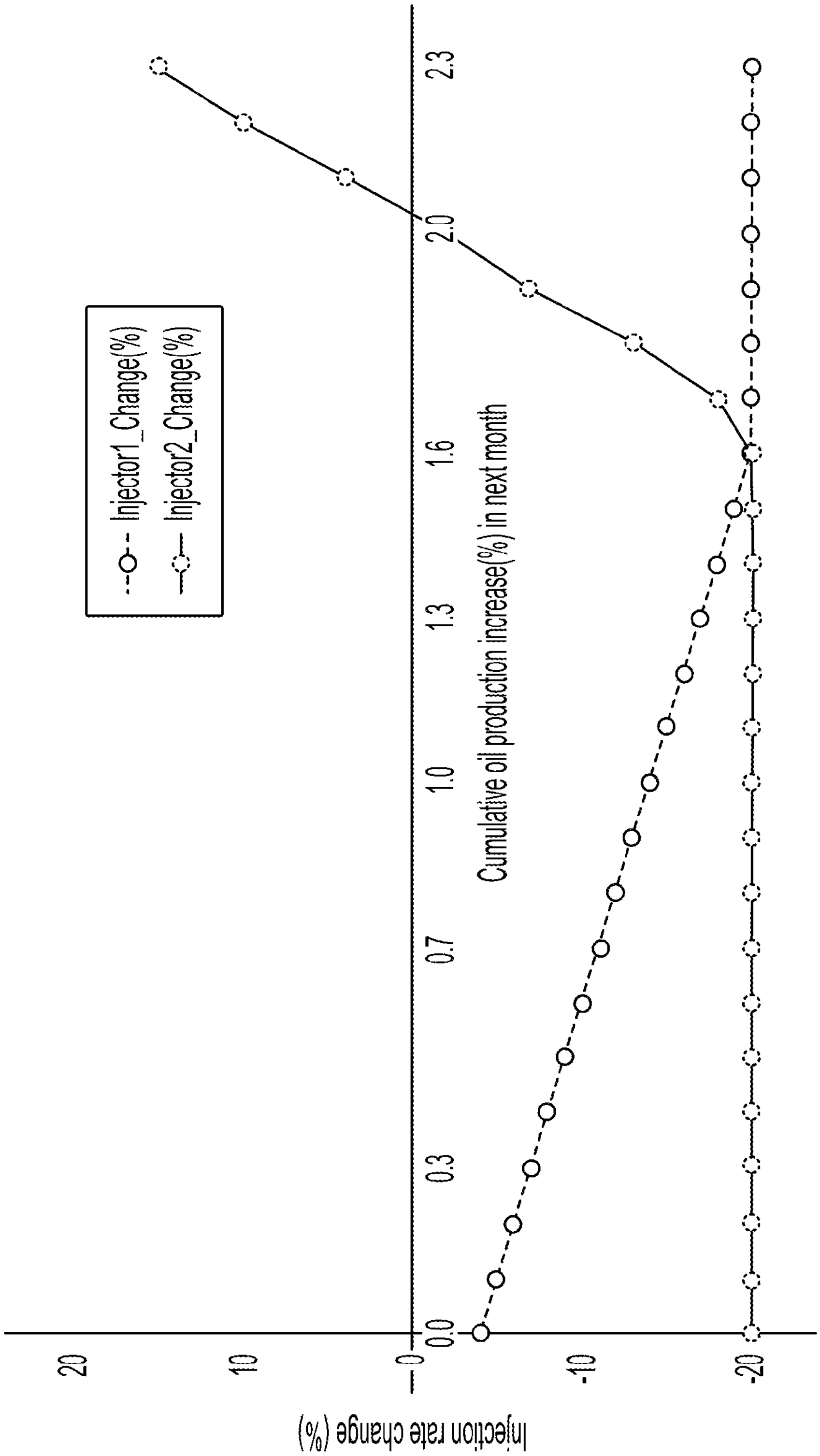
Injector1_Change(%)
Injector2_Change(%)
Cumulative oil production increase(%) in next month
Injection rate change (%)
0.0
0.3
0.7
1.0
1.3
1.6
2.0
2.3
20
10
0
-10
-20

FIG. 4C

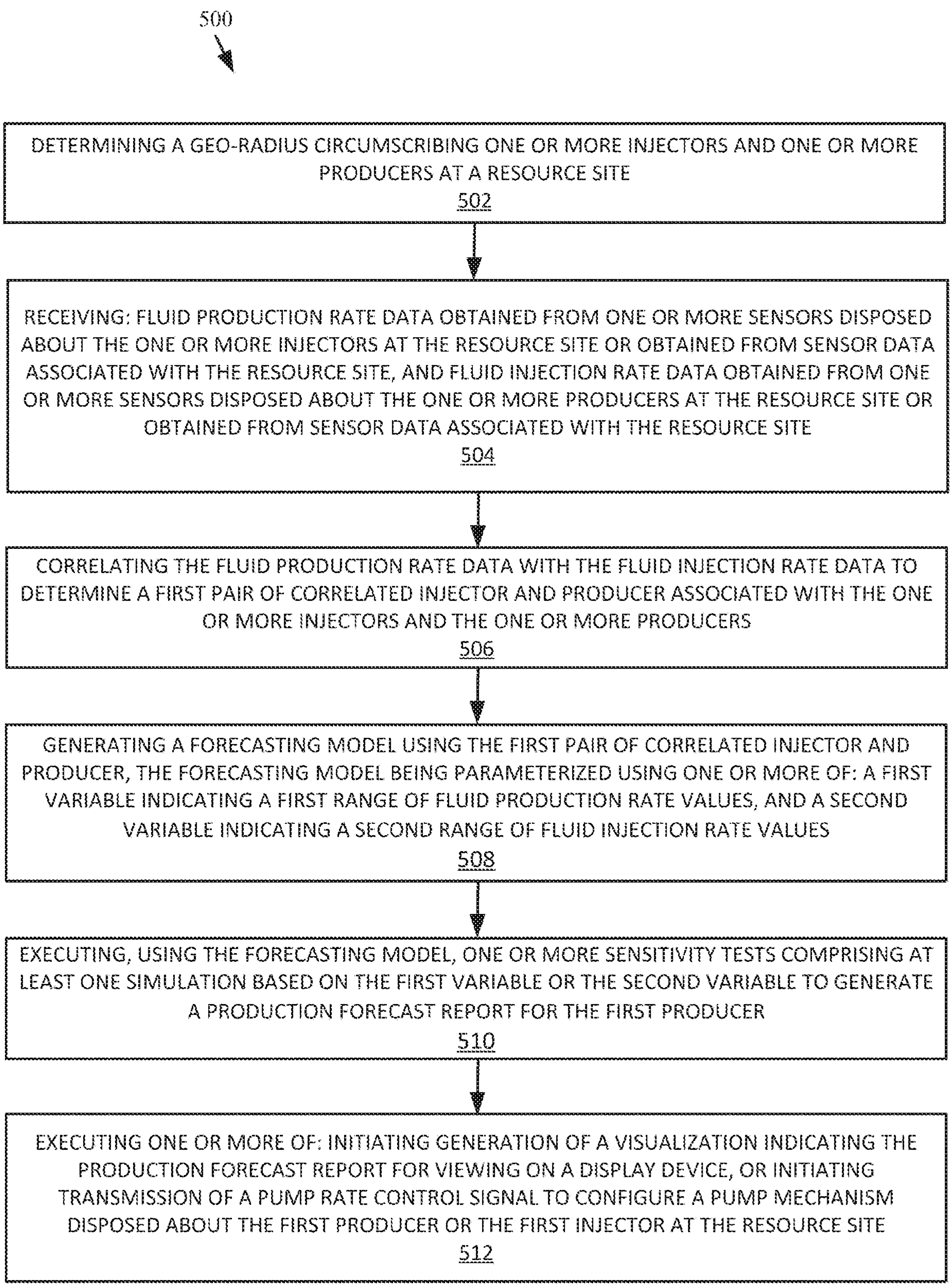
500
DETERMINING A GEO-RADIUS CIRCUMSCRIBING ONE OR MORE INJECTORS AND ONE OR MORE PRODUCERS AT A RESOURCE SITE
502
RECEIVING: FLUID PRODUCTION RATE DATA OBTAINED FROM ONE OR MORE SENSORS DISPOSED ABOUT THE ONE OR MORE INJECTORS AT THE RESOURCE SITE OR OBTAINED FROM SENSOR DATA ASSOCIATED WITH THE RESOURCE SITE, AND FLUID INJECTION RATE DATA OBTAINED FROM ONE OR MORE SENSORS DISPOSED ABOUT THE ONE OR MORE PRODUCERS AT THE RESOURCE SITE OR OBTAINED FROM SENSOR DATA ASSOCIATED WITH THE RESOURCE SITE
504
CORRELATING THE FLUID PRODUCTION RATE DATA WITH THE FLUID INJECTION RATE DATA TO DETERMINE A FIRST PAIR OF CORRELATED INJECTOR AND PRODUCER ASSOCIATED WITH THE ONE OR MORE INJECTORS AND THE ONE OR MORE PRODUCERS
506
GENERATING A FORECASTING MODEL USING THE FIRST PAIR OF CORRELATED INJECTOR AND PRODUCER, THE FORECASTING MODEL BEING PARAMETERIZED USING ONE OR MORE OF: A FIRST VARIABLE INDICATING A FIRST RANGE OF FLUID PRODUCTION RATE VALUES, AND A SECOND VARIABLE INDICATING A SECOND RANGE OF FLUID INJECTION RATE VALUES
508
EXECUTING, USING THE FORECASTING MODEL, ONE OR MORE SENSITIVITY TESTS COMPRISING AT LEAST ONE SIMULATION BASED ON THE FIRST VARIABLE OR THE SECOND VARIABLE TO GENERATE A PRODUCTION FORECAST REPORT FOR THE FIRST PRODUCER
510
EXECUTING ONE OR MORE OF: INITIATING GENERATION OF A VISUALIZATION INDICATING THE PRODUCTION FORECAST REPORT FOR VIEWING ON A DISPLAY DEVICE, OR INITIATING TRANSMISSION OF A PUMP RATE CONTROL SIGNAL TO CONFIGURE A PUMP MECHANISM DISPOSED ABOUT THE FIRST PRODUCER OR THE FIRST INJECTOR AT THE RESOURCE SITE
512

FIG. 5

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2023/085386

A. CLASSIFICATION OF SUBJECT MATTER

IPC(8) - INV. - E21B 43/20; C09K 8/58 (202401)
ADD. - G05B 13/04 (202401)

CPC - INV. - E21B 43/20; C09K 8/58 (202401)

ADD. - G05B 13/04 (202401)

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)
See Search History document

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
See Search History document

Electronic database consulted during the international search (name of database and, where practicable, search terms used)
See Search History document

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2016/0177679 A1 (CHEVRON U.S.A. INC.) 23 June 2016 (23.06.2016) entire document	1-20
A	US 10,125,586 B2 (SAUDI ARABIAN OIL COMPANY) 13 November 2018 (13.11.2018) entire document	1-20
A	US 9,703,006 B2 (STERN et al.) 11 July 2017 (11.07.2017) entire document	1-20
A	US 8,175,751 B2 (THAKUR et al.) 08 May 2012 (08.05.2012) entire document	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

"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	Date of mailing of the international search report
23 February 2024	APR 09 2024

Name and mailing address of the ISA/	Authorized officer
Mail Stop PCT, Attn: ISA/US, Commissioner for Patents P.O. Box 1450, Alexandria, VA 22313-1450 Facsimile No. 571-273-8300	Taina Matos Telephone No. PCT Helpdesk: 571-272-4300