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(54) **SYSTEM AND METHOD FOR PERFORMING STIMULATION OPERATIONS**

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(57) **ABSTRACT**

A system and method is provided for performing a fracturing operation about a wellbore penetrating a subterranean formation. The method may acquire integrated wellsite data. The method may generate a mechanical earth model using the integrated wellsite data. The method may simulate an intersection of an induced hydraulic fracture with a natural fracture using the mechanical earth model. The method may determine intersection properties of the intersected natural fracture. The method may also generate a stimulation plan using the mechanical earth model and the intersection properties. The stimulation plan may include a fluid viscosity or a rate of injection of a fracturing fluid.

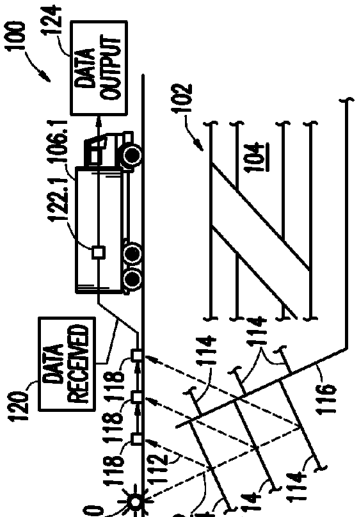


FIG. 1A

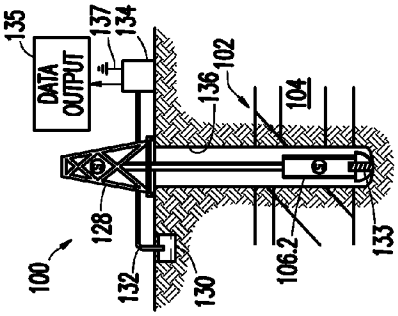


FIG. 1B

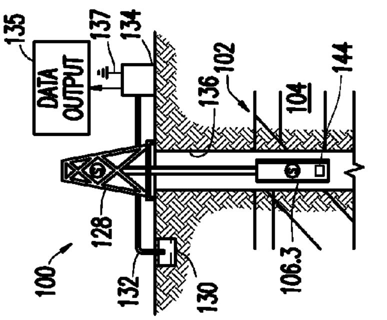


FIG. 1C

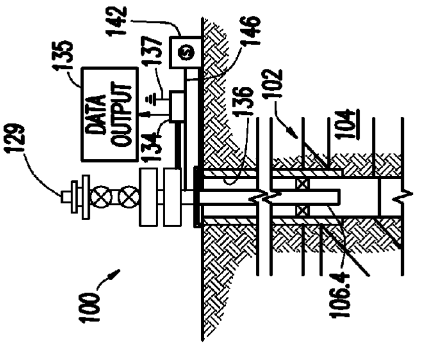


FIG. 1D

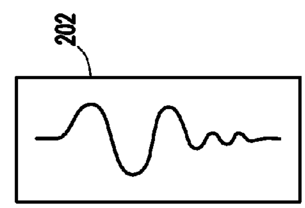


FIG. 2A

FIG. 2B

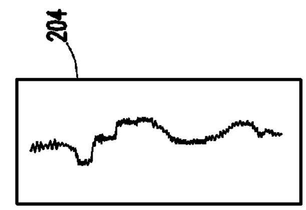


FIG. 2C

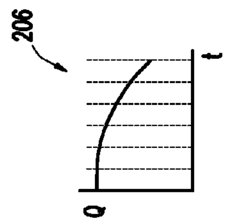
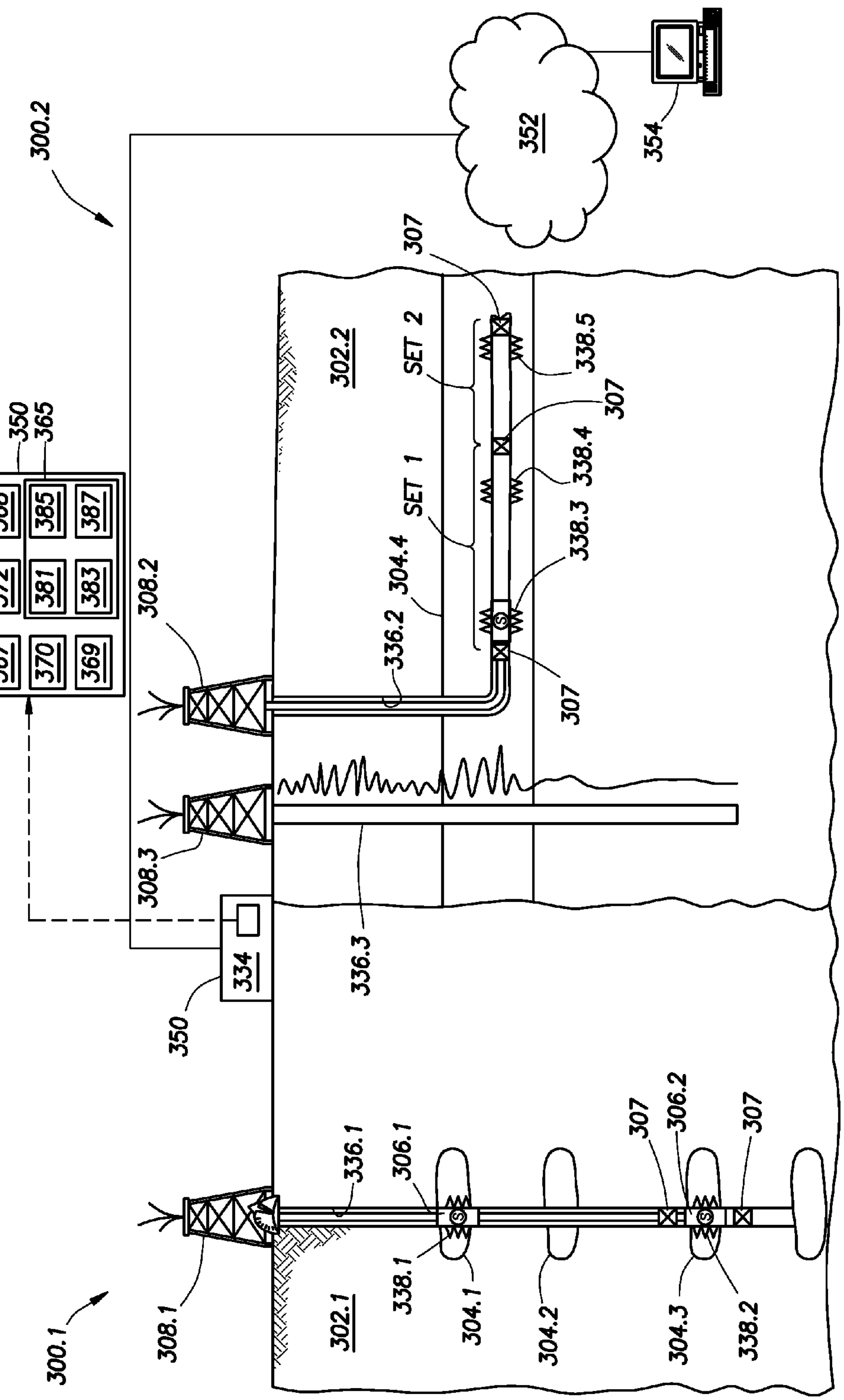


FIG. 2D

FIG. 3A


300.1
300.2
308.1
308.2
308.3
302.1
302.2
336.1
336.2
336.3
306.1
306.2
338.1
338.2
338.3
338.4
338.5
304.1
304.2
304.3
304.4
307
SET 1
SET 2
334
350
365
363
367
370
369
372
381
383
368
385
387
352
354

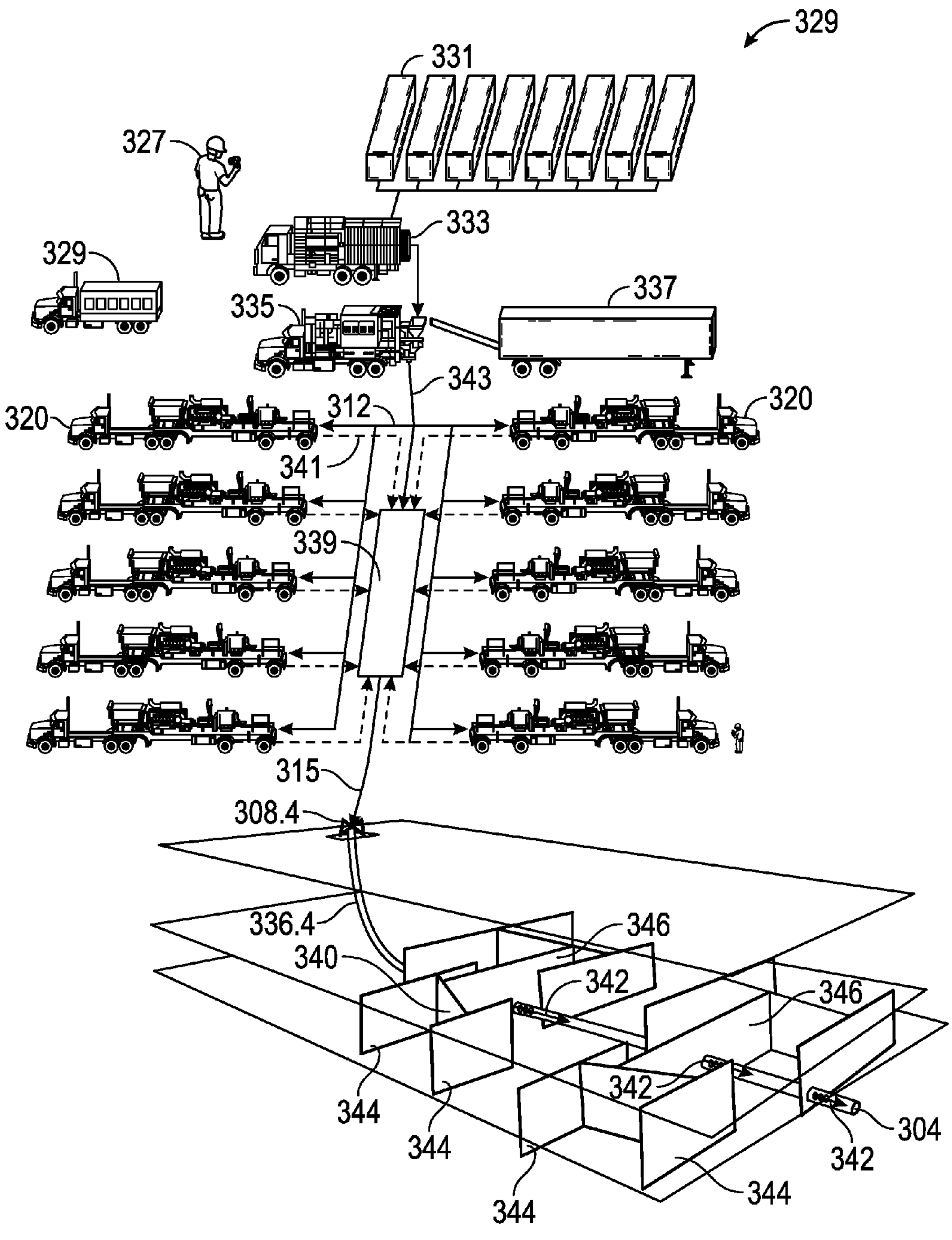

329
331
327
333
329
335
337
343
320
312
320
341
339
315
308.4
336.4
346
340
342
346
342
304
344
344
344
342
344
344

FIG. 3B

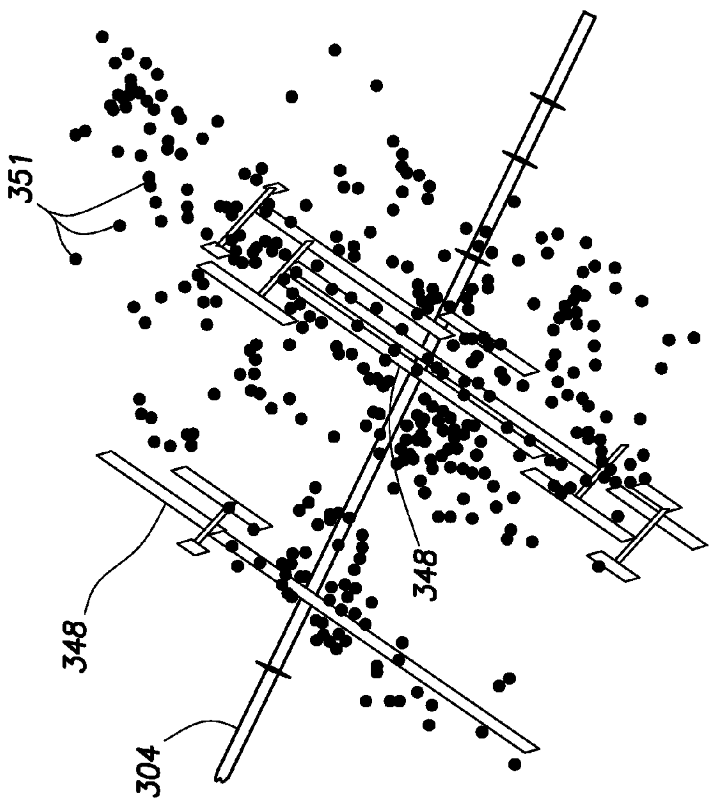


FIG. 3D

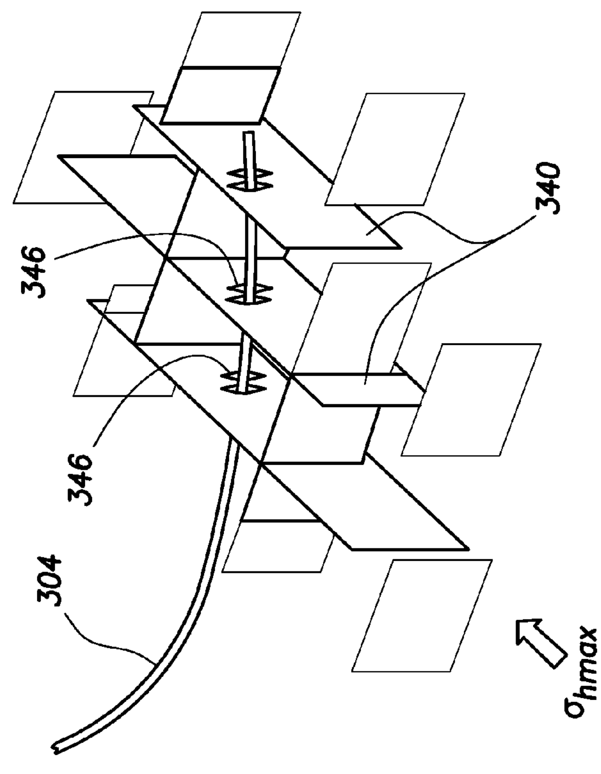


FIG. 3C

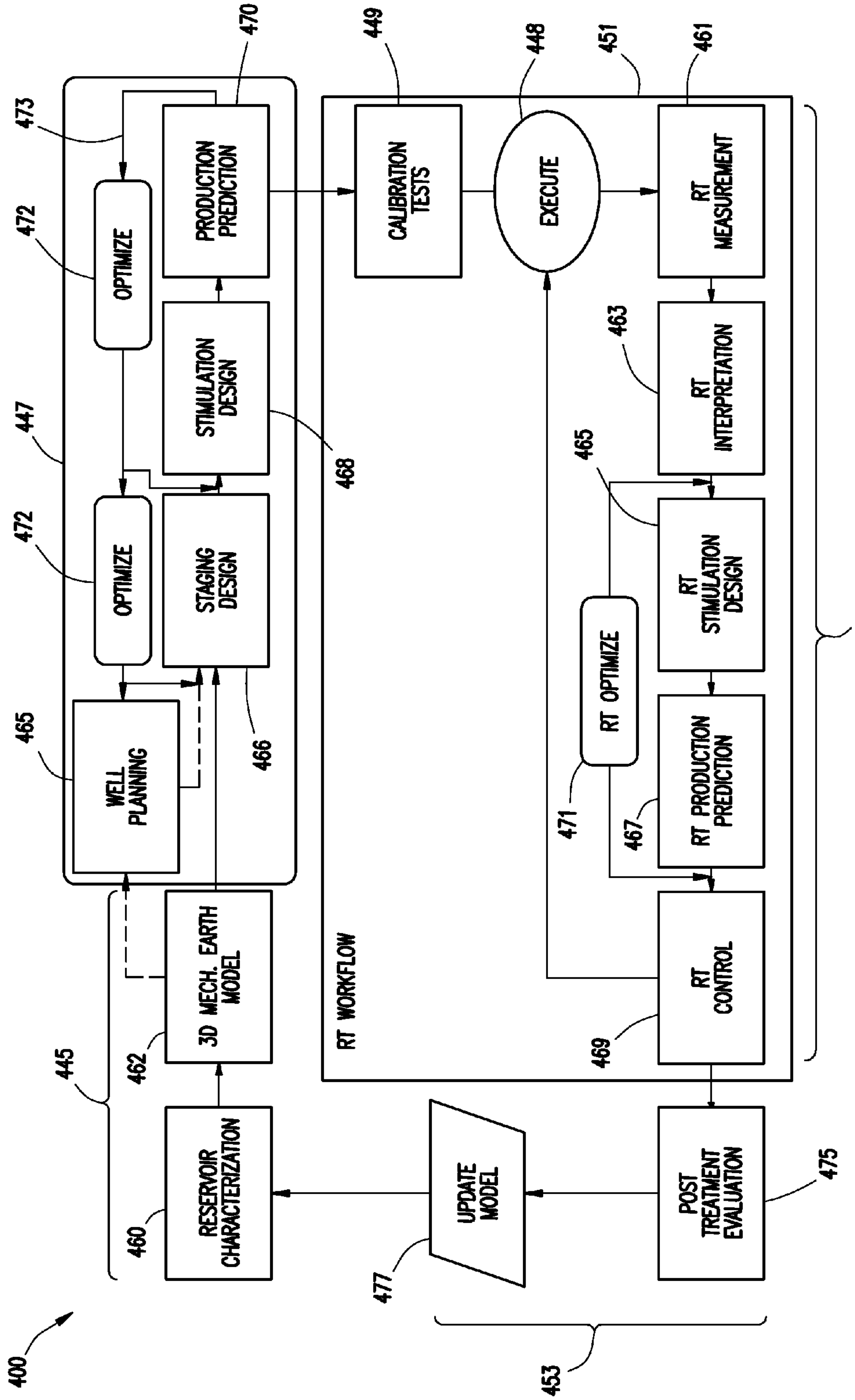

400
445
447
460
RESERVOIR CHARACTERIZATION
462
3D MECH. EARTH MODEL
465
WELL PLANNING
466
STAGING DESIGN
472
OPTIMIZE
468
STIMULATION DESIGN
470
PRODUCTION PREDICTION
473
RT WORKFLOW
449
CALIBRATION TESTS
448
EXECUTE
451
461
RT MEASUREMENT
463
RT INTERPRETATION
RT STIMULATION DESIGN
RT OPTIMIZE
471
467
RT PRODUCTION PREDICTION
469
RT CONTROL
455
475
POST TREATMENT EVALUATION
477
UPDATE MODEL
453

FIG. 4A

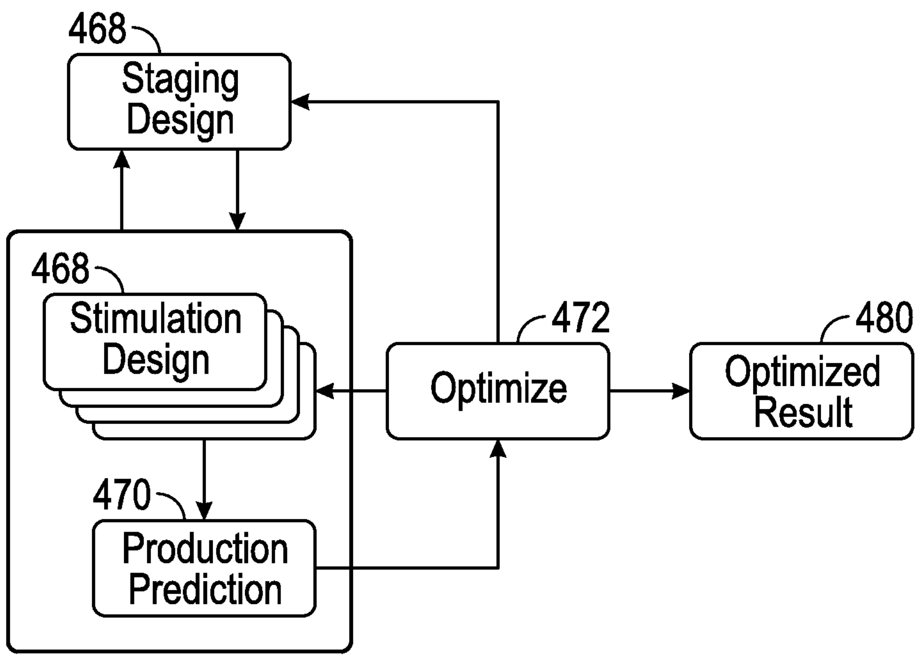

468
Staging Design
468
Stimulation Design
470
Production Prediction
472
Optimize
480
Optimized Result

FIG. 4B

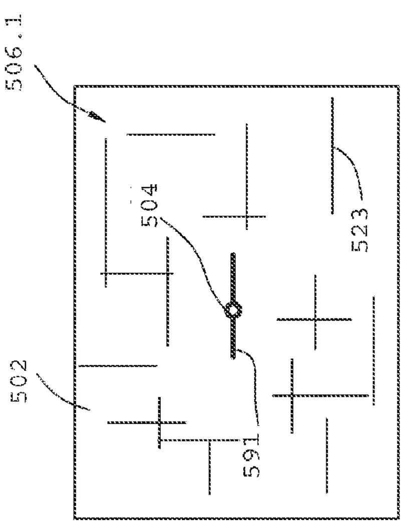


FIG. 5.1

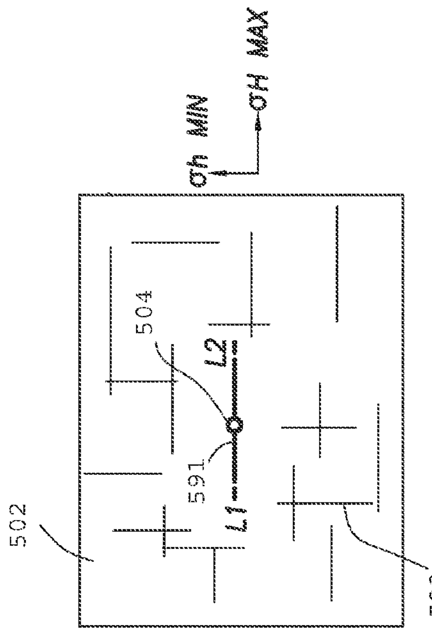


FIG. 5.2

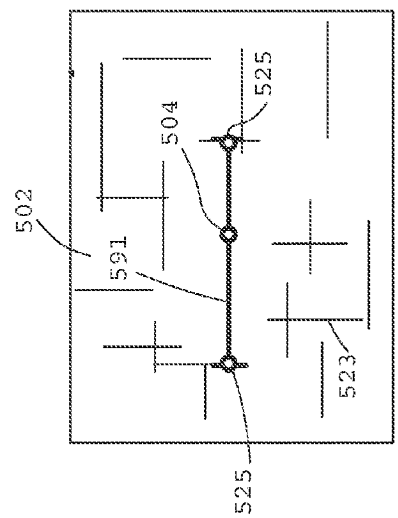


FIG. 5.3

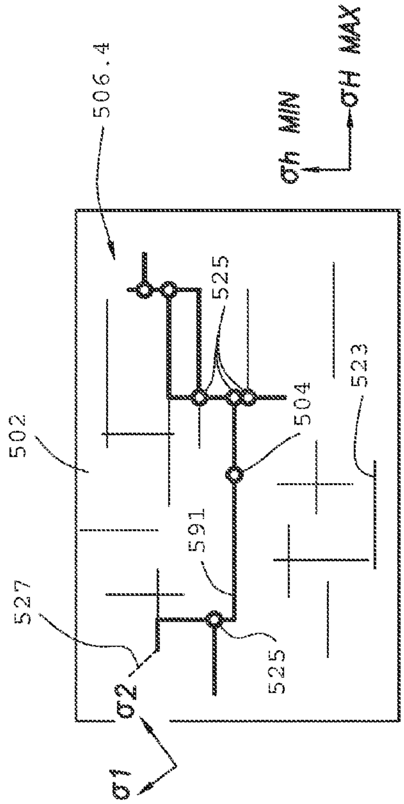


FIG. 5.4

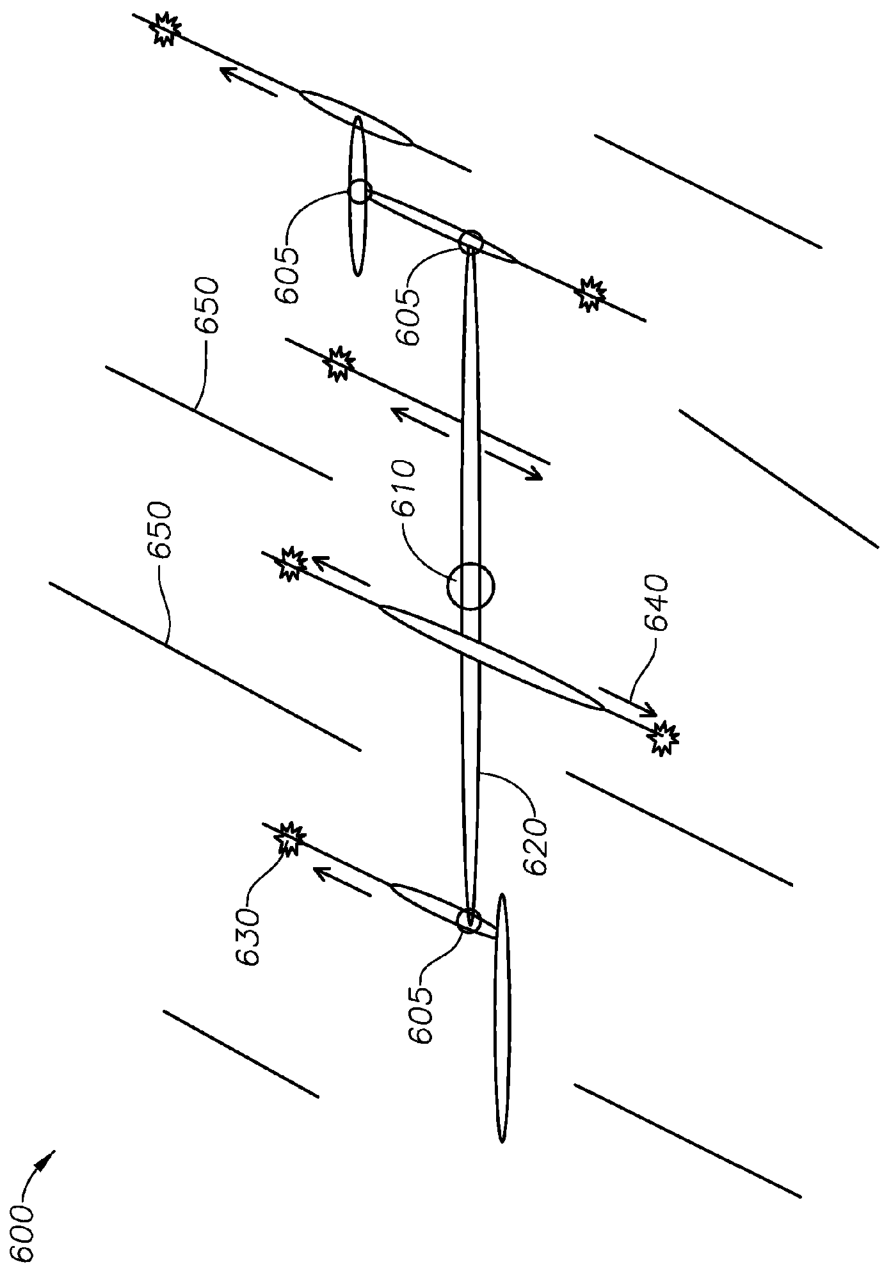


FIG. 6

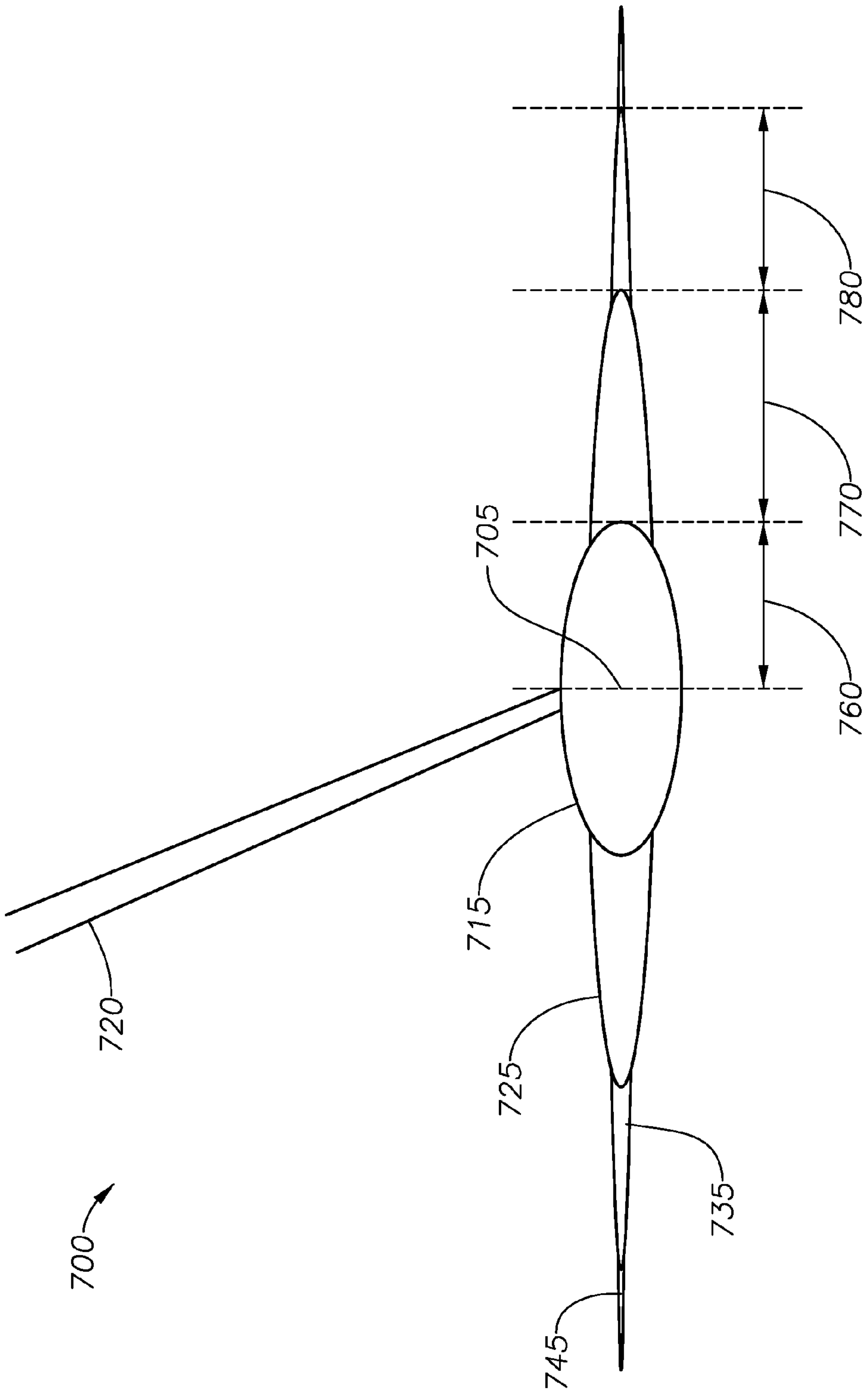


FIG. 7

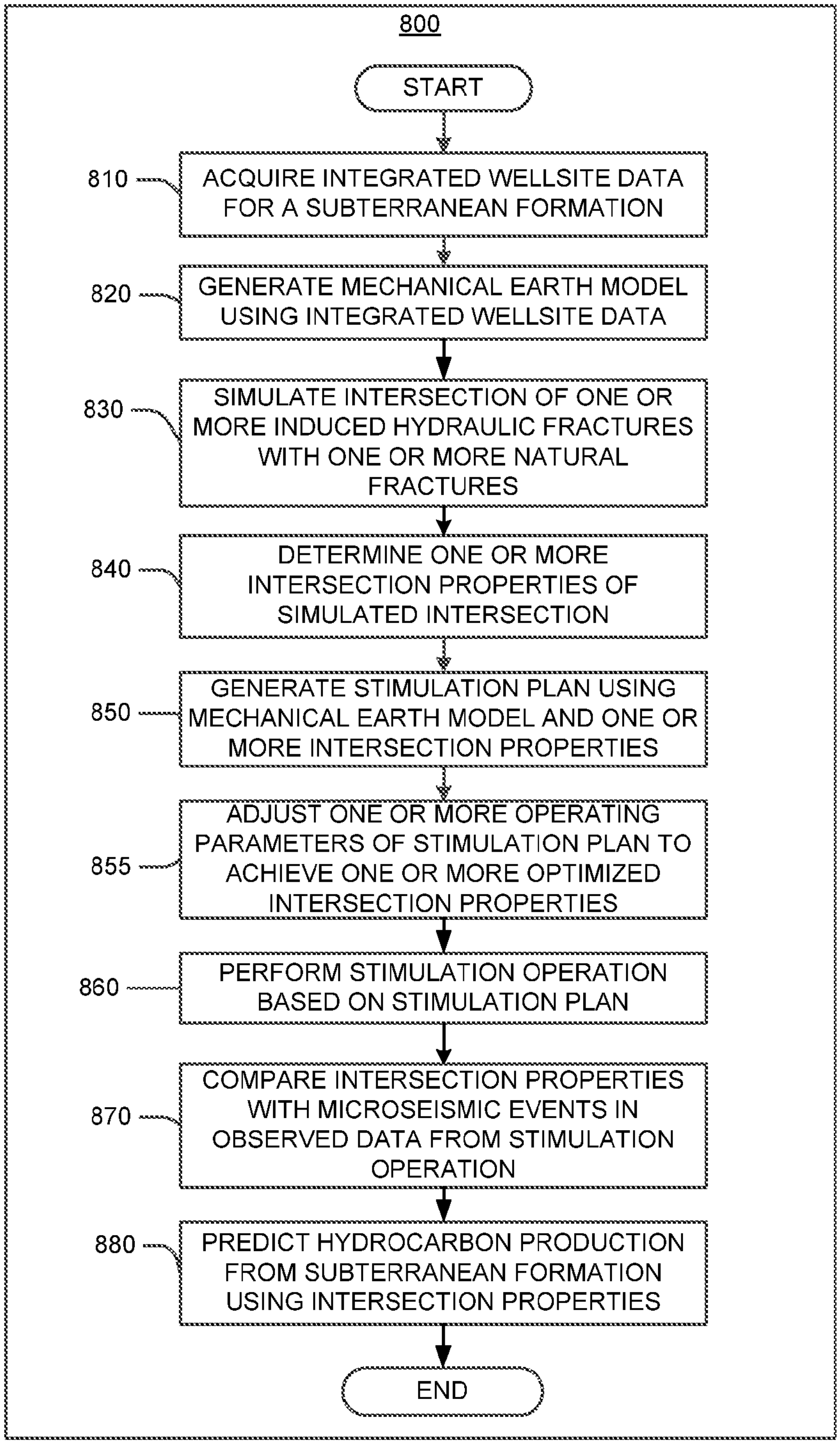

800
START
810
ACQUIRE INTEGRATED WELLSITE DATA FOR A SUBTERRANEAN FORMATION
820
GENERATE MECHANICAL EARTH MODEL USING INTEGRATED WELLSITE DATA
830
SIMULATE INTERSECTION OF ONE OR MORE INDUCED HYDRAULIC FRACTURES WITH ONE OR MORE NATURAL FRACTURES
840
DETERMINE ONE OR MORE INTERSECTION PROPERTIES OF SIMULATED INTERSECTION
850
GENERATE STIMULATION PLAN USING MECHANICAL EARTH MODEL AND ONE OR MORE INTERSECTION PROPERTIES
855
ADJUST ONE OR MORE OPERATING PARAMETERS OF STIMULATION PLAN TO ACHIEVE ONE OR MORE OPTIMIZED INTERSECTION PROPERTIES
860
PERFORM STIMULATION OPERATION BASED ON STIMULATION PLAN
870
COMPARE INTERSECTION PROPERTIES WITH MICROSEISMIC EVENTS IN OBSERVED DATA FROM STIMULATION OPERATION
880
PREDICT HYDROCARBON PRODUCTION FROM SUBTERRANEAN FORMATION USING INTERSECTION PROPERTIES
END

Fig. 8

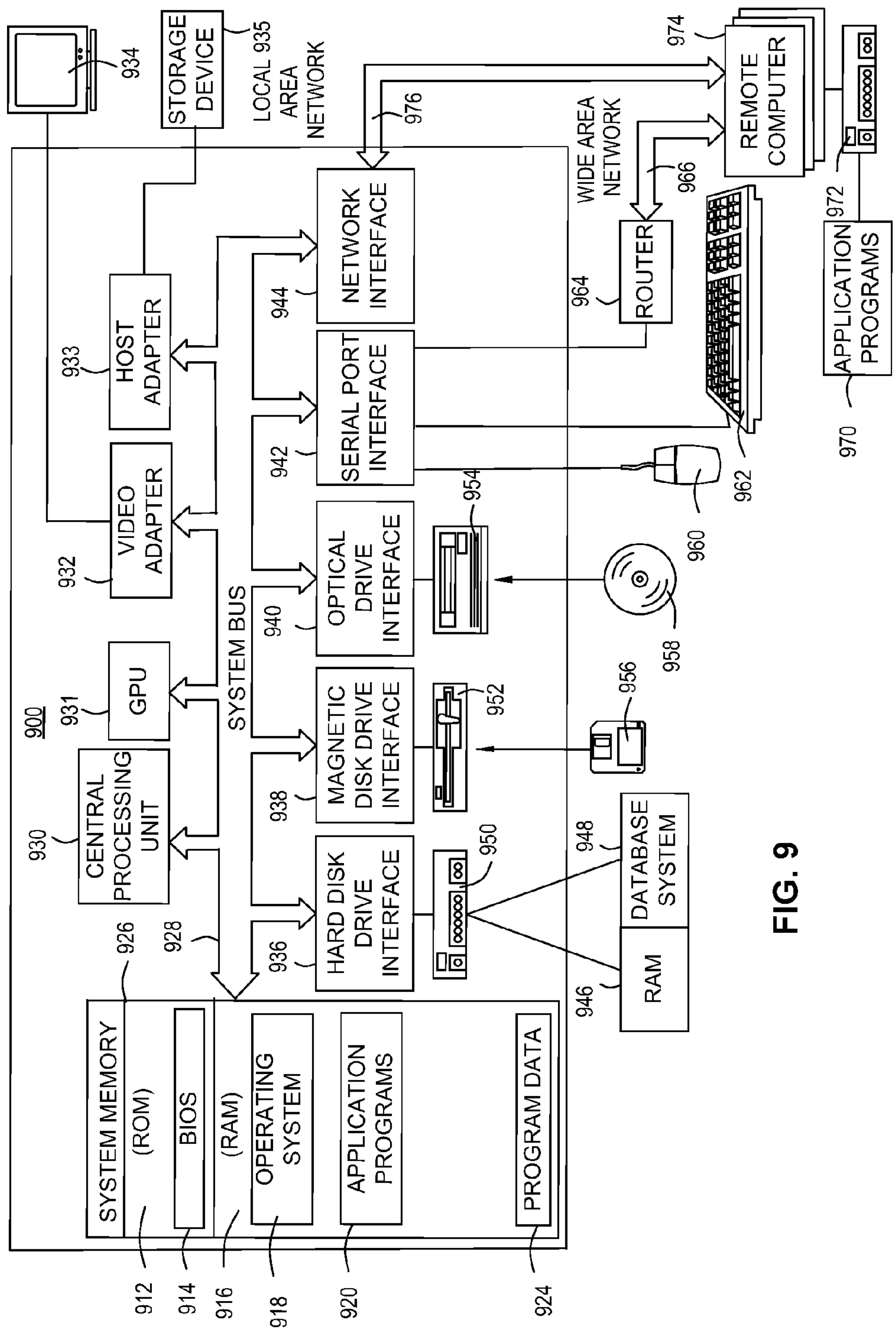

900
SYSTEM MEMORY
(ROM)
BIOS
(RAM)
OPERATING SYSTEM
APPLICATION PROGRAMS
PROGRAM DATA
CENTRAL PROCESSING UNIT
GPU
VIDEO ADAPTER
HOST ADAPTER
STORAGE DEVICE
LOCAL 935 AREA NETWORK
SYSTEM BUS
HARD DISK DRIVE INTERFACE
MAGNETIC DISK DRIVE INTERFACE
OPTICAL DRIVE INTERFACE
SERIAL PORT INTERFACE
NETWORK INTERFACE
RAM
DATABASE SYSTEM
ROUTER
WIDE AREA NETWORK
REMOTE COMPUTER
APPLICATION PROGRAMS
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FIG. 9

SYSTEM AND METHOD FOR PERFORMING STIMULATION OPERATIONS

BACKGROUND

[0001] This section is intended to provide background information to facilitate a better understanding of various technologies described herein. As the section's title implies, this is a discussion of related art. That such art is related in no way implies that it is prior art. The related art may or may not be prior art. It should therefore be understood that the statements in this section are to be read in this light, and applicant neither concedes nor acquiesces to the position that any given reference is prior art or analogous prior art.

[0002] In order to facilitate the recovery of hydrocarbons from oil and gas wells, the subterranean formations surrounding such wells can be hydraulically fractured. Hydraulic fracturing has become a valuable technique to create cracks in subsurface formations that allow hydrocarbons to move toward the well. Hydraulic fractures may extend away from the wellbore hundreds of feet in two opposing directions according to the natural stresses within the formation. Under certain circumstances, they may form a complex fracture network. Complex fracture networks can include induced hydraulic fractures and natural fractures, which may or may not intersect, along multiple azimuths, in multiple planes and directions, and in multiple regions.

[0003] A formation is fractured by introducing a specially engineered fluid (referred to as "fracturing fluid" or "fracturing slurry") at high pressure and high flow rates into the formation through one or more wellbores. Oilfield service companies have developed a number of different oil- and water-based fluids and treatments to more efficiently induce and maintain permeable and productive fractures. The composition of these fluids varies significantly, from simple water and sand to complex polymeric substances with a multitude of additives. Each type of fracturing fluid has unique characteristics, and each possesses its own positive and negative performance traits. It is desirable to selectively modify certain qualities of the fracturing fluid, and pumping characteristics, to achieve a desired complexity of the fracture network.

[0004] For example, a highly complex fracture network geometry may create much larger surface area compared to relatively simpler and straight fractures. Larger fracture surface area may enhance production in very low permeability reservoirs. On the other hand, a complex fracture network may contain tortuous fractures, multiple kinking and changes in fracture directions which may make the fracture opening too narrow or create pinch points that hampers hydrocarbon or particle transport. To achieve better production of fractured reservoirs, it may be desirable to have the optimal geometry to maximize both fracture surface area and transport characteristics.

[0005] In some cases, the occurrence of fractures and the extent of the fractures in the formation may be numerically modeled to infer hydraulic fracture propagation over time. Conventional hydraulic fracture models typically assume a bi-wing type induced fracture. These bi-wing fractures may be short in representing the complex nature of induced fractures in some unconventional reservoirs with pre-existing discontinuities, such as natural fractures (NF). Moreover, while some commercially available fracture models may take into account pre-existing natural fractures in the formation, many of the published models are oversimplified and neglect to account for the rigorous elastic solution of the interaction between induced fractures and natural fractures. Further, the vast majority of published models do not explicitly take into account the pumping properties of the fluid, which may include the injection rate, viscous properties of the fluid, and concentration of fluid additives.

SUMMARY

[0006] Described herein are embodiments of various technologies for a method for performing a fracturing operation about a wellbore penetrating a subterranean formation. The method may acquire integrated wellsite data. Integrated wellsite data may include geomechanical, geological, and/or geophysical properties of the subterranean formation as well as mechanical, geomechanical, and/or geometrical properties of natural fractures in the subterranean formation. The method may generate a mechanical earth model using the integrated wellsite data. The method may simulate an intersection of an induced hydraulic fracture with a natural fracture using the mechanical earth model. The method may determine intersection properties of the intersected natural fracture. The method may also generate a stimulation plan using the mechanical earth model and the intersection properties. The stimulation plan may include a fluid viscosity or a rate of injection of a fracturing fluid.

[0007] Described herein are embodiments of various technologies for a method for performing a fracturing operation about a wellbore penetrating a subterranean formation. The method may acquire integrated wellsite data. Integrated wellsite data may include geomechanical, geological, and/or geophysical properties of the subterranean formation as well as mechanical, geomechanical and/or geometrical properties of natural fractures in the subterranean formation. The method may generate a mechanical earth model using the integrated wellsite data. The method may simulate an intersection of an induced hydraulic fracture with a natural fracture using the mechanical earth model. The method may determine intersection properties of the intersected natural fracture. The method may predict hydrocarbon production from the subterranean formation using the intersection properties.

[0008] Described herein are embodiments of various technologies for a method for performing a fracturing operation about a wellbore penetrating a subterranean formation. The method may acquire integrated wellsite data. Integrated wellsite data may include geomechanical, geological, and/or geophysical properties of the subterranean formation as well as mechanical, geomechanical, and/or geometrical properties of natural fractures in the subterranean formation. The method may generate a mechanical earth model using the integrated wellsite data. The method may simulate an intersection of an induced hydraulic fracture with a natural fracture using the mechanical earth model. The method may determine intersection properties of the intersected natural fracture. The method may compare the intersection properties with microseismic events in observed data that is acquired from a stimulation operation based on the mechanical earth model.

[0009] Described herein are embodiments of various technologies for a method for performing a fracturing operation about a wellbore penetrating a subterranean formation. The method may acquire integrated wellsite data. Integrated wellsite data may include geomechanical, geological, and/or geophysical properties of the subterranean formation as well as mechanical, geomechanical, and/or geometrical properties of natural fractures in the subterranean formation. The method may generate a mechanical earth model using the integrated wellsite data. The method may simulate leak-off of fracturing fluid from an induced hydraulic fracture into a natural fracture using the mechanical earth model. The method may also generate a stimulation plan using the mechanical earth model. The stimulation plan may include a fluid viscosity or a rate of injection of a fracturing fluid. The method may also adjust operating parameters of the stimulation plan based on the simulated leak-off to achieve an optimized leak-off from the induced hydraulic fracture into the natural fracture.

[0010] The above referenced summary section is provided to introduce a selection of concepts that are further described below in the detailed description section. The summary is not intended to identify features of the claimed subject matter, nor is it intended to be used to limit the scope of the claimed subject matter. Furthermore, the claimed subject matter is not limited to implementations that solve any or most disadvantages noted in any part of this disclosure. Indeed, the systems, methods, processing procedures, techniques, and workflows disclosed herein may complement or replace conventional methods for identifying, isolating, and/or processing various aspects of wellsite data or other data that is collected from a subsurface region or other multi-dimensional space.

BRIEF DESCRIPTION OF THE DRAWINGS

[0011] Implementations of various technologies will hereafter be described with reference to the accompanying drawings. It should be understood, however, that the accompanying drawings illustrate various embodiments described herein and are not meant to limit the scope of various technologies described herein.

[0012] FIGS. **1**A-**1**D illustrate schematic views of oilfield operations at a wellsite in accordance with various embodiments described herein.

[0013] FIGS. **2**A-**2**D illustrate schematic views of data collections in accordance with various embodiments described herein.

[0014] FIG. **3**A illustrates a schematic view of a wellsite with various downhole stimulation operations in accordance with various embodiments described herein.

[0015] FIGS. **3**B-**3**D illustrate various fractures of a wellsite in accordance with various embodiments described herein.

[0016] FIG. **4**A illustrates a flow diagram in accordance with various embodiments described herein.

[0017] FIG. **4**B illustrates a schematic diagram of a downhole stimulation operation in accordance with various embodiments described herein.

[0018] FIGS. **5.1**-**5.4** illustrate fracture growth about a wellbore during a fracture operation in accordance with various embodiments described herein.

[0019] FIG. **6** illustrates a hydraulic fracture network in accordance with various embodiments described herein.

[0020] FIG. **7** illustrates an intersection between an induced hydraulic fracture and a natural fracture in accordance with various embodiments described herein.

[0021] FIG. **8** is a flow diagram for simulating and performing hydraulic fracturing in accordance with various embodiments described herein.

[0022] FIG. **9** illustrates a computer system in which the various technologies and techniques described herein may be incorporated and practiced.

DETAILED DESCRIPTION

[0023] The discussion below is directed to certain specific embodiments. It is to be understood that the discussion below is for the purpose of enabling a person with ordinary skill in the art to make and use any subject matter defined now or later by the patent "claims" found in any issued patent herein.

[0024] Reference will now be made in detail to various 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 claimed invention. However, it will be apparent to one of ordinary skill in the art that the claimed invention 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 claimed invention.

[0025] 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 block could be termed a second object or block, and, similarly, a second object or block could be termed a first object or block, without departing from the scope of various embodiments described herein. The first object or block, and the second object or block, are both objects or blocks, respectively, but they are not to be considered the same object or block.

[0026] The terminology used in the description herein is for the purpose of describing particular implementations and is not intended to limit the claimed invention. As used herein, 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 combinations 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, blocks, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, blocks, operations, elements, components, and/or groups thereof.

[0027] 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. Similarly, the phrase "if it is determined" or "if [a stated condition or event] is detected" may be construed to mean "upon determining" or "in response to determining" or "upon detecting [the stated condition or event]" or "in response to detecting [the stated condition or event]," depending on the context.

[0028] Various embodiments described herein are directed to systems and methods for performing and simulating a fracturing operation in a subterranean formation. These embodiments will be described in more detail with reference to FIGS. **1**-**9**.

Oilfield Operation

[0029] FIGS. **1**A-**1**D depict various oilfield operations that may be performed at a wellsite, and FIGS. **2**A-**2**D depict various information that may be collected at the wellsite. FIGS. **1**A-**1**D depict simplified, schematic views of a representative oilfield or wellsite **100** having subsurface formation

102 containing, for example, reservoir 104 therein and depicting various oilfield operations being performed on the wellsite 100. FIG. 1A depicts a survey operation being performed by a survey tool, such as seismic truck 106.1, to measure properties of the subsurface formation. The survey operation may be a seismic survey operation for producing sound vibrations. In FIG. 1A, one such sound vibration 112 generated by a source 110 reflects off a plurality of discontinuities 114 in an earth formation 116. The sound vibration(s) 112 may be received by sensors, such as geophone-receivers 118, situated on the earth's surface, and the geophones 118 produce electrical output signals, referred to as data received 120 in FIG. 1A.

[0030] In response to the received sound vibration(s) 112 representative of different parameters (such as amplitude and/or frequency) of the sound vibration(s) 112, the geophones 118 may produce electrical output signals containing data concerning the subsurface formation. The data received 120 may be provided as input data to a computer 122.1 of the seismic truck 106.1, and responsive to the input data, the computer 122.1 may generate a seismic and microseismic data output 124. The seismic data output 124 may be stored, transmitted or further processed as desired, for example by data reduction.

[0031] FIG. 1B depicts a drilling operation being performed by a drilling tool 106.2 suspended by a rig 128 and advanced into the subsurface formations 102 to form a wellbore 136 or other channel. A mud pit 130 may be used to draw drilling mud into the drilling tools via flow line 132 for circulating drilling mud through the drilling tools, up the wellbore 136 and back to the surface. The drilling mud may be filtered and returned to the mud pit. A circulating system may be used for storing, controlling or filtering the flowing drilling muds. In this illustration, the drilling tools are advanced into the subsurface formations to reach reservoir 104. Each well may target one or more reservoirs. The drilling tools may be adapted for measuring downhole properties using logging while drilling tools. The logging while drilling tool may also be adapted for taking a core sample 133 as shown in FIGS. 1B and 2B, or removed so that a core sample 133 may be taken using another tool.

[0032] A surface unit 134 may be used to communicate with the drilling tool 106.2 and/or offsite operations. The surface unit 134 may communicate with the drilling tool 106.2 to send commands to the drilling tool 106.2, and to receive data therefrom. The surface unit 134 may be provided with computer facilities for receiving, storing, processing, and/or analyzing data from the operation. The surface unit 134 may collect data generated during the drilling operation and produce data output 135 which may be stored or transmitted. Computer facilities, such as those of the surface unit 134, may be positioned at various locations about the wellsite and/or at remote locations.

[0033] Sensors (S), such as gauges, may be positioned about the oilfield to collect data relating to various operations as described previously. As shown, the sensor (S) may be positioned in one or more locations in the drilling tool 106.2 and/or at the rig to measure drilling parameters, such as weight on bit, torque on bit, pressures, temperatures, flow rates, compositions, rotary speed and/or other parameters of the operation. Sensors (S) may also be positioned in one or more locations in the circulating system.

[0034] The data gathered by the sensors may be collected by the surface unit 134 and/or other data collection sources for analysis or other processing. The data collected by the 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. All or select portions of the data may be selectively used for analyzing and/or predicting operations of the current and/or other wellbores. 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. The data may be stored in separate databases, or combined into a single database.

[0035] The collected data may be used to perform analysis, such as modeling operations. For example, the seismic data output may be used to perform geological, geophysical, and/or reservoir engineering analysis. The reservoir, wellbore, surface and/or processed data may be used to perform reservoir, wellbore, geological, and geophysical or other simulations. The data outputs from the operation may be generated directly from the sensors, or after some preprocessing or modeling. These data outputs may act as inputs for further analysis.

[0036] The data may be collected and stored at the surface unit 134. One or more surface units 134 may be located at the wellsite, or connected remotely thereto. The surface unit 134 may be a single unit, or a complex network of units used to perform the necessary data management functions throughout the oilfield. The surface unit 134 may be a manual or automatic system. The surface unit 134 may be operated and/or adjusted by a user.

[0037] The surface unit 134 may be provided with a transceiver 137 to allow communications between the surface unit 134 and various portions of the current oilfield or other locations. The surface unit 134 may also be provided with or functionally connected to one or more controllers for actuating mechanisms at the wellsite 100. The surface unit 134 may then send command signals to the oilfield in response to data received. The surface unit 134 may receive commands via the transceiver or may itself execute commands to the controller. A processor may be provided to analyze the data (locally or remotely), make the decisions and/or actuate the controller. In this manner, operations may be selectively adjusted based on the data collected. Portions of the operation, such as controlling drilling, weight on bit, pump rates or other parameters, may be optimized based on the information. These adjustments may be made automatically based on computer protocol, and/or manually by an operator. In some cases, well plans may be adjusted to select optimum operating conditions, or to avoid problems.

[0038] FIG. 1C depicts a wireline operation being performed by a wireline tool 106.3 suspended by the rig 128 and into the wellbore 136 of FIG. 1B. The wireline tool 106.3 may be adapted for deployment into a wellbore 136 for generating well logs, performing downhole tests and/or collecting samples. The wireline tool 106.3 may be used to provide another method and apparatus for performing a seismic survey operation. The wireline tool 106.3 of FIG. 1C may, for example, have an explosive, radioactive, electrical, or acoustic energy source 144 that sends and/or receives electrical signals to the surrounding subsurface formations 102 and fluids therein.

[0039] The wireline tool 106.3 may be operatively connected to, for example, the geophones 118 and the computer 122.1 of the seismic truck 106.1 of FIG. 1A. The wireline tool 106.3 may also provide data to the surface unit 134. The surface unit **134** may collect data generated during the wireline operation and produce data output **135** which may be stored or transmitted. The wireline tool **106.3** may be positioned at various depths in the wellbore **136** to provide a survey or other information relating to the subsurface formation.

[0040] Sensors (S), such as gauges, may be positioned about the wellsite **100** to collect data relating to various operations as described previously. As shown, the sensor (S) is positioned in the wireline tool **106.3** to measure downhole parameters which relate to, for example porosity, permeability, fluid composition and/or other parameters of the operation.

[0041] FIG. **1**D depicts a production operation being performed by a production tool **106.4** deployed from a production unit or Christmas tree **129** and into the completed wellbore **136** of FIG. **1**C for drawing fluid from the downhole reservoirs into surface facilities **142**. Fluid flows from reservoir **104** through perforations in the casing (not shown) and into the production tool **106.4** in the wellbore **136** and to the surface facilities **142** via a gathering network **146**.

[0042] Sensors (S), such as gauges, may be positioned about the oilfield to collect data relating to various operations as described previously. As shown, the sensor (S) may be positioned in the production tool **106.4** or associated equipment, such as the Christmas tree **129**, gathering network, surface facilities and/or the production facility, to measure fluid parameters, such as fluid composition, flow rates, pressures, temperatures, and/or other parameters of the production operation.

[0043] While only simplified wellsite configurations are shown, it will be appreciated that the oilfield or wellsite **100** may cover a portion of land, sea and/or water locations that hosts one or more wellsites. Production may also include injection wells (not shown) for added recovery or for storage of hydrocarbons, carbon dioxide, or water, for example. One or more gathering facilities may be operatively connected to one or more of the wellsites for selectively collecting downhole fluids from the wellsite(s).

[0044] It should be appreciated that FIGS. **1**B-**1**D depict tools that can be used to measure not only properties of an oilfield, but also properties of non-oilfield operations, such as mines, aquifers, storage, and other subsurface facilities. Also, while certain data acquisition tools are depicted, it will be appreciated that various measurement tools (e.g., wireline, measurement while drilling (MWD), logging while drilling (LWD), core sample, etc.) capable of sensing parameters, such as seismic two-way travel time, density, resistivity, production rate, etc., of the subsurface formation and/or its geological formations may be used. Various sensors (S) may be located at various positions along the wellbore and/or the monitoring tools to collect and/or monitor the desired data. Other sources of data may also be provided from offsite locations.

[0045] The oilfield configuration of FIGS. **1**A-**1**D depict examples of a wellsite **100** and various operations usable with the techniques provided herein. Part, or all, of the oilfield may be on land, water and/or sea. Also, while a single oilfield measured at a single location is depicted, reservoir engineering may be utilized with any combination of one or more oilfields, one or more processing facilities, and one or more wellsites.

[0046] FIGS. **2**A-**2**D are graphical depictions of examples of data collected by the tools of FIGS. **1**A-**1**D, respectively. FIG. **2**A depicts a seismic trace **202** of the subsurface formation of FIG. **1**A taken by seismic truck **106.1**. The seismic trace **202** may be used to provide data, such as a two-way response over a period of time. FIG. **2**B depicts a core sample **133** taken by the drilling tools **106.2**. The core sample may be used to provide data, such as a graph of the density, porosity, permeability or other physical property of the core sample over the length of the core. Tests for density and viscosity may be performed on the fluids in the core at varying pressures and temperatures. FIG. **2**C depicts a well log **204** of the subsurface formation of FIG. **1**C taken by the wireline tool **106.3**. The well log **204** may provide a resistivity or other measurement of the formation at various depts. FIG. **2**D depicts a production decline curve or graph **206** of fluid flowing through the subsurface formation of FIG. **1**D measured at the surface facilities **142**. The production decline curve may provide the production rate Q as a function of time t.

[0047] The respective graphs of FIGS. **2**A, **2**C, and **2**D depict examples of static measurements that may describe or provide information about the physical characteristics of the formation and reservoirs contained therein. These measurements may be analyzed to define properties of the formation (s), to determine the accuracy of the measurements and/or to check for errors. The plots of each of the respective measurements may be aligned and scaled for comparison and verification of the properties.

[0048] FIG. **2**D depicts an example of a dynamic measurement of the fluid properties through the wellbore. As the fluid flows through the wellbore, measurements are taken of fluid properties, such as flow rates, pressures, composition, etc. As described below, the static and dynamic measurements may be analyzed and used to generate models of the subsurface formation to determine characteristics thereof. Similar measurements may also be used to measure changes in formation aspects over time.

Stimulation Operations

[0049] FIG. **3**A depicts stimulation operations performed at wellsites **300.1** and **300.2**. The wellsite **300.1** includes a rig **308.1** having a vertical wellbore **336.1** extending into a formation **302.1**. Wellsite **300.2** includes rig **308.2** having wellbore **336.2** and rig **308.3** having wellbore **336.3** extending therebelow into a subterranean formation **302.2**. While the wellsites **300.1** and **300.2** are shown having specific configurations of rigs with wellbores, it will be appreciated that one or more rigs with one or more wellbores may be positioned at one or more wellsites.

[0050] Wellbore **336.1** extends from rig **308.1**, through unconventional reservoirs **304.1**-**304.3**. Wellbores **336.2** and **336.3** extend from rigs **308.2** and **308.3**, respectfully to unconventional reservoir **304.4**. As shown, unconventional reservoirs **304.1**-**304.3** are tight gas sand reservoirs and unconventional reservoir **304.4** is a shale reservoir. One or more unconventional reservoirs (e.g., such as tight gas, shale, carbonate, coal, heavy oil, etc.) and/or conventional reservoirs may be present in a given formation.

[0051] The stimulation operations of FIG. **3**A may be performed alone or in conjunction with other oilfield operations, such as the oilfield operations of FIGS. **1**A and **1**D. For example, wellbores **336.1**-**336.3** may be measured, drilled, tested and produced as shown in FIGS. **1**A-**1**D. Stimulation operations performed at the wellsites **300.1** and **300.2** may involve, for example, perforation, fracturing, injection, and the like. The stimulation operations may be performed in conjunction with other oilfield operations, such as completions and production operations (see, e.g., FIG. **1**D). As shown in FIG. **3**A, the wellbores **336**.**1** and **336**.**2** have been completed and provided with perforations **338**.**1**-**338**.**5** to facilitate production.

[0052] Downhole tool **306**.**1** is positioned in vertical wellbore **336**.**1** adjacent tight gas sand reservoirs **304**.**1** for taking downhole measurements. Packers **307** are positioned in the wellbore **336**.**1** for isolating a portion thereof, proximate adjacent perforations **338**.**2**. Once the perforations are formed about the wellbore fluid may be injected through the perforations and into the formation to create and/or expand fractures therein to stimulate production from the reservoirs.

[0053] Reservoir **304**.**4** of formation **302**.**2** has been perforated and packers **307** have been positioned to isolate the wellbore **336**.**2** about the perforations **338**.**3**-**338**.**5**. As shown in the horizontal wellbore **336**.**2**, packers **307** have been positioned at stages St_1 and St_2 of the wellbore. As also depicted, wellbore **304**.**3** may be an offset (or pilot) well extended through the formation **302**.**2** to reach reservoir **304**.**4**. One or more wellbores may be placed at one or more wellsites. Multiple wellbores may be placed as desired.

[0054] Fractures may be extended into the various reservoirs **304**.**1**-**304**.**4** for facilitating production of fluids therefrom. Examples of fractures that may be formed are schematically shown in FIGS. **3**B-**3**D about a wellbore **304**. As shown in FIGS. **3**B-**3**C, mechanical discontinuities **340**, such as natural fractures, bedding planes, faults, and planes of weakness, extend in layers in the formation. Natural fractures as described herein refer to planar discontinuities in the formation having different properties than the surrounding formation. Perforations (or perforation clusters) **342** may be formed about the wellbore **304**, and fluids **344** and/or fluids mixed with proppant **346** may be injected through the perforations **342**. As shown in FIGS. **3**B-**3**C, hydraulic fracturing may be performed by injecting through the perforations **342**, creating fractures along a maximum stress plane σ_{hmax} and opening and extending the natural fractures.

[0055] At the surface of the wellsite shown in FIG. **3**B, a pumping system **329** is positioned about the wellhead **308**.**4** for passing fluids **344** and/or fluids mixed with proppant **346** therein through tubing **315**.

[0056] The pumping system **329** is depicted as being operated by a field operator **327** for recording maintenance and operational data and/or performing maintenance in accordance with a prescribed maintenance plan. The pumping system **329** pumps the fluid **344** from the surface to the wellbore **304** during an oilfield operation.

[0057] In one example arrangement, the pumping system **329** may include a plurality of water tanks **331**, which feed water to a gel hydration unit **333**. The gel hydration unit **333** combines water from the tanks **331** with a gelling agent to form a gel. The gel is then sent to a blender **335** where it is mixed with a proppant from a proppant transport unit **337** to form a fracturing fluid **344**. The gelling agent may be used to increase the viscosity of the fracturing fluid and allows the proppant to be suspended in the fracturing fluid. It may also act as a friction reducing agent to allow higher pump rates with less frictional pressure. The gel hydration unit **333** may combine additional fluid additives to the water to form a fracturing fluid **344** with specific properties.

[0058] The fracturing fluid **344** is then pumped from the blender **135** to the treatment trucks **320** with plunger pumps as shown by solid lines **343**. Each treatment truck **320** receives the fracturing fluid at a low pressure and discharges it to a common manifold **339** (sometimes called a missile trailer or missile) at a high pressure as shown by dashed lines **341**. The missile **339** then directs the fracturing fluid from the treatment trucks **320** to the wellbore **304** as shown by solid line **315**. One or more treatment trucks **320** may be used to supply fracturing fluid at a desired rate.

[0059] Each treatment truck **320** may be normally operated at any rate, such as well under its maximum operating capacity. Operating the treatment trucks **320** under their operating capacity may allow for one to fail and the remaining to be run at a higher speed in order to make up for the absence of the failed pump. As shown, a computerized control system **345** may be employed to direct the entire pump system **329** during the fracturing operation.

[0060] FIG. **3**D shows another view of the fracturing operation about the wellbore **304**. In this view, the induced fractures **348** extend radially about the wellbore **304**. The induced fractures may be used to reach the pockets of microseismic events **351** (shown schematically as dots) about the wellbore **304**. The fracture operation may be used as part of the stimulation operation to provide pathways for facilitating movement of hydrocarbons to the wellbore **304** for production.

[0061] Referring back to FIG. **3**A, sensors (S), such as gauges, may be positioned about the oilfield to collect data relating to various operations as described previously. Some sensors, such as geophones, may be positioned about the formations during fracturing for measuring microseismic waves and performing microseismic mapping. The data gathered by the sensors may be collected by the surface unit **334** and/or other data collection sources for analysis or other processing as previously described (see, e.g., surface unit **134**). As shown, surface unit **334** is linked to a network **352** and other computers **354**.

[0062] A stimulation tool **350** may be provided as part of the surface unit **334** or other portions of the wellsite for performing stimulation operations. For example, information generated during one or more of the stimulation operations may be used in well planning for one or more wells, one or more wellsites and/or one or more reservoirs. The stimulation tool **350** may be operatively linked to one or more rigs and/or wellsites, and used to receive data, process data, send control signals, etc., as will be described further herein. The stimulation tool **350** may include a reservoir characterization unit **363** for generating a mechanical earth model (MEM), a stimulation planning unit **365** for generating stimulation plans, an optimizer **367** for optimizing the stimulation plans, a real-time unit **369** for optimizing in real-time the optimized stimulation plan, a control unit **368** for selectively adjusting the stimulation operation based on the real-time optimized stimulation plan, an updater **370** for updating the reservoir characterization model based on the real-time optimized stimulation plan and post evaluation data, and a calibrator **372** for calibrating the optimized stimulation plan as will be described further herein. The stimulation planning unit **365** may include a staging design tool **381** for performing staging design, a stimulation design tool **383** for performing stimulation design, a production prediction tool **385** for predicting production and a well planning tool **387** for generating well plans.

[0063] Wellsite data used in the stimulation operation may range from, for example, core samples to petrophysical interpretation based on well logs to three dimensional seismic data (see, e.g., FIGS. **2**A-**2**D). Stimulation design may employ, for example, oilfield petrotechnical experts to conduct manual processes to collate different pieces of information. Integration of the information may involve manual manipulation of disconnected workflows and outputs, such as delineation of a reservoir zones, identification of desired completion zones, estimation of anticipated hydraulic fracture growth for a given completion equipment configurations, decision on whether and where to place another well or a plurality of wells for better stimulation of the formation, and the like. This stimulation design may also involve semi-automatic or automatic integration, feedback and control to facilitate the stimulation operation.

[0064] Stimulation operations for conventional and unconventional reservoirs may be performed based on knowledge of the reservoir. Reservoir characterization may be used, for example, in well planning, identifying optimal target zones for perforation and staging, design of multiple wells (e.g., spacing and orientation), and geomechanical models. Stimulation designs may be optimized based on a resulting production prediction. These stimulation designs may involve an integrated reservoir centric workflow which include design, real-time (RT), and post treatment evaluation components. Well completion and stimulation design may be performed while making use of multi-disciplinary wellbore and reservoir data.

[0065] FIG. **4**A is a schematic flow diagram **400** depicting a stimulation operation, such as those shown in FIG. **3**A. The flow diagram **400** is an iterative process that uses integrated information and analysis to design, implement and update a stimulation operation. The method involves pre-treatment/pre-stimulation evaluation **445**, stimulation planning **447**, real-time treatment optimization **451**, and design/model update **453**. Part or all of the flow diagram **400** may be iterated to adjust stimulation operations and/or design additional stimulation operations in existing or additional wells.

[0066] The pre-stimulation evaluation **445** involves reservoir characterization **460** and generating a three-dimensional mechanical earth model (MEM) **462**. The reservoir characterization **460** may be generated by integrating information, such as the information gathered in FIGS. **1**A-**1**D, to perform modeling using united combinations of information from historically independent technical regimes or disciplines (e.g., petrophysicist, geologist, geomechanic and geophysicist, and previous fracture treatment results). Such reservoir characterization **460** may be generated using integrated static modeling techniques to generate the MEM **462** as described, for example, in US Patent Application Nos. 2009/0187391 and 2011/060572, the entire contents of which are hereby incorporated by reference. By way of example, software, such as PETREL™, VISAGE™, TECHLOG™, and GEOFRAME™ commercially available from SCHLUMBERGER™, may be used to perform the pre-treatment evaluation **445**.

[0067] Reservoir characterization **460** may involve capturing a variety of information, such as data associated with the underground formation and developing one or more models of the reservoir. The information captured may include, for example, reservoir (pay) zone, geomechanical (stress, elasticity, and the like) zone, geometrical (fracture orientation and size) distribution of the mechanical discontinuities (natural fractures) in the formation, and mechanical (permeability, conductivity, stress, fracture toughness, tensile strength, and the like) of the discontinuities. The reservoir characterization **460** may be performed such that information concerning the stimulation operation is included in pre-stimulation evaluations. Generating the MEM **462** may simulate the subterranean formation under development (e.g., generating a numerical representation of a state of stress and formation mechanical properties for a given stratigraphic section in an oilfield or basin).

[0068] Conventional geomechanical modeling may be used to generate the MEM **462**. Examples of MEM techniques are provided in US Patent Application No. 2009/0187391, the entire contents of which is hereby incorporated by reference. The MEM **462** may be generated by information gathered using, for example, the oilfield operations of FIGS. **1**A-**1**D, **2**A-**2**D and **3**A-**3**D. For example, the three-dimensional MEM may take into account various reservoir data collected beforehand, including the seismic data collected during early exploration of the formation and logging data collected from the drilling of one or more exploration wells before production (see, e.g., FIGS. **1**A-**1**D). The MEM **462** may be used to provide, for example, geomechanical information for various oilfield operations, such as casing point selection, optimizing the number of casing strings, drilling stable wellbores, designing completions, performing fracture stimulation, etc.

[0069] The generated MEM **462** may be used as an input in performing stimulation planning **447**. The three-dimensional MEM may be constructed to identify potential drilling wellsites. In one embodiment, when the formation is substantially uniform and is substantially free of major natural fractures and/or high-stress barriers, it can be assumed that a given volume of fracturing fluid pumped at a given rate over a given period of time will generate a substantially identical fracture network in the formation. In another embodiment, when the formation includes a complex network of mechanical discontinuities and/or high stress barriers, a desired stimulated area, volume and/or shape of volume may be achieved by adjusting at least one of the fluid viscosity, the rate of injection, and the fluid loss additives to thereby optimize the crossing behaviors between the induced fracture and the discontinuities present in the formation. Seismic data **202**, such as those shown in FIGS. **1**A and **2**A, may provide useful information in analyzing fracture properties of the formation.

[0070] The stimulation planning **447** may involve well planning **465**, staging design **466**, stimulation design **468**, and production prediction **470**. In particular, the MEM **462** may be an input to the well planning **465** and/or the staging design **466** and stimulation design **468**. Some embodiments may include semi-automated methods to identify, for example, well spacing and orientation, multistage perforation design and hydraulic fracture design. To address a wide variation of characteristics in hydrocarbon reservoirs, some embodiments may involve dedicated methods per target reservoir environments, such as, but not limited to, tight gas formations, sandstone reservoirs, naturally fractured shale reservoirs, or other unconventional reservoirs.

[0071] The stimulation planning **447** may involve a semi-automated method used to identify potential drilling wellsites by partitioning underground formations into multiple set of discrete intervals, characterizing each interval based on information such as the formation's geophysical properties and its proximity to natural fractures, then regrouping multiple intervals into one or multiple drilling wellsites, with each wellsite receiving a well or a branch of a well. The spacing and orientation of the multiple wells may be determined and used in optimizing production of the reservoir. Characteristics of each well may be analyzed for stage planning and stimulation planning. In some cases, a completion advisor may be provided, for example, for analyzing vertical or near vertical wells in tight-gas sandstone reservoir following a recursive refinement workflow.

[0072] Well planning **465** may be performed to design oilfield operations in advance of performing such oilfield operations at the wellsite. The well planning **465** may be used to define, for example, equipment and operating parameters for performing the oilfield operations. Some such operating parameters may include, for example, perforating locations, injection rate, operating pressures, stimulation fluids, and other parameters used in stimulation. Information gathered from various sources, such as historical data, known data, and oilfield measurements (e.g., those taken in FIGS. **1**A-**1**D), may be used in designing a well plan. In some cases, modeling may be used to analyze data used in forming a well plan. The well plan generated in the stimulation planning may receive inputs from the staging design **466**, stimulation design **468**, and production prediction **470** so that information relating to and/or affecting stimulation is evaluated in the well plan.

[0073] The well planning **465** and/or MEM **462** may also be used as inputs into the staging design **466**. Reservoir and other data may be used in the staging design **466** to define certain operational parameters for stimulation. For example, staging design **466** may involve defining boundaries in a wellbore for performing stimulation operations as described further herein. Examples of staging design are described in US Patent Application No. 2011/0247824, the entire contents of which is hereby incorporated by reference. Staging design may be an input for performing stimulation design **468**.

[0074] Stimulation design defines various stimulation parameters (e.g., perforation placement) for performing stimulation operations. The stimulation design **468** may be used, for example, for fracture modeling. Examples of fracture modeling are described in US Patent Application No. 2008/0183451, 2006/0015310 and PCT Publication No. WO2011/077227, the entire contents of which are hereby incorporated by reference. Stimulation design may involve using various models to define a stimulation plan and/or a stimulation portion of a well plan. Additional examples of complex fracture modeling are provided in SPE Paper 140185, the entire contents of which is hereby incorporated by reference. This complex fracture modeling illustrates the application of two complex fracture modeling techniques in conjunction with microseismic mapping to characterize fracture complexity and evaluate completion performance. The first complex fracture modeling technique is an analytical model for estimating fracture complexity and distances between orthogonal fractures. The second technique uses a gridded numerical model that allows complex geologic descriptions and evaluation of complex fracture propagation. These examples illustrate how embodiments may be utilized to evaluate how fracture complexity is impacted by changes in fracture treatment design in each geologic environment. To quantify the impact of changes in fracture design using complex fracture models despite inherent uncertainties in the MEM and "real" fracture growth, microseismic mapping and complex fracture modeling may be integrated for interpretation of the microseismic measurements while also calibrating the complex stimulation model. Such examples show that the degree of fracture complexity can vary depending on geologic conditions.

[0075] Stimulation design may integrate three-dimensional reservoir models (formation models), which can be a result of seismic interpretation, drilling geo-steering interpretation, geological or geomechanical earth model, as a starting point (zone model) for completion design. For some stimulation designs, a fracture modeling algorithm may be used to read a three-dimensional MEM and run forward modeling to predict fracture growth. This process may be used so that spatial heterogeneity of a complex reservoir may be taken into account in stimulation operations.

[0076] Microseismic mapping may also be used in the stimulation design **468** to understand complex fracture growth. Some workflows may integrate these predicted fracture models in a single three-dimensional canvas where microseismic events are overlaid (see, e.g., FIG. **3**D), which can be used in fracture design and/or calibrations. The nature and degree of fracture complexity may be assessed using microseismic mapping, and then optimized as discussed herein.

[0077] The nature and degree of fracture complexity may be analyzed to select an optimal stimulation design and completion strategy. Fracture modeling may be used to predict the fracture geometry that can be calibrated and the design optimized based on real-time microseismic mapping and evaluation. Fracture growth may be interpreted based on existing hydraulic fracture models. Some complex hydraulic fracture propagation modeling and/or interpretation may also be performed for unconventional reservoirs (e.g., tight gas sand and shale) as will be described further herein. Reservoir properties, and initial modeling assumptions may be corrected and fracture design optimized based on microseismic evaluation.

[0078] Production prediction **470** may involve estimating production based on the well planning **465**, staging design **466** and stimulation design **468**. The result of stimulation design **468** (i.e. simulated fracture models and input reservoir model) can be carried over to a production prediction workflow, where a conventional analytical or numerical reservoir simulator may operate on the models and predicts hydrocarbon production based on dynamic data. The pre-production prediction **470** can be useful, for example, for quantitatively validating the stimulation planning **447** process.

[0079] Part or all of the stimulation planning **447** may be iteratively performed as indicated by the flow arrows in FIG. **4**A. As shown, optimizations may be provided after the staging design **466**, stimulation design **468**, and production prediction **470**, and may be used as a feedback to optimize **472** the well planning **465**, the staging design **466** and/or the stimulation design **468**. The optimizations may be selectively performed to feedback results from part or all of the stimulation planning **447** and iterate as desired into the various portions of the stimulation planning process and achieve an optimized result. The stimulation planning **447** may be manually carried out, or integrated using automated optimization processing as schematically shown by the optimization **472** in feedback loop **473**.

[0080] FIG. 4B schematically depicts a portion of the stimulation planning operation **447**. As shown in this figure, the staging design **446**, stimulation design **468** and production prediction **470** may be iterated in the feedback loop **473** and optimized **472** to generate an optimized result **480**, such as an optimized stimulation plan with an optimized crossing behavior. This iterative method allows the inputs and results generated by the staging design **466** and stimulation design

468 to 'learn from each other' and iterate with the production prediction for optimization therebetween.

[0081] Various portions of the stimulation operation may be designed and/or optimized. Examples of optimizing fracturing are described, for example, in U.S. Pat. No. 6,508,307, the entire contents of which is hereby incorporated by reference. In another example, financial inputs, such as fracture operation costs (both fixed and variable), oil and natural gas futures, and contribution margins, each of which may affect operations, may also be provided in the stimulation planning **447**. Optimization may be performed by optimizing the stimulation design **466** with respect to predicted production while taking into consideration financial inputs. Such financial inputs may involve costs for various stimulation operations at various stages in the wellbore.

[0082] Referring back to FIG. **4**A, various optional features may be included in the stimulation planning **447**. For example, a multi-well planning advisor may be used to determine if it is necessary to construct multiple wells in a formation. If multiple wells are to be formed, the multi-well planning advisor may provide the spacing and orientation of the multiple wells, as well as the best locations within each for perforating and treating the formation. As used herein, the term "multiple wells" may refer to multiple wells each being independently drilled from the surface of the earth to the subterranean formation; the term "multiple wells" may also refer to multiple branches kicked off from a single well that is drilled from the surface of the earth (see, e.g., FIG. **3**A). The orientation of the wells and branches can be vertical, horizontal, or anywhere in between.

[0083] When multiple wells are planned or drilled, simulations can be repeated for each well so that each well has a staging plan, perforation plan, and/or stimulation plan. Thereafter, multi-well planning can be adjusted if necessary. For example, if a fracture stimulation in one well indicates that a stimulation result will overlap a nearby well with a planned perforation zone, the nearby well and/or the planned perforation zone in the nearby well can be eliminated or redesigned. On the contrary, if a simulated fracture treatment cannot penetrate a particular area of the formation, either because the pay zone is simply too far away for a first fracture well to effectively stimulate the pay zone or because the existence of a natural fracture or high-stress barrier prevents the first fracture well from effectively stimulating the pay zone, a second well/branch or a new perforation zone may be included to provide access to the untreated area. The three-dimensional reservoir model may take into account simulation models and indicate a candidate location to drill a second well/branch or to add an additional perforation zone. A spatial X'-Y'-Z' location may be provided for the oilfield operator's ease of handling.

Modeling Intersections Between Hydraulic Fractures and Natural Fractures

[0084] While taking into account the leak-off of the fracturing fluid into the formation, the leak-off into the natural fractures (NF) may also be considered, especially in low-matrix permeability conditions. Natural fractures influence hydraulic fracture (HF) propagation in different ways. A major aspect that leads to creation of complex hydraulic fracture network during a fracture stimulation is the possibility of a hydraulic fracture branching when a respective hydraulic fracture intersects a natural fracture. Another aspect where natural fractures effect hydraulic fracture geometry is their effect on fluid loss from the hydraulic fracture into permeable natural fractures, leading to reduced hydraulic fracture length.

[0085] FIGS. **5.1**-**5.4** depict an example of a hydraulic fracture growth pattern. As shown in FIG. **5.1**, in its initial state, a fracture network **506.1** with natural fractures **523** is positioned about a subterranean formation **502** with a wellbore **504** therethrough. As proppant is injected into the subterranean formation **502** from the wellbore **504**, pressure from the proppant creates induced hydraulic fractures **591** about the wellbore **504**. The induced hydraulic fractures **591** extend into the subterranean formation **502** along length L_1 and length L_2 (FIG. **5.2**), and encounter other fractures in the fracture network **506.1** over time as indicated in FIGS. **5.2**-**5.3**. The points of contact with the other fractures are intersections **525**.

[0086] Hydraulic fractures may extend from the wellbore **504** and into the natural fracture network of the subterranean formation **502** to form a hydraulic fracture network **506.4** including the natural fractures **523** and the induced hydraulic fractures **591** as shown in FIG. **5.4**. The fracture growth pattern is based on natural fracture parameters and a minimum stress and a maximum stress on the subterranean formation **502**.

[0087] As shown in FIGS. **5.1**-**5.4**, intersections **525** between induced hydraulic fractures **591** and natural fractures **523** may produce specific crossing behavior in multiple scenarios: (i) an induced fracture may continue propagating past the encountered natural fracture at the intersection point; (ii) an induced hydraulic fracture may stop at the encountered natural fracture or propagate along a portion of the encountered natural fracture after stopping; or (iii) an induced hydraulic fracture may propagate along the encountered natural fracture for a distance and then branch away from the natural fracture at some offset distance away from the intersection point. The crossing behavior, or intersection between the natural fracture and the induced hydraulic fracture, depends on a number of factors, such as, for example, the reservoir geomechanical properties, confining stress, the incident angle of interaction, friction coefficient, the cohesional properties of the pre-existing natural fractures, the viscosity of the fracturing fluid, the injection rate of the fluid, and the presence and concentration of fluid loss additives in the fracturing fluid.

[0088] Depending on downhole conditions, the fracture growth pattern may be unaltered or altered when the hydraulic fracture encounters a natural fracture (i.e., "the encountered fracture"). When a fracture pressure is greater than stress acting on the encountered fracture, the fracture growth pattern may propagate along the encountered fracture. The fracture growth pattern may continue propagation along the encountered fracture until the end of the natural fracture is reached. The fracture growth pattern may change direction at the end of the natural fracture, with the fracture growth pattern extending in a direction normal to a minimum stress at the end of the natural fracture. As shown in FIG. **5.4**, the induced hydraulic fracture extends on a new path **527** according to the local stresses σ_1 and σ_2.

[0089] When a natural fracture is intercepted by an induced hydraulic fracture (HF), the fluid pressure in the hydraulic fracture may transmit to the natural fracture. If the fluid pressure is less than the normal stress on the natural fracture, the natural fracture may remain closed. Even closed natural fractures may have hydraulic conductivities much larger than the surrounding rock matrix, and in this case fracturing fluid may invade the natural fractures in greater amounts than leak-off into the surrounding rock matrix. By losing fracturing fluid into closed natural fractures, the main hydraulic fracture may have reduced fracturing fluid volume available for further fracture growth.

[0090] For a closed fracture, the equivalent fluid conductivity may be expected to change with the fluid pressure since contact deformation is a function of effective normal stress. This pressure-induced dilatancy and the associated increase in conductivity may increase flow through some segments of the natural fracture path that may be subject to compressive contact stress. Also, any reduction in effective contact stress may result in fracture sliding, which can lead to local stress variations and slip induced fracture dilation, which may in turn change the overall conductivity of fracture networks. This shear-slip induced conductivity may enhance the pressure transmission in the natural fractures and may allow microseismic events to be triggered at a distance away from the actual hydraulic fractures for natural fractures that have relatively low original permeability.

[0091] Different regions or zones may coexist along a natural fracture invaded by an induced hydraulic fracture. For example, the regions along a natural fracture may include a hydraulically opened region filled with fracturing fluid, a region of the natural fracture which is still closed but invaded by fracturing fluid and/or pressure due to natural fracture permeability, and a region of the natural fracture filled with original reservoir fluid. FIG. **7** illustrates more information about the different regions or zones.

[0092] FIG. **6** depicts a complex hydraulic fracture network **600** with microseismic events **630** due to fracturing fluid leak-off **640** into natural fractures **650**. Similar to FIGS. **5.1**-**5.4**, fracturing fluid may leak into natural fractures at intersections **605** with hydraulic fractures **620**, for both the case of a hydraulic fracture crossing the natural fracture and the case of a hydraulic fracture propagating along the natural fracture. The fracturing fluid leak-off **640** may cause the fluid pressure in the natural fractures **650** to elevate above the original pore pressures. The elevated pore pressure may reduce the confining stress on natural fractures **650** and cause shear slippage along a respective natural fracture. This shear slippage may be a primary mechanism for triggering the microseismic events **630**.

[0093] By incorporating fluid loss into natural fracture simulations, a more accurate and reliable prediction of complex fracture geometry may be obtained. By modeling the fluid loss into the natural fractures, for instance, fracturing fluid invasion into the natural fractures and the rock matrix surrounding the fractures may be calculated. This fluid invasion may be used in the flow back and clean-up of the fracturing fluid when the well is produced, and may be performed for an ultra-low permeability reservoir where fluid injected may form a block to the gas during production. By accounting for the initial saturation of the fracturing fluid in a reservoir simulation model, a production estimation may be obtained. By modeling the fluid pressure inside the natural fractures, the potential shear slip condition may be evaluated along the natural fractures, and the likelihood of microseismic events may be assessed and predicted, which may provide a direct connection between the predicted fracture geometry and microseismic trigger mechanisms.

[0094] FIG. **7** illustrates an intersection **700** between an induced hydraulic fracture **720** and an intersected natural fracture **705**, and regions/zones along the intersected natural fracture **705**. Four intersection zones in particular are presented as follows:

[0095] (1) An opened zone **715** (also called "opened part") of the intersected natural fracture **705** is filled with invaded fracturing fluid. In the opened zone **715**, fluid pressure may exceed the normal stress on the intersected natural fracture **705**. The initial length **760** (also called L_{opened}) of the opened zone **715** may be evaluated from volume balance accounting for the intersected natural fracture **705** and fluid properties, which may include corresponding tip asymptotes. The width, pressure, height, leak-off volume, volume of slurry and other parameters of individual regions in the opened zone **715** may be calculated from a combination of a flow equation (e.g., laminar, turbulent, Darcy, etc.), a mass continuity equation and an elasticity equation. These calculations may also account for height growth, proppant transport and leak-off.

[0096] (2) An invaded closed zone **725** (also called "invaded closed part of NF" or "filtration zone") of the intersected natural fracture **705** is filled with fracturing fluid. In the invaded closed zone **725**, the fluid pressure may be above pore pressure but below the closure stress of the intersected natural fracture **705**. The initial length **770** of invaded closed zone **725** may be estimated based on Equation (5) below, which may account for fracturing fluid leak-off into the reservoir. The filtration front velocity of the invaded closed zone **725** may be estimated to track the interface between filtration zones (e.g., invaded closed zone **725**) and pressurized zones (e.g., noninvaded closed zone **735**). The pressure dependent permeability, mass continuity, Darcy flow, leak-off into the rock matrix, and compressibility considerations may be accounted for to estimate length, pressure, width, height, and volume within the invaded closed zone **725**.

[0097] (3) A noninvaded closed zone **735** (also called "closed pressurized part" or "pressurized zone") of the intersected natural fracture **705** is filled with pressurized original reservoir fluid and no invading fracturing fluid. In the noninvaded closed zone **735**, the fluid pressure may be above the pore pressure. The initial length **780** (also called $L_{pressurized}$) of noninvaded closed zone **735** may be evaluated based on pressure and flow rate at the interface between the invaded closed zone **725** and the noninvaded closed zone **735**. The leak-off into the rock matrix from the noninvaded closed zone **735** may be controlled by compressibility. Governing equations for the noninvaded closed zone **735** may include equations for continuity, compressibility, Darcy flow, pressure dependent permeability and conductivity.

[0098] (4) A closed undisturbed zone **745** (also called "the reservoir zone") of intersected natural fracture **705** is filled with reservoir fluid under original pore pressure conditions.

[0099] In modeling the zones of a natural fracture, various interface fronts and interfacial properties corresponding to different intersection zones may be updated throughout a simulation. For instance, the front of the invaded closed zone **725** and the front of the noninvaded closed zone **735** may be moved to different points in a respective natural fracture at different time steps. Interface fronts may be updated based on continuity (mass balance), compressibility considerations and other intersection parameters. If leak-off for the invaded closed zone **725** in the rock matrix is negligible, for instance, then there may be no pressurized region corresponding to the noninvaded closed zone **735**.

[0100] In formations with a complex discrete fracture network, special evaluation of intersections may be conducted between invaded closed zone **725**/noninvaded closed zone **735**, opened zone **715**/invaded closed zone **725** and opened closed zone **715**/hydraulic fracture **720** interceptions. Mass balance and fluid continuity conditions may be satisfied, and appropriate rules for zone interface propagation through the intersection **700** may be prescribed.

[0101] Explicit modeling of hydraulic fractures interacting with permeable natural fractures may become complicated, where the modeling may include determining intersection properties, such as the continuity of fluid mass in a natural fracture, pressure drops along natural fractures, leak-off into the formation from natural fracture walls, pressure sensitive natural fracture permeability, properties and content of natural fractures, and the fluid rheology of a natural fracture. This modeling may be performed by tracking zone interfaces along an invaded natural fracture.

[0102] Depending on rock and reservoir properties, modeling of zones (1), (2), and (3) may be performed using various equations.

[0103] The continuity of fluid mass in a natural fracture may be determined using the following equation:

$$\frac{\partial q_m}{\partial s} + \dot{m} + \rho_f q_L = 0,\ q_L = \frac{2hC_{tot}^{rock}}{\sqrt{t - \tau(s)}} \quad \text{Eq. (1)}$$

where $q_m(t)$ is mass flux (rate of change of fluid mass) in a natural fracture; s represents a length increment along the natural fracture; q_L represents a volume rate of leak-off per unit length; m represents a fluid mass in the natural fracture; h represents the height of the natural fracture; C_{tot}^{rock} represents a total leak-off coefficient from the closed invaded zone and the reservoir zone; and ρ_f represents the filtrate fluid density of the natural fracture.

[0104] Pressure drop along a closed natural fracture may be determined using the following equation:

$$\frac{\partial p}{\partial s} = \frac{\mu_f}{\rho_f k_{NF} A} q = \frac{\mu_f}{\rho_f k_{NF} wh} q, \text{ at the inlet: } p = p_{in}(t) \quad \text{Eq. (2)}$$

where k_{NF} represents the permeability of the closed natural fracture; μ_f represents the filtrate fluid viscosity of the closed natural fracture; ρ_f represents the filtrate fluid density of the closed natural fracture; A represents a cross-sectional area of the closed natural fracture, where A=wh and where w is the effective (or average) width of the natural fracture, and h is the effective height of the natural fracture; p_{in} represents the pressure at the inlet; and q represents the mass flux of the natural fracture.

[0105] Natural fracture permeability due to stress and pressure changes may be determined using the following equation:

$$k_{NF}^{n} = k_o\left\{C\ln\left[\frac{\sigma^*}{\sigma_n - p}\right]\right\}^3 \quad \text{Eq. (3)}$$

where constants C and σ* (reference stress state) are determined from field data; k_o is the natural fracture permeability (reservoir permeability under in-situ conditions); σ_n is the normal stress on the natural fracture (i.e., where n indicates normal stress); and p is the pressure in the natural fracture.

[0106] The width of closed invaded natural fracture, w(s), as a function of the distance along the natural fracture, s, may be determined using the following equation:

$$w(s) = \frac{w_o}{1 + 9\frac{\sigma_{eff}}{\sigma_n^{ref}}},\ \sigma_{eff} = \sigma_n - p_f(s) \quad \text{Eq. (4)}$$

where σ_{eff} is the effective normal stress on the natural fracture; σ_n^{ref} is the effective reference stress on the natural fracture; w_0 is the initial fracture aperture; and $p_f(s)$ is the fluid pressure as a function of the distance along the natural fracture.

[0107] Frictional sliding may occur when the shear stress reaches the frictional shear strength of the natural fractures. The slip may cause a fracture to grow in a shearing mode and may give rise to the opening of other fractures that the fracture intersects. For a closed fluid-filled fracture, the effective stress may be reduced as the pressure increases, which may result in reduced shear strength and fracture sliding. Coulomb's frictional law may be used to calculate the frictional stress and conditions for shear slippage. Shear slippage may be determined to enhance leak-off and may result in offsets in fracture growth, as well as indicate a justification for the presence of a microseismic event. Shear slippage may also cause dilation of a natural fracture and an increase in the effective width w(s), which may lead to enhanced permeability and conductivity of the natural fracture and contribute to enhancing hydrocarbon production.

[0108] When accounting for fracturing fluid leak-off into a reservoir from the walls of the natural fracture, the length **770** of the invaded closed zone **725** may be estimated using the following equation:

$$L_{filtr}^{ini}(t) = \frac{tq_{in}}{h\left(3\overline{w}_{filtr} + 4C_L\sqrt{2t}\right)},\ C_L = C_{tot}^{rock} \quad \text{Eq. (5)}$$

where q_{in} represents the initial fracturing fluid flow rate into the invaded closed zone **725** from the opened zone **715**; $\overline{w}_{filtr}$ represents an average width of invaded closed zone **725**; h represents the height of the natural fracture; t represents a time of invasion; and $C_L = C_{tot}^{rock}$ represents the total leak-off coefficient for the invaded closed zone **725** and the reservoir zone **745**.

[0109] The change in fluid density as a function of pressure and temperature may be determined from the following equation:

$$\rho_1 = \frac{\rho_0}{1 - \beta(T_1 - T_0)} \times \frac{1}{1 - \frac{p_1 - p_0}{B}} \quad \text{Eq. (6)}$$

where B is bulk modulus fluid elasticity in Pa, β is volumetric expansion coefficient, T_0 is a temperature and ρ_0 is the fluid density at pressure p_0, T_1 is a temperature and ρ_1 is the fluid density at pressure p_1.

[0110] The above equations may be solved analytically at a given time step (i.e., a reference point in time at which a hydraulic fracturing network is being modeled) for the lengths and pressure drops in specific intersection zones. The above equations may also be solved using averaged properties for a given zone. A natural fracture's permeability may also be updated based on pressure changes and shear slip for a given time increment (i.e., with the next time step). Solutions may also be obtained by solving these equations numerically by discretizing the natural fracture into smaller elements. For instance, mass balance, fluid loss into the matrix, pressure drop in the natural fracture, natural fracture permeability enhancement due to dilation and shear slip may be solved and tracked locally at a specific element to obtain pressure distributions and fluid fronts in a natural fracture.

Fracturing Operations Based on Intersection Properties Between Hydraulic Fractures and Natural Fractures

[0111] FIG. **8** illustrates a flow diagram of a method **800** for simulating and performing hydraulic fracturing in accordance with various embodiments described herein. It should be understood that while the operational flow diagram indicates a particular order of execution of the operations, in other embodiments, the operations might be executed in a different order. Further, in some embodiments, additional operations or blocks may be added to the method. Likewise, some operations or blocks may be omitted.

[0112] At block **810**, integrated wellsite data is acquired for a subterranean formation. Integrated wellsite data may include geomechanical, geological, and/or geophysical properties of the subterranean formation. Integrated wellsite data may also include mechanical, geomechanical and/or geometrical properties of natural fractures in the subterranean formation.

[0113] At block **820**, a mechanical earth model is generated using integrated wellsite data. The mechanical earth model may include a model such as the MEM **462** described in FIG. **4**A.

[0114] At block **830**, an intersection of one or more induced hydraulic fractures with one or more natural fractures is simulated. For instance, the simulation may include modeling the leak-off of fracturing fluid from the one or more induced hydraulic fractures into the one or more natural fractures. Shear failure or the shear slip of a natural fracture may also be modeled in the simulated intersection.

[0115] In one embodiment, the simulated intersection may include modeling one or more intersection zones such as those described in regard to FIG. **7**. The intersection zones may include the opened zone **715**, the invaded closed zone **725**, the noninvaded closed zone **735**, or the closed undisturbed zone **745**.

[0116] In another embodiment, a hydraulic fractured growth pattern may be simulated at block **830**. The hydraulic fractured growth pattern may include modeling new intersections between natural fractures and induced hydraulic fractures, as well as existing or previously created intersections. The simulated intersection may include updating various elements (i.e., intersection properties or altered interfacial properties of an intersected natural fracture) in one or more intersection zones at respective time steps. For instance, the gradual dilation of a respective intersection zone in a natural fracture may be modeled to show the transition from a closed undisturbed zone into an opened zone in a natural fracture. This process may include modeling the fracture growth pattern as described in FIGS. **5** and **6**.

[0117] At block **840**, one or more intersection properties of the simulated intersection and/or intersected natural fracture in block **830** are determined. Intersection properties may refer to the altered interfacial properties of an intersected natural fracture and may include specific properties relating to the modeling of intersection zones or the interfaces between intersection zones. For instance, one intersection property may include the amount of fracturing fluid leak-off from an induced hydraulic fracture into the one or more natural fractures. Other intersection properties may be the lengths of various intersection zones, the continuity of fluid mass in a natural fracture, fracturing fluid leak-off into the subterranean formation from a natural fracture's walls, pressure sensitive natural fracture permeability, fluid rheology in a natural fracture, a change in natural fracture permeability, a change in stress within a region of a natural fracture, a change in pressure within a region of a natural fracture, or any other related properties.

[0118] At block **850**, a stimulation plan is generated using the mechanical earth model and the one or more intersection properties. In generating the stimulation plan, intersection properties may be used as an input in a similar fashion to how the mechanical earth model may be used an input for stimulation planning, as described in FIGS. **4**A-**4**B. For instance, the amount of leak-off from a hydraulic fracture into the one or more natural fractures may be used determine a stimulation plan with a rate of injection for a fracturing fluid that accounts for the amount of leak-off. FIGS. **4**A-**4**B illustrate more information on stimulation planning and design.

[0119] At block **855**, one or more operating parameters of the stimulation plan are adjusted to achieve one or more optimized intersection properties. Operating parameters may include the fluid viscosity of a fracturing fluid, the rate of injection of the fracturing fluid, one or more fluid ingredients in the fracturing fluid, one or more additives in the fracturing fluid that may affect a leak-off property, a proppant size in the fracturing fluid, a proppant concentration in the fracturing fluid, or any other operating parameters.

[0120] The optimized intersection properties may be the same or different intersection properties as those from block **840**. For instance, an intersection property may be optimized to achieve a predetermined value for the respective intersection property or another intersection property (e.g., adjusting an amount of leak-off into a natural fracture may be used to obtain an optimized natural fracture permeability). Optimized intersection properties may also be used to achieve specific results, such as increasing the permeability of a reservoir.

[0121] At block **860**, a stimulation operation is performed based on the stimulation plan from block **850** or an adjusted stimulation plan from block **855**. The stimulation operation may be performed using methods as described in regard to FIGS. **1**-**4**B. Using observed data acquired from the stimulation operation, the simulated intersection in block **830** may be validated for accuracy, confidence, or any other criteria.

[0122] At block **870**, the one or more intersection properties are compared with microseismic events in observed data from the stimulation operation from block **860**.

[0123] At block **880**, hydrocarbon production from the subterranean formation is predicted using the one or more intersection properties.

Computing System

[0124] Implementations of various technologies described herein may be operational with numerous general purpose or special purpose computing system environments or configurations. Examples of well known computing systems, environments, and/or configurations that may be suitable for use with the various technologies described herein include, but are not limited to, personal computers, server computers, hand-held or laptop devices, multiprocessor systems, microprocessor-based systems, set top boxes, programmable consumer electronics, network PCs, minicomputers, mainframe computers, smartphones, smartwatches, personal wearable computing systems networked with other computing systems, tablet computers, and distributed computing environments that include any of the above systems or devices, and the like.

[0125] The various technologies described herein may be implemented in the general context of computer-executable instructions, such as program modules, being executed by a computer. Generally, program modules include routines, programs, objects, components, data structures, etc. that performs particular tasks or implement particular abstract data types. While program modules may execute on a single computing system, it should be appreciated that, in some implementations, program modules may be implemented on separate computing systems or devices adapted to communicate with one another. A program module may also be some combination of hardware and software where particular tasks performed by the program module may be done either through hardware, software, or both.

[0126] The various technologies described herein may also be implemented in distributed computing environments where tasks are performed by remote processing devices that are linked through a communications network, e.g., by hardwired links, wireless links, or combinations thereof. The distributed computing environments may span multiple continents and multiple vessels, ships or boats. In a distributed computing environment, program modules may be located in both local and remote computer storage media including memory storage devices.

[0127] FIG. **9** illustrates a schematic diagram of a computing system **900** in which the various technologies described herein may be incorporated and practiced. Although the computing system **900** may be a conventional desktop or a server computer, as described above, other computer system configurations may be used.

[0128] The computing system **900** may include a central processing unit (CPU) **930**, a system memory **926**, a graphics processing unit (GPU) **931** and a system bus **928** that couples various system components including the system memory **926** to the CPU **930**. Although one CPU is illustrated in FIG. **9**, it should be understood that in some implementations the computing system **900** may include more than one CPU. The GPU **931** may be a microprocessor specifically designed to manipulate and implement computer graphics. The CPU **930** may offload work to the GPU **931**. The GPU **931** may have its own graphics memory, and/or may have access to a portion of the system memory **926**. As with the CPU **930**, the GPU **931** may include one or more processing units, and the processing units may include one or more cores. The system bus **928** may be any of several types of bus structures, including a memory bus or memory controller, a peripheral bus, and a local bus using any of a variety of bus architectures. By way of example, and not limitation, such architectures include Industry Standard Architecture (ISA) bus, Micro Channel Architecture (MCA) bus, Enhanced ISA (EISA) bus, Video Electronics Standards Association (VESA) local bus, and Peripheral Component Interconnect (PCI) bus also known as Mezzanine bus. The system memory **926** may include a read-only memory (ROM) **912** and a random access memory (RAM) **916**. A basic input/output system (BIOS) **914**, containing the basic routines that help transfer information between elements within the computing system **900**, such as during start-up, may be stored in the ROM **912**.

[0129] The computing system **900** may further include a hard disk drive **950** for reading from and writing to a hard disk, a magnetic disk drive **952** for reading from and writing to a removable magnetic disk **956**, and an optical disk drive **954** for reading from and writing to a removable optical disk **958**, such as a CD ROM or other optical media. The hard disk drive **950**, the magnetic disk drive **952**, and the optical disk drive **954** may be connected to the system bus **928** by a hard disk drive interface **936**, a magnetic disk drive interface **938**, and an optical drive interface **940**, respectively. The drives and their associated computer-readable media may provide nonvolatile storage of computer-readable instructions, data structures, program modules and other data for the computing system **900**.

[0130] Although the computing system **900** is described herein as having a hard disk, a removable magnetic disk **956** and a removable optical disk **958**, it should be appreciated by those skilled in the art that the computing system **900** may also include other types of computer-readable media that may be accessed by a computer. For example, such computer-readable media may include computer storage media and communication media. Computer storage media may include volatile and non-volatile, and removable and non-removable media implemented in any method or technology for storage of information, such as computer-readable instructions, data structures, program modules or other data. Computer storage media may further include RAM, ROM, erasable programmable read-only memory (EPROM), electrically erasable programmable read-only memory (EEPROM), flash memory or other solid state memory technology, CD-ROM, digital versatile disks (DVD), or other optical storage, magnetic cassettes, magnetic tape, magnetic disk storage or other magnetic storage devices, or any other medium which can be used to store the desired information and which can be accessed by the computing system **900**. Communication media may embody computer readable instructions, data structures, program modules or other data in a modulated data signal, such as a carrier wave or other transport mechanism and may include any information delivery media. The term "modulated data signal" may mean a signal that has one or more of its characteristics set or changed in such a manner as to encode information in the signal. By way of example, and not limitation, communication media may include wired media such as a wired network or direct-wired connection, and wireless media such as acoustic, RF, infrared and other wireless media. The computing system **900** may also include a host adapter **933** that connects to a storage device **935** via a small computer system interface (SCSI) bus, a Fiber Channel bus, an eSATA bus, or using any other applicable computer bus interface. Combinations of any of the above may also be included within the scope of computer readable media.

[0131] A number of program modules may be stored on the hard disk **950**, magnetic disk **956**, optical disk **958**, ROM **912** or RAM **916**, including an operating system **918**, one or more application programs **920**, program data **924**, and a database system **948**. The application programs **920** may include various mobile applications ("apps") and other applications configured to perform various methods and techniques described herein. The operating system **918** may be any suitable operating system that may control the operation of a networked personal or server computer, such as Windows® XP, Mac OS® X, Unix-variants (e.g., Linux® and BSD®), and the like.

[0132] A user may enter commands and information into the computing system **900** through input devices such as a keyboard **962** and pointing device **960**. Other input devices may include a microphone, joystick, game pad, satellite dish, scanner, or the like. These and other input devices may be connected to the CPU **930** through a serial port interface **942** coupled to system bus **928**, but may be connected by other interfaces, such as a parallel port, game port or a universal serial bus (USB). A monitor **934** or other type of display device may also be connected to system bus **928** via an interface, such as a video adapter **932**. In addition to the monitor **934**, the computing system **900** may further include other peripheral output devices such as speakers and printers.

[0133] Further, the computing system **900** may operate in a networked environment using logical connections to one or more remote computers **974**. The logical connections may be any connection that is commonplace in offices, enterprise-wide computer networks, intranets, and the Internet, such as local area network (LAN) **976** and a wide area network (WAN) **966**. The remote computers **974** may be another a computer, a server computer, a router, a network PC, a peer device or other common network node, and may include many of the elements describes above relative to the computing system **900**. The remote computers **974** may also each include application programs **970** similar to that of the computer action function.

[0134] When using a LAN networking environment, the computing system **900** may be connected to the local network **976** through a network interface or adapter **944**. When used in a WAN networking environment, the computing system **900** may include a router **964**, wireless router or other means for establishing communication over a wide area network **966**, such as the Internet. The router **964**, which may be internal or external, may be connected to the system bus **928** via the serial port interface **942**. In a networked environment, program modules depicted relative to the computing system **900**, or portions thereof, may be stored in a remote memory storage device **972**. It will be appreciated that the network connections shown are merely examples and other means of establishing a communications link between the computers may be used.

[0135] The network interface **944** may also utilize remote access technologies (e.g., Remote Access Service (RAS), Virtual Private Networking (VPN), Secure Socket Layer (SSL), Layer 2 Tunneling (L2T), or any other suitable protocol). These remote access technologies may be implemented in connection with the remote computers **974**.

[0136] It should be understood that the various technologies described herein may be implemented in connection with hardware, software or a combination of both. Thus, various technologies, or certain aspects or portions thereof, may take the form of program code (i.e., instructions) embodied in tangible media, such as floppy diskettes, CD-ROMs, hard drives, or any other machine-readable storage medium wherein, when the program code is loaded into and executed by a machine, such as a computer, the machine becomes an apparatus for practicing the various technologies. In the case of program code execution on programmable computers, the computing device may include a processor, a storage medium readable by the processor (including volatile and non-volatile memory and/or storage elements), at least one input device, and at least one output device. One or more programs that may implement or utilize the various technologies described herein may use an application programming interface (API), reusable controls, and the like. Such programs may be implemented in a high level procedural or object oriented programming language to communicate with a computer system. However, the program(s) may be implemented in assembly or machine language, if desired. In any case, the language may be a compiled or interpreted language, and combined with hardware implementations. Also, the program code may execute entirely on a user's computing device, partly on the user's computing device, as a stand-alone software package, partly on the user's computer and partly on a remote computer or entirely on the remote computer or a server computer.

[0137] Those with skill in the art will appreciate that any of the listed architectures, features or standards discussed above with respect to the example computing system **900** may be omitted for use with a computing system used in accordance with the various embodiments disclosed herein because technology and standards continue to evolve over time.

[0138] Of course, many processing techniques for collected data, including one or more of the techniques and methods disclosed herein, may also be used successfully with collected data types other than wellsite data. While certain implementations have been disclosed in the context of wellsite data collection and processing, those with skill in the art will recognize that one or more of the methods, techniques, and computing systems disclosed herein can be applied in many fields and contexts where data involving structures arrayed in a three-dimensional space and/or subsurface region of interest may be collected and processed, e.g., medical imaging techniques such as tomography, ultrasound, MRI and the like for human tissue; radar, sonar, and LIDAR imaging techniques; and other appropriate three-dimensional imaging problems.

[0139] Although the subject matter has been described in language specific to structural features and/or methodological acts, it is to be understood that the subject matter defined in the appended claims is not limited to the specific features or acts described above. Rather, the specific features and acts described above are disclosed as example forms of implementing the claims.

[0140] While the foregoing is directed to implementations of various technologies described herein, other and further implementations may be devised without departing from the basic scope thereof. Although the subject matter has been described in language specific to structural features and/or methodological acts, it is to be understood that the subject matter defined in the appended claims is limited to the specific features or acts described above. Rather, the specific features and acts described above are disclosed as example forms of implementing the claims.

What is claimed is:

1. A method of performing a fracturing operation about a wellbore penetrating a subterranean formation, the method comprising:

acquiring integrated wellsite data, wherein the integrated wellsite data comprise geomechanical properties of the subterranean formation and geometrical properties of one or more natural fractures in the subterranean formation;

generating a mechanical earth model using the integrated wellsite data;

simulating an intersection of one or more induced hydraulic fractures with the one or more natural fractures using the mechanical earth model;

determining one or more intersection properties of an intersected natural fracture; and

generating a stimulation plan using the mechanical earth model and the one or more intersection properties.

2. The method of claim **1**, wherein the one or more intersection properties comprise an amount of fracturing fluid leak-off from an induced hydraulic fracture into the one or more natural fractures.

3. The method of claim **1**, wherein the one or more intersection properties comprise continuity of fluid mass in a natural fracture, fracturing fluid leak-off into the subterranean formation from natural fracture walls, pressure sensitive natural fracture permeability, fluid rheology in a natural fracture, a change in natural fracture permeability, a change in stress within a region of a natural fracture, a change in pressure within a region of a natural fracture, or combinations thereof.

4. The method of claim **1**, wherein simulating the intersection comprises modeling an opened zone of a natural fracture that is filled with fracturing fluid from an induced hydraulic fracture, wherein fluid pressure in the opened zone exceeds the normal stress of the natural fracture.

5. The method of claim **1**, wherein simulating the intersection comprises modeling a closed zone of a natural fracture that is invaded with fracturing fluid from an induced hydraulic fracture, wherein fluid pressure in the closed zone is above the pore pressure of the natural fracture and below the closure stress of the natural fracture.

6. The method of claim **1**, wherein simulating the intersection comprises modeling a closed zone of a natural fracture that is filled with original reservoir fluid and no invading fracturing fluid, wherein fluid pressure in the closed zone is above the pore pressure of the natural fracture.

7. The method of claim **1**, further comprising simulating a propagation of a network of induced hydraulic fractures.

8. The method of claim **1**, wherein simulating the intersection comprises modeling shear failure or shear slip in a natural fracture.

9. The method of claim **1**, wherein the one or more intersection properties comprise an increase in permeability in the one or more natural fractures intersected by the one or more induced hydraulic fractures.

10. The method of claim **1**, further comprising performing a stimulation operation based on the stimulation plan.

11. The method of claim **10**, further comprising validating the simulated intersection based on observed data acquired from the stimulation operation.

12. The method of claim **1**, wherein the stimulation plan comprises a fluid viscosity of a fracturing fluid or a rate of injection of a fracturing fluid.

13. The method of claim **10**, further comprising adjusting at least one of the fluid viscosity and the rate of injection of the fracturing fluid to optimize the one or more intersection properties.

14. A method of performing a fracturing operation about a wellbore penetrating a subterranean formation, the method comprising:

acquiring integrated wellsite data, wherein the integrated wellsite data comprise geomechanical properties of the subterranean formation and geometrical properties of one or more natural fractures in the subterranean formation;

generating a mechanical earth model using the integrated wellsite data;

simulating an intersection of one or more induced hydraulic fractures with the one or more natural fractures using the mechanical earth model;

determining one or more intersection properties of an intersected natural fracture; and

predicting hydrocarbon production from the subterranean formation using the one or more intersection properties.

15. The method of claim **14**, wherein the hydrocarbon production prediction uses observed data acquired from a stimulation operation that had been performed based on the mechanical earth model.

16. The method of claim **14**, wherein predicting the hydrocarbon production comprises predicting permeability of a reservoir in the subterranean formation using the one or more intersection properties.

17. The method of claim **14**, wherein simulating the intersection comprises at least one of:

modeling an opened zone of a natural fracture that is filled with fracturing fluid from an induced hydraulic fracture, wherein fluid pressure in the opened zone exceeds the normal stress of the natural fracture;

modeling an invaded closed zone of the natural fracture that is invaded with fracturing fluid from the induced hydraulic fracture, wherein fluid pressure in the invaded closed zone is above pore pressure in the natural fracture and below the closure stress of the natural fracture; and

modeling a non-invaded closed zone of the natural fracture that is filled with original reservoir fluid and no invading fracturing fluid, wherein fluid pressure in the non-invaded closed zone is above the pore pressure of the natural fracture.

18. The method of claim **17**, wherein modeling the opened zone or one of the closed zones of the natural fracture comprises using one or more of the following parameters:

flowrate of invading fracturing fluid;

length of a zone in the natural fracture;

width of a zone in the natural fracture;

shear displacement;

hydraulic fracture aperture;

reservoir permeability;

natural fracture permeability; and

pressure field.

19. A method of performing a fracturing operation about a wellbore penetrating a subterranean formation, the method comprising:

acquiring integrated wellsite data, wherein the integrated wellsite data comprise geomechanical properties of the subterranean formation and geometrical properties of one or more natural fractures in the subterranean formation;

generating a mechanical earth model using the integrated wellsite data;

simulating an intersection of one or more induced hydraulic fractures with the one or more natural fractures using the mechanical earth model;

determining one or more intersection properties of one or more intersected natural fracture; and comparing the one or more intersection properties with microseismic events in observed data acquired from a stimulation operation based on the mechanical earth model.

20. The method of claim **19**, wherein simulating the intersection comprises at least one of:

modeling an opened zone of a natural fracture that is filled with fracturing fluid from an induced hydraulic fracture, wherein fluid pressure in the opened zone exceeds the normal stress of the natural fracture;

modeling an invaded closed zone of the natural fracture that is invaded with fracturing fluid from the induced hydraulic fracture, wherein fluid pressure in the invaded closed zone is above pore pressure in the natural fracture and below the closure stress of the natural fracture; and

modeling a non-invaded closed zone of the natural fracture that is filled with original reservoir fluid and no invading fracturing fluid, wherein fluid pressure in the non-invaded closed zone is above the pore pressure of the natural fracture.

21. A method of performing a fracturing operation about a wellbore penetrating a subterranean formation, the method comprising:

acquiring integrated wellsite data, wherein the integrated wellsite data comprise geomechanical properties of the subterranean formation and geometrical properties of one or more natural fractures in the subterranean formation;

generating a mechanical earth model using the integrated wellsite data;

simulating leak-off of fracturing fluid from one or more induced hydraulic fractures into the one or more natural fractures using the mechanical earth model;

generating a stimulation plan using the mechanical earth model; and

adjusting one or more operating parameters of the stimulation plan based on the simulated leak-off to achieve an optimized leak-off from the one or more induced hydraulic fractures into the one or more natural fractures.

22. The method of claim **21**, wherein the one or more operating parameters of the stimulation plan comprise at least one of the following:

fluid viscosity of the fracturing fluid;

rate of injection of the fracturing fluid;

fluid ingredient in the fracturing fluid;

additives in the fracturing fluid that affect a leak-off property;

proppant size in the fracturing fluid; and

proppant concentration in the fracturing fluid.

23. The method of claim **21**, wherein simulating the leak-off of fracturing fluid comprises at least one of:

modeling an opened zone of a natural fracture that is filled with fracturing fluid from an induced hydraulic fracture, wherein fluid pressure in the opened zone exceeds the normal stress of the natural fracture;

modeling an invaded closed zone of the natural fracture that is invaded with fracturing fluid from the induced hydraulic fracture, wherein fluid pressure in the invaded closed zone is above pore pressure in the natural fracture and below the closure stress of the natural fracture; and

modeling a non-invaded closed zone of the natural fracture that is filled with original reservoir fluid and no invading fracturing fluid, wherein fluid pressure in the non-invaded closed zone is above the pore pressure of the natural fracture.

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