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

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
12 December 2024 (12.12.2024)

WIPO | PCT

(10) International Publication Number
WO 2024/253555 A1

(51) International Patent Classification:
G01F 1/00 (2022.01) *G06Q 10/04* (2023.01)
E21B 47/003 (2012.01)

(21) International Application Number:
PCT/RU2023/000173

(22) International Filing Date:
06 June 2023 (06.06.2023)

(25) Filing Language: English

(26) Publication Language: English

(71) Applicant *(for AG only)*: **ARAMCO INNOVATIONS LLC** [RU/RU]; Varshavskoye hwy., 9, bld. 1., Moscow, 117105 (RU).

(71) Applicant: **SAUDI ARABIAN OIL COMPANY** [SA/SA]; P.O. Box 5000, Dhahran, 31311 (SA).

(72) Inventors: **GRYZLOV, Anton Nikolaevich**; Leninskiye Gory 1-75B, Moscow, 119234 (RU). **SAFONOV, Sergey Sergeevich**; Leninskiye Gory 1-75B, Moscow, 119234 (RU). **ARSALAN, Muhammad**; c/o Saudi Aramco, P.O. Box 8459, Dhahran, 31311 (SA).

(74) Agent: **MAKHLINA, Maria Grigorievna**; st. Marshala Rybalko 2, bld. 9, of. 535, Moscow, 123060 (RU).

(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CV, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IQ, IR, IS, IT, JM, JO, JP, KE, KG, KH, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, MG, MK, MN, MU, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, ST, SV, SY, TH,

(54) Title: METHODS AND SYSTEMS FOR FLOW RATE ESTIMATION

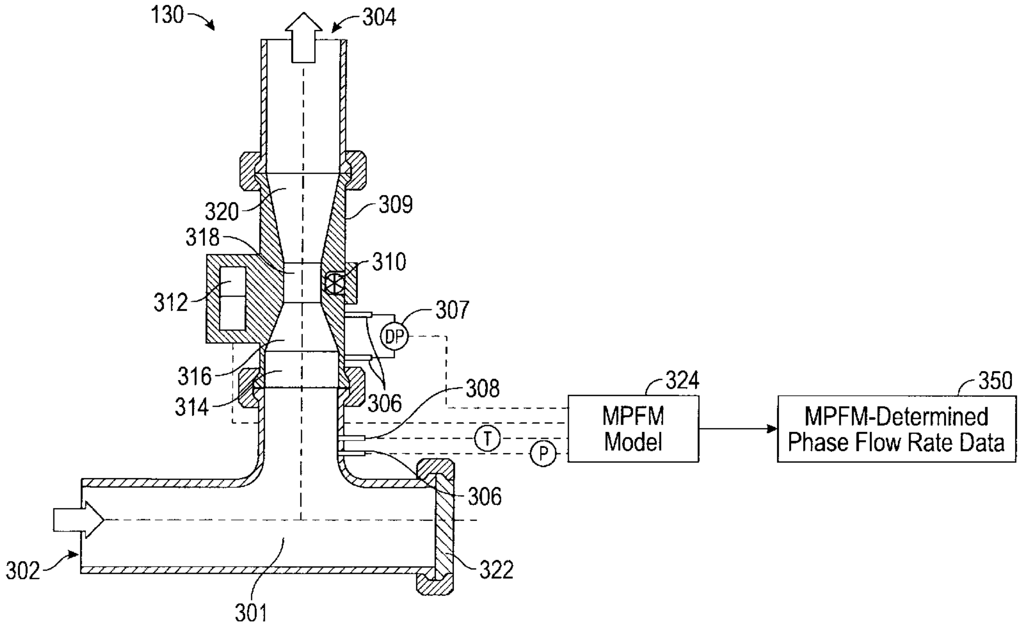


FIG. 3

(57) Abstract: A method for determining multiphase flow rates using an economical flow meter, including receiving, for a period, observed data from a multiphase flow meter (MPFM) disposed on a pipeline carrying a multiphase fluid and determining first predicted data using a numerical simulator based on a wellbore model. The wellbore model is configured by a set of wellbore model configuration parameters. The method further includes calibrating the set of wellbore model configuration parameters based on the observed data and the first predicted data forming a set of calibrated wellbore model configuration parameters. The method further includes removing the MPFM and outfitting the pipeline with the economical flow meter, where the economical flow meter measures a total flow rate. The method further includes determining second predicted data using the numerical simulator with the wellbore model configured by the set of calibrated wellbore model configuration parameters and constrained by the total flow rate.

WO 2024/253555 A1

[Continued on next page]

TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, WS, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, CV, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SC, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, ME, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

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

METHODS AND SYSTEMS FOR FLOW RATE ESTIMATION

BACKGROUND

[0001] As oil, gas, and water are produced from a well, they typically flow as a non-homogeneous mixture of phases through a pipeline from the wellhead to a separator. A multiphase flow meter (MPFM) is a device that may be installed on a pipeline to measure the rate at which each phase (oil, gas, water) is flowing. MPFM data are essential for reservoir monitoring and production optimization. However, in many circumstances, an MPFM may not be installed due to cost or other factors, such as intrusiveness. Many MPFMs operate using gamma attenuation and contain a radioactive source. In some instances, while MPFM data is important, a radioactive MPFM may be undesirable or prohibited for safety and regulatory restrictions, respectively. As such, there exists a need to acquire phase flow rate data from producing wells without using a dedicated MPFM.

SUMMARY

[0002] 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.

[0003] Embodiments disclosed herein generally relate to a method for determining multiphase flow rates using an economical flow meter that measures total flow rate. The method includes receiving, for a period, observed data from a multiphase flow meter (MPFM) disposed on a pipeline carrying a multiphase fluid and determining first predicted data using a numerical simulator based on a wellbore model, where the wellbore model is configured by a set of wellbore model configuration parameters. The method further includes calibrating the set of wellbore model configuration parameters based on the observed data and the first predicted data forming a set of calibrated wellbore model configuration parameters. The method further includes removing the MPFM from the pipeline and outfitting the pipeline with the economical flow meter, where the economical flow meter measures a total flow rate of the multiphase fluid. The method further includes determining second predicted data using the numerical simulator based on the wellbore model configured by the set of calibrated wellbore model configuration parameters and constrained by the total flow rate. The method further includes optimizing production of the pipeline based on the determined second predicted data.

[0004] Embodiments disclosed herein generally relate to a non-transitory computer-readable memory with computer-executable instructions stored thereon that, when executed on a processor, cause the processor to perform the following steps. The steps include: receiving, for a period, observed data from a multiphase flow meter (MPFM) disposed on a pipeline carrying a multiphase fluid; determining first predicted data using a numerical simulator based on a wellbore model, where the wellbore model is configured by a set of wellbore model configuration parameters; calibrating the set of wellbore model configuration parameters based on the observed data and the first predicted data forming a set of calibrated wellbore model configuration parameters; and determining second predicted data using the numerical simulator based on the wellbore model configured by the set of calibrated wellbore model configuration parameters and constrained by a total flow rate from an economical flow meter that has replaced the MPFM. The steps may further include optimizing production of the pipeline based on the determined second predicted data.

[0005] Embodiments disclosed herein generally relate to a system for determining phase flow rates of a multiphase fluid in a pipeline. The system includes a wellbore model configured by a set of wellbore model configuration parameters and a numerical simulator that simulates the flow of a multiphase fluid through the pipeline, where the numerical simulator uses the wellbore model. The system further includes an inversion system that includes an objective function. The system further includes a computer processor configured to: receive, for a period, observed data from a multiphase flow meter (MPFM) disposed on the pipeline; determine first predicted data using the numerical simulator; calibrate the set of wellbore model configuration parameters based on the observed data and the first predicted data using the inversion system, where the inversion system outputs a set of calibrated wellbore model configuration parameters; receive a total flow rate from an economical flow meter disposed on the pipeline; and determine second predicted data using the numerical simulator based on the wellbore model configured by the set of calibrated wellbore model configuration parameters and constrained by the total flow rate. The computer processor may further be configured to optimize production of the pipeline based on the determined second predicted data.

[0006] Other aspects and advantages of the claimed subject matter will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0007] FIG. 1 depicts a pipeline, in accordance with one or more embodiments.

[0008] FIG. 2 depicts a section view of a flowline, in accordance with one or more embodiments.

[0009] FIG. 3 depicts a multiphase flow meter (MPFM) in accordance with one or more embodiments.

[0010] FIG. 4 depicts a system in accordance with one or more embodiments.

[0011] FIG. 5 depicts a system in accordance with one or more embodiments.

[0012] FIG. 6 depicts a system in accordance with one or more embodiments.

[0013] FIG. 7 depicts a system in accordance with one or more embodiments.

[0014] FIG. 8 depicts a flowchart in accordance with one or more embodiments.

[0015] FIG. 9 depicts the first stage of a multiphase flow measurement system in accordance with one or more embodiments.

[0016] FIG. 10 depicts the second stage of a multiphase flow measurement system in accordance with one or more embodiments.

[0017] FIG. 11 depicts a flowchart in accordance with one or more embodiments.

[0018] FIG. 12 depicts a system in accordance with one or more embodiments.

DETAILED DESCRIPTION

[0019] In the following detailed description of embodiments of the disclosure, numerous specific details are set forth in order to provide a more thorough understanding of the disclosure. However, it will be apparent to one of ordinary skill in the art that the disclosure may be practiced without these specific details. In other instances, well-known features have not been described in detail to avoid unnecessarily complicating the description.

[0020] Throughout the application, ordinal numbers (e.g., first, second, third, etc.) may be used as an adjective for an element (i.e., any noun in the application). The use of ordinal numbers is not to imply or create any particular ordering of the elements nor to limit any element to being only a single element unless expressly disclosed, such as using the terms "before," "after," "single," and other such terminology. Rather, the use of ordinal numbers is to distinguish between the elements. By way of an example, a first element is distinct from a second element, and the first element may encompass more than one element and succeed (or precede) the second element in an ordering of elements.

[0021] It is to be understood that the singular forms "a," "an," and "the" include plural referents unless the context clearly dictates otherwise. Thus, for example, reference to "a configuration parameter" includes reference to one or more of such parameters.

[0022] Terms such as "approximately," "substantially," etc., mean that the recited characteristic, parameter, or value need not be achieved exactly, but that deviations or variations, including for example, tolerances, measurement error, measurement accuracy limitations and other factors known to those of skill in the art, may occur in amounts that do not preclude the effect the characteristic was intended to provide.

[0023] It is to be understood that one or more of the steps shown in the flowcharts may be omitted, repeated, and/or performed in a different order than the order shown. Accordingly, the scope disclosed herein should not be considered limited to the specific arrangement of steps shown in the flowcharts.

[0024] Although multiple dependent claims are not introduced, it would be apparent to one of ordinary skill that the subject matter of the dependent claims of one or more embodiments may be combined with other dependent claims.

[0025] In the following description of FIGs. 1-12, any component described with regard to a figure, in various embodiments disclosed herein, may be equivalent to one or more like-named components described with regard to any other figure. For brevity, descriptions of these components will not be repeated with regard to each figure. Thus, each and every embodiment of the components of each figure is incorporated by reference and assumed to be optionally present within every other figure having one or more like-named components. Additionally, in accordance with various embodiments disclosed herein, any description of the components of a figure is to be interpreted as an optional embodiment which may be implemented in addition to, in conjunction with, or in place of the embodiments described with regard to a corresponding like-named component in any other figure.

[0026] Embodiments disclosed herein relate to a multiphase flow rate measurement system that measures the individual and simultaneous phase flow rates of a multiphase fluid. Herein, embodiments will be described within the context of an oil and gas field, or, more specifically, embodiments will be applied to one or more producing wells. However, one with ordinary skill in the art will readily recognize that the multiphase flow rate measurement system is not limited to use with producing wells and, in general, may be used to measure the phase flow rates of various multiphase fluids.

[0027] In accordance with one or more embodiments, the multiphase flow rate measurement system produces phase flow rates based on one or more thermophysical property measurements of the multiphase fluid acquired with one or more field devices, a multiphase fluid flow model, and an economical flow meter where the economical flow meter only provides the total, or bulk, flow rate of a multiphase fluid. That is, the economical flow meter does not provide any phase fraction or individual phase flow rate measurements. Further, in general, the economical flow meter will not use a radioactive source.

[0028] In accordance with one or more embodiments, FIG. 1 depicts a simplified portion of a pipeline (100) of a multilateral well in an oil and gas field. Herein, an oil and gas field is broadly defined to consist of wells which produce at least some oil and/or gas. Hydrocarbon wells typically produce oil, gas, and water in combination. The relative amounts of oil, gas, and water may differ between wells and vary over any one well's lifetime.

[0029] For clarity, the pipeline (100) is divided into three sections; namely, a subsurface (102) section, a tree (104) section, and a flowline (106) section. It is emphasized that pipelines (100) and other components of wells and, more generally, oil and gas fields may be configured in a variety of ways. As such, one with ordinary skill in the art will appreciate that the simplified view of FIG. 1 does not impose a limitation on the scope of the present disclosure. As part of the subsurface (102) section, FIG. 1 shows an inflow control valve (ICV) (101). An ICV (101) is an active component usually installed during well completion. The ICV (101) may partially or completely choke flow into a well. Generally, multiple ICVs (101) are installed along the reservoir section of a wellbore. Each ICV (101) is separated from the next by a packer. Each ICV (101) can be adjusted and controlled to alter flow within the well and, as the reservoir depletes, prevent unwanted fluids from entering the wellbore. The subsurface (102) section of the pipeline (100) has a subsurface safety valve (SSSV) (103). The SSSV (103) is designed to close and completely stop flow in the event of an emergency. Generally, an SSSV (103) is designed to close on failure. That is, the SSSV (103) requires a signal to stay open and loss of the signal results in the closing of the valve. Also shown as part of the subsurface (102) section is a permanent downhole monitoring system (PDHMS) (124). The PDHMS (124) consists of a plurality of sensors, gauges, and controllers to monitor subsurface flowing and shut-in pressures and temperatures. As such, a PDHMS (124) may indicate, in real-time, the state or operating condition of subsurface equipment and the fluid flow.

[0030] Turning to the tree (104) section of FIG. 1 is a master valve (MV) (105), a surface safety valve (SSV) (107), and a wing valve (WV) (109). The MV (105) controls all flow from the wellbore. For safety considerations, a MV (105) is usually considered so important that two master valves (MVs) (second not shown) are used wherein one acts as a backup. Like unto the SSSV (103), the SSV (107) is a valve installed on the upper portions of the wellbore to provide emergency closure and stoppage of flow. Again, SSVs (107) are designed to close on failure. One or more WVs (109) may be located on the side of the tree (104) section, or on temporary surface flow equipment (not shown). WVs (109) may be used to control and isolate production fluids and/or be used for treatment or well-control purposes.

[0031] Also shown in FIG. 1 is a control valve (CV) (111) and a pressure gauge (PG) (113). The CV (111) is a valve that controls a process variable, such as pressure, flow, or temperature, by modulating its opening. The PG (113) monitors the fluid pressure at the tree (104) section.

[0032] Turning to the flowline (106) section, the flowline (106) transports (108) the fluid from the well to a storage or processing facility (not shown). A choke valve (119) is disposed along the flowline (106). The choke valve (119) is used to control flow rate and reduce pressure for processing the extracted fluid at a downstream processing facility. In particular, effective use of the choke valve (119) prevents damage to downstream equipment and promotes longer periods of production without shutdown or interruptions. The choke valve (119) is bordered by an upstream pressure transducer (115) and a downstream pressure transducer (117) which monitor the pressure of the fluid entering and exiting the choke valve (119), respectively. The flowline (106) shown in FIG. 1 has a block and bleed valve system (121) which acts to isolate or block the flow of fluid such that it does not reach other downstream components. The flowline (106) may also be outfitted with one or more temperature sensors (123).

[0033] The various valves, pressure gauges and transducers, and sensors depicted in FIG. 1 may be considered devices of an oil and gas field. As shown, these devices may be disposed both above and below the surface of the Earth. These devices are used to monitor and control components and sub-processes of an oil and gas field. It is emphasized that the oil and gas field devices depicted in FIG. 1 are non-exhaustive. Additional devices, such as electrical submersible pumps (ESPs) (not shown) may be present in an oil and gas field with their associated sensing and control capabilities. For example, an ESP may monitor the temperature and pressure of a fluid local to the ESP and may be controlled through adjustments to ESP speed or frequency.

[0034] The oil and gas field devices may be distributed, local to the sub-processes and associated components, global, connected, *etc.* The devices may be of various control types, such as a programmable logic controller (PLC) or a remote terminal unit (RTU). For example, a programmable logic controller (PLC) may control valve states, pipe pressures, warning alarms, and/or pressure releases throughout the oil and gas field. In particular, a programmable logic controller (PLC) may be a ruggedized computer system with functionality to withstand vibrations, extreme temperatures, wet conditions, and/or dusty conditions, for example, around a pipeline (100). With respect to an RTU, an RTU may include hardware and/or software, such as a microprocessor, that connects sensors and/or actuators using network connections to perform various processes in the automation system. As such, a distributed control system may include various autonomous controllers (such as remote terminal units) positioned at different locations throughout the oil and gas field to manage operations and monitor sub-processes. Likewise, a distributed control system may include no single centralized computer for managing control loops and other operations.

[0035] In accordance with one or more embodiments, FIG. 1 depicts a supervisory control and data acquisition (SCADA) system (125). A SCADA system (125) is a control system that includes functionality for device monitoring, data collection, and issuing of device commands. The SCADA system (125) enables local control at an oil and gas field as well as remote control from a control room or operations center. To emphasize that the SCADA system (125) may monitor and control the various devices of an oil and gas field, dashed lines connecting the plurality of oil and gas field devices to the SCADA system (125) are shown in FIG. 1.

[0036] Oil and gas field devices, like those shown in FIG. 1 (and others not shown), monitor and govern the behavior of the components and sub-processes of the oil and gas field. Therefore, the productivity of the oil and gas field is directly affected, and may be altered, by the devices. Generally, complex interactions between oil and gas field components and sub-process exist such that configuring field devices for optimal production is a difficult and laborious task. Further, the state and behavior of oil and gas fields is transient over the lifetime of the constituent wells requiring continual changes to the field devices to enhance production.

[0037] To determine the instantaneous state of the flow and to inform and optimize the settings of the field devices of a pipeline (100) to maximize hydrocarbon production, it is beneficial, if not critical, to acquire phase flow rate data. In the example of FIG. 1, the flowline (106) is outfitted with a multi-phase flow meter (MPFM) (130). An MPFM (130) is a device installed on the flowline (106) to measure the rate at which each phase – oil, gas, water – is flowing. That is, the MPFM (130) may detect the instantaneous amount of gas, oil, and water. As such, the MPFM (130) indicates additional quantities such as percent water-cut (%WC, or more simply WC) and the gas-to-oil ratio (GOR). As will be described, embodiments disclosed herein relate to the acquisition and/or determination of phase flow rate data without a dedicated MPFM (130). Specifically, in one or more embodiments, the MPFM (130) depicted in FIG. 1 is replaced by an economical flow meter capable of only measuring the bulk flow rate and phase flow rate data for a given pipeline is determined using a tailored wellbore model and wellbore sensor data (*e.g.*, field device data: PDHMS (124), etc.).

[0038] FIG. 2 depicts a simplified view of a cross-section of a flowline (106) carrying a multiphase fluid. As seen, the multiphase fluid may have multiple constituents such as gas (202), water (204), and oil (206). The various constituents of the multi-phase fluid may be distributed within the flowline (106) in a myriad of ways. As a non-limiting example, gas (202) may be enclosed by liquids (water or oil) forming bubbles (210). Or, in contrast, liquid droplets, such as oil droplets (216) and water droplets (212), may be dispersed in the gas (202) to form a mist. In general, the state of the multiphase fluid may be described using broad classifications. That is, the multi-phase fluid may be categorized as "bubbly," "annular," "churn," "mist," "stratified," or other designations (flow classes) based on the distribution of the constituents and their relative quantities. The state of the multiphase fluid may be transient such that any assignment of flow class may change with time.

[0039] In general, an MPFM (130) cannot directly measure the flow rate of the individual phases in a fluid. Rather, an MPFM (130) itself is a collection of sensors, transmitters, mechanical devices, flow conduits, and programmed relationships (*i.e.*, an MPFM model (324)) that are used to determine the individual phase flow rates. FIG. 3 depicts an MPFM (130) in accordance with one or more embodiments. An MPFM (130) may be disposed inline with a flowline (106), or proximate to a flowline (106), such that the MPFM (130) can receive the multiphase fluid (301) through a flow inlet (302) and return the fluid through a flow outlet (304). The MPFM (127) of FIG. 3 includes one or more pressure sensors (306) and temperature sensors (308) to measure the pressure (P) and temperature (T), respectively, at various locations within the MPFM (127). The pressure (P) and temperature (T) measurements are used, in part, to determine the thermophysical state and the thermophysical properties of the multiphase fluid (301). For example, the pressure (P) and temperature (T) values may be used with a functional or tabulated equation of state (EoS) to determine other properties of the multiphase fluid (301).

[0040] The MPFM (130) of FIG. 3 uses a gamma densitometer (309) to measure the bulk density of the multiphase fluid (301). The gamma densitometer (309) emits a beam of photons from a nuclear source (310) (or, more generally, a radioactive source). The emitted photons are attenuated by the multiphase fluid (301) and the amount of attenuation is determined using a nuclear detector (312) that measures the number of received photons. The amount of attenuation is greatly affected by the bulk density of the multiphase fluid (301). Further, because gas has a significantly lower density compared to water and oil, the gamma densitometer (309) can be used to accurately determine the liquid (water and oil) and gas fractions of the multiphase fluid (301).

[0041] The MPFM (127) depicted in FIG. 3 further includes a Venturi section. The Venturi section is composed of a Venturi inlet (314), a nozzle (316), a throat section (318), and a diffuser (320). The constriction in flow that occurs in the Venturi section acts to increase the bulk flow velocity of the multiphase fluid (301) and is associated with a decrease in pressure (P). The MPFM (127) is configured with pressure sensors (306) to determine the difference in pressure (DP) (307) of the multiphase fluid (301) between the Venturi inlet (314) and the throat section (318). The Venturi section is used to measure mass flow rates.

[0042] The MPFM (127) of FIG. 3 further includes a blind tee or static mixer (322). The blind tee (322) serves to condition the flow of the multiphase fluid (301) such that it is homogeneous before entering the main body of the MPFM (127). The blind tee (322) is disposed immediately upstream of the Venturi section and creates a mixing effect that stabilizes intermittent flow regimes commonly encountered in multiphase fluids (301) associated with wells. The blind tee (322) also mitigates any flow interaction with field devices located upstream from the MPFM (127) such as the choke valve (119).

[0043] The MPFM (127) is typically associated with an MPFM model (324). The MPFM model (324) receives the readings from the sensors (*e.g.*, temperature sensor (308), pressure sensor (306)) of the MPFM (127). That is, the MPFM model (324) acts, in part, as a data acquisition unit. Upon collecting the sensor data, the MPFM model (324) is used to determine the individual flow rates of the oil, gas, and water present in the multiphase fluid (301). The MPFM model (324), or rather the MPFM (130), outputs MPFM-determined phase flow rate data (350) and acquired sensor data (from sensors considered part of the MPFM (130)) to an external system such as SCADA (125). Generally, the MPFM model (324) makes use of programmed relationships to determine the phase flow rates from the acquired sensor data. The programmed relationships may include or make use of analytical or tabulated equations of state (EoS) data, phenomenological models, physics-based relationships, bounded correlations, and governing equations (*e.g.*, conservation of mass). Mathematically, the MPFM model (324) may be represented as a function:

$$q_i = f_i(DP, P, T, \rho_m, GOR, WC) \text{ for } i = o, w, g, \qquad \text{EQ 1}$$

where q_i represents the flow rate of the i^{th} phase and the subscript indexed by i may take on the values of o, w, or g representing the phases of oil, water, and gas, respectively. ρ_m is the mixture (or bulk) density. In many instances, the MPFM model (324) is defined by a manufacturer of the MPFM (130) and is not directly accessible or known to a user of the MPFM (130). In some instances, an MPFM (130) may be configured to output, or make accessible to a user or system, density and phase fraction data (*e.g.*, gas-to-oil ratio (GOR)). In other instances, a commercially-available MPFM (130) may only output the determined phase flow rates without user or external system access to intermediately derived and/or measured quantities (*e.g.*, differential pressure (DP), density, GOR).

[0044] It is emphasized that the MPFM (130) depicted in FIG. 3 is provided only as an example. In practice, many different types of MPFMs (130) exist. MPFMs (130) may differ in the types of sensors used, the data they collect, and the programmed relationships used to convert the measured flow properties to phase flow rates. For example, in some instances, an MPFM (130) may further be outfitted with a capacitance sensor to determine the fraction of oil, water, and gas in the multiphase fluid (301). In other instances, an MPFM (130) may use any combination of an X-ray source and detector, electrodes, strain gauges, magnetic resonance, and optical sensors and computer vision-based algorithms. One with ordinary skill in the art will recognize that the above description of an MPFM (130) or the components that may make up an MPFM (130) are non-exhaustive and should not be construed to impose a limitation on the instant disclosure. In general, the multiphase flow rate measurement system disclosed herein can be configured to work with and replace any type of MPFM (130). That is, the multiphase flow rate measurement system disclosed herein can work with and replace any type of MPFM (130) regardless of its manufacturer or vendor.

[0045] A high-level overview of the components and flow of data through the multiphase flow rate measurement system is depicted in FIG. 4, in accordance with one or more embodiments. It is noted that the elements shown in FIG. 4 are abstractions and that, in practice, an element may not be unique or independent from other elements of the system. As depicted in FIG. 4, the multiphase flow rate measurement system is composed of, or makes use of, a wellbore model (404). In one or more embodiments, the wellbore model (404) is a set of equations that describe the flow and behavior of a multiphase fluid through the pipeline of a producing well. In general, the set of equations can represent transient behavior and are continuous. For example, a wellbore model (404) may be composed of a set of first-principles partial differential equations enforcing the conservation of mass, conservation of momentum, and conservation of energy of each phase in a multiphase fluid (*e.g.*, the Navier-Stokes equations). One with ordinary skill in the art will recognize that various adaptions of sets of equations based on first principles exist. These adaptions generally balance the application of simplifying assumptions with a potential reduction in accuracy (*i.e.*, capability of the model to accurately represent the physical scenario). Dependent on properties of the fluid flow and its environment, often simplifying assumptions can be made without a significant or perceivable reduction in accuracy. For example, in the case of a pipeline, where a conventional pipeline has an enormous length-to-diameter ratio, an assumption of one-dimensional flow is commonly applied.

[0046] In one or more embodiments, the wellbore model (404) is parameterized by a set of wellbore model configuration parameters (402). That is, given a wellbore model (404), or a set of equations representing the flow of the produced fluid, the behavior of the wellbore model (404) may further be adjusted by one or more configuration parameters. As will be described below, the multiphase flow rate measurement system described herein determines (learns, tunes) the wellbore model configuration parameters (402) to match the observed dynamics of a well. However, for now it suffices to say that in one or more embodiments the multiphase flow rate measurement system includes a wellbore model (404) configured by one or more wellbore model configuration parameters (402).

[0047] In one or more embodiments, the wellbore model (404) used by the multiphase flow rate measurement system is an isothermal compressible three-phase drift-flux model. The isothermal compressible three-phase drift-flux model is written mathematically by the following labelled equations.

$$\frac{\partial}{\partial t}\left(\alpha_g \rho_g\right) + \frac{\partial}{\partial x}\left(\alpha_g \rho_g v_g\right) = \frac{q_g}{A} \qquad \text{EQ 2}$$

$$\frac{\partial}{\partial t}\left(\alpha_w \rho_w\right) + \frac{\partial}{\partial x}\left(\alpha_w \rho_w v_w\right) = \frac{q_w}{A} \qquad \text{EQ 3}$$

$$\frac{\partial}{\partial t}\left(\alpha_o \rho_o\right) + \frac{\partial}{\partial x}\left(\alpha_o \rho_o v_o\right) = \frac{q_o}{A} \qquad \text{EQ 4}$$

$$\frac{\partial v_m}{\partial t} + v_m \frac{\partial v_m}{\partial x} = -\frac{1}{\rho_m}\frac{\partial p}{\partial x} - g\cos\theta - \frac{2 f v_m |v_m|}{D} \qquad \text{EQ 5}$$

$$\alpha_g + \alpha_l = 1 \qquad \text{EQ 6}$$

$$\alpha_l = \alpha_o + \alpha_w \qquad \text{EQ 7}$$

$$\rho_i = \rho_i(p) \text{ for } i = g,w,o \qquad \text{EQ 8}$$

$$v_m = \alpha_g v_g + \alpha_l v_l \qquad \text{EQ 9}$$

$$\rho_m = \alpha_g \rho_g + \alpha_l \rho_l \qquad \text{EQ 10}$$

$$v_g = C_0 v_m + v_{d\theta} \qquad \text{EQ 11}$$

$$v_o = C_0^l v_l + v'_{d\theta} \qquad \text{EQ 12}$$

$$v_l = \frac{\alpha_o v_o + \alpha_w v_w}{\alpha_l} \qquad \text{EQ 13}$$

$$\rho_l = \frac{\alpha_o \rho_o + \alpha_w \rho_w}{\alpha_l} \qquad \text{EQ 14}$$

[0048] In the preceding equations describing the isothermal compressible three-phase drift-flux model, x denotes a spatial coordinate, t indicates time or a temporal coordinate, and the subscripts g, w, and o indicate the phases of gas, water, and oil, respectively. Further, α_k is the volume fraction of the k^{th} phase. Likewise, ρ_k is the density of the k^{th} phase and ρ_m is the mixture (or bulk) density. v_k is the velocity of the k^{th} phase and v_m is the mixture (or bulk) velocity. p represents pressure, g is the gravitational constant, θ is the pipe inclination angle with respect to an upward vertical, and $f = f(\alpha_g, v_m, p)$ is a friction coefficient dependent on the gas volume fraction, mixture velocity and pressure. Finally, q_k represents a mass source for the k^{th} phase and D is the pipe diameter.

[0049] The distinguishing feature of the isothermal compressible three-phase drift-flux model as wellbore model (404) is that it treats the multiphase flow as a mixture and uses only a single momentum and energy equation and any missing information is supplemented by an algebraic slip model. The isothermal compressible three-phase drift-flux model is parameterized by three wellbore model configuration parameters (402); namely, a multiphase friction factor, a distribution coefficient, and a drift velocity. Thus, in one or more embodiments, the multiphase flow rate measurement system determines the multiphase flow rates for a given well using the isothermal compressible three-phase drift-flux model with the multiphase friction factor, distribution coefficient, and drift velocity tailored (tuned) to the given well.

[0050] In general, a wellbore model (404) cannot be solved analytically and is solved (or, at least satisfied to a specified level of error or divergence) using numerical methods. Examples of numerical methods may include, but are not limited to, finite difference methods and finite element analysis. As such, in one or more embodiments, the multiphase flow rate measurement system further includes, or makes use of, a numerical simulator (406). In one or more embodiments, the numerical simulator (406) discretizes a domain of a pipeline and applies a discrete formulation of the wellbore model (404) over the discretized domain. The numerical simulator (406) outputs a distribution of pressures, temperatures, and phase fractions over the domain, temporally and spatially, consistent with the applied wellbore model (404) and any supplied initial conditions and boundary conditions. Common boundary conditions may include the measured downhole pressure and temperature. In other words, the numerical simulator (406) has access to wellbore sensor data (410) acquired using field devices disposed on/throughout the pipeline (*i.e.*, PDHMS (124)). In accordance with one or more embodiments, the numerical simulator (406) outputs a set of flow phase descriptors (408). The set of flow phase descriptors (408) contain values and properties relevant to the classification of the multiphase fluid and to determine the phase flow rates. In one or more embodiments, the set of flow phase descriptors (408) includes the mixture (or bulk) density, gas-to-oil (GOR) ratio, the water-cut (WC) of the multiphase fluid. That is, in one or more embodiments, the set of flow phase descriptors (408) includes phase fraction data.

[0051] Turning to FIG. 5, in one or more embodiments, the multiphase flow rate measurement system further includes an interpretive model (502). The interpretive model is a function or set of one or more equations that converts flow phase descriptors (408) and wellbore sensor data (410) into phase flow rate data (504), where the phase flow rate data (504) includes the flow rate of each phase in the multiphase fluid. Various interpretive models exist and any applicable interpretive model (502) may be used in the multiphase flow rate measurement system without limitation. A general mathematical expression for the interpretive model (502) may be given as

$$q_i = \widehat{f}_i\left(dP, P, T, \rho_m, GOR, WC\right) \text{ for } i = o, w, g. \qquad \text{EQ 15}$$

[0052] In general, the interpretive model (502) performs a similar function to the MPFM model (324) in that both models output the individual phase flow rates of a multiphase fluid given field device data and other quantities, such as GOR and WC, that are either measured or derived. In situations where the MPFM model (324) is known, the interpretive model (502) and the MPFM model (324) may be the same (*i.e.*, $f_i = \widehat{f}_i$). Moreover, in situations where an MPFM (130) outputs, or otherwise makes accessible, the quantities of GOR, WC, density, and measurements from its embedded sensors (*e.g.*, temperature, pressure, etc.), the MPFM model (324) may be bypassed and/or replaced using a user-supplied interpretive model (502).

[0053] Continuing with FIG. 5, in one or more embodiments, the interpretive model (502) is a function of the total flow rate, q_t, where the total flow rate considers the volume (or in some instances the mass) over time of a multiphase fluid flowing through a pipeline without consideration for the phase or constituent makeup of the multiphase fluid. In one or more embodiments, the total flow rate acts as a constraint on the interpretive model (502) and this therefore depicted as a total flow rate constraint (504) in FIG. 5. In these embodiments, the interpretive model (502) is constrained, or otherwise guided toward a solution, where the sum of the individual phase flow rates equal the total flow rate. That is, the interpretive model (502) may be represented as

$$q_i = \widehat{f}_i\left(dP, P, T, \rho_m, GOR, WC\right) \text{ for } i = o, w, g;$$
$$\text{subject to: } q_t = q_o + q_w + q_g. \qquad \text{EQ 16}$$

[0054] As stated, the multiphase flow rate measurement system described herein determines (learns, tunes) the wellbore model configuration parameters (402) to match the observed dynamics of a well. In general, the application and use of the multiphase flow rate measurement system is partitioned into two stages. In the first stage, a well is outfitted with an MPFM (130) and the wellbore model configuration parameters (402) are determined for the well using an inversion system that matches the observed dynamics of the well (*e.g.*, the output of the MPFM (130)) with the output of the numerical simulator (406) and/or interpretive model (502). In the second stage, the MPFM is removed and replaced by, or otherwise downgraded to, an economical flow meter where the economical flow meter only provides the total, or bulk, flow rate of a multiphase fluid. That is, the economical flow meter does not provide any phase fraction or individual phase flow rate measurements. Further, in general, the economical flow meter will not use a radioactive source. In one or more embodiments, the radioactive source (*e.g.*, gamma densitometer (309)) is removed from the MPFM (130) to covert the MPFM (130) to an economical flow meter. In one or more embodiments, once the well is outfitted with only an economical flow meter (*i.e.*, stage 2), flow phase descriptors (408) are determined using the numerical simulator (406) with the wellbore model (404) configured with the determined model configuration parameters (402) for that well. In one or more embodiments, once the well is outfitted with only an economical flow meter (*i.e.*, stage 2), phase flow rate data (504) is determined using the numerical simulator (406) with the wellbore model (404) configured with the determined model configuration parameters (402) for that well.

[0055] FIG. 6 depicts the process of tuning, or learning, the wellbore model configuration parameters (402) in accordance with one or more embodiments. To tune, or learn, the wellbore model configuration parameters (402), the well (or pipeline) is outfitted with an MPFM (127). In one or more embodiments, the MPFM (127) outputs, or otherwise makes available, flow phase descriptors determined by the MPFM (127). For clarity, flow phase descriptors determined by the MPFM (127) are referred to herein as MPFM-determined flow phase descriptors (610). As depicted in FIG. 6, flow phase descriptors (408) determined by the numerical simulator (406) and MPFM-determined flow phase descriptors (610) are input to an inversion system (600). In general, the inversion system (600) performs a comparison of the flow phase descriptors (408) and MPFM-determined flow phase descriptors (610). In one or more embodiments, the comparison is performed using an objective function (602), where the objective function (602) quantifies the difference between the flow phase descriptors (408) and the MPFM-determined flow phase descriptors (610). The inversion system (600) determines the wellbore model configuration parameters (402) that result in the best congruence of the flow phase descriptors (408) and the MPFM-determined flow phase descriptors (610), where the congruency is quantified by the objective function (602). In one or more embodiments, the inversion system (600) uses an iterative process where, in each iteration, the inversion system (600) outputs an update to the wellbore model configuration parameters (402) and re-runs the numerical simulator (406) until triggering a termination criterion. The termination criterion may include, but is not limited to: exceeding a pre-defined number of iterations, diminishing changes in the configuration parameters, and the objective function (602) achieving a pre-defined threshold.

[0056] FIG. 7 depicts the process of tuning, or learning, the wellbore model configuration parameters (402) in accordance with one or more embodiments. To tune, or learn, the wellbore model configuration parameters (402), the well (or pipeline) is outfitted with an MPFM (127). In one or more embodiments, the MPFM (127) outputs phase flow rate data including the individual flow rates for each phase of a multiphase fluid. For clarity, phase flow rate data determined by the MPFM (127) are referred to herein as MPFM-determined phase flow rate data (710). As depicted in FIG. 7, phase flow rate data (504) determined by the numerical simulator (406) and interpretive model (502) in view of a total flow rate constraint (506) and MPFM-determined phase flow rate data (710) are input to an inversion system (600).

In general, the inversion system (600) performs a comparison of the phase flow rate data (504) and MPFM-determined phase flow rate data (710). In one or more embodiments, the comparison is performed using an objective function (602), where the objective function (602) quantifies the difference between the phase flow rate data (504) and the MPFM-determined phase flow rate data (710). The inversion system (600) determines the wellbore model configuration parameters (402) that result in the best congruence of the phase flow rate data (504) and the MPFM-determined phase flow data (710), where the congruency is quantified by the objective function (602). In one or more embodiments, the inversion system (600) uses an iterative process where, in each iteration, the inversion system (600) outputs an update to the wellbore model configuration parameters (402) and re-runs the numerical simulator (406) and interpretive model (502) until triggering a termination criterion. The termination criterion may include, but is not limited to: exceeding a pre-defined number of iterations, diminishing changes in the configuration parameters, and the objective function (602) achieving a pre-defined threshold.

[0057] FIG. 8 depicts a high-level overview of an iterative inversion process (*e.g.*, that may be employed by the inversion system (600)), in accordance with one or more embodiments. To begin, as depicted in Block 402, an initial parameter vector is supplied. In the context of the instant disclosure, the initial parameter vector may contain the wellbore model configuration parameters (402). That is, in one or more embodiments, the initial parameter vector contains initial values for the multiphase friction factor, distribution coefficient, and drift velocity. In one or more embodiments, the initial parameter vector is initialized with values randomly selected from a physically plausible distribution.

[0058] Continuing with FIG. 8, in Block 808, a forward operator is applied to the initial parameter vector. The forward operator may be a function or computational model that maps the initial parameter vector to an observable quantity. For example, in accordance with one or more embodiments, the forward model may include the application of a numerical simulator (406) using a prescribed wellbore model (404) configured with the initial wellbore model configuration parameters (*i.e.*, initial parameter vector) and an interpretive model (502). The forward operator may further accept, as an input, additional input data as depicted in Block 809. The additional input data may include field device data such as the downhole temperature and pressure of a well. As depicted in Block 810, the forward operator produces predicted data. In one or more embodiments, the predicted data are flow phase descriptors (408) or phase flow rate data (504), as determined by the forward operator, based on the initial parameter vector. In Block 812, an update to the initial parameter vector is determined. The update is determined, in part, by comparing the predicted data to observed data, where the observed data is represented by Block 813. In one or more embodiments, the observed data is the MPFM-determined flow phase descriptors (610) or the MPFM-determined phase flow rates (710). The comparison is performed using an objective function. In one or more embodiments, additional functions are included in the objective function. These additional functions may serve to regularize the objective function and/or provide physics-based constraints on the initial parameter vector. In Block 814, a check is performed to determine if the update to the initial parameter vector is substantial. If the update to the initial parameter vector is not considered substantial, then application of the update to the initial parameter vector would not significantly alter the initial parameter vector. In such a case, the initial parameter vector is said to be converged. Thus, if according to Block 814, the initial parameter vector is converged, the inversion process ends. If, however, the initial parameter vector is not converged, the update to the initial parameter vector is applied in Block 816.

[0059] Upon updating, the initial parameter vector is considered a new parameter vector. After Block 816, the inversion process returns to Block 808 to be processed anew by the forward operator which produces new predicted data. The new predicted data is compared to the observed data to determine an update to the new parameter vector in Block 812. If the update to the new parameter vector is significant (*i.e.*, not converged), the parameter vector is updated (in Block 816) resulting in another new parameter vector. Without undue ambiguity, the new parameter vector (and subsequent updates to new parameter vector) can simply be referred to as the parameter vector. That is, in FIG. 8, after receiving an initial parameter vector, the parameter vector is updated iteratively until the parameter vector does not significantly change between iterations. Herein, the parameter vector is represented mathematically as $\boldsymbol{m}$. Using this notation, an update to the parameter vector is represented as $\delta\boldsymbol{m}$. In accordance with one or more embodiments, in Block 814, the parameter vector is considered converged if $|\delta \boldsymbol{m}| < \epsilon$, where the operator $|\cdot|$ represents the L_1 norm ("Manhattan" norm) and ϵ is a pre-defined threshold value.

[0060] In accordance with one or more embodiments, the objective function (602) is given as

$$\phi\left(\boldsymbol{m}:\boldsymbol{d}_{obs},\boldsymbol{m}_p,q_t\right) = \phi_d(\boldsymbol{m}:\boldsymbol{d}_{obs}) + \lambda_1\phi_m\left(\boldsymbol{m}:\boldsymbol{m}_p\right) + \lambda_2\phi_q\left(\boldsymbol{m}:q_t\right), \tag{EQ 16}$$

where ϕ_d is a measure of the data misfit (i.e., quantification of the difference between the observed data (813) and the predicted data (810)), ϕ_m is a model regularization term, ϕ_q is a penalty term to enforce the total flow rate constraint (506), and $\lambda_i, i = 1,...2$ are different Lagrange multipliers. The data misfit function ϕ_d, intuitively, makes use of the observed data (813), $\boldsymbol{d}_{obs}$. The model regularization function ϕ_m, in addition to the parameter vector, depends on a prior parameter vector $\boldsymbol{m}_p$ (*i.e.*, prior, or expected, values for the wellbore model configuration parameters (402)). The prior parameter vector includes any prior information known about the parameter vector. In one or more embodiments, the prior parameter vector is the same as the initial parameter vector.

[0061] FIG. 9 illustrates the multiphase flow rate measurement system applied to a single well during the first stage in accordance with one or more embodiments. As seen in FIG. 9, a pipeline (100) of a well (or, more simply, a well) carrying a multiphase fluid (*e.g.*, production fluid) is outfitted with an MPFM (130) with a radioactive source (910). The MPFM (130), due to the radioactive source (910), can output, or determine, MPFM-determined flow phase descriptors (610) including the mixture density of the multiphase fluid, GOR, and WC. Further, the MPFM (130), with embedded sensors (*e.g.*, temperature sensor, pressure sensor, etc.) can determine the total flow rate, q_t, of the multiphase fluid. The MPFM-determined flow phase descriptors (610) and total flow rate, along with any other needed wellbore sensor data (410) are processed by an interpretive model (502) to determine the phase flow rates of the individual phases of the multiphase fluid (phase flow rate data (504)). That is, the gas flow rate, q_g, oil flow rate, q_o, and water flow rate q_w are determined.

In one or more embodiments, the interpretive model (502) may be the same as the MPFM model (324) supplied with, or used by, the MPFM (130).

[0062] Continuing with FIG. 9, the multiphase flow rate measurement system further includes a numerical simulator (406) that uses a wellbore model (404) configured by a set of wellbore model configuration parameters (402). In general, the wellbore model configuration parameters must be tuned, or learned, in order to match the dynamics of the well. FIG. 9 also depicts an inversion system (600). In one or more embodiments, the inversion system (600) considers the phase flow rate data (504) as output by the interpretive model (502) to alter the wellbore model configuration parameters (402). The wellbore model configuration parameters (402) are altered such that the output of the numerical simulator (406), upon some processing, can be used to predict the phase flow rate data without the use of an MPFM (130). Once the wellbore model configuration parameters (402) have been determined by the inversion system (600), the multiphase flow rate measurement system can determine phase flow rate data without the use of the MPFM (130), as depicted in FIG. 10.

[0063] FIG. 10 illustrates the multiphase flow rate measurement system applied to a single well during the second stage in accordance with one or more embodiments. As seen in FIG. 10, a pipeline (100) of a well (or, more simply, a well) carrying a multiphase fluid (*e.g.*, production fluid) is outfitted with an economical flow meter (1030) without a radioactive source (910). The economical flow meter (1030) outputs the total flow rate of the multiphase fluid. In one or more embodiments, the MPFM (130) used during the first stage is replaced by an economical flow meter (1030). In other embodiments, the MPFM (130) used during the first stage is downgraded to an economical flow meter (1030) by removing its radioactive source (910). In one or more embodiments, the economical flow meter (1030), can further output pressure (P), temperature (T), and differential pressure (DP) (*e.g.*, across a Venturi section) measurements of the multiphase fluid using one or more embedded sensors (*e.g.*, temperature sensor, pressure sensor, etc.).

[0064] Continuing with FIG. 10, the multiphase flow rate measurement system uses the numerical simulator (406) configured with the set of wellbore model configuration parameters (402) determined during the first stage. The numerical simulator (406) outputs a set of flow phase descriptors (408). In one or more embodiments, flow phase descriptors (408) are derived quantities determined from the output of the numerical simulator (406). As such, in one or more embodiments, the multiphase flow rate measurement system further includes a flow computer (1000) coupled to the numerical simulator (406) to add in processing the output of the numerical simulator (406). The flow phase descriptors (408) and total flow rate, along with any other needed wellbore sensor data (410) are processed by the interpretive model (502) to determine the phase flow rates of the individual phases of the multiphase fluid (phase flow rate data (504)). Thus, phase flow rate data (504) may be determined without the use of an MPFM (130) using only an economical flow meter (1030).

[0065] In one or more embodiments, the inversion system (600) is applied to a diverse set of wells, each outfitted with an MPFM (130) to determine the wellbore model configuration parameters (402) specific to each well. Thus, a plurality of wellbore model configuration parameters and associated wellbore sensor data (410) may be collected. In one or more embodiments, the wellbore model configuration parameters (402) for a new well are determined without the use of an MPFM (130) or the tuning (learning) previously outlined as the first stage. Rather, in one or more embodiments, the wellbore model configuration parameters (402) of the new well are determined using the plurality of wellbore model configuration parameters. In one or more embodiments, a continuous hypersurface relating sets of wellbore model configuration parameters to wellbore sensor data (410), total flow rate constraint (506), and other well descriptors is formed. In one or more embodiments, the hypersurface is formed by means of linear interpolation between the sets of wellbore model configuration parameters in the plurality of wellbore model configuration parameters. Thus, given the wellbore sensor data, total flow rate constraint (determined used an economical flow meter), and other well descriptors of the new well, the wellbore model configuration parameters for the new well are selected from the hypersurface.

[0066] FIG. 11 depicts a flowchart that outlines processes and steps associated with the multiphase flow rate measurement system described herein, in accordance with one or more embodiments. In Block 1102, observed data is received from an MPFM disposed on a pipeline carrying a multiphase fluid. In one or more embodiments, the multiphase fluid is a mixture of oil, water, and gas produced from a well. The observed data can be flow phase descriptors (*e.g.*, bulk density, GOR, WC, etc.) or phase flow rate data (*e.g.*, oil flow rate, water flow rate, gas flow rate) depending on the MPFM. In Block 1104, first predicted data is determined using a numerical simulator. The numerical simulator itself uses, or is based on, a wellbore model that is configured by a set of wellbore model configuration parameters. In one or more embodiments, the numerical simulator receives wellbore sensor data, such as the downhole temperature and pressure, and outputs the first predicted data. In one or more embodiments, the first predicted data is flow phase descriptors as determined by the numerical simulator. In one or more embodiments, the output of the numerical simulator is processed by an interpretive model to generate phase flow rate data. In Block 1106, the wellbore model configuration parameters are calibrated using an inversion system. The inversion system compares the observed data from the MPFM and the predicted data from the numerical simulator with an objective function to determine the optimal values for each configuration parameter in the set of wellbore model configuration parameters. In instances that use an interpretive model, the inversion system may compare MPFM-determined phase flow rate data to the phase flow rate data determined by the interpretive model and numerical simulator to determine the set of calibrated wellbore model configuration parameters. In one or more embodiments, the inversion system further considers wellbore sensor data and one or more constraints (*e.g.*, the total flow rate). The output of the inversion system is a set of calibrate wellbore model configuration parameters. In Block 1108, the MPFM is removed from the pipeline. In some embodiments, the MPFM is "removed in capability" but not physically removed. That is, in these cases, the MPFM is adjusted or downgraded such that it can no longer provide phase flow rate measurements but can still provide the measurements of embedded sensors (*e.g.*, temperature, pressure, etc.) and a bulk, or total, flow rate measurement. In Block 1110 the pipeline is outfitted with an economical flow meter, where the economical flow meter measures the total flow rate of the multiphase fluid. In one or more embodiments, the economical flow meter further provides measurements from embedded sensors (*e.g.*, temperature, pressure, etc.). In one or more embodiments, the economical flow meter is a downgraded MPFM. In Block 1112, second predicted data is determined using the numerical simulator using the set of calibrated wellbore model configuration parameters. In one or more embodiments, the numerical simulator is constrained by the total flow rate as determined by the economical flow meter. In Block 1114, the production of the pipeline is optimized based on the second predicted data. That is, based on the phase flow rates determined using the multiphase flow rate measurement system employing an economical flow meter, the settings of one or more field devices may be adjusted to enhance the production of the well.

[0067] FIG. 12 shows a system in accordance with one or more embodiments. FIG. 12 depicts a block diagram of the computer system (1202) used to provide computational functionalities associated with described algorithms, methods, functions, processes, flows, and procedures as described in this disclosure, according to one or more embodiments. The illustrated computer (1202) is intended to encompass any computing device such as a server, desktop computer, laptop/notebook computer, wireless data port, smart phone, personal data assistant (PDA), tablet computing device, one or more processors within these devices, or any other suitable processing device, including both physical or virtual instances (or both) of the computing device. Additionally, the computer (1202) may include a computer that includes an input device, such as a keypad, keyboard, touch screen, or other device that can accept user information, and an output device that conveys information associated with the operation of the computer (1202), including digital data, visual, or audio information (or a combination of information), or a Graphical User Interface (GUI).

[0068] The computer (1202) can serve in a role as a client, network component, a server, a database or other persistency, or any other component (or a combination of roles) of a computer system for performing the subject matter described in the instant disclosure. The illustrated computer (1202) is communicably coupled with a network (1230). In some implementations, one or more components of the computer (1202) may be configured to operate within environments, including cloud-computing-based, local, global, or other environment (or a combination of environments).

[0069] At a high level, the computer (1202) is an electronic computing device operable to receive, transmit, process, store, or manage data and information associated with the described subject matter. According to some implementations, the computer (1202) may also include or be communicably coupled with an application server, e-mail server, web server, caching server, streaming data server, business intelligence (BI) server, or other server (or a combination of servers).

[0070] The computer (1202) can receive requests over network (1230) from a client application (for example, executing on another computer (1202)) and responding to the received requests by processing the said requests in an appropriate software application. In addition, requests may also be sent to the computer (1202) from internal users (for example, from a command console or by other appropriate access method), external or third-parties, other automated applications, as well as any other appropriate entities, individuals, systems, or computers.

[0071] Each of the components of the computer (1202) can communicate using a system bus (1203). In some implementations, any or all of the components of the computer (1202), both hardware or software (or a combination of hardware and software), may interface with each other or the interface (1204) (or a combination of both) over the system bus (1203) using an application programming interface (API) (1212) or a service layer (1213) (or a combination of the API (1212) and service layer (1213). The API (1212) may include specifications for routines, data structures, and object classes. The API (1212) may be either computer-language independent or dependent and refer to a complete interface, a single function, or even a set of APIs. The service layer (1213) provides software services to the computer (1202) or other components (whether or not illustrated) that are communicably coupled to the computer (1202). The functionality of the computer (1202) may be accessible for all service consumers using this service layer. Software services, such as those provided by the service layer (1213), provide reusable, defined business functionalities through a defined interface. For example, the interface may be software written in JAVA, C++, or other suitable language providing data in extensible markup language (XML) format or another suitable format. While illustrated as an integrated component of the computer (1202), alternative implementations may illustrate the API (1212) or the service layer (1213) as stand-alone components in relation to other components of the computer (1202) or other components (whether or not illustrated) that are communicably coupled to the computer (1202). Moreover, any or all parts of the API (1212) or the service layer (1213) may be implemented as child or sub-modules of another software module, enterprise application, or hardware module without departing from the scope of this disclosure.

[0072] The computer (1202) includes an interface (1204). Although illustrated as a single interface (1204) in FIG. 12, two or more interfaces (1204) may be used according to particular needs, desires, or particular implementations of the computer (1202). The interface (1204) is used by the computer (1202) for communicating with other systems in a distributed environment that are connected to the network (1230). Generally, the interface (1204) includes logic encoded in software or hardware (or a combination of software and hardware) and operable to communicate with the network (1230). More specifically, the interface (1204) may include software supporting one or more communication protocols associated with communications such that the network (1230) or interface's hardware is operable to communicate physical signals within and outside of the illustrated computer (1202).

[0073] The computer (1202) includes at least one computer processor (1205). Although illustrated as a single computer processor (1205) in FIG. 12, two or more processors may be used according to particular needs, desires, or particular implementations of the computer (1202). Generally, the computer processor (1205) executes instructions and manipulates data to perform the operations of the computer (1202) and any algorithms, methods, functions, processes, flows, and procedures as described in the instant disclosure.

[0074] The computer (1202) also includes a memory (1206) that holds data for the computer (1202) or other components, such as computer executable instructions, (or a combination of both) that can be connected to the network (1230). The memory (1206) may be non-transitory computer readable memory. For example, memory (1206) can be a database storing data consistent with this disclosure. Although illustrated as a single memory (1206) in FIG. 12, two or more memories may be used according to particular needs, desires, or particular implementations of the computer (1202) and the described functionality. While memory (1206) is illustrated as an integral component of the computer (1202), in alternative implementations, memory (1206) can be external to the computer (1202).

[0075] The application (1207) is an algorithmic software engine providing functionality according to particular needs, desires, or particular implementations of the computer (1202), particularly with respect to functionality described in this disclosure. For example, application (1207) can serve as one or more components, modules, applications, etc. Further, although illustrated as a single application (1207), the application (1207) may be implemented as multiple applications (1207) on the computer (1202). In addition, although illustrated as integral to the computer (1202), in alternative implementations, the application (1207) can be external to the computer (1202).

[0076] There may be any number of computers (1202) associated with, or external to, a computer system containing computer (1202), wherein each computer (1202) communicates over network (1230). Further, the term "client," "user," and other appropriate terminology may be used interchangeably as appropriate without departing from the scope of this disclosure. Moreover, this disclosure contemplates that many users may use one computer (1202), or that one user may use multiple computers (1202).

[0077] Although only a few example embodiments have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from this invention. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims.

CLAIMS

What is claimed is:

1. A method, comprising:
   receiving, for a period, observed data from a multiphase flow meter (MPFM) disposed on a pipeline carrying a multiphase fluid;
   determining first predicted data using a numerical simulator based on a wellbore model, wherein the wellbore model is configured by a set of wellbore model configuration parameters;
   calibrating the set of wellbore model configuration parameters based on the observed data and the first predicted data forming a set of calibrated wellbore model configuration parameters;
   removing the MPFM from the pipeline;
   outfitting the pipeline with an economical flow meter, wherein the economical flow meter measures a total flow rate of the multiphase fluid;
   determining second predicted data using the numerical simulator based on the wellbore model configured by the set of calibrated wellbore model configuration parameters and constrained by the total flow rate; and
   optimizing a production of the pipeline based on the determined second predicted data.

2. The method of claim 1, further comprising receiving wellbore sensor data from the pipeline.

3. The method of claim 1, wherein the first predicted data is flow phase descriptors.

4. The method of claim 3, wherein the observed data is MPFM-determined flow phase descriptors.

5. The method of claim 4, wherein the MPFM-determined flow phase descriptors and the flow phase descriptors each comprise a bulk density, a gas-to-oil ratio, and a water cut.

6. The method of claim 3, wherein the observed data is MPFM-determined phase flow rate data.

7. The method of claim 6, further comprising:

determining first phase flow rate data by processing the first predicted data with an interpretive model; and

determining second phase flow rate data by processing the second predicted data with the interpretive model,

wherein the first phase flow rate data and the second phase flow rate data each comprise a flow rate measurement for each phase of the multiphase fluid.

8. The method of claim 1, wherein the wellbore model is an isothermal compressible three-phase drift-flux model.

9. The method of claim 8, wherein the set of wellbore model configuration parameters comprises:

a multiphase friction factor;

a distribution coefficient; and

a drift velocity.

10. A non-transitory computer-readable memory comprising computer-executable instructions stored thereon that, when executed on a processor, cause the processor to perform steps comprising:

receiving, for a period, observed data from a multiphase flow meter (MPFM) disposed on a pipeline carrying a multiphase fluid;

determining first predicted data using a numerical simulator based on a wellbore model, wherein the wellbore model is configured by a set of wellbore model configuration parameters;

calibrating the set of wellbore model configuration parameters based on the observed data and the first predicted data forming a set of calibrated wellbore model configuration parameters;

determining second predicted data using the numerical simulator based on the wellbore model configured by the set of calibrated wellbore model configuration parameters and constrained by a total flow rate from an economical flow meter that has replaced the MPFM; and

optimizing a production of the pipeline based on the determined second predicted data.

11. The non-transitory computer-readable memory of claim 10, further comprising the step:

receiving wellbore sensor data from the pipeline.

12. The non-transitory computer-readable memory of claim 10, wherein the first predicted data is flow phase descriptors.

13. The non-transitory computer-readable memory of claim 12, wherein the observed data is MPFM-determined flow phase descriptors.

14. The non-transitory computer-readable memory of claim 13, wherein the MPFM-determined flow phase descriptors and the flow phase descriptors each comprise a bulk density, a gas-to-oil-ratio, and a water cut.

15. The non-transitory computer-readable memory of claim 12, wherein the observed data is MPFM-determined phase flow rate data.

16. The non-transitory computer-readable memory of claim 15, further comprising the steps:

    determining first phase flow rate data by processing the first predicted data with an interpretive model; and

    determining second phase flow rate data by processing the second predicted data with the interpretive model,

    wherein the first phase flow rate data and the second phase flow rate data each comprise a flow rate measurement for each phase of the multiphase fluid.

17. The non-transitory computer-readable memory of claim 10, wherein the wellbore model is an isothermal compressible three-phase drift-flux model.

18. The non-transitory computer-readable memory of claim 17, wherein the set of wellbore model configuration parameters comprises:

    a multiphase friction factor;

    a distribution coefficient; and

    a drift velocity.

19. A system comprising:

    a wellbore model configured by a set of wellbore model configuration parameters;

    a numerical simulator that simulates flow of a multiphase fluid through a pipeline, wherein the numerical simulator uses the wellbore model;

    an inversion system comprising an objective function; and a computer processor configured to:

receive, for a period, observed data from a multiphase flow meter (MPFM) disposed on the pipeline;

determine first predicted data using the numerical simulator;

calibrate the set of wellbore model configuration parameters based on the observed data and the first predicted data using the inversion system, wherein the inversion system outputs a set of calibrated wellbore model configuration parameters;

receive a total flow rate from an economical flow meter disposed on the pipeline;

determine second predicted data using the numerical simulator based on the wellbore model configured by the set of calibrated wellbore model configuration parameters and constrained by the total flow rate; and

optimize a production of the pipeline based on the determined second predicted data.

20. The system of claim 19, wherein the computer processor is further configured to:

determine first phase flow rate data by processing the first predicted data with an interpretive model; and

determine second phase flow rate data by processing the second predicted data with the interpretive model,

wherein the first phase flow rate data and the second phase flow rate data each comprise a flow rate measurement for each phase of the multiphase fluid.

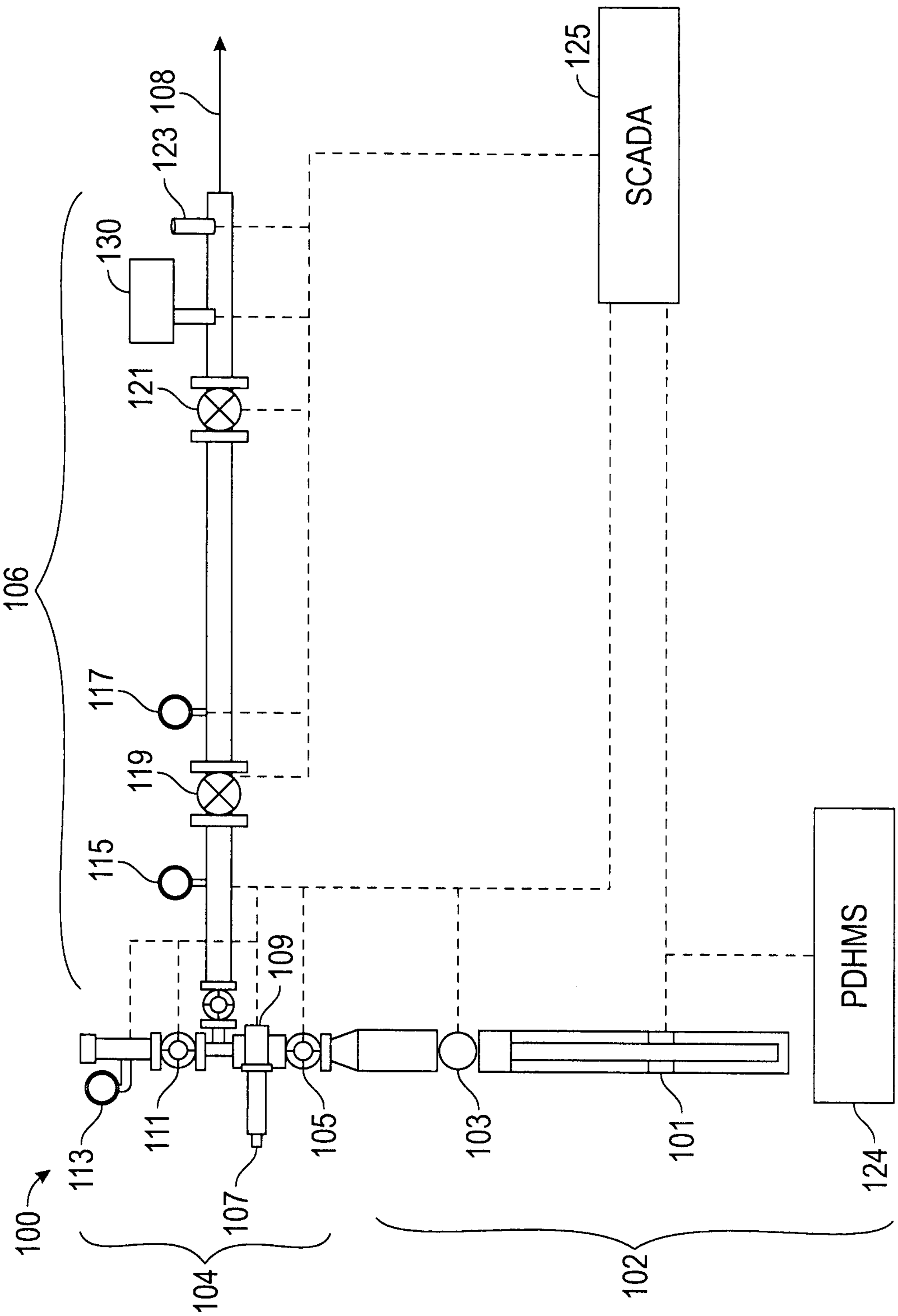

SCADA
PDHMS
100
101
102
103
104
105
106
107
108
109
111
113
115
117
119
121
123
124
125
130

FIG. 1

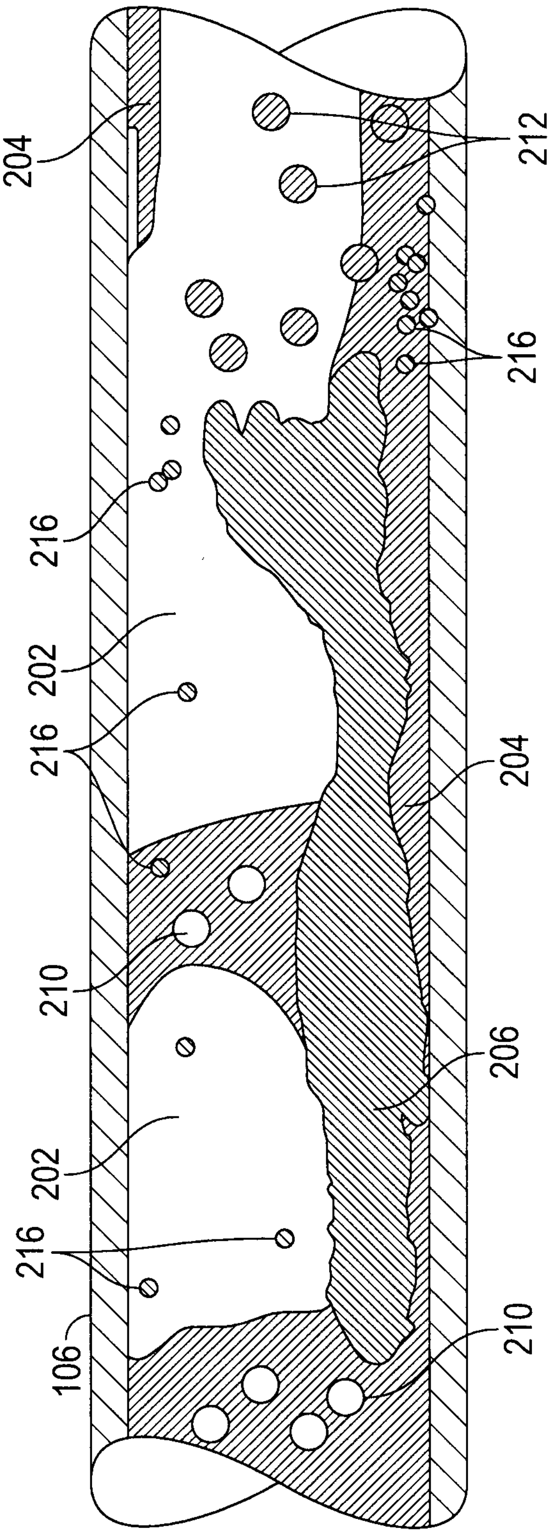


FIG. 2

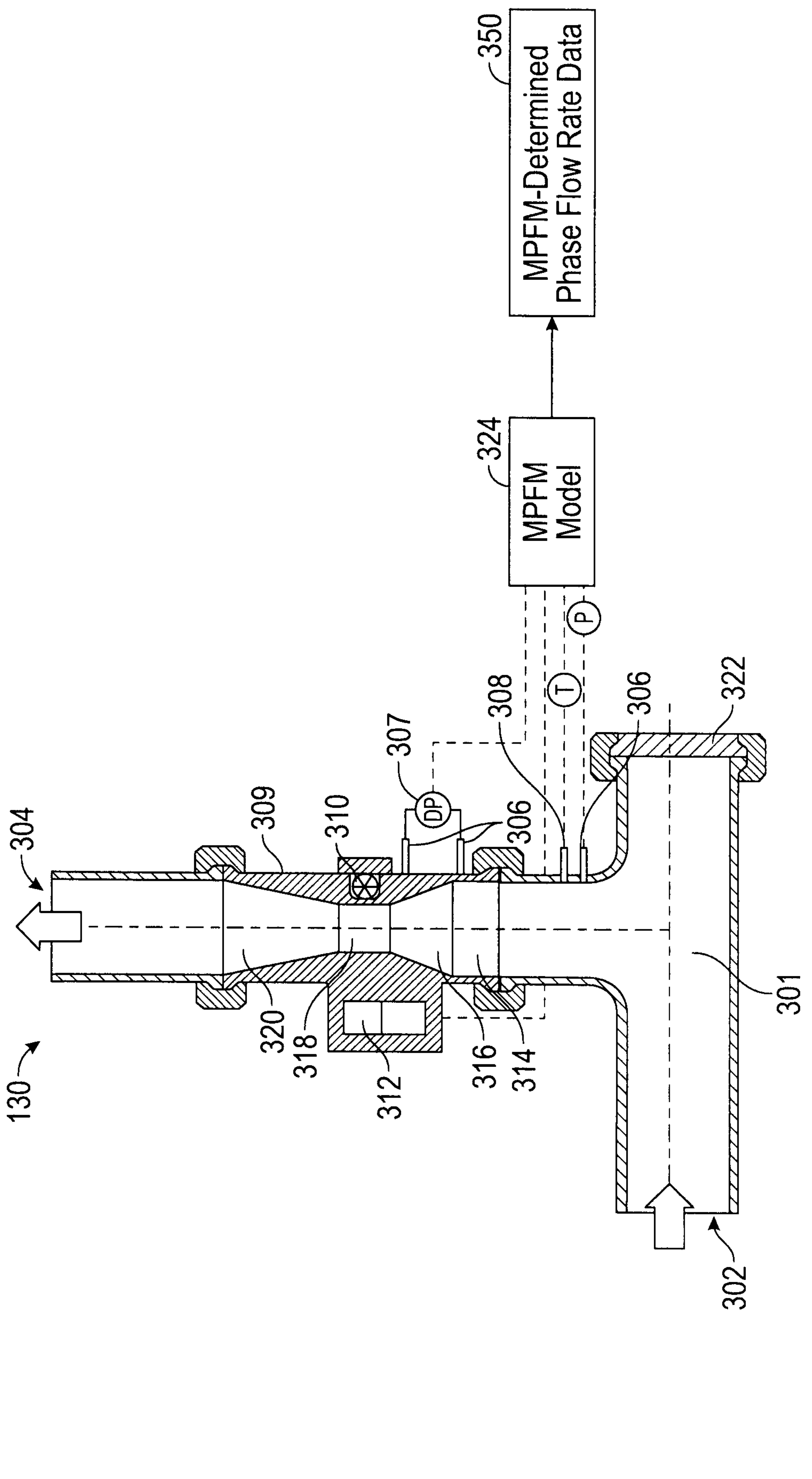

MPFM-Determined Phase Flow Rate Data
350
MPFM Model
324
DP
T
P
130
301
302
304
306
307
308
309
310
312
314
316
318
320
322

FIG. 3

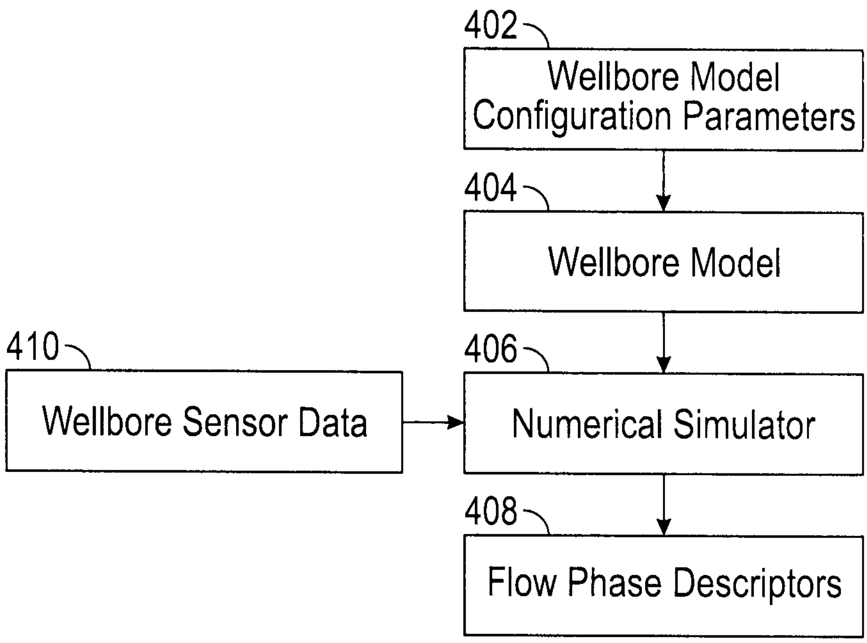

402
Wellbore Model Configuration Parameters
404
Wellbore Model
410
Wellbore Sensor Data
406
Numerical Simulator
408
Flow Phase Descriptors

FIG. 4

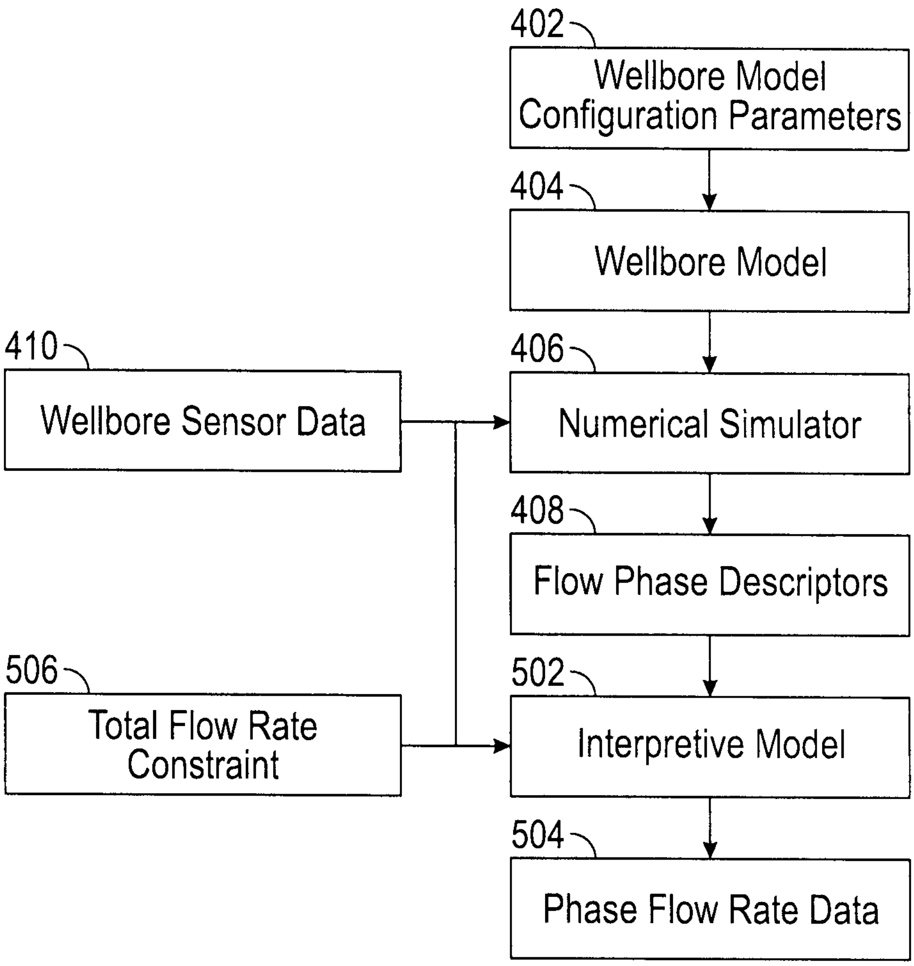

402
Wellbore Model Configuration Parameters
404
Wellbore Model
410
Wellbore Sensor Data
406
Numerical Simulator
408
Flow Phase Descriptors
506
Total Flow Rate Constraint
502
Interpretive Model
504
Phase Flow Rate Data

FIG. 5

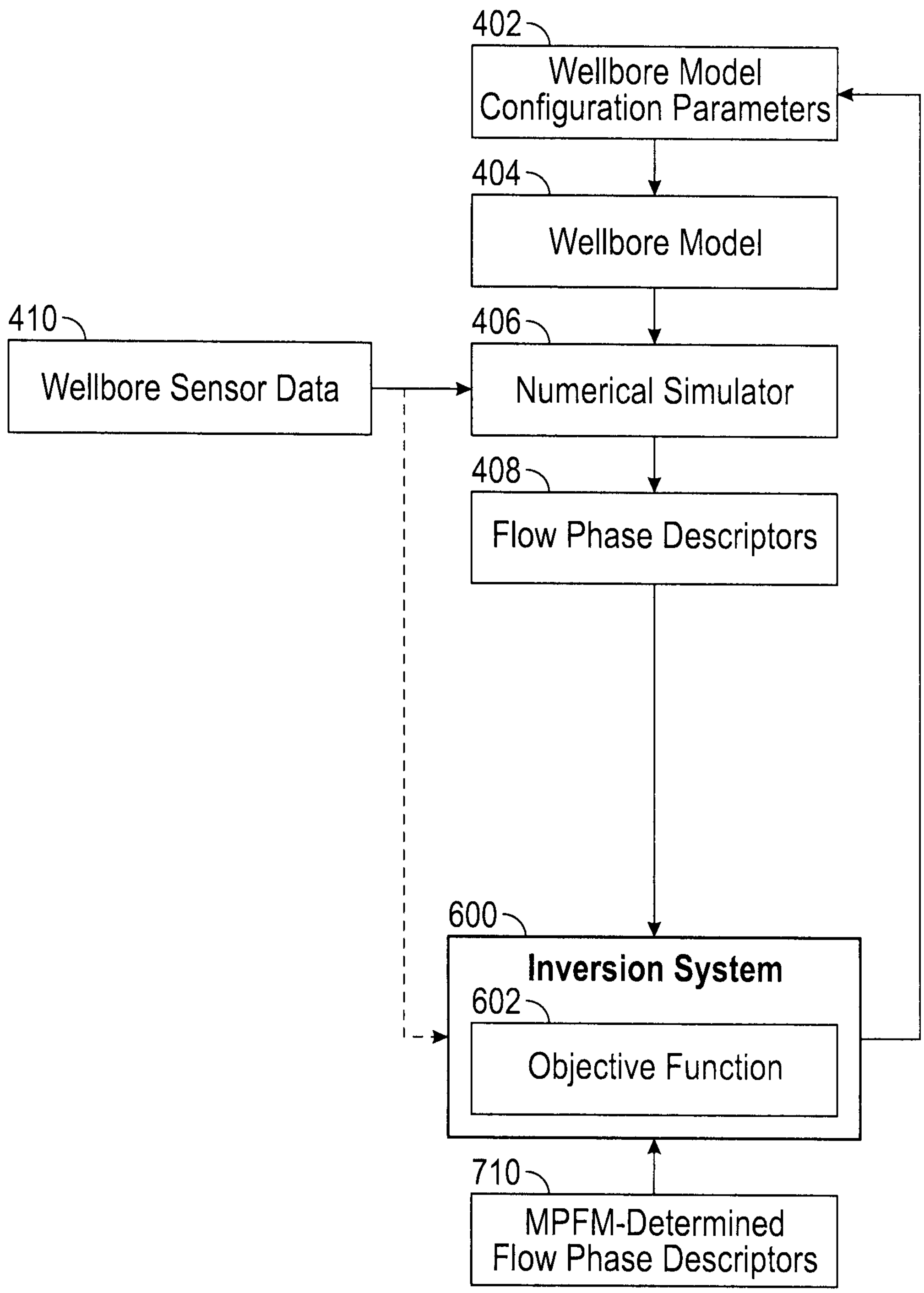

402
Wellbore Model Configuration Parameters
404
Wellbore Model
410
Wellbore Sensor Data
406
Numerical Simulator
408
Flow Phase Descriptors
600
Inversion System
602
Objective Function
710
MPFM-Determined Flow Phase Descriptors

FIG. 6

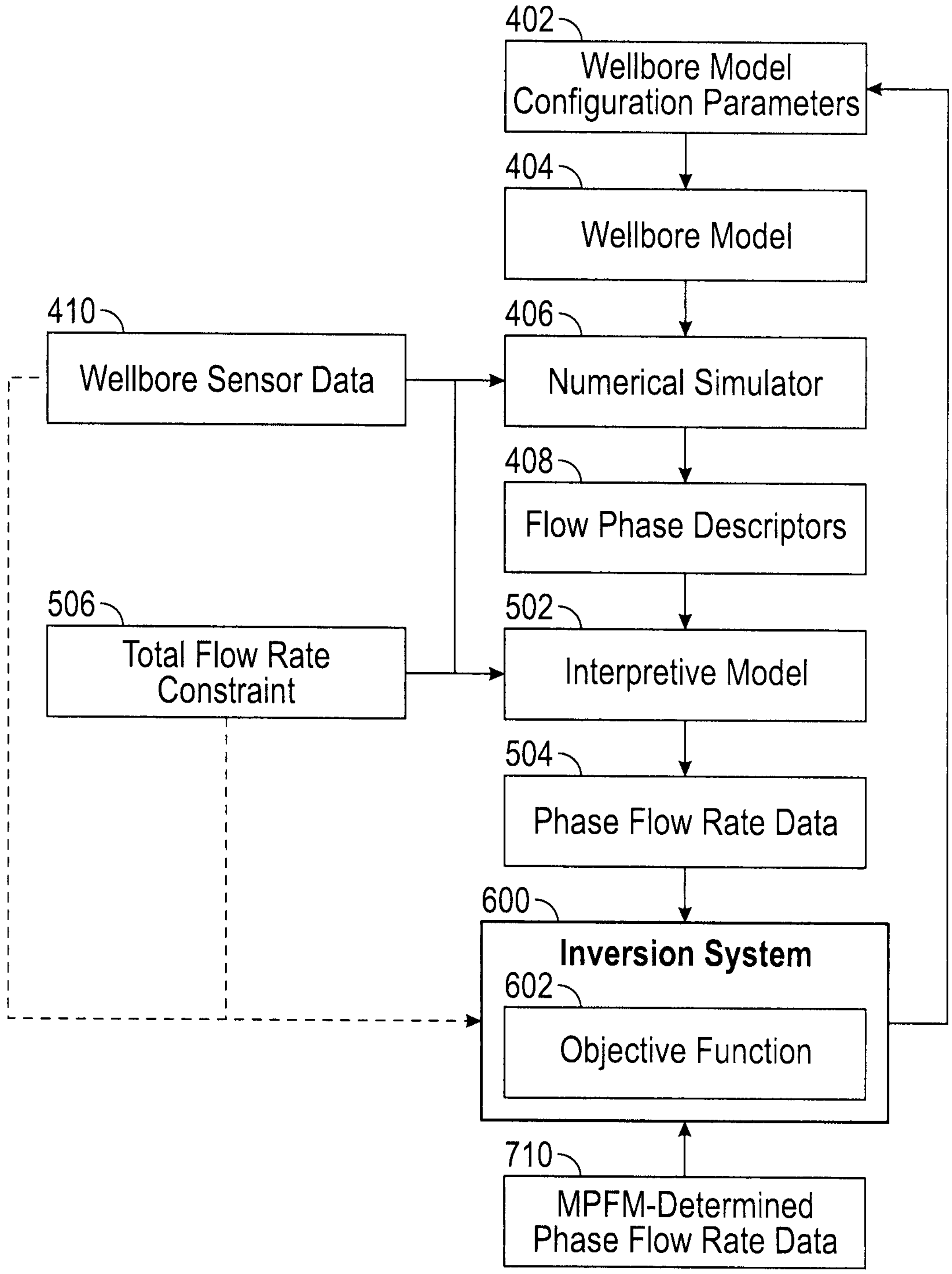

402
Wellbore Model Configuration Parameters
404
Wellbore Model
410
Wellbore Sensor Data
406
Numerical Simulator
408
Flow Phase Descriptors
506
Total Flow Rate Constraint
502
Interpretive Model
504
Phase Flow Rate Data
600
Inversion System
602
Objective Function
710
MPFM-Determined Phase Flow Rate Data

FIG. 7

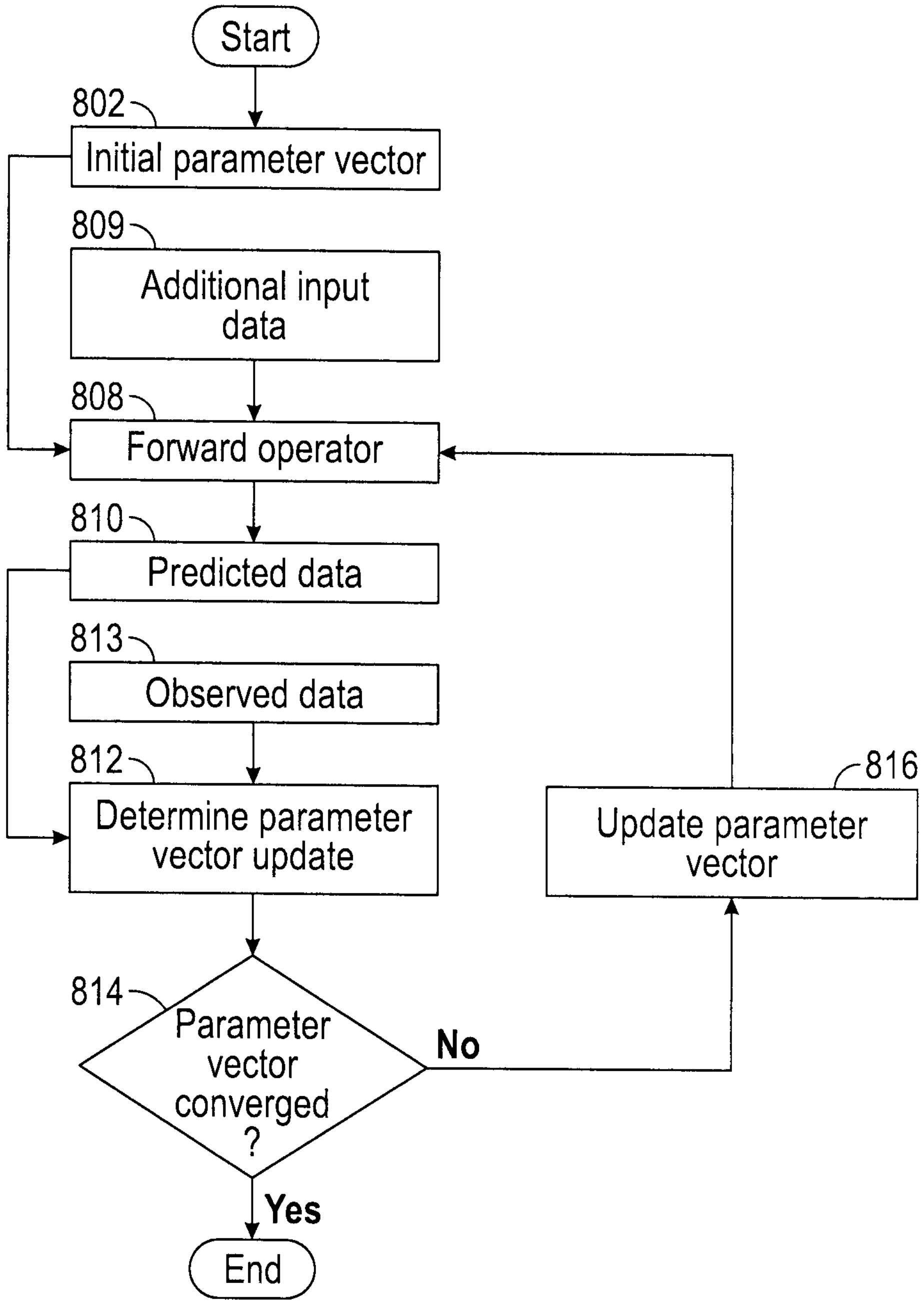
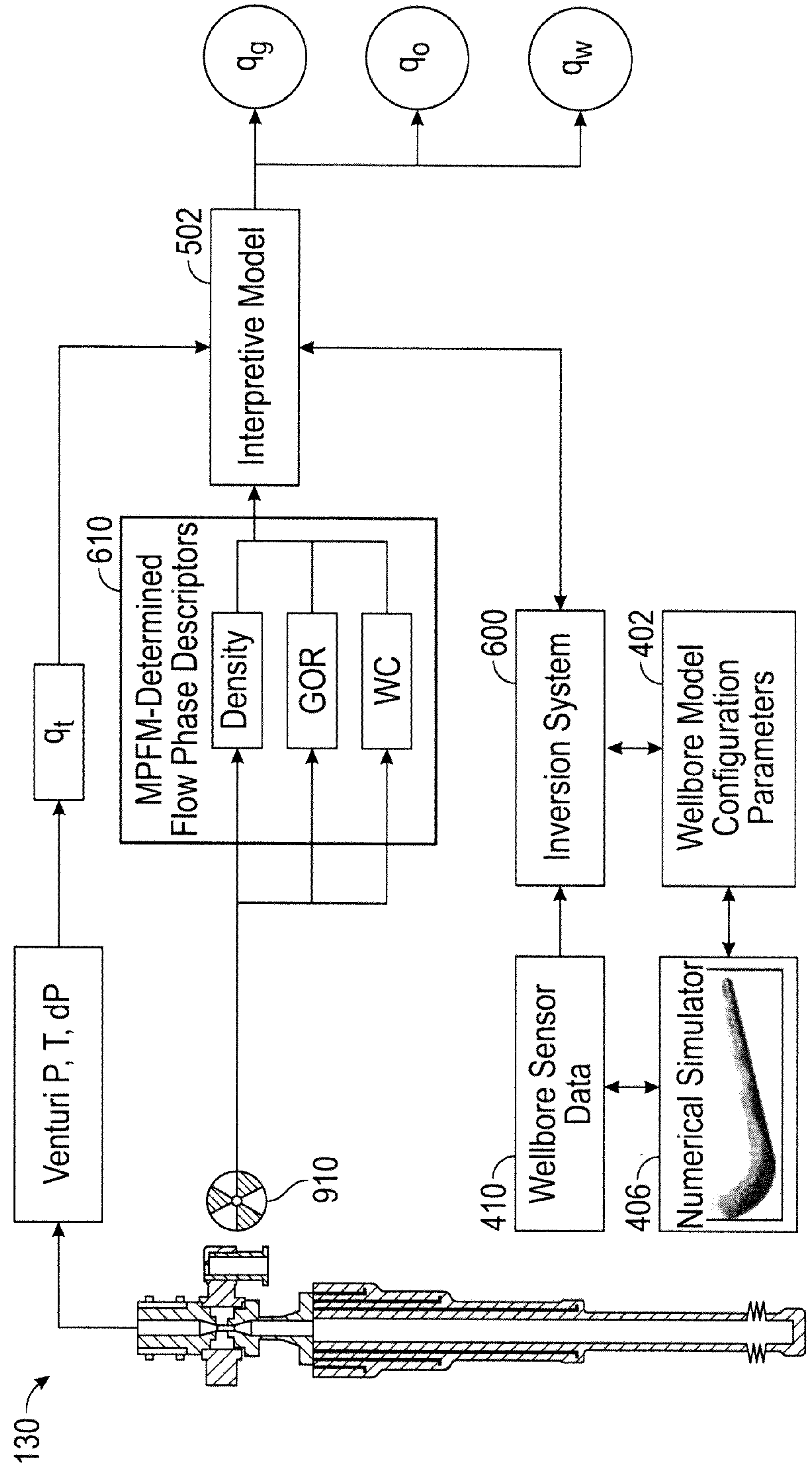

Start
802
Initial parameter vector
809
Additional input data
808
Forward operator
810
Predicted data
813
Observed data
812
Determine parameter vector update
814
Parameter vector converged ?
No
Yes
End
816
Update parameter vector

FIG. 8



q_g
q_o
q_w
502
Interpretive Model
610
MPFM-Determined Flow Phase Descriptors
Density
GOR
WC
q_t
Venturi P, T, dP
910
600
Inversion System
402
Wellbore Model Configuration Parameters
410
Wellbore Sensor Data
406
Numerical Simulator
130
102

FIG. 9

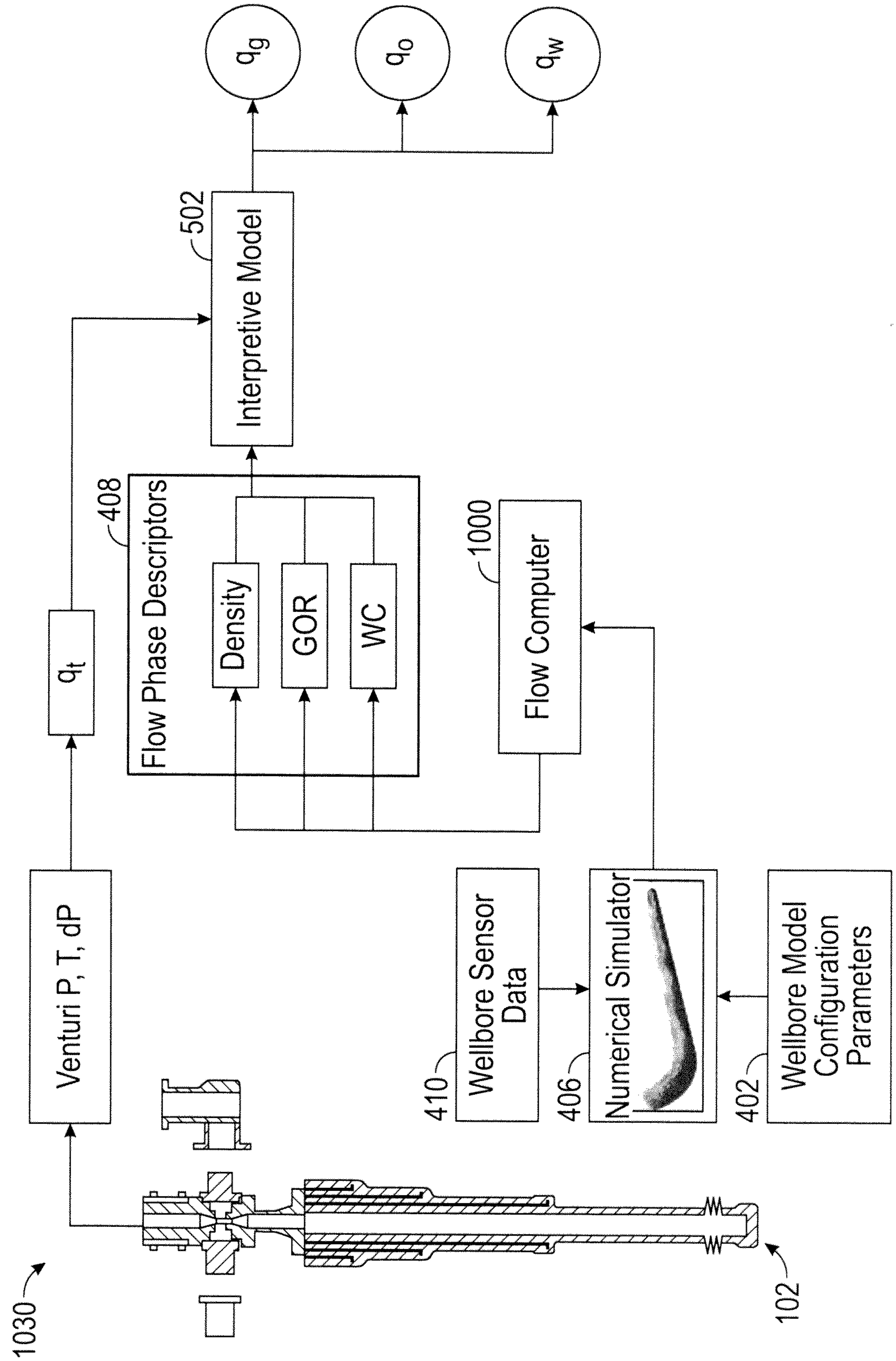

1030
Venturi P, T, dP
q_t
408
Flow Phase Descriptors
Density
GOR
WC
502
Interpretive Model
q_g
q_o
q_w
1000
Flow Computer
410
Wellbore Sensor Data
406
Numerical Simulator
402
Wellbore Model Configuration Parameters
102

FIG. 10

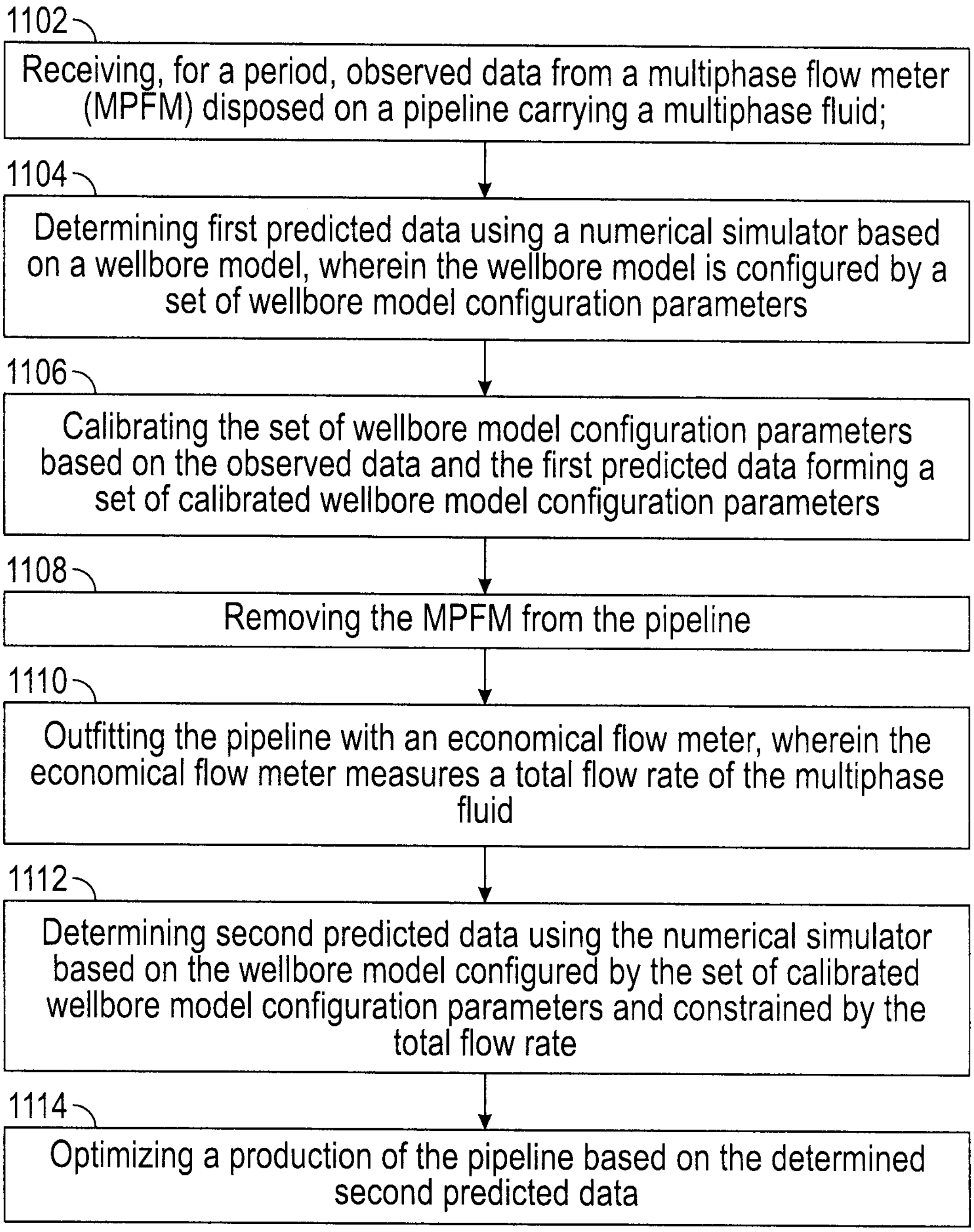

1102
Receiving, for a period, observed data from a multiphase flow meter (MPFM) disposed on a pipeline carrying a multiphase fluid;
1104
Determining first predicted data using a numerical simulator based on a wellbore model, wherein the wellbore model is configured by a set of wellbore model configuration parameters
1106
Calibrating the set of wellbore model configuration parameters based on the observed data and the first predicted data forming a set of calibrated wellbore model configuration parameters
1108
Removing the MPFM from the pipeline
1110
Outfitting the pipeline with an economical flow meter, wherein the economical flow meter measures a total flow rate of the multiphase fluid
1112
Determining second predicted data using the numerical simulator based on the wellbore model configured by the set of calibrated wellbore model configuration parameters and constrained by the total flow rate
1114
Optimizing a production of the pipeline based on the determined second predicted data

FIG. 11

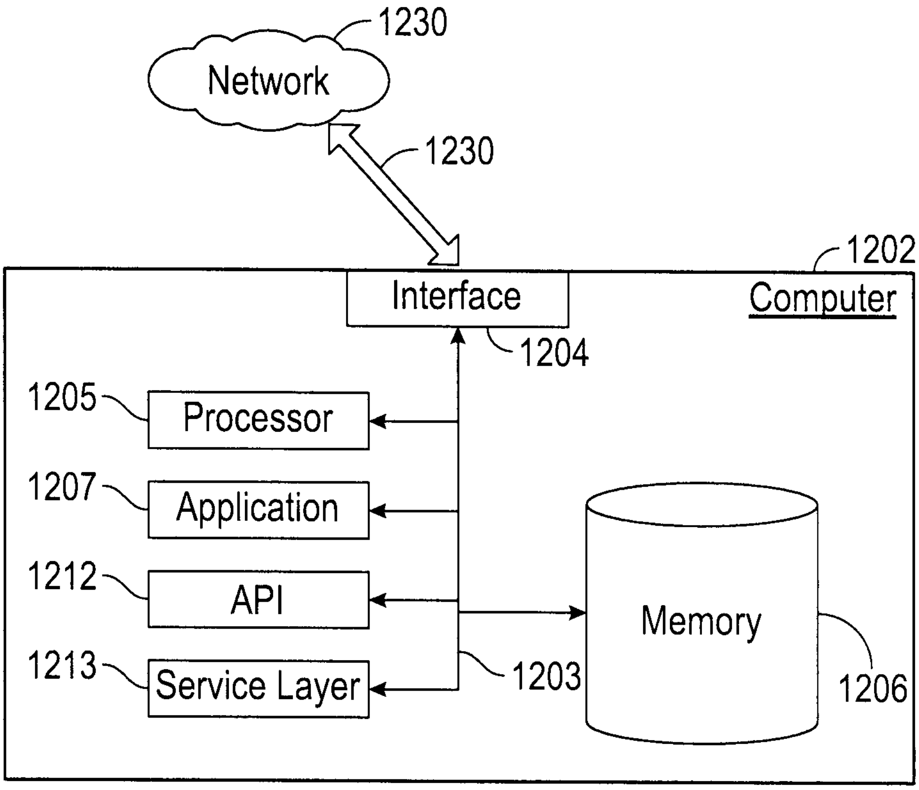

1230
Network
1230
1202
Interface
Computer
1204
1205
Processor
1207
Application
1212
API
1213
Service Layer
1203
Memory
1206

FIG. 12

INTERNATIONAL SEARCH REPORT	International application No. PCT/RU 2023/000173

A. CLASSIFICATION OF SUBJECT MATTER

G01F 1/00 (2022.01)
E21B 47/003 (2012.01)
G06Q 10/04 (2023.01)

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

G01F 1/00, E21B 43/00, 47/00, 47/003, G01N 33/00, G06Q 10/00-10/04

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

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

Espacenet, PatSearch, RUPTO, USPTO, PATENTSCOPE, Google Patents

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	WO 2023/059895 A1 (SAUDI ARABIAN OIL COMPANY) 13.04.2023	1-20
A	WO 2020/232218 A1 (SAUDI ARABIAN OIL COMPANY) 19.11.2020	1-20
A	US 2022/0214474 A1 (TATA CONSULTANCY SERVICES LTD) 07.07.2022	1-20
A	WO 2023/066547 A1 (SIEMENS ENERGY GLOBAL GMBH & CO KG) 27.04.2023	1-20

☐ Further documents are listed in the continuation of Box C. ☐ See patent family annex.

* Special categories of cited documents:

“A” document defining the general state of the art which is not considered to be of particular relevance

“D” document cited by the applicant in the international application

“E” earlier document but published on or after the international filing date

“L” document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

“O” document referring to an oral disclosure, use, exhibition or other means

“P” document published prior to the international filing date but later than the priority date claimed

“T” later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

“X” document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

“Y” document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

“&” document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
06 February 2024 (06.02.2024)	01 March 2024 (01.03.2024)

Name and mailing address of the ISA/RU:	Authorized officer
Federal Institute of Industrial Property, Berezhkovskaya nab., 30-1, Moscow, G-59, GSP-3, 125993, Russian Federation Phone No: +7(499)240-60-15, Fax +7(495)531-63-18	E. Kubasova Telephone No. 8 (495) 531-64-81