



(51) International Patent Classification:

E21B 7/12 (2006.01) *E21B 21/08* (2006.01)
E21B 21/00 (2006.01) *E21B 7/128* (2006.01)

(21) International Application Number:

PCT/US2018/041784

(22) International Filing Date:

12 July 2018 (12.07.2018)

(25) Filing Language:

English

(26) Publication Language:

English

(30) Priority Data:

62/532,655 14 July 2017 (14.07.2017) US

(71) Applicant: BP CORPORATION NORTH AMERICA INC. [US/US]; 501 Westlake Park Boulevard, Houston, Texas 77079 (US).

(72) Inventors: HOWES, Thomas B.; 501 Westlake Park Boulevard, Houston, Texas 77079 (US). SHIMI, Ahmed S.; 501 Westlake Park Boulevard, Houston, Texas 77079 (US).

(74) Agent: FALESKI, Thaddeus J.; CONLEY ROSE, P.C., 575 N. Dairy Ashford Rd., Suite 1102, Houston, Texas 77079 (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, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JO, JP, KE, KG, KH, KN, KP, KR, KW, 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: RISERLESS MANAGED PRESSURE DRILLING SYSTEMS AND METHODS

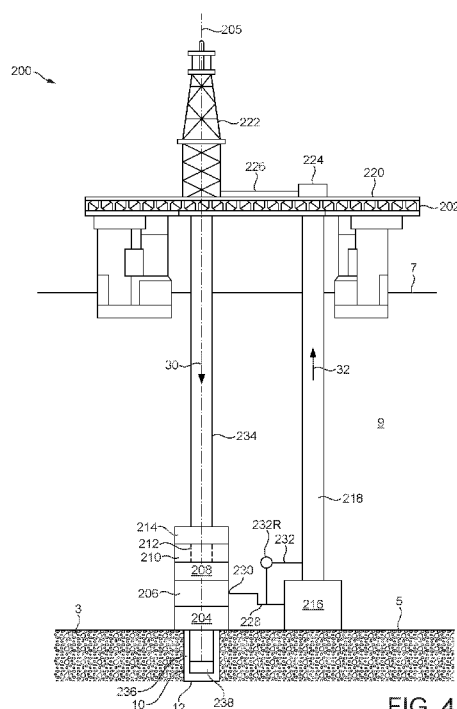


FIG. 4

(57) Abstract: A method for drilling a wellbore with an offshore, riserless drilling system, the method includes pumping a drilling fluid from a drilling vessel down a first drillstring and into an annulus within a subterranean wellbore, pumping the drilling fluid from the annulus of the wellbore to the drilling vessel with a subsea pump, applying backpressure to the drilling fluid in the annulus of the wellbore with the subsea pump, and preventing fluid flow from the annulus of the wellbore to the surrounding environment as the drilling fluid is pumped from the drilling vessel into the annulus of wellbore.

RISERLESS MANAGED PRESSURE DRILLING SYSTEMS AND METHODS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims benefit of U.S. provisional patent application Serial No. 62/532,655 filed July 14, 2017, and entitled “Riserless Managed Pressure Drilling Systems and Methods,” which is hereby incorporated herein by reference in its entirety for all purposes.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable.

BACKGROUND

[0003] Embodiments disclosed herein generally relate to wellbore drilling operations. More particularly, embodiments disclosed herein relate to managed pressure drilling (MPD) systems and associated methods for controlling wellbore pressure during the drilling operation.

[0004] Deepwater offshore drilling operations may encounter formations having reduced tolerances between the formation's natural pore pressure and fracture gradient (PPFG). Additionally, the effect of annular friction pressure (AFP) from the circulation of drilling fluid between a platform of the drilling system and the wellbore may increase the bottom hole pressure (BHP) in the wellbore, thereby reducing the drilling margin or tolerance between the formation's pore pressure and fracture gradient. Therefore, the ability to control loss circulation and influxes from the formation may be limited, and further, it may be necessary in some applications to isolate portions of the formation from pressure in the wellbore with planned or unplanned casing or liner strings affixed to an inner surface of the wellbore.

BRIEF SUMMARY OF THE DISCLOSURE

[0005] An embodiment of a method for drilling a wellbore with an offshore, riserless drilling system comprises pumping a drilling fluid from a drilling vessel down a first drillstring and into an annulus within a subterranean wellbore, pumping the drilling fluid from the annulus of the wellbore to the drilling vessel with a subsea pump, applying

backpressure to the drilling fluid in the annulus of the wellbore with the subsea pump, and preventing fluid flow from the annulus of the wellbore to the surrounding environment as the drilling fluid is pumped from the drilling vessel into the annulus of wellbore. In some embodiments, the method further comprises applying backpressure to the drilling fluid with the subsea pump at the seabed. In some embodiments, the method further comprises opening a recirculation valve of a recirculation conduit extending between a suction and a discharge of the subsea pump to apply hydrostatic pressure to the drilling fluid in the annulus of the wellbore. In certain embodiments, the method further comprises selectively applying hydrostatic pressure to the annulus from a column of fluid extending from the seabed. In certain embodiments, the method further comprises removing the first drillstring from the wellbore, and applying hydrostatic pressure to the annulus of wellbore from the column of fluid with the first drillstring removed from the wellbore. In some embodiments, the method further comprises selectively isolating the hydrostatic pressure of the support fluid from the annulus. In some embodiments, the method further comprises isolating the annulus of the wellbore from hydrostatic pressure of seawater in the ambient environment above the seabed. In some embodiments, the method further comprises adjusting a pump rate of the subsea pump to control the amount of backpressure applied to the drilling fluid in the annulus of the wellbore. In certain embodiments, the method further comprises removing the first drillstring from the wellbore and transporting the first drillstring to the drilling vessel, and inserting a second drillstring into the wellbore as the first drillstring is being transported to the drilling vessel.

[0006] Embodiments described herein comprise a combination of features and characteristics intended to address various shortcomings associated with certain prior devices, systems, and methods. The foregoing has outlined rather broadly the features and technical characteristics of the disclosed embodiments in order that the detailed description that follows may be better understood. The various characteristics and features described above, as well as others, will be readily apparent to those skilled in the art upon reading the following detailed description, and by referring to the accompanying drawings. It should be appreciated that the conception and the specific embodiments disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes as the disclosed embodiments. It should also be realized that such equivalent constructions do not depart from the spirit and scope of the principles disclosed herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] For a detailed description of various exemplary embodiments, reference will now be made to the accompanying drawings in which:

[0008] Figure 1 is a schematic view of an embodiment of a well system shown in a first configuration in accordance with principles disclosed herein;

[0009] Figure 2 is a schematic view of the well system of Figure 1 shown in a second configuration in accordance with principles disclosed herein;

[0010] Figure 3 is a schematic view of the well system of Figure 1 shown in a third configuration in accordance with principles disclosed herein;

[0011] Figure 4 is a schematic view of another embodiment of a well system in accordance with principles disclosed herein;

[0012] Figure 5 is a chart of an embodiment of a pore pressure and fracture gradient of a terranean formation of the well system of Figure 4 in accordance with principles disclosed herein; and

[0013] Figure 6 is another schematic view of the well system of Figure 4 in accordance with principles disclosed herein.

DETAILED DESCRIPTION OF EXEMPLARY EMBODIMENTS

[0014] The following discussion is directed to various exemplary embodiments. However, one of ordinary skill in the art will understand that the examples disclosed herein have broad application, and that the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment.

[0015] The drawing figures are not necessarily to scale. Certain features and components herein may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in interest of clarity and conciseness.

[0016] In the following 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. Thus, if a first device couples to a second device, that connection may be through a direct connection of the two devices, or through an indirect connection that is established via other devices, components,

nodes, and connections. In addition, as used herein, the terms “axial” and “axially” generally mean along or parallel to a given axis (e.g., central axis of a body or a port), while the terms “radial” and “radially” generally mean perpendicular to the given axis. For instance, an axial distance refers to a distance measured along or parallel to the axis, and a radial distance means a distance measured perpendicular to the axis.

[0017] Referring now to Figure 1, an embodiment of an offshore well or drilling system 100 for drilling a subsea wellbore 10 that extends into a terranean formation 3 from a sea floor or seabed 5 is shown. In the embodiment of Figure 1, system 100 generally includes a drilling vessel or platform 102 disposed at a surface or waterline 7 of the seawater 9 (i.e., at the waterline), a blowout preventer (BOP) stack 104 disposed at the seabed 5, and a marine riser system 106 extending between BOP stack 104 and the drilling vessel 102. Wellbore 10, BOP stack 104, and riser system 106 share a common central or longitudinal axis 105. In some embodiments, drilling system 100 may comprise additional components not shown in Figure 1, such as a subsea wellhead and a lower marine riser package (LMRP).

[0018] Drilling vessel 102 of drilling system 100 includes a drilling floor 108 and a derrick 110 supported on the drilling floor 108. Drilling floor 108 of vessel 102 also supports a surface pump 112, such as a mud pump, and a choke or choke manifold 114, as will be described further herein. In the embodiment of Figure 1, drilling vessel 102 is a floating offshore structure, and more particularly, a floating semi-submersible platform. However, in other embodiments, the drilling vessel (e.g., drilling vessel 102) may comprise other types of vessels, such as drilling ships and the like.

[0019] Riser system 106 includes a modified riser joint 118 that comprises a flow spool 120, a riser annular BOP 121, an annulus containment device 122, and a mid-riser or subsea pump 126. In the embodiment of Figure 1, containment device 122 is a rotating control device (RCD), and thus, may also be referred to as RCD 122. In other embodiments, containment device 122 may comprise other annular containment devices. Riser joint 118, including flow spool 120, annular BOP 121, RCD 122, and pump 126 are positioned subsea or beneath the waterline 7. In addition, riser joint 118 is spaced from the seabed 5, with a portion of riser system 106 extending between BOP stack 104 and riser joint 118.

[0020] Referring still to Figure 1, the subsea pump 126 of riser joint 118 is coupled to a bypass conduit 128 extending between a first port or fluid connection 130 formed

in the riser joint 118 and a second port or fluid connection 132 also formed in the riser joint 118. In particular, bypass conduit 128 comprises a suction conduit 134 extending between first port 130 and a suction of subsea pump 126, and a discharge conduit 136 extending between a discharge of subsea pump 126 and second port 132 that includes an actuatable discharge valve 136V for selectively isolating fluid communication therebetween. In this arrangement, bypass conduit 128 provides a fluid conduit or passageway that extends around or bypasses RCD 122. Additionally, suction conduit 134 includes a first valve 134V proximal first port 130 for selectively isolating first port 130 while discharge conduit 136 includes a second valve 136V proximal second port 132 for selectively isolating second port 132. A drilling fluid return conduit 138 extends between a third port or fluid connection 140 formed in the flow spool 120 of riser joint 118, and the choke manifold 114. Return conduit 138 includes an actuatable return valve 138V configured to selectively isolate choke manifold 114 from the third port 140 of flow spool 120. In the embodiment shown in Figure 1, subsea pump 126 is a positive displacement pump. Although in the embodiment shown in Figure 1 only a single return conduit 138 is shown, in some embodiments, drilling system 100 may include a plurality of return conduits 138 extending between flow spool 120 and choke manifold 114.

[0021] Marine riser system 106 of drilling system 100 can function as a conduit for transporting drilling fluid through seawater 9 between the drilling vessel 102 and the BOP stack 104 disposed at the seabed 5. Specifically, drilling fluid is pumped from surface pump 112 along an inlet flowpath (indicated by arrows 20) that extends through an inlet conduit 116 into a central bore or passage of a tubular drillstring 142 (shown with dashed lines) that is suspended from vessel 102 and extends through marine riser system 106, BOP stack 104, and into wellbore 10. The drilling fluid exits drillstring 142 via a drill bit 144 disposed at a lower end of drillstring 142, and flows into wellbore 10 proximal a lower terminal end or bottom 12 of wellbore 10. The drilling fluid may then circulate upwards from wellbore 10 through an annulus 146 extending radially between drillstring 142 and the inner surfaces of wellbore 10, BOP stack 104, and riser system 106, as will be discussed further herein. The annular BOP 121 of riser joint 118 includes an annular member actuatable between a radially outer position allowing fluid flow through the portion of annulus 146 extending through BOP 121 and a radially inner position that sealingly engages an outer surface of drillstring 142, thereby restricting fluid flow through the portion annulus

146 formed in BOP 121. Additionally, first port 130 is positioned below the annular seal provided by annular BOP 121 when the annular member thereof is in the radially inner position.

[0022] Drilling system 100 includes a plurality of configurations for controlling bottom-hole pressure (BHP) in wellbore 10, where each configuration provides a separate or distinct flowpath for circulating drilling and/or wellbore fluid from wellbore 10 to drilling vessel 102. More specifically, in the embodiment of Figure 1, drilling system 100 comprises a first configuration 103 that includes a first drilling fluid return or recirculation flowpath (indicated by arrows 22 in Figure 1). In first configuration 103, valves 134V, 136V, 138V are each disposed in a closed position, isolating subsea pump 126 and choke manifold 114 from fluid flow in annulus 146. Additionally, in the first configuration 103, first drilling fluid return flowpath 22 extends entirely through annulus 146 to drilling vessel 102, where neither annular BOP 121 nor RCD 122 are in sealing engagement with the outer surface of drillstring 142. In other words, drilling fluid flowing along first return flowpath 22 does not flow through either subsea pump 126 or choke manifold 114.

[0023] In the first configuration 103 shown in Figure 1, circulation of the drilling fluid along inlet flowpath 20 and return flowpath 22 is provided by surface pump 112. In addition, BHP in wellbore 10 is provided by the hydrostatic or head pressure of the vertical column of drilling fluid extending between drilling vessel 102 and the bottom 12 of wellbore 10 and the annulus friction pressure (AFP) applied to the drilling fluid as it recirculates to drilling vessel 102 along first return flowpath 22. However, when drilling fluid is not being actively circulated along flowpaths 20 and 22, such as during tripping of drillstring 142 into or out of wellbore 10, BHP in wellbore 10 is only provided by the hydrostatic pressure of the vertical column of drilling fluid extending between the bottom 12 of wellbore 10 and drilling vessel 102, amounting to a loss of BHP in wellbore 10. In addition, it may be difficult to quickly and actively control the AFP applied to the drilling fluid flowing along first return flowpath 22 to adjust the BHP in wellbore 10 in response to changing conditions in wellbore 10.

[0024] Referring now to Figure 2, drilling system 100 comprises a second configuration 107 that includes a second drilling fluid return or recirculation flowpath (indicated by arrows 24 in Figure 2). More specifically, in second configuration 107, an inner housing or seal assembly 124 is installed within the RCD 122 of riser joint 118, where seal assembly 124 is configured to sealingly engage the outer surface of

drillstring 142, including when drillstring 142 rotates within riser system 106. In this arrangement, seal assembly 124 of RCD 122 divides annulus 146 into a first or lower annulus 146A extending longitudinally between the lower terminal end of drillstring 142 disposed in wellbore 10 and seal assembly 124, and a second or upper annulus 146B extending between seal assembly 124 and the upper end of riser system 106 at drilling vessel 102. The sealing engagement provided by seal assembly 124 prevents or restricts fluid communication directly between annuli 146A, 146B. Additionally, in second configuration 107, valves 134V, 136V each remain in the closed position while return valve 138V is actuated into the open position. In this arrangement, fluid flow between annuli 146A, 146B is restricted while fluid flow from lower annulus 146B to choke manifold 114 is permitted via return conduit 138. In second configuration 107, the annular sealing element of annular BOP 121 remains in the radially outer position to allow relative for rotation of drillstring 142.

[0025] In second configuration 107 of drilling system 100, drilling fluid returns to drilling vessel 102 via second return flowpath 24 which extends through lower annulus 146B, return conduit 138, and choke manifold 114. The circulation of drilling fluid along inlet flowpath 20 and second return flowpath 24 forms a closed-loop fluid system, allowing for the rapid detection of changing fluid conditions in wellbore 10 (e.g., detection of influx or fluid loss between wellbore 10 and formation 3, etc.). Choke manifold 114 is a fluid choke configured to provide for the rapid and controlled restriction of fluid flow (e.g., via adjusting the position of the choke) along second return flowpath 24. In other words, choke manifold 114 allows an operator of drilling system 100 to controllably restrict or choke the flow of drilling fluid along second return flowpath 24 to rapidly control the amount of backpressure applied against the drilling fluid flowing along second return flowpath 24, including drilling fluid disposed in wellbore 10.

[0026] In the embodiment of Figure 2, with drilling fluid circulating along inlet flowpath 20 and second return flowpath 24, the BHP in wellbore 10 may be rapidly and precisely controlled via controlling the amount of backpressure applied to the drilling fluid flowing along second return flowpath 24 using choke manifold 114. In some applications, the rapid and precise control of BHP in wellbore 10 provided by choke manifold 114 may allow for the explorative drilling of terranean formations that have relatively limited or reduced drilling margins (e.g., the margin between the formation's pore pressure and fracture gradient at a given vertical depth). For

instance, the BHP control provided by choke manifold 114 may be used to maintain a relatively constant BHP that does not deviate towards either the pore or fracture pressures of formation 3. The rapid and precise BHP control provided by choke manifold 114 may also be useful when reacting against rapidly changing fluid conditions in wellbore 10. Choke manifold 114 offers the potential for some terranean formations to be drilled more economically by reducing the number of, or eliminating the use of, liner or casing strings or joints installed in wellbore 10 to isolate sections of wellbore 10 from pressure therein, where the installation of liner or casing strings generally increases the time and money necessary to drill wellbore 10.

[0027] Referring to Figure 3, drilling system 100 comprises a third configuration 109 that includes a third drilling fluid return or recirculation flowpath (indicated by arrows 26 in Figure 3). In particular, in third configuration 109, seal assembly 124 remains installed within RCD 122, return valve 138V is actuated into the closed position, and valves 134V and 136V are each actuated into the open position. In the arrangement of third configuration 109, fluid flow from lower annulus 146A to choke manifold 114 is restricted by the closure of return valve 138V. Additionally, while direct fluid flow from lower annulus 146A to upper annulus 146B is restricted by seal assembly 124 of RCD 122, the opening of valves 134V and 136V allows for fluid flow in lower annulus 146A to bypass seal assembly 124 via bypass conduit 128 of riser joint 118.

[0028] In third configuration 109 of drilling system 100, drilling fluid returning to drilling vessel 102 from wellbore flows along third return flowpath 26 which extends through lower annulus 146B, bypass conduit 128 (thus extending around the seal formed by seal assembly 124 against drillstring 142), and upper annulus 146A to drilling vessel 102. Additionally, in third configuration 109, the subsea pump 126 of riser joint 118 is activated to pump drilling fluid from lower annulus 146A into upper annulus 146B and drilling vessel 102. Thus, in third configuration 109, both surface pump 112 and subsea pump 126 are used to circulate the drilling fluid between drilling vessel 102 and wellbore 10 along inlet flowpath 20 and third return flowpath 26, respectively.

[0029] In the third configuration 109 of drilling system 100 shown in Figure 3, the subsea pump 126 of riser joint 118 may be operated in a first or pumped-riser mode and/or a second or hybrid mode. Particularly, in the pumped-riser mode of subsea pump 126, subsea pump 126 is operated consistently at the same pump rate as surface pump 112 to thereby compensate or reduce the effects of Equivalent

Circulating Density (ECD). As described above, the AFP applied to the drilling fluid as it flows from wellbore 10 to drilling vessel 102 via riser system 106 increases the BHP in wellbore 10, a phenomenon sometimes referred to as ECD effect. By operating subsea pump 126 at the same pump rate as surface pump 112, the pressure applied to the drilling fluid in lower annulus 146A from the column of drilling fluid disposed in upper annulus 146B may be reduced or eliminated. In this manner, BHP in wellbore 10 may be maintained at or close to the equivalent static density (ESD) of the drilling fluid disposed in riser system 106. In some applications, such as in developmental and depleted reservoir drilling, a statically balanced or overbalanced mud weight (MW) may be considered a boundary condition requiring the removal or substantial reduction of the ECD effect and a BHP equivalent to the ESD of the drilling system. Thus, the pumped-riser mode of subsea pump 126 in third configuration 109 may be advantageous in such applications.

[0030] In the hybrid mode of subsea pump 126 in third configuration 109, subsea pump 126, which comprises a positive displacement pump in the embodiment of Figure 3, is operated for a predetermined period of time at a pump rate that varies from the pump rate of surface pump 112. In some embodiments, subsea pump 126 is operated at a pump rate less than the pump rate of surface pump 112 for a predetermined period of time to trap or apply backpressure to the drilling fluid flowing along third return flowpath 26 in lower annulus 146B. Following the predetermined period of time, subsea pump 126 is operated at the same pump rate as surface pump 112, with a predetermined amount of backpressure trapped in the drilling fluid flowing through the portion of third return flowpath 26 extending through lower annulus 146A, where the amount of backpressure trapped therein is determined by the duration of the predetermined period of time and the differential between the pump rates of pumps 126 and 112 during the predetermined period of time. For instance, if subsea pump 126 is operated at a pump rate that is 10 gallons per minute less than the pump rate of surface pump 112 for a period of 30 seconds, then 5 gallons of drilling fluid will be trapped in lower annulus 146A, thereby pressurizing the drilling fluid in lower annulus 146A by a predetermined amount dictated, at least in part, by the compressibility of the drilling fluid disposed therein. Further, the amount of backpressure trapped in lower annulus 146A remains trapped therein (as long as circulation of drilling fluid via pumps 112 and 126 is maintained) following the

increase in pump rate of subsea pump 126 to match the pump rate of surface pump 112.

[0031] In the hybrid mode of subsea pump 126 in third configuration 109, the amount of backpressure trapped in lower annulus 146A may be reduced or eliminated by operating subsea pump 126 at a relatively greater pump rate than surface pump 112 for a predetermined period of time. For instance, following from the example described above, if subsea pump 126 is operated at a pump rate that is 10 gallons per minute greater than the pump rate of surface pump 112 for a period of 30 seconds, then the 5 gallons of drilling fluid trapped in lower annulus 146A will be released therefrom. Thus, by manipulating the pump rate of subsea pump 126 relative to surface pump 112, the amount of backpressure trapped or applied against the drilling fluid in lower annulus 146A (and, in turn, BHP of wellbore 10) may be rapidly controlled. In this manner, the benefits of rapid and precise control of BHP in wellbore 10 provided by second configuration 107 of Figure 2, as well as the benefit of removing or eliminating the ECD effect provided by the pumped-riser mode of subsea pump 126 of third configuration 109 may be achieved through the hybrid mode of subsea pump 126 of third configuration 109.

[0032] Referring to Figure 4, another embodiment of an offshore well or drilling system 200 for drilling subsea wellbore 10 is shown. In the embodiment of Figure 4, system 200 generally includes a drilling vessel or platform 202 disposed at waterline 7, a ram blowout preventer (BOP) 204 disposed at the seabed 5, a flow spool 206, an annular BOP 208, an annular containment device 210, a wellbore containment device 214, a subsea pump 216 disposed at the seabed 5, and an auxiliary marine riser or conduit 218 extending from the subsea pump 216 to the drilling vessel 202. Wellbore 10, ram BOP 204, flow spool 206, annular BOP 208, and containment devices 210 and 214 share a common central or longitudinal axis 205 while subsea pump 216 and auxiliary riser 218 are laterally or horizontally spaced from central axis 205. In some embodiments, drilling system 200 may comprise additional components, such as a subsea wellhead not shown in Figure 4.

[0033] Drilling vessel 202 of drilling system 200 includes a drilling floor 220 and a derrick 222 supported on drilling floor 220. Drilling floor 220 also supports a surface pump 224 and an inlet fluid conduit 226 in fluid communication therewith. In the embodiment of Figure 4, subsea pump 216 comprises a positive displacement pump. A suction conduit 228 extends between a port 230 in flow spool 204 to a

suction side of subsea pump 216, where a discharge side of pump 216 feeds into a lower end of auxiliary riser 218. In addition, a bypass conduit 232 extends between auxiliary riser 218 and suction conduit 228, where bypass conduit 232 includes an actuatable pressure regulator 232R configured to selectively control the amount of hydrostatic pressure in auxiliary riser 218 that is applied to fluid in wellbore 10. In the embodiment of Figure 4, drilling vessel 202 comprises a floating offshore structure, and more particularly, a floating semi-submersible platform, similar to the embodiment of drilling vessel 102 shown in Figure 1. However, in other embodiments, drilling vessel 202 may comprise other vessels, such as drilling ships and the like.

[0034] Referring still to Figure 4, drilling system 200 also includes a tubular drillstring 234 suspended from drilling vessel 202 into wellbore 10. Unlike the embodiment of drilling system 100 shown in Figures 1-3, the drillstring 234 of drilling system 200 does not extend through a marine riser system, and thus, drilling system 200 may be described as being a “riserless” drilling system 200. Thus, at least a portion of the outer surface of drillstring 234 is directly exposed to the seawater 9 of the surrounding environment.

[0035] Ram BOP 204 of drilling system 200 includes one or more actuatable rams configured to seal wellbore 10 from the surrounding environment (e.g., seawater 9) in emergency situations, including in response to the detection of a rapid influx of fluid from formation 3 into wellbore 10. Annular BOP 208 includes an actuatable annular member configured to seal an annulus 236 formed between the outer surface of drillstring 234 and the inner surfaces of wellbore 10, ram BOP 204, and spool 206. For instance, annular BOP 208 may be actuated when a seal assembly of annular containment device 210 is changed. Flow spool 206 provides a fluid connection between annulus 236 and suction conduit 228 via port 230. In the embodiment of Figure 4, annular containment device 210 is an RCD including an inner housing or seal assembly 212 disposed therein and configured to seal against the outer surface of drillstring 234, including when drillstring 234 rotates within an outer housing of RCD 210. In other embodiments, containment device 210 may comprise other annular containment devices. In some embodiments, drillstring 234 may include an installation or running tool configured to convey and install seal assembly 212 within RCD 210. Further, wellbore containment device 214 is configured to prevent drilling or wellbore fluids disposed in wellbore 10 from escaping into the surrounding

environment (e.g., seawater 9) when drillstring 234 is tripped out of or removed from wellbore 10, as will be discussed further herein. In the embodiment of Figure 4, spool 206, annular BOP 208, RCD 210, and wellbore containment device 214 are each coupled to ram BOP 204 and are disposed at or proximal the seabed 5, as shown in Figure 4.

[0036] In the embodiment of Figure 4, drillstring 234 of drilling system 200 provides a conduit for transporting drilling fluid through seawater 9 between the drilling vessel 202 and ram BOP 204 disposed at the seabed 5. Specifically, drilling fluid is pumped from surface pump 224 along an inlet flowpath (indicated by arrow 30) that extends through inlet conduit 226 into a central bore or passage of drillstring 234. The drilling fluid exits drillstring 234 via a drill bit 238 coupled to a lower end of drillstring 234 and flows into wellbore 10 proximal the bottom 12 of wellbore 10. In the embodiment of Figure 4, the drilling fluid then returned or recirculated to drilling vessel 202 along a return or recirculation flowpath (indicated by arrow 32) that extends upwardly through annulus 236 and into suction conduit 228 via port 230 of flow spool 206. The return flowpath 32 of the circulated drilling fluid extends through subsea pump 216 and auxiliary riser 218, which provides a conduit for the drilling fluid through seawater 9 as it returns to drilling vessel 202. Although auxiliary riser 218 in the embodiment of Figure 4 is a marine riser, in other embodiments, auxiliary riser 218 may comprise other fluid conduits, such as tubular strings, hoses, and the like.

[0037] In the arrangement shown in Figure 4, surface pump 224 pumps the drilling fluid into wellbore 10 along inlet flowpath 30 while subsea pump 216 pumps the drilling fluid from the seabed 5 to the drilling vessel 202 at the waterline 7. The seal assembly 212 of RCD 210 seals against the outer surface of drillstring 234 as drillstring 234 rotates therein and the drilling fluid is circulated along flowpaths 30 and 32. Additionally, in the embodiment of Figure 4, RCD 210 isolates the hydrostatic pressure of the column of seawater 9 extending vertically above RCD 210 from the drilling fluid disposed in wellbore 10 and annulus 236. In some embodiments, RCD 210 may transfer the force applied thereagainst by the hydrostatic pressure of seawater 9 in the ambient environment to the seabed 5 or a support structure disposed at the seabed 5. In this manner, the column of seawater 9 extending above the RCD 210 will not influence BHP in wellbore 10.

[0038] Similar to the pumped-riser mode of the subsea pump 126 shown in Figure 3, subsea pump 216 may be operated at the same pump rate as surface pump 224 to lift the drilling fluid flowing along return flowpath 32 to drilling vessel 202 and thereby substantially reduce or eliminate the ECD effect of the drilling fluid flowing through auxiliary riser 218. Additionally, instead of being positioned mid-riser as with the embodiment of subsea pump 126 shown in Figure 3, subsea pump 216 in the embodiment of Figure 4 is positioned at the seabed 5, further reducing or eliminating any ECD effect of the circulating drilling fluid of drilling system 200. Moreover, the isolation of hydrostatic pressure of seawater 9 from the BHP in wellbore 10 prevents said hydrostatic pressure from interfering with the control of BHP in wellbore 10 by subsea pump 216.

[0039] Similar to the hybrid mode of the subsea pump shown in Figure 3, subsea pump 216 may be operated in a hybrid mode to quickly and precisely control BHP in wellbore 10. For instance, subsea pump 216 may be operated at a pump rate that is less than the pump rate of surface pump 224 for a predetermined period of time to trap or apply a predetermined amount of backpressure to the drilling fluid flowing into the suction side of subsea pump 216 from wellbore 10. Following the predetermined period of time, the pump rate of subsea pump 216 may be increased to match the pump rate of surface pump 224 to thereby maintain the desired backpressure trapped in wellbore 10. If desired, subsea pump 216 may be operated at a pump rate greater than the pump rate of surface pump 224 for a predetermined period of time to reduce the backpressure trapped in wellbore 10. However, unlike the embodiment of subsea pump 126 shown in Figure 3, the embodiment of subsea pump 216 shown in Figure 4 may control BHP in wellbore 10 at the seabed 5.

[0040] Given that BHP in wellbore 10 is directly controlled at the seabed 5 in the embodiment of Figure 4, a light or low density drilling fluid may be used to drill wellbore 10 relative to conventional MPD systems, such as conventional MPD systems that utilize dual gradient fluid systems to produce an annular pressure profile that resembles the PPFG trend of the terranean formation (e.g., formation 3) being drilled. For instance, instead of relying on a high density drilling fluid below the seabed, which may rapidly intercept the fracture gradient of the formation as the wellbore is drilled (potentially necessitating the installation of a casing string to isolate a section of the wellbore), BHP in the wellbore 10 of drilling system 200 may be continuously managed with a low density drilling fluid (e.g., a drilling fluid having a

density approximately between 12 and 15 pounds per gallon (PPG) in some embodiments) by applying backpressure to the drilling fluid flowing along the portion of return flowpath 32 extending between wellbore 10 and suction conduit 228. Additionally, BHP in wellbore 10 may be managed to provide a constant overbalance relative to the pore pressure of formation 3 with an increased margin to the fracture gradient of formation, thereby reducing the risk of lost circulation of drilling fluid to the formation 3.

[0041] An exemplary PPFG chart 300 for the terranean formation 3 of Figure 4 is shown in Figure 5. PPFG chart 300 indicates pressure (in pounds per gallon equivalent (PPGE)) on an X-axis thereof and true vertical depth (e.g., from waterline 7) on a Y-axis thereof. Particularly, in the embodiment of Figures 4 and 5, PPFG chart 300 illustrates an exemplary pore pressure gradient 302 and an exemplary fracture pressure gradient 304 of formation 3. Additionally, in the embodiment of Figures 4 and 5, PPGE chart 300 illustrates an exemplary BHP profile 306 of the wellbore 10 of drilling system 200. As described above, BHP profile 306 must generally be maintained between the pore pressure and fracture gradients 302 and 304, respectively, to prevent either fluid influx into wellbore 10 from formation 3 or the fracturing of formation 3.

[0042] In the embodiment of Figure 4, the active BHP control provided by subsea pump 216 allows for the BHP profile 306 to be curved as indicated by the curved sections 308 of the BHP profile 306 shown in Figure 5. Particularly, as wellbore 10 is drilled by drillstring 234, subsea pump 216 may be operated in the hybrid mode to periodically or intermittently trap increasing amounts of backpressure in wellbore 10 to thereby gradually increase BHP in wellbore 10 such that the curved sections 308 of BHP profile 306 mirror the curved profiles 302 and 304 of the formation 3. In this manner, wellbore 10 may be drilled to a greater vertical depth relative to other drilling systems, including other MPD systems (e.g., by allowing for the use of a relatively less dense drilling fluid, etc.), before a liner or casing string must be installed to isolate sections of the wellbore from fluid pressure therein. In some embodiments, the BHP control provided by subsea pump 216 may eliminate the need for installing any liner or casing strings within wellbore 10 during the drilling thereof.

[0043] Referring now to Figures 4-6, during the operation of drilling system 200, drillstring 234 may be occasionally tripped out of wellbore 10 to allow for the installation of equipment in wellbore 10 or for other purposes, as shown in Figure 6.

When drillstring 234 is removed from wellbore 10, drilling fluid may no longer be circulated between drilling vessel 202 and wellbore 10. However, backpressure trapped in wellbore 10 from the hybrid operation of subsea pump 216 is maintained (and thus, BHP in wellbore 10 may be maintained) even when circulation of drilling fluid through inlet flowpath 30 and return flowpath 32 has ceased. In particular, in the embodiment of Figures 4-6, when circulation of drilling fluid is ceased, pressure regulator 232R can be actuated to allow a predetermined amount of hydrostatic pressure from drilling fluid disposed in auxiliary riser 218 to be applied against the drilling fluid disposed in wellbore 10. In this manner, the BHP provided in wellbore 10 prior to the ceasing of circulation of drilling fluid through wellbore 10 may be maintained once circulation has been stopped. Additionally, pressure regulator 232R can actively control BHP in wellbore 10 during tripping of drillstring 234 by varying the amount of hydrostatic pressure applied to the fluid disposed in wellbore 10 from the column of fluid disposed in auxiliary riser 218. Thus, BHP in wellbore 10 can be quickly and precisely controlled via subsea pump 216 while drilling fluid is circulated along inlet flowpath 30 and return flowpath 32 and pressure regulator 232R may be used to quickly and precisely control BHP in wellbore 10 when drilling fluid is not being circulated between drilling vessel 202 and wellbore 10.

[0044] Additionally, when drillstring 234 is removed from wellbore 10 and retrieved to drilling vessel 202, wellbore containment device 214 acts to prevent fluids in wellbore 10, such as drilling or wellbore fluids, from escaping into the surrounding environment (e.g., the seawater 9). In some embodiments, wellbore containment device 214 may actively control fluid pressure therein to maintain a hydraulic or fluid barrier between the fluids of wellbore 10 and the surrounding environment. In some embodiments, wellbore containment device 214 comprises a fluid seal between the fluids of wellbore 10 and the surrounding environment.

[0045] Given that drilling system 200 comprises a riserless drilling system with drillstring 234 exposed directly to the seawater 9, drilling system 200 may perform dual activity drilling operations with increased efficiency relative to drilling systems that include a marine riser about its respective drillstring. Particularly, prior to tripping drillstring 234 out of the wellbore 10, a second drillstring (not shown) may be suspended from drilling vessel 202 that is offset from longitudinal axis 205, where a lower end of the second drillstring is positioned proximal the seabed 5. Once drillstring 234 has been tripped-out or removed from wellbore containment device

214, the second drillstring may be repositioned (e.g., by laterally repositioning drilling vessel 202 relative wellbore 10) to align with longitudinal axis 205, and tripped-in or inserted into containment device 214 and wellbore 10. In this manner, the second drillstring may be inserted into wellbore 10 as the drillstring 234 is tripped towards the drilling floor 220 of drilling vessel 202, thereby reducing the time required for performing the dual activity operation.

[0046] While preferred embodiments have been shown and described, modifications thereof can be made by one skilled in the art without departing from the scope or teachings herein. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the systems, apparatus, and processes described herein are possible and are within the scope of the disclosure. For example, the relative dimensions of various parts, the materials from which the various parts are made, and other parameters can be varied. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims. Unless expressly stated otherwise, the steps in a method claim may be performed in any order. The recitation of identifiers such as (a), (b), (c) or (1), (2), (3) before steps in a method claim are not intended to and do not specify a particular order to the steps, but rather are used to simplify subsequent reference to such steps.

CLAIMS

What is claimed is:

1. A method for drilling a wellbore with an offshore, riserless drilling system, the method comprising:

pumping a drilling fluid from a drilling vessel down a first drillstring and into an annulus within a subterranean wellbore;

pumping the drilling fluid from the annulus of the wellbore to the drilling vessel with a subsea pump;

applying backpressure to the drilling fluid in the annulus of the wellbore with the subsea pump; and

preventing fluid flow from the annulus of the wellbore to the surrounding environment as the drilling fluid is pumped from the drilling vessel into the annulus of wellbore.

2. The method of claim 1, further comprising applying backpressure to the drilling fluid with the subsea pump at the seabed.

3. The method of claim 1 or claim 2, further comprising opening a recirculation valve of a recirculation conduit extending between a suction and a discharge of the subsea pump to apply hydrostatic pressure to the drilling fluid in the annulus of the wellbore.

4. The method of any one of the preceding claims, further comprising selectively applying hydrostatic pressure to the annulus from a column of fluid extending from the seabed.

5. The method of claim 4, further comprising:

removing the first drillstring from the wellbore; and

applying hydrostatic pressure to the annulus of wellbore from the column of fluid with the first drillstring removed from the wellbore.

6. The method of claim 4 or claim 5, further comprising selectively isolating the

hydrostatic pressure of the support fluid from the annulus.

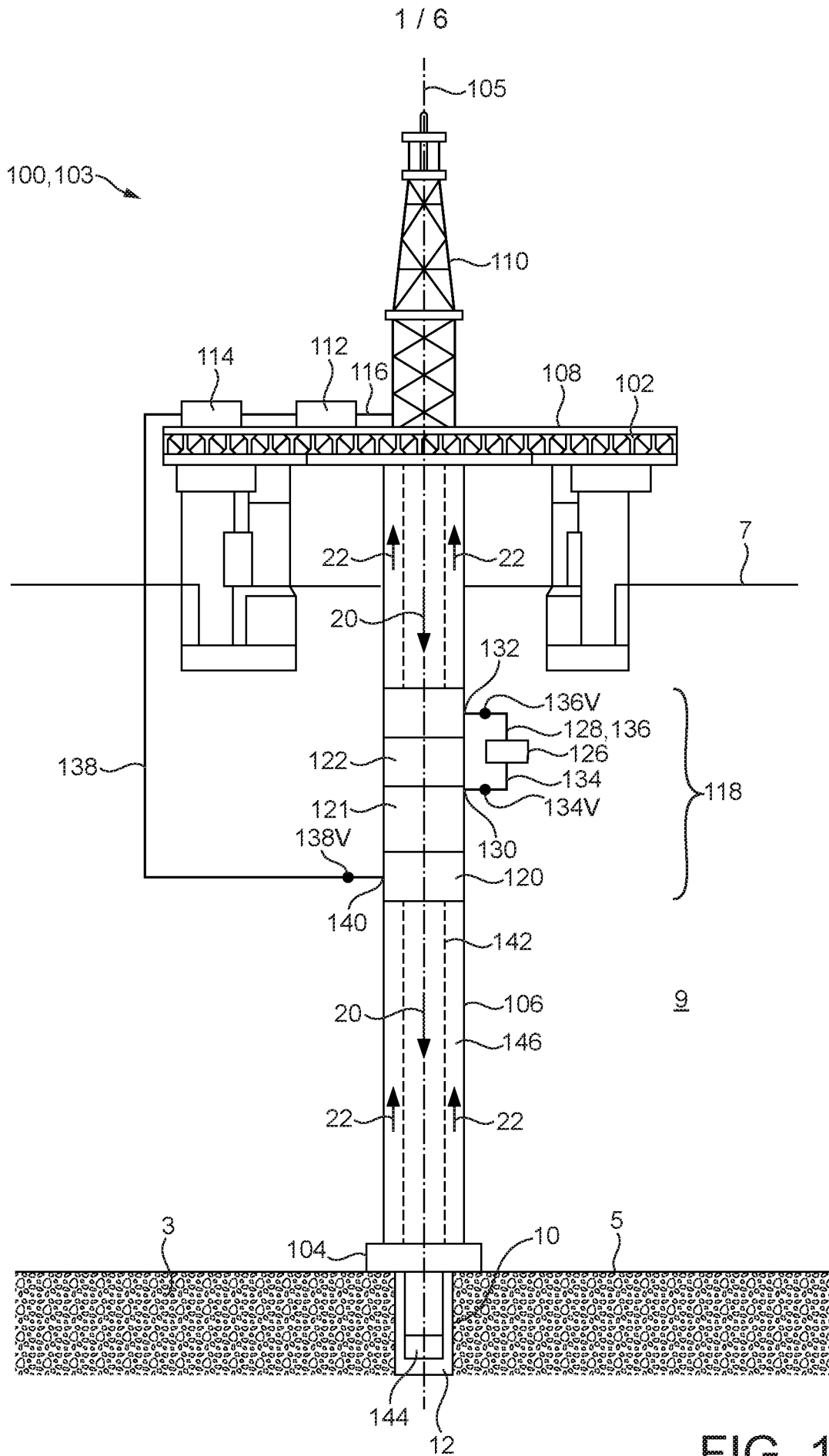
7. The method of claim 1, further comprising isolating the annulus of the wellbore from hydrostatic pressure of seawater in the ambient environment above the seabed.

8. The method of any one of the preceding claims, further comprising adjusting a pump rate of the subsea pump to control the amount of backpressure applied to the drilling fluid in the annulus of the wellbore.

9. The method of 1, further comprising:

removing the first drillstring from the wellbore and transporting the first drillstring to the drilling vessel; and

inserting a second drillstring into the wellbore as the first drillstring is being transported to the drilling vessel.



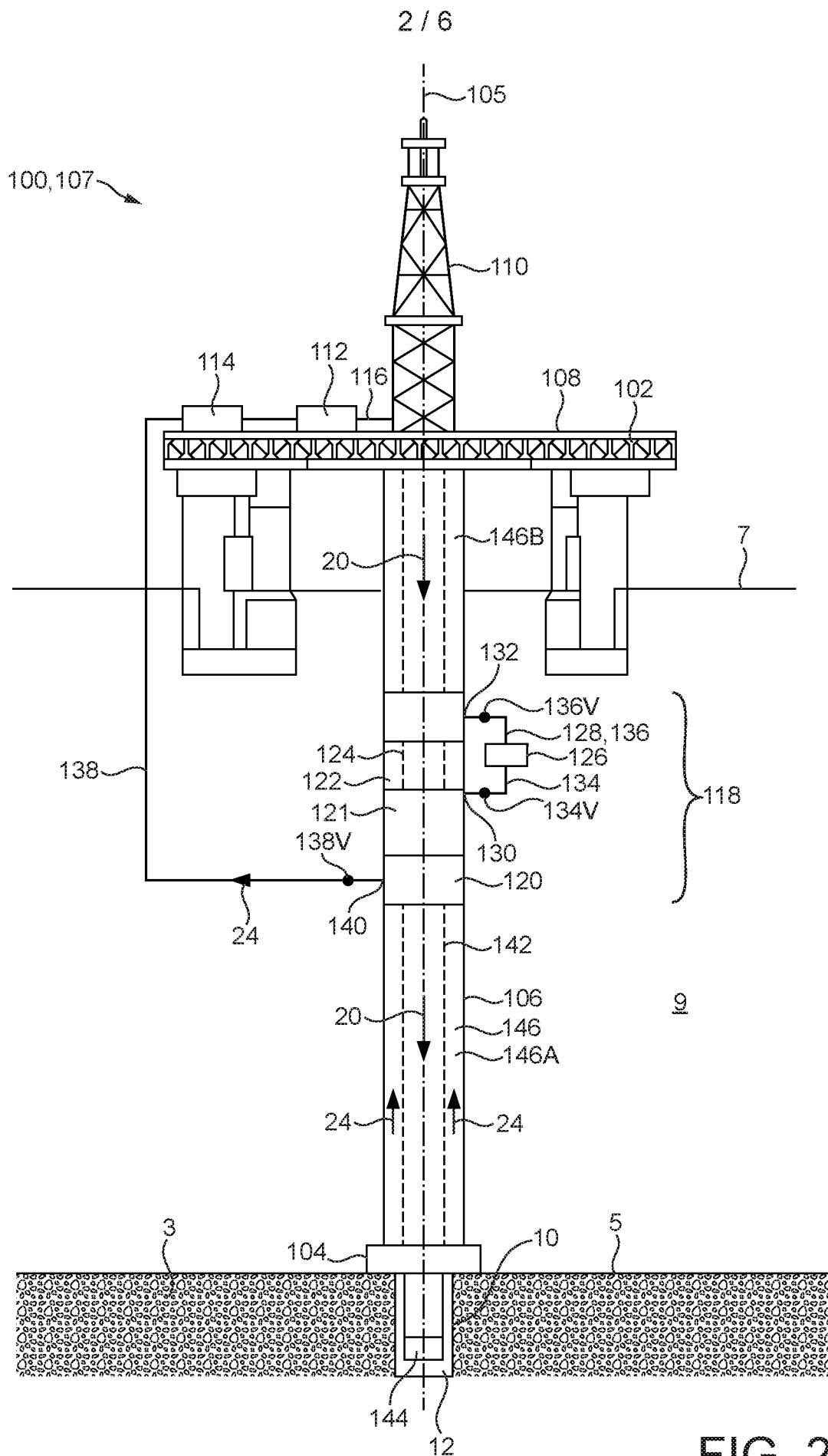


FIG. 2

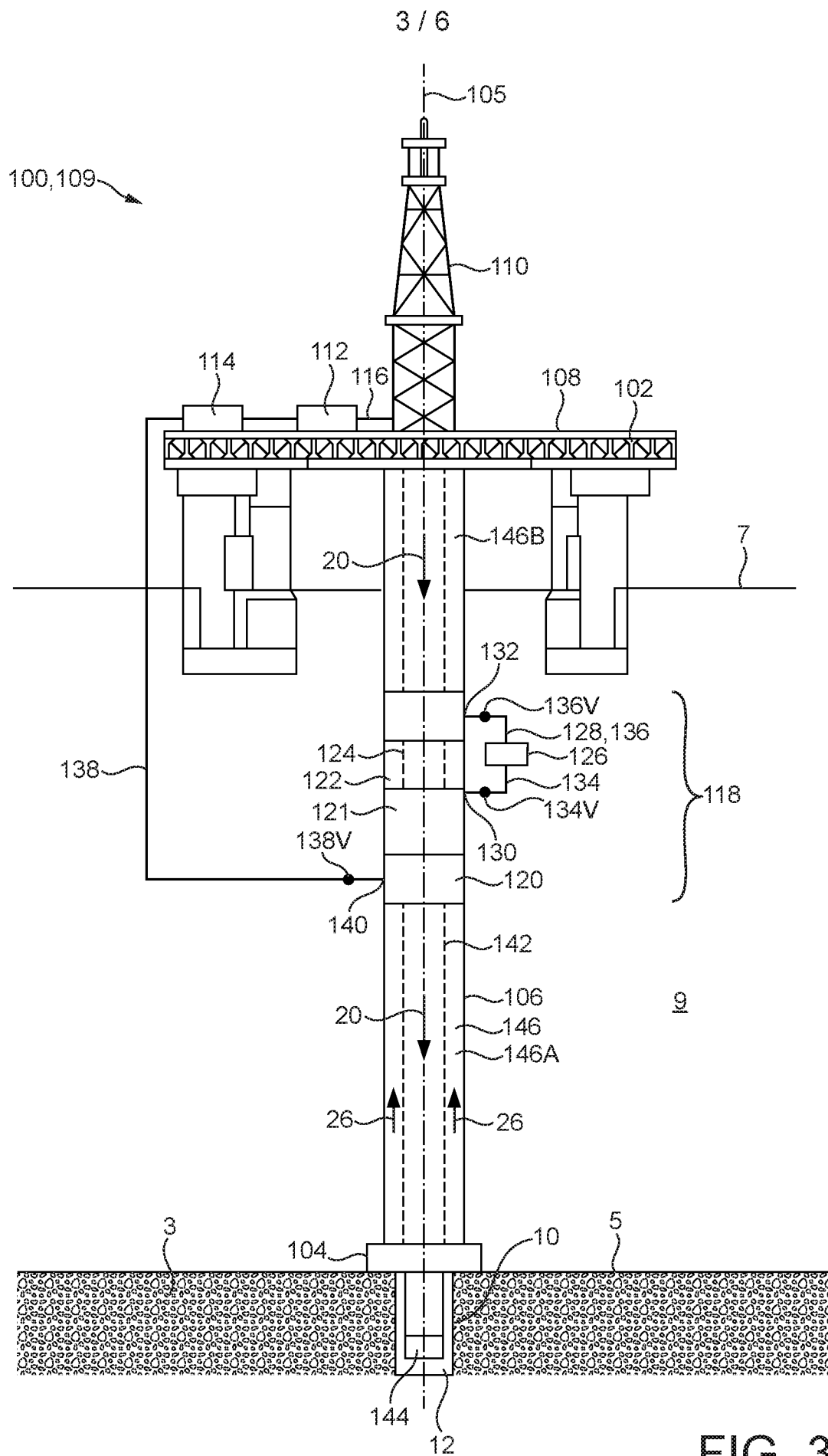


FIG. 3.

4 / 6

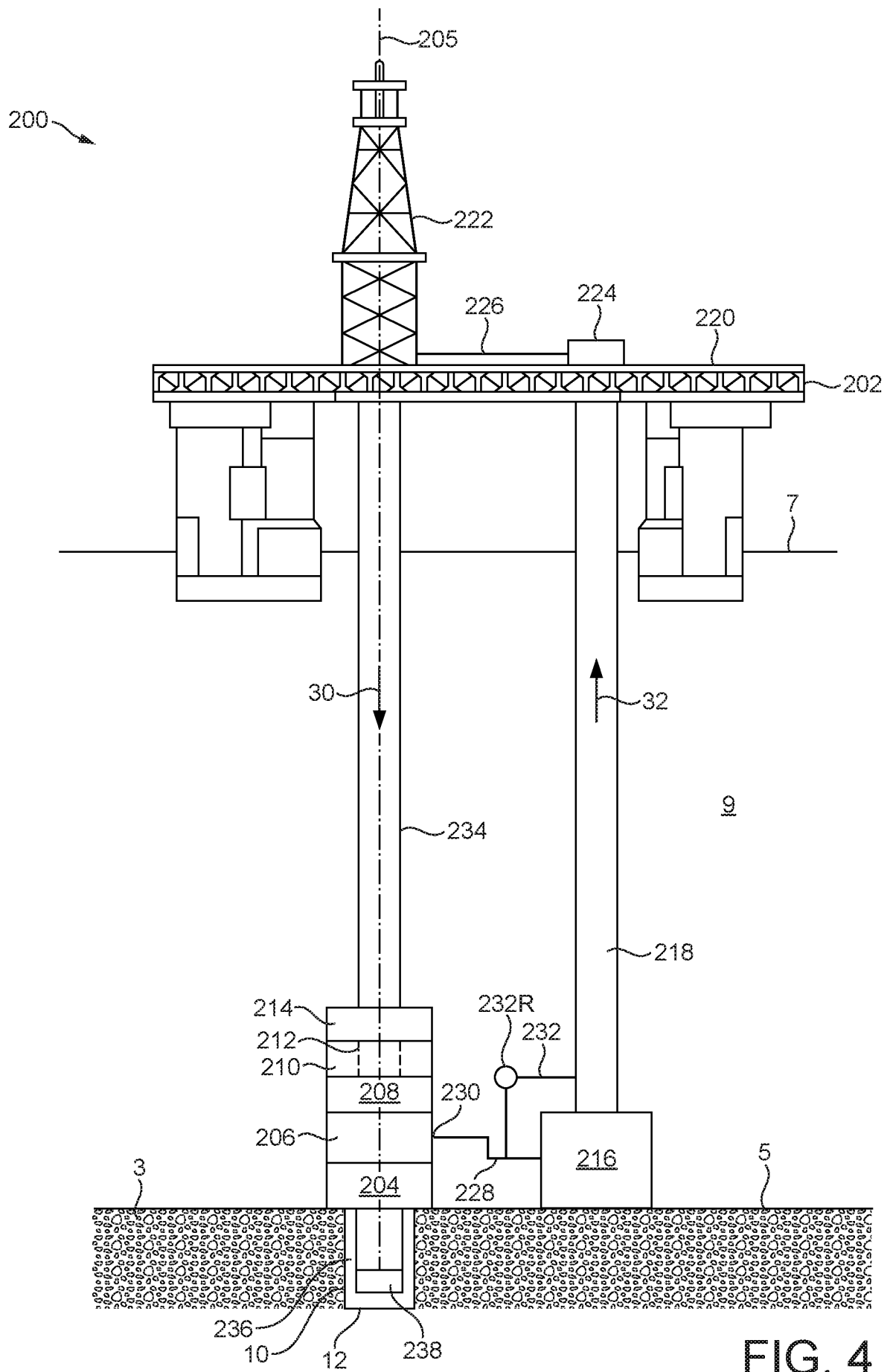


FIG. 4

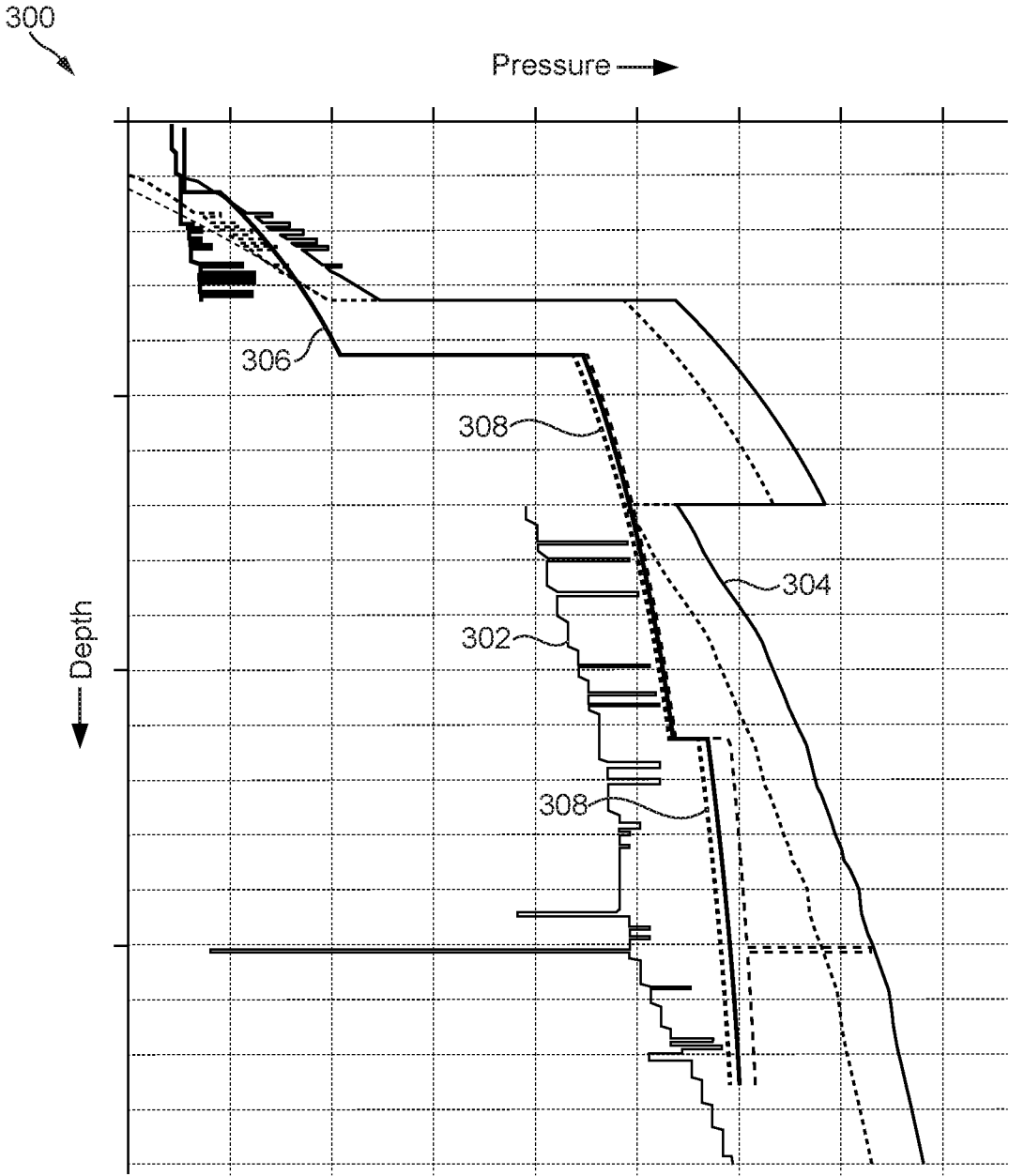
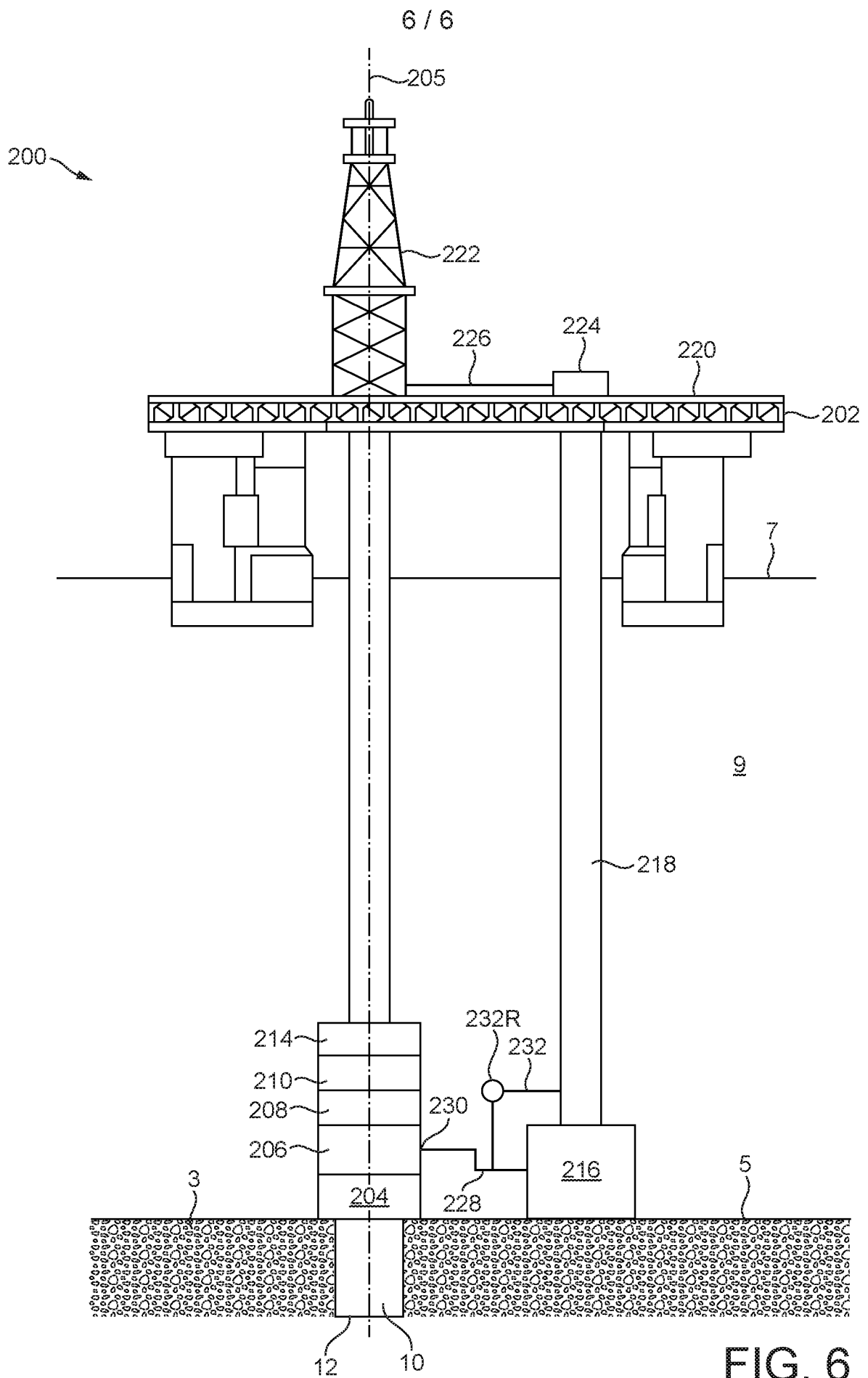


FIG. 5



INTERNATIONAL SEARCH REPORT

International application No
PCT/US2018/041784

A. CLASSIFICATION OF SUBJECT MATTER

INV. E21B7/12 E21B21/00 E21B21/08 E21B7/128
ADD.

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

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)

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2009/236144 A1 (TODD RICHARD J [US] ET AL) 24 September 2009 (2009-09-24) paragraphs [0037], [0040], [0069] - [0072]; figure 4	1-9
X	US 2015/275602 A1 (KJØSNES IVAR [NO] ET AL) 1 October 2015 (2015-10-01) paragraphs [0010], [0013], [0057], [0066] - [0070], [0078]; figure 1	1-9
X	US 2012/227978 A1 (FOSSLI BOERRE [NO] ET AL) 13 September 2012 (2012-09-13) paragraphs [0032], [0060] - [0069]; figures 4-6	1-9
	----- -/-	



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

20 September 2018

Date of mailing of the international search report

01/10/2018

Name and mailing address of the ISA/

European Patent Office, P.B. 5818 Patentlaan 2
NL - 2280 HV Rijswijk
Tel. (+31-70) 340-2040,
Fax: (+31-70) 340-3016

Authorized officer

Simunec, Duro

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2018/041784

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 2012/003101 A2 (AGR SUBSEA A S [NO]; COHEN JOHN H [US]; STAVE ROGER SVERRE [NO]) 5 January 2012 (2012-01-05) paragraphs [0002], [0003], [0005], [0011] - [0016]; figure 1 -----	1-9
A	US 2017/175466 A1 (DIRKSEN RON J [US] ET AL) 22 June 2017 (2017-06-22) the whole document -----	1-9

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No

PCT/US2018/041784

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2009236144	A1	24-09-2009	CA 2641596 A1 16-08-2007
			CA 2734546 A1 16-08-2007
			GB 2449010 A 05-11-2008
			GB 2476002 A 08-06-2011
			US 2009236144 A1 24-09-2009
			WO 2007092956 A2 16-08-2007
US 2015275602	A1	01-10-2015	AU 2012381500 A1 29-01-2015
			BR 112014029850 A2 27-06-2017
			CA 2875125 A1 05-12-2013
			GB 2502626 A 04-12-2013
			MX 353792 B 30-01-2018
			US 2015275602 A1 01-10-2015
			WO 2013178295 A1 05-12-2013
US 2012227978	A1	13-09-2012	BR 112012011127 A2 05-07-2016
			EP 2499328 A2 19-09-2012
			US 2012227978 A1 13-09-2012
			WO 2011058031 A2 19-05-2011
WO 2012003101	A2	05-01-2012	NONE
US 2017175466	A1	22-06-2017	AR 100077 A1 07-09-2016
			US 2017175466 A1 22-06-2017
			WO 2015160417 A1 22-10-2015