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SUBSEA CONNECTOR WITH A LATCHING ASSEMBLY

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims benefit of U.S. provisional patent application Serial No. 61/498,933 filed June 20, 2011, and entitled "Subsea Connector with a Latching Assembly," which is hereby incorporated herein by reference in its entirety.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable

BACKGROUND

Field of the Invention

[0003] This invention relates generally to systems and methods of subsea operations in the exploration and production of hydrocarbons. More specifically, the invention relates to systems and methods for forming a subsea connection over an existing subsea connection.

Background of the Invention

[0004] In offshore drilling operations, a blowout preventer (BOP) is installed on a wellhead at the sea floor and a lower marine riser package (LMRP) is mounted to the BOP. In addition, a drilling riser extends from a flex joint at the upper end of LMRP to a drilling vessel or rig at the sea surface. A drill string is then suspended from the rig through the drilling riser, LMRP, and the BOP into the well bore. A choke line and a kill line are also suspended from the rig and coupled to the BOP, usually as part of the drilling riser assembly.

[0005] During drilling operations, drilling fluid, or mud, is delivered through the drill string, and returned up an annulus between the drill string and casing that lines the well bore. In the event of a rapid influx of formation fluid into the annulus, commonly known as a "kick," the BOP and/or LMRP may actuate to seal the annulus and control the well. In particular, BOPs and LMRPs comprise closure members capable of sealing and closing the well in order to prevent the release of gas or liquids from the well. Thus, the BOP and LMRP are used as devices that close, isolate, and seal the wellbore. Heavier drilling mud may be delivered through the drill string, forcing fluid from the well annulus through the choke line to balance the pressures associated with the formation fluid. Assuming the structural integrity of the well has not been compromised, drilling operations may resume. However, if drilling operations

cannot be resumed, cement or heavier drilling mud is delivered into the well bore to kill the well.

[0006] In the event that the wellbore is not sealed, a blowout may occur. Such blowout may result in damage to connections between subsea well equipment. Damage to subsea connections may necessitate the need for a new connection mechanism to couple a subsea device such as a capping device to the damaged subsea connection. In cases where the subsea connection comprises mating flanges, circumstances may not allow for the separation of the existing connection. Accordingly, there is a need for systems and methods for forming subsea connections over an existing subsea connection.

BRIEF SUMMARY OF THE DISCLOSURE

[0007] These and other needs in the art are addressed in one embodiment by a subsea connection device for connecting to an existing subsea joint. In an embodiment, the device comprises a body having a central axis, a first end, a second end opposite the first end, and a throughbore extending axially from the first end to the second end. The first end comprises a connector configured to couple the body to a capping stack. In addition, the device comprises a seal element mounted in the throughbore at the second end of the body. Further, the device comprises a latching assembly disposed about the second end of the body. The latching assembly includes a base coupled to the body and a plurality of circumferentially spaced latching members pivotally coupled to the base.

[0008] These and other needs in the art are addressed in another embodiment by a method of forming a subsea connection with an existing subsea joint. In an embodiment, the method comprises (a) positioning a subsea connector adjacent an existing subsea connection. The subsea connector comprises a body having a central axis, a first end, a second end, and a throughbore extending axially between the first end and the second end. The first end comprises a connector. The subsea connector also comprises a latching assembly coupled to the body. The latching assembly comprises a plurality of circumferentially spaced latching members pivotally coupled to the body. In addition, the method comprises (b) rotating each of the latching members in a first direction to a first position. Further, the method comprises (c) receiving the existing subsea joint within the latching members. Still further, the method comprises (d) rotating each of the latching members in a second direction opposite the first direction to a second position. Moreover, the method comprises (e) engaging the existing joint with the latching members.

[0009] These and other needs in the art are addressed in another embodiment by a method for capping a subsea well. In an embodiment, the method comprises (a) coupling a subsea connector to an existing subsea joint. In addition, the method comprises (b) coupling a capping stack to the subsea connector. Further, the method comprises (c) using the capping stack to contain the subsea well.

[0010] Embodiments described herein comprise a combination of features and advantages intended to address various shortcomings associated with certain prior devices, systems, and methods. The foregoing has outlined rather broadly the features and technical advantages of the invention in order that the detailed description of the invention that follows may be better understood. The various characteristics described above, as well as other features, 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 by those skilled in the art 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 of the invention. It should also be realized by those skilled in the art that such equivalent constructions do not depart from the spirit and scope of the invention as set forth in the appended claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0011] For a detailed description of the preferred embodiments of the invention, reference will now be made to the accompanying drawings in which:

[0012] Figure 1 is a schematic view of an embodiment of an offshore drilling system;

[0013] Figure 2 is an enlarged view of the riser flex joint of the lower marine riser package of Figure 1;

[0014] Figure 3 is a schematic view of the offshore drilling system of Figure 1 damaged by a subsea blowout;

[0015] Figure 4 is a schematic view of the offshore drilling system of Figure 1 damaged by a subsea blowout;

[0016] Figure 5A is a schematic cross-sectional side view of an embodiment a subsea connector including a latching assembly in an open mode or position;

[0017] Figure 5B is a schematic cross-sectional side view of the subsea connector of Figure 5A with the latching assembly in a closed mode or position;

[0018] Figure 5C is a schematic cross-sectional side view of an embodiment of a capping stack mounted to the subsea connector of Figure 5A;

[0019] Figure 6A-6E are sequential schematic illustrations of the subsea connector of Figure 5A being deployed subsea and installed on the subsea flex joint of Figure 4;

[0020] Figure 6F is an enlarged view of Figure 6E;

[0021] Figure 7 is a schematic view of an embodiment of a capping stack deployed subsea and installed on the subsea connector of Figure 6F; and

[0022] Figures 8A-8C are sequential schematic views of a subsea capping stack including the subsea connector of Figure 5A being deployed subsea and installed on the subsea flex joint of Figure 4 to shut in the well.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0023] The following discussion is directed to various exemplary embodiments. However, one skilled 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.

[0024] Certain terms are used throughout the following description and claims to refer to particular features or components. As one skilled in the art will appreciate, different persons may refer to the same feature or component by different names. This document does not intend to distinguish between components or features that differ in name but not function. 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.

[0025] 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, or through an indirect connection via other devices, components, and connections. In addition, as used herein, the terms "axial" and "axially" generally mean along or parallel to a central axis (e.g., central axis of a body or a port), while the terms "radial" and "radially" generally mean perpendicular to the central axis. For instance, an axial distance refers to a distance measured along or parallel to the central axis, and a radial distance means a distance measured perpendicular to the central axis. Still further, as used herein, the term "ROV" refers to a remotely operate vehicle. Each ROV may include arms having a claw, a subsea camera for viewing the subsea operations (e.g., the relative positions of subsea tools or

devices such subsea connection device 500), and an umbilical extending to the surface. Streaming video and/or images from cameras are communicated to the surface or other remote location via umbilical for viewing on a live or periodic basis. Arms and claws may be controlled via commands sent from the surface or other remote location to ROV through umbilical. Power may also be provided via the umbilical.

[0026] Referring now to Figure 1, an embodiment of an offshore system 100 for drilling and/or producing a wellbore 101 is shown. In this embodiment, system 100 includes an offshore platform 110 at the sea surface 102, a subsea blowout preventer (BOP) 120 mounted to a wellhead 130 at the sea floor 103, and a lower marine riser package (LMRP) 140. Platform 110 is equipped with a derrick 111 that supports a hoist (not shown). A drilling riser 115 extends from platform 110 to LMRP 140. In general, riser 115 is a large-diameter pipe that connects LMRP 140 to the floating platform 110. During drilling operations, riser 115 takes mud returns to the platform 110. Casing 131 extends from wellhead 130 into subterranean wellbore 101.

[0027] Downhole operations are carried out by a tubular string 116 (e.g., drillstring, production tubing string, coiled tubing, etc.) that is supported by derrick 111 and extends from platform 110 through riser 115, LMRP 140, BOP 120, and into cased wellbore 101. A downhole tool 117 is connected to the lower end of tubular string 116. In general, downhole tool 117 may comprise any suitable downhole tool(s) for drilling, completing, evaluating and/or producing wellbore 101 including, without limitation, drill bits, packers, testing equipment, perforating guns, and the like. During downhole operations, string 116, and hence tool 117 coupled thereto, may move axially, radially, and/or rotationally relative to riser 115, LMRP 140, BOP 120, and casing 131.

[0028] BOP 120 and LMRP 140 are configured to controllably seal wellbore 101 and contain hydrocarbon fluids therein. Specifically, BOP 120 has a central or longitudinal axis 125 and includes a body 123 with an upper end 123a releasably secured to LMRP 140, a lower end 123b releasably secured to wellhead 130, and a main bore 124 extending axially between upper and lower ends 123a, b. Main bore 124 is coaxially aligned with wellbore 101, thereby allowing fluid communication between wellbore 101 and main bore 124. In this embodiment, BOP 120 is releasably coupled to LMRP 140 and wellhead 130 with hydraulically actuated, mechanical wellhead-type connectors 150. In general, connectors 150 may comprise any suitable releasable wellhead-type mechanical connector such as the H-4® profile subsea connector available from VetcoGray Inc. of Houston, Texas or the DWHC profile subsea connector available from Cameron International Corporation of Houston, Texas. Typically,

such wellhead-type mechanical connectors (e.g., connectors 150) comprise a male component or coupling, labeled with reference numeral 150a herein, that is inserted into and releasably engages a mating female component or coupling, labeled with reference numeral 150b herein. In addition, BOP 120 includes a plurality of axially stacked sets of opposed rams – one set of opposed blind shear rams or blades 127 for severing tubular string 116 and sealing off wellbore 101 from riser 115 and two sets of opposed pipe rams 128, 129 for engaging string 116 and sealing the annulus around tubular string 116. In other embodiments, the BOP (e.g., 120) may also include one or more sets of opposed blind rams for sealing off wellbore when no string (e.g., string 116) or tubular extends through the main bore of the BOP (e.g., main bore 124). Each set of rams 127, 128, 129 is equipped with sealing members that engage to prohibit flow through the annulus around string 116 and/or main bore 124 when rams 127, 128, 129 is closed.

[0029] Opposed rams 127, 128, 129 are disposed in cavities that intersect main bore 124 and support rams 127, 128, 129 as they move into and out of main bore 124. Each set of rams 127, 128, 129 is actuated and transitioned between an open position and a closed position. In the open positions, rams 127, 128, 129 are radially withdrawn from main bore 124 and do not interfere with tubular string 116 or other hardware that may extend through main bore 124. However, in the closed positions, rams 127, 128, 129 are radially advanced into main bore 124 to close off and seal main bore 124 (e.g., rams 127) or the annulus around tubular string 116 (e.g., rams 128, 129). Each set of rams 127, 128, 129 is actuated and transitioned between the open and closed positions by a pair of actuators 126. In particular, each actuator 126 hydraulically moves a piston within a cylinder to move a drive rod coupled to one ram 127, 128, 129.

[0030] Referring still to Figure 1, LMRP 140 has a body 141 with an upper end 141a connected to the lower end of riser 115, a lower end 141b releasably secured to upper end 123a with connector 150, and a throughbore 142 extending between upper and lower ends 141a, b. Throughbore 142 is coaxially aligned with main bore 124 of BOP 110, thereby allowing fluid communication between throughbore 142 and main bore 124. LMRP 140 also includes an annular blowout preventer 142a comprising an annular elastomeric sealing element that is mechanically squeezed radially inward to seal on a tubular extending through bore 142 (e.g., string 116, casing, drillpipe, drill collar, etc.) or seal off bore 142. Thus, annular BOP 142a has the ability to seal on a variety of pipe sizes and seal off bore 142 when no tubular is extending therethrough.

[0031] Referring now to Figures 1 and 2, in this embodiment, upper end 141a of LMRP 140 comprises a riser flex joint 143 that allows riser 115 to deflect angularly relative to BOP 120 and LMRP 140 while hydrocarbon fluids flow from wellbore 101, BOP 120 and LMRP 140 into riser 115. In this embodiment, flex joint 143 includes a cylindrical base 144 rigidly secured to the remainder of LMRP 140 and a riser extension or adapter 145 extending upward from base 144. A fluid flow passage 146 extending through base 144 and adapter 145 defines the upper portion of throughbore 142. A flex element (not shown) disposed within base 144 extends between base 144 and riser adapter 145, and sealingly engages both base 144 and riser adapter 145. The flex element allows riser adapter 145 to pivot and angularly deflect relative to base 144, LMRP 140, and BOP 120. The upper end of adapter 145 distal base 144 comprises an annular flange 145a for coupling riser adapter 145 to a mating lower riser flange 118 at the lower end of riser 115 to form a flex joint flange connection 147. As best shown in Figure 2, upper flex joint flange 145a includes a plurality of circumferentially-spaced holes 145b that receive bolts for securing upper flex joint flange 145a to a mating annular flange 118 at the lower end of riser 115. In this embodiment, flex joint 143 also includes a mud boost line 149 having an inlet (not shown) in fluid communication with flow passages 142, 146, an outlet 149b in flange 145a, and a valve 149c configured to control the flow of fluids through line 149. Although LMRP 140 has been shown and described as including a particular flex joint 143, in general, any suitable riser flex joint may be employed in LMRP 140.

[0032] Referring now to Figure 3, during a "kick" or surge of formation fluid pressure in wellbore 101, one or more rams 127, 128, 129 of BOP 120 and/or LMRP 140 are normally actuated to seal in wellbore 101. In the event wellbore 101 is not sealed, it may potentially result in the discharge of such hydrocarbon fluids subsea. In Figure 3, system 100 is shown after a subsea blowout. In the exemplary blowout scenario shown in Figure 3, BOP 120 and LMRP 140 coupled thereto have been tilted or bent from vertical by a tilt angle α , and riser 115 has collapsed and bent over proximal flex joint 143. As a result, hydrocarbon fluids flowing upward in wellbore 101 pass through BOP 120 and LMRP 140, and are discharged into the surrounding sea water proximal the sea floor 103 through punctures and breaks in riser 115. The emitted hydrocarbons fluids form a subsea hydrocarbon plume 160 that extends to the sea surface 102.

[0033] Referring to Figure 4, a substantial portion of riser 115 has been severed and removed, leaving a lower portion 115a that remains coupled to flex joint 143. Lower portion 115a has an unconventional profile and outer surface. For example, in this embodiment, lower portion 115a has an annular generally tapered or frustoconical outer surface 115b extending upward from

flange 118. If flanges 118, 145a cannot be separated, or if for some reason it is undesirable to decouple flanges 118, 145a, the geometry of lower portion 115a may complicate the connection of a device to joint 147 to contain and/or capture hydrocarbons emitted therefrom. As used herein, the terms “capping stack,” “capping device,” “containment device,” and “sealing cap” are used to refer to apparatus and systems that are deployed subsea, coupled to a subsea structure discharging hydrocarbons, and used to produce, contain, and/or shut in the subsea structure. Examples of capping stacks are described in U.S. Provisional Application Serial No. 61/475,032, filed April 13, 2011, incorporated herein by reference in its entirety for all purposes.

[0034] Referring now to Figures 5A-5C, an embodiment of a subsea connection device 500 for coupling an existing subsea joint (e.g., joint 147) to a capping stack is shown. As will be described in more detail below, connection device 500 latches onto and sealingly engages the existing subsea connection and provides a conventional upward-facing connector configured to engage a mating downward-facing connector on the capping stack. In other words, device 500 transitions between the subsea joint, which may be damaged, to a connector disposed at the lower end of the capping stack, thereby enabling the capping stack to be coupled to the existing subsea joint. Accordingly, device 500 may also be referred to as an “adapter” since it provides a transition between the existing subsea joint and the conventional connector on the capping stack. Although embodiments of connection device 500 are described with respect to subsea flange joint 147, device 500 may be used with other types of subsea connections and joints known in the art.

[0035] In this embodiment, connection device 500 comprises a tubular body 501, an annular seal element 510 disposed within body 501, and a latching assembly 520 disposed about body 501. Body 501 is a rigid tubular having a central axis 505, a first or upper end 501a, a second or lower end 501b, and a throughbore 502 extending axially between ends 501a, b. Throughbore 502 allows fluids (e.g., hydrocarbon fluids) to flow through device 500. Upper end 501a comprises a connector 503 for coupling device 500 to a capping stack. In this embodiment, connector 503 is an annular flange configured to mate and engage a flange provided on the capping stack. In particular, connector 503 includes a plurality of circumferentially spaced holes 504, which are aligned with corresponding holes in the mating flange on the capping stack. With holes 504 aligned with holes in the capping stack flange, bolts are passed through each pair of aligned holes, and nuts are threaded onto the bolts and torqued down to form the flanged connection securing the capping stack to connection device 500. Although connector 503 is a connection flange in this embodiment, in general, connector

503 may comprise any suitable type of subsea connector known in the art such as a male hub configured to mate and engage with a subsea collet connector.

[0036] Referring still to Figure 5A, seal element 510 is mounted to body 501 within throughbore 502 at lower end 501a. More specifically, body 501 has a radially inner surface 506 extending between ends 501a, b and defining throughbore 502. Inner surface 506 includes a first or upper cylindrical portion 506a extending axially from upper end 501a and a second or lower cylindrical portion 506b extending axially from lower end 501b to section 506a. First portion 506a is disposed at a radius that is less than second portion 506b. As a result, portions 506a, b intersect at an annular planar shoulder 507. Thus, lower portion 506b defines an annular recess 508 within throughbore 502 extending axially from lower end 501b to shoulder 507. Seal element 510 is disposed within recess 508 and seated against shoulder 507.

[0037] Seal element 510 has a central axis coincident with axis 505, a first or upper end 510a, a second or lower end 501b, a radially inner surface 511 extending axially between ends 510a, b, and a radially outer surface 512 extending axially between ends 510a, b. Outer surface 512 is cylindrical and sized to sealingly engage lower portion 506b of inner surface 506. Inner surface 511 is sized and shaped to mate with and sealingly engage flange connection 147. In this embodiment, inner surface 511 is contoured to mate with and sealingly engage the outer surface of lower riser portion 115a - since the outer surface of lower riser portion 115a is generally frustoconical, inner surface 511 is generally frustoconical to mate with lower riser portion 115a. In general, seal element 510 may be made of any suitable material(s) including, without limitation, a metal and metal alloy (e.g., steel, aluminum, etc.), non-metal (e.g., polymer, rubber, etc.), composite, or combinations thereof. However seal element 510 is preferably made of a metal or metal alloy suitable for the subsea environment and with sufficient strength to withstand the anticipated pressure differentials.

[0038] Referring still to Figure 5A, latching assembly 520 is mounted to body 501 at lower end 501b. As will be described in more detail below, latching assembly 520 is used to releasably connect device 500 to an existing subsea joint such as flange joint 147 previously described. In this embodiment, latching assembly 520 includes an annular base 521 disposed about body 501 and secured to lower end 501b and a plurality of circumferentially spaced latch members 526 pivotally coupled to base 521. Base 521 is a rigid plate including a plurality of circumferentially spaced apertures 522, each aperture 522 extending axially through base 521. One latch member 526 extends through each aperture 522. Latching assembly 520 preferably includes at least four uniformly circumferentially spaced apertures 522, each housing one latch member 526. In this embodiment, each latch member 526 is rotatably coupled to base 521 with

an actuator 523 disposed in the corresponding aperture 522. Each actuator 523 is configured to rotate the corresponding latch member 526 about a rotational axis 524. Axes 524 are radially spaced from axis 505 and lie in a plane oriented perpendicular to axis 505. As will be described in more detail below, actuators 523 move latch members 526 between opened positions radially spaced apart from flange joint 147 (or other existing subsea joint) and closed positions engaging flange joint 147 (or other existing subsea joint). In general, actuators 523 may comprise any rotational actuator known in the art including, without limitation, hinge type actuators or rotary style actuators with ROV buckets on the ends.

[0039] Although the rotation of latch members 526 is powered by actuators 523 in this embodiment, in other embodiments, the rotation of latch members (e.g., latch members 526) may not be powered. For example, in such embodiments, the latch members can be rotationally coupled to the base (e.g., base 521) and manually rotated about axes of rotation (e.g., axes 524) under their own weight or with a subsea ROV.

[0040] In this embodiment, each latch member 526 comprises an elongate arm 527, a clamp element or foot 528 attached to arm 527, and a fastener 529 moveably coupled to arm 527. Each arm 527 is an elongate rigid rod or shaft having a central or longitudinal axis 527c, a first or upper end 527a, and a second or lower end 527b opposite end 527a. In addition, each arm 527 extends generally vertically through a corresponding aperture 522 and is secured by the corresponding actuator 523. In this embodiment, each axis 527c, 524 are oriented such that rotation of the corresponding latch member 526 causes axis 527c to swing in a plane that contains axis 505. In other words, each axis 527c moves in a plane that is parallel to and intersects axis 505.

[0041] One clamp foot 528 is fixably attached to lower end 527b of each arm 527, and one fastener 529 is movably coupled to upper end 527a of each arm 527. Each clamp foot 528 is oriented perpendicular to its corresponding arm 527 and extends generally radially inward (relative to axis 505) from its corresponding arm 527. As will be described in more detail below, feet 528 function to engage the underside of flange joint 147 and prevent subsea connection device 500 from being pulled or moved upward and out of engagement with flex joint connection 147.

[0042] Fasteners 529 are coupled to upper ends 527a of arms 527 extending upward from base 521. In this embodiment, each fastener 529 is an internally threaded member threaded onto external threads provided on upper end 527a. To provide sufficient clearance for fasteners 529 as latch members 526 pivot relative to base 521, apertures 522 are tapered. Namely, the width or inner diameter of each aperture 522 generally decreases moving axially downward through

base 521. As will be described in more detail below, fasteners 529 are employed to compress or squeeze flange joint 147 between base 521 and feet 528, thereby securing connection device 500 to flex joint connection 147. As shown in Figure 5A, each fastener 529 is an internally threaded nut, however, in general, fasteners 529 may comprise any device or mechanism known in the art that can be controllably moved, positioned, and locked on arms 527.

[0043] Referring now to Figures 5A and 5B, latching members 526 are pivoted relative to body 511 and base 521 to transition connection device 500 between an open or unlatched position and a closed or latched position. Accordingly, latching members 526 and latching assembly 520 may likewise be described as having open and closed positions. In particular, Figure 5A illustrates connection device 500 in the open position, and Figure 5B illustrates connection device 500 in the closed position. In the open position, latch members 526 are rotated to radially withdraw lower ends 527b and feet 528 relative to axis 505, and in the closed position, latch members 526. Thus, connection device 500 is transitioned between the open and closed positions by rotating latch members 526 – to transition device 500 to the open position, feet 528 are moved radially outward by rotating arms 527 in a first direction 530, and to transition device 500 to the closed position, feet 528 are moved radially inward by rotating arms 527 in a second direction 531.

[0044] Latch members 526 are sized and positioned such that (a) feet 528 are radially spaced away from and do not interfere with flange joint 147 with connection device 500 in the open position, thereby allowing connection device 500 to be mounted to flange joint 147; and (b) feet 528 are positioned to engage flange joint 147 from below, thereby allowing connection device 500 to be secured to flange joint 147. In this embodiment, axes 527c are oriented parallel to axis 505 (and perpendicular to base 521) in the closed position, and axes 527c are oriented at an acute angle β relative to axis 505 in the open position.

[0045] As shown in phantom in Figures 5A and 5B, connection device 500 optionally includes an ROV interface panel 540 coupled to body 501. ROV interface panel 540 may include any ROV interface(s) known in the art such as handles, hot stabs, and the like. In the embodiment shown in Figures 5A and 5B, ROV interface panel 540 includes paddles that operate valves to hydraulically control actuators 523.

[0046] As previously described, subsea connection device 500 couples an existing subsea joint (e.g., joint 147) to a capping stack. In particular, connector 503 at upper end 501a attaches device 500 to the capping stack. For example, as shown in Figure 5C, a sealing cap 550 is shown coupled to connection device 500. In particular, connector 503 is coupled to a mating flange 551 provided on the lower end of cap 550. In general, sealing cap 550 may comprise

any capping stack known in the art for producing, containing, and/or shutting in a subsea structure discharging hydrocarbons. As previously described, examples of capping stacks are described in U.S. Provisional Application Serial No. 61/475,032, filed April 13, 2011, incorporated herein by reference in its entirety for all purposes. In this embodiment, sealing cap 550 is a valve manifold including a body 552 with flange 551, an inlet flow passage 553 extending through body 552, a plurality of outlet flow passages 554 extending through body 552 and in fluid communication with inlet passage 553, and a plurality of valves 555 for controlling fluid flow through passages 553, 554. Although sealing cap 550 is a separate and distinct capping stack that is coupled to connection device 500 via mating flanges 503, 551 in this embodiment, in other embodiments, the capping stack (e.g., sealing cap 550) may be integral with the connection device (e.g., device 500) or coupled to the connection device with other types of subsea connections known in the art.

[0047] Referring now to Figures 6A-6F, connection device 500 is shown being deployed and installed subsea on flange joint 147 previously described. More specifically, in Figure 6A, connection device 500 is shown being lowered subsea; in Figure 6B, connection device 500 is shown being moved laterally over flange joint 147; in Figure 6C, connection device 500 is shown being generally coaxially aligned with flange joint 147 and lowered onto flange joint 147 in the open position; in Figure 6D, connection device 500 is shown being transitioned to the closed position to engage flange joint 147 with feet 528; and in Figure 6E, connection device 500 is shown being locked onto flange joint 147 by employing fasteners 529 to compress flange joint 147 between base 521 and feet 528. In Figure 6F, connection device 500 is shown locked onto flange joint 147 with sealing engagement between seal element 510 and lower portion 115a of riser 115. Following installation of connection device 500 on flange joint 147, a capping stack 700 is deployed and mounted to connection device 500 as shown in Figure 7 to cap and contain wellbore 101.

[0048] For subsea deployment and installation of connection device 500, one or more remote operated vehicles (ROVs) are preferably employed to aid in positioning device 500, monitoring device 500, BOP 120, and LMRP 140, and transitioning device 500 between the open and closed positions. Each ROV 170 includes an arm 171 having a claw 172 at its distal end, a subsea camera 173 for viewing the subsea operations (e.g., the relative positions of device 500, plume 160, the positions and movement of arms 170, etc.), and an umbilical 174. Streaming video and/or images from cameras 173 are communicated to the surface or other remote location via umbilical 174 for viewing on a live or periodic basis. Arms 171

and associated claws are controlled via commands sent from the surface or other remote location to ROV 170 through umbilical 174.

[0049] Referring to Figure 6A, in this embodiment, subsea connection device 500 is shown being controllably lowered subsea with a plurality of wirelines or cables 180 secured to subsea connection device 500 and extending to a surface vessel (not shown). Due to the weight of subsea connection device 500, cables 180 are preferably relatively strong cables (e.g., steel cables) capable of withstanding the anticipated tensile loads. A winch or crane mounted to a surface vessel may be employed to support and lower subsea connection device 500 on cables 180. Although cables 180 are employed to subsea connection device 500 in this embodiment, in other embodiments, subsea connection device 500 may be deployed subsea on a pipe or drill string.

[0050] Using cables 180, connection device 500 is lowered subsea under its own weight from a location generally above and laterally offset from wellbore 101, BOP 120, and LMRP 140. More specifically, during deployment, connection device 500 is preferably maintained outside of plume 160 of hydrocarbon fluids emitted from wellbore 101. Lowering device 500 subsea in plume 160 may trigger the undesirable formation of hydrates within device 500, particularly at elevations substantially above sea floor 103 where the temperature of hydrocarbons in plume 160 is relatively low.

[0051] Moving now to Figure 6B, device 500 is lowered laterally offset from BOP 120 and outside of plume 160 until latching assembly 520 is slightly above lower riser portion 115a and flange joint 147. As device 500 descends and approaches flange joint 147, ROV 170 monitors the position of device 500 relative to flange joint 147. Next, as shown in Figure 6C, device 500 is moved laterally into position immediately above lower riser portion 115a and flange joint 147 with body 501 substantially coaxially aligned therewith. Due to its own weight, device 500 is substantially vertical, whereas lower riser portion 115a may be oriented at an angle relative to vertical. Thus, it is to be understood that perfect coaxial alignment of body 501 and flange joint 147 may be difficult. As shown in Figure 6C, with device 500 positioned immediately above and generally coaxially aligned with lower riser portion 115a and flange joint 147, cables 180 lower device axially downward. During deployment, connection device 500 is in the open position with feet 528 radially withdrawn (i.e., angled outward), thereby allowing lower riser portion 115a and flange joint 147 to pass within feet 528 as device 500 is lowered. Lower riser portion 115a passes into body 501 at lower end 501a until seal element 510 axially abuts and engages flange 118.

[0052] Moving now to Figure 6D, with lower riser portion 115a seated in body 501 and flange joint 147 radially disposed inside feet 528, ROV 170 transitions device 500 to the closed position, thereby moving feet 528 radially inward and immediately below flange joint 147. Next, as shown in Figure 6E, ROV 170 rotates each fastener 529 to threadingly advance it along its corresponding arm 527 to pull feet 528 upward and into engagement with the underside of flange joint 147. As fasteners 529 are tightened, flange joint 147 is squeezed between base 521 and feet 528, and seal element 510 is urged into sealing engagement with flange 118, thereby securing connection device 500 to flange 147. In this embodiment, ROV 170 employs a fastening tool 176 to engage and rotate each fastener 529.

[0053] Referring now to Figure 6F, subsea connection device 500 is shown installed and locked onto flex joint 147. The combination of fasteners 529 and feet 528 of latch members 526 securely couple subsea connection device 500 to flex joint connection 147, and form a fluid tight seal between seal element 510 and lower riser portion 115a. Once subsea connection device 500 has been secured in place, connector 503 can then now serve as a universal connection point for a capping stack. For example, in Figure 7, a capping stack 700 comprising a subsea BOP is shown deployed subsea and connected to device 500 with connector 503.

[0054] Capping stack 700 is preferably deployed subsea in the same manner as connection device 500 previously described. Namely, capping stack 700 is lowered subsea (with cables or pipestring) to connection device 500 laterally offset from BOP 120 and outside of plume 160. Once in position laterally adjacent and slightly above device 500, capping stack 700 is moved laterally over device 500, substantially coaxially aligned with device 500, and lowered on to connector 503. Next, capping stack 700 is secured to connector 503 to form a fluid tight connection with connection device 500. Capping stack 700 contains actuatable ram BOPs known in the art that are maintained open during deployment and installation, but which may be gradually closed following installation to shut in wellbore 101.

[0055] In the embodiment of the deployment and installation method shown in Figures 6A-6F and 7, connection device 500 is deployed subsea and installed on flange joint 147, and then capping stack 700 is deployed subsea and installed on connection device 500. However, in other embodiments, connection device 500 may be coupled to the capping stack (e.g., capping stack 550, 700) at the surface, deployed subsea together, and installed onto flange joint 147 as a single unit. For example, referring now to Figures 8A-8C, subsea connection device 500 is coupled to sealing cap 550 as shown in Figure 5C to form a capping assembly 800 at the surface. Assembly 800 is then deployed subsea in the same manner as connection device 500 previously described. Namely, assembly 800 is lowered subsea (with cables or pipestring) to

flange joint 147 laterally offset from BOP 120 and outside of plume 160. Once in position laterally adjacent and slightly above flange joint 147, capping assembly 800 is moved laterally over lower riser portion 115, substantially coaxially aligned with lower riser portion 115, and lowered on to flange joint 147. Next, capping assembly 800 is secured to flange joint by transitioning connection device 500 from the open to closed position. During deployment and installation of assembly 800, connection device 500 and valves 555 are maintained in the open positions. Thus, once installed, hydrocarbons flow through assembly 800 and valves 555 as shown in Figure 8B. However, with the assistance of ROV 170, each valve 555 is closed until all flow of hydrocarbons has ceased as shown in Figure 8C. Alternatively, conduits or flowlines may be coupled to one or more outlet passages 554 to route the collected hydrocarbons to the surface or subsea collection facility.

[0056] Although embodiments of subsea connection device 500 have been discussed with respect to a flange joint 147 between riser 115 and flex joint 143, embodiments of connection devices described herein (e.g., connection device 500) may be used in connection with other types of existing subsea joints or in connection with flange 145a following removal of riser 118. In such an embodiment, seal element 510 is preferably sized and shaped to mate with and sealingly engage flange 145a as opposed to lower riser portion 115a. For example, instead of an angled or tapered profile, seal element 510 may have a notched, stepped or completely flat profile. Further, embodiments described herein may also be used for other purposes other than capping or producing a subsea wellbore. In an exemplary embodiment, subsea connection device 500 may be used to provide a subsea connection in cases where the upper and lower portions of a flange connection are unable to be separated. The installation of subsea connection device 500 would be similar as described above with out the complications of having to deal with the discharge of hydrocarbons.

[0057] 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 invention. 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 subsea connection device for connecting to an existing subsea joint, the device comprising:
 - a body having a central axis, a first end, a second end opposite the first end, and a throughbore extending axially from the first end to the second end, wherein the first end comprises a connector configured to couple the body to a capping stack;
 - a seal element mounted in the throughbore at the second end of the body;
 - a latching assembly disposed about the second end of the body, wherein the latching assembly includes a base coupled to the body and a plurality of circumferentially spaced latching members pivotally coupled to the base.
2. The connection device of claim 1, wherein each latching member comprises an arm, a fastener, and a clamp element;
 - wherein each arm has a longitudinal axis, a first end coupled to the fastener, and a second end coupled to the clamp element;
 - wherein each clamp element is configured to engage the existing subsea joint.
3. The connection device of claim 2, wherein each latching member is configured to rotate about an axis of rotation radially spaced apart from the central axis of the body, wherein the axes of rotation lie in a plane oriented perpendicular to the central axis of the body.
4. The connection device of claim 3, wherein each longitudinal axis is configured to pivot in a plane containing the central axis.
5. The connection device of claim 2, wherein the latching assembly has an open position with the clamp elements radially withdrawn relative to the central axis and a closed position with the clamp elements radially advanced towards the central axis.
6. The subsea connection device of claim 1, wherein the seal element has a radially inner surface configured to mate and engage with the outer surface of the existing subsea joint.

7. The subsea connection device of claim 6, wherein the seal is configured to sealingly engage the frustoconical surface of a flange.
8. The subsea connection device of claim 3, wherein each latch member is coupled to the base with an actuator configured to rotate the latch member about the axis of rotation.
9. The subsea connection device of claim 5, wherein each longitudinal axis is oriented at an acute angle relative to the central axis with the latching assembly in the open position.
10. The subsea connection device of claim 5, wherein the clamp elements are configured to receive the existing subsea joint with the latching assembly in the open position and configured to engage the existing subsea joint with the latching assembly in the closed position.
11. The subsea connection device of claim 2, wherein each fastener is a nut threaded onto the first end of the corresponding arm.
12. The subsea connection device of claim 1, further comprising a capping stack attached to the connector at the first end of the body.
13. The subsea connection device of claim 1, wherein the connector comprises an annular flange.
14. A method of forming a subsea connection with an existing subsea joint, the method comprising:
 - (a) positioning a subsea connector adjacent an existing subsea connection, the subsea connector comprising:
 - a body having a central axis, a first end, a second end, and a throughbore extending axially between the first end and the second end, wherein the first end comprises a connector;
 - a latching assembly coupled to the body, wherein the latching assembly comprises a plurality of circumferentially spaced latching members pivotally coupled to the body;
 - (b) rotating each of the latching members in a first direction to a first position;
 - (c) receiving the existing subsea joint within the latching members;

(d) rotating each of the latching members in a second direction opposite the first direction to a second position; and

(e) engaging the existing joint with the latching members.

15. The method of claim 14, wherein the subsea connector comprises a sealing element; and

wherein (e) comprises sealingly engaging the existing subsea joint with the seal element.

16. The method of claim 14, wherein each latching member comprises a fastener.

17. The method of claim 16, further comprising moving the fasteners to secure the subsea connector to the existing subsea joint.

18. The method of claim 17, wherein the latching assembly further comprises a base, and wherein the latching members are pivotally coupled to the base.

19. The method of claim 18, further comprising squeezing the existing subsea joint between the base and a foot disposed at an end of each latching member.

20. The method of claim 14, wherein the existing subsea connection is a flange joint.

21. A method for capping a subsea well comprising:

(a) coupling a subsea connector to an existing subsea joint;

(b) coupling a capping stack to the subsea connector; and

(c) using the capping stack to contain the subsea well.

22. The method of claim 21, wherein the subsea connector comprises:

a body having a central axis, a first end, a second end opposite the first end, and a throughbore extending axially from the first end to the second end, wherein the first end comprises a connector configured to couple the body to a capping stack;

a seal element mounted in the throughbore at the second end of the body;

a latching assembly disposed about the second end of the body, wherein the latching assembly includes a base coupled to the body and a plurality of circumferentially spaced latching members pivotally coupled to the base.

23. The method of claim 22, wherein (a) comprises:

(a1) lowering the subsea connector into engagement with the existing subsea connection;

(a2) rotating the latching members; and

(a3) engaging the existing subsea joint with the latching members after (a2).

24. The method of claim 22, wherein each latching member has a lower end comprising a foot; and

wherein (a) comprises rotating each latching member to move each foot radially inward below the existing subsea joint.

25. The method of claim 22, wherein (b) occurs after (a).

26. The method of claim 21, wherein the capping stack comprises a BOP or a valve manifold.

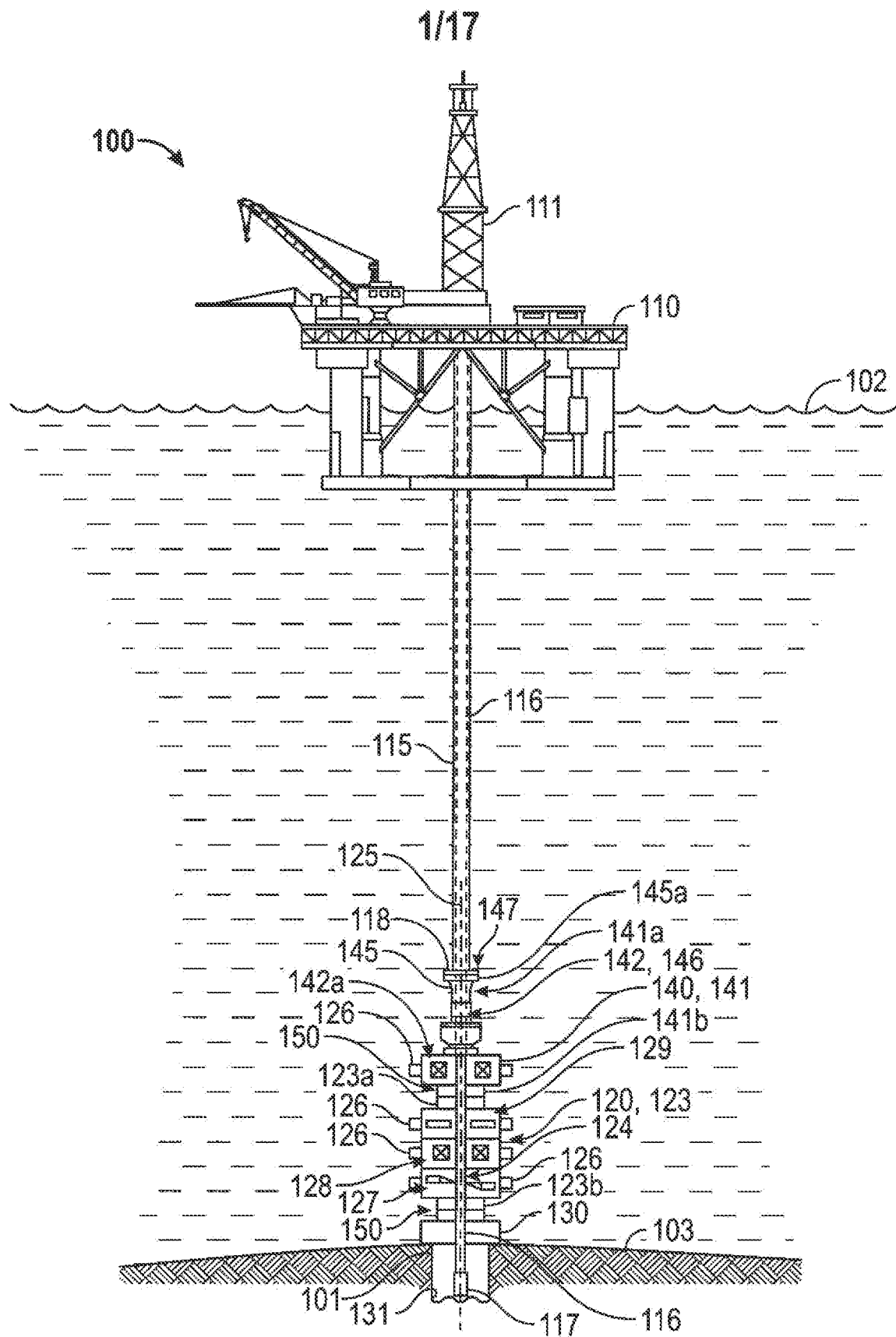


FIG. 1

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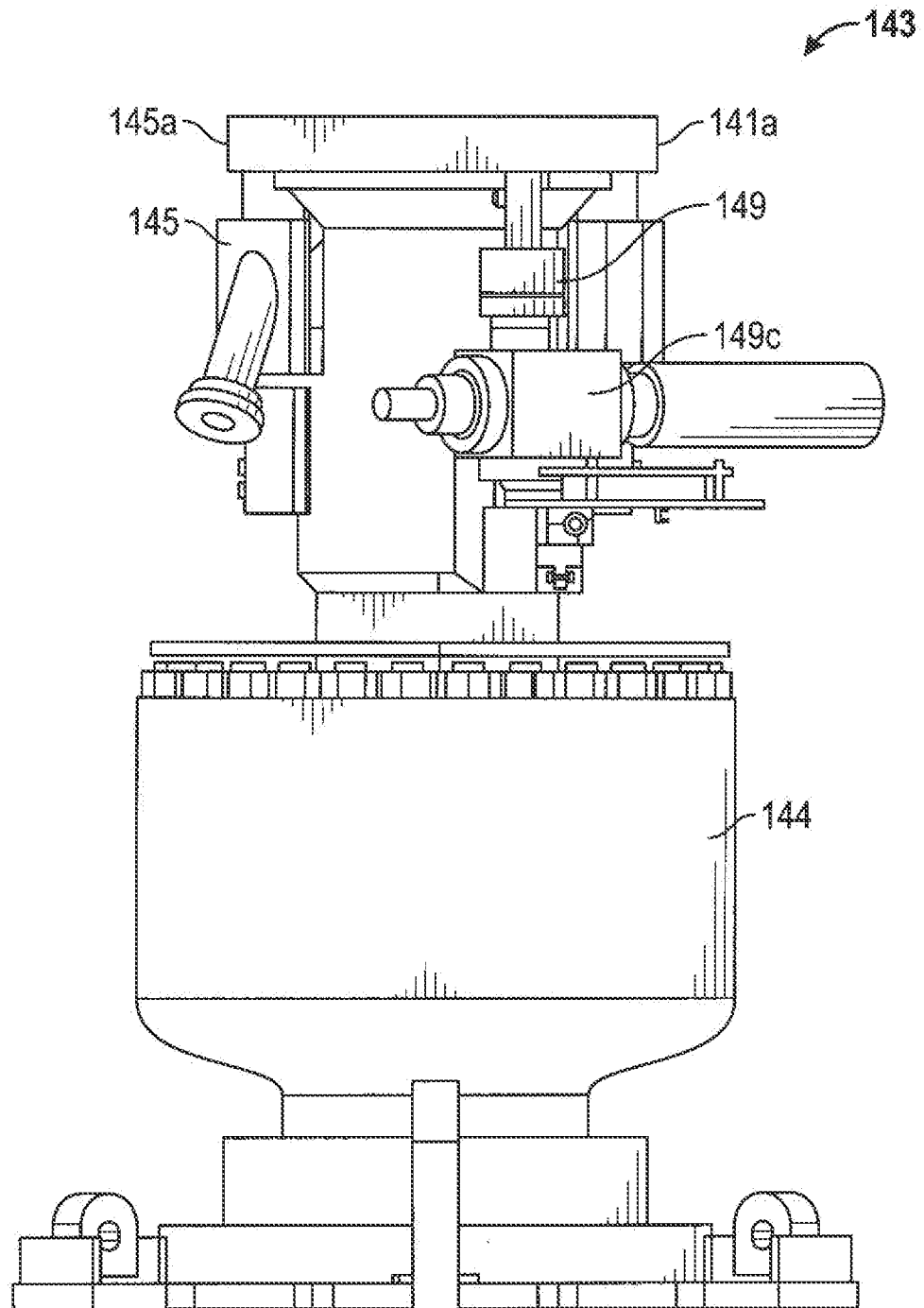


FIG. 2

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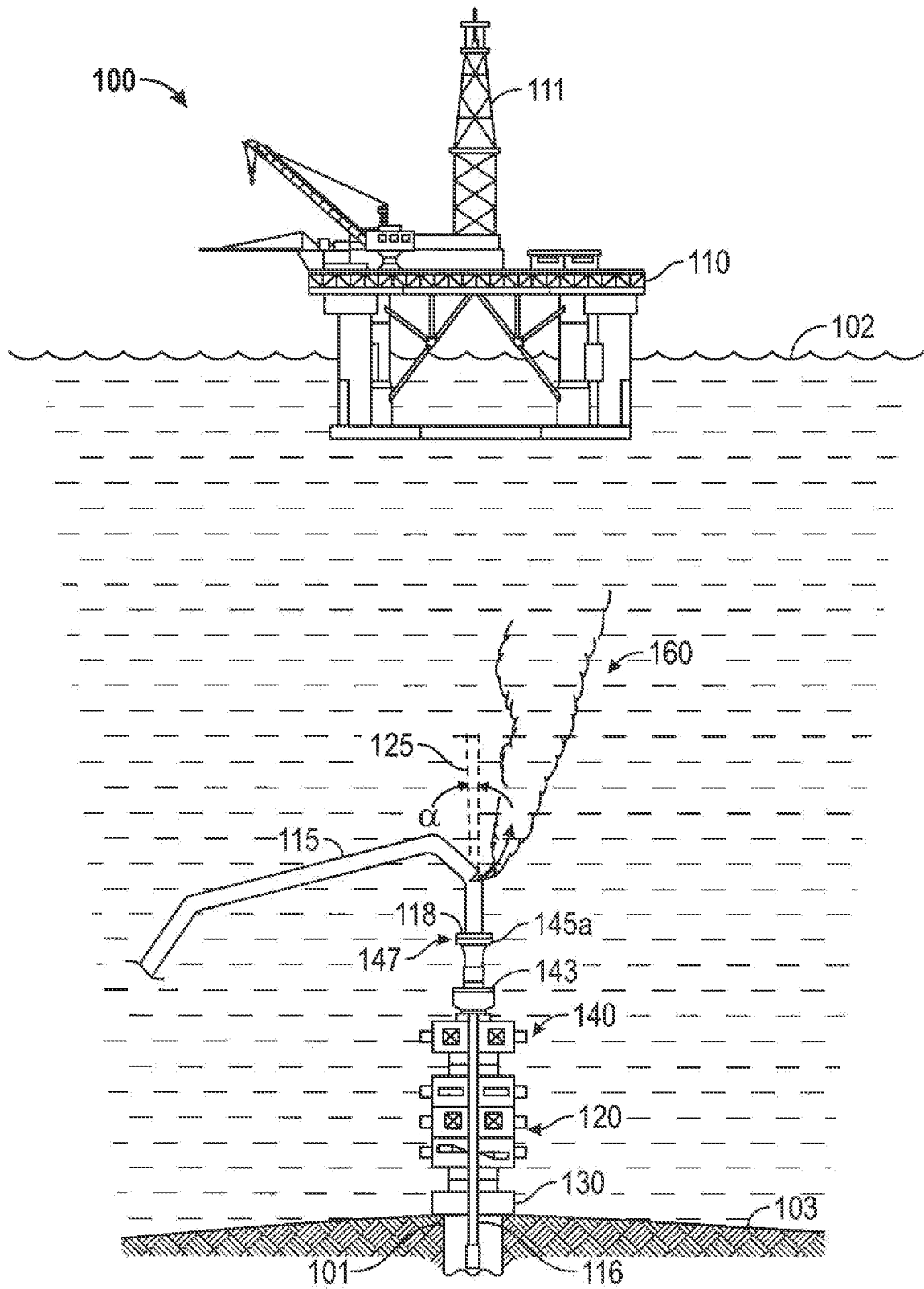


FIG. 3

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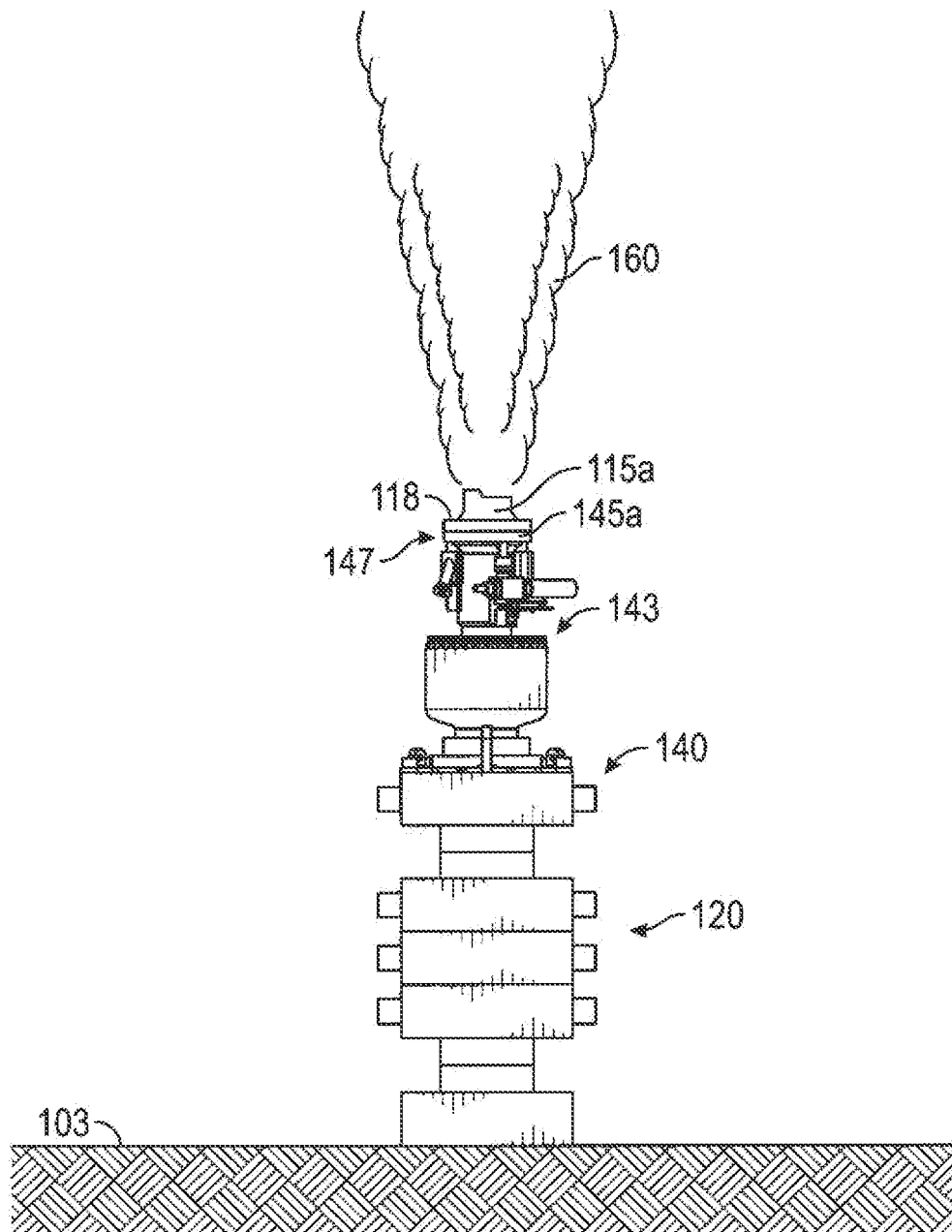
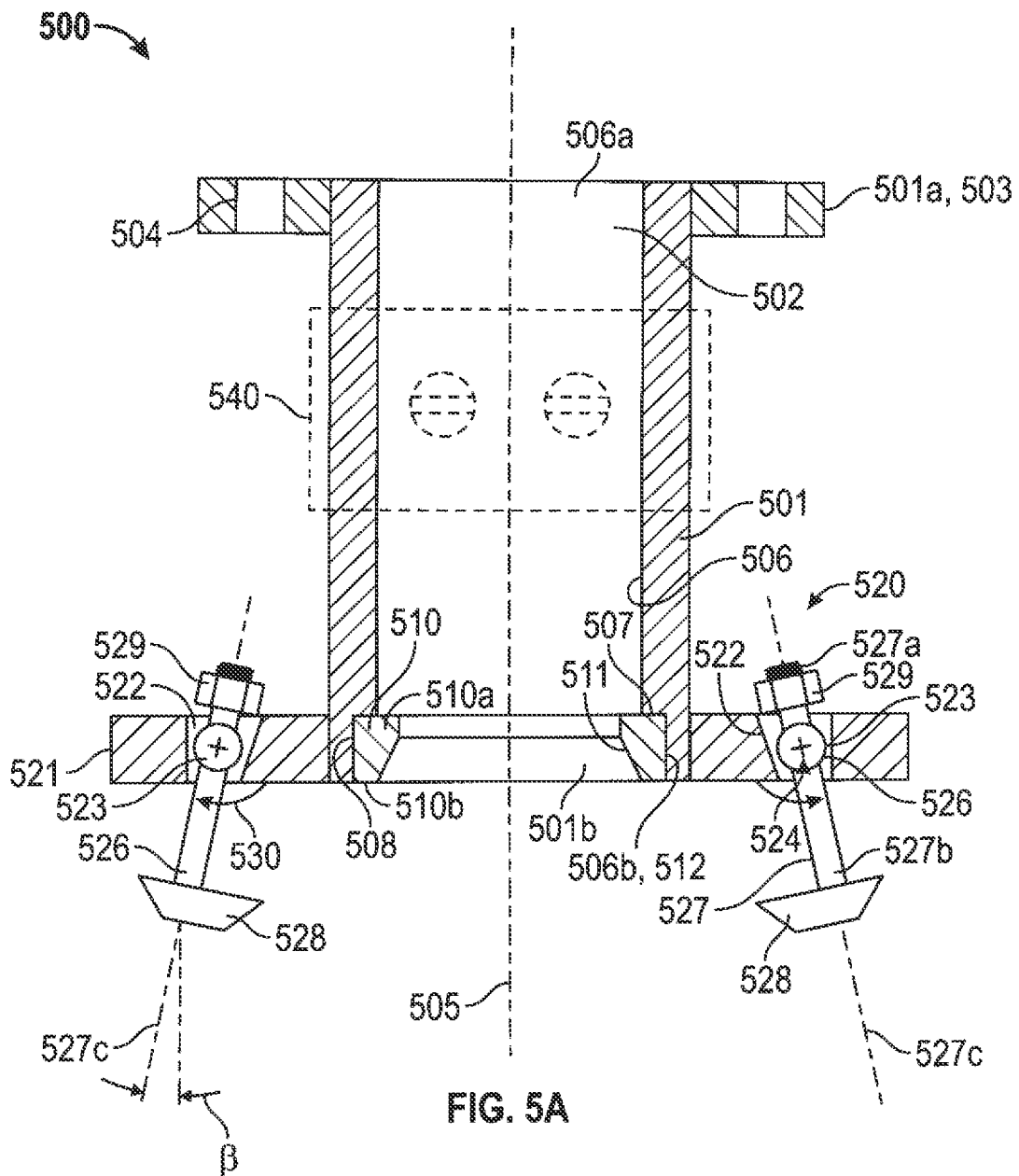


FIG. 4

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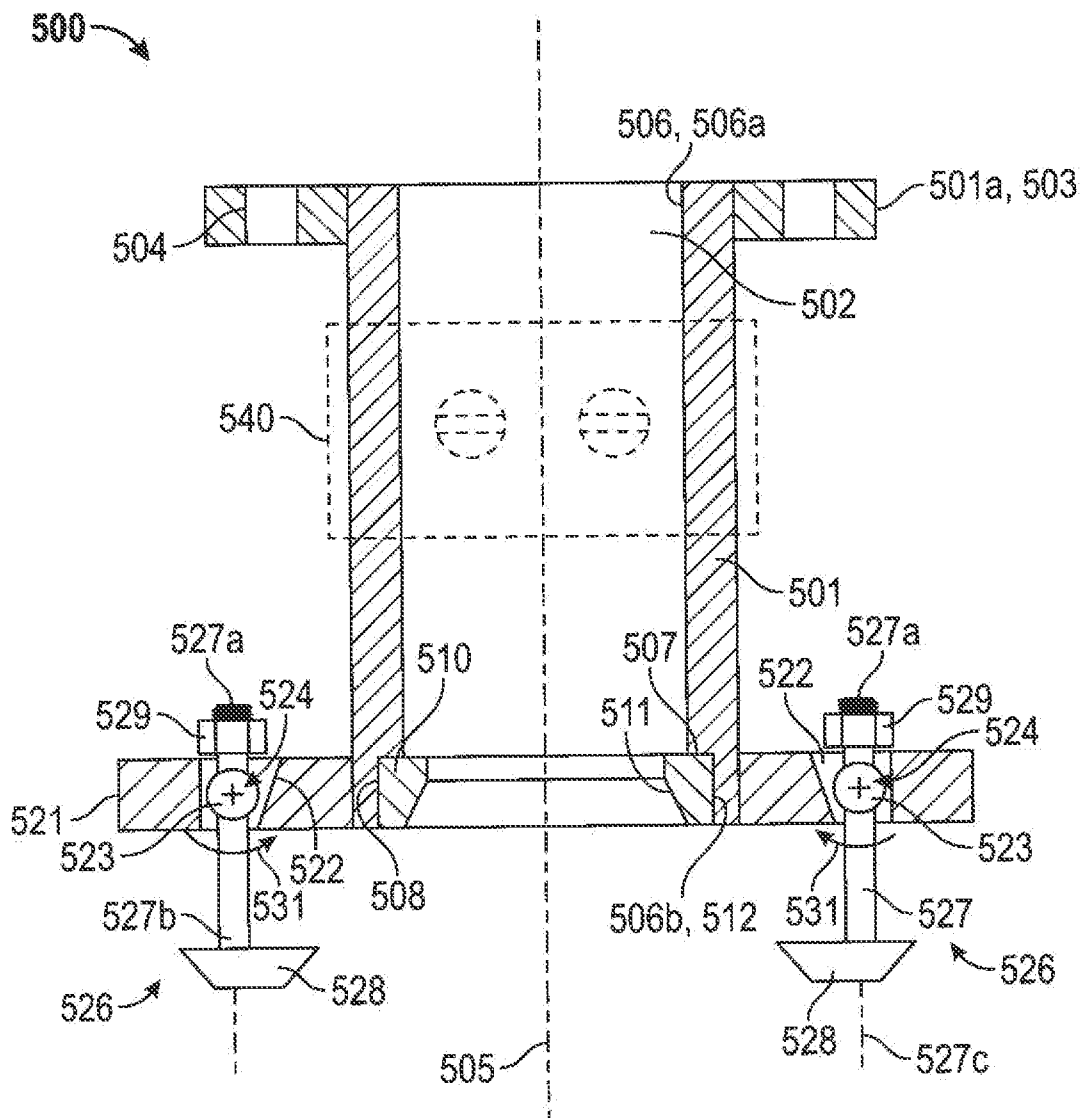


FIG. 5B

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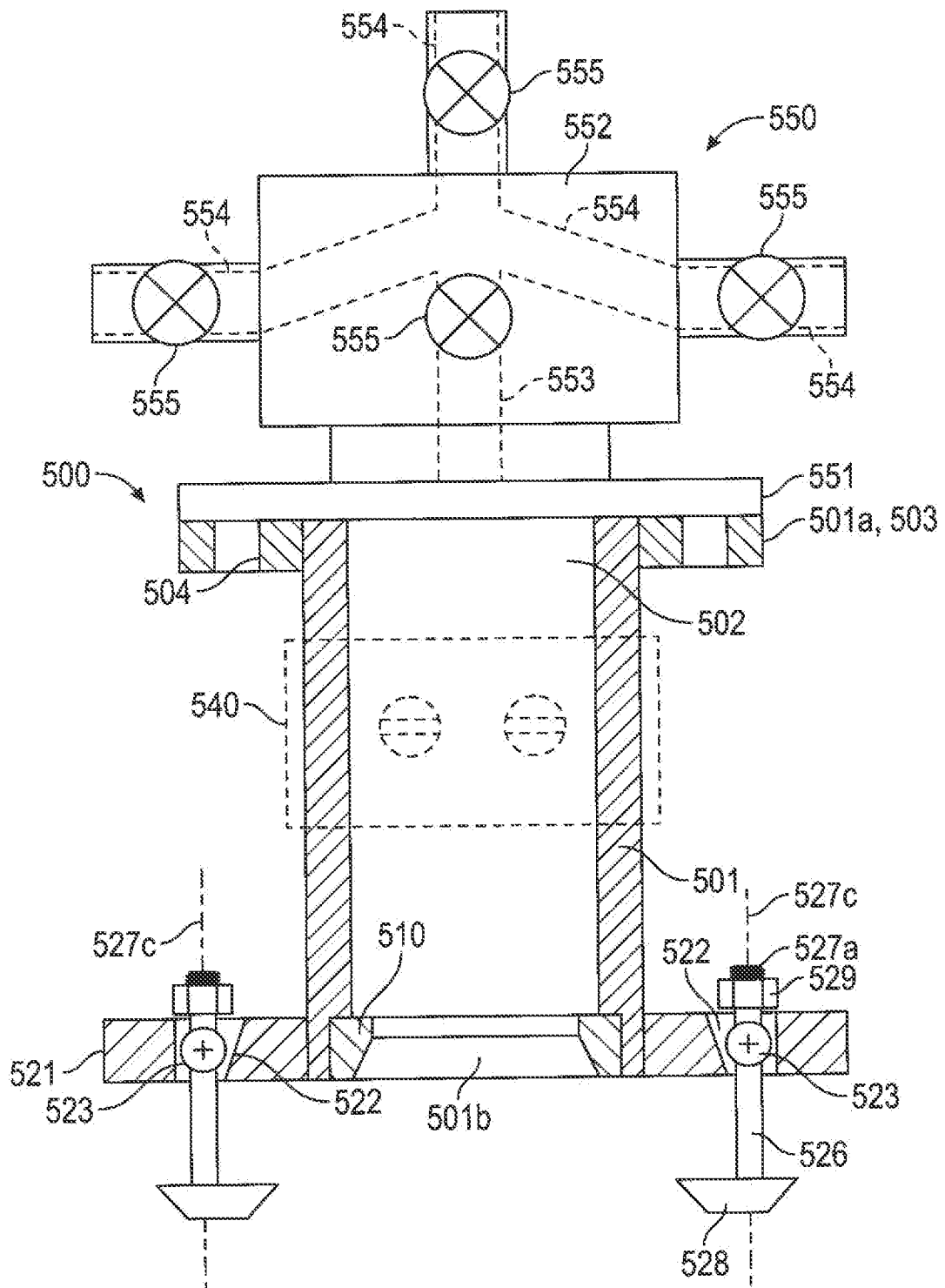


FIG. 5C

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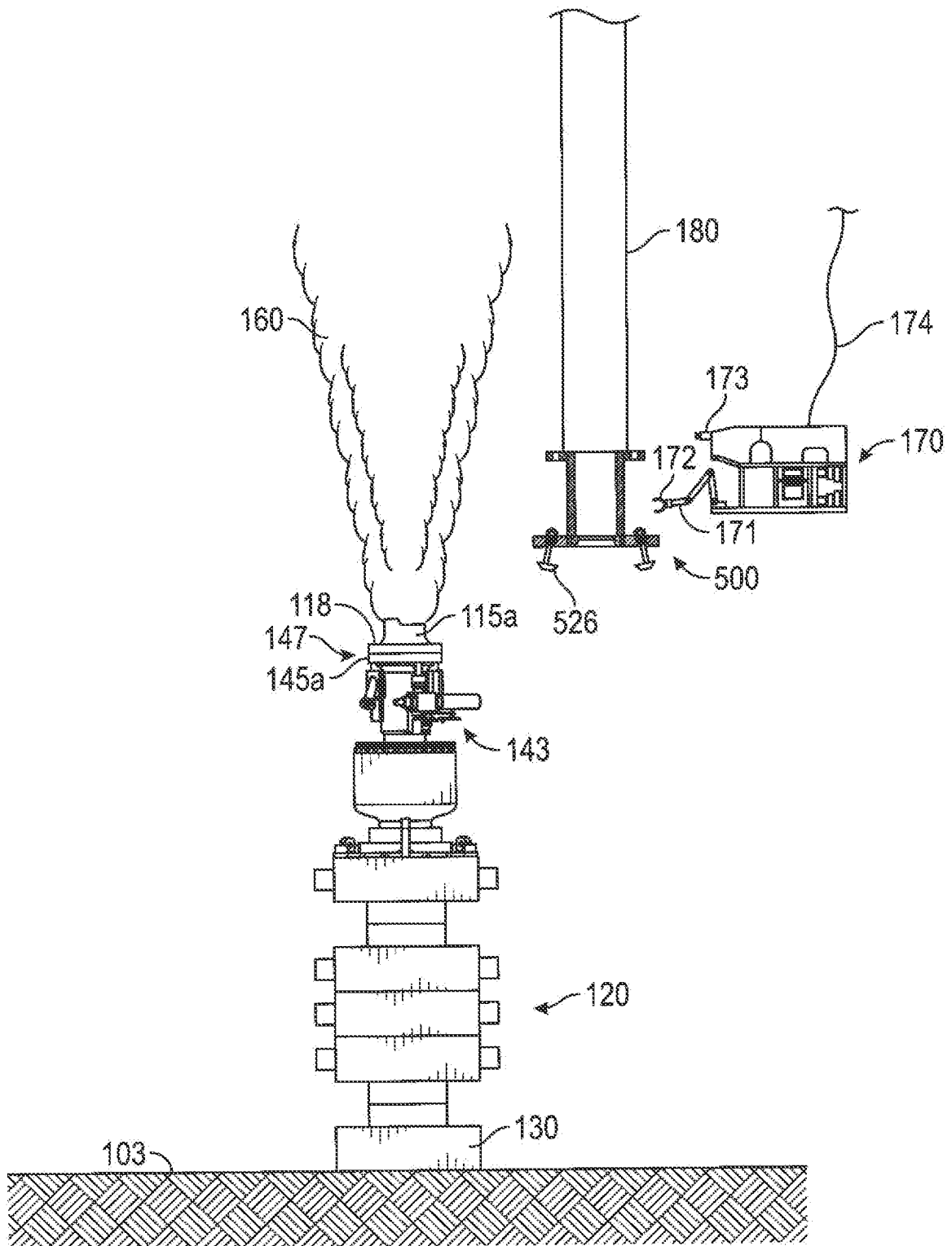


FIG. 6A

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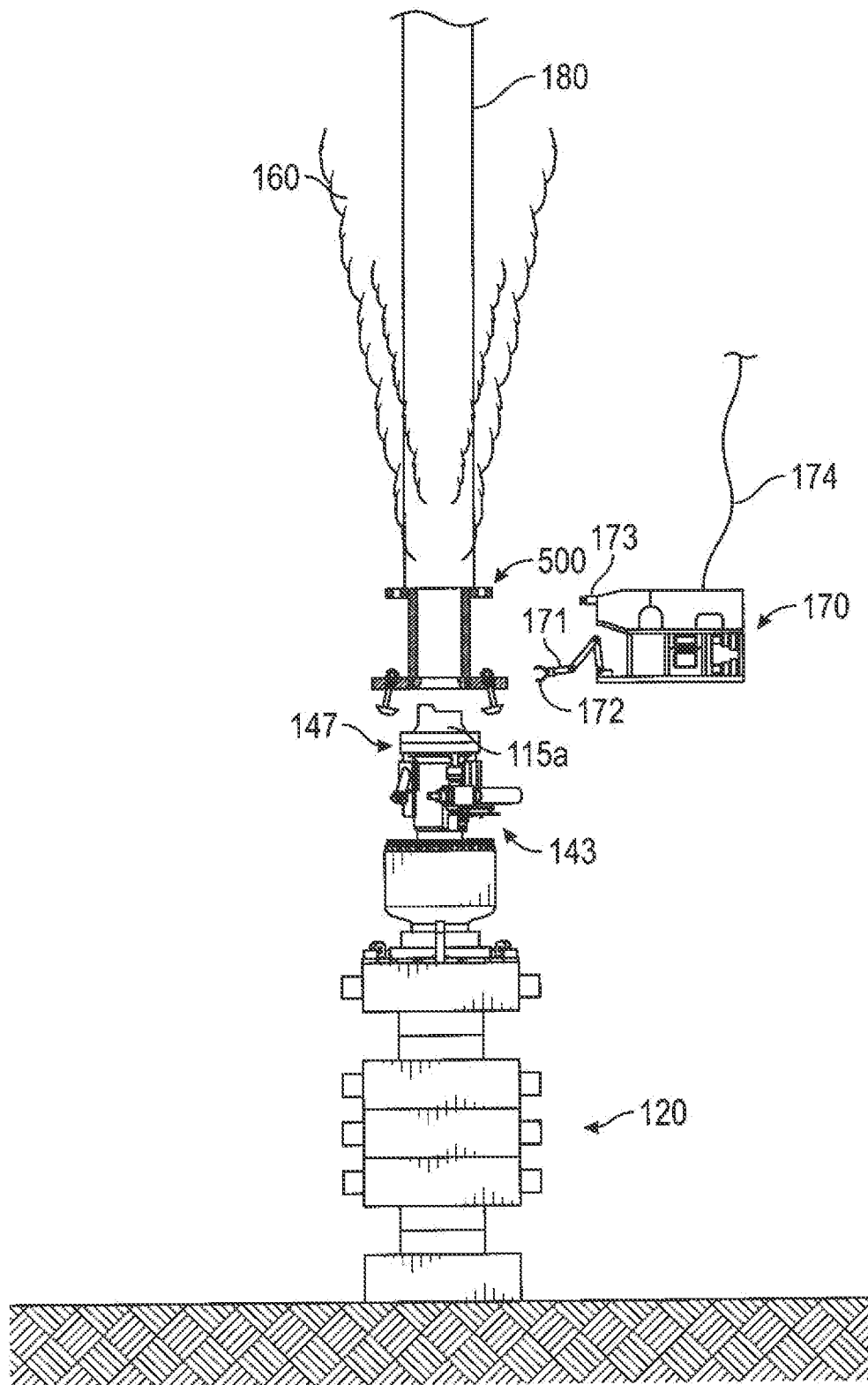


FIG. 6B

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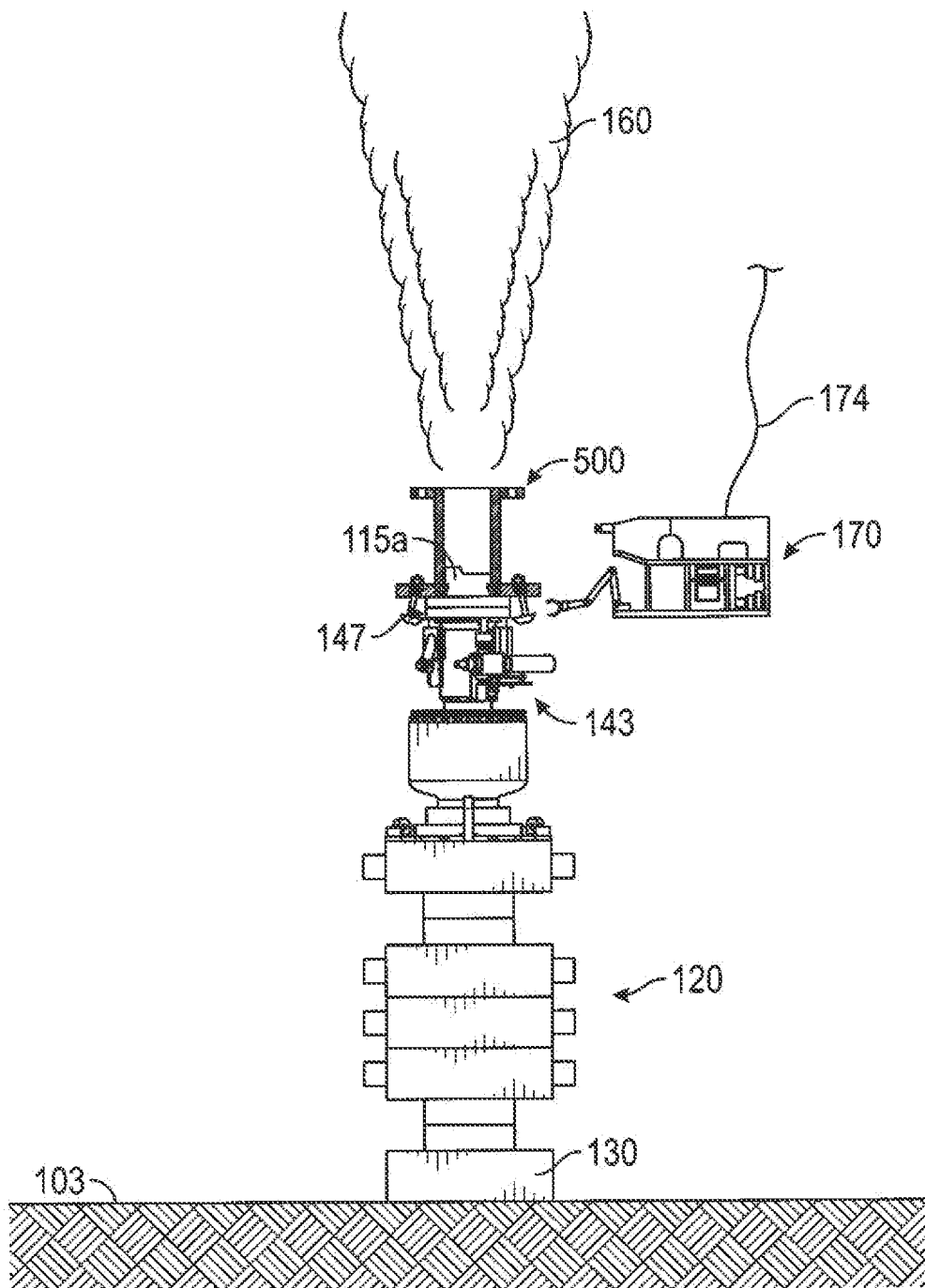


FIG. 6C

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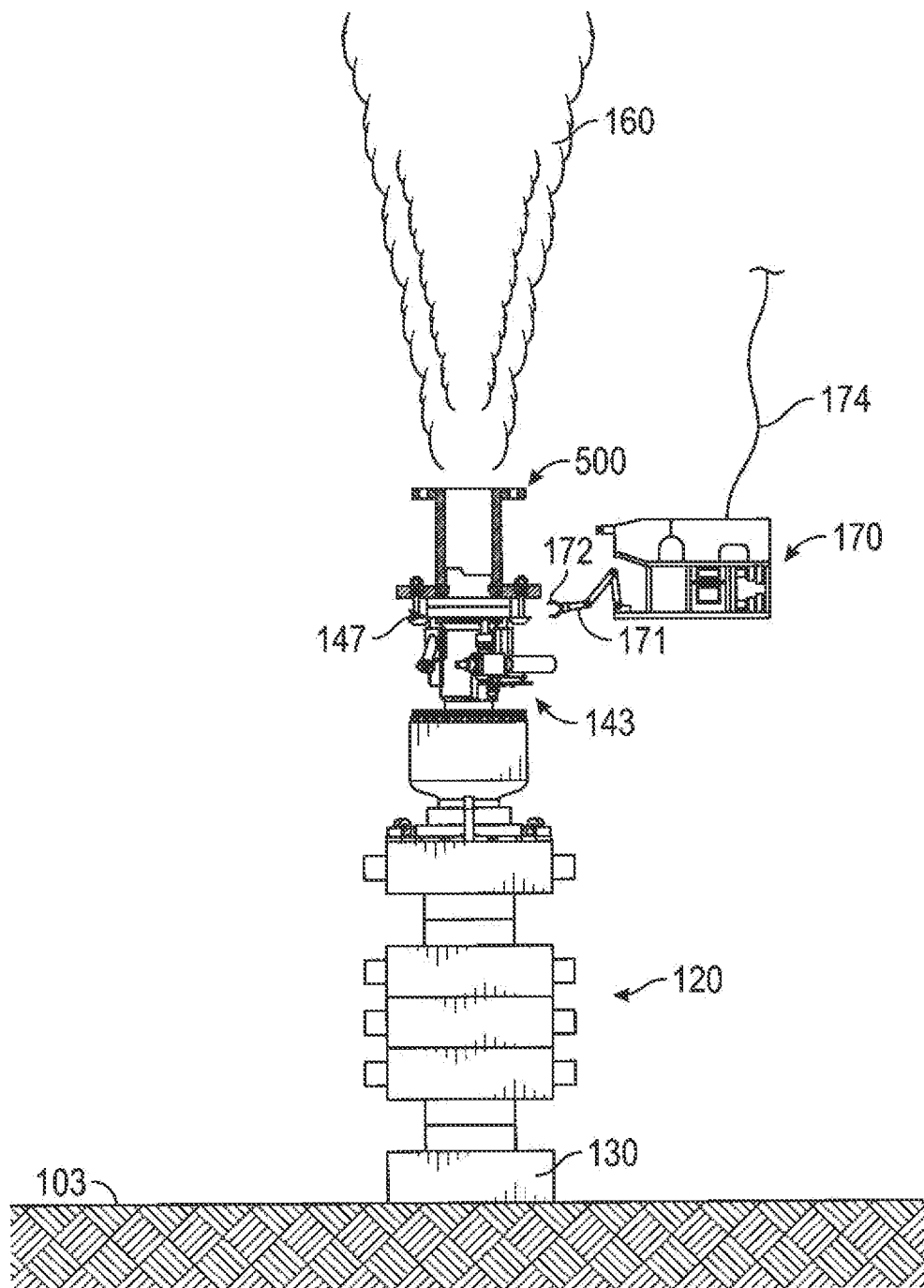


FIG. 6D

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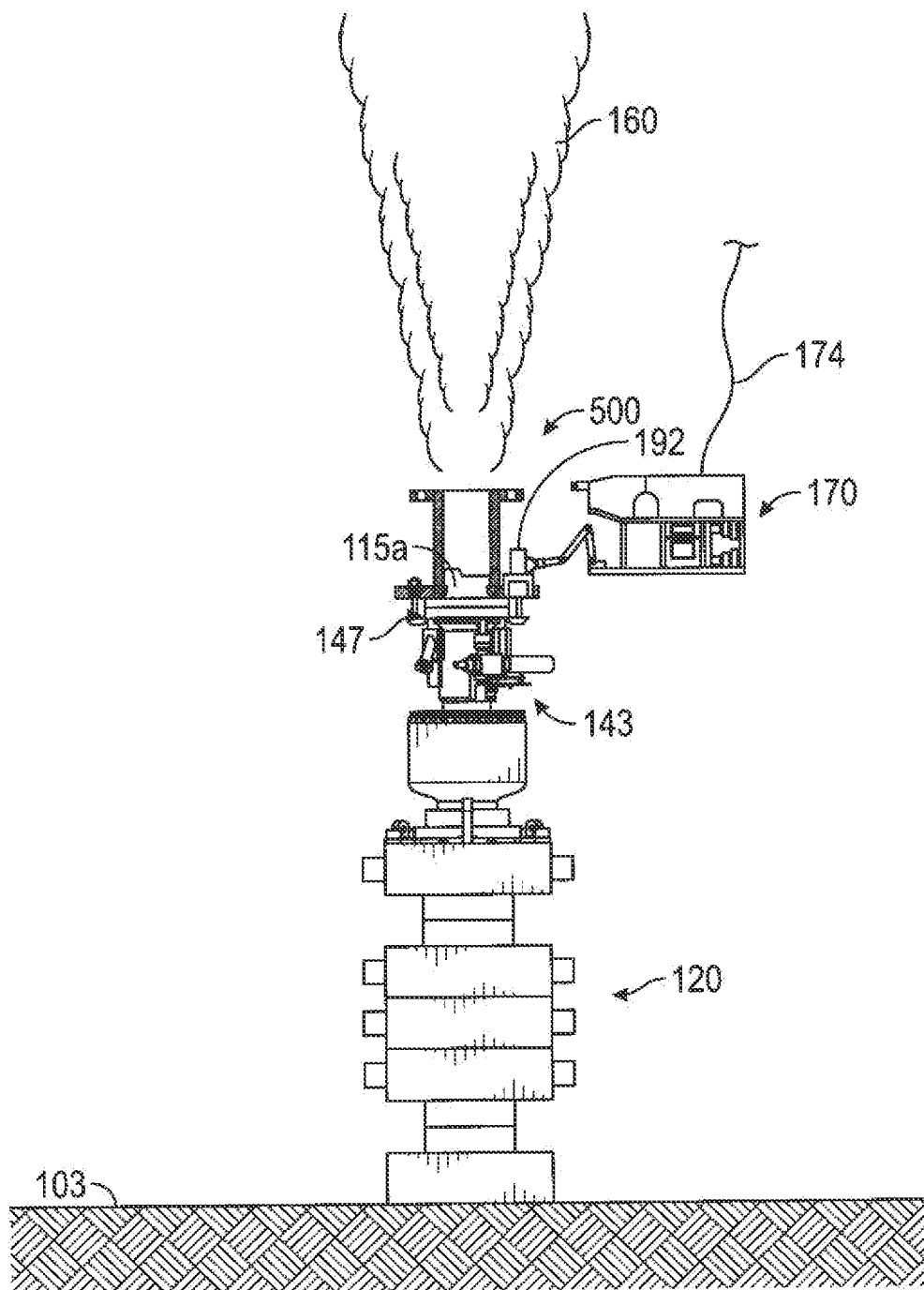
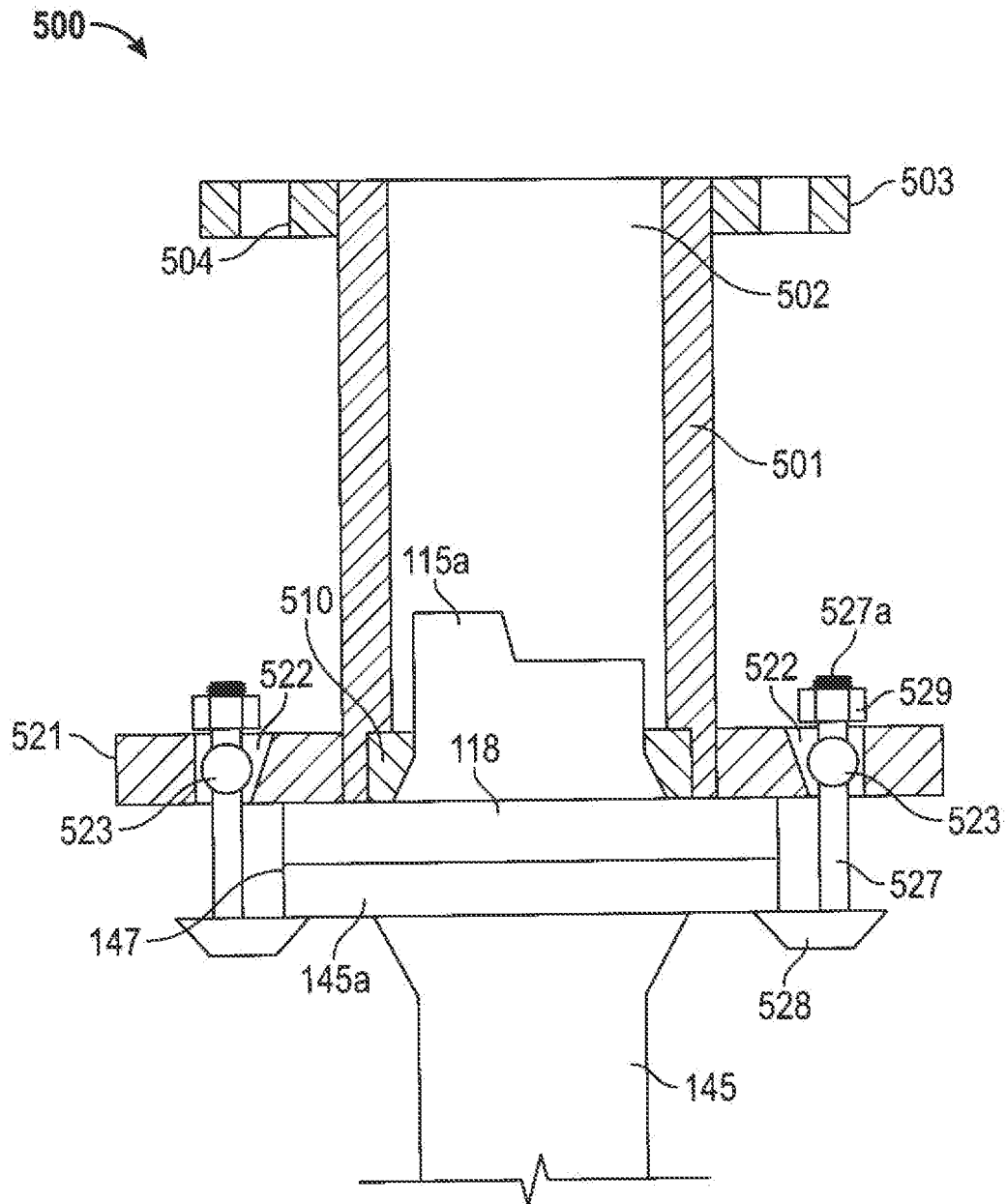


FIG. 6E

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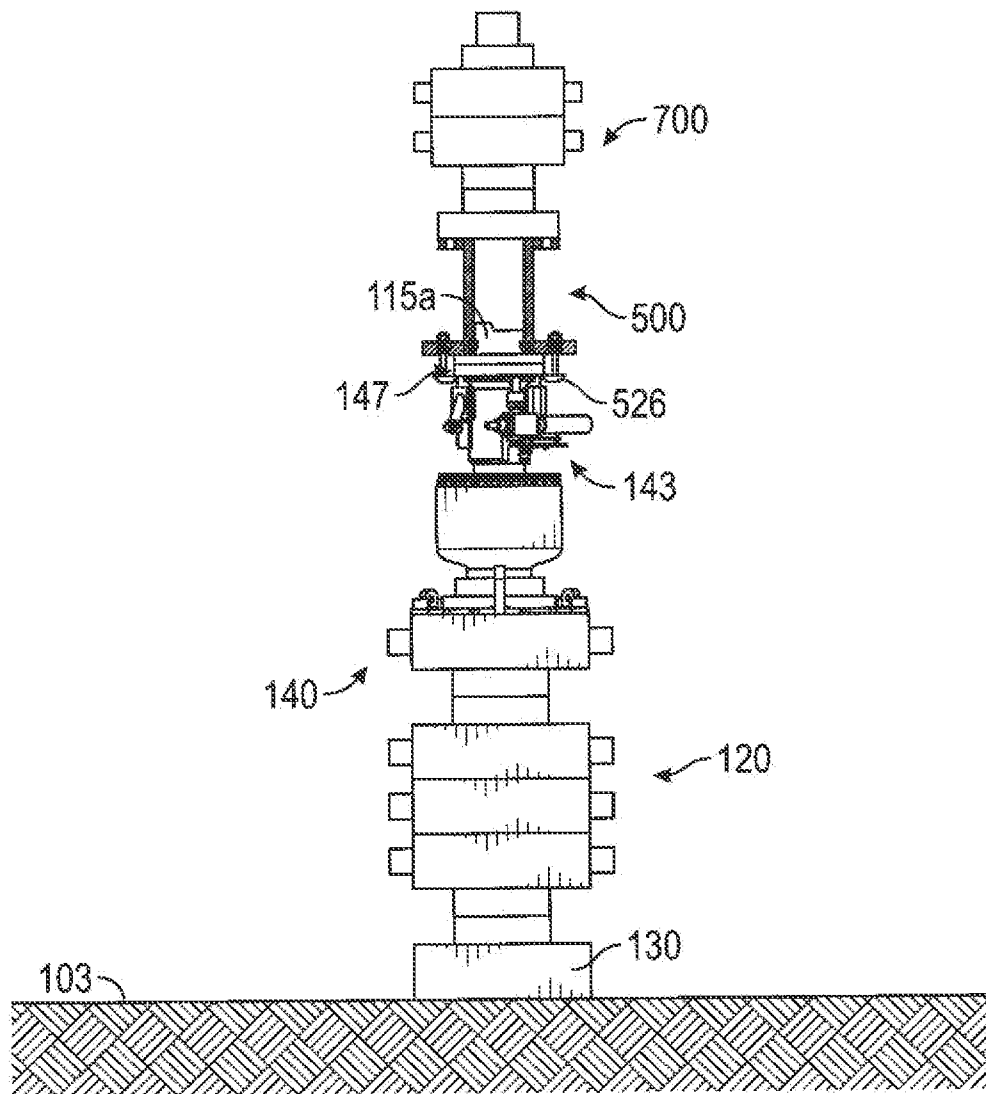


FIG. 7

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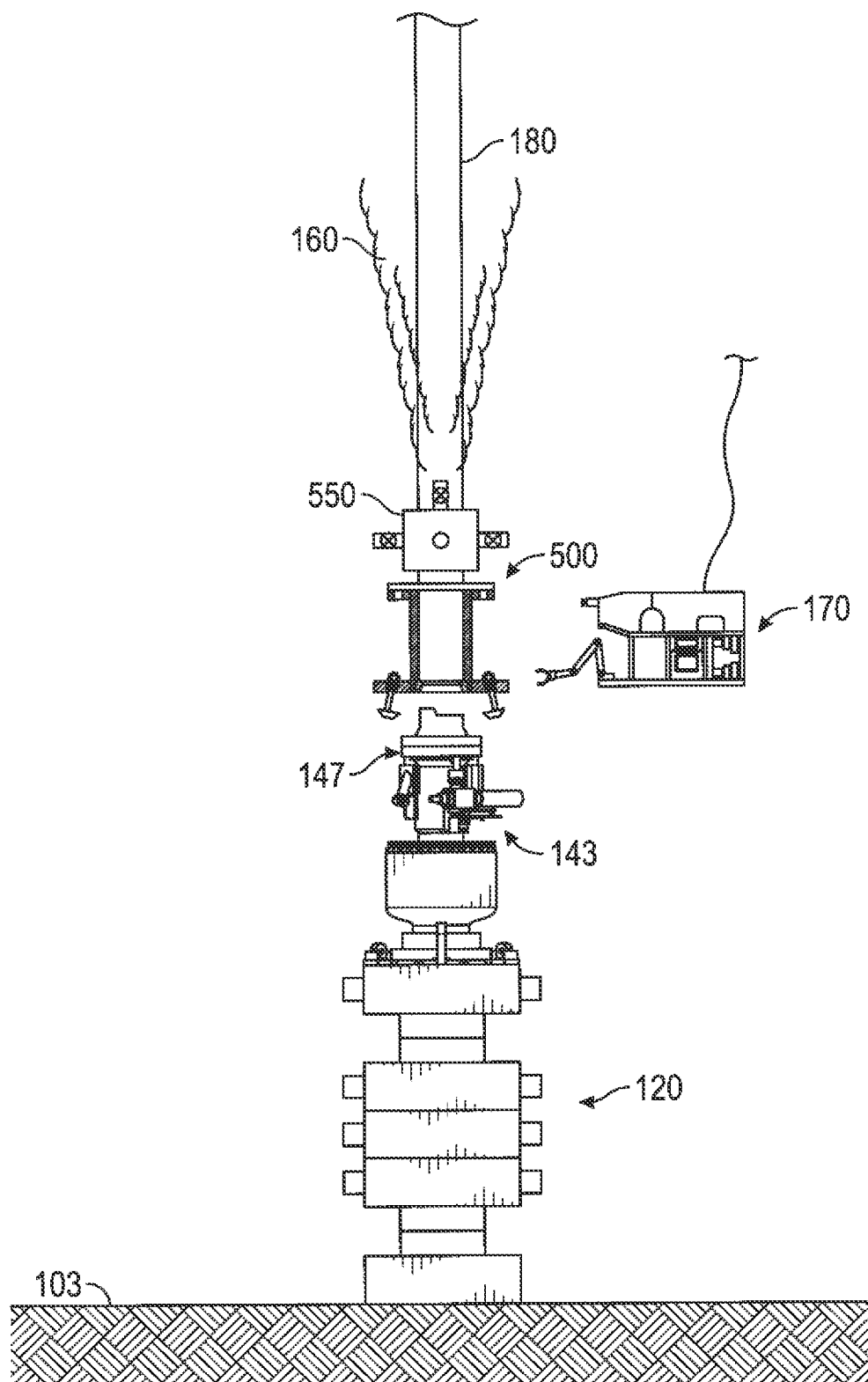


FIG. 8A

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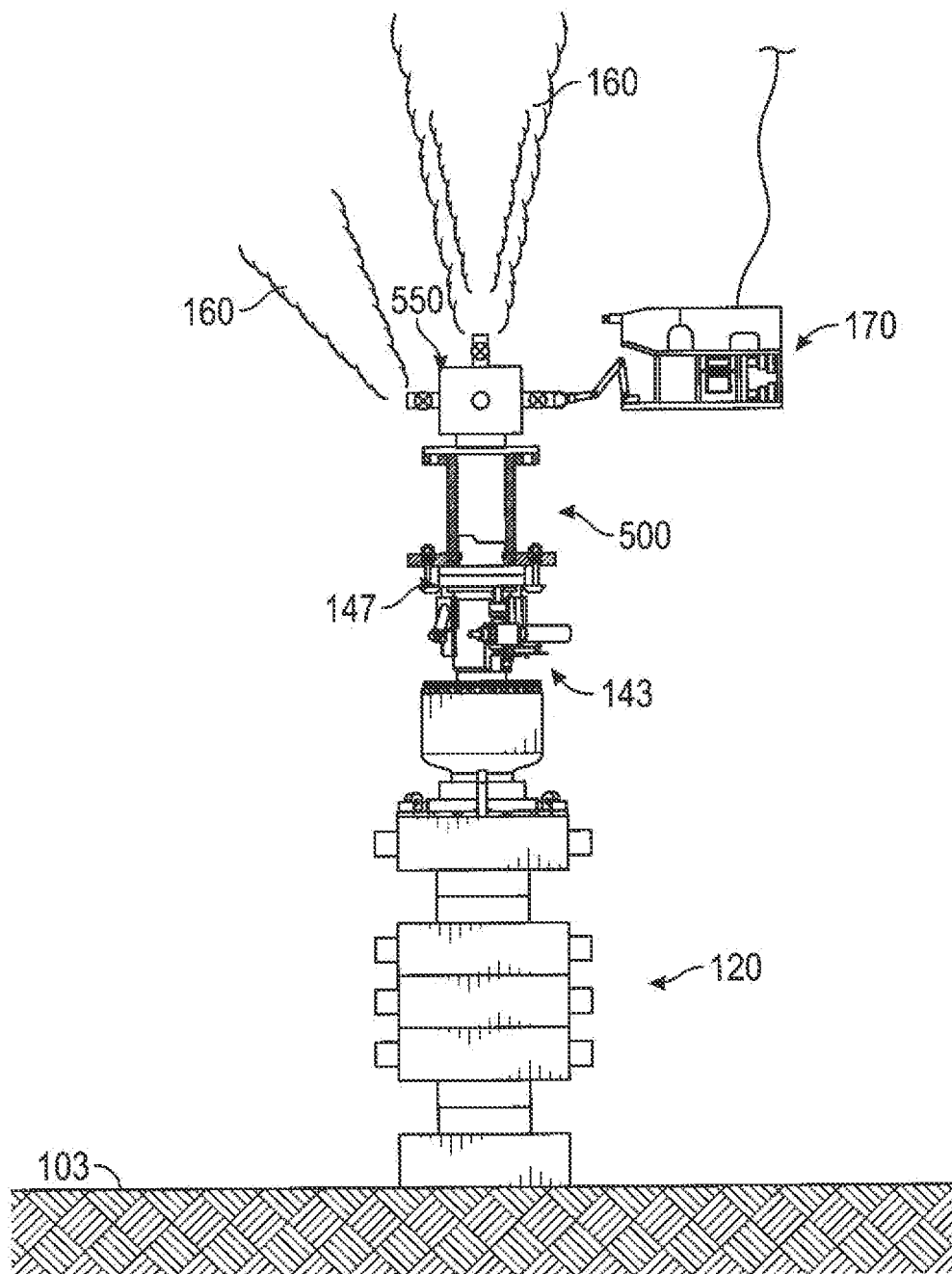


FIG. 8B

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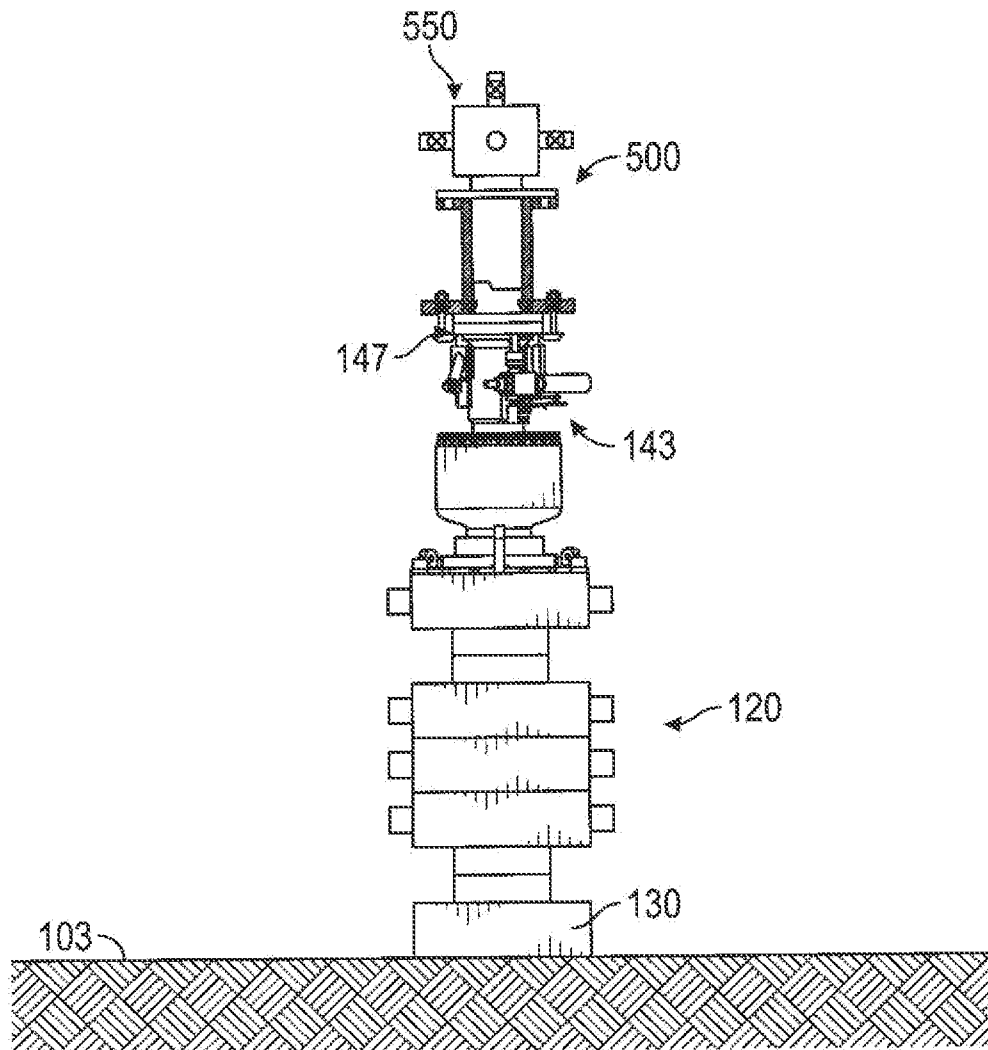


FIG. 8C

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2012/043291

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B43/01
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

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 4 708 376 A (JENNINGS CHARLES E [US] ET AL) 24 November 1987 (1987-11-24) figures 1-4 the whole document -----	1,12-26
X	US 5 971 076 A (TAYLOR WILLIAM M [US] ET AL) 26 October 1999 (1999-10-26) the whole document -----	1
X	ANONYMOUS: "Methods That Have Been Tried to Stop the Leaking Oil", NEW YORK TIMES,, 25 May 2010 (2010-05-25), pages 1-9, XP007921043, page 5 the whole document ----- -/--	21,26



Further documents are listed in the continuation of Box C.



See patent family annex.

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Date of the actual completion of the international search

27 September 2012

Date of mailing of the international search report

16/10/2012

Name and mailing address of the ISA/

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Authorized officer

van Berlo, André

INTERNATIONAL SEARCH REPORT

International application No

PCT/US2012/043291

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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A	US 2 793 700 A (ECKEL JOHN E) 28 May 1957 (1957-05-28) figures 1-3 -----	1,6
A	US 3 206 227 A (TODD WILLIAM L) 14 September 1965 (1965-09-14) abstract; figures 6,7 -----	1

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No

PCT/US2012/043291

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US 5971076	A	26-10-1999	NONE	
US 2003168857	A1	11-09-2003	NONE	
US 2793700	A	28-05-1957	NONE	
US 3206227	A	14-09-1965	NONE	