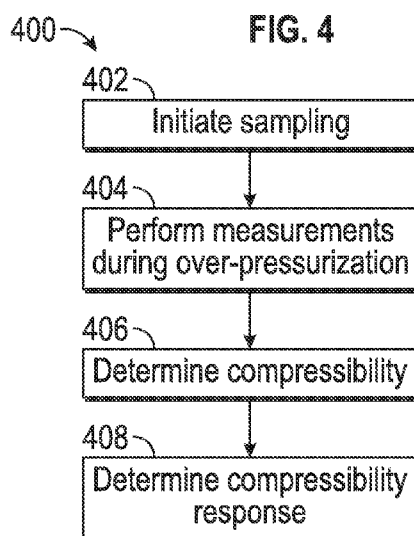




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[Continued on next page]

(54) **Title:** DOWNHOLE FLUID ANALYSIS METHODS FOR DETERMINING COMPRESSIBILITY

(57) **Abstract:** The present disclosure relates to methods for determining the compressibility of downhole fluids using measurements obtained during over-pressurization of a formation fluid sample. In certain embodiments, the density of the fluid may be measured as the fluid is directed through a flowline into a sample chamber. The density measurements can be employed in conjunction with pressure spikes that occur during over pressuring of a sample chamber to determine the compressibility.



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Downhole Fluid Analysis Methods For Determining Compressibility

Cross-Reference to Related Application

[0001] This application is based upon prior filed United States provisional patent application serial number 61/872385 filed on August 30, 2013, the entire contents of which are incorporated herein by reference.

Background of the Disclosure

[0002] Wellbores (also known as boreholes) are drilled to penetrate subterranean formations for hydrocarbon prospecting and production. During drilling operations, evaluations may be performed of the subterranean formation for various purposes, such as to locate hydrocarbon-producing formations and manage the production of hydrocarbons from these formations. To conduct formation evaluations, the drill string may include one or more drilling tools that test and/or sample the surrounding formation, or the drill string may be removed from the wellbore, and a wireline tool may be deployed into the wellbore to test and/or sample the formation. These drilling tools and wireline tools, as well as other wellbore tools conveyed on coiled tubing, drill pipe, casing or other conveyers, are also referred to herein as “downhole tools.”

[0003] Formation evaluation may involve drawing fluid from the formation into a downhole tool for testing and/or sampling. Various devices, such as probes and/or packers, may be extended from the downhole tool to isolate a region of the wellbore wall, and thereby establish fluid communication with the subterranean formation surrounding the wellbore. Fluid may then be drawn into the downhole tool using the probe and/or packer. Within the downhole tool, the fluid may be directed to one or more fluid analyzers and sensors that may be employed to detect properties of the fluid while the downhole tool is stationary within the wellbore.

Summary

[0004] The present disclosure relates to a downhole fluid analysis method that includes directing formation fluid to a sample chamber of a downhole tool, over-pressurizing the

formation fluid within the sample chamber, obtaining pressure and density measurements during the over-pressurization, and determining a compressibility of the formation fluid based on the pressure and density measurements.

[0005] The present disclosure also relates to a downhole tool that includes a density sensor to measure density of a formation fluid flowing through a primary flowline of the downhole tool, a pressure sensor to measure pressure of a formation fluid flowing through a primary flowline of the downhole tool, and a controller. The controller is designed to execute instructions stored within the downhole tool to obtain pressure and density measurements from the respective pressure sensor and the density sensor during over-pressurization of a sample of formation fluid within a sample chamber of the downhole tool, and calculate a compressibility of the formation fluid based on the pressure and density measurements.

[0006] The present disclosure relates to a downhole fluid analysis method that includes directing formation fluid to a sample chamber of a downhole tool through a primary flowline, inducing a pressure change in the formation fluid flowing through the primary flowline; obtaining pressure and density measurements during the pressure change, and determining a compressibility of the formation fluid based on the pressure and density measurements.

Brief Description of the Drawings

[0007] The present disclosure is understood from the following detailed description when read with the accompanying figures. It is emphasized that, in accordance with the standard practice in the industry, various features are not drawn to scale. In fact, the dimensions of the various features may be arbitrarily increased or reduced for clarity of discussion.

[0008] FIG. 1 is a schematic view of an embodiment of a wellsite system that may employ downhole fluid analysis methods for determining compressibility, according to aspects of the present disclosure;

[0009] FIG. 2 is a schematic view of another embodiment of a wellsite system that may employ downhole fluid analysis methods for determining compressibility, according to aspects of the present disclosure;

[0010] FIG. 3 is a schematic representation of an embodiment of a downhole tool that may employ downhole fluid analysis methods for determining compressibility, according to aspects of the present disclosure;

[0011] FIG. 4 is a flowchart depicting a fluid analysis method for determining compressibility, according to aspects of the present disclosure;

[0012] FIG. 5 is an illustration of charts depicting density, pressure, and spectrometer measurements obtained during sampling, according to aspects of the present disclosure;

[0013] FIG. 6 is an illustration of charts depicting density measurements plotted against pressure measurements obtained during sampling, according to aspects of the present disclosure;

[0014] FIG. 7 is an illustration of another chart density measurements plotted against pressure measurements obtained during sampling, according to aspects of the present disclosure; and

[0015] FIG. 8 is an illustration of a chart depicting a fitting function applied to the measurements of FIG. 7, according to aspects of the present disclosure.

Detailed Description

[0016] It is to be understood that the present disclosure provides many different embodiments, or examples, for implementing different features of various embodiments. Specific examples of components and arrangements are described below to simplify the present disclosure. These are, of course, merely examples and are not intended to be limiting.

[0017] The present disclosure relates to methods for determining the compressibility of downhole fluids. According to certain embodiments, the compressibility may be determined in substantially real-time as formation fluid is directed into a sample chamber of the downhole tool. In certain embodiments, the density of the fluid may be measured as the fluid is directed through a flowline into a sample chamber. The density measurements can be employed in conjunction with pressure spikes that occur during over pressuring of a sample chamber to determine the compressibility.

[0018] FIGS. 1 and 2 depict examples of wellsite systems that may employ the compressibility determination systems and techniques described herein. FIG. 1 depicts a rig 100 with a downhole tool 102 suspended therefrom and into a wellbore 104 via a drill string 106. The downhole tool 100 has a drill bit 108 at its lower end thereof that is used to advance the downhole tool into the formation and form the wellbore. The drillstring 106 is rotated by a rotary table 110, energized by means not shown, which engages a kelly 112 at the upper end of the drillstring 106. The drillstring 106 is suspended from a hook 114, attached to a traveling block (also not shown), through the kelly 112 and a rotary swivel 116 that permits rotation of the drillstring 106 relative to the hook 114. The rig 100 is depicted as a land-based platform and derrick assembly used to form the wellbore 104 by rotary drilling. However, in other embodiments, the rig 100 may be an offshore platform.

[0019] Drilling fluid or mud 118 is stored in a pit 120 formed at the well site. A pump 122 delivers the drilling fluid 118 to the interior of the drillstring 106 via a port in the swivel 116, inducing the drilling fluid to flow downwardly through the drillstring 106 as indicated by a directional arrow 124. The drilling fluid exits the drillstring 106 via ports in the drill bit 108, and then circulates upwardly through the region between the outside of the drillstring and the wall of the wellbore, called the annulus, as indicated by directional arrows 126. The drilling fluid lubricates the drill bit 108 and carries formation cuttings up to the surface as it is returned to the pit 120 for recirculation.

[0020] The downhole tool 102, sometimes referred to as a bottom hole assembly (“BHA”), may be positioned near the drill bit 108 and includes various components with capabilities, such as measuring, processing, and storing information, as well as communicating with the surface. A telemetry device (not shown) also may be provided for communicating with a surface unit (not shown).

[0021] The downhole tool 102 further includes a sampling system 128 including a fluid communication module 130 and a sampling module 132. The modules may be housed in a drill collar for performing various formation evaluation functions, such as pressure testing and sampling, among others. According to certain embodiments, the sampling system 128 may be employed “while drilling,” meaning that the sampling system 128 may be operated during breaks in operation of the mud pump 122 and/or during breaks in operation of the drill bit 108. As

shown in Fig. 1, the fluid communication module 130 is positioned adjacent the sampling module 132; however the position of the fluid communication module 130, as well as other modules, may vary in other embodiments. Additional devices, such as pumps, gauges, sensor, monitors or other devices usable in downhole sampling and/or testing also may be provided. The additional devices may be incorporated into modules 130 and 132 or disposed within separate modules included within the sampling system 128.

[0022] The fluid communication module 130 includes a probe 134, which may be positioned in a stabilizer blade or rib 136. The probe 134 includes one or more inlets for receiving formation fluid and one or more flowlines (not shown) extending into the downhole tool for passing fluids through the tool. In certain embodiments, the probe 134 may include a single inlet designed to direct formation fluid into a flowline within the downhole tool. Further, in other embodiments, the probe may include multiple inlets that may, for example, be used for focused sampling. In these embodiments, the probe may be connected to a sampling flow line, as well as to guard flow lines. The probe 134 may be movable between extended and retracted positions for selectively engaging a wall of the wellbore 104 and acquiring fluid samples from the formation F. One or more setting pistons 138 may be provided to assist in positioning the fluid communication device against the wellbore wall.

[0023] FIG. 2 depicts an example of a wireline downhole tool 200 that may employ the systems and techniques described herein. The downhole tool 200 is suspended in a wellbore 202 from the lower end of a multi-conductor cable 204 that is spooled on a winch at the surface. The cable 204 is communicatively coupled to an electronics and processing system 206. The downhole tool 200 includes an elongated body 208 that houses modules 210, 212, 214, 222, and 224, that provide various functionalities including fluid sampling, fluid testing, operational control, and communication, among others. For example, the modules 210 and 212 may provide additional functionality such as fluid analysis, resistivity measurements, operational control, communications, coring, and/or imaging, among others.

[0024] As shown in FIG. 2, the module 214 is a fluid communication module 214 that has a selectively extendable probe 216 and backup pistons 218 that are arranged on opposite sides of the elongated body 208. The extendable probe 216 is configured to selectively seal off or isolate selected portions of the wall of the wellbore 202 to fluidly couple to the adjacent formation 220

and/or to draw fluid samples from the formation 220. The probe 216 may include a single inlet or multiple inlets designed for guarded or focused sampling. The formation fluid may be expelled to the wellbore through a port in the body 208 or the formation fluid may be sent to one or more fluid sampling modules 222 and 224. The fluid sampling modules 222 and 224 may include sample chambers that store the formation fluid. In the illustrated example, the electronics and processing system 206 and/or a downhole control system are configured to control the extendable probe assembly 216 and/or the drawing of a fluid sample from the formation 220.

[0025] FIG. 3 is a schematic diagram of a portion of a downhole tool 302 that may employ the compressibility systems and techniques described herein. For example, the downhole tool 302 may be a drilling tool, such as the downhole tool 102 described above with respect to FIG. 1. Further, the downhole tool 302 may be a wireline tool, such as the downhole tool 200 described above with respect to FIG. 2. Further, in other embodiments, the downhole tool may be conveyed on wired drill pipe, a combination of wired drill pipe and wireline, or other suitable types of conveyance.

[0026] As shown in FIG. 3, the downhole tool 302 includes a fluid communication module 304 that has a probe 306 for directing formation fluid into the downhole tool 302. According to certain embodiments, the fluid communication module 304 may be similar to the fluid communication modules 130 and 214, described above with respect to FIGS. 1 and 2, respectively. Further, in other embodiments, the probe 306 may be replaced by a single packer, or other inlet device that directs formation fluid into the downhole tool 302. The fluid communication module 304 includes a probe flowline 306 that directs the fluid to a primary flowline 308 that extends through the downhole tool 302. The fluid communication module 304 also includes a pump 310 and pressure gauges 312 and 314 that may be employed to conduct formation pressure tests. An equalization valve 316 may be opened to expose the flowline 306 to the pressure in the wellbore, which in turn may equalize the pressure within the downhole tool 302. Further, an isolation valve 318 may be closed to isolate the formation fluid within the flowline 306, and may be opened to direct the formation fluid from the probe flowline 306 to the primary flowline 308.

[0027] The primary flowline 308 directs the formation fluid through the downhole tool to fluid analysis modules 320a and 320b that can be employed to provide in situ downhole fluid measurements. For example, the fluid analysis modules 320a and 320b may each include an optical spectrometer 322a or 322b designed to measure properties such as, optical density, fluid composition, and the fluid gas oil ratio (GOR), among others. According to certain embodiments, the spectrometer 322a and 322b may include any suitable number of measurement channels for detecting different wavelengths, and may include a filter-array spectrometer or a grating spectrometer. For example, the spectrometer 322a and 322b may be a filter-array absorption spectrometer having ten measurement channels. In other embodiments, the spectrometer 322a and 322b may have sixteen channels or twenty channels, and may be provided as a filter-array spectrometer or a grating spectrometer, or a combination thereof (e.g., a dual spectrometer), by way of example.

[0028] The fluid analysis modules 320a and 320b also may each include a density sensor 324a or 324b that can be employed to measure the density of the fluid flowing through the primary flowline 308. According to certain embodiments, the density sensors 324a and 324b may each include a vibrating rod whose resonance characteristics, for the rod oscillating in the fluid, may be employed in conjunction with electronics included in the sensors 324a and 324b to determine the density of the fluid. However, in other embodiments, the density sensors 324a and 324b may include any suitable density sensor, such as a desimeter or densitometer, among others.

[0029] The fluid analysis modules 320a and 320b further may each include a pressure and temperature sensor 323b that can be employed to measure the pressure and temperature of the fluid flowing through the primary flowline 308. As shown in FIG. 3, the pressure and temperature measurements are provided by a single sensor 323a or 323b; however, in other embodiments, the pressure and temperature measurements may be provided by separate sensors (e.g., an individual pressure sensor and an individual temperature sensor).

[0030] One or more additional measurement devices 325a and 325b, such as gas analyzers, resistivity sensors, viscosity sensors, chemical sensors (e.g., for measuring pH or H₂S levels), and gas chromatographs, may be included within the fluid analysis modules 320a and 320b. In certain embodiments, the measurement devices 325a and 325b may include a gas analyzer

having a gas detector and one or more fluorescence detectors designed to detect free gas bubbles and retrograde condensate liquid drop out.

[0031] In certain embodiments, the fluid analysis modules 320a and 320b also may include a controller 326a and 326b, such as a microprocessor or control circuitry, designed to calculate certain fluid properties based on the sensor measurements. Further, in certain embodiments, the controller 326a or 326b may govern sampling operations based on the fluid measurements or properties. As shown in FIG. 3, each fluid analysis module 320a and 320b includes a controller 326a or 326b; however, in other embodiments, the fluid analysis modules 320a and 320b may share a single controller. Moreover, in other embodiments, the controller 326a or 326b may be disposed within another module of the downhole tool 302.

[0032] The downhole tool 302 also includes a pump out module 328 that has a pump 330 designed to provide motive force to direct the fluid through the downhole tool 302. According to certain embodiments, the pump 330 may be a hydraulic displacement unit that receives fluid into alternating pump chambers. A valve block 332 may direct the fluid into and out of the alternating pump chambers. The valve block 332 also may direct the fluid exiting the pump 330 through the remainder of the primary flowline (e.g., towards the sample module 336) or may divert the fluid to the wellbore through an exit flowline 334.

[0033] The downhole tool 302 also includes a sample module 336 designed to store samples of the formation fluid within a sample chamber 338. The sample module 336 includes valves 340 and 344 that may be actuated to divert the formation fluid into a volume 342 of the sample chamber 338. For example, to direct formation fluid from the primary flowline 308 into the volume 342, the valve 344 may be opened while the valve 340 may be closed. When sampling has completed, the valve 344 may then be closed to seal the formation fluid within the sample chamber 338, while the valve 340 may be opened to direct the formation fluid from the primary flowline through the downhole tool. The sample chamber 338 also may include a valve 348 that can be opened to expose a volume 350 of the sample chamber 338 to the annular pressure. In certain embodiments, the valve 348 may be opened to allow buffer fluid to exit the volume 350 to the wellbore, which may provide backpressure during filling of a volume 352 that receives formation fluid. According to certain embodiments, the volume 342 that stores formation fluid may be separated from the volume 350 by a floating piston 353.

[0034] The valve arrangements and module arrangements described herein are provided by way of example, and are not intended to be limiting. For example, the valves described herein may include valves of various types and configurations, such as ball valves, gate valves, solenoid valves, check valves, seal valves, two-way valves, three-way valves, four-way valves, and combinations thereof, among others. Further, in other embodiments, different arrangements of valves may be employed. For example, the valves 340 and 344 may be replaced by a single valve. Moreover, in certain embodiments, the arrangements of the modules 304, 320a, 320b, 328, and 336 may vary. For example, in other embodiments, rather than two fluid analysis modules 320a and 320b, a single fluid analysis module 320 may be included within the downhole tool 302. In another example, multiple sample chamber modules 336 may be included within the downhole tool 302. Further, in certain embodiments, the sample chamber 336 may include multiple sample chambers 338, as well as other types of sample chambers, such as single phase sample bottles, among others.

[0035] FIG. 4 is a flowchart depicting an embodiment of a method 400 that may be employed to determine the compressibility of formation fluid while sampling. According to certain embodiments, the method 400 may be executed, in whole or in part, by the controller 326a and/or 326b (FIG. 3). For example, the controller 326a or 326b may execute code stored within circuitry of the controller 326a or 326b, or within a separate memory or other tangible readable medium, to perform the method 400. In certain embodiments, the method 400 may be wholly executed while the tool 302 is disposed within a wellbore. Further, in certain embodiments, the controller 326a or 326b may operate in conjunction with a surface controller, such as the processing system 206 (FIG. 2), that may perform one or more operations of the method 400. For ease of description, the method 400 is described below with respect to operation of the controller 326a and the fluid analysis module 320b. However, in other embodiments, the controller 326b may perform the method 400 instead of, or in conjunction with, the controller 326a. Further, in certain embodiments, the fluid analysis module 320a and the sensors 322a, 323a, 324a, and 325a may be employed to perform one or more of the measurements in the method 400.

[0036] The method 400 may begin by initiating (block 402) sampling of the formation fluid. For example, the formation fluid may be withdrawn into the downhole tool 302 through the

probe 305 and directed through the primary flowline 308. To initiate sampling, the controller 326a may set the valve block 332 to direct the formation fluid through the primary flowline 308 to the sample module 336. The controller 326b also may open the valve 344 and close the valve 340 to direct the formation fluid into the sample chamber 338. During filling of the sample chamber 338, the pressure and density for the formation fluid flowing through the primary flowline may be measured using the pressure and temperature sensor 323b and the density sensor 324b. In certain embodiments, during filling of the sample chamber 338, the fluid analysis module 320b also may measure the optical absorption spectra of the formation fluid using the spectrometer 322b.

[0037] The method may then continue by performing (block 404) measurements while over-pressurizing the sample. For example, the controller 326b may detect a spike in the measured pressure, which may indicate that the sample chamber 338 has been filled. The controller 326b may then continue operation of the pump 330 to over-pressurize the fluid in the sample chamber 338. During over-pressurization, the pressure and density for the formation fluid flowing through the primary flowline may be measured using the pressure and temperature sensor 323b and the density sensor 324b. In certain embodiments, during over-pressurization of the sample chamber 338, the fluid analysis module 320b also may measure the optical absorption spectra of the formation fluid using the spectrometer 322b.

[0038] FIG. 5 depicts examples of measurements that may be obtained during sampling and during over-pressurization of a formation fluid sample. The top chart 500 depicts the optical density 506 measured by the spectrometer 322b; the middle chart 502 depicts the fluid density 508 measured by the density sensor 324b, and the bottom chart 504 depicts the pressure 510 measure by the pressure and temperature sensor 323b. The x-axis of each chart 500, 502, and 504 represents elapsed time and the y-axis of each chart 500, 502, and 504 represents the optical density 506, the density 508, and the pressure 510, respectively. As shown in FIG. 5, spikes 512, 514, and 516 occur during over-pressurization of the sample. FIG. 5 depicts the filling of three separate sample chambers 338, and spikes (e.g., sharp increases in measurements) 512, 514, 516, 518, 520, 522, 524, 526, and 528 occur during the over-pressurization of each sample chamber. During filling of each sample chamber 338, the pressure remains substantially flat, as shown by

filling periods 530, 532, and 534, with the pressure then spiking 516, 522, and 528 during the over-pressurization period after sample chamber 338 has been filled.

[0039] Once measurements have been obtained during over-pressurization, the method 400 may continue by determining (block 406) the compressibility of the formation fluid. For example, the controller 326b may execute code and/or algorithms to calculate the compressibility using measurements obtained during over-pressurization of the sample. The compressibility may be determined using the pressure and density measurements obtained during over-pressurization of the formation fluid sample. According to certain embodiments, the compressibility may be determined using the following equation:

$$(1) \quad c = \frac{1}{\rho} \frac{d\rho}{dP} = \frac{d}{dP} \ln \rho$$

where c represents the compressibility; ρ is the density of fluid, for example, as measured by the sensor 324b; and P is the pressure of the fluid, for example as measured by the sensor 323b.

[0040] In other embodiments, the compressibility may be determined using the pressure and optical spectrometer measurements obtained during over-pressurization of the formation fluid sample. For example, the compressibility may be determined using the following equation:

$$(2) \quad c = \frac{1}{OD} \frac{dOD}{dP}$$

where c represents the compressibility; OD is the optical density of fluid, for example, as measured by the spectrometer 322b; and P is the pressure of the fluid, for example as measured by the sensor 323b. In these embodiments, the optical density obtained from the spectrometer measurements may be calibrated to account for measurement variations, such as spectrometer drift, electronic DC offset, optical scattering, among others. Techniques for calibrating the optical density measurements are described in commonly assigned U.S. Patent No. 8,434,356 to Hsu et al., which is incorporated herein by reference in its entirety.

[0041] In addition to determining the compressibility of the formation fluid that is sampled, the method 400 may further include determining (block 408) the pressure response for the

compressibility of the fluid. In certain embodiments, the pressure response may be employed to adjust the density measured at the primary flowline 308, to the pressure of the formation. The pressure and density and/or optical spectrometer measurements obtained during over-pressurization may be employed to determine the pressure response.

[0042] Where the formation fluid compressibility exhibits a substantially linear response, for example, for an oil-based fluid or other fluid that is not highly compressible, the pressure response of the compressibility may be determined through linear trending. For example, in certain embodiments, the controller 326b may determine a linear function or equation that represents the pressure response of the density using the measurements obtained during over-pressurization. Using the linear function, the density of the fluid can be adjusted to other pressures, such as the formation pressure, and the adjusted density can then be employed in Eq. 1 to determine the compressibility of the fluid at that pressure.

[0043] FIG. 6 depicts examples of a linear pressure response, with chart 600 representing measurements obtained during over-pressurization of a first sample; chart 602 representing measurements obtained during over-pressurization of a second sample; and chart 604 representing measurements obtained during over-pressurization of a third sample of formation fluid. The x-axis of each chart 600, 602, and 604 represents the measured pressure, and the y-axis of each chart 600, 602, and 604 represents the measured density. The points 606 represent the individual density measurements at the corresponding pressures. Trend lines 610, 612, 614 may be fit to the points 608 to determine the density response to pressure changes, which can in turn be used to determine the compressibility at different pressures.

[0044] Where the formation fluid compressibility exhibits a substantially non-linear response, for example, for a highly compressible fluid such as a gas, equations for the compressibility and/or density response as a function of pressure may be determined. For example, the controller 326b may calculate an equation that represents the pressure response of the density using the measurements obtained during over-pressurization. FIG. 7 depicts a chart 700 illustrating a non-linear response, with density represented on the y-axis and pressure represented on the x-axis. The curves 702, 704, and 706 represent the density measurements obtained while over-pressurizing three different samples, plotted against the pressure measurements and smoothed to obtain curves. The curves 702, 704, and 706 may be fit with logarithmic functions,

exponential functions, or power functions, among others. Equations 3-5 below provide three examples of fitting functions that may be employed to represent the density response as a function of pressure, for a non-linear fluid response.

$$(3) \quad \rho = a \ln P + b$$

$$(4) \quad \frac{1}{\rho} = a \exp\left(-\frac{P}{c}\right) + b$$

$$(5) \quad \ln \rho = aP + b$$

where a , b and c represent unknowns that can be fitted to determine the parameters for these unknowns. In other embodiments, the measurements may be fit to functions locally using a moving Savitzky-Golay filter as described in commonly assigned U.S. Patent No. 7, 913,556 to Hsu et. al, which is hereby incorporated by reference in its entirety.

[0045] FIG. 8 is a chart 800 depicting the fitting results for the three curves 702, 704, and 706 shown in FIG. 7. A function 802, 804, and 806 is plotted for each of the curves 702, 704, and 706 where the x-axis represents the log of pressure and the y-axis represents density. The resulting functions may be employed in Eq. 1 to determine the compressibility of fluid at different pressures.

[0046] The compressibility can also be employed to adjust the density measured in the primary flowline 308 to other pressures, such as the formation pressure. For example, Eq. 2 may be rearranged as follows:

$$(6) \quad \int_{P_s}^{P_f} c \, dP = \int_{\rho_s}^{\rho_f} d(\ln \rho)$$

where P_f and P_s are the formation pressure and flowline pressure, respectively, and ρ_f and ρ_s are the density at P_f and P_s . With some algebraic manipulation, Eq. 6 becomes:

$$(7) \quad \rho_f = \rho_s e^{\int_{P_s}^{P_f} c \, dP}$$

where e is a mathematical constant representing the base of the natural logarithm. If the compressibility c is nearly a constant within the pressure range $[P_f, P_s]$, then it can be further simplified as

$$(8) \quad \rho_f \approx \rho_s e^{c(P_f - P_s)}$$

Given the compressibility, c , the density measured in the flowline, ρ_s , P_f and P_s , Eq. 7 or 8 can be used to adjust the measured density in the flowline as if it is measured at the formation pressure.

[0047] The method described above with respect to FIG. 4 also may be employed during other periods of fluid pressurization, instead of, or in addition to, the over-pressurization of the sample fluid. For example, referring back to FIG. 3, pressure, density, and spectroscopy measurements may be obtained while the valve 340 is closed momentarily and while the valve 344 remains closed. While the valve 340 is closed, the pressure in the primary flowline 308 builds, producing pressure spikes similar to those seen during over-pressurization of a sample. In another example, the valve 340 may be an adjustable valve, orifice, or fluid restrictor that has an adjustable opening. The opening may be adjusted to build up the pressure and obtain pressure, density, and optical spectroscopy measurements for determining compressibility.

[0048] As discussed above with respect to FIG. 4, the techniques described herein may be employed using measurements obtained by the fluid analysis module 320b, the fluid analysis module 320a, or by a combination of measurements from the fluid analysis modules 320a and 320b. According to certain embodiments, the measurements from the fluid analysis modules 320a and 320b may be combined and used to provide a comprehensive compressibility analysis. Further, in certain embodiments, the measurements from the fluid analysis module 320a may represent density measurements corresponding to decreases in pressure. For example, the compressibility methods employed herein may be employed using density measurements or optical density measurements obtained during pressure drops, such as those measured by the pressure and temperature sensor 323a when fluid is drawn into the pump 330. In another example, the primary flowline 308 and/or the sample chamber 338 may be depressurized and the density measurements or optical density measurements obtained during the pressure drops may be employed to determine compressibility using techniques described above with respect to FIG. 4.

[0049] The foregoing outlines features of several embodiments so that those skilled in the art may better understand the aspects of the present disclosure. Those skilled in the art should appreciate that they may readily use the present disclosure as a basis for designing or modifying other processes and structures for carrying out the same purposes and/or achieving the same advantages of the embodiments introduced herein. Those skilled in the art should also realize that such equivalent constructions do not depart from the spirit and scope of the present disclosure, and that they may make various changes, substitutions and alterations herein without departing from the spirit and scope of the present disclosure.

WHAT IS CLAIMED IS:

1. A downhole fluid analysis method comprising:
directing formation fluid to a sample chamber of a downhole tool;
over-pressurizing the formation fluid within the sample chamber;
obtaining pressure and density measurements during the over-pressurization; and
determining a compressibility of the formation fluid based on the pressure and density measurements.
2. The downhole fluid analysis method of claim 1, wherein over-pressurizing comprises operating a pump to increase a pressure in the sample chamber after the sample chamber has been filled.
3. The downhole fluid analysis method of claim 1, wherein over-pressurizing comprises pumping the formation fluid through a primary flowline of the downhole tool, and wherein obtaining comprises measuring pressure and density of the formation fluid flowing through the primary flowline.
4. The downhole fluid analysis method of claim 1, wherein determining comprises calculating the compressibility based on the pressure and density measurements that were obtained after a pressure spike.
5. The downhole fluid analysis method of claim 1, wherein determining comprises calculating the compressibility based on a rate of change in density with respect to pressure.
6. The downhole fluid analysis method of claim 1, comprising initiating sampling of the formation fluid within the downhole tool.
7. The downhole fluid analysis method of claim 6, wherein initiating comprises opening a valve upstream of the sample chamber and closing a valve in a primary flowline of the downhole tool.

8. The downhole fluid analysis method of claim 1, wherein determining comprises determining the compressibility as a function of pressure based on the pressure and density measurements.

9. The downhole fluid analysis method of claim 1, comprising detecting that the sample chamber has been filled, wherein the over-pressurizing occurs within the sample chamber in response to detecting that the sample chamber has been filled.

10. A downhole tool comprising:
a density sensor to measure density of a formation fluid flowing through a primary flowline of the downhole tool;
a pressure sensor to measure pressure of the formation fluid flowing through a primary flowline of the downhole tool; and
a controller configured to execute instructions stored within the downhole tool to:
obtain pressure and density measurements from the respective pressure sensor and the density sensor during over-pressurization of a sample of formation fluid within a sample chamber of the downhole tool; and
calculate a compressibility of the formation fluid based on the pressure and density measurements.

11. The downhole tool of claim 10 comprising a valve selectively actuated by the controller to direct the formation fluid into the sample chamber.

12. The downhole tool of claim 10, wherein the controller is configured to execute instructions stored within the downhole tool to:
detect a spike in the pressure measurements; and
operate a pump to over-pressurize the sample of formation fluid within the sample chamber in response to detecting the spike in the pressure measurements.

13. The downhole tool of claim 10, wherein the density comprises a fluid density.

14. The downhole tool of claim 10, wherein the density comprises an optical density.
15. A downhole fluid analysis method comprising:
directing formation fluid to a sample chamber of a downhole tool through a primary flowline;
inducing a pressure change in the formation fluid flowing through the primary flowline;
obtaining pressure and density measurements during the pressure change; and
determining a compressibility of the formation fluid based on the pressure and density measurements.
16. The downhole fluid analysis method of claim 15, wherein inducing comprises restricting a flow of the formation fluid through the primary flowline.
17. The downhole fluid analysis method of claim 15, wherein inducing comprises momentarily closing a valve disposed in the primary flowline.
18. The downhole fluid analysis method of claim 15, wherein inducing comprises over-pressurizing the formation fluid within the sample chamber.
19. The downhole fluid analysis method of claim 15, wherein the pressure change comprises a pressure decrease.
20. The downhole fluid analysis method of claim 15, wherein the pressure change comprises a pressure increase.

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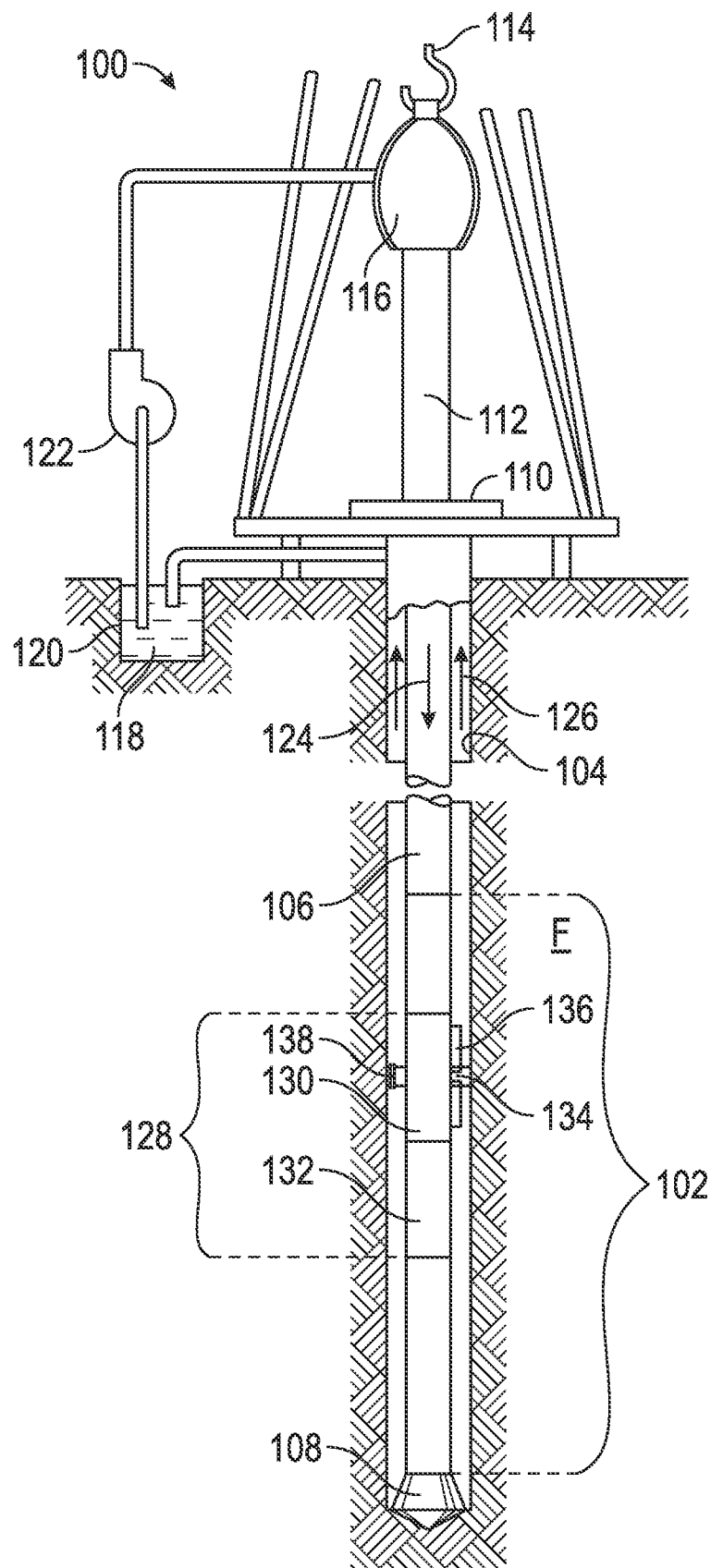


FIG. 1

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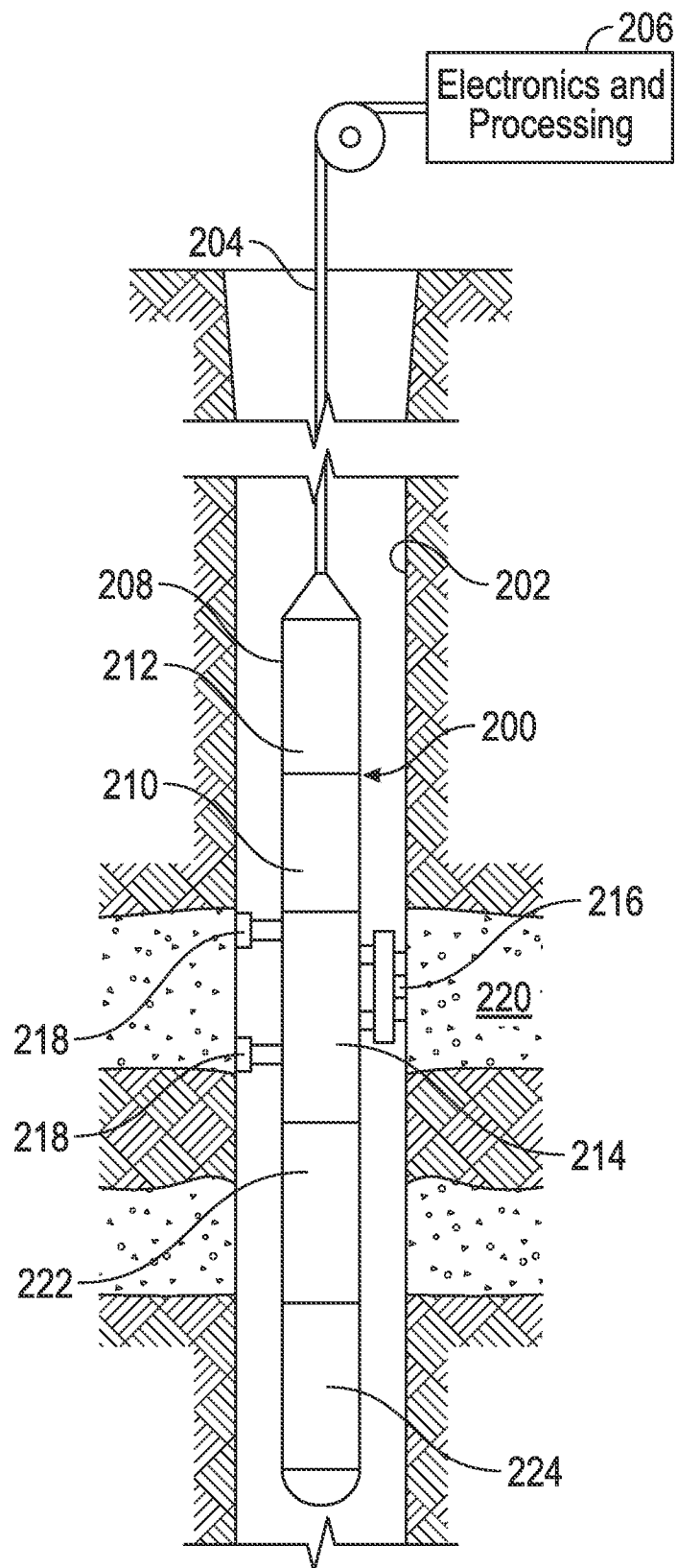


FIG. 2

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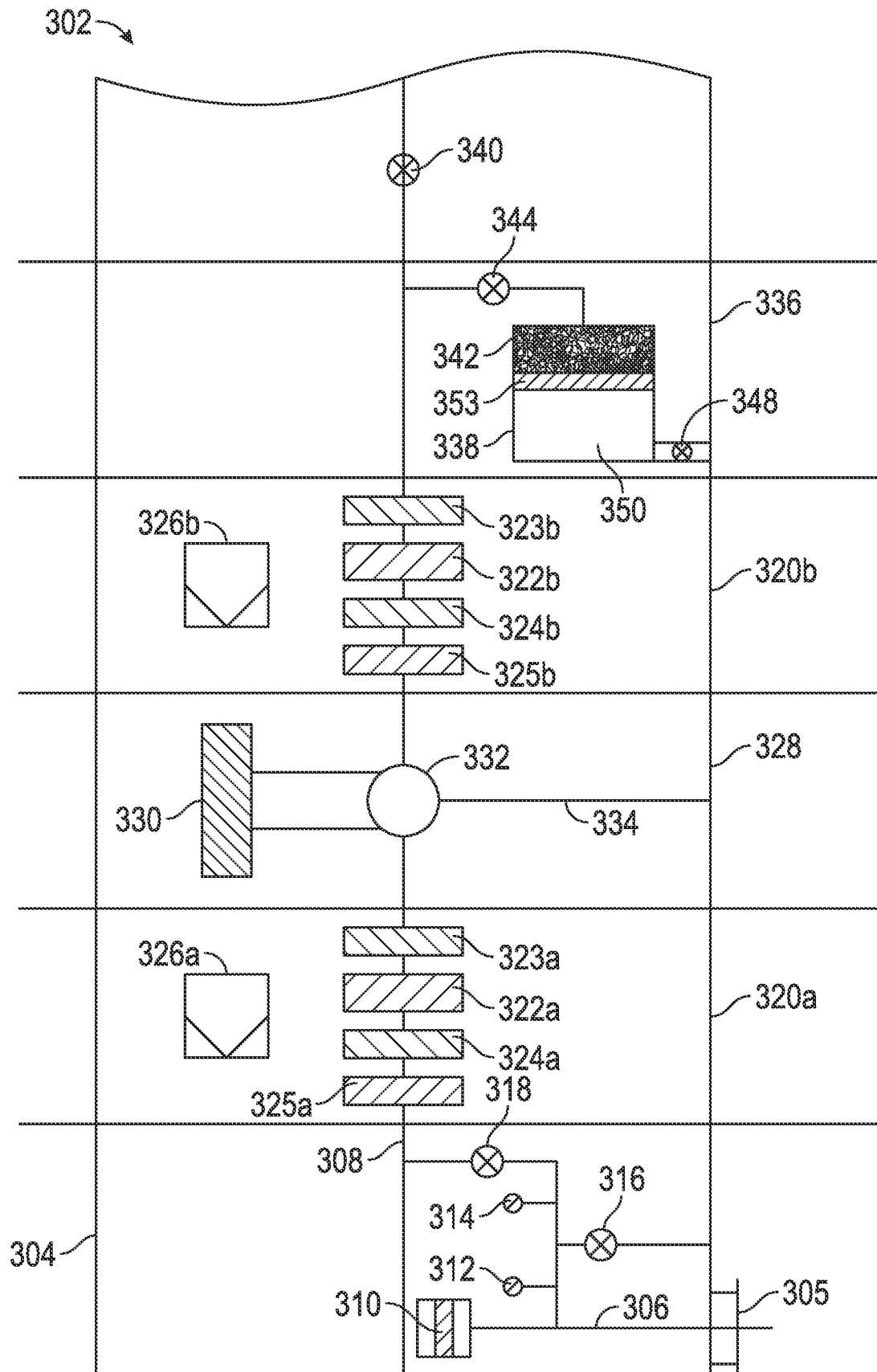


FIG. 3

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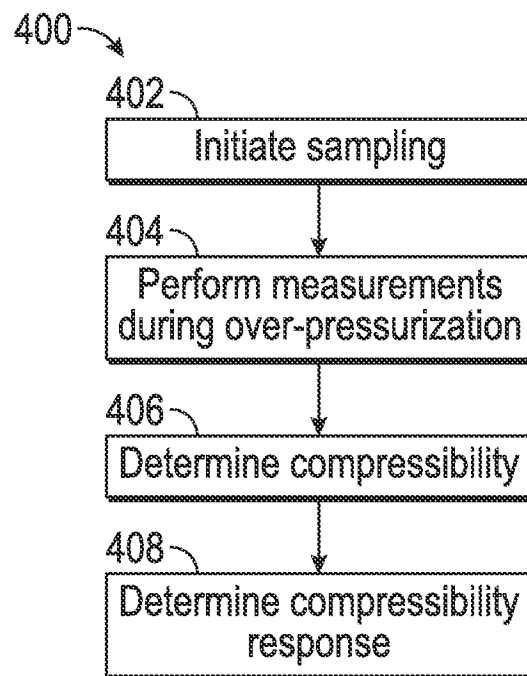
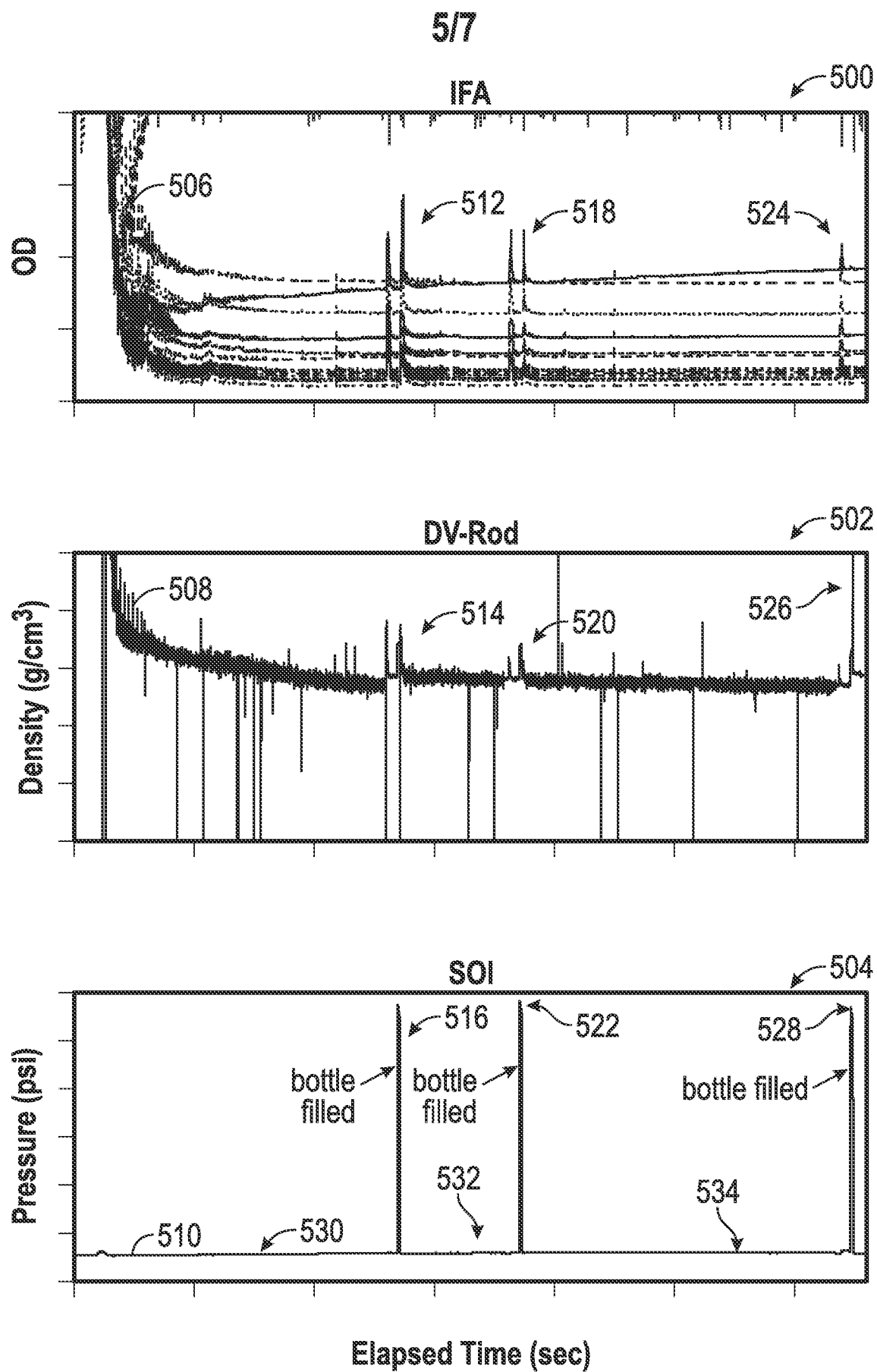


FIG. 4

**FIG. 5**

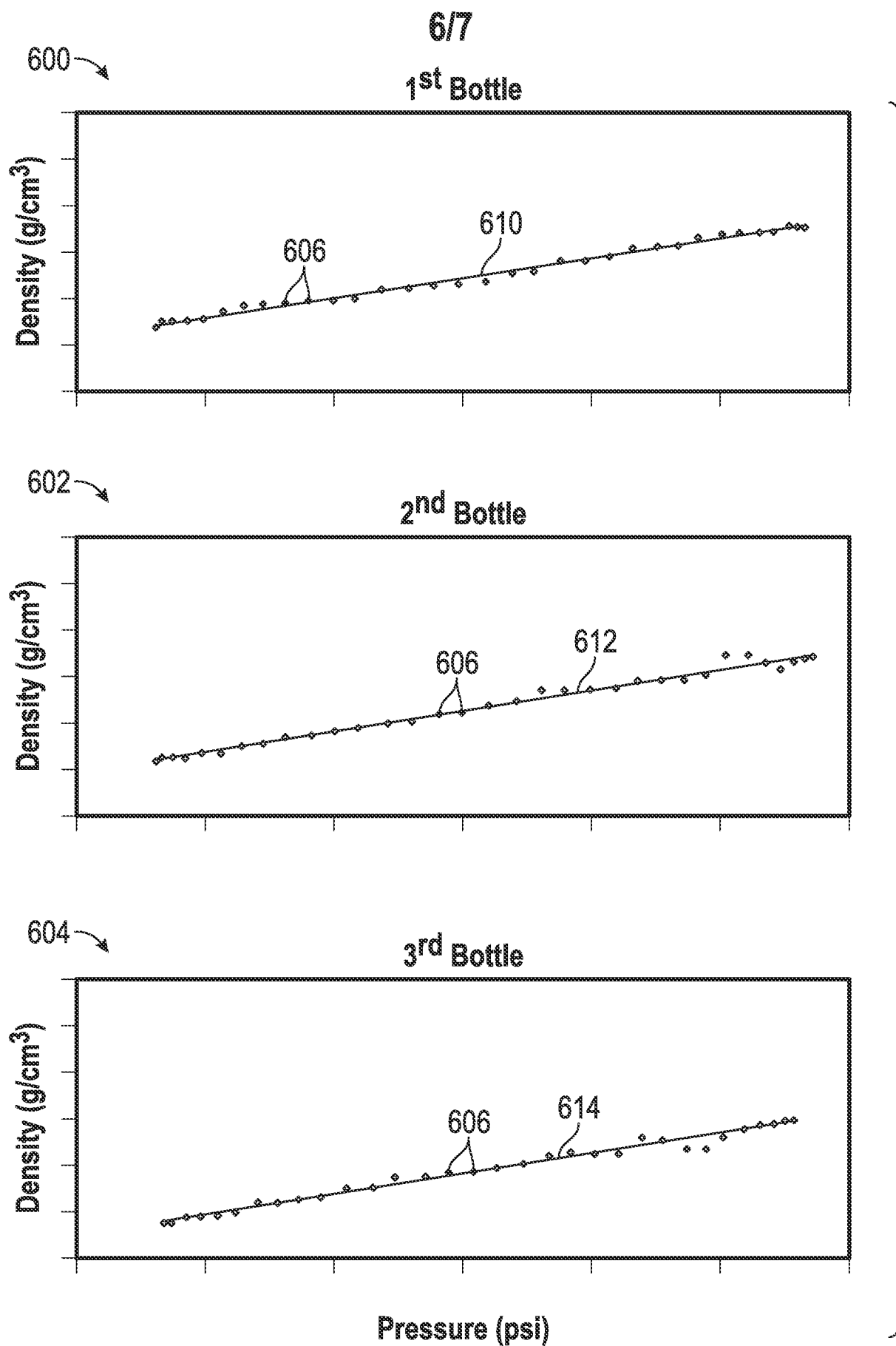


FIG. 6

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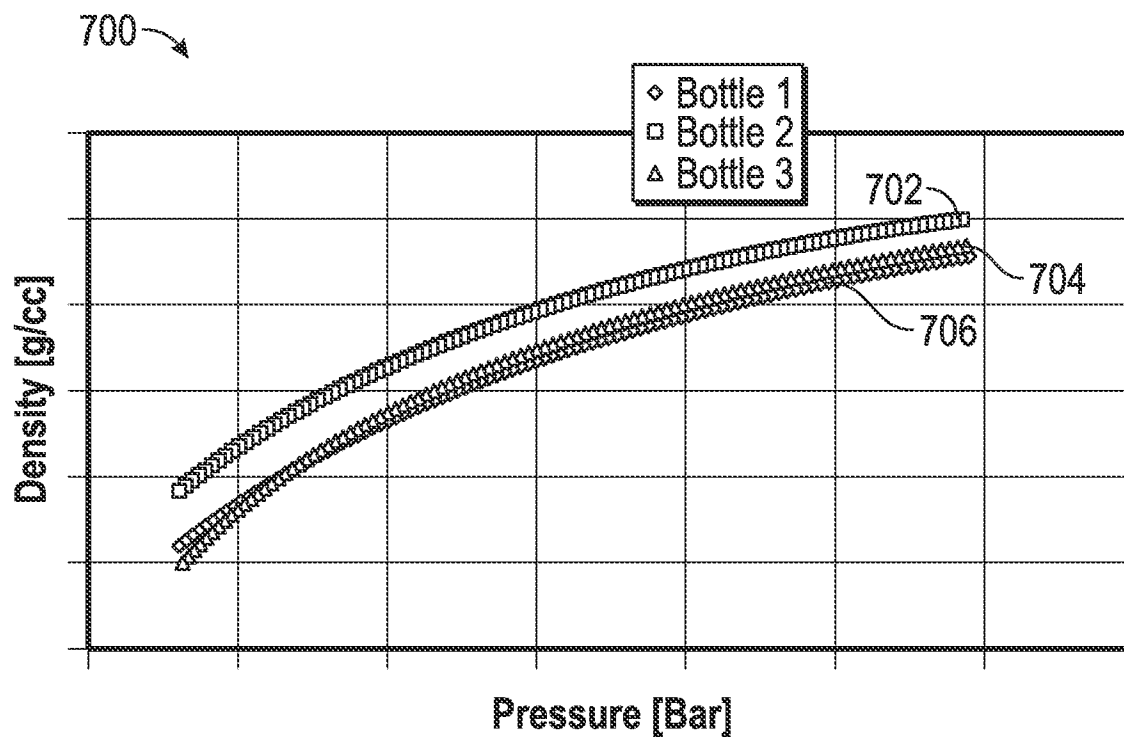


FIG. 7

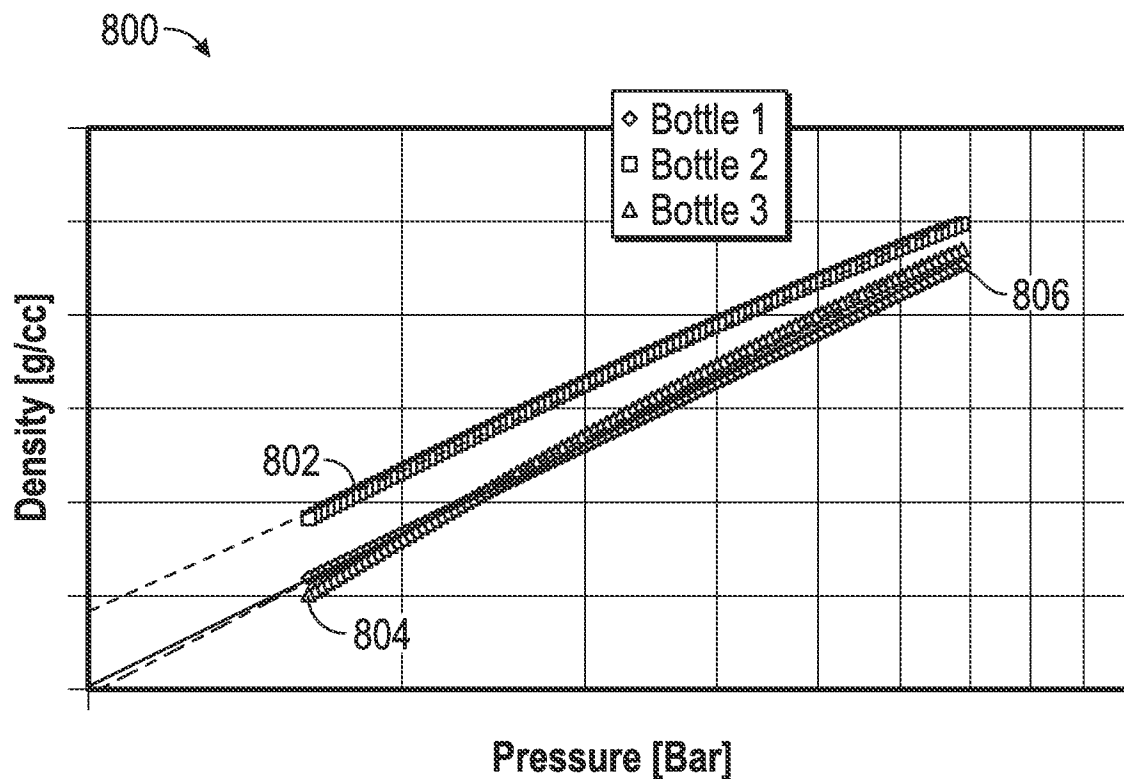


FIG. 8

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2014/053146**A. CLASSIFICATION OF SUBJECT MATTER****E21B 49/08(2006.01)i, G01N 1/10(2006.01)i, E21B 47/00(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 49/08; G06F 19/00; E21B 43/00; E21B 47/08; E21B 34/00; E21B 47/06; F04B 35/02; G01N 1/10; E21B 47/00

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: fluid, analysis, sample, formation, chamber, pressure, density and compressibility

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2009-0308600 A1 (HSU et al.) 17 December 2009 See paragraphs [0016]–[0061]; claims 1,10–11; and figures 3–4.	1–11,13–20
Y		12
Y	US 2009-0285700 A1 (CORBEIL, JASON) 19 November 2009 See paragraph [0050] and claim 1.	12
A	US 2006-0243047 A1 (TERABAYASHI et al.) 02 November 2006 See paragraphs [0014]–[0020] and claim 1.	1–20
A	US 2012-0018152 A1 (ZUILEKOM et al.) 26 January 2012 See claims 1,10 and figure 4.	1–20
A	US 2013-0047696 A1 (RASMUS et al.) 28 February 2013 See claims 1,9 and figure 1.	1–20



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents:

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"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

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"&" document member of the same patent family

Date of the actual completion of the international search

08 December 2014 (08.12.2014)

Date of mailing of the international search report

10 December 2014 (10.12.2014)

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Information on patent family members

International application No.

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