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(54) **SYSTEM AND METHOD FOR TREATMENT OPTIMIZATION**

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E21B 43/26	(2006.01)
E21B 47/06	(2012.01)

(52) **U.S. Cl.**

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(58) **Field of Classification Search**

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USPC 706/52

See application file for complete search history.

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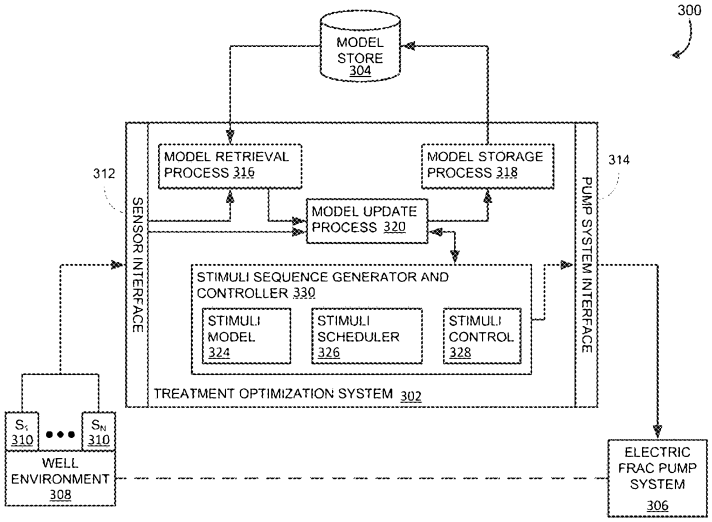
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(57) **ABSTRACT**

A sequence of stimuli produced by an electric frac pump can be generated by a treatment optimization system. Well environment responses to the sequence of stimuli may be measured by sensors and respective sensor data may be received. The sensor data may be used to select a representative system model which can then be used to control the electric frac pump. The representative system model may be used to achieve well stage objectives such as particular cluster efficiencies, complexity factors, or proximity indices.

20 Claims, 6 Drawing Sheets



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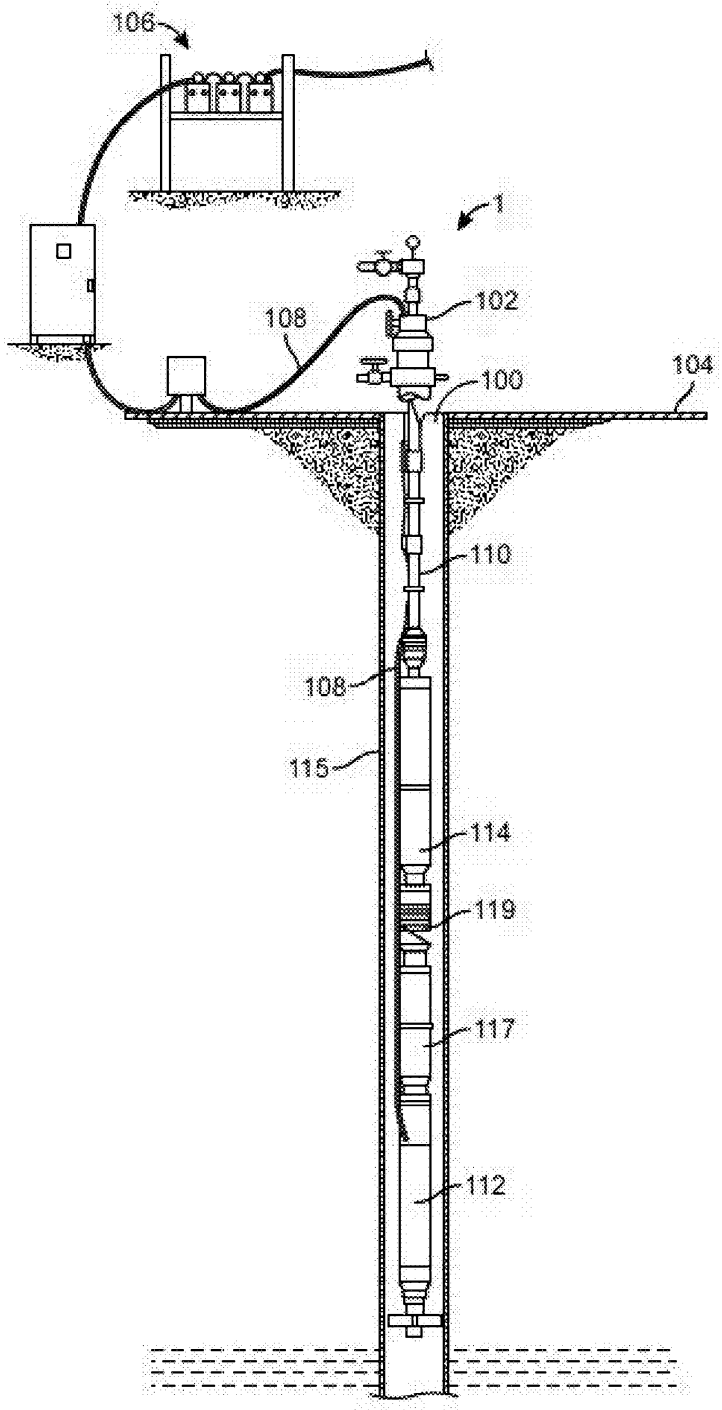


FIG. 1A

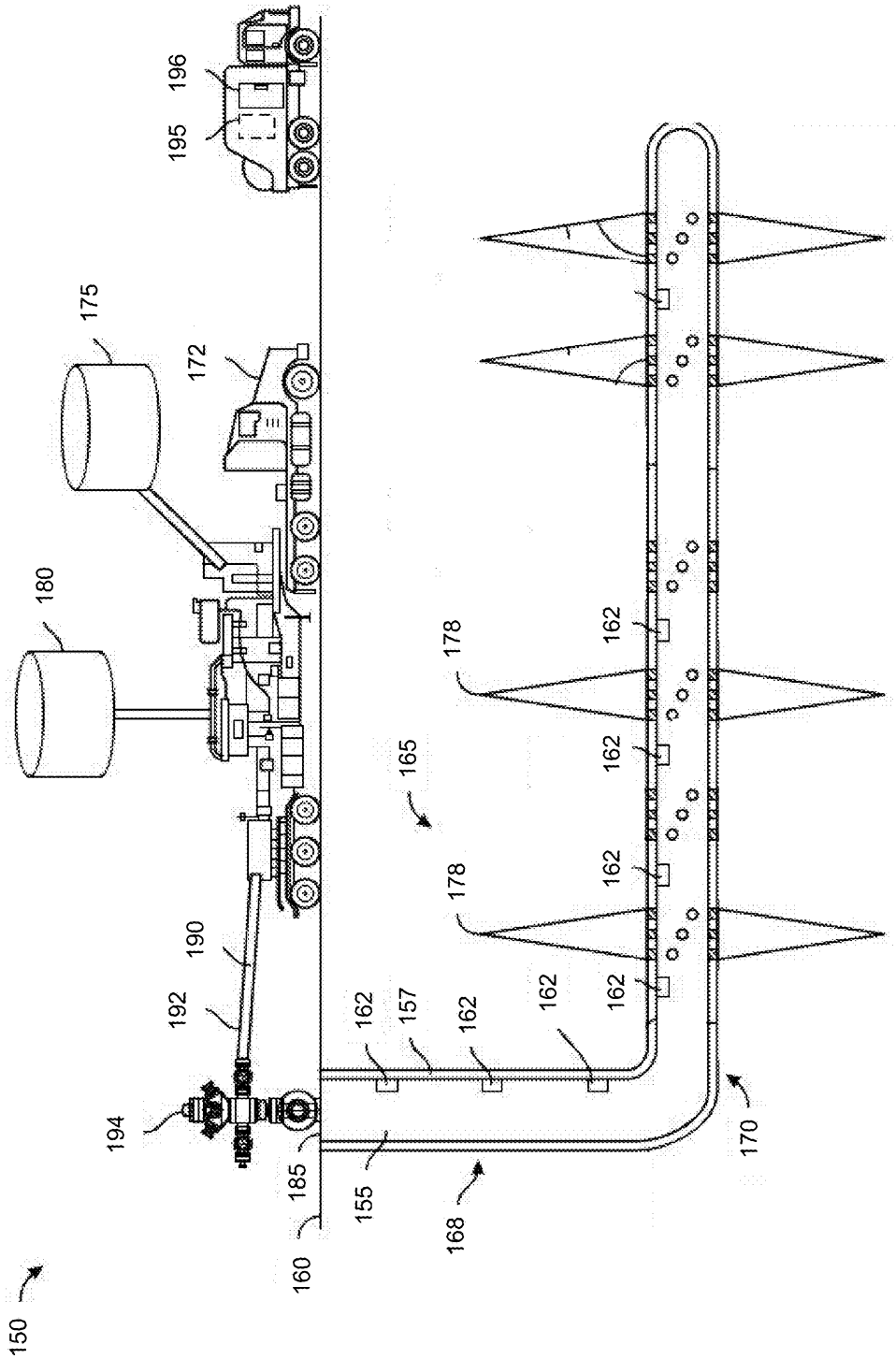

196
195
175
172
180
178
162
165
190
192
194
157
185
155
168
160
170
150

FIG. 1B

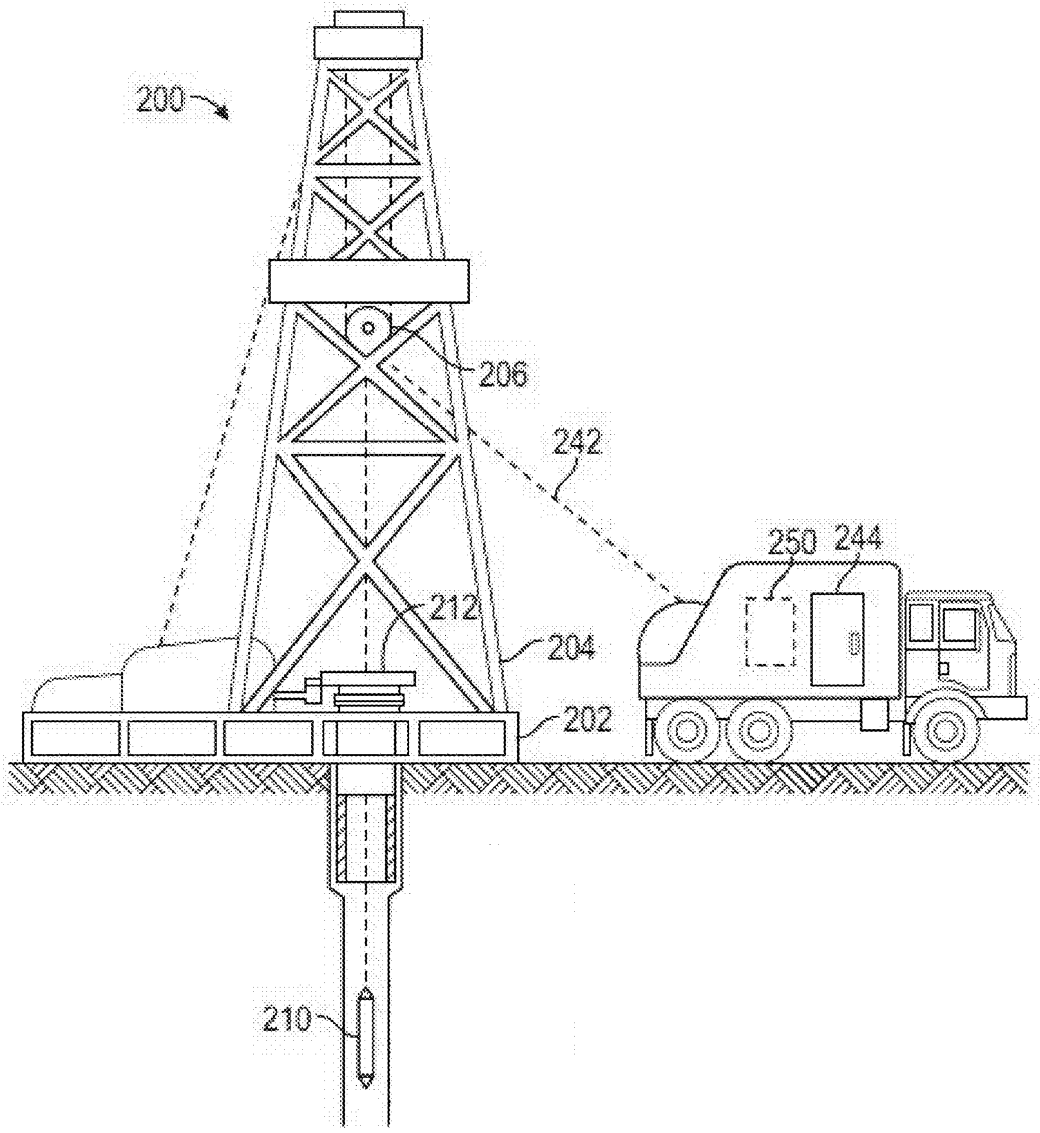


FIG. 2

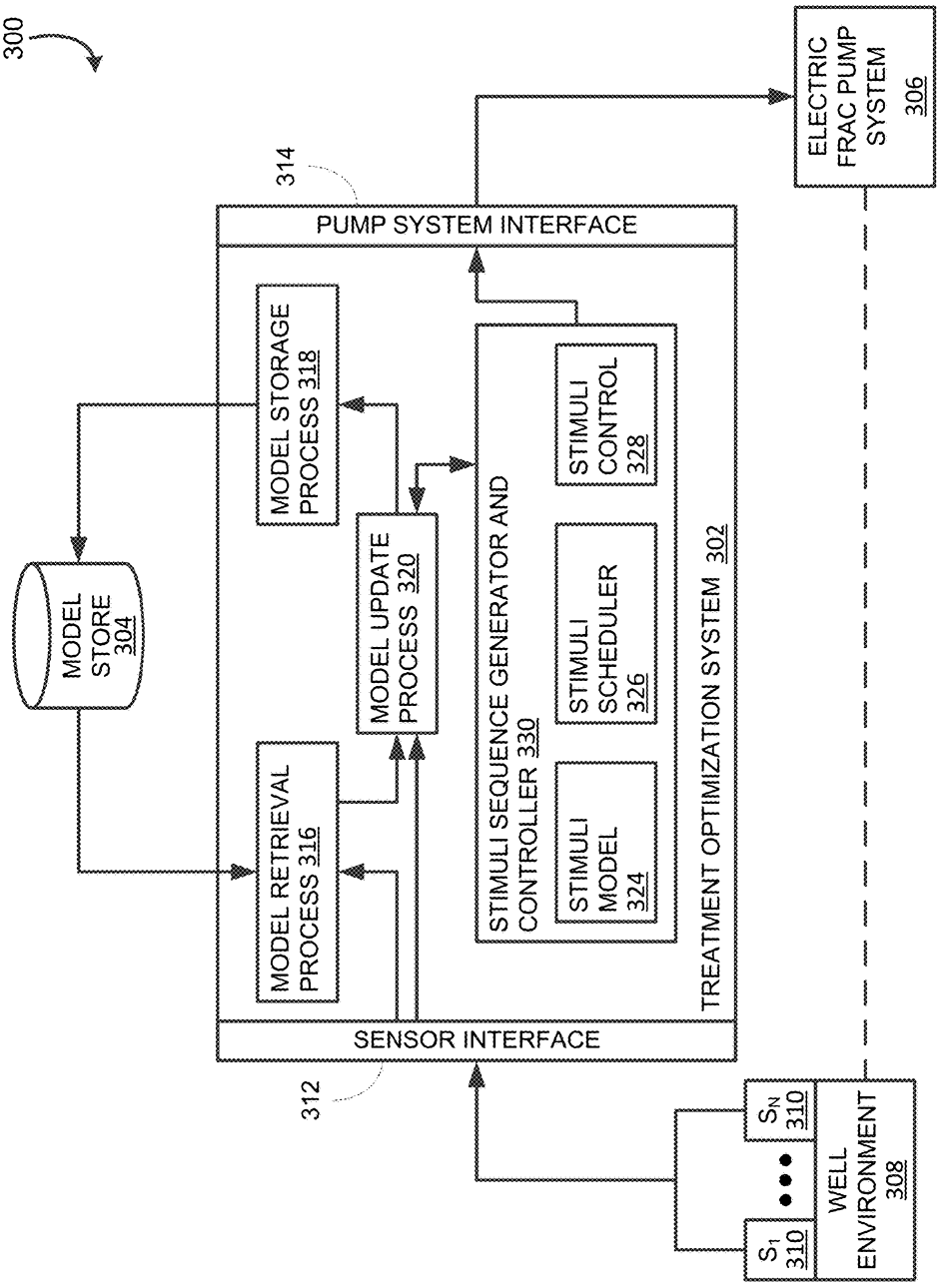

300
ELECTRIC FRAC PUMP SYSTEM 306
314
PUMP SYSTEM INTERFACE
MODEL STORAGE PROCESS 318
MODEL STORE 304
MODEL UPDATE PROCESS 320
STIMULI SEQUENCE GENERATOR AND CONTROLLER 330
STIMULI CONTROL 328
STIMULI SCHEDULER 326
STIMULI MODEL 324
MODEL RETRIEVAL PROCESS 316
TREATMENT OPTIMIZATION SYSTEM 302
SENSOR INTERFACE
312
S_N 310
S_1 310
WELL ENVIRONMENT 308

FIG. 3

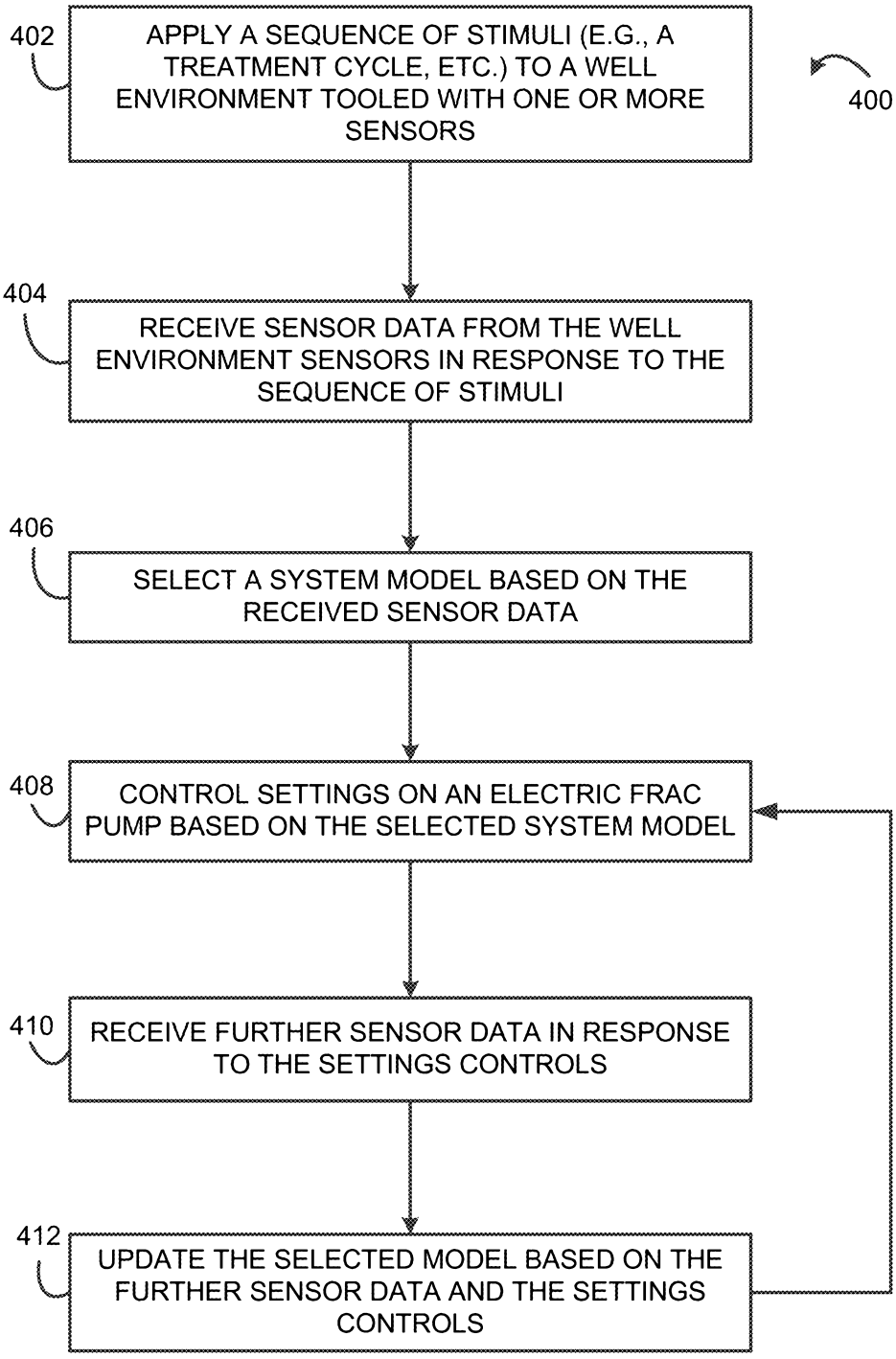

402
APPLY A SEQUENCE OF STIMULI (E.G., A TREATMENT CYCLE, ETC.) TO A WELL ENVIRONMENT TOOLED WITH ONE OR MORE SENSORS
400
404
RECEIVE SENSOR DATA FROM THE WELL ENVIRONMENT SENSORS IN RESPONSE TO THE SEQUENCE OF STIMULI
406
SELECT A SYSTEM MODEL BASED ON THE RECEIVED SENSOR DATA
408
CONTROL SETTINGS ON AN ELECTRIC FRAC PUMP BASED ON THE SELECTED SYSTEM MODEL
410
RECEIVE FURTHER SENSOR DATA IN RESPONSE TO THE SETTINGS CONTROLS
412
UPDATE THE SELECTED MODEL BASED ON THE FURTHER SENSOR DATA AND THE SETTINGS CONTROLS

FIG. 4

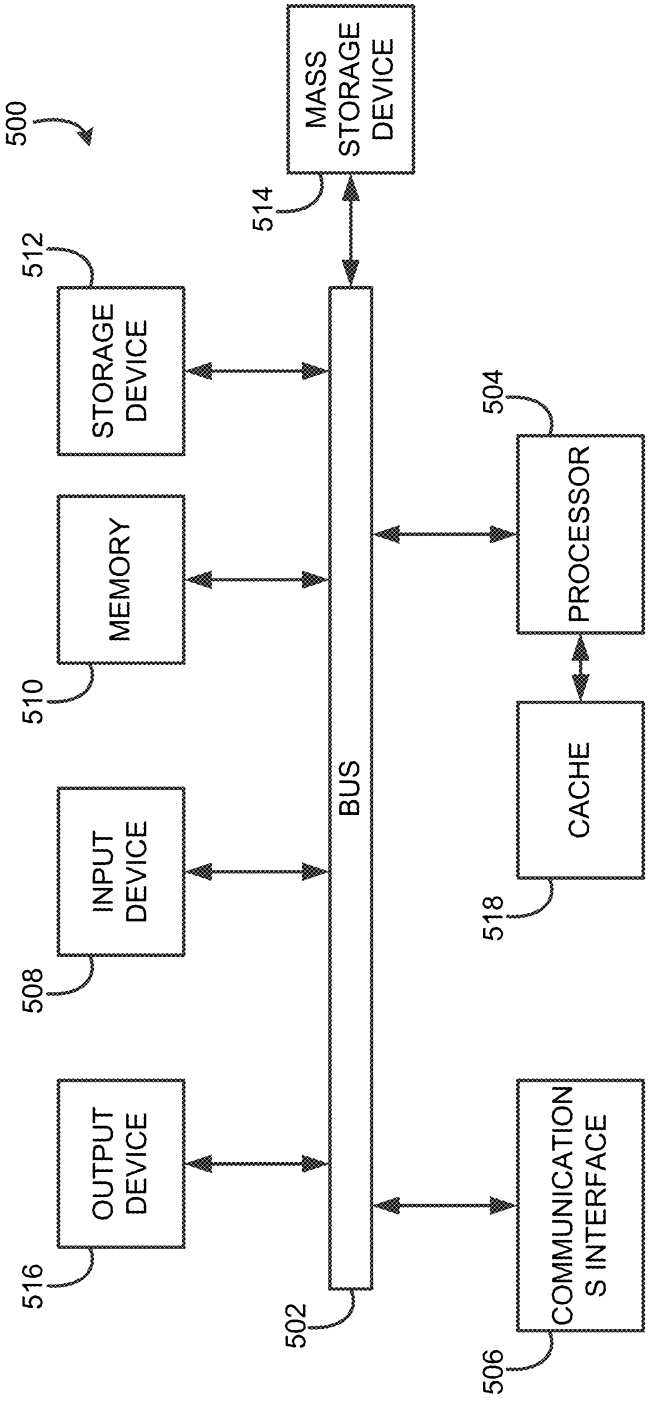

500
MASS STORAGE DEVICE
514
512
STORAGE DEVICE
504
PROCESSOR
MEMORY
510
BUS
CACHE
518
INPUT DEVICE
508
OUTPUT DEVICE
516
502
COMMUNICATION S INTERFACE
506

FIG. 5

SYSTEM AND METHOD FOR TREATMENT OPTIMIZATION

TECHNICAL FIELD

The present technology pertains to well treatment plan optimizations.

BACKGROUND

In the oil and gas industry, electric frac pumps are often controlled in order to achieve certain downhole environment responses. However, typically settings are performed manually based on manually appraised information retrieved from the downhole environment. For example, a technician may review sensor data and, based on experience, adjust various settings such as flow rate, pressure values, chemical compositions, etc., on an electric frac pump. In some cases, a representative system model may be used for determining pump settings based on sensor information; however, the representative system model is typically manually selected by a technician based on observed sensor data. Additionally, the representative system model may be a static construct and may not accurately reflect the well to which it has been deployed.

It is with these observations in mind, among others, that aspects of the present disclosure were concerned and developed.

BRIEF DESCRIPTION OF THE DRAWINGS

The embodiments herein may be better understood by referring to the following description in conjunction with the accompanying drawings in which like reference numerals indicate analogous, identical, or functionally similar elements. Understanding that these drawings depict only exemplary embodiments of the disclosure and are not therefore to be considered to be limiting of its scope, the principles herein are described and explained with additional specificity and detail through the use of the accompanying drawings in which:

FIG. **1**A is a schematic view of a downhole electric frac pump and environment, according to various embodiments of the subject technology;

FIG. **1**B is diagrammatic view of a surface electric frac pump and environment, according to various embodiments of the subject technology;

FIG. **2** is a schematic diagram of an example conveyance drilling environment, according to various embodiments of the subject technology;

FIG. **3** is a block diagram of a treatment optimization system and environment, according to various embodiments of the subject technology;

FIG. **4** is a flowchart of an example method for optimizing a well treatment plan, according to various embodiments of the subject technology; and

FIG. **5** is a system diagram illustrating a computing system, in accordance with various embodiments of the subject technology.

DETAILED DESCRIPTION

Various embodiments of the disclosure are discussed in detail below. While specific implementations are discussed, it should be understood that this is done for illustration purposes only. A person skilled in the relevant art will recognize that other components and configurations may be used without parting from the spirit and scope of the disclosure.

It should be understood at the outset that although illustrative implementations of one or more embodiments are illustrated below, the disclosed compositions and methods may be implemented using any number of techniques. The disclosure should in no way be limited to the illustrative implementations, drawings, and techniques illustrated herein, but may be modified within the scope of the appended claims along with their full scope of equivalents.

This disclosure provides techniques for optimizing well treatments using representative system models selected according to formation responses to stimuli indicated by sensor data. In particular, electrically driven pumps (e.g., electric frac pumps), electrical blenders, and other electrical surface equipment can be used to automatically generate a sequence of stimuli in a treatment well. Sensor data in response to the generated sequence of stimuli can then be received from sensors deployed throughout the well (e.g., surface sensors, downhole sensors, wireline sensors, etc.).

In some examples, the sequence of stimuli may be different than the fracturing system control set-points and/or control variables for a given treatment schedule. A given stimulus of the sequence of stimuli can be achieved by adjusting surface pressure values, flow rates, particulate composition (e.g., proppants, diverters, etc.), and/or chemical composition (e.g., friction reducers, surfactants, viscosifiers, etc.). In some examples, a sequence can include a particular stimulus (e.g., injection rate) being stepped through a sequence of various amplitudes (e.g., high, medium, low, etc.). Accordingly, response variables (e.g., responsive sensor data values such as pressure or flow distribution or microseismic events or strain events) can be measured over time to generate a record of a dynamic formation response.

The responsive sensor data may be used to select a pre-defined representative system model for stage and/or well treatment schedules (e.g., treatment sequences, compositions, etc.). In some examples, the responsive sensor data may be used to define a new more representative system model and/or refine a selected model according to specific characteristics of the respective well. For example, the selected representative system model and/or control set-points may be tuned in response to multiple iterations of a stimulus sequence, some of which (in some examples) may be part of an initial treatment schedule based on the selected model. In other examples, a representative system model may be defined based on a multitude of models using parameter uncertainty techniques well known in the art to help find models that represent the observed data more accurately.

Sensors may be deployed to a treatment or monitoring well on surface or downhole. Surface sensor data may be used to project subsurface parameters to downhole positions. For example, a measured surface pressure can be projected to a downhole location based on a model accounting for friction induced pressure drop and/or hydrostatic pressure changes due to gravity.

In particular, the sensor data from surface and/or downhole sensors may be indicative of formation responses. As a result, formation responses to the sequence of stimuli can be determined from resulting sensor data. For example, changes in flow distribution in response to a diverter drop or formation responses at different stimuli levels (e.g., high, medium, or low injection rate, etc.) can be determined based

on sensor data and used to derive a representative or appropriate treatment schedule.

Sensors can include, for example and without imputing limitation, single-point electrical sensors, single-point optical sensors, distributed fiber optic sensors, quasi-distributed fiber optic sensors, etc. The sensors may measure, for example and without imputing limitation, temperature, flow, dynamic and/or static strain, acoustic intensity, acoustic phase, resistivity, electromagnetic signals, and frequency, amplitude, or phase of any of the signals, etc. Determined formation responses may include, for example and without imputing limitation, instantaneous fluid flow through a perforation cluster, microseismic information, fracture location, fracture length, fracture height, fracture azimuth, fluid movement and any time variable information of any sensor signal etc. Additionally, sensors may be deployed, for example and without imputing limitation, on surface equipment, on the surface and/or in the vicinity of the well, one a well head, on well flow lines, embedded in or joined to well casing (e.g., a cement casing, etc.), on dispensed tubing (e.g., downhole tubing, etc.), on coiled tubing (e.g., for temporary logging, etc.), or on a wireline, cable, or bare fiber deployment using gravity and/or tractored into the well bore. Sensors may be placed in the treatment well that is being fractured and in one or multiple monitoring wells.

Stimuli can include, for example and without imputing limitation, a selection of surface concentrations of particulates and/or chemicals pumped downhole, an adjustment to fluid rate, or an adjustment to pressure, etc. Further, stimuli may be modified over a span of time as part of a sequence of stimuli. For example, concentrations of particulates and/or chemicals can be periodically varied in predetermined patterns over time to induce various formation responses detectable via deployed sensors. Electric pumps can be controlled to generate specific subsurface conditions (e.g., via fluid rate, etc.) as particulars and/or chemicals enter a formation through perforation clusters. In some examples, flow rates can be controlled dynamically to achieve a particular downhole target pressure, dynamic downhole pressure, and/or a rate profile in coordination with particulate and/or chemical concentrations in a pumped treatment fluid to achieve arrival at particular locations in the formation, such as along a network of fractures.

Response variables (e.g., responsive sensor data values) and respective stimuli (e.g., experimental data) can be used to select, define, and/or construct a representative system model. For example, stimuli and response combination can be mapped to respective system models maintained in an accessible data store. In some examples, a partial model can be generated based on stimuli and response combinations in order to select a pre-constructed representative system model most similar to the partial model. In some examples, a representative system model may be generated based on experimental data and/or data created through simulation with uncertainty parameters.

The generated representative system model may be based on a determined linear or non-linear relationship between system model inputs (e.g., stimuli) and representative system model outputs (e.g., response variables), where a control algorithm is updated (e.g., via curve fitting, etc.) to achieve certain formation responses. In some examples, historical data and/or various machine learning (e.g., neural networks, evolutionary algorithms, Markov models, etc.) processes may be used to generate the representative system model. In some examples, statistical methods can be used to build a mathematical model from experimental data and system identification using design of experiments can be used to fit one or more models and/or perform model reduction. Further, continued iterations may be used to confirm and/or optimize a generated representative system model. In some cases, multiple simulations can be used to create engineering data based on uncertainty parameters to help define cause and effect characteristics of multiple control parameters to generate a more representative system model.

The generated representative system model may be used to, for example, control fracturing operations at the same well used to generate the system model or at another well, such as in the case where the representative system model is generated at an observation well or the like. For example, the representative system model may be used to achieve uniform flow across perforation clusters by adjusting pressure, flow rates, diverter composition, proppant composition, and/or chemical composition at one or more relevant electric frac pumps based on the system model predictions. In some examples, the chosen system model can be used to control formation complexity. In some examples, the chosen system model can be used to predict interference from other wells and/or determine appropriate action to avoid interference.

In some examples, a control proxy may be used for achieving certain objects via control operations based on the chosen system model. For example, cluster efficiency (CE) may be used as a proxy for controlling an electric frac pump by a respective system model generating a cluster efficiency values. In some examples, a complexity factor (CF) may be likewise used as a control proxy for formation complexity and/or a proximity index (PI) may be used as a control proxy for well interference.

In some examples, fracturing operations may vary control parameters at different times based on the chosen system model. For example, the first third of a fracturing operation in each stage may optimize flow distribution (e.g., CE) between clusters, the second third of each stage may optimize reservoir complexity (e.g., CF), and the last third of each stage may optimize (e.g., minimize) well interference (e.g., PI). Additionally, the system model may provide for transitioning between different objects in a predetermined sequence of time or adjusting transitions (e.g., sequence, time, etc.) throughout later stages of a well as earlier sensor data and control variables (e.g., experimental data) is used to further update and revise the chosen system model. As a result, stage level data may be used to predict future stage reservoir properties and various points (e.g., starting points, transition points, etc.) for stage treatment as well as respective stimuli selection and stimuli intensities. The stage fracturing operations are not limited to a three part treatment sequence and more treatment sequences with different time variant objectives are included in the scope.

The disclosure now turns to discussion of various figures for further clarity of explanation. FIGS. **1**A, **1**B, and **2** respectively depict various environments in which the apparatuses, systems, and methods of the disclosure may be implemented. It is understood that elements and/or steps of the figures depicted may be added, removed, and/or modified without departing from the spirit and scope of the disclosure. Accordingly, the figures are provided for explanatory purposes only and a person of ordinary skill in the art with the benefit of this disclosure may implement and modify the apparatuses, systems, and methods disclosed herein without departing from the spirit and scope of the disclosure.

FIG. **1**A depicts an example of a wellbore pumping system **1** in which the apparatuses, systems, and methods of this disclosure may be deployed. The system **1** includes a wellbore **100** having a wellhead **102** at the surface **104**. The

wellbore **100** extends and penetrates various earth strata including hydrocarbon containing formations. A casing **115** can be cemented along a length of the wellbore **100**. A power source **106** can have an electrical cable **108**, or multiple electrical cables, extending into the wellbore **100** and coupled with a motor **112**. It should be noted that while FIG. **1** generally depicts a land-based operation, those skilled in the art will readily recognize that the principles described herein are equally applicable to subsea operations that employ floating or sea-based platforms and rigs, without departing from the scope of the disclosure. Also, even though FIG. **1** depicts a vertical wellbore, the present disclosure is equally well-suited for use in wellbores having other orientations, including horizontal wellbores, slanted wellbores, multilateral wellbores or the like.

Disposed within the wellbore **100** can be a tubing string **110** having an electric pump **114** forming an electric pump string. The electric pump **114** may be driven by a motor **112**. The tubing string **110** can also include a pump intake **119** for withdrawing fluid from the wellbore **100**. The pump intake **119**, or pump admission, can separate the fluid and gas from the withdrawn hydrocarbons and direct the fluid into the electric pump **114**. A protector **117** can be provided between the motor **112** and the pump intake **119** to prevent entrance of fluids into the motor **112** from the wellbore. The tubing string **110** can be a series of tubing sections, coiled tubing, or other conveyance for providing a passageway for fluids. The motor **112** can be electrically coupled with the power source **106** by the electrical cable **108**. The motor **112** can be disposed below the electric pump **114** within the wellbore **100**. The electric pump **114** can provide artificial pressure, or lift, within the wellbore **100** to increase the withdrawal of hydrocarbons, and/or other wellbore fluids. The electric pump **114** can provide energy to the fluid flow from the well thereby increasing the flow rate within the wellbore **100** toward the wellhead **102**.

FIG. **1**B is a schematic view of a wellbore operating environment **150** in which apparatuses, systems, and methods as disclosed herein may be deployed. As depicted, a wellbore **155** extends from the surface **160** of the earth through the formation **165** formed by a drilling device from a previous drilling operation (not shown). The wellbore **155** has a vertical segment **168** as well as horizontal segment **170**. The wellbore **155** has a casing **157** extending along its length and which may be cemented to the inner surface of the wellbore **155**. A plurality of sensors **162** may be provided along the length of the wellbore to detect temperature, pressure, strain, vibration, or flow rate. The plurality of sensors **162** may include for instance pressure or temperature transducers, or may include point and distributed fiber optic sensors. As discussed further below, sensors **162** may be used to generate and execute a data synthesis model. As further illustrated, pump equipment **172** is provided in the form of a truck carrying a pump is provided on the surface **160**. While a truck is shown, the pump equipment **172** can be in any form, such as a standalone unit, a plurality of pump units, within a vehicle or outside a vehicle, or integrated with a vehicle, and may be on the surface **160** or partially inserted into the wellbore **155**. The pump equipment may be electrical pumps, or hydraulic pumps, or pumps capable of quick adjustment of flow rate. A carrier fluid **175** is provided which may be mixed or blended with, for example, a proppant **180** and pumped by the pump equipment **172** to form a treatment fluid **190**. The treatment fluid **190** may be pumped through line **192** into the entrance **185** of the wellbore **155** via fracturing tree **194**. The fracturing tree **194** includes various inlets and valves necessary for various fluids, including diversion treatment fluid **140**. While the treatment fluid **190** is pumped into the wellbore **155** through the casing **157**, in other embodiments, additional tubing, such as coiled tubing, can be inserted within the casing **157** to inject or place the carrier fluid **175** and proppant **180**.

In general, the carrier fluid **175** may be continuously pumped into the wellbore **155**. The proppant **180** can be introduced periodically into the carrier fluid **175** as a small volume, concentration, or mass. The proppant **180** may be in fluid form or may be a solid, or a semi-solid, a gel, and may be in the form of a particulate, and may be degradable. The proppant **180** may be referred to as a having a concentration (e.g., a concentration of solid, semi-solid) or a mass with the carrier fluid **175** or treatment fluid **190**. Further, the proppant **180** may have a flow rate which may be the same or different than the carrier fluid **175** depending on the relative form and density of the proppant **180** and the carrier fluid **175**.

A processing facility **196** having a computer system **195** may be provided at the surface **160** for collecting, storing or processing data related to the wellbore operating environment **150**. The processing facility may be communicatively coupled, via wire or wirelessly, with the pump equipment **172**. The pump equipment **172** may have controls or be controlled by the processing facility **196** including flow rates of the carrier fluid **175**, proppant **180**, and treatment fluid **190**, as well as obtaining data related to flow rates, proppant rates, diversion materials, and chemicals. Additional data may be obtained regarding the wellbore **155**, including flow rate distribution wellbore flow distribution of fluid into fractures **178** in the wellbore **155**, including temperature and/or pressure distributions throughout the wellbore **155**, which may be obtained by the sensors **162** positioned along the length of the casing **157** to detect, for example and without imputing limitation, pressure, temperature, strain, vibration, and/or flow rates along the length of the wellbore **155**.

FIG. **2** illustrates a diagrammatic view of a conveyance logging (WL) borehole operating environment **200** (also referred to as "wireline" in the field) in which aspects of the present disclosure can be implemented. A hoist **206** can be included as a portion of a platform **202** which is coupled to a derrick **204**. The hoist **206** may be used to raise or lower equipment such as tool **210** into or out of a borehole where the borehole may be a monitoring well where response parameters may be measured in response to changes in flow rate, proppant concentration, diversion concentration or chemicals in a treatment well. A conveyance **242** provides a communicative coupling between tool **210** and a facility **244** at the surface. Conveyance **242** may be a tubular conveyance such as coiled tubing, joint tubing, or other tubulars, and may include wires (one or more wires), slicklines, cables, or the like, as well as a downhole tractor. Additionally, power can be supplied via the conveyance **242** to meet power requirements of the tool. Conveyance **242** may include optical fibers that may be used for communication or distributed fiber optic sensing where the full length of conveyance **242** may act as a distributed sensor. The distributed sensor may be used to measure temperature, acoustics, vibration and strain etc. Tool **210** may have a local power supply, such as batteries, downhole generator and the like. When employing non-conductive cable, coiled tubing, pipe string, or downhole tractor, communication may be supported using, for example, wireless protocols (e.g., EM, acoustic, etc.), and/or measurements and logging data can be stored in local memory for subsequent retrieval. Facility **244** may include a computing device **250** able to communicate with the devices and systems of the present disclosure.

FIG. **3** is a block diagram of an operating environment **300** in which a treatment optimization system **302** may be deployed. Treatment optimization system **302** may be deployed as a software application at, for example, facility **244** or processing facility **196** described above. In some examples, treatment optimization system **302** may be deployed to a remote server or cloud provider and so receive and transmit data across one or more network connections. In some examples, treatment optimization system **302** may be deployed to a computer directly or indirectly coupled to one or more electric frac pump systems **306**. Nevertheless, and in general, treatment optimization system **302** may execute the various methods and techniques discussed above.

Treatment optimization system **302** is communicatively coupled to a model store **304**, an electric frac pump system **306**, and well sensors **310**. Treatment optimization system may retrieve system models from model store **304** and store updated system models in model store **304**, which may be a local data store, such as a local memory, or a remote data store, such as networked memory or storage.

Treatment optimization system **302** sends commands to electric frac pump system **306** via a pump system interface **314**. Pump system interface **314** may provide protocol formatting, application programming interfaces (APIs), and the like for providing commands from treatment optimization system **302** that may be interpreted by a particular type of electric frac pump system **306**. Treatment optimization system **302** may receive sensors data values from sensors **310** via a sensor interface **312**, which may likewise provide protocol formatting, APIs, and the like for receiving data in a format and/or structure interpretable by treatment optimization system **302**.

In general, commands sent to electric frac pump system **306** cause electric frac pump system **306** to adjust various settings such as, for example and without imputing limitation, pressure levels, flow rates, composition and/or presence of proppant, diverter, or other chemicals within a pumped fluid, and the like. The pumped fluid is distributed into a well environment **308**, the response (e.g., formation response, etc.) of which to the settings of electric frac pump system **306** may be measured by sensors **310** and provided to treatment optimization system **302**. Sensors **310** may be located in a treatment well, a monitoring well or on the surface within the treatment equipment or on the surface above the sub-surface well environment **308**.

Treatment optimization system **302** includes a model retrieval process **316** for retrieving representative systems models from model store **304**. In particular, model retrieval process **316** may receive sensors information from sensor interface **312** in order to determine which system model to retrieve from model store **304**. A stimuli sequence generator and controller **330** may generate a sequence of stimuli which are provided as commands to electric frac pump system **306** through pump system interface **314**. The generated sequence of stimuli may be used to produce a response, and resulting sensor data from sensors **310**, from well environment **308**. As a result, model retrieval process **316** may retrieve a system model based on the response information from well environment **308** as a result of stimuli sequence generator and controller **330**.

In some examples, model retrieval process **316** may provide the retrieved model to a model update process **320**, which may update and/or modify the retrieved model based on sensor values received via sensor interface **312**. As a result, in some examples, stimuli sequence generator and controller **330** may generate iterative stimuli commands and/or sequences to update or modify a retrieved system model. In some examples, a representative system model may be generated directly as a result of the generate sequence of stimuli rather than retrieved. In some examples, updated system model parameters and/or new representative system models may be provided to model store **304** by a model storage process **318** in order to later retrieve the stored representative system models. In some examples, stimuli sequence generator and controller **330** may modify the stimuli commands and/or sequences based on the updated models.

Stimuli sequence generator and controller **330** includes a stimuli model **324**, a stimuli scheduler **326**, and a stimuli control **328**. Stimuli model **324** may be used to determine which stimuli to produce and/or modify to generate, update, or apply a representative system model. Stimuli scheduler **326** may generate a stimuli sequence based on the stimuli determined by stimuli model **324**. Stimuli control **328** may execute the generate stimuli sequence by generating respective commands, based on the scheduled sequence, to provide to pump system interface **314**.

FIG. **4** is a flowchart of a method **400** for selecting and executing a representative system model. Method **400** may be performed, for example, by treatment optimization system **302** discussed above or a substantially similar system. At step **402**, a sequence of stimuli, such as a treatment cycle or the like, is applied to a well environment tooled with one or more sensors.

At step **404**, sensor data is received from the well environment sensors in response to the sequence of stimuli. In some examples, an interface or interpreter may convert the received sensor data, which may be received in various signal formats, into a format and/or structure interpretable by a particular system. In some examples, normalization processes or the like may be applied to the received sensor data to make the data mathematically comparable, etc.

At step **406**, a representative system model is selected based on the received sensor data. The representative system model may be selected based on, for example, an operation performed on the received sensor data (e.g., transformation, hashing, or similar processes). In some examples, a partial system model may be generated based on the received sensor data and the representative system model may be selected accordingly to a similarity measure or the like.

At step **408**, settings on an electric frac pump are controlled based on the selected representative system model. Settings may include pressure, flow rate, chemical (e.g., proppant, diverter, etc.) composition of a pumped fluid, or the like. In some examples, at step **410**, further sensor data is received in response to the settings controls. At step **412**, the selected model can be updated based on the further sensor data and the settings controls. In some examples, method **400** may loop to step **408** and so the selected model may continue to go through update cycles (e.g., iterations) as control settings are adjusted in response to sensor data.

FIG. **5** is a schematic diagram of a computing system **500** that may implement various systems and methods discussed herein. The computing system **500** includes one or more computing components in communication via a bus **502**. In one embodiment, the computing system **500** may include one or more processes **504**. The processor **504** can include one or more internal levels of cache **518** and a bus controller or bus interface unit to direct interaction with the bus **502**. The processor **504** can specifically implement the various methods discussed herein. Memory **510** may include one or more memory cards and a control circuit, or other forms of removable memory, and can store various software appli-

cations including computer executable instructions, that when run on the processor **504** implement the methods and systems set out herein. Other forms of memory, such as a storage device **512** and a mass storage device **514**, can also be included and accessible by the processor (or processors) **504** via the bus **502**. The storage device **512** and mass storage device **514** can each contain any or all of the methods and systems, in whole or in part, discussed herein. In some examples, the storage device **512** or the mass storage device **514** can provide a database or repository in order to store data as discussed below.

The computing system **500** can further include a communications interface **506** by way of which the computing system **500** can connect to networks and receive data useful in executing the methods and systems set out herein as well as transmitting information to other devices. The computer system **500** can also include an input device **508** by which information is input. Input device **508** can be a scanner, keyboard, and/or other input devices as will be apparent to a person of ordinary skill in the art. The system set forth in FIG. **5** is but one possible example of a computer system that may employ or be configured in accordance with aspects of the present disclosure. It will be appreciated that other non-transitory tangible computer-readable storage media storing computer-executable instructions for implementing the presently disclosed technology on a computing system may be utilized.

Numerous examples are provided herein to enhance understanding of the present disclosure. A specific set of statements are provided as follows:

Statement 1: A computer-implemented method for controlling electrical fracturing equipment for fracturing a well includes generating a sequence of stimuli for application to a well environment, the sequence of stimuli including one or more of particulate concentrations, chemical concentrations, or a pump rate control, receiving formation response data including data from one or more downhole sensors or surface sensors, selecting a representative system model based on the received formation response data and sequence of stimuli, and controlling an electrical fracturing pump based on the representative system model.

Statement 2: The method of preceding Statement 1 may further include the representative system model being retrieved from a data store based the received formation response data.

Statement 3: The method of any of the preceding Statements may include the representative system model being generated based on data created through simulation with uncertainty parameters.

Statement 4: The method of any of the preceding Statements may include selecting the representative system model further including determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data, and updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.

Statement 5: The method of any of the preceding Statements may include the data from the one or more downhole sensors or surface sensors being used to determine changes in flow distribution in response to a diverter drop, the changes in flow distribution used to determine the representative system model.

Statement 6: The method of any of the preceding Statements may include the one or more downhole sensors or surface sensors including one or more of a single-point electrical sensors, an optical sensor, or a fiber optic sensor.

Statement 7: The method of any of the preceding Statements may include the formation response data including measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, or electromagnetic signals or frequency, amplitude or phase of any of the electromagnetic signals.

Statement 8: The method of any of the preceding Statements may include the representative system model predicting a proxy value including one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference in a neighboring well.

Statement 9: A system for controlling electrical fracturing equipment for fracturing a well includes one or more processors, and a memory comprising instructions to generate a sequence of stimuli for application to a well environment, the sequence of stimuli including one or more of particulate concentrations, chemical concentrations, or a pump rate control, receive formation response data including data from one or more downhole sensors or surface sensors, select a representative system model based on the received formation response data and sequence of stimuli, and control an electrical fracturing pump based on the representative system model.

Statement 10: The system of preceding Statement 9 may include the representative system model being retrieved from a data store based the received formation response data.

Statement 11: The system of any of preceding Statements 9-10 may include the representative system model is generated based on data created through simulation with uncertainty parameters.

Statement 12: The system of any of preceding Statements 9-11 may include selecting the representative system model further including determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data, and updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.

Statement 13: The system of any of preceding Statements 9-12 may include the data from the one or more downhole sensors or surface sensors being used to determine changes in flow distribution in response to a diverter drop, the changes in flow distribution used to determine the representative system model.

Statement 14: The system of any of preceding Statements 9-10 may include the formation response data including measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, or electromagnetic signals or frequency, amplitude or phase of any of the electromagnetic signals.

Statement 15: The system of any of preceding Statements 9-10 may include the representative system model predicting a proxy value including one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference from a neighboring well.

Statement 16: A non-transitory computer readable medium stores instructions that, when executed by one or more processors, cause the one or more processors to generate a sequence of stimuli for application to a well environment, the sequence of stimuli including one or more of particulate concentrations, chemical concentrations, or a pump rate control, receive formation response data including data from one or more downhole sensors or surface

sensors, select a representative system model based on the received formation response data and sequence of stimuli, and control an electrical fracturing pump based on the representative system model.

Statement 17: The non-transitory computer readable medium of preceding Statement 16 may include the representative system model being retrieved from a data store based the received formation response data.

Statement 18: The non-transitory computer readable medium of any of preceding Statements 16-17 may include the representative system model being generated based on data created through simulation with uncertainty parameters.

Statement 19: The non-transitory computer readable medium of any of preceding Statements 16-18 may include selecting the representative system model further including determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data, and updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.

Statement 20: The non-transitory computer readable medium of any of preceding Statements 16-19 may include the formation response data including measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, electromagnetic signals, or frequency, amplitude or phase of any of the signals, and the representative system model predicts a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference from a neighboring well.

The description above includes example systems, methods, techniques, instruction sequences, and/or computer program products that embody techniques of the present disclosure. However, it is understood that the described disclosure may be practiced without these specific details.

While the present disclosure has been described with references to various implementations, it will be understood that these implementations are illustrative and that the scope of the disclosure is not limited to them. Many variations, modifications, additions, and improvements are possible. More generally, implementations in accordance with the present disclosure have been described in the context of particular implementations. Functionality may be separated or combined in blocks differently in various examples of the disclosure or described with different terminology. These and other variations, modifications, additions, and improvements may fall within the scope of the disclosure as defined in the claims that follow.

What is claimed is:

1. A computer-implemented method for controlling electrical fracturing equipment for fracturing a well, the method comprising:

generating a sequence of stimuli for application to a well environment, the sequence of stimuli comprising one or more of particulate concentrations, chemical concentrations, or a pump rate control;

receiving formation response data comprising data from one or more downhole sensors or surface sensors;

selecting a representative system model based on the received formation response data and sequence of stimuli; and

controlling an electrical fracturing pump based on the representative system model.

2. The method of claim **1**, wherein the representative system model is retrieved from a data store based the received formation response data.

3. The method of claim **1**, wherein the representative system model is generated based on data created through simulation with uncertainty parameters.

4. The method of claim **1**, wherein selecting the representative system model further comprises:

determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data; and

updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.

5. The method of claim **1**, wherein the data from the one or more downhole sensors or surface sensors is used to determine changes in flow distribution in response to a diverter drop, the changes in flow distribution used to determine the representative system model.

6. The method of claim **1**, wherein the one or more downhole sensors or surface sensors comprises one or more of a single-point electrical sensors, an optical sensor, or a fiber optic sensor.

7. The method of claim **1**, wherein the formation response data comprises measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, or electromagnetic signals or frequency, amplitude or phase of any of the electromagnetic signals.

8. The method of claim **1**, wherein the representative system model predicts a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference in a neighboring well.

9. A system for controlling electrical fracturing equipment for fracturing a well, the system comprising:

one or more processors; and

a memory comprising instructions to:

generate a sequence of stimuli for application to a well environment, the sequence of stimuli comprising one or more of particulate concentrations, chemical concentrations, or a pump rate control;

receive formation response data comprising data from one or more downhole sensors or surface sensors;

select a representative system model based on the received formation response data and sequence of stimuli; and

control an electrical fracturing pump based on the representative system model.

10. The system of claim **9**, wherein the representative system model is retrieved from a data store based the received formation response data.

11. The system of claim **9**, wherein the representative system model is generated based on data created through simulation with uncertainty parameters.

12. The system of claim **9**, wherein selecting the representative system model further comprises:

determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data; and

updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.

13. The system of claim **9**, wherein the data from the one or more downhole sensors or surface sensors is used to determine changes in flow distribution in response to a

diverter drop, the changes in flow distribution used to determine the representative system model.

14. The system of claim **9**, wherein the formation response data comprises measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, or electromagnetic signals or frequency, amplitude or phase of any of the electromagnetic signals.

15. The system of claim **9**, wherein the representative system model predicts a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference from a neighboring well.

16. A non-transitory computer readable medium storing instructions that, when executed by one or more processors, cause the one or more processors to:

generate a sequence of stimuli for application to a well environment, the sequence of stimuli comprising one or more of particulate concentrations, chemical concentrations, or a pump rate control;

receive formation response data comprising data from one or more downhole sensors or surface sensors;

select a representative system model based on the received formation response data and sequence of stimuli; and

control an electrical fracturing pump based on the representative system model.

17. The non-transitory computer readable medium of claim **16**, wherein the representative system model is retrieved from a data store based the received formation response data.

18. The non-transitory computer readable medium of claim **16**, wherein the representative system model is generated based on data created through simulation with uncertainty parameters.

19. The non-transitory computer readable medium of claim **16**, wherein selecting the representative system model further comprises:

determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data; and

updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.

20. The non-transitory computer readable medium of claim **16**, wherein the formation response data comprises measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, electromagnetic signals, or frequency, amplitude or phase of any of the signals, and the representative system model predicts a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference from a neighboring well.

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