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(54) **CONTROL SYSTEM AND METHOD OF FLOWBACK OPERATIONS FOR SHALE RESERVOIRS**

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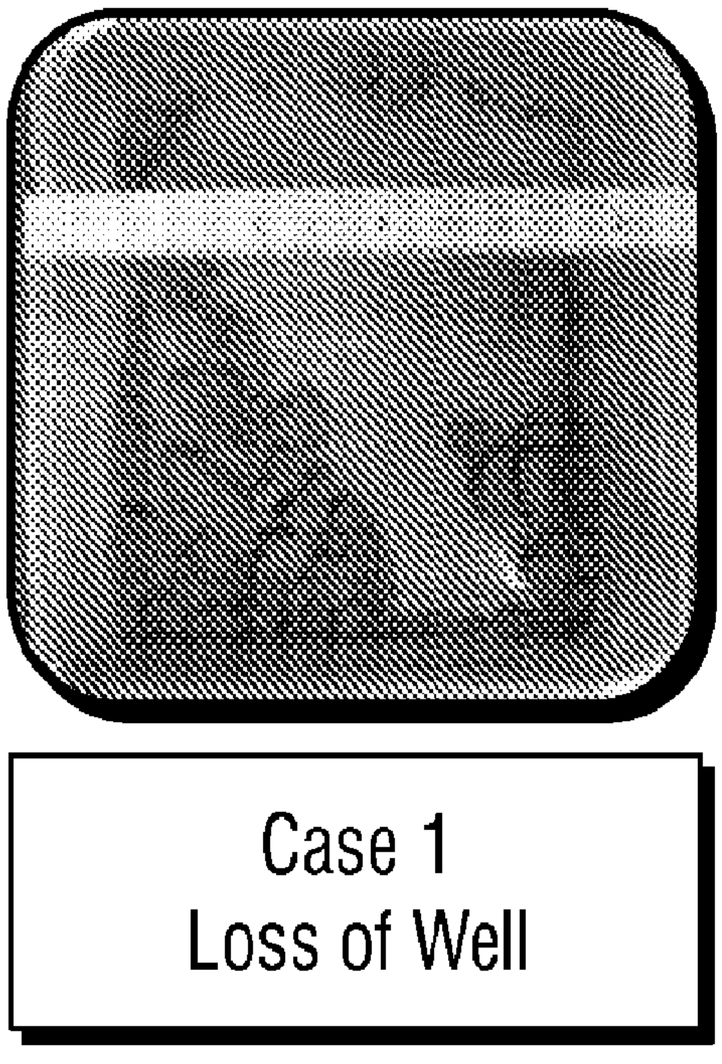
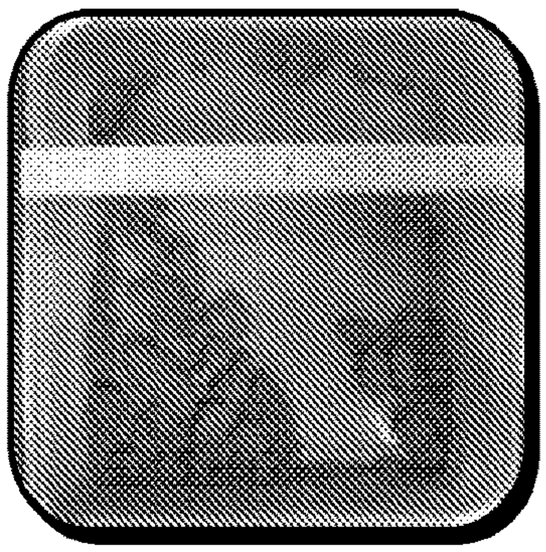
(52) **U.S. Cl.**

CPC ***E21B 43/12*** (2013.01); ***E21B 49/087*** (2013.01); ***E21B 41/0092*** (2013.01); ***E21B 43/267*** (2013.01); ***E21B 47/06*** (2013.01)

(57) **ABSTRACT**

A flowback system and method employ a flowback model that characterizes fluid properties and rock mechanical properties of the reservoir during flowback in conjunction with measurement and analysis of chemistry and solids production with respect to the flowback fluid in order to maximize efficiency during the flowback operations, while mitigating formation damage and hydraulic fracture conductivity degradation. The methodology can define a safe drawdown operating zone for conducting flowback operations.

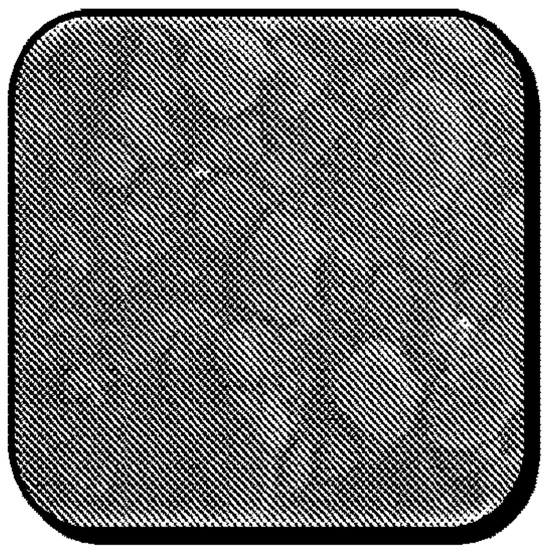




Case 1
Loss of Well

- Extensive tensile rock failure

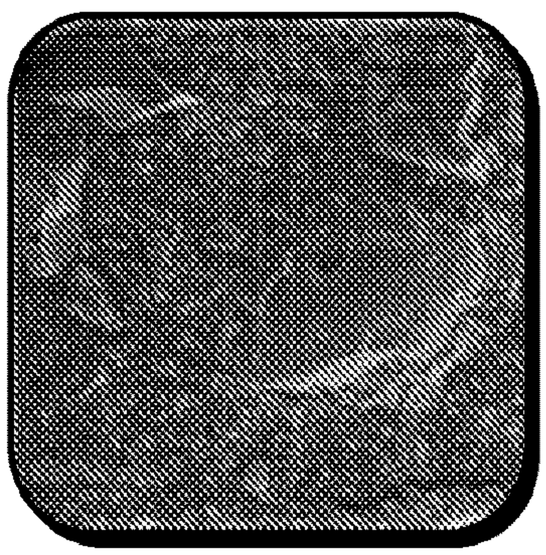
FIG. 1A



Case 2
Proppant Crushed

- 25,000 lbs of crushed proppant produced

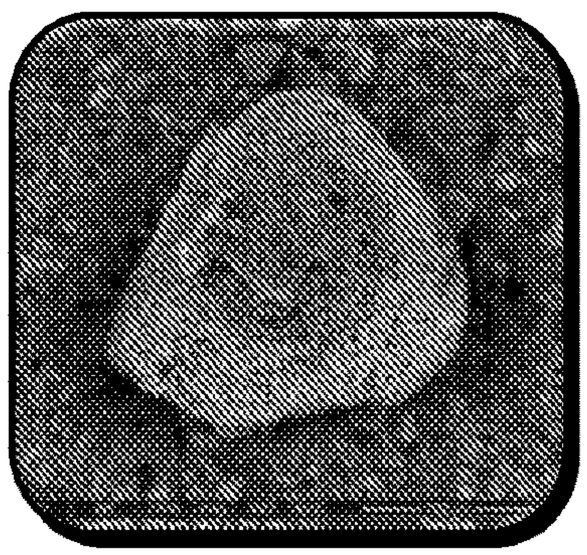
FIG. 1B



Case 3
Formation Failure and Fines Migration

- Over 3,000 lbs of fines produced

FIG. 1C



Case 4
Barite Scale Formation

- >8,000 lbs scale produced back to surface

FIG. 1D

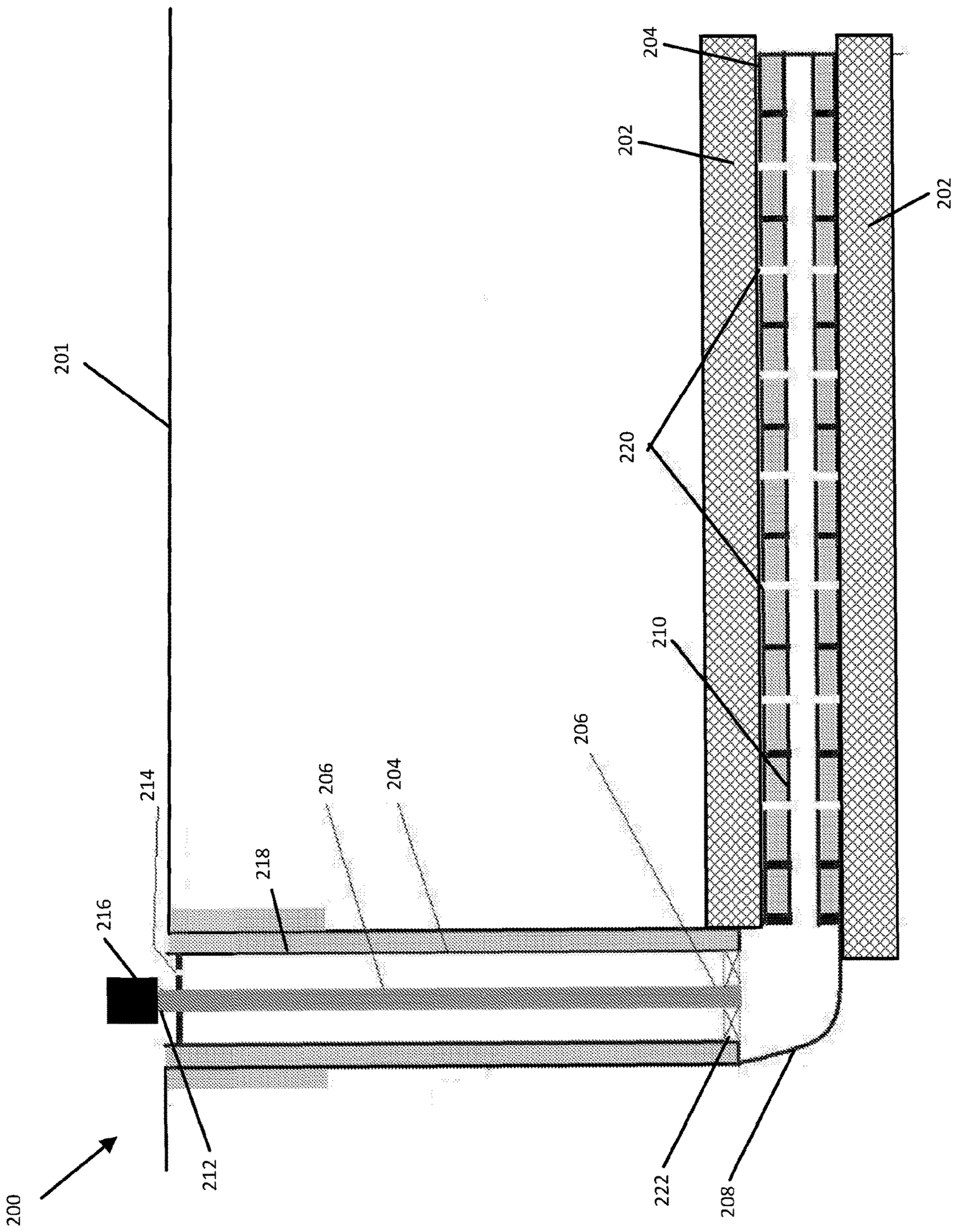


FIG. 2

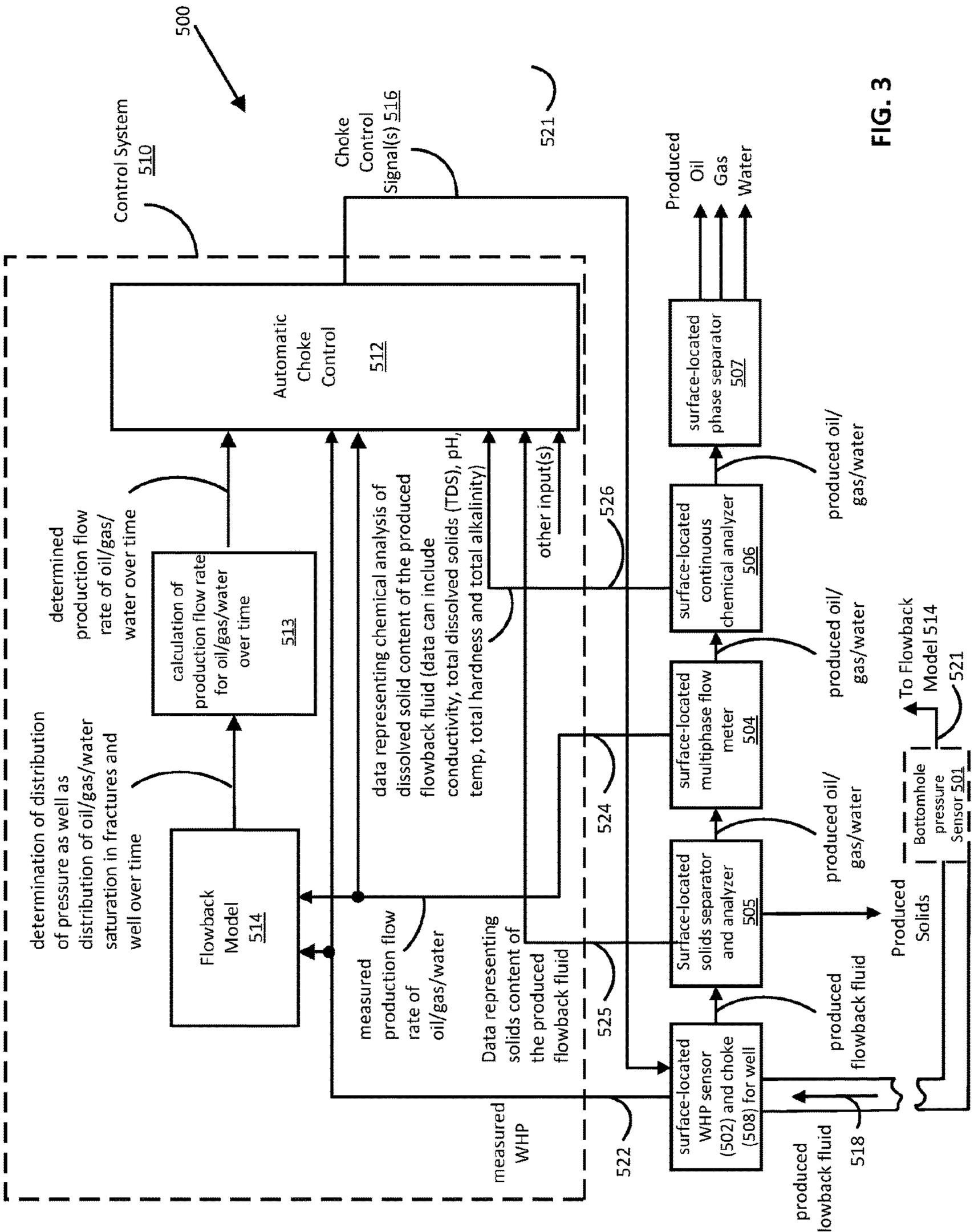

500
Control System 510
Choke Control Signal(s) 516
521
Produced Oil Gas Water
Automatic Choke Control 512
determined production flow rate of oil/gas/water over time
calculation of production flow rate for oil/gas/water over time 513
data representing chemical analysis of dissolved solid content of the produced flowback fluid (data can include conductivity, total dissolved solids (TDS), pH, temp, total hardness and total alkalinity)
other input(s)
526
524
surface-located phase separator 507
surface-located continuous chemical analyzer 506
surface-located multiphase flow meter 504
Surface-located solids separator and analyzer 505
surface-located WHP sensor (502) and choke (508) for well
Flowback Model 514
determination of distribution of pressure as well as distribution of oil/gas/water saturation in fractures and well over time
measured production flow rate of oil/gas/water
Data representing solids content of the produced flowback fluid
525
measured WHP
522
produced oil/ gas/water
produced flowback fluid
518
Produced Solids
Bottomhole pressure Sensor 501
To Flowback Model 514
521

FIG. 3

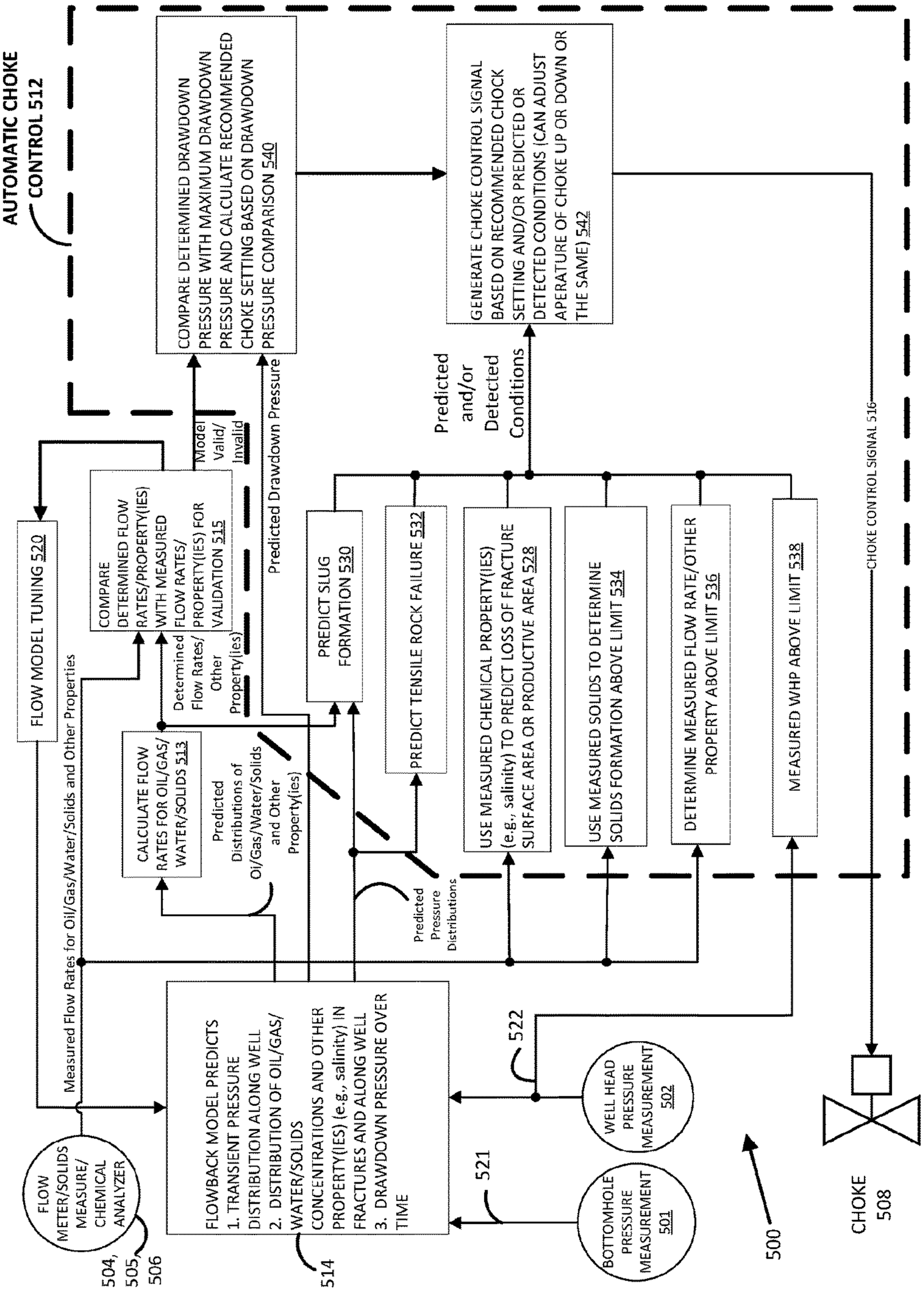

AUTOMATIC CHOKE CONTROL 512
COMPARE DETERMINED DRAWDOWN PRESSURE WITH MAXIMUM DRAWDOWN PRESSURE AND CALCULATE RECOMMENDED CHOKE SETTING BASED ON DRAWDOWN PRESSURE COMPARISON 540
GENERATE CHOKE CONTROL SIGNAL BASED ON RECOMMENDED CHOCK SETTING AND/OR PREDICTED OR DETECTED CONDITIONS (CAN ADJUST APERATURE OF CHOKE UP OR DOWN OR THE SAME) 542
Predicted and/or Detected Conditions
Model Valid/ Invalid
Predicted Drawdown Pressure
FLOW MODEL TUNING 520
COMPARE DETERMINED FLOW RATES/PROPERTY(IES) WITH MEASURED FLOW RATES/ PROPERTY(IES) FOR VALIDATION 515
Determined Flow Rates/ Other Property(ies)
CALCULATE FLOW RATES FOR OIL/GAS/ WATER/SOLIDS 513
Predicted Distributions of Oil/Gas/Water/Solids and Other Property(ies)
PREDICT SLUG FORMATION 530
PREDICT TENSILE ROCK FAILURE 532
USE MEASURED CHEMICAL PROPERTY(IES) (e.g., salinity) TO PREDICT LOSS OF FRACTURE SURFACE AREA OR PRODUCTIVE AREA 528
USE MEASURED SOLIDS TO DETERMINE SOLIDS FORMATION ABOVE LIMIT 534
DETERMINE MEASURED FLOW RATE/OTHER PROPERTY ABOVE LIMIT 536
MEASURED WHP ABOVE LIMIT 538
Predicted Pressure Distributions
CHOKE CONTROL SIGNAL 516
Measured Flow Rates for Oil/Gas/Water/Solids and Other Properties
FLOWBACK MODEL PREDICTS
1. TRANSIENT PRESSURE DISTRIBUTION ALONG WELL
2. DISTRIBUTION OF OIL/GAS/ WATER/SOLIDS CONCENTRATIONS AND OTHER PROPERTY(IES) (e.g., salinity) IN FRACTURES AND ALONG WELL
3. DRAWDOWN PRESSURE OVER TIME
FLOW METER/SOLIDS MEASURE/ CHEMICAL ANALYZER
504, 505, 506
514
521
522
BOTTOMHOLE PRESSURE MEASUREMENT 501
WELL HEAD PRESSURE MEASUREMENT 502
500
CHOKE 508

FIG. 4

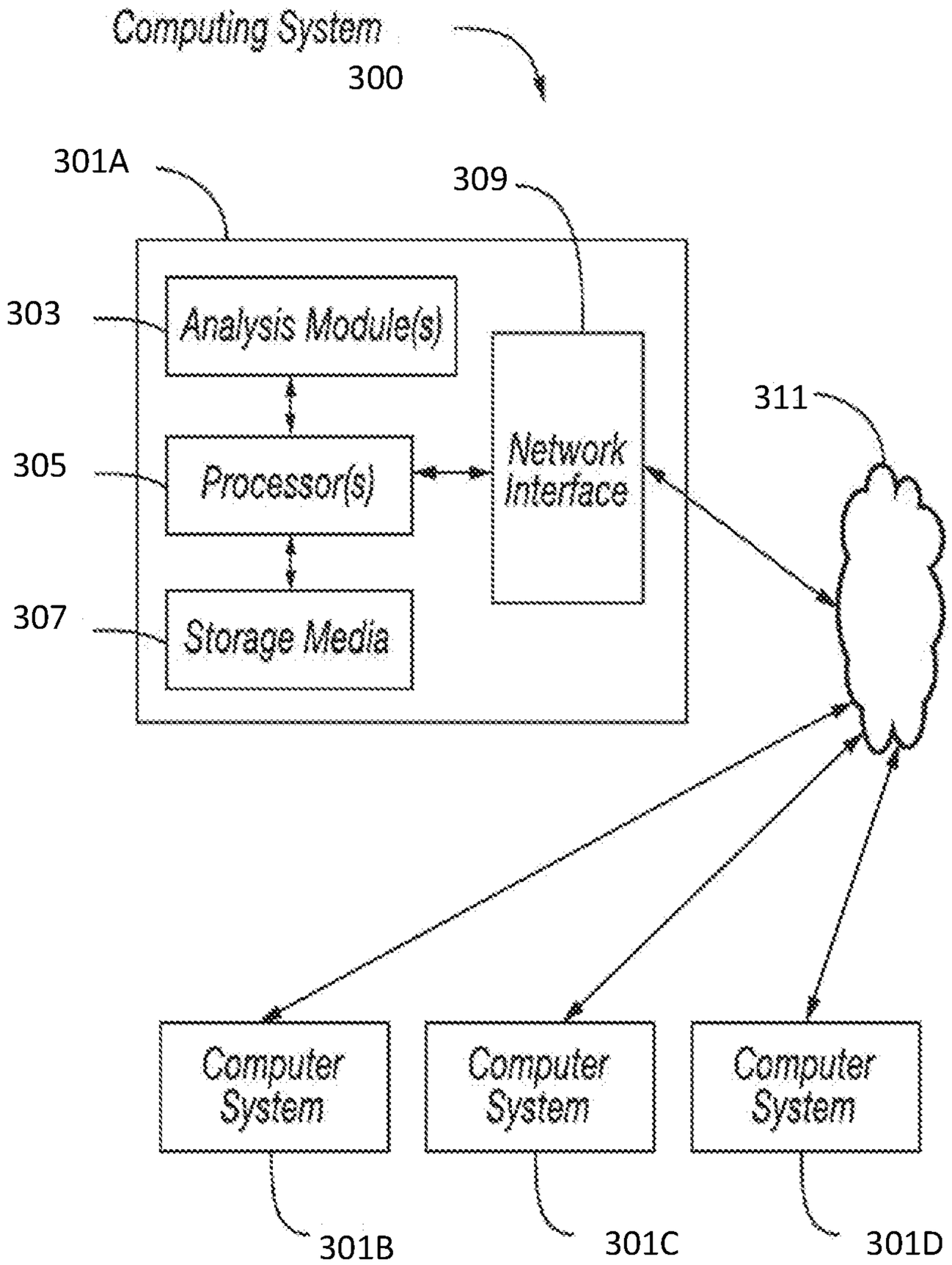

Computing System
300
301A
309
303
Analysis Module(s)
305
Processor(s)
Network Interface
311
307
Storage Media
Computer System
Computer System
Computer System
301B
301C
301D

FIG. 5

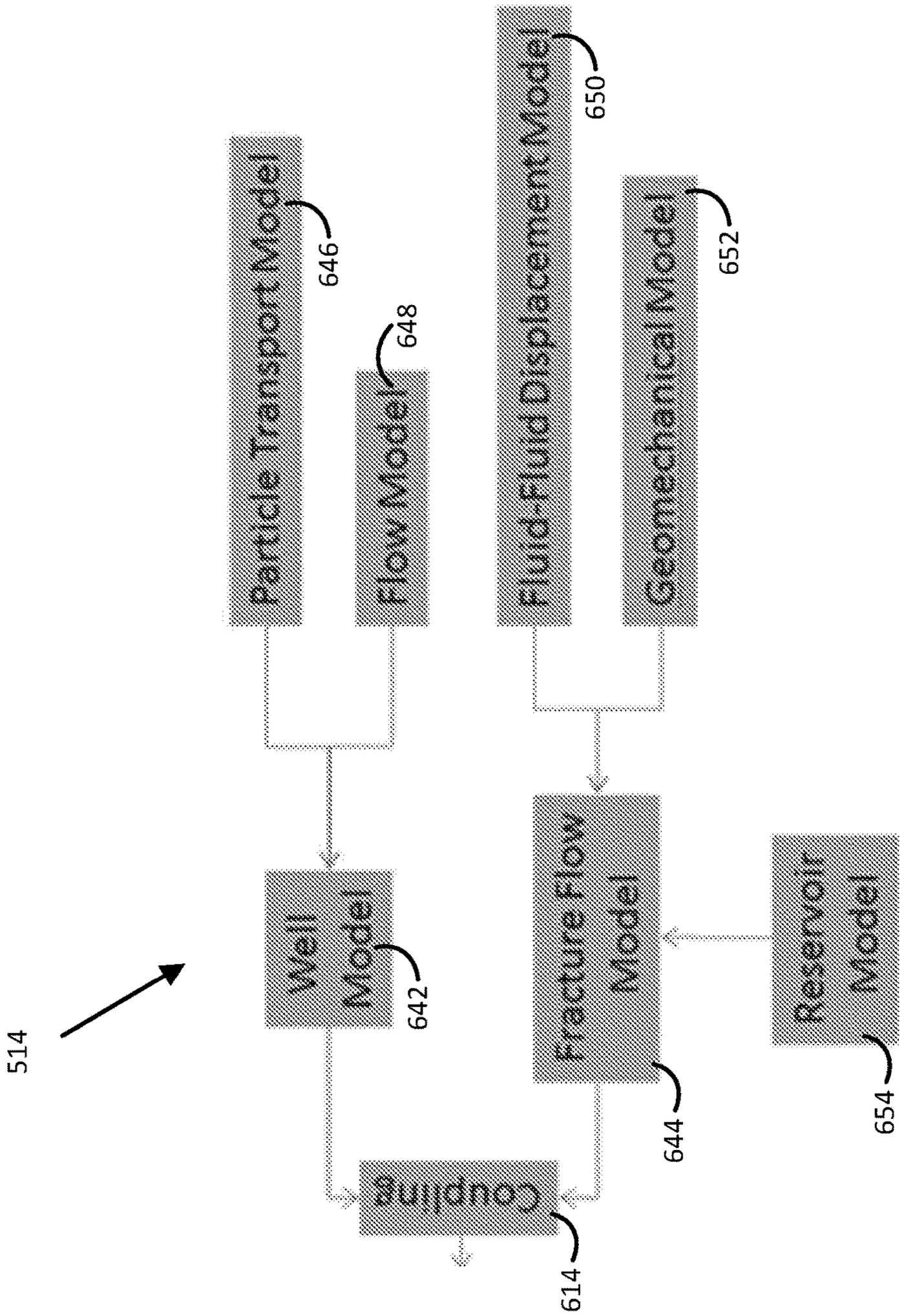

514
Particle Transport Model
646
Flow Model
648
Well Model
642
Coupling
614
Fluid-Fluid Displacement Model
650
Geomechanical Model
652
Fracture Flow Model
644
Reservoir Model
654

FIG. 6

Input Parameter	
Fracture	Scheduled position of fractures/perforation guns (MD [m], TVD [m])
	Fracture length (radius) [m]
	Fracture width (apperture) [m]
	Fracture (proppant pack) permeability [mD]
	Fracture (proppant pack) porosity [-]
Reservoir	Reservoir permeability [mD]
	Reservoir prosity [-]
	Initial reservoir presure [bar]
	Type of reservoir [oil/gas]
Wellbore	Wellbore Geometry (MD [m], TVD [m], diameters [m])
	Pressure control schedule (WHP or WHDCP or BHP vs time [bar])
	Surface chokes schedule
Fluids	Viscosity of fracturing fluid [cp]
	Viscosity of reservoir fluid [cp]
	Density of fracturing fluid [kg/m3]
	Density of reservoir fluid[kg/m3]
	Initial conditions (distribution of fluids in the system before flowback)

FIG. 7

Parameter	Purpose of Analysis
1D Pressure distribution in the fractures [bar]	tensile strength analysis
1D Pressure distribution in the wellbore [bar]	tensile strength analysis, wellbore flow regime determination
Surface flowrates [sm3/day]	flowback optimization

FIG. 8

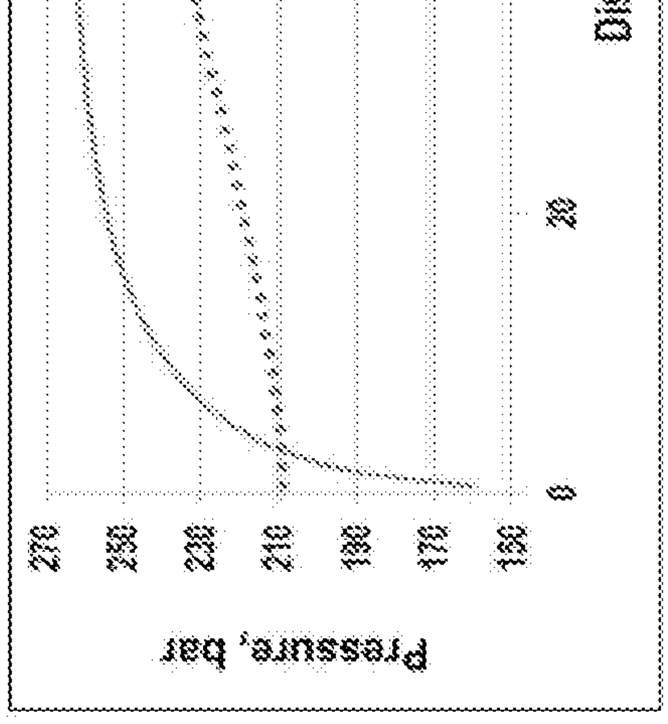


FIG. 9

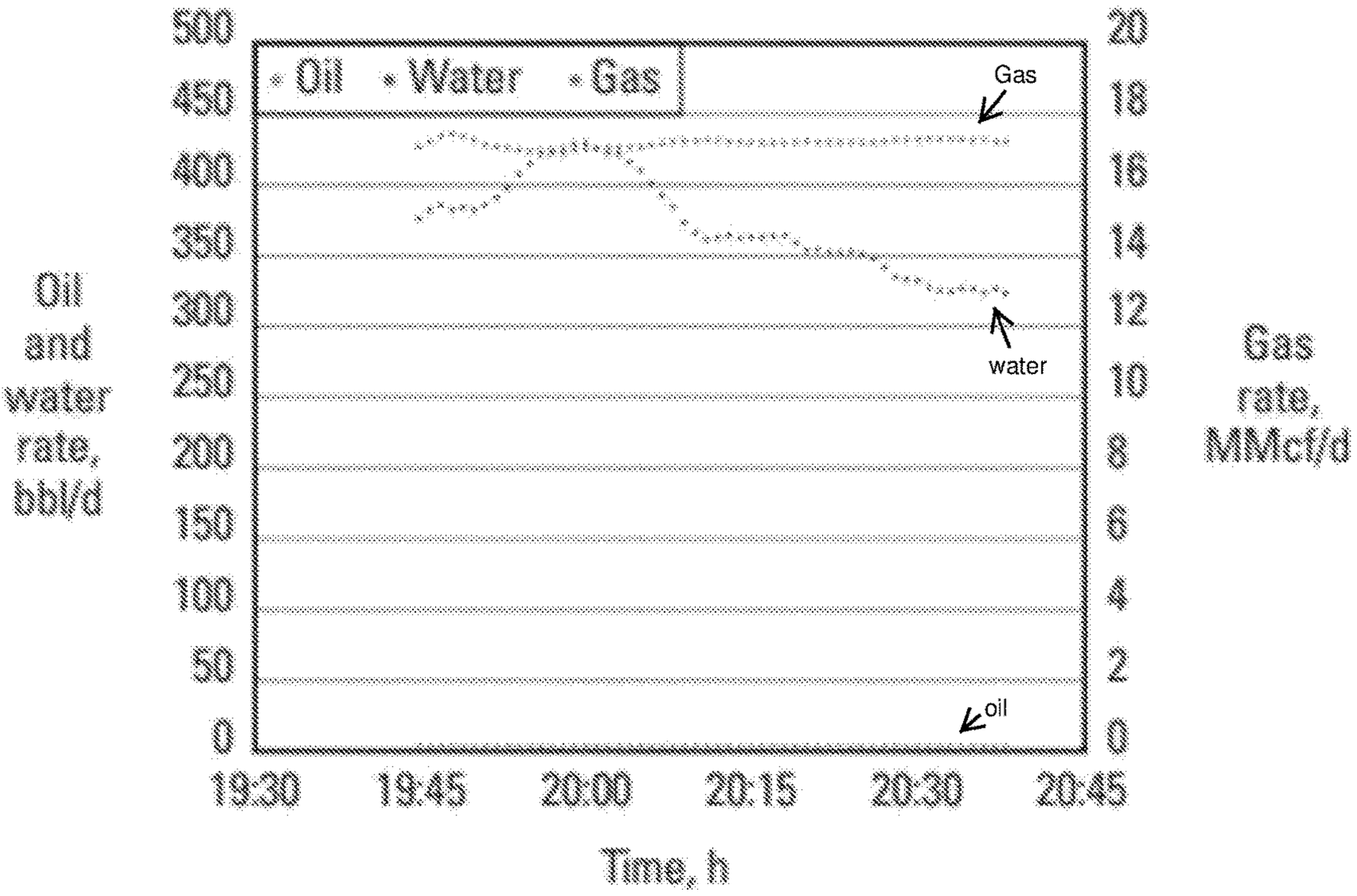


FIG. 10

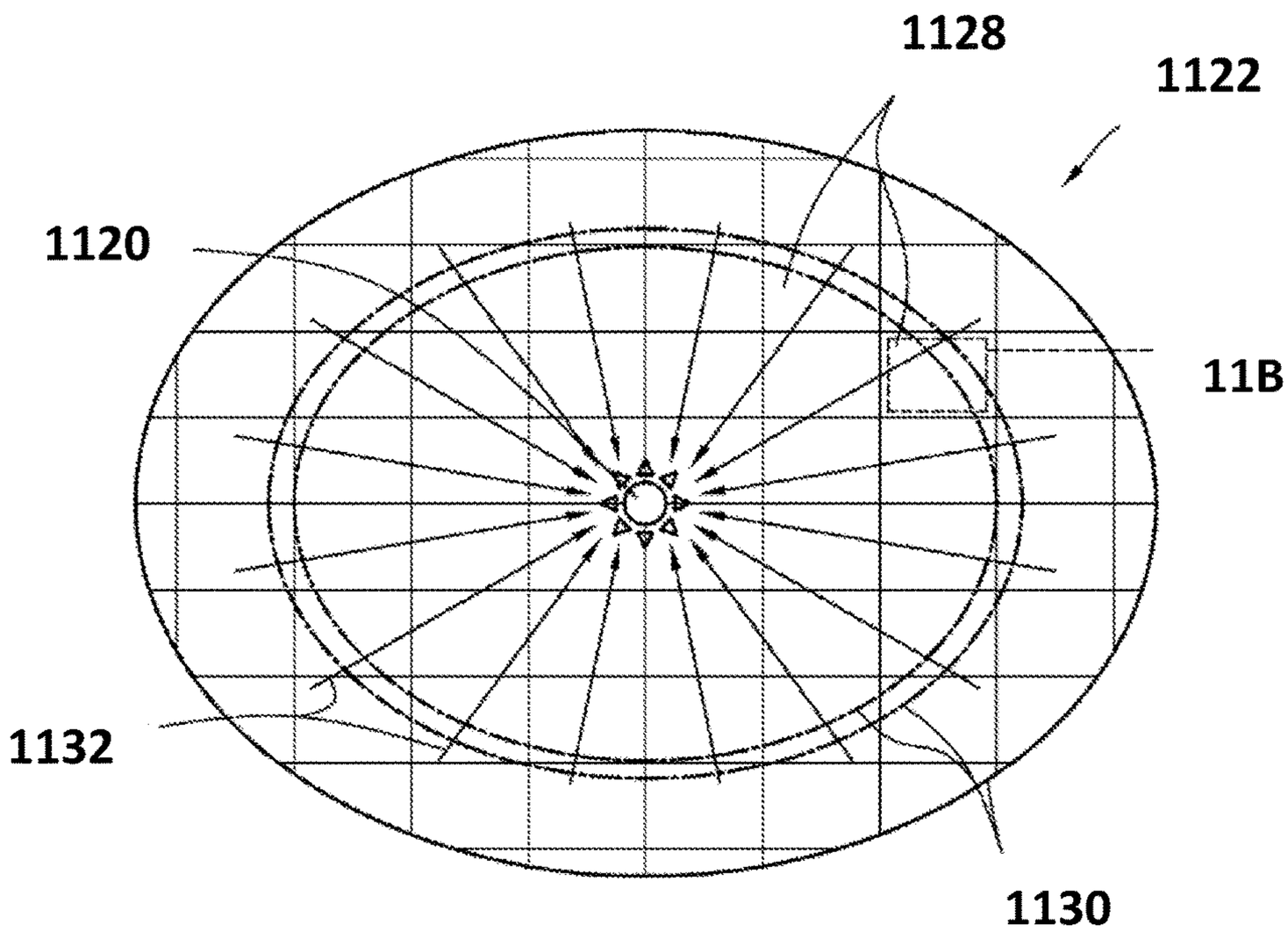


FIG. 11A

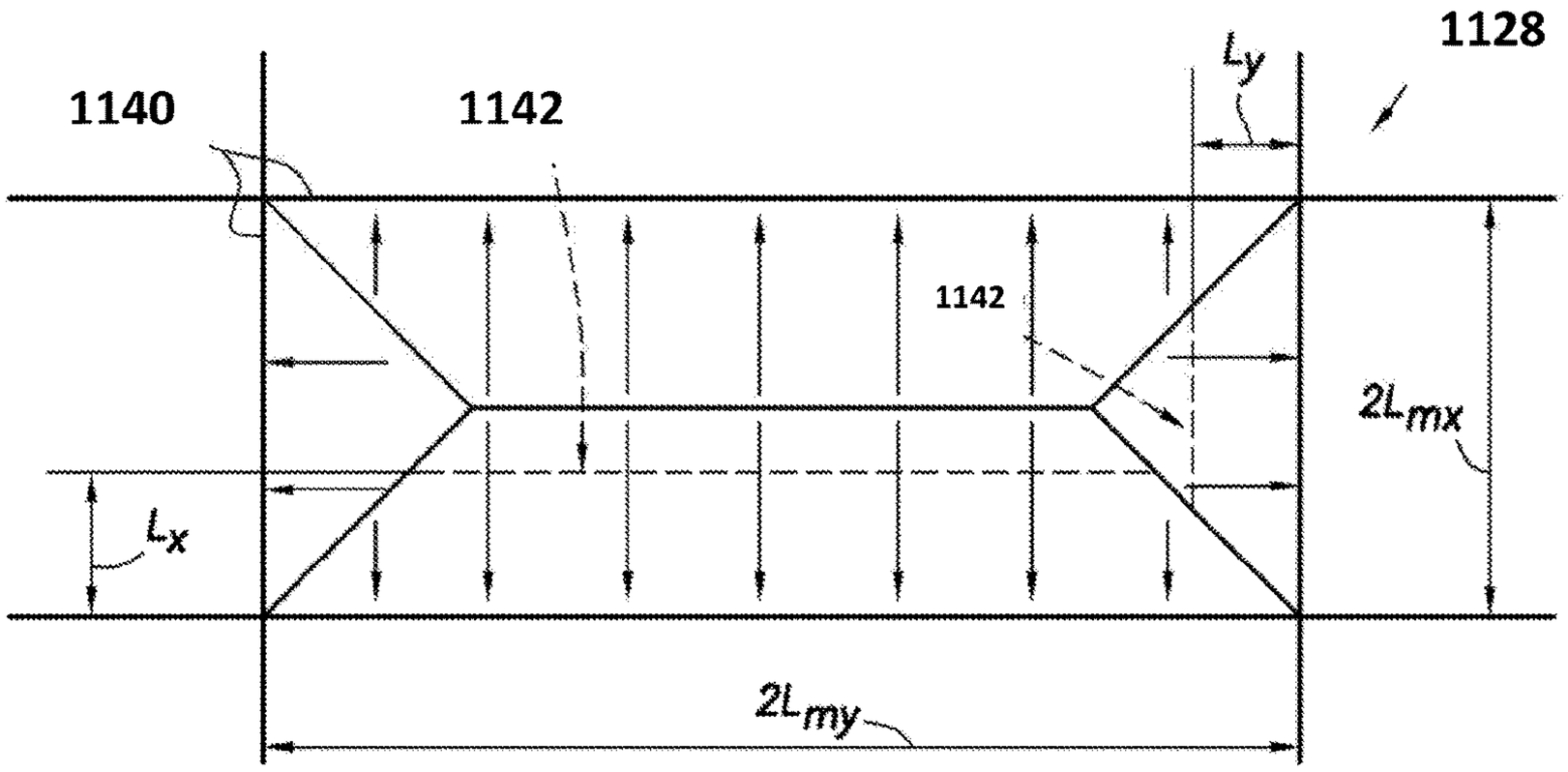


FIG. 11B

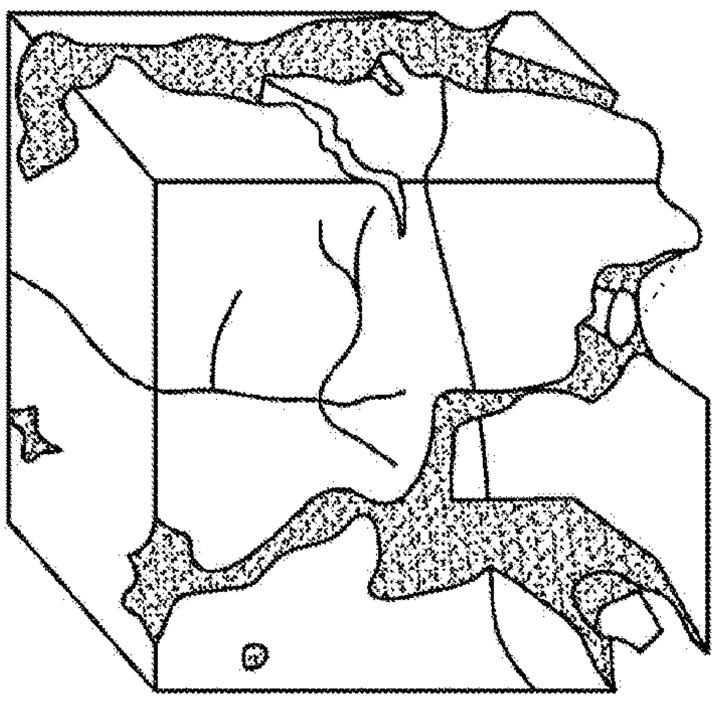


FIG. 11C

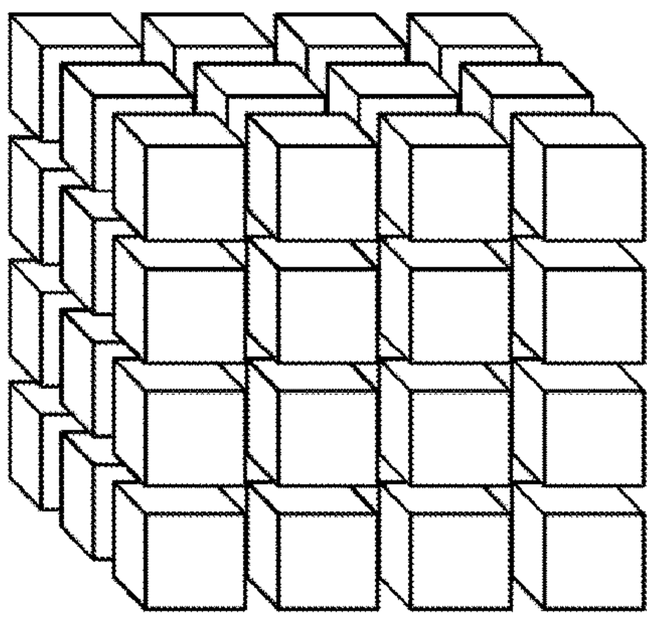
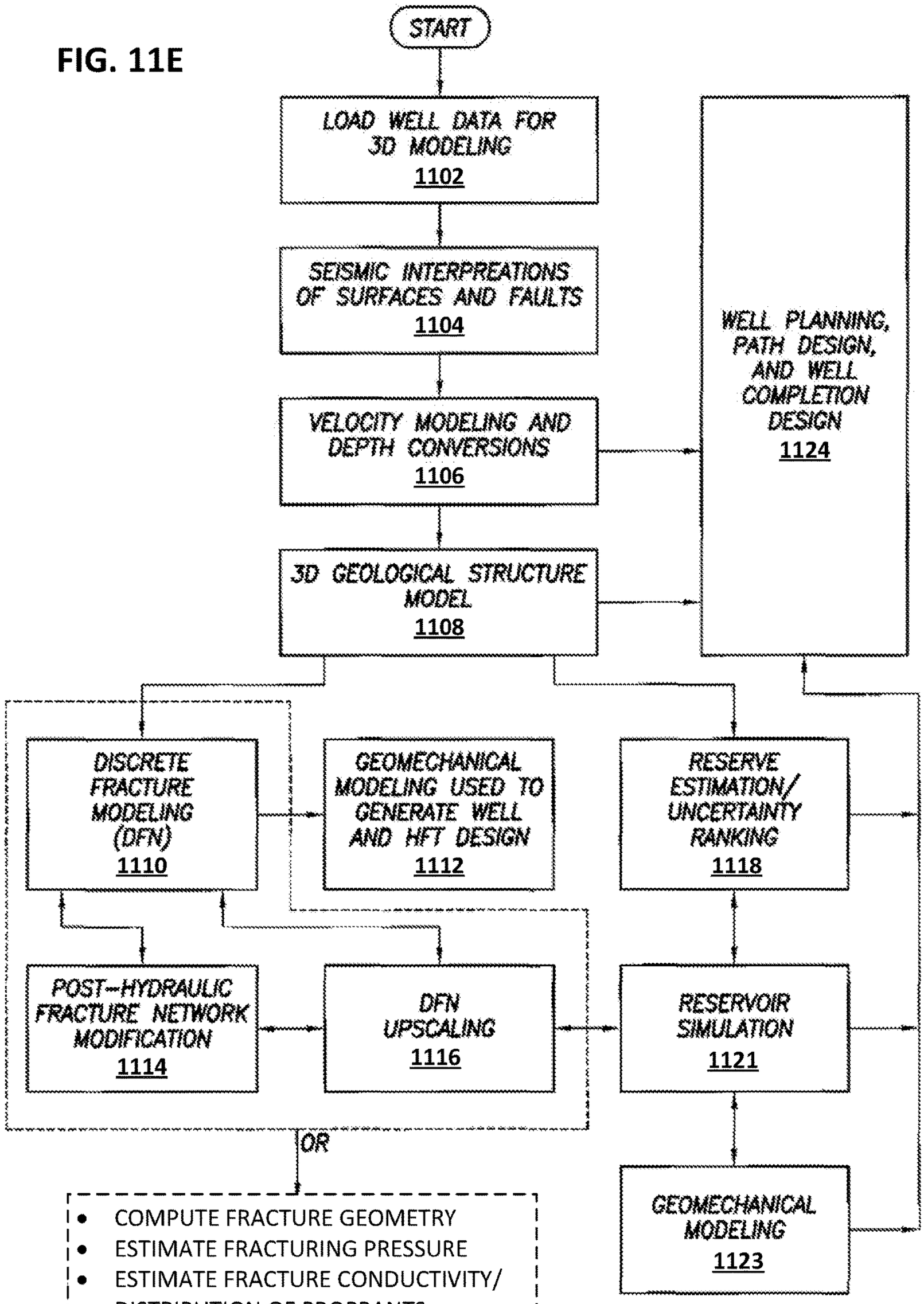


FIG. 11D

FIG. 11E


START
LOAD WELL DATA FOR 3D MODELING 1102
SEISMIC INTERPREATIONS OF SURFACES AND FAULTS 1104
VELOCITY MODELING AND DEPTH CONVERSIONS 1106
3D GEOLOGICAL STRUCTURE MODEL 1108
WELL PLANNING, PATH DESIGN, AND WELL COMPLETION DESIGN 1124
DISCRETE FRACTURE MODELING (DFN) 1110
GEOMECHANICAL MODELING USED TO GENERATE WELL AND HFT DESIGN 1112
RESERVE ESTIMATION/ UNCERTAINTY RANKING 1118
POST-HYDRAULIC FRACTURE NETWORK MODIFICATION 1114
DFN UPSCALING 1116
RESERVOIR SIMULATION 1121
GEOMECHANICAL MODELING 1123
OR
• COMPUTE FRACTURE GEOMETRY
• ESTIMATE FRACTURING PRESSURE
• ESTIMATE FRACTURE CONDUCTIVITY/ DISTRIBUTION OF PROPPANTS
• PREDICT FRACTURE PRODUCTIVITY
1117

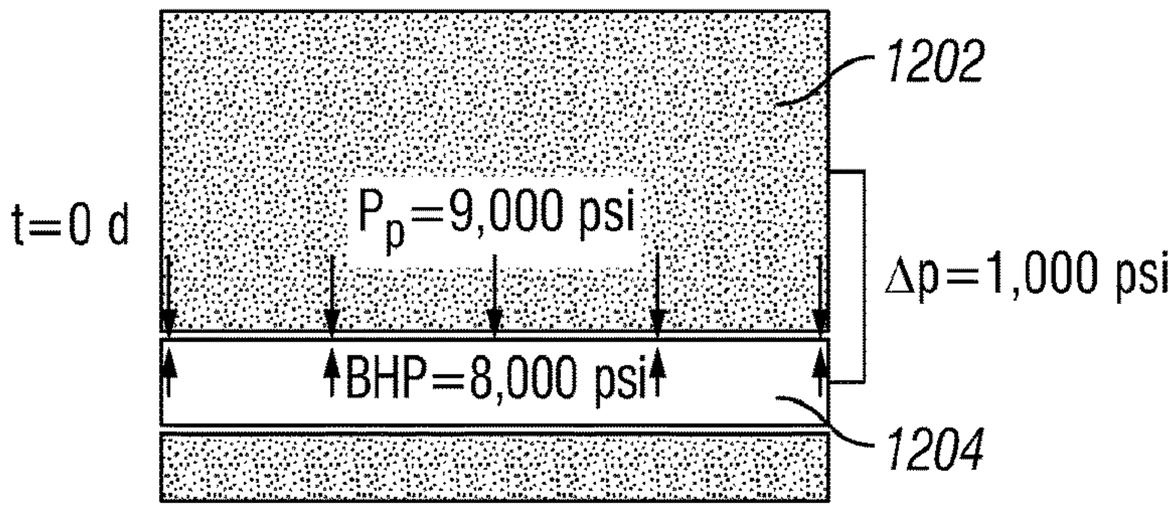

t=0 d
P_p=9,000 psi
1202
Δp=1,000 psi
BHP=8,000 psi
1204
1202b
P_p=9,000 psi
1202
t=10 d
P_p=8,000 psi
1202a
Δp=1,000 psi
BHP=7,000 psi
1204

FIG. 12

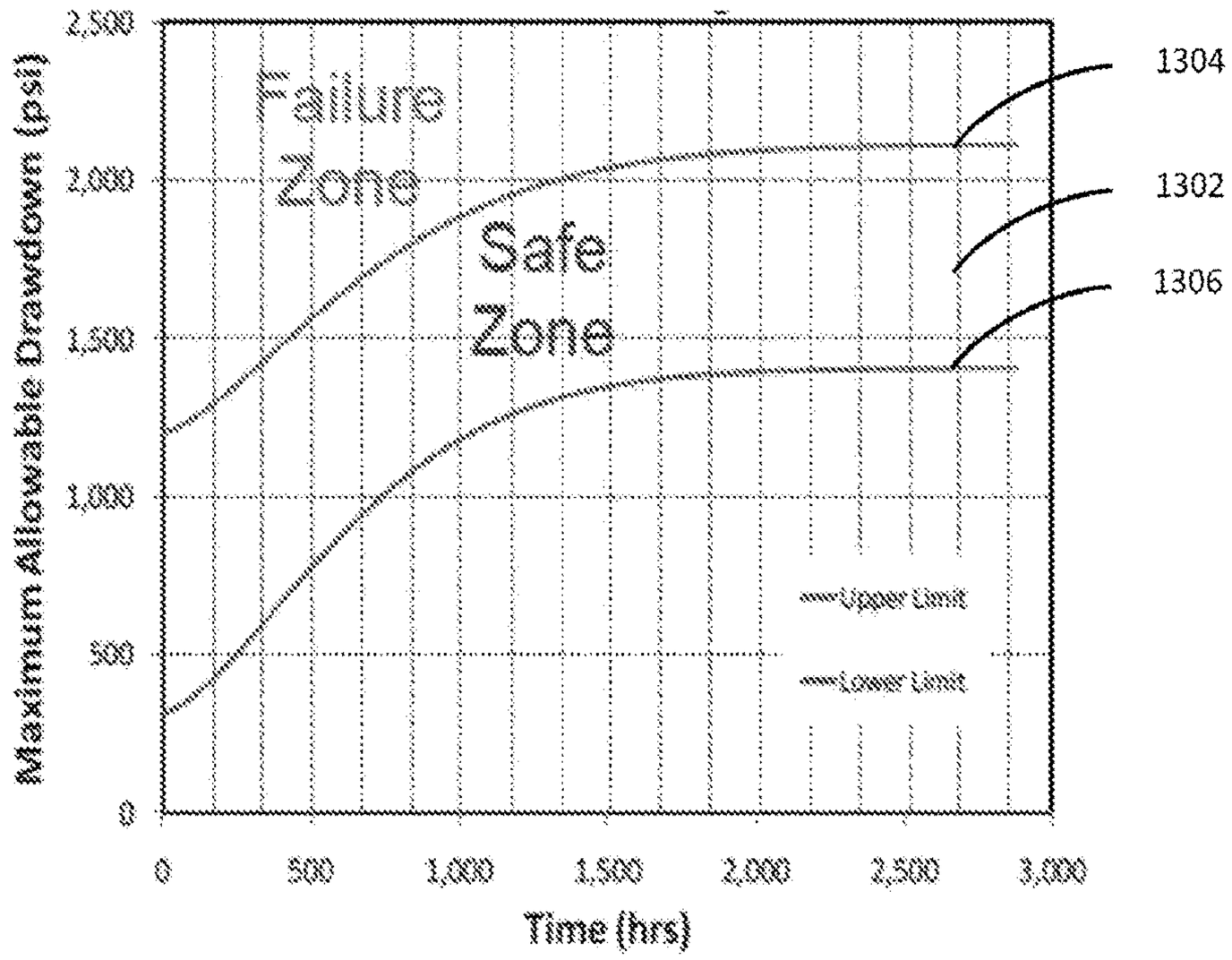

Failure Zone
Safe Zone
1304
1302
1306
Upper Limit
Lower Limit
Maximum Allowable Drawdown (psi)
2,500
2,000
1,500
1,000
500
0
0
500
1,000
1,500
2,000
2,500
3,000
Time (hrs)

FIG. 13

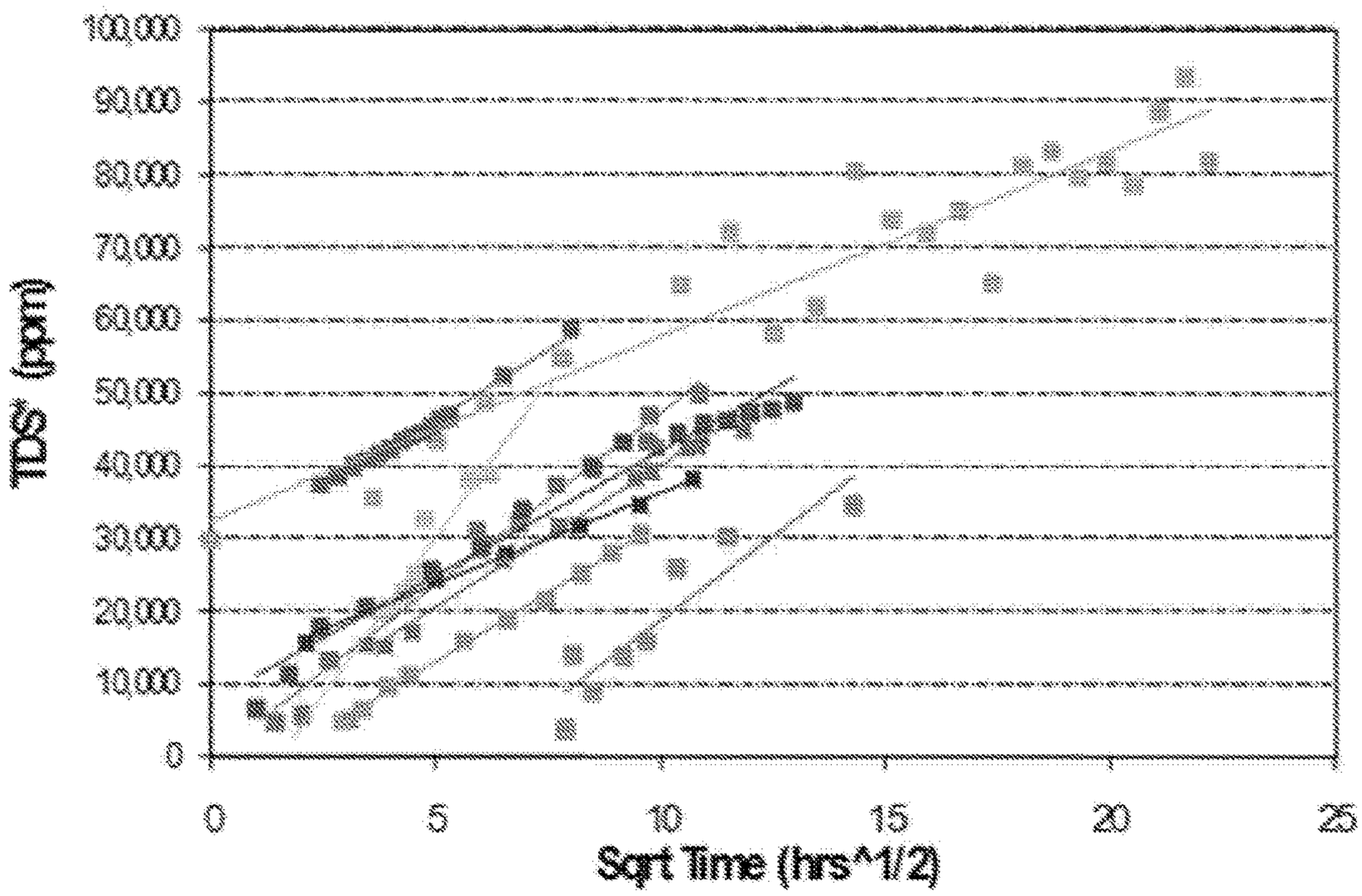

100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
TDS* (ppm)
0
5
10
15
20
25
Sqrt Time (hrs^1/2)

FIG. 14

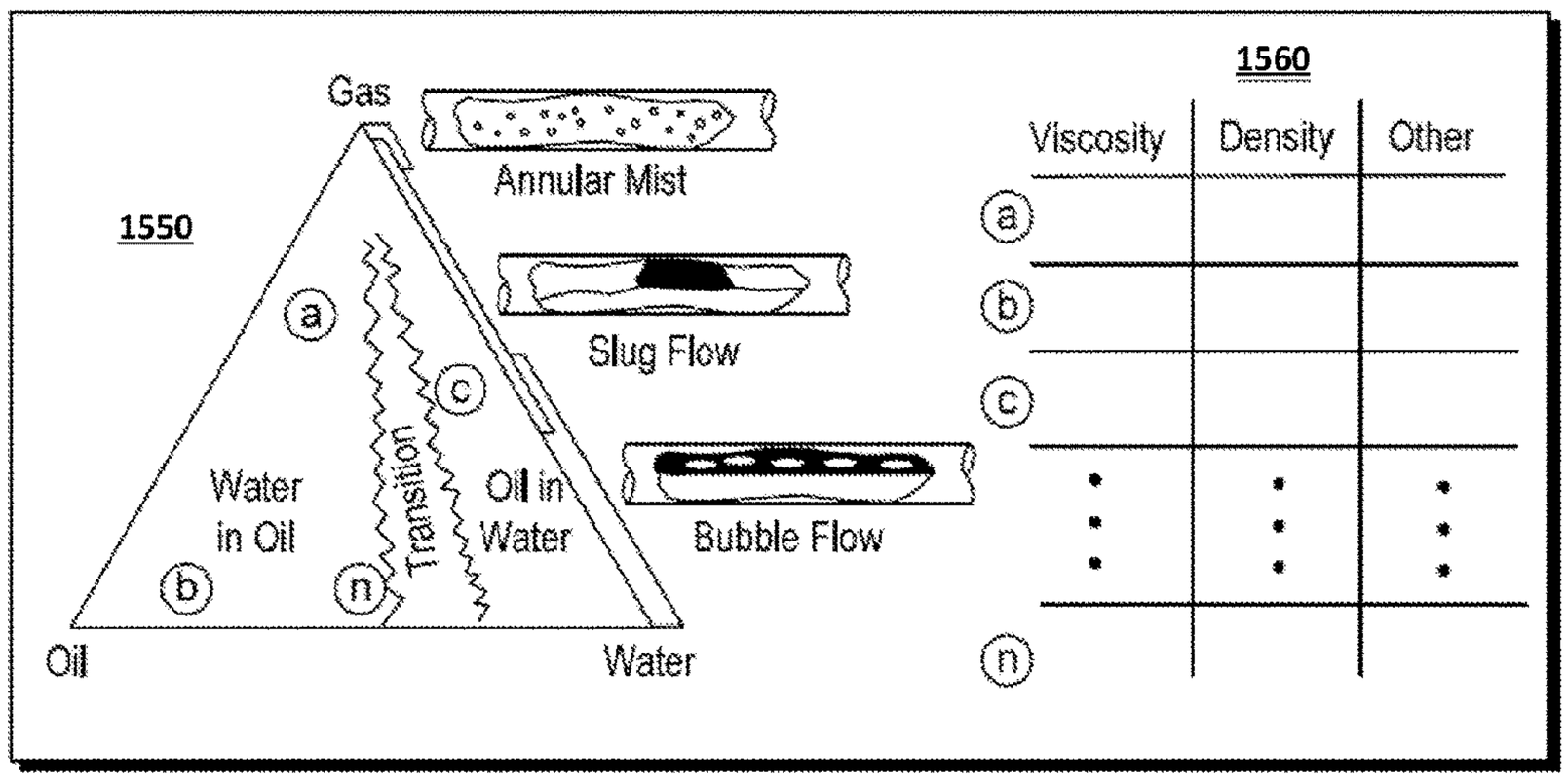

1550
Gas
Annular Mist
Slug Flow
Bubble Flow
Water in Oil
Oil in Water
Transition
Oil
Water
a
b
c
n
1560
Viscosity
Density
Other

FIG. 15

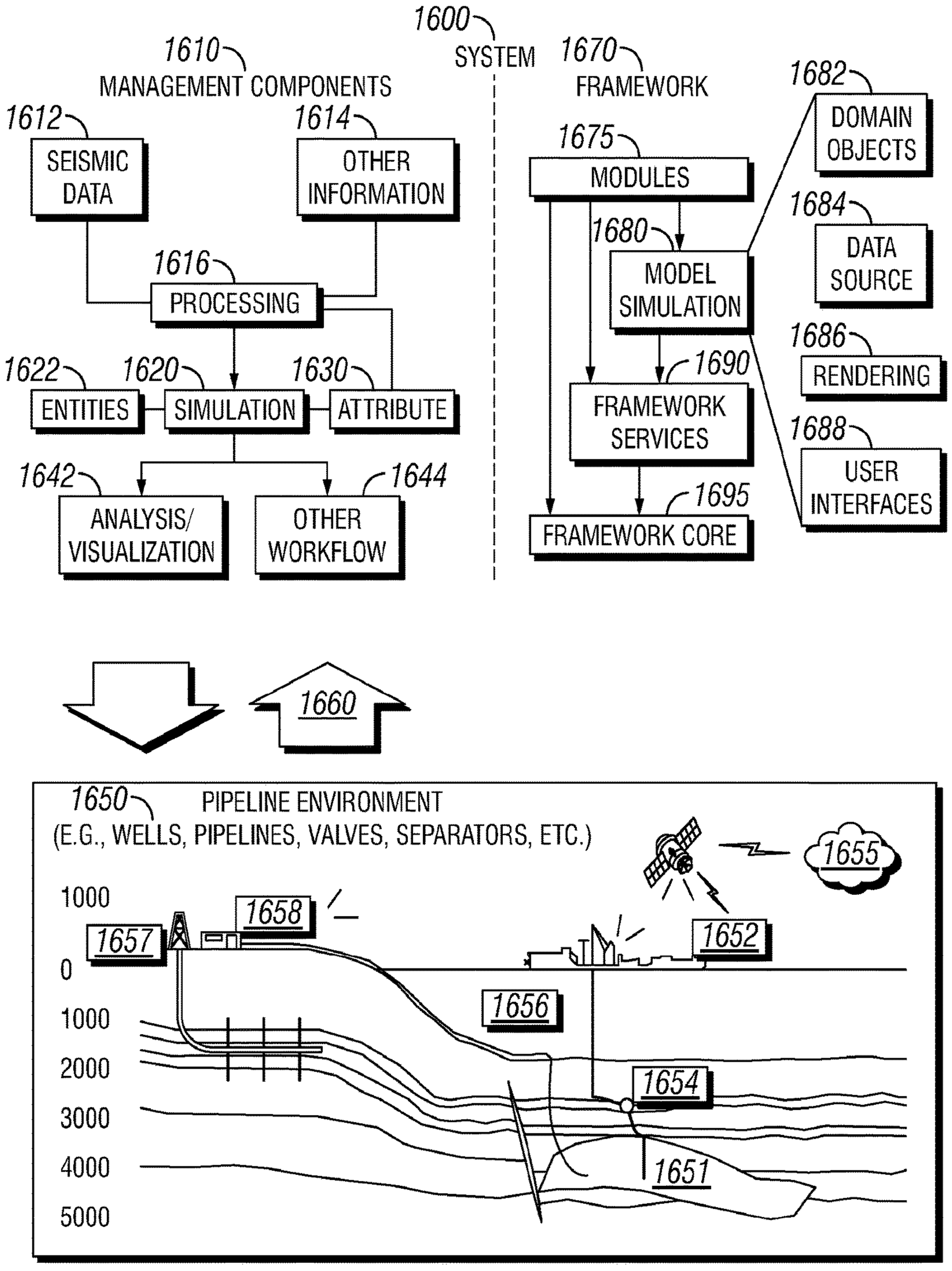

1600
SYSTEM
1610
MANAGEMENT COMPONENTS
1612
SEISMIC DATA
1614
OTHER INFORMATION
1616
PROCESSING
1622
ENTITIES
1620
SIMULATION
1630
ATTRIBUTE
1642
ANALYSIS/ VISUALIZATION
1644
OTHER WORKFLOW
1670
FRAMEWORK
1675
MODULES
1680
MODEL SIMULATION
1690
FRAMEWORK SERVICES
1695
FRAMEWORK CORE
1682
DOMAIN OBJECTS
1684
DATA SOURCE
1686
RENDERING
1688
USER INTERFACES
1660
1650
PIPELINE ENVIRONMENT
(E.G., WELLS, PIPELINES, VALVES, SEPARATORS, ETC.)
1000
0
1000
2000
3000
4000
5000
1658
1657
1656
1652
1655
1654
1651

FIG. 16

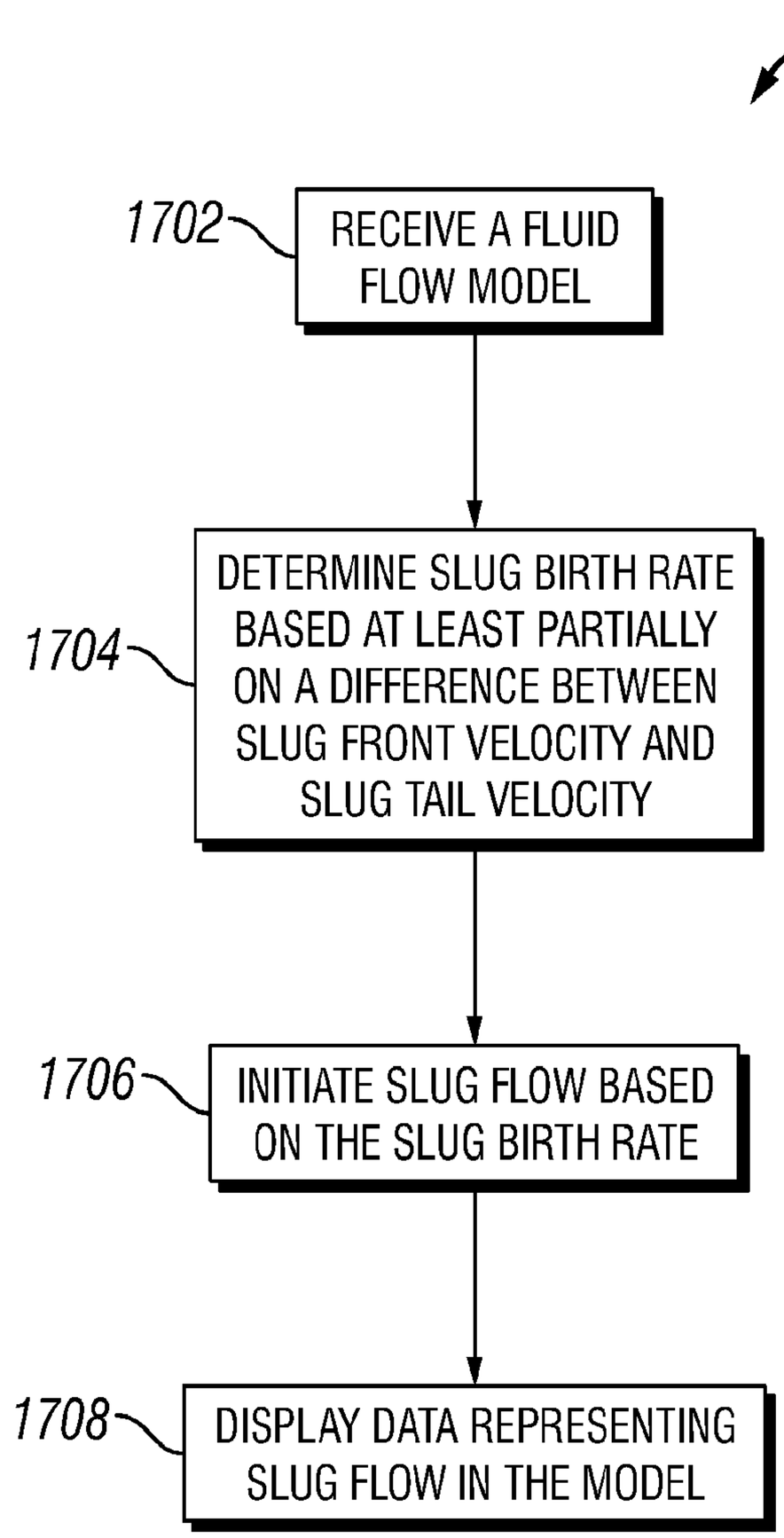

1700
1702
RECEIVE A FLUID FLOW MODEL
1704
DETERMINE SLUG BIRTH RATE BASED AT LEAST PARTIALLY ON A DIFFERENCE BETWEEN SLUG FRONT VELOCITY AND SLUG TAIL VELOCITY
1706
INITIATE SLUG FLOW BASED ON THE SLUG BIRTH RATE
1708
DISPLAY DATA REPRESENTING SLUG FLOW IN THE MODEL

FIG. 17

CONTROL SYSTEM AND METHOD OF FLOWBACK OPERATIONS FOR SHALE RESERVOIRS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims priority under 35 U.S.C. §119(e) to U.S. Provisional Application No. 62/107,157, filed on Jan. 23, 2015, the entire contents of which are incorporated herein by reference.

BACKGROUND

1. Field

[0002] The present disclosure relates to the production of hydrocarbons from subterranean reservoirs, and particularly from tight reservoirs such as reservoirs having a matrix permeability of less than 1 micro-Darcy.

2. State of the Art

[0003] During a hydraulic fracturing ("fracking") treatment, hydraulic fracturing fluid is introduced into a well under high pressure to create cracks or fractures in the reservoir rock through which trapped hydrocarbons (e.g., natural gas and/or petroleum) and connate water can flow from the rock more freely. For shale reservoirs, the hydraulic fracturing fluid typically consists primarily of water. A wide variety of chemical additives can also be used in the hydraulic fracturing fluid. Such additives can include dilute acids, biocides, breakers, corrosion inhibitors, crosslinkers, friction reducers, gels, potassium chloride, oxygen scavengers, pH adjusting agents, scale inhibitors and surfactants. Proppant such as sand, aluminum shot, or ceramic beads can also be used in the hydraulic fractures fluid. The proppant is intended to hold fractures open after the hydraulic fracturing treatment is completed.

[0004] Following the hydraulic fracturing treatment, and before placing the well into production, a process commonly referred to as "flowback" is commenced. During flowback the elevated pressure in the reservoir caused by introducing the pressurized hydraulic fluid is reduced or "drawn down" allowing fluids (including the hydraulic fracturing fluids and components thereof (such as proppant), cleaning the path for hydrocarbons (e.g., natural gas and/or petroleum) and connate water) to flow from the well back to the surface.

[0005] Procedure and time for the flowback operation are dictated by economic considerations and reservoir properties. Sometimes, it is desirable to conduct the flowback operations immediately after the fracturing treatment so that the well can benefit from non-dissipated reservoir pressure. There are also reservoirs where wells show better production performance after "seasoning", when fractured fluid is let to dissipate in formation for several weeks before initiating flowback procedure. In all cases after the flowback is initiated it is desirable to flowback the well at maximum technically and operationally allowable rate so that the well can be put into production quickly. At the same time the flowback rate should not exceed certain limits defined by formation and type of injected materials as exceeding these limits may result in excessive flowback of propping material, formation destabilization and, as a result, in poorer well production performance. Current practices for flowback operations are, in general, based on rule-of-thumb and are embodied in confidential flowback operational procedures of various well operators. Such rule-of-thumb flowback practices can cause extensive tensile rock failure, excessive proppant flowback, fines migration, and scale formation.

[0006] FIG. **1**A shows extensive tensile rock failure, which can lead to loss of the production for the treated zone or even sometimes loss of the well. FIG. **1**B shows an excessive amount of proppant that have flowed from the fractures back into the well and to the surface, which can allow the newly formed fractures to reduce in width or close, thereby restricting the flow of hydrocarbons from the reservoir rock. FIG. **1**C shows fines that have flowed from the fractures back into the well, which indicate that fines have been generated in the fracture; such fines can lead to complete plugging of the fracture and loss of the treated zone. FIG. **1**D shows scale that can be produced during flowback. The scale can coat perforations, casing, production tubulars, valves, pumps, and downhole completion equipment, and thus limit production.

SUMMARY

[0007] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

[0008] Illustrative embodiments of the present disclosure are directed to a system and method that employ a flowback model that characterizes fluid properties and rock mechanical properties of a hydraulically fractured reservoir during flowback in conjunction with measurement and analysis of chemistry and solids production with respect to the flowback fluid in order to maximize efficiency during the flowback operation, while mitigating formation damage and hydraulic fracture conductivity degradation. The methodology can dynamically control the flowback operation within a safe drawdown-operating zone in order to optimize well cleanup.

[0009] According to aspects, a flowback system for a hydraulically fractured reservoir includes a choke configured to regulate the flow of flowback fluid from a well that traverses a reservoir that has undergone hydraulic fracturing treatment; a plurality of sensors for measuring properties of the flowback fluid; and a control system coupled to the plurality of sensors and the choke. The control system is configured to receive and process measurements from the plurality of sensors and to dynamically adjust the operation of the choke (e.g., regulate the aperture of the choke) based on the measured properties of the flowback fluid. The plurality of sensors may include a multiphase flow meter, a wellhead pressure sensor, a solids analyzer, and/or a chemical analyzer. The control system can also be configured to dynamically adjust the operation of the choke (e.g., by adjust the aperture of the choke) based on a flowback model that is a function of wellhead pressure. In embodiments, measurements can be taken and processed in real-time enabling real-time control over the well flowback process. As used herein, "real-time" relates to measurement and computation times occurring over a duration of less than fifteen minutes, and in one embodiment less than ten minutes, and in another embodiment less than one second. In the context of a control system, real-time control denotes a system that generates, receives, and processes data in real-time to carry out the respective control operation.

[0010] The flowback model may incorporate various sub-models that are coupled together. Specifically, the flowback model may incorporate a well model and a fracture flow model. Thus, the flowback model models the flow in the well piping as well as through the reservoir and/or the hydraulic fracture.

[0011] The well model may incorporate output of a particle transport model and a flow model. The particle transport model models the movement of solid particles along the well and the flow model models the movement of fluids along the well.

[0012] The fracture flow model may incorporate output of a fluid-fluid displacement model within the fractures, a geomechanical model of geomechanical behavior of the formation rock, and a reservoir model that models the inflow of fluid into the fractures. The geomechanical model models the interaction between the stresses, pressures, and temperatures in the reservoir rock and the hydraulic fracture. The fluid-fluid displacement model models the displacement of oil, gas, and water by hydraulic fracturing fluid in the reservoir rock and also the displacement of the hydraulic fracturing fluid by the resident reservoir fluids. The reservoir model models the physical space of the reservoir by an array of discrete cells, delineated by a grid, which may be regular or irregular. The array of cells is usually three-dimensional, although one-dimensional and two-dimensional models can be used. Values for attributes such as porosity, permeability and water saturation are associated with each cell. The value of each attribute is implicitly deemed to apply uniformly throughout the volume of the reservoir represented by the cell.

[0013] The flowback model may have a plurality of input parameters related to the fracture reservoir, the well, and fluids expected to flow through fractures and through the well. Also, the flowback model may have a plurality of outputs including: a one-dimensional (e.g., radial direction from the wellbore) pressure distribution along fractures; a one-dimensional fluid saturation distribution for oil/gas/water along the fractures; one-dimensional pressure distribution along the length of the well; and one dimensional fluid saturation distributions for oil/gas/water along the length of the well up to the surface. The outputs can vary with time. The one-dimensional radial distributions of pressure and saturation along the fractures can be modeled at various positions along the well. The flowback model may output the aforementioned pressure and fluid distributions as a function of wellhead pressure.

[0014] In embodiments, the flowback model can determine a drawdown pressure, which is compared against a predetermined or scheduled drawdown pressure in order to dynamically adjust the operation of the choke. When the determined drawdown pressure is greater than the predetermined or scheduled drawdown pressure, the control system can dynamically throttle down the operation of the choke (e.g., lower or close the aperture of the choke). When the determined drawdown pressure is less than the predetermined or scheduled drawdown pressure, the control system can dynamically throttle up the operation of the choke (e.g., increase or open the aperture of the choke).

[0015] In further embodiments, the flowback model may be configured to determine a transient pressure distribution along the well and along fractures at various positions along the well, and a distribution of oil/gas/water/solids concentrations along the well and along the fractures at various positions along the well. The control system can be configured to use such distributions to calculate determined flow rates for oil/gas/water/solids at the surface. The determined flow rates for oil/gas/water/solids at the surface can be compared to corresponding measured flow rates for oil/gas/water/solids at the surface over time in order to determine the validity of the flowback model over time and/or to refine (tune) the flowback model over time. The determination of the transient pressure distribution and flow rates is predictive in nature, and thus can be referred to as predicted data.

[0016] The control system can also be configured to dynamically adjust the operation of the choke based on one or more failure conditions. One or more of such failure conditions can be determined from the flowback model, and thus be predictive in nature, and thus can be referred to as predicted failure conditions. The failure conditions may include a prediction of slug formation, a prediction of tensile rock failure, a prediction of loss of fracture surface area or productive area, conditions related to one or more measurements of solids produced from the flowback fluid, conditions related to flow rate measurements of one or more phases in the flowback fluid, and conditions related to wellhead pressure measurements.

BRIEF DESCRIPTION OF THE DRAWINGS

[0017] FIG. **1**A to **1**D are illustrations of some types of solids that may flow from a well to the surface during a flowback operation.

[0018] FIG. **2** is a schematic illustration of a well that traverses a hydraulically fractured reservoir.

[0019] FIG. **3** is a schematic illustration of an embodiment of a flowback system according to the present disclosure.

[0020] FIG. **4** is a schematic illustration of exemplary data flow and associated calculations within the flowback system of FIG. **3**.

[0021] FIG. **5** shows an example computing system that can be used to implement the flowback system or parts thereof of FIGS. **3** and **4**.

[0022] FIG. **6** is a schematic representation of the component parts of an exemplary flowback model.

[0023] FIG. **7** is a table showing input parameters for an illustrative flowback model.

[0024] FIG. **8** is a table showing output parameters for an illustrative flowback model.

[0025] FIG. **9** is a graph of reservoir pressure and fracture fluid saturation versus radial distance from the wellbore at a respective location along a well.

[0026] FIG. **10** is a graph of multiphase flow of oil, water, and gas versus time during an exemplary flowback operation.

[0027] FIG. **11**A is a schematic illustration of fluid flow through a dual porosity medium.

[0028] FIG. **11**B is a schematic illustration showing fluid flow through in a matrix block shown in FIG. **11**A.

[0029] FIGS. **11**C and **11**D are schematic diagrams for depicting fluid flow through a medium.

[0030] FIG. **11**E depicts an example flow chart of a method for fracture modeling.

[0031] FIG. **12** is a schematic illustration of drawdown pressures at a respective bottomhole position in a well at two different times during an exemplary flowback operation.

[0032] FIG. **13** is an example graph of scheduled maximum allowable drawdown pressure versus time during an exemplary flowback operation.

[0033] FIG. **14** is a graph of total dissolved solids in produced flowback fluid versus time for various wells.

[0034] FIG. **15** illustrates an example of a ternary diagram with an example of an associated table of fluid properties.

[0035] FIG. **16** illustrates an example of a system that includes various management components to manage various aspects of a pipeline environment, according to an embodiment.

[0036] FIG. **17** illustrates a flowchart of a method for modeling slug flow in a multiphase flow according to an embodiment of the present disclosure.

DETAILED DESCRIPTION

[0037] Illustrative embodiments of the present disclosure are described below. In the interest of clarity, not all features of an actual implementation are described in this specification. It will be appreciated that in the development of any such actual embodiment, numerous implementation-specific decisions must be made to achieve the developer's specific goals, such as compliance with system-related and business-related constraints, which will vary from one implementation to another. Moreover, it will be appreciated that such a development effort might be complex and time-consuming but would nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of this disclosure. Further, like reference numbers and designations in the various drawings indicate like elements.

[0038] FIG. **2** shows a schematic of a well **200** of a hydraulically fractured hydrocarbon reservoir **202**. While certain elements of the well **200** are illustrated in FIG. **2**, other elements of the well **200** (e.g., blow-out preventers, wellhead "surface tree") have been omitted for clarity of illustration. The well **200** includes an interconnection of pipes, including vertical and horizontal casing **204**, production tubing **206**, transitions **208**, and a production liner **210** that connect to a processing facility (not shown) at the surface **201**. The production tubing **206** extends inside the casing **204** and terminates at a tubing head **212** at or near the surface **201**. The casing **204** contacts the wellbore **218** and terminates at casing head **214** at or near the surface **201**. The production liner **210** and horizontal casing **204** have aligned radial openings termed "perforation zones" **220** that allow fluid communication between the production liner **210** and the hydraulically fractured reservoir **202**. An annular packer **222** is set at a lower end of the production tubing **206** and provides a seal between the production tubing **206** and the casing **204** so that fluid in the production liner **210** is directed into the production tubing **206** rather than between the production tubing **206** and the casing **204**.

[0039] The flow rate of the fluid flowing in the well **200** to the surface **201** is a function of the drawdown pressure of the well **200**. As used herein, "drawdown pressure" means the difference between the average reservoir pressure and the bottomhole pressure. As used herein, "average reservoir pressure" means the average pressure of the fluids trapped within the reservoir rock **202**, and "bottomhole pressure" means the pressure at a specified location at the bottom of the well, such as at the top (downstream end) of the production liner **210** in FIG. **2**. Thus, in at least one embodiment, the drawdown pressure is calculated to be the difference between the average pressure in the reservoir rock **202** and the flowing pressure in the production liner **210** at the downstream end of the production liner at a specified time. As will be discussed in greater detail below, the determination of the average pressure in the reservoir rock **202** and the flowing pressure in the production liner **210** at the downstream end of the production liner will be determined by solving for pressure and flow distributions throughout the well and the hydraulically fractured reservoir rock over time. The pressure and flow distributions may be determined throughout the well piping or the well annulus depending whether the well is flowed back through the casing and production tubing, or through the casing if the well is flown back before installation of the production tubing or the pressure might be determined throughout the annulus between the wellbore and the piping if the well is flown back through the annulus.

[0040] The drawdown pressure, and, thus, the flow rate of the fluid flowing in the well **200** to the surface **201**, can be adjusted by a surface-located wellhead choke **216** disposed at or near the tubing head **212**. For example, the choke **216** can be throttled up whereby the aperture of the choke **216** is increased or opened in order to increase the drawdown pressure and increase the flow rate of the fluid flowing in the well **200** to the surface **201**. In another example, the choke **216** can be throttled down whereby the aperture of the choke **216** is decreased or closed in order to decrease the drawdown pressure and decrease the flow rate of the fluid flowing in the well **200** to the surface **201**.

[0041] After a hydraulic fracturing treatment, and before the production of hydrocarbons can commence, the hydraulic fluid injected into the reservoir must be at least partially removed from the reservoir as part of flowback fluids that flow to the surface **201** for collection and transport. As used herein "flowback fluid(s)" include one or more of oil, water, gas, and solids, and mixtures thereof. The flow rate of flowback fluid to the surface **201** is termed the "unloading rate." Generally, it is desirable to remove the flowback fluid from the reservoir as quickly as possible (i.e., a high unloading rate) so that the well **200** can begin to produce hydrocarbons. However, if the flowback fluid is withdrawn too quickly (i.e., if the unloading rate is too high), there is a risk of unwanted conditions including tensile rock failure, excessive proppant flowback and fines migration. Moreover, because the flowback operation is a highly transient process, in which the distributions of properties change rapidly, it is important to be able to determine the evolution of these properties over time so that operational corrections can be made to manage the flowback operation efficiently and with reduced risk of damage to the well and the reservoir.

[0042] FIG. **3** illustrates an embodiment of a real-time flowback system **500** that has a plurality of sensors (including a well head pressure sensor **502**, a multiphase flow meter **504**, a solids analyzer **505**, and a chemical analyzer **506**), a well-head choke **508**, and a control system **510** that dynamically controls the operation of the choke **508** based upon a plurality of inputs from the sensors **502**, **504**, **505**, and **506**. An optional bottomhole pressure sensor **501** may also be included. The control system **510** includes a controller **512** that employs a flowback model **514**. The control system **510** processes the plurality of inputs to generate an output that includes a choke control signal **516** that is used by the choke **508** to control the drawdown pressure and flow rate of produced flowback fluid **518** during a flowback operation. The control system **510** can be configured to control the drawdown pressure and flow so that the drawdown pressure remains at or below the scheduled maximum allowable drawdown pressure, such as illustrated in FIG. **13**, for

example. By controlling the drawdown pressure over time, the above-noted unwanted conditions (including tensile rock failure, excessive proppant flowback, fines migration) can be mitigated if determined or detected by the control system **510**, as will be discussed in greater detail below. All of the blocks of the system **500**, including the measurements obtained by sensors **502**, **504**, **505**, **506**, and **507**, and the processing carried out by the control system **510** to control the choke **508**, may occur in real-time.

[0043] The control system **510** interfaces to the choke **508** via wired or wireless signal paths therebetween in order to communicate the choke control signal **516** that controls the operation of the choke **508**. The control system **510** interfaces to wellhead pressure sensor **502** via wired or wireless signal paths therebetween to receive data measurements of wellhead pressure. The control system **510** interfaces to multiphase flow meter **504** via wired or wireless signal paths therebetween in order to receive data measurements of production flow rates of oil/gas/water. The control system **510** interfaces to solids analyzer **505** via wired or wireless signal paths therebetween in order to receive data representing the type and amount of solids produced from the flowback fluid. The control system **510** interfaces to continuous chemical analyzer **506** via wired or wireless signal paths therebetween in order to receive data representing chemical analysis of solid content of the produced oil/gas/water over time, as discussed below.

[0044] The control system **510** can be configured to carry out a sequence of calculations and operations to control the drawdown pressure and the flow rate of the flowback fluid by controlling the operation of the choke **508**. The control logic can be configured by user input or other suitable data structure, which is used to configure the control system **510** in order to carry out control operations that are part of the workflow as described herein. For example, the user input or other suitable data structure can specify parameters (such as pressures, flow rates, temperatures, etc.) for such control operations of the workflow.

[0045] The choke **508** may include a variable sized aperture or orifice that is used to control fluid flow rate or downstream system pressure. As an example, the choke **508** may be provided in any of a variety of configurations (e.g., for fixed and/or adjustable modes of operation). As an example, an adjustable choke **508** may enable fluid flow and pressure parameters to be changed to suit process or production requirements. As an example, a fixed choke may be configured for resistance to erosion under prolonged operation or production of abrasive fluids. The choke **508** may be electrically or pneumatically operated.

Flowback System Sensors

[0046] In one embodiment the flowback system **500** may include a wellhead pressure (WHP) sensor **502**, a multiphase flow meter **504**, a solids analyzer **505**, and one or more continuous chemical analyzers **506**. As noted above, the flowback system **500** may include an optional bottomhole pressure sensor **501**. The sensors **502**, **504**, **505**, and **506** may be located on the surface, while the bottomhole pressure sensor **501** may be located at one or more designated bottomhole locations along the well.

[0047] The bottomhole pressure sensor **501** is configured to provide real-time bottomhole pressure measurements **521** to the control system **510**, which may be used to control the drawdown pressure and the choke **508**. Also, the bottomhole pressure measurements **521** of the bottomhole pressure sensor **501** may be used to tune the flowback model **514** and to validate the downhole pressure(s) determined by the flowback model **514**, if need be.

[0048] The wellhead pressure (WHP) sensor **502** is configured to measure the pressure of the flowback fluid at the wellhead. The wellhead pressure sensor **502** is communicatively coupled to the control system **510** and is configured to output a pressure signal **522** that characterizes the pressure of the flowback fluid at the wellhead to the control system **510**.

[0049] The flowback fluid passes by the WHP sensor **502** and on through a surface-located solids separator and analyzer **505**. The solids separator and analyzer **505** receives the produced flowback fluid and separates that fluid into two streams: a stream of produced solids; and a stream of produced oil/gas/water. The produced solids are collected and analyzed by the analyzer **505**, while the stream of produced oil/gas/water passes to the surface-located multiphase flow meter **504**. The analyzer **505** can be configured to characterize the solids content (e.g., amount of different solids types, such as proppant, formation rock, fines, etc.) that are included in the flowback fluid in real time. The solids content of the flowback fluid may include any of proppant, formation rock, and possibly fines. The analyzer **505** is communicatively coupled to the control system **510** and is configured to output solids content measurement signals **525** of the produced fluids to the control system **510**. In embodiments, the solid analyzer suitable within the present disclosure includes continuous in line devices such as clamp-on gauges, an example of commercially available device is ClampOn provided by ClampOn Inc., Houston, Tex.; continuous in line devices such as densitometers; Continuous measuring devices such as Vx multi-phase flowmeter commercially available from Schlumberger Limited; or non-continuous measurement devices such as separators.

[0050] The multiphase flow meter **504** is configured to measure flow rates of the various phases (oil/gas/water) of the stream of produced fluids in real time. In one embodiment, the multiphase flow meter **504** may be a Model Vx Spectra multiphase flow meter supplied by Schlumberger Limited of Sugarland, Tex. The multiphase flow meter **504** is communicatively coupled to the control system **510** and is configured to output flow rate measurement signals **524** for the oil/gas/water phases of the produced fluids to the control system **510**.

[0051] The stream of produced fluids passes through the multiphase flow meter **504** to the surface-located continuous chemical analyzer **506**. The continuous chemical analyzer **506** is configured to continuously analyze the produced oil/gas/water and to generate data representing chemical analyses of those fluids over time, examples of chemical analysis may include electrical conductivity measurements using capacitive type devices; pH detection using ion selective electrodes, solid state detectors, or spectrophometric methods; flow-through spectrophotometric and Infra-red spectroscopy cells; ion selective electrodes for specific ions, gas chromatography, gas detectors. The data may include conductivity, total dissolved solids (TDS), pH, temperature, total hardness, and total alkalinity. Additional water samples can also be collected and preserved for validation of field measurements in a lab and for detailed analysis for elements such as calcium, magnesium, barium, strontium, sulfate, and sulfide, for extended scaling potential analysis and safety

hazards. The continuous chemical analyzer **506** is communicatively coupled to the control system **510** and is configured to output the afore-mentioned measurement signals **526** to the control system **510**.

[0052] The stream of produced fluids passes through the continuous chemical analyzer **506** to a surface-located phase separator **507**, which is configured to separate the stream of produced oil/gas/water into separate streams of oil, gas, and water, which can be individually collected for storage and/or transport. Also, the separator **507** may also be used for measuring flow rates of the oil/gas/water.

[0053] A flowback model **514** can use the pressure signal **522** and the flow measurements **524** to operate as a transient fluid flow simulator that predicts transient pressure distributions along the well and along hydraulic fractures in the reservoir and that predicts distributions of oil/gas/water saturations along the well and along the hydraulic fractures. Those predictions may be used to calculate determined production flow rates for oil/water/gas over time at block **513**. The flowback model **514** can also possibly determine solid concentration and other properties in fractures and along the well. The flowback model **514** can also be used to characterize the bottomhole pressure and associated drawdown pressure of the well over time. The calculated production flow rates, other properties, and drawdown pressure over time may be used by the automatic choke control **512** for use in generating the choke control signal **516**.

[0054] In some embodiments, the bottomhole pressure may be calculated based on a plurality of surface measurements (e.g., wellhead pressure and multiphase flow rates) taken over time. For example, in the case of significant fluid travel time from the bottomhole location to the surface, the actual distribution of fluid composition in the wellbore may not be known. In such a case, the distributions and bottomhole conditions at each moment in time may be extrapolated from prior known measurements of multi-phase surface flow measurements measured at the surface, and parameters of such extrapolation can be later verified and additionally calibrated after the bottomhole fluid reaches the surface. Optionally, the bottomhole pressure may be measured from the bottomhole pressure sensor **501**. In this configuration, the bottomhole pressure measurement may be compared to the bottomhole pressure determined by the flowback model in order to validate the flowback model.

[0055] The flow rates of each phase of the flowback fluid (i.e., oil, gas, water, and solids) may be measured continuously using the multiphase flow meter **504** and may also be determined over time using the output of the flowback model **514** for comparison with the measured values. For example, see the description of block **515** in FIG. **4** that follows. FIG. **10** shows a plot of flow rates of oil/water/gas over time that are determined by the control system **510** using the output of the flow model **514**.

[0056] The control system **510** can be configured to receive and process measurements from the plurality of sensors **502**, **504**, **505**, and **506** and to dynamically adjust the operation of the choke (e.g., regulate the aperture of the choke) based on the measured properties of the flowback fluid. The control system can also be configured to dynamically adjust the operation of the choke **508** based on determined conditions and/or calculations derived from the flowback model **514**.

[0057] In one embodiment, the multiphase flow rates that are calculated at block **513** are updated in real time based on real time updates of fluid properties determined by the model **514**. The updated calculated multiphase flow rates are compared in real time to the measured multiphase flow rates. If the determined multiphase flow rates match the measured multiphase flow rates, then the flowback model **514** is validated and the model **514** may be used to determine the properties of the fluid column in the well between the surface located choke **508** and a bottomhole location, including bottomhole pressure at the bottomhole location. If the determined multiphase flow rates do not match the measured multiphase flow rates, then the model **514** may be tuned at block **520** (FIG. **4**) so that the flowback model **514** may be updated in real time such that the determined multiphase flow rates match the measured multiphase flow rates, and then the flowback model **514** can be used to determine the properties of the fluid column in the well including bottomhole pressure.

[0058] In another embodiment, a number of different flowback models **514** (each initialized to reflect different flowback scenarios) may be implemented concurrently. In this case, each model produces a corresponding set of determined multiphase flow rates at block **513**. Thus, multiple sets of determined flow rates may be compared against the measured multiphase flow rates to identify one of the flowback models that best matches the measured multiphase flow rate values. The selected flowback model may then be used to determine the fluid column properties in the well, including bottomhole pressure.

[0059] In yet another embodiment, the bottomhole pressure may be calculated based on a plurality of surface measurements, taken over time, of pressure (e.g., WHP) and flow rates (e.g., multiphase flows). For example, in the case of significant fluid travel time from the bottomhole location to the surface, the actual distribution of fluid composition in the wellbore may not be known. In such a case, the distributions and bottomhole conditions (e.g., bottomhole pressure) at each moment in time may be extrapolated from prior known measurements of multi-phase surface flow measurements measured at the surface, and parameters of such extrapolation can be later verified and additionally calibrated after the bottomhole fluid reaches the surface. Optionally, the bottomhole pressure may be measured from the bottomhole pressure sensor **501** and used to calculate drawdown pressure. Furthermore, the bottomhole pressure measurements may be compared to the bottomhole pressure determined by the flowback model for tuning the flowback model and for validation of the flowback model if need be.

[0060] In still another embodiment, the flowback model(s) as described above can be used to determine multiple estimates of bottomhole pressure over time and provide a statistical distribution of the bottomhole pressure over time (e.g., a maximum, minimum, average, and standard deviation). Furthermore, deviation from a determined trend or scenario, such as deviation from a predefined drawdown operating envelope, can be reported as an alarm for further analysis and decision making for updating the flowback strategy.

Control System—Automatic Choke Control

[0061] FIG. **4** shows an exemplary data flow and associated calculations within the flowback system of FIG. **3**. At block **515**, the determined multiphase fluid flow rates at the surface may be compared with the corresponding measured multiphase flow rates output by the multiphase flow meter

504. At block **520** at least some of the flowback model parameters in FIG. **7** may be tuned or refined based on the comparison of the measured and target flow rates at block **515**. Also, a validation signal (i.e., valid or invalid) may be output to the choke controller **512** based on the comparison at block **515**. The validation signal may be used by the choke controller **512** to denote whether or not the flowback model is valid. In the cases where the model is invalid, a safe mode of operation is followed until the model can be tuned and valid. As an example, such safe mode comprises keeping the current choke setting along unless surface measurements from solids/fluids indicate that the current choke settings corresponds to a danger zone of the system (e.g. a large amount of fines being produced).

[0062] In block **540**, the automatic choke control **512** is configured to maintain a controlled drawdown pressure of the well over time as determined by the output of the flowback model **514** in order to generate a recommended choke control setting. In blocks **528** to **538** the automatic choke control **512** may receive input **522** from the wellhead pressure sensor **502**, input **524** from the multiphase flow meter **504**, an input **525** from the solids analyzer **505**, input **526** from the continuous chemical analyzer **506**, as well as other inputs from the flowback model **514** and possibly other sources that are used to detect and/or determine unwanted conditions such as sand, salinity, temperature, gas saturations, or oil saturations changes.

[0063] In block **542**, the automatic choke control **512** can generate a choke control signal **516** based on the recommended choke control setting derived from the drawdown pressure analysis **540** or a choke control signal suitable for addressing the unwanted condition(s) determined or detected in blocks **528** to **538**. In this manner, the recommend choke setting recommended in block **540** may be overridden with another suitable choke settings if there is a prediction or measurement indicative of unwanted conditions such as damage to the well. For example, if rock failure, slug formation, fracture surface area loss, insufficient flow to lift the liquids and/or solids or excessive formation solids are determined or detected, then the choke controller **512** may override the choke setting recommendation from block **540** and generate an alternative choke control signal at block **542** to adjust the choke **508** based on the specific failure condition(s) that is determined or detected. For example each overridden choke control signal may be predefined and stored in a lookup table accessible to the automatic choke control **512**. Moreover, if more than one failure condition is detected or determined, the overridden choke control signal may be based on a predefined priority schedule. For example, any overridden choke control signal output from block **542** may be based on the most dangerous failure condition determined or detected.

[0064] However, if there are no determined or detected failure conditions damage, then the choke control signal recommendation from block **542** is not overridden at block **542** and the choke control setting is generated at block **542** based on the choke control signal recommendation of block **540**.

[0065] In one embodiment, the flowback model **514** can include certain parameters related to near wellbore fractures, such as unpropped fracture area and/or fracture conductivity in the near wellbore region. Note that fracture conductivity is based upon the propped fracture width and permeability of the proppant. A safe drawdown envelope can be estimated based on the flowback model **514** using these certain parameters together with reservoir mechanical and hydraulic properties. The safe drawdown envelope can be defined such that it avoids tensile failure of the formation. In this configuration, the solids content of the flowback fluid (e.g., the amount of different types of solids such as proppant, formation rock, fines, etc.) as measured by the solids analyzer **505** can be compared against predefined threshold levels (which can be derived from historical data of produced solids in similar or like wells or other methods) in order to identify a change in the parameters related to near wellbore fractures. The flowback model **514** can then be dynamically updated to accommodate the identified change in the parameters related to near wellbore fractures. The updated flowback model **514** can then used to dynamically update the safe drawdown envelope (e.g., safe zone depicted in FIG. **13**) such that it accounts for the change in near wellbore fractures over time during the flowback operations. Thus, the control scheme is linked to the behavior of the fractures in the near wellbore region, captures the uncertainties of the fracture properties in the near wellbore region, and computes safe operating envelopes for flowback and early production. The comparison of the solids content of the flowback fluid and the predefined threshold levels can also be used to identify risks of fracture failure and pinchout. Upon identifying any of these conditions, the choke control signal **516** can be dynamically adjusted such that it mitigates the detected condition(s).

Chemical Analyses

[0066] At block **528** in FIG. **4**, the output **526** of the chemical analyzer **506** may be used to determine a loss of fracture surface area or productive area in the formation. The choke setting recommendation from block **540** may be overridden based on the prediction of loss of fracture surface area or productive area in the formation.

[0067] Chemical analysis of the produced oil/gas/water may be used to monitor how the chemistry of the fracturing fluid changes over the flowback period as a result of its contact with a stimulated reservoir. Continuous monitoring of parameters such as conductivity, total dissolved solids (TDS), pH, temperature, total hardness, and total alkalinity may provide insight regarding the rock-fluid interaction. The measurements of temperature, pH, total hardness, and total alkalinity obtained by the chemical analyzer **506** relate to precipitate potential production of impairing minerals, and an understanding of these parameters can assist in understanding scaling potential. Thus, in one embodiment, if scale formation is measured or determined, and the amount of scale is determined to be excessive, the choke controller may be configured to generate a choke control signal to set the orifice size smaller or to close the choke.

[0068] Also, the salinity (or a single ionic species such as chloride) that is measured during flowback is directly linked to the reservoir that is connected to the producing hydraulic fracture network (HFN). Each sample of the flowback fluid is essentially a distinct measurement in time of the equilibration process between the fracturing fluid and the formation chemistry. In embodiments, continuous salinity measurements may also be performed. FIG. **14** shows plots of measurements of total dissolved solids (TDS) in the flowback fluid as a function of $\text{time}^{1/2}$ for a plurality of wells. As shown in FIG. **14**, each plot steadily increases, and is expected to reach an asymptote at salt concentration close to

that of the native reservoir conditions. This is likely a reflection of the fracture aperture distribution along the radial flow paths in FIG. **11**A and its signature may also indicate regional distributions due to rock type changes. These curves of salinity vs. time$^{1/2}$, have been observed to be similar for similar sized completions in the same formation and in the same field. As such they can be used as type curves for interpreting data acquired for new wells. If during the flowback from new wells, rapid, or otherwise unexpected changes in the graph or slope of the salinity vs. time$^{1/2}$ curves could indicate loss of connected fracture surfaces area. Therefore these curves, correlated with wellhead (and calculated bottomhole) pressure data, can be used as input for the choke control system.

[0069] The above-mentioned equilibration can be observed by taking multiple samples of these flowback fluids over time, and a change in the pattern of the chemistry evolution (e.g., change in chlorides slope vs. time$^{1/2}$) would indicate a change in the chemistry that was coming to equilibration with the fracturing fluid. This could be due to a change in geometry (e.g., losing connectivity with the chemistry contributed from a zone), or this could be an event brought about by crossing a pressure threshold (e.g., influx of produced fluids from an underpressured section of the reservoir). Thus, in one embodiment, the choke control signal generated by the choke controller at block **624** in FIG. **6** may be based on a change in slope of the ionic strength, salinity, chlorides salt concentrations, etc. as a function of time$^{1/2}$.

Slug Formation

[0070] As shown in FIG. **4**, at block **530**, if slug formation or slug flow is determined, an override choke setting may be generated to override the choke setting recommendation of block **540**. The term "slug flow" relates to a multiphase-fluid flow regime characterized by a series of liquid plugs (slugs) separated by a relatively large gas pockets. The resulting flow alternates between high-liquid and high-gas composition. The presence of slug flow may indicate a condition that is damaging to fractures in the formation. Slug formation can be determined from the calculated flow rates and the modeled pressure distributions. The frequency of determined slugs may be monitored and based on that frequency, the recommended choke setting may be overridden to change the choke setting to alter the frequency in a case where it is determined that the frequency of the slugs is damaging the fractures. Particular methodologies for predicting slug formations are described below with respect to FIGS. **15** to **17**. In some cases, the model may determine that slug flow is beneficial and the choke would be adjusted accordingly over variable periods of limited durations. In yet further cases, constant slug flow may be encouraged during the flowback operations if other failure modes are not triggered or have limited negative impact.

Tensile Rock Failure

[0071] At block **532** the automatic choke control **512** may determine tensile rock failure and generate an override choke setting based on the determined pressure distributions from the flowback model **514**. Tensile rock failure relates to breakage of the formation rock and is a function of the propped fracture width, the size of the near-wellbore area devoid of proppant, the closure stress, the reservoir pressure, the pressure in the wellbore in front of the fracture, the elastic properties and tensile strength of the rock (to be calibrated) and the pressure history in the wellbore in front of the fracture. Tensile failure occurs if a difference between the stress and the fluid pressure in the formation exceeds an effective formation tensile strength.

[0072] As noted above, tensile rock failure of the reservoir rock may be determined based on the above-mentioned modeled pressure distributions in the reservoir. Also, the risk of tensile rock failure may be based on the type of reservoir rock. If tensile rock failure is determined and formation failure has been identified as a high impact risk for the well, then the override choke setting from block **532** may include a setting to throttle the choke **508** further so that the downhole pressure is increased for a time that allows the pressure transient in the formation to dissipate.

Solids Formation

[0073] The recommended choke setting from block **540** may also be overridden if it is determined at block **534** that the measured solids content of the flowback fluid exceeds a predetermined threshold. The measured solids content is based on the output of the solids analyzer **505**. If the threshold is exceeded, then a suitable choke control signal that is intended to reduce the solids content in the flowback fluid can be generated at block **542** and supplied to the choke **508**.

[0074] Particle concentrations may be monitored during flowback operations by the solids analyzer **505**. In one embodiment a continuous solids monitoring acoustic device is used to monitor and determine if solids are being produced at all, if the solids flow rate is continuous or if the solids rate increases at some stages and then stabilizes or disappears. In addition, as part of the solids monitoring process, several samples of solids can be collected in the field to be sent for lab analysis to then define what types of solids were produced (i.e. formation-like solids, precipitation scale or proppant). Some on site analysis may be done depending on the complexity and available technologies.

[0075] Solids in the flowback fluid may come from the fracture (proppant) and/or from the formation (through formation failure) or even from the wellbore if prior operations did not leave the drain cleared. The presence of proppant in the flowback fluid at the surface may indicate reduction of fracture apertures and the possibility of bed formation in the undulating parts of the horizontal sections of the well piping (e.g., the production liner **210** of FIG. **1**). Also, the presence of formation rock in the flowback fluid at the surface may indicate damage to the formation reservoir and propped fracture network.

[0076] If reservoir rock is detected, a decision can be made about whether a threshold indicative of damage to the formation reservoir and fracture network has been reached based on both a combination of rate of production of those solids and total amount produced. If proppant is detected, a decision can be made about whether a threshold indicative of damage to the fracture apertures has been reached based on the rate of production and total amount of proppant produced, which can be used to estimate the fraction of proppant returned to the surface. Thus, in one embodiment, the override choke control signal generated at block **542** may be based on the measurement of the amount of proppant and/or formation rock returned to the surface. For sand or proppant production, the difference between closure pres-

sure and bottomhole pressure may be monitored to determine if a threshold is exceeded. The closure pressure data may be determined from a post fracture job analysis. In one embodiment, if the difference between closure pressure and bottomhole pressure exceeds a threshold, then the override choke control signal may be generated at block **542**, and if the difference is less than the threshold, an override choke control signal may not be generated at block **542**.

[0077] Even if the solids production is not severe enough (above the respective thresholds discussed above) to be indicative of damage to the fractures or to the formation rock, the solids production may still pose problems for production facilities and pipeline components on the surface. For example, the solids production rate may cause problems for the production facilities and the total amount of solids produced may be a problem for filling traps and filters.

Flow Measurements

[0078] At block **536** a determination is made whether one or more measured flow rates measured by the multiphase flow meter **504** is above a predefined limit. If the limit is exceeded, then a suitable choke control signal setting to override the recommended choke setting of block **540**. As an example, if the flow rate of water exceeds a predetermined limit, then a suitable choke control signal that is intended to reduce the flow rate of water can be generated at block **542** and supplied to the choke **508**. Erosion probes may provide relevant information about the extent of the potential damages and dynamics of the erosion of the production system.

Wellhead Pressure

[0079] At block **538** a determination is made whether the wellhead pressure is above or below a predefined limit. For example, above a certain limit could correspond to not having enough flow and loading the well with water, while below a certain limit could correspond to some kind of formation failure (e.g. perforation collapse). If the limit is exceeded, then a suitable choke control signal that is intended to reduce the wellhead pressure can be generated at block **542** and supplied to the choke **508**.

[0080] While not shown explicitly in FIG. **4**, flowback data from other neighboring wells may be used as part of the control scheme carried out by the automatic choke control **512**. For example, such flowback data can be used to derive one or more of the threshold limits for predicting or detecting the conditions in blocks **528** to **538**, as described above.

[0081] One problem with wellhead measurements is that the wellbore storage of fluids causes water, hydrocarbon fluids, and solid production rates at the surface to lag behind the changes to bottomhole pressure that cause such production rate changes at the surface. Pressure information travels at the speed of sound, so that pressure events at a bottomhole location generate a corresponding signal at the wellhead only a few seconds later. However, the corresponding change in the bulk flow of material (water, hydrocarbons, and solids) that accompanies that pressure event, will arrive at the surface minutes to hours later. For example, if the well piping volume is two hundred barrels, and the nominal flowback rate is fifty barrels per hour, then the measured flowrate data reflects what occurred three to four hours previously. In order to account for this inherent production lag time caused by wellbore storage of fluids, the control system **510** may be configured to calculate the lag time period between a wellhead pressure change (with corresponding downhole pressure change) and a corresponding change to the production flow rates of fluids and solids at the surface due to the wellbore storage of fluids. This lag time can be used to dynamically correlate the wellhead pressure data **502** (with the corresponding determined or measured bottomhole pressure data) over time to fluids and solids production rates at the surface over time. Also, the control system **510** may be configured to dynamically adjust the choke control setting based on such correlations.

[0082] The calculations of the flowback model **514** in determining the pressures and fluid compositions in the well including bottomhole pressure and other bottomhole conditions can involve a wide variety of data, including a set point or other predefined parameter, data from at least one other well, data characterizing mineralogy of the hydraulically fractured reservoir, data derived during drilling the well, etc.

[0083] Also note that previously acquired flowback and production data from at least one other well can be used to tune the flowback model **514**. Such other well(s) may be geographically nearby (i.e., in the same basin) the well that is undergoing flowback operations. Alternatively, such other well(s) may be located in other basins having similar properties to that of the well that is undergoing flowback operations. In those cases, the flowback model **514** is more likely to be more predictive. Previously acquired and stored flowback data from such other well(s) may assist in providing a calibrated control loop where bottomhole pressure upper and lower bounds are estimated to define a safe flowback operational envelope for other subsequent wells. Using a control flow loop that uses historical field data to enhance the current data set may lead to better predictions of bottomhole pressure than can be made before actual separator and fluid composition data is obtained.

[0084] FIG. **5** shows an example computing system **300** that can be used to implement the control system **510** or parts thereof. The computing system **300** can be an individual computer system **301**A or an arrangement of distributed computer systems. The computer system **301**A includes one or more analysis modules **303** (a program of computer-executable instructions and associated data) that can be configured to perform various tasks according to some embodiments, such as the tasks described above. To perform these various tasks, an analysis module **303** executes on one or more processors **305**, which is (or are) connected to one or more storage media **307**. The processor(s) **305** is (or are) also connected to a network interface **309** to allow the computer system **301**A to communicate over a data network **311** with one or more additional computer systems and/or computing systems, such as **301**B, **301**C, and/or **301**D. Note that computer systems **301**B, **301**C and/or **301**D may or may not share the same architecture as computer system **301**A, and may be located in different physical locations.

[0085] The processor **305** can include at least a microprocessor, microcontroller, processor module or subsystem, programmable integrated circuit, programmable gate array, digital signal processor (DSP), or another control or computing device.

[0086] The storage media **307** can be implemented as one or more non-transitory computer-readable or machine-readable storage media. Note that while in the embodiment of FIG. **5**, the storage media **307** is depicted as within computer system **301**A, in some embodiments, storage media **307** may be distributed within and/or across multiple internal and/or

external enclosures of computing system **301**A and/or additional computing systems. Storage media **307** may include one or more different forms of memory including semiconductor memory devices such as dynamic or static random access memories (DRAMs or SRAMs), erasable and programmable read-only memories (EPROMs), electrically erasable and programmable read-only memories (EEPROMs) and flash memories; magnetic disks such as fixed, floppy and removable disks; other magnetic media including tape; optical media such as compact disks (CDs) or digital video disks (DVDs); or other types of storage devices. Note that the computer-executable instructions and associated data of the analysis module(s) **303** can be provided on one computer-readable or machine-readable storage medium of the storage media **307**, or alternatively, can be provided on multiple computer-readable or machine-readable storage media distributed in a large system having possibly plural nodes. Such computer-readable or machine-readable storage medium or media is (are) considered to be part of an article (or article of manufacture). An article or article of manufacture can refer to any manufactured single component or multiple components. The storage medium or media can be located either in the machine running the machine-readable instructions, or located at a remote site from which machine-readable instructions can be downloaded over a network for execution.

[0087] It should be appreciated that computing system **300** is only one example of a computing system, and that computing system **300** may have more or fewer components than shown, may combine additional components not depicted in the embodiment of FIG. **5**, and/or computing system **300** may have a different configuration or arrangement of the components depicted in FIG. **5**. The various components shown in FIG. **5** may be implemented in hardware, software, or a combination of both hardware and software, including one or more signal processing and/or application specific integrated circuits.

[0088] Further, the operations of the workflow described above may be implemented by running one or more functional modules in information processing apparatus such as general purpose processors or application specific chips, such as ASICs, FPGAs, PLDs, SOCs, or other appropriate devices. These modules, combinations of these modules, and/or their combination with general hardware are all included within the scope of the disclosure.

Control System—Flowback Model

[0089] FIG. **6** illustrates an embodiment of the flowback model **514** including sub-models that may be used as part of the flowback model **514**. The flowback model **514** is a system of mathematical equations that characterize the pressure distributions and fluid flow in the hydraulically fractured reservoir rock and the well piping over time as a function of wellhead pressure. Specifically, the flowback model **514** includes coupling logic **614** that joins a well model **642** and a fracture flow model **644**.

[0090] The well model **642** models the flow of flowback fluid in the well piping over time as a function of wellhead pressure. The well model **642** receives input from a particle transport model **646** and a flow model **648**. The particle transport model **646** models the movement of solid particles along the well and the flow model **648** models the movement of fluids along the well.

[0091] The fracture flow model **644** models the flow of flowback fluid in the hydraulically fractured reservoir rock over time as a function of wellhead pressure. The fracture flow model **644** receives input from a fluid-fluid displacement model **650** within the fractures, a geomechanical model **652** of geomechanical properties of the formation rock, and reservoir model **654** that models the inflow of fluid into the fractures. The geomechanical model **652** models the interaction between the formation's rocks, stresses, pressures, and temperatures and the influence of these parameters on the fractures. The fluid-fluid displacement model **650** models the displacement of oil, gas, and water by hydraulic fracturing fluid in the reservoir rock and/or the displacement of the hydraulic fracturing fluid be the reservoir fluids. The reservoir model **654** models the physical space of the reservoir (e.g., reservoir **202** of FIG. **2**) by an array of discrete cells, delineated by a grid, which may be regular or irregular. The array of cells is usually three-dimensional, although one-dimensional and two-dimensional models can be used. Values for attributes such as porosity, permeability and water saturation are associated with each cell. The value of each attribute is implicitly deemed to apply uniformly throughout the volume of the reservoir represented by the cell.

[0092] The flowback model **514** may have a plurality of input parameters. As shown in an example in FIG. **7**, the flowback model **514** may have seventeen input parameters related to fractures, the reservoir, the wellbore layout and geometry and completion layout and geometry, and fluids expected to flow in the well.

[0093] Also, as shown in an example in FIG. **8**, the flowback model **514** may have a plurality of outputs that vary with time including: a one-dimensional (radial direction from the wellbore) pressure distribution along fractures; one-dimensional fluid saturation distributions for oil/gas/water along fractures; a one-dimensional pressure distribution along the length of the well to the surface; and one-dimensional fluid saturation distributions for oil/gas/water along the length of the well to the surface. This pressure distribution along the length of the well over time can be used to characterize the bottomhole pressure over time. Also, the one-dimensional radial distributions of pressure and fluid saturations along the fractures can be modeled at various locations (e.g., in perforation zones **220**) along the well. A visual representation of the one-dimensional pressure and fluid saturation distributions is shown in FIG. **9** as a function of radial distance from the wellbore.

[0094] The flowback model **514** can solve for pressure drop (e.g., pressure differential) in the well, for example, through use of momentum equations. Such momentum equations, for example, may account for factors such as fluid potential energy (e.g., hydrostatic pressure), friction (e.g., shear stress between conduit wall and fluid), and acceleration (e.g., change in fluid velocity). As an example, one or more equations may be expressed in terms of static reservoir pressure, a flowing bottomhole pressure, wellhead pressure, and flowrates for different phases of produced fluids at the surface during the flowback operations. As an example, equations may account for vertical, horizontal or angled arrangements of equipment. In another example, the flowback model may implement equations that include dynamic conservation equations for momentum, mass and energy. As an example, pressure and momentum can be solved implicitly and simultaneously and, for example, conservation of

mass and energy (e.g., temperature) may be solved in succeeding separate stages. Various examples of equations may be found in a dynamic multiphase flow simulator such as the simulator of the OLGA™ simulation framework (Schlumberger Limited, Houston, Tex.), which may be implemented for design and diagnostic analysis of the flowback operations for hydraulically fractured tight reservoirs. OLGA, being a transient multi-phase wellbore flow simulator, can be used to calculate the bottomhole pressure at one or more bottomhole locations inside of the well. To do this, OLGA uses the three-fluid mathematical model that is originally developed and validated for the horizontal flow configurations. The mathematical model in OLGA simulator is summarized in K. Bendiksen et al, "The dynamic two-fluid model OLGA: theory and application," SPE Prod. Eng., 1991, pp. 171-180, herein incorporated by reference in its entirety. Typically, to calculate the bottomhole pressure, the boundary and initial conditions are specified before the simulation. The initial conditions include the distribution of phase volume fractions, velocities, pressure and other variables inside of the well. The boundary conditions typically include the wellhead pressure specified at the outlet of the well and no-flow boundary condition at the bottom of the well. The wellhead pressure can change over in time (transient) and hence specified as a series of time steps. Once these conditions are specified, the simulation is launched. In course of the simulation, the system of conservation equations is solved at each time step to derive the distribution of volume fractions, velocities, pressure (and other variables) in the well, including the bottomhole pressure at one or more bottomhole locations in the well.

[0095] FIGS. **11**A to **11**E illustrate features of an exemplary fracture flow model that can be configured to characterize the flowback fluid flow through the fractures of a reservoir. FIG. **11**A shows a two dimensional profile through a hydraulically fractured reservoir around a circular wellbore **1120**. As shown in this view, a hydraulic fracture network (HFN) **1122** is depicted as having a plurality of concentric ellipses **1130** and a plurality of radial flow lines **1132**. The radial flow lines **1132** initiate from a central location about the wellbore **1120** and extend radially therefrom. The radial flow lines **1132** represent a flow path of fluid from the formation surrounding the wellbore **1120** and to the wellbore **1120** as indicated by the arrows. The HFN **1122** may also be represented in the format as shown in FIG. **11**A.

[0096] Due to an assumed contrast between the permeability of the matrix and that of the HFN **1122**, global gas flow through the reservoir consisting of both the HFN **1122** and the formation matrix can be separated into the gas flow through the HFN **1122** and that inside of the matrix blocks **1128**. The pattern of gas flow through the HFN **1122** may be described approximately as elliptical as shown in FIG. **11**A.

[0097] The HFN **1122** uses an elliptical configuration to provide a coupling between the matrix and HFN flows that is treated explicitly. A partial differential equation is used to describe fluid flow inside a matrix block that is solved analytically. Three-dimensional gas flow through an elliptic wire mesh HFN can be approximately described by:

$$\frac{\partial p_f}{\partial t} - \frac{1}{x}\frac{\partial}{\partial x}\left(x\kappa_f \frac{\partial p_f}{\partial x}\right) = \frac{q_g}{\phi_f \frac{\partial \rho_f}{\partial p}}, \tag{1}$$

where t is time, x is the coordinate aligned with the major axis of the ellipse, p_f and ρ_f are fluid pressure and density of fluid, φ_f and κ_f are the porosity and the x-component of the pressure diffusivity of the HFN, and q_g is the rate of gas flow from the matrix into the HFN. All involved properties may be a function of either t or x or both.

[0098] For each time t, calculations of fluid pressure using equation (1) may begin from the outmost ring of the elliptical reservoir domain and end at the center of the HFN **1122** at wellbore **1120**, or in the reverse order. Fluid pressure along the elliptical domain's boundary is taken as that of the reservoir before production. It may be assumed that no production takes place outside of the domain.

[0099] Outside of the HFN, equation (1) still applies nominally, but with $q_g=0$, $\varphi_f=\varphi_m$ and $\kappa_f=\kappa_m$, where φ_m and κ_m are the porosity and the pressure diffusivity of the reservoir matrix. Given q_g there are various ways available to solve equation (1), either analytically or numerically. Due to the complex nature of the HFN and fluid properties, numerical approaches may be used for the sake of accuracy. An example of numerical solution is given below.

[0100] Dividing the elliptic reservoir domain containing the HFN into N rings, the rate of gas production from a reservoir matrix into the HFN contained by the inner and outer boundaries of the k-th ring is

$$q_{gk}=q_{gxk}A_{xk}+q_{gyk}A_{yk} \tag{2},$$

where A_{xk} and A_{yk} are the total surface area of the fractures inside of the ring, parallel to the major axis (the x-axis) and the minor axis (they-axis), respectively, and q_{gxk} and q_{gyk} are the corresponding rates of fluid flow per unit fracture surface area from the matrix into the fractures parallel to the x- and y-axis, respectively. Fluid pressure p_f and the rate of gas production into the well can be obtained by numerically (either finite difference, finite volume or a similar method) solving equation (1) for any user specified initial and boundary conditions and by coupling the model with a well model.

[0101] Total surface area of fractures contained inside of the k-th ring can be calculated by

$$A_{xk} = 4h_k\left[\sum_{j=-N_{xo}}^{N_{xo}} \sqrt{x_k^2 - 4(jL_{my}/\gamma)^2} - \sum_{j=-N_{xi}}^{N_{xi}} \sqrt{x_{k-1}^2 - 4(jL_{my}/\gamma)^2}\right] \tag{3}$$

$$A_{yk} = 4h_k\gamma\left[\sum_{i=-N_{yo}}^{N_{yo}} \sqrt{x_k^2 - 4(iL_{mx})^2} - \sum_{i=-N_{yi}}^{N_{yi}} \sqrt{x_{k-1}^2 - 4(iL_{mx})^2}\right]$$

where γ is the aspect ratio of the elliptical HFN, x_k and h_k are the location and the height of the k-th ring, L_{mx} and L_{my} are the distances between neighboring fractures parallel to the x-axis and the y-axis, respectively, as shown in FIG. **11**B. The N_{xo} and N_{xi} are the number of fractures parallel to and at either side of the x-axis inside the outer and the inner boundaries, respectively, of the k-th ring, and N_{yo} and N_{yi} are the number of fractures parallel to and at either side of the y-axis inside the outer and the inner boundaries, respectively, of the k-th ring.

[0102] The pattern of gas flow through the HFN **1122** may also be described based on fluid flow through individual matrix blocks **1128** as shown in FIG. **11**B. FIG. **11**B is a detailed view of one of the blocks **1128** of HFN **1122** of FIG. **11**A. As shown in this view, the direction of gas flow inside of a matrix block **1128** can be approximated as perpendicu-

lar to the edges of the matrix block **1128**. Fluid flow is assumed to be linear flow toward outer boundaries **1140** of the block **1128** as indicated by the arrows, with no flow boundaries **1142** positioned within the block **1128**.

[0103] Fluid flow inside a rectangular matrix block **1128** can be approximately described by

$$\frac{\partial p_m}{\partial t} - \kappa_m \frac{\partial^2 p_m}{\partial s^2} = 0 \tag{4}$$

$$p_m(t, s) = p_r$$

$$p_m(t, L_s) = p_f(t)$$

$$\frac{\partial p_m}{\partial s}\bigg|_{s=0} = 0,$$

where s is the coordinate, aligned with the x-axis or y-axis, L is the distance between the fracture surface and the effective no-flow boundary, p_m is fluid pressure and p_r is the reservoir pressure. Equation (4) can be solved to obtain the rate of fluid flow from the matrix into the fractures inside the k-th ring

$$q_{gxk} = ⑦ \frac{dp_{fk}}{du} ⑦ \frac{L_y}{2} erfc ⑦ \frac{L_y}{4\sqrt{⑦}} + 2\sqrt{⑦}\, e ⑦\, du \tag{5}$$

$$q_{gyk} = ⑦ \frac{dp_{fk}}{du} ⑦ \frac{L_y}{2} erfc ⑦ \frac{L_y}{4\sqrt{⑦}} + 2\sqrt{⑦}\, e ⑦\, du,$$

⑦ indicates text missing or illegible when filed

where p_{fk} is the pressure of the fluid residing in fractures in the k-th ring and ρ_m is the density of the fluid residing in the matrix. The coupling p_{fk} and q_{gk} calculations can be either explicit or implicit. It may be implicit for the first time step even if the rest of the time is explicit.

[0104] Conventional techniques may also be used to describe the concept of fluid flow through a dual porosity medium. Some such techniques may involve a one-dimensional pressure solution with constant fracture fluid pressure, and depict an actual reservoir by identifying the matrix, fracture, and vugs therein as shown in FIG. **11**C, or depicting the reservoir using a sugar cube representation as shown in FIG. **11**D. Examples of conventional fluid flow techniques are described in Warren et al., "The Behavior of Naturally Fractured Reservoirs", SPE Journal, Vol. 3, No. 3, September 1963.

[0105] Examples of fracture modeling that may be used in the modeling described herein are provided in Wenyue Xu et al., "Quick Estimate of Initial Production from Stimulated Reservoirs with Complex Hydraulic Fracture Network," SPE 146753, SPE Annual Tech. Conf. and Exhibition, Denver, Colo., 30 Oct.-2 Nov. 2011, the entire content of which is hereby incorporated by reference.

[0106] FIG. **11**E shows a flow chart depicting a method for fracture modeling. In one or more embodiments, one or more of the steps shown in FIG. **11**E may be omitted, repeated, and/or performed in a different order than the order shown in FIG. **11**E. Accordingly, the scope of modeling hydraulic fracturing induced fracture networks as a dual porosity system should not be considered limited to the specific arrangement of steps shown in FIG. **11**E.

[0107] In element **1102**, well data may be loaded for three-dimensional modeling. For example, the data listed below in Table 1 may be obtained for three-dimensional modeling.

TABLE 1

Category	Data Item
Well head	Location (x, y), Kelly bushing, total depth
Well path	Deviation survey
Well logs	Conventional log and interpretations (gamma, resistivity, porosity, Sw, density, neutron, caliper etc.), Logging While Drilling (LWD) Lithology (ELAN interpretations), Mineralogy (ECS) and Toc, Sw, Perm, porosity, AdsGas, freeGas etc. (Shale Gas Advisor) Lithofacies (Cluster - reservoir quality indicator) Rock mechanical property and stress (DSI dipole shear sonic imaging/Sonic Scanner/MDT (modular formation dynamics tester) packer module) Borehole image (FMI, formation micro images) and interpretations; fracture categories, corrections and analyses
Core data	Lab test of petrophysical (k, phi, sw etc.), and geomechanical (UCI (ultrasonic casing imager), elastic properties, including anisotropy) for possible log calibration
Isothermal	Shale rock adsorption/desorption test data; gas content (Langmuir pressure and volume constants); single and multi-component data
Well tops	Marker well name, depth, dip and azimuth if any
Structure	Surface, faults interpretation if any
Seismic	Original volume, and various derived attributes, and loading parameters
Velocity	Sonic log and check shots or velocity models or parameters
Fracturing Job	Stages, gases, liquid and proppants volumes, schedules, properties of injected materials
Micro Seismic	Variety of attributes, pumping records, rate, pressure, ISIP (instantaneous shut in pressure) data
Production	Production surveys, tracer test, well testing, and production dynamic data
Completion	Wellbore data, perforation, length
Fluid & Rock	Gas composition, water and oil, and other PVT (pressure-volume-temperature) properties; saturation functions
Reports	Any previous studies and reports

[0108] In element **1104**, surface and fault interpretations may be performed in the time domain. Specifically, surface seismic interpretation can be accelerated with autotracking, and fault interpretation can be expedited through ant-tracking using simulation software. With the majority of the well data in the depth domain, seismic results may also be depth-converted and integrated. Often, check shots, sonic logs, and velocity data are available to build the velocity model. In one or more embodiments, interval velocities produced for each stratigraphic unit (zone) are satisfactory for modeling reservoirs.

[0109] In element **1106**, depth conversion may be performed to convert time domain seismic information such as original seismic data volumes or any other special seismic attributes, interpreted surfaces, and faults. Depth surfaces and/or well tops may be used to build model horizons.

[0110] At this stage, the horizons and well controls, together with proper fault modeling, segment definition, and boundary conditions are used to create a three-dimensional structure model (element **1108**). The three-dimensional model provides a framework for further geomechanical zone modification, log upscaling, seismic attributes resampling, data analysis, correlation development, fracture simulation driver development, discrete fracture modeling, and reservoir simulation gridding.

[0111] In element **1110**, a discrete fracture network (DFN) may be generated. Specifically, edge enhancement may be performed to identify faults, fractures, and other linear anomalies using seismic data. In this case, the seismic data may be conditioned by reducing noise in the signal, spatial discontinuities in the seismic data (edge detection) are then enhanced, and finally a seismic three-dimensional volume including automated structural interpretations is generated, which significantly improves the fault attributes by suppressing noise and remnants of non-faulting events. Fault patches or planes of discontinuity can then be extracted from the three-dimensional seismic volume. The patches of faults or fractures are analyzed and edited, and fracture/fault patches can be directly converted as a deterministic DFN.

[0112] In shale gas reservoir applications, the three-dimensional seismic volume is used to identify significant fault and karst features. The karst features may be extracted and modeled as faults in conjunction with production, tracer testing, and well testing analysis to reveal the large-scale reservoir connectivity. A general observation in terms of reservoir connectivity is that wells several miles apart may have pressure communications. The pressure communications may be considered by manually adding fractures in the fracture model.

[0113] Although open natural fractures may not be identified from core samples, borehole images such as formation micro-images (FMI), OBM (oil based mud) images, UBI (ultrasonic borehole imager) images, and LWD (Logging While Drilling) images may be used to interpret natural fractures (e.g., open, partially opened or healed fractures) and drilling induced fractures, which are subject to easier opening by hydraulic fracturing than virgin shale rock. In view of this, all types of interpreted fractures may be considered as constituting a "natural" or "pre-existing" fracture network that partially controls hydraulic fracture network intensity and distribution. Thus, one use of the "natural" network information is to assist the design of well path and hydraulic fracturing.

[0114] FMI interpreted fractures (and intensity logs) may also be classified, analyzed, and correlated with rock properties, geomechanical zones, and other seismic drivers. Further, various seismic attributes may be resampled into the three-dimensional model. With flexible functionalities in the three-dimensional model space, different fracture intensity drivers may be evaluated. The fracture intensity drivers include, but are not limited to, distance to faults, lithological properties, discontinuous properties, or neural network train-estimation derived properties (care should be taken to identify correlated drivers). With proper property drivers, fracture intensity three-dimensional distributions may be achieved, mostly with stochastic simulations or possible deterministic methods. Those skilled in the art will appreciate that different types or sets of fracture intensity properties can be simulated separately with different drivers to reflect specific natural characteristics. With known well control fracture dips and azimuths input as constants, two-dimensional or three-dimensional properties, and specific fracture geometry specifications, three-dimensional discrete fracture network (DFN) can be generated.

[0115] In element **1114**, microseismic (MS) mapping and post-hydraulic fracturing (PHF) network modeling may be performed. For example, based on the available field data, a proximal solution may be provided. As discussed above, MS monitoring has been used in the shale gas reservoir to monitor fracture propagation and the hydraulic job process, and to control fracture propagation through pressure/rate change and techniques such as fiber-assisted or particle-assisted diversion. The significant features of aerially similar MS events distribution indicates that the shale gas reservoir PHF system is a fracture network, and therefore various operational techniques may be used to create additional aerial coverage and an intensified PHF network.

[0116] In one or more embodiments, an MS event envelope is used to estimate a three-dimensional hydraulic fracturing stimulated reservoir volume (ESV) and then hydraulic fracturing job parameters are applied to estimate dynamic and propped fracture conductivity (possible permeability and width estimation). To estimate the PHF network, the MS event envelope may be extracted from the three-dimensional model. In simple cases, a two-dimensional mapview can be used to obtain the outside boundary. Vertically, the fractures growing into a non-reservoir formation may be considered for volume correction when calculating fluid and proppant conservations. With certain fracture propagation model assumptions, fluid and proppant mass conservation and fracture width distribution and fracture network intensity can be estimated and corresponding propped fracture width can be calculated. By applying laboratory results, fracture conductivity (FCD) may be estimated. "Natural" fracture DFN within an MS event envelope may be assumed to be opened and propped for evaluation in a base case reservoir simulation.

[0117] In element **1116**, fracture attributes and discrete fracture network (DFN) upscaling may be performed. For example, fracture attributes may be associated with a DFN. During DFN modeling as discussed above with respect to element **1110**, geometry parameters may be assigned to each fracture such as: surface area, dip angle, and dip azimuth. Other examples of attributes that may be assigned or calculated are aperture and permeability. The aperture data may be related to the calculations of porosity permeability. For both "natural" fracture networks and PHF networks with

proper aperture and permeability, respectively, upscaling may be performed. The "natural" fracture network may serve as a background reservoir, and the PHF network, as modified with the MS and fracture job data, may serve as a stimulated reservoir volume with enhanced reservoir properties.

[0118] In one or more embodiments, the discrete fracture system may be upscaled to a dual porosity/permeability reservoir model and then use simulator(s) to model the reservoir dynamics. Examples of properties generated by the upscaling process include fracture porosity, fracture permeability, Sigma (shape) factor defining the connectivity between fractures and matrix, and fracture spacing along local directions (I, J, K) for each grid cell. Those skilled in the art will appreciate that the dual porosity modeling approach may not be suitable for all cases. A proper simulation should be based on a proper understanding of the DFN and PHF fracture systems and corresponding shale production mechanism.

[0119] Elements **1110**, **1114** and **1116** may be combined or replaced with an alternative methodology as shown in element **1117**. More specifically, in element **1117** fracture geometry is computed, fracturing pressure is estimated, fracture conductivity and distribution of proppants are estimated, and fracture productivity is determined.

[0120] In element **1112**, the structure from element **1108** and the DFN from element **1110** may be used to perform geomechanical modeling, where the results are used for generating a well path and hydraulic fracturing treatment (HFT) design with stress constraints and fault/karst avoidance. Specifically, the DFN including the FMI interpreted fractures may be used to generate the HFT design, where the natural tendency of the formation to fracture may be taken into account in order to optimize the hydraulic fracturing. In other words, based on the fracture orientations, network distribution and intensity of the natural fracture determined in element **1110**, proper well orientation and fracturing stage and perforation cluster designs may be generated to maximize fracture intensity and control PHF network distribution. Further, the results are also fed into element **1121**, as expressed below as the geomechanical modeling repeated in element **1123**.

[0121] Some geomechanical and petrophysical properties may be obtained at well location for example through core analysis and log interpretation. Further, varieties of seismic attributes reflect lithofacies and mechanical and petrophysical formation characteristics. A geostatistical approach may be used to model the properties in a three-dimensional distribution using well data as the primary data source and the seismic as secondary constraints. For example, lithofacies representations may correspond to a cluster result derived from a suite of basic logs (gamma, resistivity, density). The clusters (or lithofacies) data is used to classify mechanical and petrophysical properties. Within each cluster, constant values may be assigned, or conduct stochastic simulations may be performed.

[0122] The properties modeled using well logs and seismic include, but are not limited to, cluster facies, porosity, water saturation, permeability, total organic carbon (TOC), shale gas content and Young's modulus, Poisson's ratio, etc. In one or more embodiments, Sonic Scanner/DSI (dipole sonic image) derived parameters may be direction simulated and used to obtain final properties.

[0123] In element **1118**, the petrophysical properties such as effective porosity, water saturation, and gas content from the three-dimensional geological structure model generated in element **1108** may be used to estimate gas-in-place (GIP). In this case, the petrophysical properties may also be processed using an uncertainty workflow to rank the risks of various aspects of the wellbore.

[0124] In element **1121**, a reservoir simulation may be performed.

[0125] The dual porosity reservoir properties (fracture permeability, etc.) upscaled from the DFN in element **1116** and petrophysical matrix properties (e.g., phie, Sw, etc.) by stochastic simulation may be utilized by the reservoir simulator. With a known well completion configuration and production control, production history matching may be pursued to confirm or modify the reservoir model, especially the fracture network geometry, fracture connectivity, and permeability. Further, experimental design methodology may be used to perform sensitivity analysis, assist the history-matching process, and improve the reservoir characterization. In addition, a full, automated, history-matching process may be used to link geological model variation and the reservoir simulation in an iterative process. If permeability change versus reservoir pressure is known, the impact of permeability decrease with production of flowback fluid may be considered.

[0126] In element **1123**, geomechanical modeling and stress analysis may be performed. Specifically, FMI interpreted drilling-induced fractures and possible wellbore breakouts may be used to determine stress direction and distribution. Sonic Scanner and DSI (dipole sonic image) data may also be used to estimate mechanical properties of rock formations and stresses. Wire line formation tester (e.g., modular formation dynamics tester or some other tester) tests and interpretation may be used to calibrate in-situ stress data (pore pressure and minimum stress). Further, some seismic attributes may be extracted to guide a three-dimensional stress field distribution. Using reservoir simulation software, a mechanical earth model (MEM) with rock mechanical properties, faults, fractures, overburden, underburden, side burden, complex geological structures, and pore pressure and stress/strain boundary conditions may be generated and used for pore pressure prediction, geomechanical modeling, and wellbore stability analysis. Geomechanical modeling packages (such as a stress analysis simulator) could simulate in-situ stress distribution, stress-sensitive permeability and porosity changes, and study hydraulic fracture propagation mechanism. Coupling geomechanical modeling (stress analysis simulation) with reservoir simulation may optimize reservoir development strategies, wellbore stability analysis, optimum mud weight design, formation subsidence, and casing damage analyses with reservoir depletion.

[0127] In element **1124**, well spacing, hydraulic fracturing design, and/or production optimization may be performed. In the case of production optimization, control parameters of the hydraulic fracturing process may be modified based on the reservoir simulation of element **1123** (i.e., where to create the fracture network, how intensified the network needs to be, and how to implement through operations). Further, based on reservoir characterization as proposed above, the following steps may be performed: 1) using the geological modeling result, particularly the DFN network information, geomechanical heterogeneity and stress field,

to conduct a geomechanical modeling study to provide qualitative guidance for a well path, well completion, fracture stages and cluster designs; 2) establishing a relationship among reservoir characteristics, job processes, various scenarios (e.g., well lengths, fracture stages, liquid and proppant volumes, etc.), and reservoir production behavior; 3) performing reservoir simulation sensitivity analysis (ensuring that the proper application of the dual porosity model is applied in simulation); 4) extracting guidelines for future design practices and operations.

[0128] Those skilled in the art will appreciate that portions of FIG. **11**E may be applied in various field development stages. For example, elements of FIG. **11**E may be performed to construct structural models and three-dimensional visualizations of a structural surface superimposed with seismic attributes to monitor live fracturing jobs and respond with operation modifications such as fiber diversion (e.g., a stage of slurry containing degradable fibers is used to create a temporary bridge within the fracture, and make a pressure increase and force fracture propagation into another zone or a different area of the same formation). In another example, elements of FIG. **11**E may be performed to distribute three-dimensional clusters in reservoirs (clusters denoting reservoir quality). Further, geostatistical property modeling may be used to upscale facies log and simulate with seismic attributes and neural network trained-estimation properties. In this case, the significant features of facies continuity may be confirmed with an additional cluster log, where the simulated three-dimensional result is used to guide well path design, targeting the best quality of the reservoir.

[0129] In yet another example, elements of FIG. **11**E may be performed to distribute the DFN in a three-dimensional reservoir and analyze the relationship between MS events response and "natural" fracture orientations. In this example, the total set of fractures may be divided into four subsets: N_S:N, N_S:S, E_W:E, and E_W:W. Drilling-induced fractures may be aligned with one subset (e.g., E-W) of natural fractures (thus the minimum stress direction is perpendicular to fracture strike in the E-W set). Following the workflow, the DFN network may be simulated, and MS events may be displayed over the DFN network. The MS events may be controlled by the minimum stress direction and the existing "natural" fractures. Specifically, MS events may align with the subsets of E_W:W and E_W:E, where the N_S sets help create the wide band nature of the MS events.

Control System—Choke Control

[0130] As described above, the drawdown pressure can be calculated from the determined pressure distributions output by the flowback model **514** (FIGS. **3** and **4**). For example, FIG. **12** illustrates schematically localized bottomhole and reservoir pressures at a downstream end of a production liner **1204** in a hydraulically fractured reservoir **1202**. When the choke **508** (FIGS. **3** and **4**) is partially open and fluids begin to move from the reservoir **1202** into the liner **1204**, the drawdown pressure will change over time. In the example shown in FIG. **12**, initially at time t=0, the reservoir pressure is 9,000 psi (radially uniform distribution) and the initial bottomhole pressure is 8,000 psi, resulting in an initial drawdown pressure of 1,000 psi at time t=0. Also, in the example shown in FIG. **12**, at time t=10 days, after at least some fluid has moved from the reservoir and into the liner **1204**, there is a non-uniform radial reservoir pressure distribution in which the pressure at a first, radially proximate region **1202***a* is 8,000 psi, at a second, radially distal region **1202***b* is 9,000 psi, and the bottomhole pressure is 7,000 psi. Thus, after 10 days, the average reservoir pressure is 8,500 psi, such that the drawdown pressure is 1,500 psi. Thus, in the example in FIG. **12** the drawdown pressure increased 500 psi in the span of 10 days.

[0131] The calculated drawdown pressure in the example of FIG. **12** may be continuously calculated and compared against a schedule of maximum/minimum allowable drawdown pressures over time as determined from a predetermined functional relationship, such as the curves shown in FIG. **13**. Such a schedule of drawdown pressures may be used by the automatic choke control **512** for determining the recommended choke setting in block **540**, as discussed above. FIG. **13** illustrates a safe zone **1302** in which to conduct the flowback operations. The safe zone **1302** is bounded by two drawdown curves: an upper curve **1304** for an upper limit of maximum allowable drawdown pressure; and a lower curve **1306** for a lower limit of maximum allowable drawdown pressure. The curves **1304** and **1306** in FIG. **13** may be obtained experimentally from sampling rock of the reservoir, such as reservoir **1202** in the example of FIG. **12**. For example, strength and permeability testing—ideally as a function of completion fluid type—may be done on each section of the reservoir that is expected to be contacted by the hydraulic fracture network (HFN) to determine the variability in rock strength. The initial flowback strategy may be tailored to the weakest section of the reservoir that would have an impact on production. Without these values it would not be possible to determine the initial drawdown limits in FIG. **13**, nor how they vary with time.

[0132] Turning back to FIG. **4**, at block **540** a comparison between the calculated drawdown pressure and the maximum allowable drawdown pressures on curves **1304** and **1306** may be used to make recommendations for adjustment of the choke **508**. For example, if the calculated drawdown pressure is outside of the safe zone **1302** in FIG. **13**, then adjustments to the choke **508** may be recommended to increase or decrease the bottomhole pressure. Specifically, if the calculated drawdown pressure at a respective time is above the safe zone **1302** (i.e., in the failure zone) in FIG. **13**, then a recommendation may be generated at block **540** to adjust the choke **508** to partially or fully close, to thereby limit damage to the reservoir. If the determined drawdown pressure at a respective time is below the safe zone **1302**, then a recommendation may be generated at block **540** to adjust the choke **508** to partially or fully open to increase the flow rate of flowback fluid to improve efficiency of the flowback operation.

[0133] Also, if the calculated drawdown pressure is within the safe zone **1302** of FIG. **13**, recommendations may be made to adjust the choke **508** while still operating in the safe zone **1302**. For example, if the calculated drawdown pressure is within the safe zone **1302**, there may be an opportunity to increase the flow rate of flowback fluid while still operating in the safe zone **1302**. For example, if the target flow rate of oil is higher than the measured flow rate and the calculated drawdown pressure is within the safe zone **1302**, then a recommendation can be made to adjust the choke **508** to open more to increase the flow of oil in the flowback fluid, while monitoring that the drawdown pressure does not exceed that of the upper curve **1304** in FIG. **13**.

Slug Formation

[0134] FIG. **15** illustrates a ternary diagram **1550** that includes vertices that represent single-phase gas, oil and water, while the sides represent two phase mixtures (e.g., gas-oil, oil-water and gas-water) and points within the triangle represents a three-phase mixture. A transition region indicates where the liquid fraction changes from water-in-oil to oil-in-water and vice versa (e.g., consider emulsions).

[0135] The ternary diagram **1550** also indicates some examples of ranges of multiphase flow regimes, which may be affected by one or more factors such as, for example, temperature, pressure, viscosity, density, flow line orientation, etc. The example flow regimes include annular mist, slug flow, and bubble flow; noting that other types of may occur (e.g., stratified, churn, disperse, etc.). Annular mist flow may be characterized by, for example, a layer of liquid on the wall of a pipe and droplets of liquid in a middle gas zone (e.g., mist). Slug flow may be characterized by, for example, a continuous liquid phase and a discontinuous liquid phase that is discontinuous due to separation by pockets of gas. Bubble flow may be characterized by, for example, two continuous liquid phases where at least one of the continuous liquid phases includes gas bubbles. The illustrative graphics of flow regimes in FIG. **15** correspond to flows in approximately horizontal conduits (e.g., production liner **210** of FIG. **1**); noting that a conduit may be disposed at an angle other than horizontal and that various factors that can influence flow may depend on angle of a conduit. For example, the angle of a conduit with respect to gravity can have an influence on how fluid flows in the conduit. In vertical flow (i.e., in production tubing **206** in FIG. **1**), the slug is an axially symmetrical bullet shape that occupies almost the entire cross-sectional area of the tubing.

[0136] The table **1560** of FIG. **15** shows viscosity and density as fluid properties. As to one or more other properties, consider, for example, surface tension. As indicated, the table **1560** can include information for points specified with respect to the ternary diagram **1550**. As an example, factors such as pressure, volume and temperature may be considered, for example, as to values of fluid properties, phases, flow regimes, etc.

[0137] As an example, information as to flow of fluid may be illustrated as a flow regime map that identifies flow patterns occurring in various parts of a parameter space defined by component flow rates. For example, consider flow rates such as volume fluxes, mass fluxes, momentum fluxes, or one or more other quantities. Boundaries between various flow patterns in a flow regime map may occur where a regime becomes unstable and where growth of such instability causes transition to another flow pattern. As in laminar-to-turbulent transition in single-phase flow, multiphase transitions may be rather unpredictable as they may depend on otherwise minor features of the flow, such as the roughness of the walls or the entrance conditions. Thus, as indicated in the ternary diagram **1550**, flow pattern boundaries may lack distinctiveness and exhibit transition zones.

[0138] As to properties, where fluid is single phase (e.g., water, oil or gas), a single value of viscosity may suffice for given conditions. However, where fluid is multiphase, two or more concurrent phases may occupy a flow space within a conduit (e.g., a pipe). In such an example, a single value of viscosity (e.g., or density) may not properly characterize the fluid in that flow space. Accordingly, as an example, a value or values of mixture viscosities may be used, for example, where a mixture value is a function of phase fraction(s) for fluid in a multiphase flow space. As to surface tension (e.g., σ), it may be defined for gas and/or liquid, for example, where the liquid may be oil or water. Where two-phase liquid-liquid flow exists (e.g., water and oil), then σ may reflect the interfacial tension between oil and water (see, e.g., the slug flow regime and the bubble flow regime).

[0139] Multiphase flow, including slug flow, may be modeled and simulated. Multi-dimensional simulation presents a challenge, however, as it may require an impractical amount of computing resources and/or time. Thus, at least for long pipelines, one-dimensional models may be employed, in which properties of the flow are averaged over the pipe cross-section. The model then describes how these averaged properties vary along the pipeline and with time.

[0140] Such models may implement various strategies for modeling slug flow. For example, in "slug tracking," the boundaries (front and tail) of the slugs are followed as they propagate along the pipe. Thus, the slugs and separated zones are represented on a Lagrangian grid, which is superimposed on the Eulerian grid used to solve the basic equations. In another example, "slug capturing," the underlying equations are resolved on a fine Eulerian grid, including the growth of large waves and the formation of slugs, so that each slug is represented.

[0141] These models may provide satisfactory results in a wide variety of contexts. However, some such methods of slug flow modeling and simulation may include long computation times, accuracy and/or stability issues, and/or tuning to match experimental or otherwise measured datasets, such as by using an iterative, trial-and-error process.

[0142] FIG. **16** illustrates an example of a system **1600** that includes various management components **1610** to manage various aspects of a pipeline environment **1650** (e.g., an environment that includes wells, transportation lines, risers, chokes, valves, separators, etc.). For example, the management components **1610** may allow for direct or indirect management of design, operations, control, optimization, etc., with respect to the pipeline environment **1650**. In turn, further information about the pipeline environment **1650** may become available as feedback **1660** (e.g., optionally as input to one or more of the management components **1610**).

[0143] In the example of FIG. **16**, the management components **1610** include a pipeline configuration component **1612**, an additional information component **1614** (e.g., fluid measurement data), a processing component **1616**, a simulation component **1620**, an attribute component **1630**, an analysis/visualization component **1642** and a workflow component **1644**. In operation, pipeline configuration data and other information provided per the components **1612** and **1614** may be input to the simulation component **1620**.

[0144] In an example embodiment, the simulation component **1620** may rely on pipeline components or "entities" **1622**. The pipeline components **1622** may include pipe structures and/or equipment. In the system **1600**, the components **1622** can include virtual representations of actual physical components that are reconstructed for purposes of simulation. The components **1622** may include components based on data acquired via sensing, observation, etc. (e.g., the pipeline configuration **1612** and other information **1614**). An entity may be characterized by one or more properties (e.g., a pipeline model may be characterized by changes in pressure, heat transfer, pipe inclination and geometry, etc.).

Such properties may represent one or more measurements (e.g., acquired data), calculations, etc.

[0145] In an example embodiment, the simulation component **1620** may operate in conjunction with a software framework such as an object-based framework. In such a framework, entities may include entities based on predefined classes to facilitate modeling and simulation. A commercially available example of an object-based framework is the MICROSOFT® .NET® framework (Redmond, Wash.), which provides a set of extensible object classes. In the .NET® framework, an object class encapsulates a module of reusable code and associated data structures. Object classes can be used to instantiate object instances for use by a program, script, etc. For example, borehole classes may define objects for representing boreholes based on well data.

[0146] In the example of FIG. **16**, the simulation component **1620** may process information to conform to one or more attributes specified by the attribute component **1630**, which may include a library of attributes. Such processing may occur prior to input to the simulation component **1620** (e.g., consider the processing component **1616**). As an example, the simulation component **1620** may perform operations on input information based on one or more attributes specified by the attribute component **1630**. In an example embodiment, the simulation component **1620** may construct one or more models of the pipeline environment **1650**, which may be relied on to simulate behavior of the pipeline environment **1650** (e.g., responsive to one or more acts, whether natural or artificial). In the example of FIG. **16**, the analysis/visualization component **1642** may allow for interaction with a model or model-based results (e.g., simulation results, etc.). As an example, output from the simulation component **1620** may be input to one or more other workflows, as indicated by a workflow component **1644**.

[0147] As an example, the simulation component **1620** may include one or more features of a simulator such as a simulator provided in OLGA® (Schlumberger Limited, Houston Tex. Further, in an example embodiment, the management components **1610** may include features of a commercially available framework such as OLGA® or the PETREL® seismic to simulation software framework (Schlumberger Limited, Houston, Tex.). The PETREL® framework provides components that allow for optimization of exploration and development operations. The PETREL® framework includes seismic to simulation software components that can output information for use in increasing reservoir performance, for example, by improving asset team productivity. Through use of such a framework, various professionals (e.g., geophysicists, geologists, pipeline engineers, and reservoir engineers) can develop collaborative workflows and integrate operations to streamline processes. Such a framework may be considered an application and may be considered a data-driven application (e.g., where data is input for purposes of modeling, simulating, etc.).

[0148] In an example embodiment, various aspects of the management components **210** may include add-ons or plug-ins that operate according to specifications of a framework environment. For example, a commercially available framework environment marketed as the OCEAN® framework environment (Schlumberger Limited, Houston, Tex.) allows for integration of add-ons (or plug-ins) into OLGA® or a PETREL® framework workflow. The OCEAN® framework environment leverages .NET® tools (Microsoft Corporation, Redmond, Wash.) and offers stable, user-friendly interfaces for efficient development. In an example embodiment, various components may be implemented as add-ons (or plug-ins) that conform to and operate according to specifications of a framework environment (e.g., according to application programming interface (API) specifications, etc.).

[0149] FIG. **16** also shows an example of a framework **1670** that includes a model simulation layer **1680** along with a framework services layer **1690**, a framework core layer **1695** and a modules layer **1675**. The framework **1670** may include the commercially available OCEAN® framework where the model simulation layer **1680** may be either OLGA® or the commercially available PETREL® model-centric software package that hosts OCEAN® framework applications. In an example embodiment, the PETREL® software may be considered a data-driven application. The PETREL® software can include a framework for model building and visualization.

[0150] As an example, a framework may include features for implementing one or more mesh generation techniques. For example, a framework may include an input component for receipt of information from interpretation of pipeline configuration, one or more attributes based at least in part on pipeline configuration, log data, image data, etc. Such a framework may include a mesh generation component that processes input information, optionally in conjunction with other information, to generate a mesh.

[0151] In the example of FIG. **16**, the model simulation layer **1680** may provide domain objects **1682**, act as a data source **1684**, provide for rendering **1686** and provide for various user interfaces **1688**. Rendering **1686** may provide a graphical environment in which applications can display their data while the user interfaces **1688** may provide a common look and feel for application user interface components.

[0152] As an example, the domain objects **1682** can include entity objects, property objects and optionally other objects. Entity objects may be used to geometrically represent wells, surfaces, bodies, reservoirs, etc., while property objects may be used to provide property values as well as data versions and display parameters. For example, an entity object may represent a well where a property object provides log information as well as version information and display information (e.g., to display the well as part of a model).

[0153] In the example of FIG. **16**, data may be stored in one or more data sources (or data stores, generally physical data storage devices), which may be at the same or different physical sites and accessible via one or more networks. The model simulation layer **1680** may be configured to model projects. As such, a particular project may be stored where stored project information may include inputs, models, results and cases. Thus, upon completion of a modeling session, a user may store a project. At a later time, the project can be accessed and restored using the model simulation layer **1680**, which can recreate instances of the relevant domain objects.

[0154] In the example of FIG. **16**, the pipeline environment **1650** may be outfitted with any of a variety of sensors, detectors, actuators, etc. For example, equipment **1652** may include communication circuitry to receive and to transmit information with respect to one or more networks **1655**. Such information may include information associated with downhole equipment **1654**, which may be equipment to acquire information, to assist with resource recovery, etc.

Such equipment may include storage and communication circuitry to store and to communicate data, instructions, etc. As an example, one or more satellites may be provided for purposes of communications, data acquisition, etc. For example, FIG. **16** shows a satellite in communication with the network **1655** that may be configured for communications, noting that the satellite may additionally or alternatively include circuitry for imagery (e.g., spatial, spectral, temporal, radiometric, etc.).

[0155] FIG. **16** also shows the geologic environment **1650** as optionally including equipment **1657** and **1658** associated with a well. As an example, the equipment **1657** and/or **1658** may include components, a system, systems, etc. for pipeline condition monitoring, sensing, valve modulation, pump control, analysis of pipeline data, assessment of one or more pipelines **1656**, etc. The pipelines **1656** may include at least a portion of the well, and may form part of, or be representative of, a network of pipes which may transport a production fluid (e.g., hydrocarbon) from one location to another.

[0156] As mentioned, the system **1600** may be used to perform one or more workflows. A workflow may be a process that includes a number of worksteps. A workstep may operate on data, for example, to create new data, to update existing data, etc. As an example, a workstep may operate on one or more inputs and create one or more results, for example, based on one or more algorithms. As an example, a system may include a workflow editor for creation, editing, executing, etc. of a workflow. In such an example, the workflow editor may provide for selection of one or more pre-defined worksteps, one or more customized worksteps, etc. As an example, a workflow may be a workflow implementable in OLGA® or the PETREL® software, for example, that operates on pipeline configuration, seismic attribute(s), etc. As an example, a workflow may be a process implementable in the OCEAN® framework. As an example, a workflow may include one or more worksteps that access a module such as a plug-in (e.g., external executable code, etc.).

[0157] FIG. **17** illustrates a flowchart of a method **1700** for modeling a slug flow, e.g., in a multiphase fluid flow model, according to an embodiment. The method **1700** may be employed as part of a fluid flow or pipeline model. The model may include representations of one or more fluid conduits (e.g., pipes, wells) and/or other pipeline equipment (compressors, pumps, separators, slug catchers, etc.). Such models may be representative of real-world, physical pipelines systems, or may be constructed as part of the planning of such systems.

[0158] Accordingly, in some embodiments, the method **1700** may include creating a multiphase fluid transient flow model, such as by using OLGA® or any other suitable pipeline modeling/simulation system. In another embodiment, the method **1700** may include receiving a completed fluid flow model. Either case may be considered as part of receiving a fluid flow model, e.g., as at **1702**. As indicated, the model may include a representation of one or more conduits, as well as a flow of multiphase fluid therein. The conduits may be modeled, e.g., according to geometry (e.g., diameter, length, etc.), pressure change, elevation gain, heat transfer, and/or the like. For the remainder of the present description, the model is described in terms of "pipes"; however, it will be readily apparent that the disclosure is not limited to pipes and may apply to any type of fluid conduit. In an embodiment, the multiphase fluid flow may be modeled based on the parameters of the pipes (and/or other equipment), as well as the underlying equations of mass, state, energy, etc.

[0159] The method **1700** may also include determining a slug birth rate in the multiphase fluid flow, as at **1704**. The slug birth rate may be determined based on one or more of a variety of factors, which may be provided as part of a slug birth rate model. The birth rate, generally referred to as 'B' herein, may thus represent the number of new slugs per length of pipe per second.

[0160] The slug birth rate may be zero unless conditions exist that allow slugs to form. A first one of such conditions may be known as a "minimum slip criterion" or "slug growth criterion." More particularly, in an embodiment, the minimum slip criterion may be satisfied if, were a slug to be introduced into the flow, the velocity of the slug front V_F would exceed the velocity of the slug tail V_T (i.e., $V_F-V_T>0$). The difference between V_F and V_T may represent a mean growth rate of slugs, and may also be representative of a distance from the minimum slip boundary, or the degree of instability of the local separated flow. Accordingly, the value of the difference may represent a driving force, and thus an increasing probability, for new slugs to form, as will be described below. For a slug to be counted (e.g., in the determination of N, below) it may have a length of at least the pipe diameter D. Thus, the time for a slug to form may scale as $D/(V_F-V_T)$, and the rate at which new slugs form may scale as $(V_F-V_T)/D$.

[0161] To determine slug tail velocity V_T, a correlation for slug tail velocity V_T may be implemented in terms of mixture velocity u_M, gravity g, pipe diameter D, inclination angle above the horizontal θ, and/or other quantities. Accordingly, slug tail velocity V_T may be defined as:

$$V_T=f(u_M,g,D,\theta,\ldots) \tag{6}$$

[0162] The slug front velocity V_F may be given by a mass balance across the slug front:

$$(V_F-u_{GS}{}^F)\alpha_{GS}{}^F=(V_F-u_{GB}{}^T)\alpha_{GB}{}^T \tag{7}$$

Solving equation (2) for V_F:

$$V_F=\frac{\alpha_{GB}^T u_{GB}^T-\alpha_{GS}^F u_{GS}^F}{\alpha_{GB}^T-\alpha_{GS}^F} \tag{8}$$

where $\alpha_{GS}{}^F$ and $u_{GS}{}^F$ represent the cross-sectional holdup and cross-sectional mean velocity of gas at the front of the slug, respectively, and $\alpha_{GB}{}^T$ and $u_{GB}{}^T$ represent the same quantities at the tail of the zone of separated flow immediately ahead of the slug. Further, equations (7) and (8) may be evaluated when slugs are not present. In such case, values for $\alpha_{GS}{}^F$ and $u_{GS}{}^F$ may be provided (e.g., as hypothetical values), while $\alpha_{GB}{}^T$ and $u_{GB}{}^T$ may take values corresponding to the separated flow.

[0163] When the minimum slip criterion (first condition) is satisfied, slugs may grow from the slug precursors, if such precursors are available (second condition). The spatial frequency of slug formation may thus be proportional to the number of large waves (or slug precursors) per unit pipe length N_W. However, the presence (or proximity) of slugs may decrease the subsequent formation of slugs, and thus the birth rate B may take into consideration slugs that have already formed. Accordingly, the second condition that may be satisfied in order for slug flow to exist may be that the

density of slugs present in the pipe N (slugs per unit length of pipe) may not exceed the density of large wave slug precursors (i.e., N_W–N>0).

[0164] To determine the number of slug precursors or large waves, a delay constant may be implemented. As such, the density of large wave slug precursors N_W may be estimated, as $N_W=u_L/(V_T\Omega D)$, where Ω is the delay constant and u_L is the local mean liquid velocity. In another embodiment, a mechanistic model for slug initiation frequency may be employed. For example, at the threshold of slug formation, the wave profile may be considered to be similar to the tail profile of an incipient slug, and the wave speed may approach the slug tail velocity. As such, the wavelength of the slug may be estimated using a quasi-steady slug tail profile model. The local slug density N at a particular grid point or control volume may be estimated based on the distances to the nearest slugs (if any) in each direction along the pipeline. If no slugs exist in either direction, then the slug density is zero.

[0165] In an embodiment, the wave profile may be obtained by solving a first order, ordinary differential equation for liquid holdup $\alpha_{LW}(\xi)$

$$\frac{d\alpha_{LW}}{d\xi}=\frac{Z}{Y} \tag{9}$$

[0166] This may represent a reduced form of a steady-state, two- (or more) fluid model, which may be based at least in part on an assumption that the wave (slug precursor) propagates without changing shape. As such, the flow may be considered quasi-steady in a frame of reference moving with the tail speed. In equation (9), represents the spatial coordinate measured backwards from the wave crest (tail of the slug precursor). In the two-fluid model, Z represents the equilibrium terms: friction and the axial component of gravity, which in the case where the separated flow is stratified are according to equation (10):

$$Z=\frac{\tau_{IW}S_{IW}-\tau_{LW}S_{LW}}{\alpha_{LW}A}+\frac{\tau_{IW}S_{IW}+\tau_{GW}S_{GW}}{(1-\alpha_{LW})A}-(\rho_L-\rho_G)g\sin\theta \tag{10}$$

[0167] The denominator Y in equation (9) may represent one or more non-equilibrium terms, such as inertial and hydraulic gradient terms, which, for stratified flow, may be:

$$Y=\rho_L\frac{\hat{u}_{SL}^2}{\alpha_{LW}^3}+\rho_G\frac{\hat{u}_{SG}^2}{(1-\alpha_{LW})^3}-(\rho_L-\rho_G)g\cos\theta\frac{A}{S_{LW}} \tag{11}$$

[0168] The terms τ_{IW}, τ_{LW}, and τ_{GW} represent the shear stresses between the gas and liquid, between the liquid and the pipe wall, and between the gas and the pipe wall, respectively, while S_{IW}, S_{LW}, and S_{GW} represent the corresponding perimeter lengths, and the subscript 'W' denotes "wave." A is the pipe cross-sectional area, $\hat{u}_{SL}$ and $\hat{u}_{SG}$ are the superficial velocities of liquid and gas, respectively, relative to the moving frame of reference, ρ_L and ρ_G are the liquid and gas densities, respectively, g is the acceleration of gravity and θ represents the angle of inclination of the pipe above the horizontal.

[0169] The mean holdup may be determined by integration over the wave profile:

$$\overline{\alpha_{LW}}=\frac{1}{L_W}\int_0^{L_W}\alpha_{LW}(\xi)d\xi \tag{12}$$

where L_W is the distance between the tail of one slug precursor and the front of the next. Further, the slug length of the slug precursor may be set to zero, or any other value, for example a length of a few diameters, in order to determine the frequency of slug precursors. Moreover, an approximate solution may be introduced for the wave profile in the exponential form, as equation (13):

$$\alpha_{LW}\approx\tilde{\alpha}_{LW}(\xi)=\alpha_{LW}^{E}+(\alpha_{LW}^{0}-\alpha_{LW}^{E})e^{-k\xi} \tag{13}$$

where α_{LW}^{E} is a hypothetical equilibrium holdup achieved for a very long wave tail, $\xi\rightarrow\infty$, $Z\rightarrow 0$, and α_{LW}^{0} is the hold up at the wave crest (slug tail), which may be set equal to the slug body holdup of the incipient slug. When the void in the slug is neglected, α_{LW}^{0} may be set to unity. As such, the mean holdup value of the liquid corresponding to the approximate profile may be:

$$\overline{\alpha_{LW}}\approx\alpha_{LW}^{E}+(\alpha_{LW}^{0}-\alpha_{LW}^{E})\frac{1}{kL_W}(1-e^{-kL_W}) \tag{14}$$

[0170] In embodiments, the product kL_W may be about three (or another, moderately large number), so that the stratified zone is long enough for the liquid level to approach the equilibrium value and the exponential term in equation (14) may be neglected. In such a case, L_W may be determined from:

$$L_W\approx\frac{1}{k}\frac{\alpha_{LW}^{0}-\alpha_{LW}^{E}}{\overline{\alpha_{LW}}-\alpha_{LW}^{E}} \tag{15}$$

[0171] To estimate the value of k, the spatial derivative of the exponential profile may be given as:

$$\frac{d\tilde{\alpha}_{LW}}{d\xi}=-k(\alpha_{LW}^{0}-\alpha_{LW}^{E})e^{-k\xi}=-k(\tilde{\alpha}_{LW}-\alpha_{LW}^{E}) \tag{16}$$

so that a value of the exponential coefficient k may be estimated from

$$k\approx k^R=-\left[\frac{1}{\alpha_{LW}-\alpha_{LW}^{e}}\frac{d\alpha_{LW}}{d\xi}\right]_{\alpha_{LW}=\alpha_{LW}^{E}}=\frac{-1}{\alpha_{LW}^{R}-\alpha_{LW}^{E}}\left[\frac{Z}{Y}\right]_{\alpha_{LW}=\alpha_{LW}^{R}} \tag{17}$$

Here, α_{LW}^{R} may be a reference value of the holdup taken at a point along the profile. In an embodiment, the value of α_{LW}^{R} may be selected such that the half-angle δ subtended by the liquid layer at the pipe center is between the equilibrium value δ^E and the value of the slug tail δ^0, weighted by a fraction c_K:

$$\delta^R=\delta^E+c_K(\delta^0-\delta^E) \tag{18}$$

[0172] The fraction c_K may serve as a tuning variable in the model. The value may be predetermined or received, e.g., from a user, as part of the method **1700**. For example, the fraction may be set as 0.18, but in other embodiments, may be any other suitable number. The holdup may be given in terms of the half angle δ by $\alpha_{LW}=(\delta-\cos\delta\sin\delta)/\pi$.

[0173] An estimate for the number of precursor waves per unit length may thus be:

$$N_W \approx c_W \frac{\overline{\alpha_{LW}}-\alpha_{LW}^E}{(\alpha_{LW}^0-\alpha_{LW}^E)(\alpha_{LW}^R-\alpha_{LW}^E)}\left[\frac{-Z}{Y}\right]_{\alpha_{LW}=\alpha_{LW}^R} \tag{19}$$

where c_W may be a free tuning parameter, which may be set, for example, as 1.

[0174] When the wave propagates without change of form, the liquid flux relative to the moving frame of reference may be constant along the wave profile, such that:

$$\alpha_{LW}\hat{u}_{LW}\approx\hat{u}_{SL} \tag{20}$$

where $\hat{u}_{LW}=V_W-u_{LW}$ is the liquid velocity (measured backwards) relative to the wave crest (slug tail) and $\hat{u}_{SL}=V_W-u_{SL}$ is the corresponding superficial velocity. Continuity of liquid holdup and flux across the slug tail may give $\alpha_{LW}{}^0=\alpha_{LS}{}^T$ and $\hat{u}_{SL}=(V_W-u_{LS}{}^T)\alpha_{LS}{}^T$, where $\alpha_{LS}{}^T$ and $u_{LS}{}^T$ are the holdup and velocity of liquid, respectively, at the tail of the slug precursor (e.g., the crest of the wave). In some embodiments, gas entrainment may be ignored, and $\alpha_{LS}{}^T\approx1$, $\delta^0=\pi$, and $u_{LS}{}^T=u_M$, such that $\hat{u}_{SL}\approx V_W-u_M$, where u_m is a local mixture velocity.

[0175] The mean liquid flux in the wave may be determined as:

$$q_L=\alpha_L u_L=\frac{1}{L_W}\int_0^{L_W}\alpha_{LW}(\xi)u_{LW}(\xi)d\xi \tag{21}$$

Further, as $u_{LW}=V_W-\hat{u}_{SL}/\alpha_{LW}$, liquid flux becomes:

$$q_L=\frac{1}{L_W}\int_0^{L_W}(V_W\alpha_{LW}-\hat{u}_{SL})d\xi=V_W\overline{\alpha_{LW}}-\hat{u}_{SL} \tag{22}$$

yielding:

$$V_W=\frac{u_M-q_L}{1-\overline{\alpha_{LW}}}=u_G \tag{23}$$

in which u_G is the mean gas velocity

[0176] For a developing flow, the liquid holdup α_L and the flux q_L may be determined independently. As such, the wave velocity V_W, which may be equal to the gas velocity u_G in the case with no gas entrainment, may differ from the slug tail velocity V_T. This potential inconsistency may be resolved in at least two ways. First, in a steady flow, the wave velocity may be equal to the slug tail velocity, $V_W=V_T$, which may be regarded as an approximation for unsteady flow. In such case, the wave model may take $\overline{\alpha_{LW}}$ to be the local value of α_L (and may not use the liquid flux q_L). Second, a local value for the liquid flux q_L may be determined, and equation (23) may be employed to obtain an adjusted value for the mean holdup corresponding to the wavy flow:

$$\overline{\alpha_{LW}}=1-\frac{u_M-q_L}{V_T} \tag{24}$$

In this case, the wave model may use a liquid holdup value $\overline{\alpha_{LW}}$ corresponding to the local value of q_L (and may not use α_L).

[0177] In some embodiments, determining a slug death rate model may not be needed, as a slug may simply be considered to be dead with its characteristic length Ls approaches zero. In other embodiments, a slug death rate may be determined. If slugs are present, and the slug tail velocity V_T is greater than the slug front velocity V_F, the slugs may decrease in length. The mean front and tail velocity of relatively short slugs may be considered generally constant, thus the model may neglect slugs for which the tail velocity differs from the standard form. Thus, the rate at which the slugs disappear may be proportional to (V_T-V_F) $\psi(0)$. The function $\psi(L_S)$ represents the probability density function of slugs of length L_S, and $\psi(0)$ represents the probability density of slugs of zero (or substantially zero) length. In some embodiments, $\psi(0)$ may be proportional to $N/\overline{L_S}$ thus the death rate may be estimated by

$$D=c_D\frac{N(V_T-V_F)}{\overline{L_S}},\quad V_T>V_F \tag{25}$$

where c_D is another dimensionless constant that may be tuned to data. Further, to avoid a potential singularity when $\overline{L_S}\to0$, an upper bound may be imposed for the slug death rate D by adding a constant to the denominator, such as the pipe diameter, thereby yielding:

$$D=c_D\frac{N(V_T-V_F)}{\overline{L_S}+D},\quad V_T>V_F \tag{26}$$

[0178] In an embodiment, if both of the first condition (minimum slip criterion) and second conditions (available precursors) are satisfied, the birth rate B may be determined according to the following equation:

$$B=\frac{c_B}{D}(N_W-N)(V_F-V_T) \tag{27}$$

[0179] In equation (27), D represents the pipe diameter, and c_B is a constant of proportionality that is determined by matching the model with experimental data and/or field data. The birth rate model gives the birth rate B in terms of at least two factors, which represent the degree of instability of the local stratified flow, and the spatial density of slug precursors (slugs/meter).

[0180] The method **1700** may then proceed to initiating a slug flow in the fluid flow model based at least partially on the slug birth rate, as at **1706**. In an embodiment, initiating slug flow may be conducted according to a population

equation, which may employ the birth rate and/or death rate calculated above. An example of such a population equation may be as follows:

$$\frac{\partial N}{\partial t} + \frac{\partial}{\partial x}(NU_A) = B - D \tag{28}$$

where N is the number of slugs per unit pipe length, U_A is the advection velocity, B is the slug birth rate, and D is the slug death rate. In some embodiments, as mentioned above, a model for slug death may be omitted; as length approaches zero, the slug may be considered dead.

[0181] In an embodiment, the simulation of the fluid flow model may proceed according to time steps Δt, where the equations describing the state of the cells or control volumes (e.g., lengths of pipe) of the model are resolved after one, some, or each time step. Further, the number of new slugs formed may be generally described in terms of the birth rate B, the control volume length Δz and the time step Δt as:

$$\Delta N = B\Delta z\Delta t. \tag{29}$$

[0182] However, the pipe length Δz and/or the time step Δt may be relatively short, such that ΔN is generally less than one and greater than or equal to zero. Accordingly, embodiments of the present method **1700** may employ the ΔN value as a probability. For example, the method **1700** may include generating a random or pseudo-random number X, which may be uniformly distributed on the interval [0, 1]. When ΔN>X, a slug may be initiated, and if ΔN<X, a slug may not be initiated.

[0183] When one or more slug flows at one or more lengths of pipe, at a time step, are resolved, the method **1700** may include displaying data representative of the slug flow, as at **1708**. This may take any one or more of a variety of forms and may result in a representation of an underlying object changing, based on the simulation. For example, one or more slugs may be graphically represented in a pipe. In another embodiment, a frequency of slug flow, e.g., as a plot, may be created and/or modified according to the method **1700**. In another embodiment, a slug length distribution, e.g., as a plot, may be created and/or modified according to the method **1700**. In other embodiments, other types of graphical displays based on data from the underlying actual or hypothetical physical pipeline system may be provided.

CONCLUSION

[0184] The use of the flowback model to determine drawdown pressures, along with chemical analysis of flowback fluids, solids assessment, and accurate flow rates using a multiphase flow meter that will provide data to confirm and validate the results from the model allows for a shift from rule-of-thumb practice to a data-driven approach based on rock-fluid interactions that helps preserve fracture conductivity and hence increases estimated ultimate recovery (EUR) and well production performance.

[0185] The flowback systems and methods described herein allows for prediction, detection, estimation, and response when there are rapid changes in the bottomhole pressure during flowback. The use of a multiphase flow meter provides high speed, high resolution data, which allows for flow rate adjustments to be made within one well piping volume that may not be possible with other separator/phase monitoring systems. The speed of this measurement allows for novel responses to slugging situations—detection of oscillating or rapidly varying excessive drawdown pressure change rates that are not otherwise detectable.

[0186] Also, the flowback systems and methods described herein provide automation and connection of the multiphase flow meter with water chemistry measurements such as conductivity and an automated choke that allows for control of downhole pressures in a gradual manner, maintaining conductivity in channels that are only partially propped.

[0187] Additionally, the flowback systems and methods described herein provide data storage, data integration, and data analytics processes to use as background knowledge to calibrate engineered flowback procedures for subsequent wells. Data can be incorporated into, for example, HRA (Heterogeneous Rock Analysis), or an alternate rock classification system, where the rock type data is processed for flowback management on subsequent wells.

[0188] There have been described and illustrated herein several embodiments of a flowback system and a flowback control method. While particular embodiments have been described, it is not intended that the disclosure be limited thereto, as it is intended that the disclosure be as broad in scope as the art will allow and that the specification be read likewise. In addition, while particular types of devices have been disclosed, it will be understood that other devices having the same function(s) can be used. For example, and not by way of limitation, multiple single phase flow meters may be used instead of a single multiphase flow meter. It will therefore be appreciated by those skilled in the art that yet other modifications could be made to the provided disclosure without deviating from its spirit and scope as claimed.

What is claimed is:

1. A system, for a well that traverses a reservoir, comprising:

a choke configured to regulate the flow of fluid from the well, wherein the reservoir has undergone a hydraulic fracture treatment;

at least one sensor for measuring a fluid property; and

a control system coupled to the sensor and the choke, wherein the system receives and processes a measurement from the sensor and adjusts the flow based on the measurement.

2. The system according to claim **1**, wherein:

the at least one sensor comprises a plurality of sensors including a multiphase flow meter and a wellhead pressure sensor.

3. The system according to claim **2**, wherein:

the plurality of sensors further includes a solids analyzer and a chemical analyzer.

4. The system according to claim **1**, wherein:

the control system includes a dynamic choke controller that is configured to dynamically recommend a choke setting based on a flowback model that is a function of wellhead pressure.

5. The system according to claim **4**, wherein:

the flowback model is configured to determine a drawdown pressure, which is compared against a predetermined scheduled drawdown pressure to dynamically recommend the choke setting.

6. The system according to claim **5**, wherein:

when the determined drawdown pressure is greater than the predetermined drawdown pressure, the control system recommends a choke setting to throttle the choke, and

when the determined drawdown pressure is less than the predetermined drawdown pressure, the control system recommends a choke setting to open the choke.

7. The system according to claim **5**, wherein:

the control system is configured to override the recommended choke setting based on one or more failure conditions and at least one of the failure conditions is based on the flowback model.

8. The system according to claim **7**, wherein:

the failure conditions include a prediction of slug formation, a prediction of tensile rock failure, a prediction of loss of fracture surface area or productive area, one or more measurements of solids produced from the flowback fluid, flow rate measurements of one or more phases in the flowback fluid, and a measurement of wellhead pressure.

9. The flowback system according to claim **4**, wherein:

the flowback model is configured to determine a transient pressure distribution along the well and along fractures, and a distribution of oil/gas/water/solids concentrations along the well and along the fractures.

10. The system according to claim **7**, wherein:

the control system is configured to output a choke control signal based on the recommended choke setting in a case where no failure conditions exist and to output a choke control signal based on the one or more failure conditions in a case where one or more failure conditions exist.

11. A flowback control method for a well comprising:

measuring properties of flowback fluid flowing in the well that traverses a reservoir, wherein the reservoir has undergone a hydraulic fracture treatment;

receiving and processing the property measurements;

generating a choke control signal based on the property measurements; and

regulating the choke based on the choke control signal.

12. The method according to claim **11**, wherein:

the measurements include multiphase flow rates of the flowback fluid, and wellhead pressure.

13. The method according to claim **12**, wherein:

the measurements further includes quantity of solids in the flowback fluid and a chemical analysis.

14. The method according to claim **11**, wherein:

generating a choke control signal includes:

determining a recommended choke setting based on a flowback model that is a function of wellhead pressure;

determining whether at least one failure condition exists based on the flowback model, and

overriding the recommended choke setting with an overridden choke setting based on the respective failure conditions determined to exist.

15. The method according to claim **14**, wherein:

the failure conditions include a prediction of slug formation, a prediction of tensile rock failure, a prediction of loss of fracture surface area or productive area, one or more measurements of solids produced from the flowback fluid, flow rate measurements of one or more phases in the flowback fluid, and a measurement of wellhead pressure.

16. The method according to claim **14**, wherein:

determining a recommended choke setting includes:

determining a drawdown pressure based on the flowback model;

comparing the determined drawdown pressure against a maximum drawdown pressure; and

calculating the recommended choke setting based on the comparison,

wherein:

when the determined drawdown pressure is greater than the maximum drawdown pressure, the calculated recommended choke setting is to throttle the choke and when the determined drawdown pressure is less than the maximum drawdown pressure, the calculated recommended choke setting is to open the choke.

17. The method according to claim **14**, wherein:

the flowback model is configured to determine a transient pressure distribution along the well and along fractures, and a distribution of oil/gas/water/solids concentrations along the well and along the fractures.

18. The method according to claim **17**, further comprising:

calculating multiphase flow rates of oil/gas/water based on the distribution of oil/gas/water concentrations; and

comparing the calculated multiphase flow rates of oil/gas/water with measured flow rates of oil/gas/water.

19. The method according to claim **18**, further comprising:

tuning the flowback model based on the comparison of the multiphase flow rates of oil/gas/water.

20. A non-transient computer readable medium, which when executed by at least one processor, performs a flowback method for a well, the method comprising:

measuring properties of flowback fluid flowing in the well that traverses a reservoir, wherein the reservoir has undergone a hydraulic fracture treatment;

receiving and processing the property measurements;

generating a choke control signal based on the property measurements; and

regulating the choke based on the choke control signal.

21. A flowback control method for a well that traverses a reservoir that has undergone a hydraulic fracture treatment, comprising:

measuring multiphase fluid flow rates of oil/gas/water that comprise the flowback fluid;

calculating multiphase flow rates of oil/gas/water based on a flowback model;

comparing the calculated multiphase flow rates of oil/gas/water with the measured flow rates of oil/gas/water; and

tuning the flowback model based on the comparison of the multiphase flow rates of oil/gas/water.

22. The method according to claim **21**, wherein:

predicting multiphase flow rates of oil/gas/water includes calculating a distribution of oil/gas/water concentrations along the well and along fractures in the formation based on a flowback model, and

calculating multiphase flow rates of oil/gas/water based on the distribution of oil/gas/water concentrations.

23. The method according to claim **21**, further comprising:

generating a choke control signal based on the comparison between the calculated multiphase flow rates of oil/gas/water with the measured flow rates of oil/gas/water; and

regulating the choke based on the choke control signal.

24. The method according to claim **21**, wherein:

the well is a first well and wherein the flowback model is based on previously acquired flowback and production data from at least one other well.

25. The method according to claim **24**, wherein the at least one other well is in a basin nearby the first well.

26. The method according to claim **24**, wherein the previously acquired flowback and production data from the at least one other well provide a calibrated control loop where bottomhole pressure upper and lower bounds are estimated to define a safe flowback operational envelope for the first well.

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