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(54) **DOWNHOLE ESTIMATION OF MULTIPHASE FLOWS IN PRODUCTION SYSTEMS**

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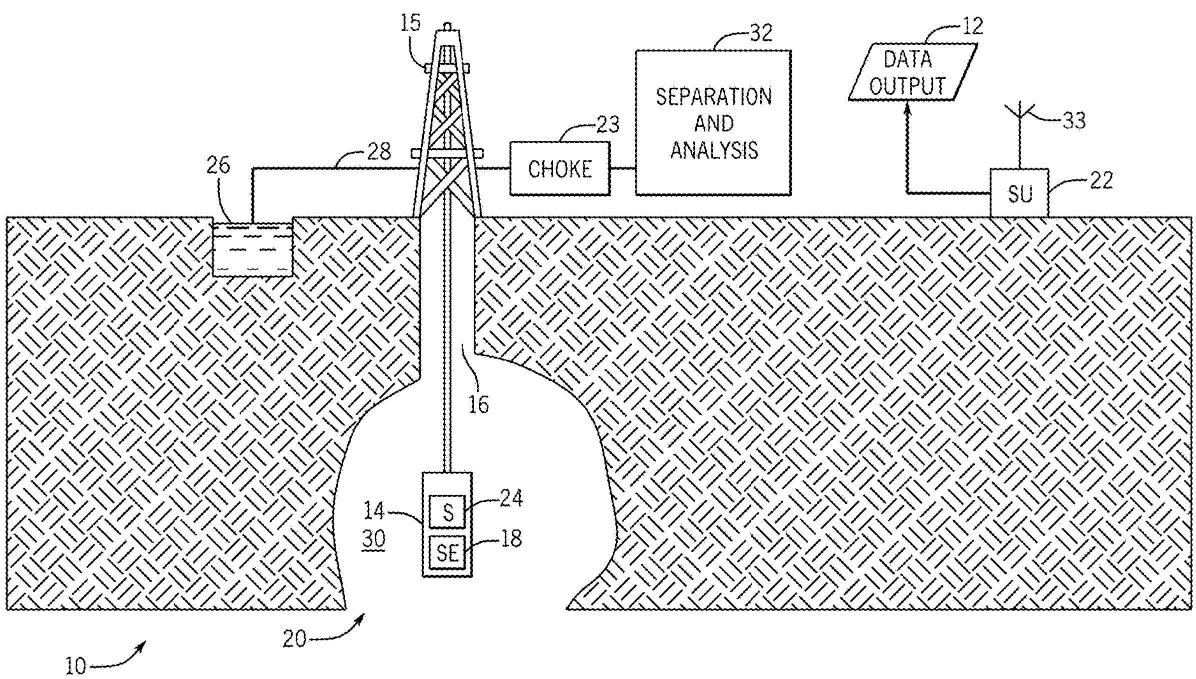
(52) **U.S. Cl.**
CPC ***E21B 47/113*** (2020.05); ***E21B 47/07*** (2020.05); ***E21B 49/0875*** (2020.05)

(57) **ABSTRACT**

This disclosure relates to systems and methods with multiple sensors located in different zones of a hydrocarbon production system. The multiple sensors are configured to capture parameters about flow through multiple zones of a wellbore. The system also includes a processor that is configured to obtain data about a multiphase flow through the plurality of zones of the wellbore of the hydrocarbon production system from the multiple sensors and to solve an interpretation problem for a first unknown in a bottommost zone. The processor is configured to use a value for the first unknown in the bottommost zone to solve for a second unknown in an upper zone that is above the bottommost zone in the wellbore of the hydrocarbon production system. The processor is configured to change control parameters of the hydrocarbon production system based at least in part on the first unknown and the second unknown.



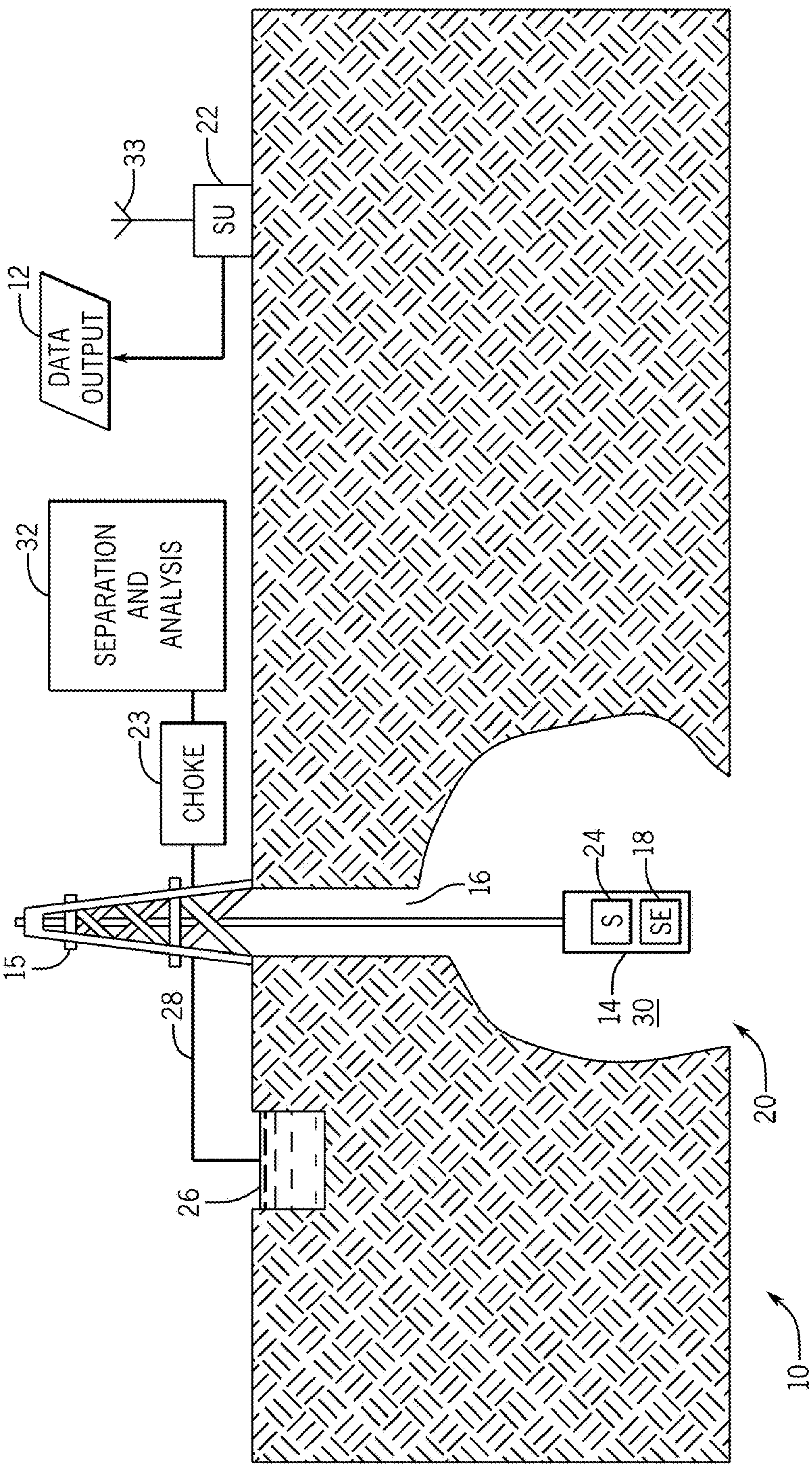


FIG. 1

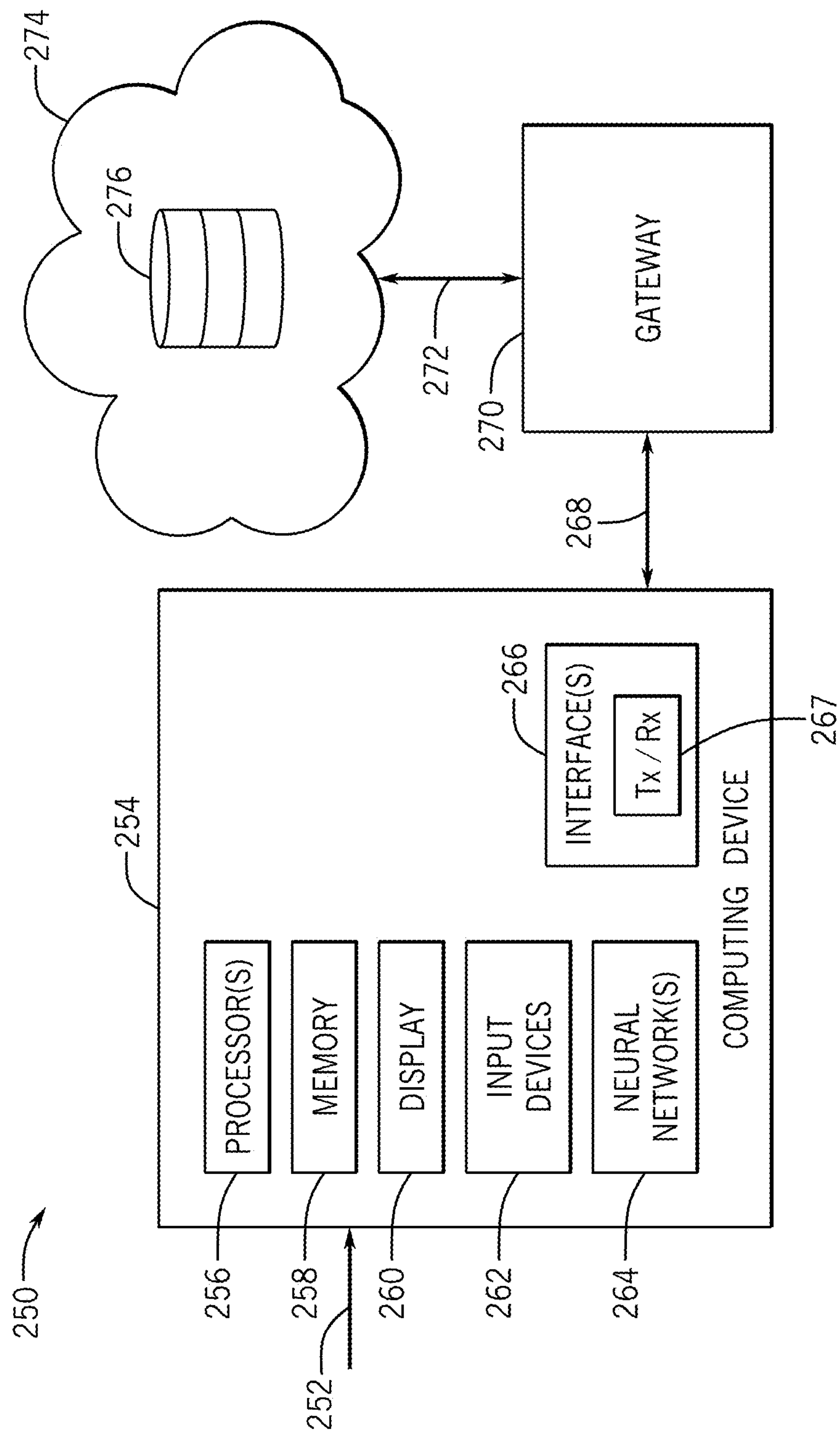

250
252
254
256
258
260
262
264
266
267
268
270
272
274
276
PROCESSOR(S)
MEMORY
DISPLAY
INPUT DEVICES
NEURAL NETWORK(S)
INTERFACE(S)
Tx / Rx
COMPUTING DEVICE
GATEWAY

FIG. 2

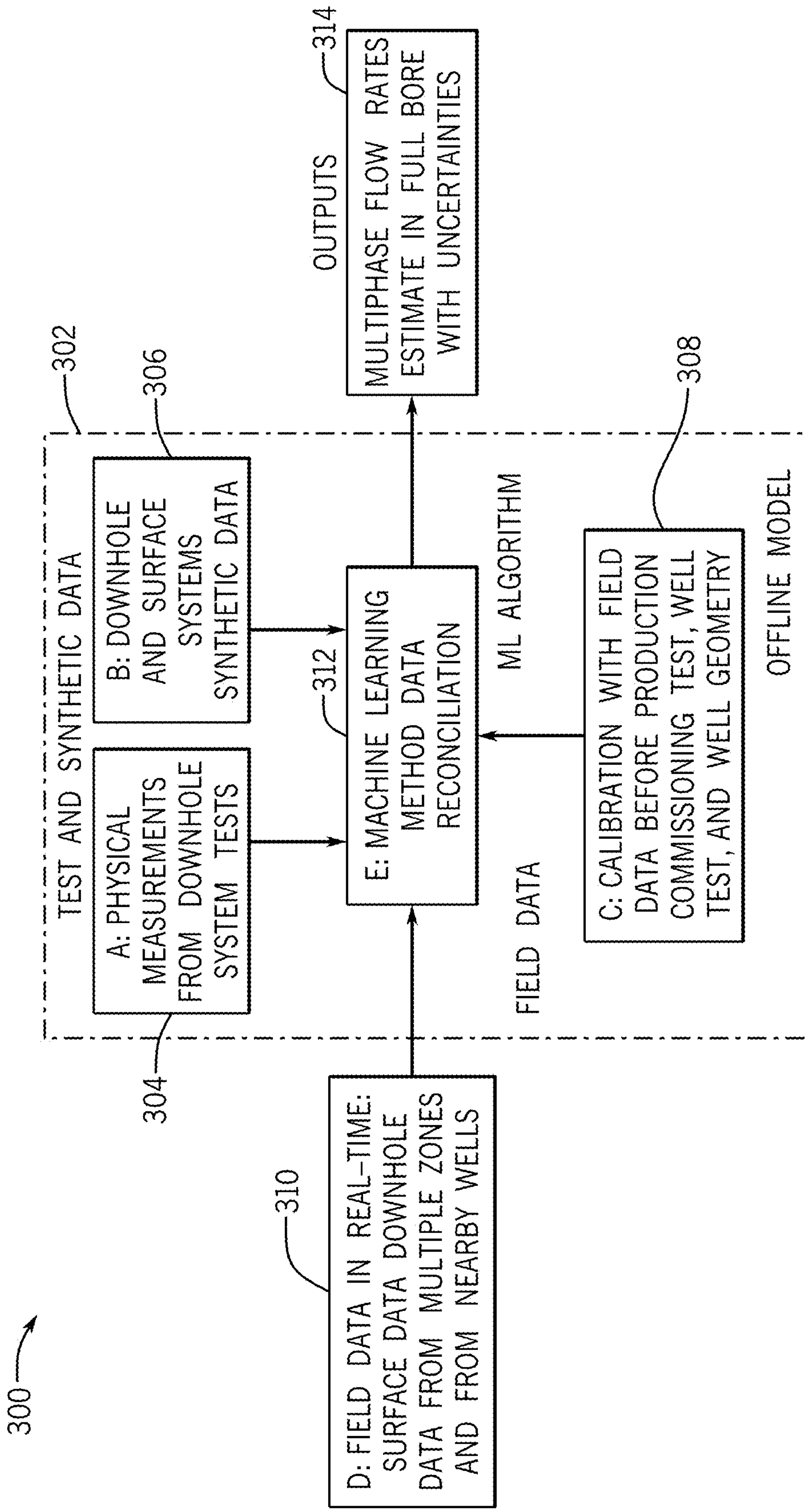
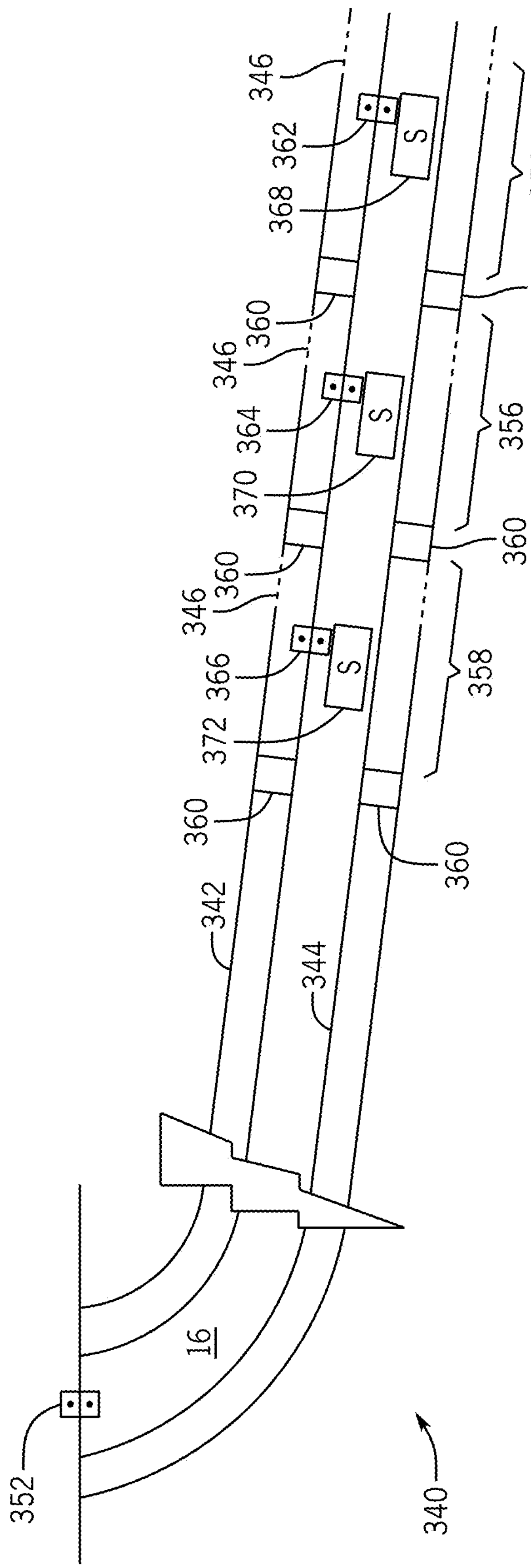

300
302
TEST AND SYNTHETIC DATA
304
A: PHYSICAL MEASUREMENTS FROM DOWNHOLE SYSTEM TESTS
306
B: DOWNHOLE AND SURFACE SYSTEMS SYNTHETIC DATA
312
E: MACHINE LEARNING METHOD DATA RECONCILIATION
ML ALGORITHM
FIELD DATA
308
C: CALIBRATION WITH FIELD DATA BEFORE PRODUCTION COMMISSIONING TEST, WELL TEST, AND WELL GEOMETRY
OFFLINE MODEL
310
D: FIELD DATA IN REAL-TIME: SURFACE DATA DOWNHOLE DATA FROM MULTIPLE ZONES AND FROM NEARBY WELLS
OUTPUTS
314
MULTIPHASE FLOW RATES ESTIMATE IN FULL BORE WITH UNCERTAINTIES

FIG. 3


346
362
368
S
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360
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364
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346
366
372
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342
344
16
352
340

FIG. 4

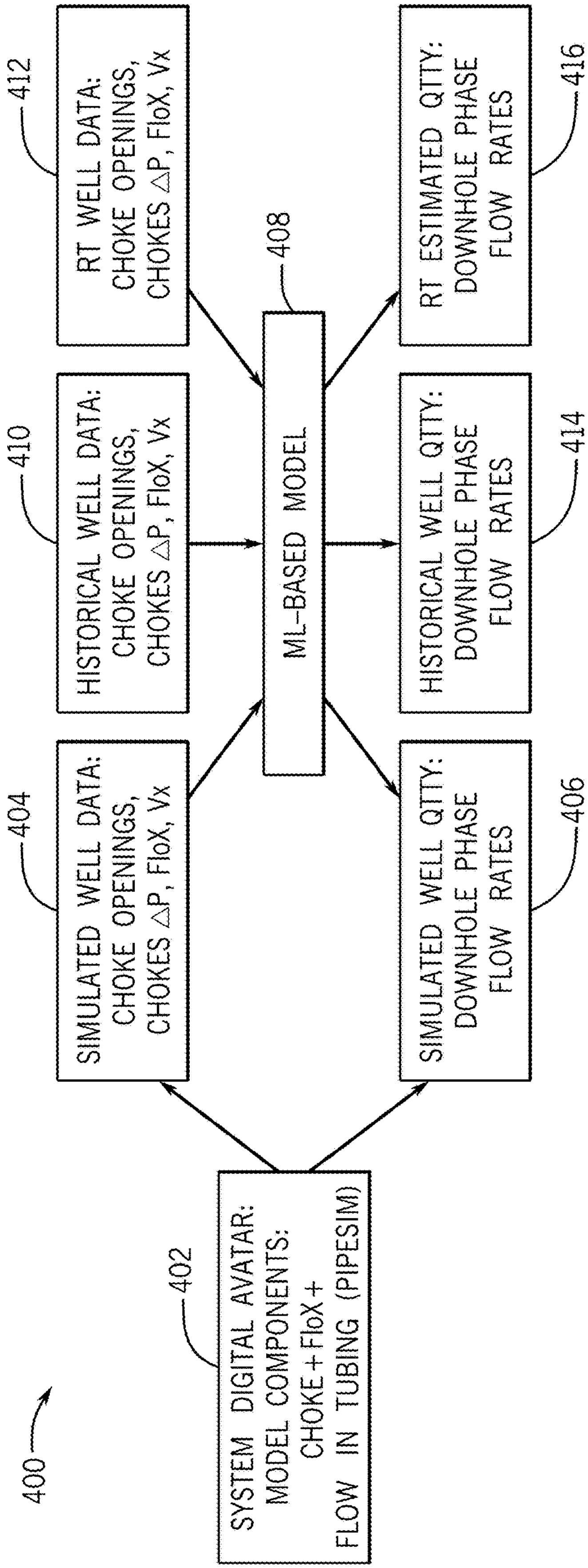
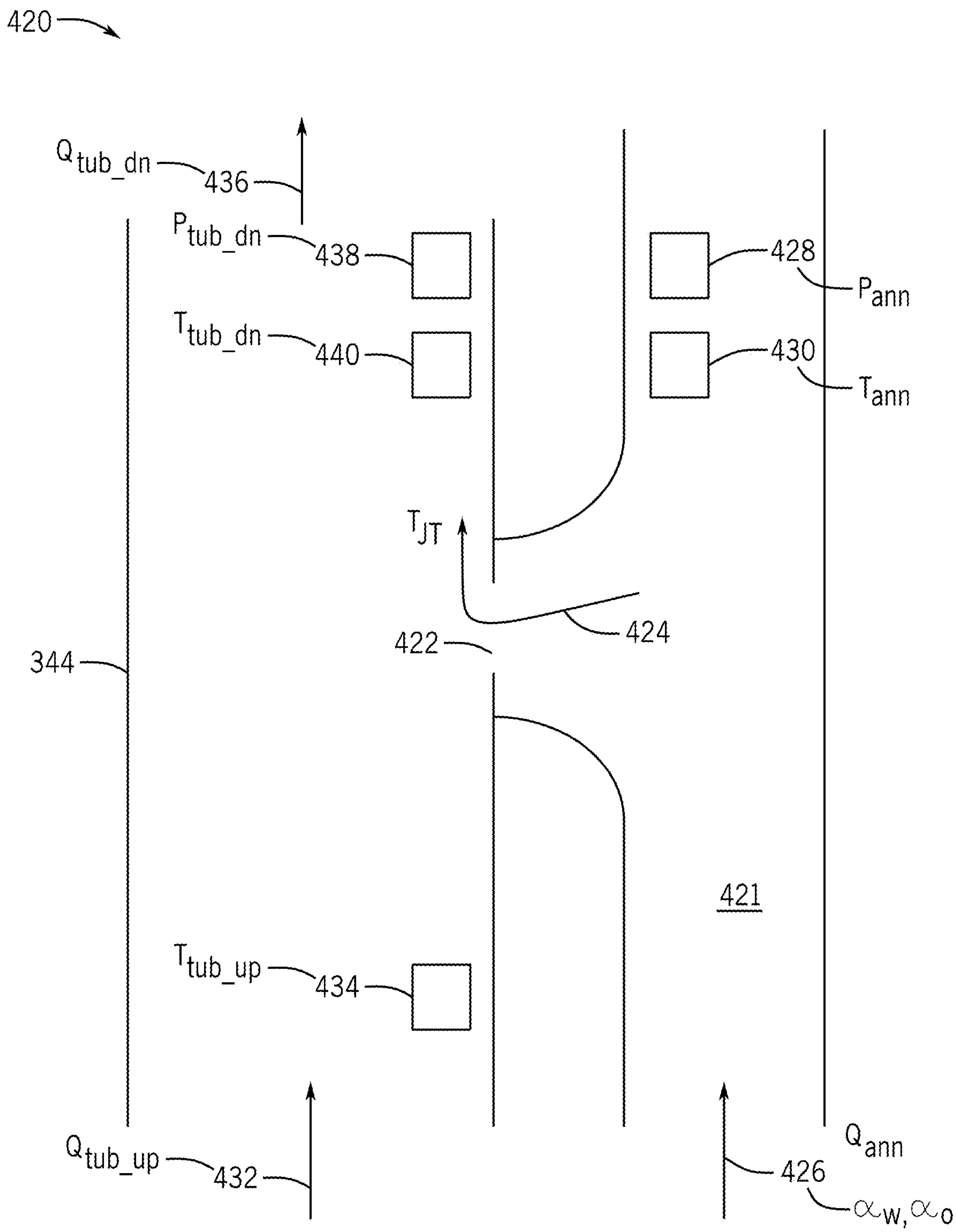
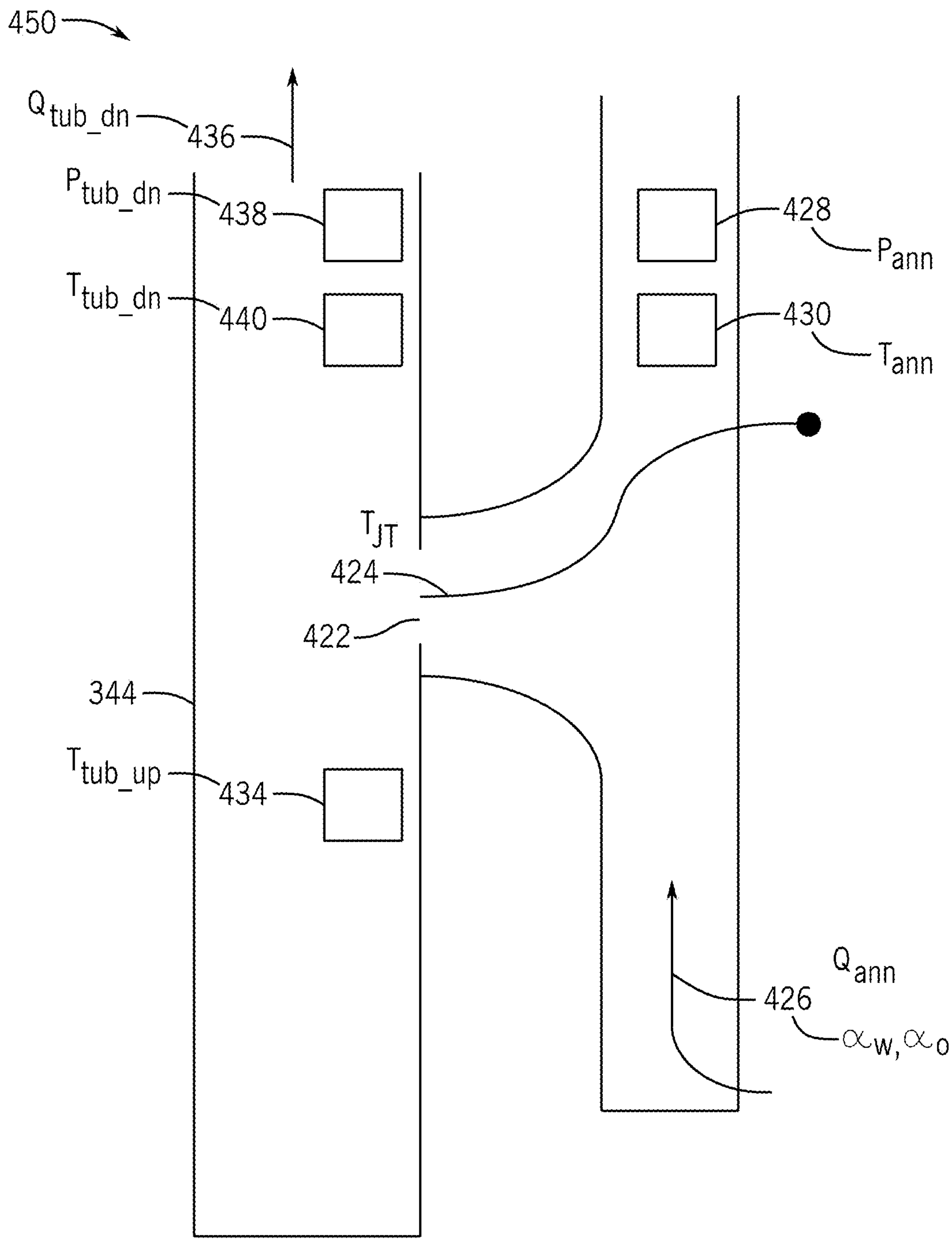

400
402
SYSTEM DIGITAL AVATAR: MODEL COMPONENTS: CHOKE + FloX + FLOW IN TUBING (PIPESIM)
404
SIMULATED WELL DATA: CHOKE OPENINGS, CHOKES ΔP, FloX, Vx
406
SIMULATED WELL QTTY: DOWNHOLE PHASE FLOW RATES
408
ML-BASED MODEL
410
HISTORICAL WELL DATA: CHOKE OPENINGS, CHOKES ΔP, FloX, Vx
412
RT WELL DATA: CHOKE OPENINGS, CHOKES ΔP, FloX, Vx
414
HISTORICAL WELL QTTY: DOWNHOLE PHASE FLOW RATES
416
RT ESTIMATED QTTY: DOWNHOLE PHASE FLOW RATES

FIG. 5



420
Q_{tub_dn}
436
P_{tub_dn}
438
T_{tub_dn}
440
428
P_{ann}
430
T_{ann}
T_{JT}
424
422
344
421
T_{tub_up}
434
Q_{tub_up}
432
Q_{ann}
426
α_w, α_o

FIG. 6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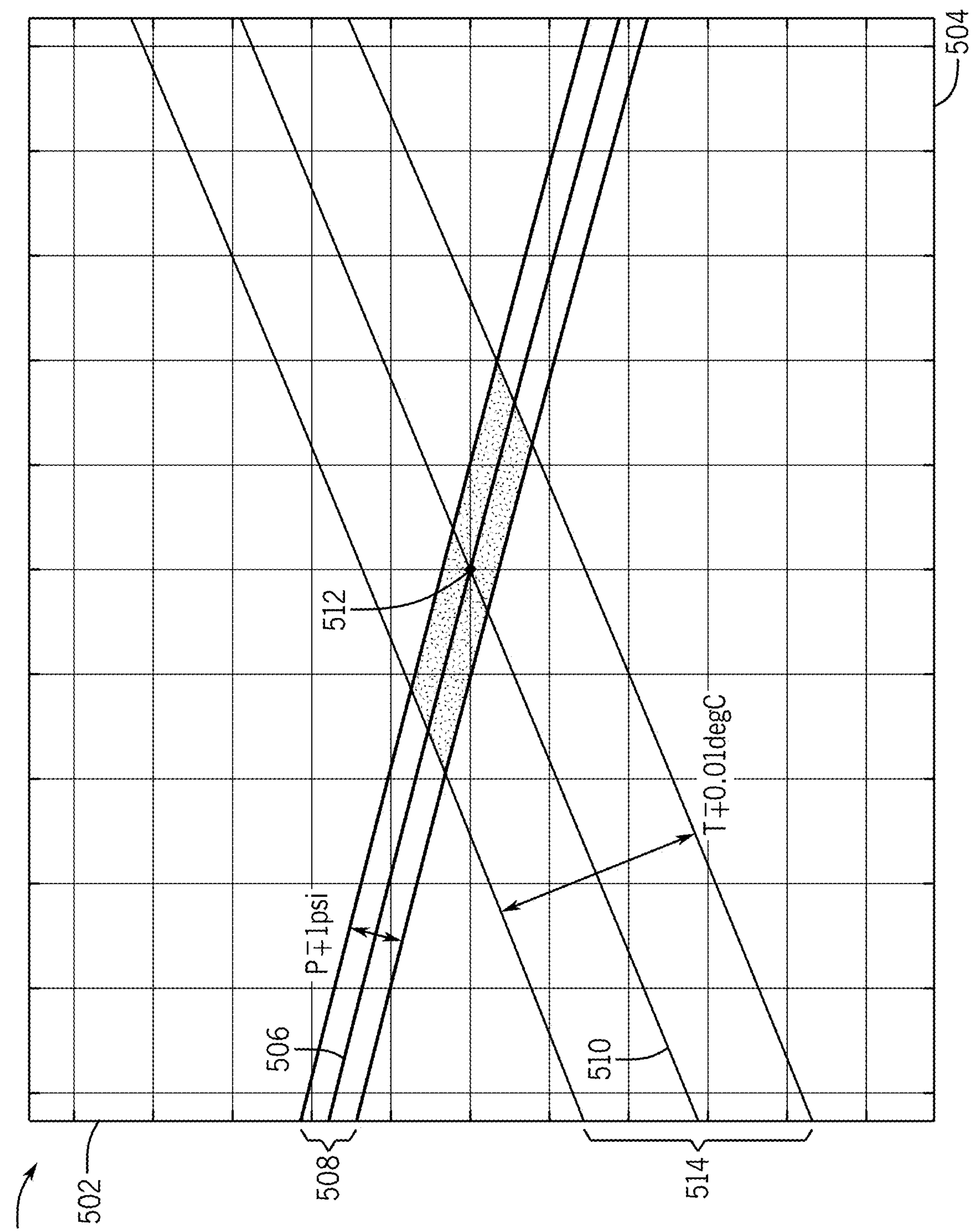
Q tub_dn
436
P tub_dn
438
T tub_dn
440
428
P ann
430
T ann
T JT
424
422
344
T tub_up
434
Q ann
426
αw, αo

FIG. 7

FIG. 8



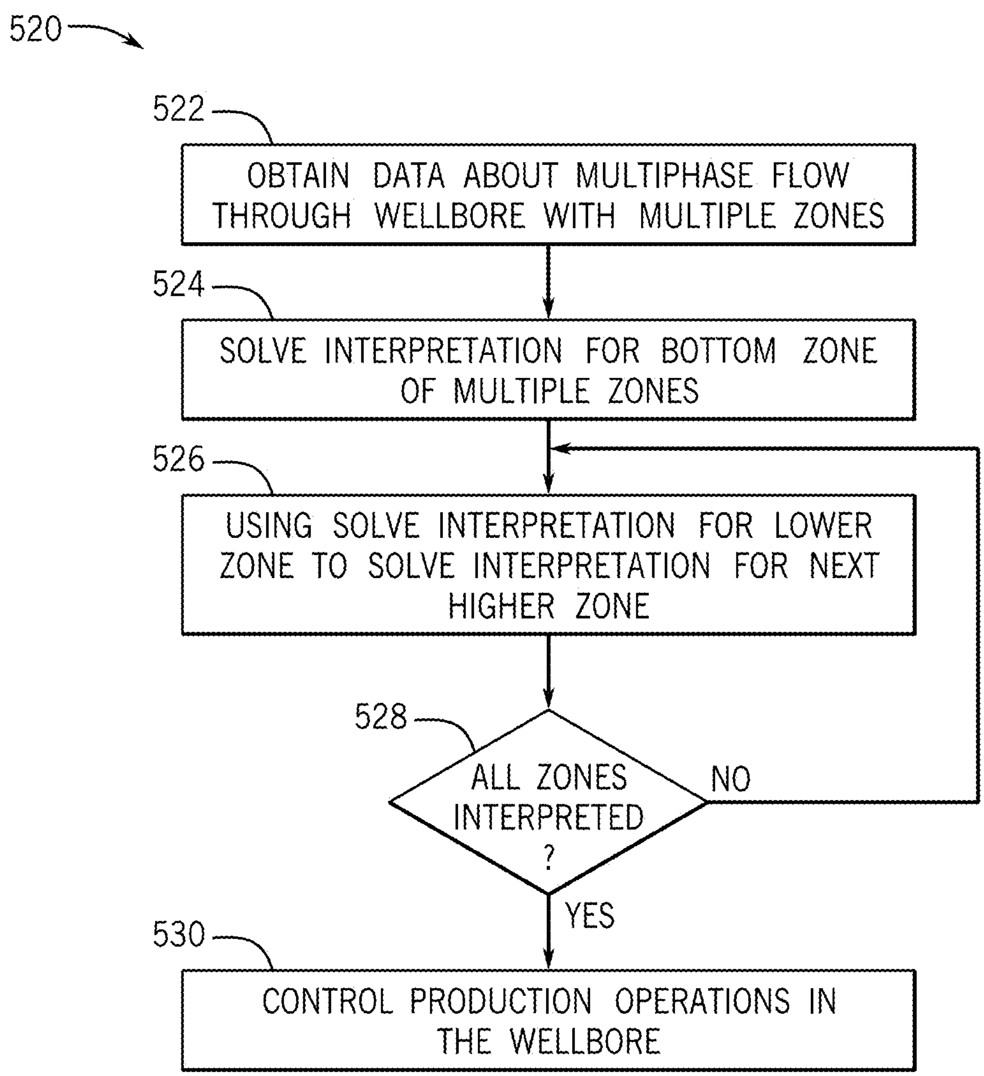

520
522
OBTAIN DATA ABOUT MULTIPHASE FLOW THROUGH WELLBORE WITH MULTIPLE ZONES
524
SOLVE INTERPRETATION FOR BOTTOM ZONE OF MULTIPLE ZONES
526
USING SOLVE INTERPRETATION FOR LOWER ZONE TO SOLVE INTERPRETATION FOR NEXT HIGHER ZONE
528
ALL ZONES INTERPRETED ?
NO
YES
530
CONTROL PRODUCTION OPERATIONS IN THE WELLBORE

FIG. 9

DOWNHOLE ESTIMATION OF MULTIPHASE FLOWS IN PRODUCTION SYSTEMS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims priority to U.S. Provisional Application No. 63/555,653, filed Feb. 20, 2024, which is incorporated by reference herein in its entirety.

FIELD OF THE INVENTION

[0002] This disclosure relates generally to hydrocarbon production and, more particularly, to methods and apparatuses to perform downhole flow metering in multiphase flows.

BACKGROUND INFORMATION

[0003] Wellbores may be drilled into subsurface rocks to create wells to access subterranean fluids, such as hydrocarbons, stored in subterranean formations. When these subterranean fluids are produced from the wells, it may be desirable to obtain certain characteristics of the produced fluids to facilitate efficient and economic exploration and production. For example, it may be desirable to obtain flow rates and/or other characteristics of the produced fluids. These produced fluids are often multiphase fluids (e.g., having some combination of water, oil, and gas) in multiple reservoir zones that have respective flowmeters. However, in some embodiments, the presence of multiple phases and zones may provide an interpretation problem where there are more unknowns than are solvable using conventional mechanisms.

SUMMARY

[0004] A summary of certain embodiments described herein is set forth below. It should be understood that these aspects are presented merely to provide the reader with a brief summary of these certain embodiments and that these aspects are not intended to limit the scope of this disclosure.

[0005] In one embodiment, a system includes multiple sensors located in different zones of a hydrocarbon production system. The multiple sensors are configured to capture parameters about flow through multiple zones of a wellbore. The system also includes a processor that is configured to obtain data about a multiphase flow through the plurality of zones of the wellbore of the hydrocarbon production system from the multiple sensors and to solve an interpretation problem for a first unknown in a bottommost zone. The processor is configured to use a value for the first unknown in the bottommost zone to solve for a second unknown in an upper zone that is above the bottommost zone in the wellbore of the hydrocarbon production system. The processor is configured to change control parameters of the hydrocarbon production system based at least in part on the first unknown and the second unknown.

[0006] In another embodiment, a method includes receiving measurements at a processor from a plurality of sensors in a plurality of zones of a wellbore of a hydrocarbon production system. The method also includes solving, via the processor, an interpretation problem for a first unknown in a bottommost zone of the plurality of zones. Moreover, the method includes using a first value for the first unknown in the bottommost zone to solve for a second unknown using the processor. The second unknown pertains to a parameter in an upper zone of the plurality of zones that is above the bottommost zone in the wellbore of the hydrocarbon production system. Furthermore, the method includes causing, by the processor, a change in an aperture of a programmable flow control valve of the hydrocarbon production system based at least in part on the first unknown and the second unknown.

[0007] In a further embodiment, a system includes a plurality of pressure sensors configured to measure pressure in a plurality of zones in a wellbore in a hydrocarbon production system. The system also includes a plurality of field control valves in the plurality of zones configured to control flow from an annulus into tubing of the wellbore based at least in part on respective aperture sizes of the plurality of field control valves. Moreover, the system includes a plurality of temperature sensors configured to measure temperature in the plurality of zones. The system further includes one or more processors configured to receive the temperature measurements for the plurality of zones and to receive the pressure measurements for the plurality of zones. The one or more processors are further configured to estimate no upstream flow in a most upstream zone of the plurality of zones. The most upstream zone is the furthest zone from a wellhead of the wellbore. The one or more processors also are configured to determine flow properties in the most upstream zone and to use the determined flow properties in the most upstream zone, respective temperature measurements, and respective pressure measurements to determine flow properties of each zone of the plurality of zones in a sequence of most upstream to most downstream. Furthermore, the one or more processors are configured to, based at least in part on flow properties of at least one of the plurality of zones, cause at least one aperture of the plurality of field control valves to change.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] Various aspects of this disclosure may be better understood upon reading the following detailed description and upon reference to the drawings, in which:

[0009] FIG. **1** illustrates a diagram of a data capturing system used to capture data in and/or around an oilfield, such as in a wellbore, in accordance with embodiments of the present disclosure;

[0010] FIG. **2** illustrates a computing system used to process data from the data capturing system of FIG. **1**, in accordance with embodiments of the present disclosure;

[0011] FIG. **3** illustrates a machine learning (ML) based workflow using the computing system of FIG. **2**, in accordance with embodiments of the present disclosure;

[0012] FIG. **4** illustrates a diagram of a well that may be located in the wellbore of FIG. **1**, in accordance with embodiments of the present disclosure;

[0013] FIG. **5** illustrates a process for using a machine learning engine to combine historical measurements, real-time measurements, and simulation results to provide output multiphase flow estimations, in accordance with embodiments of the present disclosure;

[0014] FIG. **6** illustrates a cross-section of a zone of the well of FIG. **4**, in accordance with embodiments of the present disclosure;

[0015] FIG. **7** illustrates a cross-section of a bottommost zone of the well of FIG. **4**, in accordance with embodiments of the present disclosure;

[0016] FIG. **8** illustrates a graph interpreting unknowns of the zones of FIG. **6** or **7**, in accordance with embodiments of the present disclosure; and

[0017] FIG. **9** illustrates a flow diagram of a process that may be performed using one or more computing devices of FIG. **2** to characterize flow properties in a multizonal and multiphase flow, in accordance with embodiments of the present disclosure.

DETAILED DESCRIPTION

[0018] In the following, reference is made to embodiments of the disclosure. It should be understood, however, that the disclosure is not limited to specific described embodiments. Instead, any combination of the following features and elements, whether related to different embodiments or not, is contemplated to implement and practice the disclosure. Furthermore, although embodiments of the disclosure may achieve advantages over other possible solutions and/or over the prior art, whether or not a particular advantage is achieved by a given embodiment is not limiting of the disclosure. Thus, the following aspects, features, embodiments, and advantages are merely illustrative and are not considered elements or limitations of the claims except where explicitly recited in a claim. Likewise, reference to "the disclosure" shall not be construed as a generalization of inventive subject matter disclosed herein and should not be considered to be an element or limitation of the claims except where explicitly recited in a claim.

[0019] Although the terms first, second, third, etc., may be used herein to describe various elements, components, regions, layers and/or sections, these elements, components, regions, layers and/or sections should not be limited by these terms. These terms may be only used to distinguish one element, component, region, layer or section from another region, layer, or section. Terms such as "first," "second" and other numerical terms, when used herein, do not imply a sequence or order unless clearly indicated by the context. Thus, a first element, component, region, layer, or section discussed herein could be termed a second element, component, region, layer, or section without departing from the teachings of the example embodiments.

[0020] When introducing elements of various embodiments of the present disclosure, the articles "a," "an," and "the" are intended to mean that there are one or more of the elements. The terms "comprising," "including," and "having" are intended to be inclusive and mean that there may be additional elements other than the listed elements. Additionally, it should be understood that references to "one embodiment" or "an embodiment" of the present disclosure are not intended to be interpreted as excluding the existence of additional embodiments that also incorporate the recited features. Furthermore, when reciting "or," this disclosure intends such language to be an inclusive or where "A or B" is intended as "A or B or a combination of A and B" unless explicitly indicating that a specific recitation of "or" is intended to be interpreted as an exclusive or.

[0021] As used herein, the terms "connect", "connection", "connected", "in connection with", and "connecting" are used to mean "in direct connection with" or "in connection with via one or more elements"; and the term "set" is used to mean "one element" or "more than one element". Further, the terms "couple", "coupling", "coupled", "coupled together", and "coupled with" are used to mean "directly coupled together" or "coupled together via one or more elements". As used herein, the terms "up" and "down"; "upper" and "lower"; "top" and "bottom"; and other like terms indicating relative positions to a given point or element are utilized to more clearly describe some elements. Commonly, these terms relate to a reference point at the surface from which drilling operations are initiated as being the top point and the total depth being the lowest point, wherein the well (e.g., wellbore, borehole) is vertical, horizontal or slanted relative to the surface.

[0022] Language of degree used herein, such as the terms "approximately," "about," "generally," and "substantially" as used herein represent a value, amount, or characteristic close to the stated value, amount, or characteristic that still performs a desired function or achieves a desired result. For example, the terms "approximately," "about," "generally," and "substantially" may refer to an amount that is within less than 10% of, within less than 5% of, within less than 1% of, within less than 0.1% of, and/or within less than 0.01% of the stated amount. As another example, in certain embodiments, the terms "generally parallel" and "substantially parallel" or "generally perpendicular" and "substantially perpendicular" refer to a value, amount, or characteristic that departs from exactly parallel or perpendicular, respectively, by less than or equal to 15 degrees, 10 degrees, 5 degrees, 3 degrees, 1 degree, or 0.1 degree.

[0023] Some embodiments will now be described with reference to the figures. Like elements in the various figures will be referenced with like numbers for consistency. In the following description, numerous details are set forth to provide an understanding of various embodiments and/or features. It will be understood, however, by those skilled in the art, that some embodiments may be practiced without many of these details, and that numerous variations or modifications from the described embodiments are possible. As used herein, the terms "above" and "below," "up" and "down," "upper" and "lower," "upwardly" and "downwardly," and other like terms indicating relative positions above or below a given point are used in this description to more clearly describe certain embodiments. Furthermore, "optimize" as used herein is intended to cover scenarios where certain objectives/parameters are enhanced or improved even if there may be further improvement available. In other words, an operation may be optimized without being the most optimized possible solution.

[0024] This disclosure relates to a methodology for continuously obtaining multiphase (e.g., two or more phases) downhole full bore flow rates, by combining both downhole and surface data. The method includes actual flow metering data in the full bore, completed by other type of data which shows some sensitivity to the downhole flow rates (e.g., downhole flow control valves, surface choke, and surface flow metering). The composite dataset is consumed using both physical-based and data-driven models. Traditional methodology for estimating flowrates rely on vertical flux modelling. However, this disclosure relates to using dedicated full bore downhole flow metering data to extend phase flow estimations to the flows along the tubing for multiple phases.

[0025] Additionally or alternatively, this disclosure relates to a methodology for obtaining multiphase (e.g., 2 phases) downhole full bore flow rates in multiple reservoir zones using data from a downhole flowmeter installed in each zone. The downhole flowmeter is made of a set of pressure and temperature sensors. For a given zone, the interpretation problem is stated as the determination of three unknowns. However, the flowmeter may provide only two independent data points. To circumvent this issue, the proposed methodology starts at the most bottom zone of the well, where one of the unknowns to be determined (upstream tubing flow) is known to be zero. Resolution in this bottommost zone yields the downstream tubing flow at the bottommost zone. This downstream tubing flow at the bottommost zone is equal to the upstream tubing flow for the next zone directly above the bottommost zone. With this additional knowledge, this next zone interpretation problem can then be solved (e.g., two unknowns with two data points). The procedure then continues sequentially, one zone after another until the interpretation problem is solved for all of the zones along the borehole.

[0026] With the foregoing in mind, FIG. **1** illustrates a system **10** to capture and produce data output **12** in an oilfield that is captured as part of a clean-out operation, wireline operation, pumping operation, drilling operation, extraction operation, or any other operation being performed. In the illustrated embodiment, the data capture is being at least partially performed by a tool **14** suspended by a rig **15** and into a wellbore **16** during such operations. During production, data may be acquired using some tools (e.g., surface measurements). The tool **14** is adapted for deployment into wellbore **16** for generating well logs, performing downhole tests, collecting samples, and/or collecting any other data. For instance, the tool **14** may assist in performing a logging while drilling (LWD) operation. Additionally or alternatively, the tool **14** may, for example, have an explosive, radioactive, electrical, or acoustic energy source **18** that sends and/or receives electrical signals to surrounding subterranean formations **20** and/or fluids therein. Return signals may be detected using the tool **14** and/or other tools located at other locations at/near the oilfield. Additionally or alternatively, the tool **14** may include downhole chokes, sensors (e.g., flowmeters), and/or other devices for measuring and/or controlling flows through the wellbore **16**.

[0027] Computer facilities may be positioned at various locations about the oilfield (e.g., the surface unit **22**) and/or at remote locations. The surface unit **22** may be used to communicate with the tool **14** and/or offsite operations, as well as with other surface or downhole sensors. The surface unit **22** is capable of communicating with the tool **14**, sensors, pumps, one or more chokes **23** (surface and/or subsurface chokes), and/or other equipment. For instance, the choke **23** may be an adjustable choke that controls fluid flow out of the wellbore. The surface unit **22** may also collect data generated during the drilling operation, clean-out operation, production operation, and/or logging and produces data output **12**, which may then be stored or transmitted. In other words, the surface unit **22** may collect data generated during any corresponding operation and may produce data output **12** that may be stored or transmitted.

[0028] The surface unit **22** may include one or more various sensors and/or gauges that may additionally or alternatively be located at other locations in the oilfield. These sensors and/or gauges may be positioned about the oilfield (e.g., in/at the rig **15**) to collect data relating to various field operations. As shown, at least one downhole sensor **24** is positioned in the tool **14** to measure downhole parameters which relate to, for example flow rates, porosity, permeability, fluid composition and/or other parameters of the field operation. During drilling, different or more parameters, such as weight on bit, torque on bit, pressures, temperatures, flow rates, compositions, rotary speed, and/or other parameters of the field operation, may be measured.

[0029] The surface unit **22** may include a transceiver **33** to enable communications between the surface unit **22** and various portions of the oilfield or other locations. The surface unit **22** may also be provided with or functionally connected to one or more controllers for actuating mechanisms at the oilfield. The surface unit **22** may then send command signals to the oilfield in response to data received. The surface unit **22** may receive commands via the transceiver **33** and/or may itself execute commands to the controller. A computing system including a processor may be included to analyze the data (locally or remotely), make decisions, control operations, and/or actuate the controller. In this manner, the oilfield may be selectively adjusted based on the data collected. This technique may be used to enhance portions of the field operation, such as controlling drilling, weight on bit, pump rates, and/or other parameters. These adjustments may be made automatically based on an executing application with or without user input.

[0030] A mud pit **26** is used to draw drilling mud into the drilling tools via flow line **28** for circulating drilling mud down through the drilling tools, then up wellbore **16** and back to the surface. The drilling mud may be filtered and returned to the mud pit **26**. A circulating system may be used for storing, controlling, or filtering the flowing drilling muds. The drilling tools are advanced into subterranean formations **20** to reach a reservoir **30** from which petrochemicals are extracted. Each well may target one or more reservoirs using one or more locations along the wellbore **16**.

[0031] Generally, the wellbore **16** is drilled according to a drilling plan that is established prior to drilling. The drilling plan sets forth equipment, pressures, trajectories and/or other parameters that define the drilling process for the wellsite. The drilling operation may then be performed according to the drilling plan. For instance, the wellbore **16** may have various different geometries, such as vertical (as shown), deviated, and/or horizontal.

[0032] After the drilling operation is completed, at least some drilling mud and/or other materials other than the desired subterranean fluid may remain in the wellbore. To remove these unwanted materials, a clean-up operation may be performed. As effluent travel upwards through the wellbore **16**, it travels through the choke **23**. As previously noted, this effluent may be multiphase consisting of multiple fluids (e.g., oil, gas, and water). This multiphase fluid traverses the choke **23** and enters into a separation and analysis system **32**. The separation and analysis system **32** may be at least partially included in the surface unit **22**. The separation and analysis system **32** may include a horizontal separator, a vertical separator, and/or any other mechanisms that may facilitate separation of the incoming effluent. For instance, the separator may include a 3-phase gravity separator that separates the effluent into its separate gas, oil, and water sub-elements. The analysis portion of the separation and analysis system **32** may evaluate how successful the separation of the sub-elements has been.

[0033] The data gathered by sensors **24** may be collected by the surface unit **22** and/or other data collection sources for analysis or other processing. The data collected by the sensors **24** may be used alone and/or in combination with other data. The data may be collected in one or more databases and/or transmitted to another location on-site or offsite. The data may be historical data, real time data, or combinations thereof. The real time data may be used in real time or stored for later use. The data may also be combined with historical data and/or other inputs for further analysis. The data may be stored in separate databases and/or combined into a single database.

[0034] FIG. **2** is a block diagram of a system **250** that may be used for analyzing/utilizing the data output **12** from the system **10**, as described in FIG. **1**. The data output **12**, as described in FIG. **1**, is received as input data **252** at a computing device **254**. The computing device **254** may be implemented in the surface unit **22** and/or may be implemented at other locations within the oilfield or remotely from the oilfield where the remote locations are able to receive the data via the transceiver **33**. The various functional blocks shown in FIG. **2** may include hardware elements (including circuitry), software elements (including computer code stored on a tangible, non-transitory computer-readable medium), or a combination of both hardware and software elements. It should be noted that FIG. **2** is merely one example of a particular implementation and is intended to illustrate the types of components that may be present in the computing device **254**.

[0035] As illustrated, the computing device **254** includes one or more processor(s) **256**, a memory **258**, a display **260**, input devices **262**, one or more neural networks(s) **264**, and one or more interface(s) **266**. In the computing device **254**, the processor(s) **256** may be operably coupled with the memory **258** to facilitate the use of the processors(s) **256** to implement various stored programs. Such programs or instructions executed by the processor(s) **256** may be stored in any suitable article of manufacture that includes one or more tangible, computer-readable media at least collectively storing the instructions or routines, such as the memory **258**. The memory **258** may include any suitable articles of manufacture for storing data and executable instructions, such as random-access memory, read-only memory, rewritable flash memory, hard drives, and optical discs. In addition, programs (e.g., an operating system) encoded on such a computer program product may also include instructions that may be executed by the processor(s) **256** to enable the computing device **254** to provide various functionalities.

[0036] The input devices **262** of the computing device **254** may enable a user to interact with the computing device **254** (e.g., pressing a button to increase or decrease a volume level). The interface(s) **266** may enable the computing device **254** to interface with various other electronic devices. The interface(s) **266** may include, for example, one or more network interfaces for a personal area network (PAN), such as a Bluetooth network, for a local area network (LAN) or wireless local area network (WLAN), such as an IEEE 802.11x Wi-Fi network or an IEEE 802.15.4 wireless network, and/or for a wide area network (WAN), such as a cellular network. The interface(s) **266** may additionally or alternatively include one or more interfaces for, for example, broadband fixed wireless access networks (WiMAX), mobile broadband Wireless networks (mobile WiMAX), and so forth.

[0037] In certain embodiments, to enable the computing device **254** to communicate over the aforementioned wireless networks (e.g., Wi-Fi, WiMAX, mobile WiMAX, 4G, LTE, and so forth), the computing device **254** may include a transceiver (Tx/Rx) **267**. The transceiver **267** may include any circuitry that may be useful in both wirelessly receiving and wirelessly transmitting signals (e.g., data signals). The transceiver **267** may include a transmitter and a receiver combined into a single unit.

[0038] The input devices **262**, in combination with the display **260**, may allow a user to control the computing device **254**. For example, the input devices **262** may be used to control/initiate operation of the neural network(s) **264**. Some input devices **262** may include a keyboard and/or mouse, a microphone that may obtain a user's voice for various voice-related features, and/or a speaker that may enable audio playback. The input devices **262** may also include a headphone input that may provide a connection to external speakers and/or headphones.

[0039] The neural network(s) **264** may include hardware and/or software logic that may be arranged in one or more network layers. In some embodiments, the neural network(s) **264** may be used to implement machine learning and may include one or more suitable neural network types. For instance, the neural network(s) **264** may include a perceptron, a feed-forward neural network, a multi-layer perceptron, a convolutional neural network, a long short-term memory (LSTM) network, a sequence-to-sequence model, and/or a modular neural network. In some embodiments, the neural network(s) **264** may include at least one deep learning neural network. Furthermore, the neural network(s) **264** may be at least partially implemented using the one or more processor(s) **256**. For instance, the neural network(s) **264** may be implemented using the one or more processor(s) **256**. For example, the neural network(s) **264** may be implemented using a central processing unit (CPU), a graphics processing unit (GPU), a programmable logic device (e.g., a field-programmable gate array (FPGA), an application-specific integrated circuit (ASIC)), other suitable circuitry, or a combination thereof.

[0040] The output of the neural network(s) **264** may be based on the input data **252**, such as flow rates or other data captured during drilling, clean-out, extraction/production, and/or other operations. This output may be used by the computing device **254**. Additionally or alternatively, the output from the neural network(s) **264** may be transmitted using a communication path **268** from the computing device **254** to a gateway **270**. The communication path **268** may use any of the communication techniques previously discussed as available via the interface(s) **266**. For instance, the interface(s) **266** may connect to the gateway **270** using wired (e.g., Ethernet) and/or wireless (e.g., IEEE 802.11) connections. The gateway **270** couples the computing device **254** to a wide-area network (WAN) connection **272**, such as the Internet. The WAN connection **272** may couple the computing device **254** to a cloud network **274**. The cloud network **274** may include one or more computing devices **254** grouped into one or more locations (e.g., data centers). The cloud network **274** includes one or more databases **276** that may be used to store the output of the neural network(s) **264** and/or other data. In some embodiments, the cloud network **274** may perform additional transformations on the data using its own processor(s) **256** and/or neural network(s) **264**.

[0041] The computing device **254** may be used to implement a machine learning (ML)-based methodology (e.g., using the neural network(s) **264**). As discussed below, the ML-based methodology may combine a hybrid model combining physical measurements with synthetic data and combining surface data with downhole data including monitoring data in the full wellbore **16**. FIG. **3** is a flow diagram of a ML-based process **300**. The process **300** uses an offline model **302** that is developed using module A **304** and module B **306**.

[0042] Module A **304** includes physical test measurement data from downhole tool tests (e.g., the tool **14**) including validation and verification tests for downhole systems, validation and verification tests for monitoring sensors, manufacturing for downhole systems, system integration test and so on. The measured and system control parameters can include and/or be measured using, but are not limited to the following: temperature and pressure sensors, flow rate and related sensors (e.g., Venturi sensors), thermal anemometry sensors, passive acoustic/pressure array of sensors, active acoustic measurements (Doppler, time-of-flight, etc.), induction sensors, electrical measurements (resistive, capacitive, dielectric, etc.), photoacoustic measurements, nuclear magnetic resonance (NMR) measurements, nuclear spectroscopy, data from downhole flow control valves (FCV) including choke aperture and pressure differential across the valves and the like, data from wellhead valves including choke aperture and pressure differential across the valves and the like, data from surface flow metering such as a Vx Spectra flowmeter available from SLB, and/or any other suitable physical test measurements that may impact multiphase flow through the wellbore **16**.

[0043] Module B **306** includes synthetic data that may be obtained from simulations using a simulator implemented using one or more computing devices **254**. The simulation data may represent downhole and/or surface systems based on a physical model or "digital avatar" for the system **10**. The digital avatar may model the physics of the valves in the system including downhole FCVs and/or surface chokes, flow sensors dedicated to downhole flow metering, and/or other portions of the system that may impact multiphase flow through the wellbore **16**. Moreover, the fluid flow along the whole well production system from bottom of the hole to surface may be determined using a devoted simulator, such as a steady-state multiphase flow simulator (e.g., PIPESIM), a dynamic multiphase flow simulator (e.g., OLGA), TMIX, and/or other simulators. Moreover, the simulators may also consider the temperature behavior.

[0044] The physical measurements from Module A **304** and the synthetic data from Module B **306** are calibrated in the offline model **302** using field data from Module C **308** for each well before production including the tool test data, commissioning data from all the tools considered in the interpretation, well characterizations, production tests, well geometry, cleanout results, and/or any other data from the field that may be used to calibrate the offline model **302** to the specific wellbore **16**.

[0045] The offline model **302** also receives field data in real-time as Module D **310**. For instance, the real-time field data may be and/or may include the input data **252**. The real-time field data may include data from sensors in the field during real-time operation that may include surface data, downhole data from multiple zones, or a combination thereof. The surface data may be continuous data (e.g., pressure differential and/or choke aperture) from a flow meter (e.g., a Vx Spectra flow meter). The downhole data may include choke aperture, pressure differential across the choke, temperature, wellhead pressure, and/or other suitable data from multiple zones and possibly from nearby wells.

[0046] The offline model **302** uses an ML engine, Module E **312**, that uses one or more computing devices **254** to implement machine learning. The ML engine may perform data reconciliation to decrease errors in the system. Specifically, the ML engine analyzes the relationship between input data of Module D **310** and output estimates **314** with given inputs in given conditions. The data reconciliation step applied after forming the offline model **302** using Module A **304** and Module B **306** reduces errors such as random errors from the physical measurements, systematic errors from the physical measurements, systematic errors from the simulation engine, and/or other errors in the calculations. The output of the ML engine is the output estimates **314** that estimates flow rates for multiple phases (e.g., 2, 3, or more phases). The estimates may be for various zones along the wellbore **16**, such as along the entire wellbore **16** where subsurface sensors are along with their associated uncertainties.

[0047] FIG. **4** is a diagram of a well **340** that may be in the borehole **16**. Although the well is illustrated with a particular geometry, the well **340** may have any suitable geometry, such as vertical, horizontal, deviated, and/or any other possible geometry. As illustrated, the well **340** includes a casing **342** for the well **340** and tubing **344**. The casing **342** has multiple reservoir access portions **346** where the well **340** may access one or more reservoirs from various locations. As illustrated, the reservoir access portions **346** are within respective zones of the well **340**. In the illustrated embodiment of the well **340**, the well **340** includes a first zone **354**, a second zone **356**, and a third zone **358**. However, embodiments of the well **340** compliant with the teachings herein may include any suitable number of zones, such as two, three, four, or more zones. The well **340** includes a wellhead choke **352** as a surface choke. In compartmentalized reservoirs, the first zone **354**, the second zone **356**, and the third zone **358** may be separated using packers **360**.

[0048] The well **340** also includes two or more subsurface chokes/flow control valves (FCVs). As illustrated, each zone may include a respective FCV. For instance, the first zone **354** includes an FCV **362**, the second zone **356** includes a FCV **364**, and the third zone **358** includes an FCV **366**. The FCVs **362**, **364**, and **366** may be independently controlled due to various factors in the well **340**. For instance, the apertures of the FCVs **362**, **364**, and **366** may be set at least in part on flows of various phases in the respective zones. Additionally or alternatively, the FCVs **362**, **364**, and **366** may be controlled to cause specific flow parameters, such as to shape slugs or perform cleanout of the wellbore **16**. Along with the FCVs **362**, **364**, and **366**, the first zone **354**, the second zone **356**, and the third zone **358** includes sensors **368**, **370**, and **372** that may include flow meters that measure flow rates, pressure, temperatures, and/or other parameters at, near, and/or across the FCVs **362**, **364**, and **364**. The teachings herein may include any suitable number of sensors, such as two, three, four, or more sensors.

[0049] Using the embodiment of the well **340**, Module B **306** would include inputs and outputs of a set of simulators run with a dedicated well flow simulator (e.g., PIPESIM) using the exact well geometry for a high number of cases. The main simulation inputs may include (for each of the three zones): the FCV choke aperture, the total flow through the choke, and the phase fractions (oil, water, gas, etc.) of the flow though each choke. The outputs are the simulated measurements of the flow meters in each zone, and possibly choke/flow data from the wellhead choke **352**. The Module E **312** is a trained ML model using the simulations from Module B **306** along with additional test measurements from Module A **304** and calibration from Module C **308**.

[0050] Module D **310** is the real-time acquired field data from the wellhead choke **352**, the FCVs **362**, **364**, and **366** and related sensors **368**, **370**, and **372**. Module E **312** uses this data to predict a multiphase (e.g., 3 phase) flow rate in real-time for each zone including the total flow through the respective chokes and the phase fractions of flows through the respective chokes. FIG. **5** illustrates this process **400** with the digital avatar **402** used to generate simulated well data **404** and simulated well flow rates **406**. The digital avatar **402** includes choke and flow sensor data (FloX and Vx) and simulated data while the simulated well data **404** and the simulated well flow rates **406** include choke apertures/openings, pressure differentials across the chokes, flow rates downhole and out of the well head, and/or other suitable parameters. A ML-based model **408**/ML engine may be used to refine the simulated well flow rates **406** using the simulated well data **404**, historical well data **410**, and real-time well data **412**. The historical well data **410** may include historical choke apertures/openings, historical pressure differentials across the chokes, historical flow rates downhole and out of the well head, and/or other suitable historical parameters while the real-time well data **412** includes real-time choke apertures/openings, real-time pressure differentials across the chokes, real-time flow rates downhole and out of the well head, and/or other suitable real-time parameters. The ML-based model **408** may also generate/refine historical well flow rates **414** and real-time estimated flow rates **416** based on the historical well data **410** and/or the real-time well data **412**. The historical well flow rates **414** and real-time estimated flow rates **416** may include respective flow rates for each zone and their respective phase fractions to determine flow of each phase.

[0051] FIG. **6** is a cross-section of a zone **420** (e.g., second zone **356** or third zone **358**) of the well **340**. As illustrated, the zone **420** includes a portion of the tubing **344** running through the zone **420**. The zone **420** also includes an annulus **421** that is outside of the tubing **344** but inside the casing **342**. The annulus **421** and the inside of the tubing **344** are separated by an aperture **422**. The aperture **422** may be part of an FCV, such as the FCV **364** or **366**. There is a flow **424** through the aperture **422**. This flow may be a mixture that has a temperature that is at least partially based on the Joule-Thomson effect that effects a temperature change of gas or liquid when it is forced through a pressure difference of the aperture **422**. However, this temperature (TJT) may be difficult or impossible to capture at the aperture **422**. Instead, other measurements may be made by the sensors **368**, **370**, and/or **372**. For instance, the sensors **368**, **370**, and/or **372** may be used to capture an annulus pressure (Pann) **428**, an annulus temperature (Tann) **430**, a tubing upstream temperature (Ttub_up) **434** upstream of the aperture **422** (i.e., away from the wellhead), a tubing downstream pressure (Ptub_dn) **438** downstream of the aperture **422** (i.e., towards the wellhead), a tubing downstream temperature (Ttub_dn) **440**, and/or other parameters may be measured directly. Other parameters in the zone **420** may be difficult and/or impossible to measure directly similar to the TJT. For instance, the illustrated zone **420** shows a total flow in the annulus (Qann) **426** that includes a mix of two phases (e.g., oil and water) in a phase fraction indicated by the following equation:

$$\alpha_w + \alpha_o = 1, \qquad \text{(Equation 1)}$$

where the Qann **426** is a two-phase flow of two phases (e.g., oil and water, oil and gas, water and gas, or the like). Although the following discusses oil and water phases, the following discussion may be applied consistently with any other phase mixture of multiphase flows. α_w is a phase fraction that indicates a percentage of the Qann **426** that is water while α_o is a phase fraction that indicates a percentage of the Qann **426** that is oil. As noted in Equation 1, the percentages added together form 100% of the Qann **426**.

[0052] The illustrated embodiment of the zone **420** also shows a total flow in the tubing upstream of the aperture **422** (Qtub_up) **432** flowing toward the aperture **422** and a total flow in the tubing downstream of the aperture **422** (Qtub_dn) **436**. The relationship of Qann **426**, Qtub_up **432**, and the Qtub_dn **436** are reflected in the following equation:

$$Q_{tub\_dn} = Q_{tub\_up} + Q_{ann}. \qquad \text{(Equation 2)}$$

[0053] The Qann **426** through the aperture **422** may be determined using the following equation:

$$Q_{ann} = C_d A \sqrt{\frac{2(P_{ann} - P_{tub\_dn})}{\rho(\alpha_w, \alpha_o)}} \qquad \text{(Equation 3)}$$

[0054] where Cd are choke parameters related to the geometry of the choke aperture **422**, A is the area of the aperture **422**, and $\rho(\alpha_w, \alpha_o)$ is a density of the mixture of the two phases in the Qann **426** characterized by the phase fractions and their respective densities. Deriving the total flow and the phase fractions enable determining the flows of the individual phases where multiplying the Qann **426** times the phase fraction of a phase (e.g., water, oil, or gas) provides the flow of the corresponding phase through the annulus **421**.

[0055] As previously noted, the Tur may not be practically measured directly and may be determined indirectly. For instance, T_{JT} may be found using the following equation:

$$T_{ann} - T_{JT} = [\mu(\alpha_W, \alpha_o)](P_{ann} - P_{tub\_db}), \qquad \text{(Equation 4)}$$

where $\rho(\alpha_w, \alpha_o)$ is the Joule-Thomson coefficient of the mixed fluid characterized by the phase fractions and their respective Joule-Thomson coefficients.

[0056] Furthermore, the temperature mixing of the fluids may be expressed using the following equation:

$$T_{tub\_dn} Q_{tub\_dn} = T_{tub\_up} Q_{tub\_up} + T_{JT} Q_{ann}. \qquad \text{(Equation 5)}$$

[0057] Equations 3-5 provide 2 independent equations (Equation 3 and Equations 4 and 5) with 3 independent unknowns: Q_{tub_up}, Q_{ann}, and α_w. These equations may be combined to form a new equation:

$$T_{tub\_dn}(Q_{tub\_up}+Q_{ann}) = T_{tub\_up}Q_{tub\_up}+[T_{ann}-[\mu(\alpha_w,\alpha_o)](P_{ann}-P_{tub\_dn})]Q_{ann}. \quad \text{(Equation 6)}$$

In some embodiments, this equation may be replaced by a more elaborated model from computational fluid dynamics (CFD) simulations of the flow through respective chokes. Even with the combined equation of two independent equations, the problem is under-determined due to more unknowns than independent equations. However, as illustrated in zone **450** of FIG. **7** in the bottommost zone of the well **340** (e.g., the first zone **354**), there is no flow coming from upstream of the tubing **344** to the corresponding FCV **362**. In other words, the zone **450** is like the zone **420** except that since the zone **450** is the bottommost zone, the Qtub_up **432** is 0 in this zone as opposed to some unknown value in the zone **420**. In the zone **450**, one unknown is eliminated thereby causing the problem to utilize two independent equations to solve two unknowns. For instance, the remaining unknowns Q_{ann}, and α_w may be interpreted using a graphical approach, such as using graph **500** of FIG. **8**. Additionally or alternatively, the problem equations (Equation 3 and Equations 3 plus 5) may be solved numerically by solving the problem in a non-linear system of two equations using a numerical solver (e.g., MATLAB).

[0058] As previously noted, FIG. **8** shows a graph **500** that may be used to solve the problem of the bottommost zone, such as zone **450**. The graph **500** has a vertical axis **502** that corresponds to annulus total flow (Q_{ann}) and a horizontal axis **504** that corresponds to a phase fraction (e.g., water fraction). The graph **500** also includes a line **506** that corresponds to a plot of an equation on the graph that corresponds to a pressure interpretation. For very low flow through the choke, the downstream pressure is close to the reservoir or pressure annulus (e.g., 8.5 kpsi). The higher the flow through the choke, the higher the pressure differential thereby causing a lower Ptub_dn. The graph **500** may also take into account some uncertainties in the pressure and plot a region **508** between lines that include some amount of uncertainty (e.g., ±1 psi). Furthermore, the graph **500** includes a line **510** that corresponds to a temperature interpretation. For very low flow through the choke, the downstream temperature is close to the reservoir or annulus temperature (e.g., 130° C.). The higher the flow through the choke, the higher temperature differential (e.g., due to JT effect). Tdub_dn is higher than the Tann due to the negative JT coefficients of both oil and water. Like the region **508**, the graph **500** may include an uncertainty region **514** that accommodates some amount of uncertainty (e.g., ±0.01° C.).

[0059] For the sake of an example, a solution **512** may exist for Q_{ann}=6 kbpd and α_w=10% where the lines **506** and **510** intersect. For instance, the intersection may correspond to a value (e.g., Ptub_db=8 kpsi) with a corresponding pressure differential (e.g., 500 psi) through the aperture **422**. Once these values are obtained, zonal phasic flows may be derived for both phases (e.g., oil and water). For instance, if aw is known and the water flow Qw,ann or total flow Qann may be derivable from another value. Likewise, the oil flow may be found by subtracting the water flow Qann,w from the total flow Qann.

[0060] Once a problem is solved/interpreted for the bottommost region, the values found for the Qtub_dn **436** (total and/or for any individual phases) for this zone may be used as Qtub_up **432** for an adjacent zone that is downstream of the bottommost zone. In embodiments where there is a significant pressure or temperature difference between zones, an adjustment may be made to the downstream flow of one zone to the upstream flow of the next zone. For example, this adjustment may be applied according to a well flow simulation model, such as PIPESIM. Using this known value for Qtub_up **432** for the adjacent upper zone, there are now two unknowns and two independent equations enabling solving of the unknowns for the adjacent upper zone. The solving of these unknowns may be performed similar to how the bottommost zone is resolved, such as using a numerical solver and/or solved using graphical intersections and also used to find phasic zonal flows. Once this zone (e.g., the second zone **356**) is resolved, it's Qtub_dn **436** may be used as Qtub_up **432** for the next zone (e.g., the third zone **358**). This use of flows from one zone to the next zone may be resolved in order until the complete well and all of its zones have been resolved.

[0061] FIG. **9** is a flow diagram of a process **520** that may be performed using one or more computing devices **254**. In some embodiments, at least a portion of the process **520** may be performed by well equipment located in the field (surface or sub-surface) and/or using cloud computing. The process **520** includes the one or more computing devices **254** obtaining data about multiphase flow through a wellbore with multiple zones (block **522**). For instance, one or more processors of the one or more computing devices **254** may receive temperature, pressure, flow rates, phase fractions, and/or other parameters from historical measurements in Module A **304**, synthetic data from simulators in Module B **306**, real-time surface data from sensors as Module D **310**, manual input, and/or a combination thereof. The one or more processors solves an interpretation (e.g., an interpretation problem) for a bottommost zone of the multiple zones (block **524**). For instance, the processor determines that the Qtub_up **432** of the bottommost zone is zero and solves for Qann **426** and Qtub_dn **436** using a numerical solver and/or using a graphical solver. Solving the interpretation for the bottommost zone includes solving for total flow, solving for a flow of a first phase (e.g., water) of the total flow, and/or solving for a flow of a second phase (e.g., oil) of the total flow through the annulus **421** and the tubing **344**.

[0062] The one or more processors then uses the solved interpretation (e.g., Qtub_dn **436**) of a bottommost zone to solve an interpretation of a next higher zone (block **526**). For instance, the one or more processors may solve for unknowns (e.g., Qtub_dn **436** and Qann **426**) in the next higher zone using values (e.g., Qtub_dn **436**) and values (e.g., Qtub_up **432**) from the bottommost zone. The one or more processors determines whether all zones have been interpreted (block **528**). If more zones are to be interpreted, the one or more processors moves the next zone and interprets it similar to how a previous zone has been interpreted. Once all zones have been interpreted, the one or more processors applies one or more commands to control production operations in the wellbore **16** (block **530**). For instance, the one or more processors may change aperture sizes of the programmable chokes/FCVs downhole based on the determined values. For instance, if water flow exceeds a threshold for a zone/the entire well, the one or more processors may at least partially close at least one of the chokes FCVs based on the flow rates.

[0063] Although a few embodiments of the disclosure have been described in detail above, those of ordinary skill in the art will readily appreciate that many modifications are possible without materially departing from the teachings of this disclosure. Accordingly, such modifications are intended to be included within the scope of this disclosure as defined in the claims. It is also contemplated that various combinations or sub-combinations of the specific features and aspects of the embodiments described may be made and still fall within the scope of the disclosure. It should be understood that various features and aspects of the disclosed embodiments can be combined with, or substituted for, one another in order to form varying modes of the embodiments of the disclosure. Thus, it is intended that the scope of the disclosure herein should not be limited by the particular embodiments described above.

[0064] The techniques presented and claimed herein are referenced and applied to material objects and concrete examples of a practical nature that demonstrably improve the present technical field and, as such, are not abstract, intangible, or purely theoretical. Moreover, although various actions are discussed as part of processes in a specific order, at least some of the actions may be performed in different orders. Additionally, at least some of the actions may be performed by one or more processors **256** of suitable computing devices. Further, if any claims appended to the end of this specification contain one or more elements designated as "means for [perform]ing [a function] . . . " or "step for [perform]ing [a function] . . . ," it is intended that such elements are to be interpreted under 35 U.S.C. § 112 (f). However, for any claims containing elements designated in any other manner, it is intended that such elements are not to be interpreted under 35 U.S.C. § 112 (f).29

What is claimed is:

1. A system, comprising:

a plurality of sensors located in different zones of a hydrocarbon production system, wherein the plurality of sensors is configured to capture a plurality of parameters about flow through a plurality of zones of a wellbore of the hydrocarbon production system; and

a processor configured to:

obtain data about a multiphase flow through the plurality of zones of the wellbore of the hydrocarbon production system from the plurality of sensors;

solve an interpretation problem for a first unknown in a bottommost zone of the plurality of zones;

use a value for the first unknown in the bottommost zone to solve for a second unknown in an upper zone of the plurality of zones that is above the bottommost zone in the wellbore of the hydrocarbon production system; and

change control parameters of the hydrocarbon production system based at least in part on the first unknown and the second unknown.

2. The system of claim **1**, wherein the upper zone is adjacent to the bottommost zone in the wellbore of the hydrocarbon production system.

3. The system of claim **1**, wherein the first unknown comprises a downstream flow rate for the bottommost zone.

4. The system of claim **3**, wherein the second unknown comprises a downstream flow rate of the upper zone, and solving for the second unknown comprises setting an upstream flow rate of the upper zone to the downstream flow rate of the bottommost zone.

5. The system of claim **4**, wherein solving the interpretation problem for the first unknown comprises setting an upstream flow rate of the bottommost zone to zero.

6. The system of claim **3**, wherein the downstream flow rate comprises a total downstream flow rate.

7. The system of claim **6**, wherein the processor is configured to determine a fractional flow rate of a phase of a mixture flowing from the bottommost zone into the upper zone using a phase fraction for a corresponding phase.

8. The system of claim **7**, wherein the processor is configured to receive the phase fraction from a simulator or via manual input.

9. The system of claim **3**, wherein the downstream flow rate comprises a fractional flow rate of a phase of a mixture flowing from the bottommost zone into the upper zone.

10. The system of claim **9**, wherein the processor is configured to determine a total flow rate using the fractional flow rate and a phase fraction for a corresponding phrase.

11. The system of claim **1**, wherein each of the plurality of zones comprises a flow control valve (FCV).

12. The system of claim **11**, wherein the data about the multiphase flow comprises:

a pressure of an annulus around a casing in each of the plurality of zones;

a temperature of the annulus in each of the plurality of zones;

an upstream pressure for each of the plurality of zones inside the casing inside the respective zone upstream of the respective FCV of the zone;

an upstream temperature for each of the plurality of zones inside the casing inside the respective zone upstream of the respective FCV of the zone; and

a downstream temperature for each of the plurality of zones inside the casing inside the respective zone downstream of the respective FCV of the zone.

13. The system of claim **11**, wherein changing the control parameters comprises causing an aperture size of at least one of the FCVs to be adjusted based at least in part on the first unknown or the second unknown.

14. A method, comprising:

receiving measurements at a processor from a plurality of sensors in a plurality of zones of a wellbore of a hydrocarbon production system;

solving, via the processor, an interpretation problem for a first unknown in a bottommost zone of the plurality of zones;

using a first value for the first unknown in the bottommost zone to solve for a second unknown using the processor, wherein the second unknown pertains to a parameter in an upper zone of the plurality of zones that is above the bottommost zone in the wellbore of the hydrocarbon production system; and

causing, by the processor, a change in an aperture of a programmable flow control valve of the hydrocarbon production system based at least in part on the first unknown and the second unknown.

15. The method of claim **14**, wherein the first unknown comprises a downstream flow in tubing of the wellbore in the bottommost zone, and solving for the first unknown comprises assuming that an upstream flow in the tubing of the wellbore in the bottommost zone is zero.

16. The method of claim **15**, wherein the second unknown comprises a downstream flow in the tubing of the wellbore in the upper zone, and solving for the first unknown comprises estimating that an upstream flow in the tubing of the wellbore in the upper zone is equal to the solved downstream flow in the tubing of the wellbore in the bottommost zone.

17. The method of claim **15**, wherein the second unknown comprises a downstream flow in the tubing of the wellbore in the upper zone, and solving for the first unknown comprises estimating an upstream flow in the tubing of the wellbore in the upper zone based on an adjustment to the solved downstream flow in the tubing of the wellbore in the bottommost zone, wherein the method comprises receiving the adjustment using a well flow simulation model to determine that there is a pressure or temperature difference to be accounted for between an interior of the tubing in the bottommost zone and the upper zone.

18. The method of claim **14**, comprising using a second value for the second unknown in the upper zone to solve for a third unknown using the processor, wherein the third unknown pertains to an additional parameter in an additional upper zone that is above the upper zone in the wellbore of the hydrocarbon production system.

19. A system, comprising:

a plurality of pressure sensors configured to measure pressure in a plurality of zones in a wellbore in a hydrocarbon production system;

a plurality of field control valves in the plurality of zones configured to control flow from an annulus into tubing of the wellbore based at least in part on respective aperture sizes of the plurality of field control valves;

a plurality of temperature sensors configured to measure temperature in the plurality of zones; and

one or more processors configured to:

receive the temperature measurements for the plurality of zones;

receive the pressure measurements for the plurality of zones;

estimate no upstream flow in a most upstream zone of the plurality of zones, wherein the most upstream zone is the furthest zone from a wellhead of the wellbore;

determine flow properties in the most upstream zone;

use the determined flow properties in the most upstream zone, respective temperature measurements, and respective pressure measurements to determine flow properties of each zone of the plurality of zones in a sequence of most upstream to most downstream; and

based at least in part on flow properties of at least one of the plurality of zones, cause at least one aperture of the plurality of field control valves to change.

20. The system of claim **19**, wherein the flow properties of the plurality of zones comprises a total flow of a mixture and one or more phasic flows of phases of the mixture.

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