



- (51) International Patent Classification:
E21B 43/12 (2006.01) *G05B 19/02* (2006.01)
G06F 9/455 (2006.01)
- (21) International Application Number:
PCT/US2015/036270
- (22) International Filing Date:
17 June 2015 (17.06.2015)
- (25) Filing Language: English
- (26) Publication Language: English
- (71) Applicant: **LANDMARK GRAPHICS CORPORATION** [US/US]; 10200 Bellaire Blvd., Houston, Texas 77072 (US).
- (72) Inventor: **ORTIZ, Thomas Manuel**; 3919 Essex Ln., #327, Houston, Texas 77027 (US).
- (74) Agents: **ROSE, Collin A.** et al.; 1200 Smith Street, 14th Floor, Houston, Texas 77002 (US).
- (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, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, 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, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

- (84) Designated States (*unless otherwise indicated, for every kind of regional protection available*): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, 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, 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))

(54) Title: AUTOMATED PVT CHARACTERIZATION AND FLOW METERING

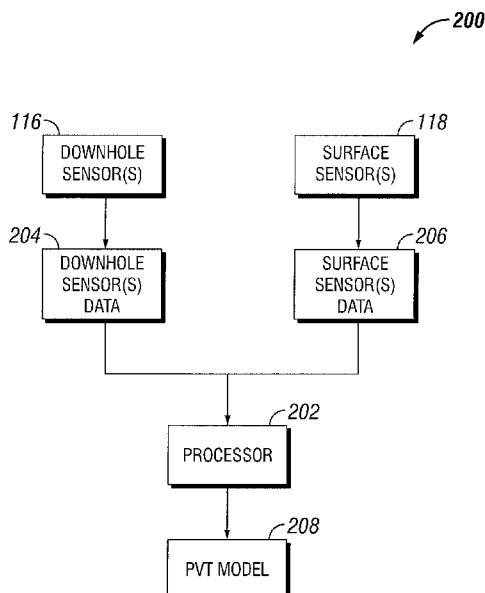


FIG. 2

(57) Abstract: A pressure-volume-temperature (PVT) modeling system includes a sensing device configured to obtain a fluid measurement of a production fluid in a downhole portion of a well system or in a surface portion of the well system, and a processor comprising a PVT model builder, the processor configured to receive the fluid measurement from the sensing device, apply the fluid measurement as an input into the PVT model builder, and generate a PVT model.

AUTOMATED PVT CHARACTERIZATION AND FLOW METERING

BACKGROUND

[0001] This section is intended to introduce the reader to various aspects of art that may be related to various aspects of the presently described embodiments. This discussion is believed to be helpful in providing the reader with background information to facilitate a better understanding of the various aspects of the present embodiments. Accordingly, it should be understood that these statements are to be read in this light, and not as admissions of prior art.

[0002] In oil and gas reservoirs, production fluids can have different thermodynamic and thermophysical properties, densities, viscosity, etc., based on the formulation of the fluid. Production fluid is generally a mixture of various hydrocarbons and other materials. An important aspect of oil and gas production operations is creating a pressure-volume-temperature (PVT) model. A PVT model allows operators and other users to understand certain behavior or characteristics of the production fluid under certain conditions and at various stages. For example, a reservoir engineer may use the PVT model to estimate how much oil/gas may be produced from the reservoir and how quickly the oil/gas can be produced. A process plant operator may use data from the PVT to determine treatment processes for processing the fluid or for creating intermediary products. An allocation engineer may use the PVT model to help determine allocation of the produced fluid.

[0003] In order to properly model the flow of oil from the reservoir into the well and through production facilities (production piping, surface pipelines, etc.), it is necessary to understand the thermodynamic properties of the fluid, and to be able to calculate them to a certain degree of accuracy. These properties can often vary quite a bit even within a reservoir depending on the zone or well as well as over time.

BRIEF DESCRIPTION OF THE DRAWINGS

[0004] Illustrative embodiments of the present disclosure are described in detail below with reference to the attached drawing figures, which are incorporated by reference herein and wherein:

[0005] FIG. 1 illustrates a production well system, in accordance with example embodiments of the present disclosure;

[0006] FIG. 2 is a high level system diagram of a PVT modeling system, in accordance with example embodiments of the present disclosure;

[0007] FIG. 3 illustrates a multiple well system instrumented with a PVT modeling system, in accordance with example embodiments of the present disclosure; and

[0008] FIG. 4 is a high level system diagram of a multiple well PVT modeling system, in accordance with example embodiments of the present disclosure.

[0009] The illustrated figures are only exemplary and are not intended to assert or imply any limitation with regard to the environment, architecture, design, or process in which different embodiments may be implemented.

DETAILED DESCRIPTION OF ILLUSTRATIVE EMBODIMENTS

[0010] The present disclosure is directed towards novel systems and methods for creating a pressure-volume-temperature (PVT) model and characterization of production fluid from fluid measurements obtained directly from the well, including at the point of influx from the reservoir, throughout the wellbore, and through the associated surface facilities. Typically, in order to create a PVT model for a particular reservoir or well system, a sample of production fluid is taken from the reservoir and brought into a lab facility for analysis. However, it can be difficult to keep the sample in its downhole condition during transport and analysis. Additionally, the sampled

production fluid may not be representative of the entire reservoir as different areas of the reservoir may produce fluid having different properties. The properties of the production fluid may also change over time, and since there is a significant delay between obtaining the fluid sample and receiving the PVT model from the lab analysis, the PVT model may be out of date. To address these challenges, the present disclosure employs a system of downhole and surface sensors, such as multi-phase flow meters, pressure sensors, and temperature sensors, to obtain production fluid characteristics, which are used to generate a PVT model of the fluid on the fly. Thus, a PVT model is produced with production fluid characteristics taken under the proper environmental conditions, and which has minimum time delay. Further, the up-to-date PVT model can be synchronized across applications and sent to “customers” who use the model for their needs, such as process plants, allocation engineers, reservoir engineers, etc. The present techniques can be used to generate black oil PVT models as well as compositional PVT models.

[0011] Turning now to the figures, FIG. 1 illustrates an example production well system 100. The well system 100 includes a well 102 formed within a formation 104. The well 102 may be a vertical wellbore as illustrated or it may be a horizontal or directional well. The formation 104 may be made up of several zones which may include oil reservoirs. In certain example embodiments, the well system 100 may include a production tree 108 and a wellhead 109 located at a well site 106. A production tubing 112 extends from the wellhead 109 into the well 102. The production tubing 112 includes a plurality of perforations 126 through which fluids from the formation 104 can enter the production tubing 112 and flow upward into the production tree 108. In some embodiments, the subsurface pressure on the fluids is large enough to push the fluid upward naturally. In some other embodiments, the production fluid is recovered using artificial lift or enhanced recovery techniques.

[0012] In some embodiments, the wellbore 102 is cased with one or more casing segments 130. The casing segments 130 help maintain the structure of the well 102

and prevents the well 102 from collapsing in on itself. In some embodiments, a portion of the well is not cased and may be referred to as “open hole”. The space between the production tubing 112 and the casing 130 or wellbore 102 is an annulus 110.

Production fluids enter the annulus 110 from the formation 104 and then enter the production tubing 112 from the annulus 110. Production fluid enters the production tree 108 from the production tubing 112. The production fluid is then delivered to various surface facilities for processing via a surface pipeline 114.

[0013] It should be appreciated that well system 100 is only an example well system and there are many other well system configurations may also be appropriate for use.

[0014] In some embodiments, the well system 100 includes one or more downhole sensors 116. The sensors 116 measure one or more conditions of the production fluid in the downhole environment. This data is used in generating the PVT model. In some embodiments, the sensors 116 are coupled to the outside of the production tubing 112 near the target formation. In some other embodiments, the sensors 116 can be located inside the production tubing 112, on the borehole 102 wall, or otherwise disposed downhole. In some embodiments, the sensors 116 may include a flow meter, a pressure sensor, a temperature sensor, a fluid composition sensor, or any combination thereof, among other types of sensors.

[0015] The flow meter measures the rate of fluid flow into the production tubing 112 downhole near the perforations 126. The pressure sensor measures the amount of production fluid pressure downhole near the perforations 126. The temperature sensor measures the temperature of the production fluid downhole near the perforations 126. The fluid composition sensor detects the chemical makeup of the production fluid downhole near the perforations 126. Depending on the operation and the desired PVT model, the well system 100 may include any one of these sensors, any combination of these sensors, or other types of sensors.

[0016] In some embodiments, the well system 100 includes one or more surface sensors 118 configured to measure properties of production fluid at the surface. This data is used in generating the PVT model. In some embodiments, the sensors 118 are coupled to a surface pipeline 114. In some embodiments, the sensors 118 may include a multiphase flow meter, a pressure sensor, a temperature sensor, a fluid composition sensor, or any combination thereof, among other types of sensors.

[0017] The flow meter measures the rate of fluid flow through the pipeline 114. The pressure sensor measures the amount of fluid pressure in the pipeline 114. The temperature sensor measures the temperature of the production fluid in the pipeline 114. The fluid composition sensor detects the chemical makeup of the production fluid in the pipeline 114. Depending on the operation and the desired PVT model, the well system 100 may include any one of these sensors disposed above ground, any combination of these sensors, or other types of sensors. In some embodiments, the well system 100 may only include one or more downhole sensors 116 and no surface sensors. In some other embodiments, the well system 100 may only include one or more surface sensors 118.

[0018] FIG. 2 is a high level system diagram of a PVT modeling system 200, in accordance with example embodiments of the present disclosure. In some embodiments, a processor 202 receives at least one downhole sensor data 204 collected from the downhole sensors 116 and/or at least one surface sensor data 206 from the surface sensors 118 and generates a PVT model 208 from the data. In some embodiments, the data 204, 206 is received in real time or quasi-real time. In some embodiments, the processor 202 receives the data 204, 206 through a direct wired connection. In some embodiments, the processor 202 receives the data 204, 206 through a wireless communication protocol such as Wi-Fi, Bluetooth, cellular network, and the like. In some embodiments, the processor 202 is coupled to or integral with one or more of the sensors 116, 118. The processor 202 may be located downhole or above ground. In some embodiments the processor 202 is disposed at the

well site 106 as a computing device or as a part of a control station. In some embodiments, the sensors 116, 118 are coupled to a transmitter or a transceiver, which communicates the data from the sensors 116, 118 to the processor 202. In some embodiments, the processor 202 can be remotely located from the sensors 116, 118 in a facility such as an office building or laboratory.

[0019] The processor 202 is communicatively coupled to or integrally includes a memory device. The memory device holds instructions for building a PVT model 208 using the data 204, 206 as inputs. The PVT model 208 can be generated using various PVT modeling algorithms. The PVT modeling algorithms may be considered a PVT model builder or a system to which one or more inputs are applied. In some embodiments, the processor 202 utilizes the sensor data 202, 206 as well as one or more previously measured or known parameters with the PVT modeling algorithm.

[0020] In some embodiments, the PVT model 208 is a black-oil model, in which the composition of the production fluid is not taken into account. In one such example embodiment, the sensor data 202, 206 includes a downhole flow rate, a surface flow rate, a downhole fluid temperature, a surface fluid temperature, a downhole fluid pressure, a surface fluid pressure, a gas rate, an oil rate, a water rate, a gas gravity, a water salinity, or any combination of such. In some embodiments, the PVT modeling algorithm for a black-oil PVT model includes the following equations:

$$Eq. 1: \quad p_r = \frac{p}{p_b}$$

$$Eq. 2: \quad R_{sr} = \frac{R_s}{R_{sb}}$$

$$Eq. 3: \quad R_{sr} = a_1 p_r^{a_2} + (1 - a_1) p_r^{a_3}$$

$$Eq. 4: \quad a_1 = f_1(T, \gamma_{API}, \gamma_g, p_b)$$

$$Eq. 5: \quad a_2 = f_2(T, \gamma_{API}, \gamma_g, p_b)$$

$$Eq. 6: \quad a_3 = f_3(T, \gamma_{API}, \gamma_g, p_b)$$

$$Eq. 7: \quad B_o = 1.023761 + 0.000122 [R_s^{0.413179} \gamma_g^{0.210293} \gamma_{API}^{0.127123} + 0.019073T]^{2.465976}$$

$$Eq. 8: \quad B_g = \frac{Z_{bh} T_{bh} p_{std}}{Z_{std} T_{std} p_{bh}}$$

$$Eq. 9: \quad p_b = 1091.47 [R_s^{0.081465} \gamma_g^{-0.161488} 10^X - 0.740152]^{5.354891}$$

$$Eq. 10: \quad X = (0.013098 T^{0.282372}) - (8.2 \times 10^{-6} \gamma_{API}^{2.176124})$$

$$Eq. 11: \quad \frac{m_{o,wh}}{\rho_{o,wh}} \frac{1}{B_{o,wh}} = N_p B_{o,bh}$$

$$Eq. 12: \quad \frac{\dot{m}_o}{\rho_o} = N_p$$

$$Eq. 13: \quad \frac{\dot{m}_g}{\rho_g} = N_p (R_p - R_s)$$

$$Eq. 14: \quad N_p [B_o + (R_p - R_s) B_g] = N B_{oi} \left[\frac{(B_o - B_{oi}) + (R_{si} - R_s) B_g}{B_{oi}} + m \left(\frac{B_g}{B_{gi}} - 1 \right) + (1 + m) \left(\frac{c_w S_{wc} + c_f}{1 - S_{wc}} \right) \Delta p \right] + (W_e - W_p) B_w$$

$$Eq. 15: \quad B_w \approx 1$$

$$Eq. 16: \quad \mu_o = 10^Y - 1$$

$$Eq. 17: \quad Y = 10^{2.9924 - 0.11027 \gamma_{API} T - 0.9863}$$

$$Eq. 18: \quad \mu_g = 10^{-4} k_v \exp \left(x_v \left(\frac{\rho_g}{62.4} \right)^{y_v} \right)$$

$$Eq. 19: \quad k_v = \frac{(9.4 + 0.02 MW_g) T^{1.5}}{209 + 19 MW_g + T}$$

$$\text{Eq. 20: } y_v = 2.4 - 0.2x_v$$

$$\text{Eq. 21: } x_v = 3.5 + \frac{986}{T} + 0.01MW_g$$

$$\text{Eq.22: } p_r = p_{bh}/p_b$$

[0021] In certain example embodiments, the processor 202 runs these equations as a system of equations and solves for the following variables:

$R_s = \text{Solution Gas Oil Ratio}$

$p_b = \text{Bubble point pressure}$

$B_o = \text{Oil Formation Volume Factor}$

$\mu_o = \text{Oil Viscosity}$

$\mu_g = \text{Gas Viscosity}$

[0022] Such variables are the PVT model parameters and thus define the PVT model. All other variables are either known in advance or calculated explicitly as a part of the process.

[0023] In some embodiments, the PVT model is a compositional model, which takes into account the composition of the production fluid. In one such example embodiment, the sensor data 202, 206 includes a downhole fluid pressure, a downhole fluid temperature, a surface fluid pressure, and a surface fluid temperature. The values of ρ_o (oil density) and ρ_g (gas density) will be measured by surface sensors. The overall composition (z_i for each component i) of the fluid at bottom hole conditions is measured by the fluid composition sensor. In some embodiments, the PVT modeling algorithm for a compositional PVT model includes the following equations:

[0024] In some embodiments, the approximate equilibrium ratio for each component is measured using a correlation, for example:

$$\text{Eq. 23 } K_i = \frac{p_{ci}}{p} \exp \left[5.37(1 + \omega_i) \left(1 - \frac{T_{ci}}{T} \right) \right]$$

In some embodiments, an initial value for the number of moles in the gas phase, n_v , is found using the following equations.

$$\text{Eq. 24} \quad n_v = \frac{\alpha}{\alpha - \beta}$$

$$\text{Eq. 25} \quad \alpha = \sum_i z_i (K_i - 1)$$

$$\text{Eq. 26} \quad \beta = \sum_i \frac{z_i (K_i - 1)}{K_i}$$

In some embodiments, a nonlinear root finding algorithm, such as Newton-Raphson, is used to converge to a final value. In some embodiments, the following system of equations is solved for the phase compositions (gas composition y_i for each component i and liquid composition x_i for each component i).

$$\text{Eq. 27} \quad \sum_i \frac{z_i (K_i - 1)}{n_v (K_i - 1) + 1} = 0$$

$$\text{Eq. 28} \quad n_l = 1 - n_v$$

$$\text{Eq. 29} \quad x_i = \frac{z_i}{n_l + n_v K_i}$$

$$\text{Eq. 30} \quad y_i = x_i K_i$$

In some embodiments, an equation of state is used to compute the liquid and vapor phase densities.

$$\text{Eq. 31} \quad f(Z) = Z^3 - Z^2 + (A - B - B^2)Z - AB = 0$$

$$\text{Eq. 32} \quad A = \frac{a_{m,\varphi} p}{R^2 T^{2.5}}$$

$$\text{Eq. 33} \quad B = \frac{b_{m,\varphi} p}{RT}$$

$$\text{Eq. 34} \quad \varphi = g, l$$

$$\text{Eq. 35} \quad a_{m,g} = \left[\sum_i y_i \sqrt{a_i} \right]^2$$

$$\text{Eq. 36} \quad b_{m,g} = \sum_i y_i b_i$$

$$\text{Eq. 37} \quad a_{m,l} = \left[\sum_i x_i \sqrt{a_i} \right]^2$$

$$\text{Eq. 38} \quad b_{m,l} = \sum_i x_i b_i$$

$$\text{Eq. 39} \quad a_i = \Omega_a \frac{R^2 T_{ci}^2}{p_{ci}}$$

$$\text{Eq. 40} \quad b_i = \Omega_b \frac{R^2 T_{ci}}{p_{ci}}$$

The largest root of $f(Z)$ will be the liquid phase compressibility factor, Z_l , and the smallest root will be the gas phase compressibility factor, Z_g . The individual phase densities is calculated using:

$$\text{Eq. 41} \quad \rho_l = \frac{p \sum x_i MW_i}{Z_l RT}$$

$$\text{Eq. 42} \quad \rho_g = \frac{p \sum y_i MW_i}{Z_g RT}$$

The calculated densities are compared with those measured using the multiphase flow meters. If the densities differ by more than a specified tolerance, a_i and b_i can be tuned by adjusting the factors Ω_a and Ω_b . This can be done using a nonlinear root finding algorithm on functions of the form:

$$\text{Eq. 43} \quad \rho_{\phi, meas} - \rho_{\phi, calc} = 0$$

Viscosities may be calculated using the following equations once the densities are known.

$$\text{Eq. 44} \quad \mu_o = 10^Y - 1$$

$$\text{Eq. 45} \quad Y = 10^{2.9924 - 0.11027 V_{API} T - 0.9863}$$

$$\text{Eq. 46} \quad \mu_g = 10^{-4} k_v \exp \left(x_v \left(\frac{\rho_g}{62.4} \right)^{y_v} \right)$$

$$\text{Eq. 47} \quad k_v = \frac{(9.4 + 0.02MW_g)T^{1.5}}{209 + 19MW_g + T}$$

$$\text{Eq. 48} \quad y_v = 2.4 - 0.2x_v$$

$$\text{Eq. 49} \quad x_v = 3.5 + \frac{986}{T} + 0.01MW_g$$

[0025] All other variables may be considered to be either known in advance, or else to be parameters that are calculated explicitly as part of the process. The solved variables are the PVT model parameters and define the PVT model. The equations and algorithms used in the examples above are purely illustrative and are not limiting. In practice, the data 204, 206 received from the downhole sensors 116 and surface sensors 118 can be manipulated and applied in various different ways to generate a PVT model 208. However, by utilizing such data directly from the well system 100, the parameters of the PVT model 208 calculated therefrom are more accurate. Thus, the generated PVT model 208 is more accurate as well.

[0026] In some embodiments, the PVT model 208 is generated by the processor 202 and published or sent to various receiving parties. In some embodiments, the parameters of the PVT model 208 are generated by the processor 202 and sent to another data processing means which generates the PVT model 208 from the parameters. In some embodiments, the PVT model parameters or the PVT model 208 can be directly sent to one or more recipients. In some embodiments, the PVT model 208 can be updated in real time or quasi-real time with up-to-date data 204, 206 measured by the sensors 116, 118. In some embodiments, the PVT model 208 is updated when one or more of the sensed measurements changes by a predetermined amount.

[0027] FIG. 3 illustrates a multiple well system 300, in accordance with example embodiments of the present disclosure. The multiple well system 300 includes a plurality of individual production well systems 302 such as a first well system 302a, a

second well system 302b, and a third well system 302c. Each of the well systems 302 is similar to the well system 100 of FIG. 1, and includes a wellbore 304, a production tubing 312, a production tree 308, a wellhead 309, and a surface pipeline 314 coupled to a main pipeline 320. In some embodiments, production fluid recovered from each of the wells 304 flows into the main pipeline 320 which delivers the combined production fluid to a facility.

[0028] In some embodiments, one or more of the well systems 302a, 302b, 302c is instrumented with one or more downhole sensors 316. The one or more downhole sensors 316 may be coupled to a portion of the production tubing, the wellbore, or elsewhere near the production formation. In some embodiments, the downhole sensors 316 may include a multiphase flow meter, a pressure sensor, a temperature sensor, a fluid composition sensor, or any combination thereof, among other types of sensors.

[0029] In some embodiments, one or more of the well systems 302 is instrumented with one or more surface sensors 318. In some embodiments, the surface sensors 318 can be coupled to the respective surface pipelines 314, production trees 308, or other surface portion of the well system 302 through which production fluid flows. In some embodiments, the surface sensors 318 may include a multiphase flow meter, a pressure sensor, a temperature sensor, a fluid composition sensor, or any combination thereof, among other types of sensors. In some embodiments, one or more of the well systems 302 may include a fluid composition sensor. The downhole and/or surface temperature, pressure, flow rates, composition, and other fluid characteristic of each well can be measured.

[0030] In some embodiments, one or more main line sensors 322 are coupled to the main pipeline 320. The one or more main line sensors 322 may include a multiphase flow meter, a pressure sensor, a temperature sensor, a fluid composition sensor, or any combination thereof, among other types of sensors. The one or more main line sensors

322 can measure the combined production fluid temperature, pressure, flow rate, composition, or any combination thereof.

[0031] It should be appreciated that multiple well system 300 is only an example well system and there are many other well system configurations may also be appropriate for use.

[0032] FIG. 4 is a high level system diagram of a multiple well PVT modeling system 400, in accordance with example embodiments of the present disclosure. In some embodiments, one or more pieces of data collected from each well system 402, such as flow rate 404 is transmitted to a processor 410. In some embodiments, each well system 402 generates an individual PVT model 406, such as in the fashion illustrated and described above with reference to FIGS. 1 and 2. In certain such embodiments, the generated individual well PVT model 406 is transmitted to the processor 410. In certain example embodiments, one or more measured data from the main line sensor 322, such as flow rate 408, is transmitted to the processor 410. In some embodiments, data transmission is via wired or wireless communication protocols, such as Bluetooth, cellular networks, Wi-Fi, and the like.

[0033] The processor 410 utilizes the data from each individual well 302 as well as the main pipeline sensor 322 to generate a mixture PVT model 412. The mixture PVT model 412 models the combined production fluid. The mixture PVT model 412 can be a black oil model or a compositional model. In some embodiments, the individual wells 302 do not generate individual PVT models. In certain such embodiments, the data collected from the downhole and/or surface sensors are transmitted to the processor to generate the mixture PVT model 412. The mixture PVT model 412 can then be transmitted to or accessed by one or more users. In some embodiments, the mixture PVT model 412 can be updated on the fly, based on a predetermined time interval, upon a certain condition, or on demand.

[0034] In addition to the embodiments described above, many examples of specific combinations are within the scope of the disclosure, some of which are detailed below:

Example 1: A pressure-volume-temperature (PVT) modeling system for modeling production fluid from a well system, comprising:

- a sensing device configured to obtain a measurement of a condition of the production fluid in a downhole portion or in a surface portion of the well system; and
- a processor configured to receive the measurement from the sensing device, apply the fluid measurement as an input into a PVT model builder, and generate a PVT model.

Example 2: The PVT modeling system of example 1, wherein the measurement of a condition of the fluid includes at least one of downhole flow rate, surface flow rate, downhole fluid temperature, surface fluid temperature, downhole fluid pressure, surface fluid pressure, gas rate, oil rate, water rate, gas gravity, water salinity, or any combination of such.

Example 3: The PVT modeling system of example 1, wherein the PVT model builder includes a system of equations configured to use the fluid measurement and known parameters of the well system to solve for a set of PVT model parameters.

Example 4: The PVT modeling system of example 3, wherein the PVT model is defined by the PVT parameters.

Example 5: The PVT modeling system of example 3, wherein the PVT parameters include a solution gas ratio, a bubble point pressure, an oil formation volume factor, an oil viscosity, a gas viscosity, or any combination of such.

Example 6: The PVT modeling system of example 1, wherein the PVT model is a black-oil PVT model.

Example 7: The PVT modeling system of example 1, wherein the PVT model is a compositional PVT model.

Example 8: The PVT modeling system of example 1, wherein the PVT model is updated when the fluid measurement changes.

Example 9: A method of generating a PVT model for a production fluid from a well system, comprising:

- receiving, from a sensing device, a measurement of a condition of the production fluid in a downhole portion or a surface portion of the well system; and
- generating a PVT model from the measurement.

Example 10: The method of example 9, further comprising:

- inputting the measurement into a PVT model builder.

Example 11: The method of example 10, further comprising:

- determining a set of PVT parameters from the measurement; and
- generating the PVT model of the production fluid using the PVT parameters.

Example 12: The method of example 9, wherein the PVT model is a black-oil PVT model.

Example 13: The method of example 9, wherein the PVT model is a compositional PVT model.

Example 14: The method of example 9, wherein the measurement includes a downhole flow rate, a downhole fluid temperature, a downhole fluid pressure, or any combination of such received from a first sensing device disposed within the well.

Example 15: The method of example 9, wherein the measurement includes at least one of surface flow rate, surface fluid temperature, surface fluid pressure, or any combination of such received from a second sensing device coupled to a surface pipeline.

Example 16: The method of example 10, further comprising:
inputting the measurement into a system of equations; and
solving the system of equations for the PVT parameters.

Example 17: The method of example 9, wherein the PVT model is generated in quasi-real time upon receiving the measurement.

Example 18: The method of example 9, comprising:
updating the PVT model when the measurement changes, at predetermined times, or upon receiving a command.

Example 19: The method of example 11, further comprising determining the set of PVT parameters from the measurements and at least one known parameter of the well system.

Example 20: The method of example 9, wherein the measurement of a condition of the production fluid includes at least one of downhole flow rate, surface flow rate, downhole fluid temperature, surface fluid temperature, downhole fluid pressure, surface fluid pressure, gas rate, oil rate, water rate, gas gravity, water salinity, or any combination of such.

[0035] This discussion is directed to various embodiments of the invention. The drawing figures are not necessarily to scale. Certain features of the embodiments may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in the interest of clarity and conciseness. Although one or more of these embodiments may be preferred, the embodiments disclosed should not be interpreted, or otherwise used, as limiting the scope of the disclosure, including the claims. It is to be fully recognized that the different teachings of the embodiments discussed may be employed separately or in any suitable combination to produce desired results. In addition, one skilled in the art will understand that the description has broad application, and the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to intimate that the scope of the disclosure, including the claims, is limited to that embodiment.

[0036] Certain terms are used throughout the description and claims to refer to particular features or components. As one skilled in the art will appreciate, different persons may refer to the same feature or component by different names. This document does not intend to distinguish between components or features that differ in name but not function, unless specifically stated. In the discussion and in the claims, the terms “including” and “comprising” are used in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to...” Also, the term “couple” or “couples” is intended to mean either an indirect or direct connection. The use of “top,” “bottom,” “above,” “below,” and variations of these terms is made for convenience, but does not require any particular orientation of the components.

[0037] Reference throughout this specification to “one embodiment,” “an embodiment,” or similar language means that a particular feature, structure, or characteristic described in connection with the embodiment may be included in at least one embodiment of the present disclosure. Thus, appearances of the phrases “in one

embodiment,” “in an embodiment,” and similar language throughout this specification may, but do not necessarily, all refer to the same embodiment.

[0038] Although the present invention has been described with respect to specific details, it is not intended that such details should be regarded as limitations on the scope of the invention, except to the extent that they are included in the accompanying claims.

CLAIMS

We claim:

1. A pressure-volume-temperature (PVT) modeling system for modeling production fluid from a well system, comprising:

a sensing device configured to obtain a measurement of a condition of the production fluid in a downhole portion or in a surface portion of the well system; and

a processor configured to receive the measurement from the sensing device, apply the fluid measurement as an input into a PVT model builder, and generate a PVT model.

2. The PVT modeling system of claim 1, wherein the measurement of a condition of the fluid includes at least one of downhole flow rate, surface flow rate, downhole fluid temperature, surface fluid temperature, downhole fluid pressure, surface fluid pressure, gas rate, oil rate, water rate, gas gravity, water salinity, or any combination of such.

3. The PVT modeling system of claim 1, wherein the PVT model builder includes a system of equations configured to use the fluid measurement and known parameters of the well system to solve for a set of PVT model parameters.

4. The PVT modeling system of claim 3, wherein the PVT model is defined by the PVT parameters.

5. The PVT modeling system of claim 3, wherein the PVT parameters include a solution gas ratio, a bubble point pressure, an oil formation volume factor, an oil viscosity, a gas viscosity, or any combination of such.

6. The PVT modeling system of claim 1, wherein the PVT model is a black-oil PVT model.

7. The PVT modeling system of claim 1, wherein the PVT model is a compositional PVT model.

8. The PVT modeling system of claim 1, wherein the PVT model is updated when the fluid measurement changes.

9. A method of generating a PVT model for a production fluid from a well system, comprising:

receiving, from a sensing device, a measurement of a condition of the production fluid in a downhole portion or a surface portion of the well system; and
generating a PVT model from the measurement.

10. The method of claim 9, further comprising:

inputting the measurement into a PVT model builder;

11. The method of claim 10, further comprising:

determining a set of PVT parameters from the measurement; and
generating the PVT model of the production fluid using the PVT parameters.

12. The method of claim 9, wherein the PVT model is a black-oil PVT model.

13. The method of claim 9, wherein the PVT model is a compositional PVT model.

14. The method of claim 9, wherein the measurement includes a downhole flow rate, a downhole fluid temperature, a downhole fluid pressure, or any combination of such received from a first sensing device disposed within the well.

15. The method of claim 9, wherein the measurement includes at least one of surface flow rate, surface fluid temperature, surface fluid pressure, or any combination of such received from a second sensing device coupled to a surface pipeline.

16. The method of claim 10, further comprising:

inputting the measurement into a system of equations; and
solving the system of equations for the PVT parameters.

17. The method of claim 9, wherein the PVT model is generated in quasi-real time upon receiving the measurement.

18. The method of claim 9, comprising:

updating the PVT model when the measurement changes, at predetermined times, or upon receiving a command.

19. The method of claim 11, further comprising determining the set of PVT parameters from the measurements and at least one known parameter of the well system.

20. The method of claim 9, wherein the measurement of a condition of the production fluid includes at least one of downhole flow rate, surface flow rate, downhole fluid temperature, surface fluid temperature, downhole fluid pressure, surface fluid pressure, gas rate, oil rate, water rate, gas gravity, water salinity, or any combination of such.

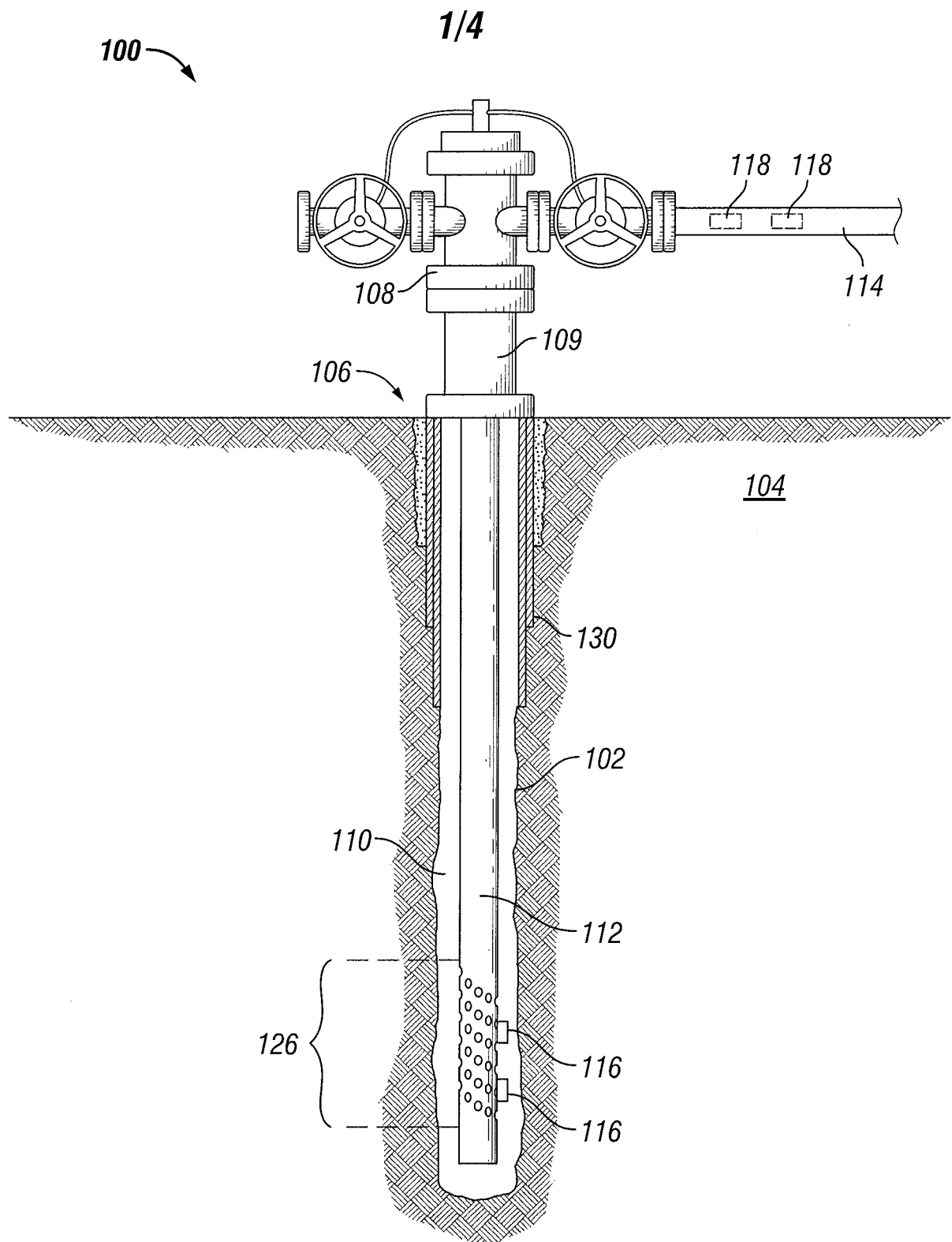


FIG. 1

2/4

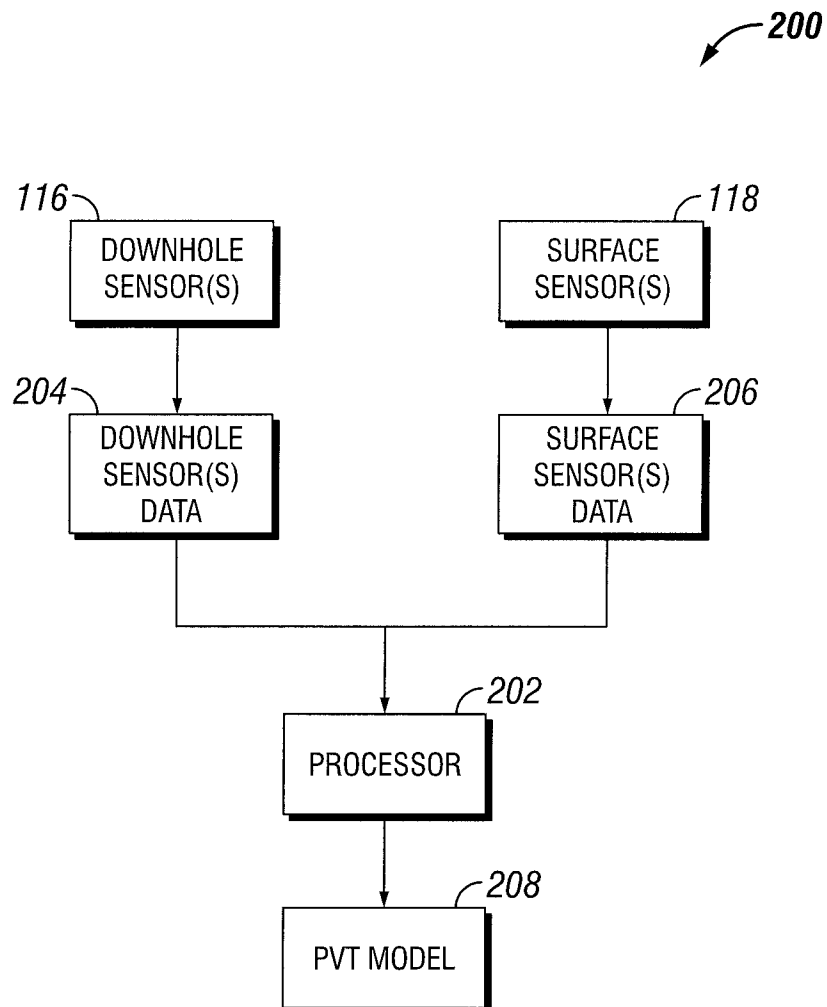


FIG. 2

3/4

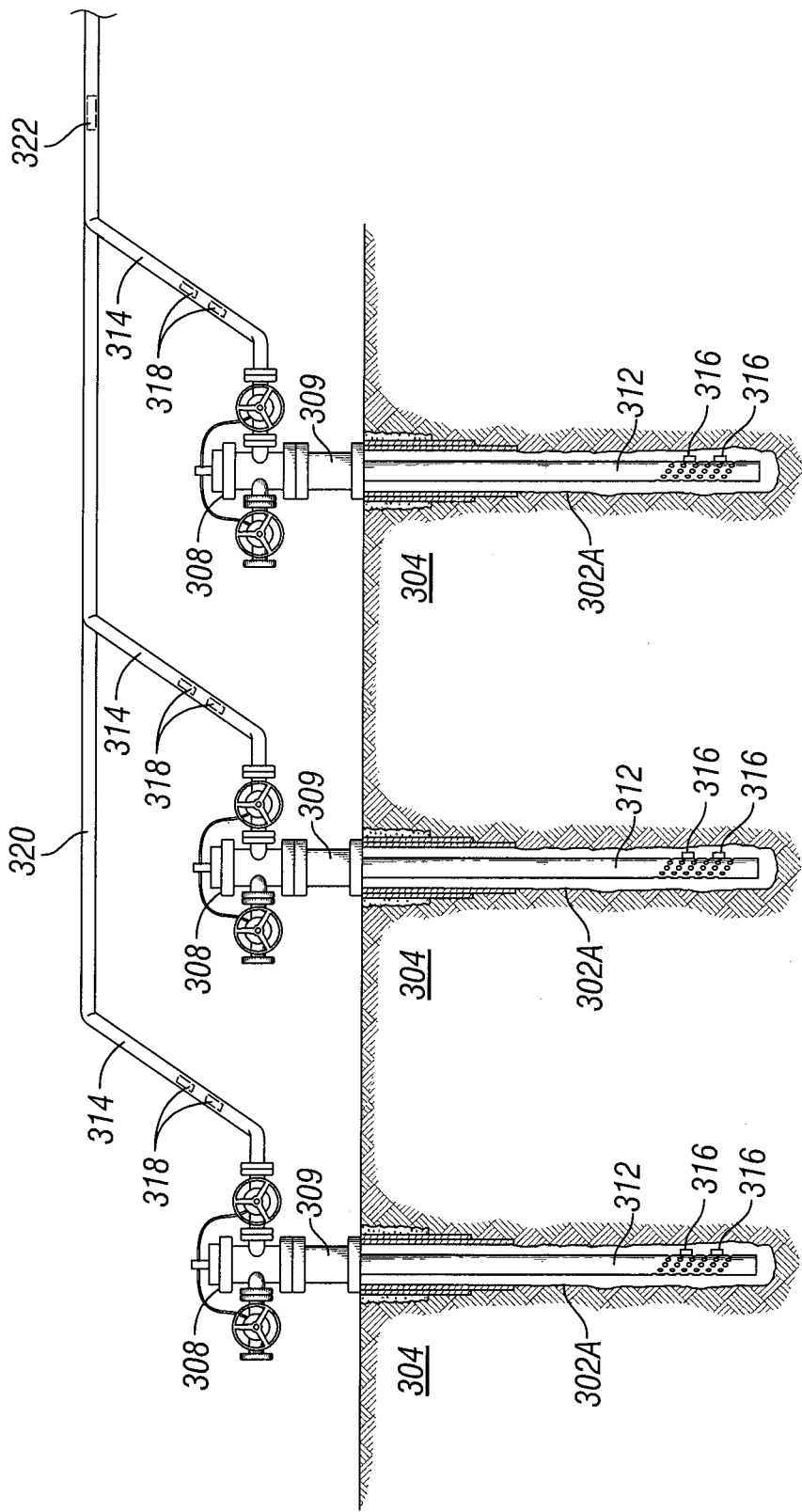


FIG. 3

4/4

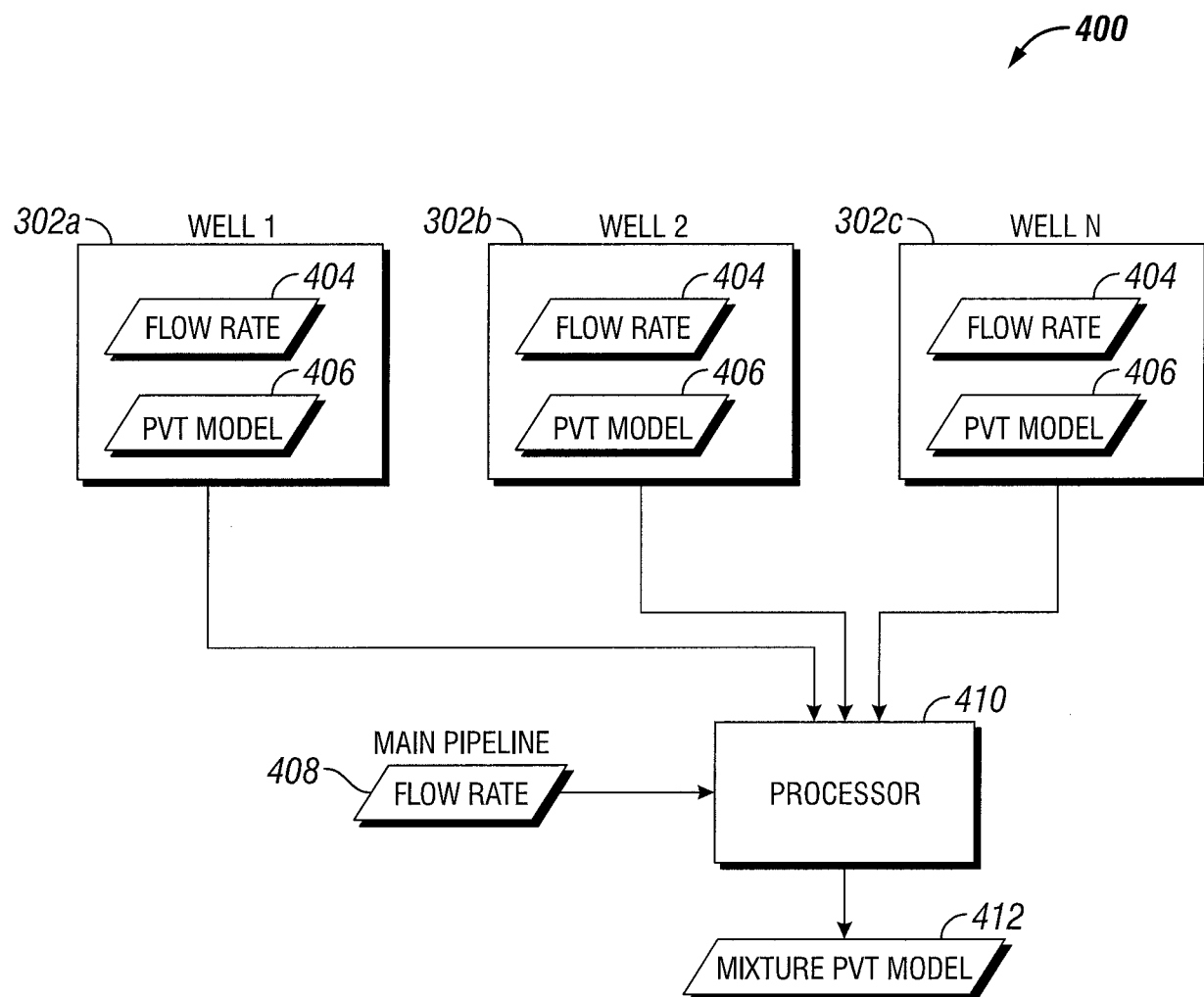


FIG. 4

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2015/036270**A. CLASSIFICATION OF SUBJECT MATTER****E21B 43/12(2006.01)i, G06F 9/455(2006.01)i, G05B 19/02(2006.01)i**

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)

E21B 43/12; G05D 7/00; G06F 19/00; E21B 44/00; G06G 7/57; G01F 1/66; G06F 9/455; G05B 19/02

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

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

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

eKOMPASS(KIPO internal) & Keywords: wellbore, PVT model, sensing device, processor, equation, and fluid measurement

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2012-0209542 A1 (GYSLING, DANIEL L.) 16 August 2012 See abstract and paragraphs [0022]–[0032].	1–3, 7–10, 13–18, 20
Y		4–6, 11–12, 19
Y	US 2003-0182061 A1 (FERWORN et al.) 25 September 2003 See paragraphs [0047], [0084]–[0096].	4–6, 11–12, 19
A	US 2014-0102697 A1 (EXPRO METERS, INC.) 17 April 2014 See paragraphs [0030]–[0035] and figures 6–8.	1–20
A	US 2013-0035920 A1 (AL-SHAMMARI, AHMAD TARIQ) 07 February 2013 See paragraphs [0063]–[0067] and figure 6.	1–20
A	US 2011-0224835 A1 (STENHAUG et al.) 15 September 2011 See paragraphs [0027]–[0032] and figures 3A–4C.	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

"E" earlier application or patent 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

08 March 2016 (08.03.2016)

Date of mailing of the international search report

09 March 2016 (09.03.2016)

Name and mailing address of the ISA/KR

International Application Division

Korean Intellectual Property Office

189 Cheongsa-ro, Seo-gu, Daejeon, 35208, Republic of Korea

Facsimile No. +82-42-472-7140

Authorized officer

RHEE, Jun Ho

Telephone No. +82-42-481-8288



INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2015/036270

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2012-0209542 A1	16/08/2012	AU 2010-282493 A1 AU 2010-282493 B2 AU 2010-282493 B2 CA 2770898 A1 EP 2464948 A1 US 9068872 B2 WO 2011-019829 A1	08/03/2012 05/02/2015 05/02/2015 17/02/2011 20/06/2012 30/06/2015 17/02/2011
US 2003-0182061 A1	25/09/2003	AU 2003-228340 A1 AU 2003-228340 B2 CA 2502627 A1 EP 1485711 A1 EP 1855109 A2 EP 1855109 A3 NO 20044076 A RU 2004130852 A RU 2302631 C2 US 7249009 B2 WO 03-081233 A1	08/10/2003 15/05/2008 02/10/2003 15/12/2004 14/11/2007 03/03/2010 14/12/2004 27/06/2005 10/07/2007 24/07/2007 02/10/2003
US 2014-0102697 A1	17/04/2014	AU 2013-331272 A1 CA 2888145 A1 EP 2909439 A2 WO 2014-062818 A2 WO 2014-062818 A3	23/04/2015 24/04/2014 26/08/2015 24/04/2014 27/11/2014
US 2013-0035920 A1	07/02/2013	CA 2843733 A1 CN 103842615 A EP 2739823 A2 US 2013-0035919 A1 US 8688426 B2 US 8731892 B2 WO 2013-019546 A2 WO 2013-019546 A3 WO 2013-019557 A2 WO 2013-019557 A3	07/02/2013 04/06/2014 11/06/2014 07/02/2013 01/04/2014 20/05/2014 07/02/2013 15/08/2013 07/02/2013 07/02/2013
US 2011-0224835 A1	15/09/2011	None	